NWT Hydrogen Study

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List of Acronyms

AEA	Arctic Energy Alliance
AEL	Alkaline Electrolysis
AFC	Alkaline Fuel Cell
ATR	Auto-Thermal Reforming
BC	British Columbia
BEV	Battery Electric Vehicle
CI	Carbon Intensity

CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Utilization and Storage
CNSC	Canadian Nuclear Safety Commission
DAC	Direct Air Capture
EU	European Union
FCEV	Fuel Cell Electric Vehicle
GBS	Gravity-Based Structures
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GNWT	Government of Northwest Territories
GJ	Gigajoule
GW	Gigawatt
GWh	Gigawatt-hour
HDT	Heavy-Duty Truck
HDV	Heavy-Duty Vehicle
HFCEV	Hydrogen Fuel Cell Electric Vehicle
HTEL	High Temperature Electrolysis
ICE	Internal Combustion Engine
kJ	Kilojoule
kW	Kilowatt
kWh	Kilowatt-hour
LCOH	Levelized Cost of Hydrogen
LDV	Light-Duty Vehicle
LNG	Liquified Natural Gas
MDV	Medium-Duty Vehicle
MDGI	Mean Daily Global Insolation
MMNR	Micro Modular Nuclear Reactor
MW	Megawatt
MWh	Megawatt-hour
NG	Natural Gas
NTPC	Northwest Territories Power Corporation
NWT	Northwest Territories
PEMEL	Polymer Electrolyte Membrane Electrolysis
PSA	Purification/Pressure Swing Adsorption
SMR	Steam Methane Reforming
SMNR	Small Modular Nuclear Reactor
SWOT	Strengths, Weaknesses, Opportunities and Threats
TJ	Terajoule
TRL	Technical Readiness Level
WGS	Water Gas Shift
ZEV	Zero Emission Vehicles

1. Executive Summary

This hydrogen study investigates if and how conventional energy (fossil fuels) can be replaced by hydrogen to reduce carbon emissions in the Northwest Territories (NWT). The current energy system and the main sources of emissions are described. Transportation emits most CO2 by a significant margin, followed by energy consumption in buildings. Most of the energy consumed is based on petroleum products such as diesel and fuel oil and sourced from Alberta from where it is railed into Hay River and distributed by truck and barge to the various locations within the Territories.

Replacing conventional petroleum products requires development of new, clean energies. This report provides a generic description of such technologies, their efficiencies, and their technical readiness. As hydrogen is principally a manufactured gas, unlike crude oil or natural gas which can be found in geological formations and extracted, hydrogen production requires energy as input to a conversion process. For hydrogen to be clean, (i.e., low carbon), the energy used to produce hydrogen must be low or zero carbon emitting.

The main types of electrolysis are discussed, converting electricity and water into hydrogen. Alternatively, hydrogen can be produced through conversion of hydrocarbons, including natural gas and biomass. These technologies include Auto-thermal reforming (ATR), Steam Methane Reforming (SMR), and Methane. ATR or SMR coupled with Carbon Capture and Sequestration (CCS) produce low carbon hydrogen, whereas Pyrolysis produces hydrogen and solid carbon. The latter process is a new development and not yet commercially available.

Other processes are available that produce low carbon fuels, such as ammonia synthesis produced from low carbon hydrogen and nitrogen. Ammonia is considered a “hydrogen carrier” as the ammonia can be reconverted back to hydrogen at point of use, or consumed directly in internal combustion engines, although direct combustion of ammonia is still under development. Other conversion processes making low carbon fuels, (such as renewable diesel) are discussed. An overview of short-term and long-term hydrogen/ammonia solutions is provided.

Developing any industrial process for hydrogen in the Northwest Territories requires know-how of designing, constructing, and operating in a cold climate and remote regions. Opportunities to initiate new energy development should involve local First Nations, through their professional organizations and alliances to implement and operate low carbon solutions, including hydrogen production and application. Examples for developing hydrogen in the NWT are reviewed, as well as aspects of work-force training and emergency response. Relevant codes supporting safe and efficient hydrogen development is presented.

A financial analysis was performed to generate indicative cost projections for producing hydrogen or ammonia from renewable electricity sources. This includes estimation of hydrogen production or ammonia produced in Alberta and shipped to NWT. The cost of hydrogen fuel through the different pathways were compared to conventional diesel and ammonia on an equivalent cost per unit of energy content on a $/GJ basis. The evaluation factors possible incentives through capital cost contributions, emissions credit creation, and investment tax credits.

Indicative cost estimates consider the cost associated with developing and building facilities in the NWT. Low-cost electricity and scale are important contributing factors to achieving hydrogen or ammonia cost below the cost of conventional diesel. To deploy these new energies, new applications must be introduced, such as power generation form internal combustion engines that use ammonia as fuel, and fuel cell electric vehicles, in particular in transit and heavy-duty trucking. Indicative cost of distributed ammonia for power generation was developed, as well as power generation through the application of stationary fuel cell technology. Estimates of hydrogen in Transit were developed at pilot scale.

Scale and innovation will further reduce cost. Hydrogen produced in Alberta from natural gas conversion with CCS, liquefaction and transportation to the NWT is approximately on par with that of conventional diesel. Large scale ammonia produced from electrolysis hydrogen at renewable electricity price will be competitive with conventional diesel, however, when this ammonia is cracked back to hydrogen, the cost of this hydrogen may be greater than that of conventional diesel, on an energy basis. When ammonia is produced in Alberta, including transportation to Hay River it could undercut diesel fuel by significant margin on an energy basis.

Cost of distributed ammonia for electricity was analysed, based on electricity needs in the Beaufort-Delta, Sahtu and Deh Cho regions. Ammonia could replace conventional diesel in a combustion engine, coupled to an electric generator. This will require engine modifications which are currently under development. The distribution analysis includes cost for pressurized and cryogenic storage of ammonia, barging, and local distribution by truck. It was found that the cost of ammonia at point of delivery produced in the NWT is approximately 80% more expensive than conventional diesel. In contrast, when the ammonia originates from Alberta, the cost increase is less at about 10%-20% relative to diesel fuel. However, carbon emissions from ammonia are negligible compared to diesel.

The cost of producing power from hydrogen in a stationary fuel cell is highly sensitive to the cost of hydrogen. When produced from electrolysis in the NWT at current power prices, the cost will be over $1,000/MWh, however, when produced from low-cost renewables the cost reduces to approximately $110/MWh.

Indicative cost of a hydrogen fueling pilot for Fuel Cell Electric Buses (FCEB) was developed, resulting in cost of $8.5M for hydrogen production from solar, compression, storage, and a fueling station. Four buses are estimated at $5.3M. This resulted in an indicative cost of $5.44/km, an increase of 26% over a calculated cost of $4.32/km for Battery Electric Buses (BEB), using electricity at current NWT price. However, FCEB being more expensive than BEB should be expected, and a choice for FCEB should be based on duty and operational requirements.

While decarbonization is NWT's goal, the production and use of hydrogen is not an objective in itself. Hydrogen must be ranked against alternatives based on its merits. If direct electrification is possible, i.e., in heating or light duty transportation, it will likely be less costly than hydrogen. However, where there are operational challenges, such as duty requirements in heavy duty transportation, energy distribution limitations (i.e., lack of power lines), low ambient temperatures (which impact BEBs more negatively than FCEVs), energy storage requirements, then the use of hydrogen should be considered.

In combination with all the above, a review was conducted of policies and incentives developed in various jurisdictions to explore opportunities for offsetting cost. Current incentives in place in Canada include CFR, ITC, and federal and provincial direct incentives.

So how proceed? Developing a small-scale hydrogen supply chain based on transit will provide invaluable insight into operating hydrogen systems in the NWT with its unique climate, remoteness, and people. Next would be the development of hydrogen fueling stations for heavy duty trucks in Hay River and Yellowknife. Such initiatives should include Indigenous businesses in the NWT, to develop know-how and experience with the new technologies, making it part of a new, low carbon way of life. These experiences should be designed from the start to include technical, operational, commercial, and cultural aspects of the transition to a low carbon society. With this knowledge and experience, the people of the NWT become familiar with the technologies and become confident implementing new technologies to build scale, as well as developing the necessary cost competitive imports from its neighbor to the south, benefiting from Alberta's strength as an increasingly low carbon energy producer at scale.

- In summary, the following information was obtained for hydrogen and its main derivative, ammonia:
- Hydrogen is a viable option for meaningful decarbonization
- As a hydrogen energy carrier, ammonia provides additional advantage in distribution and storage
- Large scale renewable power generation in the NWT is not advised as suitable areas of power generation are not necessarily where hydrogen is needed. Large scale renewables do have the potential to produce hydrogen and ammonia at lower cost than conventional diesel
- Small scale renewable power development for hydrogen production is recommended to develop experience with hydrogen applications
- Small scale hydrogen applications should be developed in transit, heavy duty trucking, and power and heating
- Longer-term, importing hydrogen and ammonia from Alberta is recommended as the cost of this hydrogen and ammonia undercuts the cost of conventional diesel and can realize the NWT 2050 objectives for carbon reduction
- Import of ammonia should be planned along the supply chain balancing end-use applications with fuel supply, storage and distribution

2. Introduction

The Government of Northwest Territories (GNWT) has committed to reduce the emissions of the Northwest Territories (NWT) by 30% below 2005 levels by 2030 and become net-zero by 2050 [1, 2, 3].
Figure 1 shows the annual GHG emissions of the NWT between 2005 and 2021. The NWT has reduced its emissions by 321 kT, or 25%, between 2005 and 2021. The NWT requires a further reduction of 193 kT, to meet the 2030 goal of 1,094 kT [2]. To be net zero by 2050, the NWT will have to reduce emissions by 1,287 kT from the 2021 emissions. The NWT has a population of approximately 41,000 people spread across five regions and 33 communities within a large geographical expanse [4, 5]. Significant regional variations exist in terms of energy supply, capacity, logistics, and climate within the NWT. Of the NWT's 33 communities, only 8 are connected to one of two hydropower grids. All communities rely on diesel to varying extents for power generation and heating. To low extents, some buildings rely on biomass for heating. Every community relies on diesel and gasoline for transportation. As shown in Figure 1 a significant portion (63% in 2021) of the NWT's emissions come from transportation, as the NWT relies on fuels like gasoline, diesel for road, rail, barge and air transport [2]. Some communities are geographically remote and are only accessible by one or a combination of air, barge or winter roads.

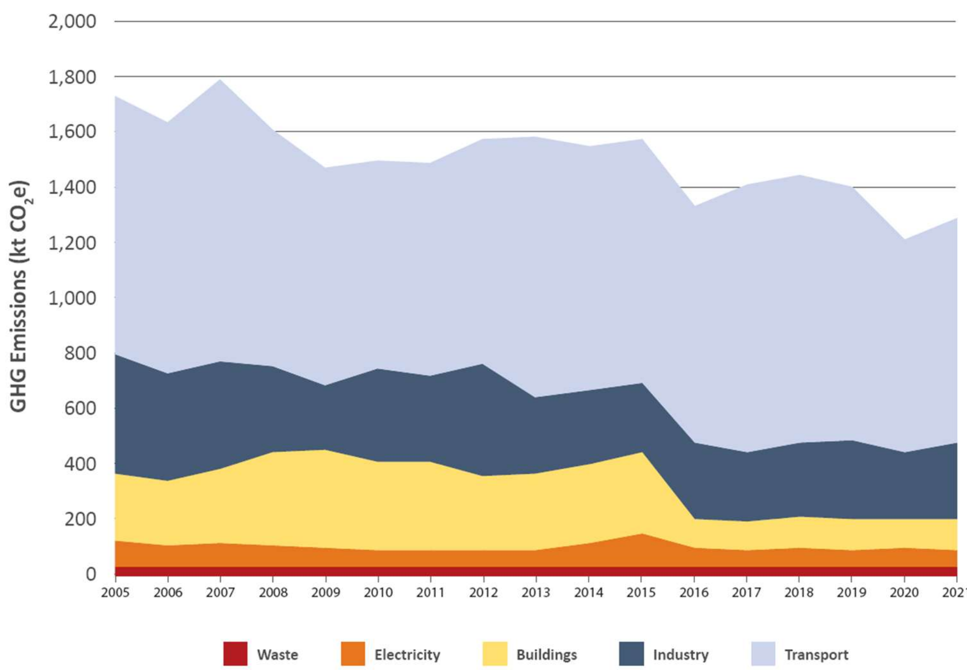


Figure 1: Annual GHG Emissions of the NWT between 2005 - 2021. Taken from [2].

In 2018, the GNWT released its 2030 Energy Strategy. This strategy highlights six strategic objectives as the GNWT works towards its 2030 emissions goal:

1. Work together to find solutions: community engagement, participation and empowerment.
2. Reduce GHG from electricity generation in diesel-powered communities by an average of 25%.
3. Reduce GHG emissions from transportation by 10% per capita.
4. Increase the share of renewable energy used for space heating to 40%.
5. Increase residential, commercial, and government building energy efficiency by 15%.
6. A longer-term vision: developing the NWT's energy potential, address industry emissions, and do our part to meet national climate change objectives.

The GNWT has implemented multiple initiatives to reduce the carbon footprint of the NWT, including:

- A 3.5 MW wind turbine installation in Inuvik

- $3.8 million, half of which was funded by the Government of Canada, invested into an electric charging corridor in the North and South Slave regions, to open in 2024
- Funding to install a biomass boiler in Yellowknife's main post office [2].

However, further action is required to meet 2030 and 2050 emission goals in the GWNT.

Hydrogen is an emerging clean form of energy, as it burns with only water as a byproduct [6]. In 2020, the Government of Canada released its *Hydrogen Strategy for Canada*. The Government of Canada sees the development of a national hydrogen economy as a crucial part of meeting its 2050 emissions target. In 2022, the GNWT held a workshop with key stakeholders to discuss the potential of introducing hydrogen to the region: *Can Hydrogen Power the North?* Participants identified that hydrogen could potentially play a role in power generation, heating and transportation in the NWT. They raised questions regarding technology suitability in the NWT's cold climate, the scale at which such technologies are feasible, the timeframe for implementing such technologies and potential government-funded pilot projects [7].

2.1 Objectives

This study accomplishes following goals:

1. Identify how the NWT can meet its 2030 and 2050 climate goals, including Objectives 2-5 of its 2030 Energy Strategy.
2. Identify whether the economics for developing a hydrogen industry exist in the NWT.
3. If a business case can be made in 2., identify how the NWT can develop a hydrogen industry.

This study considers specificities and risks of the NWT, including cold climate readiness, winter roads, barge transport and community remoteness.

2.2 Methodology

This study consists of two parts:

1. A techno-economic assessment
2. A policy analysis.

For the techno-economic assessment, we assessed low carbon intensity (CI) and net-zero energy solutions for the NWT. We analyzed the current energy landscape of the NWT, as shown in Section 3. We identified and evaluated short-term and long-term solutions for hydrogen for each of the five regions of the NWT, and performed a Strengths, Weaknesses, Opportunities and Threats (SWOT) Analysis on each combination of solution and region.

An economic model was developed to analyze and assess indicative costs of hydrogen and other low carbon fuels. The inputs to the model are based on published data and adjusted to application in the Northwest Territories. For the policy analysis, we reviewed policies in the NWT, Canada and other relevant jurisdictions related to sustainable energy and hydrogen implementation. We developed an overview of policies, programs, and incentives that support implementation of hydrogen and other types of sustainable energy.

3. Current Energy System in the NWT

3.1 NWT Energy System Sankey Diagram

Figure 2 shows a snapshot of energy flows in the Northwest Territories. Energy consumption for buildings represents approximately 28% of total energy input.

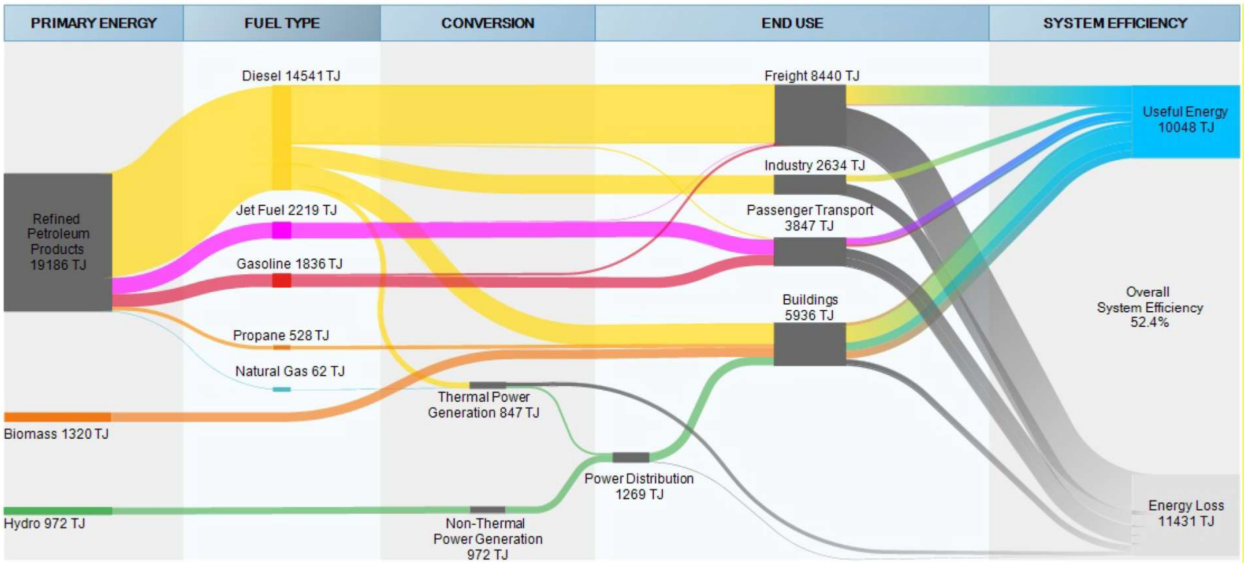


Figure 2: Sankey Diagram of the 2019 NWT Energy System. Taken from [19].

As can be seen from the diagram, energy for power is relatively small. Refined petroleum products are the predominant provider of energy in the NWT, with a share of 89% of the total energy supply. Post conversion, the end-use sectors are split as follows: Power to buildings = 6.1%, Mobility = 58.9%, Buildings = 28.5%, of which 6.1% is electricity, and Industry consumes 12.6%, of which is converted to electricity by up to 55.4MW.

3.2 Power

Canada's territories, including the NWT, have distinctive energy systems compared to the provinces due to their remote geography, cold climate, and low populations. Of the 33 communities that comprise the NWT, 25 rely mainly on diesel generators, and eight are integrated in the North or South Slave hydroelectric power grids. In addition to hydroelectricity and diesel, the NWT has low-scale solar and wind installations.

The North Slave hydroelectric grid is comprised of the Bluefish and Snare hydro stations which have a combined capacity of 37 MW [117]. These hydro sites provide power to 4 communities in the North Slave Region. The Snare River system comprises of four hydrogeneration facilities: Snare Forks, Snare Cascades, Snare Falls and Snare Rapids.

After the renovation of the facilities, the Taltson Hydro site has a capacity of 18 MW and provides power to 4 of the 6 communities in the South Slave Region. Additional capacity of 60MW is contemplated through the Taltson Hydro Expansion Project, although has not received yet received final approval [8].

The communities connected to each hydro grid can be seen in Figure 3. There are diesel generators on standby to provide power to the communities in case the hydro sites can't provide enough power to the communities.

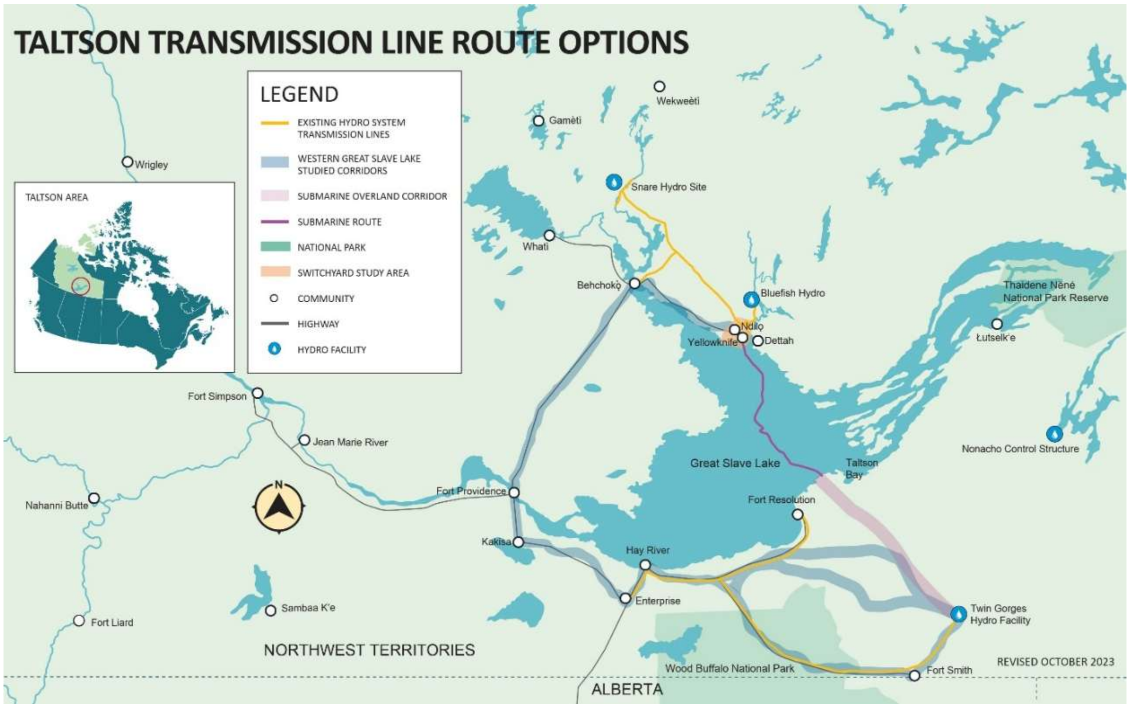


Figure 3: Planned Taltson hydro expansion map. The existing Snare, Bluefish and Taltson hydropower plants and their connections to surrounding communities are also shown. Taken from [8].

The communities in the Deh Cho, Sahtu, and Beaufort-Delta Regions are all remote and rely on diesel generators to provide most of the power. There are small solar installations installed in multiple communities across the NWT to offset the power produced by diesel, but none are large enough to remove the need for diesel powered electricity. Additionally, Inuvik has a 3.5 MW wind turbine installed which is estimated to reduce the community's diesel consumption by 30%. NG is used to provide electricity and heating in Norman Wells and Inuvik. Each community's diesel generator capacity, NG capacity, solar capacity, and wind capacity can be seen in Appendix A.

3.3 Mobility

The transportation industry is a large contributor to GHG emissions in the NWT, accounting for 63% of the NWT's GHG emissions in 2021 [2]. More than half of the emissions in the transportation sector results from road transportation such as heavy-duty trucking and light-duty vehicles (LDVs) [18]. Hence, switching to zero emission alternatives such as electric or hydrogen fuel cell vehicles is one way the NWT can significantly reduce its GHG emissions.

An analysis was conducted to approximate the amount of fuel consumed by transportation sources for each region in the NWT. The analysis used values presented in the report *Hydrogen and Ammonia Pathways Towards Net-Zero in the Northwest Territories* by Zachary Cunningham [19]. This employed the 2019 National Inventory Report and the GNWT fuel tax data to estimate the litres of fuel burned annually by transportation sources. Information in the Northern Transportation Systems Assessment Update report prepared by PROLOG Canada regarding how supply is delivered to the NWT was also used to complete the analysis [20]. The data was used to approximate the amount of fuel consumed by each of the five regions.
Rail, barge, and truck are the three main ways in which supplies are delivered to the NWT. However, some goods are airlifted into areas of the NWT that have seasonality-based access restrictions via the conventional three methods. An overview of the seasonality restrictions for communities in the NWT can be found in Figure 25 in Appendix C. Most resources delivered to the NWT originate from Alberta with a small amount coming from B.C. and Yukon as shown in **Error! Reference source not found.**.

Table 1: Distribution of inbound freight. Adapted from [21].

Region	Fuel	General Freight	Project Resources

Alberta	96%	87%	86%
British Columbia	1%	3%	8%
Yukon	3%	10%	7%

Diesel is the primary fuel combusted in the NWT, accounting for 185 million litres annually [19]. The North Slave Region consumes the largest amount of fuel of all the regions, with the South Slave Region and Beaufort Delta Region to follow. The consumption amounts for each region are shown in **Error! Reference source not found.** and the overall distribution of fuel consumed by transportation sources are shown in **Error! Reference source not found.**.

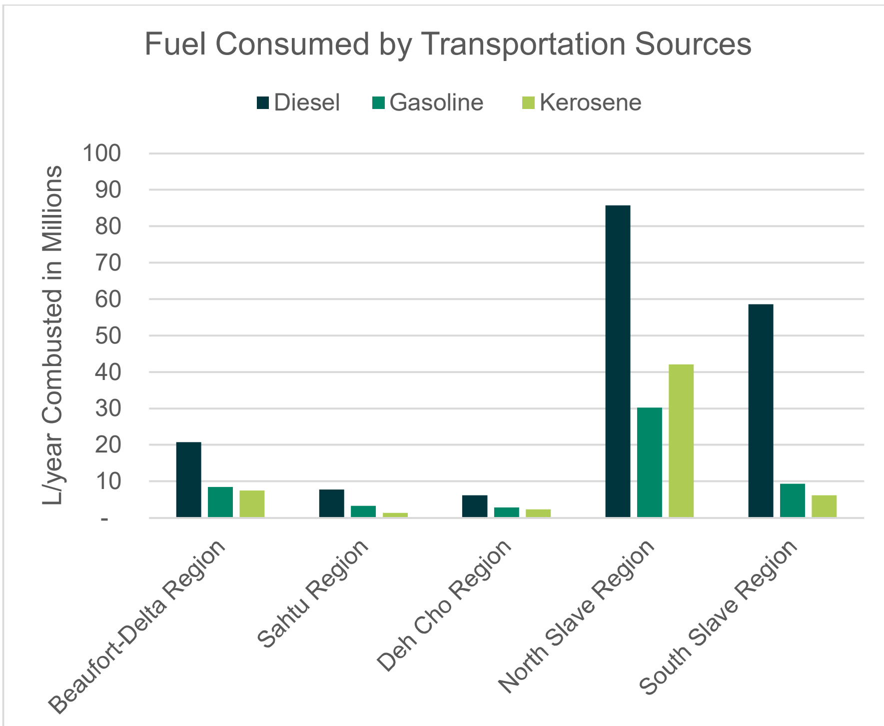


Figure 4: Distribution of fuel consumed by transportation sources. Adapted from [19].

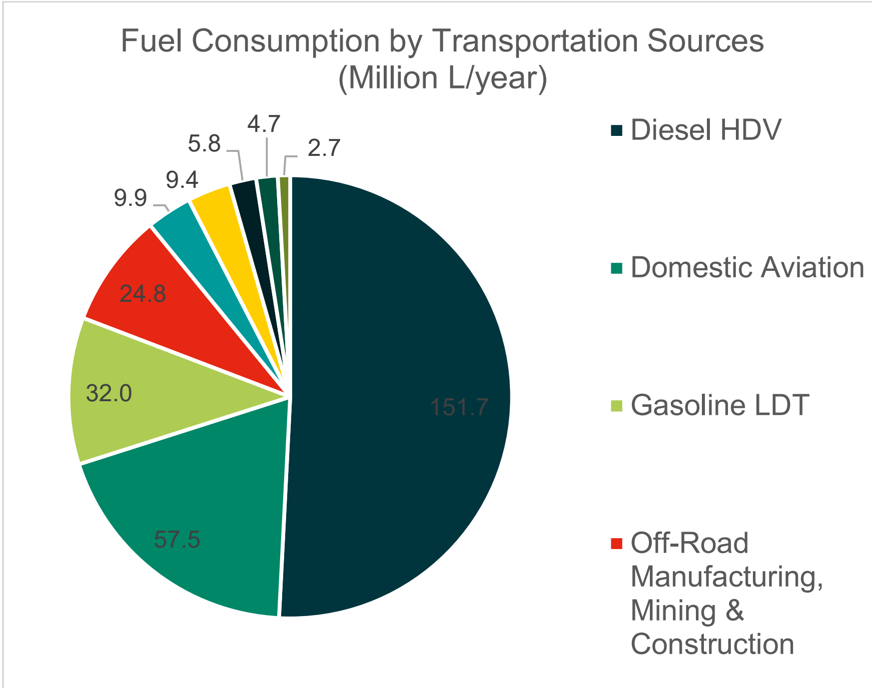


Figure 5: Fuel consumption by transportation sources in the NWT. Adapted from [19].

3.4 Heating

In the NWT, building heating is generated from a variety of fuel sources including heating oil, NG, propane, wood pellets/biomass, and electricity [9]. Heating oil is the main source of heating with NG/propane, hydro electricity, and wood pellets providing the balance. Excluding electricity, 22.4% of end-use energy is used in building heating.

3.5 Industry

The main industries in the NWT are the mining, and limited oil and gas production. These industries produce high carbon emissions and comprise a large portion of the NWT gross domestic product (GDP) [10]. The total industry emissions account for 21% of the NWT's total emissions in 2021 [2]. There are four mines currently in operation in the NWT: the Diavik Diamond Mine, Ekati Diamond Mine, Gahcho Kue Diamond Mine, and Nechalacho Rare Earth Element Mine [11]. They have installed power capacities of 55.4 MW, 30.8 MW, 14.125 MW, and 21 MW respectively [12, 13, 14, 15]. These mines only have seasonal, or winter road access. Crude oil is produced only in the Norman Wells Proven Area near the town of Norman Wells [16]. Norman Wells and Ikhil (near Inuvik) are the only two locations in the NWT that produce natura gas [16]. The mining industries rely mainly on refined petroleum products such as diesel fuel to meet their energy needs [2]. They include heating oil, propane, and electricity generated from fossil fuels for heating buildings [2]. The Diavik Diamond Mine has installed four wind turbines with a capacity of 9.2 MW (2.3 MW each) to generate electricity to displace diesel fuel consumption [16]. In its first year of construction, the wind farm offset diesel by 3.8 million litres [17].

4. Technologies for Clean Energy

This section describes the most common hydrogen production methodologies and their CO2 footprint, as well as hydrogen refueling systems. Hydrogen is a manufactured gas and when produced through electrolysis, a source of electricity is required. Several options for electricity in the NWT are discussed. Other clean energy pathways are discussed, including ammonia, a clean derivative of hydrogen.

4.1 Hydrogen

Hydrogen can be produced through the following methods:

- Electrolysis of Water: Water is split to produce hydrogen and oxygen.
- Steam Methane Reforming (SMR): Natural gas and steam react to form hydrogen and carbon monoxide.
- Autothermal Reforming: Natural gas, steam, and oxygen react to form hydrogen and carbon monoxide.
- Pyrolysis of Methane: Methane is heated without oxygen to produce hydrogen and other byproducts.

Multiple communities in the NWT have opportunities to produce hydrogen within the territory and transport it as hydrogen or as ammonia to other communities as an energy source. The following sections explain the different types of hydrogen production techniques.

4.1.1 Electrolysis

Electrolysis uses electricity and a catalyst to split water into hydrogen and oxygen gas. As it does not produce any greenhouse gases as a byproduct, if electrolysis is powered by renewable energy, it is a carbon-neutral process [35, 36].

There are three main water electrolysis processes:

- Alkaline Electrolysis (AEL)
- Polymer Electrolyte Membrane Electrolysis (PEMEL or PEM)
- High Temperature Electrolysis (HTEL) [37].

Error! Reference source not found. summarizes the strengths and weaknesses of each process, and **Error! Reference source not found.** outlines their technical specifications. Sections **Error! Reference source not found.** – **Error! Reference source not found.** explain each technology in further detail.

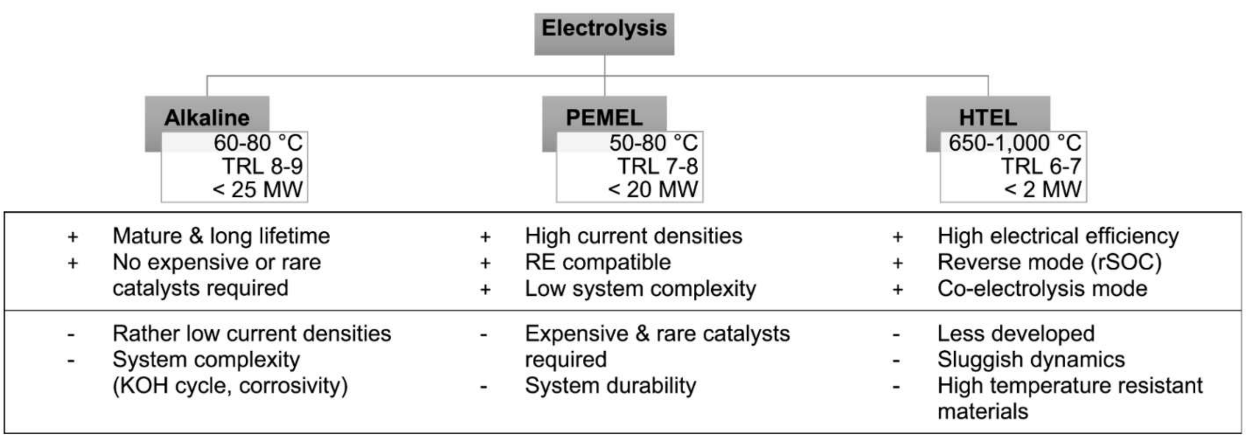


Figure 6: Advantages and disadvantages AEL, PEMEL and HTEL. Taken from [37].

Table 2: Technical parameters of the three key water electrolysis technologies. Taken from [37].

	AEL	PEMEL	HTEL
TRL [–]	8–9	7–8	6–7
System efficiency (LHV) [%]	63–70	56–65	74–84
Current density [A cm^{-2}]	0.2–0.6	0.6–3.0	0.3–1.0
Operating temperature [°C]	60–80	50–80	650–1,000
System size [MW]	Up to 25	Up to 20	Up to 2
Electricity consumption [kWh Nm^{-3}]	4.3–4.8	4.6–5.3	3.6–4.0

4.1.1.1 Alkaline Electrolysis (AEL)

As shown in **Error! Reference source not found.**, AEL is the most established water electrolysis process, with a Technology Readiness Level (TRL) of 8-9. As a result, AEL technology can be purchased from a variety of suppliers. Commercial AEL systems deliver up to 25 MW of electricity, as demonstrated by the Cachimayo plant in Peru, the highest-capacity operational AEL plant. This technology is cost-effective as it employs inexpensive, non-rare catalyst materials, and has a long operational lifespan. However, the potassium hydroxide in its assembly is corrosive, and its current density is low [37]. A low current density decreases the process's responsiveness and hence, performance.

4.1.1.2 Polymer Electrolyte Membrane (PEM or PEMEL) Electrolysis

As **Error! Reference source not found.** shows, PEM has a TRL of 7-8, in comparison to AEL's 8-9. It leverages a solid polymer electrolyte and has undergone significant research and development recently. PEM systems have achieved outputs exceeding 1 MW [37]. Air Liquide's 20 MW plant in Bécancour, Quebec, has the largest PEM capacity [38, 37]. Although PEM has a lower efficiency than AEL, 56 – 65%, it offers higher current densities. Therefore, it is more responsive, making it adaptable to the variable electricity supply from renewable energy sources. However, PEM is more expensive than AEL as its assembly requires rare metals, including iridium and platinum. Furthermore, it still requires advancements for durability and cost reduction [37].

4.1.1.3 Hight Temperature Electrolysis (HTEL)

Error! Reference source not found. indicates, HTEL is the least developed electrolyzer technology with a TRL of 6-7. It functions at elevated temperatures (650–1000°C) and separates steam rather than water. This results in lower electricity consumption for hydrogen production compared to low-temperature electrolyzers, making HTEL the most efficient of the three processes, with an efficiency of 74–84%. HTEL is reversible and can switch between hydrogen production and consumption, which potentially helps balance the electricity grid [37]. However, HTEL is slow, as indicated by its low current density of 0.3 – 1.0 A cm^{-2}. To date, it can only produce up to 2.4 MW. It is expensive, as it requires heat-resistant materials and the rare earth metal yttrium [37, 39]. Therefore, further development is required to reduce the process's cost and advance it [37].

4.1.1.4 Comparison of Electrolysis Processes

PEM is best to integrate with renewable energy sources due to its rapid responsiveness and start-up, while AEL and HTEL are better suited for stable industrial applications where longer start-up times are acceptable. Though AEL and PEMEL have high TRLs, all three electrolyzer technologies require additional development to improve performance and lower costs [37].

Table 3: Electrolysis production technologies key data. Taken from [37].

TRL	AEL	8 - 9
	PEMEL	7 - 8
	HTEL	6 - 7
Quick-start Capability	AEL	No
	PEMEL	Yes
	HTEL	No

The life of electrolysers is determined predominantly by the life of the stack and is in the range of 50,000 to 80,000 hours, with improvements expected to double the life of the stack by 2050 (IRENA). R&D main focus is in areas of diaphragm, catalysts, and electrodes. Application in cold climates requires suitable enclosures for temperature management, protection of integrity of instrumentation and electric/electronic systems, and proper water management. Hydrogen systems, including electrolyzers, can be installed in residential areas. Meeting code requirements is important for safe distance requirements, ventilation, and explosion-proof environments. Code requirements can be found in NFPA 2 and the Canadian Hydrogen Installation Guide, among others.

4.1.1.5 Fuel Cell Technology

A fuel cell performs the opposite process of an electrolysis cell. Water is formed from hydrogen and oxygen gases, and electricity is generated. Fuel cells are generally constructed in a stack arrangement and hydrogen fed at the anode where it loses electrons. An external circuit is attached to the anode to transfer electrons to the cathode, transferring power. Oxygen is fed to the cathode where it receives electrons. Water is formed from protons and oxygen ions either at the anode or the cathode, depending on the fuel cell type.

There are several fuel cell types similar to electrolysis – including PEM and Alkaline fuel cells. Alkaline fuel cells have a slightly higher efficiency than PEM at about 60%. Higher efficiencies can be achieved with Solid Oxide Fuel Cells (SOFC), in particular if these can be coupled with Small Nuclear Reactors (SMR), as the waste steam from these are high in temperature. Direct ammonia fuel cells are of the SOFC type, where gaseous ammonia is fed as a source of hydrogen. These are however, still under development and not commercially available.

Fuel cells can be particularly useful in Combined Heat & Power (CHP) applications, where waste heat from the fuel cell is used for heating applications, achieving high efficiencies of 80% to 90%.

4.1.2 Natural Gas Conversion to Hydrogen

4.1.2.1 Steam Methane Reforming (SMR)

Steam Methane Reforming (SMR) is a process that produces hydrogen from natural gas. It is a well-established and widespread technology with a TRL of 9. Under high pressures and with nickel-based catalysts, methane reacts with steam to produce syngas, a mixture of H_2 and CO. CO and water are converted into H2 and CO2 in a CO Shift Reactor. Hydrogen is separated from CO2 in a Syngas Purification unit (Amine). Hydrogen is further purified in a Pressure Swing Absorption (PSA) unit. The CO2 from the Amine unit will be dried, compressed and sent for sequestration [41]. As feed and fuel for the SMR are two separate streams, the CO2 capture rate is typically less than from an ATR as the CO2 produced from fuel is more costly to separate.

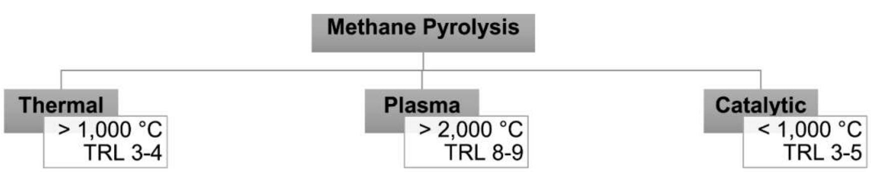
4.1.2.2 Auto-Thermal Reforming (ATR)

Autothermal Reforming (ATR) is also a mature technology, with a TRL of 8. In this process, methane reacts with both oxygen and steam. Both reactions with methane form syngas, or carbon monoxide and hydrogen. Just as with SMR, the carbon monoxide is further reacted with steam to produce carbon dioxide and hydrogen gas, and the carbon dioxide can be captured. In an ATR, the first stage partial oxidation reaction provides the necessary heat for subsequent reforming, and as the carbon dioxide from the reactions are all contained in the outlet of the ATR, which allows higher CO2 capture rate from an ATR compared with the SMR [41].

Oni *et al*. performed an economic analysis of a world-scale facility with a capacity of 607 tonnes per day of hydrogen for both SMR and ATR. They show that when SMR and ATR are developed without carbon capture, the SMR will produce hydrogen at lower cost per unit. However, with CCS, the hydrogen price from an ATR will benefit more than the SMR from carbon capture at any price for CO2, with greater benefit at higher price of CO2 [41].

4.1.2.3 Methane Pyrolysis for Hydrogen

Methane pyrolysis via NG has been utilized since 1930. The process requires electricity. Under high heat and in the absence of oxygen, methane decomposes to solid carbon and hydrogen gas, and does not produce carbon dioxide. There are three types of methane pyrolysis: thermal, plasma and catalytic pyrolysis [37]. The advantages and disadvantages of these approaches are shown in **Error! Reference source not found.**.



+ No catalysts required	+ RE compatible + Low system complexity	+ Low reaction temperatures
- Inhomogeneous heat transfer - Reactor blocking - Long warm-up time, no quick-start capability	- High electricity demand - High temperature resistant materials	- High system complexity - Catalyst regeneration - Depending on the catalyst, complex carbon separation

Figure 7: Advantages and disadvantages of methane pyrolysis methods. Taken from [37].

Plasma pyrolysis is the most mature of the three technologies with a TRL of 8-9 and adaptable for renewable energy grids with its quick-start capabilities. However, it is very energy intensive [37]. On the other hand, while catalytic decomposition uses readily available metals and low temperatures, it has a TRL of 4-5, with a pilot plant being tested in Australia [37, 42]. Thermal decomposition has a TRL of 3-4. Overall, methane pyrolysis is expected to be lower cost, and less energy intensive, and better scalable than electrolysis [37].

Given the current state of development, methane pyrolysis is not currently practical or permitted for use near residential areas, primarily due to safety, temperature, and lack of regulatory frameworks. Future small-scale, containerized units could serve community-level applications.

A comparison of methane pyrolysis with electrolysis and SMR with CCS:

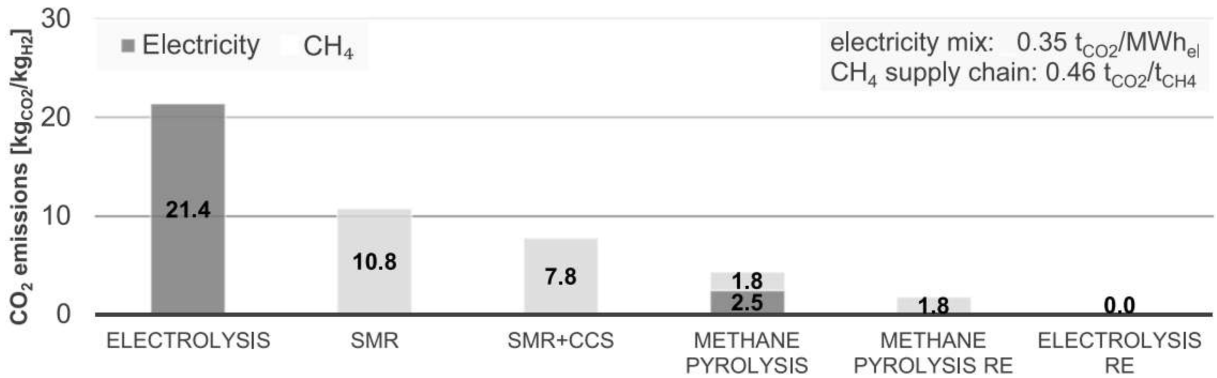


Figure 8: CO_2 emissions for six hydrogen production methods. Taken from [190].

Table 4: Methane pyrolysis

Pyrolysis of Methane		
TRL	Plasma	8 - 9
	Catalytic	3 - 5
	Thermal	3 - 4
Quick-start capability resp. RE compatibility	Plasma	Yes
	Catalytic	No
	Thermal	No

4.1.2.4 Application of Methane Conversion Processes in the NWT

The advantage of methane pyrolysis is that it does not release CO_2 when making hydrogen, only solid carbon black. Both SMR and ATR processes release CO_2. If SMR or ATR processes were developed, it would have to be combined with CCUS to reduce emissions. There is an estimated 48 trillion cubic feet of recoverable NG (mostly shale gas) in the Liard Basin near Fort Liard [16]. There is opportunity to extract this large volume of NG and convert it to hydrogen and subsequently ammonia. The ammonia can be transported to other communities and industries to be used on site to produce electricity. The volume of NG can generate large quantities of hydrogen and ammonia that can power the communities and mines in the NWT. Fort Liard also has an all-season road that connects it to the North and South Slave regions making ammonia transportation easier. Although the highway is only gravel, it is still suitable for all seasons. For these reasons, the Deh Cho Region would be the most suitable to develop methane pyrolysis hydrogen production.

There are other areas in the NWT that have large natural gas reserves. These can be seen in Appendix B. Other potential location for methane pyrolysis development includes the Beaufort Sea and the Mackenzie Delta regions. There are substantial natural gas reserves in those areas but less than the Liard Plateau and because of the remoteness of these regions, they are less suitable. It would be difficult to produce ammonia in remote areas and transport large quantities to the rest of the NWT.

An alternative method would be to develop natural gas pipelines from the natural gas reserves to a location such as Hay River or Yellowknife where the methane pyrolysis would take place. The advantage to this is decreasing the amount of ammonia transportation as Yellowknife would have the largest demand. But this method would pose the challenge of installing a pipeline and obtaining community acceptance.

4.1.3 Carbon Footprint Hydrogen Technologies

The carbon emissions from described processes are dependent on the nature of the primary input and energy source used in the process, and process configuration. The following lists indicative point of production emissions for the relevant technologies for hydrogen/ammonia production:

Table 5 Indicative Point Source Emissions

Green electrolysis:	0 kg CO2/kg H2
Auto-thermal reforming with CCS	0.5 kg CO2/kg H2 based on 10 kg CO2/kg H2 for ATR (w/o CO2 capture) and subsequent 95% capture rate
Ammonia production from ATR with CCS	0.26 kg CO2/kg NH3 including electric power consumption (2022 Alberta emissions in power generation)
Hydrogen production from Ammonia from ATR with CCS	1.12 kg CO2/kg H2 based on 76% cracking efficiency and electric power consumption (2022 Alberta emissions in power generation)
Ammonia from green electrolysis	0 kg CO2/kg H2
Hydrogen from green ammonia	0 kg CO2/kg H2

CO2 emissions from diesel combustion are 2.65 kg CO2/kg diesel, which is avoided when replaced with green hydrogen. If diesel is replaced by ammonia in an internal combustion engine application with ammonia produced from through ATR hydrogen with CCS, then the CO2 emissions are reduced to 0.6 kg CO2 per kg avoided diesel (a reduction of 77%), as the heat content of diesel is about 2.29 times that of ammonia (LHV). Replacing diesel with hydrogen from ATR/CCS and ammonia, used in a fuel cell for power generation will reduce emissions to 0.23 kg CO2 per kg avoided diesel (a reduction of 91%), as the heat content of hydrogen is 2.88 times that of diesel (LHV), and the efficiency of fuel cell electricity generation is 60% versus 35% versus conventional power generation from diesel fuel.

4.1.4 Hydrogen Refueling Systems

Fueling vehicles with hydrogen requires specialized equipment and systems that transfer locally produced or delivered hydrogen onto a hydrogen fuel cell vehicle. Figure 12 depicts an example fueling system for 700 bar vehicle fueling, however this principal layout of the system is applicable for other fueling pressures.

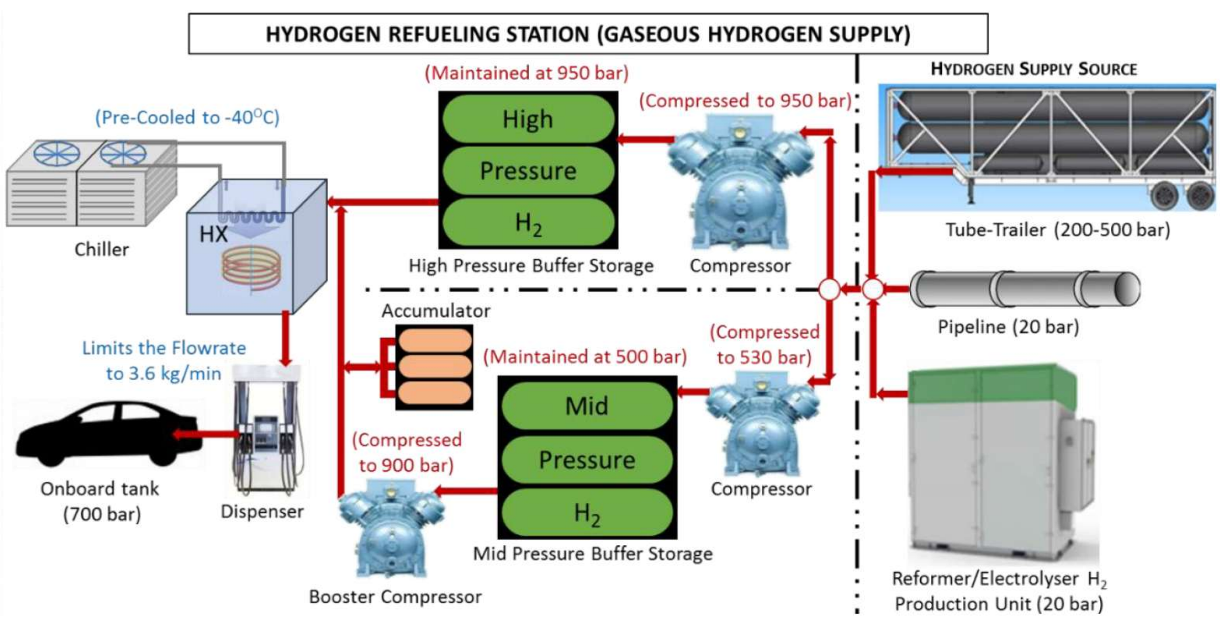


Figure 9: Schematic representation of gaseous hydrogen refueling station configurations. Taken from [7]

Delivered or locally produced hydrogen must be compressed and stored in suitable high-pressure cylinders. Figure 12 shows two solutions: direct compression to high pressure storage with subsequent transfer of hydrogen to the vehicle's on-board storage tank, or alternatively, a first stage compression to medium pressure storage, followed by a second, high pressure compression step with subsequent transfer of fuel to the vehicle. An accumulator reduces the pulsating effect of the booster compressor. The hydrogen pressure in the vehicle fuel tank is below the pressure of the vehicle fuel tank. Hydrogen properties are such that the temperature of the hydrogen increases when its pressure is reduced, for temperatures above -190 degree Celsius. A chiller system cools the hydrogen to about -40 degrees Celsius. The hydrogen flowrate of is governed by code and maintained to avoid that dispensed hydrogen heats up in the vehicles fuel tank.

The advantage of medium buffer storage is that the storage vessels are cheaper and easier to source then the those for 950 bar. However, and depending on the fueling operation, high throughput compressors may be required. The alternative of storing at high pressure is the benefit of hydrogen flowing directly from storage to vehicle tanks, potentially shortening fueling times. System cost versus operational requirement should be compared to derive at the correct system design.

4.2 Electricity

4.2.1 Solar

Solar power is an effective method to provide communities in the NWT with electricity. Solar offers multiple advantages. It supplies GHG-free electricity, panels can be incrementally installed to increase capacity when required, and it has a relatively low upfront cost. It can reduce a community's reliance on diesel imports and make it more self sustaining, as electricity is generated within the community. However, there are disadvantages to solar. As power depends on available sunlight, and it is less effective in the winter and in areas with high annual cloud cover. Snow build-up on solar panels can also decrease its performance in the winter as panels need to be cleared. Its reduced effectiveness in the winter is particularly unideal, as this is when power demand is highest.

Solar energy can effectively reduce diesel usage in the NWT, especially in communities not connected to the grid but cannot fully replace diesel to generate electricity. Figure 10 shows the annual Mean Daily Global Insolation (MDGI) in the NWT. The MDGI varies considerably across the territory. As expected, the MDGI is lowest in the north, reaching a low of 3.27 kWh/m^2, and strongest in the south of the territory, reaching a high of 4.13 kWh/m^2. Figure 11 shows the photovoltaic power of Canada. As shown, the photovoltaic potential in the South Slave region is equivalent to areas of Southern Ontario [22]. However, it is lower than southern Alberta, Saskatchewan, and Manitoba [22]. Their photovoltaic potential is 4.2 – 5.0 kWh/m^2, whereas the South Slave Region of the NWT is only 4.08 – 4.13 kWh/m^2.

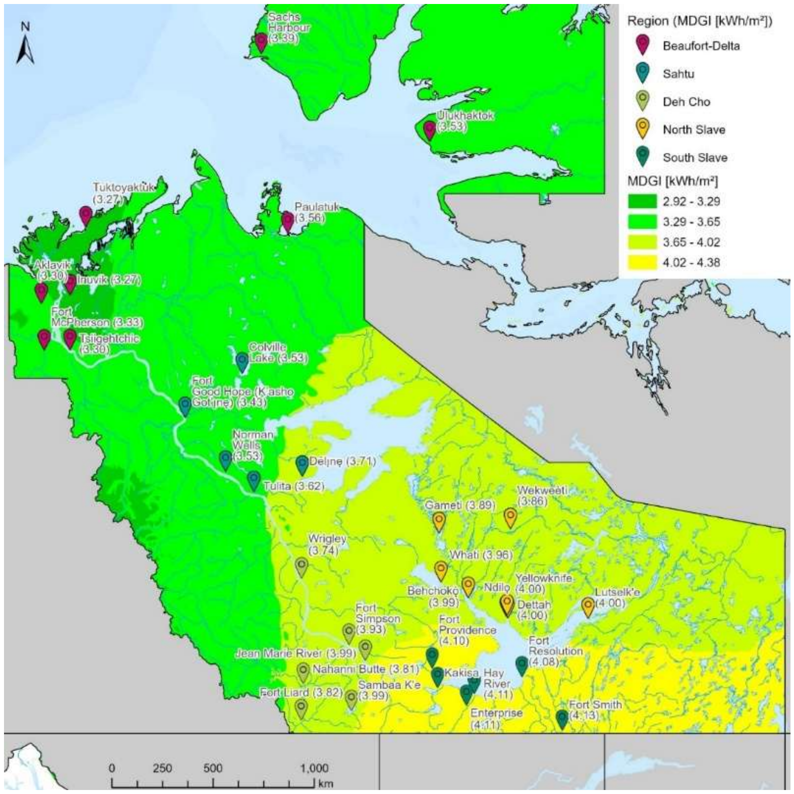


Figure 10: Annual MDGI (south-facing with latitude tilt) of the NWT. Adapted from [22, 23].

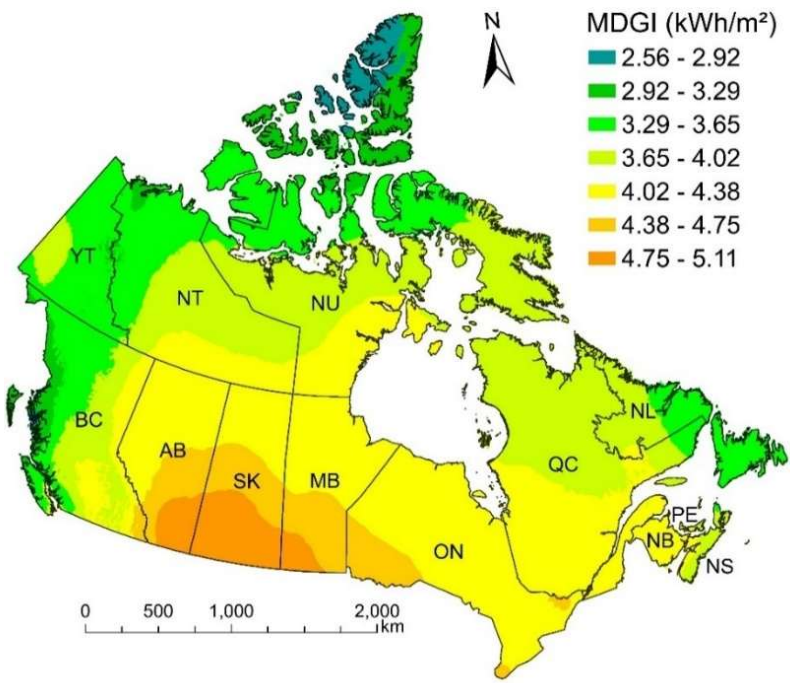


Figure 11: Annual MDGI (south-facing with latitude tilt) of Canada. Adapted from [24].

Many communities have already installed some capacity of solar panels proving that it is feasible in the NWT. Solar power can be used to offset the consumption of diesel but can't be relied on to fully replace it because of uncontrollable weather conditions. As seen in Figure 10, the South Slave Region has the highest MDGI in the NWT, with the Deh Cho and North Slave regions having the second highest MDGI, followed by the Sahtu Region, then the Beaufort-Delta Region.

The mining operations in the NWT can instal solar panels to reduce diesel consumption. As the figures show all four mines are in a region where the MDGI is 3.65-4.02 kWh/m^2. Solar panel installations can provide electricity to the mines to offset the diesel consumed by the generators for electricity production. The Diavik Mine is in the process of installing 6,600 solar panels which will generate 4.2 million kWh of electricity per year [25]. This translates to a reduction of about one million litres of diesel per year [25].

With 3.5 kWh/m2/day of solar intensity, the application of solar panels with an efficiency of 21.4%, and a performance ratio of 75%, 23.4 W/m2 will be generated. Coupled with electrolysis, 1 mT per day of hydrogen can be produced from 0.11 km2 or 330 m by 330 m of solar panel area.

4.2.2 Wind

As proven with the Inuvik Wind Project and the Diavik Diamond Mine's wind farm, wind energy can effectively reduce diesel reliance in the NWT. As shown in Figure 12, windspeeds vary across the NWT and require a threshold of 6 m/s, for economic viability [26]. Wind turbines can provide larger amounts of electricity with a smaller footprint compared to solar arrays. However, due to uncontrollable wind speeds, turbines cannot be solely relied on to provide communities with electricity. Coupling turbines with battery storage will provide consistent electricity supply.

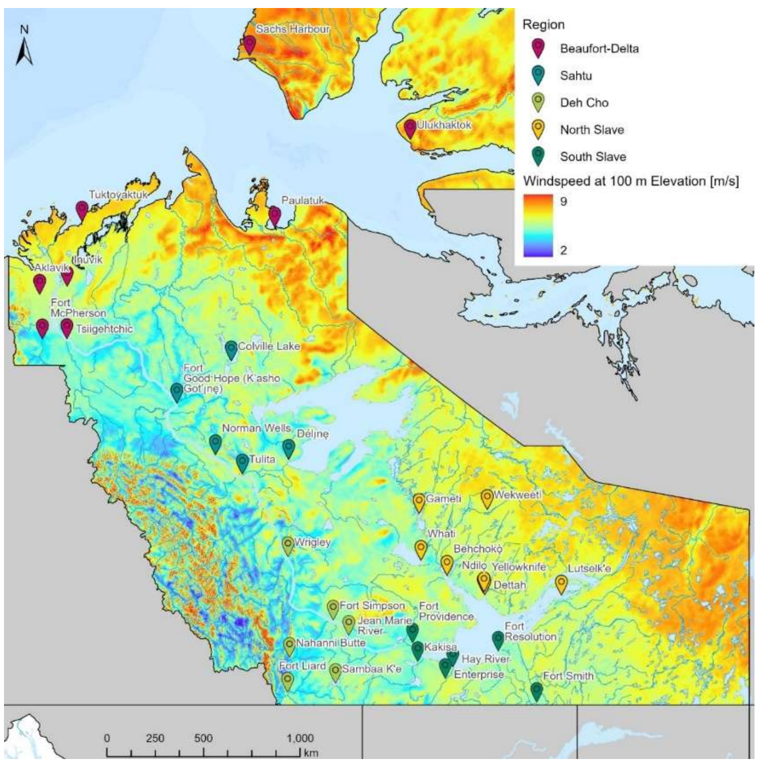


Figure 12: Wind speed profile map of the NWT. Adapted from [132].

Not all communities across the NWT that have suitable wind speeds for wind turbine installations. As seen in Figure 12, the communities with the highest wind speeds are in the Beaufort-Delta Region, primarily on the coast of the Arctic Ocean. Other suitable areas are the communities in the North Slave Region, as well as Norman Wells, Enterprise, and Sambaa K'e. The mining industry in the North Slave Region also has suitable wind speeds for turbine installations. The Diavik Diamond Mine has 4 turbines currently installed showing that wind energy is suitable in this region. Inuvik has recently installed a 3.5 MW wind turbine further showing this regions viability for wind power. Further evaluation is required to identify optimal locations within these areas to install turbines, with consideration for airport locations and community acceptance.

If installed in grid-connected communities such as Yellowknife, they can serve as a backup for the North Slave grid. For example, multiple turbines can be installed in the Yellowknife area. Due to the annual variability in windspeed, wind energy may not be able to fully replace diesel. However, this technology can be coupled with battery storage to provide electricity during periods of low windspeeds, increasing flexibility. Wind technology can be used for hydrogen production by using the electricity to power electrolysis. PEM type electrolysis is compatible with renewable energies such as wind turbines because the quick start characteristics respond to the fluctuating power output of renewable energy technology. This can allow for the NWT to start small scale pilot projects using hydrogen as power source. For example, wind turbines can be developed around the Yellowknife area to produce hydrogen which can be used to power public transit buses. This will allow the NWT to integrate hydrogen into the energy system and reduce emissions from public transit. Hydrogen FCEVs can be tested in the climate of the NWT before being rolled out on a larger scale.

A wind turbine rated at 3.3 MW will generate 1.87 MW at 6.0 m/s wind velocity. 1 mT per day of hydrogen would require 1.34 turbine, or 2 turbines will generate 1.5 mT of hydrogen per day, requiring an area of 1.8 km2.

4.2.3 Small-Scale Nuclear Energy

A potential solution to deliver consistent electricity is employing Small Modular Nuclear Reactors (SMNRs) or Micro Modular Nuclear Reactors (MMNRs). SMNRs produce up to 300 MW and MMNRs produce up to 15 MW [27]. These are significantly lower than the output of conventional nuclear reactors, such as CANDU reactors in Canadian provinces which generate 500-900 MW [28]. SMNRs and MMNRs are lower in cost, size, complexity, environmental footprint, and overall footprint. They can be prefabricated and shipped to a site for installation. MMNRs are particularly suited for remote areas. SMNRs and MMNRs are safer than conventional reactors as they as they use low operating pressures and employ passive systems for shutdown. Passive systems rely on physical phenomena such as natural circulation, convection, gravity, and self-pressurization to shut down, negating the need for human input [27]. Furthermore, electricity produced from an SMNR can directly power communities or electrolysis to produce hydrogen.

The steam produced from SMNRs can also be used in district heating networks for space heating. District heating is a method of transporting steam created from a centralized location to buildings where the steam temperature is used to heat spaces [29]. Steam is continuously transported through a network of underground insulated pipes. This method removes the need for boilers or heaters in individual buildings. District heating systems can improve energy efficiency, reduce emissions, and simplify building maintenance and operations [29].

A single SMNR reactors capacity may be too large for one community, but it can be connected to a current grid to power multiple communities. Additionally, excess power can be used to provide electricity to power electrolysis to produce hydrogen, for specific applications such as in heavy duty transportation. Social acceptance is an important aspect to incorporating small-scale reactors in the NWT. The capital cost for small nuclear reactors according to the Canadian Energy Regulator is $9,262/kW in 2020, will decline to $8,348/kW by 2030 and reach $6,519/kW by 2050 [30].

Small-scale nuclear reactors such as SMNRs and MMNRs can be part of a long-term solution for the NWT. SMNRs can be installed and connected to the North or South Slave grids to directly produce reliable baseload electricity for the connected communities. MMNRs, having smaller capacities, are more suitable for remote communities. SMNRs can be installed in a central hub community such as Yellowknife or Hay River to produce electricity for hydrogen production through electrolysis. SMNR capacities are larger than any individual community's demand, however, the additional capacity can be leveraged to produce hydrogen and ammonia in the process shown in Figure 14. Ammonia can then be exported to other communities in the NWT and used on-site as a zero-carbon fuel source for electricity generation.

Yellowknife or Hay River were determined to be ideal locations for nuclear power development because they are both connected to current hydro grids, have larger populations and power demands, and have all season road access. Hay River has advantages because it is connected to the rail system that connects to Alberta so there is potential for ammonia exports by rail. The logistics for supplying fuels and supplies to remote communities is based out of Hay River so similar methods can be employed to transport ammonia to other communities.

Norman Wells and Inuvik currently have capacities of about 17 MW and 18 MW, respectively. MMNRs can be considered to replace the reliance on NG as the capacities for these reactors go up to 15 MW.

One possible solution to meet power demands for the mining operations are using SMNRs or MMNRs. The capacities of the mines range from approximately 14 MW to 55 MW [12, 13, 14, 15]. Depending on the reactor chosen, these capacities can be matched. The SMNRs or MMNRs can be used to provide electricity directly or generate hydrogen on site through electrolysis. Hydrogen can be used in Fuel Cell Electric Vehicles (FCEVs). The benefits of using SMNRs is they can be implemented on site which will reduce the dependency on diesel imports making the mines more self sufficient.

4.2.4 Hydroelectricity

Another long-term solution to meet 2050 targets is increasing hydroelectric production in the existing NTPC grids and incorporating hydroelectricity in regions that currently do not have it. Increases in electricity from hydroelectric dams can directly power communities, industry developments, or produce hydrogen. Multiple studies have investigated bringing hydroelectricity to the Deh Cho, Sahtu and Beaufort-Delta regions. Refer to Appendix E to see potential hydro developments in those regions.

Increases in hydro power developments can be used to power electrolyser technology to produce hydrogen. Hydrogen can be further used to create ammonia for transportation purposes. An analysis of potential hydroelectric developments in the NWT can be found in Appendix E. Multiple hydro developments would be required to produce enough hydrogen to meet energy demands.

Some key potential hydro development sites to highlight include the Lockhart River and the Anderson River. On the Lockhart River, the three locations with the highest hydro potential are Anderson Falls with a 52.4 MW potential, Mosquito Canyon with 63 MW, and Parry Falls with 50.8 MW. The disadvantage to developing on the Lockhart River is the distance to either the North or South Slave grid. To feed into either of these grids, large distances of transmission lines would be required as these sites are on the eastern side of the Great Slave Lake. Locations are indicated in Figure 25. Further analysis on the feasibility of building hydro facilities would be required. The Anderson River has a 70 MW potential for hydro development. However, the Anderson River is in the Beaufort-Delta Region and is not close to any communities. The hydro potential for this site is relatively large but connecting it to the North Slave Grid would require a great distance of transmission lines and may be unfeasible. If transmission lines ran to Inuvik, excess power could be used for hydrogen production. Further analysis is required to determine if building in this location is feasible.

4.2.5 Hydrokinetic Energy

Hydrokinetic energy is an emerging option for renewable energy. This technology uses the natural flow of river currents, tides or waves to turn underwater turbines, generating electricity [31, 32]. This technology offers several advantages. Underwater units cannot be seen from land, therefore preserving the visual landscape. Moreover, unlike traditional hydroelectric systems, fish can bypass or swim through turbines. However, hydrokinetic energy has its disadvantages. With the variability of river conditions, only a limited subset of rivers is suitable for the technology. Though the environmental impacts are not as well known, the turbulence can generate dead zones in the water and affect sediment transport. Electromagnetism from equipment may interfere with marine life [31].

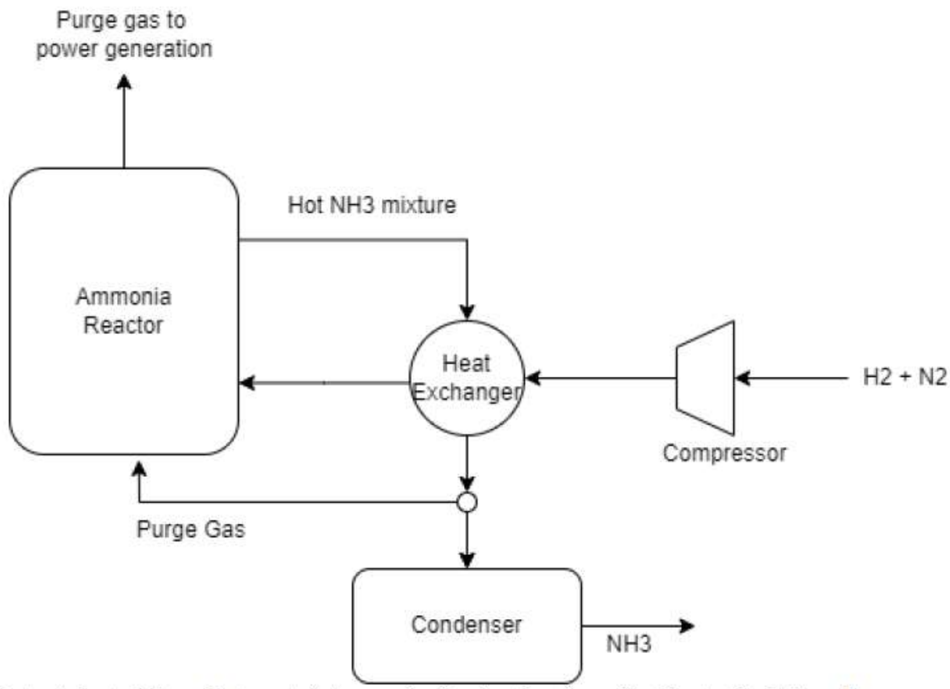
Hydrokinetic wave energy is a potential solution to provide communities with suitable water profiles with electricity. Further evaluation will be required to determine which communities have suitable water profiles for hydrokinetic turbine installation.

4.3 Other Low Carbon Fuels Technologies

4.3.1 Ammonia Production

For the past several decades, ammonia has been produced in large quantities for fertilizer production and additional applications through the Haber-Bosch process. Today, it is also a promising energy carrier, as it can be readily converted to hydrogen. Under ambient conditions, it is gaseous, but for storage in large quantities, it is either liquefied under 10 bar pressure at 25°C or refrigerated to -33°C. Notably, liquid ammonia contains more hydrogen per unit volume than liquid hydrogen.

Modern Haber-Bosch plants produce over 3,000 tons of ammonia per day by synthesizing nitrogen (from air) and hydrogen (from natural gas through steam reforming) at high pressure (60-180 bar) and temperature (300-500°C). These facilities are typically located in areas with abundant, low-cost natural gas and strong logistics for international distribution. Figure 13 shows the Haber-Bosch process. Conventional ammonia production emits approximately 2.3 tons of CO_2-equivalent per ton of ammonia.



Note: Adapted from *Integrated Ammonia Production from the Empty Fruit Bunch* (Darmawan et al., 2022)

Figure 13: Haber-Bosch process diagram. Taken from [19].

Ammonia can be produced using renewable electric power and offers a way to replace hydrocarbon fuels in power generation. Once hydrogen is converted into ammonia, it can be transported and used for electricity production by cracking it back into hydrogen and then combusting it or using a hydrogen fuel cell. Net-zero electricity technologies using ammonia are available and suitable for remote regions, including communities in the NWT.

For hydrogen production, at 55 kWh/kg using electrolysis, the power requirement for this production is 103.2 MW. Cunningham (2022) suggests using a 53% capacity factor for hydropower to compensate for availability, resulting in a total of 194.7 MW of electric capacity.

Summary of indicative energy requirements to produce hydrogen:

Table 6: Hydrogen production requirements.

Hydrogen Production: 1 Metric Tonne	Conversion Energy (Electric, MWh)	Hydro-Electric Capacity at 53% (MW)
From electrolysis only	55.0	103.8
From electrolysis, NH_3 production & cracking *	61.0	113.4
* Includes production of NH_3 required in cracking process		

The process schematic for Haber Bosch ammonia production with hydrogen produced from renewables or nuclear using electrolysis:

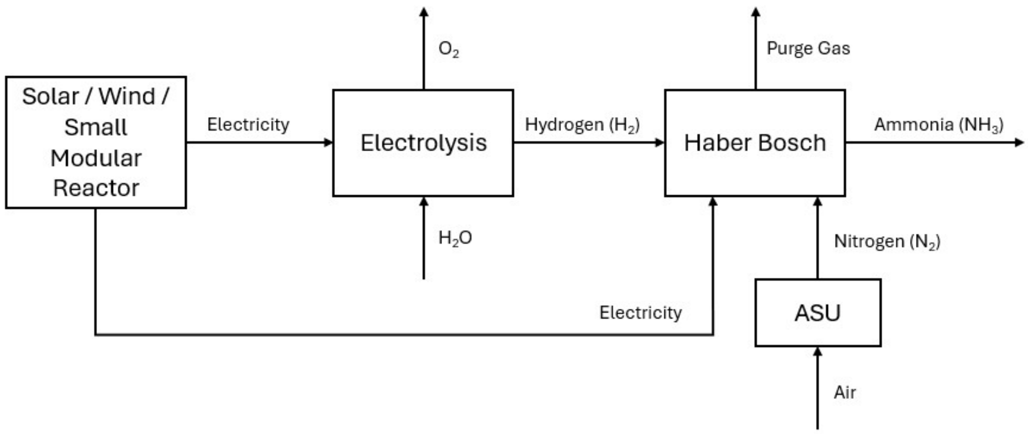


Figure 14: SMNR/renewable power and ammonia production process flow diagram.

The process flow diagram of methane pyrolysis feeding hydrogen to the Haber Bosch process for ammonia can be seen below in 8.

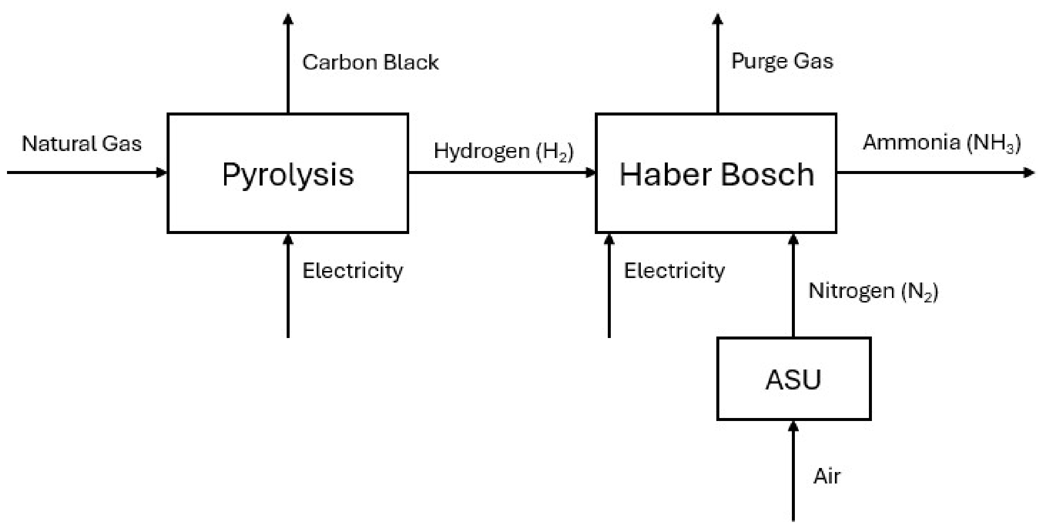


Figure 15: Methane pyrolysis and ammonia production process flow diagram.

Ammonia is expected to be able to replace diesel fuel in internal combustion engines, however, the technology is not yet ready:

Ammonia has different combustion properties compared to diesel fuel. It has a higher ignition temperature and a slower flame speed, which makes it challenging to burn efficiently in a diesel engine without modifications. Diesel engines rely on high compression to ignite fuel, and ammonia does not ignite as easily under the same conditions.

While ammonia combustion does not produce carbon dioxide (CO_2), it can result in the formation of nitrogen oxides (NOx), which are pollutants that diesel engines are already designed to control but can be more difficult to manage with ammonia due to the different chemical properties.

Ammonia is chemically aggressive and can corrode metal components over time, which poses a challenge for the fuel system, injectors, and other engine parts. Special materials and coatings would be needed to handle ammonia fuel safely without causing corrosion or damage.

Ammonia can be converted back to hydrogen through cracking, utilizing heat and catalyst in the process. This is done with an efficiency of about 76%. The development of low-temperature cracking techniques and advance catalysts is making this process more efficient and are currently under development.

4.3.2 Biomass Pyrolysis

Lignocellulosic biomass is dry biomass. It can be pyrolyzed to produce biochar, bio-oil, and syngas:

3. Syngas: Mainly hydrogen (H2), carbon monoxide (CO), and methane (CH4), with possible CO2 and higher hydrocarbons. It can be processed to purify hydrogen for fuel and industrial use.
4. Bio-oil: A dark liquid with oxygenated compounds that can be upgraded to produce diesel and gasoline substitutes.
5. Biochar: A carbon-rich solid used as a soil amendment or in industrial applications.

The composition of each of these reaction products varies by feedstock and processing conditions [43].

Syngas and bio-oil are intermediates that can be further processed to produce hydrogen, biodiesel or bio-gasoline. The yields and compositions depend on the specific biomass and pyrolysis conditions. One pathway of pyrolyzing Lignocellulosic biomass is through fast pyrolysis. Fast pyrolysis-based biomass conversion processes can achieve high efficiencies for producing liquid transportation fuels, such as gasoline and diesel blend stocks, or intermediates compatible with petroleum refineries for further conversion into liquid fuels. The heating method selected depends on reactor design, biomass characteristics, product yields, and energy efficiency [43].

In their 2015 report, *Process Design and Economics for the Conversion of Lignocellulosic Biomass to Hydrocarbon Fuels*, NREL evaluated the cost of both an in-situ and ex-situ facility to convert a 2,000 dry metric tonnes per day of woody biomass, with costs set at $80 per dry short ton. This facility requires on-purpose hydrogen production of approximately 70 mT/d, which is largely produced from fuel gas extracted from the process [43].
The full life cycle GHGs for gasoline and diesel fuel via the catalytic pyrolysis and upgrading pathways Emissions are estimated at 10.2 g CO_2e/MJ for gasoline and 10.3 g CO_2e/MJ for diesel, corresponding to a GHG reduction of 89% for both fuels [43]. A basic schematic of biomass pyrolysis to produce biogas and biodiesel can be found in Figure 15:

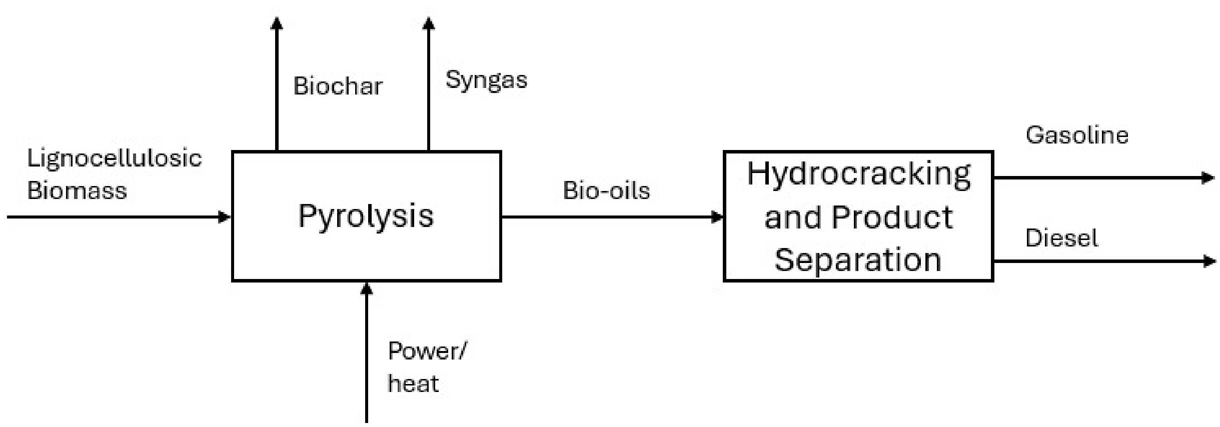


Figure 16: Biomass pyrolysis process flow diagram.

There is opportunity to produce biofuels in the NWT through biomass pyrolysis. Due to the scale and cost, this process should be developed in a central hub location and distributed to the surrounding communities.

4.3.3 Fischer-Tropsch

Fischer-Tropsch technology converts syngas into products such as diesel, kerosene, naphtha and LPGs. The syngas is produced through gasification which uses natural gas or biomass as input. Biomass requires pretreatment prior to being fed into the gasifier. The Fischer-Tropsch process requires a specific syngas ratio (ratio of H_2 to CO) in the feed, requiring the addition of hydrogen, or removal of CO2. In case of hydrogen addition, this could be produced from electrolysis. [44].

The Fischer-Tropsch process is another option for converting biomass into biofuels. This process can be used as an alternative to biomass pyrolysis as they produce similar hydrocarbon products. As the Fischer-Tropsch process requires specific ratios of syngas and additional electricity, which is not readily available at low cost, biomass pyrolysis is recommended instead. This process relies on imports of biomass. Therefore, it would be best suited to develop this technology in Hay River because biomass imports can be delivered relatively close to the facility. The biofuels would have to be distributed across the NWT and mining operations similar to current transportation of conventional fuels.

4.3.4 Biodiesel

Biodiesel is a renewable fuel source that is manufactured from plant or seed oils [45]. Biodiesels can be either conventional biodiesel or hydrogen derived renewable diesel (HDRD). Both types are made from similar feedstocks, however, HDRD is more similar to conventional diesel due to its hydrogenation and isomerization processes [46]. Like conventional diesel, biodiesel can be directly employed in diesel generators or vehicles. Therefore, over its lifecycle, it can reduce GHG emissions by over 80% [47]. Biodiesel production is increasing in Canada. Seven new renewable diesel facilities are planned or under construction, including one in Edmonton, AB and two in Saskatchewan [48]. These facilities are to be completed by 2027 and will increase Canada's biodiesel production to 70,000 barrels per day. The NWT can import biodiesel to power vehicles or diesel generators. As every community in the NWT uses diesel, importing biodiesel is a solution to the short-term that should be further investigated for availability and suitability. In a study that assesses the biofuels use in the NWT, the two main manufacturers of the NTPC's diesel generators confirmed that newer generators can run on 100% biodiesel [46]. This suggests that older generators may have to be replaced to run on 100% biodiesel [46]. However, other manufacturers that were contacted for smaller diesel generators stated that the warranty may be violated if any blend of diesel fuel was used [46]. There are considerations regarding the technical specifications when using biodiesels. Biodiesels are untested in the climate of the NWT and there are concerns regarding how it reacts in cold weather. Biodiesels can be manufactured to meet the -40°C cloud point, however, further testing and R&D is required to guarantee its operability in the NWT [46].

- Key aspects of biodiesel in cold climates:
- Poor cold flow properties
- High cloud point and pour point resulting in gel or crystallizing in fuel lines and filters
- High water content
- Oxidative stability

System design solutions include heated fuel lines and filters, and tank temperature management. A pilot project is recommended to determine the feasibility of using biodiesels in the NWT [46].

As less biodiesel is produced in Canada than conventional diesel, it may be difficult to import enough biodiesel to meet demands.

4.3.5 Carbon Sequestration

Canada's geology offers substantial potential to store CO2. Emissions from industrial facilities can be captured, compressed, and injected into deep rock formations. A suitable storage site must be deep, with micro-porous, permeable rock for CO2 diffusion and trapping, ample interconnected pore space for storage, and a dense caprock layer to prevent leakage.

Canada's total storage resources amount to 398 Gt. In the west, the Western Canada-Alberta and Williston basins account for 390 Gt [49]. Figure 17 shows a map of geological sinks in the country. In the NWT, suitable sequestration geology is found in the southern Deh Cho and South Slave regions. They form part of the large Western Canada Sedimentary Basins extending into British Columbia, Alberta, Saskatchewan and the United States.

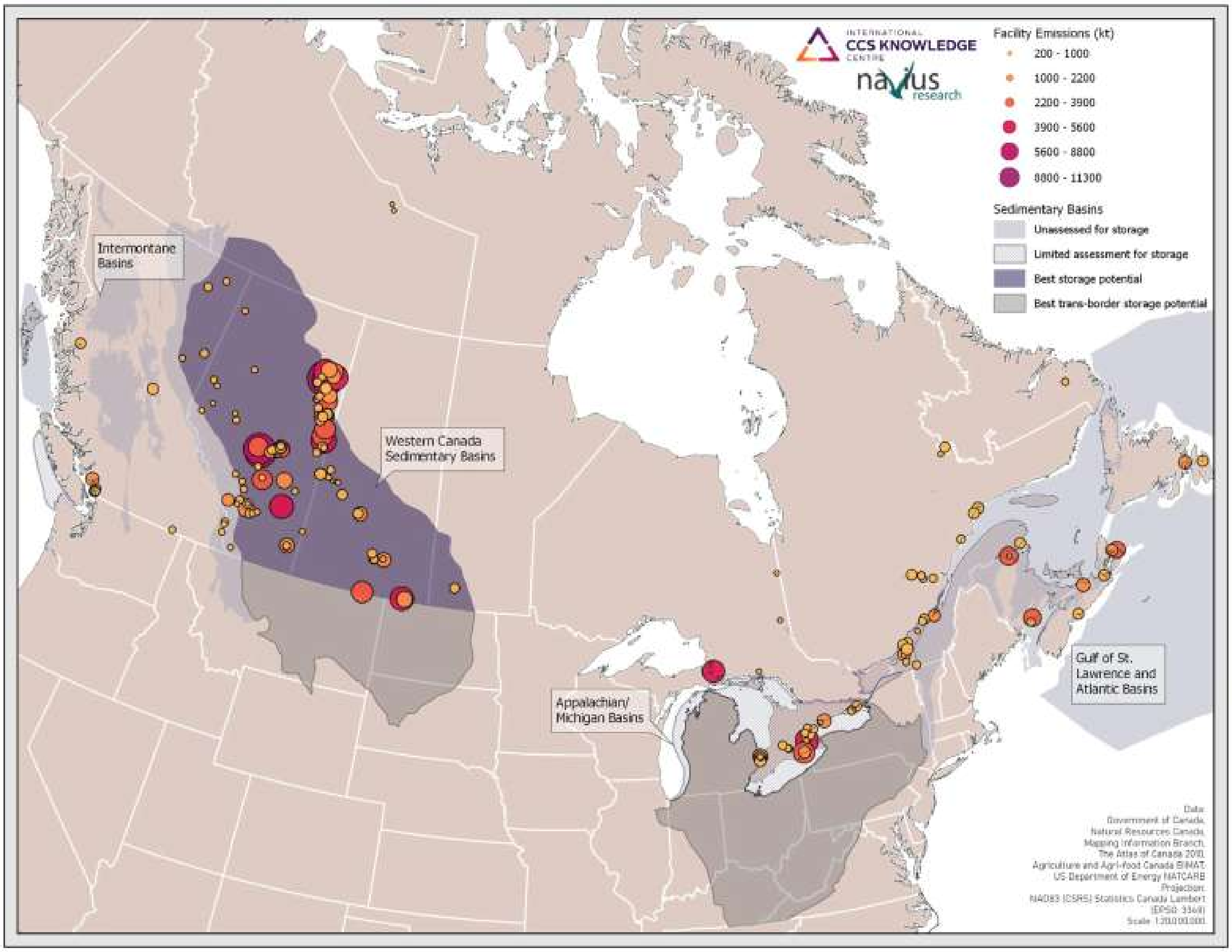


Figure 17: Map of potential CCS sites in Canada. Taken from [49].

Other potentially suitable areas for CO2 sequestration are in the Mackenzie Delta region which holds large oil and natural gas reserves. CO2 sequestration in deep geological formations beneath the permafrost is theoretically possible, however, more research is required to understand the opportunity and assess the geological, environmental, and logistical challenges.

Small Modular Reactors – described in Section 3.1.4 – can be applied to produce combined heat and power.

4.4 Clean Energies Pathways Overview

Clean The technologies described in section 4.1 through 4.3 are summarized in Figure 18. Four clean energies are presented: electricity, hydrogen, ammonia, and low carbon hydrocarbons. Note that hydrogen can be in liquid form for storage and distribution. Similarly, ammonia is suitable for distribution and storage and can be reconverted to hydrogen or applied directly at location.

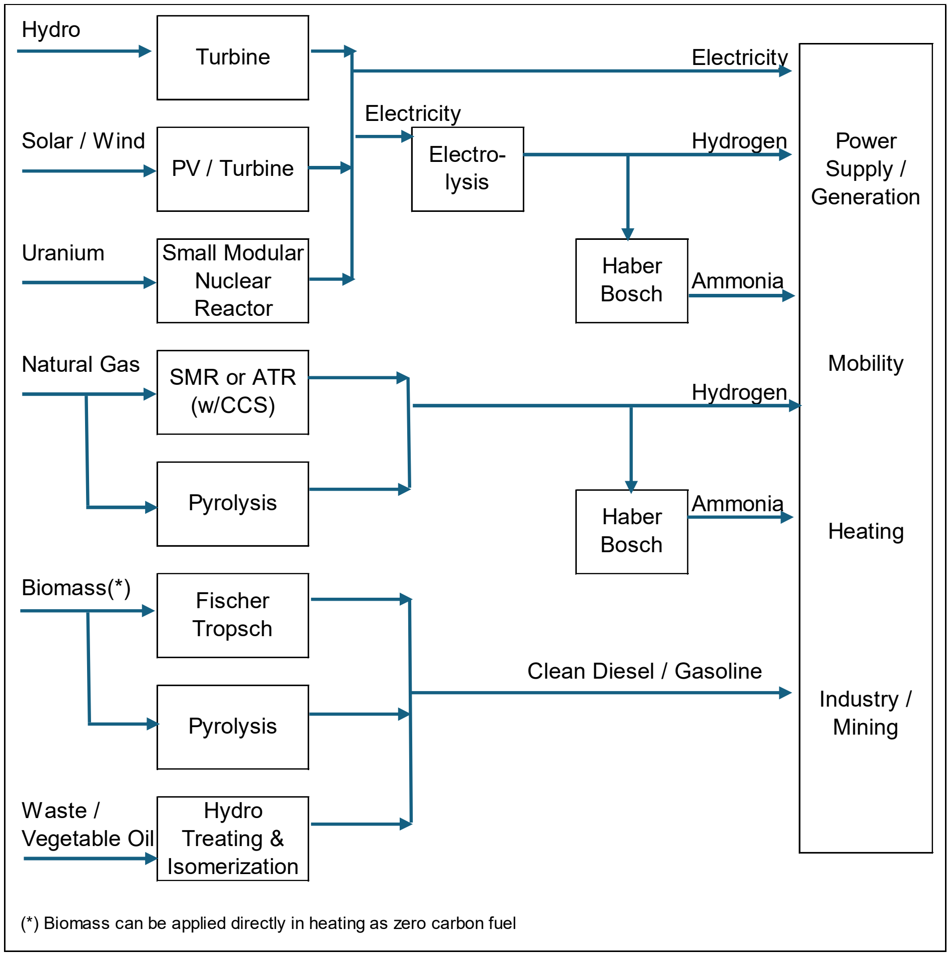


Figure 18: Pathways to Clean Energy in the NWT

5. Applications for H2 and Derivatives

5.1 Power Generation

Electricity can be generated in fuel cells from delivered or locally produced hydrogen or ammonia (cracked). Alternatively, hydrogen can be combusted in modified reciprocating engines replacing diesel engines, or in micro- or industrial turbines. Combustion applications are less sensitive to hydrogen purity, are quick to ramp up and down, or can work with ammonia. In case of ammonia combustion, NOx formation should be mitigated with

5.2 Transportation

Transportation continues to be the highest source of emissions in the NWT. To understand the current transportation systems in the NWT, a regional analysis was completed. The following sections outline the conclusions and recommendations drawn from the analysis.

5.2.1 Heavy-Duty Vehicles

Diesel HDVs consume the highest amount of fuel in the NWT. Hence, we recommend that the GNWT prioritizes converting conventional diesel ICEs to low-carbon alternatives.

Hydrogen presents a compelling alternative for the HDT industry due to its comparable refueling times with ICE vehicles, longer range than BEVs, and higher efficiencies than conventional ICE vehicles [50]. The tare weight of HDVs is an important factor when considering the feasibility of future solutions as every increase in the tare weight causes the allowable payload to be reduced, potentially impacting revenue [51]. This presents an issue for BEVs where large and heavy batteries are required for transporting shipments. In the case of hydrogen fuel cell electric vehicles (HFCEVs), tare weight is comparable to an ICE truck. Due to the limited hydrogen refueling infrastructure currently available, the heavy-duty trucking industry represents an excellent initial opportunity because truck routes are defined, allowing for appropriate placement of refueling stations along these routes. The Alberta Motor Transport Association is currently working with a variety of stakeholders to design a class 8 hydrogen truck that is designed for long-range and heavy weight hauling, and Canada's cold winter climate [52]. For hydrogen to become a viable low-carbon solution for the heavy-duty trucking industry, planning between the GNWT and surrounding regions governments is required to ensure that adequate fueling infrastructure exists along trucking routes.

Appendix D presents a regional transportation analysis, which lists estimates of current diesel consumption. Between Hay River and Yellowknife, approximately 121 million liter per year is consumed. If full replacement of diesel trucking with FCEV trucking were contemplated, this would require 34.4 mT/d of hydrogen in Yellowknife, and 38.2 mT/d of hydrogen in South Slave.

A first initiative can be established by establishing a Heavy-Duty Vehicle (HDV) FCEV corridor between Hay River and Yellowknife. This is a distance of 481 km and suitable for a pilot. Fueling stations can be placed in Hay River and Yellowknife. A first step of 2 HDVs could be deployed. Gaseous or liquid hydrogen can be imported from Alberta and complemented with locally produced hydrogen from solar. This has potential to be scaled utilizing a combination of imported and locally produced hydrogen.

5.2.2 Light-Duty Vehicles

LDVs are another top contributor to emissions in the transportation sector, however, there are several low-carbon opportunities for LDVs. Currently, BEV adoption is on the rise in the NWT which is supported by the addition of charging stations in Yellowknife and plans for a charging corridor in several communities surrounding the Great Slave Lake. Although BEVs are an excellent method to reduce transportation emissions, extreme cold such as that observed in the NWT reduce their range and increase charging times.

Hydrogen is another option for LDVs in the future. Currently, there are a limited number of HFCE LDVs available on the market and a limited availability of charging infrastructure in Canada. HFCEVs have multiple benefits including faster charging times, longer ranges and better extreme cold performance than BEVs. With the lack of hydrogen infrastructure and technology, HFCEVs are not a realistic option for the short-term. However, it has the potential to be a suitable option for the NWT in the future, especially with the development of hydrogen infrastructure.

5.2.3 Rail, Barge and Aviation

Hydrogen presents an opportunity for railway applications. The low refueling times, long ranges and better extreme cold performance make hydrogen a more suitable option than battery electric for powertrains. Successful deployment of hydrogen electric locomotives requires appropriate infrastructure for hydrogen production, storage, and distribution. As the only railway in the NWT connects to Alberta, coordination between the GNWT and the Government of Alberta is required to ensure suitable refuelling infrastructure is available. Alberta is developing hydrogen fuel cell trains and has partnered with Canadian Pacific to convert three diesel-electric powertrains to hydrogen-electric power trains [53]. We recommend a pilot study that uses these powertrains on trips to the NWT.

5.2.4 Off Road Transport

For off-road transportation, biofuels are generally recommended. This is because most of off-road transportation forms travels to isolated regions of the NWT where power infrastructure is not available for refueling. There is an opportunity to use hydrogen to fuel mining equipment. General Motors and Komatsu are together developing a hydrogen fuel cell power module for Komatsu's 930E electric drive mining truck. Hydrogen is an ideal option to replace diesel-powered applications for off-road transportation as refueling is quick and it has a high energy density. Large amounts of energy can be supplied onboard without compromising its payload carrying capacity [54].

Furthermore, as mining vehicles are normally operated at one site for their lifetime, it is feasible to incorporate charging infrastructure.

5.3 Heating

5.3.1 Biomass

The reliability of heating systems and availability of heating fuel supply are of paramount importance in the NWT. Heating solutions must reduce emissions and optimize efficiencies. Biomass is an existing low CI heating source with a functioning fuel supply chain. As it is currently being applied as fuel in the NWT, it is a suitable option for the NWT.

The IEA Bioenergy Technology Collaboration Programme - Annual Report 2023 [33] elaborates on the safe use of biomass for heating. Flue gases from biomass combustion contain pollutants and can cause different health effects as shown in various studies. Solid particulate matter such as biomass char, soot, and gas phase pollutants such as condensable organic compounds (COCs), VOCs, CO, CO2, and NOx should be minimized or avoided if possible. Moreover, more efficient biomass heaters burn less fuel, and produce less pollutants. Table 19 in Appendix I shows the organic fraction in particle matter for various combustion devices [34].

Innovations in new boiler and stove technologies have led to significantly higher efficiencies and lower emissions of unburned hydrocarbons. Advanced combustion technology plays a vital role in emission reduction by ensuring more and efficient and cleaner combustion. Practical considerations must be made in selection of biomass furnace technology, as the technical solution must match specific local requirements, which may include periods of unavailability of electricity, which could impact the electric control and monitoring systems of these modern furnace systems.

Heating in the NWT should continue the current path with increases in biomass as the main source of heating. Heating efficiency is increased using biomass boilers compared to burning biomass directly for heat. Biomass is a viable solution to deliver efficient net zero carbon emission heating to residential and commercial buildings. Further analysis around the sustainability and supply of biomass such as wood pellets is recommended.

5.3.2 Hydrogen Boilers

Hydrogen boilers are similar to natural gas boilers but use hydrogen as fuel source. When hydrogen is burned, it reacts with oxygen to produce heat and water vapor, with no carbon dioxide emissions. These boilers can be used in residential, commercial, and industrial heating systems. When combusting hydrogen, the engineering of the boiler system must address the burner for flame characteristics, flame stabilization, and NOx emissions. Further, the metallurgy must be suitable for hydrogen with a focus on embrittlement, welding requirements, and thermal stresses. As hydrogen combustion produces significant water vapor, integration of condensing technology improves efficiency.

5.3.3 Hydrogen in Fuel Cells for Combined Heat and Power (CHP)

Hydrogen fuel cells can generate electricity and heat simultaneously, providing an efficient solution for heating. In residential or commercial buildings, a hydrogen fuel cell system can supply both electricity for appliances and heat for space heating and hot water. These systems can be integrated into existing heating networks, significantly reducing carbon emissions.

5.3.4 Blending Hydrogen with Natural Gas

Another approach is blending hydrogen with natural gas in existing gas networks, a practice known as "hydrogen blending." This allows for a gradual transition to hydrogen without requiring a full infrastructure overhaul. By mixing hydrogen with natural gas in varying proportions, the overall carbon footprint of heating systems can be reduced. However, higher concentrations of hydrogen may require new infrastructure and appliances designed to handle the gas. Because of metallurgical limitations of existing natural gas transportation infrastructure, hydrogen is mixed with natural gas up to 15% to 20% on a volume basis. Due diligence must be done to validate the application, in particular related to metallurgy and leaks.

The lower heating value of natural gas versus the lower heating value of hydrogen has a ratio of about 3.5. Therefore, mixing hydrogen with natural gas will reduce the heat content of the energy. For example, if the hydrogen share of the total hydrogen/natural gas mixture is 20% on a volume basis, then the overall heat transport capacity will be reduced to 85.6%, a reduction of 14.4%.

With respect to CO2 emissions, as one m3 of natural gas produces about 1.96 kg of CO2, replacing 20% of natural gas with zero carbon hydrogen reduces the emissions by 20%, requiring for each m3 of natural gas, 0.2 m3 to be replaced with 0.7 m3 of hydrogen.

5.3.5 Hydrogen in District Heating

Hydrogen can be used in district heating systems, where heat is generated centrally and distributed to multiple buildings. A hydrogen-powered boiler or CHP plant could be used in these systems. Building size, density, and proximity are important factors for the economic feasibility of such applications.

5.3.6 Hydrogen as a Heat Storage Medium

Hydrogen can also play a role in energy storage. Renewable energy sources like wind and solar can produce excess electricity, which can be used to produce hydrogen through electrolysis (splitting water into hydrogen and oxygen). This hydrogen can then be stored and used later for heating purposes when energy demand is high, ensuring a stable supply of heat even during periods when renewable energy generation is low.

5.3.7 Other Sources of Energy for Heat

Biodiesel or bio-oils can be applied to conventional heating systems currently running on conventional fuel oil

Small Modular Reactors – described in Section 3.1.4 – can be applied to produce combined heat and power.

5.4 Industry

Hydrogen can play a role in decarbonizing mining operations, particularly in remote or off-grid settings and for heavy-duty equipment. Below is a breakdown of how hydrogen is used or planned for use across key mining activities:

- FCEVs: hydrogen powers electric drivetrains via fuel cells
- Hybrid systems: combine batteries and fuel cells to handle peak loads and regenerative braking
- Hydrogen powered drilling and blasting equipment
- Power generation for off-grid sites using hydrogen fuel cells in camps
- Hydrogen can be used in industrial process heating such as smelting and refining, thermal drying of ore or concentrate, and in boilers and kilns in mineral processing

Ammonia can be used as energy carrier and cracked on-site. Ammonia can be used directly in power generation.

5.5 Transportation of Fuels in the NWT

Transportation by road in the NWT faces challenges due to its harsh climate and remote geography. Much of the NWT is underlain by permafrost, which can thaw and shift, leading to road cracks, sinkholes, and instability. Snow and ice create dangerous driving conditions, while ever increasing maintenance requirement complicate travel and distribution of goods and fuel by road. Communities that were accessible only by ice roads are becoming less accessible due to climate change. Many communities rely on seasonal winter roads or air transport.

The application of pipelines for fuels transportation experience similar concerns as infrastructure for roads. Permafrost melting causing shift and pipeline stress and possible leaks. Remote locations make detection, servicing, and repair more difficult. The NWT is a diverse and fragile ecosystem, that could be impacted by pipeline construction and leaks. Indigenous communities will demand strict environmental protection on pipeline development. The quantities of energy to be transported for local needs are relatively small compared to pipeline development cost.

Development of hydrogen and derivatives will not only reduce the carbon intensity of fuel consumption and electricity generation. These energies have the potential to be produced locally through the application of renewable electricity production at location, as well as being stored locally. Furthermore, low carbon fuels, such as ammonia, can be produced centrally or imported into the NWT and distributed by barge during the summer months. Delivered fuel can be transferred and stored in the various regions of the NWT, and then subsequently distributed, stored, and applied locally. Distributed production of low carbon electricity and hydrogen, complimented with ammonia that is barged in and stored locally will improve control over energy supplies and enhance energy security. However, the Mackenzie River has suffered from reduced water levels during the summers of 2023 and 2024, which requires more fuel transportation by truck, which can be accomplished in winter only and is more costly.

Figure 4 provides information regarding the quantities of fuels used in each region. For diesel fuel, about 80% is consumed in North – and South Slave Lake region. This region can serve as basis for distribution of hydrogen and ammonia to the remote regions during suitable transportation windows and store the ammonia in larger cryogenic facilities for local consumption. Local cracking of ammonia to hydrogen or direct ammonia consumption provides secure energy supply for long periods of time.

These supply chains can be supported through the development of pipelines between Alberta and the NWT. The distance from Hay River to Ft McMurray is approximately 650 km and the distance to the Alberta Industrial Heartland (AIH) is about 1,060 km, and there are existing pipeline corridors between Fort McMurray and the AIH. however, such pipeline systems will be expensive, in particular since the development of hydrogen and ammonia production capacity takes time and initial volumes are low. Transportation of fuels would continue to be by rail and truck for the foreseeable future. Rail and truck transportation can be decarbonized through use of ammonia and/or hydrogen.

5.6 Short- and Long-term Solutions by Region

The use of hydrogen is a feasible method for the NWT to reduce their carbon emissions and reach the 2030 and 2050 reduction goals. To reach the 2030 goal, it is recommended that the NWT increases its reliance on solar and wind energy to provide electricity or produce hydrogen. The solar potential is highest in the South Slave Region making it suitable for hydrogen production. Combining increases in solar along with the Taltson Hydro expansion can facilitate implementation of hydrogen infrastructure. The North Slave Region could benefit from increases in solar and wind power for electricity or hydrogen production. For remote communities in the Deh Cho, Sahtu, and Beaufort-Delta Regions, increases in solar and wind capacity for electricity production is recommended. The Deh Cho region has the highest solar potential of those regions while the Beaufort-Delta Region has the lowest. Conversely, the Beaufort-Delta Region has the highest wind potential while the Deh Cho Region has the lowest. It is also recommended that the NWT explores the possibility of importing biodiesel/renewable diesel to offset the consumption conventional diesel and lower carbon emissions.

For long, one possible solution is that SMNRs are implemented in the South Slave Region near Hay River to produce electricity, and hydrogen. Transporting ammonia to remote communities can be used in fuel cells to produce electricity and heat, in the transportation industry for FCEVs, and in the mining industry for FCEVs and fuel cells. Another recommendation is to increase NG production in the Liard Basin in the Deh Cho Region. For example, NG can be converted to hydrogen through Auto-thermal Reforming (ATR) and converted to ammonia.

Table 7: Regional Short- and Long-Term Solutions

Region	Short Term (small scale)	Long Term
North Slave		
Residential/public	- Wind/solar + Electrolysis - FCEV for public transit and HDT - H2 for heat + electricity in remote communities (FC or Diesel blend)	- SMNR (direct electricity and hydrogen/ammonia production - Ammonia Import from AB or from other centralized production, i.e., South Slave or Deh Cho - Ammonia distribution within the region, (partial) conversion to H2 where required
Industrial/mining	- Wind/solar + Electrolysis - H2 for heat + electricity (FC or Diesel blend)	- Ammonia Import from AB or from other centralized production, i.e., South Slave or Deh Cho. Partial conversion to H2 where required

Region	Short Term (small scale)	Long Term
South Slave		
Residential/public	- Solar + Electrolysis - FCEV for HDT - H2 for heat + electricity in remote communities (FC or Diesel blend)	- SMNR (direct electricity and hydrogen/ammonia production - Methane pyrolysis + ammonia (w/NG from Liard basin) - Ammonia Import from AB or from other centralized production, i.e., Deh Cho - Ammonia distribution within the region, (partial) conversion to H2 where required - Biomass Pyrolysis (import biomass from AB) & fuels distribution to other NWT regions
Industrial/mining	- Wind/solar + Electrolysis - H2 for heat + electricity (FC or Diesel blend)	- Ammonia Import from AB or from other centralized production, i.e., Deh Cho. Partial conversion to H2 where required

Region	Short Term (small scale)	Long Term
Deh Cho		
Residential/public	- Solar (electricity) - Imported biodiesel/renewable diesel	- Methane pyrolysis + ammonia - ATR + CCUS + ammonia - Ammonia Import from AB or from other centralized production, i.e., South Slave - Ammonia distribution within the region, (partial) conversion to H2 where required
Industrial/mining		- Ammonia Import from AB or from other centralized production, i.e., South Slave. Partial conversion to H2 where required

Region	Short Term (small scale)	Long Term
Sahtu		
Residential/public	- Solar (electricity) - limited	- Ammonia Import from AB or from other centralized production, i.e., South Slave or Deh Cho
	- Wind (Norman Wells)	- Ammonia distribution within the region, (partial) conversion to H2 where required
	- Imported biodiesel/renewable diesel	- Maintain/expand renewables, run-of-river electricity, for energy security reducing the impact of distribution interruptions
Industrial/mining		- Ammonia Import from AB or from other centralized production, i.e., South Slave or Deh Cho. Partial conversion to H2 where required

Region	Short Term (small scale)	Long Term
Beaufort-Delta		
Residential/public	- Solar (electricity) - limited	- Ammonia Import from AB or from other centralized production, i.e., South Slave or Deh Cho
	- Wind (electricity)	- Maintain/expand renewables, run-of-river electricity, for energy security reducing the impact of distribution interruptions
	- Imported biodiesel/renewable diesel	
Industrial/mining		- Ammonia Import from AB or from other centralized production, i.e., South Slave or Deh Cho. Partial conversion to H2 where required

6. Key Factors Associated with Hydrogen Development

6.1 Challenges of Operating in Cold Climate

Operating hydrogen generation and energy systems reliably in the North presents unique engineering challenges due to extreme cold, permafrost, remoteness, and limited infrastructure. Several engineering solutions have been developed or are under development to address these constraints.

Key challenges:

- Extreme cold (-40 degrees C and below)
- Permafrost causing ground instability
- Limited daylight/wind seasonality
- Remote access/logistical constraints
- Limited grid infrastructure

6.1.1 Solutions for Facilities

Engineering solutions for Northern hydrogen and energy systems available:

Electrolyzers with thermal enclosures, internal heating elements, and temperature resistant materials. Containerized and modular systems. Examples include active thermal regulation (heating & insulation), and the use of glycol loops or phase change materials to buffer temperature swings.

PEM electrolyzers rely on water-based electrolytes and membranes that are sensitive to freezing, causing membrane or stack damage. Temperature fluctuations can affect membrane conductivity and hydration. Start-up delays can be avoided through heated enclosures or pre-heating systems.

AEL systems use liquid electrolytes (KOH or NaOH) which are corrosive and viscous at low temperatures. KOH solutions can crystallize or gel at sub-zero temperatures. As alkaline systems are typically larger, they are harder to thermally manage. Alkaline electrolyzers require active heating systems and should use corrosion-resistant materials when deployed in cold climates.

For HTEL systems have long warm-up periods, and repeated heating and cooling in cold environments can cause ceramic cracking. The high internal temperatures are hard in extreme ambient cold. Ideally, they are combined with waste heat from other industrial processes and housed in thermally stable enclosures. Hybrid Energy Microgrids: hydrogen integrated with wind, solar, batteries, and diesel in hybrid microgrids for flexibility and resilience. Renewable energy, hydrogen production and storage can be paired for energy bridging.

Low-temperature fuel cell systems can be developed with cold-start capabilities, heated membranes/electrolytes, and anti-icing vents. Examples are the development of arctic-related fuel cell backup systems for telecom and remote research facilities. Permafrost-resilient foundations and infrastructure: Elevating or thermally isolating equipment foundations using thermosyphons (passive heat exchangers to maintain permafrost), and adjustable or pile-supported bases to account for ground movement.

Water solutions consist of insulated piping, tanks, heat tracing and electric heaters. Glycol-water mixtures can be used in external systems, including heat transfer loops or feedwater pre-heaters. Cold water is preheated prior to feeding into the electrolyzer. Alkaline electrolyzers will require KOH electrolyte to be heated unless sufficiently concentrated.

Remote monitoring and automation: Application of SCADA systems with satellite/low-bandwidth communication for predictive maintenance and minimal human intervention in remote areas.

Several manufacturers have developed electrolyzers suitable for operation in Arctic and cold climates, incorporating design features to ensure reliable performance under extreme conditions, Examples are Sunfire of Germany, HydrogenPro of Norway, and Nel ASA of Norway.

6.1.2 Distribution

The Northwest Territories faces logistical and infrastructure challenges due to climate change, including river draughts, permafrost thaw, soil instability, and road damage. These impact the distribution of fuel, food, and essential goods to remote and indigenous communities. This requires a multi-layered approach combining adaptation, innovation, and infrastructure investment. The following provides an overview of solutions:

Infrastructure:

- All-season roads: Replace or supplement winter roads with all-season gravel or modular roads where feasible. This reduces reliance on ice roads increasingly threatened by warming
- Climate-resilient construction: Use of thermosyphons, elevated roadbeds, and geotextiles to stabilize permafrost under roads
- Bridge and culvert upgrades: Increase the size and flexibility of structures to handle greater variability in water flow due to droughts or floods
- Pipelines may not be applicable in various regions. They are capital-intensive with costs increasing significantly per kilometer in remote and rugged, or permafrost areas. These pipelines will be vulnerable to buckling, leaking, and rupture. Further, as the energy demand in remote communities is relatively small, the high costs become difficult to justify

Water-Based Transportation:

- Shallow-draft barges: These navigate lower river levels, extending shipping season despite low water levels
- Port upgrades: Modernize docking facilities to accommodate newer vessels and support multi-modal integration.

Local Energy and Fuel Alternatives:

- Community-scale renewable energy that support and provide energy back-up in case of supply interruptions
- Energy storage systems; batteries, large ammonia storage systems

6.2 Community and Technology Selection

When deploying advanced energy technologies like renewable power, hydrogen electrolysis, or green ammonia in or near communities—especially remote or Indigenous communities—multiple technical, social, regulatory, and workforce development factors must align. Presented below is a breakdown of key considerations:

Renewable power:

- Community consent and ownership requiring engagement to ensure the project aligns with local priorities (i.e., decarbonization)
- Visual and land impact, in particular with respect to wind and solar, consulting on land use, aesthetics, and potential conflicts with traditional use
- Opportunities in construction, maintenance, electrical work, and solar tech installation

Hydrogen production via electrolysis:

- Public concerns about explosion risk and storage safety
- Explanation of benefits of green hydrogen and its role in decarbonization
- Requires setback distances from homes as governed by code including the Canadian Hydrogen Code and NFPA2
- Local opportunity for employment and training in basic chemical plant safety, high-pressure systems, hydrogen handling and leak detection

Small Modular Nuclear Reactors:

- Requires long-term community buy-in, especially in Indigenous regions, engagement, trust-building, and environmental impact transparency
- Concerns over waste, radiation, and site decommissioning must be addressed early
- This technology requires a secure, geologically stable site, away from groundwater and populated areas
- Strict regulatory standards for containment, monitoring, and incident response plans
- Codes are governed by the Canadian Nuclear Safety Commission (CNSC)
- Requires long-term technical training for roles such as reactor operators, safety personnel, plant engineers and technicians

Green Ammonia Production Facilities:

- Strong safety requirements due to ammonia's toxicity and corrosiveness
- To be located at a safe distance from communities and water bodies
- Enclosed process with high-pressure reactors and liquid ammonia storage
- Ammonia detection, ventilation, emergency response are essential
- Strong code compliance requirements
- Roles in process operations, safety, maintenance

Methane Pyrolysis:

- Strong safety requirements as these are operating at high temperatures
- Must be located at a safe distance from communities
- Code compliance: ASME, CSA

Table 6: Technology & Community Considerations

Criteria	Renewables (Solar/Wind/Biomass)	Electrolysis (Hydrogen)	SMRs (Nuclear)	Green Ammonia	Methane Pyrolysis
1. Community Size	Small to large	Medium to large	Medium to large	Medium to large	Small to medium
2. Local Feedstock Requirement	Solar, wind, biomass, water	Electricity & water	Fuel (Uranium)	Water, electricity, air	Natural gas or biogas
3. Technical Complexity	Low to medium	Medium	High	High	Medium
4. Regulatory Burden	Moderate	High	Very high (CNSC)	High (TDG, CSA)	Medium
5. Safety Proximity to Community	Close feasible	Buffer zone recommended	Remote siting	Remote siting	Remote siting
6. Reliability (Year-round)	Variable (storage needed)	High (if energy reliable)	Very high	High	High
7. Carbon Footprint	Net-zero	Zero-emission (if green)	Zero-carbon	Zero-carbon	Low-carbon
8. Employment & Training Fit	High, accessible	Medium	Medium, complex	Medium to high	Medium
9. Scalability / Modularity	High	Moderate	Low to medium	Medium	High
10. Infrastructure Dependency	Low (especially solar/wind)	High (power, water)	High	High	Medium (gas, carbon storage)
11. Community Acceptance	Generally high	Mixed, needs outreach	Often skeptical	Requires trust	Moderate
12. Economic Viability (Remote)	High with storage or hybrid	Viable at larger scale	CapEx heavy	CapEx heavy	Viable if gas available

6.3 Project Development, Work Force Training, and Emergency Response

6.3.1 Development of Projects in Northwest Territories

Northern climates are challenging areas for project development, in particular for larger, complex facilities that traditionally have a significant component of field related work. Decades of experience in Northern Alberta have seen project cost overruns caused by cold weather delays, transportation challenges, low productivity, and related re-engineering and challenges in operating the facilities under those circumstances. Cold weather engineering and solutions, including critical equipment placed in temperature-controlled enclosures, modularization and equipment specification and design for low temperature environment have been developed. Further, there are limited local resources for construction and operation of complex facilities and skilled labour must be brought in from outside the region, adding to costs and coordination. As a consequence, these facilities are more costly to design, engineer, and construct. However, mastering those aspects strengthen control of development and construction and therefore reduce the risks of schedule and capital cost overruns.

As the NWT is home to Indigenous communities, developers and construction companies need to engage with these communities to gain support for projects. This involves consultation, agreements, and partnerships. This brings opportunity for investment in people through training and stakeholder engagement and develop programs involving investors, OEMs, developers, educational institutions, and government. This specifically allows for opportunities in development of needed industry skillsets, which can further develop over time.

The additional costs of construction are included in the economics, factoring that cold weather design, modularization, construction in the NWT could potentially double the cost of construction, relative to facilities that are benchmarked to be build in warm climate hubs with well developed infrastructure for project implementation.

While some of the identified technologies are low TRL, from the perspectives of design and engineering hydrogen systems for safety and reliability, the industry has developed significant know-how and best practices, which are formalized in codes and standards. A key selection of these is presented below:

NFPA 2
Scope & Purpose: The purpose of the code is to provided fundamental safeguards for the generation, installation, storage, piping, use, and handling of hydrogen in compressed gas (GH2) form or cryogenic liquid (LH2) form. The code addresses all aspects of hydrogen safety.

- Applications: hydrogen fuelling stations for all types of vehicles; Fuel Cell Electric Vehicle (FCEV) repair facilities; Stationary fuel cells.
- Key chapters: general safety requirements; general hydrogen requirements; gaseous hydrogen; liquid hydrogen; explosion protection; GH2 vehicle fuelling facilities; LH2 fuelling facilities; H2 fuel cell power systems; H2 generation; parking and repair garages.
- Safety specific systems for hydrogen: design; control areas (storage, dispensing, usage, handling, quantity limitations).
- Protection: fire walls; PRDs; vent stacks, sensors, equipment design, electrical classification.

NFPA 2 references various other NFPA standards:

- NFPA 55: Compressed Gases and Cryogenic Fluid Code
- NFPA 30: Flammable and Combustible Liquids Code
- NFPA 70: National Electrical Code

AS APPLICABLE: Compressed Gas Association (CGA), International Electrotechnical Commission (IEC), American Society of Mechanical Engineers (ASME), International Standards Organization (ISO)

CANADIAN HYDROGEN INSTALLATION CODE (CHIC) - CAN/BNQ 1784-000

- Sets the installation requirements for hydrogen-generating equipment for non-process end use, hydrogen utilization equipment, hydrogen-dispensing equipment, hydrogen storage, piping systems.
- Minimum Clearing Distances
- ESD; Grounding; Master Shutoff Valve, PRV
- H2 Vent Systems; Signage

SAE CODES & STANDARDS

- J2600: Fuelling nozzle-receptacle interface; harmonized hydrogen nozzle-receptacle coupling connection; IrDA (Infrared Data Association) transmitter & communication interface.
- J2601: Fast hydrogen fuelling protocol; fuelling station certification of compliance with SEA J2601/2 from dispenser supplier; H70/T40 pressure and temperature protocols; Dispenser types (T-ratings: cooling requirements for compression & fueling.
- J2719: Hydrogen fuel quality
- J2799: FCEV to hydrogen station communication standard

6.3.2 Work Force Training

Training for building, operating, and maintaining hydrogen equipment is essential to ensure safety, efficiency, and compliance with regulations. Hydrogen systems, particularly in industrial or residential settings, come with unique challenges, given hydrogen's flammability, handling requirements, and technical complexities. These trainings apply to engineers and designers (1), construction personnel (2), operators (3), or distributors of fuel (4), and designated accordingly:

1. Hydrogen Safety Training (1, 2, 3, 4)

- Hydrogen Properties and Hazards
- Gas Detection Systems: Instruction on using hydrogen gas detectors and alarms to monitor for leaks, including calibration and maintenance.
- Emergency Response Protocols:
  - Procedures for responding to hydrogen leaks, fires, or explosions.
  - Training in emergency shutdowns and evacuation processes.
- Ventilation Requirements:
  - Ensuring that hydrogen equipment is installed in well-ventilated areas to prevent gas accumulation.

2. Technical Training for Installation and Construction (1, 2)
   - Hydrogen Equipment Installation:
     - Proper installation of hydrogen storage tanks, fuel cells, compressors, pipelines, and other infrastructure.
     - Electrical and mechanical system integration, including high-pressure systems.
     - Welding and pipefitting training, particularly for handling stainless steel or other materials compatible with hydrogen.
   - System Design and Engineering Principles:
     - Understanding how hydrogen systems are designed, including storage, transport, and distribution systems.
     - Training in codes and standards including NFPA 2.
   - Pressure and Temperature Management:
     - Handling hydrogen under high-pressure conditions, ensuring safe operation of pressurized tanks and distribution systems.
3. Operation and Maintenance Training (1, 3)
   - Hydrogen Storage and Dispensing Systems:
     - How to safely manage hydrogen storage, including the operation of high-pressure storage tanks, dispensing stations, and refueling systems.
     - Managing cryogenic hydrogen systems, which involve extremely low temperatures.
   - System Maintenance:
     - Routine checks, inspections, and preventive maintenance for hydrogen production, storage, and distribution equipment.
     - Troubleshooting issues related to fuel cells, compressors, or tanks.
4. Hydrogen Production Systems (1, 3)
   - Electrolyzers:
     - Training on the operation of electrolyzers (for producing green hydrogen) and maintaining their efficiency.
     - Knowledge of electrical systems involved in electrolysis and the management of associated byproducts, such as oxygen.
5. Compliance and Regulatory Training (1, 3, 4)
   - Code and Standards:
   - Environmental Regulations:
     - Understanding environmental regulations related to hydrogen production, storage, and transport, including emissions limits and waste management.
   - Certification Requirements:
     - Gaining certifications from recognized bodies, such as the Canadian Standards Association (CSA), NFPA.
6. Operational Efficiency and Troubleshooting (1, 3)
   - System Optimization:
     - Training on optimizing the operation of hydrogen systems, ensuring maximum efficiency in hydrogen production and energy conversion.
   - Troubleshooting:
     - Skills in diagnosing issues with equipment, such as fuel cells or electrolyzers, including identifying and resolving problems related to performance, leaks, and inefficiencies.
   - Preventive Maintenance:
     - Training on the development of preventive maintenance schedules and best practices for extending the lifespan of hydrogen systems.
7. Cross-Disciplinary Skills (1, 3)

- Electrical and Mechanical Skills:
  - Training in both electrical and mechanical systems that interact in hydrogen production and distribution systems.
  - Knowledge of power electronics, control systems, and automation used in fuel cells and electrolyzers.
- System Integration:
  - Understanding how hydrogen systems are integrated with other renewable energy systems (e.g., wind, solar) or conventional power grids.

8. Renewable Energy Systems Training (1, 3)
   - Integration with Other Renewables:
     - Training on integrating hydrogen systems with renewable energy sources for green hydrogen production (e.g., coupling hydrogen systems with wind or solar energy systems).
   - Energy Storage Systems:
     - Understanding hydrogen as an energy storage medium, particularly how it can store excess renewable energy and be used during peak demand times.
9. Industry-Specific Training (1, 2, 3, 4)
   - Transportation Sector:
     - For those working with hydrogen-powered vehicles, specialized training is needed for vehicle refueling stations, including the safe handling of hydrogen as a fuel.
   - Residential and Commercial Use:
     - Training on residential hydrogen boilers, fuel cells, or blending systems to provide heating and power.
10. Dangerous Goods Handling & Transportation Training in the NWT
    1. Emergency Response Assistance Canada (ERAC):
       - Provides specialized training and emergency response services for dangerous goods, including hydrogen and ammonia.
       - This was initiated by ERAC in 2024 with a first hydrogen regional training and assessment and engaged in ammonia responder courses to enhance their expertise in handling of ammonia related incidents.
    2. Canadian Association of Agri-Retailers (CAAR)
       - Offers online training focused on safe handling and transportation of anhydrous ammonia.
    3. Transportation of Dangerous Goods (TDG) Regulations
       - NWT has adopted the federal TDG regulations, ensuring that the transportation of dangerous goods complies with national safety standards.

While the Northwest Territories (NWT) may not have a wide array of provincially offered technical and operator training programs specifically focused on hydrogen technologies, several institutions and organizations provide relevant courses accessible to NWT residents:

1. Northern Alberta Institute of Technology (NAIT):
   - CLNF280 - Introduction to Hydrogen Vehicles: Examines the theory behind hydrogen-powered vehicles and equipment, including an overview of hydrogen production and storage.
   - CLNF220 - Hydrogen Transport: Technologies and systems necessary for safe hydrogen handling and transportation, covering methods of transportation, best practices, and transport regulations.
   - Delivery: Both courses are offered online.
2. Southern Alberta Institute of Technology (SAIT):
   - SNRG 001 - Hydrogen Awareness and Understanding for Process-Related Occupations: A 24-hour online course providing foundational technical knowledge on hydrogen production and its applications, emphasizing economic and safety challenges.
   - SNRG 002 - Entry-Level Technical Applications in Hydrogen for Process Operations: A 48-hour online course offering foundational technical knowledge on optimizing hydrogen technologies, considering ethical concerns such as Indigenous rights, sustainability, and societal impact.
   - Delivery: Both courses are online.
3. Arctic Response Canada:
   - Trades Entrance Exam Preparation Program: This program prepares individuals to take the Trades Entrance Exam in the NWT and Alberta, covering math, science, English, and mechanical reasoning with an emphasis on practical skills and test preparation.

- Delivery: Primarily focused on trades entrance exams, the program offers foundational knowledge beneficial for technical roles, accessible to NWT residents.

4. Center for Hydrogen Safety (CHS):
   - Hydrogen Safety Training: CHS provides resources and training materials focused on the safe handling of hydrogen, including eLearning courses and webinars.
   - Delivery: Online resources are available.
5. Energy Training Courses Near Northwest Territories:
   - Energy-XPRT: Various energy training courses available near the NWT, including topics on renewable energy and hydrogen technologies.
   - Delivery: While some courses are in-person, online components are offered.
6. Equipment suppliers:
   - An important aspect of education is what can be provided by equipment suppliers, providing training relevant to the selected technologies, as well as through ongoing involvement and training by suppliers. This should be contracted and managed from early development stage.

6.3.3 Emergency Response

In the Northwest Territories NWT, emergency response services are available through several coordinated levels of government and industry organizations. When the emergency is related to industry (such as oil and gas, mining, construction, or hazardous material spills), a number of specialized resources are in place. For new technology and processes associated with hydrogen and/or its derivatives, additional know-how and response strategies must be identified and developed, through engagement in the development process at early stages. Application and development of operating procedures, process design Hazardous Operations (HAZOP) studies, application of safety systems, understanding of new fuels and properties of hazardous materials are important. While there are no hydrogen-specific spill response training programs in the NWT, the listed organizations and training provide valuable knowledge and skills applicable to hydrogen safety and emergency response. Relevant emergency response resources are listed below. Project proponents must engage with these to ensure awareness, education, and training.

1. Northwest Territories Emergency Management Organization (EMO)
   - Role: The NWT EMO is responsible for coordinating emergency responses and ensuring the overall safety of residents, businesses, and infrastructure in case of large-scale emergencies. They are involved in all stages of emergency response, from preparedness to recovery.
   - Key Activities: Emergency planning, coordination, response coordination, and recovery for industrial and natural disasters.
2. Environmental Emergency Response Team (EERT)
   - Role: The EERT is tasked with responding to environmental emergencies, including hazardous material spills, chemical leaks, and other incidents related to industrial activities.
   - Deployment: They are specifically trained to handle spills involving dangerous substances such as petroleum products, chemicals, and other hazardous materials used in industries like mining, oil & gas, and construction.
3. NWT Fire Marshal's Office
   - Role: The Fire Marshal’s office is responsible for ensuring public safety during emergencies involving fires or explosions in industrial settings. This includes ensuring that fire safety protocols are followed in industrial operations. The Fire Marshal’s office must be engaged in early stages of project development to assure alignment and approval of designs and safety systems.
   - Response: They work in coordination with local fire departments, industry representatives, and other relevant bodies during industrial emergencies, particularly in firefighting operations and post-incident investigations.
4. Local Fire Departments
   - Role: The NWT has local fire departments that respond to industrial fires and other emergencies in both urban and rural settings. Like the NWT Marshal’s office, the local fire department must be engaged in early stages of project development to assure alignment and approval of designs and safety systems.
   - Training: Many fire departments in NWT are equipped and trained to handle hazardous material spills, fires, and accidents related to industry. These services are generally available in communities like Yellowknife, Inuvik, Hay River, and others.
   - Response: Fire departments provide first-line emergency responses, including fire suppression, hazardous material containment, and evacuation assistance. They often cooperate with other specialized agencies.
5. Occupational Health & Safety (OHS) – NWT
   - Role: OHS, overseen by the Workers’ Safety and Compensation Commission (WSCC), is responsible for ensuring that workplaces across the NWT are adhering to safety regulations, including industrial operations. In case of industrial accidents or workplace emergencies, they may be involved in investigation, reporting, and mitigation.

- Response: OHS provides support and enforces safety standards to prevent workplace accidents. During incidents, they may work with industry and government agencies to identify hazards, assess risks, and take corrective action.

6. Industry-Specific Emergency Response Teams
   - Role: Many industries in the NWT, especially in sectors like mining, oil & gas, and construction, have their own internal emergency response teams (ERTs) trained to handle incidents specific to their operations (e.g., gas leaks, chemical spills, industrial fires). Operators of hydrogen systems should develop their ERT functions specific to the processes they operate and materials they handle.
   - Response: These teams are typically trained in dealing with high-risk environments and can provide immediate on-site response to control the situation until external agencies can assist.
   - Coordination: Industry ERTs coordinate with local responders and government agencies for larger-scale emergencies, such as environmental or community impacts.
7. Transport Canada (Marine and Aviation)
   - Role: For industrial accidents that involve transportation (such as hazardous material spills from barges, trucks, or aircraft), Transport Canada is the responsible federal agency overseeing safety regulations and response procedures. Transport Canada must be engaged in early stages of project development to assure alignment and approval of designs and safety systems.
   - Response: They assist with spill containment, environmental impact assessments, and coordination of response measures related to transportation incidents.
   - Specific hydrogen spill response actions include:
     a. Gas detection and alarm through hydrogen sensors
     b. Isolation and venting: shutdown of valves and safe venting through high-point vent stacks
     c. Inerting using inert gas systems, i.e., nitrogen
     d. Ignition control: immediate power-down of non-essential electrical systems
     e. Crew protection: PPE and Breathing Apparatus (SCBA), thermal imaging may be required as flames are not visible
     f. Water spray for cool down of nearby structures
   - Immediate shipboard actions include:
     a. Detection and alarm activation: automatic gas detection systems trigger alarms
     b. Evacuation and isolation: immediate evacuation of affected compartments, remote closure of valves, activation of water spray curtains to knock down vapours
     c. Ventilation control: shut down mechanical ventilation to limit vapor spread
     d. PPE and Breathing Apparatus (SCBA) and chemical protective gear
     e. Containment: use fixed or portable water spray systes, gas-tight doors, or cofferdams to contain leak
     f. Notification of authorities
8. Emergency Medical Services (EMS)
   - Role: EMS teams in the NWT are responsible for providing emergency medical care during industrial accidents, such as those that result in injuries or exposure to hazardous materials.
   - Response: EMS is crucial in ensuring rapid medical care, especially in remote locations where access to medical facilities may be limited. They often work closely with industrial emergency teams to stabilize injured workers before transporting them to hospitals.

7. Import and Export of Energy

7.1 Energy Import

The Alberta Industrial Heartland (AIH) is located approximately 1,400 km south of Yellowknife and home to Canada's largest energy and chemical processing corridor. This region is one of the most competitive in North America and benefits from well developed infrastructure supporting of industrial development. Electric utility and water infrastructure are well developed, and construction and operating resources are available. The region is well-suited to develop chemical industries at costs that are competitive on a global scale. Logistics solutions are well developed such as for pipelines and rail.

7.1.1 Hydrogen

Hydrogen production is well developed in Alberta, and low carbon hydrogen production facilities are currently developed. These are world-scale facilities with capacities in the range of 380 – 400 tonnes of hydrogen per day. The technology is based on autothermal reforming, combined with carbon capture and sequestration, where the captured

CO2 is dried, compressed and delivered to Alberta's carbon trunk line for permanent sequestration. This existing infrastructure for carbon management is world-leading in cost and capacity and in place today. These developments provide opportunity for the NWT to participate in and source hydrogen at competitive rates. Hydrogen can be transported as liquid by truck or train, or gaseous by pipeline into the NWT.

7.1.2 Ammonia

Ammonia is currently produced in Alberta for the production of fertilizer and is based on the Haber-Bosch process. While the conventional process is based on hydrogen produced from reforming, low carbon hydrogen can be produced from autothermal reforming combined with CCS. This allows the production of low-carbon ammonia which can be transported by pipeline or by rail. The advantage of ammonia over hydrogen is that it is easier to store over longer periods of time, as gaseous hydrogen requires much higher pressure to store, and liquid hydrogen will evaporate over time. Ammonia is also more economical to transport than hydrogen.

7.1.3 Biodiesel

Alberta has a strong presence in biodiesel production due to its agricultural industry and oilseed production (such as canola). The province has several biodiesel plants that produce biodiesel from feedstocks like canola oil.

Saskatchewan is an important producer of biodiesel, especially since it is one of the largest canola-producing regions in the country. The province has biodiesel production facilities that utilize canola oil as a primary feedstock.

Manitoba is involved in biodiesel production, with some production facilities in the region that convert agricultural products, including canola, into biodiesel.

7.1.4 Biomass

While biomass can play a role in reducing GHG emissions, its CI is not zero. The exact carbon footprint of biomass energy depends on multiple factors.

In Western Canada, sources of lignocellulosic biomass can be found in several forms:

- Forestry Residues: Residues left over from logging operations such as branches, treetops, and stumps.
- Agricultural Residues: Crop residues from agricultural activities, such as straw from wheat, barley, and other cereal crops, as well as residues from oilseed crops such as canola.
- Wood Processing Industry Waste: Waste generated from sawmills, plywood mills, and other wood processing industries.
- Municipal Solid Waste: While not exclusively lignocellulosic, municipal waste in Western Canada can include a significant portion of organic matter, which can be processed into biomass for various applications.
- Dedicated Energy Crops: Though less common in Western Canada than other provinces, there are efforts to cultivate specific crops for biomass purposes, such as willow or poplar.

These sources of lignocellulosic biomass are crucial for various applications in Canada, including bioenergy production, biofuels, and biochemicals.

Forestry residues and wood processing industry waste in Western Canada are primarily located in regions with significant forestry and wood processing activities:

Alberta:

- Foothills and Rocky Mountain Region: Area's west of Calgary and Edmonton, including regions around Jasper and Banff National Parks, have forestry operations contributing to biomass residues.
- Northern Alberta: Areas around Grande Prairie and Peace River regions where forestry operations are prevalent also have biomass residues.

La Crete, a community in northern Alberta, is one of the main suppliers of biomass to the Northwest Territories (NWT) for several key reasons:

1. Proximity and Accessibility: La Crete is in the northern part of Alberta, relatively close to the NWT border. Its geographic location makes it an ideal supplier of biomass to the NWT. Transportation logistics are more feasible from La Crete compared to farther regions in Alberta or other provinces.

2. Abundant Forest Resources: La Crete is situated in an area with significant forest resources, especially from the boreal forest. This provides access to abundant wood waste, sawdust, and other biomass materials that can be used for energy production.

3. Local Expertise and Infrastructure: La Crete has developed expertise in the production and transportation of biomass. The community has infrastructure in place to handle biomass production, including sawmills and wood-processing operations. This makes it easier to produce and transport biomass to the NWT.

4. Economic and Environmental Benefits: Using local biomass for energy generation in the NWT reduces the need for expensive and carbon-intensive imports, such as diesel.

Yukon, NWT, and Nunavut:

- The territories have limited forestry operations but may have wood processing industry waste in areas where wood is harvested for construction and heating. Therefore, biomass for the NWT is sourced from neighboring areas.

British Columbia (BC):

- Coastal Region: Areas around Vancouver Island, the Lower Mainland, and the coastal mountain ranges produce substantial forestry residues and wood processing waste due to extensive logging and milling activities.
- Interior Region: Regions such as the Cariboo, Okanagan, and Kootenays also have significant forestry operations and contribute to forestry residues and wood waste.

Saskatchewan:

- Northern Saskatchewan: Forested areas in the northern part of the province, though less extensive compared to other provinces, contribute forestry residues from logging operations.

Manitoba:

- Eastern Manitoba: Regions with forestry operations in the eastern part of the province contribute to biomass residues.

The Federal Government developed a tool to determine biomass resources by region, which can serve as a first level of guidance for biomass locations: the Biomass Inventory Mapping and Analysis Tool (BIMAT) [56]. From this tool, biomass sources can be identified within a radius of up to 250 km from a selected location. It is recommended that a thorough review is conducted to validating the availability, quantity, and sustainability of biomass resources required.

7.2 Energy Export

The prospect of producing clean energy in the Northwest Territories supports the idea of producing this energy at scale and export this energy via a port at Tuktoyaktuk. The following addresses export scenarios and the potential for port development.

7.2.1 Export Scenarios

The potential for low carbon energy production in Canada is a driver for export of this energy. This requires large scale energy development to reach economies of scale required for economical energy production. This can be achieved through production of clean hydrogen and derivatives in the NWT either within or outside the Beafort-Delta region.

Production of clean hydrogen and derivatives in the NWT within the Beaufort-Delta region has the benefit of having production and point of shipping in relative proximity, reducing the risks associated with pipeline development and operation. Given the large scale of such development required to reduce unit cost of sales, large scale production of renewable electricity is required or, alternatively, blue hydrogen and derivative production as an alternative using the natural gas reserves are available in the MacKenzie Delta [Table 14].

Natural gas from the MacKenzie Delta can be used to produce hydrogen and derivatives such as ammonia, and the carbon associated with these energies would be sequestered in deep geological formations beneath the permafrost. While the potential for sequestration is recognized, more research is required to understand the opportunity and assess the geological, environmental, and logistical situation. Alternatively, pyrolysis can be deployed in the future when adequate TRL is achieved and avoid the need for geological sequestration.

As an alternative to conventional natural gas production in the MacKenzie Delta region, natural gas hydrates are identified as potential for natural gas extraction. Recently, research was conducted [55] into the Mallik site natural gas hydrates with extensive distribution in the permafrost regions and marine sediments. Short term production tests focused on reservoir depressurization have been conducted; however, the long-term production performance characteristics of the reservoir properties are not yet known. Hydrate-reservoir modeling was developed, validated by reproducing a field depressurization test. Based on the available geological data at the Mallik site, simulations were used to predict the long-term gas production performance through depressurization from the hydrate-reservoir model. The results indicate that the long-term gas production through depressurization from hydrate reservoirs is technically feasible, but the gas production efficiency is not yet commercially viable. More geological surveys and risk assessments are necessary. Impact on local ecosystems, communities, and the permafrost must be considered.

7.2.2 Port Development

There are several drivers for port development in Tuktoyaktuk:

Strategic Arctic Access: Tuktoyaktuk is the only Canadian Arctic Ocean community connected to the national highway system via the Inuvik–Tuktoyaktuk Highway, completed in 2017. This connection enhances its potential as a logistics hub for Arctic shipping, resource extraction, and tourism.

Economic Development: A deep-sea port could stimulate regional economic growth by supporting industries such as mining, oil and gas exploration, and tourism. It would also improve resupply logistics for northern communities, reducing reliance on seasonal sealift operations.

Sovereignty and Security: Establishing a port in Tuktoyaktuk would reinforce Canada's Arctic sovereignty, providing a strategic location for asserting presence in the increasingly accessible Arctic region.

Challenges and considerations: As the Arctic environment is fragile, and port development could disrupt local ecosystems. Permafrost degradation and rising sea levels pose additional risks to infrastructure stability. Tuktoyaktuk's current harbour is shallow and unsuitable for large vessels. Significant investment is required to accommodate deep-draft ships, including extensive dredging and construction of port facilities.

Estimating the cost of constructing port infrastructure in Tuktoyaktuk to accommodate two ocean-going tankers involves several components, including dredging, berth construction, and support facilities:

- Dredging: A 2014 report estimated that dredging a 22-kilometre channel from Tuktoyaktuk's harbour into deeper waters of the Beaufort Sea would require significant and ongoing dredging.
- Berth construction: The construction of berths capable of accommodating large tankers can vary significantly in cost.
- Support facilities: Additional infrastructure such as storage tanks, pipelines, and loading/unloading equipment would add to the overall cost. These components are essential for the operation of a functional port facility.

Estimates for port infrastructure to develop a jetty for, say 2 ocean going tankers, are hard to obtain, as little information is in the public domain. High level indicative estimates are:

- Dredging: Approximately $100 million

- Berth Construction: Between $200 million and $300 million
- Support Facilities: Between $100 million and $200 million
- A 50% margin yields an indicative total cost of $900 million, with ongoing cost for dredging

To determine the impact of such investment on the cost of ammonia, for example, indicative economic analysis yields that a 1,000 mT/d ammonia facility would incur a unit cost impact of $425 per tonne, an increase of 40% over the proforma production cost, as reported in this report. A world scale ammonia facility with a capacity of 4,000 mT/d would significantly allow spread of port infrastructure cost, reducing this cost to approximately $100 per tonne, or about 10% of the green ammonia unit cost.

Based on the potential for low carbon blue hydrogen and derivative production in the Beaufort-Delta region, which is dependent on proven ability to sequester CO2, or deploy proven methane pyrolysis, further review and analysis is needed to determine the viability and economics of clean energy export based on the vast local and stranded natural gas resources.

8. Economic Model Scenarios

A financial model is developed and used to analyse various technologies with the objective to calculate the cost of low carbon energy produced. The technologies analyzed are categorized as follows:

1. Hydrogen from electrolysis
2. Hydrogen from natural gas
3. Solar and wind electricity generation
4. Small Modular Reactor (SMR) electricity generation
5. Electric bus (BEB or FCEB)
6. Hydrocarbon fuels from biomass
7. Ammonia and ammonia conversion to hydrogen
8. Supply chain scenarios
9. Low carbon energy import scenarios

Further analysis was done to understand the cost of distributed ammonia in power generation, the cost of hydrogen in a bus transit pilot configuration and producing electricity from hydrogen in a fuel cell.

The resulting cost of low carbon energies are expressed in $/GJ and include the price of diesel at $2.00/liter.

In addition, an evaluation was made comparing the cost of low carbon ammonia, either produced from renewables in the Northwest Territories, or imported as blue ammonia from Alberta.

8.1 Analysis Results

The following hydrogen production systems were modeled using the following shared parameters: the projects are assumed to be eligible for direct incentives through capital contributions through various government programs totalling 25%. Further, 40% of remaining capital was assumed as debt, with the balance of the investment raised as equity. The target leveraged return in the model is 15% for all scenarios. Avoided carbon emissions and associated credit are incorporated in the analysis. The analysis includes capital costs associated with engineering and design for construction and operation in cold climates. Investment and variable/operating costs were determined from literature and are indicative.

Hydrogen production methodologies were analyzed, and the following was observed:

PEM and alkaline electrolysis hydrogen production based on current electricity pricing in the Northwest Territories cost approximately $20 - $21 per kg hydrogen. Economies of scale from large systems reduce this to $15 - $16 per kg. A large component of hydrogen cost from electrolysis in the NWT is from electricity at a cost of $240/MWh.

The cost of electrolysis and wind generated electricity were estimated and incorporated into the model. Also, expected reduction in cost for solar power equipment and electrolysis systems were estimated and incorporated into the economics.

Natural gas conversion processes were analyzed, being Auto-thermal Reforming (ATR), Steam Methane Reforming (SMR), and methane Pyrolysis. All yield substantially lower levelized cost of hydrogen, ranging from $2.50 per kg H2 to $4.00 per kg H2, the latter representing relatively low TRL methane pyrolysis, versus the lowest costs for proven technologies of ATR and SMR.

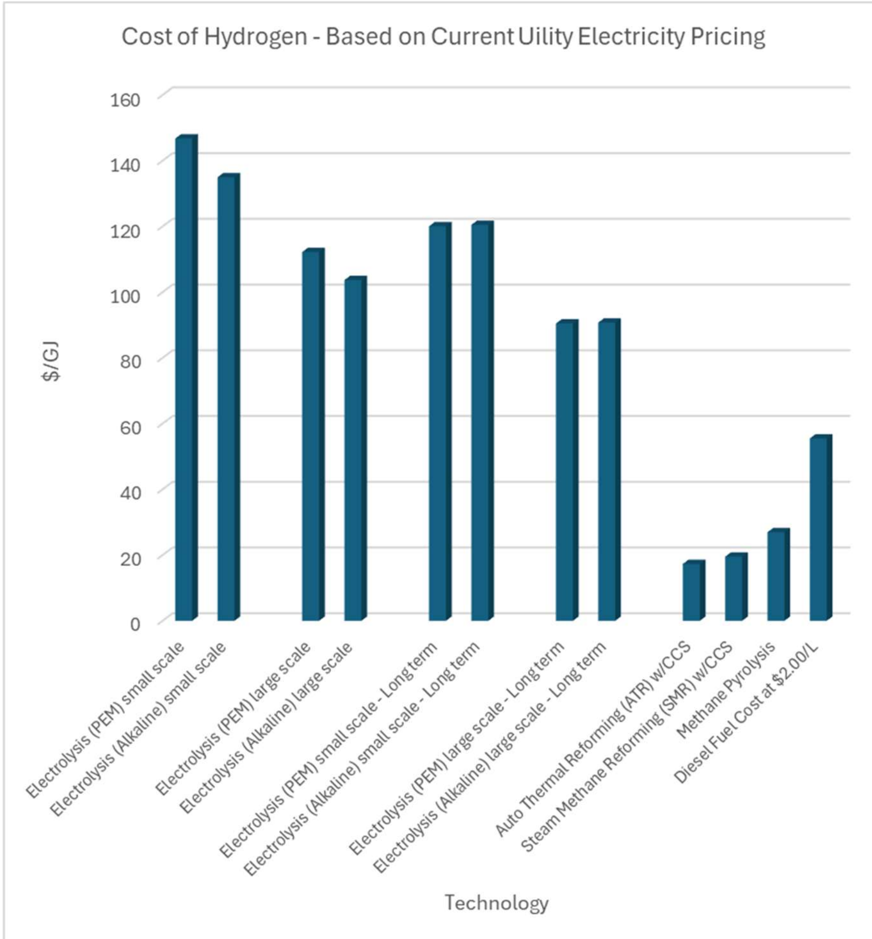


Figure 19: Cost of hydrogen based on current utility electricity pricing.

Also analyzed were the cost of developing renewable energy from wind and solar in the short and long term. The low cost of electricity from these power generation systems has the potential to reduce the levelized price of electrolysis hydrogen in the NWT by $9 to $10 per kg H2 to $10 - $12 per kg H2 for small scale PEM or alkaline electrolysis and down to $6 - $7 per kg H2 for large scale PEM or alkaline.

Estimates by IRENA for PEM and Alkaline electrolysis were used to analyze the impact of cost reduction of these technologies, further reducing the cost for PEM and alkaline produced hydrogen, with small scale hydrogen production to be $10 - $12 per kg H2, and $6 - $7 per kg H2 for large PEM and alkaline electrolysis. It is noted that IRENA expects the cost of hydrogen from PEM and alkaline to converge in the long-term. A reduction in the cost of PV would yield future cost of hydrogen to $6 - $7 per kg H2 for small electrolysis production, to about $2 - $3 per kg for large systems. This means that future electrolysis systems have the potential to compete with hydrocarbon-based hydrogen production from SMR or ATR, especially in distributed, small-scale applications.

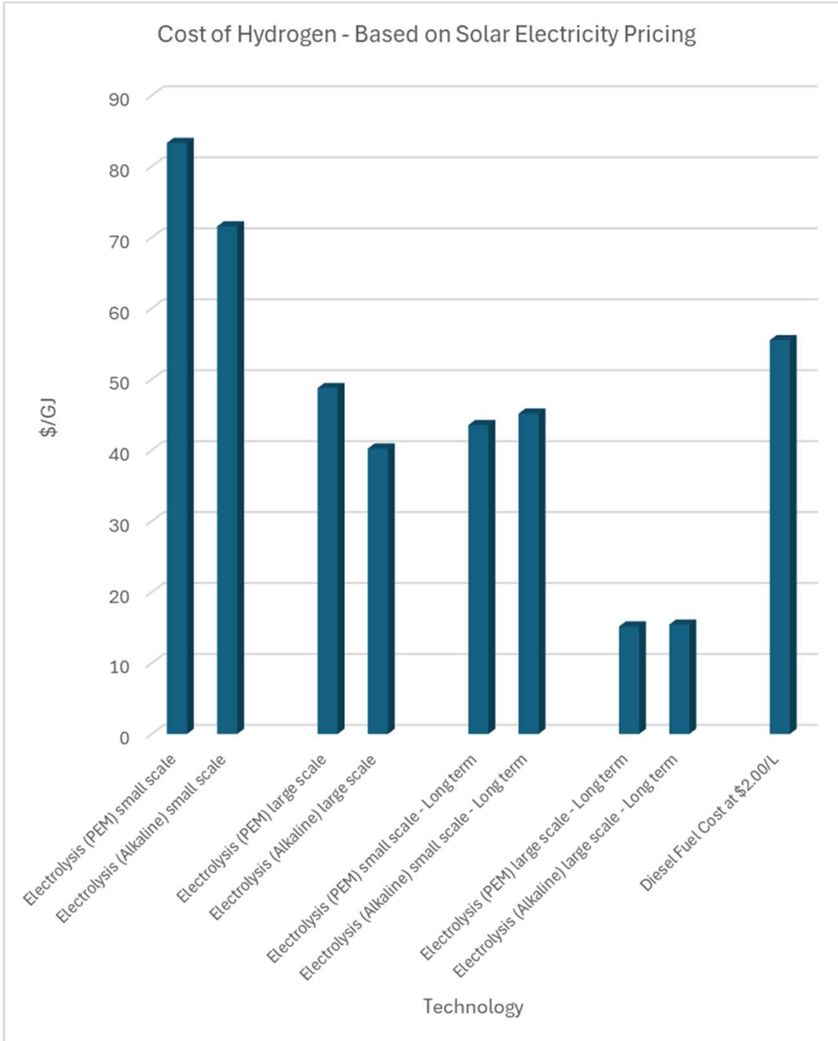


Figure 20: Cost of Hydrogen based on solar electricity pricing.

conventional conversion technologies (i.e., SMR or ATR) in terms of cost, while being more flexible in terms of scale range that can be developed.

Some analysis of Small Modular Reactors (SMR) was performed. Limited data exists in terms of cost, however there are indications that SMR capital cost will be in the $5,000 - $7,000/kW of capacity. Fuel and operating costs were taken from published materials, which typically apply to conventional reactors. It is to be expected that the cost of electricity from these systems are in the range of $100 - $200/MWh.

Ammonia produced from hydrogen electrolysis derived with low-cost renewable electricity was analyzed and the cost is expected to be about $900 per tonne when produced from solar or wind power in the short to medium term. The hydrogen produced from this ammonia is expected to cost $9 per kg. The cost can be expected to be about $10/kg H2 higher when produced from electricity at current price of $240/MWh.

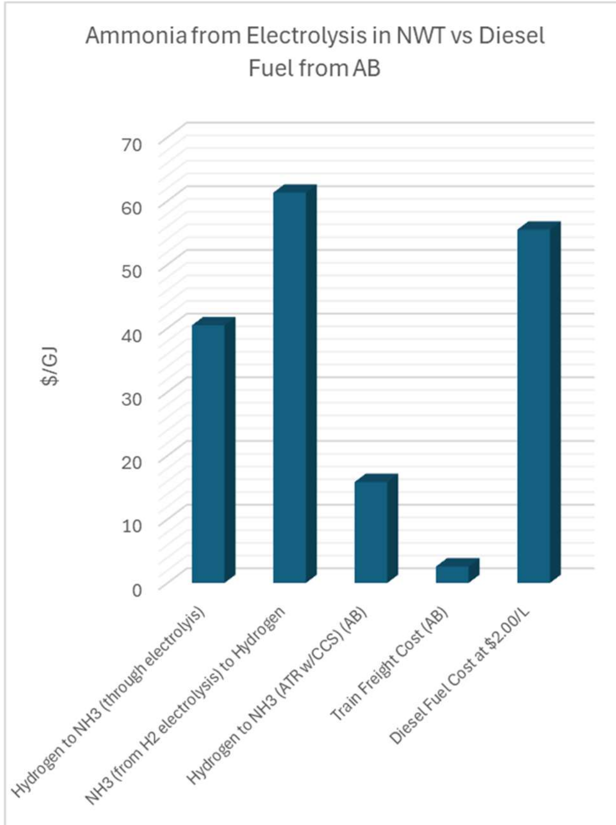


Figure 21: Ammonia from Electrolysis in NWT vs Diesel Fuel imported from AB.

Small scale production, storage, distribution and fueling for 4 buses were evaluated. The cost of hydrogen will increase to $44 - $46 per kg H2 range, at current electricity prices. Renewable power cost will reduce this by about $12 - $15 per kg H2. Future reduction in cost of the technology will bring this down by another $3 per kg H2. Additionally, this mode of energy supply is compared with battery electric bus solutions, and the analysis shows that hydrogen fuel cell electric buses will cost about 26% more than battery electric buses, including fuel.

Importing energy from Alberta shows a reduction in energy cost relative to producing the same fuels in the NWT. This is largely driven by the lower cost to develop the facilities in the Alberta Industrial Heartland given that this is an already established area for industrial development, supported by existing infrastructure and workforce. Utilizing natural gas feedstock versus electricity as energy input, combined with carbon capture and sequestration, further benefits the cost of hydrogen and ammonia produced in Alberta.

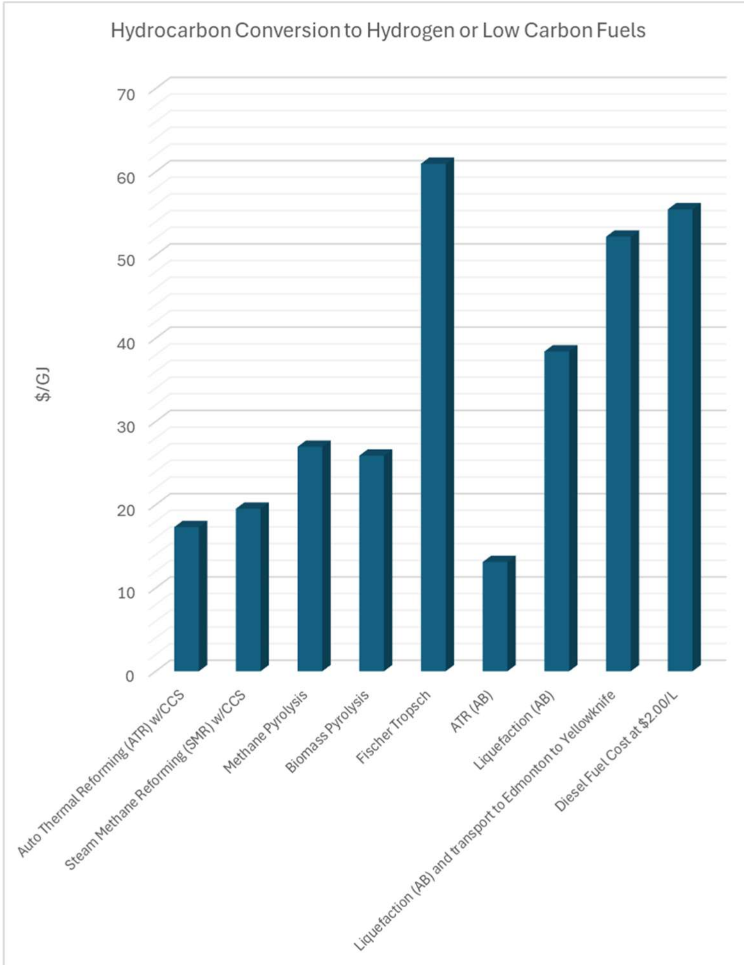


Figure 22: Hydrocarbon conversion to hydrogen or low carbon fuels.

8.1.1 Indicative Cost of Ammonia Distributed within the NWT

Further analysis of cost was performed for the transportation and storage of ammonia for electricity production or replacement of diesel for local transportation, either direct through combustion of ammonia, or through reconversion to hydrogen. The analysis compares the cost of ammonia with conventional diesel as a fuel. In this comparison, ammonia generated from renewable power in South Slave and blue hydrogen produced in Alberta and transported to Hay River. For diesel, a cost of $55.50/GJ was set ($2.00 per liter, figure 21). This compares with $41/GJ for ammonia produced from renewable power and hydrogen through electrolysis, and approximately $18.45/GJ for ammonia produced in Alberta through the Auto-thermal/CCS route.

To distribute ammonia, investment is required in the following equipment and assets:

Compressed storage systems for ammonia on board barges transporting ammonia from a base production or receiving point to a receiving location, i.e., Inuvik. As the energy density of ammonia is lower than for diesel, additional barge capacity would be needed to transport an equivalent amount of energy to the point of use. Hence, additional barge capacity would be needed, as well as push boats to move these additional barges, as well as additional fuel increasing the cost per GJ of delivered ammonia. Once arrived, barged ammonia must be stored to hold sufficient energy to bridge the cold period during which no energy deliveries can be made. This type of large ammonia storage is cryogenic. From there, ammonia must be distributed to points of use. Similar to barging, this will require additional truck capacity due to relatively low energy density of ammonia vs. diesel. Lastly, barging and trucking may be based on diesel fuel vs ammonia as fuel, the latter requiring modified engines.

Analysis shows that the cost of barging (on-board compressed storage and additional barges and push boats) accounts for approximately 50% of the overall distribution costs, followed by cryogenic storage (16%), and truck distribution costs (2%). The final result is an indicative price of distributed ammonia of $67/GJ based on ammonia produced in the NWT, a 20% increase in cost, and $45/GJ for ammonia imported from Alberta, a 19% reduction relative to conventional diesel. Total investment will depend predominantly on the size of local cryogenic storage and the final number of suitable barges and push boats. Indicative cost of such systems may exceed $175 M. It is estimated that about 100 local distribution trucks are required transporting ammonia between central storage and point of local energy usage.

Section 7 describes the challenges in distribution by barge, due to low water levels of the Mackenzie River. Alternatively, distribution of fuels can be done by trucks, during several months in winter. Such transportation does not benefit from economies of scale compared with barging, and consequently, this mode of transportation for hydrogen or ammonia will be more expensive.

8.1.2 Cost of Hydrogen Fueling for Transit Bus Pilot

Analysis of a hydrogen system for Fuel Cell Electric Buses (FCEB) was performed to understand the economics of a pilot plant for 4 FCEBs. In this scenario, each FCEB consumes up to 50 kg of hydrogen on a daily basis, for a total of 200 kg per day. The supply chain consists of PEM electrolysis, consuming electricity generated from solar photovoltaic panels. The produced hydrogen is then compressed, stored (including 3 days of fuel storage) and distributed to the fuel station. Total capital cost of this supply chain is estimated at $8.5M, excluding the cost of the four buses, which are estimated to cost $5.3M in total. The busses would drive a total distance of 580 km/d. The investment and variable cost for the FCEBs were derived from [57]

The infrastructure investment delivers fuel to the FCEBs at an indicative cost of $37/kg, or $253/GJ. This includes the cost of developing, installing, and operating the solar power generation, electrolysis, storage, dispensing and related equipment. The cost of hydrogen from electrolysis through PEM is $12/kg, or 32% of the total cost. Economies of scale will reduce both fixed and variable costs.

Including the cost of the vehicles, the cost is estimated at $5.44/km, which is 26% over a Battery Electric Bus operating at the current electric price of $240/MWh, which results in $4.32/km. Key criteria for selection of FCEB over BEB are power requirements for a bus to complete required routes, cold climate performance, refueling times, which may lead to selection of hydrogen over battery electric, despite additional cost.

8.1.3 Cost of Electricity from a Stationary Fuel Cell for Power Generation

Consistent pricing information for stationary fuel cell systems for power generation is hard to come by as cost are expected to reduce significantly going forward. Based 2020 study by the DOE for stationary power generation [58], an installed fuel cell with a capacity of 1 MW should cost $4,000/kW, which represents a cost of approximately $91/MWh, excluding the price of delivered or locally produced hydrogen, the latter being a function of how and where the hydrogen is produced. Assuming an efficiency of 60% and a hydrogen cost of $21.28/kg (small scale electrolysis at current power price in the NWT), the cost of generated electricity will reach $1,000/MWh. If a future low-cost hydrogen produced from renewables and reduced cost electrolysis at scale is used, the cost of electricity reduces to about $110/MWh. These costs are indicative and do not include distribution of hydrogen or electricity.

8.1.4 Summary Table Financial Analysis

The following table provides an overview of short term and long-term scenarios, including indicative capital costs, revenue, and resulting fuel costs:

Table 8: Economic analysis of short- and long-term scenarios.

	PRODUCT	CAPACITY	INVESTMENT	ANNUAL REVENUE YEAR 5	FUEL PRICE	CO2 REDUCTION	COST_E	COST_NG
		(mT/d)	($000)	($000)	($/kg)	(mT/yr)	($/MWh)	($/GJ)
HYDROGEN - based on current electric utility pricing								
Electrolysis (PEM) small scale	Hydrogen	0.20	$ 2,269	$ 1,522	$ 21.28	526	$ 240.00	$ -
Electrolysis (Alkaline) small scale	Hydrogen	0.20	$ 1,513	$ 1,404	$ 19.57	526	$ 240.00	$ -
Electrolysis (PEM) large scale	Hydrogen	100.00	$ 825,000	$ 588,175	$ 16.27	262,812	$ 240.00	$ -
Electrolysis (Alkaline) large scale	Hydrogen	100.00	$ 550,000	$ 545,393	$ 15.04	262,812	$ 240.00	$ -
	PRODUCT	**CAPACITY (MW)**	**INVESTMENT ($000)**	**ANNUAL REVENUE YEAR 5 ($000)**	**POWER PRICE ($/MWh)**	**CO2 REDUCTION (mT/yr)**	**COST_E ($/MWh)**	**COST_NG ($/GJ)**
LOW CARBON ELECTRICITY								
Solar Electricity	Electricity	100.00	$ 515,833	$ 65,550	$ 72.65	-	$ -	$ -
Wind Electricity	Electricity	100.00	$ 449,167	$ 63,491	$ 72.59	-	$ -	$ -
Solar Electricity - Long term	Electricity	100.00	$ 289,417	$ 37,354	$ 41.40	-	$ -	$ -
Wind Electricity - Long term	Electricity	100.00	$ 401,917	$ 58,182	$ 66.52	-	$ -	$ -
Nuclear	Electricity	100.00	$ 1,000,000	$ 161,565	$ 184.72	-	$ -	$ -
	PRODUCT	**CAPACITY (MW) (mT/d)**	**INVESTMENT ($000)**	**ANNUAL REVENUE YEAR 5 ($000)**	**PRICE ($/MWh)**	**CO2 REDUCTION (mT/yr)**	**COST_E ($/MWh)**	**COST_NG ($/GJ)**
ELECTRIC BUS								
Battery Electric Bus (BEB) & Charging Infrastructure	Electricity	0.47	$ 7,715	$ 3,309	$ 844.37	2,146	$ 240.00	$ -
Battery Electric Bus (BEB) - w/o Charging Infrastructure	Electricity	0.47	$ 5,915	$ 2,967	$ 755.92	2,146	$ 240.00	$ -
Charging Infrastructure only	Electricity	0.47	$ 1,800	$ 342	$ 88.45	-	$ 240.00	$ -
Fuelcel Electric Bus (FCEB)	0	0.17	$ 5,333	$ 4,636	$ 70.80	-	$ -	$ -
FCEBB vs EB per km cost								
	PRODUCT	**CAPACITY (mT/d)**	**INVESTMENT ($000)**	**ANNUAL REVENUE YEAR 5 ($000)**	**FUEL PRICE ($/kg)**	**CO2 REDUCTION (mT/yr)**	**COST_E ($/MWh)**	**COST_NG ($/GJ)**
HYDROGEN - based on solar electricity								
Electrolysis (PEM) small scale - Long term	Hydrogen	0.21	$ 588	$ 513	$ 6.31	552	$ 41.40	$ -
Electrolysis (Alkaline) small scale - Long term	Hydrogen	0.20	$ 560	$ 505	$ 6.55	526	$ 41.40	$ -
Electrolysis (PEM) large scale - Long term	Hydrogen	100.00	$ 127,315	$ 102,164	$ 2.20	262,812	$ 41.40	$ -
Electrolysis (Alkaline) large scale - Long term	Hydrogen	100.00	$ 127,315	$ 103,471	$ 2.24	262,812	$ 41.40	$ -
	PRODUCT	**CAPACITY (mT/d)**	**INVESTMENT ($000)**	**ANNUAL REVENUE YEAR 5 ($000)**	**FUEL PRICE ($/mT) ($/kg)**	**CO2 REDUCTION (mT/yr)**	**COST_E ($/MWh)**	**COST_NG ($/GJ)**
OTHER								
Hydrogen to NH3 (through electrolyis)	Ammonia	1000.00	$ 557,527	$ 373,191	$ 910.54	483,399	$ 72.65	$ -
NH3 (from H2 electrolysis) to Hydrogen	Hydrogen	135.28	$ 357,052	$ 433,956	$ 8.89	49,700	$ 72.65	$ -
	PRODUCT	**CAPACITY (mT/d)**	**INVESTMENT ($000)**	**ANNUAL REVENUE YEAR 5 ($000)**	**FUEL PRICE ($/kg) ($/mT)**	**CO2 REDUCTION (mT/yr)**	**COST_E ($/MWh)**	**COST_NG ($/GJ)**
ENERGY IMPORT SCENARIOS								
ATR (AB)	Hydrogen	300.00	$ 1,434,441	$ 291,256	$ 1.90	832,238	$ 125.00	$ 1.50
Liquefaction (AB)	Hydrogen	5.00	$ 43,284	$ 9,615	$ 5.57	-	$ 125.00	$ -
Hydrogen to NH3 (ATR w/CCS) (AB)	Ammonia	1000.00	$ 124,356	$ 148,646	$ 295.04	467,806	$ 125.00	$ 1.50
Train Freight Cost (AB)	Ammonia				$ 58.33			

Notes:

The cost of electricity per table 7 relate to the following:

Current electricity rate in the NWT: $240/MWh

Indicative electricity rate in AB: $125/MWh

Estimated price of solar and wind – short term: $72.50

Estimated price of solar and wind – long term: $41.40 and $61.60, respectively

Table 9: O&M Cost

O&M Cost for Selected Technologies Used in Economics	Percentage of Capital Cost	Reference
PEM Electrolysis	3.8%	Cost of electrolysis TNO-2024-R10766
Alkaline Electrolysis	3.8%	Cost of electrolysis TNO-2024-R10767
Solar Electricity	1.0%	NREL Best Practices for Operation and Maintenance of Photovoltaic and Energy Storage Systems; 3rd Edition
Wind Turbine	2.3%	NREL 2022 Cost of Wind Energy Review
Ammonia Production	4.0%	Iowa State University, Feasibility Study of Implementing Ammonia Economy
Ammonia Cracking	4.0%	Same percentage as for ammonia production
Auto-thermal Reforming	2.0%	Per industrial gases industry
Hydrogen Liquefaction	4.0%	Per industrial gases industry
Hydrogen Fueling Station	5.0%	Univ of Berkely, Introduction to the Hydrogen Maret in California
Fuel cell electric bus	18.0%	NREL Fuel Cell Bus Evaluations
Battery electric bus	16.5% & 8% (3)	Electrifying Transit: A Guidebook for Implementing Battery Electric Buses USAID & NREL

(1) Stack replacement 60k hr $400/kW (IRENA)
(2) Stack replacement 80k hr $400/kW (IRENA)
(3) Charging infrastructure maintenance

The cost of transporting hydrogen and ammonia was taken from Di Lullo *et al.*and the Transition Accelerator:

Table 10: Comparison of Hydrogen Transportation Systems **[57]**.

Comparison of Hydrogen Transportation Systems Distance: 1000 km; 600 mT/d	Low	High	
Hydrogen pipeline	$ 0.39	$ 1.16	$/kg H2
Ammonia pipeline	$ 2.52	$ 3.29	$/kg H2
Truck transport (gH2)	$ 6.46	$ 9.46	$/kg H2
Truck liquid (LH2)	$ 6.00	$ 8.08	$/kg H2
Truck ammonia *	$58.33		$/mT NH3
Truck ammonia *	$0.44		$/kg H2

Di Lullo et al., Department of Mechanical Engineering, University of Alberta
* Transition Accelerator, Blue vs. Green comparative analysis, 1300 km

NWT Marine Transportation Services (Barge) - 2024 Cargo Rates Greater of $/mT gross weight or per 2.5 cubic meters			
Selected Routes	$/mT	$/mT NH3	$/kg H2*
Hay River - Norman Wells	$ 339.00	$ 339.00	$ 2.53
Hay River - Inuvik	$ 485.00	$ 485.00	$ 3.63

* Post NH3 to H2 conversion

9. Low Carbon Energies – Development Strategy

Development of hydrogen in the NWT has potential in all four main applications. The SWOT analysis is presented for hydrogen in remote power generation, mobility, heating, and industry. Further, a SWOT analysis is presented for the various pathways that hydrogen, derivatives, and clean electricity for electrolysis can be produced.

Table 11: SWOT Analysis

HYDROGEN END USE APPLICATIONS

HYDROGEN FOR POWER

<u>Strenghts</u>
Ability to store energy (from distribution or local renewable power generation)
Distributed application
Scaleability

<u>Weaknesses</u>
Storage (compressed or as liquid). Can be mitigated through use of NH3 as intermediate
Equipment cost in the short term

<u>Opportunities</u>
Cost reduction of electrolysis and fuel cell technologies

Co-firing with diesel power generators
Use of ammonia as hydrogen carrier
Energy security remote communities (when combined with local production)

<u>Threats/Risks</u>
Capital implementation & operation in northern climate

HYDROGEN FOR MOBILITY

<u>Strenghts</u>
Proven as a zero carbon fuel in transit and heavy duty transportation
Distribution of hydrogen along trucking and transit corridors
Scaleability
Cold temperature performance
Short refueling times and extended range

<u>Weaknesses</u>
Vehicle availability and cost in the short term

<u>Opportunities</u>
Cost reduction of fuel cell technologies and vehicle cost

Short-term potential including pilot project
Strong carbon reduction potential for NWT

<u>Threats/Risks</u>
Adoption of hydrogen trucks is new technology for operators. This must be managed

HYDROGEN FOR HEATING

<u>Strenghts</u>
Ability to store energy (from distribution or local renewable power generation)
Distributed application
Scaleability

<u>Weaknesses</u>
Storage (compressed or as liquid). Can be mitigated through use of NH3 as intermediate
Equipment availability and cost in the short term

<u>Opportunities</u>
Development of hydrogen suitable materials in heating applications
Cost reduction of fuel cell technologies
Combined heat and power
Use of ammonia as hydrogen carrier
Energy security remote communities (when combined with local production)

<u>Threats/Risks</u>
Capital implementation & operation in northern climate

HYDROGEN IN INDUSTRY

Strenghts	Weaknesses
Ability to store energy (from distribution or local renewable power generation)	Storage (compressed or as liquid). Can be mitigated through use of NH3 as intermediate
Distributed application	Equipment cost in the short term
Scaleability	

Opportunities	Threats/Risks
Improvements in cost reduction in electrolysis and fuel cell technologies	Capital implementation & operation in northern climate
Co-firing with existing diesel power generators	
Use of ammonia as hydrogen carrier	

HYDROGEN PRODUCTION PATHWAYS

HYDROGEN FROM ELECTROLYSIS

Strenghts	Weaknesses
Relative ease of implementation	Availability of equipment in short term
Distributed application	Equipment cost in the short term
Scaleability	Need for large quantities of low carbon electricity
Short-term potential including pilot project	Need for large quantities of water

Opportunities	Threats/Risks
Improvement in equipment performance	Cost of electricity
Improvements in cost reduction, particularly for PEM	Availability of low carbon electricity to reach economies of scale
Hydrogen/ammonia export potential	Capital implementation & operation in northern climate

HYDROGEN FROM NATURAL GAS

Strenghts	Weaknesses
Low cost per unit of energy input	Central application because of scale - need for fuel distribution
Proven technology with ATR and SMR combined with CCS	Large capacity for one facility - optionality in final energies (H2, derivatives), distribution (NH3), and applications (Transport, Heat & Power)
Large scale development	SMR/ATR requires CCS process equipment and location dependent on location of natural gas & sequestration geology
Utilization of natural gas	High upfront capital investment
	Requires large greenfield project implementation in northern climate
	Complex process operation
	Need for highly qualified operating staff

Opportunities	Threats/Risks
Future pyrolysis technology - eliminating need for CCS	Capital implementation & operation in northern climate
Hydrogen/ammonia export potential	

AMMONIA AND AMMONIA CONVERSION TO HYDROGEN

<u>Strenghts</u>	<u>Weaknesses</u>
Large scale development	Handling and transportation of anhydrous ammonia
Direct or indirect (H2) use of ammonia energy in applications	Requiring specialized storage and rail/truck infrastructure
Low cost if produced from natural gas	Use of expensive electricity in case of electrolysis hydrogen
Storage easier than Hydrogen	Expensive if produced from electricity at current price
	Complex process operation
	Need for highly qualified operating staff

<u>Opportunities</u>	<u>Threats/Risks</u>
Centralized ammonia production	End-use equipment - readiness and availability for ammonia application
Distribution & storage of a liquid with local conversion to H2	Capital implementation & operation in northern climate

SOLAR AND WIND ELECTRICITY GENERATION

<u>Strenghts</u>	<u>Weaknesses</u>
Wind and solar unit cost of electricity	Wind and solar energy storage/backup requirement
Scaling can be matched to application development	Wind and solar region specific - need for energy distribution
Short-term potential	Seasonal variation in output for Solar

<u>Opportunities</u>	<u>Threats/Risks</u>
Reduction in capital cost for Solar long term	Capital implementation & operation in northern climate
	Community acceptance of wind turbines
	Snow/Ice build-up on turbine blades and solar panels
	Service-ability in cold climate and remote area

SMR ELECTRICITY GENERATION

<u>Strenghts</u>	<u>Weaknesses</u>
Modular designs and pre-fabricated solutions	Not yet commercial as regulatory environment not ready - 10 years
On-purpose, controlled output	Cost information on SMR
Small Modular Reactor (SMR) can strenghten renewables as baseload and backup	
Available in range of capacities from various OEMs	

<u>Opportunities</u>	<u>Threats/Risks</u>
Modular, pre-engineered and packaged solution	SMR acceptance
	Timeline to SMR availability
	Regulatory delays
	Capital implementation & operation in northern climate

LOW CARBON ENERGY IMPORT SCENARIOS

<u>Strenghts</u>	<u>Weaknesses</u>
Lower cost of delivered energy relative to NWT produced	Reduces potential for NWT investment
Existing transportation infrastructure between AB and NWT	Requires early involvement in negiotiating off-take
Constructing large facilities in existing industrial hub	
Improved opportunity for matching supply and demand for low carbon energy	
Available construction and operating resources	

<u>Opportunities</u>	<u>Threats/Risks</u>
Sharing of larger facilities' output with 3rd parties to match demand	Longer distribution distance increases risk of incident
Build brownfield vs greenfield	

Meeting the 2030 carbon objectives requires a significant reduction in the consumption of conventional hydrocarbon-based fuels in transportation, industry, and heating applications. If these fuels can be replaced by hydrogen or a hydrogen derivative such as ammonia, with hydrogen produced from electricity, it will require in approximately 100 MW of low carbon electricity to produce these low carbon fuels. Direct electrification, without the need to convert to gaseous or liquid fuels would reduce this number, however, the distributed nature of energy consumption requires distribution and long-term storage of energy, which cannot be achieved with electricity.

Large-scale hydrogen and hydrogen derivatives can be produced at low cost per unit of clean energy produced from natural gas, using autothermal reforming and carbon capture technology, possibly coupled to ammonia production. The scale at which such facilities must be developed to be economical is much larger than the ability to absorb the low carbon fuel in the short term. However, this pathway is suitable for meeting the 2050 net-zero objectives. Other hydrogen production technologies such as methane pyrolysis are still under development.

Development of large-scale hydrogen or derivatives production that support export from Beaufort-Delta is challenging as it requires complex port development, large process facilities in an arctic environment, CCS in geological formations below permafrost, or commercially uncertain natural gas hydrate processing. This requires deeper investigation and analysis. Export to the south is limited as the cost of primary energies and the development of process facilities are lower in those regions. Alberta is well established with existing, large industrial corridors, well established construction industry, low cost of natural gas, existing carbon sequestration infrastructure, and well-developed logistics systems consisting of pipelines and railway corridors. Analysis indicates that the required clean energies can be produced and imported into the NWT at lower cost compared to local production.

Economic modelling and a SWOT analysis were conducted to compare solution options and pathways, that support the following recommendations.

Northwest Territories' decarbonization of energy through hydrogen and its derivative i.e., ammonia

1. Use hydrogen and hydrogen derivatives (e.g. ammonia) for power generation and heating (combined cycle), transportation and industry. This form of energy provides meaningful **reduction in emissions** and can be **transported and stored locally**
2. In the short – to mid term: **Develop hydrogen production from renewables or future excess hydro** to match the **rate of implementation of end-use technologies** in transportation, industry, heat & power
3. **Produce** or **acquire hydrogen, hydrogen derivatives** (i.e., ammonia), **at scale** and at competitive costs **achieving full deployment of hydrogen and ammonia end-use applications**

Recommendations to the NWT

Short-term – Incorporating 2030 objectives:

Hydrogen for Mobility:

1. A hydrogen fueled transit bus pilot program
2. A hydrogen fueled heavy duty truck pilot program
3. Align with hydrogen fuel and fueling infrastructure requirements for rail as part of a developing hydrogen rail corridor between NWT and Alberta

Justification – transportation is a major source of pollution and pilot project development sets the stage for fuel cell vehicles operation along established corridors, and a basis for scale-up of operations as equipment availability improves and supply chains for hydrogen and ammonia develop.

Hydrogen based energy is technically viable, but it is best introduced to the NWT in stages.

Hydrogen for heating and electricity generation:

4. Pilot for fuel cell applications for combined heat and power in the mining industry
5. Pilot for fuel cell applications based on hydrogen for combined heat and power applications in communities not connected to the electric distribution grid

Justification – experience gained from these pilots will provide important information about operating hydrogen in remote areas, and a basis for scale-up in operation as confidence is built around energy security and performance in demanding and remote areas.

Hydrogen & derivatives production:

1. Hydrogen production from electrolysis
2. Small-scale ammonia production facility
3. Associated storage & distribution facilities

Justification – this is a first step in building a supply chain and gaining experience in operating hydrogen and derivative production. It provides important experience and know-how of operating these facilities and build confidence that such systems can be developed.

Electricity production:

1. Hydrogen is a manufactured gas and requires an energy source to produce. Hydrogen deployment at small scale can be developed through renewable electricity by implementation of solar and wind power systems, coupled with energy storage. A benefit of this clean electricity is that it can be scaled in line with the demand for hydrogen. If the Taltson hydro expansion is developed, some of the energy may be allocated to small-scale hydrogen and ammonia production.

Justification – implementation of renewable power generation capacity directly benefits the NWT goal of supporting the hydrogen supply chain benefitting remote communities in decarbonization and energy security.

Long-term – Incorporating 2050 objectives

Scale-up of low carbon energy:

1. Develop electrolysis capacity and renewable power development based on rate of implementation of end-use technologies for hydrogen and ammonia for use in transportation, industry, heat & power
2. On-going build out of transportation and storage infrastructure
3. Development access to low carbon hydrogen and ammonia produced in Alberta, to be imported into the NWT and distributed to the regions from Hay River.
4. As the overall quantity of hydrogen and ammonia is below the output of a world-scale facility, alignment with 3rd parties such as OEMs, investors/developers and other off-takers is advised. This will provide opportunity for risk sharing as well as sharing in the overall investment requirement.

Justification – large scale development of hydrogen and derivative ammonia would require significant renewable production, covering large land areas. Analysis shows that Alberta, through its well-developed infrastructure for clean energy and process capabilities, can provide world-class performance to benefit the NWT. Furthermore, off-take arrangement can be negotiated that match the aggregate consumption of clean hydrogen and ammonia in the NWT.

Solution Ranking	PEOPLE			TECHNOLOGY					REGIONAL		COST		Net Score	Rank
	Emission Reduction Potential	Social Acceptance Potential	Climate Goal Potential	Technology Readiness	Ease of Implemention	Short Term Potential	Long Term Potential	Scaling Opportunity	Logistics	NWT Comparative Strength	Initial Investment	Fuel Cost		
HYDROGEN FROM ELECTROLYSIS	5	5	3	4	3	5	2	2	4	3	4	3	**43**	**5**
HYDROGEN FROM NATURAL GAS	4	3	4	4	3	2	3	3	2	3	2	5	**38**	**7**
SOLAR AND WIND ELECTRICITY GENERATION	5	5	4	5	3	5	5	5	4	3	4	5	**53**	**1**
SMR ELECTRICITY GENERATION	4	3	4	3	2	1	4	4	3	4	2	2	**36**	**9**
ELECTRIC BUS (BEB OR FCEB)	5	5	2	3	5	5	5	5	4	2	3	3	**47**	**2**
HYDROCARBON FUELS FROM BIOMASS	4	3	4	3	2	3	4	3	3	2	2	4	**37**	**8**
AMMONIA AND AMMONIA CONVERSION TO HYDROGEN	4	3	4	4	3	3	4	4	4	3	3	3	**42**	**6**
LOW CARBON ENERGY IMPORT SCENARIOS	4	4	5	4	3	3	5	3	3	3	3	5	**45**	**3**

Key aspects for suitability of energy in the NWT:

1. Unit cost: $/GJ
2. Manageable capital cost (i.e., smaller incremental project developments)
3. CO2 reduction potential
4. Cold climate development suitability (winterization & operability)
5. Primary energy & infrastructure requirements

Overall Suitabilty for NWT

5	Highly Suited
4	Well suited
3	Reasonable
2	Possible but not ideal
1	Difficult
0	Not feasible

Figure 23: Summary analysis of low CI energy solutions.

10. Pilot Programs

Recommended pilot initiatives:

1. Development of a hydrogen fuel cell bus pilot, consisting of small-scale electrolysis, compression, storage, fueling infrastructure of up to four FCEB buses. The daily distance travelled per bus of about 600 km per day and return to base after each route.
2. Heavy Duty Vehicle (HDV) i.e. class 8 trucks pilot based of FCEB tractors. With the transmission interconnect between North Slave and South Slave regions, the 500 km distance between Hay River and Yellowknife. This would require investment in fuel cell electric trucks, hydrogen production capacity through electrolysis, compression and storage, and hydrogen fueling systems. The fixed infrastructure would be developed in Yellowknife and Hay River, with technical and fuel support based on Fort Providence. An initial pilot project could consist of 2 HDVs with fuel capacity of up to 60 kg and a range of approximately 700 km at low ambient temperatures.
3. As hydrogen is expected to play a role in providing solutions for remote communities (i.e., not connected to the electric grid) heating and electricity production, a pilot project is recommended to develop a combined heat and power project based on fuel cell technology. This involves the production of hydrogen through electrolysis, storage and distribution, and production of heat and power at location.

These early projects provide the following benefits:

1. Learnings from new infrastructure development across the supply chain – production, compression, storage, distribution.
2. Multiple pilot initiatives benefit from scale and scope.
3. The recommended pilots are representative of future application at larger scale.
4. Experience operating and maintaining the infrastructure.
5. Cold climate experience from design, engineering, operation and maintenance.
6. Workforce development and training.
7. Development of partnerships including government, investors, OEMs, engineering companies, educational institutions, indigenous involvement and workforce participation. Early alignment of all stakeholders provides opportunities for private sector investment, financing and incentives, off-take commitments, and knowledge exchange.
8. Continued engagement of OEMs and engineering firms transferring know-how and best practices to local workforce and educational institutions.

A pilot for FCEB and associated hydrogen electrolysis, storage, and fuel dispensing would involve the following indicative cost:

Table 12: Hydrogen production, storage, dispensing, and fueling station for FCEB pilot.

Pilot for FCEB			
Indicative Installed Cost (000), NWT basis			
Capacity: 200 kg/d			
Electrolysis	$	3,800	Includes compression for 350 & 700 bar dispensing
Storage system	$	2,000	3 Days of hydrogen storage (600 kg)
Fueling station	$	2,750	Includes chiller, HMI, safety systems
FCEB (4)	$	5,333	
Total *	$	13,883	
* Total cost will vary based on existing infrastructure into which the system will be integrated, as well as to the degree of automation and fueling rates			
Indicative Operating Costs			
Electricity		0.48	MW, at $240/MWh
Water		1,800	l/d
Maintenance - Periodic		$190	k, year 8 Stack replacement
Other maintenance	$	1,200	3.8% on Electrolysis, 1% on Fueling Station, 18% on FCEB
Operating resources		4	
Financial Data			
Hydrogen cost at dispenser		$37.11	per kg
Total revenue	$	2,600	per year from hydrogen production and fueling

Note: Final budget will be determined through development of a detailed scope and basis of design which depends on operating requirements and the supporting infrastructure of the project location.

Original Equipment Manufacturers (OEMs):
Electrolysis: H-Tec Systems; IMI; Next Hydrogen; NEL Hydrogen; iGas Energy
Fueling Station: Chart Industries; PowerTech Canada; NEL Hydrogen; Cummins; Air Liquide; Linde

11. Policy Review of Jurisdictions

The following Policy Review consists of a succinct overview of policies related to hydrogen and clean energy from various jurisdictions. This overview provides insights into how the energy transition is supported by policy in other jurisdictions and to develop recommendations for policies that apply to the NWT.

11.1 Canadian Policy

11.1.1 Current Policies and Incentives in the NWT

11.1.1.1 NWT Energy Strategy

The GNWT's strategy centres around six main strategic objectives that will help the territory achieve its goal of reducing GHG emissions by 30% below 2005 levels by 2030 [59]. The six objectives are:

1. Work together to find solutions through community engagement, participation, and empowerment.
2. Reduce GHG emissions from electricity generation in diesel communities by 25%.
3. Reduce emissions from transportation by 10% on a per-person basis.
4. Increase the share of renewable energy used for community heating to 40%.
5. Increase commercial, residential, and institutional building energy efficiency by 15%.
6. Develop the NWT's energy potential, address industry emissions, and do our part to meet national climate change objectives.

11.1.1.2 NWT Policies and Incentives

Arctic Energy Alliance: The AEA is a non-profit organization that is funded by the GNWT. The AEA is a key organization to enable the NWT to reduce its GHG emissions by helping communities develop community energy plans and providing rebate programs [60]. Rebate programs include:

- **Electric Vehicle Rebate:** reduces the cost of purchasing and using EVs in the NWT. This rebate includes EVs, e-bikes and on-the-land vehicles.
- **Renewable Energy Rebate:** provides funding for renewable energy sources such as solar, wind and wood pellet (biomass) heating for communities, businesses, non-profits, and NWT residents.
- **Home Improvements Rebate:** helps owners of older homes reduce the cost and GHG gas emissions associated with heating their homes.
- **Building Improvements Rebate:** helps businesses, non-profits, and community governments improve energy efficiency by reducing the amount of heating fuel, electricity and water used in buildings.
- **Energy Efficient Products Rebate:** for NWT residents that purchase more energy efficient everyday products.

Green House Gas Grant Program: The program is funded by the GNWT and the Government of Canada under the Low Carbon Economy Leadership Fund [61]. There are two streams of the program:

- **Government Stream:** Aims to provide funding to municipal Indigenous and Territorial governments for projects that reduce GHG gas emissions. Selected projects are eligible for funding up to 75% of eligible project costs.
- **Building and Industry Stream:** Focuses on reducing GHG emissions in businesses, industries, and non-profits. Businesses and industries may receive up to 25% of eligible project costs and non-profits can receive up to 40% of all eligible project costs [59].

NWT Carbon Tax: In 2019 the NWT carbon tax was introduced. Carbon tax rates were increased to $65/tonne in 2023 and will increase by $15/tonne each year [62].
GNWT EV Infrastructure Program: The program funds electric vehicle charging infrastructure projects. The program is funded under the Government of Canada's Zero Emission Vehicle Infrastructure Program. Funding up to 50% of eligible project costs is available [63].
Capital Asset Retrofit Fund (CARF): The fund was initially introduced in 2007 to help improve the energy efficiency of public buildings and in 2022-2023, $3.7 million was assigned to the fund [59].

11.1.2 Federal

11.1.2.1 Canadian Hydrogen Strategy

In 2020, the government of Canada published *The Hydrogen Strategy for Canada* which outlines the critical role hydrogen will play in Canada becoming net-zero by 2050. Due to Canada's extensive hydroelectric generation capacity, top-tier nuclear status, fossil fuel reserves, and biomass supply, it has great potential to become a leading producer of clean hydrogen and hopes that hydrogen will account for 30% of Canada's energy delivered by 2050 [64]. Canada's path forward includes three distinct stages. The first phase is the near-term phase which is focused on laying the foundation for the hydrogen economy through planning and developing new hydrogen supply and distribution. The midterm phase is planned to take place between 2025 -2030 and will focus on the growth and diversification of the hydrogen sector. Activities include the early development of hydrogen hubs, employing regulations, and development of new policies and regulations. The final stage will take place between 2030 and 2050 and will focus on market expansion. This phase will help Canada become a leading supplier of green hydrogen, generate high-paying jobs, and allow hydrogen to become a key driver to reach net-zero by 2050.

11.1.2.2 Canadian Policy

Clean Fuel Regulation (CFR): The regulation is focused on reducing the CI of transportation fuels such as gasoline and diesel over time. As of July 2023, the CFR mandates that suppliers and importers comply with the regulation. The CI reduction requirement started at 3.5 gCO_2e/MJ in 2023 and will increase by 1.5 gCO_2e/MJ each year [65]. A credit scheme has been developed where suppliers whose CI is below the CFR requirements can create credits that can be acquired by other suppliers. Compliance credits can be created by:

1. Undertaking projects that reduce the lifecycle CI of liquid fossil fuels (e.g., CCS, on-site renewable energy, co-processing)
2. Supplying low CI fuels (e.g., ethanol, biodiesel)
3. Supplying fuel or energy to advance vehicle technology (e.g., electric or hydrogen vehicles)

Suppliers can also contribute to an emission reduction funding program to account for up to 10% of the annual reduction requirement [66].

Clean Electricity Regulation: The Government of Canada is currently developing the Clean Electricity Regulation that aims to help Canada reach net zero through the development of clean electricity grids in Canada. Under the regulation, no more than 30 tonnes of CO_2 per GWh can be released by an electricity generating facilities that use fossil fuels to generate 25 MW or more of electricity [67].

Canadian Carbon Tax: The Government of Canada created a national benchmark for carbon pricing that the provinces and territories must comply with. The Government of Canada set $20 per tonne as the national minimum price on carbon pollution in 2019, increasing by $15 per tonne per year until it reaches $170 in 2030 [68].

Government of Canada Zero Emissions Vehicles by 2035: The Government of Canada has committed to 100% of all new LDVs sold being zero-emission vehicles by 2035 [69].

Zero Emission Vehicle Infrastructure Program: Fund used to aid the development of electric vehicle chargers and hydrogen refueling stations across Canada. In 2022 the program was extended to March 31, 2027, and an additional $400 million was recapitalized and Canada's Infrastructure Bank invested $500 million towards large-scale ZEV charging and refueling stations across Canada [70].

Clean Hydrogen Investment Tax Credit: In 2022 a Clean Hydrogen Investment Tax Credit was proposed. The tax credit is planned to be phased out after 2030 and will be refundable and available across a range of clean hydrogen pathways [71].

Paris Agreement: In December 2015 Canada committed to reducing GHG emissions by 30% below 2005 levels by 2030 under the Paris Agreement [72].

Canadian Net-Zero Emissions Accountability Act: The act legally outlines Canada's commitment to achieving net zero by 2050 [73].

Output-Based Pricing System: The Output Based Pricing System creates a price incentive for industrial emitters to reduce their GHG emissions. The system applies to industrial facilities that emit 50,000 tonnes of carbon dioxide equivalent or more per year. The pricing system limits the amount of GHG emissions a facility can emit. Facilities that emit more than their annual limit must provide compensation for the excess emissions. Facilities that emit less than their annual limit will earn surplus credits [74].

Net Zero Accelerator Initiative: The initiative offers up to $8 billion in funding towards developing large-scale clean energy technologies.

Clean Fuels Fund: In the 2021 budget an investment of $1.5 billion over 5 years was allocated to establish the Clean Fuels Fund. The fund aims to derisk investments associated with building new or expanding existing fuel production facilities.

Canada Growth Fund: A $15 billion growth fund used to invest in Canadian businesses and projects to help grow Canada's economy [75]. Clean energy and clean technology projects are eligible for this fund.

Investing in Canada Infrastructure Program: The program launched in 2016 and Canada has committed over $180 billion over 12 years to help support infrastructure projects across the country [76]. The fund is designed to achieve three objectives, including supporting the transition to a clean growth economy.

11.1.3 Provincial

11.1.3.1 British Columbia

11.1.3.1.1 British Columbia Hydrogen Strategy

In September of 2019, the Government of British Columbia released a Hydrogen Study and in July of 2021, the Government released its Hydrogen Strategy. BC plans to capitalize on its clean energy supply and low-cost NG resources to produce hydrogen [77]. BC's existing NG pipeline infrastructure is a key asset that can be used do distribute hydrogen across the province. BC is already a world leader in hydrogen production and fuel cell technology. More than half of Canada's companies active in the hydrogen and fuel cell sector are located in BC [78]. Key actions for BC are:

- Incentivising the production of renewable and low-carbon hydrogen.
- Developing regional hubs where production and demand are co-located.

- Financial support for deploying FCEVs and infrastructure.
- Expanding the use of hydrogen across different industrial sectors and applications.

11.1.3.1.2 British Columbia Policies and Incentives

Clean Industry and Innovation Rate: In 2021 the Clean Industry and Innovation Rate was introduced to reduce electricity rates and lower the cost of connecting to the electricity grid [79]. The Government of Canada, the Province, and BC Hydro partnered to introduce the rate. BC Hydro will offer discounted rates to:

- New clean industries setting up or expanding operations in BC, including hydrogen and biofuels.
- Eligible existing customers that install new equipment that uses electricity rather than fossil fuels.
- Eligible new customers who can demonstrate that they could have used fossil fuels rather than electricity to power their facilities.

BC's Clean Building Tax Credit: Refundable income tax credit for qualifying retrofits that improve the energy efficiency of commercial or multi-unit residential buildings [80].

B.C. Carbon Tax Act: B.C.'s carbon tax puts a price on carbon pollution in accordance with the Canadian Federal Government's nationwide carbon pricing [81].

Output-Based Pricing System: On April 1, 2024, B.C.'s Output-Based Pricing System replaced the CleanBC Industrial Incentive Program. The pricing system creates a cost incentive for industrial emitters to reduce their carbon emissions. The pricing system is mandatory for all emitters that release more than 10,000 tons of carbon dioxide equivalent into the atmosphere per year [82]. Operations that emit less than the annual emissions limit will earn credits whereas operations that emit over the limit will have to meet compliance obligations through direct payments, B.C. offset units, and earned credits.

Industrial Electrification Program: New streamlined funding process for large-scale electrification projects to reduce GHG emissions. The program combines funding from both the CleanBC Industry Fund and the Low Carbon Electrification program. The fund will cover up to 75% of all eligible project costs [83].

CleanBC Industry Fund: As of April 2024, The CleanBC Industry Fund is supported through the new B.C. Output Based Pricing System. The fund supports the development, trial and deployment of projects that reduce GHG emissions from large industrial operations. Operations that emit more than 10,000 tons of carbon dioxide equivalent are eligible for the fund. Since 2019 the fund has provided more than $215 million to assist carbon emission reduction projects [84].

CleanBC Go Electric Program: Since 2011 B.C. has committed more than $288 million in funding towards encouraging the adoption of zero-emission vehicles in B.C. [85]. The program covers the following sub-programs:

- Passenger Vehicle Rebates
- Fleet Charging Program
- Commercial Vehicle Pilots Program
- Combining Go Electric Rebates and Commercial Vehicle Pilots Program with federal medium- or heavy-duty zero-emission vehicle rebates.
- Go Electric School Bus program.
- Home and workplace charger rebates
- Public EV charging and hydrogen fueling infrastructure.
- Public education and outreach

CleanBC Communities Fund: The communities fund provides provincial and federal funding for community infrastructure projects that reduce reliance on fossil fuels. The fund is part of the Investing in Canada Infrastructure Program's. The program has provided $109 million in support of clean community projects across B.C. to date [86].

CleanBC Facilities Electrification Fund: The B.C. Government has allocated $84 million from the federal Green Infrastructure Funding towards the CleanBC Facilities Electrification Fund. The fund is aimed at reducing the cost of connecting to the clean electricity grid for B.C. Hydro customers. Eligible projects can receive funding for up to 50% of costs, up to a maximum of $15 million per project, to switch operations from carbon-based fuels to clean electricity [87].

11.1.3.2 Alberta

11.1.3.2.1 Alberta Hydrogen Strategy

In 2021 the Government of Alberta released a Hydrogen Roadmap which outlines how hydrogen will play a role in meeting it's decarbonization goals. Alberta is already Canada's largest producer of hydrogen, and the strategy outlines seven policy pillars to help them remain competitive in the clean energy economy and achieve its ambitions, which include [88]:

- Build new market demand.
- Enable CCUS.
- De-risk investment.
- Activate technology and innovation.
- Ensure regulatory efficiency, codes, and standards to drive safety.
- Lead the way and build alliances.
- Pursue hydrogen exports.

11.1.3.2.2 Alberta Policies and Incentives

Technology Innovation and Emissions Reduction Regulation: The regulation is Alberta's industrial carbon pricing and emissions trading system. The regulation applies to any facility that emits 100,000 tonnes or more of carbon emissions or those that import more than 10,000 tonnes of hydrogen annually [89]. Facilities can comply with the regulation by:

- Reducing on-site emissions.
- Submitting emission offset credits.
- Submitting emissions performance credits.
- Purchasing fund credits.

Accelerating Hydrogen Challenge: The government of Alberta committed $57 million in funding towards projects focused on hydrogen production, storage, transmission, distribution, and usage. $34.5 million of the funding is though Alberta's Technology Innovation and Emissions Reduction fund and the remaining is from Alberta Innovates [90].
Alberta Petrochemicals Incentive Program: This program covers up to 12% of eligible capital costs in the form of a grant for Alberta-based petrochemicals.

11.1.3.3 Ontario

11.1.3.3.1 Ontario Hydrogen Strategy

In 2022 Ontario released its Hydrogen Strategy that describes eight immediate actions which incudes the launch of the Niagara Falls hydrogen production pilot, planning hydrogen hub communities, reducing electricity rates to support hydrogen production, and assessing leveraging excess energy from Bruce Nuclear Generation for hydrogen production [91]. Ontario's clean electricity system, highly skilled workforce, and location within the Great Lakes position it favorably to thrive in the hydrogen economy.

11.1.3.3.2 Ontario Policies and Incentives

Hydrogen Innovation Fund: In February 2023 the Ontario Government launched the Hydrogen Innovation Fund which allocates $15 million between 2023-2026 towards the integration of hydrogen into Ontario's electricity system [92]. The fund will be used to support new and existing hydrogen facilities and research studies. The fund will cover up to 50% of eligible project costs [93].
Clean Energy Credit Registry: In 2023 Ontario launched its Clean Energy Credit Program. Each credit represents 1MWh of clean energy that has been generated and can be purchased. Clean energy produced by biofuels, biogas, biomass, hydro, nuclear, solar, or wind are all eligible to participate in the program [94].

11.2 Other Jurisdictions

11.2.1 United Kingdom

11.2.1.1 United Kingdom Hydrogen Strategy

In 2021 the UK released its Hydrogen Strategy report. Currently, most of the UK's hydrogen is produced from NG without carbon capture and is largely used to produce chemicals or to convert crude oil into different end products. The government plans to deploy CCUS technology in four industrial clusters by 2030 to help support their goal of capturing 10Mt/CO_2 per year [95]. The UK also hopes to have 5 GW of low-carbon hydrogen production by 2030. The UK Low Carbon Hydrogen Standard was published in 2023 which requires all hydrogen producers to meet an intensity level of 20g CO_2e/MJLHV for produced hydrogen and for produced hydrogen to be considered low carbon it must be below this threshold [96].

11.2.1.2 United Kingdom Policy

UK Emissions Trading Scheme: The scheme was introduced in 2021 and operated based on a cap-and-trade approach. The cap is the total amount of GHG emissions that can be legally emitted into the atmosphere and the cap is reduced over time to help achieve decarbonization goals. Free allowances are given within the cap and participants can purchase extra allowances or sell excess allowances [97].

Industrial Energy Transformation Fund: The fund was launched in 2020 and aims to support businesses with high energy use to cut their energy bills and carbon emissions by investing in energy efficiency and low-carbon technologies. The fund has allocated £500 million of funding available until 2028 [98].

CCUS Infrastructure Fund: The fund allocated £1 billion towards capital expenditures related to transport and storage and industrial carbon capture projects. The fund was developed to help support the UK's goal of deploying at least two Carbon Capture, Usage and Storage (CCUS) clusters by the mid-2020's and four clusters by 2030 [99].

Net Zero Hydrogen Fund: The £240 million fund was developed to de-risk the investment and reduce lifetime costs associated with low-carbon hydrogen production. The fund will be delivered between 2022 and 2025 [100].

Automotive Transformation Fund: The fund offers up to £1 billion to bolster the expansion of large-scale, electrified automotive supply within the UK [101]. Eligible projects must focus on batteries, electric motors, and drives, power electronics, fuel cells or the upstream supply chain of batteries, electric motors, and drives, power electronics or fuel cells.

11.2.2 European Union

11.2.2.1 EU Hydrogen Strategy

In 2020 the European Union (EU) unveiled its Hydrogen Strategy. In the past, hydrogen has mainly been produced via fossil fuels such as NG or coal, resulting in a significant amount of CO_2 emissions [102]. Europe is now prioritizing clean hydrogen production and aims to produce 10 million tonnes of clean hydrogen using primarily wind and solar energy and import 10 million tonnes by 2030 [103].

11.2.2.2 EU Policy

EU Emissions Trading System: In 2005 the EU emissions trading system was introduced. It is based on a cap-and-trade principle where there is a limit on the amount of GHG emissions that can be emitted, and the cap is reduced annually. Companies can purchase or sell credits as needed to stay within the cap [104].

Innovation Fund: The innovation fund has allocated €40 billion between 2020 and 2030 towards projects focused on low-carbon technologies, CCUS, renewable energy and storage. The innovation fund is financed through the EU Emissions Trading System and will cover up to 60% of relevant project costs in the case of regular grants and up to 100% of project costs in case of competitive bidding [105].

Modernization Fund: The fund was developed in 2018 to help modernize and improve the efficiency of energy systems in thirteen lower-income EU Member States. The Modernization Fund is financed through the EU Emission Trading System and supports projects like the generation and use of renewable energy including hydrogen, reduction of energy use through energy efficiency, energy storage, and modernization of energy networks. The fund also supports low-income households to address energy poverty and modernize their heating systems and zero-emission transportation infrastructure [106].

European Hydrogen Bank: In 2022 the European Commission launched the EU Hydrogen Bank to develop an initial market for renewable hydrogen. In efforts to reduce the cost of producing renewable hydrogen compared to fossil hydrogen, producers will receive a fixed premium per kilogram of hydrogen produced for a maximum of ten years. €800 million has been allocated under the innovation fund for the first auction that launched in the fall of 2023 [107].

European Climate Law: The European climate law was published in 2021 and writes into law the goals and targets described in the European Green Deal. This includes achieving net zero by 2050 and reducing GHG emissions by at least 55% by 2030 compared to 1990 levels [108].

Alternative Fuels Infrastructure Regulation: The regulation outlines national targets for alternative fuel infrastructure, road vehicles, vessels, and stationary aircrafts [109]. The main targets for 2025 and 2030 include:

- Fast charging stations of at least 150kW must be installed every 60km along the EU's trans-European transport network from 2025 onwards.
- Recharging stations for HDVs of at least 350kW must be installed every 60km on the trans-European transport core network and every 100km on the larger trans-European transport network comprehensive network from 2025 onwards.
- Hydrogen refueling stations must be installed in all urban nodes and every 200km along the trans-European transport network core network from 2030 onwards.
- Maritime ports that service large numbers of passenger vessels must provide shoreside electricity by 2030.
- Airports must provide electricity to stationary aircrafts at all gates by 2025.
- Operators of hydrogen or electric car fueling stations must provide electronic information about wait times, availability, and prices at different stations.

- **Renewable Energy Directive:** The Renewable Energy Directive sets rules and targets for the development of renewable energy in Europe. The directive was updated in 2023 to increase the renewable energy target from 32% set in 2018 to 42.5%. The agreement also sets a goal that hydrogen produced from renewable fuels of non-biological origin should make up 42% of hydrogen used in industry by 2030 and 60% by 2035 [110].

11.2.3 United States

11.2.3.1 US Hydrogen Strategy

In June 2023, the U.S. National Clean Hydrogen Strategy and Roadmap was released. At the time of the report, the U.S. produced ~10 MMT of hydrogen per year which is primarily used for petroleum refining, ammonia, and chemical industries. Hydrogen production in the U.S. accounts for ~100 MMT of GHG emissions released each year. The report identified three key strategies that will be used to achieve their target of producing 10 million tonnes of clean hydrogen by 2030 and 50 million tonnes by 2050 [111]. The three strategies are:

- Focus on clean hydrogen to address difficult to decarbonize sectors.
- Reduce the cost of clean hydrogen ($1 per kg to produce hydrogen by 2031)
- Focus on regional networks to enable large-scale clean hydrogen production close to hydrogen users.

11.2.3.2 US Hydrogen Policy

Bipartisan Infrastructure Law: In 2021 the US government released the Bipartisan Infrastructure Law which outlines dedicated funding programs that will help improve/develop infrastructure in the US. Three of the main focuses of the law are climate, energy, and the environment. Over $74 billion has been budgeted towards modernizing their energy system and providing low-cost clean energy to Americans [112]. This includes:

- $8 billion to support the development of at least four **Regional Clean Hydrogen Hubs**. The hubs aim to create networks of hydrogen producers, consumers, and connective infrastructure that can deliver or store energy.
- $1 billion towards the **Clean Hydrogen Electrolysis Program** that fund projects that improve efficiency, increase durability, and reduce the cost of producing hydrogen using electrolysis.
- $500 million towards the **Clean Hydrogen Manufacturing Recycling Research, Development and Demonstration Program**. Projects related to new hydrogen production, processing, delivery, storage, and use of equipment manufacturing technologies and techniques are eligible for this fund.
- $1.25 billion to support **Charging and Fueling Infrastructure Grants** which covers the deployment of EV and hydrogen charging infrastructure.

Inflation Reduction Act: The act was put into action in August of 2022 and will provide $370 billion for projects focused on clean energy and climate change [113]. This includes:

- Over $1.7 billion towards the **Rural Energy for America Program** which provides funding to agricultural producers and rural small businesses for renewable energy and energy efficiency improvement projects. Eligible projects include hydrogen.
- The **Alternative Fuel Vehicle Refueling Property Credit** provides a tax credit for alternative fuel charging stations and charging properties in low-income and rural areas. Hydrogen is an eligible alternative fuel. Base credit amounts are 6% of the cost for businesses up to $100,000 per item of property and 30% for individuals up to $1,000.
- $2 billion for the **Domestic Manufacturing Conversion Grants** which supports the production of hybrid and zero-emission vehicles including hydrogen FCEVs.
- The **Clean Fuel Production Credit** provides a tax credit to produce clean transportation fuels. The base credit amount is $0.20/gallon for non-aviation fuel and $0.35/gallon for aviation fuel, multiplied by the carbon emission factor.
- The **Clean Hydrogen Production Tax Credit** aims to incentivise clean hydrogen production by providing a tax credit for qualified clean hydrogen production facilities. The base credit amount is $0.60/kg multiplied by the applicable percentage depending on lifecycle GHG emissions.

12. Conclusions and Recommendations

12.1 Conclusions

The report reviews the NWT current energy systems and reviews suitable low carbon technologies that produce hydrogen and derivatives, such as ammonia. Financial analysis was done to quantify the cost of these energies, considering costs associated with winterization and development and construction in norther climates. The challenges related to designing, building, and operating production facilities in the north are described and require careful consideration.

Production of hydrogen and ammonia from renewable energy (solar and wind) at scale result in costs that can compete with conventional diesel fuel, although developing all energy needs through renewables may prove challenging. Small scale renewable energy development will enable early small-scale hydrogen initiatives as a first step.

Production of hydrogen and ammonia in Alberta, converting natural gas, combined with carbon capture and sequestration was investigated. As such projects are developed at scale, the cost will be below that of hydrogen and ammonia produced in the Northwest Territories. The anticipated growth in low carbon hydrogen in Alberta provide opportunity for the NWT to participate in the offtake of such hydrogen while benefitting from world-scale production economics.

Production of hydrogen and derivatives from natural gas hydrates, and export via a new harbor in Tuktoyaktuk for export was reviewed, however, commercial extraction is not yet confirmed and requires large scale development to be economically feasible.

Projects developed in the NWT using renewable energy can start at small scale and be built out as the cost and availability of applications, i.e., ammonia combustion engines for power generation, fuel cells for combined heat and power, as well as fuel cell electric vehicles for heavy duty transportation.

Hydrogen and ammonia have the potential to improve energy security through distributed generation, backed up by stored product, produced both locally and from ammonia produced at scale elsewhere in the Northwest Territories or in Alberta. Distribution of energy by truck, barge, and pipeline are discussed, and these must be viewed as a weak link in the energy supply chain, hence the importance of distributed production of energy.

There is opportunity to engage indigenous businesses to develop knowledge and experience in hydrogen technologies, supported by existing organizations and programs that have or have the opportunity to incorporate programs and training based on hydrogen technologies.

With hydrogen and ammonia technology and applications under development, it is recommended to begin pilot scale projects in transportation and heating to gain valuable insight and experience to prepare for larger scale implementation as technologies mature.

12.2 Policy Recommendations

Supporting policy and incentives are important for making hydrogen a viable option in the NWT because it will help with the development and adoption of hydrogen technologies. The new investment required to meet the 2030 and 2050 objectives are significant and policies and incentives can help bridge the cost gap and reduce the risks associated with investing in hydrogen technology. Creating a hydrogen economy in the NWT is multifaceted because, to deliver green hydrogen to the end user, proper renewable energy, infrastructure and end user demand must be developed. Hence for this reason policy and incentives must be strategically designed to support the development of these areas. Key recommended incentives and policies related to hydrogen and hydrogen derivatives:

Policy recommendations for the NWT for hydrogen include:

1. Take advantage of the Canadian Clean Fuel Regulation which is a cap-and-trade scheme geared towards reducing the CI of transportation fuels, including hydrogen. Compliance credits can be created by undertaking projects that reduce the lifecycle CI of liquid fossil fuels, supplying low carbon fuels and supplying fuel or energy to advance zero emission vehicle technology. More information on the Clean Fuel Regulation can be found in section 11.1.2. Projects developed in the NWT may benefit from credits from producing zero/low carbon fuel like hydrogen and biodiesel or generate revenue to help fund other decarbonization projects.
2. Take advantage of the Investing in Canada Infrastructure Program to develop a fund for infrastructure projects that aim to decrease dependence on fossil fuels in the NWT. The fund should focus on supplying funding for projects related to improving access to clean energy transportation, improving energy efficiency of buildings, improving production of clean energy and management of renewable energy.
3. Create a fund to support projects related to hydrogen and hydrogen derivative production, storage, distribution, and usage. This fund will encourage the advancement of hydrogen technology in the NWT. The contribution should be based on a supply chain solution, alignment of various stakeholders including First Nations. The technologies involved should align with those highlighted in this report, covering clean hydrogen production and storage, distribution and local applications for power and heat (CPH), and development criteria for objected innovation and cost.

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Appendix A Community Breakdown of Current Energy Capacities

Table 13: Current community energy capacity breakdown. Adapted from [115], [116], [117], [16], and [118].

Community	Hydro Power Capacity (MW)	Diesel Power Capacity (MW)	NG Power Capacity (MW)	Wind Power Capacity (MW)	Solar Power Capacity (MW)	Total Capacity (MW)
Inuvik Region						26.955
Sachs Harbour	0	0.8	0	0	0.023	0.823
Ulukhaktok	0	1.16	0	0	0.048	1.208
Tuktoyaktuk	0	2.21	0	0	0.098	2.308
Paulatuk	0	0.82	0	0	0.035	0.855
Inuvik	0	5.76	8	3.5	0.72	17.98
Aklavik	0	1.28	0	0	0.071	1.351
Fort McPherson	0	1.83	0	0	0.083	1.913
Tsiigehtchic	0	0.5	0	0	0.017	0.517
Sahtu Region						21.349
Colville Lake	0	0.24	0	0	0.136	0.376
Fort Good Hope (K’asho Got’ı̨nę)	0	1.23	0	0	0.068	1.298
Norman Wells	0	2.12	15	0	0.194	17.314
Délı̨nę	0	1.14	0	0	0.064	1.204
Tulita	0	1.1	0	0	0.057	1.157
Deh Cho Region						6.893
Wrigley	0	1.3	0	0	0.016	1.316
Fort Simpson	0	3.21	0	0	0.175	3.385
Jean Marie River	0	0.23	0	0	0.007	0.237
Nahanni Butte	0	0.25	0	0	0.011	0.261
Fort Liard	0	1.3	0	0	0.064	1.364
Sambaa K'e	0	0.33	0	0	0	0.33
North Slave Region					55.094	
Wekweètì	0	0.38	0	0	0	0.38
Gamètì	0	0.61	0	0	0.034	0.644
Whatì	0	0.98	0	0	0.047	1.027
Yellowknife	37	13.83	0	0	0	50.83
Behchokǫ̀	0	1.35	0	0	0	1.35
Dettah	0	0	0	0	0	0
Ndilǫ	0	0	0	0	0	0
Łutselk'e	0	0.82	0	0	0.043	0.863
South Slave Region					26.48	
Fort Providence	0	1.48	0	0	0	1.48
Kakisa	0	0.3	0	0	0	0.3
Hay River	18		0	0	0	18
Enterprise	0		0	0	0	0

Fort Resolution	0	0.7	0	0	0	0.7
Fort Smith	0	6	0	0	0	6
TOTAL	55	53.26	23	3.5	2.011	136.771

Appendix B Natural Gas Reserve Volumes

Table 14: Marketable Discovered (Expected) NG, NG Liquids, and Oil Volumes. Map showing regions can be found in Figure 24 below. Adapted from [119].

Study Area	NG billion cubic metres (trillion cubic feet)	NG liquids million cubic metres (million barrels)	Oil million cubic metres (million barrels)
Beaufort Sea	178.0 (6.2)	0.2 (1.2)	106.1 (667.4)
Mackenzie Delta	160.8 (5.7)	8.3 (52.0)	28.8 (181.0)
NWT Arctic Islands	75.2 (2.6)	0	4.9 (31.0)
Mackenzie Plain	18.3 (0.6)	0	53.5 (336.7)
Colville Hills	17.8 (0.6)	<0.1 (0.1)	1.3 (8.1)
Liard Plateau	14.2 (0.5)	0	<0.1 (<0.1)
Great Slave Plain (South)	2.5 (<0.1)	0	0.5 (3.4)
Great Slave Plain (North)	<0.1 (<0.1)	0	0
Peel Plain	<0.1 (<0.1)	0	0
Anderson Plain	0	0	0
Great Bear Plain (North)	0	0	0
Great Bear Plain (South)	0	0	0
Horton Plain	0	0	0
TOTAL	467.0 (16.4)	8.5 (53.3)	195.1 (1227.8)

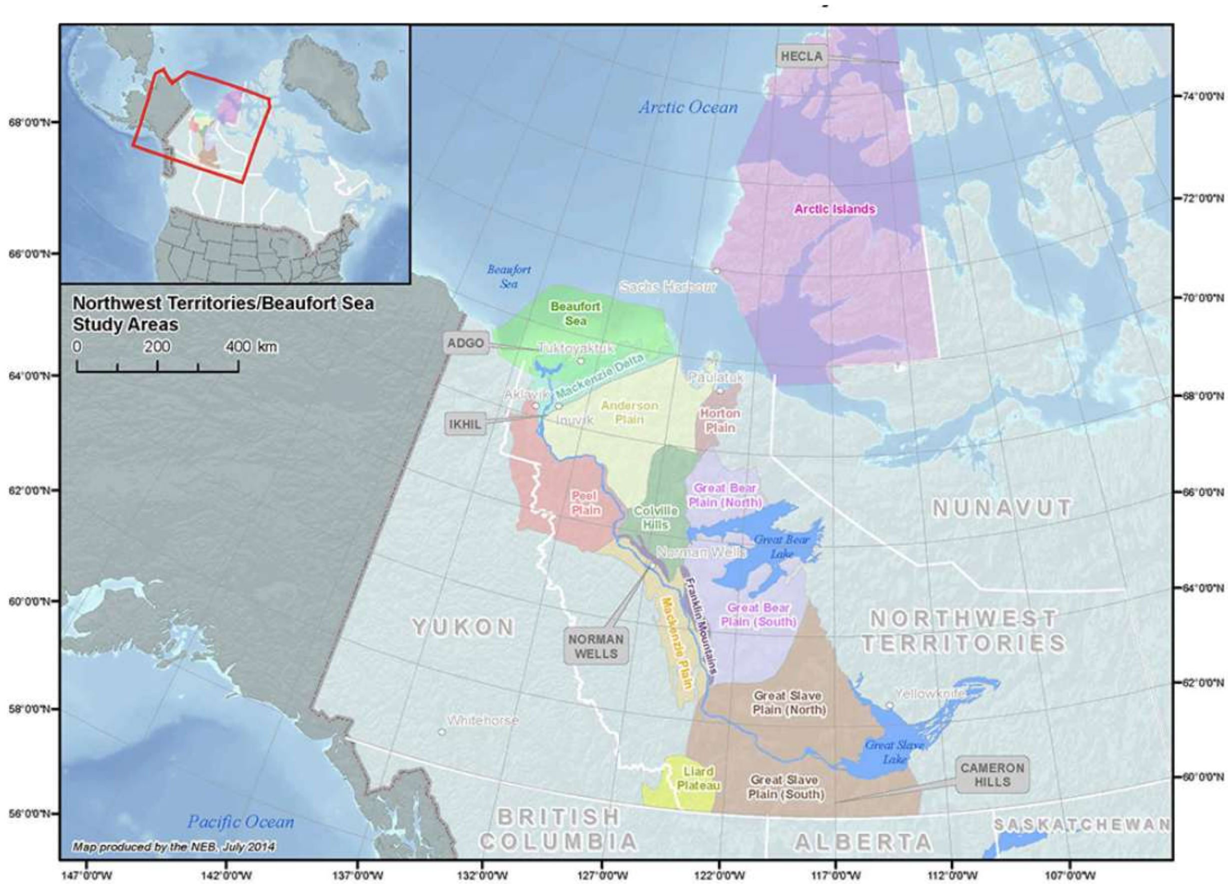

Figure 24: Map of regions for discoverable marketable NG, NG liquids, and oil volumes. Taken from [48].

Appendix C Map of Transportation Seasonality Restrictions

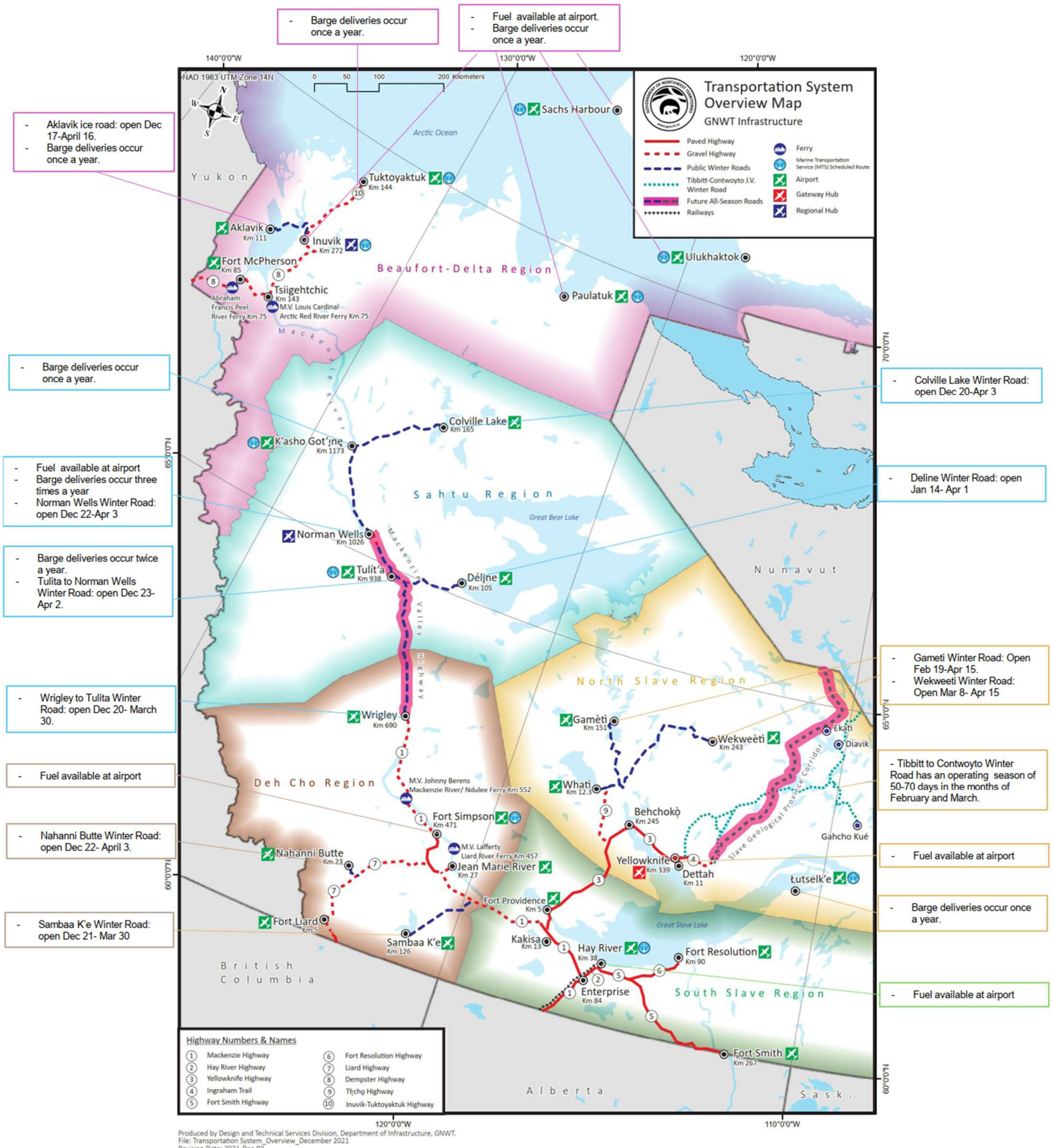

Figure 25: Transportation seasonality restrictions. Taken from [200].

Appendix D Regional Transportation Analysis

Table 15: Regional Transportation Analysis. Adapted from [19].

			Volume of Fuel Combusted by NWT Transportation Combustion Sources (L)																				
Community	**Population**	**% Total Population**	**Domestic Aviation**	**Military Aviation**	**LDV**	**LDT**	**HDV**	**Motorcycles**	**LDV**	**LDT**	**HDV**	**Railways**	**Domestic Nav**	**Fishing**	**Military Water-Borne Nav**	**Off Road A&F**	**Off-Road C&I**	**Off Road M,M&C**	**Off-Road Residential**	**Off-Road Other Transportation**	**Diesel Combusted (L/year)**	**Gasoline Combusted (L/year)**	**Kerosene Combusted(L/year)**
Fuel Type			**Kerosene**	**Kerosene**	**Gasoline**	**Gasoline**	**Gasoline**	**Gasoline**	**Diesel**	**Diesel**	**Diesel**	**Diesel**	**Diesel**	**Gasoline**	**Diesel**	**Diesel**	**Diesel**	**Diesel**	**Gasoline**	**Gasoline**			
Total	**43,778**		**57,465,759**	**1,869,553**	**5,815,768**	**32,052,678**	**9,877,473**	**91,235**	**798,889**	**4,741,315**	**151,749,917**	**76,314**	**2,683,675**	**331,538**	**889**	**145,857**	**209,059**	**24,822,309**	**895,949**	**4,941,690**	**185,228,224**	**54,006,331**	**59,335,312**
Beaufort-Delta Region	6863	15.7%	7,456,606	-	911,728	5,024,842	1,548,474	14,303	125,240	743,288	17,842,176	-	1,965,979	51,975	-		32,774	-	140,456	774,700	20,709,456	8,466,477	7,456,606
Sachs Harbour	113	0.3%	195,317		15,012	82,735	25,496	235	2,062	12,238	293,773		37,356	856			540		2,313	12,756	345,969	139,401	195,317
Ulukhaktok	441	1.0%	762,254		58,585	322,884	99,501	919	8,048	47,762	1,146,496		145,787	3,340			2,106		9,025	49,780	1,350,198	544,036	762,254
Tuktoyaktuk	994	2.3%			132,050	727,771	224,273	2,072	18,139	107,654	2,584,165		328,600	7,528			4,747		20,343	112,203	3,043,304	1,226,239	-
Paulatuk	321	0.7%	554,838		42,644	235,025	72,426	669	5,858	34,765	834,524		106,117	2,431			1,533		6,570	36,235	982,797	395,999	554,838
Inuvik	3439	7.9%	5,944,197		456,860	2,517,912	775,929	7,167	62,757	372,456	8,940,586		1,136,876	26,044			16,423		70,382	388,197	10,529,098	4,242,491	5,944,197
Aklavik	639	1.5%			84,889	467,853	144,175	1,332	11,661	69,206	1,661,249		211,243	4,839			3,052		13,078	72,131	1,956,410	788,297	-
Fort McPherson, Northwest Territories	734	1.7%			97,510	537,408	165,610	1,530	13,395	79,495	1,908,226			5,559			3,505		15,022	82,854	2,004,621	905,492	-
Tsiigehtchic	182	0.4%			24,178	133,254	41,064	379	3,321	19,711	473,157			1,378			869		3,725	20,544	497,059	224,523	-

Sahtu Region	2622	6.0%	1,370,674	-	348,324	1,919,734	591,592	5,464	47,848	283,972	6,816,579	-	615,877	19,857	-		12,521	-	53,661	295,973	7,776,797	3,234,606	1,370,674
Colville Lake, Northwest Territories	149	0.3%			19,794	109,092	33,618	311	2,719	16,137	387,365			1,128			712		3,049	16,819	406,933	183,812	-
Fort Good Hope	554	1.3%			73,597	405,619	124,997	1,155	10,110	60,000	1,440,269		183,143	4,196			2,646		11,338	62,536	1,696,168	683,437	-
Norman Wells	793	1.8%	1,370,674		105,348	580,606	178,922	1,653	14,471	85,885	2,061,612		262,153	6,006			3,787		16,229	89,514	2,427,908	978,277	1,370,674
Délįnę	610	1.4%			81,037	446,620	137,632	1,271	11,132	66,065	1,585,856			4,620			2,913		12,484	68,857	1,665,965	752,521	-
Tulita	516	1.2%			68,549	377,797	116,423	1,075	9,416	55,885	1,341,478		170,581	3,908			2,464		10,560	58,246	1,579,824	636,559	-
Deh Cho Region	2257	5.2%	2,283,305	-	299,835	1,652,494	509,239	4,704	41,187	244,441	5,867,666	-	-	17,093	-	9,600	10,778	-	46,191	254,772	6,173,672	2,784,327	2,283,305
Wrigley, Northwest Territories	126	0.3%			16,739	92,253	28,429	263	2,299	13,646	327,570			954		536	602		2,579	14,223	344,653	155,439	-
Fort Simpson	1,321	3.0%	2,283,305		175,491	967,189	298,052	2,753	24,106	143,069	3,434,287			10,004		5,619	6,308		27,035	149,115	3,613,390	1,629,640	2,283,305
Jean Marie River	80	0.2%			10,628	58,573	18,050	167	1,460	8,664	207,981			606		340	382		1,637	9,030	218,828	98,691	-
Nahanni Butte	99	0.2%			13,152	72,484	22,337	206	1,807	10,722	257,377			750		421	473		2,026	11,175	270,799	122,130	-
Fort Liard	537	1.2%			71,339	393,172	121,161	1,119	9,800	58,159	1,396,073			4,067		2,284	2,564		10,990	60,617	1,468,880	662,465	-
Sambaa K'e	94	0.2%			12,488	68,823	21,209	196	1,715	10,181	244,378			712		400	449		1,924	10,611	257,122	115,962	-
North Slave Region	24499	56.0%	40,226,031	1,869,553	3,254,614	17,937,287	5,527,621	51,057	447,073	2,653,330	63,691,601	-	101,820	185,535	889	104,201	116,993	18,616,732	501,390	2,765,464	85,732,639	30,222,968	42,095,584
Wekweeti	159	0.4%			21,123	116,414	35,875	331	2,902	17,220	413,362			1,204		676	759		3,254	17,948	434,920	196,149	-
Gamèti	286	0.7%			37,994	209,399	64,529	596	5,219	30,975	743,532			2,166		1,216	1,366		5,853	32,284	782,308	352,821	-
Whatì	538	1.2%			71,472	393,904	121,387	1,121	9,818	58,267	1,398,673			4,074		2,288	2,569		11,011	60,730	1,471,615	663,699	-
Yellowknife	20,997	48.0%	40,226,031.30	1,869,553	2,789,385	15,373,249	4,737,478	43,759	383,167	2,274,051	54,587,230			159,014	889	89,306	100,270		429,719	2,370,155	57,434,912	25,902,758	42,095,584

Behchokǫ̀	1,998	4.6%			265,428	1,462,864	450,802	4,164	36,461	216,391	5,194,327			15,131		8,498	9,541		40,891	225,536	5,465,218	2,464,815	-
Dettah	213	0.5%			28,296	155,951	48,058	444	3,887	23,069	553,750			1,613		906	1,017		4,359	24,044	582,628	262,766	-
Łutsel k'e	308	0.7%			40,917	225,507	69,493	642	5,621	33,358	800,727		101,820	2,333		1,310	1,471		6,303	34,767	944,306	379,961	-
Ekati Diamond Mine	0	0.0%			-	-	-	-	-	-	-			-		-	-	6,205,577	-	-	6,205,577	-	-
Diavik Diamond Mine	0	0.0%			-	-	-	-	-	-	-			-		-	-	6,205,577	-	-	6,205,577	-	-
Gahcho Kue Diamond Mine	0	0.0%			-	-	-	-	-	-	-			-		-	-	6,205,577	-	-	6,205,577	-	-
Nechalacho Mine	0	0.0%																6,205,577			6,205,577		
South Slave Region	7537	17.2%	6,129,143	-	1,001,266	5,518,320	1,700,546	15,707	137,540	816,284	57,531,895	76,314	-	57,079	-	32,057	35,992	-	154,250	850,782	58,630,083	9,297,951	6,129,143
Fort Providence	718	1.6%			95,384	525,694	162,000	1,496	13,103	77,762	1,866,630			5,438		3,054	3,429		14,694	81,048	1,963,977	885,754	-
Kakisa	42	0.1%			5,580	30,751	9,476	88	766	4,549	109,190			318		179	201		860	4,741	114,884	51,813	-
Hay River, Northwest Territories	3546	8.1%	6,129,143		471,075	2,596,254	800,071	7,390	64,710	384,045	47,156,240	76,314		26,854		15,082	16,934		72,572	400,275	47,713,324	4,374,491	6,129,143
Enterprise, Northwest Territories	109	0.2%			14,480	79,806	24,593	227	1,989	11,805	283,374			825		464	521		2,231	12,304	298,153	134,467	-
Fort Resolution	526	1.2%			69,877	385,118	118,679	1,096	9,599	56,968	1,367,475			3,983		2,237	2,512		10,765	59,375	1,438,791	648,895	-
Fort Smith, Northwest Territories	2596	5.9%			344,870	1,900,698	585,726	5,410	47,373	281,156	6,748,986			19,660		11,041	12,397		53,129	293,038	7,100,954	3,202,532	-

Fuel consumption was allocated to each region according to population unless otherwise stated in the assumptions below. The full analysis of fuel consumed by community can be found in Table 15 in Appendix D.

The data was used to best approximate the fuel consumptions. To perform a complete analysis, the following is required:

- Origin and final destinations of all truck, barge, and rail freight deliveries.
- Fuel consumption amounts for HDTs (heavy-duty trucks), barges, and rail.
- Trucking routes and fueling locations on the route.
- The current number of registered LDV's with primary locations.
- Fuel consumption amounts for aviation in the NWT.
- Air traffic data regarding the amount of air travel in to, out of, and within the NWT.

When calculating the transportation fuel consumption by region, the following was assumed:

- All off-road manufacturing and mining and construction fuel was consumed at the mines in the Slave Geo Corridor. Fuel consumption was divided equally by the four mines.
- Yellowknife has the largest amount of air traffic; therefore, it is assumed that 70% of domestic aviation fuel is consumed at the Yellowknife Airport. The Northern Transportation Systems Assessment Report states that the only airports with fuel available besides Yellowknife are Hay River, Fort Simpson, Sachs Harbor, Paulatuk, Ulukhaktok, Inuvik, and Norman Wells. The remaining 30% of domestic aviation fuel consumption was proportionally allocated to these regions by population.
- All military activity is based in Yellowknife.
- All rail consumption is allocated to Hay River, as it is the only community with railway access.
- Fuel consumed for domestic navigation is allocated to regions that receive freight via barge according to population.
- Transportation fuel consumed in the off-road agriculture & forestry industry is allocated to the three most southern regions of the NWT (Deh Cho, North Slave and South Slave) according to population.
- Due to the amount of truck traffic entering the South Slave Region from Alberta, the number of trucks picking up fuel delivered to Hay River by rail and the number of trucks delivering supplies to Hay River to be distributed by barge, 25% of the fuel consumed by heavy-duty vehicles (HDVs) is allocated to Hay River. The remainder is proportionally divided by population to the regions.

Appendix E Hydro Expansion Assessment

Table 16: North Slave

Body of Water	Total Power Available (MW)	Potential Sites	Cost ($1,000,000)	Sources
La Martre River	20	La Martre Falls		[120]
	10	La Martre Falls Stage 1	73.3 ('96)	[121]
	10	La Martre Falls Stage 2	17.7 ('96)	[121]
Snare River	3.3	Slemon Rapids		[121]
	12	Upper Snare Site 4 in [121]		[121]
Lockhart River	52.4	Anderson Falls	176 (50 MW) ('96) 154 (25 MW) ('96) $5.7/MWh ('69)*	[122, 123]
	63	Mosquito Canyon	170 (50 MW) ('96) 148 (25 MW) ('96) $5.7/MWh ('69)*	[122, 123]
	50.8	Parry Falls	30.25 (50 MW if combined with 50 MW Tyrell Falls plant, includes 50-mile transmission line to Fort Reliance) ('69) $5.7/MWh ('69)*	[124]
	33.4	Vee Canyon	$5.7/MWh ('69)*	[122]
	19.6	Dead Moose	$5.7/MWh ('69)*	[122]
	63	Tyrell Falls	155 (50 MW, transmission facilities included) ('93) 5.75 (10 MW) ('69) 7.8 (25 MW) ('69) 16.2 (50 MW) ('69) $7.3/MWh (63 MW, including dam at Ptarmigan Lake and 240-mile transmission line to Pine Point) ('69) $8.5/MWh (63 MW, 350-mile transmission line to Pine Point passing through Twin Gorges plant and Fort Smith) ('69) $5.7/MWh ('69)* Unfeasible [121]	[124, 122, 125, 121]
Snowdrift River	0.4	Snowdrift River Fall	3.21 (including a 15 km transmission line) ('83)	[126]
	9.8	Unnamed site in [122], includes low storage dam across the outlet from Siltaza Lake		[122]
Beaulieu River**	0.57		25 ('12)	[127]
	32	Great Slave Lake	$7.7/MWh ('69)***	[124]

Diversion from Artillery Lake into Pike's Portage Route	209	Burr Lake	$7.7/MWh ('69)***	[124]

*$5.7/MWh ('69) for the combination of plants at Tyrrell Falls, Dead Moose, Vee Canyon, Parry Falls, Mosquito Canyon and Anderson Falls [122].
** [127] used same map for both sites it investigation. Further investigation is required to identify the correct location of the site listed.
***$7.7/MWh ('69) for the combination of plants at Great Slave Lake and Burr Lake [124].

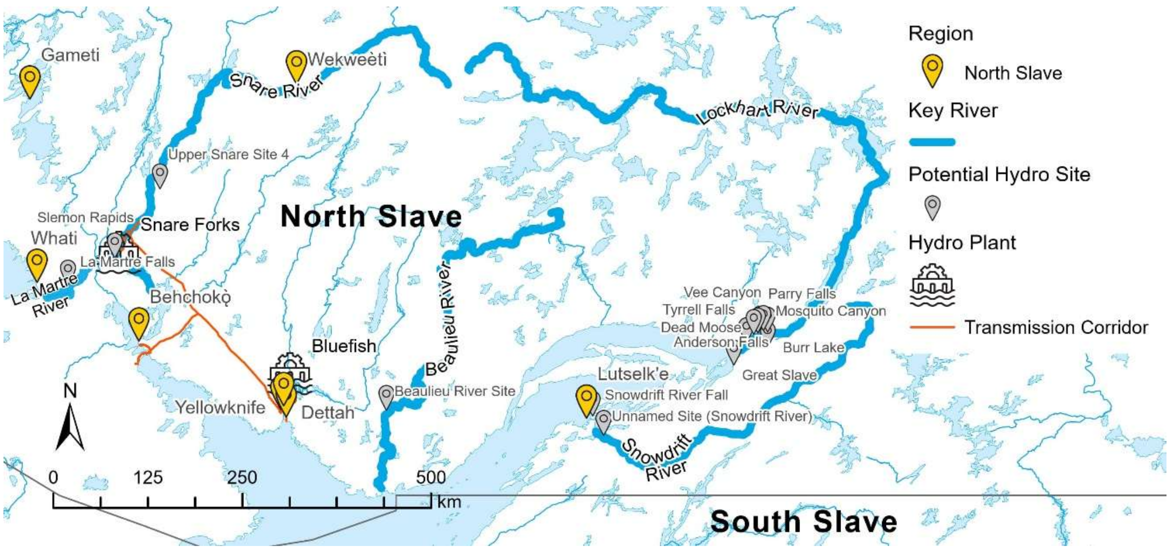

Figure 26: Potential sites for hydroelectricity in the North Slave region.

As a river profile for Pike's Portage Route was not available at the time of writing, two landmarks along the route are instead shown. As [127] employed the same map for both installations on the Beaulieu River that it investigated, that site is depicted and may not be the actual site of the identified installation.

Table 17: South Slave

Body of Water	Total Power Available (MW)	Potential Sites	Cost ($1,000,000)	Sources
Kakisa River	8.5	Lady Evelyn Falls	8 (8.5 MW option, site in proposed protected area) ('12) 0.77 (0.19 MW option, includes transmission lines) ('83)	[127, 126]
Taltson River (Twin Gorges)	36		127 ('05) $11.7/MWh (18 MW plant, assumes existing power lines at Twin Gorges will be employed) ('69)	[128, 124]
Taltson River (Other Sites)	57.9	Nende Rapids	198 (57.9 MW) ('05) 168 (38.0 MW) ('05) (Cost not indicated in [124])	[128, 124]
	38.5	Three Bears Rapids	177 ('05)	[128]
	16.5	Natalkai Falls	94 ('05)	[128]
	36*	Benna Thy	182 ('05)	[128]
	9	Nonacho	70 ('05)	[128]

Tazin River	18.9	Nettel Falls	100 ('05)	[128, 122]
	9	Othikethe Rapids	68 ('05)	[128, 122]
	7.8	Kolethe Rapids	63 (6.8 MW) ('05) $21.5/MWh (includes 40 miles of transmission lines to current Taltson Hydro plant) ('69) 20.7, or $5.2 /MWh (if above option is built after a second 18 MW hydro plant at Twin Gorges)	[128, 122]

* [128] listed the capacity of a potential Benna Thy installation plant as 36 and 38 MW at multiple points in the report. This discrepancy should be further investigated.

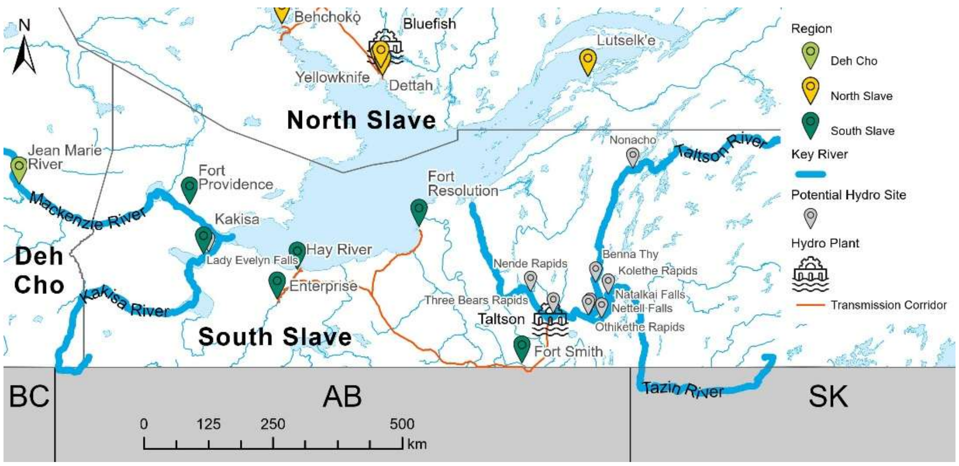

Figure 27: Potential sites for hydroelectricity in the South Slave region.

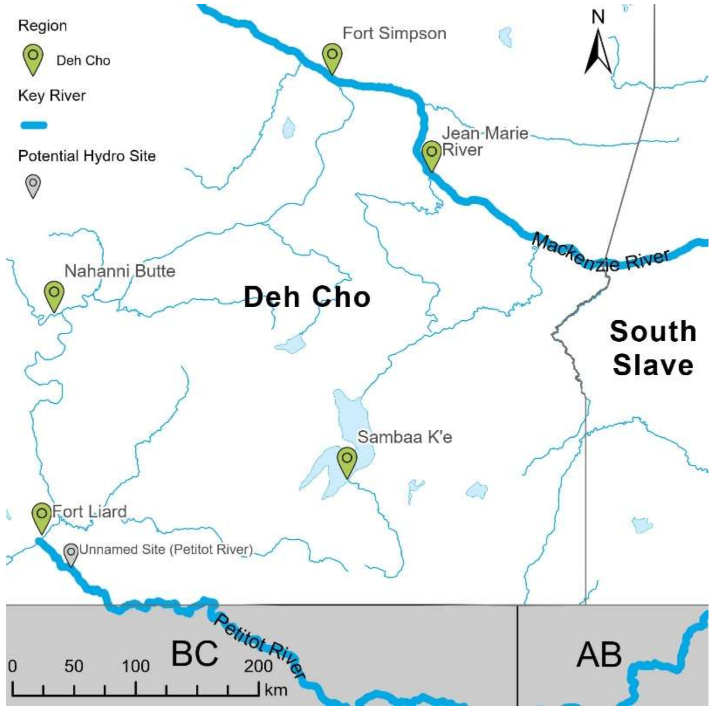

Figure 28: Potential sites for hydroelectricity in the Deh Cho region.

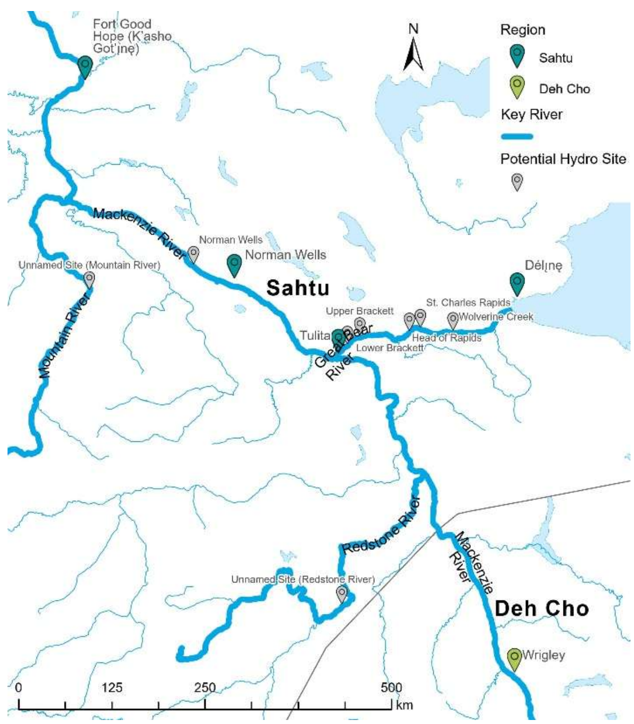

Figure 29: Potential sites for hydroelectricity in the Sahtu region.

Table 18: Beaufort Delta Region

Body of Water	Total Power Available (MW)	Potential Sites	Cost ($1,000,000)	Sources

Unnamed River near Ulukhaktok	0.3 (Seasonal Run-of-River)* 0.2 (Lake Reservoir)		15 (Seasonal Run-of-River) ('12) 12 (Lake Reservoir) ('12)	[129]
Unnamed River near Ulukhaktok	1.4 (Seasonal Run-of-River)*		41 ('12)	[129]
Unnamed River near Ulukhaktok	0.5 (Seasonal Run-of-River)*		34 ('12)	[129]
Unnamed River near Ulukhaktok	3.5 (Seasonal Run-of-River)* 2.3 (Lake Reservoir)		95 (Seasonal Run-of-River) ('12) 91 (Lake Reservoir) ('12)	[129]
Roscoe River	10.3 (Seasonal Run-of-River)		150 ('12)	[129]
Anderson River	70 (River Impoundment)		1000s ('12)	[129]
Horton River	20 (River Impoundment)		100s to 1000s ('12)	[129]
Mackenzie River	3,500 (River Impoundment)	Lower Ramparts	74,000 ('12)	[129]
Arctic Red River	200 (River Impoundment)		1000s ('12)	[129]

*Page 5-2 in [129] indicates that a total of 5.7 MW of Run-of-River hydropower is available near Ulukhaktok. However, page 5-5 indicates that only 1.9 MW are available. The conflicting information should be further investigated.

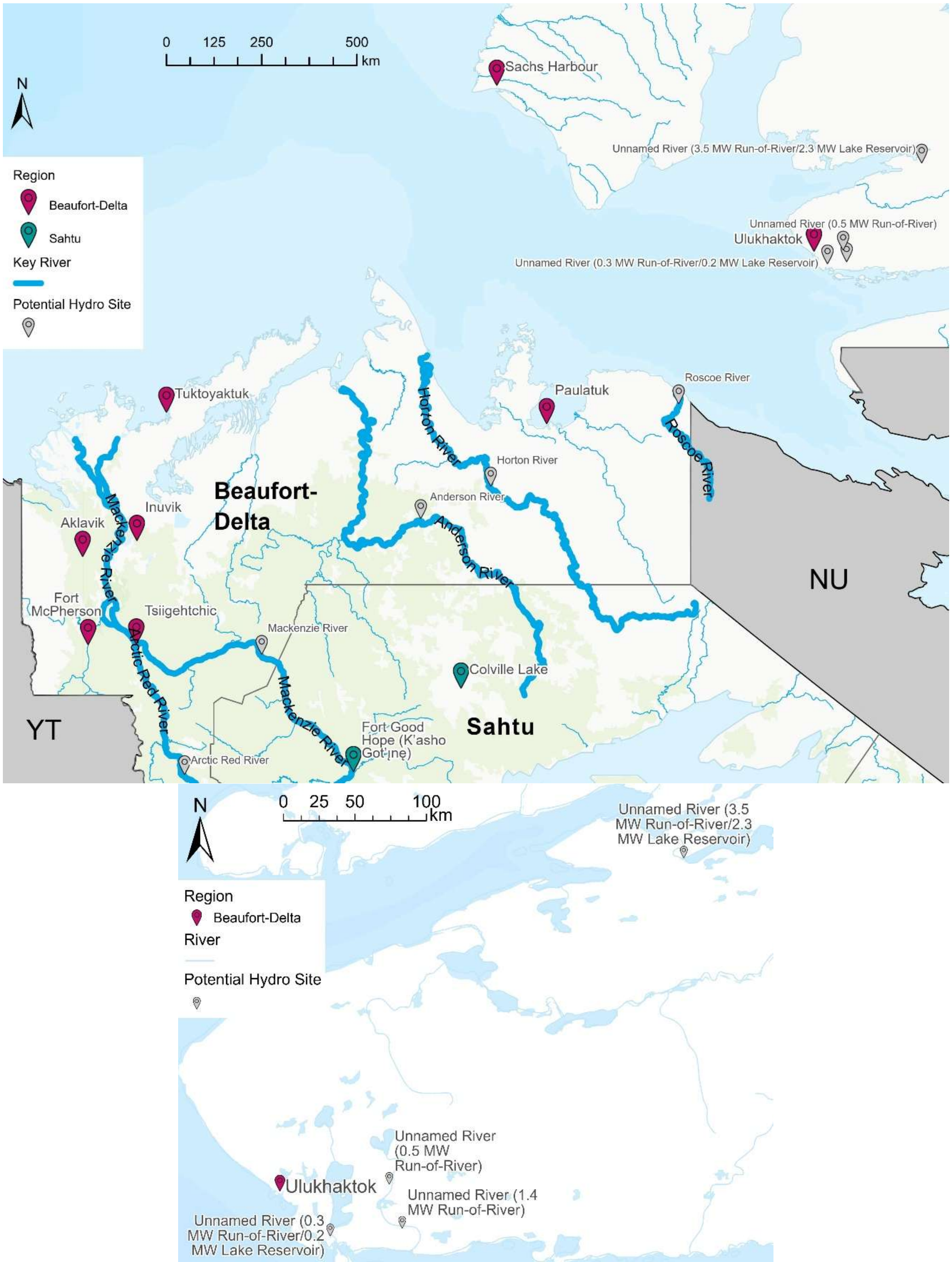

Figure 30: Potential sites for hydroelectricity in the Beaufort-Delta region and near Ulukhaktok.

Appendix F Community Fuel Consumption

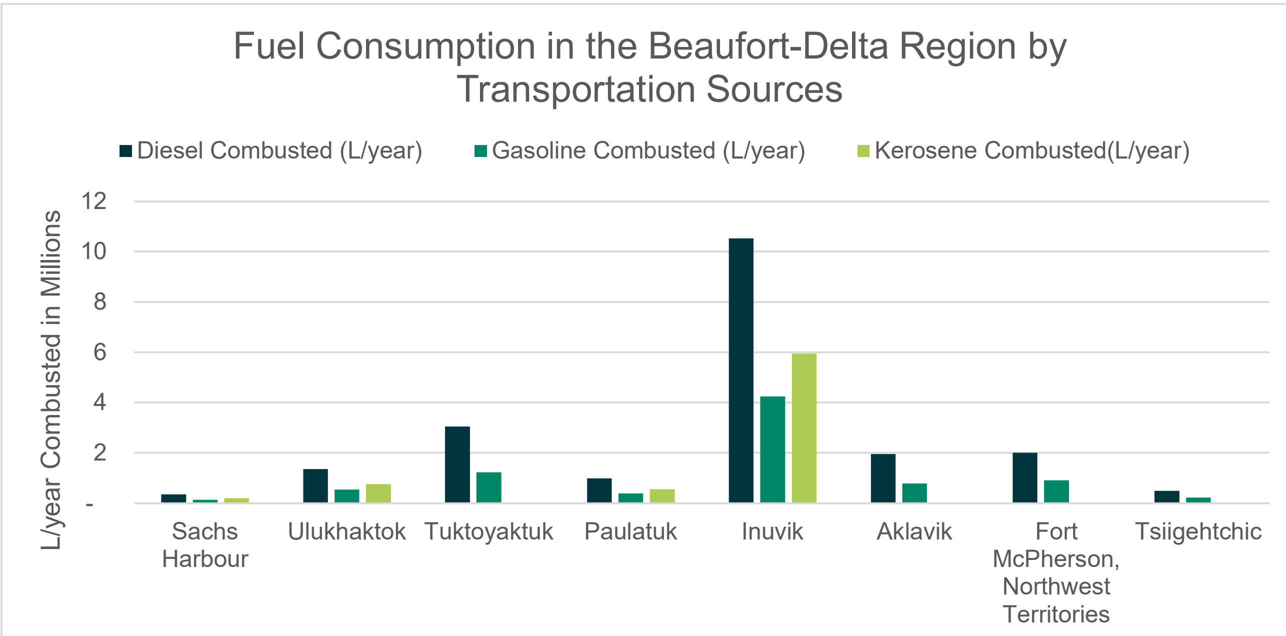

Figure 31: Fuel consumption by transportation sources in the Beaufort Delta region. Adapted from [19].

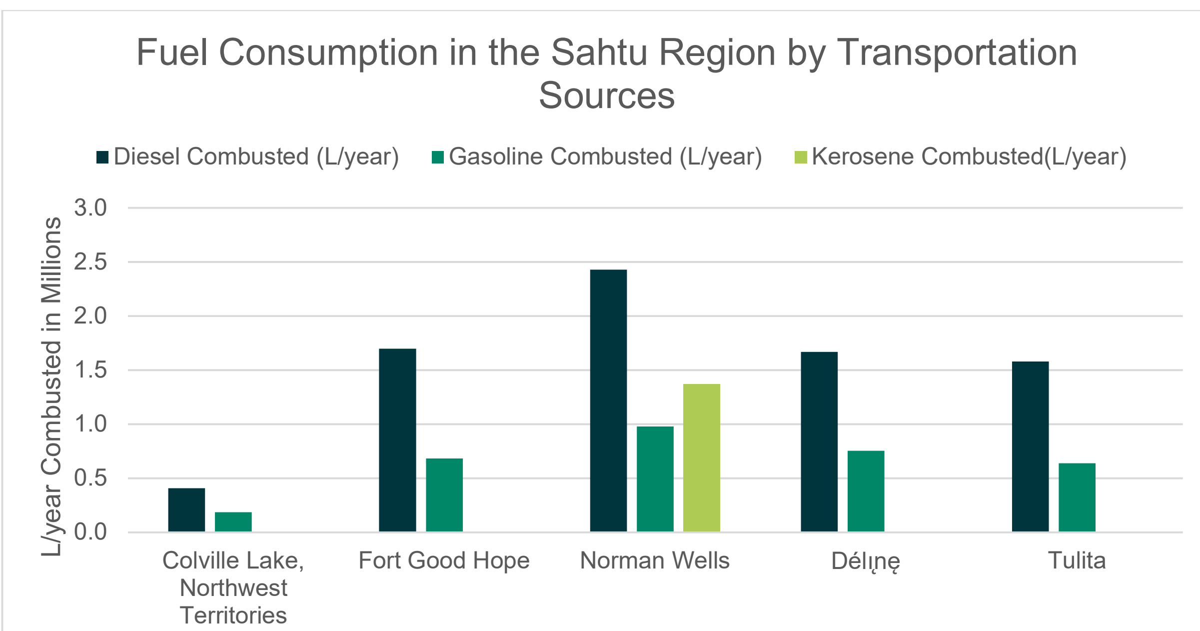

Figure 32: Fuel consumption by transportation sources in the Sahtu region. Adapted from [19].

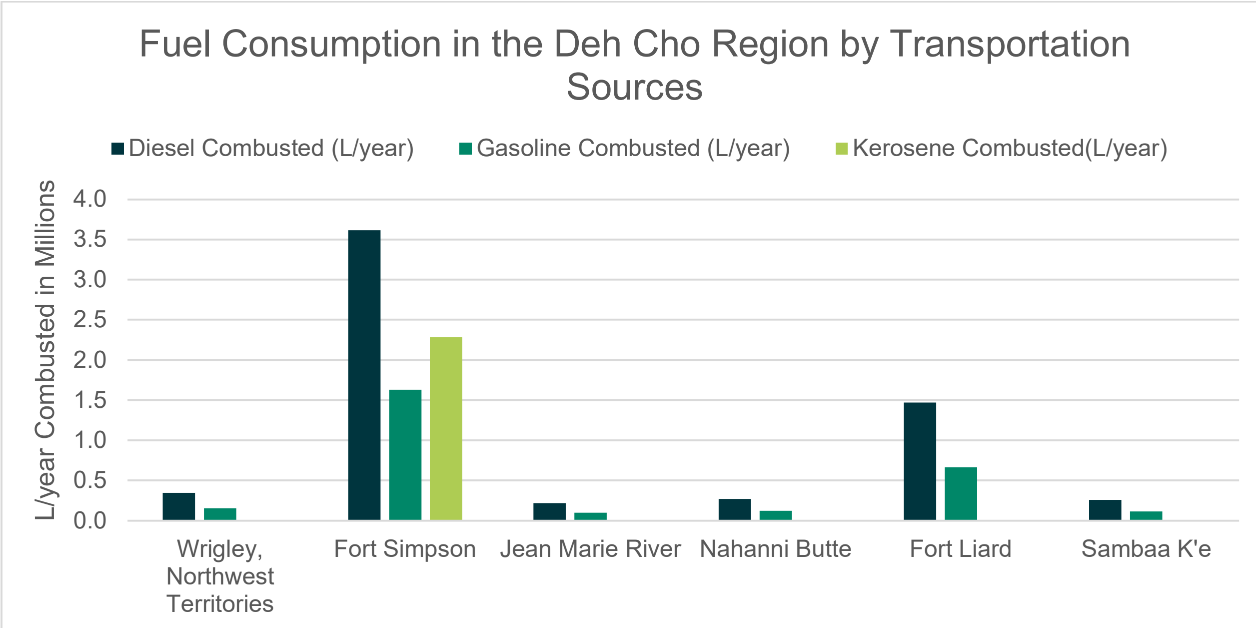

Figure 33: Fuel consumption by transportation sources in the Deh Cho region. Adapted from [19].

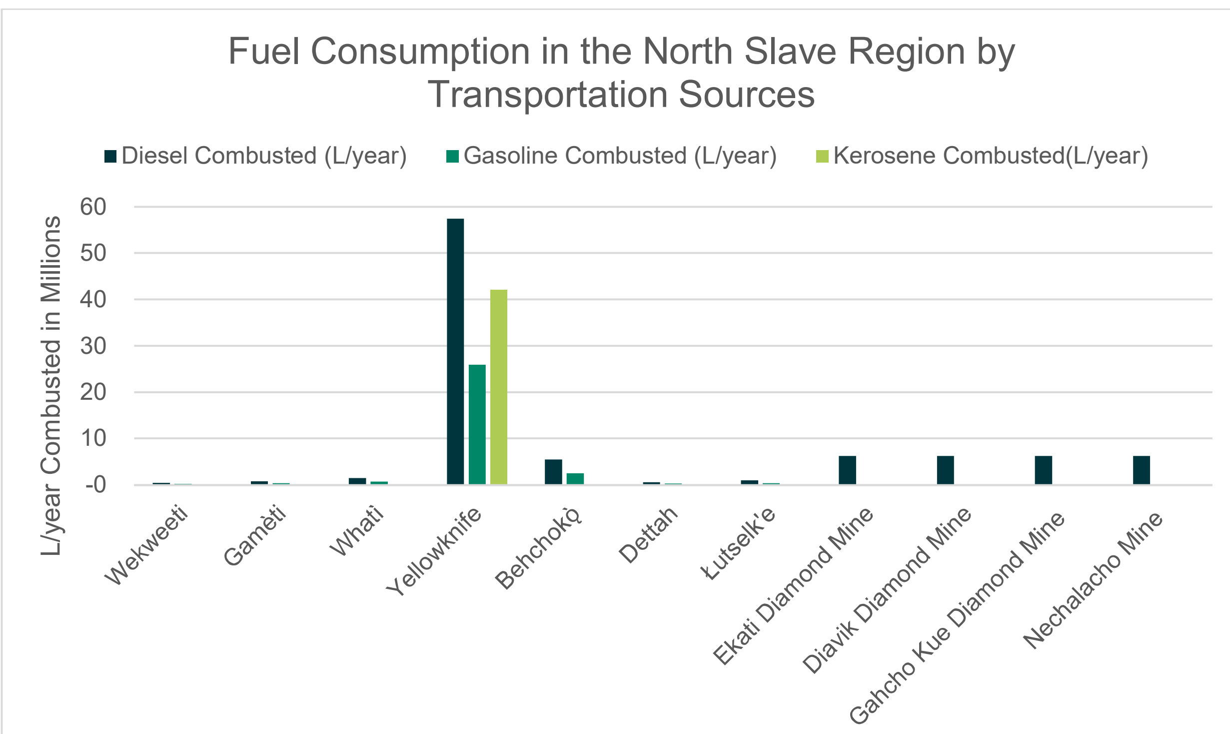

Figure 34: Fuel consumption by transportation sources in the North Slave region. Adapted from [19].

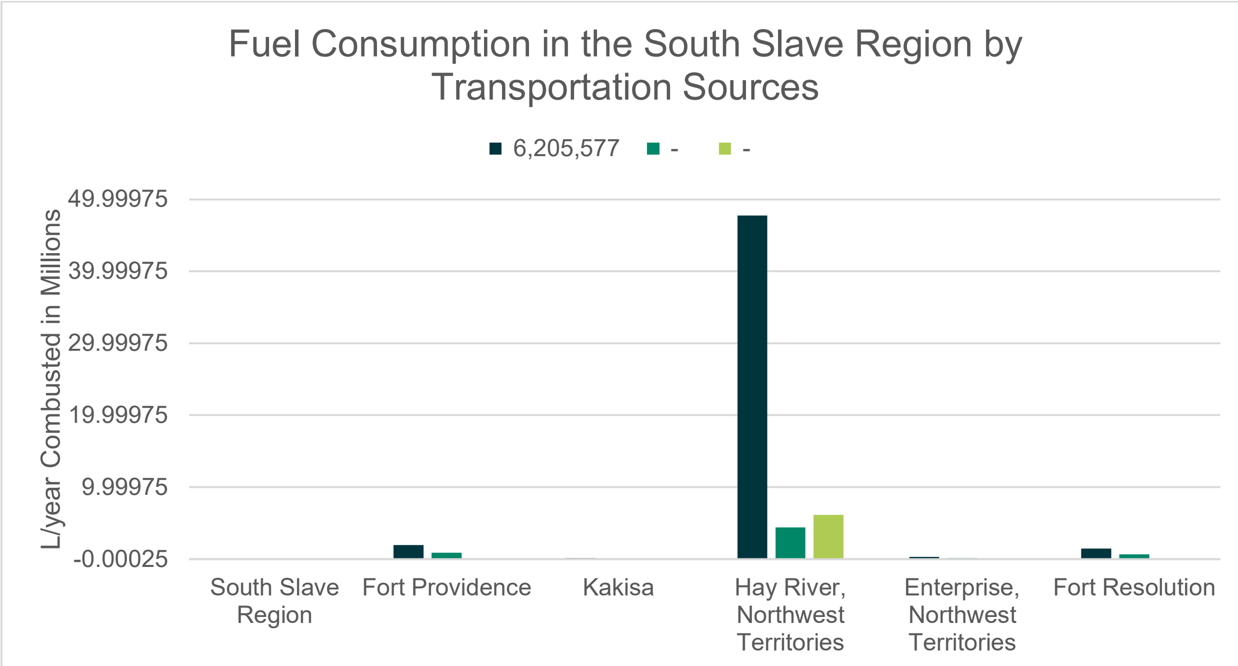

Figure 35: Fuel consumption by transportation sources in the South Slave region. Adapted from [19].

Appendix G Economic Model References

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14. Abijit Dutta et al., “Process Design and Economics for the Conversion of Lignocellulosic Biomass to Hydrocarbon Fuels”, NREL, 2015

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16. Palandri et al., “A comparative analysis of ammonia production and export in Western Canada and Australia”, 2024

Appendix H Regional Energy Summary

Region	Current Energy Sources	Current Energy Conversion	Potential Energy Sources	Potential Technologies	Potential Energy Products	Availability of Potential Energy Sources	Short Term Conclusions (2030 Goals)	Long Term Conclusions (2050 Goals)	Conclusions (short- and long-term recommendations)
Inuvik /Beaufort Delta Region	Solar (limited) Wind Biomass (wood) NG Petroleum Products	NG Generation in Inuvik is 8 MW capacity Total diesel generation capacity is 14.36 MW 3.5 MW capacity wind turbine in Inuvik Solar capacity is 0.14 MW	Wind Solar (limited) Imported Biomass Imported biodiesel Nuclear Natural Gas	Electrolysis NG conversion (requires export for economic feasibility) Biomass for heating MMNR for electricity	Electricity H_2 NH_3 Biomass	NG availability, see Table 14 in Appendix B. Biomass: Yes, see Section **Error! Reference source not found.**. Windier areas especially off the coast. Potential for added wind power. See Figure 12 wind speeds. Low potential for solar. See Figure 10. Hydro, see **Error! Reference source not found.** Appendix E.	Wind → Hydrogen Wind → electricity Solar (limited) → Hydrogen Solar (limited) → electricity Biomass → heating Imported biodiesel → electricity Hydrokinetic → electricity	MMNR → electricity NG → hydrogen → ammonia (requires export)	Short Term: utilize wind, solar (limited), biomass, and import biodiesel Long Term: MMNR, NG to ammonia, import ammonia or biodiesel

Sahtu Region	Solar (limited) Biomass (wood) NG Petroleum Products	NG Generation in Norman Wells is 15 MW capacity Total diesel generation capacity is 5.83 MW Solar capacity is 0.1 MW	Wind (regional) Solar (limited) Biomass Imported Biodiesel Nuclear NG	Electrolysis NG conversion (requires export for economic feasibility) Biomass for heating MMNR	Electricity H_2 NH_3 Biomass	NG availability, see Table 14 in Appendix B. Biomass: yes, see section **Error! Reference source not found.** Lower wind potential. Explore 150 m turbines for better wind profiles. See Figure 12 for wind speeds. Low potential for solar. See Figure 10. Hydro, see Appendix E.	Wind (regional) → Hydrogen Wind (regional) → electricity Solar (limited) → Hydrogen Solar (limited) → electricity Biomass → heating Imported biodiesel → electricity Hydrokinetic → electricity	MMNR → electricity NG → hydrogen → ammonia	Short Term: utilize wind (regional), solar (limited), biomass, and import biodiesel Long Term: MMNR, NG to ammonia, import ammonia or biodiesel
Deh Cho Region	Solar (limited) Biomass (wood) Petroleum Products	Total diesel generation capacity is 6.62 MW Solar capacity is 0.05 MW	Wind (regional) Solar (limited) Biomass NG	Electrolysis NG conversion (with transport to other regions) Biomass for heating	Electricity H_2 NH_3 Biomass	NG availability, see Table 14 in Appendix B. Biomass: yes, see Section **Error! Reference source not found.** Lower wind potential. Explore 150 m turbines for better wind profiles. See Figure 12 for	Wind (regional) → electricity Wind (regional) → Hydrogen Solar (limited) → electricity Solar (limited) → Hydrogen Biomass → heating	NG → hydrogen → ammonia	Short Term: utilize wind (regional), solar (limited), biomass, import biodiesel Long Term: NG to ammonia, import biodiesel or ammonia

						wind speeds. Potential for solar. Solar potential is better than the northern regions. See Figure 10. Hydro, see Appendix E.	Hydrokinetic → electricity		
North Slave Region	Solar Hydro Biomass Petroleum Products	Total diesel generation capacity is 17.97 MW Total hydro generation is 37 MW Solar capacity is 0.02 MW	Wind (regional) Solar (limited) Biomass Nuclear	Electrolysis Bio feedstock conversion Biomass for heating SMR	Electricity H_2 NH_3 Biodiesel Biomass	Biomass: yes, see Section **Error! Reference source not found.** Lower wind potential in some areas. See Figure 12 for wind speeds. Potential for solar. Solar potential is better than the northern regions. See Figure 10. Hydro, see Appendix E.	Wind (regional) → Hydrogen → Ammonia Wind (regional) → electricity Solar (limited) → electricity Solar (limited) → hydrogen Biomass → heating Hydrokinetic → electricity	SMR → Hydrogen → Ammonia SMR → electricity Biomass → biodiesel	Short Term: utilize wind (regional), solar (limited), biomass, import biodiesel Long Term: SMR to hydrogen/ammonia, biomass to biodiesel
South Slave Region	Hydro Biomass Petroleum Products	Total diesel generation capacity is 8.5 MW Total hydro generation is 18 MW	Wind (regional) Solar (limited) Hydro Biomass Nuclear	Electrolysis Bio feedstock conversion Biomass for heating SMR	Electricity H_2 NH_3 Biodiesel Biomass	Biomass: yes, see Section **Error! Reference source not found.** Lower wind potential. Explore 150 m turbines for better wind profiles. See Figure 12 for	Wind (regional) → Hydrogen → Ammonia Wind (regional) → electricity Solar (limited) → electricity	SMR → Hydrogen → Ammonia SMR → electricity Biomass → biodiesel	Short Term: utilize wind (regional), solar (limited), biomass, import biodiesel Long Term: SMR, biomass to biodiesel

						wind speeds. This region has the best solar potential in the NWT. However, it is not as strong as areas in southern Alberta but comparable to Ontario. See Figure 10 for MDGI. Hydro, see Appendix E.	Solar (limited) → hydrogen Biomass → heating Hydrokinetic → electricity		

Appendix I Biomass Emissions Factors

Table 19: Typical emission factors for dust and the organic carbon fraction in dust. Taken from **[130]**.

	PM total		Organic carbon in PM
	g/GJ produced heat	% OC	g OC/GJ produced heat
Open fireplaces	322 - 1610	40..75%	150 - 800
Conventional stoves	140 - 225	50%	70 - 120
Modern woodlog stoves	46 - 90	20%	10 - 20
Pellet stoves	3 - 43	10%	1 - 8
Pellet boilers	3 - 29	5%	0 - 2
Biomass boilers without dust removal	28 - 57	3%	1 - 2
Biomass boilers with dust removal	8 - 15	2%	0.2 - 0.3

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