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Low-Carbon Fuels

Blended Heat: Assessing Hydrogen Blending in Calgary District Heating System

CALGARY REGION HYDROGEN HUB

AUGUST 2026

Zachary Cunningham | Zachary Redick | Antoine Duplantie Grenier | Amy Parenteau

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Executive Summary

Calgary District Heating Inc. (CDHI) operates a natural gas-fired district heating system serving the downtown core and the East Village. This assessment explores whether hydrogen blending could play a practical role in reducing emissions from that system.

This assessment builds on CDHI's 2023 hydrogen blending pilot, which tested hydrogen-natural gas blends up to 20% by volume in a single 15MW$_t$ boiler. This pilot demonstrated that low-volume hydrogen blending was technically feasible within the CDHI system. However, the pilot was short in duration and tested only a limited range of operating conditions. The results of the pilot should be treated as an encouraging proof of concept, rather than a complete assessment of long-term performance.

Supply mechanisms for hydrogen delivery to CDHI face a variety of challenges and are likely to have varied timelines for realization. Pipeline delivery could in theory provide a continuous supply but is seen as costly and challenging given the urban environment in which CDHI operates. Rail delivery would require specialized receiving infrastructure, a more mature hydrogen rail logistics framework, and suitable rail cars. Adjacent production to CDHI is constrained by limited available land and may face setback challenges. Road delivery of gaseous hydrogen via tube trailer is seen as the only practical near-term delivery method.

Scenarios for supplying a 20% volumetric hydrogen blend and a logistically limited scenario (one tube trailer per day) were also completed to understand the volumes and the potential for emissions reduction. A key consideration is that a 20% volumetric blend of hydrogen does not translate into a 20% energy replacement or a 20% emissions reduction — at 20% by volume, it supplies slightly under 8% of the boiler's energy input. As a result, the emissions reduction from blending is modest, particularly when lifecycle emissions are accounted for. To blend at this rate, it would require 278 tonnes of hydrogen per year based on 2027 energy demand projections.

The emissions and cost results suggest that hydrogen blending is unlikely to be a primary near-term decarbonization pathway for CDHI. On-site CO_2 emissions decline when hydrogen displaces natural gas, but lifecycle benefits depend on the hydrogen's carbon intensity (CI). Under the modelled assumptions, blending results in relatively high abatement costs across the range of hydrogen prices assessed.

Overall, hydrogen blending at CDHI appears technically feasible but is constrained by practical considerations. The value of blending hydrogen is more likely to be as a strategic anchoring demand for an early hydrogen ecosystem than for competitive emissions reductions alone.

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About The Transition Accelerator

Our Objective

The energy transition is disrupting global power. The Transition Accelerator is here to help Canada win — **economically** and **geopolitically.**

Our Work

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

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

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

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

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

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

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Amy is a senior technical lead with over 20 years of experience in process engineering, process safety, and risk management within the energy sector. She uses rigorous scenario analysis to assess the safety and feasibility of complex energy projects. Throughout her career, Amy has leveraged her technical expertise to drive operational resilience, deliver margin enhancement, and align legacy asset designs with modern regulatory frameworks and industry safety standards.

List of Abbreviations

Abbreviations	Definitions
ASME	American Society of Mechanical Engineers.
ATR	Autothermal reforming; a hydrogen production process combining partial oxidation and steam reforming.
CCS	Carbon capture and storage; a process that captures CO_2 emissions from industrial sources for permanent underground storage.
CDHI	Calgary District Heating Inc.
CHP	Combined heat and power; simultaneous production of electricity and useful thermal energy from a single fuel source.
CI	Carbon intensity; greenhouse gases emitted per unit of hydrogen.
CO_2	Carbon dioxide; a greenhouse gas released by combustion and other processes.
CO_2e	Carbon dioxide equivalent; a common unit for comparing the warming impact of different greenhouse gases.
CPKC	Canadian Pacific Kansas City; the rail company formed by combining Canadian Pacific and Kansas City Southern.
DE	District energy; a system that provides thermal energy to multiple buildings through shared infrastructure.
GHG	Greenhouse gas; a gas that traps heat in the atmosphere and contributes to the greenhouse effect.
GH_2	Gaseous hydrogen; hydrogen stored and transported in compressed gaseous form.
H_2	Hydrogen; a gaseous fuel (at room temperature) composed of molecular hydrogen.
HHV	Higher heating value; total fuel energy including the heat recovered from water condensation during combustion.
ISO	International Organization for Standardization; referenced in the context of hydrogen ISO railcars.
LH_2	Liquid hydrogen; hydrogen cooled below −253°C to a liquid state for high-density storage and transport.
NO_x	Nitrogen oxides; a group of reactive nitrogen-containing gases formed during combustion.
NRCan	Natural Resources Canada; the federal government department responsible for Canada's natural resources, including energy, minerals, and forests.
RMCF	Rocky Mountain Clean Fuels; a hydrogen producer located approximately 50–70 km from CDHI.
SMR	Steam methane reforming; a process that reacts methane with steam to produce hydrogen and CO_2.
YYC	YYC Calgary International Airport; Calgary’s primary international airport.

List of Units and Symbols

Units/Symbols	Definitions
$/GJ	Dollars per gigajoule; used to express energy or fuel pricing
$/kg	Dollars per kilogram; used to express fuel production or purchase cost by weight.
$/tonne	Dollars per tonne; used mainly to express the cost of emissions abatement.
bar	Bar; unit of pressure equal to 100 kilopascals.
COP	Coefficient of Performance; the ratio of useful thermal energy delivered by a heat pump to the electrical power consumed by the heat pump.
GJ	Gigajoule; unit of energy equal to one billion joules.
kg	Kilogram; unit of mass equal to 1,000 grams.
km	Kilometre; unit of length equal to 1,000 metres.
kt	Kilotonne; unit of mass equal to 1,000 metric tonnes.
m	Metre; SI base unit of length.
m^3	Cubic metre; unit of volume.
MJ	Megajoule; unit of energy equal to one million joules.
Mt	Megatonne; one million metric tonnes.
MW	Megawatt; unit of power equal to one million watts.
MW_e	Megawatt electric; electrical power output expressed in megawatts.
MW_t	Megawatt thermal; thermal power output expressed in megawatts.
ppm	Parts per million; concentration expressed as one part per million parts.
psi	Pounds per square inch; unit of pressure.
Sm^3	Standard cubic metre; gas volume measured at a standard temperature and pressure.
t	Metric tonne; unit of mass equal to 1,000 kilograms.
TJ	Terajoule; unit of energy equal to one trillion joules.
vol%	Volume percent; concentration expressed as a percentage of total volume.

1 Background

District heating systems present a significant opportunity for integrating low-carbon energy solutions to lower emissions of building heating in dense urban areas. In Canada, these systems are typically fuelled by natural gas combustion and have established networks in cities such as Toronto, Vancouver, Markham, and Calgary. There is increasing interest in how these systems can transition toward lower-carbon energy sources while maintaining reliability and affordability. District heating loops can be thought of as large, flexible thermal batteries that can integrate thermal energy from a mix of sources, including electricity, waste heat, atmospheric or ground heat, and combusted fuels. This flexibility in the input energy sources feeding a central system creates more efficient, diversified, and resilient large-scale heating for buildings in dense urban environments.

Hydrogen blending has been proposed as a means to reduce direct combustion emissions from natural-gas-fired district heating systems. It can be blended with natural gas to reduce carbon intensity within existing infrastructure or used directly in hydrogen-ready equipment. In the early stages of a hydrogen ecosystem, district heating systems could play an important role as an anchoring demand for excess hydrogen that is produced regionally, helping to build economies of scale while other hydrogen-suitable sectors such as long-range heavy-duty transportation develop, helping to alleviate the ‘chicken and egg’ challenge that currently exists in the hydrogen ecosystem.

For Calgary, an opportunity exists in combining a historic culture of innovation, energy expertise, and a desire to reduce emissions in the city. Exploring the use of hydrogen in district heating could support the transformation of Alberta’s natural resources, build early hydrogen demand that could support pilots that work towards climate goals, and demonstrate practical applications of hydrogen beyond transportation and industry. If technically and economically viable, hydrogen blending could reduce direct emissions from CDHI and provide a local demonstration case for low-carbon district heating in a cold-climate city.

This report explores hydrogen blending in Calgary’s district heating system from a technical, logistical, and economic perspective.

1.1 City of Calgary Emissions Reduction Goals

Aligning with global emission reduction commitments, the City of Calgary has developed a climate strategy that commits to making climate change a strategic priority. The City's current targets are clear: reduce greenhouse gas (GHG) emissions by 60% below 2005 levels by 2030 and achieve net-zero emissions by 2050 [1]. These commitments are to be achieved through a mix of mitigation and adaptation, with a priority on energy efficiency, low-carbon energy sources, and resilient infrastructure.

Calgary has already made measurable progress towards this goal. Per-capita emissions fell from 16.7 t CO_2e/person in 2005 to 11.3 t CO_2e/person in 2023, a drop of about 32% [2]. However, with a rapidly growing population, these reductions in per capita emissions are insufficient to produce a large overall drop in emissions with current measures. Meeting emission commitments will require a diversified approach that balances economic development, existing infrastructure, affordability, and energy resiliency. Hydrogen blending in district heating has the potential to be a part of this diversified approach.

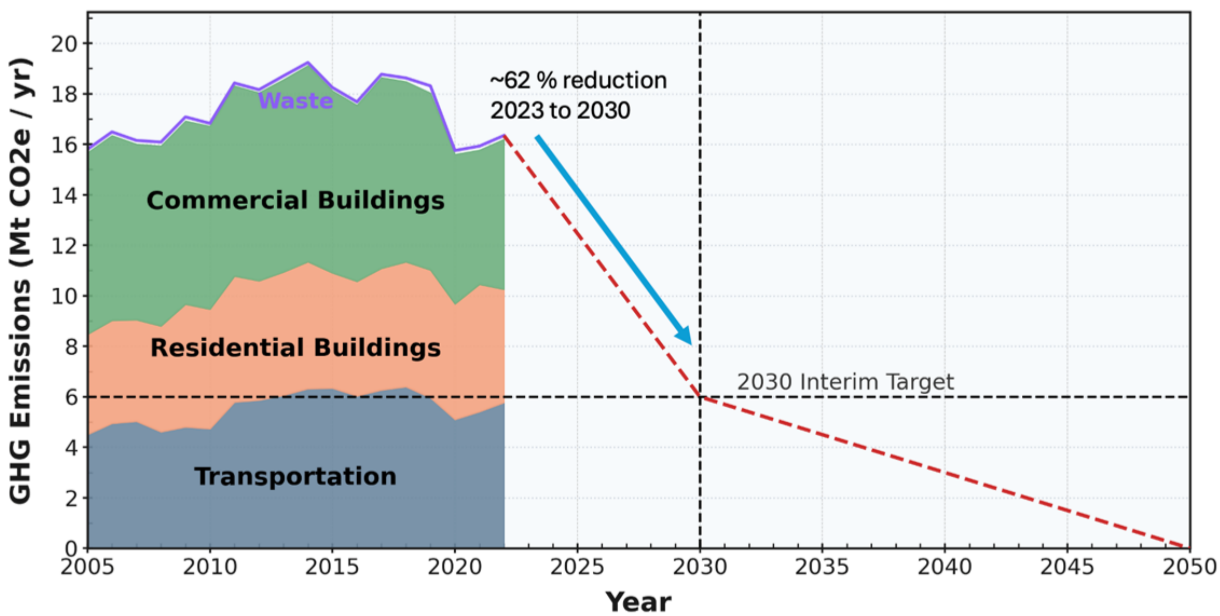

Figure 1 Calgary community-wide GHG emissions and future emission targets

Historical community-wide GHG emissions in Calgary, 2005-2023, by sector. The dashed line shows a linear pathway from 2023 emissions to the 2030 interim target and net-zero by 2050. The City reports 2023/2024 community-wide emissions at ~15.8 Mt CO_2e [3]. The 2030 target is based on Calgary's goal to reduce GHG emissions 60% below 2005 levels by 2030 [1], which implies about 6.4 Mt CO2e from the City's 2005 baseline of 15.9 Mt CO_2e.

1.2 District Heating Overview

District heating is a shared thermal infrastructure system in which a central plant supplies hot water through insulated pipes to multiple buildings along a circuit for space and water heating. Each building extracts heat through a heat exchanger and returns cooler water to the system for reheating.

Compared with conventional building-level heating, district systems centralize thermal production, enabling higher efficiency, simplified maintenance, and greater flexibility in fuel selection. This structure allows different energy inputs to be integrated within a single system over time. District energy infrastructure can also be designed to provide cooling during warmer months, either through chilled-water networks or thermal energy-sharing systems, depending on the local system design.

Thermal energy can be supplied by natural gas or biomass boilers, combined heat and power systems, large electric heat pumps, geothermal fields, and wastewater or industrial waste heat. By centralizing production and enabling the use of multiple lower-cost or locally available energy sources, district heating systems can improve overall efficiency and reduce operating costs.

Figure 2 Calgary's district energy network and key connected buildings

Schematic of Calgary District Heating's district energy network and selected connected buildings in downtown Calgary and East Village. This figure is reproduced from the Calgary District Heating website [4]. Calgary District Heating (top left) reports that its thermal distribution system currently serves 22 buildings shown as the blue line in the figure. Each building connects to the network through heat exchangers, represented by green dots.

1.3 Heating 101

Thermal energy (heat) is highly flexible because it can be produced from a wide range of inputs. Humans have deliberately generated heat using biomass for at least several hundred thousand years. Over time, heat production shifted toward coal, oil, and natural gas, largely driven by resource availability, attractive (higher) energy densities, and lower costs.

As a society, we now recognize that combustion of these fuels produces undesirable by-products, including ash, particulates, heavy metals, and CO_2, which require mitigation. As a result, a central challenge today is delivering the essential, life-sustaining heat we require with the lowest possible levels of harmful byproducts and environmental impacts.

This recognition has accelerated the development of low-carbon and non-emitting heating technologies and alternative fuels. However, viable solutions must meet three conditions:

1. Provide a reliable and highly flexible heat supply that can meet seasonal peak demand
2. Remain economically viable, particularly in cold climates where much heat energy is required
3. Rely on resource inputs that are scalable today and in the future that do not create unacceptable trade-offs in other areas (energy vs. food, energy vs. usable land, energy vs. clean air)

This section provides a high-level overview of heating options available today, along with the trade-offs and challenges associated with each.

Biomass

Biomass is one of the oldest fuels used for heat and remains widely available, locally sourced, and relatively low-cost, particularly where forestry residues are abundant. However, its combustion produces a range of undesirable by-products that vary with moisture content, combustion temperature, and appliance design. These include fine particulate matter (often at levels significantly higher than those from fossil fuels in small-scale systems), carbon monoxide, volatile organic compounds, polycyclic aromatic hydrocarbons, nitrogen oxides, and a residual ash stream requiring disposal. Combustion also releases biogenic carbon dioxide, whose climate benefits depend on forest regrowth rates and land-use assumptions, and may not be offset on meaningful time scales.

Coal

After biomass, coal is one of the oldest fuels used for heat, as it is energy-dense, relatively inexpensive, and easy to transport. However, coal combustion produces a wide range of undesirable byproducts, the exact composition of which depends on coal grade and source. These can include sulphur dioxide (acid rain-forming), nitrogen oxides, carbon monoxide, heavy metals (such as mercury), fine particulate matter, and a large solid waste component, alongside carbon dioxide. Large-scale coal mining has extensive environmental impacts.

Oil

Heating oil was widely adopted after the Second World War as an automated replacement for manual coal furnaces. Like coal, heating oil combustion produces undesirable emissions, although generally at lower levels and with less solid waste. Its use has declined substantially in Canada due to rising oil prices and the expansion of natural gas infrastructure, which has generally provided a lower-cost and more convenient alternative. Heating oil remains in limited use in areas where other heating options are not readily available.

Natural Gas

Natural gas is currently Alberta's dominant heating energy source and, as of 2023, provided approximately 86% of residential space heating demand and 92% of commercial space heating demand [5]. This is due to the relatively low cost of natural gas in the province, which has averaged around $1.43/GJ in 2025 and $1.17/GJ in 2024, according to the Government of Alberta [6]. Natural gas benefits from Alberta's well-developed infrastructure network and vast resources that are relatively insulated from international market pricing.

Natural gas end-use technology is mature and readily available across the province. However, natural gas combustion produces carbon dioxide, and capturing CO_2 from relatively dilute boiler flue gas remains challenging and expensive. In addition, fugitive methane emissions from production and delivery are recognized as a potent greenhouse gas.

Several technologies, such as oxy-combustion and the Allam cycle, are being explored or trialled to address this issue by producing a more concentrated CO_2 stream that is easier to capture and transport. Even if these technologies prove viable, carbon capture and storage infrastructure would need to be planned and built, as none currently exists in the Calgary Region today.

Electricity

Electricity-based building heating is not new; electric heating has been used for over a century and is enabled today through two main approaches: **resistive heating** and **heat pumps.**

Resistive heating systems, such as baseboard heaters, convert electricity directly into heat by passing electric current through a resistive material to create thermal heat and are effectively 100% efficient at the point of use [7].

Heat pumps, by contrast, use electricity to move heat rather than generate it directly. This is done via a vapour-compression cycle, making them far more energy-efficient than direct heating. They can draw heat from the air or ground and often deliver multiple units of heat per unit of electricity consumed, measured as a coefficient of performance (COP).

For air-source systems, heating COPs commonly fall in the range of about 2.0 to 5.4 under rated conditions, while ground-source systems generally achieve higher heating COPs, often in the range of about 3 to 5, depending on system design and operating conditions [8], [9], [10]. While efficiency declines at lower temperatures, modern cold-climate heat pumps can operate reliably below freezing temperatures. When electricity is generated from natural gas, overall efficiency and carbon intensity calculations should also account for upstream electricity generation losses.

Although heat pumps are a promising way to provide heat with lower energy input, district heating systems are likely to rely on hybrid configurations to meet large peak loads. The ability to generate and deliver sufficient energy during cold snaps, when air-source heat pump performance is reduced, and heating demand is highest, remains an important system consideration, making ground-source heat pumps more attractive in cold regions. Heat pumps are likely to play an increasing role in district heating, and the International Energy Agency notes that they are already being applied in district systems and industrial settings [11].

Geothermal

Geothermal heating uses underground thermal energy, transmitted by subsurface fluids, to provide usable heat for buildings. Geothermal resources can range from relatively low to moderate temperatures (in the shallow Western Canada context) to high-temperature volcanic systems such as those found in Indonesia or Iceland.

Shallow ground temperatures typically range from 5–20°C [9], [12], [13], while deeper sedimentary formations in Western Canada may reach 40–170°C depending on depth and geology [14], with direct-use heating applications typically targeting the 40–90°C range. Shallow, moderate temperatures are usually insufficient to directly supply district heating networks, so temperature upgrading is required. As a result, most geothermal district heating systems in Canada rely on heat pumps to raise the temperature to more usable levels.

Geothermal heating offers several advantages: stable, season-independent in-situ temperatures, low operating emissions, and the potential for long asset lifetimes. However, resource availability, drilling costs, and the need for infrastructure retrofits add complexity compared to familiar, direct-combustion heating systems. In practice, geothermal pathways in Alberta would most likely involve hybrid configurations combining geothermal heat pumps with other technologies to meet peak winter demand, rather than a fully standalone geothermal supply.

Hydrogen

Pure or blended hydrogen can be combusted to produce heat, similar to natural gas. However, hydrogen has important differences in its physical properties. On a mass basis, hydrogen contains more energy than natural gas; however, on a volumetric basis, hydrogen is less energy dense. At standard conditions, hydrogen has an energy density of ~10–12 MJ/m³, compared to 35–40 MJ/m³ for natural gas, meaning hydrogen provides only about 30–35% of the energy at the same volume and pressure [15], [16]. As a result, replacing natural gas energy with hydrogen has implications for infrastructure such as pipelines, compressors, and end-use equipment designed for natural gas.

Compared to natural gas, hydrogen combustion has a higher flame speed, a wider flammability range, and a lower ignition energy, requiring purpose-built or modified burners to manage flashback and maintain stable combustion for pure streams. While hydrogen combustion does not produce carbon dioxide at the point of use, it can generate nitrogen oxides (NO_x) from high combustion temperatures and produce more condensate in the flue gas. Material compatibility is another consideration, as hydrogen can cause embrittlement in certain steels and leakage through seals designed for larger natural gas molecules.

From a systems perspective, hydrogen faces infrastructure and cost challenges. Existing natural gas transmission networks may accommodate limited hydrogen blending, but high-percentage or pure hydrogen systems typically require pipeline upgrades, new compression equipment, dedicated storage, and appliance replacement. Hydrogen remains significantly more expensive on an energetic basis than natural gas today. While hydrogen is viewed as attractive for decarbonizing hard-to-electrify applications, its use for widespread building heating would require substantial infrastructure investments and cost reductions to become competitive. The carbon intensity of hydrogen depends heavily on its production pathway and the region where it is produced.

1.4 Calgary District Heating Inc. (CDHI)

Calgary District Heating Inc. (CDHI) is a privately owned energy utility serving the downtown Calgary core and East Village. Heat is delivered to 22 buildings through a closed-loop thermal distribution system, where large-diameter insulated underground pipes circulate hot water from a central plant to energy transfer stations in each connected building for space heating and domestic hot water.

Thermal energy is generated using four high-efficiency natural gas boilers with a total thermal capacity of 55 MW, along with a 3.3 MW combined heat and power (CHP) unit. Boiler thermal efficiency was reported to be 90–96% under typical conditions, with measured distribution losses of approximately 10% in the thermal loop. In 2023, CDHI reported 24,237 t CO_2e [17], equal to about 0.26% of building-related emissions and about 0.15% of total city emissions [3].

Figure 3 Calgary District Heating facility, downtown Calgary

Exterior view of the Calgary District Heating facility in downtown Calgary. The facility is located near Calgary's downtown core, which helps reduce distribution distances to connected buildings and supports potential future network expansion. The chimneys visible above the building are the exhaust stacks for the natural gas boilers. The facility's connection to ATCO's underground natural gas system is not visible in this image.

CDHI has investigated low-carbon heating solutions through a hydrogen-blending pilot, assessments of electric boilers and wastewater heat recovery opportunities, and is implementing heat recovery from a computing cluster. With its centralized infrastructure, flexible and controllable load, and proven openness to piloting emerging technologies, CDHI is well-positioned to lead testing and scale-up of low-carbon thermal pathways.

1.5 CDHI Hydrogen Blending Pilot

Pilot Background

This section summarizes the key findings from the *DE Hydrogen Pilot Report* provided by CDHI, which documents a six-day pilot test of hydrogen blending in the district energy system [4], [18]. This pilot was conducted in November 2023 in collaboration with TC Energy and the City of Calgary [4]. It evaluated the use of a hydrogen-natural gas blend in one 15 MW boiler, with hydrogen blended to up to 20% by volume, the maximum allowable under the existing burner configuration. The objective was to assess whether low-percentage hydrogen blends could be introduced into the existing system without requiring major capital or operational modifications.

The pilot addressed several related technical and planning objectives:

- **Equipment assessment**: evaluate the limitations of existing equipment and infrastructure, including burner and system constraints, and their adaptability for hydrogen blending.
- **Efficiency and emissions assessment**: measure and compare boiler efficiency and CO_2 emissions across hydrogen-natural gas blend ratios up to 20% by volume.
- **Integration planning**: inform future integration of hydrogen into the broader district energy system, including potential connection to on-site hydrogen generation or storage.
- **Safety and operational readiness**: identify process safety considerations and operational adjustments required to support hydrogen blending in the existing facility.
- **Future scale-up planning**: identify priorities for subsequent testing and implementation, including higher hydrogen blend ratios, NO_x testing, broader operating scenarios, system refinement, and regulatory and stakeholder engagement.

Hydrogen Supply and Delivery

Gaseous hydrogen was supplied by Air Liquide and delivered to the site by Certarus via tube trailer. The trailer carried approximately 300 kg of hydrogen at an initial pressure of about 300 bar (4,350 psi) at a purity of 99.99%. Tube-trailer delivery was the only practical supply option for the pilot, as no dedicated hydrogen distribution infrastructure exists in the area.

On-Site Injection and Blending

Hydrogen was blended with natural gas and supplied through newly installed internal piping at approximately 5 bar (73 psi). Pipework included a dedicated tie-in point and isolation valves. An outdoor blending and pressure-reduction skid received hydrogen from the tube trailers, reduced and stabilized the pressure, metered the hydrogen and natural gas streams, blended them to a controlled setpoint, and monitored operation under automated control.

The system also incorporated check valves, leak detection, venting, and emergency shutdown capability. Blending was tested in 5% increments up to 20% by volume, consistent with the existing burner limit. The setup was intended to support safe, consistent pilot operation while remaining compact and reversible after the test period.

Pilot Results

The pilot was completed successfully without incident. It was confirmed that the hydrogen injection and boiler systems could operate safely and within equipment limits, providing initial evidence of performance and emissions impacts. Although the pilot lasted over six days total, the efficiency results reported by CDHI were based on a subset of hourly intervals across only three consecutive days during which the test boiler alone supplied the district energy system load. During those intervals, hydrogen blend fractions ranged from about 5.5 to 18.5 vol%, and boiler efficiency was calculated on an HHV basis using an energy balance approach consistent with ASME Performance Test Code 4 [19].

Across the measured intervals, the weighted-average boiler efficiency during the pilot was 80.46%, compared with a baseline average of 81.10%. This represents an absolute decrease of 0.64%, or a 0.79% relative reduction in efficiency compared with the baseline value. As shown in **Figure 4**, the individual hourly efficiency points were scattered, and no strong decline in efficiency was observed as the hydrogen blend fraction increased over the tested range. The observed reduction in efficiency was therefore considered small and within the margin of error of the data collection equipment, indicating that the existing boiler could operate with hydrogen blends up to 20 vol% without modifications.

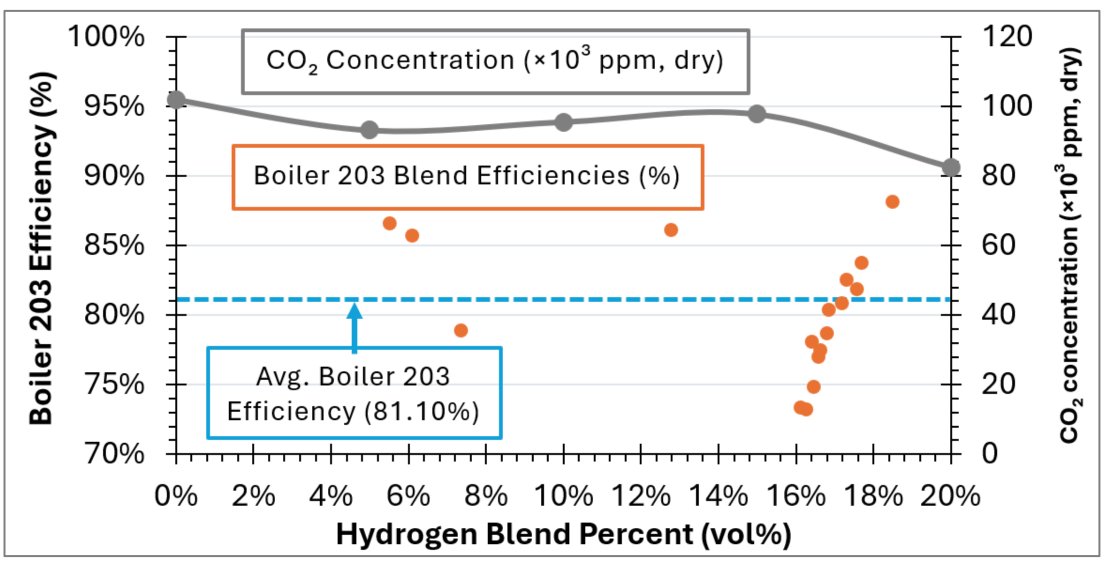

Figure 4 Boiler 203 efficiency and flue gas CO_2 concentration as a function of hydrogen blend fraction

Measured Boiler 203 efficiency and dry flue gas CO2 concentration at different hydrogen blend fractions during the CDHI hydrogen blending test. Orange markers show individual boiler efficiency measurements, and the grey line shows dry flue gas CO2 concentration at five measured blend fractions. The horizontal blue line marks the average Boiler 203 efficiency under baseline natural gas operation (81.10%). Hydrogen blend fraction is reported on a volume basis (vol%).

Stack testing by AGAT Laboratories at 0%, 5%, 10%, 15%, and 20% hydrogen by volume showed that CO_2 concentration generally declined as hydrogen fraction increased, reaching 82,600 ppm at 20 vol% hydrogen compared with 102,000 ppm at 0 vol%, which was reported as an overall reduction of about 19%. However, NO_x emissions were not measured during the pilot.

Overall, the CDHI hydrogen blending pilot provided an early proof of concept for introducing hydrogen blends into an existing district heating boiler system. Blending up to 20 vol% hydrogen was operationally feasible within the limits of the existing burner configuration, with only a small reduction in boiler efficiency and a clear directional reduction in CO_2 emissions. However, because the pilot was short in duration, based on limited measured operating intervals, and did not include NOx monitoring, the results should be interpreted as an initial demonstration rather than a definitive performance assessment.

2 Hydrogen Supply Pathways

Before modelling energy flows and hydrogen volumes for various blending scenarios, it is worth considering the practical realities of hydrogen supply and delivery, not only how much hydrogen might be needed, but how it could realistically get there. Two key questions frame this analysis:

1. **Where could the hydrogen supply come from?**
2. **How could it be delivered to CDHI?**

As shown in **Figure 5**, the CDHI's central urban location presents significant challenges for general new infrastructure development, including hydrogen-related infrastructure. With this constraint in mind, this chapter examines four potential supply pathways: **pipeline** delivery, **rail** delivery, **adjacent hydrogen production**, and **tube-trailer** delivery.

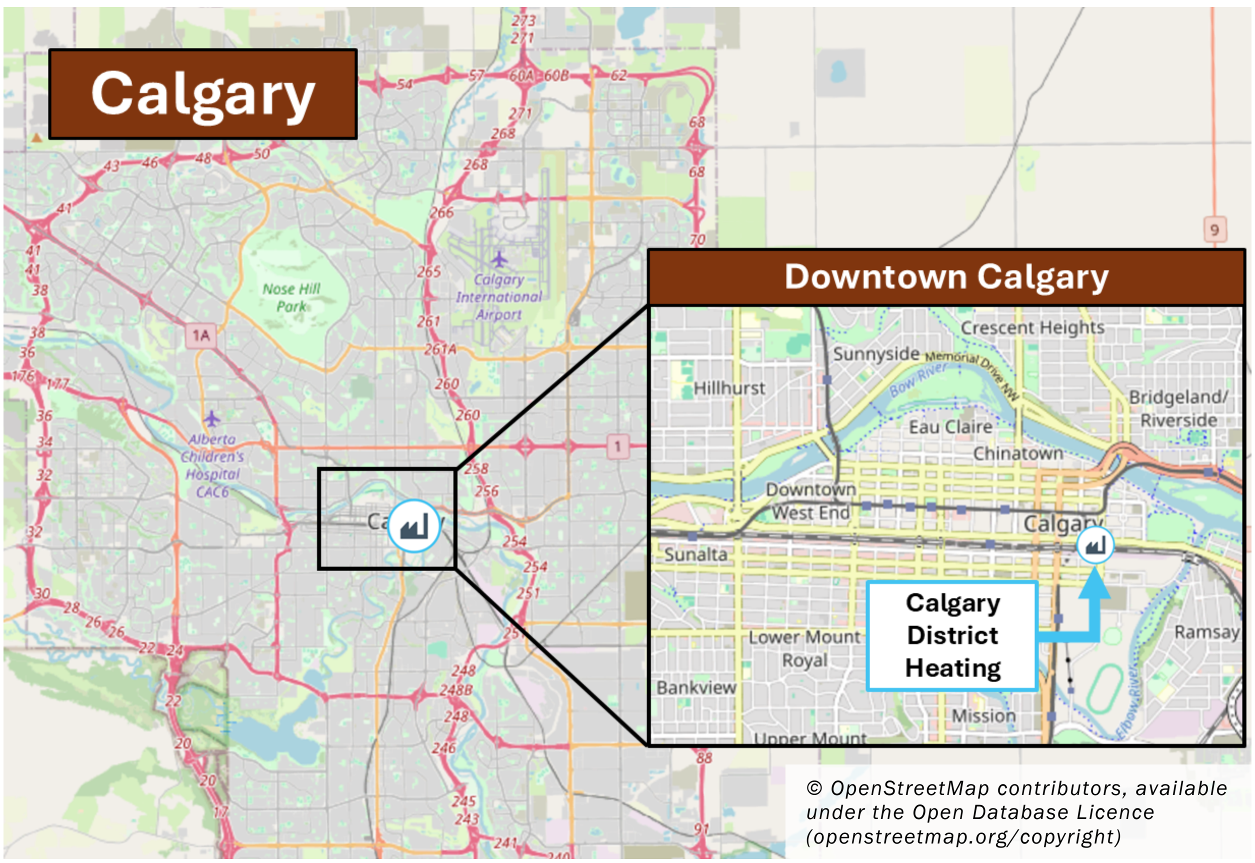

Figure 5 Location of the CDHI facility within downtown Calgary

Direct Pipeline Supply of Hydrogen

Pipelines are a proven means of reliably and continuously delivering large volumes of molecules. However, they are capital-intensive, and their economics are highly sensitive to distance, throughput, right-of-way constraints, and the complexity of routing through developed urban environments. In the CDHI context, these factors carry particular weight: road and rail crossings, utility congestion, land use restrictions, and setback requirements can substantially increase costs and reduce practicality. As open space within the downtown core is limited, this section examines potential locations in nearby areas. **Figure 6** identifies three conceptual pipeline-based hydrogen supply locations near the site and illustrates example pipeline routings for each. Hydrogen blending into the broader natural gas pipeline network through a regional gate was not considered for this analysis, as it would require accounting for other users along the network.

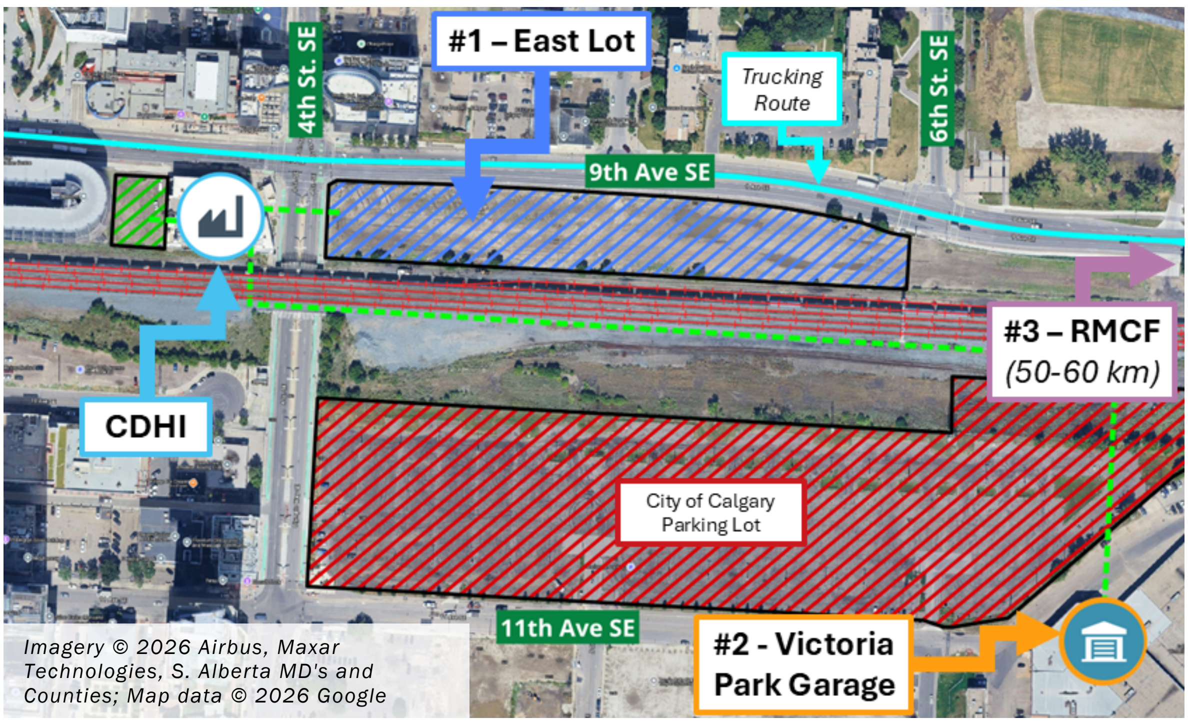

Figure 6 Potential pipeline-based hydrogen supply locations near CDHI

Annotated site map showing three conceptual pipeline-based hydrogen supply options for Calgary District Heating Inc. (CDHI): the East Lot, the Victoria Park Garage area, and Rocky Mountain Clean Fuels. The figure highlights nearby roads, the CPKC rail corridor, and approximate relative locations relevant to potential pipeline routing. The dashed green line shows example pipeline connections from each area to CDHI and is included for illustrative purposes only.

Option 1 - East Lot: As shown in **Figure 6**, the East Lot is the closest conceptual supply location to CDHI and would likely be the most practical of the three from a routing perspective. A pipeline connection from this site would still require crossing beneath 4th Street SE. The lot spans approximately 3.22 acres, but its usable footprint is limited by a narrow configuration, with maximum usable dimensions of roughly 40 m × 250 m (approximately 2.47 acres). This shape constrains equipment layout options for hydrogen production, compression, and storage, and any infrastructure sited here would also need to meet zoning and setback requirements (5 m GH_2 - 30 m LH_2 [20]), further reducing the effective working area and possibly restricting it to gas hydrogen storage only.

Option 2 - Victoria Park Garage area: This area is farther from CDHI and presents more significant routing challenges. A pipeline connection from this location would require crossing both the CPKC rail corridor and 4th Street SE. In addition to these crossing constraints, its future suitability is challenged by planned redevelopment for mass transit [21], [22].

Option 3 - Rocky Mountain Clean Fuels (RMCF): A current hydrogen producer located much farther from the site, at roughly 50 to 60 km. While this option could, in principle, provide hydrogen, the required pipeline length would be substantial, and the resulting cost was assumed to be prohibitive for the scale of hydrogen demand considered in this study.

Rail Delivery of Hydrogen

Rail was examined as a possible means of delivering hydrogen, as the CPKC mainline runs immediately adjacent to the CDHI site. Railcars could, in principle, offer higher delivery volumes than tube trailers while avoiding the capital burden of a large, dedicated pipeline, creating a potential bridging option as hydrogen demand grows. However, rail delivery would require a dedicated receiving spur, as unloading on the active CPKC mainline is not acceptable. As shown in **Figure 7**, the lot immediately west of CDHI is not a practical spur location due to limited space and an unfavourable angle to the rail corridor. The most plausible option is #1 – East Lot, which is adjacent to an existing stub-end CPKC spur approximately 180 m long; however, hydrogen unloaded there would still need to cross beneath 4th Street SE via a short underground pipeline to reach CDHI.

Beyond site layout, rail faces broader implementation challenges: hydrogen ISO railcars are not widely available, specialized handling requirements apply, and the Canadian regulatory framework for routine hydrogen rail transport is still developing. As a result, rail delivery is likely more of a long-term solution.

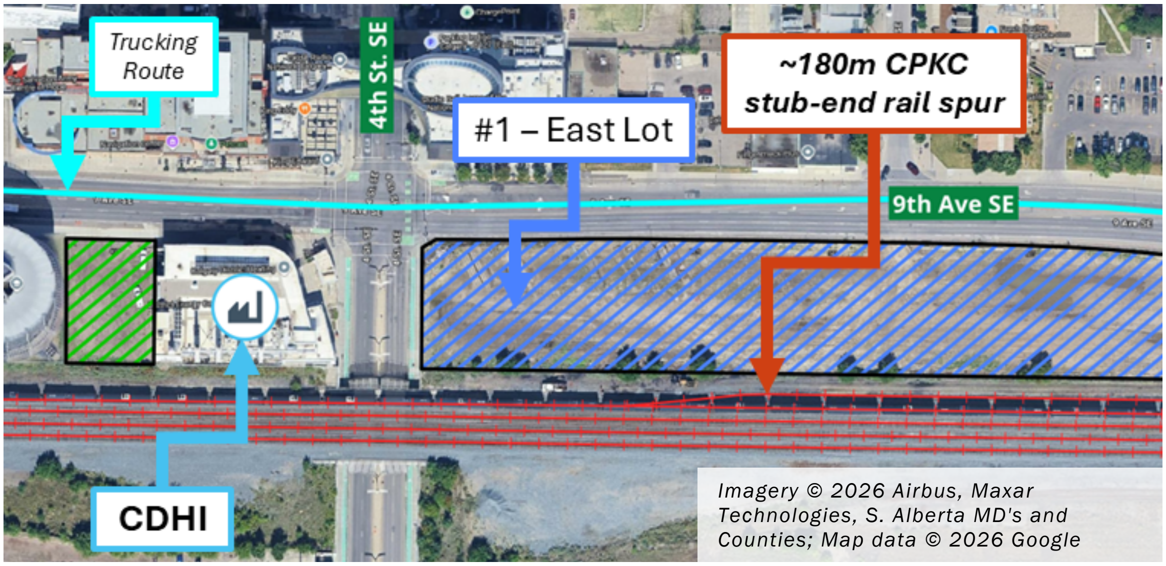

Figure 7 Potential rail-based hydrogen delivery option near CDHI

Annotated site map showing a conceptual rail-based hydrogen delivery option for Calgary District Heating Inc. (CDHI). The figure highlights the #1 – East Lot as the most likely nearby receiving area and identifies an approximately ~180m CPKC stub-end rail spur adjacent to the site.

Adjacent Hydrogen Production

Adjacent hydrogen production and storage would avoid the need for longer delivery routes and could simplify transfer to the CDHI facility. The main conceptual location identified for this option is the area labelled **#4 – West Lot**, directly adjacent to CDHI, as shown in **Figure 8**. Notably, the West Lot was used for gaseous hydrogen storage during the CDHI blending pilot, demonstrating that small-scale hydrogen storage could be feasible at this location. The question is not whether storage can work here, but whether the site can also accommodate the additional footprint required for production equipment.

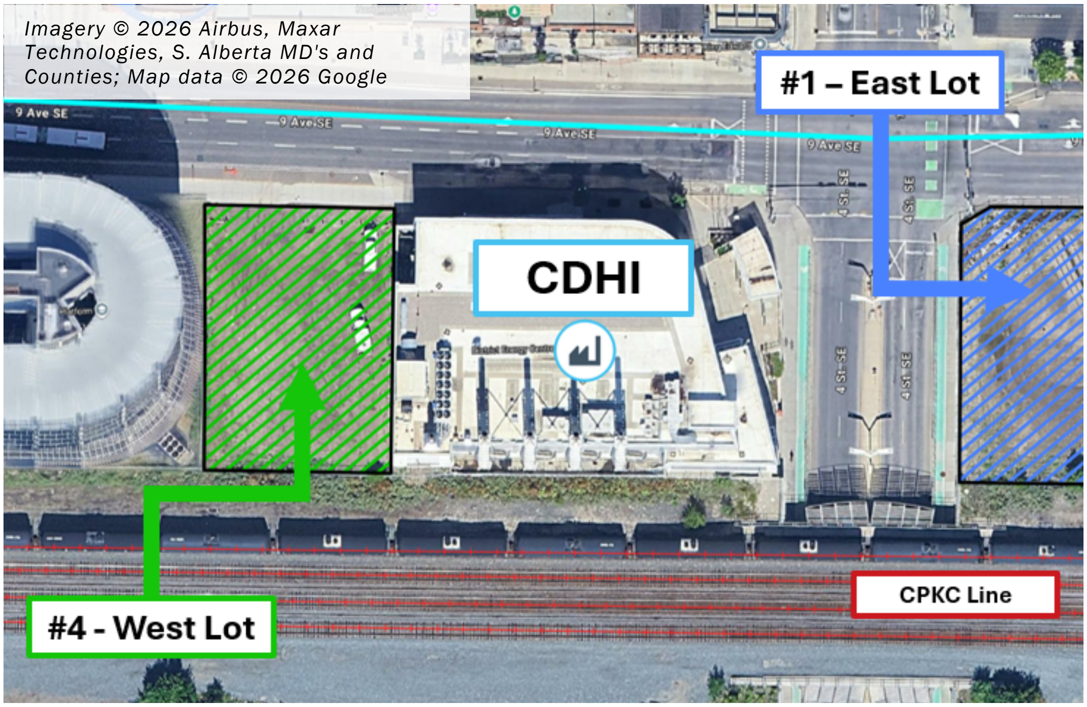

Figure 8 Potential adjacent hydrogen production or storage site near CDHI

Annotated site map showing the West Lot as a conceptual location for adjacent hydrogen production or storage serving Calgary District Heating. The figure identifies the lot's position immediately west of the CDHI facility, with proximity to the CPKC rail corridor and the East Lot shown for context.

The West Lot is relatively small, with approximate dimensions of 38.5 m by 28.5 m, and its proximity to surrounding infrastructure means setback requirements become a critical design constraint. Under the Canadian Hydrogen Installation Code [20], gaseous hydrogen storage requires a setback of 5 m, while liquid hydrogen storage requires a setback of 30 m [20]. These setback requirements would likely eliminate the option of liquid hydrogen storage and would limit gaseous hydrogen storage to a small part of the main lot. Considering production equipment alongside storage would further compress an already limited footprint.

Tube-Trailer Delivery of Hydrogen

No commercially available hydrogen supply currently exists in the city of Calgary, but several potential production sites could be envisioned. As shown in **Figure 9**, road distances from these sites to CDHI vary considerably: YYC Airport is approximately 10–18 km away, the East Calgary Landfill is approximately 12 km away, the Shepard Landfill is approximately 24 km away, and RMCF is 60–70 km via designated routes. Tube-trailer delivery is the most immediately viable of the supply options examined in this report, as it was successfully used during the CDHI blending pilot, demonstrating that the approach is workable in practice.

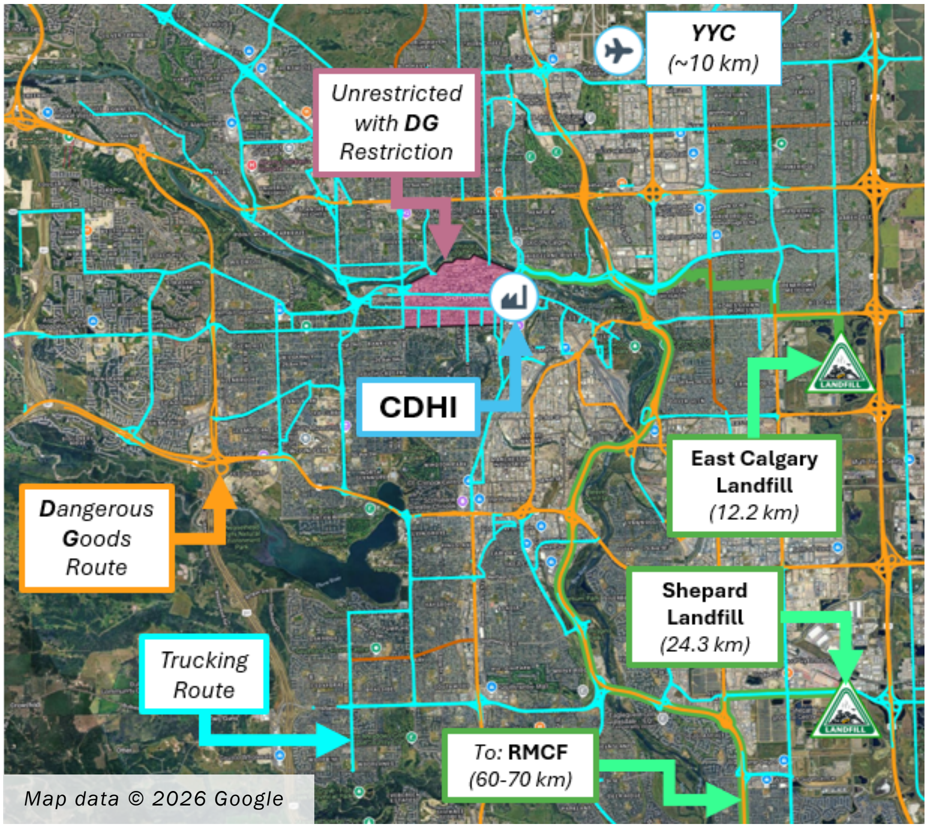

Figure 9 Potential tube-trailer hydrogen delivery routes to CDHI

Map showing Calgary District Heating Inc. (CDHI) in relation to potential tube truck hydrogen supply locations, including the East Calgary Landfill, Shepard Landfill, YYC Calgary International Airport, and Rocky Mountain Clean Fuels. The figure also shows candidate trucking routes and designated dangerous goods routes within Calgary. Under the City's truck route map and Traffic Bylaw framework, the central business district has additional dangerous goods restrictions, with transport of dangerous goods restricted from 6:00am to 6:00pm, Monday through Saturday [23].

Hydrogen is classified as a Class 2.1 flammable gas under the *Transportation of Dangerous Goods Act* [24], and the transportation of dangerous goods is restricted in the Central Business District from 6:00 am to 6:00 pm, Monday through Saturday, under Calgary's Transportation of Dangerous Goods Bylaw 13M2004 [25]. Exceptions are available, but as these hydrogen tube trailers would require placarding as a Class 2.1 flammable gas, this exemption would not apply. Delivery outside restricted hours or a special permit from the Calgary Fire Department Hazardous Materials Section would therefore be required, and any tube trailer delivery plan would need to be structured accordingly.

3 Hydrogen Blending Demand, Impacts, and Logistics Assessment

3.1 Objectives

The CDHI blending pilot established a technical foundation for hydrogen blending in district heating, addressing equipment compatibility, safety, emissions performance, and operational readiness. This section builds on that foundation by examining what hydrogen blending could look like at a larger scale, moving from pilot demonstration to system-level assessment. Four main objectives guided this analysis:

1. Determine the total volume of hydrogen required to sustain a 20% blend by volume across CDHI's district heating boilers over an annual cycle.
2. Model the likely impacts of delivering this hydrogen via a road-based supply chain, including the logistical demands and operational implications of tube-trailer delivery.
3. Characterize the energy contribution of a hydrogen blend and quantify the CO_2 reductions that could theoretically be achieved relative to natural gas combustion.
4. Provide an overview of the logistical requirements for hydrogen supply to CDHI, identifying where key gaps and constraints remain.

Together, these objectives extend the technical findings of the pilot into a system-level view, testing whether the supply, logistics, and cost conditions required to sustain blending at scale can realistically be met, and clarifying the role hydrogen blending could play within CDHI's broader decarbonization pathway.

3.2 Analysis Assumptions

- **System boundaries**: in this section, “energy demand” means the useful heat delivered to connected buildings. The analysis covers the district heating plant and the distribution network up to the building heat exchangers; anything on the customer side is outside scope.
- **System efficiency**: an overall thermal efficiency of approximately 86% for the district heating system, based on information provided directly by CDHI [18]. This figure differs from the weighted average boiler efficiency of 80.46% measured during the 2023 hydrogen blending pilot. The 86% figure reflects stack-level boiler efficiency under normal operating conditions and was used here on the basis of CDHI's operational knowledge of the system. For modelling purposes, this is decomposed into boiler losses of ~4% and thermal distribution loop losses of ~10%. The bulk of losses are therefore understood to occur across the distribution network. In future analyses, measured boiler and system efficiencies from extended pilot testing can be incorporated for greater accuracy.

- **Units and notation**: since the CDHI system utilizes condensing boilers, this analysis uses Higher Heating Values (HHV). Gas volumes are expressed at the utility's standard conditions (Sm^3). Natural gas HHV is taken as 37.3 MJ/Sm^3 [15]; hydrogen HHV is taken as 12.7 MJ/Sm^3 [16] and 141.7 MJ/kg [26]. For reference, the pilot report used a natural gas heating value of 39 MJ/Sm^3 derived from ATCO monthly supply data averaged over the prior calendar year. The difference is modest but noted for transparency.
- **Equipment**: the Combined Heat and Power (CHP) unit is excluded from this analysis; only the gas-fired boilers are considered. CHP operation at CDHI is dependent on favourable electricity rates and is not readily modelled on an annual basis. Load figures shown in this section are adjusted so that CHP thermal output is not counted; the profiles represent heat that must be met by the gas and hydrogen-fired boilers only. This is consistent with the scope of the 2023 pilot, which was also conducted with the CHP unit offline
- **Blending**: a "20% hydrogen blend" means 20% by volume at the plant meter, held constant over the year, consistent with the maximum blend ratio tested during the 2023 pilot. On an HHV basis, this corresponds to ~8% of the boiler's energy input from hydrogen, because hydrogen has a substantially lower energy density per cubic metre than natural gas. As a result, total blend throughput rises and natural gas volume falls only modestly for the same delivered heat output. Delivering the same energy input as 100% natural gas, therefore, requires approximately 15.2% more total gas blend by volume, and the same volume of blend provides approximately ~86.8% of the energy of pure natural gas, as detailed later in **Section 3.4**.
- **Carbon Intensity**: the carbon intensity of natural gas is assumed to be 54.33 kg CO_2e/GJ [27], and 35 kg CO_2e/GJ for hydrogen gas [28]. Hydrogen's CI varies widely depending on its production pathway, with estimates ranging from 10.6-47.9 kg for SMR, and 7-40.3 kg CO2/e GJ_{HHV} H_2 based on ATR with CCS included [28].
- **Trailer Capacities**: gaseous hydrogen tube trailers are assumed to carry 380 kg per trailer [29]; liquid hydrogen trailers are assumed to carry 3,823.2 kg per trailer assuming 54,000 L at 70.8 kg/m^3 LH_2 [30].
- **Data Sources:** Calgary District Heating supplied the datasets used to support the demand analysis. The data represents projected 2027 system demand, inclusive of all current and planned new customers.

Baseline Energy Balance

A simplified energy balance was used to characterize the CDHI boiler system under normal operation without hydrogen blending. Boiler losses are estimated at approximately 4% and thermal distribution loop losses at approximately 10%, consistent with the system efficiency assumptions outlined previously in **Section 3.2.** While simplified, this approach captures the order-of-magnitude energy characteristics of the system and provides a consistent baseline against which blending scenarios can be compared. The CHP unit is excluded from this analysis, given the complexity of its utilization under normal operating conditions.

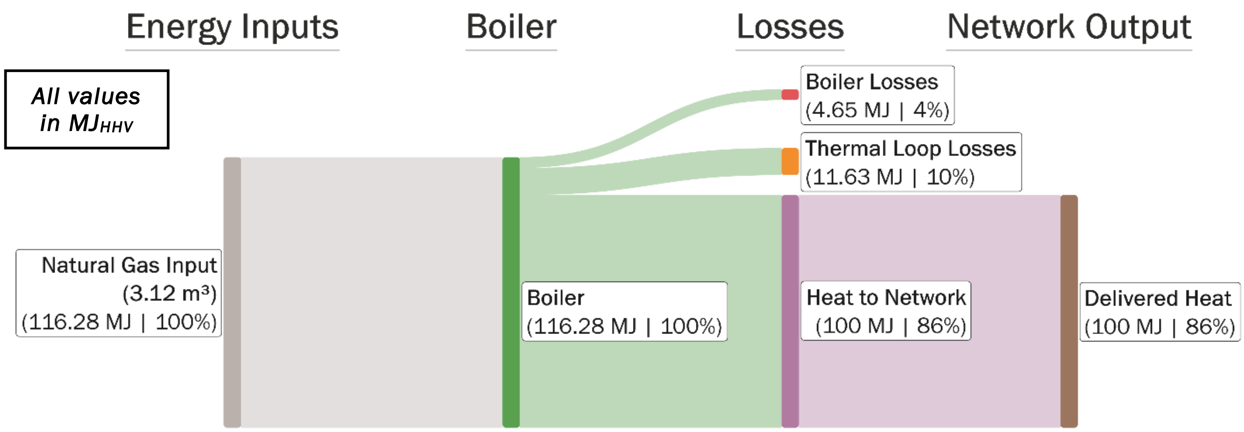

Figure 10 Illustrative energy and gas volume balance for 100% natural gas operation at CDHI

Simplified Sankey diagram showing the input energy required to deliver 100 MJ (HHV) of useful heat from the CDHI system. 116.28 MJ (HHV) of natural gas input is required to provide 100 MJ (HHV) of delivered thermal energy, with losses occurring through the boiler and the thermal loop. For simplicity, the analysis assumes 4% boiler losses and 10% thermal loop losses, while CHP operation is excluded.

Blended Energy Balance

In a 20% volume blend scenario, hydrogen contributes approximately 7.8% of the total boiler energy input, with losses assumed to be the same as in the no-blend scenario. There is an increased volume that reflects hydrogen's lower volumetric energy density compared to natural gas, meaning that a larger volumetric flow is required to deliver the same amount of energy. As a result, higher flow is required, which can affect equipment sizing and overall system performance.

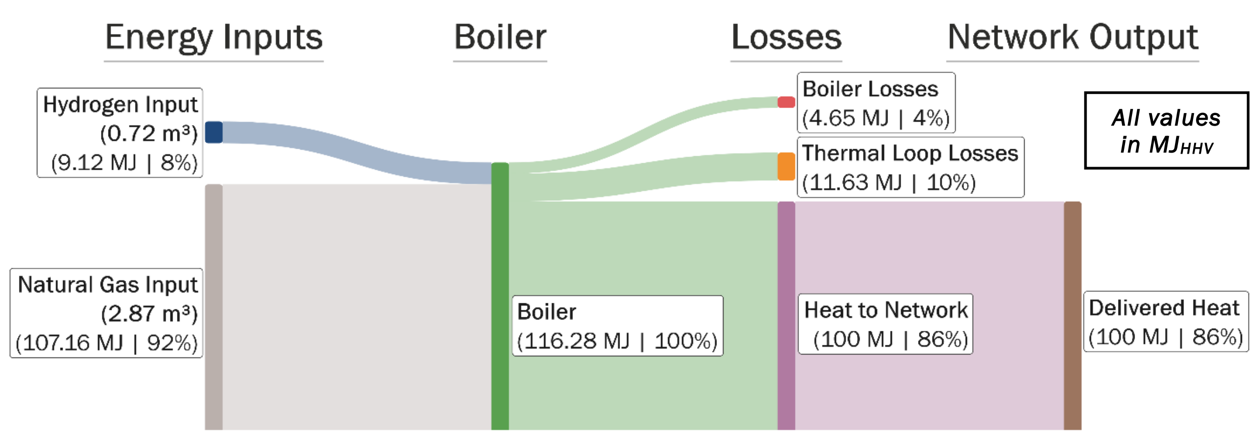

Figure 11 Illustrative energy and gas volume balance for a 20 vol% hydrogen blend at CDHI

Simplified Sankey diagram showing the energy and gas volume inputs required to deliver 100 MJ (HHV) of useful heat from the CDHI system under a 20 vol% hydrogen blend. Total input energy is approximately 116.28 MJ (HHV), consisting of about 107.16 MJ from natural gas and 9.12 MJ from hydrogen. On a volumetric basis, this corresponds to approximately 2.87 m³ of natural gas and 0.72 m³ of hydrogen, with hydrogen contributing about 8% of total boiler energy input despite representing 20 vol% of the blend. For simplicity, the analysis includes 4% boiler losses and 10% thermal loop losses, while CHP operation is excluded.

To understand the volume of natural gas that could be displaced by blending hydrogen at 20% into the modelled CDHI system, the modelled system was converted from energetic to conventionally used volumetric units. Additionally, the volume of hydrogen required to flow with the natural gas to the boiler was also calculated. This is shown in **Error! Reference source not found.**, with an example calculation showing how this was determined in **Appendix A.1.**

Operating Conditions

Under constant operating conditions, increasing hydrogen blending in natural gas reduces the maximum achievable boiler duty as compared to natural gas alone, due to hydrogen's lower volumetric energy density.

As the hydrogen fraction increases, the total energy delivered to the burner decreases if the total gas flow remains unchanged. Consequently, boilers designed for natural gas service cannot maintain their original rated output when hydrogen is blended without adjustments to system parameters. For example, a 20% hydrogen blend (by volume) reduces the effective boiler duty to approximately 86.8% of the original natural gas rating when the total gas flow rate is held constant, as seen in

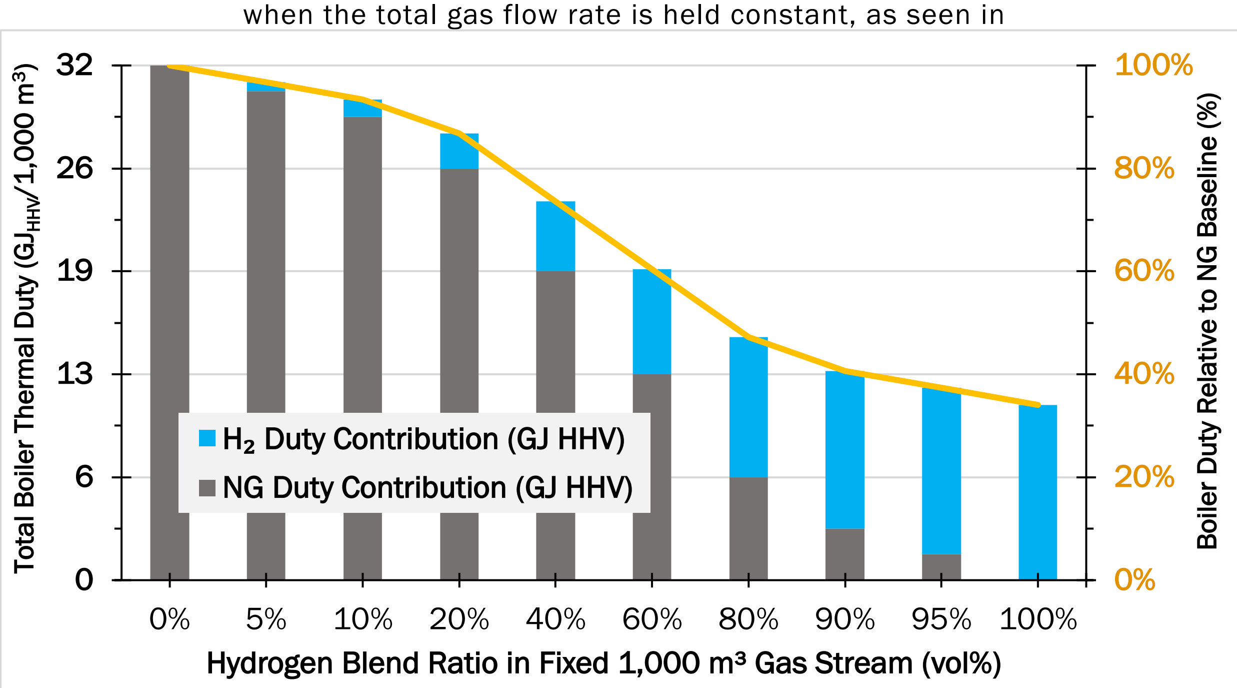

Figure 12 below.

This reduction in duty underscores a key operational consideration when introducing hydrogen into existing gas systems. While blending can reduce carbon intensity, higher hydrogen fractions progressively displace higher-energy natural gas, reducing the energy available for combustion unless compensatory measures are taken. Boiler or system modifications, such as increasing fuel flow capacity, adjusting burners, or modifying control systems, can address this effect by allowing higher total gas throughput. The results presented here should be interpreted as a demonstrative constant-flow scenario illustrating the relationship between hydrogen blending and boiler output, rather than a strict operational limit. The impact of this reduction in duty and the operational changes that might be required at CDHI are considered out of scope for this study.

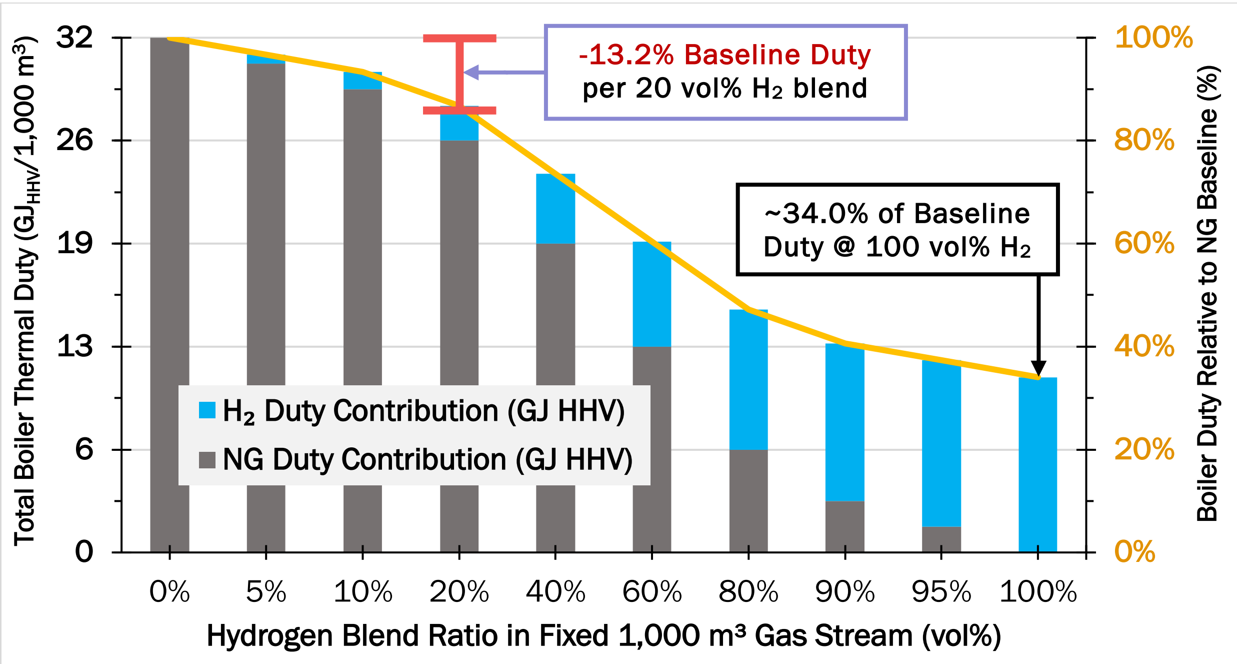

Figure 12 Decline in boiler thermal duty with increasing hydrogen blend ratio per fixed gas volume

Stacked bar chart showing natural gas and hydrogen duty contributions at selected hydrogen blend levels under fixed total gas volume. Increasing hydrogen fraction reduces total achievable boiler duty because hydrogen has a lower volumetric energy density than natural gas. In this example, duty drops by about 13.2% at a 20 vol% hydrogen blend and by about 66% at 100 vol% hydrogen relative to the all-natural-gas case.

A detailed table showing this relationship across a range of hydrogen blend levels (0–100 vol%) is provided in **Appendix A.2** (**Table 3**), showing the corresponding hydrogen and natural gas volumes, individual fuel duty contributions, and effective boiler duty relative to the all-natural-gas baseline for an illustrative gas volume of 1,000 m³.

3.3 Baseline System Demand Scenario

For this analysis, it was necessary to fully understand and characterize energy use and flow through the district heating system being serviced entirely by natural gas before modelling the impacts of hydrogen blending. This establishes a representative baseline against which a blended fuel input can be compared.

To characterize energy use and flows through the CDHI system, monthly forecasted demand data for 2027 were provided and used. This forecast accounts for planned additions to the thermal loop system, including the Calgary Events Centre, and was deemed more appropriate for this analysis than daily demand data, which would introduce unnecessary granularity.

The 2027 forecast shows monthly energy service demand delivered (blue) and the overall energy required by the boilers (sum of orange and blue, **Figure 13**). Demand fluctuates significantly throughout the year, with nearly a tenfold difference between summer and winter months. It peaks in December at approximately 92,959 GJ, reflecting space-heating requirements, and reaches its minimum in August at approximately 9,586 GJ, when energy use is primarily driven by hot water heating.

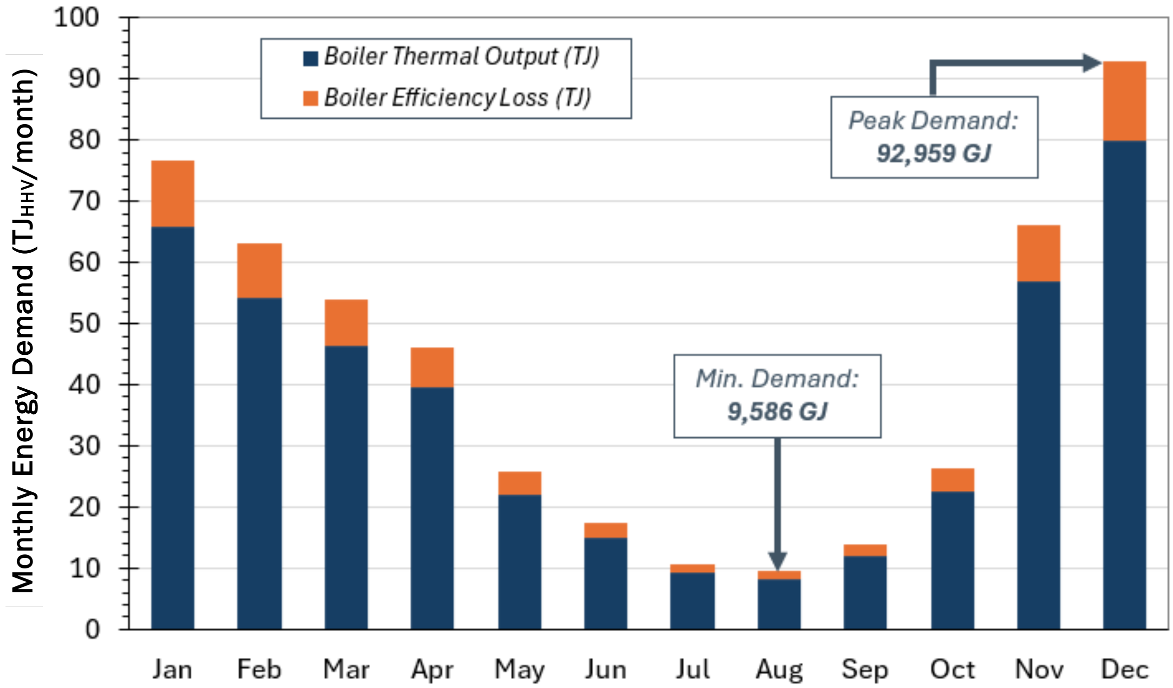

Figure 13 Projected monthly CDHI energy demand, 2027

Projected monthly CDHI energy demand (TJ_{HHV}/month) for 2027, based on forecast data provided by CDHI. The stacked bars show boiler thermal output and associated boiler efficiency loss. The forecast indicates strong seasonality, with demand peaking in December at 92,959 GJ and falling to a minimum of 9,586 GJ in August, reflecting much higher winter space-heating demand than summer domestic hot water demand.

3.4 20 vol% H_2 Blending Scenario

As the original pilot conducted for blending had a target of 20% to test boiler efficiency effects, a full 20% blending scenario has been modelled. This scenario assumes that all boilers would have access to the blended mix throughout the year, as modelling the utilization of a single, individually blended boiler was challenging and less useful. The purpose of this scenario is to provide order-of-magnitude estimates of the amount of hydrogen required and the subsequent emissions-reduction potential.

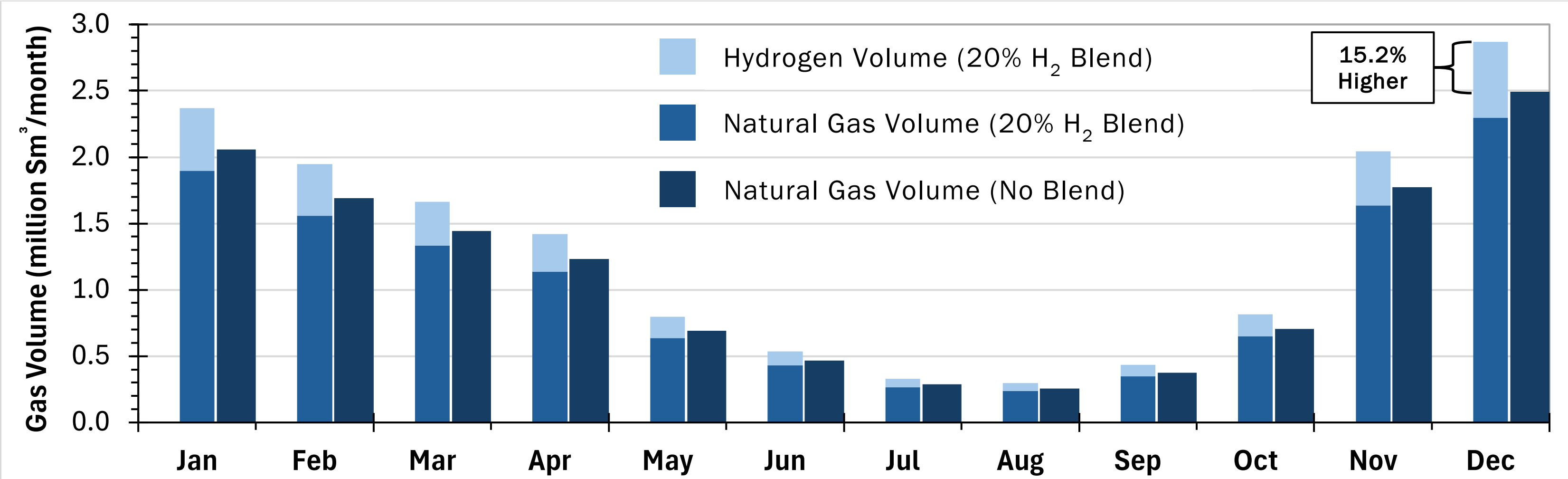

Figure 14 Monthly gas volumes for the 20 vol% hydrogen blending scenario vs. baseline natural gas, 2027

Monthly gas volumes required to deliver the same boiler duty under a 20 vol% hydrogen blend and a 100% natural gas case, based on the 2027 CDHI energy forecast. The blended case requires a higher total gas volume because hydrogen has a lower volumetric energy density than natural gas.

Table 1 2027 hydrogen demand and displaced natural gas volumes for the 20 vol% H_2 blending scenario

20 vol% H_2 Blend Results	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total (*Avg.*)
H_2 Volume [20% Blend] (thousand m³/month)	473.9	389.5	333.0	284.0	158.9	107.4	65.9	59.2	86.5	162.9	409.0	574.2	**3,104**
H_2 Mass Demand [20% Blend] (tonnes/month)	42.5	34.9	29.8	25.5	14.2	9.6	5.9	5.3	7.8	14.6	36.7	51.5	**278**
Daily Average H_2 Demand (kg/day)	1,370	1,247	962.7	848.4	459.5	320.9	190.5	171.2	258.4	470.8	1,222	1,660	**-** (*765*)
Displaced NG Volume (thousand m³/month)	161.4	132.6	113.4	96.7	54.1	36.6	22.4	20.2	29.5	55.4	139.3	195.5	**1,057**

Monthly and annual hydrogen demand, displaced natural gas volume, and average daily hydrogen supply requirements for the 20 vol% hydrogen blending scenario based on the 2027 CDHI energy forecast.

Hydrogen Demand

Hydrogen blending at a 20% volumetric rate in the CDH system is shown in **Figure 14** above, with details provided in **Table 1**. It can be seen that, as expected, monthly demand for hydrogen ranges from a peak in December of 51.5 tonnes, to a low in the summer of 5.3 tonnes in August, or 1,660 kg/day and 171 kg/day, respectively, with an annual demand being ~278 metric tonnes of hydrogen required to blend at 20% to displace 1.06 x 10^6 m^3 of natural gas.

Supply Logistics

To achieve a 20% volumetric hydrogen blend, pipeline capacity would need to be sized to meet peak winter demand. However, unless additional off-takers were available to absorb excess capacity, it would likely be underutilized during the summer months. This seasonal imbalance would weaken project economics and should be carefully considered in any pipeline development.

Given that pipeline, rail transport, and adjacent production were assessed as impractical in the near to medium term, gaseous tube-trailer delivery was also modelled as an alternative supply option (see **Figure 15**). During peak winter periods, maintaining a 20% hydrogen blend would require approximately 3 to 5 tube-trailer deliveries per day. Given CDHI's urban location, this level of delivery activity could be both socially and operationally challenging, particularly when accounting for the personnel required to manage deliveries and connect the hydrogen supply for blending.

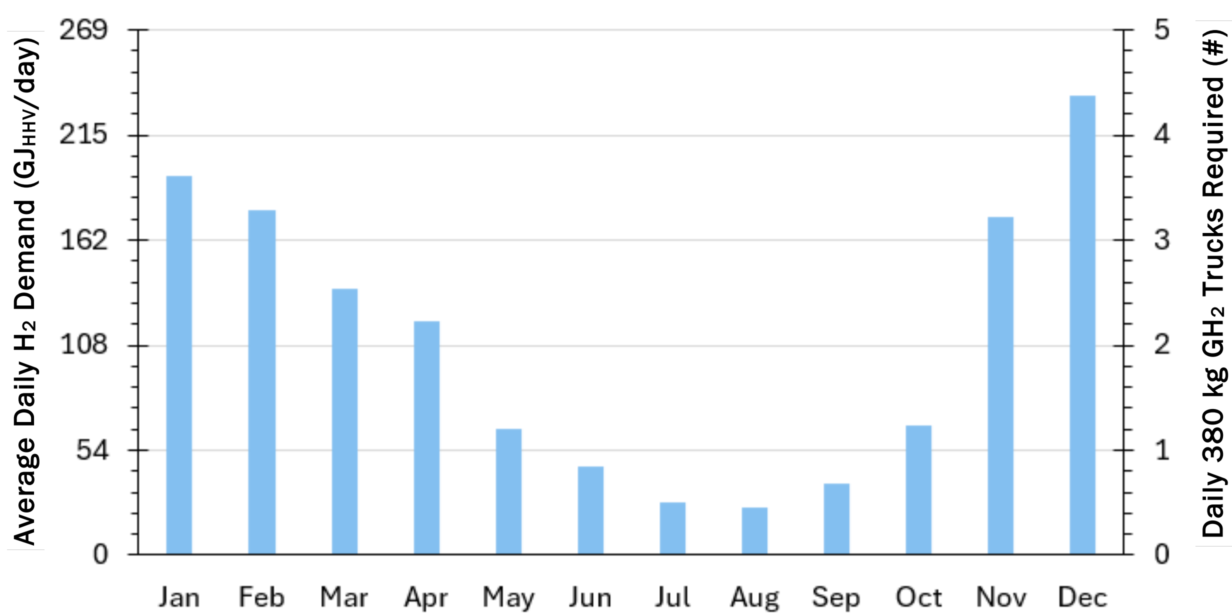

Figure 15 Average daily hydrogen demand and required 380 kg GH_2 tube-trailer deliveries for a 20 vol% blending scenario, 2027

Carbon Impact

The carbon reduction potential was calculated in two ways:

1. **On-site carbon emissions reduction** - Hydrogen was assigned a carbon intensity of 0 kg CO_2e/GJ to isolate the impact on direct, on-site emissions only.
2. **Lifecycle emissions reduction** - An average carbon intensity of 54.33 kg CO_2e/GJ was used for natural gas, and 35 kg CO_2e/GJ for hydrogen, representing hydrogen produced from natural gas with carbon capture and storage (not including transporting of hydrogen).

Figure 16 shows the resulting monthly emissions reduction under both assumptions.

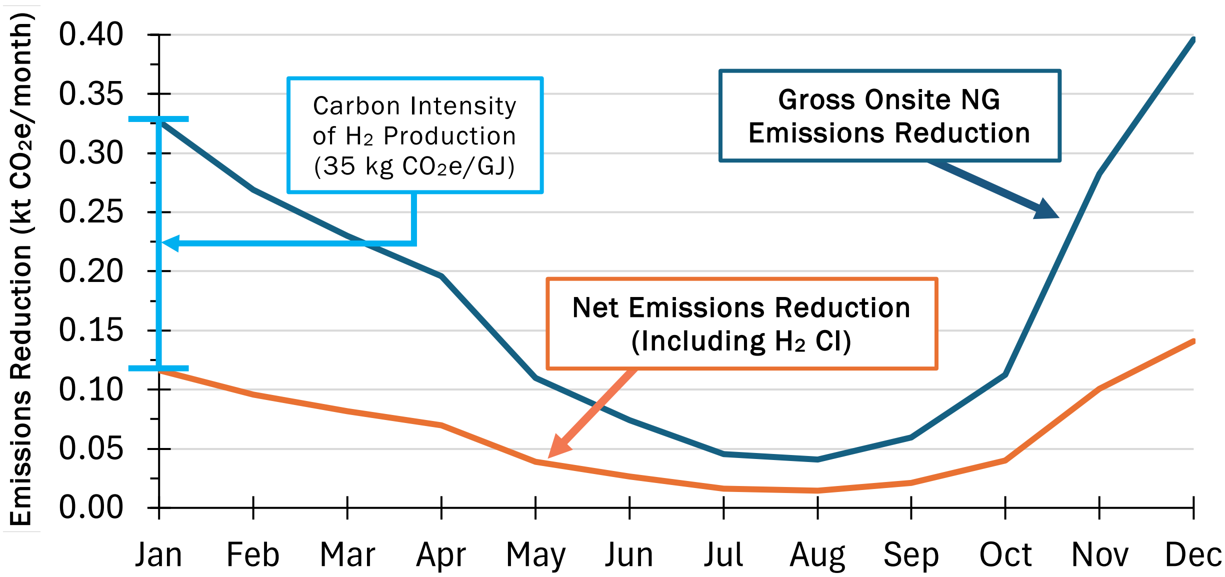

Figure 16 Monthly gross and net CO_2e emissions reductions under a 20 vol% hydrogen blending scenario, 2027

Under the on-site emissions-reduction case, gross emissions reductions follow the seasonal demand profile, with the highest reductions occurring in winter months, when natural gas consumption is highest. Reductions decrease significantly through the summer, reaching a minimum during periods of low heat demand, before increasing again in the fall. When lifecycle emissions are considered, the net emissions reductions are lower across all months. On average, lifecycle-based reductions are approximately 36% of the on-site reductions, reflecting the remaining upstream emissions associated with hydrogen production.

3.5 Daily Tube-Trailer H_2 Blending Scenario

For this scenario, one tube truck delivery of hydrogen per day (blended at a maximum rate of 20%) was explored. Liquid hydrogen trailers were not considered due to the likelihood of setback challenges of such hydrogen storage next to the CDHI facility.

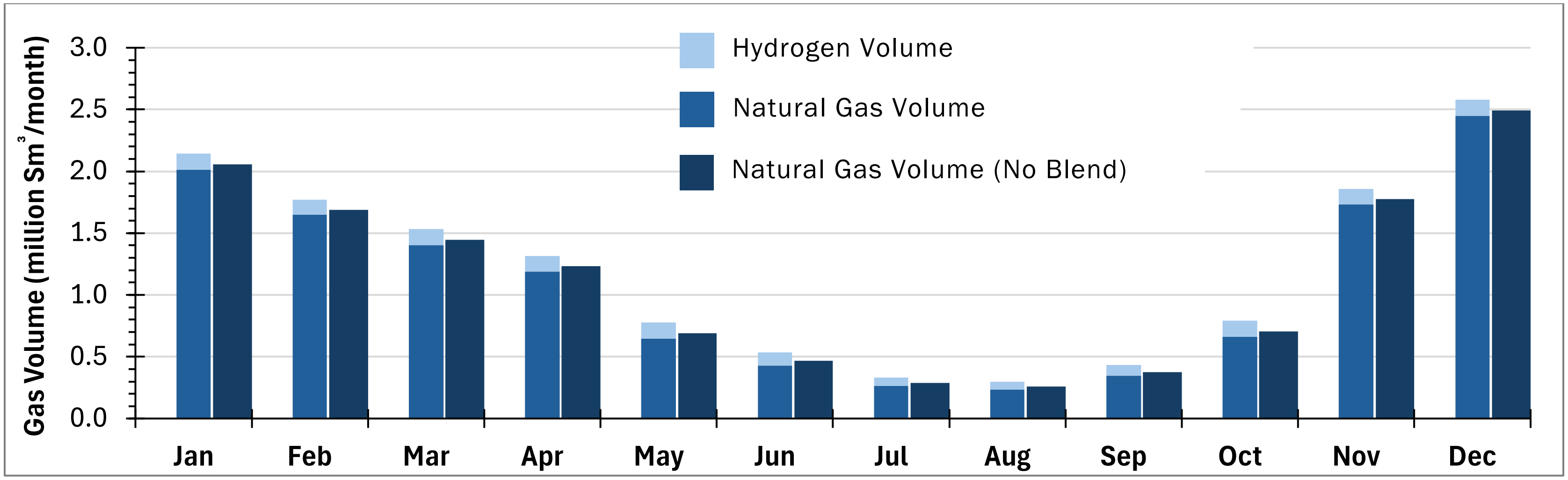

Figure 17 Monthly gas volumes for the 20 vol% daily tube-trailer delivery scenario vs. baseline natural gas, 2027

Monthly gas volumes required to deliver the same boiler duty with daily tube trailer delivery and a 100% natural gas case, based on the 2027 CDHI energy forecast. The blended case requires a higher total gas volume because hydrogen has a lower volumetric energy density than natural gas.

Table 2 Monthly hydrogen supply, displaced natural gas, and effective blend rate under the daily tube-trailer delivery scenario

Daily Tube-Trailer Results	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total *(Avg.)*
H_2 Mass Demand [20% Blend, 1 Daily TT] (tonnes/month)	11.8	10.6	11.8	11.4	11.8	9.6	5.9	5.3	7.8	11.8	11.4	11.8	**120.9**
Daily H_2 Delivery Rate (kg/day)	380	380	380	380	380	321	191	171	258	380	380	380	*(331)*
Displaced NG Volume (thousand m³/month)	44.8	40.4	44.8	43.3	44.8	36.6	22.4	20.2	29.5	44.8	43.3	44.8	**459.4**
Effective H_2 Blend Rate (vol%)	6.1%	6.7%	8.6%	9.7%	16.9%	**20%**	**20%**	**20%**	**20%**	16.6%	6.8%	5.1%	*(9.39%)*

Monthly and annual hydrogen demand, displaced natural gas volume, and average daily hydrogen supply requirements for the 20 vol% hydrogen blending scenario with one daily tube-truck delivery of hydrogen based on the 2027 CDHI energy forecast. The 9.39% annual average blend rate is a volume-weighted figure; because gas consumption is highest in winter when the blend rate is lowest (~5–7 vol%), these months dominate the annual total and pull the volume-weighted average well below the 20 vol% summer peak, compared to the time-weighted (calendar-day) average of 13.08%.

Hydrogen Supply Capacity

Figure 17 shows the monthly energy contribution from one tube trailer delivered per day, with details provided in **Table 2.** Over a month with 30 days, approximately 1.62 TJ, or 11.4 tonnes of hydrogen can be delivered. In the highest-demand winter months, the effective blend rate ranges from 5.1% to 6.8%, while in summer months, it can reach the full 20%.

Comparing this scenario with the previous 20% blend scenario, it can be seen in **Figure 18** below that in winter months, there will be a significant shortfall of hydrogen.

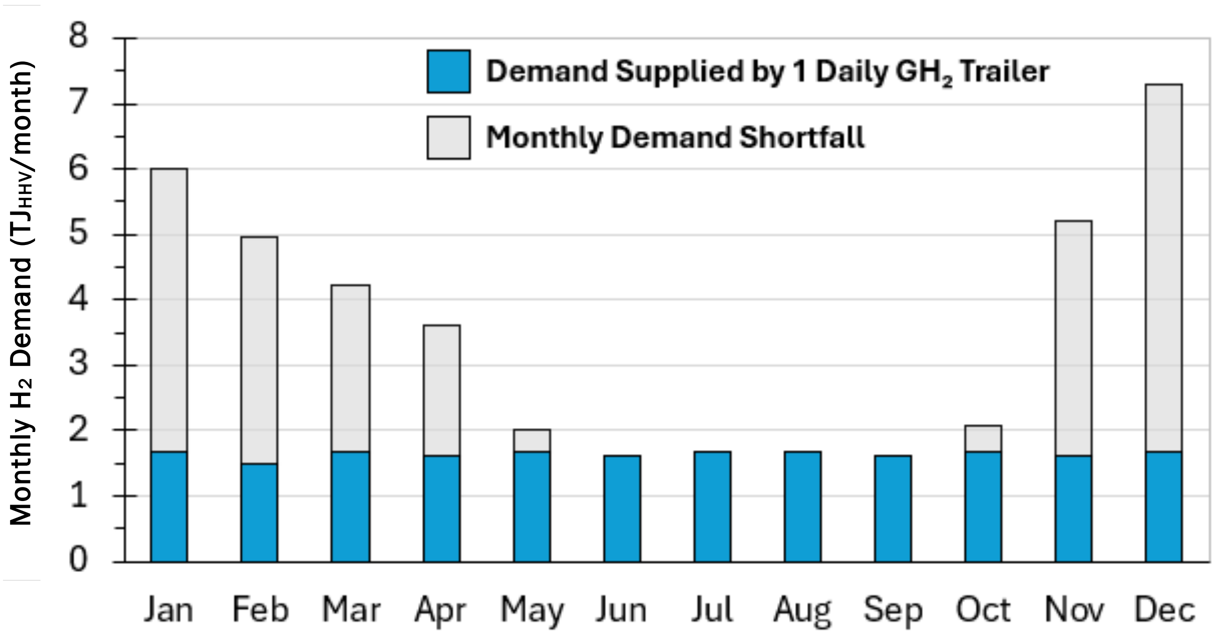

Figure 18 Monthly hydrogen demand shortfall under a one-tube-trailer-per-day delivery in the 20 vol% H_2 blending scenario, 2027

Carbon Impact

The carbon reduction potential was calculated in two ways:

1. **On-site carbon emissions reduction**: hydrogen was assigned a carbon intensity of 0 kg CO_2e/GJ to isolate the impact on direct, on-site emissions only.
2. **Lifecycle emissions reduction**: an average carbon intensity of 54.33 kg CO_2e/GJ was used for natural gas, and 35 kg CO_2e/GJ for hydrogen, representing hydrogen produced from natural gas with carbon capture and storage.

As shown in **Figure 19**, gross emissions reductions under the on-site emissions reduction case follow the seasonal demand profile but are constrained by the tube-trailer delivery limit, resulting in smaller absolute reductions than in a full 20 vol% blending scenario. In winter months, when the effective blend rate falls well below 20%, the emissions reduction is proportionally limited. When lifecycle emissions are considered, the net reductions are further reduced due to the non-zero carbon intensity of hydrogen. Compared with the unconstrained 20 vol% blending scenario, the daily tube-trailer scenario yields a more modest emissions reduction profile.

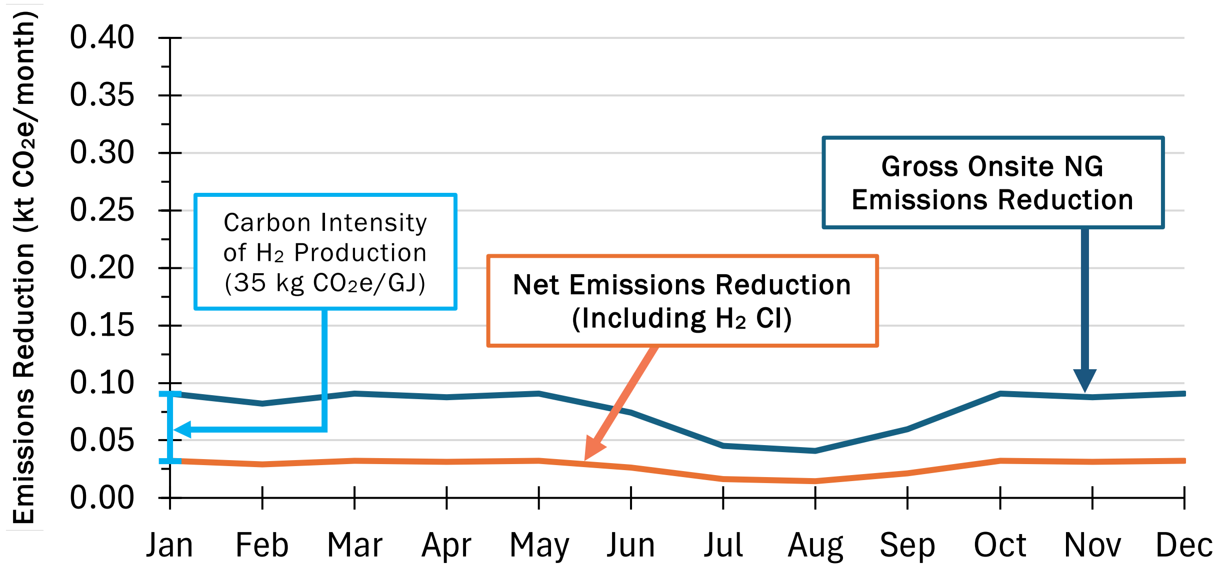

Figure 19 Monthly gross and net CO_2e emissions reductions under a 20 vol% hydrogen blending scenario with daily tube-trailer supply constraint, 2027

4 Cost Implications

The estimated cost of CO_2 abatement is highly sensitive to hydrogen price and carbon intensity. Hydrogen production costs in Alberta vary significantly by pathway: blue hydrogen from large-scale SMR with CCS has been estimated at approximately $1.50–$3.30/kg, while green hydrogen from electrolysis ranges from roughly $3.50–$10.00/kg depending on electricity cost, plant utilization, and production scale, with electricity costs representing the dominant cost driver at upwards of 57% to 87% of total levelized cost [31], [32], [33], [34], [35]. The $1–$20/kg range assessed here is therefore intentionally broad, intended primarily to illustrate the sensitivity of abatement cost to hydrogen price, which proves to be a dominant cost driver in this analysis. Under the assumptions used here, fuel-only abatement costs remain high across the assessed hydrogen price range. As shown in the figures, abatement costs decline as hydrogen prices decrease and are substantially higher when lifecycle emissions are considered. In the on-site (zero-carbon) case, costs range from approximately $2,600 per tonne of CO_2 at $20/kg hydrogen down to around $130 per tonne at $1/kg. In contrast, when a lifecycle carbon intensity of 35 kg $CO_2e/GJ\ H_2$ is applied, costs increase markedly across all price points, ranging from roughly $7,300 per tonne at $20/kg to about $365 per tonne at $1/kg.

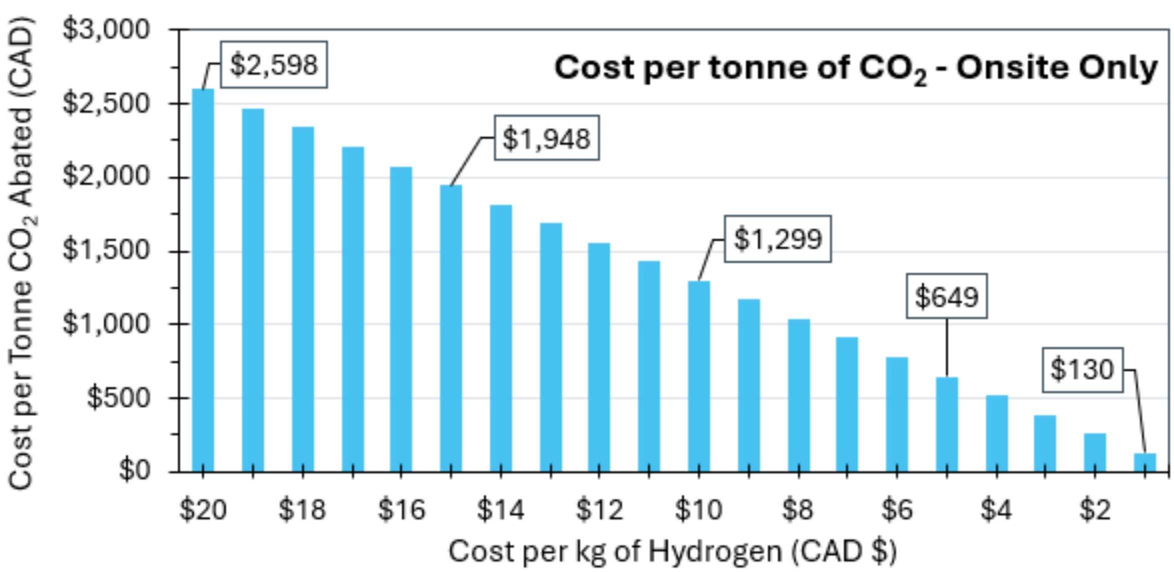

Figure 20 Cost of CO_2 abatement as a function of hydrogen price: onsite-only emissions reduction case

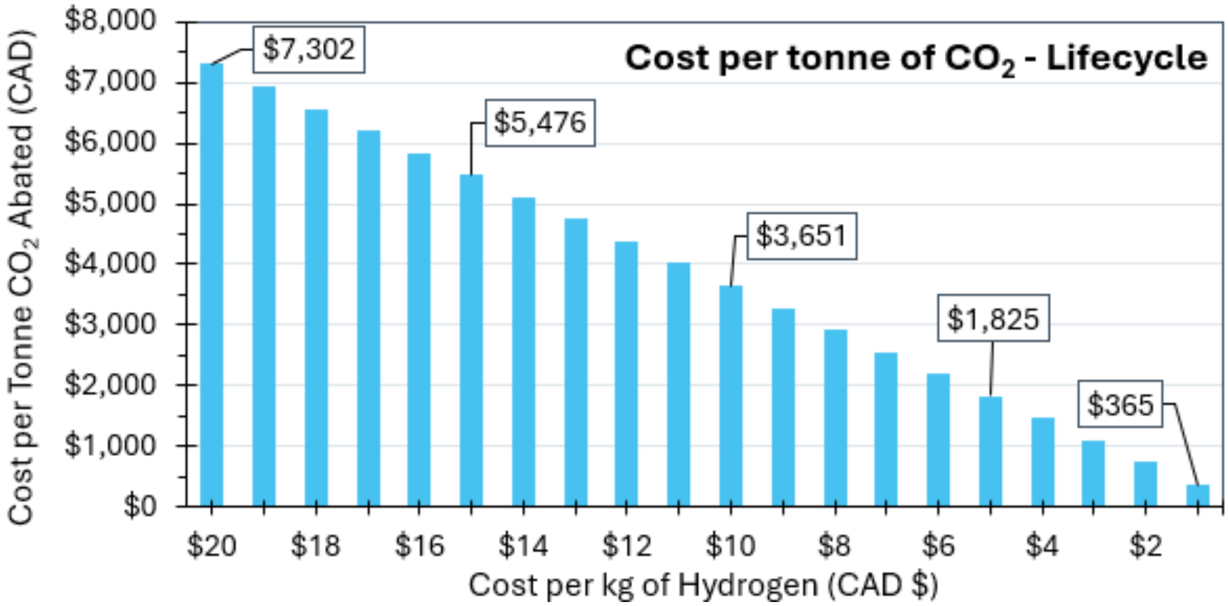

Figure 21 Cost of CO_2 abatement as a function of hydrogen price: lifecycle emissions reduction case

To support the interpretation of these results, a simplified example calculation and methodology are provided in **Appendix A.3.** Additional sensitivity calculations incorporating displaced natural gas fuel cost credits are also provided in **Appendix A.4**, demonstrating how avoided natural gas purchases reduce the net hydrogen cost and corresponding CO_2 abatement cost under different hydrogen price assumptions. While the resulting reductions are modest at higher hydrogen prices, the impact becomes increasingly significant at lower hydrogen price points due to the fixed value of the displaced natural gas credit.

5 Discussion

Technical Feasibility

The CDHI hydrogen blending pilot demonstrated successfully that low-percentage hydrogen blending can be implemented in an existing district heating boiler system without major modifications to core equipment or operations. Blending up to 20 vol% hydrogen was achieved safely and within the operating limits of the existing boiler and control systems. Measured boiler efficiency decreased only slightly from baseline, and flue gas CO_2 concentrations declined as the hydrogen fraction increased, confirming the expected benefit at the point of combustion.

However, the pilot should be interpreted as an early demonstration rather than a complete performance assessment. Longer-duration testing across a wider range of operating conditions, together with higher blend fractions, NOx monitoring, and continued system refinement, would strengthen understanding of the technical, environmental, and operational implications of broader deployment

Emissions Impact, Scale, and Logistics

Scaling hydrogen blending from pilot conditions to full-system implementation highlights the central limitation of this pathway: a 20 vol% hydrogen blend does not translate into a 20% energy or emissions reduction. Because hydrogen has a much lower volumetric energy density than natural gas, it contributes only about 7.8% of total boiler energy input at a 20 vol% blend. As a result, natural gas displacement and direct CO_2 reductions are proportionally modest.

Maintaining a 20 vol% blend across the CDHI boiler system would require approximately 278 tonnes of hydrogen per year, with demand concentrated in the winter months when district heating loads are highest, requiring several tonnes per day. This creates a significant supply challenge for a dense downtown site with limited space and constrained access.

The main barrier to scaling hydrogen blending at CDHI is therefore not combustion performance, but hydrogen supply logistics. Pipeline delivery, in theory, could provide a continuous, large-volume supply, but it would be difficult and costly to develop through a dense urban environment with road and rail crossings, utility congestion, and right-of-way constraints. Rail delivery would require specialized receiving infrastructure and a more mature hydrogen rail logistics ecosystem. Adjacent production and storage are constrained by the limited available footprint and likely setback requirements.

Tube-trailer delivery is the most viable near-term supply option, as it was successfully used during the pilot. However, it is difficult to scale. Supplying enough hydrogen to sustain a 20 vol% blend would require multiple deliveries per day during winter, introducing operational complexity, potential traffic impacts, and safety considerations. A more practical scenario of one tube-trailer delivery per day would supply approximately 121 tonnes of hydrogen annually, or roughly 40–45% of the hydrogen required for year-round 20 vol% blending. Under this constraint, the effective blend rate would fall to approximately 5–7% during winter, limiting emissions reductions when system demand is highest.

Lifecycle emissions further reduce the benefit. While hydrogen blending lowers direct onsite emissions by displacing natural gas combustion, upstream emissions from hydrogen production can offset a substantial share of the gross reduction. This means the carbon intensity of hydrogen supply is a decisive factor. Hydrogen blending only provides meaningful lifecycle emissions reductions if the hydrogen is produced through low-carbon pathways and delivered efficiently.

Cost and Strategic Role

Under current policy conditions, hydrogen blending is unlikely to be a cost-effective primary decarbonization pathway for CDHI. The cost of CO_2 abatement is driven primarily by hydrogen's cost on an energy-equivalent basis, its relatively small energy contribution at low blend fractions, and the modest emissions reductions achieved. When lifecycle emissions are included, the effective cost per tonne of CO_2 abated increases further because net emissions reductions decline.

This does not mean hydrogen blending cannot have a role. CDHI could provide a flexible early demand source for locally available low-carbon hydrogen, particularly if hydrogen is produced nearby, available at low cost, or temporarily exceeds demand from higher-value end uses. In this context, blending could support early market development, operational learning, and the formation of a local hydrogen supply chain.

However, this strategic role depends on supply conditions. If hydrogen must be delivered in small quantities by truck to a constrained downtown site, the economic and logistical challenges are significant. Hydrogen blending may be more practical at less constrained points in the energy system, such as upstream in the natural gas distribution network or in industrial areas where land, access, and infrastructure conditions are more favourable.

Broader Implications and Next Steps

The findings from this analysis suggest that hydrogen blending at CDHI is technically feasible but limited as a near-term decarbonization strategy. It can reduce direct emissions, but the magnitude of reduction is modest at 20 vol%, and the pathway is constrained by hydrogen supply, logistics, cost, and lifecycle carbon intensity. It should therefore be viewed as one potential component of a broader district heating decarbonization strategy, not as a standalone solution.

Decarbonizing district heating in cold-climate cities such as Calgary will likely require a diverse portfolio of solutions. Electrification, waste heat recovery, geothermal energy, thermal storage, low-carbon fuels, and efficiency improvements may (or may not) play a unique role depending on cost, reliability, land availability, and system design.

Future efforts should focus on longer-duration pilot testing, NOx measurement, detailed cost modelling, and comparison with other decarbonization pathways. Additional analysis should also examine whether upstream blending or integration at less constrained locations could provide a more practical route for hydrogen use than direct delivery to the CDHI site. Under current conditions, CDHI is best understood as a useful platform for continued testing and early hydrogen market development, rather than a primary pathway for deep emissions reduction in district heating.

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Appendix A Supplementary Data and Calculations

A.1 Illustrative Calculation of Hydrogen Blending at CDHI

This section provides an illustrative calculation of hydrogen blending at CDHI, demonstrating how blend composition, energy content, and total gas volume requirements are determined for a representative operating case.

An example calculation for the blended hydrogen stream through CDHI is as follows:

1. Set the target delivered heat output
   a. $Q_{delivered} = 100\text{ MJ}$
2. Back-calculate the total heat required to leave the boiler, accounting for both boiler losses (4%) and thermal loop losses (10%) occurring simultaneously from the boiler output:
   a. $Q_{boiler,\ out} = \frac{100\text{ MJ}}{100\% - (10\% + 4\%)} \approx 116.28\text{ MJ}$
3. Calculate the average HHV of the 20 vol% H_2 / 80 vol% NG blend
   a. $HHV_{blend} = (20\%\ \mathrm{H_2}) * \left(12.7\frac{\mathrm{MJ}}{\mathrm{m^3}}\right) + (80\%\ \mathrm{NG}) * \left(37.3\frac{\mathrm{MJ}}{\mathrm{m^3}}\right) = 32.38\frac{\mathrm{MJ}}{\mathrm{m^3}}$
4. Calculate the total blended gas volume required at the boiler inlet
   a. $V_{blend,\ in} = \frac{116.28\text{ MJ}}{32.38\frac{\mathrm{MJ}}{\mathrm{m^3}}} \approx 3.591\text{ m}^3$
5. Split the blended inlet volume into hydrogen and natural gas
   a. $V_{H_2,in} = (20\%\ \mathrm{H_2}) * (3.591\text{ m}^3) = 0.718\text{ m}^3\ \mathrm{H_2}$
   b. $V_{NG\ ,in} = (80\%\ \mathrm{NG}) * (3.591\text{ m}^3) = 2.873\text{ m}^3\ \mathrm{NG}$
   c. $\boldsymbol{V_{Total\ ,in} = \left(0.718\ \mathrm{m^3\ H_2}\right) + \left(2.873\ \mathrm{m^3\ NG}\right) = 3.591\ \mathrm{m^3}}$
6. Calculate the energy contribution of each gas at the boiler inlet
   a. $E_{H_2,in} = (0.718\text{ m}^3\ \mathrm{H_2}) * \left(12.7\frac{\mathrm{MJ}}{\mathrm{m^3}}\right) = 9.12\text{ MJ H}_2$
   b. $E_{NG\ ,in} = (2.873\text{ m}^3\ \mathrm{NG}) * \left(37.3\frac{\mathrm{MJ}}{\mathrm{m^3}}\right) = 107.16\text{ MJ NG}$
   c. $\boldsymbol{E_{Total,in} = (9.12\ \mathrm{MJ\ H_2}) + (107.16\ \mathrm{MJ\ NG}) = 116.28\ \mathrm{MJ}}$
7. Compare the volume to baseline NG volume to determine overall volume increase
   a. $V_{Baseline\ NG,\ in} = \frac{116.28\text{ MJ}}{37.3\frac{\mathrm{MJ}}{\mathrm{m^3}}} = 3.117\text{ m}^3$
   b. $\boldsymbol{V_{\%\ increase,\ in} = \frac{3.591\ \mathrm{m^3} - 3.117\ \mathrm{m^3}}{3.117\ \mathrm{m^3}} * 100\% = 15.2\%}$

Due to hydrogen's lower heating value, a higher volume of gas (15.2% more, based on HHVs) needs to be combusted to provide the equivalent thermal service energy as natural gas alone. In this mix, the hydrogen provides 7.8% of the total energy in the stream.

A.2 Boiler Duty Reduction with Increasing Hydrogen Blend Fraction

Table 3 presents the relationship between hydrogen blend fraction and boiler duty under a fixed volumetric flow assumption. As hydrogen content increases, total duty declines due to its lower volumetric energy density.

Table 3 Illustrative boiler duty under fixed total gas volume with hydrogen replacement

Hydrogen in Stream (vol%)	Hydrogen Volume (m^3)	Natural Gas Volume (m^3)	H_2 Duty Contribution (GJ)	NG Duty Contribution (GJ)	Total Blend Duty (GJ)	Effective Duty (% of Original NG Duty)
0%	0	**1,000**	0.00	32.1	**32.1**	100%
5%	50	950	0.55	30.5	31.0	96.7%
10%	100	900	1.09	28.9	30.0	93.4%
20%	200	800	2.18	25.7	27.8	86.8%
40%	400	600	4.37	19.2	23.6	73.6%
60%	600	400	6.55	12.8	19.4	60.4%
80%	800	200	8.74	6.42	15.2	47.2%
90%	900	100	9.83	3.21	13.0	40.6%
95%	950	50	10.4	1.60	12.0	37.3%
100%	1,000	0	10.9	0.00	10.9	34.0%

Illustrative example showing how boiler duty changes when a fixed total fuel gas volume of 1,000 m^3 is maintained and hydrogen progressively replaces natural gas on a volume basis. The table reports the corresponding hydrogen and natural gas volumes, their energy contributions, total boiler duty, and effective duty relative to the all-natural-gas case. The calculation assumes equal boiler efficiency for natural gas and hydrogen in the blend at 86%, a natural gas energy density of 0.0373 GJ/m^3 at standard conditions, and a hydrogen energy density of 0.0127 GJ/m^3 at standard conditions, equivalent to a hydrogen HHV of 0.1417 GJ/kg. Under these assumptions, replacing natural gas with hydrogen at constant total gas volume reduces the total fuel energy input and therefore the maximum achievable boiler duty.

A.3 Illustrative CO_2 Abatement Cost Calculation for Hydrogen

This section provides an illustrative calculation of CO_2 abatement cost for hydrogen, comparing on-site and lifecycle emissions outcomes for a representative hydrogen price.

An example calculation for $10/kg of hydrogen:

1. Emissions avoided
    a. On site case where NG CI = 54.33 kg CO_2e/GJ, and H_2 CI = 0
        i. $CO_2\,\text{Avoided} = 54.33\ \text{kg}\ \text{CO}_2\text{e per GJ}\ H_2$
    b. Lifecycle case where NG CI = 54.33 kg CO_2e/GJ, and H_2 CI = 35
        i. $CO_2\,\text{Avoided} = 54.33 - 35 = 19.33\ \text{kg}\ \text{CO}^2\text{e per GJ}\ H_2$
2. Calculate to kg CO_2e/kg H_2:
    a. On site case: $0.1417\frac{\text{GJ}}{\text{kg}}H_2 \times\ 54.33\ \text{kg}\frac{CO_2e}{\text{GJ}}H_2 = 7.70\ kg\ CO_2e/kg\ H_2$
    b. Lifecycle case: $0.1417\frac{\text{GJ}}{\text{kg}}H_2 \times\ 19.33\ \text{kg}\frac{CO_2e}{\text{GJ}}H_2 = 2.74\ kg\ CO_2e/kg\ H_2$
3. Cost of CO_2 abatement at \$10/kg H_2
    a. On site case: $\$10 \div \left(7.70\ kg\ CO_2e/kg\ H_2 \div 1000\frac{kg}{tonne}\right) = \$1{,}299/tonne\ CO_2e$
    b. Lifecycle case: $\$10 \div \left(2.74\ kg\ CO_2e/kg\ H_2 \div 1000\frac{kg}{tonne}\right) = \$3{,}651/tonne\ CO_2e$

A.4 Sensitivity of Hydrogen CO_2 Abatement Cost to Displaced Natural Gas Value

The cost of CO_2 abatement can be reduced by accounting for the natural gas displaced when hydrogen is blended into the system. At an energy-equivalent basis, each kilogram of hydrogen displaces 0.1417 GJ of natural gas, generating an avoided natural gas cost of \$0.47/kg H_2 at an assumed 2027 natural gas price of \$3.30/GJ [36]. This avoided fuel cost produces a fixed abatement cost reduction of \$61/tonne CO_2e in the on-site case and \$172/tonne CO_2e in the lifecycle case, regardless of hydrogen price. At \$10/kg H_2, this reduces the net cost to \$9.53/kg and lowers the corresponding abatement cost to \$1,238/tonne CO_2e in the on-site case and \$3,478/tonne CO_2e in the lifecycle case, proportional reductions of approximately 5% in both cases. However, because the avoided fuel cost is fixed in absolute terms while the hydrogen cost varies, the proportional impact grows substantially at lower price points. In the on-site case, the avoided fuel cost reduces abatement cost from \$649/tonne to \$588/tonne at \$5/kg H_2 (9%), and from \$130/tonne to \$69/tonne at \$1/kg H_2 (47%). In the lifecycle case, costs fall from \$1,825/tonne to \$1,653/tonne at \$5/kg H_2 (9%), and from \$365/tonne to \$193/tonne at \$1/kg H_2 (47%).

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