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Review

Hydrogen economy transition plan: A case study on Ontario

Faris Elmanakhly[1,#], Andre DaCosta[2,#], Brittany Berry[3,4], Robert Stasko[4], Michael Fowler[2] and Xiao-Yu Wu[1,*]

[1] Department of Mechanical and Mechatronics Engineering, University of Waterloo, 200 University Avenue West, Waterloo, ON N2L 3G1, Canada
[2] Department of Chemical Engineering, University of Waterloo, 200 University Avenue West, Waterloo, ON N2L 3G1, Canada
[3] School of Environment, Enterprise and Development, University of Waterloo, 200 University Avenue West, Waterloo, ON N2L 3G1, Canada
[4] Hydrogen Business Council, 2140 Winston Park Drive, Unit 203, Oakville, ON L6H 5V5, Canada

* **Correspondence:** Email: xiaoyu.wu@uwaterloo.ca; Tel: +15198884567.

[#] FE and AD contributed equally

Abstract: A shift towards a “hydrogen economy” can reduce carbon emissions, increase penetration of variable renewable power generation into the grid, and improve energy security. The deployment of hydrogen technologies promises major contributions to fulfilling the economy’s significant energy needs while also reducing urban pollution emissions and the overall carbon footprint and moving towards a circular economy. Using the Canadian province of Ontario as an example, this paper prioritizes certain recommendations for near-term policy actions, setting the stage for long-term progress to reach the zero-emissions target by 2050. To roll out hydrogen technologies in Ontario, we recommend promptly channeling efforts into deployment through several short-, mid-, and long-term strategies. Hydrogen refueling infrastructure on Highway 401 and 400 Corridors, electrolysis for the industrial sector, rail infrastructure and hydrogen locomotives, and hydrogen infrastructure for energy hubs and microgrids are included in strategies for the near term. With this infrastructure, more Class 8 large and heavy vehicles will be ready to be converted into hydrogen fuel cell power in the mid-term. Long-term actions such as Power-to-Gas, hydrogen-enriched natural gas, hydrogen as feedstock for products (e.g., ammonia and methanol), and seasonal and underground storage of hydrogen will require immediate financial and policy support for research and technology development.

Keywords: hydrogen economy; hydrogen production; hydrogen storage; alternative fuel; Net-Zero

CO_2 emissions; Ontario hydrogen roadmap

Nomenclature: AEL/AFC: Alkaline Electrolyzer/Alkaline Fuel Cell; BEV: Battery Electric Vehicle; CCS: Carbon Capture and Sequestration; CHP: Combined Heat and Power; CUTRIC: Canadian Urban Transit Research & Innovation Consortium; DME: Dimethyl Ether; DMFC: Direct Methanol Fuel Cell; DOE: United States Department of Energy; DPM: Diesel Particulate Matter; FCEV: Fuel-Cell Electric Vehicle; GHGs: Greenhouse Gases; HENG: Hydrogen-Enriched Natural Gas; IESO: Independent Electricity System Operator; MCFC: Molten Carbonate Fuel Cell; MEA: Membrane Electrode Assembly; MMscfd: Million Standard Cubic Feet Per Day; MOF: Metal-Organic Framework; NASCO: North American Superhighway Corridor; NO_x: Nitrogen Oxides; NRCan: Natural Resources Canada; P2G: Power-to-Gas; P2X: Power-to-X; PAFC: Phosphoric Acid Fuel Cell; PEM: Polymer Electrolyte Membrane; PEMFC: Polymer Electrolyte Membrane Fuel Cell; PEV: Plug-In Electric Vehicle; PM 2.5, PM 10: Particulate Matter 2.5 μm, 10 μm; PPB: Purple Phototrophic Bacteria; PSA; Pressure-Swing Adsorption; PTFE: Polytetrafluoroethylene; PV: Photovoltaic; RNG: Renewable Natural Gas; SDGs: United Nations' Sustainable Development Goals; SMR: Steam Methane Reforming; SOEC/SOFC: Solid Oxide Electrolyzer Cell/Solid Oxide Fuel Cell; SO_x: Sulfur Oxides; TOU: Time-of-Use; UHS: Underground Hydrogen Storage; UPE: Union Pearson Express; UPS: Uninterruptible Power Supply; VOC: Volatile Organic Compound; VRE: Variable Renewable Energy; WGS: Water-Gas Shift; YSZ: Yttria-Stabilized Zirconia; ZEV: Zero-Emission Vehicle

1. Introduction

There are two main drivers for the move towards the hydrogen economy: firstly, the desire to reduce emissions of greenhouse gases (GHGs) and improve health outcomes in urban environments by reducing criteria air contaminants, such as NO_x and particulate matter; and secondly, the need to ensure the security of the energy supply [1]. The transition towards a hydrogen economy can ensure a low-carbon, sustainable, competitive, resource-efficient, and circular economy, representing a systematic shift that builds long-term resilience, generates business and economic opportunities, and provides environmental and societal benefits. A circular economy looks beyond the current extractive industrial model that consumes finite resources, and it provides a more sustainable approach integrating renewable energy sources and managing its waste [2]. However, various barriers hinder the development of a circular economy, such as the lack of consumer interest and awareness and a hesitant business culture [3]. Careful analyses using methods such as the Strengths, Weaknesses, Opportunities and Threats—Analytic Network Process framework [4] are required to provide information for policy-making to facilitate the transition to a hydrogen economy. In addition, waste management, e.g., recycling [5] is important to a circular economy. Hydrogen technologies can ultimately factor into this process of waste reduction and utilization: first, the conversion of hydrogen into thermal and electrical energy produces mainly water as the byproduct, which prevents waste or GHG emissions; second, some wastes, e.g., municipal waste can be converted to hydrogen through fermentation [6] or pyrolysis/gasification [7] (discussed later in Table 1); third, some industrial waste streams such as CO_2 [8] or petroleum coke [9] can react with hydrogen to generate useful products such as hydrocarbons (discussed later in section 5.8). In addition, a circular economy requires the consideration of end-of-life technologies for hydrogen devices to recover valuable materials and manage the wastes [10]. In this paper, we focus on the production and utilization aspects of the hydrogen economy.

The hydrogen economy involves the production of hydrogen as an energy carrier from clean energy sources, as an energy vector providing alternative fuel for transportation and energy distribution, and as an energy storage medium. The proper implementation of the hydrogen economy must be accompanied by a significant development in the hydrogen infrastructure for production, storage, distribution, and utilization. Ultimately, the hydrogen economy can play a significant role in helping achieve the United Nations' Sustainable Development Goals (SDGs) [11,12].

By strategically developing the infrastructure, hydrogen technologies can store surplus electricity from renewables to reduce the need for curtailment, be blended into a natural gas network to reduce its associated GHG emissions and be used in fuel cells or hydrogen engines to effectively and cleanly power light and heavy transportation. Many countries and regions around the world are planning and building projects as part of their hydrogen deployment strategies, such as Australia [13], Germany [14], Japan [14], the UK [15,16], the state of California in the US [17], and most recently, Canada, both federally and specifically in the province of Alberta [18,19] (summarized in section 1.3). From a policy maker's perspective, the objective of a hydrogen transition serves various important aims, including decarbonizing the economy, creating jobs, effectively fulfilling growing energy demand, and bringing environmental benefits. Strategies must identify the sectors that will most benefit, invest in research for innovative and cost-effective technologies, account for regional context, and finally, introduce and enforce policies to encourage the production and use of hydrogen on the regional scale. As a hydrogen strategy has not been formulated yet for the Canadian province of Ontario, we look at the jurisdiction with its abundant potential for hydrogen deployment in providing this case study to demonstrate the possible hydrogen strategies fit to be implemented.

Firstly, hydrogen technologies prove advantageous for Ontario in addressing the challenges of the province's energy system. The need to reduce GHG emissions has already been mentioned, but there also remains the problem of health impacts from the air pollution that often accompanies these emissions. Other concerns to be addressed in a hydrogen strategy specifically for Ontario are the challenges of balancing supply and demand in the province's diverse and evolving energy system, including the costs of global adjustment and the curtailment of surplus, or export of low-cost surplus power. Hydrogen is the key to solve all these challenges but unlocking its true potential will require robust strategies at both national and provincial levels. In Ontario, nuclear power provides reliable low-cost baseload electricity with near-zero emissions, accounting for 13,009 MW (34%) of the province's installed capacity and making up 87.8 TWh (60%) of its electricity output [20]. However, the short-term excessive power of nuclear and intermittent wind power exacerbates the curtailment of these low-carbon electricity sources. These developments will encourage a national dialogue on the role of hydrogen as a contributing pathway to net-zero emissions and as an important driver in a new clean economy for Canada.

1.1. Hydrogen as a key energy vector

A hydrogen economy requires the widespread use of hydrogen as a key energy vector that enables the transfer of energy over space or over time so it is available for use, wherever or whenever it is needed in the desired amounts and forms [21]. Hydrogen can be used as a fuel for combined heat and power (CHP) systems or fuel cell electric vehicles (FCEVs). FCEV technology can be applied to light vehicles, or even more favorably to heavy-duty trucks, buses and trains (e.g., Metrolinx and Mississauga's MiWay in Ontario [22]), due to their predictable and consistent routes [23]. Compressed hydrogen gas, liquefied hydrogen or hydrogen carriers such as methanol and ammonia can also be used for seasonal energy storage, or long-distance energy distribution [24]. Hydrogen's high gravimetric energy density makes it a good energy vector and an ideal zero-emissions energy source, which will reduce fossil fuel consumption to decrease negative health impacts and limit global warming.

Hydrogen also serves as an important chemical feedstock or fuel in industrial applications [25], but numerous technical challenges are preventing the creation of a large-scale hydrogen economy. Despite such challenges, one goal that is relatively easy to achieve using hydrogen is in load management for smoothing out energy demand, which is done via peak clipping and load shifting [24]. Electric load management needs hydrogen as the energy storage medium to allow more variable renewable energy (VRE) into the grid [26]. Another aspect of load management compatible with hydrogen is arbitrage: producers can generate hydrogen when electricity is the least expensive according to Time-of-Use (TOU) rates [27]. Hydrogen will be distributed and used for all essential energy needs, such as for transportation fuel, for blending with natural gas for industrial or residential use, or energy storage.

To summarize, hydrogen has the following advantages as a highly effective energy vector:

1. It can be produced from various forms of energy (e.g., fossil fuels, or low- or zero-carbon sources such as wind, solar and nuclear) using a variety of methods (e.g., reforming and electrolysis) [21].
2. It can be contained (e.g., in pipelines, underground caverns and tanks) and transferred (e.g., through pipelines, hydrogen tube trailers and ships, and hydrogen carriers such as methanol and ammonia). It can even be injected directly into the natural gas grid in limited quantities (currently less than 5–15%, by volume) [28].
3. It can be converted into energy where and when needed for various applications, such as mobility, electricity, or heat generation [21].
4. It can be used as an industrial feedstock, such as for ammonia production [29], hydrogen-enriched natural gas (HENG), and various potential "Power-to-Gas (P2G)" energy pathways [30].
5. It can be combined with CO_2 to produce hydrocarbon products (such as methane via the Sabatier reaction [31]) to be used as energy vectors or a means to use the captured GHGs [32].

1.2. Hydrogen as a means of reducing CO_2 emissions

Worldwide natural gas consumption has been rising over the past 20 years. In 2019, natural gas consumption worldwide amounted to nearly 3.9 trillion cubic meters; this results in around 36.8 billion tons of carbon dioxide emissions estimated by the Global Carbon Project in 2019 [33,34].

Hydrogen can be an alternative fuel to reduce the fossil fuel dependency of various sectors such as transportation or heavy industry. Hydrogen from renewables (such as wind, solar, geothermal and biomass) and low carbon resources (such as nuclear energy) can replace fossil fuel-based feedstocks in these CO_2 emission-intensive sectors. The utilization of renewable and low carbon resources to produce hydrogen can effectively contribute to the reduction of carbon emissions as these sources have the lowest recorded carbon intensity (0 to 0.6 kg $CO_{2\text{-eq}}$ (CO_2 equivalent)/kg H_2) [35]. In addition, hydrogen can be combusted in a gas turbine or used directly in a fuel cell to generate work/electricity without GHGs. Hydrogen can also help improve urban criteria emissions (i.e., SO_x, NO_x, Ozone, VOCs, PM 2.5, PM 10) [35].

In Ontario, natural gas is usually used to provide heat and to power the grid during peak hours to stabilize the electricity supply. Storing surplus zero-emission electricity in the form of hydrogen and utilizing the hydrogen for heating and peak-shaving can offer a green and sustainable solution to decrease the natural gas consumption in power generation in Ontario [22]. Developing infrastructure to store surplus energy from VRE sources as hydrogen will also reduce the amount of VRE that is curtailed or exported at unfavorable rates.

1.3. The deployment of hydrogen strategy in various regions

Several countries and regions are developing roadmaps for the deployment of hydrogen technology and building demonstration-scale projects for either hydrogen production or consumption. For example:

- The **UK** Climate Change Act has the country committed to a 100% emissions reduction from 1990 levels by 2050 [15]. To achieve the necessary carbon reductions in the energy supply to meet this target, the UK Committee on Climate Change has released a series of recommendations for the implementation of hydrogen, placing a focus on the usage of hydrogen as a backup heat source for buildings, and a recommendation to use blue hydrogen as a means of scaling up infrastructure [16].
- **Germany** has 50 Power-to-X (P2X) projects either in development or in operation, in addition to 500 hydrogen-based uninterruptible power supply (UPS) units in operation [14]. It is predicted that under the clean energy scenarios in Germany, hydrogen energy usage would be between 300 and 600 PJ by 2050 (10% of total primary energy demand) [14].
- **Japan** is deploying technologies for hydrogen utilization, with 250,000 CHP units in buildings and 2,400 hydrogen vehicles [14]. It is predicted that hydrogen usage in Japan will be between 600 and 1,800 PJ by 2050 [14].
- **Australia** has several hydrogen projects planned or in operation, such as the Jemena Western Sydney Green Gas Project, a planned system to inject electrolytic green hydrogen (from wind and solar power) into the existing natural gas grid. Additionally, the Bulwer Island production facility will produce 2,400 kg hydrogen/month from water electrolysis, and the ATCO (an Australian natural gas company) Clean Energy Innovation Hub uses excess electricity from a 300-kW solar PV array to generate hydrogen, which is then blended into a natural gas network or used in fuel cell power generation [13].
- **California** in the US has committed to building 200 refueling stations along its “California Hydrogen Highway,” and mandated that one-third of the hydrogen in fueling stations must be produced from renewable energy [17].
- **Alberta** in Canada plans to utilize its existing capabilities for low-cost hydrogen production from natural gas and integrate carbon capture technology, potentially using captured CO_2 to aid in oil extraction [36].
- In **Canada**, the hydrogen strategy has also been considered at the federal level. In 2019, Natural Resources Canada (NRCan) issued a report on potential pathways of hydrogen implementation, recommending the development of demonstrations and the building of infrastructure. The report encourages the establishment of research goals, the development of codes and standards related to hydrogen deployment, and international information sharing and collaboration [18]. Later, in

December of 2020, NRCan issued its Hydrogen Strategy for Canada, which details 32 recommendations to ensure hydrogen plays a key role in Canada's clean energy plans [19]. The 32 recommendations are arranged into eight "pillars" including establishing strategic partnerships, de-risking hydrogen investments, stimulating innovation, harmonizing codes and standards, creating enabling policies and regulations, increasing awareness, creating regional hydrogen blueprints, and working with international markets [19].

In the following sections, we will first introduce some background for hydrogen and related technologies, and then show how to use the multitude of hydrogen opportunities available in the province of Ontario to establish the region as a global leader in the field of hydrogen technology.

2. Hydrogen production, storage, and utilization

2.1. Hydrogen color code and related carbon intensity

The climate advantage of hydrogen depends on how it is produced. It is important to understand the carbon content of the various hydrogen production methods before determining the role of hydrogen in decarbonizing the economy.

While all hydrogen is combusted or consumed in similar ways, the different production methods result in varying amounts of carbon emissions, as outlined in Table 1. A consistent methodology is urgently needed to compare the life cycle GHG reduction potential of all these hydrogen production methods in a quantitative manner.

Table 1. Comparison of various categories of hydrogen production methods.

Category	Description of Production Method(s)	Carbon Intensity
Brown	Mainly from coal gasification in water or CO_2 environments at high temperatures. The gasification product, i.e., syngas is further converted into H_2 and CO_2 in water-gas shift (WGS) reactors. Waste-to-energy incinerators can also be used to generate brown H_2 from municipal waste in the gasification process.	Significant. Carbon dioxide not captured or stored.
Grey	From natural gas reforming, followed by downstream WGS reactions and hydrogen separation. Makes up to around 78% of current hydrogen production [37]. Currently, the cheapest among all the categories and usually assumed to remain cheap in the foreseeable future [38].	Significant emissions, though lower than brown hydrogen (per mole of hydrogen produced). Carbon dioxide not captured or stored.
Blue	Produced from fossil fuels using gasification or reforming, followed by carbon capture and sequestration. Captured CO_2 can be stored indefinitely or be used in other industrial processes, such as CO_2 reduction [39].	Low to moderate, depending on carbon capture technology used [40].

Continued on next page

Category	Description of Production Method(s)	Carbon Intensity
Green	From renewable resources, e.g., water splitting powered by renewably sourced electricity (wind, solar, hydroelectricity, and purple phototrophic bacteria (PPB)), water thermolysis powered by renewable heat, and biomass/waste gasification. The amount of green hydrogen generation is expected to grow by 22 times by 2030, but its requirement for new infrastructure means significant investment is needed [41].	Low to zero. Bioenergy-based methods could have negative emissions, if the emissions produced are captured and stored [42].
Purple	Generated from water splitting powered by nuclear energy [43]. Thermochemical cycles powered by intermediate- to high-temperature nuclear heat is also a promising technology, compatible with the next generation of nuclear reactors [44]. An important low-carbon hydrogen option for countries and regions with significant amounts of nuclear electricity, such as Ontario.	Low to zero.

2.2. Hydrogen production technologies

2.2.1. Power-to-Gas (P2G)

Power-to-gas is the process of converting electricity into gaseous hydrogen, which is then injected into the existing natural gas storage and distribution infrastructure, effectively making a HENG stream. The P2G technology is considered the bridge between the electric utility and natural gas grid to provide fuel with reduced carbon intensity for heating, CHP, and transportation [30]. In addition, P2G, as an energy storage concept, could enable increased VRE in the grid and make efficient use of off-peak baseload nuclear power, thus improving life cycle emissions from power generation and transportation sectors. P2G provides an incremental transition towards the GHG emission-free hydrogen economy while using the current natural gas infrastructure [30,45].

Several different related energy pathways (illustrated in Figure 1), often called Power-to-X, most of which depend on large-scale electrolysis, allow for the convergence of electric utilities and natural gas systems, and can be implemented both gradually and incrementally as part of the hydrogen transition, such as:

1. Power to hydrogen to natural gas end-users in the form of HENG (including micro-CHP route).
2. Power to renewable hydrocarbons for blending into petroleum fuels.
3. Power to power, in which electricity is used for water electrolysis to produce hydrogen for fuel cells at stationary electricity generators.
4. Power to gas for seasonal energy storage for generating electricity.
5. Power to zero-emission transportation.
6. Power to seasonal storage for transportation.
7. Power to micro-grid.
8. Power to renewable natural gas (RNG) into the pipeline (known as “methanation”).
9. Power to RNG into seasonal storage.

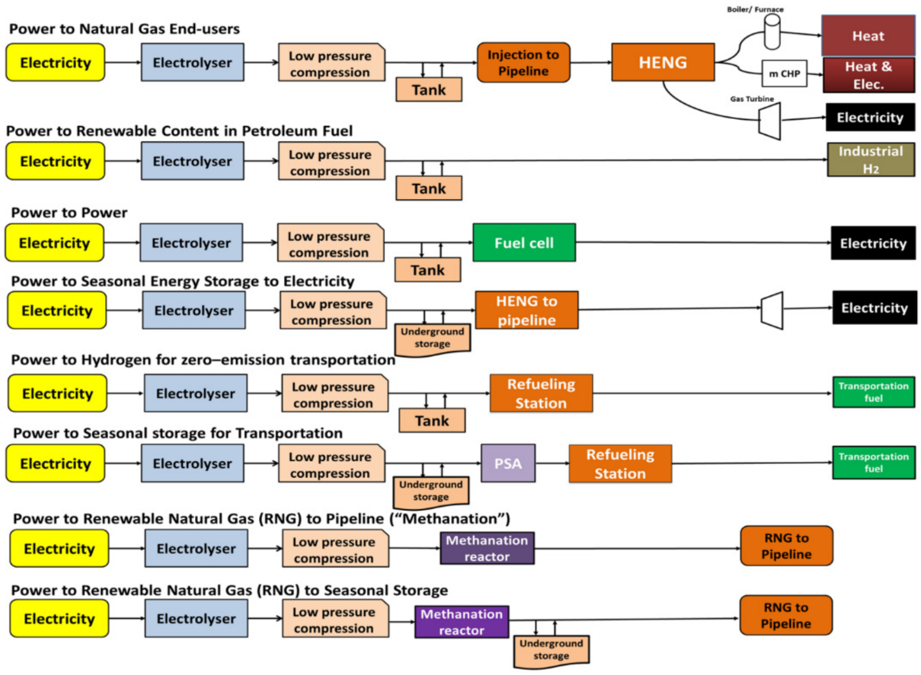

Figure 1. Different power-to-gas pathways (Reprinted from [30] under the terms of the Creative Commons CC-BY license).

2.2.2. Electrolysis

As Figure 1 illustrates, electrolysis technology is an essential component in all P2G and P2X pathways. Depending on the carbon intensity of the electricity, electrolysis can have different life cycle carbon intensity. Given the large share of nuclear and renewable power generation in Ontario, there is an opportunity to utilize these power sources to generate hydrogen with minimal lifecycle carbon emissions.

There are three major technologies for electrolysis, each of which has a respective fuel cell technology: alkaline electrolyzers or fuel cells (AEL or AFC), polymer electrolyte membrane (PEM) electrolyzers/fuel cells, and solid oxide electrolyzers or fuel cells (SOEC or SOFC). Each technology has its benefits and drawbacks. Among the three, alkaline electrolysis is currently the most mature and widespread technology, while solid oxide electrolysis is still primarily in its development phase, with few commercial systems available.

Alkaline electrolysis is currently operable at the MW scale. An alkaline system is comprised of electrodes immersed in an aqueous KOH electrolyte, separated by a diaphragm permeable to hydroxide ions. Hydrogen gas is produced at the cathode and oxygen gas is produced at the anode; each product gas is separated from its respective electrolyte stream, downstream of the electrolyzer. Alkaline electrolysis is capable of producing hydrogen gas at purities of 99.5–99.9% [46].

PEM electrolysis technology has seen rapid development in recent years due to its applicability in flexible energy storage. PEM systems are comprised of electrodes (typically with noble metals such as iridium at the anode and platinum at the cathode) mounted on a solid polymer electrolyte, permeable to protons [46,47]. Water is supplied to the anode, which is split into oxygen gas and hydrogen ions. The ions then permeate across the membrane to the cathode, where they react to form the hydrogen gas product. PEM can produce pure hydrogen in the range of 99.99% after the unreacted water is condensed [46,48]. Furthermore, PEM systems are more compact and can operate at higher current densities and pressures than alkaline systems [46]. Another advantage of PEM over alkaline is its slightly superior flexibility in operation, though both technologies possess sufficient flexibility for grid balancing services [46,49]. PEM systems can operate in a range of 0–100% of their nominal load, in comparison to alkaline, which can operate between 20–100%. PEM systems also demonstrate faster start-up times than alkaline [46]. A power-to-gas project in Markham, Ontario operated by Enbridge Gas and Cummins utilizes PEM electrolysis to provide grid balancing services for the province, with a total plant capacity of 2.5 MW [50].

SOECs and SOFCs have similar configurations, and the solid oxide technology has the potential for reversible operation (i.e., usage of the same cell as both fuel cell and electrolyzer) [46]. These cells typically use a solid electrolyte made of yttria-stabilized zirconia (YSZ) [51] and, similarly to the other technologies, produce hydrogen gas at the cathode and oxygen gas at the anode. SOEC is a developing technology with a key advantage over the other methods: a higher operating temperature (700–900 °C) [46]. The technology benefits from improved reaction kinetics and thus does not require precious catalyst material, presenting an economic advantage [46,52,53]. This higher temperature also enables higher efficiency than other methods but causes issues related to material degradation [46]. If the systems are operated at a high enough voltage, the Joule heating from the internal resistance of electrolysis cells can be used to meet the heat demand of electrolysis [54]. This is known as thermoneutral operation, but it is often not used due to degradation issues [46,55]. Thus, to maintain the high operating temperature, external heating is often required to bring the feed up to temperature and supply thermal energy to the endothermic water-splitting reaction. This opens opportunities for integration with other heat-emitting processes. Opportunities also exist within solid oxide technology for co-electrolysis of water and CO_2 to produce H_2 and CO, which may be used in tandem to produce synthetic fuels [31].

Table 2 summarizes the benefits and challenges of the three different technologies, and a quantitative comparison can be found in Ref. [46].

Table 2. Comparison of electrolysis methods.

	Alkaline electrolysis [46]	**PEM electrolysis** [46–48]	**Solid oxide electrolysis** [31,46,52,53,55]
Advantages	Mature electrolysis technology; Long lifetime; Low cost; High power capacity per stack;	Rapid startup and good flexibility in terms of operating load; Compact size; High purity of hydrogen obtainable;	Favorable reaction kinetics and high efficiency with no precious catalyst due to high temperature; Potential for integration with heat-emitting chemical processes; Co-electrolysis capability; Potential for reversible operation;
Challenges	Slow startup time and poor flexibility; Lower efficiency than the other two technologies;	Requires use of expensive precious catalyst materials; Lifetime and capacity need to be improved, and costs to be reduced;	Few commercial systems in operation; Material degradation issues due to high temperature; External heat source often required to meet high-temperature requirements;

2.2.3. Thermochemical processes to produce hydrogen from fossil fuels

Thermochemical conversion of different fossil fuel feedstocks to hydrogen is a mature technology, accounting for around 96% of global hydrogen production [56]. These processes include methane or oil reforming and coal gasification, which produce hydrogen and carbon dioxide; they must be integrated with carbon capture and sequestration (CCS) to reduce the carbon intensity in the produced hydrogen [57,58].

Steam-methane reforming (SMR) is an advanced and mature industrial process, built upon the existing pipeline infrastructure for cost-effective natural gas delivery [59]. Methane (CH_4), the major gas component in natural gas, reacts with steam on catalysts, such as nickel or noble metal (e.g., Ru and Rh) catalysts at high temperatures (700 ℃–1000 ℃) and pressures (3–25 bar) to derive syngas, which is made up primarily of carbon monoxide and hydrogen, along with a small amount of carbon dioxide [57,60]. Next, the syngas undergoes the water gas shift (WGS) reaction, catalyzed by metals or metal oxides (e.g., Fe [61–63] and Cu [62,64]) to convert carbon monoxide with steam to carbon dioxide and additional hydrogen [65]. This is followed by the pressure-swing absorption (PSA) to separate hydrogen from carbon dioxide and other impurities with CCS. The chemical reactions involved in the SMR are:

Steam-methane reforming reaction

$$CH_4 + H_2O \rightarrow CO + 3H_2 \qquad \Delta H_r = 206 \text{ kJ/mol}$$

Water-gas shift reaction

$$CO + H_2O \rightarrow CO_2 + H_2 \qquad \Delta H_r = -41 \text{ kJ/mol}$$

Here, ΔH_r is the standard reaction enthalpy for the specific reactions.

Gasification of coal and biomass can also be used to produce hydrogen as well as power, liquid fuels, and other chemicals [66,67]. Using coal gasification as an example, first, coal reacts with oxygen, steam or CO_2 under high temperatures and pressures, resulting in syngas as in the following equation [58]:

$$2CH_{0.8} + O_2 + H_2O \rightarrow CO + CO_2 + 1.8H_2 + \text{other species}$$

Next, solid impurities such as specks of dust are removed, followed by the WGS reaction to convert carbon monoxide to carbon dioxide while producing more hydrogen from steam [58]. To achieve a high purity hydrogen gas product, separation processes must be employed. Traditional gas separation methods include cryogenic distillation, pressure swing adsorption and membrane separation. Membranes such as polymeric membranes, metal-organic framework (MOF) membranes, zeolite membranes and mixed ionic and electronic conducting membranes have been developed with higher energy efficiency and intensified processes [68–70].

2.2.4. Thermochemical cycles for hydrogen production

Intermediate to high-temperature thermal energy can be supplied by next-generation nuclear reactors or renewables such as concentrated solar thermal plants. One promising thermochemical hydrogen production method is the thermochemical copper-chlorine (Cu-Cl) cycle, a complementary technology to the generation IV supercritical water reactor, the next generation of nuclear reactor set to be implemented between 2030 and 2050 [71]. The Cu-Cl cycle, with a maximum operating temperature of 530 °C [44], could use nuclear heat to produce hydrogen at a net efficiency as high as 40% (based on the lower heating value of H_2) [72]. The cycle could also potentially utilize heat from solar processes or industrial waste heat from steel or cement processes [73] to improve the economic viability.

Table 3 summarizes and compares the hydrogen production methods discussed.

Table 3. Comparison of various hydrogen production methods.

Parameter	SMR	Coal Gasification	Electrolysis	Thermochemical Cu-Cl cycle
Efficiency	74%–85% [74]	60%–75% [74]	46%–81% [46]	40% [72]
Hydrogen cost [US$/kg] [74,75]	2.27 (with CCS) 2.08 (no CCS) *2005 dollars*	1.63 (with CCS) 1.34 (no CCS) *2005 dollars*	5.78–23.27 *(solar PV, 2007 dollars)* 5.10–10.49 *(solar thermal, 2007 dollars)* 5.89–6.03 *(wind, 2005 dollars)* 2.17–2.63 *(nuclear, 2007 dollars)*	2.17 *2007 dollars* [76]
Lifecycle $CO_{2\text{-eq}}/H_2$ kg/kg] [77]	11.893	11.299	0.970 *(wind)* 2.412 *(solar)*	12.300[a]

[a] High $CO_{2\text{-eq}}$ emissions are mainly attributable to the carbon emissions from uranium processing.

2.3. Hydrogen storage

Hydrogen is an effective energy storage medium with high energy density per weight. Hydrogen can be stored as:

- compressed gas in high-pressure tubes or tanks;
- compressed gas in underground hydrogen storage (UHS);
- liquefied hydrogen in tanks (stored at −253 °C & 1 atm);
- solid by either absorbing or reacting with metal hybrids; and
- in chemical compounds such as liquid organic hydrogen carriers, or an alternative chemical form such as ammonia and methanol.

UHS requires specific geological conditions such as salt caverns, or depleted oil and gas wells [30], and it is similar to underground natural gas storage [78]. Salt caverns are considered the primary option for UHS, owing to their low permeability to gases [79]. There are also 71 salt caverns suitable for natural gas storage in the Sarnia and Windsor areas of southwestern Ontario, with a total capacity of approximately 85 million cubic meters [79]. There is a high level of feasibility in southern Ontario in Silurian bedded salts, depleted Ordovician natural gas reservoirs, saline aquifers in Cambrian sandstone, and hard rock caverns in argillaceous limestones [80].

To compare hydrogen storage technologies, important parameters are operating temperatures and pressures, hydrogen purity and delivery pressure (determined by the downstream processes), reversibility, charging/discharging rate, safety (such as operational safety and material toxicity), efficiency and costs. For example, the US Department of Energy (DOE) sets the 2020 technology targets for hydrogen storage as 1.5 kWh/kg system (4.5 wt.% hydrogen), 1.0 kwh/L system (0.030 kg hydrogen/L) and $10/kWh ($333/kg stored hydrogen capacity) [81].

2.4. Hydrogen utilization: fuel cells

In a fuel cell, electricity is produced directly from the chemical energy stored in the fuel without moving parts. Hydrogen can be used in fuel cells for electricity and/or heat generation. It can be directly fed to the fuel cell system or can be generated within the fuel cell system by reforming hydrogen-rich fuels such as methanol, ammonia, and hydrocarbons. Fuel cells provide alternative solutions in electrifying transportation; heavy vehicles are particularly well-suited to take advantage of the high energy density (per weight) of hydrogen and long-range per refuel. Fuel cells also offer a flexible option for CHP applications or stationary electrical power generation, especially in small-scale applications such as heat and power supply to a household [82].

Fuel cells consist of an electrolyte and two electrodes. Depending on the electrolyte, they can be categorized as [83]:

- **Polymer electrolyte membrane fuel cells (PEMFCs)**, also called proton exchange membrane fuel cells, deliver high power density and offer the advantages of low weight and volume compared with other fuel cells. They operate at temperatures around 80 °C which allows them to start quickly (less warm-up time) and favors transportation applications.
- **Direct methanol fuel cells (DMFCs)** are also PEMFCs, but they are powered by pure methanol, which is usually mixed with water and fed directly to the fuel cell anode [84]. Methanol is used as a hydrogen carrier and directly converted in DMFCs, eliminating the need for a methanol-reformer to generate hydrogen. Therefore, DMFCs require less space compared to conventional methanol fuel cells with reformers. DMFCs have lower power density than hydrogen-based PEMFCs [85], though they can be used to power smaller vehicles such as forklifts and tuggers [86].
- **Phosphoric acid fuel cells (PAFCs)** use liquid phosphoric acid (H_3PO_4) as an electrolyte. The efficiency is 37%–42% for electricity generation and as high as 85% for CHP [87]. PAFCs have been used for stationary power generators with output in the 100 kW to 400 kW range.
- **Molten carbonate fuel cells (MCFCs)** use molten carbonate salts such as lithium and potassium carbonates as electrolytes and are currently being developed for natural gas and coal-based power plants for electrical utility, industrial, and military applications. The cells operate at 600–650 °C, higher than DMFCs and PAFCs, but lower than SOFCs [88].
- **Solid oxide fuel cells (SOFCs)** use a hard, non-porous ceramic compound, such as YSZ as the electrolyte. SOFCs are around 60% efficient at converting hydrogen fuel to electricity, and they can work with hydrocarbon fuels such as CH_4 directly due to their high operating temperatures (i.e., 600–1200 °C) and good kinetics [89]. The applications include auxiliary power mainly due to its high efficiency and fuel flexibility.
- **Alkaline fuel cells (AFCs)** are one of the first fuel cell technologies developed and use an aqueous solution of potassium hydroxide or sodium hydroxide soaked in a matrix as an electrolyte. They operate at 23–70 °C, have fast kinetics and efficiencies above 60% [90].

Here we provide a general description of the PEMFC which is currently commercialized for FCEVs. The reactions in the PEMFC, shown in Figure 2, are the reverse of those in the PEM electrolyzer described previously. These fuel cells boast a high power density of 3.8–6.5 kWm^{-3} [52,91] and a low operating temperature of 80–120 °C but suffer from an expensive material cost for the platinum catalyst and severe sensitivity to CO contaminants in the H_2 inlet stream [52,91].

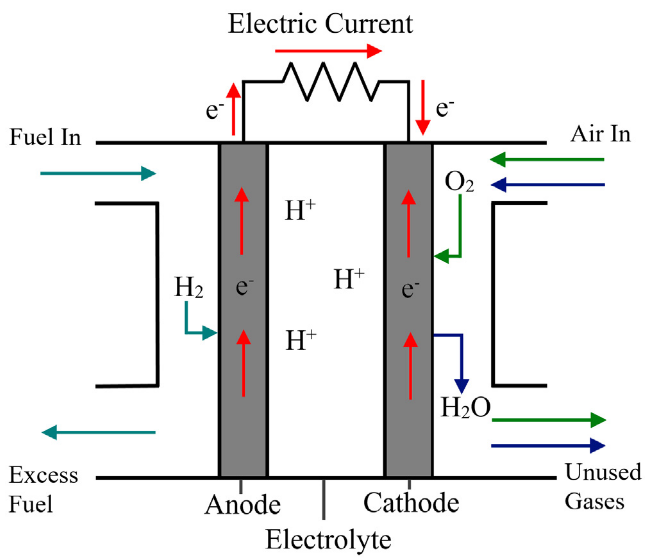

Figure 2. Schematic of a PEM fuel cell.

Figure 3 provides a more detailed diagram of the PEMFC, highlighting the individual components within each cell. The outermost layers on either side of a cell are electrically conductive bipolar plates, which are in contact with the positive electrode of one cell and the negative electrode of the adjacent cell. Channels run through either side of the bipolar plate, carrying in either hydrogen or oxygen reactant gas, and carrying out the water vapor by-product from the oxygen electrode. These plates are typically about 1.5 mm thick, with 0.5 mm deep channels [92].

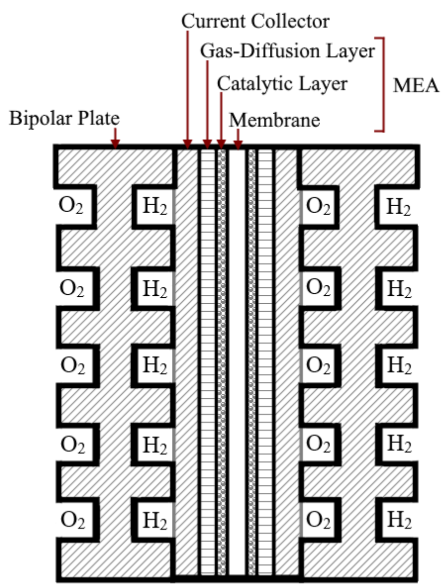

Figure 3. Diagram of PEM fuel cell components (Adapted from [92]).

Between the bipolar plates lies the membrane electrode assembly (MEA). The electrodes in a PEMFC are composed of a gas diffusion layer and a catalytically active layer. The diffusion layer is primarily made up of carbon black and polytetrafluoroethylene (PTFE) [92]. This porous layer evenly disperses reactant gas to the active layer, which is a boundary between the gas, the catalyst, and the membrane. The platinum-ruthenium catalyst is supported either by a carbon cloth, carbon paper, or simply the membrane. In the center of the MEA lies the polymer membrane, which is often made of Nafion™. With sufficient moisture within the cell, this material serves as a good conductor for H^+ ions, though it suffers from high material costs [92]. A typical MEA is about 0.5–0.6 mm thick, making the overall design of the PEM fuel cell compact [92].

3. Power and emissions in Ontario

3.1. Emissions and the health impacts

In Canada, the transportation (road, rail, air, and marine) and oil and gas sectors are the two largest GHG emitters (185.8 Mt and 193.2 Mt $CO_{2\text{-eq}}$, respectively in 2018), accounting for 52% of total emissions (shown in Figure 4*)* [93].

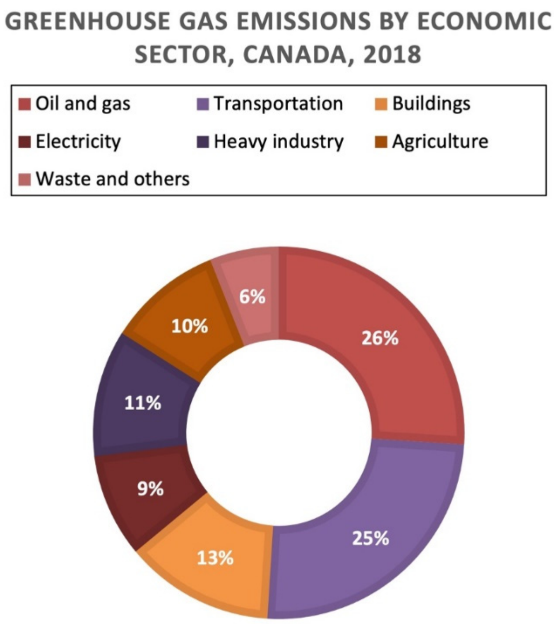

Figure 4. Emissions based on the sector in Canada, 2018 (Data from [93]).

On the other hand, pollutants from transportation have a direct impact on air quality and human health [94]. The seven key pollutants that were highlighted by Environment and Climate Change Canada are SO_x, NO_x, VOCs, NH_3, CO, PM 2.5, and black carbon.

NO_x and VOCs are sources of ground-level ozone, a major part of smog [95]. NO_x emissions were 1,768 kt in 2018 in Canada, the majority of which is from the transportation sector (41%), followed by the oil and gas sector, off-road vehicles and mobile equipment, electric utilities, and other uncategorized sources [96]. Black carbon is generated by the incomplete combustion of fossil fuels and biomass and is linked with both climate warming and adverse human health effects [96].

In Ontario, over 1700 deaths a year are attributed to poor urban air quality [97]. The Toronto Medical Officer of Health showed that in Toronto alone, 280 premature deaths and 1,090 hospitalizations each year are due to transportation pollution [97]. One of the most recognized health concerns is related to diesel exhaust particulates, or diesel particulate matter (DPM). Ideal combustion of diesel should only generate CO_2 and water vapor in the flue gas; however, the incomplete combustion of diesel fuel usually takes place, resulting in the emission of various gases such as CO, NO_x and hydrocarbons, and DPM [98].

To decrease both the GHG and pollutant emissions and the associated health impacts, the transportation sector should adopt zero-emission vehicles (ZEVs), including battery electric vehicles (BEVs), plug-in electric vehicles (PEVs), and FCEVs [24]. The possibility of introducing FCEVs to the market, especially for heavy-duty vehicle applications, will be discussed in sections 5.1 and 5.5.

3.2. Ontario energy demand

In 2017, Ontario's total energy demand was 3,012 petajoules (= 8.37×10^8 MWh). The industrial sector is the largest sector for energy demand at 37% of total demand, followed by transportation at 29%, residential at 18%, and commercial at 16% (Figure 5). Ontario's total energy demand is considered the 2nd largest in Canada, and the 8th largest on a per capita basis [99]. The costs of electricity generation facilities in Ontario have increased by 74% in the last decade, from $6.7 billion in 2004 to $11.8 billion in 2014, and may grow to $13.8 billion by 2022 [100].

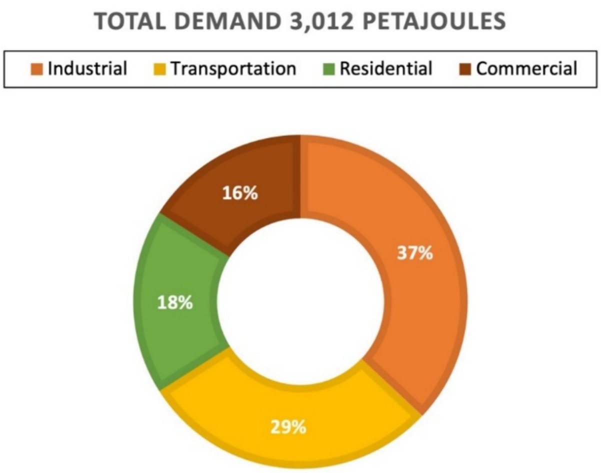

Figure 5. Ontario energy demand breakdown [99].

Ontario's climate objective, which aims to reduce emissions by 30 percent below 2005 levels by 2030, will raise the electricity demand. Various studies suggest that coupling adequate direct and indirect electrification of the economy with available emission reduction strategies can achieve the needed emissions reductions: 1.66 TWh of electricity is needed to reduce 1 Mt of GHG emissions through electrification [101]. To fully electrify Ontario's economy, an additional 280 TWh of electricity is required—equivalent to almost 6 times the electrical output from Bruce Power's (Bruce A and B combined) nuclear reactor sites [102]—almost tripling the demand on Ontario's grid.

The implementation of a smart grid and energy storage in Ontario is needed to enable further penetration of wind and solar (as this continues to be a policy objective) and support those assets already in place. Methods such as P2X (described briefly in section 2.2 and further in 5.6) can be used to facilitate the storage of energy or its use in other applications within Ontario.

Several renewable technologies, such as photovoltaic and wind turbines, are used in Ontario to supply power at peak demand and narrow the demand gap. However, the unit price of electricity production for these generators has become a limitation as they stand at much higher costs than natural gas or nuclear-based power plants. According to Maroufmashat and Fowler, the high cost of wind and solar, around 50 and 13 cents per kWh, respectively, is due to long-term contracts that were issued in Ontario as part of the Green Energy Act in 2008; meanwhile, electricity from nuclear and natural gas is around 5 and 11 cents per kWh, respectively [30,100].

3.3. Electricity curtailment

Rising numbers of power suppliers, falling market prices and decreasing electricity demand in Ontario have led to growing surplus power in the past decade [103]. When there is an excess of power generation during periods of low demand, power generation can either be exported to neighboring grids or curtailed, meaning generation is reduced from its nominal production capacity, or exported to neighboring grids. Curtailment can also occur when there is congestion in the transmission network [104]. Both VRE power, i.e., wind and solar power, and nuclear power are targets of curtailment in Ontario. To curtail wind power, wind turbine output is lowered by reducing the aerodynamic efficiency of the turbine [105]. In Ontario in 2019, 18% of wind and solar power generation was curtailed to manage surplus baseload generation, totaling 2,581 GWh [106]. In addition, nuclear generation in Ontario is subject to "nuclear maneuvers" a curtailment method for nuclear power. There were 292 maneuvers in 2019, accounting for 0.7% of total nuclear generation (604 GWh in total) [106]. Nearly 40% of Ontario's surplus electricity is curtailed, rather than exported, with curtailment reaching a total of 4.8 TWh in 2015 [107].

3.4. Electricity export and global adjustment

Electricity is also frequently exported out of Ontario. In 2019, 19,779 GWh of electricity was exported, while 6,613 GWh was imported [106]. Though they occur at unfavorable rates, exports allow electricity providers to earn revenue instead of wasting the surplus electricity generated. To cover the difference between the electricity export price and the production cost, Ontario electricity consumers pay more via the "global adjustment." Global adjustment now represents 90% of the earned revenue from exported power and it has been growing rapidly in recent years (around 20% per year increase) [103].

In Ontario, electricity customers have paid 6.3 billion dollars since 2005 to compensate for the cost of selling surplus power to the United States and other provinces. Between the years 2009 and 2014, Ontario on its own exported around 5.1 million megawatt-hours of energy, which cost around $3.1 billion more to produce than the revenue received for it [103]. Therefore, the global adjustment fee is added to the electricity price inside the province to make up for the difference, which can be as high as 5 times the average electricity production cost. For example, the average global adjustment fee for 2016 was 10 cents per kWh, while the average electricity production cost was 2 cents per kWh [30]. Global adjustment fees have increased from $650 million in 2006 to $7.03 billion in 2014 [108].

The global adjustment fee paid by consumers is derived based on two factors. The first factor is the difference between the price that the Independent Electricity System Operator (IESO) has promised to pay the electricity producers, known as the contracted rate, and the fair market value of this electricity, known as the hourly Ontario energy price. The second factor is that the curtailed energy is paid for by citizens in the form of the global adjustment rate.

The implementation of smart grids and implementation of energy storage can help suppress the increase in the global adjustment rate on Ontarians' energy bills by enabling further penetration of renewable energy through storage and utilization of off-peak clean energy in Ontario.

4. Ontario's transition to a hydrogen economy

To address the issues faced by Ontario as discussed in the preceding section and achieve an overarching goal of zero emissions by 2050, the authors worked with members of the Hydrogen Business Council to construct a set of recommendations for the province. The input was obtained from members via personal communications following a conference organized by the Hydrogen Business Council on November 19 and 20, 2020, [M. Althaus; P. Carr; B. Chittick; L. Dolenc; M. Fairlie; Professor K. Gabriel; R. Harvey; M. Kirby; R. Lounsbury; A. Maroufmashat; S. McDermott; Professor P. O'Brien; A. Potts; A. Ramesh; I. Vera-Perez].

The Council prioritizes the following recommendations for near-term action, which are required for building the long-term progress necessary to reach the 2050 zero-emissions target. In addition to incorporating personal communications from industry experts mentioned above, these policy recommendations are adapted from the Green Ribbon Panel's 2020 report [101], which the council supports. The recommendations are listed below, while the next section will summarize the priority actions. HBC members and conference attendees who have made particularly significant contributions to the recommendations are noted.

4.1. Ontario should provide enabling infrastructure and temporary incentives to spur the deployment of hydrogen in Ontario's heavy transportation sector

Heavy transport travels long distances in Ontario and hydrogen is the only practical fueling technology that can greatly reduce or eliminate emissions for trucks and ships that must travel moderately to long distances. Also, while conventional electrification can be utilized for rail transport, the required overhead wires are very expensive for the long distances and there are relatively low utilization factors (revenue per mile) of Ontario railways. Hydrogen will be a more economical technology for rail decarbonization in Ontario [R. Lounsbury].

4.2. An integrated pan-Canadian hydrogen strategy should further deploy hydrogen as an energy vector for transportation and industry applications and should leverage the country's clean electricity assets

Transit is uniquely positioned to drive consumption of hydrogen at scale, to support the economies of fuel production, drive large-scale GHG reduction, and subsequent adoption of the technology. There are currently no hydrogen fuel cell electric buses in operation in Canada, although the buses and the fuel cell technology are developed in Canada, by Canadian companies. Additionally, Ontario is uniquely positioned with a cluster of medium and large-scale transit agencies, which would support the establishment of an economic and energy-efficient fuel distribution network. The province can also leverage its status as a hub for automotive manufacturing to establish itself as a key manufacturer of hydrogen fuel cell electric vehicles and the center of a "Hydrogen Innovation Supercluster" [M. Althaus]. Ontario could be the Canadian leader in adopting this commercially proven technology that will facilitate the growth of the hydrogen economy. Developing a strategy from the federal level should offer support funding for shovel-ready projects, in transit, to demonstrate the feasibility of the technology for Ontarians and establish Ontario as the leader in Canada in this innovative technology.

4.3. Price the use of surplus electricity generating capacity for hydrogen production at the marginal cost of generation and transmission

While this price structure will be lower than for other loads such as large industrial users, hydrogen is not a load, but rather a component in the energy delivery system—an energy carrier, just like the wires for Hydro One's distribution system. As such, this policy increases the efficiency of energy delivery, benefiting existing grid-connected loads through storing and feeding power back during peak demand, and benefiting non-grid-connected loads such as remote communities and transportation that would use the hydrogen locally to produce power [R. Lounsbury].

4.4. Ontario's hydrogen policies should be coordinated with its electricity policies to maximize the efficiency of decarbonizing the Ontario economy

Electricity and hydrogen are both energy carriers. The efficiency and productivity of Ontario's economy will be maximized by using each of these carriers where they provide their respective greatest impact in terms of low cost, reliability, and customer convenience [R. Lounsbury]. Electrification of transportation as an early mechanism to reduce CO_2 emissions means that both the utilization of electricity in batteries and the electrolytic production of hydrogen have key roles to play.

4.5. Ontario's skills and education policies should include programs to train new workers to support Ontario's hydrogen industries

Hydrogen industries can be a significant contributor to Ontario's future economy and the availability of skilled workers is essential to support the future growth of these industries [R. Lounsbury]. Thousands of well-paying jobs can be created here in Ontario if this emergent hydrogen industry is developed and supported as it should be in this decade.

4.6. The federal government should create a next-generation energy innovation fund that can be used to fund hydrogen demonstration projects

The federal government should take the lead in funding the demonstrations of new CO_2 reduction technologies that have applications across multiple provinces [R. Lounsbury]. This is consistent with the Federal government's role in CO_2 emission reduction policy and can avoid duplications of efforts in multiple provinces. The government can facilitate access to capital and de-risk investments through the funding of these projects and accelerated government procurement [M. Althaus].

4.7. Government income from carbon pricing policies should be used to invest in hydrogen infrastructure

This will create positive feedback that will reduce CO_2 emissions faster and accelerate the growth of Ontario hydrogen industries [R. Lounsbury].

4.8. Provide municipalities and regional transit operator Metrolinx with incentives and direction to use hydrogen for rail and long-distance bus urban mass transit

Mass transit is amenable to early hydrogen adoption because of its potential use of centralized refueling, which will limit start-up costs. It also resides in provincial jurisdiction where action can be implemented directly [R. Lounsbury].

4.9. Provide funding for projects to replace diesel generation or power lines for remote communities with local generation using a mixture of renewable (wind, solar, hydro) power with hydrogen storage and generation

Remote mines and First Nation communities will need non-carbon emitting power sources in the future. The future prosperity of these industries and communities needs to demonstrate reliable non-CO_2 emitting power supply technologies [R. Lounsbury].

4.10. Provide support for emergent pre-commercial hydrogen technologies that have great promise to further reduce CO_2 emissions

Most, if not all the previous recommendations would make use of already commercial (or very close to commercial) hydrogen technologies. However, there may be emergent hydrogen technologies that have the potential to complement or even surpass the CO_2 reductions that would ensue from our suggested actions. These would include (but are not limited to):

1. production of "clean" or "green" ammonia and fertilizer for industry and agriculture,
2. generation of hydrogen from various biological sources or waste streams,
3. materials development to increase the potential proportion of hydrogen content in natural gas,
4. bulk hydrogen storage in geological media for a multiplicity of end uses,
5. hydrogen production using high-temperature thermochemical processes, and,
6. use of hydrogen as a fuel and buoyant gas for use in advanced autonomous airships that would deliver freight to remote northern communities with no road access.

All these technologies are already under development in Ontario and Canada.

4.11. Establish an "Ontario Hydrogen Strategy Advisory Council"

Such a group would work with the provincial government to guide the implementation of hydrogen technologies. The council would consist of key hydrogen experts, producers, end-users (individual and industrial), and project developers, as well as key representatives from the environmental community and citizen groups, including Indigenous groups (e.g., through Chiefs of Ontario) [M. Althaus].

4.12. Remove regulatory and market barriers to the deployment of hydrogen.

Under the direction of the Ministry of Energy, the IESO and Ontario Energy Board should investigate which regulatory and market barriers presently exist that restrict investments in and deployment of hydrogen as a clean fuel. The province should then work to remove such barriers promptly and thereby kick start a vibrant hydrogen economy in Ontario that will become self-sustaining within 5 years [M. Althaus].

5. Priority actions

In this section, we prioritize nine recommendations (summarized in Table 4) for short-, mid- and long-term strategies in Ontario, setting the stage for long-term progress to reach the zero-emission target by 2050.

Table 4. Short-term, mid-term, and long-term strategies for hydrogen economy transition in Ontario.

Short-term initiatives	Mid-term initiative	Long-term initiatives
5.1. Hydrogen refueling infrastructure on the 401 and 400 highway corridors	5.5. Conversion of Class 8 vehicles	5.6. Power-to-Gas
5.2. Electrolysis for the industrial sector		5.7. Hydrogen Enriched Natural Gas for the Industrial Sector
5.3. Rail infrastructure and hybrid locomotives		5.8. Hydrogen conversion to products
5.4. Hydrogen infrastructure for energy hubs and microgrids		5.9. Seasonal and underground storage of hydrogen

5.1. Hydrogen refueling infrastructure on Highway 401 and 400 corridors (Short-Term Action)

As a short-term action, hydrogen technology that is currently commercially available can be implemented along Ontario's Highway 401, a portion of the North American Superhighway Corridor (NASCO). The highway sees a large amount of heavy-duty truck traffic every day. Figure 6 shows the distribution of total traffic and truck traffic along Highway 401. As discussed in section 3.3, emissions from diesel trucks have negative impacts on public health. Thus, a partial conversion of the current diesel fleet to hydrogen fuel cell vehicles will yield significant environmental and health benefits. Trucks are a good target for fuel cell technology, thanks to the long-range granted by hydrogen's high gravimetric energy density and the quick refueling potential [23,109]. In addition, due to the consistent and predictable routes taken by these vehicles, only a small number of intelligently placed refueling stations are required to initiate their transition into FCEVs.

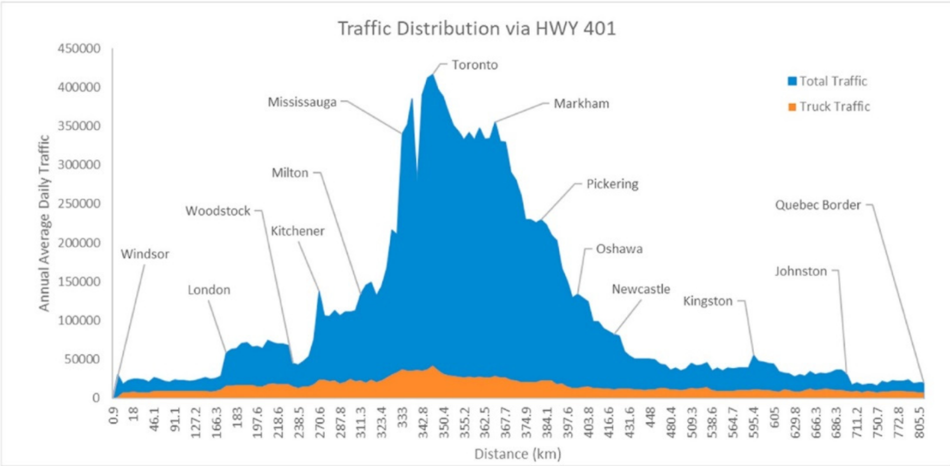

Figure 6. Total traffic and truck traffic distribution along Highway 401 (Reprinted from [23] with permission of Elsevier).[1]

One challenge for the transition of diesel trucks to FCEVs is the "chicken and egg" dilemma regarding the development of hydrogen refueling infrastructure: refueling infrastructure must be in place for widespread adoption of FCEVs to occur, but there is a reluctance to invest in refueling infrastructure without a large-scale adoption of FCEVs to fuel [23,110]. To cope with this dilemma, Shamsi et al. proposed a cost-optimized layout of refueling stations and electrolytic production sites along Highway 401 for different levels of hydrogen market penetration (i.e., the percentage of Class 7–10 diesel trucks using hydrogen fuel cells); existing ONroute rest stops were proposed as refueling/production sites, taking advantage of existing infrastructure [23]. A small-scale, initial investment into the infrastructure, exemplified by Scenario 1 (Figure 7) which assumes a 0.1% market penetration of FCEVs, will resolve this dilemma and prompt further investment into the transition. Results show that one hydrogen production plant (1000-kg H_2/day), alongside six refueling stations, can meet the refueling demand in Scenario 1 [23]. A long-term goal of 1% FCEV market share scenario was also optimized in the study (Scenario 5, Figure 7) with more hydrogen production plants (i.e., five 1500-kg H_2/day and one 1000-kg H_2/day plants) and refueling stations (i.e., sixteen 500-kg H_2/day and one 180-kg H_2/day stations) along the route [23]. Further study on the expansion of hydrogen refueling stations along the Highway 400 corridor is required to optimize the refueling for FCEVs to travel toward northern communities and the Trans-Canada Highway.

With the expansion of refueling infrastructure, the transition of other transportation sectors such as light passenger vehicles and public transit toward FCEVs will be encouraged. For example, the Canadian Urban Transit Research & Innovation Consortium (CUTRIC) seeks to demonstrate the pan-Canadian Hydrogen Fuel Cell Electric Bus Demonstration and Integration Trial, which involves the launch and analysis of 30 fuel cell-powered buses [111].

Increased adoption of FCEVs will yield a variety of benefits in carbon reduction and public health. In Ontario, the transportation sector is responsible for 35% of GHG emissions [99] and other

[1] *Reprinted from Journal of Cleaner Production, 289, Hamidreza Shamsi, Manh-Kien Tran, Shaghayegh Akbarpour, Azadeh Maroufmashat, Michael Fowler, Macro-Level optimization of hydrogen infrastructure and supply chain for zero-emission vehicles on a Canadian corridor, 125163, Copyright (2021), with permission from Elsevier* [23].

emissions, such as DPM. With a 1% market penetration of FCEVs in the trucks on Highway 401, the annual monetary benefit is estimated to be $1,450,000 due to the health benefits associated with removing diesel vehicles from the road [23].

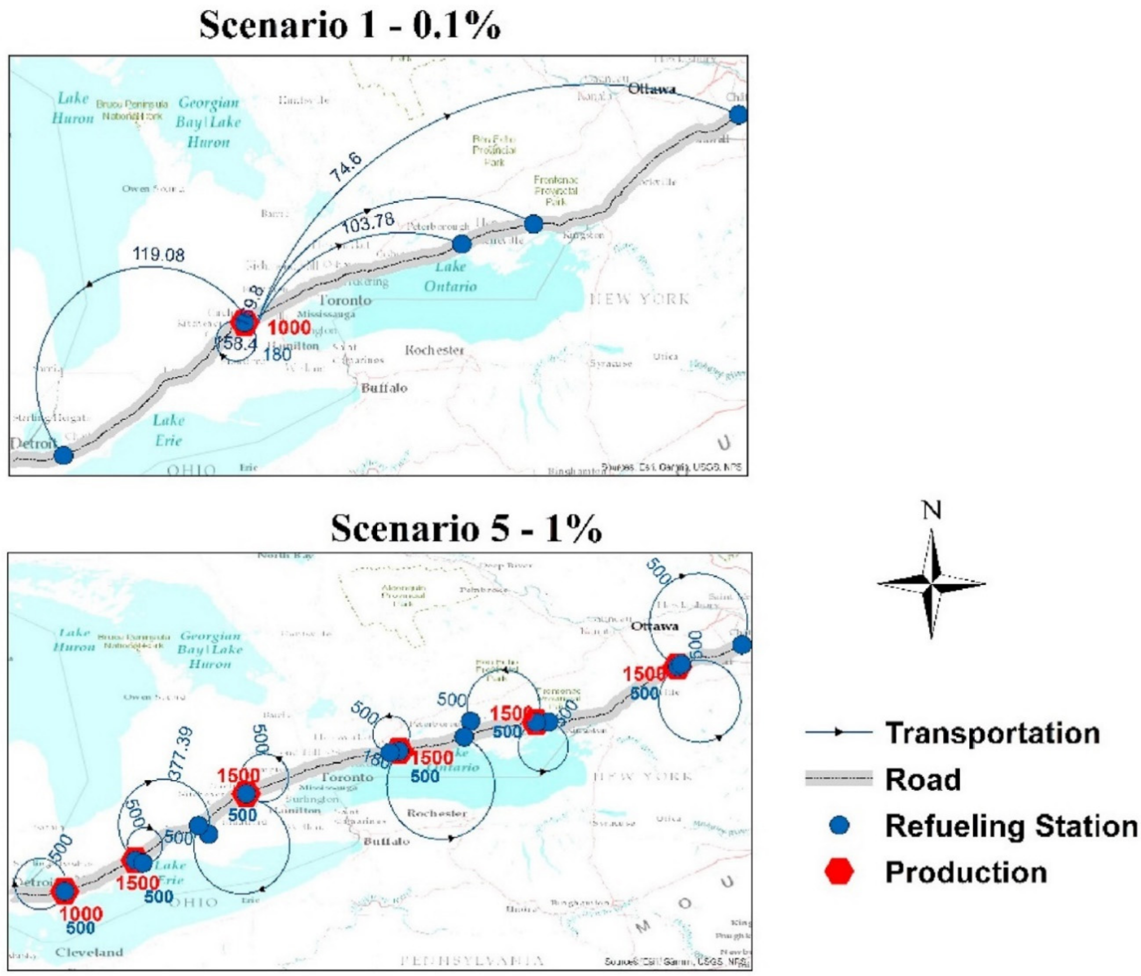

Figure 7. Proposed locations of hydrogen production and refueling stations along the 401 (Adapted from [23] with permission of Elsevier).[2]

5.2. Electrolysis for the industrial sector (Short-Term Action)

Oil refining processes account for 20% of global hydrogen consumption [112,113], most of which comes from fossil fuel-based processes such as SMR, resulting in significant carbon emissions. For example, 1 kg of hydrogen produced by SMR leads to around 11.893 kg of $CO_{2,e}$ emission, if no carbon capture process is in place [77]. Incorporating electrolysis into oil refining processes has the potential to meet the industrial hydrogen demand with less carbon emission, especially within Ontario, given its

[2] *Reprinted from Journal of Cleaner Production, 289, Hamidreza Shamsi, Manh-Kien Tran, Shaghayegh Akbarpour, Azadeh Maroufmashat, Michael Fowler, Macro-Level optimization of hydrogen infrastructure and supply chain for zero-emission vehicles on a Canadian corridor, 125163, Copyright (2021), with permission from Elsevier* [23].

largely carbon-free power generation. The surplus electricity in Ontario was found to be sufficient to replace all the provincial SMR hydrogen production using electrolysis for the years 2014–2016 [112].

Al-Subaie et al. presented a more in-depth examination of electrolytic hydrogen production for a simulated refinery with a demand of 25 million standard cubic feet per day (MMscfd) [56]. A complete transition from SMR to electrolysis will require 130 PEM electrolyzer units at the scale of 1 MW/unit [56]. The environmental benefits of this transition were also quantified, with an annual lifecycle CO_2 emission reduction from 235.1×10^3 tons $CO_{2,e}$ to 71.1×10^3 tons—equivalent to removing 34,893 passenger vehicles from the road [56].

5.3. Rail infrastructure and hybrid locomotives (Short-Term Action)

Locomotives can use various propulsion technology including diesel engines, natural gas turbines, hydrogen fuel cell stacks, batteries, and electric grid-connected continuous power systems. A hydrogen fuel cell/battery hybrid locomotive requires minimal infrastructure changes compared to an electric grid-connected locomotive. The hybrid locomotive can also take advantage of the centralized refueling stations due to the fixed routes of the trains.

A hybrid fuel cell/battery powertrain was designed for the Union Pearson Express (UPE) in Toronto, consisting of a fuel cell, battery and hydrogen storage systems; the hydrogen consumption is estimated to be 275 kg/day to meet the daily power and energy demand of the current UPE route [114]. Metrolinx also conducted a feasibility study on using hydrogen fuel cells to power electric trains for the GO rail service in Ontario and showed that by using hydrogen trains, the rail service can be partially electrified earlier than 2025 and entirely electrified in the following years [115].

5.4. Hydrogen infrastructure for energy hubs and microgrids (Short-Term Action)

In a microgrid, hydrogen can be produced electrolytically from distributed renewable sources, such as wind turbines or solar PV arrays installed in the local area, as shown in Figure 8. Mukherjee et al. examines the potential implementation of one such microgrid in Cornwall, ON, encompassing a fresh food distribution center, a residential complex, and a hydrogen refueling station [116]. The refueling station serves both the forklifts at the distribution center and the light-duty FCEVs in the residential complex. The overall system is composed of a PV solar array, eight wind turbines, three electrolyzers, and four fuel cells. The proposed design is capable of providing 10% of the baseload energy demand for the area, as well as serving as a backup power source in the event of a grid outage for up to two days [116]. Microgrids can also serve to provide remote communities with a more secure energy supply and reduce their reliance on fossil fuels, as demonstrated by the Gull Bay First Nation microgrid project [117]. Further endeavors are needed to bring hydrogen capabilities to remote communities to enhance their microgrids.

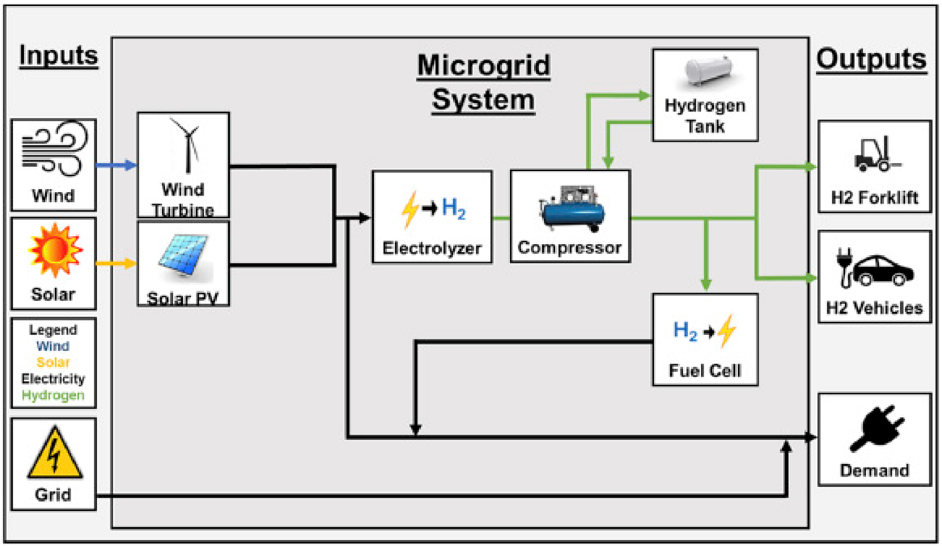

Figure 8. Schematic of hydrogen as an energy vector in a microgrid system (Reprinted from [116] with permission from Elsevier).[3]

Energy hubs can also take advantage of the hydrogen energy vector. Maroufmashat et al. examines a case of four energy hubs within a local area (shown in Figure 9): locations that receive electricity and natural gas from the grid and transfer energy between one another as electricity, heat, or hydrogen [118]. The study finds that free transmission of energy between the hubs results in an energy cost reduction of 1.8% and a reduction in natural gas consumption of 6% when compared to cases with no hub interaction [118]. Distributed hydrogen production within the local hub network is shown to yield a reduction in CO_2 emissions of 2% and a reduction in natural gas consumption of 15% [118]. The levelized cost of hydrogen produced is estimated to be \$6.74/kg-H_2, taking advantage of the low-cost electricity during the off-peak hours [118].

HENG can also play a valuable role in energy hubs and microgrids. Using HENG in natural gas applications such as heating and micro-CHP systems would reduce carbon emissions while achieving energy efficiencies of 63% and 56%, respectively [30].

[3] *Reprinted from International Journal of Hydrogen Energy, 42, Ushnik Mukherjee, Azadeh Maroufmashat, Jonathan Ranisau, Mohammed Barbouti, Aaron Trainor, Nidhi Juthani, et al., Techno-economic, environmental, and safety assessment of hydrogen powered community microgrids; case study in Canada, 14333-14349, Copyright (2017), with permission from Elsevier* [116].

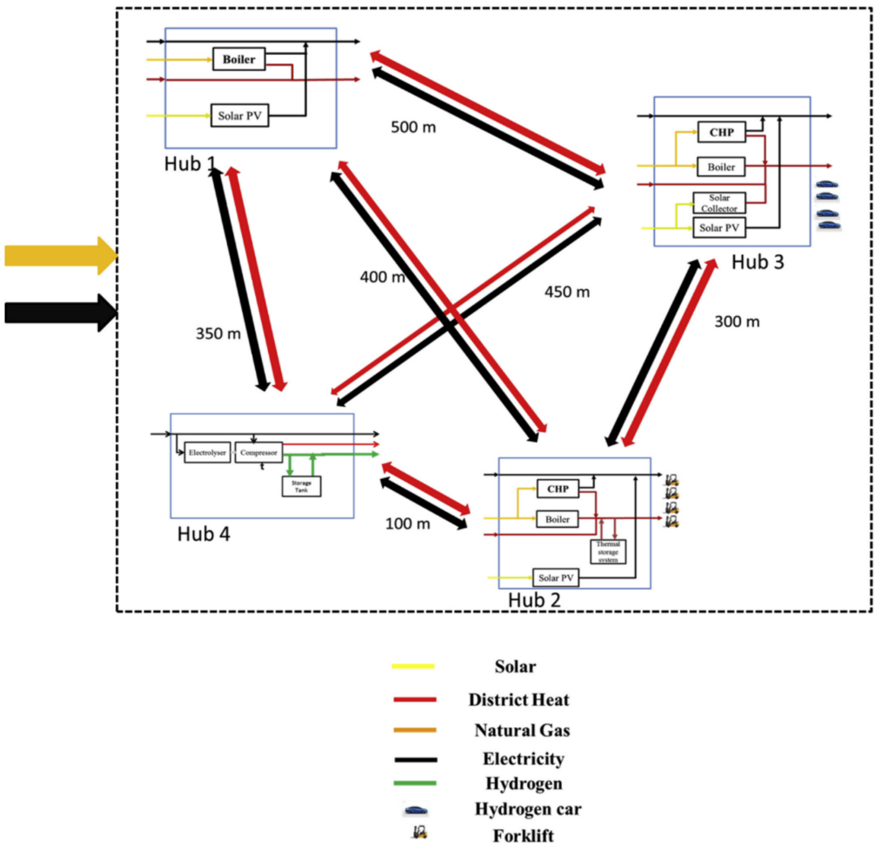

Figure 9. Diagram of energy interactions between hypothetical energy hubs (Adapted from [118] with permission from Elsevier)[4] [102].

5.5. Conversion of Class 8 vehicles (Mid-Term Action)

Class 8 vehicles are the core of the trucking sector in Canada. Ontario houses around half of Canada's trucking jobs, more than 50% of which are for exports of automobiles, machinery and electrical, and manufactured goods (shown in Figure 10) [101,119]. The trucking sector is a necessary catalyst for the economy, and efficient trucking is necessary for the development of other sectors, especially goods transportation. According to Statistics Canada, Canada's exports via trucking reached $234 billion in 2019 [101]. However, the trucking sector is a major source of carbon emissions and air pollutants. Across Canada, on-road freight produced 60 Mt of GHG emissions in 2017, accounting for 34% of all GHG emissions from transportation, in addition to being one of the major NO_x emitters [57]. The potential hydrogen transition in the trucking sector by converting existing vehicles into hydrogen-powered FCEVs can help Ontario reduce carbon and pollutant emissions from its trucking fleet.

Trucks powered by fuel cells have lower weight penalties and better cold-temperature performance compared to battery-powered vehicles. Refueling infrastructure can be built at gas

[4] *Reprinted from International Journal of Hydrogen Energy, 41, Azadeh Maroufmashat, Michael Fowler , Sourena Sattari Khavas, Ali Elkamel, Ramin Roshandel, Amir Hajimiragha, Mixed integer linear programing based approach for optimal planning and operation of a smart urban energy network to support the hydrogen economy, 7700-7716, Copyright (2016), with permission from Elsevier* [118].

stations to generate hydrogen on-site from water electrolysis, as outlined in section 5.1. It is estimated that 5.5 GW of electrolyzer capacity is needed by Ontario to convert 80% of the heavy trucks to FCEVs to sustain a hydrogen economy [101]. This priority action is directly related to the hydrogen refueling infrastructure for the 401 and 400 corridors in section 5.1, as a significant public investment and private sector buy-in would be needed to establish a hydrogen corridor along Highway 401, thereby incentivizing the conversion of vehicles into FCEVs.

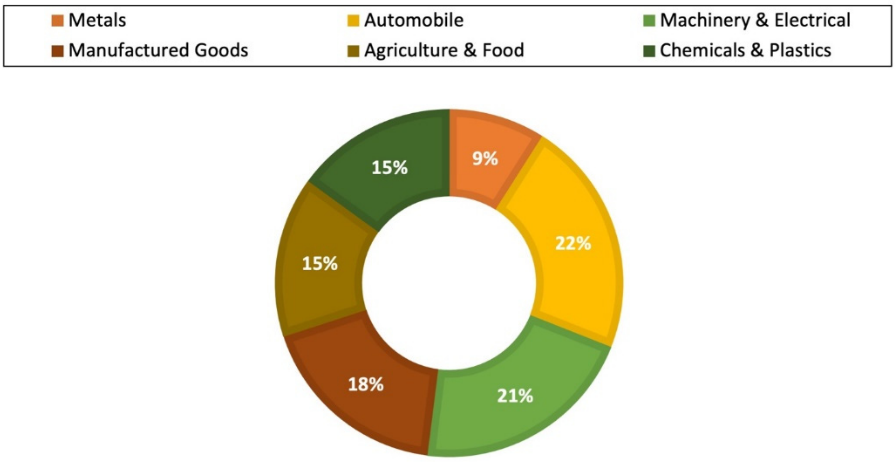

Figure 10. Ontario’s exports through trucking [101].

5.6. Power-to-Gas (Long-Term Action)

The implementation of P2G in the long term can decrease the province’s carbon intensity by using HENG. P2G limits the infrastructure costs by taking advantage of Ontario's existing natural gas systems to distribute hydrogen and allows for a gradual increase in the market uptake of hydrogen and the expansion of hydrogen infrastructure [120].

The adoption of P2G technology can occur via the 9 different pathways discussed in section 2.2, among which the pathway of Power to Natural Gas End User can start immediately to achieve efficient utilization of surplus nuclear and intermittent wind energy. Incrementally, hydrogen will penetrate the natural gas markets over the next 50 to 100 years, alongside the economic development towards a zero-carbon economy [30].

5.7. Hydrogen Enriched Natural Gas for the Industrial Sector (Long-Term Action)

Among all the P2G pathways discussed in section 2.2, blending the hydrogen from water electrolysis with natural gas provides an early source of demand with very low investment costs. The resulting gas mixture is called HENG. Pipelines can be used to distribute the HENG to industrial end-users for various applications, e.g., combined cycles to generate low-carbon electricity, combustion processes to decarbonize industrial heat [121], and high-purity hydrogen for ammonia production, steel production and oil refining (through the process of hydrogen separation from methane) [29]. The carbon intensity of the HENG depends on the hydrogen concentration and the hydrogen source. The hydrogen concentration in HENG can be increased incrementally as hydrogen production capacity increases. Blending hydrogen with natural gas at concentrations of less than 5–15% by volume is viable without significantly increasing risks associated with end-use, overall public safety, or integrity of the pipeline system [28]. However, the appropriate blend concentration varies depending on the pipeline network systems and natural gas compositions [28]. A HENG project is being constructed by Enbridge Gas and Cummins Inc., blending the electrolytic hydrogen produced in a P2G plant in Markham, Ontario into the Enbridge Gas network to serve about 3,600 customers in the region [122].

In the longer term, blending hydrogen into the natural gas distribution system can be an economical means for hydrogen distribution. In this concept, hydrogen is injected upstream at electrolysis centers using zero-carbon energy and then directed downstream close to the point of industrial end-use with separation and purification processes (e.g., membranes and PSA) depending on their hydrogen purity requirement. This can greatly reduce the cost associated with building dedicated hydrogen transportation pipelines or infrastructure [30].

5.8. Hydrogen conversion to products (Long-Term Action)

Hydrogen can be used as a feedstock in several products, including ammonia, methanol, and a variety of other hydrocarbons. Hydrogen is also used for industrial applications such as metal production [123–125], food processing in the hydrogenation of oils, flat glass production, and semiconductor manufacturing [123,124], though these applications represent a much smaller share of global hydrogen usage. Replacing fossil fuel-based hydrogen production with low-carbon production presents a tremendous opportunity for the reduction of global carbon emissions in these industrial applications.

Ammonia production is presently responsible for 53% of global hydrogen consumption [112,113]. Ammonia is primarily used in the production of fertilizers but is also currently being studied as an energy storage medium, an energy vector [126], a fuel for power generation [127], and a fuel for locomotives [128]. Ikäheimo et al. examines ammonia production in Northern Europe and finds that a transition to electrolysis for hydrogen production for ammonia has little effect on system cost while yielding considerable de-carbonization benefits [126].

Methanol is an important chemical solvent and feedstock. It can be used directly as a fuel in a combustion engine or fuel cell or converted to dimethyl ether (DME), which works as a fuel or can be further converted to other chemical products, such as ethylene, propylene, gasoline, acetic acid, and dimethyl sulphate [129]. Currently, methanol is typically produced from hydrocarbon-derived syngas (H_2 + CO). Using renewable hydrogen and captured CO_2 to produce methanol can reduce the carbon intensity in methanol and reuse CO_2. This can be achieved through the co-electrolysis of water and CO_2 using solid oxide electrolysis technology, or simply through traditional electrolysis means [8].

Hydrogen can also be used as a feedstock in the Fischer-Tropsch (F-T) process to produce hydrocarbons such as synthetic gasoline and diesel [130]. One application is to use green hydrogen and captured carbon to produce synthetic fuels. A case study on Southwestern Ontario by Ranisau et al. proposed the use of petroleum coke – a waste product – as a carbon source alongside electrolytic hydrogen as feedstocks for a polygeneration system to produce gasoline, kerosene, and diesel via an F-T process [9]. This polygeneration process was found to be profitable, with the optimal configuration sourcing 82% of its hydrogen from electrolysis [9]. Similar to low carbon methanol production, a low-carbon F-T process can utilize the syngas from co-electrolysis of water and CO_2 using green electricity [131].

5.9. Seasonal and underground storage of hydrogen (Long-Term Action)

Long-duration hydrogen energy storage applications provide medium and long-term load shifting on the grid. Compared with surface facilities, underground hydrogen storage has lower construction costs, higher security from fire and attacks, and better space management [78]. Hydrogen generation facilities can be located near electricity generators, e.g., wind farms, with daily battery energy storage acting as a complementary energy storage technology for long-term hydrogen storage. As mentioned in section 2.2.2, a 2.5 MW hydrogen energy storage project in the Markham Energy Storage Facility in Ontario was commissioned in May 2018 [50]. It is North America's first multi-megawatt P2G hydrogen storage facility, and the facility provides regulation services under contract to the IESO, correcting for short-term changes in electricity use and compensating for real-time energy supply and demand imbalances.

The importance and benefits of long-term hydrogen energy storage in the upcoming economic transfer into the hydrogen economy have been highlighted in the literature. Peng et al. [132] compared the economic and environmental benefits of five different scenarios for underground hydrogen and natural gas storage and found that the most desirable scenario is injecting hydrogen and natural gas together as HENG into reservoirs and distributing HENG to off-site users. Maroufmashat and Fowler [24] analyzed the impacts of storage technologies on the cost of hydrogen or renewable natural gas and found that the levelized cost of hydrogen with seasonal storage is around 27–35 cents per kWh, which can drop to as low as 9.3 cents per kWh in the long term. The seasonal storage of hydrogen increases the levelized cost of hydrogen by around 10 cents per kWh compared with the scenario without seasonal storage, but the gap drops to 5–6 cents per kWh in the long term [24].

6. Conclusions

In the implementation of a hydrogen economy, zero-carbon hydrogen is produced and utilized on a widespread basis as a key energy vector that can be distributed and used for all essential energy needs, and store energy for extended periods. Various countries and regions are seeking solutions to balance supply with demand, or economic costs with environmental and social costs in the diverse, evolving energy system. Here, Ontario, Canada is used as a case study to identify several general hydrogen technology applications that are suitable for deployment and provide an explanatory background for each of them. These applications are chosen based on their associated carbon intensity, their fit in the provincial and national energy sector contexts, and the promise they show for bettering the energy systems in performance and a neutral carbon footprint.

Given that 2050 marks an overarching zero-emissions goal for Ontario, appropriate policies must be established shortly to guide the continuing progress moving ahead. This report provided 12 policy priorities for today to best lead the province's zero-emission progress into tomorrow. Finally, the report offers nine priority areas for government, industry, and other stakeholders to strategically deploy hydrogen technology in the province.

This paper's recommendations for policy and technology deployment aim to ultimately shape a made-in-Ontario hydrogen economy that reliably fulfills the province's energy needs and helps fight climate change. Internationally beyond Ontario, other regions and countries are also seeing the benefits of committing to the hydrogen economy transition. If effective hydrogen strategies are planned and implemented to work together with each regions' distinct strengths, a global hydrogen movement will thrive.

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Conflict of interest

Part of this paper is prepared for the Hydrogen Business Council of Canada. BB and RS are employed by the Hydrogen Business Council of Canada.

Author contributions

FE researched and wrote sections 1.2, 2.2.1, 2.3, 2.4 (partial), 3, 3.2, 3.3, 4 (partial), 5.3, 5.5, 5.6, 5.7, 5.9, and 6 (partial).
AD researched and wrote sections 1.3, 2.2.4, 2.4 (partial), 3.1, 4 (partial), 5.1, 5.2, 5.4, and 5.8.
BB researched and wrote sections 1.1, 2.1 (partial), 2.2.3, 4 (partial), and 6 (partial).
RS guided the policy recommendations in Section 4, in addition to organizing the conference at which feedback was obtained.
MF supervised the project and provided critical revision of the article.
XYW supervised the project, provided critical revision of the article and provided final approval of the version to be published.

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