Summary of the 2023 Hydrogen Innovation Fund Research Projects

November 2025

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1. Executive Summary

As part of the IESO's 2023 Hydrogen Innovation Fund (HIF) Call for Proposals, the IESO awarded funding to nine research/feasibility study projects and five demonstration projects. All nine research reports were completed on budget and submitted to the IESO by the required deadline of June 30, 2024, while the four demonstration projects are still in progress and are therefore not included in the scope of this report. HIF 2023 has advanced the sector's understanding of hydrogen technologies and their role in supporting decarbonization in Ontario. The HIF 2023 call generated significant interest from stakeholders, with many more applications for projects than funding available.

Per the guidelines of the IESO's HIF Call, proponents were tasked with investigating how low-carbon hydrogen technologies can be integrated with Ontario's electricity grid for the purposes of balancing and strengthening its reliable electricity system. The resulting projects covered at least one of the following categories: 1) Hydrogen Production from Electricity, 2) Electricity Generation from Hydrogen, and 3) Transportation and Storage of Hydrogen as a means of integrating hydrogen and electricity within a broader hydrogen economy.

Most of the research projects explored the feasibility of site-specific hydrogen conversions at different locations across the province. Due to the site-specific nature of the studies and the nascency of most hydrogen technologies, it is difficult to generalize certain findings; however, it is still possible to uncover key trends with respect to the challenges and opportunities related to hydrogen. It is evident that while the opportunities and roles for hydrogen exist, there are several complex challenges and barriers to overcome for the foreseeable future.

Low-carbon hydrogen production is expensive due to current electrolyzer (and balance of plant) costs, energy conversion efficiencies, shortage of off-takers, and, at scale, poses challenges to electricity and water supply infrastructure. However, technological advancements through innovation and increased research and development can help reduce production costs by increasing conversion efficiency and reducing equipment costs. The projects also pointed to opportunities to overcome barriers associated with hydrogen storage, transportation, and blending for electricity generation.

Transportation and storage of hydrogen can be technically challenging due to its physical properties (low volumetric energy density and small atomic size) resulting in the need for compression and issues such as hydrogen leakage. There is also a lack of infrastructure suitable for transporting hydrogen which does not contribute carbon emissions to its life-cycle (e.g. piping and zero-emission heavy-duty trucks). Developing hydrogen hubs that strategically co-locate producers with off-takers mitigates transportation and storage challenges and provides certainty of supply and demand.

Lastly, using hydrogen to generate electricity is currently expensive due to low round-trip efficiencies and incompatibilities with integrating into existing gas generation infrastructure. Hydrogen production costs can be reduced via access to reduced electricity rates, by integrating with cheaper forms of electricity supply such as nuclear power.

As shown in HIF research reports, there is no shortage of interest in hydrogen and its role in the energy transition. Coordination across sectors and all levels of government is necessary to align on policy and support the growth of the hydrogen economy. IESO will be utilizing lessons learned in HIF 2023 to help inform upcoming future hydrogen funding initiatives.

Key learnings for the IESO

1. Hydrogen Production - Electrolyzers are energy-intensive loads and can therefore become significant contributors to demand growth if widely adopted, requiring a grid comprised of excess clean supply in order to achieve its primary purpose of decarbonization. Their fast-moving capabilities present opportunities to support the grid via wholesale market participation as dispatchable load and ancillary services such as frequency regulation and operating reserve. However, in the near-term they would face competition for these services from storage and hydro resources.
2. Electricity Generation - Existing grid-scale gas turbines can be retrofitted to accommodate small amounts of H2 blending (<30%) and provide emission reductions. It is cost-prohibitive at current hydrogen production costs. With further research and technological advancements, higher blending levels such 75 percent could result into a 50 percent reduction in CO2 emissions.
3. Storage - Hydrogen storage can become more cost competitive than battery storage at longer durations (>16 hours) and can out-compete pumped hydro and compressed air storage at the multi-day timescale (>100 hrs); however, there are complex technical and logistical challenges associated with storing and transporting. Hydrogen hubs located near end users can reduce transportation and storage costs while ensuring a ready market. They create a pathway to decarbonize industrial applications as an alternative to electrification.

It should be noted that this report reflects findings from the research projects funded by the IESO's Hydrogen Innovation Fund and does not represent the views and opinions of the IESO, nor does it provide a complete picture of the entire hydrogen sector.

Hydrogen Innovation Fund 2025

To build on the learnings from the 2023 projects, the Minister of Energy and Mines directed the IESO to launch a 2025 HIF Call for Applications ("2025 HIF Call") in support of Ontario's Low-Carbon Hydrogen Strategy.

The 2025 HIF Call aims to support innovative hydrogen pilot projects focused on two separate $15 million streams:

1. **Stream 1** – Demonstration projects with direct electricity system benefits including the integration of low-carbon hydrogen into the electricity grid.
2. **Stream 2** – Demonstration projects enabling broader energy and other sector applications such as transportation, manufacturing, and heavy industry.

The 2025 Call aims to support the sector in addressing the barriers identified in the 2023 Call and facilitate further deployment of innovative hydrogen technologies and applications.

2. Purpose

The purpose of this report is to provide a summary of the key findings from the nine HIF research projects. It is intended to reflect the commonalities amongst the various research report learnings as well as highlight relevant learnings from individual projects. The studies have informed the design of the 2025 HIF Call, and project categories as seen in the 2025 Minister's directive.

The statements or claims made in this report do not represent the views or opinions of the IESO.

3. Background

The HIF was established by the IESO in 2023, in response to a directive from the Minister of Energy to investigate and propose options to integrate low-carbon hydrogen technologies into Ontario's grid. The HIF was allocated a $15 million budget to fund projects over a three-year term (2024-2026) with the goal to investigate, evaluate, and demonstrate how low-carbon hydrogen technologies can be integrated into Ontario's electricity supply to balance and strengthen reliability and contribute to broader decarbonization.

The Call for Proposals ("the Call") sought out both demonstration and research projects under the following three categories: (1) hydrogen production from electricity; (2) electricity generation from hydrogen; (3) integrating hydrogen and electricity into a broader hydrogen economy. Of the 25 proposals received, 17 were initially selected for funding, however four projects withdrew or terminated, leaving thirteen projects remaining (four demonstration projects and nine research projects). The research projects were only granted one year to complete, with the submission deadline of June 30th, 2024.

The research projects received span from site-specific feasibility studies of electrolyzer installations, to hydrogen-natural gas blending for electricity generation, to the interaction of renewable energy sources with both electrolyzers and hydrogen turbines. Additionally, Ontario specific research was conducted on the optimal size, placement, and development of hydrogen hubs that will facilitate broader integration of hydrogen into the economy as well as research into novel hydrogen production technologies and methods that could lower the cost of hydrogen production.

Refer to the table below for a breakdown of the different types of projects and areas of research. Refer to Appendix B or the HIF webpage for additional details including project specific learnings.

Proponent	Project Title	Project Type	Primary Focus Areas
Volta Energy	Feasibility Evaluation of Sustainable, Green and Rapid-Response Metal-Supported Solid Oxide Cell Technology Integrated with Smart Hydrogen Hub	Academic hydrogen technology research	• Reversible Solid Oxide Cell technology: Solid Oxide Electrolysis Cell – Solid Oxide Fuel Cell (SOEC -SOFC)

York University	Preliminary Feasibility Study of Hydrogen Production On-Site and Utilization of Hydrogen in Existing Prime Movers	Site-specific hydrogen development	• Retrofitting existing 5 MW gas turbines to burn a fuel blend of hydrogen and natural gas
University of Windsor	Hydrogen Integrated Greenhouse Horticultural (HIGH) Energy	Site-specific hydrogen development, Supporting the broader H2 economy	• Wind powered electrolysis for H2 Blending in greenhouse CHP • Hydrogen market strategies for Ontario
York University	Optimal Deployment of Green Hydrogen Plants in Ontario Electricity Systems	Site-specific hydrogen development, Supporting the broader H2 economy	• Electrolysis coupled with storage and fuel cell generation (i.e. Green Hydrogen Plants or GHPs) for purposes of price arbitrage and facility energy management • Integration of GHPs with the distribution and transmission systems for ancillary services
Capital Power	Hydrogen Blending – Goreway Power Station, East Windsor Cogeneration Centre and York Energy Centre	Site-specific hydrogen development	• Hydrogen blending and gas turbine retrofitting at three transmission connected natural gas plants
Western University	NET-PBH2: Negative Emissions Technology for Pale Blue Hydrogen Production	Academic hydrogen technology research	• Solar powered electrolysis coupled with blue hydrogen produced via biogas and a plasma reactor • Carbon sequestration using photoreactors and micro algae
Capital Power	Kingsbridge Green Hydrogen and Storage Assessment	Site-specific hydrogen development	• Wind powered electrolysis coupled with H2 storage in underground depleted gas reservoirs and H2 Blending for power generation (turbine and combustion engine)
The Transition Accelerator	The Role of Hydrogen Hubs in Strengthening the Affordability and Reliability of Ontario's Electricity System	Supporting the broader H2 economy	• Hydrogen hub in Hamilton and considerations for broader H2 adoption across Ontario

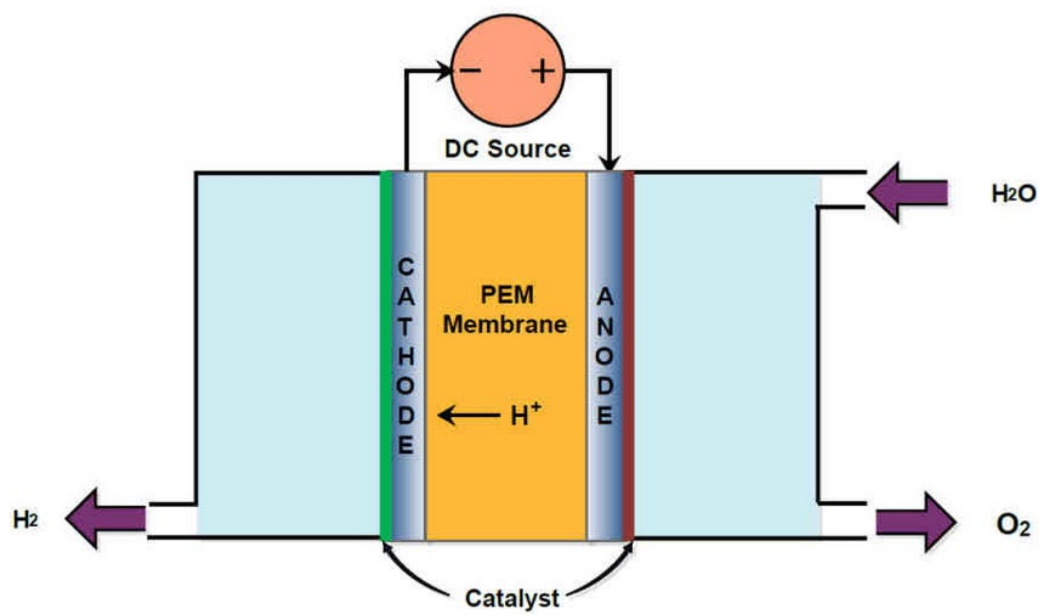
Kinectrics Inc.	Feasibility Study for an Urban Hydrogen Hub for Grid Flexibility, Resilience, and Carbon Reduction Scalable to Nuclear Power Plant Co-location.	Site-specific hydrogen development	• Solid Oxide Electrolysis Cells utilizing power and waste heat from nuclear power and fuel cell integration for power generation

4. Hydrogen Production from Electricity

Nearly all nine research projects investigated some form of low-carbon hydrogen production technology fueled by electricity. The H2 technologies investigated across the projects spanned different electrolyzer types such as Proton Exchange Membrane (PEM), Alkaline, and Anion Exchange Membrane (AEM), to solid-oxide electrolysis cells (SOECs). Some projects provided overviews of these different technologies with respect to their efficiency, utility requirements, and performance characteristics such as their ability to provide different types of grid services. Additionally, some projects focused on one specific technology type that was best suited for that particular application, while other projects studied the current state and potential pathways for the hydrogen market in Ontario.

4.1 Electrolysis

Electrolysis is the most commonly used approach for producing low-carbon hydrogen. Electrolysis is the process of passing an electrical current through water to separate the water molecules into oxygen and hydrogen gas. This process is made possible by an electrolyzer which consists of a cathode, an anode, and an electrolyte membrane in between. The voltage applied between the cathode and anode transfers the hydrogen molecules from the water across the membrane, with oxygen as a byproduct. See basic schematic below for a visual reference.



source: https://www.researchgate.net/figure/Fundamental-of-PEM-electrolysis_fig3_273125977

The type of electrolyte/membrane used is the primary differentiator between electrolyzer types, followed by the operating temperature. The three most common types of electrolyzers explored across the HIF projects are explained below including a summary of the advantages and disadvantages of each, conducive applications, etc. A more technical comparison of the technologies can be found in Appendix A.

The Kinectrics study provided a good overview and comparison of some of the key characteristics across the technologies, as shown below. To put the efficiency into perspective, 100% electrolyzer electrical efficiency equates to ~39.5 kWh/kg.

	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

The key takeaways from the table above and throughout various other HIF projects are described below.

Alkaline

- Alkaline Electrolysis is an established technology that has been in use for over a century. It has the lowest capital costs, the longest stack lifetimes, and can scale to larger than 150 MW.

- Uses an aqueous alkaline electrolyte (commonly potassium hydroxide) and is known for its durability and ability to handle large-scale hydrogen production. It has slower dynamic response times and lower current densities compared to PEM, performing best under constant load, making it less suited to intermittent power supply such as renewable variable generation; however, advancements in membrane and cell stack design show promise for increased dynamic response capabilities.

- Generally more efficient than PEM and do not require the use of precious metals such as Iridium in their catalysts.

PEM (Proton Exchange Membrane or Polymer Electrolyte Membrane)

- PEM electrolysers rely on a solid polymer membrane/electrolyte for proton exchange which allows for compact design and high current densities. They are a flexible resource capable of starting quickly, have wide operating ranges (0-100% loading), and a high speed of response.
- PEM systems are lighter and more compact than Alkaline, requiring almost half as much space; however, they are generally more expensive, requiring the use of precious metals in their catalysts which are limited in availability.
- Can be operated at lower temperatures and produce H2 at higher purities than Alkaline.

SOEC (Solid Oxide Electrolysis Cell)

- SOEC is in early stages of development; however, it is the most efficient technology of the three due to its high operating temperature (>600°C) which enables a step change in efficiency because the electrolyser is fed with water in the form of steam, effectively relieving the electrolyzer stack from having to provide latent heat and reducing the overall electrical energy input.
- Can be effectively integrated with nuclear power plants or industrial processes, utilizing waste heat to reduce electricity consumption and further improve efficiency (up to 100%), although the heat captured from the exothermic reaction of SOEC electrolysis enables the temperature to be maintained once it is preheated. However, the higher temperature operation causes thermal stresses, decreasing stack lifetime.
- Utilizes a solid-oxide ceramic electrolyte material and is the only technology capable of reversing its function to work as a fuel cell enabling it to switch between consuming and generating electricity.

4.2 Utility Requirements for Electrolysis

Producing low-carbon hydrogen via electrolysis requires two primary resources: water and electricity.

Water

- Water purity is extremely important for producing H2, requiring the water to be pretreated.
- The On-Site Production and Use of Hydrogen study by York University indicated that electrolysis requires 9L of treated water per kg of H2 produced which equates to ~19L of potable water per kg of H2.
- Another study, conducted by The Transition Accelerator, indicated that when factoring in the water requirements for cooling and reject water, ~60L of water are required to produce 1kg of H2 (50 for cooling and 10 for H2 production). Much of the water utilized for cooling is conserved and returned to the watershed but it still requires a steady access to large volumes of water.

Electricity

- Electrolyzers consume a great deal of electricity to produce hydrogen. According to Volta's study, which investigated SOEC technology, at ~100% efficiency, it takes ~39.5 kWh to produce 1kg of H2 (or 1 MWh to produce 25.4 kg).

- With efficiencies varying from 60-80% in Alkaline and PEM electrolyzers, electricity requirements can vary from ~49-66 kWh of electricity per kg of H2 (or 1 MWh to produce ~15-20 kg of H2).
- The Transition Accelerator study concluded that if hydrogen were to become widely adopted in Ontario, covering all sectors that would be difficult to decarbonize via electrification, 330 TWh of electrical energy would be required. This represents a significant amount of energy, more than twice Ontario's 2024 demand (~140 TWh).
- Additionally, power requirements are needed for the balance of the plant for water treatment, cooling, compression, and other devices.
- The cost of electricity is a contributing factor to hydrogen production costs - integrating hydrogen production with low-cost electricity sources, such as nuclear power (as shown in the Kinectrics study), can make the production process more economically attractive. At the electricity requirements noted above, using the average 2023 HOEP of ~$0.03/kWh, electricity costs contribute ~$1.5-$2/kg H2. The Kinectrics study forecasts the levelized cost of H2 at ~$7/kg by 2030, pending technological advancements.
- The business case for coupling H2 production with curtailed wind power requires careful consideration as relying solely on curtailed wind power may prove to be insufficient for any material amount of H2 production. This was the outcome of Capital Power's Kingsbridge study, requiring the project to assess H2 production from the entire energy output of the wind facility. The study determined that the capacity of the electrolyzer should be around 75% of that of the wind farm to optimize maximum H2 production using the full energy output from the windfarm (e.g. a 30 MW electrolyzer for a 40 MW windfarm) – assuming a 60% efficient electrolyzer.

4.3 Hydrogen End-use Applications

Typically, hydrogen is best suited for applications/sectors that are difficult to decarbonize using electricity such as heavy industry (e.g. steel manufacturing) and heavy-duty transportation (e.g. buses, long-haul trucking). However, the example end-use applications of steel manufacturing and long-haul trucking have yet to develop as viable sectors (i.e., off-takers). Hydrogen is needed to make ammonia, and by producing it in cleaner ways we can cut greenhouse gas emissions while also creating a more sustainable supply of fertilizer for farmers. Lastly, as shown by the majority of the HIF research reports, H2 can be converted back to electricity via a hydrogen fuel cell or via blending the H2 with natural gas in gas combustion engines/turbines. Section 5 speaks to this in greater detail.

4.4 Learnings for the IESO

1. Electrolyzers are energy-intensive loads and can therefore become significant contributors to demand growth if widely adopted. Their quick response capabilities present opportunities to support the grid via wholesale market participation as dispatchable load and ancillary services such as frequency regulation and operating reserve; however, it should be noted that there is limited near-term opportunity and increased competition for these services from storage and hydro resources.

2. Hydrogen production through electrolysis is electricity-intensive and the price of electricity, combined with equipment cost reductions, can significantly impact the business case for new installations and reduce the levelized cost of hydrogen.
3. Hydrogen hubs located near potential hydrogen users, including heavy-duty vehicle fleets and industrial facilities, enhances the practicality and feasibility of the Hydrogen Hub by ensuring a ready market for the produced hydrogen. The siting of electrolysis facilities is expected to be an important consideration for developers as well, due to electricity and water requirements.
4. While PEM and Alkaline electrolysis are already commercialized, the high efficiency and reversibility (to fuel cell) of SOEC show promise and presents further opportunities for grid support and energy storage; however further research or piloting is required.

5. Electricity Generation from Hydrogen

More than half of the 9 research projects investigated some form of electricity generation using hydrogen (H2) as a fuel source (or partial fuel source). The generation types across the projects can be broken down into two categories: (1) Thermal Generation using a blended fuel of H2 and natural gas; and (2) Fuel Cell Generation. Each generation type has its own unique suite of opportunities and challenges with respect to performance, cost, technological readiness, etc. as described below.

5.1 Hydrogen Blending – Thermal Generation

Many natural gas (NG) turbine manufacturers across the globe are starting to investigate how Hydrogen can be incorporated into their existing gas generation equipment, be it a gas turbine, internal combustion engine, or combined heat and power (CHP) engine. Pilot projects and feasibility studies—such as those conducted through the HIF—are being undertaken to understand the extent to which hydrogen can be blended with natural gas in existing gas generation equipment, the types of modifications required, the resulting emissions impacts, and the cost considerations.

One HIF project in particular stands out when it comes to H2 blending. It is a feasibility study on H2 blending at three of Capital Power's gas generation facilities (refer to Appendix B for details). The following section summarizes the opportunities and challenges from that project as well as learnings from other HIF projects which explored H2 blending.

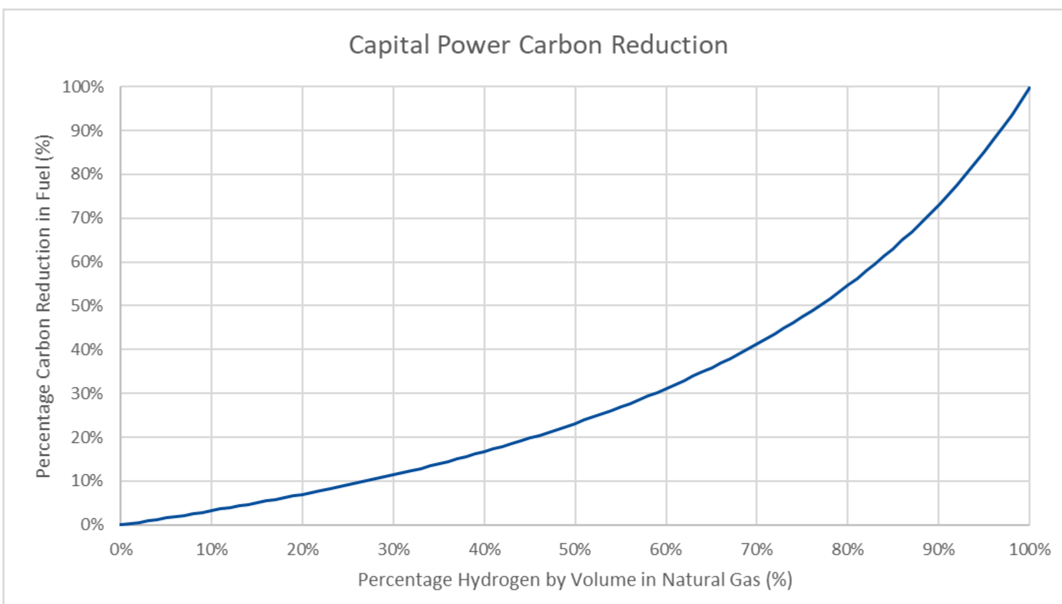
Opportunities

1. While size, type, age, and manufacturer of the equipment are all factors that need to be taken into consideration, it is technically feasible to retrofit existing gas turbine generators to burn a blended fuel of hydrogen and natural gas.

2. In most cases, existing grid-scale gas turbines were found to be capable of accommodating between 5 and 10 percent H2 blend levels (by volume) without requiring much retrofitting. Blending levels can be increased to 15-30% H2 without exceeding NOx emissions limits, however, considerable upgrades to existing equipment would be required resulting in significant increases in capital expenditures.
3. Smaller scale gas turbines, such as the 5MW generators assessed in the York University project can be retrofitted to accommodate up to 50% blending, however costly upgrades are required.
4. Many existing natural gas CHP gensets can accept up to 20% blends of H2 without modifications.

Challenges

1. Hydrogen is less energy dense (by volume) than natural gas, requiring increased volumetric flow of blended fuel to generate the same heat as natural gas alone.
2. The reduction in CO2 emissions is not material until high blend levels are achieved (e.g. a 20% H2 blend results in approx. 7% of CO2 reduction). This is due to H2's lower volumetric energy density. As the relationship is exponential, the higher the blend level, the higher the ratio of reduced emissions (e.g. a 75% blend results in approx. 50% of CO2 reduction), as seen in the figure below.



3. Burning blended fuel results in a higher flame temperature in the combustion compartment, increasing O&M costs in addition to producing higher levels of NOx emissions.
4. Embrittlement of metals is a concern. Due to H2's small atomic mass, it is highly diffusive and can embrittle the materials that enclose it, potentially leading to cracking or equipment damage. As such, low-carbon steels must be used when exposed to blended fuel.

5. Hydrogen cannot be blended until the generator reaches steady-state (e.g. minimum loading point). When shutting down, the blended fuel must also be removed. Hence, peaker plants operating minimal hours, especially those with long startup times, are unlikely to realize significant reductions in CO2 emissions.
6. Capital and O&M costs are increased. Even at current and projected carbon prices, hydrogen remains significantly more costly to source. The Transition Accelerator's study claims that H2 can become cost-competitive to NG by 2050, assuming increased NG and carbon prices, and a robust infrastructure for H2 production, transportation, and storage. Combined with the capital investments required to upgrade existing facilities to accommodate H2 blending, these additional costs would drive up electricity prices for rate-payers.
7. Transporting and delivering hydrogen in gaseous form is suitable for near-term, low-capacity factor operations, however for high-capacity factor operations hydrogen pipelines to the facility are required.
8. The Optimal Deployment of Green Hydrogen study by York University noted that on-site pre-conditioning of the H2, such as compression and blending, increases parasitic electrical load, reducing facility output/efficiency, up to ~57 kWh/kg H2.

5.2 Hydrogen Fuel Cell Generation

A few of the research projects investigated the feasibility of using the H2 produced, typically via electrolysis, to generate electricity by way of fuel cells – most notably via solid-oxide fuel cells (SOFCs). SOFCs (the reversible form of SOEC) use a solid electrolyte material to generate electricity by oxidizing a fuel (e.g. reacting H2 and O2) and are known for their high efficiency. They are very similar to a battery in the sense that an electro-chemical reaction takes place within the electrolyte material which generates electricity between the anode and the cathode.

Opportunities

1. SOFCs are relatively efficient – ranging from 60-65% efficiency to generate electricity alone, and up to 95% efficiency with waste heat recovery, far surpassing conventional power plant efficiencies.
2. Power output can be rapidly adjusted to match grid fluctuations making the technology ideal to provide grid services such as voltage support and frequency regulation, when integrated with advanced power electronics and control systems.
3. Highly complementary and able to integrate with other technologies such as electrolyzers, renewable energy sources, and H2 storage, especially considering Fuel Cell power capacity is decoupled from storage capacity.
4. Highly compatible with a variety of fuels including hydrogen, natural gas, and biofuels.

Challenges

1. SOFCs operate at extremely high temperatures, typically ranging from 300 to 800 degrees Celsius, posing issues for material durability requiring robust thermal management to ensure long term stability and safe operation.

2. Much higher degradation rates resulting in shorter stack lifetimes, when compared to other electrolyzer technologies.
3. Levelized cost of electricity (LCOE) is dominated by the fuel cost of H2, which remains high.
4. Highly sophisticated control systems need to be developed specific to operating SOFCs in a manner that is complimentary to grid operations to capitalize on the grid services SOFCs can offer.

5.3 Learnings for the IESO

1. Existing grid-scale gas turbines can be retrofitted to accommodate small amounts of H2 blending (<30%); however, it is cost-prohibitive at current and projected hydrogen costs and realizes minimal emissions reductions.
2. Hydrogen transported and stored on site at generation facilities can only sustain low-capacity factor operations – pipeline infrastructure or collocated hydrogen production is required for more sustained use.
3. Decreases in hydrogen costs can accelerate opportunities to leverage Fuel Cells for electricity generation and ancillary services due to fast ramping capabilities, decoupled integration with energy storage, and reversibility with solid-oxide electrolysis. However, highly sophisticated control systems are required which require further research/piloting.

6. Hydrogen Transportation & Storage

When H2 is not able to be consumed on site immediately after it's produced, it either needs to be stored or transported or both. The chemical and physical properties of H2 make this extremely difficult.

6.1 Transportation

There are two ways to transport H2: by pipeline, and by tube trailers. The most economical method is case-specific and requires consideration of various factors such as the distance between production and consumption points and the volume of H2 being transported. Several projects noted that transporting by tube trailer is the best option for short distances and small volumes of hydrogen while pipeline transport is the best option for long distances and larger volumes of hydrogen.

However, there are shared challenges across both methods as shown below:

- Hydrogen is the smallest atom and in its molecular form (H2), it is the smallest size of molecule. It's size makes it easy to propagate through small spaces and therefore difficult to contain and manage hydrogen leaks. Additionally, hydrogen-air mixtures are extremely easy to ignite and require minimal energy to do so.

- Another challenge is hydrogen's low volumetric energy density, which necessitates much higher volumetric flow rates to transport the same amount of energy as methane or other fuels. This increased flow rate brings its own set of issues, such as higher pressures, compression energy requirements, increased chances of leaks, and the potential for embrittlement, cracking, and failure. Materials resistant to hydrogen embrittlement, such as austenitic stainless steels, are required.
- Temperature fluctuations can cause rapid pressure changes in hydrogen systems. Hydrogen gas expands significantly with temperature increases, leading to higher pressure if contained within a fixed volume. A temperature gradient monitoring system is essential in ensuring that the gas does not undergo excessive thermal expansion.
- Moreover, being odourless, colourless, and tasteless, hydrogen leaks are difficult to detect and thus require sophisticated detection systems. One study noted that leakage typically arises from human error during installation or maintenance, such as improper torquing, welding, or sealing.

To circumvent the challenges noted above, another means of transportation that can be considered is to convert the H2 into a carrier fuel such as methane or methanol for industrial use. The molecular properties of these gases make them better candidates for transportation as well as long term storage. For example, they are significantly more energy dense by volume and require much less energy to liquefy. Methane, being the primary component of natural gas, can easily be accommodated by existing natural gas infrastructure. When hydrogen is combined with captured carbon dioxide, hydrogen can be converted and transported as these carrier fuels which when combusted will remain carbon neutral. It should be noted that this requires the carbon dioxide to be captured from another emitting process using some form of carbon capture.

6.2 Storage

Most of the HIF studies covered storage to some degree. When it comes to H2 storage, the most important factors are how the energy is being stored and for how long, with consideration given to cost, losses/efficiencies, and logistics.

6.2.1 Types of Storage

A variety of technologies have been and continue to be developed for the storage of H2 although it’s not clear which one is superior as each presents different benefits and challenges. The Volta study conducted a thorough analysis on this topic and concluded the following for the most common storage methods:

Storage Cylinders/Tanks: The most common method for storing compressed H2 gas today is in storage tanks, which differ in strength and weight of the materials used, and pressurization limits. Compressing the gas, while necessary to maximize the storage capacity, requires large amounts of energy (e.g. 6.4 kWh/kg H2 required to store at a pressure of 10,000 psi, resulting in a 19% loss in combustible energy). Tanks are extremely heavy resulting in poor portability and are quite costly to scale up for industrial use and even the most expensive tanks are prone to H2 leakage resulting in losses over extended storage periods. Therefore, compressed H2 tank storage is expensive and best suited for short-distance and small quantity applications, such as the conditions required for laboratory use.

Underground H2 Storage (UHS): UHS is an excellent solution to the scale up issues encountered by cylinders/tanks, with incredibly large storage capacities. The various forms of underground storage include geological formations such as depleted oil and gas reservoirs, saline aquifers, and salt caverns, which can all be repurposed to store very large quantities of H2. However, UHS faces its own complications including embrittlement and H2 induced cracking, cushion gas requirements, and loss of H2 via microbial interactions and permeation of formation walls.

Capital Power's Kingsbridge study assessed the feasibility of underground storage and reported similar findings. This study determined that to prevent hydrogen degradation resulting from chemical reactions with the reservoir water, a blend of hydrogen and methane (10% H2, 90% methane by volume) was required. Moreover, when extracting H2 from storage, composition of the fuel would be 45% H2/55% methane - exceeding the 20% H2 limit that most combustion units could handle, requiring additional blending prior to use for electricity generation.

Cryogenically liquefied H2: Liquifying H2 prioritizes portability of H2 by tremendously increasing its density. This improves the transportability of H2 by reducing its volume and improving the weight ratio of H2 to vessel. Unfortunately, this process is highly energy intensive requiring large amounts of energy and complex systems not only to achieve this state but also to maintain it.

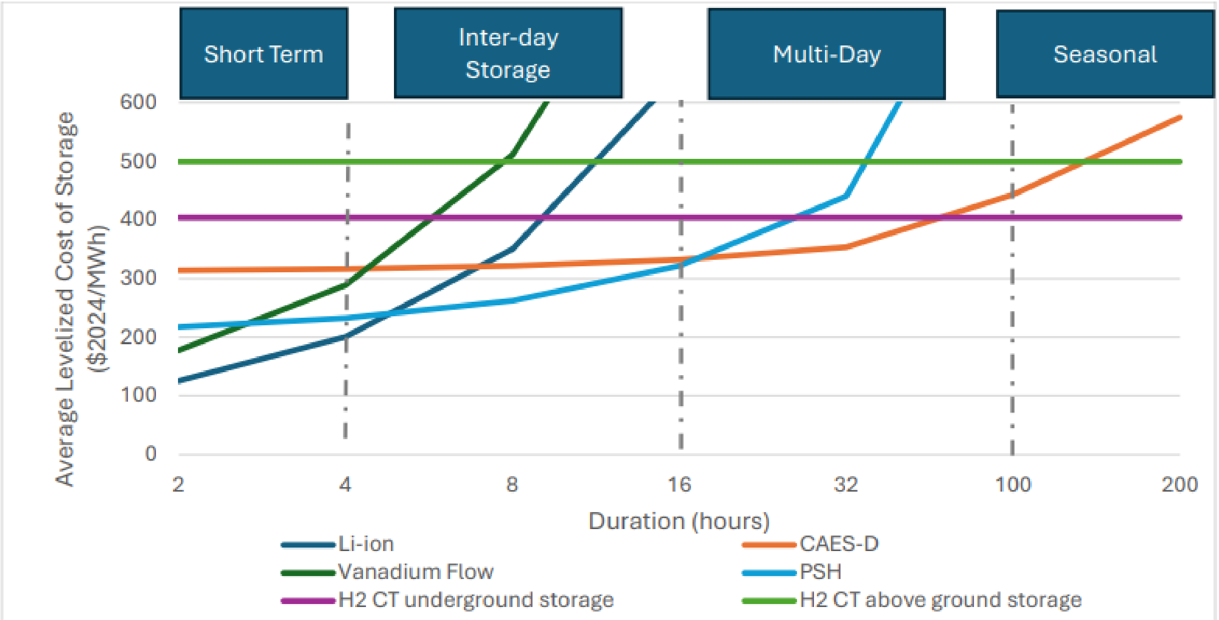
6.2.2 Optimal Storage Duration

The Transition Accelerator study conducted a cost assessment of various energy storage technologies across different storage duration ranges. Storage durations were grouped into four categories – short-term (2 to 4 hours), inter-day (4 to 16 hours), multi-day (16 to 100 hours), and seasonal (over 100 hours).

The study found that the levelized cost of storage (LCOS) of hydrogen does not change with duration. This is because in hydrogen systems, storage capacity and power capacity are decoupled. Increasing storage capacity doesn't require a proportional increase in power capacity. Conversely, the LCOS of every other evaluated technology (Li-ion, vanadium flow, compressed air, pumped hydro) increases with duration for a variety of reasons. The conclusion for H2 was:

- For short-term storage, hydrogen is the least cost competitive
- For inter-day and multi-day storage, hydrogen begins to become competitive as the LCOS of the other evaluated technologies begins to increase with increasing duration. At 16 hours duration, the LCOS of both Li-ion and Vanadium flow batteries exceeds that of hydrogen. At 32 hours duration, the only evaluated technology with a lower LCOS than hydrogen is compressed air.

- For weekly, monthly, or seasonal storage, hydrogen-fired combustion with underground storage emerges as the most economical storage option, at $400/MWh with above ground storage as the next most economical option at $500/MWh, as shown in the Figure below.



6.2.3 Area Classification

A classified area is where the risk of explosion might occur due to flammable gases, vapors or liquids, combustible dusts, combustible fibers. Area classification is crucial for safety as it reduces the risk of fires or explosions and ensures devices used in hazardous locations are safe and suitable. When H2 is being stored, produced, or consumed, a detailed classification study must be taken to comply with the applicable codes and standards.

6.3 Learnings for the IESO

1. Hydrogen storage can become more cost competitive than battery storage at longer durations (>16 hours) and can out-compete pumped hydro and compressed air storage at the multi-day timescale (>100 hrs)); however, there are complex technical and logistical challenges associated with storing and transporting hydrogen that must first be addressed, such as points 2 and 3 below.
2. Underground storage can store large volumes of H2; however, locations are dictated by geological formations which may be far from end-users, and a high degree of cushion gas (such as methane) must be blended with the H2 to prevent degradation and permeation issues, posing additional refining requirements upon extraction prior to consumption.
3. The molecular properties of hydrogen make it very difficult to store and transport, requiring increased flow rates and high-pressure compression (another energy intensive process), resulting in hydrogen-induced cracking and leakage issues in pipes and containers.

7. Conclusion

It is evident that growing the hydrogen economy presents challenges, underscoring the importance of technological innovation and cross-sector collaboration. It is clear from the HIF research studies that there are several proven technologies currently available for hydrogen production (e.g. PEM and Alkaline electrolyzers) and others which are still in early stages of development but show great potential (e.g. SOEC). As with any technology in its nascency, capital costs are high in the early years, but trend downwards over time. Continued research and development have the potential to improve conversion efficiencies and drastically improve the economics of H2 production. Despite current limitations, hydrogen is a resource that can be scaled up to reduce emissions, while also supporting the transition to cleaner energy sources.

Using hydrogen to generate electricity is expensive due to low round-trip efficiencies and incompatibilities with integrating into existing gas generation infrastructure. With further research and technological advancements, higher blending levels may be achieved, resulting in meaningful decarbonization to the electricity generation sector, benefitting from repurposing existing gas facilities and infrastructure.

Transportation and storage of hydrogen is technically challenging due to its physical properties (low volumetric energy density and small atomic size) resulting in the need for compression and issues such as hydrogen leakage.

Adopting hydrogen as an alternative energy source requires significant upgrades to existing infrastructure. This includes the development of hydrogen production facilities, storage systems, and transportation networks. While the initial investment remains high, current trends indicate that hydrogen production costs are decreasing due to technological advancements and economies of scale.

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

While the potential economic and environmental benefits of a hydrogen economy could be significant, strategic planning, investment in research and development, and supportive policy frameworks will be necessary to ensure the successful integration of hydrogen into the energy landscape.

For the IESO, it’s important to recognize that low-carbon hydrogen production at scale will represent a significant growth in electricity demand and require a grid comprised of excess clean supply in order to achieve its primary purpose of decarbonization. It’s also important to understand that this increased electrolyzer load is flexible and can therefore be managed and leveraged to support the grid via wholesale market participation as dispatchable load and ancillary services, as suggested by many of the HIF research projects, and yet to be proven by the other ongoing HIF demonstration projects.

The IESO is excited to build from the 2023 Call and further its understanding of the potential opportunities for hydrogen technologies in both the electricity sector and more broadly via the upcoming 2025 Call.

Appendix A – Comparison of Different Electrolyzer Technologies

The Kinectrics study provided the following table comparing various parameters between electrolyzer technologies. Most projects that reported findings on these technologies generally aligned with these findings, within reasonable ranges.

Parameter	**Alkaline Electrolyser**	**PEM Electrolyser**	**SOEC**
Efficiency (%)	60-70%	70-80%	80-99%
Hydrogen purity	95-99%	99.9%	99.999%
Operating Temperature (Celsius)	60 - 80	50 – 80	650 - 1000
Electrolyte type	Aqueous	Polymer Membrane	Solid Oxide
Electrolyte degradation rate	Moderate	High	Low to Moderate
Catalyst material	Nickel, Platinum, Iron, Manganese	Platinum, Iridium, Ruthenium	Nickel, Ceria, Yttria-Stabilized Zirconia
Lifetime (years)	10-20 years	5-10 years	15-25 years
Cost per kg H2 (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
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

Note: The York University On-site H2 Production study references a retail price of $20/kg of H2 from Enbridge Gas.

Appendix B - List of Projects

Volta Energy: Feasibility Evaluation of Sustainable, Green and Rapid-Response Metal-Supported Solid Oxide Cell Technology Integrated with Smart Hydrogen Hub

Project Description: Evaluating the feasibility of an integrated Smart Hydrogen Hub (SH2) and high-efficiency Solid Oxide Cell (SOC) system for hydrogen production and electricity generation from hydrogen (or hydrogen carrier fuels) for participation in a dynamic future electricity market. Technological pathways for hydrogen conversion into carrier fuels, mitigating hydrogen storage issues and decarbonization through fossil fuel displacement are also evaluated.

Key Learnings:

1. Solid Oxide Cells are extremely efficient (at high heat).
2. Reversible SOCs a promising technology for frequency regulation/renewable smoothing.
3. Hydrogen Storage and Transportation remains a challenge.

York University: Preliminary Feasibility Study of Hydrogen Production On-Site and Utilization of Hydrogen in Existing Prime Movers

Project Description: Evaluating the feasibility of retrofitting existing gas turbines to burn a fuel blend of hydrogen and natural gas in small/medium sized Gas Turbine Generators (GTGs). To assess how generating hydrogen on-site during off-peak periods can provide faster operating reserves as well as a reduction in grid load and CO2 emissions during hours when large gas plants would otherwise be operating.

Key Learnings:

1. H2 blending in gas turbines is possible up to 50%, however costly retrofitting is required.
2. Financial feasibility of this type of retrofit project is largely driven by the price of the hydrogen fuel Reversible SOCs a promising technology for frequency regulation/renewable smoothing.
3. Upfront conditioning of the hydrogen fuel may represent an increased parasitic electrical load, which may decrease total electrical output from the GTG’s as a system.

University of Windsor: Hydrogen Integrated Greenhouse Horticultural (HIGH) Energy

Project Description: Testing the feasibility of wind coupled production of hydrogen for u se in the Ontario Greenhouse Sector. Evaluating the economics of a modeled transmission connected wind farm and its major market obstacles to help better define potential hydrogen market strategies for Ontario.

Key Learnings:

1. There are several engineering challenges related to burning, storing, transporting, and integrating hydrogen with existing natural gas equipment due to higher pressure requirements and higher combustion temperatures.
2. Adopting hydrogen as a primary energy source requires significant upgrades to existing infrastructure.
3. Many existing natural gas CHP gensets are capable of accepting up to 20% blends of hydrogen.

York University: Optimal Deployment of Green Hydrogen Plants in Ontario Electricity Systems

Project Description: Analyzing the feasibility of the full integration of Large-scale Green Hydrogen Plants (GHPs) into Ontario's electricity system under optimal configurations to meet grid services such as frequency regulation, operating reserve, demand response, and smoothing of renewable energy sources. Configurations will consider different types of electrolyzer, and optional additional local power resources such as fuel cells and battery storage systems all to better understand the role of GHPs in propelling the hydrogen economy forward and decarbonization pathways in Ontario.

Key Learnings:

1. Choice of electrolyzer is important depending on the application of the GHP.
2. Batteries are more economically feasible than GHP at the York University Keele Campus to reduce emissions while providing electricity bill savings.
3. GHPs can provide market arbitrage and ancillary services opportunities however they face challenges such as cost, technological uncertainties, and regulatory issues.

Capital Power: Hydrogen Blending – Goreway Power Station, East Windsor Cogeneration Centre and York Energy Centre

Project Description: Assessing the feasibility of implementing hydrogen cofiring and blending at natural gas plants at varying levels of hydrogen while maintaining their existing reliability. Many aspects of the facilities such as performance impacts, emissions effects, and transmissions logistics will be studied to understand implications of hydrogen use and its decarbonizing potential as a fuel.

Key Learnings:

1. The amount of CO2 emissions is not directly proportional to the increase in volumetric hydrogen in the fuel.
2. Increased volumetric flow of blended fuel is required to generate the same heat as the reference natural gas; Blended fuel could produce higher NOx emissions due to higher combustion flame temperature
3. Transporting hydrogen in gaseous form is suitable for near-term, low-capacity factor operations, however for high-capacity factor operations (e.g., baseload) hydrogen pipelines are required.

Western University: NET-PBH2: Negative Emissions Technology for Pale Blue Hydrogen Production

Project Description: Investigating the feasibility of integrating green hydrogen from a PV-AEM (5 kW) electrolyzer with a Non-Thermal Plasma Reactor (NTPR) which converts biogas into blue hydrogen with simultaneous biological carbon sequestration in a microalgal photobioreactor. The water footprint of the PV-AEM electrolyzer and the carbon footprint of the NTPR will both be evaluated, and an investigation into the economics of green hydrogen, blue hydrogen, and the combined "Pale Blue Hydrogen" is also to be completed.

Key Learnings:

1. The project successfully demonstrated pale blue hydrogen production via biogas membrane filtration, Photovoltaic – Anion Exchange Membrane Electrolysis integration, methane conversion to carbon black and hydrogen via a plasma reactor, and carbon capture and water recycling using a 20,000 L photobioreactor.
2. The combined production of pale blue hydrogen (green + blue hydrogen) shows promise for economic viability and reduced environmental impact. The Life Cycle Assessment indicates that this approach can significantly lower emissions compared to grey hydrogen production.
3. This particular solution faces scalability challenges and further optimization of the plasma reactor design and membrane separation efficiency.

Capital Power: Kingsbridge Green Hydrogen and Storage Assessment

Project Description: Exploring the feasibility of a facility which creates green hydrogen from wind energy via electrolysis and stores it in underground depleted gas reservoirs. Assessment of key grid services such as demand response and peak demand generation and use cases in non-combustion purposes and hybrid hydrogen-methane turbines will be assessed to further advance Ontario's mission to a fully decarbonized grid.

Key Learnings:

1. Relying on curtailed wind power alone may be insufficient to produce hydrogen on a reasonable scale and an acceptable level of financial return.
2. Hydrogen gas could react with reservoir minerals and could produce hydrogen sulfide. Another concern is hydrogen degradation due to chemical reaction with reservoir water, requiring a significant percentage of methane to be blended to prevent such concerns.
3. The internal combustion engine is recommended over gas turbines for electricity production and it must run with greater than 50% capacity factor to burn H2 which can be cost prohibitive.

The Transition Accelerator: The Role of Hydrogen Hubs in Strengthening the Affordability and Reliability of Ontario's Electricity System

Project Description: Investigating the potential and feasibility of a hydrogen hub in clustering hydrogen production, transportation, storage, and facilitating cost-effective net-zero solutions across multiple sectors. Evaluating scenarios to reduce direct electrification, integrate hydrogen generation to address peak demand needs, and increase electricity demand from the production of green hydrogen.

Key Learnings:

1. The widespread adoption scenario for hydrogen demand being met by electrolysis would require over 330 TWh, which is more than double the current Ontario energy demand.
2. Hydrogen can be competitive with natural gas as a generation source by 2050, provided there are high natural gas and carbon costs.
3. Compared to other storage technologies, hydrogen is best suited for long-duration storage, particularly at the seasonal level.

Kinectrics Inc.: Feasibility Study for an Urban Hydrogen Hub for Grid Flexibility, Resilience, and Carbon Reduction Scalable to Nuclear Power Plant Co-location.

Project Description: Exploring the feasibility of a hydrogen hub and its potential to produce hydrogen through electrolysis powered by a surrogate heat source to emulate a nuclear power plant and explore the use of fuel cells for power generation and as a clean fuel source for vehicles. Evaluating a number of economic factors and integration of each technology to support the transition towards sustainable energy.

Key Learnings:

1. SOEC technology is scalable from the pilot-scale (1MW) to large system scale (>100MW), which provides economies of scale benefits and can reduce production costs by 18%.
2. SOECs can be effectively integrated with nuclear power plants, utilizing waste heat to reduce electricity consumption and further improve efficiency.
3. Being located near potential hydrogen users, including heavy-duty vehicle fleets and industrial facilities, enhances the practicality and feasibility of the Hydrogen Hub by ensuring a ready market for the produced hydrogen.

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