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June 1, 2022

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Mr. Patrick Wruck, Commission Secretary

Dear Mr. Wruck:

Re: FortisBC Energy Inc. (FEI)

Application for Approval of the Regional Gas Supply Diversity Development Account

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Attached please find an application to the British Columbia Utilities Commission for approval pursuant to sections 59 to 61 of the *Utilities Commission Act* of the creation of a new deferral account, the Regional Gas Supply Diversity (RGSD) Development Account (Application).

The proposed RGSD Development Account will enable FEI to commence development work on the RGSD Project by capturing development costs to determine which regional infrastructure option to support as being in the best interest of FEI and its customers, and whether it is appropriate to bring forward an application for a Certificate of Public Convenience and Necessity for the RGSD Project, as discussed in the Application.

Request for Expeditious Review Process

As the BCUC will see in Section 1.4, FEI is proposing a condensed regulatory timetable for review of this Application. While FEI is aware of the heavy regulatory calendar at present, there is a compelling commercial rationale for ensuring that the requested RGSD Development Account is in place as soon as possible.

Specifically, since the last Annual Review process (when FEI had requested a similar account), Enbridge Inc. has recently announced its intention to begin developing a $2.5 billion+ expansion of its T-South pipeline (T-South Expansion) in 2022. As the largest shipper on T-South, FEI and its customers will pay a significant portion of the cost of the T-South Expansion. Doing nothing or delaying the RGSD Project development work would effectively mean accepting the additional rate impacts of the T-South Expansion, with little to no benefit to FEI and its customers. FEI believes it is important to preserve the RGSD Project as a potentially much more beneficial alternative for customers.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Interveners in the FEI Annual Review for 2022 Delivery Rates

FORTISBC ENERGY INC.

Application for Approval of the Regional Gas Supply Diversity Project Development Account

June 1, 2022

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1. INTRODUCTION AND EXECUTIVE SUMMARY

1.1 *INTRODUCTION*

FEI is requesting BCUC approval pursuant to sections 59-61 of the *Utilities Commission Act* (UCA) for the creation of the Regional Gas Supply Diversity Project Development Costs deferral account (RGSD Development Account), a non-rate base account[1] attracting a Weighted Average Cost of Capital (WACC) return, with disposition of the balance to be proposed and addressed in a future application. As discussed further below, the proposed RGSD Development Account will enable FEI to commence development work on the Regional Gas Supply Diversity Project (RGSD Project or Project) by capturing development costs, which initially are primarily related to engagement with Indigenous Nations and exploration of options for direct Indigenous involvement in the Project. In terms of ongoing BCUC oversight, FEI is proposing to file quarterly reports starting with the quarter ending at least three months after the BCUC's decision on this Application. In lieu of a Q2 2023 quarterly report, FEI will provide an update in the Annual Review for 2024 Delivery Rates (2024 Annual Review), which FEI will be filing in July or August of 2023, and include a proposal for recovering costs incurred up to that point. FEI would take into account the BCUC's determinations in the 2024 Annual Review process in determining whether or how to proceed with further development work.

The choice currently facing FEI when it comes to new regional pipeline infrastructure is a choice of *which* regional infrastructure option to support as being in the best interest of FEI and its customers, not whether or not to participate at all. Regardless of FEI's own needs, market conditions throughout BC and the US Pacific Northwest (Region) are driving the need for new pipeline infrastructure. Regional pipeline infrastructure is already fully subscribed, and demand in the Region is increasing. Woodfibre LNG has announced its intention to proceed with its project, and upon commissioning there will be an immediate and significant capacity shortfall on Enbridge's T-South system.[2] Moreover, the demand for gas-fired electricity in the US Pacific Northwest is expected to continue growing with the retirement of coal-fired generation. These developments, among others, will drive new Regional pipeline infrastructure irrespective of FEI's own needs.

FEI, as the largest shipper on Enbridge Inc.'s T-South system, will – simply as a matter of toll design – contribute significantly to the capital cost and cost of service of any T-South expansion even though FEI does not need any new capacity on T-South. The significant additional cost that FEI customers will pay for any expansion(s) of T-South also comes with little, if any, upside in terms of access to supply, supply cost, resiliency or support for FEI's move towards a

[1] Consistent with past practice, FEI has requested to capture the development costs in a non-rate base deferral account such that the costs incurred would be held outside of FEI's rate base as well as FEI's delivery rates until BCUC approval of recovery of these incurred costs in a future application.

[2] https://woodfibrelng.ca/woodfibre-lng-issues-notice-to-proceed-to-mcdermott-international/.

renewable and low-carbon gas future.[3] In contrast, FEI has long recognized that the extension of FEI's Southern Crossing Pipeline (SCP) – now referred to as the RGSD Project – would provide additional Regional capacity in a way that provides significant benefits to FEI and its customers and reduces risks for them. FEI believes that it is in the best interest of FEI and its customers to influence which Regional infrastructure gets built, thereby maximizing the value they obtain from it.

FEI is now at a critical juncture in terms of Regional pipeline development. Enbridge Inc. has recently announced its intention to begin developing a $2.5 billion+[4] [5] expansion of its T-South pipeline (T-South Expansion) in 2022, to support growing demand in the Region, primarily triggered from Woodfibre LNG, which recently announced that it is advancing preliminary construction activities. On its own, the T-South Expansion project will have significant impacts on FEI customers, and FEI customers still face the potential for additional – and potentially even larger – T-South expansions to address unresolved Regional demand growth. FEI estimates that based on current firm capacity contracting levels by the utility on all segments of the T-South pipeline, FEI's costs could increase significantly by around $65 to $90 million per annum and leave the utility exposed to rely on a single pipeline system to serve the majority of its service territory. FEI believes that it is in the best interests of FEI and its customers to accelerate development work for the RGSD Project as soon as possible. Doing nothing or delaying the RGSD Project development work would effectively mean accepting the additional rate impacts of the T-South expansion with little to no benefit to FEI and its customers.

FEI recognizes that support from Indigenous Nations is critical to the development of new pipeline infrastructure. The bulk of the early planned development funding is thus aimed at engagement with Indigenous Nations, including exploring options for direct participation in the RGSD Project. FEI will also perform engineering, environmental, and geotechnical work that will inform Indigenous engagement, design and detailed cost estimates, building on past work done over many years to explore the viability of an extension of the SCP.

The proposed RGSD Development Account is a regulatory accounting mechanism that facilitates FEI incurring development costs (e.g., costs associated with consultation with Indigenous Nations, preparation of project cost estimates and feasibility work) pending the BCUC's future determination on the method and timing of recovery of incurred costs. The approval of the RGSD Development Account allows FEI to continue to explore the potential for the RGSD Project with Indigenous partnerships, thereby preserving a potentially beneficial alternative to the expansion of T-South. The BCUC's approval of the RGSD Development Account would in no way be a determination regarding the Project itself, which would be considered in a future CPCN application for the RGSD Project. Moreover, FEI's proposed

[3] FEI uses the term renewable and low-carbon gas throughout this Application to refer collectively to the low carbon gases or fuels that the utility can acquire under the *Greenhouse Gas Reduction (Clean Energy) Regulation* (GGRR), which are: Renewable Natural Gas (RNG or biomethane), hydrogen, synthesis gas and lignin.

[4] Refer to page 53 of the PDF regarding BC pipeline expansion plans: https://www.enbridge.com/~/media/Enb/Documents/Investor%20Relations/2021/2021_ENB_Day_Combined_Deck_FINAL.pdf.

[5] https://www.enbridge.com/media-center/news/details?id=123723&lang=en.

reporting and review as part of the 2024 Annual Review means that the BCUC will be able to review the actual costs incurred to that point (estimated to be approximately $24 million at that stage) and make findings regarding cost recovery that will inform FEI's assessment about whether and how to proceed with further development work.

1.2 ORGANIZATION OF THE APPLICATION

This Application is organized as follows:

- Section 2: Market conditions in the Region make new Regional pipeline infrastructure inevitable, irrespective of demand on FEI's own system. Multiple expansions of the T-South system, which is the likely scenario in the absence of a viable alternative, would have significant cost implications for FEI and its customers, with little to no additional long-term benefits.
- Section 3: The RGSD Project would have a number of long-term benefits for FEI's customers that would not come with other potential infrastructure projects in the Region, notably:
    - Facilitating FEI's decarbonization of the gas system by improving access to renewable and low carbon gas from new sources in and out of the Province;
    - Strengthening the resiliency of the Regional pipeline system, reducing the risk exposure to FEI's customers;
    - Improving diversity of supply in the Region; and
    - Building lasting partnerships between FEI and Indigenous Nations.
- Section 4: FEI's preliminary evaluation of potential Regional infrastructure options indicates that the RGSD Project is the most beneficial option, such that it warrants further development work to assess the Project's viability.
- Section 5: The development work is time-sensitive because delaying will increase the likelihood of FEI, the largest shipper on the T-South system, being required to underwrite Enbridge's proposed T-South expansion.
- Section 6: FEI provides the high-level Project schedule with details on the Project development work and associated costs. In the initial stages, the bulk of the development work is directed to engagement with Indigenous Nations, including exploring options for direct participation in the RGSD Project.
- Section 7: Under FEI's proposed approach, there are appropriate safeguards for customers, including quarterly reporting to the BCUC and a review of costs incurred to date in the 2024 Annual Review.

1.3 *APPROVALS SOUGHT: RGSD DEVELOPMENT ACCOUNT*

FEI requests BCUC approval pursuant to sections 59-61 of the UCA for the creation of the RGSD Development Account, a non-rate base account attracting a WACC return, on the following terms:

1. The account will capture actual development costs incurred, with disposition of the balance to be determined in a future proceeding;
2. Starting with the quarter ending at least three months after BCUC's decision on this Application, FEI will provide quarterly progress reporting to the BCUC on work completed, anticipated work, and material developments;
3. In lieu of the July 2023 quarterly report, FEI will provide as part of the 2024 Annual Review:
    a. reporting to the BCUC on work completed, anticipated work, and material developments;
    b. an update of the costs incurred to date; and
    c. a proposal for the method and timing of the recovery of those incurred costs; and
4. Any subsequent costs recorded in the RGSD Development Account will be considered in a future application, such as a subsequent annual review or in the CPCN application for the RGSD Project.

A draft Procedural Order and draft Final Order are included in Appendices C-1 and C-2, respectively.

Since FEI is seeking only to establish the RGSD Development Account at this time, the BCUC need only determine that it is just and reasonable based on the information currently available to establish the proposed account to facilitate commencing reasonable development work to confirm if the RGSD Project is a viable and superior alternative worthy of pursuing further. FEI seeks <u>no</u> findings in this Application regarding any of the following, which would all be addressed in future proceedings as applicable:

- Whether the RGSD Project itself is in the public interest;
- What and how much development work FEI reasonably needs to undertake to determine whether to proceed with the RGSD Project; and
- Whether, in carrying out the development work, FEI spent in a prudent manner.

1.4 *PROPOSED REGULATORY PROCESS*

The recent announcement of the T-South Expansion underscores the importance of a timely approval of the RGSD Development Account to facilitate FEI's development work with Indigenous Nations. As noted above, material delay in commencement of the development work for the RGSD Project will, in practice, make it more likely that FEI customers will underwrite the cost of the T-South Expansion with little to no benefit to FEI and its customers.

Therefore, FEI has proposed a condensed regulatory timetable for this deferral account Application. FEI believes that a one round of information requests (IRs) from the BCUC and interveners followed by a Streamlined Review Process (SRP) with oral submissions will provide for an appropriate and efficient review of the Application. One round of IRs is appropriate in this case as the issues have already been canvassed to a considerable extent in the 2022 Annual Review; FEI has no objection to those IR responses being added to the evidentiary record in this proceeding.

FEI proposes the following preliminary regulatory timetable:

Table 1-2: Proposed Preliminary Regulatory Timetable

ACTION	DATE (2022)
BCUC Issues Procedural Order	Tuesday, June 14
FEI to notify Annual Review Interveners	Friday, June 17
Intervener Registration	Tuesday, June 28
BCUC and Intervener Information Request No. 1	Thursday, July 14
FEI Response to Information Request No. 1	Tuesday, August 9
Streamlined Review Process / Oral Submissions	Tuesday, August 23

2. MARKET CONDITIONS ARE DRIVING NEW REGIONAL PIPELINE INFRASTRUCTURE REGARDLESS OF FEI DEMAND

This section describes how gas supply market conditions in the Region are driving the need for infrastructure development to expand Regional capacity. While these conditions exist independent of demand on FEI's own system, they will nonetheless result in significant costs, and potential risks for FEI customers. In this section, FEI's discussion is organized and focused around the following points:

- Sections 2.1 and 2.2: The need for new Regional pipeline infrastructure is predominantly driven by the following three market conditions which are outside of FEI's control:
  1. **Constrained Capacity on the T-South System:** FEI, and the Region as a whole, rely on Enbridge's T-South system for the majority of their daily gas supply. Despite nominal increases in capacity as recently as November 2021, the T-South system remains fully subscribed due to high demand in the Region.
  2. **Forthcoming Increases in Regional Demand:** Constrained pipeline capacity will be exacerbated by both the addition of load associated with the Woodfibre LNG project and load growth in the Region over time.
  3. **Expansion of Renewable and Low-Carbon Gas Supply Due to Government Policy:** BC Government policies aimed at decarbonization drive a need for renewable and low-carbon gas from new supply sources, with hydrogen blending into the gas system requiring capacity increases due to its lower energy density.[6]
- Section 2.3: Any expansion of Enbridge's existing system to accommodate these market conditions would result in significant cost increases for FEI, which means higher rates for customers.

2.1 *BC AND US PACIFIC NORTHWEST REGION RELIES ON THE T-SOUTH SYSTEM, AND IT IS FULLY SUBSCRIBED*

As discussed below, the T-South system, upon which FEI and the Region as a whole rely upon, is fully subscribed. There is no pipeline capacity to accommodate new load in the Region.

As it stands, the Region, including FEI, is served by two large transmission systems: (1) the T-South system; and (2) the TC Energy (Nova Gas Transmission, Foothills BC and Gas Transmission Northwest) system. Both systems are predominantly situated in north-south corridors with limited interconnectivity between them as denoted in the map below.

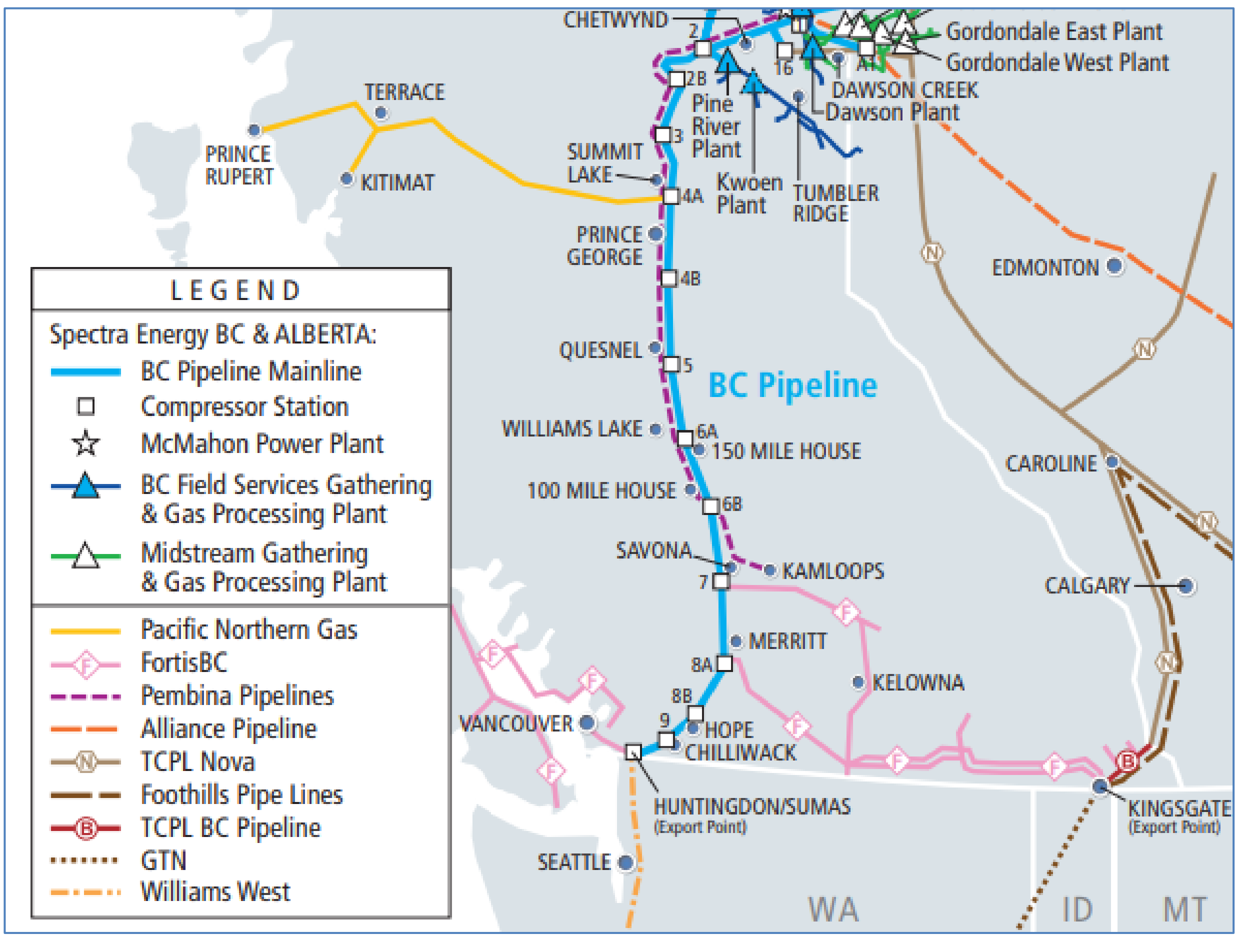
[6] Hydrogen blending requires more pipeline capacity to move the same energy; compared to natural gas hydrogen has a much lower energy content partially offset by higher velocity capability.

The T-South system has provided most of the gas supply to the Region for decades. The system consists of two looped gas transmission pipelines within the same right of way (ROW), operating as a single system that connects production fields in northeast BC with:

1. FEI's Interior Transmission System (at Savona, BC and Kingsvale, BC);
2. FEI's Coastal Transmission System (at Huntingdon, BC); and
3. Williams Northwest Pipeline (NWP) (at Sumas, Washington).

The interconnect between T-South and NWP is typically referred to as the Huntingdon market. The actual index name of the gas commodity traded at the Huntingdon hub is called the Sumas price index which is traded in US$/MMBtu for both daily and monthly priced gas. The T-South system flows north to south and runs approximately 916 km between Station 2 and Huntingdon. Figure 2-1 below shows the Region's pipelines described above:

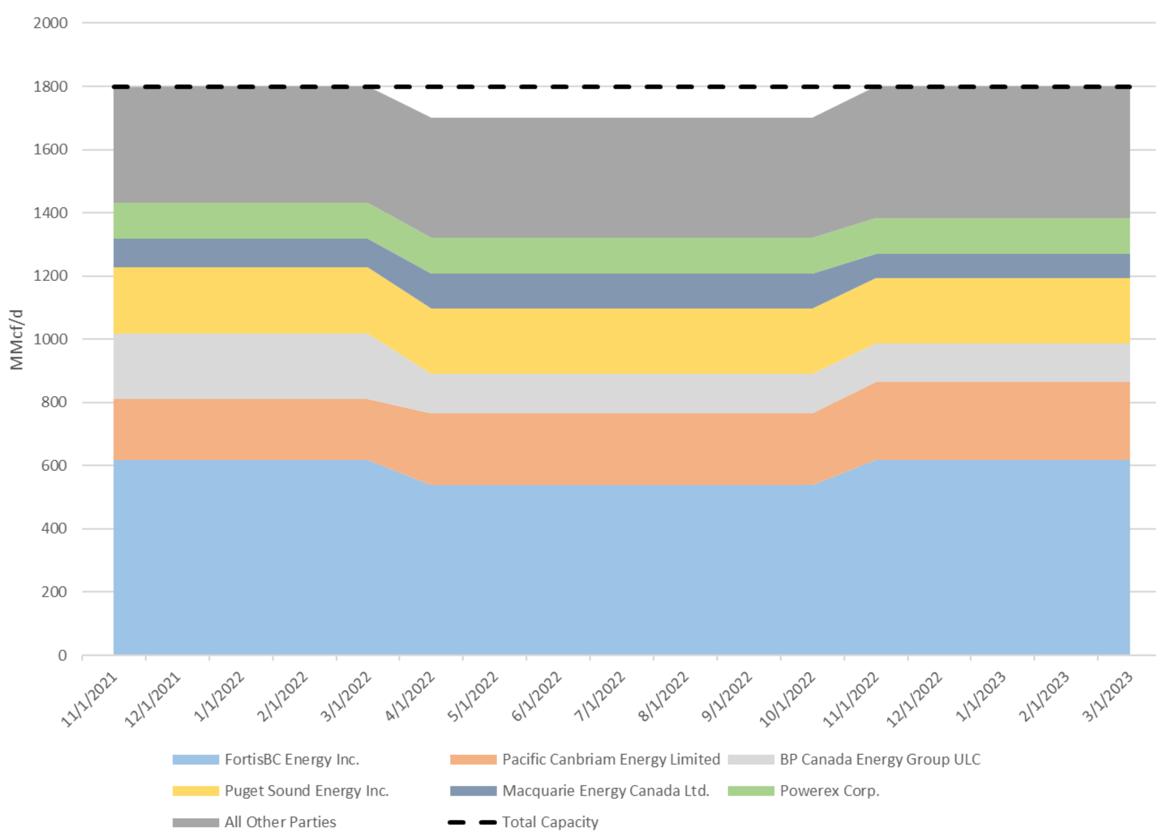
Figure 2-1: Regional Transmission Pipelines



The pipeline capacity of the T-South system is used to meet both annual and seasonal demand in the Region; however, the Region's load requirements are significantly higher during the winter months (November-March), as compared to those in the summer, due to higher heating requirements.[7]

On November 1, 2021, the T-South system's winter capacity expanded by 0.1 Bcf per day from 1.7 Bcf per day to 1.8 Bcf per day. The entire 1.8 Bcf per day of winter capacity is fully subscribed under firm contracts, including the capacity related to Woodfibre LNG as discussed below. The 0.1 BCF per day expansion capacity was also picked up by shippers under long-term contracts with Enbridge. Enbridge's plans for a T-South expansion demonstrate that there is a capacity constraint issue on the system currently. The following Figure 2-2 shows firm contracted capacity on T-South to Huntingdon since November 1, 2021. As illustrated in Figure 2-2, the entire 1.8 BCF/d or 1,800 MMCF/d is fully subscribed until winter 2023 when some contracts expire. The expired contracts are expected to be fully renewed and extended prior to the renewal deadline by shippers. The slight dip in contracted capacity in the summer months (April 1 to October 31) is due to a portion of firm winter-only capacity (160 MMscfd) coming off in the summer since this capacity is only in-service from November 1 to March 31 of each year. As illustrated in this figure, FEI (shaded in blue at the bottom of the figure) is the largest holder of firm T-South to Huntingdon compared to other shippers (denoted by the other colours).

Figure 2-2: FEI and other T-South Firm Capacity Holders to Huntingdon



[7] Underground storage resources in the Region (JPS and Mist) are typically filled during the summer when there is excess capacity on the T-South system and then used in the winter to meet Regional load above to supplement contracted T-South pipeline during bouts of colder winter weather.

As discussed further in Section 2.2.1 below, Woodfibre LNG will use its contracted firm T-South capacity once it is operational. This capacity will be used to provide gas feedstock for the LNG plant when it enters service later in the decade. However, until the plant commences LNG production, Woodfibre LNG's pre-contracted T-South capacity has been subleased to third parties that use it to supply gas to the Huntingdon marketplace for resale to meet demand of existing customers in the Region. Gas flows to Huntingdon are already at high levels in the winter months and Woodfibre LNG's released capacity is fully utilized in the current marketplace. However, once the LNG plant commences operations, the marketplace at Huntingdon will experience a major shortfall in T-South capacity (with pipeline flows being directed to the Woodfibre LNG plant rather than to the Huntingdon market) and demand from existing customers will not be met in the critical winter months. As a result, the marketplace will experience sustained levels of high prices in winter, even greater than what is already seen today, unless a pipeline expansion occurs in the Region around the same time that the Woodfibre LNG plant comes into service.

Further, FEI currently relies on the T-South pipeline for more than 80 percent of the gas entering its system. The Station 2 trading hub is illiquid with greater price volatility compared to its regional counterpart at AECO/NIT, due to its smaller market size (Station 2 physically delivers 2 billion cubic feet per day (Bcf/day) compared to 12 Bcf/day at AECO/NIT), and lower number of market participants (suppliers and end users). These factors translate into a lower amount of term supply[8] being transacted at Station 2 compared to AECO/NIT. The illiquidity at Station 2 has presented challenges for FEI, as it can affect pricing and security of supply under certain market conditions. This highlights the importance of supply diversity that would reduce FEI's reliance on the Station 2 hub and re-direct supply sourcing from AECO/NIT, one of the largest natural gas trading hubs in North America.

Other utilities in the US Pacific Northwest also rely on the T-South system for large portions of their supply. The reliance on the T-South pipeline is significant for the Region as a whole, and as discussed further below, capacity constraints on the system will drive the development of new pipeline infrastructure in the Region.

2.2 INCREASING REGIONAL DEMAND AND DECARBONIZATION INITIATIVES WILL NECESSITATE NEW REGIONAL PIPELINE INFRASTRUCTURE

In this section, FEI discusses the three key drivers that will, independently and collectively, drive the need for new regional pipeline capacity to expand: (i) the Woodfibre LNG project, which recently announced construction starting in 2023, will add major demand in the Region; (ii) general growth in Regional demand, regardless of its source or location; (iii) the emergence of, and transition to, renewable and low-carbon gas including RNG projects in locations like Alberta and blending hydrogen into the gas system.

[8] Term supply is supply covering a winter, summer, annual or longer term as opposed to spot supply which is related to daily delivery only.

2.2.1 Woodfibre LNG Will Remove Significant Regional Pipeline Capacity from the Market

One driver behind the need for new pipeline capacity in the Region is Woodfibre LNG entering service.

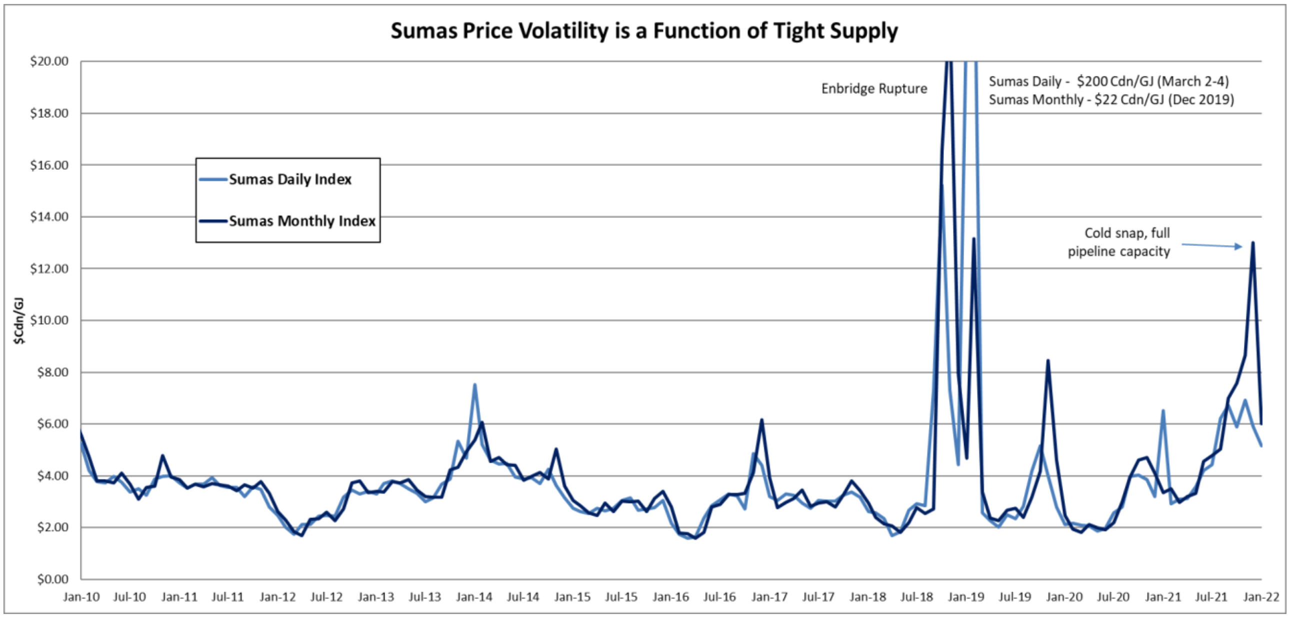
FEI estimates that Woodfibre LNG currently holds approximately 280 MMscfd (~300 TJ per day) or more of pipeline capacity on the T-South system, which it releases for sale into the Huntingdon market, pending the completion of its facility. When the LNG facility is operational (which is currently forecast to be in 2027), Woodfibre LNG will require the bulk or all of its contracted T-South capacity to produce LNG, effectively removing this gas supply from the Huntingdon market. This loss of gas supply equates to approximately 15 percent of the total available winter capacity to Huntingdon on the T-South system and will represent a fundamental shift in the Region's gas supply availability to serve existing demand. It will have significant adverse implications for customers relying on purchasing gas supply at Huntingdon without any further upstream pipeline expansion.

As it stands, the Region experiences high prices and supply tightness during the winter. Without the development of new pipeline infrastructure in the Region, removal of existing capacity of this magnitude from the market is expected to exacerbate upward price volatility. FEI expects that the potential extent of the market impacts due to the loss of Woodfibre LNG capacity will result in significant pricing increases, volatility and supply tightness especially in the winter months in the absence of incremental capacity development at Huntingdon. With Woodfibre LNG operating, the level of volatility and pricing levels at Huntingdon will be driven by prevailing market conditions that are in place during periods in the winter months such as cold weather conditions, demand from gas-fired electricity plants, and general Regional demand growth expected over the next few years.

The Huntingdon market experienced unprecedented pricing volatility during the T-South Incident that effectively reduced significant amounts of pipeline capacity for prolonged periods during the winter of 2018/19[9]. As shown in Figure 2-3 below, the market experienced a prolonged period of very high prices following the loss of capacity. The resulting level of pricing volatility experienced by customers, and the duration of such volatility, was unprecedented in the Region. As explained above, in late-2021, an additional 0.1 Bcf per day of incremental system capacity was added to the T-South system. However, as shown in the figure below, this additional capacity did not alleviate the price volatility experienced during a cold weather event during the early part of the 2021/22 winter.

[9] Restrictions were put in place by the National Energy Board (NEB) during this event. The T-South Incident is described in more detail in Section 3.2.1.

Figure 1-3: Huntingdon (Sumas) Price Volatility Over Time, Cdn$ per GJ



While the Woodfibre LNG project is a standalone driver of the need for new regional pipeline infrastructure, added to regional load growth and future hydrogen blending (discussed in Section 2.2.3 below), the combination of these factors will lead to capacity shortfalls much greater than what was experienced in 2018 and 2021. As a result, FEI believes the impact to pricing and considerable volatility in winter will be expected to occur under current levels of pipeline capacity once the above drivers enter the market. The level of pricing and volatility at Huntingdon will only be known under various operating conditions and factors when they occur especially during the critical winter season.

Higher gas costs and extreme price volatility is an undesirable outcome for parties relying on purchasing gas supply at Huntingdon and, over time, provides a strong economic impetus for new pipeline infrastructure in the Region. While FEI does not rely heavily on Huntingdon supply, and currently has sufficient capacity on the T-South system under contract to meet its core[10] customers needs, many of FEI's transportation customers (that are currently served by gas marketers) currently rely on Huntingdon and have the option of returning to FEI bundled service. Moreover, despite FEI not requiring additional capacity at this time, the utility and its customers are not insulated from cost increases due to addition of new infrastructure on the T-South system. As discussed in Section 2.3.1 below, all shippers on the T-South system, including FEI, will end up paying for the cost of expansions on the system intended to serve new demand in the Region.

2.2.2 Regional Growth Increases Demand for Pipeline Capacity

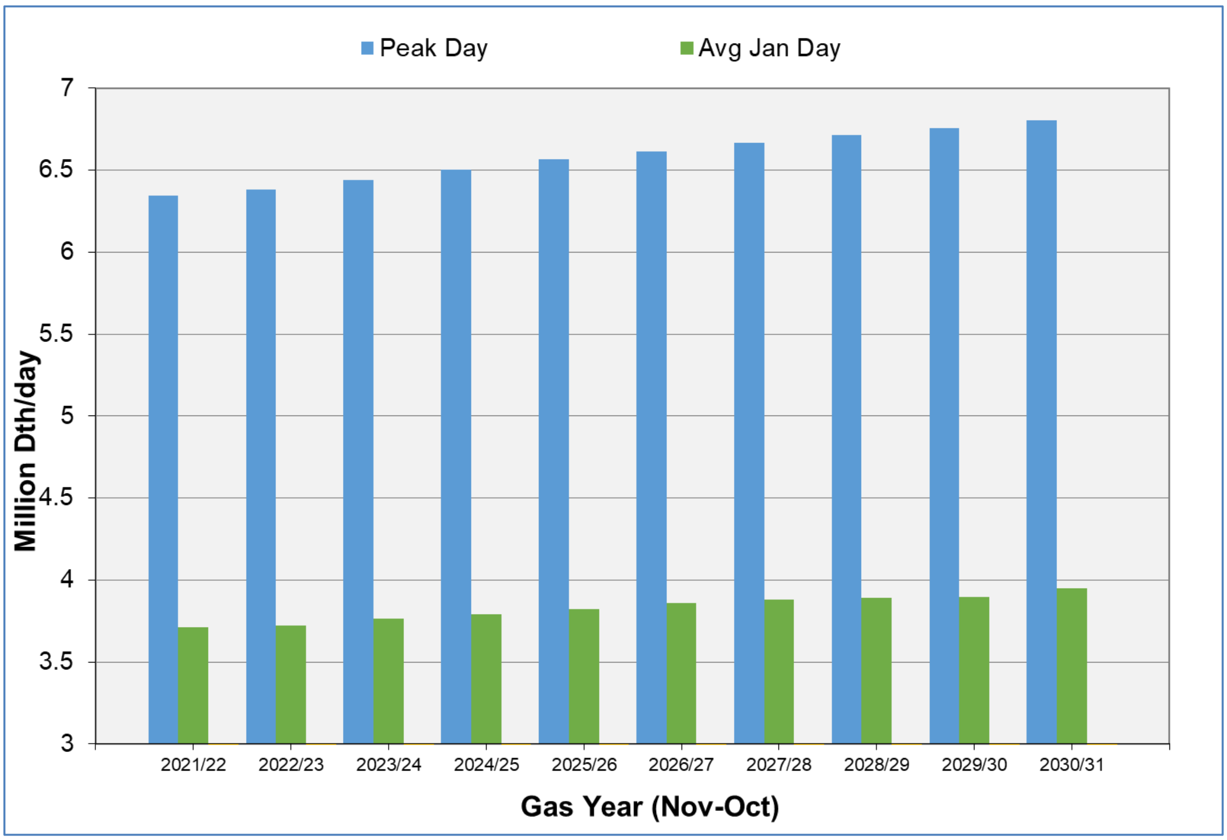
A second driver of demand for pipeline capacity is the Region's increasing growth in demand, as shown in the Northwest Gas Association's (NWGA) 2022 Pacific Northwest Gas Market

[10] FEI typically defines "core" customers as rate class 1-7.

Outlook study that was released in May 2022.[11] FEI received permission from the NWGA to include a condensed version of a chart from the study - Figure 2-4 below depicts forecast demand in the Region to 2030/31.

The chart below shows that increases in peak day and average January day consumption in the Region are forecast to continue to the end of the decade. In particular, the average January day is forecast to increase by 237 Million Dekatherms per day (Dth) or 250 TJ per day between 2021/22 and 2030/31. Similarly, the peak day is forecast to increase by 460 Million Dth per day or 485 TJ per day during the same period. Importantly, these increases do not include expected demand from the Woodfibre LNG project, which would further increase overall forecast demand.

Figure 2-4: Growing Forecast Regional Demand

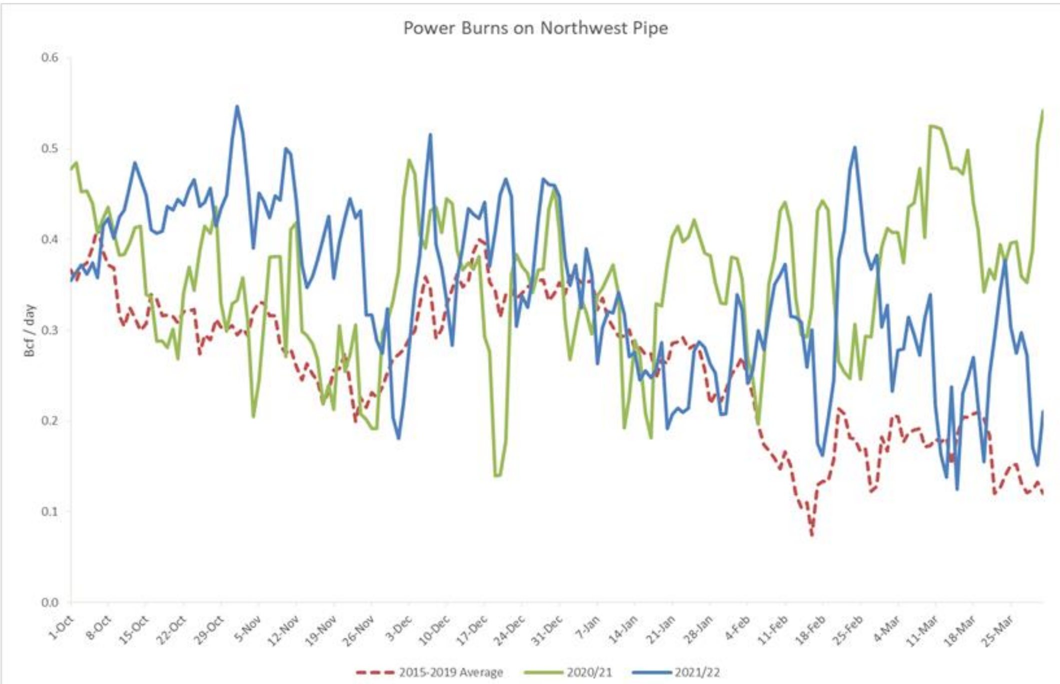


Since 2015, demand for gas-fired electricity in the Region has increased as shown in Figure 2-5 below. FEI notes that peak day demand from gas-fired electricity generation is forecast to remain consistent in the US Pacific Northwest through to the end of the decade. The trading of electricity based on favourable market prices can also drive gas-fired electricity generation facilities to run in the US Pacific Northwest, creating demand for gas. As outlined below in Figure 2-5, the Region is seeing increased demand for gas from existing power plants in the I-5

[11] Please refer to Page 13 of 28 of the 2022 Pacific Northwest Gas Market Outlook to see the actual chart that has been condensed in Figure 2-4: https://www.nwga.org/wp-content/uploads/2022/05/2022_Outlook_Web.pdf.

corridor that can range between 220 TJ/d (0.2 Bcf/d) to 400 TJ/d (0.39 Bcf/d) (per the table below). Gas-fired generation loads can vary slightly each year but there has been an increase between 2019/20 and 2021/22 illustrated in the table below and that level of demand can be expected to continue in the coming years.

Figure 2-5: Gas Demand Load for Power Generation



Gas Winter (Nov-March)	BCF/day
15/16	0.28
16/17	0.20
17/18	0.26
18/19	0.24
19/20	0.39
20/21	0.35
21/22	0.33

The demand for natural gas (and natural gas blended with renewable and low-carbon gas) in the US Pacific Northwest as a source of energy for power generation with lower GHG emissions (relative to coal) is expected to remain at consistent levels over the next decade. FEI expects this demand to exacerbate price volatility during periods of high demand in the winter season. A significant portion of the gas to power load in the Region is expected to be met with gas that comes down the T-South pipeline to the Huntingdon market. The gas from Huntingdon that flows south on to Northwest Pipeline (NWP) has the capability to flow a maximum of 1.3 Bcf per day out of the 1.8 Bcf/d that can be delivered to Huntingdon via T-South. However, the maximum 1.3 Bcf/d can flow only when FEI does not need more than 0.5 Bcf/d for its own total system load. The actual gas flows into NWP from Huntingdon have averaged over 1.0 Bcf per day over the past three winters, thus illustrating the importance and reliance on the Huntingdon market for daily gas down into the I-5 corridor. A map of gas-fired generation facilities in the US Pacific Northwest in provided in Figure 2-6 below.

At current capacity levels, demand from power generation facilities during the winter season will continue to cause price volatility at Huntingdon. Historically, the Huntingdon market has witnessed price spikes that occur whenever demand is high in the winter months due to cold weather or a capacity constraint occurs on the pipeline due to outages. Even relatively small changes in demand levels or constraints can trigger price spikes at Huntingdon that Regional market participants will recognize could be alleviated by adding new pipeline infrastructure.

Figure 2-6: Map of Gas-fired Generation Facilities in US Pacific Northwest[12]

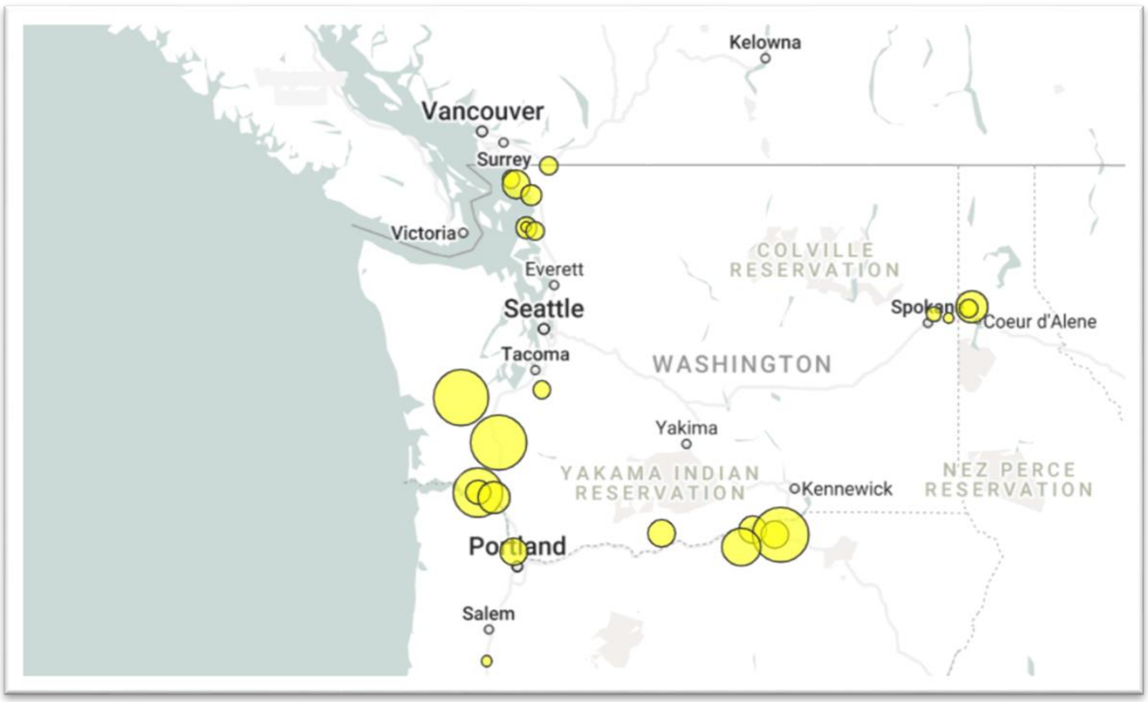


Table 2-1 below shows the maximum supply that can be delivered from Regional resources in the winter months. As the table illustrates, most of the gas supply is accessed via pipelines as opposed to storage facilities (per the column titled "Total Winter Supply (Bcf)" below). Although storage can provide high quantities of daily gas supply when storage inventory levels are high, the duration of supply that can be received over consecutive days is extremely limited over an entire winter season once storage levels are depleted. Therefore, to meet demand growth, pipeline capacity in the region needs to be developed in order to ensure that the duration of the demand in winter can be met. Normally, gas supply from storage is used to supplement piped gas supply during short bouts of colder or extreme winter weather when incremental supply is needed to meet demand.

[12] Map from Northwest Power and Conservation Council: https://www.nwcouncil.org/energy/energy-topics/power-supply/map-of-power-generation-in-the-northwest/.

Table 2-1: Maximum Supply Delivery from Current Regional Resources[13]

Pipeline	Daily Deliverability[1] (MMcf/day)	Total Winter Supply (Bcf)	Contract Status
Enbridge T-South (Huntingdon Deliveries)	1800	272	Fully Contracted
Enbridge T-South (Interior Division)	224	34	Fully Contracted
FortisBC SCP (Oliver North)	140	21	Fully Contracted
FortisBC SCP (Kingsvale)[2]	105	16	Fully Contracted
TCPL (FoothillsBC)	2930	442	Fully Contracted
NWP Gorge	534	81	Fully Contracted
Market Area Storage	**Daily Deliverability (MMcf/day)**	**Storage Capacity (Bcf)**	
Jackson Prairie (JPS)	1161	25	Fully Contracted
Mist	637	19	Fully Contracted
On System Storage	**Daily Deliverability (MMcf/day)**	**Storage Capacity (Bcf)**	
Mt. Hayes LNG	150	1.5	Fully Utilized on Peak Day
Tilbury LNG	150	1.6	Fully Utilized on Peak Day

Notes:

[1] Daily deliverability is the maximum amount of gas that can flow on the pipeline or the maximum amount of gas that can be withdrawn out of storage. It is important to note that the daily deliverability out of the market area storage is assuming storage inventories are full. The withdrawal rates of these resources decline as working gas volumes decline.

[2] The 105 MMscfd is included in the 1,800 MMscfd Huntingdon Deliveries (i.e., Kingsvale to Huntingdon).

FEI has provided a further discussion on long term supply risks in its 2022 Long Term Gas Resource Plan.[14]

2.2.3 Hydrogen Blending Requires More Pipeline Capacity

In a recent publication, the NWGA concluded that natural gas pipelines and infrastructure will play a significant role in the energy delivery system of the future.[15] The use of hydrogen in the Region (including in FEI's system) is expected to increase over time. Hydrogen blending, given the physical properties of hydrogen, will be another significant driver of the need to develop new pipeline capacity in the Region.

Hydrogen has approximately one-third of the heat value of methane. Therefore, blending hydrogen into the gas stream, which is expected to proportionally increase over time relative to methane, will require incremental pipeline capacity to deliver the same amount of energy as a

[13] Refer to Table 6-3: Existing Pipeline and Storage Resources in the Region: https://docs.bcuc.com/Documents/Proceedings/2022/DOC_66503_B-1-FEI-2022-LongTermGasResourcePlan.pdf.

[14] Refer to section 6.2.4 https://docs.bcuc.com/Documents/Proceedings/2022/DOC_66503_B-1-FEI-2022-LongTermGasResourcePlan.pdf.

[15] https://www.nwga.org/hydrogen-production-primer/.

methane-only pipeline.[16] Table 2-2 below illustrates the concept of energy loss when 737 TJ per day of 100 percent methane is blended with 20 percent hydrogen by volume. It shows that the level of energy loss with a 20 percent hydrogen blend will require approximately 9 percent more supply.

Table 2-2: Illustration of Energy Loss at a 20 Percent Hydrogen Blend

	100% Methane Gas	80% Methane Gas / 20% Hydrogen	Energy Loss	% Difference
Energy TJ/d	737	673	63	9%

Given that the current T-South system is fully subscribed, additional pipeline capacity will be required in the Region in order to deliver the same amount of energy when hydrogen blending occurs in future.

The introduction of hydrogen into a piped system also triggers the need to address metallurgical integrity of pipelines. As discussed in Section 3.1.2.2, the RGSD Project is envisioned as being “hydrogen-ready”. Ultimately, gas systems that can increase capacity levels efficiently, at the lowest possible cost, are at a significant advantage over systems that will need costly upgrades to both capacity and metallurgical integrity to deliver higher levels of hydrogen.

In the case of the T-South system, the amount of energy (in GJ per day) delivered on the pipeline could further decrease over time due to the addition of straddle plants in northern BC which remove liquid rich by-products from the gas stream resulting in reduced heat values of the gas. This would result in lower energy gas compared to current levels. FEI projects that the energy content of gas on T-South could drop by as much as 7 percent compared to gas flowing currently that is liquids-rich supply extracted from the Montney shale formation.

Further information regarding hydrogen as an energy source of the future is provided in Section 3 of this Application.

2.3 COST IMPLICATIONS OF T-SOUTH EXPANSIONS FOR FEI CUSTOMERS

As discussed below, Enbridge’s approved tolling methodology allocates costs of any expansions and the future increases to the cost of service among all shippers. Enbridge has stated that it intends to expand the T-South system and conduct an open season around mid-late 2022 to seek shipper interest in the project.[17] Enbridge has also stated that its planned T-South Expansion would add 300 MMscfd of capacity to Huntingdon at a cost expected to be over $2.5 billion. The T-South Expansion is being driven by factors unrelated to FEI, and yet FEI

[16] Hydrogen Strategy for Canada: https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/environment/hydrogen/NRCan_Hydrogen-Strategy-Canada-na-en-v3.pdf.

[17] Refer to Enbridge Presentation Slide 13: https://www.enbridge.com/~/media/Enb/Documents/Investor%20Relations/2022/2022_Q1_Earnings_Presentation_Final.pdf.

– and ultimately FEI's customers – will bear a significant portion of the cost. Given the limited nature of this announced expansion, the potential exists for other future T-South system expansions with associated additional costs for FEI and its customers.

2.3.1 Enbridge's Approved Tolling Methodology: All Shippers Share the Costs of Upgrades

The planned T-South Expansion, and any potential subsequent T-South expansions, will have significant rate impacts for FEI's customers because of associated toll increases following the capital-intensive nature of expansions expected on that pipeline.

FEI is currently the largest shipper on Enbridge's T-South pipeline, and will likely remain so for the foreseeable future, unless the RGSD Project is constructed. The bulk of FEI's contracts on the T-South system are on the full path that flows gas from Station 2 to Huntingdon, which attracts the highest toll charged by Enbridge.

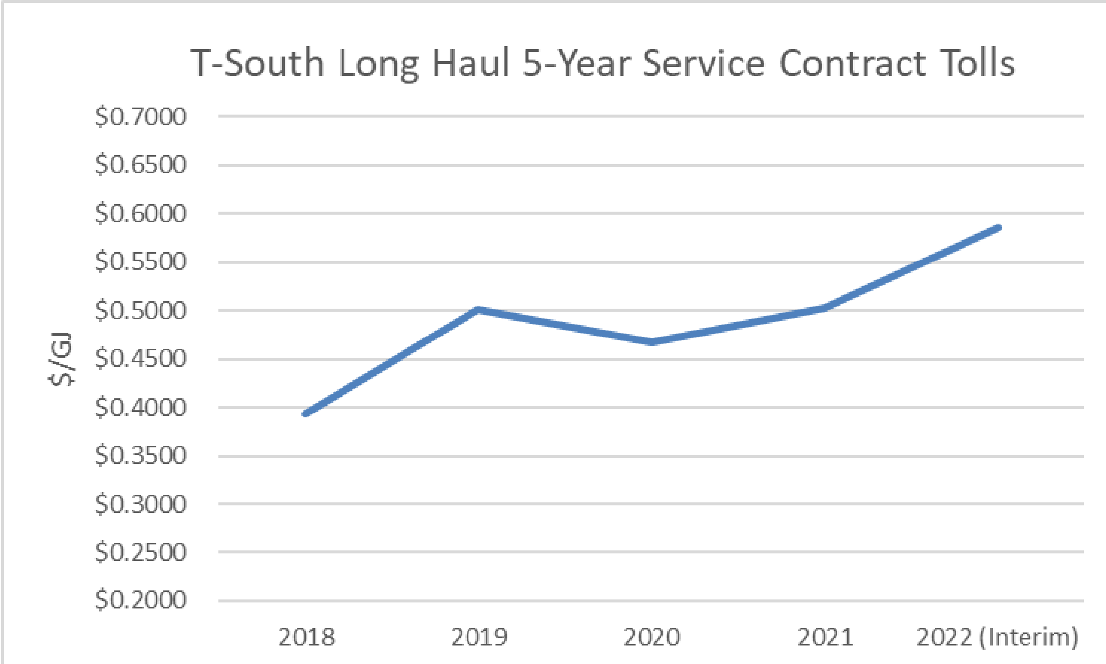
Capital costs for approved expansions or improvements to the pipeline are borne by all shippers under Canadian Energy Regulator (CER) approved methodology. As a result, any expansions on the system, on behalf of new or existing shippers, that trigger capital cost increases will be allocated amongst all shippers (based on their service delivery points and term of service) through annual cost of service increases that will be recovered via shipper tolls.

For example, the incremental expansion of the T-South system that increased capacity by 0.1 Bcf per day in late-2021 was largely facilitated by major compression upgrades, costing approximately $1 billion. This relatively minor capacity expansion resulted in toll increases for shippers of approximately $0.05 per GJ (for T-South shippers holding five-year term contracts) for service from Station 2 to Huntingdon also known as the full path. A $0.05 per GJ toll increase on T-South translates into over $12 million of additional fixed costs that will be borne by FEI's customers each year based on current contracting levels for capacity by FEI.

Figure 2-7 below shows the increasing trend of T-South tolls for holding five-year contracts. Contracted terms on T-South range from one to five years with the longer contracted five-year term (that forms the holdings in FEI's portfolio) having the lowest toll. Most of the toll increases stem from costs related to restoration of the pipeline after the 2018 T-South Incident, and major capital upgrades to the compressor fleet mentioned above.

As the figure below illustrates, tolls on the long-haul path from Station 2 to Huntingdon have increased significantly from just under $0.40 per GJ in 2018 to just under $0.60 per GJ in 2022, mainly as a result of two major cost intensive undertakings. Capacity contracted by FEI on T-South was slightly lower in 2018 than 2022. If FEI had held the same level of capacity in 2018 as it currently holds in 2022, the corresponding increase in tolls would have translated to an increase of 47 percent (or $47 million annually) that would have been recovered from customers. Further capacity additions, including the major T-South expansion discussed below, will continue to increase tolls considerably for FEI and all shippers.

Figure 2-7: Enbridge T-South Long Haul (Stn. 2 to Huntingdon) Tolls



2.3.2 Proposed T-South Expansion Would Come with Significant Cost for FEI's Customers

Enbridge has stated that the next planned expansion would add 300 MMscfd (~350 TJ per day) of capacity to Huntingdon at a cost over $2.5 billion[18]. It is expected that Enbridge will commence the process of signing up shippers for the expansion capacity by conducting an open season. Any shipper that chooses to participate in Enbridge's open season will need to qualify and enter into a minimum term contract for expansion capacity that will be specified by Enbridge during the open season process. At present, FEI does not intend to participate in the open season as it has sufficient capacity for its core market; however, future load growth forecast on FEI's system over the next few years could warrant FEI to consider securing additional gas supply and assess possible options. In order for the expansion to proceed, Enbridge would need to garner all regulatory and permitting approvals. Based on the CER's approved methodology, a T-South expansion will lead to a major toll increase for shippers. Shippers choosing to contract for the expansion capacity that enter into binding contracts with Enbridge will do so committing to the fact that the actual expansion costs could deviate from initial estimates that will be reflected accordingly in shipper tolls that will be collected from new and existing firm capacity holders.

Since FEI is the largest holder of firm capacity on the T-South pipeline, the cost increases to FEI's customers will be significant for any level of new expansion capacity. FEI estimates that based on current firm capacity contracting levels by the utility on all segments of the T-South

[18] The planned $2.5 billion plus expansion announced by Enbridge is understood to be based on preliminary cost estimates and would be subject to revision after detailed work is performed.

pipeline, costs could increase by around 45 percent or $65 million annually if expansion costs come in at $2.5 billion for the 300 MMscfd expansion compared to what FEI will pay in 2022 based on the T-South system's 2022 interim tolls. Since the $2.5 billion plus capital cost estimate is a very preliminary figure, costs to expand the system by 300 MMscfd could escalate much higher or, if an expansion is sized greater than the announced 300 MMscfd, could result in even higher capital costs and greater toll increases for all shippers. Regardless of expansion sizing or any amounts for capital costs, major expansions on T-South, whether costing at minimum $2.5 billion or amounts greater, translate into considerable rate increases for FEI's customers each year with little to no additional benefits to FEI customers.

2.3.3 Further Expansions of T-South Would Be Necessary to Meet Future Regional Demand and Hydrogen

Enbridge's proposed T-South Expansion is intended to relieve some of the capacity constraint at the Huntingdon market that will result mainly from Woodfibre LNG project entering service and other near-term demand growth. However, the proposed expansion of the T-South system would not address other drivers or market conditions affecting the Region, such that further T-South system capacity expansions will likely be necessary in the future. FEI strongly believes that the proposed 300 MMscfd expansion by Enbridge does not fully address the Region's needs for incremental capacity development to meet future needs and the need to facilitate a transition to cleaner energy sources, such as hydrogen, in order to meet the province's decarbonization targets (as further discussed in Section 3). Furthermore, any T-South expansion leaves FEI and the Region to continue their reliance on a single major source of gas supply that will leave customers with the same risks as today for supply disruptions while significantly increasing shipper tolls.

2.4 *CONCLUSION*

Due to a clear need for new pipeline infrastructure in the Region, FEI believes it is appropriate to evaluate other possible pipeline expansion options, such as the RGSD Project, that address the market conditions described above, provide additional benefits, and reduce risks for FEI's customers.

3. RGSD PROJECT WOULD PROVIDE SIGNIFICANT AND UNIQUE BENEFITS TO FEI CUSTOMERS

This section identifies, based on FEI's analysis to date, several long-term benefits that the RGSD Project would provide to FEI and its customers. These include:

- Facilitating decarbonization of the Regional gas system by improving access to renewable and low-carbon gas supply from new sources in and out of the province (section 3.1);
- Strengthening the resiliency of the Regional system, reducing risk exposure for FEI and its customers (section 3.2);
- Improving diversity of supply (section 3.3); and
- Advancing FEI's efforts towards Indigenous partnerships, inclusion and reconciliation (section 3.4).

3.1 *RGSD PROJECT WOULD FACILITATE DECARBONIZATION GOALS*

As described below, the RGSD Project would facilitate decarbonization goals by increasing FEI's ability to access renewable and low-carbon gas.

3.1.1 Government Policy Is Driving the Expansion of Renewable and Low-Carbon Gas

In 2018, the provincial government released its CleanBC Plan[19] aimed at reducing GHG emissions while creating jobs and economic opportunities. The CleanBC Plan enables natural gas utilities to reduce GHG emissions by increasing the renewable content of their gas stream to 15 percent by 2030. Displacing 15 percent of the natural gas supply with renewable and low-carbon gas would increase the annual supply of renewable and low-carbon gas in FEI's system to approximately 30 PJ.

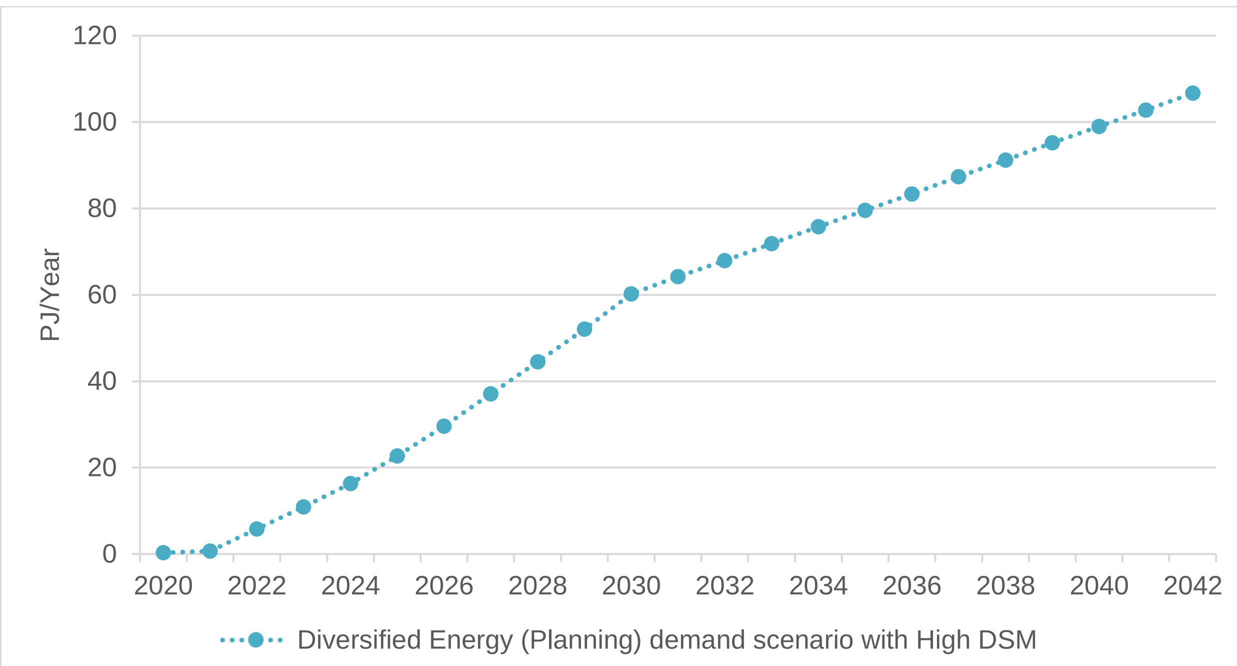
The provincial government's approach with respect to the GHG emissions of gas utilities was updated in October 2021, with the release of the CleanBC Roadmap[20] which includes reference to implementing a GHG emissions cap on gas utilities, including FEI. When introduced into legislation, the cap would impose a limit on the overall GHG emissions from the gas used by customers of gas utilities, including the residential, commercial and industrial sectors. As proposed, this policy would be a first of its kind in Canada in that it would impose an obligation on gas utilities to reduce emissions on behalf of their customers. The cap, as laid out in the CleanBC Roadmap, is set at approximately 6 Mt of CO_2e per year as of 2030. This represents a 47 percent reduction in GHG emissions from 2007 levels, and will require utilities to increase

[19] https://www2.gov.bc.ca/assets/gov/environment/climate-change/action/cleanbc/cleanbc_2018-bc-climate-strategy.pdf.
[20] https://www2.gov.bc.ca/assets/gov/environment/climate-change/action/cleanbc/cleanbc_roadmap_2030.pdf.

renewable and low-carbon gas content, invest in energy efficiency, and employ other innovative mechanisms to lower emissions. FEI expects that renewable and low-carbon gas content exceeding 15 percent will be required to meet this lower emission threshold by 2030. While details regarding the cap remain under development, and are subject to change, FEI sees the potential renewable and low-carbon gas supply requirements being between 45 and 65 PJ per annum by 2030.

In order to achieve the targets set in the CleanBC Roadmap, FEI intends to steadily increase levels of renewable and low-carbon gas in its supply portfolio as shown below in Figure 3-1 that depicts FEI's Diversified Energy (Planning) Scenario from its 2022 Long-Term Gas Resource Plan (LTGRP). Beyond 2030, British Columbia will continue to move towards a decarbonized energy future, which will require increasing volumes of renewable and low-carbon gas. Ultimately, the continued use of the Regional pipeline infrastructure is a critical component of decarbonizing the province's energy system and, over the long-term, will mitigate the cost of the energy transition to customers.

Figure 3-2: Forecast Renewable and Low-Carbon Gas Supply[21]



3.1.2 The RGSD Project is an Essential Link to Renewable and Low-Carbon Gas Supply

The expansion of capacity through the RGSD Project would enable access to renewable and low-carbon gas supply. As mentioned further below in Section 3.3, the AECO/NIT hub is where producers prefer to transact because of its liquidity.

[21] FortisBC Energy Inc. 2022 LTGRP. Figure 6-3; Page 6-12. https://docs.bcuc.com/Documents/Proceedings/2022/DOC_66503_B-1-FEI-2022-LongTermGasResourcePlan.pdf.

One of the key low-carbon fuels early on is RNG, which is a drop-in fuel (i.e., it does not require any additional upgrades or investment in capital before use in the system), and will play a significant role in FEI's gas supply portfolio to 2030. In the near term, out-of-province RNG will be critical to meeting renewable and low-carbon gas supply targets, as out-of-province projects are already producing or under development. FEI will require pipeline capacity to access the RNG that will be transacted at the AECO/NIT hub. To date, FEI has contracted over 18 PJ per annum of RNG, with the majority of this supply delivered into the AECO/NIT hub that, in the future, would be accessed by the RGSD Project pipeline. Section 4 provides a comparison of the various options, and their relative ability to facilitate decarbonization.

Hydrogen will be a key fuel for FEI to meet its long term (beyond 2030) renewable and low-carbon gas supply targets (Figure 3-1). As described below, capable regional pipeline infrastructure will be required to transport hydrogen to customers. The RGSD Project would be constructed in a way that enables a straightforward change of service to transport hydrogen. The existing SCP is a modern pipeline, constructed in 2000, and FEI has completed preliminary desktop work to better understand the requirements for hydrogen flows on the system. Conversely, the T-South system is expected to require extensive integrity and capacity upgrades (with further costs to shippers like FEI) to accept hydrogen, due to its age. Further, the RGSD Project would be a crucial piece of hydrogen ready infrastructure linking regions of large scale low-carbon hydrogen production to markets in the Lower Mainland and the US Pacific Northwest.

3.1.2.1 *Hydrogen Represents a Significant Opportunity for Decarbonization*

Low-carbon hydrogen represents a significant opportunity to decarbonize the gas system. The significance of hydrogen as a low-carbon fuel to decarbonize BC's economy was discussed during the provincial government's Throne Speech on Feb 8, 2022,[22] is aligned with the BC Hydrogen Strategy, and is supported by the BC Renewable and Low Carbon Gas Supply Potential Study filed as an Appendix A to this Application. The recent announcement of the new BC Hydrogen Office[23] to attract investment and simplify the permitting process further highlights the importance of hydrogen in the decarbonization of BC's economy.

It is well-understood that pipe which was not designed and constructed from the outset for hydrogen service can still transport some quantity of hydrogen, in some cases with little to no modifications. Industry experience from hydrogen blending pilot projects around the world has consistently demonstrated that steel pipelines can accommodate low hydrogen concentrations (approximately 10 percent or less) with no negative effects. One of the key variables determining the amount of hydrogen that can be safely blended is operating pressure. With lower pressure, issues related to embrittlement can be mitigated. FEI, PNG, and Enbridge are planning to complete a BC gas system hydrogen study, which will include desktop work and field testing that will further enhance our understanding of the capabilities of the current system.

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[22] CTV News. https://vancouverisland.ctvnews.ca/b-c-throne-speech-read-the-full-text-of-the-february-2022-speech-1.5773426.

[23] https://news.gov.bc.ca/releases/2022PREM0018-000464.

FEI's SCP is capable of safely transporting a meaningful blend of hydrogen, because it is a modern pipeline system. The materials, construction methods, and integrity status are well understood by FEI. FEI has detailed records on SCP, which was manufactured in 2000, consistent with Canadian Standards Association (CSA) Z245.1 Category II and Category III specifications. The detailed information on the metallurgy, welding, seam type, and the availability of mill test reports mean that FEI can proceed with hydrogen blending within safe limits. Lastly, as the owner/operator of the SCP system, FEI can move quickly to incorporate the initial stages of decarbonized gas flowing on the system.

Pipelines can also be constructed as fully hydrogen-ready, i.e., having been specified, designed, and constructed from their outset to transport hydrogen. Consideration is given to materials, components, and procedures (e.g., pipeline steel, welds, gaskets/seals, valves, etc.) that are known to be able to operate in this environment.

3.1.2.2 *The RGSD Project Would Be an Important Means of Transporting Hydrogen to the Lower Mainland*

The RGSD Project would enable the delivery of hydrogen to Huntingdon for use in FEI's system. FEI discusses the attributes of the RGSD Project that would allow for the delivery of hydrogen in further detail below.

1. **Hydrogen-Ready Materials:** FEI is anticipating building the new pipeline segment and equipment as certified for future hydrogen service with the capability of transporting hydrogen. Design for the new pipe and equipment would consider additional requirements for design, construction, welding, operation and integrity management to mitigate hydrogen embrittlement effects. The existing SCP, which commenced operations in 2000, was designed and constructed using modern materials, practices and procedures including modern approaches for quality assurance and quality control, meaning it is well positioned to transport higher concentrations of hydrogen. The planned use of new and existing pipelines for hydrogen is not unique to FEI; there are European initiatives to develop over 10,000 kilometres of pipeline to transport 100 percent hydrogen within the next dozen years through the construction of new pipelines and the conversion of existing natural gas pipelines. It is anticipated that hydrogen would be initially introduced to the RGSD Project pipeline and downstream FEI systems at very low concentrations that would increase over time.

2. **Sized to Account for Changes in Capacity:** The RGSD Project pipeline would be sized to account for hydrogen's lower heat content. When hydrogen is added as a blend with methane, the capacity of the pipe is reduced on an energy basis or per GJ content, due to the lower heat content of hydrogen that is partially offset by higher velocity. Therefore, FEI would plan the RGSD Project with capability to maintain the original design throughput at up to 50 percent hydrogen by volume by adding cost effective compression.

3. **Unique Asset for the Regional Market:** FEI's experience acquiring RNG demonstrates that there are significant first-mover advantages to securing supply in the renewable and low-carbon gas space – especially as interest in renewable gases continues to grow. As the market develops over the period leading to 2050, the RGSD Project could become the first gas pipeline in BC to be built specifically with the intention of transporting hydrogen as the market gradually develops going out to 2050 and beyond.

4. **Critical Infrastructure Link:** The RGSD Project would be a critical piece of infrastructure that would link large scale low-carbon hydrogen production in Alberta[24] to markets in the Lower Mainland. There would also be the potential to develop and produce various types of hydrogen from projects along the proposed route.

Given the characteristics set out above, the RGSD Project would be better positioned than the T-South system to meet the future needs of FEI's customers. Ultimately, the addition of the RGSD Project to FEI's asset portfolio would play an important part in the decarbonization of FEI's system by enabling the delivery of renewable and low-carbon gas to major demand centres.

3.2 *THE RGSD PROJECT WOULD STRENGTHEN RESILIENCY, UNLIKE EXPANDED T-SOUTH*

The Region currently lacks pipeline diversity or an additional source of piped gas supply. The 2018 T-South Incident and the November 2021 flooding have underscored the risk associated with heavy reliance on T-South. The RGSD Project would add regional pipeline infrastructure in a different geographic corridor than the T-South system, thereby significantly improving the resiliency of the regional system and reducing FEI's risk exposure in the event of a no-flow event on the T-South system. This contrasts with having to rely on an expansion of the T-South system in the same corridor, which would leave FEI heavily reliant on a single upstream system and would not add resiliency.

Expanding T-South in the same corridor as the current system, while leaving FEI heavily reliant on the T-South system, continues FEI's risk exposure in the event of a supply disruption (discussed below). Under the addition of a major load like the Woodfibre LNG project, which will flow daily baseload volume, FEI expects that additional stresses could be added to the T-South pipeline. In particular, quicker and more frequent erosion of linepack[25] particularly during the winter months and added time to respond to low linepack issues (due to a continuous high level of movement or flow of gas on the system due to the Woodfibre LNG load) could have negative implications for the pipeline. In addition, FEI expects that the T-South system could have reduced system reliability as compression utilization will increase, reducing redundancy levels built into the system that are used to manage downtimes and outages.

[24] Alberta Hydrogen Roadmap.
[25] Linepack is the intrinsic storage on a pipeline system, or the inventory of a transmission line.

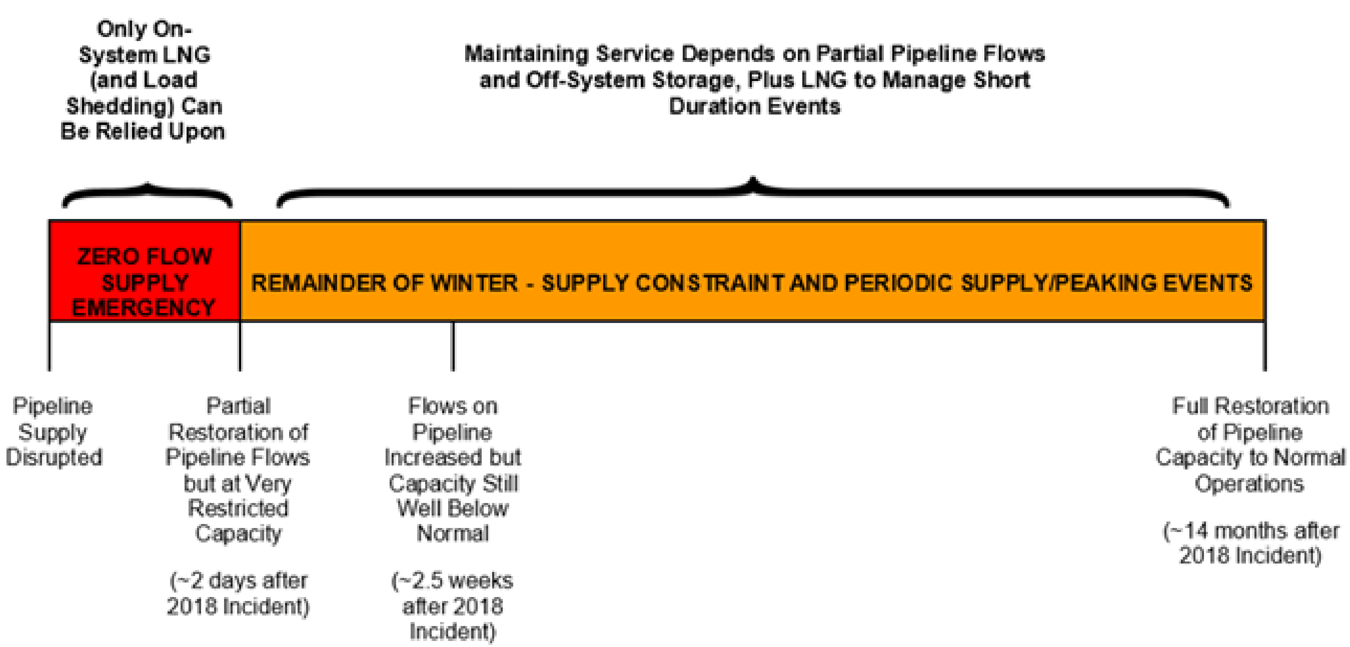
3.2.1 Recent Events Demonstrate the Risks that Come with FEI's Heavy Dependency on T-South

Recent events, including the 2018 T-South Incident and November 2021 floods have underscored the risks associated with FEI's current heavy dependency on a single source for its supply, particularly supply to the Lower Mainland. These events are discussed in further detail below.

3.2.1.1 *2018 T-South Incident*

The T-South pipeline system underwent a major disruption in 2018, beginning with a major rupture on October 9, 2018. Gas flow was completely stopped for approximately 2 days, before resuming at restricted levels for several days on one of the two remaining gas lines.[26] While supply levels gradually increased over time, maximum capacity was not available for the entire 2018/19 winter season. The T-South system operated at 80-90 percent of maximum winter capacity due to integrity work that required permitting by regulatory bodies. This decrease adversely impacted supply and lead to price volatility exposing the Region to much higher gas prices when compared to normal winter pricing volatility that stem from extreme weather conditions. The system was not able to return to 100 percent operating levels until fourteen months after the incident date. Figure 3-2 below depicts the timeline of the T-South Incident and the associated resumption of service.

Figure 3-2: Timeline of the T-South Rupture



[26] The details of the 2018 T-South major incident have been provided in FEI's TSLE Certificate of Public Convenience and Necessity (CPCN) Application that was filed with the Commission on December 29, 2020.

3.2.1.2 *2021 floods*

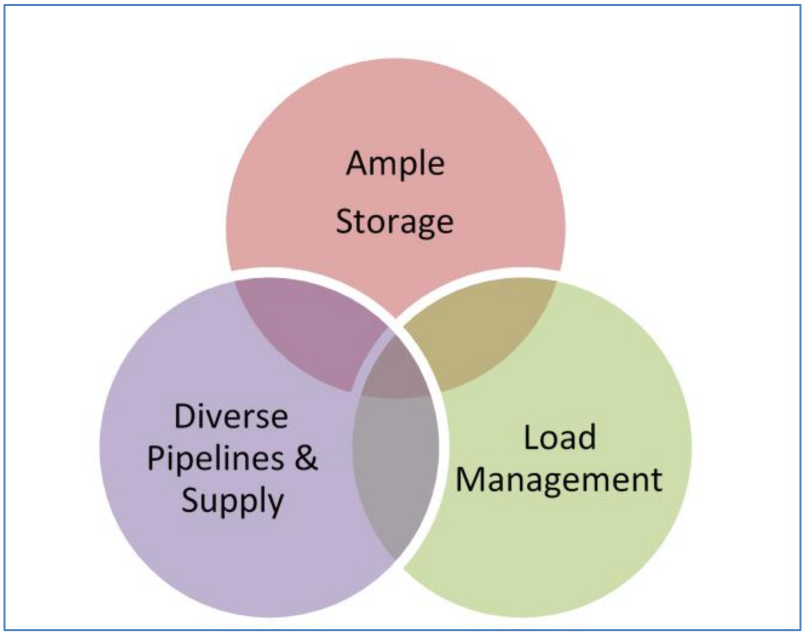
In November 2021, an atmospheric river led to pipeline washouts on the T-South system (Figure 3-3). This caused part of the T-South system to be taken out of service, resulting in a temporary reduction in service. The pipeline did not operate at 100 percent capacity for approximately a month thereafter. After the system resumed full-service in the third week of December 2021, the province experienced a major cold snap, bringing record low temperatures to the Lower Mainland and large portions of BC. The cold weather lasted for about ten days, causing consecutive days of very large (near design) loads in all of FEI's service territories. Although FEI navigated the incidents without any supply failure to customers, FEI's heavy dependency on T-South as its only major artery for gas highlights FEI's exposure to supply curtailment and system failure due to pressure loss that could be catastrophic over a longer duration for customers under winter weather conditions of this kind.

Figure 3-3: T-South Underwater During 2021 Flooding

3.2.2 The RGSD Project Provides Resiliency Benefits

Resiliency can be succinctly understood as a system's ability to withstand and quickly recover from low-probability, high consequence events. Resiliency is, in the broadest sense, based on three pillars shown in Figure 3-4 below. Pipeline diversity is beneficial because it increases the probability that gas flows can be maintained to load centres. As FEI has described in other filings, relying on only one pipeline to serve hundreds of thousands of customers in the Lower Mainland is a risk for FEI. The RGSD Project will provide another source of stable supply.

Figure 3-4: The Three Pillars of Resiliency for a Gas System



3.2.2.1 *Multiple Pipeline Paths Is Inherently Preferable from a Resiliency Standpoint*

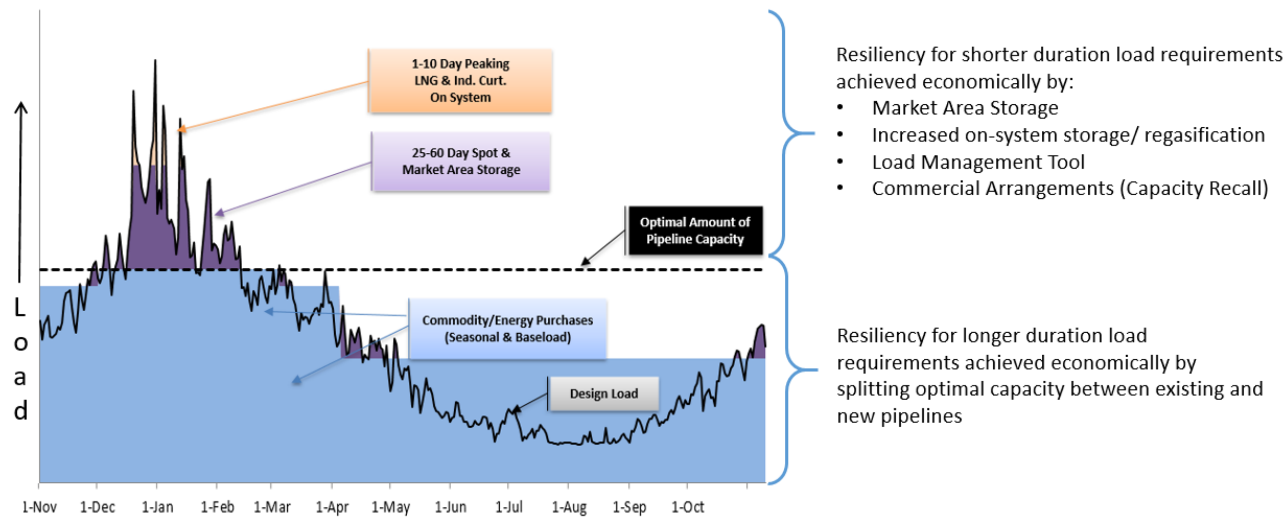
The RGSD Project is inherently preferable to T-South expansion from a resiliency standpoint, as it would entail an entirely different path from the T-South system. Having multiple paths reduces the risk of supply being completely disrupted due to a localized issue like the 2021 flooding or the 2018 T-South Incident. The resulting pipeline diversity means that FEI could still access a significant amount of supply for the Lower Mainland in the event of a no-flow event, or prolonged constraint, on either T-South or the RGSD pipeline. The RGSD Project would strengthen the resiliency of the entire regional system significantly.

3.2.2.2 *Optimal Resiliency Solution Includes Both TLSE and RGSD*

FEI's proposed Tilbury LNG Storage Expansion (TLSE) project, currently before the BCUC in another proceeding, is an example of FEI taking steps to further enhance the resiliency of its gas system. As explained in the TLSE proceeding and summarized below, the RGSD Project would be complementary to the TLSE project; the need for the RGSD Project is distinct from, and unaffected by, the type of resiliency provided by the TLSE project.

Pipeline supply that has continuous flow underpins FEI's daily gas requirements. The pipeline resource is complemented by storage resources that help to balance the system under cold winter weather conditions. FEI's supply stack requires baseload pipeline supply to cover the majority of daily operational needs and uses storage resources when demand is peaking. The same principles underlying an efficient supply portfolio also apply to resiliency. In particular, while storage like the TLSE Project addresses *shorter-term* duration events, reducing the risk associated with *longer-term* supply constraints on the T-South system requires pipeline diversity.[27] Figure 3-5 below, copied from the TLSE Application[28], shows how different resiliency resources align with FEI's efficient supply portfolio.

Figure 3-5: Optimal ACP Portfolio and Resiliency Measures



Had the 2018 T-South Incident occurred in the middle of winter, it would have led to drastic shortages in gas supply under the current portfolio of resources due to insufficient pipe supply over a significant number of days. With the benefit of TLSE, the situation improves significantly but FEI remains vulnerable to long-term supply constraints on T-South following a no-flow period.

FEI simulated the T-South Incident with three days of zero flow to Huntingdon under design load[29] weather occurring in the early part of December. In this simulation, the ACP portfolio included the proposed TLSE LNG storage tank and other current resources in the portfolio (Figure 3-6). The TSLE storage tank performed as expected, meeting the initial no-flow on T-South and complemented short-term duration supply shortage as the T-South gradually resumed operations at very restricted levels. However, once the LNG supply depleted (i.e., a storage resource) and T-South remained at very restricted levels, FEI experienced gas supply shortages each day at significant levels (as depicted in red in the figure below) until T-South levels increased (depicted in blue in the figure below). The need for piped gas supply was thus critical because the duration of winter demand exceeded the level of supply after storage resources were significantly depleted.

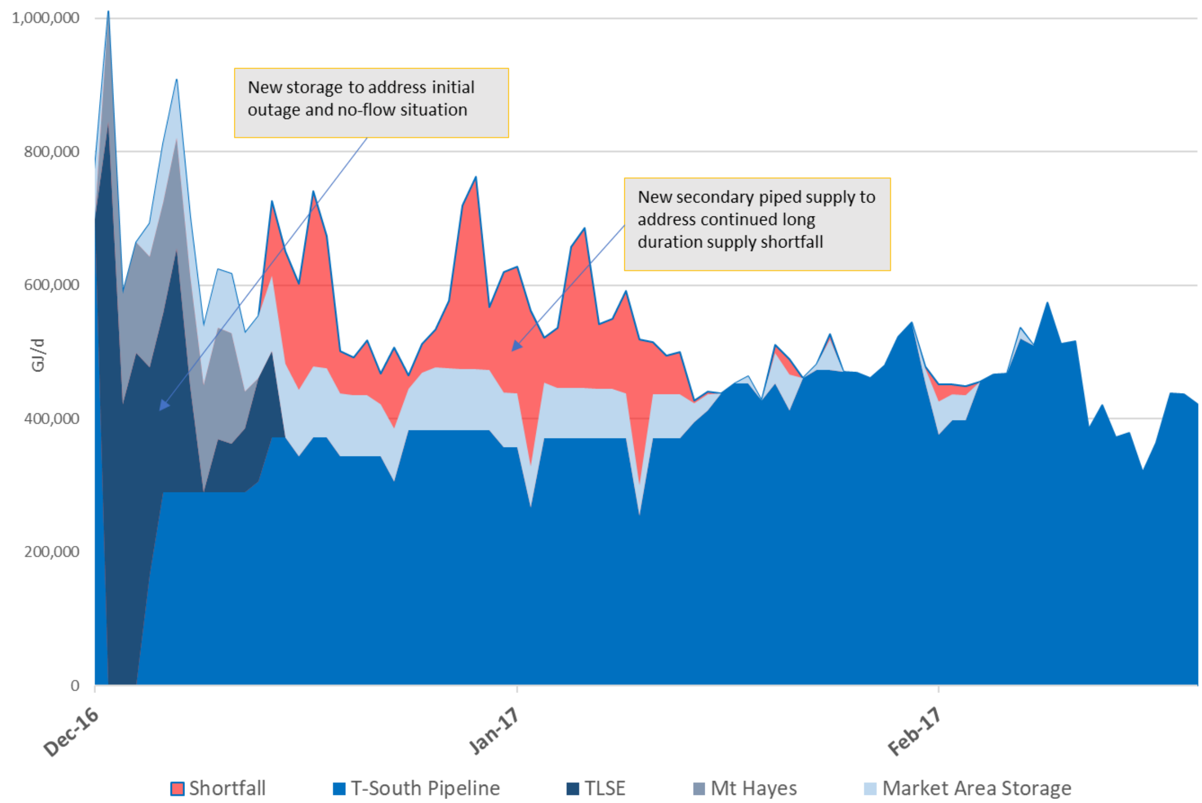
[27] FortisBC Energy Inc. Application for a CPCN for the Tilbury Liquefied Natural Gas Storage Expansion Project. Appendix C; Page 11. https://docs.bcuc.com/Documents/Proceedings/2021/DOC_60434_B-1-FEI-Tilbury-LNG-CPCN-Application-REDACTED.pdf.

[28] FortisBC Energy Inc. Application for a CPCN for the Tilbury Liquefied Natural Gas Storage Expansion Project. Figure 1-4; Page 8. https://docs.bcuc.com/Documents/Proceedings/2021/DOC_60434_B-1-FEI-Tilbury-LNG-CPCN-Application-REDACTED.pdf.

[29] The design load is the maximum demand the system is built to handle.

This simulation demonstrates that in order for FEI to meet load in winter under restricted pipeline supply, another source of piped gas supply has to be in place to ensure the resiliency of the system. Diversified regional pipeline infrastructure would enable FEI to withstand a low-probability, high consequence event on one pipeline, by using the second pipeline to cover baseload requirements. The storage resources allow the utility to react quickly, and fill the system demand, in the intermediate time until supply from the pipeline can reach the load centre.

Figure 3-6: FEI's Design Loads Simulated under a T-South Pipeline Outage



As the RGSD Project would have a different route from the existing T-South system, FEI's system and the customers served by the utility would ultimately benefit from a distinct and more resilient source of major gas supply.

3.3 THE RGSD PROJECT WOULD ADD REGIONAL CAPACITY AND ALLOW EFFICIENT FUTURE EXPANDABILITY

The RGSD Project would allow FEI to add capacity that is needed in the Region to alleviate current constraints and allow for future growth due to new loads. In addition, the incremental capacity will facilitate the impacts of hydrogen blending that is capacity intensive. In the winter, the T-South system flows at or near capacity even with the 0.1 Bcf/d capacity increase that came into effect on November 1, 2021. As discussed in Section 2, T-South is fully subscribed. The addition of the Woodfibre LNG load will significantly increase the need for new capacity to be developed to Huntingdon that would otherwise trigger expansions of other infrastructure with less beneficial attributes for FEI and its customers

Moreover, sourcing renewable and low-carbon gas supply from AECO/NIT would add greater flexibility for customers due to the size of the trading hub. The RGSD Project will offer increased capacity and a greater connection to the Alberta marketplace that will provide benefits to customers over the long-term.

3.4 RGSD PROJECT WOULD ADVANCE INDIGENOUS PARTNERSHIPS, INCLUSION AND RECONCILIATION

FEI sees the RGSD Project as defining a new way of project development. In meetings with Indigenous Nations, FEI introduced the concept for the RGSD Project, including objectives that (a) it would be owned by an Indigenous-Fortis Partnership with significant Indigenous ownership interest, (b) the related ownership model would be established early, and (c) FEI would collaborate from the outset with Indigenous Nations on routing and compressor station site selection. The RGSD Project, if these objectives are realized, will provide significant economic opportunity for Indigenous Nations. Additionally, FEI believes that garnering the support of affected Indigenous Nations will facilitate efficient and effective project delivery.

As set out in FEI's Statement of Indigenous Principles, FEI is committed to dialogue through clear and open communication with Indigenous Nations on an ongoing and timely basis for the mutual interest and benefit of all parties. This commitment aligns with the United Nations Declaration on the Rights of Indigenous Peoples (UNDRIP),[30] the Truth and Reconciliation Commission of Canada's Calls to Action,[31] and the Government of B.C.'s Declaration on the Rights of Indigenous Peoples Act.[32] FEI recognizes UNDRIP as a reconciliation framework across its business and aims to achieve Call to Action 92, which calls on the Canadian corporate sector to "commit to meaningful consultation, building respectful relationships, and obtaining the free, prior, and informed consent of Indigenous peoples before proceeding with economic development projects."[33] The RGSD Project partnership as contemplated could provide lasting and intergenerational economic opportunities for Indigenous Nations. Through the early engagement and dialogue required for the Project, FEI will develop new and existing relationships with Indigenous Nations, which in addition to ensuring the input, knowledge and

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[30] United Nations Declaration on the Rights of Indigenous Peoples. https://www.un.org/development/desa/indigenouspeoples/declaration-on-the-rights-of-indigenous-peoples.html.

[31] Truth and Reconciliation Commission of Canada's Calls to Action. https://www2.gov.bc.ca/assets/gov/british-columbians-our-governments/indigenous-people/aboriginal-peoples-documents/calls_to_action_english2.pdf.

[32] Legislative Assembly of British Columbia, Bill 41, Declaration on the Rights of Indigenous Peoples Act: https://www.leg.bc.ca/parliamentary-business/legislation-debates-proceedings/41st-parliament/4th-session/bills/third-reading/gov41-3.

[33] Truth and Reconciliation Commission of Canada's, Calls to Action, Page 10: https://ehprnh2mwo3.exactdn.com/wp-content/uploads/2021/01/Calls_to_Action_English2.pdf.

expertise of Indigenous people is incorporated into the Project, will benefit interaction with FEI's ongoing operations.

At this stage of development, the RGSD Project is expected to involve numerous Indigenous Nations along the anticipated route and FEI may need to engage with many others. As discussed in Section 6.2.1, FEI began early engagement to introduce a high-level Project concept with Indigenous Nation alliances and to gain a preliminary understanding of interest in the Project. These proactive and transparent discussions have provided an opportunity for dialogue between FEI and Indigenous Nations, where both have learned about and from one another. However, this is just the starting point and more fulsome engagement is required at the individual Nation or Band level in order to develop understandings, garner Project input and solidify opportunities for Indigenous Nations to participate in the Project.

FEI will explore how the Project benefits can sustainably flow into communities in collaboration with affected Indigenous Nations. Indigenous involvement is a cornerstone of the Project and FEI expects it to be an important opportunity to contribute to economic reconciliation efforts. FEI will work collaboratively with affected Nations to identify opportunities for involvement that align with their respective desired level of participation. Examples of potential focused arrangements include, but are not limited to:

- Partnership arrangements, specifically including equity ownership in the Project;
- Indigenous led environmental, archaeological and/or traditional use studies;
- Indigenous communities supplying renewable energy sources to power Project components like compressor stations;
- RNG and/or hydrogen production to feed into the Project; and
- Employment, contracting and training opportunities with the Project.

For a linear project such as the RGSD Project, the magnitude of engagement required to ensure adequate input from and appropriate opportunities for affected Nations is substantial. As outlined in Section 6, FEI is committed to the time and effort required for meaningful engagement with all affected Indigenous Nations and in turn has budgeted for capacity funding to enable Indigenous Nations to engage with FEI in a meaningful manner. Such engagement is a prerequisite to being able to develop partnerships and garner support for the Project to proceed to submitting a CPCN, and participate in other relevant regulatory processes applicable to the Project, including the British Columbia Environmental Assessment (BC EA).

3.5 *CONCLUSION*

As discussed in this section, the RGSD Project would provide significant long-term benefits to FEI's customers in terms of adding regional capacity with efficient future expandability, strengthening pipeline system resiliency, progressing towards a renewable and low-carbon energy future and advancing Indigenous partnerships, inclusion and reconciliation. In addition to these unique benefits, the RGSD Project represents a major infrastructure development opportunity in the Province that has the potential to provide a significant contribution to the provincial economy and positive impact to residents and businesses through the creation of additional employment, the procurement of local materials, and the use of local services. FEI plans to advance the development work in sustainable way to generate broader socio-economic benefits to British Columbians. FEI's development work on the RGSD Project will include assessing the extent of these Project's benefits in conjunction with more detailed feasibility work and financial analysis.

4. PRELIMINARY EVALUATION OF THE PIPELINE OPTIONS IN MEETING REGIONAL REQUIREMENTS

This section describes FEI's preliminary evaluation of the three potential pipeline expansion options in the Region. In light of the Regional market conditions described in Section 2, it is reasonable to expect that at least one of these options will proceed. FEI's preliminary evaluation is directed at determining which of these options offers the best value proposition for FEI and its customers.

FEI's preliminary non-financial assessment shows that the RGSD Project, unlike other options, would provide significant long-term benefits to FEI's customers and the Region as a whole. FEI also conducted a preliminary financial assessment that demonstrates that the RGSD Project is financially viable and would have a similar financial impact to FEI's gas supply portfolio costs when compared to T-South expansions. FEI believes that these preliminary evaluations provide a sound basis for establishing the requested deferral account and undertaking the further development work contemplated in Section 6, which will position FEI to make an informed decision about whether to proceed with the RGSD Project.

The remainder of Section 4 is organized as follows:

- Section 4.1 describes the three potential pipeline options in the Region.
- Section 4.2 describes FEI's preliminary evaluation methodology. FEI assessed the three potential regional options against non-financial criteria, and undertook a preliminary financial analysis comparing T-South and RGSD pipeline expansion options.
- Section 4.3 summarizes the results of the preliminary options evaluation. Based on the analysis to date, the RGSD Project is the best option for FEI customers, and also provides attributes that make it a potentially attractive option for other shippers in the Region.
- Section 4.4 provides a conclusion.

4.1 *DESCRIPTION OF PIPELINE OPTIONS IN THE REGION*

FEI has identified three potential expansion options (stated in MMsfcd of volume and TJ/d of energy[34]), with sub-variations, each of which is described below:

- **Option 1 (T-South Expansion):** A range of Enbridge's T-South expansion projects from the announced 300 MMscfd (around 350 TJ/d) and up to 450 MMscfd (around 500 TJ/d).

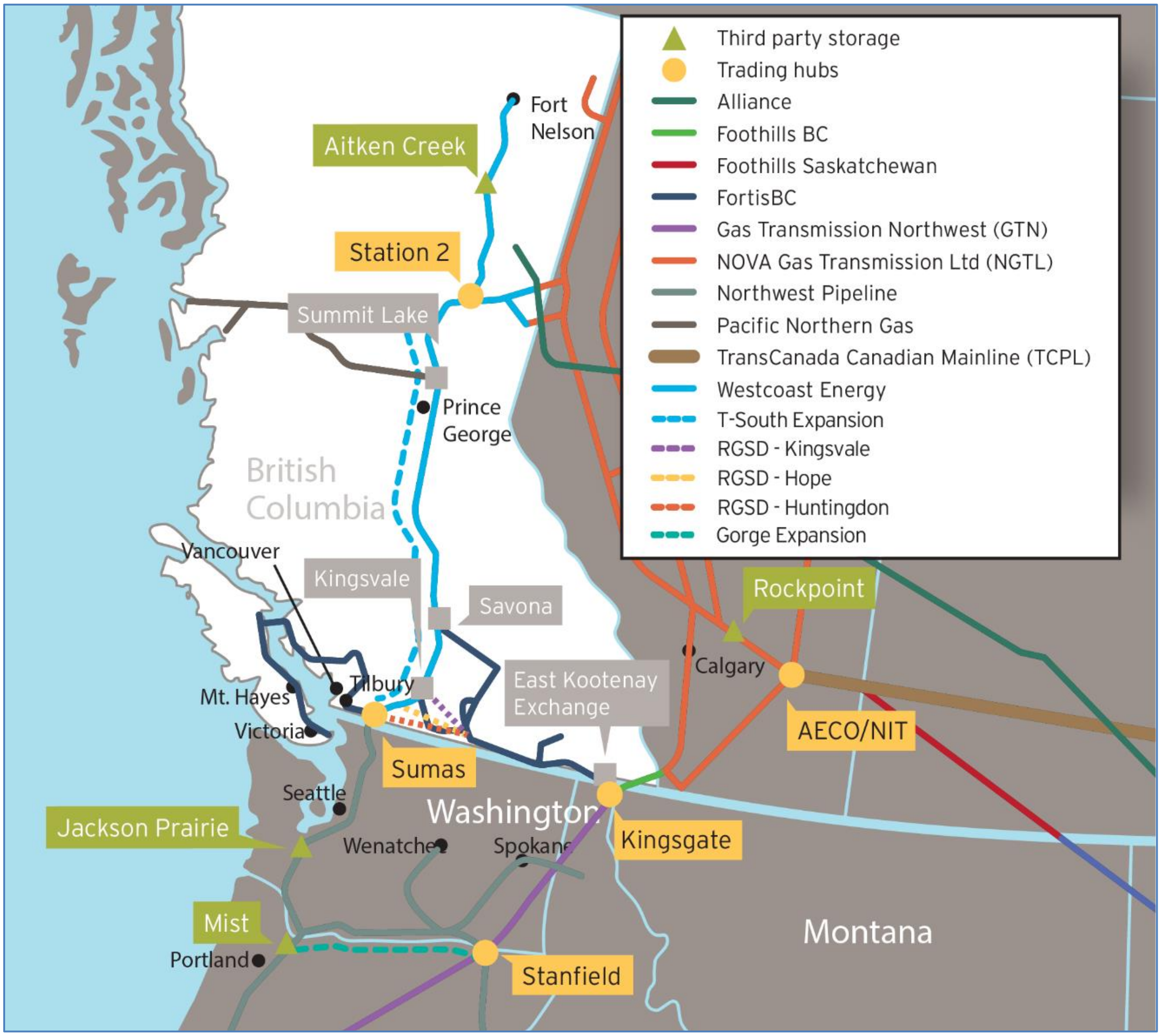
[34] The conversion of volume to energy will vary under different expansion options due to the properties of the produced gas resulting in different amounts of TJ/d when converted from MMscfd. Option 1 (T-South Expansion) is based on current energy levels on T-South that result in slightly higher GJ/d since gas produced currently in Northeastern BC currently contain rich liquids due to an absence of straddle plants, while gas sourced from Alberta under Options 2 and 3 is leaner due to liquids removal occurring in straddle plants currently in operation. Future energy levels could drop under Option 1 (T-South Expansion) if straddle plants are developed in northern BC: Enbridge planning $2.5B new gas plant, pipeline in B.C. - JWN Energy.

This range recognizes that the announced T-South Expansion (i.e. 300 MMscfd) is t primarily triggered due to Woodfibre LNG demand, however, is not sufficient to meet expected long-term Regional demand growth that would be better accommodated by a larger expansion such as a 450 MMscfd capacity increase.

- **Option 2 (RGSD Project):** The RGSD Project, which will extend FEI's existing SCP system from Oliver to Huntingdon to deliver approximately 450 MMscfd or around 500 TJ/d. While FEI has focussed on the Oliver to Huntington routing for the purposes of this preliminary analysis, it should be understood that potential variants are possible based on further work. FEI would consider other delivery points such as interconnecting with the T-South system either at Kingsvale or Hope in the event that a direct connection to Huntingdon is not deemed feasible during the development phase of the Project.
- **Option 3 (NWP Gorge Expansion):** An expansion of 450 MMscfd or around 500 TJ/d on Northwest Pipeline's (NWP) Gorge section, expanding capacity between Stanfield, Oregon and Seattle, Washington.

These regional expansion options are shown in Figure 4-1 below and described in more detail in the sections that follow.

Figure 4-1: Map of Potential Regional Expansions



4.1.1 Option 1 (T-South Expansion) – Enbridge's Expansion Options

As described in Section 2.3, Enbridge has publicly announced that it intends to expand the existing T-South system and plans to conduct an open season in the third quarter of 2022 to seek shipper interest in its T-South Expansion project. The proposed $2.5 billion-plus T-South Expansion would occur between Compressor Station 2 (near Chetwynd) and Huntingdon, and is anticipated to include lengthy NPS 42 or 42-inch diameter pipeline looping and compression upgrades. The volumetric capacity to Huntingdon would increase by about 300 MMscfd to a total of 2,100 MMscfd or 2.1 Bcf/d (from 1,800 MMscfd or 1.8 Bcf/d) available in the winter months.

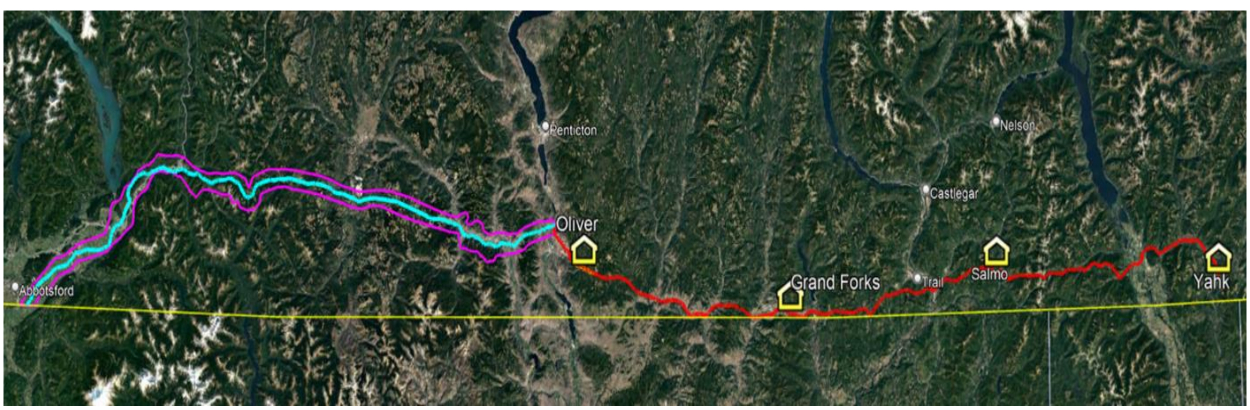
Enbridge's open season could attract shipper commitments for a larger expansion greater than 300 MMscfd, given that the announced capacity is primarily triggered due to Woodfibre LNG coming into service, and does not fully address the Region's needs for incremental capacity to meet growing long-term demand and other market conditions affecting the Region as described in Section 2. Therefore, FEI has considered a range of T-South system expansion (i.e. from 300 MMscfd to 450 MMscfd) for the purposes of completing this preliminary evaluation. FEI expects that a 450 MMscfd expansion would also entail significant pipeline looping using NPS 42 or 42-inch diameter pipe along with compression upgrades on parts of the existing T-South pipeline. The capital cost of such an expansion would be considerably greater than the announced 300 MMscfd T-South Expansion project.

4.1.2 Option 2 (RGSD Project) – FEI's SCP Expansion to Huntingdon or Alternate Delivery Points

An expansion of FEI's SCP system, by extending the system from Oliver to Huntingdon, would add approximately 450 MMscfd of incremental capacity to the Region.[35]

As currently envisioned, the RGSD Project would involve an extension of SCP from its current endpoint at Oliver to a new endpoint at Huntingdon (located around Abbotsford), by adding four compressor stations and approximately 240 km of new NPS 30 or 30-inch diameter pipe. Three more compressor stations can be added to the initial four compressor design in order to increase capacity efficiently in the future if required up to approximately 690 MMscfd. The figure below show a preliminary route corridor that FEI has identified at this early stage of the Project's assessment.

Figure 4-2: RGSD Project Overview



While a direct connection to Huntingdon is FEI's preferred expansion choice, FEI would consider an alteration to the scope of the RGSD Project that would assess other delivery points, such as tie-ins to T-South at Kingsvale or Hope, in the event that a direct connection to Huntingdon is deemed unfeasible based on further detailed assessments. These sub-variations of the RGSD Project would require capacity upgrades on T-South between Kingsvale or Hope and Huntingdon in order to deliver the incremental volume sourced from SCP.

[35] Volumetric flow assumes no hydrogen.

4.1.3 Option 3 (NWP Gorge Expansion) - Expansion of NWP Gorge Capacity

Another possible option for Regional pipeline infrastructure is an expansion on NWP along the Gorge section (between Stanfield and Portland, Oregon) of that pipeline system, which would increase the physical capacity to bring supply westbound from Stanfield or the Rockies into the I-5 corridor. Expanding the NWP Gorge capacity would allow gas to flow west into the Seattle and Portland region that would potentially decrease demand at Huntingdon.

FEI understands (based on discussions with regional parties) that the Gorge section of NWP would require major pipeline looping and compression upgrades in order to flow an incremental 450 MMscfd of gas northbound from Stanfield to serve the US Pacific Northwest up to Seattle.

While an expansion of this size would greatly increase the capacity of the Gorge section of NWP, gas would only physically move as far north as Seattle based on the system's current configuration. For gas to flow physically north beyond Seattle up to Huntingdon, the pipeline would require further major facilities, such as dedicated compressors to flow gas in the opposite direction from the system's current design. Building dedicated compressors to flow north would arguably be redundant for use on a day-to-day basis and would only be used under extreme capacity curtailment or no-flow situations on T-South to Huntingdon.

4.2 *NON-FINANCIAL OPTIONS EVALUATION*

FEI assessed the options against preliminary non-financial criteria and used a rating system to determine the best value proposition from the perspective of FEI and its customers. The non-financial evaluation criteria and results of the preliminary assessments are described in the subsections below.

4.2.1 Preliminary Non-Financial Evaluation Criteria

The following non-financial criteria were used to evaluate the options described in Section 4.1 above. FEI notes that the preliminary non-financial evaluation criteria are based on addressing the gas supply market conditions affecting the Region as described in Section 2. Each criterion is described in more detail below.

a. **Decarbonization and Access to Renewable and Low-Carbon Gas Supply**

This criterion considers the ability of the expansion option to enable the transition to renewable and low-carbon gas supply in order for FEI to meet the provincial government targets set under the CleanBC Roadmap. There are two important components to consider under this criterion:

- Access to Renewable and Low-Carbon Gas Supply – Location of new renewable and low-carbon gas supply sources and the types of renewables that the pipeline can transport safely;

- Pipeline's Hydrogen Readiness – Pipeline's structural capability to safely flow and blend increasing levels of hydrogen over the long-term.

An expansion option that facilitates these components allowing for greater access to renewable and low-carbon gas supply would meet this criterion.

b. **Pipeline System Resiliency**

This criterion considers a new pipeline path to the Lower Mainland and sourcing supply from new basins in order to strengthen Regional gas system resiliency. Having access to multiple Regional pipelines, separated geographically to serve the distribution system improves a utility's ability to reliably deliver energy to its customers under outage and capacity restrictions on one pipeline. Therefore, dependency on a single pipeline would not be a preferable choice, while a pipeline expansion option that is built on a new separate path and provides access to supply from other sources would meet this criterion.

c. **Regional Capacity Growth and Efficient Future Expandability**

This criterion considers Regional capacity growth that will directly benefit FEI's customers at Huntingdon, and the Region as well, and the ability to further expand pipeline capacity efficiently in the future when needed. This criterion considers the potential of the expansion to satisfy current and long-term Regional demand growth opportunities needing pipeline capacity. Pipeline expansion options that allow for cost-effective and efficient further expandability in the future would meet this criterion.

4.2.2 Results of Preliminary Non-Financial Evaluation of Options

FEI used a "meets" (denoted by a check mark) or "does not meet" (blank) in order to rate the non-financial criteria described in the section above. The ratings were determined through collaborative discussions with FEI's subject matter experts. While FEI understands that this methodology is preliminary, it is appropriate for the current stage of assessing options. FEI will conduct a detailed assessment of options prior to CPCN filing, as FEI advances its Project development work.

The following table provides a summary of FEI's preliminary assessment of the three options against the non-financial criteria outlined above in Section **Error! Reference source not found.**. Based on Table 4-1 below, FEI determined that Option 2 (RGSD Project) is the most beneficial option compared to other options as it provides FEI's customers with access to renewable and low-carbon gas supply over the long-term, much needed pipeline system resiliency, and capacity growth at Huntingdon to meet their long-term needs.

Table 4-1: Summary of Options Assessment

Category	Criteria	Option 1 - (T-South Expansion)	Option 2 - (RGSD)	Option 3 - (NWP Gorge Expansion)
Decarbonization & Access to Renewable and Low-Carbon Gas Supply	Access to Renewable and Low-Carbon Gas Supply	✓	✓	✓
	Pipeline Hydrogen Readiness		✓	
Pipeline System Resiliency	New Path to Lower Mainland		✓	
	Alternative Supply Source		✓	✓
Regional Capacity Growth and Efficient Future Expandability	Regional Capacity Growth	✓	✓	✓
	Efficient Future Expandability		✓	

The following sections discuss the options evaluation based on each criterion in more detail.

4.2.2.1 *RGSD Project is Rated Highest on Decarbonization and Access to Renewable and Low-Carbon Gas Supply*

FEI rated all options as "meets" for sourcing renewable and low-carbon gas supply, as this supply is expected to be produced in various locations within BC and Alberta over the long term.

Although Option 1 (T-South Expansion) is rated as "meets" and could provide some access to renewable and low-carbon gas supply, FEI does not expect the system to also flow hydrogen as the hydrogen-readiness of the current T-South pipeline could be challenging due to its age, and potentially require major capital upgrades that would ultimately be borne by FEI's customers and other shippers. FEI will require significant amounts of renewable and low-carbon gas to meet the province's decarbonization targets. Reliance on T-South singularly is not expected to provide FEI with the large quantities of renewable and low-carbon gas supply needed to meet its long-term decarbonization targets.

Option 2 (RGSD Project) to Huntingdon is rated as "meets", as it will enable FEI to incorporate renewable and low-carbon gas supply from various sources, including those developed in the interior of BC and from major markets such as Alberta. FEI's preliminary pipeline assessment work suggests that the existing SCP pipeline from Yahk to Oliver, BC would be able to blend hydrogen within safe limits due to the recent age and material composition of the pipeline as it was built around the year 2000. Access to increasing levels of cost effective renewable and low-carbon gas, particularly at the AECO/NIT hub, and hydrogen from a variety of sources that could be delivered directly to Huntingdon on SCP and the RGSD pipeline is a significant benefit that distinguishes Option 2 (RGSD Project) from others. With respect to other variations of the RGSD Project and as stated under Option 1 (T-South Expansion), it is uncertain what level of capital upgrades would be required between Kingsvale or Hope and Huntingdon on T-South in order to enable the system to flow hydrogen. However, under a Kingsvale or Hope tie-in of the RGSD Project, any capital, capacity or integrity upgrading on T-South in order to flow hydrogen is expected to be considerably less compared to a larger-scale reinforcement under Option 1 (T-South Expansion). As a result, these alternate expansion options of the RGSD Project provide significant benefits to FEI's customers and the Region compared to Option 1 (T-South Expansion).

Option 3 (NWP Gorge Expansion) is rated as "meets" for access to renewable and low-carbon gas supply from the Alberta marketplace. However, this option will only be viable if the NWP system is upgraded to physically deliver gas to Huntingdon, which is expected to be cost prohibitive for FEI's customers. Similar to Option 1 (T-South Expansion), the hydrogen-readiness of the pipeline would need to be assessed. Given the age of the Gorge pipeline, which came into service in the 1950s and, like the T-South pipeline, it is uncertain whether hydrogen can be facilitated without major upgrades to the pipeline's structure at reasonable cost on the entire length of the system. While US sourced renewable and low-carbon gas could be completed by displacement, at some point FEI will need to access the physical flow of molecules to Huntingdon over the long-term, which may not be possible under the NWP Gorge Expansion option based on the system's hydraulic configuration which requires a high level of gas to flow south from Huntingdon into the US Pacific Northwest. As a result, gas flow northbound to Huntingdon on NWP would be physically challenging and unlikely when gas is actually flowing in the opposite direction southbound that is delivered off the T-South system onto NWP.

4.2.2.2 *RGSD Project is Rated Highest on Pipeline System Resiliency*

Option 1 (T-South Expansion) is rated as "does not meet" with respect to Regional pipeline system resiliency. The expansion infrastructure would still be constructed in, or nearby, the current rights- of-way, meaning that FEI is exposed to the risk of a major pipeline failure on T-South. Under no-flow conditions, similar to what occurred immediately in 2018 after the T-South Incident, this expansion option would not provide any resiliency leaving FEI exposed to considerable risk due to a single point of failure for the majority of its daily gas supply.

Option 2 (RGSD Project) to Huntingdon is rated as "meets" because it is the only option where the pipeline is constructed in a geographically separate path and provides pipeline system resiliency as it would be operational under a no-flow condition or any other capacity restriction on the T-South pipeline. Option 2 (RGSD Project) also provides FEI access to daily gas supply sourced from a highly robust and liquid market which is the AECO/NIT hub. Please refer to Section 3 including Figure 3-6 depicting a major shortfall of supply under design load conditions that would be avoided under a RGSD Project. Option 2 (RGSD) therefore, diversifies FEI's gas supply on both a separate and distinct pipeline path, and provides supply sourcing from another basin and market hub.

Other variations of the RGSD Project such as a connection with T-South at Kingsvale or Hope are rated as "meets" as they would still provide FEI with considerable benefits compared to Option 1 (T-South Expansion), and shield FEI's customers from disruptions upstream of the interconnection point. For example, a connection to Hope is within the outskirts of the Fraser Valley, so an outage between Hope and Huntingdon would be in accessible terrain, especially in the winter months, for Enbridge to assess and conduct repairs on the pipeline and resume gas flow more expeditiously compared to conducting repairs along the more northerly and remote parts of the 916 km T-South pipeline.

Option 3 (NWP Gorge Expansion) is rated "does not meet" on resiliency from FEI's perspective in the analysis because this expansion would primarily benefit the US Pacific Northwest markets up to Seattle due to NWP's current hydraulic configuration. Under a partial disruption on T-South pipeline, this option could benefit FEI under limited operating conditions as it could allow the partial flow on T-South to serve FEI's load centres as the US Pacific Northwest would be served by the NWP Gorge expansion depending upon the size of demand at the time. In rare cases such as periods of low demand in the I-5 corridor, some volumes could hydraulically physically flow north to Huntingdon; however, it would not assist FEI in the case of an outage in periods of high demand such as the winter months, when hydraulics preclude significant quantities of gas flowing northward to Huntingdon. Addressing this issue to allow northbound flows from Seattle to Huntingdon is expected to be cost prohibitive for FEI customers as FEI would be solely responsible financially under US tolling methodology for the capital upgrades enabling gas to flow to Huntingdon.[36] Also, these facilities would only be used sporadically to manage major disruptions on the T-South system as gas flow patterns on NWP are designed to move gas southbound from Huntingdon into the US Pacific Northwest each day. Please refer to a discussion on NWP Gorge Expansion for further details that is referenced in FEI's TLSE application.[37]

4.2.2.3 *RGSD is Rated Highest on Regional Capacity Growth and Efficient Future Expandability*

Option 1 (T-South Expansion) is rated as "meets" with respect to the Regional capacity growth, but the benefit is minimal to the extent that an announced 300 MMscfd T-South expansion is primarily triggered due to Woodfibre LNG demand once it commences operations as explained in Section 2.2.1. The existing capacity on T-South has already been contracted by Woodfibre LNG but since the plant is not currently operational, the capacity has been temporarily released to the marketplace to serve existing customer demand at Huntingdon until the plant is constructed and needs that capacity to produce LNG. FEI strongly believes that a 300 MMscfd T-South expansion is insufficient to facilitate long-term Regional demand growth and accommodate hydrogen blending. As a result, Enbridge would need to develop a larger expansion if their proposed open season in Q3/2022 is subscribed to levels greater than 300 MMscfd, or proceed with a further second expansion in the future after the 300 MMscfd expansion comes into service.

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[36] Under US tolling methodology, proponents that trigger expansions are responsible to bear the incremental costs of such upgrades if the capital expenditure causes tolls to rise for existing shippers. Such will be the case if NWP is upgraded to physically flow gas from Seattle to Huntingdon and FEI will be the sole bearer of toll increases for the incremental capital cost to reconfigure the pipeline system which is expected to be cost prohibitive for FEI customers.

[37] Section 4.3.4.3 "Expansion of NWP Gorge Capacity: Not a Project Alternative Because Negligible Benefits in the Event of Supply Disruption on the T-South System" https://docs.bcuc.com/Documents/Proceedings/2021/DOC_60434_B-1-FEI-Tilbury-LNG-CPCN-Application-REDACTED.pdf.

FEI rated T-South pipeline as "does not meet" in terms of further efficient future expandability. If T-South initially is only expanded for 300 MMscfd, then FEI believes that subsequent capacity additions would require further pipeline looping, which will be more costly for FEI and other shippers as it is less efficient (from a cost perspective) to conduct another round of major regulatory and environmental filings and construction activities, instead of conducting a single major expansion all at once. As future demand for hydrogen increases over time, the T-South pipeline will be required to further expand beyond 300 MMscfd expansion in order to offset the capacity loss due to flowing lesser-dense hydrogen. In order to accommodate hydrogen, the T-South system will also be required to undertake system reinforcement activities needed to flow hydrogen safely that would be blended into the pipeline.

Option 2 (RGSD Project) to Huntingdon is rated as "meets" because it provides direct incremental capacity to Huntingdon that will alleviate current market winter capacity constraints and replace capacity that will be used by Woodfibre LNG on T-South, facilitate new long-term regional demand growth, and allow for a transition to hydrogen that is capacity intensive. Further expandability of RGSD pipeline can be conducted efficiently by adding cost effective compression only as hydrogen blending levels increase over time requiring additional pipeline capacity in order to maintain energy equivalency. This option also distributes FEI's supply sourcing, which is presently sourced primarily from Northeastern BC, to more diverse supply sourcing in its portfolio from the interior of BC and the Alberta marketplace that would include hydrogen and renewable methane. The RGSD Project would facilitate access to cost effective blue hydrogen from Alberta[38] over time as the fuel gains higher levels of acceptance and infrastructure is developed or modified to adopt hydrogen blending. More diverse supply sources combined with greater pipeline connectivity to Huntingdon would facilitate access to higher levels of hydrogen to market. Reducing FEI's current exposure on the T-South pipeline would allow FEI to release excess T-South capacity to existing or new parties that are interested in the development of projects on the south coast or expressing a need to reduce exposure to purchasing at the Huntingdon hub. Diversification of risk and supply optionality due to development of the RGSD Project provides benefits for all customers that include mitigating supply and lowering pricing risks at Huntingdon, purchasing supply from a liquid market hub (AECO/NIT) and reducing price exposure at Station 2, and access to increased number of counterparties to transact with for a mix of commodities including renewables and hydrogen. Diversification of supply to the much larger and liquid AECO/NIT basin is a major benefit of RGSD. Furthermore, concerns of excess gas supply at Huntingdon in the summer months can be avoided by the RGSD Project since FEI can sell gas in other markets such as AECO/NIT or Kingsgate rather than bring that supply to Huntingdon where it is not required due to a lack of heating load and inability to flow south on NWP due to an operational capacity issue on the NWP system at the Chehalis compressor station that restricts the amount of gas that can flow beyond that point.

Option 3 (NWP Gorge Expansion) is rated as "does not meet" from FEI's perspective for direct gas supply to Huntingdon; however, it does provide Regional capacity benefits. Option 3 (NWP

[38] https://www.bennettjones.com/Blogs-Section/Alberta-Releases-Roadmap-to-a-Hydrogen-Economy.

Gorge Expansion) allows for capacity to increase specifically within the US Pacific Northwest, so that buyers in the US could source more gas via that avenue and reduce their reliance on Huntingdon that could alleviate a capacity constraint and reduce overall Huntingdon pricing volatility. Under such conditions, current buyers, such as FEI's transport model customers, could continue purchasing gas at Huntingdon due to the reduced demand from US Pacific Northwest markets. NWP will likely need to expand capacity to around the same level as proposed under the RGSD Project or the larger T-South option in order to offset the Woodfibre LNG load and alleviate current Huntingdon capacity constraints, especially when gas-fired generation loads are strong. However, as stated in Section 4.2.2.2, this option will not provide physical gas supply to Huntingdon unless major compression and other facilities between Seattle and Huntingdon are added to flow gas north, which is expected to be cost prohibitive for FEI's customers. Finally, FEI is not aware of any recent project development of this concept, so it is unclear as to feasibility of such a NWP Gorge Expansion from a technical, environmental and financial perspective.

4.3 PRELIMINARY FINANCIAL ANALYSIS OF COMPARABLE OPTIONS SHOWS RGSD PROJECT IS A VIABLE OPTION WORTHY OF FURTHER DEVELOPMENT WORK

This section outlines FEI's preliminary financial assessment, which is based on net present value (NPV) of FEI's gas supply portfolio costs, to assess the relative impacts of two options - Option 1 (T-South Expansion) and Option 2 (RGSD Project). As explained in section above, Option 3 (NWP Gorge Expansion) is deemed not feasible to physically flow gas supply directly up to Huntingdon. Also, FEI has no basis for the cost estimates associated with Option 3 (NWP Gorge Expansion) and therefore, FEI did not proceed further with evaluating this option.

FEI conducted preliminary financial analysis on a Net Present Value (NPV) basis over 30 years to determine the impact of expansion options (i.e. Options 1 and 2) to FEI's gas supply portfolio. This NPV analysis considers how each expansion option will increase FEI's gas supply portfolio costs that would need to be recovered from customers. The increase in gas supply portfolio costs will be captured in the utility's midstream costs account which is reflected in FEI's Storage and Transport portion of the customer bill. High-level details of this preliminary financial analysis can be found in the Appendix B.

FEI's preliminary financial analysis shows that on NPV basis, FEI's gas supply portfolio costs are expected to increase in the range from $4.4 billion under a smaller 300 MMscfd expansion (that is insufficiently sized from FEI's perspective) to $5.4 billion under a larger 450 MMscfd expansion on T-South that addresses long-term Regional demand growth. The preliminary NPV analysis for a 450 MMscfd RGSD Project to Huntingdon illustrates that FEI's gas supply portfolio costs would increase by $5.3 billion. This preliminary analysis demonstrates that the RGSD Project (Option 2) would have similar cost impact when compared to T-South expansion (Option 1) but will provide significant long-term benefits to FEI's customers. On the other hand, under a T-South Expansion, FEI's customers will be subject to risks associated with continued reliance on a single pipeline and avenue of gas supply while providing minimal to no benefits.

4.4 CONCLUSION

Using the non-financial criteria, FEI determined that Option 2 (RGSD Project) is the most beneficial option, as it addresses the need for new regional pipeline infrastructure, and provides significant and unique long-term benefits to FEI's customers and the Region. A high-level financial analysis (NPV of FEI's gas supply portfolio costs) indicates that Option 2 (RGSD Project) is financially feasible and would have similar cost impact on FEI's gas supply portfolio costs as compared to Option 1 (T-South Expansion). The overall preliminary assessment of options using non-financial criteria and high-level preliminary financial analysis demonstrates that the RGSD Project merits further assessment and development work that is in the best interest of FEI's customers.

5. FEI MUST PROCEED WITH PROJECT DEVELOPMENT WORK NOW

FEI began preliminary development work on the RGSD Project in early 2021, including:

- Preparing Class 5 cost estimates and a preliminary Project schedule, and assessing the Project's potential scope and associated development costs in order to gain sufficient information to assess the Project against other pipeline expansion options and proceed with a deferral account request; and
- Undertaking informal preliminary discussions with Indigenous Nations.

There are several factors contributing to the importance of FEI ramping-up development work at this time, without delay.

First, consistent with FEI's commitment to meaningfully engage Indigenous Nations in a manner consistent with its Statement of Indigenous Principles, UNDRIP and the Truth and Reconciliation Commission of Canada's Calls to Action, FEI must substantially progress Indigenous engagement activities in advance of commencing the British Columbia Environmental Assessment (BC EA) process. In particular, FEI intends to develop new and existing relationships with Indigenous Nations through deepened engagement, fostering economic opportunities through partnership and equity ownership opportunities, and ultimately, advancing reconciliation through the Project's development and the economic opportunities for Indigenous peoples. As explained in Section 3.4, inclusion, reconciliation and partnership with Indigenous Nations is a foundational component of the RGSD Project, and the development work as proposed in this Application will enable FEI to proactively engage and collaborate with Indigenous Nations to appropriately inform Project development from the outset.

Second, there is significant work to be done to assess the potential for the RGSD Project, including determining whether it is the preferred solution for FEI and its customers in addressing Regional market conditions. This includes, in particular, pipeline and compressor Pre Front End Engineering Design (Pre-FEED) work to progress Project development activities, including incorporating Indigenous input, knowledge and expertise, leading to Class 4 cost estimates.

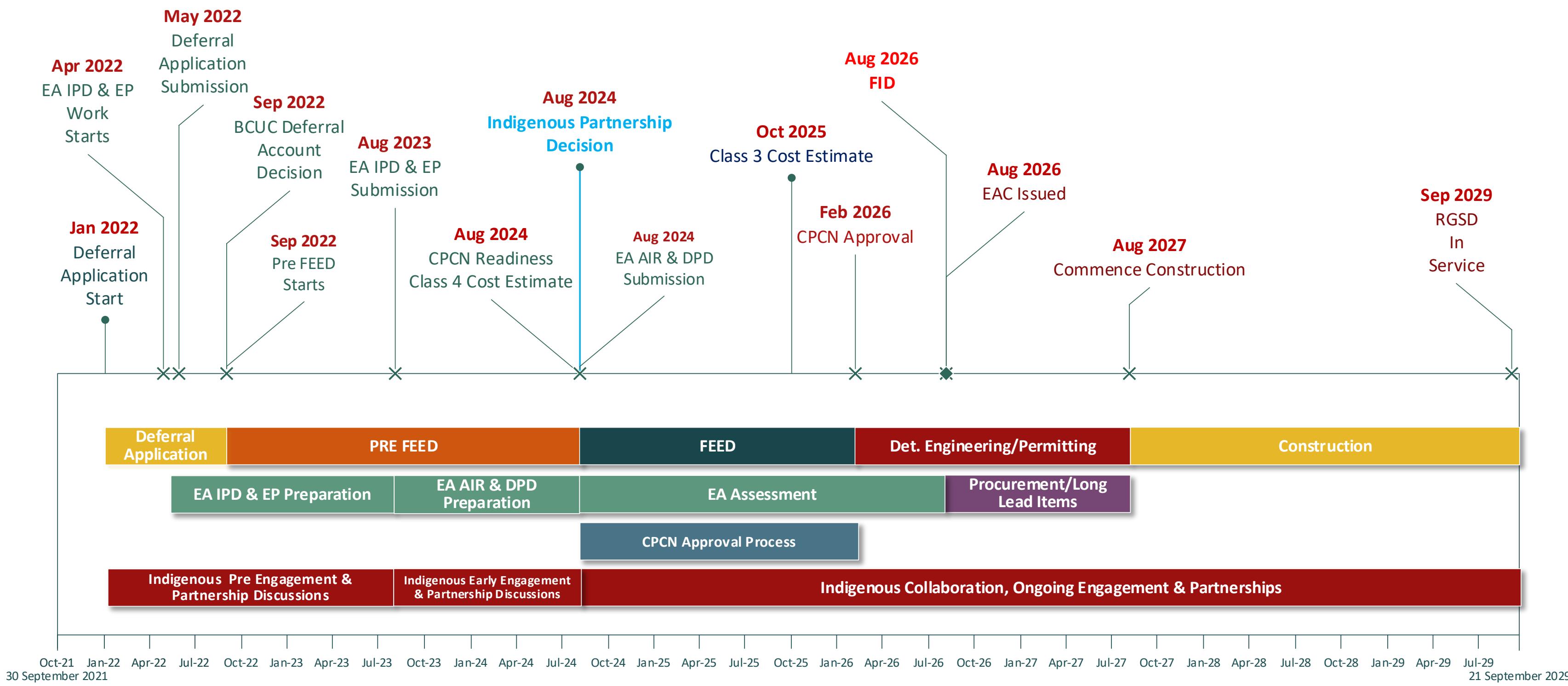
Third, FEI is also mindful of the pace of development on Enbridge's proposed 300 MMscfd T-South Expansion (Option 1 described in Section 4.1.1), and in particular the announcement of an open season. Advancing development work at this time preserves the RGSD Project as a legitimate capacity solution to address the market conditions in the Region as described in Section 2, such that the T-South Expansion could be avoided and in turn FEI would avoid bearing the costs of an expansion that provides little to no benefit to FEI and its customers.

The following figure shows the potential timelines of the RGSD Project leading to an in-service date of Q3 2029. This lags the anticipated in-service date of Woodfibre LNG and as such highlights the importance of proceeding with development work now. In the RGSD Project timeline, over a year is allowed for Indigenous engagement prior to moving into the BC EA early engagement process and thereafter timelines are based on typical regulatory review processes. While the T-South Expansion approval processes do not mirror the RGSD Project schedule, and while FEI does not have specific details regarding the T-South Expansion timelines, the T-South Expansion is a major project. It is reasonable to assume that a similar engagement and approval duration will be required to ensure full voice is given to affected Indigenous Nations. The potential RGSD Project timeline shows that, with an efficient determination of the current Application, FEI could be in a position to make a Financial Investment Decision (FID) on the RGSD Project in Q3 of 2026. While the ultimate timelines of both the RGSD Project and the T-South Expansion project will be adjusted based on progress of Indigenous engagement and the development work, the indicative timeline as shown in in Figure 5-1 below demonstrates the urgency to ramp up the RGSD Project Indigenous engagement work and other development activities.

Comparable timelines aside, it is conceivable, particularly given T-South is under separate federal regulation, that a limited T-South expansion could proceed even if the RGSD Project progresses. While this would be sub-optimal for FEI and the Region because of the unnecessary T-South expansion costs, there would still be enduring value for the RGSD Project in terms of the significant and unique long-term benefits the RGSD Project would bring as outlined in Section 3.

Further information on the RGSD Project schedule and development work is provided in Section 6.

Figure 5-1: Preliminary RGSD Project Timeline



6. DEVELOPMENT WORK AND ASSOCIATED COSTS

This section outlines the development work that FEI will be performing and the associated costs that would be recorded in the proposed RGSD Development Account. This development work will permit FEI to advance the development work on the RGSD Project to the point where FEI will be in a position to make a fully informed decision on whether to file the necessary applications to proceed with it. As further explained in this section, this development work is divided into Phase 1A and Phase 1B and FEI proposes to provide an update on costs and schedule in the reporting discussed in Section 7.

This section is organized as follows:

- Section 6.1 describes the high-level Project schedule and key milestones and activities; and
- Section 6.2 describes the Project development work scope and costs through to the anticipated CPCN filing.

6.1 *PROJECT SCHEDULE AND KEY MILESTONES AND ACTIVITIES*

Table 6-1 below provides preliminary RGSD Project schedule highlighting key milestones and activities. The Project schedule is subdivided into four phases. Additional information on the various phases is provided in the sections below.

FEI notes the following regarding the Project schedule:

- Advancing meaningful and comprehensive engagement and collaboration with Indigenous Nations to garner Project input and to develop an understanding of how to best advance the RGSD Project prior to beginning the Project approval processes is critical to ensure the RGSD Project, at the point of readiness for submission for approvals, has reasonable support and confidence on design.
- Initiating the BC EA process is expected to be the first significant step and would only be initiated after such engagement with Indigenous Nations on the RGSD Project has been completed.
- FEI plans to file a CPCN application based on a Class 4 estimate. For a linear project of this scope and magnitude, development of a Class 3 estimate would, in practice, first require full understanding of Indigenous Nation issues through detailed assessment of geophysical features along with addressing other construction constraints that may not arise until near completion of the BC EA process. It would significantly extend timelines and increase pre-CPCN process costs. Therefore, FEI contemplates preparing a Class 3 estimate during the CPCN review process and submitting such estimate as an update before the close of the evidentiary record.

- The need for meaningful engagement and collaboration with Indigenous Nations cannot be schedule-driven and this means development work prior to filing the CPCN could take longer than shown in Table 6-1. Updates on activities, schedule and milestones as appropriate will be provided as part of the progress update to be submitted with the 2024 Annual Review.
- While ramping up development work now is critical to preserve the RGSD Project as an option, FEI recognizes that the outcome of the LTGRP will be an important consideration in the decision as to whether to proceed with the Project and file a CPCN.

Table 6-1: Project Schedule, Milestones and Activities

Phase	Timing	Milestones	Activities
Pre Phase 1 (Development Work up to RGSD Development Account Approval)	Q1 2021 to Q3 2022		Ongoing: • Early Indigenous Nations engagement • Prepare and submit a deferral application • Start work on an EA Initial Project Description & Engagement Plan Completed: • Prepared Class 5 capital cost estimates for the pipeline and compressor stations addition • Prepared cost estimates for the development work required for the CPCN application • Prepared a high level EA strategy plan and an environmental constraints analysis along the potential pipeline corridor • Completed high level assessment of land requirements along the potential pipeline route and compressor station sites
	Q3 2022	RGSD Development Account - BCUC approval	
Phase 1A (Development Work)	Q3 2022 to Q3 2023 Duration: 1-year minimum		• Advance Indigenous Nations engagement and stakeholder consultation efforts • Initiate and advance Indigenous Nations Partnership understandings • Initiate Pre-Front End Engineering Design to assist with Indigenous Nations input on pipeline route selection • Advance commercial discussions with prospective shippers for potential capacity on RGSD Project pipeline • BCUC Decision in FEI's LTGRP • Develop Project Risk Register • Draft Initial Project Description (IPD) & Engagement Plan (EP) to be suitable to file with BC EAO • Prepare BCUC quarterly reports and progress update for 2024 Annual Review - Phase 1A progress/Future Phase planning updates.
	Q3 2023	EA IPD & EP suitable to file; 2024 BCUC Annual Review filing	

Phase	Timing	Milestones	Activities
Phase 1B (Development Work)	Q3 2023 to Q3 2024 Duration: 1-year minimum		• Indigenous Nations engagement; complete partnering/project term sheets &/or agreements with key Nations • Stakeholder consultation • Complete Pre-Front End Engineering Design • Complete a Class 4 Cost Estimate • Develop Class 4 Schedule • Draft CPCN application for readiness to file with BCUC • Draft application to BCUC for creation of Indigenous/Fortis partnership • Develop Detailed Project Description (DPD) & Application Information Requirements (AIR) for suitability to file with BC EAO • Complete initial commercial agreements with prospective shippers for potential capacity on RGSD Project pipeline
	Q3 2024	Indigenous-Fortis Partnership Application, CPCN, & EA DPD & AIR suitable to file	
Phase 2	Q3 2024 to Q3 2026 Duration: 2.0-years		• Commence work on EA • CPCN Application review & approval process • Complete Front End Engineering Design • Complete a Class 3 Cost Estimate • CPCN approval • EA Certificate (EAC) • Project Final Investment Decision taken post EAC • Commence Detailed Engineering • Continue Indigenous Nations collaboration & ongoing engagement; complete additional Project agreements
	Q3 2026	FID	
Phase 3	Q3 2026 to Q3 2027		• Complete detailed engineering • Permitting – ongoing application development and review • Secure construction contracts • Order long lead items • Continue Indigenous engagement and stakeholder consultation
	Q3 2027	Construction Start	
Phase 4	Q3 2027 to Q3 2029		• Project construction and commissioning • Continue Indigenous engagement and stakeholder consultation
	Q3 2029	RGSD Project In Service	

6.2 PROJECT DEVELOPMENT WORK AND ASSOCIATED COSTS

Project development work has been divided into Phase 1A and Phase 1B, each anticipated to be one year in duration. Phase 1A development work will focus on the Indigenous Nations engagement and collaboration on the pipeline route and compressor stations siting. Such work will be supported by Pre-Front Engineering End Design activities. In parallel, FEI will also work to develop Indigenous Nations partnership approaches through ongoing engagement with Indigenous Nations. At the conclusion of Phase 1A, FEI will have also prepared an Initial Project Description (IPD) and Engagement Plan (EP). Based on the outcome of the Indigenous Nations engagement and collaboration, FEI will make a decision whether to submit the IPD and EP with the BC Environmental Assessment Office (BC EAO) and progress to the next stage of development - Phase 1B. FEI will also provide an update on forecast development costs and schedule for Phase 1B.

As well as progressing the Project development including entering the BC EA process, Phase 1B will focus on continuing development of the Indigenous Nations partnership approach leading to readiness to file an Indigenous-Fortis Partnership application with the BCUC. A Pre-FEED with Indigenous Nation input will also be completed that will be used as the basis for a Class 4 cost estimate. At the conclusion of Phase 1B, FEI will have completed preparation of the Indigenous-Fortis Partnership application, CPCN application and BC EA Application Information Requirements (AIR) and Detailed Project Description (DPD). Table 6-2 below summarizes the development activities and associated costs for Pre-Phase 1 and Phase 1A & Phase 1B of the Project, which FEI is proposing to record in the requested deferral account. The sections that follow provide additional details on each line item in Phase 1. Details associated with Phases 2 through 4 will be addressed in the CPCN application.

Table 6-2: Estimated Project Development Costs ($ millions)

Line Item	Pre-Phase 1	RGSD Development Account Approval	Phase 1A	IPD & EP Submission	Phase 1B	CPCN Submission	Phase 1 Total
Pipeline Pre FEED			$3.0		$4.0		$7.0
Compressor Pre FEED			$2.0		$4.0		$6.0
Geotechnical Assessment	$0.3		$0.5		$3.1		$3.6
Environmental Application			$1.4		$0.9		$2.3
Land and Right-of-Way			$1.0		$6.5		$7.5
Indigenous & Community Relations	$1.5		$8.0		$5.0		$13.0
Legal	$0.4		$1.5		$0.4		$1.9
Application Development Costs	$0.6						
Phase Total	**$2.8**		**$17.4**		**$23.9**		**$41.3**
Cumulative Total	**$2.8**		**$20.2**		**$44.1**		**$44.1**
Contingency @ 15%			$2.6		$3.6		$6.2
Management Cost @ 5%			$0.9		$1.2		$2.1
Phase Total	**$2.8**		**$20.9**		**$28.7**		**$49.6**
Cumulative Total	**$2.8**		**$23.7**		**$52.4**		**$52.4**

FEI technical personnel worked with a number of external consulting firms regarded as experts in their respective fields to prepare the cost estimates for the RGSD Phase 1 development work. Specifically, FEI worked with the following external consulting firms:

- Innovative Pipeline Projects Limited – technical expertise for pipeline design, constructability and routing;
- Thurber Engineering Ltd. – geotechnical activities related to the terrain and constructability of the new pipeline along potential routes;
- Solaris Management Consultants Inc. – expertise on compressor stations, locations and unit configuration;
- Jacobs Engineering Group – environmental activities and the development of the BC EA applications that will be required for the Project; and
- Terra Archaeology Limited – Indigenous engagement and archaeological work.

FEI internal resources were used to develop other costs and to assess pipe sizing and compression horsepower requirements.

The Phase 1 development work outcome will include a Class 4 cost estimate for the pipeline and compressor station additions, advancing Indigenous Nations engagement and partnership discussions, community consultation, preliminary land acquisitions assessment, optimization of pipeline and compressor stations design for transporting hydrogen and ability to file the DPD and AIR with the BC EAO. The work will also include an assessment of the existing SCP to transport a blend of natural gas and hydrogen to confirm feasibility and the current hydraulics assumptions.

6.2.1 Pre-Phase 1 Work

6.2.1.1 *Pre-Phase 1 – Work Completed to date*

The RGSD Project is an evolution of previous work related to assessing an extension of the SCP. FEI had already completed some assessment work over the past few years, both internally and with the assistance of engineering, geotechnical and environmental consultants. On this basis, FEI has been able to use some of the historical information to assist in completing the following activities:

- Class 5 capital cost estimate for the pipeline extension and compressor station additions;
- a desktop geotechnical hazard assessment;
- environmental constraints analysis;
- land and right of way requirement assessment to inform cost estimates;
- hydraulics analysis to understand implications of hydrogen transportation; and

- an assessment of the Indigenous Nations and community relations requirements.

The resulting work confirmed the preliminary viability of the RGSD Project, and provided a cost basis for initial evaluation.

6.2.1.2 *Pre-Phase 1 – Ongoing Development Work*

FEI has had early discussions with Indigenous Nations and has developed an understanding of the scope of work that will be required for Indigenous Nations engagement. FEI plans to continue and advance such Indigenous Nation discussions along with developing an initial Project description/early engagement framework to help inform the ongoing Indigenous Nation discussions process while this Application is being reviewed in order to maintain dialogue and Project awareness with Indigenous Nations and advance collaboration where possible to minimize schedule delays.

FEI anticipates that this Pre-Phase 1 work will cost approximately $2.8 million.

6.2.2 Phase 1 – Development Work Scope and Costs (Phase 1A and Phase 1B)

Phase 1 is the period that follows BCUC approval of the requested deferral account. The estimated two year period has been divided into Phase 1A and 1B. The following sections provide details of the scope of development work and cost estimates based on the activities that would be completed during each phase of Phase 1 Project development. It should be noted that the scopes of work and task completion will be based on the progress of collaboration with Indigenous Nations related to pipeline route and compressor station siting.

6.2.2.1 *Pipeline Pre-FEED – Development Work and Cost Estimate*

The pipeline Pre-Front End Engineering Design (Pre-FEED) estimated development cost of $7.0 million was prepared using the expertise of Innovative Pipeline Project Limited ('IPPL') consultants. The following table 6-3 shows the summary of the estimated costs:

Table 6-3: Pipeline Pre-FEED Cost Estimate ($ millions)

Pipeline Pre-FEED Costs	Phase 1A	Phase 1B	Phase 1
Total	**$3.0**	**$4.0**	**$7.0**

This estimate was based on a review of the potential pipeline corridor and a potential pipeline alignment within this corridor. The estimate includes the following scope of activities:

- Field constructability review and routing
- Hydrogen transportation readiness design
- Desktop routing and review with Client

- Field work
- Mobilization and demobilization
- Horizontal Directional Drilling feasibility and planning
- Footprint development
- Route map preparation
- Indigenous Nations engagement and public consultation
- Meetings
- Travel allowance and miscellaneous expenses

The sequence and the timing of these activities will be based on the progress of pipeline route development in collaboration with the Indigenous Nations. The work will also be dependent on input from the separate geotechnical and environmental assessment work.

6.2.2.2 *Compressor Stations and System Pre FEED – Development Work and Cost Estimate*

The need, capability, and general locations of the Compressor stations was established by hydraulics analysis as part of Pre-Phase 1 work. The Phase 1 cost estimates in the amount of $6.0 million for the compressor station additions were prepared using the expertise of Solaris Management Consultants Inc. ("SMCI"). FEI anticipates that during Phase 1A of the Project development the scope of work will mostly entail selection of suitable sites that will be done in collaboration with the Indigenous Nations. The remainder of the Pre-FEED work will be carried out in Phase 1B. The following table 6-4 shows the summary of the estimated costs.

Table 6-4: Compressor Stations Pre-FEED Cost Estimate ($ millions)

Compressor Stations/ System Pre-FEED Costs	Phase 1A	Phase 1B	Phase 1
Total	**$2.0**	**$4.0**	**$6.0**

SMCI prepared direct field cost (DFC) estimates for this Project that were based on a combination of budgetary quotes and in-house cost data for similar projects. The Pre-FEED costs are based on a percentage allocation of the DFC including the following DFC costs:

- Site development earthworks
- Pile/pilecaps and concrete foundations
- Structural steel and pipe-racks
- Buildings
- Piping
- Electrical

- Instrumentation and controls
- Communications
- Construction labour
- Transportation of equipment and bulk materials

In order to confirm the RGSD Project capacity under various blends of hydrogen, FEI also included a cost associated with engineering assessment of the existing SCP pipeline and compressor stations. This work will determine the allowable concentrations of hydrogen and any corresponding adjustment to the pipeline operating parameters.

Pre-FEED costs in this budget section also include the allowances for the following engineering contracts to prepare the required analyses, studies and reports for the system (compressor stations, existing SCP and new pipeline) including:

- Review of SCP existing compressor stations for hydrogen transportation
- Review SCP pipeline for hydrogen transportation
- Hydrogen ready design of the new compressor stations
- Hazard and Operability Study and Design Facilitation

6.2.2.3 *Geotechnical Assessment – Work and Cost Estimate*

The Phase 1 cost estimate for the geotechnical assessment development in the amount of $3.6 million was prepared using the expertise of Thurber Engineering. During Phase 1A it is anticipated that a geotechnical consultant will provide data gathering in support of route selection with Indigenous Nations. Phase 1B work will focus on the preliminary assessment of areas of geohazards. The cost summary is shown in Table 6-5 below.

Table 6-5: Geotechnical Assessment Cost Estimate ($ millions)

Geotechnical Assessment Costs	Phase 1A	Phase 1B	Phase 1
Total	**$0.5**	**$3.1**	**$3.6**

This work is in addition to the cost of $0.3 million of field data acquisition that was completed during Pre-Phase 1. Based on the pipeline corridor and the anticipated pipeline location within that corridor as prepared during Pre-Phase 1, Thurber Engineering developed a scope of work for the Pre-FEED activities that are listed below:

- Data compilation, including:
    - Collection and review of current publicly available satellite imagery; published bedrock and surficial geology maps; digital elevation models; and online information using iMapBC and MapPlace2.

    - Compilation of a GIS workspace.
- Geohazard assessment:
    - Review proposed route and identify areas of geohazards that could impact the alignment.
    - Recommendations for further assessment, including general recommendations for further data collection, assessments, and investigations to reduce the uncertainty of the geohazard assessment.

6.2.2.4 *Environmental Application – Development Work and Cost Estimate*

The Phase 1 development cost of $2.3 million for environmental assessment work was prepared using the expertise of Jacobs Engineering Group (Jacobs). Ramp up of Indigenous Nations engagement during Phase 1A associated with route selection will result in a higher portion of the overall cost spent during this phase. The following Table 6-6 show the cost summary.

Table 6-6: Environmental Cost Estimate ($ millions)

Environmental Cost Estimate	Phase 1A	Phase 1B	Phase 1
Total	**$1.4**	**$0.9**	**$2.3**

Jacobs reviewed the actual spend from several historical projects to identify some approximate costs to meet the regulatory milestones for a project at the same scale and level of complexity as the RGSD Project. Jacobs also looked at the potential constraints encountered along the currently proposed route to determine an estimated level of effort required for inclusion in the cost estimate.

Jacobs used the following methodology to calculate approximate costs for the Project:

- Using historical knowledge of the level of support required for various office-based tasks and the proposed schedule for the Project, costs were estimated and included.
- A high-level review of the discipline specific requirements related to the constraints encountered by the Project were included to capture various survey and permitting requirements.
- Using historical actuals from similar projects, actual cost per kilometre of length of pipeline was calculated for several key tasks, compared between projects and used to estimate overall costs for this Project.

Phase 1 work is based on the following scope of work:

- BC EAO early engagement process
- Development of Application Information Requirements (AIR)

- Support for Indigenous Nations engagement
- Support for Stakeholder consultation
- Regulatory guidance
- Project management
- Archaeological Overview Assessment (AOA)
- Archeological Impact Assessment (AIA)
- Preliminary Field Reconnaissance

The completion of these activities will be driven by the progress of Indigenous Nations engagement.

6.2.2.5 *Land and Right of Way – Development Work and Cost Estimate*

The $7.5 million Phase 1 land and right-of-way cost estimate for the RGSD Project is based on a preliminary Land Acquisition Plan (LAP) prepared by FEI's Property Services team. It is anticipated that the bulk of the costs will be spent during Phase 1B once FEI and Indigenous Nations establish the pipeline route during Phase 1A. This estimate allows for engagement with landowners and authorities, development of a final LAP, and costs to secure options on Access Agreements and where possible options on rights-of-way for privately owned land. The cost summary in Table 6-7 shows the cost breakdown between Phase 1A and 1B.

Table 6-7: Land and Right of Way Cost Estimate ($ millions)

Land and Right of Way Costs	Phase 1A	Phase 1B	Phase 1
Total	**$1.0**	**$6.5**	**$7.5**

With respect to the scope of LAP work, it is estimated that, other than approximately 35 km between Oliver and Keremeos where the RGSD Project pipeline could be constructed in existing FEI rights-of-way, the Project will generally be constructed on new right-of-way. FEI will need to acquire land rights on all properties where there are no existing gas rights-of-way. A significant portion of the line is through provincial Crown land, and Statutory Right-of-Ways will be received from the BC Oil and Gas Commission (OGC) when permits are issued. Other significant segments traverse agricultural areas that are under the jurisdiction of the Agricultural Land Commission.

Lands required for Project specific purposes such as laydown yards and work-camp sites are included in the LAP scope, as are fee simple lands for facilities such as compressors or other stations. There will be many unique owner types requiring property-specific negotiation strategies.

FEI will ultimately require the following agreements to be in place to support and protect the construction and operation of the RGSD Project:

- Access agreements
- Statutory right-of-way agreements
- Temporary work space agreements
- Individual restoration agreements
- Lease agreements
- Purchase and sale agreements
- Indigenous land use agreements

During Phase 1B work, FEI will approach the property owners to pay a nominal fee as consideration to secure access agreements. These agreements are necessary for FEI to continue Project development work such as surveys, geophysical, environmental and archeological. As per the standard practice for new infrastructure projects, FEI will also continue to complete land valuation that will be required to secure the right-of-way agreements for the RGSD Project in subsequent phases.

6.2.2.6 *Indigenous Engagement and Community Relations – Work and Cost Estimate*

The following Table 6-8 provides a summary of the costs for the Project development work related to Indigenous engagement and stakeholder consultation. During Phase 1A, FEI will direct its efforts on pipeline route selection, compressor stations siting and development of partnerships with Indigenous Nations and these efforts will continue into Phase 1B.

Table 6-8: Indigenous Nations & Community Relations Cost Estimate ($ millions)

Indigenous & Community Relations Costs	Phase 1A	Phase 1B	Phase 1
Total	**$8.0**	**$5.0**	**$13.0**

The following subsections provide additional information on the Project development work during Phase 1 for Indigenous engagement and community consultation.

6.2.2.6.1 INDIGENOUS ENGAGEMENT TO DEVELOP PARTNERSHIP, COLLABORATE, AND SUPPORT UNDRIP AND ECONOMIC RECONCILIATION DEVELOPMENT WORK SCOPE AND COST ESTIMATE

As described in Section 3.4, FEI sees the RGSD Project as defining a new way of project development. In initial meetings with Indigenous Nations, FEI introduced the concept for the RGSD Project including objectives that it would be owned by an Indigenous-Fortis Partnership with significant Indigenous ownership interest, the related ownership model would be established early, and that FEI would collaborate from the outset with Indigenous Nations on routing and compressor station site selection. If these objectives are realized, the Project will provide significant economic opportunity for Indigenous Nations and this approach reflects the Provincial mandate to respect and partner with Indigenous Nations.

In line with FEI's Statement of Indigenous Principles[39], FEI believes in respectful, transparent, and timely engagement with Indigenous groups whose rights and title may be impacted by the RGSD Project. FEI's approach is also in line with global, Canadian, and BC declarations of Indigenous rights through UNDRIP,[40] the B.C. Government's Declaration of the Rights and Indigenous Peoples Act (DRIPA),[41] and the Canadian Government's Truth and Reconciliation Commission (TRC) [42] Calls to Action. Therefore, FEI's approach to Project specific Indigenous consultation and engagement is and will be thorough, meaningful, and comprehensive.

Through the mapping work conducted in Pre-phase 1, FEI understands that the Project, including compressor stations along the existing SCP and a new pipeline corridor from Oliver to Huntingdon, would be located in close proximity to reserve lands and traditional territories of about 30 Indigenous Nations (identified as Nations or Bands). These 30 Nations will be the primary focus noting that many territories overlap and some have a relatively higher interaction with the Project. In addition, there are about 50 other Nations with territories along the route and some may be interested in Project involvement.

FEI began early engagement by introducing the high-level Project concept to the four main Indigenous Nation Alliances or Tribal Councils along the route and gained a preliminary understanding of potentially favourable interest in the Project. Clear feedback from each was that engagement at the individual Nation or Band level would be essential to advance the Project. FEI has subsequently met with several of individual primary focus Nations.

The purposes of these initial conversations were to:

- Describe the Project need and vision;
- Convey the intent that the Project could be owned by an Indigenous-Fortis Partnership with significant Indigenous ownership interest and that the related ownership model would be established early;
- Convey that FEI would collaborate from the outset with Indigenous Nations on routing and compressor station site selection;
- Gain an understanding of Indigenous Nations' level of interest in the Project; and
- Gain an understanding of each Indigenous Nation's interest in potential economic/Project development partnerships.

[39] FortisBC, Our Statement of Indigenous Principles: https://www.fortisbc.com/in-your-community/indigenous-relationships-and-reconciliation/our-statement-of-indigenous-principles.

[40] United Nations Declaration on the Rights of Indigenous Peoples: https://www.un.org/esa/socdev/unpfii/documents/DRIPS_en.pdf.

[41] Legislative Assembly of British Columbia, Bill 41, Declaration on the Rights of Indigenous Peoples Act: https://www.leg.bc.ca/parliamentary-business/legislation-debates-proceedings/41st-parliament/4th-session/bills/third-reading/gov41-3.

[42] Truth and Reconciliation Commission of Canada: https://nctr.ca/about/history-of-the-trc/truth-and-reconciliation-commission-of-canada/.

The initial discussions with Indigenous Alliances and Nations regarding the Project concept have been productive and identified the need for deeper engagement with respect to partnering, other Project benefits, and routing and site selection.

FEI understands from Indigenous Alliances and Nations:

- an appreciation for early engagement, while the Project is in its earliest phases;
- there is interest in the Project concept, and willingness to continue the conversations;
- the preferred next steps for engagement, and while there is willingness resource constraints may be an issue; and
- the process will require many conversations and collaborative work with each individual Nation and therefore, significant time and resource investment will be required from both the Indigenous Nations and FEI.

Engagement, collaboration and partnering with Indigenous Nations will enable the Project to advance through the EA application development to a CPCN filing and Indigenous-Fortis Partnership application. These regulatory processes, specifically the EA process, will also provide significant engagement opportunities for Indigenous Nations and the ability to conduct Indigenous-led assessments of the Project. Throughout these processes, FEI will:

- Provide capacity funding agreements with Indigenous Nations, that will enable Indigenous Nations to:
    - consider partnering opportunities and options;
    - collaborate with and advise FEI on routing and compressor station site selection;
    - engage and consult with FEI and relevant regulators;
    - engage with community leaders and members;
    - lead or participate in Project field studies;
    - review and comment on Project study reports; and/or
    - conduct community-led studies, such as traditional use studies.
- Listen to and learn from Indigenous Nations, and include Nations' best practices in Project plans;
- Advance Project partnership agreements and other economic development opportunities with Indigenous Nations; and
- Seek opportunities to support Indigenous participation in Project construction and ancillary economic opportunities.

6.2.2.6.2 CONSULTING WITH MUNICIPALITIES, GOVERNMENT STAKEHOLDERS AND THE PUBLIC

FEI is committed to uphold its high standard of public and stakeholder engagement throughout the life of the Project. FEI has identified that the Project traverses the jurisdictions of 22 municipalities and 19 regional districts. FEI has existing relationships with many of these jurisdictions based on existing facilities and past projects. FEI will build upon the strong relationships already in place, and form relationships in new areas, by initiating consultation activities early on in the Project.

Early Project consultation with local governments leading up to CPCN readiness will focus on:

- communicating the Project concept and goals to ensure that municipalities and regional districts have a consistent, clear understanding of the Project;
- seeking initial input on the Project plan to ensure that any issues, concerns and interests are taken into consideration;
- identifying early impacts on businesses, landowners and municipalities' long-term development plans;
- exploring the opportunities for inclusive and long-lasting partnerships with local communities and stakeholders and ensuring that those who are local to the Project share in the long-term benefits; and
- sharing information with municipalities and regional districts on FEI's broader decarbonization plans that enhance resiliency, security, and reliability, and support provincial climate targets.

6.2.2.7 *Legal Cost Estimate (Development)*

The legal cost estimate is based on a range of work streams. The following Table 6-9 provides the cost summary.

Table 6-9: Legal Cost Estimate ($ millions)

Legal Costs	Phase 1A	Phase 1B	Phase 1
Total	**$1.5**	**$0.4**	**$1.9**

A considerable amount of legal work is associated with developing a project of this size. While the specific nature of the legal work is privileged, in general terms the legal work will include advisory services and negotiation / drafting services related to engagement and pursuing various types of agreements with the many Indigenous Nations involved. It also includes legal work relating to this proceeding and leading up to the filing of a CPCN application. As shown in Table 6-9, FEI anticipates that the bulk of the legal costs will be spent in Phase 1A.

6.2.2.8 *Contingency – Development work*

The following Table 6-10 shows the contingency for the Phase 1 work.

Table 6-10: Contingency ($ millions)

Contingency	Cost
Total	**$6.2**

The RGSD Project includes a new pipeline route that will be traversing areas that may be affected by conditions or circumstances not known at this time. To account for any unknowns that may impact the development costs, FEI assigned a fifteen percent contingency to the total development costs. FEI deems such amount to be appropriate given the level of engineering, geotechnical and environmental work leading to the development of this Application. The contingency would mitigate the risk on individual areas of Project development work.

6.2.2.9 *Management Costs – Development Work*

The following Table 6-11 shows the management cost amount for the Phase 1 work.

Table 6-11: Management Amount ($ millions)

Management Amount	Cost
Total	**$2.1**

The management amount of five percent of the total development cost was included to account for management resources working on this Project. This amount represents typical Project staffing levels that would include internal resources as well as consultants dedicated as the owner's engineering team.

6.3 *CONCLUSION*

The development costs for the RGSD Project that FEI anticipates recording in the proposed deferral account will enable FEI to engage with Indigenous Nations in order to respect and partner with the Nations in the formative stage of development, then develop a Class 4 cost estimate and advance the Project to the point where FEI can decide to file a CPCN and Indigenous-Fortis partnership applications for the Project with the BCUC. By using a two-stage approach for Phase 1 with initial emphasis on the Indigenous Nations engagement during Phase 1A, there will be a limit on the cost exposure that, regardless of whether the Project proceeds through Phase 1B and beyond, will improve FEI's relationship with Indigenous Nations and improve the knowledge record of the Nations' territories.

7. SAFEGUARDS AND BCUC OVERSIGHT OF DEVELOPMENT COSTS

This section describes the safeguards in place for customers with respect to the development costs being incurred. In particular:

- Section 7.1 describes FEI's approach to mitigate the Project development risks.
- Section 7.2 describes how the BCUC will have oversight of FEI's work through quarterly reporting and reviewing costs incurred in the 2024 Annual Review and subsequent applications.

7.1 *FEI'S APPROACH TO MITIGATING DEVELOPMENT PHASE RISKS*

FEI will continue to monitor and implement adjustments to plans and procedures as necessary to manage any ongoing challenges on the Project development. As discussed in Section 6, FEI has identified key milestones during the development phases of the Project that will allow FEI to track its development activities and key accomplishments.

Also as described in Section 6, meaningful and comprehensive engagement and collaboration with Indigenous Nations prior to beginning Project approval processes is critical to ensure the RGSD Project, at the point of readiness for submission for approvals, has reasonable support and confidence on design. Initial design work and supporting documentation on the RGSD Project will progress in tandem with the Indigenous engagement. This approach will, for example, allow FEI to utilize traditional knowledge from Indigenous Nations to avoid or adequately mitigate issues that may be related to pipeline design and construction activities. This key early phase, described as Phase 1A, will have a minimum duration of one year and would end with readiness to file the BC EA IP and EP. The actual duration will depend on the availability of and coordination with knowledgeable resources within the Indigenous Nations. In and of itself, success in this phase will also help mitigate risks for subsequent phases.

FEI proposes to report quarterly on progress and spending and include schedule updates as appropriate. If any unresolvable issues emerge during Phase 1A, the development work will stop at that point. Otherwise, Phase 1A work will progress to readiness to file the BC EA IP and EP, and provided there is reasonable understanding of early support from key Indigenous Nations, the BC EA IP and EP will be filed and work will progress into Phase 1B.

7.2 *BCUC OVERSIGHT: QUARTERLY REPORTING AND COST REVIEW*

The BCUC will have a high degree of oversight over the progress of the work and the costs incurred.

7.2.1 Quarterly Reporting Will Address Status, Schedule, Costs and Risks

FEI is proposing to file quarterly progress reports with the BCUC to track and monitor the development activities and spending on the RGSD Project. FEI intends to include the following details in its quarterly reports:

1. **Project development status** that will provide general status on the proposed development work and activities, milestones completed (if any) during the reporting period, any new challenges, issues or concerns that arise while performing the development work and FEI's plans for the next reporting period.
2. **Project schedule** that will discuss any changes to the schedule performance to date, change in the scope of development work and reporting on any schedule variances.
3. **Project development costs** summary including explanation of any variances from the expected development costs as included in Section 5 of this Application.
4. **Project risks, showstoppers and mitigation** that will provide any significant risks identified by FEI and their impacts to the development work and costs, how FEI plans to mitigate those risks and any new showstoppers that might come up during the development work performed in that reporting period.

7.2.2 2024 Annual Review Will Address Extent, Timing and Approach to Recovery of Costs to Date

The fact that the approval sought in this Application is limited to approving a deferral account represents an additional safeguard for FEI's customers. FEI will file as part of its 2024 Annual Review (to be filed in July or August of 2023) an update on the costs incurred to that point, along with a proposal on the method and timing of recovery of incurred costs. FEI would take into account the BCUC's determinations in the 2024 Annual Review process in determining whether or how to proceed with further development work.

With respect to development costs incurred after FEI files the 2024 Annual Review, the BCUC would determine the method and timing of recovery of incurred costs in a future proceeding. FEI expects that this would occur in either the CPCN proceeding for the RGSD Project (if the decision is made to proceed) or in a revenue requirements process (if the decision is made not to proceed).

8. CONCLUSION

The requested approvals are just and reasonable, as they facilitate development work that is in the interests of FEI and its customers. The significant additional cost that FEI customers will pay for any expansion(s) of T-South, including the announced $2.5 billion+ T-South Expansion, comes with little, if any, upside for FEI and its customers in terms of access to supply, supply cost, resiliency, or progress towards a renewable and low-carbon energy future. Therefore, FEI has assessed some potential pipeline expansion options such as the RGSD Project that address the regional market conditions, provide additional benefits, and reduce risks for FEI customers. FEI's preliminary evaluation suggests that the RGSD Project is the most beneficial option that merits further assessment and development work. The work must proceed in a timely way so as to avoid FEI having to underwrite the cost of the announced T-South Expansion.

In the initial phase of the development work, the bulk of development costs will be incurred conducting early engagement with Indigenous Nations and exploring options for direct Indigenous involvement in the Project. The development work will also enable FEI to advance the Project to the point where FEI can decide to file a CPCN for the Project. The proposed reporting and BCUC oversight provides appropriate safeguards for FEI customers.

Therefore, FEI respectfully requests BCUC to approve the creation of the RGSD Development Account as set out in the Application.

Appendix A

BC RENEWABLE AND LOW CARBON GAS SUPPLY POTENTIAL STUDY

B.C. RENEWABLE AND LOW-CARBON GAS SUPPLY POTENTIAL STUDY

FINAL REPORT

Prepared for

BC Bioenergy Network

FortisBC

Province of British Columbia

Prepared by

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January 28, 2022

EXECUTIVE SUMMARY

Report Overview and Objectives

B.C. is a major producer and supplier of natural gas and the Government of B.C. is trying to decarbonize natural gas use and usher in the clean energy transition. Renewable and low-carbon gases can be used to decarbonise many sectors that are difficult to electrify, create new economic opportunities, and serve as tools to enable the transition towards a resilient, affordable, and low-emission energy system. BC Bioenergy Network (BCBN), the Government of B.C. and FortisBC commissioned this report to estimate the technical supply potential and production costs of renewable and low-carbon gases in B.C., Canada and the United States. This study uses the best information available to inform the supply outlook for renewable and low-carbon gases in B.C. The analysis, conclusions and recommendations in this report are those of the report authors, and do not necessary reflect the views of the report's sponsors.

Background and Objective

The Province of British Columbia (B.C.) has set ambitious greenhouse gas emission reduction targets, including becoming a net-zero jurisdiction by 2050. The CleanBC *Roadmap to 2030* (the Roadmap) includes plans to establish a greenhouse gas (GHG) emissions cap for natural gas utilities.[1] It would require natural gas utilities to reduce the carbon emissions related to their gas sales to approximately 6 Mt of CO_2e per year by 2030. It is anticipated that this cap will, in part, drive the production and acquisition of renewable gases as a key measure to displace fossil natural gas. The Roadmap also expands on an earlier commitment to a minimum of 15% (energy-based) renewable content retailed annually through the natural gas distribution system by 2030. The GHG Reduction Standard proposed in the CleanBC *Roadmap* will likely require an even higher percentage of renewable gas by 2030.

Additional regulatory action has been taken to kick-start the production and use of clean and renewable gases in B.C.'s natural gas distribution system. In 2021, the Province of B.C. amended the Greenhouse Gas Reduction Regulation (GGRR) in part to widen the scope of fuels gas utilities may use to reduce GHG emissions. The GGRR incentivises the production and utility purchase of low-carbon natural gas substitutes, including hydrogen, renewable natural gas (RNG), synthesis gas (syngas), and lignin. The cost of these clean resources will be recovered from the utilities' ratepayers.

The purpose of the report was to quantify the supply potential of renewable and low-carbon gases that could be used to lower overall GHG emissions from B.C. gas use. The study did not consider alternative options, such as switching natural gas heating to wood pellets, heat pumps, or increased energy efficiency.

This report examines four pathways to transition from fossil natural gas:

1. The production of hydrogen or methane from either renewable electricity or wood (pipeline injection).
2. The production of hydrogen from natural gas combined with carbon capture and sequestration or as a by-product of carbon black production, or the use of waste hydrogen (pipeline injection).
3. The production of syngas from wood to displace natural gas used in lime kilns at pulp mills.
4. The production of lignin from black liquor to displace natural gas used in lime kilns at pulp mills.

Technologies/Pathways

The report describes various technologies and resources used to produce the above types of low-carbon gas. Each technology relies on a supply chain, e.g., feedstock production or collection, pre-treatment, and

[1] The report was written based on the 2018 renewable gas commitment rather than the emission cap announced in the Roadmap.

gas processing. Gases injected into the pipeline system also require gas conditioning and compression. The resulting combination of processes is called a 'pathway'. Pathways can be grouped by the energy resource they rely on. Three main resources have been considered for a total of twelve pathways:

- **Organic waste:** Production of methane by fermenting of organics. These include agricultural waste, municipal organics, human waste collected at wastewater treatment plants, and gas generated in landfills.
- **Woody biomass:** Production of wood gas, also called syngas, through thermochemical means, such as gasification. Syngas may then be used as a gas at the point of production or upgraded to pure hydrogen or methane for pipeline injection.
- **Non-biomass resources:** Production of hydrogen via electrolysis or using fossil natural gas, including blue and turquoise hydrogen produced from fossil natural gas and green hydrogen produced from (green) electricity. The latter is commonly termed 'green hydrogen' as it can be produced from 'green' (renewable) electricity.

For each of these three groups, four specific pathways are described in Table 6. Lignin extracted from black liquor in kraft pulp mills is another wood-based resource. It can be used as a fuel in lime kilns but is technically more challenging and more expensive than using syngas from wood gasification. The value of lignin as a feedstock for non-energy application can also be expected to rise above the value as an energy source.

Table 1 Pathways for low carbon gas considered in this report

Organic Residue* (Anaerobic treatment)	Woody Biomass (Thermochemical pathways)	Non-Biomass Resources (Electrolysis and SMR)
Agricultural RNG: Digestion and gas conditioning using agricultural waste.	Syngas: Wood gasification to produce a gas used in lime kilns of kraft pulp mills.	Green hydrogen: Electrolytic production of hydrogen from water and clean electricity.
Municipal RNG: Digestion of source-separated organics (green bin) and industrial food waste.	Hydrogen from syngas: Syngas processed with water-shift reaction.	Blue hydrogen: Steam methane reforming of fossil methane with CO_2 capture and storage.
RNG from wastewater treatment plants: Digestion of water treatment sludge to produce RNG.	Methane from syngas: Syngas processed with water-shift and methanation step.	Turquoise hydrogen: 'Pyrolysis' of fossil methane, producing carbon black and hydrogen.
Landfill gas: Gas captured at landfills and conditioned to produce RNG.	Lignin as a replacement for natural gas in the pulp industry: Lignin extracted from black liquor to produce a dry lignin fuel.	Waste hydrogen: Hydrogen produced as a by-product in industrial processes.

* In reality, some of these feedstock types can be combined at any given plant; a strict separation is not possible but is used in the report to derive estimates for the potential of each waste type

Scenarios and Cost Curves

Potential by 2030 and 2050

The potential for producing renewable and low-carbon gases differs between the pathways, mainly due to the underlying resources available in B.C. The report compares and combines existing analyses to develop a comprehensive overview of resources available by 2030 and 2050.

The resource potential represents the theoretical availability of various biomass feedstock types, electricity, and fossil natural gas to produce renewable and low-carbon gases. The technical potential constrains the resource potential as it estimates the capacity for each pathway after accounting for geographic limitations, transport constraints, conversion efficiency and various system assumptions. This also includes technological readiness and realistically achievable implementation rates. The resulting potentials in the Maximum and Minimum scenarios for each pathway are further lowered as they consider timelines, harvesting practices and different outcomes with respect to resource availability and the speed of deployment. They represent the upper and lower bounds of renewable and low-carbon gas supply potential that can likely be achieved in B.C. by 2030 and by 2050, as shown in Figure 4. Some economic constraints, such as competing uses, price, or market developments, have not been considered in the estimation of these bounds.

The 2030 scenarios assume lower gas production levels than for 2050 as there are development cycles, learning curves and build-out rates for new or emerging technologies. More mature and lower-cost projects will likely be developed first. Most renewable and low-carbon gas production by 2030 lies with anaerobically produced RNG pathways (around 6 petajoules) and blue and turquoise hydrogen. The scenarios suggest that the 2018 CleanBC target of 15% renewable content in the natural gas system by 2030 cannot be met using provincial renewable resources alone. By 2050, blue and turquoise hydrogen make up most of the potential but wood-based pathways also represent a large share of the technical potential.

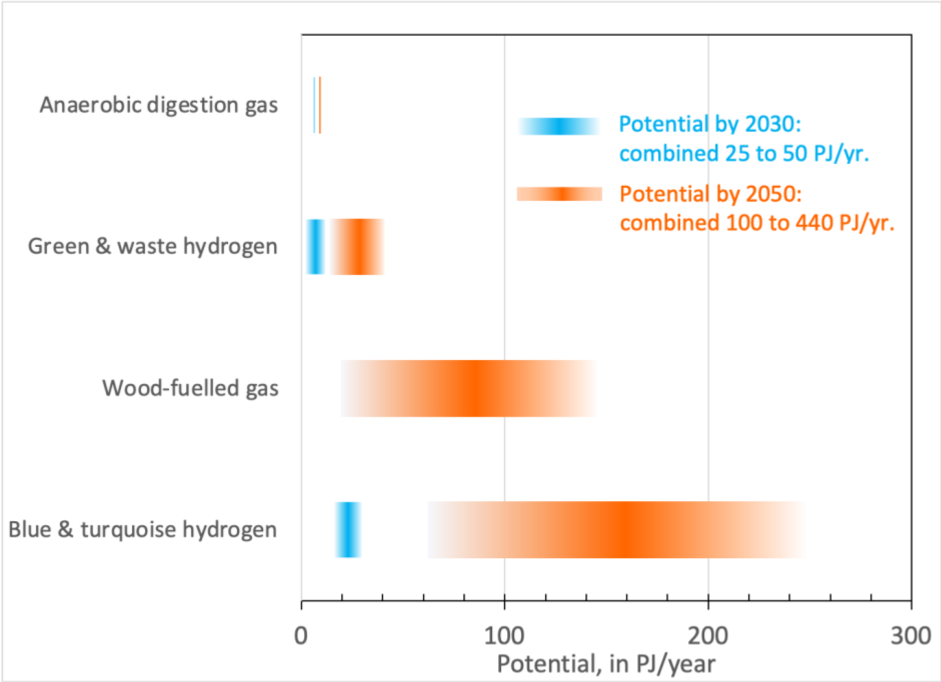


Figure 1 Minimum and Maximum Renewable and Low-Carbon Gas Production Scenarios for B.C. for 2030 and for 2050

Figure 4 shows:

1. By 2050, between 104 (Minimum) and 444 (Maximum) petajoules of renewable and low-carbon can be produced with in-province resources, i.e. between half and twice B.C.'s current natural gas use. Renewable gases alone could amount to produce between 42 and 195 petajoules annually, roughly a quarter to all of the natural gas currently retailed in B.C.
2. By 2030, between 25 (Minimum) and 50 (Maximum) petajoules can be produced with in-province resources; of the Maximum, only about 19 petajoules would be renewable gases.
3. Between 2030 and 2050, supply expands significantly in the Maximum scenario because the industry is built up quickly, and additional resources become available, such as new on-grid wind power, wood residue currently used for producing power or pellets, and the establishment of large-scale blue and turquoise hydrogen production.
4. Blue and turquoise hydrogen offer the highest technical potential. Renewable gases account for almost half of the gases produced by 2050. B.C. could replace almost all its current fossil natural gas use with renewable gas, mainly from woody feedstock.
5. Among renewable sources (as defined under the GGRR), wood-based pathways have the highest potential for renewable gas production under optimistic assumptions with respect to resource availability.
6. Traditional RNG from anaerobic digestion or biogas has lower potential (~10 petajoules by 2050). Other pathways will be crucial to achieve substantial decarbonization of the natural gas system.
7. Even with Site C being developed and the addition of 1,300 MW of new on-grid wind power, the availability of surplus electricity constrains the potential for producing green hydrogen in B.C. to about 27 petajoules by 2050 (40 petajoules when including off-grid production with wind power).

Cost curves

Each low-carbon gas has costs associated that are specific to the resource, technology, production process and various other parameters. The relation between potential and cost is illustrated in a cost curve (**Figure 3** below). The (horizontal) x-axis indicates the potential in petajoules of gas produced per year and the (vertical) y-axis indicates the production cost for each pathway, in 2021 Canadian dollars. The lowest-cost pathway is shown on the left, with the cost of respective pathways increasing to the right. Costs are determined by assumptions of initial capital expenditure, operational costs, including electricity and gas costs, and the cost of woody feedstock, where applicable.

The cumulative production potential increases as options with higher production costs are considered, resulting in a stepped graph. Eventually, costs surpass the $31 per gigajoule price limit[2] for natural gas utility acquisitions under the GGRR. The economic potential under the current regulatory framework is limited to the area outlined by a dashed black line.

Figure 2 and **Figure 3** shows that green hydrogen is expected to remain more costly than the $31 threshold (in 2021). By 2050, gases from (waste) woody biomass is projected to be available at a cost comparable to that of blue hydrogen. Production costs are estimated as sector averages; the body of the report provides more detailed cost curves for each pathway. The Maximum scenario represents an upper bound that would require very strong policies to achieve. It is unlikely that this scenario will come to pass but rather, that renewable and low-carbon gas production in B.C. will fall in-between the Minimum (104 petajoules) and Maximum (444 petajoules) scenarios by 2050. The scenarios are further elaborated in the body of the report.

[2] The threshold is indexed with inflation, so increases over time in nominal, but remains constant in 2021 dollars.

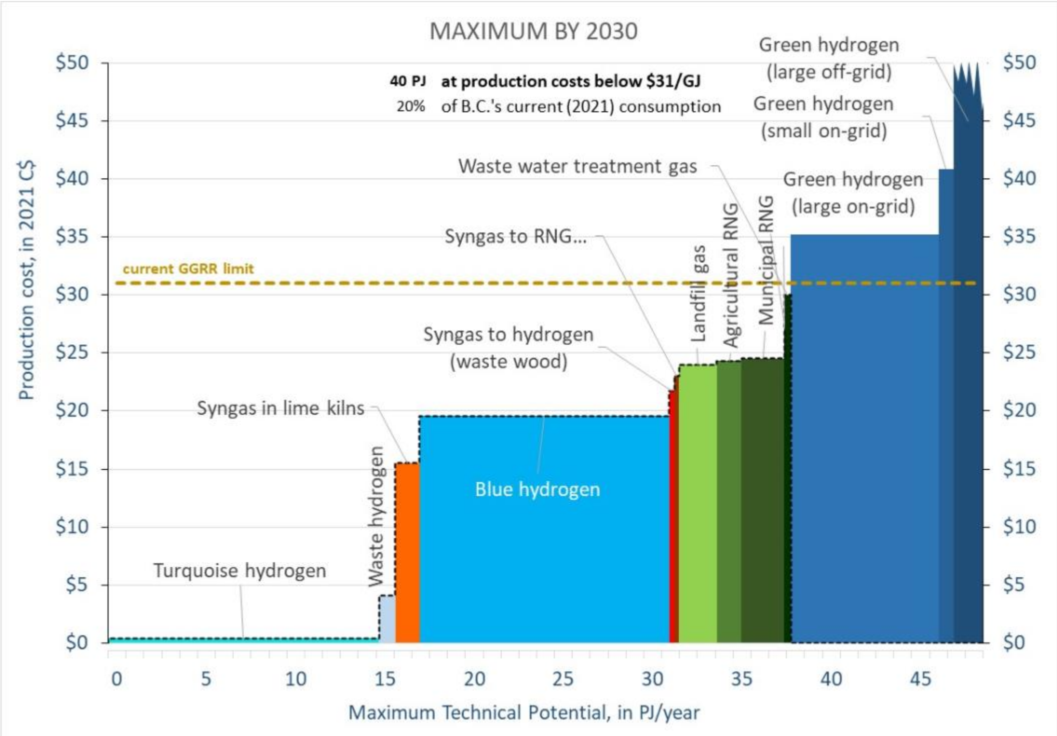
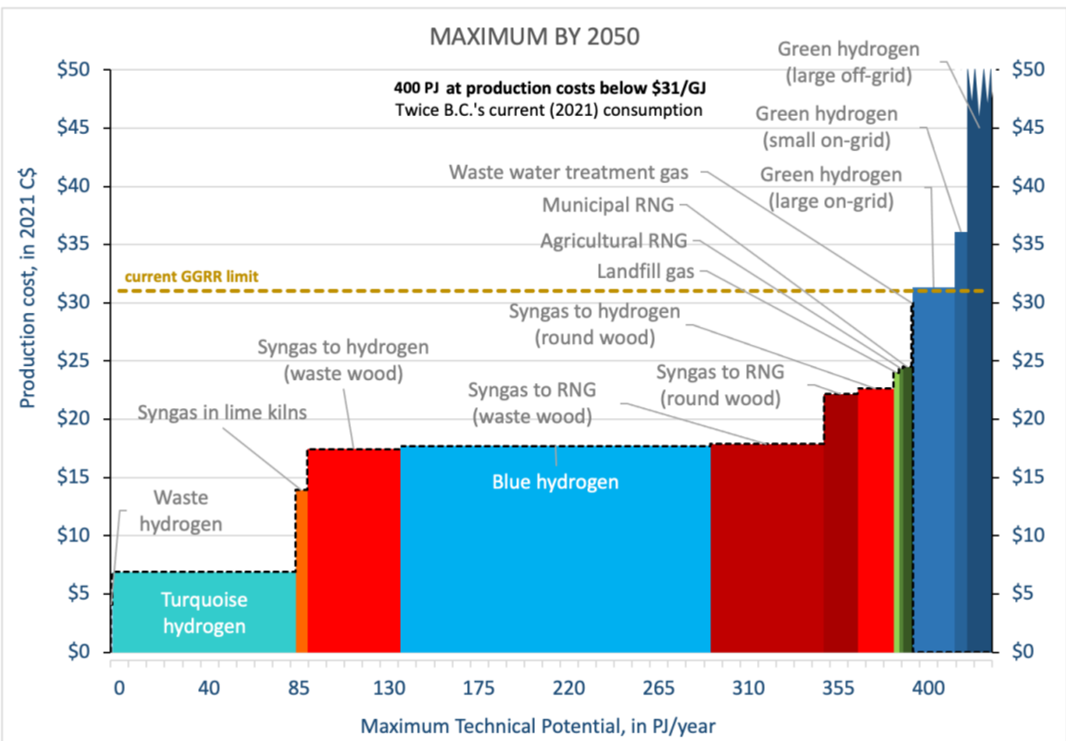


Figure 2 Production Cost and Technical Potential in the Maximum Scenario by 2030. Market prices may be higher than costs.



***Note**: For better readability, the scale of the x-axis (potential in PJ/year) is different for each graph*

Figure 3 Production Cost and Technical Potential in the Maximum Scenario by 2050. Market prices may be higher than costs.

Key Considerations

Cost Limits

In 2017, the Government of B.C. established the GGRR to require all natural gas utilities to purchase renewable natural gas up to a limit of 5% of their 2015 natural gas sales volumes, at a maximum price of $30 per gigajoule. In 2021, the regulation was further amended to:

- expand the volume limit to 15% of the utility's 2019 fossil natural gas sales;
- expand the range of resources that qualify under the initiative (i.e., to add green hydrogen, lignin, and syngas) and
- enable the maximum price to escalate each year with inflation (e.g., to $31 in 2021).

For a natural gas public utility to exceed these limits, and still recover the costs from their ratepayers, prior BC Utilities Commission approval would have to be obtained. The achievable economic potential would increase if natural gas utilities were enabled to pay higher prices for low-carbon gas. This would likely occur if the current renewable gas target were replaced with a carbon intensity target. Alternatively, the price limit could be defined as an average price, allowing for a mix of low and high-cost gas production.

Imports

Existing regulations allow gas utilities to acquire RNG from outside of B.C. Technically, there is enough potential in the rest of Canada to meet the 2030 target and when including the U.S., to replace all of B.C.'s retailed fossil natural gas by 2050. There is a trade-off between potentially lower costs for ratepayers when using out-of-province resources and socio-economic benefits when developing projects inside B.C.

Purchasing low-carbon and renewable gases outside of B.C. at low costs can hedge against higher gas costs while offering the option to sell any surplus gas later if sufficient gas can be sourced inside B.C. This could lower the cost for B.C. ratepayers but may at the same time reduce the impetus to develop projects inside B.C.

On the other hand, B.C. public natural gas utilities are unlikely to secure as much of this gas as they wish to due to competition. In the U.S., several jurisdictions have implemented renewable gas policies and have created lucrative markets for RNG certificates. Quebec has also enacted a RNG mandate. To take advantage of low-cost renewable gas supply from outside of the province, utilities will need to move quickly as competition for low-cost and low-carbon and renewable gas is likely to intensify.

GHG Reduction and Emissions

The technical potential established in this report is based on petajoules of renewable and low-carbon gas rather than tonnes of CO_2e displaced. A policy based on carbon abatement or carbon intensity of pipeline gas would have to look at a different metric to measure compliance.

Natural gas has a reported burner tip carbon intensity of 50 grams CO_2e per megajoule.[3] Another 6-12 grams need to be added for upstream emissions in B.C., according to current knowledge. The carbon intensities of renewable and low-carbon gases discussed in this report range from about 3 grams (wind-powered green hydrogen) to around 22 grams (blue hydrogen). Agricultural RNG can have negative carbon intensities due to avoided methane emissions.

The carbon intensity can vary significantly from one pathway to another, or even between projects within the same pathways. Some scientific sources claim that the additional energy needed to produce blue and turquoise hydrogen and the sequestration or conversion of carbon dioxide may result in higher carbon

[3] B.C. Best Practices Methodology for Quantifying Greenhouse Gas Emissions, 2020. B.C. Ministry of Environment and Climate Change Strategy, Victoria, B.C., April 2021

intensity than fossil natural gas itself, especially when taking into account fugitive emissions related to hydraulic fracturing. The CleanBC *Roadmap to 2030* includes measures to regulate and reduce upstream emissions from natural gas production.

Building the Renewable and Low-Carbon Gas Industry in B.C.

The cost of building a renewable and low-carbon gas production sector to replace fossil gas use in B.C. could range between \$5 billion and \$20 billion for the 2050 Minimum and Maximum scenario, respectively. This is the same order of magnitude as recent foreign investments in the Kitimat liquified natural gas terminal and will take place over more than two decades. The critical next step is for governments, indigenous communities, utilities, and other industry participants to work collectively on policies and investments that will unlock and enable this potential. The report discusses several policy instruments to attract the required investment. These include R&D and demonstration support, policies favouring gas production inside B.C., the monetisation of social and environmental co-benefits, and low-interest financing and joint ventures between gas utilities and industry.

Conclusions

The Province of B.C. is rich in natural resources, including a resilient electrical system built almost exclusively on hydropower, vast lands covered by forest, and a prosperous agricultural sector. This suggests that renewable and low-carbon gases can play the prominent role that CleanBC has assigned them.

1. The potential supply of renewable and low-carbon gases combined is sufficient to reach CleanBC's 15% target by 2030. The anticipated build-out rate of renewable gas production by 2030 will likely require either renewable gas imports from neighbouring jurisdictions and/or the use of low-carbon gas, such as blue or turquoise hydrogen, to reach the 15% target.
2. Provincially sourced renewable gases can displace 195 of the 200 PJ of natural gas by 2050 assuming, among other things, that the available agricultural, solid waste and forest residual feedstocks are used for this purpose.
3. Blue and turquoise hydrogen offer the highest technical potential, pending advancements in innovation and scaling-up.
4. Among renewable sources, i.e. excluding blue and turquoise hydrogen, wood-based pathways have the highest potential for renewable gas production under optimistic assumptions with respect to resource availability. These pathways still require research and demonstration to achieve the technical readiness required for a large roll-out.
5. Mature technologies such as anaerobic digestion can contribute most in the early stages of converting B.C.'s gas sector to renewable gas. Other pathways will be crucial to achieve substantial decarbonization of the natural gas system.
6. Based on the foreseeable cost of green electricity the production cost of green hydrogen is anticipated to be greater than \$31 per gigajoule in the 2030 and 2050 scenarios. Green hydrogen production requires the installation of significant infrastructure such as wind turbines and related electrical transmission. The maximum potential to produce green hydrogen at a cost below \$31 per gigajoule is 27 petajoules per year by 2050, even with the development of Site C hydroelectric dam and new wind-power generation.
7. Investment of up to \$20 billion may be required to facilitate the transition from natural gas to renewable and low-carbon gases by 2050. This investment is comparable to other investments in

energy in B.C., such as LNG Canada, a $40 billion terminal for the liquefaction, storage, and loading of LNG in the port of Kitimat, B.C.

8. The price limit of $31 per gigajoule set by the GGRR will likely capture most of the technical potential in B.C. Yet, offering this gas price may not be sufficient to build this industry. B.C. will need a stronger regulatory framework conducive to significant investment in renewable and low-carbon gas production. Like in the renewable electricity sector, efforts will need to focus on providing stable investment climates, moderating risks, and providing adequate returns.
9. Importing RNG from outside B.C. can hedge against future high costs to keep BC's industry competitive and protect ratepayers but may diminish the overall investment in the renewable and low-carbon gas sector within B.C.
10. National and international competition for RNG will increase further with time. California's Low-Carbon Fuel Standard (LCFS) market provides higher financial gains than B.C.'s. While B.C. could import RNG there is also a risk that some renewable and low-carbon production will be exported from the province.

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Glossary

$ or C$	Canadian dollars; all costs in this report are given in CAD
AAC	Annual allowable cut, the maximum volume of timber available for harvesting each year from a specified area of land, usually expressed as cubic metres of wood per year
AD	Anaerobic digester, a plant for producing biogas
Adt	Air dry tonne (seasoned wood, counted as having 20% moisture)
ATR	Auto-Thermal Reforming - A method of converting natural gas into hydrogen or syngas where the heat needed to reform the hydrogen is generated internally.
BCBN	BC Bioenergy Network
BCTMP	Bleached Chemi Thermo Mechanical Pulp
BCUC	BC Utilities Commission
Biogas	A methane-rich gas created by the anerobic digestion process that is not compatible with the existing natural gas system without upgrading due to its high CO_2 content and/or other contaminants.
BPA	Biomethane Purchasing Agreement
BTU	British Thermal Unit, 1 BTU = 1.055 kJ
CAPEX	Capital costs (of a project)
CCU, CCS	Carbon capture, utilization or storage are processes used to prevent the CO_2 from reaching the atmosphere by either storing it in a geological formation or mineral or by using it in a product.
CFB	Circulating fluidized bed, a reactor type used for gasification
CH_4	Methane
CHP	Combined heat and power
CI	Carbon intensity of a fuel usually measured on a life-cycle rather than consumption (tailpipe) basis
CLD	Construction, land clearing and demolition waste
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent, a measure for GHG warming potential of a gas
EU	European Union
FICFB	Fast Internally Circulating Gasifier
FN	First Nation
FPI	FPInnovations, the research arm of the Canadian forest industry
FT or F-T	Fischer-Tropsch, a gas-to-liquid technology

g	Gram
GHG	Greenhouse Gas
GGRR	Greenhouse Gas Reduction Regulation
GIS	Geographic Information System
GJ	Gigajoule 1 GJ = 0.278 megawatt-hours (MWh) or 0.95 MMBtu 1 GJ is equal to the energy content of 28 litres of gasoline (at 20°C)
H_2	Hydrogen
H_2O	Water
H_2S	Hydrogen sulfide
ha	Hectare, an area of 100 x 100 m; 1 ha = 2.4 acre
HHV	Higher Heating Value - The heat set free from the complete combustion of a material, including condensation heat released by any water in the flue gas.
HTG	Hydrothermal gasification, a technology which uses water at supercritical or similar temperatures and pressures to form a syngas.
HTL	Hydrothermal liquefaction, a technology which produces a biocrude, and in some cases, some by-product syngas
IEA	International Energy Agency
IFS	Industrial Forestry Service Ltd, a forestry consulting firm
IPP	Independent Power Producer, a non-utility generator that is not a public utility but owns facilities to generate electric power for sale to utilities and/or end users.
kg	Kilogram, 1 kg = 2.2 lb
km	Kilometer
kW	Kilowatt
kWh	Kilowatt-hour
l	Litre
LCFS	Low-carbon fuel standard
LFG	Landfill gas captured from the natural breakdown of biodegradable materials in a landfill.
LHV	Lower heating value, same as net calorific value
MC	Moisture content or the percentage of the water in the biomass fuel. The moisture content can be measured on the dry basis which is the percentage of moisture relative to the dry mass or wet basis which considers the total mass including moisture and the dry matter. The wet basis is used unless otherwise stated.
MECCS	B.C. Ministry of Environment and Climate Change Strategy

MJ	Megajoule or 1/1000th of a gigajoule
MSW	Municipal solid waste
MW	Megawatt
MWe	Megawatt of electrical output
MWh	Megawatt-hour
NGV	Natural gas vehicle (a vehicle running on natural gas)
NRCan	Natural Resources Canada
O & M	Operation and maintenance
O_2	Oxygen
odt	Oven-dry tonne, same as bone dry tonne, the solid matter content of biomass. Referred to simply as "dry tonne" in the text of this report.
OPEX	Operational cost (of a project)
OSB	Oriented strand board, an engineered panel product made from stands of wood used as a plywood alternative
PJ	Petajoule; 1 PJ = 1 million GJ
PPA	Power purchase agreement
PSA	Pressure swing adsorption - a gas upgrading system that uses the differential capacity of CO_2 to be absorbed by a media to separate methane from CO2. It has the advantage of separating oxygen and nitrogen from a gas biogas source.
psi	Pounds per square inch; 1 psi = 6.9 kPa
PV	Photovoltaic
R&D	Research and development
RFS	Renewable Fuel Standard
RIN	Renewable Identification Number, a U.S. system for subsidizing renewable fuels.
RNG	Renewable natural gas (upgraded to pipeline quality from biogas, landfill gas or syngas)
ROI	Return on Investment: the amount of net revenue provided by a capital investment, usually on an annualized basis.
SMR	Steam Methane Reforming is a method of hydrogen or syngas production where natural gas or other fuel is reacted with steam to form a mixture of hydrogen and carbon oxides.
SPF	Spruce Pine Fir, standard coniferous lumber produced primarily in the interior.
SSO	Source-Separated Organics - Organic material such as food waste, garden waste, leaves and other organic material collected separately from other municipal solid waste, often using green bins placed on the curbside.
t	Metric tonne; 1 tonne = 1,000 kg = 2,204 lb

TFL	Tree farm licence, a license (area-based tenure) to harvest timber and manage a forest, recreation and cultural heritage values. TFLs exist within TSA boundaries.
TRL	Technology Readiness Level, a method to estimate technical maturity for commercial application
TSA	Timber supply area, a geographic area defined by the government for the purpose of organization and management; tenures of various types are auctioned off from within each TSA to allocate harvesting rights.
TSL	Timber sale licence
TWh	Terawatt-hour, 1 TWh = 1 million MWh
UBC	University of British Columbia
US	United States
WWTP	Wastewater treatment plant
Yr.	Year

1.0 BACKGROUND AND OBJECTIVE

In 2018 the Government of the Province of British Columbia (B.C.) released the CleanBC Plan, demonstrating leadership in climate change mitigation through ambitious greenhouse gas emission abatement targets.[4] This Plan set a target for 2030 of displacing a minimum of 15% natural gas with renewable gas. This was reiterated in the 2021 Clean BC Roadmap to 2030, which also refers to the intent of government to set an overall emissions cap on natural gas use in B.C. Currently (2021), about 200 petajoules of natural gas are retailed each year. It is the objective of this study to update previous estimates of the renewable and low-carbon gas supply potential and develop a growth strategy for increasing production in B.C. to 2030 and 2050. Other questions addressed in this report are the cost and carbon intensity of each gas and in what B.C. regions are resources most prevalent.

1.1 Previous Work and Political Context

The CleanBC Plan and Roadmap are a continuation and consolidation of various clean energy incentives, legislation and regulations that date back more than a decade. The provincial renewable gas target aims to decarbonize the natural gas grid and builds on FortisBC's voluntary renewable natural gas program that has been operating for over ten years.

The *Greenhouse Gas Reduction Regulation*[5] (GGRR) allows regulated utilities to acquire and/or produce renewable gases up to 15% total gas supply throughput and up to a cost of $31 per GJ. To better gauge how the target is likely to be met, the report quantifies locally available resources and the relative costs of gases and lignin displacing natural gas, and determines whether additional measures are necessary to enable a transition towards low-carbon gas. This study looks at the four possible energy types eligible under the GGRR (see Section 1.5) and integrates the results.

Previous reports and studies have dealt with the provincial bioeconomy and form the basis of the current work:

1. In 2010, the B.C. government commissioned a report on the provincial bioeconomy. This report suggested that the market potential for new bioproducts could reach $200 billion, exceeding the market for bioenergy ($170 billion).[6] The report strongly suggested that a comprehensive vision for B.C.'s bioeconomy be developed, followed by an effort to resolve issues around access to forest biomass, which currently prevents new industry entrants from easily accessing feedstock. Other recommendations involved technology, infrastructure and marketing roadmaps.
2. In 2016, the B.C. Government produced a report on the future of the forestry industry, which suggested that the sector maximize its value through the development of new bioproducts, biochemicals, and bioenergy – a biorefining approach that could lead to new employment and improved performance across the sector.[7] A similar report examining the B.C. pulp and paper

[4] B.C. Gov News, "CleanBC plan to reduce climate pollution, build a low-carbon economy." December 5, 2018. https://news.gov.bc.ca/releases/2018PREM0088-002338. [Accessed Sep 26, 2021].
[5] See amendment of May 25, 2021 (Order of the Lieutenant Governor no. 306).
[6] Province of B.C., *MLA Bio-Economy Committee Report*, 2010.
[7] B.C. Ministry of Forests, Lands, Natural Resource Operations and Rural Development, *Strong past, bright future: A competitiveness agenda for BC's forest sector*, August, 2016.

industry recommended an alliance between all B.C. pulp and paper companies to examine new bioproduct opportunities.[8]

3. In 2015, Industrial Forestry Services prepared a report for BC Hydro's Long-Term Planning Process on the potential for bio-based electricity in B.C. This report found that fibre supply would decline until 2026 due to the mountain pine beetle epidemic, after which it would stabilize. The report suggested that while 21 million m^3 of biomass was surplus to the industry shortly after the peak of the epidemic in 2015, this surplus would decline to 7.9 million m^3 in 2025 and remain at that level for the foreseeable future. The report also found that most of this wood is in the form of standing timber, and that harvesting this wood would be uneconomic, costing over $150 per dry tonne delivered.[9] Finally, this report highlighted the fact that while mill closures have left surplus wood behind, these closures have reduced the amount of easily accessed processing residues that have supported pellet production in the past.
4. The Resource Supply Potential for Renewable Natural Gas in B.C. (Hallbar Consulting, 2017).
5. The B.C. Hydrogen Study (Zen Clean Energy, 2019).
6. A pre-feasibility study for syngas and biomethane production at B.C. pulp mills (Tom Browne, 2019).
7. The confidential study, Revitalization of the B.C. Bioenergy Sector: Assessment of biomass feedstocks in B.C. (ENVINT, 2019).
8. Renewable Natural Gas (Biomethane) Feedstock Potential in Canada (Torchlight Bioresources, 2020).
9. An analysis conducted by Guidehouse Consulting and FortisBC demonstrated that using the existing gas system to distribute renewable and low carbon gases can achieve an 80% GHG reduction by 2050 and be a more affordable and resilient pathway for B.C. to reduce emissions.

1.2 Purpose of this Study

The purpose of this study is to evaluate and quantify the supply potential of renewable gases that could be used for decarbonization in B.C. The province possesses a provincial energy system supported by gas and electrical delivery infrastructure. The electrical system relies almost exclusively on hydropower. The gas system is supplied by B.C.'s abundant natural gas basins. Vast lands are covered by forest, and the Province has a prosperous agricultural sector. All of this suggests that renewable and low-carbon gases can meet or even exceed the limits that CleanBC has assigned to it. This report identifies diverse sources of supply within and out of B.C., their potential volumes and production costs. The data is based on previous work inside and outside of Canada and on calculations conducted by the authors of this study. Key objectives that this report addresses include:

- Establishing B.C.-wide supply potential and carbon intensity for all renewable and low carbon gas types

[8] B.C. Ministry of Forests, Lands, Natural Resource Operations and Rural Development, *British Columbia Pulp and Paper Sector Sustainability: Sector Challenges and Future Opportunities*, September, 2016. https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/forestry/competitive-forest-industry/pulp_and_paper_sept_2016.pdf

[9] Industrial Forestry Service Ltd, *Wood-based biomass in British Columbia and its potential for new electricity generation*, July, 2015. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/wood-based-biomass-report-201803-industrial-forestry-service.pdf

- Developing cost curves for provincially produced gases and cost analysis for imported renewable natural gas (RNG),
- Updating information from previous reports with new assumptions reflecting the changing resource availability,
- Identifying unique use-cases and end-uses such as evaluating the potential for required infrastructure in B.C. and using industrial consumers as host-sites for renewable and low-carbon gas production.
- Informing strategies to increase production capacity and deployment to achieve the province's GHG reduction targets.

This study's focus is the displacement of natural gas consumption delivered through the B.C. pipeline system with renewable and low-carbon gases. The use of these gases for transportation is not specifically considered, although the latter can be achieved using gas from pipelines. The goals and metrics used, however, refer to the approximately 200 petajoules of natural gas currently being delivered throughout B.C. for a variety of purposes, mainly for industrial use and space and water heating. Leaving aside strategies such as fuel switching (with the exception of using lignin and syngas in the forest products industry) and energy efficiency, the focus is on decarbonizing the gas coming to energy users through the natural gas grid.

1.3 Structure of this Study

This report has three main sections:

1. An analysis of pathways for renewable and low-carbon gas production or fossil gas displacement (Chapters 2, 3, and 4);
2. Supply portfolios or scenarios for the development of these pathways (Chapter 5);
3. A high-level deployment strategy (Chapter 6).

The pathways themselves are grouped by product (e.g., hydrogen versus syngas), by resource (e.g., forestry versus agricultural feedstock), and by technology (e.g., biochemical versus thermochemical):

- RNG from anaerobic digestion of agricultural and municipal waste streams (Chapter 2)
- Renewable gases from forest resources (Chapter 3);
- Hydrogen from non-biomass resources (Chapter 4);

Each of these chapters provides the technical supply potential and production costs for the pathways discussed. Apart from hydrogen derived from natural gas, all pathways are resource constrained and pathways based on woody biomass compete for the same resource. Market prices and the impact of competition for the resource, the final product, or the market value of renewable and low-carbon gas for sale to the U.S. are not taken into consideration to determine the technical potential. The technical potential should be taken as an upper bound of what would theoretically be possible if each resource were fully used. This is unlikely to occur, however, and a lower minimum resource potential has also been defined, based on less optimistic assumptions. Within these scenarios, the commercial potential is defined as the amount of gas that can be produced at no more than $31 per gigajoule.

1.4 Key Metrics Used

The cost analyses always refer to Canadian dollars, unless stated otherwise in the text or tables. Cost projections are made in 2021 dollars, i.e., inflation is assumed to occur but is not reflected in these numbers as the cost projections reflect a change with respect to today's costs, net of inflation. All gas potentials are based on the higher heating value (HHV) of the gases, given gas billing and transactions are generally based on HHV in B.C.

The cost of renewable and low-carbon gases purchased by B.C. utilities for the purposes of the GGRR is currently (in 2021) limited to $31 per gigajoule, indexed with inflation. As this report uses 2021 dollars, any future increases of the carbon purchasing price limit do not affect the results and estimates. This price is an upper limit for gas costs utilities may offer while still recovering their costs from the ratepayer base. It is possible, however, to contract for gas deliveries at higher prices if the BCUC approves of such contracts. The BCUC may do so if these purchases are deemed to be in the public interest. The price limit is nevertheless used as the current limit in this report as it reflects the desire of the regulator to limit overall costs to ratepayers, and the authors' interpretation is therefore that only limited amounts of renewable and low-carbon gases (e.g., from demonstration projects) would be offered higher pricing under the current regulatory regime.

1.5 Definitions

In this report, renewable gas refers to, in line with the GGRR, hydrogen, renewable natural gas (RNG), synthesis gas made from biomass (syngas), and lignin (used to displace natural gas). The report uses the term 'Renewable Natural Gas' (RNG) as an umbrella term for all gases made from renewable resources, including through anaerobic digestion, landfill gas, or syngas conversion to RNG. Gas produced from natural gas, such as blue and turquoise hydrogen, is referred to as 'low-carbon gas'.

Biogas is gas produced from organics generated at farms, from municipal organics (green bin and industrial or commercial organic waste), and by processing sludge from wastewater treatment plants. Gases emitted and collected in landfills is called landfill gas. RNG refers to methane produced from renewable resources. This include both anaerobic processes using organic waste and thermochemical processes that gasify solid biomass to produce RNG.

The report uses colour coding for hydrogen. Colours are attributed only to signify the pathway that the gas is created by. Hydrogen itself is a colourless gas: hydrogen produced from fossil fuels through steam methane reforming (SMR) is called blue if the associated carbon is not emitted to the atmosphere but sequestered in geological formations or otherwise used. 'Turquoise hydrogen' means that carbon contained in the fossil natural gas is stripped of, and converted into, a solid, 'carbon black.' 'Green hydrogen' is produced from 'green' electricity, i.e., renewable electricity.

Resource potentials determined in Chapters 2-4 are technical potentials, i.e. they are not limited by regulation or cost. They are smaller than the theoretical potential (100% of the resource) as they are limited by the available resource and resource recovery constraints. In the case of forest-based woody feedstock, recovery factors used assume that it is only possible to recover a portion of the theoretically determined resource, such as roadside residue. For RNG from anaerobic digestion, the potential determined in Chapter 2 considers that only sites near gas pipelines will be developed and that only a portion of the feedstock produced is available for digesters. The potential for blue hydrogen is limited by suitable geological formations where carbon dioxide stripped from natural gas can be securely sequestered.

The scenarios in Chapter 5 assume further restrictions, including build-out curves and technology readiness. They represent technically feasible outcomes whose realisation will depend on policies in B.C. and the interplay between markets in the province and in other jurisdictions. The achievable (as opposed to technical or theoretical) potential does likely lie in-between the Minimum and Maximum scenarios developed.

2.0 RENEWABLE GAS FROM ANAEROBIC DIGESTION

2.1 Description of Pathway

Inside air-tight tanks, naturally occurring microorganisms convert moist or liquid organic material into biogas and digestate. Biogas consists of methane (typically 55% – 65%), carbon dioxide (typically 35% – 45%), small amounts of water, hydrogen sulphide and other trace gases, such as nitrogen and oxygen. Biogas is upgraded to renewable natural gas (RNG) by removing carbon dioxide and other impurities. It is then injected into the local gas grid, or if there is no local grid, compressed and transported to a site where it can either be injected into the gas grid or used.

Digestate is the material removed from biogas plants after micro-organisms have finished converting most of the feedstock's dry matter into biogas. It contains most of the nitrogen, and all of the phosphorus and potassium of the input feedstock, and is considered a good fertilizer.

Biogas plants are most often categorised by the type of feedstock they digest. These categories are:

- Agricultural: biogas plants that digest livestock manure and other on-farm inputs, such as crop residues and energy crops. These plants may also digest some commercial and residential source separated organics (SSOs).
- Municipal: biogas plants that digest residential and/or commercial SSOs.
- Wastewater: biogas plants that digest sludge from wastewater treatment plants. These plants may also digest some commercial and residential SSOs.

RNG can also be produced from landfill gas (LFG). LFG, a mix of methane (typically 45 – 55%), carbon dioxide (typically 45 – 55%) and many impurities, is a by-product from decomposition of organic material buried in landfills. LFG (often classified as a type of biogas) is captured through a system of perforated pipes drilled into landfills. As with biogas, LFG can be upgraded to RNG by removing carbon dioxide and impurities. These impurities, including high levels of nitrogen and oxygen, make LFG more challenging than biogas to upgrade.

2.2 Technology Update

Biogas plants typically consist of four process stages, while LFG projects consist of only two process stages (i.e., the second and third process stage below). These are:

- Feedstock pre-treatment.
- Digester tanks or LFG capture.
- Biogas or LFG upgrading.
- Digestate management.

A multitude of mechanical feedstock pre-treatment technologies are commercially available. These technologies cut/shred feedstock into smaller pieces, or separate feedstock from non-organic material, such as plastic. Other feedstock pre-treatment technologies are rarely used, except in specific circumstance (e.g., thermal hydrolysis for specified risk material or highly contaminated feedstock). This is because pre-treating feedstock is often too costly, and/or biogas production from the feedstock is insufficient to justify the cost. There are no pre-treatment technologies near to commercialization (TRL 7/8) that could significantly increase biogas production from feedstock, or reduce pre-treatment costs.

Digester tanks are gas-tight, insulated tanks, placed below or above ground. While digester tanks differ in material (i.e., concrete or steel), shape and agitation (mixing of feedstock), they are all generally similar. No digester tank design is considered universally preferential or superior.

LFG is extracted from landfills using a series of wells and a blower/vacuum system. As with digester tanks, no LFG capture technology is widely considered to be better than others, nor are there any technologies near to commercialization (TRL 7/8) that could significantly increase LFG capture or reduce capture costs.

Upgrading biogas/LFG to RNG removes carbon dioxide and other impurities (such as hydrogen sulphide and water) to increase methane content from approximately 55 - 65% to > 95% or more. Several technologies are available for upgrading biogas/LFG to RNG, including membrane, water wash, chemical scrubbing, pressure swing adsorption and cryogenic upgraders. While the cost and performance of these technologies differ, the overall outcome (cost per gigajoule of produced RNG) is relatively similar. For this reason, all biogas/LFG upgrading technologies are considered similar in performance, and there are no technologies near to commercialization (TRL 7/8) that could significantly increase RNG production or reduce production costs.

In cases where nutrients in digestate are greater than needed in the immediate vicinity of biogas plants, nutrient recovery technologies are often used. Nutrient recovery technologies extract nutrients from digestate into a more concentrated form, reducing transportation costs. Dozens of nutrient recovery technologies are available, all designed to extract different types (nitrogen, phosphorus and/or potassium) and amounts of nutrients. Because different technologies are designed for different needs/purposes, no nutrient management technologies are deemed to be superior to others. Furthermore, there are no nutrient recovery technologies near commercialization (TRL 7/8) that could significantly reduce nutrient extraction costs.

Feedstock pre-treatment, digester, upgrading and nutrient recovery technologies have been commercially available for many years. During this time, small incremental improvements have been made to many of these technologies (such as lowering costs, improving performance and increasing durability). These improvements have resulted in very small increases in RNG production and/or lower production costs. There are no biogas technologies near commercialization (TRL 7/8) that could significantly increase the production of RNG (per unit of available feedstock), or significantly lower the cost of producing RNG ($ per gigajoule).

One pre-commercial technology that could significantly increase the production of RNG is ex-situ power to RNG.[10] This two-step process starts with the electrolytical production of hydrogen. The hydrogen is then combined with carbon dioxide from the exhaust stack of a biogas/LFG upgrader, and fed into a reactor tank with specialty microorganisms to convert hydrogen and carbon dioxide into RNG. However, because the use of electricity to produce hydrogen is considered below, the use of electricity to produce RNG through ex-situ power to RNG isn't considered in this study.

[10] Ex-situ power-to-RNG is different from in-situ power to RNG (which is TRL 5) because ex-situ power-to-RNG requires a separate reactor with specialty microorganisms in it. In-situ power to RNG feeds hydrogen and carbon dioxide into the same digester tank used for producing biogas from organic feedstock, where a wide range of non-specialty micro-organisms exist.

2.3 Feedstock Availability

For the purpose of this chapter, the following potential sources of feedstock were assessed:

- Agricultural: livestock manure, including dairy and beef cows, swine and poultry.
- Source-separated organics (SSOs): residential and commercial SSOs from food processors, grocery stores, etc., and homes (typically collected as part of a "green bin" program).
- Wastewater treatment plant: sludge from processing wastewater.
- Landfilled organics: organic material placed in landfills.

B.C.'s feedstock availability was estimated using the same assumptions that were used in the 2017 RNG Production Potential Study[11] (there called the short-term achievable potential).[12] To estimate feedstock availability for 2021, 2030 and 2050, estimated availability in the 2017 RNG Production Potential Study was extrapolated using predicted agricultural and population growth rates. The annual predicted agricultural growth rates used were 0% for beef, 1% for dairy, broilers and turkeys, and 2% for layers and hogs. Population growth rates for B.C., Canada and the U.S. were extrapolated using population data from the past 20 years. LFG potential was also based on the 2017 RNG Production Potential Study. This study used LFG model estimates from Golder Associates (2008).[13] It should be noted that while this approach is likely the most reasonable, estimating RNG potential into the future becomes less and less certain as feedstock availability and LFG production are calculated using predicted and historical growth rates.

2.4 Anerobic RNG production potential in B.C.

RNG production potential in B.C. for 2021 is estimated to be 8.9 petajoules per year (Table 2). This potential assumes that all wastewater treatment plants (WWTPs) and landfills flaring LFG or using biogas/LFG to produce heat or heat and electricity switch to RNG production.

Due to its high dry matter and energy density, food waste (unlike livestock manure and WWTP sludge) can be transported up to 150 km or more to a biogas plant. This means that food waste can be digested in agricultural, municipal or WWTP biogas plants, regardless of where it is produced. In the RNG potential estimates shown in Table 2, it is assumed that most food waste is digested in municipal biogas plants. This assumption was used because in theory, municipal biogas plants should be closer to food waste than agricultural and WWTP biogas plants.

However, food waste could just as easily go to agricultural or WWTP biogas plants. Therefore, while the following agricultural, municipal and WWTP production estimates for B.C. assume an RNG division of approximately 40% from agricultural, 50% from municipal and 10% from WWTP biogas plants, in reality this division could be 70% from agricultural, 10% from municipal and 20% from WWTP biogas plants (or any other combination therein). RNG from LFG is different, as these estimates are based on estimated methane production from food waste already in B.C. landfills. The potential for 2050 assumes that organic waste is still landfilled over the coming decade; landfill gas production will decrease eventually (after 2050) if organics are more and more diverted and used for anaerobic digestion.

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[11] Hallbar Consulting, *Resource Supply Potential for Renewable Natural Gas in B.C. Public Version,* 2017.

[12] The only changes were that plant operating capacity was increased from 80% to 90%, while residential and commercial SSO availability was increased from 60% and 80% to 70% and 85% respectively. These changes were made to reflect growing maturity of B.C.'s biogas industry and greater participation in organics source separation.

[13] Golder Associates, Report on Inventory of Greenhouse Gas Generation from Landfills in British Columbia (2008).

In a 2012 B.C. RNG study,[14] theoretical RNG potential for FortisBC's Service Areas 1 and 2 (covering approximately 90% of B.C.'s population) from agricultural, residential and commercial SSOs was estimated to be 5.4 petajoules per year. This is only 0.6 petajoules lower than the 6.0 petajoules estimated in Table 2 (when LFG is excluded). Realistic RNG potential was estimated to be 1.93 – 2.38 petajoules per year. One possible reason that this study estimated much lower RNG potential than shown in Table 2 is because it assumed a maximum RNG sale price of $15.28 per gigajoule. If a higher price had been assumed, realistic RNG potential may have been much closer to the theoretical potential.

RNG production potential in B.C. for 2030 is estimated to be 9.5 petajoules per year. This is approximately one-third of FortisBC's 15% renewable gas target. The 8% growth in B.C.'s RNG potential between 2021 and 2030 is entirely due to industry (agricultural feedstock) and population (SSOs and WWTP sludge) growth estimates, and LFG production models.

RNG production potential in B.C. for 2050 is estimated to be 11.2 petajoules per year. As in 2030, the 27% growth in B.C.'s RNG potential between 2021 and 2050 is entirely due to industry (agriculture feedstock) and population (SSOs and WWTP sludge) growth estimates, and LFG production models.

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**

2.5 Anerobic RNG Production Potential in All of Canada

RNG production is constrained by feedstock availability. As such, the challenge with estimating RNG potential is that provincially-aggregated feedstock data (e.g., tonnes of manure or SSOs) can provide false perceptions. To estimate RNG potential with any level of confidence, detailed regional and municipal-level spatial feedstock data is required. This data must be overlayed with information known to impact biogas plant development.

For example, liquid manure (i.e., dairy and hog) cannot be transported far before transportation costs are greater than revenue from RNG production. Liquid manure is therefore unlikely to be available for biogas plants greater than 10 – 15 km away. Other feedstock, such as SSOs, may have competing uses (e.g., animal feed). Therefore, it may not be available for RNG production. Biogas plants also require power (a rough ballpark estimate is 1-2 kWh per cubic metre of RNG). As such, even a 100,000 gigajoules per year biogas plant requires ~300 – 600 kW of electricity. If three-phase power isn't available locally it can be very challenging to build a biogas plant.

Furthermore, biogas plants typically inject RNG into the gas pipeline. Biogas plants also produce digestate which must be managed (ideally spreading on nearby fields). While RNG can be compressed and transported for grid injection elsewhere, and while nutrient extraction technology can be used to transport nutrients to fields further away, the unavailability of a local gas grid and the requirement for nutrient extraction technology adds cost and can severely impact biogas plant economics.

Finally, while biogas plants are environmentally beneficial, they can still face community resistance if built too near communities (due to concerns with traffic, noise, odour, safety, etc.). Finding locations for biogas

[14] CH Four Biogas, Inc., *Biomethane Potential in FortisBC Service Areas 1 and 2,* December 2012.

plants that are sufficiently near feedstock (much of which comes from residential and commercial sources), yet far enough away from homes and businesses to avoid public opposition can be challenging.

The B.C. RNG production estimates above have been calculated using regional and municipal-level spatial feedstock data overlayed with information known to impact biogas plant development (including localised feedstock availability and competition, infrastructure and digestate management requirements). As such, they represent a realistic estimate of RNG production potential based not only on feedstock availability, but also on constraints known to impact biogas plant development.

Canada's livestock sectors are relatively evenly distributed across the country,[15] and B.C. and Canada's per capita commercial and residential SSOs and WWTP sludge production and capture rates are comparable. Population densities in all but the smallest provinces and territories are similar. Therefore, the above B.C. RNG production estimates have been extrapolated, with a moderate level of confidence, for the rest of Canada based on population size.

In 2021, RNG potential in Canada (including B.C.) is estimated in Table 3. Of Canadian RNG potential, 39% is estimated to be in Ontario, with 23%, 14% and 12% estimated to be in Quebec, B.C. and Alberta, respectively. All other Canadian provinces and territories account for the remaining 13% of RNG potential. As with RNG production potential in B.C., it is important to note that estimated RNG production between three of the sources (agricultural, municipal and WWTPs) in Table 3 is somewhat arbitrary. Because food waste is the greatest producer of RNG and can be transported up to 150 km or more to a biogas plant, the division of RNG between agricultural, municipal and WWTP biogas plants could be very different from that presented below.

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

In 2030, RNG potential in Canada is estimated to be 69.7 petajoules per year. Of Canadian RNG potential, 39% is estimated to be in Ontario, with 22%, 14% and 13% estimated to be in Quebec, B.C. and Alberta respectively. All other Canadian provinces and territories account for the remaining 13% of RNG potential. The 7% growth in Canadian RNG potential between 2021 and 2030 is entirely due to industry (agriculture feedstock) and population (SSOs and WWTP sludge) growth estimates, and LFG production models.[16]

In 2050, RNG potential in Canada is estimated to be 80.7 petajoules per year. Of RNG potential, 40% is estimated to be in Ontario, with 20%, 14% and 15% estimated to be in Quebec, B.C. and Alberta respectively. All other Canadian provinces and territories account for the remaining 12% of RNG potential. As with 2030, the 24% growth in Canadian RNG potential between 2021 and 2050 is entirely due to industry (agriculture feedstock) and population (SSOs and WWTP sludge) growth estimates, and LFG production models.[16]

[15] While Quebec and Ontario have more dairy cows per capita, B.C. has a higher number of poultry, Manitoba a higher number of hogs, and Alberta a higher number of beef cattle per capita. The concentration of grains and oilseeds in the prairie provinces isn't relevant as crop residues and energy crops are excluded from this study.

[16] B.C. agricultural growth estimates and LFG production models were used to estimate national increases in agricultural feedstock and LFG availability, while provincial population growth estimates were used to estimate increases in national residential and commercial SSOs.

Other studies have also attempted to estimate Canadian RNG potential. For example, according to the 2010 Alberta Innovates Technology Futures study,[17] Canadian RNG potential from manure, SSOs, WWTPs and LFG is 165 petajoules per year (68.8 petajoules per year from manure, 5.6 petajoules per year from municipal SSOs, 7.2 petajoules per year from WWTP and 83.8 petajoules per year from LFG). This estimate is for technically feasible RNG potential, and doesn't take into account actual feedstock availability, location, etc. If these RNG estimates were assessed through a more realistic lens, taking into account actual rather than theoretical feedstock availability, estimated RNG potential would likely be 50% lower at 82.5 petajoules per year.

In 2013, the Canadian Biogas Association (CBA) released a biogas study[18] that estimated Canada's RNG potential to be 92 petajoules per year. While this estimate is significantly higher than the 65 petajoules per year estimated above, it includes crop residues, which are not included in the present estimate.[19] If crop residues are removed, and only 50% of livestock manure is considered to be available (a realistic assumption identified in the CBA study), RNG potential falls to 62.5 petajoules per year.

While RNG pathway potentials in the 2013 CBA study differ significantly from those estimated in this study(for example, the 2013 CBA study estimates 6.8 and 11 petajoules per year from WWTPs and landfills, respectively), the reason for this is due to assumed feedstock end use. Most feedstocks can be used in multiple RNG pathways. For example, SSOs can be digested in agricultural, municipal or WWTP biogas plants, or can be landfilled to produce LFG. Therefore, assumptions on where feedstock is used significantly impacts how much RNG is estimated from each pathway.

In a more recent study, Torchlight Bioresources estimated the Canadian RNG potential from livestock manure, biosolids, WWTP, urban organics and LFG to be 111.5 petajoules per year.[20] However, as the study notes, this is theoretical not realistic potential. Technical RNG potential, which would require an assumption that only '40-70% of potential feedstock' is available for RNG production, is estimated to be 44.6 – 78.1 petajoules per year. Table 4 compares the results of the above-mentioned studies. Discounting the Alberta study, the results are very similar in each.

Table 4 Canadian RNG Potentials Compared, in Petajoules per Year

	This Study	Alberta Innovates	CBA	Torchlight Bioresources	Range of All Studies
Current RNG Potential	65.2	82.5*	62.5	61.4**	61.4 – 82.5

* Deemed to be 50% lower than this theoretical potential identified in the Alberta study.
** Average taken from 44.6 – 78.1 petajoules per year range estimated by Torchlight.

[17] Salim Abboud et al., *Potential Production of Methane from Canadian Wastes,* 2010.
[18] Canadian Biogas Association, *Canadian Biogas Study: Benefits to the Economy, Environment and Energy - Technical Document*, 2013.
[19] Crop residues have been excluded for several reasons. To reduce soil erosion and/or build-up organic matter, crop residues are often incorporated into the soil or, as with straw, used elsewhere (e.g., animal bedding or in mushroom production). For these reasons crop residues are often unavailable. Crop residues often have low spatial energy density and high fiber content. This means they can be costly to collect and transport, and require expensive pre-treatment. Finally, crop residue availability is highly variable, depending upon weather, crop rotation and seasonal variation, while they are also only available once or at certain times of the year. This makes them challenging to use because biogas plants require year-round feedstock availability and long-term storage is expensive.
[20] TorchLight Bioresources Inc., *Renewable Natural Gas (Biomethane) Feedstock Potential in Canada*, 2020.

2.6 Anerobic RNG Production Potential in the United States

B.C. RNG production estimates in this study were used to estimate RNG potential in Canada. This was done with a moderate level of confidence due to similarities in livestock distribution (and therefore manure production), SSOs production and capture rates, WWTP sludge production rates, and population densities across Canadian provinces.

Using the above B.C. RNG potentials to estimate U.S. RNG production potential is much less straightforward. Unlike in Canada, U.S. populations and livestock densities vary greatly. For example, California has 254 people, 4.4 dairy and 12.8 beef cows per km^2, while Wisconsin and Oregon have 44 and 109 people, 9.1 and 0.5 dairy cows and 24.6 and 5.0 beef cows per km^2 respectively.[21,22,23] This means that unlike Canada, availability of agricultural and SSO feedstocks for RNG production will vary greatly between U.S. states. Those with high populations and/or animals per km^2 will be able to collect and use a lot more feedstock than others (i.e., those with low populations and few animals per km^2).

Unlike in Canada, per capita SSOs capture rates in U.S. states are vastly different. Wisconsin and California, for example, have 0.6 and 1.9 composting facilities per 1,000 km^2, while Idaho and Texas have 0.02 and 0.05 per 1,000 km^2, respectively.[24] This means that some U.S. states (those with more compost facilities per square kilometre) will be able to collect much more SSO feedstock than others (those with less compost facilities per square kilometre). Despite this, and due to lack of available data elsewhere, the above B.C. RNG production estimates for 2021, 2030 and 2050 have been extrapolated, based on population size, to estimate RNG potential in the U.S. However, as just noted, this has been done with a low level of confidence.

Current RNG potential in the U.S. is estimated in Table 5. The 5% growth in U.S. RNG potential between 2021 and 2030 is entirely due to industry (agriculture feedstock) and population (SSOs and WWTP sludge) growth estimates, and LFG production models.[25] The 12% growth in U.S. RNG potential between 2021 and 2050 is also entirely due to industry (agriculture feedstock) and population (SSOs and WWTP sludge) growth estimates, and LFG production models.[25]

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

Other studies have also attempted to estimate U.S. RNG potential. For example, in 2011 the American Gas Foundation[26] estimated U.S. RNG potential (not including food waste) under non-aggressive and aggressive scenarios. Under the non-aggressive scenario, manure, WWTPs and LFG were estimated to

[21] Iowa State University: *Milk Cows in the United States*.
[22] Beef2Live: *Ranking of States with The Most Cattle,* September 26, 2021.
[23] U.S. Census Bureau, *Historical Population Density Data (1910-2020)*, April 26, 2021.
[24] BioCycle: *The State of Organics Recycling*, October 2017.
[25] B.C. agricultural growth estimates and LFG production models were used for estimating national increases in agricultural feedstock and LFG availability, while population growth estimates were used to estimate increases in national residential and commercial SSOs.
[26] American Gas Foundation, *The Potential for Renewable Gas: Biogas Derived from Biomass Feedstocks and Upgraded to Pipeline Quality,* September 2011.

have RNG potential of 156.1, 4.2 and 192 petajoules per year, respectively. These estimates are very similar to those presented above in Table 5.

In 2013, the National Renewable Energy Laboratory[27] estimated U.S. RNG of 110.4 petajoules per year from manure, 67 petajoules per year from commercial SSO, 135 petajoules per year from WWTP, and 142 petajoules per year from LFG. While the distribution of RNG potential is different from other estimates (likely due to the assumption that more commercial SSO will be sent to WWTPs then municipal biogas plants), total estimated RNG potential is again similar.

In 2019, the American Gas Foundation published an update to their 2011 study.[28] It estimated U.S. RNG potential under non-aggressive and aggressive scenarios in 2040. The non-aggressive scenario, which is 857.5 petajoules per year, is one-third greater than the RNG estimate for 2050 made here.

Table 6 US RNG Potential Compared, in Petajoules per Year

	This Study	American Gas Foundation (2011)		NREL	American Gas Foundation (2019)		Range of Studies
		Aggressive	*Non-Aggressive*		*Aggressive*	*Non-Aggressive*	
Current RNG Potential	561	352.4 (No food waste)	917.9 (no food waste)	455.2			352.4 – 461*
Future RNG Potential	630 (2050)				1,503.7 (2040)	857.5 (2040)	630 – 857.5*

* Using American Gas Foundation's non-aggressive scenarios.

2.7 Anerobic RNG Production Cost Curves for B.C.

2.7.1 Key Considerations

Estimating RNG production costs can be very challenging for three reasons. First, unlike renewable energy technologies that either require no biomass (e.g., wind, solar and hydro) or purchase homogenous feedstock (e.g., wood pellets), biogas plants accept a wide array of feedstock with varying quality (i.e., level of contamination) and characteristics (size, dry matter, viscosity, etc.). As such, biogas plants can require very different feedstock reception, handling, storage and processing equipment.

Second, unlike renewable energy technologies that have an established energy output per unit of technology or feedstock (e.g., kilowatts per square metre of solar panel or gigajoules per tonne pellets), biogas production of feedstock varies greatly. Some feedstocks produce ten times or more biogas per tonne than others. As such, biogas plants that are similar in size and scope can produce very different amounts of RNG.

Finally, unlike renewable energy technologies that produce no by-product (e.g., wind, solar and hydro) or very little by-product (e.g., ash from biomass plants), biogas plants produce digestate. Digestate is a low-nutrient concentration liquid (or solid if produced by a dry-batch biogas plant). If digestate cannot be used locally (e.g., spread on nearby fields), nutrient extraction technology or transportation (trucking) is often required. Both of these can add significant costs.

[27] National Research Energy Laboratory, *Energy Analysis: Biogas Potential in the United States*, October 2013.
[28] American Gas Foundation, *Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment*, December 2019.

No public data is available for RNG production costs in B.C. (biogas plants and landfills in B.C. don't make their production costs public). For this reason, estimated B.C. RNG production costs are based on the 2017 RNG Production Potential Study.[29] The 2017 RNG Production Potential Study estimated the total feedstock availability in B.C. and used realistic assumptions to determine what percentage of this feedstock could be available to biogas plants, and how much biogas this feedstock could produce.

It then looked at the size of municipalities and farms near available feedstock to determine how much feedstock would go to what type of biogas plant (municipal or agricultural), and how much RNG these plants would produce. All SSOs were assumed to go to municipal or agricultural biogas plants, while WWTPs were assumed to only digest sludge.

Once the type (municipal or agricultural) and size (gigajoules of RNG per year) of biogas plant was established, production costs ($ per gigajoule) were estimated using an industry cost-curve. This cost-curve, created using data from hundreds of biogas plants in Europe, provides an estimated cost of RNG production based on biogas plant size. As biogas plants increase in size (digest more feedstock), they are anticipated to benefit from economies of scale, and the cost of RNG production decreases. To fully understand all of the assumptions and methodology used to estimate RNG production costs, the reader is referred to the 2017 RNG Production Potential Study.[11]

Tip fee (or avoided cost) for SSOs is assumed to be $0 per tonne[30] because to meet all, or at least a high percentage of, estimated RNG potential, all available feedstock must be used. Therefore, while biogas plants are currently able to receive a tip fee of around $20-40 per tonne, it is expected that a significant increase in food waste demand will drive down the fee biogas plants are paid to take it. For 2030 and 2050, there are expectations that RNG equipment costs will come down by 5% and 10% respectively as a result of a more mature biogas sector.

2.7.2 B.C. Production Costs in 2021

Estimated B.C. RNG production costs in 2021 are shown in Figure 4. The reason there is no RNG potential for ≤$18 per gigajoule from agricultural and municipal biogas plants is due to digestate management costs assumed in populated areas (i.e., Lower Mainland and Vancouver Island). The difference in RNG potential between ≤$50 per gigajoule and the technical potential is because some biogas plants are assumed to be unable to secure SSOs. If SSOs were available , RNG production costs for these plants would decrease significantly, while technical RNG potential would increase.

RNG potential from WWTPs and landfills is much lower in cost than agricultural and municipal RNG because digester tanks, LFG capture equipment, etc. are not included in the RNG production cost estimates (this equipment is assumed to exist as WWTPs and landfills require this equipment even if they do not produce RNG). Therefore, the only cost included for RNG production for WWTP and landfills is the cost of biogas/LFG upgrading. If the cost of digester tanks, LFG capture equipment, etc. were included, WWTP and landfill RNG production costs would be significantly higher.

[29] Hallbar Consulting, *Resource Supply Potential for Renewable Natural Gas in B.C. Public Version,* 2017.

[30] Tip fee typically accounts for <15% of biogas plant revenue, so an assumption of a $0/tonne tip fees doesn't significantly impact RNG production costs.

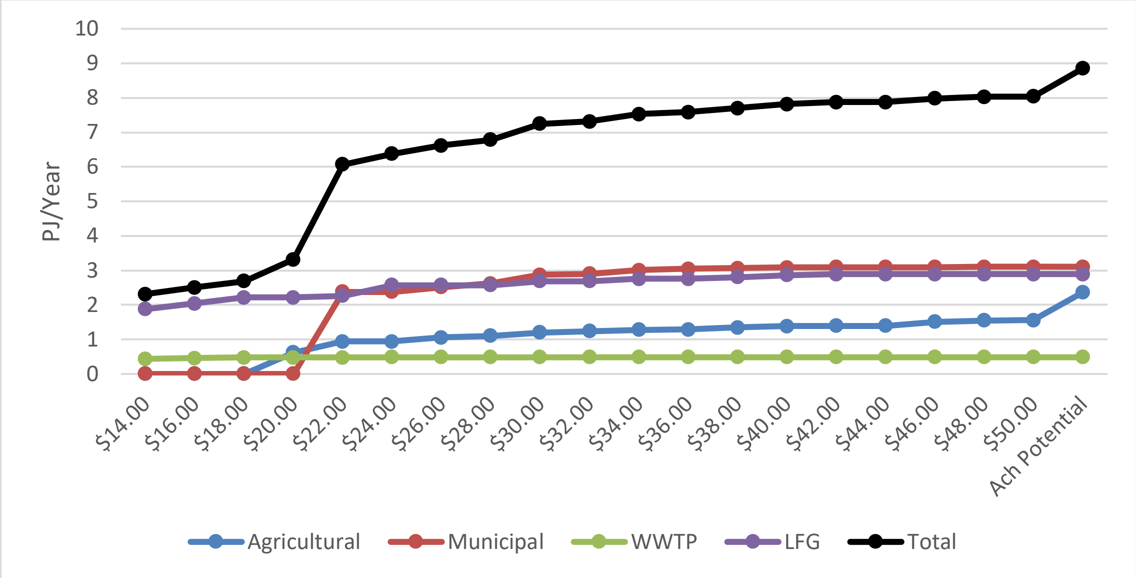

Figure 4 B.C. RNG Production Costs (2021)

2.7.3 B.C. Production Costs in 2030

Estimated B.C. RNG production costs in 2030 are shown in Figure 5.

- **Agricultural RNG** potential remains low, due to the assumption that most SSOs will be used in municipal biogas plants. As in 2021, there is no RNG potential for ≤$16 per gigajoule due to digestate management costs, while the difference in RNG potential between ≤$50 per gigajoule and technical potential is due to lack of SSOs.
- **Municipal RNG** potential is zero under $18 per gigajoule but increases to 3.3 petajoules per year for ≤ $31 per gigajoule. Technical RNG potential is 3.5 petajoules per year. As in 2021, there is no RNG potential for ≤$18 per gigajoule due to digestate management costs.
- **WWTP RNG** potential is small, even though some will be available for less than $16 per gigajoule.
- **Landfill RNG** potential is an important low-cost resource, with 2.2 petajoules available at $16 or less, and 2.9 petajoules per year for ≤ $31 per gigajoule. As in 2021, production costs for WWTP and landfill RNG only includes the cost of biogas/LFG upgrading.

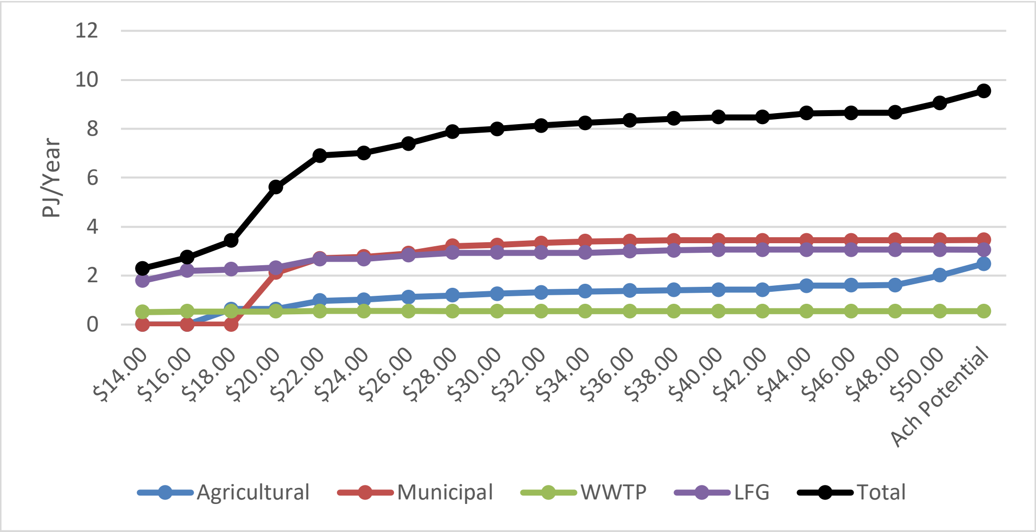

Figure 5 B.C. RNG Production Costs (2030)

2.7.4 B.C. Production Costs in 2050

Estimated B.C. RNG production costs in 2050 are shown in Figure 6.

- **Agricultural RNG** potential increases to a maximum of 2.2 petajoules for ≤50 per gigajoule. As before, there is no RNG potential under $16 per gigajoule due to digestate management costs, while the difference in RNG potential between ≤$50 per gigajoule and technical potential is due to lack of SSOs.
- **Municipal RNG** potential is significant, at 4.5 petajoules for ≤ $31 per gigajoule. There is no RNG potential for less than $14 per gigajoule due to digestate management costs.
- **WWTP RNG** potential is only slightly higher than in previous years.
- **Landfill RNG** potential is only slightly higher than in 2030, at 3.0 petajoules under $31 per gigajoule. As before, production costs for WWTP and landfill RNG only includes the cost of biogas/LFG upgrading.

Figure 7 combines the above data into a single graph that shows estimated RNG production costs for 2030, for the various sub-categories defined above. About 8 petajoules are available for ≤$30 per gigajoule. This represents the majority of the technical potential. Only a relatively small amount can be added by paying more for the RNG. Also, only a small additional amount becomes available by 2050, adding up to the total potential of 11 petajoules shown in Table 2 above.

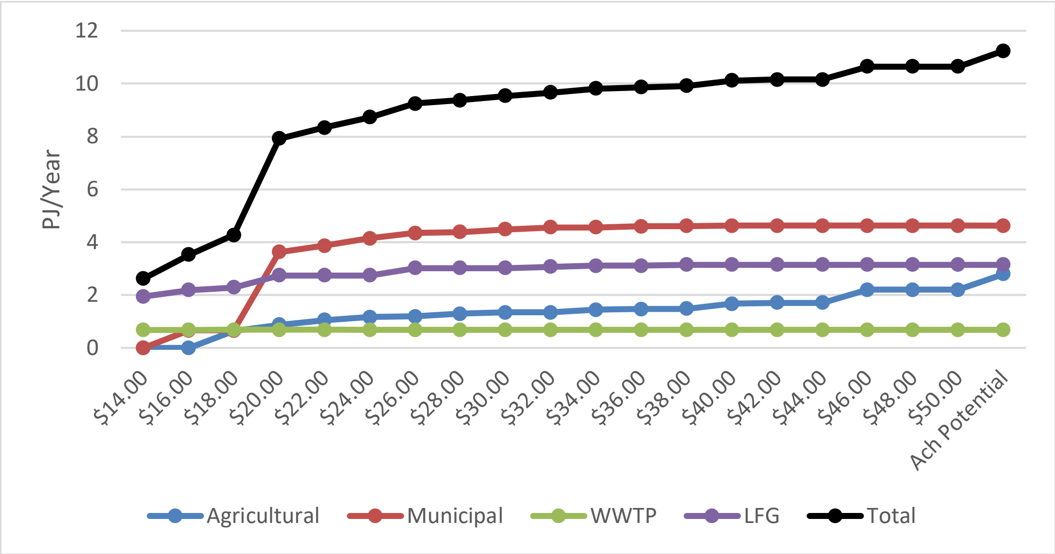

Figure 6 B.C. RNG Production Costs (2050)

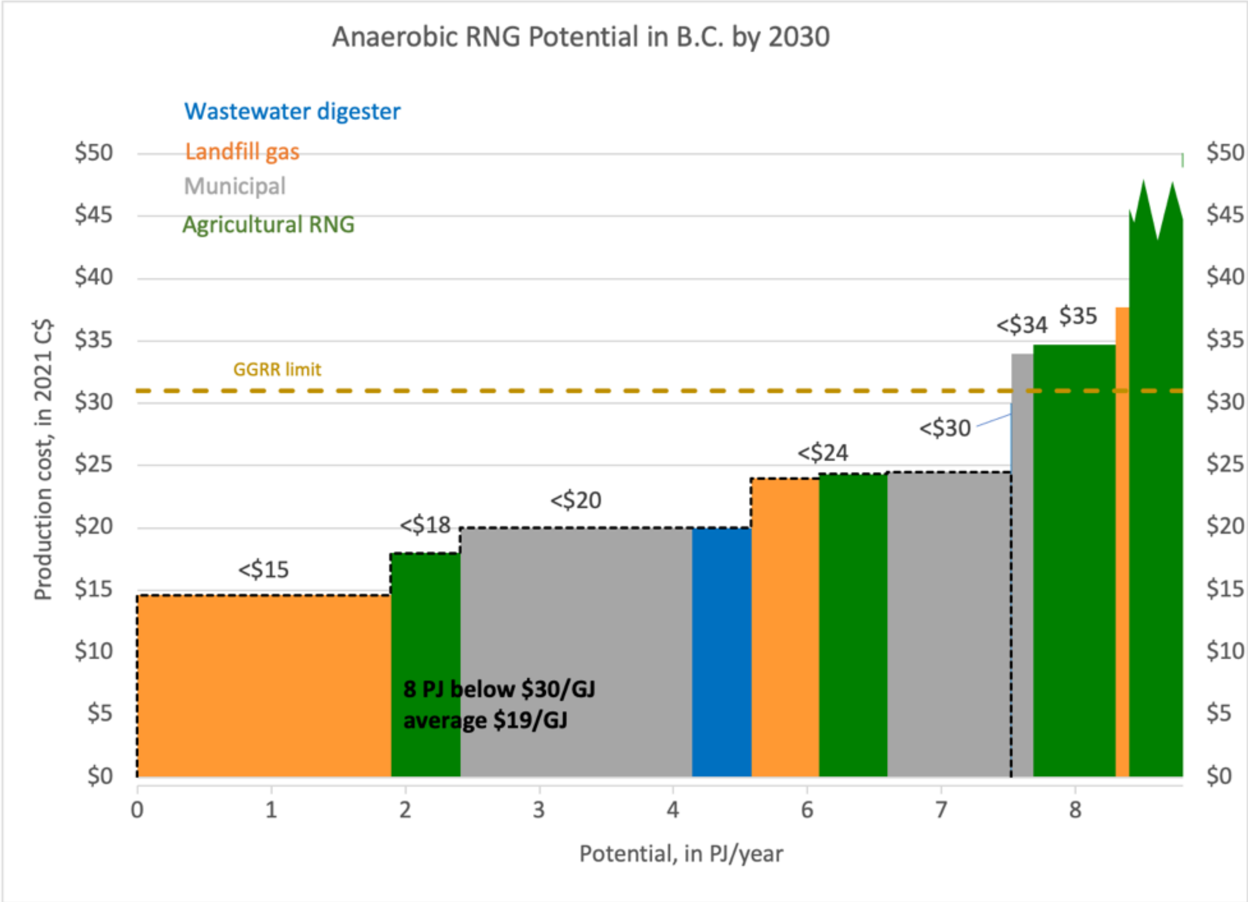

Figure 7 B.C. RNG Cost Curve for RNG from Anaerobic Digesters (in 2030)

2.8 Anerobic RNG Production Cost Curves in Canada

2.8.1 Key Considerations

The B.C. RNG production potential estimates above were used to estimate Canadian RNG potential. This was possible because Canada's livestock sectors are relatively evenly distributed, B.C. and Canada's per capita SSO and WWTP sludge production rates are the same, and population densities in all but the smallest provinces and territories are similar.

Using the B.C. RNG production cost estimates to calculate Canadian RNG production costs is more challenging. Typically, as biogas plants digest more feedstock or landfills capture more LFG (i.e., are larger), production costs per gigajoule of RNG decrease. This is because larger plants can benefit from economies of scale. Because Ontario and Quebec have significantly more feedstock than B.C., while Manitoba, Saskatchewan and the Atlantic provinces have significantly less feedstock, estimating Canadian RNG production costs using B.C. cost estimates may over- or under-estimate actual production costs.

Furthermore, the B.C. RNG production cost estimates were calculated by overlaying spatial feedstock data with local natural gas infrastructure. Gas infrastructure plays a key role in RNG production as it connects biogas plants and landfills with demand centres and end-users. The distribution of feedstock relative to the natural gas infrastructure in B.C. is not necessarily the same as in the rest of Canada. While RNG can be compressed and transported for grid injection elsewhere, doing so can increase RNG production costs by $3 – $6 per gigajoule or more.

Finally, different Canadian provinces have different policies and regulations that affect RNG production. Obstructive policies, whether intentional or not, can delay project development and result in the need for additional equipment, both of which affect RNG production costs. While this impact is less significant to production costs than project size and gas infrastructure availability, it can still be impactful.

2.7.5 Canadian RNG Production Costs in 2021, 2030 and 2050

Despite the challenges of unknown project size, gas infrastructure availability and provincial regulations, the following are Canadian RNG production cost estimates for 2021, 2030 and 2050. While these cost curves may not be as accurate as those for B.C., they still provide a good indication of Canadian RNG production costs (Figure 8).[31]

Of Canadian RNG potential in 2021, 2030 and 2050, > 65% of production for ≤$18 per gigajoule is from WWTPs and LFG. This is because estimated production costs for WWTP and LFG RNG only include the cost of biogas/LFG upgrading. In 2021, 2030 and 2050, 85% of Canadian RNG potential is for ≤$34 per gigajoule, ≤$32 per gigajoule and ≤$30 per gigajoule, respectively. From 2021 to 2050 the cost of RNG decreases due to both expectations that equipment costs will decrease (as the biogas/LFG market grows) and economies of scale will increase as a result to greater feedstock availability.

[31] Digestate management costs for agricultural biogas plant were only assumed for plants in B.C.'s Lower Mainland and Vancouver Island. Agricultural biogas plants in all other areas of Canada were assumed to have no digestate management costs.

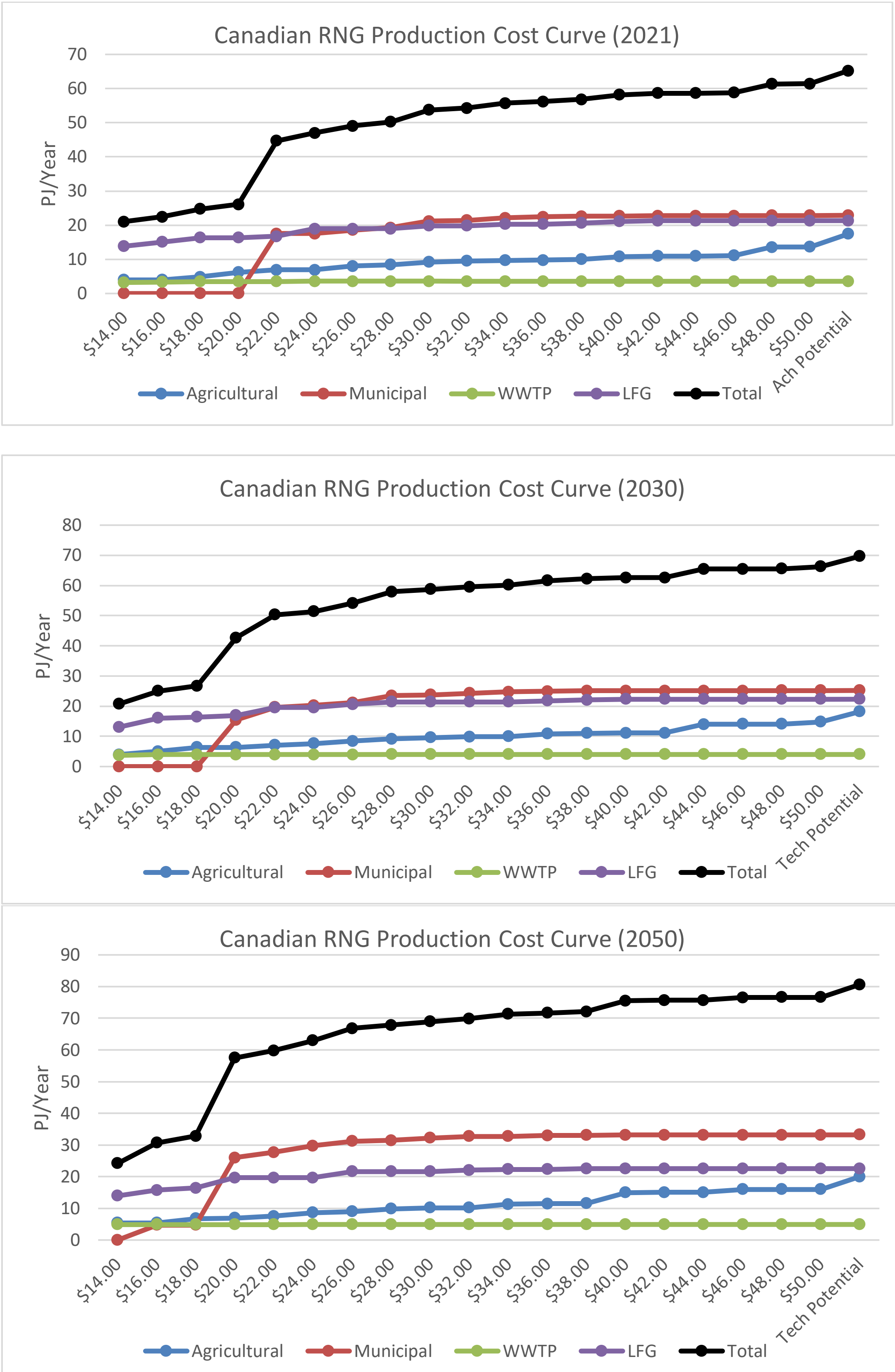

Figure 8 Canadian RNG Production Costs (2021, 2030 and 2050), in $/GJ

Other studies have also attempted to estimate the cost of Canadian RNG production. For example, the Torchlight Bioresources study[32] estimated RNG production costs ranging from $6 per gigajoule to almost $55 per gigajoule. RNG from a 0.1 petajoules per year biogas plant digesting hog manure and SSO was estimated to cost $53.90 per gigajoule, while RNG from LFG was estimated to cost $6.10 per gigajoule (best case) and $15.60 per gigajoule (most likely). While the estimated cost of $53.90 per gigajoule for agricultural RNG seems extremely high, the cost of $15.60 per gigajoule for LFG RNG is similar to that estimated above (70% of Canadian RNG from LFG is estimated to cost ≤$16 per gigajoule).

A study by Guidehouse[33] estimated current European RNG production costs to be €0.65 - €0.9 per cubic metre (~$26 - $36 per gigajoule), with RNG costs in 2050 estimated to be €0.47 - €0.57 per cubic metre (~$19 - $23 per gigajoule). While current RNG costs estimated by Guidehouse are slightly higher than the estimates above, this is likely for two reasons. First, the Guidehouse study considered the cost of biogas tanks and LFG capture equipment at WWTPs and landfills. Second, land availability in Europe is limited. Therefore, many European biogas plants require nutrient extraction technologies.

2.9 Anerobic RNG Production Cost Curves in U.S.

Using B.C. or Canadian RNG production cost estimates to estimate U.S. RNG production costs isn't possible. Canadian and U.S. agricultural sectors (both scale and density), population densities, policy structures and per capita commercial and residential SSOs capture rates aren't comparable. Furthermore, the U.S. currently has no standard market price for RNG. Instead, price is largely driven by the value of environmental commodities associated with the RNG from participating in the federal Renewable Fuel Standard and/or LCFS programs (see below). For this reason, the following RNG cost estimates were taken from previous studies by the American Gas Foundation.

The American Gas Foundation's 2011 study[34] estimated RNG production prices under a non-aggressive scenario state by state. RNG from animal manure was estimated to cost anywhere from C$8.1 – C$105.3 per gigajoule in Delaware and Alaska respectively, with an average cost of C$14.6 per gigajoule. RNG from WWTPs was estimated to cost anywhere from C$14.1 – C$40.8 per gigajoule in Illinois and Louisiana respectively, with an average cost of C$25.3 per gigajoule. RNG from LFG was estimated to cost anywhere from C$7.0 – C$18.8 per gigajoule in New York and Utah, respectively, with an average cost of C$9.7 per gigajoule.

In the American Gas Foundation's 2019 study,[35] RNG production cost ranges were again estimated, this time between C$24.4 – C$43.2 per gigajoule for biogas from animal manure, C$25.8 – C$37.6 per gigajoule from food waste, CD$9.8 – C$34.7 per gigajoule from WWTPs, and C$9.6 – C$25.4 per gigajoule from LFG. These ranges are somewhat comparable to the RNG production cost estimates above for both B.C. and Canada.

Table 7 Estimated RNG Production Costs (American Gas Foundation), in C$ per Gigajoule

	Agricultural		Food Waste		WWTP		Landfill	
Year	Low	High	Low	High	Low	High	Low	High
2011	$8.1	$105.3	N/A	N/A	$14.1	$40.8	$7.0	$18.8
2019	$24.4	$43.2	$25.8	$37.6	$9.8	$34.7	$9.6	$25.4

[32] TorchLight Bioresources Inc., *Renewable Natural Gas (Biomethane) Feedstock Potential in Canada*, 2020.
[33] Guidehouse, *Gas Decarbonization Pathways 2020-2050: Gas for Climate*, April 2020.
[34] American Gas Foundation, *The Potential for Renewable Gas: Biogas Derived from Biomass Feedstocks and Upgraded to Pipeline Quality,* September 2011.
[35] American Gas Foundation, *Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment*, December 2019.

2.10 Competition for Anerobic RNG

The above work was carried out to estimate technical RNG production potential in B.C., Canada and the U.S. today, in 2030 and 2050. Work was also carried out to estimate how much this RNG would cost to produce. However, there can be a very large difference between costs (expenses incurred producing RNG) and prices (the amount RNG is sold for). This is because RNG isn't valued based on its energy content, but on environmental benefits generated through federal and provincial/state programs.

For example, B.C. has a Low Carbon Fuel Standard (LCFS), while Canada has the proposed Canadian Clean Fuel Standard. The U.S. has the federal Renewable Fuel Standard, and the California and Oregon LCFSs, with many more under development. Most of these programs[36] assign RNG a Carbon Intensity (CI) score. The lower (more negative) the CI score, the more RNG is sold for. This is because a smaller amount of highly negative CI RNG is needed to reduce a producer's overall fuel supply CI score.

Furthermore, because most LCFS programs use a lifecycle accounting framework methodology where upstream emissions are included, two similar biogas plants can have very different CI scores. For example, Farm A and Farm B both digest 200,000 tonnes per year of manure and consume similar energy inputs. As a result of these biogas plants, both farms prevent 10,000 tonnes per year of carbon dioxide equivalent being emitted into the atmosphere from manure storage (baseline emissions).

However, because Farm A has a longer retention time and superior agitation, it produces 100,000 gigajoules per year of RNG, while Farm B only produces 75,000 gigajoules per year. The outcome is that Farm B's RNG has a more negative CI score and will attract a higher price than Farm A's RNG (this is because the 10,000 tonnes per year of carbon dioxide equivalent not emitted from manure storage is divided by the number of megajoules of RNG produced). The price that Farm B receives for its RNG could be 30+% higher compared to the price Farm A receives.

If Farm A were to add food waste feedstock to the biogas plant, RNG production would increase significantly, while the tonnes per year of carbon dioxide not emitted from manure storage would stay the same. This means that the 10,000 tonnes per year of carbon dioxide equivalent would be divided by a much larger number of megajoules, and the farms' CI score would become even less negative, resulting in an even lower price for the RNG.

In 2021 Stifel Equity Research[37] estimated that over the past few years RNG from dairy manure and LFG has sold for an average price of C$129.1 per gigajoule and C$39.9 per gigajoule, respectively. This price is potentially up to three times higher than the production cost of the RNG. For example, the American Gas Foundation[38] estimated the maximum dairy manure and LFG RNG production costs to be <C$45 per gigajoule and <C$26 per gigajoule, respectively. Figure 9 shows typical CI scores for different types of renewable energy sold into the Californian LCFS market, with green dots denoting all types of compressed RNG, including manure, food waste, WWTPs and LFG. This means that due to its highly negative CI agricultural and to a lesser degree, municipal RNG can potentially be sold for several times what they actually cost to produce.

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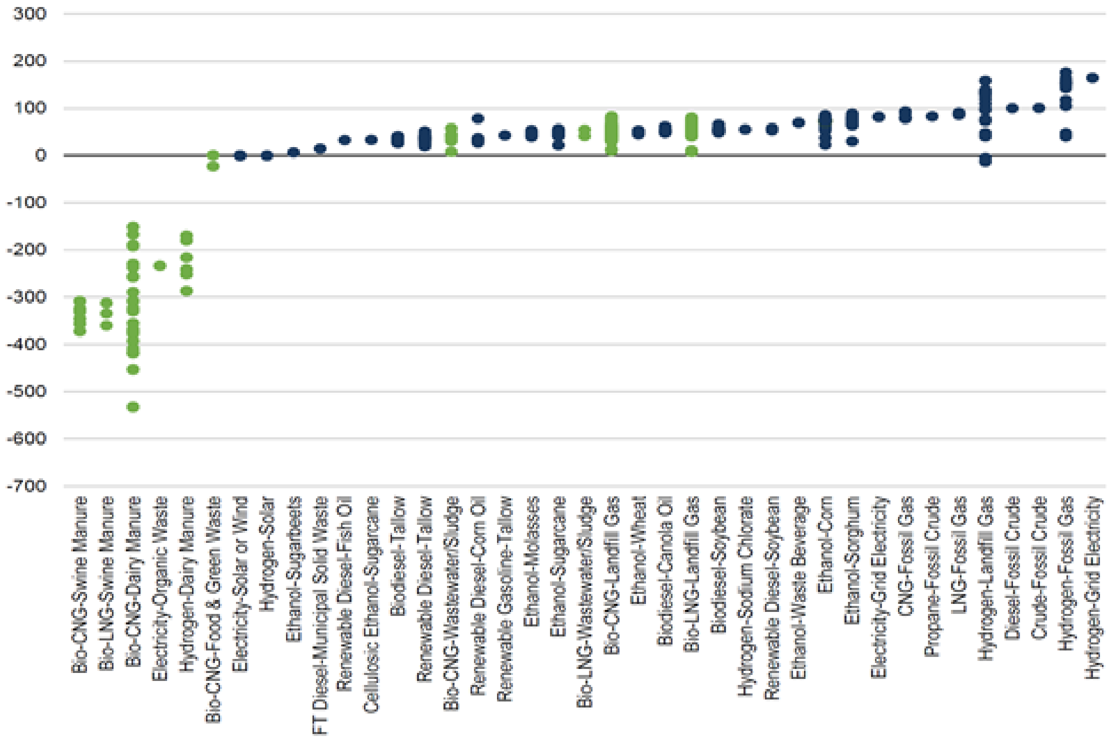
[36] The exception being the U.S. Renewable Fuel Standard, which creates renewable identification numbers which are purchased by those needing to meet their EPA-specified renewable volume obligation.

[37] Stifel Equity Research, *Energy & Power – Biofuels: Renewable Natural Gas. A game-changer in the race for net-zero*, March 8, 2021.

[38] American Gas Foundation, *Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment*, December 2019.



Note: Values determined based on the California LCFS methodology. Values for use in vehicles, based on high electricity use for gas compression, and adding emissions from truck transport.

Figure 9 Carbon Intensity Values of Certified Pathways, in in Grams per Megajoule[37]

To date, all B.C.-produced RNG has been contracted to FortisBC. This is likely for two key reasons. First, FortisBC is the largest local utility. This means injecting RNG into the local gas grid is relatively easy and more straightforward than selling RNG to another entity. Second, FortisBC offers up to 20-year (for agricultural projects) and 25-year (for municipal projects) biomethane purchase agreements (BPAs). Having a long-term BPA is often necessary to secure project financing. For these reasons, it is realistic to assume that, in the short-term, a very high percentage of RNG produced in B.C. could be available to FortisBC at or near production costs.[39] However, and depending upon the price of carbon, this percentage may decrease in the long term as the B.C. LCFS, Canadian Clean Fuel Standard and other programs mature, creating competing demand for B.C.-produced, low-carbon RNG.

Across Canada, FortisBC is successfully purchasing RNG. While FortisBC isn't the local utility for these projects, it can offer long-term BPAs. As a result, a high percentage of RNG produced in Canada could be available to FortisBC at or near production costs in the short-term. However, this percentage could fall drastically in the long-term if other Canadian utilities start offering BPAs similar to those offered by FortisBC. Furthermore, and as in B.C., the price of RNG could increase drastically when the Canadian Clean Fuel Standard or other provincial or state-based LCFS regulations are created.

Estimating the percentage of U.S. RNG that could be available at cost rather than at price is incredibly challenging. Within the U.S., FortisBC isn't the local utility but it does offer long-term BPAs. Despite this,

[39] While Pacific Northern Gas (PNG) is also able to offer long-term BPAs for RNG, the PNG natural gas lines are in Northern B.C. where livestock and population densities are low. The amount of B.C. RNG that could be produced in areas where PNG has a gas line is relatively small compared to where FortisBC has gas lines.

and as shown in Figure 9, agricultural and municipal biogas plants are typically able to achieve highly negative CI scores. This makes it unlikely that FortisBC will acquire much agricultural or municipal RNG from the U.S. at or near production costs. According to Section 2.6 above, up to two-thirds of U.S. RNG is estimated to come from agricultural and municipal biogas plants.

For these reasons, it is realistic to assume that in the short-term a medium to low percentage of RNG produced in the U.S. could be available to FortisBC at or near production cost. In the long-term, this percentage could fall if U.S. utilities start offering BPAs similar to those offered by FortisBC, while changes to the federal Renewable Fuel Standard and California and Oregon LCFS, and/or introduction of new state LCFSs could cause this percentage to fall even further.

2.11 Markets

Currently the main buyer of RNG in Canada is FortisBC (although other utilities and companies are also starting to purchase RNG). Other markets for RNG do, however, exist. These markets, which may attract RNG from projects within, and more likely, outside of B.C., include:

- The U.S. RNG certificate market is an opportunity that offers high pricing, especially for low CI agricultural and municipal RNG, and is already attracting projects development in the U.S.
- RNG can be used as a transportation fuel. This is a lucrative market, though it is often restricted to fleets running locally on RNG.
- As soon as the federal Clean Fuel Standard is enacted, demand from other gas retailers will follow. Quebec is also mandating its gas retailers to buy 10% renewable gas by 2030 and Energir is therefore buying LFG for pipeline injection.[40]

2.12 Infrastructure Needs

The equipment and technology necessary to build and operate biogas plants/LFG capture systems are all commercially available. Despite this, and at times, the existing gas infrastructure can be a limiting factor. If certain feedstock is concentrated in an area unserved by natural gas,[41] or if the existing natural gas infrastructure isn't able to accept RNG (especially during summer months, when natural gas demand is low), RNG must be compressed and transported for grid injection elsewhere. Compression and transportation can increase RNG production costs by $3 – $6 per gigajoule or more (depending upon project size and distance RNG must be transported). As Figure 10 shows, many landfills and WWTP are close to the gas pipeline. This is also true for most large urban areas, but isn't true for all farms that produce feedstock for RNG production.

Therefore, developing the full potential of RNG production with B.C., Canada and the U.S., will require expansion of the natural gas infrastructure to areas currently too far from the grid to inject any gas. Alternatively, and as done in Sweden where many biogas plants are located well away from any natural gas infrastructure, greater emphasis and support is needed to reduce the cost of RNG compression and transportation.

[40] https://www.ledevoir.com/economie/632010/le-gaz-naturel-renouvelable-dans-la-mire-d-energir-et-de-waste-management (Accessed September 1, 2021).

[41] Especially liquid, low dry matter feedstock, such as manure (i.e., dairy and hog), which typically cannot be transported far before transportation costs are greater than revenue from RNG production.

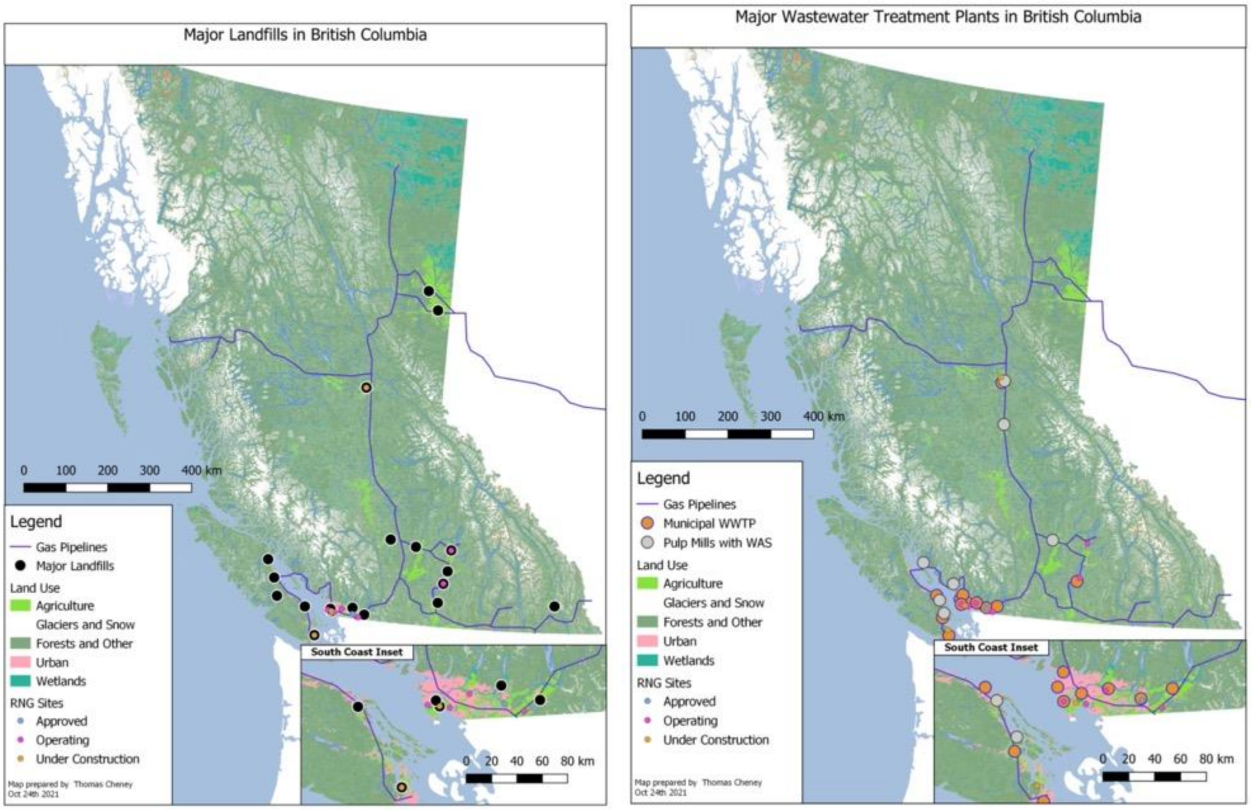


Figure 10 Locations of Major Landfills and WWTP in British Columbia

2.13 Recommendations

FortisBC is the first natural gas utility in Canada and one of the first in North America to purchase RNG. FortisBC also offers long-term BPAs. Having a long-term BPA is often necessary to secure project financing. For these reasons, FortisBC is able to purchase RNG across North America, and compete with federal and provincial/state fuel standards. However, as other Canadian and even U.S. gas utilities start offering BPAs similar to those offered by FortisBC, the ‘first-mover’ advantage that FortisBC currently has will start to erode.

Furthermore, as more fuel standards are developed, or as existing fuel standards mature, the attractiveness of these markets for RNG producers may increase (e.g., price stability and trust may increase, and/or fuel suppliers or intermediary companies may start offering long-term contracts). As such, FortisBC should leverage their current ‘first-mover’ advantage by procuring as much RNG as they can in the short-term, before the level of competition and the cost of RNG increases.

When it comes to procuring RNG, the choice for type (e.g., agricultural, municipal, WWTP or LFG) will depend upon a multitude of factors. The most important of these factors currently is cost. However, if/when there is a transition from requiring FortisBC to acquire ‘renewable content’ to acquiring gases with a certain CI score, the choice of RNG will depend upon CI calculations used. If a life cycle accounting methodology is used where credit is given for avoided methane from manure storage or food waste landfill diversion, then agricultural and municipal RNG will likely be the most attractive. Aligning these methodologies between jurisdictions is important to prevent that different GHG accounting methods may create higher value for a RNG type outside of B.C., leading to out-of-province sales.

3.0 THERMOCHEMICAL CONVERSION OF FOREST RESOURCES

This chapter deals with thermo-chemical conversion such as gasification of woody biomass. The gas generated may be upgraded to be injected into the pipeline or may be used directly at the point of production, replacing natural gas. We assume that all forest biomass available can be used by the various gasification and other technologies. It is understood that woody biomass comes in different dimensions and qualities (see Appendix C). For example, hog fuel may have higher ash content than other wood but this can be dealt with by using more potent syngas cleaning technologies. Salt contamination in coastal areas can be a problem for some processes and may then require salt removal (e.g., pre-washing) in order to use such material. Emerging technologies, such as supercritical water processing, may remove the need to pre-treat feedstock in. the future (see Appendix A).

3.1 Forest Biomass Resource Assessment

3.1.1. *Total Available Woody Biomass*

The estimates in this section are taken from the report *'Revitalization of the B.C. Bioenergy Sector*,' produced for BCBN in 2019. They are based on a commercial fibre supply model that uses the Annual Allowable Cut (AAC), mill activity, imports, and exports of fibre between regions, and estimates surplus residue at mills and in the forest. The main conclusions from this work were:

Based on the analysis in Appendix C,
combines availability data on the various wood feedstock types that have been quantified, adding typical cost ranges (see also Section 3.1.3). About half the long-term resource would come from standing trees (roundwood) at elevated pricing. The most significant low-cost resources include feedstock potentially becoming available from expiring contracts with BC Hydro for power production and feedstock currently used for wood pellet production. At the same time, these streams remain highly speculative as it is not certain that they will become available. Unused mill residue – a low-cost resource – provides a small amount throughout. Harvesting residue is one resource that is not yet fully exploited but also has limited availability unless harvesting rates increase above current levels.

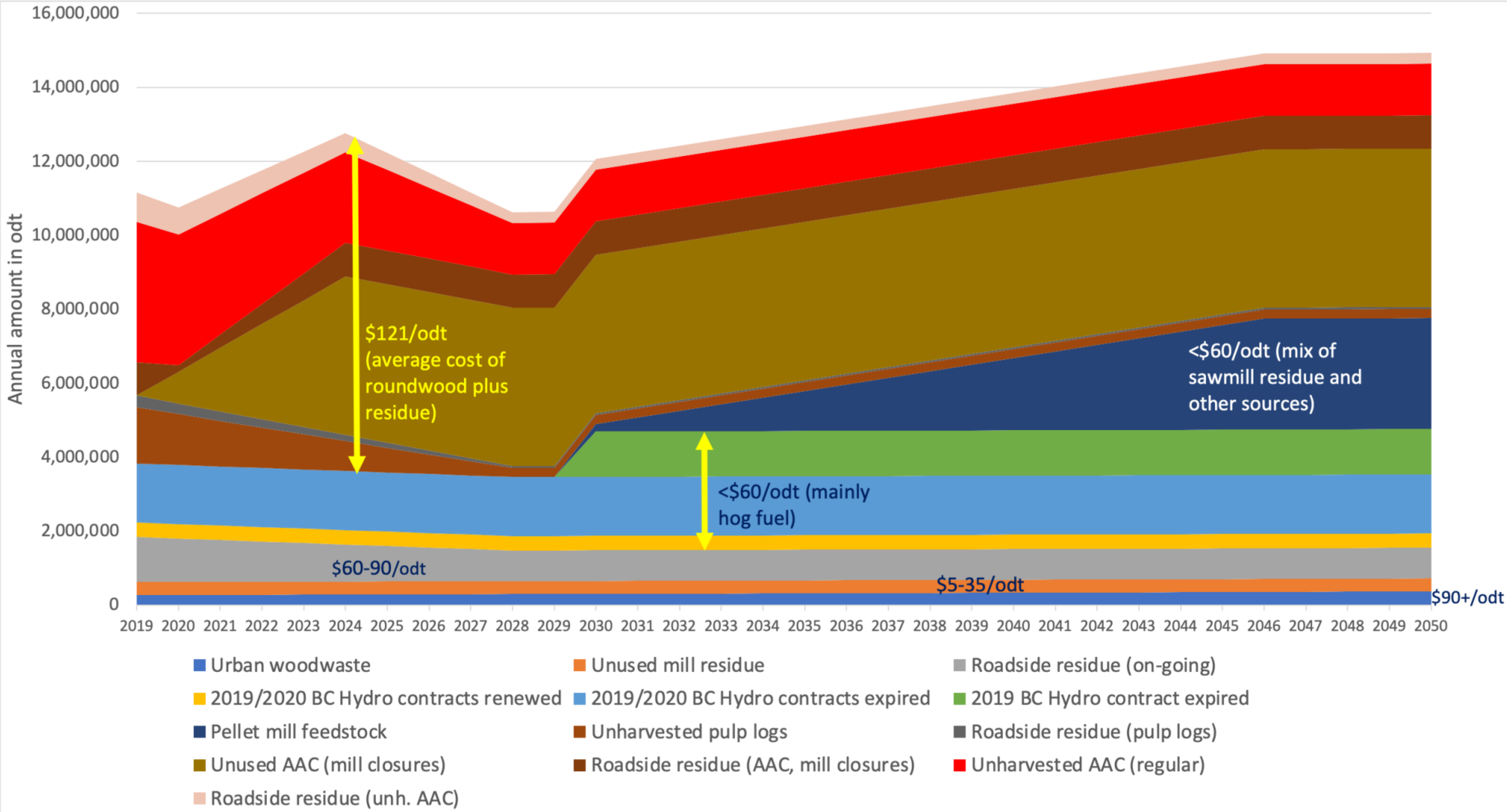


Figure 11 Assumed Amounts and Changes in Availability of Wood Fibre between 2019 and 2050

Table 8 summarizes the graph above in numbers. The largest amounts of wood available are also the most expensive to retrieve, i.e., standing trees from unused AAC. Together with the roadside residue generated from harvesting additional trees, the estimated cost of this biomass in the model is $121 per dry tonne – about twice the amount assumed for the low-cost fibre resources.

The inclusion of residue currently used for pellet production implies a conversion of this industry towards renewable gas production for local use instead of pellet exports. Such changes may be very gradual and may remain incomplete. Only some of this potential may be available.

The AAC may be further reduced due to beetle kills or wildfires, or conservation issues, such as the desire to protect old-growth forests. This would affect both AAC and residue production. Previously mentioned caveats also apply, such as how much harvesting residue may be available. It is not entirely clear if BC Hydro contracts with mills exporting excess power will be extended in 2028. Some of these uncertainties are expressed as different scenarios in the next chapter.

Converting the total amount of wood available in 2030 (217 petajoules) to hydrogen at an efficiency of 66% would result in about 143 petajoules of gas. This amount does not consider alternative uses for this biomass, either from new sawmills, for chemicals production, or pellet production. The use of lignin is not included because there are more effective ways of using biomass. Not counting the most expensive resource, i.e., unharvested AAC (and related roadside residue), the total gas production potential is then only 60 petajoules in 2030.

Table 8 Total Available Forest Biomass (Technical Potential) in B.C. and Gas Production Potential

	2021-2023		2030		2050	
Source	**Million odt**	**PJ**	**Million odt**	***PJ***	**Million odt**	***PJ***
Unharvested AAC	3,792,151	69	1,394,417	26	1,394,417	26
Roadside residue related to above	796,352	15	292,828	5	292,828	5
AAC from mill closures	4,282,789	78	4,282,789	78	4,282,789	78
Roadside residue related to above	899,385	16	899,385	16	899,385	16
Unharvested pulp logs	1,519,373	28	246,751	5	246,751	5
Roadside residue related to above	319,068	6	51,818	1	51,818	1
Unused roadside residue	1,223,419	22	831,315	15	831,315	15
Unused mill residue	349,080	6	346,199	6	346,199	6
Conversion of pellet plants	0	0	0	0	*>3,000,000*	>55
Expiring BC Hydro contracts	387,856	7	3,212,437	59	3,212,437	59
Urban wood waste (CLD)	270,000	5	300,000	5	*364,000*	7
TOTAL	**13,839,473**	**253**	**11,857,939**	**217**	**>13,839,473**	**>273**

Assumptions: Harvesting continues at recent levels, only adjusted by known and expected mill closures. Mills will continue to use residue at current amounts to sustain their operations. Nothing from BC Hydro contracts will be available before 2029.

Pellet mills have long-term contracts and are only deemed to transition towards renewable gas production after 2030. Population growth in B.C. is about 1% per year (for estimating urban wood waste).

Unused roadside residue is conservatively estimated. A higher amount may be available based on sources discussed above. Additional roadside residue from new activities is estimated as 21% of the mass of round logs.

Grey numbers identify the most expensive resource (standing trees).

3.1.2. *Conclusions on Wood Fibre Availability*

Large amounts of wood fibre are, or may become, available in B.C., including unharvested trees (most), harvesting residue, and mill residue. Yet, only limited amounts are easily accessible and currently available at low pricing (see next section). As already found in 2019, almost no mill residue is currently available for new projects. The pellet and pulp and paper industries are focusing on harvesting residue to obtain additional residue. This residue is being recovered in only a few areas, partly because of the difficulties of retrieving fibre beyond a certain distance from the road. Other reasons are the costs of recovering fibre after the primary harvest. Finally, there are legal constraints with tenure holders restricting third-party access to waste fibre. The 2019 estimate of around 1.2 million tonnes is still deemed accurate, although recovered amounts have recently started to increase and will therefore soon reduce the remaining potential. On the other hand, improved and integrated harvesting approaches may increase the availability of such residue over the coming decade.

Accessing more residual fibre will require improved supply chains that integrate tree harvesting and residue recovery and use best available technologies to reduce the cost of residue recovery. Some opportunities may exist where no pulp or pellet mills currently exist to recover additional harvesting residue for new energy projects. Costs may then be affordable, given the shorter transport distances.

Another element that would increase fibre availability are clearer regulations regarding the allocation of forestry residue and the responsibilities of the tenure holder versus the residual fibre user. If a third party is given access to a tenure holder's harvesting area, using the same logging roads, liabilities should remain with the third party and not the license holder. Failing to resolve such issues increases risk for sawmills and has led to unnecessary red tape and difficulties in accessing residue. Continued funding through e.g., the Forest Enhancement Society is needed to develop and improve related supply chains.

Another new mechanism, currently being tested in the Fort Nelson area, is the takeover of abandoned TSAs, where sawmills or other mills have been shut down. This can open access to large sources of fibre but also requires a complete business concept that makes use of both non-merchantable and merchantable wood to maximize revenue and allow projects to become bankable and operate profitably.

Summarizing thoughts on availability, it is important to understand that:

- Little unallocated mill residue is available throughout B.C. and only one or two new projects may be able to rely mainly on such resources.
- The mill residue previously used for excess power production at pulp and paper mills until 2019 is unlikely to become available for new projects. Sawmill closures have created a shortage of residuals. This biomass will likely be redistributed among existing users.
- Roadside residue appears to be the main opportunity for new projects but is already partially being used by pulp and pellet mills. Estimates of its availability vary by about a factor of two between models. Recovery becomes costly as the terrain becomes more rugged and distances to the user increase. Its availability is linked to harvesting techniques, such as skidding (most residue left in the forest) versus forwarding (more residue taken to the roadside). Changes in harvesting practices may be necessary to increase recoverable amounts.
- New stand-alone facilities to produce RNG or hydrogen will likely have to rely on more than one resource, such as some mill waste and some roadside residue, to secure their feedstock. This limits opportunities for locating such plants.

- Whole-tree harvesting, including non-merchantable wood, on abandoned TSAs where sawmills are no longer active may be a new opportunity as long as there is a high enough share of sawlogs in the stands to be cut that can be cost-effectively sold to sawmills. This concept is being tried in Fort Nelson but may not be directly transferable to other regions with limited pulp markets.
- Whole-tree harvesting for energy production may lead to a backlash from environmental groups – the scientific consensus is that harvesting is sustainable as long as a portion (usually around 20-30%) of the non-stemwood is left on the cut block but the B.C. community may still not accept large-scale operations of this type for fear of its impact on landscape and biodiversity.

3.1.3. *Feedstock Cost*

Typical feedstock costs, or the ability to pay, varies with industries. Pulp mills will pay up to about $100 per dry tonne for wood residue - possibly more for marginal amounts. Pellet mills produce a product of much lesser value and mainly rely on residue, only using small amounts of roundwood. They have typical feedstock costs of $50 per dry tonne but may also pay more for marginal amounts. Power plants usually use low-cost feedstock that costs no more than $35 per dry tonne.

Table 9 provides an overview of feedstock costs in 2015. Since then, harvested costs have increased around 30%, especially in the B.C. Interior. Stumpage fees were at about $0.25 per cubic metre in 2014 but have since increased to $20 (end of 2019).[42] Wildfires and beetle kills have reduced the resource to such a degree that longer hauls are necessary to obtain the same amount of wood. Standing timber would therefore likely cost in the area of $225 per dry tonne (delivered) today. During the second quarter of 2021, Interior sawlog pricing was reported as $128 per cubic metre for spruce-pine-fir (SPF) species and $50 ($123 per dry tonne) for pulp logs.[43]

The 2019 CFS report indicates costs of $5-15 per dry tonne for hog fuel, around $100 for residual wood chips ($120 on the coast), $40-55 per cubic metre ($98-134 per dry tonne) for pulp logs, $25-40 for sawdust. And $70-90 per dry tonne for delivered roadside residue (2018 pricing).[44]

Table 9 2015 Estimated Feedstock Procurement Costs in B.C.[45]

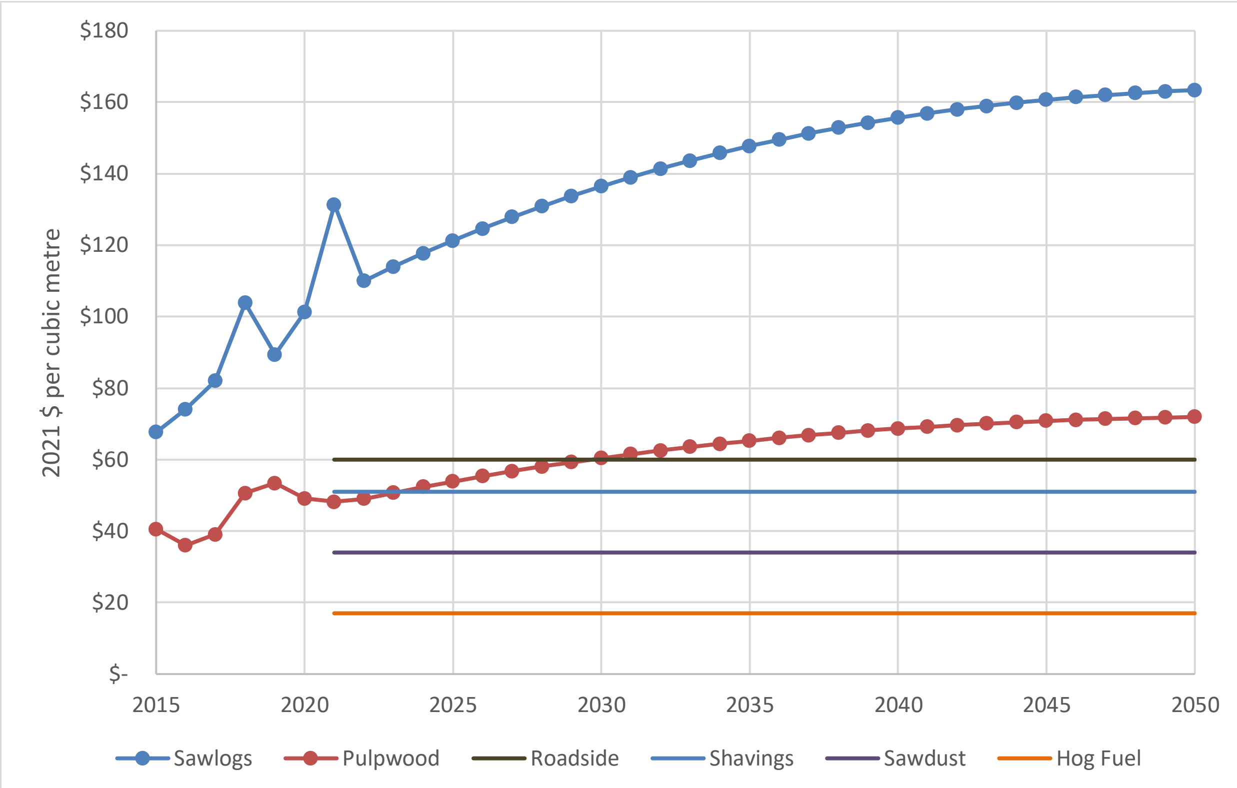
Fibre supply by source		Dry shavings	Saw-dust	Roadside residue	Hog fuel	Standing timber	Total/ average
	% supply	5%	5%	35%	5%	50%	100%
Regional fibre cost	in $/odt	$35	$20	%5	$5	$113	$61.25
Average delivery cost	in $/odt	$10	$10	$50	$10	$60	$49
Total delivered cost	**in $/odt**	**$45**	**$30**	**$55**	**$15**	**$173**	**$110.25**
	in $/m³	**418**	**$12**	**$22**	**$6**	**$71**	**$45.00**

[42] Jim Girvan and Russ Taylor (Fall 2020) "Can Stumpage Reform Save the B.C. Interior Forest Industry). *Truck Loggers*. from https://issuu.com/truckloggers/docs/truckloggerbc_fall_2020_final_lowres/s/11119030 (Accessed September 8, 2021).
[43] B.C. Interior Log Market Report for the three-month period of April 1, 2021 to June 30, 2021. Timber Pricing Branch, Ministry of Forests, Lands, Natural Resource Operations and Rural Development, Province of British Columbia, July 2021.
[44] B.C. Regional Surplus Biomass Fibre Supply Forecast. Industrial Forest Service Inc., March 2019.
[45] Wood Based Biomass in British Columbia and its Potential for New Electricity Generation. Industrial Forest Service Inc., July 2015.

The actual delivered cost of biomass depends on both harvesting and transport costs, plus any treatment at the plant that may be necessary (grinding, milling, de-barking, drying). No general cost can therefore be determined without taking the location and pre-processing requirements into account. Generally, roadside residue costs increase with distance and only a portion will be economically available. FPInnovations set the maximum cost at $60 per dry tonne and determined for various TSAs the amount deemed to be available at that cost, assuming a specific processing site. More can be recovered at a higher cost. The Forest Enhancement Society of B.C. provides one way of bringing down the delivered cost and increasing recovery rates. They contribute an average of $14 per dry tonne, allowing for a delivered cost of about $74 per tonne on average, for an amount of around 1.25 million cubic metres per year.[233]

Figure 12 shows the cost curves for woody feedstock in B.C., based on past trends, in 2021 Canadian dollars, not considering inflation. We assume that:

- Sawlog costs are based on SPF costs (Interior), although slightly lower costs are reported for other species, such as hemlock. Pricing includes logging road construction and replanting and has increased from $66 in 2014 to $128 per cubic metre in 2021 (average of $92 in 2014 to $166 in coastal TSAs), according to the Timber Pricing Branch. Some of the costs will also relate to increases in stumpage, which increased by 75% in the province's interior between 2020 and 2021. Cost increases in our model start at 5% per year in 2016, and decrease to a more modest 2% per year by 2050. Mill closures may reduce competition for logs and therefore lead to lower pricing. This cost represents the case where new facilities would access unharvested stands on their own account, as opposed to buying residue. Some economies can be expected due to whole-tree harvesting and are not accounted for in this cost.
- The cost of pulp logs increased from $40 to $50 per cubic metre since 2014, i.e., over seven years. This is about twice the 2% historical inflation rate, i.e., a 2% cost increase for pulp logs is presumed based on 2021 dollars. Cost increases in our model mirror the recent cost increases for sawlogs.
- Roadside residue costs rise with inflation. They are expected to remain constant in real dollars, at $60 per dry tonne on average. Yet, cost reductions due to supply chain improvements will lead to higher total amounts recovered.
- The cost of other residue is inflated at 2% per year to 2021 pricing from the 2015 pricing shown in Table 9, and deemed to continue to increase with inflation.



Note: Costs are expected to increase with inflation. This chart shows developments net of inflation

Figure 12 Expected Increases in Delivered Fibre Cost by Category, 2021-2050, in 2021$

3.2 Allocation of Resources

The forestry resources quantified above can be used for several of the technology pathways discussed below. Some of them therefore stand in direct competition for the same resources. Either one technology will win out over others, they will share the resource, or a staggered transition from one to another will occur. In any case, the total potential for each cannot be greater than the total wood resource. A brief outline describes the most likely outcomes:

- Lignin may be removed from black liquor to de-bottleneck recovery boilers but, once removed, higher-value markets are likely to be sought for this product. Although the energy value of lignin is fairly high at $30 per gigajoule, its use in lime kilns would require major modifications that deter its use. Recovery boilers will have to replace lignin with alternative fuels, such as hog fuel, to maintain an energy balance.

- Syngas will likely be produced at most B.C. mills using natural gas in lime kilns. This technology is deemed commercially available, even though it is still new. It is expected to be deployed gradually, starting with demonstration projects in the coming two years.[64] The scope of these gasifiers will be limited to the lime kilns and will therefore only consume a portion of the woody feedstock available, and only replace a portion of natural gas use at mills. Once established, it will likely continue for many years, possibly through 2050. Gasifiers could be used at cement kilns, veneer plants and others but we do not explore this in this report.

- Hydrogen from wood is a pre-commercial technology not yet proven at scale. It is not expected to be implemented before 2030 except for demonstration projects. It is considered to be less complex and cheaper than RNG production from wood and is therefore allocated the remaining resources not used up by syngas production. It is possible that hydrogen production may replace syngas production at some mills, or that stand-alone or separate hydrogen production will occur.

- RNG is not expected to be produced from wood due to the higher complexity of the technology and its very high capital costs. This may change after 2030 as new technologies mature, at which time it would compete with hydrogen production from wood. These dynamics are difficult to predict and hydrogen and RNG production may then be interchangeable alternatives. This is less relevant to this analysis, given the similar energy conversion efficiencies of these technologies.
- Alternative uses of forestry resources may occur but are not considered here. The production of platform chemicals or the continued or additional use for pellet production, for example, may affect the total resource available for renewable gas production.

3.3 Syngas Production from Solid Biomass

3.3.1 *Description of pathway and technology*

Syngas is the primary product of gasification (carried out at temperatures between 800-1000°C), and a co-product of pyrolysis (carried out at temperatures between 300-500°C). Gasification is a thermochemical process that uses a partially oxidized environment to generate syngas, which a mixture of H_2, CO, CO_2, and CH_4, as well as other small hydrocarbons. Oxidizing agents used in the gasification process include steam, oxygen, and air. While air is a cheap oxidizing agent, it produces syngas with lower LHV and HHV values - for biomass, HHV typically ranges between 4-7 megajoules per cubic metre.[46] The use of different oxidizing agents can deliver syngas with significantly higher HHVs - 10-18 megajoules per cubic metre for steam, and 12-28 megajoules per cubic metre for oxygen.[47]

The process of gasification of solid biomass requires the material to be dried (generally below 30% MC), reduced in size to particles or chips, combusted in the absence of oxygen (pyrolyzed), and oxidized to produce syngas. Of approximately 250 gasification facilities operating worldwide, only 10% use solid biomass as a feedstock.[47] While gasification technology itself is proven and operational (i.e. technology readiness levels (TRLs) of 7+), recent work by Binder et al. suggests that across total process chains TRLs are much lower, between TRL 5 (for dual fluidized bed technology) and TRL 3 (sorption enhanced reforming technology).[48] This is due to the lack of operational demonstrations which link all aspects of biomass recovery, processing, gasification, and gas product recovery. As such, lower TRLs would apply to new greenfield construction rather than adding gasifiers to existing pulp and paper mills. An overview of current technologies and their technology status is provided in Appendix A.

[46] Kitzler et al. (2011). Pressurized gasification of wood biomass - variation of parameter. Fuel Process Technology 92:908-914. https://doi.org/10.1016/j.fuproc.2010.12.009

[47] Solarte-Toro et al. (2018). Evaluation of biogas and syngas as energy vectors for heat and power generation using lignocellulosic biomass as raw material. Electronic Journal of Biotechnology 33:52-62. https://doi.org/10.1016/j.ejbt.2018.03.005

[48] Binder et al. (2018). Hydrogen from biomass gasification. IEA Bioenergy Task 33, December 2018.

3.3.2 *Cost Curves*

Syngas has multiple applications. Relatively few reports focus on syngas as a primary product, as most gasification processes are being optimized for hydrogen or for RNG production. Table 10 provides several sources informing about costs related to syngas from wood.

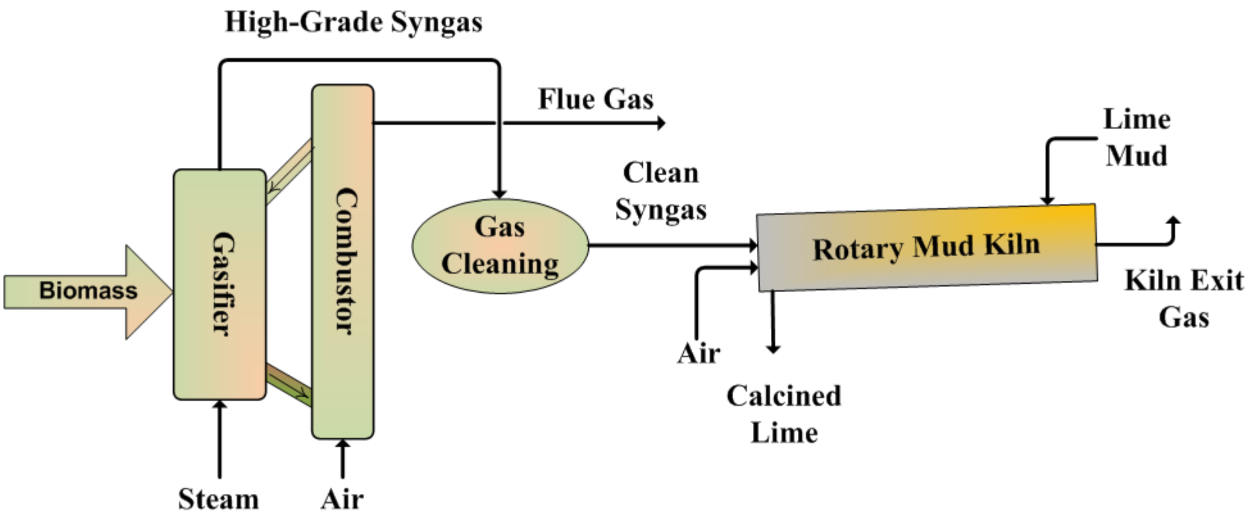
Table 10 Previous Cost Estimates on Syngas Production

Facility	Technology	Size	Energy yield	Gas cost	Capital cost	Source
Conceptual	Dual fluidized bed steam gasification	17.5 tpy		$1.22/m^3$ $17/GJ	$12.5 M US	Kim et al. 2011
Conceptual	Single-step air-steam gasification	600 ktpy	12 PJ/y	$6.45/m^3$ $92/GJ	n.d.	Nakyai and Seabea 2019.
Conceptual	Downdraft fixed bed gasification	27 ktpy	0.26 PJ/y		$13.82 M US	Mustafa et al. 2017
Lime kiln	Conventional circulating fluidized beds, or novel fixed bed	50 ktpy	0.8 PJ/y		$40-50 M US	Browne et al. 2019[227]

Capital costs for syngas production are variable, but seem to range between $1-2 million per 1,000 tonnes of material processed. Capital costs drop as plant size increases, so doubling plant size from about 25,000 to 50,000 results in a decrease of 50% in CAPEX. The capital costs used in this report are taken from Browne et al. because this reflects the B.C. situation and because they reflect the slightly lower costs associated with larger throughput.

This chapter describes the use of syngas in lime kilns of kraft pulp mills. Lime kilns are the last stage of recovering spent chemicals. To create the chemical calcination reaction with lime, kilns need to be operated at high temperatures. This is achieved by burning natural gas directly into the kilns. Across B.C., almost 6,000 gigajoules of natural gas are used in lime kilns.

Syngas can be a substitute for natural gas, more so than solid biomass, because its physical and chemical properties require little modification upstream and downstream of the existing lime kilns. In fact, medium calorific syngas could likely be used in parallel to natural gas, providing increased redundancy and a reduced conversion risk compared to other fuels, such as lignin (see chapter 3.6 below). The pathway is illustrated in Figure 13 below.



Source: Highbury Energy

Figure 13 Process Flow for the Production and Use of Syngas in Lime Kilns of Kraft Pulp Mills

Table 11 presents the default input parameters used to model gas costs. The capital cost was developed above. Operating cost parameters are based on Browne (2019.)[227] Capital costs are assumed to decrease over time due to technology improvements; the technology is fairly well understood and costs will likely drop in a fairly linear fashion. The default cost of wood is $60 per dry tonne but it is important to note that these costs could rise. While investment costs are substantive, feedstock costs are critical to the cost of these operations.

Table 11 Default Cost Parameters, Syngas from Wood for Use in Lime Kilns, in 2021$

Cost parameter	Value	Share	Comments
Annual biomass input	50,000 odt		Commercial-scale plant
Feedstock cost	$60/odt		Minimum scenario and first block of Maximum scenario
Gas yield	75%		Based on feedstock input, HHV
Capital cost	$50 million		In 2021
Capital cost	$35 million		In 2030 (-30%)
Capital cost	$25 million		In 2050 (-50%)
Amortization	$5.6 million	45%	20 years, 9.2%
Feedstock cost	$3.0 million	24%	
Personnel cost			
Labour, 9 FTE	$0.5 million	4%	
Management, 3 FTE	$0.3 million	2%	
Electricity	$0.5 million	4%	7.5 GWh/year (estimated value)
Natural gas	$0.02 million	0%	2,000 GJ/year (estimated value)
Other costs	2.5 million	20%	5% of CAPEX
TOTAL OPEX	$13 million	100%	
Gas production cost	$18/GJ		In 2021

Figure 14 depicts modelled syngas costs for use at B.C. lime kilns. We base our initial assumptions on Browne's 2019 report on syngas options for B.C. These costs evolve over time with reductions in capital offset in part by increases in feedstock costs. The primary cost of syngas systems is the cost of biomass used in the process, while capital costs are substantively lower. We use an average conversion efficiency of 70% on an energy input-output basis. The efficiency for syngas from biomass in the literature ranges between 0.42 to 0.88 gigajoules per gigajoule, so these efficiencies reflect the median conversion efficiency of systems available.

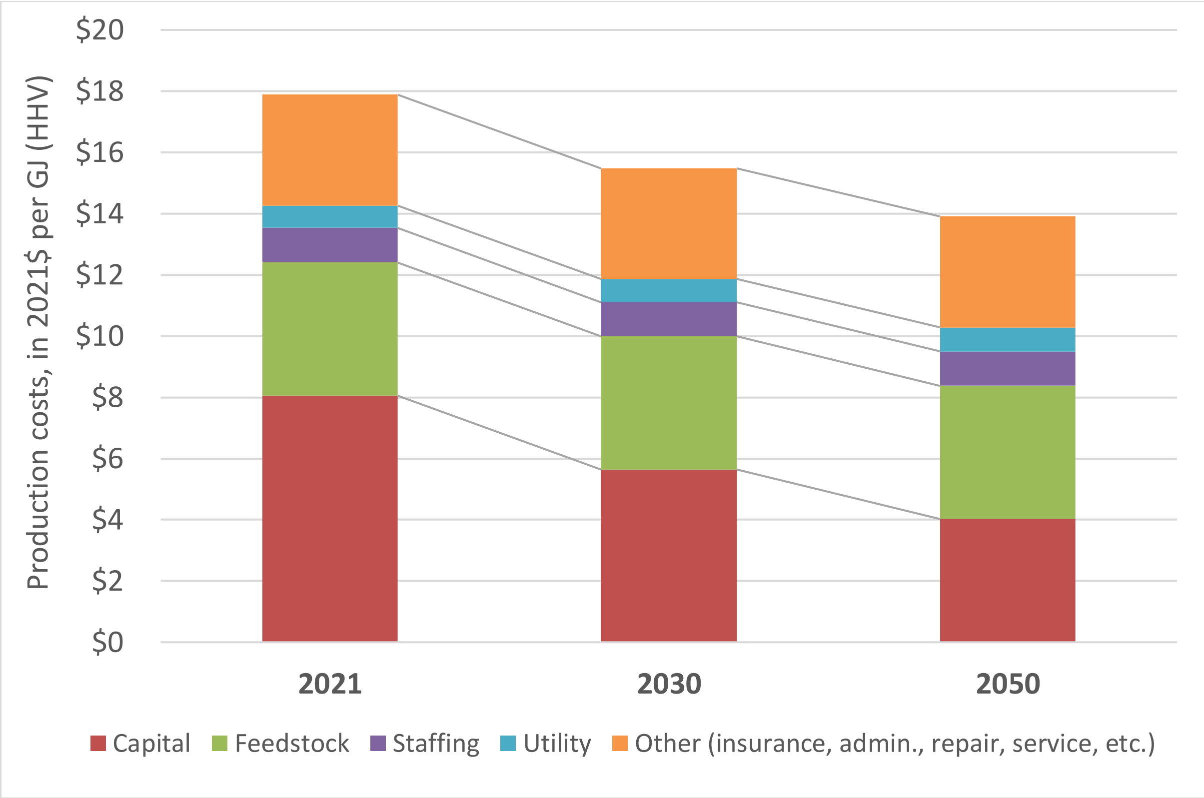


Figure 14 Modelled Cost for Syngas Use in a Pulp Mill's Lime Kiln

3.3.3 *Carbon intensity of syngas from biomass*

The use of syngas in energy production provides significant reductions in CO_2 emissions compared to natural gas on a life-cycle basis. Use of fossil fuels in the harvest and transport of biomass, and in the plant itself, contributes to emissions. Browne estimates that production of 0.8 petajoules per year of syngas would reduce GHG emissions associated with natural gas use by 41 kilotonnes CO_2e per year, in B.C.[227] Based on the model used to estimate the production costs above, B.C. values for natural gas-, electricity-, and feedstock-related GHG emissions for the production of syngas result in a CI of 3.2 grams per megajoule.

3.3.4 *Markets*

Producing syngas at existing pulp and paper facilities provides an opportunity to reduce natural gas consumption in lime kilns within these facilities. Browne estimated the impact of converting the three largest lime kilns in the province to syngas. He suggested that approximately 150,000 dry tonnes of biomass would be required per year to displace 2.4 petajoules per year of natural gas. He found that with a capital cost of US$40-50 million per conversion, and with variable operating costs of between US$5-10 per gigajoule, payback periods could be as low as 3-5 years (at $30 per gigajoule). Browne assumes that many of the capital costs for gasifiers are fixed.[227] Assuming this to be true, the market for syngas in B.C. is limited to a short list of facilities, and would consume about 150,000 dry tonnes per year. Browne considered the smaller kilns (nine in total) to be too small for economically feasible conversion. In total, these mills could consume up to 225,000 dry tonnes per year of biomass, and displace a total of 3.65 petajoules per year. Thus, the full potential of lime kiln substitution is 6.05 petajoules and would consume 475,000 dry tonnes per year of biomass.

3.3.5 *Infrastructure Needs*

Developing syngas for use in lime kilns will result in substantive savings, particularly with larger kilns. The technology is well understood and the economic feasibility for the three largest plants (150,000 dry tonnes per year in total) is strong. Expanded use of this technology with smaller lime kilns is more problematic as the capital costs are high, even for small facilities, and thus the cost of syngas goes up on a per unit basis. The best use case will focus on the largest plants and allow other biomass to be used for other renewable gas applications as discussed in following sections.

3.4 Hydrogen Production from Solid Biomass

3.4.1. *Description of Pathway and Technology Update*

As described in the previous section, gasification (or pyrolysis) produces hydrogen and CO among other gas species. These gases can be recovered through adsorption or via membrane separation.[49] CO can be further combined with H_2O via a water-gas shift reaction to produce additional hydrogen, CO_2, and a small amount of heat. The water-gas shift reaction is used to clean up syngas and produce a clean mix of CO_2, CO, and hydrogen (syngas) which can then be separated to provide a pure hydrogen stream. Key technological challenges common to most platforms include the production of better membranes to separate the gases, process simplification and high biomass costs. Commercial projects are now being planned using plasma-enhanced thermal catalytic technology, as pioneered by SGH2. An overview of current technologies and their technology status is provided in Appendix A.

3.4.2. *Cost Curves*

Examples of cost estimates in the literature are shown in Table 12. Capital costs for hydrogen-producing gasification systems are highly variable as a number of new technologies are being explored. In this study, we chose recent figures published by Binder for a large-scale dual fluidized bed gasifier, with throughput of approximately 50 tonnes per day, which reflects recent cost estimates for an established technology. We expect that capital costs for a 140,000 dry tonnes year facility will be approximately $160 million.

Table 13 presents the default input parameters used to model gas costs. The capital costs are developed above. Operating cost parameters are based on Binder et al. (2018). Capital costs are assumed to decrease over time due to technology improvements, especially after 2030. The default cost of wood is $60 per dry tonne, representing low costs. In this model, feedstock is the dominant cost, as the technology is scaled to a very large size. Note that the large plant size would suggest that transport of feedstock may become a substantive cost, which would be reflected in higher feedstock costs on a per-tonne basis.

[49] DOE Hydrogen and Fuel Cell Technologies Office. "Hydrogen Production: Biomass Gasification". Accessed August 18th, 2021 from https://www.energy.gov/eere/fuelcells/hydrogen-production-biomass-gasification

Table 12 Previous Cost Estimates for Hydrogen Production from Biomass

Facility	Technology	Size	Energy yield	Gas cost	Capital cost	Source
Conceptual	Dual fluidized bed steam gasification	218 ktpy	61% (LHV)	US$1.88/kg	US$71 M	Müller (2011)
Conceptual	Generic gasifier	700 ktpy	70-80 kg/odt	US$4.8-6.1/kg	US$214 M	Ruth (2011)
Conceptual	Generic gasifier	294 ktpy	78%	Not determined	n.d.	Meramo-Hurtado (2020)
Conceptual	Dual fluidized bed gasifier	12.5 ktpy		US$3.13/kg	US$75.3 M	Binder et al. (2018)
Conceptual	Sorption enhanced reforming	0.25 ktpy		US$6.37/kg	US$6.4 M	Binder et al. (2018)
Conceptual	Taylor Energy gasifier	700 ktpy	38.4%	US$2.49/kg	US$112 M	Raju (2019)
Sweetman Renewables	Unknown	30 ktpy			US$14M	Peacock (2021)
SGH2 Hydrogen	Plasma-enhanced thermal catalytic	42 ktpy	60% (LHV)	US$2/kg	US$55M [50]	SGH2 (2021), recycled waste

Table 13 Default Cost Parameters, Hydrogen from Wood, in 2021$

Cost Parameter	Value	Share	Comments
Annual biomass input	140,000 odt		Commercial-scale plant
Feedstock cost	$60/odt		
Gas yield	67%		Based on feedstock input, HHV
Capital cost	$160 million		In 2021
Capital cost	$144 million		In 2030 (-10%)
Capital cost	$80 million		In 2050 (-50%)
Amortization	$17.8 million	45%	20 years, 9.2%
Feedstock cost	$8.4 million	21%	
Personnel cost			
Labour, 18 FTE	$1.4 million	4%	
Management, 3 FTE	$0.5 million	1%	
Electricity		10%	60 GWh/year
Natural gas		1%	45,000 GJ/year
Other variable costs	$1.6 million	4%	1% of CAPEX
Other costs	$5.6 million	14%	4% of CAPEX
TOTAL OPEX	$29.4 million	100%	
Gas cost	$23/GJ		In 2021

Figure 14 depicts modelled hydrogen costs in B.C. The recent ZEN/BCBN report estimates the cost of hydrogen from biomass to be $2.14 per kilogram, based on a $180 per tonne feedstock cost and incorporating carbon capture and storage costs, which are included to offset non-biogenic emissions.[93] Incorporating all costs, this is about $8-12 per gigajoule. Although the assumed feedstock cost is much

[50] Ellingson (2020). World's largest green hydrogen project coming to Lancaster. https://www.bizjournals.com/losangeles/news/2020/05/19/worlds-largest-green-hydrogen-project-lancaster.html

lower, the model used for the present report shows somewhat higher costs per gigajoule, though still lower than those for RNG (see next section). Initial costs are predicated on high capital costs associated with early-stage plants, with related utility and operating costs (about $22 per gigajoule in total). The cost estimates towards 2050 bring capital costs closer to the Zen figures, at about $18 per gigajoule. An average conversion efficiency 0.67 gigajoules per gigajoule (feedstock input to gas output) was used. Efficiency ranges for hydrogen in the literature cited in this section range from between 0.56 and 0.67 gigajoules per gigajoule so we have opted for the most efficient conversion technology we are aware of.

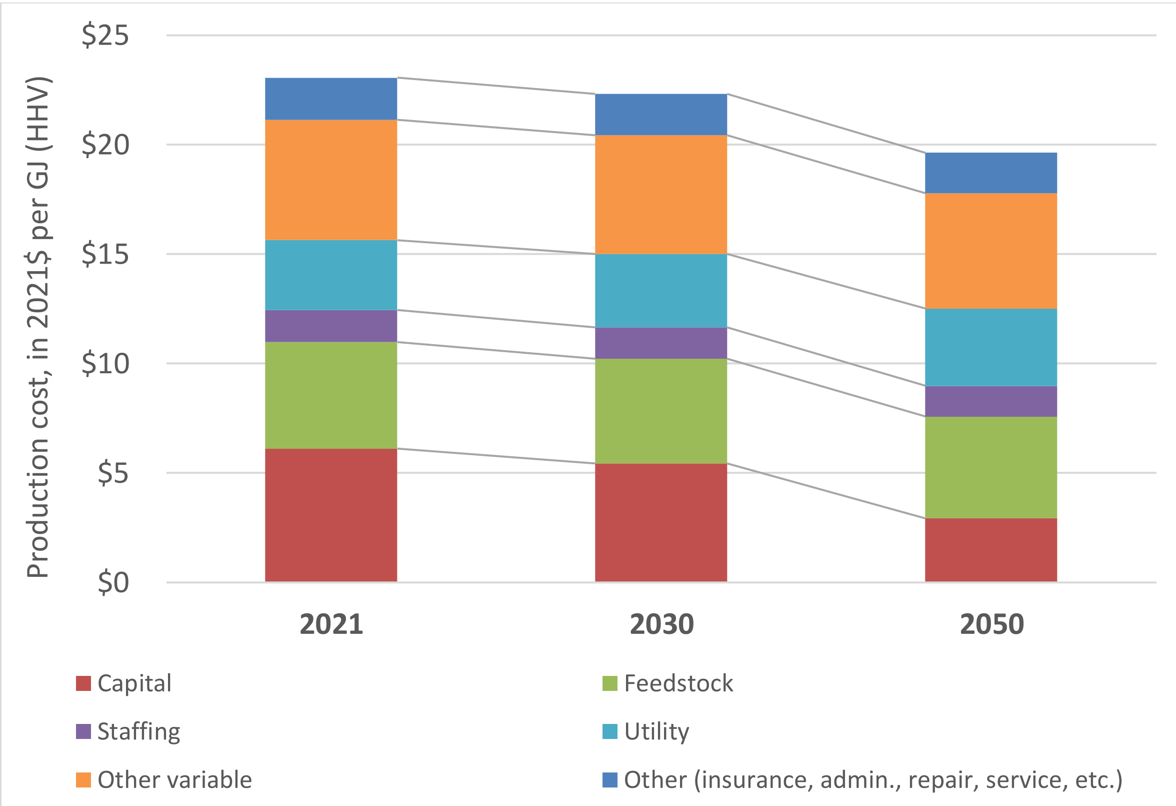


Figure 15 Modelled Hydrogen-from-Biomass Production Costs

3.4.3. *Carbon Intensity of Hydrogen from Wood*

Hydrogen from biomass has significant challenges. The very low hydrogen content in biomass itself (5-10%, tending to the lower end of this spectrum), means that most hydrogen produced is actually sourced from the water used in steam reformation. Conversely, the energy efficiency of steam reformation can be very high (56%).[51]

Biomass-sourced hydrogen has no direct GHG footprint. GHGs are still generated during the harvest and transport of biomass, and through the use of grid electricity and some natural gas in its production. Note that some technologies (e.g. SGH2) claim avoided (negative) GHG emissions of -188 grams CO_2e per megajoule H_2 (likely because of avoided landfilling).[52] The Hydrogen Council estimates the CI of hydrogen

[51] Milne et al. (2001) Hydrogen from biomass: State of the art and research challenges. IEA Hydrogen Task 16.
[52] SGH2 (2021). Technology. https://www.sgh2energy.com/technology/#hic

from wood as 1.7 kilograms per kilogram of hydrogen (12 grams per megajoule), which is the value assumed for this report.[53]

3.4.4. *Markets*

Sales of hydrogen into the gas network will depend on both updated policy targets and the cost of hydrogen produced from woody feedstock. As with other renewable gases from biomass, there is competition for wood feedstock, including cogeneration in mills, pellet production, and potentially renewable liquid fuels. By 2030, and possibly in subsequent years, several syngas projects are expected to be implemented and given priority over the more expensive and less mature hydrogen production technologies (see Section 3.2). Most hog fuel and roadside residues are likely to be used for syngas production by then, resulting in a theoretical total of up to 6 petajoules per year.

A large portion of the readily available woody biomass is currently used in power boilers of pulp mills. The power is partly used by the pulp mill and excess is fed into BC Hydro's grid under power purchase agreements that will expire before 2030. If this feedstock currently bound up in BC Hydro contracts for power exports to the grid (see Table 69 in Appendix A) becomes available and if there is a transition from pellet production to gas production in B.C., sufficient additional material will become available to also produce substantial amounts of hydrogen (see Chapter 5.0). A policy that reserves a certain amount of renewable gas for woody resources may create a captive market for hydrogen and/or RNG from wood (see Section 3.5).[227]

3.4.5. *Infrastructure Needs*

Developing hydrogen from biomass using gasification followed by a water-shift reaction will require significant development of new gasification infrastructure in B.C. Browne's report suggests that gasifiers capable of processing about 150,000 dry tonnes of biomass per year can be cost-effective, which in turn suggests that about eight facilities across the province would be sufficient to handle the 1.2 million tonnes of available biomass that we estimate from roadside residue. Facility locations would be determined via analysis of the gas grid and proximity to wood supply. Work also needs to be carried out on carbon capture and sequestration technologies to maximize the benefit of these processes.[93]

3.5 RNG from Woody Feedstock

3.5.1. *Description of pathway and technology overview*

The production of RNG from wood generally follows a stepped process that first gasifies the wood, cleans the syngas and then subjects it to a water-shift reaction (addition of steam) to add more hydrogen. Once the molar CO-H_2 ratio is about 1:3, a methanation reaction turns the syngas into a mixture with a high share of methane. Subsequent purification and compression provide pipeline-grade gas. Although these processes by themselves are all commercial, their combination is still pre-commercial. As opposed to syngas production to displace natura gas on-site, producing methane from woody feedstock requires some economies of scale. A much larger and more costly process will be needed to replace all natural gas used at a pulp and paper mill, and to insert additional gas into the pipeline system.

Appendix A identifies key technology providers for each of the main process steps (gasification, water-shift, methanation, and gas cleaning). The technologies from Sweden (GoBiGas/Valmet), the Netherlands (ECN) and the Austrian FICFB gasifier concepts are currently considered to be the best contenders for

[53] Hydrogen decarbonization pathways: A life-cycle assessment. Hydrogen Council, January 2021

gasification and gas cleaning. Methanation units can be provided by Haldor Topsoe, BASF or WOOD (Vesta). The University of Karlsruhe and ECN have also developed such technologies.

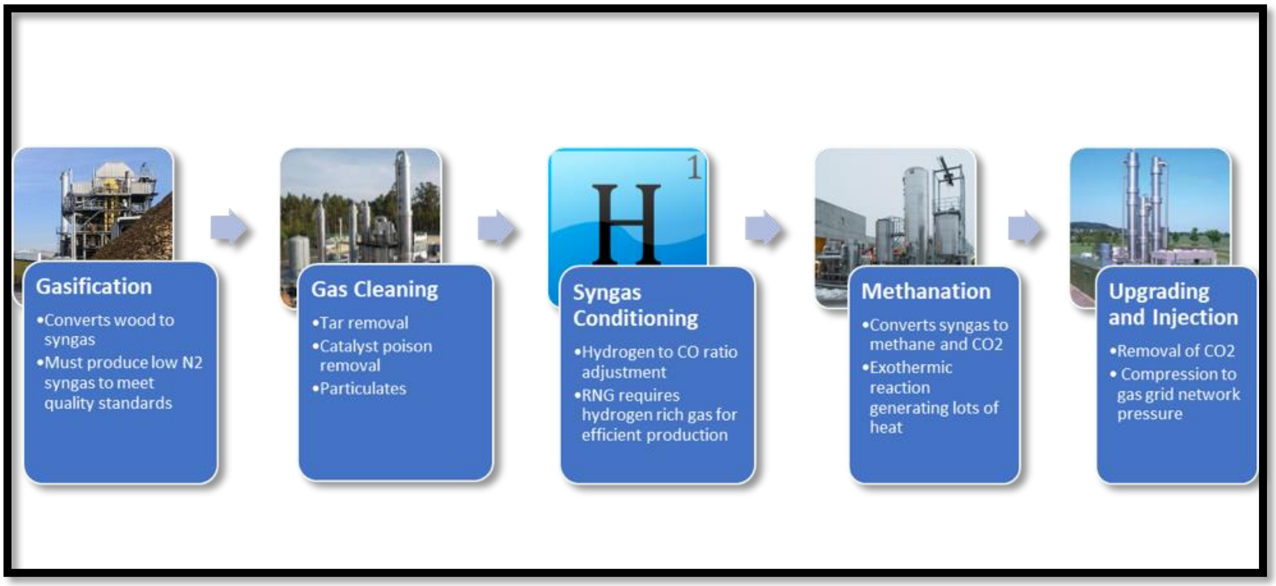


Figure 16 Generic Syngas to RNG Process

Biological methanation is an emerging technology that may soon replace the need for a chemical methanation step. Biological methanation occurs at low temperatures and pressures, similar to conventional anerobic digestion, rather than the high pressures and temperatures needed for conventional methanation.[54] Furthermore, biomethanation of syngas can yield significant savings as some contaminants, such as sulphur, do not need to be removed, meaning that the tar removal, water gas shift and guard beds can be avoided.[55] Tar removal, although likely to a lesser extent, is still necessary for biological syngas methanation. Challenges with biomethanation processes include the low solubility of syngas and the relatively low production rate.[56] The efficiency, at 50-65%,[57] is lower than catalytic methanation, which has a biomass-to-RNG efficiency of 65%-70%. Typically, syngas with high hydrogen content is best for biological methanation. Vancouver-based Highbury Energy is investigating biological methanation as a wood-to-RNG pathway. A small slipstream project testing biomethanation of syngas occurred at the gasifier in Güssing (Austria). The technology does not appear to be commercially proven with syngas but developments should be monitored.

[54] Grimalt Alemany, A., Skiadas, I. V., & Gavala, H. N. (2018). Syngas biomethanation: state-of-the-art review and perspectives. Biofuels, Bioproducts and Biorefining, 12(1), 139–158. https://doi.org/10.1002/bbb.1826
[55] Lorenzo Menin et al (2020). Techno-economic modeling of an integrated biomethane-biomethanol production process via biomass gasification, electrolysis, biomethanation, and catalytic methanol synthesis. *Biomass Conversion and Biorefinery*. DOI :10.1007/s13399-020-01178-y
[56] Sanjay Shah et al. (2017), “Methane from Syngas by Anaerobic digestion.” Conference: Proceedings of the 58th Conference on Simulation and Modelling (SIMS 58) Reykjavik, Iceland, September 25th – 27th, 2017. Accessed September 23rd 2021.
[57]Seemann M, Biollaz S, Stucki S, Schaub M. (2005). Bio-SNG from Wood – New Insight from a 10 KW Scale Test. U.S. DOE Office of Scientific and Technical Information, 2 pp. https://www.osti.gov/etdeweb/servlets/purl/20671613

Another potential paradigm changer is the pre-commercial process from G4 Insights. This Vancouver-based company proposes a simplified tar-free methane production process called hydropyrolysis that has considerably lower capital costs than the conventional gasification concept and is thought to be able to reduce the costs of methane production from woody feedstock. The process works by heating the biomass in a hydrogen atmosphere into char and a pyrolysis gas, the latter of which is then catalytically reacted to form methane. The mixture of methane, H2, syngas, water and carbon dioxide are separated. The methane is injected into the grid or used on-site. Some of the mixture is fed back to a char-fired reformer & PSA to generate and purify the necessary hydrogen.

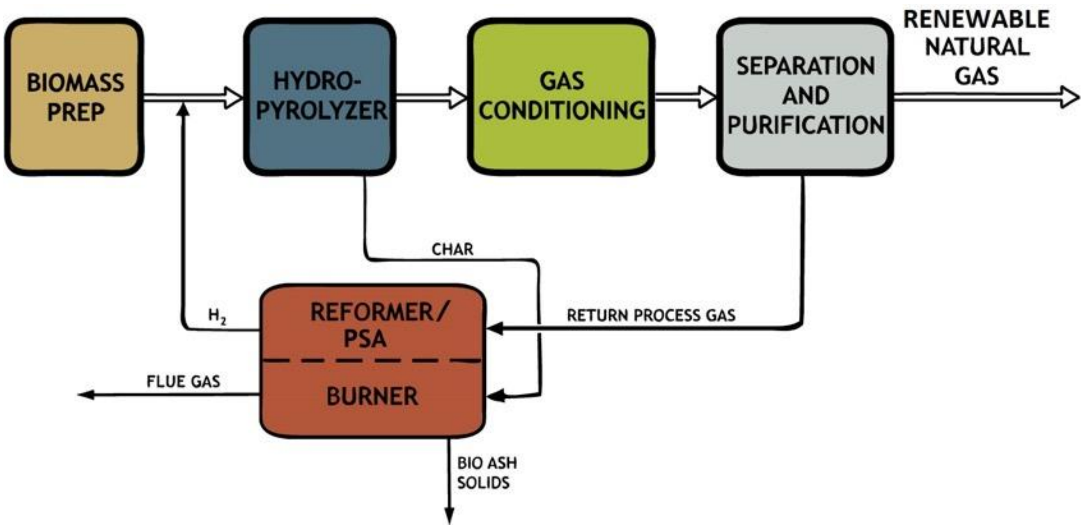


Figure 17 Pyrocatalytic Hydrogenation Wood to Methane Process

Emerging technologies around supercritical water may also open new avenues in wood methanation. Supercritical water uses the special solvent capacity of water with organic feedstocks when it is heated to a temperature greater than 374°C and pressurized above 22.1 megapascal.[58] Key advantages of supercritical water gasification include a higher carbon conversion capability and the ability to use wet feedstocks such as sewage sludge and other slurries without a significant energy penalty while Hydrothermal gasification or liquefaction can complement AD plants that have biosolids or digestate disposal issues as microplastics, some heavy metals, and pathogens are reduced or eliminated. Struvite, a desirable form of fertilizer can also be produced, aiding the nitrogen and phosphorous control benefits of the technology.[59] The efficiency is estimated to be 60-70%. Process heat recovery and conventional plant sizes are expected to be in the range of 2-3 tonnes dry mass per hour and to operate at temperatures of 600-700°C.[60]

As for the syngas produced, supercritical water gasification produces methane. The syngas can be fed into an anaerobic digester or be upgraded like conventional biogas.[61] Treatech's technology can generate

[58] ScienceDirect (n.d). "Supercritical Water Gasification". Accessed September 30, 2021 from https://www.sciencedirect.com/topics/engineering/supercritical-water-gasification
[59] Hyflex fuel (n.d) The HyFlexFuel process. Accessed September 30th 2021 from https://www.hyflexfuel.eu/technologies/
[60] GRTgaz March 2020). Hydrothermal Gasification (HTG)Converting liquid biomass into renewable gas https://www.igu.org/wp-content/uploads/2019/09/SG1.2-Hydrothermal-Gasification.pdf
[61] SINTEF Norway.(May 7th, 2021). "BioSynGas - Next generation Biogas production through the Synergetic Integration of Gasification"

around 150% more methane than anaerobic digestion. RNG can also be produced from a similar hydrothermal liquefaction process as a by-product, with 3.6 gigajoules being produced per tonne of dry feedstock. HTL plants are being developed in Vancouver and Prince George and could represent an additional RNG source as well as being a liquid fuel generator. The TRL of this technology is around 3-7 according to GRTgaz, the largest and most advanced appearing to be with SCW systems having a 2 tonnes per hour demonstrator in the Netherlands.[62]

3.5.2. *Production Cost Parameters*

For the production of RNG from wood, both capital and feedstock costs are key parameters. Table 14 summarizes the estimates made in a previous report for an RNG plant with a wood input of 200,000 dry tonnes per year, assuming a 67% energy yield based on wood input. The design includes a Carbona gasifier and a Halder Topsoe methanation unit. For operating costs (leaving out debt service), feedstock represents about a quarter, with other variable costs accounting for almost a third of OPEX. The payback determined with these costs is over 60 years. According to the study, an RNG gas price of $50 per gigajoule would be required to bring this to ten years unless subsidies can be obtained. Capital costs have a great impact on the economic performance of the plant: a 30% cost increase means the ROI at a gas price of $50 per gigajoule would drop from 19% to 15%.

Table 14 Cost Structure of Biomass-to-RNG Conversion,* as per Browne (2019)[227]

CAPEX	Million C$ (2018)	OPEX	Million C$ (2018)
Gasification	117	**Wood ($61.2/odt)**	12
Methanation	85	**Other variables**	15
Construction	184	**Labor & maintenance**	8.7
EPC fee	15	**Fixed**	10
Engineering	8		
Permits & consulting	4		
Commissioning & start-up	17		
General & administrative	4.7		
TOTAL	**410**	**TOTAL**	**46**

* 200,000 odt per year feedstock intake

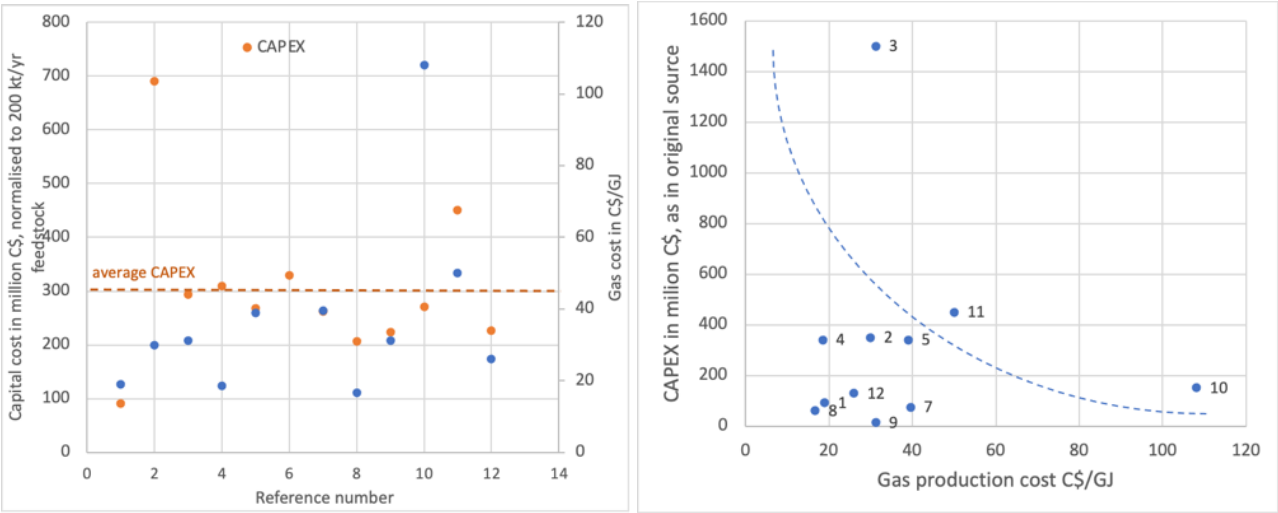
Since the methanation step is exothermic, this energy can be used as process energy. In theory, it could be used to dry pulp or lumber (depending on the site). RNG production will also increase power consumption at the mill considerably. To simplify the challenge, the approach followed here assumes that excess heat is used to produce additional power to reduce power imports from the grid.[65]

3.5.3. *Capital and Production Costs*

Figure 18 shows cost estimates for RNG production from wood. The sources for the figure are identified in Appendix B, by number (Table 60). The left graph normalises the literature values to 200,000 dry tonnes of wood input, making some assumptions about wood energy values and economies of scale for each plant (scale factor 0.8). The graph shows a wide spread of results, with capital costs varying by a factor of seven and gas costs varying from $20 to more than $100 per gigajoule. Gas cost estimates for the GoBiGas, ECN and two conceptual estimates concur with the estimate in Appendix B: at between C$30-40 per gigajoule. The REN Energy facility planned for Fruitvale, B.C. seems to be an outlier as it would only cost $130 million.63 It would use over 100,000 tonnes of wood waste, and produce about one petajoule of RNG.

[62] https://www.igu.org/wp-content/uploads/2019/09/SG1.2-Hydrothermal-Gasification.pdf (October 12th, 2021).
[63] https://www.canadianbiomassmagazine.ca/a-first-for-north-america-fortisbc-ren-energy-to-produce-rng-from-wood-waste/ (Accessed September 16, 2021).

Presumably, it would produce RNG at under $31 per gigajoule to qualify for a purchasing agreement with Fortis. The large spread of cost estimates indicates that the uncertainty regarding production costs of RNG from wood remains very high. The right graph plots the original CAPEX numbers of each source against the resulting gas costs. However, no logical cost curve showing economies of scale can be derived from this data.



Note: See Table 60 in Appendix B for sources of each data point. Data normalised to 200,000 odt per year

Figure 18 Normalized Cost Estimates for CAPEX and Gas Cost (RNG from Wood)

Capital cost estimates seem to converge around 200 to 400 million dollars for a plant with 200,000 dry tonnes of annual input. The cost estimate from the previous section therefore seems very conservative. For this report, $300 million in capital costs has been assumed. This is in line with the numbers developed for syngas and for hydrogen production in the previous sections. For 2030, no material change in capital or production costs is expected. After 2030, assuming that emerging technologies such as G4 Insights may become commercialized, a capital cost decrease of about 50% can be postulated. Because little is known about the G4 Insights process, the other operating parameters were not changed for this estimate. This may lead to a high cost estimate as the one-step process can be expected to have lower utility and personnel costs.

Based on the above, Table 15 presents the default input parameters used to model gas costs. The capital cost was developed above. Operating cost parameters are based on Browne (2019).[227] Capital costs are assumed to decrease over time due to technology improvements, especially after 2030. The default cost of wood is $60 per dry tonne but higher costs have also been modelled. High amortization costs clearly dominate operating costs, even with the somewhat generous assumption of a 20-year payback. Feedstock is the second most important cost but is considerably less important than amortization.

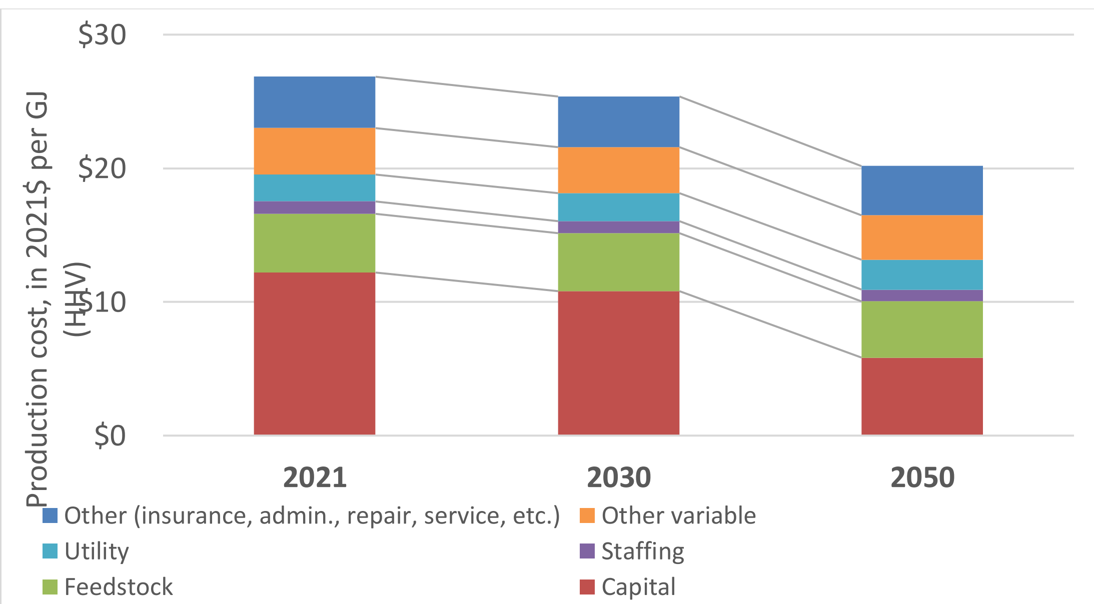
Figure 19 is the model output for RNG production costs from wood today and over the coming three decades. Capital costs are the main cost factor initially. Capital subsidies or better borrowing terms can positively influence gas production costs. The 20-year amortization period assumed is not acceptable to the forest products industry, which is known to seek amortization periods of only a few years for any investment.[64] This implies that subsidies or third-party financing (e.g., through a gas utility) would be required to implement such projects. Although feedstock is an important factor, it is only responsible for about 10% of production costs. Somewhat higher feedstock costs will therefore not have a strong impact on RNG cost.

[64] Bob Lindstrom, BC Pulp and Paper Alliance, in a conversation on Sep 27, 2021

Larger mills would likely implement syngas production during the first decade, removing around 150,000 dry tonnes from the available resource. With increased recovery of harvesting residue, about 1.2 million tonnes of this material would be available for new RNG production. This is sufficient for six facilities with an annual input of 200,000 dry tonnes, each producing 2.55 petajoules of gas per year (12.76 gigajoule per dry tonne.)[227]

Table 15 Default Cost Parameters, RNG from Wood, in 2021$

Cost parameters	Value	Share	Comments
Annual biomass input	200,000 odt		Commercial-scale plant
Feedstock cost	$60/odt		Minimum scenario and first block of Maximum scenario
Gas yield	67%		Based on feedstock input, LHV
Capital cost	$300 million		In 2021
Capital cost	$270 million		In 2030 (-10%)
Capital cost	$150 million		In 2050 (-50%)
Amortization	$33,333,633	45%	20 years, 9.2%
Feedstock cost	$12,000,000	16%	
Personnel cost		4%	
Labour, 26 FTE	$2,080,000		
Management, 3 FTE	$450,000		
Electricity	$5,124,600	7%	78,840 MWh per year
Natural gas	$376,631	1%	47,328 GJ per year
Other variable costs	$9,498,769	13%	
Other costs	$10,500,000	14%	4% of CAPEX
TOTAL OPEX	$73,363,633	100%	
Gas cost	$27/GJ		In 2021



* Feedstock cost at $60/odt

Figure 19 Anticipated Production Cost Development for RNG from Wood

3.5.4. *Carbon Intensity of RNG*

Counting wood feedstock as carbon neutral because it does not contain any fossil carbon, the feedstock procurement and process emissions still lead to emissions that need to be accounted for to arrive at a carbon intensity for RNG made from wood. For the Stockton site in the U.K., a GHG intensity of 16.8 grams per megajoule was determined.[65] This calculation took into account grid electricity emissions but also provided emission credits for the excess electricity produced in this case. These would likely cancel each other out in B.C. Another result assessed a process using the WoodRoll technology and arrived at 12 to 15 grams per megajoule for facilities of 4.8 and 18 MW capacity, respectively.[66] This includes credits for district heating that would rarely be available to a plant in B.C. Leaving out this credit but removing emissions from electricity use would lead to a very similar outcome as in the previous study. G4 Insights determined the GHG intensity of methane made from wood in California to replace motor vehicle fuels and arrived at 14 grams per megajoule.[67] The latter would imply that the GHG emission intensity will not be impacted in a major way by the technology used, since G4 Insights may be an emerging technology replacing the more conventional gasification approach. Any reductions are likely to be incremental, due to overall lower GHG emissions from transport and other sectors.

3.5.5. *Markets*

Total demand for renewable gases for injection into the provincial pipeline network is at least 15% (on a gigajoule basis) by 2030, based on the current renewable gas target set out in the CleanBC Plan. Additional potential could exist for local projects, where the gas produced would be used directly, or for exporting RNG through certificate trading, e.g., with the Californian LCFS market.

For renewable methane, the market after 2030 is theoretically equal to the total natural gas use in B.C. but actual sales into the gas network will depend on both updated policy targets and the cost of RNG produced from woody feedstock.

There is also competition for the woody feedstock itself. Alternative markets for woody feedstock exist in the power generation sector, including cogeneration at mills, which may become more attractive after 2032, when BC Hydro expects electricity production to start facing shortfalls. Competition may also come from pulp mills (for roadside residue), wood pellet mills and new concepts around producing renewable liquid fuels for direct use in vehicles or for sale to B.C. refineries. The markets that will ultimately develop and the ability of producers to pay for the woody feedstock will determine how additional feedstock will be allocated.

3.5.6. *Infrastructure Needs*

The existing 15 pulp and paper mills, where some of the feedstock will be available as hog fuel, are prime sites for the installation of RNG production facilities. They are generally close to the natural gas grid (see Figure 45 in Appendix C) and offer colocation benefits in terms of lower personnel requirements and shared infrastructure with existing mills. The estimated cost per facility is $300 million. With 26 new facilities for the Maximum scenario (Section 5.4), the total investment would come to $7.8 billion. These costs do not include additional pipeline or transport costs to take the RNG produced to an injection point. If any of the plants were to be situated at a distance from the pipeline network, additional costs would ensue.

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[65] Low-Carbon Renewable Natural Gas (RNG) from Wood Wastes. GTI, February 2019.
[66] Held, Jörgen and Olofsson, Johanna: LignoSys - System study of small-scale thermochemical conversion of lignocellulosic feedstock to biomethane. Renewable Energy Technology International AB, 2018.
[67] http://www.g4insights.com/environmentalbenefits.html (Accessed September 17, 2021).

3.6 Lignin as a Replacement Fuel for Natural Gas in the Pulp Industry

3.6.1. *Description of pathway and technology overview*

The GGRR has been amended to enable the gas utilities to work with pulp mills to displace natural gas used at their sites. Lignin is a by-product of the chemical pulping process and when extracted, can be used as a fuel in lime kilns at kraft mills. Wood fibre consists of cellulose, hemicellulose, and lignin. Cellulose is the main component used for pulp. Lignin has been traditionally burned, partly as a fuel, partly to get rid of an unwanted by-product, and to recover the pulping chemicals. Instead of burning lignin as black liquor in recovery boilers it can also be extracted from the spent chemicals.

Because lignin has a high calorific value it can be used to replace natural gas used in a pulp mill's lime kiln. Even though many kraft pulp mills produce surplus steam, lime kilns are typically fuelled by natural gas. This final stage of recovering the original chemical (NaOH) is done in direct-fired rotary kilns that cannot be heated by steam. Dried and ground to a fine powder, lignin can be injected into the kiln just like natural gas, even though the sulfur content of untreated lignin is generally high, derating the kiln capacity and causing corrosion and unwanted effluents.

Lignin can be further processed and sold to offsite markets as a high-grade solid fuel or as a feedstock for bioplastics, resin, etc. Onsite and offsite use as a natural gas replacement is discussed below. Both pathways compete with using lignin as a feedstock for various chemical processes that generally fetch higher market prices than when used or sold as a fuel.

Lignin extraction also has impacts on a pulp mill's energy balance and output capacity. These implications can be understood by looking at the various processes involved. In the chemical pulping process, cellulose is extracted by 'cooking' the wood fibre in caustic chemicals called 'white liquor.' The white liquor turns black as lignin is dissolved in it. By evaporating the water and burning the resulting 'black liquor,' the original chemicals are recovered and, after calcining in the lime kiln, can be reused. Many of these processes require steam or natural gas (Figure 20).

Most chemical pulp mills use lignin as a fuel to heat and power various processes.[68] Extracting lignin creates a fuel shortage that needs to be made up for by additional biomass. The energy balance of the specific pulp mill determines how much lignin can be extracted before lower-cost wood fuel needs to be brought in to fuel a power and steam boiler. A mill would have to have a proper heat / mass balance done to determine the impact and benefits of lignin extraction.[69] Looking only at one of the two pathways would neglect the overall systemic impact of lignin extraction (Figure 21).

Pathway 1 - Lignin replacing natural gas in a lime kiln:
To create the chemical reaction with lime and for maintenance reasons, lime kilns need to be operated at high temperatures and are typically heated by natural gas burners. Wood cannot not be used as a fuel, unless it is completely dried and finely ground or gasified. Dry lignin, however, can be burned in injection burners with the flame injected directly into the kiln. Stora Enso in Finland fires kraft lignin as a fuel in its lime kiln to reduce natural gas use by 70%.[70]

Pathway 2 - Lignin replacing natural gas in other undetermined energy producing processes:

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[68] Wells, K. *et al.* 2015. CO_2 Impacts of Commercial Scale Lignin Extraction at Hinton Pulp using the LignoForce Process & Lignin Substitution into Petroleum-based Products.

[69] Lindstrom, Bob; Personal communication. B.C. Pulp and Paper Coalition, in an email on Sep 16, 2021

[70] Pulp & Paper Canada. 2013. Stora Enso upgrading Sunila mill to produce lignin.

Because lignin has a high calorific value (26 gigajoules per tonne, HHV), it is a denser and more valuable fuel than conventional woody biomass (17 to 19 gigajoules per tonne, HHV). Like the onsite lime kiln, it can be burned with some technical modifications in the secondary wood processing industry, e.g., in direct-fired lumber drying kilns, veneer dryers or as a supplemental fuel in wood-burning processes of the paper industry.

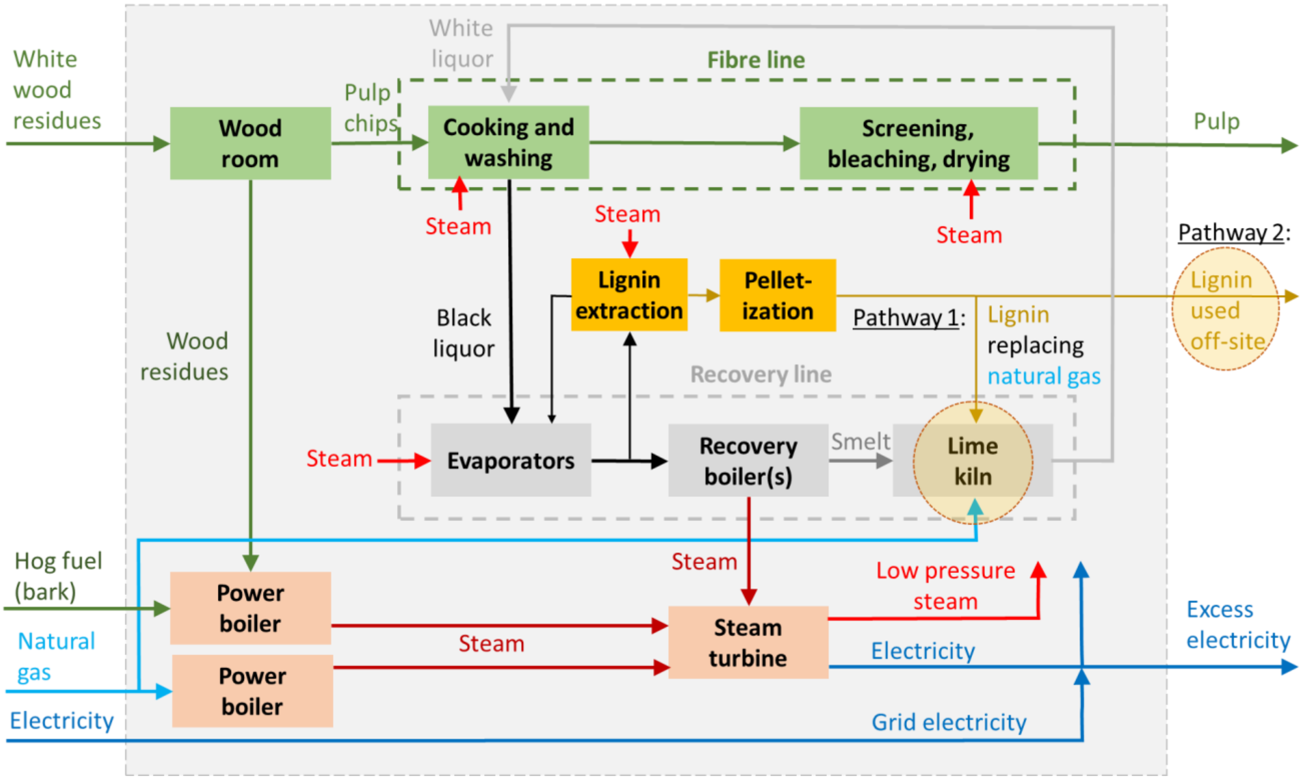

Figure 20 Processes and Energy Flows in a Pulp Mill[71]

The capacity of a kraft pulp mill is typically limited by the size of its recovery boiler, the most expensive part of a kraft mill.[72] Extracting lignin requires that less black liquor be burned in the recovery boiler, thereby allowing increased pulp output. This lignin, then, is no longer available as a fuel to heat other processes. Typically, no more than 15% of lignin can be extracted before additional heat sources are needed, such as low-value bark burned in a power boiler.[68] At a market value of $800 per tonne,[80] equivalent to $31 per gigajoule (HHV), it would be more profitable to sell lignin as a chemical feedstock and purchase additional natural gas at $8 per gigajoule than to burn lignin on site. Instead of burning high-value lignin, low-value biomass may be gasified to heat lime kilns.

[71] Graph based on: Hamaguchi M *et al.* 2012. Alternative Technologies for Biofuels Production in Kraft Pulp Mills—Potential and Prospects. *Energies* 53390:2288-2309 DOI. 10.3390/en5072288.

[72] Bruce Process Consulting for Alberta Environment. 2008. Technical and Regulatory Review and Benchmarking of Air Emissions from Alberta Kraft Pulp Mills.

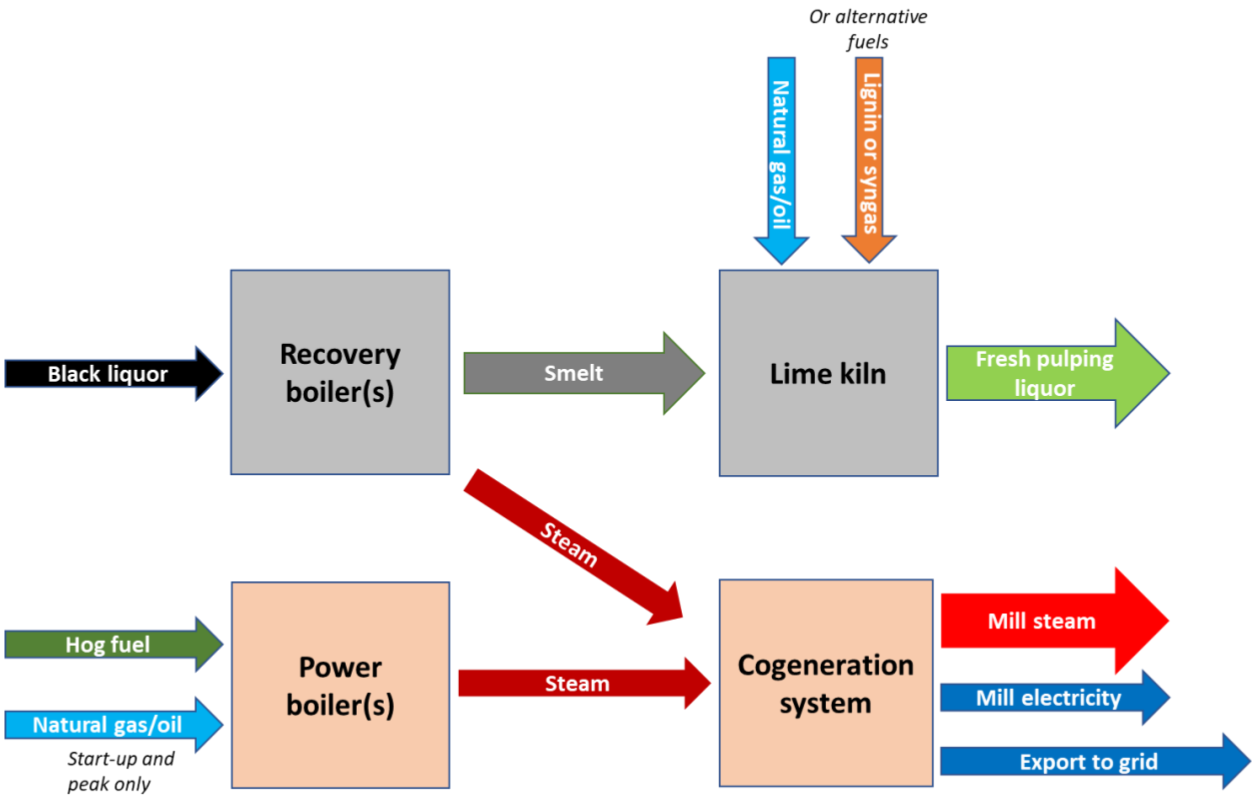

Figure 21 Energy Systems in Kraft Pulp Mills

Typically, around 1.5 tonnes of black liquor solids, consisting of lignin, hemicellulose and pulping chemicals, are created per tonne of pulp (cellulose) produced. Of the black liquor, around 15% to 25% of lignin (roughly 0.18 tonnes of lignin per tonne of pulp, at 10% moisture content)[73] can be extracted without compromising the operation of the recovery boiler. An average-sized kraft pulp mill in B.C. with a daily capacity of 1,100 tonnes of pulp can thus produce around 45,000 tonnes of lignin a year.[74]

The basic process of extracting lignin from black liquor is acidifying the caustic liquor and thereby precipitating the lignin contained in it. Washing, filtration and pelletization are downstream process steps. FPInnovations, combined with NORAM Engineering, refined the process by first oxidizing the liquor to prevent the release of hydrogen sulfate (H_2S), a toxic and foul-smelling gas. Secondly, the oxidation process reduces alkali content and thereby the need for carbon dioxide and sulfuric acid. Heat exchangers recover the heat created from the oxidation of the black liquor.

A competing technology is the LignoBoost system developed in Sweden.[75] A key difference between the LignoBoost and the LignoForce systems is that the latter oxidizes some of the reduced sulphur compounds. Oxidized black liquor has lower ash content and increased particle size of the precipitated lignin, making it easier to be filtered out. The LignoBoost system claims to have lower capital and operational costs. The LignoBoost system is marketed by Valmet and is commercially deployed at the

[73] Wells, K. et al. 2015. CO2 Impacts of Commercial Scale Lignin Extraction at Hinton Pulp using the LignoForce Process & Lignin Substitution into Petroleum-based Products.
[74] Hamaguchi, M. *et al.* 2012. Alternative Technologies for Biofuels Production in Kraft Pulp Mills. *Energies.* 53390:2288-2309. DOI. 10.3390/en5072288.
[75] Tomani, P. 2006. The LignoBoost Process. *Cellulose Chem. Technol.* 44 (1-3), 53-58 (2010).

Domtar Pulp plant in Plymouth, N.C. and Stora Enso's Sunila mill in Finland, producing 25,000 and 50,000 tonnes of lignin a year, respectively.[76]

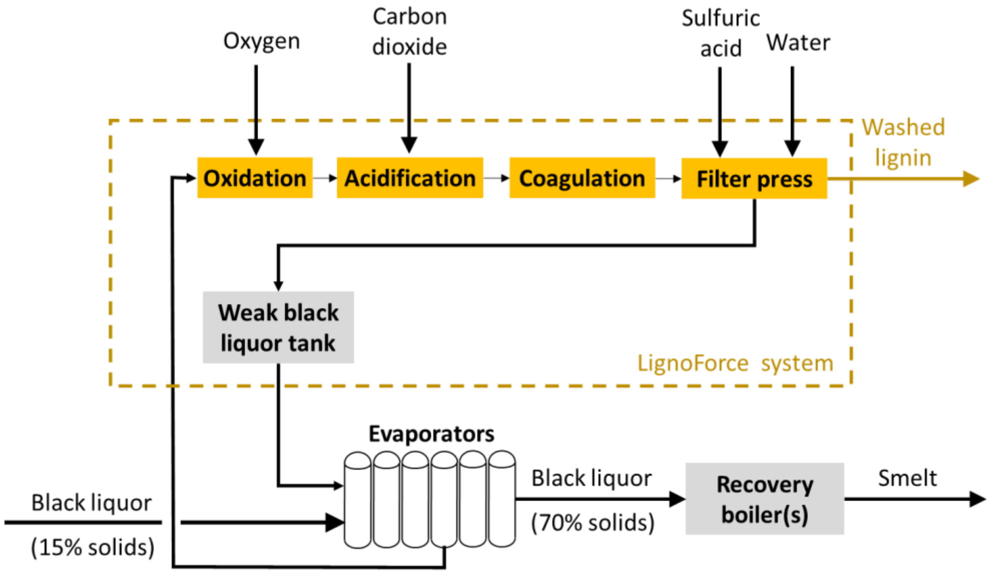

Figure 22 Schematic of the *LignoForce* Technology

One promising pre-commercial approach to producing lignin in a stand-alone plant comes from Pure Lignin Environmental Technology based in Kelowna, B.C. The process produces three separate products: cellulose, lignin and sweet liquor that can be used in the production of cellulosic ethanol. This nitric acid process increases yields compared to the traditional kraft process. A key advantage of the technology is its ability to use any type of biomass, including grasses, husks and waste wood, as feedstock. There is no commercial-scale plant in operation yet. A 50-tonne-per-day plant is said to yield a return on investment of 35%.[77] The company still appears to be at the demonstration stage with a one-vessel portable unit.[78]

3.6.2. *B.C. Potential for Excess Lignin Use*

Currently, no lignin extraction exists at any pulp mill in B.C. West Fraser operates four pulp mills in B.C. and Alberta. The company employed the LignoForce technology at its kraft mill in Hinton, AB. The technology could be replicated at other kraft mills in B.C. Each pulp mill would have the potential to produce more than twice the amount of lignin required to fuel their respective lime kilns. Theoretically, B.C. kraft mills could replace approximately 5.1 petajoules of natural gas and export the remaining 264,000 tonnes of surplus lignin off-site (Table 16).

[76] Valmet. 2017. The next generation LignoBoost – tailor-made lignin production for different lignin bioproduct markets.

[77] Pure Lignin Environmental Technology. 2020. Pure Lignin Environmental Technology (PLET) https://www.purelignin.com/ (Accessed June 11, 2020).

[78] Pure Lignin Environmental Technology. 2020. PLETS Demo Plant, https://purelignin.com/plet%E2%80%99s-plant's (Accessed Nov 27, 2021).

Table 16 Potential for Using Lignin as a Replacement for Natural Gas in Lime Kilns

Location of mill / name	Ownership	Annual capacity	Estimated potential for lignin extraction		Lime kiln natural gas use	Surplus lignin
		tonnes of pulp/year[79]	*tonnes/year*	*containing GJ/year*	GJ/year	*tonnes/year*
Prince George Intercontinental	Canfor Ltd.	329,000	41,100	945,000	461,000	18,000
Prince George Northwood	Canfor Ltd.	568,000	71,000	1,633,000	795,000	32,000
Prince George	Canfor Ltd.	316,000	39,500	909,000	442,000	18,000
Quesnel	West Fraser	349,000	43,600	1,003,000	489,000	19,000
Crofton	Paper Excellence	347,000	43,400	998,000	486,000	19,000
Kamloops	Domtar	343,000	42,900	987,000	480,000	19,000
Port Mellon	Howe Sound Pulp & Paper Corp.	372,000	46,500	1,070,000	521,000	21,000
Cedar	Nanaimo Forest Products	356,000	44,500	1,024,000	498,000	20,000
Mackenzie (closed)	Paper Excellence	0	0	0	0	0
Skookumchuk	Skookumchuk Pulp Inc	255,000	31,900	734,000	357,000	14,000
Castlegar	Zellstoff Celgar LP	461,000	57,600	1,325,000	645,000	26,000
TOTAL		**3,696,000**	**462,000**	**10,628,000**	**5,174,000**	**206,000**

Pulp mills do not produce more steam than they need for internal purposes. Removing lignin from this balance requires that an equivalent amount of energy is replaced, e.g., in the form of biomass. Instead of burning lignin in the recovery boiler, additional 'hog fuel' needs to go into the power boiler. That hog fuel needs to be imported, preferably from the region or area that the mill is located in. Additional fibre, however, may not be available. The forecast of fibre availability changes depending on the fibre model used or the region or area or zone the mill is located in. Some forecast a deficit for 2029 in certain areas and a surplus in other areas. Trucking woody residue from one area to another is an option and has been done in the past, albeit at a cost. Transportation and handling costs may exceed the value of the fibre, especially if the distance exceeds 200 kilometers one-way. The model underlying the cost projections below assumes that no import or export of fibre is done within assigned regions, areas or zones.

The theoretical potential shown in Table 16 is then constrained by the availability of fibre in the area or region that the mill is located in. Instead of 6 petajoules, the technical or resource potential is only 1.4 to 2.2 petajoules, i.e., a fraction (22% to 47%) of the theoretical potential. Figure 23 below shows the technical potential depending on the fibre model used.

[79] B.C. Ministry of Forest, Lands and Natural Resource Operations (2020). *2019 Major Timber Processing Facilities in British Columbia.* Victoria, B.C.

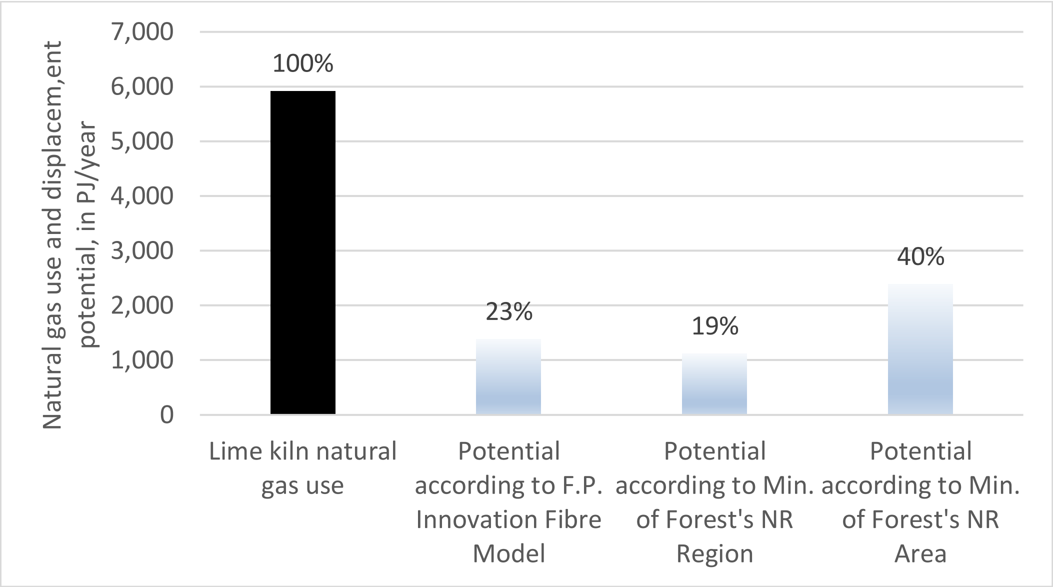

Figure 23 Technical or Resource Potential for Displacing Natural Gas in B.C. Kraft Mills

3.6.3. *Cost Curves*

The cost model shows that assuming the same feedstock costs, heating a pulp mill's limekiln with lignin is more expensive than heating it with syngas ($19 instead of $14 per gigajoule in 2030). This would apply even more when using lignin as a fuel off-site when transport costs are added in. Wherever lignin can be used as a fuel, syngas or even wood pellets likely achieve lower production costs. Moreover, lignin is likely to fetch higher prices when sold as a feedstock for non-energy markets. Current (2021) market prices for sulfate lignin are around $800 per dry tonne (Adt)[80], equivalent to $35 per gigajoule (LHV). Lignin, even in its unrefined form, is too valuable a product to use as a fuel (Figure 24).

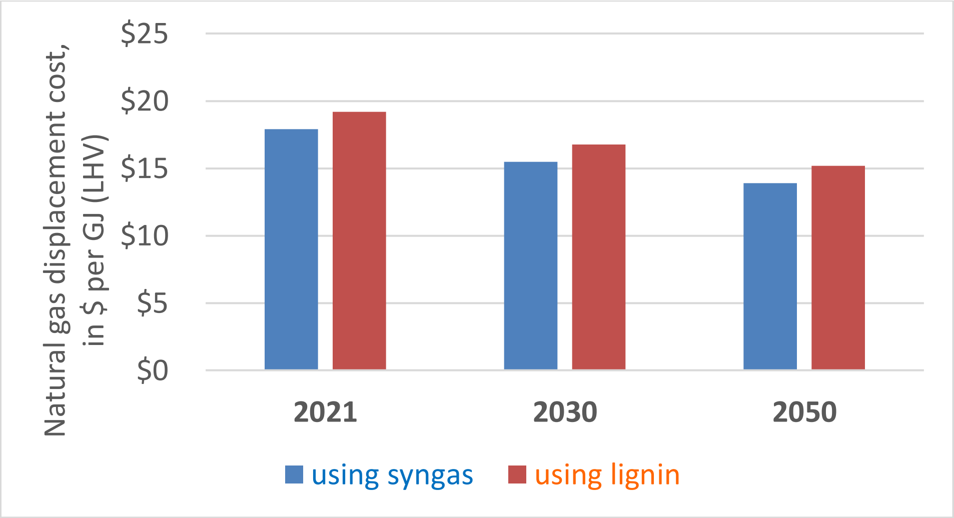

Figure 24 Cost of Replacing Natural Gas in Lime Kilns with Syngas and Lignin

80 https://www.forest2market.com/blog/more-rd-activities-open-up-lignins-feedstock-potential (Accessed September 1st, 2021).

3.6.4. *Carbon Intensity of Lignin Fuel*

Extracting lignin from a pulp mill's energy balance requires replacing it with biomass with an equivalent calorific value. Because lignin has a higher energy density (23 gigajoules per ADt, 26 gigajoules per dry tonne) compared to waste wood or hog fuel (10 gigajoules per green tonne, 18.3 gigajoules per dry tonne), a larger volume of wood fuel needs to be imported than the lignin extracted. Additionally, grid electricity has a small carbon footprint. Using the B.C. grid emission factor, less than 3 kilograms per gigajoule of calorific value would be emitted, 5% of the burner tip emissions of natural gas. Total carbon abatement would range between 54,000 and 118,000 tonnes of CO_2e per year, depending on the fibre availability model used.

Figure 25 Impacts of Lignin Diversion on Kraft Mill Energy Demands and GHG Emissions

Fuel	Amount		GHG emission factor[81]		Annual GHG emissions	
Feedstock (*wood to offset steam losses*)	45,000	odt/year	40.32	kg CO_2e/odt	1,814	t of CO_2e
Electricity	2,500	MWh/yr.	10.80	kg CO_2e/MWh	27	t of CO_2e
Avoided carbon emissions	n/a					
TOTAL			**2.67**	**kg CO_2e/GJ (HHV)**	**1,841**	**t of CO_2e**

3.6.5. *Markets*

Markets for lignin can be separated into energy use and non-energy use. The former is marginal in Canada. Beyond fuel, lignin has a wide variety of uses and applications, including opportunities to displace traditional fossil-based chemicals and products. There has been significant investment in lignin over the past 20 years. Historically, the lignin market for commercial application has been around 60,000 tonnes per year. Major markets for lignin include:[82]

- Adhesives
- Plastic/packaging materials
- Insulation
- Carbon fibre

Different lignin applications have various levels of commercialization. Thermoplastic and packaging applications are the most mature. Resins are an emerging application explored by West Fraser. Currently, lignin can replace up to a quarter of the polyurethane in foams. For carbon fibre applications, lignin-based materials can substitute for 50% to 100% of the fossil-fuel-based material used for carbon fibre[82] and is being investigated as an alternative way to reduce battery weight for lithium ion batteries.[83] Opportunities also exist to use lignin to replace the carbon black used for tires and other reinforced rubber products.[68]

[81] Factors published by B.C. Ministry of Environment: "B.C. Best Practices Methodology for Quantifying Greenhouse Gas Emissions", 2020, Accessed on Sep 26, 2021.

[82] Xiaofei Tian et al. (2016) "Properties, Chemical Characteristics and Application of Lignin and Its Derivatives" in Zeng and Smith eds. *Production of Biofuels and Chemicals from Lignin Biofuels and Biorefineries*. Singapore: Springer Science and Business Media.

[83] KTH Institute of Technology. 2014. Battery design could reduce electric car weight. https://phys.org/news/2014-06-battery-electric-car-weight.html (Accessed May 18, 2020).

3.6.6. *Infrastructure Needs*

Lignin has the potential to be used as a high-grade fuel where flame temperatures matter. Replacing natural gas in lime kilns is a potential niche application. Converting the existing gas burner with a solid fuel suspension burner is technically more challenging than burning syngas in the same kiln. The burner would have to be exchanged and the flame might have a different shape, resulting in spatially different temperature gradients inside the kiln. This might affect the chemical reaction time, the wear of the refractory, maintenance, and downstream flue gas volumes. The flue gas treatment system, especially the particulate precipitators, would likely have to be changed. This is notably more expensive than using a medium calorific gas, such as syngas from a wood gasifier that would keep the existing equipment in place.

Currently, suspension burners are used where finely ground wood fibre is available, e.g., sander dust at particle board plants. The fine particles instantly ignite as they are injected into the hot combustion chamber, dryer or kiln. Start-up of suspension burners generally requires fossil fuel to heat up the refractory beyond the flash point of the solid fuel used, generally above 300°C. Suspension burners are best used in applications that operate 24/7 without interruption. This tends to be the case in large-scale applications, such as in the pulp and paper industry, the cement industry or petrochemical industry. These operate continuously throughout the year. The sheer amount of lignin that would be needed to fuel these industries and the associated need for fuel storage, however, makes heavy industry an unlikely candidate for using lignin as a fuel.

For transport, lignin is usually compressed into pellets, see Figure 26 below. The material can then be transported in the same vessels as pellets of grain. 'Black pellets' made with, or entirely of, lignin have been used as a fuel in other parts of the world, for example in Russia where lignin is abundant as a by-product of wood alcohol production.[84]

In the Canadian context, the authors of this report consider lignin to be too valuable a product to use as a fuel. An exception may be adding lignin to enhance the calorific value and improve the physical properties of wood or herbaceous pellets used as a fuel. Wood is a sturdy material because lignin is the natural binder. In wood pellets, lignin is the material that creates dense, durable pellets. To get the same quality from pellets produced using plants with lower lignin content, such as straw, a binder must be added during the process. Lignin is a natural resin that can also be used to improve the quality of biomass pellets. Pellets without binding agent may decompose during conveying and storage, forming hazardous gases such as carbon monoxide and hexanal. Adding lignin to pellets may reduce safety concerns and occupational health problems such as wood dust exposure, fire and explosion risks. However, the increase in fuel value has to be balanced with the cost of adding lignin.

[84] Bioenergy International, "Lignin Pellets – from residual product to valuable biofuel," May 2020, Accessed on September 26, 2021 at https://bioenergyinternational.com/pellets-solid-fuels/lignin-pellets-from-residual-product-to-valuable-biofuel

Figure 26 Lignin Pellets[85]

3.7 Recommendations on the Use of Woody Feedstock

While B.C. is a largely forested province, the amount of accessible and attainable woody feedstock has declined in the past year, partly as a consequence of drawing down mountain pine beetle-killed stands and partly due to disturbances, including wildfires. The Ministry of Forests has reduced the Annual Allowable Cut to approximately half the amount available before the infestation. With the projected mill closures, the amount of mill and forestry waste will be reduced further.

In the near term, the best strategy to displace fossil methane in the forest resources industry is to use syngas for use in lime kilns. This can only displace a portion of natural gas use by the industry but still has considerable potential. It will require less feedstock (around 50,000 dry tonnes per year for the largest kilns) and considerably less investment. The gas is also likely to be produced at a lower cost than pipeline-grade methane or hydrogen. These still require technology development to become commercial.

In the longer term, hydrogen or RNG production from solid biomass is an option that can potentially displace large amounts of fossil gas. Just six full-scale RNG plants may displace more than five petajoules of demand, and recovery and use of all available biomass (an unlikely scenario) could deliver as much as 145 petajoules in the form of hydrogen or methane. Although the required technologies to achieve this exist, they are not proven technologies so demonstration and further refinement are required. Based on previous work on the GoBiGas plant and other such ventures, the most suitable technologies need to be combined and operated at a smaller scale. Once this is achieved and the process has been shown to operate successfully on a continuous basis, a full-scale plant could be built. Given the high capital cost of these plants, utility and/or government partnerships are likely necessary to realize this potential. As the technology matures and, possibly, more advanced technologies with lower capital costs become available after 2030, gas costs from these pathways are expected to decrease.

[85] https://newsroom.domtar.com/lignin-pellets-plastic-bioalternative/

4.0 HYDROGEN FROM NON-BIOMASS RESOURCES

4.1 Description of Pathways: Blue, Green, Turquoise and Waste Hydrogen

4.1.1 The Hydrogen Opportunity

Approximately 70 million tonnes per annum of hydrogen are currently manufactured globally. The vast majority is used for industrial purposes, namely the manufacture of ammonia and the upgrading of liquid fuels in refineries. It is estimated that 95% of global hydrogen produced comes from steam methane reformation (SMR) of natural gas, resulting in a relatively high carbon intensity for the hydrogen generated. Multiple pathways exist to produce low carbon intensity hydrogen. An introduction to nomenclature that has been adopted follows.

4.1.2 Green Hydrogen

The most common description of green hydrogen is its production by the electrolysis of water, using emission-free power generation sources. Other green hydrogen manufacturing technologies exist, such as the production of hydrogen in nuclear reactors. These generally have low TRLs. The term 'green hydrogen' usually presupposes the use of renewable electricity from wind, photovoltaic, geothermal and hydro power as the energy sources for the electrolysis. These energy sources have low carbon intensities, in some cases close to zero.

4.1.3 Blue Hydrogen

The production of grey hydrogen via steam methane reforming (SMR) technologies is currently the most cost competitive and common hydrogen production process used globally. This hydrogen is used mainly for the production of ammonia for fertilizers and the upgrading of petroleum products in refineries and has high carbon intensity. When the CO_2 stream from grey hydrogen production is captured, and sequestered or used, the resulting hydrogen is called blue hydrogen. The sequestration, capture and use of CO_2 can occur through a number of pathways that include the injection of the CO_2 deep into the Earth's crust. An example is the Shell Quest Project.[86] This report will only assess the potential for blue hydrogen and not grey hydrogen.

Autothermal reforming (ATR) is a technology used to produce hydrogen for methanol and ammonia production. It is being proposed as a way to produce low carbon intensity blue hydrogen from natural gas because it allows carbon capture at higher rates than conventional SMR, and at a lower cost.[87]

4.1.4 Turquoise Hydrogen

Turquoise hydrogen is a more recent addition to the description for hydrogen that is produced by breaking down methane within a natural gas stream into hydrogen and solid amorphous carbon. The process is called pyrolysis and has the potential to produce a relatively low carbon intensity hydrogen. This is because most of the carbon by-product in the process is solid (black) carbon that mainly displaces carbon produced from other fossil sources. There are a number of natural gas pyrolysis technologies. Pyrolysis hydrogen production technologies use electricity to drive the processes and would be of benefit in B.C. given BC Hydro's low CI electricity. The use of amorphous black carbon is relatively common within industries around the world for applications such as the manufacture of rubber for tires, the use as pigment blacks in polymers and in printing blacks.

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[86] Shell Quest Project. https://www.shell.ca/en_ca/about-us/projects-and-sites/quest-carbon-capture-and-storage-project.html (Accessed September 7, 2021).

[87] Pembina Institute. Carbon intensity of blue hydrogen production. August 2021 revised.

4.1.5 Waste Hydrogen

Waste hydrogen is produced at two plant locations in B.C. The North Vancouver Chemtrade plant is a chloralkali facility that focuses on the production of chlorine for numerous applications. Chemtrade has sodium chlorate production facilities, based in Prince George. Approximately 18,500 kilograms of hydrogen per day, for both plants together, is produced as a by-product. Hydra Energy has partnered with Chemtrade to use some of the waste hydrogen to power dual-fuel Class 8 trucks.[88]

Pipeline injection of any waste hydrogen would potentially require increased natural gas use to replace the hydrogen that is not emitted into the atmosphere but is used to produce heat for the Chemtrade plants. Thus, minimal or no GHG reduction benefits would accrue when using all the waste hydrogen produced. Only a portion may be available as low-carbon hydrogen for pipeline injection.

4.2 Technology update

Table 17 provides a brief overview of hydrogen production technologies. Essentially, all elements of blue and green hydrogen production are commercial, with only incremental improvements expected in the near term. Some new technologies, such as plasma pyrolysis, are expected to contribute to turquoise hydrogen production in the coming decade. More detail can be found in Appendix A.

Table 17 Overview of Hydrogen Production Technologies

Technology	Improvements/Benefits	Limitations/Challenges	Key players and Game Changers
Electrolysis: PEM	Improvement in membrane current density and lowering platinum loadings. Capex and efficiency improvements. The benefit is the fast dynamic response capability for demand-side response grid stabilisation opportunities.	Efficiency not significantly improved and thus Opex. Electricity costs are the largest component of the total cost of ownership. Capex would be negatively affected as well	Suzhou Jingli, Siemens, Areva H2gen, ITM Power, Erredue SpA , H2B2, Elchemtech, CUMMINS, NEL Hydrogen, Plug Power
Electrolysis: Alkali membrane	Improvements in Capex reduction. Alkali membrane electrolysis is a mature technology. Benefit is the low Capex per MW	Insignificant cost reduction improvements. No further dynamic response improvements.	CUMMINS, NEL Hydrogen, Teledyne Energy Systems, McPhy, Yangzhou Chungdean Hydrogen Equipment, Asahi Kasei, Verde LLC, ThyssenKrupp, Toshiba
Electrolysis: SOEC	The benefits of SOEC include the high efficiency: 30% above incumbent technologies.	SOEC is not yet commercialised. TRL of ~6. Operates at high temperatures of around 700°C and in a steady stage mode.	Haldor Topsoe, Ceres Power, Toshiba

[88] Hydra Energy. https://hydraenergy.com/news/chemtradepressrelease. (Accessed September 7, 2021).

Technology	Improvements/Benefits	Limitations/Challenges	Key players and Game Changers
ATR - CCUS	Improvement in CO_2 capture in ATR plants versus SMR technology and potential cost reduction according to a Pembina Institute report.	Not as common in the marketplace as SMR plants. GHG reduction benefits are marginal.	Air Products. New plant in Alberta planned for 2024
SMR - CCUS	Improvement in CCUS is key to the successful deployment of blue hydrogen. Both higher capture and sequestration percentages and associated costs are developing. Large SMR plants are deployed globally and produce hydrogen at a low cost of under US$2/kg. Increased efficiencies of small units that can provide smaller modularity benefits related location.	According to the Global CCS Institute[89] there are 25 technologies in various TRL stages. Which of these succeed is still unknown.	There are 26 CCUS plants in operation around the world[90]
Partial Oxidation	Shell Gas Partial Oxidation (SGP). High TRL. More than 100 plants globally. Claimed 22% lower levelised cost of hydrogen for SGP technology compared with ATR.	Past market focus for this technology has not been on hydrogen production but to monetise low-value refinery residues, asphaltenes, heavy oils, gas or biomass by converting them into syngas	Shell
Methane pyrolysis	The various pyrolysis technologies offer a low cost of H_2 and opportunities to use and sell the solid carbon by-product	Mostly low TLR. Some have a high TRL.	

4.3 Feedstock and resource availability

4.3.1 B.C. Potential for Green Hydrogen Production

The primary parameters determining the potential for green hydrogen production via electrolysis include:

- The availability of renewable electricity. Focusing on BC Hydro's most recent draft 2021 Integrated Resource Plan (IRP)[91] that addresses both demand-side efficiency improvements and demand response programs, additional capacity needs are not foreseen until 2032 (however, a high electrification ['accelerated'] scenario indicates a need for power imports as early as 2025 and new power plants being added as of 2029, despite the commissioning of the Site C hydro facility, as per Table 18 in the plan's appendix). No mention is made in this draft report about the use of electricity

[89] Global CCS Institute, Technology Readiness and Costs of CCS (2021).
[90] Global CCS Institute, Global Status of CCS 2020.
[91] BC Hydro and Power Authority DRAFT 2021 Integrated Resource Plan. BC Hydro, June 2021

for the electrolytic hydrogen production. Transmission from electricity production sites or large sub-stations will play a role in site selection.

- Availability of potable water as an electrolyser feedstock. Each megawatt of electrolyser load capacity requires about 1.4 million litres of water per annum. This subject was addressed for a number of sites up to 300 MW plants.[92] Water availability was not an issue. The addition of a potable water filtration plant was the only requirement identified.
- Hydrogen injection into the natural gas grid is faced with a number of challenges and barriers that include:
    - Critical pipeline system components including embrittlement of steel.
    - End-user equipment tolerances and operating considerations.
    - Engineering assessments that would examine the safety, integrity and reliability of the gas company and end-user-owned assets.
    - Updates to pipeline standards and policy.
    - The establishment of mixed (hydrogen/methane) gas tariffs and insurance (the gas blend still needs to meet tariff requirements).
    - Pipeline capacity (including locating hydrogen-producing facilities near major pipelines to inject it into the B.C. grid).
    - Hydrogen separation technology.
    - Gas metering for blended gases, purity and requisite specifications.[93]
    - Finally, the upper hydrogen concentration limit in the B.C. grid needs to be determined.

The above leads to three possible concepts for implementing new green hydrogen production in B.C.:

1. One or more centralized on-grid facilities: BC Hydro indicated the ability to support 300 MW of electrolyser load capacity for green hydrogen production.[92.] According to recent discussions with BC Hydro, this can be increased if power demand is close to the new Site C dam or other large power generation plants. Beyond a few hundred megawatts of demand, BC Hydro could not to guarantee power deliveries for new plants in the coming decade. It may be possible to wheel electricity from other jurisdictions, but this may again depend on plant location and transmission capacities.
2. Wind or solar PV-generated electricity. Figure 28 indicates wind farm and gas network overlapping regions that may provide opportunities to build large (100-150 MW nameplate capacity) off-grid wind farms and electrolysers. Potential for consideration includes the B.C. mainland and offshore wind generation west of Vancouver Island. Off-shore wind farms may be very large, in the range of 300-700 MW. The limitations are then dictated both by the potential amount of hydrogen that can be injected into the natural gas grid and by the time required to get such facilities permitted, built and production commissioned.
3. A third opportunity is decentralized hydrogen production using large- and small-scale facilities such as the one being developed in Chetwynd[94] or the HTEC/Mitsui 5-megawatt project.[95] Grid-

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[92] Centralized Renewable Hydrogen Production in B.C. – Final Public Report. G&S Budd Consulting Ltd., July 2019.
[93] BC Hydrogen Study. ZEN Clean Energy Solutions, July 2019.
[94] https://biv.com/article/2020/01/green-hydrogen-plant-project-has-investor (Accessed September 8, 2021).
[95] https://www.htec.ca/htec-has-partnered-with-mitsui-co-canada-ltd-to-develop-electrolytic-hydrogen-production-project-in-british-columbia-that-will-provide-fuel-to-htecs-network-of-fueling-stations-and-hel/ (Accessed September 8, 2021).

connected facilities of this or a smaller size can rely on both hydro power from the grid, and solar or wind power from a nearby facility, putting less strain on the power grid. They could be developed in various regions and inject into the local grid, albeit at somewhat higher costs because of lower economies of scale.

Table 18 outlines the resulting estimates for new green hydrogen production potential in B.C. by 2030 and by 2050 (cumulative). The current (2021) BC Hydro draft Resource Plan extends to the year 2041 and does not consider any major new power production for hydrogen consumption. The addition of large amounts of demand would likely require adapting the resource plan. The possibility of wheeling electricity from other jurisdictions is not considered here but could potentially allow for the construction of additional electrolyser capacities. About 700 MW of electrolyser capacity is required to reach the provisional volumetric variable of 5% hydrogen in the pipeline network. Note that some power plants, such as wind-based generators, have nameplate capacities that are considerably larger than their average output. For example, 100 MW of average electrolyser output from wind will likely require wind farms of at least 250 MW nameplate capacity.

The 2030 technical potential for centralized grid-connected hydrogen production is based on opportunities to use grid electricity at locations that are relatively near BC Hydro power plant sites and major sub-stations. By 2050, BC Hydro can contract for new generation capacities (or import more power) and will then be able to connect additional green hydrogen plants. The exact amounts would depend on Utilities Commission approval and direct negotiations with BC Hydro.

The estimate for total resource potential considers information provided in the ZEN Hydrogen Study that estimates 5.4 GW of wind potential.[93] With the sites tentatively indicated in Figure 28, several large off-grid wind farms seem feasible in the Interior, along the gas pipeline network. Also considering offshore locations for very large wind farms (300-700 MW), this would amount to a total of 1450 to 2000 MW of installed wind power capacity. This would result in up to 800 MW of net average power output,[96] using a 40% capacity factor. Some of this potential may also be developed as on-grid facilities. Given long lead times, only one or two on-shore and no off-shore wind farms are deemed feasible by 2030. Beyond 2030, the potential for on-grid electrolyser farms will ultimately be determined by policy and Utilities Commission directives since BC Hydro or the private sector could add considerable new renewable generation. This may increase overall power pricing and therefore needs regulatory support. Five hundred MW of new electrolyser net capacity (about 1250 MW of wind farms) between 2030 and 2050 is deemed to be a reasonable estimate in this respect. Wheeling of low-carbon electricity from other jurisdictions may also be a possibility to increase on-grid electrolyser capacities. This option is not explored here but the technical potential depends on both legal constraints and transmission and interconnection hub capacities.

For small-scale, decentralized on-grid hydrogen production, the estimate assumes a plant size of 10 MW with up to five sites being developed by 2030 and up to 30 sites by 2050. Decentralized facilities may be built near the gas distribution grid, with lower input pressures. They could be linked to local renewable energy generation to supply some of the electricity needed. Larger facilities elsewhere may feed power into the grid commensurate with increased local demand. They may be close to hydrogen users in the Lower Fraser Valley. These potential estimates can be modified based on cost evaluations and the establishment of potential sites intended for the injection of hydrogen into the natural gas grid.

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[96] Real output will fluctuate with the wind resource. In an off-grid situation, this would require either adding battery storage to ensure stable power supplies at the average level or otherwise, building electrolyser farms with capacities close to the maximum output of the wind farm in order to minimise curtailment. In an on-grid situation, the grid can serve as a “battery”, thus reducing the capital investment required.

Table 18 Estimated Green Hydrogen Production Potential in B.C. (Electrolyser Capacity)

Concept	By 2030	By 2050 Technical potential	Total Resource potential
Centralized grid connected	300 - 500 MW*	1000 MW	2100 MW net** (from wind) Additional potential exists from e.g., geothermal, photovoltaic
Centralized off-grid	60 MW	600-800 MW	
Decentralized grid connected	10 - 50 MW	300 MW	
Total	**370 – 610 MW**	**~1900 MW**	**>2100 MW**

* Current limit for new on-grid demand by 2030; ** assuming an average capacity factor of 40%.

Figure 27 indicates five areas where large off-grid wind power plants could be implemented, including an off-shore site that would need to be linked to Kitimat and two areas along the northern section of the Westcoast Energy Pipeline System. In addition, offshore wind power plants west of Vancouver Island could be implemented. As Vancouver Island requires a gas pipeline upgrade to increase capacities delivered, the upgrade could be used to install a larger pipeline that can carry hydrogen produced on the Island back to the mainland. This could occur in a reversed flow if production capacities are large enough or through a parallel hydrogen pipeline. A large (500 MW) offshore wind farm could provide the electricity for electrolytic hydrogen production. The areas indicated appear to be good candidates, but this high-level overview does not replace the need for detailed resource assessments and an examination of siting conditions and other requirements to determine suitable locations. For example, the gas flow currently goes to Vancouver Island and Kitimat. Hydrogen injected may then either be used locally or may cause the flow to be inverted, which may pose engineering and cost challenges not considered here.

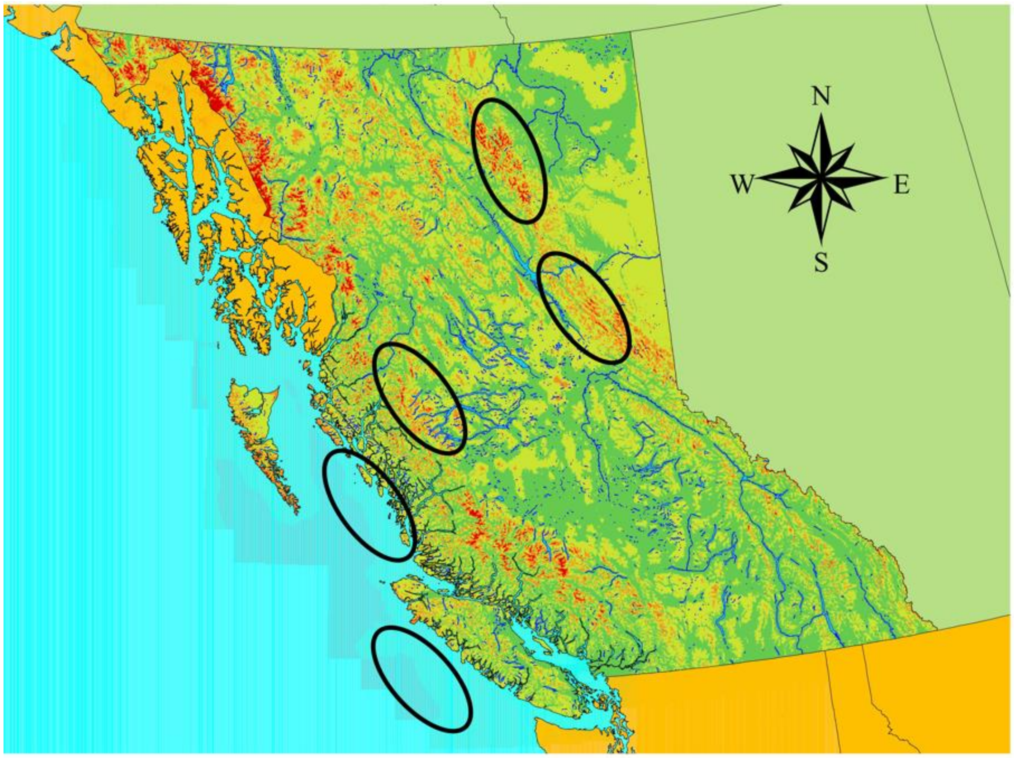


Figure 27 Promising Regions for New Wind Farms Supporting Large-Scale Green Hydrogen Production

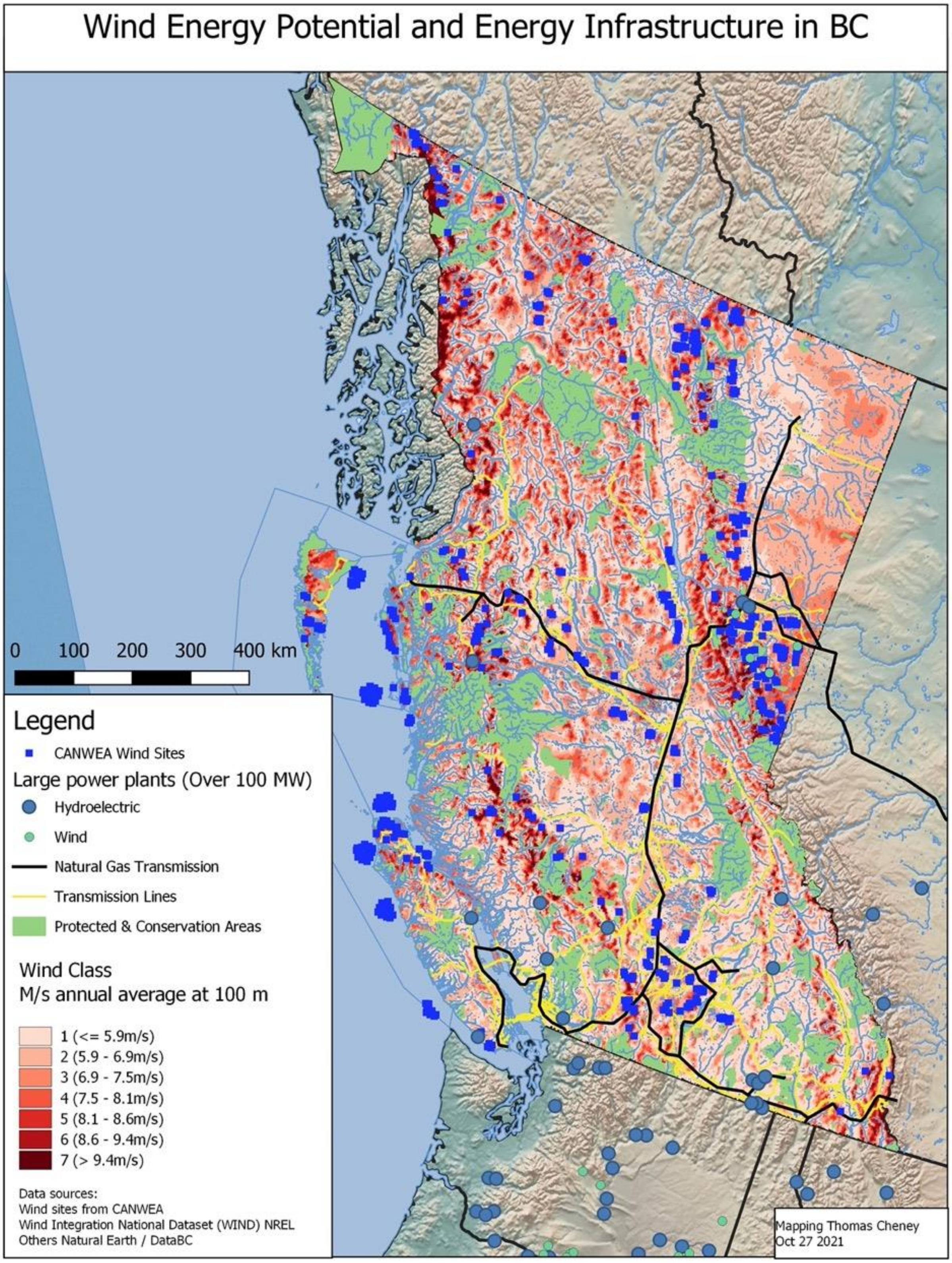


Figure 28 B.C. Predicted Wind Speeds and Potential Locations for Large Wind Farms Near the Gas Pipeline Network

For grid connected, large-scale hydrogen production, locations near large hydro facilities in the province's north appear to be ideal, in line with the regions identified for larger wind farms in Figure 27. In addition, larger facilities could also produce for industrial (direct) use and for grid injection, capturing additional economies of scale. They could produce for use in other applications that include, by way of example, fuel cell powered mobility (not within the scope of this study). Opportunities to capture and sell the by-product electrolytic oxygen need to compete with a cost of less than US$50/t from air separation plants. Colocation opportunities may exist that could use either the hydrogen or any by-product oxygen, or both. The two refineries (Burnaby and Prince George) could provide opportunities as they use large amounts of hydrogen and may continue operating if they were to move towards biofuels, using plant-based lipids and possibly biocrude. The latter, however, would stand in competition to gas production from the same resources. Although most of ground transportation may no longer use liquid fuels by 2050, air and marine transport may still rely on renewable liquid fuels.

4.3.2 B.C. Potential for Blue Hydrogen Production

The two primary feedstock types required for the production of hydrogen using SMR or ATR technologies are natural gas and water. The potential for the production of blue hydrogen is dependent on a number of factors, including:

- Carbon capture and sequestration is required to meet the proposed B.C. carbon intensity threshold for low-carbon gases of 36.4 g CO_2e per megajoule. This will require that at least 60% of the CO_2 is sequestered or used, based on a carbon intensity of 90 g CO_2e per megajoule for grey hydrogen. Geological sequestration capacity in B.C. is deemed large, as suitable sites exist close to where gas production is taking place (Figure 29). Overall estimated sequestration capacities have been used to derive the blue hydrogen potentials in the ZEN report.
- The adoption of ATR technology instead of SMR offers a simpler production stream, with a high concentration of carbon dioxide, which allows a higher percentage of carbon emissions to be captured. Capture efficiency is estimated at 90 to 95% in the conversion process and at its best, a carbon intensity of 11 kilograms CO_2e per gigajoule of hydrogen is projected.[106] It is potentially a more cost-competitive solution. However, unlike SMR, ATR requires the supply of oxygen as a feedstock. This may offer co-location benefits for green hydrogen production using the by-product oxygen as feedstock for ATR blue hydrogen production.
- The cost of the CO_2 captured and sequestered needs to be considered. For every kilogram of hydrogen produced via SMR, approximately 9.5 kilograms of CO_2 is produced. If the cost to capture and sequester the CO_2 were US$60 per tonne, an additional cost of US$0.57 per kilogram results for the cost of hydrogen produced.
- In terms of hydrogen injection into natural gas pipelines, one limitation is the amount of hydrogen the pipeline can technically tolerate unless the pipeline is converted to transport high hydrogen blends or 100% H_2. The total amount of gas that can be injected at any particular site will have to be determined and is site-specific. Given that 90% of natural gas produced in B.C. is exported, any target for the B.C. market will only have a minor impact on the renewable gas content in the main transmission lines. It is, however, possible that decentralised production of hydrogen on the gas distribution grid may lead to high hydrogen concentrations near the point of injection and would then need to include variable hydrogen flow rates to maintain the target injection percentage, especially in the summer when gas consumption may be three to four times lower than during some winter days.
- The size of the SMR plant and location along any of the natural gas pipe branches influences potential. Large plants may be limited in terms of where and how much hydrogen can be injected into the grid. Potential locations must allow either the use of CO_2 or its injection into geologic formations underground. The capacity to sequester the CO_2 below the Earth's surface in northern B.C. must

therefore be considered and may become a limiting factor. Numerous smaller high-efficiency SMR units and small CCUS modular technologies that capture CO_2 are being developed (see Section D.2 in Appendix A). These units can be placed in locations that would avoid the limitations associated with the use of large SMR and CCUS.

The overall potential for blue hydrogen production is very high. All current gas production in B.C. could theoretically be replaced with blue hydrogen, since production is about ten times larger than provincial demand. It is, however, unrealistic to expect that this will happen. By 2030, few plants will likely have been constructed. This is because the technology is relatively new and because lengthy permitting periods expected for the first B.C. CO_2 injection projects. The scenarios therefore only include limited blue hydrogen production by 2030. After this date, the industry is more likely to grow and may then obtain a large market share for low-carbon gas. The scenarios assume that up to 30 full-scale facilities may be built in the two decades between 2030 and 2050. Total potential by 2050 is based on the ZEN Hydrogen report.[93]

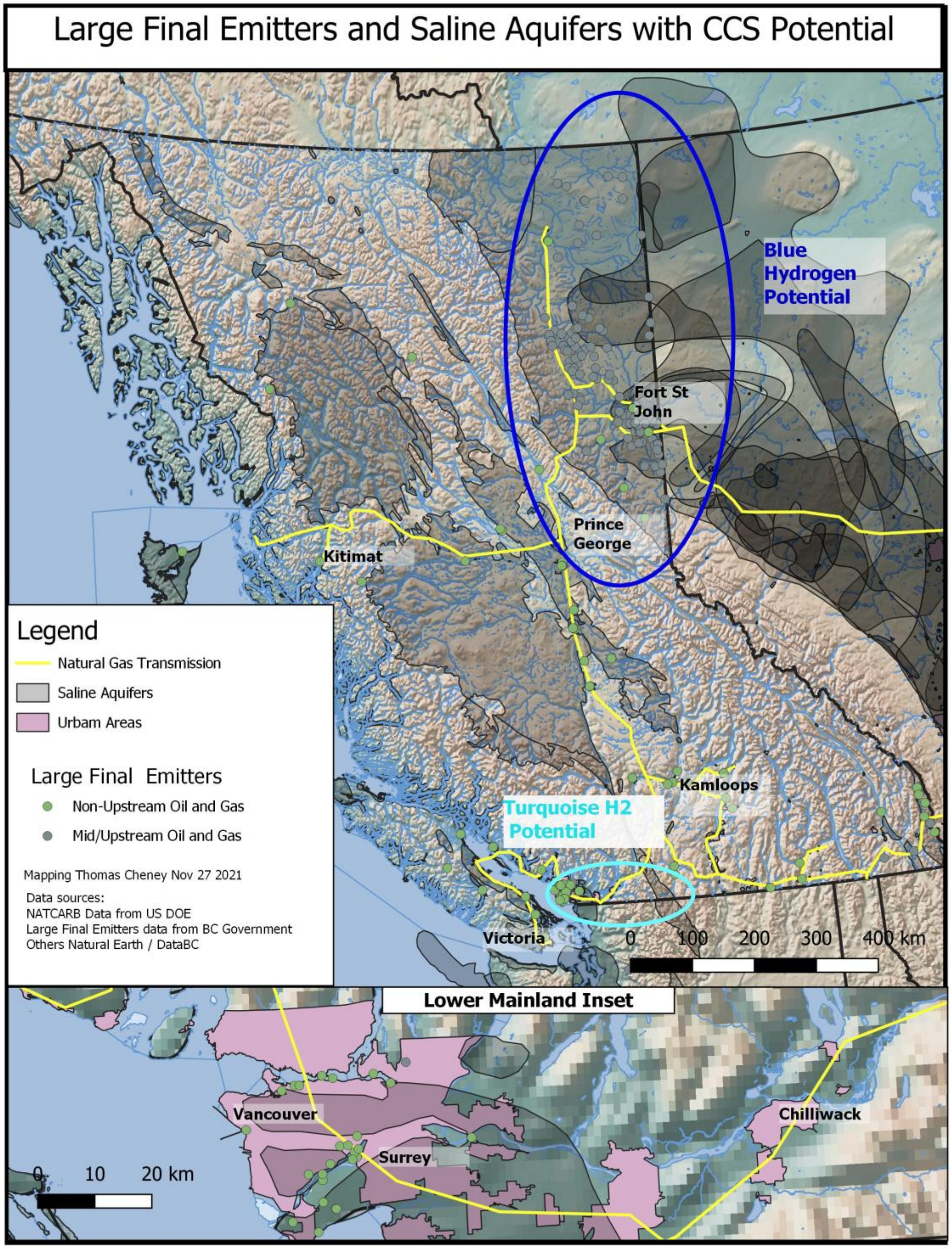
Figure 29 shows the northern area around Fort Nelson, where natural gas is produced, as the obvious region where blue hydrogen could be produced and injected, and where captured CO_2 could be injected into the ground. Turquoise hydrogen production, also indicated on the map, would more likely happen more downstream along the gas pipeline, near strategic export hubs (Kitimat, Vancouver) or near potential users of hydrogen or carbon black. This suggests that locations near refineries, where the hydrogen could be used directly, are also attractive.

4.3.3 B.C. Potential for Turquoise Hydrogen Production

A number of pyrolysis technologies have been considered in this report (Appendix A). These include plasma, fluidised bed, moving bed, molten salt and pulse methane pyrolysis. All technologies require natural gas as a prime feedstock. Using RNG would be a more costly alternative but could at the same time result in a negative-emission pathway if the carbon black produced is used in long-lived products. This section will focus on two technologies, Plasma Pyrolysis (Monolith Materials) and Pulse Methane Pyrolysis (EKONA Power). The former is chosen as this technology appears to be more advanced in terms of its TRL (see Appendix A). The potential to produce low-carbon-intensity hydrogen using a turquoise pathway depends on a number of factors, including:

- Similar to blue hydrogen, the location, plant size and allowable amount of hydrogen that can be injected into the grid, used in industrial hubs, or distributed through gas infrastructure and converted to 100% hydrogen are key.
- Methane pyrolysis yields solid carbon (high-value production output if sold as carbon black) with hydrogen as a (lower-value) by-product, which adds a revenue stream opportunity to sell the carbon as a pigment or rubber black. No CO_2 capture is necessary.
- The market for black carbon is large (US$18 billion per year and increasing[97]) so there is considerable potential for B.C. to produce this material while also making hydrogen. The projected market growth can be estimated as about 8 million tonnes by 2026. One facility in B.C. may only produce around 100,000 tonnes per year.
- The production cost of this process is close to zero once black carbon sales are factored in. Hydrogen could likely be sourced at no more than $10 per gigajoule from this source.

[97] https://www.alliedmarketresearch.com/carbon-black-market (Accessed September 30, 2021).



Promising regions for **blue hydrogen** and **turquoise hydrogen** production marked by ovals.

Figure 29 Potential CO_2 Sequestration Sites in B.C.

The potential for turquoise hydrogen, as with blue hydrogen, is very large. This resource could provide a large share of the low-carbon gas required to help achieve BC's 2030 and 2050 GHG reduction targets. In the ZEN report,[93] its potential is estimated at 92 petajoules – almost half the current B.C. gas consumption. As with green hydrogen, however, the realization of this potential will depend on the ability to source enough electricity – unless thermal pyrolysis is used as the production method. One plasma pyrolysis plant may use around 40-50 megawatts of power; 90 petajoules of hydrogen output per year would require the construction of 18 such plants, amounting to additional power demand of around 800 megawatts. Since the technology is new, the scenarios in Chapter 5.0 assume that few plants can be built by 2030. After that date, the potential is based on the ZEN Hydrogen study.

4.4 Cost Curves

4.4.1 Green Hydrogen

Figure 30 shows the cost curves resulting for electrolytic hydrogen. Costs are higher than C$31 per gigajoule throughout, and incremental cost reductions and efficiency improvements are cancelled out by expected increases in electricity pricing. Producing hydrogen off-grid will entail considerably higher costs. The latter vary greatly between on-shore (around US$1.5 million per megawatt) and off-shore wind farms (around US$5 million per megawatt). Since both are envisaged for B.C. to obtain sizeable numbers, a cost of around US$3 million per megawatt was used. The very high CAPEX for wind turbines and oversized electrolyser farms combined with the intermittent output of wind turbines (capacity factor assumed to be 40%) lead to very high costs of hydrogen produced off-grid, despite independence from grid electricity. For on-grid hydrogen production, electricity costs are the most important cost factor and changes in electricity pricing will heavily influence hydrogen costs. For off-grid, the power generation assets are owned by the producer and the capital costs for these assets and the electrolyser farm become the most important cost element, yet maintenance and operating costs are also significant. The predicted cost scenarios for green hydrogen are based on an electricity price of C$65 per megawatt-hour, including demand charges (see Section 5.1). Lower electricity costs will cause a significant reduction in the unit cost estimation for the green hydrogen produced. Future green hydrogen cost improvements will be due to developments in:

- Electrolyser Capex reduction,
- Improvements to electrolyser stack and system efficiencies,
- Decreases in operating and maintenance costs,
- Longer durability, and electrolyser system operational lifetime.

Table 19 Key Cost Impacts, On-Grid Green Hydrogen Production

Year	Status and improvements	Challenges
2021	The electrolyser capex (incl. balance of plant but excl. storage) is estimated at C$1,400/kW	Cost of electricity
2030	For this period, it is expected that further improvements will be made to the cost associated with the list above.	Inadequate supply of available renewable electricity. Cost of electricity.
2050	For this period, further improvements are expected to be made to the costs associated with the list above. PEM electrolyser target costs have been studied in the UK for a planned mega electrolyser production facility.[98]	Inadequate supply of available renewable electricity.[91] Cost of electricity.

For capital costs, the assumptions from the ZEN report were retained for 2021. Future cost reductions may be significant. A U.S. source predicts costs of only US$400 per kilowatt.[99] Strong capital cost

[98] Gigastack Bulk Supply of Renewable Hydrogen Public Report. February 2020.

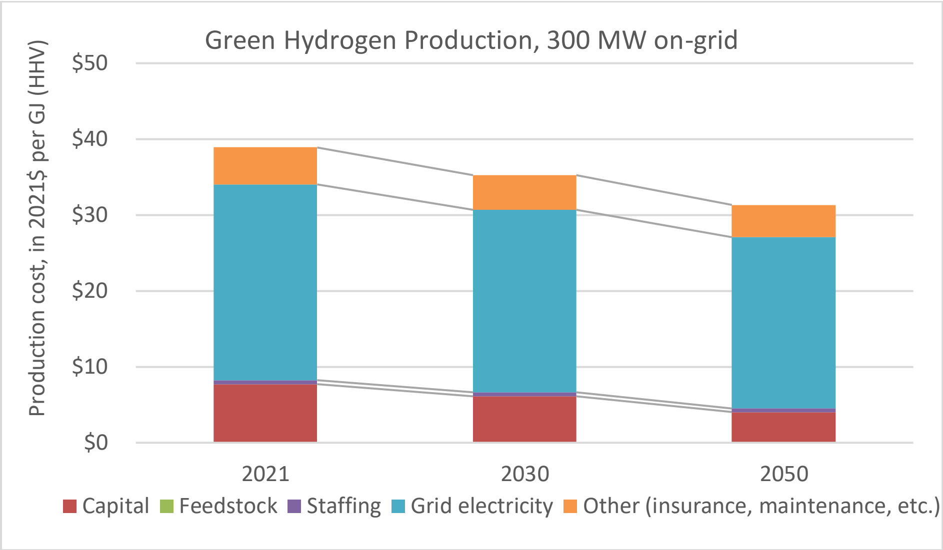
[99] Roadmap to the U.S. Hydrogen Economy – Reducing Emission and driving growth across the nation. Fuel Cell and Hydrogen Energy Association, March 2020.

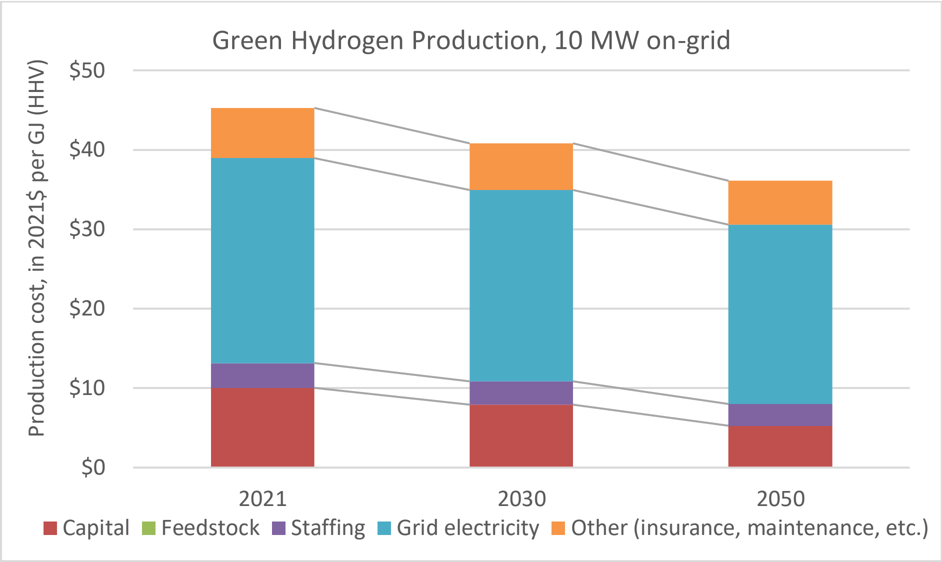
reductions for 2030 (15%) and 2050 (40%) were therefore assumed. Another important variable is electrolyser efficiency. Currently, PEM electrolysers can achieve a power-to-hydrogen conversion efficiency of up to 72%.[100] Default assumptions are 70% for 2021, 75% for 2030 and 80% for 2050. Additional assumptions for a small (10 MW) and off-grid plant can be found in the Excel model.

Table 20 Default Cost Parameters, On-Grid Green Hydrogen, in 2021$

Cost parameter	Value	Share	Comments
Electrolyser plant	300 MW		Very large
Conversion efficiency	70%		Electricity to hydrogen, GJ/GJ
Gas yield	6.48 PJ		
Capital cost	$420 million		In 2021
Capital cost	$357 million		In 2030 (-15%)
Capital cost	$252 million		In 2050 (-40%)
Amortization	$46.7 million	20%	20 years, 9.2%
Opex personnel costs		1%	
Labour, 36 FTE	$2.90 million		
Management, 2 FTE	$0.30 million		
Opex electricity	$156.00 million	66%	2,400,000 MWh per year at $65/MWh
Opex other costs	$29.40 million	12%	7% of CAPEX for maintenance, insurance, etc.
TOTAL OPEX	$235.25 million	100%	
Gas cost	$39/GJ		In 2021

[100] Hydrogen Program Plan. U.S. Department of Energy, November 2020 (footnote 80).





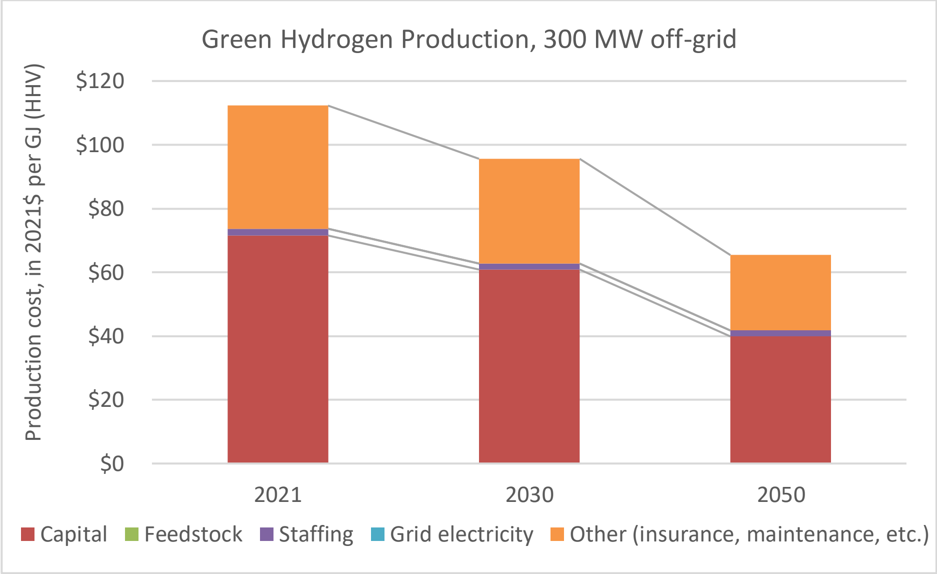


Figure 30 Cost Curves for Electrolytic Hydrogen Production

4.4.2 Blue, Turquoise and Waste Hydrogen Cost Curves

For blue hydrogen, the natural gas price is key after the cost of carbon sequestration. Presuming these plants will be built at the well, where natural gas costs are lowest and sequestration opportunities exist, any increases in natural gas pricing will negatively affect hydrogen costs. This is buffered by the expectation that sequestration costs will fall over time. Capital costs are the most important cost factor, due to the need to implement both SMR reactors and the carbon capture, compression, and sequestration infrastructure. Other models, such as the use of CO_2 in tertiary oil and gas fields, or other uses of CO_2, would strongly reduce the sequestration cost but are not likely going to be sufficiently available for the large amounts of blue hydrogen anticipated.

The conversion efficiency of natural gas to hydrogen is assumed to increase to 85% by 2050.[101] Carbon capture costs are modelled as decreasing from $75 a tonne of CO_2 in 2021, by 10% by 2030 and 25% by 2050. Capital costs will decrease more slowly at 9% by 2030 and 20% by 20% by 2050. Gas costs at the well are deemed to increase only with inflation. No carbon tax applies since natural gas is (mainly) used as a feedstock. The resulting cost of $3 per kilogram (US$2.30 per kilogram), although somewhat higher than in the ZEN study ($2.14 per kilogram), lies within the range of previous estimates.[102] The plant size of 100 tonnes per day has been retained from the ZEN report and was chosen to compare to turquoise hydrogen production; actual projects may be considerably larger.

Table 21 Default Cost Parameters, Blue Hydrogen, in 2021$

Cost parameter	Value	Share	Comments
Conversion efficiency	75%		Methane to hydrogen, GJ/GJ
Gas yield	100 tonnes/day		As hydrogen (5 PJ per year)
Capital cost	$300 million		In 2021
Capital cost	$273 million		In 2030 (-9%)
Capital cost	$240 million		In 2050 (-20%)
Amortization	$33.3 million	32%	20 years, 9.2%
Opex personnel costs		3%	
Labour, 42 FTE	$3.4 million		
Management, 2 FTE	$0.3 million		
Opex electricity	$2.3 million	2%	35,000 MWh per year at $65/MWh
Opex natural gas	$25.6 million	25%	6.6 PJ of natural gas at $3.87/GJ
Carbon capt./sequestr.	$23.6 million	23%	$75 per tonne of CO_2[103]
Other OPEX	$15 million	14%	5% of CAPEX
TOTAL OPEX	**$103.5 million**	**100%**	
Gas cost	$21/GJ		In 2021 ($2.96/kg)

For turquoise hydrogen, feedstock costs (natural gas) remain the most important factor. No capture or sequestration is required, making the process easier to locate and operate. Yet, the conversion efficiency is lower than with SMR, which increases overall production costs. Carbon black sales may, however, almost entirely compensate for the cost of production. Producing the correct grade of carbon and establishing sales channels will be key. Given the carbon in the feedstock is not emitted but turned into carbon black, likely displacing fossil carbon black sources, turquoise hydrogen production is not impacted by increasing carbon taxes (methane use as a feedstock is not subject to the carbon tax). If on the

[101] Hydrogen in a low-carbon economy. Committee on Climate Change (UK), November 2018
[102] GLOBAL STATUS OF CCS 2020. Global CCS Institute, November 2020 (Table 3)
[103] See https://www.iea.org/commentaries/is-carbon-capture-too-expensive (Accessed October 29, 2021)

distribution grid, facilities would, in theory, be affected by increasing gas pricing as is anticipated with increasing amounts of renewable and low-carbon gases being injected (see Section 5.1). It is, however, presumed here that a low gas price is offered to turquoise hydrogen producers that will only change with inflation. This is estimated by taking the current Rate 5 commodity charge plus storage and transportation charges, resulting in a gas price of only $4.70 per gigajoule. Whereas the hydrogen conversion efficiency is deemed to remain constant over time, the increasing amount of hydrogen in the gas pipeline will lead to lower rates of carbon black output, although somewhat more hydrogen is then injected into the pipeline by 2050. Alternatively, the development of hydrogen at scale in B.C. could include dedicated natural gas pipelines to deliver methane feedstock to processing facilities such as these.

Table 22 Default Cost Parameters, Turquoise Hydrogen, in 2021$

Cost parameter	Value	Share	Comments
Conversion efficiency	57%		Methane to hydrogen, GJ/GJ
Gas yield	5 PJ/year		As hydrogen
Capital cost	$153 million		In 2021
Capital cost	$139 million		In 2030 (-9%)
Capital cost	$122 million		In 2050 (-20%)
Amortization	$17.0 million	18%	20 years, 9.2%
Opex personnel costs		3%	
Labour, 30 FTE	$2.40 million		
Management, 2 FTE	$0.30 million		
Opex electricity	$22.8 million	25%	350,000 MWh per year at $65/MWh
Opex natural gas	$41.2 million	46%	8,769,600 GJ of natural gas at $4.7/GJ
Other OPEX	$7.6 million	8%	5% of CAPEX
TOTAL OPEX	$91.3 million	100%	
Carbon black revenue	-$89.6 million	-98%	112,000 tonnes at $800 per tonne
Gas cost	$0.3/GJ		In 2021

Turquoise hydrogen is a special case due to the co-production of carbon black. Depending on its exact texture and quality, carbon black can fetch considerable value in the market. It has been conservatively assumed that a value of C$800 per tonne is attainable.[104] This is sufficient to cancel out almost all of the operating cost of a new plant, leading to very low hydrogen production costs. Natural gas is the main cost parameter but somewhat higher pricing could be absorbed.

One concern with turquoise hydrogen is the anticipated change of gas composition in pipelines. If significant amounts of hydrogen will be injected, turquoise hydrogen facilities will not be able to generate the same amount of carbon black as before, which may affect their financial viability. A detailed technical analysis of this problem would be beyond the scope of this study, but it is assumed that with moderate amounts of hydrogen, the process would simply become somewhat less efficient and would produce more hydrogen as a by-product. Increasing amounts of hydrogen in the gas distribution network could also affect other industries using natural gas as a feedstock but no such industries, such as fertiliser production, were identified during the research for this report. For the cost estimate, it has been assumed that hydrogen in pipelines will amount to 2% by 2030 and 40% by 2050. This leads to somewhat less carbon black revenue but also to increased hydrogen sales. It is assumed that the hydrogen in pipeline gas would simply be injected back into the same after processing, together with the hydrogen produced by the

[104] Pricing was around US$800 in 2021, see https://www.chemanalyst.com/Pricing-data/carbon-black-42 (Accessed October 28, 2021)

process. Alternatively, plants could be situated on gas transmission pipelines where the hydrogen content may be lower than at locations on the distribution grid.

Waste hydrogen is produced at several facilities in B.C. but is generally already being used for plant process heat and as an energy vector for heavy duty truck applications, a Hydra Energy Chemtrade project. Therefore, only a small portion may be available for pipeline injection. If the gas is currently vented, the costs of harnessing the resource are fairly small (some conditioning and compression). It is the most cost-effective resource but also very limited in its potential.

Although the production costs for turquoise and waste/by-product hydrogen are estimated as less than $10 per gigajoule, it is deemed unlikely that this hydrogen would be offered on the market for less than $10. For the cost curves in Chapter 5.0, the calculated amounts were used but it is not expected that this would be the actual cost of purchasing this hydrogen.

Table 23 Default Cost Parameters, Waste Hydrogen, in 2021$

Cost parameter	Value	Share	Comments
Gas yield	0.9 PJ		All figures used based on ZEN (2019)
Capital cost	$19.3 million		In 2021 (no change for later years since no more potential)
Amortization	$2.1 million	57%	20 years, 9.2%
TOTAL OPEX	$3.7 million	43%	Labour and maintenance
Gas cost	$4/GJ		In 2021

Figure 31 shows the gas cost estimates for the present year, 2030, and 2050. The cost is lowest for turquoise hydrogen (due to the revenue generated from selling carbon black), followed by waste hydrogen and then, blue hydrogen

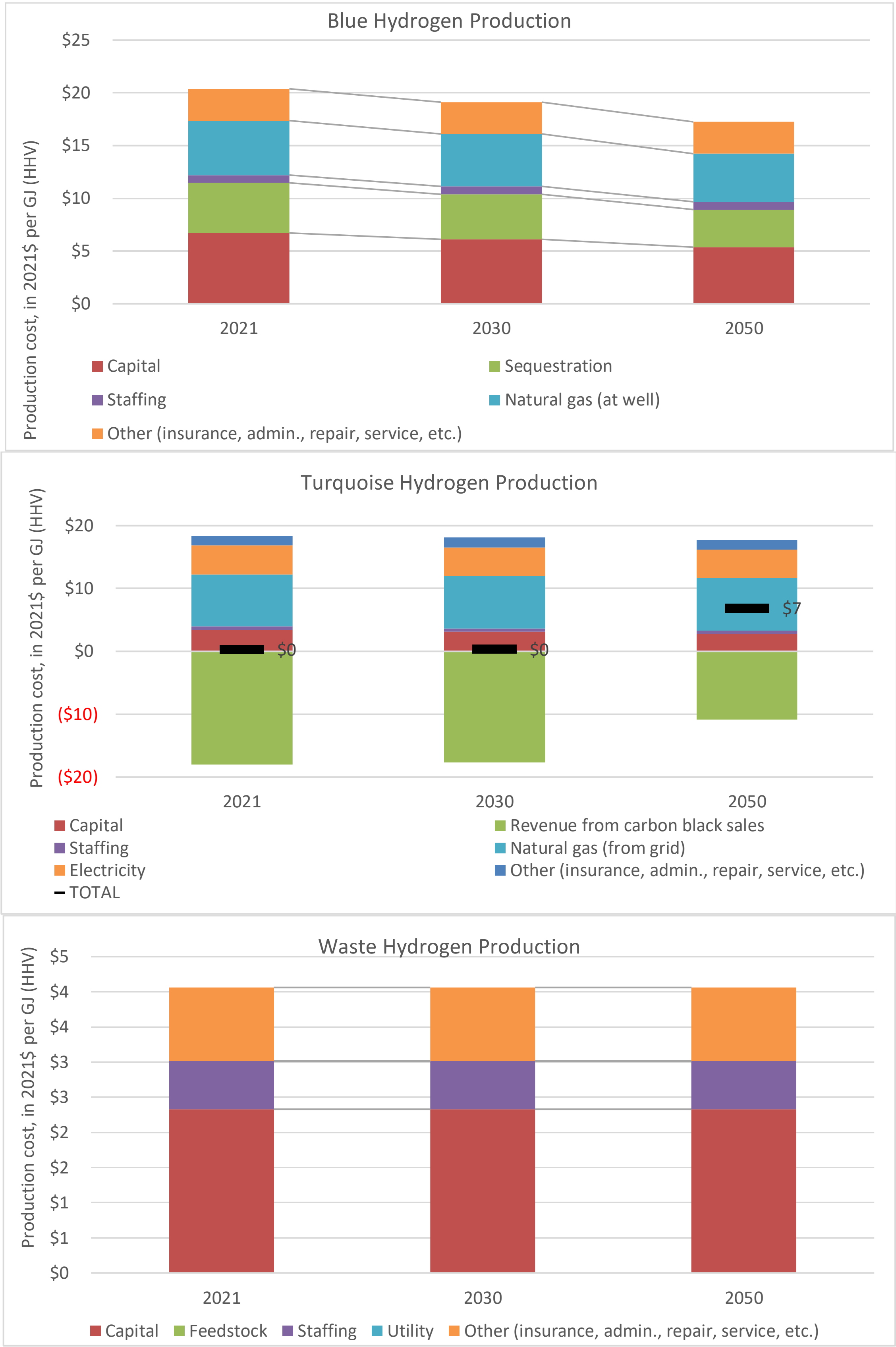


Figure 31 Cost Curves for Non-Electrolytic Hydrogen Production

4.5 Carbon Intensity of Hydrogen from Non-Biomass Sources

Table 24 shows additional values for the four types of hydrogen available in B.C. For blue hydrogen, the actual value will depend on the carbon capture efficiency. The value shown here indicates about 80% of CO_2 being captured, i.e., lower values may be achieved with more efficient technology. The life-cycle emission value for natural gas with and without carbon capture remains contested, however, as indicated in Section 5.5 below.

Table 24 Literature Values for Hydrogen Carbon Intensity

Type	Value	Source
Green	15.6 g CO_2e/MJ	Based on GHGenius[105]
	0.0 g CO_2e/MJ	ZEN (2019), off-grid
	3.3 g CO_2e/MJ	Pembina (2021)[106], wind electricity. Only plant construction
	27.4 g CO_2e/MJ	ZEN (2019), on-grid
Blue	22.4 g CO_2e/MJ	ZEN (2019), 80% capture efficiency
	14.0 g CO_2e/MJ	Pembina (2021), SMR, high performance
	10.6 g CO_2e/MJ	Pembina (2021), ATR, high performance
	26.3 g CO_2e/MJ	BC Hydrogen Strategy, 90% capture eff.[107]
	50 g CO_2e/MJ	Timmerberg (2020)[108]
Turquoise	12.5 g CO_2e/MJ	ZEN (2019), Plasma pyrolysis
Waste	10.5 g CO_2e/MJ	ZEN (2019)

4.6 Markets

The primary markets in B.C. for renewable hydrogen are:

- Pipeline injection to reduce the carbon intensity of retailed natural gas in B.C. To attain (a theoretical) 5% hydrogen by volume in the B.C. natural gas grid, 100,000 tonnes of hydrogen need to be produced and injected into the grid. If this were green hydrogen, it would require an approximate total of 700 MW of electric output to operate the electrolysers.
- The second segment is the transportation market and includes light-, medium- and heavy-duty on-road vehicles, city buses and ferries, to name a few. The Zen Hydrogen Study recommended transportation as second on their list of future demand for hydrogen, albeit over a longer period of time. The focus of this study does not include the transportation market.
- Large industrial users may buy or produce renewable and low-carbon hydrogen. This could include oil refineries and other industries that are large hydrogen users. They could produce hydrogen for on-site use and possibly for export, or a third party could produce for both markets.
- A national or interprovincial strategy to create dedicated hydrogen transport infrastructure could allow for the sale of pure hydrogen across larger portions of Canada, as well as internationally through B.C. ports, or to Western U.S. jurisdictions through pipelines. Market dynamics would then no longer be constrained by the B.C: market but would be driven by large-scale U.S: and overseas demand. Such

[105] GHGenius501d-5, www.ghgenius.ca. Numbers are for BC Hydro's integrated grid. Electricity and green hydrogen produced in the Fort Nelson grid has a much higher carbon intensity.
[106] Gorski, Jan *et al.*: Carbon intensity of blue hydrogen production - Accounting for technology and upstream emissions. Pembina Institute, August 2021.
[107] B.C. Hydrogen Strategy - A sustainable pathway for B.C.'s energy transition. CleanBC, July 2021.
[108] Timmerberg, Sebastian et al.: Hydrogen and hydrogen-derived fuels through methane decomposition of natural gas – GHG emissions and costs. Energy Conversion and Management: X Vol 7, September 2020.

infrastructure could also allow for long-term storage of hydrogen in order to stabilise the electricity grid and provide more seasonal flexibility with hydrogen delivery. In the absence of dedicated hydrogen pipelines, liquid organic hydrogen carriers (e.g., methyl cyclohexane) or liquefied hydrogen could be exported by ship to U.S. or Asian markets from B.C. Physical export or the sale of hydrogen certificates into extra-provincial markets represents a potential threat to the ability to use the gas locally if pricing is higher outside of B.C.

4.7 Infrastructure Needs

The main infrastructure for low-carbon hydrogen use is already in place: the natural gas grid. The limit to hydrogen content in the gas pipeline is currently undetermined. B.C. exports 90% of its natural gas production. Even if all B.C.'s natural gas consumption was converted to hydrogen, the average hydrogen content in the main transmission lines would be only 10% or less.

The co-location of hydrogen production at other industrial sites that could potentially use hydrogen – for example near cement plants and refineries – offers infrastructure benefits. Section 6.3.5 of this report also notes this. Additional infrastructure needed includes electrolysers, power generation assets, and other production assets linked to blue and turquoise hydrogen, as indicated in Table 25.

Table 25 Infrastructure and Planning Requirements to Increase Hydrogen Production

Requirements	Status
Additional renewable electricity production assets	BC Hydro currently developing a new integrated resource plan.
Electrolyser farms	Installation of large-scale production sites on-grid or off-grid. For off-grid sites, additional investment is required to generate electricity (PV, wind). Off-shore sites will potentially require long cable connections to the mainland.
Site local water feed for electrolysers	Filtration plants will need to be invested in.
BC Environmental Management Act. Site and plant environmental assessment and permitting will need to be undertaken for large electrolyser plants	Electrolysers use integrated water purification including ion exchange and reverse osmosis filtration processes. Feed water and grey waste water effluent will need to be addressed.
Steam methane reforming facilities	Commercial technology that needs to be financed and deployed in several locations, often near proven sites for carbon sequestration.
Carbon sequestration infrastructure	CO_2 capture units (amine-based or other technologies), compression and injection into the ground.
Methane pyrolysis plants	Production of carbon black and hydrogen near hydrogen users and/or the natural gas grid.

4.8 Recommendations

The cost curves can inform the best strategy for procuring renewable and low-carbon hydrogen from B.C. or elsewhere. Generally, hydrogen from outside the province is not expected to be cheaper, given the low electricity and gas costs in B.C. The exception would be any waste hydrogen that is currently vented, or turquoise hydrogen. If the aim is to keep costs low, available sources of waste and turquoise hydrogen should be secured first. A strategy should be developed to attract investors to B.C. who will demonstrate and then commercially produce turquoise hydrogen and by-product carbon that could be sold into the carbon black markets. The production of green and turquoise hydrogen should preferably be situated near large consumers, such as the refineries in Prince George and Burnaby. This can make use of existing infrastructure and possibly, personnel, will maximise the value of the hydrogen as it can be delivered in its pure form, and offers possibilities to better manage pipeline injection of surplus hydrogen produced that is not used on-site, thus reducing impacts on the local gas distribution pipelines.

For blue hydrogen, incentives may be needed to construct a first production site by 2030. Since carbon sequestration is likely required, permitting is expected to take several years. This may be a demonstration facility or a full-scale facility. Alternatively, the effort could focus on building a CCUS facility if a market for the CO_2 can be identified. This would avoid the need for sequestering the CO_2 and would improve economics through sale of CO_2.

The production cost of green hydrogen is currently above the GGRR price limit of $31 per gigajoule. This may change if the price ceiling is modified so that an *average* price can be used that allows more than $31 per gigajoule for some projects to be paid, or if the current policy is changed towards a carbon intensity-based target which allows for higher pricing. Green hydrogen may also become more competitive if power tariffs are implemented that reflect the ability of large-scale electrolysis to balance the power market, use constrained wind, and provide long-term (seasonal) energy storage opportunities. Given the very high potential for blue hydrogen, green hydrogen is only deemed competitive if it is incentivised through a portfolio standard approach. Implementing electrolytic hydrogen production where the by-product, oxygen, can be used will slightly improve economics. At an estimated value of $50 per tonne of oxygen, hydrogen costs could be reduced by about $2.80 per gigajoule. This is insufficient to achieve a cost of below $31 per gigajoule for green hydrogen but niche opportunities may exist where this is possible if oxygen costs are higher.

The high cost of off-grid hydrogen production strongly suggests that on-grid wind farms or other renewable electricity production technologies should be given preference for green hydrogen production. Strongly increasing green hydrogen production will require an adjustment to the BC Hydro Resource Plan to accommodate large new sources of intermittent power production and large-scale green hydrogen production.

Time-of-use electricity prices would offer benefits as hydrogen could be produced when wholesale grid pricing is zero or negative, for load balancing. Current electricity pricing structures provide no incentive for energy storage, and there is no need for such grid balancing in B.C. at this point in time as it can be handled by adjusting hydro output. This may, however, change after 2030 if large amounts of intermittent renewable power production is added to the B.C. grid.

5.0 SUPPLY PORTFOLIOS

This chapter develops scenarios that model the cost and availability of a portfolio of renewable and low-carbon gas production pathways described in the chapters above. These scenarios are not to be confused with, or taken as, a forecast. Rather, they are models that represent a possible outcome based on a set of criteria. The underlying Excel-based model considers possible factors or drivers, the interactions between pathways, and their relative contribution to the targets by 2030 and by 2050.

The model is simplistic and high-level and would need to be refined to achieve specific goals and milestones. The scenarios are based on several assumptions, mainly related to costs and the availability of resources, build-up rates, and technology readiness of each pathway.

5.1 General Assumptions

General assumptions apply to all pathways and were made to model the cost of the various renewable and low-carbon gases in 2030 and 2050, as depicted in Table 26. These cost assumptions can be modified in the model to determine their relative impact on the cost of production. The amounts are given in 2021$ – i.e., inflation is not considered but costs reflect changes above the inflation level. For natural gas, future costs were based on the "Diversified" scenario developed in the Guidehouse report. For users on the distribution grid, the Fortis Rate 5 (Lower Mainland/Southern Interior) was used. The retail cost accounts for increasing amounts of renewable and low-carbon gases in the distribution grid. For electricity costs, BC Hydro's latest Revenue Requirements Application to the BCUC indicates a bill decrease of 1.4% in 2022, then an increase of 2% in 2023 and another increase of 2.7% in 2024. In 2025, due to Site C being commissioned, another 5-6% rate increase is expected. After that, assuming that rates grow with inflation, these assumptions reflect price increases in line with 2% inflation for the entire decade. After 2030, an annual increase commensurate with inflation is assumed to continue.

Table 26 Default Cost Assumptions, in 2021$

Cost Factor	2021	2030*	2050*
Electricity	$65/MWh	+0%	+0%
Natural gas, retail (Rate 5)**	$7.96/GJ	$14.09/GJ	$21.43/GJ
Natural gas, at the well	$3.68/GJ	$3.68/GJ	$3.68/GJ
Natural gas retail demand in B.C.	200 PJ/year	200 PJ/year	186 PJ/year[109]
Renewable and low-carbon gas share in B.C. gas grid[109]	0%	15%	73%
Pipeline gas carbon intensity	49.9 g/MJ	42.4 g/MJ	20 g/MJ
Capital costs, non-biomass hydrogen	100%	-9 to -15%	-19 to -40%
Capital costs, gas from biomass	100%	-10 to -30%	-50%
Capital costs, anaerobic RNG	100%	Incremental	Incremental
WACC	9.2%	9.2%	9.2%
Loan term	20 years	20 years	20 years
Carbon tax	$45/t	$130/t***	$130/t
Wood feedstock cost (residue, average)	$60/odt	$60/odt	$60/odt
Wood feedstock cost, add. harvest	-	-	$121/odt

* In relation to 2021; ** Incl. carbon tax; *** Corresponds to $170/t in 2021, at 3% inflation

[109] Pathways for British Columbia to Achieve its GHG Reduction Goals. Guidehouse, August 2020 (Diversified Pathway).

Electricity costs include demand charges but do not consider BC Hydro's lower CleanBC Industrial Electrification Rates,[110] which are deemed to benefit the project developer and investors, but not the purchaser of renewable gases.

The B.C. carbon tax does not apply when natural gas is used as a feedstock, as opposed to a fuel.[111] This means that for turquoise and blue hydrogen production, where natural gas is the feedstock, no carbon tax applies on any volumes of CO_2 emitted at the production stage. On the other hand, wood gasification and steam reforming using natural gas are subject to the tax since the gas is used as a process fuel.

An important assumption relates to feedstock costs for gas production from wood. In line with Section 3.1.3, the cost of residue is assumed to increase with inflation, whereas the costs of pulp and sawlogs continue to increase above the inflation rate. $60 per dry tonne is taken as a conservative number for residue costs - an average between mill residue and increasing amounts of harvesting residue. This cost is also applied to any wood residue currently used for either power production for BC Hydro or for pellet manufacturing.

Additional wood could be harvested but would then require the use of standing trees within the AAC limit. This has been estimated to roughly double feedstock costs for gas production, as an average between pulp quality logs and the resulting roadside residue, also assumed to be available at a cost of $60 per dry tonne. Only about 30% of new stands harvested this way are assumed to be used for renewable gas production; most of the harvested volumes would be sold as sawlogs.

5.2 Technology Readiness

The pathways discussed in this report vary in technology readiness (see also Appendix A). The build-out rate of mature pathways will be faster than of those with little or no commercial-scale implementations. Precommercial technologies is unlikely to be mature by 2030. Unless enormous resources are poured into decarbonization, their full technical potential is likely to be reached only by 2050. With respect to the three major pathways, the following can be said:

- **Anaerobic digestion:** By and large, RNG from anerobic digestion is a well-developed technology that could grow quickly.
- **Woody biomass:** Renewable gas production from woody feedstock is not commercial technology. Technologies need to mature, with demonstration projects being built and evaluated before full technical potential can be realized. We assume a slower build-out for these pathways, with only demonstration projects producing hydrogen or RNG from wood happening before 2030. Syngas for lime kiln projects could proceed more rapidly.
- **Hydrogen from non-biomass resources:** While electrolysis is a well-known technology, large industrial-scale applications are only just being deployed. Blue hydrogen (carbon capture and sequestration) and turquoise hydrogen have to mature even further.

5.3 Resource Potential

Previous chapters describe the technical resource potential of each of the three main renewable and low-carbon gas sources: anaerobic digestion, wood gasification, and non-biomass hydrogen production. The

[110] https://app.bchydro.com/accounts-billing/rates-energy-use/electricity-rates/electrification-rates.html (Accessed November 26, 2021)
[111] https://www2.gov.bc.ca/gov/content/taxes/sales-taxes/motor-fuel-carbon-tax/business/exemptions (Accessed October 14, 2021

numbers provided in these chapters are technical potentials that need to be translated into what is realistic or desirable for B.C. Consequently, two scenarios reflecting a maximum and a minimum resource potential are developed below. What is actually achievable in B.C. with appropriate policies and investment may lie in-between these two extremes. Ultimately, the criteria to gauge potential for in-province renewable and low-carbon gas production must also consider the cost of each pathway and the relative availability of each resource. Other criteria, such as carbon intensity values for different gases or fuels, may also be taken into account.

For anaerobically produced RNG, resource potential has been assessed in detail and is well known. Scenarios for 2030 and 2050 are mainly a function of the cost associated with each pathway. For anaerobically produced RNG, the Minimum scenario only considers projects that cost less than $31 per gigajoule, the current threshold the GGRR has set to protect ratepayers from excessive rate increases. Also, only a portion of the technical potential can be realized. The Maximum scenario allows for projects that are up to $50 per gigajoule.

The potential for green hydrogen largely depends on the availability of (green) electricity. BC Hydro's long-term resource planning suggests that around 300-500 MW may be available for low-carbon fuel production. Additional or alternative sources may include on-grid power production from renewables, such as wind power.

The potential for blue hydrogen is mainly constrained by the availability of suitable geological features and abandoned wells that could be used to sequester CO_2. Turquoise hydrogen produces carbon black and can only be produced cost effectively where there are markets for this by-product. The market for carbon black is large and growing. Sufficient natural gas is available within B.C. to supply both pathways. Currently, only 10% of B.C.'s natural gas production is used provincially; the rest is exported.[112]

The supply potential of renewable gas from wood biomass is constrained by resource availability and its distribution within the province. The demand for syngas in a particular area might not match feedstock supply. Trucking woody feedstock from parts of the province that have surplus fibre may not be viable or even desirable as the energy contained in it is rather low, and trucking costs would be high. Only the Maximum scenario makes use of whole logs (beyond some unharvested pulp logs used in both scenarios). Only low-cost residue is used in the Minimum scenario. In the Maximum scenario, we assume that low-cost resources from expiring BC Hydro contracts and transitioning of mill waste from wood pellet to gas production takes place.

The numbers used for the two scenarios for wood resources are made explicit in Table 27. Both scenarios have time horizons for 2030 and 2050. The amount of wood has been converted to gas production potential using an input-output (feedstock/gas) calorific conversion rate of 67%, representative of the main technologies to be used.

[112] https://www.capp.ca/explore/natural-gas-and-the-lng-opportunity-in-british-columbia/ (Accessed October 6, 2021).

Table 27 Renewable Gas from Woody Biomass Produced in B.C. in Each Scenario (PJ per year, HHV)

Wood Resource	MINIMUM SCENARIO		MAXIMUM SCENARIO	
	2030	2050	2030	2050
Unharvested AAC	-	-	4.6	4.6
Roadside residue related to above	-	-	2.1	4.0
AAC from mill closures	-	-	14	14
Roadside residue related to above	-	-	6.5	11
Unharvested pulp logs	3.6	3.6	4.0	4.0
Roadside residue related to above	0.4	0.6	0.4	0.6
Unused Roadside residue	6.0	10	5.9	10
Mill residue not used	4.8	4.8	4.8	4.8
Conversion of pellet plants	-	-	-	44
Expiring BC Hydro contracts	-	-	47	47
Urban wood waste (CLD)	-	-	-	-
TOTAL	**15**	**19**	**89**	**143**

The table above shows that in the Minimum scenario, insufficient wood is available to reach a 15% renewable gas target (equivalent to about 30 petajoules) with wood alone. On the other hand, there are, in theory, sufficient resources overall to reach the 15% renewable gas target in 2030 and to produce up to 143 petajoules of gas in the Maximum scenario. Table 28 summarizes the assumptions underlying the subsequent tables.

Table 28 Assumptions on Wood Availability for Minimum and Maximum Scenarios

Minimum Scenario	Maximum Scenario
- BC Hydro power purchase agreements with pulp mills extended, limiting availability of mill residues for renewable and low carbon gas production - All lime kilns converted to syngas by 2050. - No whole-tree harvesting for energy occurring due to high cost or difficulty harvesting. - Demonstrations for hydrogen and possibly RNG at pulp mills by 2030. - Urban wood waste already used by others. - 50% of unused roadside residue recovered by 2030, 85% by 2050. - Pellet plants continue to operate and export after 2030.	- Substantial amounts of lower-cost biomass transitioning from BC Hydro power purchase agreements and pellet mills will buffer costs from increased use of roundwood. - All kraft mill lime kilns converted to syngas by 2050. - Hydrogen and RNG production are implemented at almost all mills, possibly some stand-alone facilities. - Max. about 30% of standing trees on a cutblock used for energy, the rest for sawmills or new uses (bioproducts). - Mixed cost of roundwood and associated roadside residue is $121 per dry tonne by 2050. - Max. 75% of unused AAC can be accessed by 2050 (remoteness, terrain, etc.). - Max. 85% of unused roadside residue recovered. - Pellet plant feedstock transitioned to gas production after 2030. - BC Hydro power purchase agreements expire around 2029 and Hydro sources electricity from wind and solar. - Urban wood waste already used by others.

Based on the above assumptions, Table 29 and Table 30 lay down the resource potentials assumed to exist in each scenario, for the years 2030 and 2050. This includes assumptions about demonstration and build-up of new gas production facilities.

Table 29 Assumptions for Gas Production in 2030 and 2050, in PJ/yr (Minimum Scenario)

Gas Type	2030	2050	Rationale
Green hydrogen (large on-grid)	0.0	8.3	Slower ramp-up than Maximum scenario
Green hydrogen (small on-grid)	0.8	1.9	Slower ramp-up than Maximum scenario
Green hydrogen (large off-grid)	0.0	2.4	A single 300 MW off-grid wind farm after 2030
Blue hydrogen	14.2	46.8	Limited by permitting and regulatory restraints
Turquoise hydrogen	1.5	15.4	Slower ramp-up than Maximum scenario
Waste hydrogen	0.9	0.9	Identical to Maximum scenario
Syngas in lime kilns	1.4	5.9	Identical to Maximum scenario
Lignin in lime kilns	0.0	0.0	Lignin a more expensive fuel than syngas
Syngas to hydrogen	0.3	13.4	No change to forestry practices. BC Hydro PPAs are extended. No use of wood pellet feedstock. Only low-cost residue used.
Syngas to RNG	0.0	0.0	Technology not advancing as expected
Agricultural RNG	0.9	1.2	Potential for production cost below \$31/GJ; 70% of 2030 technical potential (90% of 2050 potential).
Municipal RNG	2.3	4.0	
Waste water treatment gas	0.4	0.6	
Landfill gas	2.1	2.7	
TOTAL	**24.7**	**103.8**	

Table 30 Assumptions for Gas Production in 2030 and 2050, in PJ/yr (Maximum Scenario)

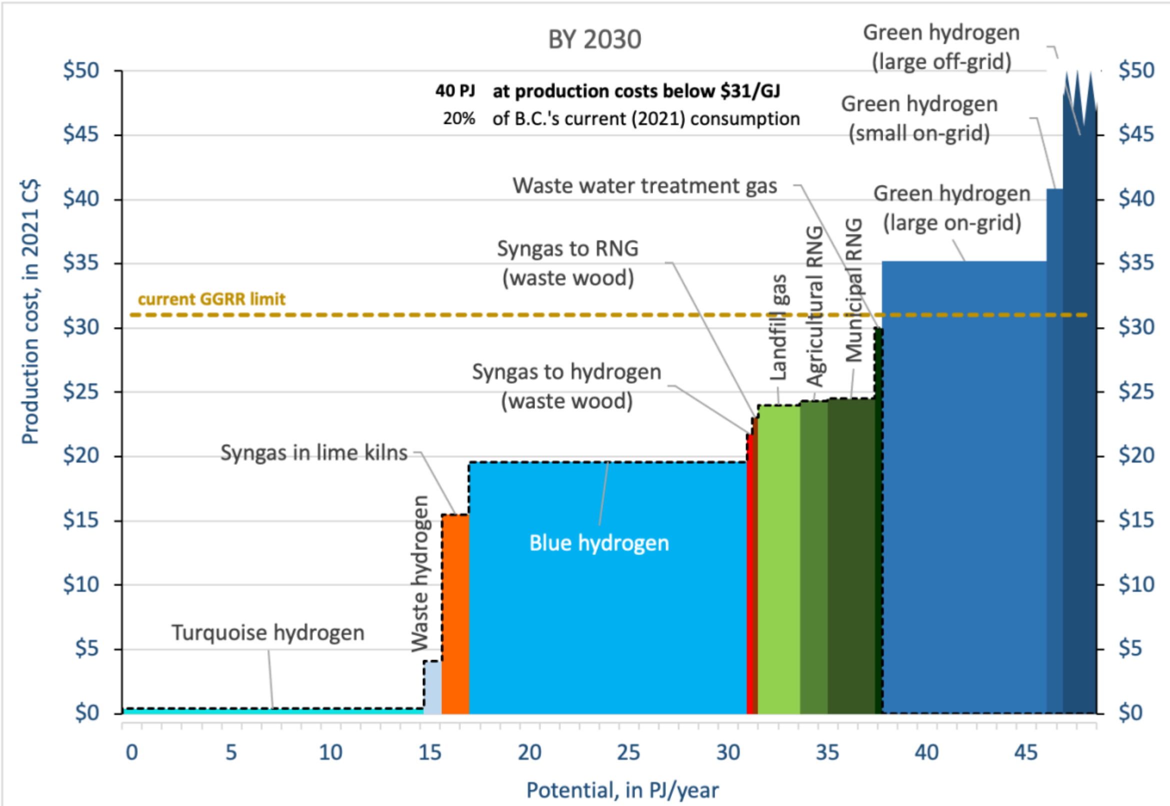
Gas Type	2030	2050	Rationale
Green hydrogen (large on-grid)	8.4	21.0	Converted to petajoules from Table 18
Green hydrogen (small on-grid)	0.8	6.3	Converted to petajoules from Table 18
Green hydrogen (large off-grid)	1.7	12.6	Converted to petajoules from Table 18
Blue hydrogen	14.2	156	From ZEN (2019) report, Figure 28 (in 2050)
Turquoise hydrogen	15.4	92.2	From ZEN (2019) report, Figure 28 (in 2050)
Waste hydrogen	0.9	0.9	From ZEN (2019) report, Figure 28
Syngas in lime kilns	1.4	5.9	100% of lime kilns are converted to syngas by 2050. BC Hydro contracts are not extended.
Lignin in lime kilns	0.0	0.0	Lignin a more expensive fuel than syngas
Syngas to hydrogen	0.3	64.9	Increased forest residue recovery. BC Hydro contracts are not extended. Pellet feedstock transitions towards gas production. 36 plants (or less if larger plant size), also using standing trees
Syngas to RNG	0.3	74.2	One demo by 2030. 26 full-size plants by 2050. Use of some roundwood
Agricultural RNG	1.4	2.0	Potential for production cost below \$50/GJ. 70% of 2030 technical potential (90% of 2050 potential).
Municipal RNG	2.4	4.2	
Waste water treatment gas	0.4	0.6	
Landfill gas	2.1	2.8	
TOTAL	**49.7**	**444**	

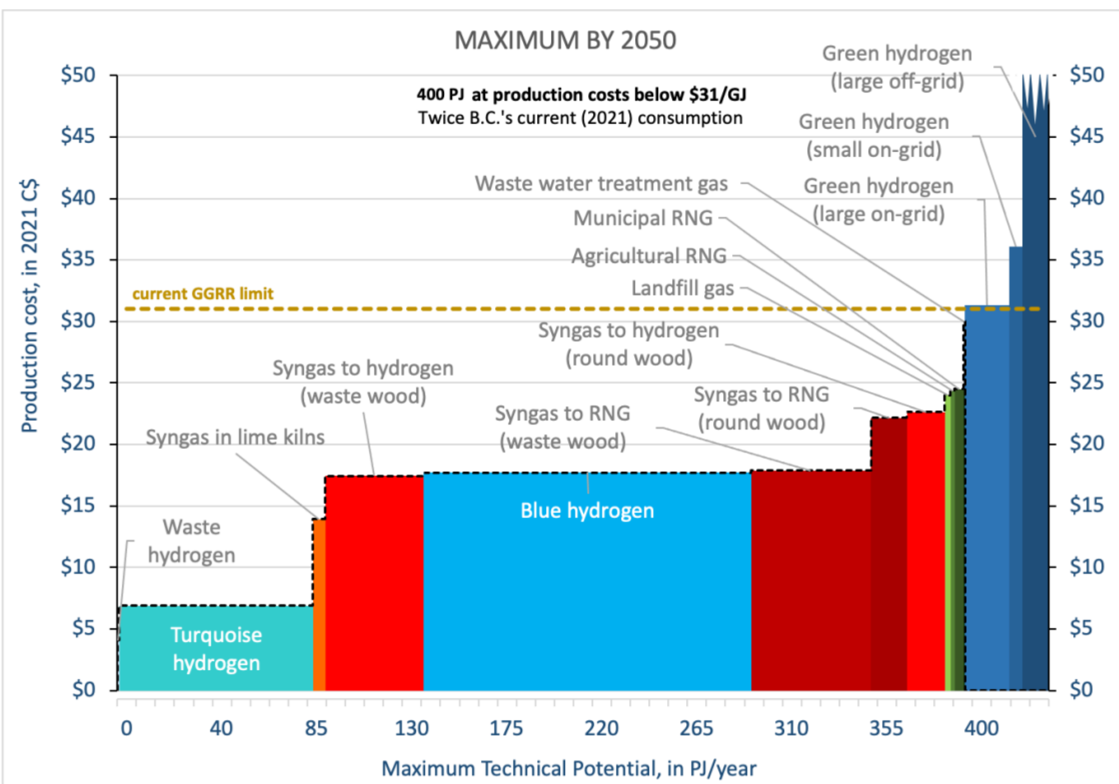
The potentials shown above result in the cost curves displayed in Figure 32 and Figure 33. The (horizontal) x-axis indicates the potential in petajoules per year and the (vertical) y-axis shows the production cost for each pathway. The lowest-cost pathway is shown on the left. The potential increases as higher-cost options are considered, resulting in a stepped curve. Eventually, the costs per gigajoule surpass the $31 threshold that the GGRR requires. The viable potential under the current regulatory framework is limited to the area in the graph that is outlined by a dashed line. Note that, to keep the graphs legible, the size of the x-axis is not the same.

There would be a gradual increase in production over time, which for some pathways only begins after 2030. For anaerobically produced RNG, the potential for 2030 developed in Section 2.4 has been reduced to 70% (90% by 2050) as developing the total potential is not realistic. Syngas production from woody feedstock is assumed to continue through 2050 even if new hydrogen or RNG production is added to mills.

Maximum scenario: the 2030 target of 15% renewable gas can be reached using only in-province resources if low-carbon gas becomes eligible. The target would be reached with a mix of gases, mainly blue hydrogen (construction of about 300 tonnes of blue hydrogen production capacity before 2030) and anaerobically produced RNG. By 2050, 100% of natural gas currently retailed in B.C. could be replaced with provincial renewable and low-carbon gas, still remaining within the $31 (2021$) cost threshold. The resulting gas mix includes a large share of blue hydrogen, high biomass use, and also the construction of carbon black production facilities that produce turquoise hydrogen. For gases from woody biomass, production sites exceed the number of existing mills, suggesting that some greenfield plants would have to be built and substantial amounts of roundwood would be used. More than the current provincial demand could be produced with provincial resources, possibly allowing for exports.

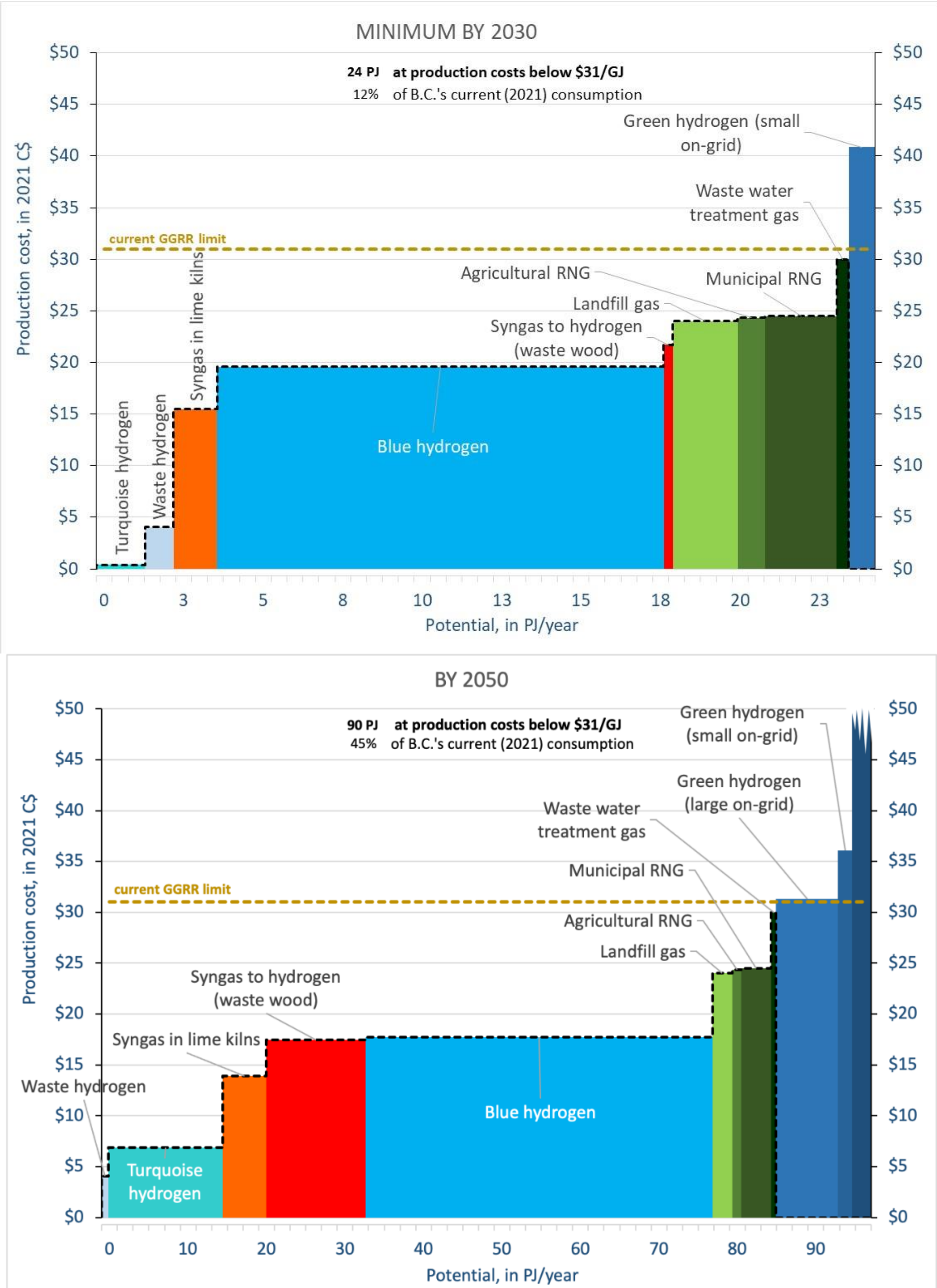
Minimum scenario: compared to the Maximum scenario, the 2030 target cannot be reached with provincial resources. If low-carbon gases are eligible and if action is taken now to implement blue hydrogen production, only 24 out of 30 petajoules per year required are produced in province. B.C: gas utilities would have to purchase 6 gigajoules a year of RNG from out-of-province resources. By 2050, the total available renewable and low-carbon gas levels off at around 100 petajoules, i.e. only about half of current natural gas distributed through pipelines can be displaced. Renewable and low-carbon gas imports would be necessary to fully decarbonize provincial gas usage unless B.C. gas consumption is reduced drastically. The lower gas production levels in this scenario are due to more pessimistic assumptions with respect to woody feedstock availability and built-out rates, as well as technology development (e.g., no RNG production from wood).





Note: To keep the graphs legible the size of the x-axis for 2030 are not the same as for 2050

Figure 32 2030 and 2050 Cost Curves for Renewable and Low-Carbon Gas Production (Maximum Scenario)



Note: To keep the graphs legible the size of the x-axis for 2030 are not the same as for 2050

Figure 33 2030 and 2050 Cost Curves for Renewable and Low-Carbon Gas Production (Minimum Scenario)

5.4 Supply Portfolios

5.4.1 Criteria for developing portfolios

The cost curves above show both costs and potential. These numbers are, in part, based on predictions and are subject to changes such as technology development and resource availability. The cost curves can be used to gauge the contribution that each pathway may make, and at what cost. Apart from the cost threshold of $31 per gigajoule (indexed with inflation), other criteria policy makers might want to consider include:

- **Geographical origin:** Gas produced outside B.C. will not have the same provincial social and economic benefits as gas produced within the province.
- **GHG footprint:** The government might set a minimum life cycle carbon intensity for gas to qualify for displacing natural gas. This could give preference to gases that have much lower – even negative – carbon intensities than others, possibly accelerating GHG reductions (Section 5.5).
- **Industry sector:** Renewable and low-carbon gas production may be promoted depending on the potential and need for job creation and how competitive the industry is.
- **Co-benefits**: Some pathways create co-benefits in addition to renewable gas. These co-benefits, which can include local employment, rural diversification and odour and nutrient management, may be considered when choosing which renewable and low-carbon gases to acquire.
- **Social acceptance:** Some pathways may be more acceptable than others. For example, social acceptance may be lower for carbon sequestration projects than for green hydrogen, or for large-scale wood gasification projects versus small-scale digesters. Buyers need to weigh the advantages of each and may have to engage in education efforts to defend purchasing decisions if they are faced with critiques in the media.
- **Speed of development:** As discussed above, some types of projects may require much longer lead times. This would apply to off-shore wind projects used to power electrolysers, or to blue hydrogen projects that need to inject carbon dioxide into the ground. Other types of projects may be developed more easily and quickly, especially to meet the 2030 targets.
- **Investment needs:** Some pathways require substantial investments for project development. A full-scale RNG production facility using woody feedstock may cost more than $300 million to build, which is more difficult to realize than smaller projects under $100 million, such as syngas production, or under $30 million, such as anaerobic digestion.
- **Technology status:** Pre-commercial pathways need to be supported with further R&D. Demonstration projects should be realized before 2030, possibly with public support, but near-term solutions lie in technologies that are already fully commercial today.
- **Diversity and hedging:** It may be advantageous to diversify the production portfolio, including several sources of renewable and low-carbon gases. This will reduce the risk of relying on a single source that may become more expensive or may even cease to exist over time, and will support the parallel development of new industries in several sectors.
- **Potential and replicability:** Some pathways have more potential than others in terms of how much gas can be produced.

5.4.2 Possible Supply Portfolios

Table 31 qualitatively compares the renewable and low-carbon gas pathways. Some clear messages can be derived:

- Green hydrogen remains too expensive for immediate consideration.
- Turquoise hydrogen is of great interest but not yet commercial.
- Waste hydrogen is also of great interest but very limited in terms of its resource potential.
- Syngas production from wood is the most achievable and lowest-cost option for using woody biomass.
- Wood-based pathways offer more social benefits than those based on electrolysis or blue hydrogen.
- Agricultural RNG is attractive based on several parameters but has limited potential.
- Anaerobic pathways are the most developed technologically and also relatively easy to develop.

Table 31 Qualitative Comparison of Renewable and Low-Carbon Gas Pathways

Pathway	Gas Cost	Invest-ment	GHG	Sector	Co-Benefits	Social	Speed	TRL	Poten-tial	Overall score
Green hydrogen (large on-grid)	--	-	+	o	o	+	+	+	+	**o**
Green hydrogen (small on-grid)	--	o	+	o	o	+	+	+	+	**o**
Green hydrogen (large off-grid)	---	--	+	o	+	+	--	+	++	**-**
Blue hydrogen	+	-	o*	+	-	-	--	+	++	**o**
Turquoise hydrogen	++	+	o*	++	-	+	-	-	+	**o**
Waste hydrogen	++	++	o	o	-	+	+	++	--	**++**
Syngas in lime kilns	o	+	+	+	o	+	o	+	+	**+**
Syngas to hydrogen	-	-	o	+	o	o	--	-	++	**o**
Syngas to RNG	-	--	o	+	o	o	--	-	++	**o**
Agricultural RNG	o	+	++*	+	++	o	+	++	+	**+**
Municipal RNG	o	+	+*	o	+	o	+	++	+	**+**
Wastewater treatment gas	+/o	+	+*	o	o	+	+	++	o	**+**
Landfill gas	+	++	+*	o	o	+	+	++	o	**+**

---- extreme; -- very bad; - bad; o neutral or small impact; + good; ++ very good

* Exact carbon intensity is disputed; see Section 5.5

In combination with the cost curves developed above, the supply portfolios for 2030 and 2050 could be structured as shown in Table 32. Options to facilitate these outcomes will be discussed in Chapter 6.0.

Another question is what role imported gases will play. This is discussed in the following section. As mentioned above among the criteria, a portfolio approach is desirable both in terms of creating more opportunities inside B.C. and offering more resilience for gas retailers that need to comply with government mandates. The breadth of this diversity will depend on the ability to pay for the gas – i.e., whether the $31 per gigajoule threshold is hard or flexible – to accommodate some of the more expensive sources. It is presumed below that such flexibility may not occur before 2030 and/or that more expensive sources may become more affordable after that date.

Table 32 Potential Supply Portfolios of Renewable and Low-Carbon Gases

	2030	2050
Primary sources	Waste hydrogen Anaerobically produced RNG Syngas in lime kilns Blue hydrogen	Turquoise hydrogen Syngas in lime kilns Hydrogen (or RNG) from wood Anaerobically produced RNG Waste hydrogen
Secondary sources	Turquoise hydrogen Hydrogen from wood (demonstration)	Blue hydrogen Green hydrogen

5.4.3 In-Province Versus Out-of-Province Supplies

FortisBC is currently buying RNG produced outside of B.C. (e.g., Lethbridge, AB and Des Moines, Iowa) for an existing voluntary market.[113] This option is in line with other jurisdictions, such as California, that use a certificate trading system to 'move' RNG between jurisdictions by separating and selling the environmental benefits of these gases. Buyers can then claim these benefits for their own gas use whereas, at the injection point, the RNG is treated as if it was generic natural gas. The green benefits therefore accrue where the buyer uses natural gas, not where the producer injects it, geographically decoupling RNG production and use.

While avoiding trade barriers, this system may leave most of the socio-economic benefits from renewable and low-carbon gas production outside of B.C. However, it can be harnessed to obtain low-cost RNG (e.g., from landfill gas sites) or hydrogen to protect B.C. ratepayers from exposure to high renewable and low-carbon gas pricing. It may also enable sourcing RNG with very low, or even negative, carbon intensities. This would be an advantage for reaching provincial and corporate GHG targets more quickly. Yet, sourcing all, or a large portion of, gases from outside B.C. will economically benefit producers in other jurisdictions, rather than keeping ratepayers' money inside the province. Some balance between imports and local production is therefore desirable.

As outlined in Chapter 2.0, the potential for anaerobic RNG production in the rest of Canada and the U.S. is large enough to cover all of B.C.'s gas needs. Both qualify as vendors of renewable gas because they are connected to B.C. through the continental gas grid. The Canadian potential (including B.C.) is deemed to be about 70 petajoules by 2030 and 80 petajoules by 2050. U.S. potential is deemed to be close to 600 petajoules in 2030 and about 630 petajoules in 2050. This means the entire 2030 B.C. target could, in theory, be procured inside Canada and any 2050 target could be complied with using Canadian and U.S. sources.

B.C. utilities are unlikely to secure as much of this gas as they wish to due to competition. In the U.S., several jurisdictions have implemented renewable gas policies and have created lucrative markets for RNG certificates (see Section 5.5). In Canada, Quebec is currently seeing uptake of RNG from landfill gas. Any first-mover advantage that B.C. gas utilities currently have may therefore disappear soon. Table 33 provides a comparison between the advantages and limitations of importing renewable and low-carbon

[113] https://www.fortisbc.com/services/sustainable-energy-options/renewable-natural-gas/meet-our-renewable-natural-gas-suppliers#tab-7 (Accessed October 5, 2021).

gases. The choice mainly relates to sourcing lower-cost, assured gas production outside B.C. versus creating more social and economic benefits inside the province.

Table 33 Renewable and Low-Carbon Gas Procurement in B.C. versus Imports

	Aspect	Purchase gas certioficates outside British Columbia	Develop renewable and low-carbon gas projects inside British Columbia
0.	Potential	Currently far in excess of required targets.	Sufficient to meet 15% by 2030 CleanBC target within $31/GJ threshold. Can theoretically replace entire B.C. gas consumption by 2050.
1.	Cost	Reduced cost to ratepayers if credits are purchased soon and for a long period.	Some of the gas purchased will cost more than out-of-province.
2.	Project portfolio	'Low-hanging fruit' will be developed first – mainly RNG from anaerobic digestion and landfills.	Range of pathways will be developed because B.C. offers better conditions than many other jurisdictions.
3.	Competition	Competition with other utilities and venture capital.	Less competition due to Fortis predominance as a gas utility in B.C.
4.	Control	Limited control over resources outside B.C. Credits may go to other bidders after initial contracting period.	Good control of biomass and electricity-based projects, some control over organic waste.
5.	Resilience to high price carbon markets	Some resilience if B.C. utilities are 'early movers'. High exposure to markets as regulatory framework is developed in other jurisdictions.	High resilience because B.C. utilities have right of first refusal.
6.	Impact on competing resource users	Low	Industries such as the pellet industry will see increased competition for 'energy wood.'
7.	Technology development	Limited incentives for technology development.	Developers and venture capital have incentive to develop and mature technologies.
8.	Compatibility with other B.C. government policies	Incompatible with desire to strengthen forest products industry and develop provincial renewable and low-carbon gas production.	Demand for electricity from B.C. Hydro will increase. Low-grade wood waste may be used for energy rather than higher-value products.
9.	Demand side management	Low gas prices discourage energy savings.	Increased gas prices will foster demand-side management.
10.	Cash flow	Net outflow of ratepayer money.	Ratepayer money stays inside B.C. Potential inflow of capital from out-of-province.

Table 34 takes a conservative approach for the potential of imported gases. A portion of RNG may be secured in the coming years as other jurisdictions ramp up their own renewable and low-carbon gas policies. After 2030, possibly, earlier, the first-mover advantage may cease to exist, and only incremental amounts may be secured. This is especially true in the U.S., where very high RNG certificate pricing has been observed together with rapidly increasing sales volumes.[114] This may price RNG out of reach for Canadian utilities. There is also the question of renewing RNG sales contracts after the 20-year procurement contract ends. A 20-year term is reasonable for the life expectancy of most RNG plants. At renewal, pricing is likely to adjust to market conditions, which may feature higher prices than at the start of such projects.

For hydrogen, low-cost resources such as waste hydrogen will likely be quickly secured by U.S. buyers. Turquoise hydrogen and other electricity-based gases would likely cost more in the U.S. than in B.C., and no imports are assumed. This leaves mainly blue hydrogen potential for imports. Since there is great potential inside B.C. for such gas, import needs are limited. They may still occur if B.C. production is slow to commence or if costs are lower outside of B.C. (e.g., where good sequestration opportunities exist). For the table, it is assumed that two large sources (100 tonnes per day) may be secured outside B.C. by 2030 and another two by 2050. The current wording of the GGRR does, however, not appear to allow for hydrogen imports as it requires that the gas must be delivered through the B.C. gas distribution system or directly used by a client to replace natural gas.[5]

Table 34 Anaerobic RNG and Hydrogen Import Potential

	Technical Potential, 2030	Achievable, 2030		Achievable, 2050	
Rest of Canada	60 PJ	10%	6 PJ	15%	10 PJ
U.S.	590 PJ	5%	30 PJ	7%	44 PJ
Blue hydrogen	Very large		8.4 PJ		17 PJ

The above assumptions are conservative and a more aggressive approach may deliver different results. Yet, even with these conservative assumptions, the resource outside B.C. will be more than sufficient to comply with the 2030 target. For 2050, an aggressive strategy would have to be in place to secure enough renewable and low-carbon gas production in competition with other jurisdictions. However, if certificate pricing remains high or increases, this may not be a profitable strategy.

With pricing of environmental credits over US$200 per tonne of CO_2 in recent years,[115] the value of renewable and low-carbon gases can be very high in the U.S. Table 35 provides a range of market values for different renewable and low-carbon gases, based on their carbon intensities (Cis). The higher CI value is typical for blue hydrogen, for example, whereas low positive values may apply to gases derived from solid biomass, and negative values refer to agricultural and municipal RNG. With a carbon intensity for natural gas of 60 kilograms per gigajoule (see next section), a gas that has an intensity of 30 kilograms per gigajoule would displace 30 kilograms per gigajoule. At C$260 per tonne of CO_2 under the California LCFS, this would reflect a value of $7.80 per gigajoule. Renewable Identification Number (RIN) pricing for R3 RINs (for RNG) have been about US$2.50 per RIN since 2020.[116] This corresponds to about C$38 per gigajoule – well above the current B.C. threshold of $31.[117]

[114] https://www.naturalgasintel.com/renewable-natural-gas-potential-just-scratching-the-surface-but-obstacles-remain/ (Accessed October 5, 2021).
[115] https://ww2.arb.ca.gov/resources/documents/lcfs-credit-clearance-market (Accessed October 5, 2021).
[116] https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rin-trades-and-price-information (Accessed October 5, 2021).
[117] https://www.waste360.com/gas-energy/where-renewable-natural-gas-moving-forward-and-what-will-mean-industry-and-states-part-2 (Accessed October 5, 2021).

Table 35 Current U.S. RNG Certificate Pricing, in C$*

Gas Carbon Intensity	RIN Value	LCFS Credit Value**	Total
30 g/GJ	$38	$7.8/GJ	$46/GJ
5 g/GJ		$14.3/GJ	$52/GJ
-100 g/GJ		$41.6/GJ	$80/GJ
-400 g/GJ		$117/GJ	$155/GJ

* Converted from US$ at a rate of C$1.3/US$

** Depends heavily upon the California Low-Carbon Fuel Standard Credit price, which has been as low as US$71/tonne in June 2017 and as high as US$217/tonne in February 2020. The price in October 2021 was US$158/tonne.[118]

The important takeaway from this table is that at current pricing levels, it is impossible for B.C. utilities to buy even gases with a comparatively high CI through certificate trading as pricing is higher than the C$31 per gigajoule threshold. This may change in the future but the best strategy is to source the gas from projects through long-term purchasing agreements at the investment stage. This implies high transaction costs and a limitation to greenfield projects or projects that have previously sold their gas into different markets (e.g., using biogas for power generation). Blue hydrogen does not fall under the RIN system but would earn LCFS credits in the U.S.

A strategy for gas utilities in B.C. is to secure renewable and low-carbon gas supplies outside the province to hedge against the risk of insufficient resources below the ceiling price in B.C. by 2030. This is a no-regrets strategy since utilities can sell surplus credits into the gas credit market later if there are enough low-cost gas sources in the province. If credit pricing remains high, this may mean that profits can be obtained from such activity, which could in turn reduce the cost of gas for B.C. ratepayers. Sourcing renewable and low-carbon gases provincially should still be a priority as it creates the support structures that establish this industry in B.C.

5.5 Carbon intensity and emission reductions of supply portfolios

The potential that this report has established is based on petajoules of renewable and low-carbon gas rather than tonnes of CO_2e displaced. A policy switch away from energy and towards carbon abatement as a measuring parameter would have to look at a different metric to measure compliance with GHG targets. This section assesses the carbon mitigation that can be achieved with the existing potential.

The various pathways differ in their use of resources and thereby in the amount of greenhouse gases (GHG) emitted. The spreadsheet model factors in carbon credits from the displacement of GHGs that would occur in the absence of the project. Using GHG emission factors published by the B.C. Ministry of Environment and Climate Change Strategy (MECCS)[119] and other data, the model determines the carbon intensity of each pathway. Literature values are also used to determine the reported range of carbon intensities. The carbon intensity can vary significantly from one pathway to another, or even between projects within the same pathways, especially when methane is emitted, a powerful GHG with a high global warming potential.

Carbon emissions of agricultural and municipal RNG: Most pathways described in this report have a GHG footprint lower than that of natural gas. Agricultural RNG, especially from projects involving liquid manure (such as dairy and hog farms), even has a strong negative carbon intensity as it captures methane that

[118] Source: California Low Carbon Fuel Standard Credit price | Neste.

[119] BC Ministry of Environment and Climate Change Strategy, « B.C. Best Practices Methodology for Quantifying Greenhouse Gas Emissions, 2020 », Victoria, B.C., April 2021.

would have escaped from manure stored in open pits.[120] Some of the carbon intensities reported do not include GHG emissions that happen outside the digester. Digestate is removed from the digester while anaerobic reactions continue to produce uncaptured methane for a while. Many life-cycle analyses include some emissions from digestate in the actual facility and some from spreading digestate on the land. The 'GHG Genius' model used by the government may not include the latest data and may exclude some emissions associated with digestate.[121]

Carbon emissions of RNG from landfill gas and WWTPs: At times, landfill gas and WWTP RNG projects reportedly have higher CI scores than natural gas in B.C. This is because most CI data for landfill gas and WWTP RNG projects comes from the California LCFS, which counts GHG emissions during RNG production and from the transportation and compression of RNG to approximately 3,600 PSI (248 bar) for use as vehicle fuel. As such, if landfill gas and WWTP RNG projects are built in U.S. states with high CI electricity, the CI of the RNG can be quite high.

Carbon emissions of natural gas: Similarly, fugitive emissions from the extraction of natural gas, especially related to hydraulic fracturing, may result in significantly higher GHG emissions than stated. The burner tip emission intensity of natural gas (close to 50 kg per gigajoule) needs to be augmented with upstream emissions, currently estimated at between 6 and 12 kilograms per gigajoule for B.C. natural gas.[122] Recent remote measurements indicate that this may still be an underestimation by a factor of two as some fugitive emissions have not been captured in previous ground surveys.[123] Any uncertainties with respect to natural gas also apply to natural gas-derived low-carbon gases.

Carbon emissions of blue hydrogen: Converting methane into hydrogen is an overall endothermic process, that is, heat/steam must be supplied to the process for the reaction to proceed. This steam is usually produced using natural gas as a fuel. The CO_2 emissions from the steam boiler may or may not be captured and sequestered. Powerful compressors are used to inject and sequester the captured CO_2 into geological formations. These pumps may be fuelled by green electricity or by natural gas. Hydrogen has a lower calorific value than natural gas (12.7 gigajoules per standard cubic metre as opposed to 39 gigajoules per standard cubic metre) requiring more pump energy per gigajoule to deliver gas through the pipeline to the end user. Most natural gas compressor stations are powered by gas-powered combustion engines,[124] which vent exhaust emissions into the atmosphere.

Blue hydrogen merits a closer look due to the uncertainties and technology pathways that can lead to significant differences in carbon intensities. The Pembina Institute evaluated the carbon intensity of blue hydrogen produced with different technology pathways. In that they found that existing steam methane reforming (SMR) technologies employed like at the Quest upgrader in Alberta leads to a modest reduction in carbon intensity.[125] Other studies suggest even higher GHG emissions for blue hydrogen than for natural

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[120] This is considered for the California LCFS but currently not for the B.C. LCFS, which may lead to very different carbon credit values from the same source.
[121] Fusi et al., "Life Cycle Environmental Impacts of Electricity from Biogas Produced by Anaerobic Digestion," March 2016, Front. Bioeng. Biotechnol., Accessed on October 8, 2021 at https://doi.org/10.3389/fbioe.2016.00026
[122] Liu, Ryan *et al.*: Greenhouse Gas Emissions of Western Canadian Natural Gas: Proposed Emissions Tracking for Life Cycle Modeling. *Environ. Sci. Technol.* 2021, 55, 14, 9711–9720
[123] Tyner, David and Johnson, Matthew: Where the Methane Is - Insights from Novel Airborne LiDAR Measurements Combined with Ground Survey Data. *Environ. Sci. Technol.* 2021, 55, 9773–9783
[124] Enbridge, "Transporting Natural Gas", accessed on Dec 4, 2021 at https://www.enbridge.com/about-us/natural-gas-transmission-and-midstream/natural-gas-101/transporting-natural-gas/compressor-stations
[125] Gorsky et al., Pembina Institute, "Carbon intensity of blue hydrogen production", Aug 2021, accessed on Jan 28, 2022 at https://www.pembina.org/pub/carbon-intensity-blue-hydrogen-production

gas.[126,127] Pembina's report states that "*there are a wide range of carbon intensities for blue hydrogen, depending on the choice of technology (SMR or ATR), carbon capture rate, emissions associated with imported electricity, and the emissions from natural gas production (which vary by production basin).*"

A robust regulatory framework that addresses upstream GHG emissions sources like fugitive methane and supports best available technologies is important to ensuring that blue hydrogen production pathways are as low-carbon as possible to align with long-term GHG reduction goals.

Carbon emissions of wood-fuelled gas: Using roundwood for energy purposes accelerates the emission of carbon contained in the wood, and creates a carbon dept that must be paid back through regrowing felled trees over time. This is because there is essentially no residence time for carbon in the final product (i.e. the fuel) before energy is created, as opposed to lumber which might remain in solid form for decades or centuries before disposal. For mill and harvesting residue, convention typically attributes the majority of emissions to the harvested wood products, such as dimensional lumber or pulp. The residue is then counted as close to carbon neutral. In the Maximum scenario, some roundwood is harvested to produce RNG or hydrogen. The initial carbon removal that is reported as a loss in the Canadian GHG inventory when a tree is cut would then be attributable to this portion of the feedstock. RNG made from wood then has a similar carbon footprint as natural gas, since the carbon in the RNG produced is counted as an emission. Unlike with natural gas, however, trees regrow over time and the carbon debt is then paid off as the same amount of CO_2 is sequestered as harvested stands are renewed. The B.C. carbon stock accounting system is not yet set up to capture these processes fully. Over a 50-to-100-year timeframe, roundwood is also carbon neutral. It will be a policy decision as to how temporary emissions from roundwood for energy are accounted for, and whether and how the repayment of carbon debt enters the equation.

The examples above show that refining emission factors and quantification protocols is still on-going and substantial uncertainties exist with the GHG profile of some of the pathways discussed in this study. The factors published by MECCS, largely used in this study, may reflect neither the latest science on the full upstream emissions of natural gas exploration nor the downstream emissions of biogas production. As science improves, carbon accounting protocols will change. MECCS updates its "B.C. Best Practices Methodology for Quantifying Greenhouse Gas Emissions" on an annual or bi-annual basis.

A climate change strategy that is largely based on blue and turquoise hydrogen or on anaerobic digestion might be at risk of having to correct the carbon intensities of these pathways over time. This may become important as the Government of B.C. is contemplating switching from targets pegged to energy production to those related to GHG intensity. Figure 34 provides the carbon intensities used in this report (solid green bar) and the range that could be gleaned from some published studies.

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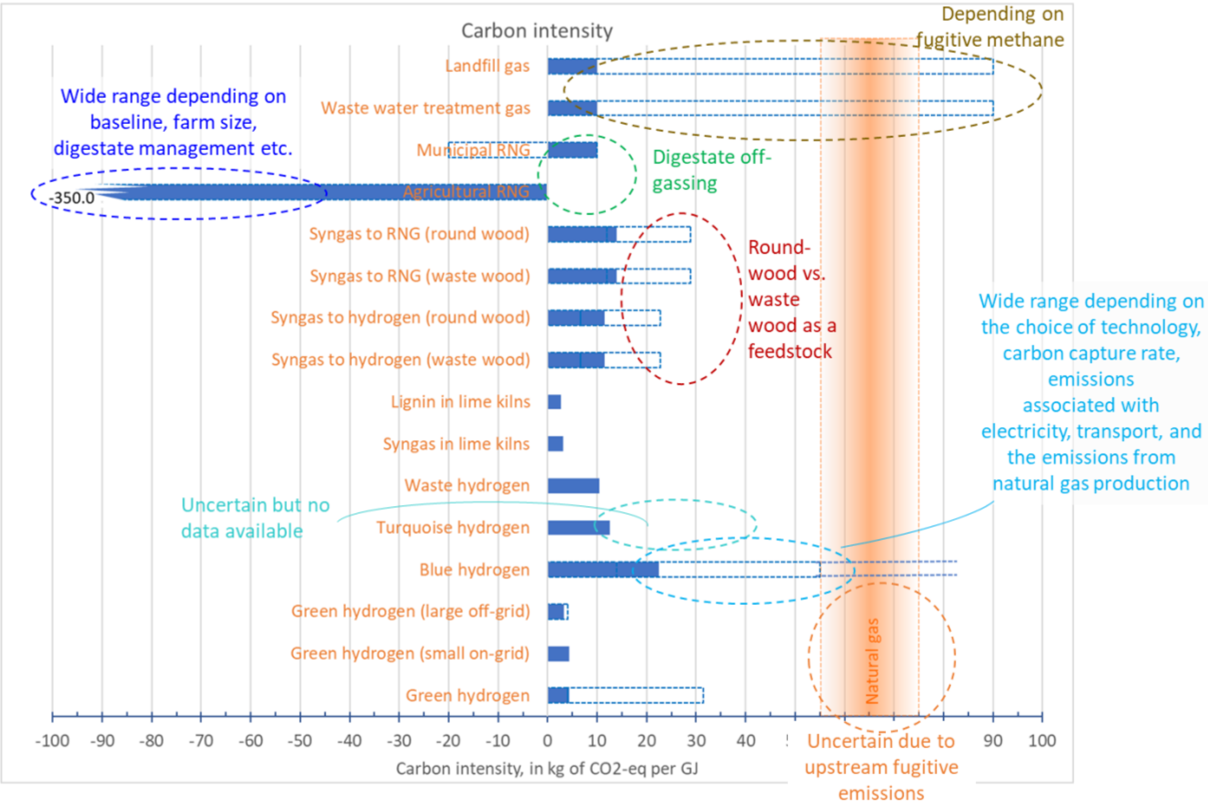
[126] Bauer et. al., "On the climate impacts of blue hydrogen production", Sustainable Energy and Fuels journal, Issue 1, 2022, accessed on Jan 28, 2022 at https://pubs.rsc.org/en/content/articlelanding/2022/se/d1se01508g

[127] Robert W. Howarth, Mark Z. Jacobson, "How green is blue hydrogen?" *Energy Science and Engineering*, August 2021, accessed on on Jan 28, 2022 at https://onlinelibrary.wiley.com/doi/full/10.1002/ese3.956

Figure 34 Carbon Intensities of Renewable and Low-Carbon Gas Pathways as reported in literature



<u>Notes</u>:

- Dashed bars indicate the range of factors stated in various publications.
- Error bars represent uncertainty with respect to life-cycle GHG emissions for various pathways.
- For anaerobic RNG, uncertainty arises with both accounting methodologies (including avoided emissions from lagoons in the agricultural sector, consideration of methane off-gassing from digestate), fugitive emissions (e.g., leakage from repeated gas transfers), as well as indirect emissions (compression to high pressures for use in transportation using more or less green electricity).
- Different conversion technologies and energy types used for gas production from wood will result in different CI values.
- For green hydrogen, the CI of the electricity used determines the CI of the hydrogen produced.
- For both natural gas and or turquoise and blue hydrogen, upstream emissions from gas production, conversion, sequestration and transport, as well as CO_2 leakage from geological storage can have impacts.
- No data is available for turquoise hydrogen but uncertainties will likely be in the same range as for natural gas.

6.0 CREATING THE B.C. RENEWABLE AND LOW-CARBON GAS INDUSTRY

6.1 Key considerations and Desired Outcomes

As discussed in Section 5.4.1, there are many considerations for the choice of renewable and low-carbon gas pathways for B.C. The B.C. Government wants to weigh three main considerations:

(a) Achieve the CleanBC *Roadmap to 2030* goals, including a minimum of 15% renewable being retailed in B.C. by 2030, reducing emissions while supporting a strong economy, supporting innovation, and implementing a cap on emissions for natural gas utilities.

(b) Keep the cost of pipeline gas affordable. Low gas prices are important to keep energy costs affordable in the province. Increasing energy costs disproportionately affects the poor and energy-intensive industries. Changes must be gradual and must occur in a considered way to be socially acceptable.

(c) Develop a bioeconomy within B.C., maximizing socio-economic benefits for the province. The renewable and low-carbon gas should be made in-province. Producing gas from local biomass can increase local benefits over the current situation, especially if wood fuel exports were redirected towards provincial renewable gas production. It could also stabilise the forest product industry if BC Hydro contracts expire without renewal around 2029. In addition, the gases produced should have a low (or negative) carbon intensity.

These considerations lead to the question of how best to support a transition towards renewable and low-carbon gas use in B.C. and what types of policies should be implemented, above and beyond those currently in place.

6.2 Best Policy Pratices in Other Jurisdictions

6.2.1 Main Policy Approaches

The promotion of anaerobic RNG and other renewable and low-carbon gas types, takes place across a broad spectrum of policy areas ranging from agricultural/forestry, waste, energy, climate, and general environmental policy. As illustrated in Figure 35, the RNG value chain can be affected and enhanced at several stages, including facilitating feedstock acquisition, creating a demand-pull using incentives or mandates, and a regulatory environment that supports RNG deployment.

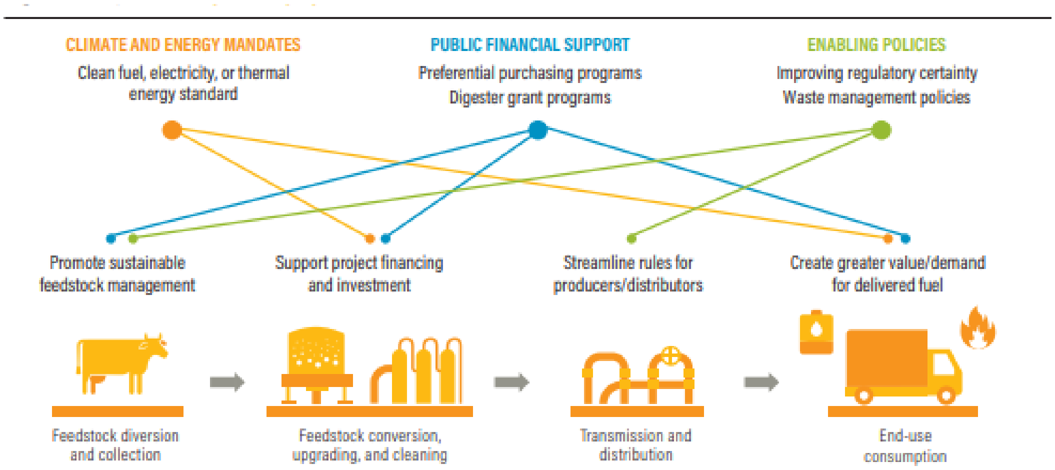


Figure 35 Policies Promoting the Development of RNG[128]

[128] Cyrs, Tom, John Feldmann, and Rebecca Gasper. 2020. "Renewable Natural Gas as a Climate Strategy: Guidance for State Policymakers." World Resources Institute. https://doi.org/10.46830/wriwp.19.00006.

Countries and states have created legislation regarding renewable energy to diversify their energy resources, promote provincial energy production and encourage economic development. Three approaches to promoting renewable energy have evolved over the last decades.

1. Renewable Portfolio Standards (RPS) or Clean Energy Standards (CES) are quantity-based schemes in which the regulator requires a specific amount or proportion of gas to come from renewable or 'clean' low-carbon sources. A carbon intensity standard is a variation of this approach.
2. Feed-in tariffs (FIT) guarantee all eligible producers a fixed price per gigajoule of gas fed into the grid. The tariffs are linked to standardized and simplified interconnection rules.
3. Public tenders: A certain amount (in gigajoules per year) or value (in $ of investment) for renewable or low-carbon gas is publicly tendered and sold to the lowest bidder or bidders with the highest volume.

Table 36 outlines key features of each instrument. All of them have been tried and tested in the electricity sector over the last decades. There are variations of, and supplementary policies for, each of them used in various jurisdictions. These are described below.

Table 36 Policy Instruments for Promoting Renewable and Low-Carbon Gas Production

	Renewable Portfolio Standard, Clean Energy Standard or LCFS	Feed-in tariff or premium system	Public tenders or auctions
Approach	Quota for renewable or low carbon gas or quota for maximum GHG intensity.	Set price for renewable or low-carbon gas fed into the grid, or premium/ bonus paid on top of fossil natural gas price.	Individual tenders for a certain type of renewable or low carbon gas. Reverse auction mechanism.
Mechanism	Volume-based	Incentive-based, can be restricted by total target volume.	Either volume or price-based.
Technology	Technology neutral. Only eligible technologies.	Technology specific. Carve-outs for specific technologies.	Technology-specific
Control of portfolio	Investors and producers decide which pathway/technology is used.	Government controls tariff for each pathway/ technology.	Tender specifies type and volume of gas, typically large projects only.
Target control	Penalty for not reaching target(s).	Markets and tariff decide uptake. Cap and floor for premiums	Penalty for winning and then not implementing capacity.
Certificate trading	Possible	Not possible.	Not possible.
Investment security	No investment security.	Stable cash flow insulates investors from revenue risks.	Binding investment limit. High risk for investors.
Adminis-trative effort	Low	Medium	High
Build-out / installed capacity	Build-out rate dependent on target.	Robust short-term growth and high build out if incentives adequate.	Many bids end up being too low and projects fail.

	Renewable Portfolio Standard, Clean Energy Standard or LCFS	Feed-in tariff or premium system	Public tenders or auctions
Local development	Certificate trading may not encourage local development.	Incentives for selective technologies can promote local and specific local development	Frequently larger bidders from out-of-province.
R&D	Lowest price technologies succeed. Little R&D.	Stimulates R&D input to reduce costs.	Lowest-price technologies succeed. Little R&D.
Cost-effective-ness	Least-cost instrument. Competition between technologies. Self-corrects. More efficient to reduce GHG emissions and cost to ratepayers.	Lack of competition leads to higher cost than RPS. Requires continual adjustment by government/utility board Low transaction cost and low risk leads to low financing cost.	Strong push for low costs but some projects then fail due to often higher than expected cost. High transaction costs.
Impact on ratepayers	Lower social risk than feed-in tariff.	Cost to ratepayer may be volatile.	Typically, lower than feed-in tariff
Key challenges	Low build-out pace.	Social acceptance might decline with increased costs to ratepayer.	Top-down approach often does not meet with reality on the ground. Monopolizes production. Political insecurity.
Compatibility with existing B.C. policies	15% renewable gas commitment Low-carbon fuel standard.	Eligible CI can be defined. Maximum cap for total or per category and per year can be defined.	BC Hydro approach to buying power from third parties.

6.2.2 Current B.C. Policy

B.C. currently has a favourable policy framework for RNG development, including market support. Both pipeline gas and vehicle fuel are supported by B.C.'s Renewable Portfolio Allowance and the LCFS. The B.C. commitment to source 15% of renewable gas in gas sales is currently the most ambitious in Canada, higher than the current 10% by 2030 target for renewables gases in Quebec, which has very similar natural gas retail demand to B.C.[129] The carbon tax of $45 per tonne of CO_2e is among the highest in North America and is scheduled to rise to $50 in 2022,[130] then to increase at least in line with federal rates. However, the

[129] https://www.quebec.ca/en/government/policies-orientations/plan-green-economy (accessed November 22, 2021)

[130] https://www2.gov.bc.ca/gov/content/environment/climate-change/clean-economy/carbon-tax (Accessed October 11, 2021).

LCFS and voluntary purchase program have been the key drivers of growth in RNG. Under the 2018 CleanBC Plan and the 2021 *Roadmap to 2030*,[131] several targets related to RNG were announced:[132]

- Minimum 15% renewable gas target by 2030.
- Increase in the Carbon Tax to $50 per tonne by 2022, then to meet or exceed federal tax levels,
- Tripling the LCFS from a 10% reduction in carbon intensity in 2020 to a 30% reduction by 2030.
- Aiming to get to 95% organic waste division and capturing 75% of landfill gas by 2030.
- A GHG emissions cap of approximately 6 Mt of CO_2e per year for 2030 for gas utilities.

Follow-up policies have included purchases of CNG buses which can easily be switched to RNG, and an Organic Infrastructure Fund, which provided $30 million of funding from various sources to improve organic waste management. Also, the Organic Matter Recycling Regulation Intentions paper calls for stricter environmental assessments and controlled atmosphere composting (negative air pressure, biofilters, leachate control for all composting facilities that consume over 15,000 tonnes of food waste or biosolids per year).[133]

At the local level, some municipalities are interested in reducing and perhaps eliminating residential natural gas use as part of their climate action strategy. Such jurisdictions include the City of Vancouver, which has the power to control its building code, and the City of North Vancouver, which allows a less strict step code adoption for natural-gas-free buildings.[134]

6.2.3 Canadian Clean Fuel Standard and Other Federal Policies

While originally planning to have separate streams for solid, gaseous and liquid fuels, the Canadian Government announced in 2020 that the Clean Fuel Standard will only apply to liquid fuels,[135] however RNG used in vehicles can be used to generate compliance credits. The Clean Fuel Standard will require a 13% reduction in fuel carbon intensity below 2016 values by 2030.[136]

The federal carbon tax is currently (2021) at $40 per tonne of CO_2e and will increase to $50 in April 2022. The government's intent is to increase it further, to $170 (nominal) per tonne in 2030.[137] This will apply to fossil natural gas in the pipeline, thus reducing the price differential between renewable and low-carbon gases and natural gas. This will also increase costs for renewable and low-carbon gas production where natural gas is used for process heat (some of the wood gasification processes).

6.2.4 U.S. Policies

Policies at the state level vary between states, with California having the most comprehensive set of policies. Most RNG policies have centred around its use as a vehicle fuel. This is primarily through its use in compressed natural gas vehicles, which currently have a 40% RNG market share in the U.S.

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[131] B.C. Ministry of Environment (2021) CleanBC: Roadmap to 2030

[132] B.C. Ministry of Environment (2018) CleanBC: Our Nature, Our Future, Our Power.

[133] B.C. Ministry of Environment (2018) OMRR Policy Intentions Paper.

[134] https://www.nsnews.com/local-news/north-vancouver-district-probes-gas-free-future-3123997 (Accessed October 5, 2021).

[135] https://gowlingwlg.com/en/insights-resources/articles/2021/canadian-clean-fuel-regulations/ (Accessed October 18, 2021).

[136] https://www.canada.ca/en/environment-climate-change/services/managing-pollution/energy-production/fuel-regulations/clean-fuel-standard/about.html (Accessed October 11, 2021).

[137] https://www.cbc.ca/news/politics/carbon-tax-hike-new-climate-plan-1.5837709 (Accessed October 11, 2021).

Some states have made significant changes, with Washington, Oregon, California and Nevada developing either voluntary or system-wide RNG policies. The combined Federal Renewable Fuel Standard credits (called 'Renewable Indentification Numbers' or 'RINs') and California's LCFS credit value adds up to around C$21 to C$107 dollars per gigajoule (see also Table 35), with most RNG being over C$31 per gigajoule. California's population and economy are larger than all of Canada and several other states have also implemented RNG policies. Considerable demand could be generated in these jurisdictions and B.C. utilities may only compete with difficulty. On the other hand, enhanced electrification and other low-carbon fuels may limit demand for RNG in the U.S. market. Nonetheless, with RNG being the first mass-produced advanced biofuel, competition with the U.S. is likely to increase in the long-haul trucking sector.[138]

LCFS programs are under discussion in the U.S. northeast and mid-Altantic[139] (Transportation and Climate Initiative). Minnesota, Colorado, Iowa, South Dakota and others are considering LCFS policies , which may significantly increase demand for low-carbon and renewable fuels. When all the proposed and existing LCFS policies are considered, demand for low-carbon-intensity fuels should increase significantly. This is noteworthy, as the Californian LCFS alone has sparked considerable RNG development across the continent, with RNG being purchased from as far away as Quebec. With increasing demand for renewable and low-carbon fuels, prices are expected to rise, particularly for very low and negative carbon intensity projects RNG. Any first-mover advantage that B.C. utilities may currently have when securing supplies of low-cost RNG will likely disappear over the coming years.[140]

State-level policies are also driving RNG demand for the natural gas utility sector. California, Washington, Oregon and Nevada are all developing either voluntary or mandatory procurement of RNG by their natural gas utilities. Other noteworthy policies include organics diversion mandates in some states (California, Connecticut and Massachusetts)[141] and low-interest loans for RNG projects in Iowa.[142] California also has a program to extend infrastructure to large clusters of dairy farms.[143] Wisconsin and Washington State have funded agricultural digesters to reduce agricultural impacts on lands and water. Finally, watershed nutrient trading is considered, which allows farmers to trade nutrient permits and thus provides economic support to solutions such as anerobic digestion.[128]

Table 37 provides an overview of the most relevant U.S. policies affecting renewable and low-carbon gas production and markets. One can cnoclude that competition for RNG and RNG certificates will increase further with time. Especially California's LCFS market provides higher financial gains than B.C.'s. Quebec also recently announded renewable gas portfolio targets that are comparable to those of B.C. There is a risk that provincially produced RNG will leave the province.

[138] EBA/WBA (2021) Smart CO2 Standards for Negative Emissions Mobility.
[139] https://www.transportationandclimate.org/ (Accessed October 11th, 2021).
[140] https://thejacobsen.com/news_items/states-considering-lcfs/ (Accessed October 11th, 2021).
[141] https://www.biocycle.net/organic-waste-bans-recycling-laws-tackle-food-waste/ (Accessed October 11, 2021).
[142] https://www.legis.iowa.gov/docs/publications/BL/1207158.pdf (Accessed October 11, 2021).
[143] https://www.act-news.com/news/massive-rng-supply-boost-in-california-dairy-digester/

Table 37 Current U.S. Policies Pertaining to Renewable and Low-Carbon Gas[144,128]

State	Low-Carbon Fuel Standard	RNG Pipeline Sales	Infrastructure/Other
California	• State LCFS[145]	• Biomethane target under development. • Utilities' (Southwest Gas, SoCalGas and SDG&E) RNG purchases including eliminating price caps for the last two (voluntary program).	• Clusters for Dairy RNG, including infrastructure funding. • Organics landfilling regulations • Cap and Trade program at state level • Short-lived Climate Pollutants plan. • Ability for developers to establish grid connection and requirement for reasonable time period for utilility. • Standardised interconnection procedures among gas utilities to facilitate RNG production • Dedicated pipelines to large, industrial dairy farm clusters
Washington	• State LCFS under development[146]	• Under development to allow either voluntary or system-wide RNG sales.[147]	
Oregon	• LCFS under development with a target of 25% below 2015 levels by 2030	• Target for 5% RNG with thermal energy credits under development. Some integration with state LCFS.	• Cap-and-reduce program for RNG to reduce GHG intensity of gas distributedin state.
Iowa			• Low-interest bonds for farm RNG development.
Nevada	• LCFS envisaged[148]	• Utilities allowed to sell RNG. Encourages RNG to be in supply portfolio.	

6.2.5 Recommendations for B.C.

B.C. has a robust framework for the development of RNG with strong price support for deployment. One threat to this leadership is competition from the California market due to the very lucrative combination of the federal Renewable Fuels Standard and state-level LCFS revenues. Acquiring RNG from out-of-province could become increasingly difficult, particularly for low or negative-carbon intensity RNG

144 https://www.rngcoalition.com/policies-legislation (Accessed October 11th, 2021).
145 https://energynews.us/2021/05/13/california-clean-fuel-standard-sparks-renewable-gas-boom-in-midwest/ (Accessed October 11th, 2021).
146 https://ecology.wa.gov/Air-Climate/Climate-change/Greenhouse-gases/Reducing-greenhouse-gases/Clean-Fuel-Standard
147 http://biomassmagazine.com/articles/15172/inslee-signs-bill-to-promote-rng-in-state-of-washington
148 https://www.argusmedia.com/en/news/2165860-nevada-includes-lcfs-in-climate-strategy (Accessed October 12, 2021).

products. B.C.'s first-mover advantage can be used to procure RNG from projects where it can be secured with 20-year contracts. This hedges against stronger than expected costs from locally produced gas. If locally-produced gas can then be procured, any excess gas credits can be sold into the open market. The following areas should also be addressed to expand renewable and low-carbon gas production in B.C.:

Feedstock:

1. Continue working on improving the ability to recover harvesting residue through subsidies (Forest Enhancement Society programs) and the supply chain, using better methods and technologies.
2. Implement meaningful cost mechanisms to motivate forest product companies to recover most of the harvesting residue.

Financial:

1. Low-interest financing could be provided for agricultural digesters (and other types of gas production), as done in Iowa.
2. Provide funding to support the additional cost of RNG deployment over composting or other organics/wastewater solids disposal options.
3. Work with agricultural organizations to promote cooperatively-owned or operated centralized RNG plants, including a possible sustainable agriculture payment scheme for digestate use and soil carbon enhancement.
4. Financially recognize the broader social and ecological benefits of anaerobic RNG production, as AD with nutrient management can play an important role in preventing nutrient overload on lands and waters, increasing soil carbon, reducing methane emissions, and providing a low-carbon fuel for the gas grid and NGVs.
5. Continue to support R&D and demonstrationand first commercial-scale facilities to produce low-carbon gas.
6. Create mechanisms to support renewable and low-carbon gas production at larger scales from woody feedstock, such as higher gas rates being paid during the first years of operation to shorten payback periods, or low-cost, long-term financing for capital-intensive projects.

Infrastructure:

1. Work within B.C. and with neighbouring jurisdictions to make the gas system hydrogen-ready.
2. Proactively plan for network meshing, reverse flows and other measures to integrate renewable and low-carbon gas.
3. Work with BC Hydro to ensure that enough new power generation capacity is available after 2029 to enable green and turquoise hydrogen production in B.C. Electrolytic hydrogen production could be linked to on-grid power production commensurate with new demand and based on facilitated grid access for new renewable power generation linked to, but not necessarily in close proximity to hydrogen production hubs.

Regulatory:

1. Prioritize AD over composting when treating separately collected organic waste.

2. Allow for an average renewable and low-carbon gas cost of $31 per gigajoule, instead of the $31 ceiling, to facilitate demonstration projects and green hydrogen at higher costs (without requring BCUC approval each time), as was proposed in a previous study.[227] This would enable increased provincial production during the initial years; the cost cap could then be reduced over time.
3. Consider a renewable gas feed-in tariff that assigns cost thresholds depending on the pathway used, similar to feed-in tariffs in the electricity sector. Mature low-cost pathways may have lower thresholds than technologies under development. These cost caps should be reduced over time as prices come down.
4. If the current percentage target is retained, define five-year carve-outs for each pathway that require gas utilities to buy gas from several different sources rather than only the lowest-cost ones.
5. Alternatively, a carbon cap that requires utilities to account for the life-cycle carbon intensity of renewable and low-carbon gases fed into the pipeline could lead to a more diversified mix where more expensive sources may still be preferred if they have low or negative CIs.
6. In the longer term, consider coupling green hydrogen production with grid balancing and for energy storage to remunerate such services with revenue created from hydrogen production and release on demand, to create incentives to add green hydrogen production.

Climate:

1. Examine means to incorporate climate benefits from lower nitrogen fertilizer use and increased soil carbon due to the use of digestate from anaerobic RNG production.
2. Align international GHG quantification protocols to better compete in the international market.
3. Review the carbon footprints of blue and turquoise hydrogen and the anaerobic pathways to ascertain their impacts in terms of GHG emission reductions.

Demand-side management and technology switching:

This study focuses on the supply potential for renewable and low-carbon gas production pathways. Pathways beyond renewable and low-carbon gas are outside the scope of this report. A more comprehensive approach would compare primary energy use of various pathways in a 'well-to-heat' manner. Currently, 45% of natural gas consumed in B.C. is used by the residential and commercial sector.[149] The residential sector alone uses around 48 petajoules per year of natural gas for low-temperature space heating.[150] This need for low-temperature heat can be met more effectively by pathways other than low-carbon gas.

For example, green hydrogen can be produced with a conversion efficiency of 65% to 75% of the electricity used. Methanation of syngas to produce RNG is expected to have 95% conversion efficiency. A downstream household may use renewable gas in its furnace or boiler at a seasonal efficiency of 80% to 85%. The total system efficiency multiplies to 46% to 61% of the electricity input. In comparison, an air-source heat pump used in the climate of southern coastal B.C., where most of the population is located,

[149] https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/provincial-territorial-energy-profiles/provincial-territorial-energy-profiles-british-columbia.html (Accessed October 17, 2021).
[150] https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/showTable.cfm?type=CP&sector=res&juris=bc&rn=8&page=0 (Accessed October 17, 2021).

can achieve a coefficient of performance (equivalent to an efficiency) of 300% to 350% of the electricity used, i.e. it is six to eight times more efficient than heating with gas.

The life expectancy of residential buildings in Canada ranges from 42 years for apartment buildings with less than five storeys to 65 years for single detached and row houses and 80 years for large apartment buildings.[151] Assuming an average age of the residential housing stock of 36 years[152] (in 2021), a large share of B.C.'s building stock will be replaced within the 29 years between 2021 and 2050. This offers opportunities to switch from natural gas to alternative forms of heating. The goal of 15% renewable gas may be achieved more easily by switching technologies than by switching to low-carbon gas.

6.3 Infrastructure, Innovation and Technology

6.3.1 A comprehensive approach

Summarizing the issues discussed above, several measures should be considered to fully enable a transition towards renewable and low-carbon gas that relies to a large degree on provincial resources. This includes:

- **Feedstock:** One key resource is forest harvesting residue. More than a million tonnes are available at an affordable cost today and more could be sourced with better technologies and supply chains. Whereas Scandinavian harvesting models may not be directly transferable to B.C. conditions, subsidies (or penalties) to enhance residue recovery and better approaches to recovering the material, such as integrated harvesting, are needed.
- **Electricity:** B.C. has significant potential for wind farm development, a resource that could be used for hydrogen production. Major investment in wind farms and related transmission infrastructure would be required if green hydrogen is to form a substantial part of a low-carbon, gas-production strategy.
- **Technology development:** Several technologies are still pre-commercial. Demonstration and further R&D are necessary to enable the production of hydrogen and/or RNG from woody feedstock. Further refinement and cost reductions are also necessary for green hydrogen. Turquoise hydrogen represents another interesting pathway that needs development support.
- **Pipeline infrastructure:** Continuing work is required to upgrade the existing natural gas pipeline network to accommodate increasing amounts of hydrogen. This should be started near hydrogen users, such as oil refineries in Burnaby and in Prince George or the ammonia plant in Trail.
- **Financing:** Capital costs to produce renewable and low-carbon gas can be very high. The forest products industry cannot accommodate long-term amortization of large investments. Systems to reduce these cost parameters through low-cost loans or other means could accelerate demonstration and deployment (see also Section 6.2.5).
- **Demand-side management and fuel switching**: The 15% renewable gas target for 2030 can be achieved easier and likely at a lower cost by reducing the demand for fossil natural gas. In the moderate climate of southern and coastal B.C., electric heat pumps can achieve GHG reductions more effectively than renewable and low-carbon gases. Similarly, pellet production and heating with pellets has a higher overall efficiency than the biomass-syngas-hydrogen-methane pathway. Switching natural gas use for low-temperature applications, such as building heat, to other fuels will reduce costs for achieving CleanBC targets. This applies especially to new construction. Vancouver City Council has

[151] https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=4610000801 (Accessed on Nov 27, 2021)

[152] https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/showTable.cfm?type=HB&sector=res&juris=00&rn=11&page=0 (Accessed on Nov 27, 2021)

approved a bylaw that bans fossil fuel appliances for low-rise buildings as of 2022.[153,154] Fossil natural gas will be phased out completely by 2050.[155] This approach could be extended to all of B.C.

6.3.2 *Investment needs*

Table 38 illustrates the investment required to realize the envisaged transition. Investment needs are around $5 billion by 2050 in the Minimum scenario and around $20 billion in the Maximum scenario. This does not include expansions or upgrades to the gas distribution network, or new power generation sources (apart from the off-grid green hydrogen pathway). Most early investment would be for anaerobic digestion, a pathway that is commercially more mature than other technologies.

Results shown in the table are taken from an Excel model that includes the cost parameters shown in Chapters 2 to 4. The corresponding amount of gas produced can be read from Figure 32 and Figure 33 in Chapter 5. This model can be used to simulate different input parameters and to model sensitivity towards varying assumptions.

Table 38 Investment Requirements, in Million Dollars (Minimum scenario)

Pathway	CAPEX per plant, 2030	Number of new plants, 2030	Total cost, 2030	CAPEX per plant, 2050	Number of new plants, 2050	Total cost, 2050	Cumulative cost, 2030 + 2050
Green hydrogen (large on-grid)	$357	1	$476	$252	1	$280	$532
Green hydrogen (small on-grid)	$15	4	$62	$11	5	$55	$66
Green hydrogen (large off-grid)	$155	0	$0	$109	1	$109	$218
Blue hydrogen	$273	3	$780	$240	7	$1,57 7	$1,817
Turquoise hydrogen	$139	0	$43	$122	3	$341	$463
Waste hydrogen	$19	1	$19	$19	0	$0	$19
Syngas in lime kilns	$35	2	$70	$25	7	$164	$189
Syngas to hydrogen	$144	0.1	$23	$80	8	$619	$699
Syngas to RNG	$270	0	$0	$150	0	$0	$150
Anaerobic RNG		*5.6 PJ*	$280 – 684		*3 PJ*	$150 – 375	$430 – 1,059
TOTAL			**$1,753 - 2,157**				**$4,584 – 5,213**

* Plant sizes vary between sites. Cost estimations based on total gas production potential.

153 www.homebuildercanada.com/news/news201214-Natural-gas-outlawed.htm (Accessed October 9, 2021).
154 City of Vancouver, "Zero Emissions Buildings Plan" (2016).
155 https://globalnews.ca/news/2958288/city-of-vancouver-votes-to-ban-natural-gas-by-2050/ (Accessed October 9, 2021).

Table 39 Investment Requirements, in Million Dollars, Maximum Scenario

Pathway	CAPEX per plant, 2030	Number of new plants, 2030	Total cost, 2030	CAPEX per plant, 2050	Number of new plants, 2050	Total cost, 2050	Cumulative cost, 2030 + 2050
Green hydrogen (large on-grid)	$357	1	$476	$252	3	$840	$1,316
Green hydrogen (small on-grid)	$15	4	$64	$11	31	$341	$405
Green hydrogen (large off-grid)	$155	1	$102	$109	5	$540	$642
Blue hydrogen	$273	3	$780	$240	29	$6,857	$7,637
Turquoise hydrogen	$139	3	$431	$122	15	$1,894	$2,324
Waste hydrogen	$19	1	$19	$19	0	$0	$19
Syngas in lime kilns	$35	2	$70	$25	7*	$164	$234
Syngas to hydrogen	$144	0.1	$23	$80	36	$2,880	$2,903
Syngas to RNG	$270	0.1	$27	$150	26	$3,900	$3,927
Anaerobic RNG		*6.3 PJ*	$315 – 770		*3.3 PJ*	$165 – 413	$480 – 1,183
TOTAL			**$2,308 - 2,763**				**$19,889 - 20,592**

* Because of the large size assumed for a syngas plant, the total is smaller than the number of kraft mills in B.C.

Investment needs are large, and vary by a factor of four between the minimum and maximum scenarios, by 2050. The $20 billion of the Maximum scenario correspond to 6.7% of the annual provincial GDP of around $300 billion, or about ten times the annual investment in the B.C. building sector.[156] Asia-Pacific countries invested about $30 billion in B.C. between 2018 and 2020, a large portion of which was dedicated to the LNG terminal in Kitimat.[157] As such, the cost of conversion to renewable and low-carbon gas production lies within the bounds of past energy infrastructure investments.

[156] https://www.saanichnews.com/news/building-investments-rose-81m-in-b-c-while-falling-across-canada/ (Accessed November 26, 2021)

[157] https://investmentmonitor.ca/insights-reports/investment-monitor-2021-report-post-covid-recovery-and-foreign-direct-investment (Accessed November 26, 2021)

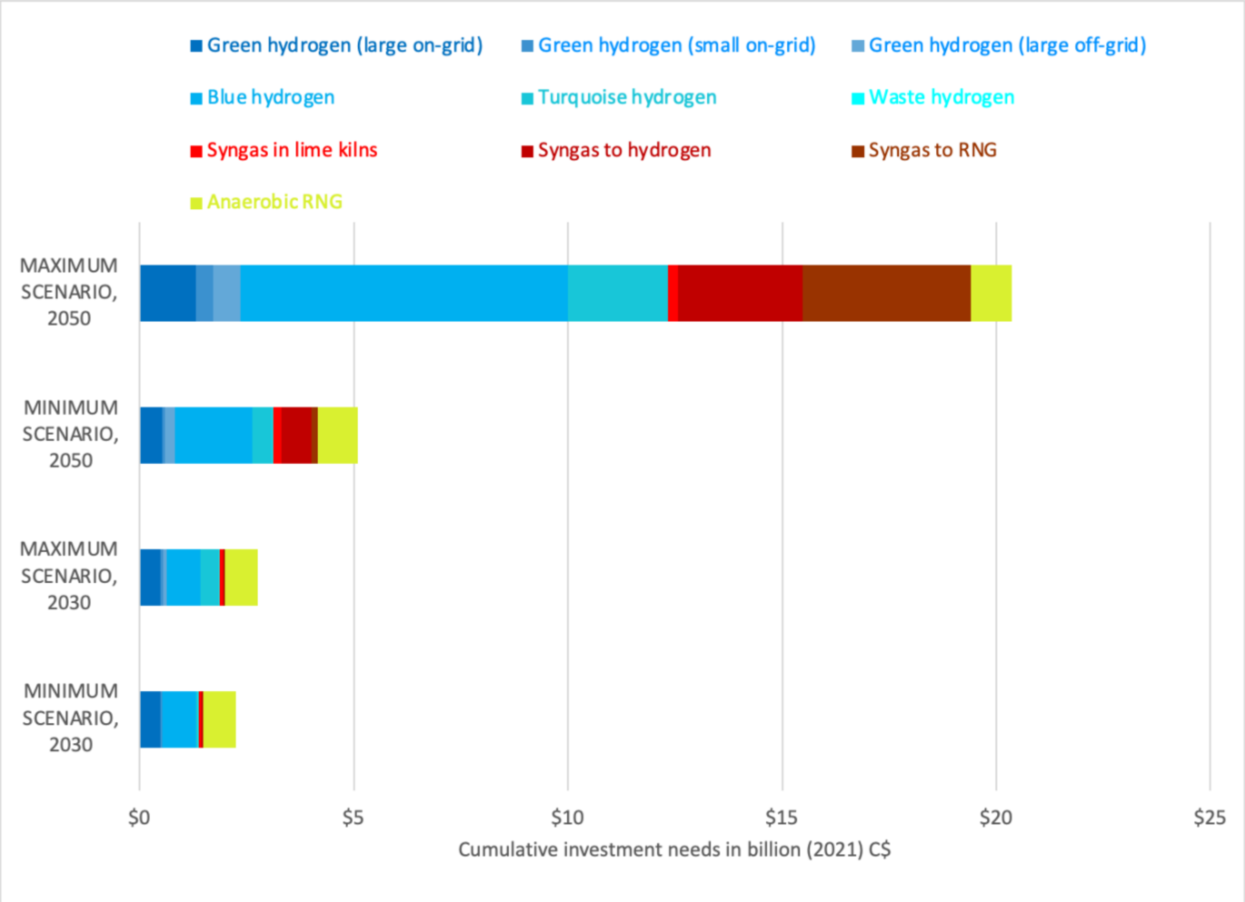


Figure 36 Cumulative Investment Needs by 2030 and 2050 in the Two Scenarios

6.3.3 Accounting for the Dynamics of a Changing Gas Production Industry

As the gas network transitions towards renewable and low-carbon gases, several aspects are changing at the same time:

- The average cost of gas from the pipeline will increase since the cost of renewable and low-carbon gases is higher than that of fossil natural gas.
- Carbon taxes are expected to increase over time, which will reduce the cost advantage of natural gas over renewable and low-carbon gases.
- The costs of renewable and low-carbon gases will decrease over time due to better and cheaper technologies.
- The carbon intensity of pipeline gas will decrease over time, as more renewable and low-carbon gases are injected – the share of fossil natural gas is expected to decrease, reducing the carbon intensity and amount of carbon tax to be paid per gigajoule.
- The pipeline gas composition will change as more hydrogen is added. This affects gas users (e.g., changed Wobbe index) and especially users that use methane as a chemical feedstock. This also concerns turquoise hydrogen production, which transforms natural gas into carbon black and hydrogen.

- Gas demand may be reduced as prices increase and if provincial strategies favour different heating technologies.

These developments have been considered at least in part in the cost model but can only be predicted with low certainty. The related uncertainties indicate the need for periodic review of the assumptions made. The latter can be modified in the Excel cost model, such that new developments can be integrated to model different outcomes.

6.3.4 Caveats With the Results of This Report

Several assumptions have gone into the preparation and underlying model of this report. These assumptions need to be verified and adapted. For users of this report, it is important to understand significant assumptions that were made for some of the pathways:

- **Anaerobic biogas:** The uncertainties are fairly minor and previous work has allowed for a fairly precise assessment of potentials, costs, and future developments. An important question is how much RNG produced in B.C. may be exported and how much RNG produced outside B.C. may be imported. This mainly depends on policies in B.C. and competing jurisdictions, and the RNG market value resulting from these policies. There is also some uncertainty about the true carbon intensity of anaerobically produced RNG, which may affect its future market potential. Any newly required technologies to reduce its carbon intensity could increase its cost. Finally, the potential by 2030 may not be realized unless there is a capital cost subsidy or other mechanism to deploy more production sites. Although the gas price offered is sufficiently high, it has not succeeded in motivating large numbers of farmers or municipalities to enter into purchase agreements with gas utilities.
- **Syngas:** The main assumption is that almost all mills can implement this technology, which is close to commercial. The potential is well understood and corresponds to current mill kiln energy demand. The main variable is the real cost of producing syngas and the reliability of the technology, which is improving quickly.
- **Wood resource:** This assessment relies on a set of assumptions, at least two of which can have major impacts on pricing and availability. These are: a) the amounts that will be available from BC Hydro PPAs expiring around 2029. It is unknown whether existing PPAs will be extended beyond this date. If they are extended, less low-cost material will become available and thus a strategy relying on large amounts of renewable gas from wood will have to account for much higher feedstock costs, including the use of some non-merchantable roundwood. Similarly, the assumption that after 2030, wood residue currently used to produce wood pellets for export may be redirected towards renewable gas production is uncertain. This material is fairly low-cost, at generally less than $60 per dry tonne, and if it does not become available, feedstock costs for future hydrogen and RNG plants will increase. Furthermore, uncertainties exist around future feedstock impacts from beetle infestations, fire damage, policy decisions impacting the AAC, and future mill closures or reopenings. At the time of writing, the treatment of old-growth forests in B.C. was under discussion and political decisions may significantly affect future AAC. All of this can have significant impacts on fibre availability and cost.
- **Hydrogen and RNG from wood:** These technologies are pre-commercial, so there is considerable risk with respect to both technology performance and related costs. Especially for RNG from wood, cost estimates vary widely.
- **Green hydrogen:** Whereas the cost parameters for green hydrogen are well understood, the future price of electricity is uncertain. Hydrogen production costs could fall after 2030 in 2021 dollars if power pricing does not increase with inflation. However, BC Hydro may need to buy more new renewable power after that date at higher costs to respond to increasing electrification demand and new users. This would leave electrolytical hydrogen one of the most expensive renewable and low-carbon gas

sources. Similar impacts would apply for turquoise hydrogen but to a much lesser degree, since this pathway has better economics than green hydrogen.

- **Blue hydrogen:** Significant uncertainty remains with respect to this pathways' carbon intensity. Future research may reveal that energy requirements for SMR, and fugitive emissions are more significant than current quantification protocols account for, which would decrease the value of blue hydrogen.
- **Turquoise hydrogen:** Similar concerns as with blue hydrogen apply to turquoise hydrogen. The technology is not mature yet and a GHG protocol needs to be developed that allocates carbon emissions between the carbon black and hydrogen products.
- **Future gas demand:** The B.C. retail market for pipeline gas beyond 2030 will depend on various developments in the industrial and building sectors, including annual growth, regulations, energy efficiency, and fuel switching. These developments may lead to shrinking pipeline gas sales in B.C. and other jurisdictions, changing the need for renewable and low-carbon gas production to reach the set targets.
- **New projects and industry changes:** Any new projects that compete for the same resources may have material impacts on the potentials identified above. For example, the CCU project announced by Huron Clean Energy will use over 300 MW of power from BC Hydro by 2025,[158] jeopardizing the addition of new electrolyser capacities through 2030 or longer. Similarly, closures of pulp and paper mills could reduce the potential for sourcing mill residue or for integrating hydrogen production plants with existing industrial operations.
- **Amortization periods:** The model uses a 20-year amortization period. This is not the usual approach for many projects. It also presupposes that a large portion of financing is provided through low-interest, long-term loans, to shorten paybacks for private equity investment. If such mechanisms are not functional, projects may not go ahead or gas pricing may be considerably higher than modelled.
- **Ownership:** The model assumes that plants are owned and operated by a private developer or an existing company, depending on the application. Each pathway has its own assumptions regarding staffing costs based on the most likely ownership model. Different ownership models may require different gas prices as they may have different cost structures.

6.3.5 Building the Renewable and Low-Carbon Gas Production Infrastructure

The transition towards renewable and low-carbon gas sources requires infrastructure upgrades. A strategy specific to infrastructure upgrades should be developed in collaboration with industry. This strategy needs to consider resource potential and related costs, as determined in the present study. Other factors to consider are geographic constraints, stakeholder interests, ratepayer impacts, regulatory issues, questions around gas imports versus provincial gas production, technical restraints to accommodate hydrogen into the gas network and competing uses for electric power and biomass resources.

This section highlights some basic considerations that can serve to inform such a strategy. This report does not recommend or suggest a 'winning' or preferred technology. Rather, actions are recommended that foster the development of all pathways considered (Table 40).

[158] https://www.alaskahighwaynews.ca/fort-st-john/carbon-capture-biofuel-plant-planned-for-bc-4514944 (Accessed October 22, 2021).

Table 40 Roadmap for Renewable and Low-Carbon Gas Pathways

	Phase 1: Develop Supply & Infrastructure 2020–2026	**Phase 2:** Commercial Expansion 2026–2030	**Phase 3:** Commercial Mainstream 2030–2050
Forestry & Feedstock	50% of roadside residue used for bioenergy.	85% of roadside residue used for bioenergy.	Integrated harvest of roundwood and residue in B.C.
Green Hydrogen	Continue R&D and observe technology developments.	Develop pilot demonstration project.	Focus on on-grid applications using new renewable energy generation.
Blue Hydrogen	Research fugitive methane emissions. Clarify hydrogen limits for existing pipelines.	Support the construction of first commercial production site near a refinery or sequestration site.	Source a portion of retailed gas from blue hydrogen.
Turquoise Hydrogen	Continue R&D and piloting of technology. Observe market developments for black carbon.	Support the construction of commercial production sites.	B.C. to become a major international player in terms of black carbon production linked to turquoise hydrogen.
Anaerobically produced RNG	The primary source of RNG in Phase 1. Continue to source RNG inside and outside B.C.	Landfill gas from all sites >1000 t/year is beneficially used. 70% of provincial potential is developed.	70% of all provincial landfill gas emissions captured and used. 90% of provincial potential is developed.
Syngas from wood	1-2 demonstration projects realised.	50% of lime kiln energy displaced by syngas.	100% of lime kiln energy displaced by syngas.
Syngas to Hydrogen or RNG	Continue R&D.	2+ demonstration projects implemented.	20-40 commercial sites developed in B.C.

Key questions to be answered for a strategy are: i) what is the timeline for recommended actions, and ii) where should new infrastructure be situated? A Geographic Information System (GIS) could be established that identifies resources, infrastructure capacities and demand from major consumers. This system will help identify the need for infrastructure upgrades. Table 41 highlights some of the elements to be considered in this GIS system.

Table 41 Development Considerations for Renewable and Low-Carbon Gas Resources in B.C.

Pathway	Location	Limitations	Comments
Green hydrogen (large on-grid)	Close to large hydrogen consumers or a natural gas transmission pipeline.	Limited by BC Hydro generation and transmission capacities.	Electricity rates too high for cost-effective production.
Green hydrogen (small on-grid)	Distributed, near loads.	Reduced impact on grid.	Electricity rates too high for cost-effective production.
Blue hydrogen	Northern B.C., near gas fields.	Long lead times.	Risk of not qualifying as a low carbon gas.
Turquoise hydrogen	Near hydrogen users, such as refineries.	Changing gas composition in grid may affect viability.	Pre-commercial Risk of not qualifying as a low carbon gas.
Waste hydrogen	Chemtrade / Hydra Energy, Prince George (see Section 4.1.5)	No other locations known.	Currently envisaged as a transportation fuel.
Syngas in lime kilns	Kraft mills	May also be used in paper mills, veneer mills, lumber drying kilns etc.	Commercial but not widely used.
Syngas to hydrogen	Pulp & paper mills, less greenfield.	Requires wood handling infrastructure.	Pre-commercial.
Syngas to RNG	Pulp & paper mills, less greenfield.	Requires wood handling infrastructure.	Pre-commercial, promising technology development.
Agricultural RNG	Lower Mainland, Vancouver Island, Peace County.	Low hanging fruit; stiff competition from other jurisdictions.	Highest carbon abatement potential.
Municipal RNG	Large urban centres	Often in cooperation with agricultural or WWTPs.	Hinges on effective organics collection system.
Waste water treatment gas	Large urban centres	Wastewater treatment plants with a 'critical mass.'	Should be made mandatory for new plants and upgrades of plants.
Landfill gas	Large urban centres	Needs at least 10 years of landfill.	Landfills produce less gas with diversion of organics

Table 42 provides a summary of ideas for a provincial strategy to foster renewable and low-carbon gas production. A full strategy would have to be created with industry input. Before engaging in strategy development, the government may want to take a more systemic approach by looking at energy use in the various sectors (residential, commercial, industrial, transport) to identify where and how overall efficiency can be increased (see Section 6.2.5) and how costs can be optimised by defining a strategy and related policies.

Table 42 Elements of a B.C. Renewable and Low-Carbon Gas Strategy

Sector	Goal	Regulation	Subsidies & Other
Forestry	• Make integrated harvesting the default approach in B.C. • More than half of all harvesting residue to be recovered by 2030.	• Create incentives to recover additional harvesting residue (e.g., increase stumpage when less is recovered). • Enhance mechanisms and funding to remove biomass from forests outside commercial harvesting, i.e., pre-commercial thinning or removal for fire prevention. • Slash burning to be (geographically) limited.	• Subsidize demonstration projects for integrated harvesting tailored to B.C. conditions. • Develop an internet platform to offer currently unharvested wood residue to potential buyers. • Work with treasury to quantify firefighting expenses and design a system to reward fire risk reduction. Develop plan to monetize benefits of increased residue harvesting.
Forest products sector	• Convert lime kilns to syngas. • Construct commercial-scale hydrogen and RNG production sites at mills. • Create new revenue streams to increase international competitivity.	• Develop rules and regulations that favour in-province renewable gas production over out-of-province purchases of RNG (for example, by offering a lower price per gigajoule for imports, due to decreased social benefits).	• Develop a new bioenergy & bioproducts strategy for B.C. • Support demonstration projects for hydrogen and RNG production from wood. • Resolve potential conflicts with mills losing the environmental benefits of renewable and low-carbon gas production and use when they sell the gas to a gas utility.
Hydrogen	• Build green hydrogen close to end users, such as refineries. • Upgrade natural gas network.	• Cannot play any major role unless $31/GJ cost cap is removed or modified. • Allowing for monetisation of grid services (energy storage, grid balancing) could improve economics.	• Review of carbon intensity of natural gas production, incl. blue hydrogen production, is necessary.
Utilities Commission	• Protect consumers. • Lower the carbon intensity of gas retailed in B.C. • Maximise social and environmental benefits for B.C.	• Consider flexibility with financing, production, and with buying gas. • Mandate carbon footprint of pipeline gas. • Consider introducing feed-in tariffs for different gas types.	• Create new funding mechanisms for commercial-scale projects. • Allow gas utilities to buy renewable and low-carbon gases at an average of $31/GJ (rather than a set maximum cost).

Sector	Goal	Regulation	Subsidies & Other
Gas utilities and gas transmitters	• Source increasing amounts of renewable and low-carbon gases. • Keep gas pricing affordable. • Hedge against high gas pricing.		• Engage with potential producers inside and outside B.C. to secure 20-year contracts. • Invite carbon black producers to B.C. by offering contracts for turquoise hydrogen. • Engage with BC Hydro and enter the queue for services early, to adjust planning for increasing amounts of electricity used for renewable gas production. • Engage with natural gas producers to facilitate blue hydrogen production.
Municipal biogas producers	• Maximise production and use in B.C.	• Widen municipal requirements to source-separate wood and organics from other waste. • Increase landfill gas use instead of flaring.	• Directly subsidize feasibility and FEED studies. • Provide bonds for WWTP upgrades and landfill gas capture. • Support demonstration of new and innovative technologies deemed to have a significant impact on advancement of biogas production in B.C.
Agricultural biogas producers	• Maximise production and use in B.C.	• Develop a Minister's Bylaw Standard for permitting agricultural digesters.	• Verify and align current GHG quantification protocols. • Reward local benefits from improved nutrient management. • Create a capital subsidy program for RNG production to accelerate deployment.
Municipal/ industrial organic waste management	• Maximise production and use in B.C.	• Require municipalities to consider anaerobic digestion when looking at compost facilities.	• Directly subsidize feasibility and FEED studies. • Provide bonds for municipalities building anaerobic digesters. • Provide support to help municipalities find long-term opportunities for land application of digestate nutrients.

Appendix A – BAT Lists

A. *Gasification of solid biomass and renewable production*

A.1 Renewable Gas Production from Solid Biomass

To produce a useful gas from biomass, the solid biomass needs to be gasified, and the resulting syngas needs to be conditioned. Unless the syngas is then used directly to replace fossil fuels, it then is further processed to maximize methane or hydrogen content. The main components of a typical facility would be:

- **Biomass pre-treatment:** depending on the gasifier type, it will require pre-treatment of the incoming biomass, such as drying and comminution. These processes are fully commercial and can be purchased to complete the other plant components.
- **Gasifier:** Several technologies exist, some of which are commercial. There was, however, no commercial biomass-to-hydrogen or -methane plant in operation at the time of writing.
- **Gas treatment:** The syngas contains a mixture of CO, H_2, CO_2, and CH_4, along with impurities and solids, and needs to be treated in order to be ready for the water-shift reaction. Several commercial gas treatment technologies (mainly, removal of tars and particulates) exist. They usually rely on gas cooling and then scrubbing or dry filtering of the syngas.
- **Water-shift reactor and methanation:** Commercial technologies exist but no commercial integration has yet taken place (see above). Compressors may be needed to achieve the required gas pressure to facilitate the reaction.
- **Hydrogen or methane separation:** Several commercial technologies exist, such as pressure-swing absorption, cryogenic or membrane technologies, and amine absorption (removal of CO_2).

A.2 Commercial Gasification Technologies

The main concerns with renewable gas production from solid biomass are the gasifier and subsequent gas treatment technologies, as well as how the entire plant is configured and operating as a whole. Gasification systems suitable for synthetic fuel product are provided by a variety of manufacturers. Several companies provide commercial, or are actively commercializing, indirectly-heated biomass gasification technologies. Table 43 presents an overview of key gasifier vendors, and their suitability to the various processes included in the project scope.

Table 43 Commercial Fluidized and Fixed Bed Gasifiers

Vendor	H_2	RNG	Lime Kiln	Products	Deployment
Synova	++	++	+	MILENA (Indirect)	Petten, NL; Portugal; India;
Enerkem	+	+	+	O_2 Blown gasifier, methanol, ethanol, jet, high octane gasoline.	Varennes, QC; Edmonton, AB; planned facilities in Tarragona, Spain and Rotterdam, Netherlands
Air Products (Texaco)	+	+	+	Over 60 Plants based on fossil fuels. Former Texaco technology	
Air Products (Shell)	+	+	+	50 plants worldwide, mainly coal	
Siemens	+	+	+	Dry feed system, can be used for a broad range of feedstock types	

Vendor	H_2	RNG	Lime Kiln	Products	Deployment
Concord Blue	++	++	+	Indirect gasifier similar to fluidized bed (called 'falling bed').	Owego, NY (MSW/Biomass); Omuta, Japan (Sewage Solids to H2); Mahad, India (Toxic Waste); Pune, India (MSW to Electricity
Valmet (CFB)	-	-	++	Air-blown gasifier used for cogeneration and lime kiln.	Vaskiluodon Voima Oy, Vaasa, Finland (Biomass syngas firing in coal power station); OKI Pulp Mill, Indonesia (Lime kiln); Aanekoski, Finland (Pulp mill lime kiln);
Repotec (Güssing)	++	++	+	Indirect CFB gasifier.	Güssing, Austria (Demonstrator/Cogeneration); GobiGas, Sweden with Valmet (Wood to RNG [mothballed]); Wajima, Japan (Thermal Power Generation); Senden, Germany (Gas Engine/ORC Combined Cycle Cogeneration)
Andritz	-	-	++	Carbon Circulating Fluidized Bed (Formerly Pyroflow)	Cheming, China (pulp mill lime kiln), Joutenso, Finland (pulp mill lime kiln), Tampere, Finland (Pilot Plant)
Air Liquide (Ruhr-Lurgi)	++	++	++	Direct fluidized bed (air/O2)	Sasol; Great Plains Synfuels, North Dakota; 101 total
Thyssen Krupp /Uhde	+	+	+	Winkler gasifier (pressurized)	70 plants (coal/pet coke)
Wood (Amec Foster Wheeler)	++	++	+	Direct fluidized bed	More than 9000 operating hours for a 12 MW gasifier (Värnamo, SE); project at Varkaus (FI) and 0.5 MW trial at VTT.[159]
Sunshine Kaidi New Energy Rentech-Silvagas	++	++	+	Indirectly heated dual-fluidized bed gasifier	One 40 MW demonstration in Burlington VT, proposed plant in Kemi, Finland
Agnion	++	++	-	Heat pipes (small-scale units only)	Developed by TU Munich
Air Products	+	+	+	Over 60 Plants based on fossil fuels. Former Texaco and then GE technology and 50 plants based on Shell technology (mainly coal)	
Exxon	+	++	-	Catalytic gasifiers	Only used with coal so far; no methanation necessary

[159] Schildhauer, Tilman and Boliaz, Serge: *Synthetic Natural Gas: From Coal, Dry Biomass, and Power-to-Gas Applications.* Wiley, 2016

Vendor	H_2	RNG	Lime Kiln	Products	Deployment
Nexterra	-	-	+	Fixed bed	
Synthesis Energy (U-Gas)	+	+	+	Fluidized bed gasifier directed at both coal and biomass markets developed in partnership with the Gas Technology Institute	Coal-based gasification projects in China and biomass demonstrations historically.
Siemens	+	+	+	Dry feed system, can be used for a broad range of feedstock types	
Thermochem Recovery International	++	++	++	Steam reforming technology	Commercial Demonstration at mill in Trenton, Ontario using black liquor for lime kiln firing

A.3 Pre-Commercial Gasifiers

Several new concepts are currently under development, and sometimes very close to commercialization. No unique gasifier concept has yet evolved that would dominate the market or even the R&D field, so future outcomes are as yet uncertain.

Table 44 Indirectly-heated fluidized bed gasification suppliers

Company Name	TRL	H_2	RNG	Lime Kiln	Products	Deployment
Highbury Energy Inc.	7	++	++	++	Indirect gasification with aims at Fischer-Tropsch liquid production. States that proprietary *in situ* tar removal process achieves 99% removal.	
Taylor Energy (New York)	6	++	++	++	Three-chambered gasification system designed for woody MSW and biomass to produce syngas with 13 MJ/M3	Project planned in Montgomery, New York with 307 tpd
West Biofuels Gasification	8	++	++	++	Modified Repotec fluidized bed gasifier	Facility under construction in Hat Creek, CA for power generation

For larger-scale plants, a partial list of CFB oxygen-blown gasifiers is shown below. In some cases, the technologies have been designed for MSW feedstocks. Nonetheless, the high biomass component in this feedstock suggests that they are also viable for RNG production from wood feedstock.

Table 45 Directly-heated fluidized-bed gasification suppliers

Company Name	TRL	H_2	RNG	Lime Kiln	Products	Deployment
TCG Global	8	++	++	++	Air/O_2 blown gasifier; building 125,000 tonne per year wood input Fischer-Tropsch plant in Oregon.	Red Rock Biofuels in Oregon
Advanced Biofuel Solutions Ltd. (Radgas)	4-5	++	++	+	Syngas production from biomass/MSW with Metso Outotec Oy oxy-steam fluidized bed with plasma treatment	Swindon, UK
Andritz Carbona (BFB)	8	+	+	++	Air blown gasifier.	Skive, Denmark (Cogeneration with Engine);
Andritz Carbona (BFB) Sungas	8	++	++	+	O_2 blown gasifier.	GTI, Chicago (demonstrator); Coal-based projects in China
Renergi	6-7	-	-	-	Two-stage gasification (air, steam) with focus on MSW and low-temperature tar reforming	Demonstration (Australia); ARENA pegged TRL at 7-8 in 2019
Suny-Cobleskill / Caribou Biofuels	5-6	-	-	++	Inclined rotary gasifier; air-blown	
Endeavour Energia	5-6	++	++	++	Fluidized-bed O2, steam-blown gasifier	Demonstration scale (UK); cold commissioning supposed to be in 2020; designed for biomethane
Jet Sprouted Bed Gasification (Taylor Energy [California])	7	++	++	+	O2-blown gasification with intermittent pulse jets to enhance reaction rate	2 t/day tested in California

Providers of entrained-flow oxygen-blown gasifiers are listed below. Many of these are designed for fossil fuels, such as coal and pet coke, but could be adapted to run on biomass.

Table 46 Entrained-flow gasifier suppliers[160]

Company Name	TRL	H_2	RNG	Lime Kiln	Products	
Lulea Green Fuels (Formerly Chemrec)	7	++	+	++	Proven with air/O_2 Blows for lime kiln and methanol DME synthesis	Pitea, Sweden (Black liquor gasification for Lime Kiln [also formerly DME synthesis]); New Bern, NC (pulp mill lime kiln)
BioLiq	6	++	+	++	Pilot plant producing under 100 Litres of gasoline per hour	Demonstration in Germany
Meva Energy	7-8	-	-	-	Entrained flow cyclone gasifier based on research at Luleå University of Technology sized at around 5 MW.	Hortlax, Sweden
Multi-fuel Conversion (MFC) Technology from RWE	3-4	++	+	++	Lab-scale but aims to recover phosphorous from biosolids and lignite using oxygen blown entrained flow gasification sized up to 125 MW (fuel input).	130 Kg/h pilot under construction in n Niederaussem, Germany

Different concepts that may pursue alternatives to the traditional three gasifier technologies described above, such as including a pyrolysis step or supercritical water, are outlined below. Their technical maturity is generally low and they are not expected to become commercially available in the coming decade.

Table 47 Other gasifier technologies

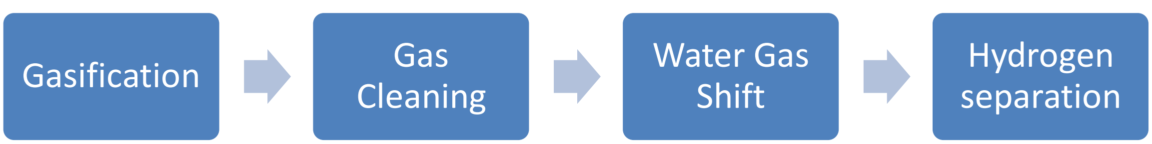
Company Name	TRL	H_2	RNG	Lime Kiln	Products	Examples
Cortus (WoodRoll)	8	++	++	+	WoodRoll Syngas units applying pyrolysis following by indirectly-heated, low-pressure, entrained-flow gasification of char.	Koping, Sweden (RNG/Syngas/Liquids Demo); Hogansas,Sweden (syngas for steel production)
Torrgas	6-7	++	++	+	Three step process involving torrefaction, low-temperature gasification and high-temperature gasification with biochar product.	700 kW demonstration and 13 MW planned plants
Wildfire Energy	3-4	+	0	+	Horizontal batch fixed bed gasification for power and hydrogen production. Oxygen blown trials planned for 2021.	Ipswich, Queensland, Australia

[160] National Energy Technology Laboratory, "Entrained Flow Gasifiers." Website. https://www.netl.doe.gov/research/coal/energy-systems/gasification/gasifipedia/entrainedflow [Accessed September 20, 2019].

Plasco (Now OMNI)	5-6	++	++	+	Multi-stage gasification based on grate gasification , fixed bed and plasma reforming. Aimed at engine generator, hydrogen, & Chemicals markets . Can be on O_2 or air blown	Richmond, Ontario
G4 Insights	7-8	-	++	-	PyroCatalytic Hydropyrolysis which converts wood to CH_4 directly	Demo in Edmonton, AB
Genifuel	7?	++	++	-	Hydrothermal Processing to liquid fuels and RNG with 20% of input converted to methane and 60%+ to biocrude	Developed at PNNL and demonstration planned at Metro Vancouver WWTP
Kore Infrastructure	N/A	++	++	+	Pyrolysis of biosolids	Demonstration planned in Los Angeles, CA
Treatech	3	++	++	+	Hydrothermal gasification	

A.4 Gas Processing to Maximize Hydrogen Content

Wood to hydrogen production is done by water shift reaction of syngas; given the low hydrogen content of wood (around 6%), additional hydrogen is added in the form of water, which is split into hydrogen and oxygen, which reacts with the carbon in the syngas to form CO_2. To maximize hydrogen content, gasifiers are operated at very high temperatures above 1,200°C, requiring more expensive materials than gasifiers used for methane production, which operate at under 900°C. In order to simplify gas separation, direct gasification with oxygen or indirect fluidized bed gasifiers (such as FICFB or Milena) are preferred. Air-blown gasification, although low cost, is not suitable. Post gasification hydrogen content for most indirect gasification ranges from 25 to under 50%. Sorption enhanced reforming can remove CO_2 in the bed material, facilitating hydrogen volumetric contents of up to 75%. In all of the above cases, further processing is needed to achieve commercial hydrogen concentrations. Hydrogen is purified using either a pressure swing adsorption and membrane filters. Some experimental work in supercritical water gasification has also been completed. Another technology under development is the Ways2H technology. which combines preheating and O_2-based reforming to generate hydrogen (Figure 37).[161]



[161] Helena Tavares Kennedy (2021, April 4th) A Waste-to-Hydrogen Tokyo Facility Ready to Rock – Is 2021 the Year of Hydrogen? *Biofuels Digest.* Accessed August 18th, 2021

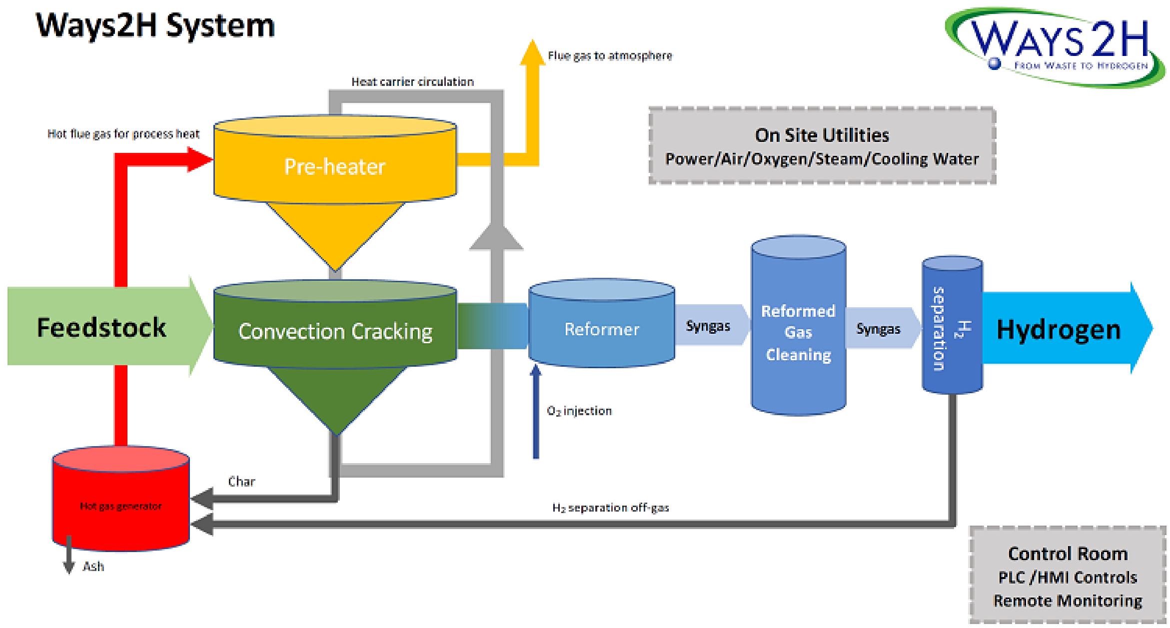


Figure 37 Process diagram of Ways2H Biomass to Hydrogen System

Table 48 lists current projects that attempt to produce hydrogen from solid biomass and MSW. Essentially, many of the technologies identified in the previous sections (gasifiers) can be used as part of such endeavours.

Table 48 Biomass to Hydrogen Systems

Vendor	Products	Deployment
Sungas Renwables	GTI fluidized bed gasification system with downstream gas cleaning and hydrogen production	Chicago Area, US
Hyper Project	Cranfield University based bulk hydrogen production project using Gas Technology Institute's sorption enhanced steam reforming process	Under development at Cranfield University, UK
Ways2H	Modular gasification technology using steam reforming of syngas	MSW-based project in Tokyo, Japan

A.5 Methanation

Pre-commercial systems: Once the syngas has been cleaned and particulates, water, sulfur and chlorine have been removed, it enters a water shift reactor. This reactor adds steam, which reacts with the carbon monoxide in the gas stream to form additional hydrogen, according to reaction (1). This hydrogen rich gas is then further processed into methane in an exothermic methanation step (2), followed by gas upgrading to pipeline standards.

(1) $CO + H_2O \leftrightarrow H_2 + CO_2$

(2) $CO + 3H \rightarrow CH_4 + H_2O$

Likewise, CO_2 can react with surplus hydrogen to form extra methane, resulting in a gas that consists of predominantly methane and some water vapour. Low temperatures (200°C) and high pressure (20-30 bar) are required to maximize methane content in the outgoing gas mixture. The Haldor Topsoe process converts H_2 and CO with a ratio of 3/1 into methane. It has a chemical efficiency of about 80 % and produces a product stream with up to 98% methane.[162] The molar ratio between hydrogen and CO needs to be close to 3 in order to maximize methane yields and minimize hydrogen in the gas. Generally, the mass yield of methane from biomass is around 0.33-0.35 kg per kg(dry),[163] which equates to 60-70% of energy. As the ratio in syngas is usually below 3, a water shift reactor needs to be added in order to adjust the ratio and maximize methane production.

The production of RNG from biomass through gasification is not commercial. Yet, numerous pilot and demonstration plants have been built – mainly in Europe. Two such project is being planned for B.C., i.e. the REN Energy project in the Kootenays and another one in Williams Lake. The best known and most successful (1200 operating hours) project has been the GoBiGas project in Sweden, which was mothballed in 2018 due to its economic underperformance, despite its relative technical success. ENGIE's Gaya project, which started in 2010 and has a demonstration unit operational since 2017, is also noteworthy. Based on the Güssing gasifier technology (FICFB), the Gaya site regroups several partners working together to make RNG production from biomass more efficient and more affordable. E.ON is also planning a commercial-size project in Sweden, using established technologies, and there are also several projects being planned in the U.S. Table 49 lists RNG projects using gasification, mainly from the past decade, as well as some planned projects. Note that although some projects are designated as TRL 8, this status could only be assumed to exist once the projects will have been commissioned successfully.

Table 49 Pre-commercial Methane Production from Biomass

Facility	TRL	Size	Technology	Deployment
GoBiGas, Gothenburg (SE)	7	20 MW (input)	Indirect gasification at atmospheric pressure (Valmet, Circulating Fluidized Bed), gas cleaning, methane production (via nickel catalyst) using Haldor Topsoe technology	One successful demonstration in Sweden, based on previous Chalmers tests
REN Energy (B.C.)	5	1 PJ/yr	Gasification at 900°C, methanation (technology unknown)	Planned for B.C.
Güssing (AT)	6	1 MW (input)	Dual fluidized bed steam gasifier (Fast Internal Circulation Fluidized Bed - FICFB), a two-stage gas cleaning system; no gas injection (internal use)	2009 Pilot was not further pursued at Güssing plant
Gaya Project (FR)	5	0.5 MW (input)	FICFB gasifier, proprietary metallic catalyst for methanation. 20 MW plant planned by ENGIE.[164]	R&D pilot (2015)
ECN (NL)	5	0.8 MW (input)	MILENA gasifier, OLGA gas cleaning and ECN's ESME methanation technology	Laboratory pilot

162 Karstensson, Johan: *Feasibility study for gasification of biomass for synthetic natural gas (SNG) production*. Department of Chemical Engineering, Faculty of Engineering, Lund University, May 2016

163 Schildhauer, Tilman and Boliaz, Serge: *Synthetic Natural Gas: From Coal, Dry Biomass, and Power-to-Gas Applications*. Wiley, 2016 (Table 2.1)

164 Sherrard, Alan: Project GAYA Passes Historic Milestone. *Bioenergy International* No. 1, March 2021

Facility	TRL	Size	Technology	Deployment
Swindon (UK)	5	1 MW (input)	Fluidized bed gasifier and plasma converter; uses refuse-derived fuel	Commercial facility planned (see below)
Advanced Biofuels Solutions Ltd	(8)	8000 tpy	ABSL RadGas and Wood VESTA; CO2 is separated and used. Uses both RDF and wood as feedstock; produces both hydrogen and RNG.	Planned for 2021[165]
Japan NEDO project	3	200 MW (input)	LPG production from biomass, using an entrained-flow biomass gasification and direct LPG synthesis process with hybrid catalyst.	4-year R&D project; apparently discontinued
Köping (SE)	5	0.5 MW	WoodRoll technology by Cortus Energy (gasifier), combined with catalytic methanation unit developed by Karlsruhe Institute of Technology	Pilot plant; first RNG produced in 2020[166]
E.ON Bio2G (SE)	(8)	345 MW	First commercial project; funding approved. Direct pressurized oxygen blown gasifier and the adiabatic TREMP (Haldor Topsoe) methanation	Decision to build not confirmed
Woodland (US)	4	1 MW (input)	FICFB gasifier	R&D project, lab scale
San Joaquin Renewables (US)	7	900 tpd	Oxygen-blown pressurized fluidized bed gasifier and methanation (catalytic BING process)	Successful pilot completed
Sungas Renewables (US)	6	1000 or 300 tpd	Bubbling fluidized bed gasifier by GTI	Successful pilot completed (Stockton, CA)
AMEC FW Vesta	(8)	315 MW (input)	AMEC CFB and VESTA methanation	Feasibility study only
Ambigo, Alkmaar (NL)	6	1 tph/4 MW	MILENA (indirect gasifier), OLGA gas cleaning, ESME methanation unit. Currently on hold.[167]	Planned demonstration project
Enerkem (CA)	4		Research facility since 2003; produced liquid fuels and RNG from a mix of feedstocks, including wood and straw	Pilot; no continuous operation
Great Point Energy (US)	5	1 tpd	Bluegas technology – catalytic gasification in fluidized bed gasifier (one-step methanation)	Company out of business since 2019[168]

[165] IEA Bioenergy. "Facilities" , Accessed August 18th, 2021 from https://www.ieabioenergy.com/installations/

[166] Cortus Energy AB (2020, March 26th). "Cortus första biosyngas i Höganäs [Cortus first biosyngas in Höganäs]",Accessed August 18th, 2021 from https://www.globenewswire.com/news-release/2020/03/26/2006761/0/sv/Cortus-f%C3%B6rsta-biosyngas-i-H%C3%B6gan%C3%A4s.html

[167] Alkmaar Centraal (2019, May 16th). "Provincie Schrapt Voorwaarde Voor 960.000 Euro Subsidie Investa Alkmaar [Province removes condition for 960,000 Euro subsidy in Alkmaar". Accessed August 17th, 2021 from https://www.alkmaarcentraal.nl/nieuws/60040330-provincie-schrapt-voorwaarde-voor-960-000-euro-subsidie-investa-alkmaar)

[168] National Energy Technology Laboratory. "Great Point Energy". Accessed August 18th, 2021 from https://netl.doe.gov/research/Coal/energy-systems/gasification/gasifipedia/gpe

Facility	TRL	Size	Technology	Deployment
IHI (JP)	5	6 tpd	TIGAR fluidized bed gasifier. Can use coal and biomass to produce methane. Successful pilot with biomass accomplished.[169]	Demonstration (50 tpd) planned for Indonesia
Transition Energy (CA)	7	n.a.	Based on GoBiGas technology	Proposed for Williams Lake
G4 Insights	5	6.7 MW (input)	Pyrocatalytic hydrogenation	Pilot at ATCO natural gas yard in EDmonton

Other emerging technologies: Although no wood-to-methane pathway is truly commercial, the above-mentioned demonstration projects have been successful in showing that the technology is technologically viable, albeit not commercially viable without stronger policies. Whereas gasification is still being perfected and appears to be the main pathway for short-term project development, hydrothermal gasification is one emerging technology that may offer advantages, mainly because it does not require pre-drying of biomass feedstock.

A catalytic hydrothermal gasification process was developed at the Paul Scherrer Institut (PSI) in Switzerland that allows for the production of methane from woody biomass. This process is carried out in an aqueous system at conditions near or above the critical point of water: 647 K (374°C) and 22.1 MPa. Whereas salts are highly soluble in subcritical water, they precipitate out in supercritical water. Supercritical water is more like an organic solvent. With a suitable device, the salts can be separated in a continuous way from the biomass stream prior to gasification. This has several advantages. Not only could salts poison the catalyst, but once separated in a concentrated form, they can also be used as nutrients. Products are clean water and SNG only – all possible hormones and bioactive proteins (e.g. prions) are destroyed. There is no solid residue that needs to be dried and burnt as hazardous waste.[170]

Supercritical water can also be harnessed for hydrogen production from biomass, such as bagasse.[171] The tolerance to water and salts suggests the technology could also be used with problematic feedstock, such as wastewater treatment sludge or industrial or agricultural wet residue otherwise used in anaerobic digesters, albeit it remains unclear what the required economies of scale would be. No demonstration plant has been constructed yet, which leaves this technology at a TRL around 3-4.

Syngas cleaning is another area of on-going R&D. Although commercial systems exist, they usually rely on a cool gas to be treated with filters or scrubbers (the Swedish Bio2G project also relies on high-temperature gas cleaning at around 600°C). The ability to remove contaminants from hot syngas instead of first cooling the gas has the potential to yield significant energy savings, thus reducing operating costs. RTI International has made progress in this area by developing a sorbent-based warm syngas cleanup process for H_2S and CO_2 removal that operates at 250–650°C. Others are using electric arcs to treat the syngas. Supercritical water would remove the need for additional gas cleaning.[172] Likewise, biological

[169] Yosuke TSUBOI et al.: SNG Production from Woody Biomass Using Gasification Process. *Journal of the Combustion Society of Japan* (2016), Volume 58, Issue 185, Pages 137-144

[170] Paul Scherrer Institute. Untitled. Accessed August 18th, 2021 from https://www.psi.ch/en/cpe/projects/sngfromhydgasificationen

[171] H. Ishaq, I. Dincer: A new energy system based on biomass gasification for hydrogen and power production. *Energy Reports*, Volume 6 (2020), Pages 771-781

[172] Modular CO_2 Capture Processes for Integration with Modular Scale Gasification Technologies: Literature Review and Gap Analysis for Future R&D. National Energy Technology Laboratory, October 2020

conversion to methane could reduce gas cleaning needs; some emerging technologies such as Electrochaea and Viessmann are listed below (see also **Table 56**).

Strictly speaking of methanation units, several commercial technologies exist. The best known are listed in Table 50. As these commercial systems are integrated into a full methane production facility, however, much fine-tuning needs to take place and therefore, such facilities have a lower TRL as indicated above.

Table 50 Commercial Methanation Technologies

Vendor	TRL	Products	Deployment
BASF	9	BASF sells methanation catalysts which are used in coal to methane facilities in China	China (location unknown); Likely with DEMOSNG but this is not confirmed
WOOD	9	Vesta system designed to simplify processing by removing CO2 after methanation, facilitating better temperature control and eliminating the need for recycling compression. The VESTA process also avoids the need for H2/CO adjustment while reducing metal dusting and coking.	
Haldor-Topsoe	9	TREMP system is designed to recovery the energy from the exothermic methanation reactions while allowing high reaction temperatures as high as 700 C.	
Johnson Matthey	9	DAVY SNG production system provides dual methanation and CO shift.	Keshiketeng County, Inner Mongolia
Man ES	9	Man Energy Systems has power to gas based CO2+H2 methanation systems suitable for power to gas, and with modification, syngas	Audi Power to Gas system
Atmostat-Alcen	5	METAMOD System is a modular technology designed primarily to handle the high heat loads generated by methanation of carbon dioxide and hydrogen in power to gas while maintaining compactness. System uses a powdered catalyst with microchannels	No information available
Electrochaea GmbH	7/8	System that feeds hydrogen and carbon dioxide to methanogenic archaea microorganisms to create methane gas.	Foulum, Denmark; Avedore, Denmark; Solothurn, Switzerland
Ineratec	8	Modular containerized methanation systems usable for syngas and power to gas applications	Koping, Sweden
MicrobEnergy (Viessman)	7/8	System that feeds hydrogen and carbon dioxide or syngas to microorganisms to create methane gas.	

A.6 Carbon Sequestration Technologies

Table 51 presents an overview of projects related to carbon capture in the biomass energy field, including waste-to-energy plants. Generally, commercial technologies are available, such as amine-based technologies currently used for demonstration projects in the fossil fuel sector. Other (amine-free) technologies are also being explored (see Table 52). Several more projects are being proposed in the U.S. due to the 45Q federal tax credit, which rewards bioenergy projects with carbon sequestration with up to US$50 per tonne of CO_2 in extra income. Not included in this table are fossil-based CCS in Canada such as the QUEST project at the Scotford Upgrader or the Boundary Dam facility near Weyburn, Saskatchewan which produces CO_2 to be used for enhanced oil production (but see Table 58 further below). It should be noted that some of the CO_2 used by Cenovus comes from the Great Plains Synfuels coal SNG plant. Due to the purity of the waste gases, around 1/3rd of the carbon in the biomass can be captured with relative ease. Around ¼ of the carbon in the biomass is lost as flue gas (unless an oxyfuel process) and the remainder goes into the RNG.

Table 51 Carbon Capture Applied to Biomass Energy Systems

Project	Carbon Capture Technology	Deployment
DRAX (UK)	C-Capture (amine-free solvent)	1 tpd pilot plant
DRAX (UK)	Mitsubishi Heavy Industries (amine-based)	Planned for 2027
Fortum (NO)	Amine scrubbers, for storage in depleted North Sea oilfields	Planned for 2024
Stockholm Energi (SE)	Hot Potassium Carbonate (carbon scrubbing – chemical adsorption/pressure swing)	Pilot underway since 2019
Copenhagen ARC (DK)	Waste incinerator; CCS for injection in depleted oilfields	Demonstration planned for 2022
Twence (NL)	Aker capture technology (amine-based); waste-to-energy plant	Planned
Mikawa (JP)	Coal-to-biomass conversion of power plant; CCS for storage in depleted oilfields	Planned
ZEROS (US)	Texas oxyfuel combustion plant for waste; CO_2 for enhanced oil recovery	Planned
Bayou (US)	Velocys project; carbon sequestration from Fischer-Tropsch biofuel production process	Planned for 2025
Summit Carbon Solutions (US)	Proposal to connect ~30 ethanol plants in the Midwest US to a carbon capture and storage system projected to store 10 mt of CO2 per year	Announced in 2021
Ambigo (NL)	Selexol	Planned; realization uncertain

Table 52 Carbon Capture Technologies

Technology	Key points	Comments
Chemical (amine) scrubbing	• Commercial • Increases energy use • Creates toxic amine residue	Technology of choice for most commercial projects; can use lower-cost heat energy instead of electricity
Physical solvent scrubbing	• Suitable for syngas separation (oxy-fuel)	Not suitable for post-combustion due to minimum 30% CO_2 concentration requirement
Solid adsorption	• Demonstration	Can be pressure or temperature-swing adsorption
Membrane separation	• Suitable for syngas separation (oxy-fuel) • Better for small streams • High energy cost	Commercial hybrid membrane/amine technologies exist; Air Liquide uses membranes to get to 95% purity;[173] also used to remove CO_2 from natural gas. Uses electricity as the energy source (high cost)
Cryogenic	• Very high energy use	More suitable for food-grade CO_2
Enzymatic	• Canadian invention • Low energy consumption • No toxic chemicals	CO_2 Solutions captures CO_2 enzymatically as bicarbonate. The company had become insolvent and its IP was sold to an Italian company, Saipem S.P.A.[174]

In terms of CO_2 utilization, several Canadian projects are underway. The potential for these technologies depends on the size of the product market, and often whether a market exists close enough to the point of production. For example, *Air Liquide* is mainly targeting the food-grade CO_2 market worldwide. *Qantiam Technologies* are targeting methanol production from CO_2 and *CarbonCure* apply CO_2 for concrete curing. Montreal-based *Carbicrete* is curing ground steel slag with CO_2, which results in a concrete substitute. *Pondtech* is using the gas to cultivate algae and Quebec company *CO2 Solutions* uses enzymes to capture CO_2. *CleanO₂ Carbon Capture Technologies* converts CO_2 to sodium carbonate. *Capital Power* is using a technology to turn CO_2 into carbon nanotubes. Other potential uses would include curing concrete with CO_2, aggregate production, technical applications of CO_2 (e.g. as a working fluid), or formic acid production.

The above means that not only is it desirable to obtain a clean hydrogen or methane stream but also, a CO_2-rich gas stream can become a product to be sold. Applicable both to traditional biogas and synthetic RNG made through a gasification process, Table 53 compares various commercial gas upgrading technologies that can be used to convert a methane-rich gas stream to pipeline grade methane. More information on these technologies and additional comparisons can be found in the original source.

[173] Air Liquide. “Membrane Technology”. Accessed December 16, 2020 from https://www.airliquideadvancedseparations.com/about/membrane-technology

[174] CO2 Solutions (2020, January 22th). “CO2 Solutions announces the sale of its assets”. *Scion.* Accessed December 14th, 2020 from www.newswire.ca/news-releases/co2-solutions-announces-the-sale-of-its-assets-844408266.html

Table 53 Gas Upgrading Technologies[175]

Biogas Upgrading Process	Pressure (psig)	Temp (°C)	CH_4 Product Content	Methane Slip	Methane Recovery	Sulfur Pre-Treatment	Consumables
Pressure Swing Adsorption	14 – 145	5 – 30	95–98%	1–3.5%	60 – 98.5%	Required	Adsorbent
Alkaline Salt Solution Absorption	0	2 – 50	78 – 90%	0.78%	97 – 99%	Required / Preferred	Water; Alkaline
Amine Absorption	0 (< 150)	35 – 50	99%	0.04 – 0.1%	99.9%	Required / Preferred	Amine solution; Anti-fouling agent; Drying agent
Pressurized Water Scrubbing	100-300	20 – 40	93– 98%	1–3%	82.0 – 99.5	Not needed / Preferred	Water; Anti-fouling agent; Drying agent
Physical Solvent Scrubbing	58–116	10– 20	95– 98%	1.5–4%	87–99%	Not needed/ Preferred	Physical solvent
Membrane Separation	100 – 600	25–60	85– 99%	0.5 – 20%	75 – 99.5%	Preferred	Membranes
Cryogenic Distillation	260 – 435	-59 to -45	96– 98%	0.5–3%	98 – 99.9%	Preferred / Required	Glycol refrigerant
Supersonic Separation	1,088 – 1,450	45 – 68	95%	5%	95%	Not needed	

B. *Lignin Production and Use*

Lignin is a by-product of the chemical pulping process and is produced by kraft pulp mills in their process of separating the cellulose from wood. Lignin has been traditionally burned, partly as a fuel for the pulping process, partly to get rid of an unwanted by-product, and to recover the pulping chemicals. Instead of burning lignin it can also be extracted from the spent chemicals.

Because lignin has a high calorific value it can be used to replace natural gas used in a pulp mill's lime kiln. Alternatively, it can be processed and sold to offsite markets as a high-grade solid fuel. The report will describe two pathways: onsite or offsite use as a natural gas replacement. Both pathways compete with using lignin as a feedstock for various chemical processes that generally fetch higher market prices than when used or sold as a fuel.

Pathway 1 - Lignin replacing natural gas in a lime kiln: For maintenance reasons lime kilns need to be operate at temperatures at or bove 800°C and are typically heated by natural gas burners. Wood needs to be gasified to be burned in a lime kiln. Dry lignin, however, in the form of dust can be burned in injection burners with the flame injected directly into the kiln.

[175] Ong, Matthew *et al.*: Comparative Assessment of Technology Options for Biogas Clean-Up (Draft). California Biomass Collaborative, October 2014 (Table 17)

Pathway 2 - Lignin replacing natural gas in other undetermined energy producing processes: because lignin has a rather high calorific value (26 gigajoules/t HHV) it is a more valuable fuel than conventional woody biomass (17 to 19 gigajoules/t HHV). Just as for the onsite lime kiln it could be burned with little technical modifications in the secondary wood processing industry, e.g. in direct fired lumber drying kilns, veneer dryers or immersion heaters used in veneer mills.

Kraft lignin is an emerging product with potential in binders, bioplastics, carbon fibre, resins and other products. Kraft lignin has different properties than lignosulfonates produced by sulfite pulping or further sulfonation of kraft lignin. Markets for lignosulfonates include dispersants, oil well drilling fluids and as binding agents.

West Fraser currently operates a commercial facility in Hinton, Alberta. Most of the demand for lignin is for lignosulfonates, with volumes of around 88 million tonnes per year, with kraft and Organosolv Lignin being 9% and 2% of the market, respectively. The total market value of lignin products is estimated at US 730 million.[176]

Lignin of lower quality has energy potential beyond its current combustion in recovery boilers, such as for lime kilns and even export to other energy users, due its high energy value (26 MJ/Kg compared to 18 MJ/Kg for typical biomass fuels). Some research has also occurred into thermochemical treatments to develop aviation fuels from lignin feedstock.

Typically, up to 20% of the lignin can be removed without impacting the mill's operations significantly. Lignin removal can even boost production in recovery-boiler constrained plants by 25% and with operational changes, around 70% of the lignin can be removed.[177] However, some mills might require a small amount of additional fuel in the power boiler to offset the energy loss from lignin.

As kraft lignin does contain sulphur, impacts of sulphur dioxide and other-sulphur compounds need to be considered due to their acidification and odour potential. Lignin has been used as fuel in district heating plants in Sweden, suggesting it could be transported and used as a fuel to displace natural gas and other fuels. Lignin-rich pellets made from Russian woody methanol production by-products is traded as a coal substitute [178] in some European markets, including Verdo CHP plant in Randers, Denmark.[179] Table 54 identifies a few recent projects related to lignin extraction and use.

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[176] Bajwa et al 2019. "A Concise Review of Current Lignin Production, Applications, Products and Their Environment Impact". *Industrial Crops and Products, 139.* DOI:10.1016/j.indcrop.2019.111526

[177] Valimaki et al. 2010 "A Case Study on the Effects of Lignin Recovery on Recovery Boiler Operation. Presented at the International Chemical Recovery Conference 2010, Williamsburg, VA, USA. Accessed August 14th, 2021 from https://www.researchgate.net/publication/267755440_A_Case_Study_on_the_Effects_of_Lignin_Recovery_on_Recovery_Boiler_Operation

[178] These black pellets do not involve torrefaction but the hydrophobic natural of the lignin allows it to be stored in the elements similar to coal and used similarly.

[179] Verdo (nd) "Black Pellets". Verdo Website. Accessed August 17th 2021 from Black pellets - ideal green addition or replacement to biomass and coal (verdo.com)

Table 54 Lignin Production Systems

Vendor	Products	Deployment
Valmet	Lignoboost uses CO_2 to precipitate lignin where it is then washed and filtered.	Domtar Plymouth, NC; Enso Sunila, Finland
FP Innovations	Lignoforce uses oxidization prior to CO_2 precipitation reducing sulphur and increasing solids size and percentage	Hinton, Alberta
Pure Lignin Environmental Technology	Dilute acid technology to produce lignin, cellulose and sweet liquor (suitable for fertilization)	
Fibria Innovations	Formerly Lignol Innovations, Organosolv extraction process held as part of Brazilian company's Fibria's bioeconomy strategy with some kraft lignin activities	Pilot plant

C. *Biogas and Landfill Gas*

C.1 Best Available Technologies

The production of Renewable Natural Gas (RNG) from organic material in digesters typically consists of four key process stages. These are:

1. Feedstock pre-treatment;
2. Digester tanks;
3. Biogas upgrading; and
4. Digestate management.

LFG projects consist of two key process stages. These are:

1. Landfill gas capture; and
2. Landfill gas upgrading.

Digester and landfill gas technologies are well-established, commercial technologies. The prediction of future trends can be based on existing technologies and incremental improvements. Feedstock pre-treatment technologies are fully commercial and can be deployed based on the specific feedstock qualities. They may be provided by anaerobic digester vendors as part of their product range, or may come from third-party providers within an overall engineering and design concept. Mechanical pre-treatment technologies enable biogas plants to accept food waste; food waste not only generates a large amount of biogas per tonne, but comes with a tip fee. For these reasons, mechanical feedstock pre-treatment technologies are often financially viable and could be considered BAT. Pre-treatment of feedstock that is difficult to digest is usually not economically feasible since the increased gas yields do not justify the pre-treatment expense.

Upgrading biogas/landfill gas to RNG is also commercial. This step removes carbon dioxide and other impurities (such as nitrogen, hydrogen sulphide and water) to increase methane content from approximately 55-65% to approximately 98%. Applicable technologies are listed in Table 53 above.

In cases where the nutrients in digestate are greater than the nutrient needs in the immediate vicinity of biogas plants, nutrient recovery technology is often used. Nutrient recovery technology extracts nutrients from digestate into a more concentrated form. The extracted nutrients can be transported away from the biogas plant more cheaply than digestate, while any remaining, nutrient-depleted liquid digestate can be spread locally.

There are dozens of different nutrient recovery technologies available, from simple large fibre removal (such as slope screen, screw press, rotary drum separator and roller press) to small fibre removal (such as dissolved air flotation, centrifuge, fiber filter and spiral filter) and almost complete nutrient recovery (such as mechanical vapour recompression and vacuum evaporation).

As with feedstock pre-treatment, digestate management technologies can be grouped into one of the following categories:

- Mechanical: such as screens, screw, belt presses, centrifuges and membranes;
- Chemical: such as flocculation and struvite precipitation; and
- Biological; such as ammonia stripping and use of nutrient accumulating organisms.

As with most feedstock pre-treatment technologies, nutrient recovery technologies are also considered uneconomical. The reason for this is that the end products of these technologies (a form of nutrient more concentrated than digestate) are almost always worth less than the cost to produce them. As such, nutrient recovery technologies are only used when absolutely necessary (i.e., when significant transportation cost savings are possible).

Table 55 lists several vendors of equipment relevant to RNG production that are active in Canada. These vendors will often sell equipment both for conventional biogas production and for gas upgrading to pipeline standards.

Table 55 Commercial Anaerobic Digester/RNG Systems*

Vendor	Products	Deployment
Air Liquide	Biogas/landfill gas upgraders	Widely deployed
Adicomp	Biogas/landfill gas upgraders	Widely deployed
Bio-en Power	Biogas plants	Widely deployed
Bioferm	Biogas plants & upgraders	Widely deployed
Bright Biomethane	Biogas/landfill gas upgraders	Widely deployed
DMT	Biogas/landfill gas upgraders	Widely deployed
Dorset Green Machine	Digestate Management	Widely deployed
France Evaporation	Digestate Management	Widely deployed
Greenlane Biogas	Biogas/landfill gas upgraders	Widely deployed
Host	Biogas plants	Widely deployed
Smicon	Feedstock pre-treatment	Widely deployed
Vincent	Digestate Management	Widely deployed
Waga Energy	Landfill gas upgraders	Widely deployed
Wartsila	Biogas/landfill gas upgraders	Widely deployed
Weltec	Biogas plants	Widely deployed

* Note: A very small sample of the > 100 vendors active in Canada's biogas industry.

C.2 Pre-Commercial Technology

While there are ultrasound, electrochemical, chemical, biological and combined process feedstock pre-treatment technologies being developed, these technologies are either TRL 6 or below, or are deemed to be uneconomical for the reasons provided above. Digester tanks and landfill gas capture systems are mature technology, and as such, subject to incremental improvements, and little sign of any significant pre-commercial technology developments.

Biogas/landfill gas upgraders are also mature technology, and while small advances are being made, these improvements are as a result of minor modifications to existing upgraders to improve energy consumption, reduce methane slip, etc., rather than development of new upgrading technology. The same is also true for digestate management technologies; improvements are as a result of minor modifications to existing technologies, rather than development of new technology.

One TRL 7/8 technology is ex-situ power to RNG technology. This two-step process starts with the production of hydrogen through water electrolysis using electricity. The hydrogen is then combined with carbon dioxide (from the exhaust stack of a biogas/landfill gas upgrader) and fed into a reactor with specialty micro-organisms that convert the hydrogen and carbon dioxide into RNG. This technology is different to in-situ power to gas (which is TRL 5) because it requires a separate reactor with specialty micro-organisms; in-situ power to gas feeds hydrogen and carbon dioxide into the same digester tank used for digesting organic feedstock, and where a wide range of micro-organisms exist.

The economic feasibility of ex-situ power to RNG technology depend heavily upon stranded electricity that has zero, or very low cost. This is electricity that has no use at time of production and cannot be easily stored, such as wind power in evenings or on particularly windy days. Once electricity has to be purchased for production of hydrogen through electrolysis, the economic feasibility of this technology quickly diminishes.[180] Therefore, until significant technology cost savings can be made, operational ex-situ power to RNG plants are financially viable only when inexpensive electricity is available.

As of 2019, there were an estimated 38 pilot and demonstration ex-situ power to RNG projects across 22 countries.[181] Of these, approximately half were able to inject RNG into the grid. Of these, a handful were of significant size (i.e., electrical load of electrolyser ≥ 1 MW electric) to be considered more than prototype demonstration. Most of these were conducted by research organizations or energy consortia. Of the most advanced and well-regarded technology supply companies, the following three stand out:

Table 56 Pre-commercial power-to-RNG technologies

Company Name	TRL	Products
Viessmann	7/8	Renewable natural gas
Uniper Energy Storage	7/8	Renewable natural gas
PFI Biotechnology	7/8	Renewable natural gas
Electrochea	7/8	Renewable natural gas

D. *Low-Carbon Hydrogen Production*

D.1 Green Hydrogen

The electrolysis of water is the primary manufacturing process used in the production of Green Hydrogen. The two most commonly used technologies are the alkali membrane and PEM technologies. Table 57

[180] For this reason, it is unlikely this technology will play a major role in BC. BC has hydro-electricity, which can be turned on/off to meet fluctuating demand, resulting in very little stranded electricity.
[181] Thema, M., Bauer, F., and Sterner, M. (2019). *Renewable and Sustainable Energy Reviews* 112, 775–787.

identifies commercial and pre-commercial technologies to produce green hydrogen, including several early-stage technologies.

Table 57 Green Hydrogen Production Technologies

Vendor	Products	TRL	Deployment
NEL Hydrogen	NEL Hydrogen, based in Norway, offers electrolysers that use two different types of membrane technologies. Alkali and Proton® PEM technologies[182].	9	NEL Hydrogen serves many different markets. By way of example but not limited to the production of ammonia fertiliser to hydrogen a coolant in power station electricity generation. NEL Hydrogen manufactures hydrogen refuelling stations that are deployed in numerous European countries, California, and other parts of the world.
ITM-Power	ITM is based in Sheffield in the UK. The organisation produces PEM technology electrolysers.	9	The company has partnered with Linde AG to serve large electrolyser market opportunities. ITM is constructing the largest PEM manufacturing plant in Sheffield, UK. It is planned to have a production capacity of 1GW per annum. The largest European electrolyser plant, 10MW was supplied recently by ITM to Shell GmbH in Germany. Delivering hydrogen to the Shell refinery. The REFYNE project.
CUMMINS	The organisation's electrolyser and fuel cell technologies base is in Mississauga Ontario. Cummins acquired Hydrogenics and manufactures, besides fuel cell systems both alkali and PEM electrolyser technologies.[183]	9	CUMMINS has supplied both alkali and PEM multi megawatt systems for numerous applications, and in the recent past for power to gas energy storage projects in Europe. The largest power to gas demonstration project in North America was conducted together with Enbridge in Markham, Ontario.[184] CUMMINS manufactured the largest PEM electrolyser plant assembly, 20MW, that was installed by Air Liquide in Bécancour, Quebec.
Siemens Energy	Siemens centre of excellence for PM electrolyser development is based in Munich, Germany.	9	Siemens Energy and Messer Group have entered into a cooperation agreement with the goal to work on green hydrogen projects in the 5-to-50-Megawatt (MW) range. The largest power to gas project in Mainz was supported by a Siemens PEM electrolyser.

[182] NEL Hydrogen. "Hydrogen Production". Accessed August 18th, 2021 from https://nelhydrogen.com/market/hydrogen-production/.
[183] Cummins. "Electrolysis". Accessed August 18th, 2021 from https://www.cummins.com/new-power/applications/about-hydrogen/electrolysis.
[184] Cummins. "Electrolysis" Accessed August 18th, 2021 from https://www.cummins.com/news/2020/11/12/its-second-year-north-americas-first-multi-megawatt-power-gas-facility-shows.

Vendor	Products	TRL	Deployment
			Messer Ibérica has already submitted three clean hydrogen projects in the chemical complex of Tarragona to the Spanish government. These projects will have a total electrolyser capacity of 70 MW.
McPhy	This company is a manufacturer of alkali technology electrolysers and is based in La Motte-Fanjas, France. The organisation also supplies hydrogen refuelling equipment.	9	Numerous milestones of the deployment and growth of the company span the last decade and more.[185]
NeXT Hydrogen	This company is a manufacturer of alkali technology electrolysers and is based in Mississauga, Ontario	9	NeXT Hydrogen manufactures state of the art alkali technology electrolysers and has deployed units at Canadian Tire in Canada to produce hydrogen and power fuel cell powerplant forklifts.
Pre-Commercial Technologies			
Enapter	Enapter, headquartered in Italy uses an alkali electrode membrane (AEM) technology	≤ 6	AEM technology is used mainly for small electrolysers. 2 to 3kW
Ionomr	This company also used AEM technology and is based in Vancouver	≤ 6	AEM technology is used mainly for small electrolysers. 2 to 3kW.
Haldor Topsoe	Solid Oxide Electrolyser Cell (SOEC)	≤ 6	This technology is interesting in that it offers up to 30% greater efficiency than do the incumbent electrolyser technologies in use. The disadvantages include that the products operate at 700°C and most effectively in a steady state mode.
Early-Stage Technologies			
	Electrolysis from renewables.	9	Done.
	Thermo chemical water splitting solar	≤ 4	Thermochemical water splitting uses high temperatures that are concentrated from solar power to split water.
	Thermo chemical water splitting nuclear	≤ 4	Thermochemical water splitting uses high temperatures that are concentrated from the waste heat of nuclear power reactions.
	Photoelectrical water splitting	≤ 4	PEC water splitting process converts water to hydrogen and oxygen using specially designed semiconductor materials. The materials used in the PEC process are similar

[185] McPhy. “Milestones”, Accessed August 18th, 2021 from https://mcphy.com/en/mcphy/milestones.

Vendor	Products	TRL	Deployment
			semiconductor materials to those used in PV electricity generation.[186]
	Photobiological water splitting	≤ 4	Photobiological hydrogen production uses microorganisms and sunlight in a process to turn water into hydrogen.[187]

D.2 Blue Hydrogen

Blue hydrogen is produced from grey hydrogen that is manufactured using a process called steam methane reforming (SMR). It is essentially hydrogen that is created from any fossil fuel while capturing carbon dioxide. The main by-product of steam methane reforming is carbon dioxide and when this gas is separated from the SMR production stream, its capture, utilization and/or storage (CCUS) turns it into blue hydrogen. There are numerous pathways that have been and will be evaluated for the sequestration and utilization of the emitted bi-product carbon dioxide. Blue hydrogen is better described as a low carbon intensity hydrogen as the SMR process does not fully prevent the emission of greenhouse gases. Table 58 identifies commercial and pre-commercial blue hydrogen production technologies, as well as related carbon capture technologies.

Table 58 Blue Hydrogen Production and Carbon Capture Technologies

Vendor	Products and CCUS	TRL	Deployment
Numerous producers of grey hydrogen including the industrial gas companies by way of example but not limited to - Air products, Air Liquide, Praxair, Linde, and manufacturers of ammonia fertilisers.	Large SMR plants	9	The large SMR plants are found worldwide and produce about 60 million tonnes of hydrogen per annum. A smaller amount of hydrogen is produced from coal gasification. The primary use is the production of ammonia fertiliser and in oil refineries to upgrade the refining process.
There are several small modular SMR manufacturers. Including in the past some of the industrial gas companies, BayoTech (USA), ONEH2 (USA) and HyGear (Netherlands).	Small SMR products	9	These companies all offer small SMR units that are modular and offer remote and localization use siting opportunities.
Large Scale Carbon Capture Plants in Canada			
Canadian Natural Resources (CNR)	Horizon project, Alberta	9	CO2 captured and combined with the tailings feed into the settlement ponds to

[186] DOE Hydrogen and Fuel Cell Technologies Office. "Hydrogen Production: Photoelectrochemical Water Splitting". Accessed August 18th, 2021 from https://www.energy.gov/eere/fuelcells/hydrogen-production-photoelectrochemical-water-splitting.

[187] DOE Hydrogen and Fuel Cell Technologies Office. "Hydrogen Production: Photobiological". Accessed August 18th, 2021 from https://www.energy.gov/eere/fuelcells/hydrogen-production-photobiological.

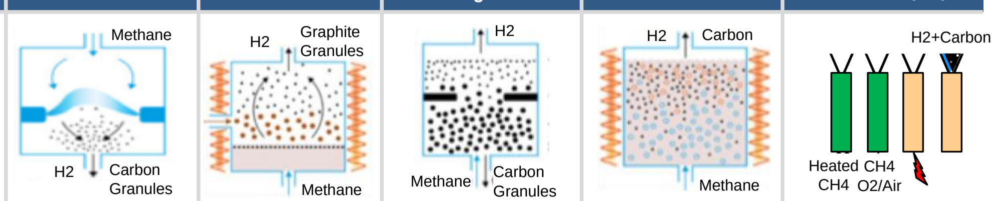
Vendor	Products and CCUS	TRL	Deployment
			react in situ and form carbonates. 438,000 tonnes CO2 captured annually.
CRN	Quest project with Shell in Alberta. Known as the Quest CCS facility is part of the Athabasca Oil Sands Project. CRN is a 70% shareholder in this project	9	CO2 captured using amines and then pumped as a liquid 2 km into the earth's crust. 5 million tonnes of C02 a year.
CRN	North West Redwater (NWR) Sturgeon Refinery. CRN is a 50% shareholder in this project	9	Carbon dioxide is captured from the SMR feeding hydrogen to the refinery, injected into the Alberta carbon trunk line and used for the process of enhanced oil recovery EOR. The CO2 is injected deep into sub-terraneous reservoirs, and this helps recover a billion barrels of light oil. Approximately 14 billion tonnes of CO2 are captured and stored.
Boundary Dam coal power plant.	SaskPower - Estevan, Saskatchewan	9	The boundary dam coal fired power plant has been retrofitted to capture 1,000,000 tonnes per annum of carbon dioxide the carbon dioxide is sold to Synovis before the use of enhanced royal recovery.
New technology Carbon Capture Organisations			
Fluor	Solvent separation	4-6	Gaseous CO2
Carbon Clean	Solvent separation	4-6	Gaseous CO2
Blue Planet	Mineralisation	4-6	Carbonates. CaCO3

D.3 Turquoise Hydrogen

Beyond green, blue and grey hydrogen we also now have a new member of the hydrogen rainbow family - turquoise hydrogen. This is a by-product of the pyrolysis of methane in natural gas. Pyrolysis splits this gas into hydrogen and solid carbon. Turquoise hydrogen is becoming more popular, and it is anticipated that this production technology can also offer competitive hydrogen at a low carbon intensity. This, however, still is dependent upon the high cost of the thermal process that is required for methane pyrolysis. The major benefit that this technology pathway may offer is the sale and supply of carbon black used in applications such as rubber pigments. The carbon black industry is very large and complex. About 80 million tonnes are currently produced globally, most of which is used in rubber applications. The organisations developing this technology pathway to manufacture very low carbon intensity hydrogen include both small start-up companies and large organisations, such as BASF. Figure 38 provides further information on turquoise hydrogen development.

Table 59 Turquoise Hydrogen Production Technologies

Vendor	Technology	TRL	Deployment
Monolith Materials. Based in Lincoln NE. Mitsubishi is one of Monolith's investors	Plasma Pyrolysis	9	Emphasis on the supply of hydrogen to various applications including clear ammonia production. Target markets for the solid carbon by-products includes tire, rubber and speciality blacks.[188] First commercial production unit started up in 2020.
Hazer Group. Based in Australia	Fluidised bed Pyrolysis	4-6	Start-up
BASF, Germany	Moving bed pyrolysis	7	A large German chemical company that has tested a lab scale production unit.
C-Zero. Based in California.	Molten metal technology	1-3	Recently received as a start-up US$11.6 million dollars for a pilot plant. Working with the Californian Pacific Gas & Electric and Southern California Gas.
TNO using Ember Technology. Based in the Netherlands	Molten metal technology	1-3	Start-up.
EKONA Power. Based in BC, Canada	Pulse Methane Pyrolysis	5	Start-up.



	Plasma	Fluidized Bed	Moving Bed	Molten Metal/Salt	Pulse Methane Pyrolysis
Process Reference: Turquoise Hydrogen from Methane Pyrolysis, H2 View, March 2021. EKONA July 2021					
Company	Monolith Materials	Hazer	BASF	C-Zero, TNO	Ekona
H2 Production	~95%	~92%	~92%	Up to 95%	Up to 95%
Carbon Production	Carbon black as powder or granules	80-95% graphite on catalyst dust	Carbon black as powder or granules	Carbon black as powder or granules	Carbon black as powder or granules
Reactor Type	Steady-state	Steady-state	Steady-state	Steady-state	Rapid-batch Constant volume
Catalyst Required	No	Iron-oxide	Carbon bed	Molten Nickel-Bismuth Manganese Chloride	No
Heating Mechanism	Direct plasma	Indirect reactor heat	Electrodes heat bed + Indirect reactor heat	Electrodes heat melt + Indirect reactor heat	Pulsed combustion of methane with O2/air
Reactor Temperature	2,000 C	900 C	1,000 – 1,400 C	650-1,100 C	1,200 – 1,500 C
Reactor Pressure	~Atmospheric	~Atmospheric	~Atmospheric	Up to 5 bar	Up to 20 bar

Figure 38 Methane Pyrolysis Pathway[189]

[188] Monolith Materials. "Pure, High Performance Carbon Black". Accessed August 18th, 2021 from rhttps://monolithmaterials.com/solutions/clean-carbon-blacks.
[189] EKONA Power and H2 View, March 2021 edition

D.4 Waste Hydrogen

Waste hydrogen is defined as "hydrogen gas produced by a commercial process the primary purpose of which is not the production of hydrogen gas."[190] It is produced at two sites in B.C., both owned by Chemtrade. The first of which is in North Vancouver at their chlor-alkali plant that produces chlorine for numerous markets such as the production of sodium hypochlorite. The waste hydrogen produced amounts to approximately 10 tonnes per day. Organisations have in the past attempted to buy this hydrogen to liquify and deliver the gas for local consumption. In October 2005 it was announced that Sacre Davy Engineering[191] together with partners were awarded $12.2 million to construct a cryogenic hydrogen plant using the waste hydrogen. Insufficient demand was identified and the project was dropped.

Chemtrade also produces waste hydrogen at its Prince George sodium chlorate plant. Some of this hydrogen will be used by Hydra Energy that has developed a hydrogen diesel dual fuel Call 8 truck power plant. Hydra Energy has partnered with Chemtrade to capture, clean and deliver the hydrogen for mobility applications, including their retrofitted Class 8 trucks. It is estimated that the Prince George sodium chlorate plat emits about 10 tonnes of hydrogen per day.

[190] https://www.canlii.org/en/bc/laws/regu/bc-reg-291-2010/latest/bc-reg-291-2010.html
[191] https://www.ic.gc.ca/eic/site/ito-oti.nsf/eng/00683.html

Appendix B – RNG Cost References

Table 60 compares some recent cost estimates for RNG production from biomass. The numbers are only partially comparable as they are based on different parameters, i.e., feedstock energy input, feedstock amount, or output. Efficiencies are from output energy in relation to woody biomass input, omitting process energy inputs. Capital costs and gas costs have been normalized for better comparison in Figure 18.

Table 60 Cost Estimates on RNG Production from Solid Biomass

#	Facility	Technology	Size	Energy yield	Gas cost	Capital cost	Source
1	Conceptual	Haldor Topsoe	200 MW (input)	47.2%	C$19/GJ	US$92 M	Karstensson (2016)
2	GoBiGas	Haldor Topsoe	100 MW (input)	70% (LHV)	€72/MWh	€350 M	Thunman (2018)
3	ECN	MILENA, ESME	1000 MW (input)	70% (LHV)	14-24 US$/GJ	US$1.5 Bn	ECN (2014)
4	Sungas Renewables	Andritz & Haldor-Topsoe	945 tpd	3 BCF/yr	US$13-15/MMBtu	US$340 M	LeFevers (2020)
5	Undefined	Gasification & methanation	315 MW	67%	$23-39/GJ	€340 M	SysEne (2016)
6	E.ON Bio2G	Sweden	345 MW (input)	60-65%	-	€450 M	IEA (2019)
7	Conceptual	AMEC CFB and VESTA methanation	6.1 MW	65%	€150/MWh	€19 M	Kraussler (2018)
			12.2 MW		€130/MWh	€30 M	
			49.1 MW		€95/MWh	€75 M	
8	Conceptual	Milena, G4, FICFB	30 MW	50-70%	C$19-40/GJ	C$60 M	Cheney (2018)[192]
9	Conceptual	G4 Insights	6.7 MW (input)	70%	€23/MWh	€13 M	Renewtec (2018)
10	Swindon (UK) – RDF as feedstock	Advanced Plasma Power, Progres-sive Energy and Carbotech	132 MW 84 MW (output)	60%	£21/MWh	£151 M	GoGreen (2017)[193]
11	B.C. pulp mills	Generic (Repotec, Carbona or Thyssen gasifier)	200,000 odt/yr, 2.5 PJ/yr of RNG output	65%	$15-20/GJ (variable only); $50/GJ w. profit	C$400-500 M	Browne (2019)[227]
12	REN Energy	Not published	>100,000 tonnes	67%	<$30	C$130 M	Boyd (2020)[63]
13	CHAR Technologies	High-temperature pyrolysis	76 odt/yr	33%	Unknown	C$30 M	Ross (2021)[194]

[192] Cheney, Thomas: Wood to Renewable Natural Gas Technology Assessment for Nelson Hydro. Thomas Cheney Consulting, November 2018.
[193] BioSNG Demonstration Plant - Summary of Commercial Results (Commercial models of full scale BioSNG plants). Gogreengas, June 2017.
[194] https://www.northernontariobusiness.com/industry-news/green/company-eyes-kirkland-lake-as-base-to-convert-forest-waste-to-green-natural-gas-4478260 (Accessed November 2, 2021).

Appendix C – Forest Biomass Resource Assessment

A. *Types of Forest Biomass*

B.C.'s forests provide woody feedstock for a variety of activities of the forest products industry, including sawlogs, pulp logs, and feedstock for wood pellet production. Table 61 describes log and residue streams and the terminology used. It is impossible to determine the amounts available of each residue stream exactly as they are often used jointly under existing fibre purchasing agreements.

Table 61 Types of Woody Feedstock

Fibre type	Description
Sawlogs	High-value trees that are used to manufacture dimensional wood products. The high value of these logs warrants the cost of building logging roads, felling and replanting. This resource is not used to produce energy but the residue from processing these logs is.
Pulp logs	Lower-value trees that can be harvested together with sawlogs. This is routinely done by forest product companies and the pulp logs are sold to pulp and paper mills at far lower pricing than sawlogs. Whenever pulp logs are not used by pulp and paper mills, they can be used to produce energy but are more expensive than other sources of fibre.
Chips	Wood chips can be made of pulp quality or for combustion in chip boilers. The latter remains exceptional in Canada, whereas large amounts of pulp chips are produced either by the pulp mills themselves or by saw or chip mills selling to pulp mills.
Roadside residue (or slash)	Also called harvesting residue, this fibre consists mainly of the limbs and tops of trees that are removed to obtain sawlog and pulp logs. Broken, small-diameter or deciduous trees are frequently part of 'slash piles.' This residue can be left in the forest but is often collected and piled up on the roadside. It is routinely burned, though sometimes recovered as a fuel for mills or as a feedstock for pellet production.
Mill residue	*Hog fuel* is the residue – mainly bark – left over from de-barking stems at pulp and paper mills. The term is also used to refer to any type of wood by-product or waste that can be burned for fuel but can't be categorized as chips, shavings, bark, or sawdust. It is high in ash and irregular in size. It is the lowest-value fuel and is often burned in recovery boilers at the mill where it is produced. Excess hog fuel is sold to other forest products companies at low pricing (sometimes for free). In coastal regions, bark may have been in contact with saltwater, which may require adapting processes or a pre-wash of such feedstock.
	Shavings from planer mills are a clean fuel that can be used for pellet or pulp production.
	White *sawdust* from sawmills is a sought-after residue for pellet production. It is more costly than hog fuel because of its higher quality (lower ash content, lower moisture).
	Mill residue data is not statistically collected in B.C. but can be estimated. It is only referred to as a combination of the above three streams in this report.
CLD	Construction, land clearing and demolition wood waste is a mixture of wood streams from construction activities. Removed trees to prepare the site, woody bits left over from construction, or wood separated out during deconstruction is included. Only clean wood can be used, which requires an efficient process to remove anything that is contaminated, covered with plastics or painted/treated wood. This separation process increases the cost of this fuel and it is often used in urban applications such as district heating, or by the cement industry if too contaminated.

B. *Previous Estimates*

The 2019 estimates in Table 62 are taken from the report *Revitalization of the B.C. Bioenergy Sector*, produced for BCBN in 2019. They are based on a commercial fibre supply model (the B.C. Fibre Model) taking the Annual Allowable Cut (AAC), mill activity, imports and exports of fibre between regions, to estimate surplus residue at mills and in the forest. The numbers represent the amounts available for new activity without negatively impacting existing uses of these resources by the forest products industry. The main conclusions from this work are:

- Little surplus mill residue is available in B.C. Some regions have a fibre deficit and are importing residue from neighbouring regions. Only small pockets with residue are still available in the western parts of the Skeena and Kootenay/Boundary Natural Resource Regions. These pockets may be exhausted by a single new project, such as a new pellet mill.
- Also, few pulp logs remain unharvested in most areas. By 2028, only small amounts will remain in few areas, which may be insufficient to sustain a new bioenergy facility on their own.
- The main resource available is forest roadside residue. Large amounts exist in some areas, especially when combined with other residue. Yet this resource is currently not fully recovered in B.C. There are issues with (physical and legal) access to and transport of this fibre so the cost will be higher than for mill residue. Fibre recovery zones have been set up to help use residuals for pulp wood and bioenergy. The amount indicated is based on costs up to $90 per dry tonne and omits regions that would require barging or other highly expensive transportation approaches.
- Stands of non-merchantable timber could be harvested for energy production. Most non-merchantable fibre consists of smaller trees with insufficient diameters to be used in mills. This may be recovered as roadside residue. As the AAC is usually defined for softwood, some regions – mainly in northern B.C. – have deciduous stands not covered in the AAC (in the South Peace, deciduous wood is already part of the AAC). These stands are not part of this inventory but may be obtained if close enough to relevant infrastructure. This would require a specific harvesting license from the Ministry.

The B.C. Fibre Model results are projected out to 2028. These results are further developed below, taking into account expected changes in the AAC and the impacts of recent mill closures. Whereas the B.C. Fibre Model uses specially-defined regions, the analysis in this report relies on the B.C. Resource Regions as commonly used in most government documentation and statistics (**Figure 39**).

ROM: Omineca; RSC: South Coast; RNO: Northeast, RTO: Thompson-Okanagan; RKB: Kootenay-Boundary; RCB: Cariboo; RSK: Skeena; RWC: West Coast.

Figure 39 B.C. Resource Regions[195]

[195] https://www2.gov.bc.ca/gov/content/environment/natural-resource-stewardship/cumulative-effects-framework/regional-assessments/kootenay-boundary (Accessed August 23, 2021).

Table 62 Fibre Availability in B.C. in 2019 and 2028, in Odt, According to the B.C. Fibre Model

	A		B		C		D	
	AAC (standing timber) not harvested		Non-sawlog timber (pulp logs) not consumed		Net roadside residue not consumed		Residual sawmill hog fuel not consumed	
	2019	2028	2019	2028	2019	2028	2019	2028
Coast	1,526,753	1,298,067	0	0	320,733	237,917	5,085	0
East Kootenay	60,515	4,228	0	0	116,848	116,427	0	0
West Kootenay	-448,384	-481,677	0	0	174,331	175,296	311,898	314,102
Kamloops-Okanagan	-81,658	-292,029	175,331	0	0	0	0	0
Cariboo	-1,825	-367,056	441,306	0	403,239	169,993	0	0
Prince George	-270,780	-691,946	0	0	75,019	0	0	0
Mackenzie	369,643	29,838	383,880	0	0	0	0	0
South Peace	385,172	17,502	115,167	143,337	69,295	69,295	0	0
East Prince Rupert	331,409	11,161	307,777	7,150	0	0	0	0
West Prince Rupert	1,010,806	977,830	95,912	96,264	63,953	62,387	32,097	32,097
Northeast	812,500	812,500	0	0	0	0	0	0
Northwest	98,000	76,000	0	0	0	0	0	0
TOTAL	3,792,151	1,394,417	1,519,373	246,751	1,223,419	831,315	349,080	346,199

Note: Negative numbers indicate a deficit of fibre. Wood has to be imported from other regions.

In total, the model projects that an equivalent of 126 petajoules of unallocated woody biomass is available in B.C. today (Table 63). The model predicts that this amount is reduced to 52 petajoules in 2029. These numbers refer to feedstock input and not to the amount of low-carbon fuel produced, which will vary by technology. Amounts available are strongly reduced for a mix of reasons, such as reduced AACs, expiring uplifts (temporary increases of the AAC to address the beetle epidemic), mill closures and the resulting redistribution of wood residue within the forest products industry.

Table 63 Total Woody Biomass Available in B.C. in 2019 and 2028

Region	A + B + C + D: Unallocated woody biomass in odt/yr		Calorific content (LHV) of unallocated woody biomass; in PJ/year	
	2019	2028	2019	2028
Coast	1,852,571	1,535,984	33.9	28.1
East Kootenay	177,363	120,655	3.2	2.2
West Kootenay	37,845	7,721	0.7	0.1
Kamloops-Okanagan	93,673	-292,029	1.7	-5.3
Cariboo	842,720	-197,063	15.4	-3.6
Prince George	-195,761	-691,946	-3.6	-12.7
Mackenzie	753,523	29,838	13.8	0.5
South Peace	569,634	230,134	10.4	4.2
East Prince Rupert	639,186	18,311	11.7	0.3
West Prince Rupert	1,202,768	1,168,578	22.0	21.4
Northeast	812,500	812,500	14.9	14.9
Northwest	98,000	76,000	1.8	1.4
TOTAL	**6,884,022**	**2,818,683**	**126.0**	**51.6**

C. *Annual Allowable Cut through 2050*

Generally, the AAC is set for 10 years for each Timber Supply Area and Tree Farm Licence.[196] In most Resource Regions, Timber Supply Areas (TSAs) provide about ten times more volume than Tree Farm Licenses (TFLs). The exception is Vancouver Island, where TFLs provide most of the allowable cut. On average, the actual timber harvest has been almost 20% lower than the allowable cut, particularly on the coast.[197,198] Harvesting levels have been affected in the interior by the pine beetle infestation and wildfires. Whereas wildfires initially affected the dead pine beetle forests, the 2018 wildfires affected harvestable areas, especially the Cassiar (5.6% losses of harvestable areas), Lakes (5%), and Morice (2.9%) TSAs. This did not, however, lead the Ministry of Forests to revise the AAC.[199] Whether this will be necessary after the 2021 wildfire season remains to be seen. Recent wildfires have mainly affected the Cariboo and Thompson-Okanagan regions.[200]

Current government projections do not foresee any increase in the AAC before the year 2070 (Figure 40). The AAC is expected to fall to below 55 million cubic metres per year throughout this report's forecast horizon (2050).[201] This is equal to 88% of the 2021 AAC and 100% of the 2019 actual harvest (see below). Table 64 and Figure 41 show current AACs as of August 2021 and make projections to reflect the future harvesting level of around 40 million m^3 per year for the interior. These AACs consider the areas most affected by the pine beetle and by wildfires.

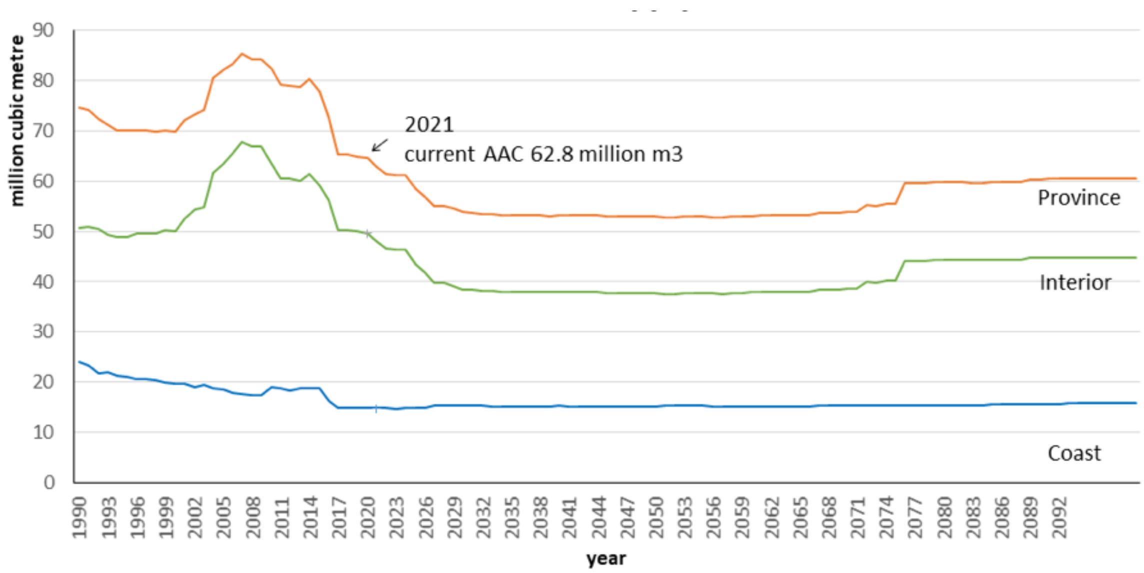


Figure 40 B.C. Timber Supply Forecast[202]

[196] https://www2.gov.bc.ca/gov/content/industry/forestry/managing-our-forest-resources/timber-supply-review-and-allowable-annual-cut/allowable-annual-cut-timber-supply-areas/cascadia-tsa (Accessed August 20, 2021).
[197] https://www.env.gov.bc.ca/soe/indicators/land/timber-harvest.html (Accessed August 23, 2021).
[198] David Elstone (2019), "TLA Breaks Down Forestry Job Loss." https://www.woodbusiness.ca/understanding-forest-industry-job-loss-4376/ (Accessed August 28, 2021).
[199] Impacts of 2018 Fires on Forests and Timber Supply in British Columbia. Office of the Chief Forester British Columbia Ministry of Forests, Lands, Natural Resource Operations and Rural Development, April 2019.
[200] https://vancouversun.com/news/local-news/b-c-wildfires-map-2021-updates-on-fire-locations-evacuation-alerts-orders?r (Accessed August 23, 2021).
[201] Nussbaum, Albert: Personal communication. Ministry of Forests, Lands, Natural Resource Operations and Rural Development, October 15, 2021.

Table 64 Annual Allowable Cut, in Cubic Metres per Year (TFLs and TSAs)[202]

	August 2021, TSA	TFL	Total AAC	*2030-2050 AAC (estimates)*
South Coast RSC	2,893,089	329,040	**3,222,129**	*3,000,000*
West Coast RWC	4,463,356	7,191,646	**11,655,002**	*12,000,000*
East Kootenay RKB	4,166,643	1,069,000	**5,235,643**	*4,500,000*
West Kootenay RTO Kamloops-Okanagan RTO	6,948,405	585,700	**7,534,105**	*6,000,000*
Cariboo RCB	6,574,805	592,500	**7,167,305**	*5,500,000*
Prince George ROM Mackenzie ROM	13,213,559	631,500	**13,845,059**	*11,800,000*
East Prince Rupert RSK West Prince Rupert RSK Northwest RSK	5,994,000	506,059	**6,500,059**	*5,300,000*
Northeast RNO South Peace RNO	6,557,350	871,000	**7,428,350**	*7,000,000*
TOTAL	**50,811,207**	**11,776,445**	**62,587,652**	***55,100,000***

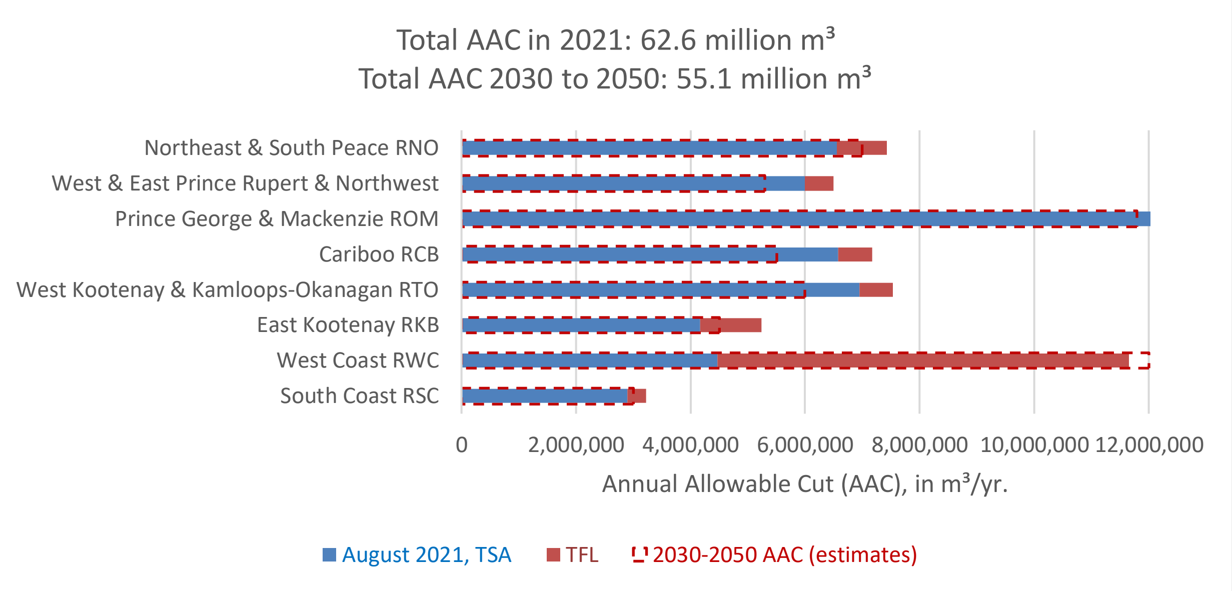


Figure 41 Annual Allowable Cut, Based on Table 64

As Table 65 indicates, the six largest forest products companies control almost half the allowable cut in B.C. This is important when trying to access harvesting residue, since users must negotiate with these companies to gain access to roadside residue.

202 Ministry of Forests, Lands, and Natural Resource Operations - Apportionment System, August 12, 2021 – see https://www2.gov.bc.ca/gov/content/industry/forestry/forest-tenures/forest-tenure-administration/apportionment-commitment-reports-aac

Table 65 TSA Rights, in Cubic Metres per Year, Six Largest Licence Holders[203]

Company	August 2021, TSA	% of total AAC allocated to TSAs
Canadian Forest Products Ltd.	9,240,762	15%
West Fraser Mills Ltd.	5,389,622	9%
Western Forest Products Inc.	4,977,35	8%
Interfor Corporation	3,688,239	6%
Tolko Industries Ltd.	3,418,829	5%
Louisiana-Pacific Canada Ltd.	1,264,710	5%
Total	**23,002,162**	**45%**

D. *Mill Closures and Production Levels*

Statistics Canada noted a downward trend in lumber production from B.C. mills, see Figure 42. Although 2021 saw a strong increase in lumber pricing due to record housing starts, prices have recently dropped to low levels,[204] whereas delivered log pricing in B.C. remains high. The small margin between log prices and lumber caused Conifex Timber to curtail the MacKenzie mill in August 2021.[205] Several other producers curtailed production due to the numerous wildfires in the summer of 2021.[206] The strong increase in housing prices observed in 2021 may also reduce short-term demand for new homes. There is no reason to believe that B.C. mill output will reach previous levels in the coming years. Public discussion blames the decline on a set of issues affecting the cost of milling in B.C., including high stumpage fees, the pine beetle infestation, wildfires, and increased conservation efforts. Fibre costs in the B.C. interior increased by 33% between 2016 and 2019, with 25% of the delivered cost being due to stumpage fees.[207] The increasing fibre cost seems to indicate a transition towards lower harvesting rates.[208]

Since the 2019 report on the *Revitalization of the B.C. Bioenergy Industry*, several mills, including one pulp mill, have been closed or indefinitely curtailed (Table 66). According to independent forestry consultants, an additional four sawmill closures appear imminent on the coast and another five in the interior.[209] Proposed policies to curtail logging in old-growth forests and to protect caribou may result in a one-million-cubic-metre decrease in the coastal AAC and a three-million-cubic-metre decrease for the interior. These developments will affect the viability of pulp and pellet mills, as well as of biomass power plants.

[203] Provincial Linkage AAC Report. Province of British Columbia, August 12, 2021. See https://www2.gov.bc.ca/gov/content/industry/forestry/forest-tenures/forest-tenure-administration/apportionment-commitment-reports-aac
[204] https://www.nrcan.gc.ca/our-natural-resources/domestic-and-international-markets/current-lumber-pulp-panel-prices/13309 (Accessed August 23, 2021).
[205] https://getfea.com/mill-capacity-changes/conifex-timber-inc-announces-2-week-curtailment-at-mackenzie-b-c-sawmill-starting-monday-august-23-2021 (Accessed August 23, 2021)
[206] https://treefrogcreative.ca/post-peak-production-will-bc-producers-pull-back/ (Accessed August 23, 2021).
[207] https://issuu.com/truckloggers/docs/truckloggerbc_fall_2020_final_lowres/s/11119030 (Accessed August 24, 2021).
[208] Bennett, Nelson: High operating costs cripple forest industry recovery. Prince George Citizen, July 22, 2020.
[209] https://biv.com/article/2021/08/more-mill-closures-loom-bc-researcher-warns (Accessed August 24, 2021).

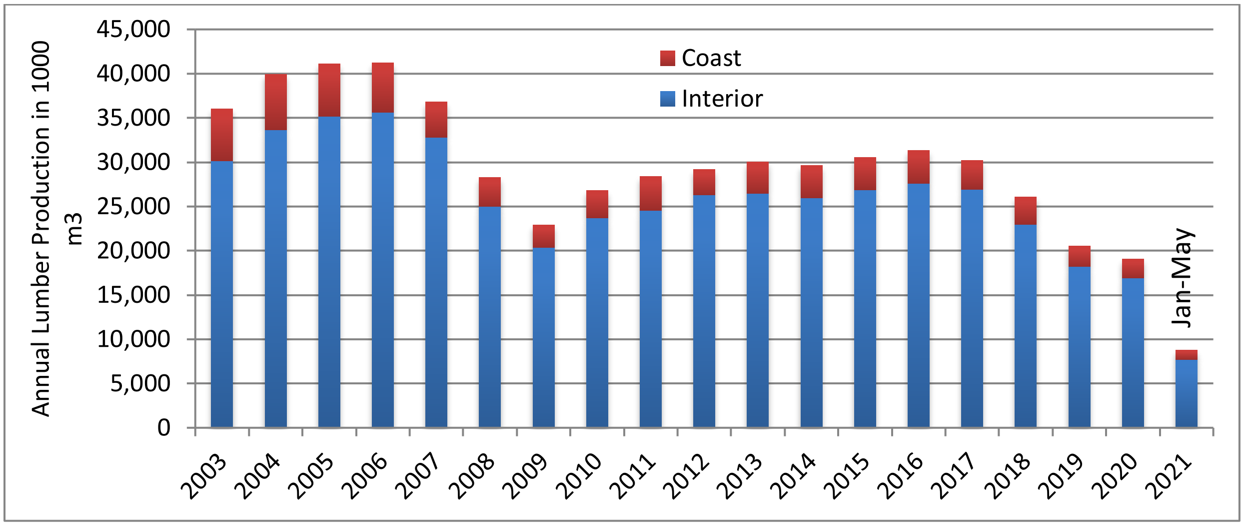


Figure 42 B.C. Lumber Production in Thousand Cubic Metres Per Year[210]

Table 66 Mill Closures and Curtailments[211]

Facility	Region	Notes	Year
Parallel 55 Fingerjoint Plant – Mackenzie	ROM	Indefinite curtailment	2019
Peace River OSB – Fort St John	RNO	Restart planned in 2022	2019
Canfor Sawmill – Mackenzie	ROM	Indefinite curtailment	2019
Conifex Sawmill - Fort St. James	ROM	Closed. Sold to Hampton Lumber	2019
Tolko Industries Sawmill – Quesnel	RCB	Closed	2019
Canfor Sawmill – Vavenby	RTO	Closed	2019
West Fraser Chasm Sawmill – 70 Mile House	RCB	Closed	2019
Norbord, 100 Mile House[212]	RCB	Indefinite curtailment	2019
Teal-Jones Harvesting Operations – Boston Bar	RSC	Closed	2019
Tolko Industries lumber mill – Kelowna	RTO	Closed	2020
Teal-Jones Harvesting Operations – Pitt Lake	RSC	Closed	2019
Interfor Hammond Sawmill – Maple Ridge	RSC	Closed	2019
Teal-Jones Harvesting Operations – Honeymoon Bay	RWC	Closed	2019
Paper Excellence (pulp), Mackenzie[213]	ROM	Closed	2021
Canfor Isle Pierre[214]	ROM	Closed	2020
Flavelle sawmill, Port Moody[215]	RSC	Closed	2020
San Group, Port Alberni[216] (small logs)	RSC	Opened	2020

[210] Statistics Canada, Table 16-10-0017-02.
[211] https://lumberforecast.com/2019-b-c-mill-closure-map/ (Accessed August 24, 2021).
[212] https://www.timescolonist.com/year-in-review-sawmill-closures-hurt-b-c-communities-1.24040975 (Accessed August 24, 2021).
[213] https://biv.com/article/2021/04/mackenzie-pulp-mill-will-close-permanently (Accessed August 24, 2021).
[214] https://getfea.com/covid-19/canfor-updates-b-c-mill-curtailments-and-closures (Accessed August 24, 2021).
[215] https://www.nipimpressions.com/bc-mill-closing-permanently-cms-10797 (Accessed August 24, 2021).
[216] https://www.woodworkingnetwork.com/news/canadian-news/first-sawmill-15-years-opens-british-columbias-west-coast (Accessed September 22, 2021).

Responsible for more than 68% of all wood consumed in B.C., sawmills remain the backbone of the forest products industry on which other mills depend. A reduction in sawmill output has impacts on downstream mills. Of the roundwood delivered to sawmills, only 45.8% become timber products in 2019,[217] 35.2% of sawmill feedstock was converted to residual chips for pulp mills and 17% was converted to sawdust and shavings used in pellet and panel mills. B.C. pulp mills processed over 22 million cubic metres of fibre, down 15% in 2019 from 2018. Of this total, pulp mills consumed about 15 million cubic metres of residual chips produced by sawmills and veneer mills, accounting for 67% of their fibre input. In addition to residual chips from sawmills, pulp mills used about 5.8 million cubic metres of whole-log chips, representing over 26% of their total fibre input. Pellet and panel mills also rely on sawmill residuals. In 2019, pellet and panel mills together processed 4.8 million cubic metres of fibre, mainly sawdust and shavings, down 5% from 2018.

Figure 43 shows the fibre flows between different players in the forestry industry of B.C. Industries depend on these fibre flows, mainly the pulp mills using chips from the sawmills and pellet mills using mainly sawdust and shavings. On the other hand, only 0.8 million cubic metres of harvesting residue is currently being used, against a remaining potential of 1.2 million tonnes (Table 62), or about 2.9 million cubic metres. The 12 B.C. veneer mills used 4.6 million cubic metres of logs. Other mills, such as shake and shingle mills, only used small amounts of fibre compared to other mill types (less than 2% of total log consumption).

Figure 44 and Figure 45 illustrate that pulp and paper mills and natural gas infrastructure are mostly near the interior working forest. Potential fibre supplies are remote for much of the coastal forest although much of the timber harvesting land base is on Vancouver Island or the south coast, close to potential users. Coastal wood is often hauled by water. Alternative logistics approaches might be needed to acquire additional feedstock suitable for gasification.

[217] 2019 Major Timber Processing Facilities in British Columbia. Ministry of Forests, Lands, Natural Resource Operations and Rural Development, January 2021.

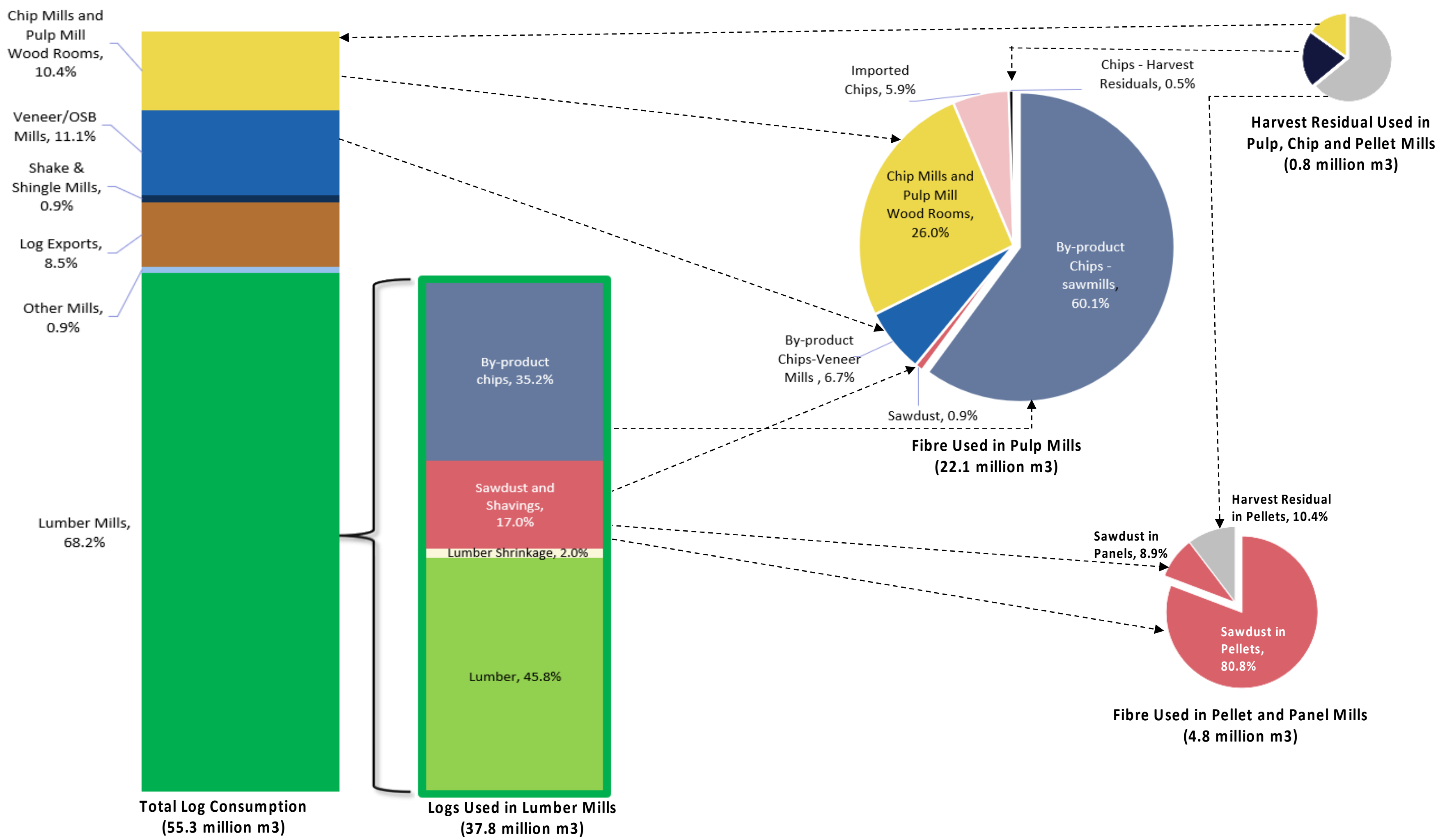


Figure 43 Fibre Flows Between Users in B.C. (2019)[217]

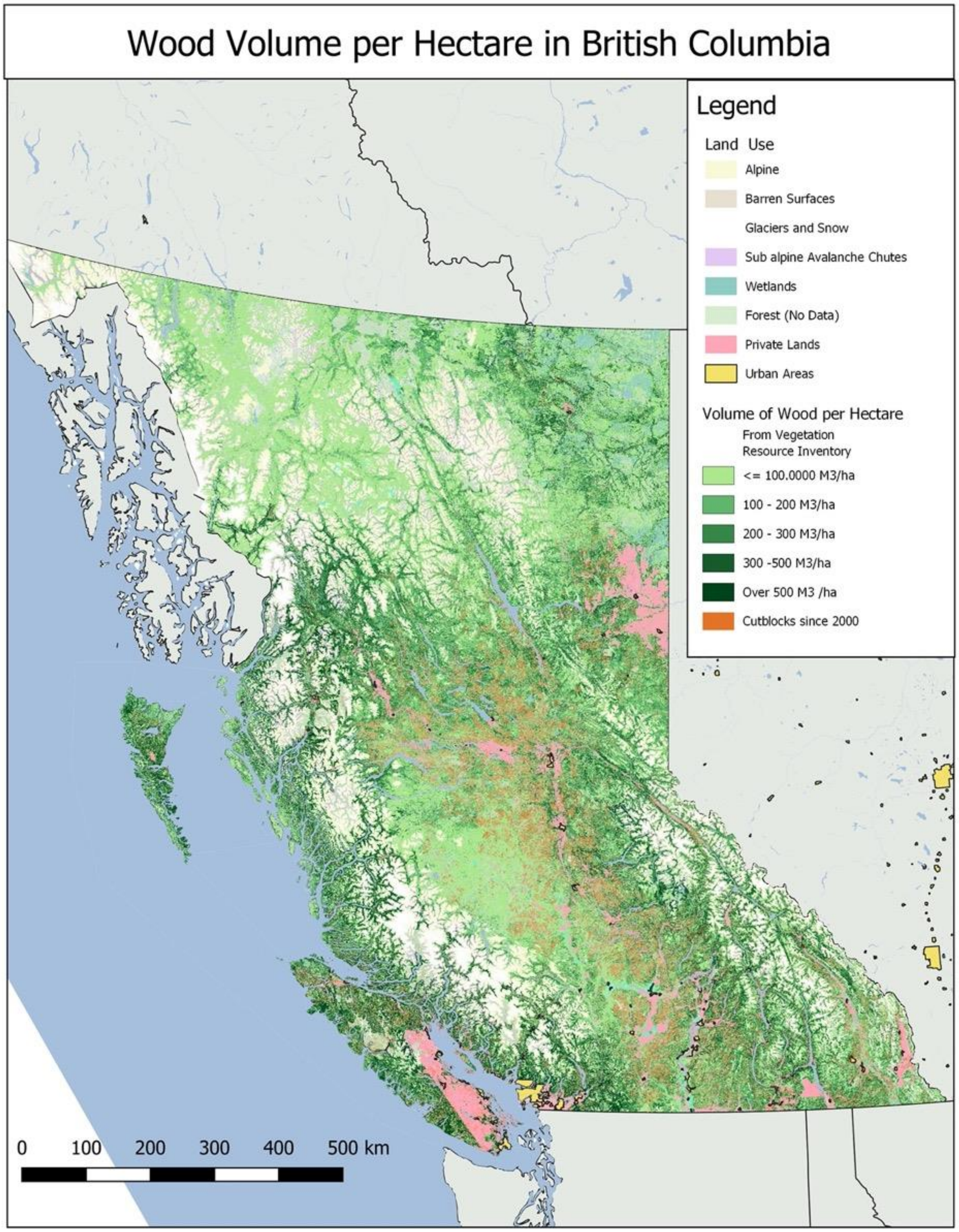


Figure 44 Concentration of Woody Biomass (Forests) in B.C.

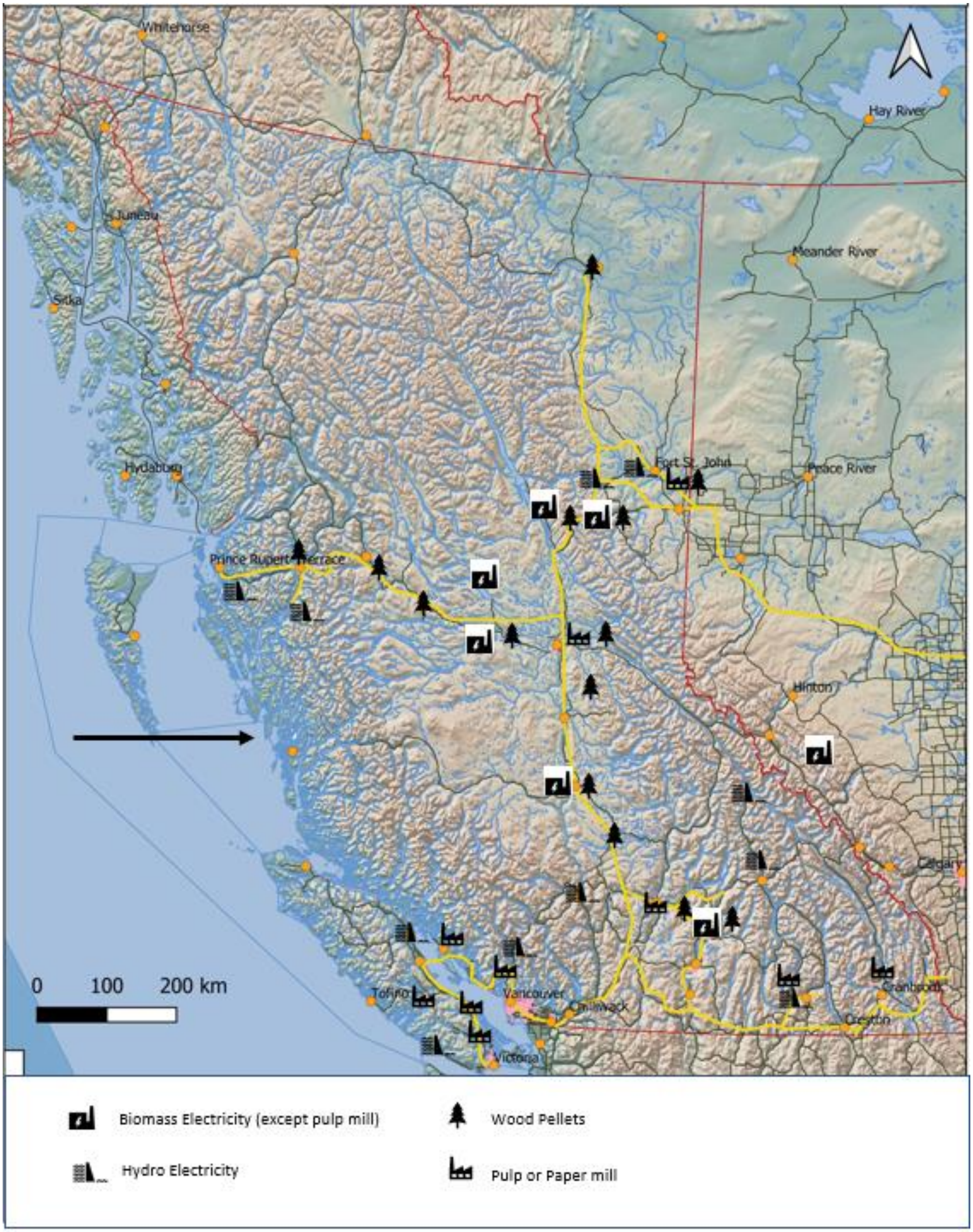


Figure 45 Location of Bioenergy Facilities and Pulp & Paper Mills

E. *Harvesting (Roadside) Residue*

Processing residues may also be augmented by roadside residue, which mainly refers to tops and branches generated during harvesting. This material may remain on the forest floor or be collected at the roadside, and a portion of the latter may be transported directly to mills to make wood products. Estimates of total roadside residue consumption were about 900,000 cubic metres in 2018[218] and 770,000 cubic metres in 2019. Whatever the total amount of residue is being consumed, the ratio of consumption by different sectors is constant, with pellet mills consuming about 64%, followed by chip mills (21%), and pulp mills (15%).

Harvesting residue has been estimated by FPInnovations (FPI) for 18 out of the 37 TSAs.[219] They determined that 2.89 million dry tonnes were available across these TSAs, representing a ratio of between 20.5% and 21.3% of the total sawlog harvest. Approximately 260,000 tonnes of estimated available residues are situated in the four coastal TSAs, and the remainder (2.63 million tonnes) are in the 14 TSAs in the interior. In the interior, FPI estimates that about 35% of this resource is economically recoverable at a cost of up to $60 per dry tonne at the plant gate. At coastal locations, only 16% are deemed recoverable at that cost. This adds up to one million tonnes of low-cost recoverable roadside residue. An additional 1.8 million tonnes may be recoverable at a cost above $60 per dry tonne. This is similar to the estimate of 1.2 million tonnes in Table 62. Note that the FPI estimates only extended to about half the total number of TSAs. Twenty percent of the total sawlog harvest across B.C. is likely to be available residues. A smaller subset is recoverable at costs acceptable to the industry. This suggests that in 2020, the total amount of available residues was as high as 3.12 million dry tonnes, based on a harvest level of approximately 37.7 million m^3.

Brian Titus of NRCan provided yet another estimate, quantifying roadside residue at a distance of 50 and 75 km from existing gas compressor stations along the pipeline network.[220] He arrived at 3.2 million dry tonnes for 50 km and 4 million tonnes for 75 km. This assessment overlaps with the FPI estimate of total available residues. It does not appear to consider existing uses of this material, or other costs such as road construction that might reduce this estimate. Uncertainties therefore remain, and improved recovery techniques and supply chains will make this resource more accessible and more affordable over time.

F. *Mill Residue Production and Consumption*

Table 67 summarizes the amounts of residue produced and consumed in B.C. for the year 2019. The great majority of mill residue is consumed within the forest products industry. Shake and shingle and other mills only consumed less than 2% of the fibre harvested (55 million cubic metres) and are left out of the table. Lumber mills accounted for almost 70% (68.2%) of harvested volumes in 2019, followed by veneer and OSB mills (11.1%) and chip and pulp mills (10.4%), which use whole tree chips for a portion of their input. Log exports were the fourth largest market for B.C. roundwood, at 8.4%.

Sawmills and veneer mills produced a total of 6.4 million m^3 of shavings and sawdust, as well as 15.7 million m^3 of chips. This meets most of the chip demand from the pulp and paper sector (22.1 million m^3),

[218] Corrected number, based on Leng, Jiali: Personal communication. Ministry of Forests, Lands, and Natural Resource Operations, October 19, 2021.

[219] https://library.fpinnovations.ca/en/viewer?file=%2fmedia%2fFOP%2f8288.PDF (Accessed September 8, 2021)

[220] Titus, Brian: Logging residue availability estimate. Pacific Forestry Centre of Natural Resources Canada. Cited in: Hallbar, Matthew: Resource Supply Potential for Renewable Natural Gas in B.C. PUBLIC VERSION. Hallbar Consulting, March 2017.

with the remainder provided by whole log chips and some chip imports from the U.S., mainly coastal mills. Chip and pellet mills also consume increasing amounts of roadside residue as less mill residue is available because of sawmills closing their doors. Sawdust and shavings are mainly consumed by pellet mills. The numbers in the table suggest a sawdust/shavings surplus of about one million m^3. This may be because the amount was overestimated (the Mill List Survey does not collect data on the actual production of sawdust and shavings from lumber mills) or because these resources were used internally by industry, such as for on-site drying (activities like this are not captured in the mill survey). It is somewhat in line with the previous estimate that about 300,000 dry tonnes of mill residue remain unused in B.C. (Table 62).

Table 67 Mill Residue Production and Consumption in B.C. (2019)[217]

Mill type (number)	Residue type	Amount of residue, per year
Lumber Mills (69)	Sawdust & shavings	6.42 million m^3
Lumber Mills (69)	Pulp chips	13.29 million m^3
Veneer Mills (12)	Pulp chips	2.47 million m^3
Pulp Mills (15)	Hog fuel	4.7 million m^3
Pulp Mills (15)	Residual chips	15 million m^3 + 5.8 million m^3 of whole log chips
Pulp mills (15)	Sawdust	199,000 m^3
Pulp Mills (15)	Roadside residue	116,000 m^3
Chip Mills (24)	Roadside residue	162,000 m^3
Pulp & paper Mills (20)	Chip imports	1 million m^3
Pellet Mills (13)	Sawdust & shavings	4.4 million m^3
Pellet Mills (13)	Roadside residue	493,000 m^3
Panel Mills (27)	Sawdust	427,000 m^3

Black: production; red: consumption

Table 68 lists existing and planned wood pellet mills in B.C. These mills predominantly use mill waste (about 70% of their input). Only about one-quarter comes from whole logs.[217] New mills, such as the one planned for Fort Nelson, would change this picture and would use mainly roundwood, co-harvesting both sawlogs to be sold to mills and non-merchantable trees to be chipped and dried for wood pellet production.[221] This again confirms that little easily available fibre is available in B.C. for new ventures. The Fort Nelson project accesses an abandoned TSA that was previously controlled by one of the large sawmill companies. Where mills close and additional value can be obtained from co-harvesting both sawlogs and pulp or energy logs, the forest products industry may be revived through new energy-related projects. The role of bioenergy as an outlet for low-grade logs and residuals is particularly important in regions where there is no existing pulp production such as the northwest (e.g., Coast Mountain Natural Resource District and Kispiox/Nass areas).

[221] https://thetyee.ca/Analysis/2021/02/17/Trees-Pellets-Fort-Nelson-Future-Hangs-Balance/ (Accessed September 1, 2021).

Table 68 Existing[222] and Planned Pellet Mills

Mill	Location	Capacity in kilotonnes per year
Canadian Forest Products (Canfor)	Fort St. John	75
Canadian Forest Products (Canfor)	Chetwynd	100
Pacific Bioenergy Corp	Prince George	350
Drax	Burns Lake	380
Canfor/Pinnacle Renewable Energy Inc.	Houston	220
Drax	Smithers	140
Drax	North Strathnayer	230
Drax	Williams Lake	230
Drax	Armstrong	72
Drax	Lavington	300
Princeton Standard Pellet Corp.	Princeton	100
Premium Pellet Ltd.	Vanderhoof	185
Skeena Bioenergy Ltd.	Terrace	95
Vanderhoof Specialty Wood Products	Vanderhoof	30
TOTAL		**2,507**
Peak Renewables[223]	*Ft Nelson*	*600*
Hazelton Bioenergy[224]	*Hazelton*	*100*
SMG Wood Pellets[225]	*Mission*	*160*

Note: Planned projects in italics

Expiring contracts of pulp and paper mills with BC Hydro to export excess power to the grid have been identified as another potential source of fibre (hog fuel). As new contracts have been concluded since 2019 and until the end of 2021 at lower pricing and lower power output levels than before (around 80% of previous levels), the biomass previously used to generate the excess electricity can now be used for other purposes, potentially also to produce renewable gases. The amount of this biomass is substantial and has been estimated as high as 2.2 million dry tonnes (bark),[226] with potentially another 700,000 tonnes from dedicated power plants if the latter can no longer operate cost-effectively.[234] This estimate compares to an estimated 0.8-1.0 million dry tonnes from a report by Tom Browne, possibly increasing to 1.7 million tonnes by 2029 as more mills cease to export excess power (power-only generators are not considered in this estimate).[227] Table 69 summarizes the information available on these contracts and estimates the feedstock potentially becoming available for other uses.

[222] SBP-endorsed Regional Risk Assessment for the Province of British Columbia, Canada. Sustainable Biomass Program, August 2021.
[223] https://www.argusmedia.com/en/news/2161961-canadas-peak-renewables-plans-new-bc-pellet-plant
[224] https://www.interior-news.com/news/south-hazelton-pellet-plant-on-track-for-2021-opening/
[225] http://www.biomassmagazine.com/articles/10766/proposed-pellet-plant-to-export-product-to-south-korea
[226] Issue Note on Biomass Energy Purchase Agreements - A Critical Component of BC's Integrated Forest Industry Submitted by Industry Members of the BC Pulp & Paper Coalition, August 2017.
[227] Browne, Tom: Syngas and Renewable Natural Gas options for the BC forest sector. Tom Browne & Associates, October 2019.

Table 69 Revised BC Hydro Contracts with Mills, in GWh per Year[228]

Facility	Previous Export	Year of Renewal	Renegotiated Export	Estimated odt becoming available
Paper Excellence, Howe Sound	400 GWh	2019	400 GWh	
Skookumchuck	266.7 GWh	2019	162.4 GWh	
Catalyst Paper, Powell River	157.5 GWh	2020	*125 GWh (est.)*	
Canfor PGP Pulp Bioenergy	123 GWh	2019	105.5 GWh	
Mercer, Celgar	241.5 GWh	2019	127.9 GWh	
Tolko, Armstrong	163.32 GWh	2019	126.8 GWh	
Atlantic Power, Williams Lake	545 GWh	2019	388.4 GWh	
Sub-total through 2020	**1,897 GWh**		**1,436 GWh**	**388,000**
Conifex, Mackenzie	220 GWh Strathmere	2029	0	*185,086 (est.)*
Merritt Green Energy*	303.5 GWh	2029	0	*255,335 (est.)*
Chetwynd Biomass	96.4 GWh	2029	0	*81,101 (est.)*
Ft St James Green Energy*	303.5 GWh	2029	0	*255,335 (est.)*
Fraser Lake Biomass	96.4 GWh	2029	0	*81,101 (est.)*
Kamloops Green Energy	288.3 GWh	2029	0	*242,547 (est.)*
Harmac Biomass, Nanaimo	209 GWh	2029	0	*175,832 (est.)*
Canfor, Intercon Green power	73 GWh	2029	0	*61,415 (est.)*
Canfor, Northwood	159 GWh	2029	0	*133,767 (est.)*
Cariboo Pulp & Paper	172.3 GWh	2029	0	*144,956 (est.)*
Sub-total by 2029	**1,925 GWh**		**0**	***1.6 million*** *(est.)*
Total potential if previous contracts expire and are not renewed				**3.2 million**

* These power plants come into full operation in 2018 and may have longer-term contracts with BC Hydro that only expire after 2030.

Almost 400,000 tonnes should be available today from modified BC Hydro contracts but over three million tonnes could become available in 2029 if the industry stopped exporting power, and if biomass power plants ceased to produce electricity. This does not take into account, however, that several sawmills have closed in recent years due to changing market conditions and changing fibre supply in various TSAs. The fibre balance in many regions has been affected. Pulp and paper mills, where cogeneration facilities are situated, may rely on at least some of this resource for their own needs, either as fuel or to produce additional wood chips. This may then affect their intake of roadside residue or hog fuel from other sources.

The 2019 Mill List[217] identifies 121 large and mid-sized lumber mills in B.C. As shown in Table 66, 14 sawmills already closed or have indefinitely suspended activities. If another nine mills are closing soon, this would mean that about 19% of B.C. mills active in 2019 will fall out of service. This, in turn, can be estimated to reduce residue production by 4.5 million cubic metres or about 1.8 million dry tonnes – about the amount potentially freed from reduced use for power production at mills. This would mean that, currently, a fibre shortage exists in B.C. and only a portion of the 3.2 million tonnes estimated in the table above may actually be available in 2029. Conversely, it is also possible that a large portion of lost production will be taken up by the remaining mills if the latter are currently running only one or two shifts per day and can now add additional shifts to increase their output. The impact of renegotiated BC Hydro contracts is therefore impossible to quantify, due to uncertainty around future negotiation outcomes, BC

[228] IPP Supply List – In Operation. BC Hydro, May 2021.

Hydro power requirements, and the internal demand of the forest products industry rebalancing in unpredictable ways.

G. *Other Sources of Wood*

Table 70 adds several more sources of wood that may contribute feedstock to a new biomass energy project. These sources are sometimes significant in size but they can also be variable or spread over a large area of B.C., so any given project may access smaller amounts of the totals estimated here. Wood from thinning around communities to reduce the fire hazard may occur regularly (i.e., thinning may have to be repeated every ten years) but is expensive to obtain. Subsidies are provided through the Forest Enhancement Society of B.C., yet the amounts recovered remain very small. Generally, a large portion of feedstock must be guaranteed for a long timeframe for a project to be bankable. This excludes many smaller or irregular resources from being counted on to start up a new project. Once in existence, however, a new facility can access a variety of these resources for part of its feedstock. The amounts of roadside residue available were estimated based on a yield of 21% of merchantable amounts.[229] Various innovations such as co-harvesting pulpwood and energy wood and yarding down to a 2” (5 cm) top is being considered in the Kootenays to use residuals that would otherwise be left on site, significantly boosting wood availability by over 20%. This approach is being employed by Celgar in the Kootenays which added specialized flail debarking technology to separate the white wood residuals from the bark. They plant to use the bark in a gasifier that will generate 1.2 million gigajoules of syngas.[230] However, road grades above 15% and cut slopes above five metres make secondary harvesting difficult with the current onsite chipping and grinding equipment. Biomass recovery on steep slopes appears to be limited without significant operational changes, such as those proposed by Celgar.

Table 70 Other Sources of Wood

Source	AAC	Roadside Residue, odt	Comments
Thinning for fire suppression (community interface, through FESBC).[231]	<40,000 m^3	16,000	124 wildfire risk reduction projects, 2016-2020; average contribution of $14 per m^3 roadside fibre recovered[232] <3% of a total of 1.25 million m^3.[233]
Heritage piles.	Unknown		Partially unusable if in state of decay.
Line and road maintenance.	Unknown		Likely thousands of tonnes, very dispersed.
Construction, demolition and land clearing.	270,000 odt[234]	270,000	Mainly in larger cities and often already being used by e.g., the cement industry or for district heating.
Sub-total		**>300,000**	Some currently used by others.
Newly available AAC due to mill closures.	10.5 million m^3	4.3 million	Roundwood; estimate based on anticipated mill closures.
		0.9 million	Roadside residue; estimate based on anticipated mill closures.
TOTAL		**>5.5 million**	

[229] Friesen, Charles: Biomass Supply in BC (slide presentation). FPInnovations, February 2020.
[230] Mercer Celgar (November 2019). [Untitled] Presentation to the City of Nelson Council.
[231] https://www.fesbc.ca/projects/ (Accessed September 2, 2021).
[232] 2021/22 – 2023/24 Service Plan. Forest Enhancement Society of BC, April 2021 .
[233] Kozuki, Steve: Personal information. Forest Enhancement Society of BC, September 3, 2021.
[234] Revitalization of The B.C. Bioenergy Sector - Final Report. ENVINT Consulting, October 2019 (confidential).

H. *Concluding Remarks and Caveats*

A high-level estimate with respect to unused AAC can be made based on the assumption that 19% of mills are closing between 2019 and 2023 and that they have control over a commensurate amount of harvestable trees. If industry harvests about 55 million cubic metres, as indicated above for the year 2019, then there should be around four million tonnes of roundwood available from these TSAs that are no longer harvested. To that, about 21% of roadside residue could be added.

This compares to almost four million cubic metres of AAC not harvested in 2019 as previously determined (see Table 62). CFS expected most of this amount to be either used by 2028 due to increase mill output, or the AAC to be reduced. These developments may therefore affect the estimate made above, even if there were additional unharvested amounts as of 2019. The estimate appears to reflect the fact that about 10-20% of AAC is routinely not harvested in many TSAs so, in theory, more wood could be extracted from TSAs that are currently managed by sawmills. Harvesting whole trees is, however, the most expensive source of wood fibre available. It is not likely that the entire harvest would be used for gas production. Rather, valuable trees would be sold as sawlogs (with pulpwood) and only non-merchantable trees would be used, reducing the overall potential for gas production.

The results for roadside residue need to be taken with some caution. The factor determined by FPInnovations (21% of roundwood harvest) serves to identify recoverable amounts. Yet, it does not take into account regional differences (e.g., steep slopes may make recovery more difficult or uneconomic), harvesting practices (tree length vs. shortwood methods (skidding may result in much less residue being recovered than forwarding), existing uses, or actual harvesting levels. Available amounts will therefore be lower than estimated here and a local feedstock assessment is necessary to determine the amount available. The theoretically estimated amounts have therefore been reduced to 50% in 2030 and 85% by 2050 to define the Minimum and Maximum scenarios in Section 5.3. Also, harvesting residue should not be relied upon as the only resource for gas production since accessing it will often only be possible during a small window of time after the trees are harvested. This indicates that feedstock diversification should be the goal.

The results of the numbers developed above are combined graphically and in tabular format in Section 3.1.1 above. This technical potential is further developed into Minimum and Maximum scenarios in Chapter 5.0.

Appendix B

PRELIMINARY FINANCIAL ANALYSIS

FortisBC Energy Inc.

RGSD Development Costs Deferral Account Application

Net Present Value of FEI's Gas Supply Portfolio Costs under Option 1 and Option 2

NPV Analysis (in $ Millions)		**Years 1 to 10**										**Year 20**	**Year 30**
	NPV @ 5.422% [(ii)]	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2048**	**2058**
OPTION 1 (T-South Expansion - 300 MMscfd & 450 MMscfd):													
T-South 300 MMscfd Expansion [(i)]	**$4,417**	**$255**	**$259**	**$263**	**$267**	**$271**	**$275**	**$279**	**$283**	**$287**	**$292**	**$338**	**$393**
T-South 450 MMscfd Expansion [(i)]	**$5,389**	**$311**	**$316**	**$321**	**$325**	**$330**	**$335**	**$340**	**$345**	**$350**	**$356**	**$413**	**$479**
OPTION 2 (RGSD Project):													
T-South Costs [(iii)]	$1,979	$114	$116	$118	$119	$121	$123	$125	$127	$129	$131	$152	$176
RGSD Costs [(iv) (v)]	$3,360	$218	$225	$230	$234	$237	$243	$245	$245	$245	$245	$221	$181
RGSD Project	**$5,339**	**$333**	**$341**	**$347**	**$353**	**$358**	**$366**	**$370**	**$372**	**$374**	**$375**	**$373**	**$357**

Key parameters:

i) T-South tolls for 300 MMscfd expansion assumes full path toll will increase to $0.90 per GJ and 450 MMscfd expansion uses $1.10 per GJ as estimated internally by FEI.

ii) NPV analysis is based on 5.422% discount rate - FEI's current weighted after-tax cost of capital.

iii) T-South costs with RGSD pipeline in FEI's gas supply portfolio assume no T-South expansion. FEI used current 2022 tolls that are escalated using internally derived estimates, FEI has reduced its level of T-South contracting in the gas supply portfolio from current levels due to addition of RGSD piepline capacity.

iv) RGSD costs are based on RGSD's cost of service less cost savings from mitigation and contracting modifications in FEI's Annual Contracting Plan due to the RGSD pipeline capacity added as a resource to the gas supply portfolio.

v) Cost mitigation efforts were derived internally and supported by an external consultant's analysis with respect to impacts on regional market dynamics with the addition of the RGSD resource in FEI's portfolio.

Appendix C

DRAFT ORDERS

bcuc
British Columbia
Utilities Commission

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ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Energy Inc.
Application for Approval of Regional Gas Supply Diversity Development Account

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On June 1, 2022, FortisBC Energy Inc. (FEI) filed an application (Application) with the British Columbia Utilities Commission (BCUC), pursuant to sections 59 to 61 of the Utilities Commission Act (UCA) for approval of the creation of the Regional Gas Supply Diversity Development deferral account (RGSD Development Account) to capture development costs for a potential Regional Gas Supply Diversity Project (RGSD Project or Project), which initially are primarily related to engagement with Indigenous Nations and exploration of options for direct Indigenous involvement in the Project;

B. In the Application, FEI states that the RGSD Development Account is a non-rate base account attracting a Weighted Average Cost of Capital (WACC) return with the disposition of the account balance to be proposed and addressed in a future application. FEI proposes to file quarterly progress reports on development costs and activities and to provide an update in the Annual Review for 2024 Delivery Rates (2024 Annual Review) along with a proposal for recovering development costs incurred up to that point;

C. FEI states that

   i. the RGSD Development Account is a regulatory accounting mechanism that facilitates FEI incurring development costs, pending the BCUC's future determination on the method and timing of recovery of incurred costs;

   ii. FEI has not decided whether to proceed with the RGSD Project, and the development work facilitated by the RGSD Development Account is to enable an informed decision in that regard; and

iii. the BCUC's approval of the RGSD Development Account would in no way be a determination regarding the Project itself, which would be considered in a future CPCN application for the RGSD Project;

D. The BCUC has commenced review of the Application and considers that the establishment of a public hearing is warranted.

NOW THEREFORE the BCUC orders as follows:

1. A public hearing process is established for the review of the Application for Approval of the RGSD Development Account in accordance with the regulatory timetable as set out in Appendix A to this order.
2. FEI must provide a copy, electronically where possible, of the Application and this order on or before Friday, June 17, 2022 to the registered Interveners in the FEI Annual Review for 2022 Rates proceeding.
3. Parties who wish to actively participate in the proceeding are to register with the BCUC by completing a Request to Intervene Form, available on the BCUC's website at https://www.bcuc.com/get-involved/get-involved-proceeding.html, by the date established in the regulatory timetable, and in accordance with the BCUC's Rules of Practice and Procedure attached to Order G-15-19.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner

Attachment

APPENDIX A
to Order G-xx-xx

FortisBC Energy Inc.
Application for Approval of Regional Gas Supply Diversity Development Costs Deferral Account

REGULATORY TIMETABLE

Action	Date (year)
FEI to notify Annual Review Interveners	Friday, June 17
Registration of Interveners	Tuesday, June 28
BCUC and Intervener Information Request No. 1	Thursday, July 14
FEI Response to Information Request No. 1	Tuesday, August 9
Streamlined Review Process / Oral Submissions	Tuesday, August 23

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ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Energy Inc.
Application for Approval of Regional Gas Supply Diversity Development Account

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On June 1, 2022, FortisBC Energy Inc. (FEI) filed an application (Application) with the British Columbia Utilities Commission (BCUC), pursuant to sections 59 to 61 of the Utilities Commission Act (UCA) for the approval of the creation of the Regional Gas Supply Diversity Development deferral account (RGSD Development Account) to capture development costs for a potential Regional Gas Supply Diversity Project (RGSD Project or Project), which initially are primarily related to engagement with Indigenous Nations and exploration of options for direct Indigenous involvement in the Project;

B. In the Application, FEI states that the RGSD Development Account is a non-rate base account attracting a Weighted Average Cost of Capital (WACC) return with the disposition of the account balance to be proposed and addressed in a future application. FEI proposes to file quarterly progress reports on development costs and activities and to provide an update in the Annual Review for 2024 Delivery Rates (2024 Annual Review) along with a proposal for recovering development costs incurred up to that point;

C. FEI states that

1. The RGSD Development Account is a regulatory accounting mechanism that facilitates FEI incurring development costs, pending the BCUC's future determination on the method and timing of recovery of incurred costs;

2. FEI has not decided whether to proceed with the RGSD Project, and the development work facilitated by the RGSD Development Account is to enable an informed decision in that regard; and

3. The BCUC's approval of the RGSD Development Account would in no way be a determination regarding the Project itself, which would be considered in a future CPCN application for the RGSD Project;

D. The BCUC has reviewed the Application and considers that approval is warranted.

NOW THEREFORE pursuant to sections 59 to 61 of the UCA, the BCUC orders as follows:

1. FEE is approved to create the RGSD Development Account as proposed in the Application.
2. FEI is directed to comply with all directives outlined in the Eecision issued concurrently with this order.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner