ELECTRICITY SUPPLY MIX STUDY

Electricity Supply Mix Study
The Retail Price Impact of Net-Zero Supply Options

Published:
December 2022

www.ospe.on.ca

ONTARIO
SOCIETY OF
PROFESSIONAL
ENGINEERS

TABLE OF CONTENTS

Acknowledgments ____ 3
Executive Summary ____ 4
Study Results ____ 4
- Background and Introduction ____ 4
- Key Assumptions ____ 5
- Energy Storage and Cost Optimization ____ 5
- Summary of Main Results ____ 6
- Average Retail Electricity Rates for Different Supply Mixes ____ 7
- New Challenges with Net-Zero Supply Mixes ____ 9
- The Supply Gap from 2025 to 2030 ____ 11

References ____ 13

ACKNOWLEDGMENTS

OSPE wishes to acknowledge the contributions of the members and subject matter experts of OSPE's Energy Task Force (ETF) in the preparation of this report.

OSPE also wishes to thank Market Intelligence & Data Analysis Corporation (MIDAC) for performing the analysis and providing the graphical presentations in this report, and to Dr. Alex Pavlak, Maryland, Dr. Eugene Preston, Texas, and Paul Acchione, Ontario, for collaborating on the development of the models used to produce the results.

OSPE is the home of the entire engineering community in Ontario, where engineers come together to realize their full potential.

EXECUTIVE SUMMARY

This report estimates the average retail electricity rate that Ontario consumers will pay using various generation supply technologies to achieve a net-zero emission goal by 2035. All the supply mixes that are presented are constrained by the need to meet the North American Electric Reliability Corporation (NERC) reliability criteria. The report examines various combinations of wind, solar, nuclear, pumped hydroelectric storage and battery energy storage systems. Estimates are also provided of the amounts of curtailed production, generation nameplate over-build and discarded thermal energy for each supply mix.

The lowest cost, net-zero supply mix that reliably serves the 2035 high demand load forecast is the 2021 Ontario supply mix with additional nuclear generation and a modest amount of pumped hydroelectric storage with natural gas plants repurposed to supply reserve generation using renewable natural gas (RNG) fuel.

This study assumes that the additional generating capacity for each supply mix can be installed in time to meet the forecast load up to the 2035 time period. For severe weather events and other contingencies, it also assumes the availability of the necessary RNG fuel supply for the reserve generation. The time we refer to includes permitting, licensing, environmental approvals, financing, design, manufacture, site preparation, construction, and commissioning of each project.

STUDY RESULTS

Background and Introduction

Over the next few years, the retirement of over 3,000 MW of zero-emission nuclear capacity at Pickering Nuclear Generating Station (PNGS) will require decisions on how the supply mix should change during the next decade and also in the longer term to meet the province's electricity system climate change goals by 2035 and for the economy as a whole by 2050.

When PNGS retires, or even if it is refurbished, there will be a short-term shortage of installed capacity in the electricity system. Ideally, we will choose generation technologies to fill that short term gap that will also fit well in the post 2030 period so that we achieve both net-zero emissions and low retail electricity rates. If we choose poorly, retail electricity rates will be higher than necessary in the post 2030 period. That would have negative implications for long term economic development, job creation and the standard of living for people of modest and low income.

Consequently, forecasting electricity retail rates due to any change to the electricity system supply mix is an essential step before any decision is made in setting the future supply mix of a power system.

This report examines the impact on retail electricity rates that will result from electricity supply mix decisions intended to achieve net-zero emissions. OSPE hopes the insights provided in this report will help Ontario political leaders, the public and energy policy decision makers choose the best supply mix for Ontario consumers.

Key Assumptions

A number of assumptions are required to undertake a study of retail electricity rates. To limit the scope of the study, this report has not made any assumptions on future events. Therefore, future improvements to present generation technology, changes to interest rates, changes to inflation rates and the commercial availability of technologies that are currently being developed like small modular nuclear reactors and advanced batteries using cheaper materials have not been included in this study. All costs are in 2020 Canadian dollars. Also, to use a consistent dataset of costs, this report uses the 2020 overnight capital costs and operating & maintenance costs reported by the US National Renewable Energy Laboratory (NREL). The NREL dataset is available to the public and a web link is provided in the References section. Equivalent Canadian dollars were obtained by applying a currency adjustment of 1.3 CAD to 1 USD.

The hourly 2035 Ontario consumer load demand was set equal to the December 2021 version of the Independent Electricity System Operator (IESO) Annual Planning Outlook (APO), "High Demand Scenario" hourly load forecast. The IESO-APO "Reference Scenario" was not used because of recent public criticism that the IESO Reference Scenario had underestimated the load growth due to electrification of transportation and heating applications as a result of recent growing emphasis on energy decarbonization.

By using the IESO-APO 2035 load forecasts, a number of future load changes are automatically included in the total demand, including population growth, industrial activity growth, electrification of transportation and heating, conservation initiatives and additional use of greenhouses for crops.

This report assumes that any energy storage that is added is co-located with the generation that it serves. This is an important constraint; otherwise, the required amount of transmission and distribution will be much higher than has been modelled and costed in this report.

This report does not include the potential costs of any additional synchronous condensers that may be required for power system dynamic stability for supply mixes with large amounts of inverter-based generation (wind and solar PV).

Energy Storage and Cost Optimization

Generation and energy storage can play some of the same roles. If we use only generation to serve load, and we have periods of low demand, it will be necessary to curtail (lower production) so that supply and demand are in balance. Curtailment implies less than full utilization of the installed generation capacity. In a zero-emission power system, fuel costs are very low and fixed costs are very high. Consequently, it is often cheaper to employ some intermediate duration energy storage (10 to 50 hours at full rated power) to lower the resulting retail electricity rates. However, due to the high cost of long duration or seasonal storage (>100 hours at full rated power), there are limits to how much surplus production can be economically stored.

Also, when we use energy storage, we must pay a penalty for the inefficiencies in the round-trip loss of energy in the storage conversion processes. Energy losses can vary depending on the storage technology used and the charge/discharge cycles employed. Storage systems also have leakage losses even if the storage devices are sitting idle.

This report analyzes the cost of two storage options. Pumped hydroelectric storage (PHS) and battery energy storage systems (BESS) are evaluated separately for each of four net-zero generation supply mixes. Other storage technologies were not evaluated in this study because they have not been commercially proven at grid-scale or they were not technically suitable to provide the functionality needed to operate at grid-scale.

The energy losses for PHS are modelled as a 15% charging loss, 15% discharging loss and 1%/month leakage loss (evaporation and ground water leakage). Energy losses for BESS are modelled as 7.5% charging loss, 7.5% discharging loss and 5%/month leakage loss. These losses include power conditioning and control system losses.

While PHS is more expensive to build, it lasts much longer than BESS. As a result, the study found that PHS results in lower retail electricity prices for storage durations exceeding about 10 hours at full rated power. Unfortunately, Ontario has a limited number of suitable PHS sites. Some of the supply mixes with large amounts of wind and solar PV use more energy storage than can likely be built in Ontario if we choose PHS. While switching to BESS for those supply mixes is theoretically possible, the amount of BESS needed is very large. There will likely be limits on the availability of battery materials if the entire world decides to choose primarily wind and solar PV generation to meet their future electricity needs. Therefore, there are likely practical limits to the amount of energy storage that can be built in Ontario for those supply mixes with large amounts of wind and solar PV generation. If energy storage capacity is reduced, the retail electricity price will be higher than reported in this study for each supply mix.

This study manually optimizes the use of generation and energy storage to minimize the retail cost of electricity for each specific supply mix. Where more than one generation technology is added to serve the future additional load, the optimization procedure iteratively optimizes the additional generation technologies and energy storage to arrive at an optimized amount of each generation technology and energy storage that minimizes the resulting retail cost of electricity.

Because long duration energy storage is very expensive, it is not possible to store all the available surplus zero-emission electricity production. Consequently, some generation is underutilized in all net-zero supply mixes and the resulting amounts of curtailed zero-emission electricity are reported in Figure 3 for all supply mixes.

Summary of Main Results

There is considerable public debate about the best supply mix option that will achieve net-zero emissions in the electricity system by 2035. The debates often revolve around the price of electricity at the power plant delivery point or the so called levelized cost of electricity (LCOE). However, the LCOE cannot be used to directly infer what the retail rates will be. Each supply technology requires a different level of integration support from the overall power system to ensure operability and make the electricity supplied to consumers dependable.

The integration costs are not directly visible in the producer's contractual LCOE or the electricity system wholesale energy market price. The integration cost for each generation technology is incurred in other power system financial accounts that collectively result in the final retail rates that consumers pay for their electricity.

Consequently, relying only on the supply technology production costs or LCOE to inform decisions on what supply mix to choose can lead to very high retail electricity rates.

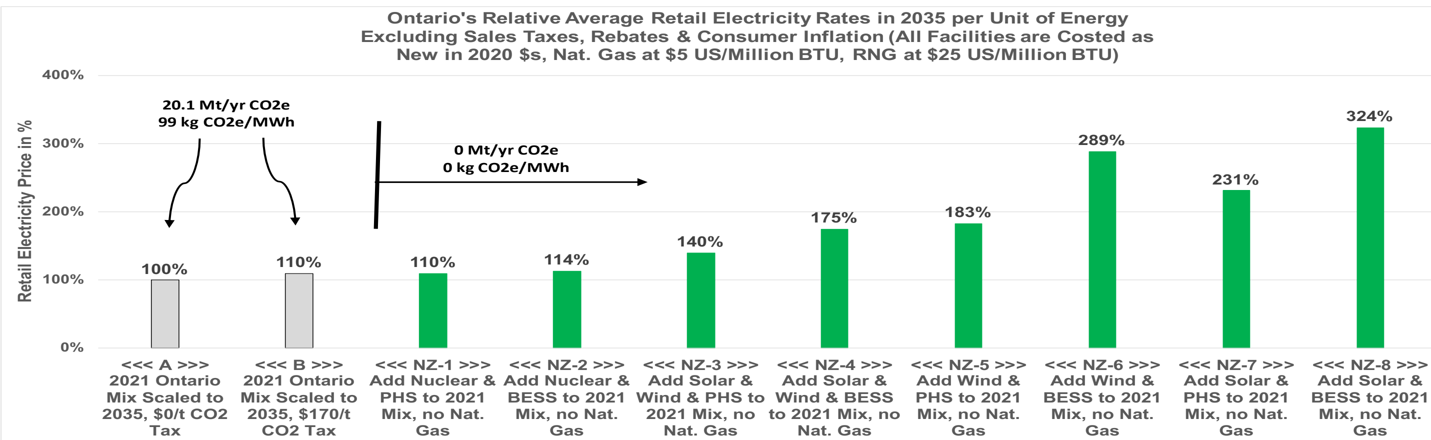
Average Retail Electricity Rates for Different Supply Mixes

The average retail electricity rate merit order of 10 different supply mixes were analyzed and are shown graphically in Figure 1 below.

Two supply mixes (supply mix "A" and "B") are not net-zero (see the grey bars in Figure 1). Supply mix A and B are included in this study for cost reference purposes. Supply mix "A" is defined as the 100% retail electricity rate reference point. It represents the 2021 Ontario supply mix scaled up proportionally to meet the 2035 peak load demand with a carbon price or tax of zero.

Supply mix A and B use natural gas to supply about 16% of the domestic electricity demand. Therefore, they are not net-zero supply mixes because we have not included the cost of carbon capture and storage (CCS). CCS costs are still too speculative to include in this cost study.

Figure 1



Supply mix B is the same as A but with a carbon tax of $170 CAD/tonne CO2. Canada's carbon tax is scheduled to reach $170 by 2030. Supply mixes A and B emissions also include a 3% leakage factor for natural gas from the well-head to the power plant with a 28x global warming potential (GWP) for methane (CH4) compared to carbon dioxide (CO2). The associated annual operating emissions of CO2 equivalent for each supply mix are also shown in Figure 1 for readers' information.

The other 8 supply mixes NZ-1 to NZ-8 are net-zero supply mixes (see the green bars in Figure 1). They are all comprised of zero-emission generation and renewable natural gas (RNG) reserve generation. Higher efficiency combined cycle gas turbines (CCGTs) are assumed for the RNG fired plants because of the very high cost of RNG.

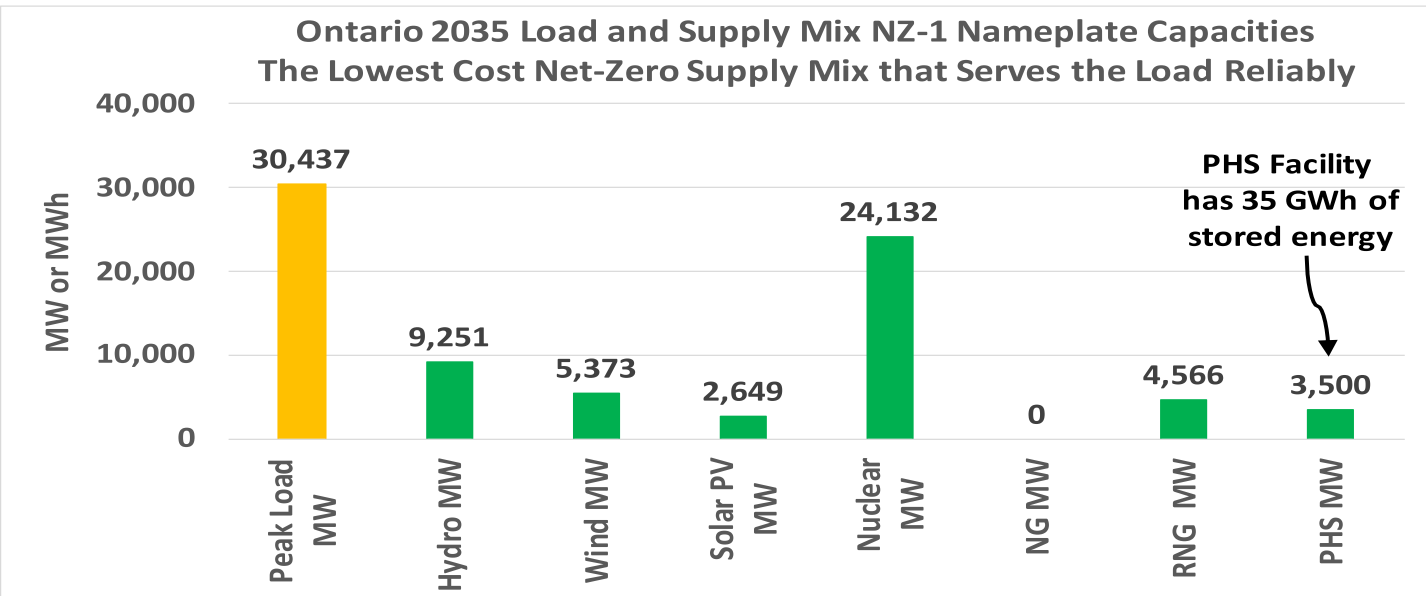
This report did not consider using RNG to supply a significant percentage of the load demand because the quantities of RNG are limited in Canada.

This report does not show a net-zero supply mix with additional hydroelectric generation because Ontario does not have any remaining low-cost hydroelectric sites close to load centers. Purchasing hydroelectric power from Hydro Quebec or Manitoba was studied in the past by Ontario Hydro and found to be prohibitively expensive compared to building nuclear generation domestically. That is one of the reasons Ontario has a large nuclear fleet instead of large transmission corridors to Quebec or Manitoba.

All net-zero supply mixes are comprised of the 2021 year-end Ontario installed nameplate capacity mix minus the Pickering Nuclear Generation (PNGS) capacity and with the natural gas plants repurposed for use as reserve generation using RNG fuel. Then, various combinations of nuclear, variable renewables (wind and solar photovoltaics (PV)), pumped hydroelectric storage (PHS) and battery energy storage systems (BESS) are added in sufficient amounts to serve the load reliably. Each combination is identified as a different net zero supply mix.

The lowest cost net-zero supply mix NZ-1 represents additional nuclear generation with a modest amount of PHS. NZ-1 will increase average retail electricity rates by 10% compared to our reference supply mix A. NZ-1 has the same average retail electricity rate as supply mix B with a $170 carbon price. Figure 2 below shows the nameplate capacities for supply mix NZ-1 needed to serve the load reliably in 2035 using the Independent Electricity System Operator (IESO) high demand scenario. The nameplate capacities shown in Figure 2 represent both the high voltage transmission connected generation and the embedded generation in the lower voltage distribution system.

Figure 2



For supply mixes A, B, NZ-1 and NZ-2, most of the solar generation is connected to the distribution system. Most of the wind, hydroelectric and RNG reserve generation is connected to the transmission system. All the nuclear generation is connected to the transmission system.

Supply mixes NZ-3 to NZ-8 contain large amounts of variable generation (wind and solar) and require significant amounts of storage to ensure system operability and serve load reliably. That means the retail electricity rates rise significantly as the variable generation nameplate capacity rises (see Figure 1).

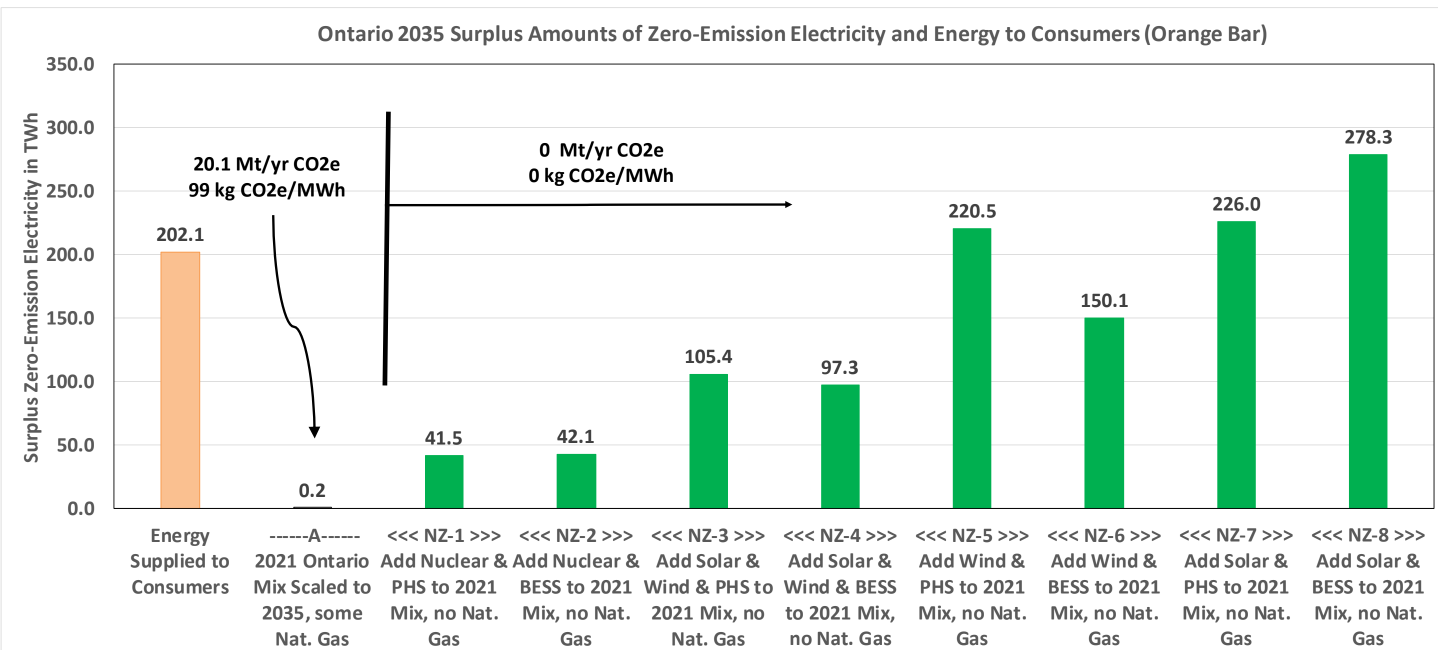
New Challenges with Net-Zero Supply Mixes

The analysis identified three additional challenges with the net-zero supply mixes that need to be managed and/or exploited to reduce the cost of our economy-wide energy transition to net-zero.

1. All net-zero electrical supply mixes resulted in significant amounts of surplus or surplus zero-emission electricity.
2. All net-zero electrical supply mixes resulted in nameplate capacity over-build. By over-build we mean the total installed nameplate exceeds the peak load demand plus reserve capacity for reliability.
3. All net-zero supply mixes that employ thermodynamic cycles or solar PV to make electricity also produce significant quantities of discarded zero-emission thermal energy.

Figure 3 below shows the amount of surplus zero-emission electricity for each supply mix that is surplus to Ontario's domestic electricity demand. Some supply mixes result in surplus zero-emission electricity that is larger than the electricity delivered to domestic consumers.

Figure 3



The magnitude of this surplus is important because it represents underutilized zero-emission generating capacity.

The surplus zero-emission electricity could be used for other purposes such as decarbonizing other sectors of the economy. However, that would require changes to our current retail electricity pricing policies. Consumers currently do not make use of that surplus because retail electricity rates do not reflect the lower wholesale market value of surplus electricity. We can of course export some of the surplus to adjoining jurisdictions (typically at low wholesale prices), but that export amount is limited by Ontario's tie line capacity. Building additional tie line capacity to export surplus electricity at low wholesale market prices is not economically justified.

In May 2023 Ontario will introduce very low overnight retail electricity rates to encourage residential consumers to charge their electric vehicles (EVs) with surplus electricity. Ontario needs to develop additional innovative retail electricity rates to encourage consumers to use the forecasted large amounts of surplus zero-emission electricity either to reduce their peak electrical load demand or to displace some of the fossil fuels we use for heating.

Figure 4 below shows the total amount of installed nameplate capacity for each supply mix. Some supply mixes result in very large nameplate over-build which indicates poor utilization of natural resources. Transitioning to a net-zero economy will be much easier if we do not place too high a demand on our valuable natural resources and our mining and refining capability. All the net-zero supply mixes that rely more heavily on nuclear generation also have the least amount of nameplate over-build (see NZ-1 and NZ-2 in Figure 4).

Figure 4

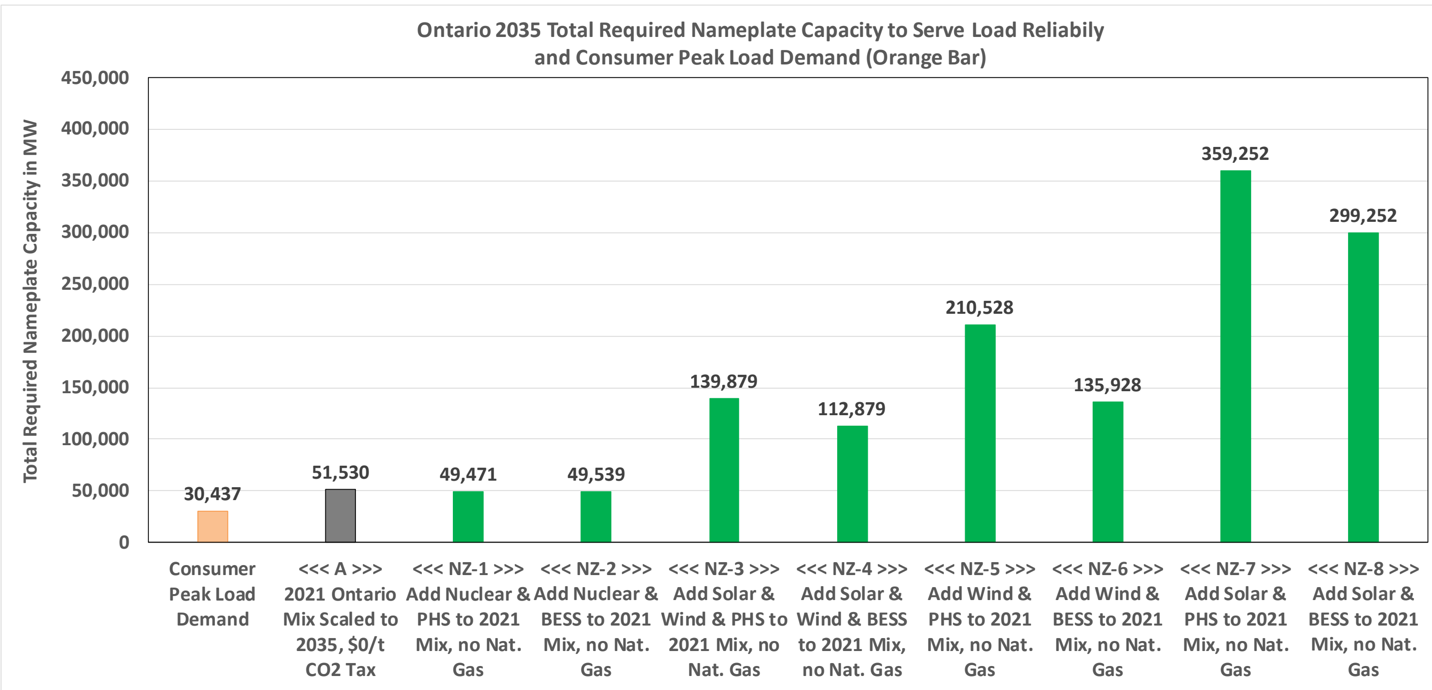
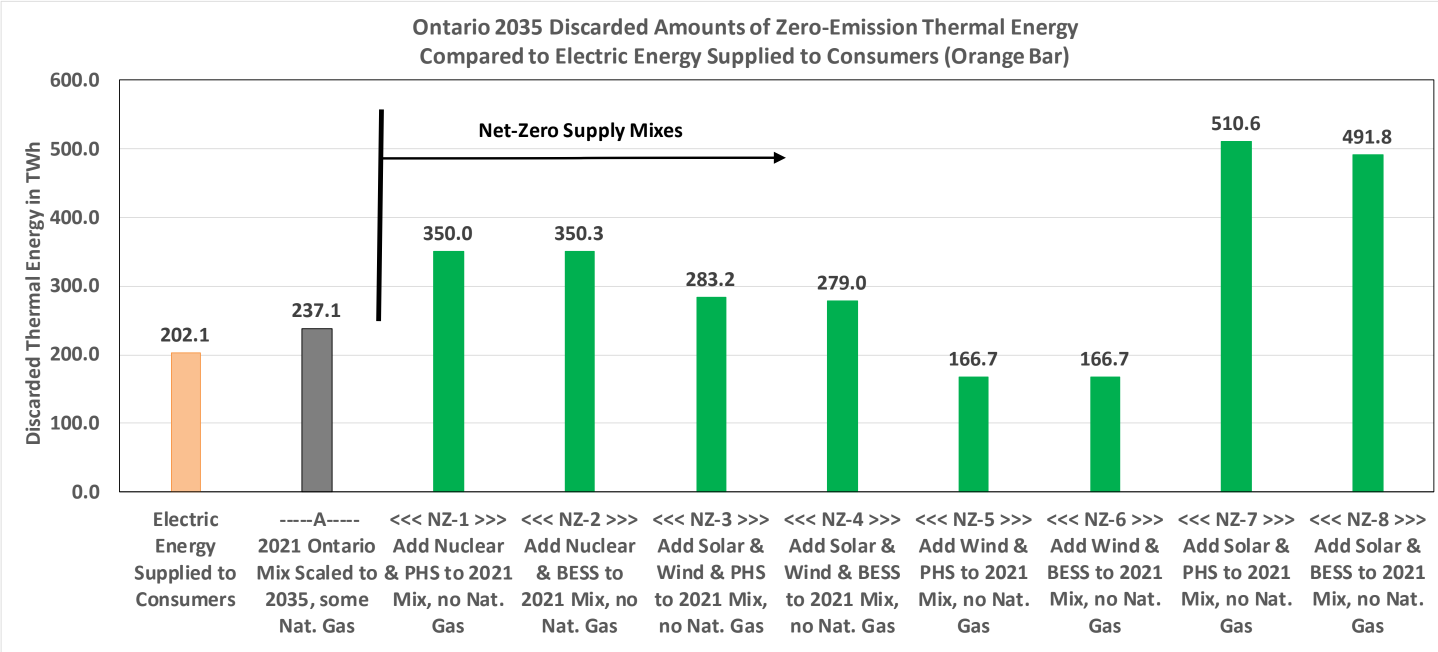


Figure 5 below shows the total amount of discarded zero-emission thermal energy for each electricity supply mix. The values in Figure 5 are in TWh, which is a very large unit of energy. Each TWh of thermal energy is sufficient to heat 67,000 typical homes for a year. This discarded energy is typically at a temperature of 20 to 80 degrees C. New low temperature district energy systems (LTDESs) have been developed in Europe. These LTDESs can productively use this low temperature thermal energy using water sourced heat pumps to provide hot water and space heating in urban locations. These LTDESs can also supply air conditioning all year round for buildings like data centres, which require air conditioning even in winter. Since most people in Ontario live in urban areas a portion of this discarded thermal energy can be productively and affordably used to heat our buildings in urban areas if we adopt LTDES technology.

Figure 5



Because the heat source temperature in a LTDES is at least 20 degrees C or higher, the coefficient of performance of the water sourced heat pumps is much higher than air sourced heat pumps that get their heat from very cold outdoor air. This has significant positive implications for the electrical power system because the required peak load on cold winter days will be much lower. If we were to adopt LTDESs for our hot water, space heating and air conditioning needs in urban areas, the amount of electrical capacity required to power the heat pumps will be much lower than if we convert from fossil fueled heating systems to air sourced heat pumps. Furthermore, LTDESs can be fitted with much longer-duration seasonal thermal storage at relatively low cost per TWh. Low cost, low temperature, seasonal thermal storage would enable us to harvest many thermal energy sources that currently are impractical to use. LTDES seasonal thermal storage would also allow us to convert surplus zero-emission electricity in the fall into thermal energy and store it for later use in the winter. This would improve the utilization of our electrical generating capacity.

The financial and economic analysis and the assessment of technical performance and practical implementation for Ontario conditions of LTDESs was not within the scope of this report. We leave that analysis for others to perform. We recommended that this analysis be done, given the potential financial benefits for consumers.

The Supply Gap from 2025 to 2030

Our analysis looked specifically at the 2035 electricity load demand and additional supply to meet that demand with a net-zero emission profile. However, as indicated earlier, there will be a capacity shortfall for several years from the mid-2020's until the early 2030's due to the shutdown of PNGS and the refurbishment of Darlington and Bruce reactors. Beyond that period all supply technologies can be built in time to meet consumer needs with the exception of supply mixes NZ-3, NZ-5 and NZ-7 because they require large amounts of PHS and there may not be enough PHS sites available in Ontario.

The IESO recently proposed, and the Minister of Energy approved proceeding with, supply options and energy efficiency measures to fill that short term capacity shortage.

The analysis in this report shows that the lowest cost net-zero supply mix in 2035, namely NZ-1, can accommodate the recent IESO recommendations to fill that short term capacity shortfall. IESO plans to address longer term needs including the net zero goal for the electrical system and provide its recommendations to the Minister of Energy by the end of 2022. OSPE therefore supports the IESO recommendations to fill the short-term supply gap and looks forward to receiving the IESO's long term recommendations.

Supply mix planning is a continuous and iterative process based on changing load demands and changing supply technologies. Any technical advances or development disappointments can easily be included in revisions to the IESO's long term plans. The important point is to let the power system design and operating experts make their best recommendations, after a thorough engineering and economic analysis, for subsequent approval by the Minister of Energy. The past practice of the Minister of Energy directing the IESO (and its predecessor planning organization the Ontario Power Authority) to deploy a specific supply mix without detailed engineering and economic analysis is a recipe for rapid retail electricity rate increases, as we have seen in the past.

Readers who are interested in additional details about the modelling methods, assumptions and results for each supply mix can contact OSPE to obtain a copy of the MS Excel Spreadsheet used to model the various supply mixes and produce the results in this report.

REFERENCES

Enbridge Gas, The Future of Clean Energy, 2021, RNG potential and cost, assessed Nov 17, 2022 at: https://www.enbridgegas.com/-/media/Extranet-Pages/Sustainability/Clean-transportation/RNG-for-Municipalities/enbridge-gas-guide-RNG.ashx

Independent Electricity System Operator. "Power Data." accessed November 17, 2022 at: https://www.ieso.ca/en/Power-Data/Data-Directory

Independent Electricity System Operator. Resource Eligibility Interim Report, October 7, 2022, accessed November 17, 2022 at: https://www.ieso.ca/en/Sector-Participants/Resource-Acquisition-and-Contracts/Resource-Eligibility

Ontario Society of Professional Engineers, Ontario's Energy Dilemma: Reducing Emissions at an Affordable Cost (Toronto: Ontario Society of Professional Engineers, March 2016), accessed November 17, 2022 at: https://www.ospe.on.ca/public/documents/advocacy/2016-ontario-energy-dilemma.pdf

TorchLight Bioresources, Renewable Natural Gas (Biomethane) Feedstock Potential in Canada, 2020, accessed November 17, 2022 at: https://www.enbridge.com/~/media/Enb/Documents/Media%20Center/RNG-Canadian-Feedstock-Potential-2020%20(1).pdf

US Energy Information Administration (EIA), Battery Storage Capacity in 2025, accessed December 13, 2022 at: https://www.eia.gov/todayinenergy/detail.php?id=54939

US Environmental Protection Agency, greenhouse warming potential of methane leakage, accessed November 17, 2022 at: https://www.epa.gov/ghgemissions/understanding-global-warming-potentials

U.S. National Renewable Energy Laboratory (NREL), Annual Technology Baseline of generation costs, 2022 V2, accessed November 17, 2022 at: https://atb.nrel.gov/electricity/2022/data

CONTACT US

Ontario Society of Professional Engineers
4950 Yonge Street, Suite 502
Toronto, Ontario M2N 6K1
1-866-763-1654

www.ospe.on.ca

ONTARIO
SOCIETY OF
PROFESSIONAL
ENGINEERS