



Annual Planning Outlook

Ontario's electricity system needs: 2023-2042

December 2021

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Foreword

The Annual Planning Outlook (APO) provides an assessment of Ontario's energy landscape to help understand potential changes in demand and available supply that will assist the IESO in shaping its plans to meet future needs. It is the first step in an annual cycle aimed at ensuring a reliable energy supply for the future.

This year, economic and population growth and an increasing focus on electrification are shifting the province's electricity system into a period of sustained demand growth, requiring action on a number of fronts.

As this report shows, demand for electricity is forecast to rise at rates not seen in many years. Economic growth coming out of the pandemic, along with electrification in many sectors, is driving energy use up across the province. These trends also bring with them new levels of uncertainty. The demand forecast, which is higher than that projected in last year's APO, may continue to be impacted by ongoing economic and policy changes, as well as evolving consumer preferences.

On the supply side, nuclear refurbishments and retirements, as well as expiring contracts, are creating medium-term capacity shortfalls. While some of this need will be managed by new commitments to existing supply through competitive mechanisms, there are also opportunities, particularly over the longer-term, to open the system up further to new supply and demand-side options and ways to procure and integrate them.

With these dynamics in play, the IESO has recalibrated its activities so that it can continue to deliver on its core mandate to ensure a reliable and affordable energy service for years to come.

Through its Resource Adequacy Framework, the IESO has established a multipronged approach to address reliability needs identified in the APO. This framework provides clarity around how it expects to meet those needs, so that the sector can anticipate and respond accordingly.

With the release of the first Annual Acquisition Report (AAR) in July, the IESO set out the steps it will take to meet reliability needs across a range of timeframes.

The Capacity Auction, which adjusts to changing energy needs from one year to the next, now secures capacity with minimum thresholds all year round, providing certainty and continuity to suppliers.

A first-ever medium-term RFP for up to 750 MW of unforced capacity (UCAP) is expected to be issued in early 2022 to bridge capacity gaps created by expiring contracts. This RFP will be open to existing generators and storage facilities whose contracts are expiring. This effort will maintain reliability, as the system prepares for greater transformation.

With more significant needs emerging in the middle and latter part of this decade that cannot be satisfied with existing resources alone, an RFP is expected to be launched in 2022 with a longer commitment period to allow a broad range of technologies to compete on a level playing field.

Upcoming RFPs will also ensure that resources are addressing needs where they are happening. Unique pockets of demand are emerging in different regions across the province – resulting from local economic growth, changes in local supply or even large electrification projects. These needs are identified with recommendations for transmission, supply and demand-side solutions through the IESO’s planning processes. Planning efforts provide a platform for municipal government and Indigenous communities to weigh in on needs, and these efforts are evolving to consider potential local solutions or non-wires alternatives to traditional transmission and supply solutions.

The longer-term RFP complements the IESO’s ongoing effort to enable the contribution of non-emitting forms of supply and unleash new opportunities for local energy projects and distributed energy resources.

The APO assesses the evolving energy sector on an ongoing basis, pointing to what adjustments are needed to ensure reliability. As Ontario’s electricity system continues on its path of fundamental transformation, the speed of change will be influenced by public policy, growing experience and improvements in new technologies, consumer preferences and economic drivers. This report, and the actions that follow, provide a window into the scope and scale of that change.

Lesley Gallinger

President and CEO

Independent Electricity System Operator



Key Findings

The APO is updated annually to provide the most current information available, and its conclusions are informed by regular feedback from a wide variety of stakeholders, as well as ongoing economic and policy considerations.

Consistent with the needs forecasted in the 2020 APO, the 2021 APO is characterized by some notable findings:

Ontario is entering a period of increasing electricity demand.

With the pandemic recovery well underway, the IESO's forecasts show steady average growth of about 1.7 per cent a year. Continued robust growth in the agricultural sector is coupled with economic recovery incentives that are supporting potential new sources of electricity demand in the mining and steel sub-sectors. In addition, decarbonization measures are driving strong transportation electrification over the long-term.

Future policy decisions, customer choice and economic growth mean long-term demand has the potential to be even higher.

Many things that affect the electricity sector are quickly evolving. As such, predicting the timing, location and scale of increases in electricity demand is becoming more challenging. In light of these uncertainties, a high demand scenario forecast has been developed to reflect factors, such as government policy, changing customer preference and industrial projects, that could increase demand by as much as 10 per cent over the reference scenario in the coming decades.

Ontario's supply mix could look very different in coming years.

The IESO's resource outlook shows the potential for considerable change through the 2020s and early 2030s due to the combined effect of nuclear retirements, ongoing nuclear refurbishment outages, and expiring supply contracts and commitments. Evolving carbon policies could also result in less gas-fired generation, while new technologies such as distributed energy resources, storage and demand response could take on greater prominence in the system.

Projected demand from electrification of transportation is forecast to grow an average of nearly 20 per cent a year over the outlook period.

The transportation sector is seeing commitments for a number of large transit electrification projects, as well as government incentives for both industry and consumers, and an ongoing shift to EV offerings from auto makers. All of these elements are contributing to increasing projected demand that rises rapidly in the early 2030s. An upcoming in-depth analysis of electrification in Ontario will help the IESO ensure the province is prepared for the growing need.

Accelerated growth is taking place in parts of the province that will need transmission support or local supply.

With the retirement of the Pickering Nuclear Generating Station (NGS) and the refurbishment of Darlington NGS, Toronto and areas east of the city are expected to account for the majority of Ontario's needs starting mid-decade. Greenhouse growth, mining and industrial electrification are also creating pockets of demand throughout the province. Integrated planning processes, including system planning and regional and community engagements, are working to identify and develop cost-effective solutions, such as targeted conservation and demand management programs and initiatives, that will support the provincial grid and local and regional needs. Work to improve the processes for considering non-wires alternatives within regional electricity planning is also being pursued.

Broader electrification is expected to lead to significant economy-wide GHG emissions reductions in Ontario over the next two decades.

Electrifying technologies across various sectors, particularly transportation, manufacturing and industry, could mean real progress in reducing overall provincial emissions. Projections for just two elements of the APO's electrification forecast – electric vehicles and a single steel plant furnace upgrade - estimate emissions reductions of more than 18 megatonnes (Mt) by 2040. Though just a small piece of the broader decarbonization picture, this would more than offset emissions from the electricity sector alone.

Ontario's Emerging Needs

Through the implementation of the Resource Adequacy Framework, capacity needs that have been identified will largely be met through to 2028. However, nuclear retirements and refurbishments create a capacity gap in the mid-2020s that will require careful consideration and potential actions. Needs begin to climb substantially by 2029 and continue throughout the next decade due to increases in demand and resources reaching the ends of their contracts.

Potential energy shortfalls are forecast to begin in 2026 and grow substantially over the next 20 years if today's supply is reduced through expiring contracts. If current supply levels are maintained, energy needs are not forecast to emerge until the late-2030s. New non-emitting resources that can supply energy or reduce or more actively manage demand will be required to address these needs.

A Timeline of Growing Electricity Needs

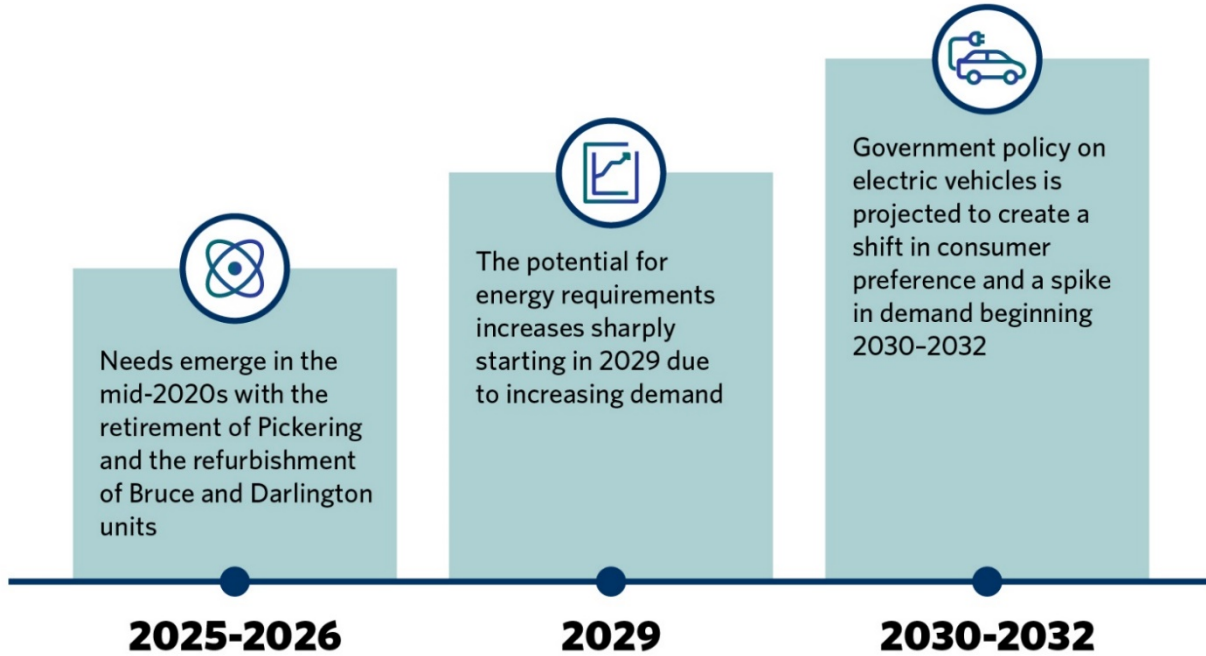




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1. Introduction

1.1 How to Interpret the Outlook

Grounded in data and market intelligence, the IESO's Annual Planning Outlook 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 energy future in Ontario. The findings will inform the development of actions described in the IESO's 2022 Annual Acquisition Report including providing inputs into the target-setting process for the IESO's upcoming procurements.

This outlook covers the period from 2023-2042.

The APO is intended to provide stakeholders, including market participants, with the data and analyses 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.

1.2 Report Contents

Chapter 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.

Chapter 3 (Supply and Transmission Outlook) assesses the availability of resources over the outlook period and the ability of existing bulk transmission interfaces and interties to continue to supply electricity when and where it is needed. This chapter 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.

Chapter 4 (Resource Adequacy) compares the demand forecast with anticipated resource performance, taking into account transmission constraints and risks such as extreme weather conditions and equipment outages. This chapter also looks at Ontario's energy adequacy, and the impact of energy production on imports and exports.

Chapter 5 (Transmission Security) explores system needs arising from the requirement to meet transmission planning standards. These needs will be referred to as transmission security needs in this report and could be more or less restrictive than the resource adequacy needs.

Chapter 6 (Integrating Electricity Needs) builds on the outcomes and findings of the previous chapters, and summarizes the system needs discussed in Chapters 4 and 5.

Chapter 7 (Outcomes and Other Considerations) concludes with a discussion on 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.

Finally, Chapter 8 (Uncertainties) outlines the potential impact of a number of significant yet highly uncertain developments on rising electricity demand and capacity needs over the course of this outlook period.

1.3 Changes/Updates Since Last Publication

This outlook supersedes the outlook published in December 2020.

In 2020, the IESO held a stakeholder engagement session focused on evaluating the appropriate level of non-firm imports to be used in resource adequacy assessments. The result was a proposal to include non-firm imports in the IESO's resource adequacy assessments starting in the 2021 APO. This current supply outlook includes 250 MW of non-firm imports in the summer and 240 MW in the winter, as compared to zero in the last APO. The IESO will continue to assess these values and may adjust them in future outlooks.

1.4 An Integrated Bulk System Planning Process

The IESO has published an overview of the high-level design for a Bulk System Planning Process (BSPP) that further consolidates the IESO's Resource Adequacy and Transmission Planning activities under a single, integrated process. The high-level design was informed by the feedback received through stakeholder engagement.

The BSPP will build on the process for developing the APO and the stakeholder engagements carried out to inform its development, and communicate the results of the APO studies. Whereas the APO process has, up to now, been focused on the outlook for demand and Ontario's resource adequacy needs, the transmission security assessments have largely been done as a series of related, but separate processes.

For example, the transmission security outlooks have been informed by individual bulk system studies, regional plans, Northeast Power Coordinating Council (NPCC) and North American Electric Reliability Corporation (NERC) regulatory compliance-driven reviews, and the experience gathered through the operation of the IESO-controlled grid and IESO-administered electricity market in real-time. Essentially, the BSPP formalizes how all of these inter-related activities fit together within a process that is aimed at ensuring Ontario's bulk power system remains reliable and secure well into the future.

Some key features of the BSPP include:

- A regular, annual cycle in which the IESO will ensure an accurate and up-to-date outlook for all system issues, including resource adequacy and transmission security. This is the "Issues Identification" cycle, and starting in 2022, it will introduce a new annual transmission planning process and improve the integration of transmission and resource planning. This process will identify the system issues to be resolved.

- Enhanced transparency around triaging system issues that can be addressed by generation vs. transmission, i.e., whether to leverage competitive mechanisms and/or explore transmission options through an Individual Bulk System Study.
- Regular opportunities to engage with stakeholders to inform and seek feedback, and the publishing of a Schedule of Planning Activities to accompany the APO. The Schedule of Planning Activities will communicate the IESO's work plans for initiating Individual Bulk System Studies to address bulk system issues.

The Schedule of Planning Activities will be reserved for when solutions are not likely to be fully addressed using the Resource Adequacy Framework, and/or when integrated planning needs are required to consider a broader range of alternatives. Individual Bulk System Studies do not exist outside of the APO nor the Resource Adequacy Framework. It is possible that bulk study recommendations could be used to acquire capacity, and in such cases, the AAR will specify how the capacity would be acquired. For system issues to be addressed by transmission or integrated solutions, there will need to be sufficient time to complete the requisite bulk studies and still implement the solution.

2. Demand Forecast

Electricity demand is forecast in this APO to grow higher than in prior outlooks, driven primarily by economic development and government policy on climate change mitigation. Notable updates include: growth from electric vehicle charging demand in the mid-2030s; northern Ontario mining expansion and primary steel producer electrification in the near-to-medium-term periods; sustained residential sector demand growth through the 2030s; and increased Industrial Conservation Initiative response over the outlook period.

Trends highlighted in prior outlooks that are continuing include: greenhouse expansion in the west-of-London area, robust economic recovery in the commercial sector, electrification of rail transit and assumed persistent delivery of conservation programs beyond the existing framework period.

Forecasting electricity demand is a challenging exercise, as it incorporates inherent uncertainties surrounding 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. To help acknowledge and mitigate uncertainties in the 2021 demand forecast, a high demand scenario has been developed and is presented in Chapter 8 – Uncertainties.

2.1 Overview

The long-term demand forecast informs system reliability and investment decisions, and sets the context for the APO, the 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.

In 2020, Ontario's electricity demand experienced significant fluctuations as a result of the COVID-19 pandemic. In the 2020 APO, the primary factor driving projected demand growth was the possible impact of the pandemic, including potential permanent and structural changes to the economy.

In this year's APO, the demand forecast represents a notable change from 2020. With the economic recovery from the pandemic well underway, primary factors driving demand are emerging electrification initiatives and growth of the economy, leading to higher electricity demand in the short, medium and long-terms.

The forecast demonstrates steady growth overall, including in the **residential** and **commercial** sectors, and continued robust growth in the **agricultural** sector. A strong

emphasis on decarbonization measures and economic recovery is also now leading to potential new sources of electricity demand in the **mining** and **steel** sub-sectors, and in the emergence of significant **transportation electrification**. Although the magnitude and exact timing of these demands is uncertain, the province is entering a time of demand growth.

Ongoing conservation and demand management programs are also factored into the forecast, which projects overall net energy demand to be 147 TWh in 2023, increasing an average of almost 2 per cent per year over the outlook period to 202 TWh in 2042, an increase of 56 TWh.

Summer and winter peak demands are expected to experience an average growth rate of approximately 1.3 and 1.8 per cent, respectively. Summer peak demand is projected to be about 24.4 gigawatts (GW) in 2023, increasing to 31.3 GW in 2042, while winter peak demand is projected to be 22.1 GW in 2023, increasing to 30.5 GW in 2042.

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

Figure 1 | Energy Demand

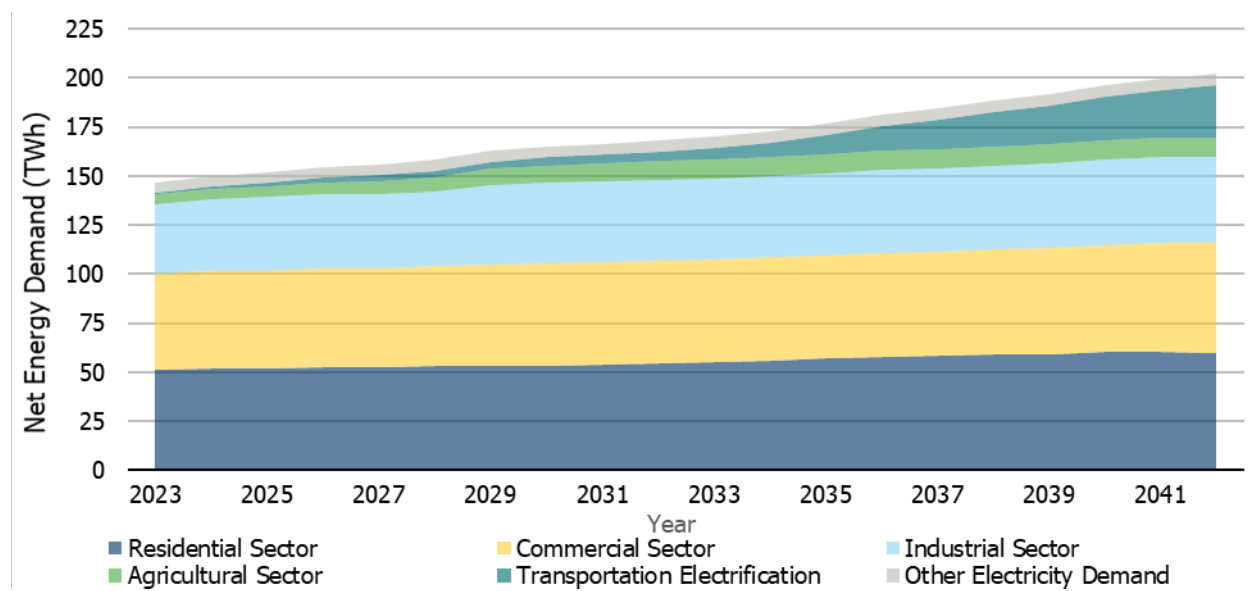
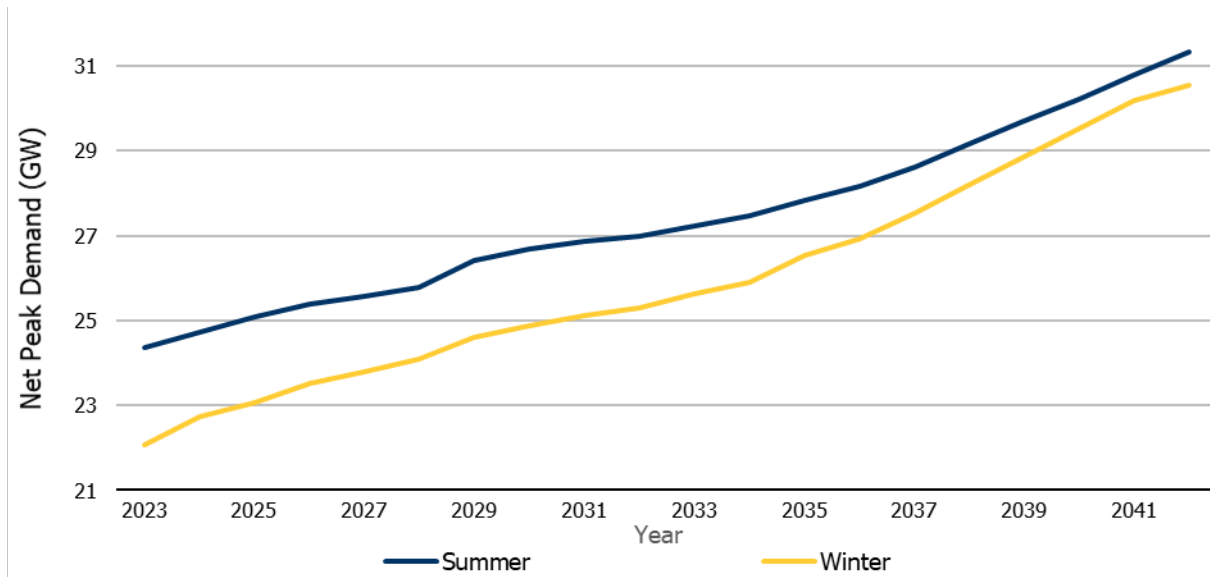


Figure 2 | Seasonal Peak Demand



2.2 Historical Energy Demand

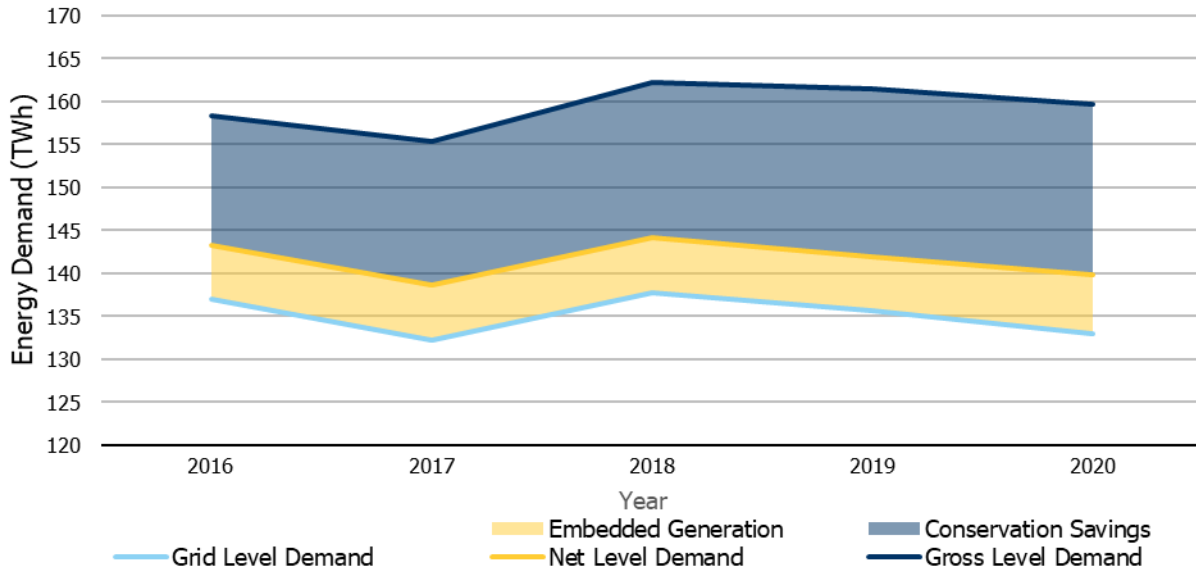
Grid-level demand¹ over the past five years has been mostly flat, ranging between 132 and 137 terawatt-hours (TWh), as shown in Figure 3.² This is primarily the result of changes in the economy, conservation program savings, and embedded generation³ all reducing the need for grid-supplied energy. Embedded generation has provided approximately 6 TWh of energy each year.

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 reduces demand through the bulk electricity system.

Figure 3 | 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 [2021 APO Demand Forecast Methodology](#).

2.3 Demand Forecast Scenarios

Demand forecasting focuses on understanding the causes of future changes in demand by examining end-uses and sector trends. However, they also reflect many dependencies and incorporate inherent uncertainty that increases with the length of the outlook period. The potential impacts of increasing distributed energy resources deployment is another factor that affects demand forecasts, and this will be explored in more detail in future APOs.

The demand forecast presented in this chapter 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, decarbonization and electrification, as well as potential economic development and policy stimulus, an unusually high level of uncertainty is present in the 2021 APO demand forecast. An assessment of these uncertainties and their potential impacts to the forecast are presented in a high demand scenario forecast in Chapter 8.

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 consumption is supported by climate change mitigation policy, stable electricity rates and increasing natural gas rates over the outlook period.

2.4.1 Residential Sector

Electricity demand from the residential sector is expected to show steady growth over the outlook period. Several factors promote this growth, including progressive immigration policies contributing to new households, a persisting level of working from home resulting in higher daily household occupancy, and continued increases in the adoption of electronics.

Overall, total sector electricity demand is forecast to grow from 51 TWh in 2023 to 61 TWh in 2042, an average annual growth rate of 0.9 per cent.

2.4.2 Commercial Sector

With the current economic recovery, electricity demand from the commercial sector is expected to be stronger and recover earlier than forecasted in the 2020 outlook. The reduction of social distancing practices and travel restrictions is increasing near-term electricity demand for the office, education, retail, restaurant and lodging hospitality sub-sectors. Post-recovery, demand growth is expected to moderate over time.

Over the course of the outlook period, a continued shift to a digital economy has been accelerated due to the pandemic, which impacts electricity demand in many sub-sectors; an emerging shift to hybrid office work models moderates electricity demand in offices; meal preparation and delivery services reduce demand in restaurants; and e-commerce results in a decrease in electricity demand in physical retail spaces, but an increase in warehouses.

Overall, total sector electricity demand is forecast to grow from 49 TWh in 2023 to 57 TWh in 2042, an average annual growth rate of 0.9 per cent.

2.4.3 Industrial Sector

Ontario's industrial sector is facing significant uncertainty as supply chains adjust to new customer preferences and government policy. Sector level demand is expected to be similar to 2020 APO forecasts, with the exception of northern Ontario mining and primary metal production. The top five sub-sectors⁴ will continue to account for roughly 60 per cent of the total sector demand.

⁴ The top five industrial sub-sectors in Ontario, by electricity demand are: 1) mining; 2) primary metals; 3) paper manufacturing; 4) chemical manufacturing; and 5) petroleum refining.

In the mining sub-sector, concentrated in northern Ontario, electricity demand is expected to grow robustly in the near-term, supported by favourable resource prices and the development of Ontario's Critical Mineral Strategy, and then slowly decline as various mines reach end of life.⁵

The primary metal sub-sector, spread across the Southwest (Hamilton, Cambridge, and Nanticoke) and Northeast (Sault Ste. Marie) Zones, is expected to grow robustly, with electrification already beginning and expected to materialize in the medium-term. Electrification incorporated in the demand forecasts includes implementation of electric arc furnaces, as a switch from traditional blast furnaces, in order to reduce greenhouse gas emissions. The [Algoma Steel Inc. project announced July 5, 2021](#) is included in both scenarios of the demand forecast, while the ArcelorMittal Dofasco project announced July 30, 2021 has been included in the high demand scenario.

Expected growth in all other sub-sectors continues to be slow. In general, the industrial sector is expected to be influenced by emerging de-globalization trends, support for increasing local industrial production capability and economic development, and electrification and general carbon emissions reductions over the outlook period.

Overall, total industrial sector electricity demand is forecast to grow, from 35 TWh in 2023 to 41 TWh in 2042, an average annual growth rate of 1 per cent.

2.4.4 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. Growth is primarily in the Kingsville-Leamington and Dresden areas⁶. Overall, sector electricity demand growth is largely unchanged from the 2020 APO and is forecast to grow from 5 TWh in 2023 to 10 TWh in 2042, an average annual growth rate of 4 per cent.

2.4.5 Transportation Electrification

In 2021, the federal government announced a focus on a green recovery intended to boost the economy post-pandemic while also working towards decarbonization and electrification. Overall, electricity demand from transportation electrification is forecast to grow from 0.9 TWh in 2023 to 26 TWh in 2042, an average annual growth rate of nearly 20 per cent.

2.4.5.1 Electric Vehicles

As part of the focus on a green recovery, the federal government created a mandatory target requiring 100 per cent of all new car and passenger truck sales in Canada to be zero-emission

⁵ *Ontario's Critical Mineral Strategy* aims to develop sources of minerals that have specific industrial, technological and strategic applications in Ontario.

⁶ The IESO's [Need for Bulk System Reinforcements West of London](#) was published to address needs arising from growing the greenhouse demand.

by 2035. The number of electric vehicles (EVs) in operation today, including light duty passenger vehicles and mass transit buses, is relatively low, but is expected to increase significantly over the outlook period as government policy is currently a key driver for EV adoption. Policy measures include purchase incentives and tax benefits for business vehicles, as well as support for EV charging infrastructure, automobile manufacturers and automobile parts suppliers.

As EV technology and production matures, and as costs fall and value increases, it is expected that consumer preferences will shift from internal combustion engine (ICE) vehicles to EVs. Many automobile producers have also announced plans and timelines to switch to EV-only offerings. The IESO's EV adoption forecast assumes EV sales to be relatively flat in the near-to-medium-terms, and to grow significantly in the years immediately preceding the 2035 milestone date.

Both EV sales and driving distance dropped in 2020 as a result of social and economic restrictions, but as the economic re-opening and recovery takes hold, EV charging is expected to increase in kind. Real-world charging data from the [Charge the North](#) project, the world's largest electric vehicle charging study, was used to develop the charging profile and EV hourly demand forecast.

The 2021 APO EV forecast is in line with [federal government zero-emission vehicle sales targets](#), which projects 6.6 million EVs in Ontario by 2042, with an annual charging demand of 24.4 TWh and a peak demand of 1,200 MW.

2.4.5.2 Rail Transit Electrification

Broad rail transit electrification is also underway in Ontario.

Eight local light rail transit (LRT) projects are being planned or are in various stages of construction. In addition, early work on three new subway projects in the GTA is underway, as is the procurement process for the multi-year electrification of GO rail corridors. Some rail transit electrification projects are at the early planning stage with little information on electricity requirements.

2.4.6 Conservation

2.4.6.1 Conservation Programs

The Conservation Program forecast includes incremental updates from 2020 to the existing IESO 2021-2024 Conservation and Demand Management (CDM) Framework⁷ delivered to consumers under the Save on Energy banner. The forecasted annual savings are 3 TWh in 2026.

⁷ For more information, refer to the [Ministerial Directive](#).

On June 4, 2021, the federal government announced the Canada Greener Homes Grant Program, providing 700,000 grants to help home owners across the country implement energy efficiency and emission reduction retrofits. The forecasted annual savings incorporated into the demand forecast are 290 GWh.

Other programs funded and/or delivered by the federal and municipal governments, including the Green Municipal Fund and the Climate Action Incentive Fund, are expected to result in additional electricity savings in Ontario. In the absence of program details, the amount of electricity savings is difficult to estimate.

It is also assumed that the delivery of conservation programs will continue after the 2021-2024 CDM Framework, and that annual savings will be consistent with levels forecast for the 2021-2024 CDM Framework on a proportion of gross demand basis. This will be updated when a post-2024 conservation program framework policy decision is made. Forecast CDM savings may also be revised based on the results of the current framework's Mid-Term Review, expected in late 2022.

Overall, the level of electricity demand savings from all conservation programs in Ontario is forecast to fluctuate, remaining at about 14 TWh from 2023 to 2028, and then declining to 10 TWh in 2042 as the demand savings attributable to past conservation programs expire.

2.4.6.2 Codes and Standards Regulations

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 through the regulation of minimum efficiency standards for equipment.

The IESO estimates 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.

Overall, electricity demand savings from codes and standards are forecast to grow, from a base year of 2023 to 7.7 TWh in 2042.

2.4.7 Industrial Conservation Initiative

The Industrial Conservation Initiative (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.

With the onset of the pandemic, the Ontario government introduced a one-year hiatus on the program, allowing consumers to focus on economic recovery rather than responding to system peaks (i.e., curtailing). During the hiatus, the 2020 Ontario provincial budget⁸ introduced the

⁸. For more information, refer to the November 5 news release, [Ontario's Action Plan: Protect, Support](#).

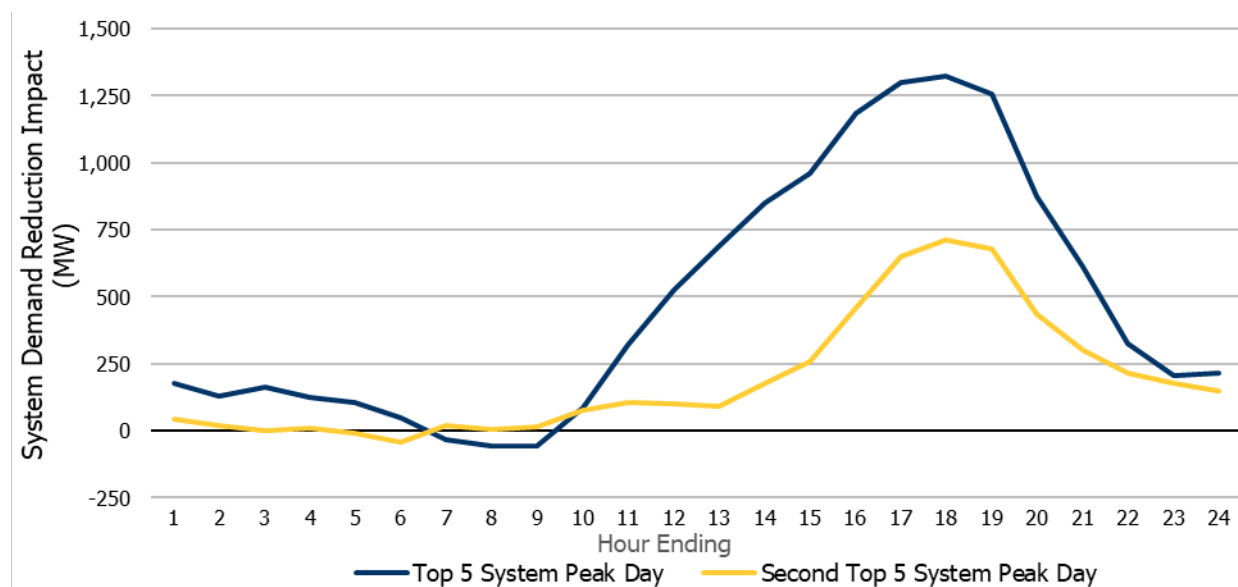
Renewable Cost Shift, a policy that reduces electricity rates and results in a dampened but still impactful price signal for curtailment. This increases the uncertainty surrounding the future impact of the ICI, but is expected to result in a lesser impact than previous years.

The IESO forecasts ICI top five system peak-day, system peak-hour demand reduction impacts to be 1,300 MW. This is an increase from 2020 APO levels, which is based on observed economic recovery and industrial electricity demand largely unaffected by pandemic impacts in 2020. The IESO also forecasts ICI demand reduction impacts of 650 MW in the next five system peak days. The ICI response is constant over the outlook period.

The IESO expects ICI drivers, including customer ICI program investment and Global Adjustment levels, will inevitably change over the course of the outlook period. ICI impacts on the demand forecast and ICI forecast methodology will be reassessed on an annual basis.

The projected impact from all ICI participants on the system peak day for each year in the outlook period is shown in Figure 4.

Figure 4 | Industrial Conservation Initiative Impact



2.4.8 Other Electricity Demand

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

- Connection of remote communities

- Electricity generators⁹
- Street lighting
- Municipal water treatment

Overall, “other sector” electricity demand is unchanged from the 2020 APO and is forecast to grow from 5.2 TWh in 2023 to 6.1 TWh in 2042, an average annual growth rate of 0.8 per cent.

2.5 Demand Forecast Uncertainties

To reiterate, the 2021 APO demand forecast presented in this chapter incorporates all known projections, announcements, status of projects with significant electricity demand and committed policy. The current level of change in the electricity sector, customer preference, economy, climate and policy environment has led to significant uncertainty regarding electricity demand. Chapter 8 outlines an assessment of the potential impact of a number of significant, yet highly uncertain, drivers of increased demand over the course of this outlook period.

⁹ Electricity generators such as nuclear and gas/oil generating stations can have electricity demand when: 1) commencing operation of generating units; and 2) generating units are not in operation, for example, the facility would have electricity demand for lighting and HVAC loads.

3. Supply and Transmission Outlook

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 many resource contracts expire.

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

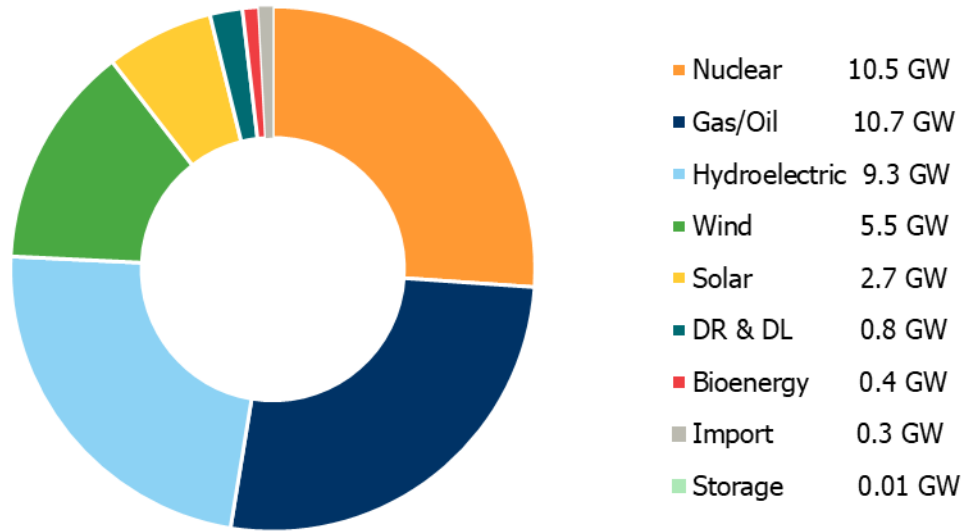
This chapter describes the availability of the province's existing supply resources over the outlook period, as well as the ability of the bulk transmission system to continue to supply electricity where it is needed.

3.1 Installed Capacity 2022

Ontario has 40.3 gigawatts (GW) of installed capacity made up of a diverse mix of resources, as shown in Figure 5.¹⁰

¹⁰ This data includes both transmission- and distribution-connected resources, either market participants and/or contracted by the IESO. For further information, please see the [2021 APO Supply, Adequacy and Energy Outlook](#) module.

Figure 5 | 2022 Installed Capacity by Fuel Type



The majority of Ontario’s installed capacity comes from nuclear (26 per cent), gas (26 per cent), and hydroelectric (23 per cent) resources, with the remainder from wind (14 per cent), solar (7 per cent), demand response and dispatchable load (DR & DL) (2 per cent) and bioenergy (1 per cent).

Imports (1 per cent) include both system-backed imports from the 2020 capacity auction and non-firm imports. Both transmission- and distribution-connected resources (e.g., embedded generation) are included in the capacity assessment.

3.2 Supply Outlook

This chapter provides an outlook for both installed capacity, or a resource’s maximum output, and effective capacity, which takes into account factors such as fuel availability, ambient conditions, and/or outages. This makes effective capacity a more meaningful measure of a resource’s ability to meet reliability needs in each season.

Ontario’s effective capacity for each fuel type, projected for summer and winter by the end of 2022, is shown in Table 1.¹¹ Going into the outlook period, the total installed capacity for the entire fleet is 40.3 GW, while summer and winter effective capacities are 28.0 GW and 30.2 GW, respectively. More detail by fuel type is provided in the [data tables](#).

¹¹ Summer months are from May to October, and winter months are from November to April.

Table 1 | Ontario's Summer and Winter Effective Capacity by End of 2022

Fuel	2022 Installed GW	2022 Summer Effective GW	2022/23 Winter Effective GW
Nuclear	10.5	9.9	10.0
Gas/Oil	10.7	8.7	9.4
Hydroelectric	9.3	6.5	7.2
Wind	5.5	0.7	2.1
Solar	2.7	0.9	0.1
DR & DL ¹²	0.8	0.6	0.7
Bioenergy	0.4	0.4	0.4
Import	0.3	0.3	0.2
Storage ¹³	0.01	0.002	0.002
Total	40.3	28.0	30.2

Figure 6 shows the total installed capacity by fuel type for the outlook period assuming the continued availability of resources following the end of their contract term or commitment. Capacity varies between 38 and 40 GW during the 2020s, due to refurbishments and retirements in the nuclear fleet, before levelling off at 40 GW in the 2030s. This number may be lower than assumed, however, if some resources reach the end of their useful life and choose to retire.

¹² These reflect the results of the IESO's [2020 Capacity Auction](#)

¹³ Includes lithium-ion battery storage through the 2020 Capacity Auction

Figure 6 | Installed Capacity 2023-2042

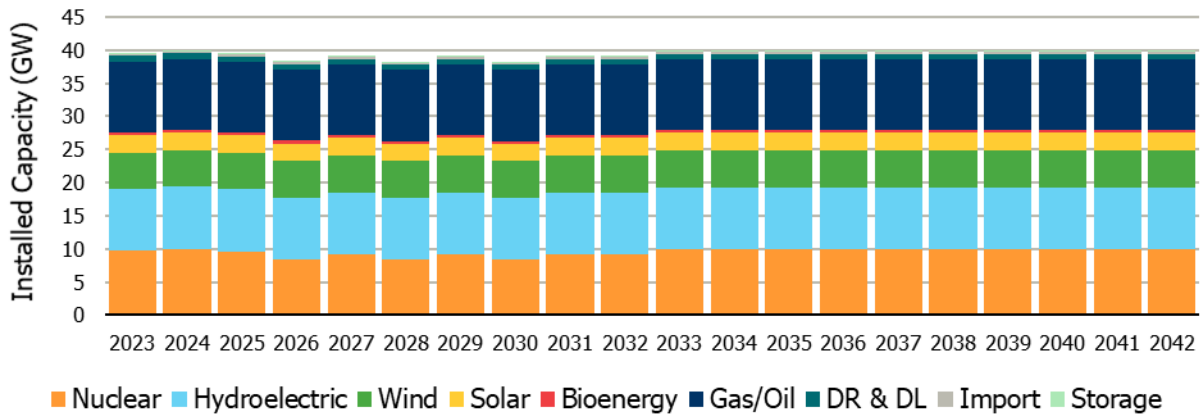


Figure 7 and 8 show the summer and winter effective capacities by fuel type for the outlook period. Summer capacity varies between 25 and 28 GW during the 2020s due to nuclear refurbishments, and then levels off at 27 GW in the 2030s. Similarly, winter availability ranges between 28 and 30 GW, plateauing at 30 GW in the long term. The supply mix over the course of the outlook generally reflects that shown in Table 1.

Figure 7 | Summer Effective Capacity 2023-2042

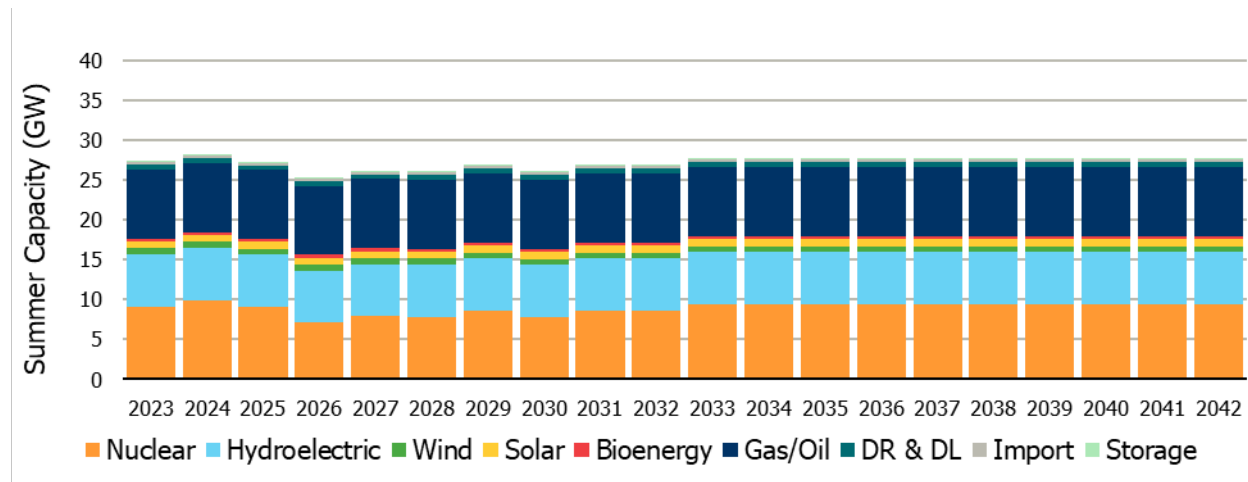
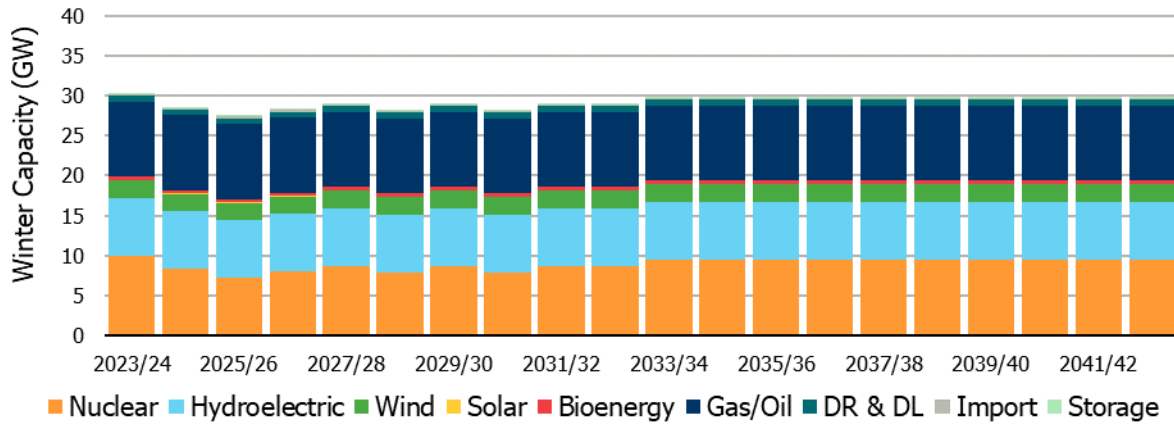


Figure 8 | Winter Effective Capacity 2023-2042



3.2.1 Nuclear Refurbishments and Retirements

Throughout the 2020s, Ontario’s electricity system will see a significant change in the available capacity of its nuclear fleet. The retirement of Pickering NGS, as well as various refurbishments that will result in long-term outages at Darlington NGS and Bruce NGS, will increase resource needs.

Figure 9 | Nuclear Refurbishment and Retirement Schedule¹⁴

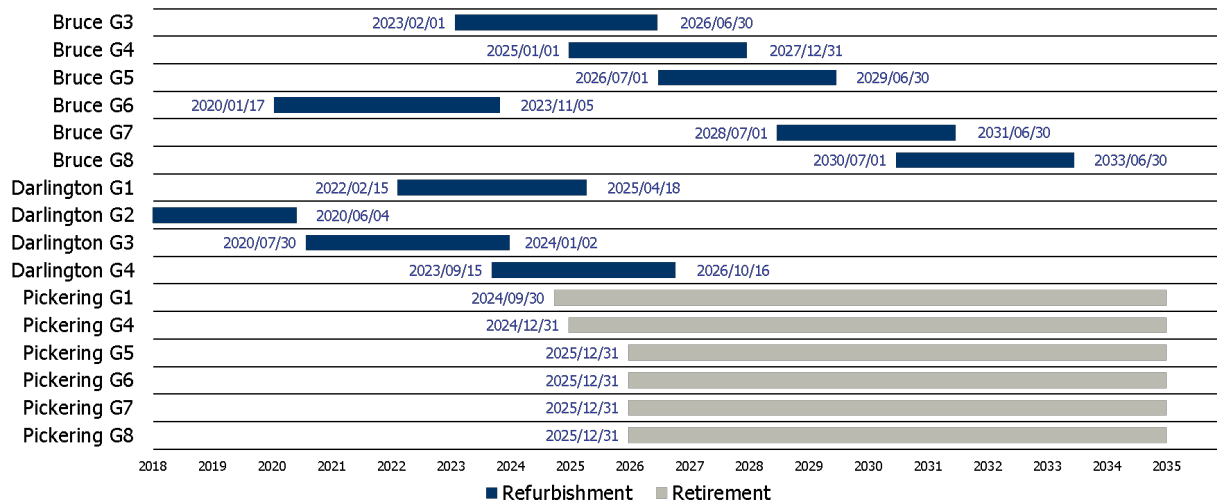
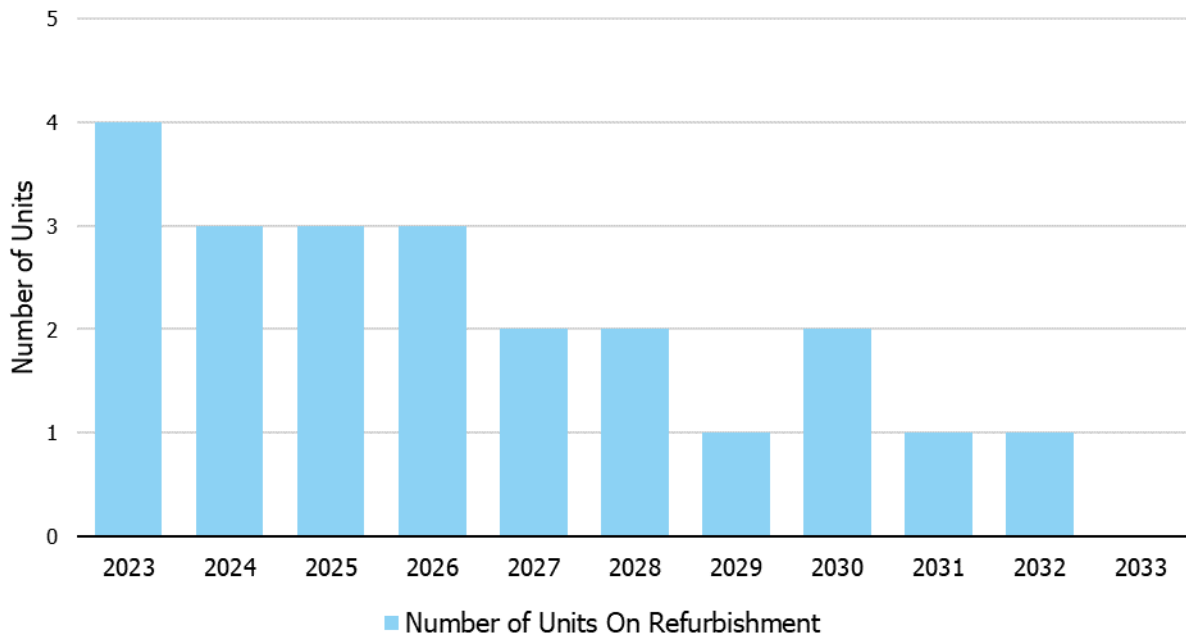


Figure 10 shows that activity will increase in the mid-2020s, with between two and four units undergoing refurbishment concurrently over the summer period. Darlington and Bruce

¹⁴ The current schedule was provided by Ontario Power Generation (OPG) and Bruce Power.

refurbishments are expected to be complete in 2026 and 2033 respectively, and by the end of 2033, a total of 9.6 GW of nuclear capacity will have undergone refurbishment.

Figure 10 | Summer Refurbishment Outages



3.2.2 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 11, many contracts have already reached their end of term, and expirations increase significantly by the end of the decade.

This outlook assumes, however, that many facilities will still be viable post-contract, and could continue to provide services through the various competitive procurement mechanisms being developed under the Resource Adequacy Framework, resulting in resource adequacy with a different supply mix.

To provide insight into the extent of the contributions of existing resources, should they continue to be available, the APO examines scenarios both with existing resources after contract or commitments have expired, as shown in Figure 6, and without, detailed in the figures below.

Figure 11 | Existing Resources Post-Contract Expiry 2023-2042 by Fuel Type

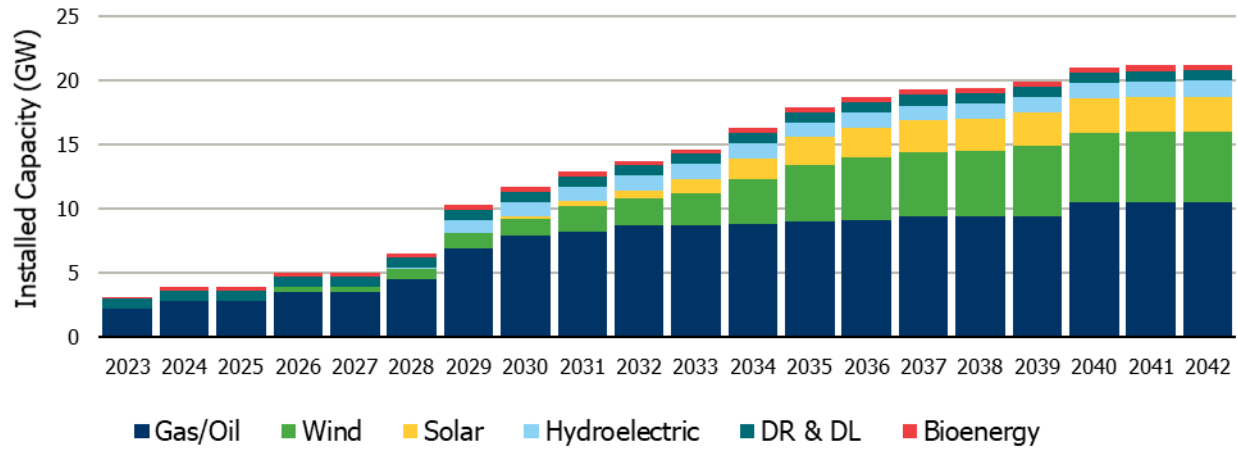


Figure 12 | Installed Capacity without Reacquisition of Expired Contracts 2023-2042

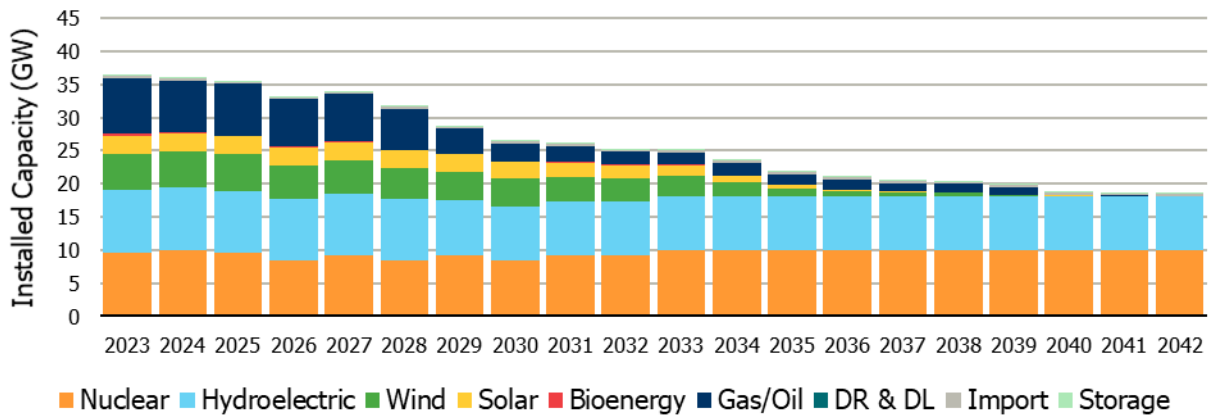


Figure 13 and Figure 14 show the summer effective and winter effective capacities, by fuel type, without availability of existing resources. Summer effective capacity is between 20 and 25 GW during the 2020s, and then levels off at 16 GW by the end of the planning horizon. Similarly, winter availability of the fleet ranges between 20 and 28 GW during the 2020s, then reaches about 16 GW by the end of the planning horizon.

Figure 13 | Summer Capacity without Reacquisition of Expired Contracts 2023-2042

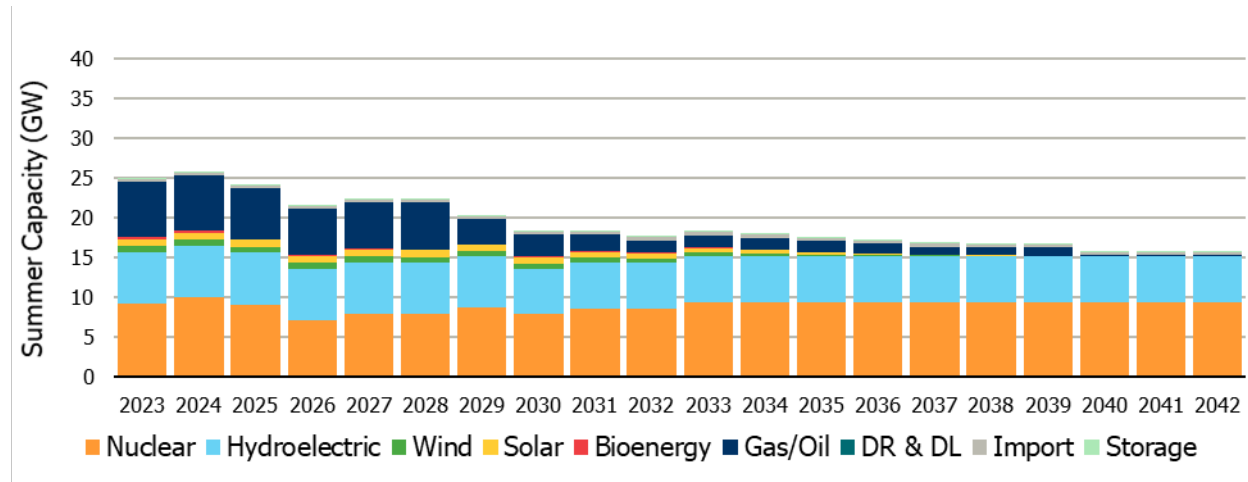
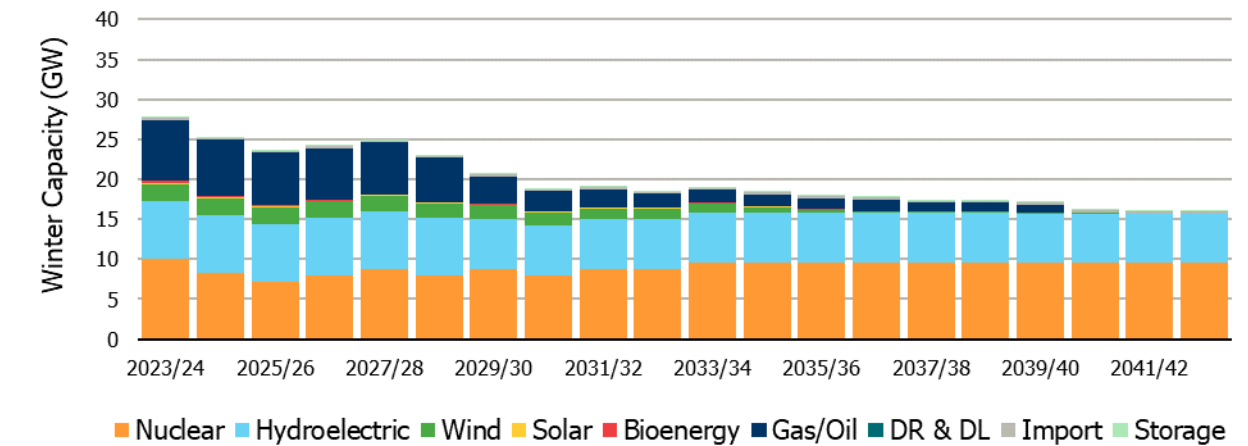


Figure 14 | Winter Capacity without Reacquisition of Expired Contracts 2023-2042



3.3 Transmission System Outlook

The following sections discuss the outlook for the bulk transmission system, which transfers electric power across the province, and highlights the transmission projects expected to come into service during this outlook period.

3.3.1 The Existing Bulk Transmission System

The bulk transmission system is critical for ensuring that the province's supply resources are able to meet system demand at all times. This includes operations under normal conditions¹⁵ and during and after disturbance events.

The capability of the transmission system is defined by the internal transmission interfaces that form the boundaries between the 10 IESO electrical zones. The ability to flow power across these interfaces is a key input to reliability assessments, because limitations on moving power from one part of the province to another can contribute to demand-supply imbalances at a zonal level. The maximum amount of power that the transmission interfaces and interties can deliver is referred to as "transfer capability."

Over time, as the transmission system is reinforced or facilities reach their end-of-life, and as new generation resources are added and old resources retire, the nature of power flows will change and different restrictive interfaces may be observed.

Power is also imported to, and exported from, Ontario through a series of bulk transmission interties located on Ontario's borders. These interties provide a number of system benefits, including the opportunity to consider imports and exports for managing resource needs, as well as supporting system stability, frequency regulation and voltage support.

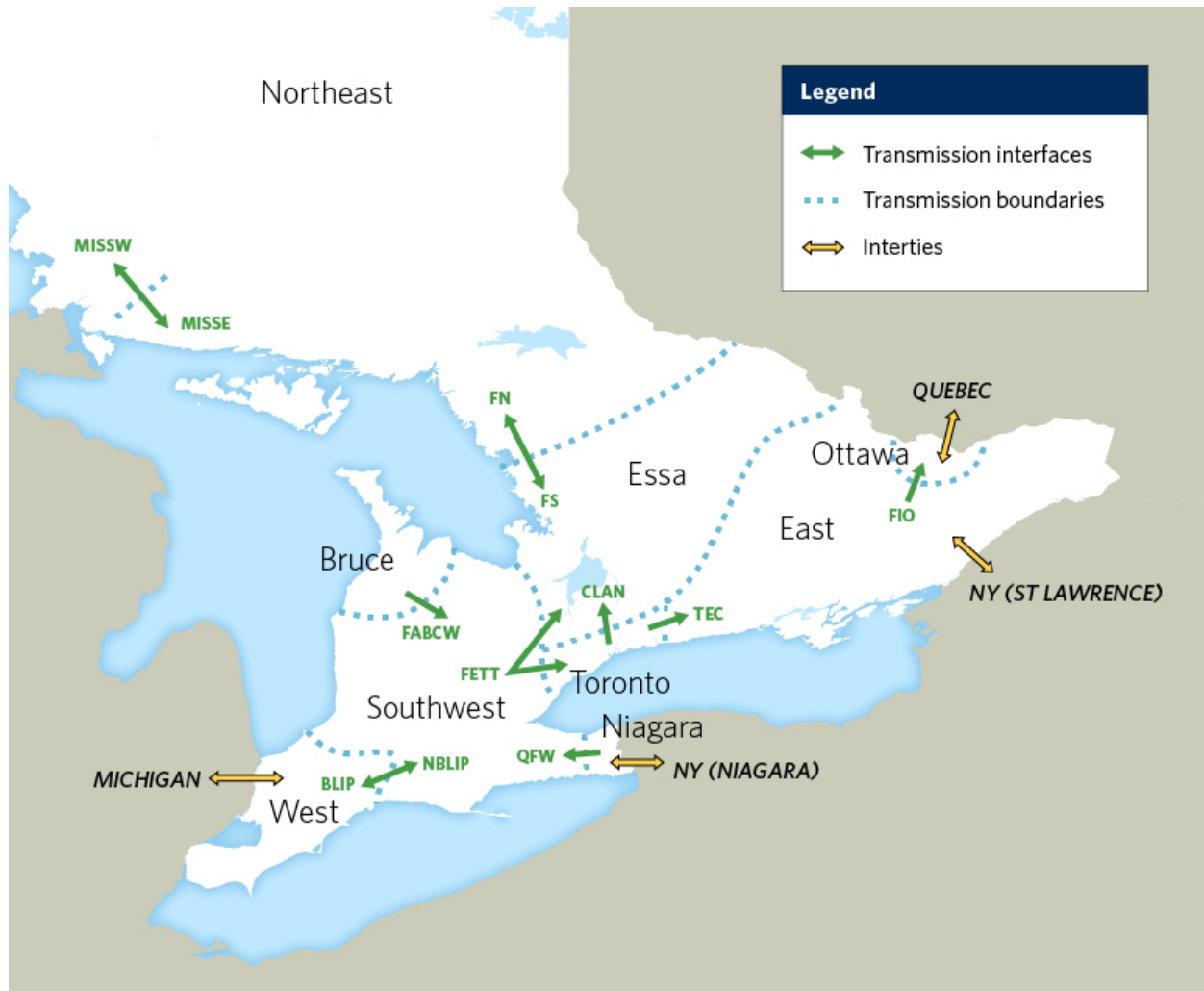
Ontario's transmission interfaces, the locations of interties with neighbouring jurisdictions, and the 10 IESO electrical zones are shown in Figure 15 and Figure 16.

¹⁵ For example, when all transmission elements are in-service.

Figure 15 | Ontario's Transmission Interfaces and Interties



Figure 16 | Focus on the Interfaces and Interties in Southern Ontario



More information about the transfer capabilities of Ontario’s transmission interfaces and interties is provided in the [Transmission Interfaces and Interties Module](#).

3.3.2 Anticipated Transmission Projects

Transmission projects that are expected to come into service within the outlook timeframe are included in the base cases for the resource adequacy and transmission security assessments carried out for this APO. These projects are sufficiently far along in their planning and development to be considered committed projects for the purpose of long-range planning. The rationale for these projects has been described in detail in past bulk system planning studies, regional plans, or 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 | Transmission Zones and Anticipated Transmission Projects



Table 2 | Anticipated Transmission Projects

Project	Description/Rationale	Expected In-Service Date
West of Chatham Area Reinforcements	<p>Strong and sustained growth in the agricultural sector is one of the main drivers of increasing demand in Ontario, and has resulted in a need for additional capacity in the Windsor-Essex region.</p> <p>This multi-phase reinforcement project consists of: a new Lakeshore Transformer Station (TS) at Leamington Junction (located in Lakeshore), two load stations in Lakeshore (South Middle Road TS DESN¹⁶ 1 and 2), and a new double-circuit, 230 kV transmission line, approximately 50 km in length, from Chatham SS to Lakeshore SS.</p> <p>A finalized addendum to the 2019 IRRP for the Windsor-Essex region is forthcoming (Q1 2022) and further recommendations to continue facilitating load connections are anticipated, namely two load stations in the Kingsville and Leamington areas, and a new double-circuit, 230 kV transmission line, approximately 20 km in length, supplying these new DESNs from Lakeshore TS.</p>	<p>Q2 2022 for Lakeshore TS and South Middle Road TS DESN 1</p> <p>Q3 2025 for South Middle Road TS DESN 2</p> <p>Q4 2025 for new Chatham SS to Lakeshore SS line</p>

¹⁶ 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/Rationale	Expected In-Service Date
West of London Area Reinforcements	<p>In addition to the West of Chatham reinforcements, this project is required to supply the agricultural sector growth in the Windsor-Essex region.</p> <p>The reinforcement project consists of a new double-circuit 230 kV transmission line, approximately 60 km in length, from Lambton TS to Chatham SS, and a new single-circuit 500 kV transmission line, approximately 135 km in length, from Longwood TS to Lakeshore TS.</p>	<p>2028 for Lambton TS to Chatham SS lines</p> <p>2030 for Longwood TS to Lakeshore TS line</p>
Hawthorne-Merivale Reinforcement	<p>The Hawthorne-Merivale transmission path supplies load in western Ottawa and delivers eastern Ontario resources and imports from Quebec to southern Ontario load centres.</p> <p>The reinforcement consists of upgrading the two 230 kV circuits between Merivale TS and Hawthorne TS, a length of 12 km.</p>	Q4 2023
Lennox Reactors	<p>This project will address acute operational challenges resulting from high system voltages in eastern Ontario and the GTA during low-demand periods.</p> <p>The reinforcement consists of two 500 kV line-connected shunt reactors to be installed at Lennox TS (near Napanee).</p>	Q1 2022

Project	Description/Rationale	Expected In-Service Date
East-West Tie Reinforcement	<p>This project aims to provide long-term, reliable electricity supply to Northwest Ontario to enable forecasted demand growth and changes to the supply mix in the region.</p> <p>The reinforcement consists of a new 230 kV transmission line roughly paralleling the existing East-West Tie Line between Wawa and Thunder Bay.</p>	Q1 2022
FETT Capacity Upgrade (Richview-Trafalgar Reinforcement)	<p>This project is required to address the transfer capability across the FETT interface, which is a concern during the summer peak demand periods, and will be exacerbated by the loss of a significant amount of supply capacity east of FETT related to the retirement of Pickering NGS and refurbishments at Darlington NGS.</p> <p>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. This reinforcement will enable some of the capacity that was lost east of the FETT interface to be replaced with capacity sited elsewhere in the province.</p>	Q4 2025

4. Resource Adequacy

Capacity needs continue to emerge, with more significant needs appearing after the Pickering NGS retirement. The potential for energy requirements begins in 2026 and increases sharply starting in 2029 if existing resources do not remain available post contract expiry.

As demand increases, Ontario is projected to become a net energy importer beginning in the mid-2020s.

A key aspect of power system reliability is resource adequacy, which describes the balance of supply and demand on the system.

Risks to the power system, such as extreme weather and generator outages, can result in demand exceeding supply for a period of time. An adequate system has enough capacity to mitigate these risks.

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 criteria¹⁷ 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 or resources enter and exit the market, 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 – like 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.¹⁸

¹⁷ For additional information, refer to [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.

¹⁸ Consult the [2021 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 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.

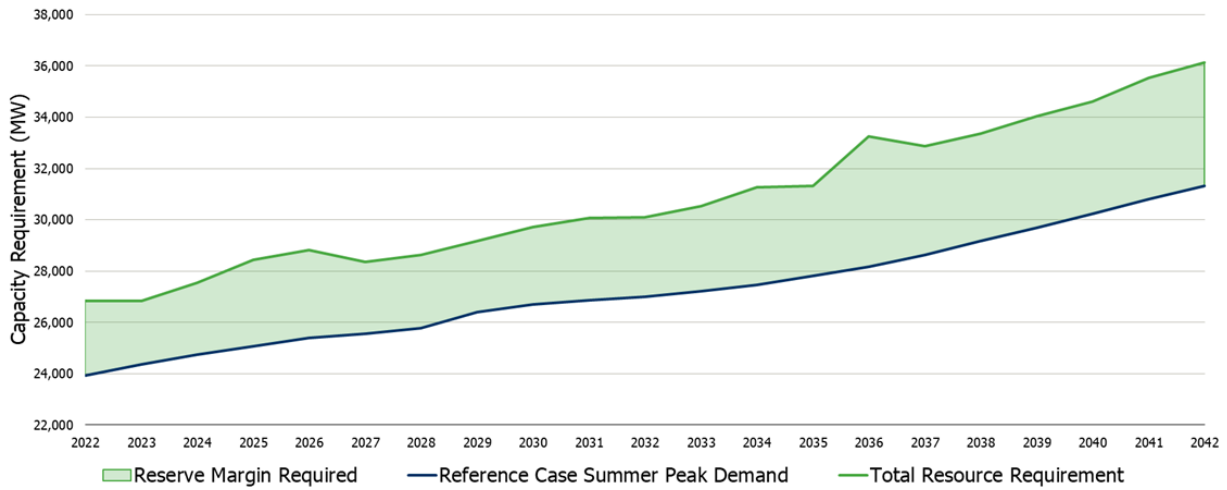
The methodology used to calculate effective capacity for each resource type also affects the reserve margin.

The reserve margin requirements for the next five years are shown in Table 3, and for the full horizon in Figure 18. Continued availability of existing resources is assumed in the calculation of the reserve margin. The [2021 APO Resource Adequacy and Energy Assessment Methodology](#) describes how the reserve margin is calculated.

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

Five-Year Reserve Margin	2022	2023	2024	2025	2026
Reference Case Summer Peak Demand (MW)	23,916	24,365	24,732	25,074	25,399
Existing Summer Effective Capacity (MW)	27,951	27,205	28,001	27,134	25,151
Total Resource Requirement (MW)	26,851	26,826	27,553	28,438	28,831
Reserve Margin Available (MW)	4,035	2,841	3,269	2,059	-248
Capacity Surplus/Deficit (MW)	1,101	379	448	-1,304	-3,680
Reserve Margin Available (%)	17%	12%	13%	8%	-1%
Reserve Margin Requirement (%)	12%	10%	11%	13%	14%

Figure 18 | Reserve Margin Requirement, 2022-2042



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 Chapter 2, and the supply and transmission outlook in Chapter 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 with and without availability of existing resources post-contract/commitment are shown in Figures 19 and 20. Capacity needs without existing resources are included to provide insight into the contributions of existing resources. Summer capacity needs emerge through 2023, with long-term needs being driven by nuclear retirement and refurbishment, resources reaching the end of their contracts, and increases in demand.

Figure 19 | Summer Capacity Surplus/Deficit

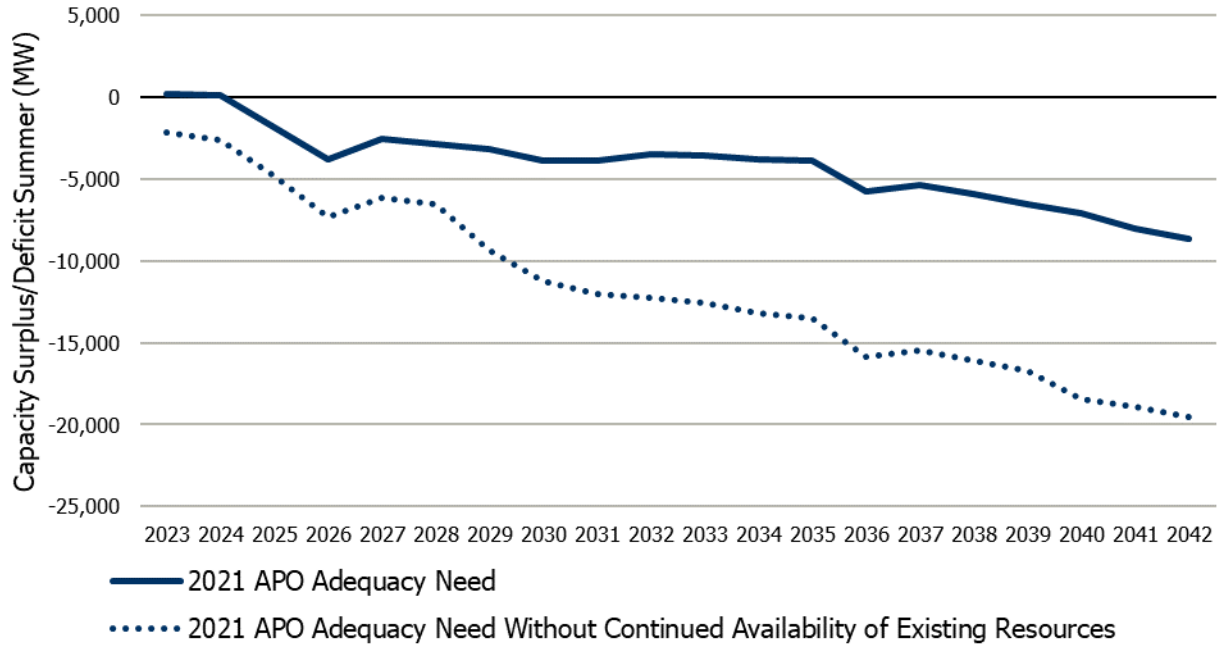
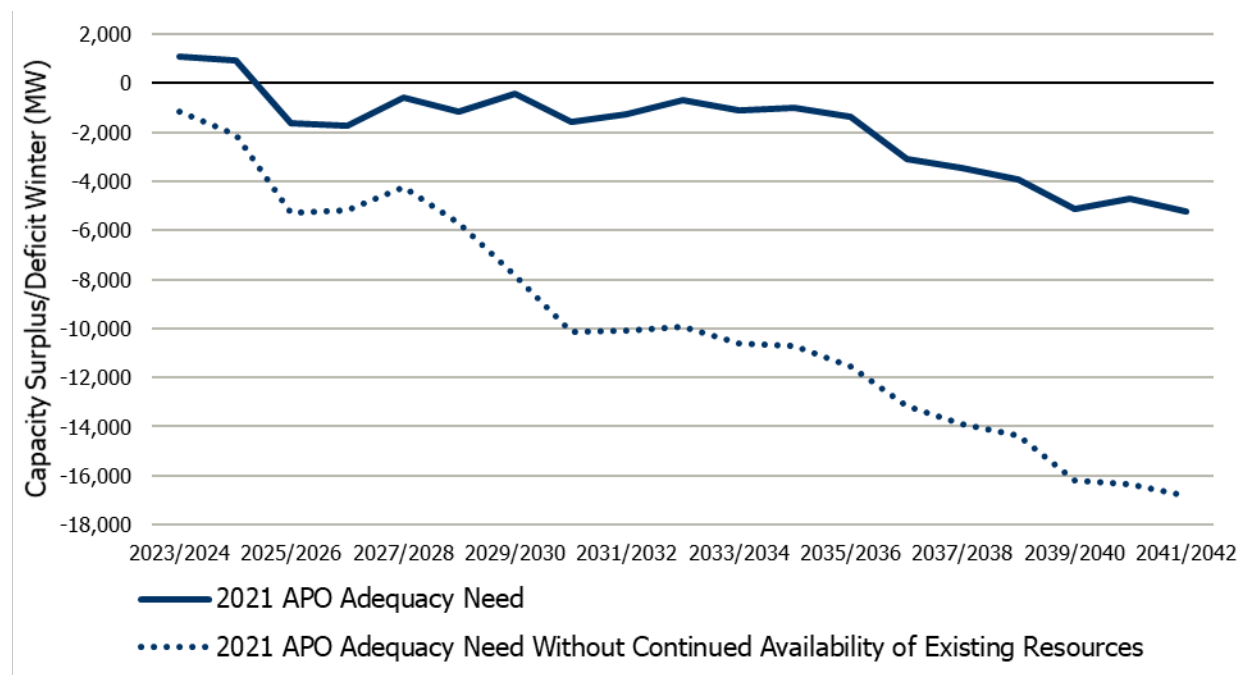


Figure 20 | Winter Capacity Surplus/Deficit



The IESO’s Resource Adequacy Framework will provide the mechanism for effectively meeting needs as they occur, but influences identified below could also reduce needs in the years ahead.

4.3 Uncertainties

There are a number of potential sources of capacity and energy that may be added to the system over the outlook period, including new resources, recontracting existing resources, and new interties to neighbouring jurisdictions. These resources are not included in this outlook; the IESO will include them in future outlooks as more information becomes available.

Each of the items listed below would reduce the adequacy needs discussed above.

Oneida Battery (government policy - under negotiation): The Ministry of Energy (ENERGY) has asked the IESO to enter into contract negotiations with NRStor Inc. and Six Nations of the Grand River Development Corp. to explore a 10-year agreement for the proposed 250 MW Oneida Battery Storage facility. The Minister’s letter asked the IESO to submit the final contract, for the Minister to consider in deciding whether to recommend that a government Directive be issued for the IESO to execute.

Lake Erie Connector (government policy - under negotiation): ENERGY has asked the IESO to enter into contract negotiations with ITC on the Lake Erie Connector project which would establish a new 1,000 MW high voltage bi-directional underwater transmission intertie between

Ontario and PJM. Direct access to the PJM market is expected to reduce Ontario capacity needs through increased non-firm imports (250 MW).

Calstock (35 MW) and Chapleau (5 MW) biomass plants (government policy - under negotiation): ENERGY has asked the IESO to enter in discussions with Atlantic Power (Calstock) and Green First Inc. (Chapleau) on potential options for new five-year contracts to support a longer-term transitional plan for the forestry sector. ENERGY has also signalled that it will continue to engage the IESO on details for contract negotiations with Thunder Bay Resolute, Hornepayne, and Atikokan biomass plants (government policy)

Small Modular Reactors (SMRs): Ontario Power Generation (OPG) has announced it will work with GE Hitachi Nuclear Energy on development and deployment of a 300 MW SMR at the Darlington new nuclear site by the end of 2028.

Small Hydroelectric Facilities program (government policy): Small hydroelectric facilities can contribute to meeting both capacity and energy needs, as well as achieving other non-electricity objectives. ENERGY has asked the IESO to explore ways to allow these facilities to continue operating beyond the expiry of their existing Power Purchase Agreements (PPAs).

Pumped storage project proposals (government policy): ENERGY has asked the IESO to continue its assessment of proposed pumped storage projects at Marmora, Meaford, and Schreiber.

4.4 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.

The extent to which an energy adequacy need emerges will depend on the availability and capacity factor (e.g. utilization) of existing resources post-contract expiry. The energy adequacy outlooks with continued availability of existing resources and without are shown in Figure 21 and Figure 22, respectively.

Figure 21 | Energy Adequacy Outlook, with Continued Availability of Existing Resources

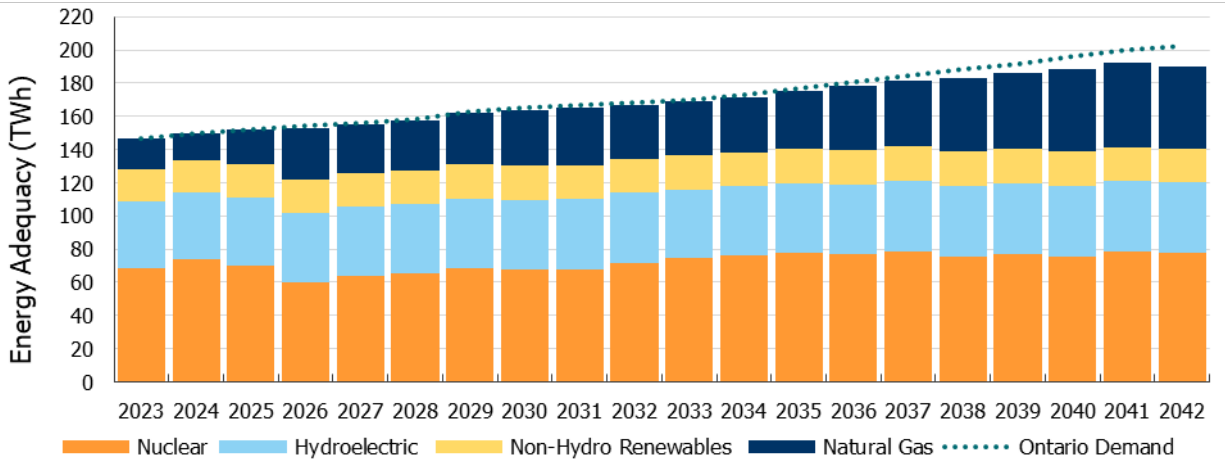
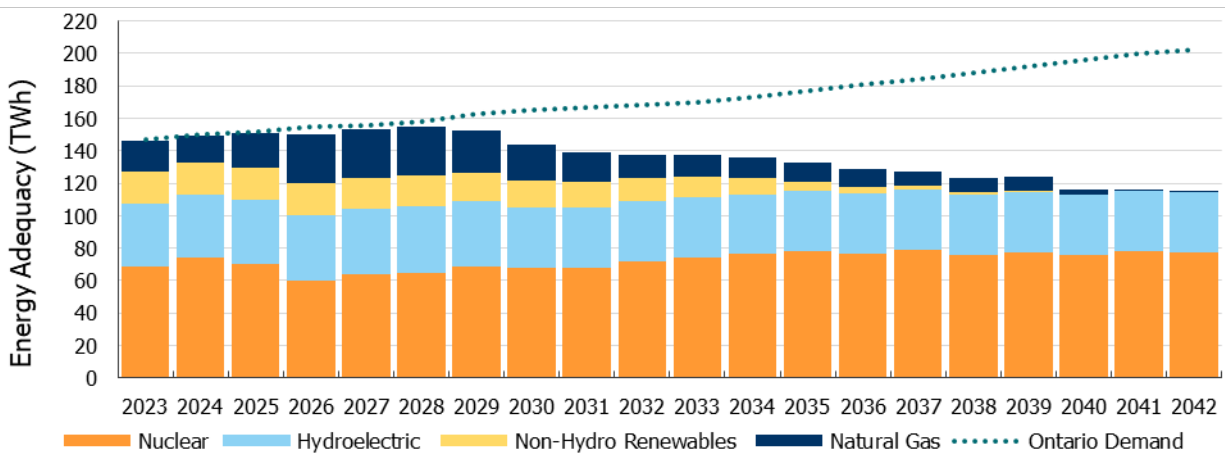


Figure 22 | Energy Adequacy Outlook, without Continued Availability of Existing Resources

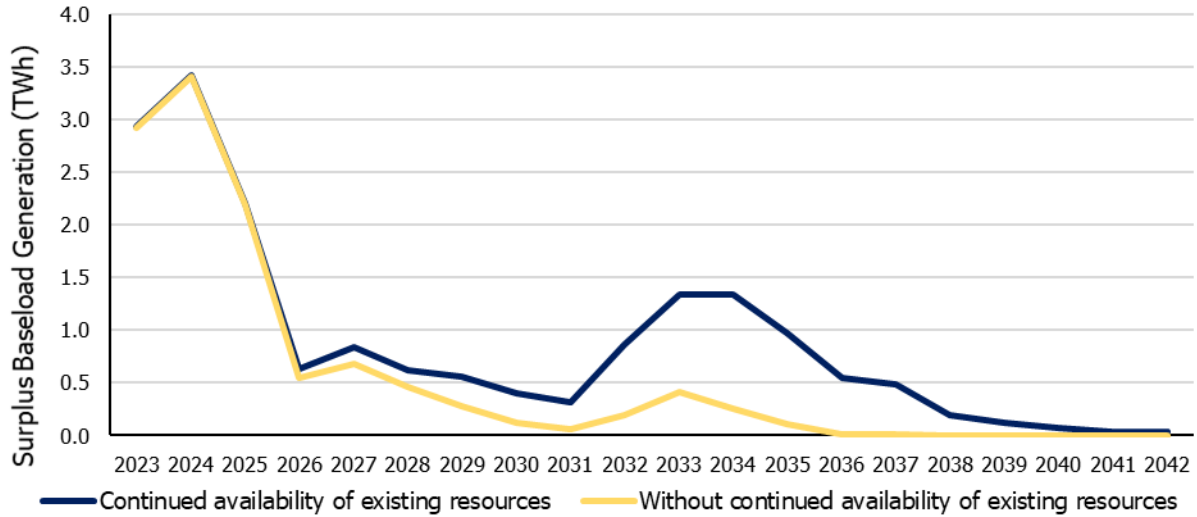


Existing resources can meet energy demands in most circumstances until the mid-2030s. An energy shortfall begins to emerge near the end of the planning horizon largely driven by increases in demand. An energy shortfall begins in 2026, and increases sharply starting in 2029, without continued availability of existing resources post contract expiry.

Surplus baseload generation (SBG), as shown in Figure 23, 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 manoeuvres/curtailment, to correct the imbalance.

By the mid-2020s, SBG begins to fall as more nuclear units undergo refurbishment and Pickering NGS retires.

Figure 23 | Surplus Baseload Generation



4.5 Provincial Energy Production Outlook

The IESO-administered energy markets are linked to Ontario’s neighbours through interconnections. Imports and exports are scheduled in the real-time energy market to take advantage of price differences between jurisdictions. In 2020, Ontario imported 5.2 TWh of energy and exported 20.4 TWh.

The energy production outlook includes interconnections with Ontario’s trading partners to more closely represent expected conditions and market outcomes. Trade with our neighbours will allow us to meet energy requirements toward the end of the outlook period, assuming continued availability of existing resources post-contract expiry, as shown in Figure 24. Ontario becomes energy inadequate without existing resources, as shown in Figure 25.

Figure 24 | Energy Production Outlook, with Continued Availability of Existing Resources

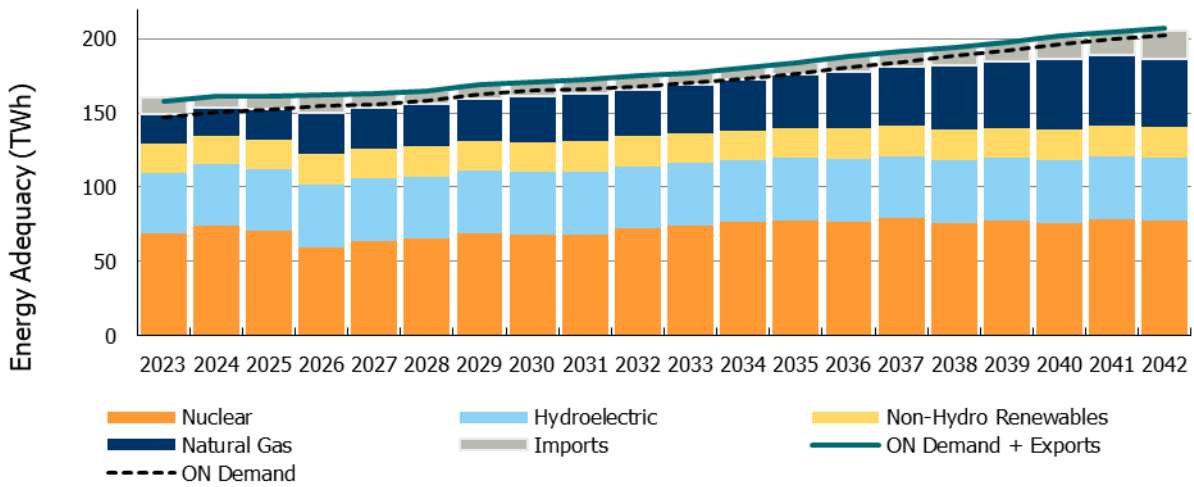
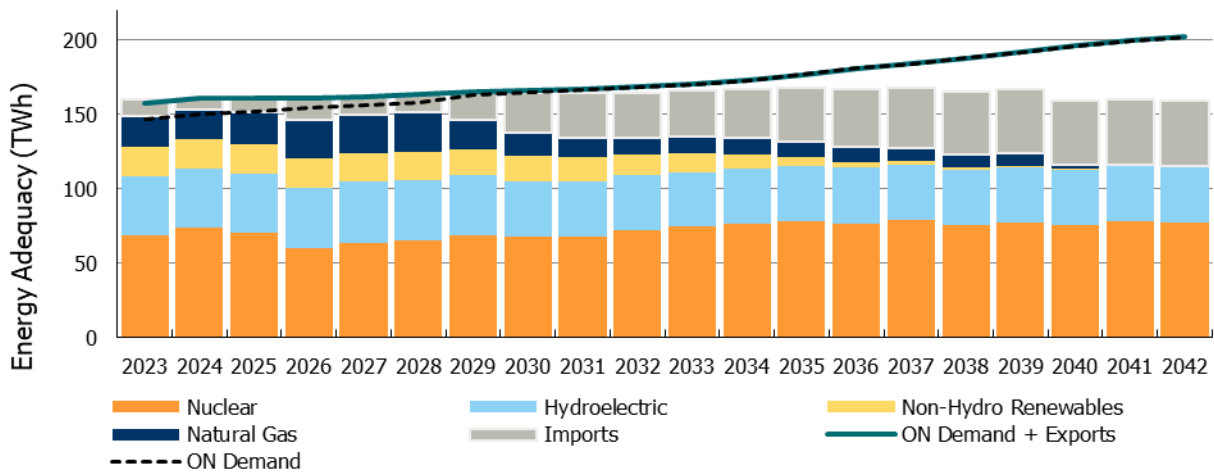


Figure 25 | Energy Production Outlook, without Continued Availability of Existing Resources

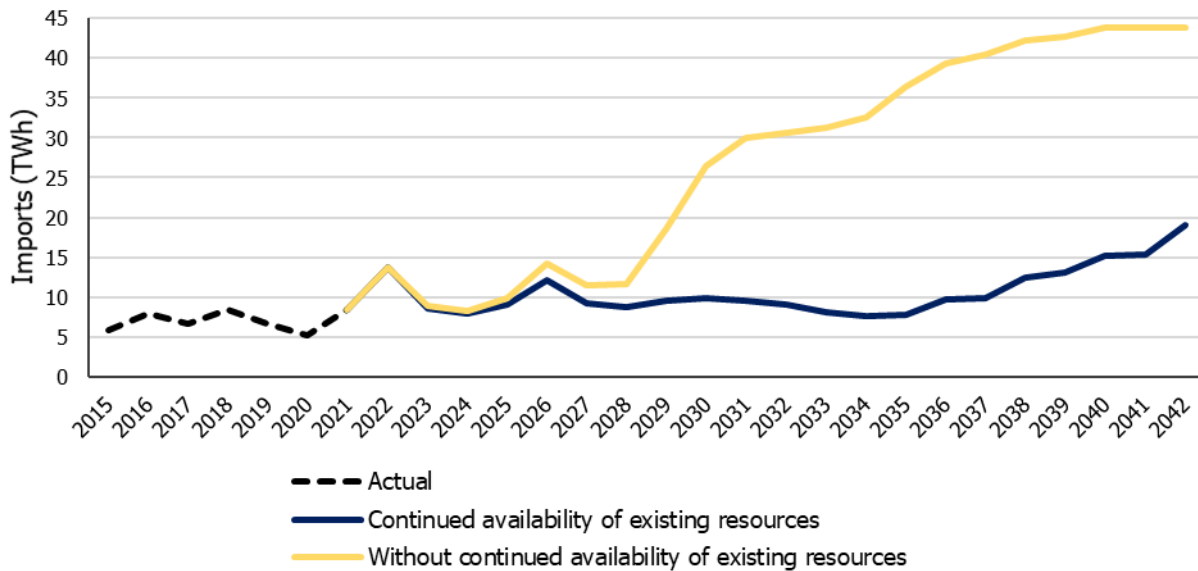


Energy production of baseload resources is similar to the energy adequacy outlook because production from baseload resources is generally insensitive to market prices. Gas production, which is often used to ensure power during times of higher demand and can provide needed flexibility in response to system 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, 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 26, imports increase from historic levels (about 6 to 8 TWh) in both scenarios. Historically, Ontario has been a net energy exporter. In the scenario assuming continued availability of resources, Ontario becomes a net energy importer starting in the mid-2020s as the demand forecast increases. In the scenario without existing resources, imports reach about 44 TWh by the end of the planning period as demand increases, existing resources retire, and imports reach the intertie limits.

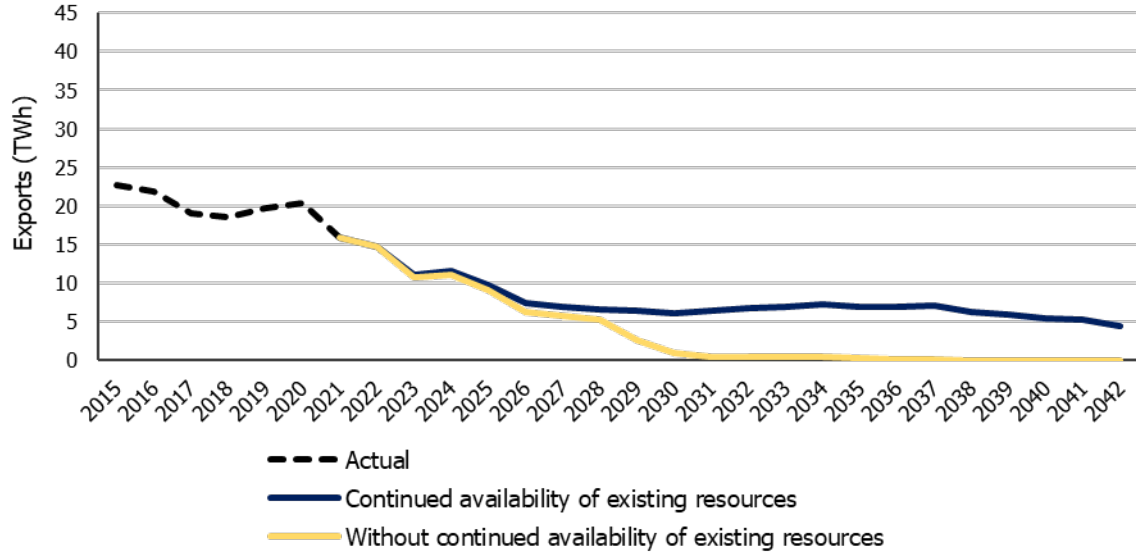
In Figure 27, energy exports decrease in the early and mid-2020s with nuclear retirements and refurbishments. Exports become minimal as demand in the 2030s increases. While the assumptions underpinning this outlook point to Ontario becoming a net importer of energy, there are many factors that could change this outcome, including the nature of any new capacity that may be built in Ontario, and developments in the electricity sectors of neighboring jurisdictions as they pursue their own decarbonization policies.

Figure 26 | Energy Production Outlook, Imports¹⁹



¹⁹ For 2021, the 2019 APO forecast values are shown. For 2022, the 2020 APO forecast values are shown

Figure 27 | Energy Production Outlook, Exports²⁰



²⁰ For 2021, the 2019 APO forecast values are shown. For 2022, the 2020 APO forecast values are shown

5. Locational Considerations Based on Transmission System Limitations

Limitations on the planned transmission system will impose requirements on where capacity must, or should not, be located to meet reliability standards. These are referred to as locational requirements and they, in effect, dictate where the capacity needed to fill the gap described in Chapter 4 must be placed within the province. In some of these cases it will be more cost-effective to reinforce the transmission system rather than siting resources in more expensive locations in Ontario.

This section describes these locational requirements based on the planned transmission system described in Section 3.7 and indicates where transmission reinforcements are being explored to lessen the requirement.

Future procurements for the capacity needed to meet provincial supply requirements will take into account the locational requirements described in this section.

The resource capacity requirements described in Chapter 4 lay out what is needed to reliably supply forecasted electricity demand in the province. This chapter discusses the locational requirements for that capacity. Section 5.1 discusses the locational requirements to meet resource adequacy criteria, and section 5.2 discusses the requirements to meet transmission security criteria. Section 5.3 ties these concepts together.

5.1 Locational Requirements for Resource Adequacy

Locational requirements exist due to limitations on the transmission system, typically specified through “transmission transfer capability limits” over transmission interfaces.

To account for transmission transfer capabilities across Ontario’s interfaces, the IESO specifies the minimum and maximum incremental capacity amounts required in certain regions of the province. These minima and maxima are typically presented at the zonal level, and in some cases are reported for groups of zones that share a common limiting interface.

The methodology for establishing the transmission transfer capabilities is provided in the [Transmission Outlook Methodology](#), while the transfer capability limits themselves are provided

in the [Transmission System Interface Data Tables](#). A description of the interfaces included is provided in the [APO modules](#).²¹

The zonal minima and maxima for select future years are shown for the summer season demand in Table 4 and for winter in Table 5.²² A zonal minimum represents the minimum required capacity necessary to meet the provincial resource adequacy criterion. A zonal maximum represents the maximum amount of capacity in a Zone that can contribute to provincial resource adequacy. In other words, the zonal minimum is a capacity requirement; capacity exceeding the zonal maximum does not provide further value from a resource adequacy perspective.

These constraints reflect the planned transmission projects listed in Table 2 (in Chapter 3), with the exception of the West of London reinforcements due to the timing of the West of London bulk study outcomes. Furthermore, plans to re-acquire existing generation are not accounted for in the zonal constraints, including the generation need that was identified in the West of London plan and the planned reacquisition of Lennox Generating Station (GS).

Under these assumptions, location-specific capacity needs emerge in the mid-2020s, mainly in the Zones east of the FETT interface (Toronto, Essa, East, Ottawa, Northeast and Northwest Zones).²³ This need is driven by the scheduled retirement of Pickering NGS and the planned refurbishments at Darlington NGS, coupled with increasing demand. The plan to re-acquire Lennox GS for operation until 2029 will address most of this need in 2026 (see Section 5.4).

The results also show an emerging need for capacity in the West Zone towards the end of the decade. This, however, does not reflect resource and transmission system reinforcements recommended in the [West of London bulk study](#). If implemented, they will address this gap.

The limited transfer capability on the Flow South interface restricts the amount of new capacity in northern Ontario (Northwest and Northeast Zones) that can contribute to resource adequacy. There are also limits on the amount of capacity that can be accommodated in southwest Ontario (Bruce, West, Niagara and Southwest Zones). These limits are reflected by the zonal maxima, and are present in both summer and winter.

²¹ The [2021 APO Resource Adequacy and Energy Assessment Methodology](#) provides a description on the methodology on how the zonal limits have been calculated. Also refer to the [2021 APO Supply, Adequacy and Energy Outlook Module](#) for additional information on the zonal capacity adequacy assessments.

²² A maximum limit of "N/A" shown in Table 4 and Table 5 indicates the actual maximum is not expected to be practically limiting.

²³ These zones were grouped together as the constraints do not bind for the individual zones.

Table 4 Incremental Summer Zonal Constraints, without Continued Availability of Existing Resources

Zone	2023 Min	2023 Max	2026 Min	2026 Max	2029 Min	2029 Max
Bruce	0	N/A	0	5,350	0	4,500
East	0	N/A	0	N/A	0	N/A
Essa	0	N/A	0	N/A	0	N/A
Niagara	0	900	0	950	0	850
Northeast	0	250	0	700	500	950
Northwest	0	50	0	400	0	200
Ottawa	0	N/A	0	N/A	0	N/A
Southwest	0	N/A	0	N/A	0	N/A
Toronto	0	N/A	0	N/A	0	N/A
West	0	850	0	1650	700	3,300
Toronto+Essa+East+Ottawa ²⁴	0	N/A	1,300	N/A	0	N/A
Toronto+Essa+East+Ottawa+ Northeast					2,200	N/A
Northeast+Northwest	0	250	0	700	500	950

²⁴ Starting in 2029, a minimum emerges in the Northeast Zone and it is observed that the minimum for Toronto+Essa+East+Ottawa becomes dependent on the amount of capacity located in the Northeast and can no longer be calculated in isolation. For example, at least 500 MW is needed in the Northeast in addition to at least 1,700 MW in Toronto+Essa+East+Ottawa to reach the 2,200 MW total reliability target).

Zone	2023 Min	2023 Max	2026 Min	2026 Max	2029 Min	2029 Max
Bruce+West+Niagara+Southwest	0	2,050	0	6,250	700	4,500

Table 5 | Incremental Winter Zonal Constraints, without Continued Availability of Existing Resources (MW)

Zone	2023/2024 Min	2023/2024 Max	2026/2027 Min	2026/2027 Max	2029/2030 Min	2029/2030 Max
Bruce	0	N/A	0	N/A	0	4,700
East	0	N/A	0	N/A	0	N/A
Essa	0	N/A	0	N/A	0	N/A
Niagara	0	750	0	850	0	900
Northeast	0	850	0	1,200	0	2,200
Northwest	0	150	0	450	0	450
Ottawa	0	N/A	0	N/A	0	N/A
Southwest	0	N/A	0	N/A	0	N/A
Toronto	0	N/A	0	N/A	0	N/A
West	0	600	0	800	950	3,150
Toronto+Essa+East+Ottawa	0	N/A	0	N/A	1,950	N/A
Northeast+Northwest	0	850	0	1,200	0	2,200
Bruce+West+Niagara+Southwest	0	1,300	0	4,950	950	5,700

5.2 Additional Locational Requirements for Transmission Security

Transmission security criteria, which are distinct from the resource adequacy criteria addressed in Section 5.1, can also introduce locational requirements. Resulting from the IESO's obligation to ensure the bulk transmission system meets NPCC and NERC reliability standards and criteria, transmission security criteria are concerned with the system's ability to withstand sudden disturbances, such as the loss of system components.

Transmission security studies determine locational capacity needs by comparing forecasted demand to the total amount of resources and interface transfer capability within a given Zone. In these assessments, the transfer capability accounts for contingencies or the loss of various system elements. Where the zonal demand exceeds the internal resources and transfer capability, there will be an additional locational requirement for capacity. In most cases, transmission security needs are more onerous than the resource adequacy need, as reflected by the zonal minima and maxima in Table 4 and Table 5.²⁵

Locational considerations resulting from the transmission security outlook are present in the West of London area, FETT interface, Ottawa, and Northeast Ontario. These issues are summarized in the subsections below.

5.2.1 West of London / Buchanan Longwood Input Interface (BLIP)

Transmission security assessments for the West of London area and BLIP transmission interface identified local capacity needs in the West of London area. Both regional and bulk plans focusing on the Windsor-Essex and West of London areas have looked to address these localized capacity needs in the near, medium and long term, which are being driven by the rapid expansion of agricultural greenhouses. The most recent study, "[Need for Bulk System Reinforcements West of London](#)" was published in September 2021.

To address a localized capacity need from 2024 to 2028, the IESO intends to begin bilateral negotiations for continued operation of Brighton Beach GS (as outlined in the 2021 AAR), which will be required to support local needs until a transmission solution is in service. Brighton Beach GS was selected to address the near-term need as it represents the only supplier in the local area with requisite scale to address this immediate need, offering 588 MW of capacity to support the growing loads in the area. Further details are available in the study referenced above.

The rest of the multi-pronged solution consists of a new 230 kV line, a new 500 kV line, and a local capacity requirement in the West of London area, starting in 2030 and progressively increasing to 1,975 MW by 2035. 550 MW of this capacity should be located in the Windsor-Essex and/or Chatham-Kent area. This capacity need assumes existing resources are not re-

²⁵ This is not universally the case, due to differences in methodological approaches and assumptions between the probabilistic resource adequacy assessments and deterministic transmission security studies.

acquired, but as there is currently sufficient capacity in the area, re-acquiring existing generation after contract expiry could meet this need.

Beyond what was recommended by the IESO in the plans for West of London, as summarized in this section, there is no additional locational requirement for capacity in the West Zone.²⁶

5.2.2 Eastern Ontario / Flow East Towards Toronto Interface

Over the next few years, supply capacity east of the FETT interface will decrease due to the retirement of Pickering NGS, expected by the end of 2025, and refurbishments at Darlington NGS. Both of these resources are located east of the FETT interface. In addition, more generation contracts will reach the end of their terms toward the end of this decade, all creating a need for additional capacity in the region.

This need will be addressed through the medium-term with a plan to reacquire Lennox GS for continued operation until April 2029 (as outlined in the 2021 AAR), and transmission upgrades to the FETT interface by the end of 2025 (described in Section 3.7). These options were chosen based on a combination of project economics, performance advantage, lower environmental impact and lower implementation risk.²⁷

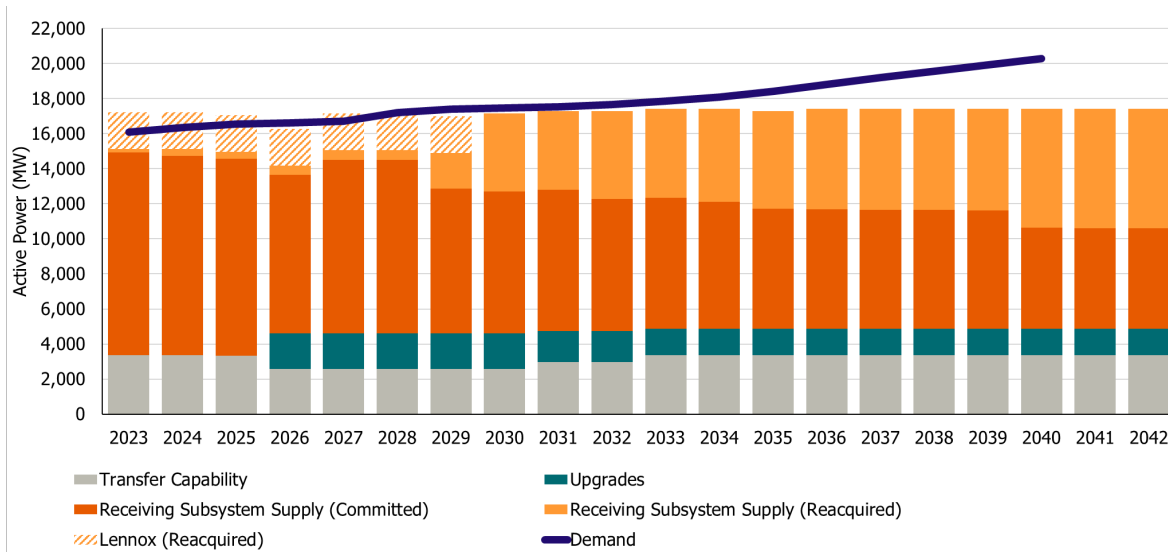
The transmission security outlook for the bulk system east of the FETT interface is illustrated in Figure 28. Assuming that the actions described in the previous paragraph (transmission upgrade and re-acquisition of Lennox) have been implemented, a small capacity gap emerges in 2026 of just under 300 MW, which is the result of a slightly higher demand forecast for 2021 compared to that of 2020. Should resources acquired to meet the province-wide capacity need in the Long-Term RFP be located east of FETT, this gap would be resolved. If sufficient new resources do not materialize east of FETT by 2026, an alternative could include exercising a 500 MW firm import option from Hydro Quebec.

In the longer term, an additional transmission security need may emerge in the early to mid-2030s driven by demand growth and transfer capability limits across the FETT interface. Any resources situated east of the FETT interface will help to alleviate this issue, including Lennox GS or other, new resources. Also, further improvements of the FETT interface or other approaches as determined through integrated bulk system planning could be considered, while closely monitoring the resource outlook and the demand levels east of FETT.

²⁶ More information on the projects can be found on the [Southwest Ontario Bulk Planning](#) web page. Information on engagement sessions, can be found on the [Windsor-Essex Regional Planning](#) web page.

²⁷ See Hydro One Networks Inc. application to Ontario Energy Board (EB-2021-0136) for further information on the supporting rationale for the transmission upgrades: <https://www.rds.oeb.ca/CMWebDrawer/Record/719761/File/document>

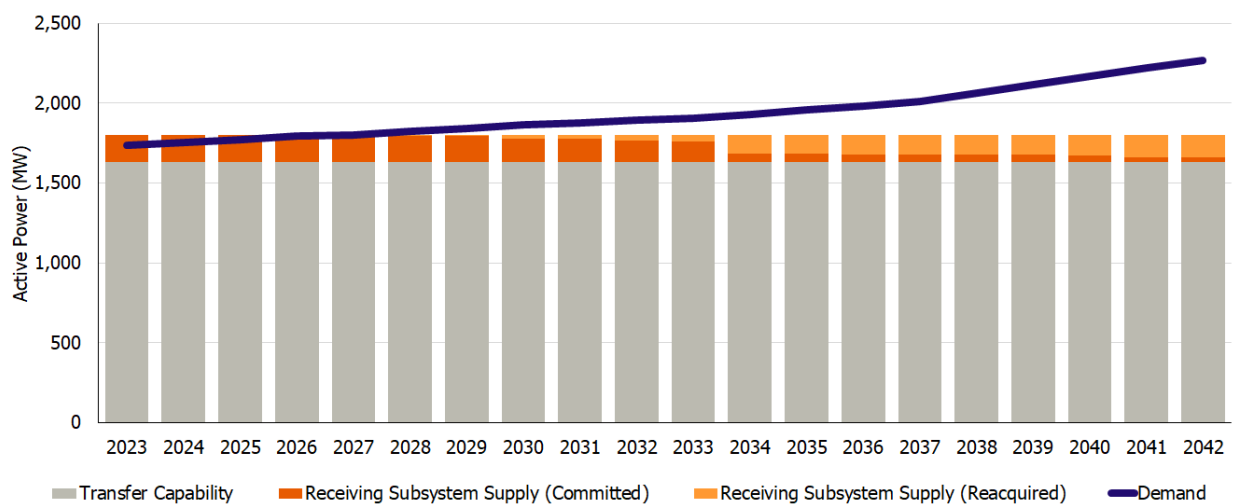
Figure 28 | FETT Security Outlook



5.2.3 Ottawa / Flow into Ottawa Interface

The transmission security outlook for the system east of the FIO Interface (Ottawa Zone) is illustrated in Figure 29. This shows an emerging need in 2027 for additional capacity to supply the Ottawa Zone. Transmission reinforcement to facilitate greater flows into Ottawa could also be an option. This need is highly sensitive to local demand growth over the next several years.

Figure 29 | FIO Security Outlook



The scope of the forthcoming Gatineau Corridor End-of-Life study is examining this need in detail and the result could be transmission enhancements that lessen or eliminate this locational capacity requirement. The Gatineau Corridor is a major transmission corridor between Pickering and Ottawa, consisting of five transmission lines with a combined line length of approximately

1,300 km. This corridor is critical for supporting the transfer capability of the FIO interface into the Ottawa Zone, as well as Flow into Dobbin and Sidney, which supplies the Peterborough to Quinte West area. Large portions of the corridor are over 80 years in age and are expected to reach end of life by the late-2020s.

The Gatineau Corridor study is examining alternative refurbishment options for the transmission facilities at end-of-life, paired with different reinforcement possibilities. Along with needs in the Ottawa Zone, the study is looking to address existing needs for the area of Peterborough to Quinte West. The study is planned to be completed in Q2 2022, and the study outcomes may inform future procurements.

5.2.4 Northeast Ontario (MISSW and FN Interfaces)

The transmission security outlook for the system west of the MISSW and FN interfaces are illustrated in Figure 30 and Figure 31, respectively.

The security outlook for MISSW shows that there is a need for approximately 400 MW of additional capacity starting in 2029, coinciding with the connection of new industrial loads. Substantial government support is being provided for decarbonization initiatives that would promote intensification of electricity use (e.g. electric arc furnaces), resulting in a potentially large increase in industrial electricity use. This additional 300 MW of industrial load is assumed to remain for the duration of the forecast period.

The zonal constraints in Section 5.1 show that to meet resource adequacy standards there are no minimum locational requirements in the Northeast. The security outlook for FN, on the other hand, shows a local capacity need of approximately 500 MW in 2029 to meet transmission security standards. This is being driven by the same connection of new industrial load described above, under the assumption that existing resources are reacquired. Without the reacquisition of existing resources, this gap could start in 2024.

A bulk power system plan is currently being developed for Northeast Ontario to address the supply gap shown in Figure 30. The scope of studies will determine if the transmission infrastructure located west of Sudbury (to Wawa) is sufficient to supply the forecasted demand growth west of Sudbury in Northeast Ontario to the Northwest region.

Finalizing the plan, and considering engagement with affected stakeholders and communities, is expected to be complete by Q2 2022.

Figure 30 | MISSW Security Outlook – All Elements Initially in Service

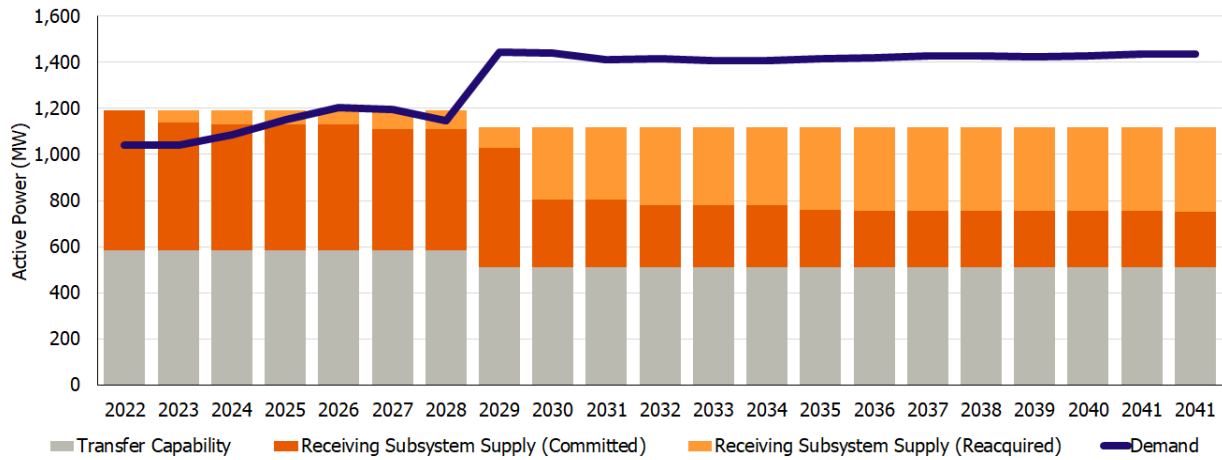
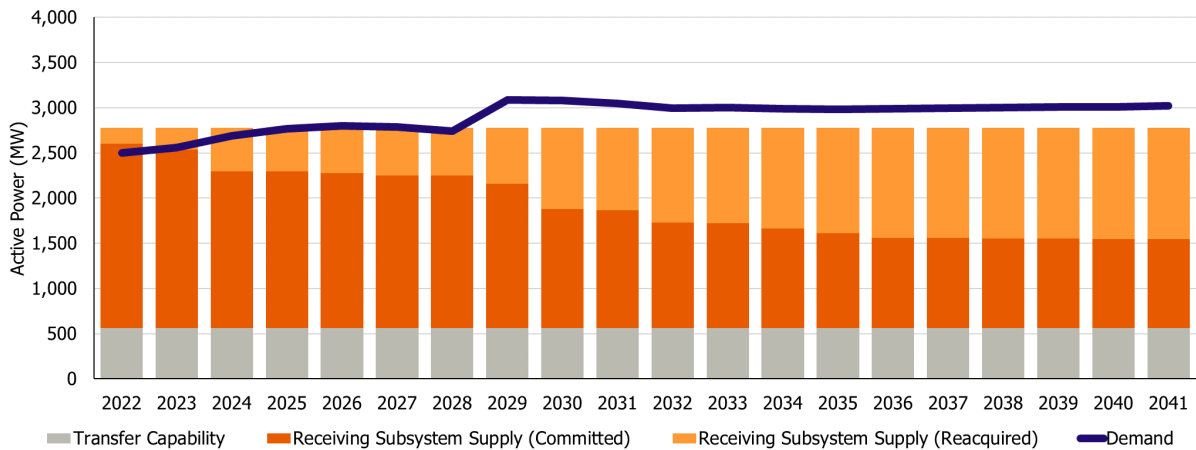


Figure 31 | FN Security Outlook – One Element Initially out of Service



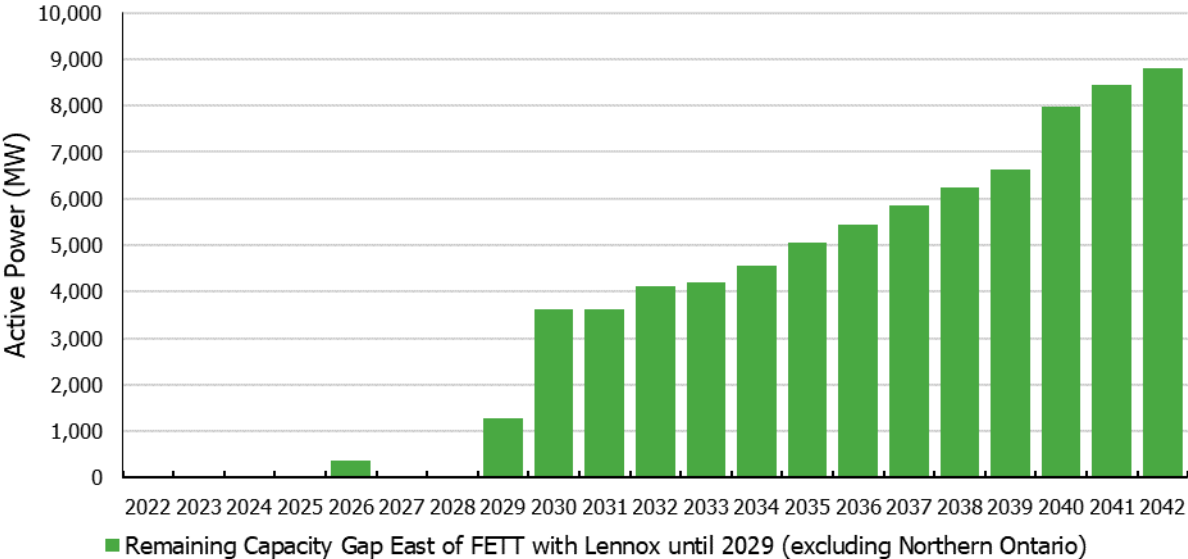
5.3 Combined Locational Requirements for Resource Adequacy and Transmission Security

This section summarizes all of the locational capacity requirements noted in this chapter. This section is intended to serve as an input to the Resource Adequacy Framework, which sets forth the mechanisms for acquiring capacity to meet both province-wide and locational needs. These locational needs, shown in Figure 32 through Figure 34, are the remaining capacity gaps in specific locations in the system, after considering the portion of the need that has been addressed through bulk and/or regional transmission plans that are already in place.

For the West Zone, there are no further requirements to locate capacity in the West of London area beyond what is described in the "[Need for Bulk System Reinforcements West of London](#)" study.

For the area east of the FETT interface, a capacity gap emerges starting in the mid to late-2020s, as illustrated in Figure 32. This is being driven by generation retirements and growing demand projections east of the FETT interface, after considering the planned FETT transmission reinforcement and Lennox GS continuing operation until 2029. Without continued availability of the remaining resources east of FETT, compliance with transmission security criteria on the FETT interface will result in the emergence of this capacity gap.

Figure 32 | Capacity Gap East of the FETT Interface (Summer)

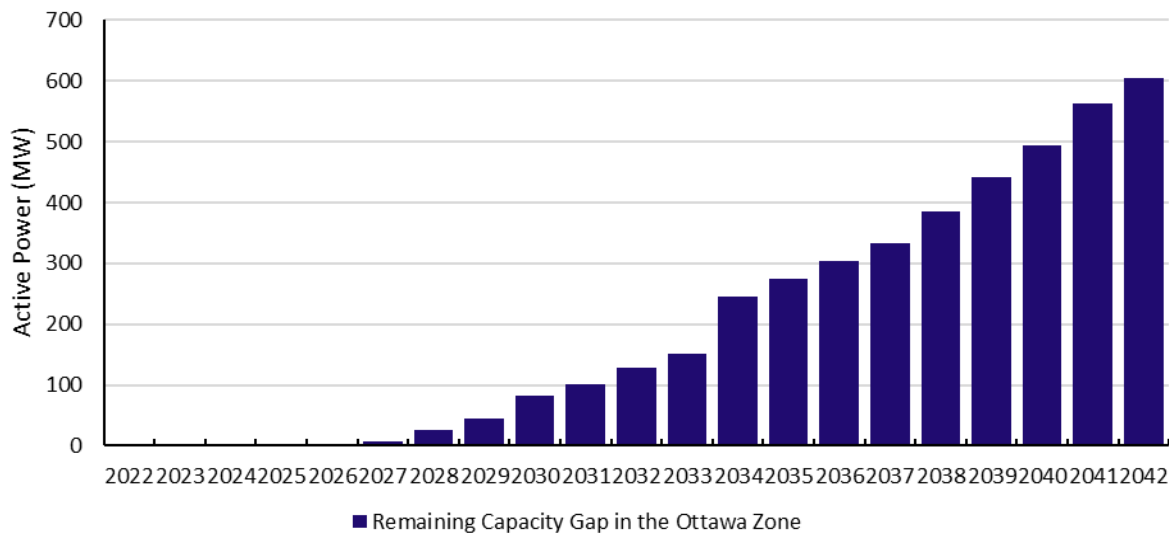


Note: Assumes that existing resources are unavailable after their commitment period ends, with the exception of Lennox GS

This situation will be monitored closely as the IESO acquires supply resources to meet the provincial resource adequacy requirement. Some of these resources are likely to be located east of FETT. Any resources acquired east of FETT, including the re-acquisition of existing resources after their commitment period ends, will contribute to addressing this need.

Growth in the Ottawa area is contributing to a capacity gap in the Ottawa Zone beginning in 2027. This gap, shown in Figure 33, is related to the transmission security outlook for the FIO interface, which will limit the amount of growth in Ottawa that can be supplied by resources from elsewhere in the province. This capacity gap occurs during the summer peak.

Figure 33 | Capacity Gap in the Ottawa Zone (Summer)

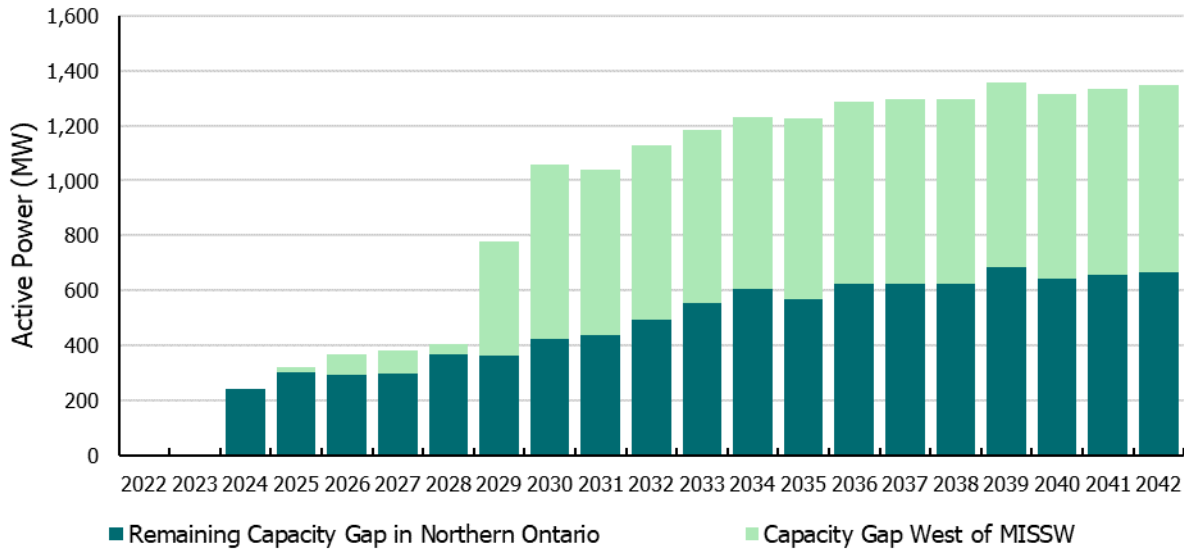


Note: Assumes that existing resources are unavailable after their commitment period ends

The Gatineau Corridor End-of-Life bulk study is looking at options that may defer this locational need into the longer-term period, as discussed in Section 5.5. These options aimed at addressing the existing end-of-life transmission infrastructure that supplies eastern Ontario, including the Ottawa and Peterborough areas, could result in an increase to the transfer capability of the FIO interface.

In the area to the west of the MISSW interface, a capacity gap begins to emerge beginning in 2025, and increases sharply in 2029 as a result of the projected industrial growth in northeast Ontario. This need occurs in the winter and is shown in Figure 34. In addition to the area west of MISSW, there is a broader capacity gap forecast for the rest of northern Ontario, as also shown in Figure 34. The remaining capacity gap in northern Ontario is due to steady industrial growth and expiring contracts of local resources.

Figure 34 | Capacity Gap in Northern Ontario including MISSW (Winter)



Note: Assumes that existing resources are unavailable after their commitment period ends. For clarity the area West of MISSW is part of Northern Ontario

The Northeast bulk system study will evaluate possible options for addressing the gap affected by the transmission security outlook for the MISSW interface. The remaining capacity need, such as that shown for northern Ontario, can be addressed by additional resources strategically located in the north, and/or transmission reinforcement.

6. Integrating Electricity Needs

Determining Ontario's overall capacity needs means integrating provincial needs with locational requirements. Building on the outcomes of Chapters 4 and 5, this chapter summarizes the system needs over the outlook period.

Given the availability of existing resources after contracts expire, Ontario is expected to see unserved energy needs, in the order of 12 TWh, by the end of the planning horizon.

In addition, through the latter part of the planning horizon, existing resources that continue to be available after contract expiry will be required to run at higher capacity factors compared to current operation, in order to meet energy demands.

6.1 Capacity Needs

Some of the province's forecasted needs can be met by the continued availability of existing resources after their contracts expire. However, what remains available depends on a number of factors, including asset age and condition, the need for capital investment, market conditions, and acquisition mechanisms.

The following figures depict locational needs without reacquired resources, and consider the resource adequacy constraints and transmission security needs identified in previous chapters. Only contracted generation, as of publishing, is included as an existing resource.

Figure 35 | Summary of Summer Capacity Needs including Locational Requirements, without Continued Availability of Existing Resources²⁸

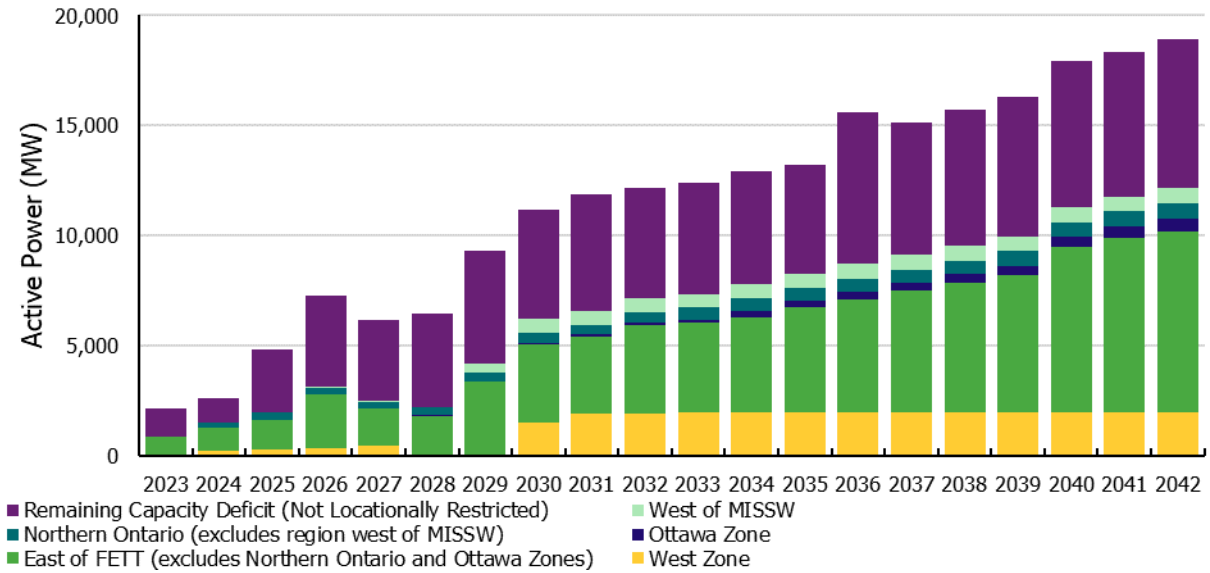
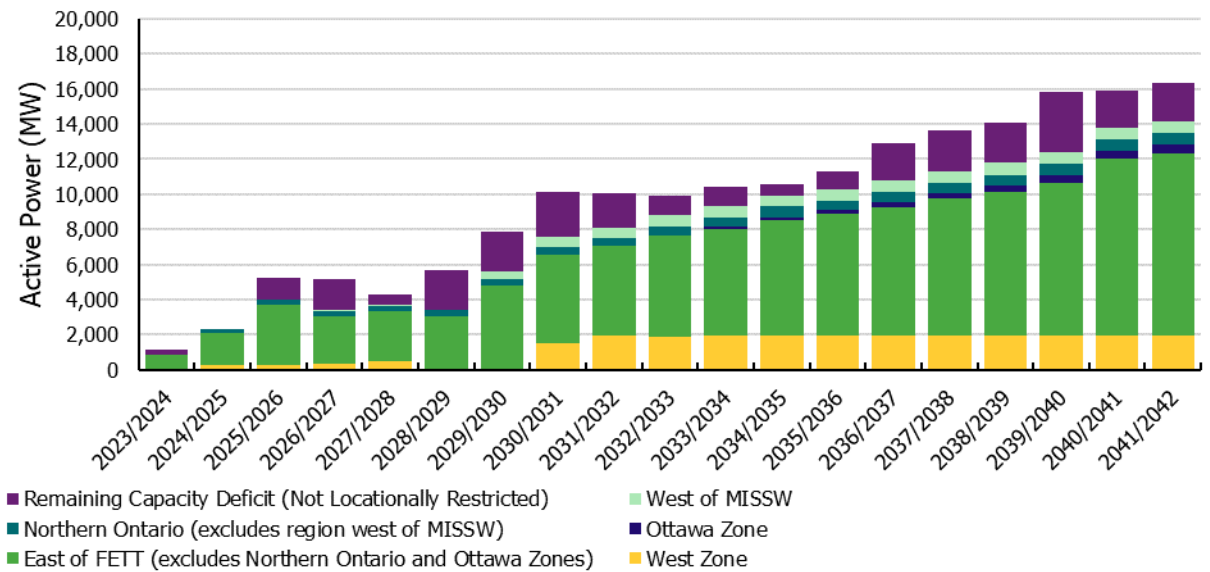


Figure 36 | Summary of Winter Capacity Needs including Locational Requirements, without Continued Availability of Existing Resources²⁹



²⁸ Northwest and Northeast capacity gaps shown are for the winter months. The summer capacity need is expected to be less than the winter capacity need.

²⁹ The east of FETT (excludes Northwest, Northeast, and Ottawa Zones) capacity gap shown considering summer transfer capabilities. The winter transfer capability of FETT is expected to be larger than the summer transfer capability of FETT, effectively reducing the capacity gap further.

Sources of forecasted capacity needs are listed below.

- The capacity need emerging in 2023 is primarily due to Lennox GS reaching the end of its contract term. This need is concentrated to the East of the FETT interface. Given the geographical significance of Lennox GS, the IESO is expected to extend its contract to 2029, as outlined in the AAR.
- The west Zone need shown in 2024 to 2028 will be addressed by the continued operation of Brighton Beach GS. The IESO intends to enter into bilateral negotiations for continued operation of Brighton Beach GS this need in this period. Other needs in the West Zone emerging in the long-term period will be addressed through implementing the West of London bulk study recommendations pertaining to local resource requirements.
- In the 2024-2025 period, Pickering NGS is expected to retire. Furthermore, the nuclear refurbishment program will continue through the 2020s and into the 2030s, with between two and four nuclear unit refurbishments at Bruce NGS and Darlington NGS taking place concurrently over the summer period for most years until 2030.
- The majority of contracts with natural gas-fired and renewable generation are expected to expire over the next two decades. If capacity from all existing resources is reacquired post contract/commitment, there is no incremental need for new capacity until 2025.
- Most of Ontario's natural gas generation facilities are located in the West Zone and Toronto Zone, contributing to the locational nature of some needs.
- The forecasted demand over the planning horizon is less significant a driver than Ontario's changing supply outlook, but demand is still an important factor contributing to Ontario's capacity needs.

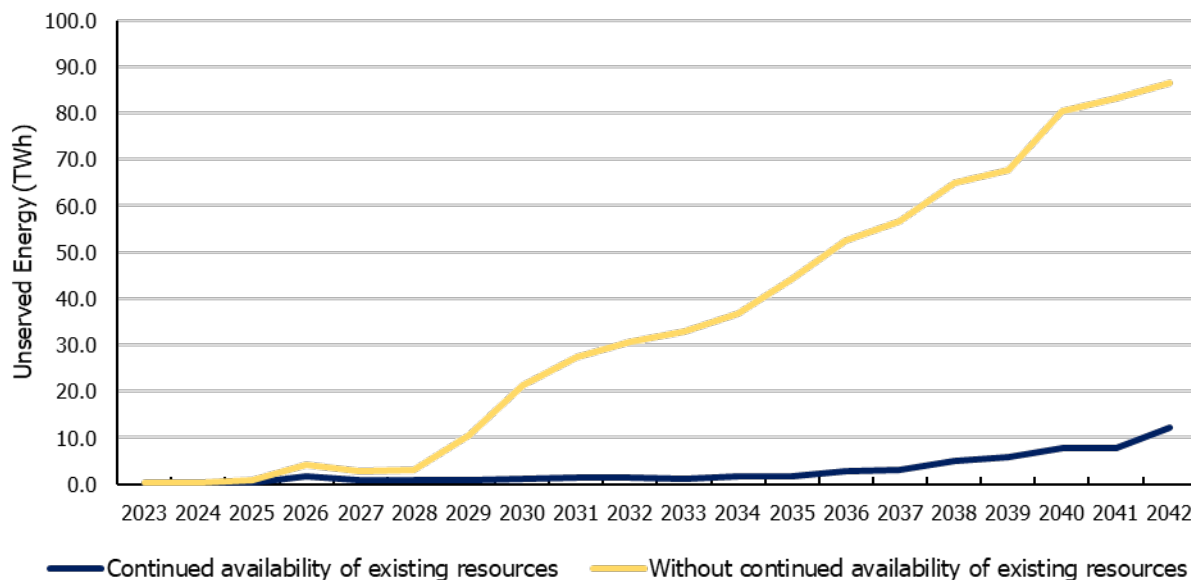
6.2 Energy Needs

Further to capacity requirements, Figure 37 illustrates the potential for unserved energy, demonstrating that capacity needs identified above also eventually lead to an energy need.

Ontario is expected to observe unserved energy needs, in the order of 12 TWh, by the end of the planning horizon should existing resources continue to be available. This suggests that existing resources will not be sufficient to meet energy requirements and Ontario will require new resources and/or imports.

If resources become unavailable or constrained, the potential for unserved energy begins in 2026 and grows substantially, suggesting that the ability to provide energy could be a consideration in the medium-term and/or long-term RFPs. These considerable energy shortfalls are mainly due to expiring contracts from both combined gas cycle generation and renewable energy resources.

Figure 37 | Potentially Unserved Energy



Another way to illustrate the extent of energy adequacy needs is through load duration curves. Assuming continued availability of existing resources in the near term, adequacy needs are primarily for capacity and not energy, as enough energy production capability exists for most periods of time. Energy needs become more prominent in the latter years of the planning horizon.

Figure 38 and Figure 39 show the duration curves of demand, demand net of baseload resources, and demand net of all existing resources (representing the unserved energy) for 2023 and 2042. Demand net of baseload resources refers to demand after the production of nuclear, hydroelectric, solar, wind, combined heat and power, and bioenergy. Demand after all existing resources represents the remaining requirement after baseload and dispatchable resources. Resources beyond what the existing fleet can provide would be required to meet this demand.

By 2042, unserved energy (i.e., demand net of all existing resources) occurs about 60 per cent of the time with continued availability of existing resources and occurs at all hours without continued availability of existing resources.

Figure 38 | Duration Curves, with Continued Availability of Existing Resources

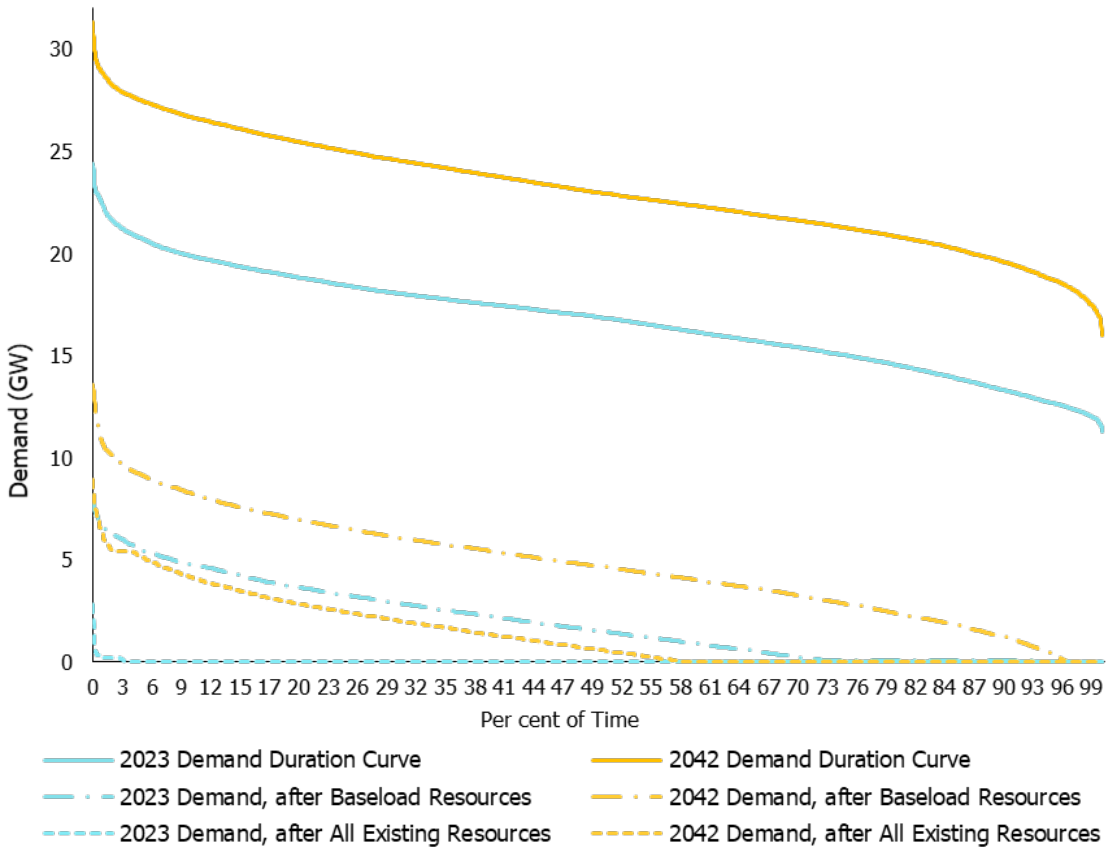
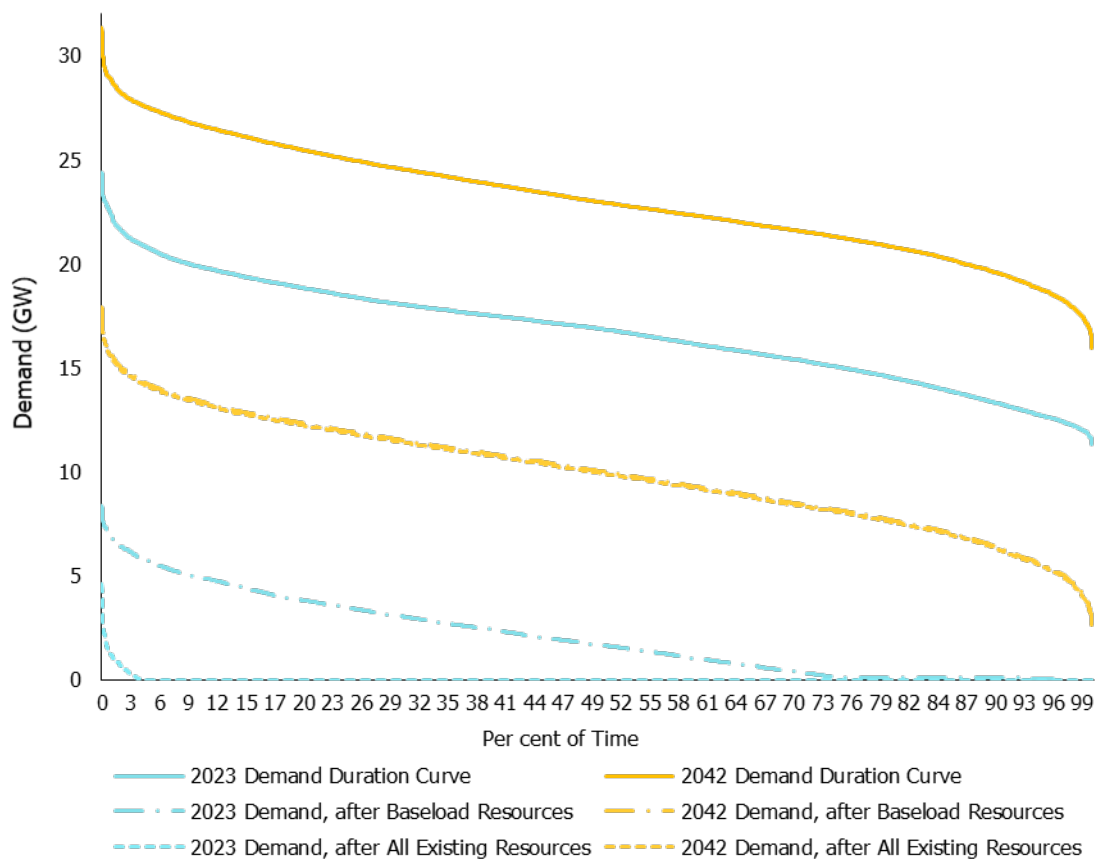


Figure 39 | Duration Curves, without Continued Availability of Existing Resources



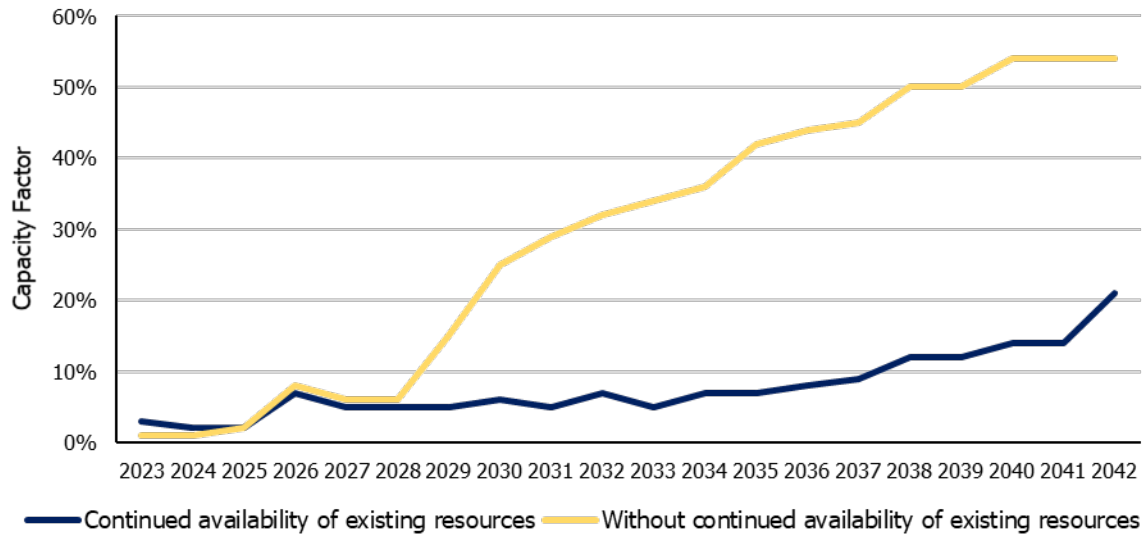
The IESO uses a new proxy resource³⁰ to demonstrate how to meet the unserved energy need observed above. To illustrate the level of energy requirement, the capacity factor³¹ of the new proxy resource used in the energy assessment to fill the gap between load requirements and the existing and committed resource fleet is shown in Figure 40. Existing resources are expected to operate at higher capacity factors should they continue to be available post contract expiry to meet increased demand requirements.

Including existing resources, the proxy resource is expected to operate at a capacity factor of around 5-10 per cent until the late-2030s, and increase to about 10-20 per cent by 2042. The capacity factor increases significantly without existing resources, illustrating system needs are not only for capacity but for energy as well. If resources become unavailable post contract expiry, the capacity factor of the proxy resource grows substantially starting in 2029.

³⁰ For electricity system modelling, proxy resources are new generation resources that are leveraged last on the supply stack and are assumed to be non-emitting.

³¹ A capacity factor is a ratio of a resource’s energy output over the maximum possible energy output over a period of time.

Figure 40 | Capacity Factor of New Proxy Resources to Meet Load Requirements



New resources required to meet future energy needs will have the opportunity to compete with existing resources in the energy and capacity markets. Resources can earn revenue in the energy market by offering energy at a lower price than the marginal resource. Flexible, dispatchable resources including dispatchable loads can also quickly react to short-term energy price spikes or provide operating reserve.

7. Outcomes and Other Considerations

The marginal cost of electricity production and electricity sector emissions are both forecast to increase over the outlook period, the first as a result of growing demand, the second due to nuclear refurbishments and retirements resulting in an increased use of Ontario's gas-fired generation fleet. Despite this forecasted increase, electricity remains a source of low-carbon energy in Ontario, and increased electrification of emissions-intensive sectors provides an opportunity to reduce overall province-wide emissions.

The results presented in this chapter are outcomes of the energy production outlook based on the supply mix discussed in Chapters 3 and 4. This mix reflects the continued availability of existing resources following the end of their contract term or commitment, and changes to the supply mix over the outlook period would result in changes to the outcomes described below.

7.1 Marginal Resources

Long-term power system plans use an economic dispatch model that schedules resources to meet system needs based on least cost. This model considers each resource's production or variable costs, which typically include fuel and variable operating 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., wind or solar). 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 usually a natural gas-fired generator; overnight during autumn, gas-fired generation is less likely to be the marginal resource.

7.2 Marginal Costs

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.

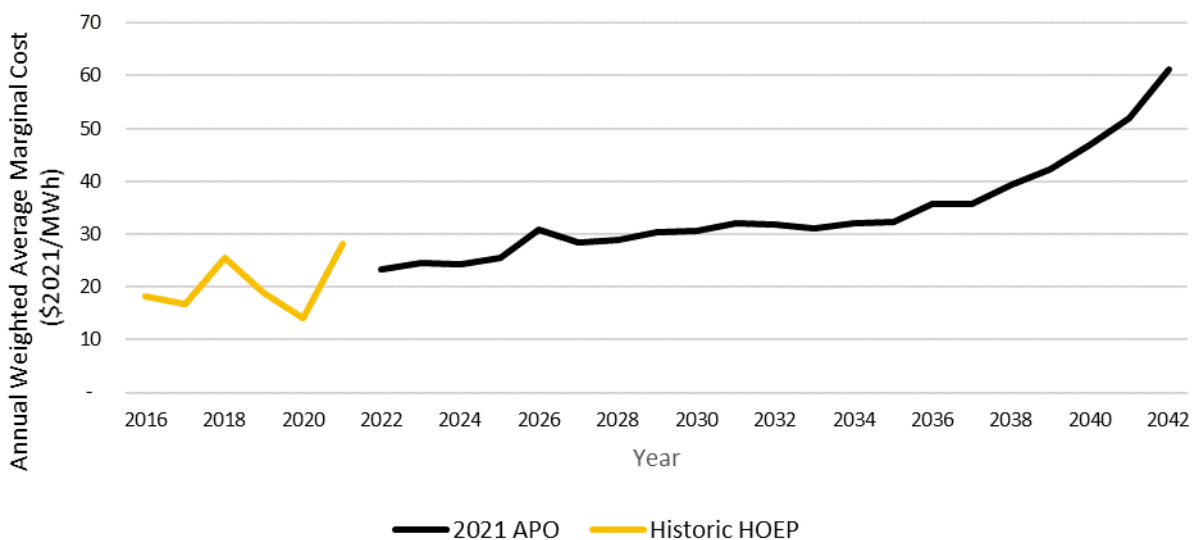
Marginal costs provide the trajectory of market prices, which can differ widely due to market participant behaviour, congestion and other factors. When a fundamental change to the supply

mix occurs – such as the retirement or refurbishment of nuclear units – marginal costs illustrate the expected impact on prices by providing an indication of the change in production costs.

With the refurbishment of nuclear units and demand increases in the long term, marginal costs are expected to increase as gas-fired generation becomes the marginal resource more often. Furthermore, the forecasted demand increase is expected to increase Ontario’s reliance on imports which could also put upward pressure on marginal costs in the long term.

Figure 41 illustrates the weighted average marginal costs forecast and the historical Hourly Ontario Energy Price (HOEP). The average marginal costs can also be found in the [data tables](#). Note that there is significant uncertainty pertaining to these values in the later years of this forecast. Substantial use of the proxy resource discussed in Section 6.2 beyond 2035 puts significant upward pressure on marginal costs; should the true resources that this represents turn out to have low marginal cost (e.g. SMRs, hybrid resources), the average marginal cost in these years would be expected to be lower.

Figure 41 | Weighted Average Marginal Costs Forecast, and Historical HOEP³²



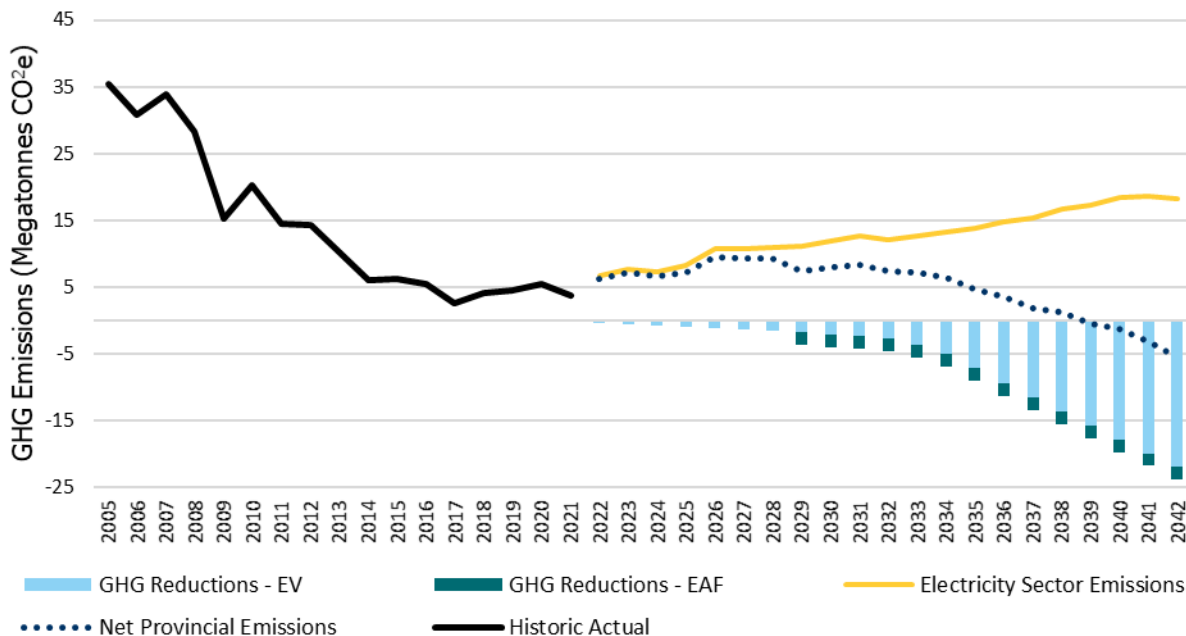
³² 2021 Actual HOEP is year-to-date as of December 7, 2021

7.3 Greenhouse Gas Emissions

Electricity sector emissions are forecast to increase to 11.9 Mt CO₂e by 2030 due to reduced nuclear production and growing demand, resulting in increased production from gas-fired generation, as shown in Figure 42.

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 overall 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 42 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: electric vehicles (EV) and the electric arc furnace (EAF) at Algoma Steel expected to be in service in 2029. The dotted line in Figure 42 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. Further details can be found in the methodology and [data tables](#).

Figure 42 | Electricity Sector Greenhouse Gas Emissions, Historical and Forecast³³



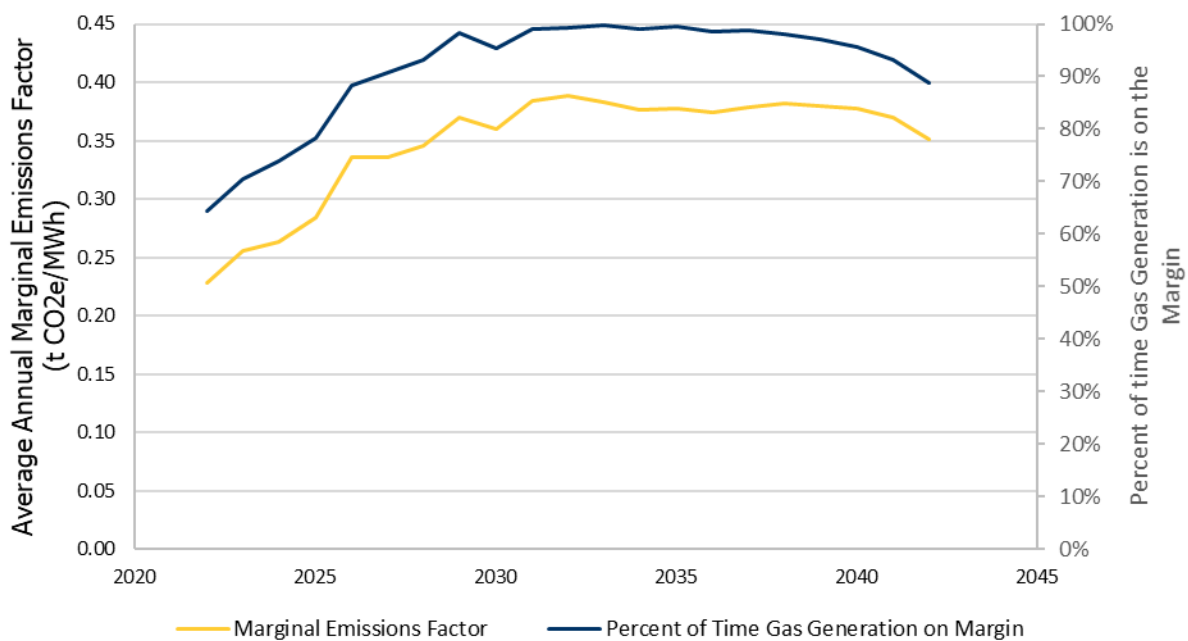
³³ Historical Emissions data for 2006 to 2019 is from Canada’s Official Greenhouse Gas Inventory: <http://data.ec.gc.ca/data/substances/monitor/canada-s-official-greenhouse-gas-inventory/>, emissions data for 2020 was estimated by IESO based on actual natural gas production. Emissions for 2021 and beyond are projected using IESO’s detailed energy dispatch model.

7.4 Marginal Emissions

Every five minutes, the IESO matches supply with demand to ensure a stable, reliable power system. Dispatch is based on price. Supply is stacked so that the cheapest resources are selected first until eventually the supply meets the demand. The last resource selected to meet demand is called the marginal resource. If additional capacity is required during this interval, the marginal resource would increase output to serve it. Therefore, the emissions rate associated with the marginal resource is an indicator of the potential GHG impact of increasing demand. The following plot summarizes the projected average annual marginal emissions factors along with the percent of time gas generation is projected to be the marginal unit.

The marginal emissions factor is very closely aligned to how often gas is on the margin since natural gas generation is the only resource type in Ontario’s fleet that generates GHG emissions.³⁴ Note that the marginal emissions factor only applies to the marginal resource (i.e., the last resource selected to meet the demand).

Figure 43 - Marginal Emissions Factors



³⁴ For the purposes of this forecast, biofuels are considered zero-emission resources.

7.5 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, which was accepted by the federal government on September 20, 2020. In the 2020 APO, the carbon price was assumed to rise to \$50/t CO₂e by 2022 and remain at that level indefinitely. In this outlook, the carbon price was increased to align with the federal government's announcement that it intends to increase the carbon price to \$170/t CO₂e by 2030, and remain at that level for the duration of the planning period.³⁵ 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](#).

³⁵ <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>

8. Uncertainties

There are a number of growing uncertainties impacting Ontario's electricity grid, ranging from the amount of electricity demand growth to supply constraints. Uncertainties in a demand forecast are not unusual, but what is different this time and relatively unseen in the last decade, is the upward pressure on demand, changing consumer preferences, government policy surrounding decarbonization, and evolving constraints on supply.

If all of the possibilities outlined in this section are realized, by 2042 energy demand could be more than 10 per cent higher than in the reference forecast, while summer and winter peaks could be 8 per cent and 11 per cent higher respectively. The IESO's Resource Adequacy Framework has been designed to flexibly address changing needs; however, the highest demand outcomes presented here will be challenging to meet in the near term.

8.1 Demand Forecast

Prior to the COVID-19 pandemic, electricity demand in Ontario trended downwards for several years. Today, with growing interest in decarbonization policies and increased economic activity, the province is expected to see increases in electricity demand for the foreseeable future. Yet as markets and policy on climate change mitigation and economic development quickly evolve, predicting the timing, location and scale of increases in electricity demand is becoming more challenging.

In light of a number of significant uncertainties, a high demand forecast has been developed to reflect potential, and reasonably probable, increases in electricity demand. This high demand scenario forecast includes: a) current trends towards electrification; and b) potential large industrial sector loads materializing in Ontario as a result of economic growth.

Should all potential drivers materialize, electricity demand could grow to 224 TWh by 2042, with a 33.7 GW summer peak and 33.8 GW winter peak. This represents a total increase of 22 TWh, with a 2.4 GW higher summer peak and 3.3 GW higher winter peak than in the reference scenario demand forecast.

The high demand scenario has an annual growth rate of 2.3 per cent for energy, 1.7 per cent for summer peak and 2.3 per cent for winter peak. Figure 44 and Figure 45 below display the delta between the reference and high demand scenarios. Table 6 illustrates the sectoral difference between the two forecasts.

Figure 44 | Energy Demand by Scenario

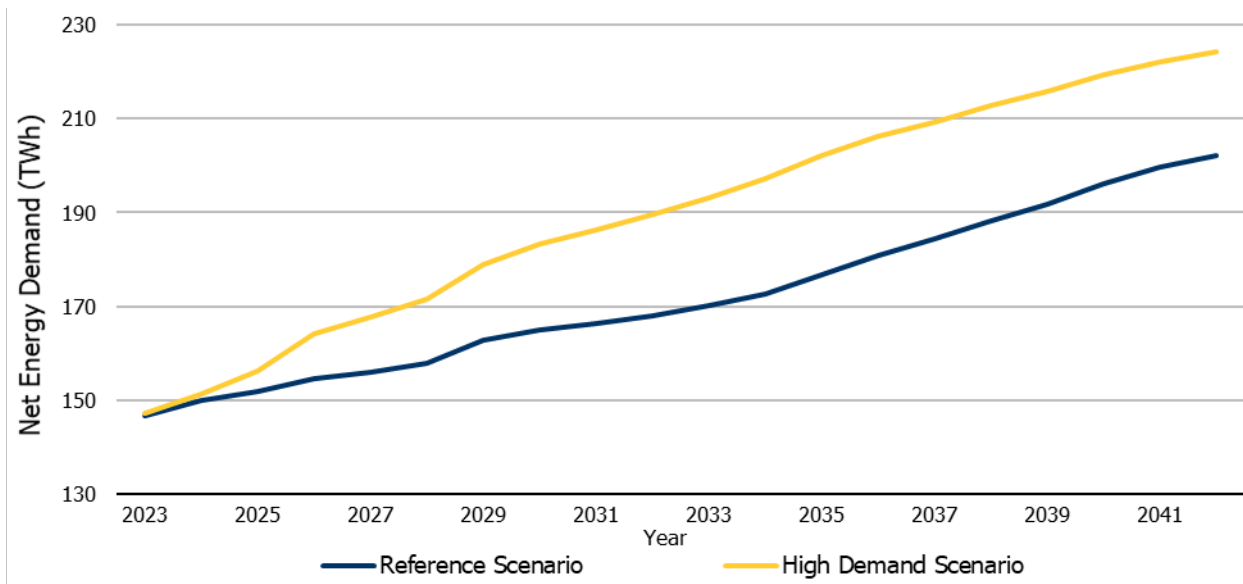


Figure 45 | Season Peak Demand by Scenario

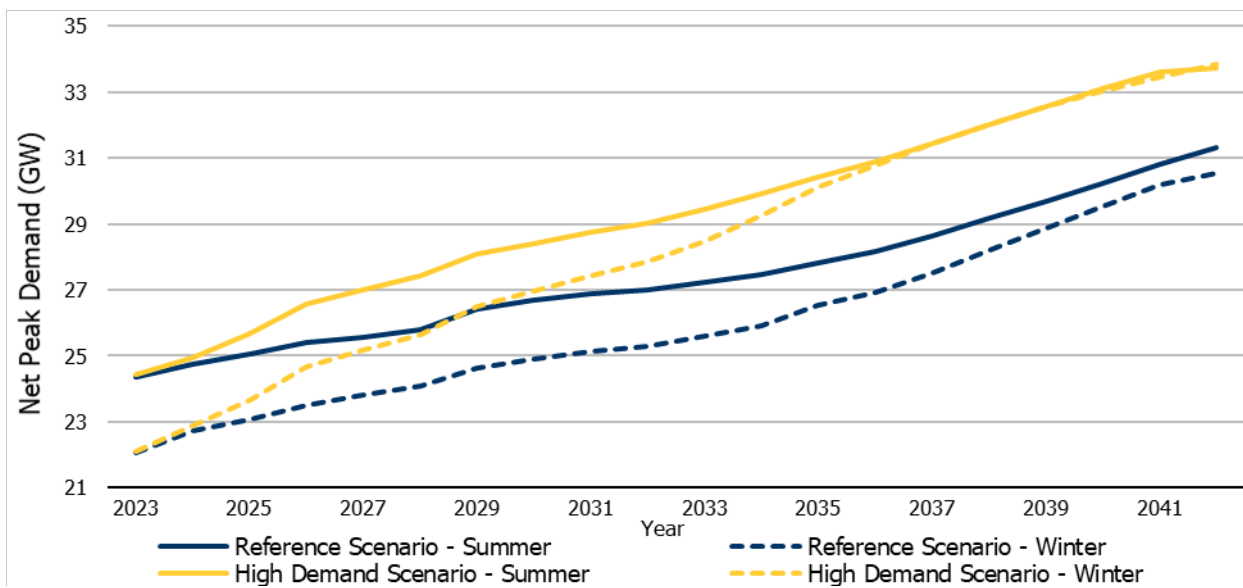


Table 6 | Sector Variance by Scenario

Sector	Reference Scenario	High Demand Scenario
Residential	Work-from-home assumption: 15% of workers for years 2023-2025 Baseline space and water heating heat pump uptake	Work-from-home assumption, 50% of workers for entire outlook period Increased uptake of electric heat pumps for space and water heating, by an incremental 15%. The increase ramps up over the first 10 years and remains constant for the last 10 years of the outlook period
Commercial	Work-from-home assumption: 15% of workers for years 2023-2025 Baseline space heating and water heating heat pump uptake	Work-from-home assumption, 50% of workers for entire outlook period Increased uptake of electric heat pumps for space and water heating, by an incremental 15%. The increase ramps up over the first 10 years and remains constant for the last 10 years of the outlook period
Industrial	Northern Ontario regional planning mining forecast reference scenario No electric vehicle battery manufacturing facilities No ArcelorMittal Dofasco electric arc furnace	Northern Ontario regional planning mining forecast high demand scenario Electric vehicle battery manufacturing facilities ArcelorMittal Dofasco electric arc furnace
Agriculture	Need for Bulk System Reinforcements West of London – reference scenario	Need for Bulk System Reinforcements West of London – high demand scenario
Transportation	Mandatory policy achievement: 100% of new vehicle sales to be GHG emissions free by year 2035	Voluntary policy achievement: 50% of new vehicle sales to be GHG emissions free by year 2030
Industrial Conservation Initiative	Response on top 5 system peak day, system peak hour remains flat at 1,300 MW for outlook period	Response on top 5 system peak day, system peak hour grows to 1,800 MW by 2030

8.1.1 Government Policy

Climate change policy has created an increased demand for clean energy technology and can be assessed by the following categorizations:

Impact on Mining: Renewable energy, storage, and electrification technologies all depend significantly on metals and minerals, many of which are mined in Ontario. Depending on the pace of energy transition, the current global demand for minerals may quadruple by 2040 if the goals of the Paris Agreement are to be met. Ontario's mining industry is well positioned to compete in this area, and the Government of Ontario's Critical Mining Strategy is encouraging growth within the sector. The mining sector in northern Ontario could potentially grow nearly 15 per cent per year through 2026 and then stabilize, as most potential new and/or expansion projects will have materialized, and remaining potential projects are offset by existing mines reaching their end-of-life phase.

Transit Electrification: Increased demand from federal targets for zero-emissions vehicle sales could mean an earlier adoption curve for light duty electric vehicles (a maximum of a 125 per cent increase over the reference scenario, occurring in 2032), and electric buses (a 10 per cent increase over the reference forecast assumptions).

Decarbonization: Several municipal governments have made public announcements either committing to, or in support of, a phase out of natural gas-fueled electricity generation. Furthermore, the Ministry of Energy has directed the IESO to [investigate pathways to a zero emissions electricity grid](#). Future carbon policy, which may be aimed at decarbonization through electrification, therefore has the potential to create additional upward pressures on electricity demand.

The high demand forecast assumes the following:

Residential Sector: for space and water heating end-uses, an assumed incremental 15 per cent increase per year in the uptake of electricity-fueled heat pumps, with a corresponding decrease in natural gas, propane and heating oil-fueled furnaces over the reference scenario.

A greater level of persisting work-from-home practices, representing 50 per cent of office workers and resulting in higher energy and peak demand over the entire outlook period.

Overall, the high demand scenario for the residential sector projects an increase in energy demand of approximately 3 TWh per year over the reference scenario forecast, nearly 5 per cent by 2042.

Commercial Sector: Similar to the residential sector, the commercial sector could experience the impact of space and water heating electrification as a result of new installations and replacement of existing stock. The high demand scenario projects an incremental 15 per cent higher uptake than the reference scenario through an increase in efficient air and ground source heat pumps, as well as a decrease in fossil fueled furnaces.

8.1.2 Economic Activity

Industrial growth is being driven by a rapidly recovering economy and significant government stimulus. A series of large projects are being proposed for Ontario, including production facilities in the emerging vehicle battery cell manufacturing sector. The auto sector is also repositioning to meet increasing demand for electric vehicles, and some investments may be located in Ontario given the province's current auto sector capability and support.

These large industrial projects and expansions are currently in the proposal stage, targeting an in-service date within five to 10 years. Depending on the location, some will require significant transmission system upgrades to connect. Not all proposed projects are expected to materialize in Ontario, but the success of a medium proportion of proposals could increase energy demand by approximately 2.3 TWh per year and approximately 500 MW.

Further, ArcelorMittal Dofasco has announced its intention to implement an electric arc furnace at its steel production facility by 2026, estimated to increase demand by approximately 300 MW.

Agricultural Sector: The higher demand forecast also assumes current connection requests are completed faster (in two years rather than five) than previously assumed, with a 6 per cent growth rate (consistent with the long-term average, rather than flat demand) through 2035 that is unconstrained. This will require a faster buildout of required infrastructure, including electricity transmission system, natural gas, and water supply.

While the above-mentioned uncertainties are likely to increase electricity demand, there are also other uncertainties linked to future government direction that may decrease it. These include the Industrial Conservation Initiative and the provincial energy efficiency programs.

Industrial Conservation Initiative: The program is a form of demand response which allows Class A customers to manage their Global Adjustment costs by reducing demand during Ontario's system peak hours and days.

The reference scenario assumes 1,300 MW and 650 MW on the system peak hour of top five and second top five system peak days respectively; the higher demand forecast assumes 1,800 MW and 900 MW for the same.

This higher reduction values are attributable to associated incremental demand growth in the industrial sector.

The following sectors / drivers have no assumption variances when compared to the reference forecast:

- Conservation Regulations (building codes and equipment standards)
- Fuel Rate Forecast (electricity, natural gas, other)
- Base Year
- Embedded Generation (non-market participant generators; solar, wind, hydro, bio, combined heat and power)

Conservation programs: The assumptions for provincial conservation programs are consistent with the reference scenario demand forecast. However, as supply constraints are increasing, the role of conservation will increase. Based on Scenario B of the joint Ontario Energy Board and IESO 2019 Conservation Achievable Potential Study, conservation has the potential to reduce energy needs by 15 TWh and 2,620 MW of peak demand.

In accordance with the September 30, 2020 Ministerial Directive, in 2022 the IESO will begin the 2021-2024 Conservation and Demand Management Framework Program and Target Mid-Term Review, and will report the findings to the Minister of Energy no later than December 31, 2022, including:

- 1) The alignment of the demand reduction target, electricity target and the CDM Framework budget with the provincial, regional and/or local electricity system needs as identified by the IESO
- 2) The alignment of the CDM program offerings with consumer needs in Ontario, and a comparison against programs from other jurisdictions
- 3) Lessons learned and recommendations from competitive mechanisms for procuring energy efficiency resources, including results to date of the Energy Efficiency Auction Pilot
- 4) The progress and impact of CDM programs, including for low-income and income-eligible consumers and on-reserve First Nations consumers, and
- 5) Recommendations on the remainder of the CDM Framework.

8.2 Resource Adequacy

Figure 46 and Figure 47 illustrate the summer and winter capacity deficits under the high demand forecast compared with the reference demand forecast, without continued availability of existing resources post contract expiry/commitment. By the end of the planning horizon, in the summer, capacity needs increase to about 22,000 MW, and in the winter to about 20,000 MW.

Figure 46 | Summer Capacity Surplus/Deficit under High Demand Forecast, without Continued Availability of Existing Resources

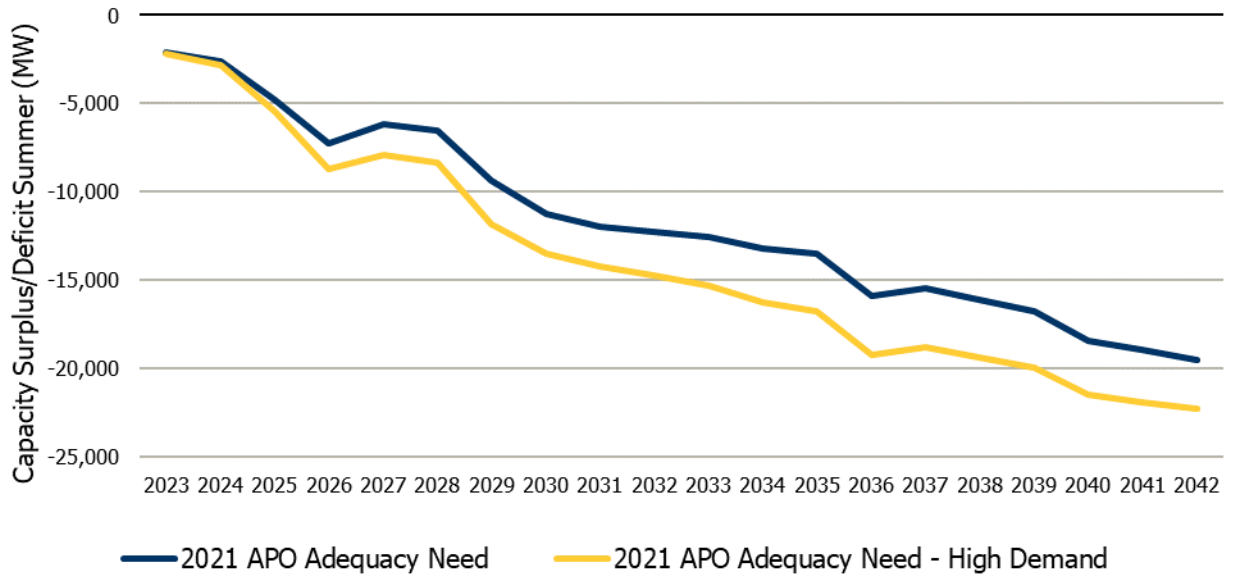
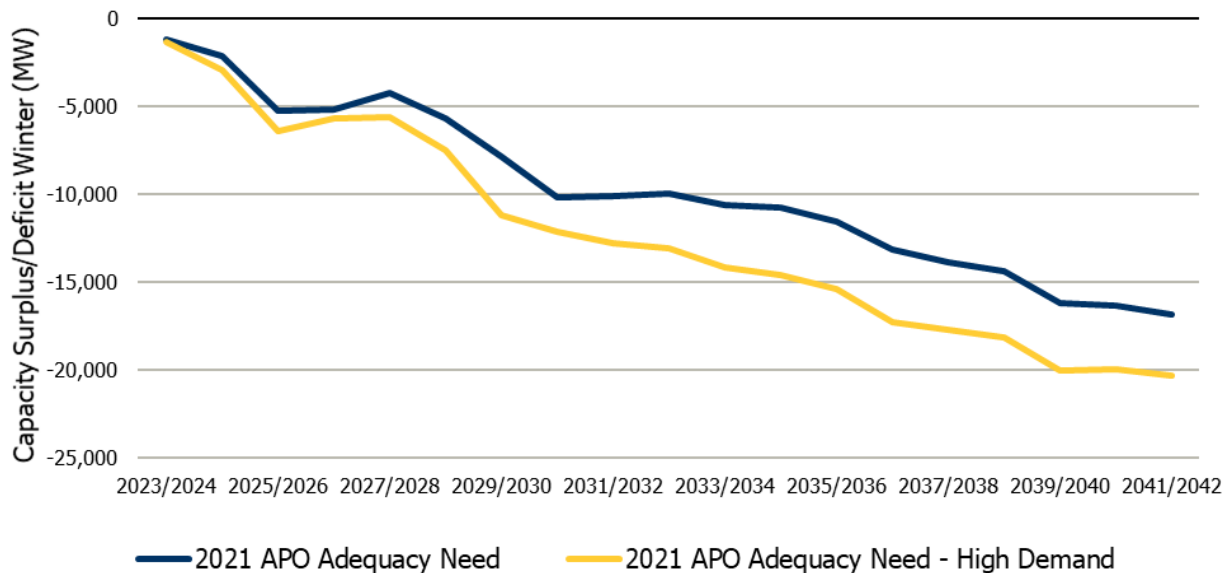


Figure 47 | Winter Capacity Surplus/Deficit under High Demand Forecast, without Continued Availability of Existing Resources



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