CALGARY HYDROGEN OPPORTUNITY ASSESSMENT

CALGARY REGION Hydrogen Hub

The Transition Accelerator

L'Accélérateur de transition

Calgary Hydrogen Opportunity Assessment

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About the Transition Accelerator

Our Objective

The Transition Accelerator is putting Canada on a path to a strong, competitive economy in a world driving to reduce emissions to carbon neutrality.

Our Work

The Transition Accelerator drives projects, partnerships, and strategies to ensure Canada is competitive in a carbon-neutral world. We're harnessing the global shift towards clean growth to secure permanent jobs, abundant energy, and strong regional economies across the country.

We work with 300+ partner organizations to build out pathways to a prosperous low-carbon economy and avoid costly dead-ends along the way. By connecting systems-level thinking with real-world analysis, we're enabling a more affordable, competitive, and resilient future for all Canadians.

Our Unique Approach

- We **understand the current system in practice**, not just in theory, identifying barriers to innovation and opportunities for change.
- We bring together industry, labour, government, Indigenous and other leaders to **define shared visions of success** for their sectors, regions, or communities.
- We mobilize partners to **develop pathways to get there**, understanding and refining them to ensure they are credible, capable, and compelling.
- We turn ideas into action and **take steps down those pathways** by launching projects and partnerships to build a more competitive future.

For more information or interview opportunities, please contact communications@transitionaccelerator.ca.

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Abbreviations	Term
ABSA	Alberta Boilers Safety Association
AESO	Alberta Electric System Operator
ACTL	Alberta Carbon Trunk Line
ATCO	ATCO Ltd.
ATR	Autothermal Reforming
AZEHT	Alberta Zero Emission Hydrogen Transit
AZETEC	Alberta Zero Emission Trucking Electrification Collaboration
BEB	Battery Electric Bus
BEV	Battery Electric Vehicle
CCS	Carbon Capture and Storage
CED	Calgary Economic Development
CH_4	Methane
CI	Carbon Intensity
CNG	Compressed Natural Gas
CO_2	Carbon Dioxide
CPKC	Canadian Pacific Kansas City
CSA	CSA Group Testing & Certification Inc. (formerly the Canadian Standards Association; CSA)
DOE	Department of Energy
EIA	Energy Information Administration
FCEV	Fuel Cell Electric Vehicle
GHG	Greenhouse Gas
GJ	Gigajoule
H_2	Hydrogen
H_2ICE	Hydrogen Internal Combustion Engine
H_2O	Water
HD2F	Hydrogen Diesel Dual Fuel
HDV	Heavy Duty Vehicle
HHV	Higher Heating Value
HTEC	HTEC Hydrogen Technology & Energy Corporation
ICE	Internal Combustion Engine
IEA	International Energy Agency

Abbreviations	Term
kW	Kilowatt
LCA	Life Cycle Assessment
LDV	Light Duty Vehicle
LHV	Lower Heating Value
LNG	Liquefied Natural Gas
LOHC	Liquid Organic Hydrogen Carrier
LRT	Light Rail Transit
MDV	Medium Duty Vehicle
MeOH	Methanol
MJ	Megajoule
MSW	Municipal Solid Waste
MW	Megawatt
N_2	Nitrogen
NETL	National Energy Technology Laboratory
NG	Natural Gas
NH_3	Ammonia
NOx	Nitrogen Oxides
O_2	Oxygen
PEM	Proton Exchange Membrane
QE2	Queen Elizabeth II Highway
RFI	Request for Information
RFP	Request for Proposal
SAF	Sustainable Aviation Fuel
SMR	Steam Methane Reforming
SOEC	Solid Oxide Electrolysis Cell
TA	Transition Accelerator
TPD	Tonnes Per Day

EXECUTIVE SUMMARY

Hydrogen is gaining traction worldwide as both an emissions-reduction tool and an economic development lever, particularly in sectors that are difficult to electrify. Globally, committed hydrogen investment reached an estimated $110 billion USD in 2025, growing at an average of 50% annually since 2020[1], driven primarily by industrial demand and climate policy.

In Alberta, low-carbon hydrogen production from natural gas offers a way to add value to abundant natural gas resources while supporting energy diversification. For Calgary, hydrogen presents a realistic opportunity to attract investment, anchor new industrial activity, and export technical expertise, while working toward emission-reduction goals.

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Hydrogen Use

Hydrogen is not a universal solution; however, it can be a compelling low-carbon alternative for specific sectors where other alternatives, such as electrification and renewable fuels, are constrained by availability, weight, energy density, duty cycle requirements, or cold-weather performance.

In Calgary, the most compelling opportunities for hydrogen use exist in the mobility sector, with a compelling case existing for long-distance heavy-duty freight transportation, high-duty-cycle vehicles (such as transit buses), and certain vocational fleets. Niche opportunities, such as in-warehouse hydrogen forklift fleets, are also being used successfully by the private sector. Hydrogen blending in natural gas for heating is technically feasible but would require a substantial hydrogen supply and robust delivery infrastructure that does not currently exist. However, hydrogen blending for heating could help serve as a local demand anchor in the early stages of hydrogen deployment to avoid underutilization while mobility markets mature.

Hydrogen Production

The analysis in this report shows that not all hydrogen production pathways in Calgary are equal. Suitability in an urban environment and resource requirements vary widely based on technology and scale. Generally, hydrogen production at a small scale (tonne-per-day) is not expected to significantly affect the immediate availability of resources such as water, electricity, or natural gas.

Looking closer at the commercial technologies available today, two main technology pathways stand out as practical: methanol to hydrogen production and water electrolysis, based on considering qualifiers such as scale suitability, technology readiness, water use, electricity and natural gas impacts and urban feasibility.

Moving Ahead

As with any new technology transition, challenges and gaps exist at the initial stages and hydrogen is no exception. Six themes have been identified through the engagement in this study, and subsequent actions for the City of Calgary have been proposed to address them:

Knowledge Gaps: Stakeholders expressed uncertainty about the credibility of hydrogen companies, realistic hydrogen pricing, and the overall stability of the H_2 market. There were also concerns about safety in high-use scenarios, regulatory and zoning uncertainty, and potential water supply constraints. Additional gaps include limited workforce training and operational experience, unclear risks associated with pilot projects and technology reliability, and a need for greater understanding of where hydrogen can be effectively applied and its broader economic opportunities.

Key Recommended Actions

- Engage with Calgary Region Hydrogen Hub at the department level
- Offer department training on hydrogen basics internally, and consider outreach to the public, alongside other climate initiatives
- Develop relationships with municipalities such as Edmonton and Winnipeg, and with U.S counterparts that are actively using hydrogen in their fleets; consider sending staff for operational knowledge transfer
- Develop internal subject matter experts who can articulate investment and operating costs and put together project budgets and business cases.

Economics and Investment: Stakeholders highlighted the need to clearly demonstrate value to businesses and citizens through cost savings, service benefits, or other tangible impacts. There is also uncertainty around funding, with a need for stronger provincial leadership and continued federal incentives. Hydrogen must compete with low-cost incumbent energy sources, particularly natural gas, while the high cost of delivered hydrogen remains a barrier, especially given low demand and the need for additional revenue streams such as carbon credits.

Key Recommended Actions

- Develop a framework/process for aggregating hydrogen demand with outside organizations
- Partner and support organizations in the hydrogen leadership space, such as the Alberta Motor Transportation Association (AMTA), and share supply infrastructure to reduce costs
- Create a cross-departmental working group to ensure all hydrogen projects are in sync to reduce supply infrastructure required at early stages; have this group develop a demand timeline to help align temporal and quantitative aspects for shared fuelling infrastructure
- Explore funding opportunities and programs from provincial and federal sources

Technology Risks: Several technology-related knowledge gaps were highlighted, including the limited availability of commercial or high-TRL hydrogen technologies and a lack of proven operational data. There were also questions about water requirements for hydrogen production, with interest in low-water-use system designs and the potential use of non-potable water sources such as wastewater.

Key Recommended Actions

- Engage with a local technology provider that has proven experience in Canada (preferably in Alberta)
- Ensure service personnel are located within or adjacent to the Calgary Region
- Ensure that all equipment is appropriately certified for use in Alberta with ABSA
- Meet with municipalities that are utilizing the same provider to understand lessons learned
- Learn from the successes and challenges of previous CNG fleet adoption efforts
- Ensure new BEB fleet is studied; understand where BEB technology may fall short and where there is a strong case for hydrogen

Policy: Uncertainty in federal low-carbon policy, including changes to the consumer carbon tax and pauses to ZEV mandates, was highlighted as a gap. There are also barriers related to allowing non-city-owned vehicles to access city land for refuelling due to liability concerns and challenges in aggregating demand across organizations. In addition, procuring new hydrogen technologies can be difficult due to limited vendors and the need for additional validation and information beyond traditional procurement processes.

Key Recommended Actions

- Establish the conditions under which non-City-owned vehicles may access City-owned land for refuelling, ensuring safety, equity, operational efficiency, and alignment with municipal objectives
- Consider conducting hydrogen technology procurement in a manner that aligns with innovation and adoption of new technologies and allows for flexibility, including sole sourcing when justified, while ensuring transparency, fairness, and alignment with municipal objectives

Infrastructure: Constraints related to urban deployment, including space, logistics, and potential operational impacts, as well as challenges associated with certain technologies and site selection. Retrofitting existing transit and fleet facilities is seen as challenging, and new multi-fuel fleet facilities require increased infrastructure planning. Land availability and competing uses were also identified as concerns, alongside limits in utility capacity such as electricity distribution and gas transmission. In addition, limited access to carbon sequestration infrastructure may pose challenges for projects that rely on carbon capture.

Key Recommended Actions

- Identify City-owned land that can be utilized for an early-stage supply project that can meet the needs of multiple interested departments and outside partners
- Understand what is required from a liability/legal perspective to enable the sharing of infrastructure
- Consider proximity to utilities such as electricity, natural gas, and wastewater sources as key factors to location selection
- Future-proof planned maintenance and fuelling facilities by ensuring they meet CSA or other available hydrogen standards

Regulatory: Engagement also identified challenges related to regulations, codes, and standards. Stakeholders noted the lack of provincial codes for hydrogen fuelling stations and gaps in local bylaws, including the absence of hydrogen considerations in existing land use regulations.

Key Recommended Actions

- Consider including a hydrogen fuelling facility in future reviews of the land use bylaw 1P2007
- Identify the required organizations that need to be involved in any hydrogen project within Calgary ahead of time (e.g. Government of Alberta, local approving authority, Alberta Boilers Safety Association, etc), and collaborate extensively with these groups
- Participate in standards process committees that relate to hydrogen, such as CSA Group, to ensure that standards are well understood and designed with municipal input
- Consider connecting with the University of Calgary and the University of Alberta on work related to H_2 standards

1 THE HYDROGEN OPPORTUNITY

Hydrogen is emerging at the intersection of innovation, economic development, and decarbonization, offering both a technological pathway to lower emissions and an economic opportunity for regions investing early. Worldwide estimates of committed hydrogen investment in 2025 alone are $110 billion USD, growing at an average rate of 50% since 2020[1]. As an energy carrier, it is particularly relevant for sectors that are difficult to electrify. Advancing hydrogen also spurs innovation in related fields, including fuel cells, materials science, carbon capture, and infrastructure systems, among many others. Together, these developments reinforce each another, creating a cycle where research, deployment, and commercialization accelerate broader technology adoption.

> Worldwide estimates of committed hydrogen investment in 2025 alone are $110 billion USD, growing at an average rate of 50% since 2020

These technological advances are inextricably linked to their economic impacts. Building out the hydrogen value chain requires new infrastructure, skilled labour, and coordinated investment, stimulating activity across engineering, construction, manufacturing, and services. In Alberta, converting abundant natural gas resources into value-added low-carbon hydrogen enhances the province's resource base and supports energy diversification.

For Calgary, hydrogen presents an opportunity to attract capital, establish new industries, and export both expertise and technology. Importantly, these outcomes align with climate objectives, as the adoption of low-carbon hydrogen contributes directly to emissions reduction. This combination of technological spillovers, resource value-added, and emissions reduction positions hydrogen as a strategic lever for cities like Calgary, where existing energy expertise, infrastructure, and corporate leadership can facilitate the transition from concept to deployment.

1.1 Calgary's Advantage

Calgary is well-positioned to support hydrogen end-use demand in Alberta. As the province's largest city, it has the critical mass of energy demand required in compelling sectors where hydrogen could play a meaningful role. Combined with its unique concentration of energy expertise, corporate decision-makers, infrastructure, and technical talent, Calgary provides a strong foundation for early adoption of hydrogen in the province.

As Alberta's largest population centre, the city has long been considered Canada's energy capital. It is home to the companies and people who have shaped Alberta's energy system for decades. Head offices of major energy firms are based here, including oil and gas companies, electricity providers, pipeline operators, and consulting firms. This combination of leadership and technical expertise makes Calgary well-suited to plan, coordinate, and execute on hydrogen projects.

Additionally, Calgary is well-regarded as a technology innovation hub, boasting one of the strongest tech talent pools in the country. It ranks second in Canada for overall tech talent, just behind Toronto.[2] This strengthens the city's capacity to support emerging sectors, such as hydrogen.

Geographically, Calgary is strategically located at the centre of major transportation corridors that connect in all directions, including the province's primary economic corridor, the Edmonton–Calgary QE2. Highway and rail infrastructure link Calgary to the rest of Alberta, Western Canada (including the Port of Vancouver), and the United States. These corridors make Calgary a key hub for freight and logistics.

Calgary is well-regarded as a technology innovation hub, boasting one of the strongest tech talent pools in the country.

Together, these unique traits make Calgary an attractive location for piloting, developing, and scaling hydrogen technology. It has the demand, the people, the companies, and the infrastructure to turn plans into real-world projects.

1.2 City of Calgary's Climate Ambitions

The City of Calgary has committed to reducing community-wide greenhouse gas (GHG) emissions by 60% below 2005 levels by 2030 and achieving net-zero emissions by 2050. These targets are set out in the Calgary Climate Strategy – Pathways to 2050[3] and the City's Net-Zero by 2050 policy[4]. They apply to emissions from all sectors, including buildings, transportation, waste, and energy supply. **Figure 1** below shows emissions progress in each sector from 2005 onwards and the decline required to meet the 2030 target.

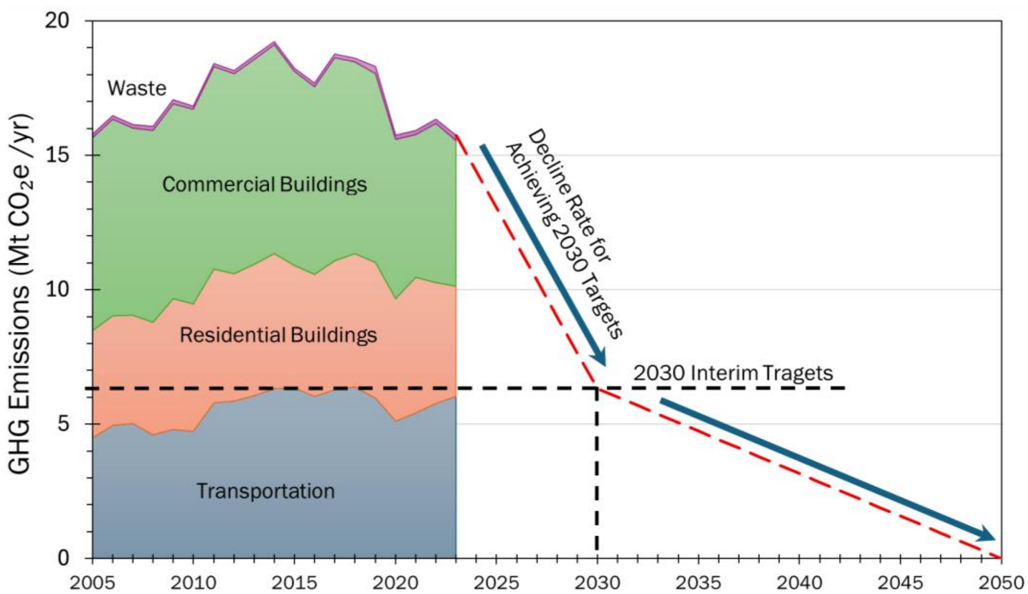

Figure 1 Greenhouse gas emissions in Calgary by sector (transportation, residential buildings, commercial buildings, and waste) from 2005 to 2023, with the 2030 interim target and required decline rates to 2050

SOURCE: City of Calgary[5]

1.3 Capturing the Opportunity

Deploying hydrogen in Calgary is not only a tool for emissions reduction. It is also an opportunity to future-proof economic growth, attract investment, and develop new industrial and energy capabilities in the city.

Hydrogen projects can deliver direct value in multiple sectors, including energy, transportation, construction, and logistics. Local firms can contribute to every stage of the hydrogen value chain, including production, distribution, storage, fuelling infrastructure, vehicle deployment, and end-use technologies. These capabilities can also be positioned for export, much like Calgary's engineering and project delivery services are utilized internationally in the oil and gas sector.

HYDROGEN'S ROLE IN MEETING CALGARY'S GOALS

It is unlikely that Calgary's climate targets can be met solely through efficiency and electrification. Several sectors of the city's energy system cannot be fully electrified with currently available technology. These include mobility applications with intense duty cycles, heavy freight, and possibly high-demand building heating systems.

Calgary's energy sector, technical talent, and logistics infrastructure create a strong foundation. However, early-stage hydrogen projects are inherently risky and rely on a new value chain that is not yet well-developed. To overcome this and de-risk municipal investments, early-stage projects will require targeted and diversified support to proceed. A coordinated approach across municipal, provincial, and federal programs is essential. This includes investment in infrastructure, supportive regulations, and procurement mechanisms that can provide market certainty.

> Broad coordination with the province and federal government is needed to unlock funding, align standards, and accelerate project timelines.

The City of Calgary can play a key role by enabling early deployment, reducing permitting barriers, and aligning city operations with hydrogen adoption where practical. Broad coordination with the province and federal government is needed to unlock funding, align standards, and accelerate project timelines.

Calgary is well-positioned to lead. Capturing this opportunity will require clear direction, early action, and sustained collaboration.

2 HYDROGEN FUNDAMENTALS

Although often portrayed as a new or emerging trend, hydrogen has been utilized in industry for over a century, with notable applications in fertilizer production and oil refining. Today, renewed interest in hydrogen is driven by efforts to expand its use beyond feedstock applications to energy-carrier applications. This carrier (fuel) can help store, transport, and deliver energy derived from other primary sources.

Development in technology that utilizes hydrogen as an energy carrier (as opposed to a feedstock) is advancing worldwide due to the recognized need for low-carbon, chemical-based energy carriers. Countries in Europe are heavily investing in hydrogen infrastructure and technology, such as pipelines and marine terminals[6–9]. These investments are necessary because hydrogen has unique physical characteristics that need specialized infrastructure for its use. This chapter outlines the basic characteristics, production and transportation methods, and potential future role of hydrogen in our energy system.

2.1 Hydrogen Characteristics

While hydrogen can be loosely compared to natural gas, both of which exist in gaseous form under normal atmospheric conditions, there are key differences. This section outlines the key physical and chemical properties of hydrogen that influence safety considerations, handling, storage, and the design of infrastructure. Topics include its combustibility, dispersion behaviour, compatibility with materials, energy density profiles, and forms of storage. Understanding and appreciating these factors is crucial for effective system design, ensuring regulatory compliance, and mitigating risk.

COLORLESS AND ODOURLESS

Hydrogen is colourless and odourless under all normal handling conditions. No approved odorant exists that is compatible with fuel cells or high-purity hydrogen systems. This makes continuous leak detection equipment mandatory in production, storage and distribution facilities[10,11].

LIGHTER THAN AIR

Hydrogen is significantly lighter than air and rises rapidly upon release. In open areas, it disperses upward at a speed of 20 m/s and dissipates quickly compared to other fuels, such as gasoline or propane, which can linger near ground level. In enclosed or semi-enclosed spaces, hydrogen leaks can accumulate near ceilings and overhead structures, requiring removal. Adequate ventilation must include high-level vents or mechanical extraction aimed at those zones to prevent gas buildup[12,13].

NO CARBON EMISSIONS AT THE POINT OF USE

When hydrogen is used in a fuel cell or burned in pure oxygen, the only byproduct is water (H_2O). However, combustion in ambient air (78% N_2, 21% O_2, 1% Other Gases) can produce nitrogen oxides, a potent greenhouse gas that must be managed. While hydrogen use emits no carbon directly at the point of use, its overall environmental impact depends on lifecycle emissions from production and distribution[14].

PRODUCTION FLEXIBILITY

Hydrogen is versatile as a variety of feedstock materials contain hydrogen, bonded with carbon atoms or oxygen in the case of water. This means that hydrogen can theoretically be produced anywhere with water, biomass, or fossil fuels, making it attractive for conventionally resource-deprived areas[15–17].

HIGH ENERGY DENSITY BY MASS, LOW ENERGY BY VOLUME

Hydrogen has a very high gravimetric energy density (~120 MJ/kg), exceeding gasoline, diesel, and batteries, which makes it attractive where weight is a limiting factor, such as in long-haul transportation[18]. However, its volumetric energy density is very low — hydrogen gas occupies far more space than liquid fuels, even when highly compressed or liquefied, it remains less dense. This limits storage and transport efficiency, often increasing costs and requiring larger systems[18,19] (see **Figure 3** for hydrogen's position relative to other fuels).

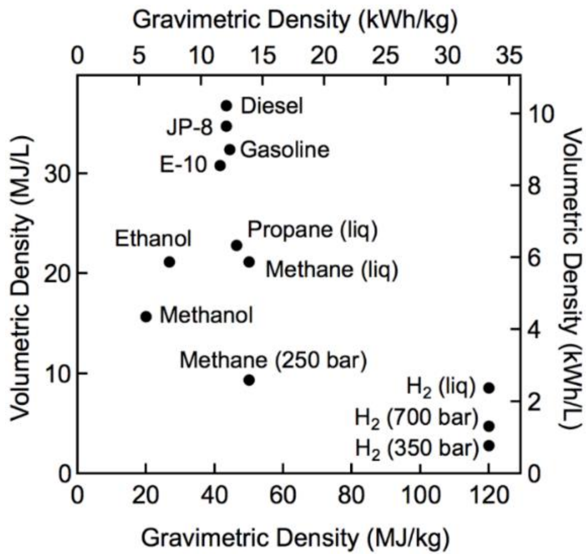

Figure 2 Gravimetric and volumetric energy density of hydrogen compared to other fuels

SOURCE: US DOE[20]

WIDE FLAMMABILITY RANGE

Hydrogen ignites over a much broader range of air mixtures than conventional fossil fuels, making it more prone to accidental ignition. Its flame is nearly invisible, generates little radiant heat, and can burn upward quickly, complicating detection and response. These characteristics present recognized safety risks, but they can be effectively mitigated through proper system design, leak detection, ventilation, and adherence to regulatory standards.[11–14].

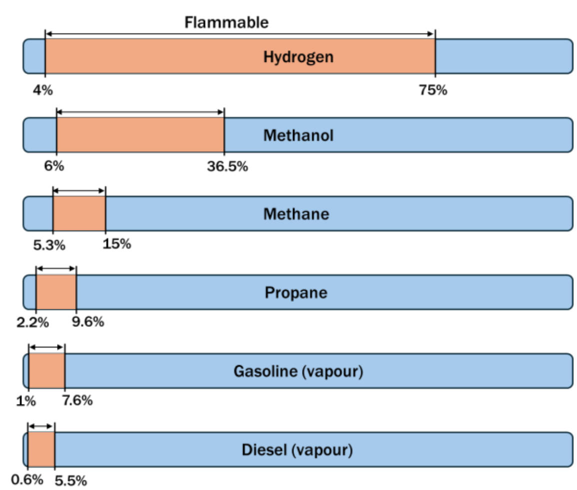

Figure 3 Flammability limits of hydrogen compared to other fuels

SOURCE: Chart courtesy Chemical Engineering Journal Advances, published under a Creative Commons license[21]

SMALL MOLECULE AND HIGH DIFFUSIVITY

Hydrogen's atom is smaller and simpler than those of other common gases, like natural gas (methane). Due to its small size, hydrogen can pass through tiny openings in flanges and seals, making it more prone to leaks than other gases, particularly in natural gas systems that are designed for larger molecules. It can also permeate and weaken specific metal compositions over time, a process known as hydrogen embrittlement. These characteristics complicate the use of existing infrastructure, though suitable pipeline materials and sealants for hydrogen are available[22].

STORAGE AND TRANSPORT IN MULTIPLE FORMS

Hydrogen can be stored as a compressed gas, a cryogenic liquid, a cryo-compressed gas, or temporarily incorporated into a chemical compound (a hydrogen carrier) such as ammonia, methanol, or other compounds, where it can be later released as pure hydrogen before use[23]. These physical and chemical traits explain both the interest in hydrogen and the technical complexity associated with its use. The following sections explain how hydrogen is produced and transported.

2.2 Hydrogen Production

Hydrogen is not commonly found as a pure element in nature. However, some geological processes are known to release pure hydrogen underground, an area of active research that is currently outside the scope of this report. Generally, hydrogen is produced by separating it from other elements, typically from water or hydrocarbons. Each method has trade-offs in terms of cost, complexity, and infrastructure. For this report, only the most common and commercially proven processes are examined.

2.2.1 Electrolysis of Water

Electrolysis uses electricity to split purified water into hydrogen and oxygen. Electrolyzers are designed to be modular and can be deployed at various scales. Small systems, typically producing less than one metric tonne per day, are used for on-site generation at fuelling stations or in remote areas, eliminating the need to transport hydrogen to the location. Large-scale facilities achieve higher output by combining multiple units. Electricity is the dominant operating cost, often accounting for 50% to 75% of total hydrogen production costs. Capital cost, efficiency, and utilization also strongly influence the economics[24,25].

ELECTROLYSIS CARBON INTENSITY

Electrolysis can yield hydrogen with either very low or very high carbon intensity (CI), depending on the intensity of the input electricity. In regions where grids rely on unabated fossil fuels, electrolytic hydrogen can be more carbon-intensive than direct fossil fuel combustion once efficiency losses in power generation, transmission, electrolysis, and end use are considered. As the grid decarbonizes, it is expected that the carbon intensity of any connected electrolyzer facilities will decrease accordingly.

TECHNOLOGY OVERVIEW

Table 1 Typical ranges of inputs and cradle-to-gate carbon intensity for hydrogen production by water electrolysis

Characteristic	Range of Values	Note
Production Scale	~10s of kgs up to ~100s tonnes per day	Highly modular in design and flexible in sizing
Water Use	9 L /kg H_2 reaction[26,27] 10–45 L /kg H_2 cooling [26,27]	Reaction water requires high purity; cooling water does not.
Electricity Use	50–83 KWh/kg [28]	Typical range for PEM electrolysis, depending on system efficiency.
Natural Gas	N/A	N/A
Cradle to Gate CI	Renewables: 5.6–38.1 kg CO2e/GJ HHV H_2 [28,29] Alberta Grid: 176.2–300.8 kg CO2e/GJ HHV H_2 [28,29]	Highly dependent on input electricity carbon intensity

2.2.2 Methane Reforming

Methane reforming produces hydrogen by reacting natural gas with steam at high temperatures. The most common method worldwide, steam methane reforming (SMR), uses steam to split methane into hydrogen and carbon monoxide, followed by a water–gas shift reaction that converts the carbon monoxide into additional hydrogen and carbon dioxide. A variation, autothermal reforming (ATR), generates heat within the reactor by adding oxygen, thereby reducing the need for an external furnace; however, it increases electricity demand due to the air separation unit required to supply oxygen. Most reformation projects in operation today are large-scale, co-located industrial production facilities that provide feedstock hydrogen for industrial processes such as refining and petrochemical production.

REFORMING CARBON INTENSITY

The methane reforming process generates substantial CO_2, so carbon capture and sequestration (CCS) is required to reduce emissions. Adding to this challenge is the high cost of CCS infrastructure tie-in, which is seen as cost-prohibitive for small-scale reformation projects, with large-scale plants being favoured due to economies of scale.

TECHNOLOGY OVERVIEW

Table 2 Typical input demands and cradle-to-gate carbon intensity values for steam methane reforming (SMR) and autothermal reforming (ATR)

Characteristic	Range of Values	Note
Production Scale	~200kg/day to over 1,000 TPD	Small-scale units are very niche; the majority of deployed SMRs are large, co-located, for industrial purposes, benefiting from economies of scale.
Water	SMR – 4.5 L /kg H_2 reaction[26,27] SMR – 5.5 – 13 L /kg H_2 cooling[26,27] ATR – 3.9 L /kg H_2 reaction[26,27] ATR - 4.8 – 21.7 L /kg H_2 cooling[26,27]	Reaction water needs high purity (deionized). Cooling water can often be of lower purity.
Electricity	SMR – 0.31 – 2.9 KWh/kg H_2 [28] ATR – 2.3 – 4 KWh/kg H_2 [28]	Electricity is mainly for compression, pumping, and air separation in ATR. Can also be co-generated onsite.
Natural Gas	SMR Feedstock – 119.9 MJ NG /kg H_2 [28] SMR Fuel– 60 – 100 MJ NG /kg H_2 [28] ATR Feedstock – 150 – 182 MJ NG/kg H_2 [28] ATR Fuel – 0 [28]	Accounts for input feedstock and process heat.
Cradle to Gate CI	SMR: 10.6–47.9 kg CO_2e/GJ_{HHV} H_2 [30,31] ATR: 7–40.3 kg CO_2e/GJ_{HHV} H_2 [15,31,32]	Carbon intensity is highly sensitive to CO_2 capture efficiency and plant design.

2.2.3 Methane Pyrolysis

Methane pyrolysis technology decomposes (breaks apart) natural gas into its constituents, hydrogen and carbon. This can be achieved via several technological pathways that use high-temperature heat or microwave energy. Unlike reforming, pyrolysis does not generate CO_2, thereby removing the need for carbon capture. However, solid carbon is produced and must be handled, which is an important consideration for implementing any pyrolysis project, particularly at large scales.

Pyrolysis has the potential to deliver low-carbon hydrogen and marketable carbon products, but it remains in its early stages of commercialization. Technical challenges include achieving stable, continuous operation and producing a consistent specification carbon byproduct. Pilot projects exist in Alberta, but large-scale commercial facilities have not yet been established in the province. Another benefit of using pyrolysis is the ability to leverage existing natural gas pipeline infrastructure, with hydrogen ideally used at the site of production, eliminating the need for transporting hydrogen long distances.

PYROLYSIS CARBON INTENSITY

Although the pyrolysis reaction does not directly produce CO_2, upstream emissions are associated with the natural gas feedstock and the energy required to power the facility. If methane is combusted as a heat source, the resulting CO_2 may still need to be captured. If electricity is used, the carbon intensity depends on the source of that electricity. Solid carbon is produced at a 3:1 weight ratio to hydrogen, which poses a significant logistical challenge for large-scale projects.

Table 3 Typical input demands and cradle-to-gate carbon intensity values for natural gas pyrolysis

Characteristic	Range of Values	Note
Production Scale	Pilots are in 200kg – 1 TPD range Commercial plants - ~5–10 TPD range	Commercial plants today prioritize carbon products, not H_2 for a revenue stream
Water	0 L /kg H_2 reaction[26,27] 1–16.3 L /kg H_2 cooling[26,27]	No water is required for the reaction. Cooling water demand depends on technology, reactor design and purity requirements are less strict than for reaction water.
Electricity	4–10 KWh/kg H_2 [33]	Can be partly generated onsite, depending on configuration.
Natural Gas	225–285 MJ NG/kg H_2 [33]	Feedstock and energy input. Energy efficiency depends on technology and heat recovery.
Cradle to Gate CI	Solid carbon output[33] 14.1–58.5 kg CO_2e/GJ_{HHV} H_2 (Alberta Electricity and Construction)[33]	Produces a solid carbon by-product at ~3:1 ratio with hydrogen; emissions depend on energy inputs for heat and construction.

2.2.4 Hydrogen from Biomass or Waste

Hydrogen can be produced by gasifying wood residues, crop waste, or sorted municipal waste. This process involves heating organic materials in low-oxygen conditions to release a syngas mixture, from which hydrogen is then separated. The output gas mixture depends on the type and condition of the material. If the carbon in feedstock is biogenic (from organic sources), the resulting hydrogen may be considered low-carbon or carbon-negative if CCS technology is employed. Pilot projects have attempted to gasify municipal waste but have faced challenges, largely due to the heterogeneous nature of the feedstock, which has led to significant process difficulties. Gasifying homogeneous feedstock, such as wood chips, is likely to pose the fewest technical hurdles, but a large-scale facility would face logistical and feedstock availability challenges.

CARBON INTENSITY

Carbon intensity depends on the source and composition of the feedstock, as well as the system's design. Biogenic inputs are generally considered low emission, particularly if methane release is avoided or biogenic CO_2 is captured and sequestered. However, feedstock sources such as railroad ties may exhibit high carbon intensities due to the creosote impregnated within the wood. Emissions must be assessed based on the quality of the feedstock, the system design, and the carbon handling process.

TECHNOLOGY OVERVIEW

Table 4 Typical input demands and cradle-to-gate carbon intensity values for biomass gasification

Characteristic	Range of Values	Note
Water	Variable water demand for reaction[27] ~8–36.4 L /kg H_2 reaction[26,27]	Water use in gasification varies widely with the type of biomass feedstock, since both its moisture content and carbon-to-hydrogen ratio affect demand.
Electricity	~5–10 KWh/kg H_2 [28]	Can be partly generated onsite, depending on configuration.
Natural Gas	N/A	N/A
Biomass	~6–8 kg biomass/ kg H_2 [15,34]	Feedstock estimates are highly variable
Cradle to Gate CI	-105.7–14.1 kg CO_2e/GJ_{HHV} H_2 [34,35]	Carbon intensity is sensitive to feedstock type, conversion efficiency, and co-product treatment.

2.2.5 Hydrogen Production from Intermediate Carriers

Hydrogen can be produced indirectly from intermediate hydrogen carriers such as methanol, ammonia, or liquid organic hydrogen carriers. Unlike methods that generate hydrogen on-site from natural gas, water, or other feedstocks, this approach does not create new hydrogen at the facility. Hydrogen is produced elsewhere, bound to a carrier, transported to the site, and then released via a conversion or separation step.

AMMONIA TO HYDROGEN

Due to its use in agriculture as a fertilizer, ammonia (NH_3) is widely produced and transported, and has been considered as an option for hydrogen transportation. Ammonia can be decomposed into hydrogen and nitrogen through thermal or catalytic processes. These processes cannibalize 13% to 20% of the energy content of the input feedstock[36–38]. The reaction itself uses no water, but cooling, purification, and catalyst conditioning systems may require it.

AMMONIA CARBON INTENSITY

Ammonia's zero-carbon molecular structure (NH_3) means the cracking process produces no direct CO_2 emissions. However, lifecycle carbon intensity depends entirely on how the ammonia feedstock was produced. Ammonia produced from natural gas without carbon capture has a high emissions footprint. In contrast, ammonia produced via carbon capture or synthesized from low-carbon hydrogen and electricity has a much lower intensity.

Characteristic	Range of Values	Note
Production Scale	~10s of tonnes up to ~100s of tonnes per day[39–42]	Commercial ammonia cracking is typically centralized and industrial, with systems generally designed at tens to hundreds of tonnes per day.
Water	1-16 L/kg H_2 [43–45]	Ammonia cracking ($2NH_3 \rightarrow N_2 + 3H_2$) does not consume water stoichiometrically. Water is needed only for process cooling, heat rejection, and H_2 purification.
Electricity	1.5-3.5 kWh/kg H_2 [45]	Excess heat can be used to produce some of the electricity.
Ammonia	5.67 -7.74 kg NH_3/kg H_2 [45,46]	The excess gas is used for heat. Cracking requires significant thermal energy (~4.2 GJ thermal/t NH_3) due to an endothermic reaction.
Natural Gas	N/A (assuming imported NH_3 feedstock)	Only if used as fuel for process heating. Many designs use off-gas H2 or imported heat.
Cradle to Gate CI	10–18 kg CO2e/kg H_2 [45] 70.5 – 126.9 kg CO_2e/GJ_{HHV} H_2 [45]	Ammonia's zero-carbon molecular structure means cracking produces no direct CO_2 emissions. Lifecycle intensity depends on feedstock: grey ammonia from natural gas is highest, blue ammonia with carbon capture is lower, and green ammonia from renewable electrolysis is lowest.

METHANOL REFORMING

Methanol can be converted to hydrogen and carbon dioxide through catalytic steam reforming at 200-300°C. Reforming efficiency depends on heat recovery integration and feedstock quality, with modern systems achieving 70-80% energy efficiency.

Water demand is inherent to the process. The steam reforming reaction requires water as a reactant ($CH_3OH + H_2O \rightarrow CO_2 + 3H_2$), consuming approximately 3 liters per kg of hydrogen produced. Additional water is needed for cooling systems, with total consumption varying by system design and whether closed-loop cooling is used.

CARBON INTENSITY

Methanol reforming produces carbon dioxide as a direct byproduct of the reaction, and the total carbon intensity also depends on how the methanol feedstock is produced. Methanol derived from natural gas carries a high emissions footprint, while bio-methanol can lower emissions depending on the biomass source and conversion pathway. Synthetic methanol made from captured CO_2 and renewable hydrogen offers the lowest carbon intensity, with remaining emissions mainly from electricity use for process heating and auxiliary systems.

Characteristic	Range of Values	Note
Production Scale	~10s of kgs up to ~10s of tonnes per day[47,48]	Currently on pilot scales
Water	~3 L/kg H_2 reaction; cooling varies by design[48]	Based on stoichiometry $CH_3OH + H_2O \rightarrow CO_2 + 3H_2$. Additional water required for cooling varies by reactor design and heat recovery configuration
Electricity	5–10 kWh/kg H_2 [49,50]	Includes reformer heating (4–8 kWh/kg H2), pumps, compressors, and auxiliaries (1–2 kWh/kg H2).
Methanol	5.3–6 kg MeOH/kg H_2 (~6.7–7.6 L MeOH/kg H_2)[48]	Based on stoichiometric requirement (32 g MeOH per 6 g H_2) with 0–13% excess. Methanol density ~0.79 kg/L. Unconverted methanol and off-gas can be recycled for heat
Natural Gas	N/A (assuming imported MeOH feedstock)	Assuming imported methanol feedstock (no on-site NG consumption)
Cradle to Gate CI	**Fossil Methanol** 93.9 – 138.8 kg CO_2e/GJ_{HHV} H_2 (13.3–19.7 kg CO_2e/kg H_2)[50,51] comprised of: (1) Reaction CO_2: ~59.4 – 67.2 kg CO_2/GJ_{HHV} H_2; (2) Methanol Production CI: 17.2 – 37 kg CO_2e/ GJ_{HHV} H_2); (3) Electricity: 17.3 – 34.6 kg CO_2e/GJ_{HHV} H_2 **Renewable Methanol** 1.7 – 73.5 kg CO_2e/GJ_{HHV} H_2 (0.24 – 10.4 kg CO_2e/kg H_2) comprised of: (1) Reaction CO_2: ~0 – 19.5 kg CO_2/GJ_{HHV} H_2; (2) Methanol Production CI: 1.7 – 19.5 kg CO_2e/ GJ_{HHV} H_2); (3) Electricity: 0 – 34.6 kg CO_2e/GJ_{HHV} H_2	**Fossil Methanol to H_2:** • MeOH Production: Upstream methanol production emissions only (cradle to gate), excludes carbon embedded in the methanol molecule. • Reaction of MeOH to H2: CO_2 released by $CH_3OH + H_2O \rightarrow CO_2 + 3H_2$. For fossil methanol this CO_2 is anthropogenic and counted fully. • Electricity Demand: Electricity CI 0.490 kg CO_2e/kWh. **Renewable Methanol to H2** • MeOH Production: Upstream renewable methanol production emissions only (cradle to gate), excludes carbon embedded in the methanol molecule. • Reaction of MeOH to H2: For renewable methanol, released CO_2 can be treated as biogenic or previously captured. • Electricity Demand: Electricity CI uses 0 to 0.490 kg CO2e/kWh bounds.

LIQUID ORGANIC HYDROGEN CARRIERS (LOHCS)

Liquid organic hydrogen carriers are organic compounds that store hydrogen through reversible hydrogenation and dehydrogenation reactions. Hydrogen is chemically bound to the carrier at a production or import site, transported in liquid form using existing fuel infrastructure, and released at the point of use. Several carrier systems are under development, including toluene–methylcyclohexane and dibenzyltoluene–perhydro-dibenzyltoluene, which are of particular interest due to their stability and compatibility with current liquid-fuel logistics.

CARBON INTENSITY

The carbon intensity of LOHC systems depends on the hydrogen source and the synthesis route of the carrier. Hydrocarbon-based carriers such as methylcyclohexane and dibenzyltoluene release hydrogen without forming CO_2, but the catalytic dehydrogenation process requires significant heat input, which can lead to indirect emissions if fossil fuels are used. Oxygenated carriers, such as formic acid or methanol derivatives, release CO_2 directly during hydrogen release. In all cases, lifecycle emissions are influenced by hydrogen production methods, process energy requirements, and carrier regeneration or replacement over time.

2.2.6 Production Carbon Intensity Comparison

ASSUMPTIONS

For this analysis, emission boundaries were limited to a “cradle-to-gate” measurement for production, including combustion emissions. Transportation-related emissions are not included. This approach aims to provide the most accurate basis for comparison between multiple energy carriers, with the understanding that emissions from transportation would need to be considered at a project-specific basis. It is also important to understand that ***these intensity values do not account for differences in end-use technology efficiencies;*** for example, a fuel cell electric vehicle requires less overall input energy to provide the same output energy as an internal combustion engine.

Lifecycle greenhouse gas emissions from hydrogen production are heavily influenced by the method of hydrogen production and its subsequent transportation to the end-use location. Additional factors include the CI of the electricity used in the process and, for gas-based technologies, the CI of the input natural gas, which encompasses upstream leakages. These leakages are significantly affected by the source of natural gas. Project-specific elements, such as technology selection and process efficiency, also play an important role. Due to this variability, the values presented in this section are based on high-level ranges reported in the literature, aiming to illustrate a spectrum of possible outcomes rather than predict the performance of any individual project.

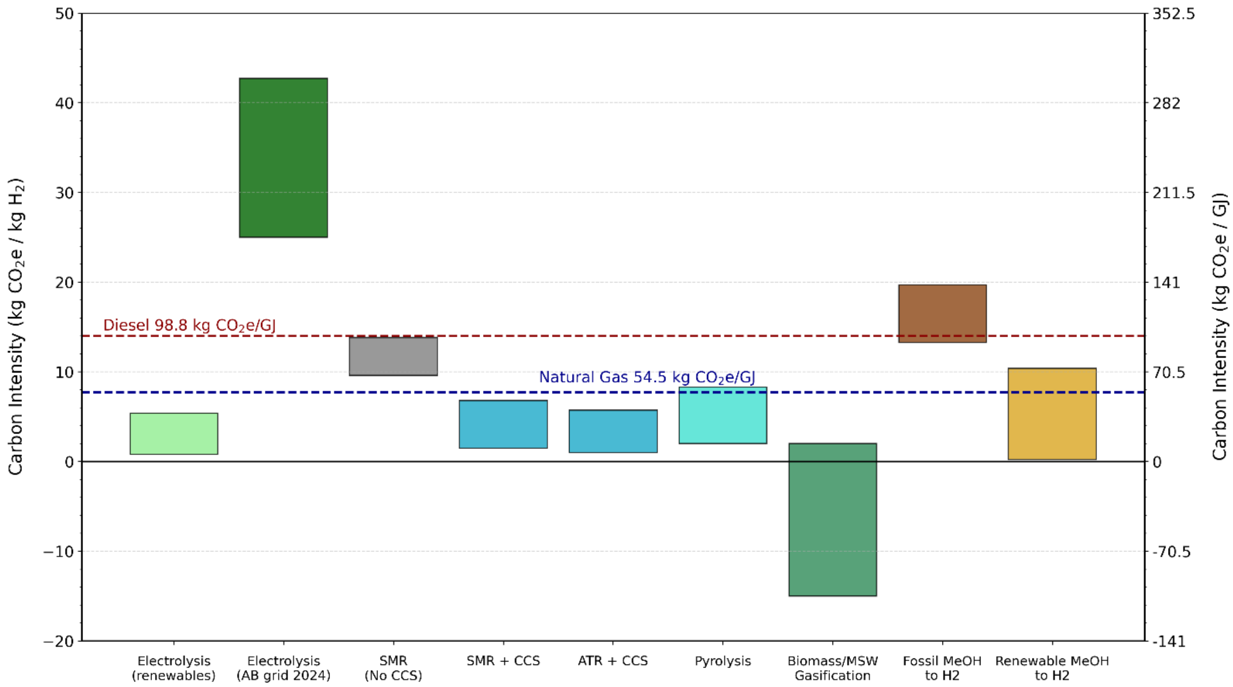

Figure 4 Lifecycle carbon intensity of hydrogen production technologies (electrolysis, reforming with and without CCS, pyrolysis, biomass gasification, ammonia-to-H_2, and methanol-to-H_2) compared with natural gas and diesel fuels

2.3 Hydrogen Transportation

Due to the early stages of using hydrogen as an energy carrier outside of co-located industrial projects, understanding the nuances of how hydrogen is transported is important. Currently, hydrogen lacks a widespread transportation network equivalent to today's incumbent energy carriers, such as natural gas. In the near term, a combination of transport methods will likely be used, while co-locating production with demand remains the most efficient option where feasible. This section outlines current knowledge and considerations for hydrogen transport.

ROAD

Hydrogen can be transported by road in three main forms: compressed gas, cryogenic liquid, or cryo-compressed, typically using tube trailers hauled by Class 8 tractors (**Table 5**). Payload capacity depends strongly on the storage state. Road transport is generally suited to short-term or short-haul demand, but it is less efficient than pipelines for long-term or large-scale delivery[52–54]. Loading and unloading require compression equipment at both ends or the use of cascade filling. Transport costs rise quickly with distance, as fuel consumption dominates operating expenses[55,56].

Liquid hydrogen trailers increase payload by storing hydrogen at −253 °C in vacuum-insulated cryogenic tanks, but liquefaction consumes ~30–40% of the hydrogen's energy content and requires significant plant-side infrastructure[57,58], This makes liquid transport practical mainly when large, centralized plants can justify capital costs. Boil-off losses during storage and transit add further complexity, with magnitude depending on tank design. While liquid trailers improve per-trip efficiency compared with gaseous trailers, both modes are far less efficient than pipelines and are primarily used today to link production sites with fuelling stations or smaller industrial users.

Table 5 Payload capacity ranges and key considerations for hydrogen transport by road using gaseous tube trailers, cryo-compressed trailers, and liquid hydrogen trailers

Technology	Payload Range	Note
Gaseous Tube Trailer	380–1,100 kg	Steel tube trailers are most commonly employed and carry approximately 380 kg onboard; the weight of the steel tubes limits their carrying capacity. Recently, composite storage vessels have been developed that have capacities of 560–1,100 kg of hydrogen per trailer [59].
Cryo-Compressed Trailer	Unknown, expected to be above Tube Trailer Range	Limited data on cryo-compressed trailer capacity exists, but research is ongoing.
Liquid Hydrogen Trailer	3,000–4,500 kg	Liquefaction consumes more than 30–40% of the energy content of the hydrogen and is expensive. In addition, some amount of stored hydrogen will be lost through evaporation, or "boil off" of liquefied hydrogen, especially when using small tanks with large surface-to-volume ratios .[60,61]

RAIL

Hydrogen rail transport is technically feasible, but it is not currently commercially deployed in Canada. In principle, gaseous hydrogen could be shipped in large tube-skid containers, loaded into railcars, similar to compressed natural gas by rail. A single railcar would be able to carry several times more than a road trailer, but a constraining challenge would still be hydrogen's low volumetric energy density. Payloads are likely to be on the order of tonnes per car. Because of this, compressed hydrogen by rail is rarely pursued beyond concept studies. Hydrogen transported by rail could be viewed as a solution for an ecosystem that has grown beyond road tube trailer transport but is not yet mature enough for mass transport via pipelines.

PIPELINES

Pipelines are the most efficient way to transport hydrogen on a large scale, but deployment depends heavily on the need for long-term demand and the willingness to invest substantial amounts of capital upfront. Existing dedicated hydrogen pipelines exist and are technically feasible —approximately 5,000 km exists globally, primarily clustered around refining and chemical hubs in Europe and the U.S. Gulf Coast. Throughputs can reach hundreds of tonnes per day, far exceeding what trucks or rail can handle, with relatively low operating costs once the pipeline is built. Compression stations are required, but energy losses are relatively small compared to those associated with liquefaction.

CHEMICAL CARRIERS

Hydrogen can be transported in chemical carrier forms such as ammonia, methanol, and liquid organic hydrogen carriers (LOHCs). These are more stable than gaseous hydrogen and can often be used with existing fuel transport infrastructure.

Each carrier has trade-offs. Ammonia stores large amounts of hydrogen but is toxic and corrosive. Methanol is easier to handle but contains carbon and, upon reconversion, releases CO_2. LOHCs are safer to handle but typically require more energy to release hydrogen. In all cases, hydrogen must first be converted into the carrier and later extracted at the destination.

Chemical carriers are often proposed for long-distance or overseas shipping, enabling large-scale transport without pipelines. However, their safety, efficiency, and environmental impacts vary by carrier type.

2.4 Hydrogen's Potential Role in a Future Energy System

Many sophisticated organizations, such as the International Energy Agency, U.S. Energy Information Administration, Canada Energy Regulator, and the International Renewable Energy Agency (among many others), release long-term energy scenarios that model energy transformations in our energy systems worldwide, which include the relative changing of energy carriers' contributions to the overall system. However, all of these scenarios and the timelines modelled should not be considered 'projections' due to the numerous unknowns, including breakthroughs in materials science, shifting political winds, geopolitical crises, and other unpredictable black swan-type events.

Despite this uncertainty, these reports do have some similar trends, which include:

1) Electricity will be the primary energy carrier of the future, with nearly all organizations predicting a 2–3x increase in the contribution of electricity to our energy system

2) Electricity, despite being the primary energy carrier of the future, will not be able to be 100% of the energy system. Despite its attractive attributes, including efficiency and the ability to be generated by technologies such as wind and solar, **a gap remains.**

3) Hydrogen will play an increasing role in our future energy system, to what exact extent is unknown.

These trends are visualized in **Figure 5** below:

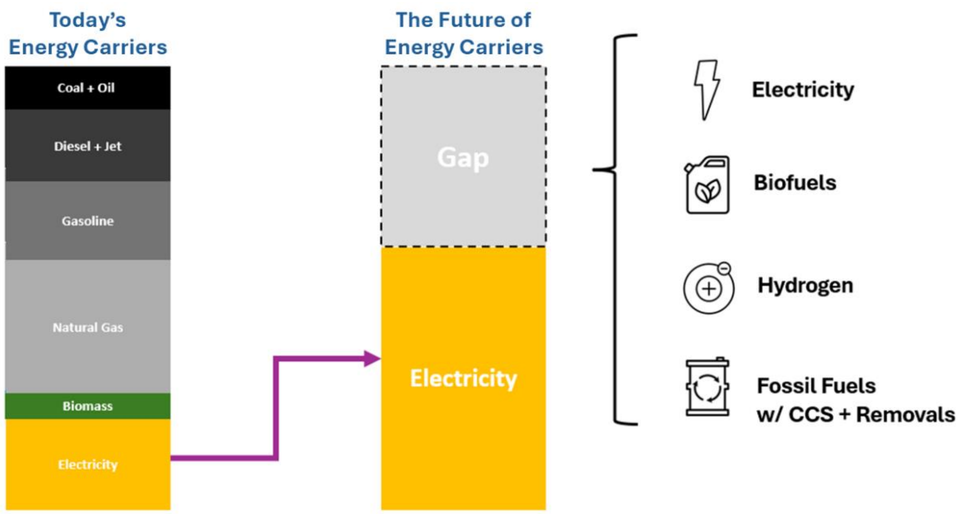

Figure 5 Comparative view of today's dominant energy carriers and a possible future energy mix

SOURCE: Figure Courtesy of The Transition Accelerator

When considering the role hydrogen will play in a future energy system, it can be easy to focus on the short-term challenges that are being faced in specific projects or on particular numbers that are outputs of long-term energy scenarios. At the same time, it may be more worthwhile to focus on the long-term inevitability and broad agreement among organizations that hydrogen will play a larger role in the future. Unfortunately, progress has been slower than anticipated, and our current focus over the past few decades has been on innovation in bytes rather than innovation in atoms, which is required for building a new energy system. The relatively slow pace of energy innovation can provide an opportunity for Alberta and Calgary to establish a leadership position in the hydrogen ecosystem.

2.5 Challenges in 2025

Hydrogen shows promise as an increasing component of a low-carbon energy system for specific, difficult-to-decarbonize use cases. Still, several challenges must be addressed before hydrogen use can be widely adopted in these sectors. These challenges span the entire value chain, from production to end use.

HYDROGEN FACES A CHICKEN-AND-EGG PROBLEM

Hydrogen systems need producers, users, infrastructure, and storage to scale together. But no one wants to move first. Producers wait for stable demand. Users wait for a reliable supply. Infrastructure investors wait for both. This slows progress across the value chain. Solving it will take coordination. Early demand signals, shared infrastructure, and clear public roles can help break the deadlock.

HYDROGEN FOR ENERGY DEPENDS ON BUILDING A SYSTEM THAT DOES NOT YET EXIST

Hydrogen has been produced and used for decades in refineries and chemical plants. These are closed systems with on-site production and no transport. Using hydrogen as an energy carrier differs from co-located industrial use. It requires a more robust network, encompassing production, pipelines, delivery, storage, and distribution to end users. That network does not exist today.

COSTS ARE HIGH BECAUSE PROJECTS ARE SMALL, SCATTERED, AND UNDERUSED

Hydrogen can be produced at low cost. Natural gas-based hydrogen is already cheap. Adding carbon capture raises cost, but not by much. Electrolysis can also be competitive where cheap power is available. The problem is not the technology. It is the lack of scale. Without strong demand and steady use, systems run below capacity. This raises the cost per kilogram for everything from production to transport.

WE HAVE CHEAP ENERGY

The cost of natural gas in 2025 has ranged from $1.05 – $1.62 / GJ[62] while the price of wholesale diesel (rack) has ranged from $0.96 – $1.13/L[63]. Compared with hydrogen on a higher heating value basis, this would be equivalent to $0.15- $0.23/kg and $3.60-$4.24/kg, respectively. In contrast, hydrogen prices today range widely and are reported to retail at as much as the mid-thirties per kg.

This low cost of energy is attractive for the consumer, but it makes it difficult for hydrogen to compete, particularly without any consumer-facing carbon tax or end-use incentives in place.

REGULATORY GAPS ADD DELAY AND RISK

Hydrogen rules are still evolving. Provinces use different standards for safety, blending, and carbon intensity. Permitting is often slow or inconsistent. These gaps make project planning harder and increase investment risk. Policy U-turns on carbon pricing and other incentives create uncertainty of feasibility in the long term.

INVESTORS LACK CONFIDENCE THAT DEMAND WILL MATERIALIZE

Hydrogen projects take time and capital. Without long-term signals such as public procurement, anchor customers, or firm offtake agreements, developers struggle to raise investment. As a result, many projects stall before construction.

3 PRODUCTION OPPORTUNITIES IN CALGARY

When evaluating any industrial technology, technical, economic, and environmental factors must be assessed to determine their regional feasibility. Hydrogen production is no exception to this process, as planning must include both current and anticipated regional hydrogen demand. By taking a systems perspective, risks associated with poor technology selection and sizing can be mitigated, leading to more effective economic optimization of projects. Considering that most early-stage hydrogen projects are anticipated to be primarily funded by the public, this should be a shared priority for all.

Questions can be asked early on that can help identify the suitability of technologies and projects to the region. In a hydrogen context, these can include:

- What is the readiness of the technology? Has it been deployed elsewhere?
- Is the technology proposed suited for the scale of hydrogen demand that is expected?
- For technologies that require natural gas, is there appropriate infrastructure (pipelines) in place, and do they have existing capacity to meet the needs of production?
- Is there suitable electricity infrastructure nearby, and spare capacity to meet the needs of this technology?
- Is there a sufficient source of year-round water available for this technology at this scale?
- Does this technology require carbon capture infrastructure to align with emissions goals? Is infrastructure available nearby, and could it realistically be deployed at this scale?

The following sections in this chapter will examine individual hydrogen production technologies within the context of Calgary (city limits, not region) and will examine these aspects.

3.1 Hydrogen from Natural Gas Reforming

The City of Calgary (and Alberta more broadly) has access to some of the most reliable and low-cost natural gas in the world. This gives the region a clear advantage in producing hydrogen using natural gas as a feedstock. Currently, most hydrogen production in the province is derived from natural gas; however, this production is associated with co-located refining and petrochemical processes, which are not present in the City of Calgary. The opportunity for SMR/ATR technology deployment within Calgary is likely to be in the longer term, contingent upon the establishment of CCS infrastructure, if at all.

PRODUCTION SCALE

Scale matters with reforming technology - SMR technology offers greater flexibility in production output, while ATR technology is only considered practically viable at large scales **(see section 2.2.2)**. In the early stages of hydrogen use in Calgary, it is likely that only the smallest-scale, less commercially proven systems (< 1 TPD) would be required to meet demand at a reasonable utilization rate and would not benefit from economies of scale. As the hydrogen ecosystem matures, a larger, more economically scaled facility could be required in principle, such as those in use at the Alberta Industrial Heartland for refining and petrochemical uses. Another important consideration is that reforming technology requires a significant start-up time to reach a steady-state of production, which is not compatible with meeting intermittent hydrogen demand, as would be experienced in the short to medium term.

WATER IMPACTS

Natural gas reforming requires a substantial amount of water for both the reforming reaction and process cooling **(see Section 2.2.2)**. Water use is an important consideration for Southern Alberta and Calgary and would likely limit the scale at which hydrogen can be produced in the city using natural gas reforming, if considering using potable surface water resources. For a theoretical small-scale SMR facility (1 TPD), an estimated water requirement would be 10–17.5 m^3/day of water (0.004–0.0011% of daily use in 2024). At the upper levels, a large-scale ATR facility producing 1,000 TPD of hydrogen could require upwards of 25,600 m^3/day of water (5.3% of daily use in 2024)[26,27,64].

ELECTRICITY AVAILABILITY

A substantial amount of electricity is required for SMR production. This could range from 0.31–2.9 MWh/day or 12.9–120.8 KW of consistent load (small-scale, 1 TPD facility) to well over 2,000 MWh/day or 83.3 MW of consistent load (1,000 TPD facility), assuming constant production. At a large scale, substantial investment in utility infrastructure would be required to meet this demand, alongside the further development of generation capacity. However, a facility of such size is unlikely to be needed in Calgary in the short to medium term. To mitigate grid impacts, onsite generation could be integrated into any large-scale facility, provided that carbon capture infrastructure is available[28,65].

NATURAL GAS AVAILABILITY

At all scales, some level of pipeline infrastructure would be required to deliver natural gas and enable an SMR facility. At a small scale (1 TPD), an estimated 179–219 GJ/day of natural gas would be required. At a large scale (1,000 TPD), an estimated 219,000 GJ/day of natural gas could be necessary.

CARBON CAPTURE INFRASTRUCTURE

For reformation-based hydrogen production in Calgary to have a meaningful impact on carbon emissions, carbon capture and sequestration infrastructure would need to be developed, similar to the Alberta Carbon Trunk Line in the Edmonton Region[66]. Currently, no infrastructure exists in the Calgary Region, although various Carbon Sequestration Hubs have been announced. In the absence of firm plans for carbon capture infrastructure, it is unlikely that reforming production will be an attractive option until such infrastructure is in place.

> **REGIONAL SPOTLIGHT**
>
> *Rocky Mountain GTL:* Operates a gas-to-liquids plant that utilizes SMR technology near Carseland. While not currently focused on hydrogen, their facility and expertise in gas processing could support future integration of hydrogen and CCS.

3.2 Hydrogen from Natural Gas Pyrolysis

Like reforming, hydrogen produced via pyrolysis can take advantage of Alberta's comparatively low-cost natural gas, but it avoids the requirement for specialized CO_2 capture and storage infrastructure. Producing hydrogen through natural gas pyrolysis could be particularly well-suited to the Calgary Region, where both CO_2 management options and water availability are limited. Unlike conventional reforming methods, pyrolysis separates natural gas into hydrogen and solid carbon, thereby eliminating direct carbon dioxide emissions.

PRODUCTION SCALE

Despite the numerous pyrolysis system designs being proposed and piloted, existing commercial production systems are limited and currently operate only in the 10–14 t H_2/day[67] range and are used for industrial carbon production, not for hydrogen production. Pilot projects are underway in Canada that range in scales from 200 kg/day–1 TPD[68,69]. Theoretically, these pilot-scale facilities could meet the near-term hydrogen demand expected to come online in the Calgary Region. The upper limit of this technology's scale is not well known (the world's largest methane pyrolysis plant is 14 TPD)[70], and similar to reforming, pyrolysis faces challenges in handling intermittent hydrogen demand that requires process ramp-up/down[26,27,64]. The handling of the solid carbon byproduct from this process (3:1 C to H_2 ratio) is likely the limiting factor for scaling projects beyond 20 TPD.

WATER IMPACTS

Unlike reforming technology, pyrolysis does not require water for the chemical reaction that produces hydrogen; however, cooling water is needed. For a small-scale facility (1 TPD), an estimated water requirement is 1–16.3 m^3/day. At these scales, this would be 0.0002–0.003% of Calgary's 2024 daily water consumption, respectively[26,27,64].

ELECTRICITY AVAILABILITY

Electricity requirements for pyrolysis production can vary significantly depending on the chosen technology pathway. Using estimated ranges from literature, a small-scale 1 TPD facility could require 0.2–0.4 MW of continuous power, up to 4.2 MW at a 10 TPD scale, depending on technology[28,65].

NATURAL GAS AVAILABILITY

At all scales, some form of pipeline infrastructure would be required to deliver natural gas and enable a pyrolysis facility. On a small scale (1 TPD), an estimated 225–285 GJ/day of natural gas would be required. At a large-scale facility (10 TPD), this could be on the high end, 2,850 GJ/day of natural gas would be required.

CARBON CAPTURE INFRASTRUCTURE

No traditional CO_2 capture infrastructure would be required for a pyrolysis project in Calgary. However, solid carbon would need to be removed at a ratio of 3:1 (3 tonnes of carbon per tonne of H_2 produced[33]. This carbon would pose logistical challenges for removal, particularly in an urban setting, and has the potential to either positively or negatively affect economics (if the carbon can be sold). Understanding the logistics of this solid carbon should be a high priority for any pyrolysis project.

REGIONAL SPOTLIGHT

Ekona Power uses high-temperature pulsed combustion to convert natural gas into hydrogen and solid carbon. Their technology is designed for larger-scale sites near gas infrastructure and is currently working towards a 1 TPD facility in Grande Prairie in partnership with ARC[71].

Aurora Hydrogen uses microwave-driven pyrolysis with no combustion and no need for water or oxygen. They are currently piloting a ~300kg/day facility in Fort Saskatchewan[72].

3.3 Hydrogen from Water Electrolysis

Electrolysis produces hydrogen using electricity. When powered by low-carbon electricity, it creates no direct emissions. It is one of several production methods with potential for very low or near-zero emissions, depending on the method of electricity generation. It is also the most electricity-intensive and capital-heavy option. Today, it remains one of the most expensive methods for producing hydrogen; however, it has the potential to be well-suited for distributed, small-scale production, particularly when a source of low-carbon electricity is available.

PRODUCTION SCALE

Electrolysis facilities have a wide range of scales, with readily available commercial units ranging from 20 kg/day to ~10 TPD of H_2. In the short to medium term, the flexible scale of electrolysis production facility size aligns well with the limited demand expected from the Calgary Region. However, at a large scale, multiple facilities could be required, as the current largest electrolyzer facility in operation is estimated at ~155 TPD only[73].

WATER IMPACTS

At a small scale, a continuously operating 1 TPD electrolysis facility could be expected to require 19–54 m^3/day of water, or 0.004–0.0011% of the daily water used in Calgary, a relatively insignificant amount. At a 10 TPD scale, this would increase the upper range to around 540 m^3/day of water use or 0.111% of 2024 average daily use[26,27,64]. It can be expected that water use will not be a significant consideration for a small-scale system, but could theoretically pose a challenge at the upper end of this technology's scale (long-term demand).

SUPPLY OF ELECTRICITY

Using an average electricity factor of 66.5 KWh/kg H_2, the electricity required to meet the needs of a small (1TPD) facility would be 66.5 MWh/day or 2.77 MW of continuous demand, unlikely to require substantial grid or generation capacity modifications. At medium capacity (10 TPD), this would be approximately 665 MWh/day, or 27.7 MW. At the most enormous scale of electrolyzer plant in operation today, this would amount to 3,591 MWh/day or 149.6 MW to meet the needs of the facility[28,65]. At these large scales, it would be unlikely that renewable energy sources could be located adjacent to production, although, in theory, a facility could utilize virtual power purchase agreements.

> **REGIONAL SPOTLIGHT**
>
> **CPKC** operates an electrolysis-based hydrogen production and refuelling site in Calgary. The system is supported by a solar farm backed up by the grid. The electrolyzer produces up to 500 kilograms of hydrogen per day used to pilot locomotive applications. The site may have a small volume of excess hydrogen available depending on operational needs.

SUPPLY OF NATURAL GAS

Not a consideration for electrolysis.

CARBON CAPTURE INFRASTRUCTURE

Not a consideration for electrolysis[74].

3.4 Hydrogen from Biomass/Municipal Solid Waste (MSW)

Calgary manages steady volumes of biosolids, organic municipal waste, and agricultural residues. These materials could serve as feedstock for hydrogen production via thermal processes, such as gasification. The city already collects and processes significant volumes of organic waste. This includes biosolids from the Bonnybrook wastewater treatment plant and source-separated organics collected through municipal services. Calgary also operates two city-managed sites, Shepard and Highfield, which could potentially support pilot-scale waste-to-hydrogen projects. The major hurdles for this technology include the logistics and costs of transporting feedstock, as well as the heterogeneous nature of MSW feedstock.

PRODUCTION SCALE

The scale of commercially planned hydrogen production technology from biomass or waste gasification is likely in the 0.5 – 10 TPD[34] range, although many technologies are still in the pilot phase. The scale of these projects is likely to favour medium- to large-scale economics, and the feasibility of an offtake at such scales would likely be in the medium- to long-term in Calgary.

WATER IMPACTS

Water use from gasification technology at a small scale could be as low as 8 m^3/day, based on literature values for a 1 TPD system. In contrast, a larger-scale 100 TPD facility could require upwards of 3,640 m^3/day to operate. An in-depth analysis of the feedstock used, and the specific project technology design would be necessary to have an accurate picture of water demand.

SUPPLY OF ELECTRICITY

While electricity use for this process is highly technology dependent, using an average electricity factor of 7.5 KWh/kg H_2, the electricity required to meet the needs of a small (1TPD) facility could be in the order of 3.1 MW of continuous demand.

SUPPLY OF NATURAL GAS

Not a consideration for hydrogen from biomass/MSW gasification.

CARBON CAPTURE INFRASTRUCTURE

For hydrogen production resulting from the gasification of biomass, the carbon intensity of the hydrogen could be considered relatively neutral due to the nature of biogenic carbon being released during the gasification process. For municipal solid waste (MSW), the carbon intensity is highly variable. To produce a negative CI hydrogen stream, carbon capture & sequestration infrastructure would need to be in place, which is unlikely to develop in the short to medium term.

3.5 Water Use Comparisons

Figure 6 below shows water use from hydrogen production as a percentage of Calgary's 2024 daily water demand[64], broken down by production scale and technology. The results indicate a wide range of water requirements, but pilot and small-scale plants are unlikely to affect the city's overall water use significantly. Reported values include both reaction and cooling water, with some portion operating as flow-through. While water use can be further reduced with additional measures, these options increase capital costs and are outside the scope of this report.

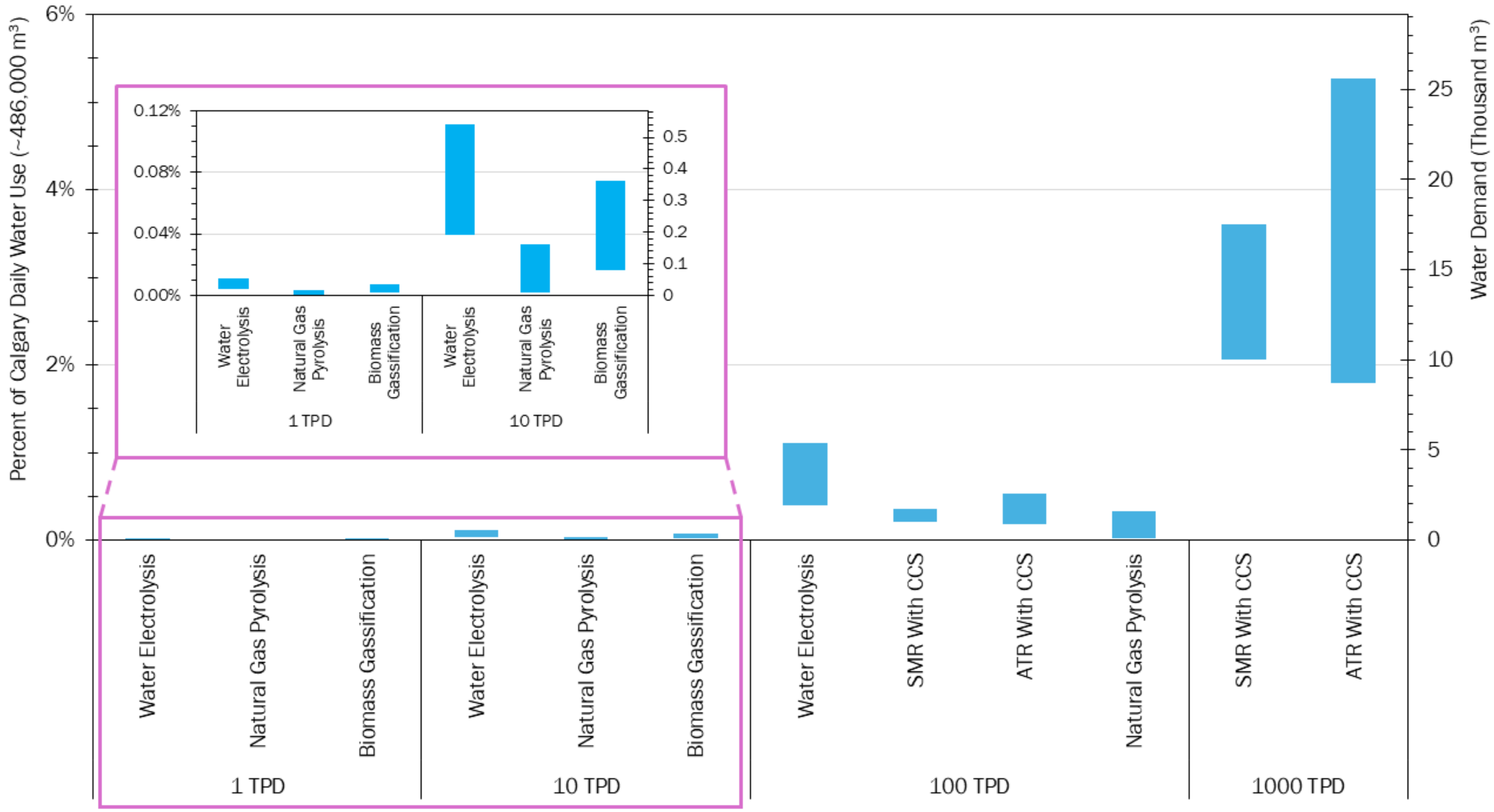

Figure 6 Estimated water demand from hydrogen production as a share of Calgary's 2024 average daily water use (~486 million litres), by technology and production scale

3.6 Electricity Demand Comparisons

Figure 7 shows electricity use from hydrogen production as a percentage of Calgary's 2024 daily electricity demand average from AESO[65], broken down by production scale and technology. The results indicate a wide range of electricity requirements, but pilot and small-scale plants are unlikely to affect the city's overall demand significantly and could be considered comparable to typical industrial consumption. Reported values account for both process and auxiliary electricity needs. It should also be noted that impacts on the grid depend not only on total electricity demand but also on when power is drawn, as concentrated loads during peak hours can create localized capacity constraints

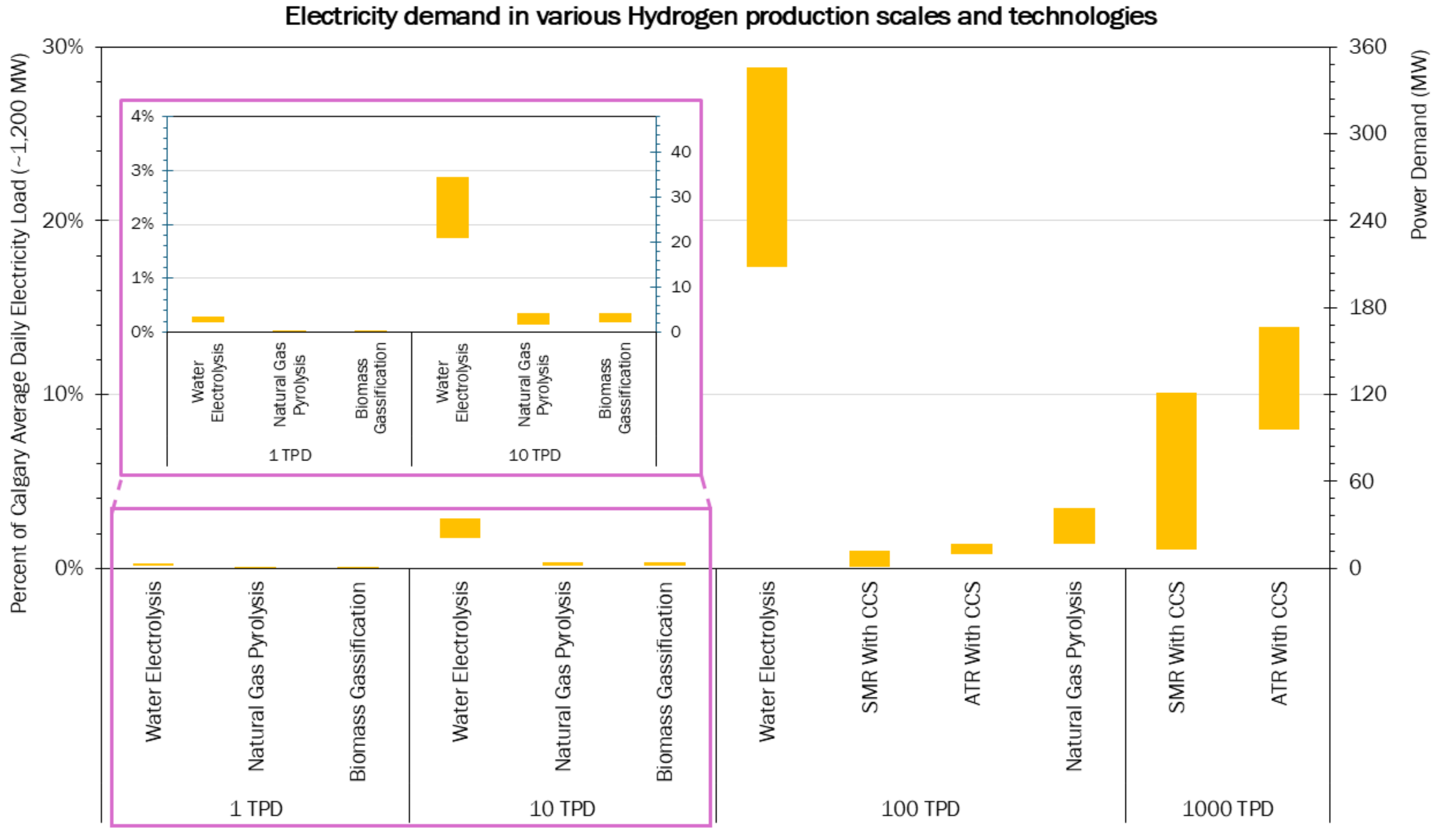

Figure 7 Electricity demand from hydrogen production as a share of Calgary's 2024 average daily load (~1,200 MW), by technology and production scale

4 HYDROGEN END-USE OPPORTUNITIES

4.1 Mobility

Hydrogen is seen as a compelling energy carrier for some transportation sectors, particularly where electrification is challenging. Overall, electrification offers greater energy efficiency; however, challenges exist for long-distance and cold-weather service, particularly when moving heavy loads across the landscape, such as heavy-duty trucking in Alberta.

Challenges for hydrogen use in Calgary mobility applications include a lack of hydrogen supply in the city, retrofitting structures to accommodate hydrogen vehicles in enclosed areas, and limited experience in maintaining and repairing vehicles.

4.1.1 Overview

HYDROGEN FUEL CELL ELECTRIC VEHICLES (FCEV)

FCEVs use a fuel cell stack to convert hydrogen and oxygen into electricity, producing only water vapour as a by-product. The electricity powers an electric powertrain, with excess power stored in a small onboard battery bank. Typical driving ranges are 500–700 km per fill, with refuelling times of 3–5 minutes at 350–700 bar stations[75]. FCEVs are commercially available in passenger cars and buses, with some deployment in heavy-duty trucks. Challenges include the cost and durability of fuel cell stacks, the expense of high-pressure storage tanks, and the high hydrogen-purity requirements of today's commercial fuel cells.[76]

HYDROGEN INTERNAL COMBUSTION VEHICLES (H_2ICE)

H_2ICEs burn hydrogen in modified spark-ignition or compression-ignition engines. They share much of the architecture of conventional engines, making them easier to adapt to existing vehicle platforms. H_2-ICEs emit no CO_2, but they can produce NO_xs due to higher combustion temperatures, requiring aftertreatment or exhaust gas recirculation[77,78]. Efficiency is generally lower than fuel cells (30–40% vs. ~50–60%)[77,78], but costs are lower because the technology leverages existing engine manufacturing. Several heavy-duty engine manufacturers are actively developing hydrogen ICEs for trucks and off-road equipment where robustness and cost are prioritized over absolute efficiency.

HYDROGEN-DIESEL DUAL-FUEL VEHICLES (HD2F)

HD2Fs substitute a portion of diesel with hydrogen, typically by port or intake injecting hydrogen while maintaining diesel direct injection for ignition. Substitution ratios of hydrogen vary, without conclusive independent analysis being available on the exact substitution that occurs at varying load cycles. HD2F technology is designed to partially reduce CO_2 emissions while retaining the torque and duty-cycle capability and reliability of diesel engines. This approach is attractive for retrofitting existing fleets, as only moderate engine modifications and added hydrogen storage are required. However, NO_x emissions can increase if combustion is not well controlled, and full decarbonization is not possible unless diesel use is eliminated. This pathway is often viewed as a transitional technology for heavy-duty transport and off-highway sectors.

4.1.2 Light-Duty Vehicles

Hydrogen has an opportunity to be utilized in commercially available light-duty FCEV vehicles in Calgary, similar to the use of Toyota Mirai vehicles in the Edmonton Region at the time of this report. However, battery electric vehicles (BEVs) are a compelling alternative for lower-duty-cycle use cases, particularly for intracity transportation, given their higher efficiency and greater commercial availability. Light-duty vehicles are expected to have a limited impact in building the hydrogen value chain and supplementing regional hydrogen demand, as they only require relatively small amounts of hydrogen to operate and should not be considered a high priority for large-scale deployment[79].

REGIONAL SPOTLIGHT – CITY OF CALGARY

The **City of Calgary's Green Fleets** department has a funded hydrogen-mobility pilot that spans multiple vehicle classes. The program includes one light-duty passenger FCEV, medium-duty vocational applications such as refuse trucks, and heavy-duty service-vehicle use cases. This cross-fleet approach allows the City to evaluate hydrogen performance across diverse duty cycles and identify where it may offer operational advantages.

4.1.3 Medium-Duty Vehicles

Hydrogen technology can be a compelling use case in some medium-duty vehicles, particularly delivery trucks, service fleets, and municipal operations that require a longer range and quick refuelling. FCEV options in this segment are emerging, with several manufacturers piloting hydrogen-powered box trucks and vans, though commercial availability remains limited compared to battery electric alternatives. BEVs are currently more attractive for short-haul and urban duty cycles due to higher efficiency, lower fuelling costs, and growing model availability. While medium-duty fleets consume more fuel than light-duty vehicles, their overall hydrogen demand remains modest compared to that of heavy-duty transport. As such, medium-duty applications with intensive duty cycles where electrification faces challenges may serve as useful early adopters for localized hydrogen hubs but are unlikely to anchor large-scale hydrogen demand on their own.

4.1.4 Heavy-Duty Vehicles

Hydrogen adoption is seen as most compelling in class 8 - heavy-duty transport, where high energy demand, long ranges, and quick refuelling make it difficult for battery electric vehicles to compete[52]. Hydrogen FCEVs and hydrogen internal combustion engines are being developed for applications such as long-haul freight, transit buses, and heavy vocational trucks. These vehicles can consume large amounts of hydrogen per day, creating a meaningful anchor load for fuelling infrastructure and regional hydrogen demand growth. While technology costs remain high and commercial models are still limited, heavy-duty fleets are widely viewed as the most strategic early market for hydrogen in transportation, given their potential scale and concentration at freight hubs, depots, and industrial corridors.

Recently, there have been several high-profile bankruptcies of heavy-duty hydrogen truck manufacturers such as Nikola[80] and Hyzon[81]. Currently, the only commercial class 8 trucks available in the province are from Hyundai[82]. For designs outside the standard class 8 tractor, HD2F retrofit kits are the next-best option for use cases such as garbage trucks, snowplows, and other vocational applications.

Due to the lack of compelling alternatives and the contribution of heavy-duty vehicles to building early-stage hydrogen demand, this class of vehicles should be considered a high priority for the city to investigate adoption for municipal fleets, and for the private sector more broadly.

4.1.5 Transit Buses

Transit buses are an attractive segment of the mobility sector where hydrogen technology can offer a strong operational fit. Unlike other hydrogen vehicle architectures, commercial models are available in Canada today, such as New Flyer. The long daily range, fast refuelling, and consistent duty cycle characteristics make them attractive for transit use without the charging downtime associated with battery buses. Several hundred hydrogen buses are already deployed in North America, including the Edmonton Region, which is currently piloting two buses as part of the Alberta Zero Emission Hydrogen Transit (AZEHT) project[83]. Compared to light-duty vehicles, transit buses consume significantly more hydrogen, creating concentrated and predictable demand at centralized depots. While upfront costs and fuelling infrastructure remain barriers, transit fleets can play an important and early role in building out hydrogen refuelling capacity and familiarization with hydrogen technology.

With the recent announcement of Calgary purchasing 120 BEV transit buses[84], an opportunity exists for the City of Calgary to gain a deeper understanding of where BEV technology excels in transit applications and where there is a gap in service needs that hydrogen technology could address. In addition, Calgary Transit should continue to support 'futureproofing' transit bus barn locations to ensure hydrogen compatibility in the future.

REGIONAL PROJECTS

Calgary Transit has plans to pilot hydrogen technology in transit operations, starting with a short-term demonstration using one of the fuel cell electric buses that are currently in operation in the Edmonton Region. Additionally, Calgary Transit, with support from Alberta Innovates, has commissioned the "*Hydrogen Fuelling and Pilot Fleet Feasibility Study*" which is scheduled for completion in 2025.

4.1.6 Rail

Hydrogen rail transport is emerging as a promising application, particularly for freight routes that are difficult to electrify with overhead wires. The relative ease of transition from diesel-electric to fuel cell electric is also an attractive factor. Fuel cell locomotives are being demonstrated in Europe, North America, and Asia, with commercial deployment expected to begin on short- to medium-distance lines first. Rail applications consume substantial amounts of fuel; locomotives can use hundreds of kilograms of hydrogen per day, making them strong candidates for creating the anchoring demand that is needed. However, limited commercial availability and the need for widespread refuelling infrastructure remain barriers. Hydrogen rail is expected to play a niche but impactful role in decarbonizing non-electrified corridors, complementing rather than replacing electrification where grid infrastructure is viable.

REGIONAL PROJECTS

Canadian Pacific Kansas City (CPKC) is a world-leader in hydrogen train design, innovation, and deployment and is headquartered in Calgary. Currently, CPKC has retrofitted three locomotives from diesel electric to fuel cell electric technology, which include a line-haul unit, yard switcher, and high-horsepower locomotive. CPKC has partnered with ATCO EnPower to build electrolysis plants in Calgary and Edmonton to meet the hydrogen requirements of their fleet.

In Calgary, a large opportunity exists in the private rail sector for hydrogen adoption (and an opportunity for shared refuelling infrastructure); however, the city-owned and operated passenger C-Train is electric and already has robust infrastructure in place to support continued use of electric technology and should not be considered for a transition to hydrogen.

4.1.7 Aviation

Hydrogen is being tested in aviation worldwide, primarily for smaller aircraft. Demonstrations range from regional planes retrofitted to run on gaseous hydrogen to larger designs that envision liquid hydrogen for short- and medium-haul flights. While aviation is a high-value target due to its immense fuel demand, it also poses the most significant technical challenge for decarbonization. Hydrogen storage and power systems add substantial weight and volume, making adoption difficult and costly. In practice, Sustainable Aviation Fuel (SAF) is expected to play the dominant role in decarbonizing aviation, with companies like Boeing projecting SAF to play a dominant decarbonization role over the next 30 years[85].

While a hydrogen-based aviation pilot could occur theoretically in the long term in Calgary, it is unlikely to be an area of growth in the short to medium term, if at all. A greater opportunity exists for shared fuelling infrastructure at Calgary International Airport, which could support both ground fleet vehicles and heavy-duty cargo transport vehicles.

4.2 Heat and Power Generation

Hydrogen is seen as an alternative to combusting natural gas for heat and power generation. However, much discourse is ongoing about the scale at which hydrogen could play a long-term role, with compelling alternatives such as electric air or ground-source heat pumps offering significantly higher efficiencies than combustion technology for heating, as well as the competitiveness of hydrogen versus other forms of renewable electricity generation.

4.2.1 Overview

Hydrogen is being assessed for use in heat and power systems, including boilers, turbines, and combined heat and power units[86,87]. Many existing natural gas technologies can be modified to burn hydrogen, but the differences in combustion properties present challenges. Hydrogen burns hotter and faster than natural gas, which can increase NO_x emissions and necessitate the redesign of burners or materials to manage higher flame temperatures. Its lower volumetric energy density also means that higher flow rates are needed for equivalent output, which impacts pipeline and equipment design. While technically feasible, these adaptations add cost and complexity and are project-specific in need.

4.2.2 Heating

Building heating during the winter months in Alberta is primarily achieved using natural gas, made possible through over a century of infrastructure development, including the construction of pipelines and seasonal-scale underground natural gas storage reservoirs. Updating this infrastructure to be hydrogen compatible would be a substantial endeavour that will take time, with significant cost implications. A possible near-term alternative to this is blending low volumes of hydrogen in existing natural gas streams, which would theoretically reduce the carbon intensity of heating. The costs and carbon benefits of these efforts need to be carefully weighed against compelling alternatives, such as ground-source and air-source heat pumps.

In the early stages of the hydrogen ecosystem in Calgary, blending H_2 into natural gas streams for heating could be a compelling opportunity, not only for reducing emissions, but to provide a substantial 'anchor demand' that can help encourage H_2 production infrastructure within the city that will have a high likelihood of being underutilized initially. This could help with both the economics of production and avoid intermittent production, which is challenging for technology that prefers a steady state of operation.

REGIONAL PROJECTS

The **Calgary District Heating (CDH)** system heats nearly six million square feet of building space in the Downtown Calgary and East Village using a thermal pipeline that extends over 12 km in length. Natural gas boilers and a combined heat and power unit provide the thermal energy. CDH successfully piloted the use of blended hydrogen in a six-day trial to test the technical feasibility of blending at 20% by volume.

4.2.3 Power Generation

Electricity generation in Alberta is dominated by natural gas. Transitioning this system to hydrogen compatibility would be a major undertaking with significant costs, similar to using it for heating. Blending hydrogen with natural gas has the potential to modestly reduce carbon intensity while leveraging existing assets. The costs and emission benefits of such approaches must be weighed against other low-carbon generation options, such as wind, solar, and carbon capture and sequestration.

5 CHARACTERIZING MATRIX

This chapter introduces the ranking matrix used to compare diverse technology characteristics and scales involved in hydrogen production and end uses, essentially enabling an “apples-to-oranges” assessment. Such comparisons are inherently complex because the importance of each metric can vary across organizations, regions, and contexts. For instance, a region facing water scarcity may place greater emphasis on water use, whereas a risk-averse organization may prioritize technological maturity.

It is also important to note that some characteristics apply only to hydrogen production (e.g., the use of water or electricity). In contrast, others are specific to end-use applications (for example, the availability of alternative low-carbon technologies). Each characterization is listed below and explained in more detail under its particular heading.

Table 6 Characterizations and applicable technologies

Scale	Technology Applicability	Reference (Units)
Technological Maturity	Production & End Use	Technology Readiness Level (TRL)
Water Impacts	Production	Cooling & Reaction Volume (m^3/day)
Electricity Impacts	Production	Grid Load (MW)
Natural Gas Impacts	Production	Natural Gas Demand (GJ/day)
Carbon Emission Impacts	Production	CO_2 Emissions (tonnes CO_2e/year)
Compelling Alternatives	End Use	Technology Availability
Urban Siting Feasibility	Production & End Use	Zoning Requirements

TECHNOLOGY MATURITY

The ranking table below outlines a technological maturity scale for assessing the readiness and deployment status of emerging technologies. The scale ranges from early-stage conceptual ideas to full commercial deployment. At the highest level, ***Commercial Scale*** technologies are already proven and operating and can be considered low risk from a technical standpoint. ***Demonstration Scale*** technologies have been validated at a meaningful scale but are not yet widespread or commercially available. ***Prototype / Pilot Scale*** refers to systems that have been integrated and tested under controlled pilot conditions but may face challenges in real-world deployment. ***Lab scale*** technologies are high risk and limited to experimental or bench-top validation. ***Conceptual*** technologies remain theoretical, with no practical testing or physical validation to date.

Color					
Technology Maturity *(Technology Readiness Level)*[88]	**Commercial Scale** Technology proven and deployed in real-world commercial operation. *(TRL 9)*	**Demonstration Scale** Technology demonstrated in operational environments but not yet commercially deployed. *(TRL 7–8)*	**Prototype / Pilot Scale** Prototype or pilot system tested in simulated or limited pilot conditions. *(TRL 5–6)*	**Laboratory Scale** Components or subsystems validated through proof of concept or laboratory testing only. *(TRL 3–4)*	**Conceptual** Basic principles observed and technology concept formulated without validation. *(TRL 1–2)*

WATER IMPACTS

The ranking table below outlines the relative water demand associated with different hydrogen production technologies and places these values in the context of Calgary's municipal water system. Calgary's total water use ranges from approximately 450,000 to 600,000 m^3/day[64] (about 350 L per person per day), providing a baseline for a simplified impact scale. **Very Low Impact** technologies have negligible water consumption and do not materially affect local supply, comparable to a small business. **Low Impact** technologies use modest amounts of water similar to typical industrial or commercial operations. **Moderate Impact** reflects noticeable water demand at the city scale and may influence municipal resource planning, such as from medium industrial users or large institutions like golf courses. **High Impact** technologies represent major commercial/industrial users consuming roughly **0.2–2%** of Calgary's daily supply, often requiring water recycling, sourcing strategies, or infrastructure upgrades. At the extreme, **Very High Impact** technologies exceed **2%** of Calgary's daily water use and impose unsustainable demands that could strain or exceed existing surface water supplies.

Color					
Water Impacts *(Volume per Day in m^3)*	**Very Low Impact** Negligible or no water consumption *(<10 m^3/day)*	**Low Impact** Low water demand; in line with typical industrial use *(10–100 m^3/day)*	**Moderate Impact** Noticeable water use at the city level *(100–1k m^3/day)*	**High Impact** Significant water use; would require additional measures *(1k–10k m^3/day)*	**Very High Impact** Unsustainable water demand requirements *(>10k m^3/day)*

ELECTRICITY IMPACTS

The ranking table below outlines the relative electricity demand associated with different hydrogen production technologies and scales. It classifies technologies based on their peak power requirements and the potential scale of their grid impact. **Very Low Impact** systems draw minimal power, comparable to a residential or small business load. **Low Impact** systems have light power needs similar to medium commercial operations. **Moderate Impact** refers to electricity use on par with extensive commercial or light industrial facilities. **High Impact** systems operate at power levels typical of major industrial users, data centres, or hospitals, and could face challenges in implementation in some areas of the city. At the upper end, **Very High Impact** projects have intensive electricity requirements, similar to large industrial complexes or dense urban developments, and may require dedicated grid connections or infrastructure upgrades.

Color					
Electricity Impacts *(Peak Demand in MW)*	**Very Low Impact** Negligible electricity use, comparable to a residential or small business load *(0.01–0.1 MW)*	**Low Impact** Minor use similar to medium commercial operations *(0.1–0.5 MW)*	**Moderate Impact** Demand similar to large commercial or light industrial users *(0.5–2 MW)*	**High Impact** High electricity use typical of large industrial users, hospitals, or data centres *(2–10 MW)*	**Very High Impact** Intensive electricity requirements similar to large industrial plants, needs dedicated infrastructure *(10< MW)*

NATURAL GAS IMPACTS

The ranking table below outlines the relative natural gas demand associated with different hydrogen production technologies. It categorizes technologies based on their reliance on natural gas and the potential implications for local gas distribution systems. **No Impact** technologies operate independently of natural gas. **Low Impact** systems use small amounts comparable to residential or small commercial facilities. **Moderate Impact** technologies have consumption similar to mid-sized commercial or light industrial operations, such as the Calgary Soccer Centre or Dalhousie LRT Station[89]. **High Impact** technologies draw natural gas at levels comparable to major industrial users or large recreational facilities like Southland Leisure Centre[89]. At the upper end, **Very High Impact** technologies have consumption on par with large-scale industrial plants and may require dedicated gas supply infrastructure or capacity upgrades.

Color					
Natural Gas Impacts *(Annual Demand in GJ)*	**No Impact** Technology operates with negligible/no NG input, comparable to an average household *(<100 GJ/year)*	**Low Impact** Low use, comparable to residential or small commercial facilities *(100–2k GJ/year)*	**Moderate Impact** Moderate use, similar to mid-sized commercial or light industrial operations *(2k–10k GJ/year)*	**High Impact** Significant use, typical of major industrial users or large recreational facilities *(10k–100k GJ/year)*	**Very High Impact** Very high use, comparable to large-scale industrial plants *(100k< GJ/year)*

CARBON EMISSION IMPACTS

The table below ranks hydrogen production technologies by their relative carbon intensity, based on Scope 1 greenhouse gas emissions. **Very Low Impact** technologies produce negligible or no direct emissions, such as renewable or nuclear-powered electrolysis. **Low Impact** systems generate small amounts of CO_2 due to effective carbon capture or low-carbon energy inputs. **Moderate Impact** technologies emit measurable CO_2, roughly comparable to efficient natural gas processes without full capture, or mid-sized commercial operations. **High Impact** systems produce significant emissions exceeding 10 kt CO_2/year, comparable to major industrial facilities required to report under the federal Greenhouse Gas Reporting Program such as the Calgary International Airport, or Calgary's District Energy Centre[90]. At the upper end, **Very High Impact** technologies rely heavily on carbon-intensive feedstocks or energy sources, resulting in emissions similar to those from conventional, unabated steam methane reforming or coal gasification. For this metric, the highest CI values were used from each range listed in Chapter 2.

Color					
Carbon Emission Impacts *(Annual Emissions in kilotonnes of CO_2e)*	**Very Low Impact** No direct process (Scope 1) related carbon emissions	**Low Impact** Minor process emissions from low-carbon or captured systems like biogenic carbon inputs *(<1 kt CO_2e/year)*	**Moderate Impact** Noticeable emissions comparable to efficient natural gas processes *(1–10 kt CO_2)*	**High Impact Carbon** Significant direct emissions typical of major industrial facilities *(10–50kt CO_2)*	**Very High Impact** Large, unabated CO_2 emissions from fossil-based processes *(Over 50kt CO_2)*

COMPELLING ALTERNATIVES

The table below categorizes hydrogen end-use technologies based on the availability and competitiveness of alternative low-carbon solutions. It describes how strongly hydrogen is positioned relative to other emerging technologies, such as battery-electric systems, direct electrification, or renewable liquid fuels. **No Viable H_2 Alternatives** indicates that hydrogen is the only practical low-carbon option for the application, such as Canadian long-haul freight. **H_2 Favoured** refers to sectors where few viable options exist and hydrogen remains strongly favoured, including heavy-duty off-road equipment or long-distance rail. **Competitive H_2 Alternatives** apply when both hydrogen and other low-carbon technologies can compete, depending on duty cycle, regional resources, infrastructure, and costs. **H_2 Alternatives Advancing** describes uses where non-H_2 technologies are advancing rapidly. **H_2 Alternatives Preferred** represents applications where other low-carbon options are more cost-effective, efficient, or practical.

Color					
Compelling Alternatives	**No Viable H_2 Alternatives** Hydrogen is the only practical low-carbon option, based on current technology.	**H_2 Favoured** Hydrogen is strongly advantaged vs. alternatives	**Competitive H_2 Alternatives** H_2 and alternatives are both viable depending on duty cycle, region, and costs.	**H_2 Alternatives Advancing** Competing technologies are advancing rapidly and may be preferred	**H_2 Alternatives Preferred** Other low-carbon options outperform hydrogen in cost, efficiency, or practicality.

URBAN SITING FEASIBILITY

The ranking table below evaluates the suitability of different H2 production technologies for installation in or near urban environments, considering footprint, emissions, safety, and noise. **Very High Urban Feasibility** systems are small, quiet, and perceived as low risk, and potentially could be located directly on commercial, institutional, or even private properties. **High Urban Feasibility** systems can be sited in dense commercial or light-industrial areas with standard safety provisions. **Moderate Urban Feasibility** systems suit industrial zones or city edges, requiring dedicated space and permitting. **Low Urban Feasibility** systems generally require heavy industrial zoning and significant setbacks from public spaces. **No Urban Feasibility** systems are typically unsuitable for any urban or peri-urban location and must be placed in remote or isolated industrial settings.

Color					
Urban Siting Feasibility	**Very Urban High Feasibility** Low-risk unit with potential for direct use on commercial or private property.	**High Feasibility** Likely suited for industrial or dense commercial zones with routine safety controls.	**Moderate Feasibility** Potentially requires industrial land, a location on the city edge with extra safety measures.	**Low Feasibility** Likely to need substantial setbacks from public spaces, similar to heavy industry.	**No Feasibility** High likelihood of being unsuitable for urban siting; may require a remote or isolated industrial location.

6 PUTTING IT ALL TOGETHER

6.1 Supply Side

SHORT TERM, SMALL SCALE (1 TPD)

		Technology Characteristics – 1 Tonne Per Day Facility Illustrative Example					
		Technology Maturity	Water Impacts	Electricity Impacts	Natural Gas Impacts	Emission Impacts[1,2]	Urban Feasibility
Technology Type	Water Electrolysis	Mature at this scale	Low water impact	High impact of over 2 MW demand	No natural gas feedstock	Significant grid emissions, reporting to GHGRP, are required	Minimal siting concerns at smaller scales
	Methane Reforming	Mature, but typically deployed at larger scales	Low water impact	Low electrical impact	Significant use, typical of large recreational facilities	Moderate emissions without CCS; CI sensitive to CH_4 leakage	Plant emissions require heavy-industrial zoning
	Methane Pyrolysis	Current pilots exist at <1 TPD	No process water required; cooling water may be required	Low electrical impact	Significant use, typical of large recreational facilities	No direct emissions (carbon black), primarily from heating	Plant emissions and noise require heavy-industrial zoning
	Biomass/MSW Gasification	Pilot/demonstration phase for hydrogen, only testing at smaller scale	Low water impact	Low electrical impact	No natural gas feedstock	Biogenic feedstock; low-carbon or carbon-negative with CCS	Plant emissions and odor require heavy-industrial zoning
	Methanol to Hydrogen	Mature at this scale	Very low water impact	Low electrical impact	No natural gas feedstock	Emissions depend on methanol lifecycle; reforming produces moderate emissions	Likely suited for industrial or light-industrial zones with routine safety controls
	Ammonia to Hydrogen	Small-scale in early commercial/prototype stage globally only	No process water required, cooling water may be required	Low electrical impact	No natural gas feedstock	Ammonia molecule does not contain carbon	Plant emissions require heavy-industrial zoning

1) Grid electricity CI values were used for emission impacts from electricity
2) It is assumed that at this scale, carbon capture infrastructure tie-in is uneconomic

MEDIUM TERM, MEDIUM SCALE (10 TPD)

		Technology Characteristics – 10 Tonne Per Day Facility Illustrative Example					
		Technology Maturity	Water Impacts	Electricity Impacts	Natural Gas Impacts	Emission Impacts[1,2]	Urban Feasibility
Technology Type	Water Electrolysis	Mature at this scale	Moderate impact similar to medium industrial users	Very high impact of ~2% of Calgary's electrical load	No natural gas feedstock	Unreasonable grid emissions at this scale; low-carbon electricity required	Likely suited for industrial or dense commercial zones
	Methane Reforming	Mature at this scale	Moderate impact similar to medium industrial users	Moderate impact similar to large commercial or light industrial users	Very high use, comparable to large-scale industrial plants	Significant direct emissions, reporting to GHGRP required	Plant emissions require heavy-industrial zoning
	Methane Pyrolysis	Demonstration facility in U.S. operating at this scale (Monolith) – other pyrolysis pathways less advanced	No process water, cooling water may be required	High electricity use, typical of large industrial users	Very high use, comparable to large-scale industrial plants	No direct emissions (carbon black), heating emissions may be of GHGRP reporting scale	Plant emissions and noise require heavy-industrial zoning
	Biomass/MSW Gasification	Pilots underway at this scale	Moderate impact similar to medium industrial users	High electricity use, typical of large industrial users	No natural gas feedstock	Biogenic feedstock may create emissions; potential carbon-negative with CCS	Plant emissions and odor require heavy-industrial zoning
	Methanol to Hydrogen	Mature at smaller scales, may be less attractive at large scales	Moderate impact similar to medium industrial users	High electricity use, typical of large industrial users	No natural gas feedstock	Significant direct emissions, reporting to GHGRP required	Likely suited for industrial or dense commercial zones with routine safety controls
	Ammonia to Hydrogen	High TRL, but 10 TPD fuel-grade units are still pilot / early commercial	No process water, cooling water may be required	Moderate impact similar to large commercial or light industrial users	No natural gas feedstock	Ammonia molecule does not contain carbon	Likely limited to industrial zones with hazardous-materials handling (ammonia storage) and robust safety systems

1) Grid electricity CI values were used for emission impacts from electricity
2) It is assumed that at this scale, carbon capture infrastructure tie-in is uneconomic

LONG TERM, LARGE SCALE (100 TPD)

Technology Type		Technology Maturity	Water Impacts	Electricity Impacts	Nat. Gas Impacts	Emission Impacts[1]	Urban Feasibility
Technology Type	Water Electrolysis	100 TPD systems are world-class in size and limited by electricity supply	Large-scale water use approaching 0.75% of Calgary's water use	Unsustainable electrical demand requirements based on current grid	No natural gas feedstock	Unreasonable grid emissions at this scale; low-carbon electricity required	Large footprint and grid connection likely require industrial or large utility-scale sites
	Methane Reforming	Mature at this scale	Large-scale water use approaching 0.28% of Calgary's water use	Very high impact of ~1% of Calgary's electrical load	Very high use, comparable to large-scale industrial plants	Large-scale direct emissions, reporting to GHGRP required	Large scale emissions and noise require heavy-industrial zoning
	Methane Pyrolysis*						
	Biomass/MSW Gasification*						
	Methanol to Hydrogen*						
	Ammonia to Hydrogen	High TRL globally; 100 TPD plants are early commercial, with limited operating experience and none in Canada	Moderate impact similar to medium industrial users	Very high impact of ~1% of Calgary's electrical load	No natural gas feedstock	Ammonia molecule does not contain carbon	Large scale of dangerous chemical usage unsuitable for any urban location, requires heavy-industrial sites with major hazardous-materials storage

Technology Characteristics – 100 Tonne Per Day Facility Illustrative Example

1) Grid electricity CI values were used for emission impacts from electricity
* Cells are greyed out to indicate that this technology is not commercially available at the scale shown.

FUTURE TERM, INDUSTRIAL SCALE (1,000 TPD)

		Technology Characteristics – 1,000 Tonne Per Day Facility Illustrative Example					
		Technology Maturity	Water Impacts	Electricity Impacts	Nat. Gas Impacts	Emission Impacts[1]	Urban Feasibility
Technology Type	Water Electrolysis*						
	Methane Reforming	Mature at this scale; world-scale SMR plants already exceed 1,000 TPD	Unsustainable water use approaching 3% of Calgary's water use	Unsustainable electrical demand requirements	Extreme use, comparable to large-scale industrial plants	Large-scale direct emissions, reporting to GHGRP required	Scale of emissions unsuitable for any urban location and must be placed in remote or isolated industrial settings
	Methane Pyrolysis*						
	Biomass/MSW Gasification*						
	Methanol to Hydrogen*						
	Ammonia to Hydrogen	High TRL for core technology, but 1,000 TPD fuel-grade plants are still conceptual / early design with no operating references	Large-scale water use approaching 1.75% of Calgary's water use	Unsustainable electrical demand requirements	No natural gas feedstock	Ammonia molecule does not contain carbon	Large scale of dangerous chemical usage unsuitable for any urban location, requires heavy-industrial sites with major hazardous-materials storage

1) Grid electricity CI values were used for emission impacts from electricity
* Cells are greyed out to indicate that this technology is not commercially available at the scale shown.

6.2 Demand Side

Table 7 On-road vehicles: technology readiness and competing alternatives

End-Use	Hydrogen Technology	Technology Maturity	Is H_2 a Compelling Option?	Alternative Low-Carbon Technology	Notes
Light-Duty Vehicles (LDV)	Hydrogen Fuel-Cell Electric	TRL 8	H_2 Alternatives Preferred	• BEVs • Plug-in hybrid-electric	Passenger vehicles such as Toyota Mirai[91] exist in Alberta, however BEVs are generally cheaper, more efficient, and are supported today by existing charging networks in Alberta.
Medium-Duty Vehicles (MDV)	Hydrogen Fuel-Cell Electric	TRL 7	Competitive H_2 Alternatives – Duty Cycle Dependent	• BEVs • Plug-in hybrid-electric	Lack of commercially available medium-duty FCEVs in Canada. BEV technology exists, but it is also challenged with intensive duty cycles, cold weather, and long distances.
	Hydrogen Diesel Dual-Fuel	TRL 9			Conversion kits are available but are considered an intermediate solution.
Heavy-Duty Vehicles (HDV)	Hydrogen Fuel-Cell Electric	TRL 9	H_2 Favoured	• BEVs (short haul) • Renewable diesel in conventional heavy-duty ICE	FCEVs are considered a strong option for long-distance trucking and intensive duty cycles, with the AZETEC project[92] and the Hyundai Xcient[93] as recent examples. Canadian weight class vehicles are not currently available.
	Hydrogen Diesel Dual-Fuel	TRL 9			Conversion kits are available but are considered an intermediate solution.
	Hydrogen ICE	TRL 4-5			Hydrogen ICE platform development is limited
Municipal Vocational Fleets	Hydrogen Fuel-Cell Electric	TRL 6–7	Competitive H_2 Alternatives – Duty Cycle Dependent	• Renewable diesel in a conventional ICE	Lack of commercially available vocational FCEVs in Canada. BEV technology exists, but it is also challenged with intensive duty cycles, cold weather, and long distances.
	Hydrogen Diesel Dual-Fuel	TRL 9			Conversion kits are available but are considered an intermediate solution.
Transit Buses	Hydrogen Fuel-Cell Electric	TRL 9	Competitive H_2 Alternatives – Duty Cycle/Route Dependent	• BEVs	New Flyer FCEV and BEV buses are manufactured and available in Canada – Challenges with winter conditions for BEVs that require diesel heaters.
	Hydrogen Diesel Dual-Fuel	**TRL 9**			Conversion kits are available but are considered an intermediate solution.

Table 8 Alternative vehicles, power, and heating: technology readiness and competing alternatives

End-Use	Hydrogen Technology	Technology Maturity	Is H_2 a Compelling Option?	Alternative Low Carbon Technology	Notes
Aviation	Sustainable Aviation Fuel (SAF)	TRL 8–9	H_2 (SAF) Favoured	• BEV or FCEV being explored, but weight challenged	Net-zero aviation research focus is mainly on SAF production.
Rail (Locomotives)	Fuel-Cell Electric Drivetrain	TRL 9	Competitive H_2 Alternatives	• BEV • Renewable diesel	Proven FCEV technology through the ERA's *Hydrogen Locomotive Program*[94] in Alberta. BEV pilots are ongoing.
Building & District Heating	Blended Hydrogen	TRL 7–8	H_2 Alternatives Advancing	• Electrified heating (resistive or heat pumps) • Renewable natural gas combustion	Pilots underway such as ATCO's Fort Saskatchewan project[95], however, requires a case-by-case review of associated infrastructure.
	Full H_2 Combustion in Boilers / Furnaces	TRL 6–7	H_2 Alternatives Advancing		ATCO has built a demonstration hydrogen-heated home[96] and is exploring 100% H_2 in limited settings.
Power Generation	H_2 Turbine / Co-firing with NG	TRL 7–8	H_2 Alternatives Advancing	• Renewable generation with storage • Grid supply with carbon offset	In Canada, the relevant turbines are largely "H_2 ready" concepts within gas-generation, but actual H_2 co-firing is minimal.
	On-site Fuel-Cell Electricity Generation	TRL 9	Competitive H_2 Alternatives		In Canada, the technology is available, but adoption is niche. TRL is 9, but market penetration is low due to costs and cheap grid electricity in Alberta.

7 REMAINING CHALLENGES

This chapter covers the challenges identified throughout the engagement process for this report, including conversations with City of Calgary employees, organizations that use hydrogen today, and various organizations across the hydrogen value chain. Each section is separated by theme.

7.1 Knowledge Gap Challenges

Table 9 Knowledge gap themes

Knowledge Gap	Other Comments
Determining the credibility of hydrogen companies in the ecosystem	• Recent bankruptcies of hydrogen companies • Start-up nature of many organizations
Understanding what a realistic price for hydrogen is	• Lack of hydrogen benchmarks • Opaque pricing within the province • Current H_2 market instability • Key metric in calculating total cost of ownership
Uncertainty about the safety of using hydrogen, particularly in high-usage scenarios	• Existing facility readiness
Regulation and zoning uncertainty	• Hydrogen is not mentioned in existing bylaws
Water usage implications	• Constrained water supply in Calgary
Employee workforce training options	• Lack of operational experience with H_2
Unknown risk level of pilots & projects	• Risk-averse nature of City organization • Questionable service reliability of technology • Unknown integration with city service priorities
Understanding where hydrogen can play a role	• Operational proof of concept
Awareness of hydrogen's economic opportunity	

7.2 Economic & Investment Challenges

Table 10 Economic and investment challenges

Economic & Investment Challenges	Other Comments
Demonstrating value to businesses and citizens within the city	• Adoption needs to show clear value in dollars saved, service benefits, or direct impacts to Calgarians
Funding uncertainty	• Leadership is needed at the provincial level • Continued federal incentives
Competing with incumbent energy sources	• Competing with low-cost energy, particularly natural gas, was seen as a key challenge for heating adoption • Lack of carbon tax
Cost of delivered hydrogen	• Secondary revenue streams need to be considered (i.e. carbon black for pyrolysis) • Low demand creates higher per-unit costs

7.3 Technology Challenges

Table 11 Technology and innovation challenges

Technology & Innovation Challenges	Other Comments
Limited availability of commercial technology or low TRL technologies	• Lack of proven operating data
Water required to produce hydrogen	• Low water use design to be considered for projects • Non-potable water inputs, such as wastewater, are desired

7.4 Policy Challenges

Table 12 Policy and regulation challenges

Policy	Other Comments
Federal uncertainty in low-carbon policy direction	• Removal of the consumer carbon tax and ZEV mandate pause
Ability for non-city-owned vehicles to access city-owned land for refuelling	• Liability issues • Challenging to aggregate demand between organizations

Procurement of new technology	• Limited vendors may exist • More information and validations are required vs. traditional technology procurement – multiple conversations are required, often running against procurement guidelines

7.5 Infrastructure Challenges

Table 13 Infrastructure challenges

Infrastructure Challenges	Other Comments
Urban Deployment	• Logistics, space, and noise factors need to be considered • Technologies such as pyrolysis may face considerable challenges with solid carbon handling and cleanliness • Brownfield and existing industrial locations are likely the best locations for H_2 projects
Challenges to retrofit existing transit and fleet facilities	• Identified as a bottleneck in CNG deployment • Understanding if hydrogen vehicles can be used in CNG-ready bays
New fleet facility planning	• Determining infrastructure requirements for multi-fuel fleet facilities
Land use	• The city owns considerable land, but there is competition for its use • Utility-served land options may be limited
Utility capacity	• Electricity distribution grid in Calgary is a constraining factor – varies by region • Gas transmission pipeline capacity is low currently – likely until 2027
Access to carbon sequestration infrastructure	• No dedicated infrastructure or access to the Alberta Carbon Trunk Line (ACTL) • Large-scale production facility required to justify a connection to a carbon capture system

7.6 Regulations, Codes, and Standards Challenges

Table 14 Codes and standards challenges

Policy & Regulation	Other Comments
Lack of provincial codes for hydrogen fuelling stations	
Local bylaw gaps	• Land use bylaw 1P2007 – no mention of hydrogen

8 MAKING THE LEAP—ACTIONABLE NEXT STEPS

This chapter outlines the actionable steps the City of Calgary can take to address key challenges identified in previous chapters, informed by extensive engagement. Table 15 below summarizes key actions to expedite hydrogen adoption.

Table 15 Actionable next steps

Challenge	Action to be Taken
Knowledge Gaps	• Engage with Calgary Region Hydrogen Hub to explore meaningful workshops and other events • Offer department training on hydrogen basics internally, and consider outreach to the public, alongside other climate initiatives • Develop relationships with municipalities such as Edmonton, Winnipeg, and with U.S counterparts that are actively using hydrogen in their fleets and consider sending staff for operational knowledge transfer • Develop internal subject matter experts who can articulate investment costs, operating costs, and put together project budgets and business cases.
Economics & Investment	• Develop a framework/process for aggregating hydrogen demand with outside organizations • Partner and support organizations in the hydrogen leadership space, such as the Alberta Motor Transportation Association (AMTA), and share supply infrastructure to reduce costs • Create a cross-departmental working group to ensure all hydrogen projects are in sync to reduce supply infrastructure required at early stages; have this group develop a demand timeline to help align temporal and quantitative aspects for shared fuelling infrastructure • Explore funding opportunities and programs from provincial and federal sources
Technology	• Engage with a local technology provider that has proven experience in Canada (preferably in Alberta) • Ensure service personnel are located within or adjacent to the Calgary Region • Ensure that all equipment is appropriately certified for use in Alberta with ABSA • Meet with municipalities that are utilizing the same provider to understand lessons learned • Learn from the successes and challenges of previous CNG fleet adoption efforts • Ensure new BEB fleet is studied, understand where BEB technology may fall short and where there is a strong case for hydrogen

Policy	• Establish the conditions under which non-City-owned vehicles may access City-owned land for refuelling, ensuring safety, equity, operational efficiency, and alignment with municipal objectives • Consider conducting hydrogen technology procurement in a manner that aligns with innovation and adoption of new technologies, allowing for flexibility, including sole sourcing when justified, while ensuring transparency, fairness, and alignment with municipal objectives
Infrastructure	• Identify city-owned land that can be utilized for an early-stage supply project that can meet the needs of multiple interested departments and outside partners • Understand from a liability/legal perspective what is required to enable the sharing of infrastructure • Consider proximity to utilities such as electricity, natural gas, and wastewater sources as key factors to location selection • Future-proof planned maintenance and fuelling facilities by ensuring they meet CSA or other available hydrogen standards
Regulations, Codes, and Standards	• Consider including a hydrogen fuelling facility in future reviews of the land use bylaw 1P2007 • Identify the required organizations that need to be involved in any hydrogen project within Calgary ahead of time (e.g. Government of Alberta, local approving authority, Alberta Boilers Safety Association, etc). Collaborate extensively with these groups • Participate in standards process committees that relate to hydrogen, such as CSA Group, to ensure that standards are well understood and designed with municipal input • Consider connecting with University of Calgary and University of Alberta on work related to H_2 standards

8.1 Supporting Hydrogen in Calgary

The key step to advancing hydrogen adoption in the city is securing a reliable hydrogen supply. A supply source within Calgary enables funded pilots, such as the Green Fleets H_2 project, to move forward without timing risks to project funding. It also reduces the barrier to entry for other interested parties evaluating hydrogen. The main supply-focused actions are:

1. Enable access to city-owned land for hydrogen fuelling infrastructure, located where Green Fleets, Transit, and heavy-duty operators can access without significant disruption to regular business.
2. Work with AMTA and other partners on first-of-their-kind fuelling projects in Calgary, while keeping future partnerships open to improve utilization and reduce costs.
3. Source technology from an Alberta-proven provider and consider a mobile or interim option with room to expand. Let experienced project partners lead the procurement of first-of-its-kind fuelling infrastructure to avoid procurement-related innovation challenges.
4. Explore funding opportunities from Provincial (ERA, HCOE) and Federal (NRCan, PrariesCan) sources to highlight the strategic significance of opening up a transportation corridor between Edmonton and Calgary that will derisk adoption for carriers.

Appendix

Color					
Technology Maturity *(Technology Readiness Level)*[88]	**Commercial Scale** Technology proven and deployed in real-world commercial operation. *(TRL 9)*	**Demonstration Scale** Technology demonstrated in operational environments but not yet commercially deployed. *(TRL 7–8)*	**Prototype / Pilot Scale** Prototype or pilot system tested in simulated or limited pilot conditions. *(TRL 5–6)*	**Laboratory Scale** Components or subsystems validated through proof of concept or laboratory testing only. *(TRL 3–4)*	**Conceptual** Basic principles observed and technology concept formulated without validation. *(TRL 1–2)*
Water Impacts *(Volume per Day in m³)*	**Very Low Impact** Negligible or no water consumption *(<10 m³/day)*	**Low Impact** Low water demand; in line with typical industrial use *(10–100 m³/day)*	**Moderate Impact** Noticeable water use at the city level *(100–1k m³/day)*	**High Impact** Significant water use; would require additional measures *(1k–10k m³/day)*	**Very High Impact** Unsustainable water demand requirements *(>10k m³/day)*
Electricity Impacts *(Peak Demand in MW)*	**Very Low Impact** Negligible electricity use, comparable to a residential or small business load *(0.01–0.1 MW)*	**Low Impact** Minor use similar to medium commercial operations *(0.1–0.5 MW)*	**Moderate Impact** Demand similar to large commercial or light industrial users *(0.5–2 MW)*	**High Impact** High electricity use typical of large industrial users, hospitals, or data centres *(2–10 MW)*	**Very High Impact** Intensive electricity requirements similar to large industrial plants, needs dedicated infrastructure *(10< MW)*
Natural Gas Impacts *(Annual Demand in GJ)*	**No Impact** Technology operates with negligible/no NG input, comparable to an average household *(<100 GJ/year)*	**Low Impact** Low use, comparable to residential or small commercial facilities *(100–2k GJ/year)*	**Moderate Impact** Moderate use, similar to mid-sized commercial or light industrial operations *(2k–10k GJ/year)*	**High Impact** Significant use, typical of major industrial users or large recreational facilities *(10k–100k GJ/year)*	**Very High Impact** Very high use, comparable to large-scale industrial plants *(100k< GJ/year)*
Carbon Emission Impacts *(Annual Emissions in kilotonnes of CO_2e)*	**Very Low Impact** No direct process (Scope 1) related carbon emissions	**Low Impact** Minor process emissions from low-carbon or partially captured systems like biogenic carbon inputs *(<1 kt CO_2e/year)*	**Moderate Impact** Noticeable emissions comparable to efficient natural gas processes *(1–10 kt CO_2)*	**High Impact Carbon** Significant direct emissions typical of major industrial facilities *(10–50kt CO_2)*	**Very High Impact** Large, unabated CO_2 emissions from fossil-based processes *(Over 50kt CO_2)*
Compelling Alternatives	**No Viable H_2 Alternatives** Hydrogen is the only practical low-carbon option, based on current technology.	**H_2 Favoured** Hydrogen strongly advantaged; alternatives are technically or economically weak.	**Competitive H_2 Alternatives** H_2 and alternatives both viable depending on duty cycle, region, and costs.	**H_2 Alternatives Advancing** Competing technologies are advancing rapidly and may displace hydrogen.	**H_2 Alternatives Preferred** Other low-carbon options outperform hydrogen in cost, efficiency, or practicality

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