# Hydrogen Integrated Greenhouse Horticultural (HIGH) Energy | Part 2: Considerations for an Ontario Hydrogen Energy Market

University of Windsor

2024-11-29

Jamie C. Smith, Kayes Md Abu Reza, Ivailo Petrov, Matt Davison, David Ting, Rupp Carriveau

Version 1.2

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 University of Windsor.*

# Table of Contents

# 1. Executive Summary

This study aims to establish the current state of the hydrogen market and develop an offer curve for electricity from $H_2$ fueled turbines. An IESO regulatory review was performed to establish how wind farm hybridization could fit into the province's electrical grid. Alternative means of providing peak generation & storage have been analyzed from the perspective of their technical and economic performance.

# 2. Introduction and Goal

## 2.1 Toward a Thriving Hydrogen Marketplace

### 2.1.1 Hydrogen Marketplace Preamble

A prime driver for considering the use of hydrogen is to reduce emission of greenhouse gases by burning hydrocarbons to drive our industrial economy. The increase of greenhouse gases in the atmosphere is recognized to be the major driver of global warming, with associated negative impacts now understood and at least partially quantified. An approach introduced by Economics Nobel Laureate William Nordhaus is the 'social cost of carbon.' In this approach, the present value of all incremental costs arising from the emission of an incremental tonne of $CO_2$ are estimated. Clearly this is a challenging task with a final answer dependent on many parameters. However, a 2019 meta-study of the literature by Wang et al. [1] reported that the average of such social cost of carbon dioxide was about US$200 per tonne, albeit with considerable variability around that mean. As **Table 1** shows, the government of Canada currently taxes carbon at C$80 (about US$60) per tonne $CO_2$, with plans to raise this tax to C$170 (US$125) by the year 2030.

Table 1 **|** Carbon Emissions Taxes (Canada), C$ per tonne $CO_2$ Equivalent

| Year | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|
| | $65 | $80 | $95 | $110 | $125 | $140 | $155 | $170 |

However, hydrocarbon-based fossil fuels are incorporated into many aspects of our modern economy from space heating to electricity generation to vehicle motive power as well as inputs to many industrial processes. While individual elements of this set of interconnected technical processes can and are being redesigned to avoid the use of fossil fuels (most notably the use of batteries in electric vehicles), rebuilding all the energy supply chains from oil and natural gas to new solutions is both technologically and economically difficult.

It is for this reason that the idea of using hydrogen to play similar roles to current fuels has become popular. Hydrogen has an energy-to-mass content almost three times natural gas or oil, and burns via the very exothermic (heat releasing) reaction: $2H_2 + O_2 \rightarrow 2H_2O$, leaving only water as a waste product. It is relatively easy to produce hydrogen either from hydrocarbons or other sources via electrolysis.

### 2.1.2 Chemistry of Hydrogen Combustion

Hydrogen is a combustible gas with the molecular formula $H_2$. Natural gas is made up of a combination of the shortest chain hydrocarbons, namely methane ($CH_4$), ethane ($C_2H_6$), propane ($C_3H_8$), and butane ($C_4H_{10}$). All these hydrocarbons have the formula of the form $C_nH_{2n+2}$, (e.g. for methane, n =1, for propane, n = 3, etc.) and so we can think of $H_2$ as being in this family with n= 0.

These hydrocarbons are a gas at standard temperature (273°K) and pressure (1 atmosphere), although butane barely so. The longer the hydrocarbon chain, the higher the boiling point. Of course, if placed under more than atmospheric pressure, the gases will liquify at higher temperatures than noted here. If the substances are warmer than their critical temperature (also an increasing function of chain length), they cannot be liquefied no matter the pressure. So natural gas, which is mostly methane, can only be liquefied after being cooled to lower than 82 degrees below zero; hydrogen must be very cold before it can be liquified or, said another way, will be very cold when a liquid. When these substances are burned they follow the (exothermic) reactions:

$$2C_nH_{2n+2} + (3n+1)O_2 \rightarrow 2n\, CO_2 + (2n+2)H_2O$$

So for instance (with n = 0) $2H_2 + O_2 \rightarrow 2H_2O$ + energy (or the reverse electrolysis reaction $2H_20$ + energy $\rightarrow 2H_2 + O_2$). But with n = 1, we arrive at the following reaction:

$$2CH_4 + 4O_2 \rightarrow 2CO_2 + 4H_2O + \text{energy}$$

It can be seen that water is always a combustion product. From this we define the lower heating value. The lower heating value measures the available thermal energy produced by a combustion of a fuel. It is defined as the amount of heat released by burning a given quantity of fuel and returning the temperature of the combustion products to 150°C, which means that any energy used in vaporizing water is not recovered. In contrast, the upper heating value is the upper limit of the amount of thermal energy which can be produced by a complete combustion of the fuel, accounting for any latent heat, etc. The upper heating value of hydrogen is 142, or about 1.2 times its lower heating value.

**Table 2** [2] [3] shows that the true hydrocarbons here all have similar LHV (lower heating value, albeit slightly decreasing with chain length) and similar $CO_2$ production (albeit slightly increasing with chain length). $H_2$ produces no $CO_2$ and also has a much higher energy content per mass. However, the molecular weight of $H_2$ is so small that the energy density per unit volume is much smaller than that of methane. This is a challenge in burning hydrogen, and also in storing it and transporting it via pipeline or truck, as pressures must be very high. When one also considers that the very small hydrogen molecules are very good at adsorbing onto surfaces and at inducing cracking, the added pressure results in considerable engineering design challenges.

**Table 3** compares the benefits of moving from natural gas to hydrogen with the benefits of shifting away from coal and gasoline. Natural gas is a much cleaner fuel than coal, and a somewhat cleaner one than oil or gasoline. This advantage is reinforced by the fact that modern combined cycle gas turbines are more efficient than coal fired power plants.

Haynes, 2014 [2] states the assumption that coal is 90% carbon by mass and all of this carbon is oxidized to $CO_2$ in combustion. The chemical composition of coal is complicated and varies by coal grade and even from deposit to deposit. The LHV is given for bituminous coal and can be taken as indicative. Bituminous coal is 1346 kg/m$^3$. A barrel of oil is 136kg and contains about 5.8MM BTU. 1MM BTU of oil emits between 139 to 161 pounds of $CO_2$ with propane at the low end and diesel at the high end. Thus, a barrel of oil emits between 139*0.454*5.8 = 366 kg and 161*0.454*5.8 = 424 kg of $CO_2$. This has been averaged to 400 kg.

Table 2 **|** Natural Gas Constituents and their Physical Properties. From basic hydrocarbon combustion stoichiometry: $2C_nH_{2n+2} + (3n+1)O_2 \rightarrow 2n\ CO_2 + (2n+2)H_2O$. Natural gas fractions from Enbridge [3] (if natural gas is 95% methane and 5% ethane it therefore has LHV 49.89 MJ/kg; $CO_2$ 2.76kg emitted/kg combusted).

| **Molecule** | **Formula** | **NatGas %** | **1 atm Boil Point (°C)** | **CritTemp (°C)** | **LHV MJ/kg** | **$CO_2$ per kg burnt** |
|---|---|---|---|---|---|---|
| Butane | $C_4H_{10}$ | Trace | -0.5 | 152 | 45.3 | 3.03 |
| Propane | $C_3H_8$ | 0.09-0.2 | -42 | 97 | 46.4 | 3.00 |
| Ethane | $C_2H_6$ | 3.1-5.7 | -89 | 32.2 | 47.8 | 2.93 |
| Methane | $CH_4$ | 93.1-96.1 | -161 | -82.1 | 50 | 2.75 |
| Hydrogen | $H_2$ | Trace-0.1 | -253 | -240 | 120 | 0 |

Table 3 **|** Heat and CO2 Emissions from Burning Typical Fuels

| **Fuel** | **State at STP** | **Moles/kg** | **LHV/kg in MJ** | **Kg $CO_2$/kg burned** | **g$CO_2$/MJ** | **LHV/m$^3$** | **$CO_2$/m$^3$** |
|---|---|---|---|---|---|---|---|
| Coal | Solid | n/a | 29 | 3.3 | 114 | 39034 | 4442 |
| Oil | Liquid | n/a | 45 | 2.94 | 65.4 | 38260 | 2501 |
| Gasoline | Liquid | n/a | 43.4 | 3.07 | 71 | 32550 | 2300 |
| Methane | Gas | 62.5 | 50 | 2.75 | 55 | 35.7 | 1.96 |
| Hydrogen | Gas | 500 | 120 | 0 | 0 | 10.7 | 0 |

However, if hydrogen can be produced without generating $CO_2$ emissions and the above-mentioned technical challenges can be addressed, the advantages of using it are clear.

Table 4 and Table 5 put together the physical and chemical properties of various fuels with their current market prices and some reckoning of the economic cost of $CO_2$ emissions.

Note that a hydrogen price of $2.12 per kg would be required to match the current carbon emissions credit – corrected price per MJ of oil, but even then, natural gas and coal would be cheaper per MJ. One might also argue that oil is a more convenient fuel than hydrogen.

Table 4 **|** Unit Cost of Typical Fuels Excluding and Including Canadian Carbon Emissions Taxes at Current Levels. Uses 2024 Canadian carbon price of C$80/tonne $CO_2$ emitted, June 2024 FX rate of 1CAD = 0.73USD. All prices current as of June 21, 2022, except for hydrogen price which is informed but optimistic estimate for green hydrogen from the US DOE [4].

| **Fuel** | **Cost** | **Units** | **MJ equivalent to cost** | **US cents per MJ** | **g$CO_2$/MJ** | **US cents per MJ for emissions** | **Total US cents per MJ** |
|---|---|---|---|---|---|---|---|
| Coal | 109.75 | USD/long ton | 29000 | 0.378 | 114 | 0.67 | 1.04 |
| Oil | 80 | USD/barrel | 5902 | 1.355 | 71 | 0.41 | 1.77 |
| Natural Gas | 2.7 | USD/MMBTU | 1055 | 0.256 | 55 | 0.32 | 0.58 |
| Hydrogen | 5 | USD/kg | 120 | 4.167 | 0 | 0.00 | 4.17 |

Table 5 **|** Unit Cost of Typical Fuels Excluding and Including Carbon Emission Taxes at Typical Social Cost of Carbon Price Levels. Prices as per Table 4 except for carbon, which follows Wang et al. [1] average of $US200 social cost of carbon price. A hydrogen price of $3.33 per kg is needed to match the energy value of oil.

| **Fuel** | **Cost** | **Units** | **MJ** | **US cents per MJ** | **g$CO_2$/MJ** | **US cents per MJ for emissions** | **Total US cents per MJ** |
|---|---|---|---|---|---|---|---|
| Coal | 109.75 | USD/long ton | 29000 | 0.378 | 114 | 2.28 | 2.66 |
| Oil | 80 | USD/barrel | 5902.4 | 1.355 | 71 | 1.42 | 2.78 |
| Natural Gas | 2.7 | USD/MMBTU | 1055 | 0.256 | 55 | 1.10 | 1.36 |
| Hydrogen | 5 | USD/kg | 120 | 4.167 | 0 | 0.00 | 4.17 |

The current market prices of energy are expected to cover all costs of production and distribution (in theory, at least). However, for future electricity developments, the Levelized Cost of Electricity (LCOE) is often used.

- The LCOE for nuclear power is approximately US$100 per MWh, or 2.8 cents per MJ, based on estimates from Figure 4.2 on page 8 of the Hatch report [5], with conversions from Canadian dollars to USD at an exchange rate of 1 USD = 0.73 CAD.
- The LCOE for onshore wind power is around US$40 per MWh, or 1.12 cents per MJ.
- The LCOE for solar power is also about US$40 per MWh, or 1.12 cents per MJ.

With this technical background complete, we can now review where various hydrogen strategies offer opportunities for a green hydrogen-led transition across several sectors. The intent of this research is to analyze elements of hydrogen supply and demand to develop an offer curve for hydrogen-powered turbines.

## 2.2 Regulatory Review

A review of the Ontario provincial regulatory framework has been performed to identify provincial policy and regulations affecting the hybridization of a wind farm - to simultaneously remain connected to both the IESO's high-voltage power grid for utility-scale transmission and localized electricity distribution for direct consumption and/or hydrogen production for storage and later combustion to produce electricity. Particular focus is to be paid to the IESO's Market Rules [6] and other publicly available materials published by the IESO that could affect aspects of the HIGH Energy scheme described in the Part 1 report accompanying this Part 2 report. Specifically, the aim is to answer whether a utility-scale wind farm (with grid-connected capacity exceeding 50 MW) has license to put excess electricity from multi-megawatt turbines toward production of hydrogen onsite, or establish whether these 'behind-the-meter' activities conflict with the IESO's regulatory mandate. Furthermore, for the case in which the wind farm was to provide electricity directly to the greenhouse on an independent distribution line for the purposes of hydrogen production, can the farm alternate between high-voltage utility grid line generator and a local utility to supply electricity to the greenhouse.

Another aim of this regulatory review is to establish IESO policy for integrating 'hybrid' electrical generation sources (those combining variable generation with a storage medium to better align supply with demand) onto the grid as operating reserve on short notice. Operating reserve, also known as stand-by power, is the range of quickly dispatchable generator sources connected to the IESO grid that can dispatch reserve power for up to an hour within a 10 or 30-minute timeframe [7].

This regulatory review only covers IESO materials that are available to the public at the time of writing, and assumes these materials are wholly inclusive of IESO policy that could conflict with the hybridization framework proposed by HIGH Energy.

## 2.3 Peaker Technical Performance and Comparative Storage Economics

Wind farm hybridization through combination of wind energy with hydrogen production and combustion provides value to the electricity grid in two primary ways:

- Grid support as operating reserve during unexpected peaks of electricity demand.
- Storage for variable renewable electricity when that energy is available but not needed on the grid.

Part 1 of the HIGH Energy report establishes three hybridization cases of the wind farm considered, which differ by the means that excess electricity from the wind farm is put toward hydrogen production and use:

1. Electricity is supplied to the greenhouse via transmission line for hydrogen to be produced onsite at the greenhouse, blended, and combusted for grid electricity production.
2. Hydrogen is produced onsite at the wind farm and transported to the greenhouse via truck, and blended and combusted at the greenhouse.
3. Hydrogen is produced onsite at the wind farm and transported to the greenhouse via new pipeline, and blended and combusted at the greenhouse.

This study aims to compare the technical performance of alternative 'peaker' generation sources and the economics of storage alternatives.

# 3. Jurisdictional Scan

## 3.1 Review of Hydrogen Strategic Plans

International organizations and nations including the UK, USA, and Canada have all developed their own hydrogen strategies over the last 5 years. These strategies are summarized in lengthy documents including references [8 – 12].

These strategies all identify two roles for hydrogen in electricity markets: a role as a low emissions provider of peak power; and its role in storage for load shifting across the day, the week, or the season. The strategies also discuss the role of hydrogen in industrial processes.

The current strategic focus is in the following areas, and described in the sections to follow:

- Substitution of hydrogen for natural gas in power generation turbines
- Improvement of electric grid system flexibility through electrolysis and storage
- Hydrogen for industrial and transportation uses
- Transition of infrastructure for hydrogen applications

### 3.1.1 Green Hydrogen for Decarbonizing Electrical Power Generation

An initial phase of utilizing hydrogen on the grid is employment of gas-hydrogen blends with normal existing gas turbines, with a later step to transition to 100% hydrogen turbines. For instance, the UK Hydrogen Strategy, 2021 [10] states that "By 2030, we could see a small but important role for low carbon hydrogen to generate power." Similarly, the Government of Canada's 2020 Hydrogen Strategy [9] states "Hydrogen can be used as a fuel for power production through either hydrogen combustion in turbines or use in stationary fuel cell power plants. Combustion turbines [using] a blend of hydrogen and natural gas are currently commercially available. Existing natural gas turbines could likely operate with a blended hydrogen/natural gas fuel supply of up to 10% to 15% hydrogen by volume."

Major modifications to, or replacement of, infrastructure and equipment would be required to combust larger proportions of hydrogen in existing power plants. Turbines capable of combusting 100% hydrogen are in development and are expected by 2030 [13].

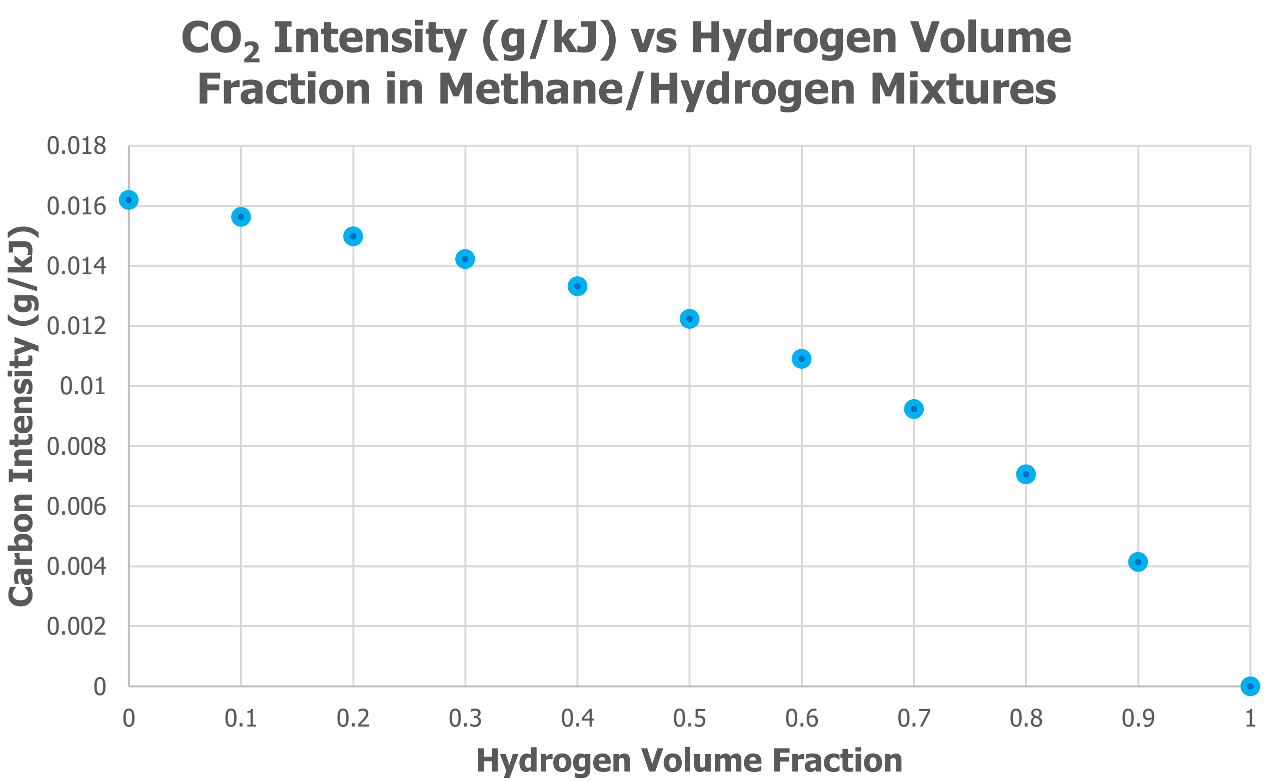
This suggests a role for fast response power, also known as 'peakers'. Peakers are used for load balancing and are essential for system stability. Typically, Combined Cycle Gas Turbines (CCGTs) are used for fast response power, but these do (obviously) emit greenhouse gases. Hydrogen can be burned in CCGT power plants, albeit at high flame temperatures which can cause technical difficulties.

Calculated values shown in

Figure 1 **|** Carbon Intensity in the Methane/Hydrogen Mixture

demonstrate that the higher the hydrogen blend for these turbines the lower the greenhouse gases emitted, although small $H_2$ volume fractions have only very incremental benefit to GHG emissions at a potentially high additional expense. While there are technical challenges to building turbines that can run on 100% hydrogen, as noted by the International Energy Agency report on hydrogen in 2019 [8] stating that "In Korea a 40MW gas turbine at a refinery has run on gases with a hydrogen content of 95% for 20 years."

Figure 1 **|** Carbon Intensity in the Methane/Hydrogen Mixture




Note the nonlinear dependence on volume fraction in

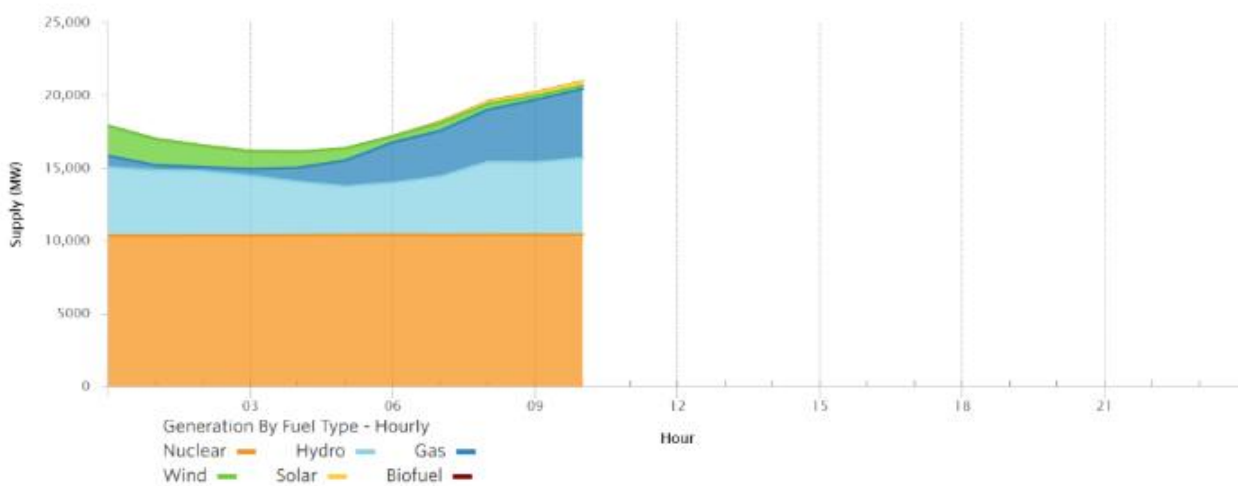
Figure 1 **|** Carbon Intensity in the Methane/Hydrogen Mixture

, which arises because most of the mass of the blend comes from methane. It would be linear in mass fraction. Later in this report, quantitative models are created for offer curves for such blended turbines.

## 3.1.2 System Flexibility Through Electrolysis & Storage

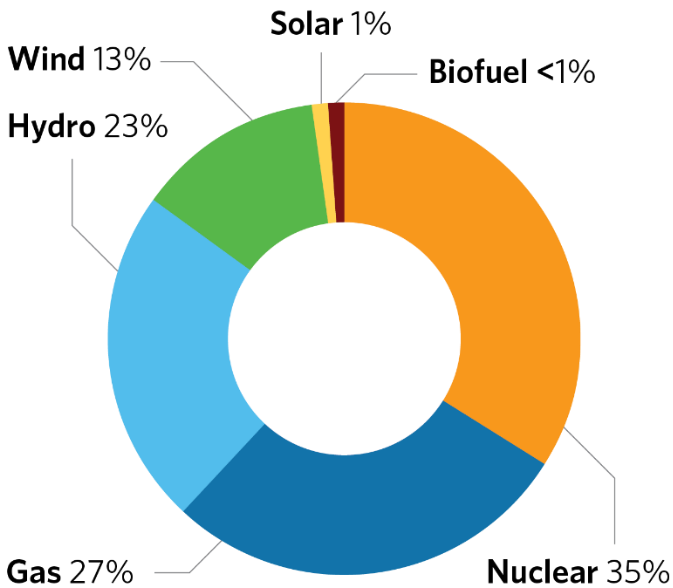
Ontario's current high-voltage grid electricity mix is heavily dependent on nuclear power plants & hydroelectric dams to provide baseload generation. See **Figure 2** below, for electricity supply mix on a late June 2024 morning as provided from the IESO website [14]. Nuclear & hydro (orange & light blue on the graph, respectively) represent near 75% of the province's electricity supply by 10:00 AM, and represent an even higher share of overall supply earlier in the day. As Ontario energy demand rises over the course of the summer morning, natural gas turbine generation (darker blue) fills the gap while nuclear & hydro remain relatively constant. Wind power (green) provides significant generation supply between the hours of 12:00 AM and 3:00 AM where nighttime wind resource can often be strongest, such that natural gas generation is minimal. Note that solar (yellow) generation is present in small quantities at the 10:00 AM time this figure was produced.

Figure 2 **|** IESO Power Supply Data on June 2024 Morning [14]




Total Ontario installed wind capacity is nearly 5,000 MW [15], see **Figure 3** below, but wind generation supply never exceeds 2,000 MW on the graph shown in **Figure 2**. This is due in part to the variable nature of the wind resource that can be forecasted but not precisely predicted. In addition to this, IESO policy since 2013 has been to curtail wind farms when excess electricity was not needed [16]. This resulted in a curtailment of 17% and 12% of renewable variable generation in 2020 & 2021 [17], respectively, indicating a loss of potential renewable energy generation due to the misalignment of the renewable wind & sun resources with the electricity demands of the province. Note that in recent years, the level of this curtailment of available wind energy has reduced [18]. But this potential misalignment provides an opportunity for storage alternatives to be paired with renewable generation to minimize the carbon generation of electricity production on Ontario's grid.

Figure 3 **|** IESO Transmission Grid-Connected Capacity [15]



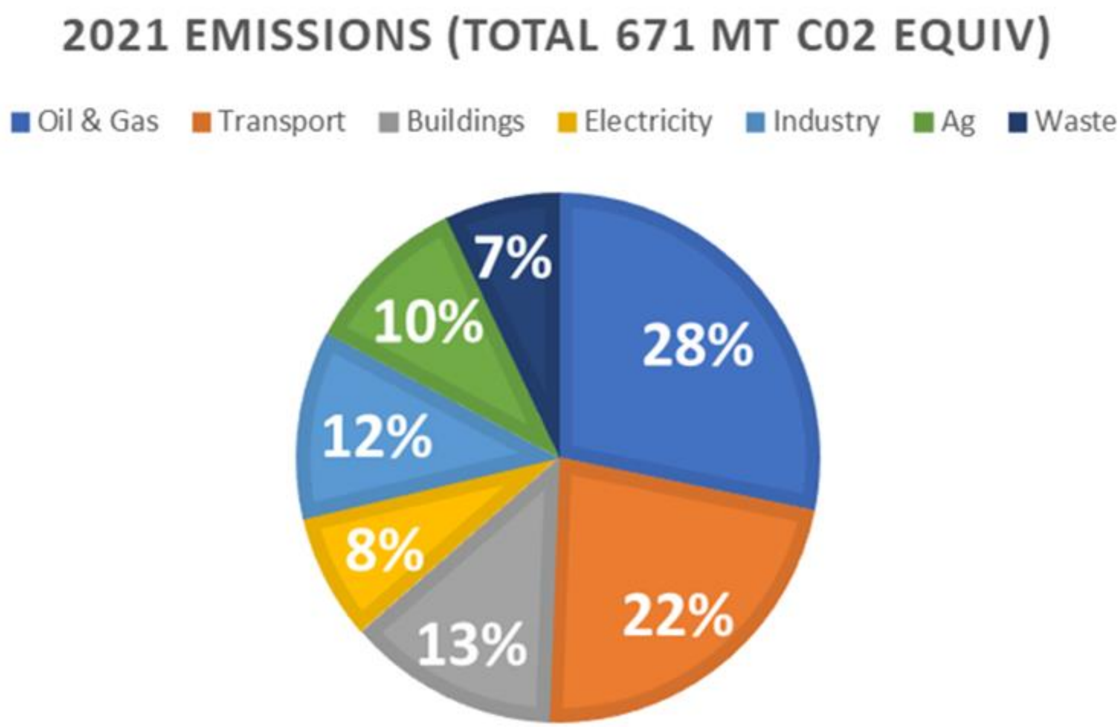

| | |
|---|---|
| **Nuclear** | 13,214 MW or 35% |
| **Gas/Oil** | 10,471 MW or 27% |
| **Hydro** | 8,862 MW or 23% |
| **Wind** | 4,943 MW or 13% |
| **Solar** | 478 MW or 1% |
| **Biofuel** | 296 MW or <1% |

One natural solution is to use surplus power from variable renewable sources to produce hydrogen via electrolysis for later use in power generation via turbine combustion – performing 'hybridization' to combine these technologies to improve the efficacy of wind power on its own. Understanding the operational details of the energy markets is essential when considering this approach. Moreover, a significant increase in off-peak power usage will impact the supply-demand imbalance that originally caused the low (or negative) prices.

The International Energy Agency's 2019 report on hydrogen [9] states "Electrolytic hydrogen production can also provide grid flexibility by drawing on 'excess' renewable or low carbon electricity that would otherwise be constrained or curtailed …. where there is an economic case to do so. Hydrogen can also provide load management capabilities, daily and even seasonal utility scale energy storage capabilities, and is an enabler for the growing variable renewable power sector", while the 2021 UK Hydrogen Strategy [10] states that "…electrolytic hydrogen can allow excess electricity to flow across different parts of the system, from power to gas, to transport or industry (.. 'sector coupling'). This…can help integrate hydrogen further into our power system by helping to balance the grid when generation from renewables is higher or lower than demand."

In the Canadian context, if the aim of hydrogen utilization is purely to reduce greenhouse gas emissions, note the electricity grid may not necessarily be an optimal starting point. **Figure 4** shows that Ontario's electricity grid represents less than 10% of overall emissions.

Figure 4 | Greenhouse Gas Emissions [19]



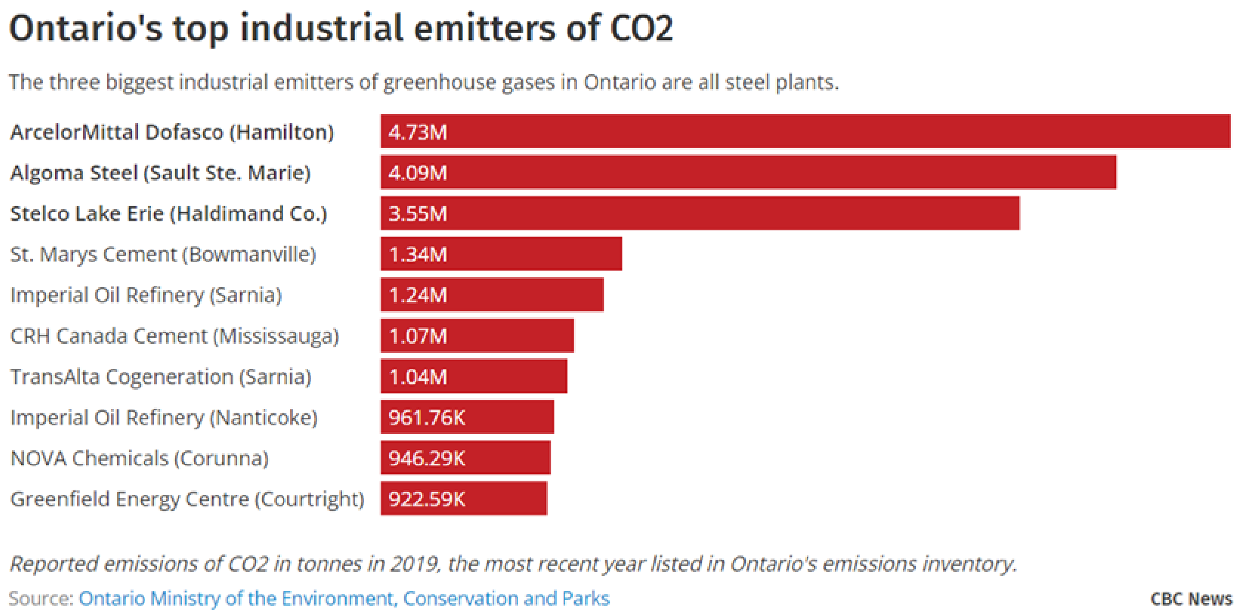

## 3.1.3 Hydrogen for Industrial & Transportation Use

Hydrogen can be used for other purposes – in other sectors – like industry, agriculture, or heating, where it can displace higher emission fuels and inputs like natural gas or coal.

**Figure 5** shows that Ontario's top industrial emitters of $CO_2$ are all steel makers, leading the others by a considerable margin. Each tonne of steel produced in 2018 emitted 1.85 tonnes of $CO_2$. A blast furnace uses coal to reduce iron oxide. Coal isn't just used to produce heat for this reaction (electricity could do that) but to provide the reducing agent needed to strip oxygen from iron ores like hematite ($Fe_2O_3$).

Hydrogen can also be used to reduce iron ore into iron and then steel, reducing life cycle $CO_2$ emissions by 40-70% according to the US Department of Energy [11].

Figure 5 | Ontario Top $CO_2$ Emitters [44]




Hydrogen-powered equipment not only emits little to no GHG, its lack of other noxious emissions also makes it much safer when used indoors (forklifts) or underground (mining equipment). Hydrogen fuel cell forklifts are already available on the market and offer fast refueling time relative to batteries. Hydrogen fuel cells have also become an area of interest of the automotive industry [20].

### 3.1.4 The Hydrogen Transition

Although hydrogen may appear to be a direct substitute into available energy infrastructure - it is a fuel that needs to be moved, by truck or by pipeline, from production site to use site. Low fractions of hydrogen, blended with natural gas, can be added to current pipeline distribution infrastructure. Hydrogen's low molecular weight and the associated issues around corrosion and adsorption, which induces brittleness, make development of this infrastructure challenging.

## 3.2 IESO Regulatory Framework

Ontario's electricity market is administered by the IESO – who monitors patterns of electricity consumption across the province and uses these patterns to forecast electricity demand at a given hour. Electricity generators use the IESO's forecast to plan their generation capacity and make offers to the IESO hourly for how much electricity they can provide (and if they have no prior agreement) the price they can offer it for. The IESO then allocates electricity onto the grid based on their needs and the prices offered by the generators [21]. The IESO publishes the Market Rules [6] for participating in the province's electricity market.

The IESO's Market Renewal Program (MRP) is planned to come online in the second quarter of 2025 and aims to improve Ontario's electricity costs and reliability through a Single Schedule Market (SSM) to better align electricity price with its dispatch [22]. This goal is to be partially achieved through the introduction of locational pricing for the electricity generation sources that accurately reflect their true value with respect to transmission distance, and to generate financially binding day-ahead markets where generators submit their day-ahead offers to compete with each other.

In September of 2013, Ontario wind farms were no longer designated as must-run 'intermittent' generators that did not receive dispatch instructions from the IESO [16]. Instead, these wind farm renewable energy generators were shifted to a 'variable' designation in which they received dispatch instructions from the IESO, who could then employ wind-produced electricity as needed for ramping services on the grid. Hybridization of wind energy and hydrogen production & combustion provide an opportunity for wind farms and the variable electricity they produce to increase their penetration onto the province's high-voltage electricity grid by more reliably aligning power production with demand.

# 4. Approach/Methodology and Assumptions

## 4.1 Robust and Liquid Markets

In order to develop a robust market for a new commodity such as hydrogen, several conditions must be met. This is especially important if it is expensive or otherwise difficult to enter the market as a buyer, a seller, or a service provider.

There must be multiple buyers for the commodity, so that a business considering entering the market as a seller can be reasonably certain of selling their product. While there may be a primary user of the product who can pay a premium price, it is optimal if any surplus production could still be sold so that economies of scale might be maintained. By the same token, there should be multiple sellers for the commodity. This is particularly important for a mission-critical inputs - an enterprise considering a retool to use that input must be reasonably certain that the exit of any one provider from the market will not negate that investment. The various services required by buyers and sellers (e.g. transportation, supply chain) must also be present, and ideally, from various counterparties.

In the case of a new technological commodity such as hydrogen; it is perhaps reasonable to also require that not just a single technology can produce the product, that the product is not needed for a single purpose, and that crucial infrastructure can be dual-use.

### 4.1.1 Price Formation & Transactions in Markets

Assume the market has $N$ sellers of hydrogen (these could be producers or importers) which are indexed by $1, 2, \ldots, N$. These sellers will accept $O_1, O_2, \ldots, O_N$ ($O$ for Offer) for quantities $Q_1, Q_2, \ldots, Q_N$.

Without loss of generality we arrange these so that the lowest price is $O_1$ and the highest price is $O_N$.

Further it is assumed that the market has $M$ buyers of hydrogen (these could be end users or potentially exporters), indexed by $1, 2, \ldots, M$. These buyers will pay $B_1, B_2, \ldots, B_M$ ($B$ for Bid) for quantities $q_1, q_2, \ldots, q_M$. Again, buyers are numbered so that the highest price is $B_1$ and the lowest price is $B_M$.

If the lowest offer price $O_N$ is higher than the highest bid price $B_M$, then no transactions will occur. Even the cheapest producer of the commodity is unable to produce it at a price the market can accept.

This will certainly not be the case for hydrogen. For example, scientific users of (relatively small quantities) of hydrogen applications will be able to pay relatively large amounts for (quite pure) hydrogen. For instance, industrial gas supplier Linde offers a bottle containing 610g of $H_2$ for C$95.33 ($156.28/kg) [23]. Even assuming a factor of 10 from wholesale retail this is still $15.63 per kg.

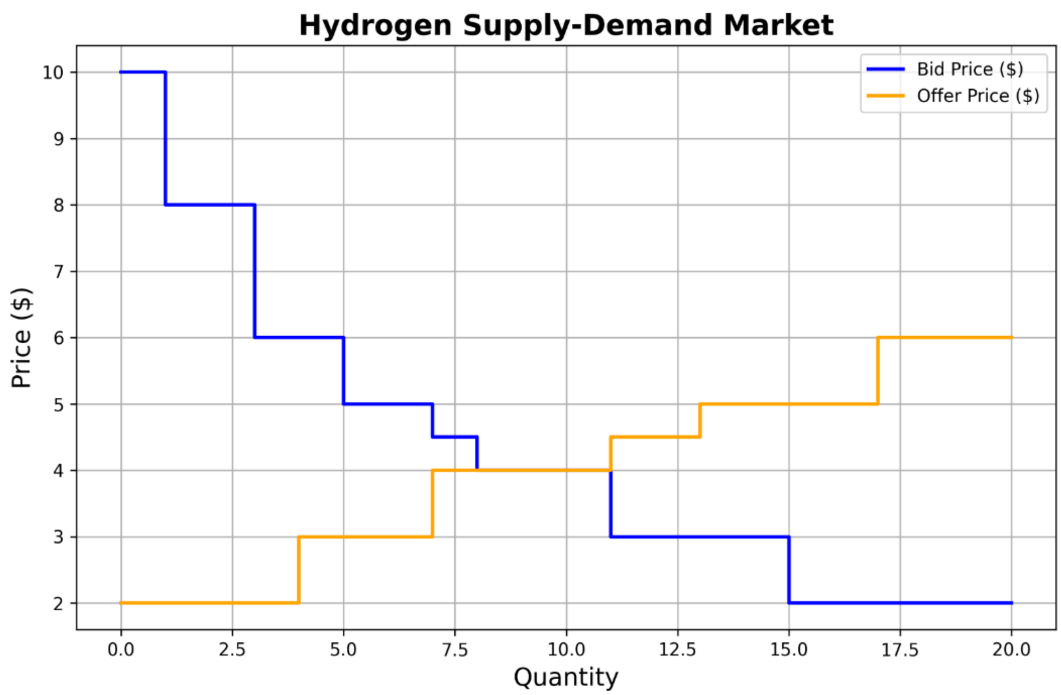
Not only is $H_2$ used for scientific instruments, it is also used for high-end welding purposes and as an ingredient in semiconductor production.

### 4.1.2 Establishing Market Price

If the quantity demanded at the highest bid is not very much, the producer must also need to sell to the second (or subsequent) bidder.

As shown in **Figure 6**, offers are stacked from lowest to highest, with price on a vertical axis and quantity on a horizontal axis. Bids are stacked from highest to lowest on the same axes.

Figure 6 | Hypothetical Hydrogen Supply-Demand Curve




The price is set where the highest offer meets the lowest bidder can still afford to pay. In **Figure 6**, that would be a quantity of 11, and a price of 4.

It is important to note that this framework does not exclude hydrocarbon-derived 'blue' or 'grey' hydrogen from the market. Those environmentally suboptimal products can nonetheless be part of a framework. Indeed, the current production of 'green' hydrogen from low emission sources is just 3450 tonnes per year, according to Natural Resources Canada in 2024 [24]. In contrast, per the Canadian Energy Council, Canada produces about 3 million tonnes of hydrogen each year for industrial use [25]. This implies that only about 0.1% of Canada's hydrogen production is currently green.

To give a scale for these hydrogen numbers, Canada currently (as of February 2024) produces a bit over 5 million barrels of crude oil per day – which corresponds in energy content to about 100 million tonnes of $H_2$ per year [26].

## 4.2 Peaker Technical Performance

Wind farm hybridization, via deployment of excess variable renewable electricity for hydrogen production & combustion, has potential to serve as a means of grid support during periods of high electricity demand on the grid. The intent is to make a comparison to competing technology alternatives from the perspective of their ramping capabilities. The flexibility of generator and/or storage technology is a key factor in determining its ability to serve as operating reserve dispatched during peak demand. Primary metrics for assessing this flexibility are as follows:

- Startup & shutdown time
- Minimum generation level & runtime
- Ramp rate

Key among these metrics is the ramp rate, typically reflected in MW / minute or % rated capacity / minute, that quantifies the speed at which a generator or storage source can intentionally increase or decrease its power output from operator input. Technologies considered as part of this comparison are as follows:

- Natural gas turbines (performance characteristics assumed approximately equal with hydrogen fuel mix)
- Hydroelectric dams
- Compressed air energy storage (CAES)
- Nuclear power plant
- Commercial-scale wind farm
- Coal-fired power plant

Where commercially available performance specifications or literature review were unavailable, industrial partners for the HIGH Energy project were consulted for ramp rate performance statistics.

## 4.2 Storage Alternative Economics

Overall cost presents another importation metric for storage option viability. Energy storage costs for utility-scale grid support are typically evaluated on the basis of $ / kW rating of the storage installation or $ / kW-h rating of the storage system (kW-h specifically referring to the product of the capacity and length of provided output). A literature survey was performed to assess relative costs of contemporary storage technologies as follows, once again consulting with industrial partners for the HIGH Energy project:

- CAES
- Thermal energy storage (TES)
- Pumped hydro
- Conventional battery

# 5. Results and Analysis

## 5.1 Offer Side: The Hydrogen Rainbow

In this section we estimate what various hydrogen producers might require for their offer prices. We then consider what various demand side producers may be willing to pay.

### 5.1.1 Green Hydrogen: Electricity

1 kg of $H_2$ contains 142MJ (Higher Heating Value; HHV) – which is 1/30 of a MWh. As such, if the electricity price is E in C$/MWh, then the energy price equivalent for green hydrogen is $142/3600\times E = 0.0395\times E$. What price should we use for electricity though?

**Figure 7** presents the Hourly Ontario Electricity Price (HOEP) for April across the years 2022, 2023, and 2024 – demonstrating significant fluctuations in electricity prices both within the day and across different years. The data suggests that using an average electricity price of around C$30 per MWh might be reasonable, but it also highlights the substantial volatility in pricing. The figure shows that electricity prices can vary widely, which means that producing green hydrogen could be more cost-effective if it is strategically timed during periods of low electricity prices.

Figure 7 | April 2022 - 2024 Ontario HOEP [45]

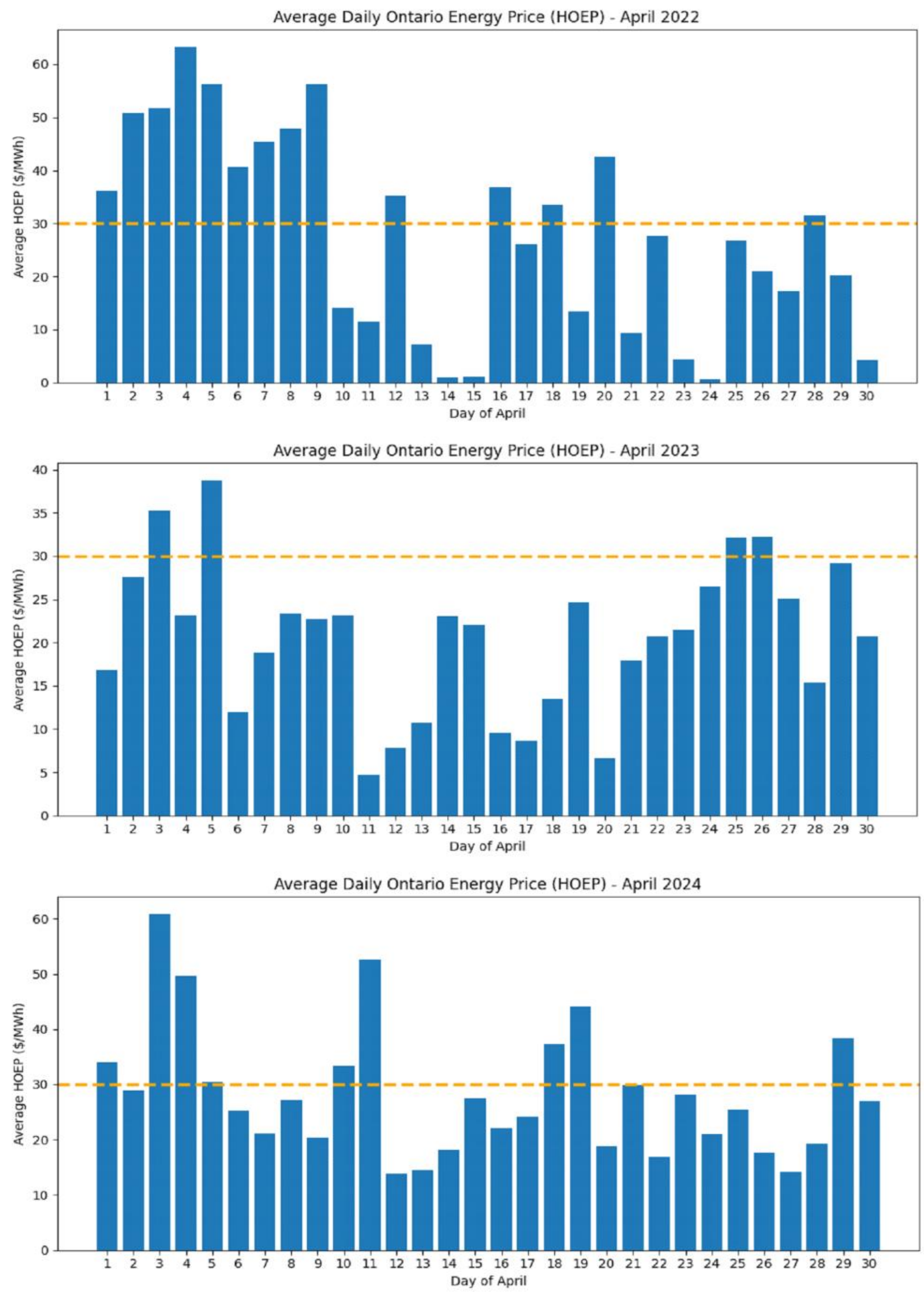


Table 6 | Monthly HOEP ($/MWh) Range Frequency (%)

| Month | 0-9 | 10-19 | 20-29 | 30-39 | 40-49 | 50-59 | 60-69 | >70 |
|---|---|---|---|---|---|---|---|---|
| Jan-22 | 3.23 | 3.23 | 9.68 | 35.48 | 16.13 | 22.58 | 3.23 | 6.45 |
| Feb-22 | 0 | 3.57 | 25 | 21.43 | 32.14 | 14.29 | 0 | 3.57 |
| Mar-22 | 0 | 6.45 | 19.35 | 29.03 | 32.26 | 12.9 | 0 | 0 |
| Apr-22 | 23.33 | 13.33 | 16.67 | 16.67 | 13.33 | 13.33 | 3.33 | 0 |
| May-22 | 16.13 | 25.81 | 12.9 | 12.9 | 12.9 | 16.13 | 0 | 3.23 |
| Jun-22 | 16.67 | 10 | 20 | 10 | 23.33 | 6.67 | 6.67 | 6.67 |
| Jul-22 | 0 | 0 | 0 | 6.45 | 19.35 | 32.26 | 25.81 | 16.13 |
| Aug-22 | 0 | 0 | 0 | 0 | 6.45 | 12.9 | 16.13 | 64.52 |
| Sep-22 | 3.33 | 3.33 | 3.33 | 13.33 | 13.33 | 13.33 | 13.33 | 36.67 |
| Oct-22 | 0 | 12.9 | 3.23 | 22.58 | 16.13 | 32.26 | 12.9 | 0 |
| Nov-22 | 16.67 | 10 | 26.67 | 20 | 10 | 16.67 | 0 | 0 |
| Dec-22 | 3.23 | 3.23 | 9.68 | 12.9 | 16.13 | 16.13 | 16.13 | 22.58 |
| Jan-23 | 0 | 3.23 | 25.81 | 51.61 | 19.35 | 0 | 0 | 0 |
| Feb-23 | 10.71 | 32.14 | 28.57 | 25 | 3.57 | 0 | 0 | 0 |
| Mar-23 | 0 | 25.81 | 54.84 | 19.35 | 0 | 0 | 0 | 0 |
| Apr-23 | 16.67 | 23.33 | 46.67 | 13.33 | 0 | 0 | 0 | 0 |
| May-23 | 22.58 | 38.71 | 32.26 | 6.45 | 0 | 0 | 0 | 0 |
| Jun-23 | 0 | 3.33 | 53.33 | 40 | 3.33 | 0 | 0 | 0 |
| Jul-23 | 0 | 0 | 9.68 | 58.06 | 19.35 | 9.68 | 0 | 3.23 |
| Aug-23 | 0 | 6.45 | 38.71 | 51.61 | 3.23 | 0 | 0 | 0 |
| Sep-23 | 0 | 0 | 53.33 | 33.33 | 0 | 6.67 | 0 | 6.67 |
| Oct-23 | 3.23 | 9.68 | 45.16 | 32.26 | 6.45 | 0 | 0 | 3.23 |
| Nov-23 | 0 | 3.33 | 50 | 43.33 | 3.33 | 0 | 0 | 0 |
| Dec-23 | 0 | 0 | 51.61 | 45.16 | 3.23 | 0 | 0 | 0 |
| Jan-24 | 0 | 0 | 9.68 | 41.94 | 35.48 | 6.45 | 0 | 6.45 |
| Feb-24 | 0 | 6.9 | 58.62 | 34.48 | 0 | 0 | 0 | 0 |
| Mar-24 | 0 | 6.45 | 54.84 | 29.03 | 6.45 | 3.23 | 0 | 0 |
| Apr-24 | 0 | 26.67 | 43.33 | 16.67 | 6.67 | 3.33 | 3.33 | 0 |
| May-24 | 0 | 19.35 | 61.29 | 12.9 | 0 | 6.45 | 0 | 0 |
| Jun-24 | 0 | 20 | 36.67 | 30 | 6.67 | 3.33 | 3.33 | 0 |
| Jul-24 | 0 | 3.23 | 35.48 | 35.48 | 12.9 | 6.45 | 3.23 | 3.23 |
| Aug-24 | 0 | 3.23 | 48.39 | 29.03 | 6.45 | 6.45 | 0 | 6.45 |
| Sep-24 | 0 | 14.29 | 71.43 | 14.29 | 0 | 0 | 0 | 0 |

To provide a more detailed perspective, **Table 6** displays the frequency distribution of HOEP values across different price ranges from January 2022 to September 2024. This table was created by obtaining hourly HOEP data from the IESO website, averaging it per day for all available months over the three-year period, and then calculating the frequencies for the specified price ranges. **Table 6** reveals that, while electricity prices in the lowest range (C$0-10 per MWh) occur intermittently throughout the year, in all months except Aug-22 HOEP was below C$40 more than 30% of the time, and in most months HOEP was below C$20 more than 30% of the time. This validates the assumption that wind generators could avoid the market on a large fraction of market hours in favour of generating H2. Of course, if $H_2$ generation became widespread by wind generators, it is possible that HOEP dynamics might change where wind generators are the marginal producer, but this should not be the case very frequently.

**Table 6** is the basis for **Figure 8**. **Figure 8a** provides a histogram of HOEP values for May 2023. This histogram shows a distribution of prices, and we observe that electricity prices are below C$10 per MWh around 30% of the time in that month. This indicates that there are opportunities to produce green hydrogen at lower costs during these periods when electricity prices are minimal.

**Figures 8b** and **8c** further illustrate the variability of HOEP prices by showing histograms of these prices over different months and years. When averaging these histograms across all available months from January 2022 to September 2024, it becomes evident that the lowest HOEP price range (C$0-10 per MWh) occurs approximately 10% of the time annually. Given there are 8,760 hours in a year, this translates to a little less than 1,000 hours per year where electricity prices are very low, creating opportunities for more economical hydrogen production.

Looking at the broader trends, the data shows that HOEP prices tend to fluctuate significantly month-to-month, but no consistent seasonal pattern is clearly discernible from the available data. The variability seems to be influenced by a range of factors, including market demand, supply from renewable sources, and regulatory constraints that require certain power plants (like nuclear and legacy hydro) to offer power at negative rates. These negative rates occur because these plants must continue to operate and supply electricity even when demand is low, which affects the overall electricity price landscape.

In conclusion, while the HOEP data demonstrates significant price volatility, the ability to produce green hydrogen cost-effectively depends on carefully timing production to coincide with periods of lower electricity prices. The variability in HOEP prices suggests that, on average, around 1,000 hours per year may offer such low-cost opportunities; primarily during periods when supply exceeds demand or when regulatory constraints influence the market dynamics.

The power price paid by large commercial uses comprises not just of the HOEP as described above (see text around our supply demand bar graph) and the Global Adjustment, which is meant to cover the costs of building and maintaining energy infrastructure and conservation efforts [27].

The Global Adjustment can actually be a large, and for some hours, the overwhelming part of the final power price. We neglect it here. Why?

The Global Adjustment is designed to reduce the need for expensive 'peaker' power plants which produce the 'last few hundred' MW required to service all loads in the market. It works by levying a per MW charge on power consumed in the highest few demand hours of the year. At these times the market is very nearly at capacity and so the HOEP tends to be very high.

Our model is based on diverting wind-generated electricity to electrolysis when the HOEP is cheap. As such, we need not consider Global Adjustment (which in any case is not paid to the producer, merely billed to the industrial or consumer scale user) on the hydrogen cost side.

On the use side, the greenhouse is burning natural gas or a natural gas-$H_2$ blend. And so not using electricity at all. It is true that a comparison with an electric heater base case might benefit by charging the electric heater base case the Global Adjustment. But that would easily enough be avoided by not heating the greenhouse on days likely to attract Global Adjustment, which are nearly always the hottest days of the year. It has been a decade or so since Ontario had a winter peak hour. So, we conservatively do not consider Global Adjustment for the use side of our hydrogen model either.

To continue this analysis, one can consider the electrolysis reaction as follows:

$$2H_2O \rightarrow 2H_2 + O_2$$

For each 1 kg of H2, we need approximately 9 L (kg) of water. Per London Hydro [28], the cost of water including sewer charges for usage of 251 – 7000 L / month is C$2.51 / $m^3$, give us C$0.022 per kg of $H_2$. IRENA [29] states that purification of this water can become significant depending on the level of purity needed, but their overall impact should be low relative to the overall cost of hydrogen as they remain around US$1 / $m^3$ [30]. This can be approximated to C$0.02 per kg of $H_2$.

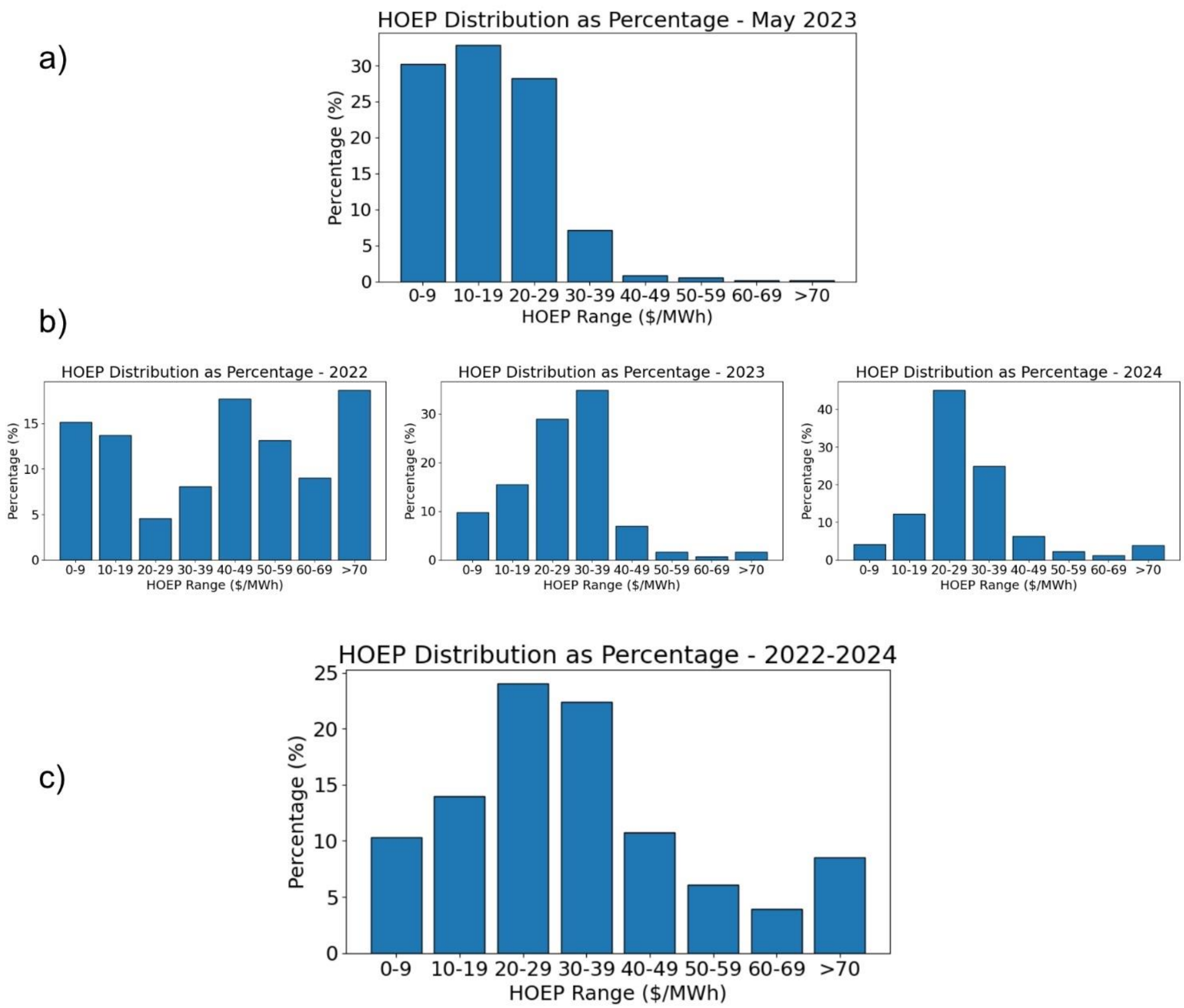
Per Table 9 in the HIGH Energy Part 1 report, initial electrolyzer costs is US$1,221.98 / kW for stack cost only. Industry estimates suggest that the balance of plant cost (BoP) can add approximately 50% to the stack cost [31]. As such, the total cost per kW after converting to Canadian currency will be approximately C$2,400 / kW. The amortized capital cost per kilogram of hydrogen can be estimated based on 4,000 hours of operation per year over ten years: C$2,400 / kW ÷ 40,000 kWh = C$2.51/kW. Thus, the capital cost per kilogram of hydrogen can be determine using hydrogen's energy content of 33.3kWh / kg: C$2.51/kW x 33.3 kWh/kg = C$1.99/kg $H_2$.

Per Table 10 in the HIGH Energy Part 1 report, an assumed operation and maintenance (O&M) cost of 1.5% of the capital expenditures (CAPEX) is used. Using 1.5% of the original approximate US$1,200/kW value for the electrolyzer (US$18/kW) and multiplying that by the cost per kilowatt-hour: US$18 / 4000 kWh = US$0.0045 / kWh. Then multiplying by hydrogen's energy content and converting to Canadian currency gives us C$0.20/kg $H_2$.

Finally, considering an electrolyzer efficiency of 67% and knowing the energy content of hydrogen, we can determine the electrical energy required per kilogram of hydrogen: 33.3 kWh/kg / 0.67 = 49.7 kWh/kg. Using an electricity price of C$30/MWh then gives us C$1.49/kg of $H_2$ (49.7 kWh/kg x C$0.03/kWh).

Summing the costs of water consumption & purification (C$0.04), the amortized capital based on BoP (C$1.99), O&M (C$0.20), and electricity (C$1.49); we arrive at an overall total hydrogen production cost of C$3.72 / kg of $H_2$, slightly higher than the previous estimate stated above.

Figure 8 | May 2023 HOEP histogram [45]




## 5.1.2 Blue and Gray Hydrogen: Natural Gas

1MMBTU = 1.055GJ of natural gas creates 53 kg of $CO_2$ when burned. As 1Kg of $H_2$ has a higher heating value of 142MJ, this has the energy content of about 7.4 kg of $H_2$.

**Figure 10** shows the degree to which natural gas prices have fluctuated historically. As shown by the Department of Energy [4], it is currently trading at the low end of its range at the time of writing this report. If E is the emissions price in tonne CO2 and G is the gas price per MMBTU, all in C$, then the energy content price of hydrogen is $(0.053/7.4)\times E + (1/7.4)\times G$ which simplifies to: $0.072\times E + 0.135\times G$

Current carbon price of E = $80 (from Table 1) and Canadian dollar gas price of about $5 (from Table 4 and Table 5) suggest an energy equivalent price of about C$1.25 per kg.

A longer run average gas price might be reckoned at US$5, or C$7, per MMBTU and the long run carbon price of C$170 suggest an energy equivalent hydrogen price of about C$1.50 per kg $H_2$.

A recent paper by Katebah et al. [32] estimates a CAPEX (capital expenditure) cost of about US$0.15, or C$0.20 per kg $H_2$ for steam methane reforming, so that would make an offer side cost of C$1.45 (current prices) or C$1.70 (longer run price projections) for grey hydrogen.

Gonzales-Calienes et al. from 2022 [33] provides an exceptionally detailed analysis of $CO_2$ emitted by producing blue hydrogen by steam methane reforming, accounting not just for input costs, but all emissions through the life cycle.

Figure 9 | Pipeline Costs [47]

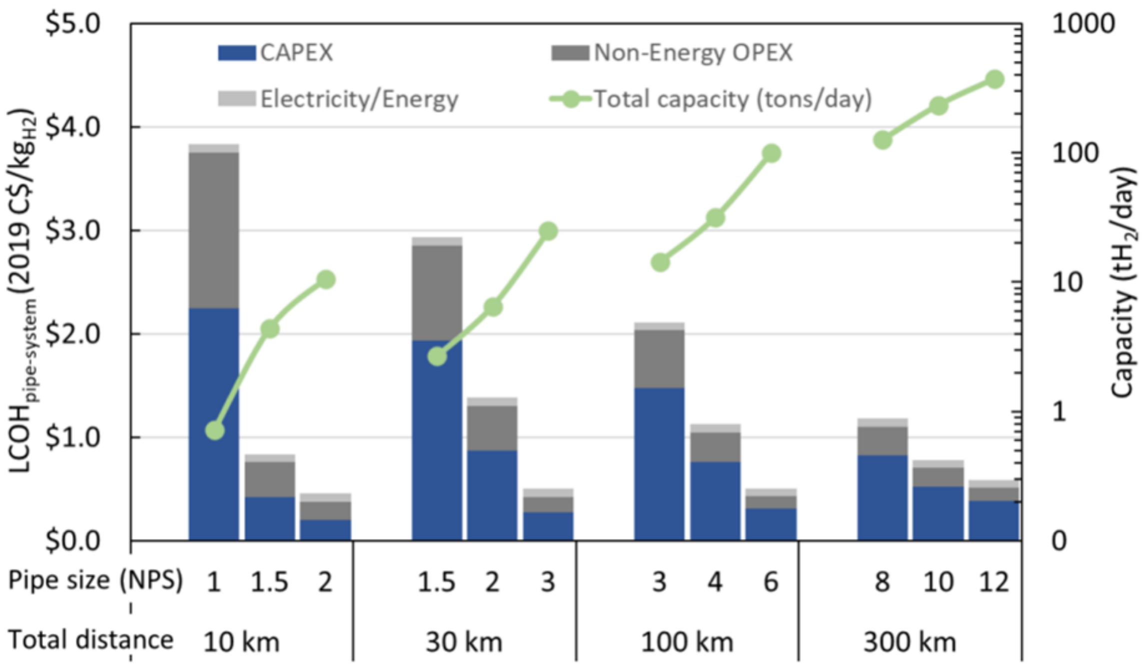
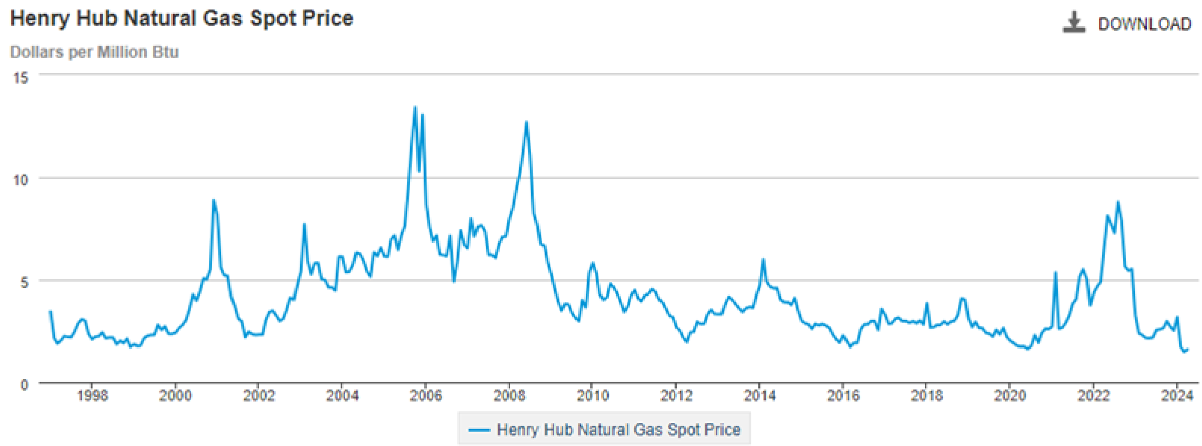



**Figure 7.4.** $LCOH_{pipe\text{-}system}$ divided into: $Capex_{pipe\text{-}system}$, Non-Energy $OPEX_{pipe\text{-}system}$ and Electricity /$Energy_{pipe\text{-}system}$ for different total distance of 10, 30, 100 and 300 km.

**Note**: For each distance, different pipe sizes were modelled to calculated capacity and $LCOH_{pipe-system}$. The inlet pressure for pipeline was assumed to be 70 bar with an outlet gas velocity of 35 m/s.

Figure 10 | Henry Hub Natural Gas Spot Price – USD/MMBTU [48]




Gonzales-Calienes et al. [33] found that blue hydrogen produced via steam methane reforming (SMR) with carbon capture and storage (CCS) emits 12.08 kg of $CO_2$ per kg of $H_2$. This is significantly lower than grey hydrogen (without CCS), but still higher than green hydrogen produced via electrolysis (1.365 kg $CO_2$ per kg $H_2$). Emissions Delta: The difference in $CO_2$ emissions between blue and green hydrogen is 10.715 kg $CO_2$ per kg $H_2$. Carbon Pricing Impact: If a carbon price of $170/tonne is applied, this emissions delta translates to an additional cost of $1.70 per kg of blue hydrogen vs $CO_2$ cost of green hydrogen via Electrolysis (1.365 kg $CO_2$ per kg $H_2$; [33]). Delta is 0.01 tonnes $CO_2$ per kg $H_2$. At $170/tonne emission credit, that is $1.70 per kg $H_2$.

### 5.1.3 White Hydrogen

Deep subsurface groundwater plus minerals such as olivine which contain iron can react with $H_2O$ to oxidize the iron, leaving $H_2$ gas. The resulting $H_2$ is often consumed by deep subsurface microbes, but the US Geological Survey believes that there may be substantial reserves of $H_2$ extant. There is informed geological speculation that large deposits of white hydrogen may be present in the far west of Ontario. It is completely premature to estimate any costs for this. However, it should be observed that the far West of the province is far from most residential, agricultural, and even industrial consumption sites, although hydrogen might be used as a reducing agent in the processing of other ores to be found in the same ring of fire district. This is, however, out of scope of this project.

## 5.2 Demand Side

### 5.2.1 Heating

Table 5 shows a natural gas price to beat of US1.36 cents per MJ of natural gas consumed. That is about C$0.02 at current exchange rates. As 1kg of hydrogen has a LHV of 120MJ, this corresponds to an offer cost of C$2.40.

### 5.2.2 Steel Production

Coal is used to make iron both for heat and for a reducing agent for the iron ore. Hydrogen can act as reducing agent; electricity for heating, to reduce carbon intensity of steel [34]. Steel making could be part of a local 'Hydrogen Hub'. NRCAN staff [35] analyze this in great detail (and obtain similar green hydrogen cost of C$3/kg that we do using similar power input costs). They find that transforming the Dofasco Steel Mill in Hamilton to $H_2$ would require about 492 tonnes of $H_2$ per day - about 150,000 tonnes per year, or 40 times current national green hydrogen production. These estimates are done with C$3/kg$H_2$ and are still not quite competitive with coal. It is possible, but outside the scope of this project, that the value of $H_2$ for steel production is greater than the value for natural gas displacement in heating.

## 5.3 IESO Regulatory Review Results

Through their Enabling Resources Program [36], the IESO is currently working to develop a framework for hybrid resource participation in the province's energy market and high-voltage grid, as operating reserve when demand unexpectedly exceeds generation. A regulatory participation framework does existing for more conventional sources [37]:

- Quick start: capable of providing grid output within 5 minutes, even if not synchronized to the grid.
- Non-quick start (gas): gas-fired generation that does not fall under quick start classification, also known as not-so-quick start.
- Imports: energy imported from one of five neighbouring grids with interconnected transmission lines.
- Variable: solar and wind resources.

These generation sources are categorized by IESO into the timeframe needed to bring them online as operating reserve (within 10 minutes or within 30 minutes) and, for the shorter 10-minute sources, whether they are spinning or non-spinning while on standby. These IESO classifications are summarized in **Table 7** below. Under currently published IESO policy, variable renewable energy generation sources are not enabled to serve as formal operating reserve and therefore not eligible to receive standby payments [38]

Table 7 **|** Summary of IESO Policy on Generation Sources as Operating Reserve

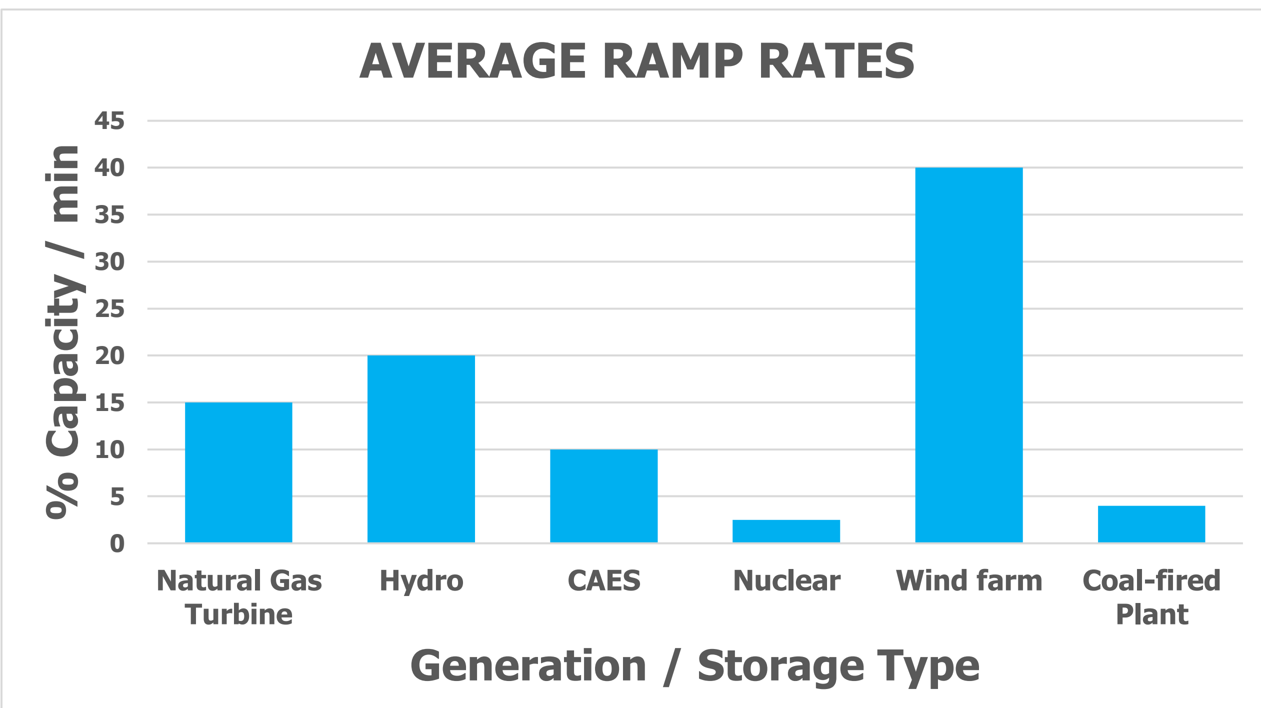
| **Resource Type** | **Dispatchable Energy Resources** | **Operating Reserve – 10 Min Spinning** | **Operating Reserve – 10 Min Non-Spinning** | **Operating Reserve – 30 Min** |
|---|---|---|---|---|
| Quick Start | Fully enabled | Fully enabled | Fully enabled | Fully enabled |
| Non-quick Start | Fully enabled | Partially enabled | Partially enabled | Partially enabled |
| Imports | Fully enabled | Not enabled | Partially enabled | Partially enabled |
| Variable | Fully enabled | Not enabled | Not enabled | Not enabled |

IESO Market Rules have specific & separate technical certification requirements for Ontario grid market participates acting as generators (producing electricity) and transmitters (outside of a micro-grid, distributing electricity to end users) but not specific regulation pertaining to parties that might serve both functions. Though Market Rules do explicitly state the requirement for IESO approval should grid connection of a generation source be altered [39]. In the first configuration proposed in the Part 1 report of the HIGH Energy project, excess electricity was to be transmitted from the wind farm to the greenhouse where it could be put to use in hydrogen production and later hydrogen combustion for supplying electricity to the grid. This could occur through the construction of a new isolated transmission line running from wind farm to greenhouse, or conceivably, a greenhouse onsite at the wind farm. Alternatively, if the wind farm were supplying excess electricity to the province's high-voltage grid directly with the understanding that the green house would be near-simultaneously drawing electricity into an electrolyzer to produce hydrogen for energy storage purposes, some accounting and coordination of this process would be required.

## 5.3 Peaker Ramp Rates

Average ramping capacities of contemporary technologies are shown in **Figure 11** below, represented as a percentage of rated capacity of the generator or storage option. Work by NREL [40] & Xu et al. [41] are referenced for commercially available values, with other values received via consultation from HIGH Energy project industrial partners. Though not shown in **Figure 11**, commercially available ramp rates of utility-grid scale battery technology storage nears 100% capacity/min with very quick discharge. Where available values were provided in a range, the average value was taken.

Figure 11 **|** Ramping Rates of Contemporary Generation & Storage Technologies [40] [41]

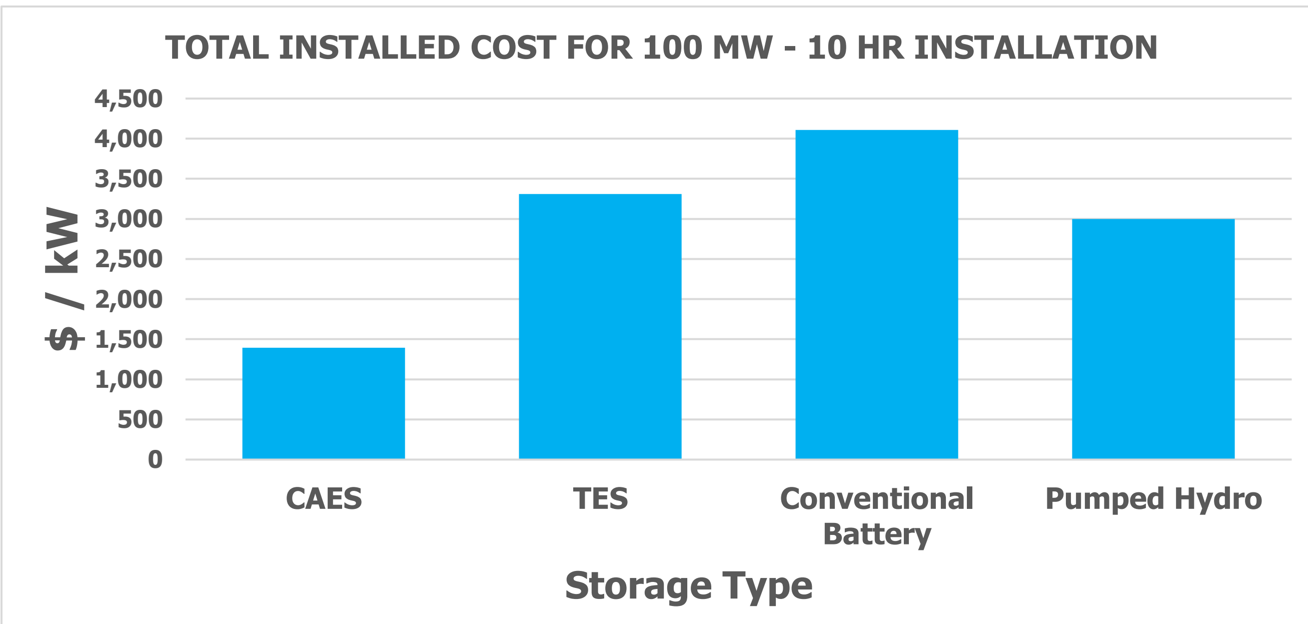



Despite representing more than 50% of Ontario's baseload power generation on a typical day, the ramping capabilities of nuclear power plants is relatively slow. Note that natural gas turbines provide moderate ramping capabilities of an average 15% capacity/min, but can reach as high as 30% capacity/min [40]. While the ramping capabilities of modern wind turbines are relatively high (production can be increased or curtailed quickly via pitch-controlling of individual turbine blades) such ramping can only be achieved when the wind resource is already available and the farm is under curtailment.

## 5.3 Storage Alternative Economics

Refer to **Figure 12** below for total installed costs (in US$, adjusted for inflation) are summarized from reference [42] generated by the Pacific Northwest National Laboratory for a 100 MW – 10 hour installation. Total costs include anticipated capital investment, operation & maintenance, and decommissioning. As shown in **Figure 12**, compressed air energy storage represents the cheapest option but will be geographically constrained due to the potential unique conditions needed to support a CAES plant.

Figure 12 **|** Total Installed Costs for Given Energy Storage Technology [42]



# 6. Offer Curve for Electricity from $H_2$ Fueled Turbines

## 6.1 Motivation

The increasing urgency to decarbonize power generation has intensified the exploration of hydrogen as a viable fuel for gas turbines. While gas turbines are a well-established and efficient technology, their reliance on natural gas is a significant contributor to carbon dioxide ($CO_2$) emissions, a major driver of climate change. Hydrogen, as a fuel source, offers a compelling solution due to its high energy density and the fact that its combustion produces only water vapor, eliminating $CO_2$ emissions entirely. This shift towards hydrogen could substantially reduce the carbon footprint of power generation, aligning with global efforts to combat climate change.

However, the transition to hydrogen-fueled gas turbines is not without its challenges. The combustion of hydrogen in gas turbines leads to increased nitrogen oxides (NOx) emissions due to higher flame temperatures. Additionally, hydrogen's faster flame speed and wider flammability range can cause flame instabilities, potentially affecting the turbine's safe and efficient operation. Furthermore, material compatibility issues, such as hydrogen embrittlement, pose risks to the long-term durability and reliability of turbine components. Overcoming these challenges requires significant research and development efforts, focusing on advanced combustion technologies, real-time monitoring systems, and the development of hydrogen-resistant materials.

## 6.2 Offer Curve Formula

To understand the economic feasibility, we developed an offer curve formula. To determine the cost per megawatt-hour (MWh) for a gas turbine operating on a mixture of hydrogen and natural gas, we need to calculate the cost of buying the required fuel in megajoules (MJ) and account for the turbine's efficiency at various hydrogen fractions. Here's a step-by-step breakdown of the formula and the factors involved.

First, we start with the basic formula:

Cost/MWh = (Cost to buy 3600 MJ of fuel) / (Efficiency at x%)

In this formula, 3600 MJ represents the amount of energy required to produce one MWh. The efficiency of the turbine, represented as $\eta(x)$, varies depending on the percentage of hydrogen in the fuel mix.

We need to consider the cost contributions of both hydrogen and natural gas. The cost of one megajoule of input fuel when using a mix of hydrogen (x%) and natural gas (1-x%) can be calculated as follows:

1. Hydrogen Cost ($P_H$):
   - One kilogram of hydrogen contains 120 MJ of energy.
   - Therefore, the cost per MJ of hydrogen PH is (1/120)×P_H.

2. Natural Gas Cost ($P_G$):
   - One million British thermal units (MMBTU) of natural gas contains approximately 1055 MJ.
   - One MMBTU of natural gas emits 53 kg of $CO_2$, which incurs an additional cost due to emissions credits.
   - Thus, the cost per MJ of natural gas $P_G$ is calculated as $(1 / 1055) \times (P\_G + 0.53 \times P\_E)$, where $P_E$ is the cost per tonne of $CO_2$ emissions.

To find the combined cost per MJ of the fuel mixture, we use the following formula:

$$\text{Cost per MJ} = (x/120 \times P_H) + ((1-x) / 1055 \times (P_G + 0.053 \times P_E))$$

To incorporate the turbine efficiency and convert the cost to a per MWh basis, we use the complete formula:

$$\text{Offer}(x) = 3600/\eta(x) \times ((x/120 \times P_H) + ((1-x) / 1055 \times (P_G + 0.053 \times P_E)))$$

where:

- x: Fraction of hydrogen in the fuel mix.
- η(x): Efficiency of the turbine at hydrogen fraction (x).
- $P_H$: Cost per kilogram of hydrogen.
- $P_G$: Cost per MMBTU of natural gas.
- $P_E$: Cost per tonne of $CO_2$ emissions.

This formula helps in determining the cost of generating electricity using a mix of hydrogen and natural gas, taking into account the efficiency of the turbine and the costs of the fuels and emissions. By adjusting the hydrogen fraction (x), we can analyze how different blends affect the overall cost and efficiency of power generation.

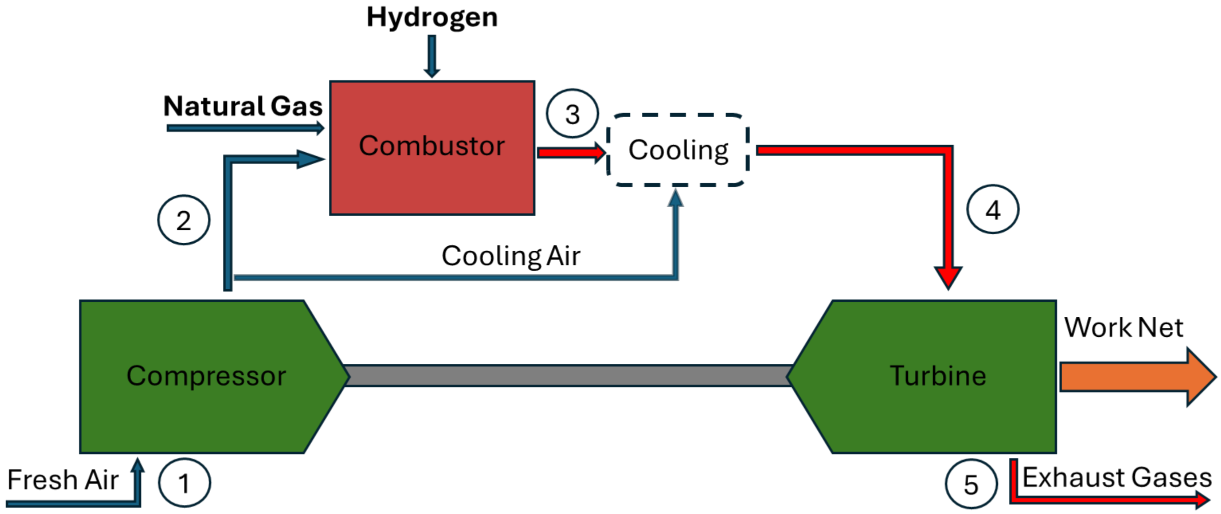
The offer curve formula provides a detailed method for calculating the cost of electricity production using mixed fuels in gas turbines, enabling better decision-making for integrating hydrogen into power generation systems. This approach considers both economic and environmental factors, crucial for transitioning to cleaner energy sources.

## 6.3 Thermodynamic Model

The gas turbine operation is modeled using a modified Brayton cycle, a standard thermodynamic cycle for gas turbines. This cycle comprises four main stages: compression, combustion, cooling, and expansion. In the compression stage, air is drawn into the compressor and pressurized. The compressed air is then mixed with fuel (hydrogen or natural gas) and ignited in the combustion chamber, resulting in a high-temperature, high-pressure gas mixture. This mixture expands through the turbine, performing work that drives the generator to produce electricity. Finally, the exhaust gases are released at a lower temperature and pressure.

See a basic schematic of a turbine operating on the Brayton Cycle in **Figure 13**.

Figure 13 **|** Brayton Cycle: System Schematic, adapted from [49]




To simulate this process accurately, the model is implemented using Cantera, an open-source software specializing in chemical kinetics. Cantera, coupled with the GRI 3.0 mechanism, a comprehensive database of natural gas combustion chemistry, allows for a detailed analysis of the combustion process and its impact on turbine performance. The model operates under several assumptions, including ideal gas behavior, adiabatic compression and expansion, negligible changes in kinetic and potential energy, complete combustion, and chemical equilibrium for the combustion products. These assumptions simplify the model while maintaining accuracy.

The simulation process involves iteratively calculating the system efficiency for various hydrogen-to-natural gas blend ratios and equivalence ratios (the ratio of actual to stoichiometric fuel-to-air ratio). The goal is to identify the optimal equivalence ratio that maximizes efficiency for each blend.

## 6.4 Key Equations

- **System Efficiency ($\eta_{sys}$):** This equation calculates the overall efficiency of the gas turbine system. It is defined as the ratio of the net power output ($\dot{W}_{net}$) to the heat input from the fuel ($\dot{Q}_{in}$). The net power output is the difference between the power produced by the turbine and the power consumed by the compressor and other auxiliary components. The heat input is the energy content of the fuel burned in the combustion chamber.

- **Combustion - Equivalence Ratio (φ):** This equation describes the ratio of the actual fuel-to-air ratio (F/A) in the combustion chamber to the stoichiometric fuel-to-air ratio $(F/A)_s$. The stoichiometric ratio is the ideal ratio for complete combustion, where all the fuel is burned with the exact amount of air needed. The equivalence ratio indicates whether the mixture is fuel-rich ($\varphi > 1$), fuel-lean ($\varphi < 1$), or stoichiometric ($\varphi = 1$).

## 6.5 Simulation Process

- **Input Parameters:** The simulation requires several input parameters, including the turbine inlet temperature, pressure ratio, ambient conditions (temperature and pressure), isentropic efficiencies of the compressor and turbine, desired power output, hydrogen fraction in the fuel blend, and a range of equivalence ratios to be tested.

- **Iterate:** The simulation iteratively calculates the system efficiency for different combinations of hydrogen fractions and equivalence ratios within the specified range. This involves solving the thermodynamic equations for the Brayton cycle and the combustion process.

- **Identify Optimal Conditions:** The goal of the simulation is to find the equivalence ratio that maximizes the system efficiency for each hydrogen fraction. This is done by analyzing the results of the iterative calculations and identifying the combination of parameters that yields the highest efficiency.

## 6.6 Mass Flow Rate

The mass flow rates of fuel and air are determined iteratively during the simulation. The goal is to achieve the desired net power output while maintaining the maximum allowable turbine inlet temperature. This ensures that the turbine operates within safe limits while maximizing power generation.

By systematically varying the input parameters and analyzing the resulting system efficiency, the simulation can provide valuable insights into the optimal operating conditions (**Figure 16**) for a hydrogen-fueled gas turbine. This information can be used to design more efficient and cleaner gas turbines that can contribute to decarbonizing the power sector.

Figure 14 | Offer Curve 2024

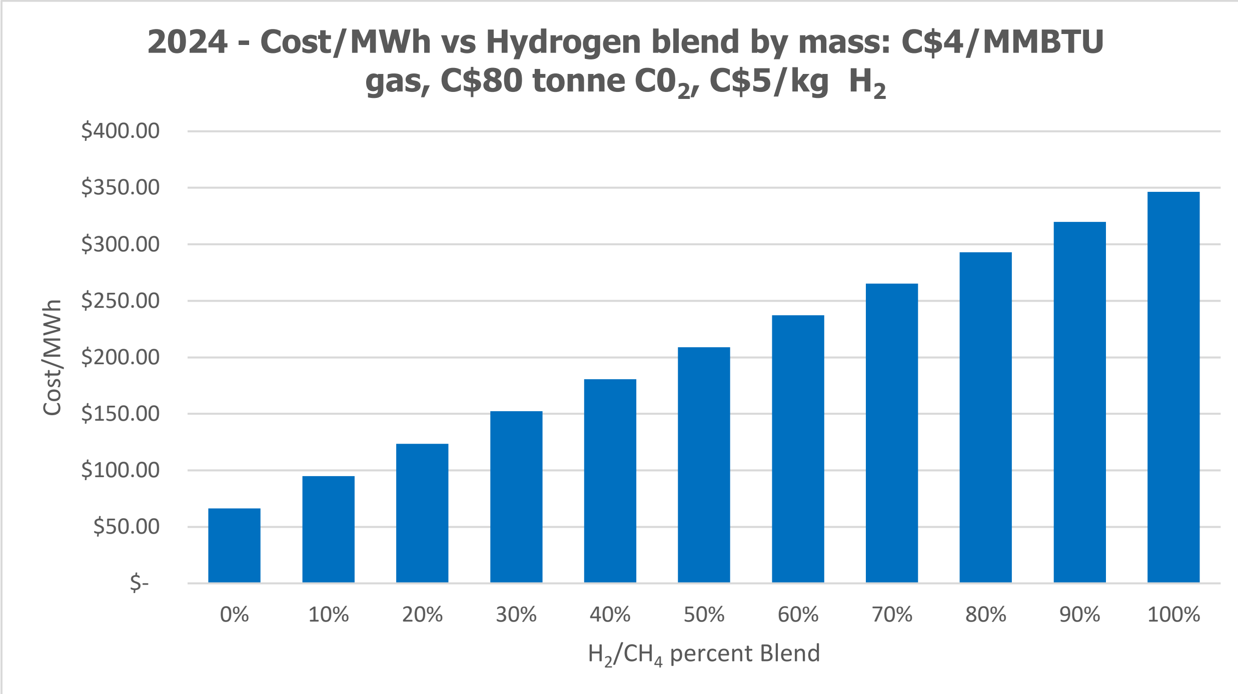



Figure 15 | Offer Curve 2030

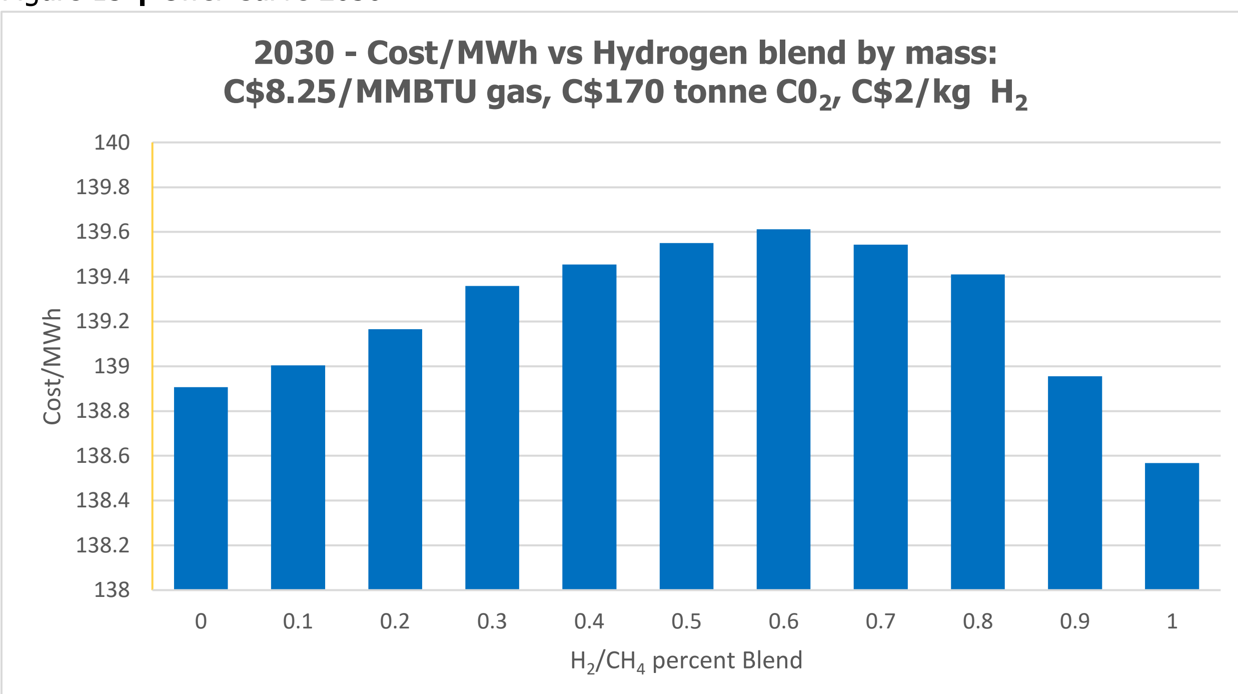


Figure 16 | Optimal System Efficiency ($\eta_{sys,opt}$) and Corresponding Equivalence Ratio ($\Phi_{opt}$) for Varying Hydrogen Volume Fractions in the Fuel Mixture [49]

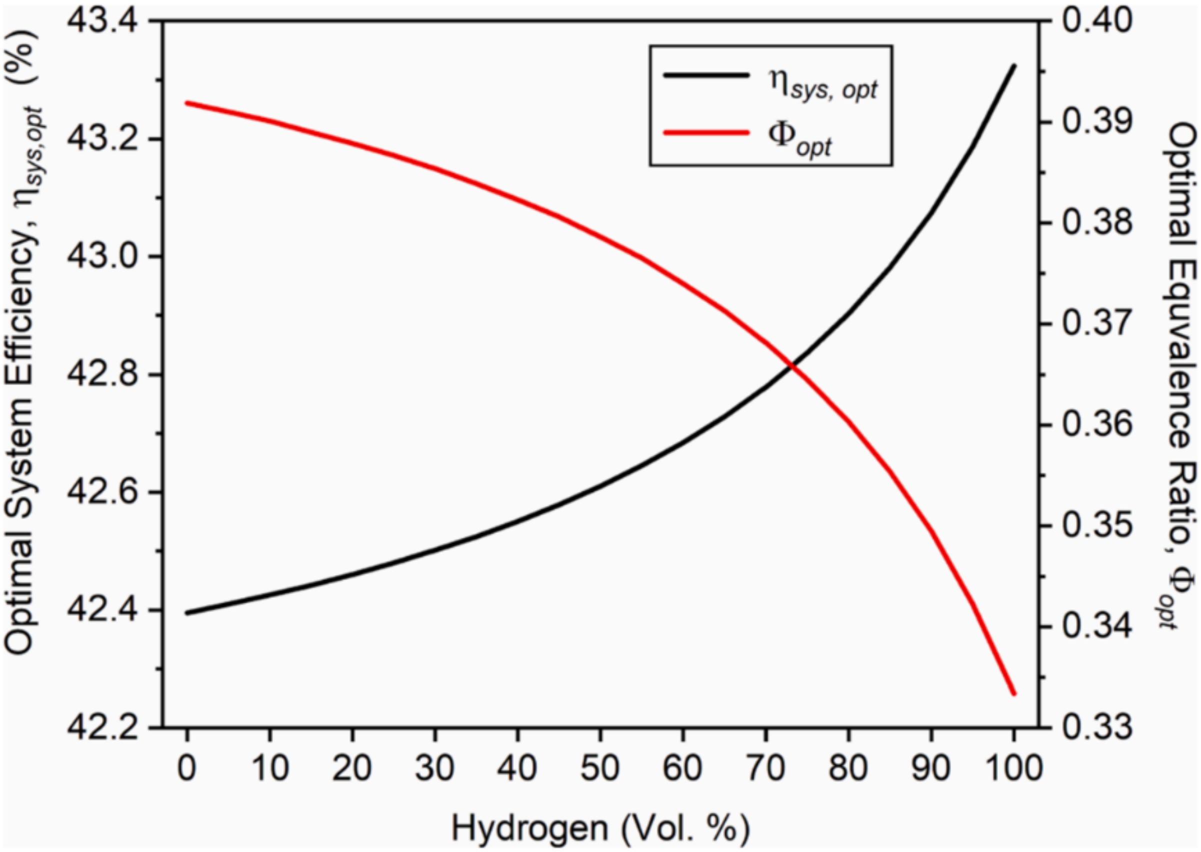



**Figure 14** and **Figure 15** illustrate the cost per MWh of different blends of hydrogen and methane (by mass) for the years 2024 and 2030, respectively. The analysis indicates that in 2024, with natural gas priced at C$4/MMBTU, a carbon tax of C$80/tonne $CO_2$, and hydrogen priced at C$5/kg, it is not yet cost-effective to use pure hydrogen. The costs increase significantly as the hydrogen blend percentage rises, making it less economically viable compared to methane.

However, by 2030, the scenario changes. With potential increase in natural gas prices to C$8.25/MMBTU, the projected carbon tax rising to C$170/tonne $CO_2$, and hydrogen priced at C$2/kg, using 100% hydrogen becomes more cost-efficient than using 100% methane. The cost per MWh for pure hydrogen is lower than that for pure methane under these future conditions. This shift highlights the potential economic benefits of transitioning to hydrogen, driven by the higher carbon tax and anticipated lower hydrogen production costs.

It is important to note that the economic feasibility of hydrogen as an energy source will depend on various factors, including advancements in hydrogen production technologies, changes in energy policies, and fluctuations in market prices for natural gas and hydrogen. The projections for 2030 suggest that, with supportive policies and technological advancements, hydrogen could become a more attractive and cost-effective option for energy production, contributing to a reduction in greenhouse gas emissions.

# 7. Discussion

## 7.1 Hydrogen Market Discussion

With current technology, best bid prices (of about $2.50) are not quite enough to meet best offer prices of about C$3. However, there is a history of innovation and mass production dramatically reducing the capital cost of green energy technologies (solar panels, batteries, wind turbines) as shown in **Figures 17 - 19**. Speculations made by the International Renewable Energy Agency (IRENA) [29] are included in **Figure 20**.  In the meantime, tax and other incentives might work to fill the gap between best bid and best offer.

Figure 17 **|** Solar Panel Cost Data [50]

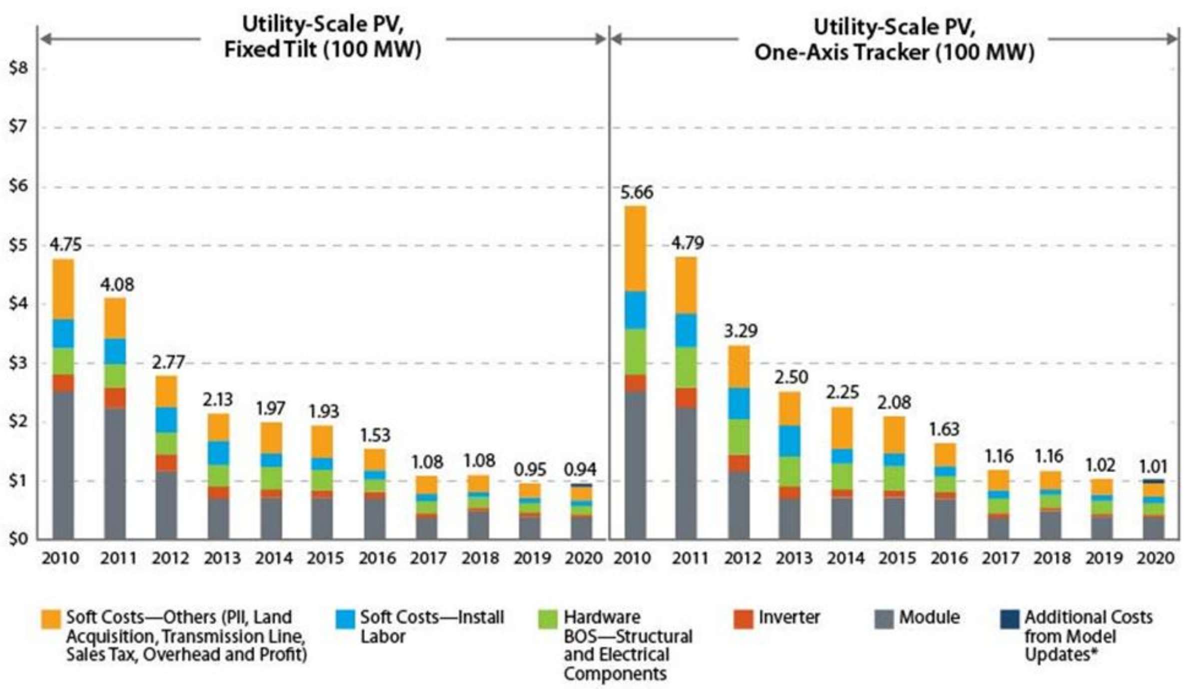


Figure 18 **|** Lithium-ion Batteries Prices in the Last 30 years [51] - note dramatic cost cuts

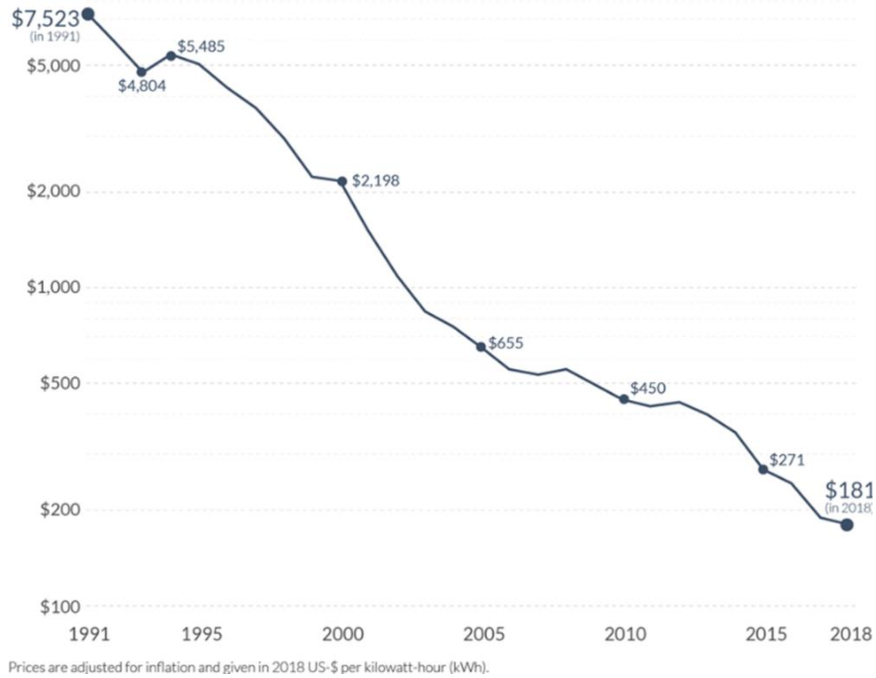



Figure 19 **|** Wind Turbine Prices in the Last 25 Years [52]

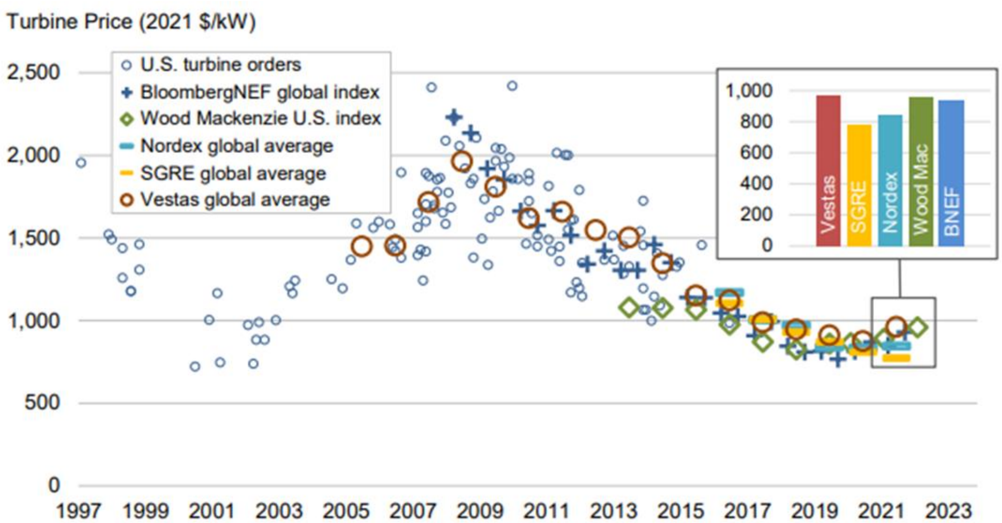
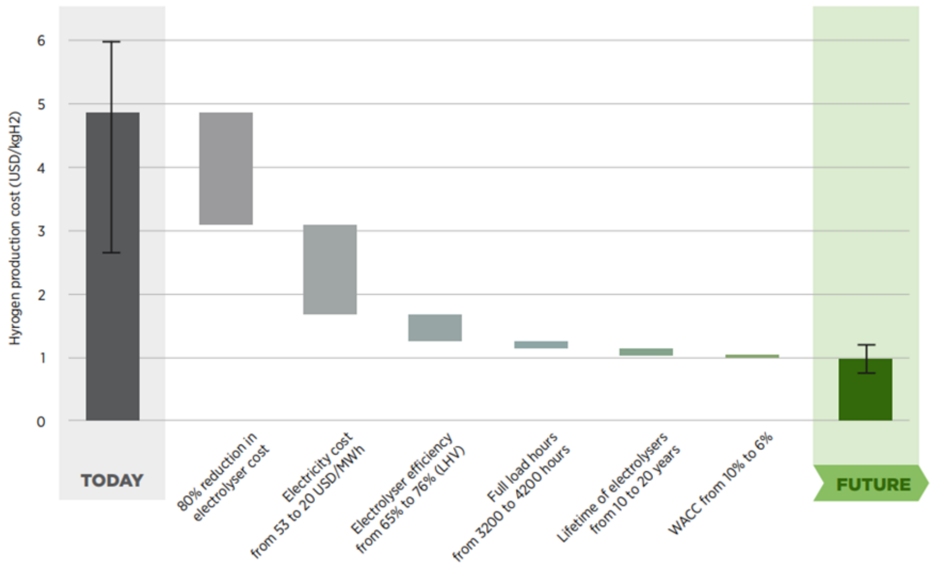


Figure 20 | Necessary Conditions for Green Hydrogen to Become a Mainstream Energy Source [29]

**Figure 35.** Step changes for achieving green hydrogen competitiveness.




Note: 'Today' captures best and average conditions, with an average investment of USD 770/kW, efficiency of 65% (LHV), an electricity price of USD 53/MWh, 3 200 full load hours (onshore wind), a WACC of 10% (relatively high risk). Best conditions are USD 130/kW, efficiency at 76% (LHV), electricity price at USD 20/MWh, 4 200 full load hours (onshore wind), and WACC of 6% (similar to renewable electricity today).

Based on IRENA analysis.

### 7.1.2 Threats to Assumptions

It is assumed that cheap power is available (likely at night) into the future: even as green transition continues and wind that is driving lower power cost is taken out of market to produce hydrogen. But electrical vehicles are charging overnight, potentially flattening yield curve.

LLM driven growth in power demand may be partly off peak (or may follow business hours).

## 7.2 Offer Curve Discussion

At current prices it is hard to imagine a hydrogen powered turbine being competitive with a state-of-the-art CCGT gas turbine even accounting for emissions costs. This will perhaps develop with time.

## 7.3 Regulatory Review Discussion

A formal means of integrating variable renewable energy sources into the standby operating reserve connected to the IESO grid provide a pathway for renewables to increase their penetration on the provincial grid. These comments are echoed in the recent Distributed Energy Resources Study produced for the IESO [43]. As is currently under review through the IESO's Enabling Resources Program, it is proposed in this report that a wind farm incorporating behind-the-meter storage via hydrogen production & combustion be recognized as a hybrid resource type capable of injecting electricity onto the grid as operating reserve, with implementation similar to that of non-quick start resources, as defined by the IESO. See **Table 8** below.

Table 8 **|** Proposed Operating Reserve Characteristics for Hybrid Wind Farm Resource

| Resource Type | Dispatchable Energy Resources | Operating Reserve – 10 Min Spinning | Operating Reserve – 10 Min Non-Spinning | Operating Reserve – 30 Min |
|---|---|---|---|---|
| Variable | Fully enabled | Partially enabled | Partially enabled | Partially enabled |

For a potential hybridization configuration in which the wind farm supplies its excess electricity directly to the high-voltage provincial power grid with the expectation that the greenhouse will draw this same quantity of electricity to put toward hydrogen production, a virtual power purchase agreement (VPPA) framework is proposed that makes this type of participation in the province's e

## 7.4 Peaker Technology Discussion

While nuclear energy currently provides a significant portion of the province's baseload generation, its limited ramping flexibility (among other reasons) ensures that other generation & storage options will continue to be needed on province's grid. And as the province continues to move away from carbon-producing generation like natural gas turbines, variable renewable energy resources such as wind and solar will need to increase their penetration onto the grid. The HIGH Energy scheme proposes pairing of variable wind farm production with hydrogen generation & combustion, where hydrogen and hydrogen-natural mixed combustion are assumed to produce similar ramping capabilities to natural gas-fired turbines. This average 15% capacity per minute ramp rate [40] is less than other generation technologies, but is sufficient to serve as operating reserve for peak demand grid support per current IESO policy.

# 8. Economic/Technical Impact, and Risk Assessments

This section evaluates the potential economic and technical impacts of the hydrogen project, alongside associated risks.

## 8.1 Economic Impact

### 8.1.1 Market Viability

The economic viability of hydrogen as a fuel largely depends on the interplay between production costs, market prices, and government incentives. Current trends indicate that hydrogen production costs are decreasing due to technological advancements and economies of scale. However, the initial investment remains high, necessitating robust financial planning and risk management strategies.

### 8.1.2 Cost-Benefit Analysis

A comprehensive cost-benefit analysis should be conducted to compare hydrogen with other energy sources. This analysis includes evaluating the Levelized Cost of Electricity (LCOE) for hydrogen against traditional fuels. Current estimates place the LCOE for hydrogen higher than that of natural gas and coal, but future projections indicate potential cost reductions with advancements in technology and scaling up of production.

## 8.2 Technical Impact

### 8.2.1 Infrastructure Requirements

Adopting hydrogen as a primary energy source requires significant upgrades to existing infrastructure. This includes the development of hydrogen production facilities, storage systems, and transportation networks. The integration of hydrogen into the current energy grid also poses technical challenges related to safety, efficiency, and reliability.

### 8.2.2 Technological Advancements

Ongoing research and development are critical for improving hydrogen production methods, such as electrolysis, and addressing technical issues like hydrogen embrittlement in pipelines. Innovations in fuel cell technology and hydrogen storage solutions will also play a crucial role in facilitating the widespread adoption of hydrogen.

## 8.3 Risk Assessments

### 8.3.1 Market Risks

The hydrogen market is still in its nascent stages, and there are significant uncertainties regarding future demand, pricing, and regulatory frameworks. Market risks include fluctuations in hydrogen prices and potential competition from other emerging energy technologies.

### 8.3.2 Technical Risks

Technical risks encompass the reliability and safety of hydrogen systems. This includes risks associated with high-pressure storage, potential leaks, and the long-term durability of hydrogen infrastructure. Mitigation strategies involve rigorous testing, compliance with safety standards, and continuous monitoring and maintenance of hydrogen facilities.

### 8.3.3 Environmental and Regulatory Risks

The environmental impact of hydrogen production depends on the source of energy used. Green hydrogen, produced using renewable energy, offers significant environmental benefits but requires substantial investment in renewable energy infrastructure. Regulatory risks involve changes in government policies and incentives that could affect the economic viability of hydrogen projects.

## 8.4 Conclusion

The transition to a hydrogen economy presents both opportunities and challenges. While the potential economic and environmental benefits are significant, careful consideration of the associated risks is essential. Strategic planning, investment in research and development, and supportive policy frameworks will be key to mitigating these risks and ensuring the successful integration of hydrogen into the energy landscape.

# 9. Lessons Learned

Key lessons learned from this study include:

- The necessity for 'depth' of the hydrogen market, in the sense that market participants can be assured that they may buy or sell hydrogen as per their needs.
- The need for producer incentives (subsidy for capital via tax incentives or a feed-in-tariff) to kickstart the hydrogen market.
- Wind energy is an extremely reflexive energy source, as modern pitch-controlled blades can ramp up and down as needed. However, this ramping ability can only be utilized where wind resource is readily available (which may not align with demand on the grid). Assuming the performance characteristics of gas-powered turbines are not significantly affected by the hydrogen-natural gas mix in a proposed hybridization scheme, the deployment of such a scheme could provide grid support purely from a technical capability perspective.

# 10. Next Steps

Next steps for the work covered in this study include:

- Developing a market plan for introduction of white hydrogen from Ontario's 'Ring of Fire' region to Southern Ontario's Industrial Region.
- In-depth analysis of green hydrogen for the steel production process.

# References


[1] Wang P, Deng X, Zhou H, Yu S. Estimates of the social cost of carbon: A review based on meta-analysis. Journal of Cleaner Production 2019; 209:1494-1507. https://doi.org/10.1016/j.jclepro.2018.11.058.

[2] Haynes W M. 2014. CRC Handbook of Chemistry and Physics, 95th ed. CRC Press.

[3] Enbridge. n.d. https://www.enbridgegas.com/about-enbridge-gas/learn-about-natural-gas.

[4] DOE. n.d. Hydrogen Shot. https://www.energy.gov/eere/fuelcells/hydrogen-shot.

[5] Hatch. 2023. Comparative analysis of electricity generation costs by source. WaterPower Canada.

[6] IESO. 2024. Market Rules & Manuals Library. https://www.ieso.ca/sector-participants/market-operations/market-rules-and-manuals-library (accessed January, 2024).

[7] IESO. 2024. Operating Reserve Markets. https://www.ieso.ca/sector-participants/market-operations/markets-and-related-programs/operating-reserve-markets (accessed April, 2024).

[8] International Energy Agency. 2019. The Future of Hydrogen. https://www.iea.org/reports/the-future-of-hydrogen.

[9] Government of Canada. 2020. Hydrogen Strategy for Canada: Seizing the opportunity for Hydrogen: A Call to Action. https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/environment/hydrogen/NRCan_Hydrogen-Strategy-Canada-na-en-v3.pdf.

[10] Her Majesty's Government. 2021. UK Hydrogen Strategy. https://www.gov.uk/government/publications/uk-hydrogen-strategy.

[11] U.S. Department of Energy. 2023. US National Clean Hydrogen Strategy and Roadmap. https://www.energy.gov/eere/fuelcells/us-national-clean-hydrogen-strategy-and-roadmap

[12] Canada Energy Regulator. 2023. Canada's Energy Future. https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2023/index.html.

[13] Öberg S, Odenberger, M, Johnsson, F. Exploring the competitiveness of hydrogen-fueled gas turbines in future energy systems. International Journal of Hydrogen Energy 2022, 47(1): 624-644. https://doi.org/10.1016/j.ijhydene.2021.10.067.

[14] IESO. 2024. Power Data. https://www.ieso.ca/power-date (accessed June, 2024).

[15] IESO. 2024. Ontario's Electricity Grid - Supply Mix and Generation. https://www.ieso.ca/Learn/Ontario-Electricity-Grid/Supply-Mix-and-Generation (accessed June, 2024).

[16] Energy and Mines Ministers' Conference. 2014. Integration of variable output renewable energy sources: The importance of essential reliability services. St. Andrews by-the-Sea.

[17] IESO. 2021. 2021 Year-End Date. https://www.ieso.ca/en/Corporate-IESO/Media/Year-End-Data/2021 (accessed June, 2024).

[18] Kruger Energy. 2024. Personal Communication. May, 2024.

[19] Environment and Climate Change Canada. 2023. Canadian environmental sustainability indicators: Greenhouse gas emissions. https://www.canada.ca/en/environment-climate-change/services/environmental-indicators/greenhouse-gas-emissions.html.

[20] General Motors. 2023, December 12. GM’s HYDROTEC fuel cell technology to power Navistar’s production trucks in 2024. GM News: https://news.gm.com/newsroom.detail.html/Pages/news/us/en/2023/dec/1212-hydrotec.html.

[21] IESO. 2024. About the IESO: Managing the Power System. https://www.ieso.ca/Learn/About-the-IESO/Managing-the-Power-System (accessed January, 2024).

[22] IESO. 2024. What is the Market Renewal Program. https://www.ieso.ca/Market-Renewal/Background/Overview-of-Market-Renewal (accessed January, 2024).

[23] Ragogna P. 2024. Personal Communication.

[24] Natural Resources Canada. 2024. Hydrogen Strategy for Canada: Progress Report. Government of Canada. https://natural-resources.canada.ca/climate-change/canadas-green-future/the-hydrogen-strategy/hydrogen-strategy-for-canada-progress-report/25678.

[25] Energy Council of Canada (2023). Canadian hydrogen: A world leading innovative technology. https://energy.ca/naio/canadian-hydrogen/#:~:text=Canada%20ranks%20in%20the%20top%2010%20of%20global,%E2%80%93%20approximately%204%20percent%20of%20the%20global%20total.

[26] Canada Energy Regulator. 2024, May 24. Estimated Production of Canadian Crude Oil and Equivalent. Oil and Petroleum Products: https://www.cer-rec.gc.ca/en/data-analysis/energy-commodities/crude-oil-petroleum-products/statistics/estimated-production-canadian-crude-oil-equivalent.html.

[27] IESO. 2024. Global Adjustment (GA). https://www.ieso.ca/power-data/price-overview/global-adjustment (accessed September, 2024).

[28] London Hydro. 2024. Water Rates. https://www.londonhydro.com/accounts-services/water/water-rates (accessed September, 2024).

[29] International Renewable Energy Agency. 2020. Green hydrogen cost reduction: Scaling up electrolysers to meet the 1.5°C climate goal. International Renewable Energy Agency. https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Dec/IRENA_Green_hydrogen_cost_2020.pdf.

[30] Hand S, Guest J, Cusick R. 2019. Technoeconomic analysis of brackish water capacitive deionization: Navigating tradeoffs between performance, lifetime, and material costs. Environmental Science & Technology.

[31] Sandquist J B. 2023. Cost breakdown and scaling of electrolyzer systems: A review. Applied Energy.

[32] Katebah M, Al-Rawashdeh M, Linke P. Analysis of hydrogen production costs in Steam-Methane Reforming considering integration with electrolysis and CO2 capture. Cleaner Engineering and Technology 2022, 10:100552. doi:https://doi.org/10.1016/j.clet.2022.100552.

[33] Gonzales-Calienes G, Kannangara M, Yang J, Shadbahr J, Deces-Petit C, Bensebaa F. 2022. Life Cycle Assessment of Hydrogen Production Pathways in Canada. NRC.

[34] Fischedick M, Marzinkowski J, Winzer P, Weigel M. Techno-economic evaluation of innovative steel production technologies. Journal of Cleaner Production 2014, 84:563-580.

[35] Khan M, Powell M, Tampier M, Thorn E, Layzell D. 2023. Hydrogen and the decarbonization of steel production in Canada. Canadian Steel Producers Association.

[36] IESO. n.d. Enabling Resources Program. https://www.ieso.ca/Sector-Participants/Engagement-Initiatives/Engagements/Enabling-Resources-Program (accessed September, 2024).

[37] IESO. 2021. Expanding participation in operating reserve and energy: IESO participation requirements, and misalignments with models of participation.

[38] IESO. 2011. Guide to operating reserve.

[39] IESO. 2021. Market Rules Chapter 4: Grid Connection Requirements.

[40] NREL. 2020. Ramping up the ramping capability: India's power system transition.

[41] Xu T, Birchfield A, Gegner K, Shetye K. 2017. Application of large-scale synthetic power system models for energy economic studies. Hawaii International Conference on System Sciences.

[42] Viswanathan V, Mongird K, Franks R, Li X, Sprenkle V, Baxter R. 2022. 2022 Grid energy storage technology cost and performance assessment. PNNL-33283.

[43] Dunsky Energy + Climate Advisors. 2022. Ontario's distributed energy resrouces (DER) potential study volume 1: Results & recommendations. IESO.

[44] CBC News. 2022, February 15. Ontario takes aim at climate change by investing in green steel technology. https://www.cbc.ca/news/canada/toronto/ontario-climate-change-steel-co2-greenhouse-gas-emissions-1.6353814.

[45] IESO. 2024, April. Average HOEP Prices for the Month. Hourly Ontario Energy Price : https://www.ieso.ca/Power-Data/Monthly-Market-Report.

[46] Kumar A, Lim H. 2022. An overview of water electrolysis technologies for green hydrogen production. Energy Reports.

[47] Khan M, Young C, Layzell D. 2023. The techno-economics of hydrogen pipelines (Version 2). The Transition Accelerator.

[48] U.S. Energy Information Administration. n.d. Henry Hub Natural Gas Spot Price. Natural Gas: https://www.eia.gov/dnav/ng/hist/rngwhhdM.htm.

[49] Skabelund BB, Jenkins CD, Stechel EB, Milcarek RJ. Thermodynamic and emission analysis of a hydrogen/methane fueled gas turbine. Energy Conversion and Management July 2023 19: 100394.

[50] Feldman D, Ramasamy V, Fu R, Ramdas A, Desai J, Margolis R. 2021. U.S. Solar Photovoltaic System and Energy Storage Cost Benchmark: Q1 2020. National Renewable Energy Laboratory.

[51] Ritchie H. 2021. The price of batteries has declined by 97% in the last three decades. OurWorldInData.org: https://ourworldindata.org/battery-price-decline.

[52] Wiser R, Bolinger M. 2022. Land-Based Wind Market Report: 2022 Edition. Wind Energy Technologies Office of the U.S. Department of Energy.