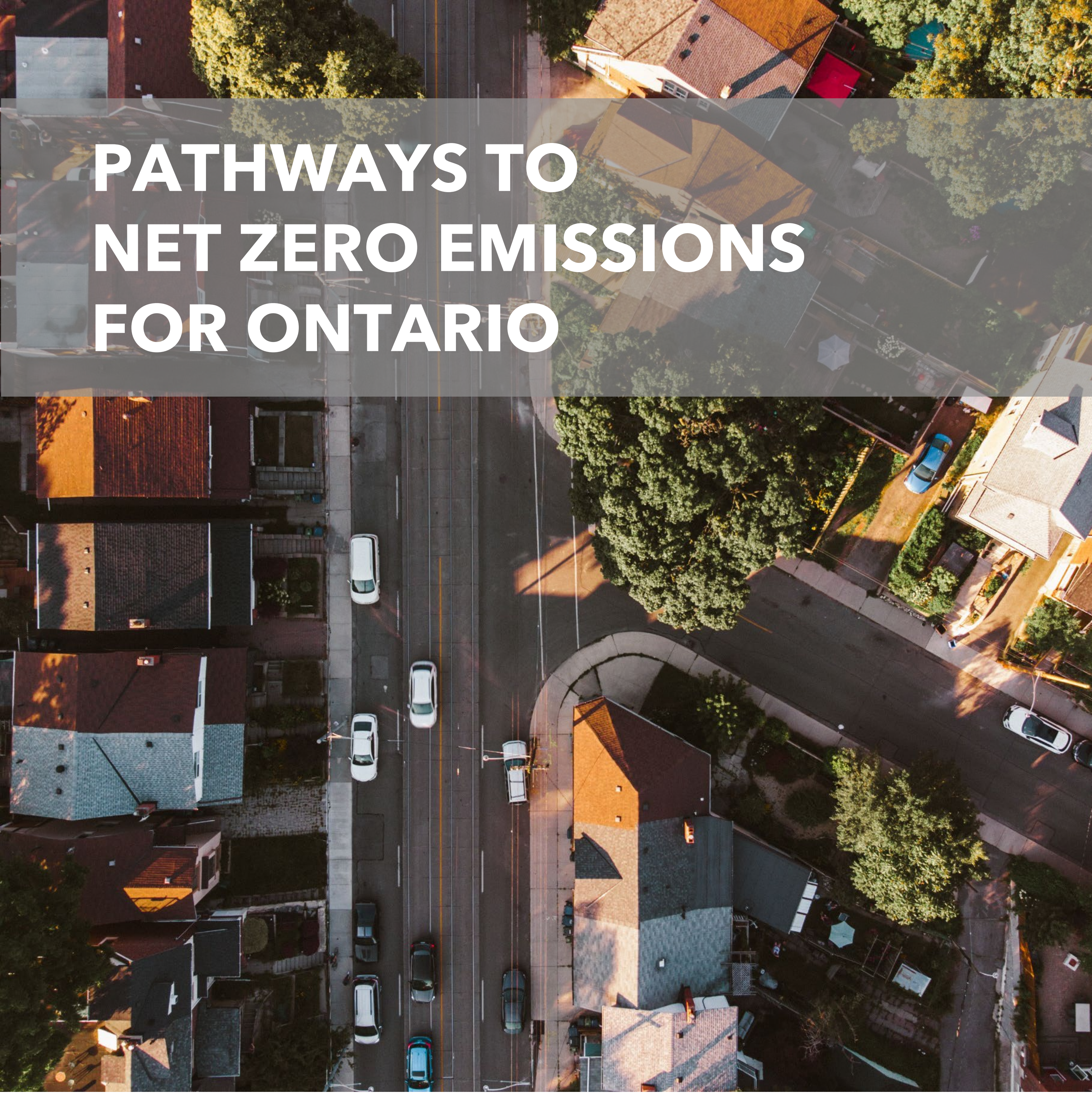
PATHWAYS TO NET ZERO EMISSIONS FOR ONTARIO



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While this study aims to adequately simulate an increasingly integrated electricity and gas system in Ontario, the results of this analysis are not intended to dictate when and where infrastructure investments will take place. The results presented in this report are purely reflective of a cost optimization modelling exercise and may not reflect specific technical, operational, and locational (spatial) constraints of the Ontario electricity and gas systems. The pathway results presented in this report are contingent on developments in provincial and federal energy policy, regulation, and other related areas. All analysis is based on credible assumptions, but these are subject to the uncertainty typical in long-term forecasting exercises. Findings from this study should be read in this context and should take into consideration limitations of the analysis.

Executive Summary

In July 2021, the Government of Canada committed to reducing its greenhouse gas (GHG) emissions by 40%- 45% below 2005 levels by 2030, and to achieve net zero emissions by 2050.[1] Achieving net zero emissions means the Canadian economy either emits no GHG emissions or emits a small amount of emissions that are offset through actions such as reforestation or capturing carbon before it is released into the air.[2] Policymakers at all levels of government are developing new climate policies to support the achievement of these targets. In November 2020, Enbridge Inc. (Enbridge) was among the first North American midstream energy companies to announce a target of net zero emissions by 2050.[3] Enbridge Gas Inc. (Enbridge Gas), which serves over 98% of the natural gas demand in Ontario, has an interest in both understanding the role of the company's existing gas distribution system under ambitious federal and provincial emission reduction policies and in helping its customers and the province to achieve their emission reduction goals.

Enbridge Gas commissioned Guidehouse to evaluate two different scenarios that achieve net zero emissions for Ontario by 2050, to chart GHG reduction pathways that can achieve these net zero emissions scenarios, and to examine each pathway in terms of overall feasibility, energy system capacity, system reliability and resiliency, GHG emissions reductions, and cost. The objective of this analysis was not to determine the best or most likely pathway to net zero for the entire energy system. Rather, this analysis was meant to examine how Ontario's energy systems can support the achievement of net zero emissions in Ontario by 2050, including identifying what investments in electricity, hydrogen, and methane supply capacity, storage, and infrastructure would be required. This report does not contemplate how future technology innovations could change the identified investment requirements. Note that this analysis represents data available and market conditions in June 2022 when the report was first published.

This report presents the findings from that analysis, which concluded that a diversified approach that includes a targeted approach to electrification tied with deployment of low- or zero-carbon gases, including renewable natural gas (RNG), hydrogen, and natural gas with carbon capture, is the most cost-effective and resilient method to achieve net zero emissions in Ontario. The analysis found that a diversified approach that leverages existing gas delivery infrastructure to deliver low-carbon fuels and offers cost savings compared to an electrification focused approach that would underutilize existing infrastructure. The analysis also demonstrates the role gas delivery infrastructure has in both approaches, delivering low-carbon fuels across sectors in the diversified approach and for hard-to-abate sectors like industry and heavy transport in an electrification approach. This is consistent with the findings of similar analyses Guidehouse has conducted regarding utilities' roles in energy transition across Europe and North America[4]. Similarly, these studies consistently found that net zero pathways that focus on a diversified approach can achieve GHG reductions at a lower cost and achieve greater energy system resiliency. This report is intended to provide quantitative and qualitative information about the total costs, benefits, and risks of the two net zero pathways, that are

[1] Government of Canada (2021). Canada's Climate Actions for a Healthy Environment and a Healthy Economy. Available: https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/climate-plan-overview/actions-healthy-environment-economy.html

[2] Government of Canada (2021). Net-Zero Emissions by 2050. https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/net-zero-emissions-2050.html

[3] This net-zero target includes scope 1 (direct emissions from operations such as stationary fuel combustion, mobile combustion, and fugitive, flaring, and vented emissions) and scope 2 (indirect emissions from purchased and imported electricity consumption) emissions. It does not include scope 3 (selected indirect emissions related to operations: utility customers' natural gas use, business travel, and transmission and distribution (T&D) losses from electricity usage) emissions.

[4] For example, Guidehouse (2020). Pathways for British Columbia to achieve its GHG reductions goals. Available: https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/guidehouse-report.pdf; Navigant (2019). Gas for Climate 2050: The optimal role for gas in a net zero emissions energy system (Europe). Available: https://gasforclimate2050.eu/wp-content/uploads/2020/03/Navigant-Gas-for-Climate-The-optimal-role-for-gas-in-a-net-zero-emissions-energy-system-March-2019.pdf; Navigant (2019). Pathways to Net-Zero: Decarbonising the Gas Networks in Great Britain. Available: https://www.energynetworks.org/industry-hub/resource-library/pathways-to-net-zero-decarbonising-the-gas-networks-in-great-britain.pdf; McKinsey (2020). How the European Union could achieve net zero emissions at net-zero costs. Available: https://www.mckinsey.com/business-functions/sustainability/our-insights/how-the-european-union-could-achieve-net-zero-emissions-at-net-zero-cost; UK Climate Change Committee (2020). The Sixth Carbon Budget - The UK's path to Net Zero. Available: https://www.theccc.org.uk/wp-content/uploads/2020/12/The-Sixth-Carbon-Budget-The-UKs-path-to-Net-Zero.pdf

required to generate dialogue and solutions-focused thinking about approaches and policies for GHG reduction.

Scenario Analysis Methodology

Guidehouse developed two scenarios for Ontario's energy system to achieve net zero by 2050:

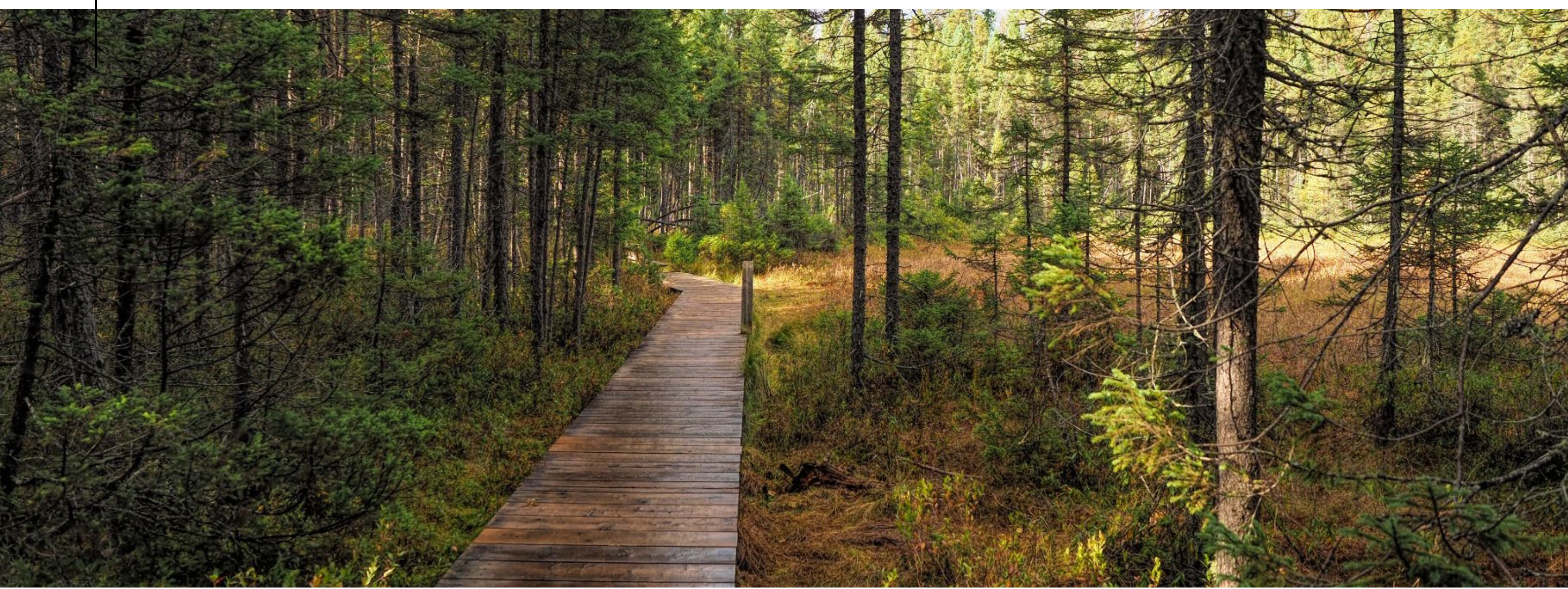
- A **Diversified Scenario** in which low and zero carbon gases and the gas delivery infrastructure are used in combination with end-use electrification to reduce GHG emissions in all sectors.
- An **Electrification Scenario** that focuses on electrification of all sectors, with low and zero carbon gas use limited to cases where no reasonable alternative energy source exists.

Both scenarios share similarities that reflect accepted and well-understood approaches to GHG emissions reduction for several subsectors (e.g., energy efficiency and building codes reduce heating energy demand, light duty road transport is electrified, the steel industry uses hydrogen to reduce GHG emissions). Nevertheless, there are some key differences between the scenarios, illustrated in Figure ES-1.

To model cost-optimal net zero pathways to 2050 for these two scenarios, this study uses an integrated energy system model: Guidehouse's Low Carbon Pathways (LCP) model. This model was adapted to the characteristics of Ontario's gas and electricity networks, including evolving energy supply-demand conditions, and interties with neighbouring regions. This study includes technologies that are commercialized or are near commercialization today, and it does not include future technologies that may evolve to reduce GHG emissions.

Figure ES-1. Description of Demand Scenario Hypotheses

	Diversified Scenario	Electrification Scenario
BUILDINGS	Gas heating continues to play a key role in building heating, complemented by electric heat pumps. Gas-equipped buildings shift to gas-powered heat pumps, fueled by low- or zero-carbon gas. Energy efficiency and building codes reduce heating energy demand.	Electric heat pumps replace most natural gas heating in buildings. The small share of buildings that remain on gas adopt gas-powered heat pumps, fueled by low- or zero-carbon gas. Energy efficiency and building codes reduce heating energy demand.
TRANSPORT	Hydrogen plays a major role in all heavy transport. Light road transport is largely electrified using battery electric vehicles. RNG (as bio-CNG) plays a role in heavy road transport.	Electrification and biofuels play major roles in all transport methods. Hydrogen's role is limited to aviation (via synthetic kerosene).
INDUSTRY	Low temperature processes are electrified; medium and high temperature processes are served by hydrogen or methane gas with carbon capture.	Low and medium temperature processes are electrified. High temperature processes are served by hydrogen or methane gas with carbon capture.



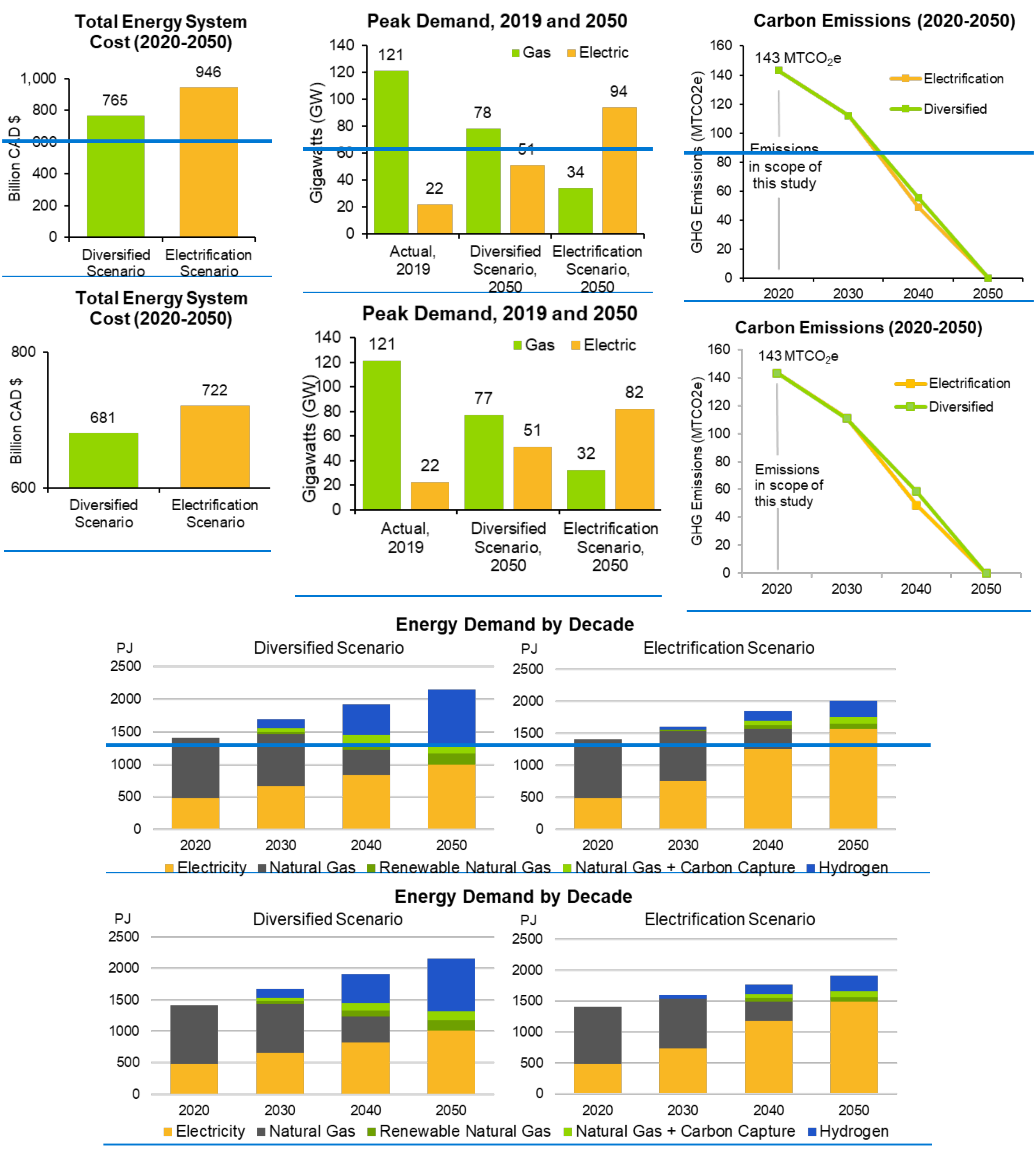
Summary of Results

The study's key findings are as follows:

- The Diversified and the Electrification Scenarios both achieve interim 2030 targets and net zero GHG emissions by 2050.
- The pathway to a Diversified scenario saves $~~181~~41 billion by 2050 compared to the Electrification pathway because the Diversification scenario requires less new electric infrastructure to meet peak demand.
- Both pathways will require a significant scale up of electrical infrastructure.
  - Electric peak demand will increase twofold in the Diversified scenario or nearly fourfold in the Electrification scenario.
  - This will require changes to electricity capacity and infrastructure planning and to the speed of new development.
- The development of carbon storage in Ontario will be critical in both scenarios.
- The electricity and gas systems will become increasingly integrated in the future.
  - Gas-powered generation will play a critical role in Ontario's electricity system, and electricity generation will shift from natural gas to hydrogen sources.
  - Residential hybrid heating systems can reduce peak electric load and save Ontario an additional $~~21~~9 billion by 2050 compared to alternative heating systems in the base Diversified scenario.
- In both Pathways, gas infrastructure must evolve to deliver RNG and hydrogen.
  - Ontario will need a dedicated network of hydrogen pipelines and some gas infrastructure in the province will be repurposed to deliver hydrogen.
  - Domestic sources of low- and zero-carbon gas will be developed in Ontario and will reduce Ontario's reliance on gas imports in both scenarios.
- Energy system resilience will be a key consideration as peak electric demand grows in both scenarios.
  - The Diversified Pathway provides resilience and reliability benefits and provides solutions for hard-to-electrify sectors, such as industrial customers and heavy transport vehicles.

The Diversified Pathway achieves interim 2030 emissions targets and net zero emissions by 2050 at a lower total cost, with a lower electric system peak demand compared to the Electrification scenario. These summary results are illustrated in Figure ES-2.

Figure ES-2. Comparison of Key Results for Diversified and Electrification Scenarios



Sensitivity Analysis

As with any analysis attempting to model a future integrated energy system, the results of this analysis are uncertain, and real-world outcomes may vary greatly if growth trends and price conditions vary from assumptions. To understand how the findings of this study may be influenced by different assumptions, Guidehouse analyzed four sensitivity cases.

Sensitivity 1. Increased Decentralized Electricity: Assumes that solar energy, wind energy, and battery storage decline in cost, leading to rapid deployment of distributed energy resources

(DER), with 50% of new capacity located behind the meter.
Outcome: In both scenarios, the reduced cost for renewables and electric storage resulted in an increased deployment of decentralized renewable capacity. This yields cost savings of $12 billion for the Electrification scenario and $~~13~~11 billion for the Diversified scenario.

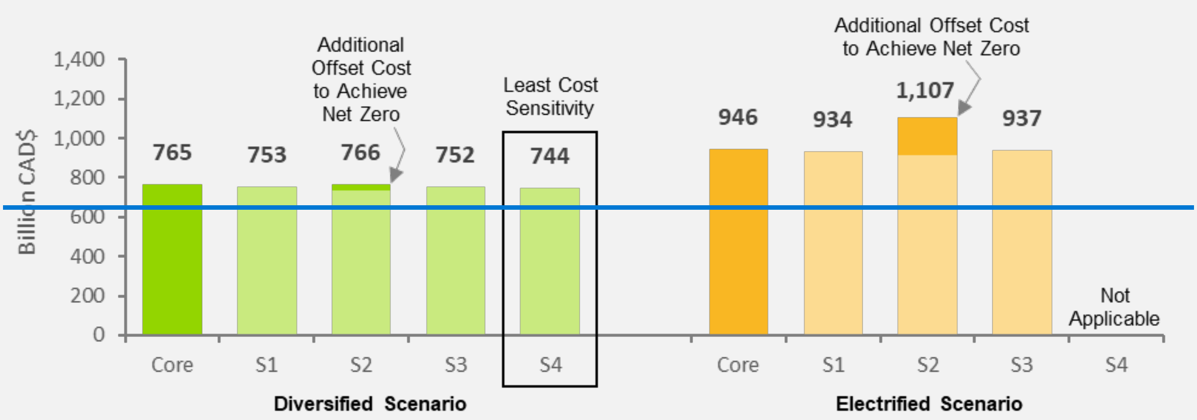
Sensitivity 2. Limited Investment in Gas Supply and Infrastructure: Explores how a decrease in the gas infrastructure investment included within both scenarios would impact Ontario's ability to meet net zero emissions by 2050.
Outcome: Decreasing future investments in the gas system ~~by 10% or more~~ through 2050 is projected to cause unabated emissions of more than ~~12~~13 $MTCO_2$ in 2050 for either scenario. From the Diversified or Electrified pathways, significant reductions in gas system spending will result in even greater spending towards emissions offsets to achieve net zero emissions by 2050.

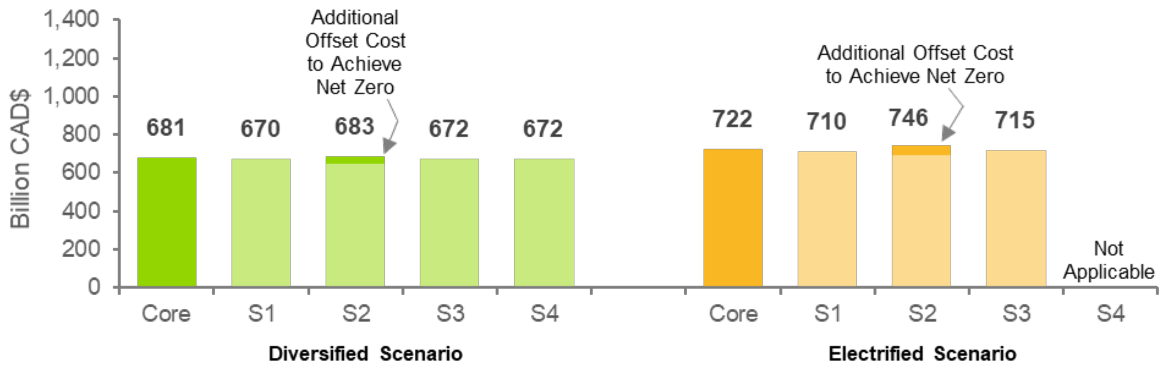
Sensitivity 3. Lower Electrolyzer and Hydrogen Storage Costs: Assumes that electrolyzer and wind costs are reduced by over 50% and hydrogen storage costs are reduced by 25% compared to the scenario assumptions.
Outcome: Lower electrolyzer costs lead to an increase in the buildout of electrolyzer capacity and an increase in hydrogen production from renewable energy sources. ~~This yields cost~~Lower wind costs lead to savings of $~~9~~7 billion for the Electrification scenario and $~~13~~9 billion for the Diversification scenario.

Sensitivity 4. Adoption of Hybrid Heating Technologies: Assumes that a significant portion of residential buildings adopt hybrid heating systems that combine electric heat pumps with high efficiency gas-fired furnaces fueled by low- or zero-carbon gas.
Outcome: The deployment of hybrid heating systems reduces electrical peak loads in the Diversified scenario and has the potential to save $~~21~~9 billion in total energy system costs compared to the core Diversified Scenario. ~~This is the lowest cost pathway identified in this report.~~

These sensitivity cases had several commonalities. Like the Diversified and Electrified pathways, all the sensitivity cases required a large buildout of renewable generation capacity and hydrogen supply. Figure ES-3 summarizes the impact that these sensitivity cases have on total energy system costs from 2020-2050 and demonstrates that the findings of this analysis are not highly sensitive to reductions in the cost of hydrogen production or distributed generation. Figure ES-3 also illustrates that for sensitivity 2, the additional costs of emissions offsets required to achieve net zero make sensitivity 2 more costly than the central Diversified and Electrified scenarios. The figure shows that changes to these assumptions do not alter the key finding of this analysis, that net zero emissions is less costly to achieve in a Diversified scenario than in an Electrified scenario.

Figure ES-3. Sensitivity Analysis Results, Total Energy System Costs (2020-2050)





Policy Implications

This report identifies a set of strategic actions and initiatives for Ontario's energy stakeholders to implement within the next few years, described in Figure ES-4.

Figure ES-4. Strategic Actions and Initiatives for Ontario's Energy Stakeholders

	Electricity	Hydrogen	RNG	CCS
Government Ministries	• **Streamline the permitting and approval process for generation and transmission infrastructure** and make the process more predictable. • **Analyze the potential economic value and societal impacts of wind power in the province,** to bolster support for wind energy, and **initiate citing studies** to provide clear direction to plan transmission needs. • The Ministry should **develop an electricity system pathway** that supports the reduction of GHG emissions of Ontario's economy by 2050.	• **Define medium-term (2030) and long-term (2045) planning targets** for hydrogen supply.[5] • **Investigate market measures and incentives that support hydrogen adoption** such as low carbon fuel incentives, carbon pricing, targets for fuel cell electric vehicle (FCEV) and hydrogen-fueled appliance deployment, and renewable gas mandates. • **Expand the regulatory oversight of the Ontario Energy Board (OEB) to include hydrogen,** hydrogen-derivatives and the associated supply, transport, and storage infrastructure. • **Enable carbon capture and storage** for blue hydrogen production.	• **Define binding medium-term (2030) and long-term (2045) RNG production targets** to provide a long-term investment horizon for RNG market players. • **Investigate supply and demand market measures that can bolster RNG adoption** in Ontario (e.g., guarantees of origin, RNG registers, low-carbon fuel incentives, waste reduction policies), and renewable gas mandates.	• **Amend prohibitions on the injection of carbon dioxide for storage** to allow potential carbon storage for the purpose of GHG emission abatement**.** • **Develop a streamlined permitting regime for approving CCS projects** that encourages commercial-scale CCS projects.

[5] A planning target is not intended to be legally binding; rather, it is a strategic objective that can provide clarity for electricity and gas system planning and regulatory planning.

	Electricity	Hydrogen	RNG	CCS
Ontario Energy Board	• **Lead the development of an integrated energy planning working group** involving major electricity and gas utilities. • **Develop regulatory structures that measure and value energy system resilience** and require consideration of resilience as a part of all utility planning efforts.	• **Gather stakeholder views and investigate best practices** for a hydrogen regulatory framework. • **Allow utilities to recover the cost of hydrogen at a different cost than natural gas** and in line with the market price of hydrogen.	• **Work with the Ministry of the Environment** to ensure existing and future environmental regulations are supportive of RNG production. • **Allow utilities to recover the cost of RNG at a different cost than natural gas** and in line with the market price of RNG.	• **Develop regulatory structures that facilitate the adoption of CCS** from fuel-fired electric generation.
Gas and Electric Utilities and System Operators	• **Develop a GHG emissions reduction pathway for the electricity and gas systems** to achieve Ontario's economy-wide net zero target by 2050 while controlling costs and maximizing GHG reductions.[6]	• **Conduct pilots** to assess the hydrogen readiness of the existing gas system (Enbridge Gas has pilot projects underway). • **Develop a made-in-Ontario hydrogen infrastructure plan** akin to National Grid's Project Union in the UK, Gasunie's HyWay 27 in the Netherlands, and SoCal Gas's Angeles Link Project.[7,8,9] • **Conduct an electricity transmission impact assessment** to identify future network impacts of green hydrogen production.	• **Develop tariffs specific to RNG.** Having separate rates for RNG and conventional natural gas may incentivize project development by RNG suppliers, as utilities would be able to recover the higher cost associated with RNG.	• **Develop pilot CCS projects** to demonstrate feasibility of CO_2 collection, transport, and sequestration.

[6] This recommendation covers a larger scope than the Ministry's October 2021 directive, which only covers the decarbonization of the electricity system, not the entire economy.
Ministry of Energy (October 2021). Available: https://www.ieso.ca/-/media/Files/IESO/Document-Library/corporate/ministerial-directives/Letter-from-Minister-Gas-Phase-Out-Impact-Assessment.ashx

[7] National Grid. Project Union. Available: https://www.nationalgrid.com/stories/journey-to-net-zero-stories/making-plans-hydrogen-backbone-across-britain

[8] Gasunie. HyWay 27. Available: https://www.gasunie.nl/en/expertise/hydrogen/hyway-27

[9] SoCal Gas (2022). Application of Southern California Gas Company (U904g) for Authority to Establish a Memorandum Account for the Angeles Link Project. Available: https://www.socalgas.com/sites/default/files/A22-02-SOCALGAS-Angeles_Link_Memorandum_Account_Application.pdf

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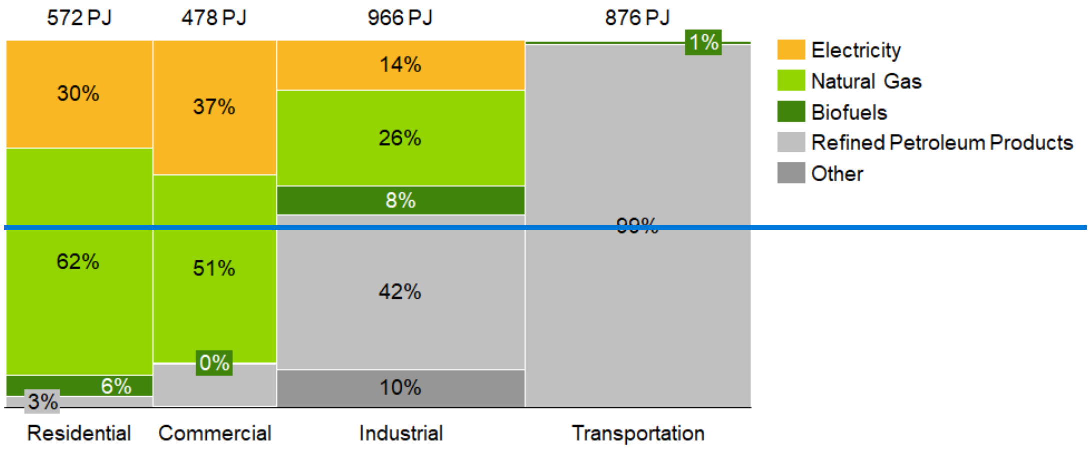
1. Introduction

Canada has set ambitious greenhouse gas (GHG) emissions reduction targets, including the achievement of net zero GHG emissions by 2050. An interim emissions reduction target has also been established, targeting a 40%-45% reduction by 2030 compared to 2005 levels (equal to a 20% reduction from today). Ontario's current climate targets, which were set before the new federal targets were established, commit the province to a 30% reduction below 2005 levels by 2030 (a 10% reduction from today).

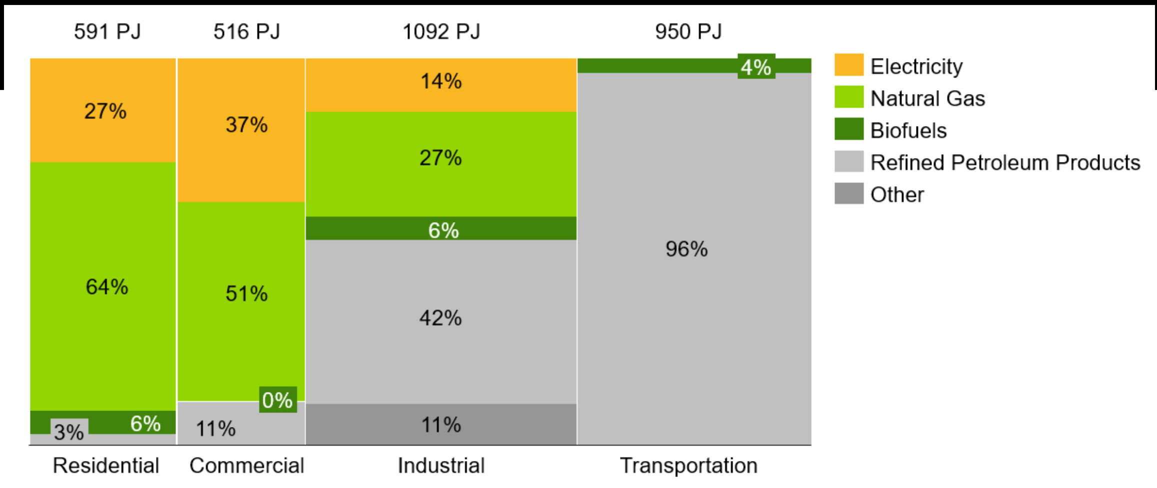
Ontario has made significant progress in reducing the GHG emissions of its energy system. Following the decommissioning of the coal-fired electricity generation fleet, Ontario's electricity mix is largely made up of low carbon and renewable electricity. Ontario's electricity system, however, only accounts for a small fraction of the province's total energy demand. ~~From 2016 to 2020~~In 2019, electricity represented only 16% of total energy demand across all sectors – residential, commercial, industrial and transportation – while natural gas and petroleum accounted for 30% and ~~45~~46% of demand, respectively.[10] The use of natural gas in Ontario is largely associated with heating residential and commercial buildings, and industry, as shown below in Figure 1, whereas the use of petroleum is largely associated with industry and transport.

Figure 1: Ontario Energy Demand by Sector and Fuel (~~2020~~2019)[11]



[10] Canada Energy Regulator (2021). Canada's Energy Future 2021: Energy Supply and Demand Projections to 2050. Available: https://apps.cer-rec.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA

[11] Ibid.



591 PJ
516 PJ
1092 PJ
950 PJ
27%
64%
6%
3%
37%
51%
0%
11%
14%
27%
6%
42%
11%
4%
96%
Electricity
Natural Gas
Biofuels
Refined Petroleum Products
Other
Residential
Commercial
Industrial
Transportation

Figure 2: Ontario's Historical GHG Emissions by Sector (1990-2020)[12]

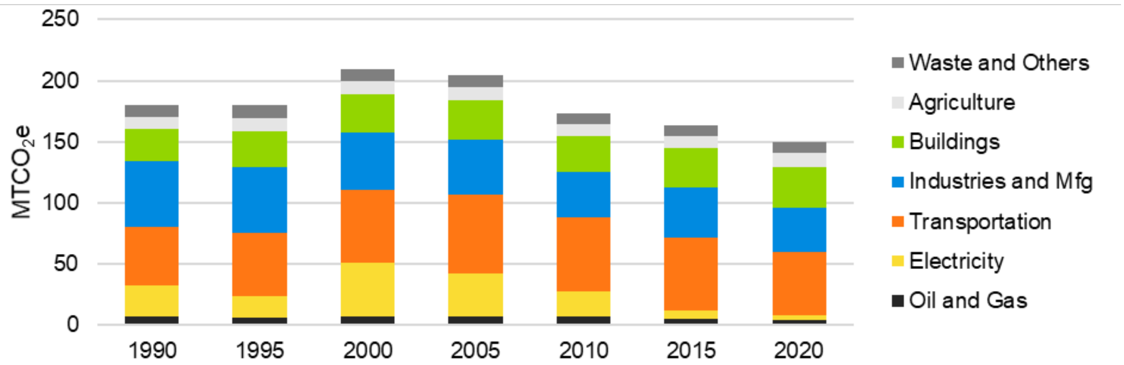


Figure 2 presents Ontario's historical GHG emissions by sector. The challenge of reducing GHG emissions is not unique to Ontario. Most of Canada's provinces and territories, along with most other world economies, are facing the need to reduce GHG emissions from high-emissions sectors, including building heating, transport, and industry. How best to reduce GHG emissions from these sectors and how to do it cost-effectively are some of the key questions policymakers and regulators are faced with today. This study focuses on the challenge of reducing GHG emissions from these sectors and provides insight and guidance to policymakers.

This report explores two potential pathways for Ontario to achieve a net zero future by 2050, focusing primarily on the roles of the gas and electric systems in reducing GHG emissions in the province. The report takes an Ontario-specific view that considers the province's unique electricity and gas systems, its energy infrastructure and resources, and how those can be leveraged to reduce GHG emissions in the building heating, transport, and industry sectors.

The objective of this report is to compare the two potential scenarios and, within the constraints of the scenarios, identify the most cost-effective pathway to net zero emissions based on the information available at the time the report was prepared. Additionally, this report addresses the following questions:

- **What role can electricity and low- and zero-carbon gas play** in achieving a net zero future in Ontario by 2050?
- **What pathways** could achieve the net zero scenarios defined for 2050? **What will it cost** to pursue these pathways and **how feasible are they**?
- **What are the major implications and opportunities** of Ontario's transition to net zero?

The remainder of the report is divided into the following sections:

- **Ontario's Energy Systems:** describes the current state of Ontario's electricity and gas systems. This section also provides background information on some of the future sources of low- and zero-carbon gases, like hydrogen and RNG.
- **Study Methodology:** describes the study approach and modelling methodology to assess different energy transition pathways for Ontario.
- **Developing Net Zero Scenarios for Ontario:** describes the two net zero scenarios developed for this study: a Diversified Scenario and an Electrification Scenario.
- **Comparing Pathways to a Net Zero Future** compares the results of the Diversified and Electrification Scenarios, identifies the least-cost pathways (given the constraints of each scenario) for Ontario to achieve net zero emissions, describes the impact of each sensitivity analysis, and describes challenges and opportunities.
- **Implications on Ontario's Energy System** describes key implications for Ontario associated with achieving interim GHG emissions targets and setting the province on a net zero pathway.

[12] Government of Canada (2022). Canada's Official Greenhouse Gas Inventory. Available: https://data.ec.gc.ca/data/substances/monitor/canada-s-official-greenhouse-gas-inventory/A-IPCC-Sector/?lang=en

2. Ontario's Energy System

Ontario has an extensive energy system with electricity and gas infrastructure spanning most of the province and serving as mainstays for economic activity in the province.

The **electricity transmission system**—primarily operated by Hydro One—is made up of over 30,000 km of high voltage power lines connecting electricity supply resources across Ontario with major demand centres.[13]

The **natural gas transmission system**—primarily operated by TC Energy and Enbridge Gas—is made up of roughly 5,500 km of high-pressure pipelines connected to upstream pipelines and supply basins across North America.[14] The natural gas distribution system, which is the distribution backbone of gaseous energy in the province, includes about 148,000 km of main and service lines.[15]

As illustrated in Figure 1, a large portion of Ontario's energy demand is presently served by refined petroleum products such as gasoline. In particular, consumption of petroleum products in Ontario's transportation sector represented ~~30~~29% of the total energy demand from buildings, industry, and transport. Though not discussed in detail here, this analysis modeled the transportation sector's shift from a reliance on refined petroleum products to electricity and low- and zero~~-~~-carbon gases.

2.1 Ontario's Electricity System

Ontario's electricity system has an installed generation capacity of approximately 40 GW, producing approximately 150 TWh of electricity every year. Ontario's annual electricity consumption is roughly 135 TWh, and in 2020 the province's net exports of electricity to neighbouring regions were 15.2 TWh.[16] Ontario's revenues from exported electricity are often less than the cost of production.[17] Over the last 5 years, 93% of the electricity produced in Ontario was low emissions or emissions-free, with 61% of electricity supply being generated from nuclear power, 25% from hydro, and 7% from renewables. Only 7% of Ontario's electricity supply is generated from natural gas despite natural gas turbines making up approximately 28% of installed generation capacity.[18]

While electricity supply from natural gas is limited, natural gas-fired peaking plants play a critical role in supporting Ontario's electricity system to meet system peaks cost-effectively while maintaining system reliability. The importance of the natural gas fleet to the electricity system was highlighted by a recent IESO study[19], which estimated the costs of decommissioning the natural gas fleet to eliminate GHG emissions from the electricity system by 2030. The report found that, even in an optimistic scenario, eliminating natural gas generation in Ontario by 2030 would require over $27 billion of

[13] Hydro One (2021). Our Subsidiaries. Available: https://www.hydroone.com/about/corporate-information/subsidiaries

[14] Enbridge Gas (2020). 2019 Annual Report. Available: https://www.enbridge.com/investment-center/reports-and-sec-filings/~/media/Enb/Documents/Investor%20Relations/2020/ENB_2019_Annual_Report.pdf

[15] Enbridge Gas (2021). Infrastructure Map. Available: https://www.enbridge.com/Map.aspx#map:infrastructure

[16] IESO (2021). 2021 Annual Planning Outlook, December 2021. ~~Available: ~~rhttps://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook

[17] OSPE (2017). Empower Ontario's Engineers to Obtain Opportunity. Available: https://ospe.on.ca/public/documents/advocacy/submissions/OSPE_Electricity_Export_Analysis.pdf

[18] IESO (2021). Generator Output by Fuel Type. Available: http://reports.ieso.ca/public/GenOutputbyFuelMonthly/

[19] IESO (2021). Decarbonization and Ontario's Electricity System. Available: https://www.ieso.ca/en/Learn/Ontario-Supply-Mix/Natural-Gas-Phase-Out-Study

investment and result in a 60% increase to ratepayers' electricity bills. Phasing out Ontario's 11 GW gas fleet would require adding at least 17 GW of non-emitting generation capacity (e.g., wind, solar, battery storage, demand response, and imports, among others), 1.6 GW of energy efficiency improvements, and significant investment in transmission infrastructure. The IESO study concluded by recognizing the potential that alternative technologies could have in enabling more cost-effective pathways to reducing emissions from the natural gas fleet; among these, the use of hydrogen-fired peaking plants was discussed. Another pillar of Ontario's electricity supply mix is its 13 GW nuclear fleet. Ontario's nuclear fleet has provided most of its baseload electricity for decades—roughly 60% of total supply in recent years. However, there are plans to retire the Ontario Power Generation Pickering nuclear plant beginning in 2024/2025,[20] leaving a meaningful firm capacity supply gap. Replacing this gap with fossil fuels would lead to an increase in GHG emissions in the province, so renewables and energy efficiency will need to be leveraged to minimize the GHG impact of nuclear retirements.[21] It should be noted that Ontario Power Generation has planned to install 0.3 GW of Small Modular Reactors (nuclear SMR) to be completed as early as 2028, but this is not nearly enough to mitigate the effects of the Pickering nuclear plant retirements.[22] The importance of Ontario's nuclear fleet may, in the future, extend beyond the electricity system. On April 7, 2022, the Government of Ontario published its first Low-Carbon Hydrogen Strategy and, as one of eight immediate actions to enable production and expand the low-carbon hydrogen economy, the strategy calls for Bruce Power to explore opportunities to leverage excess energy from the Bruce station for hydrogen production.[23] Bruce Power intends to use electrolysis to produce hydrogen from nuclear and renewable power when electricity demand is low instead of curtailing power.[24]

Ontario's electricity grid does not operate in isolation; it is part of a highly interconnected transmission network with neighbouring provinces and states. Ontario's electricity grid has interties with Quebec, Manitoba, New York, Michigan, and Minnesota. New York and Michigan are largely importers of Ontario's electricity, importing net 7-8 TWh/year and 9-10 TWh/year on average, respectively. Ontario also exports 1-3 TWh/year to Quebec; however, imports from Quebec are greater, with overall net imports of 2-5 TWh/year. Electricity trade with Manitoba and Minnesota is minimal.[25] Figure 3 shows electricity imports and exports in 2020 between Ontario and its neighbouring regions.

A 1 GW intertie called the Lake Erie Connector between southern Ontario and Pennsylvania has been proposed to connect the IESO to PJM, the largest electricity market in the world. Construction is expected to begin in 2022, with operation by the mid-to-late 2020s. This intertie will provide each with enhanced optionality to manage their energy needs and respond to shifting supply/demand conditions, outages, and system planning requirements.[26]

[20] Ontario Power Generation (2021). The Future of Pickering Generating Station. Available: https://www.opg.com/powering-ontario/our-generation/nuclear/pickering-nuclear-generation-station/future-of-pickering/

[21] Pollution Probe (2020). Replacing Pickering: The Next Step in the GTA's Clean Energy Transition. Available: https://www.pollutionprobe.org/energy/replacing-pickering/

[22] Ontario Power Generation Media Release (2021). Available: https://www.opg.com/media_releases/opg-advances-clean-energy-generation-project/

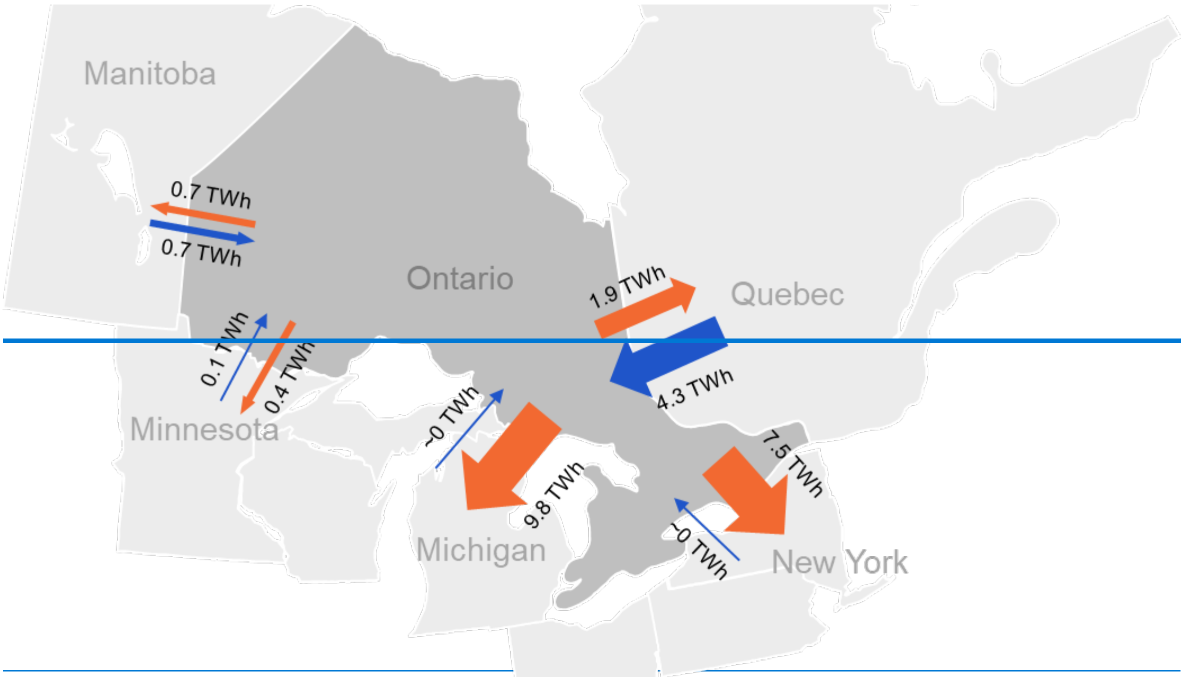
[23] Government of Ontario (2022). Ontario's Low-Carbon Hydrogen Strategy. p.41. Available: https://www.ontario.ca/files/2022-04/energy-ontarios-low-carbon-hydrogen-strategy-en-2022-04-11.pdf

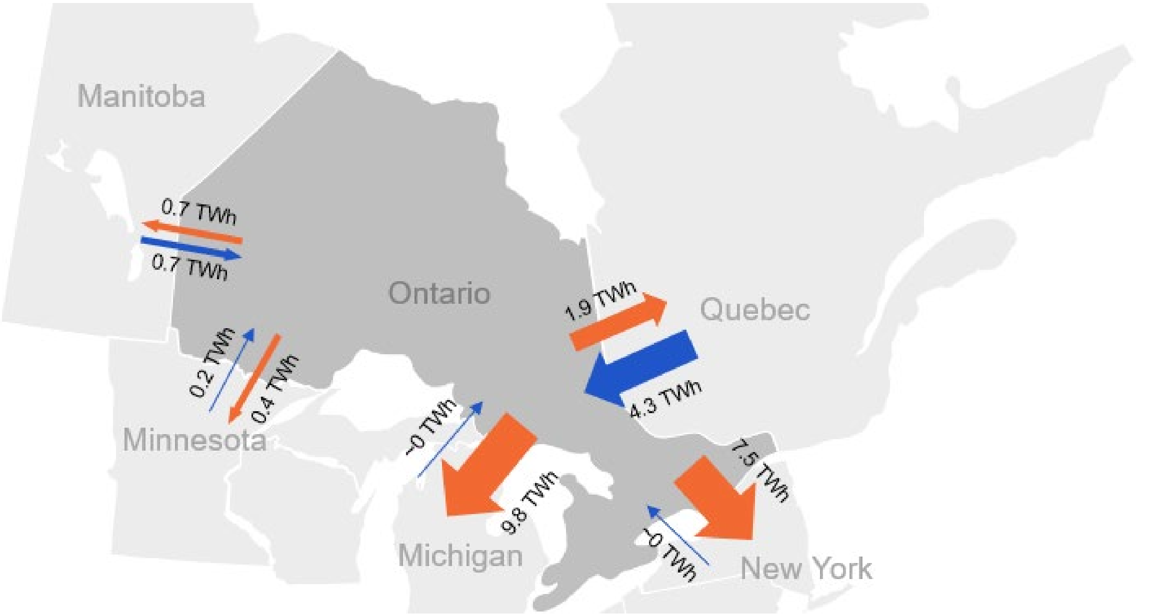
[24] Bruce County (2020). Foundational Hydrogen Infrastructure Project. Available: https://brucecounty.on.ca/sites/default/files/file-upload/bruce_innovates_-_foundational_hydrogen_infrastructure_project_-_overview_-_2020.pdf

[25] IESO (2021). Imports and Exports. Available: https://www.ieso.ca/en/Power-Data/Supply-Overview/Imports-and-Exports

[26] ITC Investment Holdings (2022). Lake Erie Connector Project. Available: https://www.itclakeerieconnector.com/

Figure 3. Electricity Imports and Exports with Neighboring Regions (2020)





2.2 Ontario's Natural Gas System

In 2019, Ontario consumed approximately 940 PJ of natural gas.[27] Converted to electricity units, this is roughly 261 TWh, which is almost twice the province's annual electricity consumption (~135 TWh/year). Figure 4 shows this comparison of annual electricity and gas demand.

Natural gas demand is primarily driven by building heating (63% of demand) and industry (37% of demand), with very limited use in transport. Most of the natural gas consumed by buildings is used for heating during the winter months, and more than 80% of building heating in Ontario is fueled by natural gas.[28] Natural gas is also used in industrial processes such as the manufacturing of metals, chemicals, and fertilizers, and pulp and paper processes.[29]

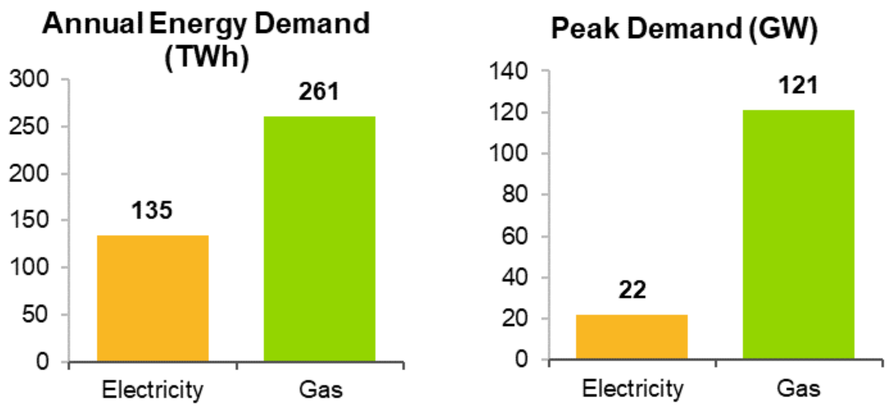
Natural gas plays a critical role in meeting peak energy demand. Ontario's peak-hour natural gas demand is approximately 435 TJ/hour,[30] which translates to approximately 121 GW. This is more than 5 times the magnitude of the electricity peak demand of 22 GW.[31]

Scope of Natural Gas Demand in this Study

This study models reductions in GHG emissions of the Ontario-wide energy system, aiming to capture all gas demand in the province. The baseline forecast of gas demand used in this analysis is based exclusively on Enbridge Gas demand, accounting for 98%-99% of gas demand in Ontario (see footnote 27). This also captures a small share of natural gas demand from industry for use as feedstock in non-energy purposes – roughly 1.5% or 15 PJ.[32]

The remaining 1%-2% of gas demand (not served by Enbridge Gas) is not explicitly captured. Nevertheless, future demand for low- and zero-carbon gases from new sectors such as transport and industry are captured.

Figure 4. Comparison of Ontario's Electricity and Natural Gas Demand (2019)



Ontario represents 24% of total natural gas consumption in Canada. However, with limited natural gas production in Ontario—representing less than 0.1% of total Canadian gas supply—Ontario is almost completely reliant on natural gas imports.[33] Ontario has historically relied on natural gas supply from Western Canada, also acting as a transit hub for natural gas export to the US. However, the Appalachian Basin, specifically the Marcellus and Utica shale gas formations, has experienced the

[27] According to the Canada Energy Regulator's (CER's) Energy Futures 2021 report, natural gas demand in Ontario was 940 PJ in 2019, while it fluctuated between 800 PJ and 950 PJ over the 2010-2019 period. Enbridge Gas accounts for the vast majority of gas demand in the province, with limited additional gas demand from other gas distributors (some regulated and some not). For example, while the CER estimated Ontario-wide natural gas demand in 2019 at 941 PJ, the OEB reported natural gas demand from Ontario's regulated distributors (Enbridge Gas and EPCOR) at 939 PJ, or 26.7 billion cubic meters. Of this, Enbridge Gas accounted for 936 PJ, equivalent to 99.5% of demand reported by CER. Enbridge Gas's share of Ontario's total gas demand, however, has varied year-over-year. On average, from 2015 to 2019, Enbridge Gas accounted for 98.3% of gas demand.

Canada Energy Regulator (2021). Canada's Energy Futures 2021. Available: https://apps.cer-rec.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA

Ontario Energy Board (OEB, 2019). 2019 Yearbook of Gas Distributors. Available: https://www.oeb.ca/utility-performance-and-monitoring/natural-gas-and-electricity-utility-yearbooks

[28] Natural Resources Canada (2021). Space Heating Secondary Energy Use. Available:
Residential Sector, Ontario:
~~https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/data_e/downloads/comprehensive/Excel/2018/res_on_e_8.xls~~https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/data_e/downloads/comprehensive/Excel/2018/res_on_e_8.xls
Commercial / Institutional Sector, Ontario:
https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/data_e/downloads/comprehensive/Excel/2018/com_on_e_24.xls

[29] Statistics Canada (2021). Supply and demand of primary and secondary energy in natural units. Available: https://www150.statcan.gc.ca/t1/tbl1/en/cv.action?pid=2510003001

[30] Enbridge Gas internal analysis. Gas peak demand is 11 million m^3/hour, equivalent to ~435 TJ/hour.

[31] IESO (2021). Hourly Demand Report. *PUB_Demand_2019*. Available: http://reports.ieso.ca/public/Demand/

[32] The Ontario Fuels Technical Report (2016), prepared by Navigant (now Guidehouse) for the Ministry of Energy estimated non-energy natural gas demand by industry at 15 PJ in 2015.

[33] Canada Energy Regulator (2021). Provincial and Territorial Energy Profiles. Available: https://www.rec-cer.gc.ca/en/data-analysis/energy-markets/provincial-territorial-energy-profiles/provincial-territorial-energy-profiles-ontario.html?=undefined&wbdisable=true#s2

most prolific natural gas production growth in North America. This abundant natural gas supply is located within the Great Lakes region near Ontario, the Dawn Parkway System, and other eastern North American-consuming markets.

This supply is delivered to Ontario through Michigan (via the Great Lakes Canada Pipeline Ltd./Great Lakes Gas Transmission; Vector Pipeline L.P.; DTE Energy/St. Clair Pipelines [St. Clair Pipelines L.P.]; Bluewater Gas Storage, LLC/Bluewater Pipeline [St. Clair Pipelines L.P.], Panhandle Eastern Pipeline, and Niagara Gas Transmission Limited LINK Pipeline) interconnecting to the Dawn Hub. Ontario is also interconnected with New York (via pipelines at Niagara and Chippawa), interconnecting with the Dawn Parkway System Kirkwall. As shale gas production from the US has scaled over the last decade, supply from Western Canada has declined, resulting in an increasing share of gas supply into Ontario coming from New York.

Balancing gas supply and demand in Ontario is largely supported by the province's gas storage resources. The Enbridge Gas-owned Dawn Hub is a natural gas storage facility in southwestern Ontario, with storage capacity of 281 Bcf (about 296 PJs or 82 TWh), equivalent to 30% of Ontario's annual natural gas demand.

Natural gas storage allows suppliers to minimize price volatility for customers because they can purchase and store gas when prices or demand are low and withdraw it when prices or demand are high. The Dawn Hub also provides Ontario security of natural gas supply during peak periods in case of shortages, emergencies, or extended cold waves. Beyond Ontario, the Dawn Hub plays a major role in the operation of the natural gas system across North America. The Dawn Hub is one of the most important natural gas trading hubs and pricing benchmarks, with access to supply routes from Western Canada, mid-continental US, the Rockies, the Gulf of Mexico, and markets in the Midwest, Eastern Canada, and the US Northeast.[34] The Dawn Hub is also connected through various upstream natural gas transmission pipelines to all major natural gas supply basins across Canada and the continental US including Western Canadian Sedimentary Basin in Alberta and the Marcellus shale production region in the US Northeast.

Natural gas is one of the most flexible forms of energy because, unlike electricity, it can be stored relatively inexpensively for long periods of time. This flexibility allows the gas system to deal with large fluctuations in demand and volume, which are common in Ontario due to the seasonal nature of space heating and process heating loads in the province. Serving Ontario's energy needs with a purely electric system would require building sufficient generation, transmission, and distribution capacity to meet those extreme energy needs in real time, for example, on low-wind and low-sun days, or when above-ground infrastructure is impacted by severe weather events like ice or high winds. Ontario's gas distribution infrastructure is largely underground, where it is protected from most weather events.

2.3 Low- and Zero-Carbon Gases

One approach to reducing GHG emissions in natural gas systems is to displace natural gas with low- or zero-carbon gases, such as RNG and hydrogen. This analysis considered the development of RNG and hydrogen resources in Ontario, as well as the importation of these gases from neighbouring provinces. This subsection provides a brief introduction to these technologies and summarizes the current status of these fuels in Ontario. Table 1 summarizes the primary technologies used to produce these fuels, followed by discussion of the technologies in scope for this analysis.

[34] Enbridge Gas (2021). The Dawn Hub. Available: https://www.enbridgegas.com/storage-transportation/doing-business-with-us/our-dawn-facility

Table 1. Renewable Natural Gas and Hydrogen Production Technologies

Renewable Natural Gas (RNG)			Hydrogen[35]	
Anaerobic Digestion	**Biomass Gasification**	**Landfill Gas**	**Grey and Blue Hydrogen**	**Green and Pink Hydrogen**
Anaerobic digestion is a well-known and widely used biological process for converting biomass or natural feedstock into biogas in the absence of oxygen. Typical feedstocks for anaerobic digestion are wet organic waste materials such as manures, sewage sludge, and food wastes as well as crops such as maize. Landfills and anaerobic digestors receive these feedstocks and then produce biogas, which is then upgraded to RNG.	Biomass gasification uses solid feedstock such as wood residues from manufacturers or discarded wood products. This feedstock is heated in the presence of a reduced concentration atmosphere (comprising air, oxygen, or steam) to produce a synthetic gas (syngas). This syngas must then go through a methanation process to be cleaned and converted into bio-syngas (bioSNG).	Landfill gas is a natural by-product of the decomposition of organic material in landfills. Landfill gas is composed of roughly 50% methane, 50% CO_2, and a small amount of non-methane organic compounds. Landfill gas can be upgraded to RNG through treatment processes by increasing its methane content and, conversely, reducing its CO_2, nitrogen, and oxygen contents.	Hydrogen can be produced via SMR, which is based on a thermochemical conversion of natural gas. Hydrogen production via SMR produces carbon emissions **Grey hydrogen** refers to hydrogen produced via SMR without carbon capture. **Blue hydrogen** refers to hydrogen produced via SMR and paired with carbon capture and storage (CCS) to significantly reduce carbon emissions. Hydrogen produced in this manner is also termed low carbon hydrogen.	Hydrogen can be produced via electrolysis, a process that uses electricity to split water into hydrogen and oxygen.[36] Hydrogen production via electrolysis can be free of carbon emissions depending on the source of electricity. **Green hydrogen** is produced using electricity from renewable energy (wind, solar, or hydro power) and is completely emissions-free. **Pink hydrogen** is produced from nuclear power and is also free of GHG emissions.

Renewable natural gas is produced primarily via anaerobic digestion of organic waste (from landfills, wastewater, and agricultural waste) and biomass gasification. RNG is considered a carbon-neutral fuel because it comes from organic sources that once absorbed carbon dioxide from the atmosphere during photosynthesis. RNG has even greater benefits when it's produced from organic waste that would otherwise decay and create methane emissions.

Another RNG production technology is power-to-gas RNG, where hydrogen can be used as feedstock to produce synthetic methane. Synthetic methane is produced via the hydrogenation of CO_2, using captured CO_2 from anaerobic digestion plants or other biogenic sources and hydrogen from excess electricity. Our analysis did not include power-to-gas RNG because it is more costly and, given the feedstock and inputs needed, more limited in availability.

Hydrogen is produced primarily via steam methane reforming (SMR) and electrolysis. Because hydrogen is a carbon-free molecule, the ~~use~~combustion of hydrogen does not directly produce GHG emissions at the burner tip. However, hydrogen use may lead indirectly to GHG emissions if the process used to produce hydrogen creates GHG emissions; the quantity of these indirect emissions depends on the method and energy source used to produce hydrogen. With its low rate of GHG emissions, Ontario's electricity grid offers a significant advantage to produce low-carbon hydrogen. As mentioned in Section 2, 93% of electricity generated in Ontario is low emissions or emissions-free. As such, hydrogen produced using surplus electricity from Ontario's grid can be considered green hydrogen.

Two alternative hydrogen production methods are described in the following bullets. Our analysis focused exclusively on hydrogen production via SMR and electrolysis and did not include these technologies because they are at a less mature stage of technology development and are more costly than current alternatives.

[35] The industry and government, including Canada's federal government, are moving to simplify the terminology to either renewable hydrogen or low-carbon hydrogen.

[36] There are different types of electrolyzers; alkaline electrolyzers, proton exchange membrane, and solid oxide electrolysis cells. Alkaline electrolyzers are the most mature and cost-effective technology, although other technologies are rapidly approaching cost parity.

- **Auto-thermal reforming (ATR)**: An alternative to hydrogen production via SMR is ATR. SMR is more dominant than ATR. Unlike SMR, the ATR process requires an additional oxygen supply, which can lead to additional emissions and costs if the oxygen is not supplied as a by-product from a separate process.
- **Bio-hydrogen:** Another production method is biomass gasification, which involves the thermochemical (or biochemical) conversion of biomass resources or biomass waste to produce hydrogen. Hydrogen produced via biomass gasification is also referred to as bio-hydrogen. Due to relatively high biomass feedstock costs, bio-hydrogen is unlikely to play a role in hydrogen supply in the long term.

Hydrogen is traditionally transported and delivered in two ways: via pipelines and road transport.

- **Pipeline:** Pipeline transport is an economical and efficient method of transporting hydrogen. However, large volumes are required before building a pipeline can be justified. Most hydrogen is produced onsite at refineries in Southwestern Ontario where it is also used. This means hydrogen transport via pipeline is currently limited in Ontario, likely only used for relatively short distances within facilities.
- **Road transport:** Road transport is a more costly transportation method because of constraints on the amount of volume that can be transported by trucks and the additional compression infrastructure required. Hydrogen can also be liquified for storage or delivery. This increases the energy density significantly but requires extreme cooling and compression, which are expensive.

Ontario's Experience with Low- and Zero-Carbon Gases

While Ontario's RNG and hydrogen supplies remain largely undeveloped today, the scale-up of RNG and hydrogen is becoming an increasingly relevant topic for policymakers and gas utilities at the provincial and federal levels. At a federal level, in December 2020, Natural Resources Canada (NRCan) published Canada's Hydrogen Strategy outlining a vision for the development of hydrogen supply and infrastructure across Canada.[37] In April 2022, the Ontario government released its Low-Carbon Hydrogen Strategy, which describes near-term actions to launch a hydrogen production pilot, identify strategic locations for hydrogen hubs, support hydrogen storage and grid integration pilots, transition industry to hydrogen-ready equipment, and support ongoing hydrogen research, among other actions.[38] Operational experience with RNG and hydrogen supply remains relatively limited across Canada, but as described below, several high-profile projects in Ontario are changing this.

RNG production in Ontario: There are several RNG production facilities in Ontario including the City of Toronto's Dufferin Solid Waste Management Facility, which produces RNG from the city's Green Bin program; Hamilton's Woodward Avenue Water Treatment plant, which produces RNG from captured raw biogas; and London's StormFisher facility, which produces RNG from organic waste. As of April 2021, Enbridge Gas customers can voluntarily pay $2/month via the OptUp program[39] to fund RNG to be added to Enbridge Gas' gas supply.[40]

Enbridge Gas is also collaborating with Walker Industries and Comcor Environmental to build Ontario's largest RNG production facility, to be located in Niagara Falls, Ontario. The plant is expected to be operational in 2023 and is expected to generate enough energy to heat 8,750 homes.[41] Demand for RNG has also begun materializing in heavy road transport applications with cities like Hamilton introducing a blend of RNG in some of their compressed natural gas (CNG)

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[37] NRCan (2020). Hydrogen Strategy for Canada. Available: https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/environment/hydrogen/NRCan_Hydrogen-Strategy-Canada-na-en-v3.pdf

[38] Government of Ontario (2022). Ontario's Low-Carbon Hydrogen Strategy. Available: https://www.ontario.ca/page/ontarios-low-carbon-hydrogen-strategy

[39] Enbridge Gas (2020). OptUp. Available: https://www.enbridgegas.com/sustainability/optup

[40] Enbridge Gas (2021). Ontario Customers Can OptUp to Greener Choices. Available: https://www.enbridge.com/stories/2021/april/enbridge-gas-optup-voluntary-renewable-natural-gas-initiative

[41] Enbridge Gas (2020). Enbridge and Partners Break Ground on Ontario's Largest RNG Plant. Available: https://www.enbridge.com/stories/2020/october/enbridge-and-partners-break-ground-ontarios-largest-rng-plant

buses.[42] The City of Hamilton operates 137 buses on CNG, representing approximately 2% of Ontario's fleet of transit buses. A portion of the natural gas supplied to these buses is RNG from organic waste. Over the next five years, Hamilton's bus fleet is anticipated to add 177 more CNG-powered buses.

Ontario's RNG Potential

While the supply of RNG in Ontario is currently small and more costly that importing natural gas, the province has significant RNG production potential. Torchlight Bioresources estimated Ontario's RNG potential via conventional RNG production technologies like anaerobic digestion and landfill gas.[43] Torchlight's report estimated that Ontario has the technical potential to produce around 40 PJ per year of RNG supply from wet organic wastes and up to around ~~240~~224 PJ per year if agricultural residues are included. These agricultural residues reflect waste products such as corn stover and corn silage, and not new crop production that would need to be redirected to RNG production. This RNG potential represents roughly 4%-26% of Ontario's annual natural gas demand.[44]

Most of Ontario's RNG is exported and, with other provinces setting ambitious RNG goals, this trend may continue. This may limit Ontario's ability to access local RNG supplies in the near term. The province of Quebec has announced in its Green Economy Plan that it aims to increase its renewable gas (including RNG and hydrogen) supply to 10% of its total gas supply by 2030.[45] The British Columbia government has a 2030 goal for 15% of gas consumption to come from renewable gas, which may include RNG and hydrogen.[46]

Hydrogen production in Ontario: Enbridge Gas and Cummins collaborated to develop a hydrogen and natural gas blending project in the southern Ontario city of Markham. The project leverages their Markham 2.5 MW power-to-gas facility, which uses proton exchange membrane electrolyzer technology to produce hydrogen and store it while providing regulation services to the IESO. In January 2022, Enbridge Gas announced that the first-of-a-kind hydrogen blending initiative is fully operational, successfully serving 3,600 customers in Markham.[47]

Limited hydrogen infrastructure is in operation in Ontario. As a result, there is also limited technical and operational experience in the operation of hydrogen transmission and distribution (T&D) networks. Most experience in hydrogen is limited to the handling of hydrogen in an industrial setting, with the main users in Ontario being refineries and fertilizer production industries. Safety procedures and standards in the production, transport, storage, and handling of hydrogen are known within industry; however, outside industry, safety procedures and standards are less known and established.

2.4 Carbon Capture and Storage

Carbon capture and storage (CCS) involves the capture of carbon dioxide emissions from industrial processes or from the burning of fossil fuels. This carbon is then transported from where it was produced and stored deep underground in geological formations. There are no active CCS projects in Ontario since Ontario laws currently prohibit the geologic storage of carbon dioxide. However, in

[42] City of Hamilton (2021). Enbridge Gas Partners with City of Hamilton to Fuel Ontario's First Carbon-Negative Bus. Available: https://www.hamilton.ca/government-information/news-centre/news-releases/enbridge-gas-partners-city-hamilton-fuel-ontarios

[43] Torchlight Bioresources (2020). Renewable Natural Gas (Biomethane) Feedstock Potential in Canada. Available: https://www.enbridge.com/~/media/Enb/Documents/Media%20Center/RNG-Canadian-Feedstock-Potential-2020%20(1).pdf?la=en

[44] Torchlight's ~~240~~224 PJ estimate is based on anaerobic digestion and landfill potential and does not reflect more advanced RNG production technologies like biomass gasification or power-to-gas, which are not yet commercially available. Of the ~~240~~224 PJ estimate, landfill gas accounts for approximately 21 PJ, equivalent to 9%.

[45] Government of Quebec (2022). 2030 Plan for a Green Economy. Available: https://cdn-contenu.quebec.ca/cdn-contenu/adm/min/environnement/publications-adm/plan-economie-verte/plan-economie-verte-2030-en.pdf?1635262991

[46] Government of British Columbia (2021). CleanBC Roadmap to 2030. p.60. Available: https://www2.gov.bc.ca/assets/gov/environment/climate-change/action/cleanbc/cleanbc_roadmap_2030.pdf

[47] Enbridge Gas (2020). Groundbreaking $5.2M Hydrogen Blending Project Aims to Green Ontario's Natural Gas Grid. Available: https://www.enbridge.com/Stories/2020/November/Enbridge-Gas-and-Hydrogenics-groundbreaking-hydrogen-blending-project-Ontario.aspx

January 2022, the Ministry of Northern Development, Mines, Natural Resources and Forestry issued a discussion paper exploring possible legislative changes to remove barriers to the storage of carbon dioxide, which would enable the creation of a regulatory framework to govern CCS and other new technologies.[48]

Prior studies have assessed CCS options in Ontario and have determined that the only sequestration option is geological sequestration in saline aquifers. Carbon dioxide is expected to be stored in these aquifers for long periods, from one hundred years to several thousand years depending on the size, properties, and location of the reservoir. Prior studies identified two different major reservoirs appropriate for CCS in southwestern Ontario: one located in the southern part of Lake Huron and the other located inside Lake Erie. These sites have approximate storage capacities of 289 million and 442 million tonnes of CO_2 emissions.[49]

The analysis presented in this report assumes that the use of CCS would begin around 2030 and would be used for two purposes: (1) to store CO_2 by-products from hydrogen production via steam methane reformation of natural gas feedstocks, and (2) to store CO_2 emissions produced from the combustion of natural gas.

[48] Canada Ministry of Northern Development, Mines, Natural Resources and Forestry (2022). Discussion Paper: Geologic Carbon Storage in Ontario. Available: https://prod-environmental-registry.s3.amazonaws.com/2022-01/Geologic%20Carbon%20Storage%20Discussion%20Paper%20-%20FinalENG%20-%202022-01-04_0.pdf

[49] Shafeen, Ahmed & Croiset, Eric & Douglas, Peter & Chatzis, Ioannis. (2004). CO_2 sequestration in Ontario, Canada. Part I: Storage evaluation of potential reservoirs. Energy Conversion and Management. 45. 2645-2659. Available: http://dx.doi.org/10.1016/j.enconman.2003.12.003

3. Study Methodology

This study developed two main scenarios that accomplish net zero GHG emissions in the Ontario energy system by 2050: a **Diversified Scenario** in which low- and zero-carbon gases are used for targeted applications in combination with electricity, and an **Electrification Scenario** in which electrification is the main approach, with a limited role for low- and zero-carbon gases. These scenarios, detailed in section 4, define constraints for the future energy system.

To model pathways for these two scenarios from today to 2050, this study used an integrated energy system model, Guidehouse's Low Carbon Pathways (LCP) model. This model was adapted to the characteristics of Ontario's gas and electricity networks, its energy supply-demand conditions, and its interties with neighbouring regions. For each net zero scenario, our analysis produced a cost-optimal pathway of how the electricity and gas systems could reduce GHG emissions by 2050, including identifying what investments will be required for electricity, hydrogen, and methane. The pathways describe investments in generation and supply capacity, storage, and infrastructure, as well as when those investments will be needed.

The study approach was divided into three phases (see Figure 5).

Figure 5. Overview of Study Methodology

Phase 1: Data Collection and Input Development	Phase 2: Development of Net Zero Scenarios	Phase 3: Low-Carbon Pathway Modelling
Techno-economic parameters: Development and collection of techno-economic parameters for all supply capacity technologies (wind, solar, hydrogen production technologies, etc.) and transmission infrastructure (power lines, gas pipelines, etc.).[50] **Ontario energy system data:** Characterization of the current state of the electricity and gas system (electricity supply mix, transmission interties between Ontario and neighbouring regions, etc.). **Technology scope:** Including all electricity generation and gas production technologies, conversion technologies, storage, and transmission infrastructure. **Appendix A** presents the inputs and assumptions used in this study.	**Net zero scenarios:** Development of 2020-2050 forecasts for electricity, hydrogen, and methane demand in Ontario. **Geographies:** Including electricity demand forecasts through 2050 for all neighbouring regions. Hydrogen and methane demand is not defined in neighbouring regions. **Appendix B** describes the approaches and assumptions used for each sector.	**Energy supply and infrastructure:** Configuration of the LCP model to the Ontario energy system and neighbouring regions to optimize the buildout of supply capacity and transmission infrastructure. **Alternative scenarios and sensitivities:** Exploration of the impact of alternative demand scenarios and sensitivities on the role of gas supply and infrastructure. **Appendix C** describes the modelling approach.

[50] These inputs were sourced from Ontario and Canadian energy stakeholders, including the IESO, the CER, and Enbridge Gas. Technology costs were sourced from a collection of international organizations, including the International Energy Agency (IEA) and the European Network of Transmission System Operators for Electricity (ENTSO-E), among others.

4. Developing Net Zero Scenarios for Ontario

This study developed two net zero scenarios of energy demand to 2050: a Diversified scenario and an Electrification scenario. These scenarios represent two different but plausible futures of energy demand in Ontario. Neither scenario is intended to represent the optimal or most likely pathway. Rather, the scenarios are potential future outcomes that use different pathways to achieve net zero emissions in the energy sector. This section defines the scenarios and their constraints in depth, and Section 5 describes how energy systems and the power sector would evolve differently to meet each scenario's constraints. The objective of this scenario analysis was to assess the costs associated with two different pathways to net zero and to explore the role played by electricity and low- and zero-carbon gases. This study's consideration of cost-optimal pathways does not attempt to pick technology winners or losers. There are different options for reducing GHG emissions and many solutions will be needed to achieve net zero.

The analysis focused on energy demand from three sectors: buildings, transport, and industry.[51] Figure 6 describes the scope of each sector and the ways in which they may reduce GHG emissions.

[51] The analysis does not capture emissions from agriculture, land use, waste, or embedded emissions from products or materials. These external sectors are assumed to reduce GHG emissions in step with the rest of the economy.

Figure 6. Description of Energy Demand by Sector

BUILDINGS	**Building heating** includes heating demand from residential and commercial buildings	With more than 80% of Ontario's buildings heated by natural gas, building heating, and approximately 24% of Ontario's emissions coming from buildings[52], it is the second largest contributor of emissions. GHG emissions from building heat demand can be reduced through low-carbon heating alternatives such as electric heat pumps (air-source and geothermal), and transitioning over time to utilizing hydrogen or RNG in hybrid dual fuel (gas and electric) systems, hydrogen- or RNG-based furnaces, and gas heat pumps, among other alternatives. Additionally, more efficient heating equipment will be available in the future, while newer and renovated buildings will have better insulation due to changes in building codes and standards, which will reduce heating demand.
TRANSPORT	**Transport** includes energy demand from light and heavy road transport, marine transport, rail, and aviation	Transport is the highest emitting sector in Ontario, accounting for 45% of emissions. Today, energy demand in the transport sector heavily relies on fossil fuels. Road transport relies largely on diesel and gasoline, aviation relies on jet fuel, rail transport relies on diesel, and marine transport relies on medium and heavy fuel oil. Energy transition options include electrification, hydrogen and hydrogen-derivatives, and bio-CNG (also called compressed renewable natural gas, or CRNG), among others. Ontario's transport sector will reduce GHG emissions in line with global trends. This is because Ontario's fueling and charging infrastructure will need to be largely consistent with the rest of North America and the world to enable international transport.
INDUSTRY	**Industry** includes energy demand from all major energy-intensive industries	Industry is the third largest emitting sector in Ontario, accounting for 23% of Ontario's GHG emissions. With the main industries being ferrous and non-ferrous metal production, oil and petroleum refining, and fertilizer and chemical manufacturing. For low temperature industrial processes (e.g., below 150°C) the transition to net zero will most likely rely on electrification. Medium temperature processes (e.g., 150°C to 400°C) may use electrification or low carbon gas. Industrial processes requiring high temperature heat will be more challenging and may require research and development into new low carbon and carbon capture technologies.

The two scenarios modelled differ in the approaches used to reduce GHG emissions in each sector. Table 2 shows those differences.

[52] Canada Energy Regulator (2022). Provincial and Territorial Energy Profiles – Ontario. Available: https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/provincial-territorial-energy-profiles/provincial-territorial-energy-profiles-ontario.html

Table 2. Scenario Assumptions by Demand Sector

Sector	Diversified Scenario	Electrification Scenario
	Low- and zero-carbon gases serve targeted uses in combination with electricity to reduce GHG emissions.	**Electricity is the main means of reducing GHG emissions. Low- and zero-carbon gases are limited to sectors that cannot feasibly be electrified.**
BUILDINGS	**Gas heating continues to play a key role in building heating.** • Gas heat pumps (fuelled by low carbon gas) play a dominant role in heating, complemented by electric heat pumps, including both air-source and geothermal. • Energy efficiency and building codes reduce heating energy demand.	**Electric heating displaces natural gas in most building heating.** • Electric heat pumps, including both air -source and geothermal, replace most gas heating in buildings. Low- and zero-carbon gas serves remaining gas heated buildings. • Energy efficiency and building codes reduce heating energy demand.
TRANSPORT	**Hydrogen plays a major role in all heavy transport.** • Light road transport is largely electrified using battery electric vehicles (BEVs) with a limited role for hydrogen fuel cell electric vehicles (FCEVs). • RNG (as bio-CNG) plays a limited role in heavy road transport. • Hydrogen plays a major role in road, marine (via ammonia), and aviation (via synthetic kerosene). • GHG emissions from rail are reduced using hydrogen and electrification.	**Electrification and biofuels play major roles in all transport methods.** • Light road transport is fully electrified via BEVs. • GHG emissions from heavy road and marine transport are reduced using electrification and biofuels. • The role of hydrogen is limited to aviation (via synthetic kerosene). • GHG emissions from rail are reduced using electrification.
INDUSTRY	**Hydrogen and natural gas + CCS play a key role in industry.** • Most industrial segments adopt hydrogen or natural gas + CCS for medium and high temperature processes. • Low temperature heat processes are electrified.	**Hydrogen and natural gas + CCS play a key role in industry.** • Hydrogen and natural gas + CCS play a role in high temperature heat processes and certain industries. • Most medium and low temperature heat processes are electrified.

In the **Diversified scenario**, **building heating** is mainly supplied by gas. Natural gas furnaces are the predominant heating method through 2030, but gas-equipped buildings are assumed to shift to gas-powered heat pumps in later years to meet the government's long-term goal that by 2035, all space heating technologies for sale in Canada meet an energy performance of more than 100%.[53] The emissions of gas heating appliances will decrease over time, as the gas supply is projected to shift from fossil natural gas to low- and zero-carbon gases. Fully electric heating plays a complementary role to gas heating through the deployment of electric air-source heat pumps and geothermal heat pumps. In **transport**, light road transportation is largely electrified, with hydrogen limited to a minor role. In heavy road transport, biodiesel, hydrogen, and electrification all play major roles supported by a small share of bio-CNG. Marine transport relies on ammonia (a hydrogen derivative) and, to a lesser degree, on electrification for short-distance transport. Rail transport is assumed to move from diesel to an equal share of hydrogen and electricity by 2050. In **industry**, hydrogen becomes the prominent option to displace natural gas in medium and high temperature industrial processes. Natural gas + CCS also plays a significant role. For low temperature heat processes, electrification is the main option.

[53] Energy and Mines Ministers' Conference (2017). Market transformation strategies for energy-using equipment in the building sector. p.16. Available: https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/emmc/pdf/Market-Transformation-Strategies_en.pdf

In the **Electrification scenario**, electricity plays a greater role in buildings, transport, and industry. With an increased role for electrification, low- and zero-carbon gas plays a limited role in all sectors. **Building heating** is mostly electrified as gas furnaces are replaced by electric heat pumps (including geothermal and air-source heat pumps), with gas heat pumps serving a small share of all buildings. In **transport**, light duty transport is fully electrified. Heavy duty transport relies mostly on electrification and biodiesel, with hydrogen only playing a limited role. Marine transport is less reliant on ammonia than in the Diversified scenario, with electrification and biodiesel also playing critical roles. In **industry**, electrification becomes the prominent option for low and medium temperature industrial processes, while natural gas + CCS plays a role for high temperature processes. Hydrogen is limited to steelmaking and other industries, where it is the only available pathway for achieving net zero.

While the Diversified and Electrification scenarios are intended to represent different views of a net zero future for Ontario, some sub-sectors are assumed to follow the same net zero pathway in both scenarios. These similarities reflect the confidence and certainty shared by stakeholders on how some sub-sectors are expected to reduce GHG emissions. For example:

- In the **buildings sector**, total energy demand for space heating decreases due to energy efficiency improvements in the new building stock and renovation of existing buildings.
- In the **iron ore and steel industry**, the views of most major stakeholders, globally and in Ontario, have consolidated behind the adoption of hydrogen-based direct reduction of iron ore (HDRI) as the only plausible option to eliminate GHG emissions. ArcelorMittal Dofasco and the Government of Canada have announced that they will be investing $1.8 billion into reducing the GHG emissions from ArcelorMittal Dofasco's Hamilton steel plant by pursuing natural gas-fired DRI and electric arc furnace production.[54] ArcelorMittal has successfully tested the use of green hydrogen in the production of direct reduced iron and, in the longer term, the Hamilton plant may be able to replace some of its natural gas use with hydrogen.[55] Hence, the rollout of the HDRI technology is incorporated in both scenarios.
- Similarly, in the **aviation sector**, the reduction of GHG emissions is expected to be driven by global aviation trends rather than by unique market drivers in Ontario. Because of this dependence on global trends, the approach for the aviation sector is the same in both scenarios, with roles for synthetic kerosene (produced with hydrogen) and biojet fuel.
- In the **light duty road transport sector**, the adoption of BEVs is expected to be the most common way of reducing GHG emissions from passenger vehicles. As a result, both scenarios are based on a large adoption of BEVs: 100% BEV penetration in the Electrification scenario and 95% BEV / 5% hydrogen FCEVs penetration in the Diversified scenario.

4.1 Comparison of Demand Scenarios

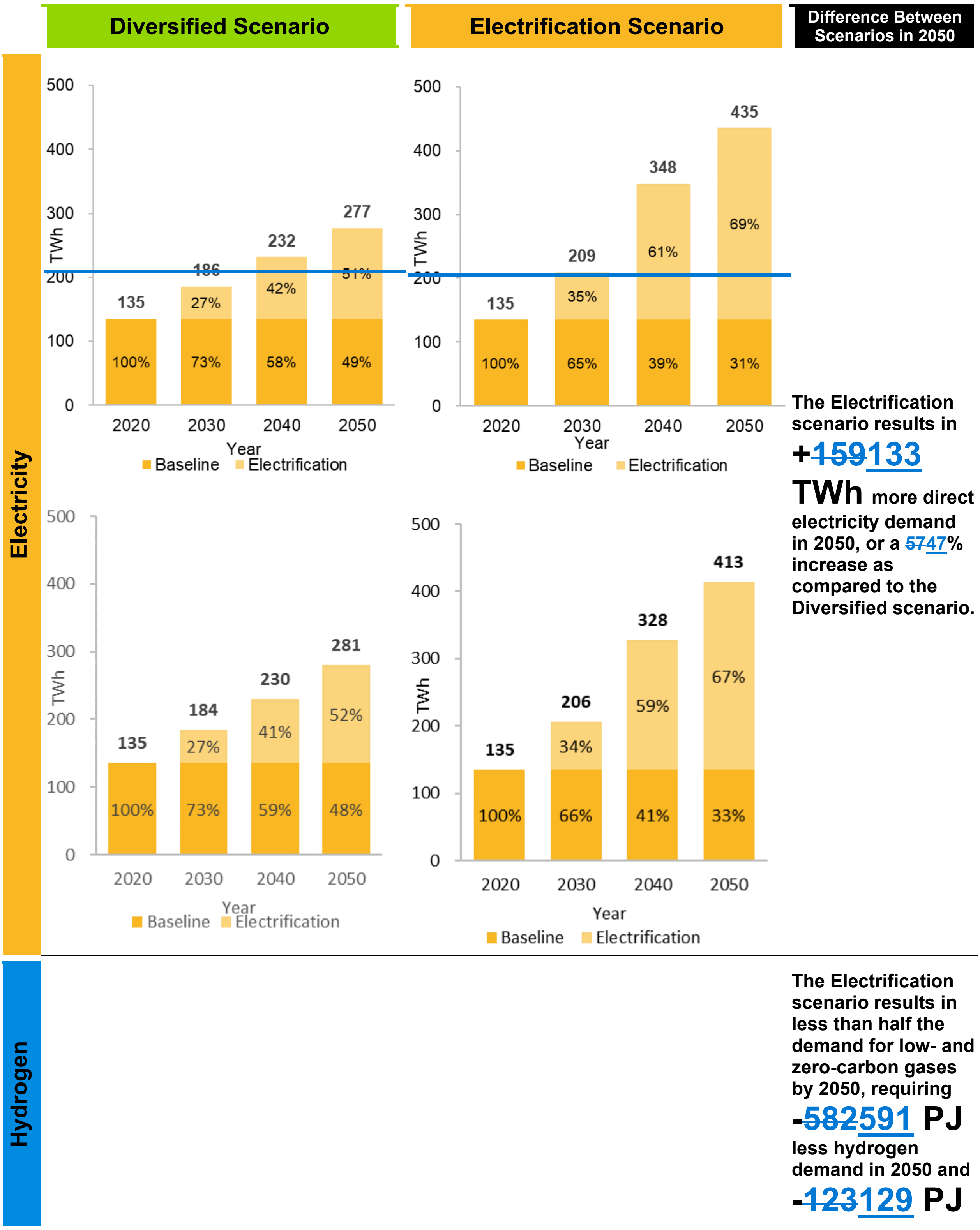
The following charts describe how the demand for different energy carriers evolves over time for the buildings, industry, and transportation sectors. Three energy carriers are considered in detail:

- **Electricity:** Annual electricity demand increases significantly in both scenarios. In the Diversified scenario, electricity increases two-fold from 135 TWh today to ~~277~~281 TWh by 2050, while in the Electrification scenario, demand increases over three-fold to ~~435~~413 TWh.
- **Methane:** In 2050, methane demand is met by a combination of RNG and natural gas paired with CCS. In the Diversified scenario, annual methane demand decreases from 922 PJ today to ~~310~~304 PJ by 2050, while in the Electrification scenario, demand decreases to ~~182~~175 PJ by 2050. Natural gas is predominantly displaced by hydrogen, as described below.
- **Hydrogen:** In the Diversified scenario, annual hydrogen demand increases from 0 PJ today to ~~839~~844 PJ, while in the Electrification scenario, hydrogen demand increases to ~~262~~253 PJ by 2050.

[54] ArcelorMittal (2021). ArcelorMittal and the Government of Canada announce investment of CAD$1.765 billion in decarbonisation technologies in Canada. Available: https://corporate.arcelormittal.com/media/press-releases/arcelormittal-and-the-government-of-canada-announce-investment-of-cad-1-765-billion-in-decarbonization-technologies-in-canada

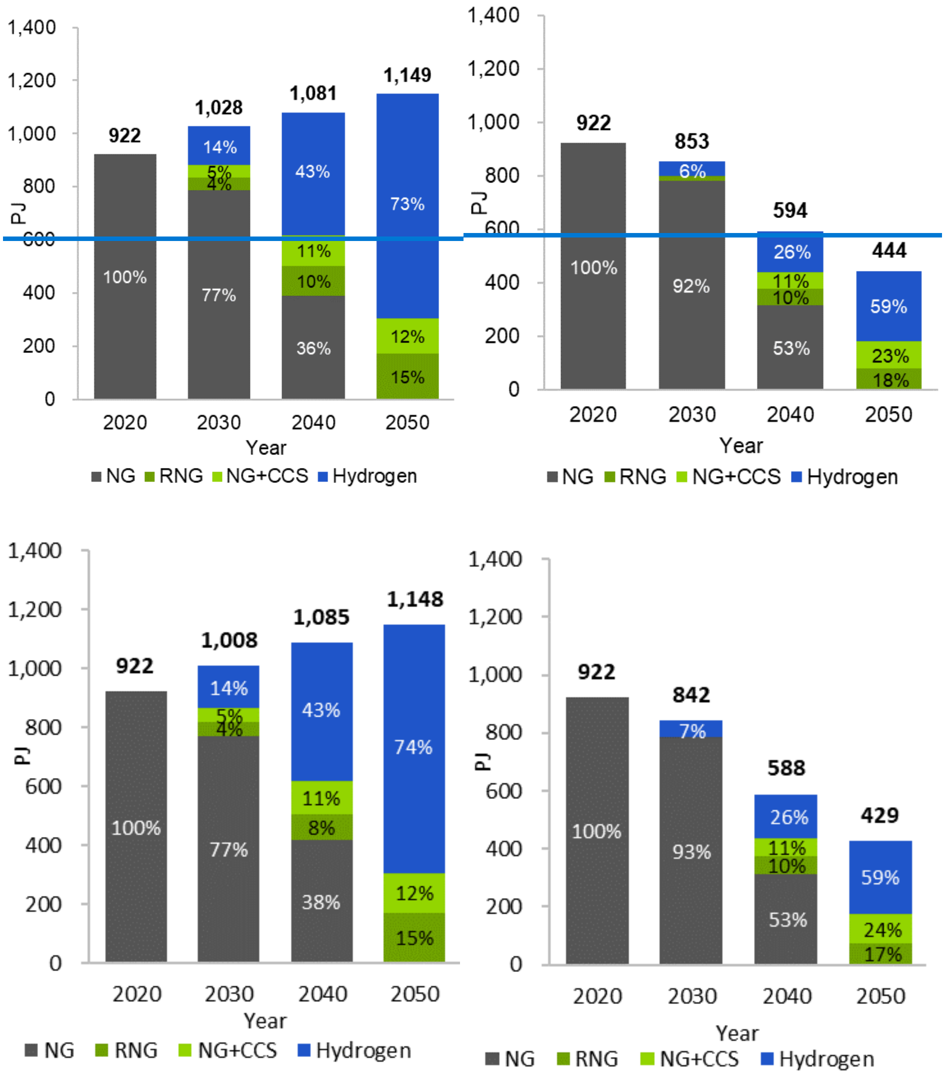
[55] The Bay Observer (2022). Arcelormittal Experimenting with Clean Hydrogen in Steelmaking. Available: https://bayobserver.ca/2022/05/04/arcelormittal-experimenting-with-clean-hydrogen-in-steelmaking/

Figure 7. Comparison of Annual Demand Scenario Forecasts by Energy Type[56]



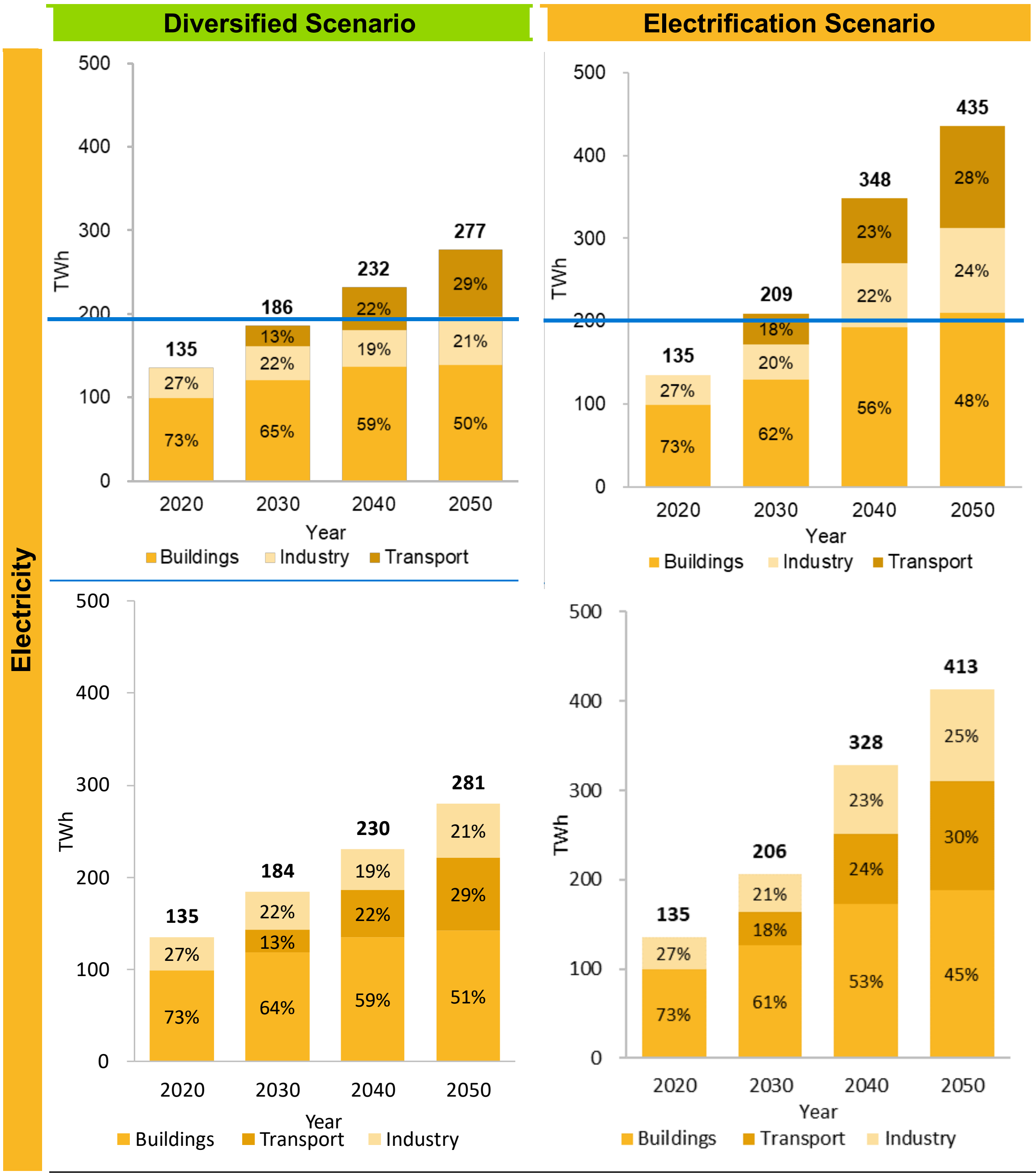
[56] Note that the percentages in this graphic have been rounded ~~to the nearest decimal~~ for ease of visual inspection. Any calculations based on them are subject to rounding errors.

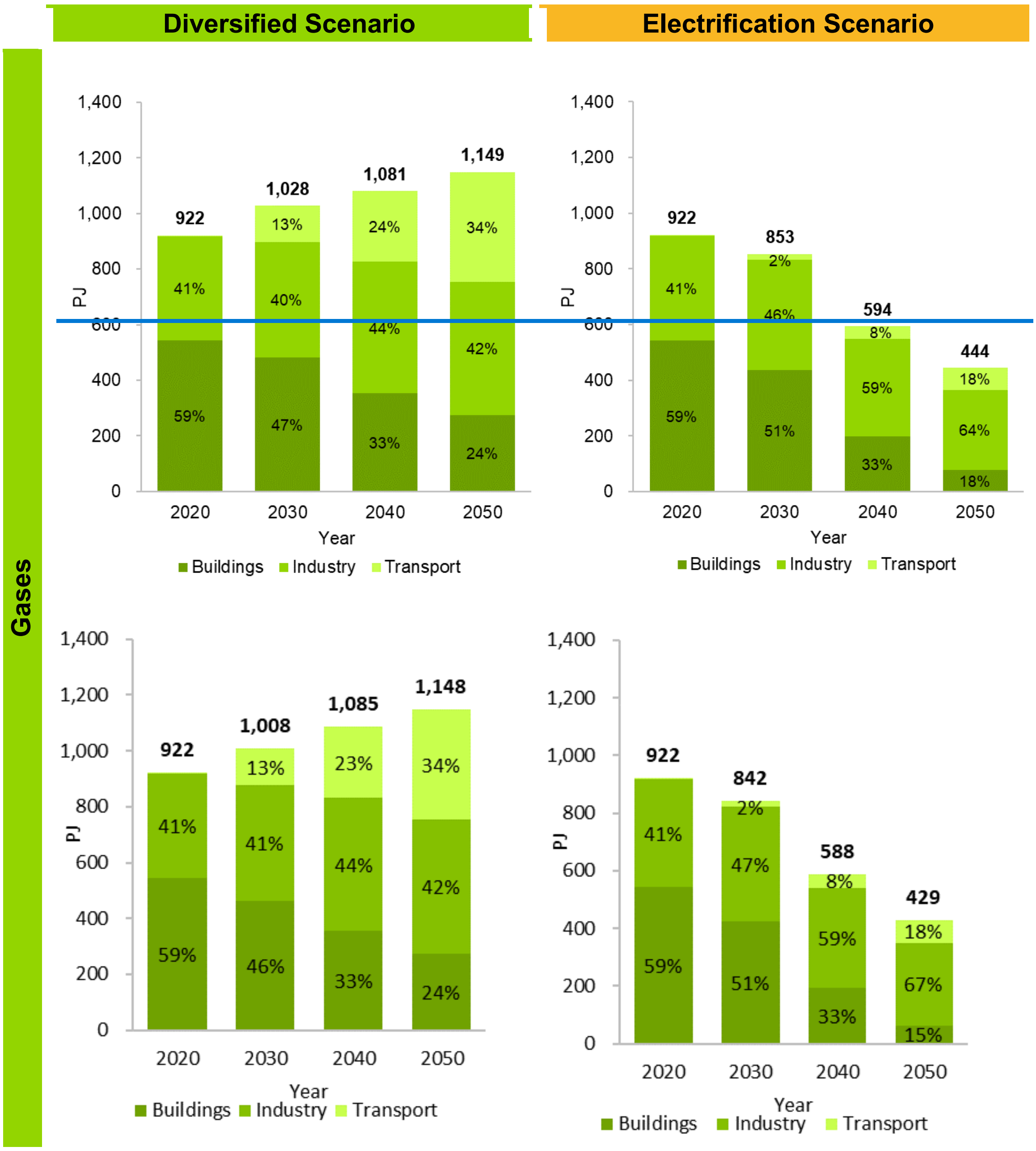
Methane



less methane demand in 2050 compared to the Diversified scenario.

Figure 8. Comparison of Annual Demand Scenario Forecasts by Sector





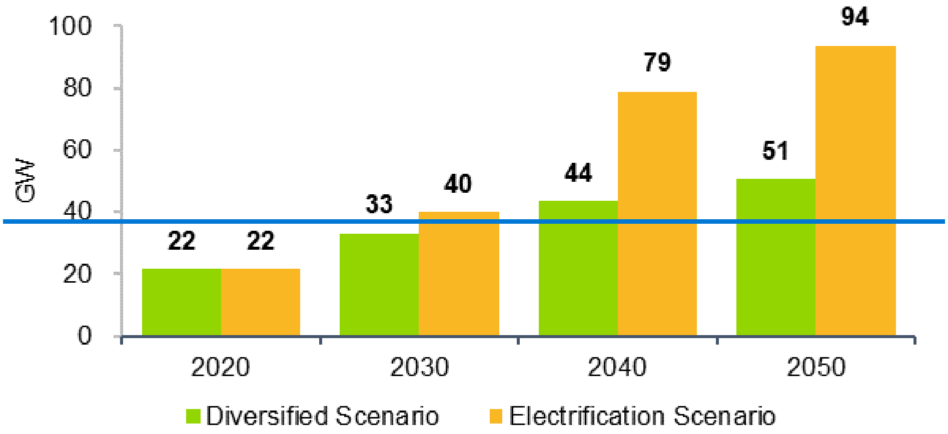
In addition to annual energy demand, the degree of fuel switching in each scenario has a large impact on energy system peak demand over time. Historically, Ontario has a winter peaking energy system for natural gas and a summer peaking system for electricity. In 2019, the electricity system experienced peak demand on July 29th at a magnitude of 22 GW.[57] Looking towards a net zero future, decisions around electrifying building heating will have the largest impacts of any sector on the electric system peak. For electric heating technology, this study focused on the adoption of cold climate air-source heat pumps and geothermal heat pumps to comply with the Pan Canadian Framework. Currently, 7% of homes in the province rely on electric heat pumps for space heating.[58] While the upfront installation and equipment cost for air-source heat pumps is considerably less than geothermal heat pumps, the efficiency of the air-source heat pump system decreases with colder outside air temperatures. To provide adequate heating in winter conditions, electrically heated homes

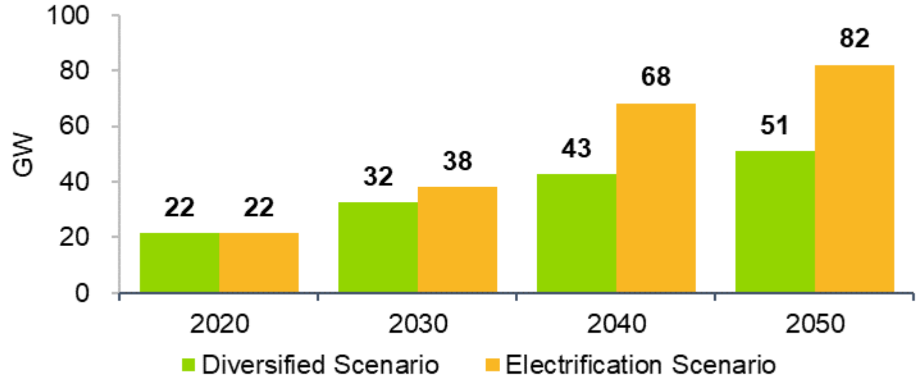
[57] IESO (2021). Hourly Demand Report. *PUB_Demand_2019*. Available: http://reports.ieso.ca/public/Demand/

[58] NRCan (2018). Residential Sector Heating System Stock. Available: https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/showTable.cfm?type=CP&sector=res&juris=on&rn=21&page=0
Note: This source states that 67% of residential buildings have a natural gas-fired appliance for primary heat. Consistent with this statistic, section 2 and section 4 of this report note that 80% of total energy consumed for space heating in residential and commercial buildings is provided by natural gas.

need to be well-insulated and weatherized to minimize heat leakage. This analysis assumes that homes with electric heat pumps undergo deep energy efficiency retrofits. The Electrification scenario assumes that, by 2050, 85% of all buildings will convert to electric heating systems and most will adopt cold climate air-source heat pumps over geothermal heat pumps due to the up-front cost of geothermal systems. This results in a ~~three~~nearly four-fold increase in system peak compared to ~~today~~2020. In contrast, the Diversified scenario assumes that 55% of buildings will be heated by gas heat pumps, and that the penetration of electric heat pumps only climbs to 40% by 2050. This results in an increase in electricity system peak to more than double what it is today. The change in electricity system peak over the study period for both scenarios can be seen in Figure 9 below.

Figure 9. Electricity System Peak Demand

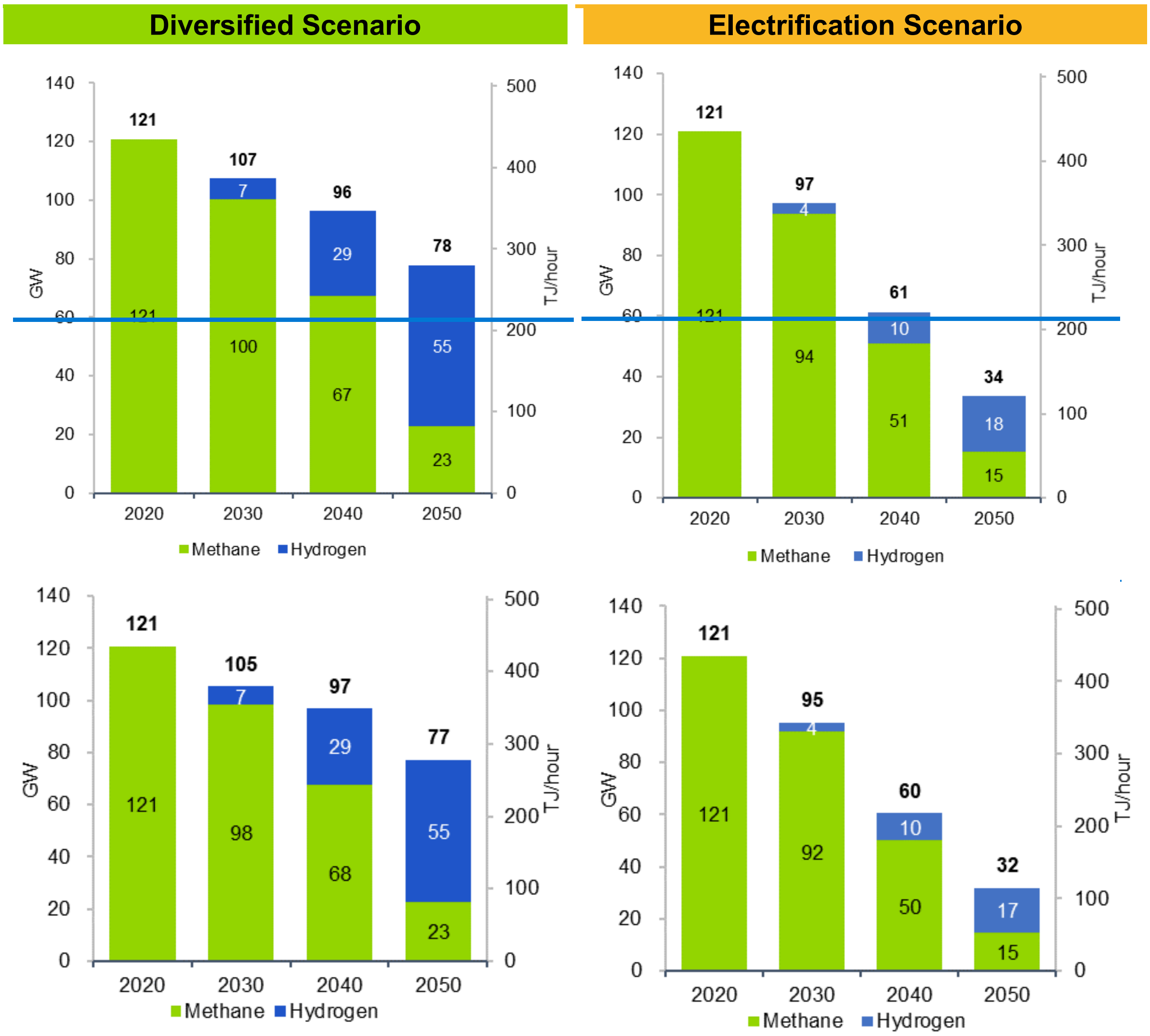




Gas system peak demand in the province today is 11 million m^3/hr which is equivalent to 121 GW. In both net zero scenarios, the peak energy demand rapidly decreases as imported conventional natural gas from fossil reserves is replaced by electricity, hydrogen, and RNG. In some industry sector cases, conventional natural gas is outfitted with CCS technology to reduce emissions. The Diversified scenario assumes that methane in the form of RNG and NG + CCS will play a larger role in the energy system in 2050 compared to the Electrification scenario.

Hydrogen peak demand starts at zero in 2020 in both scenarios. In the Diversified scenario, hydrogen, as a proportion of peak demand scales up considerably to power industry, transportation, and buildings. In the Electrification scenario, hydrogen is mostly used in the industrial sector for processes that are difficult to electrify, such as high temperature heating. The methane and hydrogen peak demands over the study period can be seen in Figure 10 below.

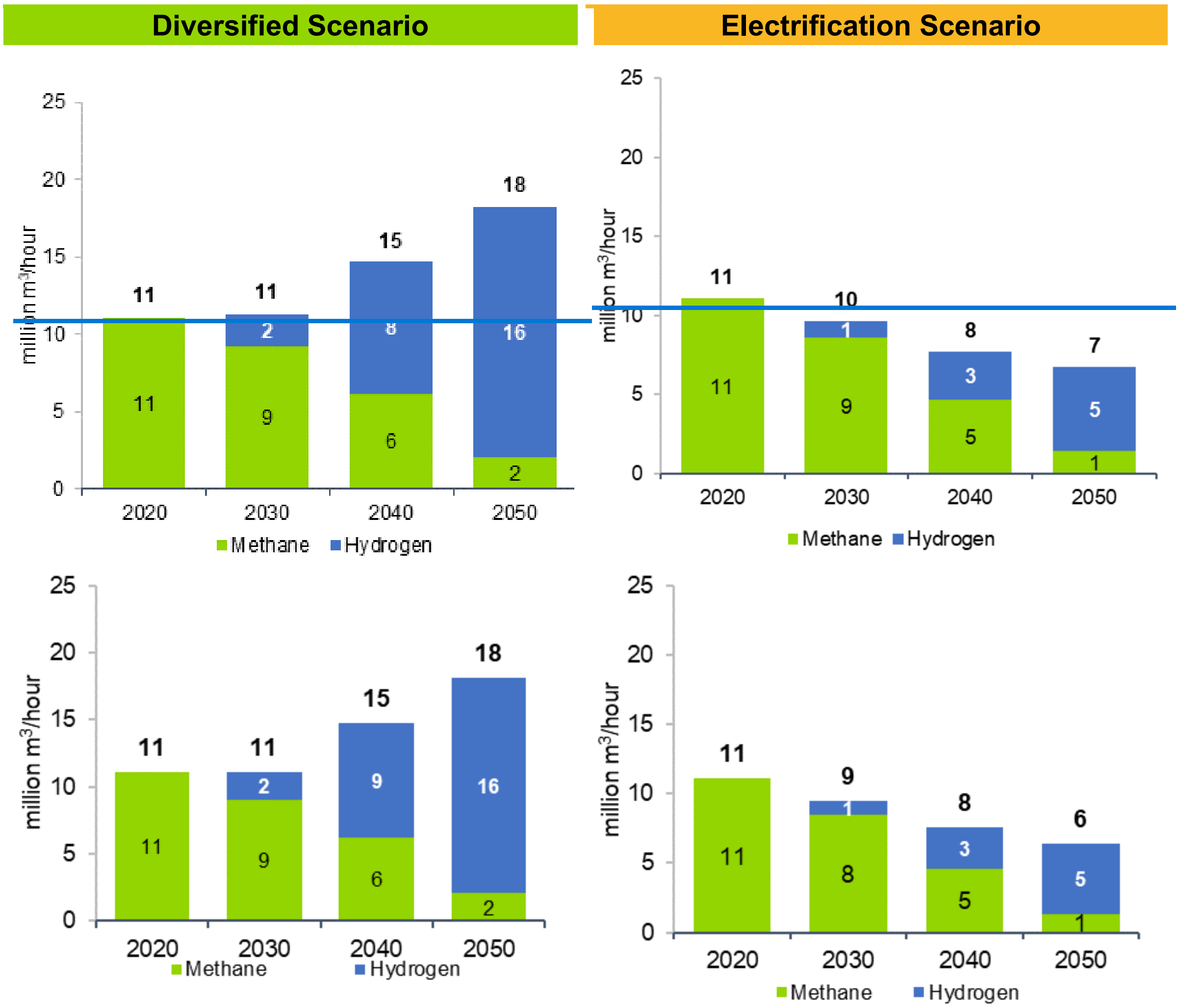
Figure 10. Gas System Peak Demand[59]



While the gas system peak declines for both scenarios in energy terms, the volumetric gas system peak rises significantly in the Diversified scenario. This is because hydrogen has a lower energy density than methane, so more volume is needed to provide the same amount of energy. This trend, along with the volumetric gas system peak for the Electrification scenario can be seen below in Figure 11.

[59] The methane peak demand presented in this chart is adjusted from the peak demand used in the model to reflect ETSA inputs. As a result, peak methane demand is slightly understated in the model. This calibration does not affect the model's optimization or the cost results that it produces because the model calculates costs associated with the existing methane system based on energy content, not capacity, and because no new methane infrastructure capacity is built in any scenario considered in this analysis.

Figure 11. Volumetric Gas System Peak Demand[6059]



4.2 Benchmark to Other Demand Forecasts

Electricity demand projections from the Diversified scenario in 2050 are broadly aligned with other net zero electricity demand estimates, which range from 240 TWh to 405 TWh, as Figure 12 shows. In the Electrification scenario, electricity demand slightly exceeds the range of these studies at ~~435~~413 TWh, which is expected given the Electrification scenario represents a future with aggressive electrification across all sectors. The reports used for comparison are as follows:

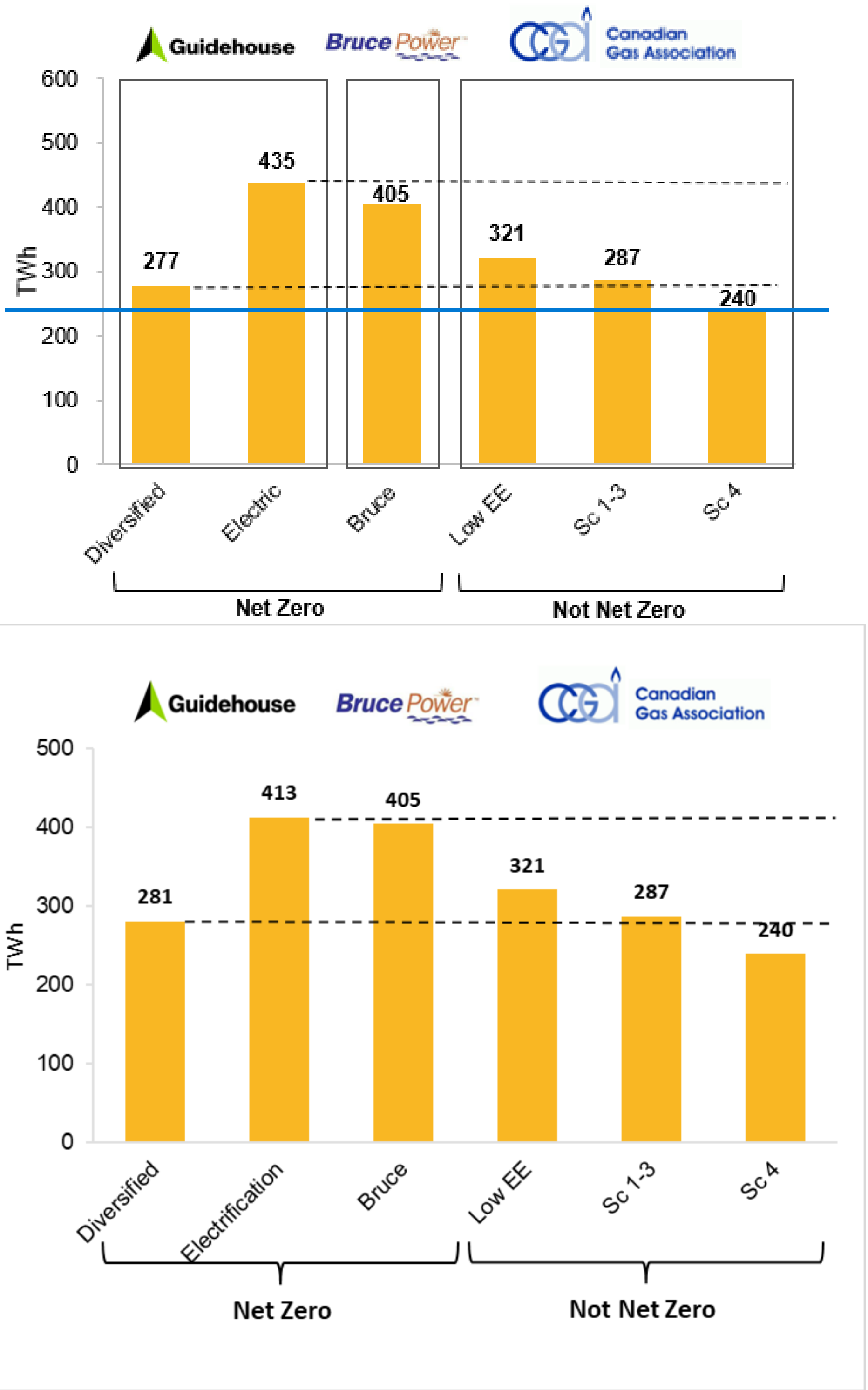
- **Bruce Power, The Next 50 Years Report:**[60] This 2050 electricity forecast for Ontario incorporates electricity demand used in the production of green hydrogen. In comparison, the Guidehouse demand scenarios do not. In the current study, electricity used to produce hydrogen is modelled separately, as a supply option, and is presented in Section 5.2.1 of this report.
- **Canadian Gas Association (CGA), Implications of Policy-Driven Electrification in Canada:**[61] The CGA study is a Canada-wide analysis. The 2050 electricity demand forecasts reported in Figure 12 have been estimated for Ontario by applying the growth rates in Canadian electricity demand from 2020 to 2050 to Ontario's 2020 electricity demand. The CGA study was completed prior to the federal government's announcement of a net zero

[60] BrucePower (2021). The Next 50 Years. Available: https://www.brucepower.com/wp-content/uploads/2021/07/210219D_Next50YearsReport_R000.pdf

[61] Canadian Gas Association (2019). Implications of Policy-Driven Electrification in Canada. Available: https://www.cga.ca/wp-content/uploads/2019/10/Implications-of-Policy-Driven-Electrification-in-Canada-Final-Report-October-2019.pdf

target for 2050, and therefore the scope of the emission reductions contemplated in the study do not achieve net zero. In comparison, both Guidehouse demand scenarios do achieve net zero.

Figure 12. Comparison of Electric Demand Projections, 2050



Source: Guidehouse analysis and reports listed in text above

The electric demand projections do not align with the IESO's 2021 Annual Planning Outlook (APO)[62] since the APO does not aim to meet any carbon emissions reduction targets. While the APO does account for moderate transportation electrification, it does not assume the same amount of economy-wide electrification as the Diversified or the Electrification scenarios. Thus, the APO's total forecasted annual electricity demand of 196 TWh in 2040 is lower than the forecasted ~~232~~230 TWh in 2040 for the Diversified scenario and is significantly lower than the forecasted ~~348~~328 TWh in 2040 for the Electrification scenario.

The mix of 2050 total energy demand met by hydrogen in the Diversified scenario (~~28~~39%) is ~~largely aligned~~consistent with the higher end of results from other Canadian and European estimates, ranging from 19% to 36%. The Electrification scenario (with ~~9~~13% of 2050 total energy demand met by hydrogen) is not comparable to the other estimates because of its aggressive electrification assumptions.[63] Of these comparisons, there are two Canadian reference studies. All other studies reported focus exclusively on Europe. These studies include the following:

- **NRCan, Hydrogen Strategy for Canada:**[64] This Canada-wide study estimates 20 Mt of hydrogen demand across Canada in 2050, corresponding to 30% of Canada's end-use energy.
- **University of Calgary, Towards Net Zero Energy Systems in Canada:** This Canada-wide study estimates 3,300 PJ of hydrogen demand across Canada, corresponding to 36% or 27% of energy demand depending on the baseline estimate of 2050 energy demand.[65]
- **McKinsey, Net Zero Europe:** This Europe-wide study estimates 1,510 TWh of hydrogen demand, equivalent to 19% of total energy demand.[66]
- **Guidehouse, European Hydrogen Backbone:** The 2021 European Hydrogen Backbone study estimated 1,995 TWh of demand for the European Union and the United Kingdom, equivalent to 24% of total energy demand.[67]
- **European Commission, Impact Assessment:** The European Commission's impact assessment staff working document #176 estimated 2,162 TWh of hydrogen demand, equivalent to 30% of energy demand.[68]
- **Fuel Cells and Hydrogen, Hydrogen Roadmap Europe:** This study estimated 2,251 TWh of hydrogen demand, equivalent to 28% of total energy demand.[69]
- **International Energy Agency (IEA), World Energy Outlook 2021:** In the IEA Announced Pledges Scenario (APS), total global hydrogen production increases to 5,560 TWh in 2050 (equivalent to 4% of global energy demand) and plays a key role in displacing oil in transport and coal and natural gas in power generation and industry. In the more aggressive Net Zero Emissions Scenario (NZE), global hydrogen production increases to 16,680 TWh in 2050

[62] IESO (2021). Annual Planning Outlook. Available: https://ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook

[63] Figures reported here show hydrogen demand as a percentage of total energy demand, referencing the total provincial energy demand as reported by the CER, which includes energy demand from sectors such as agriculture that are outside the scope of this study.

[64] NRCan (2020). Hydrogen Strategy for Canada. Available: https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/environment/hydrogen/NRCan_Hydrogen-Strategy-Canada-na-en-v3.pdf

[65] The Transition Accelerator (2021). Towards Net-Zero Energy Systems in Canada: A Key Role for Hydrogen. Available: https://transitionaccelerator.ca/wp-content/uploads/2020/09/Net-zero-energy-systems_role-for-hydrogen_200909-Final-print-1.pdf

[66] McKinsey & Company (2020). Net-Zero Europe: Decarbonization pathways and socioeconomic implications. Available: https://www.mckinsey.com/~/media/mckinsey/business%20functions/sustainability/our%20insights/how%20the%20european%20union%20could%20achieve%20net%20zero%20emissions%20at%20net%20zero%20cost/net-zero-europe-vf.pdf

[67] Gas for Climate (2021). European Hydrogen Backbone: Analysing future demand, supply, and transport of hydrogen. Available: https://gasforclimate2050.eu/wp-content/uploads/2021/06/EHB_Analysing-the-future-demand-supply-and-transport-of-hydrogen_June-2021_v3.pdf

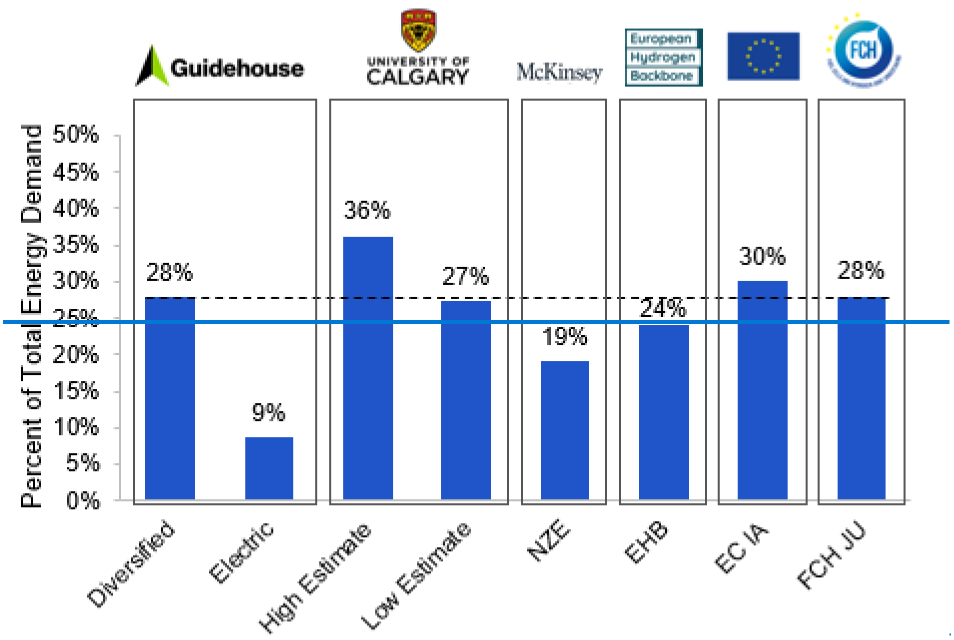
[68] European Commission (2020). Stepping up Europe's 2030 Climate Ambition. Available: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A52020SC0176

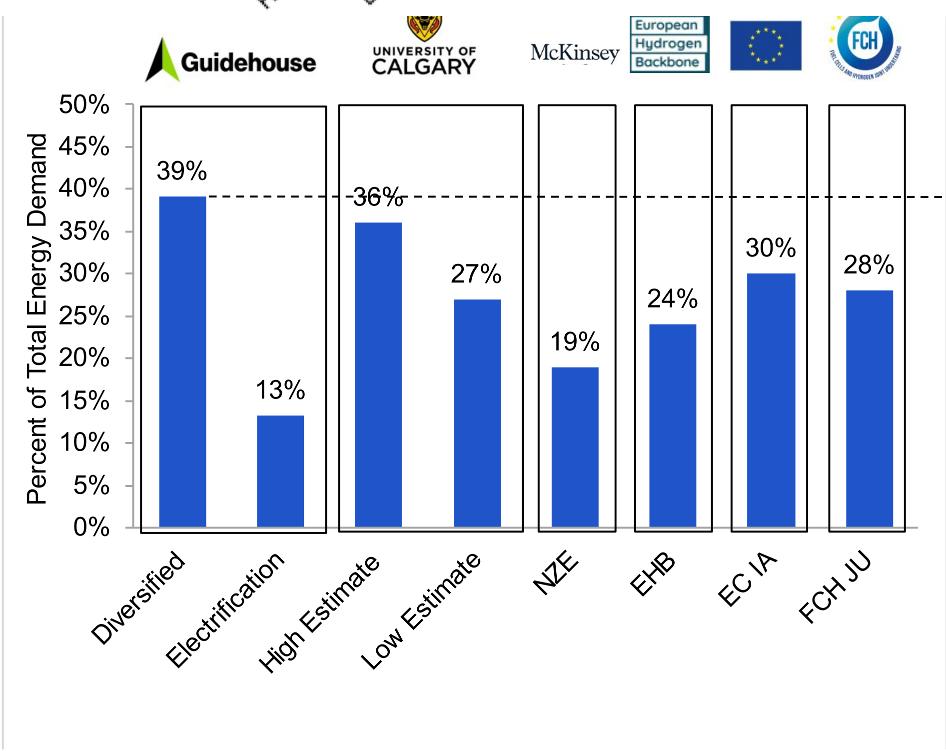
[69] Fuel Cells and Hydrogen 2 Joint Undertaking (2019). Hydrogen Roadmap Europe. Available: https://www.fch.europa.eu/sites/default/files/Hydrogen%20Roadmap%20Europe_Report.pdf

(equivalent to 17% of global energy demand), around one-quarter of which is converted into hydrogen-based fuels.[70]

Figure 13 summarizes our review of hydrogen demand projections.

Figure 13. Comparison of Hydrogen Demand Projections, 2050





Source: Guidehouse analysis and reports listed in text above

[70] International Energy Agency (2021). World Energy Outlook 2021. pp. 236-237, 300, 310. Available: https://iea.blob.core.windows.net/assets/4ed140c1-c3f3-4fd9-acae-789a4e14a23c/WorldEnergyOutlook2021.pdf

Case Studies: Sweden and Denmark

To demonstrate stakeholders' roles in defining and actualizing GHG reductions, this section presents case studies of two countries that are advanced in their development of low carbon fuels.

With the EU aiming to reach net zero GHG emissions by 2050, the deployment of low carbon gases is set to play a foundational role in strategies for achieving a low carbon energy system. Low carbon gases offer a unique advantage by leveraging existing gas infrastructure to support the transition to an energy system with net zero emissions at the lowest societal cost. As a result of ambitious climate targets set by the Green New Deal as well as limited domestic fossil energy sources, Europe's RNG sector has been experiencing rapid growth and development compared to the global context. In 2021 alone, the EU saw a 13% increase in RNG production capacity. With varying national-level approaches across the EU, Denmark and Sweden stand as two case studies of successful strategies that have realized the deployment potential of RNG. In 2020, Denmark produced 4 TWh of power from RNG and Sweden produced 1.8 TWh, enough production to meet 12% or more of both countries' total gas demand.[71]

Non-binding national-level strategies informed by partnerships between government and domestic energy companies have been the driving force behind Denmark and Sweden's success. In Denmark, the government and private sector worked together to develop a strategic RNG roadmap to increase domestic biogas production to 4 TWh today and 13.3 TWh by 2030. Stakeholders envision RNG primarily being used in domestic industry and for heat and power production.[72] These future and current RNG deployments are underpinned by innovative infrastructure integrations such as biogas pooling systems where small- to medium-sized biogas plants are connected via biogas pipelines to one large RNG upgrading facility. This makes RNG production more economical as grid connection costs are reduced. Reverse flow facilities are also being tested, allowing for flexible physical flows between the T&D grid. If too much RNG is injected into the low-pressure distribution grid, the RNG is compressed and injected into the high-pressure transmission grid.[73] This ensures more flexibility for the gas system and expands the possibility for decentralized RNG injection.

Further north in Sweden, a similar non-binding national strategy named the National Biogas Strategy 2.0 launched by Energigas sets a biogas growth target of 15 TWh by 2030, with the majority of RNG deployment to be used in the hard-to-electrify segments in the transport and industrial sectors. Sweden is the European leader for transport sector RNG deployment with 68 onsite bio-CNG production plants. Bio-CNG is often produced in areas without a gas grid or with a limited gas grid where RNG must be transported—for example, via fuelling trucks. Bio-liquified natural gas (bio-LNG) and bio-CNG have a similar composition to fossil LNG and CNG, so the same infrastructure can be used. Furthermore, bio-LNG and bio-CNG can be blended into the gas supply at any percentage, which allows a fast upscaling of its use in these sectors. RNG is also becoming more attractive due to EU carbon prices, which treat RNG as a non-GHG-emitting fuel.

In Denmark, subsidies support the large-scale build out of RNG deployment. In 2018, the base subsidy for grid injection of RNG was €39/MWh (CAD 58.65/MWh), with an additional price adder adjusted based on the natural gas price. The adder allows biogas production to remain competitive, even at low gas prices. However, a new subsidy system consisting of an annual pool of €32 million (CAD 48.1 million) will be assigned in tenders due to the original subsidy not being capped. As for Sweden, the current support scheme primarily works through avoided carbon taxes and fiscal incentives for certified low carbon gas, which the Swedish Energy Agency approves in a national biogas registry. Compared to gasoline, the tax reduction for RNG equates to €74/MWh (CAD 111/MWh). There is also production support for biogas from manure (€20/MWh, CAD 30/MWh) and RNG upgrading (€26/MWh, CAD 39/MWh), except for sewage sludge, landfill, food, or feed crops.[74]

[71] European Biogas Association (EBA), EBA Statistical Report 2021. https://www.europeanbiogas.eu/eba-statistical-report-2021/

[72] Marc-Antoine Eyl-Mazzega and Carole Mathieu (eds.), Biogas and Biomethane in Europe: Lessons from Denmark, Germany and Italy, Ifri, April 2019. https://www.ifri.org/sites/default/files/atoms/files/mathieu_eyl-mazzega_biomethane_2019.pdf

[73] Guidehouse, Market state and trends in renewable and low-carbon gases in Europe, prepared for Gas for Climate, December 2021. https://gasforclimate2050.eu/wp-content/uploads/2021/12/Gas-for-Climate-Market-State-and-Trends-report-2021.pdf

[74] Klackenberg, L., National Biogas Strategy 2.0, The Swedish Gas Association, April 2018, https://www.energigas.se/media/boujhdr1/biomethane-in-sweden-210316-slutlig.pdf

5. Comparing Pathways to a Net Zero Future

This section presents the results of our pathways analysis for the Diversified and Electrification scenarios. The Diversified and Electrification scenarios represent two different but plausible visions of how Ontario could achieve net zero emissions. This section focuses on the development of electricity, hydrogen, and RNG supply in both scenarios and compares the total energy system costs associated with each. This section also presents the results of four sensitivity scenarios, each exploring how different drivers impact results.

- **Section 5.1** compares how the electricity supply mix evolves from 2020 to 2050 in each of the two scenarios.
- **Section 5.2** compares the evolution of the gas supply mix, with a focus on the development of hydrogen and RNG supply.
- **Section 5.3** compares the total energy system costs in each of the two scenarios, identifying the key cost drivers.
- **Section 5.4** compares the emissions reduction pathways for the two scenarios.
- **Section 5.5** discusses the challenges associated with implementing the emissions reduction pathways
- **Section 5.6** summarizes key results for the four sensitivity cases.

5.1 Electricity Supply Development

Both scenarios lead to a significant increase in generation capacity, but the Electrification scenario leads to a more aggressive buildout of capacity. In both scenarios, installed generation capacity is forecast to increase significantly: around 3 times in the Diversified scenario, from 40 GW in 2020 to ~~116~~129 GW in 2050; and nearly 4 times in the Electrification scenario, from 40 GW to ~~166~~148 GW. This increase in capacity is driven by the growth in electricity demand—more than doubling in the Diversified scenario and ~~nearly~~ tripling in the Electrification scenario. In the Electrification scenario, the greater increase in peak demand is driven by higher penetration of electric heat pumps and the electrification of transport, triggering significant investment in hydrogen gas turbine capacity and T&D infrastructure. A large portion of the growth in supply capacity occurs post-2030, in line with the timeline of growth

for hydrogen production. These trends can be observed in greater detail in Figure 14.

Both scenarios require a large scale-up in wind capacity and hydrogen-fired gas turbines.[75] Most of the increase in generation capacity results from an increase in installed wind. In the Diversified scenario, wind capacity increases in the near term to ~~18~~21 GW in 2030 and ~~42~~43 GW in 2040, rising to ~~68~~75 GW in 2050. In the Electrification scenario, it increases ~~even more dramatically~~at a similar rate, to 21 GW in 2030, ~~57~~43 GW in 2040 and ~~84~~72 GW in 2050. To meet peak demand and to enable this large scale-up in variable generation capacity, there is a significant need for dispatchable generation such as hydrogen-fired gas turbines and battery storage, particularly in the Electrification scenario. By 2040, ~~33~~20 GW of hydrogen gas turbine capacity is installed in the Electrification scenario, and this number rises to ~~48~~35 GW by 2050. In the Diversified scenario, only ~~15~~13 GW of hydrogen gas turbine capacity is installed by 2050 due to the lower electricity~~-~~-system peak~~ and less reliance on wind generation~~. In both scenarios, new battery storage capacity complements the build out of hydrogen gas turbine capacity to provide the electricity system with flexibility and resiliency.~~[76]~~

Electricity peak demand increases substantially in both scenarios. In the Diversified scenario, peak demand ~~increases over 2 times~~more than doubles, from 22 GW in 2020 to 51 GW by 2050. In the Electrification scenario, peak demand increases almost 4 times, to ~~94~~82 GW by 2050. The Electrification scenario sees a drastic increase in peak demand for the 2030-2040 period (Figure 14) as a result of the high degree of electrification in buildings, driven by the government's goal that by 2035, all space heating technologies for sale in Canada meet an energy performance of more than 100%.[77] The Diversified scenario shows a slower growth in peak demand post-2030 because it assumes a higher portion of homes switch to gas heat pumps, which have a small impact on peak electric demand. The Electrification scenario is primarily dependent on a single energy system (electricity) and the implications on energy system resilience should be studied in more depth. Consideration of energy system resilience is important given the increased risks of extreme weather events and potential cyberattacks.

Annual electricity generation is comparable in both scenarios. While electricity demand is significantly higher in the Electrification scenario compared to the Diversified scenario, the Diversified scenario also requires significant electricity supply to produce hydrogen. By 2050, roughly ~~193~~181 TWh of electricity supply is used in the Diversified scenario for hydrogen production, whereas ~~53~~37 TWh of electricity supply is needed in the Electrification scenario.

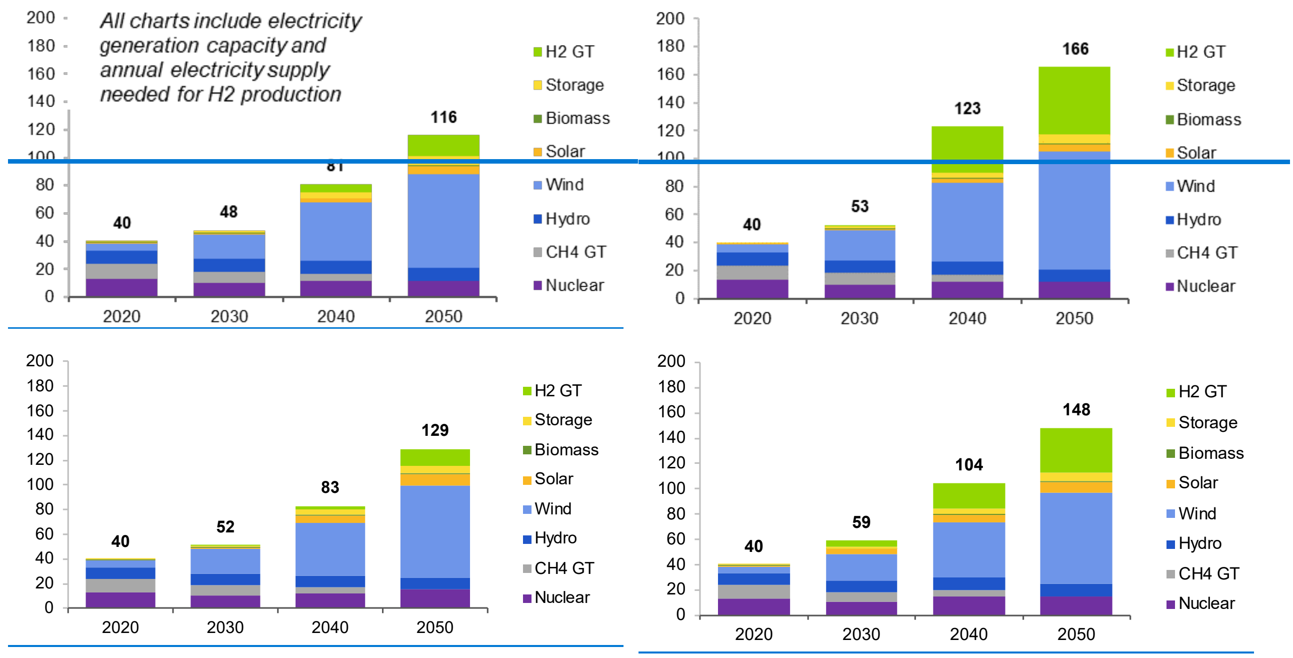
[75] Guidehouse's analysis focuses on the use of hydrogen gas turbines in both scenarios rather than natural gas-fired gas turbines. Hydrogen gas turbines are intended to reflect natural gas-fired gas turbines retrofitted to hydrogen or new hydrogen gas turbines. Our analysis does not make any explicit assumptions on whether existing gas turbines are retrofitted, nor when. For simplicity, we assume all hydrogen gas turbines are costed out as new gas turbines.

~~[76] In the Electrification scenario, the amount of battery storage capacity decreases from 2040 to 2050. This is because storage capacity installed in 2030 is retired in 2045 based on a storage lifetime of 15 years. In 2030, 7 GW of battery storage is installed. An additional 2 GW is installed in 2040, for a total capacity of 9 GW of storage available in 2040. By 2050, the 7 GW of storage capacity installed in 2030 is retired, and while new additional storage capacity is installed in 2050, there is a drop in total storage capacity between 2040 and 2050. This drop in storage capacity does not impact the resiliency and reliability of the electricity system because there is a large increase in hydrogen gas turbine capacity over the same time period (2040-2050).~~

[77] Energy and Mines Ministers' Conference (2017). Market transformation strategies for energy-using equipment in the building sector. p.16. Available: https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/emmc/pdf/Market-Transformation-Strategies_en.pdf

Figure 14. Electricity Supply for the Diversified and Electrification Scenarios[78,79]

Diversified	**Electrification**
Electricity Supply Capacity (GW)	**Electricity Supply Capacity (GW)**

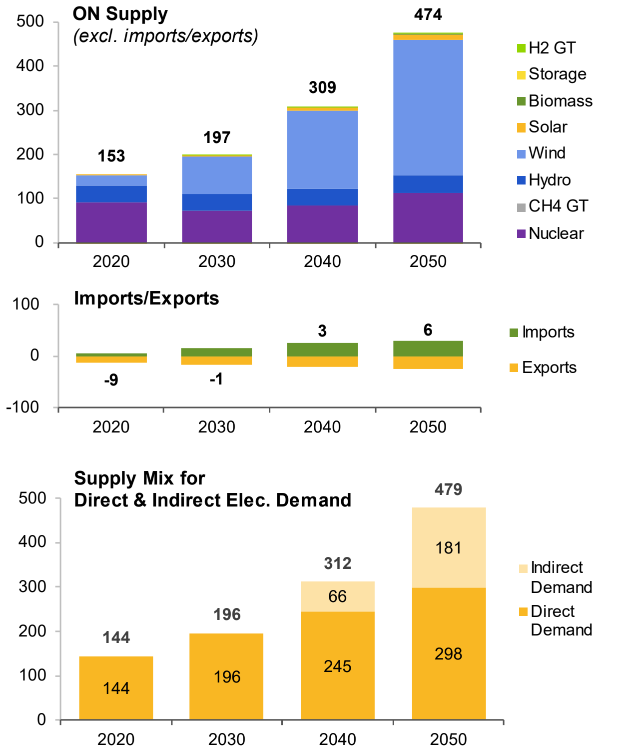


[78] The electricity supply capacity and supply mix graphs reflect the capacity and supply needed to produce green hydrogen.

[79] Direct demand is the electricity needed to meet end user demand without any conversion across energy carriers (i.e., converting electricity into hydrogen). Indirect demand is the electricity needed to produce hydrogen via electrolyzers.

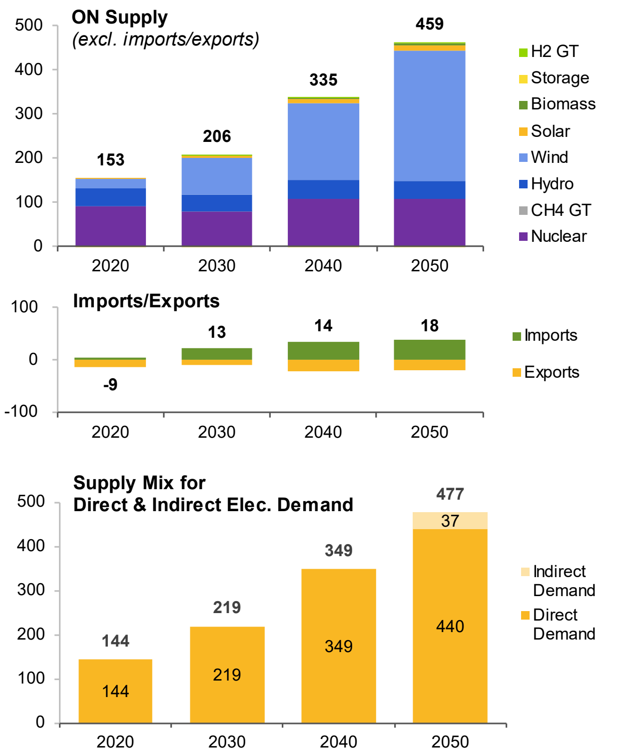
Diversified

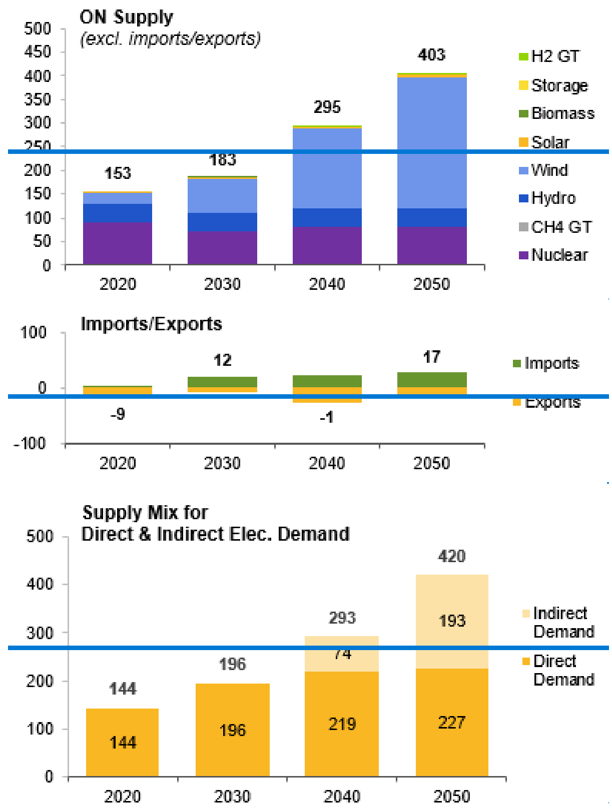
Electricity Supply Mix (TWh)

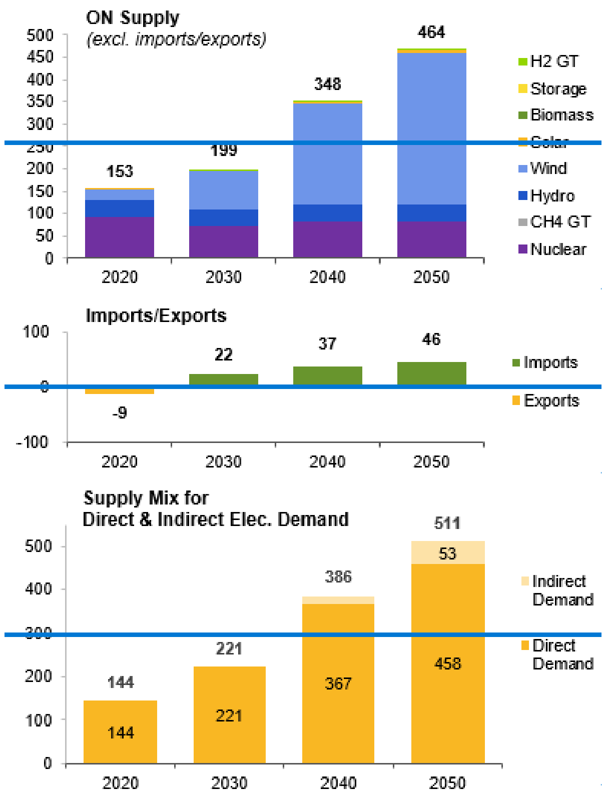


Electrification

Electricity Supply Mix (TWh)



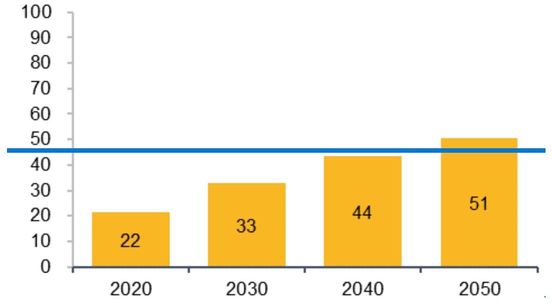




***Note**: Total electricity supply (domestic supply +/- imports and exports) is greater than demand due to losses in T&D. Storage denotes battery storage and pumped hydro storage; however, pumped hydro storage makes up less than 3% of total storage.*

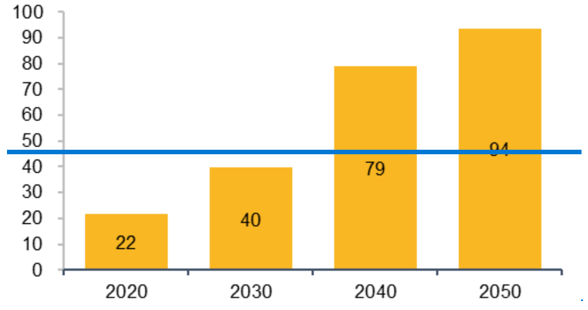
Diversified

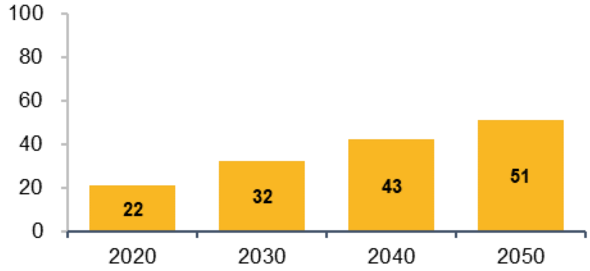
Electricity Peak Demand (GW)

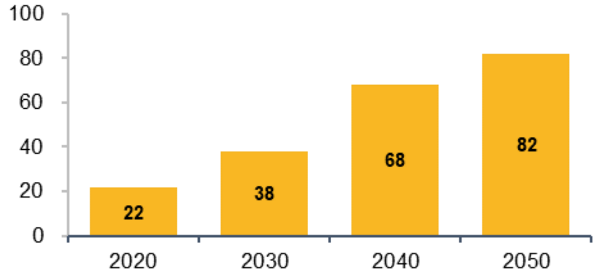


Electrification

Electricity Peak Demand (GW)



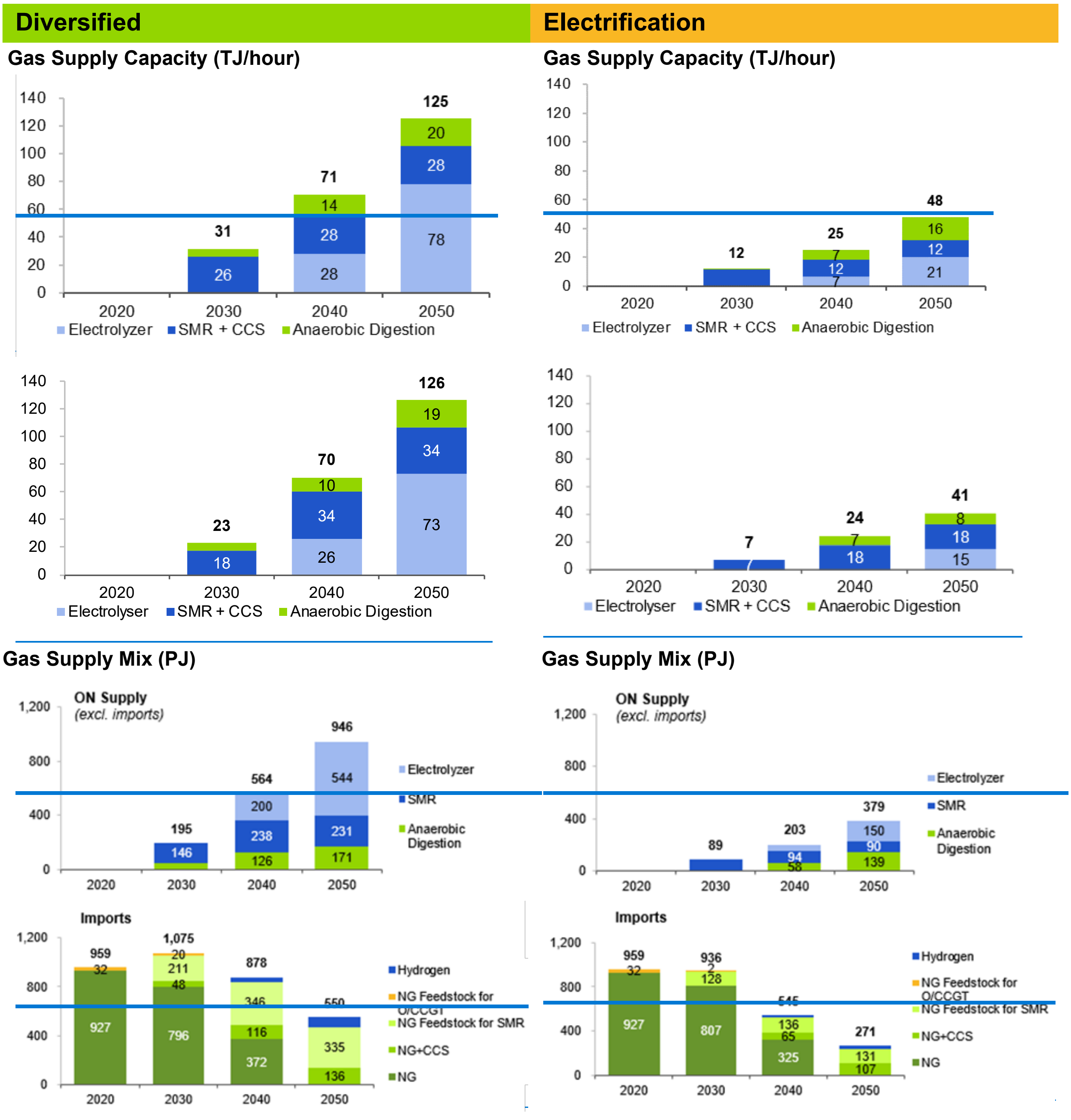




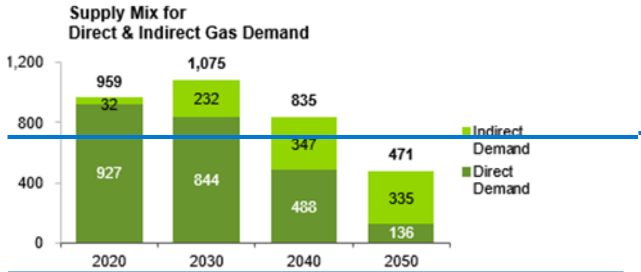
5.2 Gas Supply Development

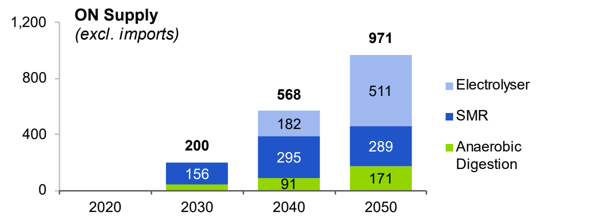
Today, Ontario imports all natural gas used in the province. As the province moves toward a net zero future, conventional natural gas will be replaced by hydrogen, RNG or the end use will be outfitted with CCS to abate emissions. This provides Ontario with the opportunity to develop domestic gas supply. The Diversified scenario presents a future in which this supply is sharply scaled up to ~~125~~126 TJ/hour in 2050 to meet demand (~~106~~107 TJ/hour of hydrogen and 19~~.5~~ TJ/hour of methane). In contrast, the Electrification scenario uses these fuels only for end uses that are difficult to electrify, such as high temperature. Therefore, domestic gas supply scales to reach a total capacity of ~~48~~41 TJ/hour in 2050 (~~32~~33 TJ/hour of hydrogen and ~~16~~8 TJ/hour of methane). These supply capacities, as well as imports, can be seen in Figure 15 below. While the gas system peak declines for both scenarios in energy terms, the volumetric gas system peak rises significantly in the Diversified scenario. This is because hydrogen has a lower energy density than methane, so more volume is needed to provide the same amount of energy.

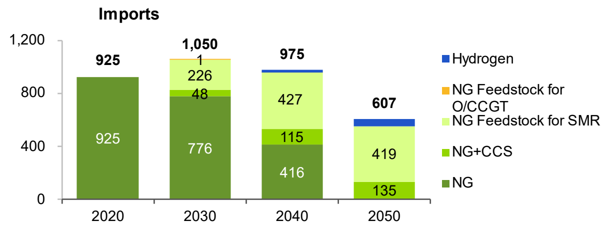
Figure 15. Gas Supply for the Diversified and Electrification Scenarios

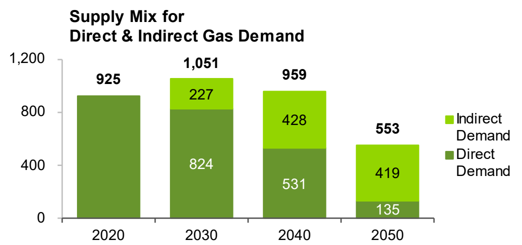


Diversified

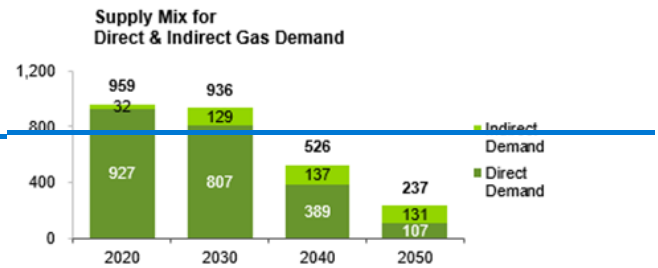


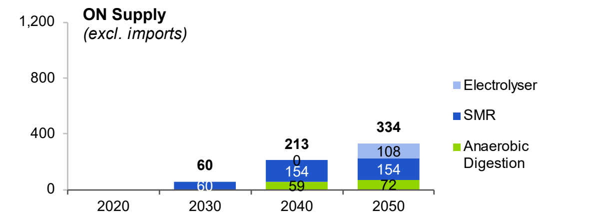


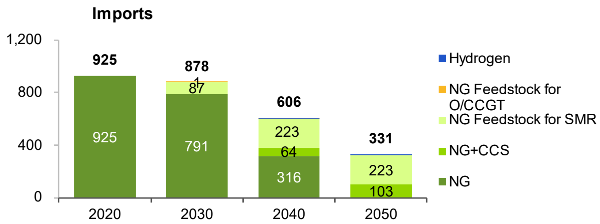


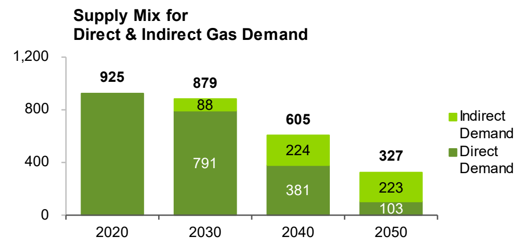


Electrification



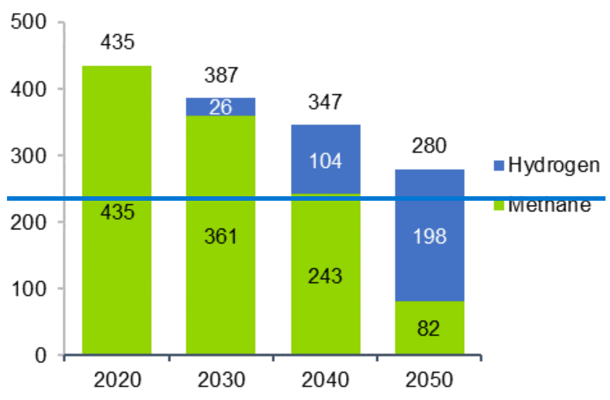


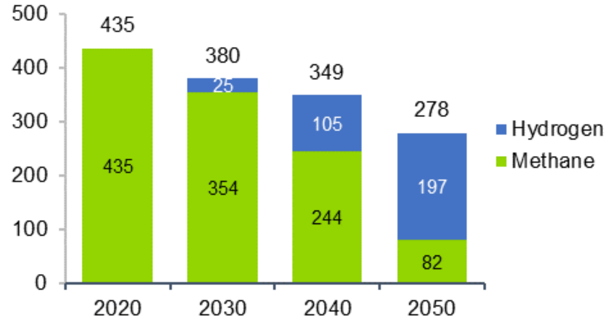




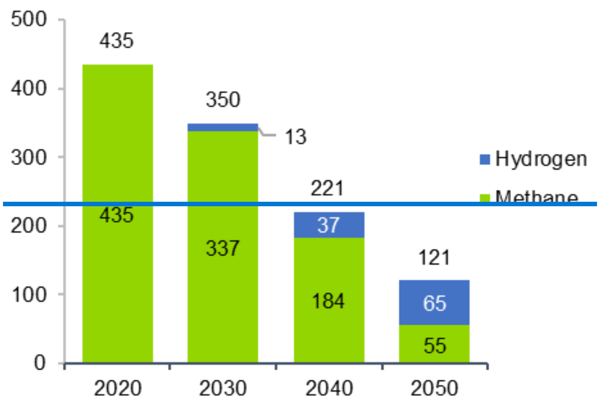
Note: *Total gas supply (domestic supply plus imports) is greater than demand due to losses in T&D.*

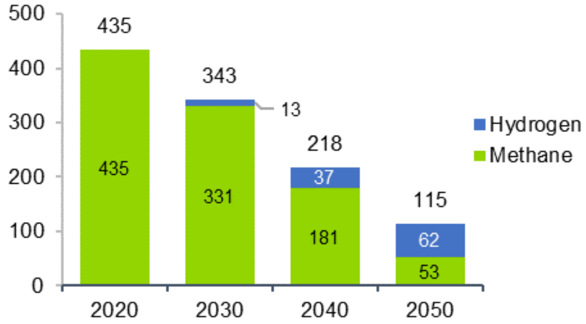
Gas Energy Peak Demand (TJ/hour)



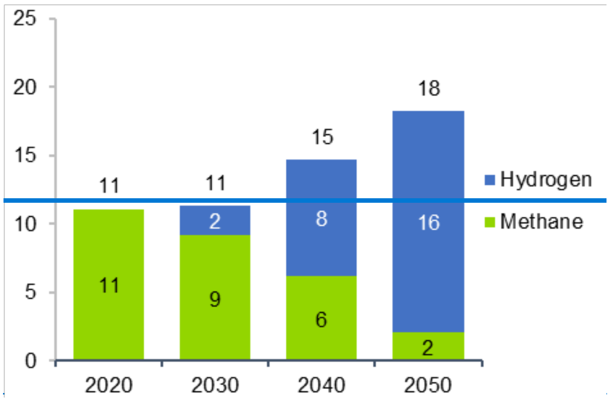


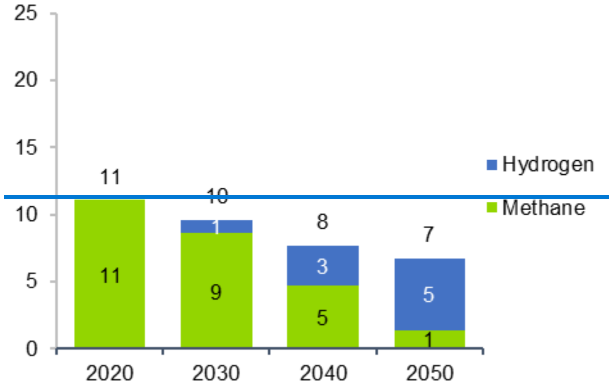
Gas Energy Peak Demand (TJ/hour)

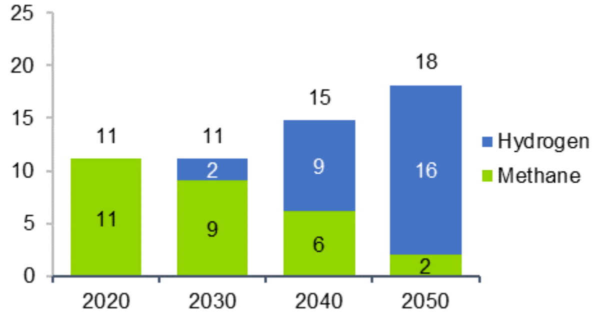


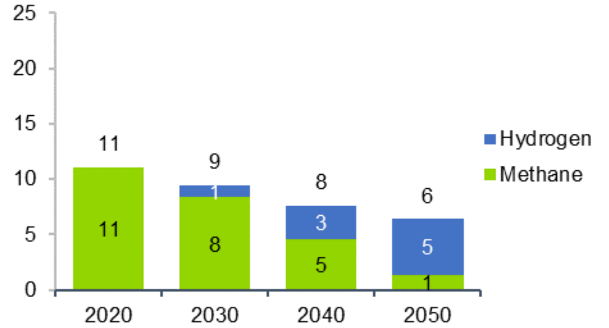


Diversified	Electrification
Gas Volume Peak Demand (million m³/hour)	Gas Volume Peak Demand (million m³/hour)









5.2.1 Hydrogen Supply Mix

Compared to the Electrification scenario, the Diversified scenario leads to a significantly larger scale-up of domestic hydrogen supply and a greater need for hydrogen imports transported via pipeline from neighbouring regions. In the Diversified scenario, domestic hydrogen supply[80] is forecast to increase to ~~775~~800 PJ by 2050: ~~544~~511 PJ of green hydrogen (via electrolyzers) and ~~231~~289 PJ of blue hydrogen (via SMR + CCS). The increase of hydrogen supply in the Electrification scenario is more limited. The domestic hydrogen supply is forecast to increase to ~~240~~262 PJ by 2050: ~~150~~108 PJ of green hydrogen (via electrolyzers) and ~~90~~154 PJ of blue hydrogen (via SMR + CCS).

Blue hydrogen plays a major role in meeting hydrogen demand in the near term. In both scenarios, the scale-up of blue hydrogen (SMR + CCS) leads the scale-up of green hydrogen (electrolyzers). Up to 2030, blue hydrogen production is more cost-effective than green, making it the preferred production method. From 2030 to 2040, while decreasing costs of green hydrogen lead to a buildup in green hydrogen supply, blue hydrogen supply continues to scale. By 2050, no new additional blue hydrogen supply comes online. Nevertheless, existing supply—installed by 2030 and 2040—continues operating and meets a significant share of hydrogen demand.

Hydrogen demand is met mostly via domestic supply rather than imports. In both scenarios, most hydrogen demand is met via domestic supply as a combination of blue and green hydrogen. By 2050, in the Diversified scenario, domestic hydrogen accounts for ~~91~~94% of total supply, equivalent to

[80] Domestic hydrogen supply refers to hydrogen produced in Ontario, whether via SMR + CCS (blue hydrogen) or electrolyzers (green hydrogen).

~~775~~800 PJ, while imports from Western Canada and Quebec account for ~~9~~6%, or ~~78~~54 PJ. Similarly, in the Electrification scenario, imports play a small role contributing ~~34~~5 PJ, or ~~12~~2%, by 2050.[81] [82]

Increased demand for hydrogen boosts the scale-up of green hydrogen supply. High demand for hydrogen in the Diversified scenario results in significant scale-up of green hydrogen supply capacity. Much of this increase in demand occurs from 2040 to 2050, when the levelized cost of green hydrogen becomes more competitive than blue hydrogen. This results in all new hydrogen supply capacity installed after 2040 to be green. Overall, while blue hydrogen plays a major role in the near term, by 2050, the mix of domestic hydrogen supply is dominated by green hydrogen. In comparison, in the Electrification scenario, low demand for hydrogen results in a hydrogen supply build out of 32 TJ/hour of capacity by 2050. ~~Similar~~Compared to the Diversified scenario, blue hydrogen plays a ~~major~~larger role in ~~developing~~ the hydrogen market~~, but by~~. By 2050~~ most~~, a slight majority of the capacity is ~~green~~blue hydrogen.

Green hydrogen supply leads to significant, additional demand for electricity supply.[83] The scale-up of green hydrogen supply in the Diversified scenario has major implications for the electricity system in 2040 and 2050. By 2040, green hydrogen scales to ~~200~~182 PJ of supply, requiring roughly ~~74~~66 TWh of electricity supply. This is equivalent to a ~~51~~46% increase in Ontario's electricity demand today. By 2050, the impact on the electricity system is even greater, increasing by more than two times. Green hydrogen supply scales to ~~544~~511 PJ, requiring roughly ~~193~~181 TWh of electricity supply, roughly equivalent to ~~130~~126% of the province's total electricity demand today. In comparison, since the demand for hydrogen is much lower in the Electrification scenario, the electricity required to power the electrolyzers is much ~~less. By 2040, green hydrogen scales to 51 PJ, requiring about 19 TWh of electricity supply. In~~lessIn 2050, green hydrogen supply reaches ~~150~~108 PJ, which would require approximately ~~53~~37 TWh of electricity, or the equivalent of over one ~~third~~quarter of the electricity used in the province today.

Figure 16. Hydrogen Supply for the Diversified and Electrification Scenarios

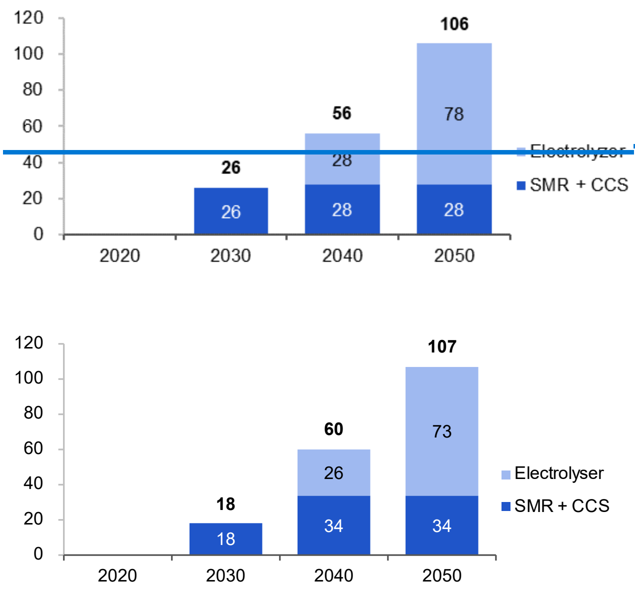
Diversified	Electrification
Hydrogen Supply Capacity~~ ~~(TJ/hour)	**Hydrogen Supply Capacity (TJ/hour)**

[81] Guidehouse's analysis assumes inter-provincial transmission pipelines are not repurposed for hydrogen until 2040. This means hydrogen imports are not available in 2030. By 2040, we assume some of the existing natural gas pipeline capacity from Western Canada is repurposed for hydrogen, allowing for hydrogen imports in Ontario. Our analysis assumes the mix of hydrogen imports to be a 50/50 split between blue and green hydrogen. Finally, by 2050, we assume existing gas pipelines between Ontario and Quebec are also repurposed, enabling hydrogen imports from Quebec to Ontario. Hydrogen imports from Quebec are assumed to be 100% based on green hydrogen.

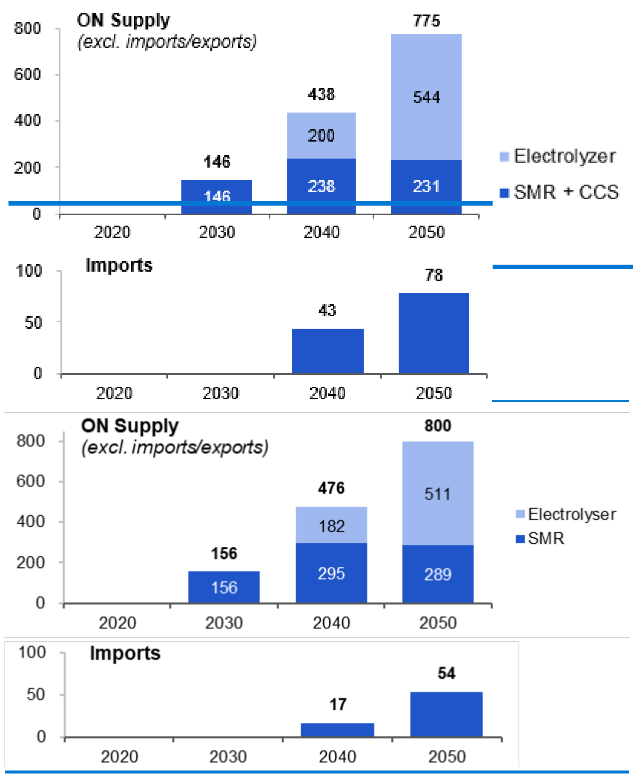
[82] The share of green versus blue imports into Ontario varies across scenarios. ~~While the~~The Diversified scenario leads to a ~~slightly~~ greater reliance on imports from Quebec versus Western Canada ~~versus Quebec,~~and green hydrogen dominates imports accounting for ~~about 75~~nearly 87% of import volumes. By comparison, green hydrogen accounts for ~~nearly 90~~56% of imports in the Electrification scenario, with most hydrogen imports coming from Western Canada.

[83] Guidehouse's analysis does not forecast a major role for surplus baseload generation (SBG) in the production of green hydrogen. While SBG conditions are not uncommon today, increased electricity demand over the coming decade is expected to significantly reduce the frequency and magnitude of SBG. This is consistent with findings from the IESO's 2021 APO, which forecasts the magnitude and frequency of SBG to decline significantly from 2023/2024 onward. Because the scale-up of green hydrogen supply begins in 2040 in our analysis, SBG does not play a role in hydrogen production.

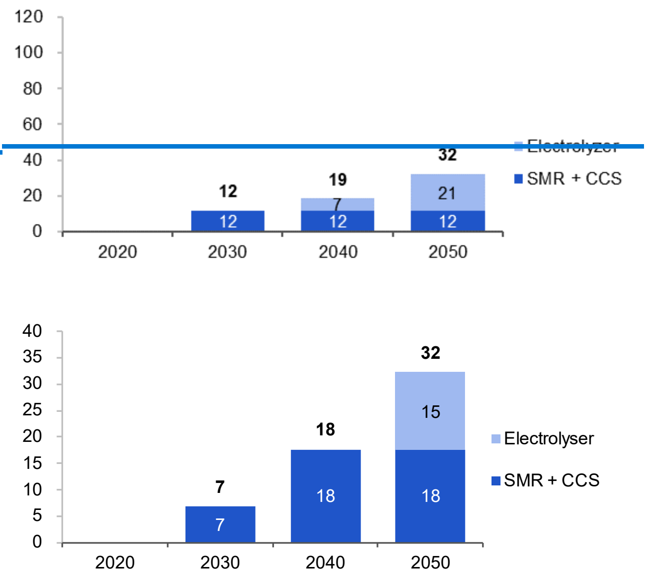
Diversified



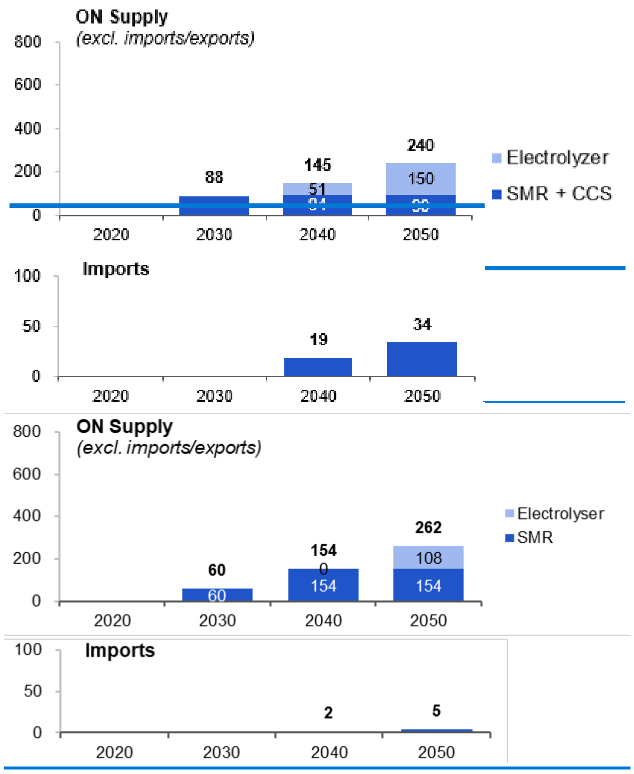
Hydrogen Supply Mix (PJ)



Electrification



Hydrogen Supply Mix (PJ)



***Note**: Total hydrogen supply (domestic supply plus imports) is greater than demand due to losses in T&D.*

5.2.2 Methane Supply Mix

Both scenarios require a significant scale-up in RNG supply capacity over time. The increase in supply capacity for RNG production will be primarily via anaerobic digestion, reaching 171 PJ by 2050 in the Diversified scenario and ~~139~~72 PJ in the Electrification scenario. These figures represent a significant share of Ontario's RNG potential, estimated to be ~~240~~224 PJ.[84] Other RNG production technologies such as biomass gasification do not play major roles in RNG supply today; however, local conditions and the availability of low-cost biomass feedstock (such as in Northern Ontario) may encourage the development of gasification plants in the future.

While RNG achieves significant scale, natural gas imports continue to play a major role in meeting gas demand. The scale-up in domestically produced RNG leads to a significant share of Ontario's overall methane demand being met by RNG. By 2050, domestic RNG scales to amount to ~~27~~56% of overall direct methane demand in the Diversified scenario, and ~~37%~~ 41% in the Electrification scenario.[85] This increase in RNG, along with decreased demand for natural gas, leads to a reduction in the volume of natural gas imports from Western Canada and New York. Despite this, natural gas imports continue to play a key role in meeting overall methane demand because of the need for natural gas in the production of blue hydrogen (via SMR + CCS) and the adoption of CCS in natural gas use. The Electrification scenario assumes less production of blue hydrogen, and natural gas imports are expected to decline more in the Electrification scenario.

CCS is fundamental in reducing GHG emissions from natural gas. By 2050, 100% of natural gas consumption incorporates CCS, whether for blue hydrogen production or directly in natural gas use. Therefore, share of natural gas with CCS installed at the end user and natural gas used to create blue hydrogen increases significantly over time in both scenarios. In the Diversified scenario, natural gas used for both technologies accounts for ~~25~~26% by 2030, equivalent to ~~259~~274 PJ, increasing to ~~471~~553 PJ by 2050. In the Electrification scenario, this share accounts for ~~14~~10% by 2030, equivalent to ~~128~~87 PJ, increasing to ~~237~~327 PJ by 2050. The scale-up of CCS for blue hydrogen and natural gas use is required to reach net zero emissions in both scenarios.

The development of carbon storage in Ontario will be critical in all net zero pathways. To achieve the emissions reduction targets, the development of carbon storage in Ontario will be required to store captured carbon emissions from blue hydrogen production and the use of natural gas in industry applications that are difficult to electrify. The Diversified scenario will require more than double the storage capacity than the Electrification scenario. In the Diversified scenario, the total storage required up to 2050 is for ~~332~~415 megatonnes of CO_2 (MTCO_2), reaching ~~23~~26 MTCO_2 of new storage needs per year in 2050. In the Electrification scenario, the storage required up to 2050 is ~~153~~194 MTCO_2, with ~~11~~16 MTCO_2 of new storage needs each year from 2050 onward.

An Ontario study estimated the amount of CO_2 storage of two major reservoirs in Ontario totalling approximately 730 MTCO_2.[86] The CO_2 storage requirements for the Diversified and Electrification scenarios up to 2050 would be satisfied with these two reservoirs. In the Diversified scenario, these two major reservoirs would provide sufficient storage volumes up to ~~2058~~2062, while in the Electrification scenario, they would be sufficient up to ~~2077.~~2084[87]

[84] Torchlight Bioresources (2020). Renewable Natural Gas (Biomethane) Feedstock Potential in Canada. Available: https://www.enbridge.com/~/media/Enb/Documents/Media%20Center/RNG-Canadian-Feedstock-Potential-2020%20(1).pdf?la=en

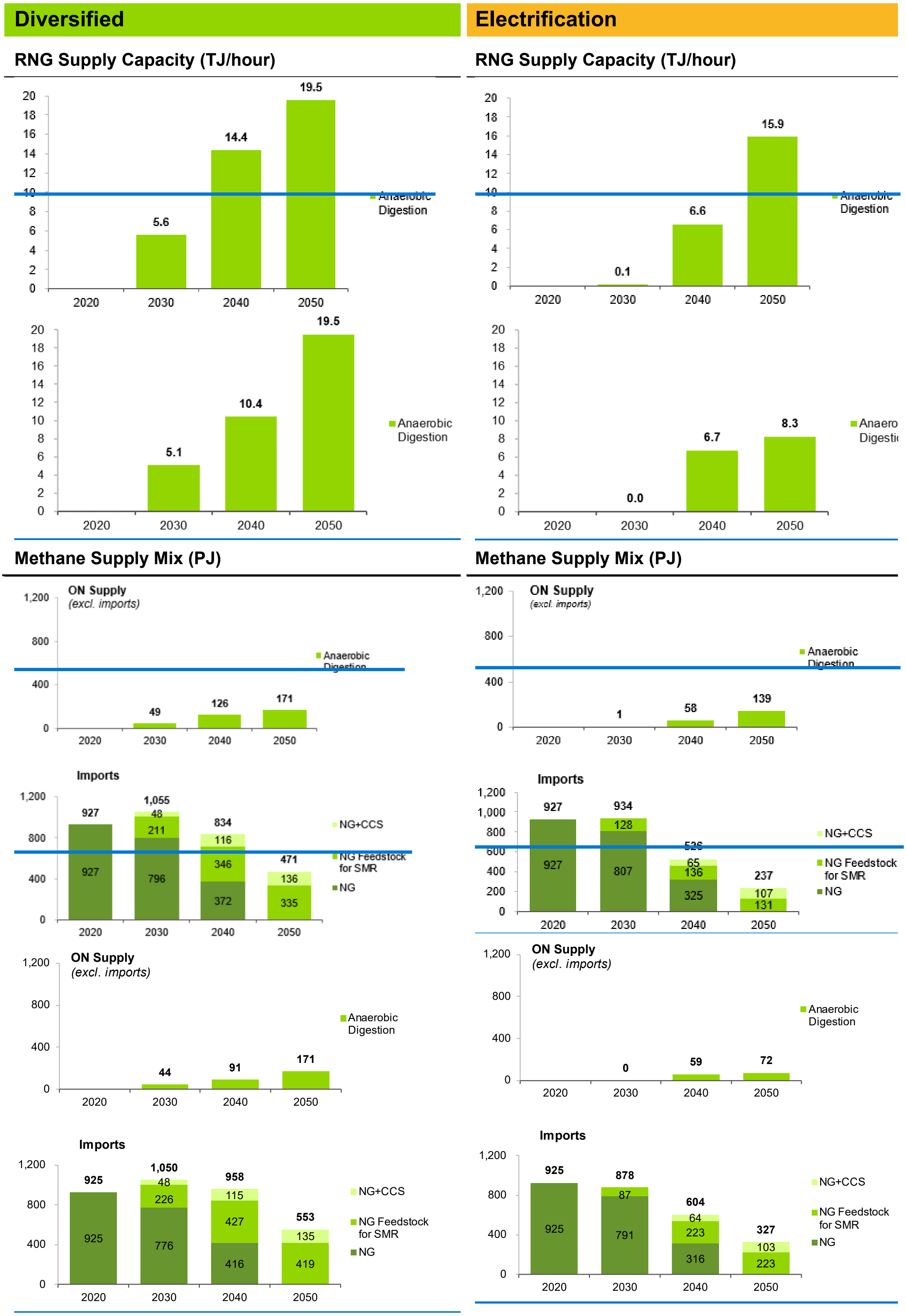
[85] The larger share of RNG in the Electrification scenario reflects a much lower forecast of total methane demand.

[86] Shafeen, Ahmed & Croiset, Eric & Douglas, Peter & Chatzis, Ioannis. (2004). CO_2 sequestration in Ontario, Canada. Part I: Storage evaluation of potential reservoirs. Energy Conversion and Management. 45. 2645-2659. Available: http://dx.doi.org/10.1016/j.enconman.2003.12.003

[87] Ontario may not be constrained by the volume of domestic CO_2 storage reservoirs. CO_2 storage in neighboring jurisdictions may also be tapped. For example, the Midwest Regional Carbon Sequestration Partnership in nearby US states may have up to 245 billion metric tonnes of CO_2 storage potential in deep rock salt formations.

US Department of Energy (2011). Midwest Has Potential to Store Hundreds of Years of CO2 Emissions https://www.energy.gov/fecm/articles/midwest-has-potential-store-hundreds-years-co2-emissions

Figure 17. Methane Supply for the Diversified and Electrification Scenarios



***Note**: Total methane supply (domestic supply plus imports) is greater than demand due to losses in T&D.*

Residual CO_2 Emissions

The production of hydrogen from SMR + CCS and the use of natural gas + CCS are assumed to have a 95% carbon capture rate.[88] The remaining emissions need to be eliminated or offset in the 2050 timeframe to achieve a carbon-neutral energy system. Hydrogen production via SMR + CCS or the use of natural gas + CCS has the potential to become a source of negative emissions if the methane comes from RNG instead of natural gas. See Section 2.3 for further information.

[88] The IEA's Assumptions Annex to its Future of Hydrogen Report reports captures rates for CCS technologies (e.g., SMR + CCS, natural gas + CCS) ranging between 90% and 95% capture rates. Guidehouse's analysis assumes a 95% capture rate is required to achieve the 2050 emissions reductions targets.

IEA (2019). The Future of Hydrogen, Assumptions Annex. Available: https://www.iea.org/reports/the-future-of-hydrogen/data-and-assumptions

5.3 Comparison of Pathway Energy System Costs

The estimated cost for the Diversified scenario is $~~181~~41 billion less as compared to the Electrification scenario, cumulative from 2022-2050, or ~~19~~6% lower. The reduced costs are due to less spending on electricity generation capacity and infrastructure, end user heating systems, and building energy efficiency retrofits.[89]

The Diversified scenario costs sum to $~~765~~681 billion through 2050. Of these costs, gas system costs amount to approximately ~~23~~29%. Gas system costs increase over time driven by the costs of deploying and operating new hydrogen and RNG production facilities. Costs increase over time as gas infrastructure is repurposed to hydrogen and as more hydrogen and RNG volumes are injected into the transmission and distribution network. Electricity system costs amount to ~~46~~45% of costs, increasing steadily and are driven primarily by investments in wind and solar capacity and transmission infrastructure. Emissions costs amount to ~~16~~18% of costs. End-user costs account for the remaining ~~15~~8% of costs. End-user costs ramp up ~~over time~~initially as adoption of heat pumps (gas and electric) increase, accompanied by investments in building retrofits and insulation. However, they are much lower from 2040 to 2050. Note that these costs are lower due to the construction of the analysis that does not include the salvage value of assets past 2050. Therefore, things such as heat pumps installed in the final decade have lower cost as their total lifetime would extend beyond the end of the study period.

In comparison, **the Electrification scenario costs amount to $~~946~~722 billion through 2050**. ~~Figure 18~~Figure 18 illustrates that, in each decade of the study period, the gas system infrastructure and operating costs in the Electrified scenario are lower than in the Diversified scenario~~. This is because the first and last decade of the study period have~~, which is consistent with lower projected demand for low- or zero-carbon gases from end-users and less investment in the associated gas supply and infrastructure. In the middle decade, from 2030 to 2040, ~~however,~~ emissions costs are $~~49~~43 billion higher in the Electrification scenario than in the Diversified scenario. This is because in that decade, carbon emissions will still be significant, and the price of carbon will have risen significantly. The Electrification scenario uses a higher projected price of carbon compared to the Diversified scenario, resulting in higher emissions costs in that decade. The carbon price projections for each scenario can be seen in Appendix ~~A.1.~~A.1. Electricity system costs are $~~111~~32 billion higher than in the Diversified scenario~~. This~~, which is driven by a much larger electricity peak demand in the Electrification scenario (~~94~~82 GW) compared to the Diversified scenario (51 GW). This increase in peak is driven by higher penetration of electric heat pumps and the electrification of transport, ~~triggering~~leading to significant investment in hydrogen gas turbine capacity and T&D infrastructure. Finally, end-user costs are $~~56~~17 billion higher compared to the Diversified scenario. End-user costs are higher because of the high penetration of electric heat pumps which require significant upfront investment in equipment for geothermal heat pumps and costly building retrofits to maintain the same level of comfort for air-source heat pumps.[90] The higher end user costs and higher system wide costs in the Electrification scenario may require more social policy actions to protect low income and small business customers and ensure their access to energy.

[89] ~~Based on~~This cost differential is consistent in magnitude and direction with previous studies, where a cost difference of ~10%-25% is common in a comparison of economy-wide GHG emissions reduction pathways between scenarios that lean in opposing directions in terms of the role played by electricity and gas. While results are impacted by electricity and gas supply-demand conditions unique to each jurisdiction, there is a strong degree of consistency across most studies. The results of our scenario analysis for Ontario are directionally consistent with most literature.

For example, in a Canadian context, FortisBC (2020) estimated savings of 16% between a Diversified scenario and an Electrification scenario in its pathways assessment for achieving 80% emissions reductions in British Columbia. From a European perspective, Gas for Climate (2019) estimated savings of 11% between an Optimised Gas scenario and a Minimal Gas scenario in its 2050 net-zero assessment covering the EU27 countries and the UK. ENA (2019) estimated savings of 12% between a Balanced and an Electrified scenario in its 2050 net-zero pathways assessment for Great Britain (England, Scotland, and Wales).

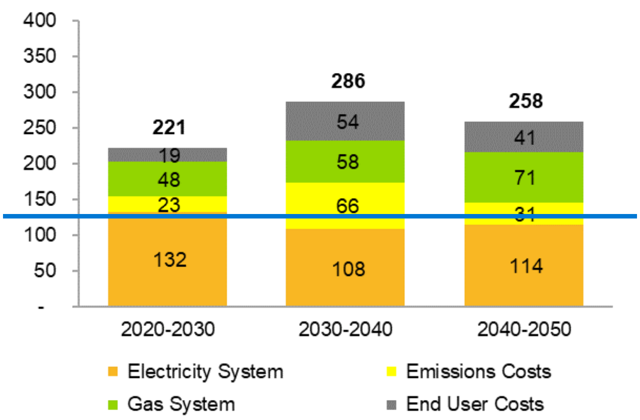
[90] To provide adequate heating in winter conditions, electrically heated homes need to be well-insulated and weatherized to minimize heat leakage. Reduction of heat loss is important for electrically heated homes because the heating capacity of air-source heat pump systems is less than gas furnaces, especially at low outdoor temperatures. A regular-sized gas furnace usually provides 20 to 35 kW of heat output, while a whole-home heat pump may only provide 5 to 15 kW of heat output at colder outdoor temperatures.

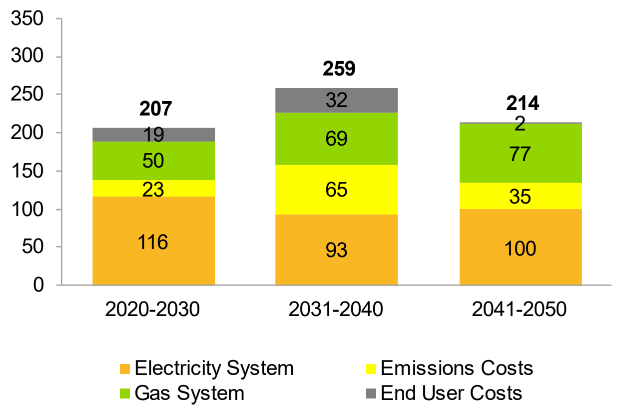
In the discussion of sensitivity analyses in section 5.6, emissions costs are allocated to the gas system. Figure 18 reports emissions costs separate from gas system costs to better demonstrate the costs associated with investment in the gas system.

Figure 18. Energy System Costs for Diversified and Electrification Scenarios[91]

Diversified

Energy System Costs (billion CAD, real 2020$)



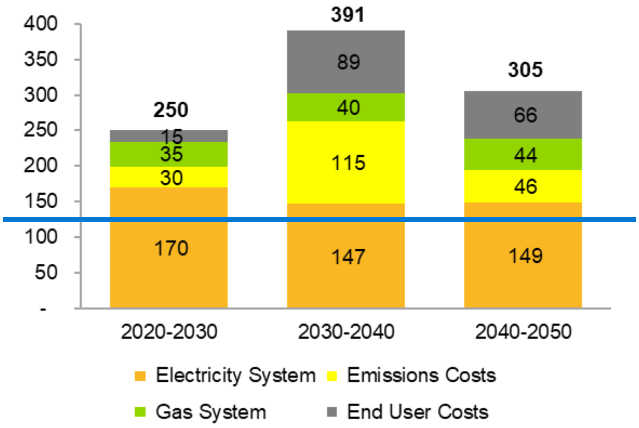


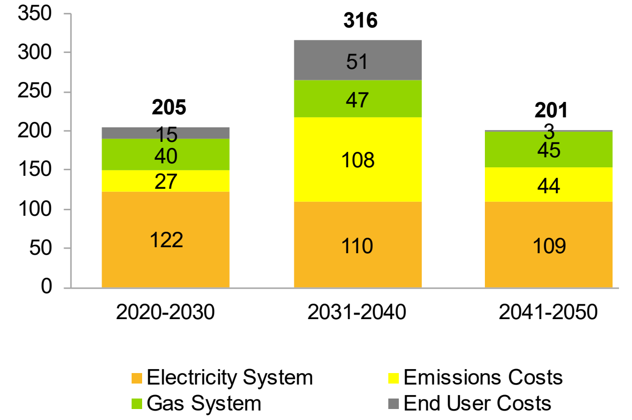
Billion CAD, real 2020$

	2020-30	~~2030~~2031-40	~~2040~~2041-50	Total
Gas System	~~48~~50	~~58~~69	~~71~~77	~~177~~197
Elec. System	~~132~~116	~~108~~93	~~114~~100	~~354~~309
Emissions	23	~~66~~65	~~31~~35	~~120~~122
End Users	19	~~54~~32	~~41~~2	~~114~~53
Total	~~221~~207	~~286~~259	~~258~~214	~~765~~681

Electrification

Energy System Costs (billion CAD, real 2020$)





Billion CAD, real 2020$

	2020-30	~~2030~~2031-40	~~2040~~2041-50	Total
Gas System	~~35~~40	~~40~~47	~~44~~45	~~119~~132
Elec. System	~~170~~122	~~147~~110	~~149~~109	~~466~~341
Emissions	~~30~~27	~~115~~108	~~46~~44	~~191~~179
End Users	15	~~89~~51	~~66~~3	~~170~~70
Total	~~250~~205	~~391~~316	~~305~~201	~~946~~722

[91] This analysis also calculated the average annual energy system costs of scenarios on a per capita basis and found:
Diversified scenario: costs of $1,~~390~~300/year per person in 2025, rising to $1,~~620~~470/year in 2035, and falling to $1,~~310~~090/year in 2045.
Electrified scenario: costs of $1,~~570~~290/year per person in 2025, rising to $~~2,220~~1,790/year in 2035, and falling to $1,~~540~~020/year in 2045.
This calculation of per capita costs assumes that Ontario's population rises to 15.9 million people in 2025, to 17.6 million people in 2035, and to 19.7 million people in 2045, as projected by Ontario's Ministry of Finance, at: https://www.ontario.ca/document/ontarios-long-term-report-economy/chapter-1-demographic-trends-and-projections

Scope of Energy System Costs

The energy system costs included in this study are broken down into three categories: gas system costs, electricity system costs, and end-user costs. The cost allocation approach for each of these categories is described as follows:

The allocation of costs across these categories is not intended to identify who is responsible for accruing these costs (e.g., gas system vs. end users) since all costs are ultimately recovered from consumers. Rather, this cost allocation is intended to represent where costs originate. For example, costs associated with RNG supply could be reflected under gas system costs or end-user costs. Our analysis reports RNG costs are under gas system costs because gas infrastructure companies are responsible for developing and initially paying for RNG supply infrastructure, not end users.

In some cases, costs have been allocated to either the gas or electricity systems based on reporting simplicity. For example, all costs associated with the generation of electricity—whether for hydrogen production or direct electricity demand—are allocated to the electricity system. How these costs are ultimately distributed across the energy supply chain would depend on factors such as tariff formulation and regulatory policy.

- **Gas system costs:** Gas system costs include CAPEX and OPEX of new gas supply capacity (e.g., RNG, hydrogen production, CCS), and ~~T&D network~~gas transmission pipeline costs (including hydrogen and RNG integration and injection costs). These costs include the cost of intra-province pipelines necessary to connect new resources to the gas network. The ongoing costs of natural gas imports and operating existing pipeline infrastructure are included and are roughly equal in both scenarios.
- **Electricity system costs:** Electricity system costs include CAPEX and OPEX of new electricity supply capacity (e.g., wind, solar, battery storage, hydrogen gas turbines) and new ~~or reinforced T&D~~transmission infrastructure. These costs include the cost of incremental transmission wires necessary to connect new generation assets to the electric grid. As noted above, the costs of electricity generation capacity used for hydrogen production are reported under electricity system costs. The costs of continuing to operate existing electricity supply capacity (e.g., nuclear, hydro) and T&D infrastructure are included and are roughly equal in both scenarios.
- **End-user costs:** End-user costs include CAPEX ~~and OPEX~~ of all residential building heating equipment upgrades including gas heat pumps (hydrogen- or methane-fired), and electric heat pumps.[92] Costs associated with insulation retrofit requirements (for new and existing homes) are also included. Insulation costs vary based on the type of heating system used. For example, there are different insulation requirements for a home heated with a gas furnace versus an electric heat pump. The analysis focuses purely on the end-user costs associated with building heating and not any other end-user sectors.
- **Out of Scope costs:** In the Electrification scenario, with large amounts of customers switching away from gas-fired heating, it is possible that portions of the gas network may be retired and/or decommissioned before the end of their useful life. There are large uncertainties regarding the timing, extent, and geographic scope of decommissioning. Thus, the results of this study *exclude* the potential costs for decommissioning portions of the gas network. These costs warrant further study, though, as cost estimates from UK-based utilities suggest that Ontario's decommissioning costs could exceed $1.0 billion per year.[93]

  Costs for expanding and upgrading gas and electricity distribution systems (last-mile delivery) are out of scope.

  End user costs associated with the transport sector (e.g., electric vehicles, charging infrastructure) and end user costs in the industrial sector (e.g., electric arc furnaces, kilns) are not captured in the analysis. Based on a similar study performed for British Columbia, Guidehouse would not expect these costs to have a material impact on results.[94]

  Costs associated with improving the resiliency of either the electric or the gas system are not captured in this analysis. The future may see more investments in system resiliency, given the increased risks of extreme weather events and potential cyberattacks. And, at least in the Electrification scenario, the

[92] This does not include wood or biomass heating or district heating, nor the cost of existing heating system.

[93] Decommissioning costs are based on a high level estimate developed for four gas distribution companies in the UK: Cadent Gas, Northern Gas Networks, Scotia Gas Networks, and Wales & West Utilities. These four UK gas distributors estimated decommissioning costs of GBP1.24 billion per year (incurred annually over 20 years) based on several gas network characteristics including kilometres of distribution pipelines, compression stations, gas storage capacity, and gas connections, among other gas system characteristics. If these UK-based cost estimates are scaled linearly to represent Ontario based on the extent of the gas distribution network (e.g., reduced to 148,000 km in Ontario vs. 280,000 pipeline-km of distribution network in the UK), Ontario decommissioning costs are roughly estimated at CAD1.10 billion per year (or GBP0.66 billion per year).

UK Energy Networks Association (2019). Pathways to Net-Zero: Decarbonising the Gas Networks in Great Britain. Available: https://www.energynetworks.org/industry-hub/resource-library/pathways-to-net-zero-decarbonising-the-gas-networks-in-great-britain.pdf

[94] FortisBC (2020). Pathways for British Columbia to Achieve its GHG Reduction Goals. Available: https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/guidehouse-report.pdf?sfvrsn=dbb70958_4

increased reliance on a single energy system may prompt customers to invest in backup generators as insurance against adverse events.

5.4 Comparison of Emissions Pathways

In both the Diversified and Electrification scenarios, Ontario emissions decrease significantly toward 2030 and 2040, reaching the net zero emissions target by 2050. The emissions pathways of both scenarios are largely consistent. This is driven by two factors:

- First, both scenarios take a consistent approach to reducing GHG emissions in large portions of the transportation and industrial sectors. For example, light road transport will reduce GHG emissions via electrification, while the steel and iron ore industries will reduce GHG emissions via hydrogen.

- Second, both scenarios are based on emissions reduction trajectories with the same magnitude—e.g., GHG emissions from trucks and buses are reduced at roughly the same rate, whether by electrification (in the Electrification scenario) or by hydrogen (in the Diversified scenario).

Because total energy system costs are lower in the Diversified scenario as compared to the Electrification scenario, the costs of reducing emissions are also proportionally lower. The cost of emissions reductions in the Diversified scenario are estimated at approximately $~~330/MTCO$_2$e~~269MTCO$_2$e compared to $~~370~~275/MTCO$_2$e in the Electrification scenario.

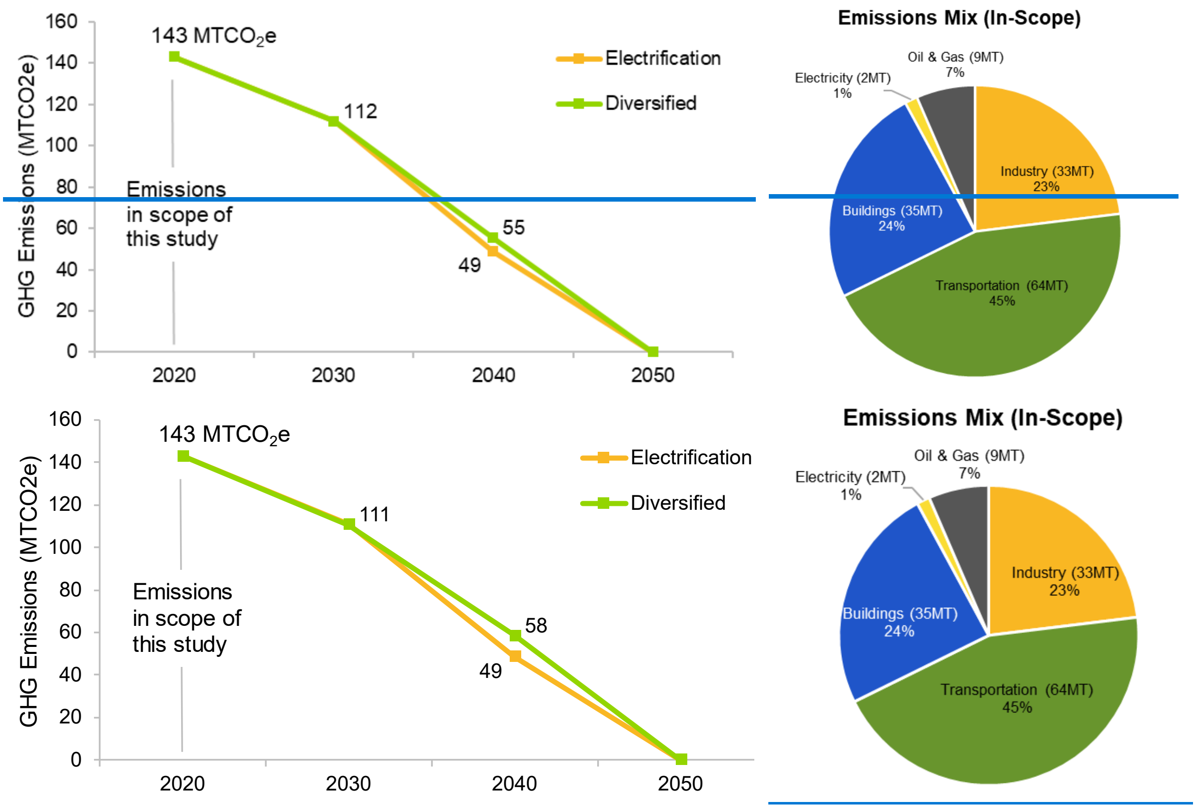
Scope of GHG Emissions

The scope of this study does not capture all Ontario-wide emissions, estimated to be 159 MTCO$_2$e in 2018. This study captures approximately 90% of provincial emissions, or roughly 143 MTCO$_2$e. [95]

The breakdown of Ontario emissions in the scope of this study are presented in the pie chart shown in Figure 19 and include transportation (45%), buildings (24%), industry (23%), oil and gas (7%), and electricity (1%).

The remaining 10% of provincial emissions (not included in the pie chart) are associated with agriculture, waste, and other sources—all of which are not captured in this study. Our analysis assumes these out-of-scope sectors reduce GHG emissions in step with society.

Figure 19. Ontario Emissions Pathways[96]



[95] Ontario emissions reported by NRCan for 2018 are adopted as an estimate for 2020 and are used as the baseline for this study.

Natural Resources Canada (2020). Comprehensive End Use Database. Available: https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/menus/trends/comprehensive_tables/list.cfm

[96] The scope of this study does not capture 100% of Ontario-wide emissions. The scope of this study is approximately 90% of provincial emissions, or roughly 143 out of 159 MMTCO$_2$e.

These in-scope emissions are associated with buildings, transport, industry, and power. The remaining 10% of emissions are associated with agriculture, waste, and other sources, all of which are not part of the analysis. We assume these out-of-scope sectors reduce GHG emissions in step with society.

One of the differences between the Diversified and Electrification scenarios is the magnitude of residual emissions from gas supply. In the Diversified scenario, blue hydrogen (SMR + CCS) and natural gas + CCS scale up significantly, whereas in the Electrification scenario, they play a limited role because GHG emissions from most demand sectors are reduced via electrification. Because CCS does not capture 100% of emissions, some residual emissions remain in both scenarios. In both scenarios, ~~these~~ residual emissions in 2050 are minimal: 2.~~5~~4 $MTCO_2e$ in the Diversified scenario and 1.5 $MTCO_2e$ in the Electrification scenario. In both scenarios, residual emissions are offset via the use of bioenergy with CCS in power generation.

5.5 Pathway Feasibility

For both the Diversified and Electrification scenarios, there will be challenges in implementing the pathways to net zero emissions. Both pathways rely on the development of new low- and zero-carbon gas sources. The Diversified pathway requires rapid adoption of electrolyzer and CCS technologies, and ~~on~~ industrial customers' conversion to hydrogen-consuming equipment. The Diversified pathway also assumes that within a decade, building owners will begin converting their heating systems to gas heat pumps – a technology that is not widely available today. The deployment of these new technologies results in a more gradual increase in peak electric demand.

In contrast, the Electrification pathway largely relies on electric heat pump technologies that are readily available today. The main challenge for the Electrification pathway is in the scale of deployment of new electric infrastructure that will be needed to power these solutions. As shown in Figure 14, the Electrification pathway will see ~~an 80~~a 73% increase in electric peak demand in the 2020-2030 decade, followed by a further doubling of electric peak demand in the 2030-2040 decade. This will require rapid growth in electric generation capacity and in T&D infrastructure to avoid electric system failures, especially during extreme events such as low-wind and low-sun days, or when above-ground infrastructure is impacted by severe weather like ice or high winds. This growth will be especially challenging given the anticipated 4,000 to 6,000 MW capacity shortfalls driven by the retirement of the Pickering Nuclear Generating Station.[97]

Beyond the cost impacts detailed in section 5.3, stakeholders must consider the feasibility of pursuing the rapid but diffuse adoption of new technology compared with the equally rapid deployment of new electric infrastructure.

5.6 Sensitivity Scenario Results

Previous sections compared the results of the Diversified and Electrification scenarios. These sections concluded that, for Ontario, the Diversified scenario presents a more cost-optimal and feasible pathway for reducing GHG emissions through 2050. In this section, we stress-test the results of the Diversified and Electrification scenarios by exploring how these two central scenarios would evolve in other potential net zero visions for Ontario. These alternative net zero visions capture relevant trends in the energy system which may lead to other possible futures for Ontario's energy system. For example, if current trends on the adoption of distributed electricity resources – like rooftop solar and battery storage – were to accelerate aggressively, how would this impact the results of the Diversified and Electrification scenarios? Alternatively, if the adoption of hybrid heating systems were to take off and became the most common heating equipment by 2050, how would this impact the electricity and gas peak?

The objective of this section is to explore the impact of these trends, and others, on the Diversified and Electrification scenarios. This includes four sensitivity scenarios:

- **Sensitivity 1: Increased Decentralized Electricity** explores the impact of an increase in the degree of decentralized electricity supply on total energy system costs.

[97] See IESO (2022). Annual Acquisition Report: April 2022. pp. 1, 14, and Figure 13. Available at: https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/aar/Annual-Acquisition-Report-2022.ashx

- **Sensitivity 2: Limited Investment in Gas Supply and Infrastructure** explores the impact of decreased investment in gas infrastructure on Ontario's ability to meet net zero emissions by 2050.
- **Sensitivity 3: Lower Electrolyzer and Hydrogen Storage Costs** explores the impact of lower hydrogen production costs and hydrogen storage costs on the development of hydrogen supply infrastructure.
- **Sensitivity 4: Adoption of Hybrid Heating Technologies** explores the impact if a significant portion of homes adopt hybrid heating systems that combine gas-fired furnaces with electric heat pumps.

5.6.1 Sensitivity 1: Increased Decentralized Electricity

This sensitivity explores a future where distributed and renewable energy resources play a more central role in the evolution of the electricity system. This sensitivity assumes this scenario is accompanied by aggressive capital cost reductions for solar, wind, and battery storage. These cost reductions lead to high adoption of small-scale, behind-the-meter solar and battery storage resources, which have an impact on the need for T&D power lines. The shift in electricity supply from centralized locations (e.g., large-scale solar) to end users (e.g., behind-the-meter solar) results in avoided T&D investments that would otherwise be required to transport power from centralized locations to end users.

The premise for this sensitivity is based on the development of microgrid projects and large-scale, residential solar-and-storage projects across Ontario. Some high-profile examples include Elexicon's Pickering microgrid and Alectra's PowerHouse project in Vaughan.[98] [99]

The core assumptions underlying this sensitivity are:

- Higher uptake in customer-sited solar and battery storage with 50% of all new capacity assumed to be behind-the-meter and not centralized.
- Capital costs of solar, wind, and battery storage decrease 25% compared to the base Diversified and Electrification scenarios.

Impact on Total Energy System Costs

The impact of this sensitivity on energy system costs is a slight decrease in total energy system costs for both scenarios. The assumed cost reductions in solar, battery storage, and wind lead to an increase in the amount of installed renewable capacity compared to both base scenarios. Additional battery storage capacity in the Electrification scenario provides some balancing of the increase in renewables.[100]

In the Diversified scenario, the assumptions adjusted in this sensitivity decrease the overall energy system costs by $~~13~~11 billion from $~~765~~681 to $~~752~~670 billion due to abundant renewables making green hydrogen more attractive than in the base scenario. ~~This~~Cheaper renewables decrease the electricity system costs by $8 billion over the study period. A greater share of hydrogen produced by electrolysis reduces the need for ~~natural gas feedstock for~~ blue hydrogen, thus reducing overall gas system costs. For the Electrification scenario, this sensitivity results in $12 billion in total energy

[98] Global News (2021). Pickering community can go off-grid with nested microgrid technology. Available: https://globalnews.ca/news/8370542/off-grid-pickering-nested-microgrid-community/

[99] Alectra (2020). POWER.HOUSE virtual power plant delivers peace of mind. Available: https://www.alectra.com/sites/default/files/assets/pdf/Alectra_GREATCentre_PowerHouse_2020-07-15.pdf

[100] It should be noted that outside of this modelling exercise, depending on scenario, it is assumed that 95-100% of light duty vehicles in Ontario are electric by 2050. While out of scope for this study, these vehicles represent significant storage capabilities for the province when not in use, and this storage capacity should be analyzed further.

system savings, largely concentrated in the electricity system and mainly due to reduced capital cost of renewables and reduced investments in transmission and distribution.

Impact on Diversified Scenario:

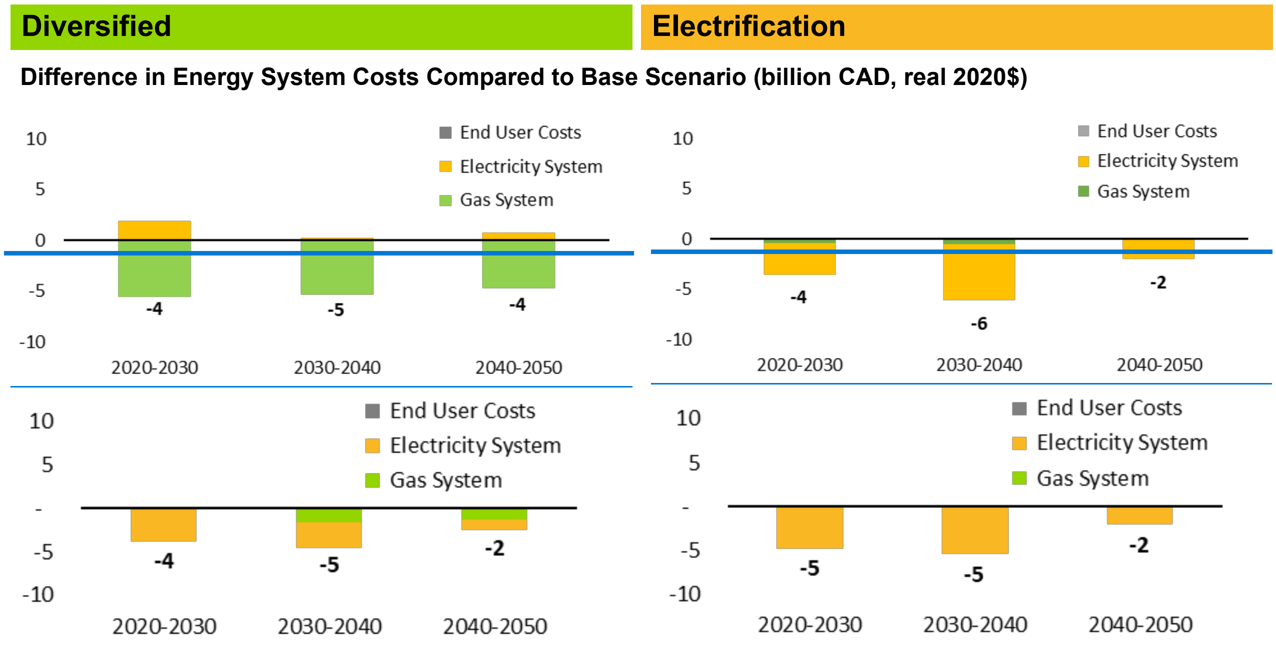
- **Slightly ~~increased~~reduced electricity system costs:** The decrease in solar costs results in a significant increase in solar capacity to ~~just over 9 GW. Thus, electricity system costs increase by $3 billion to accommodate the additional renewable capacity installed~~approximately 27 GW in 2050, which replaces baseload nuclear SMR capacity that is built in the base scenario. Slightly more hydrogen fired gas turbines are required to balance the added solar capacity. The reduced cost of solar capacity as well as the reduced build out of nuclear SMR offset the increase in cost due to increased solar and hydrogen fired capacity, which results in an overall reduction of $8 billion in electricity system costs.
- **Gradual cost savings over time.** With a more moderate approach to electrification, the investments in solar, wind, and battery storage are distributed over the study period.
- **Lower gas system costs:** With the lower cost of renewables, the cost of green hydrogen is reduced and becomes competitive with blue hydrogen earlier in the study period. ~~In the central Diversified scenario, domestic hydrogen production in 2030 is all from blue hydrogen.~~ In this sensitivity, green hydrogen accounts for ~~32~~51% of ~~2030~~2040 hydrogen capacity~~.~~ and 72% of 2050 hydrogen capacity, compared to 44% and 69% in the central Diversified scenario. Gas system costs are reduced because with a reduced build out of SMR + CCS, there is less natural gas feedstock for SMR required.

Impact on Electrification Scenario:

- **Lower electricity system costs:** ~~Solar~~The decrease in solar costs results in an increase in solar capacity ~~increases~~ by ~~2~~5 GW, to ~~7~~13 GW by 2050~~. Since~~, which replaces additional hydroelectric capacity in the base Electrification scenario ~~already has a higher saturation of renewable generation, less capacity~~. Since hydroelectricity is ~~added by the cost reductions in this sensitivity. Therefore~~a more costly resource, the reduction in capital costs results in $12 billion in electricity system savings.
- **Significant upfront cost savings.** Over half of the cost savings of this sensitivity occur in in the first decade of the study period. This is because in the base Electrification scenario, significant investments in battery storage, solar, and wind occur before the mid 2030's due to the immediate and aggressive electrification efforts needed to meet demand that was previously met by the gas system.

  Slight decrease in gas system costs: While electricity system costs are the main impact area of this sensitivity, gas system costs decrease as well by $~~1 billion~~30 million. Similar to the Diversified scenario, the reduction in gas system costs is due to lower capital costs for renewable which make green hydrogen more cost-effective than in the base scenario. This ~~avoids~~results in an increase in green hydrogen in 2050. Increased electric capacity also reduces the need for more costly ~~blue hydrogen capital investments in 2040, which also leads to reduced operational costs~~methane imports from 2030 to 2040.

Figure 20. Sensitivity 1 – Comparison of Energy System Costs



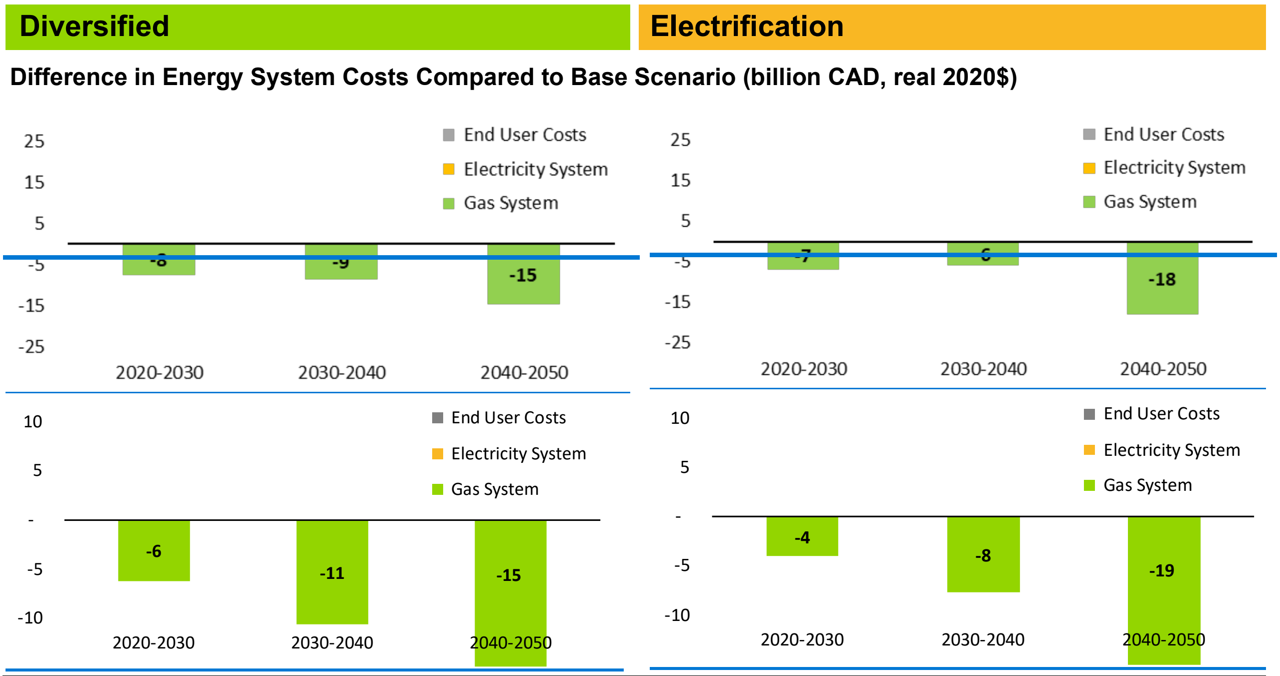
Note: In this comparison chart, changes in emissions costs are included in the "Gas System" series.

5.6.2 Sensitivity 2: Limited Investment in Gas Supply and Infrastructure

This sensitivity explores the impact of reduced investment in the gas system compared to the base Diversified and Electrification scenarios. This sensitivity analyzes how constrained spending on reducing GHG emissions of the gas supply and infrastructure could impact Ontario's ability to reach net zero by 2050. This reduction in investment is assumed to impact the buildout of blue hydrogen supply capacity (SMR + CCS~~),~~) and the development of RNG supply~~, and the adoption of CCS by industry.~~. As a result, gas demand previously met by blue hydrogen~~, RNG,~~ and ~~natural gas with CCS~~RNG is now met by unabated natural gas. The callout box at the end of this section explores the cost of offsetting the increased emissions that arise from this sensitivity, if such a magnitude of offsets were available.

Guidehouse's analysis assumes a **~~10%~~ reduction in gas system investment compared to the base Diversified and Electrification scenarios**, leading to a reduction in spend of approximately $31-32 billion, cumulative through 2050. This reduction in achieved through a reduction of the capacity buildout of SMR + CCS, anaerobic digestion, and natural gas + CCS compared to the base scenarios.

Figure 21. Sensitivity 2 – Comparison of Energy System Costs

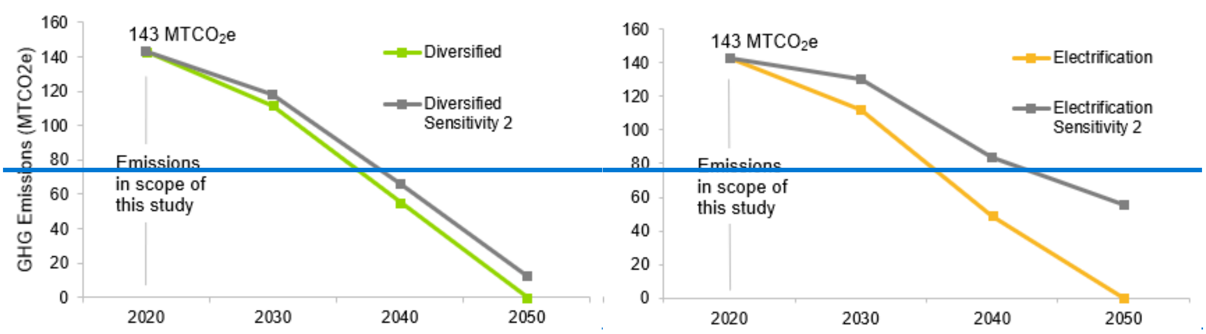


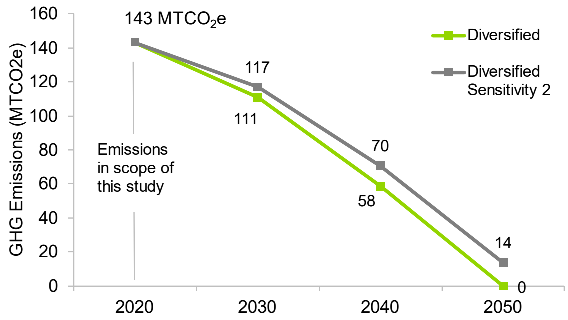
Note: In this comparison chart, ~~changes~~increases in emissions costs are not included~~ in the "Gas System" series.~~.

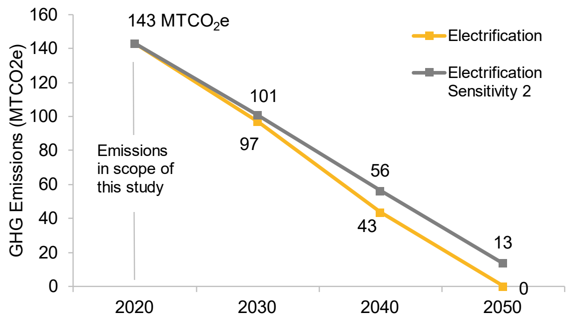
Impact on Emissions Pathway

For the Diversified scenario, the impact of this sensitivity is unabated emissions of ~~12~~14 $MTCO_2$ in 2050 compared to the base Diversified scenario. This is equivalent to roughly ~~8~~10% of Ontario's natural gas emissions today. For the Electrification scenario, however, the impact on blue hydrogen and RNG production is much greater in magnitude since this scenario assumes the minimum investment in the gas system needed to achieve net zero emissions. Thus, these investment dollars are targeted towards end uses that are difficult to electrify such as high-temperature industry and heavy transport. It is important to note that these sectors also contribute significantly to present day emissions. Reducing this investment ~~by 10%~~ results in unabated emissions of ~~56~~13 $MTCO_2$ in 2050, which is equivalent to roughly ~~39~~9% of Ontario's natural gas emissions today. It is important to note that **under the conditions of this sensitivity, Ontario does not achieve net zero emissions by 2050 in either scenario**. ~~In the case of the Electrifications scenario, this~~This sensitivity results in Ontario only reducing emissions by ~~60~~approximately 90% of current emission levels by 2050. The carbon emissions trajectories traced by this sensitivity analysis can be seen in ~~Figure 22~~Figure 22 below for both scenarios.

Figure 22. Comparison of Emissions Pathways of Sensitivity 2 for Both Scenarios







Cost of Residual Emissions

This sensitivity analysis determined that in the Diversified scenario, reducing spending on the gas system by $~~30~~32 billion will result in ~~12~~14 $MTCO_2$ of residual emissions in 2050, or the equivalent of an additional ~~234~~257 $MTCO_2$ in cumulative emissions released into the atmosphere from 2020 to 2050. For the Electrification scenario, reducing gas system spending by ~~10% (or~~ approximately $~~30~~31 billion~~)~~ would result in ~~56~~13 $MTCO_2$ of residual emissions in 2050, or the equivalent of ~~840~~239 $MTCO_2$ in cumulative emissions over the study period. For these magnitudes of residual emissions~~, especially for the Electrification scenario~~, *it cannot be assumed that sufficient offsets will be available to reach net zero* if Ontario addressed these residual emissions using carbon offsets.

Using the projected carbon tax values in Table A-2 as a proxy for the price of carbon emissions, it would cost Ontario $~~31~~34 billion (2020$) to offset these residual emissions if the gas system spending is reduced by $~~30~~32 billion in the Diversified scenario. Similarly, it would cost Ontario $~~191~~55 billion for the emissions created if the gas system spending is reduced by $~~30~~31 billion in the Electrification scenario. Because the cost of emissions offsets outweighs the cost of GHG mitigation through gas system investments, we conclude that targeted gas system investments are more cost-effective than carbon offsets to reduce GHG emissions.

5.6.3 Sensitivity 3: Lower Electrolyzer and Hydrogen Storage Costs

This sensitivity explores the impact of a future with decreased green hydrogen costs compared to today's price forecasts. The core assumptions underlying this sensitivity are:

- Capital costs for electrolyzer and wind follow a lower price forecast than assumed in the Diversified scenario. These cost reductions lower the cost of green hydrogen production in Ontario and neighbouring jurisdictions, which leads to a decrease in the cost of hydrogen imports from Western Canada and Quebec.
- Costs of hydrogen storage decrease 25% compared to hydrogen storage costs in the Diversified scenario.

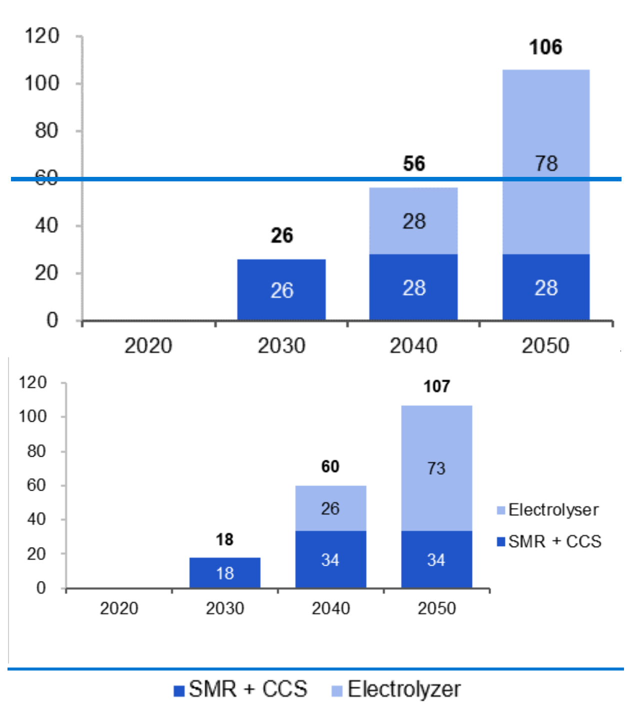
The impact of this sensitivity in the Diversified scenario is a decrease in total energy system costs by just ~~under $13~~over $9 billion from $~~765~~681 billion to $~~753~~672 billion. In the Electrification scenario, this reduction is smaller at $~~9~~7 billion from $~~946~~722 billion to $~~937~~715 billion. While this sensitivity affects the costs of both the electricity and gas systems, the majority of savings come from reduced ~~gas system costs~~electricity system costs in the Electrification scenario, and relatively evenly from both gas and electricity system savings in the Diversified scenario.

For the Diversified scenario, the result of this sensitivity is ~~a slightly higher hydrogen capacity in 2050 (see Figure 23). This is because~~that green hydrogen meets a larger share of the overall hydrogen demand due to decreased costs. SMR + CCS operates at a higher utilization than electrolyzers because it does not depend on renewables, so to meet the same demand with electrolyzers powered by renewables, slightly more capacity needs to be installed~~. Wind~~ (e.g. in 2030 and ~~hydrogen storage~~2040). The electricity system cost ~~reductions result in an increase~~savings are due to the reduction in ~~the amount of installed capacity of each~~wind costs compared to the base Diversified scenario.

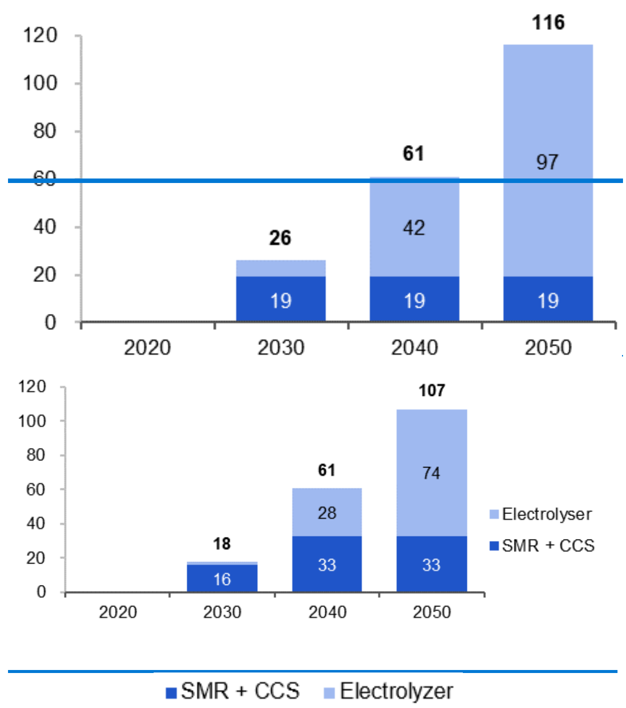
Figure 23. Sensitivity 3 – Comparison of Hydrogen Supply Capacity and Imports

Diversified	**Sensitivity 3**

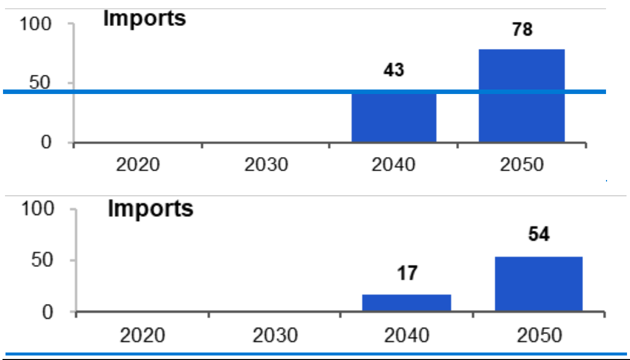
Hydrogen Supply Capacity (TJ/hour)



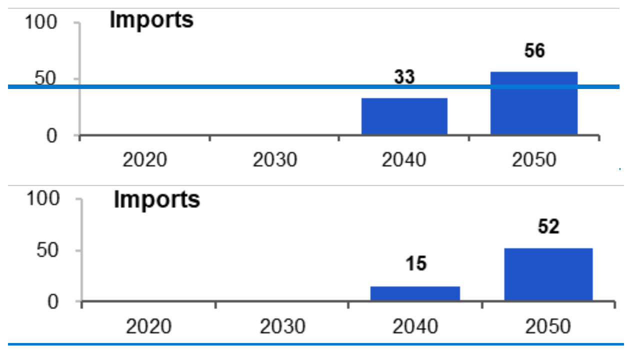
Hydrogen Supply Capacity (TJ/hour)



Hydrogen Import Supply (PJ)

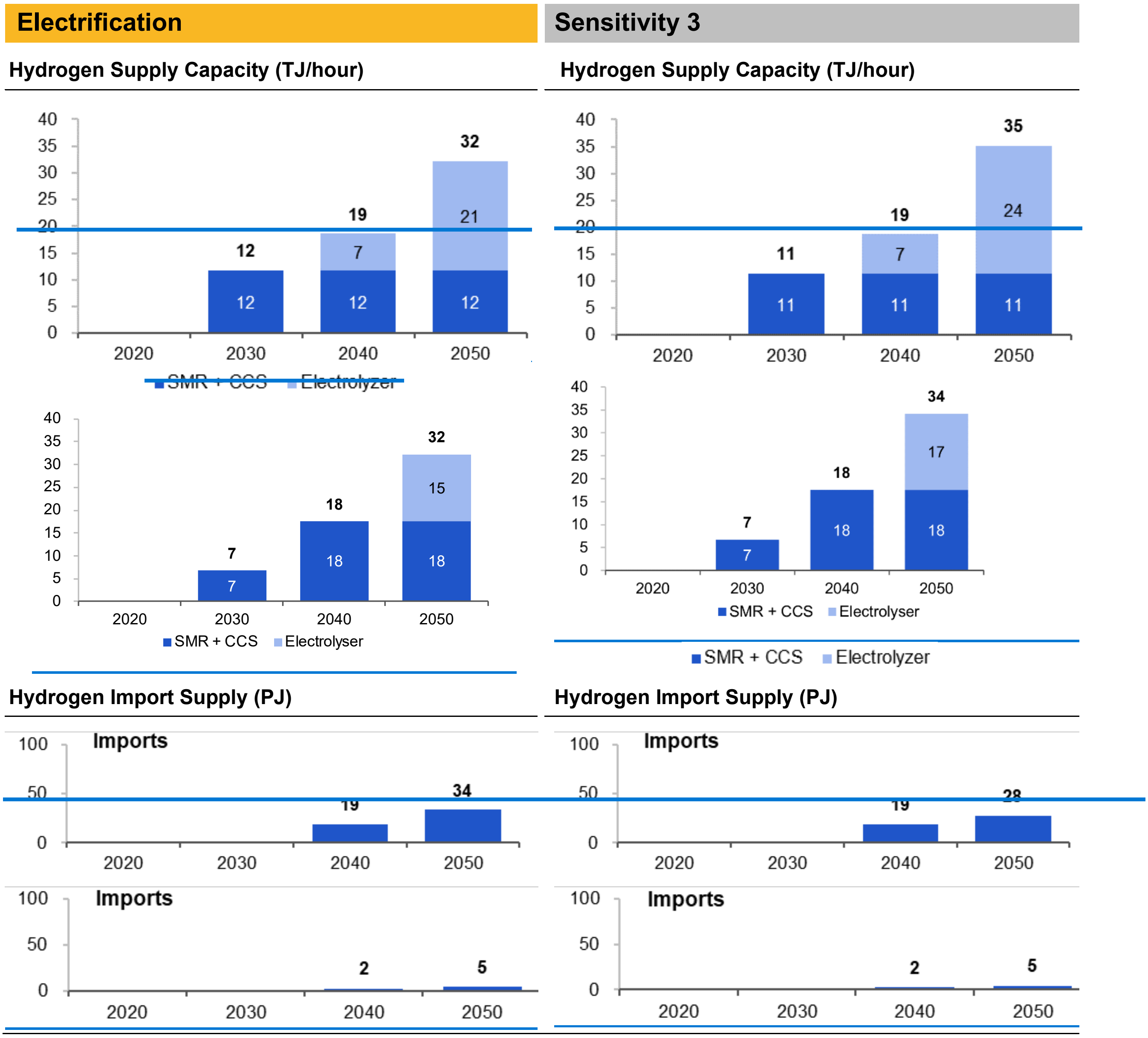


Hydrogen Import Supply (PJ)



Similarly for the Electrification scenario, reduced electrolyzer and hydrogen storage costs increase the share of green hydrogen in the production of hydrogen overall (see Figure 24). Due to this, overall hydrogen capacity increases due to the capacity factors of the renewable electricity generation that the electrolyzers rely upon.

Figure 24. Sensitivity 3 – Comparison of Hydrogen Supply Capacity and Imports



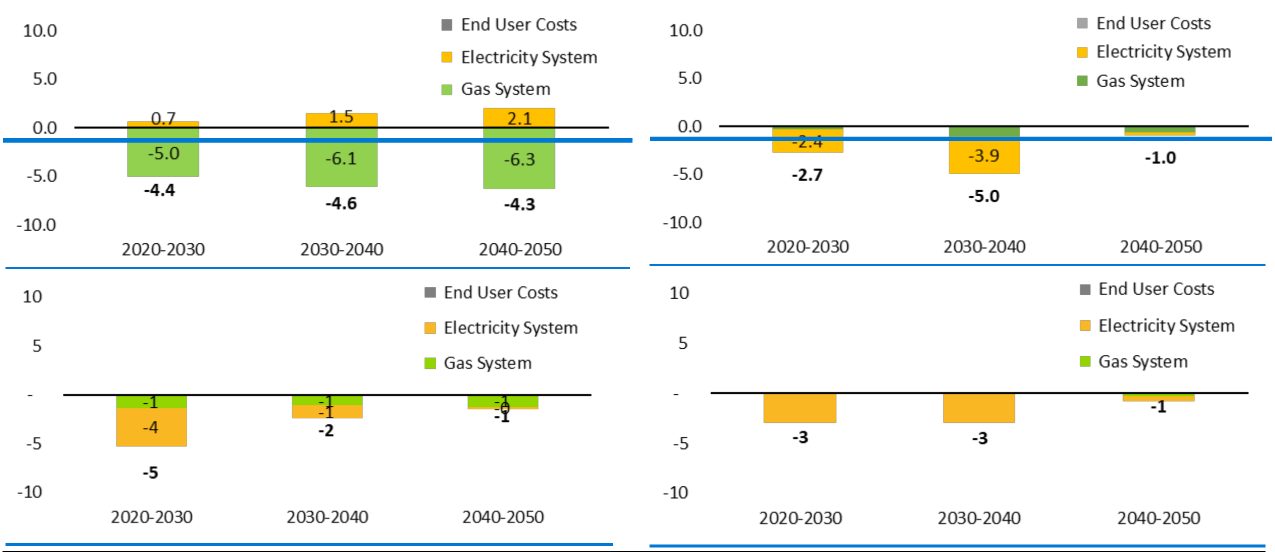
Compared to the base Diversified scenario, gas system costs fall by $~~18~~4 billion~~, while~~ and electricity system costs ~~rise~~fall by $~~4 billion. This is due to the additional 9.4 GW of wind capacity needed since green hydrogen meets a larger share of the overall hydrogen demand as mentioned above. Since green hydrogen is powered by renewables which have lower capacity factors, more capacity needs to be installed to meet the same baseload demand required. The costs of this additional capacity outweigh the savings~~5 billion, due to reduced wind energy costs~~, leading to a slight increase in electricity system costs.~~

~~Compared~~. Similarly, compared to the base Electrification scenario, electricity system costs decrease by $7 billion due to decreased wind energy costs~~, even though there is an addition build out of 1.3 GW of wind capacity (Figure 25).~~. Gas system costs decrease by ~~$2~~close to half a billion due to decreased hydrogen import costs, decreased electrolyzer costs, and decreased hydrogen storage costs.

Figure 25. Sensitivity 3 – Comparison of Energy System Costs

Diversified	Electrification

Difference in Energy System Costs Compared to Base Scenario (billion CAD, real 2020$)



Note: In this comparison chart, changes in emissions costs are included in the "Gas System" series.

5.6.4 Sensitivity 4: Hybrid Heating System Adoption

This sensitivity explores the peak load reduction potential of hybrid heating systems, which combine gas-fired furnaces with electric heat pumps, installed in residential homes across the province in comparison to the base Diversified scenario. The core assumption underlying this sensitivity is the aggressive adoption of hybrid heating systems for residential space heating outlined in Table 3 below.

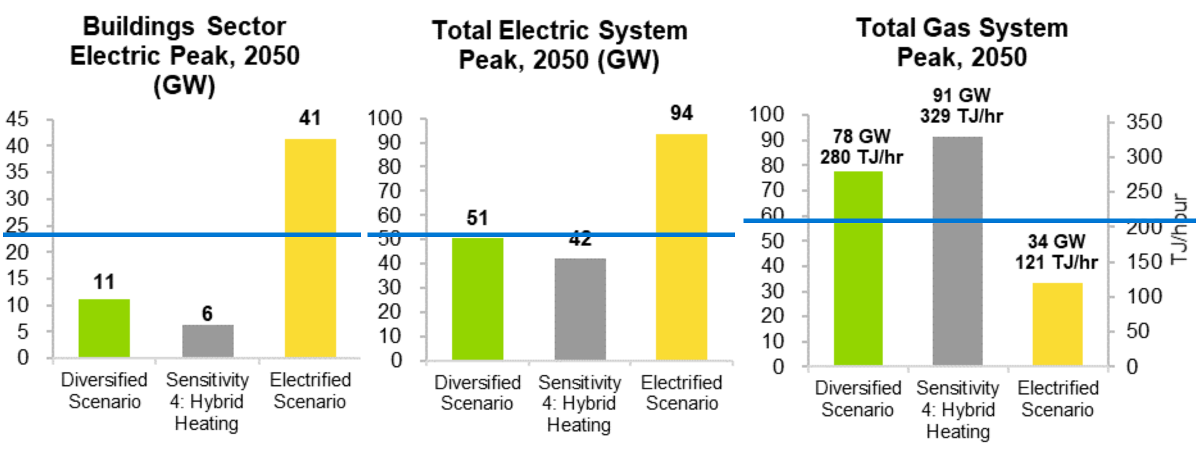
Table 3. Sensitivity 4 – Residential Heating Equipment Shares

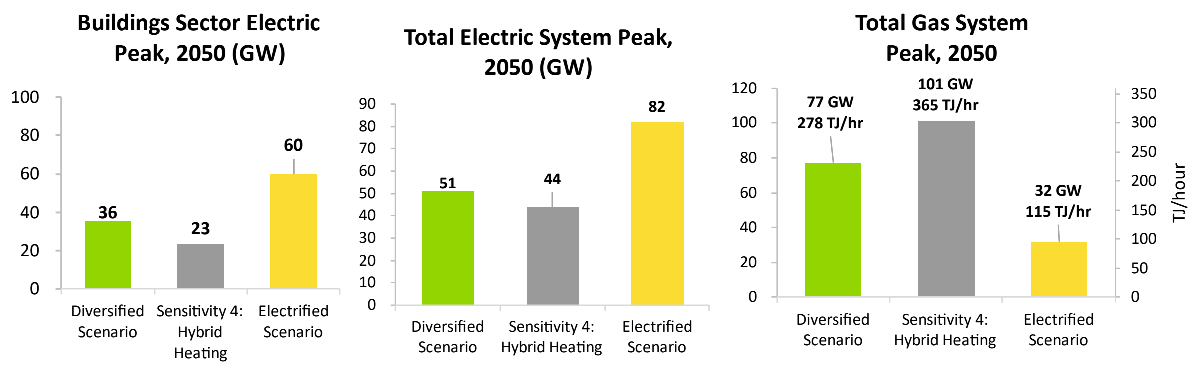
Space Heating	2020	2030	2040	2050
Gas heat pump	0%	1%	15%	20%
Air-source heat pump	7%	7%	8%	10%
Geothermal heat pump	0%	4%	7%	10%
Hybrid heating system	0%	14%	35%	55%
Natural gas furnace	82%	65%	28%	0%
Other	11%	9%	7%	5%

The impact of this sensitivity is the optimization of peak demand through integration of the electricity and gas systems at the end-use level. This optimization results in reduced electric system peak demand in 2050 and~~ a~~ reduced annual gas demand through the study period compared to the base Diversified scenario due to homes moving away from natural gas as their sole heating source. Hybrid heating technology mitigates the effects of cold temperature on electric heat pump performance, so the electric peak is significantly lower than the base Electrification scenario~~. This~~ and somewhat lower than the base Diversified scenario. Relative to the Diversified scenario, this reduction in peak leads to a 5 GW decrease in electricity supply build out and cumulative savings of $~~8 billion~~670 million in electricity system spending~~ as compared to the Diversified scenario.~~. Reducing winter peak demand should also improve system resilience in cold climate regions. While the cost of the gas system increases by $~~15~~4 billion due to increased gas system peak compared to the base Diversified scenario, this is more than offset by the significant decrease in ~~electricity system costs and end user costs. Figure 26 summarizes the peak load impacts of this sensitivity~~end user costs. Figure 26 summarizes the peak load impacts of this sensitivity.

The buildings sector electric peak values in Figure 26 the peak of just the buildings sector, which may coincide with the electric system peak, depending on the scenario. For the Diversified scenario in 2050, the buildings sector electric demand shown in Figure 26 occurs at a separate time from the coincident electric system peak load. For the Electrification scenario in 2050, the buildings sector peak occurs at the same time as total system peak.

Figure 26. Sensitivity 4 – Comparison of Peak Load in 2050





A large share of cost savings, $~~28~~12 billion, come from decreased end-user costs. In the base Diversified scenario, gas-fired heat pumps overtake natural gas furnaces as the most prevalent space heating technology in the province. Sensitivity 4 results in cost savings because hybrid heating systems are less costly to install than gas heat pumps and do not require the deep energy efficiency retrofits that are accompany cold-climate air-source heat pump installations. The costs of each technology can be seen in Table 4 below.

Table 4. Sensitivity 4 – Residential Space Heating Technology Costs[101]

Space Heating Technology	Cost (2020$)
Gas heat pump with low-capacity A/C unit	$12,200
Electric cold climate heat pump with electric resistance backup	$11,100
Hybrid heating system	$11,350

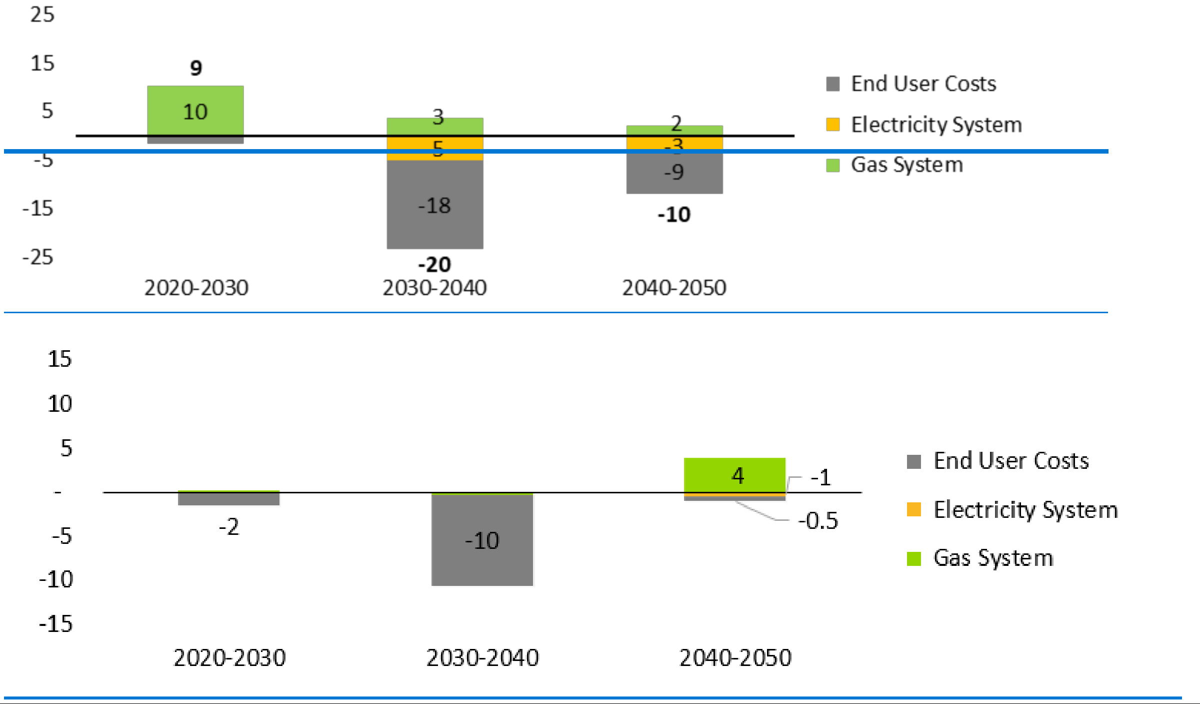
Gas system costs increase by $~~15~~4 billion dollars because of an increase in gas system peak when compared to the base Diversified scenario. Although there are associated savings with slightly reduced ~~gas import volumes~~hydrogen gas supply built in Ontario over the entire study period, the ~~upkeep of infrastructure to maintain gas system peak~~increase in reliance on gas import volumes negates these savings. Since hybrid heating systems only switch to gas heating below a certain design temperature, less gas is needed on an annual basis compared with using a gas furnace or a gas fired heat pump. ~~The slight increase in gas system costs in the first decade of the study~~These cost differences can be seen in Figure 27 below~~ is due to additional SMR+CCS capacity. Although the same amount of SMR+CCS capacity is built cumulatively across the study period, there is greater need for it upfront in this sensitivity~~.

[101] Residential space heating equipment costs were sourced from Enbridge Gas Inc. (2021). Answer to Interrogatory from Ontario Energy Board, pp.343-356. Available: https://www.rds.oeb.ca/CMWebDrawer/Record/732115/File/document

Figure 27. Sensitivity 4 – Comparison of Energy System Costs

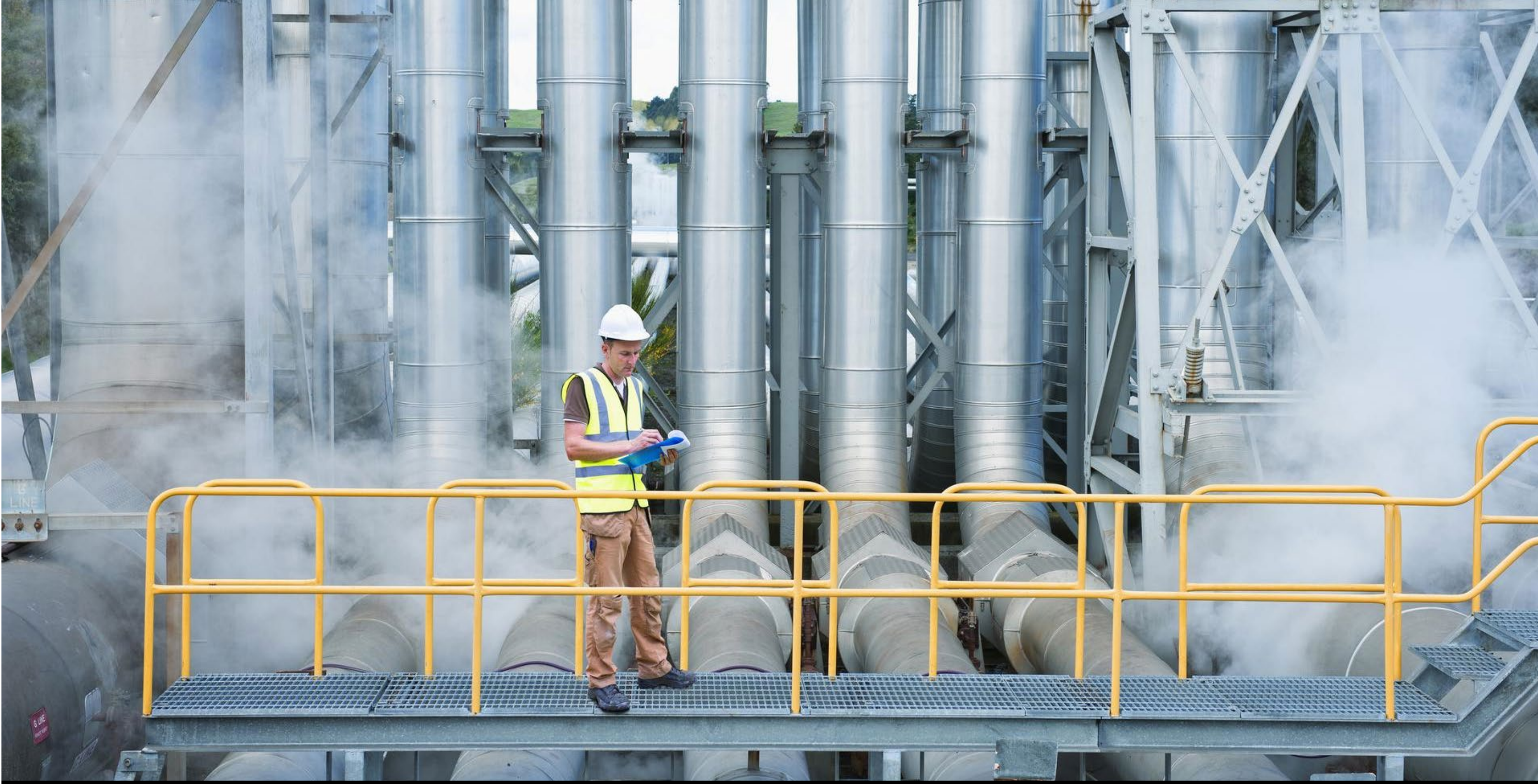
Diversified

Difference in Energy System Costs compared to Base Scenario (billion CAD, real 2020$)



Note: In this comparison chart, changes in emissions costs are included in the "Gas System" series.

This sensitivity analysis shows that ~~with significant~~through peak demand management via adoption of hybrid heating systems in residential homes, Ontario has the potential to save $~~21~~9 billion compared to the base Diversified scenario~~, which is the lowest cost pathway identified in this report~~. The addition of hybrid heating to the core Diversified scenario improves the scenario's feasibility in two ways: (1) Fewer homes will require deep energy retrofits with the inclusion of hybrid heating systems, since hybrid heating systems rely on gas-fired backup heating systems during cold weather periods and the heating capacity of gas-fired systems does not diminish in cold outdoor temperatures. (2) Since hybrid heating systems rely on gas-backup during peak cooling periods, the deployment of hybrid heating systems reduces the amount of electric capacity growth needed to supply heat during winter peak conditions (see Figure 26).

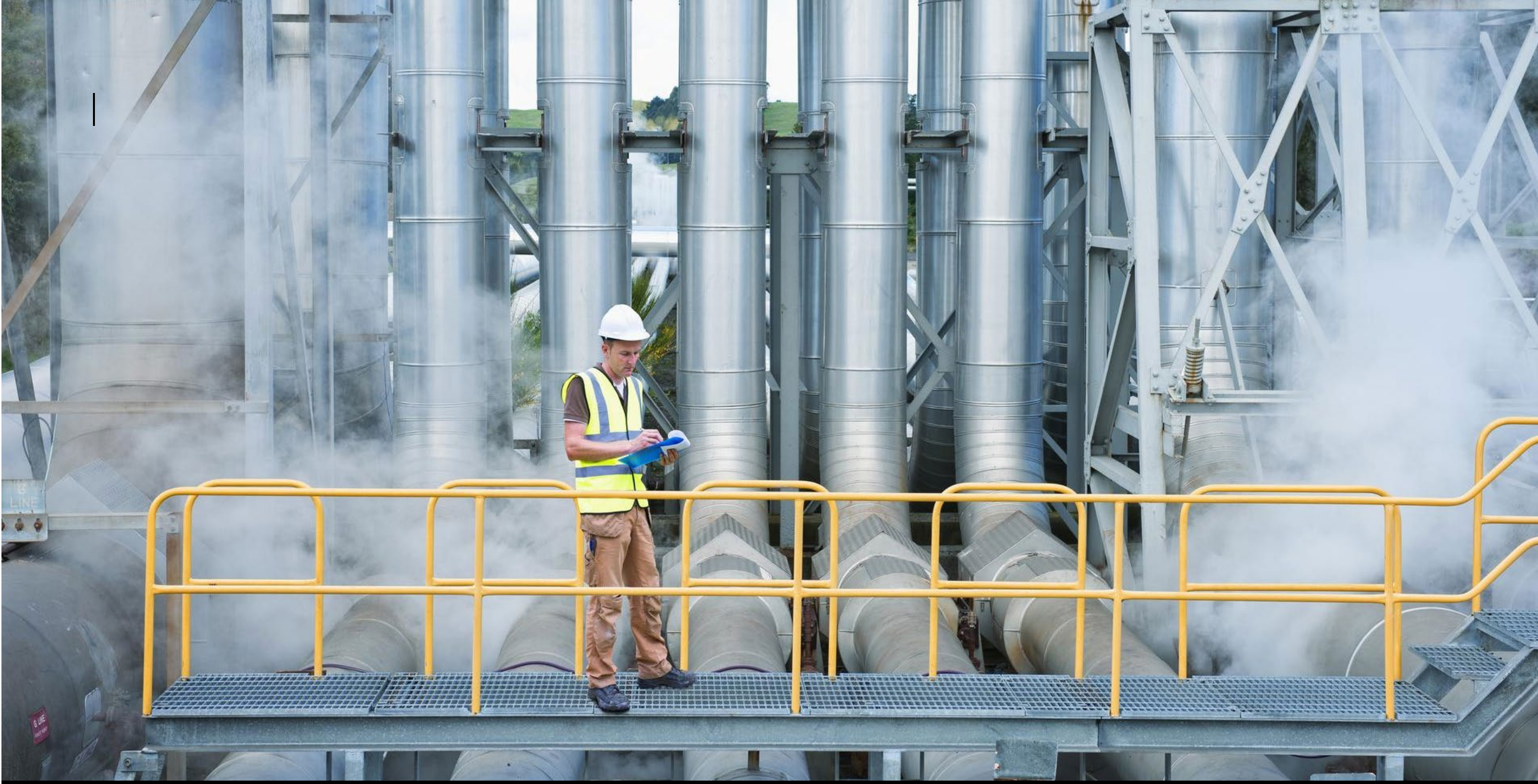


6. Implications for Ontario's Energy System

Guidehouse's analysis determined the Diversified scenario is more cost-effective than the Electrification scenario when modelling how Ontario could reach net zero emissions by 2050. To stress-test our findings, we also evaluated the impact of four scenario sensitivities relative to the base Diversified and Electrification scenarios. ~~The Hybrid Heating System Adoption sensitivity was determined to be the most cost-effective pathway, although other sensitivities also provided cost savings compared to the Diversified scenario.~~The sensitivities explored, including increased decentralized electricity, lower electrolyzer and hydrogen storage costs, and adoption of hybrid heating technologies illustrated pathways that could further reduce energy system costs relative to the Diversified scenario. None of the sensitivities altered the directionality of the Diversified scenario having lower estimated energy system costs than the Electrified scenario.

In all scenarios and sensitivities, the analysis shows that Ontario's energy system will require energy infrastructure to increase significantly in scale and will require drastic changes in the way the electricity and gas systems operate. Across all these scenarios, several common themes emerged. This section summarizes these common themes and explores some of the major implications on the future of Ontario's electricity and gas grids.

~~1.~~ **Low- and zero-carbon gas will be indispensable to get to net zero.**
While electrification is a powerful tool for reducing GHG emissions, electrification is not practical for all sectors. Some sectors such as heavy transport or industries with high temperature processes like steel and chemicals have considerable carbon footprints and are challenging or next-to-impossible to decarbonize through electrification. Reaching net zero emissions in Ontario by 2050 cannot be achieved through electrification only. Low- and zero-carbon gases like RNG and hydrogen will play a role in the GHG emissions reductions of most sectors, particularly in hard-to-abate sectors like heavy transport and industry.



2.

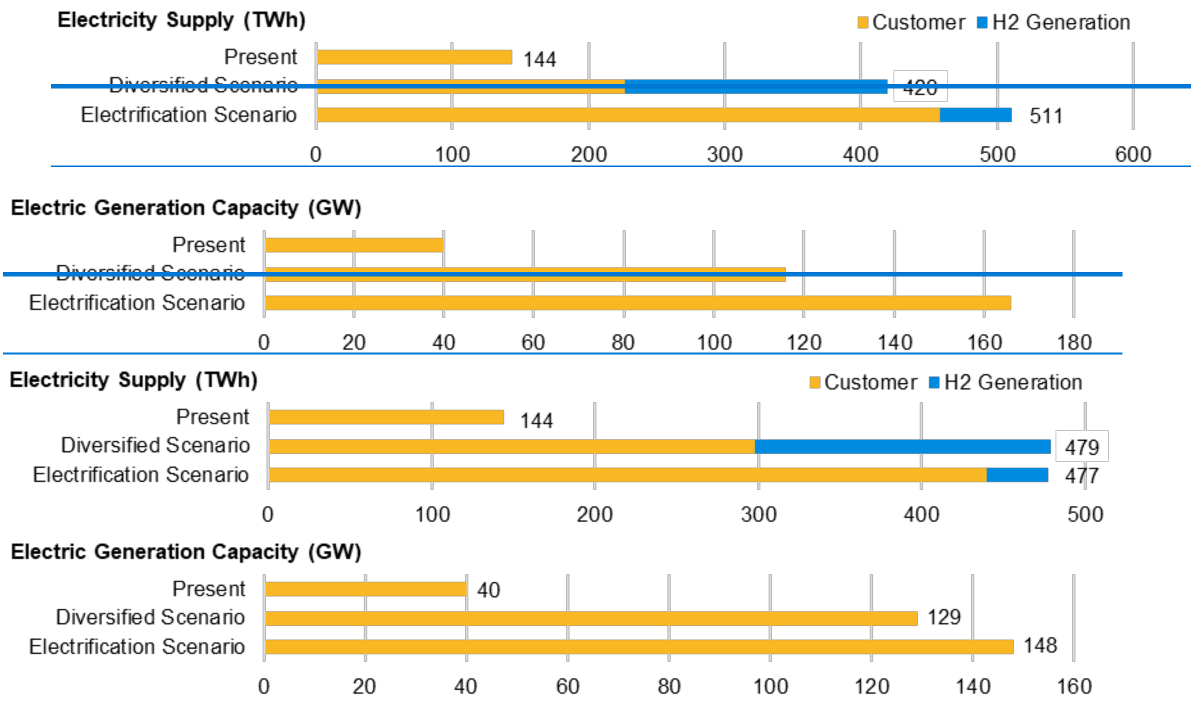
[redacted]

increase in the Electrification scenario to ~~458~~413 TWh. Additionally, in the Diversified scenario, electricity generation capacity will also have to scale up to meet indirect electricity demand for green hydrogen production.[102] Our analysis estimated ~~544~~511 PJ of green hydrogen production in 2050, leading to an additional approximately ~~193~~181 TWh of electricity demand in the Diversified scenario.

[102] Direct energy supply to end users and indirect energy supply for green hydrogen production are treated separately in our model and are impacted by various factors including the availability of surplus electricity, gas/electricity storage and energy imports.

~~3.~~1. In all scenarios and sensitivities, the magnitude of the increase in electricity demand will require a significant buildout of generation capacity, T&D infrastructure, and storage capacity. Our analysis forecasts generation capacity increasing from 40 GW today to ~~116~~129 GW in the Diversified scenario and to ~~166~~148 GW in the Electrification scenario. An increase in scale of this magnitude will require changes in the way electricity generation capacity and transmission infrastructure is planned and evaluated, and the speed at which it is developed.

Figure 28. Comparison of Present and Future Electricity Supply and Generation Capacity



~~4.~~2. **The electricity and gas systems will become increasingly integrated.**
These two energy delivery systems will grow more interconnected on the journey to net zero. Our analysis has shown how important energy conversion between electricity and hydrogen will be in the future. Electricity supply will be critical to scale up green hydrogen supply and meet hydrogen demand. Hydrogen supply will also be critical in meeting peak electricity demand through hydrogen-fired gas turbines. Hydrogen will become an important long-term electricity storage option. Hydrogen will be produced during periods of electricity oversupply, and it will be used in periods of peak demand. This integration can also happen behind the meter, with dual fuel technologies like hybrid heating systems operating intelligently to optimize the use of electricity and gas for space heating. Hybrid heating systems can reduce electricity system costs by reducing peak electric load. Our analysis shows that significant adoption of residential hybrid heating systems can save Ontario $~~21~~9 billion compared to the base Diversified scenario.

~~5.~~3. **Reducing GHG emissions from the gas system will be a less disruptive and more cost-effective option than full electrification**.
The analysis shows that the Diversified scenario can save Ontario $~~181~~41 billion by 2050 relative to the Electrification scenario. The benefits from this scenario are not only limited to costs savings, but also largely to ease of implementation. The Diversified scenario avoids highly disruptive building retrofits and heating equipment upgrades, both of which are required in the Electrification scenario. With more than 65% of residential buildings in Ontario already equipped with either gas furnaces or boilers,[103]~~,~~ replacing them with electric heat pumps will require extensive and disruptive renovation to ensure buildings are adequately heated and insulated. Despite these energy efficiency improvements, electricity peak demand will

[103] NRCan (2018). Residential Sector Heating System Stock. Available: https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/showTable.cfm?type=CP&sector=res&juris=on&rn=21&page=0

increase significantly. This will lead to major investments in new generation, transmission, and distribution infrastructure.

The Diversified scenario offers an opportunity to avoid some of this disruption. Heating with low- and zero-carbon gas requires limited building renovation. In the near term, blending RNG and hydrogen into the gas grid does not require new heating systems. Only in the longer term, with a 100% hydrogen gas grid, would hydrogen-ready heating systems be needed.

~~6.~~4. **The transition to low- and zero-carbon gas will reduce Ontario's reliance on energy imports**.
Our analysis shows that domestic sources of low- and zero-carbon gas will be developed right here in Ontario in the future. In the Diversified scenario, domestic RNG supply is expected to scale up to deliver roughly 15% of gas supply, while domestic green hydrogen will grow to meet roughly ~~47~~44% of gas supply. Overall, more than half of Ontario's gas supply can be met with domestic resources. RNG and hydrogen present an excellent opportunity to minimize Ontario's reliance on energy imports and promote energy independence.

~~7.~~5. **Ontario's gas infrastructure can be cost-effectively repurposed to hydrogen to avoid costly investments in new electricity infrastructure.**
Ontario has an extensive natural gas pipeline network, delivering nearly twice as much energy per year as the province's electricity system and an even greater contribution to peak energy demand. Ontario's pipeline network is ideally suited to be repurposed to a hydrogen network, as the province's newer pipelines, typically made of polyethylene, are already largely hydrogen-ready. Metal pipes will require integrity assessments and internal coatings before they can be used to transport hydrogen. Nevertheless, this can be done for less than a quarter of the cost to build new hydrogen pipelines.[104] Repurposing existing natural gas infrastructure for hydrogen, as in the Diversified scenario, would be a more efficient use of existing infrastructure than the Electrification scenario, in which much of the gas network would be decommissioned. Utilizing the existing pipeline infrastructure will also allow stakeholders to continue benefitting from the reliability that gas utility systems provide. Additionally, the inherent characteristics of pipeline infrastructure (which is mostly underground) support a resilient energy system.

Additionally, the Electrification scenario would likely face major societal acceptance challenges associated with the development of new electricity transmission infrastructure and associated land area requirements. For example, to transport the equivalent volume of energy as a traditional 48-inch gas pipeline would require the equivalent of 5-6 overhead high voltage alternating current transmission lines. These land area considerations are particularly important in high density regions like the metro areas of Toronto, Ottawa, and Hamilton, and crossing Indigenous territories.

~~8.~~6. **Gas generation will continue to play a critical role in Ontario's electricity system.**
Today, electricity system resiliency is achieved with dispatchable natural gas turbines. In a net zero future, the Diversified and Electrification scenarios project a major role for hydrogen-fired turbines in meeting peak demand and ensuring system resiliency and reliability. Hydrogen plays an even more pivotal role in the face of over ~~67~~70 GW of wind capacity forecasted by both scenarios, with ~~increasingly drastic~~ hour-to-hour fluctuations in generation and the potential for week-long periods with little or no electricity generation from wind (commonly known as a *dunkelflaute* event). Without hydrogen-fired generation, a net zero electricity system would require overbuilding generation capacity and interties with neighbouring regions to ensure adequate peak supply. This approach would be more expensive, and it would be less resilient in cases of emergency with limited availability of imports and limited renewable generation. According to the IESO, phasing out natural gas generation by 2030 would require more than $27 billion of investment in supply and transmission infrastructure, translating to a 60% increase in electricity bills, and it would still result in blackouts.[105]

[104] Guidehouse (2021). European Hydrogen Backbone: Analysing the future demand, supply and transport of hydrogen. Available: https://gasforclimate2050.eu/wp-content/uploads/2021/06/EHB_Analysing-the-future-demand-supply-and-transport-of-hydrogen_June-2021.pdf

[105] IESO (2021). Decarbonization and Ontario's Electricity System: Assessing the impacts of phasing out natural gas generation by 2030. Available: https://www.ieso.ca/en/Learn/Ontario-Supply-Mix/Natural-Gas-Phase-Out-Study

Repurposing gas infrastructure for hydrogen would also bring an enormous storage benefit. Electricity storage technologies like batteries are expensive and only capable of storing electricity for several hours. Hydrogen is a promising solution to this problem because it can be created from electricity with electrolyzers and converted back to electricity via fuel cells, internal combustion engines, and turbines. Electricity can be stored as hydrogen indefinitely, and Ontario has enormous gas storage potential in the Dawn Hub, which may be used for hydrogen pending further analysis to determine geological compatibility. A hydrogen system could be used to address daily, weekly, monthly, and seasonal variation in electricity and gas demand instead of overbuilding electricity generation, transmission, and storage capacity.

~~9.~~7. **A dedicated hydrogen pipeline network will be required.**
This analysis shows that by 2050 between 59 and ~~73~~74% of gas demand will be hydrogen. To supply hydrogen to end users from production sites across Ontario and from neighbouring regions, T&D infrastructure will be repurposed for hydrogen. Planning to develop this network and repurpose the existing natural gas network needs to begin now to ensure Ontario is ready to transition.

Our analysis indicates that by 2030, hydrogen demand—primarily from industry and heavy transport—will be met exclusively via blue hydrogen because green/renewable hydrogen costs will remain high in the near term. By 2040, blue hydrogen imports from Western Canada are expected to materialize~~.~~ in the Diversified scenario. As hydrogen demand scales across all demand sectors, regional hydrogen networks will develop to connect green hydrogen supply points to end users across the province. This will require some pipeline capacity from the TC Canadian Mainline to be repurposed for hydrogen. By 2050, a full hydrogen transmission backbone will develop across Ontario. Green hydrogen supply potential from Quebec may also lead to imports into Ontario~~.~~, which is reflected in modeling results of the Diversified scenario showing most of hydrogen imports being from Quebec.

As peak electric demand grows, energy system reliability and resilience will be key considerations.
Significant growth in energy production from intermittent renewable resources, such as wind and solar, requires energy storage and dispatchable electricity generation capabilities to ensure that energy system reliability can be maintained. An American Gas Foundation study published in January 2021 demonstrates that "Utilities, system operators, regulators, and policymakers need to recognize that resilience will be achieved through a diverse set of integrated assets … policies need to focus on optimizing the characteristics of both the gas and electric systems." [106] The IESO examined the possibility of phasing-out natural gas generation by 2030 and concluded that, "Diversity in energy supply strengthens the reliability and resilience of Ontario's power system, as different types serve different functions in order to meet needs…. Maintaining a diverse supply mix, where the different forms of supply complement each other, is an effective way to balance supply and demand to maintain the reliability of Ontario's power system."[107]

6.1 Recommended Actions by Stakeholders

To achieve net zero emissions by 2050, actions are required by all Ontario stakeholders. Policymakers, regulators, and utilities must consider the outlook to 2050 when evaluating different GHG emissions reduction pathways because some options that achieve 2030 goals may not enable cost-effectively achieving net zero emissions by 2050.

Table 5. Recommended Actions to Scale Electricity Supply and Infrastructure

Electricity	
Ministry of Energy	• **Investigate streamlined and predictable permitting and approval process.** Large-scale generation and transmission projects often face

[106] American Gas Foundation (2021). "Building a Resilient Energy Future: How the Gas System Contributes to US Energy System Resilience" Available at: https://gasfoundation.org/2021/01/13/building-a-resilient-energy-future/

[107] IESO (2021). Decarbonization and Ontario's Electricity System: Assessing the impacts of phasing out natural gas generation by 2030. p.7. Available: https://www.ieso.ca/en/Learn/Ontario-Supply-Mix/Natural-Gas-Phase-Out-Study

Electricity	
	years of delay during the permitting process. The Ministry should investigate ways to streamline the permitting and approval process for generation and transmission infrastructure and make the process more predictable. • **Develop a provincial wind development strategy.** Wind capacity is projected to increase ~~roughly~~by more than 10-fold by 2050 and will be critical in meeting electricity and hydrogen demand. The Ministry should develop a provincial wind strategy to ensure coordination at all levels of government to provide clear direction to plan transmission needs, identify bottlenecks, and develop a grid connection strategy. • **Develop an electricity system pathway to a net-zero Ontario.** The Ministry should develop an electricity system pathway that supports the reduction of GHG emissions of Ontario's economy by 2050. This recommendation covers a larger scope than the Ministry's October 2021 directive,[108] which only covers GHG emissions reduction for the electricity system, not the entire economy.
Ontario Energy Board (OEB)	• **Develop integrated electricity and gas system planning.** Electricity system planning must take a holistic view of the evolving energy system and be closely aligned with gas system planning. The OEB should lead the development of an integrated energy planning working group involving major electricity and gas utilities. • **Develop regulatory structures that value energy system resilience.** The increased reliance on intermittent renewable sources establishes the need for a new consideration of the resilience of the energy system. Policies that foster complementary operations of electric and pipeline systems for resilience will reduce risks to local economies and communities.
Gas and Electric Utilities and System Operators	• **Develop a GHG emissions reduction pathway for the electricity and gas systems** to achieve Ontario's economy-wide net zero target by 2050 while controlling costs and maximizing GHG reductions. Utilities should support the Ministry with capacity expansion planning that supports the reduction of GHG emissions of Ontario's economy by 2050.

[108] Ministry of Energy (October 2021). Available: https://www.ieso.ca/-/media/Files/IESO/Document-Library/corporate/ministerial-directives/Letter-from-Minister-Gas-Phase-Out-Impact-Assessment.ashx

Table 6. Recommended Actions to Scale Hydrogen Supply and Infrastructure

Hydrogen	
Ministry of Energy	• **Establish hydrogen supply planning targets.** The Ministry should define medium-term (2030) and long-term (2045) planning targets for hydrogen supply[109] much like the strategic ambitions set by other countries such as the UK (5 GW), France (6.5 GW), and Spain (4 GW) and by the European Commission (40 GW). • **Support GHG emissions reductions of end users.** The Ministry should investigate market measures and incentives that support hydrogen adoption such as low carbon fuel incentives, carbon pricing, targets for FCEV and hydrogen-fueled appliance deployment, and renewable gas mandates. • **Expand the regulatory oversight of the Ontario Energy Board (OEB) to include hydrogen**, hydrogen-derivatives and the associated supply, transport, and storage infrastructure. • **Enable carbon capture and storage** for blue hydrogen production.
Ontario Energy Board	• **Develop regulatory framework for hydrogen and infrastructure.** Without clarity on how hydrogen supply and infrastructure investments will be regulated, utilities and end users can only rely on the existing natural gas framework as an example. The OEB should gather stakeholder views and investigate how other jurisdictions are approaching the development of a hydrogen regulatory framework. • **Allow utilities to recover the cost of hydrogen at a different cost than natural gas** and in line with the market price of hydrogen.
Gas and Electric Utilities and System Operators	• **Assess future hydrogen network needs.** Enbridge Gas should conduct pilots to assess the hydrogen-readiness of the existing gas system and to determine the next steps required to realize a hydrogen network. This is underway—Enbridge Gas is in the process of planning a hydrogen-readiness assessment and is piloting a hydrogen blending initiative that is serving customers in the city of Markham. • **Develop hydrogen infrastructure plan.** Enbridge Gas should plan how and when natural gas infrastructure can be repurposed for hydrogen and where new infrastructure will be required. This is akin to National Grid's Project Union in the UK, Gasunie's HyWay 27 in the Netherlands, and SoCal Gas's Angeles Link Project.[110,111,112] • **Perform electricity transmission impact assessment.** The IESO and HydroOne should perform a transmission grid impact assessment to identify future network impacts of green hydrogen production on transmission capacity requirements and regional energy flows.

[109] A planning target is not intended to be legally binding; rather, it is a strategic objective that can provide clarity for electricity and gas system planning and regulatory planning.

[110] National Grid (2021). Making plans for a hydrogen 'backbone' across Britain. Available: ~~https://www.nationalgrid.com/stories/journey-to-net-zero-stories/making-plans-hydrogen-backbone-across-britain~~https://www.nationalgrid.com/national-grid-explores-plans-uk-hydrogen-backbone

[111] Gasunie (2021). HyWay 27. Available: https://www.gasunie.nl/en/expertise/hydrogen/hyway-27

[112] SoCal Gas (2022). Application of Southern California Gas Company (U904g) for Authority to Establish a Memorandum Account for the Angeles Link Project. Available: https://www.socalgas.com/sites/default/files/A22-02-SOCALGAS-Angeles_Link_Memorandum_Account_Application.pdf

Table 7. Recommended Actions to Scale RNG Supply and Infrastructure

RNG	
Ministry of Energy	• **Establish an RNG production binding target**. The Ministry should define binding medium-term (2030) and long-term (2045) RNG production targets. Adopting binding RNG targets will provide a clear long-term planning horizon and investment certainty for RNG market players, investors, and for regulatory planning. • **Strengthen market support for RNG**. The Ministry should investigate supply and demand market measures that can bolster RNG adoption in Ontario (e.g., guarantees of origin, RNG registers and certificates, low carbon fuel incentives, waste reduction policies), and renewable gas mandates.
Ontario Energy Board	• **Work with the Ministry of the Environment** to ensure existing and future environmental regulations are supportive of RNG production. • **Allow utilities to recover the cost of RNG at a different cost** than natural gas and in line with the market price of RNG.
Gas and Electric Utilities and System Operators	• **Develop tariffs specific to RNG.** Having separate rates for RNG and conventional natural gas may incentivize project development by RNG suppliers, as utilities would be able to recover the higher cost associated with RNG

Table 8. Recommended Actions to Advance Carbon Capture and Storage

CCS	
Ministry of Northern Development, Mines, Natural Resources and Forestry	• **Amend prohibitions on the injection of carbon dioxide for storage**. The *Oil, Gas and Salt Resources Act* prohibits the injection of CO_2 associated with different regulated activities, and the *Mining Act* prohibits the permanent storage of any substance under storage leases covered by the Act. These prohibitions should be narrowed to allow potential carbon storage for the purpose of GHG emission abatement. • **Develop a streamlined permitting regime for approving CCS projects.** The Ministry should develop a permitting process that encourages commercial-scale CCS projects.
Ontario Energy Board	• **Develop regulatory structures that facilitate the adoption of CCS from fuel-fired electric generation.**
Gas and Electric Utilities and System Operators	• **Develop pilot CCS projects** to demonstrate the feasibility of CO_2 collection, transport, and sequestration.

List of Acronyms

This section defines key terms and acronyms used throughout this report.

APO	Annual Planning Outlook, a report from IESO
ASHP	Air-source heat pump
ATR	Auto-thermal reforming
bcm	Billion cubic metres, a unit of volume
BEV	Battery electric vehicles
Bio-CNG	Biologically derived compressed natural gas
BioSNG	Bio-syngas
CAD	Canadian dollar
CAPEX	Capital expenditures
CCS	Carbon capture and storage
CGA	Canadian Gas Association
CH4	Methane
CNG	Compressed natural gas
CO_2	Carbon dioxide, a greenhouse gas
CONE	Cost of new entry
CRNG	Compressed renewable natural gas
DSM	Demand side management
ETSA	Energy transition scenario analysis, conducted by Enbridge Gas
EU	European Union
EV	Electric vehicle
FCEV	Fuel cell electric vehicle
FOM	Fixed operating and maintenance costs
GHG	Greenhouse gas
GJ	Gigajoule, a unit of energy
GSHP	Ground-source heat pump
GT	Gas turbine
GW	Gigawatts, a unit of power
H2	Hydrogen
HDRI	Hydrogen-based direct reduction of iron ore
IEA	International Energy Agency
IESO	Independent Electricity System Operator
km	Kilometre, a unit of distance
kW	Kilowatt, a unit of power
LCP	Low Carbon Pathways model
LNG	Liquified natural gas
m^3	Cubic metres, a measurement of volume
Mt	Megatonnes

$MTCO_2$	Megatonnes of carbon dioxide
MW	Megawatt, a unit of power
MWh	Megawatt-hour, a unit of energy
NRCan	Natural Resources Canada
OEB	Ontario Energy Board
OPEX	Operating expenses
PJ	Petajoules, a unit of energy
PJM	A regional transmission organization in the United States
PV	Photovoltaic
RNG	Renewable natural gas
SMR	Steam methane reforming
T&D	Transmission and distribution
tCO_2e	Tonnes of carbon dioxide equivalent
TJ	Terajoules, a unit of energy
TWh	Terawatt-hour, a unit of energy
US	United States
VOM	Variable operation and maintenance costs

Appendix A. Model Inputs and Assumptions

A.1 General Economic Parameters

Natural Gas Price Forecast

The forecasts of natural gas prices from 2020 to 2050 are based on 2019 prices from Enbridge Gas escalated until 2038 based on the Dawn Hub consensus forecast. ~~The Diversified scenario is expected to follow this reference case. The Electrification scenario is taken as 50% lower than the reference case due to decreased demand.~~ This analysis extrapolates the 2020-2038 trends out to 2040 and 2050~~.~~ by escalating gas prices annually at inflation (2%).

~~The Diversified scenario is extrapolated by escalating gas prices annually at inflation (2%), whereas the Electrification scenario is taken as 50% of the Diversified gas price forecast.~~

Table A-1. Natural Gas (cents/m^3) (nominal CAD$)

Year	~~Diversified~~Natural Gas Price	~~Electrification~~
2020	8.55	~~8.55~~
2030	13.51	~~6.76~~
2040	16.54	~~8.27~~
2050	20.17	~~10.08~~

Carbon Price Forecast

The forecasts of carbon prices from 2020 to 2050 are based on a forecast done in a previous Enbridge Gas analysis that forecasted the carbon prices to 2038 using the Greenhouse Gas Pollution Pricing Act[113] scheduled to 2022 and the recently announced update to the Pan-Canadian approach to carbon pollution pricing from 2023 through 2030.[114] For the Diversified scenario, the carbon price increases with inflation after 2030. For the Electrification scenario, the Parliamentary Budget Officer estimates[115] required to meet Canada's 2030 climate targets are used. The prices were adjusted for the calendar year, from the ECCC calendar year. Carbon prices from 2038 to 2050 are extrapolated by escalating prices annually at inflation (2%). This is done for both scenarios. Below the prices are presented for both scenarios in nominal 2020 dollars.

Table A-2. Carbon Price Forecast (nominal CAD$/tCO2e)

Year	Diversified	Electrification
2020	$28	$28
2030	$166	$282
2040	$206	$351
2050	$251	$427

Discount Rate

The analysis assumes a 4% real discount rate consistent with the OEB's guidance to gas and electric utilities on the evaluation of demand-side management programs, as per the Conservation First Framework.[116]

[113] Government of Canada (2022). Greenhouse Gas Pollution Pricing Act. Available: https://laws-lois.justice.gc.ca/eng/acts/G-11.55/

[114] Government of Canada (2021). Update to the Pan-Canadian Approach to Carbon Pollution Pricing 2023-2030. 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

[115] Parliamentary Budget Office (2021). Carbon Pricing for the Paris Target: Closing the Gap with Output-Based Pricing. Available: https://www.pbo-dpb.gc.ca/web/default/files/Documents/Reports/RP-2021-019-S/RP-2021-019-S_en.pdf

[116] Ontario Energy Board (2014). Filing Guidelines to the Demand Side Management Framework for Natural Gas Distributors (2015-2020). https://www.oeb.ca/oeb/_Documents/EB-2014-0134/Filing_Guidelines_to_the_DSM_Framework_20141222.pdf

A.2 Electricity and Gas Supply Inputs

Existing Electricity Supply Capacity

Existing electricity supply capacity for all six regions was obtained primarily from public independent system operator (ISO~~) or~~), utility reports, or Guidehouse internal forecasts. Installed capacities for Ontario (ON), Manitoba (MB), Quebec (QC) and New York (NY) are modelled for the entire electricity interconnection regions, while for the Midcontinent Independent System Operator (MISO) and the Pennsylvania, New Jersey, Maryland Interconnection (PJM), only the sub-regions contiguous to ON are modelled. For simplicity, only Ontario electricity supply capacities are reported in Table A-3.

Table A-3. 2020/2021 Installed Electricity Generation Capacity in Ontario (GW)[117]

Resource	Capacity (GW)
Wind	5.5
Solar PV	~~2.7~~0.5
Hydroelectric	9.~~4~~3
Nuclear	~~11.3~~13.1
Gas/oil	10.~~7~~8
Bioenergy	0.~~4~~6
Battery Storage	0
Total	**~~41~~40**

Planned New Electricity Supply Capacity

Planned new electricity supply capacity was obtained for all six regions from a variety of sources, including public ISO or utility reports (where available), press releases, and S&P Capital IQ. Installed capacities for ON, MB, QC and NY are incorporated in the model for the entire electricity interconnection regions, while for MISO and PJM, only the sub-regions contiguous to ON are modelled.

For ON, our modelling incorporates the option to build additional capacity in addition to planned capacities to determine the cost-optimal installed supply capacity mix in each modelled year. The planned capacities for ON are obtained from the IESO 2020 APO~~.[115] All electricity capacities are forecast to remain the same in the IESO 2020 APO, except for nuclear power; reactors at the Bruce and Darlington Nuclear Generation Stations are expected to be refurbished in the next 10-12 years.~~ as well as Guidehouse internal forecasts.[118] For non-ON regions, the model will not optimize the installed electricity supply capacity above and beyond planned investments.

Planned Electricity Supply Retirements

Planned supply capacity retirements are also incorporated into Guidehouse's analysis. This incorporates Ontario's planned decommissioning schedule ~~at Pickering.~~ for various nuclear power stations in the province. The IESO 2020 APO shows that the nuclear reactors at the Bruce, Darlington, and Pickering Nuclear Generation Stations are expected to be refurbished in the next 10-12 years. In addition, it is assumed that existing gas turbines will be linearly phased out from 2030 to 2050, and planned new gas turbines in 2030 will be decommissioned by 2050. This leads to no natural gas-fired gas turbines in the electricity supply mix by 2050. The only gas-fired turbines in 2050 are hydrogen-powered turbines.

Renewable Energy Capacity Factors

Solar and wind generation resources in ON and each neighbouring region are characterized with different capacity factors. Capacity factors for Canadian provinces are available from the NRCan

[117] ~~IESO (2020). Annual Planning Outlook. https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook~~ IESO (2020). Transmission-Connected Generation. https://www.ieso.ca/en/Power-Data/Supply-Overview/Transmission-Connected-Generation

[118] IESO (2020). Annual Planning Outlook. https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook

database (2020).[119] We use wind and solar capacity factors specific to ON and QC, whereas Western Canada (WC) is characterized as an average of capacity factors for MB, SK, and AB. Solar and wind capacity factors for MB, SK and AB only vary slightly.

For US regions, we use wind capacity factors from Berkeley Lab.[120] Because wind capacity factors are available for each US state, we use state-level capacity factors for the New York Independent System Operator (NYISO), MISO (using an average of Michigan and Wisconsin), and PJM (using Ohio). Solar capacity factors were obtained from the Berkeley Lab.[121] These capacity factors were available for individual electricity market regions. As a result, no state-level aggregation of capacity factors was required. We used capacity factors defined for NYISO, MISO and PJM.

The wind and solar capacity factors obtained from the sources above are based on the performance of the existing wind and solar fleets in each region~~.~~ To reflect improvements in technologies and increased capacity factors, we assumed a fleet-wide 0.~~5~~75%/year annual improvement factor across all regions. The resulting capacity factors are presented in Table A-4.

Table A-4. Renewable Capacity Factors (%)

Region	Wind	Solar
ON	~~44~~47%	~~15~~16%
QC	~~31~~33%	~~15~~16%
WC	~~44~~46%	~~16~~17%
NY	~~41~~44%	~~21~~22%
PJM	~~37~~39%	~~22~~23%
MI	~~44~~47%	~~22~~23%

Green Hydrogen Supply Costs

Green hydrogen production costs are determined assuming that hydrogen is produced from renewable sources: solar PV, wind, and hydro. The wind and solar capacity factors shown previously produce hydrogen supply costs specific to each region. In general, hydrogen produced from wind and hydro (if hydro is available, e.g., QC and WC) are the most price-competitive hydrogen supply resources. We assume hydrogen supply costs in each region are defined by the most price-competitive resource. For example, in QC and WC, hydrogen supply costs are based on hydroelectric power, whereas in NY, PJM, and MI, hydrogen supply costs are based on wind power.

The calculation of hydrogen supply costs for neighbouring regions is performed to identify potential supply routes for hydrogen imports into ON. Based on the hydrogen costs calculated, hydrogen supply from QC and WC are the most competitive. As a result, our analysis gives ON the option to meet hydrogen demand with imports from QC and WC. The costs of hydrogen production from NY, PJM, and MI are less attractive and are not modelled as supply routes for ON.

Our analysis assumes the costs of hydrogen imports from QC and WC to be static. This means hydrogen import costs do not change hour-to-hour. In comparison, the cost of hydrogen production in ON is not static, but rather changes hour-to-hour based on several factors, including hour-to-hour changes in hydrogen demand, the electricity supply mix, periods of surplus electricity generation, among other factors. The impacts of all these factors are modelled endogenously via our energy systems model.

To allow for a simple comparison of hydrogen supply costs between ON and neighbouring regions, Table A-5 shows static hydrogen costs in all regions. While hydrogen imports appear more cost-effective than domestic hydrogen production in ON, imports may be not available until, or if, gas interconnections are not repurposed to hydrogen.

[119] Government of Canada (2020). Renewables. https://www.nrcan.gc.ca/our-natural-resources/energy-sources-distribution/renewable-energy/7293
[120] Berkeley Lab (2021). Lab-based Wind Market Report. https://emp.lbl.gov/wind-technologies-market-report/
[121] Berkeley Lab (2021). Utility-scale Solar. https://emp.lbl.gov/utility-scale-solar/

Table A-5. Green Hydrogen Costs (CAD$/kg)[122]

Region	2030	2040	2050
ON	2.5	1.8	1.6
QC	2.0	1.6	1.5
WC	2.3	1.7	1.6
NY	2.7	1.9	1.7
PJM	3.0	2.2	1.9
MI	2.5	1.8	1.6

Blue Hydrogen Supply Costs

Table A-6~~The costs of blue hydrogen imports are presented for the Diversified and Electrification scenarios. Blue hydrogen costs vary by scenario because each scenario uses different forecasts of natural gas and carbon prices, as presented previously.~~

~~The costs of blue hydrogen are estimated based on~~ below shows the techno-economic parameters ~~presented in Table A-6 and based on~~ and the cost of SMR+CCS capacity ~~given in Table A-7.~~.

Table A-~~6. Blue Hydrogen Costs (CAD$/kg)~~-6

6	~~Diversified~~	~~Electrification~~
~~**2030**~~	~~2.4~~	~~2.0~~
~~**2040**~~	~~2.6~~	~~2.2~~
~~**2050**~~	~~2.9~~	~~2.4~~

~~Table A-7.~~. Techno-Economic Parameters of Blue Hydrogen

	Value
CAPEX (CAD/MW)	~~650~~3,150,000
Efficiency (%)	69%
Capture Rate (%)	95%
CO_2 Transport & Storage Costs (CAD/tCO_2)	30
Utilization Factor (%)	90%
Lifetime (years)	~~20~~25
Discount Rate (%)	5%

Hydrogen Import Costs

The costs of hydrogen imports are presented in Table A-7. Hydrogen imports from Quebec are assumed to be 100% green hydrogen. Hydrogen imports from western Canada are assumed to be 50% green hydrogen in 2030 through 2040 and 75% green hydrogen in 2050. The remaining 50% and 25%, respectively, is assumed to be blue hydrogen. The source of hydrogen import costs is the European Hydrogen Backbone.[123]

Table A-76. Hydrogen Import Costs (CAD$/kg)

	Imports from Quebec	Imports from Western Canada

[122] A discount rate of 5% is used for levelized cost of hydrogen (LCOH) calculations. Capacity factors used to calculate the green hydrogen costs are different in 2030, 2040, and 2050 based on 0.~~5~~75%/year improvement – described in the "Renewable Energy Capacity Factors" section of Appendix A.2.

[123] European Hydrogen Backbone (2020). Extending the European Hydrogen Backbone. https://gasforclimate2050.eu/wp-content/uploads/2021/06/European-Hydrogen-Backbone_April-2021_V3.pdf

2030	2.0	2.4
2040	1.6	2.1
2050	1.5	1.8

RNG Supply Potential

RNG potential in ON is in the range of 1.2 to 6.4 bcm per year depending on whether agricultural residues are included. Previous work conducted by Enbridge Gas forecasted RNG demand by 2038 in two different scenarios: 2.7 bcm in the Diversified scenario and 1.3 bcm in the Electrification scenario. In both scenarios, RNG demand is greater than the non-crop RNG potential of 1.2 bcm per year. This suggests RNG demand in 2038-2050 will exceed non-crop feedstock and will require some share of crop feedstock. Crop feedstock would not only reflect purpose-grown crops (e.g., dedicated for RNG supply) but also a notable contribution from crop wastes.

Table A-8 and Table A-9 show RNG demand in each of the Enbridge Gas scenarios and maximum RNG supply potential (with and without crop feedstock).

Table A-7. RNG Demand by Enbridge Gas Scenario (bcm/year)[124]

Unit	bcm		PJ	
Year	**2030**	**2038**	**2030**	**2038**
Diversified	1.~~2~~3	~~2.7~~3.0	~~44~~46	~~96~~105
Electrification	0~~.03~~	1.3	0~~.9~~	46

Table A-8. RNG Supply Potential (bcm/year and PJ)[125]

	bcm	PJ
Supply (excl. crops)	1.2	41
Supply (incl. crops)	6.4	224

The costs of RNG crop feedstock shown in Table A-10 are estimated based on the techno-economic parameters presented.

Table A-9. RNG Crop Feedstock Cost

	2020	2030	2040	2050
Cost of crop feedstock for RNG in (real 2020$/~~MW~~MWh)	42	39	38	36

Costs of Electricity and Gas Supply Technologies

The economic parameters for each supply technology are characterized as shown in Table A-11. The cost parameters are broken down into fixed operating and maintenance costs (FOM), variable operation and maintenance costs (VOM), and cost of new entry (CONE). CONE figures are analogous to CAPEX costs. In addition, the efficiency of electrolyzers is included in the table and is forecasted to increase from 2030 to 2050. The FOM and CONE for natural gas fired turbines, solar, and wind, as well as the VOM for gas turbines are based ENTSO-E's TYNDP 2020 report.[126] Hydrogen fired gas turbines are assumed to cost 15% more than natural gas fired turbines.[127] The

[124] Enbridge Gas scenarios.

[125] Torchlight Bioresources (2020). Renewable Natural Gas (Biomethane) Feedstock Potential in Canada. Figure 19. Available: https://www.enbridge.com/~/media/Enb/Documents/Media%20Center/RNG-Canadian-Feedstock-Potential-2020%20(1).pdf?la=en

[126] ENTSO-E (2020), TYNPD 2020. https://www.entsos-tyndp2020-scenarios.eu/wp-content/uploads/2020/07/TYNDP_2020_Scenario_Building-Guidelines_03_Annex_2_Cost_Assumptions_final_report.pdf

[127] Oberg et al. 2022. Available: https://doi.org/10.1016/j.ijhydene.2021.10.035

cost assumptions are based on IEA (2019)[128] for batteries, Guidehouse (2019)[129] for anerobic digestion, biomass ~~gasification~~ and biomass + CCS, and Guidehouse (2021)[130] for SMR + CCS and electrolyzers. Guidehouse (2021)~~[125]~~ [130] reports the price of hydrogen storage to cost between 5 and 20 €/MWh H_2 (~7 and 29 CAD$/MWh H_2). Based on this range of costs, for this analysis, a levelized cost of 11 CAD$/MWh H_2 is assumed for hydrogen storage. As it is a levelized cost, it is defined as the VOM in the model.

The ~~costs~~cost of nuclear ~~and hydro are~~is the Ontario Power Generation's prescribed generation payment amounts for 2021.[131] Since these are levelized costs, they are defined as VOM. The CONE cost of small modular nuclear reactors (nuclear SMR) is from the CER's Canada's Energy Future 2021 report.[132] The FOM is assumed to be 2.5% of the CAPEX, or CONE. The VOM is the cost of uranium.[133] The costs for hydro were sourced from a report commissioned by the Ontario Water Association.[134]

The cost of combined cycle gas turbines assumed in our analysis is comparable to recent Ontario projects. For example, Ontario Power Generation recently acquired 3 combined cycle gas turbines with a combined 2.15 GW for CAD$2.8 billion, roughly equivalent to $1.3 million/MW.[135] This deal includes the Halton Hills combined cycle gas turbines, with capacity of 683 MW, for CAD$700 million, roughly equivalent to $1.0 million/MW.[136] ~~Our analysis assumes the CONE (CAPEX) of H_2 and CH_4 is equivalent by 2030.[137]~~

Table A-10. Supply Techno-Economic Parameters

Supply Technology	Cost Type	Unit	2030	2040	2050
Wind Onshore	FOM	CAD$/MW-year	25,000	25,000	25,000
	VOM	CAD$/MWh	- 0	- 0	- 0
	CONE	CAD$/MW	1,~~300,000~~412,875	1,~~100,000~~212,875	1,~~000,000~~112,875
Wind Offshore	FOM	CAD$/MW-year	~~39~~40,000	30,000	30,000
	VOM	CAD$/MWh	- 0	- 0	- 0
	CONE	CAD$/MW	2,~~560,000~~662,875	2,~~020,000~~112,875	~~1,980,000~~2,112,875
Solar PV	FOM	CAD$/MW-year	22,000	18,000	18,000
	VOM	CAD$/MWh	- 0	- 0	- 0

[128] IEA (2019). Capital cost of utility-scale battery storage systems in the New Policies Scenario, 2017-2040. https://www.iea.org/data-and-statistics/charts/capital-cost-of-utility-scale-battery-storage-systems-in-the-new-policies-scenario-2017-2040

[129] Guidehouse (2019). Pathways to Net-Zero: Decarbonizing the Gas Networks in Great Britain. https://www.energynetworks.org/assets/images/Resource%20library/ENA%20Gas%20decarbonisation%20Pathways%202050%20FINAL.pdf

[130] Guidehouse (2021). Analysing future demand, supply, and transport of hydrogen. Available: https://gasforclimate2050.eu/wp-content/uploads/2021/06/EHB_Analysing-the-future-demand-supply-and-transport-of-hydrogen_June-2021_v3.pdf

[131] Ontario Energy Board (2021). Regulated Price Plan: Price Report. Available: https://www.oeb.ca/sites/default/files/rpp-price-report-20210422.pdf

[132] CER (2021). Canada's Energy Future 2021. Available: https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2021/canada-energy-futures-2021.pdf

[133] Canadian Energy Research Institute (2004). Levelised Unit Electricity Cost Comparison of Alternate Technologies for Baseload Generation in Ontario. Available: https://inis.iaea.org/collection/NCLCollectionStore/_Public/43/123/43123919.pdf

[134] Hatch (2013), commissioned by the Ontario Water Association. Northern Hydro Assessment Waterpower Potential in the Far North of Ontario. Available: https://www.owa.ca/wp-content/uploads/2017/01/NorthernHydroFinal-Executive-Summary.pdf

[135] EnerData (2020). OPG's Atura Power acquires 3 CCGT power plants for US$2bn. Available: https://www.enerdata.net/publications/daily-energy-news/opgs-atura-power-acquires-3-ccgt-power-plants-us2bn.html

[136] Power Technology (2020). Halton Hills Combined Cycle Plant. Available: https://www.power-technology.com/projects/halton-hills-combined-cycle-plant/

~~[137] Hydrogen Council (2020). Path to Hydrogen Competitiveness: A Cost Perspective. Available: https://hydrogencouncil.com/wp-content/uploads/2020/01/Path-to-Hydrogen-Competitiveness_Full-Study-1.pdf~~

Supply Technology	Cost Type	Unit	2030	2040	2050
	CONE	CAD$/MW	~~950,000~~1,062,875	~~700,000~~812,875	~~600,000~~712,875
Nuclear	VOM	CAD$/MWh	96	96	96
Nuclear SMR	FOM	CAD$/MW-year	175,000	150,000	125,000
	VOM	CAD$/MWh	~~46~~7	~~46~~7	~~46~~7
	CONE	CAD$/MW	7,000,000	6,000,000	5,000,000
Hydro	FOM	CAD$/MW-year	60,306	60,306	60,306
	CONE	CAD$/MWh	6,892,114	6,892,114	6,892,114
	FOM	CAD$/MW-year	20,000	20,000	20,000
~~Open Cycle~~ Gas Turbine – CH4/H2	VOM	CAD$/MWh	~~1~~2.4	~~1.~~2.4	~~1.1~~2.4
	CONE	CAD$/MW	660,000	660,000	660,000
	FOM	CAD$/MW-year	~~22~~23,000	~~22~~23,000	~~22~~23,000
~~Combined Cycle~~ Gas Turbine – ~~CH4/~~H2	VOM	CAD$/MWh	~~1.4~~3	~~1.2~~ 3	~~1.1~~ 3
	CONE	CAD$/MW	~~1,160~~759,000	~~1,130~~759,000	~~1,130~~759,000
	FOM	CAD$/MW-year	30,000	28,000	24,000
Battery Storage	VOM	CAD$/MWh	-	-	-
	CONE	CAD$/MW	1,200,000	1,100,000	950,000
	FOM	CAD$/MW-year	~~14~~20,000	~~10~~14,000	8,000
Electrolyzer	VOM	CAD$/MWh	~~-~~ 0	~~-~~ 0	~~-~~ 0
	CONE	CAD$/MW	~~410~~570,000	~~300~~390,000	~~200~~240,000
	Efficiency	%	71%	76%	80%
	FOM	CAD$/MW-year	~~15,000~~ 94,500	~~15,000~~ 94,500	~~15,000~~ 94,500
SMR + CCS	VOM	CAD$/MWh	~~-~~6	~~-~~ 6	~~-~~ 6
	CONE	CAD$/MW	~~650~~3,150,000	~~650~~3,150,000	~~650~~3,150,000
	FOM	CAD$/MW-year	287,300	287,300	287,300
Biomass + CCS	VOM	CAD$/MWh	1.4	1.4	1.4
	CONE	CAD$/MW	5,780,000	5,780,000	5,780,000
	FOM	CAD$/MW-year	89,640	89,640	89,640
Anaerobic Digestion	VOM	CAD$/MWh	~~-~~ 70	~~-~~ 69	~~-~~ 67
	CONE	CAD$/MW	446,820	446,820	446,820
	FOM	CAD$/MW-year	~~370,000~~19,338	~~315,000~~19,338	~~230,000~~19,338
Biomass ~~Gasification~~	VOM	CAD$/MWh	~~-~~ 2	~~-~~ 2	~~-~~ 2
	CONE	CAD$/MW	~~3,540,000~~654,500	~~2,820,000~~654,500	~~2,100,000~~654,500
Hydrogen Storage	VOM	CAD$/MW	11	11	11

Lifetime of Electricity and Gas Supply Technologies

The assumed lifetime of each supply technology is presented in the table below.

Table A-11. Assumed Lifetimes of Electricity and Gas Supply Technologies

Supply Technology	Assumed Lifetime
Wind Onshore	25
Wind Offshore	25
Solar PV	25
Nuclear	50
Nuclear SMR	50
Hydro	50
Hydro Pumped Storage	50
~~Open Cycle~~ Gas Turbine – CH4/H2	25
~~Combined Cycle Gas Turbine – CH4/H2~~	~~25~~
Battery Storage	15
Electrolyzer	25
SMR + CCS	25
Biomass + CCS	25
Anaerobic Digestion	25
Biomass ~~Gasification~~	25
Hydrogen Storage	50

Existing Electricity and Gas Interconnections

The capacity of existing electricity and gas interconnections across regions is characterized as per Table A-13. No existing hydrogen interconnections exist; however, the analysis allows for existing gas interconnections to be repurposed to hydrogen, as well as new hydrogen interconnections to be built. The existing electricity capacities are based on the IESO Fall 2021 Reliability Report, and the gas interconnection capacities values are based on the Canadian Energy Regulator (2021).[138,139,140]

Table A-12. Existing Electricity and Gas Interconnections between ON and Neighboring Regions

	Region 1	Region 2	Import Capacity	Export Capacity	Notes
Electricity	ON	WV	300 MW	300 MW	Interconnection with Manitoba
	ON	QC	2,165 MW	2,350 MW	Combined interconnection capability via Northeast, Ottawa, and East zones
	ON	NY	2,100 MW	1,950 MW	Combined interconnection capability via St. Lawrence and Niagara
	ON	MI	1,650 MW	1,700 MW	via Michigan
	ON	PJM	-	-	No existing electricity interconnections.
Gas	ON	NY	0.65 bcf/day + 0.2 bcf/day		Via Niagara and Chippawa
	ON	QC	1.21 bcf/day		Via Iroquois
	~~ON~~	~~MI~~	~~1.30 bcf/day~~		~~Via Vector~~
	ON	WC	~~3.50~~5.30 bcf/day		Via Northern Ontario Line (NOL) and the Vector Pipeline

[138] IESO (2021) Fall 2021 Reliability Report. https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Reliability-Outlook

[139] Canadian Energy Regulator (2021). Natural Gas Pipeline Transportation System. https://www.cer-rec.gc.ca/en/data-analysis/facilities-we-regulate/canadas-pipeline-system/2021/natural-gas-pipeline-transportation-system.html

[140] Canadian Energy Regulator (2021). Pipeline Profiles: TC Canadian Mainline. https://www.cer-rec.gc.ca/en/data-analysis/facilities-we-regulate/pipeline-profiles/natural-gas/transcanadas-canadian-mainline.html

General Interconnection Parameters

Lifetime and Line Losses: The economic decision of building new interconnections is also affected by line losses and the lifetime of infrastructure. All transmission line and pipelines are assumed to have a 70-year life. ~~Electricity~~Intra-regional electricity line losses are assumed to be 6%. Inter-regional electricity line losses are estimated at 1.1% per 100-km while gas losses from inter-region pipelines (methane and hydrogen) are estimated at 0.~~7~~5% per 100-km. For gas ~~distribution~~intra-regional pipelines, line losses are estimated at 0.4%.[141]

Costs of Gas Infrastructure

Gas infrastructure costs include the cost of repurposing gas infrastructure to hydrogen (e.g., pipeline, compression costs), operation costs associated with transporting hydrogen and RNG, and integration (injection) costs. The cost of repurposing existing gas infrastructure to transport hydrogen vary by pipeline size. For inter-jurisdiction transmission pipelines to Ontario, we assume 48-inch pipelines. The gas transmission repurposing from natural gas to hydrogen and new hydrogen pipeline CAPEX values shown in Table A-14 and Table A-15 and are based on the European Hydrogen Backbone.[142] Natural gas and RNG T&D OPEX costs are low because these reflect the existing natural gas infrastructure being reused for RNG transport, while higher hydrogen costs reflect repurposing of gas infrastructure, as shown in Table A-16.

Table A-13. New Gas Transmission CAPEX (CAD $M/km)

Diameter	Pipeline CAPEX	Compression CAPEX	Total CAPEX
48-inch	4.2	0.9	5.1
36-inch	3.3	0.5	3.8
20-inch	2.3	0.1	2.4

Table A-14. Repurposed Gas Transmission CAPEX (CAD $M/km)

Diameter	Pipeline CAPEX	Compression CAPEX	Total CAPEX
48-inch	0.8	0.9	1.7
36-inch	0.6	0.2	0.8
20-inch	0.5	0.1	0.6

Table A-15. Gas T&D OPEX (CAD$)

	OPEX
Transmission	H2: $0.9/GJ-year NG/RNG: $0.4/GJ-year
Distribution	H_2: $1/GJ-year NG/RNG: $0.4/GJ-year

Integration costs capture the costs of grid pipeline connection to production sites as well as injection costs. The T&D OPEX and integration costs for hydrogen are based on the 2019 Decarbonising Gas Networks in Great Britain report.[143] The integration costs for RNG are based on values provided by Enbridge Gas from recent in-house example projects. The integration costs account for upgrading and injection.

Table A-16. RNG Integration CAPEX and OPEX (CAD$)

CAPEX	OPEX

[141] Enbridge Gas internal source

[142] European Hydrogen Backbone (2020). Extending the European Hydrogen Backbone. https://gasforclimate2050.eu/wp-content/uploads/2021/06/European-Hydrogen-Backbone_April-2021_V3.pdf

[143] Decarbonising Gas Networks in Great Britain (2019). https://www.northerngasnetworks.co.uk/wp-content/uploads/2019/11/Navigant-Pathways-to-Net-Zero-2-min.pdf

Integration (Injection)	H2: $6.74/GJ RNG: $5.23/GJ	H_2: $0.48/GJ-year NG/RNG: $3.42/GJ-year

Cost of Electricity Infrastructure

The electricity infrastructure costs used in our analysis reflect the cost of building electric transmission and distribution lines. These costs are presented in Table A-18. The electricity T&D infrastructure costs are based on CIGRE (2019) and IESO (2017), which present a blended cost including overhead lines and buried lines, with the assumption that buried lines comprise less than 5% of total.[144,145] Distribution infrastructure costs were converted from annualized units ($/kW-year) to upfront CAPEX ($/kW) and OPEX ($/kW-year) by de-annuitizing them based on an assumed cost of capital of 4.5% (consistent with inputs presented below) and a useful asset lifetime of 70 years.

Table A-17. Intra-Regional Electricity Transmission Infrastructure Investment Cost Inputs

Cost Component	Unit	New Overhead Line
CAPEX	[Million CAD$/ MW-km]	376
OPEX	% of CAPEX	1%

Table A-18. Ontario Electricity Distribution Infrastructure Investment Cost Inputs

Component	Unit	Distribution
Annualized CAPEX + OPEX	[CAD$/kW-year]	4.7
Lifetime	[year]	70
Cost of Capital	[%]	4.5%
Overnight cost of Infrastructure (CAPEX+OPEX)	[CAD$/~~kW~~MW]	~~99,700~~81,204

End-User Costs

In addition to electricity and gas system costs, this analysis also captures costs associated with end-user investments in building heating equipment and building insulation and renovation work. Because this report does not distinguish between demand side management (DSM) and activities mandated through regulation, the figures presented here are not prescriptive forecasts of DSM activities. This analysis does not include wood or biomass heating or district heating, nor the cost of existing heating system and end-of-life replacements.

End-user costs associated with the transport and industrial sector are not captured in the analysis. In other words, costs associated with GHG emissions reduction for transport (e.g., electric vehicles [EVs], electric buses or trucks, charging infrastructure, investments in ships, aircrafts) and industry (e.g., electric arc furnaces, electric kilns, hydrogen furnaces, CCS equipment) are not included.

The end-user costs include CAPEX and installation costs of gas furnaces (hydrogen/methane), gas heat pumps, hybrid heat pumps, and electric heat pumps. The costs for end-user equipment are from Enbridge Gas's 2021 answer to interrogatory from OEB.[146] This excludes the cost of electric geothermal heat pumps in existing homes, which is from The Economic Value of Ground Source Heat Pumps for Building Sector Decarbonization prepared for the HRAI by Dunsky[147]. This value was then

[144] CIGRE (2019). Available here: https://e-cigre.org/publication/775-global-electricity-network-feasibility-study

[145] IESO (2017). Local Avoided Costs – Overview. https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Toronto/engagement/Toronto-LAC-20170926-Local-Avoidable-Costs.ashx

[146] Enbridge Gas Inc. (2021). Answer to Interrogatory from Ontario Energy Board, pp.343-356. Available: https://www.rds.oeb.ca/CMWebDrawer/Record/732115/File/document

[147] Dunsky (2020). The Economic Value of Ground Source Heat Pumps for Building Sector Decarbonization. Available: https://ontariogeothermal.ca/downloads/dunsky--hrai-benefitsofgshps--2020-10-30-.pdf/

scaled for new builds using ground-source heat pump program data from the Massachusetts Clean Energy Center[148]. These values are given in Table A-20 below.

Table A-19. Building Heat Equipment Costs

Heating Equipment	Unit	Existing Homes	New Builds
Gas Heat Pump with A/C Unit	[CAD$/unit]	12,200	12,200
Cold Climate Electric Air-Source Heat Pump with Electric Resistance Backup	[CAD$/unit]	11,100	11,100
Electric Geothermal Heat Pump	[CAD$/unit]	27,500	24,655
Hybrid Heat Pump	[CAD$/unit]	11,350	11,350

Costs associated with building insulation retrofit requirements (for new and existing homes) are also included. Insulation costs vary based on the type of heating system used (e.g., different insulation needs for a home with a gas furnace vs. electric heat pumps; electric heat pumps require better building insultation). Homes with electric heat pumps are assumed to undergo deep energy efficiency retrofits.[149] All other homes are assumed to undergo moderate energy efficiency retrofits. Our analysis assumes that not all Ontario homes will be retrofitted due to technical and economic suitability, among other reasons. In total, 70% of homes are assumed to be retrofitted by 2050. The costs of moderate and deep retrofits are based on the open-source Energy Transition Model tool.[150] The Energy Transition Model tool has previously been ~~in~~ used in comparable studies in other jurisdictions.[151]

Table A-20. Building Energy Efficiency Insulation/Retrofit Costs

Retrofit Type	Home Type	2020	2030	2040	2050
Moderate Retrofit	[thousand CAD$/household]	13	12	11	10
Deep Retrofit	[thousand CAD$/household]	~~22~~31	~~20~~29	~~18~~26	~~17~~24

To calculate the total cost of heating equipment and building retrofits, a forecast of Ontario households is used. Our analysis adopts the IESO's APO household forecast.[152]

Table A-21. Number of Households in Ontario

	2020	2030	2040	2050
Households (# Millions)	5.8	6.6	7.2	8.0

[148] Massachusetts Clean Energy Center (2022). Ground-Source Heat Pump Residential Projects Database. Available: https://www.masscec.com/public-records-requests

[149] To provide adequate heating in winter conditions, electrically heated homes need to be well-insulated and weatherized to minimize heat leakage. Reduction of heat loss is important for electrically heated homes because the heating capacity of air-source heat pump systems is less than gas furnaces, especially at low outdoor temperatures. A regular-sized gas furnace usually provides 20 to 35 kW of heat output, while a whole-home heat pump may only provide 5 to 15 kW of heat output at colder outdoor temperatures

[150] Energy Transition Model (2021). Insulation. https://docs.energytransitionmodel.com/main/insulation

[151] For example, the Energy Transition Model has been used by Gasunie, TenneT, and regional grid operators to help better understand the necessary required investments to reach a Climate-neutral energy system in the Netherlands by 2050 (https://www.netbeheernederland.nl/dossiers/toekomstscenarios-64). In addition, the Energy Transition Model has been used by the UK Government Department for the Economy to develop an energy strategy for Northern Ireland (https://www.economy-ni.gov.uk/consultations/consultation-policy-options-new-energy-strategy-northern-ireland).

[152] IESO (2020). Annual Planning Outlook. https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook

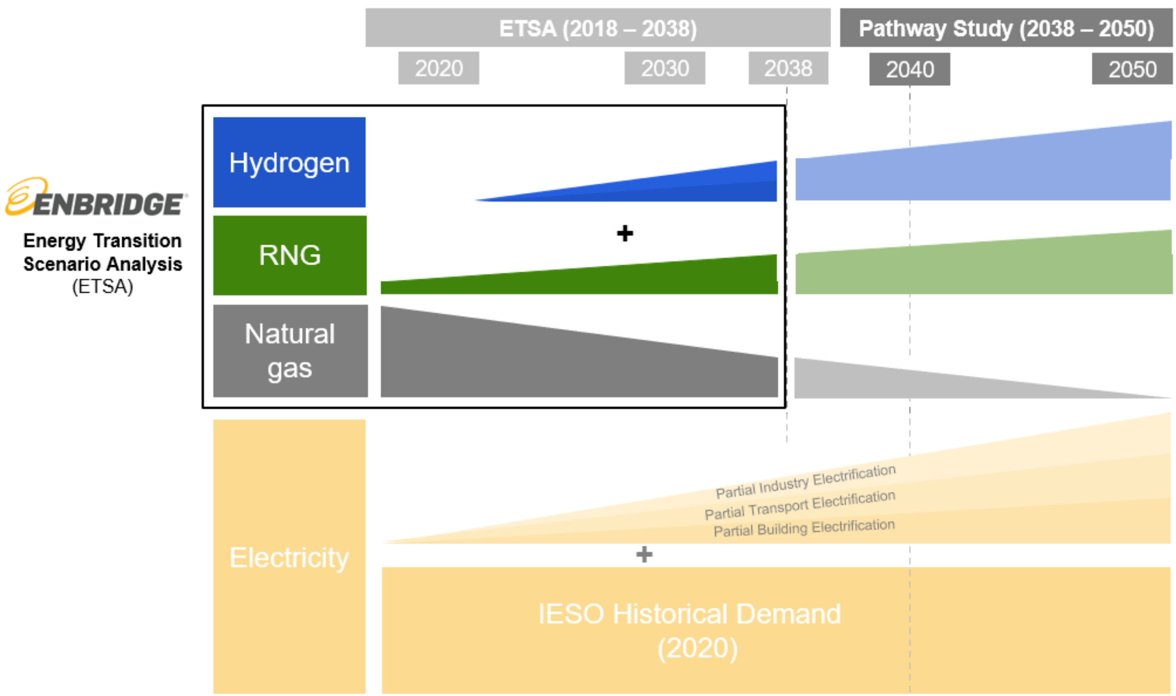
Appendix B. Development of Net Zero Scenarios

B.1 Using Previous Enbridge Gas Scenario Development as a Starting Point

This study expands on previous energy transition scenario analysis (ETSA) done by Enbridge Gas that forecasts gas demand from 2020 to 2038. More specifically, this study expands the Enbridge Gas forecasts from 2038 to 2050 and develops electricity demand scenarios that are internally aligned with the underlying assumptions of Enbridge Gas's gas forecasts. This section describes the forecasting methodology and presents the gas and electricity demand forecasts for the Diversified and Electrification scenarios. The Diversified and Electrification scenarios are intended to represent plausible, potential future visions of the Ontario energy system by 2050. They are not intended to represent the most optimal or perfect scenarios.

The Enbridge Gas scenarios establish gas demand (hydrogen, RNG, and natural gas) for 2018-2038 by forecast gas demand in the residential, commercial, and industrial sectors. In this study, these forecasts are extended out to 2050 assuming continued GHG emissions reduction in all sectors. Electricity demand is also forecasted out to 2050. The study uses IESO historical electricity demand figures as baseline demand and incorporates future electricity demand associated with the electrification of industry, transportation, and buildings in each of the Diversified and Electrification scenarios. A graphical representation of the forecasting exercise is shown in Figure B-1.

Figure B-1. Graphical Representation of the Extrapolation Used to Develop the Demand Scenarios



The examination of several demand sub-sectors were outside of the scope captured by the Enbridge Gas scenarios: namely **non-heavy road transport** (e.g., light road transport, aviation, marine transport) and **non-natural gas fossil fuel use from industry** (e.g., coal, coke). This study's Diversified and Electrification scenarios do account for these sub-sectors. Incorporating these areas in our analysis is critical because this ensures the Diversified and Electrification scenarios represent economy-wide, net zero futures by 2050.

- **Non-heavy road transport:** The Enbridge Gas scenarios focus exclusively on the adoption of CNG in heavy road transport.[153] This study expands the scope of transport to all modes of transport. This study uses a bottom-up approach to model GHG emissions reduction for light road transport, aviation, and marine transport via electrification, RNG, and hydrogen. For consistency in approach across all modes of transport, this study also applies a bottom-up approach to heavy road transport in place of the Enbridge Gas approach. Appendix B.2.2 describes the approach and assumptions used in reducing GHG emissions from transportation.
- **Non-gas fossil fuel industry demand:** The Enbridge Gas scenarios do not account for the emissions reduction of fossil fuel use by industry, other than natural gas. For example, the use of coke and coal by the steel and mining industries is not captured. This study, however, does account for emissions reductions of non-gas fossil fuels via electrification, hydrogen, RNG, and natural gas + CCS. The inclusion of non-gas fossil fuel demand in our analysis results in additional gas demand relative to the baseline gas demand. Appendix B.2.3 describes the approach used to model the GHG emissions reductions of non-gas fossil fuel use by industry.

The impact of incorporating these areas not covered by the Enbridge Gas scenarios is that the gas demand forecasts developed in this study are higher than the Enbridge Gas scenarios.

B.2 GHG Emissions Reduction Assumptions by Sector

B.2.1 Buildings

The demand forecast for reducing GHG emissions from buildings was based off the Enbridge Gas demand forecasts per sector (residential and commercial) and per end use (space heating, water heating, cooking, and washing/drying appliances). For residential buildings, the gas consumption for each end use was extrapolated out to 2050 based on a linear trendline from the last 5 years of the Enbridge Gas forecasts (2033-2038). This way, the forecasts were able to capture the change in demand more relevant to 2040 and 2050. The IESO's residential household projections, less the number of gas households each year per end use from the Enbridge Gas scenarios, yielded the annual rate of electrification in the province. For commercial buildings, the growth rate of the total commercial building stock from the IESO's 2019 Conservation Achievable Potential Study was used to determine annual new builds.[154] The total commercial gas stock and gas consumption per area of floorspace came from the Enbridge Gas scenarios and was extrapolated out to 2050 using the last 5 years of the forecast (2033-2038).

- **Space heating**: This end use predominantly relies on natural gas and accounts for most of the energy requirements in residential and commercial buildings. Although energy efficiency retrofits and new building codes are expected to reduce heating loads per building, both scenarios assume a large increase of electric energy demand in this end use due to electrification. Moving toward 2050, the adoption of electric and hybrid heat pumps through full or partial fuel-switching plays the dominant role in reducing GHG emissions from buildings. In the Diversified scenario, 55% of Ontario space heating load will still be met by gas but with hydrogen or RNG instead of natural gas, and 40% of the load will be electrified. The Electrification scenario assumes that by 2050, 85% of Ontario space heating load will be met by electricity and 10% by gas. Trends up to 2040 are based on the trajectory of Enbridge Gas's Diversified scenario. The remaining 5% of load in 2050 for both scenarios is met by other fuel sources such as wood and propane, down from 11% today.

  The Enbridge Gas scenarios do not make any explicit assumptions around the transition of building heating equipment mix (e.g., mix of furnaces, electric heat pumps); rather, it only defines the electric versus gas fuel shares. Embedded within those fuel shares is a mix of heating equipment. As a result, we have made assumptions on how those fuel shares break down into individual heating equipment in our analysis. For example, in 2050, the Diversified

[153] The Enbridge Gas scenarios determined the use of CNG in heavy road transport by assuming some fixed proportion of the energy demand forecast (developed by the CER) adopted CNG.

[154] IESO (2019). 2019 Conservation Achievable Potential Study. Available: https://www.ieso.ca/2019-conservation-achievable-potential-study

scenario assumes that 55% of households have gas heating provided by gas heat pumps, an extrapolation of the Enbridge Gas scenario. To comply with the Pan-Canadian Framework, gas-equipped buildings are assumed to shift to gas-powered heat pumps post-2035. In addition, 40% of household heating is electric heating, which is assumed to be a mix of air-source and geothermal heat pumps. In 2050, the Electrification scenario assumes that 85% of households have electric heating, an extrapolation of the Enbridge Gas scenario. The 85% is assumed to be 75% air-source heat pumps and 10% geothermal heat pumps. Geothermal heat pumps are assumed to be primarily installed in new builds to bring down costs and so they are applicable to a large share of homes. The 10% of household heating powered by RNG is entirely gas heat pumps. The share of household heating technologies are given in Table B-1 and Table B-2 for the Diversified and Electrification scenarios, respectively.

Table B-1. Share of Households per Space Heating Technology Type – Diversified Scenario

Space Heating	2020	2030	2040	2050
Gas Heat Pump	0%	6%	34%	55%
Air-Source Heat Pump	7%	13%	24%	30%
Geothermal Heat Pump	0%	4%	7%	10%
Natural Gas Furnace	82%	~~67~~68%	~~27~~28%	0%
Other	11%	10%	~~8~~7%	5%

Table B-2. Share of Households per Space Heating Technology Type – Electrification Scenario

Space Heating	2020	2030	2040	2050
Gas Heat Pump	0%	4%	6%	10%
Air-Source Heat Pump	7%	14%	52%	75%
Geothermal Heat Pump	0%	4%	7%	10%
Natural Gas Furnace	82%	68%	27%	0%
Other	11%	10%	~~7~~8%	5%

- **Water heating:** Most Ontario homes rely on natural gas for hot water. Increased fuel switching to electric water heaters, both instant and storage-based, drive the GHG emissions reductions for this end use. The Electrification scenario assumes that by 2050, all Ontario homes will rely on electricity for hot water. The Diversified scenario assumes that just over half of homes will still rely on gas via hydrogen or RNG. This is consistent with space heating since a high penetration of integrated space and water heating systems is assumed.
- **Cooking:** One in four Ontario homes rely on gas cooking appliances today. This stock slowly and steadily declines over time based on the Enbridge Gas forecasts. By 2050, one in five homes will still rely on gas cooking appliances in the Diversified scenario while one in 10 will in the Electrification scenario.
- **Washing/drying appliances:** This end use is predominately electric. The Diversified scenario assumes that approximately half of homes with gas laundry appliances will switch to electric appliances by 2050. The Electrification scenario assumes that more than half of homes with gas laundry appliances will switch to electric appliances by 2050. Both scenarios assume new builds with gas washing and drying appliances are negligible.

B.2.2 Transport

The Pathways scenarios account for areas of transport not covered by the Enbridge Gas scenarios. Incorporating these areas is critical because this ensures the Diversified and Electrification scenarios are net zero by 2050. The Enbridge Gas scenarios adopted a forecast by the Canada Energy Regulator to simulate the adoption of CNG in heavy road transport. This study follows a different methodology and expands the scope to all modes of transportation. This study uses a bottom-up approach to model reductions in GHG emissions from road, aviation, and maritime transportation via electrification, RNG, and hydrogen. For light and heavy duty road transport, passenger kilometers from NRCan's Comprehensive Energy Use Database multiplied by the appropriate fuel energy intensities are used to project energy use over time.[155] For aviation, rail, and marine transport, the energy use from NRCan's Comprehensive Energy Use Database is linearly forecasted to project the overall energy use over the study period. These energy use projections, in combination with the assumed fuel share breakdowns provided in the tables below, encompass the assumptions made regarding transportation electrification in this study.

- **Light duty road transport** (cars and light commercial vehicles): The adoption of EVs is the most effective and common way of reducing GHG emissions for light transportation. Both scenarios are based on a large adoption of EVs. The Diversified scenario assumes light duty road transport is largely electrified, with gas only playing a limited role via hydrogen in niche applications. The Electrification scenario assumes light duty road transport is fully electrified.

Table B-3. Light Duty Road Transport Fuel Share Breakdown for the Diversified and Electrification Scenarios

		Diversified	Electrification
Fuel	**2020**	**2050**	**2050**
Gasoline	100%	0%	0%
Electricity	0%	95%	100%
Hydrogen	0%	5%	0%

- **Heavy road transport (buses and trucks):** The Diversified scenario assumes that for buses, hydrogen and electricity play major roles, while for trucks, only hydrogen plays a major role, complemented by electricity and CNG. The Electrification scenario assumes that for buses, electricity plays a dominant role, with only a limited role for hydrogen. Similarly, for trucks, electricity also plays a dominant role in reducing GHG emissions, with a limited role for CNG and biodiesel. RNG is not expected to play a major role in reducing GHG emissions from buses. Both scenarios reach 0% CNG by 2050. In the Diversified scenario, CNG is forecast to play an intermediate role, with 10% of buses in 2030 being CNG powered and 5% in 2040.

Table B-4. Bus Fuel Share Breakdown for the Diversified and Electrification Scenarios

		Diversified	Electrification
Fuel	**2020**	**2050**	**2050**
Gasoline	~~100~~98%	0%	0%
Electricity	0%	~~95~~75%	~~100~~90%
Hydrogen	0%	~~5~~25%	~~0~~10%
CNG	2.5%	0%	0%

Table B-5. Truck Fuel Share Breakdown for the Diversified and Electrification Scenarios

		Diversified	Electrification
Fuel	**2020**	**2050**	**2050**
Diesel/ Gasoline	100%	0%	0%
Electricity	0%	40%	70%
Hydrogen	0%	35%	0%
CNG	0%	5%	0%
Biodiesel	0%	20%	30%

[155] Natural Resources Canada (2021). Comprehensive Energy Use Database: Transportation Sector - Ontario. Available: https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/menus/trends/comprehensive/trends_tran_on.cfm

- **Aviation:** The reduction of GHG emissions from jet fuel is expected to be driven by global aviation trends rather than by unique market drivers in Ontario or Canada. Driven by this global dependence, the treatment of the aviation sector is the same in both scenarios, with biojet fuel and synthetic kerosene playing equal roles. Synthetic kerosene, or e-kerosene, is produced with hydrogen.

Table B-6. Aviation Fuel Share Breakdown for the Diversified and Electrification Scenarios

		Diversified	Electrification
Fuel	**2020**	**2050**	**2050**
Jet Fuel	100%	0%	0%
Electricity	0%	0%	0%
E-Kerosene (H_2)	0%	40%	40%
Biojet Fuel	0%	60%	60%

- **Marine:** The Diversified scenario assumes that ammonia (produced via hydrogen) plays a dominant role in reducing GHG emissions of marine transport, primarily in long distance shipping. Bio-LNG is also expected to play a role in long distance shipping. Electricity is expected to play a major role in short distance, domestic marine transport. The Electrification scenario assumes electricity is the largest contributor to reducing marine transport emissions, primarily in short distance, domestic shipping. Bio-LNG and biodiesel are the drivers of GHG emissions reduction in long-distance shipping.

Table B-7. Shipping fuel share breakdown for the Diversified and Electrification scenarios

		Diversified	Electrification
Fuel	**2020**	**2050**	**2050**
Heavy Fuel Oil/ Marine Fuel Oil	100%	0%	0%
Electricity	0%	30%	50%
LNG	0%	0%	0%
Ammonia (H_2)	0%	60%	0%
Biodiesel	0%	10%	50%

B.2.3 Industry

The reduction of GHG emissions from the industrial sector via hydrogen, RNG, and natural gas + CCS is primarily based on the methodology defined by the Enbridge Gas scenarios for individual sectors. However, as described in the previous section, because this analysis aims to model emissions reduction of the Ontario-wide economy, additional gas demand associated with the reducing emissions from non-gas fossil fuel demand is also considered.

Our analysis assumes ~~This~~this also captures a small share of natural gas demand from industry for use as feedstock in non-energy purposes – roughly 1.5% or 15 PJ.[156]

- **In 2030:** Industrial gas demand is adopted directly from Enbridge Gas's Diversified and Electrification scenarios.
- **In 2040:** Industrial gas demand in 2040 is determined by extrapolating linearly Enbridge Gas's Diversified and Electrification scenarios from 2038 to 2040. This extrapolation is based on the last 5-year period of the Enbridge Gas forecast (i.e., 2034-2038). This exercise is performed on all gases: natural gas, natural gas + CCS, hydrogen, and RNG. Hydrogen does not play a role in the Electrification scenario, only in the Diversified scenario.

[156] The Ontario Fuels Technical Report (2016), prepared by Navigant (now Guidehouse) for the Ministry of Energy estimated non-energy natural gas demand by industry at 15 PJ in 2015.

- **In 2050:** Total gas demand in 2050 is determined by extrapolating Enbridge Gas's Diversified and Electrification scenarios to 2050. The mix of gases used to meet total gas demand is determined differently for each gas.
    - **RNG:** In both scenarios, RNG supply is assumed to grow at a more moderate pace during 2040-2050, compared to 2030-2040. The analysis assumes RNG supply increases more moderately over the 2040-2050 period compared to the 2030-2040 growth in RNG supply. We assume the 2040-2050 growth is 25% of the 2030-2040 growth in RNG supply. A more aggressive assumption (e.g., 50%) would likely result in Ontario's RNG supply approaching the theoretical maximum potential.
    - **Natural Gas + CCS and hydrogen:** The share of natural gas + CCS and hydrogen is determined based on their potential to replace natural gas in each industrial segment. Some industrial segments will replace natural gas with hydrogen, whereas others will replace natural gas with natural gas + CCS. This segment-specific approach is consistent with and based on the Enbridge Gas scenarios.

      In the Diversified scenario, hydrogen and natural gas + CCS are assumed to displace natural gas in all process heating uses (e.g., direct process heating, or indirect via water or steam), while electricity displaces natural gas in non-process heating end uses (e.g., heating, ventilation, and air conditioning, process cooling, and a small share of other processes).

      In comparison, the Electrification scenario does not assume a role for hydrogen. This means natural gas + CCS is the only option for reducing GHG emissions from process heating uses. The Electrification scenario also incorporates a modification to the Enbridge Gas scenario approach. In the spirit of the Electrification scenario, with more aggressive economy-wide electrification assumptions, we assume the development of advanced industrial electrification technologies targeted for medium and high temperature industrial applications. Our analysis assumes that by 2050, the reduction of GHG emissions from 25% of direct process heating energy demand is achieved via electrification, while the remaining 75% is achieved via natural gas + CCS.

For industrial applications that use natural gas as feedstock for non-energy purposes – estimated to be approximately 15 PJ based on historical data[157] –our analysis assumes that this natural gas demand continues towards 2015.

GHG Emissions Reduction Approach for Non-Gas Fossil Fuel Demand

Non-gas fossil fuel energy demand from industry is estimated as roughly 240 PJ.[158] Nearly 80% of this is coke, petroleum coke, and coal, of which the vast majority is associated with the iron and steel industry. Our analysis assumes most fossil fuel use in the iron and steel sector is displaced by hydrogen in both scenarios. This is based on the adoption of HDRI technology by industry players in Ontario.[159]

The remaining 20% of non-gas fossil fuel use relates to heavy, medium, and light fuel oil and kerosene. Our analysis assumes these fuels are displaced by hydrogen, electricity, and biofuel. The Diversified scenario assumes GHG emissions reductions for these fuels is equally via hydrogen and electricity. The Electrification scenario, however, assumes electricity plays a dominant role complemented by biofuel.

[157] Ministry of Energy (2015). Ontario's Fuels Technical Report (see Figure 21). Available: https://www.ontario.ca/document/fuels-technical-report/state-system-10-year-review

[158] NRCan. Comprehensive Energy Use Database. Industrial Sector – Aggregated Industries, Ontario. https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/showTable.cfm?type=CP&sector=agg&juris=on&rn=1&page=0

[159] Green Car Congress (2021). "*ArcelorMittal plans major EAF, DRI investments for decarbonizing steel production in Canada*". https://www.greencarcongress.com/2021/07/20210731-arcelor.html

Table B-8. Fuel Switching Assumptions for Heavy, Medium, and Light Fuel Oil and Kerosene

	Diversified	Electrification
Fuel	**2050**	**2050**
Hydrogen	50%	0%
Electricity	50%	70%
Biofuel	0%	30%

Appendix C. Integrated Energy System Modelling

To determine the cost-optimal way to reduce GHG emissions from the Ontario energy system, this study used Guidehouse's Low Carbon Pathways (LCP) model, our in-house energy system model. The LCP model optimizes the build out of supply capacity, transmission interties, and gas and electric storage assets to meet future energy demand, simulating the hourly dispatch of electricity, hydrogen, and methane resources. The analysis models an integrated electricity and gas system, reflecting the linkages and dependencies that exists between electricity, methane (both geologic and renewable natural gas), and hydrogen.

In this project, Guidehouse applied the LCP model to optimize the supply of electricity, hydrogen, and methane to meet demand in two 2050 net zero demand scenarios: the Diversified and the Electrification scenarios. The following describe some of the major features of the LCP model as applied in this project:

- **Capacity expansion and dispatch optimization:** Optimization of generation, storage, and interconnections assets across the electricity and gas (methane and hydrogen) networks.
- **Lowest-cost net zero pathway:** Optimized pathways to achieve net zero carbon emissions targets in 2050.
- **Intra-annual temporal resolution:** Uses representative and peak days to reflect the seasonal variability of electricity and gas demand loads and supply resources.
- **Geographical resolution:** Simulates the Ontario energy system and five neighbouring systems – Western Canada (WC), Quebec (QC), MISO (MI), New York (NY), and PJM.

The LCP model is an integrated capacity expansion and dispatch optimization model used to identify the lowest-cost pathway to a low carbon energy system. The cost-optimization engine of the LCP model minimizes the net present value of the total system costs over the analysed study timeframe while considering various constraints at the energy system level (e.g., the buildout and availability of supply resources, the development of interconnections) and operational constraints at the individual technology level (e.g., the operation of power generation plants). The analysis *solves* the expansion and GHG emissions reduction of the electricity and gas (hydrogen and methane) system by adding new supply capacity over time (e.g., onshore/offshore wind, solar).

As an integrated energy system model, the cross-sector interactions between electricity, hydrogen, and methane are an integral part of the analysis (e.g., electrolyzers increase demand for electricity, hydrogen gas turbine increase hydrogen demand). The analysis also models the use of transmission interties across regions (e.g., power lines and pipelines) and storage assets (e.g., gas and electricity storage) to balance supply and demand. The modelling methodology is based on a "copper plate" for each region, meaning the focus of the analysis is primarily on inter-connections (across regions) rather than intra-connections (i.e., network capacity within each region; although nominally allowed for in the energy system costs, it is not the focus of the modelling).

The LCP model uses a nodal network to model an interconnected energy system, each node with its unique energy supply and demand varying over time. The LCP model is configured to a geographical scope of Ontario and the five neighbouring regions previously mentioned. All existing electricity and gas interties between regions are simulated in the model. The model also allows for existing interties to be expanded or for new ones, where applicable, to be constructed and for the option to repurpose methane interties for hydrogen.

A description of the main configuration parameters of the LCP model and several other modelling considerations is presented in Figure C-1.

Figure C-1. LCP Model Configuration and Key Modelling Considerations

Geographic Scope

This study models Ontario (ON) and five neighbouring regions: Western Canada (WC), Quebec (QC), MISO (MI), New York (NY), and PJM.

All six regions are modelled as individual copper-plate nodes, each with its unique energy supply and demand conditions varying over time.

Regions are modelled as an interconnected network of nodes with energy infrastructure connecting a node with its neighbouring nodes. Figure C-2 maps the current electricity (yellow solid lines) and natural gas (green solid lines) interties between ON and its neighbouring regions. The yellow dashed line represents the planned electricity intertie between ON and PJM.

- **Electricity** transport between each region is optimized model-endogenously. Electricity demand and supply capacities in each of the five neighbouring regions is scenario-defined and largely based on publicly available information.
- **Methane** is imported from WC and NY. **Hydrogen** can be imported from any neighbouring region, however, based on the cost-competitiveness of hydrogen supply from WC and QC, availability of hydrogen for imports in ON is limited to these two regions.

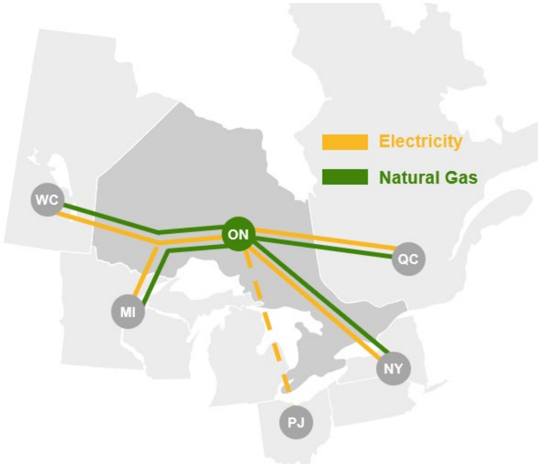


Figure C-2. Electricity and Natural Gas Interties between ON and Neighboring Regions

Energy Carriers

Our demand scenarios forecast energy demand in ON across three energy carriers: **electricity**, **hydrogen, methane**. Methane reflects demand for natural gas, RNG, and natural gas + CCS.

The two net zero demand scenarios only reflect *direct* energy demand (e.g., energy demand from end users) but not *indirect* energy demand (e.g., electricity demand needed for hydrogen production). Indirect energy demand is determined within our model and is impacted by various factors including the availability of surplus electricity, gas/electricity storage and energy imports.

Analysis Timeframe	Temporal Resolution
Our demand scenarios extend from 2020 to 2050, creating snapshots of the Ontario energy system every 10 years: 2030, 2040, and 2050. 2020 is used as the base year of the analysis and is calibrated to match the current supply mix of the Ontario electricity and gas systems. 2050 is used as the final year of the analysis as it is the target year for Ontario to achieve net zero emissions.	Employing four representative seasonal days—winter, spring, summer, and fall—and one peak day—winter peak—to reflect the variability of demand loads and supply resources in Ontario and in neighbouring jurisdictions.

Emissions and Sectoral Scope

The focus of our analysis is on achieving the 2050 net zero target. Because the scope of our analysis is on the energy system—more specifically energy demand from buildings, industry, transport, and the power sector—some sectors are excluded from the study. The analysis does not capture emissions from agriculture, land use, waste, or embedded emissions from products or materials. These external sectors are assumed to reduce GHG emissions in step with the rest of the economy.

Discount Rate

~~Capital costs are converted to a levelized amount using an annuity factor based on the economic lifetime of each type of investment and~~The analysis uses a real discount rate of 4~~%.~~% within the optimization of the LCP model, to compute the net present value of energy system costs. This discounting is done to enable the optimization of all decision variables across all analysis years at the same time. This 4% real discount rate is consistent with the OEB's guidance to gas and electric utilities on the evaluation of demand-side management programs, as per the Conservation First Framework.[160]

[160] Ontario Energy Board (OEB) (2014, December 22). Filing Guidelines to the Demand Side Management Framework for Natural Gas Distributors (2015-2020). https://www.oeb.ca/oeb/_Documents/EB-2014-0134/Filing_Guidelines_to_the_DSM_Framework_20141222.pdf

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