Feasibility Study for an Urban Hydrogen Hub: Grid Flexibility, Resilience, and Carbon Reduction Scalable to Nuclear Power Plant Co Location Opportunities

Kinectrics Inc. in partnership with Bruce Power and FuelCell Energy

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1. Executive Summary

Hydrogen is a key element in the clean-energy ecosystem. When paired with a nuclear generating station, there is significant potential for increasing reliability, reducing carbon intensity, and improving sustainability to Ontario's electricity grid.

This report presents the findings of the feasibility study undertaken for an urban hydrogen production and use facility. The methodology used to develop the feasibility study is summarized in the following table:

Technology Assessment	Economic Assessment	Design Requirements
Assemble available data.	Define the system.	High-Level Requirements.
Learn from operational experience.	Estimate capital costs.	Hydrogen Plant Design.
Analyse the data and simulations.	Calculate operating costs.	Site Justification and Layout Planning.
	Analyse cash flow and profitability.	Safety and Environmental Impact.

The case study used for this assessment is an urban hydrogen facility referred to as the "*Hydrogen Hub*". The proposed pilot hub, strategically located in Toronto, Canada, consists of a 1.1 MW solid oxide electrolyser cell (SOEC) system, a 250-kW solid oxide fuel cell (SOFC) for power generation, and a hydrogen refueling station. SOEC systems were selected because they have a higher output and offer several advantages as compared to other systems. The technology assessment includes technology readiness, advantages and disadvantages, and environmental impact.

The economic assessment was completed for SOECs of electrical input of 1.1 MW, 11 MW, and 110 MW. The economic assessment included estimating capital costs, determining operating costs, and evaluating cash flow and profitability for these three power systems. The findings showed that the SOECs of 11 MW and 110 MW are more economic than the smaller pilot scale of 1.1 MW. This is because the electricity cost is the most significant factor contributing to the hydrogen cost, not the capital. If a high-power system can be installed to use heat and electrical input from a low-carbon nuclear power plant nearby, or utilizing the waste heat from another process, the levelized cost of hydrogen produced can be as low as \$6.97 CAD/kg-H_2, emphasizing the economic viability of this approach. Improvements in technology and declining CAPEX by 2030 will drive down the cost.

The study also proposes a vehicle refueling system as an end use for the hydrogen produced in addition to the use of hydrogen for grid electricity. This end use was chosen as hydrogen vehicles offer several distinct advantages for decarbonizing the transport sector, a traditionally hard to decarbonize sector, and it is anticipated that more hydrogen powered vehicles will be on our roads in the coming decades. Successful hydrogen projects are operating in Canada and around the world.

In alignment with the Ontario Low-Carbon Hydrogen Strategy, this report presents a practical and specific business case for hydrogen. Hydrogen storage, transportation, and distribution remain the primary challenges for integrating hydrogen into the overall energy-economy system. Initial pilot production facilities could be instrumental in the development of a sustainable hydrogen solution, with operating experience and lessons learned available for future projects.

2. Introduction and Goal

As global concerns about climate change and environmental sustainability intensify, the search for clean and renewable energy sources has accelerated. Among the various alternatives, hydrogen has emerged as a promising candidate due to its potential to serve as a clean energy carrier. This study aims to evaluate the feasibility of hydrogen as a key component of the future energy landscape.

Purpose

The purpose of the report is to provide a feasibility assessment of a commercial demonstration of hydrogen as an energy carrier within the electricity system. This report aims to provide insights into the opportunities and challenges of hydrogen use in the electricity system and will enable the IESO, and the industry at large, to better understand the integration of hydrogen into the energy ecosystem.

Goal

1. Assess the Technology.
    - Focus on improving SOEC and SOFC, using process engineering and system integration. The goal is to improve performance, durability, and efficiency based on operating parameters.
    - Prove technical viability and environmental sustainability of the integrated technology. The goal is to optimize the technology, scale-up and understand the challenges for integrating hydrogen into the energy ecosystem.
2. Assess the economic feasibility of an urban Hydrogen Hub.
    - Consider the costs and payback of the Hydrogen Hub, including the production, storage, and use of hydrogen.
    - Assess the scaling costs of hydrogen production.
3. Assess the site and design requirements
    - Define the design requirements for the Hydrogen Hub
    - Assess the potential site and identify potential challenges and opportunities
4. Assess the landscape.
    - Review and determine the readiness of regulations, codes and standards, and safety considerations.
    - Review other hydrogen production projects, both in Canada and internationally, and integrate learnings.

Acronyms

Many acronyms are used throughout this report. All acronyms have been provided in this list to be used as reference throughout reading.

AC .... Alternating Current
AEM .... Anion Exchange Membrane
AI .... Artificial Intelligence
AMI .... Advanced Metering Infrastructure
AODA .... Accessibility for Ontarians with Disabilities Act, 2005
BEV .... Battery Electric Vehicle
CAD .... Canadian Dollar
CAPEX .... Capital Expenditure
CCS .... Carbon Capture and Storage
CEAA .... Canadian Environmental Assessment Act
CEC .... Canadian Electric Code
CEPCI .... Chemical Engineering Plan Cost Index
CI .... Carbon Intensity
CNSC .... Canadian Nuclear Safety Commission
CO2 .... Carbon Dioxide
CSA .... Canadian Safety Association
CCUS .... Carbon Capture, Utilisation, and Storage
CNSC .... Canadian Nuclear Safety Commission
DC .... Direct Current
DI .... De-ionized
DRI .... Direct Reduction Ion
EA .... Environmental Assessment
EMS .... Environmental Management System
EPMs .... Environmental Protection Measures
EPR .... Environmental Protection Review
ERA .... Environmental Risk Assessment
ETC .... Energy Transitions Commission
FCI .... Fixed Capital Investment
FMC .... Fixed Manufacturing Cost
GDL .... Gas Diffusion Layer
GHG .... Greenhouse Gas
GT .... Gas Turbine
H2 .... Hydrogen
H2FAST .... Hydrogen Financial Analysis Tool
HTE .... High-Temperature Electrolysis
IA .... Impact Assessment
IAA .... Impact Assessment Act

IESO ....Independent Electricity System Operator
KW ....kilowatt
LCOE.. Levelized Cost of Energy
LCOH .... Levelized Cost of Hydrogen
MCP .... Market Clearing Price
MSR ....Molten Salt Reactor
Mt ....megatons
MW ....megawatt
NEC.. National Electric Code
NG .... Natural Gas
Ni ....Nickel
NPP..Nuclear Power Plant
NREL.. National Renewable Energy Laboratory
NWTP.. New Water Treatment Plant
NSCA... Nuclear Safety and Control Act.
O2 .... Oxygen
OSHA ....Occupational Safety and Health Administration
PEM ....Proton-Exchange Membrane
Pl ....Platinum
POM ....Partial Oxidation of Methane
PSA .... Pressure Swing Absorption
PV ....Photovoltaic
R&D .... Research and Development
SCADA... Supervisory Control and Data Acquisition
SEM ....Scanning Electron Microscope
SMR ....Small Modular (Nuclear) Reactor
.... Steam Methane Reforming
SOEC...Solid Oxide Electrolyser Cell
SOFC.. Solid Oxide Fuel Cell
SSC ....Structure, System, and Component
TTC...Toronto Transit Commission
TDG ....Transportation of Dangerous Goods
TPC ....Total Production Cost
TRL ....Technology Readiness Level
USD .... American Dollar
WTP ....Water Treatment Plant
YSZ ....Yttria-Stabilized Zirconia

3. Approach/Methodology, and Assumptions

Our Approach: Case Study

Previous projects have assessed the feasibility of hydrogen production and power generation in regions around the world; however, this project is unique in that it focuses on the establishment of a localized (urban) hydrogen hub providing not only hydrogen generation capacity but also electricity production through fuel cell technology. Additionally, this study seeks to consider localized consumption of hydrogen for transportation applications. This "Hydrogen Hub" approach is the key distinguishing feature of this study.

The proposed "Hydrogen Hub" is an installation of a hydrogen production facility in combination with a hydrogen power generation facility (fuel cell), and a vehicle refueling station. While the hub will aim to illustrate that incorporating hydrogen generation output can enhance grid reliability and pairs well with scenarios where there may be excess energy production, it will also allow for the use of hydrogen as a fuel for use in transportation. This would provide an alternative and potentially more efficient fuel for local clean transport applications.

> The proposed commercial pilot hub is intended to demonstrate the potential for large-scale deployment of hydrogen production and power generation technology across the Ontario electricity grid.

Case Description

The Hydrogen Hub is intended to be strategically placed at Kinectrics' 800 Kipling Avenue site in Toronto, Ontario. This location provides an ideal location to evaluate the urban hydrogen production and use scenario. Kinectrics owns the property, has technical experts on location, has a facility available to house the hydrogen production units, and is in a commercial/industrial area. The site offers access to necessary infrastructure and resources (for example, high-voltage power supply and water). The site is also next door to heavy-duty vehicle fleets, including the Kipling Terminal for the Toronto Transit Commission (TTC) and a major Purolator courier fleet depot. There are a number of commercial and industrial facilities nearby who could be potential users of hydrogen, along with a growing interest in hydrogen for heavy transport within the vicinity.

Pilot scale

The proposed pilot system is a 1.1 MW solid oxide electrolyser cell (SOEC) for hydrogen generation and a 250-kW solid oxide fuel cell (SOFC) for power generation.

Systems with SOEC capacities of 11 MW and 110 MW were also evaluated to assess scalability and economic feasibility. These larger-scale systems are expected to be deployed in proximity to medium- to high-capacity facilities, such as nuclear generation stations, in the coming decade.

Methodology: Technology Assessment

The technology assessments were completed using the following steps:

1. Assemble available data.
    a. The technology assessment includes both a general overview of hydrogen and a more detailed evaluation of technologies. Data was both from research studies conducted on similar hydrogen hubs across Canada, along with relevant scientific literature and technical reports.
    b. Specifically, the comprehensive data set on the properties of SOEC and SOFC technologies was acquired directly from FuelCell Energy, a leading company in the hydrogen industry.
2. Incorporate operating experiences.
    a. Operating experiences shared by industry experts from Kinectrics and Bruce Power as well as other industry partners was collected.
    b. Where possible, lessons learned, and insights were incorporated from other hydrogen production projects both in Canada and internationally.
3. Analyse the data and simulations.
    a. Complementary data analysis and simulations were conducted using RETScreen Clean Energy Management Software.
4. Collect and analyse market data.
5. Understand national hydrogen consumption patterns.
6. Use historical and projected hydrogen pricing data.
7. Request information on hydrogen technology vendors.

Additionally, there was an interest in understanding how to integrate nuclear generation with hydrogen production and therefore, we assessed nuclear power plant heat characteristics for evaluating the feasibility of hydrogen production integration.

Methodology: Economic Assessment

Economic simulations and analyses of hydrogen production was conducted using the following steps:

1. Define the system.
2. Estimate capital costs.
3. Estimate operating costs.
4. Perform a cash flow profitability analysis.
5. Integrate Refueling Station Costs

A general overview of these steps is provided below, with additional details available in Appendix 2.

Step 1: Define the System

The study evaluated the following three hydrogen production plant scales:

- 1.1 MW
- 11 MW
- 110 MW

Rationale for three production scales

1. The 1.1 MW scale is suitable for a pilot plant facility and is currently the model size commercialized by FuelCell Energy.
2. The 11 MW scale is considered most suitable for medium-scale production facilities powered by electricity and heat, using the modularity of the power plant for commercialization.
3. Larger modular units, such as the 110 MW system, are expected to be economically practical when set up near a nuclear power plant, enabling integration with available steam and electricity to produce a significant amount of hydrogen for commercial purposes or electricity generation via fuel cells. Development of these larger facilities is expected within this decade, requiring electrolyser modular units with capacities of 10 to 20 MW for viability.

Step 2: Estimate Capital Costs

The capital cost for the system was estimated using the percentage of delivered equipment cost method outlined in Peters [1]. This method enables the estimation of contributing capital costs as percentages of equipment costs, offering flexibility in cost estimation. Using this approach, two scenarios were modeled using parameter values which closely aligned with the cost factors used in the Hydrogen Financial Analysis Scenario Tool (H2FAST) from the National Renewable Energy Laboratory (NREL)[1].

The scenarios were developed to be representative of the Hydrogen Hub site while minimizing or eliminating direct depreciable capital costs that were deemed unlikely or not applicable. For example, land cost was removed as it is assumed that the Hydrogen Hub will be built on a pre-owned site. The lower of the two capital cost estimates employs cost factors which align with the Hydrogen Analysis (H2A) tool from the National Renewable Energy Laboratory (NREL) and represents a best-case scenario. Conversely, the second scenario incorporates additional cost factors which were deemed potentially relevant and provides an upper cost limit.

Up-to-date purchased equipment costs for the 1.1 MW SOEC and 250 kW SOFC were sourced directly from FuelCell Energy. Where required, values were scaled up for larger system sizes using the six-tenths rule (see Appendix 2 for more details). All costs were adjusted as needed to 2024 CAD$, using the current conversion rate for currency conversions (i.e., $1.35 CAD/USD from February 2024) and the Chemical Engineering Plant Cost Index (CEPCI) for time conversions (i.e., to 2024 $ values).

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[1] The National Renewable Energy Laboratory is located in the United States of America, and its missions is to lead research, innovation, and strategic partnerships to deliver solutions for a clean energy economy. It has several research areas including advanced manufacturing, bioenergy, energy storage, hydrogen and fuel cells, integrated energy solutions, and grid modernization.

Step 3: Calculate Operating Costs

The operating costs for the economic assessment were calculated using the method outlined in Turton [2] (like the method outlined in Peters [1]).

This approach involves calculating four fundamental operating cost categories for the system:

1. Raw materials,
2. Waste treatment,
3. Utilities, and
4. Operating labour.

Types of Costs

In consideration of operating cost categories, three distinct types are:

1. Direct manufacturing costs,
2. Fixed manufacturing costs, and
3. General expenses.

Under these categories, various specific operating costs, including maintenance and repairs, plant overhead, and R&D expenses, are classified.

General Expenses and Other Exemptions

Certain costs including general expenses such as administration, distribution, marketing, and R&D costs, are not applicable to this case study. These expenses are considered integral to the broader operations of Kinectrics and are therefore already accounted for elsewhere in the analysis and in the general operating costs of Kinectrics.

Additionally, specific costs like laboratory charges and expenses associated with patents and royalties, categorized as direct manufacturing costs, were also considered irrelevant in this context. These exclusions align with the scope of the assessment and ensure a focused and exact assessment of operating costs pertinent to the Hydrogen Hub's operations.

Step 4: Perform a Cash Flow Profitability Analysis

The profitability analysis assessed the plant economics over a set analysis period, considering the fixed capital investment (FCI), total production cost (TPC), revenue from selling the product(s), as well as other factors such as depreciation, taxes, tax incentives, salvage value, and the time-value-of-money.

Step 5: Integrate the Refueling Station Costs

The costs associated with the refueling station (i.e., compression, storage, and dispensing) were obtained from literature and adapted for the Hydrogen Hub, considering an average daily production rate of 600 kg/day. The literature values were adjusted using the CEPCI and the H2FAST economic tool to determine the $/kg cost. These costs were then added on to the LCOH resulting from the profitability analysis to determine the full Hydrogen Hub costs (i.e., hydrogen production with a refueling station, and with or without SOFC integration).

Hydrogen Hub Design Assessment

Using literature and other hydrogen projects, the following high-level design requirements were defined:

- Defining plant functional aspects including interface requirements and support systems,
- SOEC and SOFC performance criteria,
- Hydrogen storage,
- Distribution, and
- Dispensing.

Furthermore, the design entails specifying control and automation systems for process checking and optimization, incorporating elements such as heat source, water infrastructure, electricity source, output requirements, grid interface, and hydrogen capacity needs within the electricity generation system.

Hydrogen Plant Design

The hydrogen plant design process involved outlining the layout encompassing all essential concept design elements, spanning civil and electrical design tasks, along with specific considerations such as the hydrogen fuel cell curve as required by the Independent Electricity System Operator (IESO).

Site Justification and Layout Planning

The site assessment included factors like proximity to water sources, grid connections, and safety zones. This analysis was integral to ensuring ideal conditions for pilot plant construction and potential scalability.

The location of Kinectrics facilities at 800 Kipling Avenue in Toronto was strategic. The site offers access to necessary infrastructure and resources (for example, high-voltage power supply and water). A site walkdown (assessment) was completed to determine if the suitability of the site held true and to identify any additional design requirements.

Safety and the Environmental Impact

Ensuring compliance with safety codes and standards involves assessing the environmental impact, with a focus on emissions reduction potential, and rigorously adhering to safety and environmental regulations. Both safety and environmental impact were evaluated through assessment against the available codes and standards as well as regulations pertaining to this scope.

Concurrently, an operational requirements analysis was conducted, accompanied by a preliminary risk assessment to list potential challenges, and mitigate risks.

Technical Assumptions

The following assumptions were made:

1. The pilot case (1.1MW) is scalable. Meaning, cost estimates made at the pilot level can be scaled for higher power levels.
2. Trucking of compressed gaseous H_2 will be used for distribution/transportation of H_2 from plant to off-site.
3. Any O_2 produced from operation of the SOEC will be vented to atmosphere.
4. Demineralized water and cooling water may be supplied from a new water treatment plant (NWTP).
5. The project will involve an assessment of the feasibility of installing an SOEC and an SOFC from FuelCell Energy. All data related to this equipment will be provided by FuelCell Energy.
6. The study will consider nuclear energy as the main source of energy and heat, within the temperature range of 150 to 500°C in the context of a nuclear reactor, including existing CANDU nuclear reactors, new large nuclear and small modular reactors (SMR).
7. A techno-economic ranking was based on literature review, available data from Bruce Power, and resource availability in different databases (Scopus, Elsevier, etc.) at the time of the report. Any new information (after May 2024) has not been included in the report.

4. Results and Analysis

In assessing technologies there are several factors which must be considered. These include:

- Available resources such as water, natural gas, and coal;
- Available energy resources, including cost of energy;
- Plant output and expected availability; and
- Environmental impact.

This section presents the results and analysis of the technology assessment including hydrogen technology, hydrogen storage and distribution, policy and regulatory landscape, and general costs.

Hydrogen Production Technologies

Currently there are many ways that hydrogen can be produced. The way in which hydrogen is produced is important as the current hydrogen naming scheme and classification is based on their primary energy feedstock, that is hydrogen produced from coal energy is "black hydrogen", whereas hydrogen produced from renewable energy is "green hydrogen". In addition to the energy feedstock, hydrogen can also be produced via electricity or heat. Figure 1 shows the current hydrogen production pathways including carbon intensity, production process, and classification. Many of the hydrogen processes use heat as the energy source, with nuclear having three classifications of hydrogen including "purple hydrogen" produced with electricity, "red hydrogen" produced with heat, and "pink hydrogen" being produced with high temperature electrolysis. It should be noted that the *colour* of hydrogen is used as a classification scheme to better understand the carbon intensity of hydrogen production. In Canada, because of the integration of hydrogen production within refining facilities, production is primarily supplied by natural gas reforming methods ("grey hydrogen") [5].

Figure 1 | Hydrogen Production Sources and their Carbon Intensity [8]

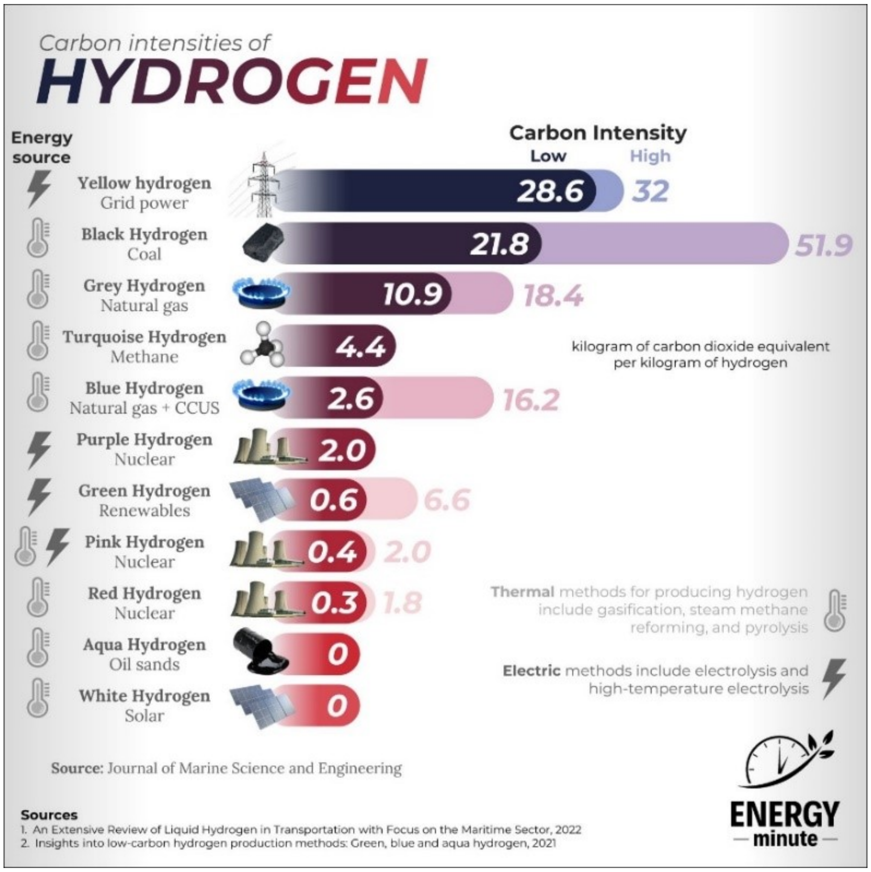


Table 1 summarizes the following current hydrogen feedstocks and production pathways in development. Practical production processes include:

- Partial oxidation of methane (POM) (grey)
- Fossil fuels (blue)
- Electricity from renewable sources (green)
- Nuclear energy with high-temperature electrolysis (pink).

Table 1 | Common Hydrogen Feedstock and Production Pathways [3]

Production Process	**Feedstock & Energy Source**	**Pros and Cons**	**Examples**
Grey (Natural Gas) Produced by steam methane reformation without CCS	**Feedstock:** Natural gas, gasified coal	**Pros:** Lowest cost, abundant **Cons:** Highest carbon intensity	Canada produces approximately 3 million tons of grey hydrogen per year primarily for industrial use.
Blue (Fossil Fuels) Produced from fossil fuels by steam methane reformation, pyrolysis, or other processes with CCS.	**Feedstock:** Natural gas, coal, crude bitumen	**Pros:** Low-cost, abundant, low CI, pyrolysis offers scale and siting flexibility **Cons:** Steam Methane Reforming pathway siting is constrained by CCS, feedstock is not renewable	Alberta's Quest project
Green (Renewable) Produced from water by electrolysis using renewable electricity such as hydroelectricity, wind or solar.	**Feedstock:** Water **Energy source:** Renewable electricity	**Pros:** Lowest carbon intensity, scalable **Cons:** Highest cost, opportunity cost - competes with electrification demand	Air Liquide's 20 MW electrolyser plant in Betancourt, Projects developing in BC to support hydrogen fueling network.
Pink (Nuclear) Produced from water by electrolysis or high temperatures from nuclear energy	**Feedstock:** Water **Energy source:** Uranium / nuclear electricity	**Pros:** Low carbon intensity **Cons:** Limited availability and siting constraints	Feasibility study completed in Bruce County by Bruce Power.

Discussion of Various Hydrogen Feedstocks

Fossil Fuels

Currently, most hydrogen is produced from fossil fuels, either through steam methane reforming of natural gas (74% of total) or coal gasification (22%). Both processes emit carbon dioxide (CO_2), and the adoption of carbon capture and storage (CCS) is limited. CCS technologies can reduce direct emissions from steam methane reforming by up to 90%, with an increase in production costs. Upstream processes in natural gas production and distribution also produce substantial residual methane emissions. The use of CCS in coal gasification processes appears technologically more challenging and less likely to be economically competitive.

Coal gasification is another fossil fuel-based technology. It represents about 18% of the worldwide hydrogen production, which is part of the produced syngas. Syngas passes through gas shift reaction, for pure hydrogen production.

Steam Reforming

The most common method for hydrogen production is steam reforming of natural gas. This high heat process is fueled by huge amounts of fossil fuel. In this process steam, at temperatures between 500°C to 900°C, reacts with natural gas in the presence of a nickel (Ni) catalyst.

The chemical reaction can be described as:

$$CH_4 + H_2O + \text{energy(heat)} = CO + 3H_2 \tag{1}$$

In practice, the above reaction is usually accompanied by a lower temperature gas shift reaction, recovering additional dihydrogen using the carbon monoxide obtained in the steam methane reforming reaction above.

This chemical reaction can be described as:

$$CO + H_2O = CO_2 + H_2 + \text{energy} \tag{2}$$

Whereas the reaction (1) requires energy to produce hydrogen, the reaction (2) produces a limited amount of energy.

Partial Oxidation of Methane (POM)

The partial oxidation of methane (POM) is an alternative method to produce hydrogen with reduced energy costs. POM is a fast, exothermic, non-catalytic process in which methane is oxidized to generate syngas as indicated in the following reaction:

$$CH_4 + \tfrac{1}{2} O_2 = CO + 2H_2 + \text{energy (heat)} \tag{3}$$

The process is considered more cost-effective than Steam Methane Reforming because it requires neither catalyst nor external heat, both of which significantly contribute to the operating costs. In the POM process, supported metal catalysts are often used.

Electricity

Hydrogen can also be produced using electricity in a process called electrolysis. Electrolysis splits water into its basic components, hydrogen, and oxygen, using electricity. Currently this technology accounts only for 4% of total hydrogen production as the carbon footprint of this process is high when electricity generation source is not a carbon-free energy source, as this technology requires significant electricity inputs. Recently, it has attracted strong interest due to the potential to generate hydrogen with a very low carbon footprint when it is paired with wind, solar and nuclear energies and even can support seasonal energy storage when the energy source is intermittently produced, such as renewables. A widespread use of electrolysers can provide benefits only if directly coupled to a low-carbon source such as wind, solar or nuclear power, or if the power generation mix is mostly decarbonized.

There are several types of tested and technologically mature electrolysis processes. These include low temperature (< 80°C) Alkaline and Proton Exchange Membrane (PEM) electrolysers and high temperature Anion Exchange Membrane (AEM) electrolyser and Solid Oxide Electrolyser Cells (SOEC). There are benefits to the higher operating temperatures, primarily lower energy consumption and higher electrical efficiencies.

Low-temperature electrolysis, or commonly known as water electrolysis, is the most currently available straightforward approach to produce hydrogen directly from water. In the electrolysis process, electricity is used to split water into hydrogen and oxygen. About 9 L of fresh water is needed for every 1 kg of H_2 and 8 kg of oxygen (O_2) produced.

The resulting hydrogen is very pure and can be used directly in transportation and other end-uses without further processing. The oxygen, while often vented, can also be used in medical or industrial applications.

Electrolyser Technologies

Table 2 and Figure 2 offer a detailed comparison of the different types of electrolysers currently available. The main electrolyser technologies are Alkaline, PEM, AEM, and Solid Oxide Electrolysis Cells (SOEC):

- Alkaline is an older technology that has been in use for over a century. It runs best with a constant load, has low capital costs, and can scale to larger than 150 MW.
- PEM electrolysers rely on a Nafion selective membrane for protons. They can be run at a range of loads and can respond dynamically, making them useful for electrical utilities looking for flexible demand to pair with variable renewables.
- AEM electrolysis uses an anion exchange membrane, allowing anions to pass while blocking cations. It is currently still in the Research and Development (R&D) phase.
- SOEC is recently being commercialized and runs at high temperature.

Table 2 | Comparison of the Main Types of Commercially Available Electrolysers [4] [5]

Parameter	Alkaline Electrolyser	PEM Electrolyser	SOEC
Efficiency (%)	60-70%	70-80%	80-99%
Hydrogen purity	95-99%	99.9%	99.999%
Operating voltage (per ell)	1.8-2.2 V	1.8-2.0 V	0.6-1.0 V
Electrolyte type	Aqueous	Polymer Membrane	Solid Oxide
Electrolyte material	Alkaline (KOH)	Polymer (Nafion)	Ceramic (YSZ, GDC, SDC)
Electrolyte conductivity (S/cm)	10-80 mS/cm	0.01-0.2 S/cm	0.05-0.5 S/cm
Electrolyte degradation rate	Moderate	High	Low to Moderate
Electrolyte regeneration	Not Required	Not Required	Required (Carbon Deposition)
Catalyst material	Nickel, Platinum, Iron, Manganese	Platinum, Iridium, Ruthenium	Nickel, Ceria, Yttria-Stabilized Zirconia
Anode material	Nickel or Platinum Group	Platinum Group	Nickel-Cermet
Cathode material	Nickel or Platinum Group	Platinum Group	Cermet (Ni-YSZ)
Lifetime (years)	10-20 years	5-10 years	15-25 years
Operating Pressure (bar)	1-10 bar	1-20 bar	1-15 bar
Cost per kg H_2 (USD)[2]	\$1.5-\$2.5	\$2.0-\$3.0	\$1.8-\$2.8
Electrolyte stability	- Sensitive to impurities, requiring high-purity water - Prone to degradation over time	- Sensitive to impurities, requiring high-purity water - Prone to dehydration and membrane degradation	- Stable at high temperatures - Less sensitive to impurities
Stack durability	Stack components may have shorter lifespans	Membrane durability may be a concern	Solid oxide stacks tend to have longer lifespans
Byproduct generation	Chlorine gas, Sodium Hypochlorite	Chlorine gas, Bromine gas	Oxygen gas, water vapor
Maturity	Well-established technology	Established technology	Emerging technology
Maintenance Requirements	Moderate	Moderate to High	Moderate to High
Scale-up feasibility	Moderate	Challenging	Moderate to High
Utilization of nuclear reactors	Impractical	Possible	Possible
Hydrogen Delivery options for current projects	Tube Trailers, Pipelines	Compression or Liquefaction	Pipelines or Tube Trailers

[2] This is the expected cost of hydrogen production by 2030, when the technologies are more mature, specifically only for direct hydrogen production.

Figure 2 | Comparison between the Different Types of Electrolysers [6][3]

	Alkaline Electrolyser	PEM Electrolyser	SOEC Electrolyser
Commercial status	Mature	Commercial, fast growth	Demonstration plants
Electrolyser electrical efficiency kWh/kg hydrogen	Today: 48 – 53 2030: 47 – 51 Long term: 42 – 48	Today: 56 – 59 2030: 49 – 53 Long term: 45 – 50	Today: 41 – 45 2030: 40 – 43 Long term: 37 – 43
Operating temperature (°C)	60 – 80	50 – 80	650-1,000
Plant footprint m^2 / kW	0.095	0.048	-
Characteristics	• Slower dynamic response[1]	• Faster dynamic response	• Highest efficiency, no cycling[2]
Implications	• Less well suited to **intermittent power supply** (e.g. renewables) – likely to be overcome by innovation for faster ramping and batteries to smooth short term variations.	• Well suited to a **variable electricity supply** (e.g. intermittent renewables) • Suitable for voltage regulation services	• Potentially well suited for **constant base-load H_2 production** in future • Only technology to reverse function and able to work as fuel cell to produce electricity
Stack lifetime (2030)	• 90,000 – 100,000	• 60,000-90,000	• 40,000-60,000
Major producers (non-exhaustive)	• Suzhou Jingli, Thyssenkrupp, Nel	• Siemens, ITM Power, Cummins	• Haldor Topsøe, Ceres, Sunfire

High temperature electrolysis will be further explored in subsequent sections. Low-temperature electrolysis methods, including Alkaline Electrolysis and PEM Electrolysis, run at significantly lower temperatures (typically below 60°C for Alkaline and around 60-80°C for PEM).

These technologies are more mature and have different advantages:

- Alkaline Electrolysis: This method is well-established and relatively low-cost. It uses an alkaline electrolyte (commonly potassium hydroxide) and is known for its durability and ability to handle large-scale hydrogen production. However, it has slower response times and lower current densities compared to PEM.
- PEM Electrolysis: PEM electrolysers use a solid polymer electrolyte, allowing for compact design and high current densities. They offer rapid start-up times and can efficiently handle variable loads, making them ideal for integration with renewable energy sources like solar and wind. However, PEM systems are generally more expensive due to the use of precious metals as catalysts.

Solid Oxide Electrolyser Cell Technology

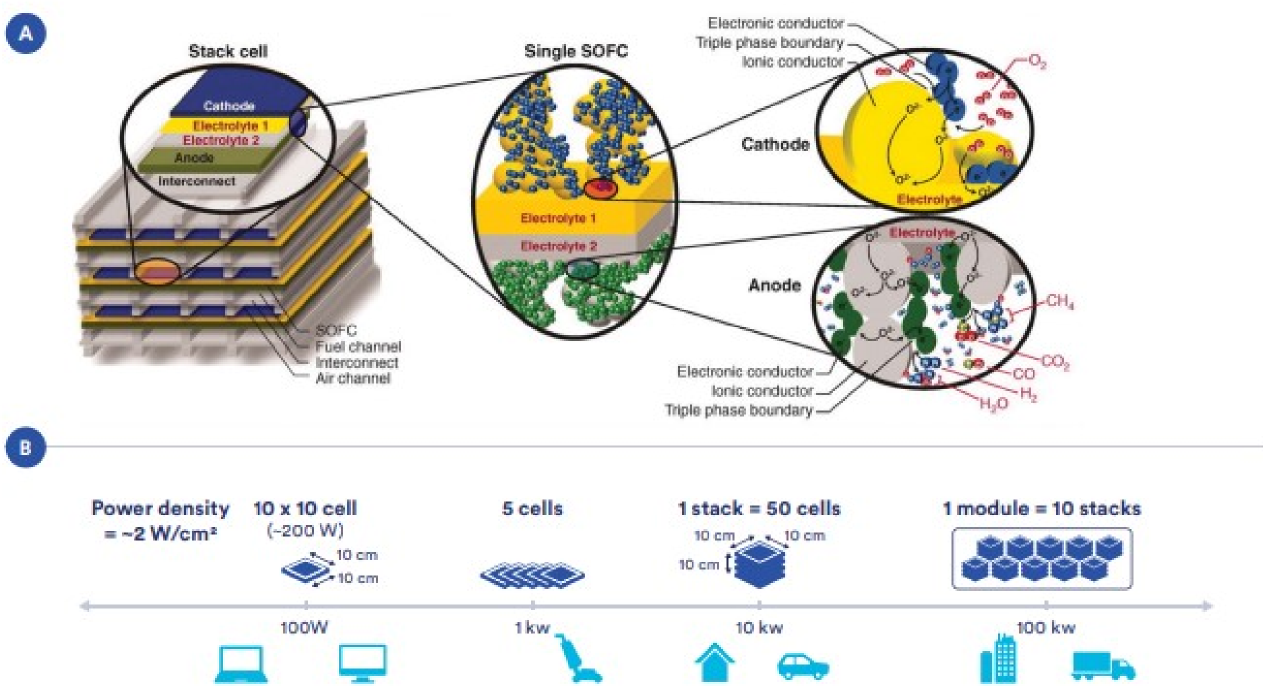
The terms "high temperature" and "solid oxide" electrolysis are often used interchangeable for the simple reason that solid oxide electrolysers are uniquely capable of operation at high temperatures (generally between 500 and 1000°C). High-temperature operation enables a step change in efficiency because the electrolyser will be fed with water in the form of steam, effectively relieving the electrolyzer stack from having to provide latent heat.

[3] The current temperature range for high-temperature electrolysis, based on current suppliers, is 150 to 300°C. However, in the near future, this temperature is expected to increase to a theoretical range of 650 to 1000°C.

A Solid Oxide Electrolyser Cell (SOEC) Plant

A typical SOEC plant has a hierarchical assembly, beginning with the individual cell. Individual cells are the grouped into stacks, each stack consisting of many cells. Next, these stacks are integrated into modules, typically made from four to five individual stacks. These modules are designed to fit conveniently into shipping containers, typically organized in groups of about 10. They form multiple installed modules to make a fully operational SOEC plant. See Figure 3 for an example of a SOEC plant, module, stack, and cell.

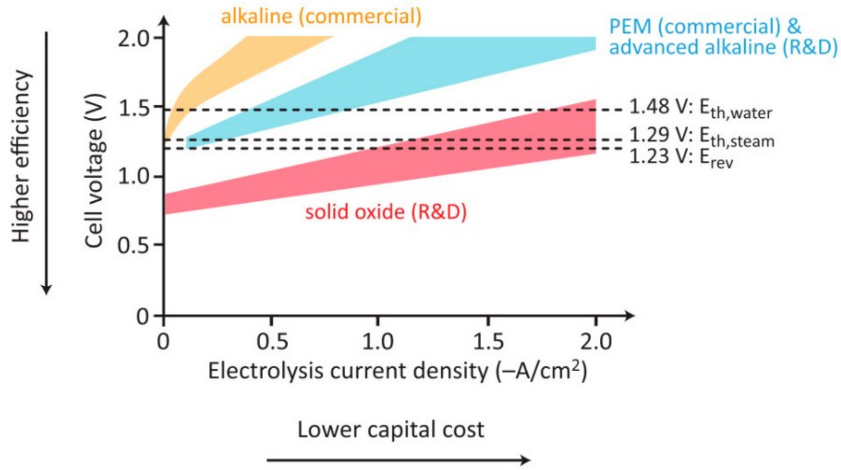
Figure 3 | Schematic Representation of the Hierarchy within a SOEC Plant [45]



Temperature Range and Efficiency

SOECs operate within a temperature range of 650°C to 1000°C when configured in a stack. Within this temperature range, electrolysis needs less total energy input and electrical demand, which is reflected in the lower operating voltage. As a result, SOEC technology is one of the most efficient methods for water electrolysis. To compare the energy efficiency of SOEC ("solid oxide") to alkaline and PEM, see Figure 4.

Figure 4 | SOEC Energy Efficiency Compared to Other Technologies [6]



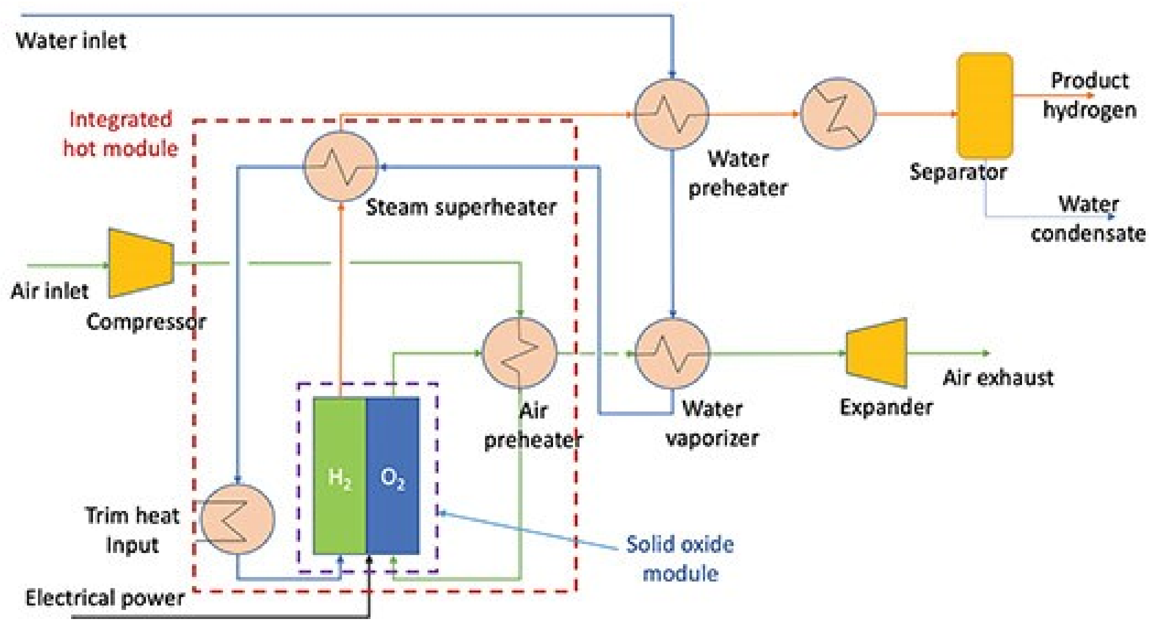
As temperature increases, the energy efficiency of SOECs improves. The integration of individual cell stacks, or multiple stacks makes SOECs very efficient. The system can recover and effectively use energy, resulting in an approximate overall system efficiency of 95%. However, it is important to note that high-temperature operation is a double-edged sword. Although efficiency is improved, stack failure is more likely or is accelerated due to thermal stress.

Heat integration in SOEC

The SOEC presents compelling advantages particularly when integrated into industrial processes like steel or ammonia production, which typically discard large amounts of low-grade heat especially steam at 100°C- 150°C to their condensate systems. Importing steam from an industrial source boosts efficiency of at least 14%, but in practice this efficiency gap may be around 25% due to the imperfect operation of PEM, alkaline or AEM systems. This boost in efficiency is particularly valuable in situations where electrical resources are limited or constrained.

SOEC are able to accommodate different energy inputs. Figure 5 outlines the integration of various components, including electrical heaters and boilers, illustrating the adaptability of the system to diverse heat sources. Notably, the electrical heater can be substituted with a boiler, using steam sourced from an industrial plant or a nuclear reactor. Although the specific input steam conditions can vary among vendors, reported data suggests a feed steam temperature of approximately 150°C. To reach the operational temperature exceeding 500°C, a final electric trim heater is employed, depending on the electrical operating point of the cell.

Figure 5 | Process Flow Diagram and Equipment for SOEC Hydrogen Production Plant [7]



In the case of low-temperature electrolysers such as alkaline and PEM, degradation typically occurs at a rate between 0.5-1.5% per year of operation. This degradation translates into a significant rise in electricity demand throughout the system's lifespan and an increased need for heat dissipation.

However, in an SOEC system, where heat serves as one of the primary energy inputs, as stack efficiency diminishes, more heat is rejected back into the system and used to preheat the steam feed to the stack, thereby avoiding any net increase in total energy demand. Degradation can persist until the maximum operating temperature of the system is reached, beyond which hydrogen production diminishes.

Nuclear Energy and High-Temperature Electrolysis (HTE)

Nuclear energy can produce hydrogen not only in large quantities, but also at a relatively low cost without any greenhouse gas (GHG) emissions. All types of nuclear reactors can be used to produce low carbon intensity (CI) hydrogen, as they can provide electricity and heat. Large reactors are more suitable for cogeneration of electricity and hydrogen production. Small reactors are more suitable as a single-purpose plant for hydrogen production. For better economics, hydrogen can be made from electrolysis, using inexpensive off-peak electricity from existing nuclear power plants.

There are several hydrogen production pathways that use the high-temperature heat produced by nuclear reactors. One method is to use the steam produced by nuclear reactors as the reactant in the steam methane reformation process. This would avoid the need to use fossil fuels to create steam, therefore reducing the environmental impact. Another method is using high-temperature electrolysis (HTE) which has improved efficiencies for hydrogen production and requires less electricity input. Examples of HTE include molten carbonate (550-700°C) and solid oxide (650-1000°C) systems.

Many new nuclear reactor designs in early stages of commercialization, including advanced small modular reactors (SMR), high-temperature fission reactors, and future fusion reactors, the output water (steam) temperature will enable HTE to capitalize on the higher output temperatures and when nuclear energy is also providing the electricity- reduce the overall environmental impact substantially.

High-temperature nuclear hydrogen production could be a valuable cogeneration process for Canada's next generation nuclear sites, improving the overall system efficiency.

Table 3 shows a breakdown of the output temperatures and conversion efficiencies for some of the most common SMR designs. The thermal efficiency and temperature output of a nuclear reactor depend on various factors such as the reactor design, fuel type, cooling system, and operating conditions. While Table 4 shows a comparison of the proposed nuclear hybrid energy systems for the production of hydrogen and their expected energy consumption and efficiencies.

Table 3 | Comparison of Output Temperatures and Thermal Efficiencies for the Available Reactor Designs [8]

Reactor	Output temperatures*	Thermal efficiencies*
Advanced Gas Reactors (AGRs)	280°C to 650°C	35-40%
Pebble Bed Reactors	600°C to 900°C	45-50%
Fast Reactors	500°C to 650°C	40-45%
Pressurized Water Reactors (PWRs)	290°C to 330°C	30-35%
Boiling Water Reactors (BWRs)	260°C to 290°C	30-35%
Molten Salt Reactors (MSRs)	550°C to 700°C	40-45%
GE Prismatic Reactors	325°C to 530°C	30-35%

* These values are general estimates. They can vary depending on factors such as reactor size, fuel type, and specific design features.

Table 4| Nuclear Hybrid Energy Systems for Hydrogen Production [9]

	Alkaline electrolysis	PEM electrolysis	Solid oxide electrolysis (HTE)	Steam methane reforming	Thermochemical S-I
Technology readiness	9	6-8	5	9	4
Temperature (°C)	60	60	800	870	910
Pressure (atm)	1	1	1.57	4.1	3.85
Efficiency (HHV, %)	30	27	36	79	25
Natural gas (kg)	0	0	0	2.9	0
CO_2 out (kg)	0	0	0	5-11	0
Production cost	$5.92	$3.56-5.46	$2.24-3.73	$1.54-2.30	$2.18-5.65

Technology Readiness of SOEC

The Canadian federal government rates technology from Technology Readiness Level (TRL) 1 to 9. TRL 1 is the concept stage. At TRL 8, the actual technology is qualified through tests and demonstrations. At TRL 9, the technology is proven and successfully applied in an operational setting. [10].

SOECs exhibit varying levels of Technology Readiness (TRL) between 8 and 9, depending on factors such as scale and operational mode. These versatile electrochemical systems can function in both standard electrolysis mode (TRL 9) and co-electrolysis mode (TRL 8), where carbon monoxide (CO) is employed alongside water to produce syngas. Additionally, SOECs can be configured to run in a fuel cell mode, where hydrogen and oxygen are introduced to generate electricity (TRL 9).

The largest SOEC systems installed to date range between 100 kW and 1 MW in size. Most have been installed as pilot or demonstration projects, and thus do not represent commercial deployments. However, judging the commercial readiness of SOEC based on these projects would not be sufficient in assessing the readiness of the technology for deployment. SOECs are practically identical in design and manufacturing to solid oxide fuel cells (SOFCs), which have been deployed as well above the gigawatt (GW) scale in backup power generation and microgrid applications. Therefore, many lessons learned, and significant operating experience can be cross-functional across these systems.

Hydrogen Fuel Cells

SOFCs are a promising technology for efficient and clean hydrogen-based electricity generation. Despite their potential, there are challenges in improving their performance, longevity, and economic viability. Various strategies to enhance the performance of hydrogen SOFCs are described in this section.

Advanced Materials and Manufacturing

To enhance SOFC performance, advanced materials development plays a crucial role. Yttria-Stabilized Zirconia (YSZ) is widely used as an electrolyte in SOFCs due to its high ionic conductivity and stability at elevated temperatures. Optimizing YSZ through doping with elements like scandium or cerium can substantially boost the fuel cell's overall performance. Researching alternative electrolytes such as gadolinium-doped ceria (GDC) or lanthanum strontium gallium magnesium oxide (LSGM) is also vital. These materials operate at lower temperatures and offer superior ionic conductivity, potentially enhancing SOFC efficiency and longevity.

On the anode side, nickel-based anodes are prevalent, but enhancing them with improved catalysts can heighten electrochemical activity and mitigate issues like coking, which can degrade performance. Additionally, ceramic anodes like lanthanum strontium chromite (LSC) or lanthanum strontium titanium oxide (LST) are being developed for enhanced durability and resistance to sulfur poisoning, crucial when using fuels containing sulfur compounds.

For the cathode, advancements in perovskite cathodes such as lanthanum strontium cobalt ferrite (LSCF) can improve oxygen reduction reactions, critical for SOFC efficiency. Further innovation in mixed ionic-electronic conductors (MIECs) capable of conducting both ions and electrons promises significant efficiency gains, making SOFCs more robust and effective overall. These material advancements underscore ongoing efforts to push the boundaries of SOFC technology towards greater performance and reliability.

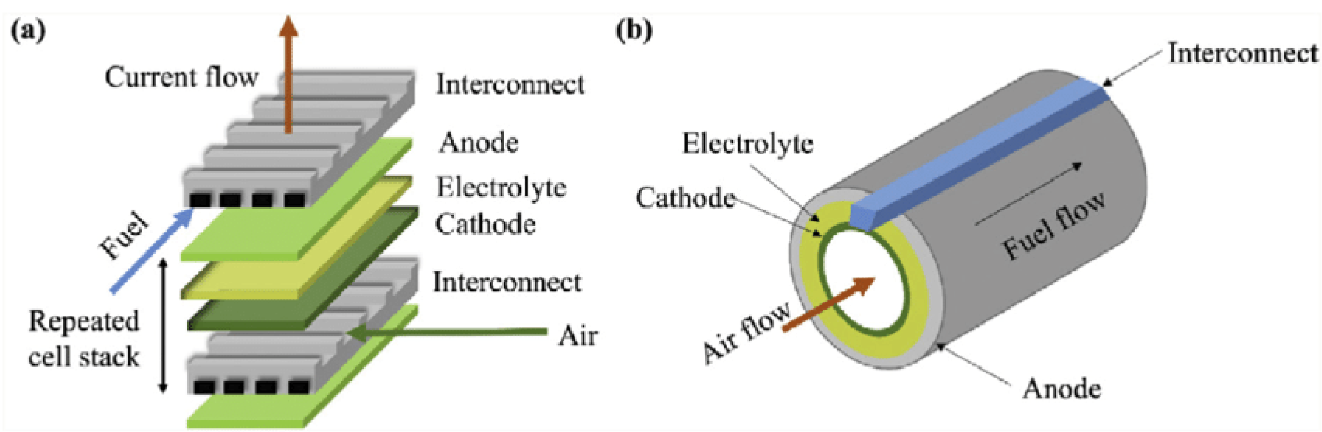
To prevent degradation and maintain optimal performance over time, various strategies are employed. Protective coatings are applied to anodes and cathodes to shield them from contaminants such as sulfur and carbon, thereby extending their lifespans. Improvements in interconnect and seal durability through enhanced materials and design enable these components to withstand the demanding conditions within SOFC systems.

Advancements in fuel processing technologies also contribute significantly to enhancing SOFC performance. Integration of advanced reforming techniques allows SOFCs to efficiently utilize diverse hydrocarbon fuels, supporting high efficiency and operational flexibility. Moreover, employing advanced hydrogen purification technologies such as pressure swing adsorption (PSA) or membrane separation ensure a high-purity hydrogen supply to SOFCs, further improving the overall system efficiency and longevity. Additionally, developments in gas diffusion layer (GDL) materials and structures aim to improve gas transport kinetics within cells, thereby minimizing mass transfer limitations and enhancing overall efficiency.

Multifunctional Cell Designs

Optimizing the design of SOFC systems is another crucial aspect of performance enhancement. Figure 6 shows the typical configurations of the SOFC, planar and tubular. The choice between planar and tubular design is significant because each has its advantages and trade-offs. Planar designs typically offer higher power densities and are easier to manufacture in large quantities, while tubular designs provide better thermal management and mechanical stability. Developing multifunctional cell designs by incorporating sensors for monitoring parameters such as temperature, pressure, or gas composition, real-time feedback can be provided to improve operating conditions and detect abnormalities.

Figure 6 | (a) Planar and (b) Tubular SOFC [46]



Effective Thermal Management

Effective thermal management systems are also vital to ensure uniform temperature distribution across the cell, reducing thermal stresses that can lead to degradation and failure. Implementing heat recovery systems can use waste heat for preheating incoming air or fuel, thus improving the overall system efficiency, and reducing operational costs. Implementing combined heat and power (CHP) systems allows the use of waste heat from SOFCs for more applications, such as residential heating or industrial processes, increasing overall system efficiency. Developing smart grid compatible SOFC systems capable of providing ancillary services, such as voltage and frequency regulation, supports grid stability. These integrations enable SOFCs to contribute effectively to modern energy systems.

Operational Improvements

Predictive maintenance schedules based on real-time monitoring and data analytics play a pivotal role in maximizing the lifespan and performance of SOFC systems. By employing advanced diagnostic tools and sensors, operators can continuously assess the health of the SOFC stack and detect potential issues early. This proactive approach ensures that SOFCs operate at peak efficiency, supporting their long-term reliability in energy applications.

Regular maintenance protocols and inspections are vital to promptly identifying and addressing early signs of degradation, ensuring consistent performance and reliability throughout the operational lifespan of the SOFC installation. Continuous monitoring of key performance parameters using techniques like electrochemical impedance spectroscopy (EIS) and scanning electron microscopy (SEM) provides valuable insights into the electrochemical processes and structural integrity of SOFCs. By monitoring parameters such as polarization resistance and microstructural evolution, potential issues can be identified early, facilitating timely interventions to mitigate degradation and maintain optimal cell performance.

Integration with Other Technologies

Integration with other technologies can significantly enhance the performance and utility of SOFCs. SOFC-Gas turbine hybrid systems can use high-temperature exhaust gases to increase power generation, significantly increasing overall system efficiency. Similarly, combining SOFCs with Battery storage systems can provide a stable power supply, handle peak loads, and improve system response times, making the entire energy system more resilient and efficient. Using SOFCs in conjunction with renewable energy sources like solar or wind power can provide a reliable and continuous power supply, compensating for the intermittency of renewables. Coupling SOFCs with electrolysers to use excess renewable energy for hydrogen production can store hydrogen for later use, ensuring a steady energy supply even when renewable generation is low.

Through continued initiatives across industry, academia, and government sectors, SOFCs can realize their full potential as a cornerstone of sustainable energy solutions.

Combining an SOEC with an SOFC

SOFCs are electrochemical devices that convert chemical energy directly into electricity. These cells can use a variety of fuels, including hydrogen, natural gas, and biofuels, making them suitable for a wide range of applications. SOFCs offer several advantages, including high efficiency, low emissions, and fuel flexibility. Moreover, SOFCs exhibit high durability and reliability, making them ideal for continuous power generation in both stationary and mobile settings.

The high operating temperatures of both SOECs and SOFCs enable efficient electrochemical reactions and offer advantages such as high efficiency, fuel flexibility, and low emissions. When integrated with nuclear energy systems, SOECs and SOFCs can use the high-temperature heat produced by nuclear reactors, enhancing overall system efficiency, and enabling co-generation of electricity and hydrogen

[11] [12]. This integration presents a practical pathway for using nuclear energy to produce clean hydrogen for various industrial applications while simultaneously generating low-emission electricity, enhancing system flexibility, and contributing to the transition towards a sustainable energy future by providing efficient and scalable solutions for both power generation and hydrogen production.

Challenges

One of the biggest hurdles to commercializing SOEC is its reputation for poor durability. A literature review puts the average degradation rate for SOEC systems at 1% per 1,000 hours of operation. When combined with the operating capacity of 80% of nameplate capacity, a 1% degradation rate would imply a stack lifetime of around 2.5 years at full load [31]. This is significantly improved from a decade or two ago; however, it is 4-8 times shorter than the typical expected lifetimes for PEM and alkaline technologies.

However, one of the mitigating factors to using the degradation rate for assessing longevity is the increased conductivity from operating at a higher temperature. Unfortunately, compensating with increased temperatures does add to overall thermal stress and increases risk of failure. Nevertheless, most SOEC will fail before PEM or alkaline stacks.

These challenges are being explored and there are ways to mitigate some of the shortcomings, including advanced materials, materials choices, integration of manufacturing and operating experiences and changes in designs.

Advancements to SOEC and SOFC

Ongoing advancements in current technology for SOEC and SOFC target the following key areas:

- Reduction of weight and cost of interconnects and backing plates: This optimization contributes to the overall efficiency and affordability of SOEC systems.
- Manufacturing scale-up: The aim is to produce enough SOEC and SOFC units, enabling large-scale operation.
- Operation at greater current densities: This results in greater hydrogen production rates and improved efficiency, making a more competitive production method.
- Increased stack life: Aims to reduce maintenance costs and extend system longevity, improving the economic viability of SOEC and SOFC technology.
- Enhanced electrode materials: Advancements in materials science aim to boost the electrocatalytic activity, leading to more efficient hydrogen and oxygen production and electricity generation.
- Advanced gas diffusion layers: To enhance mass transfer and improve reactant distribution within the cell, ultimately improving performance.
- Improved electrolyte materials with higher ionic conductivity and improved chemical stability: These materials contribute to the reduction of ohmic losses and extend the operational life of SOEC and SOFC.
- Integrated Heat Management: To improve heat distribution within SOEC stacks, reducing thermal gradients and enhancing overall performance.

- Robust SOEC and SOFC stack materials: The development of durable and corrosion-resistant materials is critical for long-term operation and reduced degradation.

Storing, Transporting, and Distributing Hydrogen

Hydrogen's potential to serve as a clean energy carrier is unparalleled, yet realizing its full potential requires overcoming significant challenges in storage, transportation, and distribution. Unlike traditional fuels, hydrogen's unique properties demand specialized infrastructure and innovative solutions to ensure its efficient and safe handling.

On a mass basis, hydrogen has nearly three times the energy content of gasoline. While hydrogen has high energy density per unit mass, it has low volumetric energy density at room conditions (around 30% of methane at 15 °C, 1 bar) and an ability to permeate metal-based materials, which can present operational and safety constraints. This makes storage and transporting hydrogen a challenge, because it requires high pressures, low temperatures, or chemical processes to be stored compactly. The following sections describe the main technologies to store, distribute, and transport hydrogen.

Hydrogen Storage

Hydrogen's low volumetric energy density makes storage a challenge, both as a bulk commodity at the point of production and in end-use applications such as fuel storage on-board vehicles. Bulk hydrogen for non-mobile applications can be stored as a compressed gas in tanks above and below ground, as liquid hydrogen in large, insulated tanks, and in natural gas pipelines. Hydrogen storage involves various methods and pressures tailored to different scales and requirements. The most suitable storage method depends on the scale of the plant, its specific operational requirements, and economic considerations.

The following are the most used hydrogen storage methods:

- Gas High-Pressure Storage: As the name implies, hydrogen is stored at elevated pressures, typically between 250 and 700 bar. This high-pressure storage requires specialized storage tanks and large compressors.
- Liquid Hydrogen Storage: To convert hydrogen from gas to liquid involves super cooling the gas. This supercooling, referred to as cryocooling, cools hydrogen to extremely low temperatures around 20°K (-250°C). While effective for specific applications, cryogenic storage is comparatively expensive for the size of the hydrogen production plants under consideration and is typically reserved for special applications. Cryostorage containers are complex, requiring pressurization, thermal insulation, and cooling mechanisms to ensure the safe storage of liquid hydrogen.
- Underground Storage: When large amounts of hydrogen are produced it can be stored in underground facilities, such as salt caverns, as has been proven in projects in the UK, US, and throughout Europe. Engineered salt caverns are used for NG storage in many provinces in Canada. These caverns are created by first boring a hole to storage depths and creating the storage space via solution mining, which dissolves the salt by pumping in fresh water and pulling out the brine stream. The compact structure and composition of salt rock formations make the structures inherently gas tight, and the cavern's only

surface access is the borehole, which is plugged to prevent leakage. Dried and compressed hydrogen can be injected through the borehole and stored in the cavern indefinitely.

Another form of storage can also be used effectively for the transportation of hydrogen, further discussed in a subsequent section, in addition to acting as a form of storage.

- Tube Trailer Storage: At smaller scales, standard hydrogen tube trailers at pressures of 200-300 bars can be used safely. These trailers allow for transportation of hydrogen to local consumers, providing flexibility and convenience in the distribution and end-use of the hydrogen.

Each method has its advantages and challenges as illustrated in Table 5 making it essential to tailor the storage approach to the unique needs of the hydrogen production facility.

Table 5 | Comparison of the Different Hydrogen Storage Technologies [13]

Storage Technology	Advantages	Disadvantages	Applications
High-Pressure Storage	- Well-suited for static applications - Efficient for small to medium-scale - Relatively cost-effective - Quick refueling of hydrogen vehicles	- Requires specialized tanks - Large compressors needed - Energy-intensive compression - Vulnerable to leaks and rupture	- Industrial hydrogen storage - Fueling stations for hydrogen vehicles - Small to medium-sized hydrogen plants - Backup power supply systems
Liquid Hydrogen Storage	- High energy density - Suitable for specific applications - Effective for long-term storage - Minimal hydrogen loss during storage	- Cryogenic cooling required - Complex storage containers - High energy consumption - Potential hydrogen boil-off	- Space-constrained facilities - Backup power generation - Specialized research and industrial use - Aerospace, rocket propulsion
Underground Storage	- Natural containment and safety - Minimal environmental impact - Cost-effective in suitable locations - Enhanced security and protection	- Site-specific geological suitability - Initial site assessment required - Limited to certain geological areas - Long-term planning and construction	- Large-scale industrial hydrogen storage - Strategic hydrogen reserve facilities - Grid balancing and energy management - Energy storage and peak shaving
Tube Trailer Storage	- High flexibility and mobility - Convenient for small to medium scales - Minimal infrastructure requirements - Quick deployment for emergency needs	- Limited storage capacity - Frequent refilling needed - Not suitable for large-scale storage - Relatively short transit range	- Direct distribution to local consumers - Small to medium-sized hydrogen plants - Fueling stations for hydrogen vehicles - Backup power supply for remote areas

Vehicle Storage

In end-use applications, such as heavy-duty vehicles, gaseous hydrogen is typically stored in high-pressure tanks, with pressures ranging from 350 to 500 bar. Hydrogen tanks for forklifts, buses and heavy-duty vehicles today generally use hydrogen compressed to a pressure of 350 bar. Light-duty vehicles store hydrogen at 500 bar as higher pressures allow for smaller tanks which can be fit more easily into conventional vehicle designs. In the future, liquid hydrogen may be used for onboard storage for certain applications such as trucks.

Hydrogen Transportation & Distribution

Gaseous hydrogen is primarily transported in tube trailer trucks today, at pressures of up to 300 bar with 180-200 bar being more typical. Transport Canada regulates transport of gaseous hydrogen through the Transport of Dangerous Goods (TDG) Regulations. Steel tube trailers are most employed for gaseous delivery today, but weight regulations limit how much can be delivered by each truck. Several companies are developing 450 bar hydrogen storage delivery systems using composite materials to increase the amount of hydrogen that can be delivered by each truck, thereby reducing costs and transportation emissions.

Natural Gas Pipelines

Natural gas (NG) pipelines can be used to store and transport hydrogen. Hydrogen can be blended into NG pipelines, typically at pressures less than 100 bar. Blending up to 5 percent hydrogen in the NG stream is considered safe. However, if higher amounts of hydrogen are blended into the pipeline, there is an increased risk of pipeline leaks and significant material challenges associated with designing and repurposing pipelines for hydrogen service due to the risk of hydrogen embrittlement. Hydrogen embrittlement is a process that may occur in metals, including carbon steel, when exposed to hydrogen in a pressurized environment and results in a material prone to cracking and reduced toughness against crack growth.

Despite the recommended safe level of 5%, there are reports that some are considering blends of up to 20 % hydrogen. This level of blending would require significant modifications to accommodate the higher hydrogen content. There have been considerable advancements in developing a hydrogen-ready supply chain for new pipeline infrastructure, the conversion of existing networks remains a significant challenge.

In addition to the material challenges in using natural gas pipelines for the distribution of hydrogen, it is currently difficult to separate the hydrogen from the NG once blended. However, there are many initiatives and research into improving this process and this is expected to become practical in the midterm and would allow the separated hydrogen to be used in fuel cell applications.

Hydrogen Policy and Regulatory Landscape

Canada’s hydrogen policy and regulatory landscape is evolving rapidly to position the country as a global leader in the hydrogen economy. The federal government released its Hydrogen Strategy for Canada in December 20202, outlining a framework for integrating hydrogen into the nation’s energy mix to achieve net-zero emissions by 2050. This strategy emphasizes the development of both green hydrogen (renewable energy based) and blue hydrogen (produced from natural gas with carbon capture), aiming to leverage Canada’s vast natural resources and technological expertise. Regulatory efforts include updating codes and standards to ensure safety and reliability in hydrogen production, distribution, and usage.

Additionally, various provinces have launched their own initiatives, such as Alberta’s Hydrogen Roadmap and Quebec’s Hydrogen and Bioenergy Strategy, focusing on local resources and industrial strengths. Collaboration between federal and provincial governments, industry stakeholders, and international partners is critical to advancing research, infrastructure, and market development for hydrogen in Canada.

Ontario’s Low-Carbon Strategy

In April 2022, Ontario’s Low-Carbon Hydrogen Strategy was launched. The Strategy outlines a vision for a low-carbon hydrogen economy that supports economic growth and GHG emission reductions. It builds on the Made-in-Ontario Environment Plan released in November 2018, which announced the government's commitment to reduce Ontario's GHG emissions by 30% compared to 2005 levels by 2030, in line with the federal government's 2030 target.

Government intends for Ontario's hydrogen strategy to be guided by four principles:

1. Generating economic development and jobs,
2. Promoting energy resilience,
3. Reducing barriers and enabling action, and
4. Being economically feasible.

The strategy suggests hydrogen could become cost-competitive with traditional fossil fuels in four main areas:

1. Industry, where low carbon hydrogen could be used in fertilizers and oil refineries.
2. Transport, where hydrogen can be used in vehicles that would include buses, commuter trains, ferries, and forklifts.
3. Electricity production and storage, where hydrogen can be produced from excess electricity and stored for later use in high demand periods.
4. Buildings and communities, where it can be blended with natural gas for heating purposes.

Ontario's Low-Carbon Hydrogen Strategy highlights the potential of nuclear hydrogen production to support the transition to a low-carbon economy in Ontario. Noting that nuclear energy can produce hydrogen through high-temperature electrolysis, thermochemical processes, and through coupling nuclear power plants with hydrogen production facilities in times of high electricity production and lower grid demand. The strategy also recognizes the importance of safety and security in nuclear hydrogen production and the need for collaboration with regulatory bodies to ensure safe deployment and operation of nuclear hydrogen technologies.

Costs of Hydrogen Production

Understanding the costs, and the factors affecting the costs, of hydrogen production is crucial for evaluating its economic viability and potential for widespread adoption. This section considers the various factors that influence the cost of hydrogen production, including the type of production method, the scale and location of operations and energy pricing.

Hydrogen Costs by Production Pathway

The production pathway has a major influence on the cost of hydrogen production. Blue hydrogen (natural gas with carbon capture and storage- CCS) production costs are currently below those for green (renewable) hydrogen, and the production of grey hydrogen (natural gas without CCS) is cheaper still. Figure 7 shows estimates for each, with green hydrogen costing about \$3-6/kg, blue around \$2/kg, and grey around \$1.5/kg.

Figure 7 | Hydrogen Production Costs by Production Pathway [14]

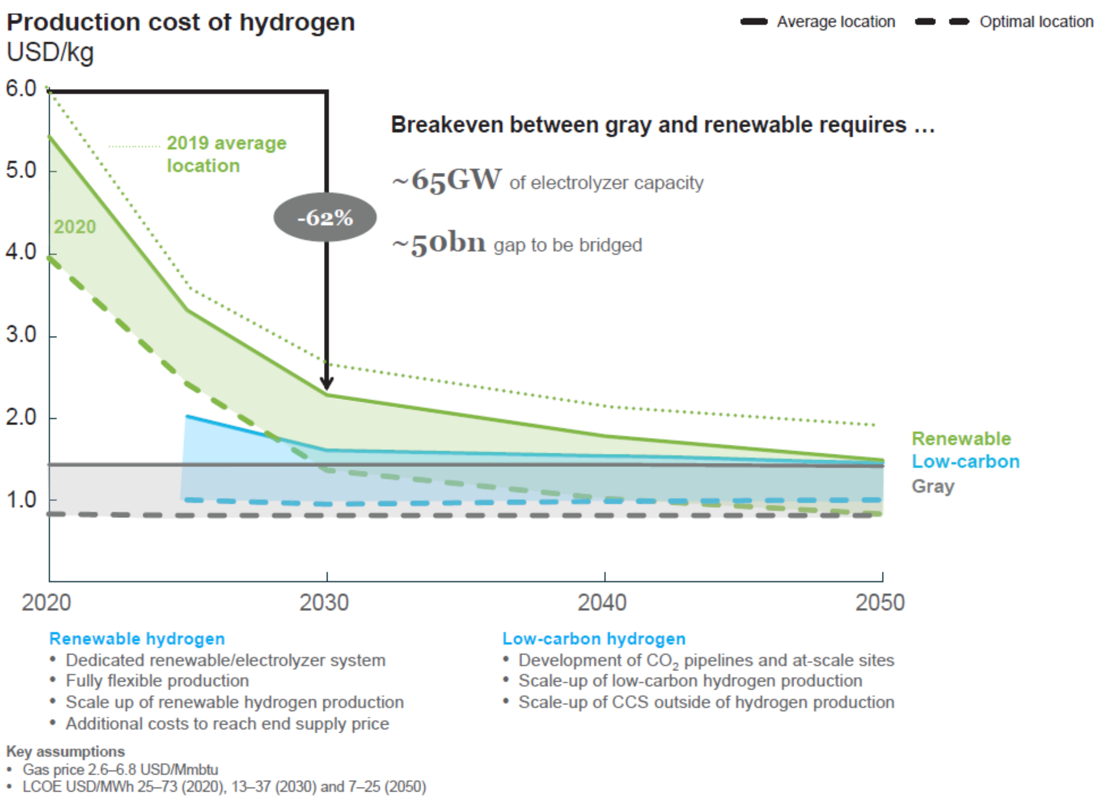
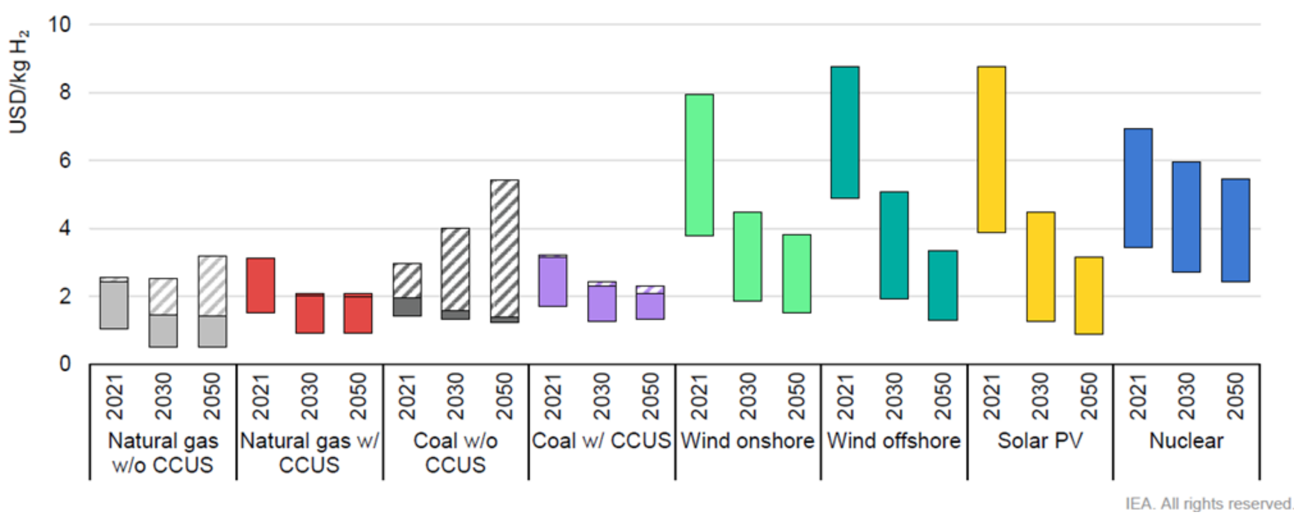


Figure 8 shows the current levelized costs of hydrogen production by pathway and the anticipated improvements to costs in 2030 and 2050 respectively.

The wide range in the projected of the LCOH, from \$2 to \$6 even for 2050, can be explained by several factors. Technological advancements, which can vary significantly in pace, affect efficiency and cost. The scale of production also plays a role, as larger operations benefit from economies of scale, reducing costs, while smaller ones may incur higher expenses. Energy prices, a major input for hydrogen production, fluctuate based on regional and market dynamics. The regulatory environment, including policies and incentives for clean energy, can influence cost structures.

Additionally, variations in capital costs for infrastructure and technology, as well as differences in operational efficiency and maintenance expenses, contribute to the broad cost range. Thus, while the optimistic projection for 2030 estimates costs at $1 to $2 per kilogram for direct production, the wider range up to $6 by 2050 accounts for less favorable conditions and uncertainties in these influencing factors. Fossil production is still anticipated to be the lowest cost pathways; however, with carbon taxes implemented it is possible that renewable generation pathways will become comparable to fossil pathways.

Figure 8 | Levelized Cost of Hydrogen Production by Technology in 2021 and in the Net Zero Emissions by 2050 Scenario, 2030 and 2050 [15]



Hydrogen production from solar photovoltaic (PV) and wind is driven by the availability of these variable renewable resources. For a given electrolyser capacity, the production from variable renewables can result in lower full load hours over a year compared to the use of firm power supply from the grid, resulting in lower annual hydrogen production and increased costs. However, pairing solar and wind with hydrogen production as a means of energy storage can improve the reliability of electricity production from these intermittent sources.

Hydrogen Production Using Nuclear Energy

The latest NEA report *The Role of Nuclear Power in the Hydrogen Economy: Cost and Competitiveness* [16] details the economics of hydrogen production and delivery from water electrolysis using nuclear power. The report concludes that nuclear power can be used to produce hydrogen effectively and efficiently at a production cost comparable to fossil fuels. In fact, amortised reactors in long-term operation can unlock a production cost of around $2/kg [11].

Producing hydrogen with nuclear energy offers many opportunities; particularly increased scale, high temperature (more-efficient) electrolysis technologies, co-location allowing current infrastructure to be leveraged and collaboration among industry to address barriers and foster innovation.

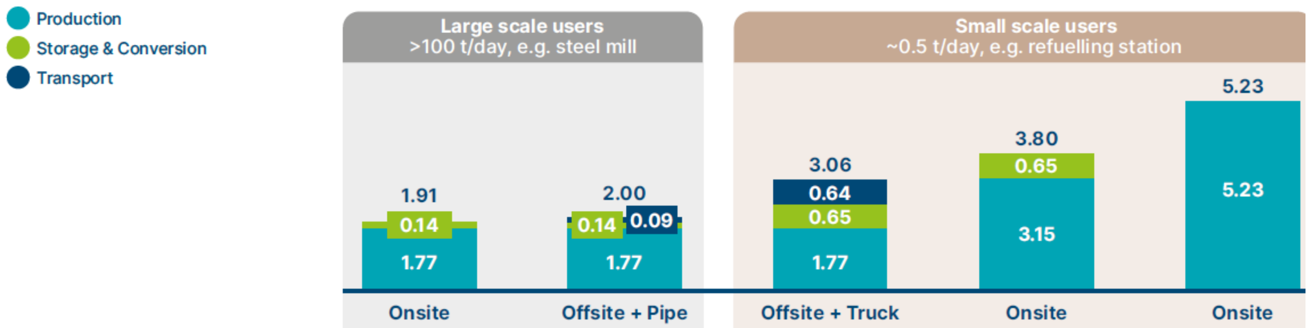
The cost of hydrogen production from nuclear energy will also depend on factors such as the cost of nuclear power, the cost of feedstock, and the cost of the hydrogen production technology used.

Scale and location of operations

Total costs, including conversion, transport, and storage of delivered hydrogen is the essential metric for hydrogen off-takers and will vary significantly according to specific circumstances. Hydrogen use in small distributed applications (for example, refueling stations) will cost significantly more than in large-scale industrial process cases. Large-scale production close to the off-taker offers the lowest-cost option, where costs range from $1.91/kg to $2.00/kg. Small scale users see dramatically increased costs, with production costs alone being higher depending on the electricity source and the electrolyser costs.

The costs associated with small scale users, increase the likelihood that hydrogen's role will lie primarily in large-scale applications (for example, steel, ammonia plants) where storage and transport requirements are lower.

Figure 9 | Cost of Delivered Hydrogen, including Production, Transportation, and Storage in 2030 [6]



			Onsite	Offsite + Pipe	Offsite + Truck	Onsite	Onsite
Production	Electricity source		PV (large-scale)	PV (large-scale)	PV (large-scale)	PV (small-scale)	Continuous grid
	Electricity cost¹	$/MWh	24	24	24	40	100
	Electrolyser CAPEX²	$/kW	290	290	290	580	580
Storage	Mode³		Rock cavern	Rock cavern	Pressurised tank	Pressurised tank	N/a
Transport	Mode⁴		N/a	Pipe (13cm)	Truck	N/a	N/a
	Distance	km	N/a	50	200	N/a	N/a

Drivers for Reduced Costs

Green hydrogen production costs have the potential to decrease drastically and fall below grey hydrogen costs, while blue hydrogen costs are not expected to decrease significantly due to the high costs of carbon capture. Green hydrogen costs depend on two factors – the cost of zero-carbon renewable electricity, and the capital cost of electrolysers. Both are likely to continue to decrease as the market demand and production increases; for example, the levelized cost of renewable electricity has fallen by 70-90% over the last decade, with recent production prices below $15/MWh.

Currently, electrolysers are also a large component of the costs associated with hydrogen production and although electrolyser cost has decreased significantly over the past decade, it is still far too expensive to meet cost parity with fossil-derived hydrogen production. Electrolyser capital costs average $2,000 USD/kW[4]; although electrolyser costs of $300/kW are available in China, and estimates suggest that electrolysers could be widely available for $200/kW by 2030 and $100/kW by 2050. As a result, green hydrogen could reach below $1/kg in many locations by 2050.

Three factors are and will continue to drive lower costs for clean hydrogen production:

1. A significant electrolyser CAPEX decline by 2030 – to about USD 200-250/kW at the system-level (electrolyser stack, voltage supply and rectifier, drying/purification, and compression), due to a faster scale-up of electrolyser supply chains.
2. The levelized cost of energy (LCOE) is declining as a result from the deployment of at-scale renewables.
3. Large-scale, integrated renewable hydrogen projects are more efficient. This performance is driven largely by the centralization of production, a better mix of renewables and design optimization.

Hybrid Electrolyser Systems

The hydrogen economy relies heavily on the advancement and integration of various electrolytic technologies for hydrogen production. Among these, high-temperature electrolysis, particularly SOEC, and low-temperature electrolysis methods, such as Alkaline and PEM Electrolysis, play pivotal roles. Understanding the interactions and synergies between these technologies can significantly enhance the efficiency and feasibility of large-scale hydrogen production.

Potential Synergies of Combining SOEC with PEM or Alkaline Systems

The synergy between different electrolysis technologies, specifically SOECs, and low-temperature electrolysers like PEM or Alkaline systems, offers numerous advantages across various operational contexts. Integrating SOECs with PEM or Alkaline systems enhances hydrogen production capabilities under diverse conditions. SOECs excel in high-efficiency scenarios, utilizing waste heat effectively, whereas PEM or Alkaline systems are adept at responding swiftly to fluctuating renewable energy availability or electricity prices. This hybrid approach not only optimizes costs by leveraging each technology's strengths but also bolsters reliability. If one system encounters issues, the other can continue hydrogen production, ensuring continuous supply.

Moreover, the scalability of PEM and Alkaline systems complements SOECs' modular design, allowing flexible deployment from small-scale immediate needs to large-scale, long-term production requirements. Environmental benefits are also substantial, as the combination reduces CO_2 emissions per unit of hydrogen and offers a pathway to net-zero when paired with low-carbon energy. Effective system integration, advanced thermal management utilizing waste heat, efficient water management, and comprehensive lifecycle strategies further enhance sustainability and operational efficiency. Integration with advanced storage solutions and other renewable technologies, along with

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[4] https://www.hydrogen.energy.gov/docs/hydrogenprogramlibraries/pdfs/24005-clean-hydrogen-production-cost-pem-electrolyzer.pdf?sfvrsn=8cb10889_1

collaborative research initiatives, promises ongoing improvements in performance and materials, solidifying the potential of synergistic hybrid systems for future hydrogen production.

The integration of high-temperature electrolysis (SOEC) with low-temperature electrolysis methods offers significant potential for improving hydrogen production. By using the unique advantages and addressing the challenges of each technology, a more efficient, cost-effective, and resilient hydrogen infrastructure can be developed.

This synergy not only enhances the feasibility of large-scale hydrogen production but also supports the broader goal of transitioning to a sustainable and clean energy future. Through continued research, development, and strategic implementation, the full potential of these complementary technologies can be realized, driving forward the hydrogen economy.

5. Discussion

Economic Opportunity and Demand for Hydrogen

The economic landscape for hydrogen is evolving rapidly, driven by its potential to address critical challenges in the energy transition including industrial and transportation decarbonization. As global economies pivot towards achieving net-zero emissions targets, hydrogen has emerged as a versatile energy carrier capable of integrating renewable energy sources, enhancing energy security, and reducing greenhouse gas emissions across traditionally hard to decarbonize sectors.

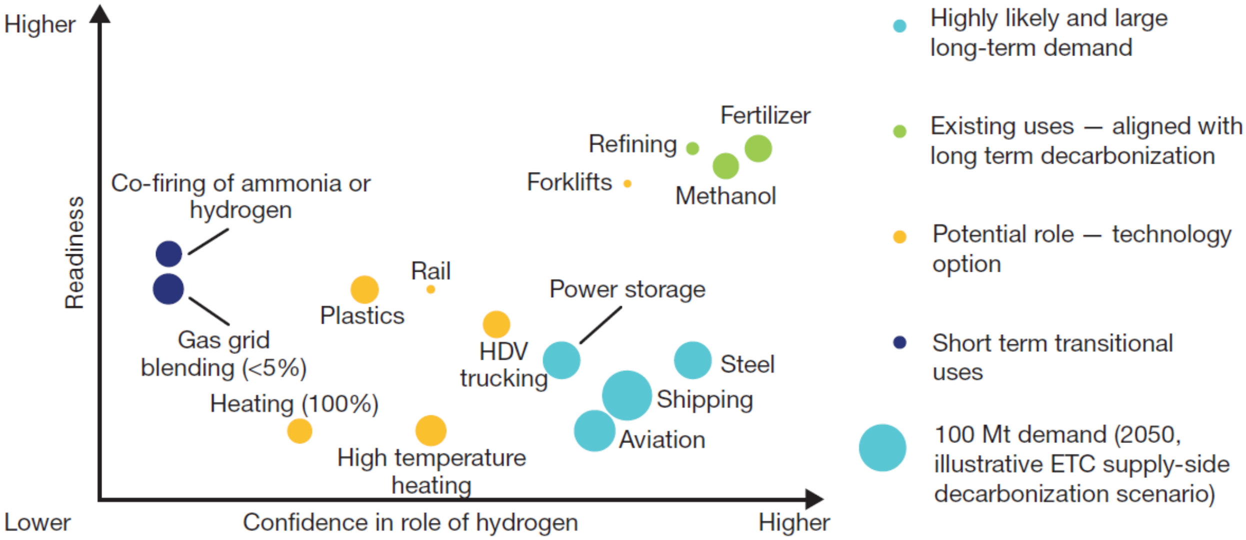
The Global Demand for Hydrogen

Global hydrogen demand reached about 94 megatons (Mt) in 2022, primarily in oil refining and the chemical sector, where it is used as feedstock for ammonia and methanol production. Smaller amounts are also used in steel production, transport and in the manufacturing of other materials and equipment such as metals, glass, and electronics. Demand for hydrogen is expected to increase significantly in the next 30 years as the transition towards a net zero economy advances.

> The Energy Transitions Commission (ETC) estimates that 500 to 800 Mt/year will be needed in 2050, a four- to six-fold increase from current demand levels.

The ETC foresees a range of potential long-term applications for clean hydrogen (see Figure 10). Sectors with high potential in the long term include steel production, shipping, aviation, and the power sector. In other sectors, such as domestic heating, high-temperature heat applications, manufacture of plastics, and heavy-duty transport, hydrogen is seen as a possible alternative to direct electrification or other decarbonization options.

Figure 10 | Current, Likely and Predicted Uses of Hydrogen in a Low Carbon Economy [17]



Examples of Successful Hydrogen Projects in Canada

Canada is entering a transformative phase in hydrogen usage. Industries, from ammonia production to steel and tar sands, are strategically integrating hydrogen.

Noteworthy projects by key hydrogen consumers across diverse sectors are listed below.

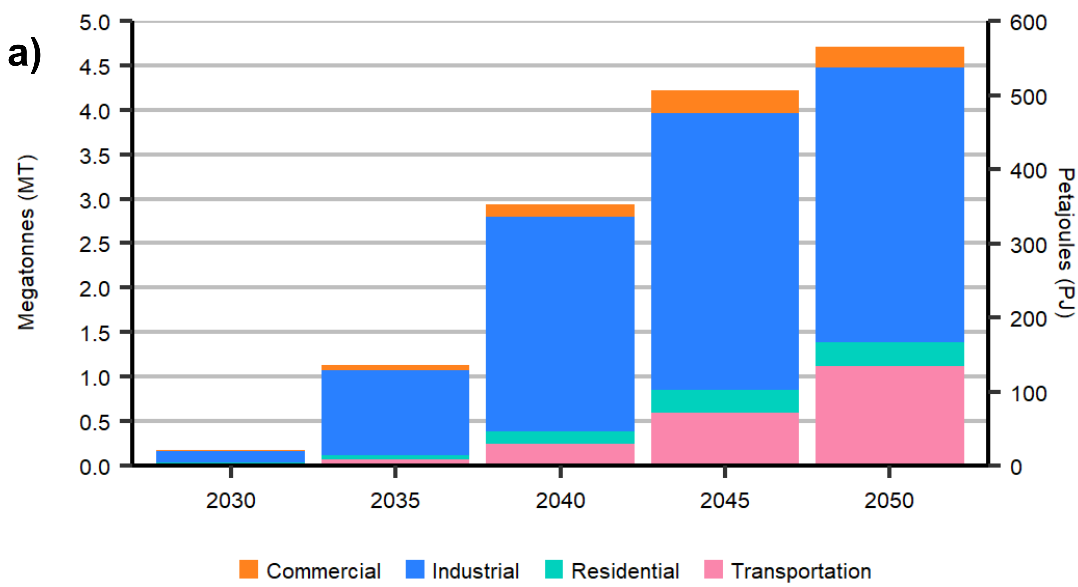
1. In the ammonia sector, with 12 plants collectively producing 5500 kilotons annually, hydrogen is a fundamental feedstock for the Haber-Bosch process, used in ammonia synthesis.
2. In the steel industry, ArcelorMittal Dofasco runs a Quebec-based Direct Reduction Iron (DRI) plant using 88 kilotons of hydrogen annually. A new facility in Hamilton is under construction, set to require 220 kilotons yearly, initially sourced from natural gas. The company's long-term vision includes transitioning to clean hydrogen.
3. In tar sands operations, hydrogen catalyzes hydrocracking, converting bitumen into crude oil. Irving Oil's 5 MW electrolyser initiative signifies a shift towards on-site hydrogen production for refining processes.
4. Atura Power's integration of hydrogen into combined cycle gas turbines involves intricate engineering for combustion optimization.
5. Enbridge's project focuses on the technical challenges of blending green hydrogen into natural gas networks, involving considerations of gas composition, infrastructure compatibility, and combustion characteristics.

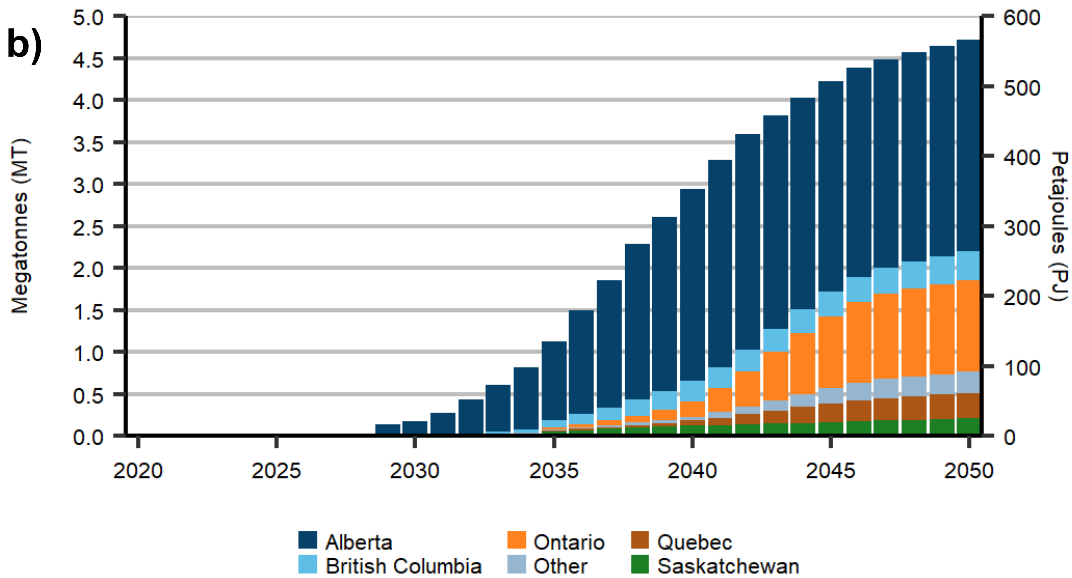
The Growing Demand for Hydrogen in Canada

The demand for hydrogen, as illustrated in Figure 11, is projected to exponentially grow across Canada. By 2050, the total hydrogen demand is expected to reach 4.7 Mt, or 565 PJ, as shown in Figure 11 (a)**.** This accounts for 6% of total end-use energy demand. From this, the industrial sector accounts for 65% of hydrogen use. Hydrogen is used in steel manufacturing, oil sands production, and chemical and fertilizer production. The transportation sector accounts for 25% of hydrogen demand, mostly displacing diesel in long distance freight trucking and marine transportation. The final 10% of hydrogen is used in the residential and commercial sectors, where it is blended into the natural gas stream and used for space and water heating.

Figure 11 (b) illustrates the provincial demand for hydrogen. Hydrogen demand is the highest in Alberta, which accounts for 53% of total hydrogen demand in 2050. Alberta's high demand is due to its existing industrial makeup, and its ability to produce hydrogen from natural gas with CCS, which has lower costs than electrolysis earlier in the projection period. Alberta's future hydrogen use is in oil sands production, where it is used to replace natural gas as a source of process heat. Ontario falls next in the demand curve, being driven primarily by the transport sector.

Figure 11 | Projected Hydrogen Demand by a) Sectors and b) Regions in Canada (2023-2050) [18]





Canada's Regional Hydrogen Production Pathways

In Canada, the hydrogen production pathways adopted in each region will depend on the availability of feedstocks and energy inputs. Each region/province will need to carefully consider their entire energy system before investing in any one production pathway. Overall, the production pathway that makes the most sense for each region will minimize costs and carbon intensity (CI) while maximizing the use of local feedstocks and energy sources. A balanced, regional approach to developing Canada's hydrogen supply from a mix of fossil fuel-derived and clean electricity-derived sources is expected to evolve. Provincial governments in collaboration with industry will decide which hydrogen production pathways will come to fruition over what timeframes in Canada, with government playing the role of writing policy and creating incentives, and industry deciding how hydrogen can best meet their changing needs.

Navigating Peak Energy Demand: Trends, Dynamics, and Initiatives in Ontario

The landscape of peak energy demand in Ontario is undergoing significant shifts, driven by a convergence of factors including decarbonization efforts, economic expansion, and population growth. Current trends show an annual growth rate of 1.5% for summer peaks and 1.8% for winter peaks, with projections suggesting a dual-peaking system by 2030. By this time, both summer and winter peaks are expected to reach around 27GW, compared to the current summer peak of 24GW[5].

Amidst these evolving demand dynamics, the energy market in Ontario shows remarkable responsiveness to demand fluctuations. Generators in the Ontario wholesale market send hourly price/volume offers to the Independent Electricity System Operator (IESO). Utilizing a dispatch algorithm, the IESO selects the least-cost generation resources to meet demand every five minutes,

[5] According to the 2024 Annual Planning Outlook Report. https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook

setting the Market Clearing Price (MCP) for each interval. As a result, energy market prices in Ontario fluctuate, reflecting a real-time balance between supply and demand.

To enhance the accuracy of energy demand forecasts, particularly during peak hours, the IESO is spearheading initiatives using smart grid tools and advanced technologies. These efforts include the integration of smart meters and end-user data, alongside the implementation of machine learning algorithms. By harnessing AI-based techniques, the IESO aims to refine demand forecasting, enabling more precise anticipation of peak energy demand. This proactive approach not only enhances grid reliability but also improves efficient resource allocation and supports the transition towards a more sustainable energy future.

Uses for Hydrogen in Ontario

In Ontario, hydrogen has several use cases, categorized into industrial and transportation applications, with more potential in the energy sector.

- Industrial sector: Hydrogen is primarily used by petroleum refineries and fertilizer production facilities as a feedstock. Additionally, hydrogen is being explored as an alternative reducing agent in metallurgical processes, particularly for sustainable or low-carbon steel production.
- Transportation sector: Hydrogen is used as a fuel source for various vehicles through direct combustion or fuel cells. This includes personal vehicles, public rail and bus transport, and fleet vehicles in industrial facilities and warehouses.
- Energy sector: Hydrogen is being tested for integration into natural gas systems to reduce carbon emissions from heating. It can also replace natural gas for heating in industrial processes. Hydrogen fuel cells or hydrogen-powered turbine generating stations can produce electricity at industrial sites or for grid distribution during peak demand, potentially reducing carbon emissions from peak demand plants, which usually rely on natural gas.

These applications show hydrogen's versatility and potential for contributing to Ontario's sustainability and decarbonization efforts across various sectors.

Global Hydrogen Production Projects

The global push for sustainable energy solutions has positioned hydrogen as a key player in the transition to a low-carbon future. There are numerous hydrogen production projects in Canada and internationally, as governments move toward a low-carbon economy.

> Hydrogen, often touted as the fuel of the future, has the potential to significantly reduce greenhouse gas emissions, enhance energy security, and drive economic growth.

Table 6 | Operational and Expected Hydrogen Production Projects in Canada Table 6 outlines upcoming hydrogen projects in Canada, reflecting the nation's commitment to expanding its hydrogen initiatives and embracing the potential of hydrogen as a sustainable energy carrier. Noteworthy is that Canada does not currently have any SOEC projects ongoing. Table 6 and Table 7 when combined offer insights into the current state of hydrogen projects and the promising developments in hydrogen production, both within Canada and internationally.

Table 6 | Operational and Expected Hydrogen Production Projects in Canada [19] [20]

Project	Technology	End Use
Atura Niagara Centre (ON)	PEM (20 MW)	Mobility/industrial use
Becancour (QC)	PEM (20 MW)	Mobility/industrial use
Planetary Hydrogen (ON)	PEM	
Prince George Refinery (BC)	ND	Ammonia
Markham Energy (ON)	PEM (2.5 MW)	Natural Gas Blend
Hydrogen Fueling Station (ON)	Alkaline (0.5)	Mobility/Vehicles

While Canada currently does not have operational SOEC projects, Table 7 offers a broader perspective by presenting SOEC projects from around the world, showing the global interest in harnessing this advanced technology for hydrogen production. This table encompasses SOEC projects from various corners of the world, underlining the global movement towards adopting SOECs as a key player in the hydrogen production landscape.

Table 7 | SOEC Hydrogen Production Projects Around the World [21] [22]

Project	Energy Source	Status	End Use
Xcel Energy Prairie Island (USA)	Nuclear	DEMO	Not Specified
Multiply	Renewable	Under construction	Not Specified
Hypos – Sunfire (Germany)	Renewable	Demo	Heating
REFLEX (Italy)	Not Specified	Operational	Power

Opportunities and Challenges to Clean Electrolytic Hydrogen Production

Electrolytic hydrogen production stands at the forefront of the global push towards sustainable and clean energy solutions, offering a versatile pathway to generate hydrogen using nuclear and renewable electricity. This method, known as clean electrolytic hydrogen production, holds immense promise in facilitating the transition to a low-carbon economy by leveraging renewable resources such as nuclear, solar, and wind power. As nations intensify efforts to curb carbon emissions and achieve climate targets, the focus on electrolytic hydrogen has grown exponentially; however, amidst its promising opportunities, challenges exist.

The multifaceted advantages of adopting clean electrolytic hydrogen production on a large scale include:

- Environmental Benefits

  The primary advantage of clean electrolytic hydrogen production is the reduction in greenhouse gas emissions. When powered by renewable energy sources, electrolysers produce hydrogen with zero carbon emissions, significantly lowering the environmental footprint compared to conventional methods. In addition, when used in fuel cells or combustion processes, hydrogen produces only water as a byproduct, avoiding greenhouse gas emissions at the point of use.

- Energy Storage and Grid Balancing

  Hydrogen produced through electrolysis can serve as a form of energy storage, addressing the intermittency of renewable energy sources. Excess nuclear and renewable electricity can be stored as hydrogen and later converted back to electricity or used in other applications during periods of low nuclear and renewable energy generation. This capability enhances grid stability and allows for greater integration of different energy into the power system.

- Energy Security and Independence

  Hydrogen production from renewable resources can enhance energy security by diversifying the energy supply and reducing dependence on imported fossil fuels. Countries with abundant renewable energy resources can produce hydrogen domestically, creating a more resilient and self-sufficient energy system

- Economic Growth and Job Creation

  The development of a hydrogen economy can drive economic growth by creating new industries and job opportunities. Investments in hydrogen production, infrastructure, and technology development can stimulate economic activity and support a transition to a sustainable energy future. Furthermore, the export of hydrogen and related technologies can open new markets and revenue streams.

Similarly, there are several challenges to adopting clean electrolytic hydrogen production on a larger scale, each of which will be subsequently discussed:

- Cost of production

  The capital costs of electrolysers, along with the need for renewable energy infrastructure, contribute to the overall expense. Economies of scale, technological advancements, and supportive policies are necessary to reduce costs and make electrolytic hydrogen competitive.

- Infrastructure development

  The existing hydrogen infrastructure is primarily designed for fossil fuel-based hydrogen production. Transitioning to clean hydrogen requires significant investment in new infrastructure, including carbon-free energy generation such as nuclear, wind and solar, hydrogen storage and distribution networks, and refueling stations.

- Efficiency and durability

While electrolysis technologies have made significant progress, further improvements in efficiency and durability are needed. PEM and SOEC electrolysers pose challenges related to catalyst materials and high-temperature operations. Continued research and development are crucial to enhance the performance and longevity of these systems.

- Policy and regulatory framework readiness

  Governments need to implement policies and establish regulatory frameworks around an increased use of hydrogen. These policies could include incentives for hydrogen adoption, research and development funding, and safety analysis cases for easier regulatory transitions.

Future Prospects and Pathways

To fully harness the potential of clean hydrogen production, several strategic pathways must be pursued. Firstly, continuous investment in technology innovation is essential. Research and development efforts focusing on materials, system design, and process optimization can significantly enhance electrolysis efficiency, lower costs, and improve the scalability of electrolysers. Secondly, implement hybrid systems that combine different nuclear and renewable sources further strengthening the resilience and stability of hydrogen production. Lastly, scaling up production capacity is crucial. Establishing large-scale electrolysis plants near renewable energy installations or industrial centres enables economies of scale, driving down production costs and meeting the escalating demand for clean hydrogen effectively. These strategic initiatives will collectively pave the way for widespread adoption of clean electrolytic hydrogen, advancing the transition to a sustainable energy future.

> Sustainable hydrogen production is not just a technological and economic imperative. It is a crucial step towards a more resilient, secure, and environmentally friendly energy future.

Nuclear Power and Hydrogen

There are two primary methods for using nuclear power in hydrogen production:

1. Using surplus or off-peak electricity for water electrolysis and
2. Employing heat and steam from a nuclear power plant (NPP) for thermal treatments.

Currently, Canada's nuclear power sector consists of 19 active CANDU reactors and proposals for several advanced small modular reactors currently under regulatory review.

Policies and Regulations for Nuclear Hydrogen Applications

The regulatory and licensing requirements for a stand-alone hydrogen facility resemble those of a typical industrial facility. These requirements cover several key areas, including air emissions, wastewater discharge, handling of hazardous waste, site redevelopment, zoning amendments, transport of dangerous goods, emergency plans, building permits, and electrical connections. These regulations would apply to a hydrogen facility using nuclear energy outside the immediate vicinity of an NPP.

For a hydrogen facility integrated within a regulated nuclear site, the Canadian Nuclear Safety Commission (CNSC) would enforce federal legislation. The Nuclear Safety and Control Act outlines key regulations relevant to NPPs, specifically the Class I Nuclear Facilities Regulations and the Radiation Protection Regulations. Existing nuclear facilities have their requirements included with site operating licences and the licence conditions handbook for each station. Any modifications to a nuclear site, such as adding a hydrogen production facility, would be evaluated according to these site licence requirements.

For newly constructed NPPs including SMRs, integrated with hydrogen production several CNSC regulatory documents would be applicable:

- Site Evaluation and Site Preparation for New Reactor Facilities, REGDOC-1.1.1
- Licence Application Guide: Licence to Operate a Nuclear Power Plant, REGDOC-1.1.3
- Supplemental Information for Small Modular Reactor Proponents, REGDOC-1.1.5
- Design of Reactor Facilities, REGDOC-2.5.2.

Potential Hazards and Risks

Integrating a hydrogen production facility with an NPP introduces potential hazards and risks to people, site infrastructure, and the safety of both the NPP and the hydrogen facility. These hazards stem from various factors, including the method and rate of hydrogen production, hydrogen storage requirements, and the characteristics of the NPP and its supporting infrastructure.

To address these risks, standardization efforts focus on two main themes:

1. Siting of Hydrogen Production and Storage Facilities

   This includes considerations for NPP safety analysis, emergency planning, hydrogen storage location, safe distances to structures, systems, and components (SSCs), and other mitigation measures to ensure safety.

2. Interfacing of NPPs and Hydrogen Production Facilities.

   This includes issues related to supplying electricity or thermal energy from the NPP, nuclear safety aspects of energy extraction, fluctuations in thermal energy use, and the potential for cross-contamination of produced hydrogen.

Safety Assessments

The CNSC mandates comprehensive safety assessments for NPPs integrating hydrogen production facilities. According to CNSC's REGDOC 2.4.2, a probabilistic safety assessment is needed, following the method in CSA N290.17. Additionally, REGDOC 2.4.1 requires a deterministic safety analysis. These assessments must consider safety issues arising from the presence of hydrogen production facilities, hydrogen transmission pipelines, and hydrogen storage facilities, even if they are not part of the NPP. The potential effects of a hydrogen explosion on critical NPP structures, systems, and components (SSCs), particularly those crucial for nuclear safety and reactor shutdown during serious accidents, must be evaluated. This includes assessing impacts on switchyard components and auxiliary transformers, as well as used nuclear fuel dry storage facilities.

Emergency Planning Zones

Given the variety of possible NPP and hydrogen production facility combinations, emergency planning zones should be assessed on a case-by-case basis. This is particularly relevant for small modular reactors, where a graded approach to developing emergency planning zones may be suitable.

The separation distance is critical between an NPP and a hydrogen production and storage facility and depends on several factors, including the risk of hydrogen fires or explosions. The safety of SSCs outside the reactor building must be considered, especially the hazards posed by on-site hydrogen production. CNSC REGDOC 1.1.1 requires that external human-induced hazards, including fires and explosions, be evaluated in site assessments. Factors such as the specific location of hydrogen production and storage facilities, the safety architecture of the NPP, and the hydrogen production facilities, must be considered. Mitigation measures like physical barriers (for example, berms, blast walls) may be necessary to specify safe separation distances.

On-Site Storage

Hydrogen may be stored on-site in large, high-pressure vessels or shipped off-site, each presenting fire and explosion hazards. Even with continuous off-site shipment, hydrogen production facilities and associated piping pose risks of explosions that could affect worker safety, ancillary facilities like switchyards and used fuel dry storage, and safety systems' operations. Real-time hydrogen sensors in production and storage areas could provide early warning of hydrogen releases and are a mitigation measure to consider.

Harnessing Heat and Steam

For water-cooled nuclear reactor technologies, thermal energy can be supplied in the form of steam directly from the NPP reactor's cooling systems or as hot water from steam in a utility plant. The extraction of steam from the cooling system needs evaluation of implications for nuclear safety, ensuring the protection of key components and safe shutdown capability during emergencies. Any process changes in the NPP require safety assessments to be updated to support relicensing.

Nuclear reactor technologies using molten salt thermal storage can extract thermal energy from molten salt heat storage, which can mitigate the impact of heat extraction loss from the NPP. Considerations about potential contamination of the hydrogen facility with radionuclides include monitoring thermal energy sources for radioactive contamination and specifying intervention measures. Occupational health and safety at the hydrogen production facility and potential radiation contamination of produced hydrogen must be addressed to ensure low levels of radioactive contamination, particularly for thermal energy supplied from boiling water reactors where direct contact with fuel channels may occur. Integrated systems with multiple barriers may require intermediate heat exchangers to isolate the nuclear side from hydrogen production. Special consideration for tritium may be necessary in these cases.

Applicable Canadian Safety Association (CSA) Standards

The following CSA standards should be reviewed to ensure the safe integration of a hydrogen production plant with an NPP. The following CSA standards are particularly relevant:

- CSA N286: Management System Requirements for Nuclear Facilities
- CSA N290 Series: Safety Systems and Safety Analysis Requirements
- CSA N293: Fire Protection for Nuclear Power Plants
- CSA N1600: General Requirements for Nuclear Emergency Management Programs.

CSA N286: Management System Requirements for Nuclear Facilities

This standard applies to senior management with overall accountability for the nuclear facility. It integrates management system requirements for health, safety, environment, security, economics, and quality. Integrating a hydrogen production facility with an NPP may introduce more health, safety, and environmental requirements that need to be considered in this standard.

CSA N290 Series: Safety Systems and Safety Analysis Requirements

Relevant standards in this series include:

- CSA N290.1: Requirements for the Shutdown Systems of Nuclear Power Plants
- CSA N290.11: Requirements for Reactor Heat Removal Capability During Outage of Nuclear Power Plants
- CSA N290.15: Requirements for the Safe Operating Envelope of Nuclear Power Plants
- CSA N290.17: Probabilistic Safety Assessment for Nuclear Power Plants
- CSA N290.19: Risk-Informed Decision Making for Nuclear Power Plants

These standards are critical, especially for the extraction of nuclear thermal energy for hydrogen production. CSA N290.17 provides key insights as the probabilistic safety assessment influences various NPP programs, including operational programs, accident management procedures, and emergency planning.

CSA N293: Fire Protection for Nuclear Power Plants

This standard sets the minimum fire protection requirements for the design, construction, commissioning, operation, and decommissioning of NPPs and small modular reactors. Integrating a hydrogen production facility with an NPP introduces potential fire hazards. Review CSA N293 to assess the need for more guidance or requirements to address these unique hazards.

CSA N1600: General Requirements for Nuclear Emergency Management Programs

This standard outlines the requirements for a comprehensive nuclear emergency management program. The integration of a hydrogen production facility with an NPP, along with the extraction of electrical and thermal energy and the potential for a flammable and explosive hydrogen-rich atmosphere near the NPP, introduces more hazards.

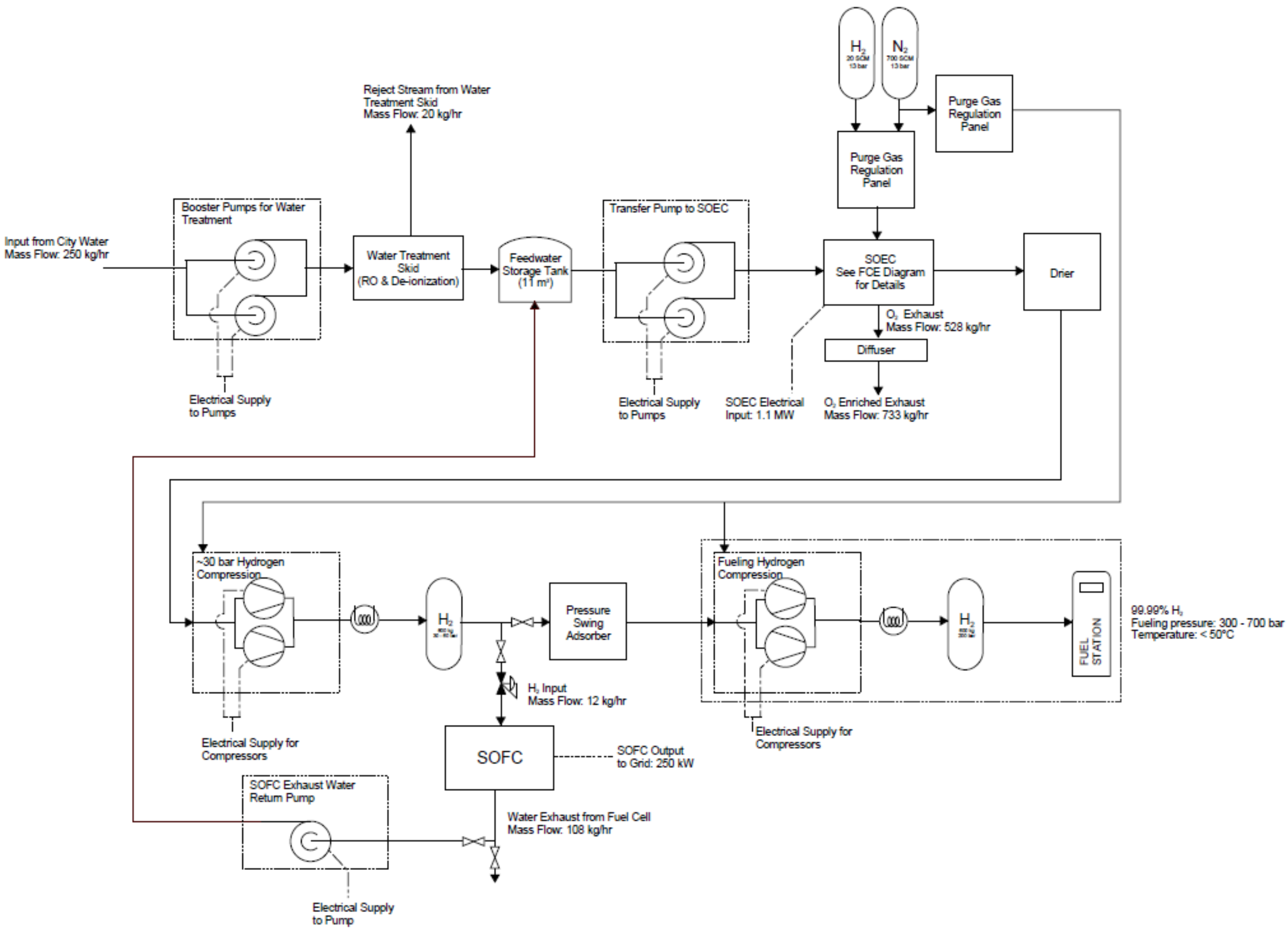
6. Economic/Technical, and Risk Assessments

Conceptual Design

System Description

The integrated system encompasses an SOEC, an SOFC, and a refueling station, as illustrated in Figure 12. This system is designed to produce hydrogen from deionized (DI) water with a power input of 1.1 MW, resulting in a capacity of 600 kg/day of H_2. It features high power density in a compact stack, allowing faster response times. The system can use DI water or steam for hydrogen production, with nitrogen and hydrogen as purging gases for start/shutdown operations. Utilizing steam increases efficiency and reduces energy consumption. Operating at 125-150°C and 1 atm pressure, it produces hydrogen at 99.8% purity and 1 bar of pressure. It has a 25-year lifespan, with the stack requiring replacement every 5 years.

Figure 12 | Process Flow Diagram of the Proposed Hydrogen Hub



Water is the primary feedstock for the system and is fed at ambient conditions at a rate of 230 kg/hr. This water undergoes a purification process to reduce its conductivity to 1 μS/cm, ensuring the production of deionised (DI) water. The DI water is stored in an 11 m^3 reservoir, from where it is supplied to the 1.1 MW SOEC unit at the ideal operational pressure of 2 bar.

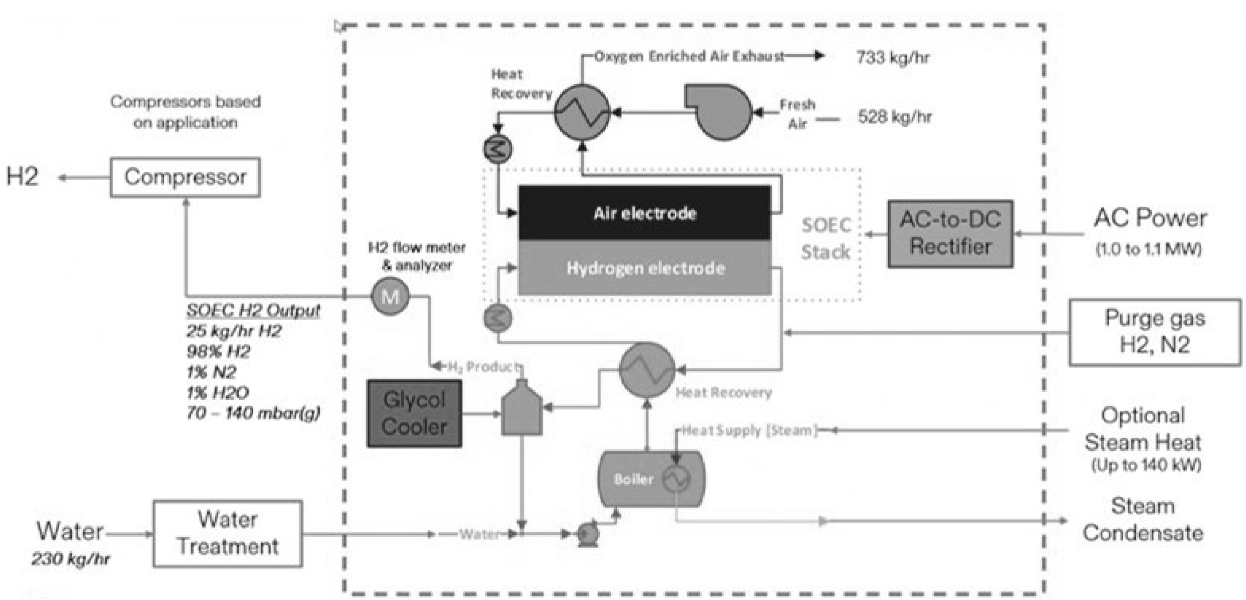
To start and keep the SOEC running, a vital process involves purging the system with hydrogen and nitrogen, both during startup and shutdown phases. Additionally, a key part integrated into the Hydrogen Hub SOEC system is a 140-kW boiler. This boiler serves a dual purpose within the system framework. Firstly, it ensures that the SOEC operates within the best temperature range of 125-150°C, essential for its efficient performance. Secondly, the boiler significantly enhances the overall energy efficiency of the process. Given the current limitations in infrastructure, where access to process steam is unavailable, the boiler serves as a substitute, running solely on electrical energy to fulfill the required functions. As the scale of facilities expands, particularly in scenarios like nuclear sites, it is expected that the presence of steam will become prevalent, thus enhancing the energy efficiency of the system.

Figure 8 offers a comprehensive overview of the electrolyser's specifications, including essential input requirements and key operational parameters. Additionally, Figure 13 provides a visual representation of the elements supplied to the electrolyser and highlights its primary operating conditions. The products of water electrolysis are oxygen and hydrogen. The oxygen undergoes dilution with air to meet safety standards, while the hydrogen (approximately 25 kg/hr) undergoes drying to separate it from water, achieving a purity of 99.9% (dry basis).

Subsequently, part of the purified hydrogen (12 kg/hr) is directed to the SOFC (see Table 9 for further specification), where its combustion generates 250 kW of electricity. The efficiency of this conversion process is improved by the rectifier, ensuring seamless integration of the generated electricity (AC to DC) into the electrical grid. The byproduct, water, is collected and recirculated to the water treatment plant (WTP) for sustainable reuse. Furthermore, the remaining hydrogen (approximately 13 kg/hr) is purified using a pressure swing adsorption unit, achieving a purity of around 99.99% as per the ISO 14687:2019 standard. The hydrogen is then compressed and stored at approximately 200 bar. For dispensing, the hydrogen is cooled to below 50°C and dispensed at 300 bar and 700 bar, ensuring its suitability as a fuel for heavy-duty vehicles. Further details for the hydrogen dispensing system are provided in Table 10.

The system has 350 cells to match power supply limits and uses no platinum, iridium, or other exotic materials, reducing costs and rare earth content. FuelCell Energy plans to market the 1.1 MW system by mid-2024, testing it at Heysham NPP in England as part of the Bay Hydrogen project. The SOEC operates on 480 VAC at 60 Hz and includes heat recovery, an air diffuser, a glycol cooler, a hydrogen flow meter, an analyzer, and an optional steam generation system.

Figure 13 | SOEC System Flow Diagram for Sustainable Hydrogen Generation [23]



In terms of the utilities for the Hydrogen Hub, it is recommended to adopt the following approach. Electricity should be obtained from the grid, while exploring alternative behind-the-meter options alongside grid connection. DI water can be supplied from the WTP, and instrument air can be sourced from a diffuser through the WTP.

Table 8 | Key Parameters of the SOEC System [24]

Parameter	Values
Operating Temperature	125-150°C at 1 atm
Efficiency	39.4 kWh/kg of H_2 (with heat) 43.8 kWh/kg of H_2 (no heat)
Power Input	1.1 MW
Input Voltage	480 V (400 V Option)
Steam Input	Temperature Range 126-146°C Pressure Range 1.38-3.25 bar Flow Rate 154-258 kg/hr
Production Output	600 kg/day
Hydrogen Purity	98% wet basis 99.9% dry basis
Water Requirements	The water quality is based on Type II of ASTM D1193 Standards for Laboratory Reagent Water Conductivity < 1 µS/cm
Purging Gases	Hydrogen and nitrogen
Other Inputs	Steam (optional)
Technology Readiness Level (TRL) [10]	8
Required Interfacing Systems (Balance of Plant)	Needed interfacing systems for SOEC: Water treatment Heat exchangers Compression Drying Storage Further purification (optional)
Scalability	Development of at-grade, multi-MW systems with common BOP and headers for projects ranging from 5-25MW facilitates scalability. Scalability achieved through the addition of additional SOEC units, allowing for large-scale installations
Operating Life	System design life 25 years Cell module life 40,000 hours (~5 years)
Maintenance Requirements	There are semi-annual inspections requiring no shutdown, and one planned annual service requiring a shutdown of 72 hours duration. Every 5 years a replacement of the stack module is required which requires 2 weeks shutdown.
Installation Requirements	Foundation requirements are a function of weights and soil composition. Concrete pad is typical.
Regulatory Compliance (for example, safety standards)	ISO 22734, NFPA 2 The electrical design standard for the plant is by NFPA 79. Site wiring is NFPA 70 (NEC). Functional safety based on ISO 13849. NFPA 2 is the hydrogen safety standard used in the design. NFPA 497 is the basis for the Area Classification. There are many others, but those are the major electrical standards.
Certification status (for example, UL, CE)	CE
Warranty	Standard warranty is one year. Additionally, the service agreement referenced in item 25 is comprehensive and covers preventive maintenance, monitoring, and repair services as needed in addition to stack module replacement.

Parameter	Values
Remote Monitoring	The SOEC is equipped with a data connection for remote monitoring, which is a condition of the warranty.
Footprint	8'W X 40'L X10'H per module. There are 2 modules in the standard configuration.

Table 9 | Key Parameters of the SOFC System [25]

Parameter	Values
Power @ plant rating	250 kW
Standard output AC voltage	480 V (options available)
Electrical efficiency (LHV)	65 ± 2%
Exhaust temperature	167 ± 11 C
Exhaust flow	1780 kg/h
Fuel consumption	129 Nm^3/h
Startup water consumption	91 SLPD
Water production	2360 SLPD

Table 10 | Key Parameters of the Hydrogen Refueling System [26]

Feature	Description
Types of Vehicles	300 and 700 bar cars Buses (35MPa for demonstration)
Options	300 bar vehicle refueling line (possible to refuel buses) T20 and T40 chiller and/or smaller compressor for optimization of CAPEX Third-party payment system Stationary storage (20MPa or 30MPa)
Specifications	Footprint for the whole station: 6m x 3m x 4m (EU) Power supply: 480V, 3 phases, 100kW (EU & US) Modular design for scalability and ease of installation
Output	Refueling capacity: up to 200 cars per day
Dispenser Types	Single dispenser (1 filling point) Dual dispenser (2 filling points at the same location, consecutive fillings) Double dispenser (2 filling points at the same location, simultaneous fillings)
Certification	Certified in Germany according to OIML R139, for an Accuracy Class 2 (Type Examination Certificate)

Design Considerations

Drying of Hydrogen Output

Downstream of the SOEC, hydrogen needs drying before compression to prevent moisture from condensing and damaging the equipment. Depending on the SOEC's output pressure and the drying equipment's pressure drop, a blower or compressor might be necessary upstream. Various drying methods for hydrogen include adsorption drying, refrigeration drying, and cryogenic drying.

- Adsorption drying uses solid desiccants like silica gel to capture water vapor, which is then removed through pressure swing or thermal methods and regenerated.
- Refrigeration drying cools the hydrogen below its dew point, condensing the water vapor into liquid for removal, suitable for large quantities but not for low dew points.
- Cryogenic drying cools the hydrogen to below -100°C, solidifying the water vapor for mechanical separation, achieving very low dew points but requiring high energy input.

The electrolyser's hydrogen output has a moisture content of 1.9-2.9%, which can cause condensation in compressors and must be removed to meet quality standards for different applications. For example, the acceptable dew point for generator hydrogen cooling systems is higher than for hydrogen cylinders and fuel.

Hydrogen Compression

Due to the significant pressure difference between the SOEC output and the required dispensing pressure at the Hydrogen Production Plant (HPP), multi-stage compression is necessary. Cooling between each stage ensures the gas stream's temperature stays suitable for compressors and purification equipment. The SOEC output is between 1 and 2 atmospheres, needing initial compression up to around 30 bar before further multi-stage compression to achieve the desired pressures.

For bulk storage, approximately 200 bar is needed for efficient hydrogen trailer filling. Other uses, like fuel cell vehicles, require 350-700 bar. A final multi-stage compressor at the dispensing location is essential, followed by a heat exchanger to keep acceptable hydrogen temperatures post-compression.

Oil-free compressors are recommended to avoid hydrocarbon contamination, which is critical for fuel cells and hydrogen cylinders. The specific compressor type will be chosen during preliminary design, and both water- and air-cooling options are available to manage the heat generated during compression.

Pressure Swing Adsorption

To meet the purity standards for hydrogen fuel cells and cylinders, a pressure swing adsorption (PSA) system will be needed. PSA systems are designed to remove impurities such as oxygen, nitrogen, carbon dioxide, and other gases from the hydrogen output. These impurities can originate from the steam or demineralized water used in the electrolyser. The PSA system runs by alternating between high and low pressures to selectively adsorb contaminants onto a material such as activated carbon or zeolites, allowing the purified hydrogen to pass through. This process ensures the hydrogen meets stringent purity requirements for various applications, supporting the performance and longevity of fuel cells and hydrogen storage cylinders.

Purge Gas Distribution System

Sufficient bottled nitrogen and hydrogen will be needed for start-up, shut-down, hot-standby, and purging operations. Before start-up, the SOEC must be purged with nitrogen to prevent explosive mixtures. Nitrogen is also necessary for hydrogen compressors to keep an oxygen-free environment and for purging hydrogen handling equipment during maintenance. Compressed hydrogen is essential for start-up, shut-down, and hot-standby of the SOEC, acting as an oxygen scavenger to prevent oxidation and degradation of the SOEC components when not producing hydrogen.

Hydrogen Storage Tanks

The proposed hydrogen storage facility will have a capacity to store 600 kg of hydrogen, aligning with the average requirements of similar storage facilities in Canada and the USA. Stainless steel components will be used for the hydrogen storage tank systems, chosen for their corrosion resistance and durability under high-pressure conditions. To provide efficient thermal insulation for the storage vessels, polyurethane foam with a low thermal conductivity coefficient (less than 0.025 W/mK) will be applied. This will support the integrity and efficiency of the storage tanks.

Safety measures will include the implementation of pressure relief devices to prevent over-pressurization of the storage tanks. Additionally, humidity levels will be closely checked to prevent moisture buildup, which can lead to corrosion and degradation of the storage tanks.

Hydrogen Hub System Functional Requirements

The Hydrogen Hub shall be capable of producing hydrogen from demineralized water or steam using a SOEC, drying and purifying the hydrogen to meet end-use requirements, compressing the output hydrogen for storage, and dispensing hydrogen to trucks, trailers, or other transport methods. Additionally, the hub must provide its own backup power for safe shutdown in compliance with relevant codes and standards and be able to enter a safe shutdown state to protect against operational hazards.

The Hydrogen Hub shall continuously check hydrogen production rates, purity, system temperature and pressure, system chemistry, and other key performance parameters, as well as relevant input parameters from supporting systems such as temperature, pressure, conductivity, flow rate, voltage, and current. It must also provide a bulk alarm for transmission to the pertinent control room and automatically cease hydrogen production upon reaching pre-determined set points within defined system operating limits.

Interfacing System Requirements

The Hydrogen Hub will need:

- Class IV electrical power for water electrolysis.
- Class IV electrical power supply for auxiliary systems.
- Compressed nitrogen supply for purging of the SOEC and compressors.
- Compressed hydrogen supply for purging of the SOEC during start-up, shutdown, or hot stand-by.
- A method of valve actuation, either electrical power (Class IV Power) or compressed air.
- An ambient air source for operation of the SOEC.
- A supply of demineralized water or steam condensate, and cooling water.
- Annunciation of bulk alarms at the pertinent control room based on system location and interfaces.

All interfacing systems must be capable of supplying the necessary inputs to the Hydrogen Hub without compromising their own functionality or performance. Additionally, all direct system interfaces between the hub and external systems should have isolation capabilities to separate the hub from the interfacing systems when needed. Furthermore, these interfaces must be designed to ensure that any failure within the systems does not hinder the interfacing systems from performing their unrelated functions.

Safety Considerations for Hydrogen Generation

Hydrogen, whether in gas or liquid form, presents significant safety risks due to its high flammability, broad range of ignition, and low ignition energy. Furthermore, hydrogen is imperceptible to humans—it's colorless, tasteless, and odorless—raising concerns about potential releases. Its small molecular size also increases the likelihood of leakage and absorption into materials, which can lead to structural issues in piping systems.

In addition, hydrogen dissipates rapidly into the environment due to its lightness. To manage the dangers of hydrogen explosions and fires, the safety approach of the HPP focuses on minimizing leaks, preventing the buildup of explosive mixtures, and promptly venting and diluting any released hydrogen to safe levels. Key design principles include installing hydrogen detectors to alert operators and trigger automatic safety protocols during high hydrogen levels, ensuring equipment can withstand explosion pressures, and adhering to established codes and standards for hydrogen handling and storage (such as NFPA 2, ISO 16110, and ASME B31.12).

Moreover, reliable ventilation systems are essential to prevent gas accumulation, and appropriate electrical equipment must be used in areas where combustible gas mixtures may occur. Overall, the design of the HPP must prioritize robust safety measures to mitigate the potential impact of hydrogen-related accidents.

Risk Analysis

As with any complex technological system, the development and operation of HPPs pose inherent risks that must be carefully analyzed and mitigated to ensure safety, reliability, and efficiency. Risk analysis plays a pivotal role in specifying potential hazards, vulnerabilities, and uncertainties associated with the interconnected components of an HPP. By systematically assessing these risks, stakeholders can proactively implement mitigation strategies to minimize adverse impacts and maximize the benefits of hydrogen technology deployment.

The integration of SOECs, SOFCs, and refueling stations introduces a multitude of technical, operational, and regulatory challenges that must be addressed comprehensively. From electrolyte degradation in SOECs to hydrogen embrittlement of pipelines and grid voltage fluctuations, the diverse nature of risks underscores the need for tailored mitigation measures. The risk analysis and mitigation strategies presented in the following tables (Tables 11-14) serve as valuable tools for guiding stakeholders in navigating the complexities of hydrogen hub deployment and ensuring its long-term viability in a sustainable energy landscape.

Table 11 | Potential Risks Associated with Hydrogen Operation of a Hydrogen Hub [27]

Potential Risk	Mitigation Strategies
Cross-Contamination of Hydrogen Streams	Design separate pipelines and storage tanks for each hydrogen source. Implement strict quality control and monitoring protocols.
Electrical Grid Instability	Integrate power conditioning systems to stabilize electrical inputs. Utilize energy storage systems for grid interaction.
Thermal Management Challenges	Implement comprehensive thermal management systems to regulate temperatures across the interconnected systems.
Regulatory Compliance	Stay updated on regulations governing hydrogen production, distribution, and refueling. Engage with regulatory bodies for compliance.
Interconnection Compatibility	Ensure compatibility of equipment and protocols across the interconnected systems. Conduct interoperability testing.
Operational Dependence	Establish contingency plans for each system to maintain operation in case of failures or maintenance downtime.
Staff Training and Expertise	Provide specialized training for personnel operating and maintaining the interconnected hydrogen hub systems.
Electrical Grid Instability	Use advanced power conditioning equipment with grid-forming capabilities. Employ energy storage for grid stability.
Thermal Management Challenges	Integrate sophisticated thermal control systems with precise temperature monitoring and feedback mechanisms.
Regulatory Compliance	Conduct thorough analysis of regulatory requirements and ensure compliance at every stage of operation.
Interconnection Compatibility	Standardize interface specifications and conduct compatibility testing during system design and integration.
Hydrogen Storage Capacity	Optimize hydrogen storage infrastructure design to balance capacity, pressure, and safety considerations.
Electrolysis Efficiency	Utilize advanced electrolysis cell designs with optimized catalysts and electrode configurations.
Fuel Cell Stack Degradation	Implement online monitoring of SOFC stack performance parameters and predictive maintenance algorithms.
Hydrogen Embrittlement of Pipelines	Utilize hydrogen-compatible pipeline materials and employ cathodic protection systems to mitigate embrittlement.
Electrolyte Degradation in SOEC	Research and implement advanced electrolyte materials with enhanced stability under high-temperature, high-pressure conditions.
Grid Voltage Fluctuations	Install voltage regulation equipment and active power filters to mitigate grid voltage fluctuations and ensure stable power supply.
Thermal Shock in SOFC Stack	Design thermal expansion joints and implement gradual heating and cooling cycles to minimize thermal shock on SOFC stack components.
Hydrogen Dispenser Calibration Drift	Implement regular calibration checks and automated monitoring systems to detect and correct dispenser calibration drift.
Carbon Deposition on SOEC Electrodes	Develop novel electrode materials or coatings resistant to carbon deposition and implement periodic cleaning procedures.
Electrochemical Impurities in Hydrogen	Employ advanced gas purification technologies such as pressure swing adsorption or catalytic reactors to remove impurities from hydrogen.
Interference between SOFC and SOEC	Design separates operating cycles or integrate bypass valves to prevent interference between the SOFC and SOEC components.

Potential Risk	Mitigation Strategies
Grid Power Quality	Install power quality monitoring systems and active power filters to ensure consistent and high-quality power supply to the Hydrogen Hub.
Water Management in SOEC	Develop efficient water management strategies to maintain proper hydration levels in the SOEC while avoiding electrolyte flooding.
Hydrogen Leakage Detection	Deploy hydrogen leakage detection sensors throughout the hydrogen infrastructure and implement automated shutdown systems.
Electrode Sintering in SOFC	Optimize electrode microstructure and operating conditions to minimize electrode sintering and maintain performance over time.
Corrosion in Hydrogen Storage Tanks	Utilize corrosion-resistant materials for hydrogen storage tanks and implement protective coatings or cathodic protection systems.
Electrolyte Decomposition in SOEC	Conduct research to find stable electrolyte compositions and implement preventive measures to minimize electrolyte decomposition.

Table 12 | Potential Risks Associated with Solid Oxide Electrolyser Cells [27]

Potential Risk	Mitigation Strategies
High Operating Temperatures	Use advanced materials with higher thermal stability. Implement effective thermal management systems.
Material Compatibility and Cost Concerns	Conduct thorough material testing and research. Explore alternative materials or coatings to enhance compatibility.
High Capital Cost	Optimize system design to minimize material and manufacturing expenses. Seek funding opportunities or partnerships.
Performance Degradation Over Time	Implement regular maintenance and monitoring protocols. Invest in ongoing research to improve system durability.
Electrode Performance Loss	Optimize electrode design and composition through advanced modeling and experimentation. Implement electrode rejuvenation techniques. Conduct extensive electrolyte material testing under operational conditions. Develop protective coatings or doping.
Deficient Gas Purity Requirements	Implement robust fuel purification systems. Regularly monitor fuel quality and adjust operation parameters accordingly. Install gas purification systems to maintain required purity levels. Monitor gas composition continuously and adjust purification systems as needed.
Gas Leakage	Employ high-quality seals and gaskets. Conduct rigorous pressure and leak testing during assembly and operation.
Corrosion	Choose corrosion-resistant materials for critical components. Apply coatings or surface treatments for enhanced protection.
Hydrogen Embrittlement	Select materials with high hydrogen compatibility and resilience. Incorporate design features to mitigate hydrogen-induced damage.
Mechanical Stress Fatigue	Perform detailed structural analysis and simulations to identify stress concentrations. Design components with adequate strength margins.

Potential Risk	Mitigation Strategies
Chemical Poisoning of Catalysts	Employ catalysts with high resistance to poisoning. Implement catalyst regeneration techniques when feasible.
Water Management Issues	Develop effective water management strategies to prevent flooding or drying out of the electrolyte. Implement drainage and recirculation systems.
Grid Instability	Integrate SOEC systems with grid stabilization technologies like energy storage or demand response. Implement control strategies for grid interaction.

Table 13 | Potential Risks Associated with Solid Oxide Fuel Cells

Potential Risk	Mitigation Strategies
Fuel Cross-Contamination	Implement robust fuel handling and delivery systems to prevent cross-contamination. Regularly inspect and maintain fuel pathways.
Cathode Delamination	Utilize high-quality cathode materials with strong adhesion properties. Optimize fabrication processes to enhance cathode bonding.
Carbon Deposition on Anode	Choose anode materials resistant to carbon deposition. Implement periodic cleaning or regeneration processes.
Power Degradation Over Time	Implement regular stack performance monitoring and maintenance protocols. Conduct stack rejuvenation or replacement as needed.
Electrical Short Circuits	Design electrical insulation systems with appropriate dielectric strength. Implement protective measures to prevent short circuits.
Fuel Supply Interruptions	Establish redundant fuel supply systems and backup power sources. Maintain emergency protocols for quick response to supply interruptions.
System Contamination	Implement filtration and purification systems to prevent contaminants from entering the system. Conduct regular system inspections and maintenance.
Corrosion of Metallic Interconnects	Utilize corrosion-resistant interconnect materials such as stainless steel or cermet alloys. Apply protective coatings or surface treatments.
Cathode Poisoning	Employ cathode materials resistant to poisoning by contaminants such as sulfur or carbon. Implement gas purification systems.
Anode Cracking	Select anode materials with high mechanical strength and resistance to thermal cycling. Optimize operating conditions to minimize stress.
Fuel Cell Thermal Runaway	Implement thermal management systems to regulate temperature and prevent runaway reactions. Incorporate safety shutdown mechanisms.
Hydrogen Leakages	Utilize high-quality seals and gaskets to prevent hydrogen leakage. Conduct rigorous pressure testing during assembly and operation.

Table 14 | Potential Risks Associated with Hydrogen Refueling Stations [27]

Potential Risk	Mitigation Strategies
Hydrogen Supply Shortages	Establish reliable hydrogen supply agreements with multiple suppliers. Invest in onsite hydrogen production output.
Storage and Handling Safety	Implement strict safety protocols for hydrogen storage and handling. Train staff on safety procedures and emergency response.
High Capital Investment	Conduct thorough cost-benefit analysis to justify investment. Seek funding opportunities or partnerships to offset costs.
Site Selection Challenges	Conduct detailed site assessments to identify suitable locations. Consider factors such as proximity to highways and accessibility. Engage with local authorities early in the planning process. Navigate permitting and zoning requirements effectively.
Infrastructure Development	Invest in infrastructure upgrades for utilities such as power and water supply. Coordinate with utility providers for installation.
Public Acceptance and Awareness	Conduct public outreach and education campaigns to raise awareness of hydrogen technology and its benefits.
Technological Complexity	Partner with experienced technology providers for station design and implementation. Provide comprehensive staff training.
System Reliability and Maintenance	Implement regular maintenance schedules and monitoring systems. Establish contingency plans for system failures.
Vehicle Compatibility	Ensure compatibility with existing and upcoming heavy-duty hydrogen fuel cell vehicles. Collaborate with vehicle manufacturers. Coordinate with industry stakeholders.
Fueling Time and Throughput	Optimize station design for fast fueling times and high throughput. Invest in multiple dispensers to accommodate peak demand.
Dispenser Malfunctions	Implement redundant dispensing systems and regular maintenance protocols. Conduct thorough testing and calibration.
Pressure Management Issues	Design pressure management systems to regulate hydrogen flow and pressure. Install safety relief valves for overpressure protection.
Gas Compression Challenges	Use high-efficiency compression systems and consider cascading compression for energy savings. Monitor compressor performance.
Electrolyser Water Management	Develop effective water management systems to maintain proper electrolyte levels and prevent dehydration.
Hydrogen Storage Capacity	Size hydrogen storage tanks adequately to meet demand. Implement on-demand hydrogen generation to supplement storage.
Thermal Runaway Prevention	Design cooling systems to manage heat generated during electrolysis. Incorporate temperature monitoring and automatic shutdowns.
Hydrogen Dispenser Contamination	Implement filtration systems to remove contaminants from hydrogen gas. Conduct regular maintenance and filter replacement.
Hydrogen Purity Monitoring	Install continuous hydrogen purity monitoring systems. Implement alarms and automatic shutdowns for deviations from acceptable levels.

Site Justification and Layout Planning

Two Primary Locations

There are two primary locations under consideration for the development of the hydrogen, selected based on available data. The first location, noted as *Location 1* is located at the east-central area of the Kipling site*.* The second location, noted as *Location 2*, is at the northwest corner of the Kipling site. Location 1 and Location 2 are shown in Appendix 2D.

The design alternatives assessed in this report are based around the two locations noted above:

- Location 1: A 1.1 MW electrolyzer is provided with demineralized water from a tie-in to the proposed WTP. Power for electrolyzers and supporting equipment is provided from one of the supply options discussed in the Power Interface section. The hydrogen output is fed from the electrolyzer to a drier, compressors, and pressure swing adsorber prior to a storage tank and fill station.
- Location 2: A 1.1 MW electrolyzer is provided with demineralized water for electrolysis input via the proposed WTP. Power for electrolyzers and supporting equipment is provided from one of the supply options discussed in the Power Interface section. The hydrogen output is fed from the electrolyzer to a drier, compressors, and pressure swing adsorber prior to a storage tank and fill station.

Walkdown Summary

A walkdown of the potential locations for the HPP and surrounding potential system interfaces was conducted on December 15th, 2023. The findings on the Hydrogen Hub site options and the tie-in options that could be accessed during the walkdown are summarized below.

The following findings are grouped by relevant category, including general location findings, demineralized water tie-in findings, and electrical tie-in findings:

- Location of Design Alternative 1: This area is located at is located at the east-central area of the Kipling site*.* It holds concrete slabs and asphalt paving. The location is currently being used for storage, and several storage skids are present at the south end of the site.
- Location of Design Alternative 2: This area is located at the northwest corner of the Kipling site. The area was noted to be low lying, and currently overgrown.
- Demineralized Water Interface: A new demineralized water plant is conceptualized to be build south of the West end of the Hydrogen Hub. There are above ground obstructions to a tie-in routed west from the existing general water line from the water will be taken.
- Electrical Interface: There are obtained for the several switching areas, such a substation and a switchgear where power can be obtained.

Evaluation Criteria

Alternatives mentioned will be evaluated against the following criteria (Table 15). These criteria were derived with feedback from subject matter experts and key stakeholders and used to assess each alternative.

Table 15 | Evaluation Criteria [27]

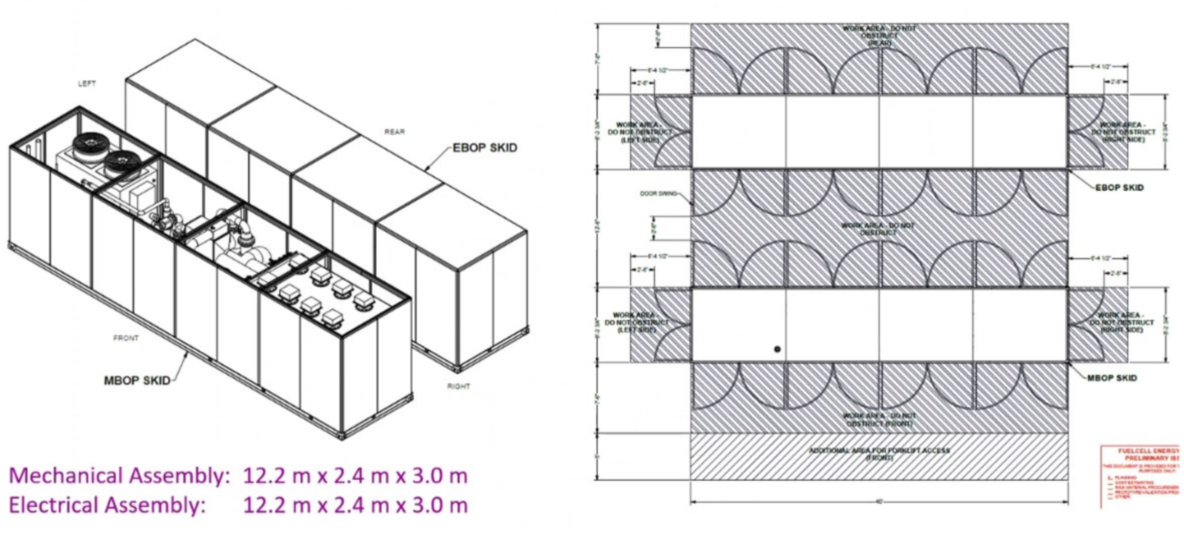
Criteria	Description
Capital Cost	The overall cost to design, procure, and install the Hydrogen Hub should be minimized.
Operating Cost	The cost to operate the installed HPP should be minimized.
Simplicity	The overall design should avoid unnecessary complexity.
Implementation Time	The required timeline for the HPP be to be installed and operational should be minimized.
Operational Flexibility	The capability to operate at different levels of throughput should be maximised.
Environmental Impact	The impact of the hub on environment should be minimized.
Scalability	The hub design should allow the introduction of additional capacity in future, and minimize the complexity associated with introduction of additional capacity where possible.

Layout for the Solid Oxide Electrolyzer Cell (SOEC) in Two Shipping Containers

> The layout for the Solid Oxide Electrolyzer Cell (SOEC) and Solid Oxide Fuel Cell (SOFC) systems is designed to ensure the best functionality, safety, and ease of maintenance.

The SOEC system consists of two 40-foot-long shipping containers. These containers will house the electrolyzer units, which are critical for hydrogen production. To provide a stable and secure foundation, the containers will be placed on a reinforced concrete pad. This pad will have dimensions of 55 feet by 60 feet and a thickness of 5 inches. The design of this concrete pad ensures adequate support for the weight and operational vibrations of the containers, while also providing resistance against environmental factors. See Figure 14 for a detailed representation of the container setup.

Figure 14 | Representations of SOEC and SOFC Systems along with their Mechanical Rooms, Detailing Dimensions and the Area Required for Installation [23]



Layout for the SOFC in One Shipping Container

Similarly, the SOFC system, which is essential for the conversion of hydrogen into electricity, will be housed in a 30-foot-long shipping container. This container will also require a stable foundation to ensure its efficient operation and longevity. Therefore, it will be placed on a concrete pad with dimensions of 30 feet by 50 feet and a thickness of 4 inches. This pad is designed to support the fuel cell container, providing stability and protection from potential ground movements and weather conditions.

Interface Options for Kinectrics Hydrogen Hub

The following sections provide a summary of the available interfaces for provision of demineralized water, power, and annunciation in the vicinity of the design alternatives considered.

Demineralized Water Interface

The proposed WTP will be the nearest existing source of demineralized water to the location options under the existing design alternatives. This facility would be able to provide the demineralized water at a maximum flow rate of 300 L/h via one demineralization trains. The water is provided with a maximum conductivity of 0.01 mS/m, maximum total silica of 15 µg/kg, and a maximum sodium content of 4 µg/kg. The maximum conductivity allowed in the FuelCell Energy SOEC is 1 µS/cm (0.1 mS/m), which the NWPT demineralized water supply is capable of providing.

The most feasible position tie-in locations to the WTP is the pipe that is fed from the water treatment trains. The connection to this line is below grade to the north of its penetration of the WTP foundation. The tie-in and piping to the Hydrogen Hub would require burial for freeze protection.

Each FuelCell Energy's SOEC needs 230 liters of DI water per hour for hydrogen production. A DI system needs to be designed to produce a minimum of 1200 liters per hour for future extension for the SOEC and for future extension of cells. The DI water system will be placed in a 3'x 3' room.

Power Interface

Power for the new hydrogen plant will be sourced from the nearest available power supply at the hub. After evaluating several options during the conceptual design phase, the most feasible is connecting to a 13.8kV power line near the proposed hub.

To supply power to either area, a 13.8kV Disconnect Switch and a 13.8/0.6kV (with verification needed for 600V or 480V suitability for the hydrogen plant) 2500kVA Transformer will be installed at the hub. The Disconnect Switch and Transformer will be sized to support the new hydrogen plant with additional capacity for future loads.

Consideration of the ac supply voltage rating and availability of uninterrupted power is important as power interruptions and poor power quality such as voltage sags, swells and spurious harmonics could disrupt the quality of the electrolysis process.

To mitigate risks due to power interruptions and power quality disturbances, it is suggested that the input power supply to the electrolyser includes power quality monitoring instrumentation as well as redundant primary supply configurations which could imply multiple sources that are separate and distinct depending on the level of power reliability in the location. The power quality instrumentation will be installed as an integral part of the input power apparatus of the electrolyser. Power quality instrumentation metering such as commercially offered by Eaton, Siemens, Schneider, and ABB will be useful for this purpose.

Instrumentation, Control, and Annunciation Systems

While the SOEC and SOFC instrumentation and control is built-into their systems, additional instrumentation and control will be needed for upstream and downstream sections.

The requirements include:

- Monitoring of header pressure and flow rate for demineralized water, steam, and cooling water interfaces.
- Control of valves and pumps for steam, demineralized water, and cooling water tie-ins.
- Automatic shutdown mechanisms for pumps, blowers, compressors, and interface points upon detection of issues such as hydrogen leaks, electrical supply loss, unacceptable steam and water supply disturbances, or equipment over-temperature conditions.
- Instrumentation For SOEC and SOFC, pumps, water storage tanks, H_2 and N_2 cylinders, compressors, control valves, and hydrogen storage tanks.

Integration of instrumentation data from the SOEC and SOFC skid and other components to a common interface panel for overall monitoring. Finally, Wireless transmission is recommended to avoid the high cost of running underground signal cables.

Design Alternative 1

The site is at the east-central area of the Kipling site. The total footprint required by the plant is estimated to be 1500 m^2. The maximum steam demand of any of the SOEs is 337 kg/hr supplied at 150 – 200°C and 450 – 550 kPa. The maximum demineralized water demand is 227 L/hr (1 GPM). The maximum electrical demand is 1.1 MW. The advantages and disadvantages of Alternative 1 are documented in Table 16.

Table 16 | Advantages and Disadvantages of Alternative 1 [27]

Advantages	Disadvantages
Requires minimal site preparation (fill, grading, compaction).	Alternative 1 will limit the amount of hydrogen than can be stored, preventing future expansion.
Conveniently located for provision of wireless instrumentation and control.	Alternative 1 requires a higher volume of demineralized water, as it is also used for cooling unless air-cooled compressors can be procured.
Closer to electrical power lines, making it less costly to route power connections compared to Alternative 2.	

Design Alternative 2

This area is located at the northwest corner of the Kipling site. Water lines are close to the WTP. Any of the electrical tie-in locations could be used to provide power to this location. However, it should be noted that this location is closer to the centre of site electrical tie-in options, and cost to tie into these sources would be mitigated due to the shorter distance compared to the Alternative 1 option.

The advantages and disadvantages of Alternative 2 are documented in Table 17.

Table 17 | Advantages and Disadvantages of Alternative 2 [27]

Advantages	Disadvantages
Alternative 2 is closer to electrical substation, decreasing the cost to route connections from the proposed power line at these locations.	Alternative 2 will require additional site preparation as the area is currently low lying, and uneven.
	Alternative 2 use of on-site water treatment will require the design, procurement, and installation of additional equipment to handle water treatment.

Applicable Safety Codes and Standards for Design and Operation

The following Codes and Standards shall be considered in the design and operation of the Hydrogen Hub:

- Hydrogen and compressed gas codes and standards
- Electrical codes and standards
- National construction and fire codes
- Applicable safety codes and standards for the quality of hydrogen
- Standards for explosion protection
- National Electric Code (NEC) and Canadian Electric Code (CEC)

Hydrogen and Compressed Gas Codes and Standards

- NFPA 2, Hydrogen Technologies Code
- NFPA 55, Compressed Gases and Cryogenic Fluids Code
- ASME B31.12, Hydrogen Piping and Pipelines
- CSA B22734 - Hydrogen generators using water electrolysis – Industrial, commercial, and residential applications.
- CSA/ANSI FC 5, Hydrogen generators using fuel processing technologies
- CSA/ANSI HGV Series for hydrogen fueling stations and vehicle components
- CSA/ANSI standards for stationary and portable fuel cell power systems and fuel cell modules
- Pressure Vessel and Power Piping Codes and Standards
- CSA B51, Boiler, pressure vessel, and pressure piping code
- ASME BPVC, Section VIII, Boiler and Pressure Vessel Code
- ASME B31.1, Power Piping.

Electrical Codes and Standards

- CSA-C22.1, Canadian Electrical Code Safety Standard for Electrical Installation
- CSA C22.2 No. 61010-1, Safety Requirements for Electrical Equipment for Measurement, Control and Laboratory Use Part 1: General Requirements
- Instrumentation and Control Standards
- IEC 61000 (series), IEC series of standard for EMC Compatibility
- IEC 61226, Nuclear Power Plants Instrumentation and Control Systems Important for Safety Classification of I&C Functions
- BP-PROC-00784.

National Construction and Fire Codes

- NFCC, National Fire Code of Canada
- NBCC, National Building Code of Canada

Applicable Safety Codes and Standards for the Quality of Hydrogen

The following Codes and Standards shall be considered in the quality of hydrogen produced by the Hub:

- ISO 14687:2019, Hydrogen fuel quality: Applicable standard if the hydrogen produced is to be used in fuel cell powered vehicles
- The CSA N-Series Codes and Standards: Applies to hydrogen, based on location and system interfaces as per the conditions of a Nuclear Generating Station in Canada, which runs a CANDU reactor. This shall include, but is not limited to, the following:
- CSA N286 -2012, Management system requirements for nuclear facilities
- CSA N290.15 -2010 Update 1 (2016), Requirements for the safe operating envelope for nuclear power plants
- CSA N286.7 -2016, Quality assurance of analytical, scientific, and design computer programs
- CSA N290.12 -2014, Human factors in design for nuclear power plants
- CSA N290.14 -2015, Qualification of digital hardware and software for use in instrumentation and control applications for nuclear power plants
- CSA N291 -2015, Requirements for safety-related structures for nuclear power plants (2015)
- CSA N285.0 -2012 Update No. 1 (Sep. 2013) & Update No. 2 (Nov. 2014), General requirements for pressure-retaining systems and components in CANDU nuclear power plants

- CSA N289.1 -2008, General requirements for seismic design and qualification of CANDU nuclear power plants
- CSA N289.2 -2010, Ground motion determination for seismic qualification of CANDU nuclear power plants
- CSA N289.3 -2010, Design procedures for seismic qualification of CANDU nuclear power plants
- CSA N289.4 -2012, Testing procedures for seismic qualification of nuclear power plant structures, systems, and components
- CSA N289.5 -2012, Seismic instrumentation requirements for nuclear power plants and nuclear facilities
- CSA N290.13 -Reaffirmed 2015, Environmental qualification of equipment for CANDU nuclear power plants
- CSA N285.4 -2014, Periodic inspection of CANDU nuclear power plant components
- CSA N285.7 -2015, Periodic inspection of CANDU nuclear power plant balance of plant systems and components
- CSA N290.7 -2014, Cyber security for nuclear power plants and small reactor facilities
- CSA N293 -2012, Fire protection for nuclear power plants
- CSA C22.2 NO. 30:20 - Explosion-proof equipment

National Electric Code (NEC) and Canadian Electric Code (CEC)

For electrical equipment and systems used in hazardous locations, the National Electric Code (NEC) applies in the USA and in Canada, the Canadian Electrical Code (CEC). Among other things, the differences are in the division of the explosive areas, the construction of the resources, and the installation of the electrical systems. These codes have the character of installation regulations for electrical systems in all areas and refer to a series of standards from other institutions, which include provisions for the installation and construction of suitable operating equipment.

The installation methods for the zone concept according to NEC 505 correspond to the class/division system. Various standards and determinations apply for the construction and testing of explosion-protected electrical systems and resources in North America. In Canada, follow the standards of the Canadian Standards Association (CSA). Areas where flammable gases, vapor or fog will occur are Class I, where dust will occur as Class II and where fibers and lint will occur, Class III. The frequency and duration of occurrence of these materials define the hazardous locations as Division 1 or Division 2.

With respect to the CEC, the Electrolyser in the Kinectrics Hydrogen Hub pilot at Kipling, is categorized as Class I – gas and vapour environment. The electrolyser is a hazardous location, due to the presence of gases or vapours that are present in the air in sufficient quantity to produce explosive or ignitable mixtures. Locations identified as Class I need explosion-proof enclosures and fittings.

Class I hazardous locations are further subdivided into zones:

- **Zone 0:** Continuous hazard
- **Zone 1:** Intermittent hazard
- **Zone 2:** Hazard under abnormal conditions

The electrolyser would be considered as Zone 1 location as explosive gas (oxygen and nitrogen) atmospheres may exist because of repair or maintenance operations or because of leakage. The location would also be further classified by the type of gas group available. Hydrogen is in the Group IIC. The electrolyser would be manufactured to ensure it does not become a source of ignition and all equipment and components within will be clearly identified with Class I, Zone 1 Location" marking. Leakage gas detection will be provided for gas group IIC (See Table 18). Cables and connecting apparatus to the electrolyser will be flame rated at FT4 and will be designed to CEC Class 1, Zone 1 standard. Cable and conduit connections to be sealed appropriately in conformance with the CEC Class 1 Zone 1 requirements.

Table 18 | Comparison of Hazardous Location Gas Group Destinations from Most Restrictive to Least Restrictive [28]

Typical gas hazard	1988 CEC and IEC gas groups
Acetylene	-
Hydrogen	IIC
Ethylene	IIB
Propane	IIA

ATEX Rating – Worldwide Free Goods Traffic

ATEX rating, also known as an "*ATEX Equipment Category*," is a classification system used for the level of protection provided by equipment used in potentially explosive environments. The ATEX rating system is defined in the ATEX Directive, which is a set of regulations by the European Union to ensure the safe use of equipment in areas where there is a risk of explosion due to the presence of flammable gases, vapours, dusts, or powders.

It is important to note that the ATEX rating is different from the ATEX zones (0,1,2) which classify the hazardous areas based on the likelihood and duration of the presence of an explosive atmosphere. The ATEX rating classifies the equipment according to the level of protection needed, while the ATEX zones classify the areas where the equipment will be used. The relationship between ATEX zones and required equipment are shown in Table 19.

Table 19 | Relationship between ATEX Zones and Required Equipment [29, 27]

Zone: a place in which an explosive atmosphere is:	Gasses (ATEX Zone)	Dusts (ATEX Zone)	Level of protection is assured in:	Category	Gasses (Marking)	Dusts (Marking)
Continually present	0	20	The event of two faults occurring independently of each other	1	II 1G	II 1D
Likely to occur in normal operation occasionally	1	21	The event of one equipment fault	2	II 2G	II 2D
Likely to occur in normal operation and only for very short durations	2	22	Normal Operation	3	II 3G	II 3D

The electrolyser presents an atmosphere in which gases are likely to occur in normal operation occasionally. The equipment would be expected to shut down in a gas leak. The environment therefore falls into ATEX zone 1 and into category 2 for explosion-proof equipment. The equipment will therefore have ATEX marking "Ex II 2G".

The electrolyser to be installed at the Hydrogen Hub at the Kinectrics premises in Kipling Ontario is expected to include a few internationally sourced components in the electrical equipment integrated within. There will be an assurance by the manufacturer that all components of international origin have authentic ATEX marking and will be rated for the c ATEX Equipment Category.

Occupational Safety and Health Administration (OSHA) Regulations

The Occupational Safety and Health Administration (OSHA) of the US department of Labor published guidelines and standards on the production, handling, storage, and delivery of hydrogen including the locating and installation of hydrogen generators.

The following OSHA regulations apply to the electrical systems within 15 feet of Hydrogen Generators in Canada, including the electrolyser being proposed:

1. Equipment Assembly
   - Valves, gauges, regulators, and other accessories shall be suitable for hydrogen service.
   - Installation of hydrogen systems shall be supervised by personnel familiar with proper practices with reference to their construction and use.
   - Storage containers, piping, valves, regulating equipment, and other accessories shall be accessible and protected against physical damage and tampering.
   - Cabinets or housings that hold hydrogen control or operating equipment shall be adequately ventilated.

- Each mobile hydrogen supply unit used as part of a hydrogen system shall be adequately secured to prevent movement.

2. Marking

- The hydrogen storage location shall be permanently placarded as follows: "HYDROGEN - FLAMMABLE GAS - NO SMOKING - NO OPEN FLAMES," or equivalent.

3. Testing

- After installation, all piping, tubing, and fittings shall be tested and proved hydrogen gas tight at maximum operating pressure.
- Systems shall not be beneath electric power lines.
- There shall be no sources of ignition from open flames, electrical equipment, or heating equipment.
- Electrical equipment shall follow CEC Class I, zone 1 locations.
- Heating, if provided, shall be by steam, hot water, or other indirect means.

4. Electrical Systems

- Electrical wiring and equipment within 3 feet of a point where connections are regularly made and disconnected, shall be per CSA22.2, for Class I, zone 1 locations.
- Except as provided in (a) of this subdivision, electrical wiring, and equipment within 25 feet of a point where connections are regularly made and disconnected or within 25 feet of a liquid hydrogen storage container, shall be per CEC regulations for Class I, zone 1 locations. When equipment approved for class I, group IIC atmospheres is not commercially available, the equipment may be purged or ventilated per NFPA No. 496-1967, Standard for Purged Enclosures for Electrical Equipment in Hazardous Locations, intrinsically safe, or Approved for Class I, Group IIB atmospheres. This requirement does not apply to electrical equipment which is installed on mobile supply trucks or tank cars from which the storage container is filled.
- Cabinets or housings that hold hydrogen control equipment shall be ventilated to prevent any accumulation of hydrogen gas.

5. Bonding and Grounding

- The liquefied hydrogen container and associated piping shall be electrically bonded and grounded.
- There shall be no sources of ignition.
- Electrical wiring and equipment shall follow pertinent CEC and CSA regulations.
- Heating, if provided, shall be by steam, hot water, or other indirect means.

6. Outdoor Locations

- Electrical wiring and equipment shall follow pertinent CEC and CSA regulations.
- Adequate lighting shall be provided for nighttime transfer operation.

7. Grounding
    - The mobile liquefied hydrogen supply unit shall be grounded for static electricity.

Hydrogen Storage and Dispensing Facilities Design

Hydrogen Storage System Requirements

This section provides comprehensive recommendations for the hydrogen storage facility, focusing on compressed hydrogen storage. The goal is to ensure safe, efficient, and economically practical storage to support hydrogen fuel cell electric vehicles (FCEVs).

The primary focus of this feasibility study is on compressed hydrogen gas storage due to its cost-effectiveness compared to liquid hydrogen and adsorption methods. Liquid hydrogen storage, while offering higher density, involves high capital and operational costs, making it less suitable for this application where hydrogen transportation is not needed. The system must provide hydrogen at pressures up to 700 bar, aligning with the typical working pressure of FCEV storage tanks. Additionally, the storage configuration should aim to minimize the time needed to refuel the FCEVs and reduce deep pressure cycling of storage tanks and start/stop cycles of compressors to enhance equipment lifespan.

Supply and Demand Management

The Hydrogen Hub must keep a sufficient supply of pressurized hydrogen to bridge the gap between production, which is 25 kg/hr, and peak demand during refueling. A typical hydrogen fuel cell bus consumes approximately 25 kg of hydrogen per day with a total fuel mass capacity of 40 kg [27]. To allow for refueling in a shorter time and minimize cycling the SOEC and compressors on and off, pressurized hydrogen storage is needed at or next to the fuelling site. The storage facility will have a capacity to store 250 kg of hydrogen, which is consistent with the requirements of similar refueling stations in Canada and the USA.

Environmental and Operational Considerations

The storage facility and refueling station will run in ambient temperature conditions ranging from -20°C to +40°C. To ensure durability and efficiency, stainless-steel components will be used for hydrogen compression systems due to their corrosion resistance and durability under high-pressure conditions. Additionally, polyurethane foam with a thermal conductivity coefficient of less than 0.025 W/mK will be applied for thermal insulation of storage vessels.

Safety and Maintenance

Pressure relief devices will be implemented to prevent over-pressurization of storage tanks. Humidity levels will be checked to prevent moisture buildup, which can cause corrosion and degradation of storage tanks. Regular inspections and maintenance will be conducted to ensure the integrity and safety of the storage system.

Hydrogen Refueling and Dispensing Station Recommendations

This section provides comprehensive recommendations for the hydrogen refueling and dispensing station. The goal is to ensure the station runs safely, efficiently, and in compliance with industry standards.

Operating Hours and Dispensing Rate

The refueling station will run during standard business hours, assuming 12 hours of operation per day. The station will support a dispensing rate in line with industry standards, with an average rate of 1 kg/min for vehicles and until 3 kg/min for heavy-duty vehicles. This rate ensures that refueling is quick and efficient, minimizing downtime for vehicles and maximizing the station's throughput.

Materials and Component Selection

Hydrogen is dispensed at high pressures, typically ranging from 350 bar (5,076 psi) to 700 bar (10,152 psi), depending on the vehicle's storage system. The materials and components used in the dispensing system must be carefully selected to handle these high pressures safely and efficiently. Stainless steel is the preferred material for hydrogen dispenser components due to its compatibility with hydrogen and resistance to corrosion. Additionally, palladium alloy filters will be used for hydrogen filtration. These filters effectively remove impurities, ensuring that the hydrogen dispensed is of high purity, which is crucial for the efficient operation of FCEVs.

Dispensing System Design

The design of the dispensing system should incorporate various features to ensure safety and efficiency. These features include:

- Pressure Relief Devices: To prevent over-pressurization of the system.
- Leak Detection Sensors: To identify and mitigate any leaks quickly.
- Emergency Shutoff Valves: To shut down the system in case of an emergency.
- Fire Suppression Systems: To manage any potential fire hazards.

Materials such as aluminum and reinforced polymers, known for their high strength and compatibility with hydrogen, will be used alongside stainless steel in the construction of the dispensing system.

Safety Standards and Compliance

Dispensing systems must follow relevant safety standards and regulations to ensure safe operation. ISO 19880-1 is the primary standard for hydrogen fueling stations, outlining requirements for system performance, safety, and testing. Additionally, the system must adhere to local codes and regulations governing gas handling and storage.

Storage and Supply Management

To ensure a consistent supply of hydrogen for refueling, the station will need an adequate storage system. This system must be capable of storing enough hydrogen to meet the daily demand without frequent refills. High-pressure storage tanks, capable of handling up to 700 bar, will be used to maximize storage capacity and ensure efficient use of space.

Maintenance and Monitoring

Regular maintenance and monitoring are crucial for the safe and efficient operation of the refueling station. The station will be equipped with sensors and monitoring systems to provide real-time data on pressure, temperature, and hydrogen purity. Regular inspections and maintenance schedules will be set up to ensure all components are functioning correctly and to find and address any potential issues before they become critical.

Solid Oxide Fuel Cells and Electricity Generation

SOFCs may play an important role in enhancing grid stability in Ontario, Canada, powered predominantly by nuclear reactors. Their high efficiency, exceeding 65% for electricity generation alone and up to 95% with heat recovery, surpasses conventional plants, ensuring reliable power supply even during peak demand. SOFCs swiftly adjust output to match grid fluctuations, crucial for balancing supply with variable renewables like wind and solar.

Integrated into distributed generation and microgrid systems, SOFCs lower transmission losses and enhance overall grid efficiency, particularly advantageous during peak demand. In microgrids, they provide localized power and heat, ensuring stability during disturbances. SOFCs also offer essential grid services such as voltage support and frequency regulation, adjusting output in real-time. Some systems feature black start capability, vital for restoring power post-blackout, especially in critical infrastructure.

Environmentally, SOFCs operate efficiently and cleanly, reducing emissions and supporting sustainability goals while improving air quality. Their multifaceted benefits make them potential assets for Ontario's grid stability and goals around environmental stewardship.

Challenges of SOFCs Interconnection to the Electrical Grid

Connecting SOFCs to Ontario's electrical grid presents several challenges stemming from the unique characteristics of each SOFC technology, the requirements of the grid, and regulatory environments. Overcoming these challenges is essential for successfully integrating SOFCs into the grid infrastructure and achieving their potential to contribute to a sustainable and reliable energy system.

One of the technical challenges is the high operating temperature of SOFCs, which ranges from 300°C to 700°C. This poses issues for material durability and requires robust thermal management systems to ensure long-term stability and safe operation. Another technical challenge is dynamic load matching. SOFC systems must rapidly adjust their output to changes in electrical demand while still being efficient and preventing damage to the cell structure. Developing control systems capable of seamlessly working with grid management systems to respond to fluctuating demand and supply conditions requires sophisticated engineering and real-time communication.

Voltage and frequency regulation is crucial for ensuring that the electrical output of SOFCs aligns with the grid's specifications. This requires advanced power electronics and control algorithms capable of precise adjustments, especially under variable operating conditions. Compliance with grid interconnection standards adds another layer of complexity. These standards, which vary by region and are subject to change, encompass safety, performance, and reliability criteria that SOFC systems must meet to be connected to the grid.

On the regulatory and economic front, obtaining approval for grid connection involves navigating a complex landscape of local, regional, and national regulations. Delays in approval processes can hinder the deployment of SOFC technology and increase project costs. Additionally, the start-up capital costs of SOFC systems, including the necessary grid integration infrastructure, can be high. Achieving economic viability requires not only reducing the costs of SOFC technology through advancements in materials and manufacturing but also using policy incentives and innovative business models. Furthermore, upgrading existing grid infrastructure to accommodate distributed generation models represented by SOFC installations may be necessary, entailing enhancements to transmission and distribution networks, as well as upgrades to grid management systems.

Addressing these challenges requires a multidisciplinary approach involving advancements in SOFC technology, strategic planning for grid integration, and collaboration among technology developers, grid operators, regulators, and stakeholders. Through such collaboration, the benefits of SOFC technology, such as high efficiency, fuel flexibility, and environmental sustainability, can be effectively harnessed to support the transition to a more resilient and clean energy system.

SOFC and Infrastructure Upgrades

Integrating SOFCs with the electrical grid in Ontario, Canada, demands various infrastructure upgrades to ensure seamless operation and compliance with regulatory standards. The SOFC's 250 kW output must align closely with the grid's needs to prevent energy imbalances, particularly during low-demand periods. Infrastructure upgrades encompass multiple aspects including electronics and conversion systems, communication and control systems, thermal management infrastructure and regulatory compliance.

Impact of SOFC Integration on Grid Dynamics and Stability

The integration of SOFCs into the electrical grid has been a subject of extensive research, aiming to evaluate their impact on grid dynamics and stability. Numerous studies have explored various aspects of SOFC integration, including their operational flexibility, ability to provide ancillary services, and impact on renewable energy integration.

Research has underscored the operational flexibility of SOFCs, emphasizing their rapid response capability to adjust power output in line with grid demands. This adaptability is important for stabilizing the grid amidst fluctuations in demand or supply, especially with the rising penetration of intermittent renewable energy sources. SOFCs can serve as a balancing power source, mitigating the variability of renewables and ensuring a steady power supply.

Assessments have also delved into the potential of SOFCs to offer ancillary services, such as frequency regulation and voltage support. Leveraging advanced power electronics, SOFCs can help keep power quality on the grid, ensuring that frequency and voltage remain within specified ranges. This is essential during peak demand periods or sudden load changes, where SOFCs can avert grid disturbances.

Furthermore, studies have explored how SOFCs facilitate the integration of renewable energy sources into the grid. By providing dispatchable power, SOFCs reduce reliance on conventional peaking plants, enhancing grid stability and supporting a cleaner energy mix. In addition, research into microgrid and distributed generation applications has highlighted SOFCs' positive impact on local grid stability and resilience. In microgrids, SOFCs supply electricity and heat, improving energy usage and offering a reliable power source during outages.

Advanced modeling and simulation studies have further contributed to understanding SOFC-grid interaction. Dynamic models simulate SOFC behavior under various conditions, showing their potential to improve grid stability by providing steady, controllable power and responding effectively to disturbances. These simulations aid in finding the best deployment strategies, considering factors like location, scale, and integration with other energy resources.

Moreover, real-world pilot projects and demonstration plants offer practical insights into SOFC integration. These projects explore specific applications, contributing to understanding technical, economic, and regulatory challenges. They also highlight benefits such as enhanced grid stability and reduced environmental impact.

Integration of SOFCs for peak load management

The integration of SOFCs with grid load forecasting systems offers a sophisticated approach to managing energy supply and demand, particularly during predicted peak periods. This integration allows for the optimization of SOFC operation, enhancing grid stability, increasing efficiency, and reducing operational costs.

Grid load forecasting is essential for predicting electricity demand on the grid over specific timeframes, ranging from short-term to long-term periods. Accurate forecasts enable grid operators to plan the best mix of energy generation resources to meet expected demand. Modern load forecasting uses advanced statistical techniques, machine learning algorithms, and data analytics, incorporating variables such as historical consumption patterns, weather data, economic indicators, and societal trends.

By using predictive load forecasting, SOFC operation can be finely tuned to match expected demand fluctuations. During peak periods, SOFCs can be pre-emptively activated or scaled up to contribute more power to the grid, effectively shaving off peaks in demand and mitigating the need for costly and environmentally damaging peaker plants[6]. Conversely, during off-peak times, SOFC operation can be reduced to conserve fuel and reduce wear, ensuring efficient and sustainable energy use.

Facilitating this integration needs robust communication and control infrastructure. Standard communication protocols, such as Modbus, DNP3, and IEC 61850, form the backbone of data exchange between SOFCs, grid operators, and forecasting systems. Advanced energy management systems play a pivotal role in interpreting load forecasts and orchestrating the dynamic operation of SOFCs, improving parameters such as fuel flow rate and power output to align with forecasted demand. Additionally, predictive maintenance strategies can be seamlessly integrated, ensuring the reliability and availability of SOFCs when needed most.

Beyond its technological intricacies, the integration of SOFCs with load forecasting systems holds substantial economic and environmental implications. While initial capital costs may be high, the long-term benefits of reduced operational costs, lower emissions, and improved grid stability render SOFCs a compelling solution for peak-load management. Government incentives, carbon pricing

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[6] A peaker plant is a plant or energy system that is run when there is high demand. They are generally fossil fuel generating stations due to the requirement for quick ramping to meet the grid's need. Peaker plants work to balance the grid.

mechanisms, and the declining costs of renewable energy and SOFC technologies further bolster their economic viability.

SOFC and Energy Storage Integration

The integration of SOFCs with energy storage systems presents a promising solution to enhance grid interconnection transactions. By coupling SOFCs with energy storage, such as batteries or hydrogen storage, a hybrid system can provide continuous, reliable power. This integration contributes to enhanced grid stability by acting as a buffer against fluctuations in demand and supply. SOFCs with energy storage systems offer a stable and reliable power supply that complements the variable nature of renewable energy sources. They can respond quickly to changes in demand, making them effective for demand response and peak shaving strategies. This reduces the need for conventional peaker plants, resulting in cost savings and environmental benefits.

Moreover, SOFC systems can provide valuable ancillary services to the grid, such as frequency regulation and voltage support. When combined with energy storage, this capability is enhanced, allowing for more precise and efficient support to grid operations. Additionally, by integrating renewable energy and reducing reliance on fossil-fuel-based power generation, SOFCs with energy storage contribute to decarbonizing the energy sector.

While the start-up investment and technological complexity are challenges, the long-term benefits of SOFCs combined with energy storage outweigh these costs. Continued research and development are crucial to improving the efficiency, durability, and cost-effectiveness of SOFCs and associated energy storage technologies. Despite challenges related to cost and technological maturity, the potential benefits underscore the importance of continued investment and innovation in this field.

Managing SOFC Output Voltage and Frequency Regulation for Grid Integration

The integration of SOFCs into the electrical grid demands precise management of output voltage and frequency to ensure compliance with grid standards. Typically, SOFC systems employ advanced power electronics like inverters and converters to effectively manage and condition their electrical output. These components play a pivotal role in converting the direct current (DC) output from the SOFC into the alternating current (AC) used by the grid, enabling precise control over voltage and frequency.

Voltage and frequency regulation require real-time monitoring and adjustments based on grid demands and conditions. For instance, during periods of high demand, the SOFC can increase its output, while during low demand, it can scale back its power production. This flexibility not only ensures grid stability but also enhances the SOFC's efficiency and lifespan by avoiding continuous operation at full power. Moreover, modern control systems within SOFC installations can respond rapidly to grid frequency changes, providing ancillary services such as frequency regulation and voltage support, further bolstering grid reliability.

SOFCs also offer potential to store energy for grid interconnection. While known for high-efficiency electricity generation, their integration with energy storage technologies, especially hydrogen storage, presents an opportunity to enhance grid transactions. During periods of low demand or excess renewable energy generation, SOFCs can produce hydrogen and store it for later use, serving a dual function of electricity generation and energy storage.

This feature becomes invaluable where direct electricity production by SOFCs may not be the most economical method. In such cases, the SOFC system can switch to hydrogen production mode, effectively storing energy in chemical form. This stored hydrogen can then be used to regenerate electricity via the SOFC during periods of high demand or for other applications like fuel for hydrogen-powered vehicles or industrial processes, diversifying the SOFC's utility and enhancing grid flexibility.

The concept of integrating SOFCs into an energy system with energy storage and renewable sources enhances the grid's ability to manage supply and demand fluctuations, improve resilience, and reduce reliance on fossil fuels. It also introduces new business models and revenue streams for SOFC operators, allowing participation in various markets depending on economic conditions.

Economic Assessment: Capital Expenses, Production Costs, and Levelized Cost of Production for the Hydrogen Hub

Parameter Selection

The parameters used in the economic assessment are summarized in Table 20 below. All dollar values are presented in CAD 2024.

Table 20 | Parameter Values Used for the Hydrogen Hub Economic Assessment.

SOEC System Electrical Capacity (input)	MW	1.1	11	110
Hydrogen Capacity (output)	kg/day	600	6,000	60,000
Purchased Equipment Cost (undelivered)	$M	1.69	13.5	121.5
Operating Labour[1]	$K/year	15.6	62.4	156.0
Raw Materials	Not applicable	Electricity for electrolysis		
Utilities	Not applicable	Water, air, electricity for heat		
Waste Treatment	Not applicable	None		

SOFC System Electrical Capacity (output)	kW	250	500	2.5×10^3	2.5×10^4	2.5×10^5	2.5×10^6
Hydrogen Capacity (input)	kg/day	288	576	2.88×10^3	2.88×10^4	2.88×10^5	2.88×10^6
Purchased Equipment Cost (undelivered)	$M	1.69	2.56	6.72	26.7	106.5	423.9
Operating Labour[1]	$K/year	15.6	15.6	62.4	156.0	624.0	1,248.0
Raw Materials	Not applicable	Hydrogen					
Utilities	Not applicable	Water, air, electricity[2]					
Waste Treatment	Not applicable	None					

Capital Costs Estimation Method	Estimated using percentage of delivered equipment cost method from Peters [1].
Low Scenario	Minimal contributing capital costs, aligned with default values in H2A DOE Tool
High Scenario	All contributing capital costs which could reasonably apply to Hydrogen Hub

Operating Costs Electricity Cost	$/kWh	0.104
Water Cost	$/L	0.00439
Air Cost	$/kg	0
Hydrogen Cost[3]	$/kg	11
Capacity Factor	Not applicable	0.9

Profitability Analysis Start-up Year	Not applicable	2025
Construction Period	Years	1
Start-up Period	Years	1
Regular Operating Period	Years	10
Total Analysis Period	Years	12
Plant Life	Not applicable	Duration of analysis period
Depreciation Type	Not applicable	Straight-Line
Depreciation Period	Years	10
Teething Factor[4]	Not applicable	0.8
Start-up Expenses[5]	Not applicable	0.005
Discount Rate	Not applicable	0.1
Income Tax Rate	Not applicable	0.265
Salvage Value[5]	Not applicable	0.05
Tax Incentives	Not applicable	With or without 40% Clean Hydrogen Tax Investment Credit
Electricity Sale Price (for SOFC)	$/kWh	0.104 or 0.40

[1] Assumes less than one full time employee is required to monitor and maintain the SOEC and/or SOFC systems.

[2] Assumes a minimum amount of electricity is needed to run the SOFC (e.g., instrumentation, process equipment, lighting, etc.)

[3] Cost of hydrogen assumed for the SOFC economic analysis. For the combined SOEC and SOFC system, the cost of hydrogen was assumed to captured by costs of the SOEC (i.e., value of $0/kg assigned).

[4] Fraction of normal plant capacity.

[5] Fraction of Fixed Capital Investment (FCI).

Capital Costs

As discussed previously, two scenarios were evaluated to provide bounding estimates for the capital costs. The median values are presented below for the 1.1 MW SOEC and 250 kW SOFC systems, along with the bounding range (±). Note that the PECs supplied by FuelCell Energy for the 1.1 MW SOEC and 250 kW SOFC were the same. Since the FCI estimate is based on the PEC, and the cost factors for estimating the contributing capital costs were assumed to be the same, the resulting FCI and TCI values are also the same for both systems.

For the combined SOEC and SOFC system, the PEC was assumed to be the sum of the individual PECs. As a result, the FCI and TCI for the combined system (SOEC with SOFC) are double those for the individual systems. Since the cost of connecting the individual systems to the required infrastructure is captured in the individual cost estimates, it is assumed that connecting the systems together would be equivalent to connecting the systems to other equivalent infrastructure. Thus, no additional costs were captured for the combined system.

- **SOEC (1.1 MW):**
    - FCI: $5.07M ± $2.47M
    - TCI: $5.96M ± $2.90M

- **SOFC (250 kW):**
  - FCI: $5.07M ± $2.47M
  - TCI: $5.96M ± $2.90M
- **Combined system, with SOEC (1.1 MW) and SOFC (250 kW):**
  - FCI: $10.14M ± $4.94M
  - TCI: $11.92M ± $5.81M

Operating Costs

When evaluating the operating costs, the total production cost (TPC) is the final parameter of interest. The TPC factors in all costs associated with operating a plant including selling the product, maintaining, and ensuring the system, recovering the capital investment, and contributing to the company's corporate functions (e.g., management, research, and development, etc.). As previously discussed, the economic assessment only considered operating costs that are relevant to the Hydrogen Hub. As with the capital costs, the median TPC values are provided below with the associated range.

Two TPCs are reported for the 1.1 MW SOEC, 250 kW SOFC, and combined system (1.1 MW SOEC with 250 kW SOFC). The first provides the TPC without any capital costs considered, while the second captures the capital costs of the system by assuming 10% of the FCI is depreciated annually. TPC values incorporate a capacity factor (CF) of 90%, which assumes the plant operates at 90% of its total capacity over the course of any given year.

- **SOEC (1.1 MW):**
  - TPC with CF: $1.18M ± $0.12M
  - TPC with CF and Depreciation: $1.69M ± $ 0.37M
- **SOFC (250 kW):**
  - TPC with CF: $1.33M ± $0.12M
  - TPC with CF and Depreciation: $ 1.84M ± $ 0.37M
- **Combined system, with SOEC (1.1 MW) and SOFC (250 kW):**
  - TPC with CF: $1.45M ± $0.25M
  - TPC with CF and Depreciation: $2.5M ± $0.74M

The TPC for both the SOEC and SOFC is largely dictated by the feedstock consumption and price (electricity for the SOEC and hydrogen for the SOFC). For the combined system, it is assumed that the hydrogen requirements for the SOFC are met by the SOEC. The cost of the hydrogen is thus captured by the SOEC costs, rather than treated as an additional feedstock cost. The TPC for the combined system is higher than the individual systems as it captures the utility requirements for both the SOEC and SOFC systems. Additionally, certain operating costs are estimated based on the FCI and thus higher for the combined system than the individual systems.

Profitability Analysis: Levelized Cost of Production

The profitability analysis assesses the plant economics over a set period, considering the FCI, TPC (with CF), revenue from selling the product(s), as well as other factors such as depreciation, taxes, tax incentives, salvage value, and the time-value-of-money. For the Hydrogen Hub, the profitability analysis is used to determine the levelized cost of production for hydrogen (LCOH) or electricity (LCOE) over the defined analysis period. The levelized cost of production provides a criterion for assessing the economic performance of the system.

The profitability analysis period is divided into three sub-periods: construction, start-up, and regular operation. Start-up is similar to regular operation but assumes the system operates at a lower capacity and incurs additional start-up expenses. The start-up period captures the fact that plants rarely operate optimally immediately after start-up and that unforeseen expenses can occur during the period of optimization.

The levelized costs of production for the 1.1 MW SOEC (LCOH), 250 kW SOFC (LCOE), and the combined system (1.1 MW SOEC and 250 kW SOFC) are provided below. For the combined system, two products are considered: hydrogen from the SOEC (not used by the SOFC) and electricity from the SOFC. When assessing the combined system, the LCOH was determined assuming an electricity selling price. As with the capital and operating costs, the median LCOH values are provided below with the associated range.

The LCOH for the combined system was evaluated at two electricity prices, both of which were informed by the previous Feed-in Tarriff (FIT) Program run by IESO until 2016 [30] [31]. The lower electricity selling price was set at 10.4 cents/kWh which represents the lower range of the FIT Program and is also equal to the purchase price of electricity used by the SOEC. Comparatively, the higher electricity selling price was set at 40 cents/kWh. The higher electricity selling price represents a best-case-scenario which could be obtainable if another FIT Program (or similar) is introduced in future. For the individual SOFC system, the LCOE was determined assuming that the hydrogen price was approximately equal to the median value of the LCOH for the SOEC (i.e., $11/kg).

- **SOEC (1.1 MW):**
  - LCOH ($/kg): $11.21 ± $3.21
- **SOFC (250 kW):**
  - LCOE ($/kWh): $1.20 ± $0.33
- **Combined system, with SOEC (1.1 MW) and SOFC (250 kW):**
  - LCOH ($/kg) at electricity selling price of 10.4 cents/kWh: $32.15 ± $12.34

- LCOH ($/kg) at electricity selling price of 40 cents/kWh: $26.46 ± $12.34

Based on these results, the combined system is currently limited by the SOFC's performance. However, if the SOFC efficiency can be improved and the capital costs reduced (for example, through technology development and economies of scale), the SOFC's economic performance could improve significantly. Improvements in the SOEC system will also benefit the SOFC by reducing the inherent cost of hydrogen.

Comparing the LOCH for the combined system at the two electricity selling prices also demonstrates the value of incentives such as the FIT program, particularly for technologies that are still early in development. Financial incentives help these technologies become more economically competitive, thereby encouraging investment, and ultimately accelerating their development.

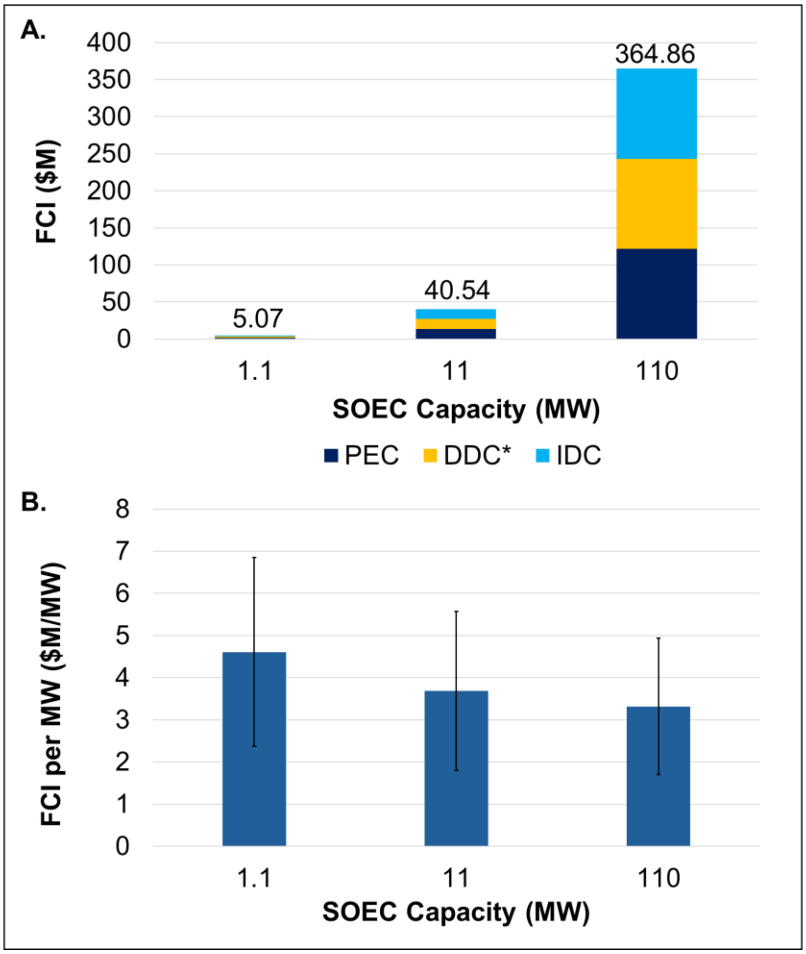
Case Study: SOEC Scalability

To explore the system scalability, the economic assessment was expanded to evaluate the same SOEC system at 11 MW and 110 MW. The 11 MW scale system is expected to become technologically feasible in the near term, while the 110 MW capacity represents a long-term scenario that could be particularly relevant for integrating SOEC systems with nuclear reactors. For this analysis, PEC values for each system size were sourced directly from FuelCell Energy, and thus accurately reflect current (2024) costs for these systems. In alignment with the earlier analyses, the same bounding scenarios were used for the capital cost estimation and the median values are presented here. In select cases, the associated range is also provided.

Capital Costs

Figure 15 summarizes the capital costs for the 1.1, 11, and 110 MW SOEC systems. In (A), the FCI values are provided, broken down by each of the main categories of capital costs (direct depreciable capital costs; DDCs and indirect depreciable capital costs; IDCs). In (B), the FCI values are provided on a per MW basis, with error bars denoting the bounding range. Note that although the PEC is typically considered a direct depreciable cost (DDC), it is presented separately from other DDCs in (A). Note that non-depreciable capital costs (NDCs) are not shown in (A) as none were considered in the economic assessment.

Figure 15 | SOEC Fixed Capital Investment (FCI) with Increasing System Capacity in (A) $M and (B) $M per MW

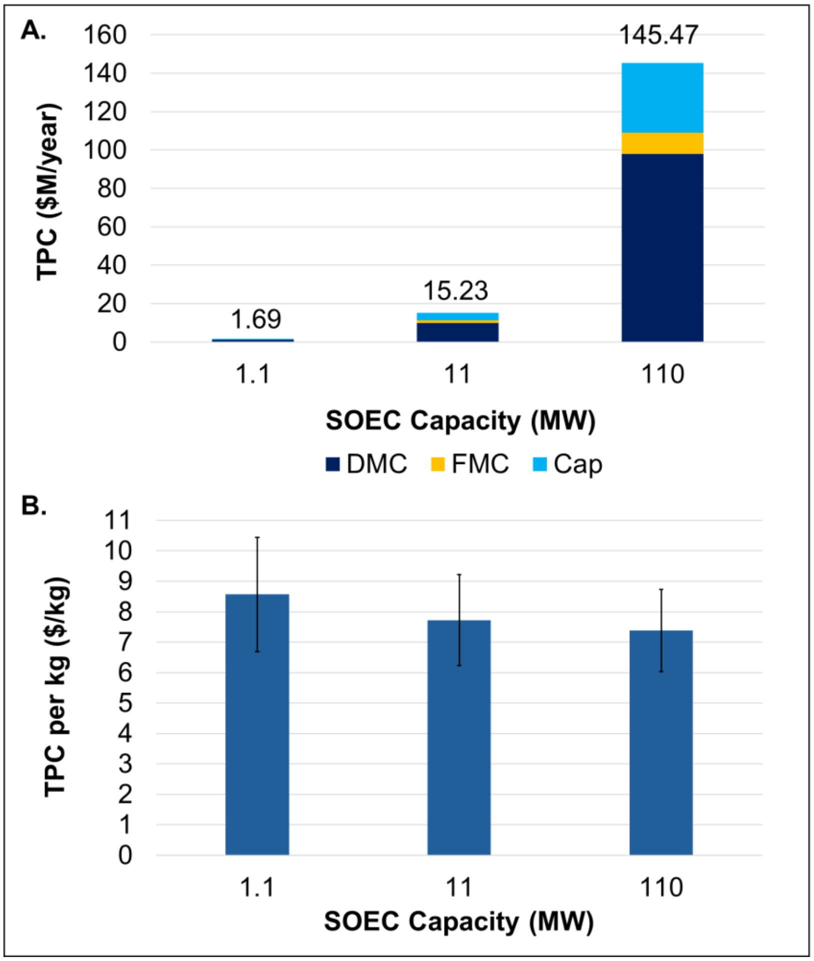


As shown, the FCI increases with system capacity, rising from $5.07M for the 1.1 MW system to $364.86M for the 110 MW system. This increase in FCI reflects the larger infrastructure and equipment needed to support higher production rates. When considered on a per MW basis, the FCI for the 1.1 MW is $4.61M/MW versus $3.32M/MW for the 110 MW system. It is noteworthy that while the increase in capacity does provide capital costs savings, it falls short of the six-tenths rule commonly used to scale system costs in industry. This is likely attributable to the maximum SOEC module size being only 1.1 MW. As 5-10 MW modules become available, the capital costs for larger scale systems may decrease further. Additionally, as these modules are produced and sold at a larger scale (i.e., more systems sold per year), economies of scale could lead to further reductions in capital costs.

Operating Costs

Figure 16 summarizes the operating costs for the 1.1, 11, and 110 MW SOEC systems. In (A) the yearly TPC values are provided, broken down by each of the main categories of operating costs (direct manufacturing costs, DMCs; fixed manufacturing costs, FMCs). No general expenses (GEs) are shown in (A) as they are not applicable to the Hydrogen Hub. In (B) the TPC values are provided per kg of hydrogen produced, with error bars denoting the bounding range. All the TPC values presented in Figure 16 roughly capture the capital expenditure by assuming 10% of the FCI is paid annually.

Figure 16 | SOEC Total Production Cost (TPC) with Increasing System Capacity in (A) $M/year and (B) $ per kg of Hydrogen Produced per MW

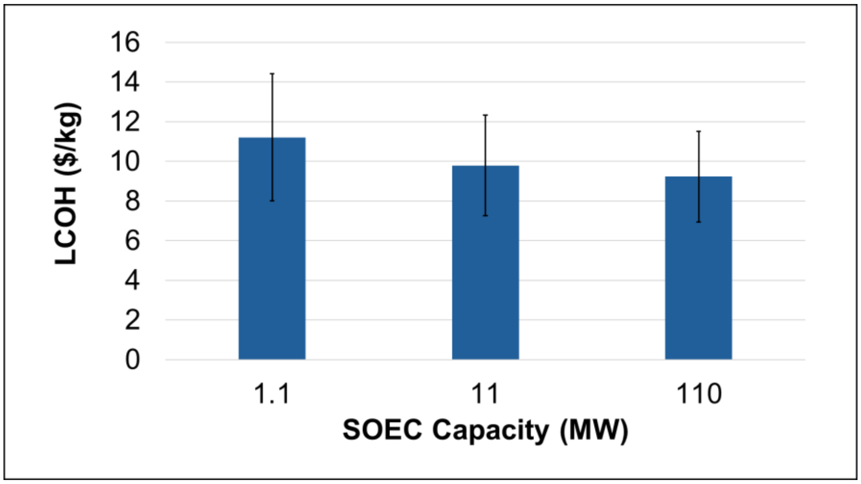


As shown, the TPC increases with system capacity, rising from $1.69M for the 1.1 MW system to $145.47M for the 110 MW system. When the costs are compared on the basis of hydrogen produced, the TPC for the 1.1 MW system is $8.57 per kg of hydrogen versus $7.38 per kg of hydrogen for the 110 MW system. The majority of the TPC is associated with the cost of raw materials and utilities, which are assumed to scale linearly with system capacity. However, many of the other operating costs do not scale linearly with capacity and thus lead to cost savings as the capacity increases. For example, the operating labour costs per kg are 0.07, 0.03, and 0.01 $/kg for the 1.1, 11, and 110 MW SOEC systems, respectively.

Profitability Analysis

Figure 17 summarizes the LCOH for the 1.1, 11, and 110 MW SOEC systems, with error bars denoting the bounding range. As shown, the LCOH decreases with the system capacity, dropping from $11.21 per kg of hydrogen for the 1.1 MW system to $9.24 per kg of hydrogen for the 110 MW system.

Figure 17 | SOEC Levelized Cost of Hydrogen (LCOH) with Increasing System Capacity



The LCOH differs from the TPC as it considers the time value of money. In other words, it captures the lost investment opportunity for the capital that is invested in the Hydrogen Hub. This lost investment opportunity is captured by applying an internal discount rate and assuming that the full FCI is paid during the construction period. For the Hydrogen Hub, an internal discount rate of 10% was used in the economic assessment. It is noteworthy, however, that the LCOH values approach the TPC values as the internal discount rate tends towards zero.

Case Study: Optimizing SOFC Integration with Ontario's Electricity Grid

To successfully integrate the SOFC with Ontario's electricity grid, the LCOE will need to decrease significantly from the values predicted by the profitability analysis. Factors that can reduce the LCOE include increasing the SOFC capacity, reducing the hydrogen costs, reducing the capital costs, and applying tax incentives. The impact of factors on the LCOE were investigated by evaluating the LCOE across multiple hydrogen costs and system capacities. At each hydrogen cost and system capacity, both a maximum and minimum LCOE were evaluated based on the previously defined lower and upper capital cost scenarios. Additionally, the minimum scenario also captures a 40% hydrogen tax investment credit. The results from the investigation are shown in Figure 18 below.

Note that regardless of the system capacity, capital costs, or tax incentives, the LCOE eventually approaches a theoretical limit (TL) which is determined by the cost of hydrogen. The theoretical limit (TL) can be determined using the stoichiometry of the SOFC conversion (i.e., electricity to hydrogen ratio) and assuming that hydrogen is the only system cost. For the SOFC system investigated here, the limit is based on the conversion ratio of 288 kg/day of hydrogen to 6000 kWh of electricity (i.e., 250 kW times 24h). For reference, the TL values for each hydrogen cost are plotted at the far right of Figure 18**.**

Figure 18 | Levelized Cost of Electricity (LCOE) versus SOFC Capacity (kW; log scale), for the Maximum and Minimum Cost Scenarios Modelled at Three Hydrogen Costs

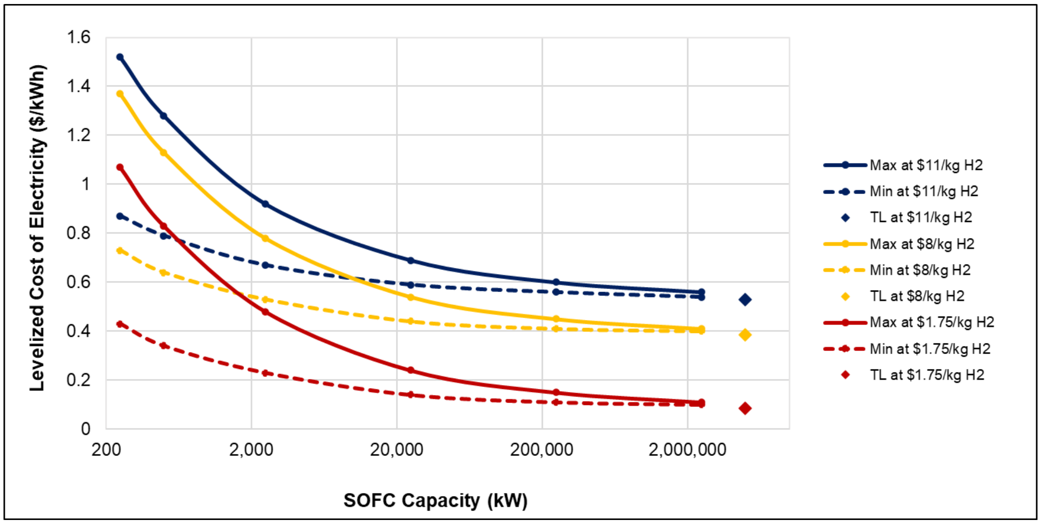


Figure 18 shows that for the current SOFC design to become economically competitive, the hydrogen price would need to drop below $2/kg, in addition to achieving reductions in capital costs (i.e., via technology development and economies of scale). Incentives, such as FIT programs and tax investment credits, can also help by supplementing capital reductions. Increasing the system efficiency also provides another means for improvement, though efficiency improvements will also eventually approach a theoretical limit.

Ultimately, while the SOFC is not yet economically competitive, there are multiple opportunities and avenues to improve the technology's economic performance. Additionally, the SOFC could be strategically deployed to supply Ontario's electricity grid during periods of peak demand, which would allow the electricity to be sold at a higher price and thus improve the technology's profitability. In a combined SOEC-SOFC system, this strategy would also increase the ratio of hydrogen sold, which could further improve the economic performance of the system as a whole.

Refueling Station Costs

The refueling station costs for the Hydrogen Hub were determined by adapting the costs of hydrogen storage and dispensing from a study conducted by M. Aydin et al [32] which examined the costs of refueling stations for a proposed Hydrogen Hub in Oshawa, ON. Additional information was also sourced from a study by the NREL on the cost of hydrogen compression, storage, and dispensing [33]. Together, the results were analyzed and adapted for the Hydrogen Hub, considering hydrogen is produced on-site at the refueling station with an average daily production rate of 600 kg/day.

Once produced, the hydrogen is stored in tanks capable of holding up to 250 kg at a pressure of 250 bar. The refueling station itself runs at pressures of 300 and 700 bar, in conformance with current standards for bus refueling stations with two dispensers [27] [33] [34]. The prices from literature were adjusted to 2024 values using the CEPCI and adapted for the Hydrogen Hub using the H2FAST economic tool. Based on this analysis, the estimated cost for hydrogen storage and delivery for the Hydrogen Hub is $1.55 ±$0.30 per kg of hydrogen.

Levelized Cost of Production for the Hydrogen Hub

Building on the LCOH values for the production systems (SOEC and SOFC), the total LCOH values for the Hydrogen Hub (including the refueling station) are listed below. Values are provided with and without an SOFC.

- **SOEC (1.1 MW) and Refueling Station:**
  - LCOH ($/kg): $12.76 ± $3.51
- **Combined system, with SOEC (1.1 MW), SOFC (250 kW), and Refueling Station:**
  - LCOH ($/kg) at electricity selling price of 10.4 cents/kWh: $33.70 ± $12.64
  - LCOH ($/kg) at electricity selling price of 40 cents/kWh: $28.01 ± $12.64

Without the SOFC present, the lower end of the LCOH values are competitive, especially considering that the technology is still evolving and that the SOEC costs will continue to decrease as technology efficiency and scalability improves. Furthermore, the LCOH values are comparable with current green technologies such as alkaline and proton exchange membrane (PEM) electrolysers, reinforcing the competitiveness of SOEC-based hydrogen production.

By comparison, the SOFC requires more substantial performance improvements to become economically competitive (i.e., increased efficiency, reduced capital costs, economies of scale, etc.). The SOFC will also benefit from improvements in the SOEC via reduced hydrogen costs.

Presently, the economic performance improves as the capacity of the SOEC increases with respect to the capacity of the SOFC, with the best scenario eliminating the SOFC entirely. However, with improvements in the SOFC, the optimal configuration in future may include both an SOEC and SOFC, and the optimal ratios may change depending on whether the electricity is sold during or outside of peak periods of demand. The presented analysis assumed the SOFC operates at a 90% capacity factor. However, if only producing electricity during peak periods of demand, the actual capacity factor would be lower. Restricting electricity production to peak periods of demand would increase the overall ratio of hydrogen sold to hydrogen used by the SOFC, while ensuring the electricity produced is sold at the highest possible price. Both these factors would improve the economics of the combined system.

Finally, the presented analysis also demonstrates the role incentives (e.g., FIT programs and tax incentives) can play in reducing costs. Cost reductions associated with incentives encourage technology investment and adoption, which in turn accelerate technology development and drive faster improvements in economic performance.

Exploring the Technical Feasibility of Integrating SOEC with Nuclear Energy

The integration of SOEC with nuclear energy systems holds immense promise for advancing sustainable, affordable, and reliable hydrogen production. This integration capitalizes on the synergies between these two technologies, using the surplus heat generated by nuclear reactors to drive the high-temperature electrolysis process in SOECs. By doing so, it offers a possible pathway to produce low-carbon hydrogen, a clean and carbon-free energy carrier crucial for decarbonizing various sectors and achieving climate goals.

To realize the full potential of this integration mechanism, several key recommendations should be considered:

- Optimization of Operating Parameters: This includes fine-tuning temperature, pressure, and flow rates to maximize hydrogen production efficiency while ensuring the stability and longevity of SOEC components.
- Materials Development and Compatibility: Continued R&D is needed to find and develop materials (for electrolyte membranes, electrodes, interconnects, and seals) that can withstand the harsh operating conditions of SOECs to increase stack life thereby reducing cost.
- Safety and Regulatory Considerations: This includes rigorous risk assessments, safety protocols, and compliance with nuclear and hydrogen safety standards to mitigate potential hazards and ensure public acceptance.
- Scalability and Commercialization: Scaling up SOEC technology for commercial deployment alongside nuclear reactors requires significant investments in manufacturing, supply chains, and infrastructure. Achieving cost reductions, increasing production output, and streamlining deployment processes are key to unlocking the full potential of integrated nuclear-SOEC systems.

The integration of SOEC with nuclear energy is also hindered by significant licensing and regulatory challenges [34] [11]. The complexities of navigating existing regulatory frameworks governing nuclear reactors and hydrogen production facilities pose more barriers to deployment. Traditional licensing processes may not adequately address the unique safety considerations associated with integrating SOECs, highlighting the need for tailored regulatory frameworks to address these integrated systems' specific requirements.

Safety assessments require rigorous evaluation of potential risks and hazards. Comprehensive analyses of reactor operation, hydrogen storage, and electrolysis processes are essential to ensure the safety of personnel, the public, and the environment. Robust safety protocols and risk mitigation strategies are necessary to address any identified safety implications effectively [35]. Moreover, technology demonstration and validation play a critical role in the licensing process, requiring pilot projects or demonstration facilities to provide essential data on system performance and safety features. However, conducting comprehensive technology demonstrations demands significant time, resources, and collaboration among technology developers, regulatory agencies, and stakeholders [16].

Additionally, public opinion and acceptance are crucial to securing regulatory approval and public support for integrated nuclear-SOEC systems. Transparent communication, public engagement initiatives, and stakeholder consultations are essential for addressing public concerns related to nuclear safety, hydrogen handling, and environmental impacts. Furthermore, international collaboration and harmonization of regulatory standards are key to navigating licensing challenges for integrated systems. Aligning licensing requirements, safety protocols, and technical standards across jurisdictions streamlines the licensing process and reduces regulatory barriers, helping the broader deployment of integrated nuclear-SOEC systems [11].

Licensing and Environmental Challenges for Hydrogen-Nuclear Facility Integration

Co-locating a hydrogen production facility within the secured/protected area of a nuclear power plant (NPP) requires careful consideration of licensing and environmental implications. Such a change would need evaluation by the local regulatory body, such as the Canadian Nuclear Safety Commission (CNSC), to assess its impact on the existing facility. License amendment processes typically involve a thorough examination of proposed changes, including their effects on safety analyses, emergency response plans, physical security measures, fire protection protocols, and environmental impacts.

The CNSC's support for a license amendment hinges on the determination that co-locating the hydrogen facility poses no statistically significant increased risk to the NPP. Thus, comprehensive risk assessments are essential, requiring an evaluation of the reliability of the hydrogen production facility and an examination of potential accident scenarios and their consequences. Any potential impacts on the release of radioactive materials from the NPP must also be assessed.

In addition to licensing considerations, co-locating a hydrogen production facility triggers environmental review processes under the Impact Assessment Act (IAA) This involves a federal Impact Assessment to evaluate the need for the project, its proposed description, environmental impacts, alternative options, and resource use. The assessment must also address radiological and non-radiological impacts associated with the project, including those related to storage and transport of hydrogen within the site.

The decision to co-locate the hydrogen production facility within the secured/protected area of the NPP site needs a thorough examination of its necessity and benefits compared to alternative siting options. While proximity to the NPP may offer advantages such as reduced heat loss for steam use, alternative locations outside the secured/protected area may provide similar benefits without posing risks to the NPP. Additionally, evaluations of emergency plans and safety protocols must consider the presence of the hydrogen facility and its potential impacts on evacuation strategies and worker safety within the site.

Environmental Considerations

A summary of the environmental considerations for a HPP near a nuclear site is provided in Figure 20**.** This figure offers an overview of the various environmental considerations and requirements for the HPP project, based on guidance from REGDOC-2.9.1, which outlines Environmental Principles, Assessments, and Protection Measures, as well as information from relevant federal and provincial public service webpages. These considerations are essential to ensure that the hydrogen production plant runs sustainably and in harmony with the surrounding environment. Figure 20 provides a detailed summary of these factors, emphasizing the importance of integrating environmental protection measures into the project planning and execution phases.

Figure 19 | Text of Overview of Environmental Considerations and Requirements for a Hydrogen Facility Close to a Nuclear Site [36]

Environmental Review(s) - Federal Level (IAA)

- IA under IAA – is the project a "designated project"
- Federal lands review under IAA – is the project on federal lands?

Environmental Review(s) - Provincial Level (EA)

- Is a provincial EA required?

If IA, federal lands review, and EA are all not applicable...

- Does the project have potential environmental interactions?
- If yes, EPR is required under the NSCA.

Public and Indigenous Engagement

- CNSC determines appropriate level of participation opportunities on case-by-case basis.

Environmental Protection Measures (EPM):

- First, establish EPMs (initially)
- Predictive ERA performed in graded manner (per CSA N286.6)
- Predictive ERA informs establishment of Monitoring Programs (per CSA standards) and Environmental Management Systems (per ISO 14001).
- Second, maintain EPMs (ongoing).
- Updated periodically, taking into account new information or insight gained over time.

Acronyms used in the text above:

- CNSC: Canadian Nuclear Safety Commission
- EA: Environmental Assessment
- EMS: Environmental Management System

- EPR: Environmental Protection Review
- EPMs: Environmental Protection Measures
- ERA: Environmental Risk Assessment
- IA: Impact Assessment, IAA: Impact Assessment Act
- NSCA: Nuclear Safety and Control Act.

7. Conclusion and Recommendations

An Urban Hydrogen Hub is a Practical Solution

The establishment of an urban Hydrogen Hub in Toronto presents a promising opportunity to demonstrate the potential of hydrogen to contribute to sustainable energy and decarbonization goals, improving electrical grid reliability and resiliency. The integration of high-temperature water electrolysis powered by a surrogate heat source, imitating conditions of a nuclear power plant, offers a practical solution for hydrogen production. Therefore, a future application wherein a heat source such as a nuclear power plant is available presents an attractive opportunity for the production of hydrogen. In addition to the proposed hub, consisting of a 1.1 MW SOEC pilot system, a 250 kW SOFC for power generation, and a hydrogen refueling station, higher capacity SOEC systems were also simulated, showing scalability and versatility in the hub's design.

Hydrogen is Emerging as a Cost-Competitive Solution

Hydrogen is emerging as a cost-competitive and versatile player in the energy ecosystem. Offsetting the need for other fuel sources, hydrogen has the potential to utilize clean electricity to produce hydrogen fuels which can be stored, transported, and used for other direct applications. Although the focus of the economic analysis was on a pilot scale plant, the economics underscore the importance economies of scale in that deploying higher-power systems (multiple stacks or modules) improve cost efficiency. **The cost of electricity to the system is a primary driver of the production cost, even over capital.** By using heat and electrical input from nearby nuclear facilities, the cost of hydrogen production can be significantly reduced to as low as $8.01/kg, highlighting the economic feasibility and competitiveness of the proposed approach. Advancements in electrolysis technology will continue to drive down production costs, making hydrogen increasingly competitive with conventional fuels. As infrastructure develops and economies of scale kick in, hydrogen promises to play a pivotal role in decarbonizing our energy systems while offering a viable, cost-effective alternative to fossil fuels.

It is emphasized that that it will be necessary for an attractive, fixed, and guaranteed long-term rate for electricity used for hydrogen production in order for such a project to be economically viable. Therefore, it is recommended that the IESO, and other grid operators consider how electricity rate incentives can be created to help with technology adoption and early projects.

Success Hinges on Positive Public Opinion, Advancements in Technology, and Collaboration

Despite the long-term promising economic outlook, several challenges and considerations must be addressed to start up and run the urban Hydrogen Hub. Regulatory frameworks, safety assessments, public opinion, and international collaboration are among the key factors that require careful attention and strategic planning. Additionally, ongoing advancements in technology, coupled with collaborative efforts between stakeholders and regulatory bodies, will be essential in overcoming barriers and ensuring the successful implementation of the Hydrogen Hub. Overall, the findings of this study underscore the potential of integrating high-temperature water electrolysis with nuclear energy to drive sustainable hydrogen production and foster a transition towards a low-carbon energy future.

Recommendations Based on Lessons Learned

Key recommendations from lessons learned in this project include:

1. Electricity costs are the primary factor in the economic competitiveness of hydrogen production. An electricity rate specific to hydrogen production should be considered to allow for early projects to be economically attractive (and viable).
2. Larger scale improves the economics of the project. Consideration should be made for the end-use, and factor in the ability of the production facility to use modules to increase capacity.
3. Leveraging advanced materials, specifically those with thermal and hydrogen tolerance, and computational modelling and simulation techniques will enable pilot studies and development projects to advance more quickly.
4. Investing in research and development is a key factor in reducing costs associated with hydrogen production and the overall economy of the project.
5. Prioritise specific use cases or applications in the determination of projects, where will hydrogen be needed or used and how does it best fit into the energy ecosystem are important considerations for the success of the project.

Recommendations for Next Steps

Key recommendations to move forward include:

1. Ongoing Research and Development: improvements can be made to better understand materials, integration, cogeneration, and overall system development.
2. Market Analysis: Identify potential end-users and market opportunities for hydrogen products generated by SOEC systems through a market analysis.
3. Supply Chain Development: To reduce costs, establish a robust supply chain for sourcing materials and systems.
4. Regulatory Compliance: Establish regulatory frameworks, standards and permitting requirements for hydrogen production operations.
5. Stakeholder Collaboration: Collaborate with industry stakeholders, government agencies, research institutions, and technology developers to accelerate hydrogen technology development and deployment.
6. Pilot Demonstration: Initiate pilot projects to validate the feasibility and performance of SOEC and other hydrogen production technologies, especially co-located with nuclear power plants.

7. Capacity Building: Provide training and capacity building programs for personnel involved in, or interested in, operating, and supporting hydrogen production facilities.

These recommendations collectively underscore the importance of systematic planning, collaboration, compliance, and sustainable practices in successfully deploying and scaling hydrogen production.

8. Lessons Learned

Build On Our Experiences, Reduce Risks, and Find Innovative Solutions

Reflecting on the lessons learned throughout the Hydrogen Hub project is essential for our progress and success. By carefully examining the challenges we faced and the successes we achieved during the feasibility study, we can pinpoint areas that need improvement and develop strategies to improve our systems. This process will help us enhance the efficiency and reliability of hydrogen production and refueling, ensuring the project's long-term sustainability and viability. By focusing on what we have learned, we can build on our experiences, reduce potential risks, and find innovative solutions to propel our Hydrogen Hub toward its full potential.

Leverage Advanced Computational Modeling and Simulation Techniques

The SOEC and SOFC technologies being in the developmental stage present a challenge in getting precise and reliable data for analysis. Leveraging advanced computational modeling and simulation techniques to extrapolate performance metrics based on theoretical principles and existing experimental data enabled the study to have a more accurate picture of the proposed Hydrogen Hub.

Invest in Research and Development

Several technology challenges are significant barriers to commercial scale operation and deployment of SOEC and SOFC. These include the high operating temperatures, material compatibility, electrode performance, stack design and manufacturing, fuel contaminants, system integration and general cost and economics of these new systems. Investing in research and development to improve manufacturing processes and scale up production can significantly increase the output of SOECs and SOFCs.

Prioritise Specific Use Cases or Applications

The scope of the project is very ambitious, encompassing both hydrogen as a fuel and as an energy carrier. Instead of trying to tackle the entire spectrum of hydrogen applications simultaneously, prioritise specific use cases or applications where hydrogen can offer the greatest benefits. Additionally, future pilot projects should ensure that the end-use is considered, and that the pilot is able to effectively be scaled, or is scalable, to the end use.

Adapt the Method for Predicting Economic Performance

Various methods exist for predicting the economic performance of SOEC systems, SOFC systems, and related infrastructure. One challenge was selecting which method was most suitable for the system under investigation. Applying relevant standards from related industries or sectors, such as nuclear power generation, hydrogen production, and industrial safety enabled more accurate inputs to the requirements of the system. We were able to adapt or repurpose elements of these standards for the specific needs of integrating nuclear and hydrogen technologies.

A literature review was performed to specify the economic assessment methods that are typically employed for SOEC/SOFC systems. Per this review, and building on prior experience, the economic analysis was developed based on an accepted method. While this method is widely employed in industry, it is designed to be generic and widely applicable to a range of processes. For our economic analysis, we adapted the method to better reflect the system being modelled. For example, for the capital cost estimates, two bounding internal analysis types were developed, which more closely represent the expected direct depreciable capital costs for the system scale and location.

Use System-Specific Data and Cost Factors for Accurate Economic Analysis

The accuracy of an economic analysis is highly dependent on the availability of system-specific cost data. Data from literature was used as a starting point for the analysis, and this data was updated as more system-specific information became available. By maximizing the use of system-specific data and cost factors, the accuracy of the economic analysis is improved.

For example, equipment costs found in literature were scaled based on the year and system capacity using industry-accepted methods (i.e., cost indexing and sixth-tenths rule). These values were later replaced with current values reported directly from FuelCell Energy Inc. A second example relates to the capital and operating cost factors employed as part of the selected method. These factors were changed where suitable, based on a combination of engineering judgement, experience, and expert knowledge of the site to ensure they accurately reflected the system being modelled.

9. Next Steps

Ongoing Research and Development

Resource Optimization: Prioritize efficiency in energy, water, and raw material usage to minimize environmental impact during scale-up.

Integration Planning: Develop a comprehensive strategy for integrating SOEC and hydrogen generation into existing or new infrastructure

Cogeneration Opportunities: Explore opportunities for co-generating hydrogen alongside low-carbon sources of energy. Considering specifically the ability of hydrogen to scale and act to stabilize the grid.

Incorporate Sustainability: Incorporate sustainability principles into the planning and operations of the Hydrogen Hub to minimize environmental impacts and maximize environmental benefits. This may involve implementing advanced process control strategies, recycling waste streams, and perfecting system integration to reduce resource consumption. This includes setting sustainability goals, implementing measures to reduce carbon emissions and environmental footprint, and exploring opportunities for renewable energy integration and carbon capture and use.

Improve performance: Implement measures to perfect the performance of SOFCs for electricity generation. This could include adjustments to operating parameters, improvements in system efficiency, and enhancements in fuel processing and management.

Technology Challenge Assessment: Conduct a thorough analysis to understand the specific reasons for the challenges met in electricity generation using SOFCs. This may involve examining factors such as system design, operating conditions, fuel quality, and integration with the grid.

Collaboration and Market Opportunities

Market analysis: Conduct a market analysis to find potential end-users and market opportunities for hydrogen products generated by the SOEC system. This analysis should assess demand trends, competitive landscape, pricing dynamics, and regulatory drivers.

Explore new market opportunities and applications: Exploring new opportunities for hydrogen produced by the SOEC system beyond the start-up target sectors. This may include investigating potential uses in sectors such as power generation, energy storage, chemical manufacturing, and agriculture, and developing strategies to penetrate these markets.

Collaborate with industry stakeholders, government agencies, research institutions, and technology developers to accelerate the deployment and adoption of hydrogen technologies. This includes forming strategic partnerships, taking part in industry groups, and using funding opportunities for collaborative research and development projects.

Develop a Robust Supply Chain

Develop a Supply Chain: Develop a robust supply chain for sourcing raw materials, components, and equipment needed for SOEC and hydrogen production operations. Strengthen the resilience of the hydrogen supply chain by diversifying sourcing options for raw materials, components, and equipment used in SOEC and refueling station operations. This may involve setting up partnerships with multiple suppliers, exploring local sourcing opportunities, and developing contingency plans for supply chain disruptions.

Establish Compliance Frameworks

Ensure compliance with relevant regulations, standards, and permitting requirements for SOEC and hydrogen production operations. This may involve obtaining permits, licenses, and approvals from regulatory authorities and addressing environmental and safety considerations. Advocate for supportive policies, incentives, and regulatory frameworks to promote the adoption of hydrogen as a clean energy carrier. This includes engaging with policymakers, advocating for hydrogen-friendly regulations, and taking part in industry advocacy efforts to drive policy change.

Work closely with regulatory authorities and licensing agencies to navigate the regulatory framework governing the integration of SOEC technology with Nuclear Power Plants. This includes obtaining necessary permits, licenses, and approvals, as well as addressing regulatory concerns related to safety, environmental impact, and nuclear security.

Continuously Assess Performance and Opportunities for Improvement

Implement comprehensive monitoring and optimization protocols to continuously assess the performance of scaled-up SOEC systems and find opportunities for improvement. This may involve deploying advanced monitoring technologies, conducting regular performance audits, and implementing corrective actions to improve system efficiency.

Establish mechanisms for continuous monitoring, evaluation, and improvement of SOEC and hydrogen generation operations. This includes implementing performance metrics, conducting regular audits, and asking for feedback from stakeholders to drive ongoing optimization and innovation.

Raise Awareness and Build Support for Hydrogen Technology

Engage with local communities, potential customers, stakeholders, and the public to raise awareness about the benefits of hydrogen technology and address any concerns or misconceptions. This may involve conducting outreach activities, hosting educational events, and fostering partnerships with community organizations to build trust and support for hydrogen initiatives.

Engage with stakeholders, including local communities, policymakers, and the public, to raise awareness and build support for the integration of SOEC technology with Nuclear Power Plants for hydrogen production. This may involve conducting public outreach events, educational campaigns, and stakeholder consultations to address questions and concerns about the technology. This includes developing educational materials, hosting workshops and webinars, and engaging with industry associations and advocacy groups to give information about hydrogen technology and its applications.

Provide training and capacity-building programs for personnel involved in running and supporting scaled-up SOEC systems. This includes specialized training on system operation, maintenance procedures, safety protocols, and emergency response preparedness to ensure safe and efficient operation of the integrated system.

Develop Plans to Build a Hydrogen Distribution Network

Develop plans to build a hydrogen distribution network to supply hydrogen produced by the SOEC system to various end-users, including industrial facilities, transportation fleets, and residential consumers. List potential distribution routes, infrastructure requirements, and partnership opportunities with logistics providers. Implement quality assurance measures to ensure the purity and safety of the hydrogen produced by the SOEC system. Establish quality control protocols, conducting regular testing and checking of hydrogen purity levels, and adhering to industry standards and regulatory requirements for hydrogen production and distribution.

Develop a Strategic Plan to Scale Up Integration of Hydrogen

Develop a long-term strategic plan for scaling up the integration of SOEC technology with Nuclear Power Plants to achieve commercial-scale hydrogen production. This plan should outline milestones, timelines, and resource requirements for expanding the integrated system, as well as strategies for market penetration and business growth.

Develop a long-term sustainability strategy for the Hydrogen Hub, including plans for renewable energy integration, carbon capture and use, and environmental stewardship. This includes setting ambitious sustainability goals, implementing measures to minimize environmental impacts, and tracking progress towards achieving sustainability goals.

Initiate a pilot demonstration project to confirm the feasibility and performance of integrating SOEC technology with a Nuclear Power Plant. This project should involve designing, constructing, and running a small-scale demonstration facility to showcase the viability of the integrated system and gather real-world data for further analysis.

Evaluate Opportunities to Expand the Infrastructure of the Hydrogen Hub

Evaluate opportunities to expand the infrastructure of the Hydrogen Hub to accommodate increased production output and future growth. This may involve expanding the size of the SOEC system, adding more electrolyser units, or upgrading the refueling station to handle higher throughput.

Upgrade infrastructure to support the scaled-up integration of SOEC technology with Nuclear Power Plants. This may include modifications to existing facilities, installation of more equipment, and upgrades to electrical and hydrogen distribution systems.

Conduct scalability studies to decide the best scale-up approach for SOEC technology, considering factors such as stack size, system configuration, and manufacturing processes. This will help to find the most cost-effective and efficient methods for scaling up hydrogen production output.

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Appendix 1: Kinectrics' Vision and Work in the Hydrogen Industry

Our Vision

Kinectrics has a long-term vision to be the service provider of choice for clean energy technologies and their effective use within energy networks.

Kinectrics operates an expansive network of laboratories that can support technology development, scale-up, and deployment. Extensive staff in all disciplines support hydrogen generation at industrial scale, including design engineering, materials, safety analysis, etc. We are an ambitious, privately-owned, and nimble company that is passionate about clean energy and a net-zero future.

Working Throughout the Hydrogen Generation Lifecycle

Kinectrics has extensive experience in many aspects of the hydrogen generation lifecycle, including:

- Hydrogen Production and Helius Facility: Specializing in hydrogen technology research, Kinectrics leads in the assessment of technologies using full-scale high-temperature loops.
- Conceptual Study on Hydrogen Production Technologies: Conducting a comprehensive study to find and analyze hydrogen technologies in need of commercial demonstration.
- Market Needs Evaluation and Cost Analysis: Assessing local power demand and analyzing sites for potential benefits from local power generation in targeted Canadian markets.
- Policy and Regulatory Landscape: In-depth understanding and analysis of existing policies and regulations, providing licensing and regulatory support for new nuclear build and hydrogen facilities.
- Stakeholder Engagement: Supporting public consultations, including the development of Indigenous community engagement strategies.

Engineering, Development, and Deployment Abilities

Kinectrics stands out for its exceptional engineering, development, and deployment abilities. With years of experience and knowledge, Kinectrics has set up significant relationships with key players in the nuclear power generation industry. These relationships have also provided Kinectrics with access to valuable resources, such as innovative technologies and critical data. At the forefront of the industry, Kinectrics is uniquely qualified to develop effective, efficient solutions with the IESO.

Participation in Working Groups

Kinectrics is a member of the NRCan Nuclear Working Group (NWG) under the Hydrogen Strategy for Canada and takes part in the sub-teams set up around this initiative. Kinectrics is also a participant in the Nuclear Hydrogen Initiative, which consists of a nonpartisan, global collaboration of more than 50 companies, academic institutions, government agencies, and non-profit organizations. Together, members work to advance nuclear hydrogen as a critical climate solution within a shared vision of a decarbonized global energy system. Furthermore, Kinectrics is a proud participant in the nuclear program of the CSA standards framework and is one of the most active industry members across all standards areas.

Our Testing Facility and Research Campus ("Helius")

In addition to industry projects related to the licensing, construction, and operation of advanced nuclear reactors incorporating industrial applications such as nuclear-derived hydrogen, Kinectrics is also leading a pursuit of a significant testing facility and research campus that will be used to conduct performance testing and R&D for high temperature nuclear applications, known as Helius.

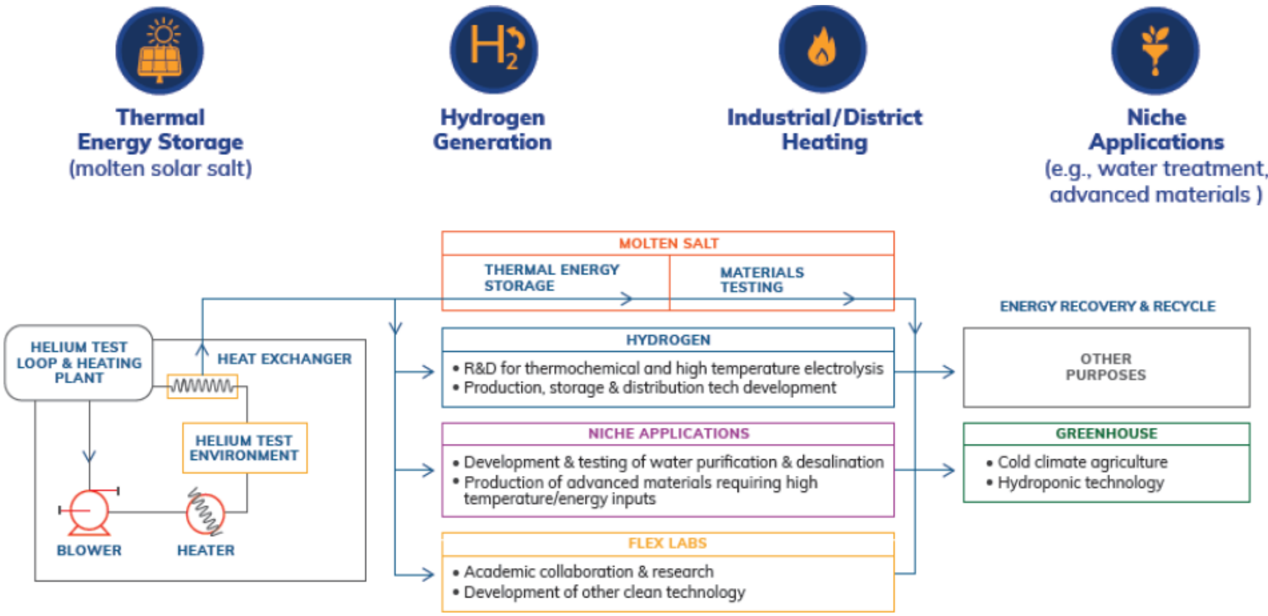
> The focus of this campus will be on the development, testing, qualification, and long-term support of clean energy technologies, including the next generation of nuclear reactors and hydrogen generation.

The cornerstone of this innovation campus is an electrically heated, helium test loop for the development, testing, and qualification of materials, components, and systems used in high temperature gas reactors.

Secondary loops mimic the actual usage of technologies to be married with advanced nuclear reactors, including:

1. Thermal energy storage (molten solar salt)
2. Hydrogen generation
3. Industrial/district heading
4. Niche applications (for example, water treatment and advanced materials).

Figure 20 | Helius Campus Research Potential R&D and Testing Facilities



Appendix 2: Specifications, Diagrams, and Economic Analyses

Purpose

The following appendices provide detailed specifications, diagrams, and economic analyses crucial to the comprehensive understanding of our project. Each appendix serves a distinct purpose and offers in-depth insights into various aspects of the project.

These appendices collectively provide a thorough understanding of the technical, logistical, and economic dimensions of the project, ensuring that all stakeholders have access to detailed and correct information necessary for informed decision-making.

Below are the links to the specified appendices and a brief overview of each is below:

- Appendix 2 A SOEC Specification Sheet:https://go.fuelcellenergy.com/hubfs/solid-oxide-electrolyzer-spec-sheet.pdf
- Appendix 2 B SOFC Specification Sheet: https://go.fuelcellenergy.com/hubfs/Solid%20Oxide%20Fuel%20Cell%20Spec%20Sheet.pdf
- Appendix 2 C Water Treatment Plant Specifications: https://www.rodisystems.com/uploads/1/0/8/3/108367751/rodi_systems_purebox_high_purity_brochure.pdf
- Appendix 2 D Location of the Hub Diagram – Diagram included in Appendix 2
- Appendix 2 E Economic Appendix Explanation – Included in Appendix 2

Appendix 2 A SOEC Specification Sheet

The ASIEC Specification Sheet lists the technical specifications of the Solid Oxide Electrolyser Cell (SOEC) used in the project. It includes details on the operational parameters, efficiency ratings, input requirements, and safety features of the SOEC. This information is essential for understanding the capabilities and limitations of the electrolyser within our hydrogen production process.

Appendix 2 B SOFC Specification Sheet

The Solid Oxide Fuel Cell (SOFC) specification sheet provides a comprehensive overview of the fuel cell technology employed in our project. This includes performance metrics, fuel consumption rates, and technical specifications that highlight the efficiency and operational characteristics of the SOFC. This appendix is critical for assessing the fuel cell's role in converting hydrogen into electricity.

Appendix 2 C Water Treatment Plant Specifications

This appendix details the specifications of the water treatment plant, which is integral to the project's hydrogen production process. It includes the types of water treatment technologies used, output, input and output water quality parameters, and operational guidelines. Understanding the water treatment plant specifications is essential for ensuring the supply of high-purity water needed for the SOEC and overall system efficiency.

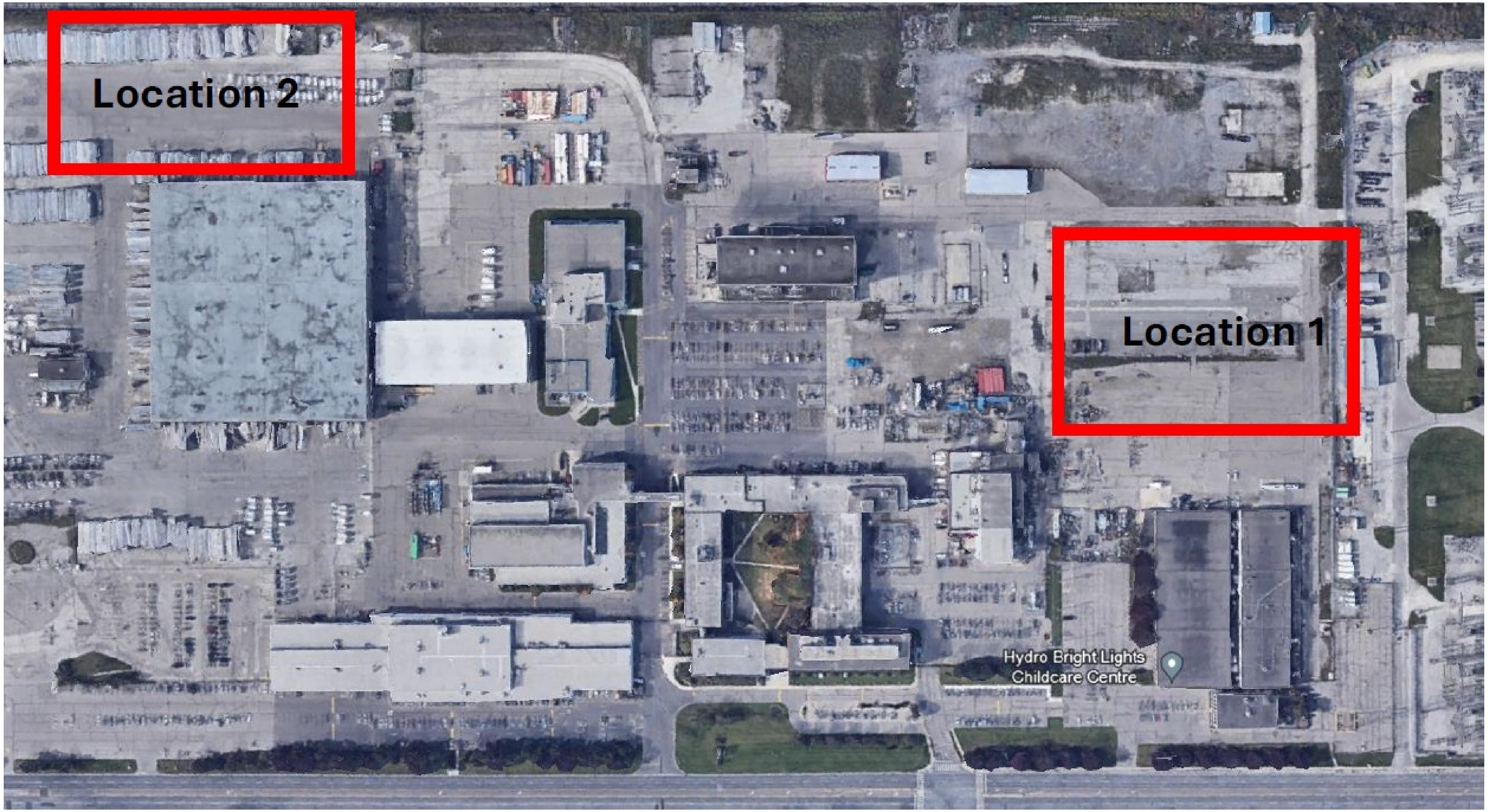
Appendix 2 D Location of the Hub Diagram

This diagram illustrates the geographical layout and strategic positioning of the hub within the project site. It includes the relative locations of key infrastructure components such as the SOEC, SOFC, storage facilities, and transportation links. This visual representation aids in understanding the spatial organization and logistical planning of the project.

Appendix 2 E Economic Analysis

The economic appendix provides an analysis of the financial aspects of the project. This includes cost estimates, profitability projections, and a breakdown of capital and operational expenditures. It also explains the economic assumptions and methodologies used in the analysis, providing transparency and clarity on the financial viability and economic impact of the project.

Appendix 2 D Location of the Hub Diagram



Appendix 3: Analysis of SOEC Efficiency and Its Impact on Market Offering

As the hydrogen economy continues to develop, the efficiency of electrolyzers becomes increasingly important. The efficiency of these systems directly affects the cost of hydrogen production, which in turn impacts the electrolyzer's competitiveness in the electricity market.

Solid Oxide Electrolyzer Cells (SOECs) are recognized for their superior efficiency in kWh/kg of hydrogen produced when compared to other types of electrolyzers, such as Proton Exchange Membrane (PEM) and Alkaline electrolyzers [1].

Table 21 | Comparison of efficiency ranges (kWh/kg of Hydrogen) for different electrolyzer types.

Electrolyzer Type	Efficiency (kWh/kg)
Alkaline	47-66[7]
PEM	42.2-65.6[8]
SOEC	37.5-55[9]

As it is seen, SOECs offer the highest efficiency, typically ranging between 37.5-55 kWh/kg of hydrogen produced. This high efficiency is achieved through the operation of SOECs at elevated temperatures (>150°C). At these temperatures, the electrolysis reaction is favored, reducing the overall energy requirement for hydrogen production.

Impact of Operating Conditions on SOEC Efficiency

The efficiency of SOECs is not a fixed parameter; it varies depending on several key operating conditions, primarily the type of feedstock used (water or steam) and the operating temperature.

When SOECs use steam as the feedstock, their efficiency increases significantly compared to when liquid water is used. This is because steam, being at a higher enthalpy state, requires less additional

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energy to split into hydrogen and oxygen. Using steam at >150°C can improve efficiency by approximately 15% compared to using liquid water [1] [2].

Temperature also plays a crucial role in determining SOEC efficiency. Higher operating temperatures improve the ionic conductivity of the electrolyte, thereby reducing the electrical resistance of the cell. This reduction in resistance lowers the overall energy consumption. However, operating at such high temperatures also introduces challenges related to material durability and system longevity.

Efficiency Analysis of SOEC Systems from 1 MW to 20 MW

To understand how SOEC efficiency scales with power level, we analyzed a SOEC system ranging from 1 MW to 20 MW using different inputs, saturated water and steam. Figure 21 illustrates the efficiency (measured in kWh/kg of hydrogen produced) as a function of the power level of the electrolyzer. This analysis is based on data from FuelCell Energy [2].

Figure 21 | Efficiency of SOEC systems at different power levels (1 MW to 20 MW) under two conditions: using saturated water at 100°C and steam at 150°C, both at 1 atm.

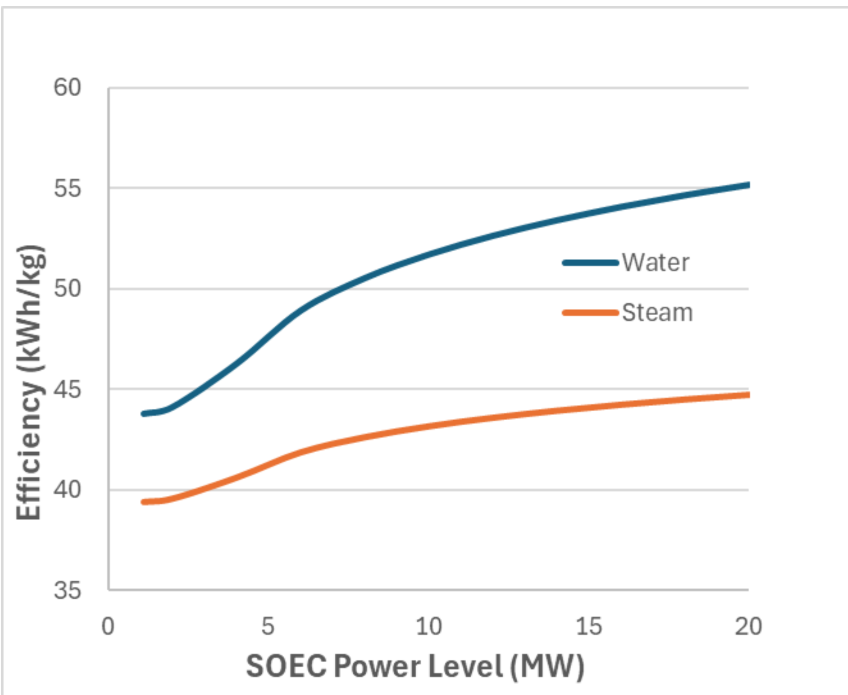

Figure 21 shows that as the power level increases, the efficiency tends to decrease (i.e. the energy consumption per kilogram of hydrogen produced increases). SOECs maintain competitive efficiency across this range, typically between 37.5-55 kWh/kg. This trend is consistent with the inherent thermal and electrical losses that scale with system size.

As expected, operating with steam at temperatures above 150°C is significantly more efficient than using saturated water. This efficiency gain is primarily due to the latent heat of vaporization in steam, which provides substantial endothermic energy required for splitting the water molecules. The difference in efficiency becomes even more pronounced at higher electrolyzer capacities, as the increased heat input helps to overcome resistances more effectively.

It is important to note that reliable data beyond 20 MW is scarce, and extrapolating efficiency values beyond this point introduces significant uncertainty. As such, the analysis is limited to the 1 MW to 20 MW range electrolyzer power capacity.

Comparative Analysis: FuelCell Energy vs. Topsoe and Bloom Energy

Currently, SOEC systems are supplied by companies such as FuelCell Energy, Bloom Energy, and Topsoe, which produce industrial-scale systems ranging from 1 to 5 MW. Although these suppliers utilize the same fundamental SOEC technology, there are variations in their operational conditions and system configurations. These differences can influence the efficiency of their systems. The efficiencies of SOECs from these suppliers, based on their available power levels in the market, are presented in Table 22, reflecting their performance under current technological capabilities.

Table 22 | Efficiencies of SOEC Systems from FuelCell Energy, Bloom Energy, and Topsoe at Various Power Levels [2] [3] [4].

SOEC Supplier	Power Level (MW)	Efficiency (kWh/kg)
FuelCell Energy	1.1 MW	43.8 kWh/kg (water at 100°C)
		39.4 kWh/kg (steam at 150°C)
Bloom Energy	1.2 MW	37.5 kWh/kg (steam at 150°C)
Topsoe	5 MW	39.8 kWh/kg (steam at 200°C)

Among the leading suppliers of SOEC systems, FuelCell Energy stands out for its high-efficiency solutions, particularly in the upper range of the power scale. This high efficiency, combined with the company’s focus on reliability and system longevity, makes FuelCell Energy’s SOECs a preferred choice for large-scale applications where operational efficiency is paramount.

Topsoe offers a competitive alternative, with systems that are also highly efficient but are particularly noted for their integration with renewable energy sources [4]. Topsoe's SOECs are designed for flexibility and scalability, allowing them to adapt to varying energy inputs, which is a significant advantage in markets where energy prices are volatile [5].

Bloom Energy, while offering slightly lower efficiency compared to FuelCell Energy and Topsoe [3], provides systems that are engineered for durability under extreme operating conditions (currently, they are testing systems capable of operating at temperatures up to 500°C and pressures of 5 atm). Bloom Energy’s SOECs are ideal for applications where long-term stability is critical, even if this comes at the cost of marginally lower efficiency [6].

Market Implications

The efficiency of the SOEC system directly influences how hydrogen production can position itself in the electricity market. Higher efficiency translates to lower operating costs, which allows the facility to offer hydrogen at more competitive rates. For instance, a facility utilizing FuelCell Energy's SOEC system can bid into the electricity market at lower prices compared to facilities using less efficient PEM or Alkaline electrolyzers.

Furthermore, the high efficiency of SOECs enhances the facility's ability to respond to market signals, particularly in regions where electricity prices fluctuate. By optimizing hydrogen production during periods of low electricity prices and reducing production during peak pricing periods, the facility can maximize its profitability while maintaining a stable supply of hydrogen.

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Kinectrics Inc.
800 Kipling Avenue, Unit 2
Toronto, Ontario
Canada M8Z 5G5

kinectrics.com
twitter.com/KINECTRICS
linkedin.com/company/kinectrics