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July 20, 2026

BC Sustainable Energy Association (BCSEA)
Thomas Hackney, Consultant

My Sea to Sky (MS2S)
Eoin Finn, Research Director

Dear BCSEA-MS2S:

**Re: FortisBC Energy Inc. (FEI)**

**2026 Long Term Gas Resource Plan (LTGRP)**

**Response to BCSEA-MS2S Joint Information Request (IR) No. 1**

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On March 27, 2026, FEI filed the 2026 LTGRP referenced above. In accordance with the regulatory timetable established in BCUC Order G-84-26 for the review of the 2026 LTGRP, FEI respectfully submits the attached response to BCSEA-MS2S IR No. 1.[1]

FEI notes that BCSEA-MS2S has provided lengthy preambles to many of its information requests, which contain a significant amount of content that FEI takes issue with. In many instances, the manner in which BCSEA-MS2S has framed its information requests appears to attempt to provide intervener evidence. However, this is procedurally improper. As the BCUC has stated:

> The BCUC reminds all interveners that the purpose of IRs is not to enable the author of the IR to introduce evidence. The purpose of IRs is to elicit relevant information on the evidentiary record or to clarify or test existing evidence to contribute to a better understanding by the BCUC of the relevant issues in the proceeding. Any statements that are included in the preamble to an IR should be restricted to providing context for a question relevant to the proceeding submitted by the party to whom the IR is directed.
>
> Finally, whereas letters of comment are intended to provide for any member of the public to contribute views, opinions, and impact or potential impact, with respect to a matter before the BCUC, IRs must not be letters of comment.[2]

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1 For convenience and efficiency, if FEI has provided an internet address for referenced reports instead of attaching the documents to its IR responses, FEI intends for the referenced documents to form part of its IR responses and the evidentiary record in this proceeding.

2 In the matter of the *FEI Application for a CPCN for the Advanced Metering Infrastructure Project*, in its letter dated September 28, 2021 (Ex. A-15).

FEI has provided its responses to the information requests by focusing on the questions themselves, rather than parsing and rebutting each preamble. However, FEI wishes to be clear that the preambles contain inaccuracies and characterizations that FEI does not accept. As such, FEI's silence regarding the content of a preamble should not be interpreted as agreement. FEI will object to any attempt by BCSEA-MS2S to rely in final argument on the content of preambles to its information requests.

If further information is required, please contact the undersigned.

Sincerely,

**FORTISBC ENERGY INC.**

***Original signed:***

Sarah Walsh

Attachments

cc (email only): Registrar
Registered Interveners

**Topics**



**1.0 Topic: Collaboration between Utilities**

**Reference: Exhibit B-1 (Application), Appendix D-1 (Okanagan Capacity Mitigation Project) at p. 4, Table 1-1 (pp. 5-6); Section 4 at p. 4-23, Figure 4-14**

In Table 1-1 of Appendix D-1 (p. 5-6) in the 2026 Long Term Gas Resource Plan (Application), FortisBC Energy Inc (FEI) refers to a "Joint Okanagan Energy Plan (Electrification)." On page 4 of Appendix D-1, FEI states:

> "Finally, FEI and FortisBC Inc. (FBC) are pursuing an approach to joint electrification that is most beneficial to customers by utilizing dual-fuel heating systems to leverage both energy systems, reduce electric peak demand growth,

> and reduce GHG emissions by reducing annual gas demand. Dual fuel heating systems are a form of joint electrification, which use electric heat pumps to reduce GHG emissions from shoulder season heating and use gas heating during the winter to avoid electric peak demand growth. Avoiding rapid growth in electric peak demand by continuing to rely on the gas system for peak heating needs will help avoid accelerating electric capacity expansions, including the need for upgrades to the gas system for a simple cycle gas turbine (SCGT), which has been identified in FBC's previous two long term electric resource plans as the most cost effective and reliable option to meet FBC's firm peak demand requirements. <u>FEI and FBC's approach to joint electrification planning recognizes the gas system's capability to meet peak heating needs cost effectively and the current challenge facing electric peak demand in the Okanagan region. This approach also addresses the challenges of other electrification plans, including conflicts with FEI's duty to serve, the absence of enabling legislation and a lack of cost recovery mechanisms for programs that eliminate gas use."</u> [underline added]

On page 4-23 of the Application, regarding Figure 4-14, FEI states:

> "Therefore, shifting significant amounts of existing peak loads currently served by FEI's gas system [to FBC's system], while accommodating new electric growth due to policy, population or other factors, would cause a large increase to [FBC's] electric winter peak relative to the summer peak, thereby reducing the load factor and increasing the average cost per unit of energy. Electrical supply and infrastructure must all be sized to meet peak demand, to ensure that energy can reliably flow to customers when they need it during the coldest hour of the year." [footnote omitted]

1.1 Please describe FEI's joint planning with FBC in more detail, including for example the scope and depth of analysis and the extent to which various alternative combinations of electrification and gas were modeled.

**<u>Response:</u>**

As two utilities under common ownership, FEI and FBC have developed an increasingly integrated approach to long-term planning over the past several years, identifying opportunities to align planning assumptions, methodologies and analyses across both utilities where it is beneficial to do so. However, it is important to recognize that, ultimately, FEI and FBC are separate and distinct utilities, each with their own customer base and energy service, and each is individually responsible for preparing and filing its own long-term resource plan pursuant to section 44.1 of the *Utilities Commission Act* (UCA).

Joint planning between FEI and FBC occurs across three primary areas:

1. Coordinated long-term resource planning and scenario development;
2. Understanding the impacts of electrification on the gas and electric systems; and

3. Evaluating integrated energy strategies and solutions.

***Coordinated long-term resource planning and scenario development***

FEI and FBC have been progressing a coordinated long-term planning approach that leverages the unique position of having an overlapping service area in which they provide both gas and electric service.

As part of the preparation for the 2026 LTGRP and the forthcoming 2026 long-term electric resource plan (LTERP), FEI and FBC worked closely together to align key planning assumptions, methodologies and plausible scenario pathways within both resource plans, where applicable. As discussed in Section 2.2.5 of the 2026 LTGRP, this included the development of common assumptions related to population growth, housing development, customer adoption of new technologies, government climate policies, building codes, energy efficiency standards, and other drivers influencing fuel-switching decisions. Section 3.2 of the 2026 LTGRP describes in detail how these assumptions and scenarios were integrated between FEI's 2026 LTGRP and FBC's upcoming 2026 LTERP.

The coordinated analysis enabled FEI and FBC to assess a range of potential outcomes across multiple scenarios, including the continued reliance on the gas system, increased adoption of dual-fuel heating systems, and varying levels of electrification. Through this coordinated scenario development, FEI and FBC have been able to assess how changes affecting one energy system influence energy demand, peak capacity requirements, and infrastructure investment needs on the other. For example, the implications of differing levels of energy conservation and fuel switching adoption can be assessed and compared across the 2026 LTGRP and the forthcoming 2026 LTERP.

***Understanding the impacts of electrification on gas and electric systems***

Through the Kelowna Electrification Case Study and the ongoing Kelowna Dual-Fuel Study, FEI and FBC are working together to understand the implications of electrification on both utility systems and the impacts on customers.

The Kelowna Electrification Case Study, which examined the impacts of electrification on winter peak demand, associated electric transmission and distribution infrastructure requirements, and customer affordability, provided an important foundation for FEI's and FBC's coordinated planning efforts. Since then, the methodologies, analytical approaches and key findings from the study have informed ongoing long-term planning activities, including the Kelowna Dual-Fuel Study. Using increasingly detailed customer, building and energy-use data, FEI and FBC are able to evaluate different combinations of gas and electric system utilization as part of long-term planning. This includes assessing how variations in customer technology adoption, fuel choice and rate impacts may affect energy demand, peak demand, infrastructure requirements, system costs, customer affordability, and GHG emissions reductions.

As a result, FEI's and FBC's analyses are no longer limited to discrete studies or specific regional assessments. Rather, consideration of the interactions between the gas and electric systems have become a component of coordinated resource planning, enabling the utilities to assess how alternative combinations of gas and electric demand may influence affordability, reliability and sustainability outcomes for customers and BC.

***Evaluating integrated energy strategies and solutions***

Beyond coordinated scenario planning and electrification analysis, FEI and FBC have been jointly evaluating energy strategies that leverage the complementary capabilities of the gas and electric systems.

A key example of this coordinated approach is the development and implementation of FEI's dual-fuel programs for residential and commercial customers. Through joint analysis, FEI and FBC have evaluated how dual-fuel systems can continue to leverage the gas system's storage and deliverability capabilities during periods of peak winter demand while also supporting GHG emissions reductions through lower gas consumption. The analysis indicates that integrated gas and electric solutions may provide a practical and cost-effective approach to meeting customer energy needs while helping to moderate growth in electric peak demand.

FEI and FBC are also coordinating planning activities related to future energy supply and infrastructure requirements in the Okanagan region. This includes consideration of transmission and distribution system needs, regional peak demand growth, and the potential role of future generation resources, including the simple-cycle gas turbine (SCGT) identified in FBC's 2021 LTERP. Through this work, FEI and FBC continue to assess how future gas and electric infrastructure decisions interact and how the two systems can work together to support affordable, reliable, and lower-carbon energy services for customers.

Overall, FEI's and FBC's collaboration extends beyond information sharing and includes coordinated scenario development, integrated DSM assessments, evaluation of alternative electrification pathways, infrastructure planning, and assessment of joint energy strategies. These efforts support a more comprehensive understanding of the interactions between the gas and electric systems and inform long-term resource planning across both utilities.

1.2 Please confirm that FEI is not asking the BCUC to approve or accept any of the outcomes of the FEI's and FBC's joint planning or draw conclusions about FBC's resource requirements in this proceeding, but that FEI expects FBC to file information these issues that will be subject to review in the BCUC review of FBC's 2026 LTERP.

__Response:__

FEI is seeking BCUC acceptance of the 2026 LTGRP as being in the public interest pursuant to section 44.1(6) of the UCA.

The 2026 LTGRP presents FEI's long-term scenarios of annual energy and peak demand requirements of customers, and plans for FEI's demand- and supply-side resources. Dual-fuel heating systems are a key demand-side resource, and the joint planning done by FEI and FBC through the Kelowna Dual-Fuel Study, while ongoing, provides important analysis in support of the inclusion of dual-fuel heating systems in FBC's resource planning.

While Part 1 of the Kelowna Dual-Fuel Study provides some analysis on the impacts to FBC's system, FBC's 2026 LTERP will provide further analysis on the impact of dual-fuel heating systems as it relates to FBC's resource planning. FBC will be seeking BCUC acceptance of the 2026 LTERP as being in the public interest pursuant to section 44.1(6) of the UCA.

**2.0 Topic: Demand-Side Resources**

**Reference: DEMAND-SIDE RESOURCES**

**Exhibit B-1 (Application), Section 4, pp. 4-1 to 4-42; Section 6, p. 6-5, Figure 6-2**

In sections 4.1 through 4.4 of the Application, FEI provides a high-level listing of DSM measures it could pursue and analyses of energy savings and costs of pursuing Low, Medium and High settings of DSM, in which incentive levels cover 25%, 50% and 100% respectively of the incremental costs of the DSM measures. However, FEI only commits to pursuing DSM that is adequate and cost-effective in terms of the DSM Regulation.

2.1 Please discuss the pros and cons of FEI undertaking to pursue all cost effective DSM in its LTGRP.

**<u>Response:</u>**

In response to the comment in the preamble that FEI "only" commits to pursuing DSM that is adequate and cost-effective, section 44.1 of the UCA requires the BCUC to consider whether FEI's DSM portfolio is adequate and cost-effective as defined by the DSM Regulation.

It would not be feasible to implement all cost-effective DSM. As set out in Appendix C of the 2026 LTGRP,[1] cost-effectiveness is the economic potential constraint that limits the scope of technically feasible DSM measures to those that are cost-effective based on the economic screen the utility is required to use. However, when deciding what DSM measures to pursue, there are also market potential constraints and the utility-related program potential needs to be considered. Thus, it is not actually achievable to implement all cost-effective DSM.

On page 4-6 of the Application, Figure 4-2 shows DSM savings potentials for FEI's Diversified Approach at Low, Medium and High settings. Figure 6-2 on page 6-5 shows FEI's forecast of its gas resource mix out to 2050.

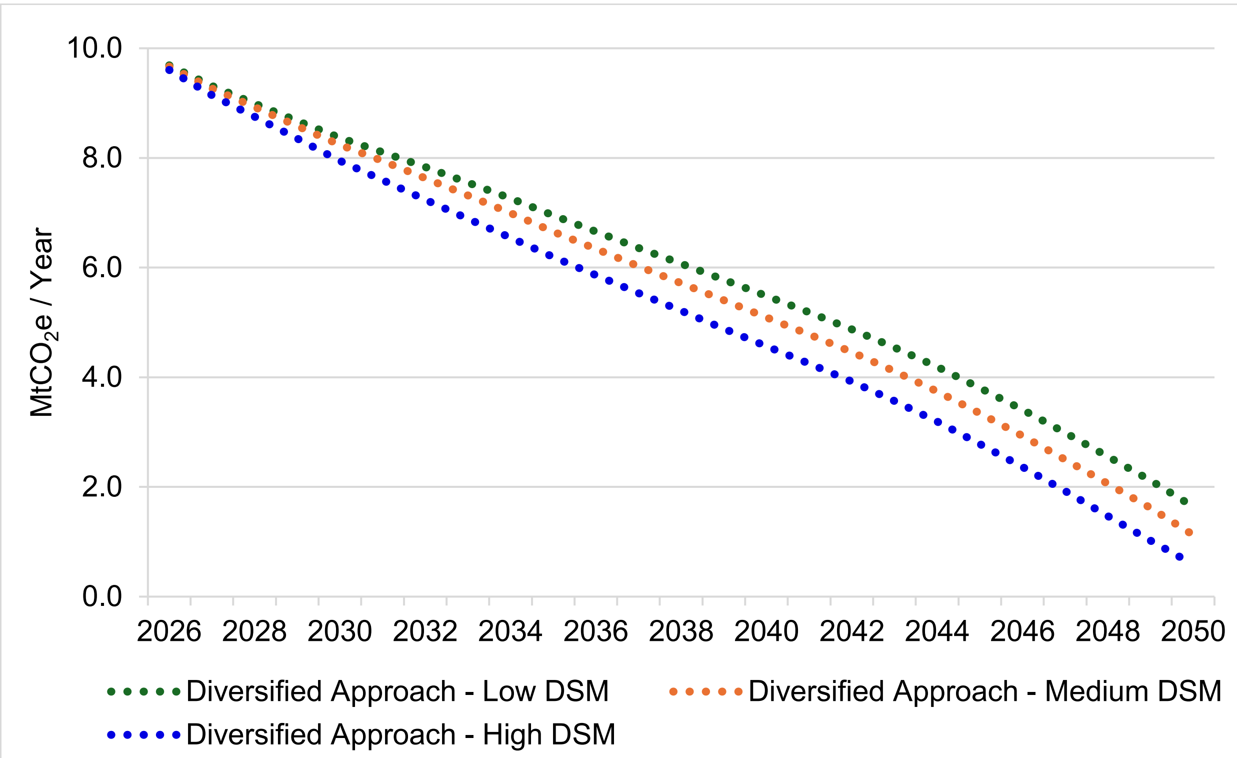
2.2 Please indicate the GHG emissions reductions that would correspond to the DSM savings shown in Figure 4-2 for each of the Low, Medium and High settings assuming: (a) the current RNG mix is maintained through to 2050 and (b) the gas resource mix shown in Figure 6-2.

[1] 2024 Conservation Potential Review (CPR) Report, p. 12, Exhibit 2: Differences Between Technical, Economic, and Market Potential.

**Response:**

The GHG emissions associated with the Diversified Approach scenario using the Low, Medium, and High DSM settings presented in Figure 4-2 of the 2026 LTGRP are illustrated in Figure 1 below. These results are estimated using end-use emission factors consistent with Table 9-2 of the 2026 LTGRP and reflect DSM savings applied to residential, commercial, and industrial gas demand sectors.

**Figure 1: Total GHG Emissions for Diversified Approach Scenarios under Different DSM Settings**




***(a) Current RNG Mix Maintained Through 2050***

In addition to the DSM-related GHG emissions reductions shown in Figure 1 above, FEI assessed the incremental GHG emissions reduction opportunity associated with increasing RNG supply relative to maintaining the current RNG supply mix through 2050. RNG supply is approximately 13 PJ in 2026 and is forecast to increase to approximately 60 PJ by 2050 under the Diversified Approach supply outlook. The additional RNG volumes available in 2050 would result in approximately 2.4 $MtCO_2e$ of incremental GHG emissions reductions relative to maintaining the 2026 RNG supply level through 2050.

***(b) Gas Resource Mix Shown in Figure 6-2***

FEI is unable to directly quantify the GHG emissions reductions corresponding to the DSM savings presented in Figure 4-2 using the gas resource mix shown in Figure 6-2. DSM savings are estimated only for the built environment sectors (residential, commercial, and industrial) and represent reductions in end-use natural gas demand. In contrast, the gas resource mix presented in Figure 6-2 reflects the resource portfolio required to serve the demand requirements of FEI's Core customers, including Rate Schedules (RS) 1 to 7 and RS 46 sales service customers. This demand includes residential, commercial, industrial, transportation, and marine and ISO shipments sectors.

In section 4.3.3 of the Application (starting on page 4-4), FEI provides a list of DSM measures included in its analysis.

2.3 Please confirm or otherwise explain that FEI is considering for its DSM program only Class A DSM measures in the terms of the DSM Regulation.

**Response:**

Not confirmed. For its DSM program, FEI is considering class A DSM measures as defined in the DSM Regulation, as well as measures excluded from the definition of class B DSM measures. FEI is not considering any class B DSM measures.

In the DSM Regulation, a demand-side measure is a class B demand-side measure if it

(a) directly or indirectly encourages the acquisition or installation of gas-fired space or domestic water heating equipment, and

(b) is not excluded under subsection (2) from the definition of "class B demand-side measure".

Exclusions under subsection (2) generally include gas-fired space or domestic water heating equipment considered as advanced DSM measures and fall within the definitions below:

- integrated dual-energy space heating systems consisting of an electric heat pump and gas-fired equipment;
- gas-fired heat pumps; and
- integrated hybrid gas-fired heat pump systems consisting of a gas-fired heat pump that serves as the principal source of heat and another type of gas-fired equipment.

These systems must be operated by a single system of controls, connected to a single heat distribution system, and either are designed, rated and sold together as a single heating system, or combined into a single package and sold together as a single heating system.

The exclusions under subsection (2) also generally include minimum Seasonal Coefficient of Performance (SCOP) requirements depending on system technology and climate zone.

On page 4-7 of the Application, Table 4-2 shows the break-down by type of the DSM measures assumed for the Diversified Scenario with a Medium DSM setting.

2.4 Please discuss the pros and cons for customers and for BC's gas and electric systems of FEI pursuing a DSM program that would maximize the energy efficiency performance of its customers' building shells.

**Response:**

DSM programs that improve building shell performance provide meaningful energy and non-energy benefits to customers and to the gas and electric systems through reduced energy use and demand. The "cons" of such programs are related to their cost, which must be considered to ensure cost-effective program delivery, consistent with FEI's DSM program design and regulatory framework.

DSM programs that target improvements to building shell performance are demand-side measures as defined in the *Clean Energy Act*, which include measures to conserve energy and reduce the energy demand that must be served by a public utility. Enhancing building envelope performance, through measures such as improved insulation and airtightness, reduces uncontrolled air leakage and overall thermal losses, which lowers energy consumption for space heating and provides non-energy benefits such as improved occupant comfort and building durability. The measurement and verification activities conducted by third-party engineering consultants as part of FEI's Deep Energy Retrofit pilot demonstrate that building envelope upgrades contribute to measurable reductions in annual energy use (GJ/year) and associated GHG emissions.

For customers, the primary benefits of a DSM program focused on building shells are reduced energy consumption and lower utility costs, as well as improved indoor environmental conditions due to enhanced thermal performance and reduced air leakage. From a system perspective, reduced end-use demand lowers the overall energy requirements that must be met by both gas and electric systems, contributing to system efficiency and supporting DSM portfolio objectives, including cost-effective energy savings and regulatory adequacy requirements.

However, building envelope retrofits can involve higher upfront capital costs and may require coordination with ventilation system upgrades to ensure appropriate indoor air quality, as excessive reductions in air leakage can limit natural air exchange without proper mechanical ventilation. Delivering building shell measures at scale may also require additional administrative resources, including program design, technical support, and verification activities. Additionally, equitable access to building shell upgrades must be considered, as higher capital cost measures can present participation barriers for certain customer segments without targeted program design.

FEI considers both the benefits and costs of these measures in designing a cost-effective DSM program, consistent with FEI's DSM program design and regulatory framework.

**3.0 Topic: Kelowna Dual-Fuel Study**

**Reference: Exhibit B-1 (Application), Section 4.7, pp. 4-21 to 4-42, Table 4-8; Exhibit A-4 (Application), BCUC IRs 7.1, 11.1 and 13.1**

3.1 If not done in response to BCUC IR 7.1, please file a copy of the entirety of the Kelowna Dual-Fuel Study that has been completed to date.

**Response:**

FEI has provided the entirety of the study results completed to date in Sections 4.6 and 4.7 of the 2026 LTGRP. FEI and FBC continue to assess the broader system-wide implications of dual-fuel systems, and the results of that work will be considered as part of FBC's 2026 LTERP. At this time, FEI has no additional information related to the Kelowna Dual-Fuel Study beyond what has been provided in the 2026 LTGRP. Please also refer to the response to BCUC IR1 7.1.

3.2 Apart from the availability of DSM incentives, is FEI's analysis of dual-fuel hybrid heating systems equally applicable to retrofit and new build situations?

**Response:**

The analysis of dual-fuel heating system peak and energy impacts in Section 4.7.2 of the 2026 LTGRP is specifically for existing customers retrofitting a gas furnace with either a dual-fuel or electric heat pump system. As described in the first paragraph of Section 4.7.4 of the 2026 LTGRP, the household-level and customer affordability analyses in Sections 4.7.3 and 4.7.4 of the 2026 LTGRP are based on a subset of existing FEI customers.

FEI expects that the analysis for new construction would be directionally similar to that for existing customers, with new buildings typically having improved thermal envelopes, resulting in lower overall energy use and, consequently, reduced incremental savings.

For further information on how FEI is supporting dual-fuel heating systems in new construction, please refer to the response to BCUC IR1 13.2.

3.3 In Table 4-8 on page 4-29, what gas usage is assumed to continue after installing a ccASHP? If the usage is not for space heating, please provide a revised version of Table 4-8 that includes only energy used for heating.

**Response:**

Please refer to the response to BCUC IR1 11.3.

3.4 Building on BCUC IRs 11.1 and 13.1, please discuss whether the modeled electric demand assumes that a cold climate air source heat pump (ccASHP) would operate at the same time as electric resistance back-up heating. If so, please provide load shapes and peak demands where it is assumed instead that the ccASHP carries load to its rated low-temperature capacity before the back-up resistance heating engages.

**Response:**

The ccASHP was modelled to switch discretely to electric resistance back-up heating below a set temperature of -20˚C,[2] but not to run simultaneously with the electric resistance back-up heating.

[2] In the Kelowna Dual-Fuel Study, in Section 4.7.2 on page 4-25 of the 2026 LTGRP, FEI stated "Notably, at temperatures below -22˚C such as during the winter design peak day in Kelowna, the modelled heat pumps have a coefficient of performance (COP) of approximately 1.0". However, FEI confirms that the model actually used -20˚C as the temperature where heat pumps operate fully in electric resistance back-up mode, with a COP of approximately 1.0.

**4.0 Topic: Dual-Fuel Hybrid Systems Switchover Setting**

**Reference: FEI 2026 and 2027 Incremental DSM Expenditures, Exhibit B-3, FEI response to BCUC IR 5.5 at p. 21 (pdf p. 22)**

FEI's response to BCUC IR 5.5 in the FEI 2026 and 2027 Incremental DSM Expenditures proceeding states in part:

> "As customers retain control of their HVAC system, it is possible to adjust set-points or use the emergency heat mode function, which overrides the set-point. However, results from the 2025 Dual Fuel System Rebate Evaluation indicated that it is uncommon for customers to adjust their set-points at all, and only a minor subset have adjusted their set-points above the program maximums." [3]

4.1 Please confirm or explain otherwise that there is a continuing risk that the owner of a dual-fuel hybrid heating system or their contractor may adjust the switchover point higher than whatever temperature is recommended by FEI or other party, thus partly or completely negating the reduction in gas use and GHG emissions that a dual-fuel hybrid heating system makes possible.

**Response:**

The evidence from program evaluations demonstrates that owners of a dual-fuel heating system rarely adjust the switchover temperature (SOT) higher than the initial setting, and that the likelihood of such actions materially affecting program outcomes is low.

Results from the 2025 Dual Fuel System Rebate Evaluation indicate that it is uncommon for customers to adjust their SOT after installation, and only a minor subset of participants have adjusted their SOT above program maximums. This is supported by evaluation evidence referenced in the responses to BCUC IR1 5.5 and 6.8 in the FEI 2026 and 2027 Incremental DSM Expenditures proceeding, where a third-party program evaluation survey of 593 participants found that nearly 9 out of 10 participants had not changed their SOT after installation. Among the small proportion of participants who made changes, approximately one third adjusted the SOT above 5°C, representing approximately 3 percent of participants overall.

Thermostat controls vary in complexity depending on the system and manufacturer. Adjusting the outdoor SOT is different and more complex than adjusting the indoor heating temperature set-point on a programmable thermostat. To adjust an SOT, a customer would need to review and understand the thermostat manufacturer's instructions and back-end programming to change the settings.

Results from site visits completed through the program's quality assurance process identified that some contractors chose to lock out customers from altering their SOTs. Based on anecdotal feedback from installers, this is likely because improper adjustments to the SOT could have a

[3] Exhibit B-3 in the FEI 2026 and 2027 Incremental DSM Expenditures, "FEI submitting responses to BCUC Information Request No. 1", online: <https://docs.bcuc.com/documents/proceedings/2026/doc_87280_b-3-fei-response-bcuc-ir1.pdf>.

negative impact on the system's overall functionality and result in a service call to the installing contractor to correct.

Based on these findings, while a theoretical risk exists that customers or contractors may adjust the SOT in a manner that reduces gas savings and associated GHG emissions reductions, program evaluation evidence indicates that such behavior is rare and is unlikely to materially affect portfolio-level outcomes.

**5.0 Topic: Dual-Fuel Hybrid Systems for MURBs and Commercial Buildings**

**Reference: Exhibit B-1 (Application), Section 4 at p. 4-19**

On page 4-19 of the Application, FEI says it has been pursuing cost-effective dual-fuel heating options for multi-unit residential buildings (MURBs) and commercial buildings.

5.1 Please provide the results of any analysis of costs, gas and electricity usage and GHG emissions that FEI has performed regarding the use of dual-fuel hybrid systems for MURBs or commercial buildings.

**<u>Response:</u>**

FEI's analysis for commercial dual-fuel rooftop units (RTUs) that combine an electric air-source heat pump with a gas-fired burner under integrated controls shows climate zone-specific performance across costs, energy use, and GHG emissions reductions for MURBs and commercial buildings as compared to a standard efficiency gas RTU:

- In climate zones 4 and 5, the heat pump supplies a larger share of annual heating, resulting in a 50 to 80 percent reduction in natural gas consumption for the heating load, while electricity use increases up to 15,000 kWh per unit in the heating season; and
- In colder climates (climate zones 6 to 8), performance is more moderate, with a 15 to 40 percent reduction in natural gas consumption for the heating load, and increases in electricity use up to 12,000 kWh per unit in the heating season.

These shifts in fuel use translate to estimated GHG emissions reductions related to reduced natural gas heating load of 15 to 40 percent for climate zones 6 to 8, and 50 to 80 percent for climate zones 4 and 5, due to differences in outdoor air and switchover temperatures in different regions.

From a cost perspective, FEI's analysis to date, based on consultant cost estimates, vendor inputs, and program modeling assumptions, indicates average incremental equipment and other costs, including labour, of approximately $59,000 per 25-ton RTU (approximately $2,400 per ton) relative to a baseline gas RTU. These higher upfront costs are driven by the addition of the heat pump component, integrated control systems required to manage switchover between electric and gas operation, and site-specific upgrades that may be required (e.g., electrical upgrades, structural modifications, and system integration).

**6.0 Topic: Dual-Fuel Hybrid Systems – Effects on Demand and GHG Emissions**

**Reference: Exhibit B-1 (Application), Executive Summary at p. ES-8, Table ES-1; Section 3 at pp. 3-1 to 3-28; Section 4 at pp. 4-1 to 4-42**

On page ES-8 of the Application, in Table ES-1, FEI states in part that dual-fuel heating systems at a switchover temperature of 2 degrees Celsius can reduce building emissions by approximately 41%.

6.1 Please confirm or otherwise explain that the GHG emissions reductions achieved by dual-fuel hybrid heating systems are predominantly a linear function of the reduced usage of natural gas.

**Response:**

The natural gas GHG emissions reductions associated with dual-fuel heating systems are predominantly a function of decreased natural gas usage, relative to a natural gas appliance baseline, using the respective end-use emission factors.

6.2 Please indicate which demand curves in section 3 and which DSM curves in section 4 show the demand effects of adopting dual-fuel hybrid systems, and please quantify the assumed rates of adoption and proportions of retrofits and new-build installations.

**Response:**

The demand scenarios shown in Section 3 are pre-DSM; therefore, the scenarios do not include the demand effects of adopting dual-fuel systems, as it was assumed that any natural adoption of dual-fuel measures beyond CPR uptake rates is negligible.

Section 4 incorporates the impacts of DSM savings on the pre-DSM demand curves. As discussed in Section 4.3 of the 2026 LTGRP, the 2024 CPR (and the market potential) was used to inform the Low, Medium, and High DSM settings. The Low DSM setting was utilized for the Baseline Trends, Electrification Focus, Prolonged Transition, and Lower-Carbon Transportation and LNG Future scenarios, while the Medium DSM setting was utilized for the Diversified Approach scenario.

For the assumptions related to dual-fuel system adoption, please refer to the response to CEC-COSCO-RCIA IR1 14.1.

6.3 Please discuss FEI's assumptions about the rate of adoption of dual-fuel hybrid heating systems in retrofit and new-build situations, and assumptions about building stock turnover.

**<u>Response:</u>**

The 2024 CPR determined market potential trajectories for energy efficiency and fuel switching measures, including residential dual-fuel heating systems, for a forecast period of 2026-2050. Section 4.4.2 of Appendix C to the 2026 LTGRP states how dual-fuel was modelled so that a requirement of the measure is that it replaces existing equipment.

Dual-fuel potential in new-build installations is captured within the New Construction DSM Measure Group using a whole-building approach, not representing forecast adoption of individual measures; therefore, there is no applicable assumption about building stock turnover in regard to dual-fuel systems.

For the assumptions related to dual-fuel system adoption, please refer to the response to CEC-COSCO-RCIA IR1 14.1.

**7.0 Topic: Cross-Price Elasticity**

**Reference: ENGAGEMENT APPROACH & UNDERSTANDING OUR FUTURE ENERGY NEEDS**

**2022 Long Term Gas Resource Plan Decision and Order G-78-24 March 20, 2024 p. 54; Exhibit B-1 (Application), Section 2 at p. 2-16, Section 3 at p. 3-12, Section 7 at p. 7-24, Section 8 at p. 8-12**

On page 54 of Decision and Order G-78-24 (March 20, 2024) of the 2022 LTGRP (Decision and Order G-78-24),[4] the BCUC asked FEI and BC Hydro to "identify planning assumptions that are common to each plan, and provide information on those assumptions to facilitate a comparison of the approaches taken by each utility." One relevant assumption identified in Decision and Order G-78-24 at page 54 was cross-price elasticity.

On page 8-12 of the Application, FEI states: "Neither FEI nor BC Hydro include an explicit assumption in their resource plans about cross-price elasticity between gas and electric prices. FEI includes a modelling driver for own-price elasticity of demand for natural gas, which is discussed in Section 3.5.2."

However, on page 2-16, FEI says: "FEI expects that gas rates will likely rise as DSM spending increases and as renewable and lower carbon gas comprise a larger share of the fuel mix delivered to customers. Electricity rates will also likely rise due to the impacts of electrification and population growth and the need to meet increased peak demand with generation, transmission and distribution infrastructure. Depending on the relative increase in electricity versus gas rates, there is a strong case for gas to remain an affordable and practical solution for FEI customers." While FEI does not explicitly include an assumption in its resource plan about cross-price elasticity between gas and electric, the relative increase of electricity versus gas rates is part of FEI's Application planning environment.

On pages 20-21 of Decision and Order G-78-24, BCUC asked FEI to include research on long-term price elasticity and cross-elasticity effects.[5] Each of those factors is relevant to predictions of gas demand, especially in light of the rapidly maturing marketplace for

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4 BCUC, "FortisBC Energy Inc. 2022 Long-Term Gas Resource Plan Decision and Order G-78-24" (20 March 2024), online: <https://docs.bcuc.com/documents/other/2024/doc_76411_g-78-24-fei-2022-long-term-gas-resource-plan-decision.pdf>.

5 Ibid at pp. 20-21: "...the Panel generally agrees with the CEC's suggestion that in the next long-term gas resource plan, FEI should further investigate modelling the price elasticity effects of low carbon gases… While FEI notes this may be an area with limited data at this time, this does not preclude FEI from conducting further research or analysis ahead of its next plan, including consideration of cross-price elasticity effects with renewable electricity."

electrically-powered heat pumps,[6] and the adoption of higher levels of ESC and ZCSC by many Lower Mainland municipalities, including Vancouver, all three North Shore municipalities, City of Victoria, Capital Regional District and elsewhere.[7] FEI has instead substituted the "Price Impact to Customer" segment in Section 3.12 of the Application, which does not illuminate either price or cross-price elasticity.

Despite the absence of considering cross-price elasticity in the Application, on page 7-24, FEI asserts that new electric generation will be "costly," based solely on a five year old study from its 2021 LTERP and LT DSM Plan.[8] However, the levelized cost of electricity (LCOE) for solar power has improved significantly. In 2024, according to the International Renewable Energy Agency, solar PV was about 41% cheaper than the lowest-cost fossil fuel option globally.[9] The International Renewable Energy Agency also reported that, in 2024, average LCOE was about 43 dollars per megawatt-hour for solar.[10] Similarly, industry-experts Lazard reports that, in 2025, the LCOE's for renewable wind and solar were far lower than fossil-fuel alternatives.[11] Moreover, the United Nations reports that "[b]y 2023, an estimated 96% of newly installed, utility-scale solar photovoltaics (PV) and onshore wind capacity had lower power generation costs than new coal and gas plants, while around 75% of new wind and solar PV plants offered cheaper power than existing fossil fuel facilities globally."[12]

7.1 Please provide and explain each assumption FEI used for cross-price elasticity between gas and electric prices in the Application and, if FEI did not use any such assumption, explain how the omission of cross-price elasticity between gas and electricity prices affects the reliability and utility of each of the five scenarios.

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6 In British Columbia, heat pumps have seen rapid growth, with sales beginning to outpace natural gas furnaces in recent years. Over 31,000 heat pumps have been tracked through federal retrofit initiatives, while the CleanBC program has provided over 26,000 heat pump rebates. Heat pumps now make up roughly 13% of all B.C. home heating systems (up from 5% in 2008). They became the most popular newly installed heating equipment for retrofits, with annual installation numbers doubling the five-year average prior to 2024: Government of British Columbia, "Powering Our Future: BC's Clean Energy Strategy" (Last updated 27 June 2024), online: <https://www2.gov.bc.ca/gov/content/industry/electricity-alternative-energy/powering-our-future>; Government of Canada, "Heat pumps uptake at a glance" (March 2026), online: <https://natural-resources.canada.ca/energy-efficiency/home-energy-efficiency/canada-greener-homes-initiative/heat-pumps-uptake-glance-0>; British Columbia Energy and Climate Solutions, "B.C. makes heat pumps more affordable for people with low incomes" (9 April 2025), online: <https://news.gov.bc.ca/releases/2025ECS0014-000309>.

7 Government of British Columbia, "Local government adoption of Zero Carbon Step Code" (Last updated 9 June 2025), online: <https://www2.gov.bc.ca/gov/content/industry/construction-industry/building-codes-standards/bc-codes/2024-bc-codes/step-codes/zero-carbon-step-code/local-gov-adoption>.

8 FEI 2021 Long-Term Electric Resource Plan and Long-Term Demand-Side Management Plan, Table 10-2 and Figure 10-2, pp. 166-168, online: <https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/regulatory-affairs-documents/electric-utility/210804-fbc-2021-lterp-lt-dsm-plan.pdf>

9 International Renewable Energy Agency, "Renewable Power Generation Costs in 2024 (2025) at p. 6, online: <https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2025/Jul/IRENA_TEC_RPGC_in_2024_Summary_2025.pdf>.

10 Ibid at p. 4.

11 Lazard, "Levelized Costs of Energy" (June 2025) at p. 8, online: <https://www.lazard.com/media/uounhon4/lazards-lcoeplus-june-2025.pdf>.

12 United Nations, "Seizing the moment of opportunity: Supercharging the new energy era of renewables, efficiency, and electrification" (2025) at p. 1, online: <https://www.un.org/sites/un2.un.org/files/un-energy-transition-report_2025.pdf>.

**Response:**

As stated in the preamble, neither FEI nor BC Hydro include an explicit assumption for cross-price elasticity between natural gas and electric prices in their resource plans. Instead, the 2026 LTGRP includes a modelling driver for own-price elasticity of demand for natural gas, reflecting how gas demand responds to changes in natural gas prices, as described in Section 3.5.2 of the 2026 LTGRP.

The 2026 LTGRP uses a scenario-based approach to explore a range of potential future pathways, with key drivers outlined in Section 3.5 of the 2026 LTGRP. Section 3.5.2 describes how FEI used natural gas price elasticity estimates from reputable third-party studies to model the change in gas demand relative to the change in natural gas prices over the planning horizon. The scenarios reflect different levels of electrification and customer adoption over the planning horizon, which capture potential shifts in demand driven by the relative competitiveness of gas and electricity.

Consequently, while cross-price elasticity is not explicitly modelled, the impact of natural gas and electricity competitiveness on natural gas demand is implicitly captured across the five demand scenarios.

**8.0 Topic: Woodfibre LNG and Second Large Generic Industrial Customer**

**Reference: UNDERSTANDING OUR FUTURE ENERGY NEEDS**

**Exhibit B-1 (Application), Section 3 at pp. 3-17, 3-18, Figure 3-3, Appendix B at p. 8; 2022 Long Term Gas Resource Plan (2022 LTGRP), Section 4.3.3 at pp. 4-7, 4-8, p. 4-16**

On pages 3-17 and 3-18 (see also Figure 3-3) of the Application, FEI identifies new large loads as a key driver for the input settings and states that:

> "FEI modelled the Woodfibre LNG Project at an expected demand of 110 PJ/year as of 2028, and included this project as a global parameter in all scenarios." There is no Low setting for Woodfibre LNG and the Medium setting reflects Woodfibre LNG Project alone, while the High setting includes "the Woodfibre LNG Project plus a second generic large industrial customer, also assigned 110 PJ/year as of 2033"

Pages 4-7 and 4-8 of the 2022 LTGRP contained similar statements about a "generic industrial customer" with the same demand profile as Woodfibre LNG:

> "FEI's consideration of new large industrial customers is limited to two customers, each with similar, very large annual demand. The first of these is Woodfibre LNG project, for which expected demand and operational timing have been announced publicly. The second customer is a generic industrial customer with a similar annual demand expectation to that of Woodfibre LNG project. Such a customer has not currently been identified by FEI and is modelled generically to ensure that FEI is assessing what system impacts might be required if such a customer were to come forward during the planning horizon."

Federal Energy and Natural Resources Minister Hodgson recently acknowledged that Woodfibre LNG "has ambitions to double and triple the size of their production."[13]

On page 7-13, the Application contains specific assumptions about this "generic" new large industrial load, including that it would be "near or downstream of Squamish on the VITS" (p. 7-13) and that it would require exactly the same amount of gas as Woodfibre LNG (110 PJ/year now, up from 95 PJ/year on page 4-16 of the 2022 LTGRP).

8.1 Please explain the rationale and provide any evidentiary basis for modeling this "new large industrial load" as identical in size and location to the envisioned Woodfibre LNG expansion.

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[13] Stefan Labbé, "Minister reveals ambition to triple production at B.C. LNG terminal" (1 April 2026), online (Business in Vancouver): <https://www.biv.com/news/economy-law-politics/minister-reveals-ambition-to-triple-production-at-bc-lng-terminal-12089730>.

**Response:**

FEI's modelling of a new large industrial load is consistent with FEI's past resource plans which have used Woodfibre LNG as an illustrative example of a new large load that could materialize. The use of a comparable demand magnitude for the second load is intended to provide a consistent and reasonable planning approach for evaluating potential system impacts, rather than to represent a specific proposal. This approach supports a robust assessment of system capability and infrastructure requirements under plausible growth scenarios, while maintaining appropriate flexibility given uncertainty regarding future large industrial developments.

In Section 3.4.9 of the 2017 LTGRP (Potential Large New Industrial Annual Demand), FEI considered the potential impact of large industrial loads on its system. The Woodfibre LNG Project was presented as an illustrative example of a large point load and its potential contribution to annual demand. At that time, the project was assumed to enter service no earlier than 2021, with estimated annual demand of approximately 95 PJ.

In Section 4.4.3 of the 2022 LTGRP (End-Use Annual Method of Demand Forecasting for the New Large Industrial Demand Category), FEI incorporated the anticipated demand associated with the Woodfibre LNG Project, modelled at approximately 95 PJ per year beginning in 2025. In addition, FEI considered the potential for a second large industrial facility as part of its long-term planning framework. For modelling purposes, FEI assumed that such a facility would be of a comparable order of magnitude to the Woodfibre LNG Project and applied an in-service assumption beginning in 2028.

Consistent with this approach, the Diversified Energy (Planning) Scenario in the 2022 LTGRP included only the Woodfibre LNG Project, while the Upper Bound Scenario incorporated both the Woodfibre LNG Project and the second representative large industrial facility.

This planning assumption is maintained in the 2026 LTGRP, as described in Section 3.5.5, where such loads are intended to capture the potential for significant demand. FEI modelled the Woodfibre LNG Project at approximately 110 PJ per year beginning in 2028 and included this load as a global parameter across all scenarios, reflecting its advanced stage of development. In the Lower-Carbon Transportation and LNG Future scenario, FEI also included a second generic large industrial customer, assigned a comparable demand of approximately 110 PJ per year with a later in-service assumption of 2033.

**9.0 Topic: New Large Loads: Price Impact of LNG**

**Reference: BALANCING AFFORDABILITY, RELIABILITY AND SUSTAINABILITY**

**Exhibit B-1 (Application), Section 9 at pp. 9-20, 9-21, Table 9-10**

On page 9-21 of the Application, Table 9-10 (reproduced below) indicates that three of FEI's five scenarios forecast a 2050 natural gas price of $3.50/GJ, and the Lower-Carbon Transportation and LNG Future forecasts a 2050 natural gas price of $4.60/GJ.

**Table 9-10: Summary of Renewable and Lower-Carbon Gas Percentage and Price by 2050**

| | Diversified Approach | Electrification Focus | Prolonged Transition | Lower-Carbon Transportation and LNG Future | Baseline Trends |
|---|---|---|---|---|---|
| RNG & Hydrogen in FEI's System by 2050 (%) | 84% | 15% | 10% | 93% | 13% |
| Natural Gas Price in 2050 ($/GJ) | $ 3.5 | $ 6.5 | $ 3.5 | $ 4.6 | $ 3.5 |
| RNG Price in 2050 ($/GJ) | $ 11.9 | $ 40.2 | $ 11.9 | $ 28.6 | $ 11.9 |
| Hydrogen Price in 2050 ($/GJ) | $ 17.9 | $ 62.9 | $ 17.9 | $ 25.1 | $ 17.9 |

Research from the Institute for Energy Economics and Financial Analysis (IEEFA) shows that Australia's domestic LNG prices tripled since exporting LNG to foreign markets.[14] A 2025 study from Deloitte reports that Cedar LNG and Woodfibre LNG "...will add an estimated 0.7Bcf/d of offtake capacity by 2028. This added demand for natural gas is expected to support increased gas prices in Alberta and British Columbia."[15] In addition to Woodfibre LNG and Cedar LNG, much larger volumes of natural gas will continue to be exported from LNG Canada Phase 1 (1.84 Bcf/d)[16] and may be exported from LNG Canada Phase 2 (1.84 Bcf/d)[17] and Ksi Lisims LNG (1.58 Bcf/d),[18] once those approved projects receive positive final investment decisions and begin operations. Since the relatively small amounts exported from Cedar LNG and Woodfibre LNG are expected to push gas prices higher in British Columbia, the much larger amounts exported from those other projects can also be expected to push domestic gas prices up.

9.1 For each of FEI's five scenarios, please quantify the portion of the forecast 2050 gas price (Application, p. 9-21, Table 9-10) that is caused by LNG exports from British Columbia. If FEI did not quantify this "basin lift" effect on domestic prices when preparing its gas price forecast, please explain why and how that omission informed FEI's statement that "growth in LNG demand and a new large industrial load would result in significant benefits to FEI's customers" (Application, p. 9-20).

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14 Kevin Morrison, "Queensland LNG exports: A decade of high domestic prices, falling local demand" (6 Feb 2025), online (Institute for Energy Economics and Financial Analysis): <https://ieefa.org/resources/queensland-lng-exports-decade-high-domestic-prices-falling-local-demand>.

15 Deloitte, "Energy, oil, and gas price forecast: How LNG Canada might shape gas prices" (June 30, 2025), online: <https://www.deloitte.com/content/dam/assets-zone3/ca/en/docs/industries/energy-resources-industrials/2025/ca-OandGforecast_EN.pdf>.

16 Government of Canada, "Canadian liquified natural gas projects" (last modified on 7 Jan 2025), online (Government of Canada): <https://natural-resources.canada.ca/energy-sources/fossil-fuels/canadian-liquified-natural-gas-projects>.

17 Ibid.

18 Ibid.

**Response:**

FEI relied on natural gas price forecasts developed by third-party market information providers[19] for the 2026 LTGRP. Given the range of factors that influence natural gas prices over time, FEI uses third-party forecasts to incorporate an independent, market-based perspective specific to Western Canada.

The third-party forecasts underlying Table 9-10 of the 2026 LTGRP do not explicitly disaggregate or quantify a distinct "basin lift" component attributable solely to LNG exports (referred to as ISO shipments in the 2026 LTGRP). Instead, any effects related to LNG exports are implicitly reflected within the overall price outlook. Additionally, the five demand scenarios presented in Table 9-10 are based on differing underlying assumptions; however, in some of those scenarios there is no material impact on the natural gas price forecast.

It is also important to note that Western Canadian natural gas markets differ materially from other LNG-exporting jurisdictions, such as Australia. Differences in market structure, infrastructure constraints, supply dynamics, regulatory frameworks, and the degree of integration with global LNG markets mean that price formation mechanisms are not directly comparable. As such, assumptions or methodologies that isolate LNG-driven "basin lift" effects in other regions may not be directly applicable to the Western Canadian context reflected in the third-party forecasts used by FEI.

There are also countervailing perspectives indicating that Western Canada – particularly the Montney formation – has a substantial and highly productive resource base capable of supporting incremental demand from LNG exports without necessarily resulting in significant or sustained price increases. This view suggests that supply responsiveness and ongoing resource development may mitigate potential price impacts over time.

With respect to the statement on page 9-20 of the 2026 LTGRP that LNG demand and new large industrial load growth would result in significant benefits to FEI's customers, this conclusion is based on several system-level considerations rather than solely commodity price effects, including improved asset utilization, incremental contribution margins, and resulting downward pressure on delivery rates.

9.2 For the Diversified Approach (84% RNG and H2 in 2050: Application, p. 9-21, Table 9-10) and Lower Carbon Transportation and LNG Future (93% RNG and H2 in 2050: Application, p. 9-21, Table 9-10) scenarios, please explain the impact of higher feedstock prices (RNG and Hydrogen are significantly more expensive than fossil gas) on the economic viability of the anticipated LNG projects.

[19] External forecasts from S&P Global and Northwest Power Coordinating Council.

**Response:**

The inclusion of lower-carbon energy solutions such as RNG in conventional LNG fuel supply represents a pathway for complying with emerging regulatory frameworks such as the International Maritime Organization's (IMO) prospective net-zero framework, FuelEU Maritime,[20] and Canada's Clean Fuel Regulations (CFR). These regimes require reductions in lifecycle GHG emissions over time. As a result, any incremental cost associated with including lower-carbon energy solutions can be partially or fully offset through avoided compliance costs, reduced exposure to carbon pricing, and potential monetization of environmental attributes.

Additionally, including RNG in FEI's LNG supply leverages its existing infrastructure without requiring marine customers to retrofit their vessels, representing a cost-effective means of complying with increasingly stringent emissions-reduction policies. For example, waste-derived RNG, particularly manure-based RNG, can achieve lifecycle GHG emissions reductions that are comparable to, or lower than, modeled green methanol and green ammonia pathways, and in some cases can achieve net-negative well-to-wake emissions because of avoided methane emissions.[21]

[20] European Commission "Mobility and Transport", (2023), online at: https://transport.ec.europa.eu/transport-modes/maritime/decarbonising-maritime-transport-fueleu-maritime_en.

[21] SEA-LNG "The Role Of Bio-Lng In The Decarbonisation Of Shipping" (2022), online at: https://sea-lng.org/wp-content/uploads/2022/10/SEA-LNG_BioLNG-Study-Key-Findings-Document_October-2022.pdf.

**10.0 Topic: RNG Supply Projections**

**Reference: SUPPLY-SIDE RESOURCES & BALANCING AFFORDABILITY, RELIABILITY AND SUSTAINABILITY**

**Exhibit B-1 (Application), Section 5 at pp. 5-7, Table 5-1, pp. 5-8, 5-19, Section 9 at pp. 9-10, 9-21, Table 9-10; Appendix D-2 (B.C. Renewable and Low-Carbon Gas Supply Potential Study) of the 2022 Long Term Gas Resource Plan**

On page 5-8 of the Application, FEI indicates that the Diversified Approach applies a Medium renewable and lower-carbon gas supply setting. On page 5-7 of the Application, FEI indicates that, under the Medium setting, RNG and lower-carbon gas make up 15% of total gas supply in 2030. On page 9-21 of the Application, FEI provides Table 9-10, which indicates FEI's plan that, under the Diversified Approach, by 2050, RNG and lower-carbon gas is expected to make up 84% of total gas supply.

That extraordinary rise from 15% RNG and lower-carbon gas to 84% in just 20 years is driven by a significant increase in projected hydrogen supply (from 1.0 PJ/Year in 2030 to 60 PJ/Year in 2050; see Table 5-1, p. 5-7, reproduced below). RNG supply is also projected to nearly double (from 29 PJ/Year in 2030 to 60 PJ/Year in 2050 - see Table 5-1, p. 5-7).

**Table 5-1: Renewable and Lower-Carbon Gas Supply Outlook (PJ/Year)**

| | Low Setting | | | | Medium Setting | | | | High Setting | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Milestone Year | RNG | $H_2$ | Other Fuels | Total | RNG | $H_2$ | Other Fuels | Total | RNG | $H_2$ | Other Fuels | Total |
| **2030** | 16.8 | 0.0 | 0.0 | **16.8** | 29.0 | 1.0 | 0.0 | **30.0** | 39.5 | 4.5 | 0.0 | **44.0** |
| **2040** | 16.8 | 0.0 | 0.0 | **16.8** | 48.5 | 13.2 | 0.0 | **61.7** | 71.1 | 21.3 | 1.3 | **93.6** |
| **2050** | 16.8 | 0.0 | 0.0 | **16.8** | 60.0 | 60.0 | 0.0 | **120.0** | 90.1 | 70.0 | 5.0 | **165.1** |

On page 5-9 of the Application, FEI highlights some of the challenges and uncertainties associated with the development of RNG:

> "There is a significant potential for RNG across North America and globally. With respect to the global potential, a study published by the IEA estimates that there is the potential for about 38,000 PJ. More recently, the Inner City Fund (ICF) published a report estimating about 275 PJ of expected RNG supply by 2030 within North America based on existing projects. The available future supply of RNG remains underdeveloped. However, all of that potential may not be realized as the viability and scalability of the RNG supply forecast hinges upon three interconnected factors: (1) feedstock limitations; (2) technology challenges and opportunities; and (3) policy dependence."

In Appendix D-2 of the 2022 LTGRP, FEI's consultants forecasted RNG production potential in British Columbia (Appendix D-2, Table 2, p. 22), Canada (Appendix D-2, Table

3, p. 23), and the United States (Appendix D-2, Table 5, p. 24) in 2030 and 2050 (reproduced below):

**Table 2 B.C. RNG Potential, in Petajoules (PJ) per Year**

| | Agricultural | Municipal | WWTP | LFG | Total |
|---|---|---|---|---|---|
| **2021** | 2.4 | 3.1 | 0.48 | 2.9 | **8.9** |
| **2030** | 2.5 | 3.5 | 0.55 | 3.1 | **9.5** |
| **2050** | 2.8 | 4.6 | 0.69 | 3.1 | **11.2** |

**Table 3 RNG Potential in Canada, in Petajoules per Year**

| | Agricultural | Municipal | WWTP | LFG | Total |
|---|---|---|---|---|---|
| **2021** | 17.4 | 22.9 | 3.6 | 21.3 | 65.2 |
| **2030** | 18.2 | 25.2 | 4.0 | 22.3 | 69.7 |
| **2050** | 20.0 | 33.2 | 4.9 | 22.5 | 80.7 |

**Table 5 RNG Potential in the U.S., in Petajoules per Year**

| | Agricultural | Municipal | WWTP | LFG | Total |
|---|---|---|---|---|---|
| **2021** | 150 | 197 | 31 | 184 | 561 |
| **2030** | 154 | 213 | 34 | 189 | 590 |
| **2050** | 156 | 259 | 38 | 176 | 630 |

Since the 2022 LTGRP, FEI's forecast 2030 RNG production in Canada and the United States has dropped from 659.7 PJ/year (69.7+590) to 275 PJ/year (per ICF's estimation on p. 5-9, Application): a decline of about 58%.

Using the ICF estimate of 275 PJ/year of expected RNG supply in all of North America, FEI's projected RNG use in 2030 represents 6.1% (Low), 10.5% (Medium), and 14.4% (High) of all North American RNG, despite British Columbia representing about 1.5% of the North American population.[22]

FEI's 2022 LTGRP forecast total 2050 North American RNG potential at 710.7 PJ/year. Using that forecast, FEI's projected RNG use in 2050 represents 2.3% (Low), 8.4% (Medium), and 12.6% (High) of total North American RNG.

If the 2022 LTGRP forecast for 2050 suffered the same 58% decline as its forecast for 2030, then the adjusted forecast for 2050 North American RNG would be approximately 300 PJ/year. In that case, FEI's projected RNG use in 2050 would represent 5.6% (Low), 20% (Medium), and 30% (High) of total North American RNG.

[22] According to the Government of British Columbia, B.C.'s population was 5,697,536 in 2025: Government of British Columbia, "Annual population, July 1, 1867-2025 (CSV)" (last updated 29 May 2026), online: <https://www2.gov.bc.ca/gov/content/data/statistics/people-population-community/population/population-estimates>; According to the Government of Canada, Canada's population was 41,575,585 by the end of 2025: Statistics Canada, "Population estimates, quarterly", online: <https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=1710000901>. According to the United States Census Bureau, the United States' population was 342,276,470 by the end of 2025: United States Census Bureau, "U.S. and World Population Clock", online: <https://www.census.gov/popclock/>.

On page 9-10 of the Application, FEI states that its Diversified Approach scenario "supports FEI's vision for the future of energy in BC" and "FEI acknowledges that meaningful progress towards GHG emissions reductions is dependent on FEI's ability to prompt the development of renewable and lower-carbon gas supply and continued investment and customer uptake in DSM programs. FEI's ability to meet provincial targets is also linked to external conditions and this needs to be considered rationally when evaluating the ability to meet provincially legislated emissions reductions objectives."

10.1 FEI's ability to meet the 2050 provincial GHG emissions reduction target under the Diversified Approach scenario depends on FEI acquiring a disproportionately large share of total North American RNG supply for an extended period of time. Please provide any evidence and rationale for this assumption, in light of the "external conditions" on which it relies, including competing demand for North American RNG and the recent removal of consumer carbon tax that heretofore incentivised the arbitrage market for "environmental attributes" between jurisdictions.

**Response:**

FEI disagrees with the statement in the question that the Diversified Approach scenario depends on FEI "acquiring a disproportionately large share of total North American RNG supply". FEI's assumptions regarding RNG reflect an expectation that both supply and demand will continue to develop over time as the market matures. FEI is not assuming that it will acquire a predetermined share of existing North American production.

The ICF estimate of 275 PJ per year reflects near-term expected production rather than the full long-term potential of RNG supply and is therefore considered to be a conservative point-in-time estimate, not an upper limit on the market available to FEI over the planning horizon. The American Gas Foundation assessed the potential of pipeline-injected RNG to be 1,700 to 3,399 PJ per year in the long run.[23] Supply is expected to expand as additional projects are developed in response to demand and technological progress.

Policy support in the future can also play a role in expanding supply by creating incentives for project development, production, and market participation. For example, measures such as the US Section 45Z Clean Fuel Production Credit may contribute to increasing overall supply.

FEI has been successful in securing RNG offtake agreements with multiple suppliers. Approximately 16.8 PJ of RNG supply has already been contracted, indicating that supply can be secured under current market conditions. Current annual production of RNG in the US is estimated at about 125 to 150 PJ,[24] which means FEI has a demonstrated market share of approximately 13 percent. Therefore, it is not unreasonable to assume that FEI could secure a significant amount of North American supply over time, particularly where FEI continues to

[23] American Gas Foundation, Renewable Natural Gas Supply Assessment (July 2025), Section 6, online at: https://gasfoundation.org/wp-content/uploads/2025/07/AGF-RNG-Study_FINAL-09022025.pdf.

[24] Ibid, p. 9.

contract with multiple suppliers and participate in a developing market rather than relying on a single source or jurisdiction.

FEI's acquisition of RNG is based on securing long-term supply, not on carbon price arbitrage, and is influenced by external enabling factors in policy, technology, customer behaviour and market conditions. Overall, FEI considers the Diversified Approach scenario to be reasonable and plausible as a planning scenario based on a set of assumptions that include continued market development, policy support, supplier participation, and FEI's demonstrated ability to secure RNG supply.

**11.0 Topic: Hydrogen Supply Projections and Methane: Hydrogen Blending**

**Reference: SUPPLY SIDE RESOURCES, SUPPLY PORTFOLIO PLANNING & UNDERSTANDING OUR FUTURE ENERGY NEEDS**

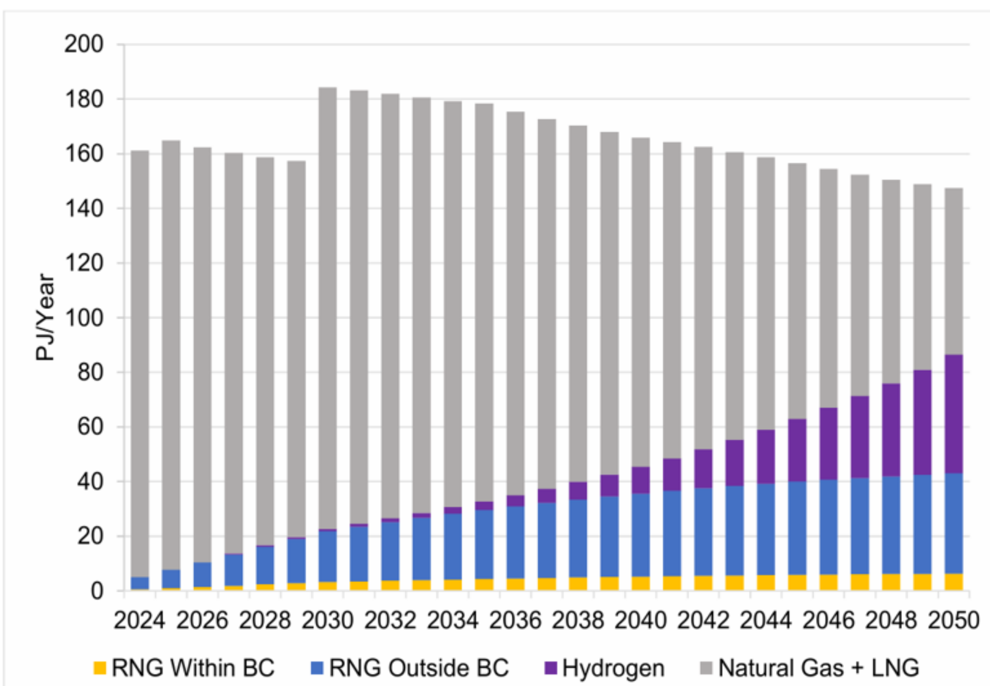
**Exhibit B-1 (Application) Section 3 at p. 3-13, Table 3-9, Section 5 at pp. 5-10, 5-12, 5-14, Section 6 at p. 6-5, Figure 6-2, Section 7 at p. 7-25**

On page 5-14 of the Application, FEI highlights some of the challenges and uncertainties associated with the development of hydrogen:

> "FEI views hydrogen as a strategic enabler of long-term GHG emissions reductions and system resilience, but its large-scale deployment will depend on a set of market, policy, technology and economic signposts that must align. These signposts reflect both indicators to monitor as well as elements of the broader enabling environment – policy stability, regulatory clarity, technological readiness, cost competitiveness, demand certainty, and market confidence – that must be built collectively to make hydrogen viable at scale. FEI's roadmap therefore outlines a potential trajectory rather than a fixed timeline, materializing only if critical conditions are met."

Based on Figure 6-2 on page 6-5 (reproduced below), we have estimated that, for 2024 and 2050, the percentages, by energy content, of gases constituting the mix delivered to FEI's core customers will be, approximately, as shown in the table below.

**Figure 6-2: Forecast Renewable and Lower-Carbon Gas Supply for Core Customers (Portfolio Planning Horizon: 2024 - 2050)**[152]



| Gas component | 2024 (GJ) | 2050 (GJ) |
|---|---|---|
| BC RNG | 1% | 3% |
| External RNG | 2.5% | 24% |
| Hydrogen | 0% | 31% |
| Fossil Gas | 96% | 41% |
| Other | 0% | 0% |

On page 5-10, section 5.3.4, of the Application, FEI recognizes some of the barriers to hydrogen becoming a significant supply source:

> "FEI continues to explore opportunities to better understand how lower-carbon intensity hydrogen could play an important role in reducing customer emissions. The market for hydrogen in BC remains nascent, with supply development still at an early stage due to policy uncertainty, challenging economics, infrastructure constraints, and limited demand aggregation. While these barriers limit near-term deployment, hydrogen remains a strategic long-term priority given its potential to support GHG emissions reductions in hard-to-electrify sectors and enhance system resilience within the broader renewable and lower-carbon gas portfolio."

However, the Application does not address important technical, safety, and cost issues that arise from using elevated blends of hydrogen and methane, such as:

- **Energy content dilution and network pressures**: The energy content of pure hydrogen gas is, for equal gas volumes and pipeline pressures, less than one-third that of pure methane.[25] In order to maintain the energy value of delivered gas, the volumes of hydrogen that must be blended and transmitted through the pipeline network must be three times the volume of methane displaced. This will necessarily require an increase in operational pipe pressures in all three pipeline regions (ITS, CTS, VITS) to compensate for the drop in energy content delivered to customers;
- **Infrastructure and customer equipment:** Compressor stations (especially those with gas turbines) are designed to cope with specific gas blends. They struggle to cope with other blends, such as those planned in Figure 6-2 (page 6-5 of the Application) for 2024-2050, that require them to work harder to propel significantly more volumes of gas through the system than they were designed to handle. Similarly, burner tips on customer equipment – stoves, furnaces, boilers, etc – are designed to burn efficiently in a specific air-to-methane mix. Outside of that mix, appliances struggle to remain lit and to burn efficiently until at least the burner unit is replaced;
- **Safety:** Blending more than 5% hydrogen into natural-gas grids introduces fundamental physical and chemical challenges.[26] Among other things, it creates significant issues for existing infrastructure, increasing the risks of pipeline

[25] SFC, "Density of Hydrogen", online: <https://www.sfc.com/glossary/density-of-hydrogen/>.
[26] Abi Grogan, "Pros and cons of hydrogen in natural gas systems" (3 Feb 2025), online (Montel) <https://montel.energy/resources/blog/pros-and-cons-of-hydrogen-in-natural-gas-systems>.

degradation, equipment failure, and appliance malfunction. Hydrogen has a faster flame speed than methane, which increases the risk of "flashback" (the flame traveling backward in the pipe into the burner) in residential appliances. This can cause delayed ignition, burner overheating, and potential gas buildup;[27]

- **Pipeline embrittlement:** Recent science has shown that hydrogen can penetrate metal microstructures, leading to a phenomenon known as Hydrogen Embrittlement.[28] This weakens pipelines, promotes intergranular fractures, and significantly accelerates material fatigue;[29] and
- **Cost and rate impacts:** On page 3-13 of the Application in Table 3-9 (reproduced below), FEI outlines the projected costs of the constituents of the gas supply from 2024 to 2050. FEI predicts that prices for the gas blend will increase between approximately 350% and 690% between 2024 and 2050: a Compound Annual Growth Rate of ~5.0%-7.5%, respectively. With regard to the likely retail price of hydrogen, BCUC's 2023 Inquiry into the Regulation of Hydrogen Energy Services Final Report put it plainly (with respect to the widespread use of hydrogen as a transportation fuel). It stated: "the main barrier to commercial deployment is the price of hydrogen compared to incumbent fuels. It is estimated that for hydrogen to be competitive in the commercial vehicle market, the retail price needs to fall to approximately US$5/kg. The current price of hydrogen is approximately US$9/kg in BC."[30]

**Table 3-9: Assumed Scenarios for Relative Change in Blended Gas Price ($2023 Real CAD/GJ)**

| Setting | 2024 Price | 2050 Price | Relative Change |
|---|---|---|---|
| **Low** | $1.68 | $5.86 | 3.5x |
| **Medium** | $1.90 | $9.95 | 5.3x |
| **High** | $2.22 | $15.36 | 6.9x |

Over the past 20 years (2006-2025), BC Hydro's residential rate has increased by a more modest 193% (from $0.064/kWh[31] in 2006 to $0.124 /kWh in 2025[32]).

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[27] Clean Energy Group, "Potential Dangers of Blending Hydrogen and Natural Gas in Pipelines" (February 2025) at p. 3, online: <https://www.cleanegroup.org/wp-content/uploads/Hydrogen-Blending-Fact-Sheet.pdf>.

[28] Mohammed Sofian et al, "A review on hydrogen blending in gas network: Insight into safety, corrosion, embrittlement, coatings and liners, and bibliometric analysis" (22 March 2024) Int J of Hydrogen Energy 867 at p. 880, online: <https://www.sciencedirect.com/science/article/abs/pii/S0360319924005810>.

[29] Nuna Rosa et al, "Advances in hydrogen blending and injection in natural gas networks: A review" (4 March 2025) Int J of Hydrogen Energy 367 at p. 368, online: <https://www.sciencedirect.com/science/article/pii/S0360319925003519>;

[30] British Columbia Utilities Commission, "Inquiry into the Regulation of Hydrogen Energy Services - Final Report" (23 Nov 2023) at p. 10, online: <https://docs.bcuc.com/documents/other/2023/doc_75049_bcuc-inquiry-hydrogen-regulation-finalreport.pdf>.

[31] British Columbia Hydro and Power Authority Financial Statements (31 March 2006) at p. 105, online: <https://www2.gov.bc.ca/assets/gov/british-columbians-our-governments/government-finances/public-accounts/2005-06/sup-e/bc-hydro-fs-2005-06.pdf>.

[32] BC Hydro, "Sustainability performance update: Fiscal Year 2025" at p. 3, online: <https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/accountability-reports/esg-reports/f2025-bchydro-sustainability-update.pdf>.

11.1 Please explain how FEI plans to address the technical, safety, and cost concerns arising from increased hydrogen:methane blending.

**Response:**

FEI continues to address the technical, safety, and cost concerns arising from higher blend percentages of hydrogen in natural gas through a process of strategic learning, technology de-risking, and pilot demonstrations in parallel with monitoring industry-wide progress prior to any deployment by FEI, small-scale or otherwise. Factors such as system capacity, distribution network and customer equipment compatibility, and operational safety would be thoroughly assessed prior to the introduction of hydrogen in any localized distribution networks, and the allowable blend percentage would be set accordingly.

11.2 Please provide a list of operating examples in North America of hydrogen:methane blends close to or exceeding 20% for residential customers (please include details such as the number of customers subscribed to the blended service, the blend composition percentages, the length of time it has been operating at that level, any special piping involved, and the rates for such service) and the rationale for the assumption that FEI's gas supply will be 31% hydrogen in 2050.

**Response:**

BCSEA-MS2S's reference in the preamble and in its question that FEI has assumed its gas supply will be a 31 percent hydrogen blend in 2050 is inaccurate. The table in the preamble with this calculated percentage was prepared by BCSEA-MS2S, not FEI.

The Diversified Approach scenario assumes that FEI's gas supply to customers could be composed of 29 percent hydrogen in 2050 through the use of multiple pathways, including, but not limited to, blending.

FEI is only aware of Hawaii Gas as an example in North America of a local distribution company using close to 20 percent hydrogen. In the 1970s, Hawaii Gas began producing and using hydrogen to convert naphtha, a by-product from the local oil refineries, for the manufacture of synthetic natural gas (SNG) in the Campbell Industrial Park, Kapolei, on the island of Oahu. Up to 15 percent of the gas in the Hawaii Gas pipeline system on Oahu is hydrogen.[33] Hawaii Gas currently serves 36,000 utility customers.

However, the lack of more examples of hydrogen blending to this degree is not indicative of the potential for FEI to achieve a certain percentage of hydrogen in its supply mix, as there are multiple pathways for hydrogen to be delivered to customers, including:

[33] Hawaii Gas, "Hydrogen", online at: https://www.hawaiigas.com/sustainability/hydrogen.

1. **Blending:** hydrogen is blended into existing gas infrastructure, where the blend percentage at a particular location in the FEI system would depend on a number of factors, including end-use compatibility and pipeline compatibility;

2. **Co-location of production and use:** hydrogen can be produced and consumed on a customer site, typically adjacent to large use industrial customer sites; and

3. **Dedicated infrastructure:** hydrogen can be produced, transported and delivered to customers via dedicated hydrogen infrastructure.

The hydrogen assumptions considered in the 2026 LTGRP Diversified Approach scenario are intended to represent a potential long-term pathway rather than a forecast or committed outcome. FEI views hydrogen as a strategic enabler of the transition to a lower-carbon future, supporting long-term GHG emissions reductions and energy system resilience. However, large-scale deployment remains contingent on a range of market, policy, technology, regulatory, and economic conditions being achieved over time.

The hydrogen outlook reflected in the Diversified Approach scenario contemplates increasing hydrogen adoption after 2040, provided that key signposts demonstrate the viability of hydrogen at scale. These signposts include policy stability, regulatory clarity, technological readiness, cost competitiveness, demand certainty, market confidence, and the development of a broader enabling environment to support hydrogen production, transportation, and end-use applications. As such, the hydrogen pathway outlined in the 2026 LTGRP represents a potential trajectory that would materialize only if these conditions are met.

As discussed in Section 5.3.4.7 of the 2026 LTGRP, full commercial deployment of hydrogen infrastructure in the 2040s and beyond – including dedicated pipelines and multiple hydrogen production and distribution hubs – would proceed only if signposts confirm economic viability, regulatory enablement, and sufficient aggregated demand. Accordingly, the hydrogen supply assumptions reflected in the Diversified Approach scenario should be viewed as conditional and indicative of a possible future state rather than a prediction of future hydrogen supply levels.

On page 5-12 of the Application, FEI acknowledges that "...the development of dedicated hydrogen-ready transmission pressure pipelines will require a critical mass of demand to justify investment. Hydrogen-ready transmission pressure pipelines must be purpose-built to serve concentrated, commercial and industrial-scale loads where sustained offtake is assured."

On page 7-25 of the Application, FEI indicates that it is "...considering scenarios whereby a large industrial load could be directly fed hydrogen blends, for example, through a supply such as Methane Pyrolysis (as discussed in Section 5.3.4.3)."

Downstream of FEI's gas receiving point from T-South at Huntingdon/Sumas are three sizeable LNG plants – the peak-shaving Tilbury LNG which is proposed to expand, the under-construction for-export Woodfibre LNG (Squamish), and the peak-shaving Mount Hayes plant on Vancouver Island. A 2022 LNG industry publication authored by two senior engineers employed by the firm constructing Woodfibre LNG emphasized the absolute requirement to have the input stream to the liquefaction units consist of pure methane to avoid significant safety and operational issues with the production of LNG in the presence of gaseous hydrogen.[34] However, none of the three plants – two of which are owned by FEI – are currently equipped to deal with this separation need, nor are they kitted to store/vent/flare the hydrogen separated from the supplied blend. Because of hydrogen's ultra-low (minus 253$^{0}$C) liquefaction temperature, most hydrogen operations must be accomplished in its gaseous form.

11.3 Please explain how FEI proposes to deal with the issue of downstream LNG plant capacity to (a) handle hydrogen:methane blends (please include details on who FEI expects to pay for the equipment needed to separate the hydrogen from the hydrogen blend) and (b) store/vent/flare the hydrogen without limiting access to large segments of its customer base downstream of Huntingdon/Sumas and without undermining the supposed GHG reductions that the blend is intended to enable.

**Response:**

All LNG facilities that are supplied by FEI infrastructure are fed from FEI's transmission system. FEI currently has no plans to introduce hydrogen blends into its transmission system.

FEI's explanation in response to MS2S IR3 3.2 in the 2022 LTGRP proceeding[35] provides further discussion of the relationship between FEI's transmission, distribution and LNG system assets and how hydrogen blending can be achieved in ways that prevent introduction of hydrogen into LNG facility feed gas.

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[34] Jeffery J. Baker & Randall W. Redman, Chicago Bridge & Iron (BC&I), "Hydrogen Blending and LNG" in LNG Industry magazine (October 2022), online: <https://www.lngindustry.com/magazine/lng-industry/october-2022/>: An excerpt from this piece states: "Though a limited presence of hydrogen in natural gas has minimal effects on residential appliances and industrial burners, even a small percentage of hydrogen in the feed gas to an LNG peak shaving facility will affect the liquefaction process. When possible, it is highly recommended that hydrogen injection be located downstream of an LNG peak shaving facility to avoid issues with liquefaction". Note: CB&I (Chicago Bridge & Iron) is a construction subsidiary of McDermott International, the company contracted by Woodfibre LNG to construct its LNG plant near Squamish, BC.

[35] Exhibit B-43, MS2S IR3 3.2, online at: https://docs.bcuc.com/documents/proceedings/2023/doc_74343_b-43-fei-ms2s-ir3-response.pdf.

**12.0 Topic: GHG Emissions Targets**

**Reference: BALANCING AFFORDABILITY, RELIABILITY AND SUSTAINABILITY**

**Exhibit B-1 (Application), Executive Summary at p. ES-18, Section 9 at pp. 9-6, 9-7, 9-9, Figure 9-4, p. 9-10, Table 9-4, p. 9-21, Table 9-10**

FEI refers twice to the possibility of British Columbia delaying its 2030 GHG emissions reduction target to 2035. The Province of British Columbia has not publicly stated its intention to relax or delay that legislated target.

12.1 Please provide all information FEI possesses concerning the possible delay of BC's 2030 GHG emissions reduction target and, if FEI does not possess any such information, please delete this counterfactual and revise the Application accordingly.

**Response:**

To FEI's knowledge, the BC government has not announced any intention to repeal or lower the 2030 target. However, FEI considered the potential for the BC government to delay its 40 percent GHG emissions reduction target from 2030 to 2035 because the Climate Change Accountability Report[36] states that the current suite of climate policies does not put the Province on track to meet its 2030 goals. Specifically, the report projects emissions will be 20 percent below 2007 levels by 2030, well short of the target of 40 percent.

Given the current trajectory of provincial GHG reductions, the 2026 LTGRP illustrates how FEI's Diversified Approach scenario would perform if the target date were to be delayed to 2035, as it is projected to substantially meet that target, achieving a 39 percent emissions reduction by 2035. This information is useful for understanding the robustness of the Diversified Approach scenario and its potential contribution to reducing GHG emissions in the province.

On pages 9-6 to 9-7 of the Application, FEI sets out BC's GHG emission targets:

"BC's GHG emissions reduction targets are established in the CCAA. Using 2007 as a baseline, BC has committed to reducing GHG emissions as follows:

- 16 percent by 2025;
- 40 percent by 2030;
- 60 percent by 2040; and

[36] Province of British Columbia, Climate Change Accountability Report 2025, pp. 4, 16, online at https://www2.gov.bc.ca/assets/gov/environment/climate-change/action/cleanbc/2025_climate_change_accountability_report.pdf.

- 80 percent by 2050."

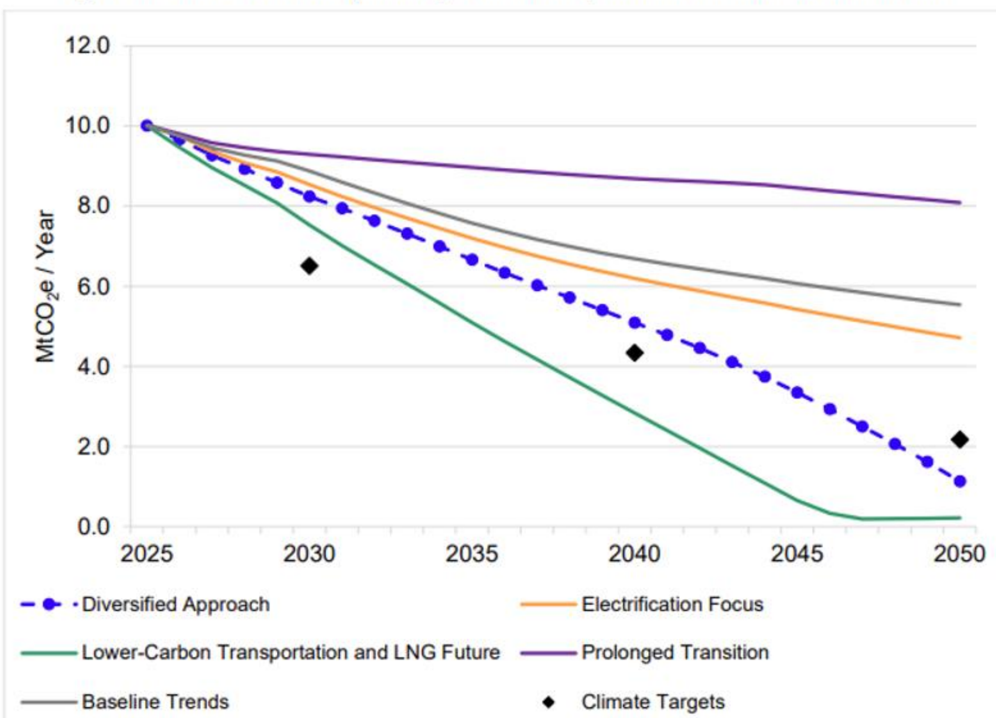
Table 9-4 (reproduced below) on page 9-10 of the Application indicates that, under the Diversified Approach, FEI does not plan on meeting the 2030 Provincial GHG emission reduction target and will not meet any of BC's GHG emissions targets until 2050.

**Table 9-4: GHG Emissions Reductions (End Use) – Residential, Commercial and Industrial Sectors for the Diversified Approach Scenario**

| Milestone Year | Energy Demand (Post-DSM) (PJ/Yr) | Total Emissions ($MtCO_2e$/Yr) | Emission Reductions Relative to 2007 ($MtCO_2e$/ Yr) | FEI Percentage Decrease from 2007 (%) | Provincial GHG Emission Reduction Targets (%) |
|---|---|---|---|---|---|
| **2007** | 216 | 10.846[210] | N/A | N/A | N/A |
| **2030** | 193 | 8.240 | 2.607 | 24% | 40% |
| **2035** | 176 | 6.658 | 4.188 | 39% | N/A |
| **2040** | 162 | 5.093 | 5.754 | 53% | 60% |
| **2045** | 151 | 3.344 | 7.502 | 69% | N/A |
| **2050** | 140 | 1.126 | 9.721 | 90% | 80% |

On page 9-9 of the Application, Figure 9-4 (reproduced below) shows FEI's projected GHG Emissions (End Use) for each annual demand scenario alongside the legislated BC climate targets:

**Figure 9-4: GHG Emissions (End Use) – Residential, Commercial and Industrial Sectors**




The only two scenarios considered by FEI that eventually meet some of BC's legislated GHG emissions targets are Diversified Approach and Lower-Carbon Transportation and LNG Future. Those scenarios only meet those targets by making aggressive assumptions about the amount of RNG and hydrogen in the gas supply (84% and 93% by 2050, respectively; see Application, Table 9-10, p. 9-21). It is not clear that FEI has considered the second order effects of either (a) substantially increased LNG exports on domestic gas prices and affordability or (b) substantially increased RNG and H2 blend on the economic and technical viability of LNG exports (see IRs 9.1 and 9.2). Furthermore, this entire exercise excludes consideration of electricity and cross-price elasticity (see IR 7.1).

On page 9-10 of the Application, FEI states: "FEI acknowledges that meaningful progress towards GHG emissions reductions is dependent on FEI's ability to promote the development of renewable and lower-carbon gas supply and continued investment and customer uptake in DSM programs."

12.2 Please identify the concrete actions FEI will take to promote the development of renewable and lower-carbon gas supply, the costs associated with those actions, the likelihood of their success in stimulating the large increase in supply forecast under the Diversified Approach and the Lower Carbon Transportation and LNG Future scenarios, and the criteria and process FEI will use to determine whether those actions were effective.

**Response:**

The renewable and lower-carbon gas assumptions in the 2026 LTGRP were developed for long-term planning purposes and are scenario-based. They are not commitments or specific implementation plans. As stated in the 2026 LTGRP, the five long-term demand scenarios represent a range of plausible futures and FEI has not estimated the probability of any scenario materializing.

Accordingly, the assumptions regarding renewable and lower-carbon gas supply are intended to test potential long-term pathways under different futures, including futures in which provincial policy, market demand, technology readiness, customer adoption, and supply availability evolve in ways that support higher levels of renewable and lower-carbon gas.

FEI's ability to increase renewable and lower-carbon gas supply over time will depend on a range of external and internal factors, including the availability and cost of supply, regulatory and policy support, technology development, customer demand, infrastructure requirements, and overall affordability considerations. These factors are inherently uncertain over the 2026 LTGRP planning horizon.

The costs associated with achieving materially higher levels of renewable and lower-carbon gas supply would depend on the specific actions ultimately pursued and the pace at which they are implemented. Potential cost categories could include supply acquisition, interconnection and system integration, customer or end-use infrastructure, program administration, and regulatory compliance. As noted in the 2026 LTGRP, incorporating a significant portion of renewable and lower-carbon gas into the system would be expected to lead to future customer bill impacts, and there is a trade-off between affordability and GHG emissions reductions under scenarios with increased adoption of renewable and lower-carbon gas.

For the same reason, FEI has not assigned a likelihood of success to the level of renewable and lower-carbon gas supply assumed in the Diversified Approach or the Lower-Carbon Transportation and LNG Future scenarios. The scenarios are intended to support long-term planning by illustrating potential outcomes under different assumptions, not to predict how a specific level of supply will be achieved.

To the extent specific actions are pursued in the future to support renewable and lower-carbon gas supply development, their effectiveness would be assessed through the appropriate planning, procurement, regulatory, and internal governance processes. Relevant considerations would include volumes secured, delivered cost, customer bill impacts, GHG emissions reduction outcomes, infrastructure requirements, project development progress, and alignment with applicable policy and regulatory requirements.

Accordingly, while FEI may consider a range of actions over time to advance renewable and lower-carbon gas supply, those actions would be developed, evaluated, and brought forward through the applicable future processes rather than determined through the 2026 LTGRP.

12.3 Please explain why FEI did not include at least one scenario in which FEI's GHG emissions met each of British Columbia's legislated GHG emissions targets in 2030, 2040, and 2050, and why there is no scenario where FEI projects a planned phaseout of the gas utility.

**Response:**

FEI did not include a scenario specifically designed to meet British Columbia's legislated GHG emissions reduction targets in 2030, 2040, and 2050 because the purpose of the 2026 LTGRP scenarios was not to model outcomes optimized for a single objective, but rather to evaluate a range of plausible futures that balance affordability, reliability, and sustainability. Accordingly, FEI's scenarios are grounded in existing policy, market conditions, technology trends and customer preferences.

FEI did not align a scenario with the Province's 2030 legislated target because current provincial policies are not projected to achieve it. As reported in the *Climate Change Accountability Report 2025*, existing measures are projected to reduce GHG emissions by approximately 20 percent below 2007 levels by 2030, compared to the legislated target of 40 percent below 2007 levels.

While the scenarios were not designed to explicitly achieve BC's legislated GHG emissions reduction targets, they support substantial long-term emissions reductions and meaningful progress toward the Province's climate objectives. Some of FEI's scenarios achieve GHG emissions reductions that meet or exceed BC's 2050 target of 80 percent below 2007 levels.

The scenario results demonstrate that FEI can contribute meaningfully to provincial GHG emissions reductions across multiple sectors. As illustrated in Figure 9-4 of the 2026 LTGRP, all scenarios result in GHG emissions reductions across the residential, commercial, and industrial sectors relative to baseline conditions. In addition, Figure 9-6 of the 2026 LTGRP demonstrates that the transportation, marine, and ISO shipment sectors achieve significant GHG emissions reductions across all scenarios relative to the continued use of other fuels (e.g., marine gas oil and diesel). These findings highlight the role that renewable and lower-carbon gas solutions can play in supporting emissions reductions across multiple sectors, while enabling FEI to continue balancing affordability and reliability objectives within its resource planning framework.

FEI did not include a scenario that assumed a planned phaseout of the gas utility, as there is currently no legislative or regulatory requirement mandating such an outcome. The 2026 LTGRP represents FEI's long-term resource planning process, developed to assess further energy and peak demand, resource requirements, infrastructure needs, and system impacts under a range of plausible planning assumptions. Its purpose is to support informed planning by evaluating how FEI can continue to provide safe, reliable, and affordable energy services while supporting the transition to a lower-carbon energy future. The scenarios examine a range of pathways, including varying levels of electrification, energy efficiency, renewable and lower-carbon gas, and customer adoption trends.

**13.0 Topic: RNG and Hydrogen GHG Emissions**

**Reference: BALANCING AFFORDABILITY, RELIABILITY AND SUSTAINABILITY & SUPPLY-SIDE RESOURCES**

**Exhibit B-1 (Application), Section 5 at p. 5-11, Section 9 at p. 9-7, 9-8, Table 9-2, Table 9-3; 2022 Long Term Gas Resource Plan Decision and Order G-78-24 March 20, 2024 at p. 45**

On page 45 of Decision and Order G-78-24,[37] the BCUC wrote:

> "FEI submits that to its knowledge, there is no guidance from world leading authorities (such as the Intergovernmental Panel on Climate Change) or from Canadian federal or provincial governments on the subject [of hydrogen's global warming potential]. FEI adds that it will monitor the evolution of climate science and rely on emission factors as established by government authorities where available."

However, on page 9-7, Table 9-2 and page 9-8, Table 9-3 of the Application, it appears that FEI is using a near-zero Global Warming Potential (GWP) for both Hydrogen and RNG imported from outside BC based on the Intergovernmental Panel on Climate Change's (IPCC) Fifth Assessment Report (AR5), published in 2014, which does not reference Hydrogen. In the later IPCC Sixth Assessment Report (AR6),[38] published in 2023, Hydrogen is classified as an indirect greenhouse gas with a GWP20 (Global Warming Potential over a 20-year time horizon) of approximately 34.4.[39]

On page 5-11 of the Application, in section 5.3.4.3, FEI outlines the various technologies of hydrogen gas production necessary to fulfill the Application's quotient of ~31% hydrogen content under the Diversified Scenario by 2050.[40] However, the analysis lacks details necessary for estimating the effect on atmospheric $CO_2$ and $H_2$ concentration of increased hydrogen production in BC, including their (a) carbon intensity, (b) production expectations, and (c) current cost per GJ/ economic viability. Absent estimates of the emissions from the production, distribution, and end-use of hydrogen, the impact on GHG emissions, and the contribution of the Application towards achievement of BC's climate targets cannot be accurately estimated. The Government of British Columbia publication on the Low Carbon Clean Fuel Standard (LCFS) states that:

> "Under the LCFS, fuel suppliers must progressively decrease the average carbon intensity of their fuels to achieve a 30% reduction in 2030. The carbon intensity of

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[37] BCUC, "FortisBC Energy Inc. 2022 Long-Term Gas Resource Plan Decision and Order G-78-24" (20 March 2024), online: <https://docs.bcuc.com/documents/other/2024/doc_76411_g-78-24-fei-2022-long-term-gas-resource-plan-decision.pdf>.

[38] IPCC, "Chapter 6: Energy Systems" (20 March 2023) in the IPCC Sixth Assessment Report, online, <https://www.ipcc.ch/report/ar6/wg3/chapter/chapter-6/>.

[39] See "H2, GWP(20) IPCC AR6" in Table 3 at Warwick et al, "Atmospheric composition and climate impacts of a future hydrogen economy" (2023) J of Armos. Chem. Phys. 23 13451 at "Table 3", online: <https://acp.copernicus.org/articles/23/13451/2023/acp-23-13451-2023.html>.

[40] The 31% Hydrogen content figure is derived from Figure 6-2 on page 6-5 of the 2026 LTGRP. See Topic 11 for our calculations.

a fuel represents the greenhouse gas emissions associated with its production and use as determined by a life cycle assessment, presented in terms of grams of carbon dioxide equivalent per mega joule (gCO2eq/MJ) of the produced fuel. A life cycle assessment considers the emissions associated with each stage of a fuel product's life and all materials and energy used throughout the life cycle."[41]

According to the Government of British Columbia, the carbon intensity of hydrogen (123.96 gCO2e/MJ) is over 10 times that of electricity (12.11 gCO2e/GJ) and twice that of CNG (63.91 gCO2e/GJ).[42] The comparison table from the Government of British Columbia document is reproduced below:[43]

**Table 7: Default Carbon Intensities**

| Fuel Category | Carbon intensity (gCO2e/MJ) |
|---|---|
| Electricity | 12.11 |
| Non-fossil diesel fuel | 100.10 |
| Non-fossil gasoline fuel | 93.67 |
| Non-fossil jet fuel | 87.33 |
| Hydrogen | 123.96 |
| Natural gas - CNG | 63.91 |
| Natural gas - LNG | 90.11 |
| Propane | 79.72 |

13.1 Please re-do and publish the calculations in Table 9-2 and Table 9-3 using the IPCC AR6 emissions factors for hydrogen and RNG and provide an estimate of the GHG emissions for all scenarios throughout the planning time period for the lifecycle GWP100 and GWP20 of (a) FEI's hydrogen supply and (b) FEI's RNG supply, including production, distribution, and end-use(s) of the product (i.e. Scope 1, 2 & 3 emissions).

**Response:**

FEI respectfully declines to revise estimates of GHG emissions across all scenarios using AR6 GWP100 and GWP20 values as this would require a departure from applicable government guidance and methodologies for quantifying GHG emissions for the purposes of LTGRP modeling.

[41] Government of British Columbia, "B.C. Low Carbon Fuel Standard: Technical Requirements Intentions Paper" (20 Dec 2022) at p. 4, online (pdf): <https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/transportation/renewable-low-carbon-fuels/technical_regulation_intentions_paper_december_2022.pdf>.

[42] Ibid at Table 7, p. 12.

[43] Ibid.

FEI's LTGRP modelling approach is designed to maintain alignment with applicable government policies, standards, and reporting requirements. Emission factors used in the 2026 LTGRP are therefore intentionally sourced from recognized provincial and federal methodologies.

The emission factors applied in Table 9-2 (end-use) and Table 9-3 (life cycle) of the 2026 LTGRP are derived from established provincial regulatory frameworks and government-approved methodologies. Specifically, end-use combustion emission factors in Table 9-2 reflect those adopted under the BC *Greenhouse Gas Industrial Reporting and Control Act* (GGIRCA)[44] and associated guidance, which are based on GWP values from the IPCC AR5[45] and a 100-year averaging period. Similarly, life cycle emission factors used in Table 9-3 are aligned with the Clean Fuel Regulations,[46] which relies on the OpenLCA model[47] for determining carbon intensity. The OpenLCA model is also based on AR5 GWP assumptions.

Accordingly, revising Tables 9-2 and 9-3 of the 2026 LTGRP to incorporate using AR6 GWP100 and GWP20 emission factors would not be consistent with the policy frameworks FEI is participating in, and inconsistent with current provincial reporting requirements and established regulatory practice.

[44] Government of British Columbia, "Greenhouse Gas Industrial Reporting and Control Act" (June 2026), online at: https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/14029_01.

[45] The Intergovernmental Panel on Climate Change (IPCC), "Fifth Assessment Report", online at: https://www.ipcc.ch/assessment-report/ar5/.

[46] Government of Canada, "Clean Fuel Regulations" (February 17, 2023), online at: https://www.canada.ca/en/environment-climate-change/services/managing-pollution/energy-production/fuel-regulations/clean-fuel-regulations.html.

[47] Government of Canada, "Fuel Life Cycle Assessment Model", (October 2025), online at: https://www.canada.ca/en/environment-climate-change/services/managing-pollution/fuel-life-cycle-assessment-model.html.

**14.0 Topic: Hydrogen Production Pathways' Varying GHG Emissions**

**Reference: SUPPLY-SIDE RESOURCES**

**Exhibit B-1 (Application), Section 5 at p. 5-11, 5-18, Table 5-4; 2022 Long Term Gas Resource Plan Decision and Order G-78-24 March 20, 2024 at pp. 37-38**

On pages 37-38 of Decision and Order G-78-24,[48] the Panel wrote:

> "FEI's pursuit of hydrogen specifically appears to be aspirational at this point, as there is a lack of any level of detailed planning in this LTGRP to explain how FEI will deliver meaningful amounts of hydrogen by 2030 as forecast. By finding that the pursuit of infrastructure investments for the provision of low carbon gases (such as hydrogen) is prudent and reasonable, the Panel is indicating that it is important that FEI better understand how the integration of low-carbon gases will impact system infrastructure planning. Based on the extent of information presented in this LTGRP, the Panel considers that it is premature to say that hydrogen will be the ultimate solution to FEI's GHG-reduction objectives. The Panel expects more detail regarding specific low-carbon gas related infrastructure investments in the next long-term gas resource plan."

On page 5-11 of the Application, Section 5.3.4.2, FEI states: "... hydrogen represents a critical component of FEI's broader renewable and lower-carbon gas portfolio over the planning horizon." On page 5-11, FEI goes on to state that:

"FEI maintains a technology-agnostic approach to hydrogen production, selecting solutions based on project-specific requirements and broader system considerations. FEI's evaluation framework recognizes the distinct characteristics of the three primary production pathways:

- **Electrolysis ("Green Hydrogen"):** This pathway is one of the most technologically mature and offers the potential for the lowest carbon intensity when paired with renewable electricity. However, it is currently constrained by high production costs and scalability challenges, primarily due to significant electricity requirements.
- **Methane Reforming with Carbon Capture and Storage ("Blue Hydrogen"):** This option provides large-scale potential and cost advantages at commercial scale where suitable geological formations for carbon sequestration exist. Its applicability is limited for smaller distributed projects and in regions where sequestration opportunities are scarce.
- **Methane Pyrolysis ("Turquoise Hydrogen"):** This emerging pathway demonstrates promising scalability and modularity, with the potential to balance lower-carbon intensity and cost competitiveness. Achieving commercial viability

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48 BCUC, FortisBC Energy Inc. 2022 Long-Term Gas Resource Plan Decision and Order G-78-24 (dated March 20, 2024), online: <https://docs.bcuc.com/documents/other/2024/doc_76411_g-78-24-fei-2022-long-term-gas-resource-plan-decision.pdf>.

will require further technological advancement and successful monetization of the solid carbon co-product."

A "technology-agnostic approach" to hydrogen production obfuscates the fact that the three primary pathways to produce hydrogen described by FEI – via water electrolysis (Green), via Steam- Methane reforming (SMR) with carbon capture and storage (Blue)[49], and via Methane Pyrolysis (Turquoise)[50] – have different GHG emissions. It is misleading to characterize hydrogen as a "lower-carbon gas," for all but Green hydrogen (which produces virtually no associated GHG emissions), because "the environmental footprint of hydrogen production varies dramatically depending on the pathway."[51]

With regard to Blue hydrogen, the associated carbon capture and storage (CCS) is a technology that is unproven at scale, and FEI's assumption that it would capture 90%-plus of all $CO_2$ emissions from the process are belied by its performance at the two major Western Canada trials to date (capture rates at Saskatchewan's Boundary Dam and Shell's Quest CCS facilities have been 57% and 78%, respectively).[52] Additionally, the proposed $16.5 Billion "Pathways" CCS project in Alberta is stalled amid industry statements that it is uneconomic as it contends with high capital and operating costs, which outweigh the potential revenue from carbon credits; without massive public subsidies and stable, high carbon prices, the Pathways project's struggles continue.[53]

The GHG emissions associated with the production of Turquoise hydrogen are currently unknown, as the technology appears to be in a very fledgling state, as is its energy budget (i.e. energy in and out of the process), the market size for and value of the by-product graphite, and the potential for this approach to get from laboratory experiment to commercial production in the 2024-2050 period.

14.1 Please outline the current state of Turquoise hydrogen production (methane pyrolysis) and its use in BC, including (a) its energy budget (i.e energy in and out of the process); (b) the feedstock(s) used to generate the hydrogen; (c) the source(s) of the supply of production that would provide the ~60 PJ/annum required, by 2050, for the Application; (d) the transportation and distribution

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49 Institute for Energy Economics and Financial Analysis, "Blue Hydrogen: Not clean, not low carbon, not a solution" (23 Sept 2023), online: <https://ieefa.org/articles/blue-hydrogen-not-clean-not-low-carbon-not-solution>.

50 DOB Energy, "Suncor/Hazer Pilot Project - Methane Pyrolysis: A New, Low-Emission Hydrogen Process" (20 Jan 2023), online: <https://www.dobenergy.com/news/headlines/2023/01/20/suncorhazer-pilot-project-methane-pyrolysis-a-new->.

51 Dave Michael, "Comparing Carbon Emissions of Different Hydrogen Production Methods and Exploring Future Innovations" (Nov 2024), online: <https://www.researchgate.net/publication/393790722_Comparing_Carbon_Emissions_of_Different_Hydrogen_Production_Methods_and_Exploring_Future_Innovations>.

52 Bob Weber (CBC), "Missed emissions goals at Sask. carbon capture project raising questions" (2 May 2024), online (CBC): <https://www.cbc.ca/news/canada/saskatoon/boundary-dam-carbon-capture-missing-emmision-goals-1.7191867>.

53 Drew Anderson (The Narwhal), "Alberta's crown jewel of carbon capture quietly reduces its targets - by 77%" (4 June 2026), online (The Narwhal): <https://thenarwhal.ca/oilsands-pathways-emissions-promise/>; Darius Snieckus (Canada's National Observer), "Flagship $20B-plus carbon capture project lowered goals in Ottawa-Alberta oilsands deal" (20 May 2026), online (Canada's National Observer): <https://www.nationalobserver.com/2026/05/20/news/flagship-20b-plus-carbon-capture-project-lowered-goals-ottawa-alberta-oilsands-deal>.

network required, including special pipe, pipe coatings, and compression technology; and (e) its predicted GHG emissions.

**Response:**

At present, methane pyrolysis technologies are at early commercial stages, with limited deployment in British Columbia. Future hydrogen supply could be derived from the province's natural gas resources through either centralized production facilities or distributed facilities located closer to end-use applications.

Hydrogen produced through the methane pyrolysis pathway could be transported through a combination of pipelines, trucking, or blending into existing natural gas systems required to support hydrogen service. The solid carbon co-product may also have potential value in carbon black, graphite substitute, battery-material, graphite-electrode, and other performance-material markets. Consistent with the CICE report,[54] carbon revenues could materially improve methane pyrolysis economics, although monetization of this co-product remains an important commercial assumption and would depend on carbon quality and consistency, certification requirements, customer qualification timelines, market depth, and competitiveness relative to incumbent mined or synthetic graphite products. Please refer to Attachment 14.1 for a copy of the CICE report.

Overall, methane pyrolysis represents a potential lower-carbon hydrogen pathway under the GGRR framework, subject to continued advancement toward technology maturity and commercial-scale deployment.

***Technical Background***

Turquoise hydrogen, produced via methane pyrolysis ($CH_4 \rightarrow 2H_2 + C$), is an emerging hydrogen production pathway that utilizes methane or other methane-containing feedstocks and generates solid carbon rather than carbon dioxide as a direct by-product. The process is endothermic and requires high-temperature heat and electricity inputs, typically on the order of approximately 7–15 kWh per kg of hydrogen produced, with additional energy required for purification and compression. A theoretical mass and energy balance for methane pyrolysis includes:

- Input of 5.2 kWh Heat
- Input of 3,978 kg Methane
- Output of 1,000 kg Hydrogen
- Output of 2,978 kg Carbon[55]

Methane pyrolysis has the potential to achieve lifecycle carbon intensities consistent with the GGRR requirement of approximately 30.8 $gCO_2e$/MJ or lower.

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[54] Potential for Methane Pyrolysis in BC by BC Centre for Innovation and Clean Energy (CICE), April 2024.

[55] Ibid.

**15.0 Topic: Fuel Switching**

**Reference: ENGAGEMENT APPROACH**

**Exhibit B-1 (Application) Section 8 at pp. 8-12, 8-13, Table 8-5**

On pages 8-12 (Table 8-5) to 8-13 of the Application, FEI indicates that it plans for 3,700-4,600 GWh of fuel switching volumes by 2050 in its Diversified Approach, whereas BC Hydro only plans for 1,600 GWh. This means that there is roughly 2-3 times more electrification baked into FEI's planning model than BC Hydro's plan.

On page 8-13 of the Application, FEI describes this discrepancy as "reasonable," but does not explain the difference.

15.1 Please explain how the affordability, reliability, and sustainability of the Diversified Approach scenario would change if only 1,600 GWh of fuel switching occurred by 2050, as planned by BC Hydro. Please include, among other things, specific information on the cost of gas, the overall cost of power, and the amount of GHG emissions.

**Response:**

If only 1,600 GWh of fuel switching occurs by 2050, as modelled by BC Hydro in its Integrated Resource Plan (IRP), this amount would fall between the amounts reflected in the Prolonged Transition and Diversified Approach scenarios, as outlined in Table 8-5 of the 2026 LTGRP.

With respect to affordability, all else equal, FEI expects that rate impacts would fall between those of the Prolonged Transition and Diversified Approach scenarios, as illustrated in Section 9.4 of the 2026 LTGRP. A lower level of fuel switching would moderate the cost impacts associated with decreased gas load due to electrification relative to the Diversified Approach scenario.

With respect to reliability, FEI plans its gas system to maintain reliable and resilient service across all scenarios and continuously monitors changes in demand due to fuel switching and other factors. If only 1,600 GWh of fuel switching occurred by 2050, the long-term demand would still fall within the range of demand under the scenarios in the 2026 LTGRP.

With respect to sustainability, Figure 9-5 of the 2026 LTGRP illustrates the relationship between fuel switching and GHG emissions reductions. An amount of fuel switching of 1,600 GWh, compared to the estimated 3,700 to 4,600 GWh in the Diversified Approach scenario, would result in relatively higher GHG emissions from natural gas and correspondingly lower emission reductions attributable to fuel switching. While the direction of this impact is illustrated in Figure 9-5, FEI has not quantified the increment change in GHG emissions associated with a 1,600 GWh fuel switching case.

With respect to the cost of natural gas, FEI relies on price forecasts developed by third-party expert entities, including S&P Global and the Northwest Power and Conservation Council (NWPCC), which incorporate a broad range of market factors. As such, a change in fuel switching demand of this magnitude within BC is not expected to materially influence natural gas commodity prices.

With respect to the overall cost of power, this analysis falls within the scope of BC Hydro’s planning and modelling.

**16.0 Topic: Hard-to-Electrify Sectors**

**Reference: SUPPLY SIDE RESOURCES & BALANCING AFFORDABILITY, RELIABILITY AND SUSTAINABILITY**

**2022 Long Term Gas Resource Plan Decision and Order G-78-24 March 20, 2024 at p. 57; Exhibit B-1 (Application), Appendix A, Table 4 at p. 20, Section 5 at pp. 5-10, 5-13, Section 9 at p. 9-6**

On page 57 of Decision and Order G-78-24,[56] BCUC indicated that it would be helpful for FEI to include its views on the prioritization of specific uses of low carbon gas in its next LTGRP.

On page 20 of Appendix A of the Application, FEI says: "This matter was not addressed in the Application. FEI will consider the Panel's guidance in its next LTGRP."

On pages 5-10 and 5-13 of the Application, FEI indicates that hydrogen will support GHG reductions in hard-to-electrify sectors.

On page 9-6 of the Application, FEI states:

> "Transportation emissions, down four percent YOY, remain one of the most significant and challenging sources of emissions to reduce, underscoring the need for increased use of renewable and lower-carbon gas in this sector."

16.1 Please provide FEI's views on prioritizing the use of available RNG and hydrogen in the hardest-to-decarbonize sectors, such as transportation, including specific steps FEI can take to prioritize the use of low-carbon gas in hard-to-electrify sectors, and revise the Application in order to reflect those views.

**Response:**

FEI's planning analysis indicates that renewable and lower-carbon gas may provide particular value in applications where alternative GHG emissions reduction pathways are more challenging due to operational, technical, economic, infrastructure, or reliability considerations. For example, FEI's planning analysis identifies medium- and heavy-duty transportation as one of several potential applications where hydrogen may contribute to emissions reductions, particularly in duty cycles that may be difficult to electrify. FEI may therefore focus its market development activities in certain sectors of market demand, as discussed in the response to BCUC IR1 15.2 regarding the role of hydrogen in the transportation market.

However, FEI does not prioritize the use of available RNG and hydrogen to particular end-use sectors for renewable and lower-carbon gas resources. Rather, the use of these resources is dictated by customer demand, which is driven by economics, technology readiness, applicable policy frameworks, and the emissions reduction benefits that can be achieved in different

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[56] BCUC, "FortisBC Energy Inc. 2022 Long-Term Gas Resource Plan Decision and Order G-78-24" (20 March 2024), online: <https://docs.bcuc.com/documents/other/2024/doc_76411_g-78-24-fei-2022-long-term-gas-resource-plan-decision.pdf>.

applications. Further, as a public utility subject to the *Utilities Commission Act*, FEI has a duty to provide service to customers within its service territory, and any differentiation amongst customers must not constitute unjust or undue discrimination.

# Attachment 14.1

# The Potential for Methane Pyrolysis in B.C.

**Leveraging British Columbia's energy infrastructure to accelerate low carbon hydrogen production**

APRIL 2024

# Acknowledgement

*The Potential for Methane Pyrolysis in British Columbia (B.C.)* study is the result of collaboration between the B.C. Centre for Innovation and Clean Energy (CICE), Sky Point Resources Ltd. (Sky Point), and Orion Projects (Orion). Our teams have worked closely to obtain and validate the data inputs and assumptions required to investigate low carbon hydrogen production and deployment in B.C. that best leverages existing resources and infrastructure.

We would like to thank all of the stakeholders that have contributed to the development of this study by providing data and market knowledge and participating in the discussion and evaluation of the scenarios modelled within. These stakeholders were intended to represent the full breadth of the energy transition value chain, including technology developers, existing utility operators, think tanks and accelerators, research organizations, regulatory bodies, industrial suppliers, First Nations, and other commercial developers and end-users.

We acknowledge with respect and gratitude that this report was produced on the traditional, ancestral, and unceded territories of the Coast Salish peoples — including the xwməθkwəy'əm (Musqueam), **Skwx̱wú7mesh** (Squamish), and **səl'il'wətaʔɬ**/ sel'íl' witulh (Tsleil-Waututh) Nations, whose deep connections with this land continue to this day.

# Notice to reader

This study explores opportunities in production and deployment of low carbon hydrogen in British Columbia and beyond. The province's natural resources and established energy infrastructure can be leveraged to spur innovation, attract investment, and accelerate the hydrogen economy. However, difficult challenges remain in developing the full value chain of production, storage, distribution, and utilization in a rapidly maturing but still nascent industry.

The study investigates a wide variety of emerging ideas, approaches, and technologies being advanced in the hydrogen sector to accelerate decarbonization and achieve climate targets. It includes an in-depth techno-economic and environmental analysis of hydrogen production pathways that leverage existing natural gas systems in B.C., based on various scales of end-use applications. Decentralized production and distribution-focused technologies are viewed as potential means to maximize the utilization of existing assets and overcome the limitations of centralized industrial models that require significant water resources and clean electrical capacity. This study includes references to previous CICE reports and focuses on the regulatory requirements, challenges, important considerations, and opportunities to accelerate low carbon hydrogen project deployment in B.C. It includes a summary of existing technologies and compares hypothetical deployment scenarios using B.C.-specific case studies to analyze barriers that must be removed to achieve maximum benefit to people and climate.

It is important to note that further region-specific studies are required to gain a holistic and in-depth understanding of hydrogen development and demand in the province. This study is intended to provide data and insights to support decision making in strategic investments and policy developments that could result in hydrogen pathways with the highest emissions reduction and economic impact. CICE recognizes that this study represents a current snapshot of a dynamic hydrogen market, and that any identified opportunities will continue to evolve with ongoing policy and market development.

This study serves as a guide to CICE for future investment direction and intelligence work in hydrogen. It identifies the challenges associated with hydrogen generated from natural gas and electricity, and highlights potential for innovation areas that show great promise but are currently underexplored, such as utilization of different forms of carbon generated from methane pyrolysis. It presents key drivers and barriers to hydrogen adoption within high-emitting sectors, helping CICE to align support for innovation advancement with unmet industry needs.

This study is an assessment of potential technologies at various levels of commercial development based on the interpretation of the authors using professional judgement and reasonable care. Therefore, any conclusions or actions resulting from this study should be subject to further due diligence by the reader. The authors have utilized a customary level of judgement to compile the information presented in this study but assume no responsibility for the consequences of any error or omissions that may be contained therein.

Studies like this are a key part of the data gathering that underpins CICE's investment thesis and shapes our future calls for innovation. Our intelligent, risk-taking framework empowers us to confidently lead investment into disruptive, clean energy innovation where traditional revenue metrics can be a barrier. By leveraging the knowledge gathered through a combination of deep-dive reports, community engagement, and world-class subject matter experts, CICE uniquely validates future pathways to net zero—identifying the optimal, high-impact convergence point of breakthrough decarbonization solutions and the real-world readiness to implement.

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# Executive summary

Hydrogen is a versatile energy vector that can be used to reduce emissions across sectors, particularly for hard-to-abate applications which do not yet have a viable pathway to direct electrification. Given its abundant natural resources, B.C. is well suited to achieve low-cost and low carbon hydrogen generation in a variety of ways, including: water electrolysis using renewable electricity; reforming of natural gas with carbon capture, utilization, and storage (CCUS); and methane pyrolysis (may also be referred to as just 'pyrolysis' in this document). This study evaluates the delivered levelized cost of hydrogen production (LCOH) across these three production technologies as a decarbonization pathway for different scales of demand.

Alongside Canada's net-zero by 2050 targets, the CleanBC roadmap outlines a number of ambitious and time-based emissions reduction targets across different sectors including transport, industry, oil and gas, and buildings and communities. To achieve B.C.'s decarbonization targets, hydrogen usage could achieve the reduction of 7.2 megatonnes per year of carbon dioxide equivalent ($CO_2e$) by 2050.[1,13] Possible use cases include:

- **Hydrogen to directly displace natural gas or coal in high grade heating industrial operations.**
- **Transport decarbonization through deployment of hydrogen fuel cell and hydrogen combustion vehicles, alongside hydrogen refuelling stations.**
- **Utilizing low carbon hydrogen to reduce the blended carbon intensity of liquid fossil fuels, including the production of renewable fuels like biofuels, renewable diesel, methanol, sustainable aviation fuels, and hydrogen feedstock-based processes like ammonia production.**
- **Hydrogen as an electricity storage medium to meet peak power demand or stabilize local power supply in grids with high penetration of intermittent renewable power generation.**
- **Hydrogen as an energy source in remote communities.**
- **Hydrogen injection into the natural gas grid to reduce the blended average carbon intensity of industrial, commercial, and residential heating.**

» **Large-scale hydrogen production and hydrogen-derived fuels for export markets.**

In Canada, the existing hydrogen industry has been developed around large-scale industrial feedstock demand, in which hydrogen is produced primarily from steam methane reforming. The proposed pathway to reduce the carbon intensity of this hydrogen is implementing carbon capture and storage. Some large-scale water electrolysis projects have been proposed in areas without readily available carbon sequestration reservoirs. The emerging use cases and geographically diverse demand for low carbon hydrogen will require a combination of different production technologies and pathways — centralized and distributed.

The long-term viability of distributed hydrogen production via electrolysis may be challenged by competing priorities, such as increasing demands on the B.C. electricity grid from the electrification of residential heating and transport. The build out of new electricity generation, transmission and distribution lines is a highly expensive and lengthy process. Currently, B.C. produces some of the lowest-cost and lowest-GHG natural gas globally. However, centralized, large-scale hydrogen reforming projects are likely to be limited to Northeast B.C., as it is the only part of the province currently to have known potential for suitable $CO_2$ sequestration pore space.

One emerging solution to solve the problem of cost-competitive distributed hydrogen production is methane pyrolysis. This can provide a low-cost, low carbon intensity hydrogen production pathway utilizing B.C.'s existing abundant natural gas resource as the energy carrier. Given B.C.'s significant gas production and distribution network, and potential to install cost-effective incremental gas infrastructure to under-serviced or non-serviced areas of the province, methane pyrolysis offers a pathway for rapid and wide deployment of low carbon hydrogen.

Methane pyrolysis provides a low-cost, low carbon intensity hydrogen production pathway that could result in rapid and wide-spread hydrogen deployment across the province.

Methane pyrolysis involves the physical dissociation of methane into elemental hydrogen and solid carbon in the presence of heat. At the time this report was written, thirty-two methane pyrolysis technology developers have been identified globally. These developers differ mainly in the way they deliver heat to their process reactions and the types of carbon co-product they produce. These technologies are currently at Technology Readiness Levels (TRLs) between TRL 4 and 8 and will require significant commercialization efforts over the coming years.

At a high level, methane pyrolysis technologies can be grouped into three main categories:

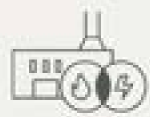
- **Thermal: The more established technology and the least capital intensive to build due to the simple reactor design. The process involves the direct decomposition of methane using a heat source, which could be natural gas, recycled hydrogen, or other renewable fuels.**
- **Catalytic: Similar to the thermal process, but the decomposition of methane occurs in the presence of a catalyst, which may be carbon or a certain transition metal. The catalyst reduces the temperature needed for the reaction and provides greater control of the carbon co-product properties. However, there is an additional expense for catalyst inputs and regeneration.**
- **Plasma: A newer reactor design that uses thermal and non-thermal energy sources such as microwave or electric arcs to deliver significant energy in a short span to decompose methane or other feed gas into a plasma. This plasma interacts with and decomposes methane molecules. Though ongoing technology development work may prove otherwise, plasma is currently viewed as the highest capital alternative.**

The reactor design and process temperatures of a pyrolysis reaction can influence the type and characteristics of the solid carbon that is produced. Carbon black is formed at higher temperature reactions, graphite can form with carbon-based catalysts, and carbon nanotubes or fibres are typically formed from metal-based catalysts. Cost effective carbon management, such as preventing carbon build-up in the reactor, ensuring continuous process flow, and optimizing the carbon stream, can be a significant challenge and opportunity for pyrolysis reactions.

> On one hand, solid carbon processing and handling can create additional costs and increase LCOH when hydrogen is viewed as the only product. On the other hand, optimizing the carbon co-product properties and value can create an additional revenue stream from the process, as well as decrease LCOH and overall carbon intensity.

To evaluate the competitiveness of methane pyrolysis as a decarbonization pathway in B.C. against electrolysis and centralized reforming with CCUS, a techno-economic evaluation calculated the delivered LCOH of the three production technologies across three scenarios representative of applicable scales of demand. Assumptions were made for each technology and scenario based on the best available data at the time of writing. Due to the evolving nature of hydrogen generation, assumptions were made to reflect the authors' best forecast of the technologies' capital and operating parameters for the 2030 timeframe. These are summarized below.

**Scenarios of hydrogen production and use cases for decarbonization in B.C.**

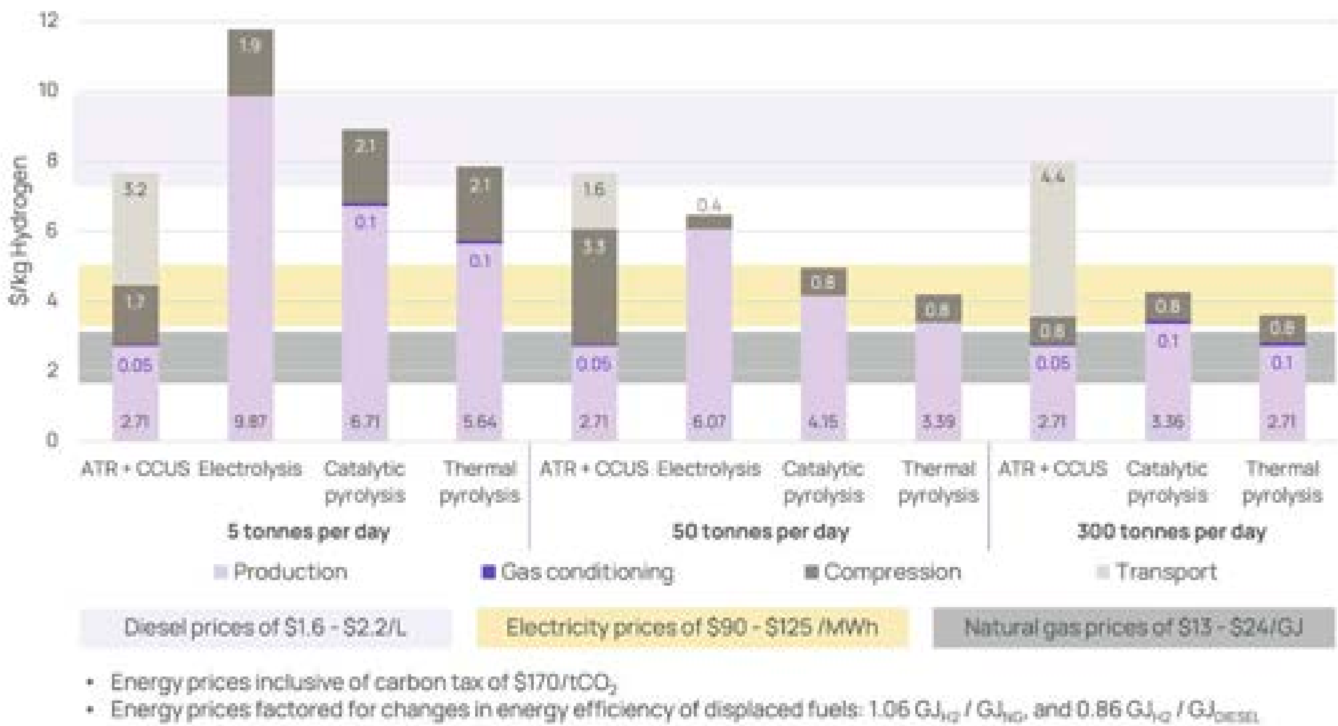
| Scenario | S1: Small-scale | S2: Industrial decarbonization | S3: Large-scale |
|---|---|---|---|
| $H_2$ production |  Up to 5 tpd |  Up to 50 tpd |  Up to 300 tpd |
| Typical applications | $H_2$ refueling or back-up power | Heating load for industrial facility or peaker plant | Petrochemical, refining or fuel production |
| $H_2$ production or delivery method | Trucked centralized reformation or onsite pyrolysis & electrolysis | Trucked centralized reformation or onsite pyrolysis & electrolysis | Pipelined centralized reformation or onsite pyrolysis |

Scenarios 1 and 2 assume that hydrogen could be produced through any of the technologies, contingent on connectivity to a source of water, electricity, natural gas, and connection to transport corridors. It is assumed that electrolysis and pyrolysis would be constructed at site, but a reforming plant would be constructed in Northeast B.C., with hydrogen distributed to the point of demand via tube trailer (800 km for 5 $tH_2$/d demand), and via liquid deliveries (1,200km for 50 $tH_2$/d demand). Scenario 3 will likely only be met through pipeline connection of a centralized production facility or having a large-scale methane pyrolysis facility co-located with the demand facility. Electrolysis was not considered for this third scenario due to the extensive power requirements that would require either a substantial expansion and modification of the B.C. power grid to supply approximately 0.7 GW, or a solar and wind project of up to 2.5 GW to account for an average combined capacity run factor.

The figure below is a summary of the techno-economic analysis, showing the LCOH of each technology across scenarios, and how the LCOH compares to forecasted 2030 retail prices of different energy sources in B.C. The results are based on net neutral costs for the carbon co-products, under the assumption that no incremental costs or revenues are realized for the handling of carbon.

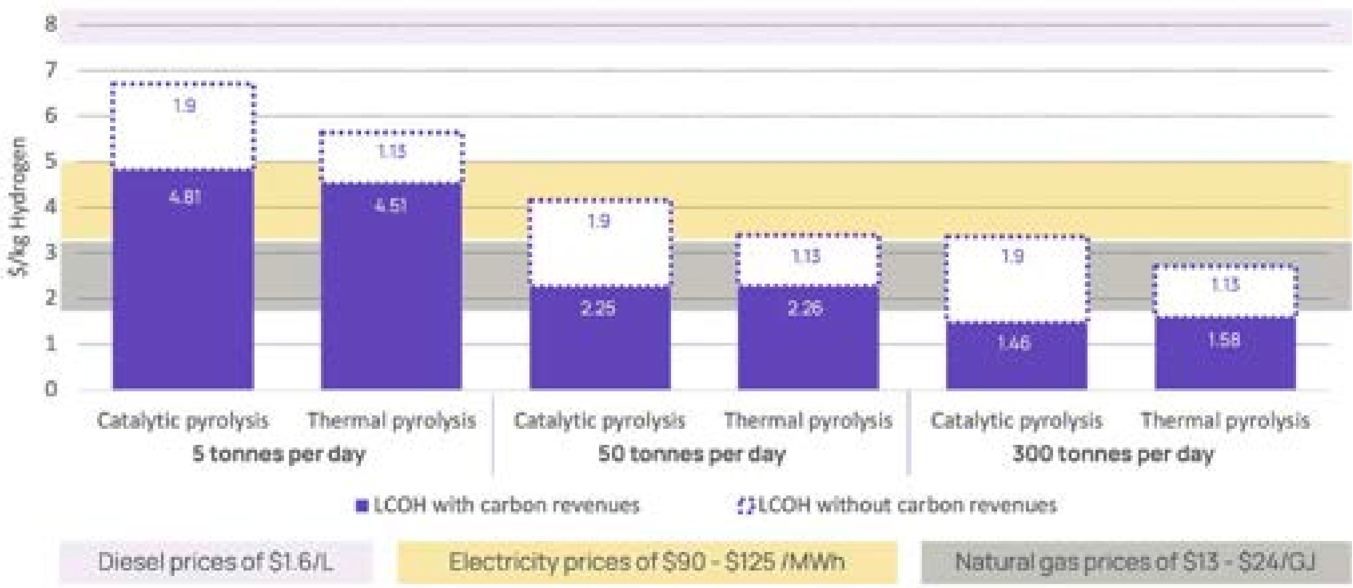
Methane pyrolysis offers a cost competitive pathway across small to large-scales of hydrogen production.

**Delivered cost of hydrogen across scenarios and comparison to costs of incumbent energy sources in B.C.**




The actual revenues or costs of pyrolysis would depend on the location of the project, the type of co-product that is produced, and the potential end use cases for those co-products. The following figure demonstrates the impact of carbon revenues on the LCOH from methane pyrolysis using conservative sales prices of $500/t for catalytic co-product carbon, and $250/t for thermal co-product carbon. Catalytic processes have the potential to produce higher value carbon allotropes like graphite, which is more likely to achieve a higher market value.

**Facility gate cost of hydrogen from pyrolysis based on carbon co-product revenues**




- Catalytic carbon sales price: $500/t Thermal carbon sales price: $250/t
- Energy prices factored for changes in energy efficiency of displaced fuels: 1.06 $GJ_{H2}$ / $GJ_{NG}$, and 0.86 $GJ_{H2}$ / $GJ_{DIESEL}$

These economics could be further enhanced by incorporating investment tax credits, government grants, and carbon offsets, which were excluded from this analysis due to the current policy uncertainty around the eligibility of methane pyrolysis for various public funding mechanisms.

> The analysis shows that costs for hydrogen produced via methane pyrolysis can potentially be lower than the forecast 2030 incumbent fossil fuels in B.C., inclusive of carbon tax.

The flexibility of methane pyrolysis, in terms of scalability and location, makes it an effective decentralized, distributed hydrogen production pathway. Specifically, a pathway which can utilize existing natural gas and electrical infrastructure to deliver hydrogen at the point of demand without long distance distribution. However, its wide-scale development and deployment in the province will require greater industry collaboration and government support. In particular:

» **Support for continued technology development: Government funding to help advance the TRL of methane pyrolysis technologies and prove out first-of-a-kind commercial facilities.**

- **Coordination to build a market for carbon utilization: Industry-wide collaborations are required to build out the supply chain for carbon co-products, which would improve the overall economics of methane pyrolysis projects. An advanced materials economy will require product development, testing, certification, market acceptance/product uptake, updates to public procurement policies to allow for carbon utilization in industrial products (e.g., cement and asphalt), and potential incentives for users of solid carbon.**
- **Recognition of methane pyrolysis as a low carbon hydrogen production pathway: Inclusion of methane pyrolysis as a hydrogen production pathway in various provincial and federal funding mechanisms, including: the Hydrogen Investment Tax Credit, the Clean Fuel Standard, Low Carbon Fuel Standards, and other government funding programs.**
- **Recognition of solid carbon as a sequestration pathway: Inclusion of solid carbon sequestration as a pathway to generate carbon sequestration credits under provincial and federal funding programs.**
- **Regulatory certainty: Certainty of carbon policy and future pricing mechanisms to de-risk investments and increase the long-term costs of incumbent carbon-intensive energy sources.**
- **Industry collaboration and distributed hydrogen model development: Facilitating connections between technology developers and project developers, financiers, and hydrogen and carbon co-product users to build clusters of demand where early projects can be proven. Also, linking multiple end-use applications such as refuelling stations and microgrid support.**

Methane pyrolysis may serve as a key transitional technology in the path to a net-zero future. Distributed hydrogen production from methane pyrolysis can help decarbonize hard-to-abate applications where direct electrification is not feasible or viable. It also ensures continued utilization of long-life natural gas infrastructure that is a vital component of B.C.'s and Canada's economies. Given B.C.'s proximity to international markets, and as a hub for energy export, methane pyrolysis could create significant opportunities for international markets. Rather than transporting hydrogen or hydrogen carriers, methane could be exported with applicable pyrolysis technologies deployed in importing countries to produce low carbon hydrogen. Canada's abundant natural resources and strong environmental regulations makes it one of the lowest cost and lowest carbon intensive natural gas producers globally. Methane pyrolysis ensures this competitive advantage is leveraged for the low carbon future.

> The wide deployment of methane pyrolysis in B.C. could accelerate the province's ambitions to achieve net-zero emissions.

# 1. Overview

## Report goals and objectives

The objective of this study is to conduct a comprehensive evaluation of low carbon hydrogen production pathways that utilize existing energy infrastructure in British Columbia, with a particular focus on the viability for hydrogen production from methane pyrolysis. The study further discusses the risks and opportunities of distributed hydrogen as a decarbonization pathway, evaluates the current state of methane pyrolysis technologies, and makes recommendations to address the key gaps by researchers, industry, and government to accelerate its widespread deployment.

Specifically, this study aims to:

- » **Examine the diversity of low carbon hydrogen production technologies, particularly methane pyrolysis and the integrated solutions built around them.**
- » **Report on the current state of development of these technologies and applicability to different scales of demand applications, both in the near and longer term.**
- » **Develop scenarios comparing decentralized distributed production versus large centralized production models for methane pyrolysis, methane reforming, and water electrolysis; identify applicable restrictions (electricity, water use/purification, land availability, regulatory), and auxiliary considerations.**
- » **Evaluate carbon abatement potential of different pathways: methane reforming $CO_2$ versus methane pyrolysis solid carbon co-products.**
- » **Provide guidance for investments in technology innovations (primary and ancillary), cost, manufacturing, and business models that will create new opportunities or enhance economic competitiveness.**
- » **Discussion of regulatory aspects necessary for hydrogen production, distribution, and use, making suggestions about regulatory changes, policy incentives, and subsidies that may be required to encourage private industry participation in technology deployment.**
- » **Position the above in the context of British Columbia; providing strong techno-economic analysis that can be referenced for public discussion based on the needs of the evolving hydrogen ecosystem and opportunities for B.C. stakeholders.**

## B.C. landscape: regulatory and policy, and energy transition trends

Canada's Net Zero Emissions Accountability Act mandated the country's commitment to achieve net-zero emissions by 2050. The government of B.C. subsequently published the CleanBC Roadmap, which outlines targets fundamental to achieving climate action goals, including the reduction of greenhouse gas emissions 40% below 2007 levels by 2030, 60% by 2040, and 80% by 2050.[2] A number of policies and sector-specific emissions reduction targets underpin the province's broader decarbonization goals, which are summarized in **Table 1.**

**TABLE 1: B.C. 2030 sector-specific emission reduction targets and key intervention levers**

| Sector | 2030 Target (2007 baseline) | Specific policies and goals |
|---|---|---|
| **Transportation** | 27-32% | Low Carbon Fuel Standard (LCFS), which increased the carbon intensity reduction requirement from 20% to 30% by 2030 for liquid fuels, and the penalty rate of non-compliance from $200/t to $600/t. [3]<br>Zero-Emission Vehicles Act with a target for all new cars sold in B.C. to be zero emission by 2035, five years ahead of the original 2040 target.<br>Shift public support towards active transportation and public transit. |
| **Industry** | 38-43% | Under the Energy Action Framework, a regulatory emissions cap for the oil and gas industry to ensure 2030 targets are met (under development).<br>Stronger price on carbon pollution, aligned with or exceeding federal requirements of $65/t in 2023, increasing to $170/t by 2030.<br>Made-in-B.C. output-based pricing mechanism starting April 2024 for large industrial emitters, which will price emissions that exceed specific limits.<br>Requirements for new large industrial facilities to work with the government to demonstrate alignment with B.C.'s legislated targets and submit plans to achieve net-zero emissions by 2050.<br>100% Clean Electricity Standard by 2030. |
| **Oil and gas** | 33-38% | Stronger policies to reduce methane emissions from the oil and gas sector by 75% by 2030.<br>Cap on GHG emissions for natural gas utilities to encourage investment in low carbon technologies and energy efficiency.<br>Target for 15% renewable natural gas blending into the grid by 2030. |
| **Buildings and communities** | 59-64% | Requirements for all new buildings to be zero carbon and new space and water heating to be at highest efficiency by 2030.<br>Program to support local government climate and resiliency goals. |

As highlighted in the 2022 Climate Change Accountability Report,[4] B.C.'s 2020 emissions were 64.6 Mt $CO_2e$ **(Figure 1)**, representing 876.8 PJ of energy consumption **(Figure 2)**.[5] Transportation is the single largest emitting sector, representing 40% of total emissions and 37% of energy consumption, 76% of which is gasoline and diesel, increasing to 88% with the inclusion of aviation fuel. For residential and commercial buildings and industry, natural gas and electricity represents the dominant fuel. In aggregate, natural gas is the most utilized fuel source in B.C. across all sectors, representing 31% of the energy consumed in 2020 **(Figure 3)**, with electricity being the second most utilized, representing 25% of energy use.

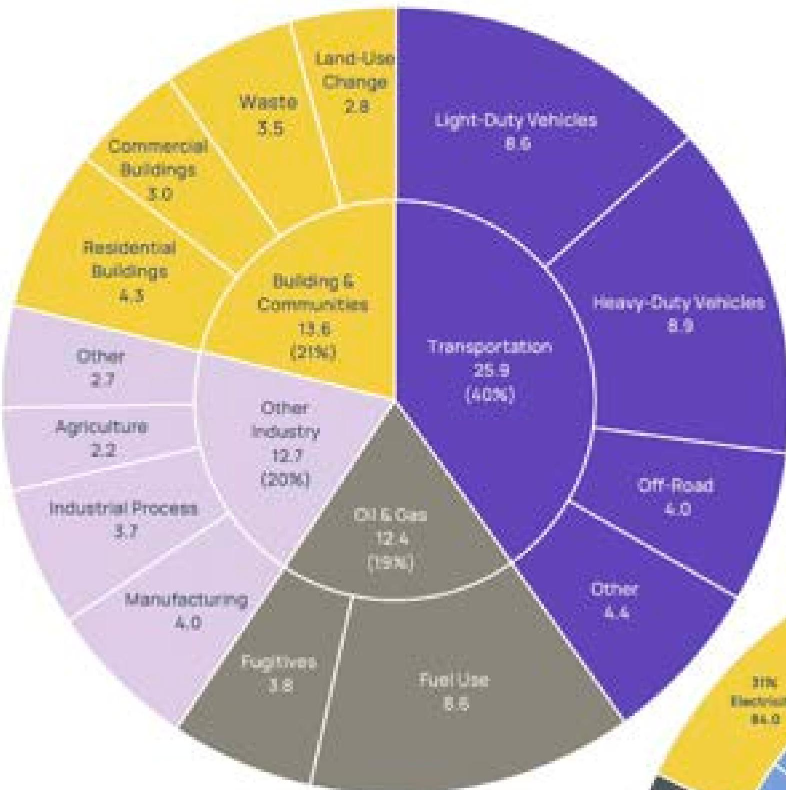



**FIGURE 1:** B.C. sector specific emissions 2020

Note: Emissions in Mt $CO_2$

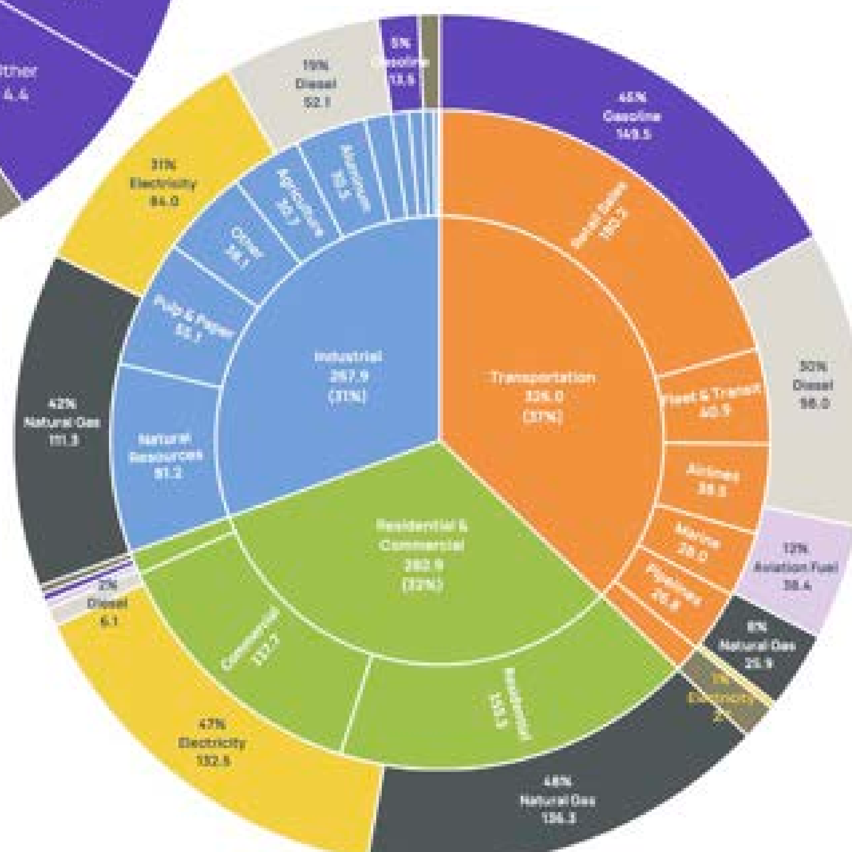
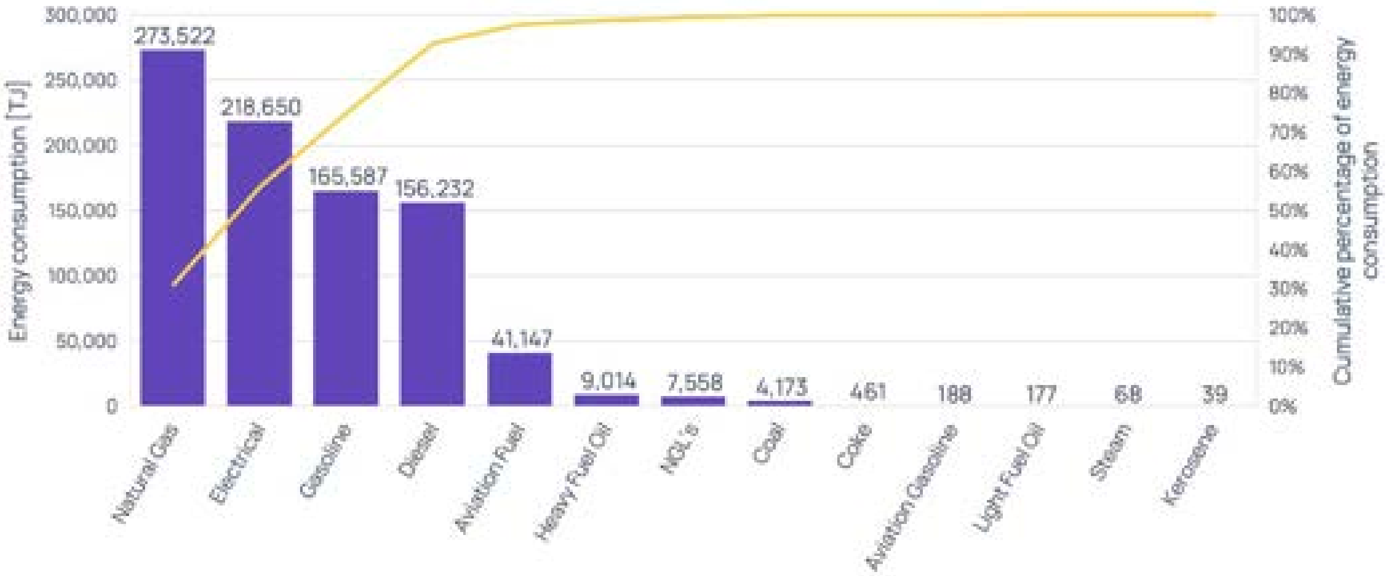



**FIGURE 2:** B.C. energy consumption by sector and fuel source 2020 [PJ]

**FIGURE 3:** B.C. energy consumption by cumulative fuel source 2020

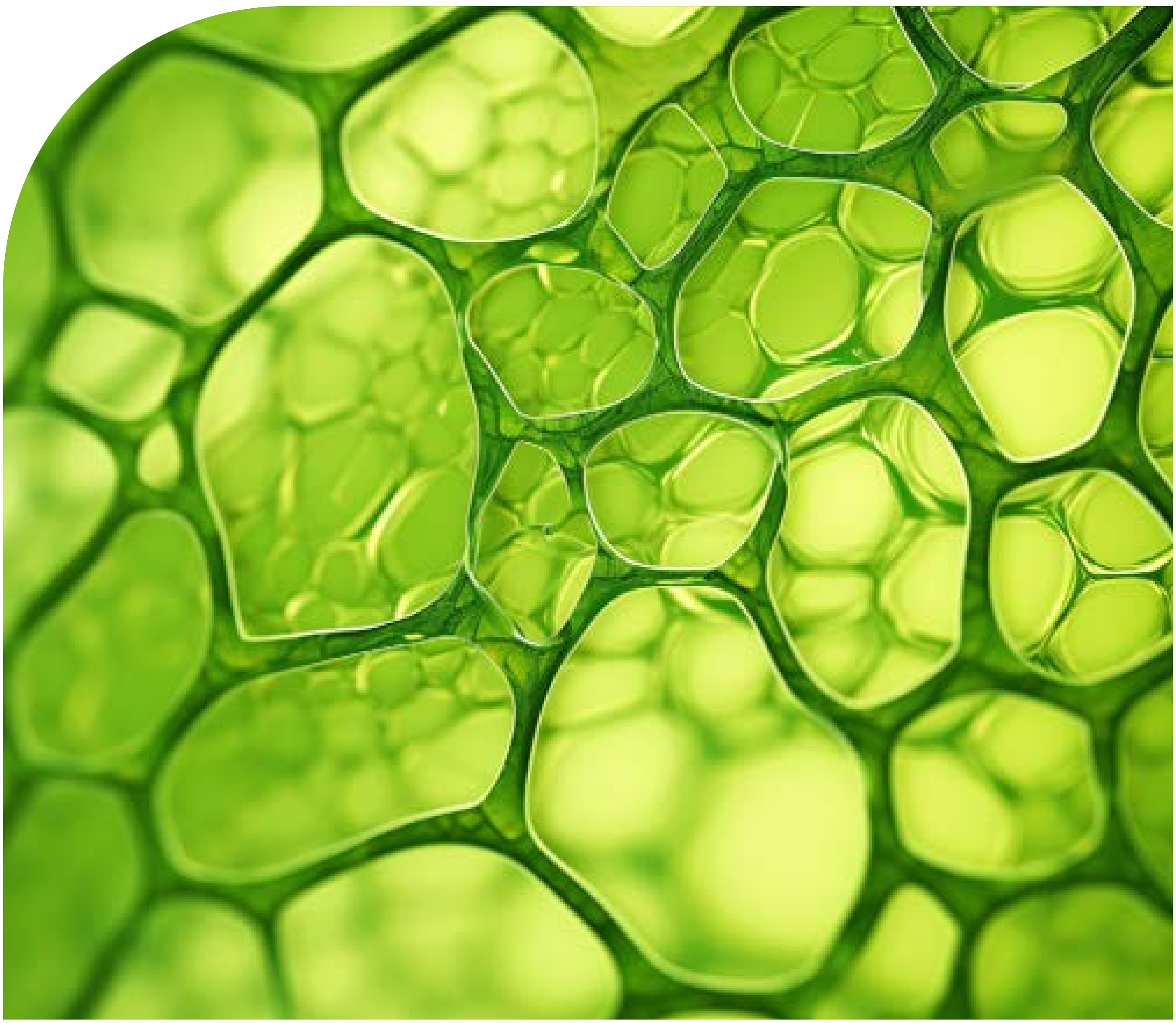



Furthermore, any low carbon alternative will need to match the portability and on-demand nature of chemical fossil fuels in order to meet the lifestyle needs of rural and remote areas of the province.

Hydrogen is an important decarbonization tool that can supplement direct electrification, and B.C. is well situated to achieve significant low carbon hydrogen generation, due to the province's existing resources and infrastructure. Hydrogen can also support decarbonization through electrification in a peaking and grid stabilization capacity via micro-grid connectivity to offset the capital and operating inefficiencies of additional transmission lines.

Electrification as a means to achieve the province's emissions reduction mandate will encounter functional and economical challenges. This is due to the significant amounts of new generation and incremental transmission grid wires that would be required to displace natural gas, diesel, gasoline, and aviation fuel, which collectively make up approximately 75% of B.C.'s current energy use.

However, as hydrogen is an energy carrier derived from primary fuel sources, like natural gas or electricity, it will still rely on the availability and price points of these energy sources. By pricing or incentivizing hydrogen's other attributes, such as the ability to not emit carbon emissions, improving drive train efficiencies in transport applications, or maximizing co-product value, hydrogen could become a cost competitive, low carbon fuel source. The market-based mechanisms established to reduce industrial emissions alongside B.C.'s carbon offset market are pathways to incentivize these hydrogen benefits. B.C.'s policies to reduce upstream oil and gas emissions are expected to further drive down the life cycle emissions associated with natural gas, resulting in lower overall carbon intensity of hydrogen production pathways derived from natural gas, such as methane pyrolysis.

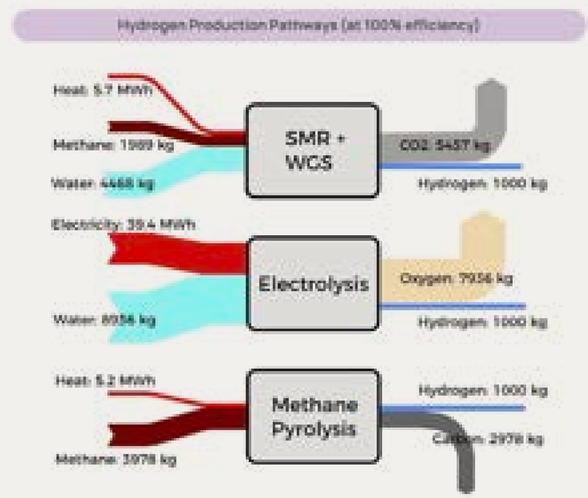


# 2. Introduction

Hydrogen is a zero-emission energy vector that produces water when combusted or oxidized in a fuel cell. Because of its versatility, it is one of the only chemical feedstocks for decarbonizing hard to abate sectors where direct electrification is not practical, such as industrial heating, heavy-duty transportation, or baseload and peaking electrical generation. Hydrogen could also have a role in satisfying residential and commercial energy requirements in rural and remote locations. Estimates suggest that in British Columbia alone, hydrogen has the potential to reduce annual emissions by 7.2 megatonnes (Mt) by 2050, equivalent to 11% of the province's 2018 emissions.[6]

Due to the abundant renewable electricity, natural gas resources, and geological deposition in the province, B.C. is one of the few jurisdictions globally where generation of low-cost, low carbon intensity (CI) hydrogen is possible throughout the province. However, given potential electricity constraints for generation as well as the underdeveloped carbon dioxide storage reservoirs, the near-term path to low cost and low CI hydrogen production could be challenging if solely reliant on technologies like electrolysis and natural gas reforming with carbon capture.

**FIGURE 4:** **Theoretical mass balance comparison of reforming, electrolysis, and pyrolysis**




An alternative approach to hydrogen production is methane pyrolysis, which utilizes natural gas as a feedstock and requires substantially less electricity and no water **(Figure 4)**. The methane pyrolysis reaction produces solid carbon rather than gaseous carbon dioxide by-product. This process could utilize the extensive natural gas resource and distribution infrastructure in B.C. to unlock wider decarbonization opportunities in an accelerated time frame across the province.

## Hydrogen production technologies

Hydrogen can be produced from stripping the carbon out of fossil fuels, biomass or other organic material, or from breaking apart water molecules using electricity. Small amounts of hydrogen are also produced as a by-product in some industrial processes, such as chlorine and rubber production, and have been found naturally occurring in very select underground deposits globally.

More than 95% of hydrogen production globally currently comes from coal gasification or natural gas reforming, with less than 1% produced from fossil fuels with carbon capture or water electrolysis using renewable electricity.[7] A summary of the various hydrogen production pathways and their TRL are summarized in **Table 2.**

Historically, colours have been utilized to describe various hydrogen production processes, but this has become a distraction and catalyst for environmental debate, regarding the favoured technology to produce hydrogen. This is due to the perceived CI of different hydrogen colours, when in fact the CI of any process depends on the source of energy feedstock, the energy efficiency of the production process, and how co-products are handled. As modern technologies for hydrogen generation are advanced and GHG emissions are minimized across both upstream feedstock and production processes, the determination of how 'clean' the hydrogen is by colour is increasingly becoming abstract and misleading. All processes that can produce hydrogen at low carbon intensity have a role in the energy transition and the suitability of each process should be evaluated on the merits of the technology in its specific situation.

**TABLE 2: Selection of hydrogen production technologies, including their feedstock, TRL, conversion efficiency, reaction temperature and technology description[8, 9]**

| Co-product | Technology type | Feedstock | Conversion efficiency | Reaction temp | TRL | Description |
|---|---|---|---|---|---|---|
| Production of $CO_2$ gas that could be captured and stored in underground reservoirs or sequestered | Steam reforming (SMR) | Natural gas / light oils (naphtha) | 74-85% | 700 – 1,000°C | 9 | Most established $H_2$ production technology that involves a reaction of methane with a catalyst to produce syngas ($H_2$ and CO). A subsequent water-gas shift (WGS) reaction and purification via pressure swing adsorption (PSA) produces a pure steam of hydrogen. |
| | Partial oxidation (POX) | Natural gas / oil | 60-75% | 800 – 1,000°C | 7-9 | Non-catalyst process whereby feedstock is gasified in the presence of oxygen to produce syngas, which goes through subsequent WGS and PSA to produce a pure stream of hydrogen. Faster reaction than SMR but lower conversion efficiency. |

Continued on p15

| Co-product | Technology type | Feedstock | Conversion efficiency | Reaction temp | TRL | Description |
|---|---|---|---|---|---|---|
| Production of $CO_2$ gas that could be captured and stored in underground reservoirs or sequestered | Autothermal reforming (ATR) | Natural gas | 60-75% | 700 – 1,000°C | 7-9 | ATR combines SMR with POX to produce hydrogen at greater production and energy efficiency. Methane is reacted with steam and oxygen to produce a syngas, which goes through WGS and PSA to produce hydrogen. |
| | Electrified steam reforming | Natural gas / light oils (naphtha) | 60-85% | 600 – 900°C | 4 | Variation of SMR that replaces natural gas fuelled combustion with electrically heated reformers, with potential for significant emission reductions if using renewable power. |
| | Gasification | Coal / biomass waste | 35-50% | 800 – 1,000°C | 4-9 | Thermochemical conversion of feedstock into syngas in air, oxygen and/or steam following by WGS and PSA to produce a pure $H_2$ stream. |
| Production of solid carbon or non-emitting carbon | Pyrolysis | Natural gas / oil / coal / biomass | 9-85% | 900 – 2,300°C | 4-9 | Thermochemical decomposition of hydrocarbons at high temperatures dependent on the catalytic, thermal or plasma process utilized. The process produces a solid carbon co-product. |
| | In-situ reservoir production | Natural gas / oil | 9-60% | N/A | 4 | Injection of oxygen into reservoirs that initiates in-situ combustion, splitting hydrocarbons into their basic elements. A selective membrane extracts hydrogen from the reservoirs. Conversion efficiencies can be low due to minimal control over reaction conditions. |
| | Reservoir production | Naturally trapped gases | N/A | N/A | 7 | First sustained naturally sub-surface hydrogen production from Bourakebougou, Mali at 98% purity. Exploration being conducted globally with $H_2$ seeps identified in Oman, New Caledonia, Canada, Russia, Australia, Japan, Germany, and New Zealand. Little is currently known of the sub-surface model for hydrogen generation or trapping. Continued on p16 |

| Co-product | Technology type | Feedstock | Conversion efficiency | Reaction temp | TRL | Description |
|---|---|---|---|---|---|---|
| No direct GHG Emissions (indirect emissions based on electricity source) | By-product (chlor-alkali) | Brine (sodium chloride) | 50-60% | 40 – 90°C | 9 | Hydrogen is a by-product of the electrolytic decomposition of salt in which chlorine and sodium hydroxide are produced. |
| | Proton exchange membrane (PEM) | Water & electricity | 67-82% | 20 – 100°C | 9 | Electricity used to split water into hydrogen and oxygen using a solid specialty polymer material. |
| | Alkaline electrolysis | Water & electricity | 62-82% | 40 – 90°C | 9 | Electricity used to split water into hydrogen and oxygen using a liquid electrolytic solution such as potassium (KOH) or sodium hydroxide (NaOH). |
| | Solid oxide electrolysis (SOEC) | Water & electricity | Up to 100% | 700 – 1,000°C | 4-7 | Electricity used to split water into hydrogen and oxygen using a solid ceramic material that operates at high temperatures. |

Carbon intensity of hydrogen is calculated by determining its life cycle GHG emissions, which includes the feedstock, the energy source, and the physical process utilized, and is commonly expressed in kg $CO_2e$/kg $H_2$ or a g$CO_2e$/MJ $H_2$. Globally, it is accepted that values at or below the European low carbon standard of 4.37 kg $CO_2e$/kg $H_2$ (36.4 g $CO_2e$/MJ $H_2$)[10] is considered low carbon hydrogen. For British Columbia, the CICE report "Carbon Intensity of Hydrogen Production Methods"[11] evaluated the specific carbon intensity of various hydrogen production processes, determining that methane reforming, methane pyrolysis and electrolysis can all be utilized to generate low carbon hydrogen.

## Hydrogen application sectors and demand

The Hydrogen Council has enumerated seven supportive roles hydrogen can play in global decarbonization efforts, which are summarized in **Figure 5**.[12] Some of these include directly displacing incumbent fossil fuels with hydrogen (such as combustion in a hydrogen-ready boiler, or fuelling a hydrogen fuel cell electric vehicle), while others involve the use of hydrogen-derived fuels like ammonia or renewable methanol.

Hydrogen is recognized as having a key role in achieving B.C.'s decarbonization targets, with the B.C. Hydrogen Strategy identifying specific sectors in which hydrogen will have the biggest impact on emission reductions by 2050:[13]

» **Medium and heavy-duty transport (4.32 Mt)**

» **Industry decarbonization and synthetic fuels production (1.8 Mt)**

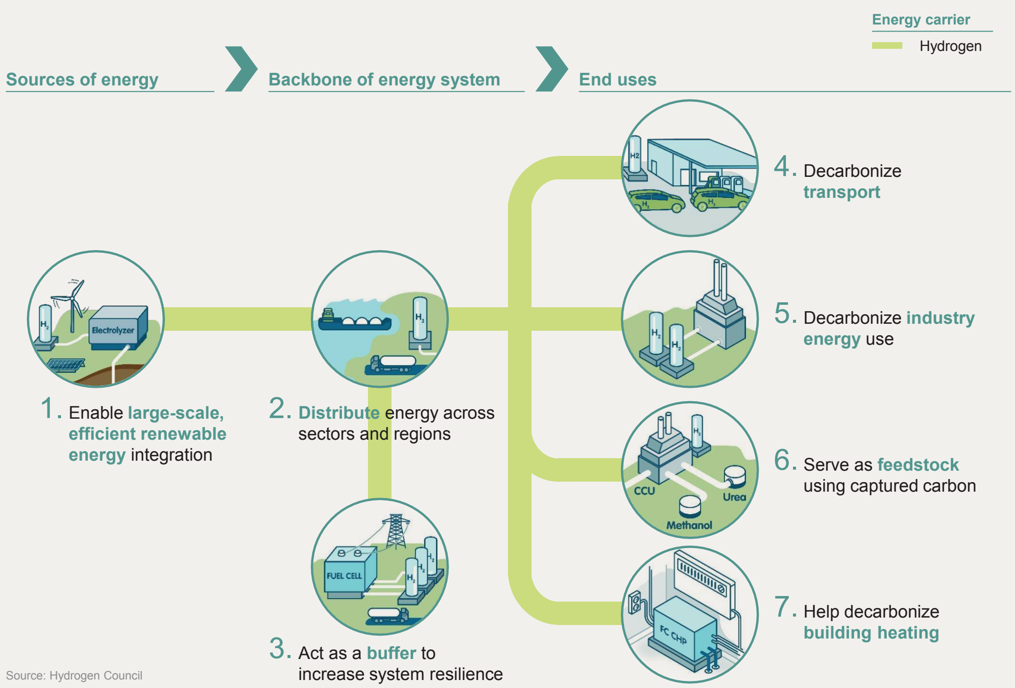
» **Natural gas displacement (1.08 Mt)**

» **Displacing diesel used for electricity generation in remote communities (0.07 Mt)**

Ultimately, these forecasts may prove to be conservative. Wide-scale adoption of hydrogen could mean increased roles in fuelling passenger and light weight vehicles utilized outside of dense urban centres, including marine and air transport, agricultural and off-road equipment, and electrical generation via micro-grid for peaking and transmission stabilization.

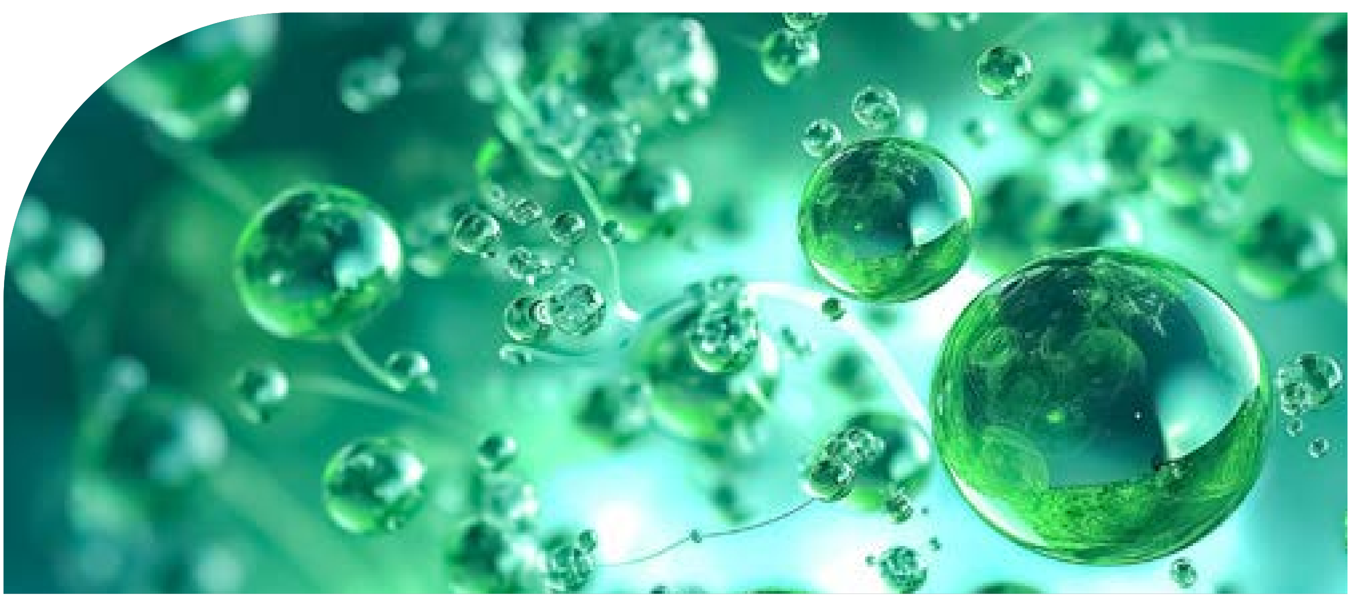
It is important to note that hydrogen is not a silver bullet decarbonization solution and that the marginal abatement costs of emission reductions will vary by region and application. The availability of land, utilities, existing energy infrastructure, and a region's natural resources will all have an impact on the viability of clean energy solutions. These solutions could include any combination of renewable electricity paired with batteries, geothermal heat or power, biomass energy, nuclear, or hydrogen. The level of development and population density within a region will also influence the deployment of decarbonization solutions due to space, energy demand, and energy infrastructure constraints.

**FIGURE 5:** Potential roles for hydrogen decarbonization[12]



Most current hydrogen generation occurs within highly industrialized areas where the supply of hydrogen-heavy syngas is directly utilized in industrial processes, such as ammonia, methanol, or petroleum refining. Hydrogen's use as an energy vector to date has been challenged due to the lack of a readily available demand market. Existing industrial equipment may not be able to directly use hydrogen as a substitute fuel. For example, internal combustion engines and industrial burners likely require substantial modification for hydrogen combustion, and then further additional $NO_x$ emission reduction. Pipeline infrastructure and fuelling facilities also cannot simply be changed over to hydrogen. Thus, design and adoption of hydrogen-ready end devices are crucial in building consumer use confidence, and ultimately, hydrogen demand.

The low carbon hydrogen industry to date has focused on large-scale demand opportunities in major industrial complexes, large urban cities, and major highway freight corridors. This ring-fenced approach limits the adoption of hydrogen end-use devices due to the limitations it imposes on accessible areas. The slow adoption in the battery vehicle industry is facing this issue by following a similar model of development, whereby travel outside of city centres is difficult in an electric vehicle due to infrastructure limitations. Low carbon hydrogen demand in remote and rural locations outside of major cities, urban areas, and highway corridors will require hydrogen production at the point of use to overcome high costs and emissions associated with hydrogen transport from centralized production. One solution to accelerating hydrogen acceptance and uptake of hydrogen vehicles would be to establish distributed hydrogen supply and fuelling infrastructure throughout the province and country. This would require a hydrogen production technology that can produce cost-competitive fuel on small scales across multiple locations, creating a robust merchant hydrogen network.



## Distributed hydrogen model

A distributed hydrogen model relies on existing energy infrastructure to produce hydrogen at the point of energy demand, thus eliminating the costs and logistical issues of transporting hydrogen great distances. The distributed model allows for numerous smaller scale hydrogen generation sites to expand access to hydrogen across the province without relying on centralized production and distribution. Electrolysis has historically been the preferred distributed production pathway, but it relies on access to significant amounts of renewable electricity and water. Given B.C.'s significant electrical requirements post 2030, electrolysis will require further investments in transmission grid expansion and additional new renewable or hydro generation.[14]

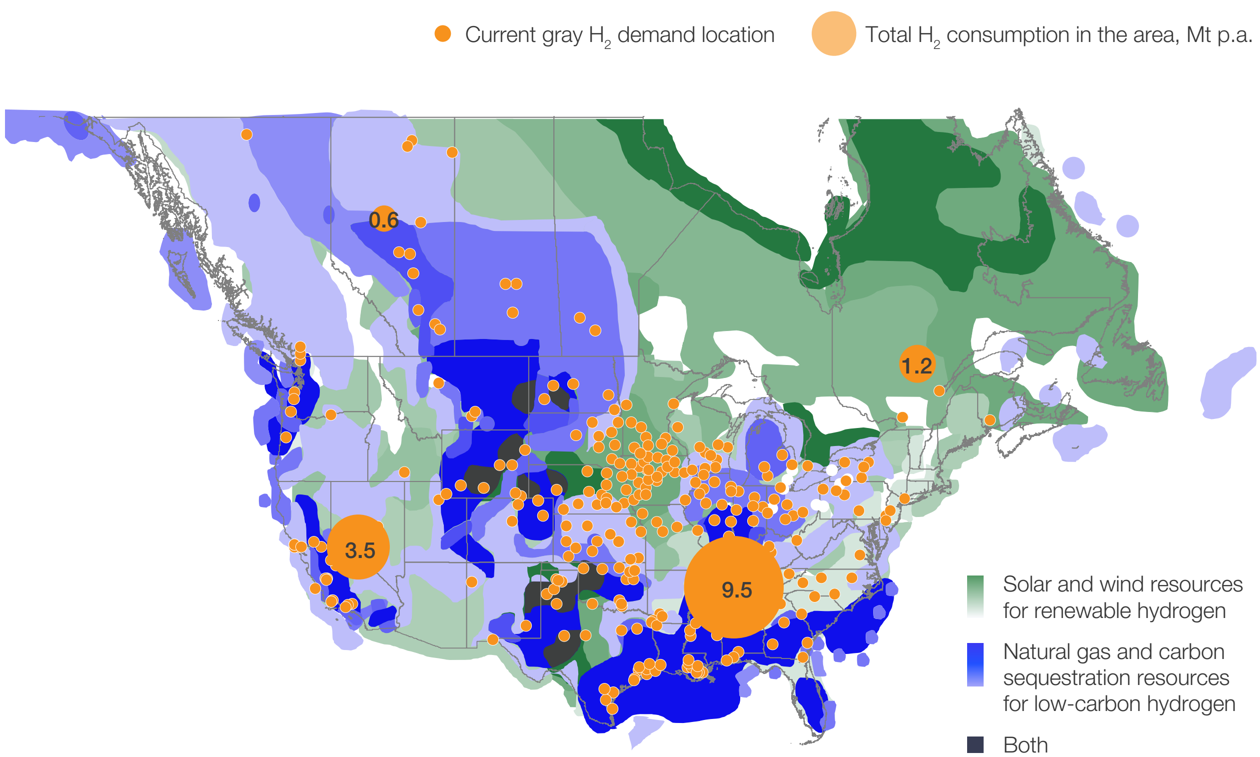
Planning and construction of new transmission infrastructure and addition of incremental generation can take 10 to 15 years due to the substantial stakeholder engagement that is required. The use of methane pyrolysis is believed to be a significant technology in achieving a distributed hydrogen model throughout the province within a five-to-ten-year timeframe by utilizing existing natural gas resources and transportation infrastructure. Methane pyrolysis also possesses the ability to generate hydrogen without using water, producing carbon dioxide, or requiring carbon capture.

## Hydrogen transition in B.C.

According to the Hydrogen Council, the U.S. and Canada combined are the second-largest consumers of hydrogen in the world, using 15 Mt per year in 2023, representing 17% of total global demand. The bulk of this demand is driven by the chemical and refining industries, which are currently met by hydrogen produced from steam methane reforming (SMR) without carbon capture. As per **Figure 6**, there is limited direct demand for hydrogen in B.C. today, but this is expected to change as hydrogen's role in the decarbonization of various sectors are commercially and technically proven.[15]

Under the CleanBC Roadmap, the B.C. Government set a goal to be a world leader in growing the hydrogen economy by accelerating the production and use of low carbon hydrogen. B.C. is already home to more than 50% of Canada's hydrogen fuel cell companies, and accounts for 60% of Canada's research investments in hydrogen and fuel cell development. The province introduced a discounted electricity rate applicable to hydrogen production from electrolysis and enabled natural gas utilities to add hydrogen to the grid under the Greenhouse Gas Reduction Regulation.[16] The government has also directly funded several hydrogen projects through various funding levers, including the B.C. Innovative Clean Energy Fund, the Part 3 Agreements under the B.C. LCFS, the B.C. Hydrogen Station and Fleet Program, and various CleanBC funding initiatives.[17]

**FIGURE 6: Sites of current hydrogen demand across North America and identification of regions best suited for electrolysis and methane-based hydrogen production.**[15]




In March 2022, the B.C. Government established the B.C. Hydrogen Office as a one-stop shop to advance hydrogen projects and facilitate its role across the province's energy systems.[18] Upon inception, the Office identified 49 hydrogen projects proposed or under construction in B.C., representing more than $5 billion CDN in potential investment. Many are small or medium-sized projects for local hydrogen supply, but some are amongst the largest green hydrogen projects in the world, such as the 1,000 MW green hydrogen and ammonia plant proposed by Fortescue in Prince George.[19] Hydrogen activities in B.C. can largely be grouped according to end-use applications across industrial heating loads, transport, and hydrogen feedstock.

### Decarbonization of natural gas network and heating loads

Natural gas currently represents the greatest source of carbon emissions from the built environment, where it is commonly used for space and water heating in residential and commercial buildings, as well as process heating at large industrial sites like mines, pulp and paper, and refineries. One way to reduce emissions associated with natural gas is injecting hydrogen into the gas grid to reduce the blended average carbon intensity of gas. However, studies have shown the impact of hydrogen induced cracking (HIC) in pipeline materials and pipeline welded affect areas. Metals with higher tensile strength experience greater HIC than metals with lower tensile strength. Many blending demonstrations internationally have proven that low hydrogen percentage blending is feasible, with the most successful and longest-running project led by Hawaii Gas's introduction of a 12-15% blend in its network.

In Canada, blending projects by Enbridge in Markham Ontario at 3% and ATCO Gas in Fort Saskatchewan at 5% are operating with the intention of increasing blends upwards of 20%. ATCO is also designing a 100% fuelled hydrogen building and working with Qualico in the development of a new 100% hydrogen subdivision development in Strathcona county. In B.C., FortisBC has been an active proponent of hydrogen blending within their natural gas distribution system and have set a blend target of 15% by 2030 for all low carbon gases.

Though there are still knowledge gaps to better inform decision makers on future blending projects, utility companies around the world are moving forward with projects to introduce hydrogen blending or to create new infrastructure for hydrogen distribution. Higher concentration blending may also require upgrades to gas distribution pipeline materials and end use appliances, such as furnaces and boilers.[20] However, the role of hydrogen in decarbonizing residential and commercial heating is yet to be determined and may be minimal based on the emissions impact and applicability of superior alternatives.

In addition to decarbonizing the natural gas pool, there are opportunities to reduce emissions from the natural gas supply chain, such as line heaters and large compressor stations. Through interviews, gas transmission companies in B.C. have indicated that they are evaluating electrification of their compression fleet as part of emission reduction mandates, which would require hundreds of megawatts to gigawatts of additional electricity demand. Onsite hydrogen production through methane pyrolysis could be an alternate low carbon solution for turbines in grid constrained regions.

### Hydrogen as a transport fuel

Transportation represents the largest source of GHG emissions in B.C., representing 40% of the province's total annual emissions.[21] Under the Zero-Emission Vehicles (ZEV) Act, B.C. requires automakers to meet an escalating annual percentage of new light-duty ZEV sales and leases, reaching 26% by 2026, 90% by 2030, and 100% by 2035. A consultation paper identified additional targets for the medium and heavy-duty vehicle segments (MHD), with annual ZEV sales targets for different vehicle classes starting in 2026, and an aim for 100% MHD ZEV sales from 2036 and beyond.[22] Hydrogen-powered vehicles, including both hydrogen fuel cell electric and hydrogen combustion drivetrains, are already being tested by fleets in B.C., due to their suitability for heavy payloads, short refuelling times, and greater operational range compared to electric vehicles, including the ability to operate in temperatures as low as -30°C.

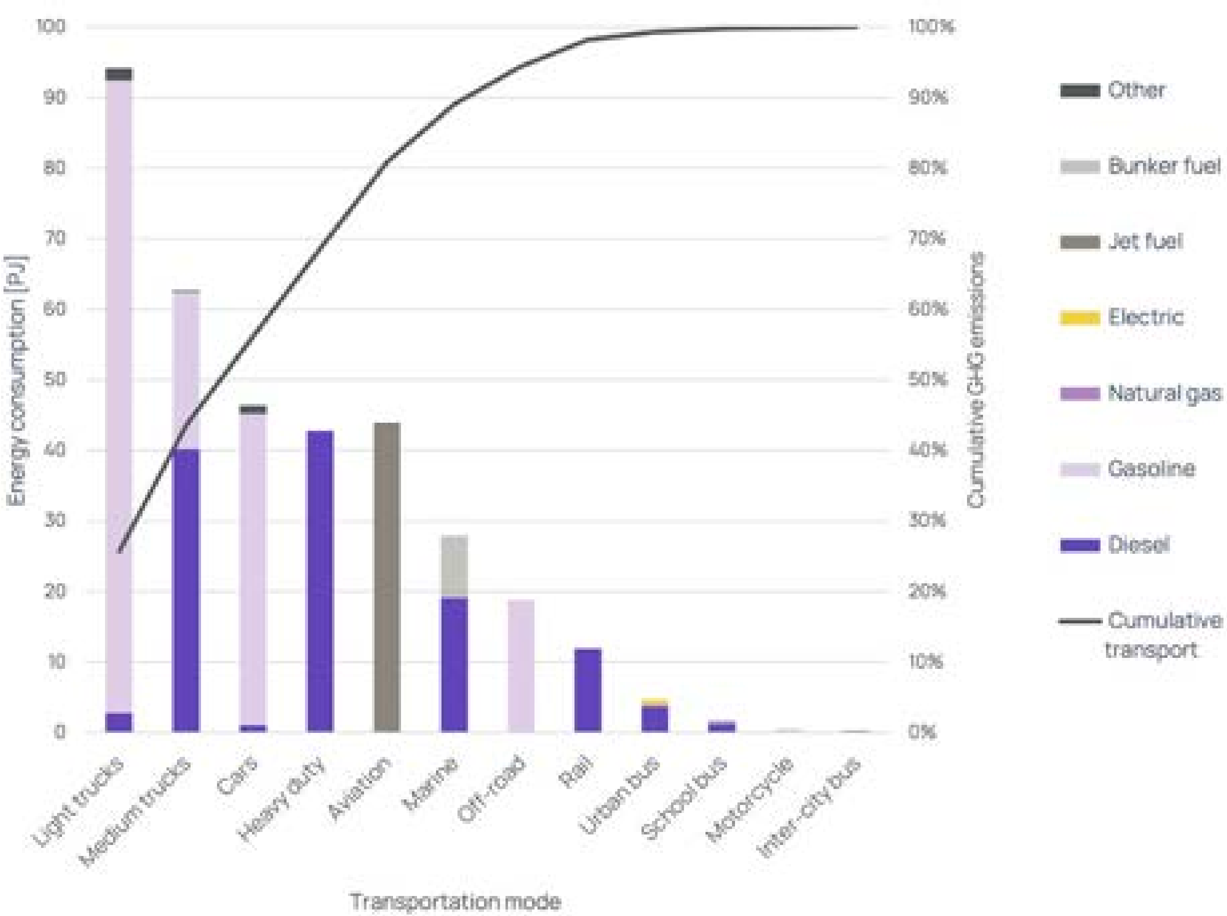
Several policies in B.C. are also designed to reduce the total cost of ownership (TCO) of hydrogen vehicles compared to incumbent diesel vehicles, including direct rebates for the procurement of ZEVs, the ability for ZEVs to generate credits under the B.C. LCFS, and an escalating carbon tax on traditional fossil fuels. The CleanBC Go Electric Hydrogen Fleets Program, along with the Advanced Research and Commercialization Program, have directly funded several companies developing and commercializing hydrogen transport technologies. Provincial rebates and LCFS incentives could be stacked with federal clean vehicle rebates and clean fuel regulation credits to further close the TCO gap between hydrogen and diesel vehicles.

The B.C. Government has also created several funding mechanisms to promote the development of hydrogen refuelling infrastructure, such as the CleanBC Electric Hydrogen Fuelling Infrastructure Program. Though initial hydrogen fuelled transportation was achieved via a 20-bus hydrogen powered fleet in Vancouver during the 2010 Winter Olympics, the first B.C. and Canadian retail hydrogen fuelling station did not open until 2018 in Vancouver. An additional four stations have been developed to date, all owned and operated by HTEC. The locations of these stations are included in **Figure 7**.[23]

The focus for hydrogen transport has been on the transition of heavy-duty trucks with the assumption that remaining lighter vehicles will transition to battery electric vehicles (BEV). However, as shown in **Figure 8**, the majority of GHG emissions in transport are attributable to passenger cars and trucks as well as medium duty trucks.[24] While passenger vehicles that predominantly travel within large urban centres as well as freight trucks that are part of shorter distance return-to-base fleets are expected to be dominated by BEVs, vehicles in rural areas or which are driven outside of major urban centres on a regular basis would require faster refuelling and longer range for greater distances travelled. These vehicles will require a flexible chemical-based fuel and would be better suited for hydrogen.

**FIGURE 7: Locations of active hydrogen refuelling stations in B.C.**[23]


**FIGURE 8: Energy use by mode of transportation and fuel type with cumulative associated GHG emissions 2020**



The B.C. Light-Duty Vehicle Hydrogen Fuelling Network Study estimated the deployment of 250,000 to 300,000 fuel cell vehicles in the province by 2040, which would require 150-250 fuelling stations **(Figure 9)**.[25] The key to facilitate this transition and encourage wide-spread acceptance and adoption of these vehicles will be the establishment of a province-wide refuelling network, which lends itself to a distributed hydrogen generation model. As has been noted in previous studies,[26] the key to successfully creating a robust hydrogen fuel cell network includes:

» **Automaker commitment to deliver quality fuel cell electric vehicles (FCEVs) to the market.**

» **Financial safety net framework to support initial investment into hydrogen refuelling stations.**

» **Maintenance and repair support mechanism for FCEV and refuelling stations to ensure high reliability and up-time.**

» **Plan to implement a widespread fuelling infrastructure along with coordination tools to ensure driver confidence is established.**

Previous studies on the development of battery electric and hydrogen networks in California has found that the two most significant deterrents of vehicle adoption have been the lack of a widespread fuelling/charging network and poor operational reliability of stations. Therefore, having dedicated hydrogen generation at or near stations would improve reliability of fuel supply.

In addition to conventional highway vehicle refuelling, hydrogen fuelled industrial trucks pose a significant opportunity for B.C., as large mining haul trucks are utilized in the numerous coal and ore mines throughout the province and consume significant amounts of diesel for daily operations. It is estimated that a single mining haul truck that consumes 250 L/hr of diesel, would consume one tonne per day of hydrogen when converted to fuel cell electric, and realize a 40% efficiency gain. With twenty or more trucks operating out of a single mine, significant demand for hydrogen could be realized at each site. Demand creation can also be realized in other resource industries that utilize trucking as a significant portion of their operations, including oil and gas and forestry industries.

**FIGURE 9: Proposed province wide refuelling network**[25]

### Producing low carbon and synthetic fuels

Another option to indirectly reduce transport emissions is using hydrogen to produce low carbon and synthetic fuels, which can be utilized in existing internal combustion engines. CleanBC set a target to ramp up production of renewable fuels to 1.3 billion litres by 2030, and the B.C. LCFS requires fuel suppliers to gradually reduce the average carbon intensity of their fuels. This can be achieved by increasing the volume of biofuels blended with conventional fossil fuels, by supplying lower carbon fuels like hydrogen and electricity, or by using low carbon fuels to produce or refine conventional fossil fuels.

The bulk of current hydrogen demand comes from refining and petrochemical operations. In refining operations hydrogen is used to hydrocrack and desulphurize crude oil into gasoline and diesel. In petrochemical operations, hydrogen is directly converted into chemical products like methanol and ammonia. Since most of that hydrogen is currently produced from fossil fuels without CCUS, finding ways to produce the hydrogen with lower emissions could also reduce the life cycle emissions of fossil fuel-based products. Hydrogen is also a major feedstock into the production of renewable fuels, such as co-processing biocrudes from biomass like canola oil, or oil derived from animal fats.

An emerging use case for hydrogen is synthetic fuel production, where low carbon hydrogen and captured carbon dioxide are used to create syngas, which can then be further processed for a variety of end-uses including renewable natural gas, renewable diesel or sustainable aviation fuel (SAF). Synthetic fuels can be used to decarbonize hard-to-abate sectors which currently do not have viable zero emission solutions, like marine, aviation, and remote off-road heavy-duty equipment.

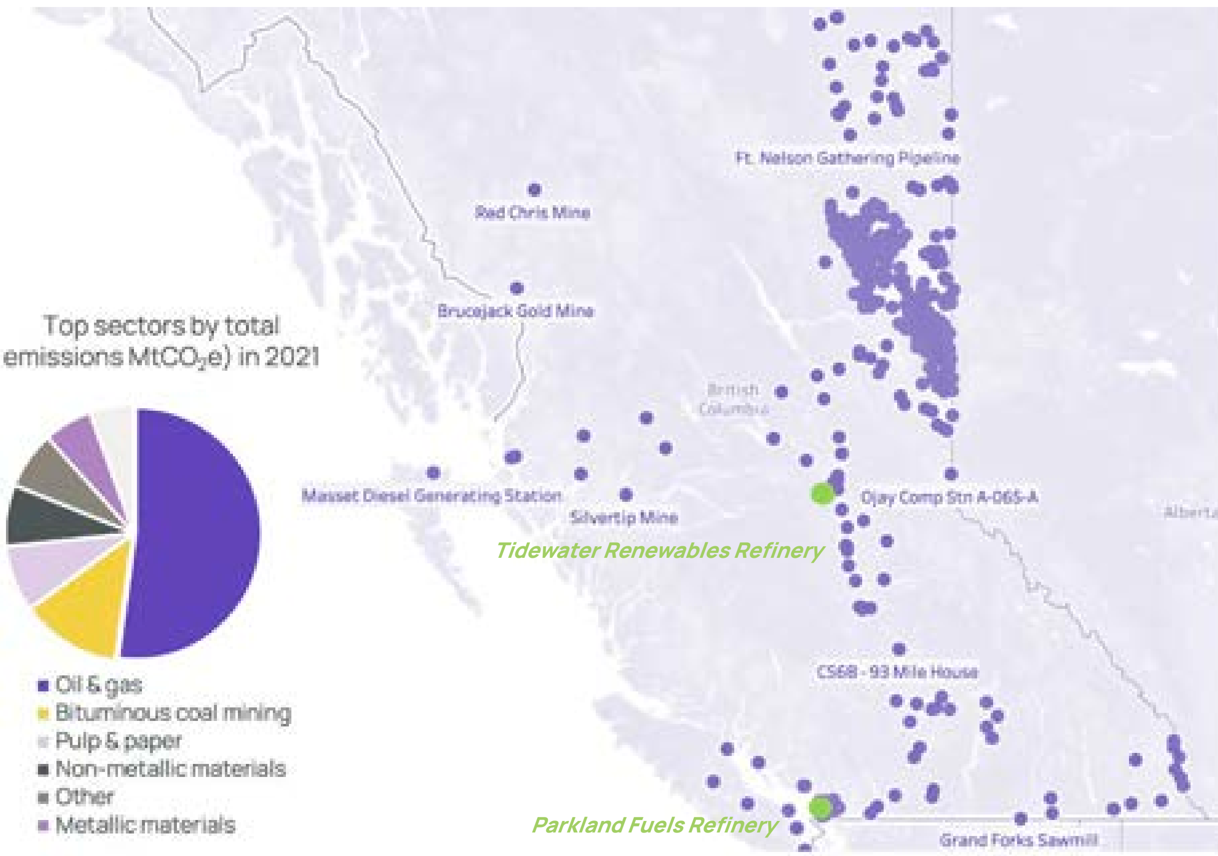
### Industrial processes and high heating loads

In addition to refining and petrochemicals, hydrogen is used as a feedstock for large-scale industrial processes such as ammonia-based fertilizer and steel production, with small volumes used in semiconductor manufacturing, glass purification, aerospace applications and pharmaceuticals, among others.[27] Hydrogen's high heat combustion also makes it an effective zero emission fuel for industries with high process heat requirements that cannot be electrified, like cement, pulp and paper, metal smelting, upstream fossil fuel extraction, and other steam reliant processes.[28]

Large industrial emitters often have high heat requirements, for which hydrogen could be used to displace natural gas or coal. These sites could also serve as potential hydrogen-focused decarbonization hubs, whereby a hydrogen project would focus on the energy loads of a specific facility, while also contributing to regional decarbonization of transport, merchant hydrogen demand, or remote/back-up power.

**Figure 10** shows the locations of high emitters across B.C. along with the breakdown of emissions by sector.[29] The greatest concentration of emissions is in the northeast of the province, which houses the bulk of the province's oil and gas production. B.C. currently has two oil refineries in operation, one in Burnaby and one in Prince George, which would represent the greatest volume of direct hydrogen demand. Several large-scale methanol and ammonia projects have been announced, which would also require large-scale hydrogen production. However, none of these projects have progressed to the construction stage.

**FIGURE 10: Locations of large industrial emitters in B.C. and total emissions by sector**[29]

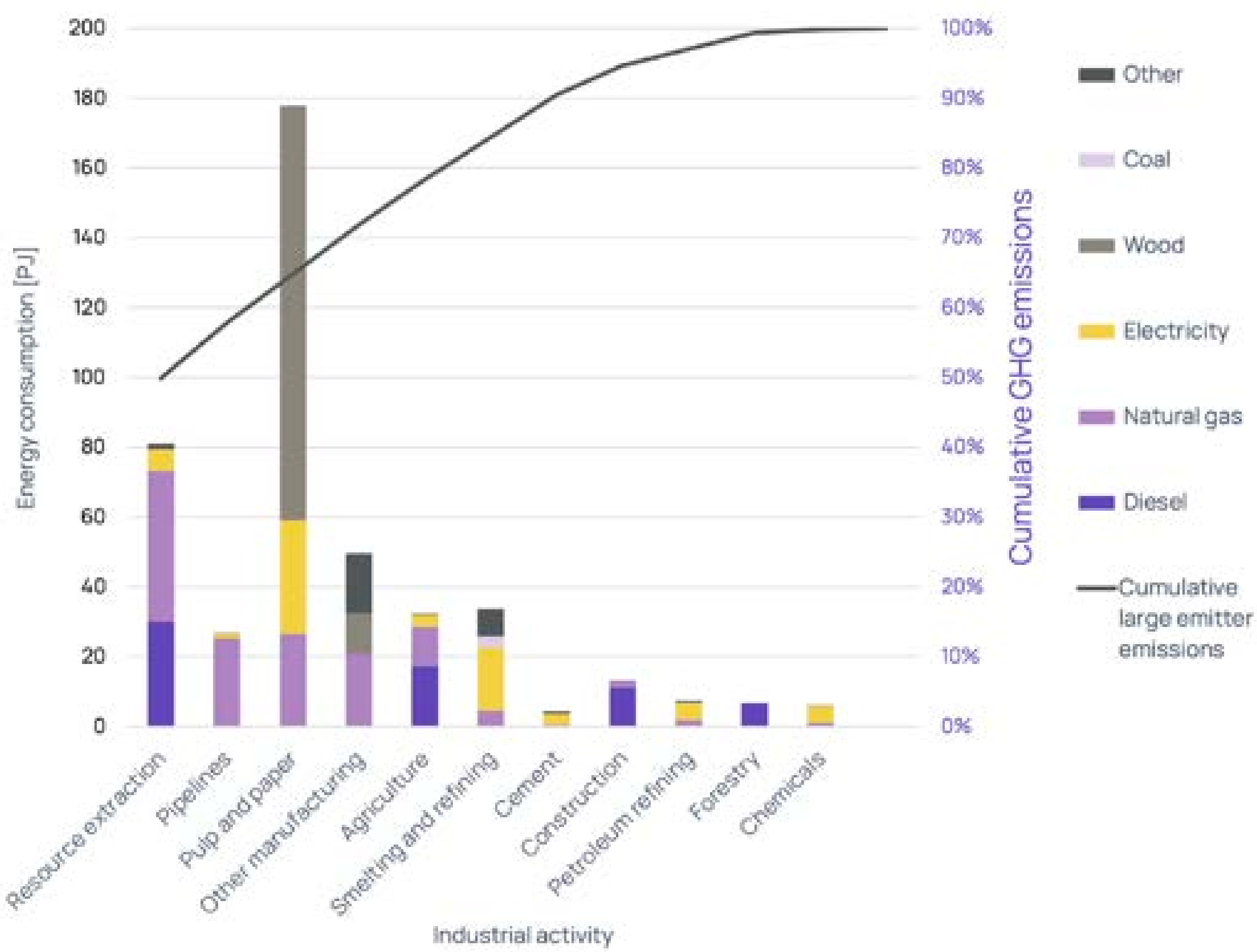



* B.C. only has 2 remaining oil refineries and no petrochemical facilities (largest direct use cases of $H_2$)

**Figure 11** shows the total energy consumption by fuel type for various industrial sectors, as well as the cumulative GHG emissions reported by large emitters within an industrial category.[24] Resource extraction, which includes mining and oil and gas extraction, is the largest consumer of both diesel and natural gas, representing 50% of large emitter GHG emissions. Diesel is consumed by mining haul trucks alongside various trucking and oil field drilling and service equipment. Natural gas is used primarily for process heat and stationary equipment. Utilization of hydrogen within this sector could have a significant impact in reducing GHG emissions. Since much of the consumption is spread throughout the province at distinct operational sites, a distributed hydrogen model utilizing methane pyrolysis could be effective in delivering the required volumes economically.

Agriculture, construction, and forestry are other sectors with significant diesel consumption. As with resource extraction, utilization of hydrogen to power the vehicles and equipment in these sectors would have a material impact on emission reduction. The pulp and paper industry is the largest energy consumer in this group, where most of the energy is supplied by residual wood waste and thus does not result in reportable GHG emissions. The sector does continue to utilize natural gas for high heat processes, which could be transitioned to hydrogen. Similar to the resource extraction sector, many of these sites are in discrete remote areas, thus strong candidates to benefit from the distributed hydrogen model.

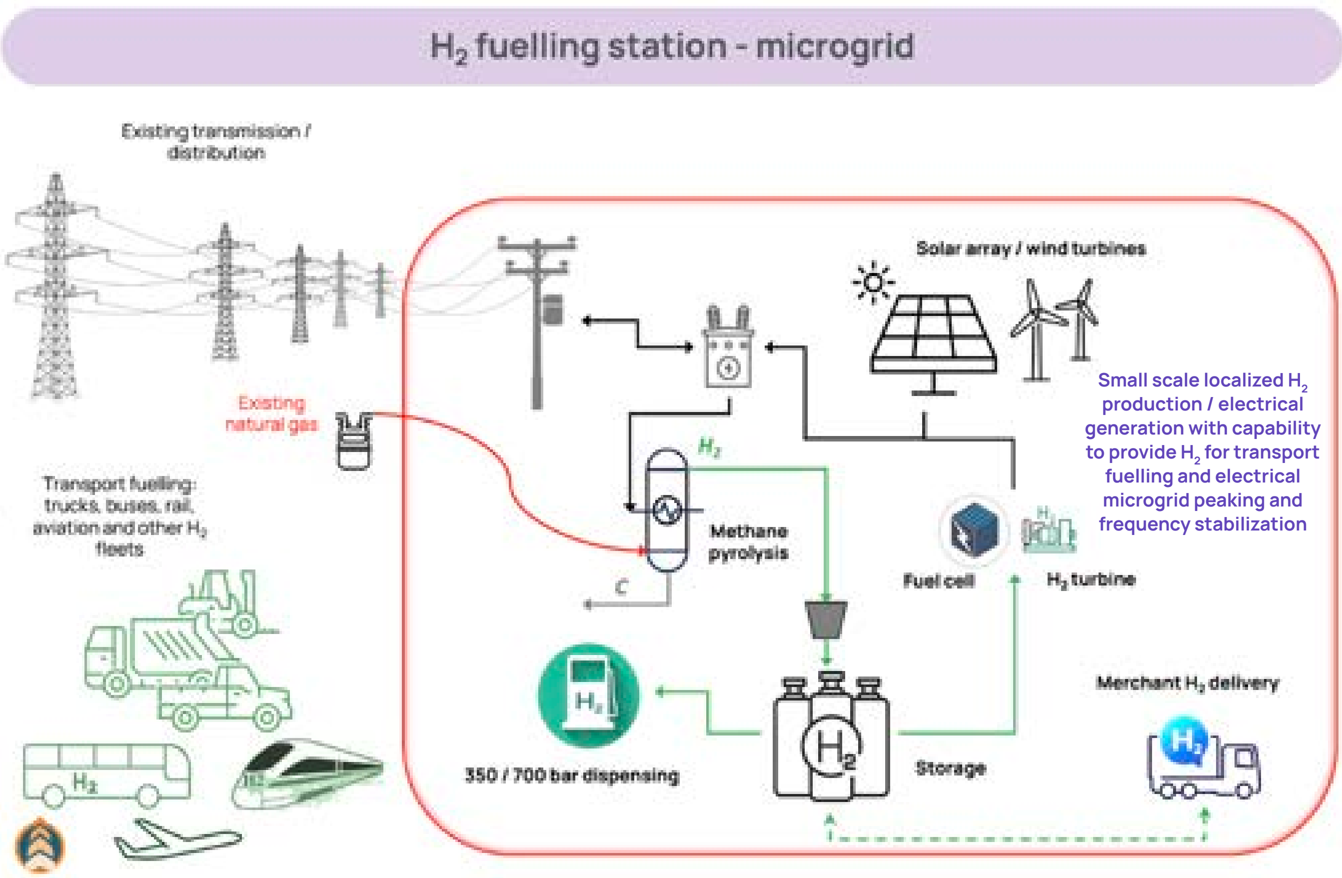
**FIGURE 11: B.C. industrial activity energy consumption by fuel type with corresponding large emitter GHG emissions for 2020**



### Peaking and transmission line optimization and stability by utilizing microgrids

Distributed hydrogen generation, in conjunction with supplying the refuelling network, can be used to power a microgrid to support local electricity loads. As illustrated in **Figure 12**, hydrogen could be generated and stored on-site for use as fuel for fuel cells, and hydrogen compatible internal combustion engines or combustion turbines, which would generate on-demand power for the local power distribution system. When peak loads are experienced, or if average load in the area increases beyond the transmission capacity of the system, hydrogen fuelled power generation can be added to the grid to satisfy the intermittent peak requirements. This can also be done in conjunction with renewable energy, with hydrogen offering long-term energy storage to compliment the variable nature of renewable power generation.

**FIGURE 12: Schematic of the hydrogen supported microgrid concept**



Microgrids have significant benefits for both regional- and province-wide electrical transmission, including:

» **Providing low-cost, clean energy directly at point of demand, improving supply reliability.**

» **Providing local area participation opportunities and improving on demand availability of power generation to match load requirements.**

» **Increasing grid resilience by limiting centralized risk and isolation from broader grid disruptions.**

» **Improving operational efficiency and stability of a wider electrical grid by reducing the need to overbuild transmission infrastructure to meet peak demand conditions, while managing renewables' low-capacity factors.**

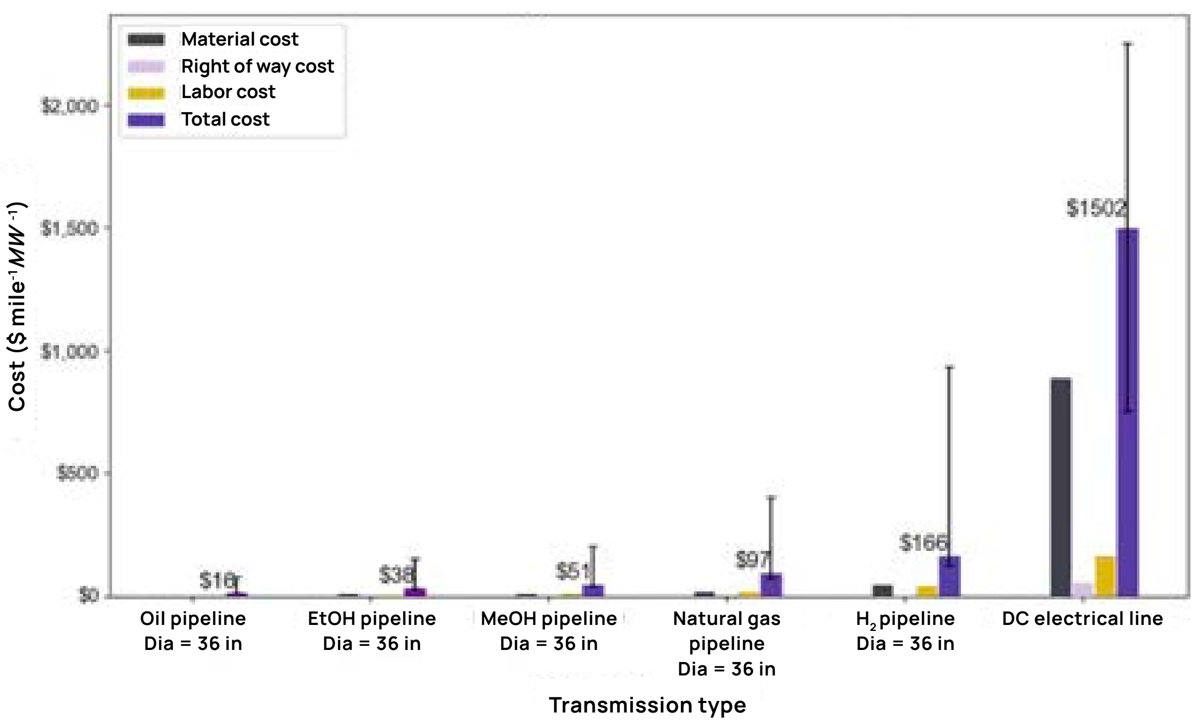
» **Reducing over capitalization of transmission build-out.**

» **Reducing province-wide wire losses due to long-distance transmission.**

### Remote communities and regional integrated decarbonization pathways

There are up to fifty remote communities in B.C. which are not connected to the natural gas or electricity distribution systems, and which subsequently rely on expensive and emissions-intensive diesel-powered generators to meet their energy requirements. Under CleanBC, the Province plans to reduce diesel generation of electricity by 80% by 2030. Many of these communities are interested in adopting clean energy solutions that will reduce their carbon footprint, while achieving energy self-sufficiency and resiliency.

**FIGURE 13: Capital cost of energy transmission over 1,000 miles by different energy carriers**[30]



On-site hydrogen generation via methane pyrolysis can benefit remote, unconnected, or under-connected communities with connections to natural gas. As shown in **Figure 13**, electrical grid connection can be greater than ten times the cost of natural gas pipelines on an equivalent energy basis.[30] Additional benefits of natural gas connection as compared to transmission connection is the ability for the natural gas pipeline to act as a storage medium to allow for on demand energy requirements when peak loads are experienced. Transmission losses are also much lower for natural gas at 2% compared to 13% for electricity.

Hydrogen-powered microgrids which can deliver combined heat and power, while also offering a transport fuel solution, are one option to shift the reliance of remote communities away from diesel. Another option is the integration of hydrogen with renewable resources to reduce intermittency issues of variable renewable electricity generation. However, many of these solutions are still technically and commercially complex and would need to be evaluated based on the specific size, climate, geography, and energy needs of specific communities.

Some regional initiatives are already beginning to evaluate hydrogen's role in an integrated decarbonization solution, such as the First Nations Climate Initiative (FNCI) in Northern B.C. FNCI's Climate Action Plan includes a role for pyrolysis to repurpose gas infrastructure to produce hydrogen to fuel ships and provide back-up power to grid constrained areas.[31] As part of this commitment, the Metlakatla First Nation and Lax Kw'alaams Band signed an MOU with Prince Rupert's Ridley Terminals, and are evaluating pathways to produce hydrogen for various local uses. The project is one amongst many other First Nations' led hydrogen projects across the country.[32] FNCI is also evaluating the role of biomass to produce renewable natural gas, which could further be processed through pyrolysis or reformed into hydrogen.

### Hydrogen export

As jurisdictions around the world recognize the role of hydrogen in helping achieve their decarbonization targets, demand is expected to grow across international markets. Some regions will be better positioned than others to produce hydrogen, making them net exporters, while others with limited availability of natural gas feedstock, carbon sequestration reservoirs, or renewable power generation potential—will be net importers.

**Figure 14** shows the potential distribution of hydrogen around the world by 2050, including significant export potential out of Western Canada.[33] British Columbia is well positioned to meet a portion of global hydrogen demand due to extensive low-cost and low-GHG intensity natural gas reserves, clean electricity, and proximity to large hydrogen export markets. Asia-Pacific is expected to represent more than 55% of global hydrogen demand by 2050, with Europe representing the second largest consumer.

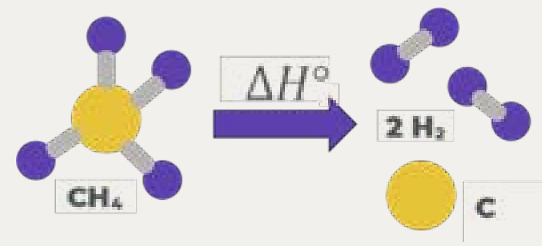
Transport of hydrogen over long distances will continue to be a challenge due to the lack of existing liquid hydrogen transport vessels. There are also toxicity and inefficiencies related to the conversion and transport of hydrogen through other compounds such as ammonia, methanol, and liquid organic carriers. However, since the liquid natural gas (LNG) market and infrastructure is already well established, the commercialization and deployment of methane pyrolysis at the export market will allow the conversion of natural gas into hydrogen and carbon for local use.

**FIGURE 14: Global hydrogen trade flows by 2050**[33]

# 3. Methane pyrolysis

Pyrolysis of wood was one of the first chemical processes adopted by humans dating back to the 12th century for the extraction of pine tar used in ship building.[34] During the First World War pyrolysis was used to compensate for a shortage of diesel and gasoline, by utilizing wood or coal to generate a syngas for combustion in vehicles. Current conventional thermal pyrolysis of coal, bunker oil, and natural gas is utilized for the generation of carbon black and other conductive carbon products, with the hydrogen-rich syngas consumed within the process for heat generation.

As illustrated in **Figure 15**, pyrolysis becomes a favorable reaction above 547°C, with a 90% conversion rate realized above 760°C, approaching 100% conversion above 1,100°C.[35]




As introduced in Section 2, methane pyrolysis is the physical dissociation of methane into elemental hydrogen and carbon in the presence of heat. The chemical equation of the reaction is shown in Equation 1, with the ideal mass balance and energy balance reaction equations shown in Equation 2 and Equation 3, based on the energy of reaction of 75 kJ/mole required at 0° and 1 Bar.

**Equation 1 – Pyrolysis Chemical Equation:**

$$CH_4(g)+\Delta H^\circ \rightarrow C(s)+2H_2(g)$$

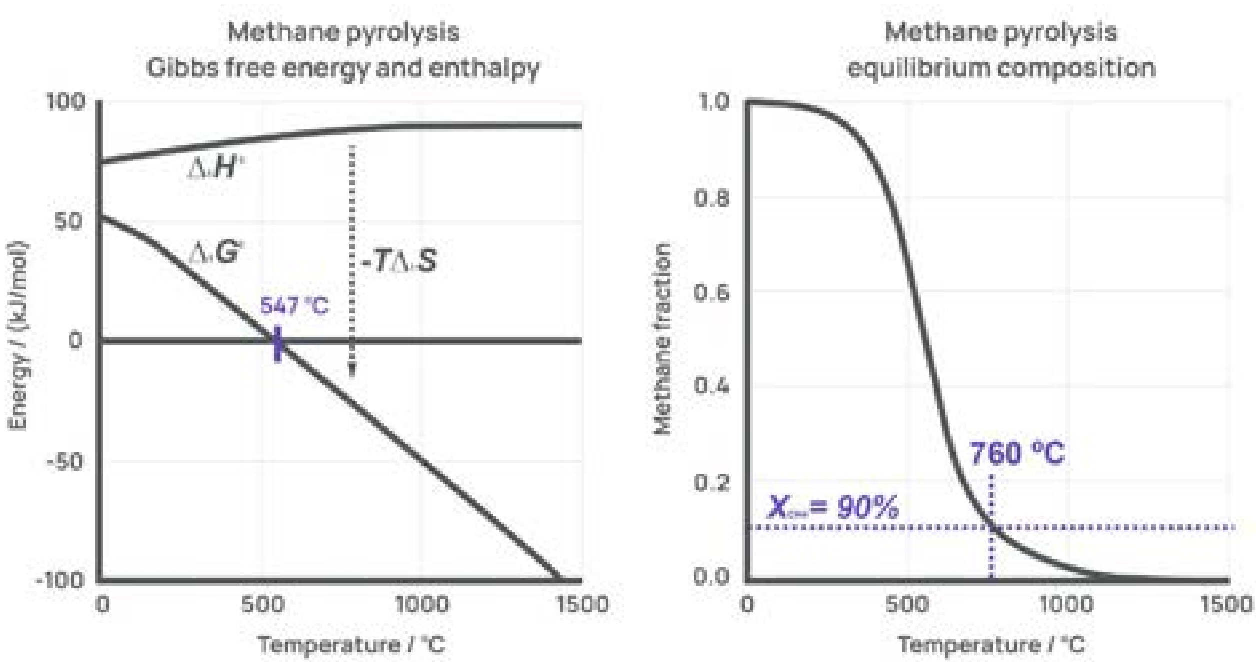
**Equation 2 – Pyrolysis Mass Balance:**

$$16.04\,\frac{g}{mole} \rightarrow 12.01\,\frac{g}{mole} + 2(2.015)\,\frac{g}{mole}$$

**Equation 3 – Pyrolysis Energy Balance [HHV @ 0°C, 1 Bar]:**

$$891\,\frac{kJ}{mole} + 75\,\frac{kJ}{mole}\,\Delta H^\circ \rightarrow 394\,\frac{kJ}{mole} + 572\,\frac{kJ}{mole}$$

**FIGURE 15: Enthalpy of reaction and composition equilibrium for methane pyrolysis**[35]



However, this does not address the slow reaction kinetics until temperatures more than 1,300°C are realized. To address the kinetics of the pyrolysis reaction, various alterations to the reaction process and reactor design are being developed by numerous start-up technology companies. These changes may result in many unique alterations to the pyrolysis process to achieve efficient conversion of methane into hydrogen, as well as to control the specific allotrope of the solid carbon created from the reaction. As a result, there are many combinations of high temperature and low temperature reactions utilizing unique combinations of combustion, direct electrical heating, plasma, microwaves, and waste heat capture, as well as utilizing many distinct types of catalysts.

Some of these reactor designs and their reaction temperatures are summarized in **Figure 16**.[36]

**FIGURE 16: Methane pyrolysis technologies and their reaction temperatures**[36]

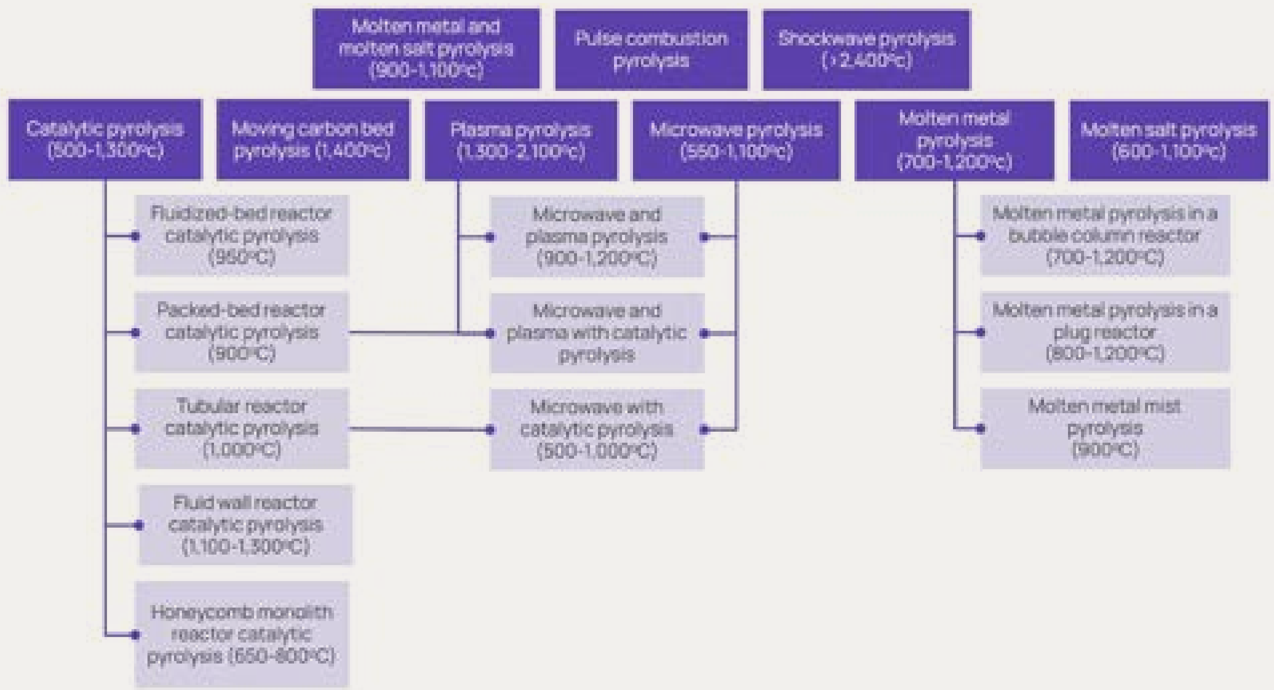



**Table 3** is a list of methane pyrolysis technology companies identified at the time of this report. The technologies being developed by these companies are believed to vary between Technology Readiness Levels (TRL) 4 to 8. A simplified description of the ratings between TRL 1 and TRL 9 is shown in Figure 61 within the Appendix for reference. The most advanced of these companies is believed to be Monolith Inc., which is currently operating a 13 t/day hydrogen facility in Nebraska, utilizing hydrogen to produce carbon-free ammonia and selling carbon black co-product to Goodyear for tire manufacturing. Monolith aims to expand the facility to a total output of 165 t/day of hydrogen, which will propel its technology to TRL 9.

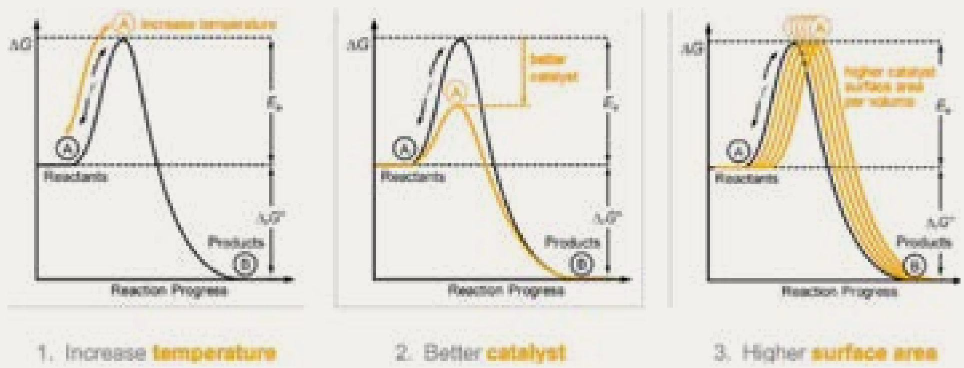
## Types of pyrolysis technologies

Pyrolysis technologies differ mainly in the way heat is delivered to the process. The most established and early pyrolysis reactors were designed around thermal decomposition of methane at extremely high temperatures to form hydrogen and methyl radicals, and their reaction with other intermediate hydrocarbon species. Controlling the temperature at various parts of the reaction would avoid the formation of excessive methyl radicals and maximize hydrogen production. However, the extremely high reaction temperatures required much more expensive and durable construction materials and higher energy loads.

Over time, newer reactor designs emerged to reduce operating temperatures and optimize the enthalpy of pyrolysis reactions while maximizing hydrogen yields. These are summarized in **Figure 17**[35] and include:

- **Rapid increase in reactor temperature.**
- **Utilization of a catalyst to decrease the temperature needed for the reaction.**
- **Increasing the surface area of the catalyst to increase the speed of reaction.**
- **Directly targeting methane molecules using microwave or electric beams.**

**FIGURE 17: Impacts of different methods to improve kinetics of pyrolysis reaction**[35]




At a high-level, pyrolysis technologies can be grouped into three main types: thermal, catalytic, and plasma. An overview and comparison of these technologies are provided in Table 4.[37] [38] [39] [40] [41] [42] [43] [44] Thermal pyrolysis is the more established technology and the least capital intensive to build, whereas thermo-catalytic and plasma are newer processes with reduced carbon intensities that offer some ability to customize the produced carbon allotrope. Plasma pyrolysis is diverse in its application and reactor design, offering a wide range of energy requirements, and which can often be paired with molten metal or molten salt to facilitate hydrogen and carbon separation.

**TABLE 3: List of methane pyrolysis companies and technologies, in order of estimated TRL level**

TRL 8

| | Company name | Country of origin | Status | Tech |
|---|---|---|---|---|
| | Methane pyrolysis | | | |
| 1 | Monolith | US (Nebraska) | Commercial plant (13 t/d) in Nebraska 2020, expansion to 165 t/d in 2026 | High temperature electric heating - plasma |
| 2 | Hazer Group | Australia (Perth) | Demo plant (275 kg/d) in Perth 2023, commerical plant (7 t/d) in BC 2025 | Low temp fluid bed iron ore catalytic pyrolysis |
| 3 | C-Zero | US (Goleta, California) | Pilot plant (400 kg/d) Q4 2023, commercial plant (6 t/d) 2025 | Bubble column molten metal / salt pyrolysis |
| 4 | Huntsman Nanocomp | US (Merrimack, N.H) | Bench scale (1 kg/d), pilot plant (25 kg/d) in Texas 2023, demo plant (1 t/d) in 2026 | Thermal catalytic pyrolysis |
| 5 | H-Quest | US (Pittsburgh, Pa.) | Pilot plant (250 kg/d) 2023, with commercial target of 1 t/d | Microwave plasma pyrolysis |
| 6 | Hiiroc Hydrogen | UK (Kent) | 2 demo plants in operation (UK), pilot plant (400 kg/d) in Germany 2023 | Vortex plasma torch and molten metal pyrolysis |
| 7 | Modern Hydrogen | US (Seattle, Wash.) | 2 micro demo plants (5 kg/d) 2023, pilot plant (500 kg/d) 2024 | High temp pyrolysis |
| 8 | Ekona Power | Canadian (Burnaby, BC) | Bench scale reactor (200 kg/d), pilot plant (1 t/d) in Alberta 2024 | Thermal pulsed methane pyrolysis |
| 9 | Hycamite | Finland (Kokkola) | Bench scale, pilot plant (5.5 t/d) 2024 (Finland) | Thermocatalytic pyrolysis |
| 10 | Levidian | UK (Cambridge) | 3 demo plants (27 kg/d) in Scotland 2024 and Demo Plant (55 kg/d) in UAE 2025 | LOOP - microwave plasma methane cracking |
| 11 | Plenesys | France (Valbonne) | Demo plant (150 kg/d) in Australia with commercial target of 275 kg/d and 2.7 t/d units | Hyplasma (AC plasma arc) |
| 12 | GraforcE | Berlin, Germany | Demo plant in Austria with commercial target of 1.2 t/d units | Plasmalysis - renewable electricity and plasma pyrolysis |
| 13 | Etch | US (Baltimore, Md.) | Bench scale reactor, demo plant (135 kg/d) 2023 | Catalytic thermochemical redox |
| 14 | Innova Hydrogen | Canadian (Calgary, AB) | 2 demo plants (2 t/d) in Alberta 2024 and pilot plant (5 t/d) in BC 2026 | HIP reactor (high temp impulse) - catalytic pyrolysis |
| 15 | Aurora Hydrogen | Canadian (Edmonton, AB) | Demo plant (200 kg/d) in Alberta 2024 | Microwave pyrolysis |
| 16 | Nu:Ionic Technologies | Canadian (Fredericton, NB) / US (Tulsa, Ok.) | Demo plant (2.4 t/d) in New Brunswick 2025 | Microwave catalytic reforming |
| 17 | Vulcanx | Canadian (Vancouver, BC) | Pilot plant (55 kg/d) in Alberta 2023 | High temp bubble column with recirculating molten metal |
| 18 | Basf | Germany (Ludwigshafen) | Bench scale reactor (11 kg/d) | High temp moving fluid bed iron ore catalytic pyrolysis |
| 19 | Hydrograph | Canadian (Toronto, ON) | Bench scale reactor, demo plant (30 kg/d) in Manhattan, KS. | Hyperion - detonation pyrolysis (graphene focused) |
| 20 | Clean Hydrogen | US (New York) / India (Arjun Datir) | Bench test | CHT - catalytic high temp plasma fluid bed pyrolysis |
| 21 | Maat Energy | US (Cambridge, Mass.) / France (Venissieux) | Bench test | AMP - atmospheric microwave plasma system |
| 22 | New Wave Hydrogen | Canadian (Calgary, AB) | Bench test | Wave rotor shockwave pyrolysis |
| 23 | Spark Hydrogen | France (Gif-sur-Yvette) | Bench test | Plasmalysis - cold nanopulsed plasma |
| 24 | Tomsk Polytechnic Institute | Russia (Tomsk) | Bench test | Microwave catalytic + cold plasma torch |
| 25 | Gasplas / University Of Cambridge, Uk | Norway (Oslo) | Conducting bench testing | Microwave plasma pyrolysis |
| 26 | Seid As | Norway (Sandnes) | Lab testing | ColdSpark (low temp pyrolysis) |
| 27 | Susteon (Palo Alto Research) | US (Palo Alto, Calif. / Cary, NC) | Lab testing | Centrifugal cascading molten zinc |
| 28 | Susteon (Stanford University) | US (Palo Alto, Calif. / Cary, NC) | Lab testing | Low temp catalytic pyrolysis |
| 29 | Susteon (Gupta) | US (Cary, NC) | Lab testing | Silicon catalytic pyrolysis |
| 30 | Thiozen | US (Beverly, Mass) | Lab testing | Thermochemical iodine sour gas pyrolysis |
| 31 | Universal Matter Advanced Materials | Canadian (Burlington, On) / US (Houston, TX) / UK (Redcar) | Lab testing | Flash pulse pyrolysis (turbostatic graphene focused) |
| 32 | Pacific Northwest National Laboratory | US (Richland, Wash) | Proof of concept | Fluidized bed bimetallic catalytic pyrolysis |

TRL 4

**DISCLAIMER:** All information compiled in Table 3 has been gathered from various public sources and represents the authors' best understanding of each company listed at the time of this report. Any specific questions with regards to each listed company's technology or development status should be directed to the company for clarification.

**TABLE 4: Overview of three main methane pyrolysis technologies**

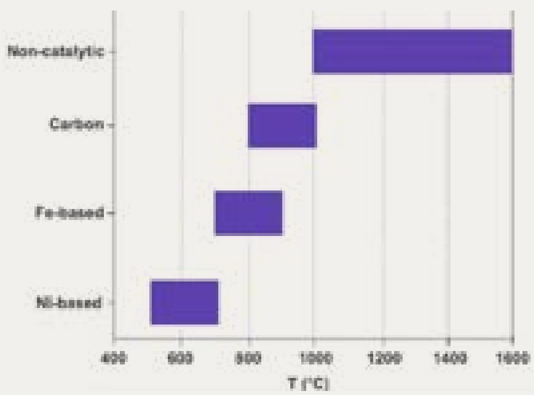
| Parameters | Thermal Pyrolysis | Thermo-Catalytic Pyrolysis | Plasma-based Pyrolysis |
|---|---|---|---|
| **Operating temperature** | 1,100–2,000°C | 800–1,000°C | ‹1,000°C (cold plasma)<br>›1,100°C (hot plasma) |
| **Process Description** | Direct decomposition of methane using a heat source, which could be natural gas, recycled hydrogen, or other renewable fuels | Decomposition of methane in the presence of a catalyst, which may be carbon or a certain transition metal at a relatively lower temperature | A plasma generator (non-thermal sources: microwave, dielectric barrier discharge or electron beam; thermal sources: electric arc) is used to deliver significant energy in a short span to decompose methane or other feed gas into a plasma, which interacts with methane molecules to split them into $H_2$ + C |
| **Advantages** | No novel or proprietary equipment is required | Decreased utility costs due to comparatively lower operating temperatures. The desired carbon allotrope can be obtained based on the catalyst and temperature | High one-pass-conversion rates with high hydrogen purity (if paired with molten salt/metals). Can use renewable electricity to provide process energy |
| **Disadvantages** | Higher carbon intensity product due to combustion of methane and recirculated $H_2$, less capability to control carbon allotrope, higher carbon-to-$H_2$ ratio due to $H_2$ consumption and increased methane feed | Increased operating costs due to catalyst expenses, potential for carbon caking on internal heated surfaces, carbon contamination due to embedded carbon material, greater requirements for recirculation loop due to lower first-pass conversion rates | Higher capital costs, higher energy costs, more complex processes (particularly with the integration of molten salts and metals) |
| **Relative Energy Needs** | High | Medium | Low to high — specific process dependent |

The following section provides more details about different sub-categories of pyrolysis technologies and examples of companies that are developing those types of technologies.

### Thermal catalytic pyrolysis

Catalytic methane pyrolysis relies on the dissociative adsorption of methane on a catalyst surface, which significantly reduces pyrolysis reaction temperatures. Carbon catalysts (most commonly carbon black, graphite, diamond powder, and carbon nanotubes, among others), are much cheaper and more resistant to impurities than metal catalysts but can be less effective. The common metal catalysts include cobalt, nickel, and iron, in order of most to least expensive and effectiveness. As per **Figure 18**, metal-based catalysts have a much greater impact on temperature than carbon-based ones, with some metal catalysts reducing temperatures from 1,000°C to as low as 500°C.

**FIGURE 18: Temperature range of applicability of different catalysts for methane pyrolysis reaction**[36]




An example of a company commercializing thermo-catalytic decomposition is Finland-based Hycamite, which has developed a suite of proprietary catalysts to produce hydrogen and catalyst-specific electrically conductive carbon nanoproducts.[45] Hycamite has been operating a pilot plant since 2021 and is currently building a 5.5 $tH_2$/d pilot plant in Kokkola, Finland. The company is also evaluating several sites for a commercial facility in North America.

Another company developing similar technology is Alberta-based Innova Hydrogen Corp., which has developed the novel HIP™ methane pyrolysis technology that only uses methane as its feedstock, a catalyst, and electric heating to generate required temperatures and turbulence to break down methane.[46] **Figure 19** shows the HIP process, which utilizes a thermo-catalytic process to produce higher value carbon products like graphite and graphene. Innova is operating a demo facility in Calgary and is currently designing its first field pilot for deployment in 2024, with two early commercial facilities (2 $tH_2$/d) planned in Alberta for 2025, and a full-scale facility (4.5 $tH_2$/d) planned for B.C. in 2026.

The Hazer Group, a Perth, Australia based company, also utilizes this technology in their HAZER® Process, which generates high quality graphite utilizing iron ore as a process catalyst within a fluidized bed.[47] In January 2024, Hazer announced the successful commissioning of their commercial demonstration plant to achieve hydrogen and graphite production **(Figure 20)**. A project for a 7 $tH_2$/d demonstration plant in B.C. has been announced in partnership with FortisBC.

**FIGURE 19:** Overview of the innova hydrogen hip methane pyrolysis process[46]

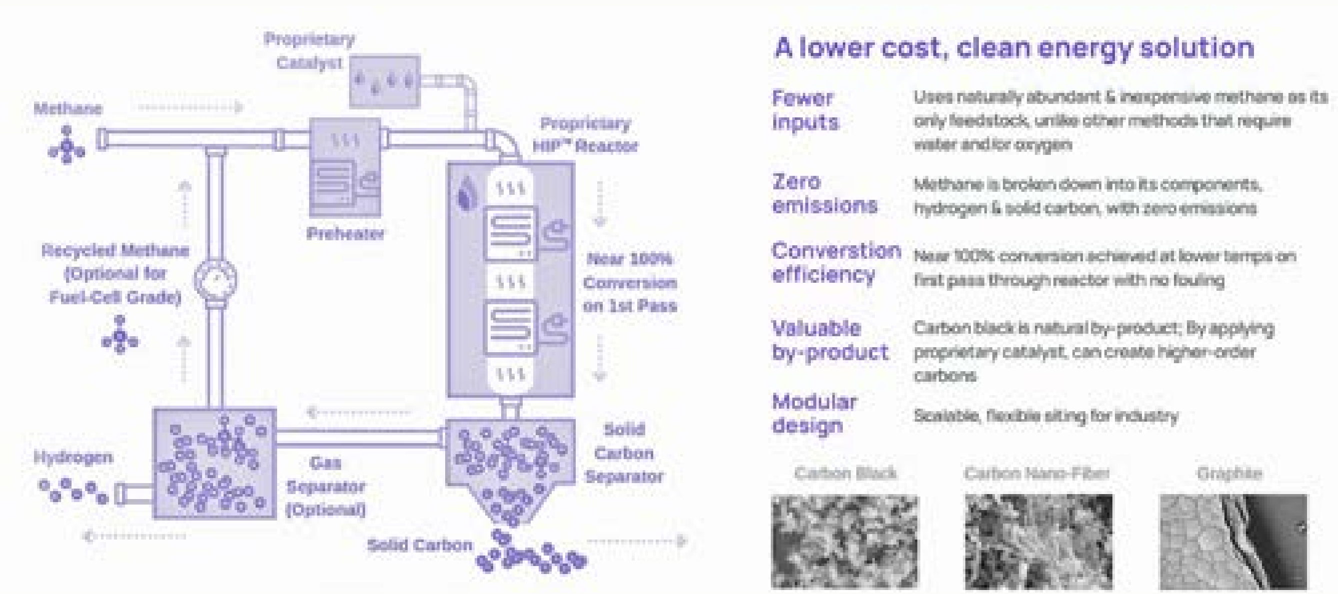



**FIGURE 20:** Hazer commercial demonstration plant, Perth Australia Dec 21, 2023 (Copyright Hazer Group Limited © 2023)

### Moving carbon bed pyrolysis

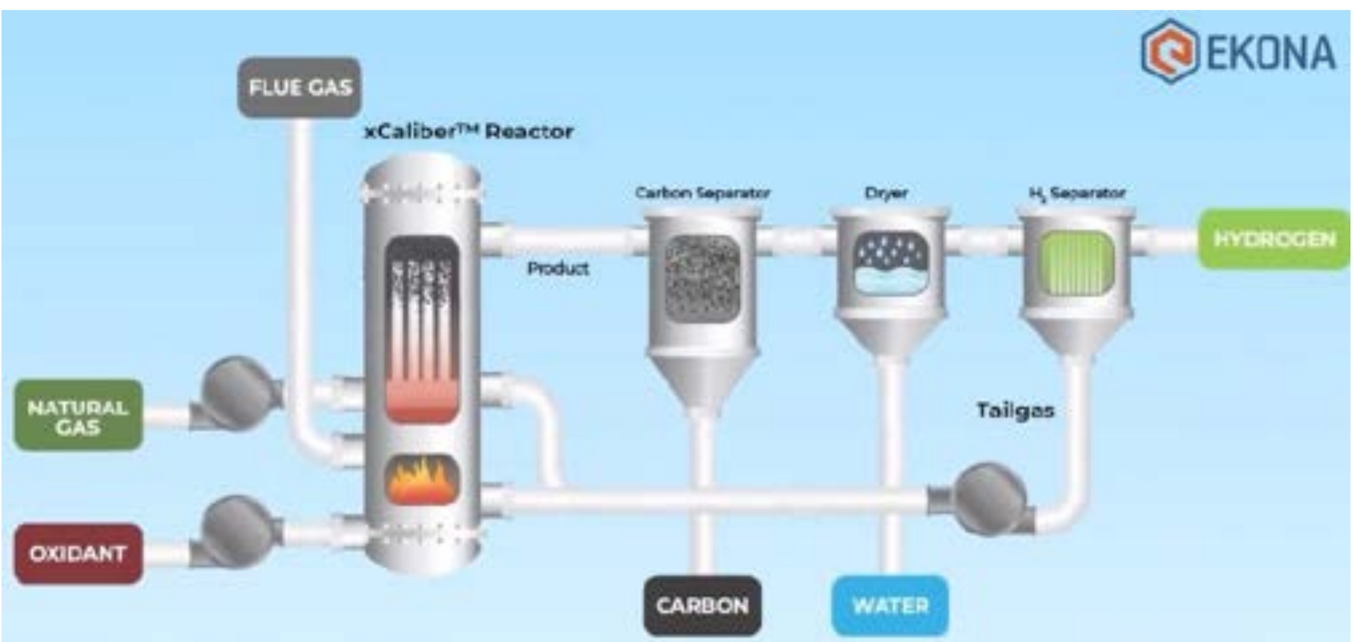
In this process, the reactor is filled with a carbon bed or another catalyst and heated to 1,400°C. Methane is flowed through the bed, in which solid carbon is separated and deposited on the pre-existing solids in the reactor, while hydrogen is separated out. The process results in a pure stream of carbon that can be reused in the reactor bed but relies on extremely elevated temperatures. A consortium led by BASF has been working on developing this technology since 2013, with a bench reactor constructed in 2019 in Ludwigshafen, Germany.[48]

### Pulse combustion pyrolysis

During this process, the pulsed ionized stream of intermittent oxy-fired combustion of methane or recycled hydrogen is introduced into the reactor at high velocities, which mixes with an introduced methane stream to produce solid carbon and hydrogen. The process is simple and easy to scale since it does not require a catalyst but relies on the combustion of methane and hydrogen with oxygen to generate heat. The recirculation of hydrogen for heat production can reduce reaction yields and increase balance of plant costs.

An example of a company commercializing pulse combustion pyrolysis is B.C.-based Ekona Power, and their xCaliber™ methane pyrolysis reactor. An overview of Ekona's novel, non-catalytic pulsed combustion in a high-speed gas chamber is summarized in Figure 21.[49] Ekona built a 200 kg/d pilot facility in Burnaby, B.C. in 2022 and is currently developing a 1 t$H_2$/d demonstration plant in northern Alberta, due to be completed in 2024.

**FIGURE 21: Schematic of Ekona's xCaliber pulse combustion reactor**[49]



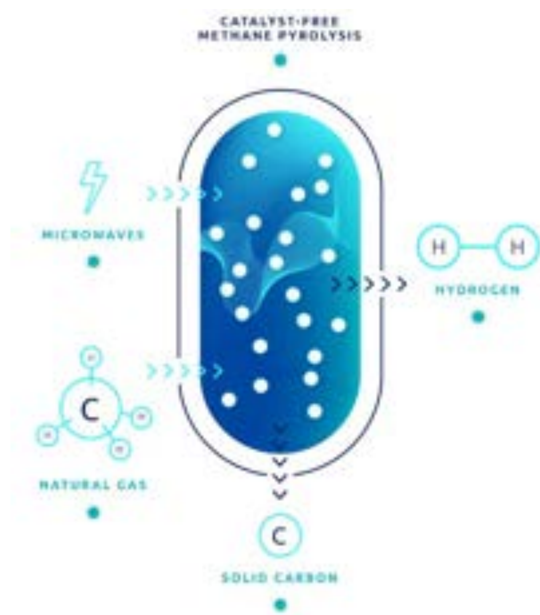
### Microwave pyrolysis

During microwave pyrolysis, microwave energy is concentrated on carbon catalyst particles, creating a micro-plasma at the interface of the particles, which decomposes methane into hydrogen and solid carbon. The solid carbon agglomerates on the carbon catalyst surface until it reaches a critical size, at which point it drops out of the reactor, with smaller remaining particles in the reactor acting as the new catalyst.

Variations of the microwave pyrolysis technology include switching the carbon catalyst with one that is metal-based, which reduces the reaction temperature to 450-600°C. Microwave energy can also be used to create a plasma region within the reactor, which would then become the site of reaction instead of the catalyst bed.

An example of a company commercializing microwave pyrolysis is Alberta-based Aurora Hydrogen, which uses carbon as a microwave susceptor, and microwave energy to provide the heat needed to break hydrocarbon chains. The simplicity of the process makes it highly scalable. Aurora is currently in the process of constructing a 200 kg/d demonstration facility in Edmonton, with plans to scale-up subsequent facilities by an order of magnitude.[50] An illustrative schematic of the Aurora microwave pyrolysis reactor is shown in **Figure 22**.[51]

**FIGURE 22: Illustrative schematic of Aurora Hydrogen microwave pyrolysis reactor**[51]

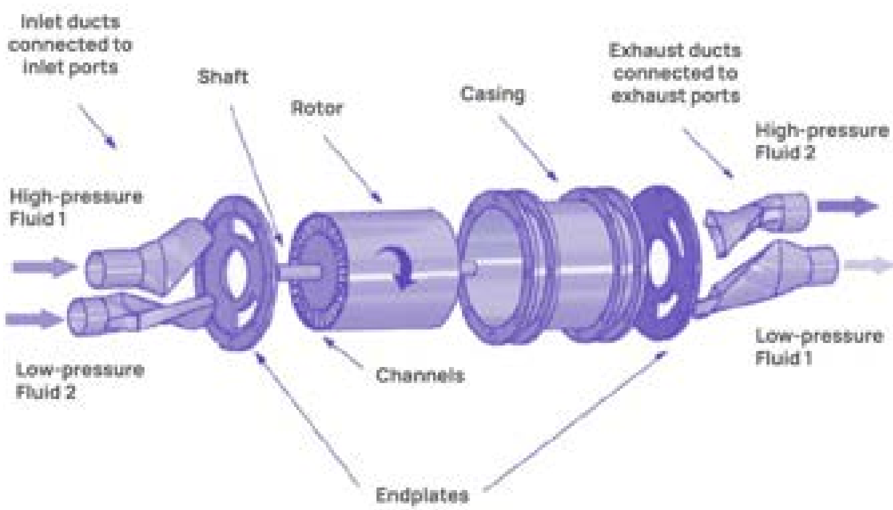



### Shock wave pyrolysis

A shock wave is created by sending a high-pressure gas stream into a reactor that contains a large low-pressure volume of gas. This gas-to-gas compression creates moving shock waves, transferring energy between the gases and increasing gas temperatures excess of 2,400°C, which initiates the decomposition of methane into hydrogen and solid carbon. To support continuous production a wave rotor is used. A wave rotor is analogous to a spinning bank of shock tubes, arrayed around a rotating drum. This allows successive injection of high-pressure and low-pressure gas streams into the channels and supports continuous production as the products rapidly exit each channel. Some of the benefits of high-pressure shock wave reactors include reduced potential for coke build-up and highly efficient heat production.

An example of shock wave pyrolysis is New Wave Hydrogen's Wave Reformer, which can be directly integrated to natural gas regulating stations to utilize high-pressure pipeline gas, or any pressurized gas source. The wave reformer transfers energy via shock waves using wave rotor architecture, amplifying the temperature of the gases to directly decompose hydrocarbon fuels into hydrogen and solid carbon. Using shock wave heating to drive the reaction, instead of electricity, offers cost and environmental benefits. The process is applicable to any source of biogas, natural gas, other hydrocarbons, and other compounds, including ammonia.[52] New Wave Hydrogen is currently working towards field trials in Alberta with the first generation of Wave Reformers as shown in **Figure 23**.[53]

**FIGURE 23: Gt2022 -80865-quasi-two-dimensional numerical model for shock wave reformers[53]**




## Plasma pyrolysis

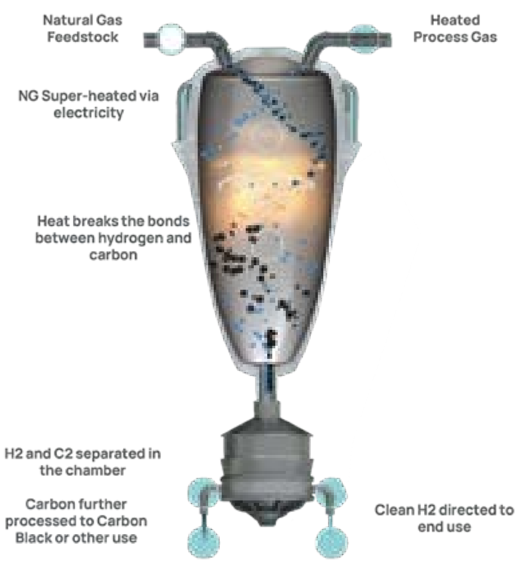
A plasma arc, created between electrically powered graphite electrodes, is used to heat methane as it moves through the reactor. The resulting plasma gas, defined as ionized gas and composed of positively charged ions and free electrons, is accelerated through a nozzle to react with methane at temperatures of 1,000 to 3,500°C. The process does not require a catalyst and offers good control of the reaction, which can generate high-quality carbon black as compared to other forms of pyrolysis. However, the elevated temperature of reaction requires significant amounts of electricity, which can increase operating costs. Variations of plasma pyrolysis include:

» **Pulsing of plasma gas from torches that are not influenced by the flow of methane, increasing the energy efficiency of the process.**

» **Cold pulsed plasma that generates a noble gas, which collides with methane gas and creates a shockwave that decomposes methane.**

» **Methane is fed through an electric arc which is used to produce a plasma region that decomposes methane.**

**FIGURE 24: Schematic of the Monolith hydrogen plasma pyrolysis reactor**[54]




As mentioned earlier, an example of a company commercializing plasma pyrolysis is Monolith, which uses a combined feed of natural gas and heated process gas flowing through an electrically induced plasma arc to produce hydrogen and carbon black. This process is summarized in **Figure 24**.[54] Having secured more than U.S. $1.3B USD in equity funding and Department of Energy (DOE) loans, Monolith already has an operational commercial facility in Hallam, Nebraska **(Figure 25)** with a capacity of ~13 tpd hydrogen, which is expected to scale up to 165 tpd hydrogen by 2025.[55]

A U.S.-based plasma pyrolysis developer with technical operations in India, Clean Hydrogen Technologies Corp., is using a catalyst to produce hydrogen and carbon black, with further processing into carbon nano-objects.[56]

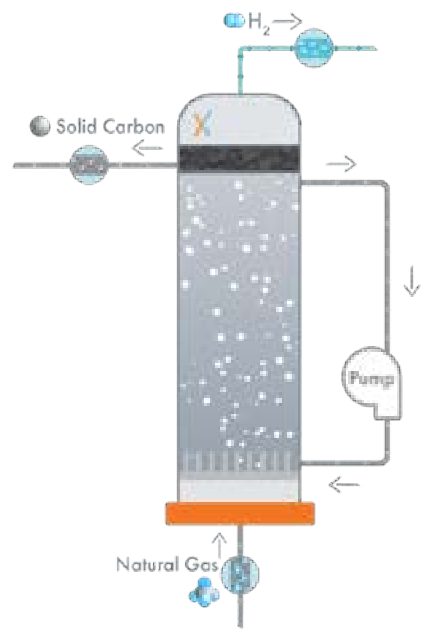
**FIGURE 25: Monolith Olive Creek Plant phase 1**[54]

### Molten metal/molten salt pyrolysis

Methane is bubbled through a molten metal or salt at 900 to 1,200°C, whereby carbon particles are separated and adsorbed into the molten material and rise to the surface. Low melting point metals such as tin, gallium, lead, and indium are effective heat transfer mediums for methane, particularly because of their insolubility with carbon, which allows for easier mechanical separation of carbon from the reactor. To increase the reactive process further and lower the operating temperature to 950°C, a catalytic molten metal like zinc creates a mist under pressure, which increases the contact area for carbon adsorption in the reactor.

Molten salts have been investigated as means of extracting a clean carbon particle stream due to their lower densities. These salts can be created from any combination of potassium, sodium, magnesium, zinc, lanthanum, lithium with fluoride, chloride, bromide, iodine, hydroxide, sulphur trioxide, or nitrate. Salts can be used in combination with metals in a reactor, acting as a separation barrier to remove solid carbon. One downside of this combination is increased corrosion within the reactor, alongside metal fatigue, thermal shocking, and coke formation on the reactor walls.

**FIGURE 26: Vulcan X recirculating molten metal reactor schematic**[54]




An example of a company commercializing molten salt pyrolysis is C-Zero Inc., which uses thermocatalysis – splitting methane into hydrogen and carbon using elevated temperatures by moving it through a mixture of molten salts. C-Zero's first pilot plant is expected to come online in 2023, which will be capable of producing up to 400 kg/d.[57]

Another example is VulcanX, a Vancouver-based company created through Merida Labs from the University of British Columbia, which has developed a patented Methane Thermal Cracking (MTC) reactor that utilizes a moving molten metal bed and methane bubble flow through the reactor shown in **Figure 26**.[58] The company is developing a 200 kg/d pilot project in Alberta.[59]

## Other technologies

Some companies utilize a combination of different pyrolysis processes within their reactors to achieve cost efficiencies and greater yields. An example of this is U.K.-based HiiROC Limited's Thermal Plasma Electrolysis reactor, which uses patented plasma torches to split hydrocarbons at high pressures. On the back end, the company uses a molten metal or salt to separate solid carbon from hydrogen, allowing the reactor to operate in continuous flow rather than batch processes. This process is summarized in **Figure 27**.[60] HiiROC started developing its first commercial pilot project in the U.K. in 2022 with Centrica for inline natural gas blending at the Brigg Gas Fired power station.

**FIGURE 27: Schematic of HiiROC's TPE reactor**[60]

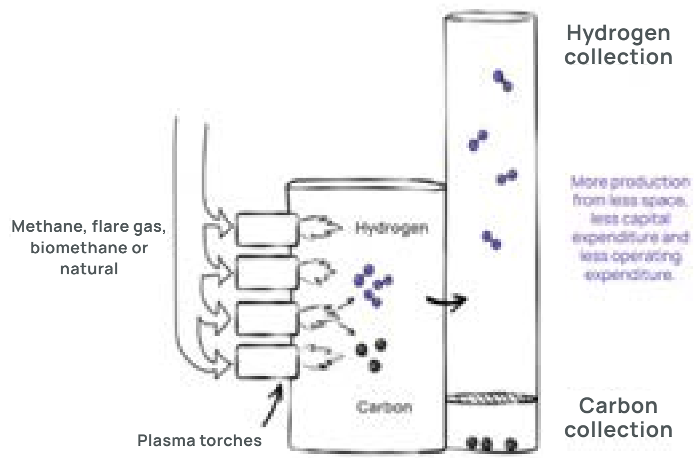
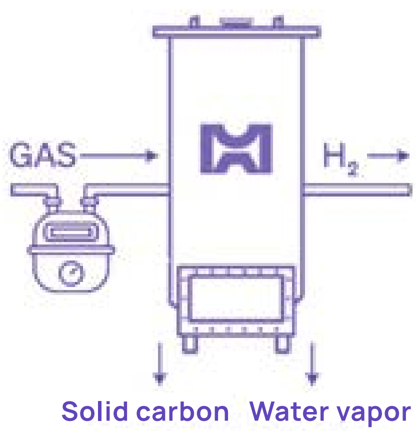



**FIGURE 28: Modern hydrogen concurrent combustion pyrolysis technology schematic**[61]



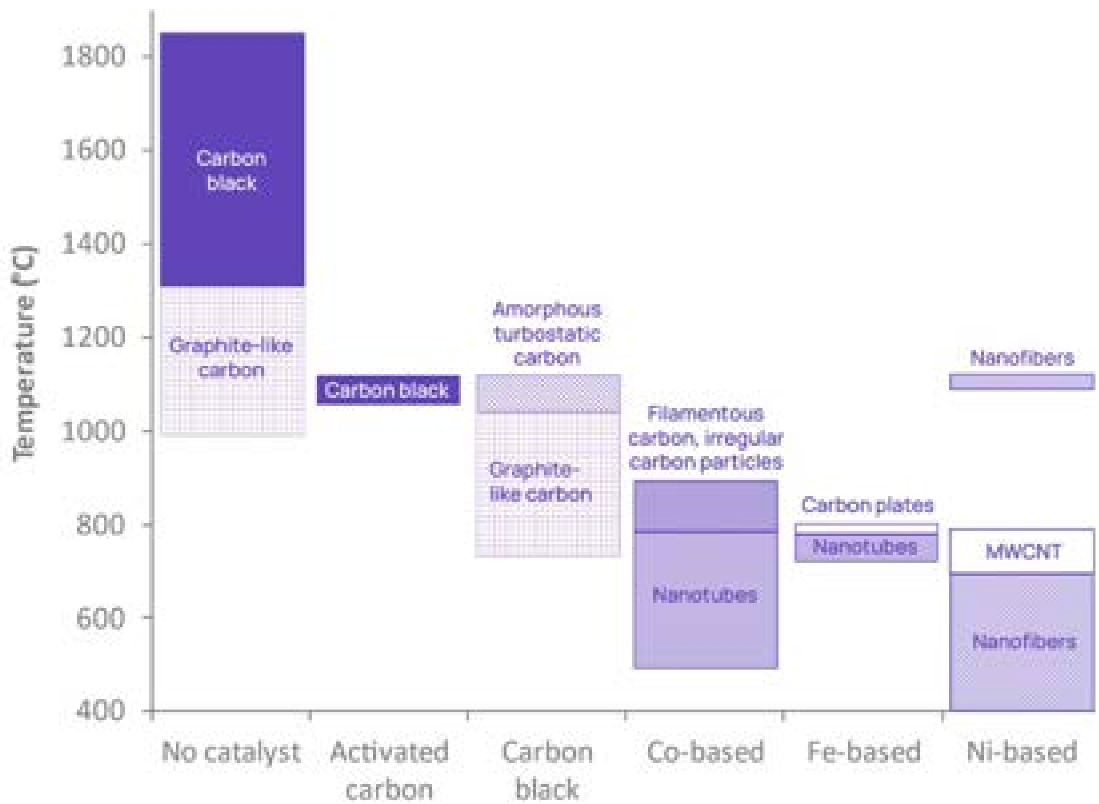

U.S.-based Modern Hydrogen uses a concurrent combustion pyrolysis process, relying only on heat from combustion to initiate thermal pyrolysis, without electrical heating, water, or catalyst.[61] The process combusts a portion of its produced hydrogen to generate heat, resulting in the splitting of methane. This process is shown in **Figure 28**. The company has been actively working with utilities and industrial operators to decarbonize heat and steam. Modern Hydrogen also markets its co-produced solid carbon as an enhancement to concrete and asphalt. Modern Hydrogen has several active projects in five U.S. states and one Canadian province utilizing Modern Asphalt, an asphalt binder derived from the company's carbon co-product.[62]

Other pyrolysis variations that are currently under development include: flash detonation of methane to split the molecule; use of non-metallic catalysts; use of bimetallic catalysts or bimetallic molten metals; non-thermal plasma, and other turbo-static processes.

## Methane pyrolysis co-product — solid carbon

The reactor design and process temperatures of a pyrolysis reaction can influence the type and characteristics of the solid carbon that is produced. The carbon material typically formed based on the type of pyrolysis reaction and catalyst used is summarized in **Figure 29**.[63] A significant amount of research is currently being undertaken by pyrolysis technology companies to create carbon streams of specific allotrope composition. Carbon black is formed at higher temperature reactions, graphite can form with carbon-based catalysts, and carbon nanotubes or fibres are typically formed from metal-based catalysts.

**FIGURE 29: Deposition of carbon allotrope as a function of temperature and catalyst material**[63]




Management of solid carbon is one of the biggest issues for pyrolysis reactions, with three tonnes of solid carbon produced for each tonne of hydrogen. For catalytic processes, carbon co-products can agglomerate around the catalyst, reducing its exposed surface area and decreasing its effectiveness, requiring the removal of spent catalyst and addition of new catalyst into the reactor. Another issue that can occur is coking, where carbon is deposited on heated elements of the reactors; this can reduce the heating efficiency, disrupt the reactor flow, and eventually lead to complete process shut down. Therefore, an important aspect of any reactor design is the prevention of carbon build-up in the reactor and the ability to remove and add catalysts for continuous process flow.

Removal of the carbon embedded catalyst and separation of the solid carbon can become an expensive and technically onerous process, and a major challenge for pyrolysis technology scale-up. Some processes regenerate catalysts using combustion, which can produce additional emissions. Other processes use an acid wash to separate some portion of the catalyst from the carbon stream and then recover the catalyst from the acid wash stream through precipitation. To overcome the cost of regeneration, lower cost sacrificial catalysts can be utilized and if possible, left within the final carbon co-product should the carbon end user permit it. Depending on the carbon structure and characteristics of the required carbon allotrope formed, trace amounts of metal within the carbon can be beneficial to the end user, which can alleviate the issue of catalyst removal.

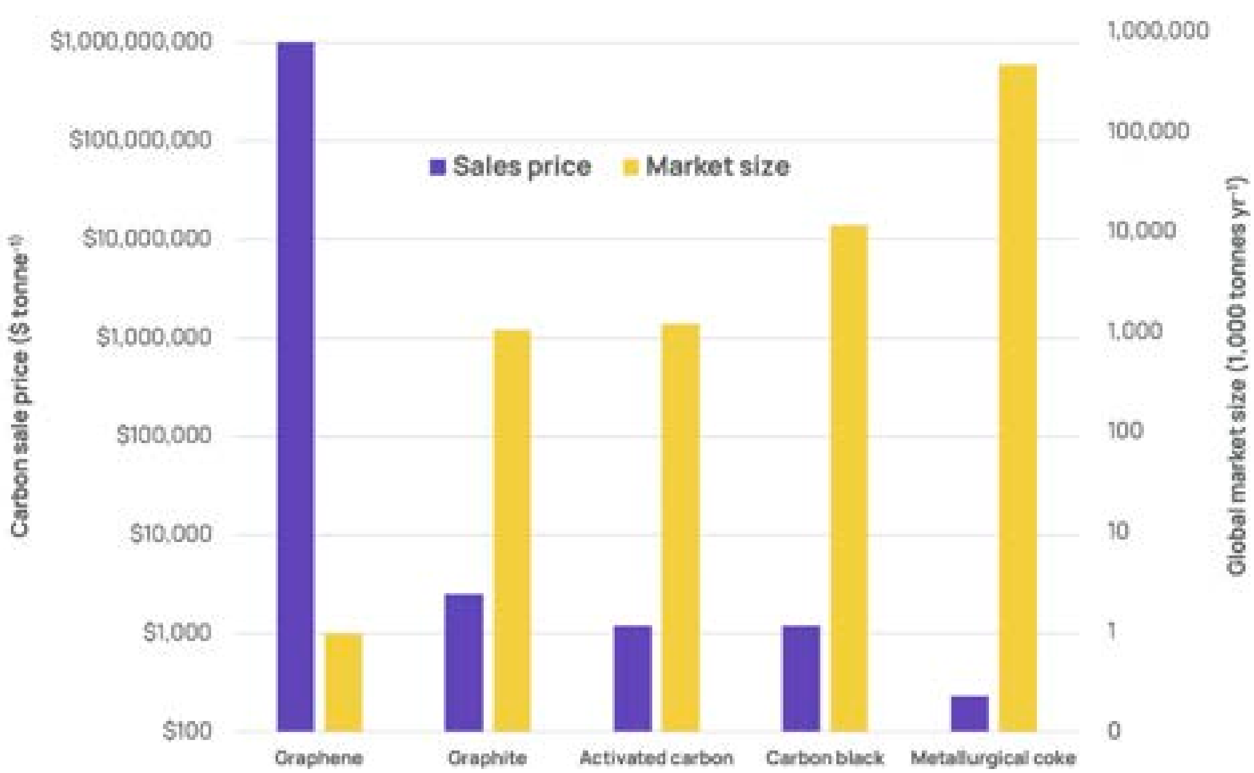
A variation in reactor design also utilizes molten metals and salts as a means to continuously remove carbon. However, this process can also lead to metal contamination of the carbon product, requiring further processing of the carbon product for ultimate use.

While formation and removal of solid carbon can be an issue for cost-effective pyrolysis, the optimization of the carbon stream and its further processing can create additional value for project developers and produce two low carbon product streams. The most common allotropes of carbon are shown in **Figure 30**, of which the most notable forms from pyrolysis are carbon black, graphite, carbon nanotubes, and carbon fibres. Carbon black is a micro-crystalline carbon structure, which forms a fine black powder in its purest form. It has the most established market, with uses in tires, pigments, UV stabilizers, or as a conductive or insulating agent in rubbers, plastics, and coating applications.[64] Graphite is a crystalline carbon consisting of hexagonal rings that is typically deposited in thin parallel sheets, and it can be further processed into graphene. Carbon nanotubes have a similar deposition to graphite, but with the edges of each layer terminating in a tube. Carbon fibers are crystalline carbon filaments that accumulate in long chains.

The highest-value carbon allotrope corresponds to the smallest end-use market, with single-layer graphene currently driving prices more than $100,000/kg but a global market of less than 1,000t per year. **Figure 31** shows the approximate global market size and sales price of various carbon allotropes as of 2017.[65] With increased utilization of graphene and carbon nanotubes in renewable energy, batteries, electronics, pharmaceuticals, and construction, demand is expected to increase rapidly in the next decade. Graphene is anticipated to grow by 19% per annum through 2025, driven by the automotive industry for composite structural components, automotive batteries, tires, anti-braking systems, and other developing applications. There is increasing demand of graphene from the electronics industry due to its remarkable properties for electrical conductivity, transparency, thermal conductivity, and impermeability.[66]

**FIGURE 30: Overview and description of carbon allotropes**


**FIGURE 31: Approximate size and cost per tonne of major carbon markets in 2017**[65]



## Commercializing pyrolysis technologies

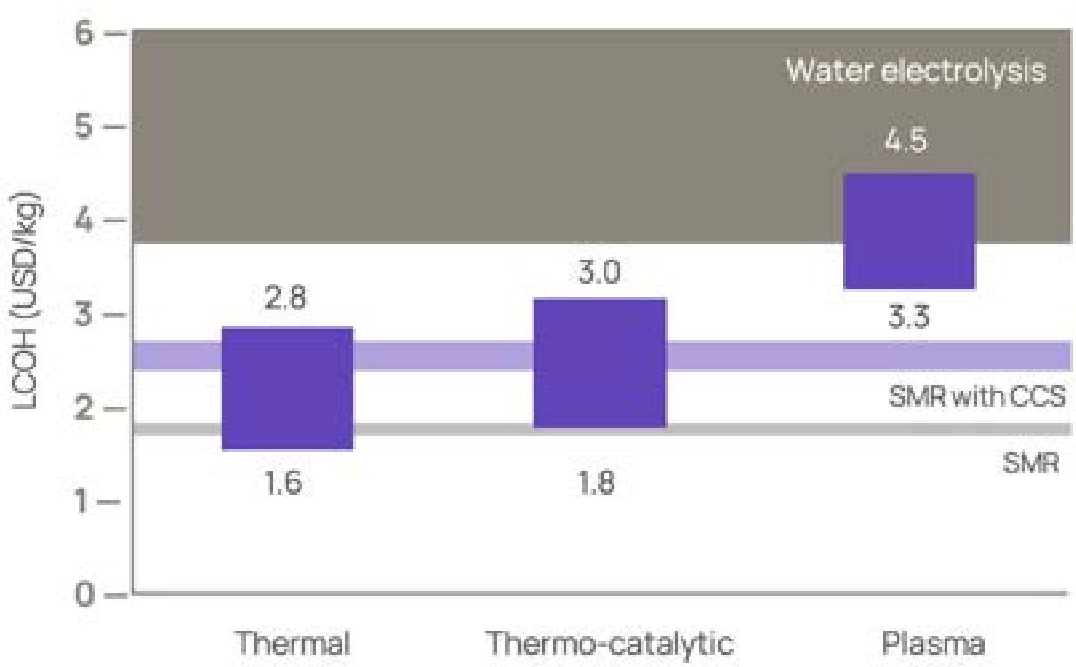
There are more than 50 pyrolysis-focused technology developers globally at various stages of development, with 32 of those specific to methane pyrolysis, identified previously in **Table 3**. Most producers are still at the lab (<100 kg/d) or pilot project scale (<500 kg/d), and require additional testing and adjustments to their processes to scale-up to larger facility sizes (>2 $tH_2$/d). Controlling reaction conditions at larger scales, while maintaining theoretical performance targets, particularly where extremely elevated temperatures are required, can be a major challenge for technology commercialization. Additionally, some pyrolysis pathways require specialized catalysts, or where extreme temperatures are involved, specialized metal alloys to design the reactor. The prices for such materials can be in flux and their supply chains are often limited, which could create additional barriers to technology scale-up and risks for cost overruns.

One of the main challenges of scale-up for pyrolysis technologies is moving from batch production to continuous feed, whereby solid carbon can be removed from the reactor without shutting down the process. Another issue is the management of solid carbon by finding a direct end-use market or further processing co-products for a specific market. Many technology developers recognize that monetizing the carbon product stream will have a significant impact on the financial returns of pyrolysis projects.

The next major challenge is sourcing funding and performing demonstrations to prove out pyrolysis technologies. Designing the first reactor to scale a technology by up to ten times can be experimental, with minimal performance guarantees. Therefore, well-funded pyrolysis developers, with well-capitalized and risk-tolerant funding and demonstration partners, will be better positioned to quickly advance their technologies in a competitively evolving landscape. A prime example of this is Monolith, which has been able to advance the commercialization of its technology by securing $300M USD in equity funding and a $1B USD loan guarantee from the U.S. DOE.[67]

Ultimately, the adoption of methane pyrolysis technologies will depend on the competitiveness of its LCOH with other hydrogen production pathways, as well as incumbent fuels. While data is currently limited to develop detailed cost models on commercial-scale pyrolysis pathways, some researchers have aimed to provide indicative LCOH values based on different hydrogen production pathways. One such summary is shown in **Figure 32**, which assumes no value for carbon co-product.[37] The analysis breaks down pyrolysis into three main technology subtypes and contrasts the LCOH range for each against forecasts for reforming with CCUS and electrolysis. The results show that the LCOH for pyrolysis can be comparable with reforming, though these values could be even lower if value for the carbon co-product is realized. **Section 5** of this report develops B.C. specific scenarios to calculate and validate LCOH values.

**FIGURE 32: Third party indicative levelized cost of hydrogen production by pyrolysis technology type and comparison with other hydrogen production pathways**[37]



# 4. B.C. energy, infrastructure, and environment

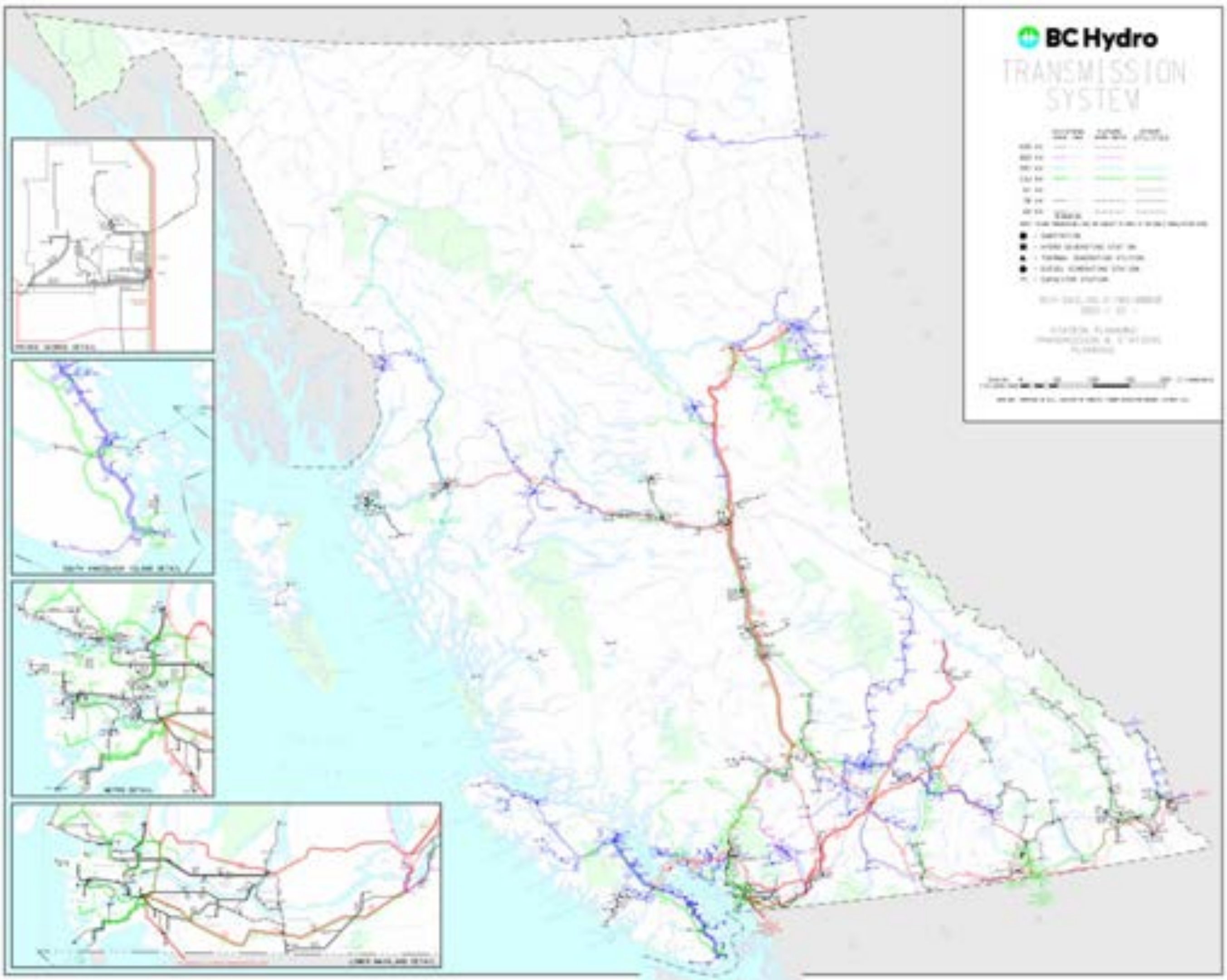
While many of the incumbent hydrogen technologies proposed in Section 2 have achieved high TRL levels and are technically viable, their commercial deployment is often limited by the availability of natural resources or energy infrastructure. Large-scale electrolysis, for example, would add additional electrical demands on an already constrained electricity grid, which is expected to see increased demands of more than 15% by 2030 through the electrification of vehicles and residential heat.[68] Centralized, large-scale hydrogen production from natural gas reforming and carbon capture will be limited by the availability of $CO_2$ sequestration pore space, which is currently only probable in the Northeast of the province. Pyrolysis on the other hand, benefits from the ability to produce hydrogen anywhere in the province that is connected to the natural gas grid.

## Electrical generation and transmission

B.C. is the fourth largest producer of electricity in Canada, with a total generating capacity of 19.1 GW as of 2022. This includes 12.2 GW operated by BC Hydro,[69] 1.5 GW operated by FortisBC,[70] and 5.4 GW operated by independent power producers (IPPs).[71] In 2022, total generation in the province was 76 TWh.[72] Of the province's generation, 86% is produced from hydroelectric sources, most of which are located on the Columbia River in Southeastern B.C. and the Peace River in the Northeast. Site C Dam is a new 1,100 MW hydroelectric facility on the Peace River that is planned for completion in 2025. Other sources of electricity in the province include biomass and geothermal, which accounts for 5% of B.C.'s generation capacity. Wind accounts for 4% of generation, solar accounts for 2%, and the remaining is natural gas.[73] Diesel electricity generation represents an exceedingly small portion of generation capacity and is limited to off-grid communities.[74]

BC Hydro is the main electricity producer and distributor in the province, operating more than 80,000 km of transmission and distribution lines and 292 substations, with connections to other utilities in Alberta, Washington, Oregon, and California. **Figure 33** shows the map of the BC Hydro bulk and regional transmission system, as of June 2022.[75] Additionally, IPPs account for 5.4 GW of additional generation capacity that BC Hydro purchases and manages as the BC Power Authority.

**FIGURE 33:** **BC Hydro transmission system**[75]




FortisBC is a service provider for both electrical and natural gas service. Their provided electrical service is focused in the southern part of B.C., with 7,300 km of transmission and distribution lines and 65 substations with 225 MW of operated hydroelectric generation and 1.3 GW of third party generation capacity.[70 76] **Figure 34** shows FortisBC's service area for electrical distribution.[77]

Transmission limitations are a major concern in regards to increasing future transition to electrical utilization. In addition to vast parts of the interior and northern areas of B.C. not being connected to any electricity infrastructure, high density and highly industrialized regions like Prince George, North Coast (Prince Rupert), East Kootenays, the Lower Mainland, and Vancouver Island have constrained transmission systems and will require transmission line upgrades.

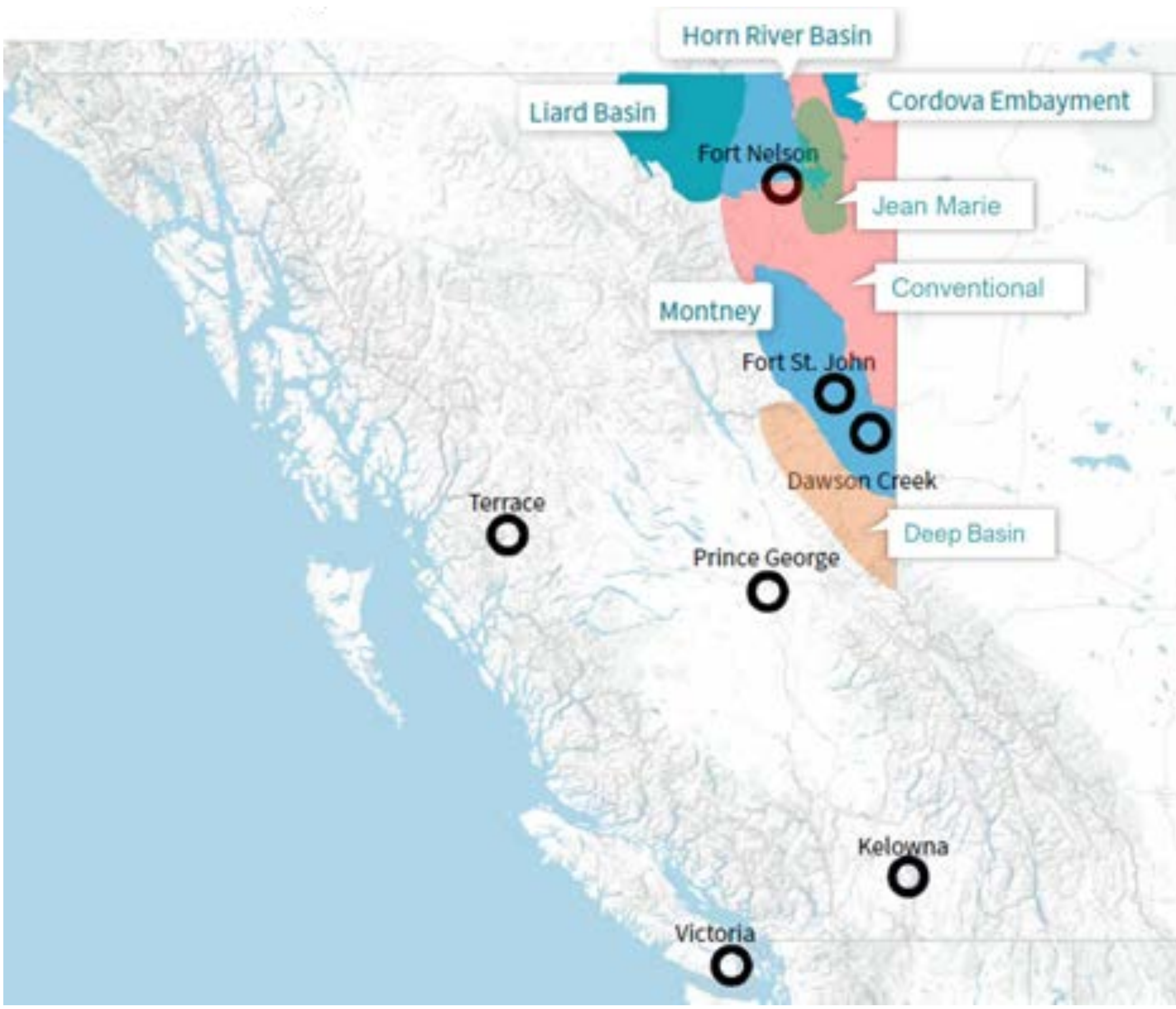
In its 2023 updates, BC Hydro reiterated a goal to advance the Prince George to Terrace Capacitor Project, as well as make updates to the second Northwest and Vancouver Island transmission lines, which could take on average 5-10 years to build.[14] In June 2023, BC Hydro announced a call for new sources of renewable electricity in the province, after forecasting shortfalls of up to 3,000 GWh by 2030.[78] Wide deployment of electrolyzers in B.C. could serve to further exacerbate limited electricity supplies, as well as constrain transmission and distribution infrastructure.


**Figure 34:** FortisBC natural gas and electrical service area[77]

## Natural gas resource and distribution

B.C. is a major producer and exporter of natural gas, with an annual production in 2022 of 2,834 PJ (2.5 trillion cubic feet [TCF]), the equivalent of 787.2 TWh, of which only 10% was used for domestic consumption.[79] Natural gas in the province is produced in the Northeast and is currently dominated by the unconventional development of the Montney reservoir **(Figure 35)**. At the end of 2022 it is estimated that British Columbia holds 87.8 TCF of remaining recoverable natural gas reserves, 93% attributable to the Montney reservoir. Additionally, B.C. is estimated to hold an incremental 532 TCF of marketable resources.[80]

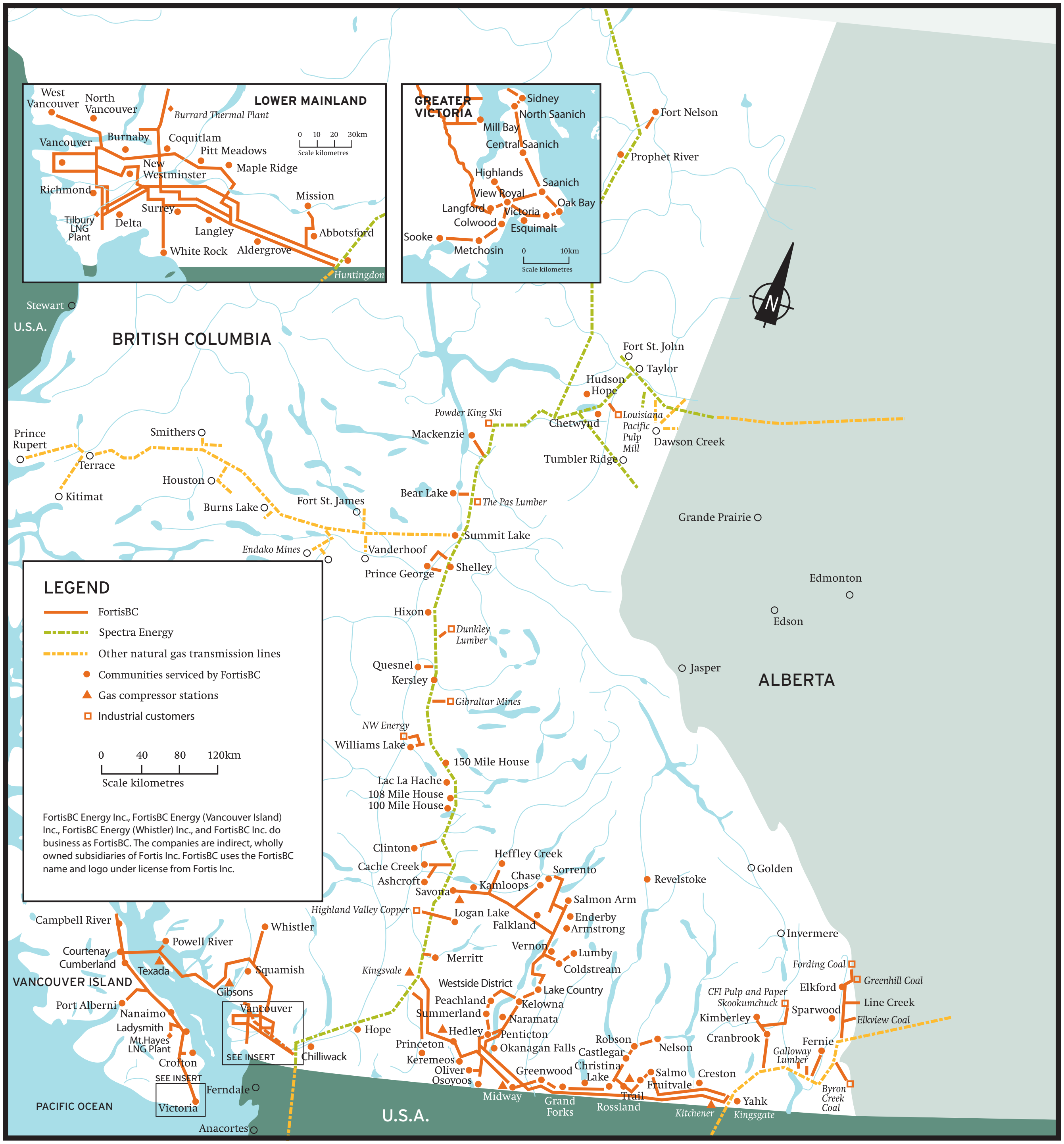
**FIGURE 35: Major natural gas production areas in Northeast British Columbia**[80]



The Montney Formation is one of the largest natural gas resources in the world and it extends from the northeast of the province into Alberta; the Montney is currently the primary source of B.C.'s gas production. The B.C. portion is estimated to contain 369 TCF of recoverable gas, of which less than 4.5% has been recovered to date. Other significant gas resources are located in the Horn River and Liard Basins, with 248 TCF of recoverable resource, but currently representing only 1.5% of production. At current annual production volumes, B.C.'s natural gas assets represent nearly 250 years of energy resource.

**Figure 36** shows B.C.'s natural gas pipeline infrastructure, including gas transmission lines (green and yellow) and distribution lines (orange).[81] The Alliance Pipeline and the TC Energy North Montney Mainline provide natural gas export capability through Alberta and into markets in central U.S. and eastern Canada. Enbridge (Spectra Energy) provides current internal B.C. provincial natural gas transmission service. The T-South pipeline with a capacity of 2.1 billion cubic feet per day (BCF/d) of natural gas transmission between northeast B.C. and the U.S. border (Huntington/Sumas). This system is currently undergoing a $3.6 billion dollar expansion that will increase capacity to 2.4 BCF/d. Enbridge also operates the T-North pipeline system with a capacity of 1.5 BCF/d, which feeds into T-South as well as other export lines in northeast B.C.[82] Pacific Northern Gas provides transmission services to Prince Rupert, distribution services to communities in northeastern B.C. (Tumbler Ridge, Dawson Creek, and Fort St. John), and transmission from Prince George to Prince Rupert. This transmission line is fed from T-South and has a capacity of 110 million cubic feet per day (MMCF/d).[83] FortisBC operates distribution lines throughout southern B.C. as well as servicing communities along T-South and northeast B.C., supplying approximately 650 MMCF/d of natural gas to both residential and industrial customers.[77] Hydrogen production from pyrolysis could be positioned along the distribution grid system, which would create a hub and spoke distribution model, with much of the province being serviced within 150 to 200 km of the grid.

**FIGURE 36: B.C. natural gas pipeline system**[81]

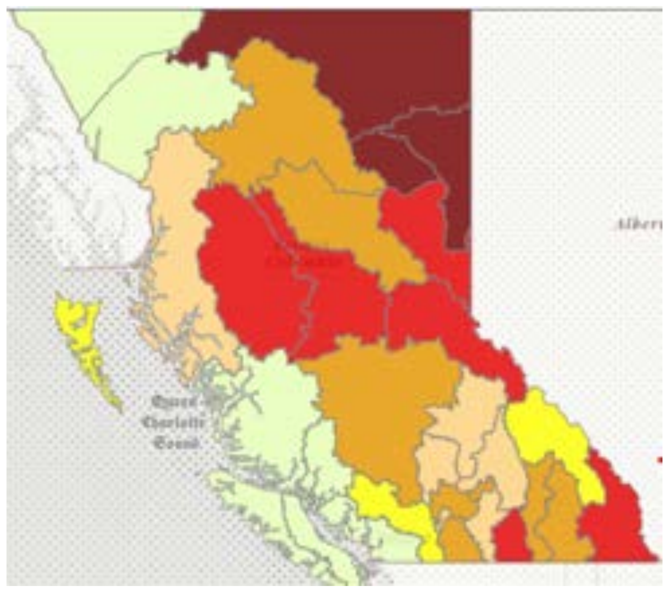


## Water availability

Freshwater is a key component of several hydrogen production technologies, including water electrolysis and methane reforming. There is abundant water supply along the coasts, and water can also be acquired through desalination, but the Northeast, Kootenay, and interior B.C. are all experiencing severe drought levels at unprecedented conditions.[84] **Figure 37** shows a map of the six levels of drought classifications in B.C., where the lightest colour represents sufficient water to meet socioeconomic and ecosystem needs, and the darkest colour represents adverse impacts in which conservation and local water restrictions apply.

Though not as widely monitored as surface water, groundwater levels have shown rates of decline in 15% of the 121 examined observation wells (65 in the south and west coast regions) throughout the province.[85] As groundwater levels are sensitive to precipitation and aquifer storage recharge rate, effects of drought and increased human withdrawal rates are likely to have negative impacts on groundwater level trends and could indicate adverse impacts for industrial use.

**FIGURE 37: B.C. Drought Information Portal (DIP) drought levels map[84]**



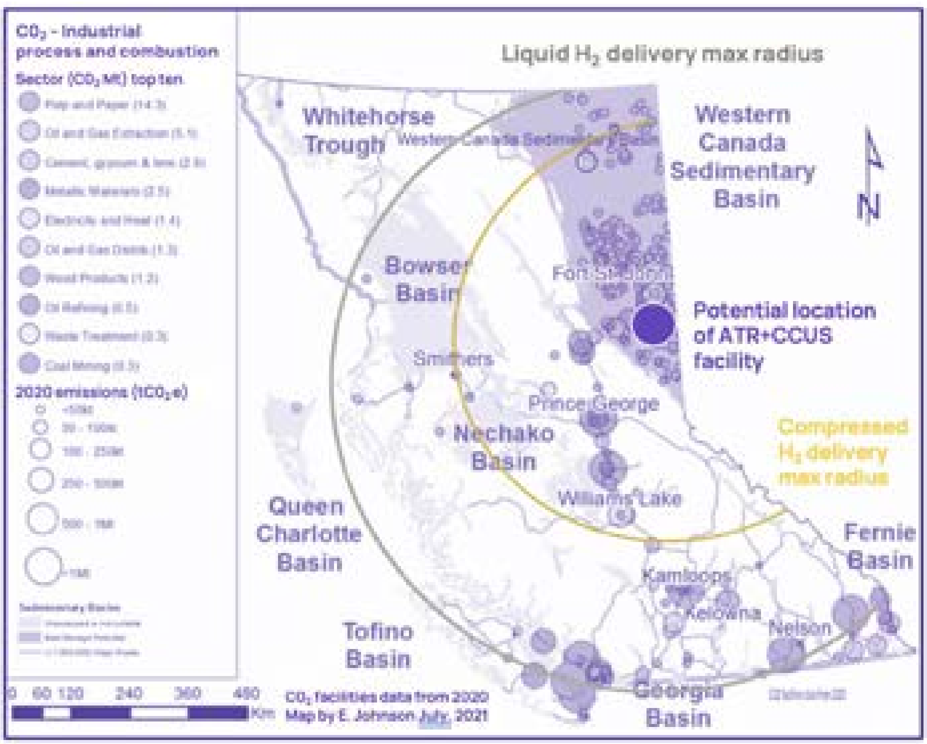
As shown, the greatest levels of water scarcity are in the Northeast. The northeast is also the area where there is CCUS potential, allowing for large centralized natural gas reforming into hydrogen. However, this process involves high water consumption. The middle of the province and the Kootenays are also water scarce, which could limit options for the deployment of water electrolysis projects. Methane pyrolysis does not require water as part of its hydrogen generation process and thus would be an attractive technology that is independent of water availability.

## $CO_2$ sequestration

Carbon capture and storage (CCUS) has been identified as a priority emission reduction and mitigation strategy by both federal and provincial governments in Canada. To evaluate the potential of large-scale emission sequestration and hydrogen production projects in B.C., a CICE study titled "Northeast B.C. Geological Carbon Capture and Storage Atlas" was published in January 2023 to identify and quantify the best $CO_2$ storage potential locations in the province.[86] The Atlas focused on two types of permanent geological storage formations: saline aquifers composed of porous sedimentary rocks hosting salt water and depleted or nearly depleted subsurface reservoirs that previously produced natural gas.

The study identified 12 formations with a total of 4.2 Gt of $CO_2$ storage potential. However, the Northeast is the only region with the most advanced sequestration reservoirs, with specific aquifers identified in Fort St. John and south of Fort Nelson. As shown in **Figure 38**, this is also the region with the greatest concentration of oil and gas emissions, which suggests early CCUS projects are likely to emerge to decarbonize the energy sector.[87]

**FIGURE 38: Locations of known $CO_2$ sequestration basins and their proximity to major $CO_2$ sources from industrial processes and combustion**[87]




### Characterizing B.C. CCUS Basins:

**Northeast (Western Canada Sedimentary Basin):** Probable and suitable reservoirs — extends to AB.

**Southwest (Georgia Basin):** Thick, deep, sandstone aquifers, but lack geologic seals. Research needed to prove sequestration potential.

**Central Interior (Nechako Basin):** Assessment shows significant basin size with overlain basalts, but more research needed to determine favourable characteristics.

**West Coast Offshore Basins (Tofino):** Drilling studies completed in 1970s, which identified potentially suitable reservoirs, but more characterization needed.

Based on the current state of the industry, an ideal location for large-scale hydrogen production with CCUS in B.C. is near the Fort Nelson or Fort St. John areas, which would require hydrogen distribution at distances of up to 1,300 km to reach major demand centres in the interior. **Figure 38** illustrates the potential limits of these hydrogen deliveries across the province from the point of production.

## Infrastructure limitations

Many of the regions in B.C. with clusters of industrial activity also have high concentrations of residential and commercial activity, in which space could be a major constraint for building out pyrolysis production facilities. While many pyrolysis producers endeavor to build compact modular reactors, conversations with several technology providers suggest an average footprint of 4,000 $m^3$ for a small-scale facility. The large space requirements would include storage, processing, loading, and hauling away of solid carbon co-products. A similar sized facility for electrolysis is the equivalent of two-40ft container units.[88] However, additional space may be required for dedicated renewable energy generation via wind or solar, or transmission substation connections, along with water treatment. **Figure 39** shows the comparative space required for similar sized electrolysis and pyrolysis facilities. The larger space needed for pyrolysis could be a hindrance for finding an appropriate site, and subsequently contribute to higher land acquisition costs.

**FIGURE 39: Comparison of space required for a typical small-scale pyrolysis vs. electrolysis facility**

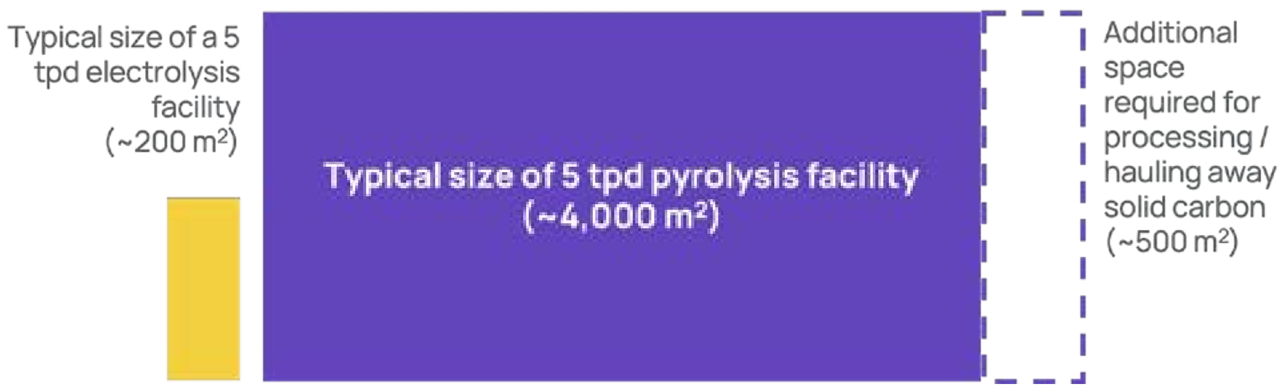
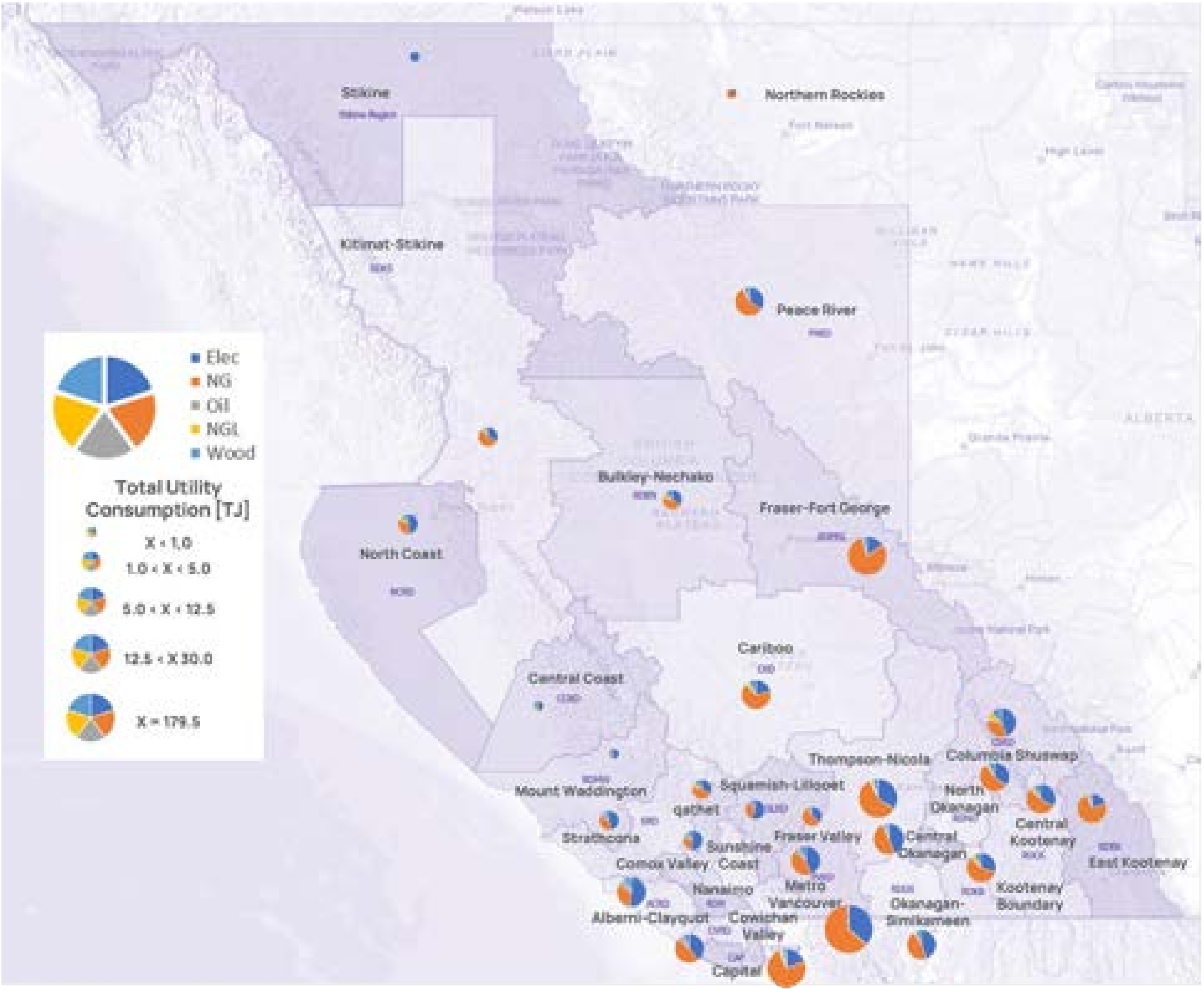



**Figure 40** shows the quantity of energy consumption across B.C. by resource type, with the size of the section in the pie chart representing the quantity of energy consumed. Significant consumption is seen in the southern part of the province and the Lower Mainland. When compared to the infrastructure maps, the high proportion of electrical consumption follows the main transmission lines. Many of the transmission lines delivering power to areas such as the North Coast, Kootenays, and Vancouver Island are constrained and will require upgrades to meet demands post 2030. These limitations do not appear to be present in regards to the natural gas distribution system. However, the main natural gas transmission line (T-South operated by Enbridge) is fully contracted and is being upgraded to increase line capacity. Though this could pose near-term challenges for securing large natural gas offtakes, the bulk of B.C.'s gas is currently sold to the United States, which creates flexibility to shift volumes into B.C. if incremental volumes are required in the future.

**FIGURE 40:** **B.C. residential and commercial utility consumption by region**




## Permitting and regulatory

Hydrogen projects would be subject to the same provincial, federal, and municipal regulatory standards as other large-scale capital projects, with requirements based on the layout and design of project proponents, process inputs, production methods, and process outputs. In November 2022, the B.C. Government created the BC Energy Regulator (BCER), establishing an authority to regulate the manufacturing of hydrogen, ammonia, methanol, and $CO_2$ transportation, in addition to oil and gas.[89]

However, the British Columbia Environmental Assessment Act (BCEAA) and the federal Impact Assessment Act (IAA) would precede all other permitting requirements. The BCEAA has hydrogen-specific thresholds under the organic and inorganic chemical industry group, requiring any project with more than 100,000 tpy (~270 $tH_2$/d) production to automatically submit an environmental assessment (EA) **(Table 5)**. Other project components including on-site electricity generation, marine terminal construction, or shoreline modification also trigger an EA.[90] The BCEAA has established a seven-step process that includes early engagement, EA readiness, process planning, application development and review, effects assessment, recommendation, and decision. The IAA governs the preliminary approval process for large capital projects at the federal level and does not currently specify hydrogen production thresholds, but may require an EA depending on other project attributes.

The BCEAA also incorporates consensus-seeking with Indigenous groups as part of its EA process, which includes consultation and negotiation requirements from planning to project implementation. Similar requirements apply for federal EAs, with a focus on engagement early in the project development lifecycle and creating opportunities for Indigenous peoples to participate in the assessment process.

Depending on the design and configuration of projects, regulatory application approvals related to hydrogen at the provincial level can be categorized into design and site location-specific requirements, which are summarized below. These would be in addition to any zoning and local by-law requirements at municipal levels.

**TABLE 5: High-level summaries of B.C. design and location-specific permitting requirements**

| Design-based requirements | | Location-specific requirements | |
|---|---|---|---|
| **Water Sustainability Act** | Water licences | **Water Sustainability Act** | Notification and approval for changes in and about a stream |
| **Environmental Management Act** | Waste discharge approvals for air emissions and effluent discharge permits | **Environmental Management Act** | Release notices for contaminated sites |
| **Utilities Commission Act** | Approvals for public utilities | **Utilities Commission Act** | Permits related to fish and wildlife |
| **Oil and Gas Activities Act** | Permits for construction and operation of facilities and pipelines | **Oil and Gas Activities Act** | Investigation and alteration permit |
| **BC Hydro** | Connection standards and approvals | **BC Hydro** | Licenses of occupation and approvals for non-farm use of Agriculture Land Reserve |
| **Transportation of Dangerous Goods Act** | Transport requirements | **Transportation of Dangerous Goods Act** | Licenses/permits to cut |

The B.C. Hydrogen Regulatory Mapping Study provides a comprehensive review of various hydrogen production pathways according to the BCEAA thresholds under the Reviewable Projects Regulation. It defines proxy projects, including hydrogen production from pyrolysis, and their applicability to different sections of the IAA and BCEAA, in addition to outlining the full impact assessment process required to develop hydrogen projects in B.C. The study also provides a comprehensive review of the provincial, federal, and municipal permitting authorizations and approvals needed for different project types.

In 2023, the British Columbia Utilities Commission (BCUC) established an inquiry to explore the development of hydrogen energy services in B.C. and to determine the commission's scope for effective and efficient regulation of services.[91] The final report suggested that BCUC would not regulate hydrogen in certain situations, provided the entity providing the service is not a public utility.

Those situations where BCUC would not regulate hydrogen are:

» **Provision of hydrogen as a transportation fuel.**

» **The production of hydrogen as a fuel for electricity production or as a fuel for transportation or heating.**

» **The provision of hydrogen delivery by truck.**

# 5. Techno-economic scenario analysis

The techno-economic analysis of the three technologies discussed in this report, electrolysis, reforming, and pyrolysis compares their LCOH at various scales of production. Each technology has its own set of high-level advantages and disadvantages, which are summarized in **Table 6**.[92] While water electrolysis has been commercially proven at small scales and projects are relatively easy to implement with simple balance of plant connections, the costs of $H_2$ production can be very high due to high feedstock and equipment costs and long equipment lead times.

Conversely, reforming with CCUS generally has a very low LCOH due to large economies of scale, and low relative CAPEX per kg of hydrogen. However, facilities are large, complex, and limited to locations with proven carbon sequestration potential. Pyrolysis technologies, while still under development, have the potential of bridging the benefit gaps of the other two technology pathways by producing hydrogen at a distributed scale at lower costs than electrolysis and with lower GHG emissions than reforming.

**TABLE 6: Qualitative assessment of different hydrogen production technologies**

| Characteristic | Water electrolysis | Methane pyrolysis | Reforming with ccus |
|---|---|---|---|
| Balance of plant and space requirements | Simple, modular solution at small-scale | Complex, fit for purpose, large space requirements | Complex, large-scale |
| Scalability and commercial readiness | Medium–proven at scales of up to 300mw (~60 $tH_2$ /d) | Some technologies are commercially proven (monolith), others still under development | Commercially viable and proven at large scales (>300 $tH_2$ /d) |
| Operating temperature | Low | High | High |
| System efficiencies and energy conversion | Medium | Low | Medium |
| $H_2$ purity | Fuel cell grade | Medium impurities | Medium impurities |
| Emissions | Low if using a low-ci grid or renewables | Potentially low since carbon produced in solid form; need to consider life cycle analysis (LCA) CI | Medium (based on ccus rates and leakage) |
| By-products | Oxygen (easy to dispose, low potential to monetize) | Solid carbon (difficult to dispose and/or monetize) | Gaseous carbon (difficult to dispose or monetize) |
| Feedstock availability and costs | Renewable power cheap (behind-metre) but low/ variable capacity | Renewable power cheap and natural gas widely available, subject to price uncertainty | Natural gas widely available but carbon sequestration reservoirs undeveloped |
| Levelized capex | High | Medium | Low |
| Overall levelized cost of $H_2$ | High | Medium | Low |

The techno-economic study evaluates the delivered cost of hydrogen at the point of demand for the three technologies identified above, based on the three size scenarios of production that are intended to represent applicable scales of deployment in B.C. The results are summarized in **Figure 41**. The small and mid size cases, Scenarios 1 and 2, are assumed to be at remote sites with co-located or near-located demand. The large-scale case, Scenario 3, is assumed to be at an industrialized site that utilizes the full volume of hydrogen production. In all Scenarios, no value was attributed to the solid carbon generated by pyrolysis but some sensitivity on potential carbon co-product revenues is discussed in **Section 6**. It is also assumed that all of the evaluated pathways would fulfill the standards for low carbon hydrogen (below 4.37 kg $CO_2$e/kg $H_2$ (36.4 g $CO_2$e/MJ $H_2$). The carbon intensity of production is briefly discussed in **Section 6**.

Scenarios 1 and 2 assume that hydrogen could be produced through any of the technologies identified above, contingent on connectivity to a source of water, electricity, natural gas, and connection to transport corridors. It is assumed that electrolysis and pyrolysis would be constructed at site, whereas a reforming plant would be constructed in Northeast B.C., based on the location of CCUS infrastructure, with hydrogen distributed to the point of demand. Under Scenario 2, electrolysis could be a viable pathway, but a 50 tpd hydrogen facility would require a minimum electrical connection of more than 110 MW, or greater than 350 MW if directly connected to solar or wind generation without storage, and operated based on the renewable electricity capacity factors. The electrical grid in B.C. will need to evolve to overcome significant grid constraints from increased electrification of transport and heating to be able to accommodate large electrical connections for hydrogen generation over the long-term.

The third scenario represents large-scale 300 tpd hydrogen requirements for petrochemical operations or hydrogen-derived fuel production such as ammonia or methanol. Scenario 3 is likely to only occur through pipeline connection of a centralized production facility, or by co-locating large-scale production with demand facilities. Under this scenario, it is assumed that reforming with CCUS technology would not be located at the demand point anywhere outside of Northeast B.C. and would require a pipeline connection. For methane pyrolysis, it is assumed production could be located anywhere at the point of demand, while recognizing that high volumes of carbon co-product at this scale could pose logistical challenges.

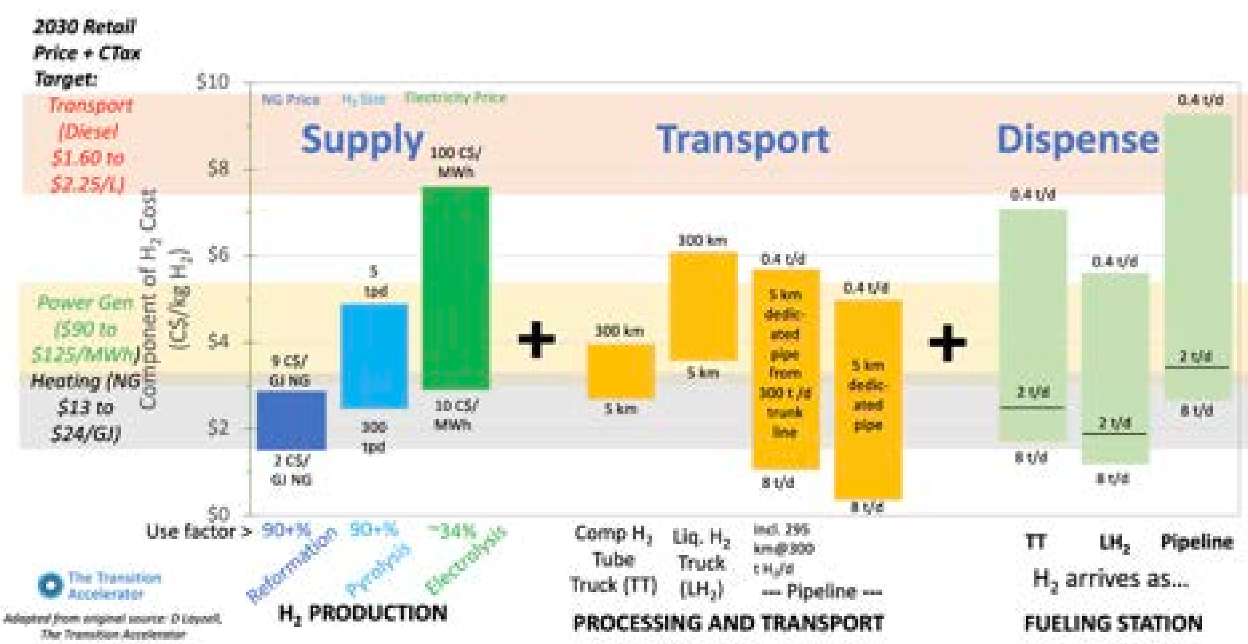
The scale-up of pyrolysis is also a major challenge due to the current level of technology development, representing additional uncertainty for a pyrolysis pathway under Scenario 3. However, based on interviews with various technology developers, who provided the technical and economic data for reactor sizes at 300 t$H_2$/d, a pyrolysis pathway was modelled at this scale. Electrolysis was not considered for this scenario due to its extensive power requirements, of up to 2.5 GW based on the supply of variable solar and wind power. It was assumed that the current B.C. power grid would be unlikely to be able to provide this level of electricity without substantial expansion and modification.

**FIGURE 41:** **Scenarios of hydrogen production and use cases for decarbonization in B.C.**

| Scenario | S1: Small-scale | S2: Industrial decarbonization | S3: Large-scale |
|---|---|---|---|
| $H_2$ production | Up to 5 tpd | Up to 50 tpd | Up to 300 tpd |
| Typical applications | $H_2$ refueling or back-up power | Heating load for industrial facility or peaker plant | Petrochemical, refining or fuel production |
| $H_2$ production or delivery method | Trucked centralized reformation or onsite pyrolysis & electrolysis | Trucked centralized reformation or onsite pyrolysis & electrolysis | Pipelined centralized reformation or onsite pyrolysis |

Hydrogen compression, loading, and transport can add significant costs to the total LCOH, between \$0.2/kg to \$6/kg depending on the transport distances, volumes, and transportation method. **Figure 42** shows the supply, transport, and distribution costs of various hydrogen configurations based on analysis from the Transition Accelerator.[93] This data was used to extrapolate the supply chain costs at the point of demand for the various technologies modelled in this report. The transport cost would only be applicable to large-scale centralized reforming that would need to be compressed and transported, whereas pyrolysis and electrolysis would not incur this expense as they would be constructed at site under the distributed hydrogen model.

**FIGURE 42:** **Refuelling costs for hydrogen vehicles for different components of the supply chain and across supply chain scenarios**



A detailed economic model was developed to calculate the plant gate LCOH for each technology across the three scenarios identified. For each scenario, a unique utilization case was assumed to demonstrate the incremental costs from end-use requirements including purity level, compression, storage, and distribution. For example, in Scenario 1: Small-scale, fuelling into a FCEV requires hydrogen at 99.97% purity and compression up to 520-bar, whereas in Scenario 2: Industrial decarbonization, hydrogen used in a co-generation system needs to be delivered at 50-bar and can be of lower grade purity (<99%).

Since each modelled technology produces hydrogen at various purity and compression levels, additional processing is included to meet the needs of specific end-use cases. Hydrogen storage in underground caverns is currently being evaluated, but is still early in its development and indifferent to production technology, so it was not included in this study.

The variation in assumption criteria between scenarios is also represented in the transportation costs. Tube trailer compressed hydrogen is used in Scenario 1, trucked liquid hydrogen is used in Scenario 2 due to greater distribution volumes and distance, and pipelined hydrogen is used for Scenario 3, due to even greater volumes. The values for these incremental costs are independent of the technology being evaluated and thus, have been gathered from other available sources and referenced accordingly.

**The Appendix** details the specific inputs, variables and calculations that were used in the economic analysis. As indicated earlier in the report, each of the technology pathways utilize different feedstocks and processes which imply different costs, operating conditions, and outputs. The variables would further vary for each individual technology provider within the same category. Thus, to limit the considerable number of potential permutations that could be modelled, a representative technology was chosen and data was aggregated across technology providers. Data sources included interviews with technology developers in conjunction with published information to provide a basis of comparison across hydrogen production pathways.

For electrolysis, the chosen technology was Proton Exchange Membrane (PEM), due to the flexible nature of its operations and ability to ramp up and down based on variable renewable energy inputs. For methane reforming, Auto-Thermal Reforming (ATR) was chosen due to greater cost efficiencies of hydrogen production, and much higher proportion of carbon capture over Steam Methane Reforming (SMR). For pyrolysis, thermal and catalytic technology classes were selected due to their maturity of development.

Although plasma pyrolysis is a major subset of methane pyrolysis, it was not specifically modelled due to significant variances in parameters across plasma technology types. Published data on plasma pyrolysis indicate capital and operating costs that are greater than thermal and catalytic processes, however, interviews with plasma technology developers suggest these costs could be comparable. Therefore, the pyrolysis technology values presented in this report could be viewed as a proxy for other pyrolysis pathways, such as plasma.

## Scenario 1: Small-scale

Scenario 1 represents hydrogen production at scales of up to 5 $tH_2/d$, which could be best suited for hydrogen refuelling stations or for electricity storage and microgrid support. In either case, any hydrogen produced would need to be of high purity for fuel cell use, and stored on-site, typically in compressed tanks at up to 520 bar pressure. **Figure 43** shows the different pathways that are considered under this scenario, in which hydrogen from pyrolysis and electrolysis is produced on-site, and hydrogen from ATR+CCUS is transported from Northeast B.C. at an average distance of 800 km.

**FIGURE 43: Scenario 1 supply chain schematic for 5 tpd hydrogen production for FCEV refuelling or electricity storage**

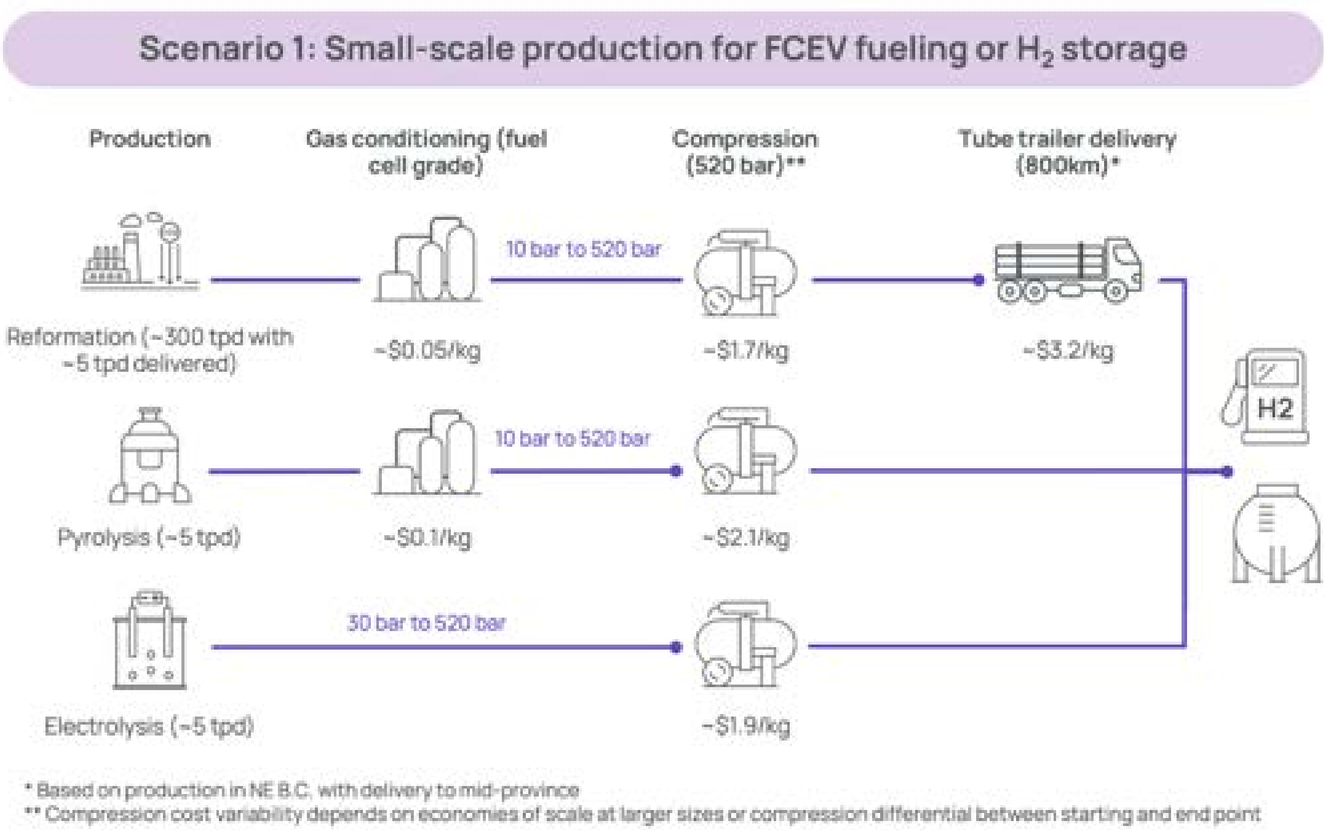


**FIGURE 44: Scenario 1 production gate LCOH (left) and delivered LCOH (right) at 5 $tH_2$/d scale in ($/kg)**

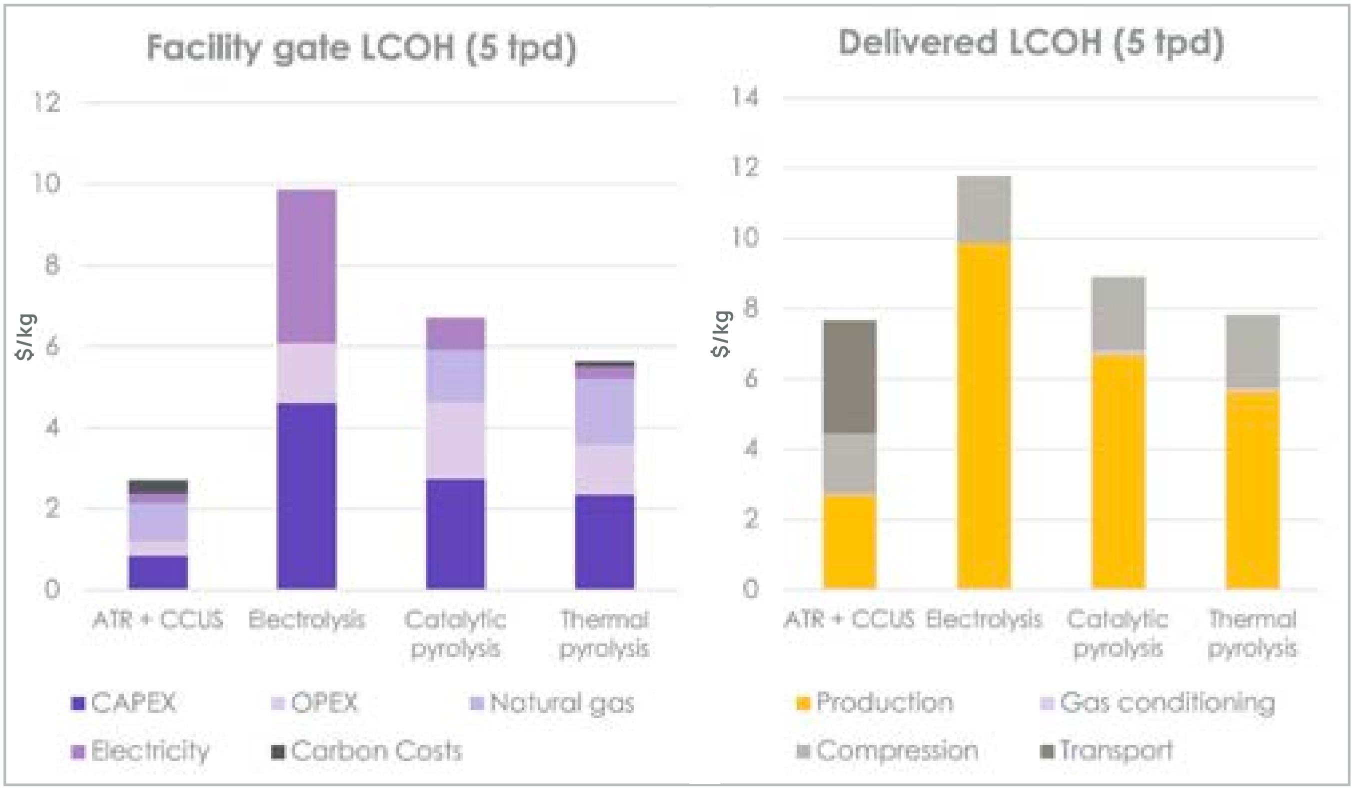



**Figure 44** shows the levelized cost of hydrogen production for each pathway by expense category at the plant gate, and the cumulative estimated delivered cost of hydrogen at the customer level. At the 5 $tH_2$/d scale, electrolysis has the highest levelized cost of production, due to very high CAPEX of electrolyzers and cost of electricity. ATR+CCUS has the lowest plant gate LCOH, as well as the lowest delivered LCOH, despite additional transport-related costs. The transport costs were modelled at 800 km from the point of production, but these could vary depending on the actual distance travelled and associated storage that may be required. Pyrolysis, both thermal and catalytic, has an indicative LCOH at the plant gate that falls between electrolysis and ATR, with catalytic being approximately 15% higher due to higher operating expense attributed to catalyst costs. When the total LCOH delivered is considered, the pyrolysis process generates equivalent values to ATR+CCUS.

## Scenario 2: Industrial decarbonization

Scenario 2 represents hydrogen production at scales of up to 50 $tH_2$/d, which could be best suited for industrial facility heating loads. In this case, hydrogen is expected to be produced via pyrolysis or electrolysis on-site or near-site, with a direct pipeline line to the facility **(Figure 45)**. Depending on the load profile of facility equipment, such as industrial boilers, combined heat and power plants, or large compressor stations, buffer storage may be required, but this was excluded in the modelling as it was viewed to be equivalent for each pathway.

For the ATR+CCUS case, the high volume of hydrogen required would make compressed hydrogen transport unfeasible, so liquid hydrogen deliveries were modelled. Liquid trailers have up to 3-4X the carrying capacity of hydrogen by weight compared to a 500-bar composite tube trailer, making it much more efficient for high volume and long-distance hydrogen transport. Since this scenario assumes hydrogen combustion, a PSA unit is not required, other than in the ATR+CCUS case to support liquefaction.

**FIGURE 45: Scenario 2 supply chain schematic for 50 tpd hydrogen production for industrial facility loads.**

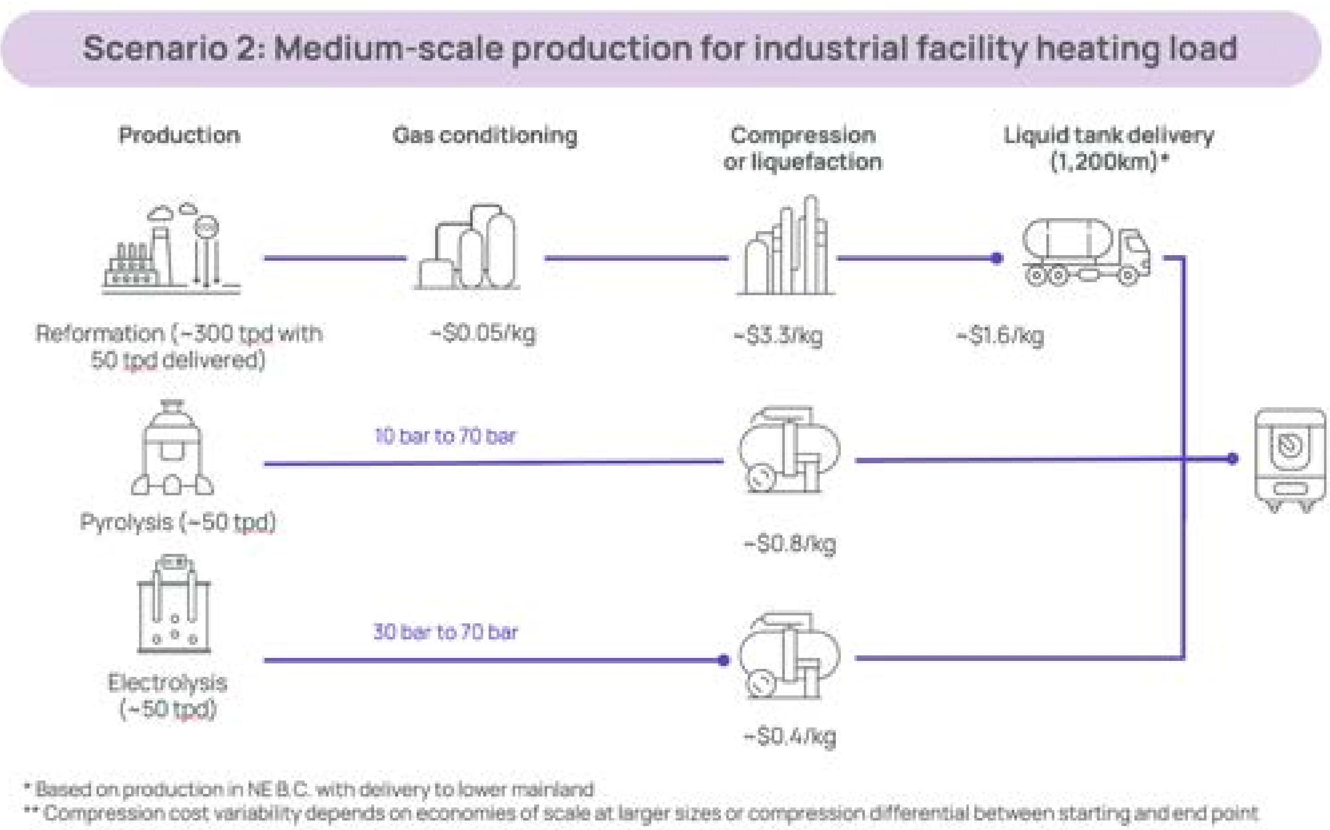
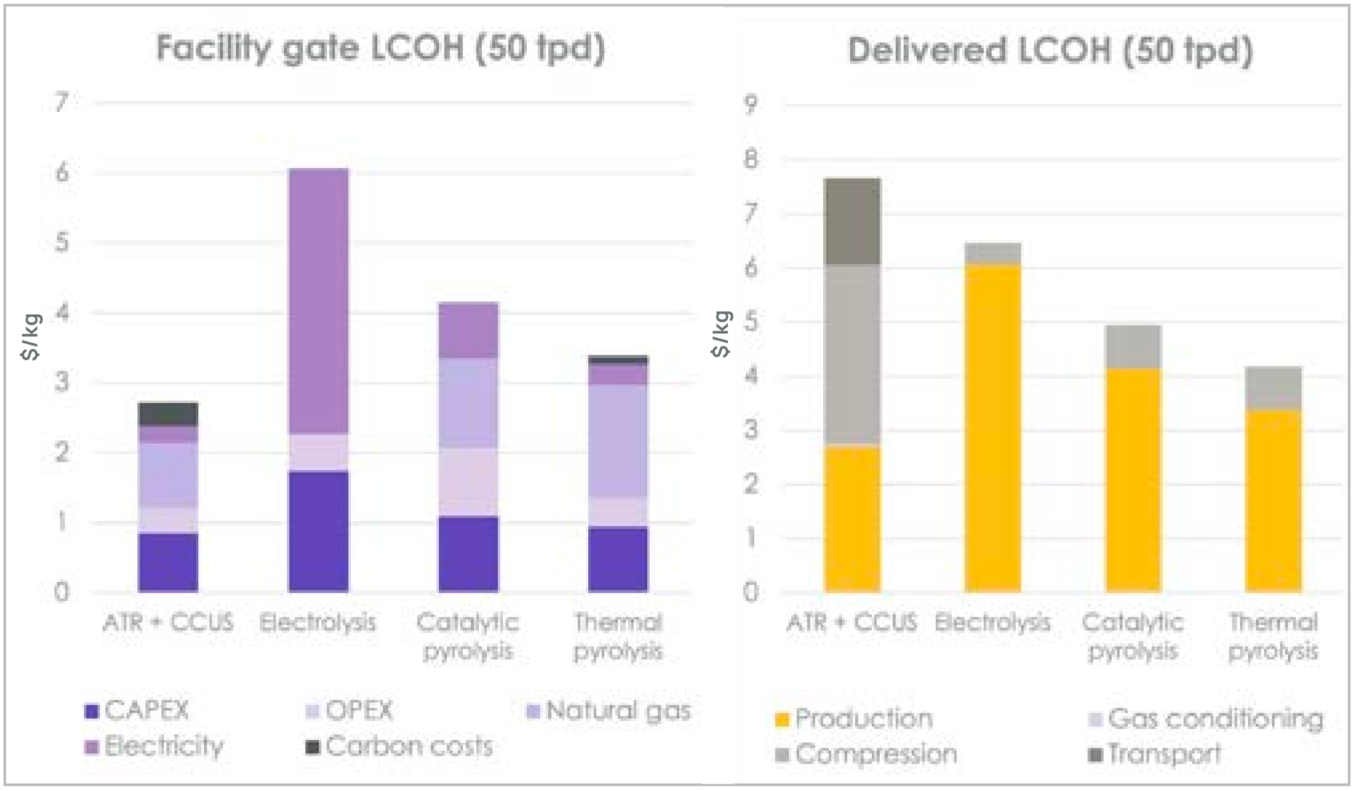


**FIGURE 46:** **Scenario 2 production gate LCOH (left) and delivered LCOH (right) at 50 $tH_2$/d scale in ($/kg)**




Similar to Scenario 1, ATR+CCUS has the most competitive LCOH at the facility gate. However, as shown in **Figure 46**, this pathway becomes the least competitive option in Scenario 2 due to the associated transport costs, which more than double the LCOH. Larger-scale decentralized pyrolysis and electrolysis facilities also benefit from significant economies of scale, with CAPEX intensities expected to be more than 50% lower than Scenario 1. There are additional OPEX efficiencies, with labor and maintenance expenses amortized over greater volumes of hydrogen production. The pyrolysis LCOH begins to approach those of ATR+CCUS but remains approximately 50% higher at the plant gate, with thermal again being the lower of the two processes.

## Scenario 3: Large-scale

Scenario 3 represents hydrogen production at scales of up to 300 $tH_2/d$ or greater, with expected use cases for hydrogen as a feedstock for renewable fuel production including methanol, renewable diesel, ammonia, or for petrochemical refining. Hydrogen at this scale could also be used for baseload, large-scale centralized power production of up to 310 MW. At this scale, it is expected that only the ATR+CCUS and pyrolysis pathways will be feasible, unless there is a material change in electrolysis technologies, or the economics of large scale dedicated renewable power projects. As previously mentioned, up to 2.5 GW of renewables could be required to service an electrolysis project of this scale. In addition to the grid constraints that would make it difficult to deploy a 300 $tH_2/d$ electrolysis plant, this scale of electrolyzer has yet to be deployed globally. Currently, the largest operating electrolyzer in the world is a 250 MW facility in China, with the largest electrolyzer in Canada sitting at 20 MW.[94] Globally, announced projects with electrolyzer capacities at the GW scale have yet to be commissioned.

The Scenario 3 schematic is shown in **Figure 47**, with the pyrolysis plant constructed at the point of demand, and the ATR+CCUS plant located in Northeast B.C. To meet demand outside of Northeast B.C., hydrogen from an ATR+CCUS plant would need to be transported via pipeline, incurring additional expenses. This supply chain component has been modelled at a distance of 1,200 km, which is also the approximate distance between Fort St. John in Northeast B.C. to the nearest port of Prince Rupert.

**FIGURE 47: Scenario 3 supply chain schematic for 300 tpd hydrogen production for refining or fuel production**

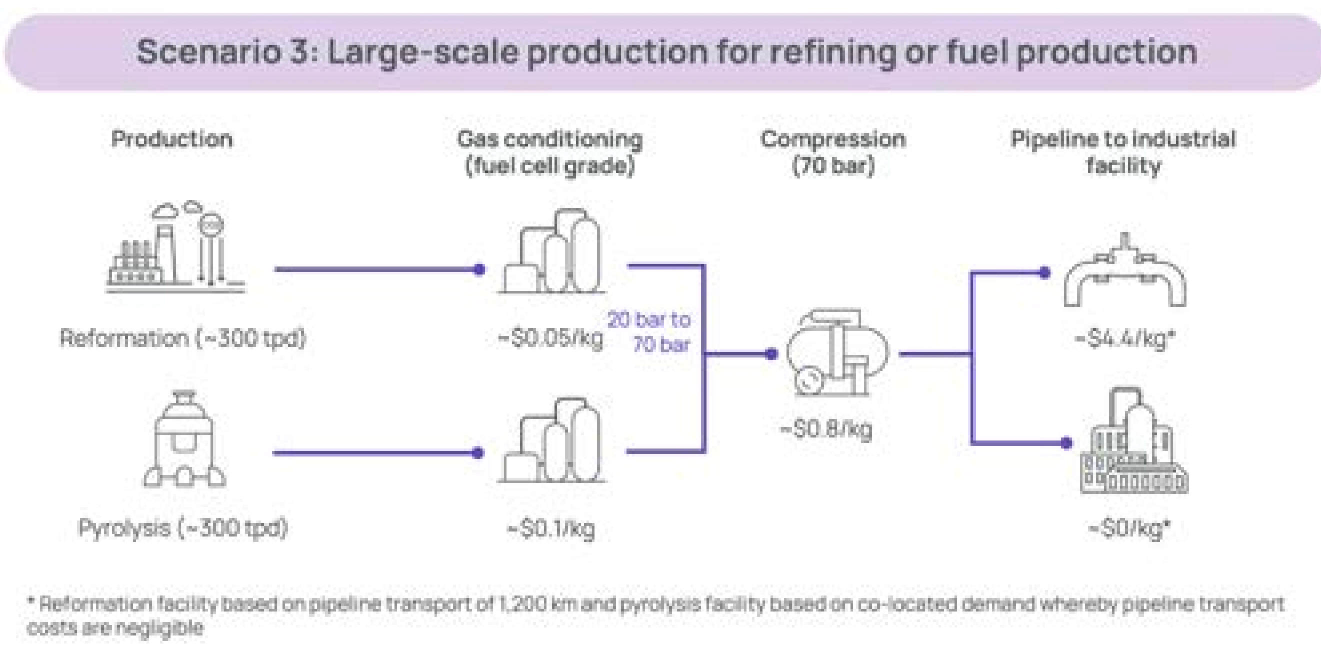


**FIGURE 48: Scenario 3 production gate LCOH (left) and delivered LCOH (right) at 300 $tH_2/d$ scale in ($/kg)**

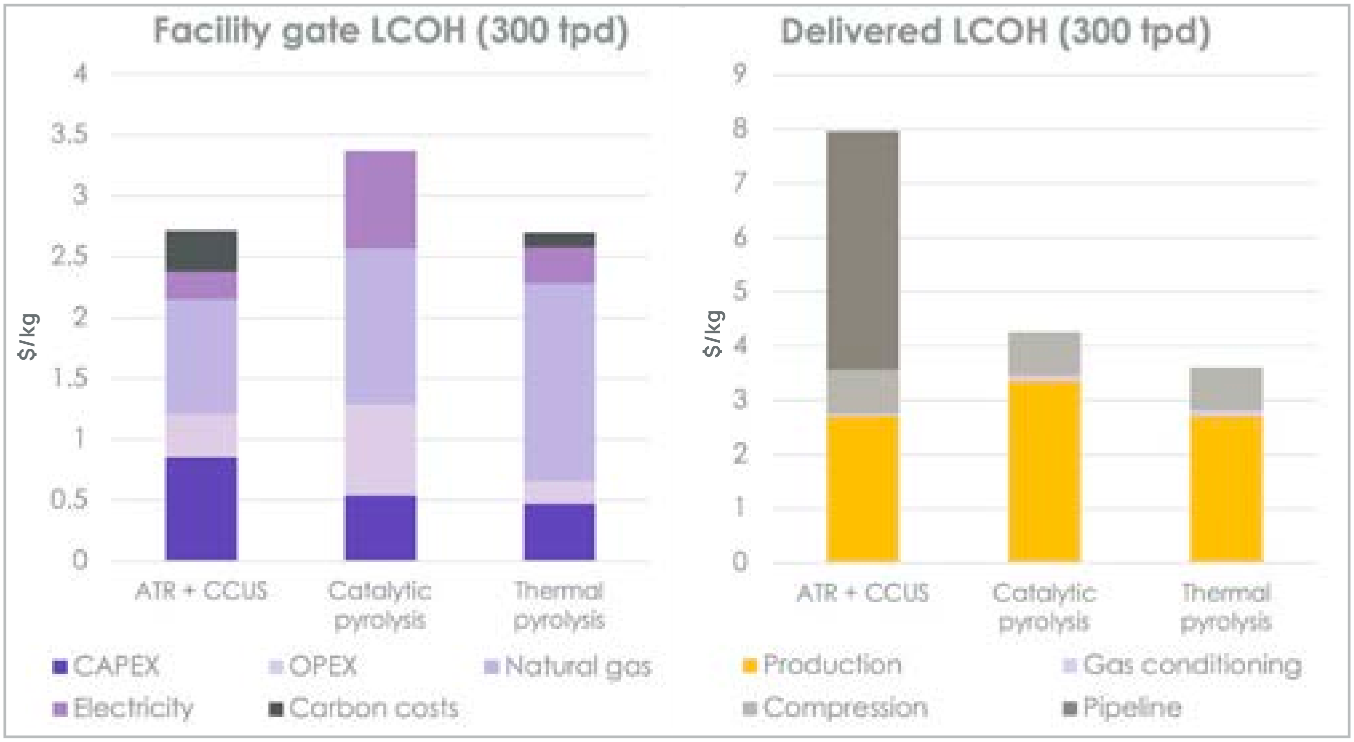



Figure 48 illustrates that the facility gate values for the two technologies are comparable. However, if pipeline connection is required to a centralized facility, the delivered LCOH is significantly impacted. The modelled costs only consider delivery of prescribed hydrogen volumes, so costs for this distance could be higher if a larger pipeline is constructed and utilized at a low capacity. Costs could also be lower if a pipeline is built in conjunction with other projects focused on the export of hydrogen or hydrogen-derived fuels like ammonia. However, even if pipeline costs are reduced to one-third of the modeled rate, pyrolysis would still achieve a lower delivered LCOH.

As demonstrated in Scenarios 2 and 3, the LCOH of pyrolysis at the plant gate approaches that of ATR+CCUS at greater scales of production. This provides the support for a distributed model where hydrogen from pyrolysis could be generated in locations without a $CO_2$ sequestration reservoir at the lowest LCOH across hydrogen production pathways. However, this will depend on the continued development of pyrolysis technologies to commercial levels and achieving the economies of scale that are predicted at larger scales. Many technology developers are projecting significant CAPEX cost declines at larger scales. Therefore, these will need to be validated as commercial projects are constructed. Currently, catalytic pyrolysis incurs higher operating expenses from catalyst use and regeneration, but these could potentially be offset from revenues with higher-value carbon co-product sales.

# 6. Discussion

A summary of all the delivered LCOH values for each pathway modeled is shown in **Figure 49**, demonstrating the competitive nature of a distributed hydrogen model that eliminates the costs of long-distance hydrogen deliveries from a centralized facility. Electrolysis also appears more competitive at larger scales, but the fundamental demand of electricity and water and the stress that it would apply to current infrastructure suggests a challenge to wide-spread adoption. With the scale-up assumptions applied to pyrolysis, the results suggest that LCOH for large scale hydrogen production could be on par with ATR+CCUS at the plant gate, and further advantaged by being easily deployable throughout the province. There could be additional positive impacts on the LCOH calculations with the inclusion of government grants, incentives, or hydrogen/CCUS tax credits, which were not included in the techno-economic model.

The techno-economic analysis highlights the competitive LCOH for methane pyrolysis at the point of demand against large-scale ATR+CCUS and electrolysis.

Further illustrated in **Figure 49** is the comparison of 2030 forecast pricing of energy in B.C. with the calculated LCOH of the various hydrogen production pathways evaluated, all shown on a $/kg hydrogen equivalency basis. Utilizing relative efficiency assumptions ($GJ_{H2}/GJ_{INPUT}$) presented by the Transition Accelerator, and assuming a carbon tax of \$170/t$CO_2$, the graph demonstrates that the LCOH for nearly all pathways are currently competitive as a fuel replacement for diesel. Moreover, larger scale pathways could be competitive for electrical generation at specific price points.

Closing the price gap between hydrogen and incumbent energy sources will require government incentives, and societal discretion in willingness to pay the incremental price for low carbon alternatives.

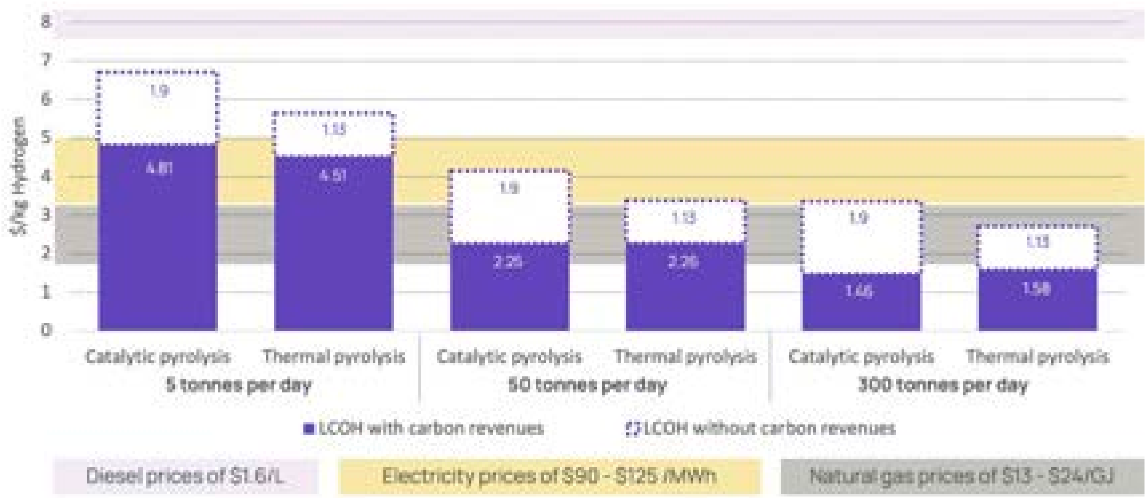
Hydrogen replacement of natural gas as a heating fuel appears challenging primarily due to natural gas being a feedstock for hydrogen generation, thus having a direct influence on LCOH. However, it should be noted that the price for renewable natural gas (RNG) is expected to be twice that of natural gas in 2030, which would make hydrogen a competitive low carbon gas alternative.

**FIGURE 49: Delivered cost of hydrogen across scenarios and comparison to costs of incumbent energy sources in B.C. Downstream CI in Figure 49 calculated at 1,200 km and adjusted to 800 km**


- Energy prices inclusive of carbon tax of $170/tCO_2$
- Energy prices factored for changes in energy efficiency of displaced fuels: 1.06 $GJ_{H2}$ / $GJ_{NG}$, and 0.86 $GJ_{H2}$ / $GJ_{DIESEL}$

The techno-economic results presented thus far have assumed that no revenue would be realized for the solid carbon generated through pyrolysis. As introduced earlier and examined in greater detail in **Section 6.3**, the carbon generated from pyrolysis could generate significant value as a critical mineral in the battery sector and if deployed as a low carbon advanced structural material. The commercial results are based on net neutral costs for carbon co-products, under the assumption that products are sold at the potential cost of recovery and disposal. The actual revenues or costs of methane pyrolysis will depend on the location of the project, the allotrope of the carbon co-product that is produced, and potential end uses cases for those co-products.

**FIGURE 50: Facility gate cost of hydrogen from pyrolysis based on carbon co-product revenues**




- Catalytic carbon sales price: $500/t Thermal carbon sales price: $250/t
- Energy prices factored for changes in energy efficiency of displaced fuels: 1.06 $GJ_{H2}$ / $GJ_{NG}$, and 0.86 $GJ_{H2}$ / $GJ_{DIESEL}$

The LCOH for catalytic and thermal pyrolysis become equivalent as the increased value of the graphite carbon for the catalytic process offsets its higher incremental capital and operating costs

**Figure 50** shows the impact that potential carbon co-product revenues would have on the LCOH from pyrolysis. Using conservative sales prices of $500/t for catalytic graphite carbon and $250/t for thermal carbon black, the LCOH for both catalytic and thermal become more equivalent as the increased value of the graphite carbon offsets the higher incremental capital and operating costs. The introduction of carbon revenue also results in pyrolysis LCOH values dropping below ATR+CCUS at large scales and become a competitive alternative to natural gas, which would not have been possible based on the hydrogen value alone.

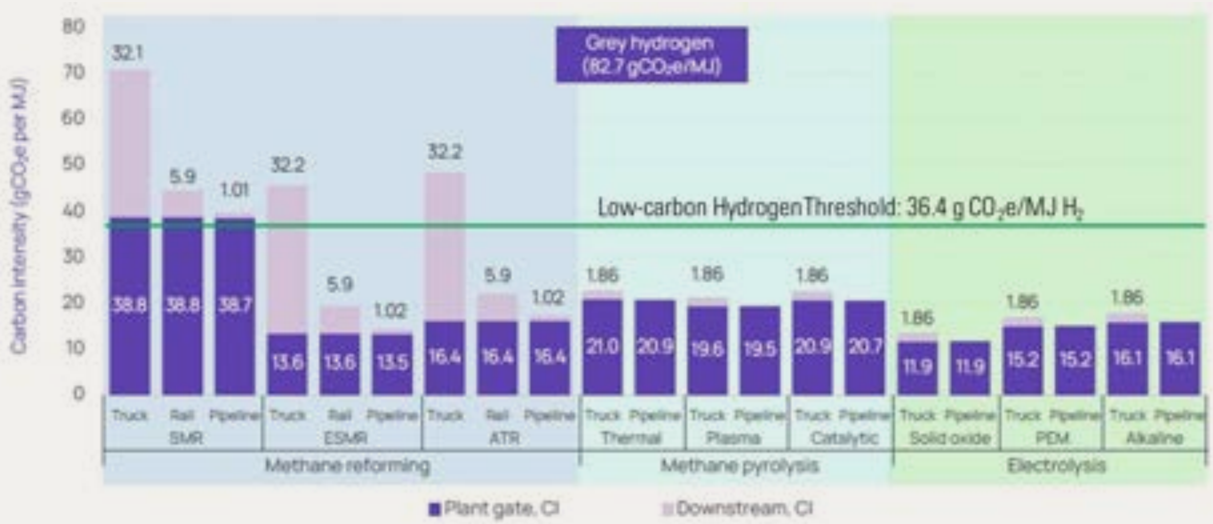
## Carbon Intensity Calculations

This report does not evaluate the carbon intensity of the hydrogen pathways modelled, because a previous CICE report, "Carbon Intensity of Hydrogen Production Methods," completed an extensive evaluation of the life-cycle carbon intensity of electrolysis, reforming, and pyrolysis. The results of the study, as it applies to life-cycle emissions, including modes of transporting compressed hydrogen, are summarized in Figure 51. To summarize the conclusions of that report:

- B.C. is well situated to produce low carbon hydrogen regardless of technology utilized, whether that is reforming with CCUS, pyrolysis, or electrolysis.
- Modelled plant gate hydrogen CI for ATR+CCUS is 16.4 g $CO_2$e/MJ, catalytic methane pyrolysis is 20.7 g $CO_2$e/MJ, thermal methane pyrolysis is 20.9 g $CO_2$e/MJ, and PEM electrolysis is 15.2 g $CO_2$e/MJ.
- Hydrogen CI for methane pyrolysis with consideration of solid carbon sales could drop to 8.2 g $CO_2$e/MJ by 2050.

As illustrated in Figure 51, if traditional fuels are used for the compression and delivery of the hydrogen, the life-cycle assessment (LCA) CI of the hydrogen from the ATR+CCUS increases dramatically, with the total CI for Scenario 1 calculated at 37.9 g $CO_2$e/MJ, which would not be considered low carbon hydrogen. This high CI would act as a deterrent to utilize transported hydrogen and be a further factor to support distributed hydrogen generation by methane pyrolysis.

**FIGURE 51:** Carbon intensity for compressed hydrogen by technology family, pathway, and conventional fuelled transport mode



## Potential for methane pyrolysis in B.C.: Key opportunities

As demonstrated in **Section 5**, hydrogen production from pyrolysis is a cost-effective distributed decarbonization pathway at various scales of demand. With flexibility in scale, pyrolysis can address fuel requirements in various sectors at the point of demand, and be a competitive pathway for transport decarbonization, particularly when clean fuel credits and investment tax credits are included.

Utilization of pyrolysis to establish distributed hydrogen clusters throughout B.C. could address the decarbonization of concentrated emissions in electrically constrained regions. This could be applied in areas such as the East Kootenays, Trail/Castlegar, Lower Mainland, Vancouver Island, the North Coast, and Prince George, all of which don't have the option of carbon capture and sequestration. As discussed in **Section 2.3**, hydrogen clusters could have the greatest impact if demand is aggregated amongst some of the largest industrial emitters. These could include hydrogen use for regional supply of transport fuel, heating, and electrical stability. Other industrial synergies in the forestry, mining, agriculture, oil and gas, and refining/smelting industries would offer brownfield installation opportunities by aggregating demand across industrial clusters.

Methane pyrolysis utilizes existing infrastructure to deliver low carbon hydrogen at the point of demand and could be viewed as a method of pre-combustion carbon capture, removing the excessive energy and infrastructure requirements from post-combustion carbon dioxide capture and sequestration.

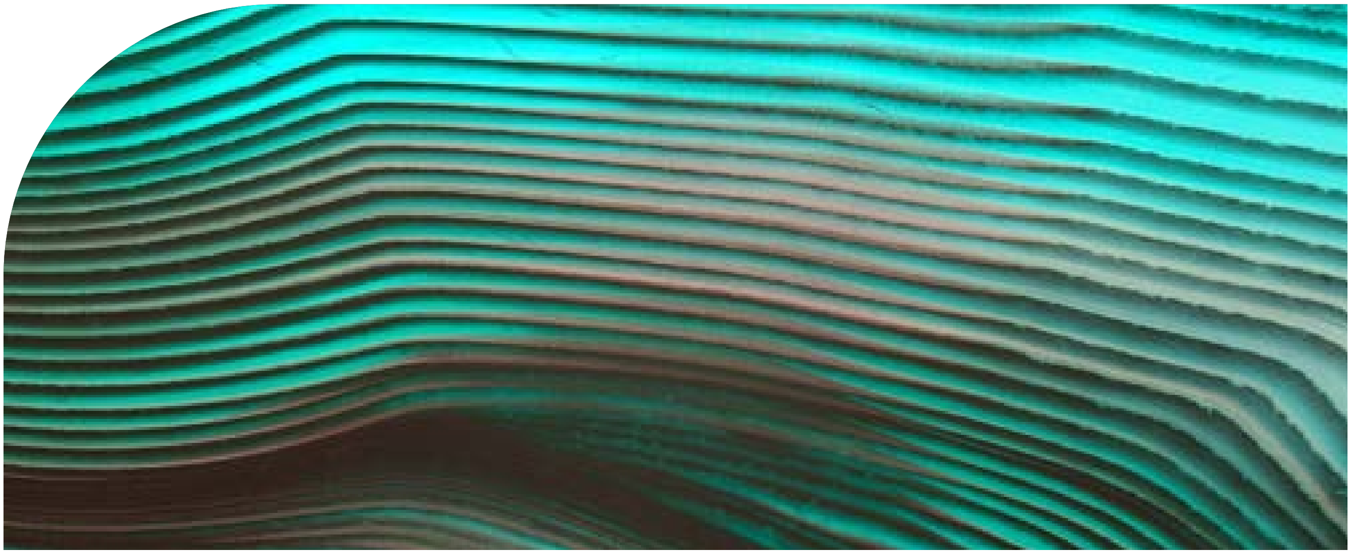
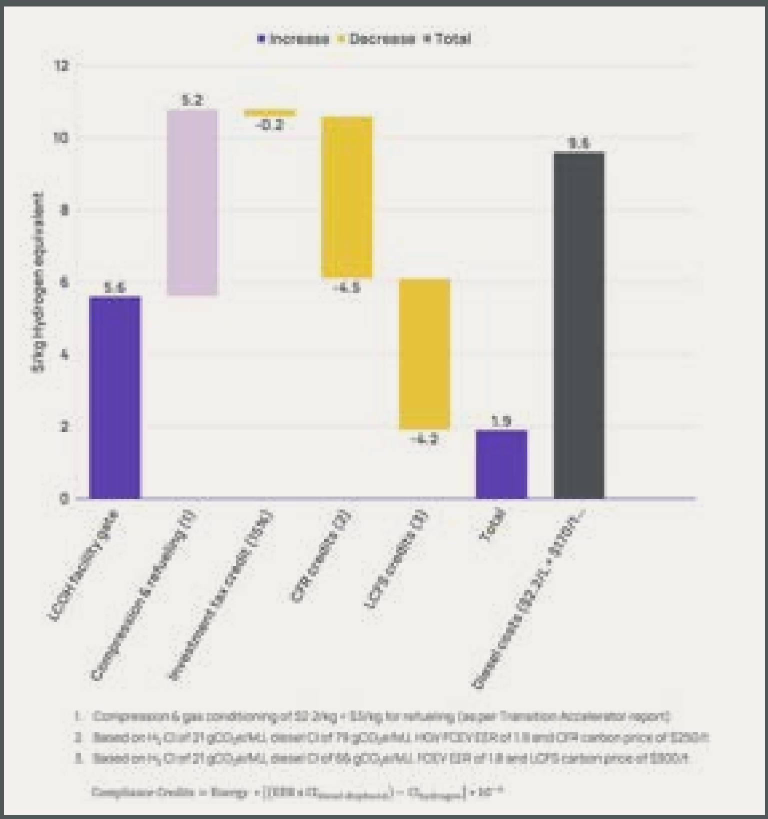


**FIGURE 52:** Comparing the cost competitiveness of $H_2$ from a 5 $tH_2$/d thermal pyrolysis facility in 2030 to displace diesel (FCEV)




## Case study: $H_2$ use in transport

**Target sectors or applications for diesel displacement:**

- » Freight companies with return-to-base operations or strategic long-haul routes
- » Offroad equipment at remote mine sites
- » Drilling and completions equipment for oil and gas operations

**Options for carbon utilization**

- » Cement or asphalt filler for local municipalities and industrial projects
- » Displacement of petroleum coke
- » Soil enhancement

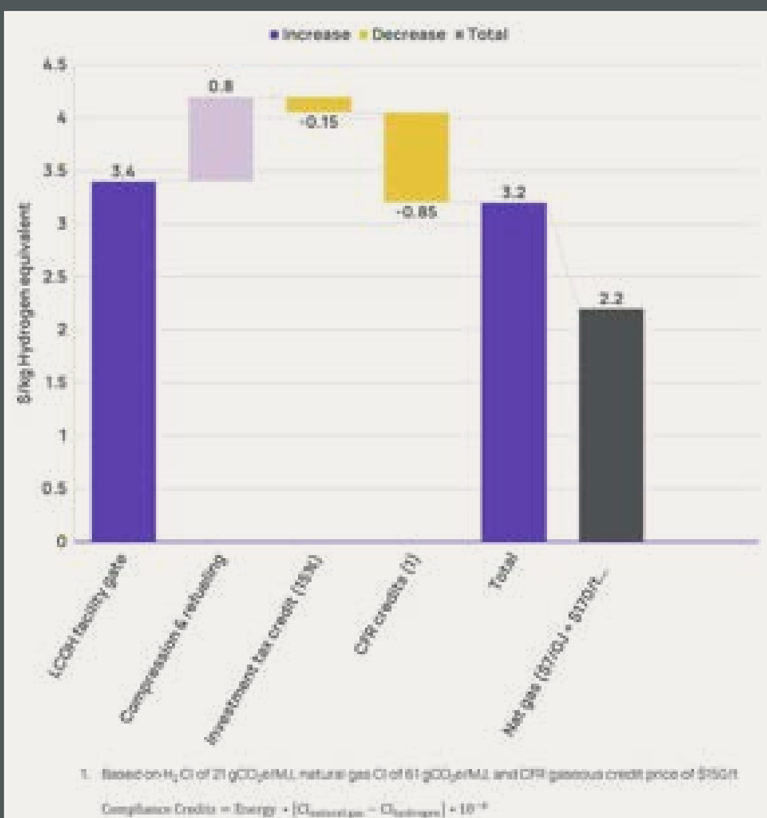
**Figure 52** shows the comparison between hydrogen and diesel fuel at the refuelling station in 2030, based on expected carbon pricing and clean fuel incentives.

A freight company operating a heavy-duty hydrogen fuel cell electric vehicle (FCEV) could save up to 78% of fuel costs compared to a diesel internal combustion engine equivalent (ICE) by stacking clean fuel credits at the provincial and federal levels. Hydrogen combustion engine vehicles would result in a lower number of credits due to different energy effectiveness ratios[2].

Carbon credits can also be generated from the displacement of natural gas, under compliance category two of the CFR, which can make up to 10% of a regulated entity's compliance obligations. Since there is a cap on the use of these credits, they are expected to trade at a discount to the liquid fuel credits. There are no heating emission reduction incentives at the provincial level, so the credits cannot be stacked. As shown in **Figure 53**, hydrogen from pyrolysis is expected to be priced at a 150% premium to natural gas by 2030, despite a high carbon tax of $170/t.

Additional decarbonization incentives in the form of carbon offsets, or the pairing of additional credits generated from pyrolysis technologies such as carbon capture could help reduce this price gap in the future. Business models for deploying pyrolysis technologies could take the form of a tolling agreement in which project developers would charge a fee for methane decarbonization, based on the production facility CAPEX and OPEX. The utility company, like FortisBC, and the end user would take on the commodity price risk of the methane feedstock, which would reduce long-term contract risk for the project developer.

**FIGURE 53:** Comparing the cost of competitiveness of $H_2$ from a 50 t$H_2$/d thermal pyrolysis facility in 2030 to displace natural gas




## Case study: $H_2$ use for heat / power

**Target sectors or applications for natural gas displacement:**

- Cement plant furnaces
- Pulp and paper mill boilers
- Boilers at other manufacturing facilities
- Industrial heat for oil and gas facilities
- Powering utility-scale compressor stations

**Options for carbon utilization**

- Cement or asphalt filler for local municipalities and industrial projects
- Soil enhancement
- Disposal

## Potential scale-up challenges for pyrolysis technology

Almost all pyrolysis technology developers today are still at the pre-commercial pilot and demonstration phases. Some companies like Hycamite and C-Zero are focused on large-scale, industrial hydrogen demand, while others like Modern Hydrogen and Innova have implied a strategy focused on modular, smaller-scale facilities to meet distributed demand. Regardless of the end goal, maturing a technology from lab/pilot to commercial scale (TRL 4 to TRL 9) will take time, patience, and millions of dollars in development expenses. The variations in the technology may present unique challenges specific to each developer, ranging from specialty materials for reactor construction, to managing the process heat requirements, including the impacts of free-flowing solids in low pressure gas spaces.[95]

> With limited commercial deployment of pyrolysis projects, the capital intensity of scale-up is one of the biggest unknown variables of the technology.

Furthermore, scale-up efficiencies and/or challenges will depend on the type of pyrolysis technology and the complexity of the reactor design. Some thermal pyrolysis technology developers indicate a linear scaling process, where the only limitation from larger sizes is the efficient processing and extraction of carbon co-products. Given a robust and established carbon industry, the processes and equipment required for thermal pyrolysis reactors have already been commercially developed and are widely available. The carbon handling system is also a well-known technology that has been used in carbon black plants for years. However, the integration and scale up of these systems could create engineering challenges, particularly in cases where high-value carbon allotropes are required using catalysts, or where there are process changes that impact the way energy is used.

It is generally accepted that any scale up and commercial deployment would include the installation of more than one reactor with potentially a n+1 redundancy of reactor trains to achieve a high availability while allowing for reactors to be taken out of service for maintenance. Several companies have indicated that a single reactor design can be increased in size to reach higher production capacities, while others believe that bundles of reactors may be needed to ensure optimum reaction efficiencies. This suggests that a large-scale pyrolysis plant could contain several large reactors or reactor bundles connected in parallel, which could create production economies of scale. Additional economies of scale could result from lower incremental design and construction costs for a larger-scale balance of plant. The operating and capital costs are less known for the reactors which are in early development, however, balance of plant items are standard commercially demonstrated equipment that have known capital and operating costs.

Discussions with pyrolysis technology developers suggest that economies of scale may have already been achieved in the manufacturing of some equipment specific to methane pyrolysis, such as carbon handling. The carbon black industry already has commercially mature technology for handling the carbon that would achieve better economies of scale with increased plant capacities.

## Generating value from co-product

One of the biggest challenges and opportunities of hydrogen production from pyrolysis is managing the carbon co-product, which can make up more than three times the produced weight of hydrogen. As shown earlier in **Section 6**, generating value from carbon can significantly improve the economics of pyrolysis projects and reduce the carbon intensity of hydrogen production by attributing GHG emissions to the utilized carbon co-product. Conversely, treating the generated carbon as a waste product and landfilling it increases the levelized cost of hydrogen production through additional disposal costs and increases the carbon intensity of the hydrogen stream.

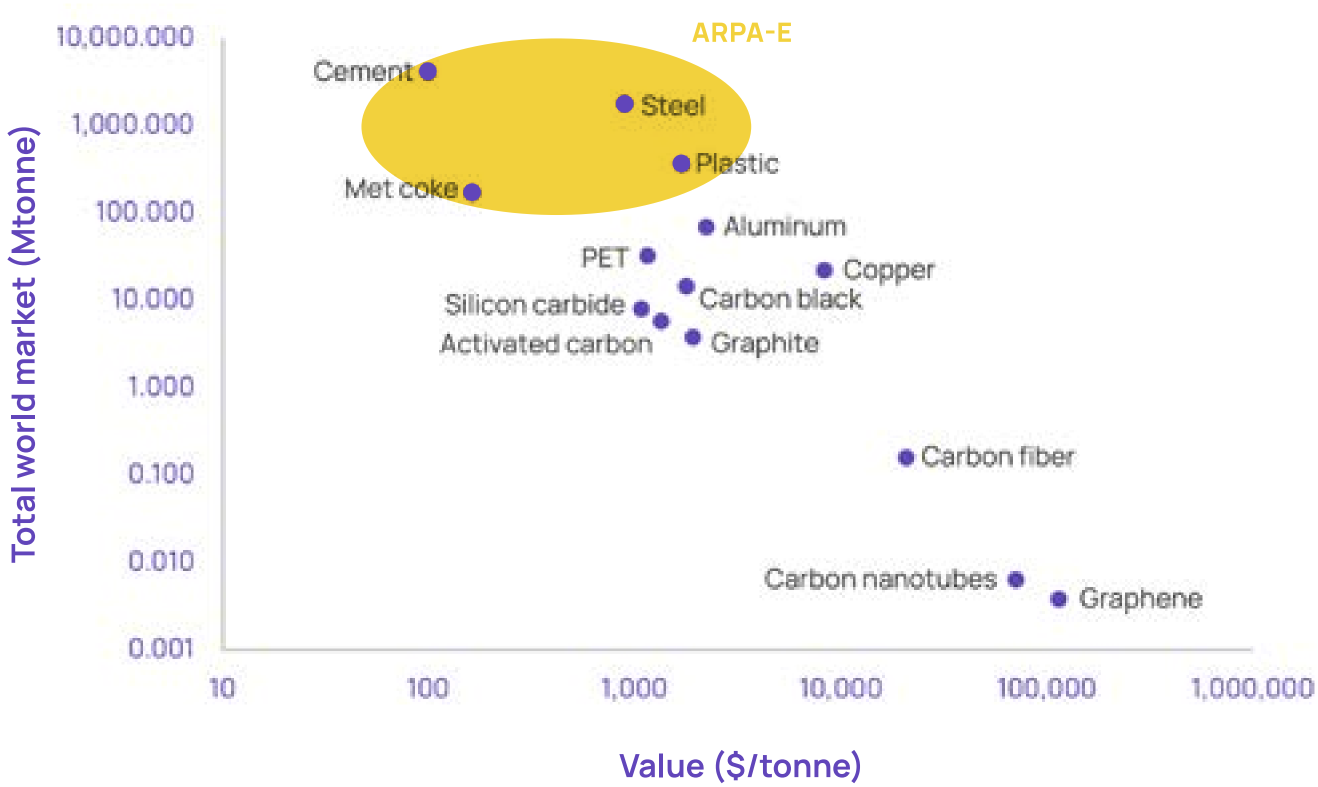
The main allotropes formed through pyrolysis are carbon black, graphite, carbon nanotubes, and carbon fibres. Carbon can vary in size, from grains to flakes measuring mm to μm in size and is generally handled as a dust within the operating process. Depending on the use of molten metals or metal-based catalysts, some metal impurities can be trapped within the carbon and could require additional treatment dependent on final utilization. Not dissimilar to other industrial processes that produce substantial amounts of solid product, transport of the generated carbon can be via bulk bag, or be pelletized and shipped by truck or rail.

Carbon samples from pyrolysis projects would need to be tested to determine their specific carbon attributes and to help identify specific applications.

In addition to the uncertainty of repeatable carbon characteristics, a significant challenge for developing a robust solid carbon market is managing the large volumes of carbon that will be generated from pyrolysis in comparison to the current size of the carbon black and graphite markets, which are 14 MT and 4 MT per year respectively.[96] Though both are growing, a small or medium-sized pyrolysis project could easily oversupply either market. Thus, other applications for the carbon will need to be developed in sectors with larger volume requirements. As shown in **Figure 54**, the Advanced Research Projects Agency–Energy (ARPA-E) identified steel and plastics as large potential demand sectors for solid carbon. This can be expanded to cement and metallurgical coal/coke.[97]

> The markets for methane pyrolysis-generated carbon are currently underdeveloped and indeterminant, partially due to the lack of commercial deployment of pyrolysis technologies that would establish consistent and standardized carbon properties.

**FIGURE 54:** **Global carbon market 2022 (US$)**



A further challenge is the uncertainty as to whether the commercial processes will be successful in producing both carbon and hydrogen at high qualities, and thus be able to demand higher prices for the carbon without further processing. Pyrolysis reactors and processes can often be configured to optimize the efficiency and value of one product, but typically at the expense of the other product. This is important for higher value markets, particularly where carbon is used to produce electronic parts, which have very strenuous material specifications based on the shape, size, and durability of carbon molecules. These markets also have significant testing and certification processes for potential suppliers.

## Graphite market and potential to overcome geographic scarcity

High grade graphite is one of the most valuable and growth-oriented minerals due to its use in semi-conductors and the anodes of lithium-ion batteries. Graphite is the single largest mineral component, making up 20% to 30% of the mass of an EV battery, and is poised for significant growth in line with increased demand for electric vehicles. As per **Figure 55**, China currently controls 70% of the global production of raw graphite flakes and 99% of spherical graphite, which come from naturally occurring graphite reserves or synthetic graphite formed from coal or petroleum coke.[98] Current mined graphite in Canada is estimated to have a full life cycle carbon intensity of 9.5 kg $CO_2e$/kg graphite, while graphite from China is estimated at 16.8 kg $CO_2e$/kg graphite.[99]

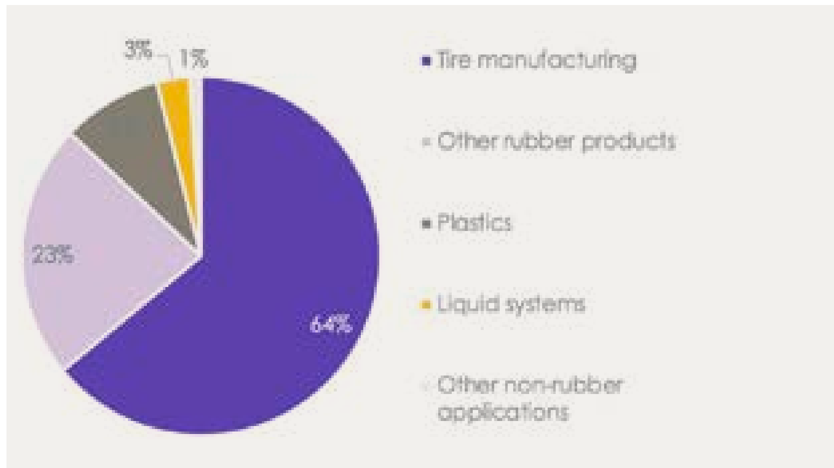
Starting Dec 1st, 2024, Chinese companies will need to obtain permits to export graphite, which is likely to cause short-term disruption in the market. However, given the strenuous purity requirements (>99.5%) and certifications needed for electronic-grade graphite, it is unlikely that new supply from pyrolysis co-product will address this disruption in the short term. Over the long term however, graphite from methane pyrolysis could be used as both a replacement of existing high-intensity graphite, as well as a source to fill growing demand, which is estimated to grow to 3.5 Mt by 2040.[100]

**FIGURE 55: Graphite production by country in 2021 (thousand tonnes)**[98]

## Carbon black market in Canada and applications in B.C.

According to data reported under Section 71 of the Canadian Environmental Protection Act (CEPA), there were 228,000 tonnes of carbon black manufactured in Canada in 2006, with another 26,400 tonnes imported. As of 2008, furnace black accounted for nearly 81% of Canadian production, which involves the partial combustion of residual aromatic oils at elevated temperatures. **Figure 56** shows the use profile for carbon black in Canada in 2008, with less than 1% of the product used in high value markets like batteries or high temperature insulating materials.[101]

**FIGURE 56: Carbon black use by application in Canada (2008)**[101]




The North American carbon black market is expected to grow at a CAGR of >2.5% per year by 2028.[102] However, this is based on historic and current carbon black costs of up to USD $2,000 per tonne.[103] While the current market for carbon black is limited, a greater availability of low-cost, and low-GHG co-product carbon from pyrolysis could create opportunities for large-scale, bulk utilization of carbon in new and existing markets. For example, the availability of lower cost carbon black could accelerate its market growth by making it a competitive alternative to other materials such as bitumen. Currently Monolith is supplying their produced carbon black to Goodyear.

Another near-term market that could be explored by pyrolysis companies is the displacement of metallurgical coal and coke. Metallurgical coal is utilized to create coke, which is an essential component in the steelmaking and smelting industries. Significant GHG emissions are associated with this product, both in the mining and shipping of coal to site, but also in the coking of the coal. While the substitution of coke with carbon generated from methane pyrolysis would not directly eliminate emission, it could significantly reduce current emissions. The markets for pyrolysis carbon co-product are currently being evaluated, and their applicability to B.C. is summarized in **Table 7**.

**TABLE 7: Overview of end use markets for carbon listed in order of their applicability to B.C.**

| Industry | Carbon Application | Applicability to B.C. |
|---|---|---|
| Construction Materials | Mixing or displacing aggregates and binding agents (cement, concrete, asphalt) | One large integrated materials plant in Delta, two cement plants in Kamloops and Richmond, and several asphalt plants in Vancouver, but no facilities outside the Lower Mainland. The benefits of various carbon allotropes in cement need to be validated, and public procurement policies need updates to incentivize greater adoption. |
| Soil Additive | Improves soil structure and health (water retention, microbe dispersion, heat adsorbent) | Significant opportunity for B.C.'s $4B agriculture industry (as of 2020), which is concentrated in the Lower Mainland, Okanagan, and Kootenay regions. Further testing is required to determine effective carbon structure. |
| Advanced Manufacturing | Extrusion polymers used for 3D printing, or pigment for inks, paints, coatings, and plastics | Applicable to manufacturing subsectors (pharma, electronics, machinery, shipbuilding) which collectively makes up to 57% of B.C.'s manufacturing sector. |
| Aluminium Smelting | Filler in carbon anodes used in aluminium electrolysis | Only one aluminum smelter in B.C. (Rio Tinto in Kitimat). |
| Batteries & Battery Recycling | Production of graphite anodes and sodium-ion batteries | First battery production plant to be built in Maple Ridge by E-One Moli. |
| Carbon Fibre | Carbon fibre additive to polymer and resin for added strength | Used in the aerospace, defense, sporting goods, and other industrial manufacturing. Strong manufacturing sector in lower mainland. |
| Activated carbon | For water filtration and pharmaceutical uses | Small, distributed producers across Canada. |
| Rubber & Tire Production | Used to strengthen rubber | There is no rubber or tire manufacturing in B.C., but significant market potentially accessible by rail transport. |
| Steel Production | Charged carbon to increase carbon content of steel and/or displacing met coke in blast furnaces | There are no steel mills in B.C. but there are zinc and lead smelting and refining. There are further export opportunities to steel producing regions in Asia. |

Ultimately, the carbon co-product value needed to ensure commercial viability will vary by producer, due to the energy mass balance of individual pyrolysis technologies. Different companies may also tailor their processes to maximize the value of carbon co-products, depending on the geographies they are targeting and their proximity to end-use carbon markets. For purposes of this study, conservative values of $250/t for thermal carbon black and $500/t for catalytic graphite were used in Figure 50 to demonstrate the carbon impacts on the LCOH of methane pyrolysis. If robust new markets can be developed to allow for realized pricing of $1,000 to $2,000/t, it is possible that hydrogen could be generated and sold for less than $1/kg while achieving significant rates of return for project developers.

## Potential second-order problems

### Carbon intensity and upstream emissions

The carbon intensity of hydrogen generated by methane pyrolysis is driven by the upstream emissions of natural gas and the carbon intensity of the energy sources utilized for the process. Emissions from electricity could be reduced by utilizing renewable power or connecting to the B.C. grid, which already has very low emissions intensity due to the high penetration of hydro power. If combustion is a required component of the pyrolysis technology, recirculating the produced hydrogen to produce energy would reduce the overall carbon intensity of the process. An alternative low carbon energy source could be biomass or utilizing renewable natural gas, which could potentially result in a negative carbon intensity.

The largest driver of the CI of methane pyrolysis is upstream natural gas production and processing emissions. These emissions are expected to come down over time, in line with provincial and federal mandates to achieve net zero by 2050. Several policies have also been announced in the interim to drive down emissions specifically from the oil and gas sector.[104]

There are three accepted means for allocation of total emissions across produced products. This can be done via energy content, mass balance, or economic value, as long as there is a useful end-use case for carbon co-products rather than simple disposal via landfilling. Mass balance allocation could reduce the CI of pyrolysis hydrogen by up to four times in cases where carbon is sold for its structural and strength properties.

The second most common allocation is by energy balance, which would reduce the CI by a factor of two times. The argument for utilizing this allocation could be supported if the carbon were being utilized for energy production, such as in the substitution of metallurgical coal. The third means of allocation via economic value is difficult and can vary substantially. In theory, the value of the hydrogen stream and carbon stream can be estimated and thus provide an allocation of emissions. However, neither product have set market values, and they

> A further means of reducing the lifecycle GHG emissions of methane pyrolysis is by allocating emissions to carbon co-products.

### Policies to drive down upstream natural gas emissions:

- **Federal regulations to reduce methane emissions from the oil and gas sector by 75% by 2030, but the B.C. government takes this further to achieve 'near zero' methane emissions by 2035**
- **Investment tax credits for deployment of carbon capture utilization and storage (CCUS) projects**
- **Energy Action Framework cap on emissions for the B.C. oil and gas sector**

can vary substantially depending on the specific end market, as has been shown for the potential variance in carbon pricing alone. Therefore, an allocation by economics is not practical.

Given the various initiatives underway to reduce both embedded natural gas and energy associated emissions in B.C., the CI of hydrogen produced via methane pyrolysis is expected to be one of the lowest amongst hydrogen production technologies. Furthermore, as shown in **Section 6.1**, the reduction of lifecycle emissions from hydrogen production could also make pyrolysis technologies eligible for higher investment tax credits, which would further drive down the LCOH.

### Environmental and health effects of carbon

The fine particulate nature of the solid carbon formed during pyrolysis requires proper handling and safety measures. Finely dispersed carbon particles are considered a combustible dust with the auto-ignition temperature greater than 500°C, so it must be handled accordingly. Carbon dust particles are heavy and drop quickly from the air. The solids are dark in colour and have a propensity to stick to the surfaces that they come in contact with.

In 2013, the Government of Canada conducted a science-based evaluation of carbon black, including a screening assessment to evaluate its potential harm to the general population and the environment. The assessment found that carbon black is not expected to accumulate in organisms, and that the quantities released to the environment are below the levels expected to cause harm. The Government of Canada subsequently deemed carbon black as not harmful to the general population at low levels of exposure.[105] Solid carbon is viewed as a stable solid compound that will not degrade or react with its surroundings. Formation of solid carbon via pyrolysis is viewed as a means of sequestration of $CO_2$ emissions associated with natural gas with 1 kg of solid carbon having the equivalency of 3.67 kg of $CO_2$.

### Labour challenges

Based on conversations with pyrolysis technology developers, operating expenses— particularly labour can make up a significant portion of pyrolysis LCOH at small scales. This is partly a function of a new technology development, with greater automation expected with subsequent deployments. Larger plants will also result in the distribution of labour costs across a greater volume of hydrogen production, driving down relative costs further. Some technology providers suggested the ability to utilize staff across various distributed methane pyrolysis sites, under hub and spoke models. Many of the technical competencies required for operating pyrolysis facilities are consistent with those required in other resource sectors such as oil and gas production. Due to the large work force in these areas, a shortage of labour is not expected to be a barrier to deployment.

# 7. Next steps

As demonstrated in this report, decentralized hydrogen generation via methane pyrolysis has the potential for wide-ranging decarbonization of B.C. and Canada as a whole, if the technology can achieve a mature stage of development. This will require both private sector investment along with government incentives and support to fast-track technology scale-up and commercial market development for both the hydrogen and the carbon co-product. Significant advancements have been made by pyrolysis companies over the last 5-10 years, but this has been concentrated on lab scale testing and technology confirmation. The next 5-10 years will focus on field demonstration through constructing and operating facilities, which will provide the confidence for wider scale deployment of the technology at greater scales of production.

The development of markets for the carbon co-product will start to emerge once pyrolysis companies can demonstrate consistent and predictable generation of carbon products at the desired specifications. This will also require the commitment of user industries, across concrete, steel, asphalt, or batteries and electronics, to test carbon co-products for incorporation into existing products. The end customers of user industries, such as municipalities and prime contractors, will be crucial for long-term adoption of carbon from pyrolysis. The ability to generate carbon sequestration credits or offsets from producing or using co-product carbon, could further accelerate market adoption.

## Blueprint for action

- **Provide funding opportunities and encourage industry partnerships to advance methane pyrolysis technology development and fast-track the path to commercialization.**
- **Design support mechanisms for the hydrogen sector based on objective metrics like LCOH and carbon intensity. As illustrated in this report, regional characteristics can determine the type of hydrogen production that is most advantageous. Metrics should be established to allow advancements of various technologies, to improve the probability of success for the hydrogen industry more broadly.**
- **Establish and promote the role of hydrogen in microgrids across the province to both support the local generation of hydrogen for other industrial uses and provide the means to address local electrical requirements and peaking capabilities. Microgrid support allows for the optimization of existing transmission and distribution grids without requiring the time-consuming and costly expansion of full grid systems.**
  - Work with BC Hydro, FortisBC, BCUC and BCER to establish regulations and protocols for the connection of local microgrids to the main B.C. grid. This could include outlines for dispatch services, connection fees, market pricing, and operating requirements.
- **Embrace the economic value that is held in the province's natural gas reserves and infrastructure.**
  - Ease capacity constraints on the existing low carbon electricity grid to satisfy increasing demand from BEV, heat pumps, and other first order transitional equipment.
  - Unleash the economic benefits of natural resources in B.C. to provide low carbon, low-cost hydrogen domestically, but also create the opportunity to export natural gas as a hydrogen carrier, with utilization of pyrolysis in import countries to generate energy without producing $CO_2$ emissions.
- **Work with municipal, provincial, and federal governments to establish acceptance of solid carbon as a means of achieving carbon sequestration and provide incentives and credits for the adoption of this material into existing structural products.**
- **Establish an Advanced Material Carbon Hub to bring together academia, regulatory, technology developers, financial investors, and large industrial organizations to work on developing a robust carbon market.**
- **Promote methane pyrolysis as a low carbon hydrogen production pathway and continue to increase market demand for hydrogen.**

## GHG implications and carbon monetization

The hydrogen narrative needs to move beyond the two dominant colours of blue and green and consider production pathways based on their carbon intensity. Policy makers should acknowledge the growing influence and potential of methane pyrolysis as a hydrogen production pathway in public funding programs and initiatives.

Any producer aiming to generate credits under the CFR would need to apply for a new quantification pathway under the Environment and Climate Change Canada Fuel Life Cycle Assessment Modelling Tool (Open LCA). However, there is currently no specified methodology to quantify the life cycle emissions of methane pyrolysis in the Open LCA tool. Furthermore, the Hydrogen Investment Tax Credit (ITC) in Canada currently does not specify methane pyrolysis as an eligible production pathway, even though it could be one of the lowest carbon intense ways to produce hydrogen. The final design of the ITC quantification methodology, such as the emissions boundary and the default factors applied, could have significant implications for the deployment of methane pyrolysis in Canada.

In addition to hydrogen production subsidies, there are currently no means to benefit from the sequestered carbon from methane pyrolysis in B.C.; this challenge is similarly faced by other jurisdictions. The sequestration of carbon in solid form is not recognized under the Alberta TIER carbon offset protocol for carbon capture and storage, and there is no recognition of solid carbon in any subsidy programs at the federal level. Several companies in Alberta are seeking amendments to the TIER program to be able to generate sequestration credits for pyrolysis projects. In an ideal project scenario, in which all products of a pyrolysis reaction are utilized, credits would be generated for carbon sequestration, with emissions allocated for and revenue generated from both hydrogen and carbon production.

This story is similar in the U.S., which currently does not recognize any hydrogen production pathways other than methane reforming, electrolysis, or biomass gasification. None of the announced regional hydrogen hubs in the U.S. have pyrolysis as a production pathway, and there is no mention of pyrolysis in any public funding programs, including the production tax credit (PTC).[106] There is also currently no way to generate a carbon intensity value for pyrolysis projects under CA-GREET, which is the main tool to calculate the LCA of fuels in the U.S. Furthermore, the 45Q tax credit for CCUS in the U.S. does not recognize solid carbon or solid oxides.

## Advanced materials economy

According to InnoTech Alberta, if methane pyrolysis displaced just 5% of current hydrogen production in Canada, there would be more than 450 kt of elemental carbon production per year, representing more than 100% of Canada's total carbon black demand.[107] Research collaboration and investment is needed to ensure a market can be developed for this carbon, including:

- **Identifying and characterizing elemental carbon products by collecting samples and building a database of carbon types and properties.**
- **Assessing applications and markets for elemental carbon by analyzing market sizes and potential applications.**
- **Developing optimal product-to-application matches, including testing products.**

For pyrolysis companies to be able to supply the existing carbon black market, their carbon co-products will require significant testing and approvals under ASTM standards. In addition to the Joint Industry Project currently being established by InnoTech Alberta, there are research projects underway between individual technology companies and universities across Western Canada to accelerate the commercialization of these products, however, greater coordination is required across the industry. An Advanced Material Carbon Hub concept, similar to the one under development at Rice University, which brings together stakeholders across the carbon and hydrogen value chain, is important for identifying potential markets and building value chains for use of the pyrolysis carbon co-product.[108]

## Electrical transmission and micro-grid support

Three examples highlight the current pressure that B.C.'s electrical generation and transmission grid is facing as demand for electrical services continues to increase:

1. **The Site C Clean Energy Project (Site C) will be completed in 2024 at a cost of $16 billion and will add 1.1 GW of hydro electric power to the B.C. grid, increasing BC Hydro's total generation capacity from 12.2 GW to 13.3 GW. The Site C project was originally proposed in 1981 but did not gain approval until 2010, with construction starting in 2015. The project was expected to satisfy B.C.'s electricity requirements for the next 15 years, but new estimates suggest further generation may be required as early as 2030.**[14]
2. **In 2022, hydro generation in B.C. operated at an annual capacity factor of 54%, due to the drought conditions pervasive in large parts of the province. In July of 2023, the province imported 2.1 million MWh to cover shortfalls in generation related directly to low snowpack melt and reduced precipitation.**[109]
3. **Transmission capacity limitations have been identified in many areas of the province, including the North Coast, Kootenays, the Lower Mainland, and Vancouver Island. Incremental power requirements in the North Coast region have resulted in the approval to construct the North Coast Transmission system expansion (Figure 57). This project was initially proposed in 2014 and is now proceeding with a targeted full in-service date of 2032. The project aims to build out capacity from Prince George to Terrace through a $3 billion, 445 km, 500 kV line, which could later be extended to Kitimat and Prince Rupert.**[110]

**FIGURE 57: B.C. Hydro North Coast electrification transmission system expansion**[110]

These examples highlight the potential benefit that a distributed hydrogen generation model based on methane pyrolysis coupled with microgrid capability could have in addressing power requirements throughout the province. In addition to concentrating the generation at the point of demand, pyrolysis could create a network of electrical hubs to support centralized generation and help maximize operating and capital efficiency of the transmission system. Microgrids coordinated and dispatched by the grid operator would be able to react to regional peaking requirements and system instabilities.

## Exporting $H_2$ using LNG

British Columbia will enter the global liquid natural gas market with the completion of LNG Canada's 14 Mt/yr Phase 1 facility and TC Energy's 4 BCF/d Coastal Gaslink pipeline in 2024. Phase 2 is currently being evaluated, which would double the province's export capacity. The various export projects and proposed natural gas pipelines are illustrated in **Figure 58**.[111] Other LNG projects being proposed include Cedar LNG in Kitimat, Woodfibre LNG in Squamish, Tilbury LNG on Tilbury Island in Delta, and Ksi Lisims LNG at Wil Milit on Pearse Island. If all these projects are completed, they would total 47.6 Mt/yr (6.4 BCF/d) of exports, representing approximately 10% of the current global LNG capacity and less than 5% of global LNG import capacity **(Figure 59)**.[112]

**FIGURE 58:** **B.C. natural gas infrastructure and LNG export terminals**[111]

**FIGURE 59: LNG export and import capacity change 2023 to 2024**[112]

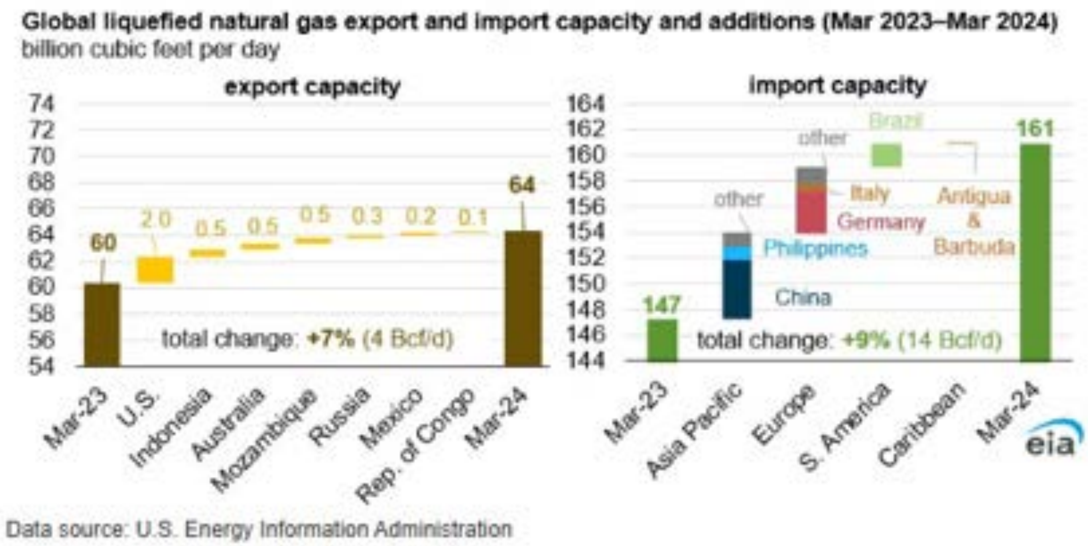
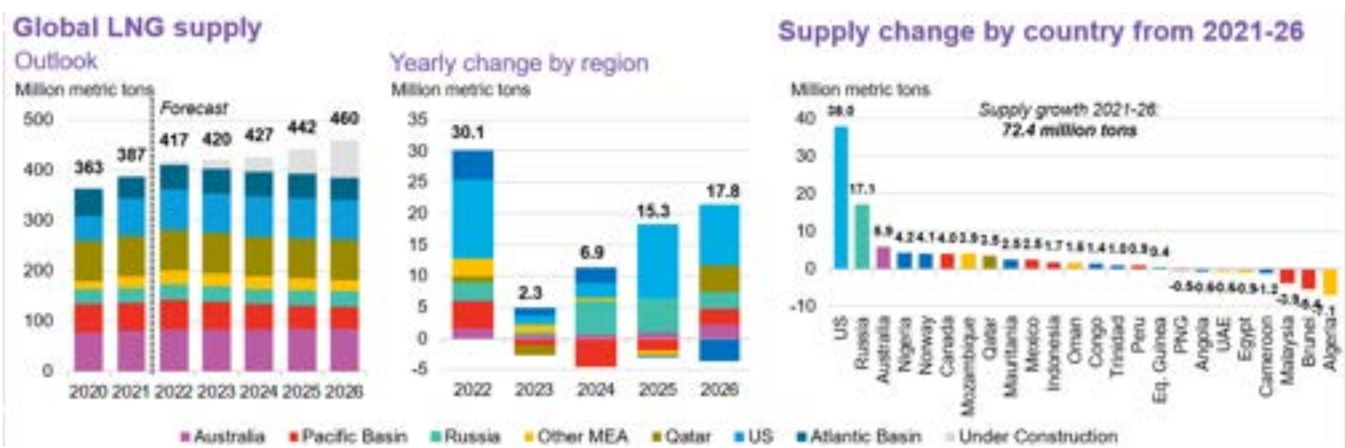



**FIGURE 60: Global import/export LNG capacity**[113]




Global LNG exports are forecast to grow, albeit slight declines have been seen in short term contracts, particularly in Europe due to focus on hydrogen imports **(Figure 60)**.[113] The U.S. has continued to experience growth in export capacity and has become the world's largest LNG exporter, surpassing Australia in 2022.

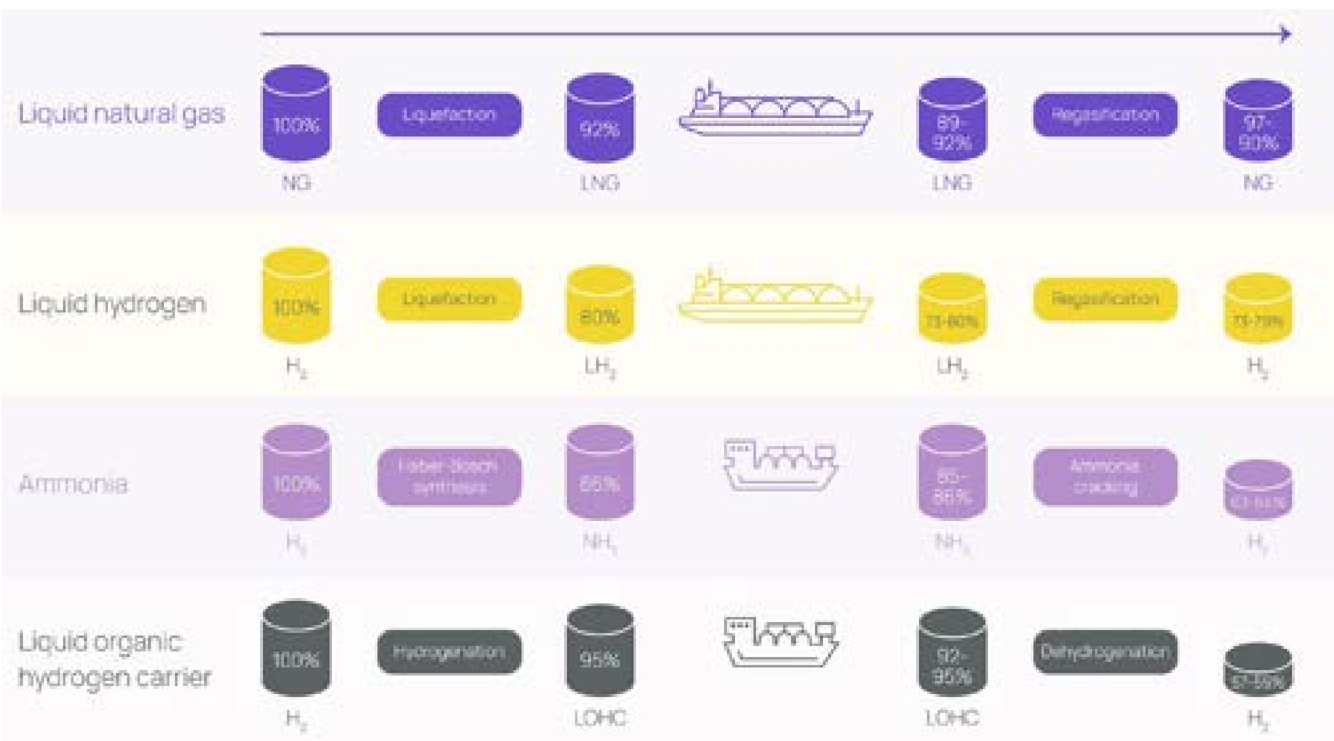
While natural gas has traditionally been seen as a transitional fuel away from coal, a greater focus on net-zero emissions is changing the narrative to focus on pure zero emission fuels like renewable ammonia or hydrogen. However, transporting hydrogen in compressed or liquid forms is a highly capital and energy intensive process. Hydrogen carriers such as ammonia and liquid organic hydrogen carriers (LOHC) are being evaluated due to their higher degree of stability and high energy content but are offset by the fluids' toxicity and low energy efficiency in conversion.

**Figure 61**[114] shows the efficiencies of shipping LNG, liquid hydrogen and the two hydrogen carriers, Ammonia and LOHC. The data represents the approximate distance between B.C. and Japan (8,000 km) and demonstrates that LNG is the most efficient carrier, with liquid hydrogen being second best. However, this does not tell the entire story, as liquid hydrogen has a low energy density by volume in comparison to the other options. For example, it would take more than 2.5 cargo ships of liquid hydrogen to match the same energy content of a single LNG shipment.

The commercial development of methane pyrolysis could solve the commercial challenge of hydrogen transport and improve the long-term prospects of LNG as a zero-emission fuel by allowing import countries to use natural gas for energy generation without emissions. The export of pyrolysis alongside LNG could allow for the continued use of the existing LNG infrastructure without requiring the build-out of additional carbon capture and sequestration infrastructure in import countries. These concepts could be proven out in B.C. with strong prospects for exports over the long term.

**FIGURE 61: Hydrogen Carriers — Energy efficiencies along conversion and transport chain**

**Represents the energy efficiency of shipping one unit volume via marine transport of 8,000 km (BC to Japan) and the losses that occur for each step until landing [Source: IEA]**



## Regulatory and policy changes

Regulatory changes are needed both to streamline the regulatory processes for hydrogen production and distribution, and to help create the market for pyrolysis-generated carbon black and graphite. Hydrogen has traditionally been grouped with other poisonous and toxic chemicals under the BCEAA, including the classification of hydrogen as a dangerous good for distribution. However, as per **Section 4.6**, the BCUC recently conducted an enquiry on hydrogen regulations, identifying exceptions for certain hydrogen use cases. It will be important for these exemptions to also apply to hydrogen production through methane pyrolysis to ensure this pathway has an opportunity to develop in the province.

Policy changes at the municipal level related to public procurement can also move the needle on methane pyrolysis by creating a market for carbon materials. The asphalt, aggregates, and cement industries could represent a significant demand source for carbon co-products in B.C., through direct augmentation and/or replacement of existing feedstock. Based on an interview with a cement and concrete manufacturer in B.C., cement makes up 20% of concrete by mass but represents more than 80% of embodied carbon emissions. Fly ash from landfills is one alternative, low carbon option for cement, and there are experiments underway for utilization of solid carbon. However, public procurement processes at the municipal and provincial levels need to incentivize the use of low carbon materials.

Based on discussions with asphalt and concrete providers in B.C., municipalities have a perception of reduced product quality from product substitution. Asphalt and concrete providers are penalized for substituting feedstock with recycled or alternative lower carbon materials beyond the minimum targets. Increasing these blending targets or creating new by-laws to promote lower carbon materials could open up new markets for solid carbon.

Policy is also important for driving greater demand for low carbon fuels like hydrogen. British Columbia has a LCFS to incentivize transport decarbonization, but there are no policy incentives for industrial decarbonization broadly. The absence of a carbon border adjustment mechanism (CBAM), like the one recently implemented in Europe, makes large trade-exposed industrial emitters less competitive and likely to implement decarbonization initiatives.[115] Applying carbon pricing to imports could be one method for driving greater adoption for lower carbon fuels like hydrogen.

# Glossary and abbreviations

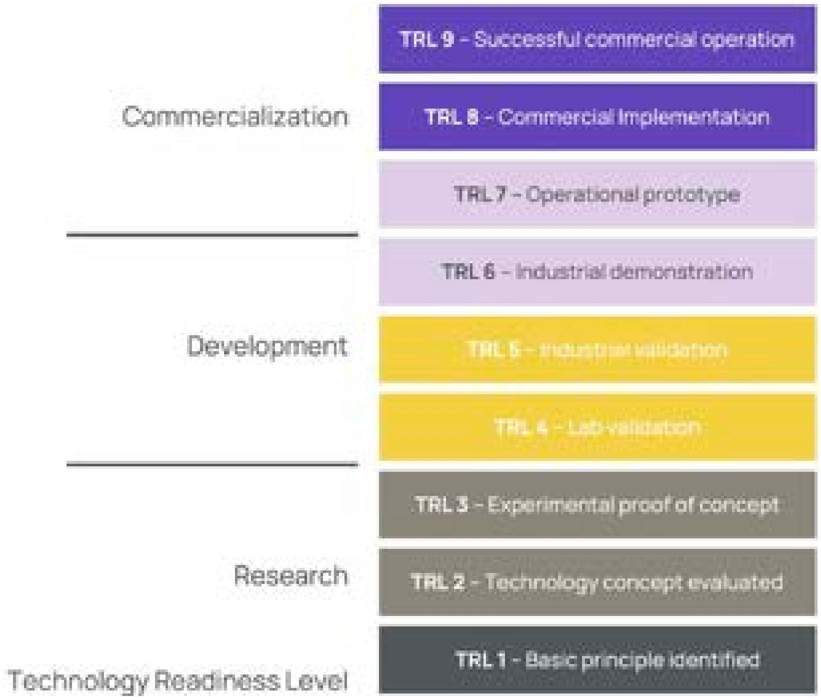
| | |
|---|---|
| **°C** | degree Celsius |
| **APEGA** | The Association of Professional Engineers and Geoscientists of Alberta |
| **ARPA-E** | Advanced Research Projects Agency–Energy |
| **ASTM** | American society for testing and materials |
| **ATR** | Autothermal reforming |
| **B.C.** | British Columbia |
| **BCEAA** | British Columbia Environmental Assessment Act |
| **BCER** | British Columbia Energy Regulator |
| **BCF** | Billion cubic feet (109 cubic feet) |
| **BCUC** | British Columbia Utilities Commission |
| **BEV** | Battery Electric Vehicle |
| **BOP** | Balance of plant |
| **CAD** | Canadian dollar |
| **CAGR** | Compound annual growth rate |
| **CAPEX** | Capital Expenditure |
| **CBAM** | Carbon border adjustment mechanism |
| **CCUS** | Carbon capture, utilization, and storage |
| **CEPA** | Canadian Environmental Protection Act |
| **CFR** | Clean fuel regulation |
| **CI** | Carbon intensity |
| **CICE** | B.C. Centre for Innovation and Clean Energy |
| **$CH_4$** | Methane |
| **CO** | Carbon monoxide |
| **$CO_2$** | Carbon dioxide |
| **$CO_2e$** | Carbon dioxide equivalent |
| **d** | day |
| **DIP** | Drought information portal |
| **DOE** | U.S. Department of Energy |
| **EA** | Environmental assessment |
| **EPCM** | Engineering, Procurement, and Construction Management |
| **EU** | Europe |
| **EV** | Electric vehicle |
| **FCEV** | Fuel cell electric vehicle |
| **FNCI** | First Nation Climate Initiative |
| **GHG** | Green House Gas |
| **GJ** | Gigajoule (109 joule) |
| **GLJ** | GLJ Energy Consultants |
| **GREET** | Greenhouse gases, Regulated Emissions, and Energy use in Technologies. |
| **Gt** | Gigatonne (109 tonne) |
| **GW** | Gigawatt (109 watt) |
| **GWh** | Gigawatt hour |
| **$H_2$** | Hydrogen |
| **HDV** | Heavy duty vehicles |
| **HHV** | Higher heat value |
| **HIC** | Hydrogen induced cracking |
| **hr** | Hour |
| **IA** | Impact assessment |
| **IAA** | Impact assessment act |
| **ICE** | Internal combustion engine. |
| **IPP** | Independent Power Producer |
| **ITC** | Investment tax credit |
| **kg** | Kilogram ($10^3$ gram) |

| | |
|---|---|
| **kJ** | Kilojoule ($10^3$ joule) |
| **km** | Kilometre ($10^3$ metre) |
| **KOH** | Potassium hydroxide |
| **kt** | Kilotonne ($10^3$ tonne) |
| **kV** | Kilovolt ($10^3$ volt) |
| **kW** | Kilowatt ($10^3$ watt) |
| **kWh** | Kilowatt hour |
| **l** | Litre |
| **LCA** | Life cycle emissions assessment |
| **LCFS** | Low carbon fuel standard |
| **LCOH** | Levelized cost of hydrogen. |
| **$LH_2$** | Liquid hydrogen |
| **LHV** | Lower heat value |
| **LNG** | Liquified natural gas |
| **LOHC** | Liquid organic hydrogen carrier |
| **MHD** | Medium- and Heavy-duty |
| **MJ** | Megajoule ($10^6$ joule) |
| **MMCF** | Million cubic foot ($10^6$ cubic feet) |
| **MOU** | Memorandum of understanding |
| **MTC** | Methane thermal cracking |
| **Mt** | Megatonne ($10^6$ tonne) |
| **MW** | Megawatt ($10^6$ watt) |
| **MWh** | Megawatt hour |
| **NE** | North-east |
| **NPS** | Nominal pipeline size |
| **OPEX** | Operating Expense |
| **Orion** | Orion Projects |
| **PEM** | Proton exchange membrane |
| **PJ** | Petajoule ($10^{15}$ joule) |
| **PSA** | Pressure swing adsorption |
| **PTC** | Production tax credit |
| **RNG** | Renewable natural gas |
| **SAF** | Sustainable aviation fuel |
| **SE** | South east |
| **Sky Point** | Sky Point Resources Ltd. |
| **SOEC** | Solid oxide electrolysis cell |
| **SPE** | Society of Petroleum Engineers |
| **SMR** | Steam methane reforming |
| **TA** | Transition Accelerator |
| **TCF** | Trillion cubic feet ($10^{12}$ cubic feet) |
| **TCO** | Total cost of ownership |
| **TIER** | Technology innovation and emission reduction regulation |
| **$tH_2/d$** | Tonnes Hydrogen per day |
| **TPD** | Tonnes per day |
| **TPY** | Tonnes per year |
| **TRL** | Technology Readiness Level |
| **TW** | Terawatt ($10^{12}$ watt) |
| **TWh** | Terawatt hour |
| **UK** | United Kingdom |
| **US** | United States of America |
| **USD** | United States dollar |
| **WGS** | Water gas shift |
| **ZEV** | Zero emission vehicles |

# Appendix

## Technology Readiness Level descriptions

**FIGURE 62: Technology Readiness Level descriptions**




## Modelling inputs and calculations

This appendix provides a breakdown of the key variables used in the techno-economic analysis for each technology and scenario, and is broken into the technology types.

## Electrolysis

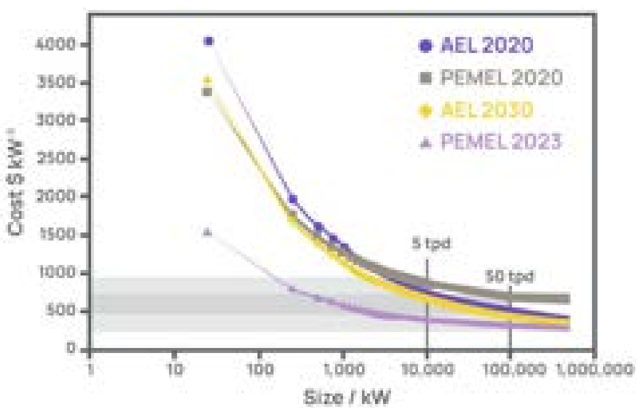
The basis of electrolysis modelling relies on a PEM system with the following key parameters: using average data across several academic sources, and high-level quotes from producers. The key inputs are summarized in **Table 8** below. The electrolysis pathway assumes run-time of up to 95%, assuming grid-connected electrolyzers, but the LCOH could change considerably if the facilities are connected directly to renewable power projects with time-based matching. The capacity factors for solar and wind power in B.C. can be 20% to 45% respectively, so running the electrolyzer at lower capacities would increase the levelized CAPEX per kg of hydrogen produced.

**TABLE 8: Electrolysis economic assumptions**

| Key parameter (water electrolysis) | Value | Unit |
|---|---|---|
| **Outputs and co-products (per kg of hydrogen)** | | |
| Hydrogen | 1 | kg |
| Oxygen | 7.9 | kg/kg$H_2$ |
| Wastewater | 1.65 | L/kg$H_2$ |
| **Inputs (per kg of hydrogen)** | | |
| Electricity | 50 | kWh/kg$H_2$ |
| Water | 16.5 | L/kg$H_2$ |
| **Capital costs** | | |
| Electrolyzer (5 t$H_2$/d / 11 MW) | 1,600 | CAD$M/MW |
| Electrolyzer (50 t$H_2$/d / 105 MW) | 800 | CAD$M/MW |
| Balance of plant | 80% | % of CAPEX |
| Development expense | 10% | % of CAPEX |
| **Operating costs** | | |
| Sustaining capital (incremental to stack replacement every 8 years) | 1% | % of CAPEX |
| Stack replacement (based on 60,000 hours) | 525-400 | CAD$M/MW |
| Water demineralization | $2.7 | Per $m^3$ |
| Maintenance | 2% | % of CAPEX |
| SG&A and insurance | 1.3% | % of CAPEX |
| Labour (5 – 50 t$H_2$/d) | 2.5% - 1% | $ per year |
| **Other variables** | | |
| Assigned value for co-product (oxygen) | $0 | Per kg |

The biggest factors contributing to the LCOH for electrolyzers is the capital costs of the electrolyzer stack and electricity. While electricity prices will slowly increase over time with inflation and scale with size, the greatest cost declines will include economies of scale from CAPEX at larger sizes. Electrolyzer CAPEX can typically be split into the electrolyzer stack costs and the electrical and mechanical balance of the plant. Larger electrolyzer plants require a greater number of stacks to be connected together, which naturally result in lower prices due to bulk buying discounts. Electrolyzer stacks currently have low life spans with estimated cycle times of 60,000 hours, which result in incremental sustaining capital requirements. Based on Wright's Law, every doubling of production should decrease the CAPEX of the electrolyzers by a consistent amount. Several studies have estimated cost reductions along an exponential declining curve, as per Figure 63.[116] Additional savings would be realized with continued development of electrolyzers and their increased cycle time.

**FIGURE 63: Cost prediction for PEM and Alkaline electrolyzers in 2020 and 2030**




There may be additional cost declines from optimizations to the balance of plant, with the marginal costs of greater mechanical and electrical components dropping per kg of $H_2$ produced. Electric Hydrogen is one company that claims to reduce the installed CAPEX of electrolyzers by more than 50%.[117] However, to maintain conservativeness, BOP and installation costs were assumed to be 100% of the plant CAPEX.

## Pyrolysis

With the numerous alterations of pyrolysis that are currently being developed, identifying one set of variables to define the technology is difficult. For the purposes of this study, thermal and catalytic pyrolysis were utilized to provide a range of outcomes based on two of the less complex technology variants. Plasma pyrolysis has a great deal of variation from one technology to the next, and thus was not included in the techno-economic evaluation. Third party sources generally indicate plasma as being a higher cost and ultimately higher LCOH pathway. However, in interviews with these technology companies, it was indicated that the range of results obtained utilizing thermal and catalytic pyrolysis can be used as a proxy to the values that could be obtained through plasma pyrolysis.

The modelling parameters are based on average data across several potential catalytic and thermal pyrolysis technology developers. It is expected that thermal reactors would have higher volumes of solid carbon production due to recycling of hydrogen to produce additional heat. It is assumed that the catalyst-based pyrolysis producers would use electricity for heat generation, though some developers could utilize natural gas or hydrogen combustion. The CAPEX for thermal reactors is expected to be lower than catalytic pyrolysis reactors due to the absence of a catalyst in the reactor, resulting in lower balance of plant costs. Catalysts typically make up to 25% of operating costs, resulting in higher opex as compared to thermal. The key inputs are summarized in **Table 9** below:

**TABLE 9: Pyrolysis economic assumptions**

| Key parameter (pyrolysis) | Thermal | Catalytic | Unit |
|---|---|---|---|
| **Outputs and co-products (per kg of hydrogen)** | | | |
| Hydrogen | 1 | 1 | kg |
| Solid carbon | 3.5 | 3 | kg/kg$H_2$ |
| **Inputs (per kg of hydrogen)** | | | |
| Electricity (includes reactor + balance of plant) | 4 | 10 | kWh/kg$H_2$ |
| Natural gas | 285 | 225 | MJ/$kg_{H2}$ |
| **Capital costs (inclusive of BOP and installation)** | | | |
| 5 t$H_2$/d reactor | $30M | $35M | CAD$M |
| 50 t$H_2$/d reactor | $121M | $141M | CAD$M |
| 300 t$H_2$/d reactor | $355M | $413M | CAD$M |
| Development expense | 10% | 10% | % of CAPEX |
| **Operating costs** | | | |
| Sustaining capital | 1% | 1% | % of CAPEX |
| Catalyst costs | $0.02 | $0.47 | $/kg$H_2$ |
| Maintenance | 2% | 2% | % of CAPEX |
| SG&A and insurance | 1.28% | 1.28% | % of CAPEX |
| Labour (5 t$H_2$/d – 50 t$H_2$/d - 300 t$H_2$/d) | 2.5%- 1%-0.5% | 2.5%- 1%-0.5% | % of CAPEX |
| Other variables | | | |
| Assigned value for co-product (carbon) | $0- $250 | $0- $500 | Per tonne |
| **Other variables** | | | |
| Assigned value for co-product (oxygen) | | $0 | Per kg |

As described in **Section 6**, most pyrolysis plants today are at very small scales, which introduces uncertainty around how larger facilities will scale. While most of the balance of plant is standardized industrial equipment, including nozzles, carbon handling systems and furnaces, larger reactors and the connection of multiple reactors together will need to be designed. There are economies of scale that can be expected on both the reactor and balance of plant, but the degree of cost reductions will depend on further engineering. The CAPEX for larger reactors was based on estimates provided through conversations with various pyrolysis technology developers.

### Reforming

A majority of current hydrogen and hydrogen syngas is produced via steam methane reforming (SMR). However, new designed facilities are utilizing auto-thermal reforming (ATR) technology as it offers superior ability to capture $CO_2$. For this model, an ATR facility is utilized in conjunction with a co-located carbon capture and sequestration plant, with power purchased from the grid. The facility boundary includes both the ATR reactor and carbon capture and processing equipment, including an amine system, dehydrator, and compressor **(Table 10)**. It is assumed that a large-scale ATR will be connected to a $CO_2$ pipeline, which will carry captured carbon dioxide for sequestration in saline aquifers or for enhanced oil recovery. Based on studies conducted by the Great Plains Institute, the costs of $CO_2$ transport average USD $10-$20/t and the sequestration/storage costs are approximately USD $5/t.[118] No credits or incentives were utilized in the economic evaluation.

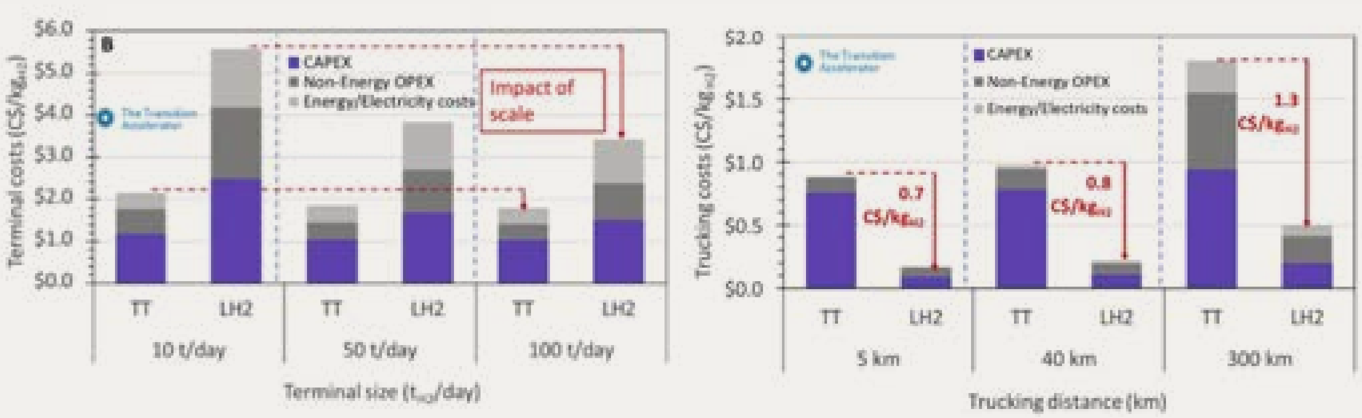
**TABLE 10:** **ATR + CCUS economic assumptions**

| Key parameter (ATR + CCUS) | Value | Unit |
|---|---|---|
| **Outputs and co-products (per kg of hydrogen)** | | |
| Hydrogen | 1 | kg |
| Carbon dioxide released (assumed 97% carbon capture) | 0.3 | kg/kg |
| Waste water | 1.7 | L/kg |
| **Inputs (per kg of hydrogen)** | | |
| Electricity | 3 | kWh/kg |
| Natural gas | 165 | MJ/kg |
| Water | 6.1 | L/kg |
| **Capital costs (inclusive of BOP and installation)** | | |
| 300 tpd reactor + carbon capture and compression | 646 | CAD$M |
| Development expense | 10% | % of CAPEX |
| **Operating costs** | | |
| Sustaining capital | 1% | % of CAPEX |
| Catalyst & chemical costs | $0.024 | $/kg$H_2$ |
| Maintenance | 2% | % of CAPEX |
| SG&A and insurance | 1.28% | % of CAPEX |
| Labour | 0.5% | % of CAPEX |
| Carbon transport & sequestration fee | $40 | Per tonne $CO_2$ |
| **Other variables** | | |
| Assigned value for co-product (carbon dioxide) | $0 | Per tonne in 2030 |
| Facility uptime | 350 | Days of year |

# Supply chain costs

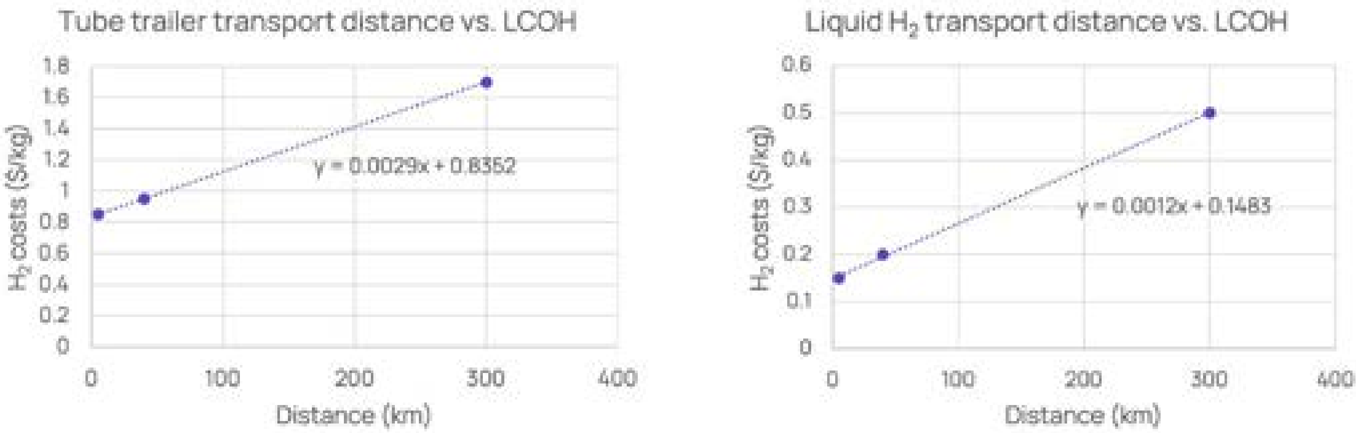
The supply chain costs of hydrogen conditioning, from the production gate to end-use were calculated using several external data sources, with **Table 11** providing a summary of the factors used across each scenario including references and calculations. The compression, terminal, and hydrogen distribution costs were calculated using figures from the Transition Accelerator (TA) report on the technoeconomic evaluation of hydrogen value chain for heavy duty transport.[93] **Figure 5.1** from the report was used to determine the compression costs for Scenario 1 as well as the liquefaction costs for a centralized facility for Scenario 2. The transportation and trucks costs for the centralized facility in Scenarios 1 and 2 were captured in **Figure 5.3**. The two charts from the TA report are referenced in **Figure 64**.

**FIGURE 64: Figures from the TA report for compression terminal costs (5.1) and distribution/trucking costs (5.3) in $CAD/kg of $H_2$**



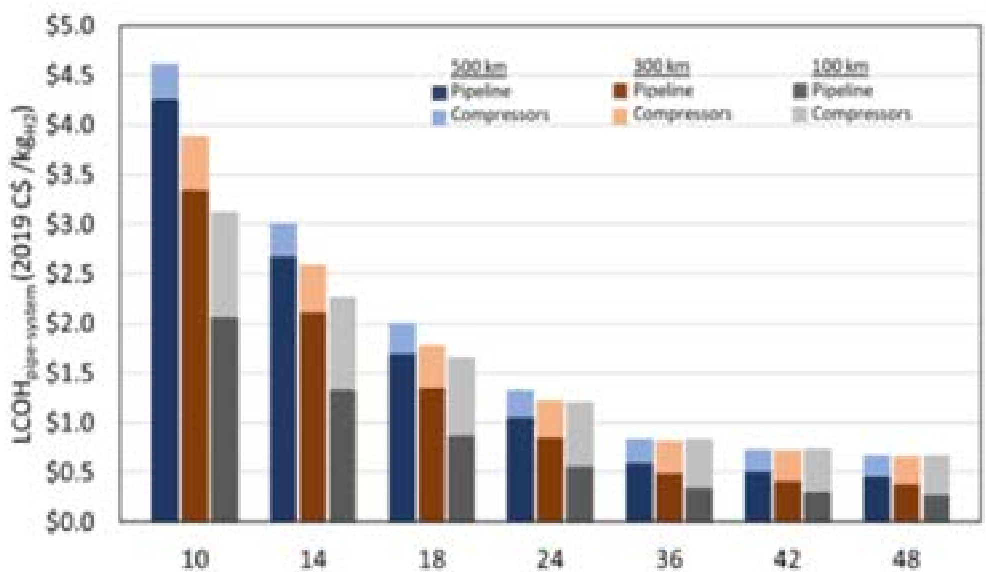

The figures were then adjusted for any differences in scale of production and compression, according to **Table 11.** The relative differences in compression costs were determined using quotes from the Hyjack tool.[119] For example, if the compression required for electrolysis was from 30 bar to 500 bar, instead of 20 bar to 500 bar for pyrolysis, the proportional difference calculated from Hyjack was applied to the factor from the TA report. The transportation costs were extrapolated based on a linear equation applied to the data points from the TA report. As per **Figure 65**, the three data points based on trucking distance and costs from Figure 64 were plotted, along with a line of best fit representing the relationship between the three data points. An equation was derived through Excel and was used to determine the costs for transport distances of up to 800 km for compressed hydrogen and 1,200 km for liquid hydrogen.

**FIGURE 65: Equations used to calculate LCOH for transport distances based on data from TA report figure 5.3**




Gas conditioning costs are also applied based on section 5.1 from the TA report, which estimates costs for PEM fuel cell requirements using pressure swing adsorption (PSA). It is assumed that most electrolysis producers include some form of gas treatment within their basis of design, which will make treatment costs negligible. The quality of hydrogen gas produced from pyrolysis can vary significantly, but it is assumed that it contains much more impurities than the ATR process, so the purification costs were assumed to be double. Gas treatment was only applied to Scenarios 1 and 3, with the assumption that the combustion end use for Scenario 2 would be able to handle higher levels of impurities.

**FIGURE 66: Figure 7.3 from TA report on techno-economic analysis of hydrogen pipelines broken down by pipeline and compression costs at various pipe sizes and distances**



Pipeline transmission costs for Scenario 3 were based on a separate TA report on the techno-economics of hydrogen pipelines in Canada. **Figure 7.3** in the report provides the LCOH of pipelines at various distances and pipe sizes, which is shown in **Figure 66**.[120] The TA report suggests that the optimal pipe size for a 300 $tH_2$/d facility is 12-14 NPS, which increases at increments of $0.4/kg for every 200 km of distance.

**TABLE 11: Summary of supply chain costs across each Scenario, including reference source and description.**

| | Production type | Supply chain | Factor used | Source/description |
|---|---|---|---|---|
| Scenario 1 | ATR + CCUS | Compression | $1.7/kg | TA report (TT and 100 $tH_2$/d) adjusted down by 4% as per Hyjack |
| | | Tube trailer | $3.2/kg | Using equation Y = 0.0029*800 + 0.8352 |
| | Pyrolysis | Compression | $2.1/kg | TA report (TT and 10 $tH_2$/d) |
| | Electrolysis | Compression | $1.9/kg | TA report (TT and 10 $tH_2$/d) adjusted down by 12% as per Hyjack |
| Scenario 2 | ATR + CCUS | Liquefaction | $3.3/kg | TA report ($IH_2$ and 100 $tH_2$/d) adjusted down by 4% as per Hyjack |
| | | Liquid Trailer | $1.6/kg | Using equation Y = 0.0012*1200 + 0.1483 |
| | Pyrolysis | Compression | $1.0/kg | TA report (TT and 50 $tH_2$/d) adjusted down by 45% as per Hyjack |
| | Electrolysis | Compression | $0.4/kg | TA report (TT and 50 $tH_2$/d) adjusted down by 80% as per Hyjack |
| Scenario 3 | ATR + CCUS | Pipeline | $4.4/kg | TA report (14 NPS) and 500 km plus $0.4/kg * 3.5 |
| | | Compression | $0.8/kg | TA report (TT and 100 $tH_2$/d) adjusted down by 56% as per Hyjack |
| | Pyrolysis | Compression | $0.8/kg | |

## Utility costs and other modelling parameters

Costs related to utility connections, including electricity, natural gas, water and wastewater, and carbon pricing were based on published Government of B.C. data along with projections by well-reputed commodity firms in Canada. There were several other modelling parameters that were similar across each scenario and technology, related to maintenance, insurance, cost of capital, and tax rates, summarized in **Table 12**.

**TABLE 12: Additional economic assumption**

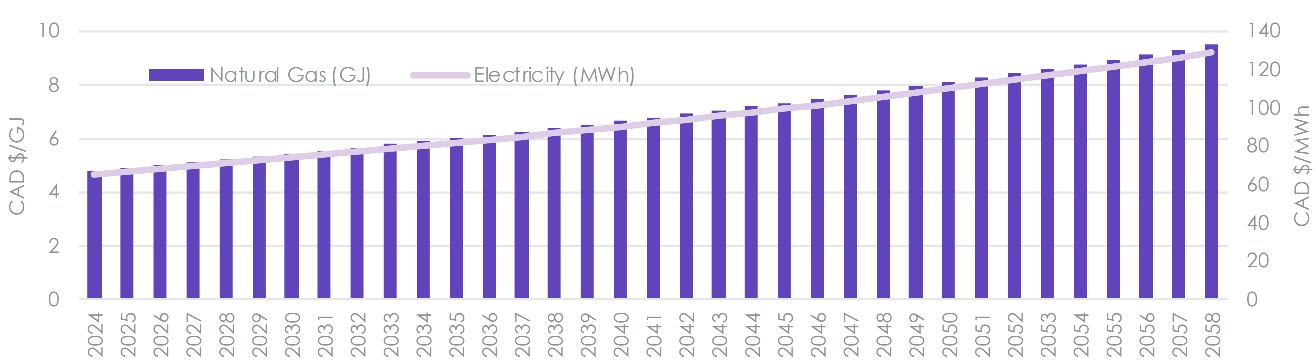
| Other Modelling Parameters | Value | Unit |
|---|---|---|
| **Utility Costs** | | |
| Fresh Water | $1.5 | $m_3$ |
| Wastewater | $2.0 | $m_3$ |
| **Financial Parameters** | | |
| Discount Rate | 10 | % |
| Inflation (until 2028 - post 2028) | 1.5% | % |
| **Other Modelling Parameters** | | |
| Facility Life | 30 | Years |
| Facility Uptime | 350 | Days per Year |
| Exchange Rate | 1.33 | CAD: USD |

There has been significant volatility in the natural gas market over the last few years which makes price forecasting difficult, as per **Figure 67**, which shows historical and future prices for natural gas in B.C. FortisBC has standardized rates for natural gas, which are reviewed by the BC Utility Commission every year and vary by region. Rate 7 was used for modelling all pyrolysis and large-scale hydrogen production pathways, which is focused on large-volume customers and is made up of both fixed and variable charges which bundle delivery and commodity charges through FortisBC.[121]

**FIGURE 67: Natural gas price history and forecast for Station 2 in B.C. (GLJ) with price projections (dashed line) & futures (dotted line)**


The electricity price is based on the BC Hydro Large General Service Rate, which is for businesses with an annual peak demand of at least 150 KW.[122] Since most projects modelled in this report would take 3-5 years to commission, the special electricity rates for hydrogen and industrial electrification were not used, as they would expire by 2030 and would have a negligible impact on the project costs. The full natural gas and electricity prices included in the model are summarized in **Figure 68**. These include both the commodity costs and the transmission, distribution, and delivery charges, and are escalated by 2% annually.

**FIGURE 68: Modelled B.C. electricity and natural gas prices (2024-2058)**



# About B.C. Centre for Innovation & Clean Energy

Founded in October 2021, the B.C. Centre for Innovation and Clean Energy (CICE) is an independent, not-for-profit corporation that provides early-stage investment to fast-track the commercialization and scaling of B.C.'s clean energy solutions — from Canada to the world. With $105M raised through public and private member partnerships and grants, CICE propels climate-first innovation and market adoption that leads to the creation of good jobs, diversity, intellectual property, global leadership, and investment into B.C.'s green economy. CICE's mission is to advance the world towards a net-zero carbon future.

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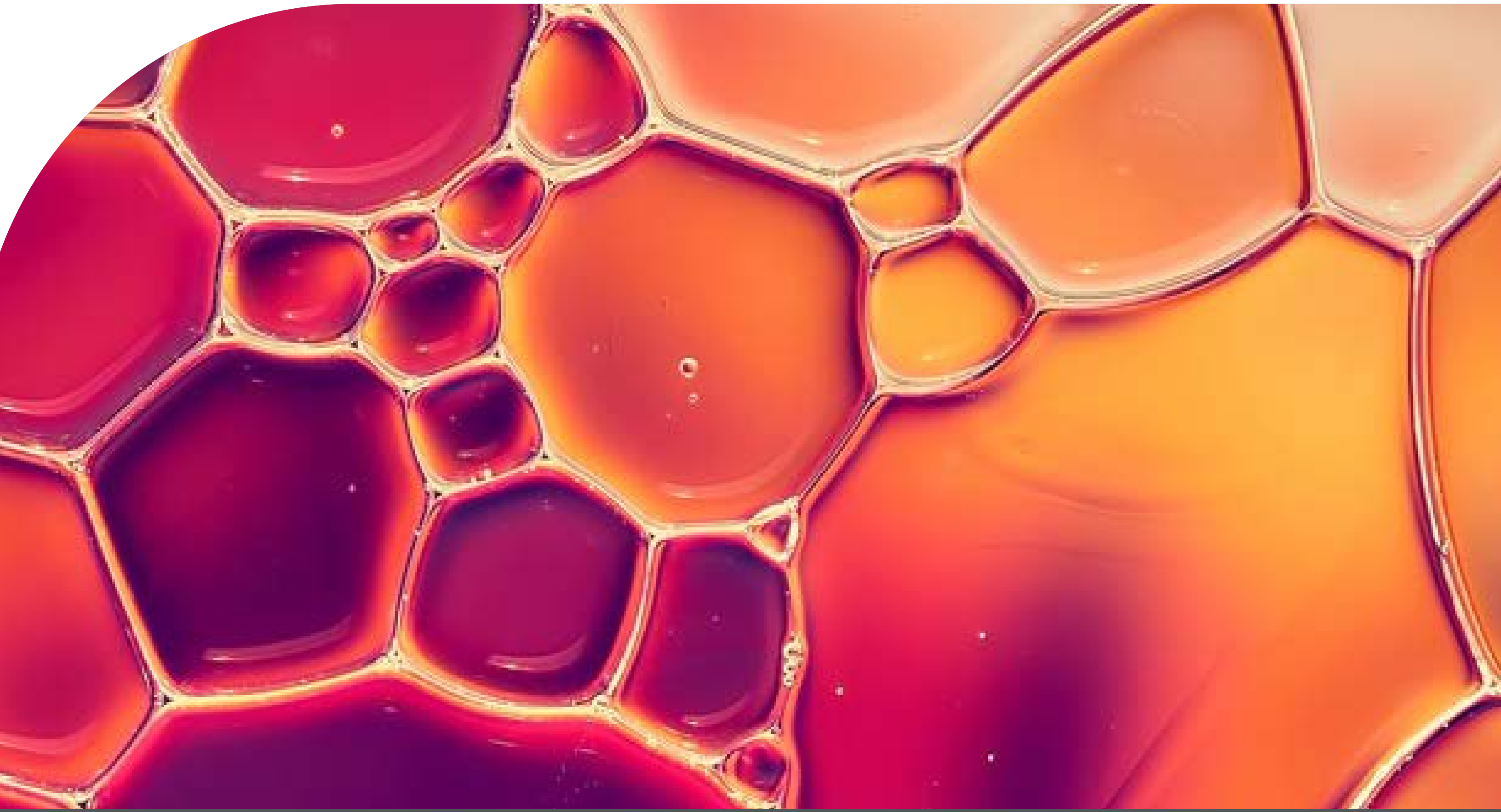

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