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TECHNO-ECONOMICS OF A NEW HYDROGEN VALUE CHAIN SUPPORTING HEAVY DUTY TRANSPORT

Mohd Adnan Khan, PhD
Catherine MacKinnon, MSc, P. Eng.
Cameron Young, MSc, P.Eng.
David B. Layzell, PhD, FRSC

The Transition Accelerator
L'Accélérateur de transition

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Mohd Adnan Khan, PhD
Energy Systems Analyst
TRANSITION ACCELERATOR

Catherine MacKinnon, P.Eng., MSc
Energy Systems Analyst
CESAR, UNIVERSITY OF CALGARY

Cameron Young, P.Eng., MSc
Energy Systems Analyst
CESAR, UNIVERSITY OF CALGARY

David B. Layzell, PhD, FRSC
Energy Systems Architect
TRANSITION ACCELERATOR

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ABOUT THE TRANSITION ACCELERATOR

The Transition Accelerator (The Accelerator) exists to support Canada's transition to a net zero future while solving societal challenges. Using our four-step methodology, The Accelerator works with innovative groups to create visions of what a socially and economically desirable net zero future will look like and build out transition pathways that will enable Canada to get there. The Accelerator's role is that of an enabler, facilitator, and force multiplier that forms coalitions to take steps down these pathways and get change moving on the ground.

Our four-step approach is to understand, codevelop, analyze and advance credible and compelling transition pathways capable of achieving societal and economic objectives, including driving the country towards net zero greenhouse gas emissions by 2050.

1. UNDERSTAND the system that is being transformed, including its strengths and weaknesses, and the technology, business model, and social innovations that are poised to disrupt the existing system by addressing one or more of its shortcomings.

2. CODEVELOP transformative visions and pathways in concert with key stakeholders and innovators drawn from industry, government, indigenous communities, academia, and other groups. This engagement process is informed by the insights gained in Stage 1.

3. ANALYZE and model the candidate pathways from Stage 2 to assess costs, benefits, trade-offs, public acceptability, barriers, and bottlenecks. With these insights, the process then re-engages key players to revise the vision and pathway(s), so they are more credible, compelling, and capable of achieving societal objectives that include major GHG emission reductions.

4. ADVANCE the most credible, compelling, and capable transition pathways by informing innovation strategies, engaging partners, and helping to launch consortia to take tangible steps along defined transition pathways.

ABOUT THE AUTHORS

Mohd Adnan Khan PhD

TRANSITION ACCELERATOR

Mohd Adnan Khan, PhD, is as an Energy Systems Analyst who joined the Transition Accelerator to help design pathways towards the establishment of a sustainable energy future. Adnan has a PhD in Material Science and Engineering and is passionate about working on renewable energy systems and contributing to the development of a future H_2 economy. He has over 8 years of industrial and academic experience leading research teams across the value chain of technology development and commercialization, driving innovation, and fostering collaboration among industry, government, and academia. He has published over 35 articles in top scientific journals, has 7 granted patents and now hopes his work will lead to the spin-out of consortia led projects, get change moving on the ground and help drive Canada towards a net-zero future.

Catherine MacKinnon P.Eng., MSc

CESAR, UNIVERSITY OF CALGARY

Catherine MacKinnon, P.Eng., MSc is an Energy Systems Analyst at the CESAR Initiative at the University of Calgary. She has a Master of Science degree in Sustainable Energy Development (SEDV) and a Bachelor of Science degree in Chemical Engineering from the University of Calgary. She is a Professional Engineer in good standing with The Association of Professional Engineers and Geoscientists of Alberta and has more than nine years of professional experience in the upstream energy industry in various technical, corporate, and financial roles. She recently completed her capstone project, exploring the carbon footprint and carbon management strategies of direct and indirect GHG emissions associated with operations of a remote, off-grid research station in the Yukon.

Cameron Young P.Eng., MSc

CESAR, UNIVERSITY OF CALGARY

Cameron Young, P.Eng., MSc is an Energy Systems Analyst at CESAR. He joined CESAR to help create a hydrogen economy in Canada. His work will include research on different pathways for hydrogen production, transmission, and distribution to provide pragmatic information for industry and policy makers. He hopes his work will help develop projects that convert Alberta's resources into a sustainable source of hydrogen fuel. Cameron has a Chemical Engineering & Management double-major bachelor's degree from McMaster University, a Masters in Sustainable Energy Development from the University of Calgary and is registered as a Professional Engineer with APEGA. He has 10 years of process engineering and project development experience in Alberta's energy sector.

David B. Layzell PhD, FRSC

TRANSITION ACCELERATOR

David B. Layzell, PhD, FRSC is an Energy Systems Architect with the Transition Accelerator, a Faculty Professor at the University of Calgary, and Director of the Canadian Energy Systems Analysis Research CESAR Initiative. Between 2008 and 2012, he was Executive Director of the Institute for Sustainable Energy, Environment and Economy (ISEEE), a cross-faculty, graduate research, and training institute at the University of Calgary. Before moving to Calgary, Dr. Layzell was a Professor of Biology at Queen's University, Kingston (cross appointments in Environmental Studies and the School of Public Policy), and Executive Director of BIOCAP Canada, a research foundation focused on biological solutions to climate change. While at Queen's, he founded a scientific instrumentation company called Qubit Systems Inc. and was elected 'Fellow of the Royal Society of Canada' (FRSC) for his research contributions.

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LIST OF ABBREVIATIONS

ABBREVIATION	DEFINITION
AIH	Alberta Industrial Heartland, a region in Alberta which includes Edmonton, Strathcona, Fort Saskatchewan, Sturgeon, and Lamont counties
ATR	Autothermal Reforming
BEB	Battery Electric Bus
Blue H_2	Hydrogen produced from natural gas with carbon capture and storage
CESAR	Canadian Energy Systems Analysis Research
CCS	Carbon Capture and Storage
CCSU	Carbon Capture, Storage and Utilization
CO_2	Carbon Dioxide
CRF	Capital Recovery Factor
DTE	Drivetrain Efficiency
EOR	Enhanced Oil Recovery
EWMC	Edmonton Waste Management Centre
FCEB	Fuel Cell Electric Bus
GHG	Greenhouse Gas
GJ	Gigajoule (10^9 Joules)
Green H_2	Hydrogen produced by water electrolysis using intermittent zero-carbon electricity generated from wind and solar facilities
Gray H_2	Hydrogen produced from natural gas or coal without carbon capture and storage

H_2	Hydrogen
HDV	Heavy-Duty Vehicle: Vehicles with a gross vehicle weight rating >= 15 metric ton or tonne
HFCEV	Hydrogen Fuel Cell Electric Vehicle
HFS	Hydrogen Fueling Station
HHV	Higher Heating Value
ICE	Internal Combustion Engine
IF	Installation Factor
LCOH	Levelized Cost of Hydrogen
LDV	Light-Duty Vehicle
LH_2	Liquid Hydrogen
MDV	Medium-Duty Vehicle
NG	Natural Gas
NWR	Northwest Redwater
O&M	Operations and Maintenance
PJ	Petajoule (10^{15} Joules)
SF	Scale Factor
SMR	Steam Methane Reforming
SUT	Single Unit Truck
TCI	Total Capital Investment
TIC	Total Installed Cost
UC	Uninstalled Cost

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EXECUTIVE SUMMARY

Concerns about the adverse impacts of climate change have led Canada and other nations around the world to commit to net-zero greenhouse gas (GHG) emissions by 2050. The distributed, end use combustion of fossil-carbon based energy carriers (gasoline, diesel, jet fuel, natural gas) accounts for almost half of Canada's GHG emissions and another 24% can be attributed to their recovery and upgrading [1]. Clearly, the transition pathway to net-zero requires new energy systems where traditional fossil-carbon based fuels are replaced with zero-emission energy carriers that are produced with minimal or no GHG emissions.

While low carbon electricity will play a major role in replacing carbon-based fuels, there are certain sectors that require a zero-emission chemical energy carrier like hydrogen gas (H_2). Hydrogen is seen as the zero-emission fuel of choice for sectors such as heavy-duty transport, space heating in cold climates, many industrial sectors and as a backup for intermittent renewables in power generation.

The use of low GHG hydrogen to decarbonize our energy systems is of particular relevance in Alberta. The province is strategically positioned to be a global H_2 leader, blessed with excellent wind and solar resources to support electrolytic low GHG 'green' hydrogen production, as well as abundant natural gas and the geology for permanent CO_2 storage to make low GHG 'blue' hydrogen from fossil fuels.

Alberta currently produces more than 5000 tons of low-cost H_2 (about 0.9 to 1.4 C$/kg$_{H2}$) per day, but most is coupled to significant emissions of GHGs, and virtually all is used as industrial feedstocks for the production of crude oil, fertilizers, fuels, and chemicals. Decarbonization of the province's hydrogen has the potential to reduce the carbon intensity of these industrial processes, generate zero emission fuels for export to other nations, and provide low GHG fuel hydrogen to decarbonize domestic transportation, space heating and power generation.

Based on Alberta's energy system in 2018 [2], the potential domestic fuel hydrogen market is about 13,000 t_{H2}/day, with transportation accounting for 21%, building space and water heating for 37%, and industrial heat and power generation for 42%. However, the successful buildout of a fuel hydrogen economy will require the creation of new value chains that will connect hydrogen supply to new demand sectors and make hydrogen available at a reasonable cost at widely distributed locations.

Since Canadians pay 5 to 10 times more per unit of energy for transportation fuels than for heating fuels, the transportation fuel market for hydrogen, especially for heavy-duty vehicles, holds the greatest promise for early adoption. In the transportation fuel market, target retail prices for hydrogen should be in the range of 5 to 8 C/kg_{H2}$ to be competitive with the current prices for diesel. For heating markets in a net-zero future, retail hydrogen prices of 2-3 C/kg_{H2}$ is a reasonable target.

This report presents the design and techno-economic analyses of new value chains for delivering hydrogen from centralized production sites to fueling stations supporting heavy duty vehicles, including trucks, buses, and trains. It builds on earlier studies from CESAR [3-5] and the Transition Accelerator [6-8], that show hydrogen to be the net-zero fuel of choice for heavy duty vehicles, and analysis on the techno-economics of compressing and pipelining hydrogen [9,10].

While the findings presented here should have relevance to any region of Canada interested in centralized, low GHG hydrogen production, the model parameters were chosen for their relevance to the Edmonton Region Hydrogen HUB (https://erh2.ca/), where different sized (0.4, 2 or 8 t_{H2}/day) hydrogen fueling stations (HFS) were assessed at distances of 5, 40 or 300 km from a centralized production facility.

Three hydrogen transportation modes were considered including: (A) compressed hydrogen in tube trailers (TT) trucked to stations, (B) liquid hydrogen (LH_2) in cryogenic tanks trucked to stations, and (C) compressed hydrogen in pipelines to the station. Detailed techno-economic analyses of the various processing units across the different value chains revealed the pre-tax, refueling costs of hydrogen which were then compared with what is needed to be competitive with diesel fuel without public subsidies.

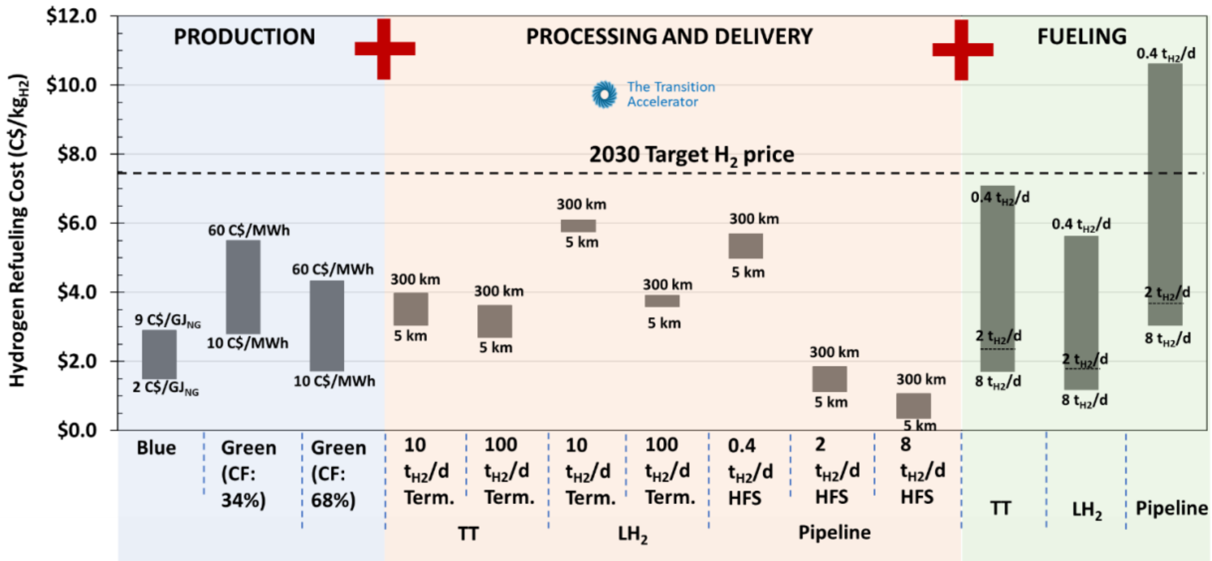

Figure ES. 1. Refueling cost of hydrogen (C$/$kg_{H2}$) for the different Supply Chains (A, B and C) and divided into production plus processing & delivery plus fueling cost.

Note: The black dash line represents the target hydrogen retail price based on a diesel cost of 1.25 C$/$L_{diesel}$, drive train efficiency of 0.86 PJ_{H2}/PJ_{diesel} plus a 2030 carbon price of 170 C$/$t_{CO2}$, without any fuel taxes on hydrogen. The analysis assumes use of large transmission pipelines capable of transporting 300 t_{H2}/day over 295 km and 100 t_{H2}/day over 35 km.

The techno-economic results revealed that processing, delivery and fueling of hydrogen is complex with several factors impacting the refueling cost of hydrogen. However, in a mature hydrogen economy, by employing economies of scale the total estimated refueling cost of hydrogen (**Figure ES. 1**) should be competitive with diesel for heavy duty transport at 5 to 8 C$/$kg_{H2}$ or 35 to 56 C$/$GJ_{H2}$. The **hydrogen costs can be summarized** as follows:

1. **Production costs**: The analysis reveals that to target a hydrogen refueling cost that is competitive with diesel in 2030, centralized production costs will have to be <3 C$/$kg_{H2}$. Green hydrogen production costs depend on the cost and near continuous availability of low-carbon electricity

supply. With the current cost of electrolyzers, if low-carbon electricity is available ≥68% of the time at low costs (< 30 C$/MWh), green hydrogen can be made for <3 C$/$kg_{H2}$. On the other hand, centralized blue hydrogen production via methane reforming represents the lowest cost (<1.8 C$/$kg_{H2}$) option in a province like Alberta with availability of low-cost natural gas and geology for CCS. Additionally, blue hydrogen offers the possibility of quickly getting to scale which will drive down costs.

2. **Processing and delivery costs**: As a low-density gas, the processing and delivery costs for hydrogen are high. In the early stages of market development with low demand (<1 t_{H2}/station/d), compressed hydrogen delivery via tube trailers makes the most sense for short distances, while liquid hydrogen delivery is more attractive for distances over 300 km. However, the processing and delivery costs with these supply chains (3-6 C$/$kg_{H2}$) are too high to be used in heating applications. In a mature market, dedicated pipeline delivery to large (≥2 t_{H2}/day) fueling stations will have lowest delivery costs (<1 C$/$kg_{H2}$) if there is large, aggregated demand (~1 t_{H2}/day per km of pipeline) to amortize the cost of the transmission pipelines.

3. **Fueling (HFS) costs**: The fueling station costs are impacted by delivery method (via TTs, liquid hydrogen tanks or pipelines), but in all cases, the larger the fueling station, the better the economics. This is also tied to the demand; with high utilization of the station's dispensing capacity critical to lowering fueling cost. The deployment of large fueling stations (≥2 t_{H2}/day) in combination with high utilization can lead to fueling station costs of 1.5-3 C$/$kg_{H2}$ depending on delivery method.

The techno-economic analyses identified a few key **observations**:

1. **Scale is critical**: The capital cost of many components in the value chain (e.g., liquefaction units, pipelines, compressors) have a much greater impact on the levelized cost of hydrogen at smaller scales than at large scales.

2. **Demand will drive down costs**: While employing economies of scale is important, it will only reap benefit if there is high utilization of the capacity of various process units. In other words, scale and demand must work together. Creating substantial demand (e.g., >2 t_{H2}/fueling station/day) in concentrated hydrogen hubs and corridors would be essential to economic viability. In transportation, this requires 100+ transit fuel cell buses, or 40+ Class 8 fuel cell trucks refueling daily at each station.

3. **Dedicated pure hydrogen pipelines are essential to enable use in multiple sectors**: With centralized hydrogen production, pipelines are the only practical option that enables opportunities in multiple sectors (transport, heat, power) and realize a cost and scale of supply that justifies the necessary infrastructure investments. Such a synergy among multiple demand sectors delivers benefits to all and should be integrated into strategic planning for the buildout of the hydrogen economy.

4. **Hydrogen value chain is capital intensive**: Hydrogen delivery and fueling costs are dominated by the capital expenditure that contributes 45-65% of the total cost per kg H_2 (assumes 8% return on investment).

5. **Technology development is necessary**: As a low-density gas, the compression and/or liquefaction are the costliest processing steps of the value chain. Technological improvements that increase

efficiency, reliability and lifetime of currently available compressors and liquefaction units will be critical to drive down cost of hydrogen.

To conclude, hydrogen not only offers a great opportunity to advance towards a clean future, but it is also an economic driver that opens up diverse opportunities. Yet as this study reveals, the challenges are substantial as fuel hydrogen value chains are complex, and the risks faced by investors are significant. Based on the techno-economic results, the report provides a few **recommendations** that can accelerate the adoption of hydrogen as a clean fuel.

1. **Strategic planning is needed** to fully utilize the potential of hydrogen and unlock significant economic value for Alberta and Canada. The government needs to work together with different stakeholders to develop strategic transition plans that coordinate and leverage current resources, infrastructure, know-how and expertise. A key part of the strategic planning would be to analyze the interdependencies among different demand sectors and plan infrastructure development, policies, and incentive programs accordingly. The results presented in the report indicate that pipelines are the only delivery option that would enable market opportunities in multiple sectors (transport, heat, power). Therefore, they should be integrated into planning the transition to a sustainable hydrogen economy.

2. **Creation of Regional Hydrogen Hubs and Economic Corridors** would be key to improve coordination and connect supply to demand. The work done in establishment of regional hubs such as the ERH2 could be used as a template to create similar hubs across the country. The energy transition is a complex challenge, and these hubs will be key to bring together various stakeholders from government, industry, and demand sectors to work together to minimize barriers.

3. **Mitigate investment risks**. The results indicate that the buildout of a new hydrogen value chain will be capital intensive. Therefore, there needs to be risk mitigation for that capital until demand increases. Policy makers and financial institutions need to employ various policies and financial tools to remove market barriers, ease regulatory burdens and mitigate investment risk which will attract private investment. Technical assistance, grants and interest free loans can play a critical role early in the project. Other tools could be in the form of guaranteed off-take agreements to meet utilization targets, or conditional capital to reduce utilization targets. Public finance institutions can make key contributions by providing investors with risk guarantees and other insurance tools.

4. **Support demand creation**. As mentioned earlier, while employing economies of scale is key, it fails without securing the demand for hydrogen fuel. Traditionally, most government policies and incentives programs have focused on low-carbon hydrogen production. Boosting the role of low carbon hydrogen in clean energy transitions requires a step change in demand creation. The results presented in this study indicate that for heavy-duty transport, significant demand will not materialize without a range of available vehicles at acceptable prices, together with predictable and affordable fuel prices. Therefore, incentive programs need to be developed to purchase heavy-duty fuel cell electric vehicles in parallel with programs to build a network of large size fueling stations.

5. **Promote innovation and pilot projects**. In an early market with many uncertainties, it will be important to provide support to shovel ready pilot projects and promote innovation. These projects will provide real world data and insights that must be made public, with transparent discussions, to identify bottlenecks to address.

1 INTRODUCTION

To limit the increase in global warming to less than 1.5°C, Canada and dozens of other nations have committed to net-zero greenhouse gas (GHG) emissions by 2050 [11]. Since the extraction, refinement, distribution, and combustion of fossil fuels accounts for over 80% of GHG emissions ([1]), a major effort is required to displace carbon-based energy carriers like gasoline, diesel, and natural gas with zero-emission energy carriers such as electricity and hydrogen (H_2).

In the transition to net-zero emissions, electrification of end-use energy demand has an advantage since much of the value chain infrastructure (e.g., electrical grid) and conversion technologies (e.g., heaters, heat pumps, motors, electric cars) already exist. While the electrical grid and conversion technologies may need to be upgraded or expanded, this can be done incrementally.

However, there are some sectors and regions of Canada where electricity as the energy carrier is hard to justify because of the need for large-scale seasonal storage (e.g., space heating in cold climates, backup for intermittent renewables), the weight of the storage media (e.g., batteries on vehicles), or the time it takes to 'refuel' (e.g., commercial trucks/trains/ships/planes). In such cases, H_2 is seen as the zero-emission fuel of choice.

Currently Canada produces over 8000 t_{H2}/day ([7]), which is primarily used as an industrial feedstock to upgrade bitumen, refine oil, or make ammonia and other chemicals (**Figure 1.1A**). Most of this H_2 is made by reforming natural gas, and the carbon dioxide (CO_2) byproduct is released to the atmosphere as a GHG. The resulting 'gray' H_2 is associated with emissions of 9 to 10 kg_{CO2}/kg_{H2} plus an additional 1.5 to 2 kg CO_{2eq}/kg_{H2} associated with the recovery and upgrading of the natural gas ([12]).

To achieve the net-zero objective, H_2 must be made with minimal or no GHG emissions. Large hydro-power resources position many provinces such as British Columbia, Ontario, and Quebec with a source of low carbon electricity [13] that can be used to make 'green' H_2 through water electrolysis. Other provinces such as Alberta and Saskatchewan with large fossil fuel resources and porous rocks that can be used for permanent CO_2 storage [14], can make 'blue' H_2. In the scenario where carbon capture utilization and storage (CCUS) permanently sequesters 90% or more of the GHG emissions, the total GHG emissions for blue H_2 should be less than 3 $kg_{CO2(eq)}/kg_{H2}$ ([7]). Furthermore, the implementation of new regulations on methane emissions ([15]) should lower the total GHG emissions for blue H_2 to <1.5 $kg_{CO2(eq)}/kg_{H2}$, a GHG intensity similar to the 'green' H_2 made from water electrolysis using renewables or nuclear ([16]).

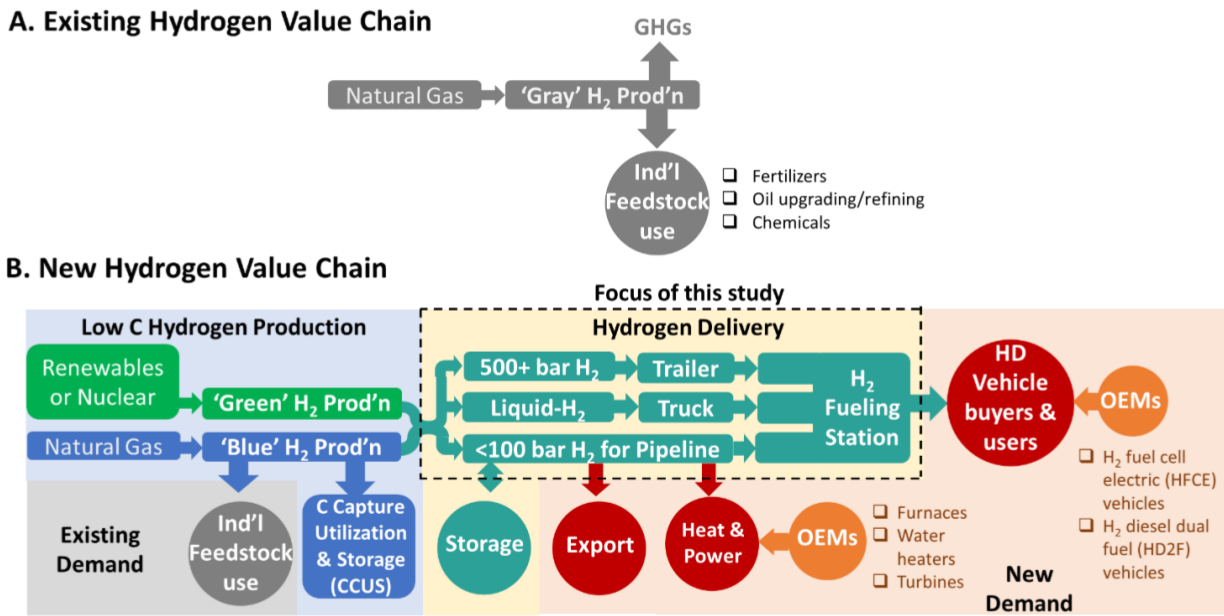

Figure 1.1. Comparison of Canada's existing H_2 value chain (A) and a new value chain (B) based on centralized production of H_2 and its use in fuel markets for heavy-duty (HD) vehicles, heat & power generation, and export.

Note: GHGs: Greenhouse Gases; OEMs: Original Equipment Manufacturers.

Transitioning to a net-zero energy system where H_2 is an end-use fuel will require the creation of new value chains that make H_2 available at a reasonable cost at widely distributed locations across Canada. One strategy involves the use of low carbon electrical grid, if available, to bring power to where it is needed or use dedicated renewable power to make 'green' H_2 on site (i.e., in a distributed manner). While this strategy would benefit from more study, the cost of grid connections [17], limited availability of low-cost renewable power at distributed locations around the city, high cost and small production capacity of water electrolyzers ([18]) will result in green H_2 that is two to three times the cost of blue H_2 ([7]). This will be discussed in more details later in the report.

Another alternative is to build new value chains around the centralized production of H_2 as shown in **Figure 1.1B**. This is the strategy and the focus of this report, with a particular emphasis on delivering H_2 to fueling stations supporting heavy duty vehicles, including trucks, buses, and trains.

This report analyzes the cost components associated with producing, transporting, and delivering low-GHG fuel H_2 for heavy duty vehicles in Canada. Three sizes of H_2 fueling stations (HFS) are assessed (0.4, 2 or 8 t_{H2}/day) at distances of 5, 40 or 300 km from a centralized H_2 production facility. Three H_2 transportation modes are considered including a) compressed H_2 in tube trailers (TT) trucked to stations, b) liquid H_2 in cryogenic tank trucked to stations, and c) compressed H_2 in pipelines to the station (**Figure 1.1B**). We calculate the pre-tax, levelized refueling costs of H_2 (LCOH) and compare that with what is needed to be competitive with diesel fuel without public subsidies.

While the findings presented here should have relevance to any region of Canada interested in centralized, low GHG H_2 production, the model parameters were chosen for their relevance to the Edmonton Region

Hydrogen HUB (https://erh2.ca/), and the Alberta Industrial Heartland (https://industrialheartland.com/) where current H_2 production exceeds 2000 t_{H2}/day along with world class infrastructure for CCUS ([8]).

The balance of this report is separated into the following topics:

- ☐ **Section 2: Market assessment for fuel hydrogen:** The size of Alberta's fuel H_2 market is assessed, focusing on the transport, building, and power sectors. In addition, calculations are made for the target price of H_2 when competing with diesel for a share of the heavy-duty transportation market.
- ☐ **Section 3: Cost of low carbon hydrogen production:** The cost of low carbon H_2 production in Canada is assessed for a range of feedstock costs and other factors.
- ☐ **Section 4: Design of different supply chains delivering hydrogen to fueling stations for heavy-duty vehicles:** The design of different supply chains is presented along with the techno-economic assumptions for delivering H_2 across distances of 5, 40 or 300 km to a heavy-duty fueling station using a tube trailer (TT) truck, liquid hydrogen (LH_2) truck or pipeline.
- ☐ **Section 5: Cost of processing and delivery of hydrogen:** Includes the capital, operating and energy costs for the central terminal, trucks and pipelines used to deliver hydrogen to respective fueling stations.
- ☐ **Section 6: Cost of hydrogen fueling stations:** Includes the capital, operating and energy costs for the respective fueling stations as function of delivery method and size (0.4, 2 or 8 t_{H2}/day).
- ☐ **Section 7: Levelized cost of hydrogen (LCOH) for heavy duty vehicles:** Draws on sections 3, 5 and 6 to calculate the LCOH at the fueling station using different delivery modes and compares this to the equivalent cost for diesel as a transportation fuel.
- ☐ **Section 8: Growing a fuel hydrogen economy in the Edmonton Region:** This section proposes a regional strategy for the deployment of H_2 fueling stations serving heavy-duty transport in the Edmonton Region.
- ☐ **Section 9: Recommendations:** Based on TEA, recommendations that can help accelerate the adoption of H_2 as a clean fuel are provided.

2 MARKET ASSESSMENT FOR FUEL HYDROGEN IN ALBERTA

2.1 Potential Markets for Fuel Hydrogen in Alberta

To estimate the potential market size for H_2 in Alberta in a net-zero future, three sectors were considered, and the following assumptions were made for the transition to clean energy carriers:

Transportation: Natural Resources Canada's (NRCan) Comprehensive Energy Use Database (CEUD, [2]), reported that vehicles in Alberta consumed 462 PJ_{hhv}/year of transportation fuel in 2018 (**Figure 2.1A**). Light-duty (LD) vehicles were the largest energy consumer followed by heavy-duty (HD) and medium-duty (MD) trucks, airplanes, and rail. Gasoline is the primary transport fuels for light duty (LD) vehicles while diesel is mainly used for buses, trucks, and rail. The remaining energy use is derived from aviation turbo fuel with minor contributions from electricity and natural gas.

As a first approximation of demand for fuel H_2 in Alberta's transportation sector in a net-zero future, the 2018 demand was allocated to electricity, biofuels, or H_2 (i.e., no allowance for population or economic growth), based on perceived 'fit-for-service'. In the transportation sector, most light-duty, personally owned vehicles, school buses and lighter-duty freight vehicles were assumed to shift to plug-in battery electric. H_2 was considered the fuel of choice for heavy-duty, and longer-distance freight vehicles. Biofuels and H_2 were assumed to share the market for aviation fuels.

The fraction allocated to H_2 is:

- ☐ Light-duty vehicles: 10%,
- ☐ School buses and medium duty trucks: 20%,
- ☐ Airplanes, passenger rail and off-road vehicles: 50%,
- ☐ Transit buses: 60%,
- ☐ Intercity buses and heavy-duty trucks: 80%
- ☐ Freight trains: 100%

Applying these fractions to Alberta's 2018 fuel energy demand resulted in an estimate that 40% (183.7 PJ_{hhv}/yr) of current demand would be displaced by H_2 (outer ring in **Figure 2.1**) with the remaining fulfilled by either low carbon electricity and/or biofuels. In most cases, it was assumed that the internal combustion engine (ICE) would be replaced with H_2 fuel cells, batteries, and electric motors, resulting in improvements in the relative efficiency of fuel use as summarized in **Table 2.1**. These estimates for relative efficiency were drawn from the literature [19] and were based on the high efficiency of fuel cells, benefits of regenerative braking and the avoidance of idling that characterizes fuel use in many ICE vehicles.

Using these assumptions and the transportation energy demand for Alberta in 2018, the estimated market for H_2 as a transportation fuel is 2797 t_{H2}/d (**Table 2.1, Item 8**). This is equivalent to about half of the 5400 t_{H2}/d that is currently produced in Alberta, and used as industrial feedstocks [8].

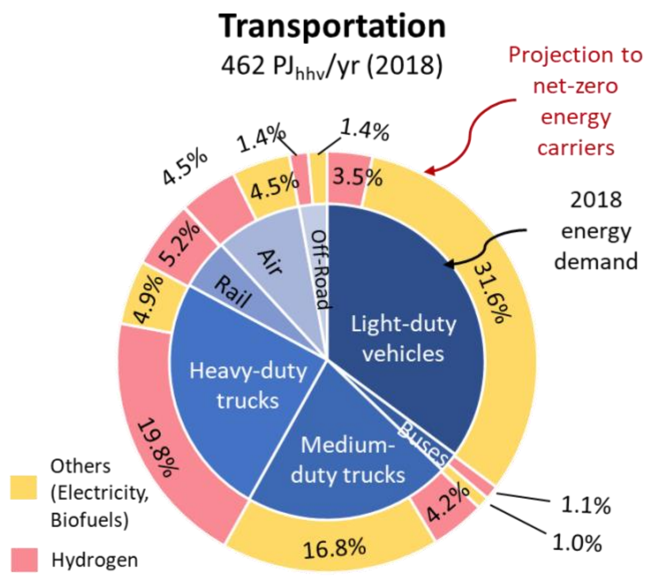

Figure 2.1. Energy use for transportation in Alberta by vehicle type in 2018 (inner circle) and proportion of energy use for each vehicle type that is projected to be served by H_2, low-carbon electricity or biofuels in a net-zero emission future.

Source: Data from NRCan's Comprehensive Energy Use Database [2].

Building Heating: Alberta's natural gas energy use for space and water heating in 2018 was 330 PJ_{hhv}/yr **(Figure 2.2)**, with 54% and 46% consumption coming from residential and commercial buildings, respectively. Large seasonal swings in energy demand (up to 10-fold) [20], and poor performance of heat pumps when faced with cold winter temperatures [21] make it difficult to envisage electrification of this sector, especially in a province like Alberta. Renewable natural gas was not considered a credible option due to severely limited supplies. Repurposing the existing natural gas infrastructure to H_2 was identified as the most credible alternative [22]. In the transition to a net-zero emission energy system, it was assumed that 75% of this heat energy requirement would be supplied by low carbon H_2, as summarized by the outer ring in **Figure 2.2**. In the building sector, H_2 would be combusted to provide space and water heating, similar to the combustion of natural gas today. In combustion, the lower heat value (LHV) of a chemical defines the useful extracted energy better than the higher heat value (HHV). Since the ratio of LHV/HHV for hydrogen (0.84) is 7% lower than the LHV/HHV for natural gas (0.90), a relative efficiency of 1.07 J_{H2}/J_{NG} was assumed (**Table 2.1, Items 9 and 10**) and the calculated average daily H_2 demand is 5094 t_{H2}/d (**Table 2.1, Item 11)**. There would be a large seasonal variation in this demand, from about 1000 t_{H2}/d in August to about 8000 t_{H2}/day in January [8].

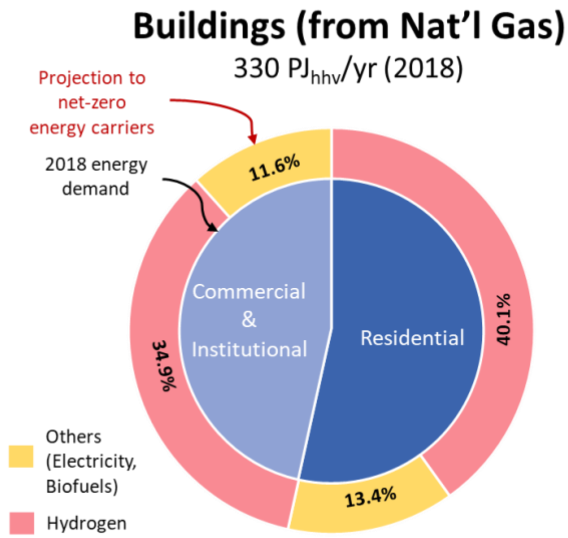

Figure 2.2. Natural gas demand for residential and commercial buildings in Alberta in 2018 (inner circle) and proportion of energy use for each building type that was projected to be served by H_2, low-carbon electricity or biofuels in a net-zero emission future.

Source: Data from NRCan's Comprehensive Energy Use Database [2].

Power Generation: In Alberta, annual electricity generation is about 86 TWh/yr (310 PJ_e/yr) **(Figure 2.3)** [23]. In recent years, coal-powered generation facilities have been gradually converted to lower carbon fuel sources, primarily natural gas, reflecting the impact of increased emissions costs on their profitability. Currently, most of the electricity in the province will be generated via natural gas-powered simple cycle, combined cycle, and cogeneration plants. At the same time, renewable electricity capacity in the form of solar, hydro and in particular wind has increased in the province. Between 2010 and 2017, Alberta's wind capacity doubled and is projected to double again by 2023 as Alberta continues its efforts to decarbonize the electricity grid [24]. Rising carbon taxes and a reduction in the benchmark allowed for emissions without taxes is expected to continue to drive this transition.

For larger scale industrial energy use in Alberta, continued use of natural gas, coupled to post-combustion carbon capture and storage (CCS) was calculated to be the most cost effective. However, H_2 is expected to be the fuel of choice for peak power generation / backup power generation and for a portion of industrial or building cogeneration. In a net-zero future where renewable sources are the major contributor to electricity generation, it is envisaged H_2 will be used as a dispatchable energy source, to firm peak demand, and contribute 10% of total annual electricity generation (i.e., 31 PJ_e/yr, **Table 2.1, Item 12**). In addition, H_2 will play a role in cogeneration of heat and power, contributing perhaps 20% of the electricity requirement (**Table 2.1, Item 13**). Assuming 33% efficiency of generating electricity from H_2 (e.g., single cycle gas turbines, relative efficiency of 3 J_{H2}/J_e), the total H_2 demand from the power sector would be 5397 t_{H2}/d (**Table 2.1, Item 14**).

Table 2.1. The calculation of potential demand for fuel H_2 in Alberta in a net-zero emission future using government estimates for fuel demand in 2018 [2]

Potential of hydrogen as fuel in Alberta							
						All Alberta	
Item Number	Sector	End use	PJ(FF)/yr (2018)	PJ(FF)/yr (2018) allocated to transition to Hydrogen	Relative efficiency (PJ(H2)/PJ(FF))	PJ(H2)/yr	t(H2)/day
1	Transport	LD vehicles	162.6	10% cars; 10% light trucks; 0% motorcycles	0.40	6.5	125
2		Buses	9.4	20% school ; 60% transit and 80% inter-city	0.59	3.0	57
3		MD trucks	97.1	20% of medium duty trucks	0.86	16.7	323
4		HD trucks	114.5	80% of heavy duty trucks	0.86	78.8	1523
5		Rail	24.4	50% passenger rail; 100% freight rail	0.55	13.2	256
6		Airplanes	41.5	50% passenger air; 50% freight air	1.0	20.8	401
7		Off road	13.4	50% of off-road vehicles	0.86	5.8	111
8	**Total for transport**					145	2797
9	Heat	Residential space and water heating	176.3	75% of natural gas use	1.07	141	2724
10		Commercial space and water heating	153.5	75% of natural gas use	1.07	123	2371
11	**Total for heat**					263	5094
12	Electricity generation	Peaking to firm intermittent renewables	31.0	10% of all generation	3.00	93	1799
13		Co-generation	62.0	20% of all generation	3.00	186	3598
14	**Total for electricity generation**					279	5397
15	**Total hydrogen demand in Alberta**					**687**	**13289**

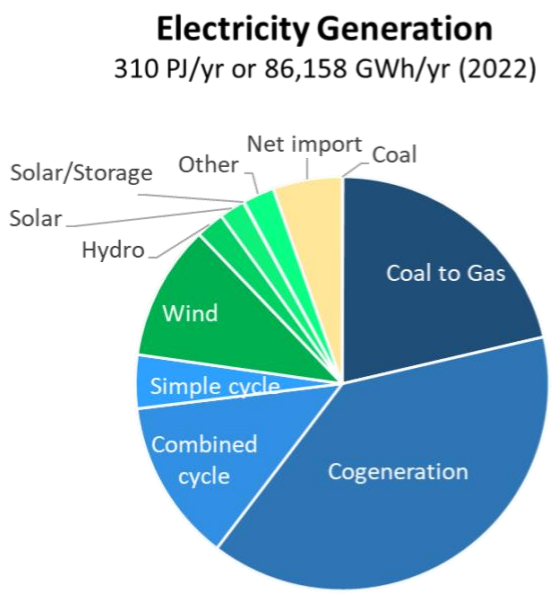

Figure 2.3. Electricity generation in Alberta by source in 2022 as documented by Alberta Electric System Operator (AESO) [23].

Total Potential Fuel Hydrogen Market in Alberta: In total, the estimated potential domestic demand for H_2 in Alberta is 13,289 t_{H2}/d (**Table 2.1, Item 15**), equivalent to 2.5 times the current industrial feedstock H_2 production in the province. The analysis does not account for increases in provincial energy demand associated with population or economic growth, or the production of low-carbon H_2 for export. Therefore, the use of H_2 as fuel in Alberta will not only require the construction of a new value chain but will also provide a great economic opportunity for H_2 producers and create jobs in the province.

2.2 What Fuel Hydrogen Markets Have the Greatest Near-Term Potential?

As a chemical-based energy carrier, H_2 is easier (i.e., lower cost, less loss) to store than electricity, so it is preferred for heavy duty mobile applications, or where there are large seasonal swings in energy demand (e.g., space heating in cold climates). As noted above, H_2 also has potential to provide zero emission industrial heat and electricity in cases where the location, demand frequency or scale makes post combustion CCS unfeasible. However, which of these markets has the greatest near-term potential?

Figure 2.4 shows that per gigajoule of energy, Canadians pay considerably less for heating fuels than for transportation fuels. Given this current reality, the heavy-duty transportation market is the most promising market for fuel H_2. Therefore, special attention needs to be paid to the costs associated with moving and processing the fuel, so it is available to heavy-duty vehicles at strategically located fueling stations.

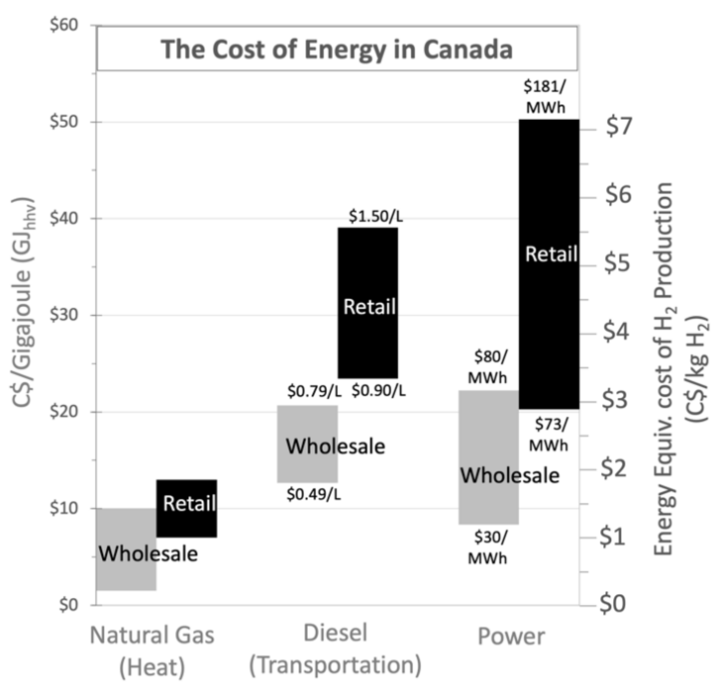

Figure 2.4. Approximate wholesale and retail costs for building heating, transportation fuels and electrical power in Canada.

In Alberta, heavy-duty freight currently pays 24-40 C$/GJ$_{diesel}$ versus 3-4 C$/GJ$_{NG}$ used for heat and power generation. For H_2 to be competitive on an energy basis with current diesel price, without requiring government subsidies, the refueling cost of H_2 at the pump needs to be between 3.3-5.5 C$/kg$_{H2}$, not counting for drivetrain efficiency (DTE) for HFCE vehicles versus conventional diesel trucks [7].

For example, if the relative efficiency of a HFCE locomotive is 0.55 J_{H2}/J_{diesel} (**Table 2.1, Item 5**), the target price for H_2 could be between 6 and 10 C$/kg$_{H2}$. For heavy-duty trucks driving long intercity routes, the relative efficiency is expected to be about 0.86, and with that value, **Figure 2.5** shows the target price of H_2 versus diesel as function of different carbon prices of 50 C$/t$_{CO2}$ in 2022, 110 C$/t$_{CO2}$ in 2026 and 170 C$/t$_{CO2}$ in 2030. These are the announced carbon taxes by the federal government in Canada [25,26].

The results indicate that higher carbon prices on diesel use is advantageous for the adoption of H_2 in heavy-duty transport. For example, at a retail price of ~1.25 C$/L$_{diesel}$ [25,26], the target retail price of H_2 in 2022 would be 5.9 C$/kg$_{H2}$, 6.7 C$/kg$_{H2}$ in 2026 and 7.4 C$/kg$_{H2}$ in 2030. The refueling cost of H_2 will be a major factor in the acceptance of HFCEVs in the heavy-duty freight industry because of its impact on the levelized cost of driving in C$ per km and is equal to the sum of production, delivery and fueling station cost.

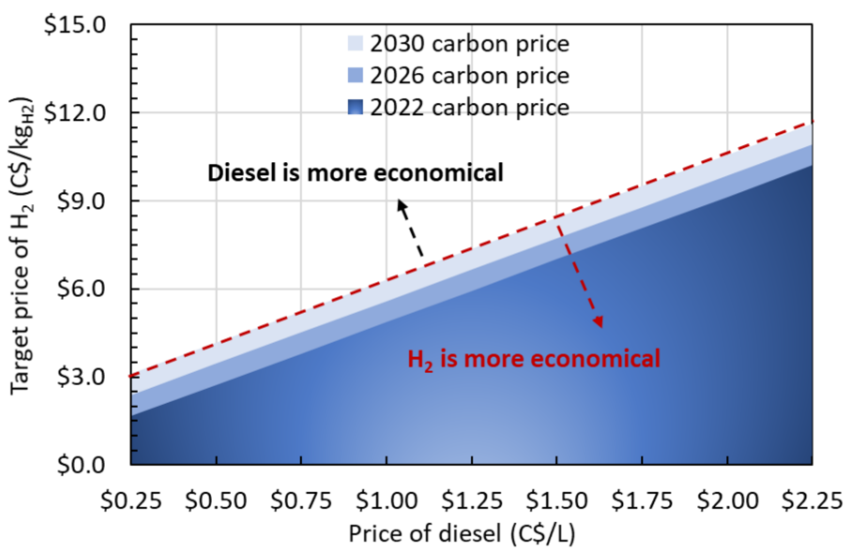

Figure 2.5. Target price of H_2 (C$/kg$_{H2}$) in Alberta calculated based on retail price of diesel and federal carbon pricing targets.

Source: Targets for federal carbon pricing targets taken from report titled: “2020 expert assessment of carbon pricing systems: A report prepared by the Canadian Institute for Climate Choices” [25].

3 PRODUCTION COSTS OF LOW CARBON HYDROGEN

3.1 Green Hydrogen from Water Electrolysis

'Green' H_2 is produced from water electrolysis powered by low-carbon electricity. Proton exchange membrane (PEM) electrolyzers tend to be the system-of-choice due to their compact design, high efficiency (52–69%, LHV basis) at high current density (>1–2 Amps/cm^2), fast response, dynamic operation (0–160% of the nominal load), low temperature operation (20–80 °C), and the ability to produce ultrapure H_2 at elevated pressures (30–80 bar) [16,27].

Table 3.1. Model parameters for PEM electrolyzer costs as reported in IEA 2019 report [28].

PEM Water Electrolyzer		Today	2030	Long term
CAPEX	C$/kWe	1180	920	590
Efficiency (LHV)	%	64	69	74
Annual OPEX	% of CAPEX	1.5	1.5	1.5
Stack lifetime (operating hours)	hrs	95000	95000	100000

With the current efficiency of PEM technology (52 kWh/kg$_{H2}$), each MWh of generation has the potential to generate about 19 kg H_2. Therefore, 1.5 MWh/day of electricity is needed to support a single municipal hydrogen fuel cell electric (HFCE) bus, 3 MWh/day is needed to fuel one HD HFCE truck or train, and about 105 MWh/day is needed to support a 2 t$_{H2}$/day fueling station.

The production costs of H_2 from water electrolysis are influenced by various technical and economic factors, including the capital cost (CAPEX) of the electrolyzer, its conversion efficiency (kWh/kg$_{H2}$), electricity costs and annual operating hours. Using model parameters from the International Energy Agency (IEA) Future of Hydrogen (2019) report as summarized in **Table 3.1**, and assuming a 8% return on capital cost investment, the LCOH today, by 2030 and in the future was calculated as a function of the electricity price and annual operating hours (**Figure 3.1A to C**).

The results indicate that the key cost determinant of H_2 produced from water electrolysis is the price of the electricity. For example, an increase in the electricity price from 20 to 100 C$/MWh can increase the LCOH by 2-3 times, irrespective of the electrolyzer CAPEX. Furthermore, there is a significant impact of annual operating hours on the LCOH, which are in turn determined by the capacity factor of electricity/power source.

In today's scenario, there is a significant challenge for economically viable (< 3 C$/kg$_{H2}$) green H_2 production, requiring near-continuous access (ideally 6000+ hrs/year) to low-cost (< 30 C$/MWh), low-carbon electricity. Large hydro-powered provinces such as British Columbia, Ontario, and Quebec have reported the availability of excess or surplus low-carbon electricity [13,29-31]. Since electricity is expensive to store, this excess electricity could be used to make green H_2 through water electrolysis.

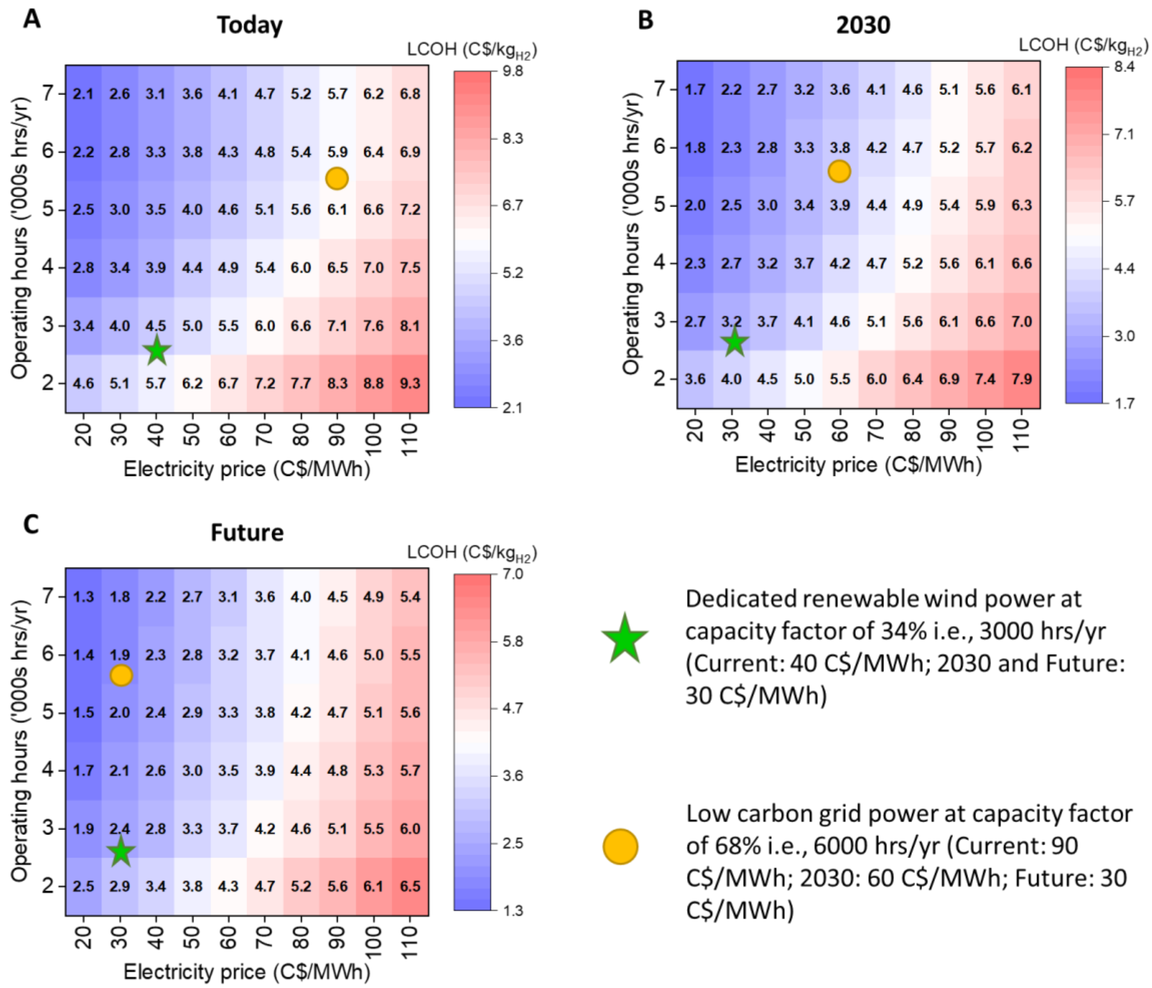

Figure 3.1. The effect of electricity cost (C$/MWh) and annual operating hours (hrs/year) on the cost of green H_2 production for a 4.2 MW PEM Electrolyser today (A), in 2030 (B) and in the future (C) when the market is mature.

Note: The symbols on each chart show the approximate production costs for scenarios in which either low-cost wind power with only 34% capacity factor is used to make H_2 (Green star) or higher cost low carbon grid power available 68% of the time is used to make H_2 (Yellow circle).

Source: Model adapted from the IEA Future of Hydrogen (2019) report [28].

Provinces like Alberta currently do not have low-carbon grid power available to produce green H_2. In such provinces, dedicated renewable power such as that from centralized wind farms could be used for electrolysis. However, the low-capacity factor (34%) and current costs of wind electricity (40 C$/MWh) in the province will make it challenging to make low-cost green H_2. Yet in the near term, i.e., by 2030, the lower cost of PEM electrolyzers will make it possible to use dedicated renewable wind power to produce green H_2 at a competitive cost in centralized locations in the province.

Alternatively, electrolytic H_2 production can also be carried out at or near the site of demand, eliminating the cost of H_2 transport. However, bringing the electricity to the site of demand is not without cost. Grid connection charges in Canada can add 20 to 30 C$/MWh or more to the cost of power generation [17], and as noted above, the cost of the electricity has a major impact on the LCOH production.

In the long-term scenario, with the forecasted decline in PEM electrolyzer costs [32], green H_2 could be produced at < 3 C$/kg$_{H2}$, with electricity prices < 50 C$/MWh, available for 3000+ hrs/year. This would allow flexibility with various options to produce green H_2 at competitive prices across the country.

3.2 Blue Hydrogen from Natural Gas

Blue H_2 is produced by steam reforming of natural gas (SMR) and capturing 90% or more of the CO_2 so it can be permanently sequestered in the sub-surface. The carbon capture and storage (CCS) process differentiates blue H_2 production from conventional 'gray' H_2 production which accounts for most of the 8000+ t_{H2}/day that occurs in Canada today. Most of the current H_2 is used as an industrial feedstock for oil upgrading / refining or fertilizer / chemical production, not as a fuel / energy carrier that is being proposed in this study.

A typical centralized industrial-scale steam methane or autothermal reformer designed to make blue H_2 produces 400 to 800 t_{H2}/day and generates 1.3 to 2.6 Mt_{CO2}/yr for CCS. This scale of CCS is required for the cost-effective sequestration of the CO_2 in porous rocks at least 1 km underground. Not all regions of Canada have the geology needed for CCS, but the Western Canadian Sedimentary Basin (WCSB, includes northern British Columbia, Alberta, and southern Saskatchewan) is an ideal location for low-cost blue H_2 production due to the supply of low-cost natural gas, and a geology that can safely and securely store the CO_2 by-product [8].

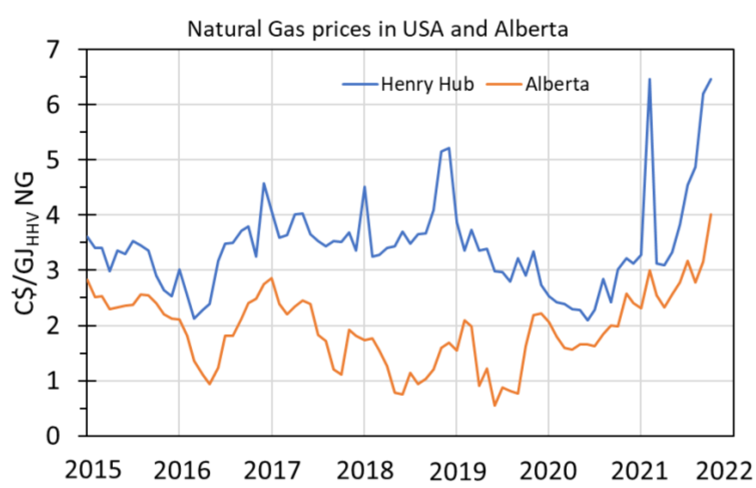

Figure 3.2. Comparative prices for natural gas (C$/GJ$_{HHV}$ NG) in the United States (Henry Hub [33]) and Alberta [34] from 2015-2021.

Source: US$ to C$ conversion was done using historical data [35].

The cost of blue H_2 is sensitive to natural gas prices which have been relatively stable in North America from 2015-2021 (**Figure 3.1**) but have seen a sharp spike recently [33,34]. **Figure 3.2** provides a breakdown of LCOH production as a function of natural gas prices (C$/GJ$_{HHV}$ NG) and production scale (t_{H2}/day). The calculations were done for a current, 2030 and a future scenario based on the IEA Future of Hydrogen (2019) report, and assuming an 8% return on capital cost investment. The analysis reveals that the current cost of blue H_2 at large (≥ 300 t_{H2}/day) centralized production facilities would be <1.70 C$/kg$_{H2}$ when natural gas prices are ≤4 C$/GJ$_{NG}$.

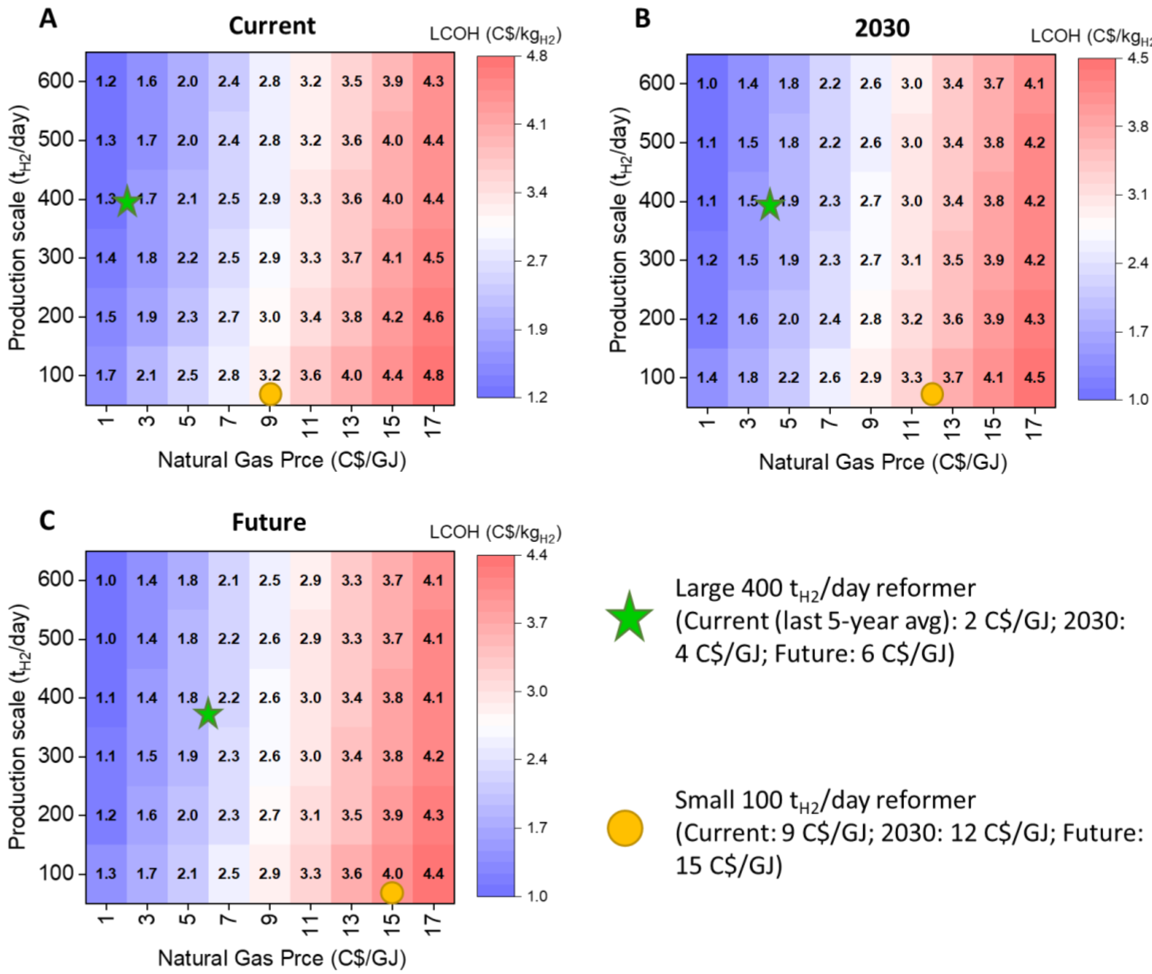

Figure 3.3. The effect of natural gas prices and scale of production (t_{H2}/day) on the cost of H_2 (LCOH) from a steam methane reformer coupled to carbon capture and storage today (A), in 2030 (B) and in the future (C).

Note: The symbols show the approximate production costs for scenarios in which either large reformer with low-cost natural gas (Green star) or small reformer with higher priced natural gas (Yellow circle) is used.

Source: Model adapted from the IEA Future of Hydrogen (2019) report [28].

This scenario is relevant for Alberta since the province is currently one of the lowest cost producers of blue H_2 in the world. With improvements in large scale deployment of technologies linking H_2 production to CCUS, the LCOH is projected to decrease even further to <1.5 C$/kg$_{H2}$ if natural gas prices remain stable. Furthermore, even if the natural gas price increases to 6 C$/GJ$_{NG}$, the cost of blue H_2 production would still be ≤2 C$/kg$_{H2}$. The maturity of reforming technologies means that even in markets that can only support smaller scale reformers (e.g., 100 t$_{H2}$/day) and with high natural gas price (e.g., 9-15 C$/GJ$_{NG}$), the cost of blue H_2 would be 3.5 to 4.2 C$/kg$_{H2}$, and competitive with green H_2 production, discussed above.

3.3 Turquoise Hydrogen from Natural Gas

Currently there is much interest in the development and commercialization of novel technologies for the production of H_2 from natural gas using a conversion technology where the byproduct is carbon black (elemental carbon) rather than gaseous CO_2. If cost effective, these 'methane pyrolysis' technologies to produce "turquoise hydrogen" could be deployed anywhere there is natural gas supply, even if there is not potential for carbon capture and storage. This could rapidly expand the availability of fuel H_2 for transportation, building or heat and power markets by piggybacking on existing natural gas infrastructure.

Companies working on this technology include:

- Ekona Power (https://www.ekonapower.com/)
- Aurora Hydrogen (https://aurorahydrogen.com/)
- New Wave Hydrogen (https://www.newwaveh2.com/)
- BASF (https://www.basf.com/ca/en/who-we-are/sustainability/we-produce-safely-and-efficiently/energy-and-climate-protection/carbon-management/interview-methane-pyrolysis.html)
- Modern Electron (https://modernelectron.com/)

Since these technologies are not yet commercial, little, or no publicly available details exist on their efficiency, the quality and purity of the end product, costs involved and market demand for carbon black. Hence, it is difficult to predict when or what markets the produced H_2 is best suited to fill.

4 DESIGN OF HYDROGEN SUPPLY CHAINS FOR HEAVY-DUTY TRANSPORT

To have any hope of meeting net-zero 2050 objectives, efforts must begin immediately to build fuel H_2 demand, and the supply to meet that demand. As noted above, using proven technologies, the most cost-effective, low-carbon fuel H_2 production is done centrally, either by piggybacking on industrial 'blue' H_2 production or making 'green' H_2 where excess electricity is generated and therefore not exposed to charges for grid distribution.

While distributed fuel H_2 production may have a significant role in a future H_2 economy, the sheer scale of demand (13 kt_{H2}/day, just for Alberta, **Table 2.1**) in a net-zero future means that a substantial system will be required for moving H_2 to where it is needed.

As stated earlier, the heavy-duty transportation market is the most promising early adopter market for fuel H_2. Consequently, the costs associated with moving and processing the fuel require special attention, so it is available to heavy-duty vehicles at strategically located HFS's.

The refueling cost of H_2 at HFS's will be a major factor in the acceptance of HFCEVs. The refueling cost of H_2 at the dispenser comprises of the production, delivery cost and fueling station (HFS) cost.

H_2 refueling cost =

Production cost + Processing and delivery cost + Fueling station (HFS) cost

The production cost of H_2 includes all costs incurred in producing H_2 from its feedstock, while the processing and delivery cost includes costs associated with processing and transporting H_2 to the HFS's. The processing and delivery costs depend on the scale, distance, and processing technology used to transport H_2, while the HFS cost is linked to the delivery method and station size. This analysis is based on three different supply chains for H_2 delivery from centralized production facilities to heavy-duty HFS's, where the stations vary in size (0.4, 2 or 8 t_{H2}/day) and are 5, 40 or 300 km from the production facility. The three different supply chains analyzed in this study (**Figure 4.1**) consists of: A) Compressed H_2 via tube trailer (TT) trucks, B) Liquid H_2 via LH_2 trucks or C) Compressed H_2 via pipelines.

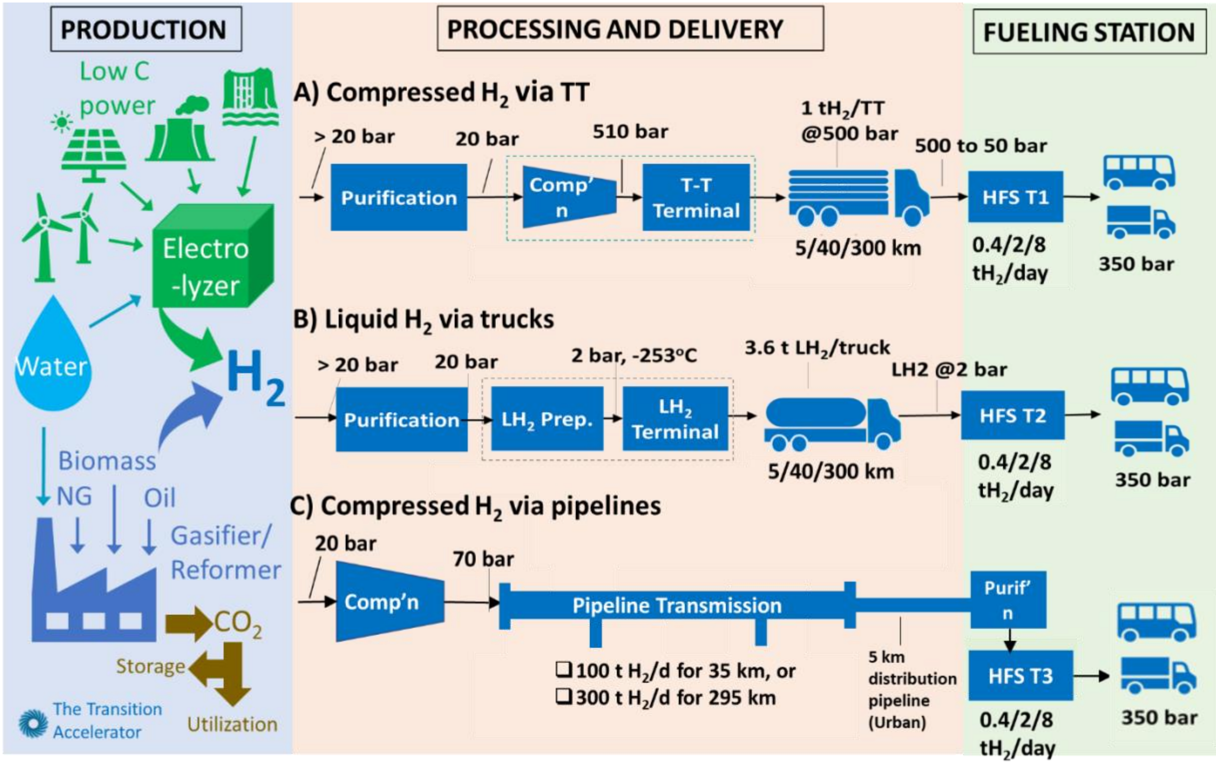

Figure 4.1. H_2 delivery routes from a centralized production facility to HFS's for heavy-duty freight via: A) Compressed H_2 via tube trailers, B) Liquid H_2 via trucks or C) Compressed H_2 via pipelines.

A few important notes and assumptions used in the analysis are listed below:

- The costs were calculated assuming an 8% return on capital cost investment and reported in 2019 Canadian dollars (C$).
- The analysis was done assuming a large H_2 hub which serves multiple HFS's.
- Three different delivery distances were analyzed: 5 km, 40 km, or 300 km.
- Central compressor, TT terminal, liquefier and LH_2 terminals are assumed to be placed on/near production site and designed as large-scale facilities (10-100 t_{H2}/day).
- The HFS's were analyzed operating at three different scales: 0.4 t_{H2}/day, 2 t_{H2}/day and 8 t_{H2}/day and dispensing H_2 at 350 bars.
- Large transmission pipelines were modelled for transporting 300 t_{H2}/day over 295 km distance and 100 t_{H2}/day over 35 km. It was assumed that in a large H_2 hub these pipelines would be serving industrial sites, power generation facilities and end-users for residential and commercial heat.

The techno-economic analysis of compressors and pipelines was conducted using the methodology described in The Transition Accelerator's technical reports on "Techno-economics of H_2 compression" [9] and "Techno-economics of H_2 pipelines" [10]. The techno-economic modelling of central terminals and trucking costs was performed using the H_2 delivery scenario analysis model (HDSAM) developed by Argonne National Laboratory [36]. The HDSAM model is an open-source software package that is built on an Excel interface to calculate H_2 delivery and refueling costs based on user defined market demand scenarios. The model calculates the capital and operating cost of various refueling components and their respective contribution to the total H_2 cost [37]. The data in the model are based on quotes from vendors, open literature, industry and stakeholder input, and basic engineering design calculations. In addition, the model has gone through careful examination and an annual review is conducted by industry experts [38,39]. The HFS costs were calculated using the Heavy-Duty Refueling Station Analysis Model (HDRSAM), also developed by Argonne National Laboratory [40]. Unlike HDSAM, HDRSAM focuses solely on refueling station costs for heavy-duty vehicles and optimizes various design aspects such as the size and power required for compressor/pumps, storage, and refrigeration at the HFS.

4.1 Compressed Hydrogen Delivery via Tube Trailer Trucks

The literature on techno-economic analysis of H_2 delivery costs suggests that when HFCEV market penetration is high (i.e., H_2 demand > 50 t_{H2}/day) and delivery distances are long (> 100 km), the most economical delivery modes are pipelines and liquid H_2 trucks [37,41,42]. However, during an initial period when the HFCEV market penetration is lower, delivery via TT trucks could be an interim solution.

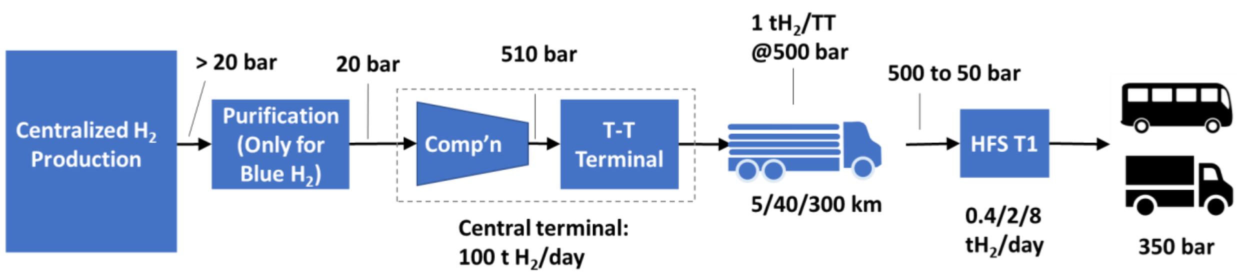

Figure 4.2. Schematic of Supply Chain A delivering compressed gaseous H_2 via tube trailers.

Figure 4.2 shows a schematic of Supply Chain A that delivers H_2 to HFS's using TT trucks. If the H_2 source is from an SMR plant, a central purification unit must be used to attain fuel cell grade purity H_2. A pressure swing adsorption (PSA) unit is the industry standard for H_2 purification and can reduce CO emissions to ≤ 0.2 ppm, as required by fuel cells [43]. Methanation is the alternate technology for purifying gas streams but cannot purify to less than 10 ppm CO [43]. Only the the additional cost of increasing H_2 purity to < 0.2 ppm CO and 300 ppm N_2 from a PSA unit is considered, which is assumed to be available at the SMR plant. This comes at an additional cost related to an increase in PSA adsorbent volume [43,44].

A central terminal was designed to compress, store, and dispense H_2 to tube trailers at 500 bars. The terminal is designed with storage and TT loading diaphragm compressors operating at an isentropic efficiency (η_{isen}) of 60% [9]. The storage consists of multiple medium (200 bars) and high pressure (400 bars) units, 20 kg in size each, with total storage time of 0.1 days and total storage capacity equal to 22% of terminal capacity [36,37]. The remainder of the terminal consists of piping, supply, electrical and instrumentation components [36].

Upon loading from the terminal, the trucks deliver the TT with compressed H_2 at 500 bars to the HFS at distance of 5, 40 or 300 km. Therefore, the round trip considered was 10, 80 and 600 km respectively where an empty truck returns to terminal. The TT truck is assumed to have a total capacity of 1 t_{H2}/truck, and runs on diesel at a cost of 1.2 C$/$L_{diesel}$ with an average truck mileage of 3.3 km/L_{diesel}.

The gaseous HFS is designed for 350 bar cascade dispensing at fast fueling rate of 7.2 kg/min with an average of 80 kg H_2 dispensed amount per vehicle. It consists of compressors, a medium-pressure buffer storage system, refrigeration unit, dispenser, and other control hardware as shown in **Figure 4.3** [37,45]. Gaseous H_2 is delivered to the HFS via the TT, where it is left behind as part of the storage system at the gaseous HFS. The assumption is that the TT tanks can never be completely emptied, with a minimum pressure of 50 bars. The function of buffer storage is to satisfy a predefined dispensing rate during peak-demand hours [45]. To allow for fast refueling, the H_2 from the high-pressure storage system is directed by a dispenser into the vehicle's onboard tank via a refrigeration unit, which pre-cools the H_2 to about ~5 °C to avoid overheating the vehicle's tank. The dispenser measures the flow rate of H_2 and keeps track of the amount of H_2 dispensed into the vehicle's onboard storage tank. Meanwhile, the compressor can operate to refill the idle banks of vessels (i.e., those not discharging to the dispenser) in a predefined order [45]. Like the terminal, (η_{isen}) of the HFS compressors was assumed to be 60%. When all the pressure vessels in the tube trailer are drawn down to the return pressure, the tube trailer is replaced with another fully loaded tube trailer.

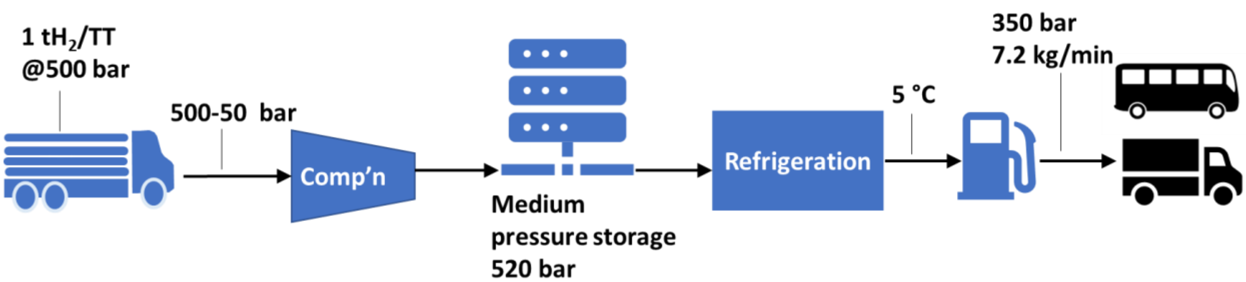

Figure 4.3. Schematic representation of a gaseous HFS supplied by TT.

Source: Adapted from References [37,39,46].

4.2 Liquid Hydrogen Delivery via Trucks

While gaseous H_2 is supplied to the HFS via TT's or pipelines, liquid H_2 is stored in an onsite cryogenic tank, which is replenished by a liquid H_2 truck. **Figure 4.4** shows a schematic of Supply Chain B that is the LH_2 delivery route adopted in this analysis. The central purification process in the supply chain was considered to be identical to Supply Chain A. The outlet of the SMR purification unit goes to the LH_2 terminal consisting of the liquefier unit and the LH_2 terminal facility consisting of pumping and storage equipment. The liquefier in this analysis was designed based on a conventional three-step liquefaction process: compression, cooling (via liquid nitrogen and heat exchangers) and expansion. The LH_2 terminal is designed with LH_2 pumps which operate at an isentropic efficiency (η_{isen}) of 60%, and LH_2 storage was designed to handle plant outages assumed to be 10 days/yr [36]. The remainder of the terminal consisted of piping, supply, discharge, electrical and instrumentation components. Upon loading from the terminal, the truck delivers the LH_2 to the HFS at distance of 5, 40 or 300 km. Therefore, the round trip considered was 10, 80 and 600 km respectively where an empty truck returns to terminal. The LH_2 trucks are assumed to have a total capacity of 3.6 t_{LH2}/truck, running on diesel at a cost of 1.2 C$/$L_{diesel}$ with an average truck mileage of 2.7 km/L_{diesel}.

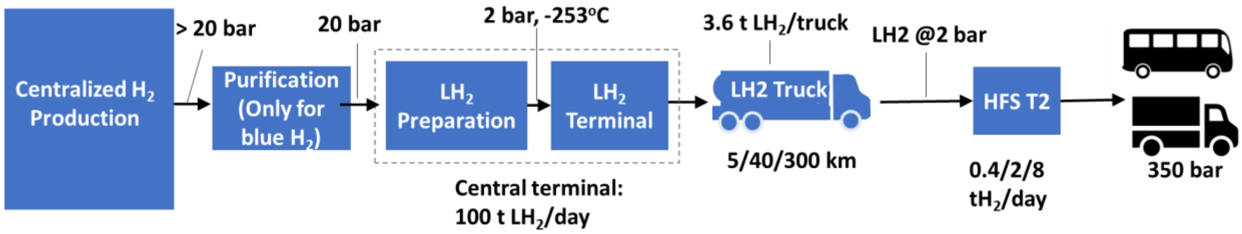

Figure 4.4. Schematic of Supply Chain B delivering liquid H_2 via trucks/tankers.

Like the HFS of Supply Chain A, the liquid HFS was designed for 350 bar cascade dispensing at fast fueling rate of 7.2 kg/min into HDV with an average of 80 kg H_2 dispensed per vehicle. The liquid H_2 from the cryogenic storage tank is pressurized by a cryogenic pump and then gasified via an evaporator as shown in **Figure 4.5** [37]. The medium-pressure gaseous H_2 from the evaporator is stored in the storage system, which is later precooled to 5°C by the cooling unit before being dispensed into the vehicle tanks. The pre-cooling unit in this configuration utilizes the cryogenic H_2 to cool the H_2. It is important to note that the boil off losses for the LH_2 supply chain were considered when calculating the H_2 cost.

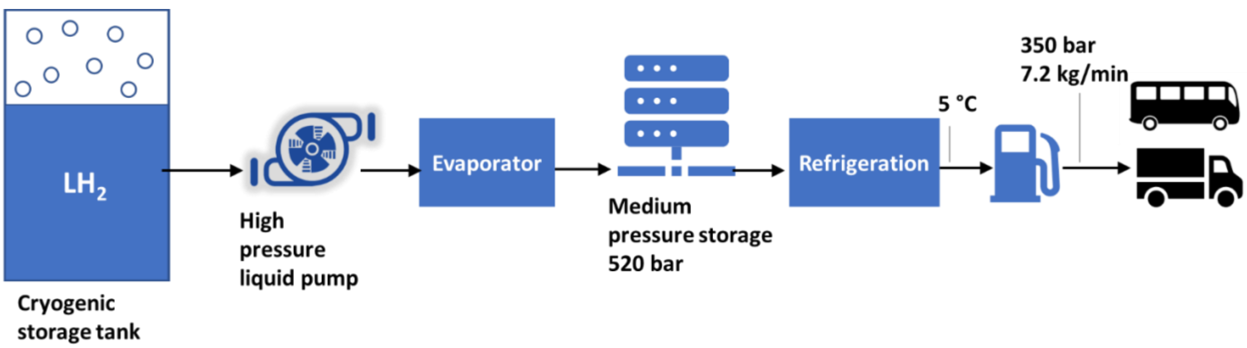

Figure 4.5. Schematic representation of a liquid HFS supplied by liquid H_2 truck and stored in a cryogenic storage tank.

Source: Adapted from Reference [37].

4.3 Compressed Hydrogen Delivery via Pipelines

Figure 4.6 shows a schematic of Supply Chain C that is the pipeline route adopted in this analysis. A key difference versus the TT or LH_2 route is that there is no need for a central terminal for distribution of H_2.

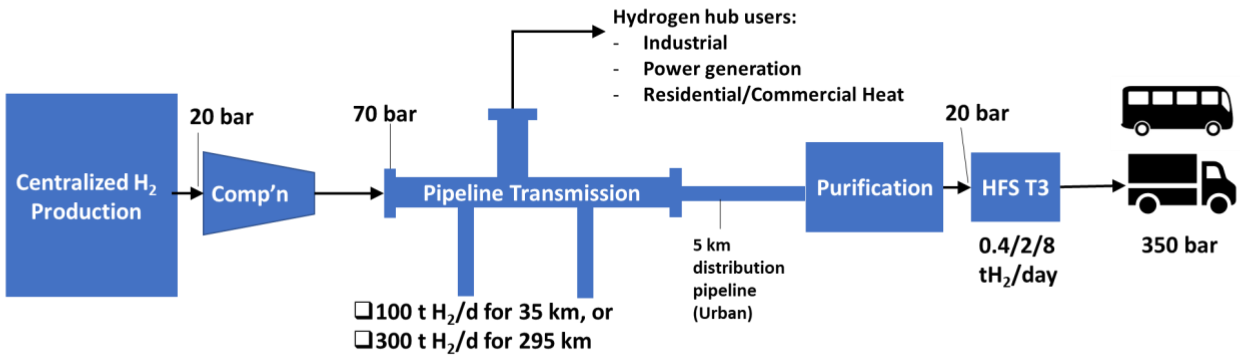

Figure 4.6. Schematic of Supply Chain C delivering compressed gaseous H_2 via pipelines.

Source: Adapted from Reference [37].

A central inlet compressor with η_{isen} of 80% was used to compress H_2 from 20 to 70 bars for the transmission pipeline [9]. The inlet compressors were designed at the same size/scale as the transmission pipeline i.e., 100 t_{H2}/day (35 km pipeline) and 300 t_{H2}/day (295 km pipeline).

The gas flow calculation methodology described in The Transition Accelerator's technical report on "The techno-economics of hydrogen pipelines" [10], was used to optimize pipeline size and costs. For the 295 km transmission pipeline with a capacity of 300 t_{H2}/day, a 12-inch steel pipeline with inlet pressure of 70 bar, outlet gas velocity of 30 m/s, pipe roughness of 0.0178 mm and flow temperature of 15 °C was used. For the 35 km pipeline, a 6-inch pipeline was used to transport 100 t_{H2}/day. In both cases no enroute compression stations were used along the transmission pipeline. The distribution pipelines were designed to be dedicated pipelines servicing the different size HFS's (0.4 t_{H2}/day, 2 t_{H2}/day and 8 t_{H2}/day), with sizes of 1.5-inch, 2-inch, and 3-inch respectively.

The HFS design for the pipeline scenario was identical to the TT route as shown in **Figure 4.7**, except that the inlet pressure was lower at 20 bar, resulting in increased compression power, storage requirement and associated costs. A summary of all design parameters used in the analysis is provided in **Table 4.1**.

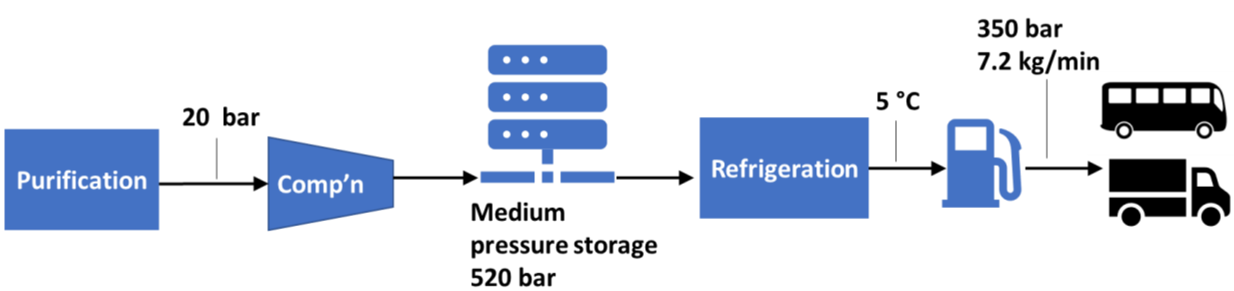

Figure 4.7. Schematic representation of a pipeline supplied HFS.

Source: Adapted from Reference [37].

Table 4.1. Summary of techno-economic parameters used in analysis of the three different supply chains.

Component	Supply Chain A	Supply Chain B	Supply Chain C
Terminal	100 t_{H2}/day. 20 to 510 bars. $\eta_{isen} = 60\%$. 0.1-day storage capacity.	100 t_{H2}/day. RT to -253 °C. $\eta_{isen} = 60\%$. 10-day storage capacity.	---
Trucking/Pipeline	1 t_{H2}/TT. 500 bar TT pressure. 3.3 km/L_{diesel}.	3.6 t_{H2}/truck. LH_2 @ -253 °C. 2.7 km/L_{diesel}.	12-inch (295 km)/6-inch (35 km) transmission pipeline + 3/2/1.5-inch distribution pipeline. Inlet compressor: 20 to 70 bars.
HFS	350 bar cascade dispensing. Fueling rate of 7.2 kg_{H2}/min. Avg dispensed amount per vehicle of 80 kg. Inlet pressure: 500-50 bar.	350 bar cascade dispensing. Fueling rate of 7.2 kg_{H2}/min. Avg dispensed amount per vehicle of 80 kg. Inlet: Liquid H_2 at 2 bar	350 bar cascade dispensing. Fueling rate of 7.2 kg_{H2}/min. Avg dispensed amount per vehicle of 80 kg. Inlet pressure: 20 bar.

5 PROCESSING AND DELIVERY COSTS

5.1 Central Purification Costs

If the H_2 is sourced from a central 'blue' H_2 production facility, it must be purified according to the requirements of PEM fuel cells used in transport vehicles. PEM fuel cells require extremely pure H_2 due to the platinum catalysis that drives the reaction. Presence of reactive impurities such as hydrogen sulfide or carbon monoxide can deactivate the catalyst and degrade the entire fuel cell. The H_2 purity requirements for PEM fuel cell applications are listed in ISO 14687 standard [43] and summarized in **Table 5.1**.

Table 5.1. Fuel quality specification for PEM fuel cell road vehicle application in ISO/FDIS 14687 [43].

Constituents	PEM fuel cell grade
Hydrogen Fuel index	99.97%
Total non-hydrogen gases	300 µmol / mol
Water	5 µmol / mol
Total hydrocarbon except methane (C1 equivalent)	2 µmol / mol
Methane	100 µmol / mol
Oxygen	5 µmol / mol
Nitrogen	300 µmol / mol
Carbon dioxide	2 µmol / mol
Carbon monoxide	0.2 µmol / mol
Total sulfur compounds	0.004 µmol / mol

Methanation and pressure swing adsorption (PSA) are currently the two available technologies that could be used to reduce carbon monoxide from H_2. Pressure swing adsorption (PSA) is the industry standard for H_2 purification and can reduce CO emissions to ≤ 0.2 ppm, as required by fuel cells [43]. Methanation is the alternate technology for purifying gas streams but cannot purify to less than 10 ppm CO [43]. When used to reduce carbon monoxide levels to those considered here, PSA also reduces other impurities to levels with low impact on the end users considered.

PSA uses adsorbent technology to purify H_2 from a gas mixture and is typically part of the SMR unit. PSA operates on the principle that some gaseous components adsorb preferentially to others on highly porous materials. These materials adsorb larger amounts of impurities at high partial pressure than at low partial pressure [44]. Thus, the column is fed with a high-pressure feed gas containing impurities and the pressure is then lowered to regenerate and then to purge the column. To reduce the partial pressure and desorb impurities, the adsorber pressure is swung from the higher feed gas pressure to lower tail gas pressure.

Besancon and coworkers [44] reported the impact of varying targeted H_2 purity on parameters of the reformer and the PSA. In the study, a PSA used in an industrial reformer is modelled, and the impurity concentration (and H_2 loss) is varied by changing the PSA adsorbent volume. The simulation results for a SMR, showed that a decrease in CO level from 250 ppm (industrial grade H_2) to < 0.2 ppm requires an increase in adsorbent volume from 13.6 m^3 to 15.8 m^3 (Δ = 2.2 m^3) and results in a decrease in hydrogen yield by 2.1%.

The Hy4Heat hydrogen purity report [43] reported a cost benefit analysis based on the parameters presented by Besancon study [44], to reflect the impact of using a PSA to purify H_2. The results tabulated in Table 30 and 32 of the report [43], indicate that under the simulated parameters by Besancon, an increase in purity from industrial grade H_2 to fuel cell grade H_2 would result in a 16.2% increase in PSA capital costs. Depending on the initial cost of the PSA unit, the levelized cost of energy (LCOE) to increasing purity of H_2 in SMR unit from 250 ppm CO to < 0.2 ppm CO is between 0.07-0.09 p/kWh. Based on a conversion factor of 1 pence = 0.017 2019 C$ [47], the resulting cost of central purification would range from 0.04-0.05 C$/$kg_{H2}$.

5.2 Central Terminal Costs

Reliable H_2 distribution via compressed gas TT or LH_2 trucks will require a central terminal facility for compression/liquefaction, storage, and distribution. This is one of the major advantages of Supply Chain 'C' which distributes H_2 directly from the production site to respective HFS's via pipelines, eliminating the need for a central facility with an extra compression/liquefaction step. For the compressed H_2 route, the central terminal consists of large-scale storage and truck loading compressors, utilizing diaphragm compressors. It is assumed that H_2 is delivered to the terminal at 20 bar inlet pressure where is it compressed and stored in medium and high-pressure storage tanks, at 200-400 bars pressure. Similarly, the LH_2 terminal consists of a large-scale liquefaction facility based on a conventional liquefaction process that follows three steps, namely compression, cooling (via liquid nitrogen and heat exchangers) and expansion. Both the compressed H_2 and LH_2 terminals consist of storage tanks that helps meet daily variations in supply and demand, and to maintain a reliable supply during seasonal variations or outages.

Figure 5.1 presents the terminal costs in (A) C$/year and (B) C$/kg_{H2} as function of terminal size (t_{H2}/day). The annualized costs indicate that installing and operating LH_2 terminals would be significantly more expensive with total annualized costs of ~20 million C$/year versus ~8 million C$/year for a compressed H_2 terminal, at a scale of 10 t_{H2}/day. At a scale of 100 t_{H2}/day, these costs can exceed more than 120 million C$/year for the LH_2 terminal and 60 million C$/year for the compressed H_2 terminal (**Figure 5.1A**).

The annualized costs (C$/year) can be converted into levelized costs (C$/$kg_{H2}$) by dividing the annualized costs with the total H_2 dispensed at the terminal in a given year. The results indicate the dominant role of capital expenditure (CAPEX), contributing between 40-60% to the total terminal cost, which is a result of the high cost of compressors and liquefier units.

The results also indicate the importance of capitalizing on economies of scale, whereby the levelized terminal cost decreases with increasing the terminal size. In particular, liquefier units have higher benefit of operating at large scale as indicated by the dashed red lines in **Figure 5.1B**. Comparatively, the cost for the LH_2 terminals decreases by 2.2 C$/$kg_{H2}$ versus 0.4 C$/$kg_{H2}$ for compressed H_2 terminal, when terminal sizes increase from 10 t_{H2}/day to 100 t_{H2}/day.

Another important difference in the operation of the two different terminals is the higher electricity costs associated with operating a LH_2 terminal at ~1.0 C$/$kg_{H2}$ versus ~0.3 C$/$kg_{H2}$ for the compressed H_2 terminal, at a 100 t_{H2}/day terminal size. The higher electricity costs are a result of the energy intensive liquefaction process (~9 kWh/kg_{H2}) which needs ~3 times higher energy versus compression (~3 kWh/kg_{H2}). This electrical usage accounts for ~27% and ~9% of the lower heating value (LHV) of H_2 for the LH_2 and compressed H_2 terminal, respectively.

The terminal costs were also analyzed by categorizing them based on the different equipment used in the terminal i.e., the compressors/liquefier, storage, and remainder of terminal which consists of piping, electrical connections, instrumentation, the building and other structures. The results presented in **Figure 5.2A**, indicate that compression or liquefaction (including pumping) is the costliest component, contributing > 80% to the terminal cost.

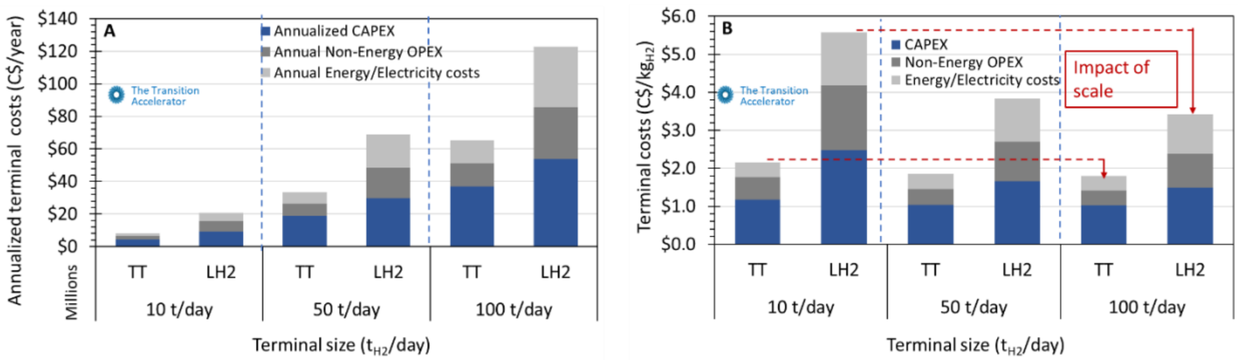

Figure 5.1. Central terminal costs in: (A) C$/year and (B) C$/kg_{H2} as function of terminal size (t_{H2}/day) and divided into CAPEX, Non-energy OPEX and energy/electricity costs.

A breakdown of the CAPEX, non-energy operating expenditure (OPEX) and electricity costs (**Figure 5.2(B-D))** based on contributions from different components indicates that CAPEX and non-energy OPEX costs are a comprised of the costs associated with the compressors/liquefier and storage units, while the remainder of the terminal facility namely the piping, supply, discharge, electrical and instrumentation components has a negligible contribution [40]. Additionally, the electricity costs in the terminal are only a result of the compression or liquefaction process.

The results suggest that a combination of technological improvements to increase the efficiency of compression, liquefaction and economies of scale can be employed in the future to reduce costs. However, due to thermodynamic limitations on the energy requirement for compression and liquefaction, the costs of a central terminal facility will remain significant. Therefore, it could be beneficial to reduce this extra step which is possible with the use of pipelines as proposed in Supply Chain 'C'.

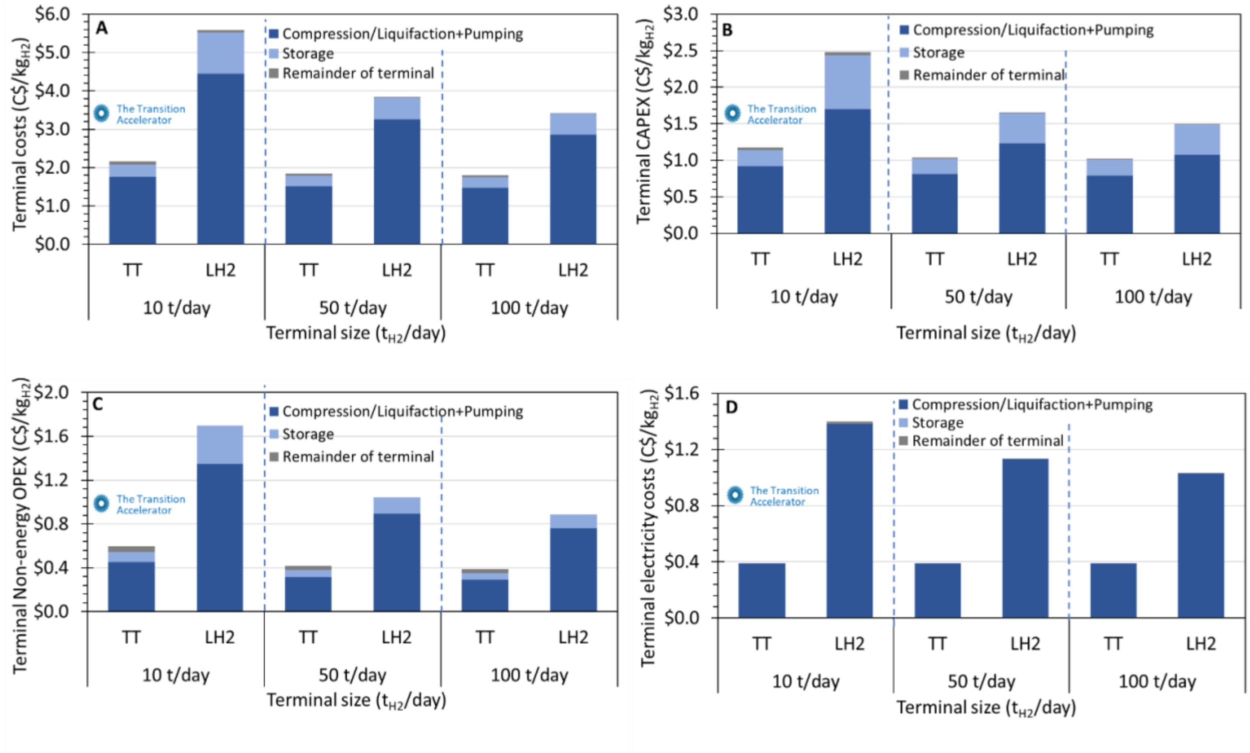

Figure 5.2. (A) Central terminal costs (C$/kg$_{H2}$), (B) Terminal CAPEX, (C) Terminal Non-energy OPEX and (D) terminal electricity costs based on scale and H_2 delivery method i.e., TT or LH_2.

Note: The costs are further divided into contributions from different components such as compression, liquefaction (includes pumping), storage, and the remainder of the terminal.

5.3 Trucking Costs

After processing the H_2 at the central terminal, the H_2 can be delivered to respective HFS's via TT or LH_2 trucks. Truck delivery of gasoline and diesel fuel from refineries or storage terminals to fueling stations is well established. However, it is necessary to compress or liquify H_2 for transport because of its low volumetric energy density.

The first delivery mode considered in Supply Chain 'A' examines compressed gaseous truck transport. These are large trucks carrying TT's containing H_2 at a high pressure of 500 bar and a capacity of 1 t_{H2}/TT. The TT is filled at the central terminal, attached to the truck, and then driven to the respective HFS where it is left behind as part of the storage system at the gaseous HFS. It is assumed each truck cab makes several round trips per day between the central terminal and HFS's (including time for connecting a full TT to the truck cab, traveling between the plant and the HFS, dropping off a full TT and picking up an empty one, and returning the empty trailer to the H_2 plant. The number of truck cabs is determined by the total H_2 demand, truck capacity, the average time of each trip (including loading and unloading), and truck availability.

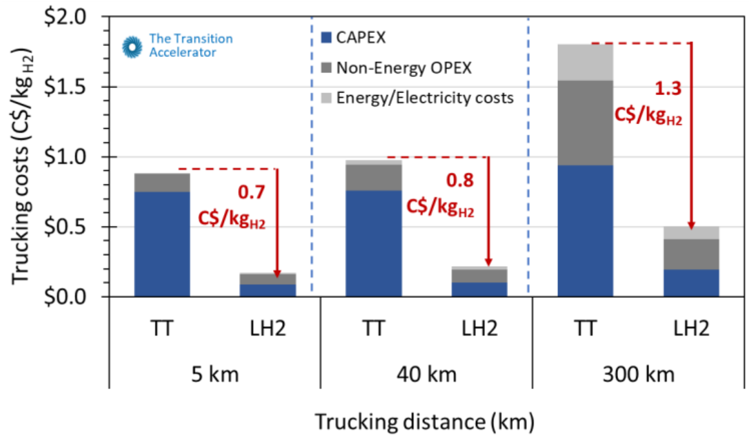

Figure 5.3. Trucking costs (C$/kg$_{H2}$) via TT or LH_2 trucks for different delivery distances (5, 40 or 300 km) and divided into: (A) CAPEX, (B) Non-energy OPEX and (C) energy/ electricity.

Table 5.2. Summary of assumptions used for compressed gas and LH_2 trucks [36].

Compressed gas truck	LH_2 truck
Truck capacity: 1 t_{H2} Max tube pressure: 520 bar Minimum tube pressure: 50 bar Truck yearly availability: 98% Time to pick up trailer at terminal: 1.5 hours Time to drop off trailer at terminal: 0.5 hours Time to drop off trailer at station: 1.5 hours Driver cost per truck: C$ 120,000/yr Diesel cost: C$ 1.2/L Truck mileage: 3.3 km/L Cab cost: C$ 163,996 TT cost: C $1,440,058	Truck capacity: 3.6 t_{LH2} Tank temperature: -253 °C Boil off losses at loading/unloading: 5% Truck yearly availability: 98% Loading time at terminal: 3 hours Unloading time at station: 3.5 hours Driver cost per truck: C$ 120,000/yr Diesel cost: C$ 1.2/L Truck mileage: 2.7 km/L Cab cost: C$ 174,340 TT cost: C $1,440,058

The second delivery mode in Supply Chain 'B' is based on liquid H_2 truck delivery. Each liquid H_2 truck consists of a truck cab and a large single liquid H_2 tank with a capacity of ~ 3.6 t_{H2}/tank. Like compressed gas trucks, the LH_2 trucks also fill their tanks at a central liquefaction terminal and then deliver to the respective LH_2 HFS. However, unlike TTs, LH_2 tanks are not left at the HFS. The large capacity of the LH_2 tank allows for fewer trucks and trips to supply a network of HFS. The main factors that determine H_2 delivery costs of both compressed gas and LH_2 trucks are the capital costs of the truck cabs and tube trailers/LH_2 tanks, the driving distance, the driver labor cost, diesel fuel cost, and operations and maintenance (O&M) costs. The detailed assumptions are listed in **Table 5.2**.

Figure 5.3 shows the trucking costs for Supply Chains 'A' and 'B' and as expected, the results show higher delivery costs as the distance between production site and HFS increases. Even when delivery distance increase, the trucking costs are dominated by capital costs of the TT or LH_2 truck while fuel (diesel) costs are only a minor contribution. In the near future, it can be expected that these delivery vehicles would be the first to be converted into HFCEV's. Lastly, the results also indicate that trucking via LH_2 trucks is more economical versus TT and the advantage for LH_2 trucking is magnified with increasing distance. The larger capacity of LH_2 trucks means multiple HFS's can be fueled in a single trip and although LH_2 tanks cost more than TT, the trucking cost per unit of H_2 delivered is lower due to the large capacity.

5.4 Pipeline Costs

As an alternative to trucking, a combination of transmission and distribution pipelines can also be used for delivering the hydrogen to HFS's. **Figure 5.4** shows the total installed costs/km of steel pipelines as function of nominal pipe size (NPS) for transmission and distribution lines. The total installed costs of the pipeline include material, labor, right of way and other miscellaneous costs. These costs were calculated using the HDSAM model developed by the Argonne national laboratory and are based on historical data for natural gas pipelines in the United States [36]. The detailed cost equations are available in The Transition Accelerator's report on "Techno-economics of H_2 pipelines" [10].

With small pipelines, the installed cost per km has little dependence on pipeline diameter as material costs are a relatively small fraction of total costs. The labor and right of way costs dominate in such a scenario. With larger pipes (>24 NPS), the installed cost per km is more sensitive to material costs. Additionally, the labor costs are higher for distribution versus transmission pipelines, because it includes pavement removal and replacement in urban areas.

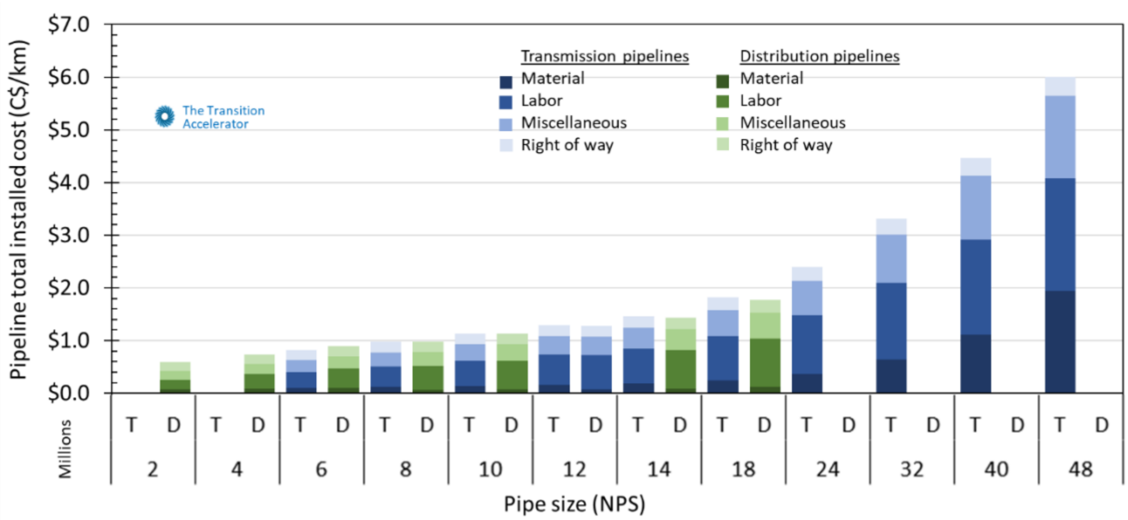

Figure 5.4. Total installed costs (TIC) of transmission (blue) and distribution (green) pipelines as function of nominal pipe size (NPS).

Note: TIC is divided into material, labor, right of way and other miscellaneous costs. T: Transmission pipelines. D: Distribution pipelines.

Since the results indicate that pipeline construction and installation is an expensive process costing millions of C$/km, substantial demand for H_2 will be required to amortize the cost over time.

5.4.1 Transmission Pipeline Cost

The ideal time to minimize the cost of gas transport via pipeline is during the initial design and construction, where gas flow calculations, project demand and other limitations are combined to optimize pipeline size, compressor units, flow rates, operating pressures etc. To gauge the appropriate transmission pipeline sizes for the different scenarios presented in Supply Chain 'C', gas flow calculations for different pipeline lengths of 295 km and 35 km, were conducted. The inlet pressure was assumed to be at 70 bars, outlet gas velocity of 30 m/s, flow temperature of 15 °C and a pipe roughness of 0.0178 mm. A single compressor station was modelled at the inlet of the transmission pipeline, using a centrifugal compressor with compression ratio per stage (x) of ~2.1, isentropic efficiency (η_{isen}) of ~80% and a motor efficiency ~95%.

Figure 5.5A shows the calculated pipeline capacity (t_{H2}/day) and pressure drop (bar) as function of nominal pipe size (NPS) for a 295 km long transmission pipeline. Pipe selection depends on many factors such as expected flow rates or volume, acceptable pressure drops and pipeline costs. Based on an assumed HFS inlet pressure of 20 bar and demand of 300 t_{H2}/day, the gas flow calculations indicate that pipes ≥ 12 NPS are required.

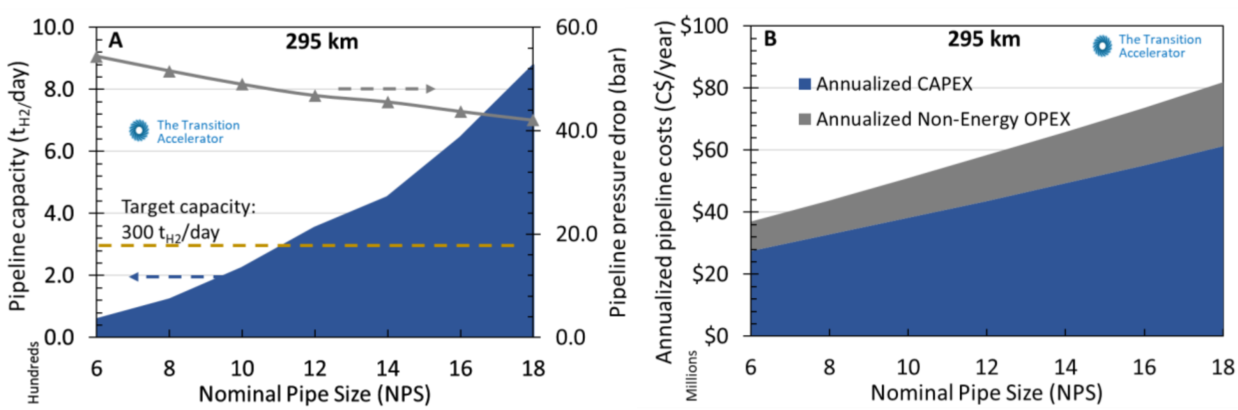

Figure 5.5. (A) Pipeline capacity (t_{H2}/day), pressure drop (bar) and (B) Annualized pipeline costs (C$/year) as a function of nominal pipe size (NPS) for a 295 km long transmission pipeline.

Note: The gas flow calculations were performed using an inlet pressure of 70 bars, outlet gas velocity at 30 m/s, flow temperature of 15 °C and a pipe roughness of 0.0178 mm.

The cost of the pipeline also is a key factor in pipe selection. **Figure 5.5B** shows the total annualized costs for a 295 km pipeline as function of pipe size, calculated over a lifetime of 50 years and at a discount rate of 8%. Since these costs are in millions of C$/year and increase with pipe size, it is critical to select a pipe large enough to allow for an adequate supply of gas to flow through but not so large that it remains underutilized and drives up the capital investment and H_2 delivery costs. Since the maximum demand in the proposed scenario was assumed to be 300 t_{H2}/day, a 12-inch steel pipe with a capacity of ~ 352 t_{H2}/day, was selected to model the transmission pipeline system costs over 295 km.

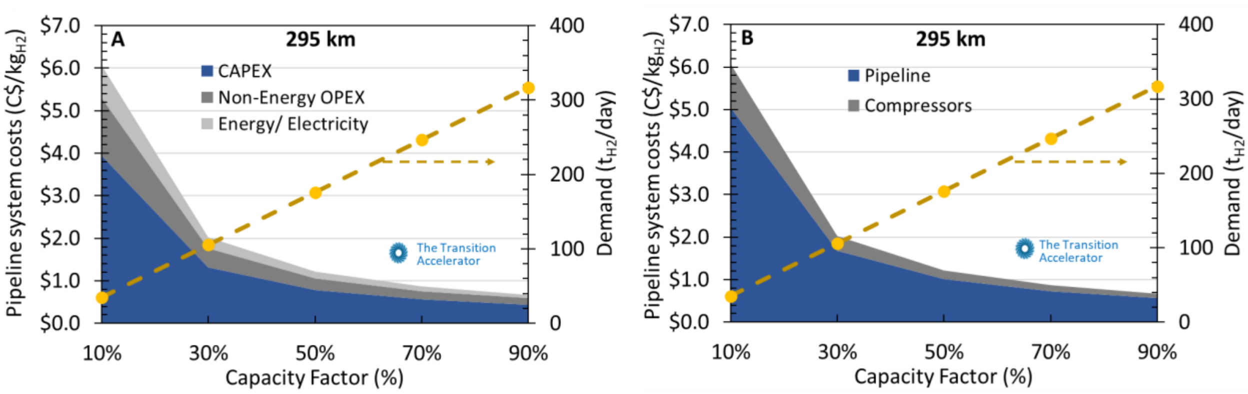

Figure 5.6. Pipeline system costs (C\$/kg_{H2}) and demand (t_{H2}/day) for a 295 km long transmission pipeline as a function of average capacity factor (%) and divided into: (A) CAPEX, Non-energy OPEX and electricity costs or (B) Pipeline and compression costs.

Note: Inlet pressure is 70 bars, outlet gas velocity is 30 m/s, flow temperature is 15 °C and the pipe roughness is 0.0178 mm.

Ideally, a pipeline should be utilized at maximum capacity to lower the delivery cost of H_2. However, pipelines are designed with a higher capacity than the average flow rate to account for time variations in flow and allow for expansion. This leads to underutilized capital, which is modeled as an average capacity factor. **Figure 5.6** shows the pipeline system costs (C\$/kg_{H2}) and calculated demand (t_{H2}/day) as a function of the average capacity factor (%). These costs have been divided into: (A) CAPEX, Non-energy OPEX and electricity costs or (B) Pipeline and compression costs. The results indicate the importance of working at high-capacity factors to reduce pipeline delivery costs. At a demand of 300 t_{H2}/day (utilization ~85%), the pipeline system costs are as low as 0.72 C\$/kg_{H2}, with the major contribution from pipeline costs at 0.59 C\$/kg_{H2} and only 0.13 C\$/kg_{H2} due to compression. It is important to note that the pipeline delivery costs are capital intensive, with CAPEX contributing ~ 65% to the costs. These costs could be supported through government grants in an initial transition period where H_2 demand is not enough to attract private investment.

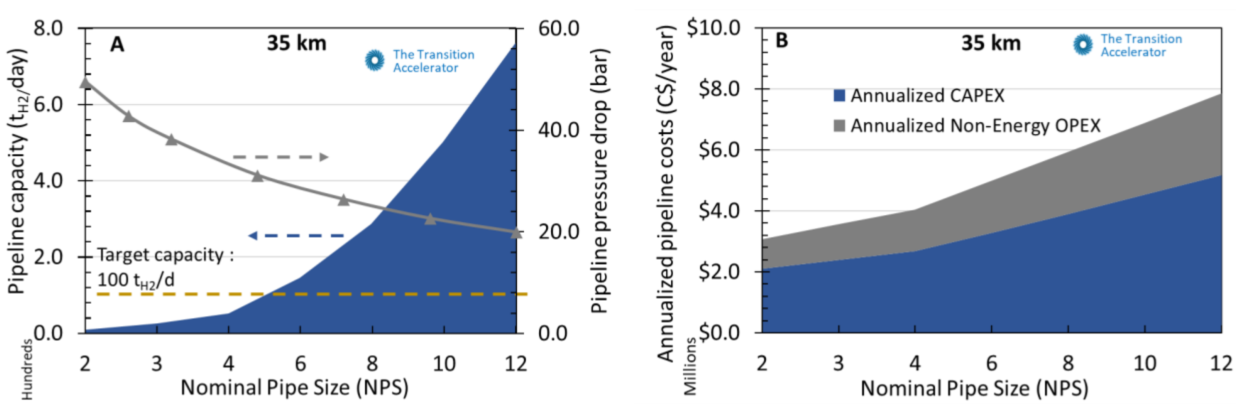

Figure 5.7. (A) Pipeline capacity (t_{H2}/day), pressure drop (bar) and (B) Annualized pipeline costs (C\$/year) as a function of nominal pipe size (NPS) for a 35 km long transmission pipeline.

Note: The gas flow calculations were performed using an inlet pressure of 70 bars, outlet gas velocity at 30 m/s, flow temperature of 15 °C and a pipe roughness of 0.0178 mm.

Following the same methodology, pipeline capacity (t_{H2}/day) and pressure drop (bar) were calculated for a 35 km long transmission pipeline as shown in **Figure 5.7**. The 35 km distance leads to higher outlet pressures and lower annualized costs compared to the 295 km long transmission pipeline. In this scenario, a 6-inch steel pipe with a capacity of ~140 t_{H2}/day, was selected to analyze the costs over 35 km. **Figure 5.8** shows the pipeline system costs (C\$/kg_{H2}) and calculated demand (t_{H2}/day) as a function of average capacity factor (%) for the 35 km transmission pipeline. In this case, the assumed demand of 100 t_{H2}/day with a ~75% capacity factor helps achieve pipeline system costs of 0.3 C\$/kg_{H2}. Unlike long distance pipelines which are capital intensive, there is an equally important contribution from the electricity cost of compression. Nonetheless, the results indicate that if the demand is high enough, then a pipeline could be a low-cost option to transport H_2. This was described in The Transition Accelerator's report on "Techno-economics of H_2 pipelines" [10], which stated that for short distance pipelines that operate with only an inlet compressor, **"a demand of ~1-1.2 t_{H2}/day/$km_{pipeline}$ is needed to drive economic viability"**.

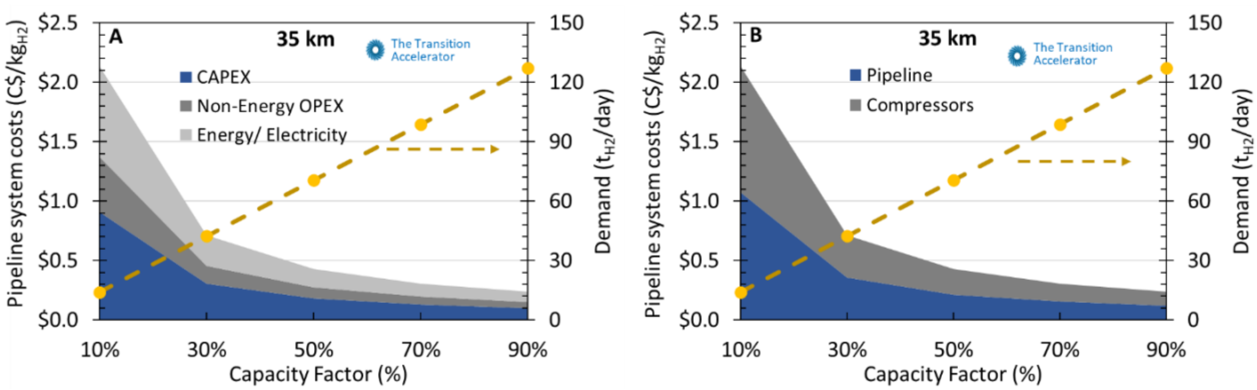

Figure 5.8. Pipeline system costs (C\$/kg_{H2}), demand (t_{H2}/day) for a 35 km long transmission pipeline as a function of average capacity factor (%) and divided into: (A) CAPEX, Non-energy OPEX and electricity costs or (B) Pipeline and compression costs.

Note: Inlet pressure is 70 bars, outlet gas velocity is 30 m/s, flow temperature is 15 °C and the pipe roughness is 0.0178 mm.

5.4.2 Distribution Pipeline Cost

The design of Supply Chain 'C' as presented in Section 4.3, was based on dedicated distribution pipelines servicing the HFS's of different size: 0.4 t_{H2}/day, 2 t_{H2}/day and 8 t_{H2}/day, with an inlet pressure of 20 bar. Based on these design parameters, pipe size and costs were optimized, and the results are shown in **Figure 5.9**. The distribution pipelines were assumed to have an inlet pressure of 25 bars, outlet gas velocity of 20 m/s, flow temperature of 15 °C and a pipe roughness of 0.0178 mm. The gas flow calculations suggested the use of 1.5-inch, 2-inch, and 3-inch dedicated pipelines servicing the 0.4 t_{H2}/day, 2 t_{H2}/day and 8 t_{H2}/day HFS's. As a result, the annualized costs for short distance distribution pipelines are < 1 MM C\$/yr and we observe a modest increase in pipeline costs relative to an increase in pipeline capacity. The pipeline system costs (C\$/kg_{H2}) of these distribution pipelines with respect to HFS size is discussed next.

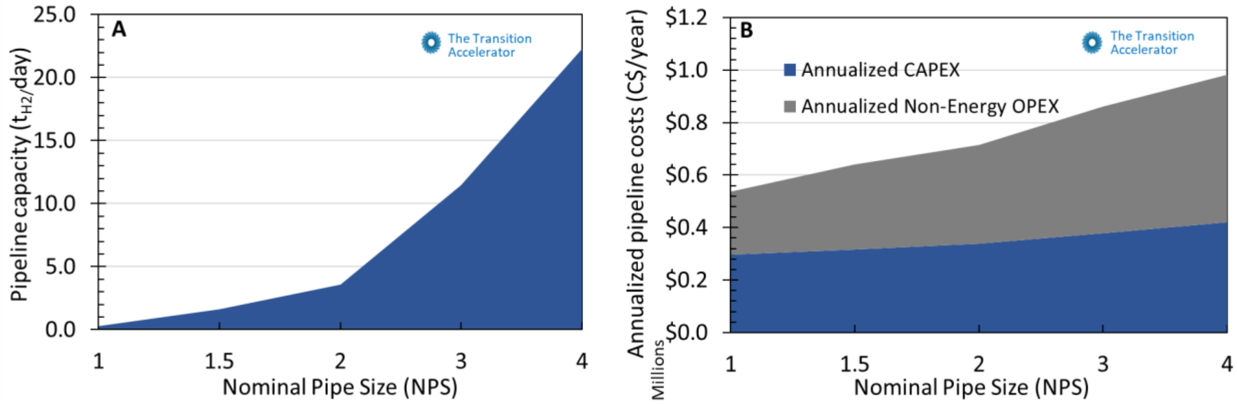

Figure 5.9. (A) Pipeline capacity (t_{H2}/day) and (B) Annualized pipeline costs (C$/yr) as a function of nominal pipe size (NPS) for a 5 km long distribution pipeline.

Note: The gas flow calculations were performed using an inlet pressure of 25 bars, outlet gas velocity at 20 m/s, flow temperature of 15 °C and a pipe roughness of 0.0178 mm.

5.4.3 Total Pipeline Cost

A summary of pipeline delivery costs of the different routes analyzed to deliver H_2 from production facility to respective HFS's is presented in **Figure 5.10**. The results indicate that 5 km long dedicated distribution pipelines have delivery costs of 5.03 C$/$kg_{H2}$, 1.15 C$/kg_{H2} and 0.36 C$/$kg_{H2}$ supplying 0.4 t_{H2}/day, 2 t_{H2}/day and 8 t_{H2}/day, respectively to the HFS's. Therefore, dedicated pipeline delivery will only be economically feasible to large sized HFS's.

For longer distances of 40 and 300 km, the total delivery costs using pipelines can be calculated by adding the cost of the 5 km distribution line with the respective transmission pipeline (35/295 km). The levelized pipeline system costs for a 40 km distance are 5.33 C$/$kg_{H2}$, 1.46 C$/kg_{H2} and 0.67 C$/$kg_{H2}$ delivering H_2 to fueling stations of different sizes, namely: 0.4 t_{H2}/day, 2 t_{H2}/day and 8 t_{H2}/day, respectively. The cost contribution of the 35 km transmission pipeline transporting 100 t_{H2}/day is only 0.3 C$/$kg_{H2}$.

Similarly for 300 km distance, the costs vary from 5.75 C$/$kg_{H2}$ to 1.08 C$/$kg_{H2}$ depending on HFS size and the contribution of the 295 km transmission line is only 0.72 C$/$kg_{H2}$.

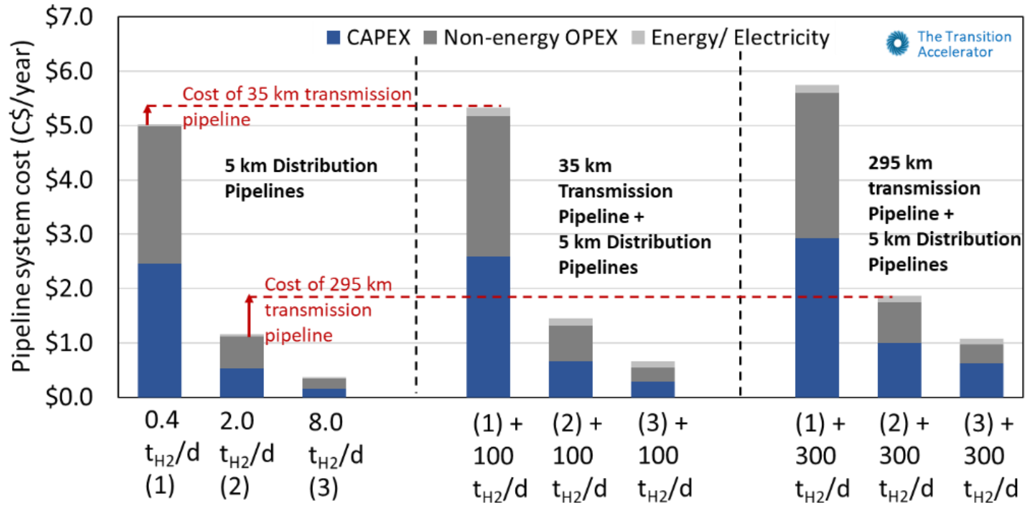

Figure 5.10. Pipeline system costs (C$/kg$_{H2}$) for Supply Chain 'C' as a function of different delivery distances, HFS size and divided into: (A) CAPEX, Non-energy OPEX and electricity costs.

5.5 Hydrogen Processing and Delivery Costs

This section draws on the results presented in sections 5.1-5.4, to calculate the H_2 processing and delivery costs for Supply Chains A, B or C, i.e., delivery by TT's, LH_2 trucks or pipelines. For delivery via TT or LH_2 trucks, the cost of the central terminal (Section 5.2) and trucking (Section 5.3) were added to compare versus pipeline delivery (Section 5.4). **Figure 5.11** provides a comparison of H_2 processing and delivery costs across the three value chains as function of both distance and HFS size.

The first observation is that the HFS size only impacts the delivery cost in Supply Chain C, based on dedicated pipeline delivery to respective HFS. The results highlight that dedicated pipeline delivery will only be economically feasible to large heavy-duty HFS's that are dispensing ≥ 2 t_{H2}/day. Large size HFS's are the expected norm for heavy-duty transport as large Class 8 trucks will typically be carrying anywhere between 50-80 kg of H_2 fuel per vehicle.

Secondly, the results clearly indicate that pipelines are the lowest cost option to deliver H_2 at scale followed by TT and LH_2 trucks.

The third observation is that within the distances (5-300 km) analyzed in this study, the total processing and delivery cost via the LH_2 route is higher versus TT delivery due to the expensive liquefaction step. However, the results also indicate that delivery via LH_2 trucks will be more attractive for long distances (> 300 km) versus TT delivery.

Lastly, the analysis reveals that processing and delivery of H_2 is capital intensive, with CAPEX contributing 45-65% to processing and delivery costs, irrespective of delivery method. However, it is important to note that these costs are not the refueling cost of H_2 at the dispenser, which also comprises of the HFS cost as discussed next.

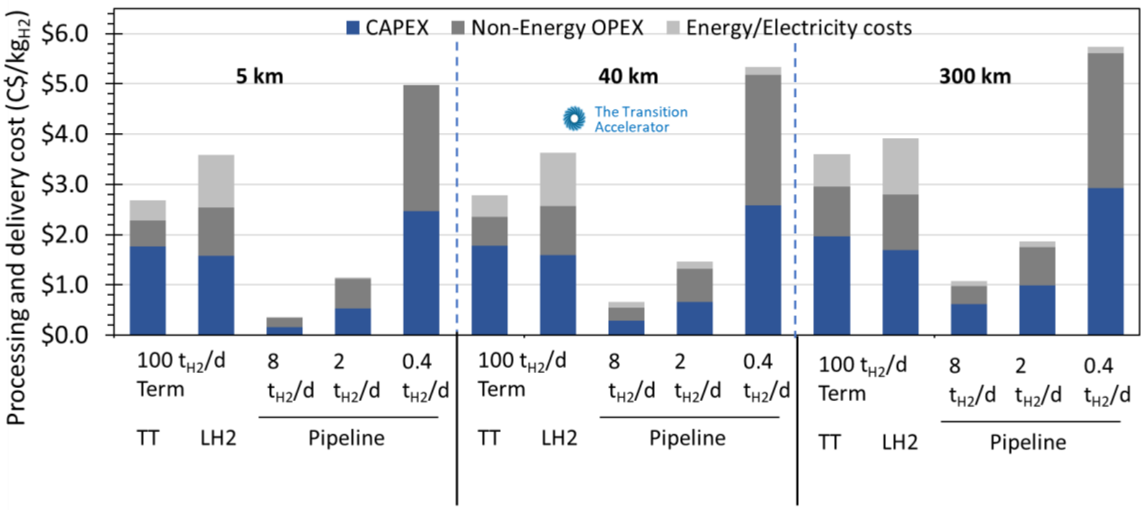

Figure 5.11. Processing and delivery costs (C$/kg$_{H2}$) for Supply Chains A, B and C, and divided into: CAPEX, Non-energy OPEX and electricity costs.

6 HYDROGEN FUELING STATION COSTS

6.1 Hydrogen Fueling Station Purification Costs

In the case of H_2 delivery by pipeline, the cost of further purification on site at the HFS must be considered. As mentioned earlier, PSA purification is the primary technology adopted for H_2 purification at centralized large-scale production facilities. Recently there have been several reports and pilot scale demonstrations of PSA purification for small-scale distributed H_2 production scenarios at HFS's [48-50]. Cerniauskas and coworkers [51] reported the capital and operating costs of a PSA unit for downstream H_2 purification. The capital cost can be calculated using the following correlation:

$$PSA_{capex} = a + b \times \frac{Q}{n_{H2}}$$

Where Q is the H_2 flow rate (mol/s) at the purification outlet and n_{H2} is the H_2 concentration in the feed flow. The PSA parameters are summarized in **Table 6.1**.

Table 6.1. Model parameters for a PSA unit deployed at pipeline-supplied HFS

Source: Adopted from Reference [51].

PSA parameters	Value
n_{H2}	98%
a	664,800
b	16,537,000
Lifetime	20
Operation and Maintenance (%)	4%
Recovery Rate (%)	93%
Electricity requirement (kWh/kg_{H2})	2.46

Using these parameters, the cost of onsite purification was calculated as shown in **Figure 6.1**. The results indicate that there will be a significant cost associated with small-scale on-site purification for small sized HFS's. However, with a large size HFS (8 t_{H2}/day), the purification costs are relatively low (< 0.4 C$/$kg_{H2}$) with the major contribution from electricity costs.

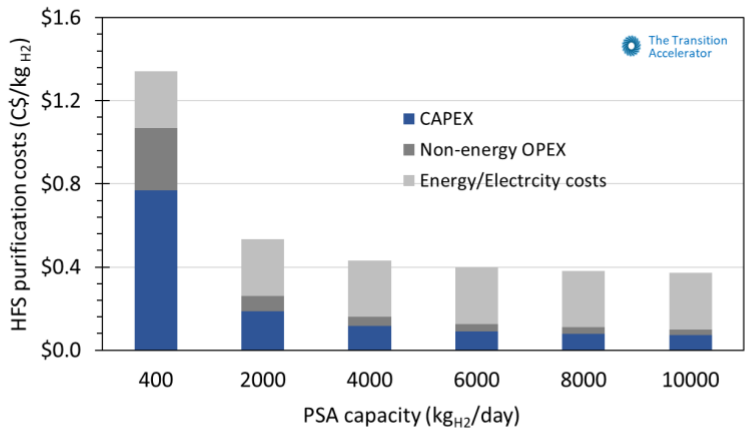

Figure 6.1. Purification costs for a pipeline supplied HFS (Supply Chain C), as a function of PSA capacity and divided into: CAPEX, Non-energy OPEX and electricity costs.

6.2 Hydrogen Fueling Station Costs based on Delivery Method

It is widely accepted that HFS's are the most complex component of the supply chain and have a significant contribution to the total refueling cost of H_2 at the pump [37,41,46]. Sections 4.1-4.3 described the design of the respective HFS's, and the operating parameters were summarized in **Table 4.1**. All the different HFS's are designed to address a typical hourly demand as shown in **Figure 6.2A**. The capacities of the compressor and buffer storage are interdependent [37,46] and defined by the hourly fueling-demand profile, which was taken from data by Chevron, based on statistics from its gasoline stations [52]. This data was based on light-duty passenger vehicles and does not ideally represent the demand profile at a heavy-duty HFS. However due to unavailability of the respective data, the HFS costs were modelled based on Chevron light-duty vehicles data [52]. The HFS size or dispensing capacity was controlled by changing the number of vehicles, as shown in **Figure 6.2(B-D)** [41,45]. The vehicle fill time dictates the maximum number of vehicles fills possible per hour per dispenser. Thereafter the number of dispensers required was calculated based on number of vehicles queued up to fuel at peak hours and the maximum number of vehicles fills possible per hour per dispenser. Based on the fueling rate of 7.2 kg/min and hourly demand, the number of dispensers was 1, 1, and 2 for HFS of size 0.4 t_{H2}/day, 2 t_{H2}/day and 8 t_{H2}/day.

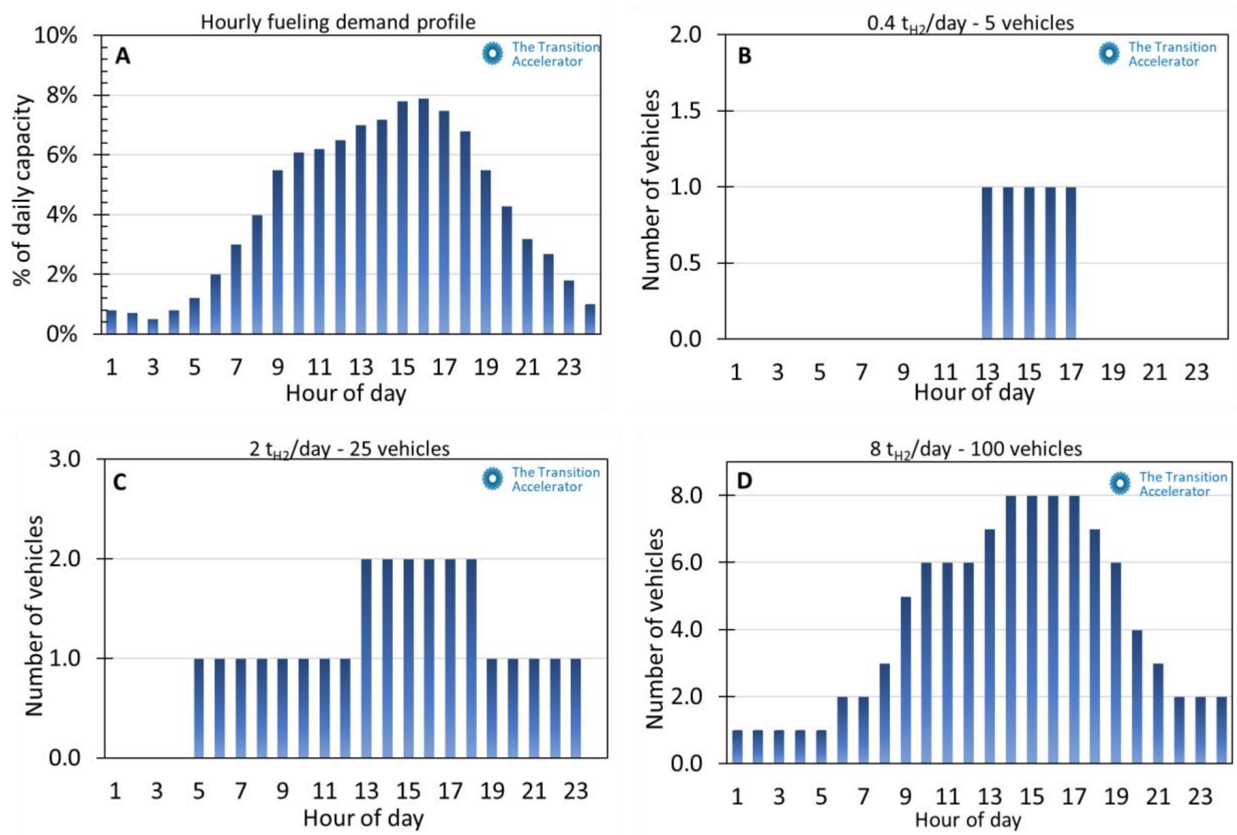

Figure 6.2. (A) Hourly fueling-demand profile for a Chevron gas station for light-duty vehicles [52] and number of vehicles for each hour for (B) 0.4 t_{H2}/day, (C) 2 t_{H2}/day and (D) 8 t_{H2}/day based on an average dispensed amount per vehicle of 80 kg.

Figure 6.3 presents the HFS costs in (A) C$/year and (B) C$/kg$_{H2}$ as a function of HFS size (t_{H2}/day). The results imply that pipeline supplied HFS's are the costliest followed by TT supplied HFS's, and the LH_2 HFS's have the lowest cost. This trend is irrespective of the size of the HFS.

The first observation is that all the HFS's are capital intensive with CAPEX costs contributing 50-70% of the total levelized costs. The second key takeaway is on the importance of going to scale with any type of HFS. At small scales (0.4 t_{H2}/day) HFS's are expensive to install and operate with levelized costs between 5-9 C$/kg$_{H2}$, which will not be feasible in any transportation market. Small fueling stations can be deployed for pilot demonstrations but the ability to quickly add capacity will be critical to reduce costs.

While building large size HFS's is key to reduce costs, it will only work when there is a demand for the H_2. In other words, the H_2 available at the station must be sold to amortize the cost of the station. In an early market, it is expected that the majority of HFS's will be underutilized. This will lead to significant impact on the cost of H_2 and the results for a 2 t_{H2}/day TT supplied HFS is presented in **Figure 6.4**. At 100% utilization, the levelized HFS cost is 2.29 C$/kg$_{H2}$ but increases sharply to 11.13 C$/kg$_{H2}$ at a 20% utilization factor. To give some context to the demand for a 2 t_{H2}/day fueling station, it will require 40 class 8 trucks using 50 kg$_{H2}$/day, or 80 transit buses using 25 kg$_{H2}$/day, or 2000 cars using 1 kg$_{H2}$/day to fully utilize the capacity of station. This suggests that certain H_2 fuel subsidies will be required to bring down the HFS costs during the initial deployment phase, which will be discussed in more detail in Section 9.

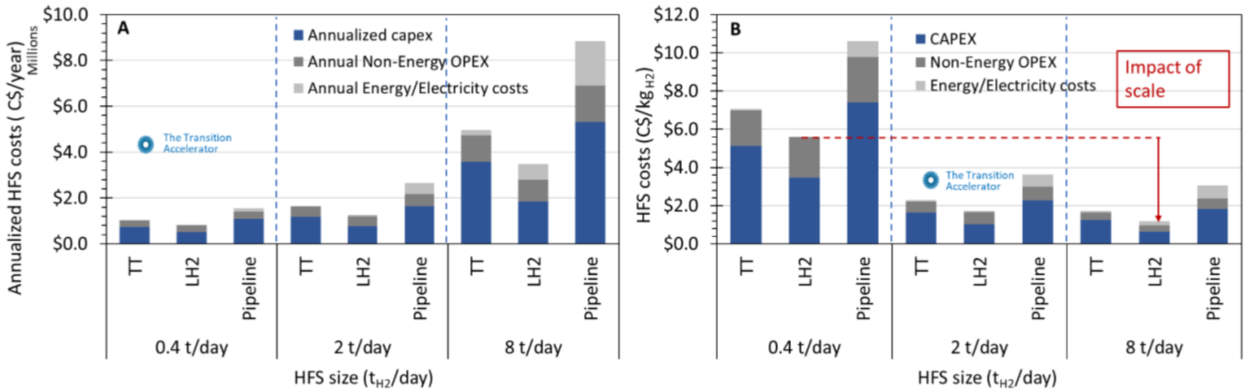

Figure 6.3. HFS costs in: (A) C$/year and (B) C$/kg$_{H2}$ as a function of HFS size (t$_{H2}$/day) and divided into CAPEX, Non-energy OPEX and energy/electricity costs.

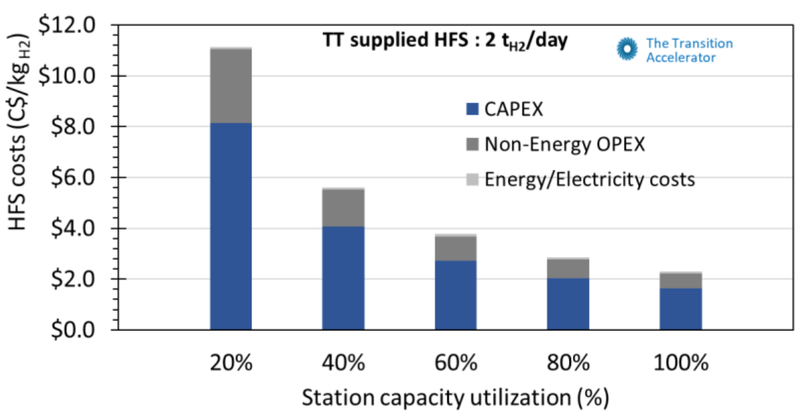

Figure 6.4. HFS costs of 2 t$_{H2}$/day TT supplied HFS as a function of capacity utilization (%).

The HFS costs were also analyzed by looking at the contribution from different components. The results presented in **Figure 6.5**, suggest that in small (0.4 t$_{H2}$/day) HFS's, both compression and storage are costly components. For pipeline supplied HFS's the cost of purification is also significant at small scales (0.4 t$_{H2}$/day). However, the storage and purification units exhibit a strong economy of scale and in larger HFS's the compressors become the costliest component. Additionally, LH_2 stations have a lower cost per kg since liquid storage costs less than gas storage and liquid H_2 pumps cost less than H_2 gas compressors. This is validated by looking at the breakdown of CAPEX and non-energy OPEX costs by different components as shown in **Figure 6.5B and C**. However, this is counteracted by the high costs of liquefaction at the central terminal as discussed in section 5.2. TT supplied HFS's are less expensive than the pipeline supplied HFS's as gaseous truck delivery has lower station storage costs because the tube trailers comprise most of the storage system (only a small high-pressure buffer storage tank is used to top off the vehicles). In addition, the high pressure H_2 delivery by TT to the HFS also reduces the compression energy requirement and this is observable by looking at the electricity costs in **Figure 6.4D**, that are the highest for pipeline supplied HFS, followed by LH_2 HFS and are the lowest for a TT supplied HFS. However, the lower costs for TT supplied HFS are counteracted by the extra compression and storage costs at the central H_2 terminal, as discussed in section 5.2.

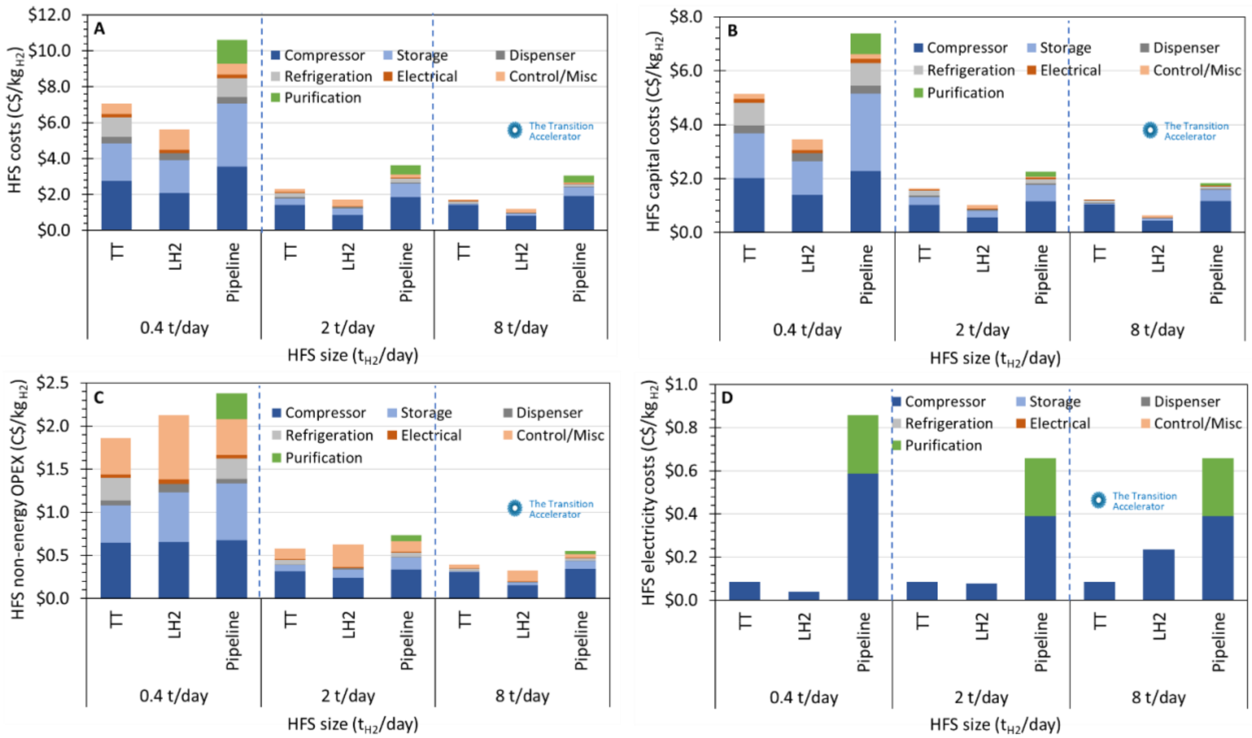

Figure 6.5. (A) HFS costs (C$/kg$_{H2}$), (B) HFS CAPEX, (C) HFS Non-energy OPEX and (D) HFS electricity costs as a function of HFS size (t$_{H2}$/day).

Note: Costs are divided into contribution from different components: Compressor, storage, dispenser, refrigeration, electrical and control system.

It is important to highlight that HFS costs are highly sensitive to demand profile. For example, a back-to-back filling profile requires additional compression and storage capability which could significantly increase costs [41]. Furthermore, various configurations and cost optimization strategies for HFS's could be used to bring down the costs. However, a detailed analysis of all these configurations and strategies is beyond the scope of this report.

7 SUMMARY: REFUELING COST OF HYDROGEN

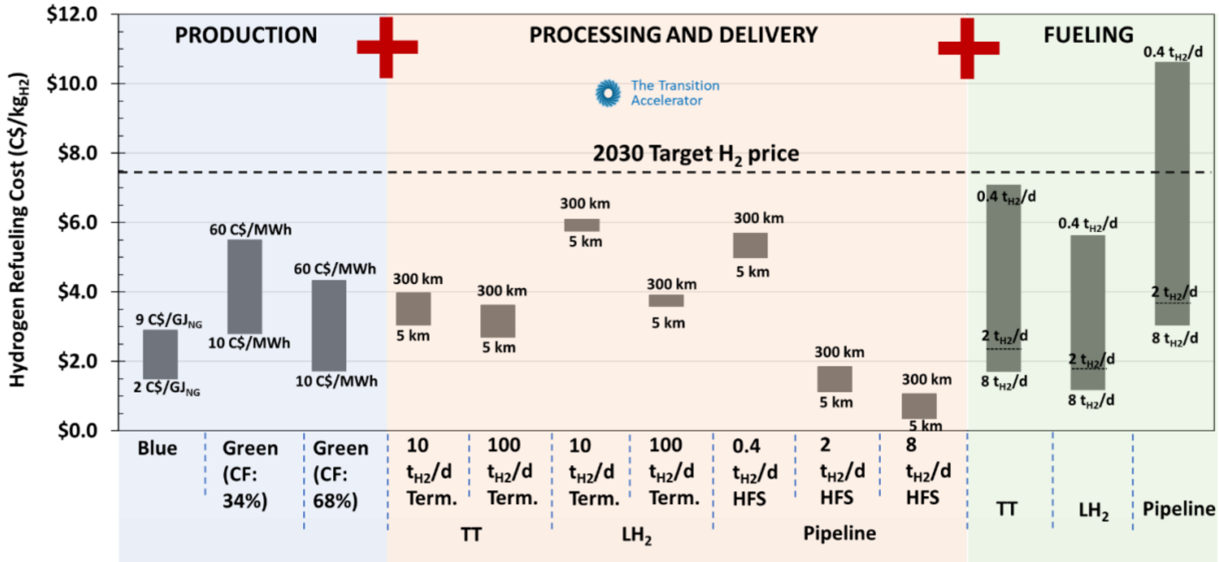

Figure 7.1. Refueling cost of H_2 (C$/kg$_{H2}$) for the different supply chains (A, B and C) and divided into production plus processing & delivery plus fueling cost.

Note: The black dash line represents the target H_2 retail price based on a diesel cost of 1.25 C$/L$_{diesel}$, drivetrain efficiency of 0.86 PJ$_{H2}$/PJ$_{diesel}$ plus a 2030 carbon price of 170 C$/t$_{CO2}$, without any fuel taxes on H_2. The analysis assumes use of large transmission pipelines capable of transporting 300 t$_{H2}$/day over 295 km and 100 t$_{H2}$/day over 35 km.

The results presented in Sections 3, 5 and 6 are summarized in **Figure 7.1** as a function of critical parameters that determine the refueling cost of H_2. The production costs are presented for both blue and green centralized H_2 production as a function of natural gas (2 to 9 C$/GJ$_{NG}$) or electricity (10 to 60 C$/MWh) price, respectively. For green H_2 production costs, the impact of the capacity factor of power source is also presented. The processing plus delivery costs is presented for various Supply Chains as function of delivery distance (5 to 300 km). These costs are also categorized as function of central terminal size (10 and 100 t$_{H2}$/day) for Supply Chains A (TT) and B (LH$_2$) and HFS size (0.4 to 8 t$_{H2}$/day) for Supply Chain C (pipelines). Finally, the HFS/fueling costs are also presented as a function of HFS size (0.4 to 8 t$_{H2}$/day).

As stated earlier, the refueling cost of H_2 at the dispenser can be calculated from **Figure 7.1** as sum of production, processing plus delivery and fueling (HFS) cost. As an example, the lowest refueling cost calculated in the analysis was ~4.6 C$/kg$_{H2}$ based on using blue H_2 produced at a large central reformer with a natural gas price of 2 C$/GJ$_{NG}$ and delivered over a short distance of 5 km via a dedicated distribution pipeline to a large 8 t_{H2}/day HFS. Interestingly, the highest delivery cost of ~20.3 C$/$kg_{H2}$, would also be via pipeline delivery, in the case of green H_2 being produced via dedicated renewable electricity at a cost of 60 C$/MWh, and delivered over a distance of 300 km using a 295 km trunkline and 5 km distribution pipeline, to a small 0.4 t_{H2}/day HFS.

A few important observations can be summarized as follows:

- **Production costs:** The analysis reveals that to target a H_2 refueling cost that is competitive with diesel in 2030 at ~7-8 C$/$kg_{H2}$, the production costs will have to be < 3 C$/$kg_{H2}$. Currently this is only possible with centralized blue H_2 production irrespective of the natural gas or electricity price. In the future with an expected drop in electrolyzer costs, green H_2 production is expected to be competitive.
- **Processing and delivery costs:** The results also reveal that dedicated pipeline delivery will have the lowest costs as long as there is large demand (~1 t_{H2}/day per km of pipeline) to amortize the cost of the transmission pipeline and the distribution network supplies H_2 to large size HFS's. On the other hand, while trucking costs with LH_2 are low, total delivery costs are severely impacted by liquefaction costs. However, these costs can be significantly decreased by employing large scale facilities.
- **Fueling (HFS) costs:** The results indicate that LH_2 HFS's are relatively less expensive versus gaseous-supplied HFS's and irrespective of delivery mode, small sized HFS's will not be feasible if H_2 refueling costs must compete with diesel.

Figure 7.2 illustrates the processing plus delivery plus fueling costs (excluding production costs) for an ideal scenario whereby H_2 is delivered within a large mature hub which contains large (100 t_{H2}/day) central terminals for distribution and large sized (2 and 8 t_{H2}/day) HFS's. The costs are divided into: (A) CAPEX, non-energy OPEX and electricity costs or (B) Compression/Liquefaction and other costs. The results indicate that the delivery and fueling costs are CAPEX dominated with ~45-65% contribution for the different supply chains. In addition, the analysis highlights that compression and/or liquefaction are the costliest processing steps of the supply chains.

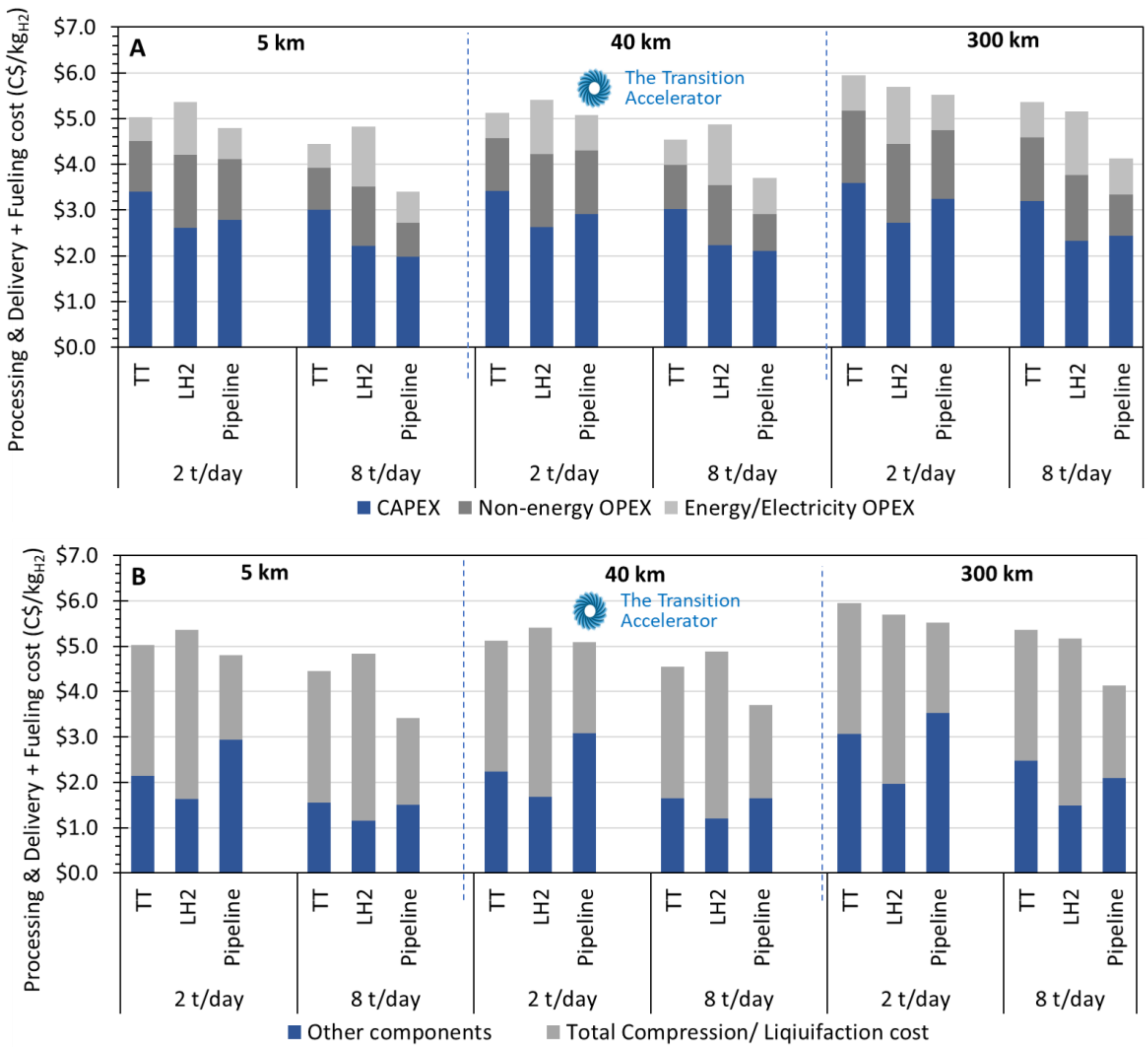

Figure 7.2. Processing & delivery plus fueling costs (C$/$kg_{H2}$) for a scenario where H_2 is delivered in a large mature hub which contains large (100 t_{H2}/day) central terminals for distribution and large size (2 and 8 t_{H2}/day) HFS's.

Note: Costs are divided into (A) CAPEX, Non-energy OPEX, energy/electricity costs and (B) Compression/Liquefaction and other costs.

The analysis resulted in the following **key takeaway messages:**

1) **Scale/Demand is critical:** The levelized cost of various components greatly depends on scale. There is a significant cost advantage by employing economies of scale, particularly for liquefier units, pipelines and HFS's. While employing economies of scale is important, it will only reap benefit if there is high utilization of the capacity of various process units. In other words, scale and demand must work together. Creating substantial demand (e.g., >2 t_{H2}/fueling station/day) in concentrated hydrogen hubs and corridors would be essential to economic viability. In transportation, this requires 100+ transit fuel cell buses, or 40+ Class 8 fuel cell trucks refueling daily at each station. This was demonstrated in **Figure 6.4** where we showed that the cost of an underutilized 2 t_{H2}/day HFS can increase exponentially.

2) **Small HFS are not feasible:** Even in under optimized conditions where the delivery components are operating at large scale, the use of a small sized (0.4 t_{H2}/day) HFS is not economically feasible. However, in an early market with a low number of HFCEVs, it is likely that small sized HFS's that require a lower capital investment will be deployed. Therefore, it is critical that these HFS's are designed with the capability to increase capacity quickly as H_2 fuel demand increases.

3) **Demand will dictate suitable delivery option:**
   a. Delivery via TTs is more suitable in an early market whereby delivery and fueling are done at a smaller scale. This is because scale has a lower impact on the cost of central compression versus liquefaction or dedicated pipelines.
   b. Liquefaction is highly sensitive to scale and adds substantially to the H_2 fuel cost (+3 C$/$kg_{H2}$) but reduces the cost of both truck delivery and HFS infrastructure. Therefore, LH_2 is the technology of choice for larger stations (2 to 8+ t_{H2}/day) that are further from the site of production, especially if pipeline infrastructure is not available.
   c. In a mature market where the H_2 fuel is delivered at scale (100s of t_{H2}/day) and large HFS's ($\geq$ 2 t_{H2}/day) are deployed, delivery via pipeline will be the lowest cost.

4) **Pipelines are essential to enable H_2 use in multiple sectors:** Given current technologies and potential demand for H_2 fuel (Refer to Section 2.1), pipelines are the only practical option that enables opportunities in multiple sectors (transport, heat, power) and realize a cost and scale of supply/demand that justifies the necessary infrastructure investments. This synergy among multiple demand sectors delivers benefits to all and should be integrated into strategic planning for the energy transition in Canada.

5) **New value chain is capital intensive:** H_2 delivery and fueling costs are dominated by the CAPEX contribution that is ~45-65% for the different supply chains. Additionally, as economies of scale are employed to drive down the costs, the required capital investment will be in millions of C$. Therefore, as we move forward various policies and financial instruments will be required to remove market barriers, mitigate this risk, and accelerate the transition. This will be discussed further in Section 9.

6) **R&D required on compression and liquefaction technology:** The analysis also highlights that the compression and/or liquefaction are the costliest processing steps of the supply chains. Technological improvements that increase efficiency, reliability and lifetime of currently available compressors and liquefaction units will be critical to reduce both capital and operating expenses.

8 GROWING A FUEL HYDROGEN ECONOMY IN EDMONTON REGION

The results presented in the previous section, illustrate the importance of minimizing barriers in connecting supply to demand. The analysis also indicates the scale of the challenge in developing a new value chain which will take coordinated effort between different stakeholders to quickly scale up demand and drive down costs. Moving forward, a key step would be the creation of regional hydrogen hubs and economic corridors to improve coordination and connect supply to demand. While the findings presented here should have relevance to any region of Canada, the analysis is of particular relevance to the Edmonton Region Hydrogen HUB (ERH2) (https://erh2.ca/), and Alberta Industrial Heartland (AIH) (https://industrialheartland.com/). Regional hubs such as the ERH2 are key to bring together various stakeholders from government, industry, independent think tanks, end users and Indigenous leaders to launch strategic projects and kickstart the H_2 economy. Edmonton and the AIH region are strategically positioned to be a global H_2 leader, whereby current H_2 production capacity exceeds 2000 t_{H2}/day along with world class infrastructure for CCUS ([8]). To this end, potential demand centres for heavy-duty H_2 freight and corridors which can connect H_2 supply with demand are identified.

Connecting supply to demand is one of the greatest challenges associated with building-out a new H_2 value chain. Centralized H_2 production facilities in AIH are in close proximity to each other and adjacent to existing H_2 and CO_2 pipeline assets [8,53]. The region is underlain by geological formations with large sequestration potential at the right depth for permanent CO_2 storage. More importantly, supply is also in close proximity to corridors/areas in and around Edmonton that have potential for substantial demand for H_2.

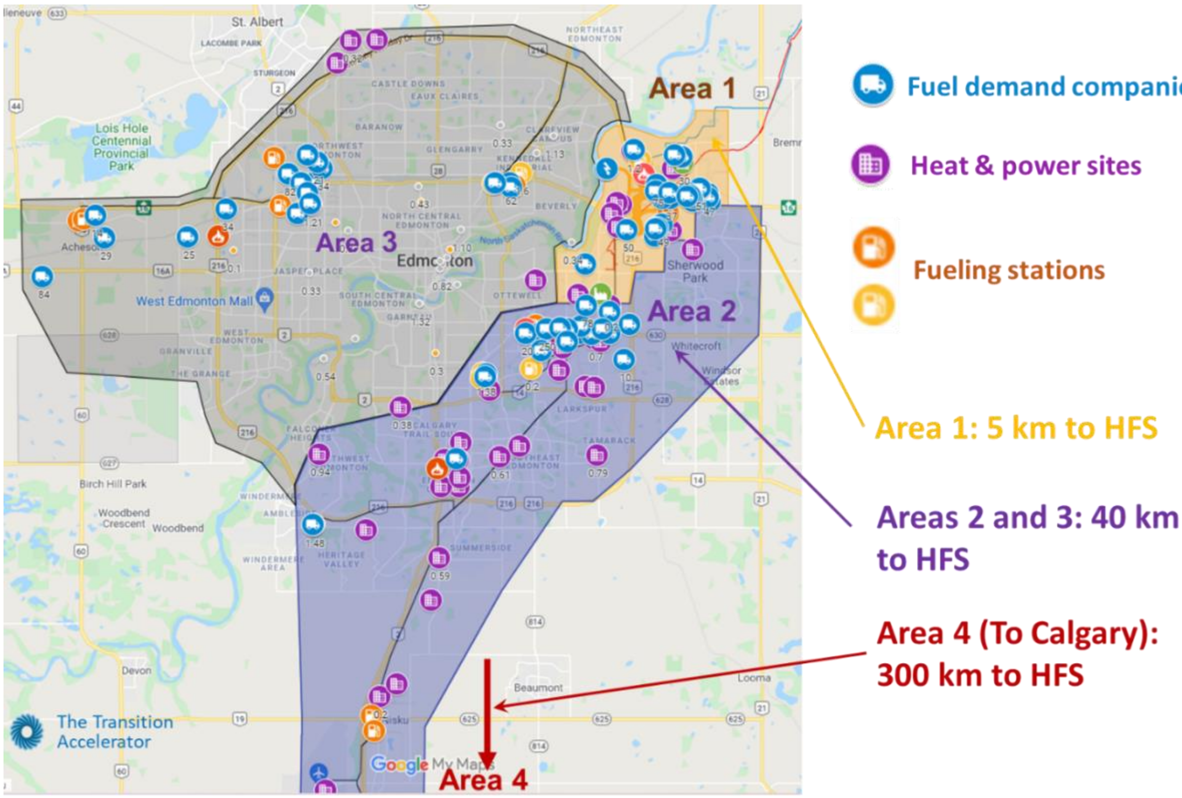

Figure 8.1. Areas in Edmonton/AIH region where supply can be connected to demand for H_2 use as transportation fuel for heavy-duty freight.

Of the approximately 34,000 heavy-duty vehicles (HDV) registered in the Edmonton region for commercial transportation [8,54], the majority are associated with commercial carriers found along Highway 16 which cuts across the north side of the City of Edmonton. There is another industrial corridor that moves across from the north-east side of the city of Edmonton (**Figure 8.1**) i.e. Sherwood Park, bisecting the south-east quadrant of the city, 40 km down to Edmonton International Airport (EIA) [8]. The estimated fuel demand for heavy-duty freight from this region is ~ 23 PJ diesel/yr [8]. Based on a DTE of 0.86 GJ_{H2}/GJ_{diesel} and the energy density of H_2, the potential H_2 demand from the heavy-duty freight sector in the region can be calculated to be about ~382 t_{H2}/day.

There is also significant fuel demand associated with trucks on major highways moving from the region to cities such as Calgary and Fort McMurray, representing potential H_2 demand of ~150 t_{H2}/day [8]. The 300 km Calgary-Edmonton highway is the busiest representing a potential demand of ~93 t_{H2}/day [8]. Furthermore, municipal fleets in the region can play a key role in building H_2 fuel demand. Municipal fleet buses account for ~3% of the city's diesel demand, which translates into ~ 20 t_{H2}/day demand [8].

Several large refueling stations can be found in the same regions (**Figure 8.1**), providing heavy-duty trucks and municipal vehicle fleets with diesel fuel. Ideally, HFS's would be co-located with diesel at existing stations. One advantage of targeting the commercial carrier segment is that only a few, high-capacity stations are needed to supply a large fuel market. This is essential for rapid transition of the fuel supply and delivery systems that can compete with the incumbent diesel market without ongoing public investment. Based on the analysis of supply, potential demand, and HFS locations we propose the buildout of HFS's in four different zones/areas as the base case to developing a new H_2 value chain as identified on the map in **Figure 8.1**. On an average the various HFS's in these areas would be 5, 40 and 300 km respectively from a central H_2 production site.

Therefore, the TEA results of the different supply chains analyzed in this study can be applied to the region as follows:

- Compressed H_2 TT delivery could be used in an initial market with low demand and short distances. This could be envisioned as a feasible option for initial pilot demonstrations such as those in the Sherwood Park area or at/near EIA. Furthermore, since a TT supplied HFS can potentially be converted to a pipeline supplied HFS, the TT route can be adapted to increasing demand and offers a pathway to cost competitiveness.
- LH_2 truck delivery can be a solution when there is a small to medium H_2 demand and long distances involved. Moreover, LH_2 delivery is an ideal option to distant remote locations where building of pipelines is not feasible in the near to medium term. This route can be envisioned in transporting H_2 from Edmonton to Calgary until demand is high enough to justify building a pipeline.
- To achieve retail costs for fuel H_2 that are competitive with current diesel prices, pipeline transport of H_2 to various HFS's in Edmonton and to Calgary offers the most potential. However, to justify the infrastructure investments, an 'economy-of-scale' is needed that is best achieved by H_2 pipelines following transportation corridors to serve the transport sector in the region while also delivering fuel H_2 for power generation and buildings in a net-zero future.

9 CONCLUSIONS AND RECOMMENDATIONS

Underpinned by a global shift toward decarbonization, H_2 is receiving unprecedented interest and investments. At the beginning of 2021, over 30 countries have released H_2 roadmaps, the industry has announced more than 200 H_2 projects, and governments worldwide have committed more than 70 billion US$ in public funding. This momentum exists along the entire value chain and is accelerating cost reductions for H_2 production, transmission, distribution, retail, and end-use.

The Government of Alberta also recently released its H_2 Roadmap detailing the role of a clean H_2 economy in Alberta's future. With an established oil and gas industry, rapidly growing renewable sector, and access to ideal geology for permanent storage of carbon dioxide, the onus is on Alberta to fully utilize the potential of H_2 in its net-zero journey and unlock significant economic value for the province. Yet the challenges ahead are substantial as H_2 value chains are complex, and the risks faced by investors are significant. Co-ordination problems between different parts of value chains persist, costs are changing quickly, and technologies are developing rapidly. Therefore, it will take smart policies and a concerted effort on behalf of industry, government, and consumers to grow supply and demand.

Based on the results discussed in this report, there are a few recommendations that can accelerate the adoption of H_2 as a clean fuel and highlight the synergy between different demand sectors. These recommendations cover various critical needs such as scaling up demand, developing infrastructure that caters to different sectors, attracting investors, reducing costs, and ensuring refueling infrastructure is strategically located. The recommendations are as follows:

1. **Develop strategic plans and regional hubs.**
2. **Target economies of scale and mitigate investment risks.**
3. **Support demand creation.**
4. **Promote innovation, strategic projects, and knowledge-sharing.**

9.1 Develop Strategic Plans and Regional Hubs

As mentioned earlier the Governments of Canada and Alberta have released their respective H_2 Strategy [55] and Roadmap [22]. These reports summarize how H_2 can be used to support decarbonization efforts and describe policy pillars required to make sure the full potential of H_2 can be tapped. These were vital first steps to provide stakeholders with certainty about the future marketplace of H_2.

In the context of Alberta, H_2 not only offers a great opportunity to advance towards a clean future but as an economic driver that creates diverse opportunities. As summarized in Section 2.1, the potential demand for H_2 fuel in the province is ~13,289 t_{H2}/day. If domestic and international export potential is added to this, the economic opportunity ahead will be in billions of C$ per year. This will also have widespread, direct, and indirect social and economic benefits, where new employment opportunities are created to support the H_2 economy. In the next step, to activate their strategies and roadmaps, government should create a strategic suite of policies and incentive programs that stimulate demand in coordinated ways that will be economically sustainable in the long-term.

A key part of the strategic planning would be to analyze the **interdependencies among different demand sectors** and plan infrastructure development for the future accordingly. The analysis presented in this report highlights that transportation presents the first target sector for H_2 fuel use (Section 2.2), as it can attract a much higher price versus heat or power generation. In an early market scenario where demand is low, the development of a new value chain around the use of TTs and LH_2 trucks to deliver H_2 fuel for transport will make more economic sense. However, the strategic planning must consider that pipelines will represent the lowest-cost delivery option in a mature market where demand is higher. More importantly, the high cost of H_2 compression for tube trailers, or of liquefaction for LH_2 transport, undermines the economic viability for H_2 fuel to be used for electricity generation or for space/water heating in buildings. Given current technologies, pipelines are essential in enabling all three market opportunities and realizing a scale of supply and demand that justifies the necessary infrastructure investments. The use of pipelines to deliver H_2 fuel for transport will **lead to a virtuous cycle** that enables different demand sectors and delivers benefits to all. Therefore, this should be integrated into strategic planning for the energy transition in Canada.

In addition, as highlighted in the previous section, moving forward, a key step would be **the creation of regional H_2 hubs and corridors to improve coordination and connect supply to demand**. As an example, the build out of HFS's along key transport corridors should be targeted, as discussed in section 8. Commercial carriers and fleet vehicles with high daily mileage along these fixed corridor routes present a promising opportunity, that could help increase the utilization rate of refueling stations on the main routes they use. Other opportunities exist with fleet vehicles at industrial sites, clusters and at ports. The work done in the establishment of regional hubs such as the ERH2 could be used as a base case template to form similar hubs across the country. The energy transition is a complex challenge, and these hubs will be instrumental in bringing together various stakeholders from the government, industry, and demand sector to work together to minimize barriers.

9.2 Target Economies of Scale and Mitigate Investment Risks

The factors limiting H_2 use today are economic rather than technological, as H_2 is not yet cost competitive compared to conventional fuel options such as diesel. The key takeaway message from this report is that: '**Scale Matters**', and the cost benefits of economies of scale in H_2 supply and distribution must be realized. Thereafter, once we get to 'efficiencies of scale', an economically viable system will take over. Getting to scale will require significant capital investment in millions of C$ that supports infrastructure development for delivery and refueling. However, the capital investment will only pay back if the equipment is well utilized, so there must be risk mitigation for that capital till demand increases. Therefore, policy makers and/or financial institutions need to employ various policies and financial tools to remove market barriers, ease regulatory burdens and **mitigate investment risk** which will attract private investment. Technical assistance, grants and interest free loans can play a critical role early in the project. Other tools could be in the form of time-bound capacity payments in exchange for a fixed or indexed H_2 delivery price to incentivize build-out at scale, or guaranteed off-takes to meet utilization targets, or conditional capital to reduce utilization targets. Public finance institutions can make key contributions by providing investors with risk guarantees and other insurance tools.

9.3 Support Demand Creation

While employing economies of scale is key, it fails without securing the demand for H_2 fuel. Thus, supporting demand creation goes hand-in-hand to ensure quick ramp-up to maximize utilization and gain the benefit of economies of scale. The focus of most government policies is on producing low-carbon H_2, while measures to increase demand receive less attention. Boosting the role of low-carbon H_2 in clean energy transitions requires a step change in **demand creation**. For the heavy-duty transport sector, non-financial incentives like priority lanes, zones and parking spaces can help, but significant demand will not materialize without a range of available vehicles at acceptable prices, coupled with predictable and affordable fuel prices. Currently, both vehicles and H_2 delivery costs are high due to a low production volume and lack of infrastructure. These costs are expected to decrease dramatically with an increase in production, technology improvements and buildup of associated infrastructure. Until then, vehicle purchase and fuel subsidies along with other tools, such as carbon pricing and credits, will be required to incentivize fuel-switching from diesel to H_2. These demand building policy tools and programs should be designed to support an achievable rate of adoption, and need to be coordinated in scope, scale, and timeline with infrastructure development plans, policy tools, and programs.

9.4 Promote Innovation, Pilot Projects, and Knowledge-Sharing

As discussed in Section 7, the results indicate that compression and liquefaction are the costliest components of the supply chains, contributing >50% to refueling costs. **Technological innovation** that increases efficiency, reliability, lifetime and reduces the manufacturing costs of currently available compressors and liquefaction units will be critical to drive down both annualized capital and operating expenses in the long term. Therefore, research efforts on these key components will be important in the next few years. In addition, R&D efforts are needed to drive down fuel cell stack, material, and manufacturing costs, as well as other HFCEV specialty component costs such as H_2 storage tanks.

Importantly, providing **support to shovel-ready projects** can kick-start the scaling up of low-carbon H_2 production, development of infrastructure to connect supply sources to demand centres, and manufacturing capability from which later projects can benefit. These pilot projects can be used to explore 'fit for service' potential of H_2-using vehicles under real-world conditions in Alberta and across Canada, helping prepare demand sectors for adoption of hydrogen at scale. Insights must be made public, including transparent discussions of pros and cons, to assess the viability of H_2 vehicles for specific end-uses. When evidence of 'fit for service' has been achieved, public support will be required to deploy dozens to hundreds of HFCE and/or H_2-diesel vehicles (including buses, trucks, trains) in partnership with municipalities or companies, relying on multiple HFS's. The Transition Accelerator has played a key role in launching strategic demonstration projects such as the Alberta Zero-Emission Truck Electrification Collaboration (AZETEC) [56] and Alberta Zero-Emission Hydrogen Transit (AZEHT) [57] together with key industrial players and different levels of government organizations. The AZETEC project involves the development of two HFCEV trucks running between Edmonton and Calgary along with the mobile refueler. Similarly, AZEHT involves the purchase and testing of two HFCEV buses for Edmonton and Strathcona County. These projects will play a key role in laying the foundation for Alberta's energy transition.

Lastly, as highlighted earlier, the H_2 value chain is complex and the successful adoption of H_2 will require **effective communication and knowledge sharing** between different stakeholders. During this phase, government, Hubs, and non-profit think tanks, such as The Transition Accelerator can play a key role to ensure there is effective knowledge sharing and an accessible market for everyone.

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