The Role of Hydrogen in Strengthening the Affordability and Reliability of Ontario's Electricity System

The Transition Accelerator

2024-09-19

This project was supported by the financial contribution of the Independent Electricity System Operator.

This project is supported by the financial contribution of the Independent Electricity System Operator (IESO), through its Hydrogen Innovation Fund. However, the views, opinions and learnings expressed in this report are solely those of the Transition Accelerator.

Table of Contents

Executive Summary

This report examines the potential pathways for adopting and integrating hydrogen into Ontario's energy system to achieve net-zero emissions by 2050 and its impacts on Ontario's electricity system. Significant uncertainty exists regarding the optimal mix of zero- and low-emission energy carriers needed to reach a net-zero economy, including hydrogen's role. This uncertainty challenges electricity system planning in terms of future demand and supply. Understanding Ontario's potential decarbonization pathways is essential for planning a net-zero aligned electricity system.

To explore these dynamics, our methodological approach is structured into three sequential steps:

1. **Define Hydrogen Pathway Scenarios**: We developed scenarios representing various levels of hydrogen use and different production options for a net-zero economy in 2050.
2. **Evaluate Impacts, Costs, and Feasibility**: We then evaluated the technical and economic feasibility of each scenario, focusing on the conditions necessary for hydrogen to fulfill its envisioned role.
3. **Analyze Electricity System Impacts**: Finally, we analyzed how the hydrogen pathway scenarios may impact Ontario's electricity system, including necessary adaptations to support hydrogen use and production, and the role of hydrogen in providing reliable, affordable, and net-zero electricity.

Key Results

Hydrogen Demand

Figure 1 summarizes the three hydrogen demand scenario definitions, illustrating varying degrees of coordination and support for hydrogen use in Ontario.

Figure 1 | Hydrogen Demand Scenario Descriptions

Hamilton Only	Hydrogen demand is limited to the Hamilton region, targeting difficult-to-decarbonize sectors like steel production. This scenario envisions a future with an isolated hydrogen hub in Hamilton without broader provincial support for a hydrogen economy.
Low - Ontario	Hydrogen demand has expanded across Ontario, focusing on the most promising applications. This scenario includes cohesive transitions in industrial and transportation sectors, with hydrogen refuelling infrastructure in urban centers and for off-road transportation.
High - Ontario	Hydrogen demand is expanded to include a broad range of applications across Ontario, envisioning large-scale hydrogen infrastructure deployment by 2050. This scenario covers all sectors that will be difficult to decarbonize without hydrogen.

Table 1 shows the estimated annual hydrogen consumption among sectors and end-uses where hydrogen may be a viable energy carrier in 2050 for each defined scenario.

Table 1 | Hydrogen Demand by Sector in 2050

	Mt H_2/year			Ton H_2/day		
Sector	Hamilton	Low - ON	High - ON	Hamilton	Low - ON	High - ON
Transport	0.01	0.91	2.26	0.04	2,489	6,187
Buildings	0.02	0.27	0.92	0.07	746	2,522
Industry	0.18	0.71	1.53	492	1,940	4,188
Total	**0.22**	**1.89**	**4.71**	**597**	**5,174**	**12,896**

In the **Hamilton scenario**, hydrogen demand is primarily driven by the city's steel production, with minimal amounts for transport and building heating applications, requiring about 597 tonnes H_2/day, or 1.1% of Ontario's projected 2050 energy demand for hydrogen-compatible uses. It is anticipated that a single large-scale hydrogen facility would accommodate the hydrogen needs for this scenario and would be located near the point of demand.

Expanding to promising end-uses across Ontario in the **Low-ON scenario**, hydrogen demand increases nearly tenfold to over 5,000 tonnes per day, representing 10.5% of energy demand. This scenario would require hydrogen generation at numerous locations to satisfy the various demands of each sector. Large-scale production facilities will likely be required for the supply of industrial sector demands with smaller-scale production required to address the province-wide requirements in transportation, heating and transient requirements for agriculture and construction. The establishment of a last-mile delivery service for hydrogen will be critical to minimize the added cost of transportation.

Under the most optimistic scenario, the **High-ON scenario** projects nearly 13,000 tonnes per day of hydrogen demand, representing over a quarter of energy demand. Similar to the previous scenario, this projection further emphasizes the need for both large-scale industrial generation of hydrogen and smaller-scale distributed hydrogen generation, but on a wider pan-Ontario scale. This will require consideration of other infrastructure build such as CO2 pipelines to link facilities in areas of no local sequestration potential to southwestern Ontario. Additionally, this scenario would suggest even further penetration of hydrogen generation into northern, remote, and rural areas of Ontario highlighting the need to limit distribution expense for hydrogen and generate volumes at the point of demand.

If end-uses transition directly to electrification instead of hydrogen, electricity consumption could increase between 0.7 TWh and 93 TWh under the Hamilton and High-ON scenarios, respectively.[1] In the context of a net-zero 2050 Ontario, with massive electrification expected in many sectors, low-carbon fossil fuel-derived hydrogen should be considered an asset. It can help reduce electricity demand in what is likely to be an already substantial build-out in capacity to meet demand.

[1] These values assume that the majority of energy consumption transitioning to hydrogen would instead directly electrify, representing an upper limit to the level of "avoided electrification" represented by estimated hydrogen consumption.

Hydrogen Supply

To understand the impacts, costs, and feasibility of supplying the levels of hydrogen consumption envisioned in the three scenarios, we evaluated four low-carbon intensity (CI) hydrogen production options:

- Autothermal reformation with carbon capture ("ATR + CCS"),
- Steam methane reformation with carbon capture ("SMR + CCS"),
- Methane (i.e., natural gas) pyrolysis ("NG Pyrolysis"), and
- Electrolysis

We also qualitatively considered the ability to import hydrogen into the province to satisfy domestic demand. We focused on these options due to their technological maturity, scalability, potential economic viability, and ability to produce hydrogen with relatively low carbon intensity, aligning with net-zero emission goals.

Feedstock and Energy Requirements

Each production technology has different energy requirements, either electrical or thermal. Thermal energy can be supplied by natural gas combustion, generated hydrogen, or waste heat capture. Additionally, each technology has varying feedstock needs, primarily natural gas and water. **Table 2** provides the annual natural gas, water, and electricity requirements for each hydrogen supply technology by demand scenario.[2]

Table 2 | Hydrogen Supply Technology Natural Gas, Water, and Electricity Requirements by Demand Scenario

Technology	Natural Gas Requirements (Mm^3 per year)			Water Requirements (Mm^3 per year)			Electricity Requirements (TWh per year)		
	Hamilton	ON - Low	ON - High	Hamilton	ON - Low	ON - High	Hamilton	ON - Low	ON - High
ATR+CCS	930	8,053	20,071	6.1	53.3	132.7	0.9	7.6	18.9
SMR+CCS	1,244	10,778	26,865	6.5	56.7	141.2	0.4	3.8	9.4
NG Pyrolysis	1,522	13,184	32,861	0.7	6.4	16.0	2.4	20.6	51.2
Electrolysis				13.2	114.6	285.7	15.7	136.0	339.1

At the macro-level, under current conditions, **natural gas and water requirements for domestic hydrogen production are unlikely to be a limiting factor for hydrogen's potential role in achieving a net-zero energy system in Ontario**. The quantities needed to meet 100% of hydrogen demand via the most feedstock-intensive technologies are likely within Ontario's infrastructure capabilities.

- **Natural Gas Requirements:** The maximum estimated requirement is an average daily demand of 90 Mm^3 for methane pyrolysis under the High-Ontario scenario. Ontario's existing

[2] The feedstock and energy requirement results assume that each production technology individually meets 100% of the hydrogen demand, illustrating the upper bound of potential impacts. In practice, a combination of these technologies will likely be employed to meet the hydrogen demand.

natural gas transmission and distribution system, which sources natural gas from western Canada and the United States, has a capacity of 208 Mm^3 per day and an average utilization of 73 Mm^3 per day. Therefore, the system has sufficient capacity to handle the increased demand.

- **Water Requirements:** The maximum estimated requirement is 286 billion litres annually. This represents only a 1.3% increase in Ontario's current water consumption. Moreover, over 80% of this water would be used for cooling purposes and subsequently returned to Ontario's water supplies. Approximately 49 billion litres annually would be consumed in the electrolysis process.

Electricity requirements, on the other hand, pose a significant challenge, depending on the technology option and the scale of hydrogen production. The electricity demand for domestic hydrogen production varies greatly based on the production technology and the level of demand.

Electrolysis has the highest electrical energy requirement, needing 340 TWh per year under the High-Ontario scenario. This is more than 2.5 times the total electricity consumption in Ontario in 2023 and exceeds the electricity demand projected for the rest of Ontario's economy in the decarbonization scenario outlined in IESO's Pathways to Decarbonization (P2D) study – essentially doubling the level of electricity needed in the net-zero scenario(1). Meeting this demand would increase the average demand on Ontario's electricity system by nearly 39 GW. Meeting this demand with variable renewables like wind and solar would necessitate even greater capacity due to their lower capacity factors.

Carbon Byproducts

In addition to feedstock and energy requirements, several hydrogen production methods also generate significant carbon byproducts, both as emissions and solid carbon, as shown in **Table 3**.

Table 3 | Hydrogen Supply Technology Carbon Emissions and Solid Carbon Byproduct Production

Technology	CO_2 Captured ($Mt\ CO_2e/yr$)			CO_2 Emitted ($Mt\ CO_2e/yr$)			Solid Carbon (Mt/year)		
	Hamilton	ON - Low	ON - High	Hamilton	ON - Low	ON - High	Hamilton	ON - Low	ON - High
ATR+CCS	1.69	14.67	36.57	0.14	1.17	2.92			
SMR+CCS	1.57	13.58	33.84	0.43	3.74	9.32			
NG Pyrolysis							0.72	6.19	15.44
Electrolysis									

Large-scale use of production options that capture gaseous emissions (ATR+CCS and SMR+CCS) under a high hydrogen demand scenario will likely be constrained by the capacity to store the captured CO_2 in Ontario. For the ON-High scenario, reformation production options would require the permanent storage of approximately 34 to 37 Mt CO_2e per year. Current research indicates that Southwestern Ontario is the most viable area for geological CO_2 storage, with potential capacities of up to 289 Mt under Lake Huron and 442 Mt under Southwestern Ontario and

Lake Erie (2). The CO_2 captured from ATR+CCS and SMR+CCS technologies would utilize this storage capacity within approximately 20 years, not accounting for CO_2 from other industrial processes. However, for the Hamilton scenario, where the most likely storage location would be Southwestern Ontario, it would take over 150 years to utilize the entire estimated storage potential.

Additionally, both ATR+CCS and SMR+CCS are not 100% efficient at capturing emissions, resulting in some residual atmospheric CO_2 emissions. SMR+CCS emits nearly 10 Mt CO2e annually under the ON-High scenario, about 6% of Ontario's 2023 emissions (3). ATR+CCS emits nearly 3 Mt CO2e annually, around 2% of Ontario's 2023 emissions. These emissions would need to be offset to meet net-zero targets.

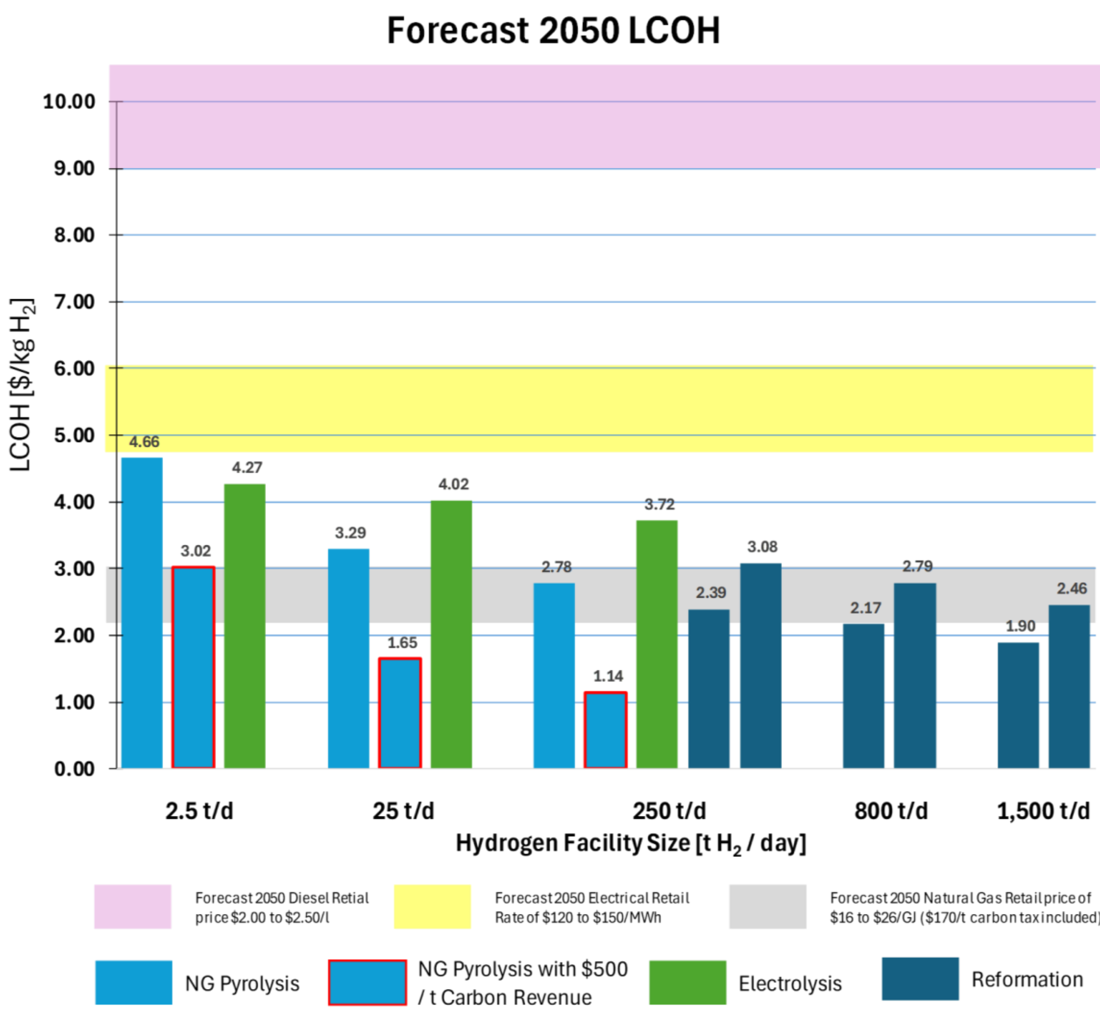
NG Pyrolysis generates up to 15 Mt of solid carbon annually under the ON-High scenario. The economic value of these carbon byproducts can help reduce hydrogen production costs. Additionally, solid carbon serves as a stable sequestration medium, effectively capturing carbon without creating CO2.

Supply Costs

The levelized cost of hydrogen (LCOH) will depend on various factors, including capital costs, feedstock and energy prices, facility size, operational characteristics, and transportation expenses, many of which are highly uncertain when projecting to 2050. **Figure 2** shows LCOH for each hydrogen production option at various facility sizes assuming a high-capacity factor (90%) and electrical and natural gas input prices of $70/MWh and $5.50/GJ, respectively.[3] Under these assumptions, **all evaluated hydrogen production technologies have the potential to deliver hydrogen for end-use at competitive costs**.

[3] Due to the high uncertainty of input prices in 2050, Appendix 1 includes LCOH sensitivity analyses for a wide range of input cost assumptions for each technology option and facility size.

Figure 2|2050 LCOH FORECAST, BY VARIOUS FACILITY SIZES



Compared to potential retail costs for other energy sources (diesel, electricity, and natural gas)[4], the range of LCOH estimates for hydrogen is favorable on an energy-equivalent basis. Projected hydrogen costs for all technologies and facility sizes are significantly lower than diesel costs and slightly below electricity costs. However, due to the relative efficiencies of hydrogen vs. electric end-use applications, electrification may still be more competitive in many cases.

For natural gas, only NG Pyrolysis and Reformation options are cost-competitive on an efficiency-adjusted energy equivalent basis. NG Pyrolysis' competitiveness hinges on larger production facilities, continued capital cost reductions by 2050, and revenue from solid carbon byproducts. Reformation options benefit from larger facilities but depend on cost-effective CO2 sequestration, which is challenging at large scales as previously discussed. However, at lower demand levels, such as in the Hamilton Only scenario, where a centralized facility sized between 250 t/d and 800 t/d, our analysis

[4] Retail prices for diesel, electricity, and natural gas in 2050 are derived from the Canadian Energy Regulator's Canada's Energy Future 2023 report (Canada Net-Zero Scenario).

indicates that LCOH would be competitive with natural gas and carbon storage challenges would be lessened.

While electrolysis and NG pyrolysis (without carbon revenue) costs struggle to compete with natural gas, this analysis does not account for distributed hydrogen production where conventional energy delivery costs are higher due to remoteness or infrastructure constraints. In such cases, on-site hydrogen production combined with local renewable energy sources (e.g., wind or solar) could become a cost-competitive option, for example.

Hydrogen Imports

Ontario may import hydrogen to meet its domestic consumption needs. Potential sources include the USA and Canadian provinces such as Alberta, Saskatchewan, Quebec, and the Atlantic provinces. Alberta's established hydrogen production and export framework is a strong candidate to support Ontario's hydrogen needs, and Quebec's abundant hydroelectric power also offers potential. Additionally, the US is developing Regional Clean Hydrogen Hubs, several of which are in close proximity to Ontario, bolstered by federal funding and incentives.

The feasibility of importing hydrogen will hinge on transportation infrastructure. Pipelines are the most practical and cost-effective method for transporting large volumes of hydrogen over long distances. Transport costs from neighbouring US states targeted for hydrogen hubs to Ontario, for instance, could be as low as $0.50 to $0.60 per kg H2 at demand levels represented in all three scenarios, making imports economically viable if production costs are low enough.

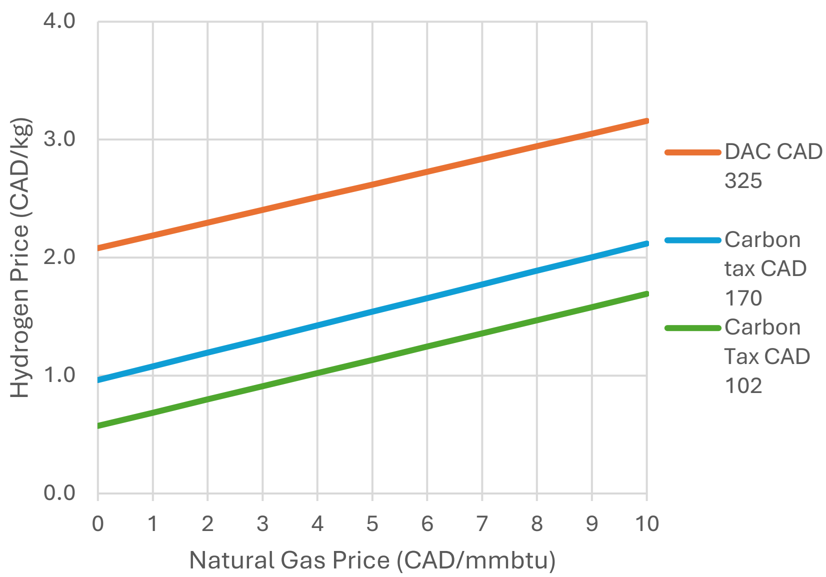
Hydrogen as an Electricity System Resource

Hydrogen has the potential to support net-zero aligned electricity systems in two primary ways: (1) as a flexible and firm generation resource and (2) as an electricity storage resource when combined with electrolytically produced hydrogen. However, hydrogen must compete with other technologies economically, heavily influenced by its cost.

For generation, we compare a hydrogen-fired combustion turbine against an unabated natural gas combustion turbine.[5] The breakeven price at which the levelized cost of energy (LCOE) for a hydrogen-fired generator is competitive with a gas generator, as shown in **Figure 3** depends significantly on the cost of hydrogen and natural gas in 2050. **Our analysis suggests that delivered hydrogen costs must be below $3 per kg H2 to compete against unabated natural gas peaking generation**, even under high gas commodity costs ($10 per MMBtu) and carbon costs ($325 per tonne).

[5] For peaking electricity services, national net-zero optimization studies suggest some unabated natural gas generation may be cost-effective even with the added cost required to mitigate emissions via atmospheric removal of CO2. We also compare hydrogen against abated natural gas and nuclear generation in the main body of the report.

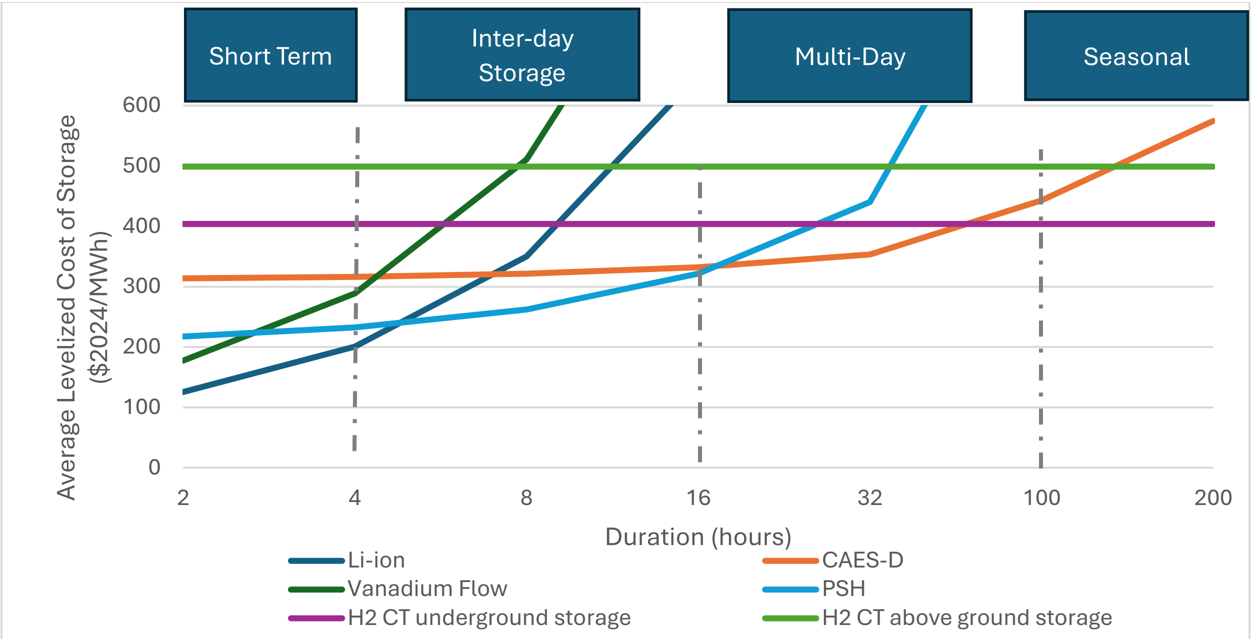
Figure 3 | Hydrogen vs. Unabated Natural Gas by Carbon Cost Breakeven Price



As can be seen in the figure, the breakeven price is highly sensitive to the implied cost of carbon, which could take the form of a carbon tax or the cost of atmospheric carbon removal via direct air capture. Considering the relative heat rates of hydrogen and natural gas combustion turbines, **the implied cost of carbon would need to increase by $155/tonne for every $1/kg difference in the LCOH at a given natural gas price for hydrogen to achieve price parity**.

As a storage resource, hydrogen is most viable for longer-duration storage applications, as shown in Figure 4. The levelized cost of storage (LCOS) for hydrogen remains stable regardless of storage duration. In contrast, other storage technologies, such as Li-ion and Vanadium Flow batteries, have lower LCOS for short durations but see a rapid increase in LCOS as storage duration increases. For multi-day storage, the only evaluated technologies with lower LCOS than hydrogen are compressed air energy storage (CAES) and pumped storage hydro (PSH), both of which are limited to locations with suitable geological features. For seasonal storage durations of 200+ hours, hydrogen becomes the most cost-competitive option.

Figure 4 | Hydrogen vs. Other Storage Technologies



Key Insights

Overall, our analysis highlights several key insights into the potential pathways for hydrogen adoption in Ontario:

Minimal Hydrogen Role Challenges Net-Zero Pathway

In the Hamilton Only scenario, providing cost-competitive hydrogen supplies is feasible, likely through natural gas-based processes (ATR+CCS or SMR+CCS) or low-cost imports from the United States. However, this minimal role means Ontario's remaining energy requirements must be met by other net-zero energy carriers, primarily electricity. This could strain Ontario's electricity system if energy uses that could be fulfilled by hydrogen instead of directly electrifying to meet net-zero requirements, potentially incurring considerable costs.

Logistical Challenges of a Large Hydrogen Role

In the ON-High scenario, significant challenges arise in supplying cost-competitive hydrogen due to input requirements and the need to address carbon byproducts. Reformation processes (ATR+CCS and SMR+CCS) will likely be limited by carbon sequestration capacity. NG Pyrolysis requires robust markets for solid carbon byproducts, while hydrogen via electrolysis would necessitate substantial incremental electricity generation and capacity.

Hydrogen as a Competitive Peaking Generation Asset

Hydrogen can be a competitive peaking generation asset in a net-zero aligned electricity system if the delivered cost is below $3/kg, a feasible target based on our supply cost analysis. Above this threshold, alternative resources, including unabated natural gas bearing the full cost of offsetting emissions via atmospheric carbon removal, may be more cost-effective.

Hydrogen's Role in Long-Duration Storage

As a storage asset, hydrogen is most beneficial for long-duration storage, particularly at the seasonal level. This value depends on the characteristics of the wider electricity grid in a net-zero future, with seasonal storage becoming more valuable with higher penetrations of variable renewable electricity. For shorter-duration applications, other storage technologies are likely more cost-effective, even at low assumed hydrogen costs.

Infrastructure and Accessibility Requirements

The use of hydrogen in Ontario's electricity system depends on accessing sufficient hydrogen where generators can interconnect with the grid. This requires robust infrastructure for production, storage, and distribution. Key factors include developing regional hydrogen hubs, repurposing existing natural gas pipelines for hydrogen transport, and ensuring reliable supply chains.

Key Conclusions and Recommendations

This report highlights several critical conclusions and recommendations for integrating hydrogen into Ontario's energy system to achieve net-zero emissions by 2050.

Technological Advancements and Cost Reductions

Continued advancements in hydrogen production technologies and cost reductions are essential. Investments in research and development can lead to more efficient production methods and lower overall costs. To secure hydrogen's role in Ontario's net-zero future, it is crucial to:

- Invest in advanced hydrogen technologies
- Promote adoption across key industries
- Foster collaboration and innovation to accelerate the transition to low-carbon hydrogen
- Support technology development and commercialization
- Promote industrial decarbonization
- Encourage greater collaboration among stakeholders in this space

These steps are necessary to drive the technological progress required for widespread hydrogen adoption.

Provincial Coordination Required for Hydrogen's Role in a Cost-Effective Net-Zero Electricity Grid

Hydrogen has the potential to play a crucial role in Ontario's net-zero electricity grid, but its success depends on meeting specific conditions. A robust infrastructure for production, storage, and distribution is essential, including the development of regional hydrogen hubs and the repurposing of existing natural gas pipelines.

It is important to note that many of these factors are beyond the control of the IESO and require broader coordination across provincial government and industry stakeholders. The successful integration of hydrogen into Ontario’s electricity grid will thus depend on a holistic approach that aligns energy policies, economic incentives, and infrastructure planning across the province. Ontario's electricity system (via IESO) needs to collaborate closely with other energy-intensive sectors to make hydrogen a viable component. This includes creating a Hydrogen Strategy Task Force, aligning policies and regulations, developing coordinated investment strategies, and conducting joint infrastructure planning.

Embracing Diverse Hydrogen Production Pathways and Developing Hydrogen Hubs

To establish a robust hydrogen economy, it is crucial to embrace a diversified approach to hydrogen production and develop strategic hydrogen hubs and corridors. There is no single optimal pathway for hydrogen production; each method has unique advantages and challenges:

- Technologies such as ATR + CCS and SMR + CCS offer cost-competitive options but are limited by the need for extensive CO2 sequestration infrastructure.
- NG Pyrolysis, which produces solid carbon byproducts, provides a viable alternative in regions where geological CO2 storage is not feasible.
- Electrolysis, despite its high electricity demand, is essential for distributed hydrogen production, reducing transport costs and enhancing regional energy resilience.

These varied methods should be integrated strategically, leveraging regional strengths and resources to meet hydrogen demand sustainably and economically.

Additionally, developing hydrogen hubs in strategic locations like Hamilton, Sarnia-Lambton, and Niagara, and creating corridors along major transportation routes, is essential for ensuring widespread accessibility and efficiency. These hubs should integrate hydrogen production, storage, and distribution to maximize efficiency and reduce transportation costs.

Establishing hydrogen corridors to support heavy-duty vehicles and other transportation needs is also critical. Additionally, a distributed hydrogen generation network utilizing existing natural gas infrastructure and potential islanded renewable generation will likely need to be established to meet demand in northern, remote, and rural areas.

By embracing diverse hydrogen production pathways and developing well-coordinated infrastructure, Ontario can optimize the integration of hydrogen into its energy economy, ensuring the benefits of each production method while minimizing associated challenges.

1. Introduction and Goal

The Province of Ontario has set targets to reduce greenhouse gas emissions by 80% by 2050. Aligning with federal policies, which target net-zero emissions by 2050, will require even more aggressive action. To achieve these targets, Ontario must transition from unabated fossil-fuel combustion-based energy to zero-emission alternatives such as electricity, biomass and biofuels, hydrogen (H_2), ammonia (NH_3), and fossil fuels coupled with carbon capture.

The shift to these alternatives will impact Ontario's electricity system through three primary mechanisms:

- **Increased Demand from Electrification**: Transitioning from fossil fuel-based energy end-uses to those that use electricity will increase electricity demand stressing existing electrical infrastructure and requiring Ontario's electricity system to adapt to increasing consumption.
- **Electricity Use in Zero-Emission Energy Production**: Producing non-electric zero-emission energy carriers may require substantial amounts of electricity depending on their production pathways.
- **Non-Electric Carriers as Electricity Sources**: Non-electric zero-emission energy carriers could serve as fuels for generating and storing electricity, serving as a resource for achieving a net-zero electricity system.

This study focuses on how hydrogen's role in this energy transition may impact Ontario's electricity system. Specifically, it examines:

- **Competition Between Electrification and Hydrogen**: Analyzing how hydrogen might complement or compete with direct electrification, affecting overall electricity demand.
- **Hydrogen Production via Electrolysis**: Investigating how hydrogen production could further elevate electricity demand, given the energy-intensive nature of this process.
- **Hydrogen in Electricity Generation and Storage**: Considering hydrogen as a potential resource for zero-emission electricity generation and storage.

There is significant uncertainty regarding the optimal mix of zero-emission energy carriers needed to achieve a net-zero economy in Ontario, including the role hydrogen will play. This uncertainty poses challenges for electricity system planning from both demand (how much electricity the future grid must deliver) and supply (what types of resources will be available for the future grid) perspectives. Understanding Ontario's potential pathways toward decarbonization is crucial for planning a net-zero aligned electricity system.

But the truth is that no one can predict the future with absolute certainty. This study does not aim to forecast the future of hydrogen in Ontario but to explore possible scenarios for its role, the conditions needed for those scenarios to emerge, and the implications for Ontario's electricity system. The goal is to help fill critical gaps in understanding and enable the Independent Electricity System Operator (IESO) and the broader industry to better grasp the opportunities and challenges posed by hydrogen as a decarbonization pathway. **Figure 5** outlines the main areas of inquiry for the study, focusing on the demand and supply dynamics of hydrogen and its integration into the electricity system.

Figure 5 | Key Research Questions

Hydrogen Demand

- What is the range of potential hydrogen demand scenarios in the Hamilton region and beyond?

Hydrogen Supply

- What are potential supply pathways for the various levels of aggregated demand?
- What are the potential costs, likelihood, emissions, and infrastructure requirements of these supply pathways?

Electricity System Impacts

- For each demand scenario, how much is competing against direct electrification?
- For each supply scenario, what are the electricity system requirements and considerations?
- For potential hydrogen demand and supply scenarios, what is the viability of using hydrogen for supporting Ontario's electricity system?

To address these research questions, we constructed several hydrogen pathway scenarios in Ontario, representing different assumptions about the coordination and support for developing hydrogen as a net-zero energy carrier. These scenarios illustrated a range of hydrogen demand based on varying levels of adoption across different end-uses and geographic scopes. We then considered the impacts and likelihood of various hydrogen production options to meet these demand levels. Finally, we evaluate the electricity system impacts under these various hydrogen pathway scenarios.

2. Background & Context

To contextualize our analysis, the following section provides background information on hydrogen as it relates to net-zero emission pathways and its potential role in net-zero aligned electricity systems. It also provides a brief jurisdictional scan of relevant research and policy context related to hydrogen's role in meeting net-zero targets in Ontario, specifically.

What Is Hydrogen, What Is It Used For, and How Can It Be Used as an Energy Carrier?

Hydrogen exists as the molecule H_2, the smallest molecule in existence. When hydrogen is oxidized, either by combustion or electrochemically, it releases a significant amount of energy. Hydrogen has approximately three times the gravimetric energy density (i.e., energy per kilogram) of natural gas, gasoline, or diesel; however, it has only about one-third the volumetric energy (i.e. energy per litre) compared to those other fuels (4). In practice, this means that hydrogen is a very light fuel but requires more storage space, or higher compression or liquefaction, than other kinds of fuel to deliver the same amount of energy.

Unlike hydrocarbon fuels such as natural gas or diesel, hydrogen oxidizes in a manner that produces few greenhouse gases (GHG).[6] The reason for this is that a hydrogen molecule does not contain any carbon atoms, so when H2 is oxidized, the reaction products are energy and water (H_2O) with no CO_2 produced. The combination of high energy density and low carbon intensity makes hydrogen an important candidate for a net-zero energy carrier.

How Is Hydrogen Currently Used in Canada

Canadian industry currently uses hydrogen in various applications, including:

- **Chemical Production**: Hydrogen is used in producing ammonia fertilizers and synthesizing organic compounds such as methanol.
- **Hydrocarbon Refining**: Hydrogen is used as syngas and to upgrade fossil fuels, such as converting bitumen into synthetic crude oil.
- **Hydrogen Fuel Cells**: These are used to produce power in targeted applications, including hydrogen-powered vehicles.
- **Blending with Natural Gas**: In Ontario and Alberta, hydrogen is blended into the bulk natural gas system to reduce the carbon intensity of home heating (5).
- **Electricity Production**: There are plans to blend hydrogen with natural gas for turbine electricity production, with a pilot facility expected to come online in 2024 in the Niagara region (6).
- **Steelmaking**: Hydrogen is being tested as a replacement for coal, serving both as a heat source and a chemical reducing agent in innovative steelmaking processes (7). In

[6] A limited amount of GHG emissions is due to different NOx chemicals which are generated during combustion.

steelmaking, the reducing agent removes oxygen from the iron ore to produce a usable metal that then can be mixed with carbon and other additives to make steel.

When hydrogen is not used for a chemical reaction, such as in fertilizer production, it can be considered an energy carrier. In this role, an end-user utilizes hydrogen's energy content either through combustion or electrochemical processes via a fuel cell.

How Can Hydrogen Be a Low Carbon Intensity Energy Carrier?

Hydrogen is already used in various processes in Canada, but most of it is derived from syngas generation via industrial reformation processes with no consideration of capture of CO_2 emissions, thus resulting in high carbon intensity hydrogen. Fortunately, several low-carbon intensity (CI) hydrogen production processes exist. Hydrogen's potential in the net-zero economy lies in its ability to replace hydrocarbon fuels as an energy carrier and the possibility of producing hydrogen with low carbon intensity.

Three common ways that low CI hydrogen can be manufactured are: (a) the additional of carbon capture and storage (CCS) to existing or new reformation projects; steam methane reforming (SMR) with lower capture efficiencies or autothermal reforming (ATR) with higher capture efficiencies, (b) pyrolysis, and (c) electrolysis, each of which is described later in this section.

We define low carbon intensity (CI) hydrogen as hydrogen produced with a Life Cycle Assessment (LCA) below 4.4 kg CO_2 per kg H_2. To achieve this CI, it is assumed that low carbon intensity electricity and natural gas are accessed for the process. Low carbon intensity electricity can be achieved utilizing renewable generation sources (wind / solar / hydro), nuclear, biofuel, or fossil fuel derived generation with carbon capture and storage, achieving an effectiveness of 90% or higher. If natural gas is used as the hydrogen production feedstock, the CI will also depend on the LCA of the specific production method of the natural gas and the distance it travels from the gas field to the production facility. Considering both upstream and process emissions, the European Union has further defined Renewable hydrogen as producing less than 3.40 kg CO_2 per kg H_2. The United States has set a threshold of 4.0 kg CO_2 per kg H_2 (8). Although there is no global standard for low CI hydrogen, major markets are converging on a CI range of 3.40 to 4.4 kg CO_2 per kg H_2 as the benchmark (9,10).

It is important to note that the CI of each hydrogen production method is different and sensitive to the emission intensity of the production source, the local electricity grid, and the emission intensity of supplied natural gas. Furthermore, each production method has varying electricity input requirements (11). Low CI hydrogen can be realized from all three of the common hydrogen manufacturing processes stated above, with the appropriate utilization of CCS, low CI electrical generation, and low LCI natural gas (12).

Methane Reformation with Carbon Capture

Three separate types of methane reformation exist but all require some form of carbon capture and storage technology to capture the carbon emissions each process produces to be considered low CI hydrogen.

Steam Methane Reformation

At temperatures ranging from 700°C to 1,000°C and under pressure, methane and steam react to form carbon monoxide and hydrogen. Subsequently, a "water-gas shift" reaction between carbon monoxide and steam produces carbon dioxide and additional hydrogen. Pressure swing adsorption is then used to separate carbon dioxide and other impurities from the hydrogen. The majority of the carbon dioxide is then captured to prevent its venting into the atmosphere.

Partial Oxidation

In the partial oxidation reaction, methane undergoes a reaction with a limited supply of oxygen, insufficient to completely oxidize it to carbon dioxide and water. This reaction primarily yields hydrogen and carbon monoxide. Subsequently, the "water-gas shift" process facilitates the conversion of carbon monoxide and steam into additional hydrogen and carbon dioxide. Through "pressure-swing adsorption," carbon dioxide and other impurities are extracted from the gas stream, leaving behind pure hydrogen. This carbon dioxide must then be captured to prevent its venting into the atmosphere. Partial oxidation generally proceeds more rapidly than SMR but yields a lower quantity of hydrogen per methane unit.

Autothermal Reformation

Autothermal reforming (ATR) merges steam methane reforming (SMR) with partial oxidation, yielding enhanced energy efficiency, increased hydrogen production and superior carbon capture potential. The ATR integrated process comprises a reformer, where methane and steam combine with oxygen, and a reactor, facilitating partial oxidation. One reason ATR is more efficient is that heat generated within the reactor is harnessed in the reformer. Additionally, the "water-gas shift" reaction is used to convert carbon monoxide and steam into extra hydrogen and carbon dioxide. This carbon dioxide must then be captured to prevent its venting into the atmosphere. Through "pressure-swing adsorption," carbon dioxide and other impurities are separated from the gas stream, leaving behind pure hydrogen. ATR advantages include a smaller, more compact design, reduced capital investment, economies of scale, enhanced hydrogen generation efficiency, and improved CO2 capture efficiency.

Methane Pyrolysis

Methane Pyrolysis (NG Pyrolysis) involves the thermal breakdown of methane at elevated temperatures ranging from 800°C to greater than 2,000°C, depending on the specific method employed. NG Pyrolysis yields a large-particle, high-density carbon product that can be of various allotropic characteristics, such as carbon black, graphite, carbon nanotubes or carbon fibre, some of which can be further refined into advanced materials such as graphene and utilized in various applications. These applications include structural additives for steel, concrete, and asphalt, highly conductive elements for electricity and heat in batteries and electronics, additives for polymer composite materials and coatings, and lubricants in the chemical sector. While NG Pyrolysis offers the advantage of minimal or no CO_2 emissions, its hydrogen from feedstock production efficiency tends to be lower compared to Steam Methane Reforming (SMR) and Autothermal Reforming (ATR) processes. NG Pyrolysis has three general variants that are considered here although there are other emerging pyrolysis family technologies, both utilizing natural gas as well as other organic waste, so this is not an exhaustive list.

Thermal

Thermal pyrolysis requires temperatures above 1,000°C to decompose methane into hydrogen and carbon. This process requires high sustained temperatures and higher energy input, often through the initial combustion of natural gas and upwards of 20% of the generated hydrogen during the process but is generally simpler than other production methods.

Thermocatalytic

Thermocatalytic pyrolysis uses heat and specially designed catalysts to split methane. The advantage of thermocatalytic production is that it can operate at lower temperatures than thermal pyrolysis (< 1,000°C) and the catalysts can be designed to directly produce specific carbon compounds such as graphite which have value in other industrial processes. Thermocatalytic production also offers higher net hydrogen production efficiency than thermal pyrolysis, though it can have higher operating costs due to the expense of the catalyst.

Plasma et al

There is a wide range of other technologies that differ from Thermal and Thermocatalytic and rely on plasma or other means to achieve the breakdown of the methane molecule. Plasma pyrolysis uses electricity to generate plasma, an ionized gas, and that plasma is brought in contact with methane in various ways which results in the decomposition of methane into its component hydrogen and carbon atoms. Plasma is a broad class of different processes that are currently under investigation and piloting. Molten metals and salts are often added to plasma reactors to allow for an efficient reaction and the removal of the solid carbon from the reactor. Other variations of the technology include the deployment of microwaves as well as wave pulses. With the advancement in technology, plasma pyrolysis has the potential to deliver low-cost, low-carbon, hydrogen.

Electrolysis

Hydrogen can be produced through electrolysis when an electrical current is passed through water which splits the water atoms into hydrogen and oxygen with the hydrogen being collected. This method can deliver low CI if powered by low-carbon intensity electricity including wind, solar, hydro and nuclear. For electrolysis, a device called an electrolyzer is used. This device is comprised of an anode and a cathode, segregated by an electrolyte membrane. The primary benefit of electrolysis-derived hydrogen is that does not rely on fossil fuels and does not require an additional CCS system to prevent GHG emissions. The primary drawback is that electrolysis systems require substantial purified fresh water supplies and large electricity inputs.

Within the electrolysis hydrogen umbrella, the three most common designs are alkaline, polymer electrolyte membrane, and solid oxide.

Alkaline

The alkaline electrolyzer employs a liquid electrolyte solution, typically containing potassium hydroxide (KOH) or sodium hydroxide ($NaOH$), mixed with water. At the anode, oxygen gas is produced, while at the cathode, hydrogen gas is generated. Alkaline systems are a fully mature technology and are found worldwide.

Polymer Electrolyte Membrane

Polymer electrolyte membrane (PEM) electrolyzers utilize a specialized solid polymer material to separate the anode and cathode. At the anode, oxygen gas and positively charged hydrogen ions are produced. Those ions then travel to the cathode where they combine to produce hydrogen gas. Previous studies have found that PEM is better suited when intermittent renewables provide the electricity because a PEM system can operate efficiently on variable electricity (13,14) however more recent work finds that both Alkaline and PEM systems can ramp up or down their production flexibly so the determination of which system is best for a given location will come down to other factors than the availability of renewable power (15).

Solid Oxide

The solid oxide electrolyzer (SOEC) is crafted from solid ceramic material and functions optimally at temperatures exceeding 700°C. The SOEC cathode produces hydrogen gas while simultaneously generating negatively charged oxygen ions. Those ions then migrate to the anode, where they combine to form oxygen gas. SOEC is a newer technology and the BC Centre for Innovation in Clean Energy (CICE) reports this technology at variable levels of readiness between 4 (laboratory validation) to 7 (demonstration prototype) (16).

Challenges to Using Hydrogen as an Energy Carrier

There are several major challenges to increasing the use of hydrogen as an energy carrier in the economy:

- **Lack of Supply and Demand:** Almost all hydrogen production today is used in industrial processes such as refining and ammonia production. There is currently very limited demand for hydrogen as an energy carrier so consequently supply is limited as well. This issue creates a circular challenge where the lack of supply subsequently leads to a lack of adoption which limits demand and so on.
- **High Cost:** This circular challenge means that hydrogen has yet to be produced and consumed at a scale where its cost can reach parity or lower with the fossil fuels it's replacing.
- **Lack of Infrastructure:** Another reason for hydrogen's high cost is the high initial investment required. As a consequence of hydrogen being a new energy carrier, new infrastructure to support its value chain, from production through distribution to end-use, must be built up. In addition, due to a phenomenon called hydrogen embrittlement, hydrogen may not be compatible with some materials used in existing gas infrastructure so some of this infrastructure will need to be upgraded or replaced to distribute hydrogen. Additionally, due to the size of the hydrogen molecule in comparison to methane and other gases within natural gas, hydrogen leakage within existing natural gas systems needs to be addressed. This includes seals at joints and the various measurement and end devises within the natural gas system.
- **Storage & Transport:** The safe operation of hydrogen pipelines presents more challenges compared to natural gas pipelines. Hydrogen is the smallest molecule, making it difficult to contain and manage its leaks. Additionally, hydrogen-air mixtures are extremely easy to ignite and require minimal energy to do so. Another challenge is hydrogen's low volumetric energy density, which necessitates much higher volumetric flow rates to transport the same amount of energy as methane. This increased flow rate brings its own set of issues, such as higher pressures, compression energy requirements, increased chances of leaks, and the potential for embrittlement. (17). Moreover, being odourless, colourless, and tasteless, hydrogen leaks

are not detected by human senses. Therefore, the use of hydrogen sensors is recommended to detect leaks successfully, along with a ventilation system that mitigates potential damage by enabling hydrogen to escape to adjacent spaces

The transport of hydrogen through high-pressure pipelines is not yet widespread. Most hydrogen pipelines that are currently operating are located in industrial sites, a fact that is reflected by the low number of recent incidents that are related to hydrogen pipelines (only 9 such incidents have been recorded in the Hydrogen Incidents and Accidents Database (HIAD) and H2tools database). Further investigation into the 9 reported incidents revealed that 2 of the incidents did not involve hydrogen ignition, while 5 incidents resulted in hydrogen fires. The remaining 2 incidents were found to have resulted in an explosion.

The root causes of these reported incidents were studied. For three incidents, the causes were unknown. The other six incidents were due to design errors, human error, inadequate pipeline maintenance, and procedural deficiencies. These types of incidents are typical of those that occur in any major hazard pipeline carrying hazardous substances such as flammable gas (methane) or liquid hydrocarbons. Therefore, the same causative risk profile can be assumed for hydrogen as well (18).

It is important to address the misconception regarding leakage in system design. Leakage should not be considered a permissible factor in the design of hydrogen pipeline systems, although it can occur. As observed with current fugitive natural gas emissions, these emissions are measured from existing facilities and cannot be projected or incorporated into the design process. Leakage typically arises from human error during installation or maintenance, such as improper torquing, welding, or sealing. Consequently, this issue is managed reactively, with regulations mandating natural gas companies to detect and repair leaks. This reactive approach underscores the necessity for stringent installation and maintenance protocols to minimize leakage risks.

The secondary challenges to implementing hydrogen, which relate to the current state of the industry and the ability to overcome the primary challenges, include but are not limited to:

- **Safety:** The oil and gas industry, as well as everyday consumers, have lifetimes of experience in the safe handling of hydrocarbons. The same cannot be said for hydrogen and while hydrogen is not necessarily any more or less dangerous than other fuels, experience working with it needs to be built up.
- **Geological Storage Capacity:** For SMR to be part of the net zero economy vast geological storage for the captured CO_2 is required. The availability, and regulatory framework for geological storage of CO_2 are not in place in every jurisdiction that may want to use hydrogen in their economy.
- **Availability of Electricity:** The electricity system is being called upon to meet the energy needs of electric vehicles, electric heat pumps, and industry in general. Low CI hydrogen production requires varying amounts of electricity with electrolytic hydrogen requiring the most. It is unclear if enough new electric generation capacity can be added to meet all net zero needs, or if hydrogen production will be the best use of clean electricity.

Hydrogen Hubs and Corridors

Given the many challenges associated with hydrogen adoption, a logical question is what can be done to overcome these obstacles. Based on previous analysis and experience in founding and launching Canada's first hydrogen hub in the Edmonton Region, the Transition Accelerator recommends that the transition pathway to hydrogen begins with a hubs and corridors model.

Hydrogen Hubs

A hydrogen hub is a concentrated geographic area where hydrogen producers, consumers, and innovators are closely linked. The goal of a hub is to reduce the cost of hydrogen production by efficiently connecting hydrogen demand with hydrogen suppliers. As hydrogen demand grows, it is expected that investments in hydrogen infrastructure will increase, and hydrogen costs will further decrease through both experience gained in working with hydrogen technology and novel innovations fostered within the hub.

Canada’s first hydrogen hub was launched in the Edmonton Region in April 2021, where leaders from government, Indigenous groups, academia, industry, and economic development shared their vision for the future use of hydrogen as a net-zero energy carrier. The Edmonton region plan focuses on applications such as heavy-duty trucks, rail, public transport, farm machinery, and home heating.

Hydrogen Corridors

Given that Canadians pay more per unit of energy for transportation fuel than other fuels (Khan, 2022), one early market opportunity for hydrogen use is in transportation, specifically long-haul heavy-duty trucking where battery electric vehicle technology may not be suitable. Establishing hydrogen corridors along heavily trafficked trucking routes to fuel these vehicles offers the potential for significant and regular hydrogen consumption. This approach would foster consistent demand from hydrogen hubs and link them within a region initially, eventually expanding to a national network while decarbonizing a significant source of transportation emissions.

Hydrogen’s Potential Contribution to a Net-Zero Economy in 2050

Governments in the US, EU, and Canada, among others, have all investigated the potential role of hydrogen in the net-zero economy and have come to similar conclusions: hydrogen has a significant role to play in the 2050 net-zero future in both the transportation and industrial sectors as well as potential roles elsewhere.

- Across all economic sectors, BNEF estimates that hydrogen will make up 11%, 8%, and 10% of final energy use demand in Canada, the US, and the EU by 2050, respectively (19).
- The United States published a 2050 hydrogen production estimate of 50 MT/year, which would reduce the GHG intensity of the entire US economy including transportation and industry by 10% (20).
- To meet net zero energy demands for such sectors as transport and industry throughout the EU and to reduce the need for Russian natural gas, the EU expects to produce 10MT of hydrogen domestically and import another 10MT by 2030 (21).
- The Canadian Energy Regulator estimates that by 2050, Canada will use between 8.5 and 9.5MT of hydrogen annually with the majority used in the transportation and industrial sectors. By 2050, the CER projects that the transportation sector will draw approximately 30% of its total energy from hydrogen while heavy industry will source 6% of its total energy from

hydrogen. When hydrogen use in all sectors is tallied the CER estimates that the Canadian economy will get 11.6% of its total energy from hydrogen(22).

The Transition Accelerator has specifically investigated several areas where hydrogen is likely to support Canada's economy-wide decarbonization including:

- **Heavy trucking**: In the transportation sector, electricity is a credible and compelling option for replacing GHG fuels in most light-duty passenger vehicles. Heavy and/or high-duty cycle vehicles may have difficulties economically using battery electric energy because they operate for longer distances, and/or longer durations than a typical light-duty passenger vehicle. If batteries were used to power a heavy-duty or high-duty cycle vehicle over very long distances and times between recharges, the mass of the battery needed would cannibalize the cargo capacity of the vehicle. Hydrogen, because of its high energy density and ability to add fuel capacity by simply increasing the storage tank size offers a more economical solution for zero-emission heavy-duty and high-duty cycle vehicles (23).
- **Aviation fuel**: The aviation sector requires energy-dense and low-mass fuel. Currently, that fuel of choice is kerosene however hydrogen has the potential to be either used directly in planes or used to manufacture synthetic kerosene (24).
- **Heavy industry**: could make increased use of low CI hydrogen sources to replace current hydrogen use and/or other energy sources, particularly for high-temperature heat. A primary contender for this is in steel manufacturing where hydrogen can replace coking coal both as a heat source and a chemical reducing agent (25).
- **Space and water heating**: Hydrogen could be used to replace natural gas, in part or whole, in home heating which would allow people to reduce or eliminate emissions from home heating (26).

In addition to these end-uses, hydrogen is also seen as a key component in decarbonizing the electricity sector. The potential role of hydrogen in this sector is discussed in the next section.

Net-Zero Aligned Electricity Systems and Hydrogen

There is strong alignment among studies modelling electricity systems in a net-zero context that *net-zero aligned electricity systems* will be required to:

1. Decarbonize electricity production through the increased use of non-emitting generation, and
2. Dramatically expand electricity production, transmission, and distribution infrastructure to enable the replacement of fossil fuels in a wide range of end-uses within transport, buildings, and industry.

These studies model various technological pathways to achieve these goals, but a common element is the integration of significant amounts of new variable renewable electricity (VRE) resources, such as wind and solar, while reducing reliance on unabated fossil fuel generation (i.e., fossil fuel generation without carbon capture).

Challenges of Net-Zero Aligned Electricity Systems

With increasing penetration of variable renewable energy (VRE), such as wind and solar, several challenges emerge. The output of VRE fluctuates based on weather conditions, time of day, and season. This variability makes it challenging to ensure a continuous and reliable electricity supply that matches electricity demand.

When conditions are unfavourable, electricity production may fall short of demand. Conversely, favourable VRE conditions can result in electricity surpluses, producing more energy than the grid can absorb, leading to VRE curtailment. During curtailment, the excess energy from VRE is forgone and not utilized. This variability challenge underscores the need for other resources to provide flexible generation in ways that align with net-zero goals (i.e., no or low carbon intensity). Additionally, it highlights the increasing value of being able to store electricity to take advantage of periodic overabundances of VRE to provide flexibility and reliability when VRE conditions are not favourable.

There are many potential solutions for addressing these challenges, including:

- **Zero-emission firm generation sources**: Hydroelectric and nuclear power are used as zero-emission electricity generators that offer dispatchable power. Of the two, hydro is more flexible in its ability to ramp production up or down to meet the current balancing needs of the grid. Enhanced geothermal generation, though still in the early stages of development and highly site-specific, has the potential to deliver significant amounts of zero-emission energy with fast ramping speeds.
- **Abated fossil fuel generation sources**: Natural gas-powered turbines are currently used worldwide to provide flexible and dispatchable generation to meet daily energy demand peaks and balance VREs. To align with net zero, natural gas turbines must capture the GHGs produced through additional carbon capture and storage (CCS) technology, though this technology is still developing and not yet widely deployed.
- **Limited use of unabated fossil generation sources**: While net-zero modelling consistently indicates that the vast majority of electricity production in net-zero aligned electricity systems will be free from GHG emissions or otherwise abated, some models show that a limited amount of unabated fossil fuel generation may be part of the most cost-effective pathways to net zero by 2050. These remaining unabated generators are generally low-capacity factor natural gas turbines, often called peaker plants. The assumption is that it will be significantly cheaper to offset peaker plant emissions (e.g., via direct air capture) than to completely replace those flexible generators with non-emitting technology, though this remains speculative.
- **Energy storage technologies**: Short-term energy storage solutions, such as lithium-ion batteries, have become increasingly cost-effective and are already used to manage daily and inter-day fluctuations in VRE production. Long-duration storage solutions, such as compressed air and hydrogen, can address seasonal variations in VRE output and provide backup power during extended periods of low renewable generation.
- **Interties**: Since VRE energy production is dependent on local weather conditions and time of day, interregional interties (i.e., transmission lines) can connect areas experiencing VRE overgeneration with those experiencing an electricity generation deficit. However, implementing interties involves significant infrastructure investments and regulatory coordination.
- **Distributed energy resources**: Distributed generation, distributed storage, microgrids, demand-side management, energy efficiency, and demand reduction are new technologies and practices that offer the potential to reduce total electricity consumption and optimize the

grid for local, real-time conditions. Grid optimization should allow VREs to be used more effectively.

Hydrogen's Potential Role in Net-Zero Aligned Electricity Systems

Hydrogen has the potential to support net-zero aligned electricity systems in two primary ways. First, hydrogen-fired combustion turbines and fuel cells can serve as both flexible and firm zero-emission electricity generation resources. Second, when hydrogen generation is combined with hydrogen produced via electrolysis, it can also serve as an electricity storage resource, storing electricity chemically in the form of hydrogen that can be converted back into electricity later. More specifically:

- **Providing firm and flexible power:** Although not currently deployed, when they do reach the market hydrogen-fired Combined Cycle Gas Turbine (CCGT) or Open Cycle Gas Turbine (OCGT) plants will be able to offer flexible and/or firm capacity, suitable for meeting peak demand. These plants will have the ability to provide reliable and dispatchable power generation, ensuring grid stability during periods of high demand.

  While currently rare, hydrogen-powered fuel cells are used today, and they offer a novel approach to zero-emission generation. Fuel cells are currently limited in size to a feasible maximum of about 2 MW of generation (27). In comparison, gas-fired turbines can exceed 300 MW but are generally not economical below 5 MW (28). Because of the generation scale differences, fuel cells are better suited for distributed applications, and turbines for large central generators. In either case, the hydrogen fuel must be produced in a low-carbon intensity (CI) manner.
- **Providing short-term to long-term energy storage:** Hydrogen can serve as a versatile storage medium. Surplus electricity can be converted into hydrogen and stored for various lengths of time allowing for both short-term and long-term electricity storage. Underground storage in salt caverns.

Hydrogen Fuel Cells vs. Hydrogen Fired Combustion

Hydrogen-fired generators and fuel cells both utilize hydrogen but differ significantly in their operational characteristics. Hydrogen-fired generators operate similarly to traditional combustion engines, allowing for rapid ramp-up and ramp-down capabilities. This flexibility makes them suitable for applications where power demand is variable and needs to be adjusted quickly such as in backup power systems and peaking power plants.

In contrast, fuel cells are designed for continuous, steady-state operation. They are less suited for applications requiring frequent start-stop cycles or rapid changes in power output. However, their higher efficiency (40-60% for PEM fuel cells and up to 85% for CHP applications) makes them an excellent choice for steady, high-demand applications, such as data centres and hospitals, where reliability and environmental performance are critical.

In addition to providing generation and storage resources, hydrogen can also support a net-zero aligned electricity system by contributing to supply and demand optimization, transmission system operation, generation diversity, and ancillary services. More specifically:

- **Grid Level Supply and Demand Optimization**: Electrolytic hydrogen production can act as a flexible electric load by ramping up to absorb excess VRE generation during periods of low system demand and/or excess electricity production and ramping down hydrogen production during high electricity demand periods and/or low VRE production. By acting as a flexible load, electrolytic hydrogen production can increase the efficiency of the electricity system by preventing other generators from having to ramp up or down in response to changing system demand, reducing the wasteful curtailment of excess electricity produced by VRE, and increasing the overall utilization factor of the electricity system.
- **Transmission System Optimization:** Hydrogen enhances grid diversity by offering a new fuel type and complementary energy pathway, such as electrolytic hydrogen production as energy storage. By leveraging hydrogen as an energy carrier, the grid can mitigate risks associated with dependence on any single energy source or technology, enhancing resilience and adaptability.
- **Improving Resiliency and Adaptability:** Hydrogen enhances grid diversity by offering a new fuel type, and complementary energy pathway i.e. electrolytic hydrogen production as energy storage. By leveraging hydrogen as an energy carrier, the grid can mitigate risks associated with dependence on any single energy source or technology, enhancing resilience and adaptability.
- **Ancillary Services**: The operation of the electricity grid requires considerations including, but not limited to, voltage regulation, black start capability, voltage control, reactive power, and operating reserve. Flexible hydrogen generation, flexible electrolytic hydrogen production, and hydrogen-based energy storage collectively provide grid operators with several tools to offer ancillary services and ensure grid reliability.

Hydrogen's Role in Ontario's Electricity System

Multiple recent studies have modelled economy-wide net-zero pathways in Ontario – generally in the context of national analyses. These studies model techno-economic pathways to achieve net-zero emissions across all sectors of the economy, including the electricity sector. Across these studies, there is general alignment on the significant role Ontario's electricity system will need to play in achieving net-zero emissions cost-effectively. However, while there is consensus on the importance of electricity in Ontario's net-zero future, the magnitude and character of the electricity system differ greatly between studies, including the relative importance and impact of hydrogen.

Ontario's electricity system must produce more electricity.

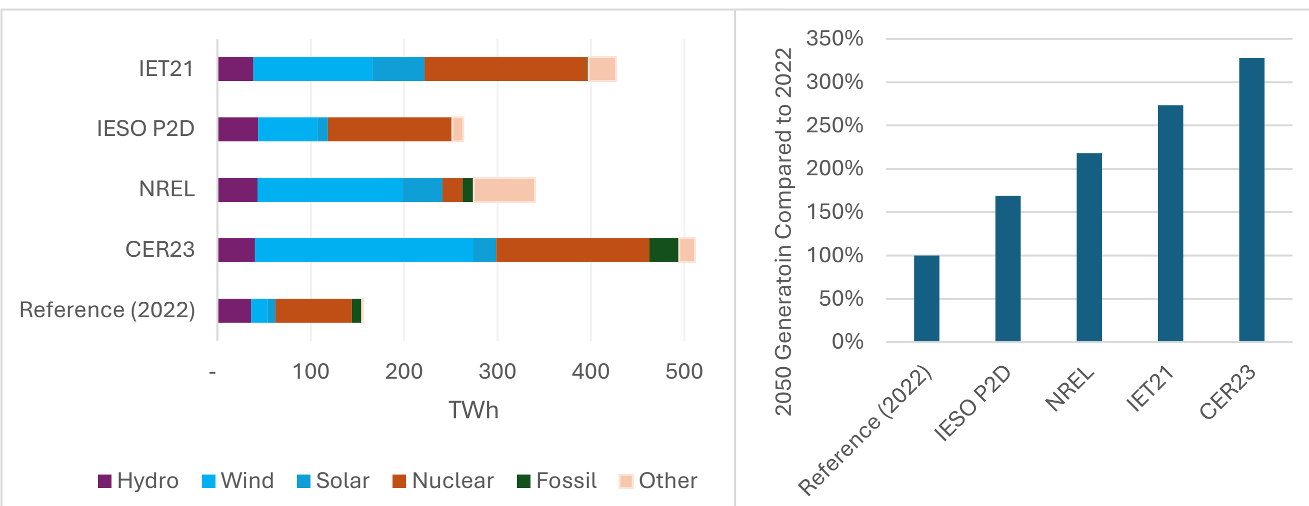
All the studies estimate that Ontario's electricity system will need to grow to more than twice its current size in terms of installed capacity. The IESO report "Pathways to Decarbonization" (P2D) estimates that by 2050, Ontario's generation fleet will need to grow from 42,000 MW to 88,400 MW. However, because many generation assets will reach the end of their life before 2050, Ontario will need just under 69,000 MW of new generation capacity over the next 26 years. This growth will be spread across several different generation types, with the largest new contributions from nuclear (17,800 MW), wind (17,600 MW), and hydrogen (15,000 MW), as shown in **Table 4**. The P2D report assumes that natural gas generation will be entirely phased out by 2050 and that there will be no hydrogen production in Ontario, so all hydrogen will need to be imported.

Table 4 | IESO P2D Estimated Electricity Sources Needed for 2050

Energy Source	New Capacity Required by 2050 (MW)	Total Capacity in 2050 (MW)
Bioenergy	0	41
Storage	2,000	2,000
Imports	3,800	4,131
Solar	6,000	6,259
Demand Response	5,936	6,744
Hydroelectric	657	10,005
Hydrogen	15,000	15,000
Wind	17,600	17,760
Nuclear	17,800	26,453
Total MW	**68,793**	**88,393**

Other studies, including the Canadian Energy Outlook 2021 by the Institut de l'énergie Trottier (IET21), the North American Renewable Integration Study by the National Renewable Energy Laboratory (NREL), and Canada's Energy Future 2023 by the Canada Energy Regulator (CER23), have also attempted to estimate the amount of electrical energy Ontario will need in 2050 as shown in **Figure 6**. Each study finds differing total amounts of TWh required and different amounts of each generation type. **Figure 6** also includes Ontario's electricity capacity as of 2022 for comparison. Across all estimates the IESO is the most conservative in total TWh required.

Figure 6 | Estimated Electricity Generation Under Net-Zero Modelling Needed For 2050, Total TWh and Percent Compared to 2022 Generation, All Models



Ontario's electricity system must accommodate significantly more VRE.

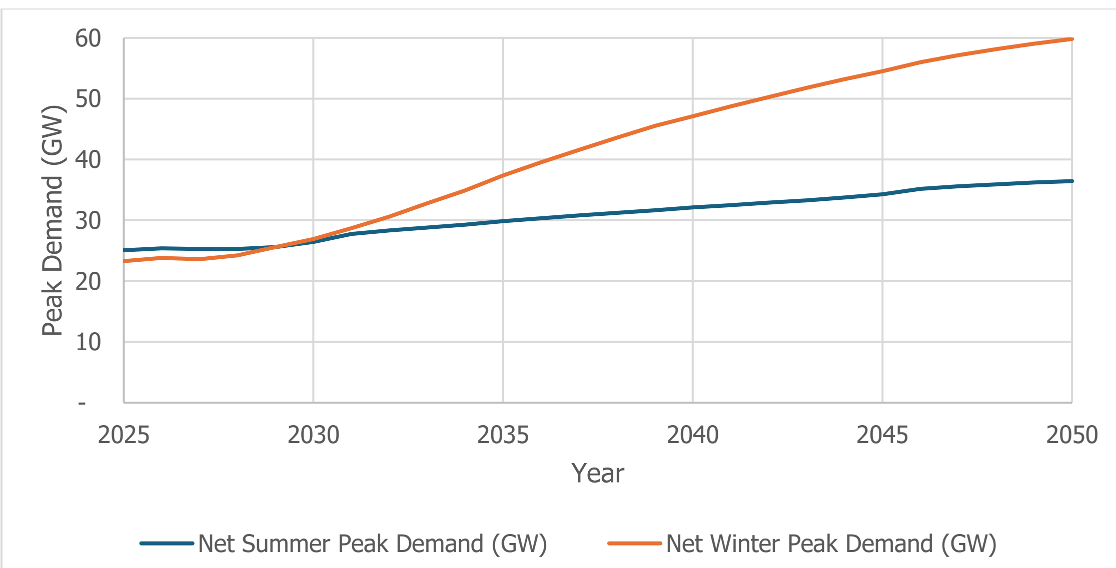
Wind and solar currently contribute approximately 17% of Ontario's annual electricity generation and under net-zero modelling assumptions for cost-effectiveness, the various models calculate that VRE makes up a substantial portion of the 2050 generation fleet. Estimates of how much of Ontario's total energy will be delivered by VRE vary considerably between studies, with estimates ranging from as low as 28% to as high as 58% as shown in **Table 5**.

Table 5|Ontario Variable Renewable Energy (VRE) Generation in 2050.

Model	Wind-percentage of total (TWh)	Solar-percentage of total (TWh)	Total VRE (TWh)
2022			
Reference (2022)	11%	5%	17%
2050			
CER23	46%	5%	51%
NREL	46%	13%	58%
IESO P2D	24%	4%	28%
IET21	30%	13%	43%

In addition to needing more electricity, the P2D net zero scenario calculates that Ontario's electricity system's peak demand will change with the current summer peak shifting to a winter peak around 2030. Under the P2D net-zero scenario the winter peak is calculated to progressively grow, reaching a level of about 2.4 times the current peak by 2050 as shown in **Figure 7**. This shift is largely due to the electrification of space and water heating.

Figure 7|Ontario Winter and Summer Electrical Peak Demand



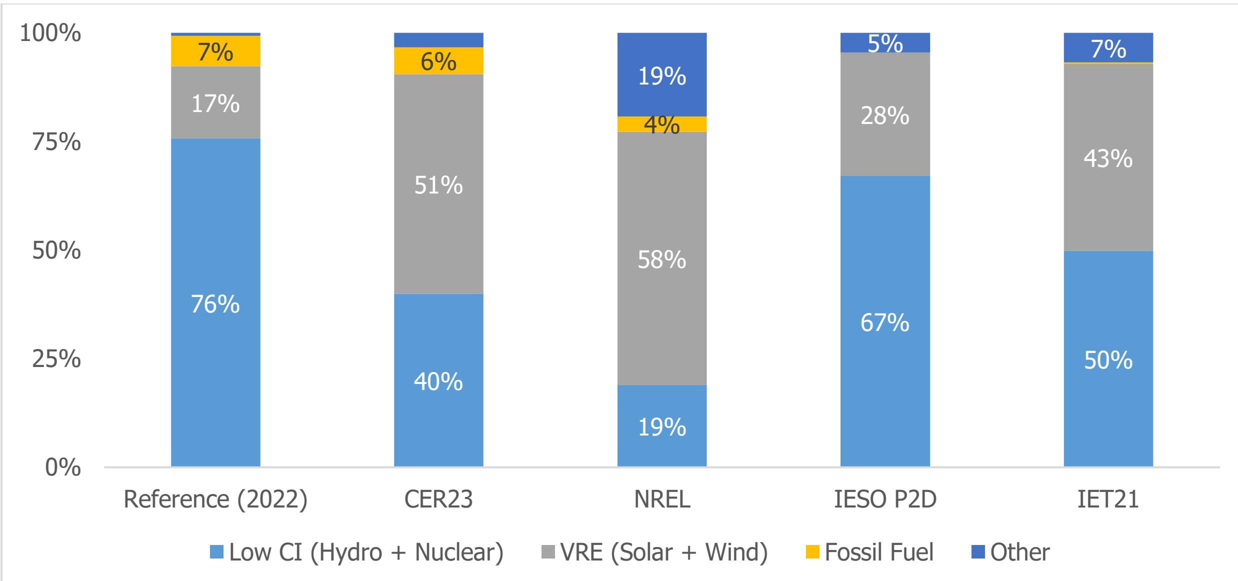
Because hydrogen is one of the few technologies that can economically offer seasonal energy storage, it is likely to play a role in Ontario's electricity system given the predicted divergence of summer and winter peaks by the P2D study.

Ontario's electricity system must decrease reliance on unabated fossil fuels.

In the projected net-zero future, Ontario will use other electricity resources in place of unabated fossil fuels to provide flexible generation. Natural gas currently represents approximately 7% of

Ontario's electricity generation where it plays an important role of being a flexible generation source that can balance VRE supply and grid demand as well as be called upon to meet peak demand events. While the studies come to different conclusions about the proportions of low CI generation and VRE generation in a future net-zero aligned electricity grid, all of the models calculate a decrease in fossil fuel generation compared to the 2022 reference as shown in **Figure 8**.

Figure 8 | Percent Generation Type in Different Net-Zero Models



Given the variability of VRE generation and its increasing share in the 2050 electricity system, additional low CI flexible generation and energy storage capacity will be essential for maintaining system reliability. Hydrogen, with its capacity to act as a flexible generator to meet peak demands, absorb excess VRE generation, and serve as short or long-duration storage to span seasonal VRE generation peaks and troughs, has the potential to compliment VRE expansion and replace unabated fossil fuel generators.

The P2D report projects that 5% of Ontario's 2050 generation will come from hydrogen. Given the implied capacity factor of 9.13%, this hydrogen will most likely be used for grid balancing and seasonal storage needs. It is important to note that the P2D report considers hydrogen as a proxy for all low-carbon fuels.

However, other studies do not reach the same conclusions regarding hydrogen. The CER23 report assessed hydrogen as a potential generation source but concludes that "we do not project any hydrogen use in the power sector in the Global Net-zero Scenario." Similarly, the IET21 study found hydrogen potentially economical in Quebec and Nova Scotia but not in other provinces or territories. The NREL study did not consider hydrogen storage but instead calculated economical net-zero generation by including 61 TWh of curtailment, which is captured in the 'other' category in **Figure 6** and **Figure 8**. Comparing these various studies highlights that the role of hydrogen in economically developing a net-zero aligned electricity system remains a topic of active debate.

Actions to Date Supporting the Role of Hydrogen in a Net Zero Economy in Ontario

The following section provides a high-level overview of the studies, policy documents and work undertaken to date regarding the role of hydrogen in Ontario's net-zero transition.

Ontario's Low-Carbon Hydrogen Strategy

Ontario's Low-Carbon Hydrogen Strategy outlines the province's ambitious roadmap for establishing a low-carbon hydrogen economy (29). The strategy aims to leverage Ontario's strengths in clean electricity, skilled labour, and existing industrial infrastructure to create jobs and reduce greenhouse gas emissions. Outlined in the strategy are eight concrete and immediate actions designed to significantly boost the province's low-carbon hydrogen production capacity to support both the broader economy and Ontario's electricity system. The strategy aims for an eight-fold increase in production, while also supporting the nascent market to meet its potential. The strategy focuses on immediate actions to enable production and expand the low-carbon hydrogen economy in Ontario. Among the eight actions are several innovative pilot projects that will drive this transformation.

Those summary recommendations are:

1. Launching the Niagara Falls Hydrogen Production Pilot
2. Identifying Ontario's Hydrogen Hub Communities
3. Assessing the Feasibility of Hydrogen Opportunities at Bruce Power
4. Developing an Interruptible Electricity Rate
5. Supporting Hydrogen Storage and Grid Integration Pilots
6. Transitioning Industry Through the Use of Low-carbon Hydrogen
7. Consulting on an Ontario Carbon Sequestration and Storage Regulatory Framework
8. Supporting Ongoing Hydrogen Research

Moreover, Ontario plans to significantly increase its low-carbon hydrogen production capacity. The strategy foresees a substantial rise in hydrogen demand across various sectors, including industrial processes, transportation, and potential blending into the natural gas network. The development of hydrogen hubs across the province is aimed at meeting this localized demand efficiently. Besides the Niagara Hydrogen Centre, Atura Power has identified four potential hydrogen hubs:

- **Halton Hills Energy Centre** aims to support heavy-duty trucking, and potentially blend hydrogen with natural gas for electricity generation during peak demand in Atura Power's Halton Hills combined-cycle gas turbines. The energy centre aims to utilize surplus clean electricity from the Sir Adam Beck hydroelectric generating station to produce hydrogen (6). The facility plans to incorporate a 20 MW electrolyzer capable of providing grid balancing services and utilizing low-cost off-peak electricity to produce low-carbon hydrogen. This hydrogen is intended for use in heavy-duty trucking, municipal mobility, and industrial applications, better monetizing off-peak electricity generation either from must-run generators or excess renewable generation.
- **Nanticoke Hydrogen Centre** on Lake Erie aims to supply hydrogen to nearby heavy industries using existing electricity infrastructure. Previously a coal-fired site, its transformation includes 44 MW of solar generation in partnership with Indigenous communities. Atura Power is exploring low-carbon hydrogen production to support local decarbonization efforts.
- **Brighton Beach Energy Centre** in Windsor is evaluating hydrogen production and underground salt cavern storage. As the hydrogen demand is established, the Brighton Beach

combined cycle gas turbine can consume the hydrogen, thereby reducing emissions during peak electricity generation periods.

- **Lambton Hydrogen Centre**, located at a former coal site in Lambton-Sarnia, is being considered for large-scale hydrogen production to support local heavy industry.

Hamilton is highlighted within the strategy for its strategic role in the hydrogen economy, particularly through clean steelmaking investments. The provincial government's support for ArcelorMittal Dofasco's $1.8 billion project to transition to hydrogen-ready electric arc furnaces exemplifies the integration of low-carbon hydrogen technologies in traditional industries. This project alone is poised to reduce GHG emissions by about three million tonnes annually (29).

Overall, Ontario’s strategy integrates the development of low-carbon hydrogen into its broader energy and environmental goals, promoting a diverse and sustainable energy mix that leverages its clean electricity grid to support economic growth and environmental sustainability.

Ontario-focused Hydrogen Research

Ontario's Hydrogen Hub in Sarnia-Lambton

The Strategic Plan for Ontario's Hydrogen Hub in Sarnia-Lambton outlines the region's transformation into a leading low-carbon hydrogen production and utilization center (30). The report lays out a detailed approach to leverage the existing industrial base and infrastructure towards developing a robust low-carbon hydrogen economy.

The Sarnia-Lambton region in Southern Ontario stands as a major center for hydrogen production and usage, primarily involving steam methane reforming of natural gas without carbon capture technology. Annually, the region produces and utilizes over 150,000 tonnes of hydrogen mainly for refining, chemicals, and fertilizer production. However, there is a strategic shift towards developing this hub into Ontario’s largest low-carbon hydrogen center, leveraging existing infrastructure like a 30-km hydrogen pipeline, skilled workforce, research facilities, and extensive transport routes.

Sarnia-Lambton is a significant energy consumer, primarily dependent on natural gas. The transition to low-carbon hydrogen is seen as a pivotal move to reduce greenhouse gas emissions from large industrial sectors in the region. One of the primary demand sources is industrial decarbonization, where transitioning from high to low-carbon intensity hydrogen production in oil, gas refining, and ammonia manufacturing is a significant target.

The plan includes blending hydrogen into the local low-pressure natural gas network that serves residential, commercial, and light-industrial users, as a transitional strategy to gradually reduce carbon emissions from natural gas heating. For the transportation sector, although hydrogen demand for fueling stations currently represents a small fraction of current fuel demand that demand is expected to grow significantly. That growth is expected particularly for fleets and heavy-duty transportation along major corridors like the 400 series highways. There is also potential for hydrogen to replace diesel in heavy-duty vehicles like tractors and other farming equipment, contributing further to Ontario’s decarbonization efforts.

Regarding power generation, the Sarnia-Lampton hydrogen hub report determines that blending hydrogen into the natural gas already used in power plants is a viable option for reducing the peak carbon intensity of the electricity grid, which aligns with broader decarbonization efforts. The plan also recognizes the significant potential for exporting hydrogen and hydrogen-derived fuels like ammonia to markets across North America via established trade routes.

Sarnia-Lambton's strategic plan outlines a framework for enhancing hydrogen production, particularly focusing on low-carbon hydrogen to replace the current high CI hydrogen production primarily sourced from natural gas. The region can become Ontario's largest centralized source of low carbon intensity hydrogen derived from SMR with CCS, pending overcoming regulatory barriers related to the storage of captured carbon. Moreover, significant investments are being considered in electrolysis facilities to enable the production of hydrogen, leveraging the region's existing infrastructure and skilled workforce. There are also plans to capitalize on the abundant salt cavern resources for hydrogen storage, which could further support grid-scale energy storage and help manage the provincial electric grid's carbon intensity.

Forecasting Low-Carbon Hydrogen Market Characteristics in Ontario to 2050

The "Forecasting Low-Carbon Hydrogen Market Characteristics in Ontario to 2050" report discusses the results of a techno-economic assessment model for hydrogen production and utilization in Ontario (31). The model simulates hydrogen value chain development across sectors and regions, providing estimates for hydrogen production, use, capital investments, operating expenses, job creation, and carbon intensity up to 2050. The report aims to support the government of Ontario's previously published Low-Carbon Hydrogen Strategy by creating roadmaps and implementation plans, focusing on market-wide assessments to inform regional and sector-specific hydrogen system planning and policy development.

Among hydrogen's multiple end-use applications within the industrial and transport sectors, the report identifies hydrogen as a promising option for several electricity sector-related applications. A few examples of these include its use as portable power generation for temporary events (i.e. motion picture industry, construction industry, agriculture), or as stationary electricity generation, where hydrogen offers a low-carbon alternative to diesel in remote communities and critical facilities (i.e. hospitals, data centers), especially when produced using local renewable power. Additionally, hydrogen can be stored for future electricity use and grid management services, as well as blended with natural gas for use in existing natural gas-fired electricity generators.

The report discusses the geographic locations of prospective hydrogen hubs across Ontario. Thirteen market hubs and five representative hubs were identified based on criteria such as urban population centers, industrial end-use applications, and regional demand consolidation. This mapping enables a comprehensive analysis of hydrogen supply and demand, ensuring that both urban and remote areas are included in hydrogen market planning.

The report finds that Ontario can achieve self-sufficiency in low-carbon hydrogen and become a net exporter by prioritizing its productive capacity. Simultaneous support of market adoption of hydrogen end-use applications results in greater job creation and GHG emissions reductions. This increase in production relies on developing new technologies for the efficient conversion of available feedstocks to hydrogen. Moreover, expanding renewable and nuclear power capacities will support cost-effective hydrogen pathways, while natural gas, through methane reforming with CCUS also contributes to lower-cost hydrogen production.

The report concludes that by focusing on applications that can consume higher volumes of hydrogen with less reliance on capital-intensive infrastructure, demand can scale up faster at lower costs of delivered hydrogen. The goal of that strategy is to keep levelized costs low in the early years of market scale-up.

3. Methodology and Assumptions

This study aims to explore possible scenarios for hydrogen's role in meeting Ontario's net-zero targets, including its use, production, the conditions required for these scenarios to emerge, and the implications for Ontario's electricity system. To achieve this, our methodological approach is structured into three sequential steps, as illustrated in **Figure 9**. These steps are designed to systematically analyze hydrogen demand, assess various hydrogen production technologies, and explore the integration of hydrogen into Ontario's electricity grid. By following this structured approach, we aim to provide insights that inform policy decisions and strategic planning for Ontario's future energy system.

Figure 9 | Methodological Approach

Define Hydrogen Pathway Scenarios:

The first step involves defining a set of potential hydrogen pathway scenarios. These scenarios are crafted to represent a range of potential pathways hydrogen could take towards Ontario's net-zero emission goals. By designing diverse scenarios that differ in the extent and nature of hydrogen use and production methods, we aim to evaluate the range of potential impacts that may be experienced by the electricity system due to the use and production of hydrogen in Ontario.

Evaluating Impacts, Costs, and Feasibility:

Following the scenario definition, we assess each pathway for technical and economic feasibility with a focus on understanding the conditions that need to be in place for hydrogen to play the role envisioned by the pathway in decarbonizing Ontario's economy. This evaluation includes quantitative modeling of hydrogen demand examining the potential impacts, requirements, and costs associated with the use and production of hydrogen in each scenario, which feed into our analysis of the viability and likelihood of these hydrogen pathways.

Analyzing Electricity System Implications:

The final step involves analyzing how the hydrogen pathway scenarios may impact Ontario's electricity system. This includes determining how the electricity system might need to adapt to support hydrogen use and production as well as how hydrogen could serve as a resource for providing reliable, affordable, and net-zero electricity.

The sections that follow provide a more detailed explanation of each step in our methodology. Appendix 1 contains additional detailed information on the inputs and assumptions used in this study.

Hydrogen Pathway Scenarios

To define the hydrogen pathway scenarios used to calculate possible demand, we constructed three scenarios to illustrate the upper and lower ranges of hydrogen's potential role as a net-zero energy carrier in Ontario. These scenarios represent varying degrees of coordination and support for hydrogen use in Ontario. It is important to note that these are not forecasts but "what if" scenarios designed to explore a range of outcomes and their potential impacts on the electrical grid from different levels of hydrogen adoption.

For each scenario, we consider a range of low-carbon hydrogen supply options. Given the broad spectrum of potential hydrogen supply technologies and pathways, we focus on key supply pathways that could practically meet the scale of demand and are most likely to play significant roles in a potential hydrogen economy in Ontario.

Hydrogen Demand

In scoping hydrogen demand, we constructed three scenarios for hydrogen demand to represent varying degrees of coordination and support for the use of hydrogen in Ontario. These scenarios consider hydrogen use in all sectors of the economy except for power generation as the focus of this analysis is to understand the complex relationship between how the electricity system may integrate and be impacted by hydrogen's development as a net-zero energy carrier in the wider economy. **Figure 10** summarizes these three scenarios followed by more detailed descriptions of each scenario.

Figure 10 | Hydrogen Demand Scenario Descriptions

Hamilton Only	• Hydrogen demand is concentrated within the Hamilton region. • Hydrogen use is constrained to promising end-uses or in sectors where pilots are underway or are planned in other parts of Ontario.
Low - Ontario	• Hydrogen demand is expanded beyond the Hamilton region to include all of Ontario. • Hydrogen is used for the most promising applications based on current knowledge.
High - Ontario	• Hydrogen demand is expanded beyond the Hamilton region to include all of Ontario. • Hydrogen is used for an expanded set of end-uses, including both promising applications and the offsetting of some energy uses that may have alternative decarbonization pathways.

Hamilton Only

In this scenario, hydrogen demand is limited to the Hamilton region of Ontario, targeting only the most difficult-to-decarbonize sectors and to a much smaller extent, local energy end-uses that may also benefit from a centralized supply. This includes the steel industry, along with a portion allocated to long-haul heavy-duty trucking, rail transport, and space heating in large commercial and residential buildings (see **Table 6** for more information). The scenario envisions a future where the Hamilton region supports the coordinated development of an isolated hydrogen hub, but coordinated support to develop a hydrogen economy province-wide does not materialize.

Low Ontario Coordination

In this scenario, hydrogen demand is expanded to include energy end-uses across Ontario, but hydrogen use remains constrained to only the most promising applications and a small number of applications where alternatives do exist. This involves a more cohesive transition within the industrial and transportation sectors, while also allocating a greater share towards space heating where feasible (see **Table 6** for more information). The scenario envisions a future where hydrogen hubs and corridors are supported and developed province-wide, but hydrogen is not adopted in a major way for most energy end-uses with alternative decarbonization pathways.

Urban centers are envisioned to have hydrogen refuelling infrastructure shared by medium-heavy duty road vehicles. Off-road transportation, such as rail and marine, will have refuelling infrastructure at railyards and ports, built and operated synchronously. Additionally, it is assumed that a portion of Ontario's industrial activity is located around these hubs, utilizing the hydrogen produced to offset natural gas use, thereby assisting in creating economies of scale.

High Ontario Coordination

In this scenario, hydrogen demand is expanded to include energy end-uses across Ontario, encompassing a broader range of applications beyond the most promising ones (see **Table 6** for more information). This scenario envisions an optimistic future where large-scale hydrogen infrastructure deployment is achieved by 2050 in Ontario.

This scenario includes all sectors considered difficult to decarbonize directly without hydrogen. It also involves hydrogen replacing a relatively small portion of natural gas energy use, assuming that hydrogen transmission and distribution infrastructure is present nearby.

Hydrogen Supply

For each demand scenario, we consider a range of implications for various low-carbon hydrogen supply options. Due to the large range of hydrogen supply technologies and pathways that may be available in the future, we focus on a subset of key hydrogen supply options that are most likely to play significant roles in a potential hydrogen economy in Ontario.

For this analysis, we focus on the following hydrogen supply options for generation within the province:

- Autothermal Reformation with carbon capture (“ATR + CCS”)
- Steam Methane Reformation with carbon capture (“SMR + CCS”)
- Methane Pyrolysis (“NG Pyrolysis”)
- Electrolysis

We also qualitatively consider the ability to import hydrogen into the province to satisfy domestic demand.

We focus on these options for the following reasons:

- **Technological Maturity and Scalability**: ATR + CCS, SMR + CCS, NG Pyrolysis, and electrolysis are likely to be among the most developed and scalable hydrogen production technologies. They have been demonstrated at various scales and are considered feasible for large-scale deployment.
- **Carbon Intensity**: These technologies offer pathways to produce hydrogen with low-carbon intensity. ATR + CCS and SMR + CCS are mature hydrogen generation technologies that can generate low-carbon hydrogen by integrating carbon capture and storage, significantly reducing CO_2 emissions. Methane pyrolysis produces low-carbon hydrogen while capturing carbon in a solid form without greenhouse gas emissions. Electrolysis can produce low-carbon intensity hydrogen without utilizing fossil fuels and virtually zero carbon emissions by utilizing electricity to split water.
- **Economic Viability**: The selected technologies have the potential to become cost-competitive as the hydrogen economy grows and technology improves. ATR + CCS and SMR + CCS benefit from being established industrial-scale technologies combined with existing natural gas infrastructure and economies of scale. NG Pyrolysis and Electrolysis offer the potential of economic small-scale hydrogen generation though will require technological advancement over the next decade to fully realize the expected lower costs.
- **Technology Deployment**: In evaluating the various scenarios, each technology will be considered to fully satisfy the hydrogen generation requirements. It is reasonable to assume that the outcome will consist of a combination of various technologies and outcomes to address the regional-specific conditions and requirements of the time.

Evaluating Impacts, Costs, and Feasibility

To evaluate the impacts, costs, and feasibility of our hydrogen pathway scenarios, we first quantify the portion of energy transition attained by sector and the aggregate amount of hydrogen demand created by each scenario. For each scenario, a determination of the equivalent electrical offset achieved by the hydrogen transition will be determined, for the sectors that have the potential to be directly offset by transition to electricity. It should be noted that the scenarios presented represent only a portion of the total conventional fuel transition that is required to meet the Net-Zero climate initiatives. For the portion not transitioned to hydrogen, other alternatives will be necessary, which will include incremental electrical generation, biofuels, and carbon capture. The impact of these alternatives to IESO has not been evaluated and could have even greater implications than what is presented in this report.

For the various hydrogen supply options for each scenario; key feedstock and other implications are determined corresponding to each of the evaluated generation technologies. To further understand the implications of the hydrogen generation for each scenario, a techno-economic analysis was completed for each technology at various size assumptions. The levelized cost of hydrogen (LCOH) will be compared to the forecast retail price of the conventional fuel transition as well as the anticipated cost of electricity.

Estimate Hydrogen Demand

To estimate the hydrogen demand under each scenario, we followed these three steps:

1. Understand Ontario's Energy System
2. Estimated Hydrogen End-use Adoption
3. Calculated Hydrogen Demand for End-uses

Understand Ontario's Energy System

To explore hydrogen adoption as an energy carrier, we first identified the current energy carriers used by each sector in Ontario and the services they provide. We then postulated how hydrogen could replace, wholly or partially, these energy carriers by leveraging proven examples and pilot projects. This analysis qualitatively considers the infrastructure and economic challenges associated with hydrogen use, acknowledging that further detailed analysis is needed for specific use cases.

Examining the current energy landscape, including energy carriers and end-use characteristics, was crucial to understanding the potential range of hydrogen adoption in a net-zero 2050 Ontario, which is discussed further in the next section.

To understand Ontario's current energy system, we established a baseline using 2019 energy use data from Natural Resources Canada's Comprehensive Use Database. We chose this year as it is the most recent data unaffected by impacts on energy-use patterns resulting from COVID-19. This data, along with population projections and industry growth factors, was incorporated into the Transition Accelerator's Net Zero Energy System Transition (NZEST) model. The NZEST model is a novel, bottom-up, end-demand-based energy system model that has been developed by The Transition Accelerator to project technology transition energy system impacts and energy use at the provincial and national levels.

From here, we developed a *Status Quo* (SQ) scenario that estimated energy demand by sector in Ontario for both the short term (2025) and long term (2050), assuming no changes to the current energy source mix, but considering growth based on population projections (for buildings, transportation, and agricultural sectors) and industry-specific macro growth trends. More information on sector-specific assumptions can be found in Appendix 1. The SQ scenario served as a reference point for estimating sector energy demand scale and composition in 2050, which was the basis for creating three scenarios of varying levels of hydrogen adoption.

For the Hamilton Only scenario, we estimated energy demand within the city based on Ontario data. Unfortunately, significant data limitations were encountered due to a cybersecurity event that prevented the City of Hamilton staff from providing current energy usage data. However, we obtained greenhouse gas (GHG) data for large emitters in the region, revealing that the ArcelorMittal Dofasco steel production facility accounted for 86% of Hamilton's industrial emissions. We excluded the remaining 14% of emissions linked to 18 smaller facilities, as they were considered unlikely to significantly utilize hydrogen. Consequently, we focused on the ArcelorMittal Dofasco facility and estimated small shares of transportation and building energy use.

Estimate Hydrogen End-use Adoption

To estimate hydrogen end-use adoption in each scenario, we analyzed 17 different sectors for their potential to use hydrogen as an energy carrier. We then developed assumptions about hydrogen adoption that aligned with the definitions of each scenario in terms of the percentage of energy use met by hydrogen for each end-use under each scenario. **Table 6** summarizes these assumptions. For detailed assumptions and rationales underlying this analysis, see Appendix 1.

Table 6 | End-Use hydrogen adoption assumptions

		% of Sector Energy Use to H_2		
Sector	**Abbreviation**	**Hamilton**	**Low ON**	**High ON**
Transportation				
Ligh Duty Vehicles	LDV	0%	0%	6%
Medium Duty Vehicles	MDV	0%	22%	45%
Heavy-Duty Vehicles	HDV	1%	50%	100%
Rail Transport	Rail	1%	50%	100%
Inter-City Buses	ICB	0%	39%	79%
Urban Buses	UB	0%	42%	84%
Marine Transport	Marine	0%	0%	99%
Buildings				
Residential Space Heating	RSH	0.4%	3%	11%
Commercial Space Heating	CSH	0.4%	7%	22%
Industry				
Motive Agriculture	Agr Mot	0%	0%	31%
Non-Motive Agriculture	Agr Nmot	0%	0%	31%
Steel Industry	Steel	10%	10%	10%
Non-Ferrous Smelting	NF Smelting	0%	28%	56%
Extractive Industries	Ext Ind	0%	0%	22%
Cement Industry	Cement	0%	4%	8%
Chemical Industry	Chemicals	0%	33%	67%
Other Manufacturing Industries	Other Mfg.	0%	14%	28%
Construction	Constr.	0%	21%	53%

It is important to note that the sectors analyzed do not represent an exhaustive list of energy end-uses in Ontario. Although sectors like aviation and school buses may adopt hydrogen by 2050, they are not anticipated to significantly drive the hydrogen economy and have thus been excluded from this analysis. It should also be noted that these scenarios are not predictions or forecasts of future adoption.

Calculate Hydrogen Demand for End Uses

Once we established the percentage of energy use met by hydrogen for each end-use, we estimated annual hydrogen demand under each scenario. The steps involved were:

1. **Delineate Total Sector Energy Demand for 2050**: Based on the analysis in the *Understand Ontario's Energy System* section, we broke down sector energy demand from the

SQ baseline scenario (projected from CEUD data) into individual energy carriers (gasoline, diesel, natural gas, etc.).

2. **Analyze Proportion of Energy Use by Carrier**: Based on the analysis in the *Estimate Hydrogen End-use Adoption* section, we determined the proportion of energy used by each carrier that is replaced by hydrogen.
3. **Calculate and Assign Relative Efficiency Factors**: Relative efficiency factors were calculated based on energy carrier conversion technology efficiencies from literature to account for changes in service energy required (e.g., a Hydrogen Fuel Cell Electric Vehicle (HFCEV) powertrain is more efficient than a diesel ICE, and thus requires less overall energy to provide the same amount of service to the user.) To calculate relative efficiencies, the following equation was used:

$$Incumbent\ Energy\ to\ Transition\ * \frac{Eff.Incumbent}{\mathrm{Eff.}\,New\ Tech}$$

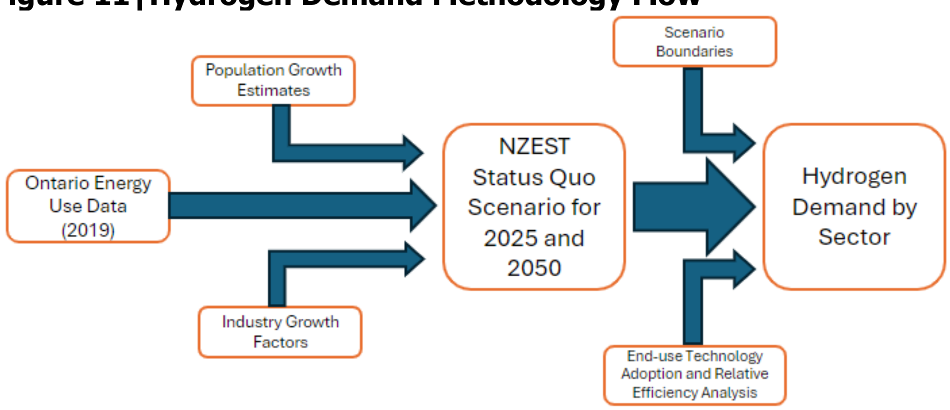
The following equation shows an example of this calculation for the conversion of a diesel ICE vehicle to HFCEV for a relative efficiency factor of 0.91 (diesel ICE to HFCEV):

$$Diesel\ Use\ to\ HFCEV\ (PJ)\ * \frac{0.41\frac{Jout}{Jin}}{0.45\frac{Jout}{Jin}} = 0.91 \text{ J energy new tech/J incumbent req'd}$$

4. **Determine Hydrogen Needed for Each Sector**: We combined the proportion of energy allotted to hydrogen transition for each sector with the relevant energy carrier technology's efficiency factor to calculate the hydrogen needed (in PJ) to meet the same service requirements as the incumbent technology.
5. **Aggregate Hydrogen Demand**: We aggregated hydrogen demand by sector and then totalled it for each scenario.

Figure 11 illustrates the methodological flow of these steps.

Figure 11 | Hydrogen Demand Methodology Flow



Estimate Hydrogen Supply Impacts and Costs

To understand the implications of producing enough hydrogen to satisfy the three demand scenarios, we analyze the potential impacts and costs of the four production technologies identified in the *The sections that* follow provide a more detailed explanation of each step in our methodology. Appendix 1 contains additional detailed information on the inputs and assumptions used in this study.

Hydrogen Pathway Scenarios section – Autothermal Reformation with carbon capture ("ATR + CCS"), Steam Methane Reformation with carbon capture ("SMR + CCS"), Methane Pyrolysis ("NG Pyrolysis"), and Electrolysis.

Specifically, we evaluate each production technology for:

- Feedstock and Energy Requirements
- Carbon Emissions and Energy Efficiency
- Supply Costs

For this analysis, an "average" technology profile has been utilized to assess NG Pyrolysis and Electrolysis, as each of these technologies has numerous different variations at varying levels of technical readiness and commercialization, which presents itself with different operating characteristics. The use of an average parameter for these technologies is intended to provide a macro assessment of requirements and results that should capture the overall implications of the technology as a group. Additionally, as both NG Pyrolysis and Electrolysis technologies are expected to advance in their commercial development, a comparison of what current technology capital and operating assumptions are to those expected to be realized in 2050 is presented to illustrate the impact on LCOH. Additional details and references for specific assumptions are included in Appendix 1.

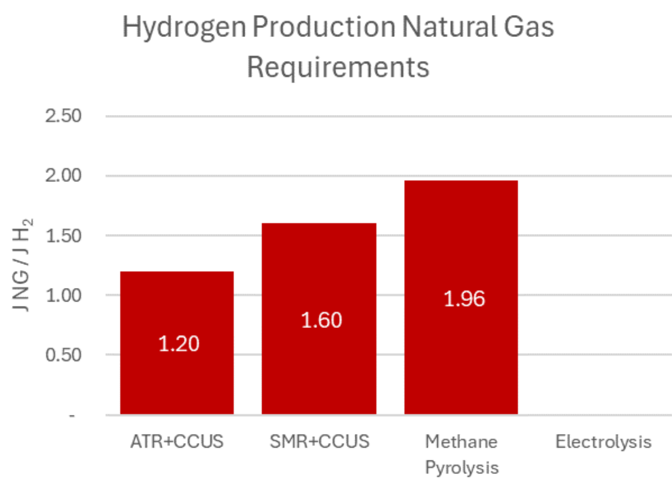
Feedstock and Energy Requirements

Hydrogen is a secondary fuel and thus requires the supply of technology-specific feedstock and energy to generate the volume of hydrogen required to achieve the fuel transition represented in the scenarios. The primary feedstock for ATR + CCS, SMR + CCS, and NG Pyrolysis is natural gas. Secondary feedstocks for each is electricity with ATR + CCS and SMR + CCS also requiring water as a secondary feedstock. For Electrolysis, the primary feedstock for the process is electricity with water being a secondary feedstock.

Natural Gas Requirements

Three of the four evaluated technologies are based on natural gas as a feedstock. For ATR + CCS, SMR + CCS, and NG Pyrolysis, natural gas, or specifically methane and the other hydrocarbon constituents in the natural gas stream, are subject to heat-induced chemical reactions that split the methane molecule to its atomic elements and result in the generation of hydrogen. Natural gas is also a significant requirement for the thermal energy requirement for the reformation process, as well as some thermal pyrolysis processes. **Figure 12** summarizes the natural gas feedstock requirements for ATR + CCS, SMR + CCS, and NG Pyrolysis on a Joule per Joule H_2 basis. NG Pyrolysis requires the greatest amount of natural gas on a Joule of natural gas per Joule of hydrogen basis at 1.96, as all hydrogen is derived from the methane molecule. Reformation has a greater efficiency and requires less natural gas due to the presence of water in the reaction process and its contribution of hydrogen atoms for a higher percentage of hydrogen production. SMR + CCS requires 1.6 J_{NG}/J_{H2} whereas ATR + CCS requires 1.2 J_{NG}/J_{H2}. Though ATR + CCS requires a greater amount of natural gas from a stoichiometric perspective than SMR + CCS, ATR + CCS is far greater in capturing and utilizing the waste heat from the process and thus requires less natural gas for purposes of heat generation and thus less natural gas overall.

Figure 12 | Natural Gas Input Requirement Assumptions by Supply Option



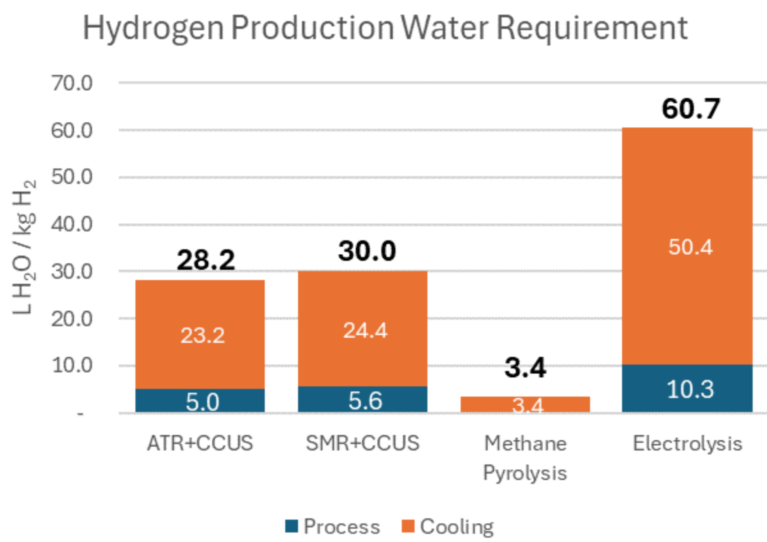
Water Requirements

All four of the evaluated technologies appear to have some level of water requirement, whether it is for the hydrogen production process or cooling purposes. The amount of requirement for each process is shown in **Figure 13**.

NG Pyrolysis water requirements are the lowest (3.4 L / kg H_2) of the four evaluated technologies with many of the technology companies indicating no water requirement at all due to waste heat capture and utilization of air cooling. Conversely, Electrolysis requires the greatest amount of water (60.7 L / kg H_2) due to high purity requirements for the electrolysis process and the reject water volumes associated with purifying the raw water and the high cooling requirements. Much of the water utilized for cooling is conserved and returned to the watershed but it still requires a steady access to large volumes of water. Depending on the source of water and the ambient conditions during operations, the potential raw water supply could double the requirements utilized for this evaluation. Further advancements in the technology could see air cooling introduced but at this time water cooling is the accepted means.

For both ATR + CCS and SMR + CCS, similar volumes of water are required for each process, with ATR + CCS being slightly lower at 28.2 vs 30 L / kg H2 for SMR + CCS. In terms of process water, Electrolysis consumes 10.3 L / kg H2 whereas ATR + CCS and SMR + CCS consume 5.0 and 5.6 L / kg H2 respectively, and no process water requirement for NG Pyrolysis (32–37).

Figure 13 | Hydrogen Production Water Requirement Assumptions by Supply Option

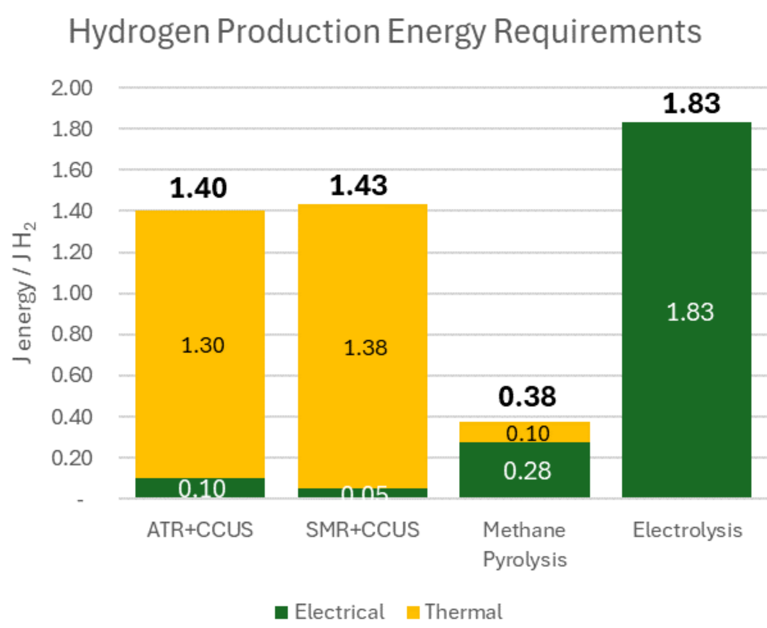


Electrical Requirements

All of the hydrogen generation processes are endothermic and rely on energy input to generate hydrogen. This can be accomplished in a variety of ways, whether it is from heat of combustion, waste-heat capture, or electrification. In addition to the heat energy required for the chemical reactions, additional energy is required for the balance of plant design whether for additional heat requirements, compressors, pumps, lighting and controls, and other required equipment.

Figure 14 illustrates the energy requirements on a Joule of energy per Joule of hydrogen basis for each process evaluated and separated by the portion identified as being specifically electrical-originated or thermal-originated. These values are intended to be representative of each technology for this techno-economic analysis and thus are a compilation of various data sources, but it should be noted that any specific design could alter these requirements. This is true where electrical heaters are used in place of typical combustion heating for steam generation, or, in the case of NG Pyrolysis, variations in the technology can influence the degree to which electrical-derived heating is used vs combustion and the overall energy demand. Examples of this are highlighted by the differing requirements for high-temperature thermal pyrolysis which utilizes combustion, to low-temperature catalytic pyrolysis and plasma pyrolysis which can be fully satisfied by electrical heating and electrical-driven devices such as plasma torches and microwaves. Waste-heat capture from these processes is also a significant source of energy input and varies by process and individual design.

Figure 14 | Hydrogen Production Energy Requirements, per production pathway



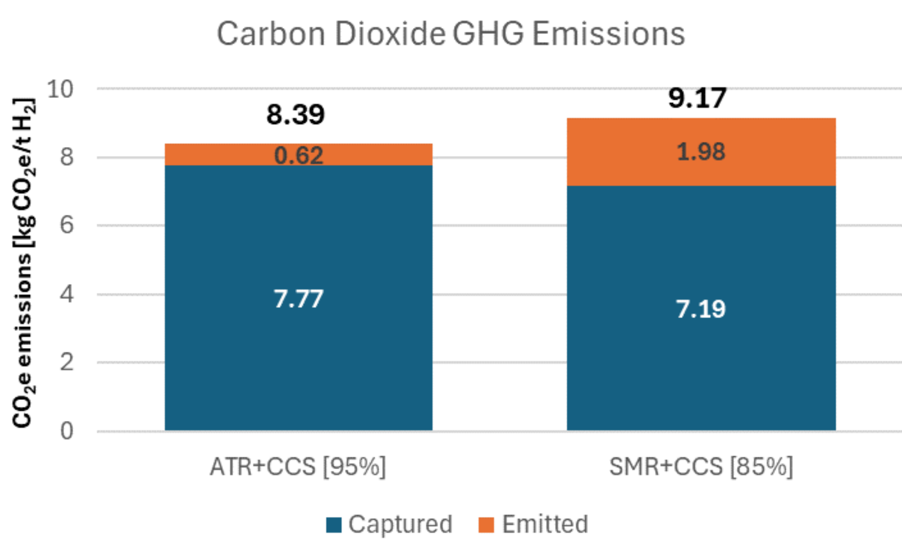
Electrolysis has by far the greatest utilization of electrical power, requiring the physical flow of electrical current through an electrolyzer to facilitate the separation of the hydrogen and oxygen atoms within the water molecule. Additionally, power requirements are required for the balance of the plant for water treatment, compression, and other devices. It is estimated that Electrolysis would require 1.83 Joules of electricity for each Joule of hydrogen produced. ATR + CCS and SMR + CCS require total energy inputs of 1.4 and 1.43 Je / JH_2, however, most of the energy is derived from thermal sources such as combustion or waste heat capture. Actual electrical-derived energy is low for both processes and mainly utilized for the balance of plant purposes, especially with the inclusion of CO_2 capture and sequestration. ATR + CCS is estimated to require 0.1 Je / JH_2 and SMR + CCS 0.05 Je / JH_2. NG Pyrolysis is estimated to require 0.38 Je / JH_2 though specific pyrolysis technologies can vary by +/- 50%. Though many of the NG Pyrolysis technologies can be run fully on an electrical supply, some thermal energy was assumed for the macro evaluation and thus it was assumed that 0.28 Je / JH_2 would be electrically satisfied for purposes of this evaluation.

Carbon Emissions and Solid Carbon

For carbon emissions and the associated life cycle carbon intensity of the hydrogen, we have assumed that for each of the presented processes the hydrogen generated would meet low-carbon standards and thus will not go into detail analyzing the implications of upstream methane-associated emissions and those associated with required electrical production, such as wire losses, loss of land use, and generation. However, to differentiate the hydrogen generation processes specifically, emissions associated with the direct generation of hydrogen have been determined.

Reformation processes generate CO2 emissions as part of the chemical reaction process as well as the combustion process to generate steam. For the technology to generate low-carbon hydrogen CCS must be a part of the process and capture a majority of the generated CO2 emissions. The emissions associated with the hydrogen generation are shown in **Figure 15**. ATR+CCS is a more efficient process for the capture of emissions and is capable of achieving 95% CO2 capture. As SMR relies more heavily on natural gas combustion for heat, CO2 capture is viewed as more challenging with existing SMR units only achieving upwards of 65% recovery. New SMR-designed facilities with CCS specifically associated with the design are believed to be able to achieve 85% recovery or higher. The ATR+CCS process is assumed to generate 8.39 kg CO_2e/t H_2 of GHG emissions, of which 7.77 kg CO_2e/t H_2 are assumed to be captured and sequestered in underground storage. For SMR+CCS, the process generates 9.17 kg CO_2e/t H_2 of GHG emissions and 7.19 kg CO_2e/t H_2 are captured and sequestered. These reformation processes still result in 0.62 kg CO_2e/t H_2 for ATR+CCS and 1.98 kg CO_2e/t H_2 for SMR + CCS emissions.

Figure 15 | CO2eq emissions associated with hydrogen production for ATR+CCS and SMR+CCS



Electrolysis does not utilize natural gas as part of the hydrogen generation process and thus does not have any associated CO_2 emissions. NG Pyrolysis is a chemical reaction in the absence of oxygen and thus does not generate CO_2. The pyrolysis process generates solid carbon at a stochiometric ratio of 3:1 kg C / kg H_2. With the macro assumptions made for purposes of this report to reflect that some methane pyrolysis processes utilize hydrogen generated in the process, as with thermal methane pyrolysis, the ratio of solid carbon generation to hydrogen is 3.28 kg C / kg H_2. As solid carbon maintains carbon in a stable state and does not react to form CO_2, the creation of solid carbon can be considered as permanent sequestration of an equivalent of 3.66 kg CO_2e / kg C.

Supply Costs

To understand the economic feasibility of satisfying the hydrogen production of the three scenarios, techno-economics were run on the four production processes to determine economic Levelized Cost of Hydrogen (LCOH) calculations for each technology. To account for expected technology gains, the models were run based on current technology conditions and assumptions (Today) as well as with the incorporation of technology advancements and optimizations that are expected to occur by 2050 (2050). Both ATR + CCS and SMR + CCS are assumed to be mature technologies, thus only one run for each was conducted as no significant technology improvements are anticipated. NG Pyrolysis is shown with and without nominal value for produced solid carbon. It is assumed that a reduction of capital and operating costs will be achieved with the commercialization of the technology, especially as it relates to smaller volume units. Electrolysis is assumed to advance capital cost and supply chain certainty as well as electrolyzer efficiencies.

Further detailed in Appendix 1, a range of results for each technology was evaluated by varying the main feedstock variable (natural gas price for ATR+CCS, SMR+CCS, and NG Pyrolysis, electrical price for Electrolysis), along with the operating time for the facility, which evaluates the impact of non-continuous operations most often associated with Electrolysis and direct connection to interruptible low-capacity factor renewable energy sources such as wind and solar. **Figure 16** is an example of the results for ATR+CCS at an assumed facility capacity size of 250 t/d H_2.

In addition to the range of results shown for the specific facility size, additional runs were made at increased facility sizes of 800 t/d and 1,500 t/d H_2. For both ATR+CCS and SMR+CCS, the 250 t/d facility is viewed as the minimum size of the reformation facility that would be constructed due to the CCS requirement. This similar analysis was completed for NG Pyrolysis and Electrolysis. However, for these facilities, it was assumed that facility sizes of 2.5 t/d, 25 t/d, and 250 t/d H_2 would be constructed. For Pyrolysis and Electrolysis, the 250 t/d H_2 size of the facility was assumed to be the largest facility size for these technologies based on the current level of technology development and the challenges of scaling the technologies to larger sizes. It is recognized that smaller-scale reformation and larger-scale pyrolysis and electrolysis may be achieved but likely would be case-specific to the conditions and capabilities of the day.

Figure 16 | LCOH calculations for the ATR+CCS production pathway

ATR + CCS

Pyrolysis Size (t H2/day)		$US MM	$CA MM		Power Price [$/Mwh] includes delivery	
250	CAPEX	$ 367	$ 502	Effic (LHV)	90%	$ 70.00

LCOH - capex+ opex [$/kg H2]

Load / Use Factor / Utilization	5.7%	11.4%	22.8%	34.2%	45.7%	57.1%	68.5%	79.9%	91.3%
Hours of Operation	500	1000	2000	3000	4000	5000	6000	7000	8000
Power use (MWhr/yr)	18,797	37,594	75,188	112,781	150,375	187,969	225,563	263,156	300,750
t H2/yr	4,688	9,375	18,750	28,125	37,500	46,875	56,250	65,625	75,000
t H2/day	12.84	25.68	51.37	77.05	102.74	128.42	154.11	179.79	205.48
CAPEX ($/kg)	$ 10.92	$ 5.46	$ 2.73	$ 1.82	$ 1.36	$ 1.09	$ 0.91	$ 0.78	$ 0.68
OPEX ($/kg)	$ 2.53	$ 1.53	$ 1.03	$ 0.87	$ 0.78	$ 0.73	$ 0.70	$ 0.68	$ 0.66
Total ($/kg)	**$ 13.45**	**$ 6.99**	**$ 3.76**	**$ 2.69**	**$ 2.15**	**$ 1.82**	**$ 1.61**	**$ 1.46**	**$ 1.34**

LCOH - total [$/kg H2]

CDN/GJ [includes delivery cost to site]	Hours of Operation: 500	1000	2000	3000	4000	5000	6000	7000	8000
		1	2	3	4	5	6	7	8
$0.00	$ 13.45	$ 6.99	$ 3.76	$ 2.69	$ 2.15	$ 1.82	$ 1.61	$ 1.46	$ 1.34
$0.50	$ 13.53	$ 7.08	$ 3.85	$ 2.77	$ 2.23	$ 1.91	$ 1.69	$ 1.54	$ 1.43
$1.00	$ 13.62	$ 7.16	$ 3.93	$ 2.86	$ 2.32	$ 1.99	$ 1.78	$ 1.63	$ 1.51
$1.50	$ 13.70	$ 7.25	$ 4.02	$ 2.94	$ 2.40	$ 2.08	$ 1.86	$ 1.71	$ 1.60
$2.00	$ 13.79	$ 7.33	$ 4.10	$ 3.03	$ 2.49	$ 2.16	$ 1.95	$ 1.80	$ 1.68
$2.50	$ 13.87	$ 7.41	$ 4.19	$ 3.11	$ 2.57	$ 2.25	$ 2.03	$ 1.88	$ 1.76
$3.00	$ 13.96	$ 7.50	$ 4.27	$ 3.19	$ 2.66	$ 2.33	$ 2.12	$ 1.96	$ 1.85
$3.50	$ 14.04	$ 7.58	$ 4.36	$ 3.28	$ 2.74	$ 2.42	$ 2.20	$ 2.05	$ 1.93
$4.00	$ 14.13	$ 7.67	$ 4.44	$ 3.36	$ 2.83	$ 2.50	$ 2.29	$ 2.13	$ 2.02
$4.50	$ 14.21	$ 7.75	$ 4.53	$ 3.45	$ 2.91	$ 2.59	$ 2.37	$ 2.22	$ 2.10
$5.00	$ 14.30	$ 7.84	$ 4.61	$ 3.53	$ 3.00	$ 2.67	$ 2.46	$ 2.30	$ 2.19
$5.50	$ 14.38	$ 7.92	$ 4.70	$ 3.62	$ 3.08	$ 2.76	$ 2.54	**$ 2.39**	$ 2.27
$6.00	$ 14.47	$ 8.01	$ 4.78	$ 3.70	$ 3.17	$ 2.84	$ 2.63	$ 2.47	$ 2.36
$6.50	$ 14.55	$ 8.09	$ 4.87	$ 3.79	$ 3.25	$ 2.93	$ 2.71	$ 2.56	$ 2.44
$7.00	$ 14.64	$ 8.18	$ 4.95	$ 3.87	$ 3.34	$ 3.01	$ 2.80	$ 2.64	$ 2.53
$7.50	$ 14.72	$ 8.26	$ 5.03	$ 3.96	$ 3.42	$ 3.10	$ 2.88	$ 2.73	$ 2.61
$8.00	$ 14.81	$ 8.35	$ 5.12	$ 4.04	$ 3.51	$ 3.18	$ 2.97	$ 2.81	$ 2.70
$8.50	$ 14.89	$ 8.43	$ 5.20	$ 4.13	$ 3.59	$ 3.27	$ 3.05	$ 2.90	$ 2.78
$9.00	$ 14.98	$ 8.52	$ 5.29	$ 4.21	$ 3.67	$ 3.35	$ 3.14	$ 2.98	$ 2.87

Avg hours operation per day								
1.4	2.7	5.5	8.2	11.0	13.7	16.4	19.2	21.9

To compare LCOH results across different technologies and facility sizes, pricing of $70/MWh for electricity and $5.50/GJ for natural gas were assumed, with both prices representing a forecast to 2050 pricing, inclusive of delivery, and other charges to be representative to a delivered retail price at the point of generation. A comparison of all technologies LCOH can be done at the 250 t/d H2 scale. The increased sizes for the reformation technologies allow for the evaluation of LCOH at a significant industrial scale, which would be required to address the hydrogen demand in the Low-Ontario and High-Ontario scenarios. It is assumed that small regional or sectoral demand would need to be satisfied by utilizing transportation from these centralized sites. This would compare to the LCOH values determined in the pyrolysis and electrolysis runs. It is assumed that a range of hydrogen generation sizes, as well as technologies, will be required to address the varied regional needs and varied sector demands; thus, a combination of various-sized facilities will ultimately be deployed and determine the overall LCOH for the hydrogen in the transition scenarios.

The variables incorporated into the techno-economic evaluation are summarized in **Table 7**. This identifies the parameters as they apply to the 250 t/d H_2 facility for each technology considered. As technology advancements in capital and efficiencies are anticipated to occur for NG Pyrolysis and Electrolysis, the corresponding variables for 2050 are also included.

At this level of hydrogen generation, the higher capital cost per unit of hydrogen for the reformation process can be noted. This variable decreases with the size of the facility thus larger-scale reformation would realize lower capital cost per unit of hydrogen. This is similar to the expected decrease in capital cost associated with NG Pyrolysis and Electrolysis by 2050.

Table 7 | Input variables for each LCOH calculation, by process*

at 250 t/d H2	MM$/t H_2/d Capacity	$/t H_2/yr					Efficiency	LCOH
	Capital	OPEX	Natural Gas	Electricity	Water	Carbon Tax		
ATR+CCS	$ 2.01	$ 188	$ 933	$ 281	$ 85	$ 105	90%	$ 2.39
SMR+CCS	$ 2.54	$ 250	$ 1,249	$ 140	$ 90	$ 337	90%	$ 3.08
NG Pyrolysis	$ 1.28	$ 290	$ 1,527	$ 762	$ 3		95%	$ 3.06
Electrolysis	$ 1.80	$ 403	$ -	$ 3,589	$ 427		65%	$ 5.43
NG Pyrolysis [2050]	$ 0.64	$ 245	$ 1,527	$ 762	$ 3		95%	$ 2.78
Electrolysis [2050]	$ 0.58	$ 190	$ -	$ 2,744	$ 427		85%	$ 3.72

** Additional details and references are provided in Appendix 1.*

Analyze Electricity System Impacts

We examined the implications of various hydrogen pathway scenarios for the electricity system across three key dimensions:

- **Hydrogen vs. Electrification**: We explored the dynamics between hydrogen, serving as a net-zero energy carrier, and direct electrification within net-zero pathways. Utilizing hydrogen could potentially circumvent the need for direct electrification, thereby influencing the electricity demand on Ontario's system.
- **Electricity Requirements for Hydrogen Production**: We assessed how different hydrogen production methods impact the electricity system. Depending on the chosen pathway, domestic production of hydrogen might demand substantial electricity inputs.
- **Hydrogen as an Electricity System Resource**: We investigated the potential of hydrogen to act as a resource within a net-zero electricity system. Hydrogen can fuel combustion turbines and fuel cells, offering flexible and dispatchable zero-emission power generation.

The following sections describe our approach to analyzing each of these electricity system implications.

Hydrogen vs. Electrification

As part of the hydrogen demand analysis, we conducted a "What If" analysis to evaluate the extent of "avoided electrification" resulting from the use of hydrogen for each hydrogen demand scenario. This analysis calculates the amount of electricity that would be required if the end-use energy fulfilled by hydrogen within each scenario was instead provided by direct electrification. Through this, we established an upper limit to this "avoided electrification" by determining the electric energy needed to electrify all technically viable end-uses of hydrogen. End-uses where electrification is not technically feasible are excluded from this calculation.

Similar to calculating hydrogen demand, electricity demand was calculated by accounting for energy carrier conversion technology, efficiency differences between incumbent carrier technologies, and newer technologies such as Battery Electric Vehicles (BEVs).

To estimate the electrification demand (that would otherwise be offset by hydrogen) in each net-zero scenario, the following steps were taken:

1. **Delineate Total Sector Energy Demand for 2050**: Sector energy demand was broken down by individual energy carriers.
2. **Analyze Proportion of Energy Use by Carrier**: Based on the analysis in the 'end-use adoption' section, we determined what proportion of energy use by carrier could be replaced by hydrogen.
3. **Calculate and Assign Relative Efficiency Factors**: Efficiency factors were calculated based on energy carrier conversion technologies to account for efficiency changes (e.g., a BEV powertrain is more efficient than a gasoline Internal Combustion Engine (ICE)).
4. **Determine Electricity Needed for Hydrogen Alternatives**: The proportion of energy allotted to hydrogen transition for each sector was combined with the hydrogen technology alternative to produce the electricity needed (in PJ) to meet the same service requirements as the incumbent technology.
5. **Aggregate Electricity Demand**: Electricity demand was aggregated by sector and then totalled for each scenario.

Hydrogen Production Electricity Requirements

As part of our analysis of hydrogen supply options, we evaluate the input and energy requirements of hydrogen production, which includes electricity. This is described in the previous sections.

Hydrogen as an Electricity System Resource

To evaluate hydrogen's potential role in a net-zero electricity system in 2050, we developed levelized cost models to estimate the break-even price for hydrogen-fueled electricity resources compared to alternative technologies and fuels. Our analysis aimed to determine the conditions under which hydrogen may become a preferable choice over other technologies that could provide similar contributions to the electricity system.

The analysis is divided into two main components. First, we assess hydrogen as a flexible and firm generation resource relative to other generation resources. Second, we evaluated hydrogen as an electricity storage resource, where electricity is used to produce hydrogen through electrolysis, the hydrogen is stored and then combusted after a certain duration.

We then compare these results with our analysis of hydrogen demand and supply to understand the broader economic context in Ontario. This allows us to determine the circumstances under which hydrogen could be a viable resource for Ontario’s electricity system.

Economics of Hydrogen as a Generation Resource

To understand the economics of hydrogen as a generation resource, we modelled the levelized cost of electricity (LCOE) production for various hydrogen and non-hydrogen generation technologies under different conditions. We then compared the LCOE of hydrogen generation technologies to non-hydrogen technologies to determine the break-even price at which hydrogen becomes the more economical option.

We focus our comparison on the following technology sets:

- Hydrogen vs. Unabated Natural Gas
- Hydrogen vs. Abated Natural Gas
- Hydrogen vs. Nuclear

These comparisons are chosen because each of these technologies represents firm generation resources that can potentially contribute to a net-zero aligned electricity system in Ontario. For unabated natural gas, some net-zero modelling studies show potential roles for this generation source under the assumption that emissions are offset by carbon removals elsewhere. Due to the cost of carbon removal, these studies generally model low-capacity factor roles (i.e., peaking plants) for this type of generation. For abated natural gas, the ability to capture and store emissions from natural gas combustion may allow natural gas generation to play a more significant role in net-zero aligned electricity systems by operating at higher capacity factors (between 20% to 40% in most modelling studies) and supplying more electricity. However, the feasibility of widespread CCS deployment remains uncertain in Ontario. Finally, nuclear generation is poised to play a significant role in Ontario's electricity system with its existing nuclear fleet and provincial plans to refurbish and expand it in the coming years, pending regulatory approval and financing.

For each technology comparison set, the model estimated LCOE based on a number of input assumptions. Break-even prices were analyzed across a range of critical input assumptions, selected due to their uncertainty and the sensitivity of LCOE to their values. These critical assumptions included hydrogen fuel costs, natural gas fuel costs, carbon costs, and capital costs.

The generation technology comparison sets, along with a description of the input assumptions and the continuum along which the break-even prices are evaluated, are listed below. More detail on the LCOE calculation and assumption values are provided in Appendix 1.

Hydrogen vs. Unabated Natural Gas

We compared the hydrogen-fired generation to the unabated natural gas-fired generation. For both hydrogen-fired and unabated natural gas generation, we considered a frame CT plant.

We evaluated break-even prices for different values of hydrogen costs, natural gas costs, and carbon costs. We did not consider different capacity factors as a variable since the capital costs of a hydrogen-fired combustion turbine and a natural gas-fired combustion turbine are identical. This makes the levelized cost of capital within the LCOE of each technology option the same across different capacity factors.

We included carbon costs as a critical input assumption, as we assumed unabated natural gas generation will be subject to some form of carbon cost—whether implicit or explicit—by 2050. For this analysis, we evaluated break-even prices under the following three 2050 carbon price assumptions and their rationales:

- $102/tonne (CAD 2024$), which is $170/tonne in 2050 in nominal terms assuming an annual inflation rate of 2% between 2024 and 2050. This represents the price of carbon as currently projected under existing carbon pricing policies, adjusted for inflation over the specified period.

- \$170/tonne (CAD 2024\$), which represents an increased carbon price in 2050 under the assumption that more stringent carbon pricing policies will be implemented to accelerate decarbonization efforts. This assumes that the government will set higher carbon prices to drive further reductions in greenhouse gas emissions.
- \$325/tonne (CAD 2024\$), which represents an upper-bound carbon price based on the potential cost associated with the direct air capture (DAC) of a tonne of CO2 in 2050 (38). This scenario assumes that policies will exist requiring any unabated emissions to be offset through atmospheric carbon removal (e.g., DAC) and that the costs associated with this removal will be borne by the electricity generator, reflecting the higher end of potential future carbon costs.

Hydrogen vs. Natural Gas with Carbon Capture and Storage

We compared hydrogen-fired generation to abated natural gas-fired generation. For hydrogen-fired generation, we considered a combined-cycle-gas-turbine (CCGT). For abated natural gas generation, we considered a CCGT with carbon capture and storage (CCS) capable of 95% carbon capture.[7]

We evaluated break-even prices for different values of hydrogen cost, natural gas prices and capacity factors. Since the capital costs of a hydrogen-fired CCGT and natural gas-fired CCGT differ significantly, the capacity factor of these power plants will influence their costs and relative break-even prices. The capacity factors of abated natural gas in a net-zero aligned electricity system will be dependent on a number of external factors such as the overall generation mix of the system. We consider capacity factors of 30% and 50% reflecting a mid-order plant providing firm capacity.[8] While there are uncertainties around the effectiveness of CCS at capacity utilization of less than 50% today, the efficiency improvements in CCS technology are likely to improve the capture rate, at lower capacity factors, by 2050.

Hydrogen vs. Nuclear Generation

We compared hydrogen-fired generation to nuclear generation. For hydrogen-fired generation, we considered a hydrogen-fired CCGT. For nuclear generation, our analysis incorporated both conventional large-scale nuclear generation as well as small module reactor (SMR) nuclear.

We evaluated break-even prices for different values of hydrogen costs and capital costs for nuclear generation. The range of capital costs included in the analysis includes the capital cost assumptions representative of new large nuclear and new small modular reactor nuclear, which is the primary differentiating factor between these two technologies from an economic modelling standpoint.

---

[7] With the technology available today, effectiveness of CCS is reduced at capacity factors of less than 50% as the frequent starts and stops would mean the capture plant warms up and cools down too much, so it may not be able to capture that amount of CO_2. For natural gas with CCS to be run as a dispatchable plant and to be as effective in capturing emissions 95% of the time, the efficiency of capture technology would have to be improved. Additionally, the costs would have to come down significantly for it to be economically viable compared to other generation technologies.

[8] Other studies modeling net zero electricity system for other jurisdictions have estimated load factor of 30% to 40% for CCGTs providing firm capacity(39)

We evaluated both generation technologies using a capacity factor of 80% and 90% as the various studies that have modelled Ontario's net zero have estimated 80 – 90% capacity utilization of nuclear in 2050.

Economics of Hydrogen as a Storage Resource

To understand the economics of hydrogen as a storage resource, we modelled the levelized cost of storage (LCOS) for hydrogen and non-hydrogen storage technologies and configurations under different conditions and use cases (i.e., durations). We then compared the LCOS of hydrogen storage resources to non-hydrogen storage solutions to determine the break-even price at which hydrogen becomes the more economical option.

For hydrogen electricity storage, the LCOS will be heavily influenced by the cost of producing and storing hydrogen and the subsequent combustion of hydrogen back into electricity. For this analysis, we assume hydrogen storage applications use electrolytic hydrogen produced by low-cost renewable electricity resulting in a low levelized cost of hydrogen at plant gate. We estimated the LCOS of hydrogen electricity storage under two LCOH assumptions representing above-ground and below-ground hydrogen storage options:

- Salt Caverns for underground storage: Salt caverns storage are the cheapest storage and most viable option due to low capital cost, and the lowest leakage rate.
- Compressed gas storage for above-ground storage: Compressed hydrogen can be quickly filled into and discharged from storage tanks, making it suitable for applications requiring rapid response times.

We focused our comparison on the following storage technologies:

- Li-ion Batteries: Lithium-ion batteries account for most of the newly installed energy storage capacity. This technology is already relatively mature, even for grid-scale applications. Li-ion batteries have also had the highest learning rate.
- Flow Batteries: The vanadium flow battery is better suited to long-term storage. The advantage of flow batteries is that capacity (MW) and storage volume (MWh) can easily be separated. The vanadium flow battery is the most advanced type of flow battery, with a relatively high TRL.
- Compressed Air Energy Storage (CAES): CAES is an evolving technology for providing large-scale, long-term electricity storage. It can provide energy storage for extended periods (10 hours or more).
- Pumped Hydro Storage (PHS): Pumped Hydro Storage is a highly efficient and widely used method of energy storage around the world. However, it faces challenges such as water rights and site selection issues. Additionally, unlike other storage technologies experiencing cost reductions over time, the capital costs of pumped storage have remained relatively static.

Each of these storage technologies represents mature and/or emerging storage technologies that are well-situated to provide short and/or long-duration electricity storage.

More detail on the LCOS calculation and assumption values are provided in Appendix 1.

4. Results and Analysis

The following chapter presents the main results and analysis of the study organized by the key research questions.

Hydrogen Demand

- What is the range of potential hydrogen demand scenarios in the Hamilton region and beyond?

Hydrogen Supply

- What are potential supply pathways for the various levels of aggregated demand?
- What are the potential costs, likelihood, emissions, and infrastructure requirements of these supply pathways?

Electricity System Implications

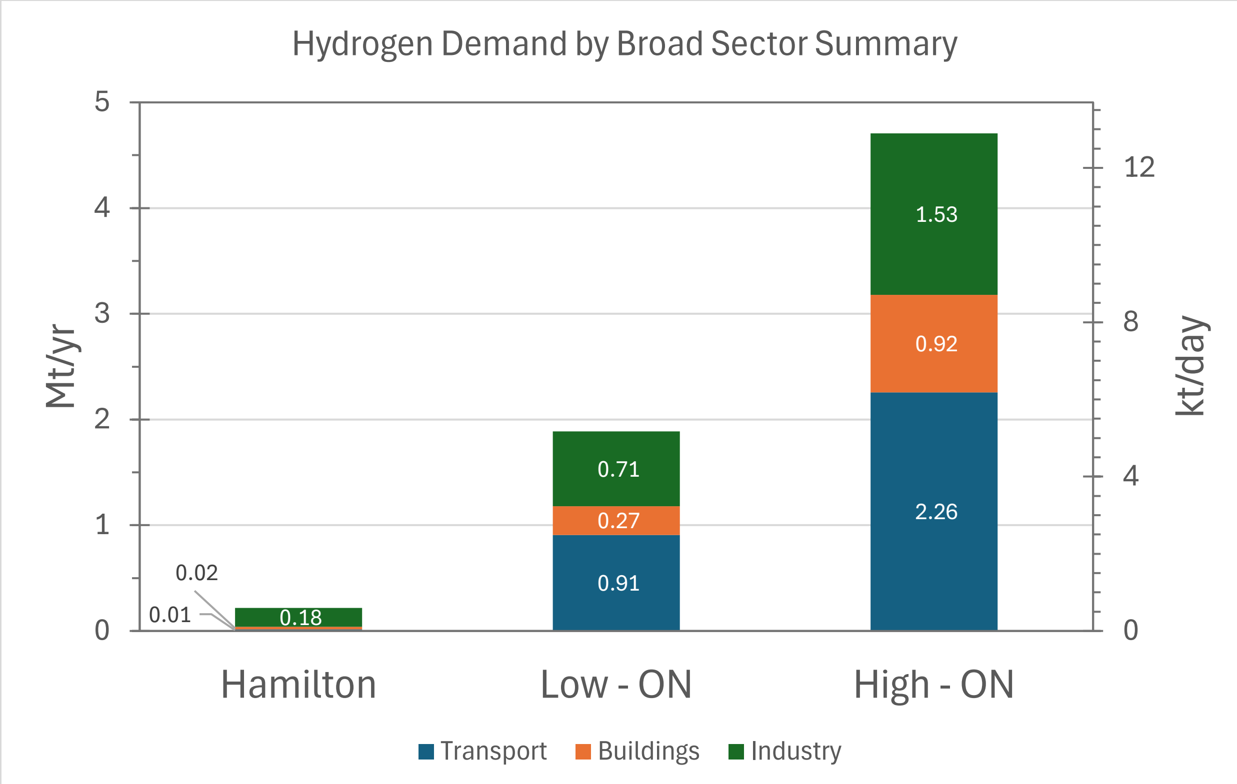
- For each demand scenario, how much is competing against direct electrification?
- For each supply scenario, what are the electricity system requirements and considerations?
- For potential hydrogen demand and supply scenarios, what is the viability of using hydrogen for supporting Ontario's electricity system?

Hydrogen Demand

The results of each hydrogen demand scenario are displayed below in annual and daily demand (**Figure 17**) and are also summarized in **Table 8**. Each of these scenarios is further explored in the following scenario-specific chapters. Annual demand ranges from 0.22 Mt (Hamilton scenario) to 4.71 Mt (High Ontario Coordination scenario), while on a daily basis, this corresponds with a 597 ton/day output up to a 12,896 ton/day hydrogen output, respectively[9].

[9] It should also be mentioned that this analysis does not account for potential energetic transportation costs (hydrogen needed for pipeline compression, etc.), which would marginally increase consumption values.

Figure 17 | Annual and daily hydrogen demand in all three scenarios by broad sector



Note: Transportation, Buildings, and Industry are further broken down into specific sectors in the Methodology section, **Table 6**.

Table 8 | Demand for Hydrogen by Broad Sector

	Mt/year			Ton/day		
Sector	Hamilton	Low - ON	High - ON	Hamilton	Low - ON	High - ON
Transport	0.01	0.91	2.26	39.65	2,489	6,187
Buildings	0.02	0.27	0.92	65.74	746	2,522
Industry	0.18	0.71	1.53	492	1,940	4,188
Total	**0.22**	**1.89**	**4.71**	**597**	**5,174**	**12,896**

In the Hamilton scenario, hydrogen demand is primarily used for steel production, requiring around 492 tons H_2/day. This accounts for approximately 1.1% of Ontario's total projected energy demand in 2050 for sectors and end-uses where hydrogen may be a viable energy carrier.[10] This targeted use in a major industrial hub demonstrates the potential for significant emission reductions in heavy industries, setting a model for other sectors and regions to follow.

[10] Ontario-wide energy use in 2050 is based on a status quo scenario that assumes no changes to the current energy source mix, but considers growth based on population projections and industry-specific macro growth trends.

In the Low Coordination Ontario scenario, total hydrogen demand is approximately 1,889,000 tons/year. This represents about 10.5% of Ontario's projected 2050 energy demand, with heavy-duty vehicles consuming around 41% of this demand. This scenario shows the potential for substantial hydrogen integration in transportation and industrial applications, highlighting the need for infrastructure development and policy support to achieve these levels of adoption.

The High Coordination Ontario scenario projects hydrogen demand at 4,707,000 tons/year, equating to 26.2% of Ontario's projected energy demand in 2050. This includes significant use in transportation (43%) and heating (20%). Achieving this high level of hydrogen adoption would require extensive infrastructure and coordinated policy efforts, demonstrating the potential for hydrogen to play a major role in decarbonizing the province’s energy system.

For the Low and High Ontario scenarios, hydrogen demand represents approximately 10.5% and 26.2% of Ontario-wide energy use in 2050 for sectors and end-uses where hydrogen may be a viable energy carrier, respectively.

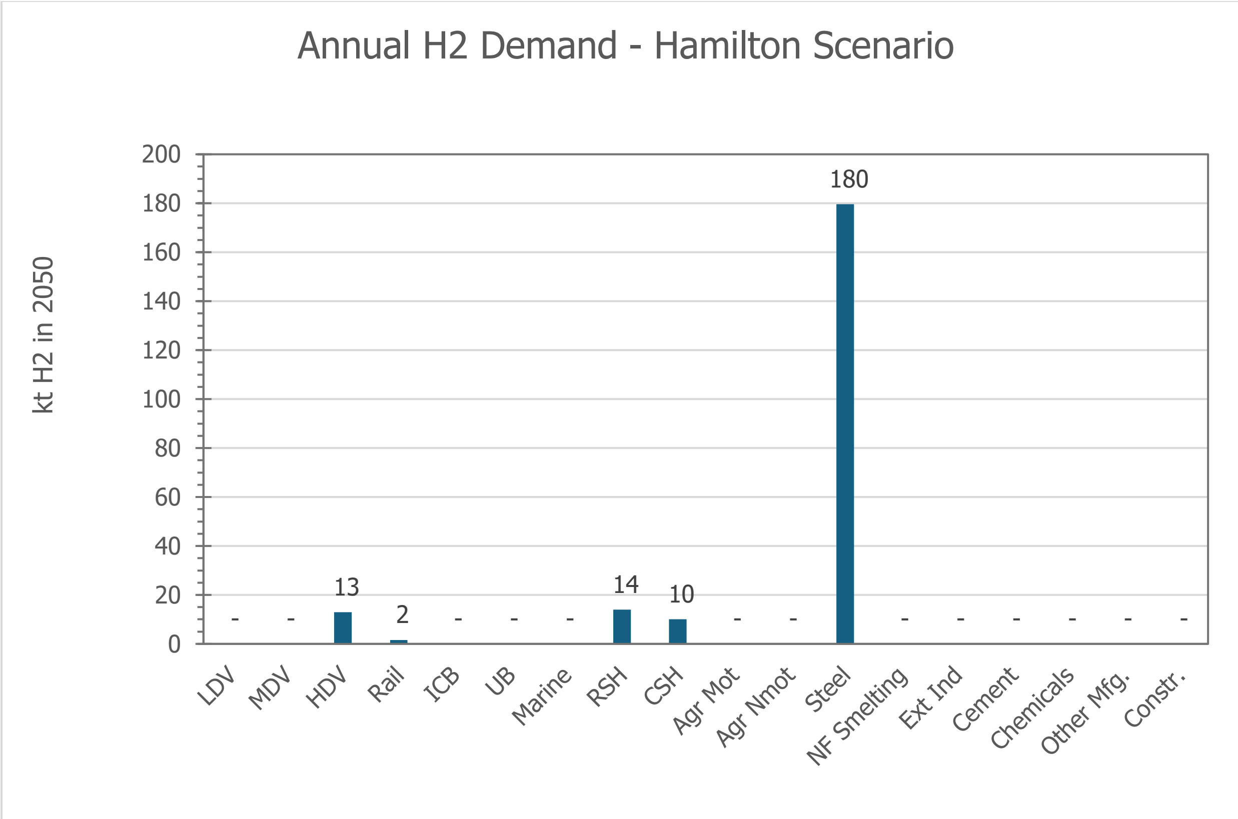
Hamilton Only Scenario

In the Hamilton scenario, very modest use of hydrogen in heavy transport and space heating was modelled, based on a central hydrogen supply existing in Hamilton. This central hydrogen supply was assumed to be built to service industrial energy users, in particular, primary steel production.

To best understand how H_2 could be used in an industrial facility like ArcelorMittal facility, this report relied on recent work conducted by the **Transition Accelerator** and the **Canadian Steel Producers Association** (25) that specifically examined how hydrogen could decarbonize steel production through the use of a direct hydrogen reduction process. This study found that 492 t/day of H_2 would be required to feed a gas-based reduction process in addition to the 2,959 MWh/day needed to power an Electric Arc Furnace (EAF). For other steel facilities in the region, H_2 reduction is not currently being considered a decarbonization pathway, instead, increased electrification using EAF processes is the future goal, which in itself will have substantial implications for the electricity system.

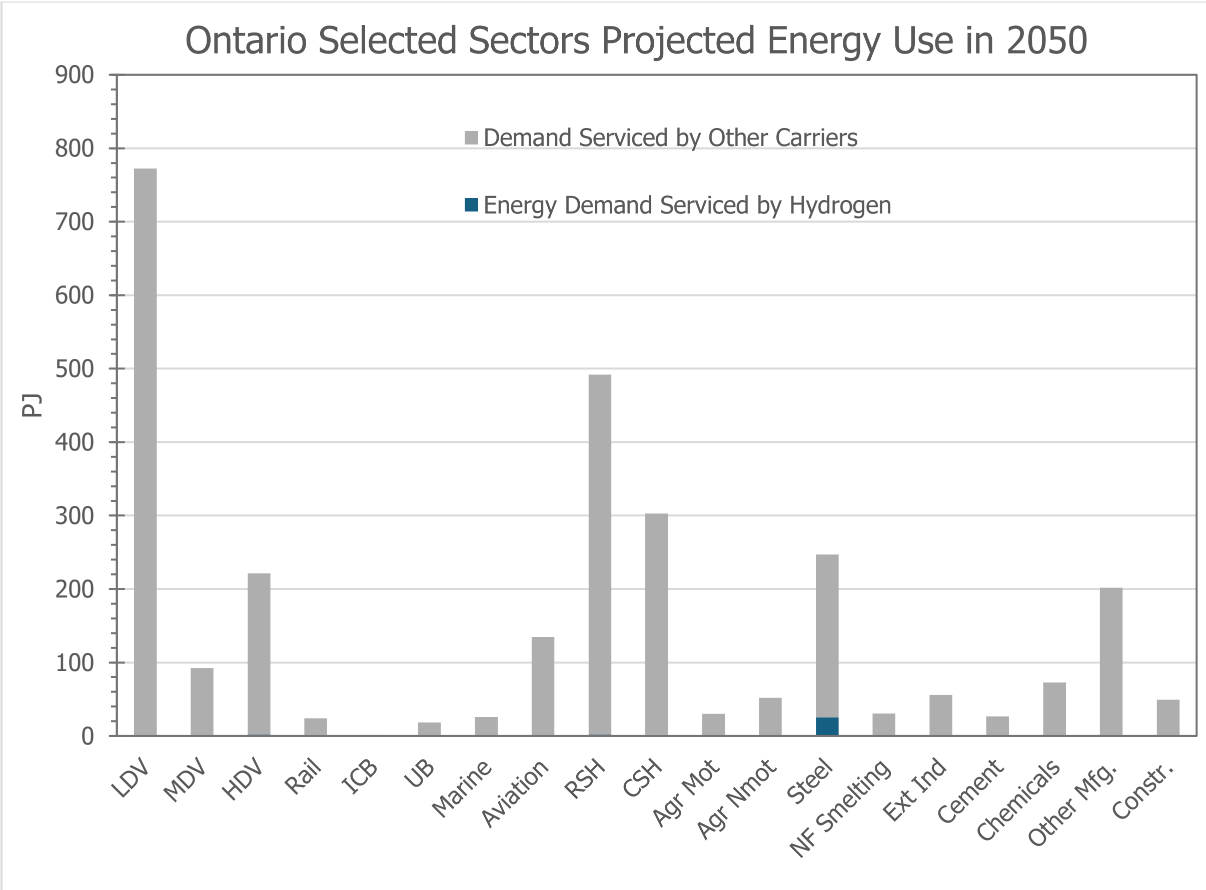
The resulting total hydrogen required to meet these demands is 218 kt annually, as seen below in **Figure 18**.

Figure 18 | Hamilton Scenario Hydrogen Demand by Sector Results



To help contextualize this scenario and understand the relative impact H_2 has in Ontario, it is useful to visualize H_2 use as compared to other high-energy use sectors, as seen in **Figure 19**. It should be noted that this figure is only representative of a 'status quo' 2050 energy system to illustrate the relative role H_2 has in this scenario. Likely, absolute energy demand in sectors not met by hydrogen will be different with a transition to more energy-efficient technologies, such as electrification. In this scenario, hydrogen plays a relatively small role in transportation and heating from an energy systems perspective and only offsets a portion of overall steel energy use.

Figure 19 | Status Quo Projection for 2050 With H2's Illustrative Role in the Hamilton Scenario



Ontario – Low Coordination Scenario

In the low coordination Ontario scenario as visualized in **Figure 20**, the largest component of demand is in the transportation sector which makes up 48% of total hydrogen demand in 2050; within transportation, the largest share (71%) of demand is projected to be servicing HDV vehicles, requiring 646 kt of H_2 annually, with demand spread out over the heavily travelled corridors that these vehicles normally travel on. Following transportation, industrial usage of H_2 (37%) is projected to be the largest consumer, with other manufacturing, chemical, and steel industry making up most of the remaining demand. Following transportation and industry, buildings are projected to make up 14% of demand. Despite the demand in this scenario being substantially larger than the Hamilton-only scenario, it can be seen in **Figure 21** that still, hydrogen is projected to play a relatively minor role as compared to other energy carrier serviced high-energy use sectors in Ontario.

Figure 20 | Low Coordination Ontario Scenario Hydrogen Demand by Sector Results

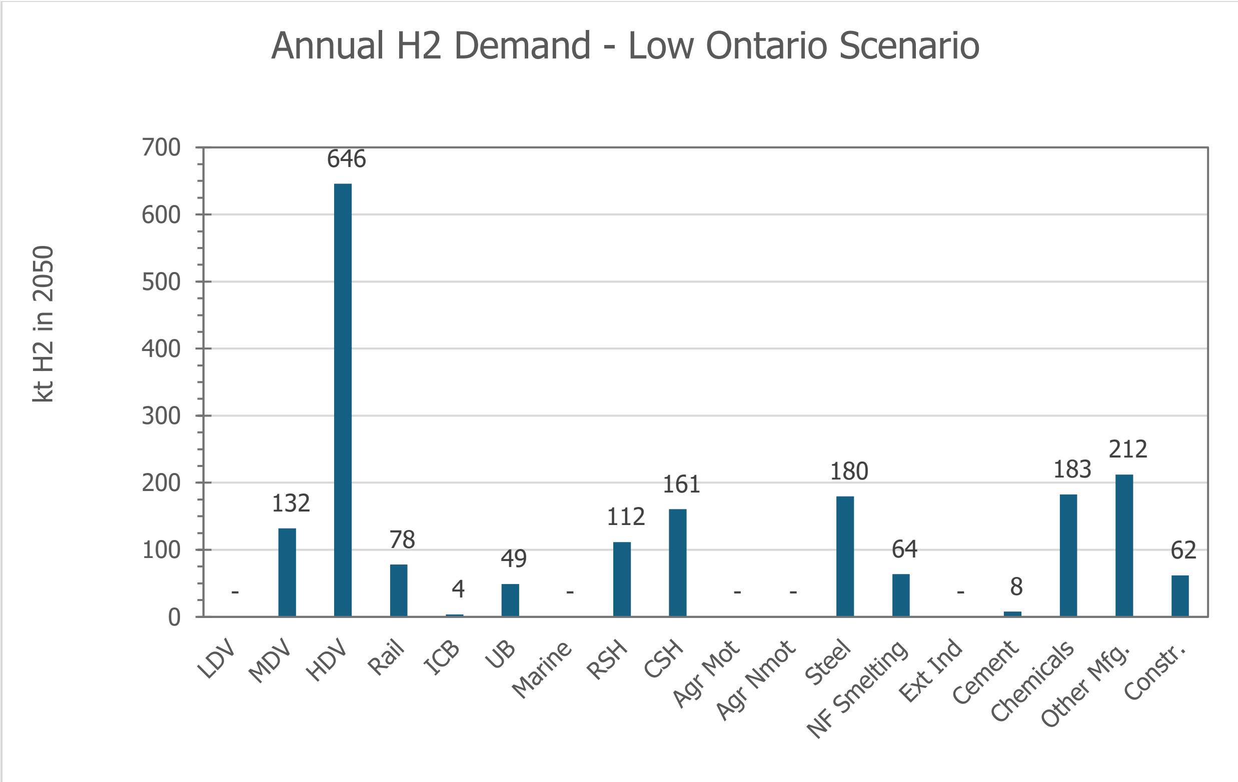
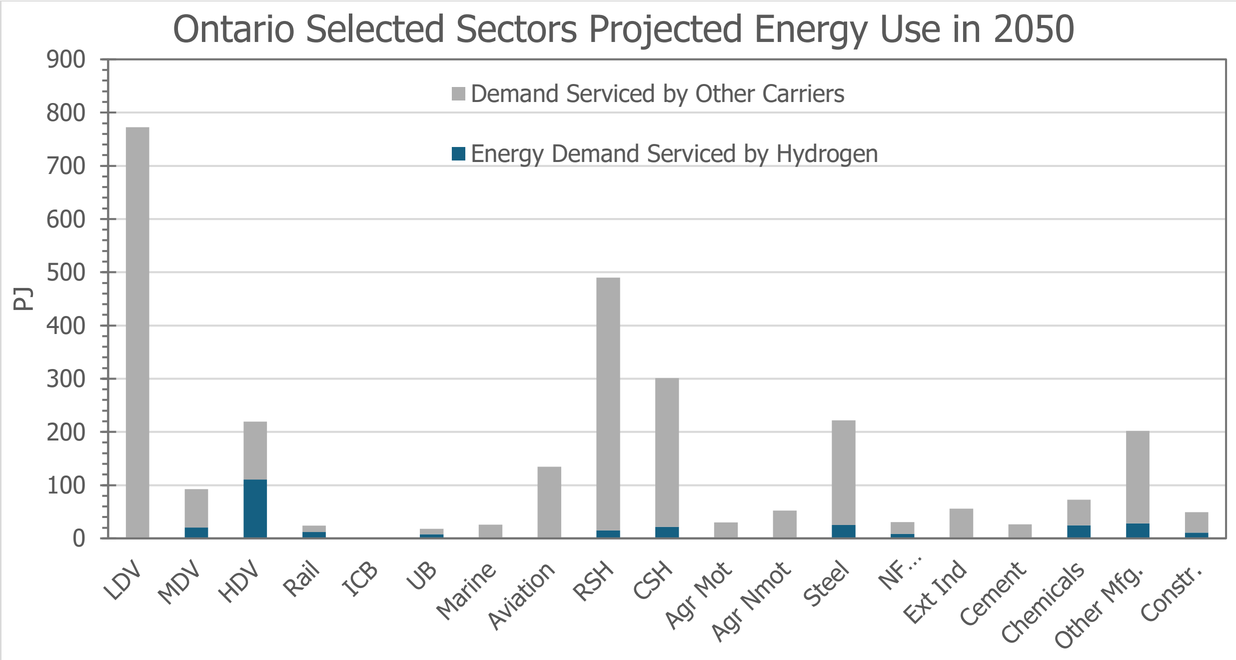


Figure 21 | Status Quo Projection for 2050 With H2's Illustrative Role in the Low Coordination Ontario Scenario



Ontario – High Coordination Scenario

In the high Ontario coordination scenario (**Figure 22**), transportation makes up the largest share of projected H_2 demand, making up 48% of aggregate demand, followed by industry (32%), and buildings (20%). The largest demand by an order of magnitude in this scenario is the energy needed to meet HDV demand. Demand of this scale would certainly require some form of large-scale storage to be available, particularly when considering H_2 offsetting highly seasonal natural gas demand for residential and commercial heating. From the perspective of a 'status quo' 2050 Ontario energy system, hydrogen in the high coordination scenario makes up around a quarter of energy demand as compared to select other high energy use sectors, as seen in **Figure 23**.

Figure 22 | High Coordination Ontario Scenario Hydrogen Demand by Sector Results

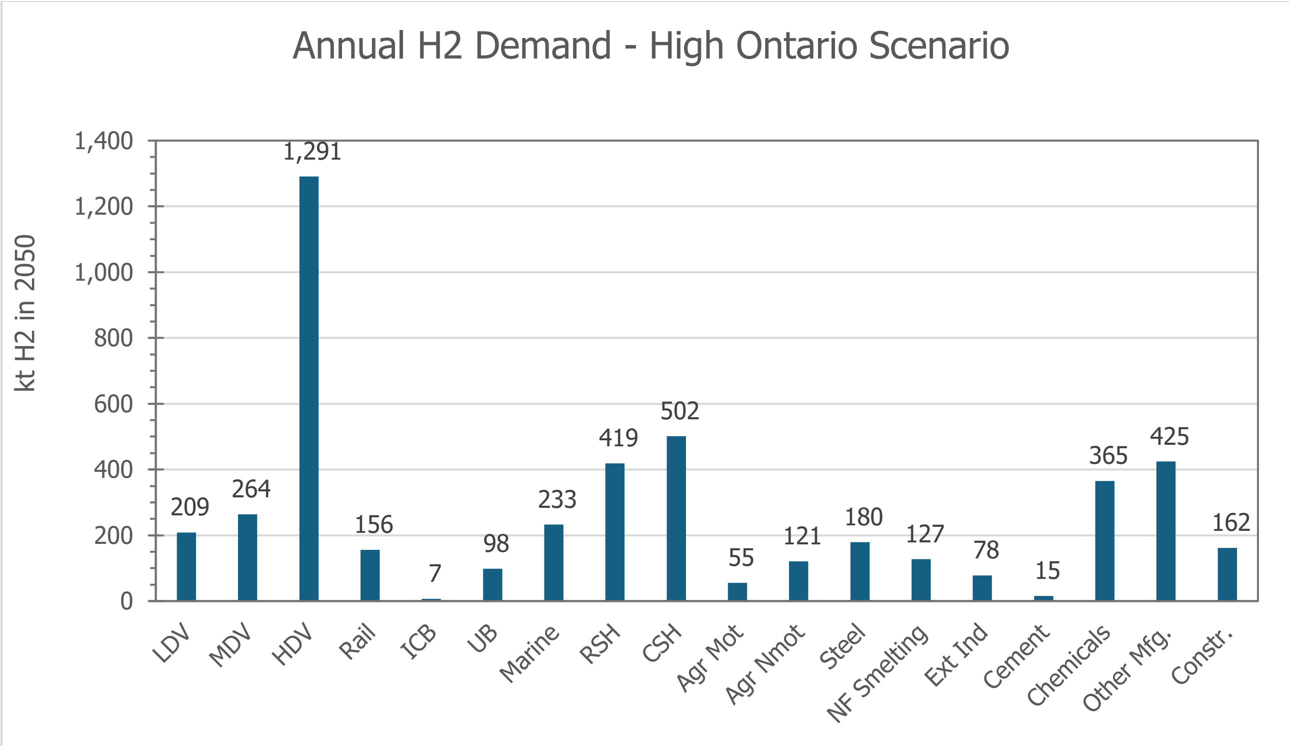
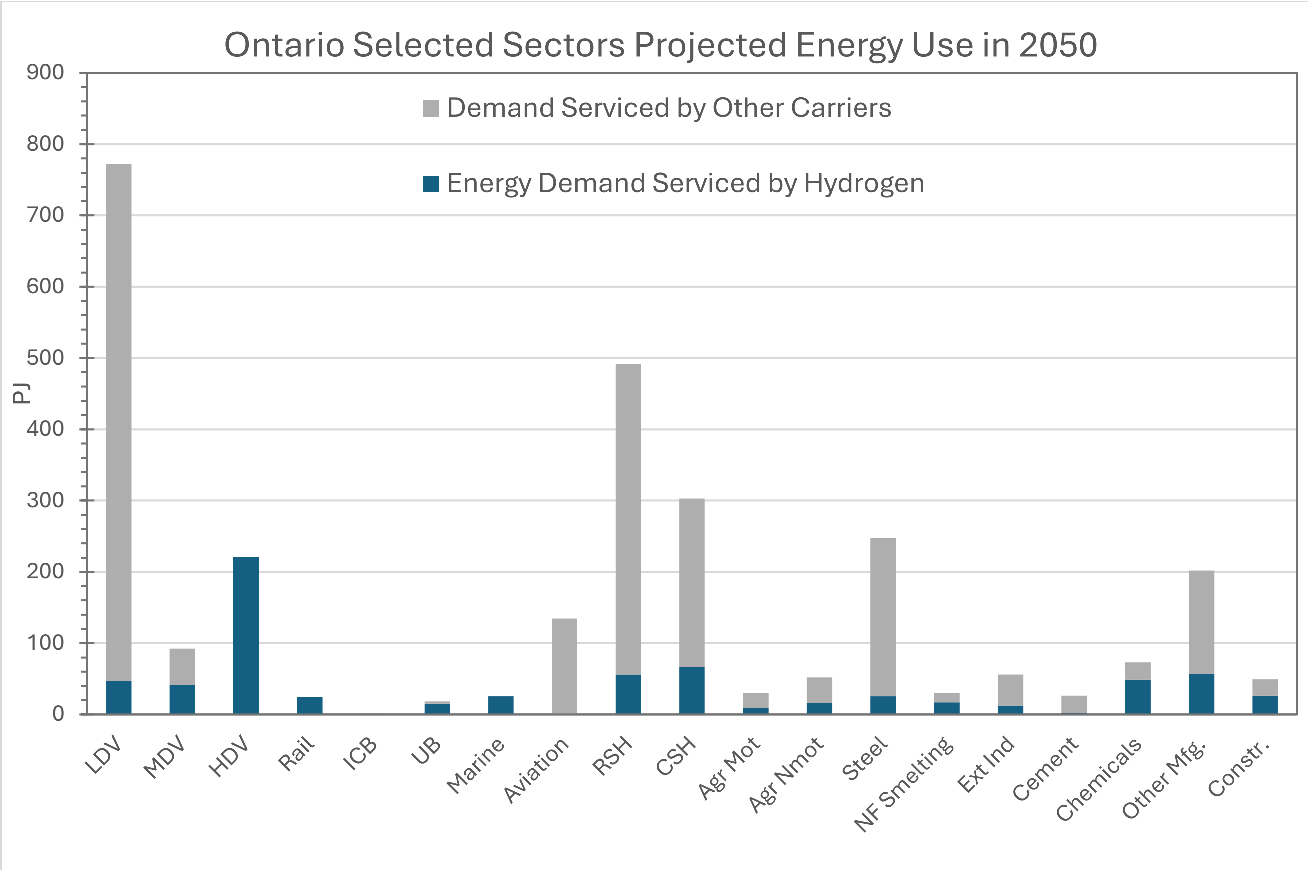


Figure 23 | Status Quo Projection for 2050 With H2's Illustrative Role in the High Coordination Ontario Scenario



Hydrogen Supply

Feedstock and Energy Requirements

Each of the production technologies has varying degrees of energy requirements, whether it is electrical or thermal, with thermal being satisfied by either the combustion of natural gas or utilization of a portion of the generated hydrogen or by waste heat capture. Similarly, each technology has various feedstock requirements, mainly represented by natural gas and water. The natural gas and water requirements are illustrated in **Table 9**.

Table 9 | Hydrogen Supply Natural Gas and Water Requirements by Supply Technology and Demand Scenario

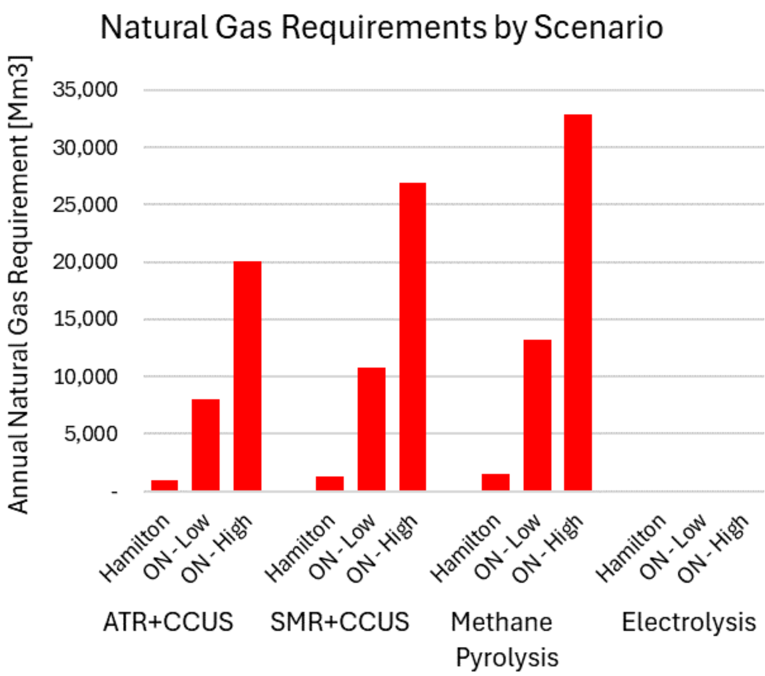
Prod'n Tech	Scenario	Hydrogen PJ H_2/yr	Hydrogen t H_2/yr	NG Req'd (PJ/yr)	NG Req'd (Mm^3/yr)	Water (Process) Mm^3	Water (Cooling) Mm^3	Water (Total) Mm^3
ATR + CCS	Hamilton	30.9	218,048	37.0	929.73	1.09	5.06	6.15
	ON - Low	267.6	1,888,556	320.5	8,052.52	9.44	43.81	53.26
	ON - High	667.0	4,707,182	798.8	20,070.71	23.54	109.21	132.74
SMR + CCS	Hamilton	30.9	218,048	49.5	1,244.46	1.22	5.32	6.54
	ON - Low	267.6	1,888,556	429.0	10,778.47	10.58	46.08	56.66
	ON - High	667.0	4,707,182	1,069.2	26,865.08	26.36	114.86	141.22
NG Pyrolysis	Hamilton	30.9	218,048	60.6	1,522.19	-	0.74	0.74
	ON - Low	267.6	1,888,556	524.7	13,183.98	-	6.42	6.42
	ON - High	667.0	4,707,182	1,307.9	32,860.76	-	16.00	16.00
Electrolysis	Hamilton	30.9	218,048			2.25	10.99	13.24
	ON - Low	267.6	1,888,556			19.45	95.18	114.64
	ON - High	667.0	4,707,182			48.48	237.24	285.73

Natural Gas Requirement

Total natural gas requirements for each of the hydrogen generation processes for each scenario are tabulated in **Table 9** and illustrated in **Figure 24**. The range of requirement for each scenario is 930 to 1,522 10^6m^3 for Hamilton, 8,053 to 13,184 10^6m^3 for Low-Ontario, and 20,070 to 32,861 10^6m^3 for High-Ontario.

This volume of natural gas would need to be accessed via the existing Enbridge transmission and distribution infrastructure with natural gas shipped from western Canada or imported from the United States. The Enbridge system, with over 114,000 km of transmission and distribution pipelines in the province, is listed as having a capacity of 208.4 10^6m^3/d with a 2019 utilization of 73.1 10^6m^3/d (40). The maximum natural gas requirement in the High-Ontario scenario would equate to 90 10^6m^3/d, within the listed infrastructure available capacity (41). However, without further detailed infrastructure review and specific knowledge of natural gas demand locations, it is likely that further modifications would be required to physically deliver the natural gas, though macro supply and infrastructure do not appear to be an issue.

Figure 24 | Natural Gas Requirements by Demand Scenario and Supply Option



Water Requirement

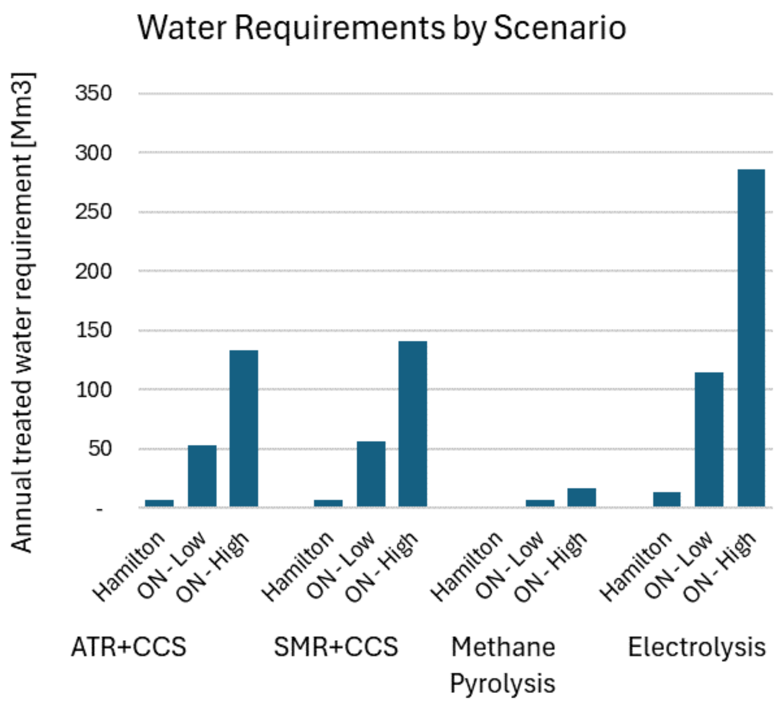
As shown in **Table 9** and illustrated in **Figure 25**, the water volume required for electrolysis is significantly higher than for ATR + CCS or SMR + CCS, with NG Pyrolysis having negligible water requirements. In the High-Ontario scenario, generating hydrogen via electrolysis would require 286 billion litres of water annually. According to Ontario's 2020 Water Takings data, this represents a 1.3% increase in the province's total water resource usage (42). Although only 48.5 billion litres of this water would be physically consumed in the chemical process of electrolysis, which would in turn produce 676 PJ of hydrogen, the total withdrawal volume of 286 billion litres could be challenging to secure although this is tempered by the fact that much of the water required for cooling can be immediately discharged back to its original source.[11] Southern Ontario is classified as having a high water availability threat level, meaning over 40% of the water supply is already used (43).

In contrast, ATR + CCS and SMR + CCS require 133 and 141 billion litres of water, respectively, with 24 and 26 billion litres being consumed. These volumes are significantly lower than those for electrolysis but still substantial. In the Low-Ontario scenario, water requirements are about 40% of those in the High-Ontario scenario, yet they still represent significant volumes. Given the minimal water requirements for NG Pyrolysis, it is likely that specific area considerations will need to be factored in when determining the appropriate hydrogen generation process, particularly in regions with water scarcity concerns.

---

[11] Electrolysis water requirements vary significantly based on the type of cooling systems used in hydrogen production, with cooling needs differing by process type and climatic conditions. Our analysis assumes that most hydrogen production will rely on once-through cooling systems in southern Ontario, given their lower energy demands, capital costs, and water use compared to evaporative or air cooling (see reference 33 for more details on hydrogen production water requirements). However, the mix of cooling processes in a large-scale electrolytic hydrogen production scenario in Ontario is uncertain, adding to the uncertainty of overall water requirements.

Figure 25 | Water Requirements by Demand Scenario and Supply Option



Electrical Requirement

Table 10 details the energy requirements for each hydrogen production process, divided between thermal and electrical energy needs. Electrolysis demands the highest electrical energy input, especially in the High-Ontario scenario, requiring 1,220.6 PJ/year. This is significantly higher compared to the requirements for NG Pyrolysis (184.4 PJ/year), ATR + CCS (68.0 PJ/year), and SMR + CCS (34.0 PJ/year).

Converted to an equivalent electrical requirement, electrolysis would necessitate 339 TWh/year of incremental generation. This is more than 2.5 times Ontario's total electricity consumption in 2023 and exceeds the electricity demand for the rest of Ontario's economy in the decarbonization scenario outlined in IESO's Pathways to Decarbonization report. Producing this much electricity would necessitate nearly 39 GW of additional electric capacity operating at a 100% capacity factor.

Although not insignificant, the other technologies have much lower future energy requirements. NG Pyrolysis would need 5.8 GW of additional generation capacity, ATR + CCS would require 2.2 GW, and SMR + CCS would need 1.1 GW. The incremental energy requirements for each technology and scenario are further illustrated in **Figure 26** and **Figure 27**.

Table 10 | Energy Requirements for each production process, by scenario

Prod'n Tech	Scenario	Hydrogen PJ H_2/yr	Hydrogen t H_2/yr	Elec. Req'd (PJ/yr)	Elec Req'd (Thermal) (PJ/yr)	Elec Req'd (Electrical) (PJ/yr)	Elec. Req'd (TWh/yr)	Elec Req'd @ 100% Capacity (MW)
ATR + CCS	Hamilton	30.9	218,048	43.3	40.2	3.2	0.88	100
	ON - Low	267.6	1,888,556	375.3	348.0	27.3	7.58	866
	ON - High	667.0	4,707,182	935.4	867.4	68.0	18.90	2,157
SMR + CCS	Hamilton	30.9	218,048	44.4	42.8	1.6	0.44	50
	ON - Low	267.6	1,888,556	384.2	370.6	13.6	3.78	432
	ON - High	667.0	4,707,182	957.6	923.7	34.0	9.43	1,077
NG Pyrolysis	Hamilton	30.9	218,048	11.5	3.0	8.5	2.37	271
	ON - Low	267.6	1,888,556	99.7	25.7	74.0	20.56	2,347
	ON - High	667.0	4,707,182	248.5	64.0	184.4	51.24	5,849
Electrolysis	Hamilton	30.9	218,048	56.5		56.5	15.71	1,793
	ON - Low	267.6	1,888,556	489.7		489.7	136.03	15,529
	ON - High	667.0	4,707,182	1,220.6		1,220.6	339.06	38,706

Figure 26 | Annual Electrical Generation Requirements, by production process and scenario

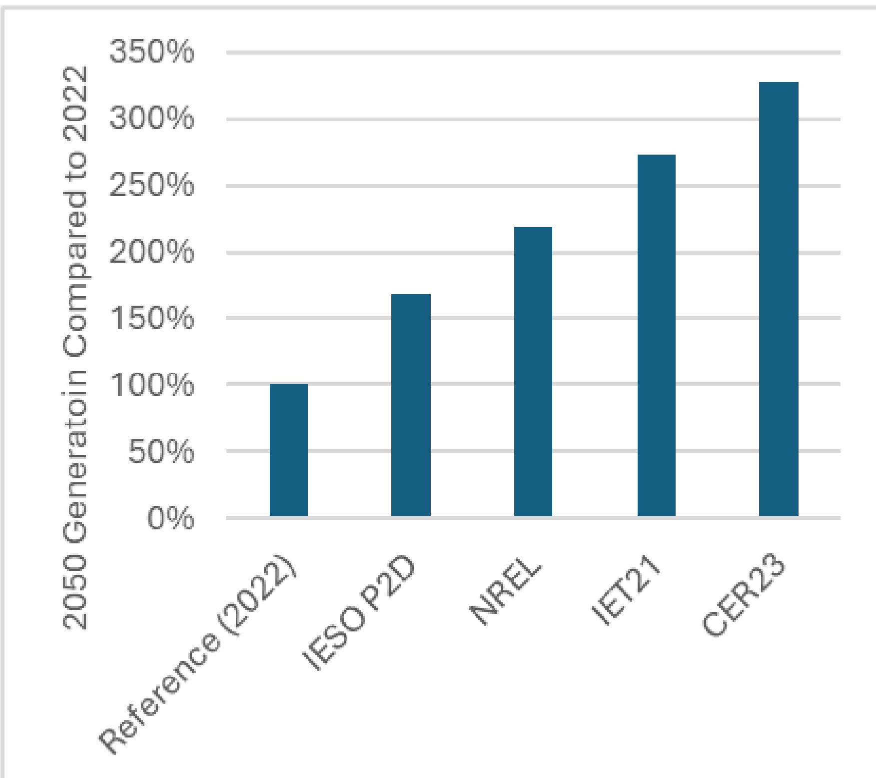
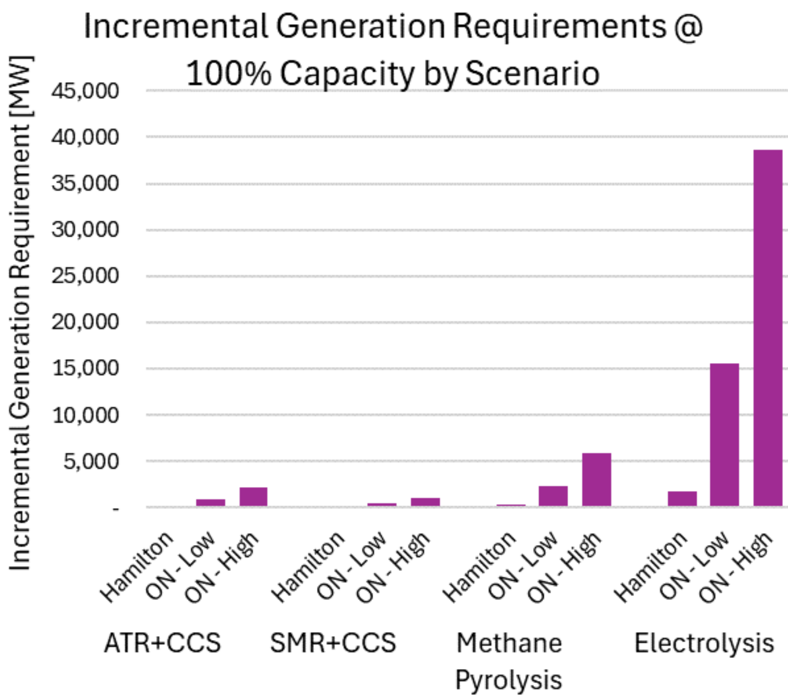


Figure 27 | Incremental Electricity Capacity Requirements, by production process and scenario



Carbon Emissions and Solid Carbon

Electrolysis, being independent of natural gas, does not contribute to incremental carbon emissions nor produce any significant by-products. Although oxygen is generated alongside hydrogen during electrolysis, it is assumed that this oxygen will be released into the atmosphere without any impact on greenhouse gas emissions.

In contrast, NG Pyrolysis, ATR + CCS, and SMR + CCS rely on natural gas as a feedstock for hydrogen production, resulting in carbon by-products. For ATR + CCS and SMR + CCS, these by-products primarily take the form of CO2. To produce low-carbon hydrogen, this CO2 must be captured and sequestered in underground storage. ATR technology has a higher carbon capture efficiency, assumed to be 95%, whereas SMR technology, even with advancements, is assumed to capture a maximum of 85% of CO2.

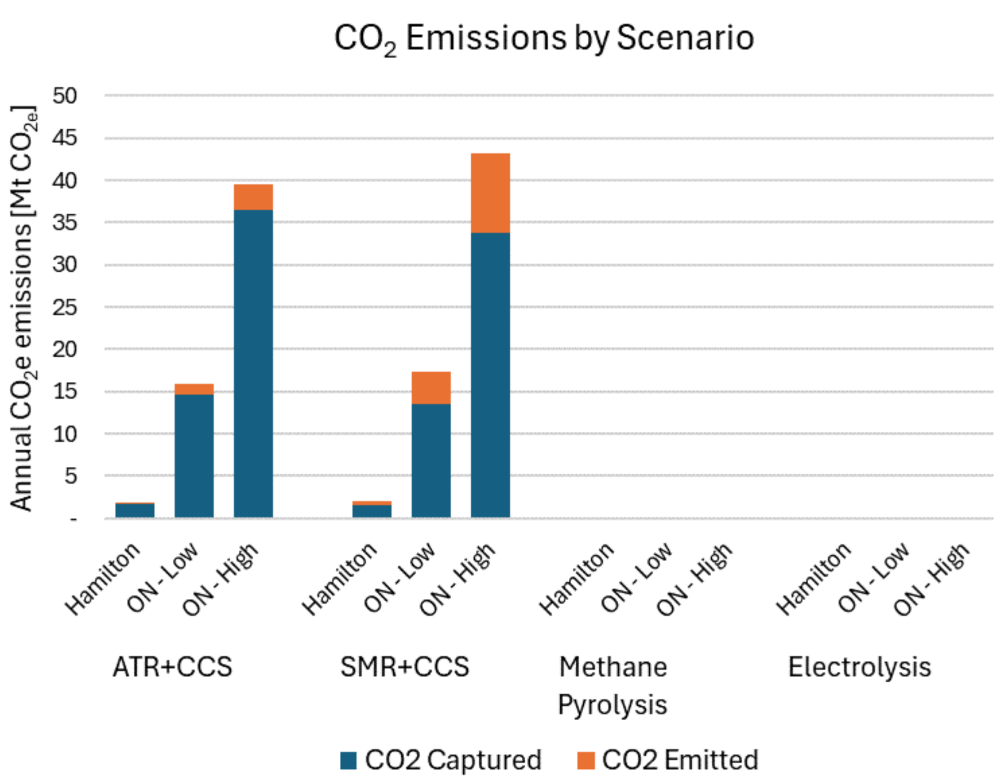
Table 11 illustrates the calculated CO2 emissions associated with hydrogen production for various scenarios, divided into the portion captured for sequestration and the portion emitted. In the High-Ontario scenario, ATR + CCS is expected to capture 36.6 Mt of CO2 annually for sequestration. This would require multiple sequestration sites based on the physical location of hydrogen production facilities. In the Hamilton scenario, the captured CO2 volume drops to 1.7 Mt/year, likely managed at a single site. The remaining 5% of CO2 emissions from ATR + CCS equates to 2.9 Mt/year in the High-Ontario scenario and 0.1 Mt/year in the Hamilton scenario.

For SMR+CCS, due to lower capture efficiency, the captured CO2 volume is less despite higher CO2 production per kg of hydrogen. In the High-Ontario scenario, SMR + CCS is expected to sequester 33.8 Mt/year of CO2, reducing to 1.6 Mt/year in the Hamilton scenario. However, emissions from this process are significantly higher, with 9.3 Mt/year of CO2 emitted in the High-Ontario scenario and 0.4 Mt/year in the Hamilton scenario. **Figure 28** provides a visual representation of the captured and emitted CO2 from ATR + CCS and SMR + CCS.

Table 11 | Calculated CO2 emissions associated with hydrogen production for various scenarios

Prod'n Tech	Scenario	Hydrogen PJ H_2/yr	Hydrogen t H_2/yr	CO_2 Captured Mt CO_2e/yr	CO_2 Emissions Mt CO_2e/yr	Solid C Mt/yr	Solid C CO_2 equivalent seqestration Mt CO_2e/yr
ATR + CCS	Hamilton	30.90	218,048	1.69	0.14		
	ON - Low	267.61	1,888,556	14.67	1.17		
	ON - High	667.01	4,707,182	36.57	2.92		
SMR + CCS	Hamilton	30.90	218,048	1.57	0.43		
	ON - Low	267.61	1,888,556	13.58	3.74		
	ON - High	667.01	4,707,182	33.84	9.32		
NG Pyrolysis	Hamilton	30.90	218,048			0.72	2.62
	ON - Low	267.61	1,888,556			6.19	22.67
	ON - High	667.01	4,707,182			15.44	56.51
Electrolysis	Hamilton	30.90	218,048				
	ON - Low	267.61	1,888,556				
	ON - High	667.01	4,707,182				

Figure 28 | Annual CO2 emissions, by scenario and production pathway



For NG Pyrolysis, natural gas is split in the absence of oxygen, so no CO2 is generated. This process produces valuable solid carbon by-products. Depending on the pyrolysis conditions and the presence of catalysts, various carbon allotropes are created, each with unique properties. Carbon black, a common product from pyrolysis, consists of very fine particles extensively used in tire manufacturing and as pigments and dyes. Other significant carbon allotropes include graphite, carbon nanotubes, and carbon fibers.

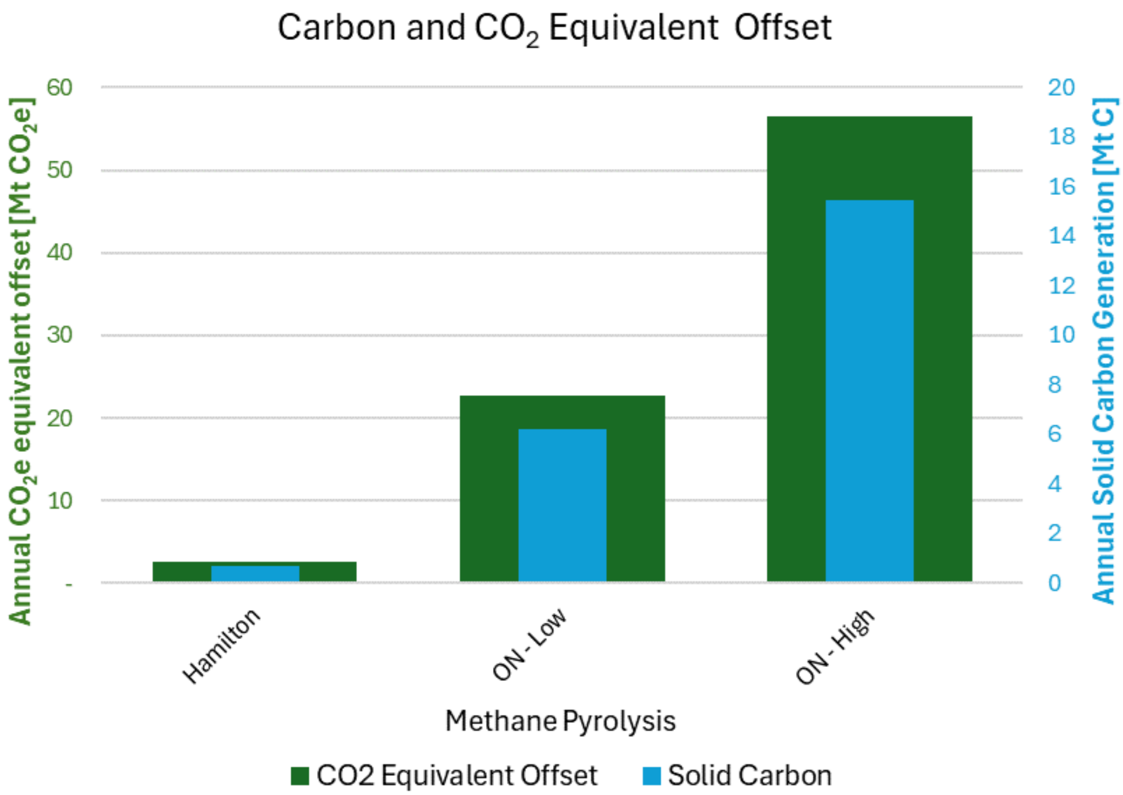
These allotropes have impressive properties that make them attractive for advanced material applications. They offer greater tensile strength than steel, are lightweight, have higher conductivity than copper, are flexible, possess antibacterial properties, and can be used at atomic thickness levels for near-complete transparency. Graphite, a critical mineral, represents the largest volume of material required in lithium-ion batteries and can be exfoliated to produce graphene. Nanotubes and fibers are combined with plastics and other materials to provide strength while remaining lightweight.

Additionally, sectors such as cement, asphalt, and steel, as well as soil amendment, anodes, electronics, 3D printing, and low-carbon intensity substitution for metallurgical coal, are investigating the use of these carbon allotropes. The market value of these allotropes varies significantly, from hundreds of dollars per ton for materials like metallurgical coke to hundreds of thousands of dollars per ton for nanotubes and graphene.

The economic value of these carbon by-products can help reduce the overall cost of hydrogen produced from NG Pyrolysis. Moreover, solid carbon acts as a stable sequestration medium due to its ability to be stripped from hydrocarbons without creating CO2. One kilogram of produced solid carbon has a CO2 sequestration potential of 3.66 kg CO2e/kg C.

Table 11 and **Figure 29** illustrate the amount of solid carbon generated under three scenarios and the equivalent CO2 sequestration potential. NG Pyrolysis would generate 0.7 Mt of carbon in the Hamilton scenario and up to 15.4 Mt in the High-Ontario scenario. From a sequestration perspective, the generated carbon would equate to capturing 2.6 Mt of CO2e in the Hamilton scenario and up to 56.5 Mt of CO2e in the High-Ontario scenario.

Figure 29 | Carbon and CO2 equivalent offset



Carbon Capture and Underground Sequestration

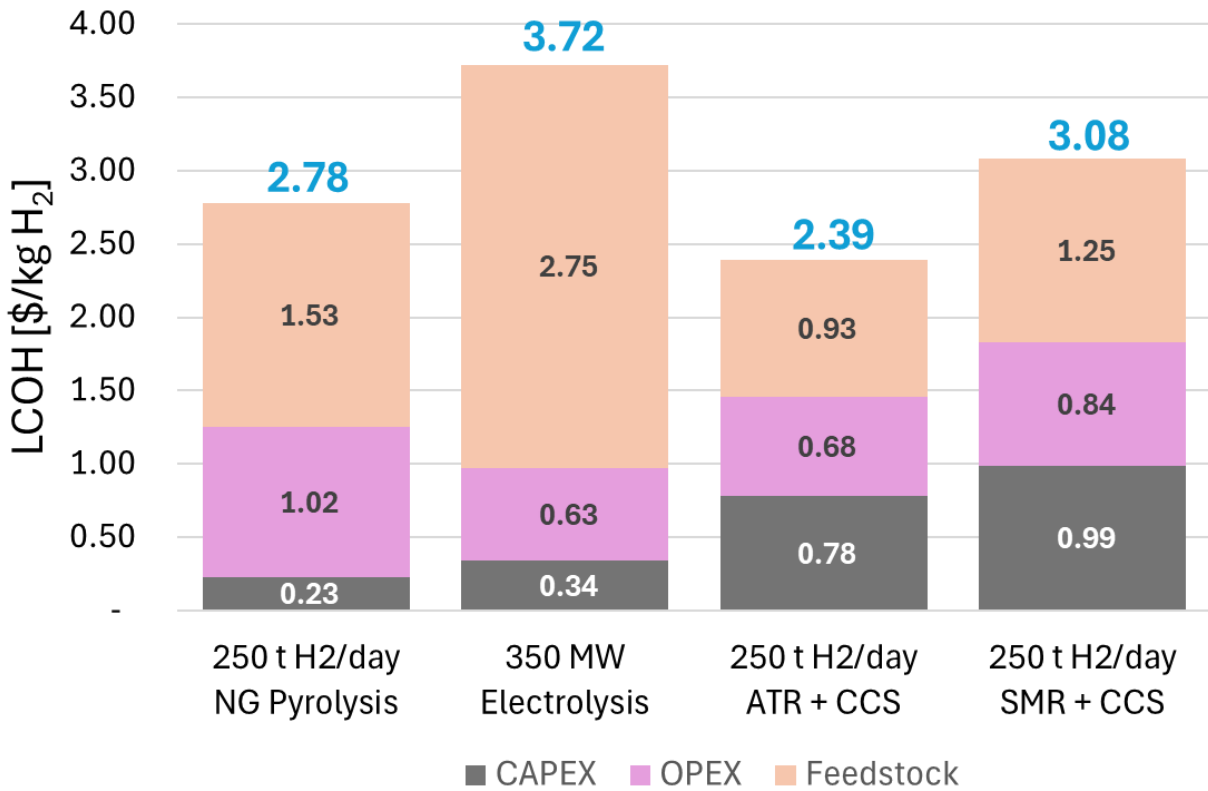
As indicated above, for ATR + CCS and SMR + CCS to be feasible to address the potential hydrogen requirements in the presented scenarios, suitable downhole storage for the capture of CO_2 needs to be developed. In the Geological CO_2 Storage in Southwestern Ontario report by Geofirma, it was identified that subsurface geology in southwestern Ontario appears suitable for CO_2 sequestration in the Basal Cambrian formation. From the report, it was estimated that upwards of 10 Mt of CO_2 could be captured annually in this area by 2030 with an ultimate storage potential of 289 Mt of CO_2 under Lake Huron and 442 Mt of CO_2 under southwestern Ontario and Lake Erie (44).

Though significant, this finding and the geographical limitation to southwestern Ontario appear to limit the capability of ATR + CCS and SMR + CCS due to insufficient volume to store all the CO_2 generated from the process when coupled with the capture of other industrial emissions. With low sequestration potential outside of southwestern Ontario, hydrogen generation outside of the region would require extensive pipeline networks to transport the CO_2 for sequestration increasing the high cost of capture further.

Supply Costs

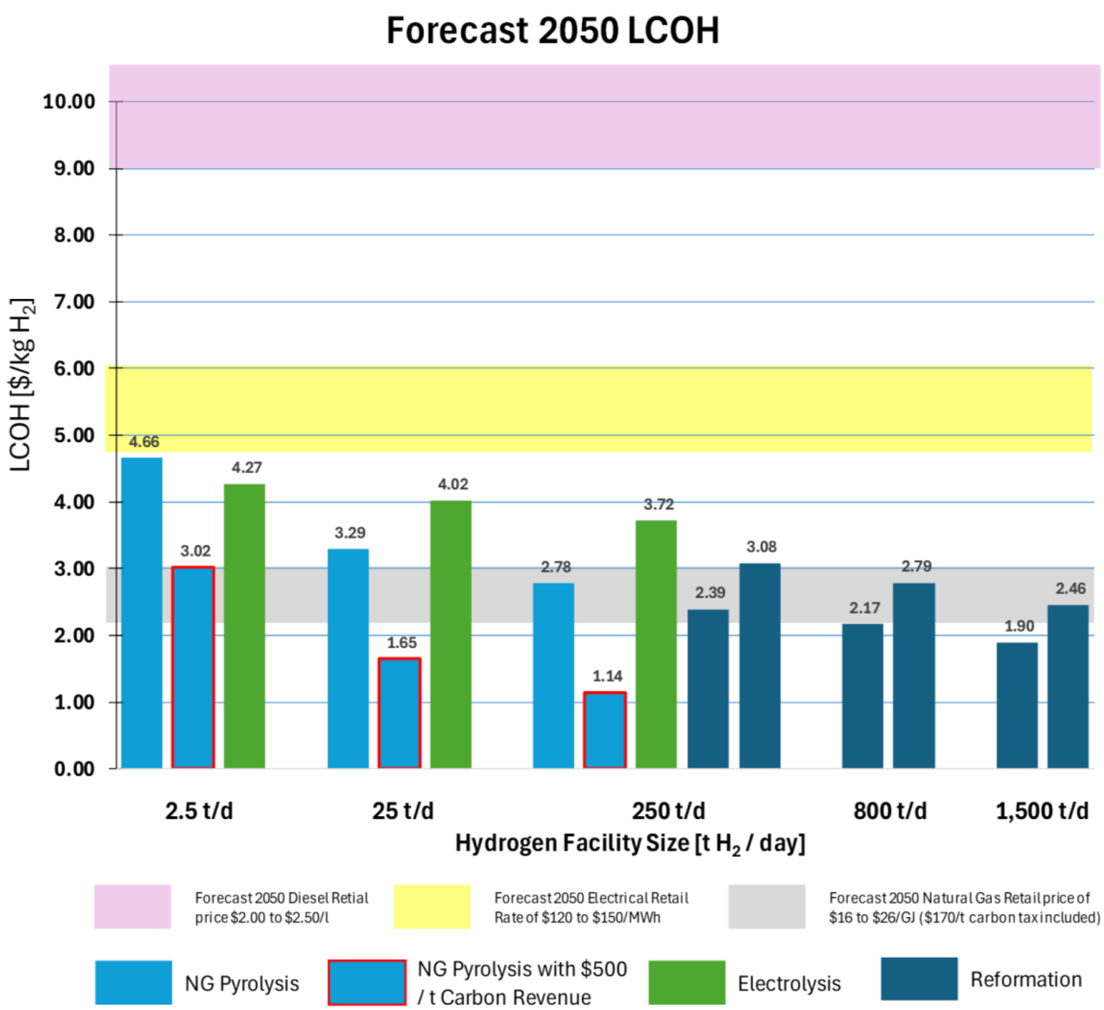
The techno-economic analysis of the four hydrogen generation technologies projects a 2050 Levelized Cost of Hydrogen (LCOH) ranging from $2.39 to $3.72 per kg H2. This analysis assumes a facility size of 250 tons of H_2 per day, a run time of 90%, and prices of $70/MWh for electricity and $5.50/GJ for natural gas. **Figure 30** illustrates the LCOH breakdown for each process, with ATR+CCS delivering the lowest LCOH and electrolysis delivering the highest under these assumptions.

Figure 30 | LCOH breakdown for different hydrogen production processes



As shown in **Figure 31**, by 2050, all evaluated hydrogen production technologies, at various facility sizes, are expected to deliver hydrogen at costs below $5.00 per kg H2. This figure highlights the economic viability of hydrogen as a low-carbon transitional fuel compared to projected costs for diesel, electricity, and natural gas. While the future retail costs of these fuels are highly uncertain, we compare projected hydrogen costs to other fuel retail cost projections from Canada's Energy Future 2023 report by the Canada Energy Regulator, which estimates retail costs under net-zero scenarios. Retail diesel, including a $170/t carbon tax, is forecasted to be equivalent to $9.00 per kg H2. The forecasted cost of electricity ranges from $4.70 to $6.00 per kg H2. Including the $170/t carbon tax, natural gas is forecasted to be equivalent to $2.15 to $3.50 per kg H2 (22).

Figure 31 | 2050 LCOH forecast, by various facility sizes



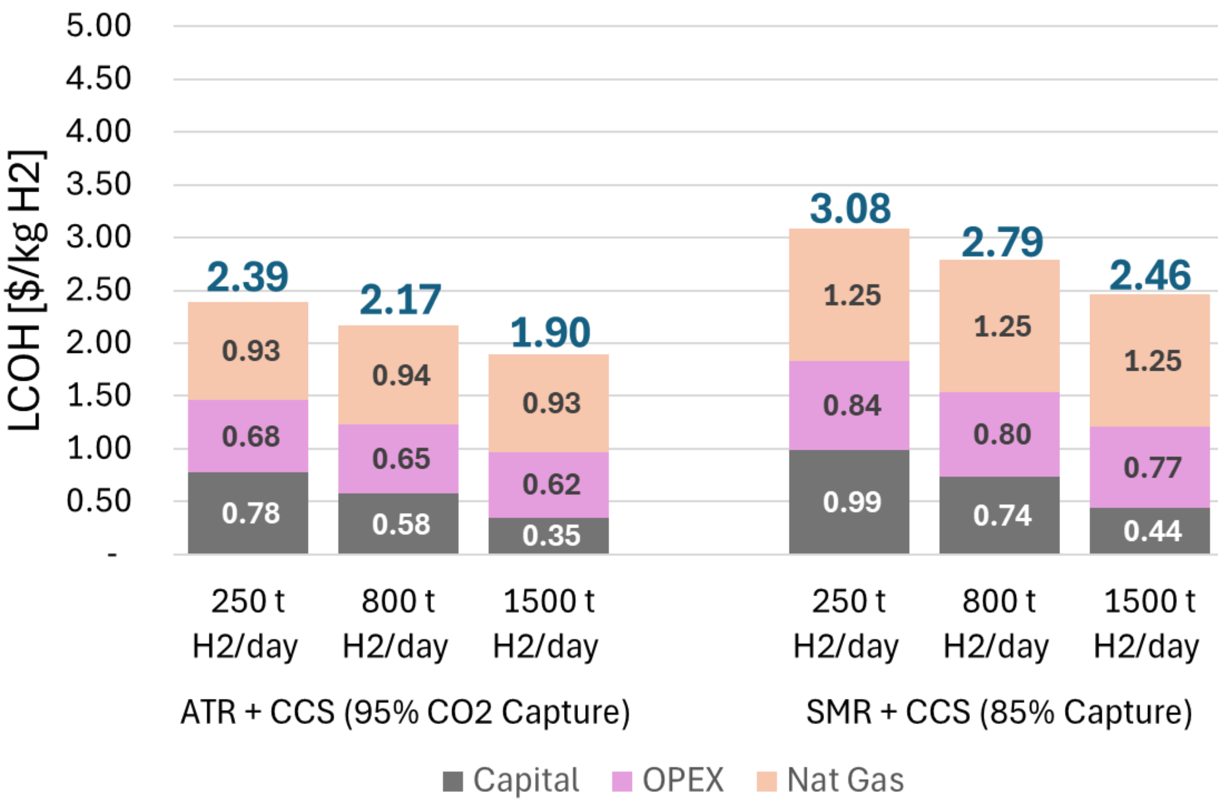
All hydrogen production technologies are anticipated to deliver hydrogen at or below the forecasted 2050 prices for electricity and diesel. For natural gas, NG Pyrolysis and SMR+CCS are projected to be economically viable for replacement at production scales of 250 tons per day (t/d) and higher. The economic feasibility of NG Pyrolysis depends on obtaining value for the solid carbon co-product and producing hydrogen at the point of demand to minimize transportation costs.

Mature Reformation Processes

A comparison of ATR + CCS and SMR + CCS economics was undertaken to understand the comparative LCOH for each process and the impact of large-scale centralized hydrogen production. Location and centralized hydrogen requirement at one location for the Hamilton scenario suggest installation of one large-scale ATR + CCS would satisfy hydrogen requirements. With Hamilton geographically lying within the Basil Cambrian potential area, sequestration of the resulting CO_2 would appear feasible.

Figure 32 illustrates the LCOH comparison for ATR + CCS and SMR + CCS. Using forecasted values of $5.50/GJ for natural gas and $70/MWh for electricity, an 800 t/day ATR + CCS facility is estimated to deliver hydrogen at an LCOH of $2.17/kg. Further reductions in LCOH could be achieved by constructing larger facilities, which would cater to additional hydrogen demands as contemplated in the Low-Ontario and High-Ontario scenarios. Notably, the single largest component of the LCOH is the cost of natural gas feedstock, accounting for nearly 50% of the total LCOH.

Figure 32 | LCOH comparison between ATR+CCS and SMR+CCS production pathways, by facility size



The analysis highlights that while both ATR + CCS and SMR + CCS can provide competitive LCOH values, SMR + CCS generally results in higher costs and greater emissions. The smallest practical facility size for these technologies, when combined with CCS requirements, is considered to be 250 t/day. As demonstrated, larger facilities benefit from improved LCOH, underscoring the economic advantages of scaling up hydrogen production infrastructure.

Emerging NG Pyrolysis and Electrolysis

Significant technology advancements are expected for both NG Pyrolysis and Electrolysis, leading to substantial improvements in the Levelized Cost of Hydrogen (LCOH) as these technologies move towards full commercialization.

For NG Pyrolysis, it is anticipated that specific processes will be optimized for either small-scale or large-scale facilities. Consequently, the average parameters used in this evaluation may be pessimistic, as evidenced by the estimated LCOH of $4.66/kg H2 for the 2.5 t/day model shown in **Figure 33**. At a small scale, capital expenditure, operating costs, and natural gas feedstock equally impact the LCOH. As facility size increases, significant reductions in capital costs and operating expenses are expected, potentially lowering the LCOH of large-scale NG Pyrolysis to $2.78/kg H2, comparable to reformation technologies.

The revenue from the carbon co-product is the most sensitive variable in reducing the LCOH of NG Pyrolysis. As illustrated in **Figure 34**, achieving a nominal value of $500/t of carbon can reduce the LCOH by 40% or more for larger facilities. Given that Carbon Black sells for over $2,000/t and Graphite for over $50,000/t, there is potential for hydrogen to be produced at very low LCOH values. NG Pyrolysis, as a distributed hydrogen alternative, will be necessary in all three scenarios to meet smaller and remote demands where transportation from a large, centralized generation point would be prohibitively expensive.

Figure 33 | LCOH breakdown for natural gas pyrolysis, by facility size

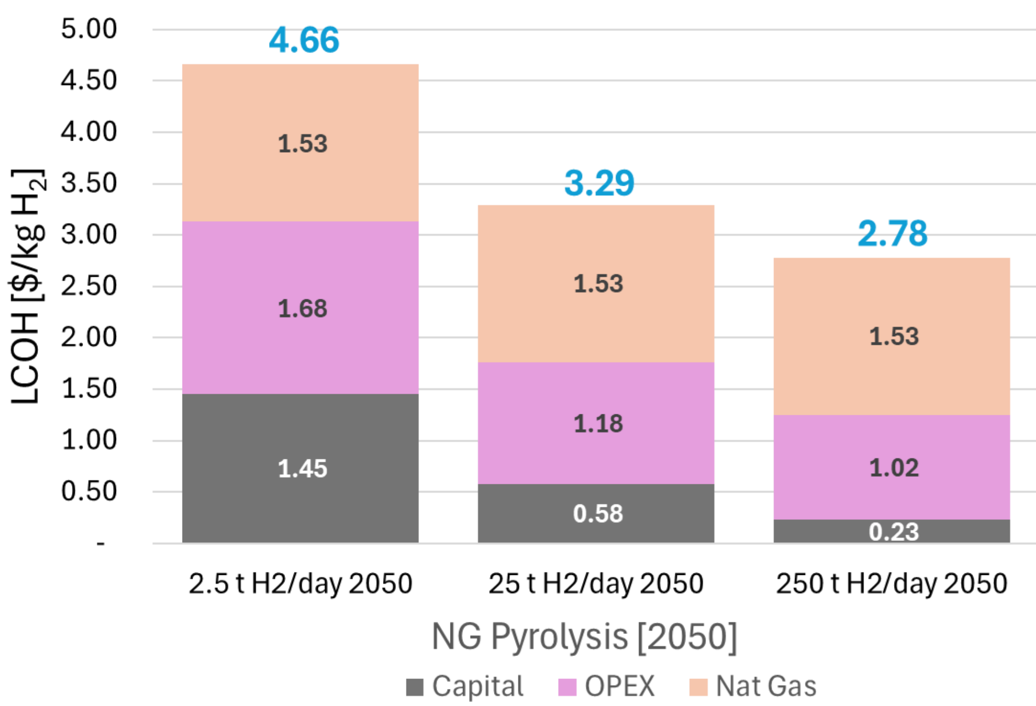
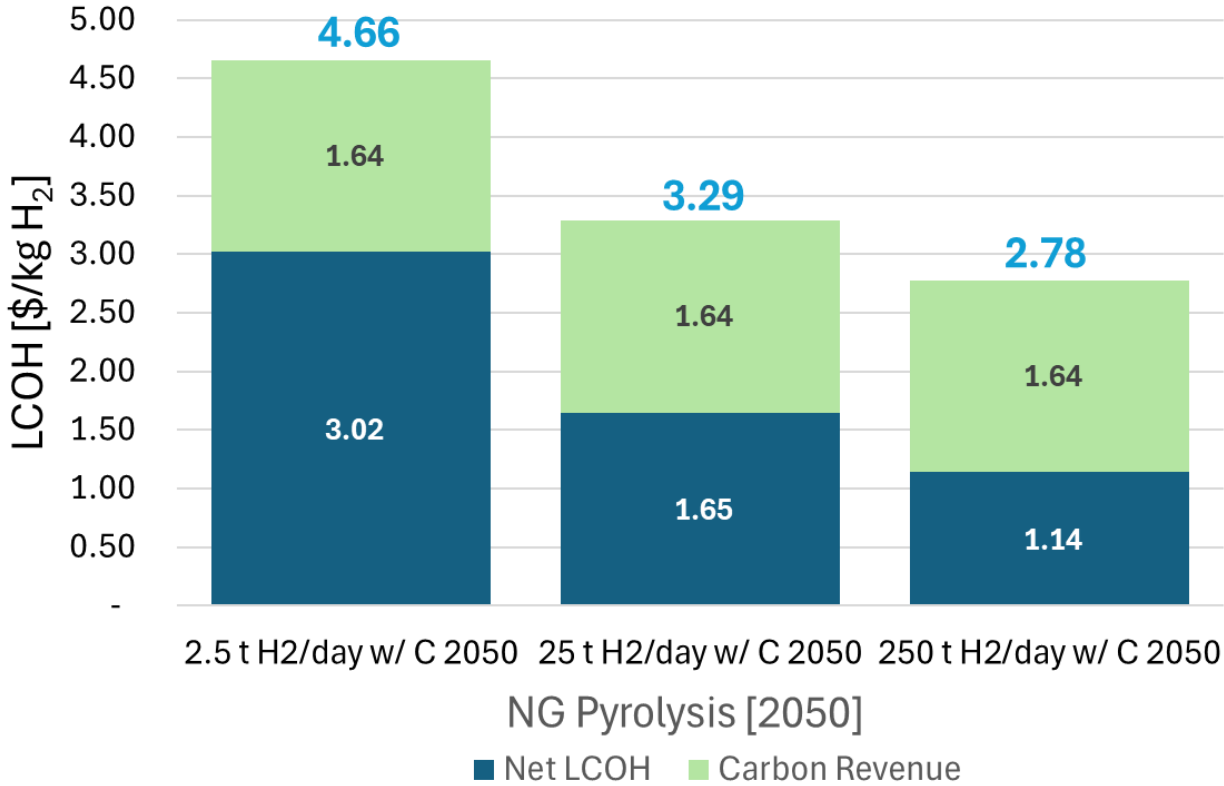
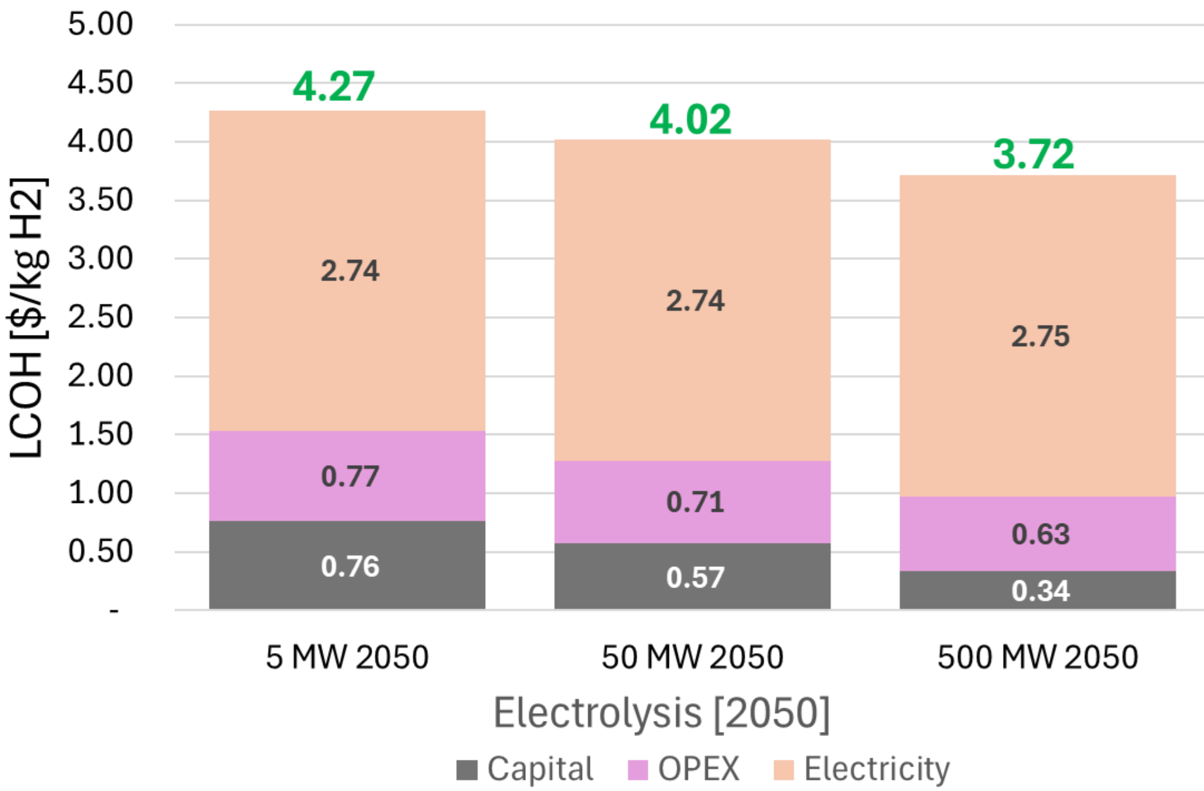


Figure 34 | LCOH breakdown for natural gas pyrolysis in 2050, by facility size



For electrolysis, manufacturing and supply chain improvements will be critical in realizing the anticipated reduction in costs, as well as the anticipated improvement in operating efficiency. The cost of electrical power will continue to dominate the LCOH calculation for the technology (**Figure 35**) and can be significantly reduced if directly connected, islanded power is considered the source for the process, with a realized power cost of $35/MWh reducing the Electrical portion of the LCOH in half based on the $70/MWh assumption. Utilization of electrolysis when excess grid generation is available without incurring wire and other associated transmission, and distribution costs would be an effective means of generating hydrogen from electricity that would otherwise need to be dumped from the system to maintain generation and demand balance.

Figure 35 | LCOH breakdown for Electrolysis in 2050, by the size of the electrolyzer



Hydrogen Imports

Instead of producing hydrogen domestically, Ontario may import hydrogen from outside the province to meet some or all of its domestic hydrogen consumption needs. This is a key assumption in the IESO's P2D study, which states that "hydrogen is produced outside of Ontario and therefore has no impact on demand." For this strategy to be viable, several conditions must be met. Jurisdictions outside of Ontario must develop sufficient capacity to produce low-carbon intensity (CI) hydrogen at competitive costs, and they must be able to transport this hydrogen to Ontario efficiently.

Importing hydrogen will likely require the use of pipelines, as this method is the most practical and cost-effective for transporting large volumes of hydrogen over long distances. Pipelines offer a continuous, reliable supply of hydrogen and are more economical compared to other transportation methods like trucks or ships. This transportation network may involve building new pipelines specifically designed for hydrogen or repurposing existing natural gas pipelines if and when natural gas consumption declines. Repurposing existing pipelines could be a cost-effective solution, but it requires addressing technical challenges such as hydrogen embrittlement and ensuring the integrity and safety of the pipelines for hydrogen transport.

Potential Sources of Hydrogen Imports

Ontario may import hydrogen from various locations, including the USA and other parts of Canada such as Western Canada (i.e., Alberta, Saskatchewan), Quebec, and the Atlantic provinces.

Western Canada: According to Alberta's Hydrogen Roadmap, the province has significant potential for hydrogen production and export, aiming to maintain market access for energy commodities and to ensure future competitiveness. Alberta can produce up to 45 million tonnes of clean, cost-competitive hydrogen annually by 2050, sufficient to meet both local and global demand. Target export markets include North America, Europe, and Asia Pacific, with options for hydrogen transport via pipelines, converted natural gas pipelines, and hydrogen carriers like ammonia and methanol. Alberta plans to export 1 million tonnes of hydrogen and 1 million tonnes of hydrogen carriers (i.e.: ammonia) by 2030, potentially growing to 10 million tonnes per year by 2050.

Given this capacity, importing hydrogen from Alberta to Ontario is a viable opportunity. Alberta's robust production and export framework could support Ontario's hydrogen needs, contingent on necessary infrastructure development.

While Saskatchewan is also making strides in hydrogen production, its focus remains on CO2 infrastructure and CCUS technology. In April 2024, the Transition Accelerator and the Saskatchewan Research Council (SRC) released a report on the "Hydrogen Hub Potential in the Regina-Moose Jaw Industrial Corridor (RMJIC)", which explored the potential for Saskatchewan to produce, use, and export low GHG hydrogen. The RMJIC benefits from strong road and rail infrastructure, connecting Saskatchewan to the Port of Vancouver in the west and to Ontario and the Maritimes in the east via TransCanada and Canada's rail network.

Quebec: Québec released its Green Hydrogen and Bioenergy Strategy in 2022, prioritizing hydrogen for applications where other decarbonization options are limited. The province primarily targets hydrogen for domestic decarbonization, viewing export as a long-term goal. Despite its abundant and affordable hydroelectric power, Québec's grid must support increasing future demands, including electric vehicle charging and industrial operations. The government is cautiously evaluating electrolysis project requests to ensure grid capacity can handle these loads alongside competing interconnection demands. Exporting hydrogen to Ontario presents potential but requires careful planning and grid management. Furthermore, Québec's proximity to the U.S. means that the U.S. will be a significant competitor with Ontario as an export market.

Maritime Provinces: The Maritime provinces have developed hydrogen strategies to establish green hydrogen production. For example, Nova Scotia's Green Hydrogen Action Plan and New Brunswick's Hydrogen Roadmap focus on international exports, primarily targeting Europe and the Northeastern US. While the current focus is on these markets, there is potential for future supply to Ontario if production capacities increase and local infrastructure develops.

This option may be viable if the Maritime provinces can develop sufficient production capacity to meet both domestic and export demands. Overcoming competition from international markets and developing local hydrogen infrastructure will be key.

United States: The US is establishing Regional Clean Hydrogen Hubs under the Bipartisan Infrastructure Law, aiming to create a national network of hydrogen producers, consumers, and infrastructure. These hubs, such as those in the Appalachian, Heartland, and Midwest regions, could potentially supply hydrogen to Ontario. Significant federal funding and incentives under the Inflation Reduction Act support the development of these hubs, enhancing their feasibility as suppliers.

The feasibility of importing hydrogen from the US depends on the successful development of Regional Clean Hydrogen Hubs and the establishment of robust supply chains. Efficient transport infrastructure and favorable trade agreements will play significant roles in making this option feasible.

Figure 36 | Selected Regional Clean Hydrogen Hubs – United States

- **The Appalachian Hydrogen Hub**, spanning across West Virginia, Ohio, and Pennsylvania, will leverage the region's ample access to low-cost natural gas to produce low-cost clean hydrogen and permanently store the associated carbon emissions. The strategic location of the Appalachian Hydrogen Hub and the development of hydrogen pipelines, multiple hydrogen fueling stations, and permanent CO2 storage also have the potential to drive down the cost of hydrogen distribution and storage. This Hub will focus on replicable projects to create a pathway for reducing long-term technology costs that can scale greater benefits for the region and beyond. The Hub intends to reduce CO2 emissions by 9 million metric tons per year.
- **Heartland Hydrogen Hub:** The Heartland Hydrogen Hub consists of project locations across North Dakota, South Dakota, and Minnesota, with the potential to expand into neighboring states, that will leverage the region's abundant energy resources to help decarbonize the agricultural sector's production of fertilizer and decrease the regional cost of clean hydrogen. The Heartland Hydrogen Hub also proposes to use clean hydrogen for power generation in a manner that may catalyze co-firing hydrogen in utility-owned generation across the country. The Heartland Hydrogen Hub's use of open-access storage and pipeline infrastructure will create a hydrogen network accessible to both current and new hydrogen users.
- **Midwest Hydrogen Hub:** The Midwest Hydrogen Hub network spans Illinois, Indiana, and Michigan, with the potential to expand into other Midwestern states. Located in a key U.S. industrial and transportation corridor, the Midwest Hydrogen Hub will enable decarbonization through strategic hydrogen uses including steel and glass production, power generation, refining, heavy-duty transportation, and sustainable aviation fuel. The decarbonization of these sectors will reduce carbon emissions by approximately 3.9 million metric tons per year. The Midwest Hydrogen Hub plans to produce hydrogen by leveraging diverse and abundant energy sources, including renewable energy, natural gas, and low-cost nuclear energy.

Import Transportation Costs

The transportation costs of hydrogen from outside Ontario to Ontario are influenced by various factors including pipeline design, demand, and compression requirements. Dedicated hydrogen pipelines, despite challenges like hydrogen embrittlement, are considered the most efficient means for large-scale transport.

Given the proximity of potential production facilities in Michigan, Ohio, or Pennsylvania, the transport distance to demand centers in Ontario (assuming the Hamilton region) is approximately 400 km. In a previous analysis by The Transition Accelerator, the techno-economic analysis of hydrogen transport via pipelines indicated that pipeline delivery costs of as low as $0.50 to $0.60 per kg$H_2$ could be achieved if the throughput of hydrogen in the distribution system was high enough (e.g., demand is high enough to warrant pipeline transmission) with roughly 1 to 1.2 tonnes of H_2 per day per km of pipeline required to drive economic viability (17).

For a 400 km pipeline, this translates to a throughput of approximately 400 to 480 tonnes of H_2 per day, which is analogous to the estimated demand in the Hamilton Only scenario.

In addition to the transmission cost associated with the import of the hydrogen volumes, distribution costs would be incurred to move the hydrogen from the import location to the point of demand. This would likely be done via truck transport and dependent on distance and volume, could add $1.50 to $3.50 / kg H_2.

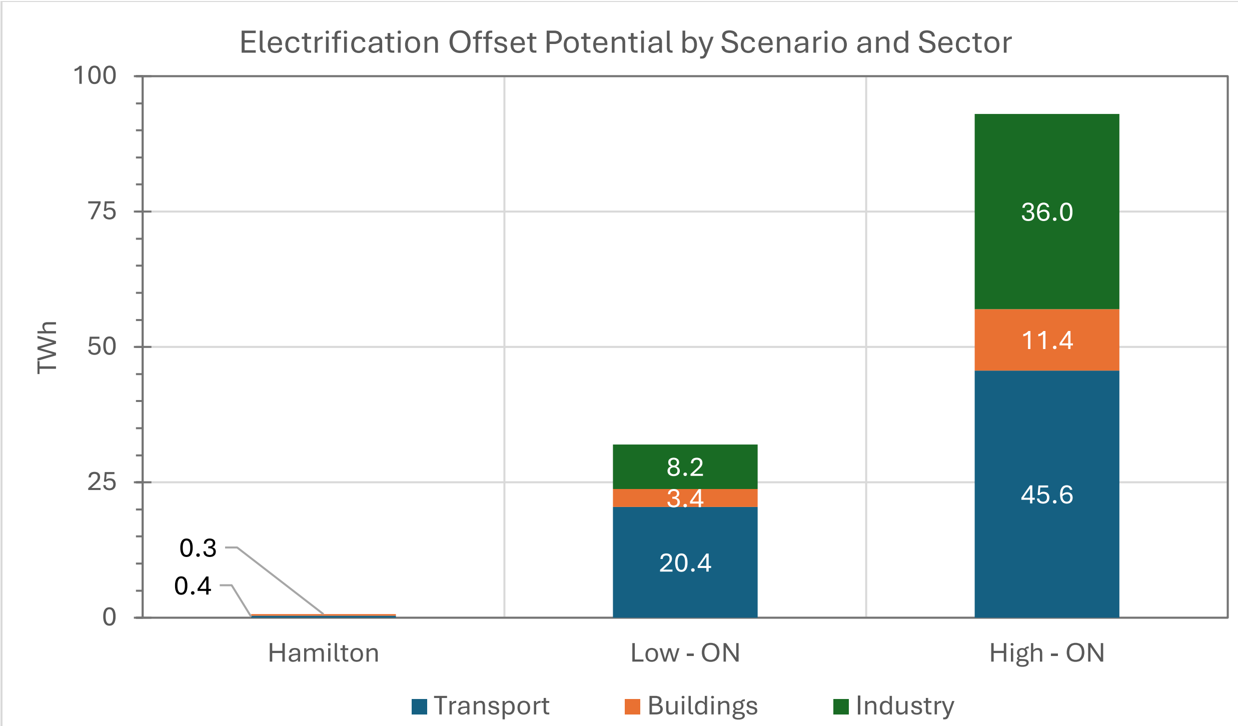
Electricity System Impacts

Any deployment of hydrogen in the future has the potential to affect the electricity system. These impacts could be in the form of a person choosing to buy an FCEV vehicle instead of a BEV, subsequently reducing direct electricity usage. It could also be in the form of using electricity to produce hydrogen. Finally, hydrogen could be used to generate and store electricity – playing a role in a net-zero aligned electricity system. This section presents the results of our analyses exploring these complex relationships.

Hydrogen vs. Electrification

Figure 37 presents the results of the "What If" analysis to evaluate the extent of "avoided electrification" resulting from the use of hydrogen. As a reminder, the analysis estimates the amount of annual electricity that would be required if the end-use energy fulfilled by hydrogen within each scenario was instead provided by direct electrification. There are many sectors and situations where electricity is not the best suited in a net-zero future, however, based on specific end-use characteristics and current technological limitations. End-uses where electrification is not technically feasible are excluded from this calculation, representing an upper bound to the amount of "avoided electrification". It further needs to be noted that this analysis is only applicable to the percentage of energy considered transitioned to hydrogen. The remaining energy not considered for hydrogen will require some alternative low-carbon transition option most likely dominated by incremental electrical generation. These scenarios are detailed further in Table 13.

Figure 37 | Electrification Offset Potential by Scenario and Sector



Based on these results, the following observations can be made:

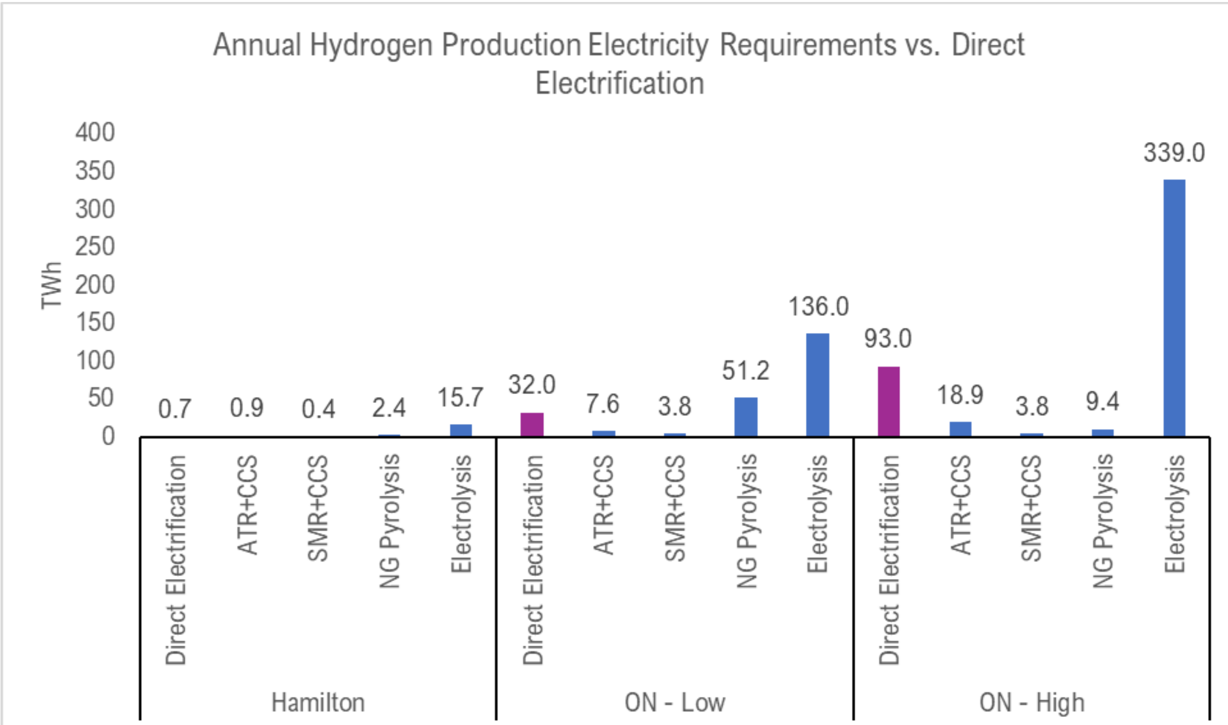
- The use of hydrogen in applicable sectors has the potential to offset up to 0.66 TWh (Hamilton Scenario), 32 TWh (Low Ontario Scenario), and at the maximum, 93 TWh (High Ontario Scenario) of potential electricity demand.
- Under the High Ontario Scenario, 93 TWh of annual electricity demand is equivalent to 61% of total Ontario generation in 2019 (45). This amount represents 18% to 35% of the total projected Ontario generation in the four studies we previously examined, which had projected values for 2050.
- Transportation electrification is likely to have the highest competition with H_2 as an energy carrier – in particular, the LDV & MDV segments; it should be noted that the highest transportation energy use is associated with HDV transport, a segment that has significant challenges from an electrification perspective.
- Industry electrification in the 'other manufacturing' and 'chemicals' sectors may have the greatest competition with H_2, although electrification retrofits of older facilities and high-temperature requirements may challenge this and require further research.
- Hydrogen use in buildings is projected to have the least impact on electrification due to the substantially higher efficiency of heat pumps and the subsequent need for less energy to provide the same heat service.

In the context of a net-zero 2050 Ontario with massive electrification expected in many of these sectors, low-carbon fossil fuel-derived H_2 should be looked at as an asset to help reduce electricity demand in what is likely to be an already massive build-out in capacity to meet demand.

Hydrogen Production Electricity Requirements

The electricity requirements to produce H_2 vary widely as a function of the technology and feedstock used. The results are displayed in **Figure 38** for all scenarios and production types compared to the electricity requirements that would be needed if these end-uses were directly electrified.

Figure 38 | Electricity Demand Associated with Varying Hydrogen Production Technologies in all Scenarios vs. Direct Electrification Requirements



Based on these results, a key insight is the significant difference in electricity requirements between direct electrification and various hydrogen production technologies across different scenarios. In the ON – High scenario, direct electrification demands 93.0 TWh, which is substantially lower compared to the electricity needed for hydrogen production via electrolysis, which requires an immense 339.0 TWh. Natural gas-based production options also demand electricity, but it is still far less than electrolysis or direct electrification.

Hydrogen as an Electricity System Resource

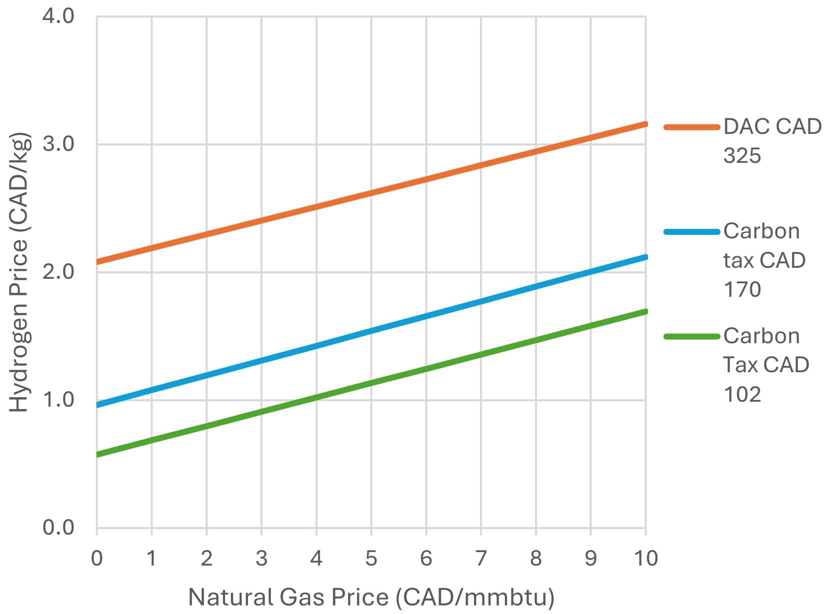
The following section presents the results of the hydrogen as an electricity system resource analysis. The results presented here focus on the breakeven price of hydrogen versus various other technologies.

Economics of Hydrogen as a Generation Resource

Hydrogen vs Unabated Natural Gas

Figure 39 shows the breakeven price at which the LCOE for a hydrogen-fired combustion turbine is competitive with an unabated natural gas combustion turbine at various hydrogen and natural gas prices. Natural gas prices represent the delivered cost of natural gas to the generator but do not include any carbon costs. Each line is the breakeven price evaluated at different carbon costs.

Figure 39 | Breakeven Price: Hydrogen vs. Unabated Natural Gas by Carbon Cost



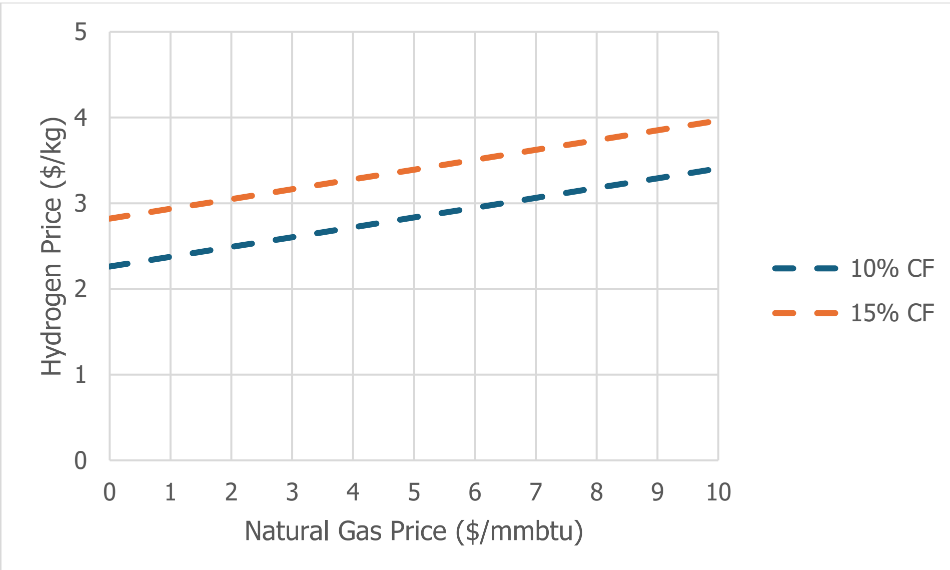
Note: The area below each line represents hydrogen and natural gas price combinations at which hydrogen is the more economical option. The area above each line represents combinations of natural gas is the more economical option. All values are expressed in CAD 2024$.

Based on these results, the following observations can be made:

- The breakeven price of hydrogen increases by $1/kg for roughly every $10/MMBtu increase in the cost of natural gas and every $155/tonne increase in the cost of carbon emissions.
- Under existing carbon pricing, the cost of hydrogen must be at or below $2/kg to be competitive against unabated natural gas even at historically high natural gas costs (i.e., $10/MMBtu). If the natural gas prices in 2050 are similar to today's costs (i.e., less than $4 /MMBtu), hydrogen will only be competitive if the delivery price of hydrogen is less than $1/kg.
- Indexing carbon costs to inflation slightly improves the breakeven price for hydrogen by increasing the real carbon cost by approximately $70 in 2050.
- With a significantly higher carbon cost representative of the cost of removing carbon from at atmosphere via DAC, the breakeven price of hydrogen approaches a floor of $2/kg.

It is important to note that this analysis assumes the capacity factor for hydrogen and unabated natural gas generators is the same. The specific capacity factor assumption does not influence the breakeven price since the analysis assumes capital costs are the same for each technology option. However, the federal government's proposed Clean Electricity Regulations (CER), published in Part 1 of the Canadian Gazette (CG1), would limit unabated natural gas generation with emissions greater than 30 tonnes per GWh to 450 operating hours per year, equating to a capacity factor of approximately 5% (46). A hydrogen-fired combustion turbine burning zero- or low-CI hydrogen, resulting in an emission rate below 30 tonnes per GWh, would not be subject to this limitation and could operate at a higher capacity factor, improving hydrogen's breakeven price relative to unabated natural gas. As illustrated by the figure below, if unabated natural gas generation was limited to a 5% capacity factor, while hydrogen peakers could operate at higher capacity factors of 10% or 15%, the floor of hydrogen's breakeven price would increase to $2.2/kg (compared to $0.5/kg) under the existing proposed carbon price of $170 in 2030.

Figure 40 | Comparison with unabated Natural Gas by Capacity Factor

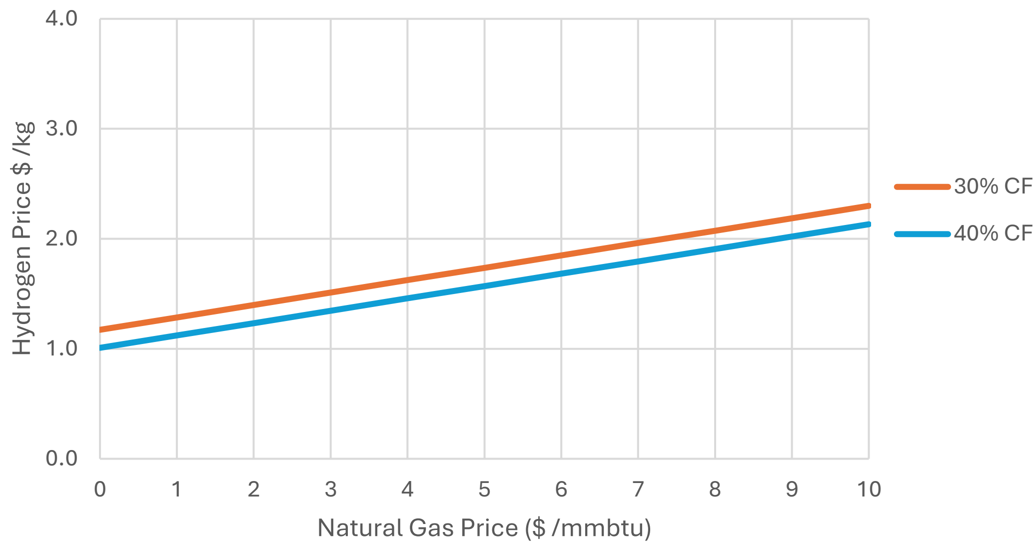


The CER has yet to be finalized, and the federal government has indicated that the final version will likely incorporate additional flexibility provisions for generators, potentially loosening this requirement. Any loosening of these requirements, allowing unabated natural gas to operate at a higher capacity factor, would reduce the potential advantage that hydrogen-fired generators have over unabated natural gas.

Hydrogen vs Abated Natural Gas

Figure 41 shows the breakeven price at which the hydrogen CCGT plant will be competitive with a natural gas plant with CCS at 30% and 40% capacity factors.

Figure 41 | Breakeven Price: Hydrogen CCGT vs. Natural Gas CCGT with CCS



Note: The area below each line represents hydrogen and natural gas price combinations at which hydrogen is the more economical option. The area above each line represents combinations of natural gas is the more economical option. All values are expressed in CAD 2024$.

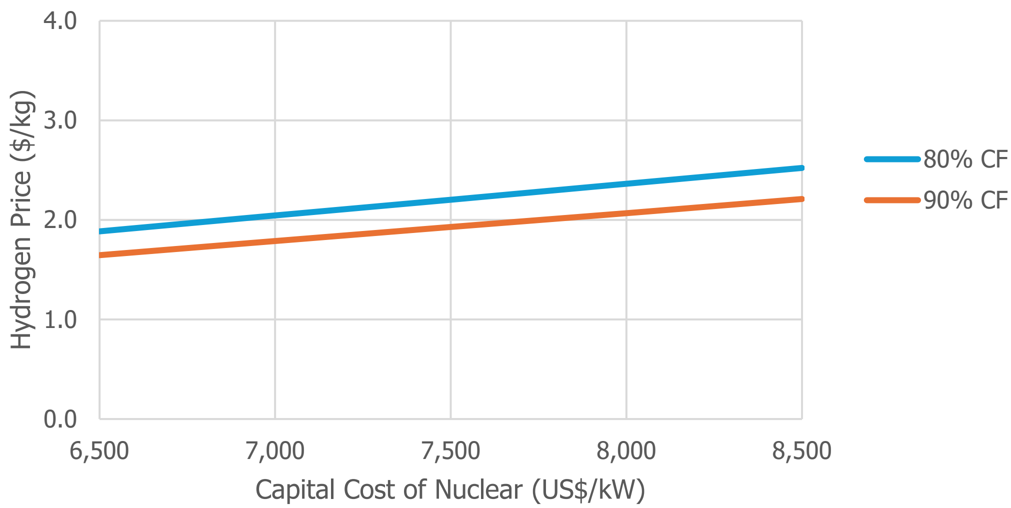
Based on these results, the following observations can be made:

- The analysis indicates that the economic feasibility of hydrogen slightly improves when it is compared to electricity generation from a CCS plant because of the high capex of CCS and the cost of capturing, storing and transporting CO_2
- Even with a carbon price of $170 nominal, a hydrogen price of $1.6/kg will allow it to be competitive with generation from CCS at the current level of natural gas prices.
- The prospects for hydrogen improve at lower capacity factors because a higher breakeven price for hydrogen is estimated for the same natural gas price.
- The competitiveness of hydrogen-based generation compared to that from CCS is therefore affected by the capacity utilization of each of these plants which in turn is dependent on the available hourly generation and the hourly electric load.

Hydrogen vs Nuclear

Figure 42 shows the breakeven price at which a hydrogen CCGT plant will be competitive with a nuclear power plant at 80% and 90% capacity factors.

Figure 42 | Breakeven Price: Hydrogen CCGT vs. Nuclear



Note: The area below each line represents hydrogen and nuclear generation capital cost combinations at which hydrogen is the more economical option. The area above each line represents combinations where nuclear generation is the more economical option. All values are expressed in CAD 2024$ except nuclear capital costs, which are expressed in USD 2024$.

Based on these results, the following observations can be made:

- Hydrogen CCGT plants can potentially be cost-competitive with nuclear plants at the delivered price of $1.7/kg to $2.5/kg depending on the capacity utilization and capital cost of nuclear.
- At a 90% capacity factor, hydrogen would need to be produced at a lower price to compete as a higher capacity factor improves the economics of nuclear making it more competitive.

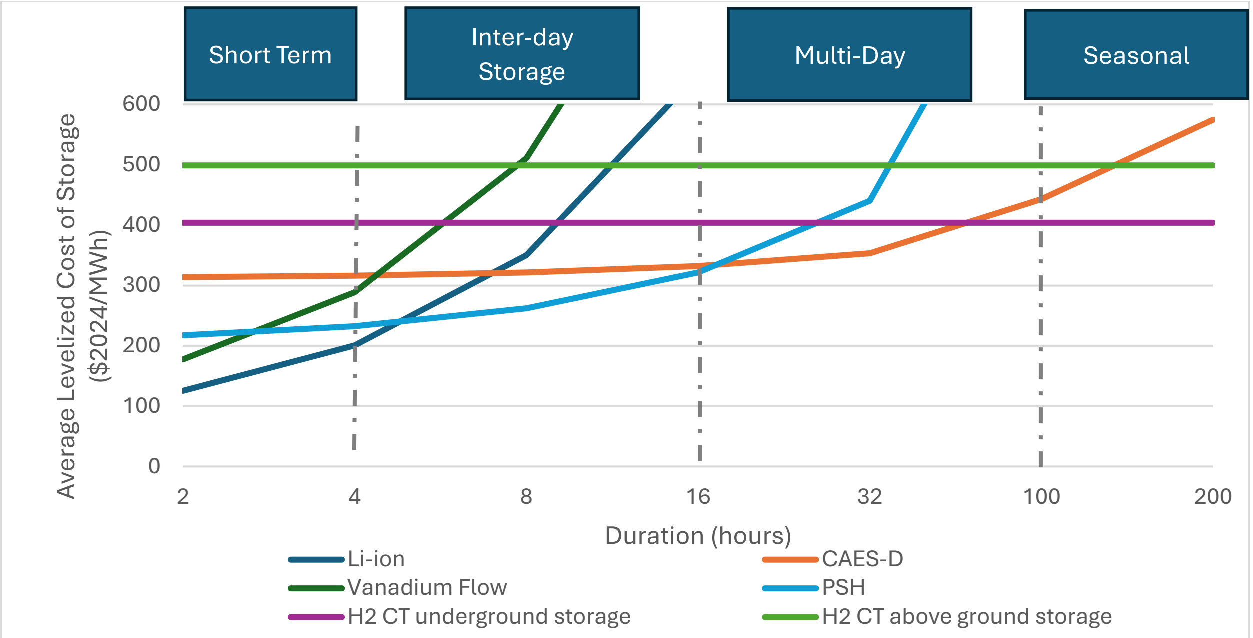
While low-cost hydrogen (at a price of less than $2.5/kg) may be cost-competitive with nuclear generation, the magnitude of hydrogen supply is likely to be the most significant limiting factor for hydrogen to play a role as a baseload generator akin to that of nuclear generation.

However, replacing even 200 MW of nuclear generation (operating at 93% capacity factor) with hydrogen-based electricity generation would require 135,900 tonnes of hydrogen annually. At this capacity factor, replacing the Pickering Nuclear Generating Station would require over 2.1 MT tonnes of hydrogen annually, which is over half of the hydrogen consumption estimated in the Ontario High Coordination hydrogen demand scenario.

Economics of Hydrogen as a Storage Technology

Figure 43 shows the LCOS of hydrogen in comparison to other storage technologies for different storage durations. We group storage durations into four categories – short-term (2 to 4 hours), inter-day (4 to 16 hours), multi-day (16 to 100 hours), and seasonal (over 100 hours).

Figure 43 | Comparison of Storage Technologies



Based on these results, the following observations can be made:

- The LCOS of hydrogen does not change with duration. This is because in hydrogen systems, storage capacity and power capacity are decoupled. Increasing storage capacity doesn't require a proportional increase in power capacity. Conversely, the LCOS of every other evaluated technology increases with duration for a variety of reasons.
- For short-term storage, hydrogen is not cost competitive with all other evaluated technologies having a lower levelized cost with Li-ion being the least cost.
- For inter-day and multi-day storage, hydrogen begins to become competitive as the LCOS of the other evaluated technologies begins to increase with increasing duration. At 16 hours duration, the LCOS of both Li-ion and Vanadium flow batteries exceeds that of hydrogen. At 32 hours duration, the only evaluated technology with a lower LCOS than hydrogen is CAES.
- For seasonal storage, hydrogen-fired combustion with underground storage emerges as the most economical storage option.

Other Considerations

Pipelines vs. Transmission Lines

Our analysis of hydrogen as an electricity resource compares hydrogen-fired technologies against various other technologies. Implicit in our analysis is the assumption that both hydrogen and alternative technologies can be located in areas where they can connect to Ontario's electricity grid, ensuring that the electricity they produce is deliverable to loads. This assumption is critical as it affects the feasibility and cost-effectiveness of the different technologies being compared.

However, this analysis does not consider the potential role of distributed hydrogen-fired generation. Distributed generation could provide local resilience and reduce the need for extensive transmission infrastructure. In certain scenarios, it may be more cost-effective to site hydrogen generation nearer to remote loads or loads located on constrained parts of Ontario's electricity grid, rather than building or upgrading transmission capacity. This implies that constructing hydrogen distribution infrastructure, such as pipelines, might be cheaper and more efficient than developing new transmission lines or upgrading existing ones.

Each scenario will need to be evaluated on a case-by-case basis to determine the most cost-effective approach. Hydrogen should be considered a viable non-wires alternative in specific circumstances, potentially providing a flexible and efficient solution to meet local energy demands while minimizing the need for extensive transmission investments.

The use of hydrogen for microgrid support would prove to be very attractive due to the ability to generate hydrogen at the point of demand and avoid the high capital expense associated with incremental transmission and distribution wires. Due to the transmission of an equivalent amount of energy in electron form being ten times more expensive than the transport of the same amount of energy in chemical form (hydrogen)(47), hydrogen has a role to play in satisfying regional peaking requirements and maximize stability, utilization, and capital efficiency of the electrical grid.

Breakthrough Technologies

Our analysis considers several potential firm generation and storage technologies, but it is essential to acknowledge that technological breakthroughs could fundamentally alter the economic cases of various electricity resources. Innovations in energy storage or new energy carriers could significantly impact the viability and cost-effectiveness of hydrogen and other resources.

Breakthroughs in alternative technologies, such as advanced nuclear reactors, next-generation batteries, or new renewable energy capture methods, could shift the competitive landscape. These advancements could render some of the current assumptions obsolete and necessitate a re-evaluation of the role of hydrogen in Ontario's electricity system. For instance, if a breakthrough in battery technology significantly reduces storage costs, it could make hydrogen less competitive as a storage solution.

Continuous monitoring of technological advancements and a flexible approach to energy planning will be essential. Policymakers and planners must be prepared to adapt strategies as new technologies emerge and mature. This adaptive approach will help ensure that Ontario's electricity system remains efficient, cost-effective, and aligned with net-zero goals.

5. Discussion, Conclusion, and Recommendations

The demand and supply analysis highlights several key insights into the potential pathways for hydrogen adoption in Ontario. Hydrogen can serve as a versatile energy carrier and provide a pathway to decarbonize various sectors. The analysis underscores the importance of developing a mix of hydrogen production methods, including ATR + CCS, SMR + CCS, NG Pyrolysis, and Electrolysis. Each method presents unique advantages and challenges, with varying implications for cost, carbon intensity, and scalability. The diversity of hydrogen supply options is critical for ensuring a resilient and adaptable hydrogen economy in Ontario.

In theory, hydrogen can compete against other resources to provide clean, firm power generation. However, its ability to do so depends on access to cost-competitive hydrogen supply in sufficient amounts to meet power generation needs. Hydrogen's role as an electricity system resource is promising but contingent on several factors, including the development of infrastructure and technological advancements.

Our analysis indicates that hydrogen can compete against unabated natural gas generation if the cost of hydrogen is sufficiently low or if the cost of unabated natural gas combustion is sufficiently high. By 2050, hydrogen will be competitive at a price of $2 to $3 per kg, assuming all unabated emissions must bear the cost of offsetting their emissions through atmospheric carbon removal. This price point is crucial for hydrogen to be a viable option for power generation.

As a storage resource, cost-competitive hydrogen applications are likely to be for long-duration use cases. Hydrogen can serve as a medium for storing excess electricity generated from renewable sources, which can then be converted back to electricity during periods of high demand or low renewable generation. Depending on the scale of VRE deployment in Ontario, this long-duration storage capability may be an essential component for balancing the variability of renewable energy sources and ensuring a stable and reliable electricity supply.

In addition to being cost-competitive, the use of hydrogen in Ontario's electricity system depends on the ability to access sufficient amounts of hydrogen in locations where hydrogen generators can interconnect with Ontario's electricity grid. This requires a robust infrastructure for hydrogen production, storage, and distribution. The development of regional hydrogen hubs and the repurposing of existing natural gas pipelines for hydrogen transport are key factors that will determine the availability and accessibility of hydrogen in Ontario. Ensuring that these supply chains are reliable and can deliver hydrogen to where it is needed will be crucial for integrating hydrogen into Ontario's electricity system.

Key Insights

Overall, our analysis highlights several key insights into the potential pathways for hydrogen adoption in Ontario:

Minimal Hydrogen Role Challenges Net-Zero Pathway

If hydrogen's role is minimal, as represented by the Hamilton Only scenario, our analysis suggests it will be feasible to provide cost-competitive hydrogen supplies, likely through natural gas-based processes such as ATR+CCS or SMR+CCS, or low-cost hydrogen imported from the United States. However, at this level of demand, Ontario's remaining energy requirements will need to be met by other net-zero energy carriers such as electricity. This could strain Ontario's electricity system if energy uses that could be fulfilled by hydrogen, as represented in the ON-Low and ON-High scenarios, instead directly electrify to meet net-zero requirements, incurring considerable costs.

Logistical Challenges of a Large Hydrogen Role

Conversely, if hydrogen's role is larger, as represented by the ON-High scenario, the input requirements and need to adequately address carbon byproducts could pose significant challenges to supplying cost-competitive hydrogen. Reformation processes that require gaseous carbon emissions to be captured and sequestered will likely be limited by the capacity to sequester the required magnitudes of carbon. NG Pyrolysis requires robust markets for solid carbon byproducts, and hydrogen via electrolysis would necessitate substantial incremental electricity generation and capacity.

Hydrogen as a Competitive Peaking Generation Asset

Hydrogen can be a competitive peaking generation asset as part of a net-zero aligned electricity system in Ontario if the delivered cost of hydrogen is below $3/kg. This is a feasible target based on our supply cost analysis. If hydrogen costs cannot meet this threshold, it will likely be more cost-effective to use alternative resources, including unabated natural gas that bears the full cost of offsetting emissions via atmospheric carbon removal.

Hydrogen's Role in Long-Duration Storage

As a storage asset, hydrogen's most beneficial role is likely to be as a long-duration storage solution, particularly at the seasonal level. This value will depend on the characteristics of the wider electricity grid in a net-zero future, with seasonal storage becoming more valuable with higher penetrations of variable renewable electricity. For shorter-duration applications, other storage technologies are likely to be more cost-effective, even at low assumed hydrogen costs.

Infrastructure and Accessibility Requirements

In addition to being cost-competitive, the use of hydrogen in Ontario's electricity system depends on accessing sufficient hydrogen in locations where hydrogen generators can interconnect with the grid. This requires robust infrastructure for hydrogen production, storage, and distribution, as well as addressing the logistical challenges mentioned earlier. The development of regional hydrogen hubs and the repurposing of existing natural gas pipelines for hydrogen transport are key factors that will determine the availability and accessibility of hydrogen in Ontario. Ensuring reliable supply chains to deliver hydrogen where needed is crucial for integrating hydrogen into Ontario's electricity system.

Key Conclusions

The analysis of potential pathways for hydrogen adoption in Ontario has led to several important conclusions. These conclusions highlight the necessity for technological advancements, coordinated planning, diverse production methods, and the conditions required for hydrogen to play a significant role in Ontario's net-zero energy future.

Need for Technological Advancements and Cost Reductions

Continued advancements in hydrogen production technologies and cost reductions are essential to making hydrogen a viable and competitive energy carrier. Investments in research and development can lead to more efficient production methods and lower overall costs. Our economic analysis indicates that natural gas-based hydrogen production technologies, such as ATR + CCS and SMR + CCS, are cost-competitive today. However, for electrolysis to become cost-competitive, further technological advancements and reductions in electricity prices are necessary. Innovations in production methods like Electrolysis and NG Pyrolysis also show potential for cost reductions and efficiency improvements. Additionally, the use of electrolysis and NG Pyrolysis will be critical in addressing smaller volume demands, where distributed hydrogen generation can significantly reduce the transport costs associated with centralized hydrogen generation.

Need for Coordination and Support Across Sectors and Government Levels

The adoption of hydrogen as a widespread net-zero energy carrier necessitates substantial coordination and support across various sectors and levels of government. This includes creating an integrated approach that aligns policies, regulations, and incentives to promote hydrogen production, distribution, and utilization. Collaboration between federal, provincial, and municipal governments, along with industry stakeholders, is essential to overcome barriers and foster a robust hydrogen economy that could represent greater than 26% of the total provincial energy consumption.

The High-ON scenario predicts an annual hydrogen demand of 4.71 Mt, equivalent to 12,896 tons/day. Meeting this demand requires extensive infrastructure development, including production facilities and distribution networks. The Low-ON scenario highlights the need for widespread hydrogen distribution, particularly for transportation, which accounts for 48% of the total demand (2,488 tons/day). Significant coordination is required to ensure these infrastructure needs are met efficiently and effectively.

Embracing Diverse Hydrogen Production Pathways

There is no single, optimal pathway for hydrogen production. Each method has unique advantages and challenges with different implications for cost, carbon intensity, and scalability. Our analysis highlights that a diversified approach leveraging regional strengths and resources is crucial for meeting hydrogen demand sustainably and economically.

ATR + CCS and SMR + CCS technologies, for instance, offer cost-competitive options today, but their large-scale adoption is limited by the need for extensive CO2 sequestration infrastructure. Southwestern Ontario shows potential for geological CO2 storage, but capacity constraints mean that these technologies might only be viable for a limited time without significant expansion of storage solutions. This emphasizes the logistical challenges of deploying these methods on a large scale.

NG Pyrolysis, producing solid carbon byproducts, presents another viable pathway. Its economic viability hinges on developing robust markets for these byproducts, such as carbon black and graphite. Additionally, NG Pyrolysis can be advantageous in regions where geological CO2 storage is not feasible, providing a stable carbon sequestration alternative.

Electrolysis, requiring substantial electricity, poses significant challenges in terms of energy supply. In the High-Ontario scenario, the demand for 340 TWh per year of electricity for electrolysis is more than 2.5 times Ontario’s total electricity consumption in 2023. Meeting this demand necessitates a massive increase in renewable energy generation and capacity. However, electrolysis is essential for smaller, distributed hydrogen production, reducing transport costs and enhancing regional energy resilience.

These findings underline the need for a diversified hydrogen production strategy, tailored to regional conditions and resource availability. Integrating various technologies can mitigate the logistical and cost challenges identified in our analysis. Embracing this diversity and strategically implementing technologies best suited to specific regional circumstances will be key to establishing a robust, sustainable hydrogen economy in Ontario.

By focusing on a diversified approach, policymakers and industry stakeholders can optimize the integration of hydrogen into Ontario's energy economy, ensuring that the benefits of each production pathway are maximized while minimizing the associated challenges.

Provincial Coordination Required for Hydrogen's Role in a Cost-Effective Net-Zero Electricity Grid

Hydrogen has the potential to play a crucial role in Ontario's net-zero electricity grid, but its success depends on meeting specific conditions. Hydrogen can be competitive as a peaking generation asset and a long-duration storage resource if the delivered cost is below $3/kg and a reliable and sustainable hydrogen supply is available. Achieving this requires advances in production technologies and the coordinated development of hydrogen’s role in the overall economy that addresses the barriers and limitations highlighted in this study.

A robust infrastructure for production, storage, and distribution is essential, including the development of regional hydrogen hubs and the repurposing of existing natural gas pipelines. Additionally, a province-wide distributed hydrogen generation network is likely necessary to meet smaller-scale demands, particularly in northern, remote, and rural locations. It is important to note that many of these factors are beyond the control of the IESO and require broader coordination across provincial government and industry stakeholders. The successful integration of hydrogen into Ontario’s electricity grid will thus depend on a holistic approach that aligns energy policies, economic incentives, and infrastructure planning across the province.

Recommendations

To support the adoption and integration of hydrogen into Ontario's energy system and achieve net-zero emissions by 2050, we propose the following recommendations. These recommendations aim to address the key insights and conclusions drawn from our analysis, focusing on inter-governmental coordination, strategic planning, technological advancement, and infrastructure development to create a robust hydrogen economy.

Inter-governmental and System Planning Coordination

The successful integration of hydrogen into Ontario's electricity system necessitates substantial coordination across various sectors and levels of government. Ontario's electricity system (via IESO) needs to collaborate closely with other energy-intensive sectors to make hydrogen a viable component. This can include:

- **Creating a Hydrogen Strategy Task Force:** Establish a task force with representatives from federal, provincial, and municipal governments, industry stakeholders, and academic experts to ensure a cohesive strategy and path to implementation through policies, regulations, and incentives.
- **Aligning Policies and Regulations:** Harmonize policies and regulations to support hydrogen production, storage, and distribution. This involves standardizing safety regulations, permitting processes, and technical standards.
- **Developing Coordinated Investment Strategies:** Attract private sector investment and efficiently allocate public funding through financial incentives such as tax credits, grants, and subsidies.
- **Conducting Joint Infrastructure Planning:** Ensure hydrogen production, storage, and distribution networks are integrated into broader energy and transportation infrastructure plans.

Develop Hydrogen Hubs and Corridors

To establish a robust hydrogen economy, it is crucial to develop hydrogen hubs in strategic locations and create corridors along major transportation routes. This effort should be complemented by a distributed production network to ensure widespread accessibility and efficiency. Key steps include:

- **Identifying Strategic Locations**: Conduct assessments to identify strategic locations for hydrogen hubs based on industrial activities, demand potential, and existing infrastructure, prioritizing regions like Hamilton, Sarnia-Lambton, and Niagara.
- **Integrating Hydrogen Production, Storage, and Distribution**: Develop integrated hydrogen hubs that co-locate production facilities, storage sites, and distribution networks to maximize efficiency and reduce transportation costs.
- **Establishing Hydrogen Corridors**: Create hydrogen corridors to support heavy-duty vehicles and other transportation needs, including refuelling stations and maintenance facilities.
- **Establishing a Distributed Hydrogen Generation Network**: Utilize existing natural gas infrastructure and potential islanded renewable generation to generate hydrogen at points of demand, particularly in northern, remote, and rural areas.

Investing in Hydrogen Technology and Promoting Industrial Decarbonization

To secure hydrogen's role in Ontario's net-zero future, it is essential to invest in advanced hydrogen technologies and promote their adoption across key industries. This includes fostering collaboration and innovation to accelerate the transition to low-carbon hydrogen. Key recommendations include:

- **Support Technology Development and Commercialization**: Invest in hydrogen generation technologies such as NG Pyrolysis and Electrolysis, which are critical for a diverse and viable energy transition. Provide financial incentives, including tax credits and grants, to support innovative hydrogen projects and address funding challenges for smaller-scale initiatives.

- **Promote Industrial Decarbonization**: Encourage key industries, especially steelmaking, refining, and chemical production, to adopt low-carbon hydrogen. This can significantly reduce greenhouse gas emissions and set a standard for other sectors.
- **Foster Collaboration and Innovation**: Promote collaboration among industry stakeholders, academic institutions, and government agencies to share knowledge and resources. Establish industry consortia to coordinate efforts and accelerate the adoption of hydrogen solutions.

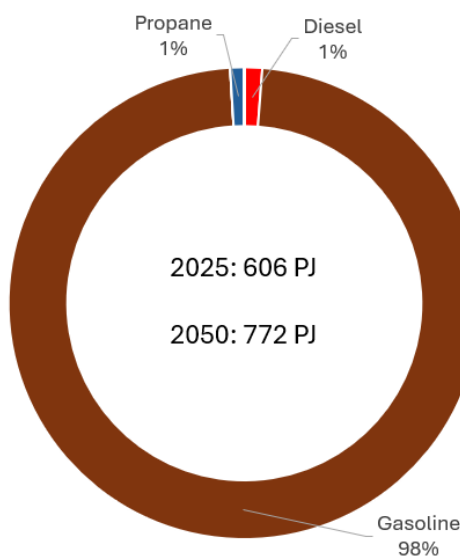
6. Appendix 1: Detailed Methodology and Assumptions

Hydrogen Demand

Sector End Use Analysis

Light Duty Vehicles

Figure 44 | Light duty vehicle energy use by energy carrier in Ontario.



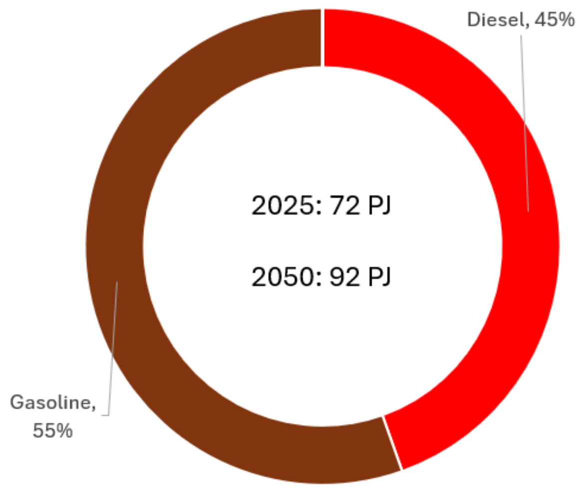
Light duty vehicles (LDVs) are a significant source of energy demand in Ontario with the sector predominately using gasoline (**Figure 44**); near-term demand is expected to reach 606 PJ, with 2050 demand expected to reach 772 PJ, based on population growth projections.

Considerable analysis has been conducted on this sector's transition away from liquid fuels. The preferred route for most uses is battery electric vehicle (BEV) technology that can easily be charged overnight at home for most owners (48). However, current BEV technology faces challenges with intensive-duty cycle operation and long-distance, rural use (49,50). Hydrogen fuel cell electric vehicles (HFCEVs) may be employed at a small scale to meet the needs of these duty cycles due to timely refuelling characteristics and long-distance capabilities if appropriate infrastructure exists (51,52).

For this report, the massive trend towards BEV is not disputed; however, 5% of gasoline and 100% of diesel LDV energy use was assumed to have an intensive duty cycle amenable to HFCEV conversion (taxis, delivery vehicles etc.). Further analysis to better understand intensive duty-cycle vehicles' contribution to the energy system in Ontario would be useful in future work.

Medium Duty Vehicles

Figure 45 | Medium duty vehicle energy use by energy carriers in Ontario.

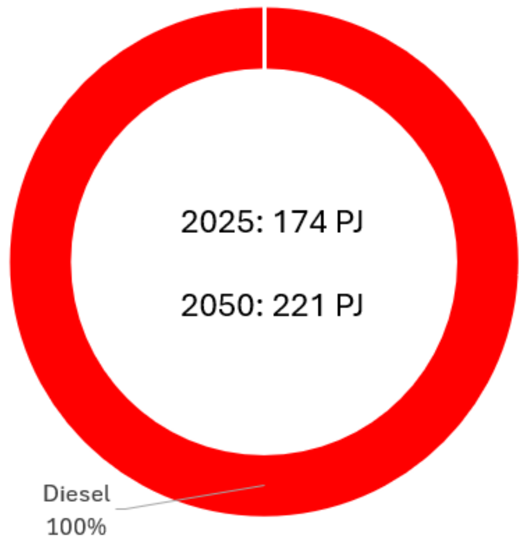


Medium-duty vehicles (MDVs) make up a smaller part of Ontario's transportation sector with gasoline and diesel currently serving demand nearly equally, with energy demand projected to reach 92 PJ by 2050 as a function of population growth in Ontario (**Figure 45**). MDVs are assumed to serve commercial and, to a smaller extent, personal transportation vs. LDVs, which are primarily associated with meeting personal transportation needs.

It has been assumed that a large portion of MDVs (particularly those with a gasoline powertrain) can be transitioned to BEV technology while still meeting required service needs without substantial changes to operational behaviour. It is also assumed that a portion of MDV use will consist of long-distance trips and intensive duty cycles, particularly for delivery trucks, which would be more suited to HFCEV technology. Knowing the exact proportions of these uses is difficult, however, it is assumed that diesel use is associated with heavier duty-cycle use based on diesel ICE vehicles' increased fuel efficiency and driving range characteristics (53). It is also assumed in this work that only diesel MDV energy use would potentially be transitioned to HFCEV technology.

Heavy-Duty Vehicles

Figure 46 | Heavy duty vehicle energy use by energy carriers in Ontario.



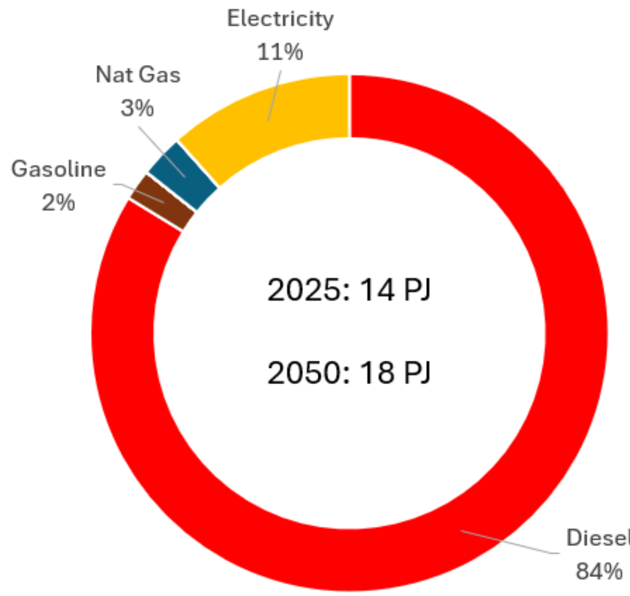
Heavy duty vehicles (HDVs) are a significant source of energy demand in Ontario that serve a critical service, with near-term energy projections modelled at 174 PJ and growing to 221 PJ in 2050 based on population growth (**Figure 46**). Energy use in this sector is almost entirely met by diesel, with most of the use assumed to be connected to long-haul trucking, with a minority share of short-haul use.

Recognized challenges to the decarbonization of HDVs include the ability for the alternative to have fast refuelling, long-range, and be able to handle the same cargo weight (54). These challenges are particularly pronounced in the case of BEV technology for long-haul trucking, with HFCEV being suggested as the best choice for long-distance hauling due to superior refuelling and weight characteristics for this application (55,56). It was assumed that a portion of this sector would prefer to use BEV technology for short-haul purposes.

It should be noted that although existing Federal ZEV sales mandates dictate that 35% of HDVs be ZEV by 2030 and 100% by 2040 (based on feasibility), this does not mean that all vehicles will be ZEV by 2040 and that a substantial portion of the existing ICE vehicle stock will still exist. Further analysis using in-depth stock and flow models would be required to adequately estimate energy use by incumbent vehicles in 2050, however, broader assumptions based on the scenario framing have been made for this work (between 1% – 100% transition).

Urban Buses

Figure 47 | Urban bus energy use by energy carriers in Ontario.

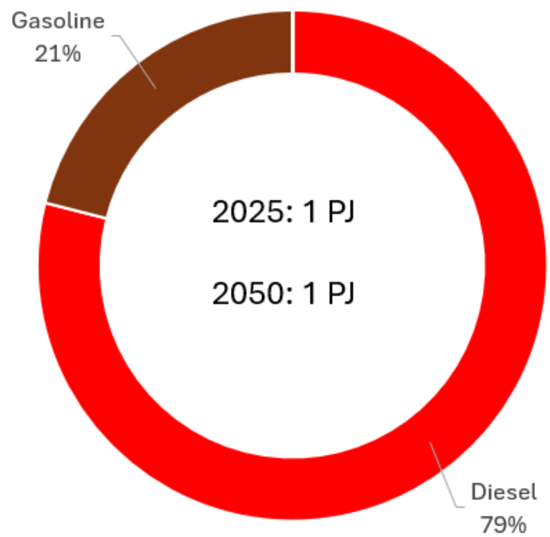


A relatively small proportion of the energy system in Ontario on an energy basis, urban buses are primarily serviced by diesel and to a smaller extent by electricity, natural gas, and gasoline with energy demand in the short term projected to be 14 PJ, reaching 18 PJ by 2050 (**Figure 47**). Urban buses have a unique duty cycle that includes frequent stop-and-go driving to pick up passengers along routes.

Due to the intense duty-cycle of these vehicles, it appears that HFCEVs may be particularly suited to this class of vehicle, particularly for longer routes. However, when looking at trends in the decarbonization of urban buses, examples of both electrification (57) and HFCEVs (58) can be seen. In this work, it is assumed that a portion of diesel urban bus energy use can be transitioned to HFCEVs.

Inter-City Buses

Figure 48 | Inter-city bus energy use by energy carriers in Ontario.



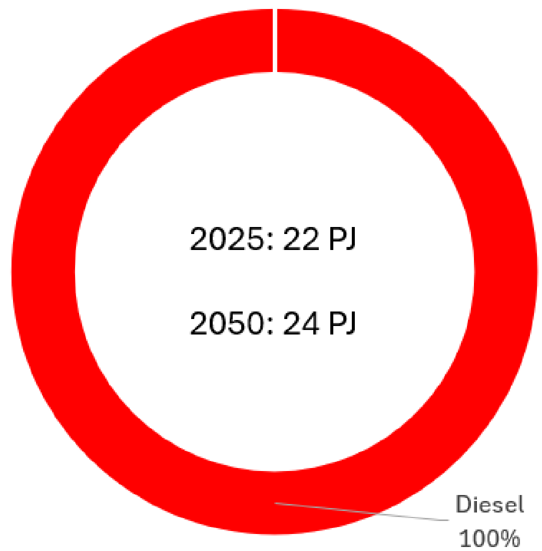
Inter-city buses make up a very small part of the Ontario energy system, with limited growth expected in the future as major Canada-wide operators close down routes due to changing ridership levels (59). Near and long-term energy use in this sector is projected to remain relatively unchanged at ~1 PJ (**Figure 48**).

Diesel fuel is the largest component of this sector due to the long-distance routes these buses usually take with a smaller (21%) portion of the sector using gasoline, likely used for smaller buses that follow shorter routes.

In this analysis, it has been assumed that routes serviced by gasoline vehicles are likely to switch to BEV technology, while a proportion of routes serviced by diesel could be met preferentially by HFCEV technology.

Rail

Figure 49 | Rail energy use by energy carriers in Ontario.



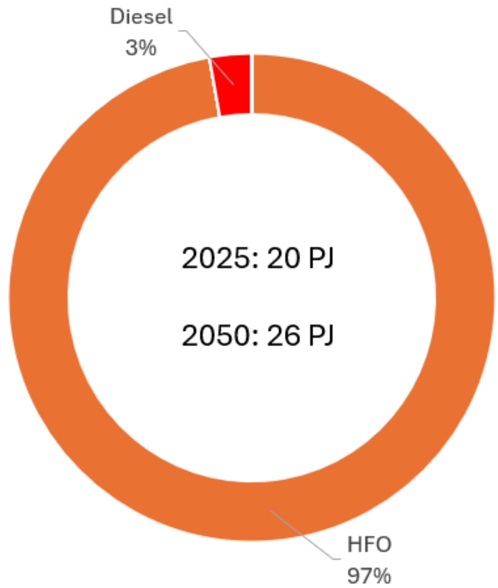
Rail transportation in Ontario is a significant user of diesel fuel, with near-term and long-term demand projected to be 22 PJ and 24 PJ, respectively (**Figure 49**). Rail is dominated by freight hauling which makes up ~98% of energy use in this sector (60). This sector relies on diesel-electric locomotives, which provide superior drivetrain characteristics vs. older, diesel-mechanical versions.

Rail trains have substantial room to carry additional weight and cargo, and thus both BEV and FCEV technology are currently being piloted (61,62). It is likely that a combination of these technologies will be deployed in the future, depending on the service need of the locomotive (yard use or long haul) and the energy infrastructure available between routes.

It has been assumed that a proportion of rail energy use can and likely will use HFCEV technology, particularly for long-haul segments.

Marine

Figure 50 | Marine energy use by energy carrier in Ontario.



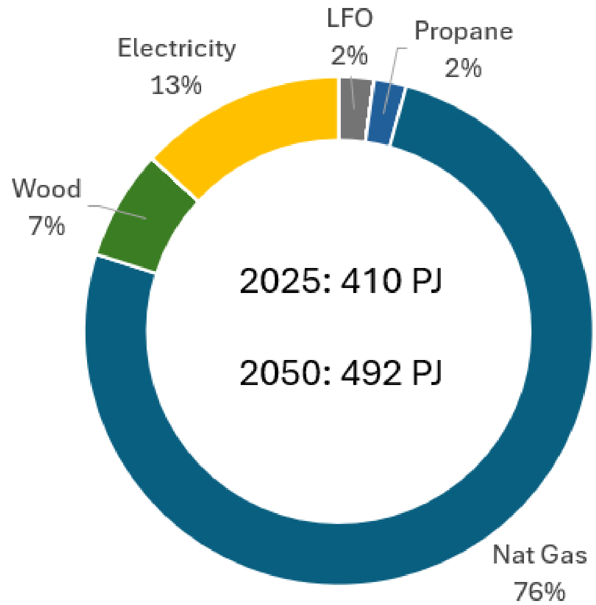
Marine transportation energy use in Ontario is projected to account for 20 PJ in the near term, and 26 PJ by 2050 (**Figure 50**). Marine transport is characterized primarily by the combustion of heavy fuel oil (HFO), with a limited proportion of smaller vessels using diesel. The largest proportion of this energy use is connected with the Port of Hamilton, which handles an estimated 10 million metric tons of marine cargo annually, with ~50% of this cargo being domestic, and 50% from abroad (63).

Large cargo vessels travel long distances without access to refuelling infrastructure, making decarbonization particularly challenging. Much discussion on the merits of combusting ammonia or using other H_2 carriers made from low-carbon hydrogen is ongoing (64–66), and pilot projects are underway already with HFCEV vessels, although there are still energy storage challenges with gaseous H_2 (67–69).

It is assumed in this work that HFO energy use associated with marine transportation could be met by ammonia combustion or HFCEV technology.

Residential Space Heating

Figure 51 | Residential space heating energy use by energy carriers in Ontario.



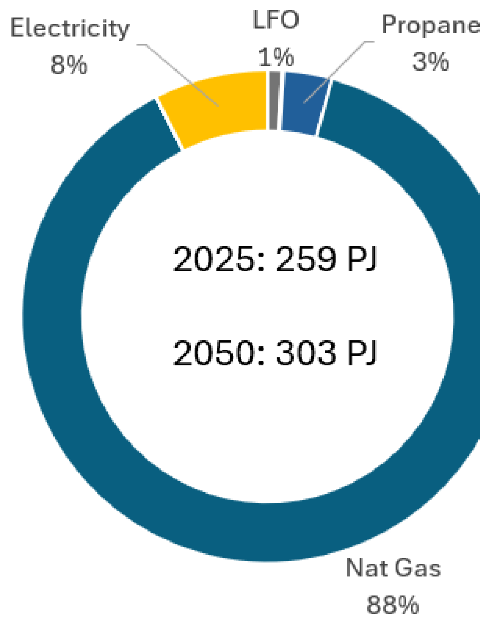
Heating in residential homes is a major consumer of energy in Ontario, with short-term demand projected to reach 410 PJ, rising to 492 PJ by 2050, based on population growth (**Figure 51**). Currently, the majority (76%), of this demand is met by combusting natural gas.

Due to the highly seasonal nature of this demand, decarbonizing this sector is challenging from an energy system standpoint. Vast underground storage facilities exist in Ontario that hold volumes of gas that can be drawn on to meet this seasonal demand (70) which in the future will need to be replaced with building an alternative system that can meet peak seasonal demand. The most likely replacement of this heat service will come from heat pump technology due to its superior efficiencies (71,72). However, there may be small segments of this sector that could adopt hydrogen as a replacement, such as large boiler systems in apartment buildings that currently make up 16.4% of natural gas energy use in Ontario, although economics and a lack of cheap, fossil-derived H_2 would prove to be challenging to adoption in this region (73). In addition, hydrogen may provide supplemental heat energy during extreme cold spells when heat pumps have reduced efficiencies (74).

In this work, 15% of natural gas building heating energy use is considered for potential transition to hydrogen.

Commercial Space Heating

Figure 52 | Commercial space heating energy use by energy carriers in Ontario.



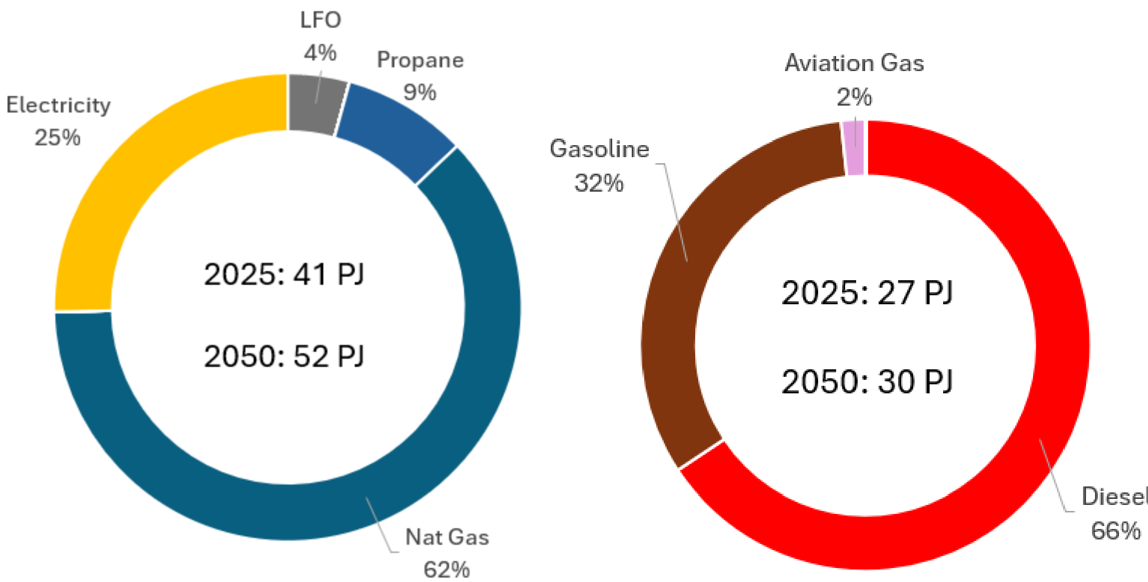
Commercial and institutional space heating is projected to reach 259 PJ in the near term, and 303 PJ by 2050, based on population growth (**Figure 52**). Fundamentally different from most residential heating systems, commercial space heating is large-scale and often centralized in nature. Despite these differences, commercial heating relies on a very similar energy mix and seasonal usage pattern with residential heating with natural gas making up 88% of demand.

There is little doubt that heating needs in this sector can and will be met using various heat pump technologies (particularly due to Ontario's relatively mild climate), however, there may exist a segment of this service that could be met with H_2. Large, combined heat and power (CHP) units could be an example of this – during heating season power could be generated to offset increased load from other heat pump installations.

Agriculture

The agricultural sector energy use consists of two parts – motive energy use and non-motive (**Figure 53**). This sector is unique in that it uses energy intensely over a short period of time (planting, harvesting) and is located around rural areas, with the need to store large amounts of fuel onsite to avoid frequent long-distance trips to refuelling infrastructure. These characteristics also make decarbonisation challenging.

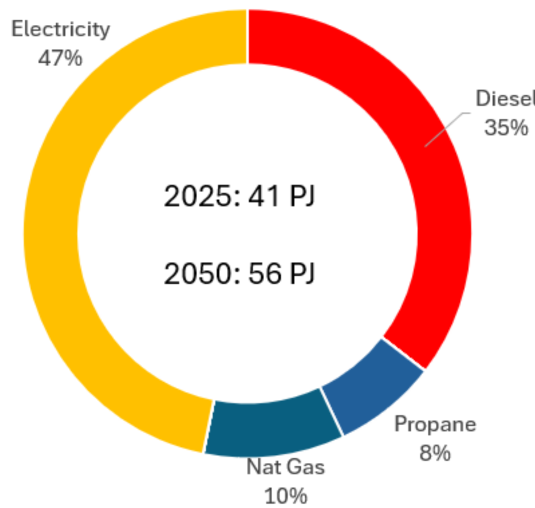
Figure 53 | A) Non-motive and B) motive agricultural energy use by energy carrier



In the case of non-motive agricultural energy use, hydrogen could play a role through direct combustion for uses such as grain drying and heating of large, poorly insulated agricultural buildings. For motive agricultural energy use that is used in a heavy-duty cycle, HFCEV technology using hydrogen generated from pyrolysis locally or from the decomposition of ammonia as a carrier could be used for vehicles such as tractors and other heavy equipment as piloted by Amogy (75).

Extractive Industries

Figure 54 | Extractive industries energy use in Ontario.



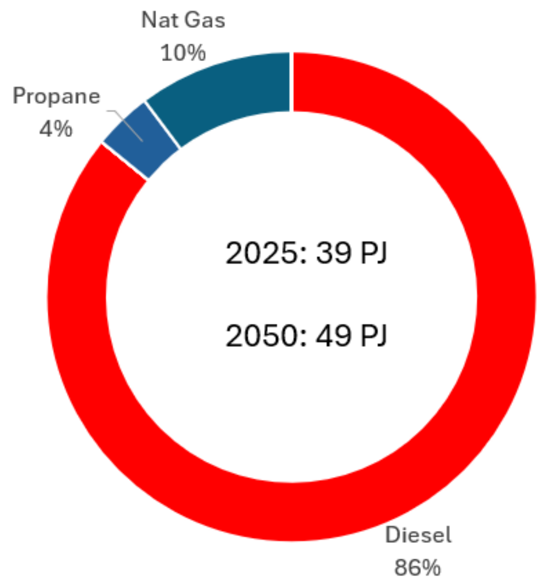
Extractive industries in Ontario are projected to account for 41 PJ of energy use in the short term, growing to 56 PJ by 2050 (**Figure 54**), with growth being dictated by macroeconomic growth trends in mining and forestry. In particular, the mining sector is anticipated to grow greatly over the upcoming decades to meet the demand for technology minerals and metals (76). A significant portion of energy use in this sector can be characterized as logistically challenged field operations which currently rely on easy-to-transport, energy-dense fuels such as diesel and propane, while centralized, more permanent processing facilities are located with access to electricity and natural gas.

For extremely logistically challenged and temporary operations, biofuels are likely the preferred choice of energy carrier due to their energy density and the simplicity of energy conversion technology. However, more long-term remote operations such as mines may use BEV or HFCEV technology, with promising developments occurring in each technology (77,78). These need to be considered on a case-by-case basis, as many nuances exist in determining the best technological solution, particularly when considering the economics of the operation.

For non-logistically challenged operations, it can be argued that some of the natural gas used in this sector is for high-temperature pyrometallurgy processes, which could be equally serviced by hydrogen combustion (79).

Construction

Figure 55 | Construction energy use in Ontario.

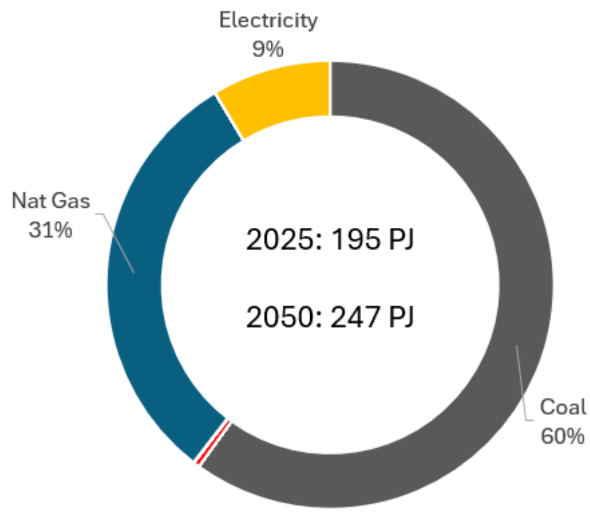


The construction sector is comprised of operations involved in constructing and repairing buildings, engineering works, and developing land, and is projected to account for 49 PJ of energy use by 2050, due to a rapidly increasing population (**Figure 55**).

Much of the energy demand in construction is met by way of diesel fuel – this can be attributed to running heavy equipment and other equipment such as large onsite generators. In the future, construction could be largely electrified if temporary infrastructure is put in place before operations commence, or equipment could potentially transition to technology such as HFCEV with equipment manufacturers already developing prototypes (80,81). For operations using natural gas (asphalt plants etc.), hydrogen could play a role as demonstrated in pilot projects (82).

Steel Production

Figure 56 | Steel energy use in Ontario.



Steel production is a major energy user in Ontario, with near-term energy demand projected to be 196 PJ, reaching 247 PJ by 2050, based on macroeconomic factors (**Figure 56**). Primary iron and steel production requires significant amounts of coal for reduction reactions and requires vast amounts of heat (met also, in part by coal) throughout the process.

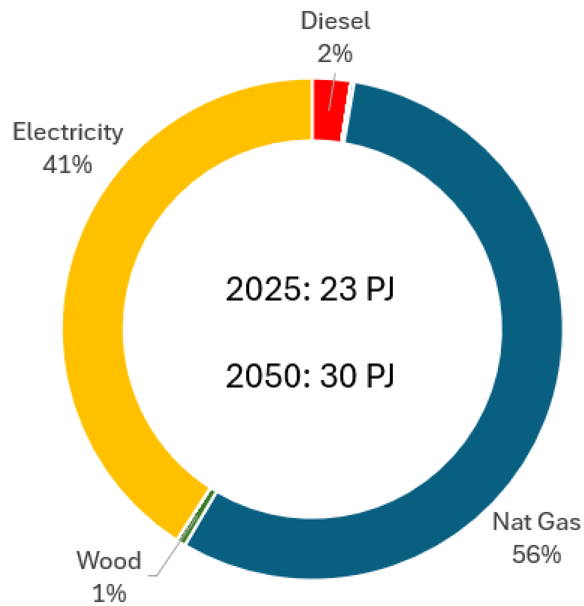
Replacing the incumbent reducing agent and providing the necessary heat energy to fuel the process is challenging. Alternatives include hydrogen direct iron reduction (83) and increased electrification (84). Various pilot projects exist for alternative pathways for this (85).

The Transition Accelerator has completed significant work on the decarbonization of steel production using hydrogen (25). In the Ontario region, seven steel production facilities exist, with only one facility planning on using hydrogen direct reduction as a decarbonization strategy (ArcelorMittal Dofasco, in Hamilton). The remaining six facilities are intending to use increased electrification to decarbonize operations.

For the purposes of this report, the hydrogen demands calculated in the 'Hydrogen and the Decarbonization of Steel Production in Canada' (25) report were used for all scenarios (492 t/day H_2), as only the ArcelorMittal Dofasco facility is likely to utilize hydrogen in any of the scenarios.

Non-Ferrous Smelting

Figure 57 | Non-ferrous smelting energy use in Ontario.

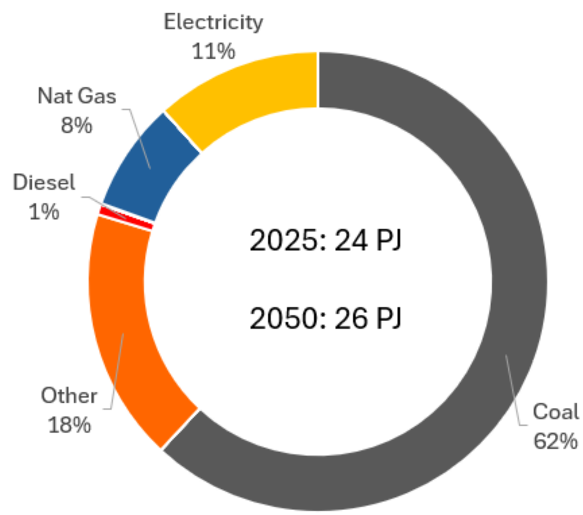


Non-Ferrous smelting is projected to account for 23 PJ of energy use in the short term, with significant growth to 30 PJ expected by 2050 (**Figure 57**). The sector includes the processing and refining of various metal concentrates, with the processes used being highly heterogenous depending on the feedstock and the product that is produced, making broad assumptions of decarbonization pathways difficult.

Not having a clear picture of what exact processes are happening can make it difficult to assume what role hydrogen *could* play in decarbonizing it. However, it can be assumed that a portion of the heating demand that is met by natural gas may be for high-temperature processes and that hydrogen could be suited best to meet these needs.

Cement

Figure 58 | Cement energy use in Ontario.



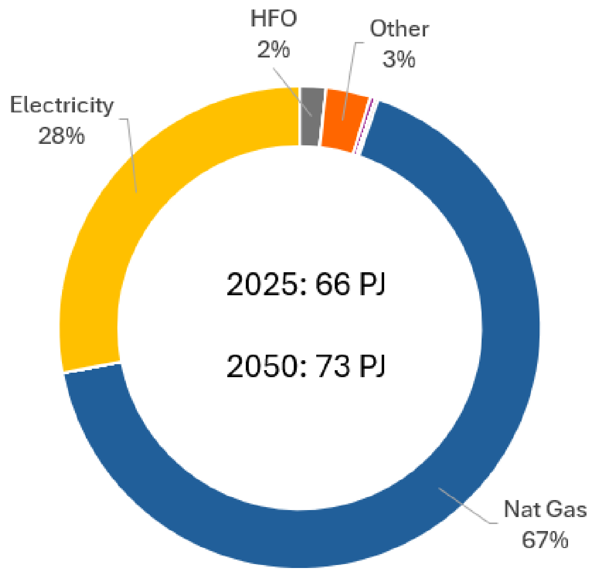
The cement industry in Ontario is projected to account for 24 PJ of energy use in the short term, reaching 26 PJ by 2050 (**Figure 58**). This industry group is involved in manufacturing cement, ready-mix concrete, bricks, and related precast and other concrete products, and heavily relies on coal, combustible wastes, and fossil fuels for heat energy.

A large part of energy use in this sector is associated with high-temperature (1,450°c) rotary kilns that are used to facilitate the calcination reaction between limestone and other minerals during the production of 'clinker' (the glue used in cement products). This process in itself creates non-combustion process CO_2 emissions, and is a substantial (~40%) contributor to overall production emissions in this sector, lending CCUS technology to clinker production (86).

The Cement Association of Canada has anticipated up to 15% of energy used for combustion could be provided by Hydrogen by 2050 (87). In this work, a relatively small portion of heat energy is assumed to be met by hydrogen.

Chemicals

Figure 59 | Chemical production energy use in Ontario.



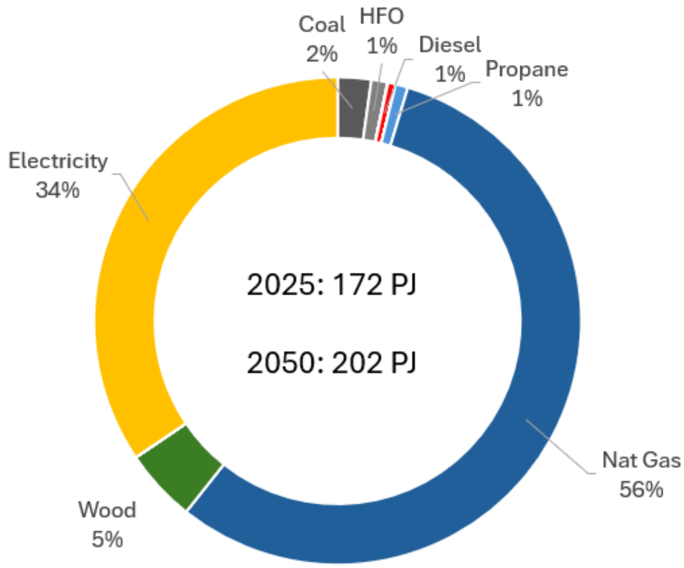
The chemical sector in Ontario is a significant energy user, projected in the short term to consume 66 PJ of energy, rising to 73 PJ by 2050 based on the difficulty in replacing chemical products in modern life (**Figure 59**). This includes the manufacturing of a large variety of chemicals from both organic and inorganic feedstocks and may include finished or intermediate chemical products.

Chemical manufacturing involves heating and mixing a variety of ingredients together to create various products – most of this heat energy is currently provided by natural gas, which also doubles as an important feedstock for many chemicals. Hydrogen is used in a variety of chemical manufacturing processes already with notable examples including the production of ammonia, methanol, and hydrogen peroxide, among others(88).

Theoretically, hydrogen can be used to replace the heat service that is provided by natural gas – this could be made from natural gas feedstock on site with the carbon sequestered underground if the geology is amenable. In this work, a portion of the replacement of natural gas heat energy to hydrogen is considered.

Other Manufacturing

Figure 60 | Other manufacturing energy use in Ontario.



The other manufacturing sector in Ontario is estimated to consume 172 PJ in the short term, with growth projected to 202 PJ by 2050 (**Figure 60**). This grouping of manufacturing industries includes many, unique manufacturing processes that produce a large variety of products, some of these include motor vehicle parts, resin and synthetic rubbers, wood products, food products, furniture, electronics, and a variety of others. The exact details and makeup of these products on a provincial basis were not examined due to project scope limitations.

Like any other kind of manufacturing, heat energy derived from a variety of energy carriers is used to transform materials into products, with the most used carrier in Ontario being natural gas. The exact nature of the heating needs in these processes is unknown at this level of analysis, and further case-by-case examination would be required, however, it is possible for hydrogen to be used in a similar manner to natural gas, with some retrofits required. It is also possible that some of these manufacturing processes require high temperatures (over 1,800C), where hydrogen could be the preferred carrier of choice (86).

Hydrogen Demand by Sector

Table 12 | Hydrogen Demand in PJs for All Sectors Modelled

Sector	Hamilton	Low - ON	High - ON	Note
LDV	-	-	29.58	Based on 0.45 J_{out}/J_{in} FCEV
MDV	-	18.73	37.45	
HDV	1.83	91.50	182.99	
Rail	0.22	11.03	22.07	
ICB	-	0.51	1.02	
UB	-	6.94	13.89	
Marine	-	-	32.97	Based on 0.35 J_{out}/J_{in} NH3 ICE & 0.45 $_{Jout/Jin}$ FCEV
RSH	1.98	15.83	59.36	Based on 0.7755 J_{out}/J_{in} H_2 Heat
CSH	1.42	22.75	71.09	
Agr Mot	-	-	7.86	Based on 0.45 J_{out}/J_{in} FCEV
Agr Nmot	-	-	17.08	Based on 0.7755 J_{out}/J_{in} H_2 Heat
Steel	25.45	25.45	25.45	Based on Khan et. Al
NF Smelting	-	9.02	18.04	Based on 0.846 J_{out}/J_{in} H_2 Heat
Ext Ind	-	-	11.06	Based on 0.846 J_{out}/J_{in} H_2 Heat & 0.45 $_{Jout/Jin}$ FCEV
Cement	-	1.10	2.20	Based on 0.846 J_{out}/J_{in} H_2 Heat
Chemicals	-	25.89	51.78	Based on 0.846 J_{out}/J_{in} H_2 Heat
Other Mfg.	-	30.09	60.17	Based on 0.846 J_{out}/J_{in} H_2 Heat
Constr.	-	8.78	22.96	Based on 0.846 J_{out}/J_{in} H_2 Heat & 0.45 $_{Jout/Jin}$ FCEV
Total (PJ)	**30.90**	**267.61**	**667.01**	

Electricity Displacement Details and Assumptions

Table 13 | Electricity Offset Values (in TWh) and Assumptions Used

Note: Sector abbreviations are found in **Table 6** *of the methodology*

Sector	Hamilton	Low - ON	High - ON	Note
LDV	-	-	4.76	Based on 0.777 J_{out}/J_{in} BEV
MDV	-	3.01	6.02	
HDV	0.32	16.22	32.45	Unlikely for the long haul to electrify; Based on 0.777 J_{out}/J_{in} BEV
Rail	-	-	-	Unlikely to electrify
ICB	-	0.08	0.16	Based on 0.777 J_{out}/J_{in} BEV
UB	-	1.12	2.23	
Marine	-	-	-	Unlikely to electrify
RSH	0.17	-	5.18	Based on 2.47 J_{out}/J_{in} CCASHP
CSH	0.12	-	6.20	
Agr Mot	-	-	1.26	Based on 0.777 J_{out}/J_{in} BEV
Agr Nmot	-	-	1.05	Based on 3.5 J_{out}/J_{in} GSHP
Steel	-	-	-	Primary steel production unlikely to electrify
NF Smelting	-	2.12	4.24	Based on 1 J_{out}/J_{in} resistive heating
Ext Ind	-	-	3.13	Based on 0.777 Jout/Jin BEV & 1 J_{out}/J_{in} resistive heating
Cement	-	-	-	Unlikely to electrify
Chemicals	-	6.08	12.17	Based on 1 J_{out}/J_{in} resistive heating
Other Mfg.	-	-	14.14	Based on 1 J_{out}/J_{in} resistive heating
Constr.	-	-	-	Unlikely to electrify completely (hybrid)
Total (TWh)	**0.62**	**32.00**	**93.00**	

Hydrogen Supply: Techno-Economics

A techno-economic evaluation was undertaken for four hydrogen generation technologies; ATR+CCS, SMR+CCS, NG Pyrolysis, and Electrolysis.

ATR and SMR are industrial standard methane reformation technologies in use today and are being modified with the inclusion of CCS to realize low-carbon hydrogen production. Due to the capital requirements of these facilities, it is assumed for purposes of this evaluation that the smallest reformation size deployed would be 250 t/d of hydrogen. To demonstrate the impact of economy of scale additional sized facilities of 800 t/d and 1,500 t/d of hydrogen were evaluated. This size of the facility corresponds to existing operating and planned reformation generation. Though all technologies will advance over time, it is assumed that the existing conditions associated with reformation will be similar to what is expected in future years.

NG Pyrolysis is an advancing technology that is based on turn-of-the-century technology that is being fine-tuned to deliver low-carbon merchant hydrogen as well as selective carbon allotropes that can be deployed in today's critical mineral sector. With numerous variations of the technology currently being developed and the TRL level of many of the start-up technology companies being in the range of TRL 4 to TRL 6, it is expected that significant economic improvements will be made with a number of the technologies reaching TRL 9 or higher by 2050. For purposes of this report a macro NG Pyrolysis case is being evaluated that is a proxy to the various technologies currently being developed; thermal, catalytic, plasma, etc. Information gathered for the various technologies has been compiled into a pseudo model with economy of scale assumptions for the three sizes evaluated; 2.5 t/d, 25 t/d, and 250 t/d of hydrogen. Development of the technology is expected to scale to a large industrial scale, however, 250 t H_2 / d is viewed as a current size limitation due to no commercial projects being greater than 13t H_2 / d currently. For 2050, technology advancement is anticipated to lower capital and operating expenses.

Electrolysis is an established small-scale technology that is currently being developed utilizing different electrolyzer designs to both improve capital and operating efficiency. Though GW-scale facilities have been proposed globally, the largest commercial development to date is a 260 MW facility in China that became operation in 2023. Similar to NG Pyrolysis, a macro Electrolysis case was developed combining the current properties of Alkaline, PEM, and SOEC electrolyzers. The pseudo model was then run at 5 MW, 50 MW, and 500 MW sizes to correspond to the same hydrogen throughput used for NG Pyrolysis. Development of the electrolysis technology is anticipated to reduce the capital cost of the electrolyzers as well as improve on current low efficiencies. With these advancements, the 2050 evaluation utilizes design sizes of 3.5 MW, 35 MW, and 350 MW to keep the size of hydrogen production uniform.

Table 14 illustrates the economic parameters utilized for each of the technologies as it corresponds to the common 250 t/d of hydrogen. For comparison, the values that are expected for 2050 are also shown for NG Pyrolysis and Electrolysis.

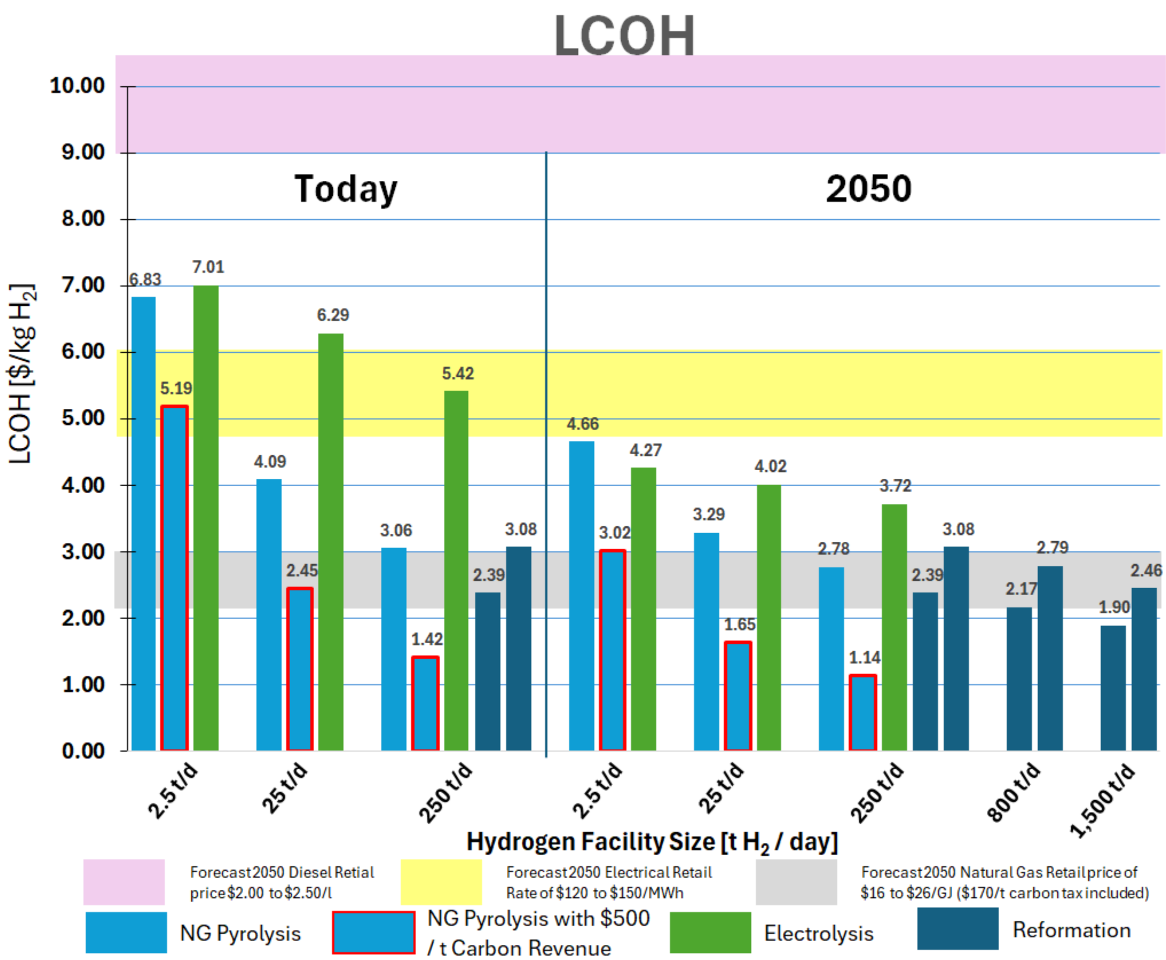
Table 14|Economic parameters utilized for each technology, corresponding to a common 250 t/d of hydrogen

at 250 t/d H2	MM$/t H_2/d Capacity Capital	$/t H_2/yr OPEX	Natural Gas	Electricity	Water	Carbon Tax	Efficiency	LCOH
ATR+CCS	$ 2.01	$ 188	$ 933	$ 281	$ 85	$ 105	90%	$ 2.39
SMR+CCS	$ 2.54	$ 250	$ 1,249	$ 140	$ 90	$ 337	90%	$ 3.08
NG Pyrolysis	$ 1.28	$ 290	$ 1,527	$ 762	$ 3		95%	$ 3.06
Electrolysis	$ 1.80	$ 403	$ -	$ 3,589	$ 427		65%	$ 5.43
NG Pyrolysis [2050]	$ 0.64	$ 245	$ 1,527	$ 762	$ 3		95%	$ 2.78
Electrolysis [2050]	$ 0.58	$ 190	$ -	$ 2,744	$ 427		85%	$ 3.72

The results for each of the techno-economic cases are shown in **Figure 61**, utilizing a fixed electricity price of $70/MWh and natural gas price of $5.50/GJ. As can be seen, a significant reduction in LCOH is achieved for NG Pyrolysis and Electrolysis based on the advancement of the technology to 2050. The drop in LCOH is also apparent with economy of scale, with the largest reformation cases delivering the lowest LCOH at $1.90/kg H_2. Similar to earlier in the report, the forecast pricing equivalent of diesel, electricity, and natural gas, adjusted to retail pricing inclusive of a carbon tax, is shown in the figure. On a fuel-to-fuel comparison, the current forecast LCOH is cost-competitive to diesel. With advancements in technology, hydrogen is anticipated to be cost-competitive to electricity by 2050, with natural gas transition possible with large-scale hydrogen production.

Further illustrated in **Figure 61** is the impact that the co-production of solid carbon has on the LCOH determination of NG Pyrolysis. Utilizing a nominal revenue stream of $500 / t of carbon, the LCOH of hydrogen from this process can be reduced by 40% or greater. This highlights one of the key components of the technology.

Figure 61 | Impact of co-production of solid carbon on the LCOH determination of NG Pyrolysis



Sensitivity Charts by technology

Included within the report are techno-economic summary tables and charts for each of the generation technologies considered Each chart shows the LCOH sensitivity to the most significant feedstock variable and facility run time. Specifically for NG Pyrolysis and Electrolysis, a further sensitivity was completed to compare the best estimate of capital and operating costs available today with the expected optimization values expected in 2050. Three sizes of facilities were evaluated; 2.5 t H_2/d , 25 t H_2/d, and 250 t H_2/d to determine the impact of the facility on LCOH. For Electrolysis, this range corresponded to 5 MW, 50 MW, and 500 MW for current conditions but due to the expectations for electrolyser efficiency gains by 2050, these facilities become 3.5 MW, 35 MW, and 350 MW to achieve the same hydrogen generation. For ATR + CCS and SMR + CCS, sizes below 250 t H_2/d are not viewed as operationally feasible. Thus, for these cases, the three sizes evaluated are 250 t H_2/d, 800 t H_2/d, and 1,500 t H_2/d, to correspond to likely large industrial-scale development using this technology.

In the tables included below, the LCOH values have been color coded for ease of recognition; values less than $3/kg are shaded green, values between $3/kg and $5/kg are white, values between $5/kg and $10/kg are yellow, and all values above $10/kg are red. Estimated 2050 natural gas pricing of $5.50 / GJ and electrical pricing of $70 / MWh were used to normalize a comparison price of all technologies at a load factor of 80%. This value is highlighted on the tables with a bold border. The feedstock sensitivity (natural gas or electricity) is listed on the left side of the table, with a wide range of potential values for the feedstock. The operating capacity is varied across the top of the table to demonstrate the impact on LCOH of discontinuous operations. Though most facilities would be expected to run near capacity, this sensitivity is included to address the potential low run time of electrolysis facilities that utilize renewable energy as their feedstock. The typical capacity factor (generation time) for solar is approximately 20% and for wind 40%. Each table shows the breakdown of the LCOH in terms of CAPEX and OPEX and by difference, the key feedstock pricing.

Following the tables for each technology is a group of three three-dimensional figures representing the results of the tables at the different sizes run to illustrate the sensitives of each case. On these corresponding figures the comparison price at the above conditions is indicated by a star and $5.00 / kg H_2 LCOH is illustrated with a bold black line. For NG Pyrolysis with included carbon pricing, the $0 / kg H_2 LCOH is illustrated with a bold red line to show the significance of carbon revenue.

Figure 62 and **63** are a representation of each technology and sensitivity to selected variables. These figures each provide insight into the values shown in the accompanying tables. For ATR+CCS, LCOH is most sensitive to operating time. The natural gas feedstock, capital, and operating expenses have similar impacts. For SMR+CCS, a similar conclusion can be reached, however a slightly higher sensitivity to capital can be observed. For NG Pyrolysis, the most significant variable in determining LCOH is the potential carbon revenue that can be realized. The natural gas feedstock has a significant effect on LCOH with capital and operating time being of high sensitivity as well. This would support the significant decrease in LCOH that occurs in evaluating the technology with 2050 lower capital assumptions. The combination of capital and operating time also is an indicator that economy of scale is effective in lowering LCOH at larger hydrogen production volumes. Electrolysis demonstrates a significant sensitivity to efficiency and electrical prices. As with pyrolysis, this would correspond to the significant decrease in LCOH that is realized in the 2050 runs.

Figure 62 | Sensitivity analysis of various variables to the LCOH for ATR+CCS and SMR+CCS Technologies

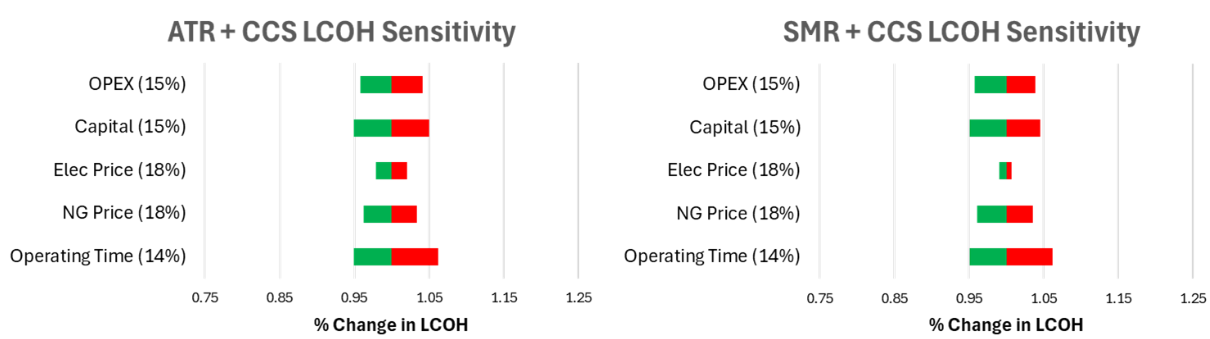
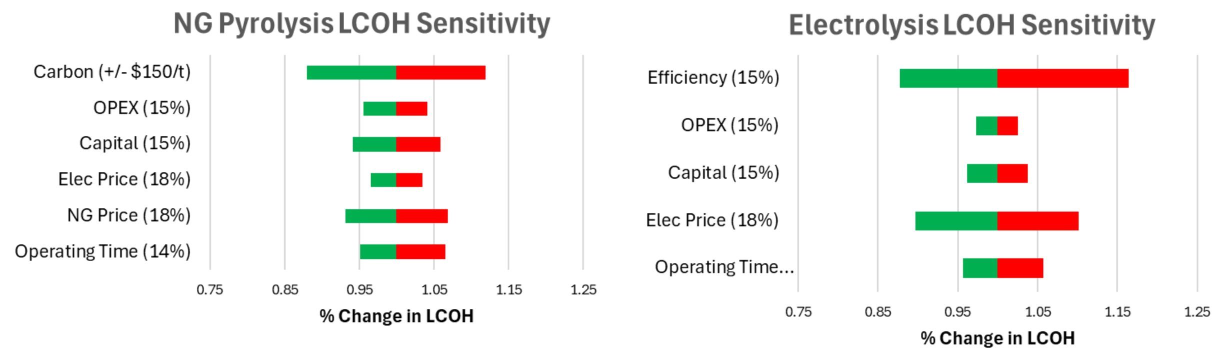


Figure 63 | Sensitivity analysis of various variables to the LCOH for NG Pyrolysis and Electrolysis Technologies



ATR + CCS Sensitivity Charts

The following tables have been generated to demonstrate the LCOH sensitivity to the size of the facility, natural gas pricing, and operational hours. Reformation technology is viewed as mature, therefore little is anticipated to change in terms of capital reduction or operating performance(89–92).

Table 15 | Sensitivity Analysis of LCOH for ATR+CCS Production Pathway Considering Facility Size (250 t H2/day), Natural Gas Pricing, Operational Hours

ATR + CCS

Pyrolysis Size (t H2/day)		$US MM	$CA MM			Power Price [$/Mwh] includes delivery
250	CAPEX	$ 367	$ 502	Effic (LHV)	90%	$ 70.00

LCOH - capex+ opex [$/kg H2]

	Load / Use Factor / Utilization								
	5.7%	11.4%	22.8%	34.2%	45.7%	57.1%	68.5%	79.9%	91.3%
	Hours of Operation								
	500	1000	2000	3000	4000	5000	6000	7000	8000
Power use (MWhr/yr)	18,797	37,594	75,188	112,781	150,375	187,969	225,563	263,156	300,750
t H2/yr	4,688	9,375	18,750	28,125	37,500	46,875	56,250	65,625	75,000
t H2/day	12.84	25.68	51.37	77.05	102.74	128.42	154.11	179.79	205.48
CAPEX ($/kg)	$ 10.92	$ 5.46	$ 2.73	$ 1.82	$ 1.36	$ 1.09	$ 0.91	$ 0.78	$ 0.68
OPEX ($/kg)	$ 2.53	$ 1.53	$ 1.03	$ 0.87	$ 0.78	$ 0.73	$ 0.70	$ 0.68	$ 0.66
Total ($/kg)	**$ 13.45**	**$ 6.99**	**$ 3.76**	**$ 2.69**	**$ 2.15**	**$ 1.82**	**$ 1.61**	**$ 1.46**	**$ 1.34**

LCOH - total [$/kg H2]

		Hours of Operation								
		500	1000	2000	3000	4000	5000	6000	7000	8000
			1	2	3	4	5	6	7	8
CDN/GJ [includes delivery cost to site]	$0.00	$ 13.45	$ 6.99	$ 3.76	$ 2.69	$ 2.15	$ 1.82	$ 1.61	$ 1.46	$ 1.34
	$0.50	$ 13.53	$ 7.08	$ 3.85	$ 2.77	$ 2.23	$ 1.91	$ 1.69	$ 1.54	$ 1.43
	$1.00	$ 13.62	$ 7.16	$ 3.93	$ 2.86	$ 2.32	$ 1.99	$ 1.78	$ 1.63	$ 1.51
	$1.50	$ 13.70	$ 7.25	$ 4.02	$ 2.94	$ 2.40	$ 2.08	$ 1.86	$ 1.71	$ 1.60
	$2.00	$ 13.79	$ 7.33	$ 4.10	$ 3.03	$ 2.49	$ 2.16	$ 1.95	$ 1.80	$ 1.68
	$2.50	$ 13.87	$ 7.41	$ 4.19	$ 3.11	$ 2.57	$ 2.25	$ 2.03	$ 1.88	$ 1.76
	$3.00	$ 13.96	$ 7.50	$ 4.27	$ 3.19	$ 2.66	$ 2.33	$ 2.12	$ 1.96	$ 1.85
	$3.50	$ 14.04	$ 7.58	$ 4.36	$ 3.28	$ 2.74	$ 2.42	$ 2.20	$ 2.05	$ 1.93
	$4.00	$ 14.13	$ 7.67	$ 4.44	$ 3.36	$ 2.83	$ 2.50	$ 2.29	$ 2.13	$ 2.02
	$4.50	$ 14.21	$ 7.75	$ 4.53	$ 3.45	$ 2.91	$ 2.59	$ 2.37	$ 2.22	$ 2.10
	$5.00	$ 14.30	$ 7.84	$ 4.61	$ 3.53	$ 3.00	$ 2.67	$ 2.46	$ 2.30	$ 2.19
	$5.50	$ 14.38	$ 7.92	$ 4.70	$ 3.62	$ 3.08	$ 2.76	$ 2.54	**$ 2.39**	$ 2.27
	$6.00	$ 14.47	$ 8.01	$ 4.78	$ 3.70	$ 3.17	$ 2.84	$ 2.63	$ 2.47	$ 2.36
	$6.50	$ 14.55	$ 8.09	$ 4.87	$ 3.79	$ 3.25	$ 2.93	$ 2.71	$ 2.56	$ 2.44
	$7.00	$ 14.64	$ 8.18	$ 4.95	$ 3.87	$ 3.34	$ 3.01	$ 2.80	$ 2.64	$ 2.53
	$7.50	$ 14.72	$ 8.26	$ 5.03	$ 3.96	$ 3.42	$ 3.10	$ 2.88	$ 2.73	$ 2.61
	$8.00	$ 14.81	$ 8.35	$ 5.12	$ 4.04	$ 3.51	$ 3.18	$ 2.97	$ 2.81	$ 2.70
	$8.50	$ 14.89	$ 8.43	$ 5.20	$ 4.13	$ 3.59	$ 3.27	$ 3.05	$ 2.90	$ 2.78
	$9.00	$ 14.98	$ 8.52	$ 5.29	$ 4.21	$ 3.67	$ 3.35	$ 3.14	$ 2.98	$ 2.87

Avg hours operation per day								
1.4	2.7	5.5	8.2	11.0	13.7	16.4	19.2	21.9

Table 16 | Sensitivity Analysis of LCOH for ATR+CCS Production Pathway Considering Facility Size (800 t H2/day), Natural Gas Pricing, Operational Hours

ATR + CCS

Pyrolysis Size (t H2/day)		$US MM	$CA MM		Power Price [$/Mwh] includes delivery	
800	CAPEX	$ 880	$ 1,206	Effic (LHV)	90%	$ 70.00

LCOH - capex+ opex [$/kg H2]

Load / Use Factor / Utilization	5.7%	11.4%	22.8%	34.2%	45.7%	57.1%	68.5%	79.9%	91.3%
Hours of Operation	500	1000	2000	3000	4000	5000	6000	7000	8000
Power use (MWhr/yr)	60,150	120,300	240,600	360,900	481,200	601,500	721,800	842,100	962,400
t H2/yr	15,000	30,000	60,000	90,000	120,000	150,000	180,000	210,000	240,000
t H2/day	41.10	82.19	164.38	246.58	328.77	410.96	493.15	575.34	657.53
CAPEX ($/kg)	$ 8.19	$ 4.09	$ 2.05	$ 1.36	$ 1.02	$ 0.82	$ 0.68	$ 0.58	$ 0.51
OPEX ($/kg)	$ 2.13	$ 1.33	$ 0.93	$ 0.80	$ 0.73	$ 0.69	$ 0.67	$ 0.65	$ 0.63
Total ($/kg)	**$ 10.32**	**$ 5.43**	**$ 2.98**	**$ 2.16**	**$ 1.76**	**$ 1.51**	**$ 1.35**	**$ 1.23**	**$ 1.14**

LCOH - total [$/kg H2]

CDN/GJ [includes delivery cost to site]	Hours of Operation: 500	1000	2000	3000	4000	5000	6000	7000	8000
		1	2	3	4	5	6	7	8
$0.00	$ 10.32	$ 5.43	$ 2.98	$ 2.16	$ 1.76	$ 1.51	$ 1.35	$ 1.23	$ 1.14
$0.50	$ 10.40	$ 5.51	$ 3.06	$ 2.25	$ 1.84	$ 1.60	$ 1.43	$ 1.32	$ 1.23
$1.00	$ 10.49	$ 5.60	$ 3.15	$ 2.33	$ 1.93	$ 1.68	$ 1.52	$ 1.40	$ 1.31
$1.50	$ 10.57	$ 5.68	$ 3.23	$ 2.42	$ 2.01	$ 1.77	$ 1.60	$ 1.49	$ 1.40
$2.00	$ 10.66	$ 5.77	$ 3.32	$ 2.50	$ 2.10	$ 1.85	$ 1.69	$ 1.57	$ 1.48
$2.50	$ 10.74	$ 5.85	$ 3.40	$ 2.59	$ 2.18	$ 1.94	$ 1.77	$ 1.66	$ 1.57
$3.00	$ 10.83	$ 5.94	$ 3.49	$ 2.67	$ 2.27	$ 2.02	$ 1.86	$ 1.74	$ 1.65
$3.50	$ 10.91	$ 6.02	$ 3.57	$ 2.76	$ 2.35	$ 2.11	$ 1.94	$ 1.83	$ 1.74
$4.00	$ 11.00	$ 6.11	$ 3.66	$ 2.84	$ 2.44	$ 2.19	$ 2.03	$ 1.91	$ 1.82
$4.50	$ 11.08	$ 6.19	$ 3.74	$ 2.93	$ 2.52	$ 2.28	$ 2.11	$ 2.00	$ 1.91
$5.00	$ 11.17	$ 6.27	$ 3.83	$ 3.01	$ 2.61	$ 2.36	$ 2.20	$ 2.08	$ 1.99
$5.50	$ 11.25	$ 6.36	$ 3.91	$ 3.10	$ 2.69	$ 2.45	$ 2.28	**$ 2.17**	$ 2.08
$6.00	$ 11.34	$ 6.44	$ 4.00	$ 3.18	$ 2.77	$ 2.53	$ 2.37	$ 2.25	$ 2.16
$6.50	$ 11.42	$ 6.53	$ 4.08	$ 3.27	$ 2.86	$ 2.61	$ 2.45	$ 2.34	$ 2.25
$7.00	$ 11.51	$ 6.61	$ 4.17	$ 3.35	$ 2.94	$ 2.70	$ 2.54	$ 2.42	$ 2.33
$7.50	$ 11.59	$ 6.70	$ 4.25	$ 3.44	$ 3.03	$ 2.78	$ 2.62	$ 2.51	$ 2.42
$8.00	$ 11.68	$ 6.78	$ 4.34	$ 3.52	$ 3.11	$ 2.87	$ 2.71	$ 2.59	$ 2.50
$8.50	$ 11.76	$ 6.87	$ 4.42	$ 3.61	$ 3.20	$ 2.95	$ 2.79	$ 2.67	$ 2.59
$9.00	$ 11.85	$ 6.95	$ 4.51	$ 3.69	$ 3.28	$ 3.04	$ 2.88	$ 2.76	$ 2.67

Avg hours operation per day								
1.4	2.7	5.5	8.2	11.0	13.7	16.4	19.2	21.9

Table 17|Sensitivity Analysis of LCOH for ATR+CCS Production Pathway Considering Facility Size (1500 t H2/day), Natural Gas Pricing, Operational Hours

ATR + CCS

Pyrolysis Size (t H2/day)		$US MM	$CA MM		Power Price [$/Mwh] includes delivery	
1500	CAPEX	$ 990	$ 1,356	Effic (LHV)	90%	$ 70.00

LCOH - capex+ opex [$/kg H2]

	Load / Use Factor / Utilization								
	5.7%	11.4%	22.8%	34.2%	45.7%	57.1%	68.5%	79.9%	91.3%
Hours of Operation	500	1000	2000	3000	4000	5000	6000	7000	8000
Power use (MWhr/yr)	112,781	225,563	451,125	676,688	902,250	1,127,813	1,353,375	1,578,938	1,804,500
t H2/yr	28,125	56,250	112,500	168,750	225,000	281,250	337,500	393,750	450,000
t H2/day	77.05	154.11	308.22	462.33	616.44	770.55	924.66	1,078.77	1,232.88
CAPEX ($/kg)	$ 4.91	$ 2.46	$ 1.23	$ 0.82	$ 0.61	$ 0.49	$ 0.41	$ 0.35	$ 0.31
OPEX ($/kg)	$ 1.73	$ 1.13	$ 0.83	$ 0.73	$ 0.68	$ 0.65	$ 0.63	$ 0.62	$ 0.61
Total ($/kg)	**$ 6.64**	**$ 3.59**	**$ 2.06**	**$ 1.55**	**$ 1.30**	**$ 1.14**	**$ 1.04**	**$ 0.97**	**$ 0.92**

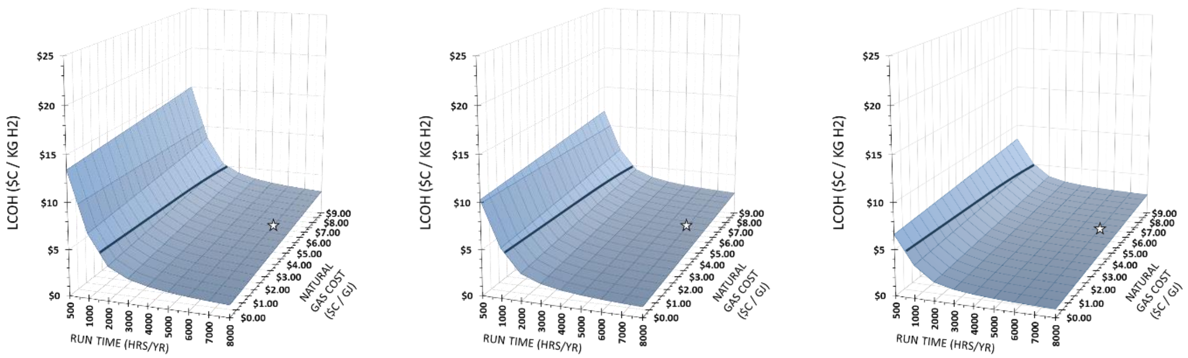
LCOH - total [$/kg H2]

		Hours of Operation								
		500	1000	2000	3000	4000	5000	6000	7000	8000
			1	2	3	4	5	6	7	8
CDN/GJ [includes delivery cost to site]	$0.00	$ 6.64	$ 3.59	$ 2.06	$ 1.55	$ 1.30	$ 1.14	$ 1.04	$ 0.97	$ 0.92
	$0.50	$ 6.73	$ 3.67	$ 2.15	$ 1.64	$ 1.38	$ 1.23	$ 1.13	$ 1.05	$ 1.00
	$1.00	$ 6.81	$ 3.76	$ 2.23	$ 1.72	$ 1.47	$ 1.31	$ 1.21	$ 1.14	$ 1.08
	$1.50	$ 6.90	$ 3.84	$ 2.32	$ 1.81	$ 1.55	$ 1.40	$ 1.30	$ 1.22	$ 1.17
	$2.00	$ 6.98	$ 3.93	$ 2.40	$ 1.89	$ 1.64	$ 1.48	$ 1.38	$ 1.31	$ 1.25
	$2.50	$ 7.07	$ 4.01	$ 2.49	$ 1.98	$ 1.72	$ 1.57	$ 1.47	$ 1.39	$ 1.34
	$3.00	$ 7.15	$ 4.10	$ 2.57	$ 2.06	$ 1.81	$ 1.65	$ 1.55	$ 1.48	$ 1.42
	$3.50	$ 7.24	$ 4.18	$ 2.66	$ 2.15	$ 1.89	$ 1.74	$ 1.64	$ 1.56	$ 1.51
	$4.00	$ 7.32	$ 4.27	$ 2.74	$ 2.23	$ 1.98	$ 1.82	$ 1.72	$ 1.65	$ 1.59
	$4.50	$ 7.41	$ 4.35	$ 2.82	$ 2.32	$ 2.06	$ 1.91	$ 1.81	$ 1.73	$ 1.68
	$5.00	$ 7.49	$ 4.44	$ 2.91	$ 2.40	$ 2.15	$ 1.99	$ 1.89	$ 1.82	$ 1.76
	$5.50	$ 7.58	$ 4.52	$ 2.99	$ 2.49	$ 2.23	$ 2.08	$ 1.98	**$ 1.90**	$ 1.85
	$6.00	$ 7.66	$ 4.61	$ 3.08	$ 2.57	$ 2.32	$ 2.16	$ 2.06	$ 1.99	$ 1.93
	$6.50	$ 7.75	$ 4.69	$ 3.16	$ 2.65	$ 2.40	$ 2.25	$ 2.15	$ 2.07	$ 2.02
	$7.00	$ 7.83	$ 4.78	$ 3.25	$ 2.74	$ 2.49	$ 2.33	$ 2.23	$ 2.16	$ 2.10
	$7.50	$ 7.92	$ 4.86	$ 3.33	$ 2.82	$ 2.57	$ 2.42	$ 2.32	$ 2.24	$ 2.19
	$8.00	$ 8.00	$ 4.95	$ 3.42	$ 2.91	$ 2.65	$ 2.50	$ 2.40	$ 2.33	$ 2.27
	$8.50	$ 8.09	$ 5.03	$ 3.50	$ 2.99	$ 2.74	$ 2.59	$ 2.49	$ 2.41	$ 2.36
	$9.00	$ 8.17	$ 5.12	$ 3.59	$ 3.08	$ 2.82	$ 2.67	$ 2.57	$ 2.50	$ 2.44

Avg hours operation per day								
1.4	2.7	5.5	8.2	11.0	13.7	16.4	19.2	21.9

As shown in the above tables (Tables 15,16,17) and illustrated in **Figure 64**, ATR + CCS achieves very low LCOH at all scales run with the ability to run at near half capacity and still able to achieve LCOH values below \$3.00 / t H_2. It is also apparent that the process can sustain low LCOH in high natural gas price environments if high facility run times are achieved. With the significant amount of hydrogen required in the Low-Ontario and High-Ontario cases, this becomes a critical realization as it could suggest that combining reformation with CO_2 pipeline infrastructure to transport CO_2 significant distances may prove to be viable where large, centralized volumes are required.

Figure 64|LCOH visualization for ATR+CCS production pathway across various facility sizes, natural gas pricing, and operational hours



SMR + CCS Sensitivity Charts

Similar to the runs completed for ATR + CCS, calculations were completed for SMR + CCS and are shown in Tables 18, 19, and 20. Though LCOH values are higher, these runs support the ability of reformation technology to deliver low-cost hydrogen regards of specific processes. However, greater sensitivity to natural gas prices is evident.

Table 18|Sensitivity Analysis of LCOH for SMR+CCS Production Pathway Considering Facility Size (250 t H2/day), Natural Gas Pricing, Operational Hours

SMR + CCS

Pyrolysis Size (t H2/day)		$US MM	$CA MM			Power Price [$/Mwh] includes delivery
250	CAPEX	$ 464	$ 636	Effic (LHV)	90%	$ 70.00

LCOH - capex+ opex [$/kg H2]

	Load / Use Factor / Utilization								
	5.7%	11.4%	22.8%	34.2%	45.7%	57.1%	68.5%	79.9%	91.3%
	Hours of Operation								
	500	1000	2000	3000	4000	5000	6000	7000	8000
Power use (MWhr/yr)	9,375	18,750	37,500	56,250	75,000	93,750	112,500	131,250	150,000
t H2/yr	4,688	9,375	18,750	28,125	37,500	46,875	56,250	65,625	75,000
t H2/day	12.84	25.68	51.37	77.05	102.74	128.42	154.11	179.79	205.48
CAPEX ($/kg)	$ 13.81	$ 6.91	$ 3.45	$ 2.30	$ 1.73	$ 1.38	$ 1.15	$ 0.99	$ 0.86
OPEX ($/kg)	$ 3.23	$ 1.94	$ 1.30	$ 1.09	$ 0.98	$ 0.91	$ 0.87	$ 0.84	$ 0.82
Total ($/kg)	**$ 17.04**	**$ 8.85**	**$ 4.75**	**$ 3.39**	**$ 2.70**	**$ 2.29**	**$ 2.02**	**$ 1.83**	**$ 1.68**

LCOH - total [$/kg H2]

		Hours of Operation								
		500	1000	2000	3000	4000	5000	6000	7000	8000
			1	2	3	4	5	6	7	8
CDN/GJ [includes delivery cost to site]	$0.00	$ 17.04	$ 8.85	$ 4.75	$ 3.39	$ 2.70	$ 2.29	$ 2.02	$ 1.83	$ 1.68
	$0.50	$ 17.16	$ 8.96	$ 4.87	$ 3.50	$ 2.82	$ 2.41	$ 2.14	$ 1.94	$ 1.79
	$1.00	$ 17.27	$ 9.08	$ 4.98	$ 3.61	$ 2.93	$ 2.52	$ 2.25	$ 2.05	$ 1.91
	$1.50	$ 17.38	$ 9.19	$ 5.09	$ 3.73	$ 3.05	$ 2.64	$ 2.36	$ 2.17	$ 2.02
	$2.00	$ 17.50	$ 9.30	$ 5.21	$ 3.84	$ 3.16	$ 2.75	$ 2.48	$ 2.28	$ 2.13
	$2.50	$ 17.61	$ 9.42	$ 5.32	$ 3.96	$ 3.27	$ 2.86	$ 2.59	$ 2.39	$ 2.25
	$3.00	$ 17.72	$ 9.53	$ 5.43	$ 4.07	$ 3.39	$ 2.98	$ 2.70	$ 2.51	$ 2.36
	$3.50	$ 17.84	$ 9.64	$ 5.55	$ 4.18	$ 3.50	$ 3.09	$ 2.82	$ 2.62	$ 2.48
	$4.00	$ 17.95	$ 9.76	$ 5.66	$ 4.30	$ 3.61	$ 3.20	$ 2.93	$ 2.74	$ 2.59
	$4.50	$ 18.07	$ 9.87	$ 5.77	$ 4.41	$ 3.73	$ 3.32	$ 3.04	$ 2.85	$ 2.70
	$5.00	$ 18.18	$ 9.99	$ 5.89	$ 4.52	$ 3.84	$ 3.43	$ 3.16	$ 2.96	$ 2.82
	$5.50	$ 18.29	$ 10.10	$ 6.00	$ 4.64	$ 3.95	$ 3.54	$ 3.27	**$ 3.08**	$ 2.93
	$6.00	$ 18.41	$ 10.21	$ 6.12	$ 4.75	$ 4.07	$ 3.66	$ 3.38	$ 3.19	$ 3.04
	$6.50	$ 18.52	$ 10.33	$ 6.23	$ 4.86	$ 4.18	$ 3.77	$ 3.50	$ 3.30	$ 3.16
	$7.00	$ 18.63	$ 10.44	$ 6.34	$ 4.98	$ 4.29	$ 3.88	$ 3.61	$ 3.42	$ 3.27
	$7.50	$ 18.75	$ 10.55	$ 6.46	$ 5.09	$ 4.41	$ 4.00	$ 3.73	$ 3.53	$ 3.38
	$8.00	$ 18.86	$ 10.67	$ 6.57	$ 5.20	$ 4.52	$ 4.11	$ 3.84	$ 3.64	$ 3.50
	$8.50	$ 18.97	$ 10.78	$ 6.68	$ 5.32	$ 4.64	$ 4.23	$ 3.95	$ 3.76	$ 3.61
	$9.00	$ 19.09	$ 10.89	$ 6.80	$ 5.43	$ 4.75	$ 4.34	$ 4.07	$ 3.87	$ 3.72

Avg hours operation per day								
1.4	2.7	5.5	8.2	11.0	13.7	16.4	19.2	21.9

Table 19 | Sensitivity Analysis of LCOH for SMR+CCS Production Pathway Considering Facility Size (800 t H2/day), Natural Gas Pricing, Operational Hours

SMR + CCS

Pyrolysis Size (t H2/day)		$US MM	$CA MM		Power Price [$/Mwh] includes delivery	
800	CAPEX	$ 1,114	$ 1,525	Effic (LHV)	90%	$ 70.00

LCOH - capex+ opex [$/kg H2]

	Load / Use Factor / Utilization								
	5.7%	11.4%	22.8%	34.2%	45.7%	57.1%	68.5%	79.9%	91.3%
	Hours of Operation								
	500	1000	2000	3000	4000	5000	6000	7000	8000
Power use (MWhr/yr)	30,000	60,000	120,000	180,000	240,000	300,000	360,000	420,000	480,000
t H2/yr	15,000	30,000	60,000	90,000	120,000	150,000	180,000	210,000	240,000
t H2/day	41.10	82.19	164.38	246.58	328.77	410.96	493.15	575.34	657.53
CAPEX ($/kg)	$ 10.36	$ 5.18	$ 2.59	$ 1.73	$ 1.29	$ 1.04	$ 0.86	$ 0.74	$ 0.65
OPEX ($/kg)	$ 2.72	$ 1.69	$ 1.17	$ 1.00	$ 0.91	$ 0.86	$ 0.83	$ 0.80	$ 0.78
Total ($/kg)	**$ 13.08**	**$ 6.87**	**$ 3.76**	**$ 2.73**	**$ 2.21**	**$ 1.90**	**$ 1.69**	**$ 1.54**	**$ 1.43**

LCOH - total [$/kg H2]

		Hours of Operation								
		500	1000	2000	3000	4000	5000	6000	7000	8000
			1	2	3	4	5	6	7	8
CDN/GJ [includes delivery cost to site]	$0.00	$ 13.08	$ 6.87	$ 3.76	$ 2.73	$ 2.21	$ 1.90	$ 1.69	$ 1.54	$ 1.43
	$0.50	$ 13.19	$ 6.98	$ 3.87	$ 2.84	$ 2.32	$ 2.01	$ 1.80	$ 1.66	$ 1.55
	$1.00	$ 13.30	$ 7.09	$ 3.99	$ 2.95	$ 2.44	$ 2.13	$ 1.92	$ 1.77	$ 1.66
	$1.50	$ 13.42	$ 7.21	$ 4.10	$ 3.07	$ 2.55	$ 2.24	$ 2.03	$ 1.88	$ 1.77
	$2.00	$ 13.53	$ 7.32	$ 4.22	$ 3.18	$ 2.66	$ 2.35	$ 2.15	$ 2.00	$ 1.89
	$2.50	$ 13.64	$ 7.43	$ 4.33	$ 3.29	$ 2.78	$ 2.47	$ 2.26	$ 2.11	$ 2.00
	$3.00	$ 13.76	$ 7.55	$ 4.44	$ 3.41	$ 2.89	$ 2.58	$ 2.37	$ 2.22	$ 2.11
	$3.50	$ 13.87	$ 7.66	$ 4.56	$ 3.52	$ 3.00	$ 2.69	$ 2.49	$ 2.34	$ 2.23
	$4.00	$ 13.98	$ 7.77	$ 4.67	$ 3.63	$ 3.12	$ 2.81	$ 2.60	$ 2.45	$ 2.34
	$4.50	$ 14.10	$ 7.89	$ 4.78	$ 3.75	$ 3.23	$ 2.92	$ 2.71	$ 2.57	$ 2.45
	$5.00	$ 14.21	$ 8.00	$ 4.90	$ 3.86	$ 3.34	$ 3.03	$ 2.83	$ 2.68	$ 2.57
	$5.50	$ 14.32	$ 8.11	$ 5.01	$ 3.98	$ 3.46	$ 3.15	$ 2.94	**$ 2.79**	$ 2.68
	$6.00	$ 14.44	$ 8.23	$ 5.12	$ 4.09	$ 3.57	$ 3.26	$ 3.05	$ 2.91	$ 2.80
	$6.50	$ 14.55	$ 8.34	$ 5.24	$ 4.20	$ 3.68	$ 3.37	$ 3.17	$ 3.02	$ 2.91
	$7.00	$ 14.67	$ 8.46	$ 5.35	$ 4.32	$ 3.80	$ 3.49	$ 3.28	$ 3.13	$ 3.02
	$7.50	$ 14.78	$ 8.57	$ 5.46	$ 4.43	$ 3.91	$ 3.60	$ 3.39	$ 3.25	$ 3.14
	$8.00	$ 14.89	$ 8.68	$ 5.58	$ 4.54	$ 4.03	$ 3.72	$ 3.51	$ 3.36	$ 3.25
	$8.50	$ 15.01	$ 8.80	$ 5.69	$ 4.66	$ 4.14	$ 3.83	$ 3.62	$ 3.47	$ 3.36
	$9.00	$ 15.12	$ 8.91	$ 5.81	$ 4.77	$ 4.25	$ 3.94	$ 3.74	$ 3.59	$ 3.48

Avg hours operation per day								
1.4	2.7	5.5	8.2	11.0	13.7	16.4	19.2	21.9

Table 20 | Sensitivity Analysis of LCOH for SMR+CCS Production Pathway Considering Facility Size (1500 t H2/day), Natural Gas Pricing, Operational Hours

SMR + CCS

Pyrolysis Size (t H2/day)		$US MM	$CA MM		Power Price [$/Mwh] includes delivery
1500	CAPEX	$ 1,253	$ 1,716	Effic (LHV) 90%	$ 70.00

	Load / Use Factor / Utilization								
	5.7%	11.4%	22.8%	34.2%	45.7%	57.1%	68.5%	79.9%	91.3%
LCOH - capex+ opex [$/kg H2]	**Hours of Operation**								
	500	1000	2000	3000	4000	5000	6000	7000	8000
Power use (MWhr/yr)	56,250	112,500	225,000	337,500	450,000	562,500	675,000	787,500	900,000
t H2/yr	28,125	56,250	112,500	168,750	225,000	281,250	337,500	393,750	450,000
t H2/day	77.05	154.11	308.22	462.33	616.44	770.55	924.66	1,078.77	1,232.88
CAPEX ($/kg)	$ 6.21	$ 3.11	$ 1.55	$ 1.04	$ 0.78	$ 0.62	$ 0.52	$ 0.44	$ 0.39
OPEX ($/kg)	$ 2.20	$ 1.43	$ 1.04	$ 0.91	$ 0.85	$ 0.81	$ 0.78	$ 0.77	$ 0.75
Total ($/kg)	**$ 8.42**	**$ 4.54**	**$ 2.60**	**$ 1.95**	**$ 1.63**	**$ 1.43**	**$ 1.30**	**$ 1.21**	**$ 1.14**

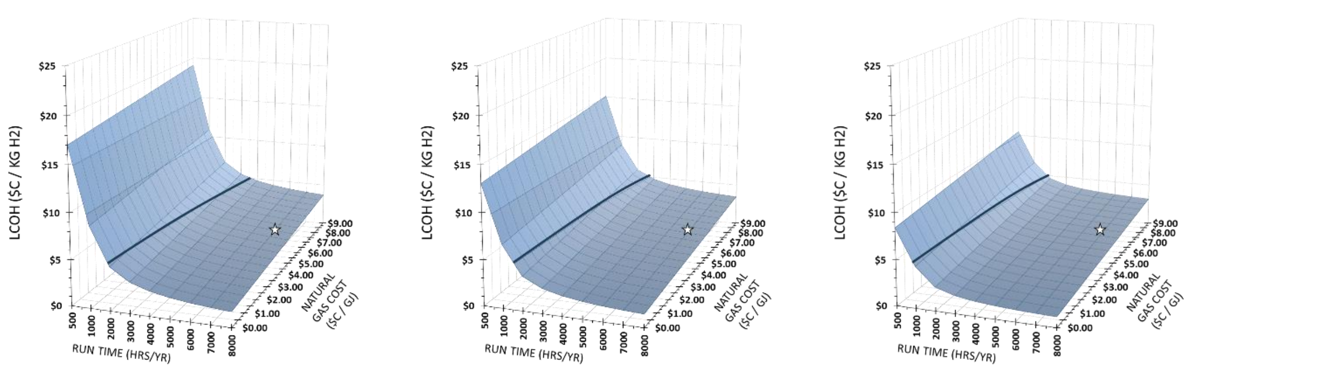
LCOH - total [$/kg H2]

		Hours of Operation								
		500	1000	2000	3000	4000	5000	6000	7000	8000
			1	2	3	4	5	6	7	8
CDN/GJ [includes delivery cost to site]	$0.00	$ 8.42	$ 4.54	$ 2.60	$ 1.95	$ 1.63	$ 1.43	$ 1.30	$ 1.21	$ 1.14
	$0.50	$ 8.53	$ 4.65	$ 2.71	$ 2.06	$ 1.74	$ 1.55	$ 1.42	$ 1.32	$ 1.25
	$1.00	$ 8.64	$ 4.76	$ 2.82	$ 2.18	$ 1.85	$ 1.66	$ 1.53	$ 1.44	$ 1.37
	$1.50	$ 8.76	$ 4.88	$ 2.94	$ 2.29	$ 1.97	$ 1.77	$ 1.64	$ 1.55	$ 1.48
	$2.00	$ 8.87	$ 4.99	$ 3.05	$ 2.40	$ 2.08	$ 1.89	$ 1.76	$ 1.66	$ 1.60
	$2.50	$ 8.98	$ 5.10	$ 3.16	$ 2.52	$ 2.19	$ 2.00	$ 1.87	$ 1.78	$ 1.71
	$3.00	$ 9.10	$ 5.22	$ 3.28	$ 2.63	$ 2.31	$ 2.11	$ 1.98	$ 1.89	$ 1.82
	$3.50	$ 9.21	$ 5.33	$ 3.39	$ 2.74	$ 2.42	$ 2.23	$ 2.10	$ 2.01	$ 1.94
	$4.00	$ 9.33	$ 5.44	$ 3.50	$ 2.86	$ 2.53	$ 2.34	$ 2.21	$ 2.12	$ 2.05
	$4.50	$ 9.44	$ 5.56	$ 3.62	$ 2.97	$ 2.65	$ 2.45	$ 2.32	$ 2.23	$ 2.16
	$5.00	$ 9.55	$ 5.67	$ 3.73	$ 3.09	$ 2.76	$ 2.57	$ 2.44	$ 2.35	$ 2.28
	$5.50	$ 9.67	$ 5.79	$ 3.85	$ 3.20	$ 2.88	$ 2.68	$ 2.55	**$ 2.46**	$ 2.39
	$6.00	$ 9.78	$ 5.90	$ 3.96	$ 3.31	$ 2.99	$ 2.79	$ 2.67	$ 2.57	$ 2.50
	$6.50	$ 9.89	$ 6.01	$ 4.07	$ 3.43	$ 3.10	$ 2.91	$ 2.78	$ 2.69	$ 2.62
	$7.00	$ 10.01	$ 6.13	$ 4.19	$ 3.54	$ 3.22	$ 3.02	$ 2.89	$ 2.80	$ 2.73
	$7.50	$ 10.12	$ 6.24	$ 4.30	$ 3.65	$ 3.33	$ 3.14	$ 3.01	$ 2.91	$ 2.84
	$8.00	$ 10.23	$ 6.35	$ 4.41	$ 3.77	$ 3.44	$ 3.25	$ 3.12	$ 3.03	$ 2.96
	$8.50	$ 10.35	$ 6.47	$ 4.53	$ 3.88	$ 3.56	$ 3.36	$ 3.23	$ 3.14	$ 3.07
	$9.00	$ 10.46	$ 6.58	$ 4.64	$ 3.99	$ 3.67	$ 3.48	$ 3.35	$ 3.25	$ 3.19

Avg hours operation per day								
1.4	2.7	5.5	8.2	11.0	13.7	16.4	19.2	21.9

The LCOH of SMR + CCS for the various sizes evaluated are shown in **Figure 65**. Though similar to ATR + CCS in the fact that low LCOH can be achieved, SMR + CCS does have greater sensitivity to higher natural gas prices as well as a greater need to run at full capacity.

Figure 65 | LCOH visualization for SMR+CCS production pathway across various facility sizes, natural gas pricing, and operational hours



Methane Pyrolysis Sensitivity Charts

Though pyrolysis is not a new technology and dates back to the early twentieth century, new processes focused on hydrogen production and specific carbon co-products are being advanced from Technical Readiness Levels (TRL) of 4 to 5, with the expectations that a number of the current dozens of technology providers will achieve TRL 8 or higher by 2030. The other aspect under development is the establishment of commercial markets for the solid carbon generated by the processes.

As such, various cases were run to both demonstrate the benefits of scale and capital reductions that are anticipated to occur as well as the impact carbon revenue will have on LCOH for the process. For NG Pyrolysis, volumes of 2.5, 25, and 250 t H_2/d were evaluated under both current-day economic assumptions and those anticipated in 2050. Additionally, a nominal carbon value of \$500 / t_C was utilized to show the LCOH sensitivity to carbon pricing. This is viewed as a conservative value for the carbon, equivalent to metallurgical coke. In comparison, carbon black and graphite are currently valued between \$2,000 and \$5,000 / t_C, and carbon fibres, nanotubes, and graphene are valued at \$50,000 to more than \$100,000 / t_C (16,91).

For NG Pyrolysis, natural gas was used as the sensitivity variable as it represents the highest-cost feedstock. To remain consistent in the assumptions of other technologies, a fixed price of \$70 / MWh was utilized for purposes of this evaluation. Thus, if lower electrical prices are achieved the LCOH will decrease from stated values, as the sensitivity discussion from earlier in the report indicated.

For the 2.5 t H_2 / d case (**Table 21**), a LCOH of \$6.83 is calculated. Increasing the size of the facility to 25 t H_2/d reduces the LCOH below \$5.00 (**Tables 22 and 23**).

Methane Pyrolysis Sensitivity Charts – Current economic assumptions and no carbon revenue

Table 21 | Sensitivity Analysis of LCOH for Methane Pyrolysis Production Pathway Considering Facility Size (2.5 t H2/day), Natural Gas Pricing, Operational Hours, and Absence of Carbon Revenue

Methane Pyrolysis Today

Pyrolysis Size (t H2/day)		$US MM	$CA MM		Power Price [$/Mwh] includes delivery		Carbon Price [$/t]
2.5	CAPEX	$ 14	$ 20	Effic (LHV)	95%	$ 70.00	$ -

LCOH - capex+ opex [$/kg H2]

	Load / Use Factor / Utilization								
	5.7%	11.4%	22.8%	34.2%	45.7%	57.1%	68.5%	79.9%	91.3%
	Hours of Operation								
	500	1000	2000	3000	4000	5000	6000	7000	8000
Power use (MWhr/yr)	538	1,077	2,153	3,230	4,307	5,383	6,460	7,537	8,613
t H2/yr	49	99	198	297	396	495	594	693	792
t H2/day	0.14	0.27	0.54	0.81	1.08	1.36	1.63	1.90	2.17
CAPEX ($/kg)	$ 40.70	$ 20.35	$ 10.18	$ 6.78	$ 5.09	$ 4.07	$ 3.39	$ 2.91	$ 2.54
OPEX ($/kg)	$ 20.95	$ 10.96	$ 5.96	$ 4.30	$ 3.46	$ 2.96	$ 2.63	$ 2.39	$ 2.21
Carbon ($/kg)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total ($/kg)	**$ 61.65**	**$ 31.31**	**$ 16.14**	**$ 11.08**	**$ 8.55**	**$ 7.03**	**$ 6.02**	**$ 5.30**	**$ 4.76**

LCOH - total [$/kg H2]

		Hours of Operation								
		500	1000	2000	3000	4000	5000	6000	7000	8000
			1	2	3	4	5	6	7	8
CDN/GJ [includes delivery cost to site]	$0.00	$ 61.65	$ 31.31	$ 16.14	$ 11.08	$ 8.55	$ 7.03	$ 6.02	$ 5.30	$ 4.76
	$0.50	$ 61.78	$ 31.44	$ 16.27	$ 11.22	$ 8.69	$ 7.17	$ 6.16	$ 5.44	$ 4.90
	$1.00	$ 61.92	$ 31.58	$ 16.41	$ 11.36	$ 8.83	$ 7.31	$ 6.30	$ 5.58	$ 5.04
	$1.50	$ 62.06	$ 31.72	$ 16.55	$ 11.49	$ 8.97	$ 7.45	$ 6.44	$ 5.72	$ 5.17
	$2.00	$ 62.20	$ 31.86	$ 16.69	$ 11.63	$ 9.11	$ 7.59	$ 6.58	$ 5.85	$ 5.31
	$2.50	$ 62.34	$ 32.00	$ 16.83	$ 11.77	$ 9.24	$ 7.73	$ 6.72	$ 5.99	$ 5.45
	$3.00	$ 62.48	$ 32.14	$ 16.97	$ 11.91	$ 9.38	$ 7.87	$ 6.85	$ 6.13	$ 5.59
	$3.50	$ 62.62	$ 32.28	$ 17.11	$ 12.05	$ 9.52	$ 8.01	$ 6.99	$ 6.27	$ 5.73
	$4.00	$ 62.76	$ 32.42	$ 17.25	$ 12.19	$ 9.66	$ 8.14	$ 7.13	$ 6.41	$ 5.87
	$4.50	$ 62.90	$ 32.55	$ 17.38	$ 12.33	$ 9.80	$ 8.28	$ 7.27	$ 6.55	$ 6.01
	$5.00	$ 63.03	$ 32.69	$ 17.52	$ 12.47	$ 9.94	$ 8.42	$ 7.41	$ 6.69	$ 6.15
	$5.50	$ 63.17	$ 32.83	$ 17.66	$ 12.61	$ 10.08	$ 8.56	$ 7.55	**$ 6.83**	$ 6.28
	$6.00	$ 63.31	$ 32.97	$ 17.80	$ 12.74	$ 10.22	$ 8.70	$ 7.69	$ 6.97	$ 6.42
	$6.50	$ 63.45	$ 33.11	$ 17.94	$ 12.88	$ 10.36	$ 8.84	$ 7.83	$ 7.10	$ 6.56
	$7.00	$ 63.59	$ 33.25	$ 18.08	$ 13.02	$ 10.49	$ 8.98	$ 7.97	$ 7.24	$ 6.70
	$7.50	$ 63.73	$ 33.39	$ 18.22	$ 13.16	$ 10.63	$ 9.12	$ 8.10	$ 7.38	$ 6.84
	$8.00	$ 63.87	$ 33.53	$ 18.36	$ 13.30	$ 10.77	$ 9.25	$ 8.24	$ 7.52	$ 6.98
	$8.50	$ 64.01	$ 33.67	$ 18.50	$ 13.44	$ 10.91	$ 9.39	$ 8.38	$ 7.66	$ 7.12
	$9.00	$ 64.14	$ 33.80	$ 18.63	$ 13.58	$ 11.05	$ 9.53	$ 8.52	$ 7.80	$ 7.26

Avg hours operation per day								
1.4	2.7	5.5	8.2	11.0	13.7	16.4	19.2	21.9

Table 22 | Sensitivity Analysis of LCOH for Methane Pyrolysis Production Pathway Considering Facility Size (25 t H2/day), Natural Gas Pricing, Operational Hours, and Absence of Carbon Revenue

Methane Pyrolysis Today

Pyrolysis Size (t H2/day)		$US MM	$CA MM		Power Price [$/Mwh] includes delivery		Carbon Price [$/t]
25	CAPEX	$ 58	$ 79	Effic (LHV)	95%	$ 70.00	$ -

LCOH - capex+ opex [$/kg H2]

Load / Use Factor / Utilization	5.7%	11.4%	22.8%	34.2%	45.7%	57.1%	68.5%	79.9%	91.3%
Hours of Operation	500	1000	2000	3000	4000	5000	6000	7000	8000
Power use (MWhr/yr)	5,383	10,767	21,533	32,300	43,067	53,833	64,600	75,367	86,133
t H2/yr	495	990	1,979	2,969	3,958	4,948	5,938	6,927	7,917
t H2/day	1.36	2.71	5.42	8.13	10.84	13.56	16.27	18.98	21.69
CAPEX ($/kg)	$ 16.34	$ 8.17	$ 4.08	$ 2.72	$ 2.04	$ 1.63	$ 1.36	$ 1.17	$ 1.02
OPEX ($/kg)	$ 6.98	$ 3.97	$ 2.47	$ 1.97	$ 1.72	$ 1.57	$ 1.47	$ 1.39	$ 1.34
Carbon ($/kg)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total ($/kg)	**$ 23.32**	**$ 12.14**	**$ 6.55**	**$ 4.69**	**$ 3.76**	**$ 3.20**	**$ 2.83**	**$ 2.56**	**$ 2.36**

LCOH - total [$/kg H2]

	Hours of Operation	500	1000	2000	3000	4000	5000	6000	7000	8000
			1	2	3	4	5	6	7	8
CDN/GJ [includes delivery cost to site]	$0.00	$ 23.32	$ 12.14	$ 6.55	$ 4.69	$ 3.76	$ 3.20	$ 2.83	$ 2.56	$ 2.36
	$0.50	$ 23.46	$ 12.28	$ 6.69	$ 4.83	$ 3.90	$ 3.34	$ 2.97	$ 2.70	$ 2.50
	$1.00	$ 23.60	$ 12.42	$ 6.83	$ 4.97	$ 4.04	$ 3.48	$ 3.11	$ 2.84	$ 2.64
	$1.50	$ 23.73	$ 12.56	$ 6.97	$ 5.11	$ 4.18	$ 3.62	$ 3.24	$ 2.98	$ 2.78
	$2.00	$ 23.87	$ 12.70	$ 7.11	$ 5.25	$ 4.31	$ 3.76	$ 3.38	$ 3.12	$ 2.92
	$2.50	$ 24.01	$ 12.84	$ 7.25	$ 5.38	$ 4.45	$ 3.89	$ 3.52	$ 3.26	$ 3.06
	$3.00	$ 24.15	$ 12.97	$ 7.39	$ 5.52	$ 4.59	$ 4.03	$ 3.66	$ 3.39	$ 3.20
	$3.50	$ 24.29	$ 13.11	$ 7.53	$ 5.66	$ 4.73	$ 4.17	$ 3.80	$ 3.53	$ 3.33
	$4.00	$ 24.43	$ 13.25	$ 7.66	$ 5.80	$ 4.87	$ 4.31	$ 3.94	$ 3.67	$ 3.47
	$4.50	$ 24.57	$ 13.39	$ 7.80	$ 5.94	$ 5.01	$ 4.45	$ 4.08	$ 3.81	$ 3.61
	$5.00	$ 24.71	$ 13.53	$ 7.94	$ 6.08	$ 5.15	$ 4.59	$ 4.22	$ 3.95	$ 3.75
	$5.50	$ 24.85	$ 13.67	$ 8.08	$ 6.22	$ 5.29	$ 4.73	$ 4.36	**$ 4.09**	$ 3.89
	$6.00	$ 24.98	$ 13.81	$ 8.22	$ 6.36	$ 5.43	$ 4.87	$ 4.49	$ 4.23	$ 4.03
	$6.50	$ 25.12	$ 13.95	$ 8.36	$ 6.50	$ 5.56	$ 5.01	$ 4.63	$ 4.37	$ 4.17
	$7.00	$ 25.26	$ 14.09	$ 8.50	$ 6.63	$ 5.70	$ 5.14	$ 4.77	$ 4.51	$ 4.31
	$7.50	$ 25.40	$ 14.22	$ 8.64	$ 6.77	$ 5.84	$ 5.28	$ 4.91	$ 4.64	$ 4.44
	$8.00	$ 25.54	$ 14.36	$ 8.77	$ 6.91	$ 5.98	$ 5.42	$ 5.05	$ 4.78	$ 4.58
	$8.50	$ 25.68	$ 14.50	$ 8.91	$ 7.05	$ 6.12	$ 5.56	$ 5.19	$ 4.92	$ 4.72
	$9.00	$ 25.82	$ 14.64	$ 9.05	$ 7.19	$ 6.26	$ 5.70	$ 5.33	$ 5.06	$ 4.86

Avg hours operation per day								
1.4	2.7	5.5	8.2	11.0	13.7	16.4	19.2	21.9

Table 23 | Sensitivity analysis of LCOH for Methane Pyrolysis production pathway considering facility size (250 t h2/day), natural gas pricing, operational hours, and absence of carbon revenue

Methane Pyrolysis Today

Pyrolysis Size (t H2/day)		$US MM	$CA MM		Power Price [$/Mwh] includes delivery		Carbon Price [$/t]
250	CAPEX	$ 233	$ 319	Effic (LHV)	95%	$ 70.00	$ -

LCOH - capex+ opex [$/kg H2]

	Load / Use Factor / Utilization								
	5.7%	11.4%	22.8%	34.2%	45.7%	57.1%	68.5%	79.9%	91.3%
	Hours of Operation								
	500	1000	2000	3000	4000	5000	6000	7000	8000
Power use (MWhr/yr)	53,833	107,667	215,333	323,000	430,667	538,333	646,000	753,667	861,333
t H2/yr	4,948	9,896	19,792	29,688	39,583	49,479	59,375	69,271	79,167
t H2/day	13.56	27.11	54.22	81.34	108.45	135.56	162.67	189.78	216.89
CAPEX ($/kg)	$ 6.56	$ 3.28	$ 1.64	$ 1.09	$ 0.82	$ 0.66	$ 0.55	$ 0.47	$ 0.41
OPEX ($/kg)	$ 2.41	$ 1.69	$ 1.33	$ 1.21	$ 1.15	$ 1.11	$ 1.09	$ 1.07	$ 1.06
Carbon ($/kg)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total ($/kg)	**$ 8.97**	**$ 4.97**	**$ 2.97**	**$ 2.30**	**$ 1.97**	**$ 1.77**	**$ 1.63**	**$ 1.54**	**$ 1.47**

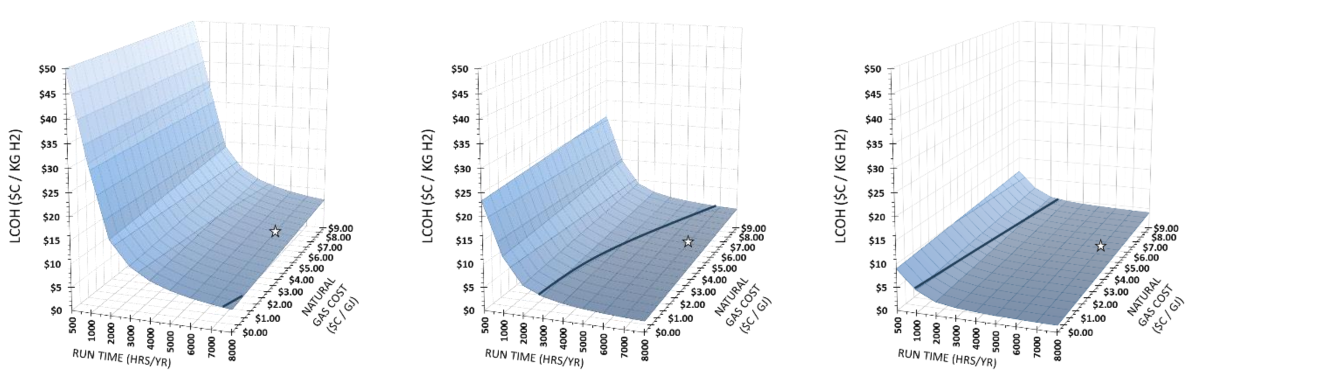
LCOH - total [$/kg H2]

		Hours of Operation								
		500	1000	2000	3000	4000	5000	6000	7000	8000
			1	2	3	4	5	6	7	8
CDN/GJ [includes delivery cost to site]	$0.00	$ 8.97	$ 4.97	$ 2.97	$ 2.30	$ 1.97	$ 1.77	$ 1.63	$ 1.54	$ 1.47
	$0.50	$ 9.11	$ 5.11	$ 3.11	$ 2.44	$ 2.10	$ 1.90	$ 1.77	$ 1.68	$ 1.60
	$1.00	$ 9.25	$ 5.25	$ 3.24	$ 2.58	$ 2.24	$ 2.04	$ 1.91	$ 1.81	$ 1.74
	$1.50	$ 9.39	$ 5.39	$ 3.38	$ 2.72	$ 2.38	$ 2.18	$ 2.05	$ 1.95	$ 1.88
	$2.00	$ 9.53	$ 5.52	$ 3.52	$ 2.85	$ 2.52	$ 2.32	$ 2.19	$ 2.09	$ 2.02
	$2.50	$ 9.67	$ 5.66	$ 3.66	$ 2.99	$ 2.66	$ 2.46	$ 2.33	$ 2.23	$ 2.16
	$3.00	$ 9.81	$ 5.80	$ 3.80	$ 3.13	$ 2.80	$ 2.60	$ 2.47	$ 2.37	$ 2.30
	$3.50	$ 9.94	$ 5.94	$ 3.94	$ 3.27	$ 2.94	$ 2.74	$ 2.60	$ 2.51	$ 2.44
	$4.00	$ 10.08	$ 6.08	$ 4.08	$ 3.41	$ 3.08	$ 2.88	$ 2.74	$ 2.65	$ 2.58
	$4.50	$ 10.22	$ 6.22	$ 4.22	$ 3.55	$ 3.22	$ 3.02	$ 2.88	$ 2.79	$ 2.72
	$5.00	$ 10.36	$ 6.36	$ 4.36	$ 3.69	$ 3.35	$ 3.15	$ 3.02	$ 2.93	$ 2.85
	$5.50	$ 10.50	$ 6.50	$ 4.49	$ 3.83	$ 3.49	$ 3.29	$ 3.16	**$ 3.06**	$ 2.99
	$6.00	$ 10.64	$ 6.63	$ 4.63	$ 3.97	$ 3.63	$ 3.43	$ 3.30	$ 3.20	$ 3.13
	$6.50	$ 10.78	$ 6.77	$ 4.77	$ 4.10	$ 3.77	$ 3.57	$ 3.44	$ 3.34	$ 3.27
	$7.00	$ 10.92	$ 6.91	$ 4.91	$ 4.24	$ 3.91	$ 3.71	$ 3.58	$ 3.48	$ 3.41
	$7.50	$ 11.05	$ 7.05	$ 5.05	$ 4.38	$ 4.05	$ 3.85	$ 3.72	$ 3.62	$ 3.55
	$8.00	$ 11.19	$ 7.19	$ 5.19	$ 4.52	$ 4.19	$ 3.99	$ 3.85	$ 3.76	$ 3.69
	$8.50	$ 11.33	$ 7.33	$ 5.33	$ 4.66	$ 4.33	$ 4.13	$ 3.99	$ 3.90	$ 3.83
	$9.00	$ 11.47	$ 7.47	$ 5.47	$ 4.80	$ 4.47	$ 4.27	$ 4.13	$ 4.04	$ 3.96

Avg hours operation per day								
1.4	2.7	5.5	8.2	11.0	13.7	16.4	19.2	21.9

Under current capital and operating condition assumptions, LCOH is very sensitive to size and the assumed economy of scale benefits achieved with larger facilities (**Figure 66**). Due to the large demand for natural gas, pricing also becomes a limiting factor in LCOH determination.

Figure 66 | LCOH visualization for Methane Pyrolysis production pathway across various facility sizes, natural gas pricing, operational hours, and absence of carbon revenue



Methane Pyrolysis Sensitivity Charts – Current economic assumptions with carbon revenue

With the inclusion of carbon revenue, significant reductions in LCOH are realized, with values under \$3.00 / kg H_2 being achieved in the 25 and 250 t H_2/d cases (Tables 24, 25, and 26).

Table 24 | Sensitivity analysis of LCOH for methane pyrolysis production pathway considering facility size (2.5 t h2/day), natural gas pricing, operational hours, and carbon revenue

Methane Pyrolysis Today

Pyrolysis Size (t H2/day)		$US MM	$CA MM		Power Price [$/Mwh] includes delivery			Carbon Price [$/t]
2.5	CAPEX	$ 14	$ 20	Effic (LHV)	95%	$ 70.00		$ 500.00

LCOH - capex+ opex [$/kg H2]

	Load / Use Factor / Utilization								
	5.7%	11.4%	22.8%	34.2%	45.7%	57.1%	68.5%	79.9%	91.3%
	Hours of Operation								
	500	1000	2000	3000	4000	5000	6000	7000	8000
Power use (MWhr/yr)	538	1,077	2,153	3,230	4,307	5,383	6,460	7,537	8,613
t H2/yr	49	99	198	297	396	495	594	693	792
t H2/day	0.14	0.27	0.54	0.81	1.08	1.36	1.63	1.90	2.17
CAPEX ($/kg)	$ 40.70	$ 20.35	$ 10.18	$ 6.78	$ 5.09	$ 4.07	$ 3.39	$ 2.91	$ 2.54
OPEX ($/kg)	$ 20.95	$ 10.96	$ 5.96	$ 4.30	$ 3.46	$ 2.96	$ 2.63	$ 2.39	$ 2.21
Carbon ($/kg)	-$ 1.64	-$ 1.64	-$ 1.64	-$ 1.64	-$ 1.64	-$ 1.64	-$ 1.64	-$ 1.64	-$ 1.64
Total ($/kg)	**$ 60.01**	**$ 29.67**	**$ 14.50**	**$ 9.44**	**$ 6.91**	**$ 5.39**	**$ 4.38**	**$ 3.66**	**$ 3.12**

LCOH - total [$/kg H2]

		Hours of Operation								
		500	1000	2000	3000	4000	5000	6000	7000	8000
			1	2	3	4	5	6	7	8
CDN/GJ [includes delivery cost to site]	$0.00	$ 60.01	$ 29.67	$ 14.50	$ 9.44	$ 6.91	$ 5.39	$ 4.38	$ 3.66	$ 3.12
	$0.50	$ 60.14	$ 29.80	$ 14.63	$ 9.58	$ 7.05	$ 5.53	$ 4.52	$ 3.80	$ 3.26
	$1.00	$ 60.28	$ 29.94	$ 14.77	$ 9.72	$ 7.19	$ 5.67	$ 4.66	$ 3.94	$ 3.40
	$1.50	$ 60.42	$ 30.08	$ 14.91	$ 9.85	$ 7.33	$ 5.81	$ 4.80	$ 4.08	$ 3.53
	$2.00	$ 60.56	$ 30.22	$ 15.05	$ 9.99	$ 7.47	$ 5.95	$ 4.94	$ 4.21	$ 3.67
	$2.50	$ 60.70	$ 30.36	$ 15.19	$ 10.13	$ 7.60	$ 6.09	$ 5.08	$ 4.35	$ 3.81
	$3.00	$ 60.84	$ 30.50	$ 15.33	$ 10.27	$ 7.74	$ 6.23	$ 5.21	$ 4.49	$ 3.95
	$3.50	$ 60.98	$ 30.64	$ 15.47	$ 10.41	$ 7.88	$ 6.37	$ 5.35	$ 4.63	$ 4.09
	$4.00	$ 61.12	$ 30.78	$ 15.61	$ 10.55	$ 8.02	$ 6.50	$ 5.49	$ 4.77	$ 4.23
	$4.50	$ 61.26	$ 30.91	$ 15.74	$ 10.69	$ 8.16	$ 6.64	$ 5.63	$ 4.91	$ 4.37
	$5.00	$ 61.39	$ 31.05	$ 15.88	$ 10.83	$ 8.30	$ 6.78	$ 5.77	$ 5.05	$ 4.51
	$5.50	$ 61.53	$ 31.19	$ 16.02	$ 10.97	$ 8.44	$ 6.92	$ 5.91	**$ 5.19**	$ 4.64
	$6.00	$ 61.67	$ 31.33	$ 16.16	$ 11.10	$ 8.58	$ 7.06	$ 6.05	$ 5.33	$ 4.78
	$6.50	$ 61.81	$ 31.47	$ 16.30	$ 11.24	$ 8.72	$ 7.20	$ 6.19	$ 5.46	$ 4.92
	$7.00	$ 61.95	$ 31.61	$ 16.44	$ 11.38	$ 8.85	$ 7.34	$ 6.33	$ 5.60	$ 5.06
	$7.50	$ 62.09	$ 31.75	$ 16.58	$ 11.52	$ 8.99	$ 7.48	$ 6.46	$ 5.74	$ 5.20
	$8.00	$ 62.23	$ 31.89	$ 16.72	$ 11.66	$ 9.13	$ 7.61	$ 6.60	$ 5.88	$ 5.34
	$8.50	$ 62.37	$ 32.03	$ 16.86	$ 11.80	$ 9.27	$ 7.75	$ 6.74	$ 6.02	$ 5.48
	$9.00	$ 62.50	$ 32.16	$ 16.99	$ 11.94	$ 9.41	$ 7.89	$ 6.88	$ 6.16	$ 5.62

Avg hours operation per day								
1.4	2.7	5.5	8.2	11.0	13.7	16.4	19.2	21.9

Table 25 | Sensitivity analysis of LCOH for methane pyrolysis production pathway considering facility size (25 t h2/day), natural gas pricing, operational hours, and carbon revenue

Methane Pyrolysis Today

Pyrolysis Size (t H2/day)		$US MM	$CA MM		Power Price [$/Mwh] includes delivery		Carbon Price [$/t]
25	CAPEX	$ 58	$ 79	Effic (LHV)	95%	$ 70.00	$ 500.00

LCOH - capex+ opex [$/kg H2]

Load / Use Factor / Utilization	5.7%	11.4%	22.8%	34.2%	45.7%	57.1%	68.5%	79.9%	91.3%
Hours of Operation	500	1000	2000	3000	4000	5000	6000	7000	8000
Power use (MWhr/yr)	5,383	10,767	21,533	32,300	43,067	53,833	64,600	75,367	86,133
t H2/yr	495	990	1,979	2,969	3,958	4,948	5,938	6,927	7,917
t H2/day	1.36	2.71	5.42	8.13	10.84	13.56	16.27	18.98	21.69
CAPEX ($/kg)	$ 16.34	$ 8.17	$ 4.08	$ 2.72	$ 2.04	$ 1.63	$ 1.36	$ 1.17	$ 1.02
OPEX ($/kg)	$ 6.98	$ 3.97	$ 2.47	$ 1.97	$ 1.72	$ 1.57	$ 1.47	$ 1.39	$ 1.34
Carbon ($/kg)	-$ 1.64	-$ 1.64	-$ 1.64	-$ 1.64	-$ 1.64	-$ 1.64	-$ 1.64	-$ 1.64	-$ 1.64
Total ($/kg)	**$ 21.68**	**$ 10.50**	**$ 4.91**	**$ 3.05**	**$ 2.12**	**$ 1.56**	**$ 1.19**	**$ 0.92**	**$ 0.72**

LCOH - total [$/kg H2]

	Hours of Operation	500	1000	2000	3000	4000	5000	6000	7000	8000
			1	2	3	4	5	6	7	8
CDN/GJ [includes delivery cost to site]	$0.00	$ 21.68	$ 10.50	$ 4.91	$ 3.05	$ 2.12	$ 1.56	$ 1.19	$ 0.92	$ 0.72
	$0.50	$ 21.82	$ 10.64	$ 5.05	$ 3.19	$ 2.26	$ 1.70	$ 1.33	$ 1.06	$ 0.86
	$1.00	$ 21.96	$ 10.78	$ 5.19	$ 3.33	$ 2.40	$ 1.84	$ 1.47	$ 1.20	$ 1.00
	$1.50	$ 22.09	$ 10.92	$ 5.33	$ 3.47	$ 2.54	$ 1.98	$ 1.60	$ 1.34	$ 1.14
	$2.00	$ 22.23	$ 11.06	$ 5.47	$ 3.61	$ 2.67	$ 2.12	$ 1.74	$ 1.48	$ 1.28
	$2.50	$ 22.37	$ 11.20	$ 5.61	$ 3.74	$ 2.81	$ 2.25	$ 1.88	$ 1.62	$ 1.42
	$3.00	$ 22.51	$ 11.33	$ 5.75	$ 3.88	$ 2.95	$ 2.39	$ 2.02	$ 1.75	$ 1.56
	$3.50	$ 22.65	$ 11.47	$ 5.89	$ 4.02	$ 3.09	$ 2.53	$ 2.16	$ 1.89	$ 1.69
	$4.00	$ 22.79	$ 11.61	$ 6.02	$ 4.16	$ 3.23	$ 2.67	$ 2.30	$ 2.03	$ 1.83
	$4.50	$ 22.93	$ 11.75	$ 6.16	$ 4.30	$ 3.37	$ 2.81	$ 2.44	$ 2.17	$ 1.97
	$5.00	$ 23.07	$ 11.89	$ 6.30	$ 4.44	$ 3.51	$ 2.95	$ 2.58	$ 2.31	$ 2.11
	$5.50	$ 23.21	$ 12.03	$ 6.44	$ 4.58	$ 3.65	$ 3.09	$ 2.72	**$ 2.45**	$ 2.25
	$6.00	$ 23.34	$ 12.17	$ 6.58	$ 4.72	$ 3.79	$ 3.23	$ 2.85	$ 2.59	$ 2.39
	$6.50	$ 23.48	$ 12.31	$ 6.72	$ 4.86	$ 3.92	$ 3.37	$ 2.99	$ 2.73	$ 2.53
	$7.00	$ 23.62	$ 12.45	$ 6.86	$ 4.99	$ 4.06	$ 3.50	$ 3.13	$ 2.87	$ 2.67
	$7.50	$ 23.76	$ 12.58	$ 7.00	$ 5.13	$ 4.20	$ 3.64	$ 3.27	$ 3.00	$ 2.80
	$8.00	$ 23.90	$ 12.72	$ 7.13	$ 5.27	$ 4.34	$ 3.78	$ 3.41	$ 3.14	$ 2.94
	$8.50	$ 24.04	$ 12.86	$ 7.27	$ 5.41	$ 4.48	$ 3.92	$ 3.55	$ 3.28	$ 3.08
	$9.00	$ 24.18	$ 13.00	$ 7.41	$ 5.55	$ 4.62	$ 4.06	$ 3.69	$ 3.42	$ 3.22

Avg hours operation per day								
1.4	2.7	5.5	8.2	11.0	13.7	16.4	19.2	21.9

Table 26 | Sensitivity analysis of LCOH for methane pyrolysis production pathway considering facility size (250 t h2/day), natural gas pricing, operational hours, and carbon revenue

Methane Pyrolysis Today

Pyrolysis Size (t H2/day)		$US MM	$CA MM		Power Price [$/Mwh] includes delivery		Carbon Price [$/t]
250	CAPEX	$ 233	$ 319	Effic (LHV)	95%	$ 70.00	$ 500.00

LCOH - capex+ opex [$/kg H2]									
Load / Use Factor / Utilization	5.7%	11.4%	22.8%	34.2%	45.7%	57.1%	68.5%	79.9%	91.3%
Hours of Operation	500	1000	2000	3000	4000	5000	6000	7000	8000
Power use (MWhr/yr)	53,833	107,667	215,333	323,000	430,667	538,333	646,000	753,667	861,333
t H2/yr	4,948	9,896	19,792	29,688	39,583	49,479	59,375	69,271	79,167
t H2/day	13.56	27.11	54.22	81.34	108.45	135.56	162.67	189.78	216.89
CAPEX ($/kg)	$ 6.56	$ 3.28	$ 1.64	$ 1.09	$ 0.82	$ 0.66	$ 0.55	$ 0.47	$ 0.41
OPEX ($/kg)	$ 2.41	$ 1.69	$ 1.33	$ 1.21	$ 1.15	$ 1.11	$ 1.09	$ 1.07	$ 1.06
Carbon ($/kg)	-$ 1.64	-$ 1.64	-$ 1.64	-$ 1.64	-$ 1.64	-$ 1.64	-$ 1.64	-$ 1.64	-$ 1.64
Total ($/kg)	**$ 7.33**	**$ 3.33**	**$ 1.33**	**$ 0.66**	**$ 0.33**	**$ 0.13**	**-$ 0.01**	**-$ 0.10**	**-$ 0.17**

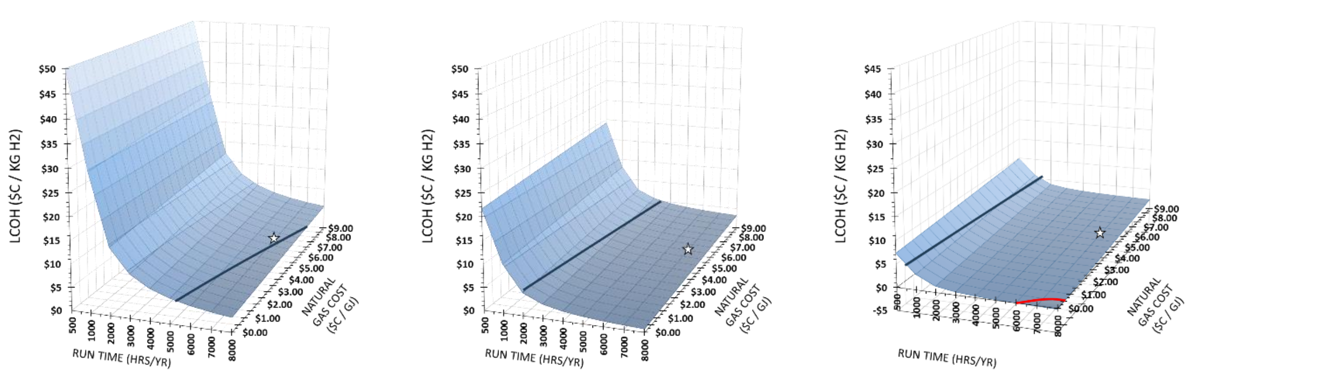
LCOH - total [$/kg H2]

CDN/GJ [includes delivery cost to site]	Hours of Operation: 500	1000	2000	3000	4000	5000	6000	7000	8000
		1	2	3	4	5	6	7	8
$0.00	$ 7.33	$ 3.33	$ 1.33	$ 0.66	$ 0.33	$ 0.13	-$ 0.01	-$ 0.10	-$ 0.17
$0.50	$ 7.47	$ 3.47	$ 1.47	$ 0.80	$ 0.46	$ 0.26	$ 0.13	$ 0.04	-$ 0.04
$1.00	$ 7.61	$ 3.61	$ 1.60	$ 0.94	$ 0.60	$ 0.40	$ 0.27	$ 0.17	$ 0.10
$1.50	$ 7.75	$ 3.75	$ 1.74	$ 1.08	$ 0.74	$ 0.54	$ 0.41	$ 0.31	$ 0.24
$2.00	$ 7.89	$ 3.88	$ 1.88	$ 1.21	$ 0.88	$ 0.68	$ 0.55	$ 0.45	$ 0.38
$2.50	$ 8.03	$ 4.02	$ 2.02	$ 1.35	$ 1.02	$ 0.82	$ 0.69	$ 0.59	$ 0.52
$3.00	$ 8.17	$ 4.16	$ 2.16	$ 1.49	$ 1.16	$ 0.96	$ 0.83	$ 0.73	$ 0.66
$3.50	$ 8.30	$ 4.30	$ 2.30	$ 1.63	$ 1.30	$ 1.10	$ 0.96	$ 0.87	$ 0.80
$4.00	$ 8.44	$ 4.44	$ 2.44	$ 1.77	$ 1.44	$ 1.24	$ 1.10	$ 1.01	$ 0.94
$4.50	$ 8.58	$ 4.58	$ 2.58	$ 1.91	$ 1.58	$ 1.38	$ 1.24	$ 1.15	$ 1.08
$5.00	$ 8.72	$ 4.72	$ 2.72	$ 2.05	$ 1.71	$ 1.51	$ 1.38	$ 1.29	$ 1.21
$5.50	$ 8.86	$ 4.86	$ 2.85	$ 2.19	$ 1.85	$ 1.65	$ 1.52	**$ 1.42**	$ 1.35
$6.00	$ 9.00	$ 4.99	$ 2.99	$ 2.33	$ 1.99	$ 1.79	$ 1.66	$ 1.56	$ 1.49
$6.50	$ 9.14	$ 5.13	$ 3.13	$ 2.46	$ 2.13	$ 1.93	$ 1.80	$ 1.70	$ 1.63
$7.00	$ 9.28	$ 5.27	$ 3.27	$ 2.60	$ 2.27	$ 2.07	$ 1.94	$ 1.84	$ 1.77
$7.50	$ 9.41	$ 5.41	$ 3.41	$ 2.74	$ 2.41	$ 2.21	$ 2.08	$ 1.98	$ 1.91
$8.00	$ 9.55	$ 5.55	$ 3.55	$ 2.88	$ 2.55	$ 2.35	$ 2.21	$ 2.12	$ 2.05
$8.50	$ 9.69	$ 5.69	$ 3.69	$ 3.02	$ 2.69	$ 2.49	$ 2.35	$ 2.26	$ 2.19
$9.00	$ 9.83	$ 5.83	$ 3.83	$ 3.16	$ 2.83	$ 2.63	$ 2.49	$ 2.40	$ 2.32

Avg hours operation per day								
1.4	2.7	5.5	8.2	11.0	13.7	16.4	19.2	21.9

The addition of carbon revenue breaks the dependent relationship between natural gas prices and LCOH, where the addition of carbon revenues can lead to negative pricing on hydrogen as illustrated in **Figure 67** for the 250 t H_2/d case.

Figure 67 | LCOH visualization for Methane Pyrolysis production pathway across various facility sizes, natural gas pricing, operational hours, and absence of carbon revenue



Methane Pyrolysis Sensitivity Charts – Future reduced economic assumptions and no carbon revenue

With the expectations that a reduction in capital will be achieved by 2050, the LCOH for NG Pyrolysis is anticipated to be reduced significantly and the operation of small-scale plants will be feasible, especially as it relates to distributed hydrogen and the ability to eliminate if not significantly reduce transportation expense. As shown in Tables 27, 28, and 28, LCOH of future NG Pyrolysis is anticipated to be below \$5.00 / kg H2 and sub \$3.00 / kg H2 for large-scale production. These values become comparable to the LCOH achievable utilizing reformation.

Table 27|Sensitivity analysis of LCOH for methane pyrolysis production pathway in 2050 considering facility size (2.5 t h2/day), natural gas pricing, operational hours, and absence of carbon revenue

Methane Pyrolysis 2050

	Pyrolysis Size (t H2/day)		$US MM	$CA MM		Power Price [$/Mwh] includes delivery			Carbon Price [$/t]
	2.5	CAPEX	$ 7	$ 10	Effic (LHV)	95%	$ 70.00		$ -

LCOH - capex+ opex [$/kg H2]	Load / Use Factor / Utilization								
	5.7%	11.4%	22.8%	34.2%	45.7%	57.1%	68.5%	79.9%	91.3%
	Hours of Operation								
	500	1000	2000	3000	4000	5000	6000	7000	8000
Power use (MWhr/yr)	538	1,077	2,153	3,230	4,307	5,383	6,460	7,537	8,613
t H2/yr	49	99	198	297	396	495	594	693	792
t H2/day	0.14	0.27	0.54	0.81	1.08	1.36	1.63	1.90	2.17
CAPEX ($/kg)	$ 20.35	$ 10.18	$ 5.09	$ 3.39	$ 2.54	$ 2.04	$ 1.70	$ 1.45	$ 1.27
OPEX ($/kg)	$ 10.96	$ 5.96	$ 3.46	$ 2.63	$ 2.21	$ 1.96	$ 1.80	$ 1.68	$ 1.59
Carbon ($/kg)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total ($/kg)	**$ 31.31**	**$ 16.14**	**$ 8.55**	**$ 6.02**	**$ 4.76**	**$ 4.00**	**$ 3.49**	**$ 3.13**	**$ 2.86**

LCOH - total [$/kg H2]		Hours of Operation								
		500	1000	2000	3000	4000	5000	6000	7000	8000
			1	2	3	4	5	6	7	8
	$0.00	$ 31.31	$ 16.14	$ 8.55	$ 6.02	$ 4.76	$ 4.00	$ 3.49	$ 3.13	$ 2.86
	$0.50	$ 31.44	$ 16.27	$ 8.69	$ 6.16	$ 4.90	$ 4.14	$ 3.63	$ 3.27	$ 3.00
	$1.00	$ 31.58	$ 16.41	$ 8.83	$ 6.30	$ 5.04	$ 4.28	$ 3.77	$ 3.41	$ 3.14
	$1.50	$ 31.72	$ 16.55	$ 8.97	$ 6.44	$ 5.17	$ 4.42	$ 3.91	$ 3.55	$ 3.28
	$2.00	$ 31.86	$ 16.69	$ 9.11	$ 6.58	$ 5.31	$ 4.55	$ 4.05	$ 3.69	$ 3.42
	$2.50	$ 32.00	$ 16.83	$ 9.24	$ 6.72	$ 5.45	$ 4.69	$ 4.19	$ 3.83	$ 3.56
	$3.00	$ 32.14	$ 16.97	$ 9.38	$ 6.85	$ 5.59	$ 4.83	$ 4.33	$ 3.97	$ 3.69
	$3.50	$ 32.28	$ 17.11	$ 9.52	$ 6.99	$ 5.73	$ 4.97	$ 4.47	$ 4.10	$ 3.83
CDN/GJ [includes delivery cost to site]	$4.00	$ 32.42	$ 17.25	$ 9.66	$ 7.13	$ 5.87	$ 5.11	$ 4.60	$ 4.24	$ 3.97
	$4.50	$ 32.55	$ 17.38	$ 9.80	$ 7.27	$ 6.01	$ 5.25	$ 4.74	$ 4.38	$ 4.11
	$5.00	$ 32.69	$ 17.52	$ 9.94	$ 7.41	$ 6.15	$ 5.39	$ 4.88	$ 4.52	$ 4.25
	$5.50	$ 32.83	$ 17.66	$ 10.08	$ 7.55	$ 6.28	$ 5.53	$ 5.02	**$ 4.66**	$ 4.39
	$6.00	$ 32.97	$ 17.80	$ 10.22	$ 7.69	$ 6.42	$ 5.67	$ 5.16	$ 4.80	$ 4.53
	$6.50	$ 33.11	$ 17.94	$ 10.36	$ 7.83	$ 6.56	$ 5.80	$ 5.30	$ 4.94	$ 4.67
	$7.00	$ 33.25	$ 18.08	$ 10.49	$ 7.97	$ 6.70	$ 5.94	$ 5.44	$ 5.08	$ 4.81
	$7.50	$ 33.39	$ 18.22	$ 10.63	$ 8.10	$ 6.84	$ 6.08	$ 5.58	$ 5.21	$ 4.94
	$8.00	$ 33.53	$ 18.36	$ 10.77	$ 8.24	$ 6.98	$ 6.22	$ 5.71	$ 5.35	$ 5.08
	$8.50	$ 33.67	$ 18.50	$ 10.91	$ 8.38	$ 7.12	$ 6.36	$ 5.85	$ 5.49	$ 5.22
	$9.00	$ 33.80	$ 18.63	$ 11.05	$ 8.52	$ 7.26	$ 6.50	$ 5.99	$ 5.63	$ 5.36

Avg hours operation per day								
1.4	2.7	5.5	8.2	11.0	13.7	16.4	19.2	21.9

Table 28 | Sensitivity analysis of LCOH for methane pyrolysis production pathway in 2050 considering facility size (25 t h2/day), natural gas pricing, operational hours, and absence of carbon revenue

Methane Pyrolysis 2050

Pyrolysis Size (t H2/day)		$US MM	$CA MM		Power Price [$/Mwh] includes delivery		Carbon Price [$/t]
25	CAPEX	$ 29	$ 40	Effic (LHV) 95%	$ 70.00		$ -

LCOH - capex+ opex [$/kg H2]

Load / Use Factor / Utilization	5.7%	11.4%	22.8%	34.2%	45.7%	57.1%	68.5%	79.9%	91.3%
Hours of Operation	500	1000	2000	3000	4000	5000	6000	7000	8000
Power use (MWhr/yr)	5,383	10,767	21,533	32,300	43,067	53,833	64,600	75,367	86,133
t H2/yr	495	990	1,979	2,969	3,958	4,948	5,938	6,927	7,917
t H2/day	1.36	2.71	5.42	8.13	10.84	13.56	16.27	18.98	21.69
CAPEX ($/kg)	$ 8.17	$ 4.08	$ 2.04	$ 1.36	$ 1.02	$ 0.82	$ 0.68	$ 0.58	$ 0.51
OPEX ($/kg)	$ 3.97	$ 2.47	$ 1.72	$ 1.47	$ 1.34	$ 1.27	$ 1.22	$ 1.18	$ 1.15
Carbon ($/kg)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total ($/kg)	**$ 12.14**	**$ 6.55**	**$ 3.76**	**$ 2.83**	**$ 2.36**	**$ 2.08**	**$ 1.90**	**$ 1.76**	**$ 1.66**

LCOH - total [$/kg H2]

	Hours of Operation	500	1000	2000	3000	4000	5000	6000	7000	8000
			1	2	3	4	5	6	7	8
CDN/GJ [includes delivery cost to site]	$0.00	$ 12.14	$ 6.55	$ 3.76	$ 2.83	$ 2.36	$ 2.08	$ 1.90	$ 1.76	$ 1.66
	$0.50	$ 12.28	$ 6.69	$ 3.90	$ 2.97	$ 2.50	$ 2.22	$ 2.04	$ 1.90	$ 1.80
	$1.00	$ 12.42	$ 6.83	$ 4.04	$ 3.11	$ 2.64	$ 2.36	$ 2.17	$ 2.04	$ 1.94
	$1.50	$ 12.56	$ 6.97	$ 4.18	$ 3.24	$ 2.78	$ 2.50	$ 2.31	$ 2.18	$ 2.08
	$2.00	$ 12.70	$ 7.11	$ 4.31	$ 3.38	$ 2.92	$ 2.64	$ 2.45	$ 2.32	$ 2.22
	$2.50	$ 12.84	$ 7.25	$ 4.45	$ 3.52	$ 3.06	$ 2.78	$ 2.59	$ 2.46	$ 2.36
	$3.00	$ 12.97	$ 7.39	$ 4.59	$ 3.66	$ 3.20	$ 2.92	$ 2.73	$ 2.60	$ 2.50
	$3.50	$ 13.11	$ 7.53	$ 4.73	$ 3.80	$ 3.33	$ 3.05	$ 2.87	$ 2.74	$ 2.64
	$4.00	$ 13.25	$ 7.66	$ 4.87	$ 3.94	$ 3.47	$ 3.19	$ 3.01	$ 2.87	$ 2.77
	$4.50	$ 13.39	$ 7.80	$ 5.01	$ 4.08	$ 3.61	$ 3.33	$ 3.15	$ 3.01	$ 2.91
	$5.00	$ 13.53	$ 7.94	$ 5.15	$ 4.22	$ 3.75	$ 3.47	$ 3.28	$ 3.15	$ 3.05
	$5.50	$ 13.67	$ 8.08	$ 5.29	$ 4.36	$ 3.89	$ 3.61	$ 3.42	**$ 3.29**	$ 3.19
	$6.00	$ 13.81	$ 8.22	$ 5.43	$ 4.49	$ 4.03	$ 3.75	$ 3.56	$ 3.43	$ 3.33
	$6.50	$ 13.95	$ 8.36	$ 5.56	$ 4.63	$ 4.17	$ 3.89	$ 3.70	$ 3.57	$ 3.47
	$7.00	$ 14.09	$ 8.50	$ 5.70	$ 4.77	$ 4.31	$ 4.03	$ 3.84	$ 3.71	$ 3.61
	$7.50	$ 14.22	$ 8.64	$ 5.84	$ 4.91	$ 4.44	$ 4.17	$ 3.98	$ 3.85	$ 3.75
	$8.00	$ 14.36	$ 8.77	$ 5.98	$ 5.05	$ 4.58	$ 4.30	$ 4.12	$ 3.98	$ 3.89
	$8.50	$ 14.50	$ 8.91	$ 6.12	$ 5.19	$ 4.72	$ 4.44	$ 4.26	$ 4.12	$ 4.02
	$9.00	$ 14.64	$ 9.05	$ 6.26	$ 5.33	$ 4.86	$ 4.58	$ 4.40	$ 4.26	$ 4.16

Avg hours operation per day								
1.4	2.7	5.5	8.2	11.0	13.7	16.4	19.2	21.9

Table 29|Sensitivity analysis of LCOH for methane pyrolysis production pathway in 2050 considering facility size (250 t h2/day), natural gas pricing, operational hours, and absence of carbon revenue

Methane Pyrolysis 2050

Pyrolysis Size (t H2/day)		$US MM	$CA MM		Power Price [$/Mwh] includes delivery		Carbon Price [$/t]
250	CAPEX	$ 116	$ 159	Effic (LHV)	95%	$ 70.00	$ -

LCOH - capex+ opex [$/kg H2]

	Load / Use Factor / Utilization								
	5.7%	11.4%	22.8%	34.2%	45.7%	57.1%	68.5%	79.9%	91.3%
	Hours of Operation								
	500	1000	2000	3000	4000	5000	6000	7000	8000
Power use (MWhr/yr)	53,833	107,667	215,333	323,000	430,667	538,333	646,000	753,667	861,333
t H2/yr	4,948	9,896	19,792	29,688	39,583	49,479	59,375	69,271	79,167
t H2/day	13.56	27.11	54.22	81.34	108.45	135.56	162.67	189.78	216.89
CAPEX ($/kg)	$ 3.28	$ 1.64	$ 0.82	$ 0.55	$ 0.41	$ 0.33	$ 0.27	$ 0.23	$ 0.20
OPEX ($/kg)	$ 1.69	$ 1.33	$ 1.15	$ 1.09	$ 1.06	$ 1.04	$ 1.03	$ 1.02	$ 1.01
Carbon ($/kg)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total ($/kg)	**$ 4.97**	**$ 2.97**	**$ 1.97**	**$ 1.63**	**$ 1.47**	**$ 1.37**	**$ 1.30**	**$ 1.25**	**$ 1.22**

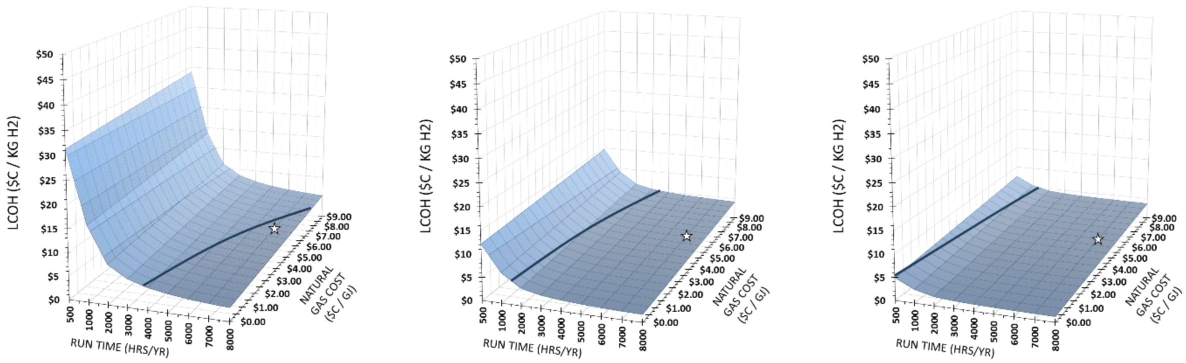
LCOH - total [$/kg H2]

CDN/GJ [includes delivery cost to site]	Hours of Operation								
	500	1000	2000	3000	4000	5000	6000	7000	8000
		1	2	3	4	5	6	7	8
$0.00	$ 4.97	$ 2.97	$ 1.97	$ 1.63	$ 1.47	$ 1.37	$ 1.30	$ 1.25	$ 1.22
$0.50	$ 5.11	$ 3.11	$ 2.10	$ 1.77	$ 1.60	$ 1.50	$ 1.44	$ 1.39	$ 1.35
$1.00	$ 5.25	$ 3.24	$ 2.24	$ 1.91	$ 1.74	$ 1.64	$ 1.58	$ 1.53	$ 1.49
$1.50	$ 5.39	$ 3.38	$ 2.38	$ 2.05	$ 1.88	$ 1.78	$ 1.72	$ 1.67	$ 1.63
$2.00	$ 5.52	$ 3.52	$ 2.52	$ 2.19	$ 2.02	$ 1.92	$ 1.85	$ 1.81	$ 1.77
$2.50	$ 5.66	$ 3.66	$ 2.66	$ 2.33	$ 2.16	$ 2.06	$ 1.99	$ 1.95	$ 1.91
$3.00	$ 5.80	$ 3.80	$ 2.80	$ 2.47	$ 2.30	$ 2.20	$ 2.13	$ 2.08	$ 2.05
$3.50	$ 5.94	$ 3.94	$ 2.94	$ 2.60	$ 2.44	$ 2.34	$ 2.27	$ 2.22	$ 2.19
$4.00	$ 6.08	$ 4.08	$ 3.08	$ 2.74	$ 2.58	$ 2.48	$ 2.41	$ 2.36	$ 2.33
$4.50	$ 6.22	$ 4.22	$ 3.22	$ 2.88	$ 2.72	$ 2.62	$ 2.55	$ 2.50	$ 2.46
$5.00	$ 6.36	$ 4.36	$ 3.35	$ 3.02	$ 2.85	$ 2.75	$ 2.69	$ 2.64	$ 2.60
$5.50	$ 6.50	$ 4.49	$ 3.49	$ 3.16	$ 2.99	$ 2.89	$ 2.83	**$ 2.78**	$ 2.74
$6.00	$ 6.63	$ 4.63	$ 3.63	$ 3.30	$ 3.13	$ 3.03	$ 2.96	$ 2.92	$ 2.88
$6.50	$ 6.77	$ 4.77	$ 3.77	$ 3.44	$ 3.27	$ 3.17	$ 3.10	$ 3.06	$ 3.02
$7.00	$ 6.91	$ 4.91	$ 3.91	$ 3.58	$ 3.41	$ 3.31	$ 3.24	$ 3.19	$ 3.16
$7.50	$ 7.05	$ 5.05	$ 4.05	$ 3.72	$ 3.55	$ 3.45	$ 3.38	$ 3.33	$ 3.30
$8.00	$ 7.19	$ 5.19	$ 4.19	$ 3.85	$ 3.69	$ 3.59	$ 3.52	$ 3.47	$ 3.44
$8.50	$ 7.33	$ 5.33	$ 4.33	$ 3.99	$ 3.83	$ 3.73	$ 3.66	$ 3.61	$ 3.58
$9.00	$ 7.47	$ 5.47	$ 4.47	$ 4.13	$ 3.96	$ 3.86	$ 3.80	$ 3.75	$ 3.71

Avg hours operation per day								
1.4	2.7	5.5	8.2	11.0	13.7	16.4	19.2	21.9

Though lower than the current calculated LCOH, future LCOH will still be sensitive to facility size due and the significance of natural gas pricing (**Figure 68**).

Figure 68|LCOH visualization for Methane Pyrolysis production pathway in 2050 across various facility sizes, natural gas pricing, and operational hours, and absence of carbon revenue



Methane Pyrolysis Sensitivity Charts – Future reduced economic assumptions with carbon revenue

The inclusion of carbon pricing has the same significant impact on LCOH as illustrated under current conditions. However, under future conditions, the revenue for carbon and the potential to drive negative hydrogen values becomes more pronounced (Tables 30, 31, and 32).

Table 30|Sensitivity analysis of LCOH for methane pyrolysis production pathway in 2050 considering facility size (2.5 t h2/day), natural gas pricing, operational hours, and carbon revenue

Methane Pyrolysis 2050

Pyrolysis Size (t H2/day)		$US MM	$CA MM		Power Price [$/Mwh] includes delivery			Carbon Price [$/t]
2.5	CAPEX	$ 7	$ 10	Effic (LHV)	95%	$ 70.00		$ 500.00

LCOH - capex+ opex [$/kg H2]

	Load / Use Factor / Utilization								
	5.7%	11.4%	22.8%	34.2%	45.7%	57.1%	68.5%	79.9%	91.3%
	Hours of Operation								
	500	1000	2000	3000	4000	5000	6000	7000	8000
Power use (MWhr/yr)	538	1,077	2,153	3,230	4,307	5,383	6,460	7,537	8,613
t H2/yr	49	99	198	297	396	495	594	693	792
t H2/day	0.14	0.27	0.54	0.81	1.08	1.36	1.63	1.90	2.17
CAPEX ($/kg)	$ 20.35	$ 10.18	$ 5.09	$ 3.39	$ 2.54	$ 2.04	$ 1.70	$ 1.45	$ 1.27
OPEX ($/kg)	$ 10.96	$ 5.96	$ 3.46	$ 2.63	$ 2.21	$ 1.96	$ 1.80	$ 1.68	$ 1.59
Carbon ($/kg)	-$ 1.64	-$ 1.64	-$ 1.64	-$ 1.64	-$ 1.64	-$ 1.64	-$ 1.64	-$ 1.64	-$ 1.64
Total ($/kg)	**$ 29.67**	**$ 14.50**	**$ 6.91**	**$ 4.38**	**$ 3.12**	**$ 2.36**	**$ 1.85**	**$ 1.49**	**$ 1.22**

LCOH - total [$/kg H2]

		Hours of Operation								
		500	1000	2000	3000	4000	5000	6000	7000	8000
			1	2	3	4	5	6	7	8
CDN/GJ [includes delivery cost to site]	$0.00	$ 29.67	$ 14.50	$ 6.91	$ 4.38	$ 3.12	$ 2.36	$ 1.85	$ 1.49	$ 1.22
	$0.50	$ 29.80	$ 14.63	$ 7.05	$ 4.52	$ 3.26	$ 2.50	$ 1.99	$ 1.63	$ 1.36
	$1.00	$ 29.94	$ 14.77	$ 7.19	$ 4.66	$ 3.40	$ 2.64	$ 2.13	$ 1.77	$ 1.50
	$1.50	$ 30.08	$ 14.91	$ 7.33	$ 4.80	$ 3.53	$ 2.78	$ 2.27	$ 1.91	$ 1.64
	$2.00	$ 30.22	$ 15.05	$ 7.47	$ 4.94	$ 3.67	$ 2.91	$ 2.41	$ 2.05	$ 1.78
	$2.50	$ 30.36	$ 15.19	$ 7.60	$ 5.08	$ 3.81	$ 3.05	$ 2.55	$ 2.19	$ 1.92
	$3.00	$ 30.50	$ 15.33	$ 7.74	$ 5.21	$ 3.95	$ 3.19	$ 2.69	$ 2.33	$ 2.05
	$3.50	$ 30.64	$ 15.47	$ 7.88	$ 5.35	$ 4.09	$ 3.33	$ 2.83	$ 2.46	$ 2.19
	$4.00	$ 30.78	$ 15.61	$ 8.02	$ 5.49	$ 4.23	$ 3.47	$ 2.96	$ 2.60	$ 2.33
	$4.50	$ 30.91	$ 15.74	$ 8.16	$ 5.63	$ 4.37	$ 3.61	$ 3.10	$ 2.74	$ 2.47
	$5.00	$ 31.05	$ 15.88	$ 8.30	$ 5.77	$ 4.51	$ 3.75	$ 3.24	$ 2.88	$ 2.61
	$5.50	$ 31.19	$ 16.02	$ 8.44	$ 5.91	$ 4.64	$ 3.89	$ 3.38	**$ 3.02**	$ 2.75
	$6.00	$ 31.33	$ 16.16	$ 8.58	$ 6.05	$ 4.78	$ 4.03	$ 3.52	$ 3.16	$ 2.89
	$6.50	$ 31.47	$ 16.30	$ 8.72	$ 6.19	$ 4.92	$ 4.16	$ 3.66	$ 3.30	$ 3.03
	$7.00	$ 31.61	$ 16.44	$ 8.85	$ 6.33	$ 5.06	$ 4.30	$ 3.80	$ 3.44	$ 3.17
	$7.50	$ 31.75	$ 16.58	$ 8.99	$ 6.46	$ 5.20	$ 4.44	$ 3.94	$ 3.57	$ 3.30
	$8.00	$ 31.89	$ 16.72	$ 9.13	$ 6.60	$ 5.34	$ 4.58	$ 4.07	$ 3.71	$ 3.44
	$8.50	$ 32.03	$ 16.86	$ 9.27	$ 6.74	$ 5.48	$ 4.72	$ 4.21	$ 3.85	$ 3.58
	$9.00	$ 32.16	$ 16.99	$ 9.41	$ 6.88	$ 5.62	$ 4.86	$ 4.35	$ 3.99	$ 3.72

Avg hours operation per day								
1.4	2.7	5.5	8.2	11.0	13.7	16.4	19.2	21.9

Table 31 | Sensitivity analysis of LCOH for methane pyrolysis production pathway in 2050 considering facility size (25 t h2/day), natural gas pricing, operational hours, and carbon revenue

Methane Pyrolysis 2050

Pyrolysis Size (t H2/day)		$US MM	$CA MM		Power Price [$/Mwh] includes delivery		Carbon Price [$/t]
25	CAPEX	$ 29	$ 40	Effic (LHV)	95%	$ 70.00	$ 500.00

LCOH - capex+ opex [$/kg H2]

Load / Use Factor / Utilization	5.7%	11.4%	22.8%	34.2%	45.7%	57.1%	68.5%	79.9%	91.3%
Hours of Operation	500	1000	2000	3000	4000	5000	6000	7000	8000
Power use (MWhr/yr)	5,383	10,767	21,533	32,300	43,067	53,833	64,600	75,367	86,133
t H2/yr	495	990	1,979	2,969	3,958	4,948	5,938	6,927	7,917
t H2/day	1.36	2.71	5.42	8.13	10.84	13.56	16.27	18.98	21.69
CAPEX ($/kg)	$ 8.17	$ 4.08	$ 2.04	$ 1.36	$ 1.02	$ 0.82	$ 0.68	$ 0.58	$ 0.51
OPEX ($/kg)	$ 3.97	$ 2.47	$ 1.72	$ 1.47	$ 1.34	$ 1.27	$ 1.22	$ 1.18	$ 1.15
Carbon ($/kg)	-$ 1.64	-$ 1.64	-$ 1.64	-$ 1.64	-$ 1.64	-$ 1.64	-$ 1.64	-$ 1.64	-$ 1.64
Total ($/kg)	**$ 10.50**	**$ 4.91**	**$ 2.12**	**$ 1.19**	**$ 0.72**	**$ 0.44**	**$ 0.26**	**$ 0.12**	**$ 0.02**

LCOH - total [$/kg H2]

	Hours of Operation									
		500	1000	2000	3000	4000	5000	6000	7000	8000
			1	2	3	4	5	6	7	8
CDN/GJ [includes delivery cost to site]	$0.00	$ 10.50	$ 4.91	$ 2.12	$ 1.19	$ 0.72	$ 0.44	$ 0.26	$ 0.12	$ 0.02
	$0.50	$ 10.64	$ 5.05	$ 2.26	$ 1.33	$ 0.86	$ 0.58	$ 0.40	$ 0.26	$ 0.16
	$1.00	$ 10.78	$ 5.19	$ 2.40	$ 1.47	$ 1.00	$ 0.72	$ 0.53	$ 0.40	$ 0.30
	$1.50	$ 10.92	$ 5.33	$ 2.54	$ 1.60	$ 1.14	$ 0.86	$ 0.67	$ 0.54	$ 0.44
	$2.00	$ 11.06	$ 5.47	$ 2.67	$ 1.74	$ 1.28	$ 1.00	$ 0.81	$ 0.68	$ 0.58
	$2.50	$ 11.20	$ 5.61	$ 2.81	$ 1.88	$ 1.42	$ 1.14	$ 0.95	$ 0.82	$ 0.72
	$3.00	$ 11.33	$ 5.75	$ 2.95	$ 2.02	$ 1.56	$ 1.28	$ 1.09	$ 0.96	$ 0.86
	$3.50	$ 11.47	$ 5.89	$ 3.09	$ 2.16	$ 1.69	$ 1.41	$ 1.23	$ 1.10	$ 1.00
	$4.00	$ 11.61	$ 6.02	$ 3.23	$ 2.30	$ 1.83	$ 1.55	$ 1.37	$ 1.23	$ 1.13
	$4.50	$ 11.75	$ 6.16	$ 3.37	$ 2.44	$ 1.97	$ 1.69	$ 1.51	$ 1.37	$ 1.27
	$5.00	$ 11.89	$ 6.30	$ 3.51	$ 2.58	$ 2.11	$ 1.83	$ 1.64	$ 1.51	$ 1.41
	$5.50	$ 12.03	$ 6.44	$ 3.65	$ 2.72	$ 2.25	$ 1.97	$ 1.78	**$ 1.65**	$ 1.55
	$6.00	$ 12.17	$ 6.58	$ 3.79	$ 2.85	$ 2.39	$ 2.11	$ 1.92	$ 1.79	$ 1.69
	$6.50	$ 12.31	$ 6.72	$ 3.92	$ 2.99	$ 2.53	$ 2.25	$ 2.06	$ 1.93	$ 1.83
	$7.00	$ 12.45	$ 6.86	$ 4.06	$ 3.13	$ 2.67	$ 2.39	$ 2.20	$ 2.07	$ 1.97
	$7.50	$ 12.58	$ 7.00	$ 4.20	$ 3.27	$ 2.80	$ 2.53	$ 2.34	$ 2.21	$ 2.11
	$8.00	$ 12.72	$ 7.13	$ 4.34	$ 3.41	$ 2.94	$ 2.66	$ 2.48	$ 2.34	$ 2.25
	$8.50	$ 12.86	$ 7.27	$ 4.48	$ 3.55	$ 3.08	$ 2.80	$ 2.62	$ 2.48	$ 2.38
	$9.00	$ 13.00	$ 7.41	$ 4.62	$ 3.69	$ 3.22	$ 2.94	$ 2.76	$ 2.62	$ 2.52

Avg hours operation per day								
1.4	2.7	5.5	8.2	11.0	13.7	16.4	19.2	21.9

Table 32 | Sensitivity analysis of LCOH for methane pyrolysis production pathway in 2050 considering facility size (250 t h2/day), natural gas pricing, operational hours, and carbon revenue

Methane Pyrolysis 2050

Pyrolysis Size (t H2/day)		$US MM	$CA MM		Power Price [$/Mwh] includes delivery		Carbon Price [$/t]
250	CAPEX	$ 116	$ 159	Effic (LHV)	95%	$ 70.00	$ 500.00

LCOH - capex+ opex [$/kg H2]									
Load / Use Factor / Utilization	5.7%	11.4%	22.8%	34.2%	45.7%	57.1%	68.5%	79.9%	91.3%
Hours of Operation	500	1000	2000	3000	4000	5000	6000	7000	8000
Power use (MWhr/yr)	53,833	107,667	215,333	323,000	430,667	538,333	646,000	753,667	861,333
t H2/yr	4,948	9,896	19,792	29,688	39,583	49,479	59,375	69,271	79,167
t H2/day	13.56	27.11	54.22	81.34	108.45	135.56	162.67	189.78	216.89
CAPEX ($/kg)	$ 3.28	$ 1.64	$ 0.82	$ 0.55	$ 0.41	$ 0.33	$ 0.27	$ 0.23	$ 0.20
OPEX ($/kg)	$ 1.69	$ 1.33	$ 1.15	$ 1.09	$ 1.06	$ 1.04	$ 1.03	$ 1.02	$ 1.01
Carbon ($/kg)	-$ 1.64	-$ 1.64	-$ 1.64	-$ 1.64	-$ 1.64	-$ 1.64	-$ 1.64	-$ 1.64	-$ 1.64
Total ($/kg)	**$ 3.33**	**$ 1.33**	**$ 0.33**	**-$ 0.01**	**-$ 0.17**	**-$ 0.27**	**-$ 0.34**	**-$ 0.39**	**-$ 0.42**

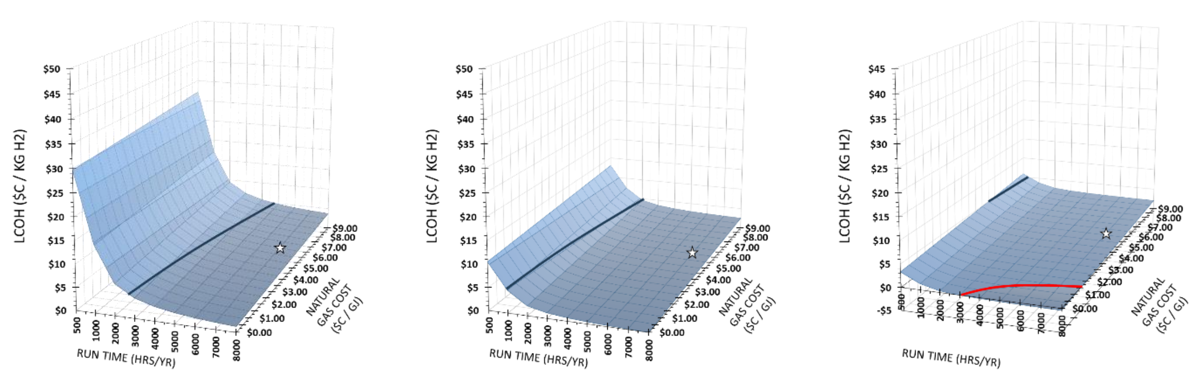
LCOH - total [$/kg H2]

CDN/GJ [includes delivery cost to site]	Hours of Operation: 500	1000	2000	3000	4000	5000	6000	7000	8000
		1	2	3	4	5	6	7	8
$0.00	$ 3.33	$ 1.33	$ 0.33	-$ 0.01	-$ 0.17	-$ 0.27	-$ 0.34	-$ 0.39	-$ 0.42
$0.50	$ 3.47	$ 1.47	$ 0.46	$ 0.13	-$ 0.04	-$ 0.14	-$ 0.20	-$ 0.25	-$ 0.29
$1.00	$ 3.61	$ 1.60	$ 0.60	$ 0.27	$ 0.10	$ 0.00	-$ 0.06	-$ 0.11	-$ 0.15
$1.50	$ 3.75	$ 1.74	$ 0.74	$ 0.41	$ 0.24	$ 0.14	$ 0.08	$ 0.03	-$ 0.01
$2.00	$ 3.88	$ 1.88	$ 0.88	$ 0.55	$ 0.38	$ 0.28	$ 0.21	$ 0.17	$ 0.13
$2.50	$ 4.02	$ 2.02	$ 1.02	$ 0.69	$ 0.52	$ 0.42	$ 0.35	$ 0.31	$ 0.27
$3.00	$ 4.16	$ 2.16	$ 1.16	$ 0.83	$ 0.66	$ 0.56	$ 0.49	$ 0.44	$ 0.41
$3.50	$ 4.30	$ 2.30	$ 1.30	$ 0.96	$ 0.80	$ 0.70	$ 0.63	$ 0.58	$ 0.55
$4.00	$ 4.44	$ 2.44	$ 1.44	$ 1.10	$ 0.94	$ 0.84	$ 0.77	$ 0.72	$ 0.69
$4.50	$ 4.58	$ 2.58	$ 1.58	$ 1.24	$ 1.08	$ 0.98	$ 0.91	$ 0.86	$ 0.82
$5.00	$ 4.72	$ 2.72	$ 1.71	$ 1.38	$ 1.21	$ 1.11	$ 1.05	$ 1.00	$ 0.96
$5.50	$ 4.86	$ 2.85	$ 1.85	$ 1.52	$ 1.35	$ 1.25	$ 1.19	**$ 1.14**	$ 1.10
$6.00	$ 4.99	$ 2.99	$ 1.99	$ 1.66	$ 1.49	$ 1.39	$ 1.32	$ 1.28	$ 1.24
$6.50	$ 5.13	$ 3.13	$ 2.13	$ 1.80	$ 1.63	$ 1.53	$ 1.46	$ 1.42	$ 1.38
$7.00	$ 5.27	$ 3.27	$ 2.27	$ 1.94	$ 1.77	$ 1.67	$ 1.60	$ 1.55	$ 1.52
$7.50	$ 5.41	$ 3.41	$ 2.41	$ 2.08	$ 1.91	$ 1.81	$ 1.74	$ 1.69	$ 1.66
$8.00	$ 5.55	$ 3.55	$ 2.55	$ 2.21	$ 2.05	$ 1.95	$ 1.88	$ 1.83	$ 1.80
$8.50	$ 5.69	$ 3.69	$ 2.69	$ 2.35	$ 2.19	$ 2.09	$ 2.02	$ 1.97	$ 1.94
$9.00	$ 5.83	$ 3.83	$ 2.83	$ 2.49	$ 2.32	$ 2.22	$ 2.16	$ 2.11	$ 2.07

Avg hours operation per day								
1.4	2.7	5.5	8.2	11.0	13.7	16.4	19.2	21.9

Figure 69 demonstrates the increasing capability of carbon revenue to drive negative hydrogen prices, as illustrated in the 250 t H_2 /d scenario.

Figure 69 | LCOH visualization for Methane Pyrolysis production pathway in 2050 across various facility sizes, natural gas pricing, and operational hours, and with carbon revenue



Electrolysis Sensitivity Charts

The following tables (Tables 33, 34, and 35) have been generated to demonstrate the LCOH sensitivity to the size of the facility, electricity pricing, and operational hours. The price of electricity has been identified as the most sensitive variable. These charts are also helpful in understanding the implications of running electrolysis with interruptible power produced from solar and wind. With run capacity factors of 20% for solar and 40% for wind, LCOH of less than $8.00 / kg H_2 is difficult to achieve, with large-scale deployment only realizing $7.00 / kg H_2. Electrolysis utilization in generating hydrogen will be dependent on connection to very low-cost electricity and the ability to run at greater than 50% utilization. To be economical under interruptible conditions, electricity needs to be provided at a very low cost (93–109).

Electrolysis Sensitivity Charts – Current economic assumptions

Under current estimates LCOH, below $5.00 / kg H_2 becomes difficult to realize with only low electricity pricing and high utilization able to achieve the desired low LCOH.

Table 33| Sensitivity analysis of LCOH for Electrolysis production pathway considering electrolyzer size (5 MW), electricity pricing, and operational hours

Electrolysis Today

	Elect. Size (MW)		$US/kWe	$CA/kWe					
	5	CAPEX	$ 1,450	$ 1,986	Effic (LHV)	65%			
	Load / Use Factor / Utilization								
	5.7%	11.4%	22.8%	34.2%	45.7%	57.1%	68.5%	79.9%	91.3%
LCOH - capex+ opex [$/kg]	Hours of Operation								
	500	1000	2000	3000	4000	5000	6000	7000	8000
Power use (MWhr/yr)	2500	5000	10000	15000	20000	25000	30000	35000	40000
t H2/yr	49	98	195	293	390	488	585	683	780
t H2/day	0.13	0.27	0.53	0.80	1.07	1.34	1.60	1.87	2.14
CAPEX ($/kg)	$ 30.08	$ 15.04	$ 7.52	$ 5.01	$ 3.76	$ 3.01	$ 2.51	$ 2.15	$ 1.88
OPEX ($/kg)	$ 10.72	$ 5.63	$ 3.09	$ 2.24	$ 1.81	$ 1.56	$ 1.39	$ 1.27	$ 1.18
Total ($/kg)	**$ 40.80**	**$ 20.67**	**$ 10.61**	**$ 7.25**	**$ 5.57**	**$ 4.57**	**$ 3.90**	**$ 3.42**	**$ 3.06**

LCOH - total [$/kg]

		Hours of Operation								
		500	1000	2000	3000	4000	5000	6000	7000	8000
			1	2	3	4	5	6	7	8
CDN/MWh [includes delivery cost to site]	$0	$ 40.80	$ 20.67	$ 10.61	$ 7.25	$ 5.57	$ 4.57	$ 3.90	$ 3.42	$ 3.06
	$10	$ 41.31	$ 21.18	$ 11.12	$ 7.76	$ 6.09	$ 5.08	$ 4.41	$ 3.93	$ 3.57
	$20	$ 41.83	$ 21.70	$ 11.63	$ 8.28	$ 6.60	$ 5.59	$ 4.92	$ 4.44	$ 4.08
	$30	$ 42.34	$ 22.21	$ 12.14	$ 8.79	$ 7.11	$ 6.11	$ 5.43	$ 4.96	$ 4.60
	$40	$ 42.85	$ 22.72	$ 12.66	$ 9.30	$ 7.63	$ 6.62	$ 5.95	$ 5.47	$ 5.11
	$50	$ 43.36	$ 23.24	$ 13.17	$ 9.82	$ 8.14	$ 7.13	$ 6.46	$ 5.98	$ 5.62
	$60	$ 43.88	$ 23.75	$ 13.68	$ 10.33	$ 8.65	$ 7.64	$ 6.97	$ 6.49	$ 6.13
	$70	$ 44.39	$ 24.26	$ 14.20	$ 10.84	$ 9.16	$ 8.16	$ 7.49	**$ 7.01**	$ 6.65
	$80	$ 44.90	$ 24.77	$ 14.71	$ 11.35	$ 9.68	$ 8.67	$ 8.00	$ 7.52	$ 7.16
	$90	$ 45.42	$ 25.29	$ 15.22	$ 11.87	$ 10.19	$ 9.18	$ 8.51	$ 8.03	$ 7.67
	$100	$ 45.93	$ 25.80	$ 15.73	$ 12.38	$ 10.70	$ 9.69	$ 9.02	$ 8.54	$ 8.18
	$120	$ 46.95	$ 26.82	$ 16.76	$ 13.40	$ 11.73	$ 10.72	$ 10.05	$ 9.57	$ 9.21
	$140	$ 47.98	$ 27.85	$ 17.78	$ 14.43	$ 12.75	$ 11.75	$ 11.07	$ 10.59	$ 10.24
	$160	$ 49.00	$ 28.87	$ 18.81	$ 15.45	$ 13.78	$ 12.77	$ 12.10	$ 11.62	$ 11.26
	$180	$ 50.03	$ 29.90	$ 19.83	$ 16.48	$ 14.80	$ 13.80	$ 13.12	$ 12.65	$ 12.29
	$200	$ 51.05	$ 30.92	$ 20.86	$ 17.50	$ 15.83	$ 14.82	$ 14.15	$ 13.67	$ 13.31
	$220	$ 52.08	$ 31.95	$ 21.89	$ 18.53	$ 16.85	$ 15.85	$ 15.18	$ 14.70	$ 14.34
	$240	$ 53.11	$ 32.98	$ 22.91	$ 19.56	$ 17.88	$ 16.87	$ 16.20	$ 15.72	$ 15.36
	$260	$ 54.13	$ 34.00	$ 23.94	$ 20.58	$ 18.90	$ 17.90	$ 17.23	$ 16.75	$ 16.39

Avg hours operation per day								
1.4	2.7	5.5	8.2	11.0	13.7	16.4	19.2	21.9

Table 34 | Sensitivity analysis of LCOH for Electrolysis production pathway considering electrolyzer size (50 MW), electricity pricing, and operational hours

Electrolysis Today

Elect. Size (MW)		$US/kWe	$CA/kWe		
50	CAPEX	$ 1,450	$ 1,986	Effic (LHV)	65%

LCOH - capex+ opex [$/kg]

	Load / Use Factor / Utilization								
	5.7%	11.4%	22.8%	34.2%	45.7%	57.1%	68.5%	79.9%	91.3%
	Hours of Operation								
	500	1000	2000	3000	4000	5000	6000	7000	8000
Power use (MWhr/yr)	25000	50000	100000	150000	200000	250000	300000	350000	400000
t H2/yr	488	975	1,951	2,926	3,901	4,877	5,852	6,827	7,803
t H2/day	1.34	2.67	5.34	8.02	10.69	13.36	16.03	18.70	21.38
CAPEX ($/kg)	$ 22.56	$ 11.28	$ 5.64	$ 3.76	$ 2.82	$ 2.26	$ 1.88	$ 1.61	$ 1.41
OPEX ($/kg)	$ 8.18	$ 4.36	$ 2.45	$ 1.81	$ 1.50	$ 1.31	$ 1.18	$ 1.09	$ 1.02
Total ($/kg)	**$ 30.74**	**$ 15.64**	**$ 8.09**	**$ 5.57**	**$ 4.32**	**$ 3.56**	**$ 3.06**	**$ 2.70**	**$ 2.43**

LCOH - total [$/kg]

CDN/MWh [includes delivery cost to site]	Hours of Operation								
	500	1000	2000	3000	4000	5000	6000	7000	8000
		1	2	3	4	5	6	7	8
$0	$ 30.74	$ 15.64	$ 8.09	$ 5.57	$ 4.32	$ 3.56	$ 3.06	$ 2.70	$ 2.43
$10	$ 31.25	$ 16.15	$ 8.60	$ 6.09	$ 4.83	$ 4.07	$ 3.57	$ 3.21	$ 2.94
$20	$ 31.76	$ 16.66	$ 9.12	$ 6.60	$ 5.34	$ 4.59	$ 4.08	$ 3.72	$ 3.45
$30	$ 32.27	$ 17.18	$ 9.63	$ 7.11	$ 5.85	$ 5.10	$ 4.60	$ 4.24	$ 3.97
$40	$ 32.79	$ 17.69	$ 10.14	$ 7.63	$ 6.37	$ 5.61	$ 5.11	$ 4.75	$ 4.48
$50	$ 33.30	$ 18.20	$ 10.65	$ 8.14	$ 6.88	$ 6.12	$ 5.62	$ 5.26	$ 4.99
$60	$ 33.81	$ 18.72	$ 11.17	$ 8.65	$ 7.39	$ 6.64	$ 6.13	$ 5.77	$ 5.51
$70	$ 34.33	$ 19.23	$ 11.68	$ 9.16	$ 7.90	$ 7.15	$ 6.65	**$ 6.29**	$ 6.02
$80	$ 34.84	$ 19.74	$ 12.19	$ 9.68	$ 8.42	$ 7.66	$ 7.16	$ 6.80	$ 6.53
$90	$ 35.35	$ 20.25	$ 12.70	$ 10.19	$ 8.93	$ 8.18	$ 7.67	$ 7.31	$ 7.04
$100	$ 35.86	$ 20.77	$ 13.22	$ 10.70	$ 9.44	$ 8.69	$ 8.18	$ 7.83	$ 7.56
$120	$ 36.89	$ 21.79	$ 14.24	$ 11.73	$ 10.47	$ 9.71	$ 9.21	$ 8.85	$ 8.58
$140	$ 37.91	$ 22.82	$ 15.27	$ 12.75	$ 11.49	$ 10.74	$ 10.24	$ 9.88	$ 9.61
$160	$ 38.94	$ 23.84	$ 16.29	$ 13.78	$ 12.52	$ 11.76	$ 11.26	$ 10.90	$ 10.63
$180	$ 39.96	$ 24.87	$ 17.32	$ 14.80	$ 13.54	$ 12.79	$ 12.29	$ 11.93	$ 11.66
$200	$ 40.99	$ 25.89	$ 18.34	$ 15.83	$ 14.57	$ 13.81	$ 13.31	$ 12.95	$ 12.68
$220	$ 42.02	$ 26.92	$ 19.37	$ 16.85	$ 15.59	$ 14.84	$ 14.34	$ 13.98	$ 13.71
$240	$ 43.04	$ 27.94	$ 20.39	$ 17.88	$ 16.62	$ 15.87	$ 15.36	$ 15.00	$ 14.73
$260	$ 44.07	$ 28.97	$ 21.42	$ 18.90	$ 17.65	$ 16.89	$ 16.39	$ 16.03	$ 15.76

Avg hours operation per day								
1.4	2.7	5.5	8.2	11.0	13.7	16.4	19.2	21.9

Table 35 | Sensitivity analysis of LCOH for Electrolysis production pathway considering electrolyzer size (500 MW), electricity pricing, and operational hours

Electrolysis Today

Elect. Size (MW)		$US/kWe	$CA/kWe		
500	CAPEX	$ 1,450	$ 1,986	Effic (LHV)	65%

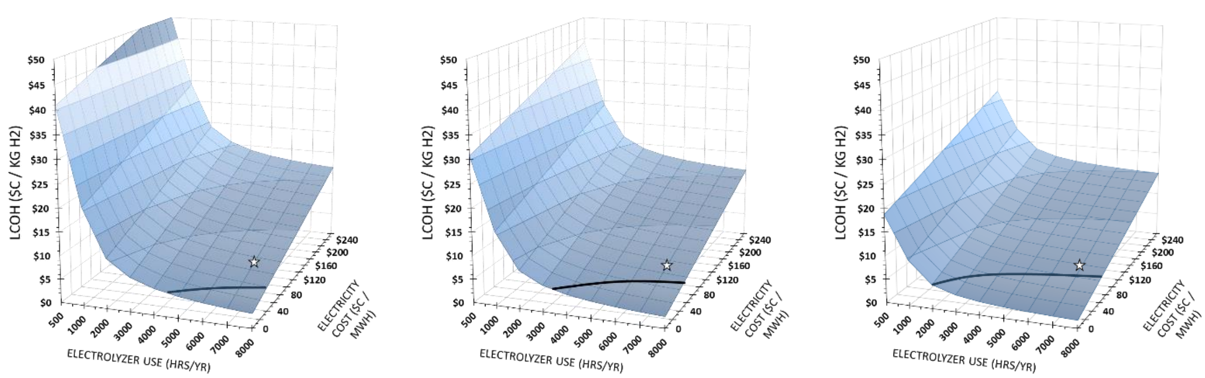
LCOH - capex+ opex [$/kg]									
	Load / Use Factor / Utilization								
	5.7%	11.4%	22.8%	34.2%	45.7%	57.1%	68.5%	79.9%	91.3%
	Hours of Operation								
	500	1000	2000	3000	4000	5000	6000	7000	8000
Power use (MWhr/yr)	250000	500000	1000000	1500000	2000000	2500000	3000000	3500000	4000000
t H2/yr	4,877	9,753	19,507	29,260	39,013	48,766	58,520	68,273	78,026
t H2/day	13.36	26.72	53.44	80.16	106.88	133.61	160.33	187.05	213.77
CAPEX ($/kg)	$ 13.53	$ 6.77	$ 3.38	$ 2.26	$ 1.69	$ 1.35	$ 1.13	$ 0.97	$ 0.85
OPEX ($/kg)	$ 5.12	$ 2.83	$ 1.69	$ 1.31	$ 1.11	$ 1.00	$ 0.92	$ 0.87	$ 0.83
Total ($/kg)	**$ 18.66**	**$ 9.60**	**$ 5.07**	**$ 3.56**	**$ 2.81**	**$ 2.35**	**$ 2.05**	**$ 1.84**	**$ 1.67**

LCOH - total [$/kg]		**Hours of Operation**								
		500	1000	2000	3000	4000	5000	6000	7000	8000
			1	2	3	4	5	6	7	8
CDN/MWh [includes delivery cost to site]	$0	$ 18.66	$ 9.60	$ 5.07	$ 3.56	$ 2.81	$ 2.35	$ 2.05	$ 1.84	$ 1.67
	$10	$ 19.17	$ 10.11	$ 5.58	$ 4.07	$ 3.32	$ 2.87	$ 2.56	$ 2.35	$ 2.19
	$20	$ 19.68	$ 10.63	$ 6.10	$ 4.59	$ 3.83	$ 3.38	$ 3.08	$ 2.86	$ 2.70
	$30	$ 20.20	$ 11.14	$ 6.61	$ 5.10	$ 4.34	$ 3.89	$ 3.59	$ 3.37	$ 3.21
	$40	$ 20.71	$ 11.65	$ 7.12	$ 5.61	$ 4.86	$ 4.40	$ 4.10	$ 3.89	$ 3.72
	$50	$ 21.22	$ 12.16	$ 7.63	$ 6.12	$ 5.37	$ 4.92	$ 4.61	$ 4.40	$ 4.24
	$60	$ 21.73	$ 12.68	$ 8.15	$ 6.64	$ 5.88	$ 5.43	$ 5.13	$ 4.91	$ 4.75
	$70	$ 22.25	$ 13.19	$ 8.66	$ 7.15	$ 6.40	$ 5.94	$ 5.64	**$ 5.42**	$ 5.26
	$80	$ 22.76	$ 13.70	$ 9.17	$ 7.66	$ 6.91	$ 6.45	$ 6.15	$ 5.94	$ 5.78
	$90	$ 23.27	$ 14.21	$ 9.69	$ 8.18	$ 7.42	$ 6.97	$ 6.67	$ 6.45	$ 6.29
	$100	$ 23.79	$ 14.73	$ 10.20	$ 8.69	$ 7.93	$ 7.48	$ 7.18	$ 6.96	$ 6.80
	$120	$ 24.81	$ 15.75	$ 11.22	$ 9.71	$ 8.96	$ 8.51	$ 8.20	$ 7.99	$ 7.83
	$140	$ 25.84	$ 16.78	$ 12.25	$ 10.74	$ 9.98	$ 9.53	$ 9.23	$ 9.01	$ 8.85
	$160	$ 26.86	$ 17.80	$ 13.27	$ 11.76	$ 11.01	$ 10.56	$ 10.25	$ 10.04	$ 9.88
	$180	$ 27.89	$ 18.83	$ 14.30	$ 12.79	$ 12.03	$ 11.58	$ 11.28	$ 11.06	$ 10.90
	$200	$ 28.91	$ 19.85	$ 15.32	$ 13.81	$ 13.06	$ 12.61	$ 12.30	$ 12.09	$ 11.93
	$220	$ 29.94	$ 20.88	$ 16.35	$ 14.84	$ 14.08	$ 13.63	$ 13.33	$ 13.11	$ 12.95
	$240	$ 30.96	$ 21.90	$ 17.37	$ 15.87	$ 15.11	$ 14.66	$ 14.36	$ 14.14	$ 13.98
	$260	$ 31.99	$ 22.93	$ 18.40	$ 16.89	$ 16.14	$ 15.68	$ 15.38	$ 15.16	$ 15.00

Avg hours operation per day								
1.4	2.7	5.5	8.2	11.0	13.7	16.4	19.2	21.9

Figure 70 illustrates the difficulty in achieving LCOH below \$5.00 / t H_2.

Figure 70 | LCOH visualization for Electrolysis production pathway across various electrolyzer sizes, electricity pricing, and operational hours



Electrolysis Sensitivity Charts – Future reduced economic assumptions

With the significant improvement in capital costs and electrolyser efficiencies, LCOH values below \$5.00 / kg H_2 can be achieved, though the ability to realize sub \$3.00 LCOH is very much dependent on low electrical pricing. With the improved efficiencies, electrolyzer sizes can be reduced to 3.5 MW, 35 MW, and 350 MW to achieve the targeted hydrogen production of 2.5 t/d, 25 t/d, and 250 t/d H_2.

Table 36 | Sensitivity analysis of LCOH for Electrolysis production pathway in 2050 considering electrolyzer size (3.5 MW), electricity pricing, and operational hours

Electrolysis 2050

	Elect. Size (MW)		$US/kWe	$CA/kWe					
	3.5	CAPEX	$ 670	$ 918	Effic (LHV)	85%			
	Load / Use Factor / Utilization								
	5.7%	11.4%	22.8%	34.2%	45.7%	57.1%	68.5%	79.9%	91.3%
LCOH - capex+ opex [$/kg]	Hours of Operation								
	500	1000	2000	3000	4000	5000	6000	7000	8000
Power use (MWhr/yr)	1750	3500	7000	10500	14000	17500	21000	24500	28000
t H2/yr	45	89	179	268	357	446	536	625	714
t H2/day	0.12	0.24	0.49	0.73	0.98	1.22	1.47	1.71	1.96
CAPEX ($/kg)	$ 10.63	$ 5.31	$ 2.66	$ 1.77	$ 1.33	$ 1.06	$ 0.89	$ 0.76	$ 0.66
OPEX ($/kg)	$ 4.11	$ 2.32	$ 1.42	$ 1.12	$ 0.97	$ 0.88	$ 0.82	$ 0.77	$ 0.74
Total ($/kg)	**$ 14.74**	**$ 7.63**	**$ 4.07**	**$ 2.89**	**$ 2.29**	**$ 1.94**	**$ 1.70**	**$ 1.53**	**$ 1.41**

LCOH - total [$/kg]

		Hours of Operation								
		500	1000	2000	3000	4000	5000	6000	7000	8000
			1	2	3	4	5	6	7	8
CDN/MWh [includes delivery cost to site]	$0	$ 14.74	$ 7.63	$ 4.07	$ 2.89	$ 2.29	$ 1.94	$ 1.70	$ 1.53	$ 1.41
	$10	$ 15.13	$ 8.02	$ 4.46	$ 3.28	$ 2.69	$ 2.33	$ 2.09	$ 1.92	$ 1.80
	$20	$ 15.53	$ 8.41	$ 4.86	$ 3.67	$ 3.08	$ 2.72	$ 2.49	$ 2.32	$ 2.19
	$30	$ 15.92	$ 8.81	$ 5.25	$ 4.06	$ 3.47	$ 3.12	$ 2.88	$ 2.71	$ 2.58
	$40	$ 16.31	$ 9.20	$ 5.64	$ 4.46	$ 3.86	$ 3.51	$ 3.27	$ 3.10	$ 2.97
	$50	$ 16.70	$ 9.59	$ 6.03	$ 4.85	$ 4.25	$ 3.90	$ 3.66	$ 3.49	$ 3.37
	$60	$ 17.09	$ 9.98	$ 6.43	$ 5.24	$ 4.65	$ 4.29	$ 4.05	$ 3.88	$ 3.76
	$70	$ 17.49	$ 10.37	$ 6.82	$ 5.63	$ 5.04	$ 4.68	$ 4.45	**$ 4.28**	$ 4.15
	$80	$ 17.88	$ 10.77	$ 7.21	$ 6.02	$ 5.43	$ 5.08	$ 4.84	$ 4.67	$ 4.54
	$90	$ 18.27	$ 11.16	$ 7.60	$ 6.42	$ 5.82	$ 5.47	$ 5.23	$ 5.06	$ 4.93
	$100	$ 18.66	$ 11.55	$ 7.99	$ 6.81	$ 6.21	$ 5.86	$ 5.62	$ 5.45	$ 5.33
	$120	$ 19.45	$ 12.33	$ 8.78	$ 7.59	$ 7.00	$ 6.64	$ 6.41	$ 6.24	$ 6.11
	$140	$ 20.23	$ 13.12	$ 9.56	$ 8.38	$ 7.78	$ 7.43	$ 7.19	$ 7.02	$ 6.89
	$160	$ 21.01	$ 13.90	$ 10.35	$ 9.16	$ 8.57	$ 8.21	$ 7.97	$ 7.81	$ 7.68
	$180	$ 21.80	$ 14.69	$ 11.13	$ 9.94	$ 9.35	$ 9.00	$ 8.76	$ 8.59	$ 8.46
	$200	$ 22.58	$ 15.47	$ 11.91	$ 10.73	$ 10.14	$ 9.78	$ 9.54	$ 9.37	$ 9.25
	$220	$ 23.37	$ 16.25	$ 12.70	$ 11.51	$ 10.92	$ 10.56	$ 10.33	$ 10.16	$ 10.03
	$240	$ 24.15	$ 17.04	$ 13.48	$ 12.30	$ 11.70	$ 11.35	$ 11.11	$ 10.94	$ 10.81
	$260	$ 24.93	$ 17.82	$ 14.27	$ 13.08	$ 12.49	$ 12.13	$ 11.89	$ 11.73	$ 11.60

Table 37 | Sensitivity analysis of LCOH for Electrolysis production pathway in 2050 considering electrolyzer size (35 MW), electricity pricing, and operational hours

Electrolysis 2050

Elect. Size (MW)		$US/kWe	$CA/kWe		
35	CAPEX	$ 670	$ 918	Effic (LHV)	85%

LCOH - capex+ opex [$/kg]

	Load / Use Factor / Utilization								
	5.7%	11.4%	22.8%	34.2%	45.7%	57.1%	68.5%	79.9%	91.3%
	Hours of Operation								
	500	1000	2000	3000	4000	5000	6000	7000	8000
Power use (MWhr/yr)	17500	35000	70000	105000	140000	175000	210000	245000	280000
t H2/yr	446	893	1,786	2,678	3,571	4,464	5,357	6,250	7,142
t H2/day	1.22	2.45	4.89	7.34	9.78	12.23	14.68	17.12	19.57
CAPEX ($/kg)	$ 7.97	$ 3.99	$ 1.99	$ 1.33	$ 1.00	$ 0.80	$ 0.66	$ 0.57	$ 0.50
OPEX ($/kg)	$ 3.22	$ 1.87	$ 1.19	$ 0.97	$ 0.85	$ 0.79	$ 0.74	$ 0.71	$ 0.69
Total ($/kg)	**$ 11.19**	**$ 5.85**	**$ 3.18**	**$ 2.29**	**$ 1.85**	**$ 1.58**	**$ 1.41**	**$ 1.28**	**$ 1.18**

LCOH - total [$/kg]

		Hours of Operation								
		500	1000	2000	3000	4000	5000	6000	7000	8000
			1	2	3	4	5	6	7	8
CDN/MWh [includes delivery cost to site]	$0	$ 11.19	$ 5.85	$ 3.18	$ 2.29	$ 1.85	$ 1.58	$ 1.41	$ 1.28	$ 1.18
	$10	$ 11.58	$ 6.24	$ 3.58	$ 2.69	$ 2.24	$ 1.98	$ 1.80	$ 1.67	$ 1.58
	$20	$ 11.97	$ 6.64	$ 3.97	$ 3.08	$ 2.63	$ 2.37	$ 2.19	$ 2.06	$ 1.97
	$30	$ 12.36	$ 7.03	$ 4.36	$ 3.47	$ 3.03	$ 2.76	$ 2.58	$ 2.45	$ 2.36
	$40	$ 12.75	$ 7.42	$ 4.75	$ 3.86	$ 3.42	$ 3.15	$ 2.97	$ 2.85	$ 2.75
	$50	$ 13.15	$ 7.81	$ 5.14	$ 4.25	$ 3.81	$ 3.54	$ 3.37	$ 3.24	$ 3.14
	$60	$ 13.54	$ 8.20	$ 5.54	$ 4.65	$ 4.20	$ 3.94	$ 3.76	$ 3.63	$ 3.54
	$70	$ 13.93	$ 8.60	$ 5.93	$ 5.04	$ 4.59	$ 4.33	$ 4.15	**$ 4.02**	$ 3.93
	$80	$ 14.32	$ 8.99	$ 6.32	$ 5.43	$ 4.99	$ 4.72	$ 4.54	$ 4.41	$ 4.32
	$90	$ 14.71	$ 9.38	$ 6.71	$ 5.82	$ 5.38	$ 5.11	$ 4.93	$ 4.81	$ 4.71
	$100	$ 15.11	$ 9.77	$ 7.10	$ 6.21	$ 5.77	$ 5.50	$ 5.33	$ 5.20	$ 5.10
	$120	$ 15.89	$ 10.56	$ 7.89	$ 7.00	$ 6.55	$ 6.29	$ 6.11	$ 5.98	$ 5.89
	$140	$ 16.67	$ 11.34	$ 8.67	$ 7.78	$ 7.34	$ 7.07	$ 6.89	$ 6.77	$ 6.67
	$160	$ 17.46	$ 12.12	$ 9.46	$ 8.57	$ 8.12	$ 7.86	$ 7.68	$ 7.55	$ 7.46
	$180	$ 18.24	$ 12.91	$ 10.24	$ 9.35	$ 8.91	$ 8.64	$ 8.46	$ 8.34	$ 8.24
	$200	$ 19.03	$ 13.69	$ 11.02	$ 10.14	$ 9.69	$ 9.42	$ 9.25	$ 9.12	$ 9.02
	$220	$ 19.81	$ 14.48	$ 11.81	$ 10.92	$ 10.47	$ 10.21	$ 10.03	$ 9.90	$ 9.81
	$240	$ 20.59	$ 15.26	$ 12.59	$ 11.70	$ 11.26	$ 10.99	$ 10.81	$ 10.69	$ 10.59
	$260	$ 21.38	$ 16.04	$ 13.38	$ 12.49	$ 12.04	$ 11.78	$ 11.60	$ 11.47	$ 11.38

Table 38 | Sensitivity analysis of LCOH for Electrolysis production pathway in 2050 considering electrolyzer size (350 MW), electricity pricing, and operational hours

Electrolysis 2050

Elect. Size (MW)		$US/kWe	$CA/kWe		
350	**CAPEX**	**$ 670**	**$ 918**	**Effic (LHV)**	85%

LCOH - capex+ opex [$/kg]

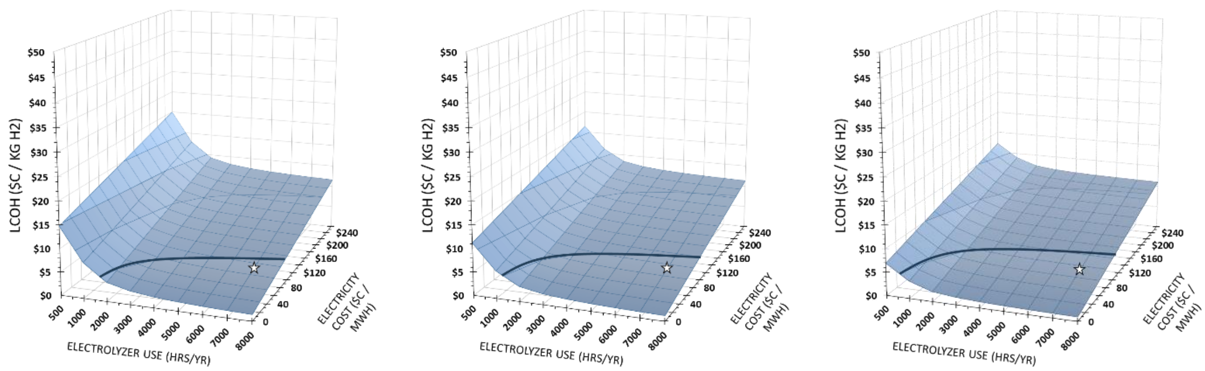
	Load / Use Factor / Utilization								
	5.7%	11.4%	22.8%	34.2%	45.7%	57.1%	68.5%	79.9%	91.3%
	Hours of Operation								
	500	1000	2000	3000	4000	5000	6000	7000	8000
Power use (MWhr/yr)	175000	350000	700000	1050000	1400000	1750000	2100000	2450000	2800000
t H2/yr	4,464	8,928	17,856	26,784	35,712	44,640	53,568	62,496	71,424
t H2/day	12.23	24.46	48.92	73.38	97.84	122.30	146.76	171.22	195.68
CAPEX ($/kg)	$ 4.78	$ 2.39	$ 1.20	$ 0.80	$ 0.60	$ 0.48	$ 0.40	$ 0.34	$ 0.30
OPEX ($/kg)	$ 2.14	$ 1.33	$ 0.92	$ 0.79	$ 0.72	$ 0.68	$ 0.65	$ 0.63	$ 0.62
Total ($/kg)	**$ 6.92**	**$ 3.72**	**$ 2.12**	**$ 1.58**	**$ 1.32**	**$ 1.16**	**$ 1.05**	**$ 0.97**	**$ 0.92**

LCOH - total [$/kg]

		Hours of Operation								
		500	1000	2000	3000	4000	5000	6000	7000	8000
			1	2	3	4	5	6	7	8
CDN/MWh [includes delivery cost to site]	$0	$ 6.92	$ 3.72	$ 2.12	$ 1.58	$ 1.32	$ 1.16	$ 1.05	$ 0.97	$ 0.92
	$10	$ 7.31	$ 4.11	$ 2.51	$ 1.98	$ 1.71	$ 1.55	$ 1.44	$ 1.37	$ 1.31
	$20	$ 7.70	$ 4.50	$ 2.90	$ 2.37	$ 2.10	$ 1.94	$ 1.83	$ 1.76	$ 1.70
	$30	$ 8.09	$ 4.89	$ 3.29	$ 2.76	$ 2.49	$ 2.33	$ 2.23	$ 2.15	$ 2.09
	$40	$ 8.49	$ 5.29	$ 3.68	$ 3.15	$ 2.88	$ 2.72	$ 2.62	$ 2.54	$ 2.48
	$50	$ 8.88	$ 5.68	$ 4.08	$ 3.54	$ 3.28	$ 3.12	$ 3.01	$ 2.93	$ 2.88
	$60	$ 9.27	$ 6.07	$ 4.47	$ 3.94	$ 3.67	$ 3.51	$ 3.40	$ 3.33	$ 3.27
	$70	$ 9.66	$ 6.46	$ 4.86	$ 4.33	$ 4.06	$ 3.90	$ 3.79	**$ 3.72**	$ 3.66
	$80	$ 10.05	$ 6.85	$ 5.25	$ 4.72	$ 4.45	$ 4.29	$ 4.19	$ 4.11	$ 4.05
	$90	$ 10.45	$ 7.25	$ 5.65	$ 5.11	$ 4.84	$ 4.68	$ 4.58	$ 4.50	$ 4.44
	$100	$ 10.84	$ 7.64	$ 6.04	$ 5.50	$ 5.24	$ 5.08	$ 4.97	$ 4.89	$ 4.84
	$120	$ 11.62	$ 8.42	$ 6.82	$ 6.29	$ 6.02	$ 5.86	$ 5.75	$ 5.68	$ 5.62
	$140	$ 12.41	$ 9.21	$ 7.61	$ 7.07	$ 6.81	$ 6.65	$ 6.54	$ 6.46	$ 6.40
	$160	$ 13.19	$ 9.99	$ 8.39	$ 7.86	$ 7.59	$ 7.43	$ 7.32	$ 7.25	$ 7.19
	$180	$ 13.97	$ 10.77	$ 9.17	$ 8.64	$ 8.37	$ 8.21	$ 8.11	$ 8.03	$ 7.97
	$200	$ 14.76	$ 11.56	$ 9.96	$ 9.42	$ 9.16	$ 9.00	$ 8.89	$ 8.81	$ 8.76
	$220	$ 15.54	$ 12.34	$ 10.74	$ 10.21	$ 9.94	$ 9.78	$ 9.67	$ 9.60	$ 9.54
	$240	$ 16.33	$ 13.13	$ 11.53	$ 10.99	$ 10.73	$ 10.57	$ 10.46	$ 10.38	$ 10.33
	$260	$ 17.11	$ 13.91	$ 12.31	$ 11.78	$ 11.51	$ 11.35	$ 11.24	$ 11.17	$ 11.11

From the tables above, Electrolysis can be seen to be very sensitive to electrical prices and cost for development. LCOH deteriorates rapidly after pricing of $100/MWh, thus is likely not a technology to be run on a continuous basis connected to the provincial grid. Electrolysis is likely best suited to an islanded generation where the delivered price can be kept low without inclusion of wire costs, or in situations where the process is run intermittently when the grid has very low power cost or in situations where the grid requires to shed generation due to low customer demand and is willing to forgo wire charges. Electrolysis is also very sensitive to capital investment and experiences high LCOH when run at low operating hours, such as those experienced in solar and wind generation supply.

Figure 71 | LCOH visualization for Electrolysis production pathway across various electrolyzer sizes, electricity pricing, and operational hours



Hydrogen as an Electricity System Resource

The following section provides more detailed information supporting our approach to analyzing hydrogen as an electricity system resource.

Levelized Cost of Electricity (LCOE)

The following equation outlines the calculation for the levelized cost of energy.

$$LCOE = \frac{(Overnight\ Capital\ Cost * Capital\ Recovery\ Factor + Fixed\ O\&M)}{Capacity * 8760 * Capacity\ Factor} + Fuel\ Cost * Heat\ Rate + Variable\ O\&M$$

The table below provides the costs and technical parameters used for the comparison. The costs used are for the 2050 vintage.

Table 39 | Assumed costs and technical parameters for levelized cost of generation comparison

Parameters	New Frame CT Plant	New H2 CCGT Plant	Gas CCS 95%	Nuclear
Capital Cost ($/kW)[1]	872	971	1,611	Various
FOM ($/kW-y)[1]	20.30	20.30	40.40	148
VOM ($/MWh)[1]	6.44	3.32	3.63	2
Heat Rate (MMBTU/kWh)[1]	10.38	6.36	6.85	
Discount Rate (%)[3]	8%			
Economic Life (years)[1]	30	30	30	60
Capacity (MW)[1]	100	500	500	200
Cost of capturing CO_2 ($/ton)[2]				52
H2 Heating Value (kWh/kg H2)[4]	33	33		
Natural Gas Emissions Factor (tCO_2/GWh)[5]			0.42	

Note: All costs are expressed in US$2021 unless otherwise stated. Values are inflated and converted to CAD$2024 using a 2021-2024 US inflation factor of 18% and a currency conversion factor of 1.3 CAD/US$.

1 (110)

2 (111)

3 (112)

4 (113)

5 (114)

Levelized Cost of Storage (LCOS)

Assumptions for the levelized cost of hydrogen storage are provided in the table below

Table 40 | Assumptions for the levelized cost of hydrogen storage

Capacity Factor (%)	15%
Hydrogen Price ($/kg)[1]	$2.5
Levelized cost of underground storage ($/kg)[1]	$0.20
Levelized cost of above-ground storage ($/kg)[2]	$0.90

1 (25)

2 (98)

The levelized cost of storage for other storage technologies is calculated as

$$LCOS = \frac{CAPEX + \frac{\sum_n^N OPEX}{(1+r)^n}}{\frac{\sum_n^N Energy\ Discharged}{(1+r)^n}}$$

where:

(1) $CAPEX = \ Rated\ Power * Capacity\ Cost\ \left(\frac{\$}{kW}\right) + Rated\ Power * Duration * Capacity\ Cost\ \left(\frac{\$}{kWh}\right) + \frac{\sum_n^N Replacement\ Cost}{(1+r)^n}$

(2) $OPEX = \frac{Rated\ Power * Opex\ Cost\ \left(\frac{\$}{kW}\right) + Energy\ Discharged * Opex\ Cost\left(\frac{\$}{kWh}\right)}{(1+r)^n}$

(3) $Energy\ Discharged = \ Capacity\ Factor * Rated\ Power * RTE * \sum_n^N (1 - Degradation)$

We assume a 15% capacity factor for calculating LCOS as a common benchmark for comparing the performance and economics of these storage technologies. A 15% capacity factor is representative of how storage will be used to manage the variability and intermittency of renewable energy sources.

The LCOS calculations exclude the expenses related to charging batteries or pumping water in the case of pumped hydro. This assumption is based on the idea that, for the same discharge duration, batteries will adhere to the same charging and discharging schedule, resulting in similar electricity prices. Consequently, the model computes the levelized cost of storing energy while assuming that total charging costs remain consistent across various storage technologies.

There is significant uncertainty surrounding the costs of these technologies, influenced by factors such as global deployment and learning curves. This analysis utilizes publicly available data on costs and performance parameters. **Table 40** provides assumptions used for calculating LCOS.

Table 40 | Assumed cost and technical parameters for levelized cost of storage comparison

Parameters	Li-ion	CAES	Vanadium Flow Battery	Pumped Hydro
Capex (USD/kW)	146[1]	1061[2]	113[2]	1100[3]
Capex (USD/kWh)	250[1]	6.31[2]	305[2]	50[3]
OPEX (USD/kW)	2.5% of Capex (USD/kW)	9.8[2]	8.1[2]	18.7[1]
OPEX (USD/kWh)	2.5% of Capex (USD/kWh)		1.1[2]	
Replacement USD/kW	50[3]	100[3]	90[3]	120[3]
Replacement USD/kWh	150[3]	0[3]	0[3]	
Replacement Interval	3.5[3]	1.5[3]	3.5[3]	7.5[3]
RTE	85%[1]	60%[3]	70%[3]	80%[1]
Capacity factor	15%			
Economic Life	20[1]	60[3]	20[2,3]	80[1,2]
Degradation	1%[3]		0.15%[3]	
Discount Rate	8%			
Capacity (MW)	100[4]	1000[4]	100[4]	800[4]

Note: All costs are expressed in US$2021 unless otherwise stated. Values are inflated and converted to CAD$2024 using a 2021-2024 US inflation factor of 18% and a currency conversion factor of 1.3 CAD/US$.

1.(115)

2.(116)

3.(117)

4.(118)

7. References

1. Independent Electricity System Operator. Pathways to Decarbonization [Internet]. 2022 [cited 2024 May 23]. Available from: https://www.ieso.ca/en/Learn/The-Evolving-Grid/Pathways-to-Decarbonization

2. Geofirma Engineering. Geological CO2 storage in southwestern Ontario: a roadmap for CCUS deployment in Ontario. CanmetEnergy Natural Resources Canada; 2023.

3. Government of Canada. Canada's official greenhouse gas inventory. [cited 2024 Jun 26]. ECCC Data Catalogue / Catalogue de données d'ECCC. Available from: https://data-donnees.az.ec.gc.ca/data/substances/monitor/canada-s-official-greenhouse-gas-inventory/A-IPCC-Sector/?lang=en

4. Mazloomi K, Gomes C. Hydrogen as an energy carrier: Prospects and challenges. Renew Sustain Energy Rev. 2012 Jun 1;16(5):3024–33.

5. ATCO. Fort Saskatchewan Hydrogen Blending Project [Internet]. [cited 2024 May 28]. Available from: https://gas.atco.com/en-ca/community/projects/fort-saskatchewan-hydrogen-blending-project.html

6. Atura Power. Atura Power. 2023 [cited 2024 May 23]. Niagara Hydrogen Centre. Available from: https://aturapower.com/our-projects/hydrogen/niagara-hydrogen-centre/

7. Canadian Hydrogen Association. Hydrogen's Role in Decarbonizing the Steelmaking Industry: Insights from the 'Hydrogen and Decarbonization of Steel Production in Canada' Report [Internet]. Canadian Hydrogen Association. 2023 [cited 2024 May 28]. Available from: https://canadah2.ca/hydrogens-role-in-decarbonizing-the-steelmaking-industry-insights-from-the-hydrogen-and-decarbonization-of-steel-production-in-canada-report/

8. U.S. Department of Energy. U.S. Department of Energy Clean Hydrogen Production Standard (CHPS) Guidance. 2023; Available from: https://www.hydrogen.energy.gov/docs/hydrogenprogramlibraries/pdfs/clean-hydrogen-production-standard-guidance.pdf?sfvrsn=173e9756_1

9. Gregor Erbach, Sara Svensson. EU rules for renewable hydrogen. 2023 Apr;

10. Natural Resources Canada. The Hydrogen Strategy [Internet]. Natural Resources Canada; 2020 [cited 2024 May 23]. Available from: https://natural-resources.canada.ca/climate-change/canadas-green-future/the-hydrogen-strategy/23080

11. IEA. IEA. 2023 [cited 2024 Jun 5]. Comparison of the emissions intensity of different hydrogen production routes, 2021. Available from: https://www.iea.org/data-and-statistics/charts/comparison-of-the-emissions-intensity-of-different-hydrogen-production-routes-2021

12. B.C. Centre for Innovation and Clean Energy, B.C. Hydrogen Office, B.C. Ministry of Energy, Mines and Low Carbon Innovation, Deloitte Canada, (S&T)2 Consultants Inc. B.C. Centre for Innovation and Clean Energy. 2023 [cited 2024 Jun 24]. Carbon Intensity of Hydrogen Production Methods Report. Available from: https://cice.ca/knowledge-hub/carbon-intensity-of-hydrogen-production-methods-report/

13. Benziger JB, Satterfield MB, Hogarth WHJ, Nehlsen JP, Kevrekidis IG. The power performance curve for engineering analysis of fuel cells. J Power Sources. 2006 Apr 21;155(2):272–85.

14. Ramsden T, Ruth M, Diakov V, Laffen M, Timbario TA. Hydrogen Pathways: Updated Cost, Well-to-Wheels Energy Use, and Emissions for the Current Technology Status of Ten Hydrogen Production, Delivery, and Distribution Scenarios [Internet]. 2013 Mar [cited 2024 May 23] p. NREL/TP-6A10-60528, 1107463. Report No.: NREL/TP-6A10-60528, 1107463. Available from: http://www.osti.gov/servlets/purl/1107463/

15. Rob Cockerill. Electrolyser technologies.

16. B.C. Centre for Innovation and Clean Energy. The Potential for Methane Pyrolysis in B.C. [Internet]. 2024. Available from: https://cice.ca/knowledge-hub/the-potential-for-methane-pyrolysis-in-b-c-report/

17. Khan MA, Young C, Layzell DB. The Techno- Economics of Hydrogen Pipelines. 2021;1(2). Available from: https://transitionaccelerator.ca/wp-content/uploads/2023/06/The-Techno-Economics-of-Hydrogen-Pipelines-v2.pdf

18. OECD. Risk-based Regulatory Design for the Safe Use of Hydrogen [Internet]. OECD; 2023 [cited 2024 Jun 21]. Available from: https://www.oecd-ilibrary.org/governance/risk-based-regulatory-design-for-the-safe-use-of-hydrogen_46d2da5e-en

19. BloombergNEF. New Energy Outlook 2024 [Internet]. BloombergNEF. 2024 [cited 2024 Jun 4]. Available from: https://about.bnef.com/new-energy-outlook/

20. U.S. Department of Energy. DOE National Clean Hydrogen Strategy and Roadmap. 2022 Sep; Available from: https://www.hydrogen.energy.gov/docs/hydrogenprogramlibraries/pdfs/clean-hydrogen-strategy-roadmap.pdf?Status=Master

21. European Commission (EU). A hydrogen strategy for a climate-neutral Europe [Internet]. 2020 [cited 2024 May 31]. Available from: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52020DC0301

22. Canada Energy Regulator. Canada’s Energy Future 2023: Energy Supply and Demand Projections to 2050. 2023; Available from: https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2023/canada-energy-futures-2023.pdf

23. Khan MA, MacKinnon C, Eng P, Young C, Eng P, Layzell DB. Techno-Economics of a New Hydrogen Value Chain Supporting Heavy Duty Transport. 2022;4(5).

24. Bentley Allan, Jonas Goldman, Geoff Tauvette. The C-SAF Roadmap: Building a feedstocks-to-fuels SAF supply chain in Canada [Internet]. Canadian Council for Sustainable Aviation Fuels (C-SAF); 2023. Available from: https://transitionaccelerator.ca/wp-content/uploads/2023/07/CSAF_Roadmap_Full_Report_Digital-1.pdf

25. Khan MA, Powell M, Tampier M, Corthay E, Layzell D. Hydrogen and the Decarbonization of Steel Production in Canada: Reaching Economies of Scale [Internet]. Transition Accelerator; 2023 [cited 2024 May 28]. Available from: https://transitionaccelerator.ca/reports/hydrogen-and-the-decarbonization-of-steel-production-in-canada/

26. Layzell DB, Millington D, Lee R. Towards a Fuel Hydrogen Economy in the Calgary Region: A Feasibility Study. Transit Accel Rep [Internet]. 2023;5. Available from: https://transitionaccelerator.ca/wp-content/uploads/2023/05/TA-Report-5.1_Towards-a-Fuel-Hydrogen-Economy-in-the-Calgary-Region.pdf

27. U.S. Department of Energy. Office of Energy Efficiency & Renewable Energy. [cited 2024 Jun 4]. Comparison of Fuel Cell Technologies. Available from: https://www.energy.gov/eere/fuelcells/comparison-fuel-cell-technologies

28. U.S. Department of Energy. Office of Energy Efficiency & Renewable Energy. 2016 [cited 2024 Jun 4]. Gas Turbines (DOE CHP Technology Fact Sheet Series) – Fact Sheet, 2016. Available from: https://www.energy.gov/eere/amo/articles/gas-turbines-doe-chp-technology-fact-sheet-series-fact-sheet-2016

29. Ontario Government. Ontario's Low-Carbon Hydrogen Strategy [Internet]. 2022 [cited 2024 May 23]. Available from: http://www.ontario.ca/page/ontarios-low-carbon-hydrogen-strategy

30. Sarnia-Lambton Economic Partnership. Sarnia-Lambton Economic Partnership. 2022 [cited 2024 May 23]. Strategic Plan Ontario's Hydrogen Hub in Sarnia-Lambton. Available from: https://www.sarnialambton.on.ca/hydrogen-hub

31. H2GO Canada. Hydrogen Village. 2023 [cited 2024 May 23]. Forecasting Low-Carbon Hydrogen Market Characteristics in Ontario to 2050. Available from: https://hydrogenvillage.ca/h2go

32. Arjun Makhijani Ph.D., Thom Hersbach Ph.D. IEER. 2024 [cited 2024 Jun 24]. Water requirements for various approaches to hydrogen production. Available from: https://ieer.org/wp/wp-content/uploads/2024/01/Water-requirements-for-hydrogen-production-January-2024.pdf

33. Arup, Department of Climate Change, Energy, the Environment and Water (DCCEEW), Australian Hydrogen Council (AHC). Water for Hydrogen. Dep Clim Change Energy Environ Water Aust Hydrog Counc [Internet]. 2022 Nov 14 [cited 2024 Jun 24]; Available from: https://h2council.com.au/wp-content/uploads/2023/02/221114-Arup-Technical-paper-Water-for-Hydrogen-report-FINAL.pdf

34. Dr. P. Kim Sturgess, C.M., P.Eng., FCAE. Study of Water Impacts of Hydrogen Development in Alberta. Alta Innov [Internet]. 2023 Jun 8; Available from: https://watersmartsolutions.ca/wp-content/uploads/2023/06/WaterSMART_Hydrogen-Study_Report_V1.pdf

35. Jon Fennell, M.Sc., Ph.D., P.Geol., Mohammed Awad, P.Eng., Adam Leece, M.Sc., P.Eng. Hydrogen Production Water Management: Understanding the Challenges [Internet]. Integrated Sustainability. 2024 [cited 2024 Jun 24]. Available from: https://www.integratedsustainability.com/insights/water/hydrogen-production-water-management/

36. Océane Mbaguta, Lines J, Brandwood R, McCann P, Booth M-J. A Review Of Water Use For Hydrogen Production. Jt Environ Programme JEP [Internet]. 2023; Available from: https://www.energy-uk.org.uk/wp-content/uploads/2023/03/2022_PSP_EC_2957.pdf

37. Rain Saulnier, BSc, MASc, Keith Minnich, P.Eng, Dr. P. Kim Sturgess, C.M., P.Eng., FCA. Water for the Hydrogen Economy [Internet]. 2020 [cited 2024 Jun 24]. Available from: https://watersmartsolutions.ca/wp-content/uploads/2020/12/Water-for-the-Hydrogen-Economy_WaterSMART-Whitepaper_November-2020.pdf

38. ETH Zurich. ScienceDaily. 2024 [cited 2024 May 30]. Cost of direct air carbon capture to remain higher than hoped. Available from: https://www.sciencedaily.com/releases/2024/03/240304135808.htm

39. E3. Hydrogen Opportunities in a Low-Carbon Future: An Assessment Of Long-Term Market Potential in the Western United States [Internet]. 2020 [cited 2024 Jun 26]. Available from: https://www.ethree.com/wp-content/uploads/2020/07/E3_MHPS_Hydrogen-in-the-West-Report_Final_June2020.pdf

40. Government of Ontario. Ontario energy snapshot [Internet]. 2024 [cited 2024 Jun 25]. Available from: http://www.ontario.ca/page/ontario-energy-snapshot

41. Enbridge. Pathways to Net Zero Emissions for Ontario. 2022;39.

42. Government of Ontario. Water Taking - Dataset - Ontario Data Catalogue [Internet]. 2022 [cited 2024 Jun 6]. Available from: https://data.ontario.ca/dataset/water-taking

43. Environment and Climate Change Canada. Water availability: indicator initiative [Internet]. 2017 [cited 2024 Jun 6]. Available from: https://www.canada.ca/en/environment-climate-change/services/water-overview/quantity/availability-indicator-initiative.html

44. Felder M, Hervas A, Noyahr C. Evaluation of carbon capture and storage potential in Canada. Clean Prosper Net-Zero Pathw Can Proj [Internet]. 2024 Apr; Available from: https://cleanprosperity.ca/wp-content/uploads/2024/04/Evaluation_of_carbon_capture_and_storage_potential_in_Canada.pdf

45. Government of Canada CER. CER – Provincial and Territorial Energy Profiles – Ontario [Internet]. 2024 [cited 2024 May 31]. Available from: https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/provincial-territorial-energy-profiles/provincial-territorial-energy-profiles-ontario.html

46. Government of Canada. Canada Gazette, Part 1, Volume 1, Number 1: Clean Electricity Regulations [Internet]. Government of Canada, Public Works and Government Services Canada, Integrated Services Branch, Canada Gazette; 2023 [cited 2024 Jun 4]. Available from: https://www.gazette.gc.ca/rp-pr/p1/2023/2023-08-19/html/reg1-eng.html

47. DeSantis D, James BD, Houchins C, Saur G, Lyubovsky M. Cost of long-distance energy transmission by different carriers. iScience. 2021 Dec 17;24(12):103495.

48. U.S. Department of Energy. Alternative Fuels Data Center: Charging Electric Vehicles at Home [Internet]. [cited 2024 May 23]. Available from: https://afdc.energy.gov/fuels/electricity-charging-home

49. Deng J, Bae C, Denlinger A, Miller T. Electric Vehicles Batteries: Requirements and Challenges. Joule. 2020 Mar 18;4(3):511–5.

50. U.S. Department of Transportation. Implementation Challenges and Evolving Solutions for Rural Communities | US Department of Transportation [Internet]. 2023 [cited 2024 May 23]. Available from: https://www.transportation.gov/rural/ev/toolkit/ev-benefits-and-challenges/challenges-and-evolving-solutions

51. NIST Weights and Measures. Frequently Asked Questions about Commercial Hydrogen Vehicle Refueling. 2019 Sep; Available from: https://www.nist.gov/system/files/documents/2020/03/23/nist_h2_faqs-final-03oct2019-h2_website.pdf

52. U.S. Department of Energy. Alternative Fuels Data Center: Fuel Cell Electric Vehicles [Internet]. [cited 2024 May 23]. Available from: https://afdc.energy.gov/vehicles/fuel-cell

53. U.S. Department of Energy. Diesel Vehicles [Internet]. [cited 2024 May 23]. Available from: https://www.fueleconomy.gov/feg/di_diesels.shtml

54. Kusoglu A, Million Mile Fuel Cell Truck Consortium, Lawrence Berkeley National Laboratory. Decarbonizing Heavy -Duty Vehicles. Renew ENERGY [Internet]. 2023 Sep 21; Available from: https://www.energy.gov/sites/default/files/2023-10/h2iqhour-09212023.pdf

55. Aryanpur V, Rogan F. Decarbonising road freight transport: The role of zero-emission trucks and intangible costs. Sci Rep. 2024 Jan 24;14(1):2113.

56. Cunanan C, Tran MK, Lee Y, Kwok S, Leung V, Fowler M. A Review of Heavy-Duty Vehicle Powertrain Technologies: Diesel Engine Vehicles, Battery Electric Vehicles, and Hydrogen Fuel Cell Electric Vehicles. Clean Technol. 2021 Jun;3(2):474–89.

57. Ontario Government. news.ontario.ca. 2023 [cited 2024 May 23]. Ontario Launching Electric Vehicle GO Bus Service. Available from: https://news.ontario.ca/en/release/1003042/ontario-launching-electric-vehicle-go-bus-service

58. Eudy L, Post M. Fuel Cell Buses in U.S. Transit Fleets: Current Status 2020. Natl Renew Energy Lab [Internet]. 2021; Available from: https://www.nrel.gov/docs/fy21osti/75583.pdf

59. Brett Bundale. CTV News. 2021 [cited 2024 May 23]. Greyhound Canada to cut all routes, end operations. Available from: https://www.ctvnews.ca/business/greyhound-canada-to-cut-all-routes-end-operations-1.5426464?cache=a%2Bhref

60. Natural Resources Canada. Comprehensive Energy Use Database, Transportation Sector, Table 16 [Internet]. Government of Canada, Natural Resources Canada; 2024 [cited 2024 May 23]. Available from: https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/showTable.cfm?type=CP&sector=tran&juris=on&year=2021&rn=16&page=0

61. Kelly Cryderman. A different kind of steam engine: How CPKC aims to decarbonize its fleet with hydrogen locomotives. The Globe and Mail [Internet]. 2024 Apr 1 [cited 2024 May 23]; Available from: https://www.theglobeandmail.com/business/article-hydrogen-trains-cpkc/

62. Smith K. International Railway Journal. 2021 [cited 2024 May 23]. CN purchases FLXdrive battery-electric freight locomotive. Available from: https://www.railjournal.com/locomotives/cn-purchases-flxdrive-battery-electric-freight-locomotive/

63. Hamilton Oshawa Port Authority. Port of Hamilton [Internet]. HOPA Ports. [cited 2024 May 23]. Available from: https://www.hopaports.ca/locations/port-of-hamilton/

64. Natural Resources Canada. Ammonia shows promise as fuel for hard-to-decarbonize sectors [Internet]. 2023 [cited 2024 May 23]. Available from: https://nrc.canada.ca/en/stories/ammonia-shows-promise-fuel-hard-decarbonize-sectors

65. Raucci C., McKinlay C., Karan A. Lloyd's Register Maritime Decarbonisation Hub. 2023 [cited 2024 May 23]. The future of maritime fuels. What you need to know. Available from: https://maritime.lr.org/l/941163/2023-09-04/86cyj/941163/1693881339KV19NyGO/LR_Fuel_Mix_Report_v1.pdf

66. Yara. Yara. 2023 [cited 2024 May 23]. The world's first clean ammonia-powered container ship. Available from: https://www.yara.com/corporate-releases/the-worlds-first-clean-ammonia-powered-container-ship/

67. Čučuk A. New zero-emission hydrogen-powered vessel to ship goods on Rhine [Internet]. Offshore Energy. 2024 [cited 2024 May 23]. Available from: https://www.offshore-energy.biz/new-zero-emission-hydrogen-powered-vessel-to-ship-goods-on-rhine/

68. Holtze B. World's first hydrogen-powered ship is powered by Ballard fuel cells [Internet]. 2023 [cited 2024 May 23]. Available from: https://blog.ballard.com/marine/worlds-first-liquid-powered-hydrogen-ship-mf-hydra-is-powered-by-ballards-fuel-cells

69. HySeas III. The HySeasIII Project [Internet]. [cited 2024 May 23]. Available from: https://www.hyseas3.eu/the-project/

70. Enbridge. Enbridge Natural Gas Storage. 2023; Available from: https://www.enbridge.com/~/media/Enb/Documents/Factsheets/FS_Natural_Gas_Storage.pdf?rev=5cff1271c85249618c56ecb214ccd273&hash=4A38C69D626CA1C1DA103B9F220646A2

71. Canada Energy Regulator. CER – Market Snapshot: Growing heat pump adoption – how does the technology work? [Internet]. 2023 [cited 2024 May 23]. Available from: https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/market-snapshots/2019/market-snapshot-growing-heat-pump-adoption-how-does-technology-work.html

72. Natural Resources Canada. Heating and Cooling With a Heat Pump [Internet]. Natural Resources Canada; 2022 [cited 2024 May 23]. Available from: https://natural-resources.canada.ca/energy-efficiency/energy-star-canada/about/energy-star-announcements/publications/heating-and-cooling-heat-pump/6817

73. Natural Resources Canada. Comprehensive Energy Use Database, Residential Sector, Table 38 [Internet]. Government of Canada, Natural Resources Canada; 2024 [cited 2024 May 23]. Available from: https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/showTable.cfm?type=CP&sector=res&juris=on&year=2021&rn=38&page=0

74. Natural Resources Canada. Why use a heat pump? [Internet]. Natural Resources Canada; 2023 [cited 2024 May 27]. Available from: https://natural-resources.canada.ca/energy-efficiency/homes/canada-greener-homes-initiative/oil-heat-pump-affordability-program/why-use-heat-pump/24914

75. Casey Crownhart. MIT Technology Review. 2023 [cited 2024 May 23]. This unlikely fuel could power cleaner trucks and ships. Available from: https://www.technologyreview.com/2023/06/08/1074284/unlikely-fuel-power-trucks-ships/

76. IEA. The Role of Critical Minerals in Clean Energy Transitions – Analysis [Internet]. 2021 [cited 2024 May 27]. Available from: https://www.iea.org/reports/the-role-of-critical-minerals-in-clean-energy-transitions

77. Beauchemin A. Is the future of mining electric? As mines transition equipment, new risks emerge. CBC News [Internet]. 2023 Apr 29 [cited 2024 May 27]; Available from: https://www.cbc.ca/news/climate/electric-mining-equipment-1.6825671

78. Chen A. The world's first hydrogen-powered haul truck could help clean up the mining industry. CNN [Internet]. 2022 Oct 6 [cited 2024 May 27]; Available from: https://www.cnn.com/2022/10/06/world/hydrogen-mining-truck-first-mode-anglo-american-climate-spc-intl/index.html

79. Carvalho D. Beyond electricity: is hydrogen the key to greener smelting and refining? | Wood Mackenzie [Internet]. 2023 [cited 2024 May 28]. Available from: https://www.woodmac.com/news/opinion/beyond-electricity-is-hydrogen-the-key-to-greener-smelting-and-refining/

80. Komatsu. Komatsu develops medium-sized hydraulic excavator concept machine with a hydrogen fuel cell [Internet]. 2023 [cited 2024 May 23]. Available from: https://www.komatsu.com/en/newsroom/2023/hydraulic-excavator-concept-with-hydrogen-fuel-cell/

81. UK Department of Transport. GOV.UK. 2023 [cited 2024 May 23]. World's first hydrogen-powered digger set to drive on UK roads. Available from:

https://www.gov.uk/government/news/worlds-first-hydrogen-powered-digger-set-to-drive-on-uk-roads

82. Veidekke. Veidekke: The world's first asphalt plant on hydrogen [Internet]. 2023 [cited 2024 May 23]. Available from: https://www.veidekke.com/investor-relations/company-disclosures/veidekke-the-worlds-first-asphalt-plant-on-hydrogen/

83. World Steel Association. World Steel Assocation. 2022 [cited 2024 May 23]. Fact Sheet: Hydrogen (H2)-based ironmaking. Available from: https://worldsteel.org/wp-content/uploads/Fact-sheet-Hydrogen-H2-based-ironmaking.pdf

84. Casey Crownhart. MIT Technology Review. 2022 [cited 2024 May 23]. How green steel made with electricity could clean up a dirty industry. Available from: https://www.technologyreview.com/2022/06/28/1055027/green-steel-electricity-boston-metal/

85. Primetals Technologies. Spectra. 2024 [cited 2024 May 28]. The three phases to green steel production. Available from: https://spectra.mhi.com/the-three-phases-to-green-steel-production

86. Friedmann SJ, Fan Z, Tang K. Low-Carbon Heat Solutions for Heavy Industry: Sources, Options, and Costs Today. Columbia Cent Glob Energy Policy [Internet]. 2019 Oct; Available from: https://www.energypolicy.columbia.edu/wp-content/uploads/2019/10/LowCarbonHeat-CGEP_Report_111722.pdf

87. Cement Association of Canada. Concrete Zero - Canada's cement and concrete industry action plan to net-zero [Internet]. 2023. Available from: https://cement.ca/wp-content/uploads/2023/05/ConcreteZero-Report-FINAL-reduced.pdf

88. American Chemical Council. Hydrogen & The Chemical Industry [Internet]. 2023. Available from: https://www.americanchemistry.com/content/download/14690/file/Hydrogen-and-the-Chemical-Industry.pdf

89. Eric Lewis, Shannon McNaul, Matthew Jamieson, Megan S. Henriksen, H. Scott Matthews, John White, et al. Comparison of Commercial, State-of-the-Art, Fossil-Based Hydrogen Production Technologies. Natl Energy Technol Lab [Internet]. 2022 Apr 12; Available from: https://netl.doe.gov/projects/files/ComparisonofCommercialStateofArtFossilBasedHydrogenProductionTechnologies_041222.pdf

90. Katebah M, Al-Rawashdeh M, Linke P. Analysis of hydrogen production costs in Steam-Methane Reforming considering integration with electrolysis and CO2 capture. 2022 Oct 1 [cited 2024 Jun 24]; Available from: https://manara.qnl.qa/articles/journal_contribution/Analysis_of_hydrogen_production_costs_in_Steam-Methane_Reforming_considering_integration_with_electrolysis_and_CO_sub_2_sub_capture/24551461/1

91. Oni AO, Anaya K, Giwa T, Di Lullo G, Kumar A. Comparative assessment of blue hydrogen from steam methane reforming, autothermal reforming, and natural gas decomposition technologies for natural gas-producing regions. Energy Convers Manag. 2022 Feb 15;254:115245.

92. Zapantis A. Blue Hydrogen. Glob CCS Inst [Internet]. 2021 Apr; Available from: https://www.globalccsinstitute.com/wp-content/uploads/2021/04/CCE-Blue-Hydrogen.pdf

93. Adam Christensen. Assessment of Hydrogen Production Costs from Electrolysis: United States and Europe [Internet]. International Council on Clean Transportation. 2020 [cited 2024 Jun 24]. Available from: https://theicct.org/publication/assessment-of-hydrogen-production-costs-from-electrolysis-united-states-and-europe/

94. Aliaksei Patonia, Rahmatallah Poudineh. Cost-competitive green hydrogen: how to lower the cost of electrolysers? Oxf Inst Energy Stud [Internet]. 2022 Jan [cited 2024 Jun 24]; Available from: https://www.oxfordenergy.org/wpcms/wp-content/uploads/2022/01/Cost-competitive-green-hydrogen-how-to-lower-the-cost-of-electrolysers-EL47.pdf

95. Amini Horri B, Ozcan H. Green hydrogen production by water electrolysis: Current status and challenges. Curr Opin Green Sustain Chem. 2024 Jun 1;47:100932.

96. David Layzell, Jonathan Leary, Jessica Lof, Song Sit, Cameron Young. Towards Net-Zero Energy Systems In Canada: A Key Role For Hydrogen [Internet]. The Transition Accelerator. 2020 [cited 2024 Jun 24]. Available from: https://transitionaccelerator.ca/reports/towards-net-zero-energy-systems-in-canada-a-key-role-for-hydrogen/

97. El-Shafie M. Hydrogen production by water electrolysis technologies: A review. Results Eng. 2023 Dec 1;20:101426.

98. Frank Graves, Josh Figueroa, Ragini Sreenath, Lorenzo Sala, Jadon Grove, Stephen Thumb. Emerging Economics of Hydrogen Production and Delivery. Brattle [Internet]. 2024 Feb; Available from: https://www.brattle.com/wp-content/uploads/2024/02/Emerging-Economics-of-Hydrogen-Production-and-Delivery-2-2024.pdf

99. María Villarreal Vives A, Wang R, Roy S, Smallbone A. Techno-economic analysis of large-scale green hydrogen production and storage. Appl Energy. 2023 Sep 15;346:121333.

100. Marius Holst, Stefan Aschbrenner, Tom Smolinka, Christopher Voglstätter, Gunter Grimm. Fraunhofer Institute for Solar Energy Systems ISE. 2021 [cited 2024 Jun 24]. Cost Forecast for Low Temperature Electrolysis – Technology Driven Bottom-Up Prognosis for PEM and Alkaline Water Electrolysis Systems. Available from: https://www.ise.fraunhofer.de/en/publications/studies/catf.html

101. Nami H, Rizvandi OB, Chatzichristodoulou C, Hendriksen PV, Frandsen HL. Techno-economic analysis of current and emerging electrolysis technologies for green hydrogen production. Energy Convers Manag. 2022 Oct 1;269:116162.

102. Rizwan M, Alstad V, Jäschke J. Design considerations for industrial water electrolyzer plants. Int J Hydrog Energy. 2021 Oct 29;46(75):37120–36.

103. Schmidt O, Gambhir A, Staffell I, Hawkes A, Nelson J, Few S. Future cost and performance of water electrolysis: An expert elicitation study. Int J Hydrog Energy. 2017 Dec 28;42(52):30470–92.

104. Shaner MR, Atwater HA, Lewis NS, McFarland EW. A comparative technoeconomic analysis of renewable hydrogen production using solar energy. Energy Environ Sci. 2016 Jul 6;9(7):2354–71.

105. Shiva Kumar S, Lim H. An overview of water electrolysis technologies for green hydrogen production. Energy Rep. 2022 Nov 1;8:13793–813.

106. Tong W, Forster M, Dionigi F, Dresp S, Sadeghi Erami R, Strasser P, et al. Electrolysis of low-grade and saline surface water. Nat Energy [Internet]. 2021 Sep 1;6. Available from: https://researchrepository.universityofgalway.ie/entities/publication/efecba5c-f489-46ef-ac95-c8d3d68c6348

107. Urs RR, Chadly A, Al Sumaiti A, Mayyas A. Techno-economic analysis of green hydrogen as an energy-storage medium for commercial buildings. Clean Energy. 2023 Feb 1;7(1):84–98.

108. Yang B, Zhang R, Shao Z, Zhang C. The economic analysis for hydrogen production cost towards electrolyzer technologies: Current and future competitiveness. Int J Hydrog Energy. 2023 Apr 30;48(37):13767–79.

109. Yates J, Daiyan R, Patterson R, Egan R, Amal R, Ho-Baille A, et al. Techno-economic Analysis of Hydrogen Electrolysis from Off-Grid Stand-Alone Photovoltaics Incorporating Uncertainty Analysis. Cell Rep Phys Sci [Internet]. 2020 Oct 21 [cited 2024 Jun 24];1(10). Available from: https://www.cell.com/cell-reports-physical-science/abstract/S2666-3864(20)30224-1

110. National Renewable Energy Laboratory (NREL). Electricity Annual Technology Baseline (ATB) Data [Internet]. 2023 [cited 2024 May 30]. Available from: https://atb.nrel.gov/electricity/2023/2023/data

111. BloombergNEF. BloombergNEF. 2024 [cited 2024 May 30]. Capture Cost Model High-Concentration Sources (CCHS 1.0.2). Available from: https://www.bnef.com/insights/31207

112. Khan MA, Young C, Mackinnon C, Layzell DB. The Techno-Economics of Hydrogen Compression. Transit Accel Tech Briefs [Internet]. 2021;1(1). Available from: https://transitionaccelerator.ca/wp-content/uploads/2023/04/TA-Technical-Brief-1.1_TEEA-Hydrogen-Compression_PUBLISHED.pdf

113. National Research Council and National Academy of Engineering. The Hydrogen Economy: Opportunities, Costs, Barriers, and R&D Needs [Internet]. The National Academies Press; 2004 [cited 2024 Jun 3]. Available from: https://nap.nationalacademies.org/read/10922/chapter/21

114. Environment and Climate Change Canada. National Inventory Report 1990-2021: Greenhouse Gas Sources and Sinks in Canada Part 3 [Internet]. 2023 [cited 2024 Jun 3]. Available from: https://publications.gc.ca/collections/collection_2023/eccc/En81-4-2021-3-eng.pdf

115. Viswanathan V, Mongird K, Franks R, Li X, Sprenkle V. 2022 Grid Energy Storage Technology Cost and Performance Assessment. US Dep Energy [Internet]. 2022; Available from: https://www.energy.gov/sites/default/files/2022-09/2022%20Grid%20Energy%20Storage%20Technology%20Cost%20and%20Performance%20Assessment.pdf

116. PNNL. Energy Storage Cost and Performance Database. [cited 2024 Jun 26]. Pacific Northwest National Laboratory | PNNL. Available from: https://www.pnnl.gov/

117. Mulder S, Klein S. Techno-Economic Comparison of Electricity Storage Options in a Fully Renewable Energy System. Energies. 2024 Jan;17(5):1084.

118. National Renewable Energy Laboratory (NREL). 2022 Grid Energy Storage and Technology Assessment. 2022;