Hydrogen Naturally Inc.

Carbon Dioxide Removal Purchase Application
Fall 2022

General Application - Prepurchase

(The General Application applies to everyone; all applicants should complete this)

Company or organization name

Hydrogen Naturally Inc.

Company or organization location (we welcome applicants from anywhere in the world)

Calgary, Alberta, Canada

Name(s) of primary point(s) of contact for this application

Neil Dobson, Chief Sustainability Officer
Brett Jackson, President
Stuart Primrose, Chief Financial Officer

Brief company or organization description

We are building four multiphase plants to sequester 4mt/yr of CO2 from forest harvest residual while also producing negative-emission hydrogen.

1. Project Overview[1]

a. Describe how the proposed technology removes CO_2 from the atmosphere, including as many details as possible. Discuss location(s) and scale. Please include figures and system schematics. Tell us why your system is best-in-class, and how you're differentiated from any other organization working on a similar technology.

The solid wood market sustainably harvests over 600 million m3 of logs in Canada and United States

[1] We use "project" throughout this template, but note that term is not intended to denote a single facility. The "project" being proposed to Frontier could include multiple facilities/locations or potentially all the CDR activities of your company.

annually. From the raw logs, 50% of this fibre becomes mill residuals (sawdust and chips) and there is a further 200 million m3 of residual fibre also from the harvest area which currently is uneconomic to extract and is burned in slash piles or rots (tree tops, branches, fire kill and other marginal waste fibre). All combined, these residuals contain over 400 million tonnes of CO_2 equivalent (tCO_2e) which ultimately ends up back in the atmosphere squandering the hard work done by the tree to concentrate CO_2 from 400 to 500,000 parts per million. This is an incredible amount of emissions (equating to 2/3rds of the annual CO_2 emitted from passengers cars in the U.S.) that could be avoided. Hydrogen Naturally (H2N) makes it economical to retrieve this fibre through a biomass-to-hydrogen with carbon removal and sequestration (BiRCS) process we are calling 'Natural Air Capture'.

We transport the waste fibre to a pellet mill local to the harvest areas and then rail the pellets to one of our four centralized carbon removal hubs where the pellets are gasified. The resulting gas from the gasifier (procured from SunGas Technologies) is purified into two streams – CO_2 and hydrogen. The CO_2 is then compressed and injected into saline aquifers for permanent storage. Each carbon removal hub is comprised of eight production lines called trains. We are constructing our first hub near Edmonton, AB, Canada; with plans for a second in the southern U.S.; a third in Nova Scotia and a fourth back in Western Canada. Hub locations are proximate to ideal sequestration sites; Central Alberta and the U.S. Gulf have established carbon capture and sequestration (CCS) regulations and infrastructure which is prompting us to site the first two hubs in those locations first while the regulations are put in at the other two geologically favourable locations. Each hub will sequester 4 million CO_2 ($MtCO_2$) per year. While our process is designed primarily for CCS, 20kt/ year of carbon-negative hydrogen is produced as a co-product to our CO_2 sequestration from each production train. We intend to use our hydrogen internally to produce the power we need to run the process initial as well as sell it to: displace natural gas directly into the public utility system, or directly at an industrial user; displace diesel in the BC Low Carbon Fuel System of Canadian Clean Fuel Regulations; or to generate power. Longer term we may also use it as a fertilizer feedstock; or make ammonia using the nitrogen we also separate from the air at the beginning of our process.

H2N will have 1.1 $MtCO_2$ sequestered by 2030, 160 Mt by 2050 and 0.5 gigatonnes over the lifetime of all four hubs.

Our system is best-in class because of the full suite of benefits and products/ co-products provided which other technologies or approaches may only offer a portion of but can't match, in full, either technically or economically.

1. Rapid scale-up and megatonnes of CO_2 in the ground before 2030 because: we are packaging proven technologies together, refining the interface of each to optimize the efficiency for the highest environmental benefit; and we have designed, built and operated gasification and CCS technologies before in greater scale so we do not have a learning curve to address compared to up-and-coming technologies yet to be proven at scale.
2. The design is built to serve the immediate needs for reducing atmospheric CO_2 now; the backend of the plant after the gasification has a focused design on CCS but we still are generating significant volumes of carbon-negative hydrogen. We can scale how much hydrogen goes to market or is used internally and adjust as the market for hydrogen develops or grid electricity emissions reduce. Some other air capture processes do not make clean fuel without the addition of inefficient process steps such as reinjecting carbon.
3. We do not require significant volumes of water or precious renewable power. We can create all the power we need internally giving us the ability to scale up and remove CO_2 at the volumes needed to aid in reaching global greenhouse gas targets at a very competitive short- and long-term cost per tonne.

4. Our process is expanding a very small existing market for forest-derived residual fibre into a significant CCS market to go after the 400m tonnes of CO_2 returning to the air each year, in many cases with significant air pollution due to the burning of slash-piles; H2N will create large scale demand for this carbon-rich fibre which will spur investment to utilize this fibre leading to new thousands of new permanent jobs. No other domestic demand for wood pellets will be higher, no other carbon removal technology will support as many jobs.
5. This new domestic demand for fibre provides a more environmentally friendly path than the export of pellets for international power production which has lifecycle emissions of 2 tCO_2e/tonne of pellets versus our process which is -1.5 tCO_2e/t.
6. We support social justice by giving Indigenous communities opportunity to directly participate, not just through jobs, but also as partners in our process through equity ownership and operators of the forest residual pellet mills and supporting services plus ownership options in the hub facilities.
7. We are building flexible CCS infrastructure to serve the needs of the current and future generations. This infrastructure will be central to the successful development of other CCS technologies such as direct air capture and post-combustion capture who will need facilities to transport and sequester the CO_2 they capture
8. Significant CO_2 reduction capacity combined with negative emission clean fuel or electricity production to meet the future H_2 market demands; no capital changes are needed to adjust for this flexibility. Other carbon-negative co-products include ash from gasification which can be used in cement, nitrogen for fertilizer and sulfur for chemical and fertilizer production.
9. Creating demand for forest-derived residuals supports the forest products industry, leads to better managed forests and helps improve forest health and sequester more carbon in them.
10. The use rather than slash-pile burning of the residuals helps improve air quality in rural regions and supports environment justice.
11. We are building in Alberta, a jurisdiction with significant, proven carbon sequestration reservoirs and a well developed regulatory regime for CCS
12. We can accomplish the above while keeping the cost below $100/tonne CO_2e sequestered in the long run with the revenue from our co-products.

We believe best-in-class goes beyond just how much CO_2 is removed; we can remove global scale amounts of CO_2 and we can do it while improving life in our Indigenous and rural communities, improving forest health and decarbonizing industry through negative-emission energy products at the same time.

b. What is the current technology readiness level (TRL)? Please include performance and stability data that you've already generated (including at what scale) to substantiate the status of your tech.

With the selected technologies H2N is employing, we believe the process is a TRL 8. This is based on our selected licensor having a 20 tonne per day (tpd) pilot facility and also a commercial facility in Europe operating at 150 tpd (European facility is a TRL 9 as per IEA). This technology has also been proven at scale in coal for decades. Other core equipment in the gasification process is the tar removal reactor and syngas cooler. Both of these technologies have been used in industrial applications, most recently the Sierra Biofuels plant in Nevada, US (listed as TRL 8 by the IEA). The other technologies in the facility (water gas shift, amine absorption, CO_2 compression) are well proven and considered to be TRL 10.

c. What are the key performance parameters that differentiate your technology (e.g. energy intensity, reaction kinetics, cycle time, volume per X, quality of Y output)? What is your current measured value and what value are you assuming in your nth-of-a-kind (NOAK) TEA?

Key performance parameter	Current observed value (units)	Value assumed in NOAK TEA (units)	Why is it feasible to reach the NOAK value?
Carbon capture percentage from pellet feedstock	90%	92%	1) Improve the CO to CO2 conversion in shift reactor (97% to 98%) 2) Improve CO2 recovery in amine unit (99%)
M3 water / tonne of CO2 (for H2N facility only, does not include 667 tonnes per day emitted in the pellet drying process).	0.84 m3 / tonne CO2	0.67 (20% reduction)	1) Improvements to heat integration, reduced boiler capacity 2) Improvements to water treatment technologies for water recycling 3) Lowering water to CO ratios in shift reactor
Natural gas use (GJ/tCO2)	0.02	0.01	1) Use of N2 for flare sweep and purge gases 2) Use of alternate energy for building heat (electrical, steam)
Electricity use (kWh/tCO2)	388	272	1) Improved heat integration in the design 2) Energy savings in alternate amine solvents with improved energy savings

d. Who are the key people at your company who will be working on this? What experience do they have with relevant technology and project development? What skills do you not yet have on the team today that you are most urgently looking to recruit?

H2N was founded by two highly experienced project developers who have done everything involved in our process before. The senior management team supplements the founders and adds executional capacity needed to construct H2N Hubs quickly and on budget.

Founders

- Peak Renewables, held by the Brian Fehr Group (BFG). BFG is a BC-based world-class developer of renewable resources development projects and manufacturing innovation. Prior to, Brian founded and grew BID Group into a billion-dollar business.
- North West Capital Partners (NWC). NWC built and operated the Sturgeon Refinery in Aberta which contains the world's largest blue hydrogen plant (using gasification technology). NWCP invented and built the Alberta Carbon Trunk Line (ACTL), the largest operational CO2 system in the world with an installed capacity of 15 million tonnes of CO2/year currently capturing, transporting, and sequestering more than 1 million tonnes per year.

Principal Partners; NWC and Peak 50/50.

- Ian MacGregor, Chairman of North West (Exec. Chairman H2N)
- Brian Fehr, Chairman of BFG (Chairman H2N)

Leadership Team

- Brett Jackson, President: gasification background, infrastructure project development/engineering and manufacturing.
- Stuart Primrose: CFO: Partner NWC; various CFO roles, corporate finance, restructuring, economic modeling.
- Larry Vadori: CTO/Operations: EVP/COO North West Refining, GM Shell Scotford Refinery, 40 years business management.
- Neil Dobson: Chief Sustainability Officer: ESG, carbon market development and government relations, Previously Executive Director of CleanBC in the BC Government.
- Scott Bax: VP Forestry/ CEO of Peak Renewables: 25+ years in forest products industry, ex-COO of Pinnacle Pellets.
- Dave Nikolejsin: VP External Relations: Global leader in ESG/strategic advisory roles, 15 years BC government, previously Deputy Minister of Energy and Mines.
- Adam Couillard: Director of Operations: Hydroprocessing, process engineering/EPC management.
- Mike Schmidt: VP Sequestration: 19 years in injection/disposal wells of all fluid types; with real world gas injection design and operating experience in Saskatchewan.

e. Are there other organizations you're partnering with on this project (or need to partner with in order to be successful)? If so, list who they are, what their role in the project is, and their level of commitment (e.g., confirmed project partner, discussing potential collaboration, yet to be approached, etc.).

Partner	Role in the Project	Level of Commitment
Fort Nelson First Nation	Forestry tenure holder, equity partner for first pellet plant	Memorandum of Understanding

Enhance	Potential carbon sequestration partner	Yet to be approached but were founded by NWCP who are a significant shareholder of Enhance.
Peak Renewables	Forestry and pellet plant partner	50% owner of H2N
Hatch	Engineering consultant. Developed FEL1 engineering study.	Supplier
Sungas	Gasification technology provider	Supplier
Le-ef Consulting	GHG lifecycle analysis and carbon market consultant	Supplier
The International Brotherhood of Boilermakers, Iron Ship Builders, Blacksmiths, Forgers and Helpers	Supporting with public and government awareness campaigns and advocacy	Have supplied marketing support

f. What is the total timeline of your proposal from start of development to end of CDR delivery? If you're building a facility that will be decommissioned, when will that happen?

> The first train will take four years to engineer and construct, based on H2N's experience and knowledge of long lead equipment required. Each train will operate for 50+ years.

g. When will CDR occur (start and end dates)? If CDR does not occur uniformly over that time period, describe the distribution of CDR over time. Please include the academic publications, field trial data, or other materials you use to substantiate this distribution.

> First production train is expected online in mid-2027 with subsequent trains online every 6-18 months. Each operates for 50 years, and has CDR of ~306,000 tonnes annually on a gross basis. We are targeting 10 megatonnes of CDR annually by 2050 from four HUBs with eight trains each.

h. Please estimate your gross CDR capacity over the coming years (your total capacity, not just for this proposal).

Year	Estimated gross CDR capacity (tonnes)
2023	0
2024	0
2025	0
2026	0
2027	153,000 (1 train online 50% of year)
2028	459,000 (2nd Train online Q2)
2029	765,000 (3rd Train online Q3)
2030	1,071,000 (4th Train online Q3`)

i. List and describe at least three key milestones for this project (including prior to when CDR starts), that are needed to achieve the amount of CDR over the proposed timeline.

	Milestone description	Target completion date (eg Q4 2024)
1	Initial Project Financing	Q1 2023
2	Front End Engineering Complete	Q3 2024
3	Environmental Permit / Impact Assessment Complete	Q3 2024
4	Construction Start	Q4 2024
5	Engineering, Procurement, Construction Complete	Q1 2027
6	Plant operational - CDR starts	Q2 2027

j. What is your IP strategy? Please link to relevant patents, pending or granted, that are available publicly (if applicable).

H2N does not require its own IP. H2N will leverage the IP owned by SunGas Renewables through their licensed technology. If required SunGas Patents can be requested.

Our competitive advantage doesn't come from IP as we are using proven technologies. It comes from our founders past experience in the forestry, pellet plant, gasification and CCS industries. We know every step in our process and have experience financing, building and operating plants with those processes and technologies in, as well as fixing them if they don't function as planned.

By having Peak Renewables as a founder, we also have secured pellet plant sites and secure access to the pellet feedstocks the plant requires. Our first pellet plant site in Fort Nelson, BC, has all the forestry tenures and First Nations agreements in place as well. We believe we will create the best-in-class solution through our combined experiences across the technology we are using as well as project finance, building and ownership.

k. How are you going to finance this project?

<300 words

H2N management and founders have extensive experience financing large capital projects. Two relevant examples include the structuring and raising of over $10 billion to build the Sturgeon Refinery and $1 billion for the construction of the Alberta Carbon Trunk Line system.

Initial equity is funded by the founders to progress commercial structuring, securing feedstock, and offtake contracts to enable raising equity and project debt financing for construction.

H2N will raise the remaining capital through a combination of debt and additional equity. We are in discussions with end users for offtake contracts on terms we expect to be sufficient to attract the required capital and provide the lowest cost carbon removals.

Debt capital will be raised in a combination of the commercial bank loan market and either the investment grade bond market or term loan B markets. Commercial banks represent one of the largest sources of debt financing for projects, usually offer the most economical terms and can provide the ability to do delayed drawdown, thereby minimizing negative carry. The investment grade bond market is an attractive source of capital for project finance where cash flows are contracted, offering extended terms, up to 30 years, with capacity in excess of $1 billion per project. If required, the term loan B market is an attractive funding source for projects with sub-investment grade risk profiles.

Equity capital will be required to underpin the financing. The commercial structure is designed to attract the necessary amount of equity capital. A number of investors in NWCP's prior ventures have expressed interest in a larger financial commitment to H2N when offtake contracts are secured.

With the secured feedstock and offtake contracts currently in discussions, H2N will be able to finance its capital requirements at an attractive cost of capital which minimizes the cost of carbon reductions.

l. Do you have other CDR buyers for this project? If so, please describe the anticipated purchase volume and level of commitment (e.g., contract signed, in active discussions, to be approached, etc.).

Not directly for CDR-only. H2N is however in active discussions with several counter parties to secure offtake contracts for our hydrogen co-product. These contracts likely necessitate some of the CDR attributes being sold with the hydrogen energy to create a negative-emission energy purchase. The intent would be to obtain contracts for a majority of the volume of CDR and hydrogen production for extended terms to enable project financing.

We also have a buyer interested in the hydrogen without the CDR attributes attached, and one of the reasons for the Alberta location is proximity to a number of existing and potential industrial hydrogen

users (refineries, fertilizer plant, cement plant).

m. What other revenue streams are you expecting from this project (if applicable)? Include the source of revenue and anticipated amount. Examples could include tax credits and co-products.

During construction we expect to receive refundable investment tax credits from the Government of Canada's announced CCUS ITCs and Clean Technology ITCs (which includes hydrogen). These ITCs could provide up to $500 million of capital funding for eligible equipment during construction. During operations, H2N will receive revenue from the sale of our hydrogen production, depending on the structure of hydrogen sales, i.e. whether bundled with CDR attributes or energy only sales, annual revenue could be up to $100 million, equivalent to $350 per tonne of CDR. The initial markets for the negative-emission hydrogen are the BC Low Carbon Fuel Standard and the BC Natural Gas utility renewable gas mandates. Additional markets are also developing – Canada's Clean Fuel Regulations, Clean Electricity Delivery Standard, Output Based Pricing System and more.

n. Identify risks for this project and how you will mitigate them. Include technical, project execution, ecosystem, financial, and any other risks.

Risk	Mitigation Strategy
The markets for the CO2 sequestration credits, negative-emission fuels and/or hydrogen are still immature, and long term pricing is not certain creating revenue uncertainty.	1) Only build a single production train for now, and plan to build one at a time in alignment with market conditions. 2) We intend to sell the majority of our credits/ hydrogen from the first production train into the known regulated carbon/fuel markets in British Columbia that have historical prices above the levels we need for profitability (Low Carbon Fuel Standard; Natural Gas Utility Renewable Gas Mandate). See question 1n above. 3) We can make multiple different end products to sell into different markets depending on demand – CCS credits; hydrogen; ammonia (we have nitrogen as a co-product); electricity; renewable diesel; synthetic fuels. 4) We can sell our co-products with or without the environmental attributes attached to create multiple sales pathways. 5) By locating in the Alberta Industrial Heartland we are near the biggest hydrogen market in the country and one that is developing fast with the Edmonton Hydrogen Hub, funded by the Canadian Government and managed by The Transition Accelerator. 6) Actively pursue multiple regulated and voluntary markets and analyze the right end product/ sales market for the credits/ hydrogen from each production train as it is being designed and constructed based on the status of each developing market. Some of the potential markets for future trains include: a. BC Natural Gas Utility Emissions Cap (expected 2025)

	b. Canadian Clean Fuel Regulations; Output Based Pricing System (active now but with uncertain/low credit price at this stage) c. Oil and Gas Emissions Cap; Clean Electricity Delivery Standard; fertilizer emissions reduction target (in development by Canada) d. Voluntary GHG reduction emissions commitments for 2030/40/50 from a growing number of companies (fast evolving market) 7) Capital and operating cost improvements over time bringing the cost of sequestration down, allowed our products to be more competitive over time as cheaper reductions are less available. Our long-term cost per tonne of sequestration is below the level of planned carbon pricing in Canada (C$170/tonne by 2030) providing more certainty that the revenues we need are available in the medium term.
Access to the right feedstock from the right sources at the right price - We need residual fibre/ wood waste to achieve sufficient carbon reductions over BAU - In a growing pellet market prices might rise or access to fibre might tighten	1) Compliance level measurement and monitoring of feedstock supplies in the cut blocks and entering the pellet plant to ensure appropriate sourcing. 2) Higher quality fibre has much greater value in the lumber market and the economics don't justify it being used for pellets making it unlikely this fibre will be available to us. 3) With Peak Renewables as a founder, we have security of price and supply of pellets – the pellet plant build out is connected to the H2N Hub build out. 4) Our model of providing a market for residual fibre increases the economic viability of more potential forestry areas and supporting the primary lumber-based forestry activity which should increase the total available residual feedstock. 5) Our economics are based on paying transportation adjusted market price for pellets with no discount. Furthermore with our central location we can access currently land-locked fibre that does not have a economically viable path to serve export markets because of the transportation distances and associated costs and emissions. 6) Our overall economics are not especially sensitive to feedstock costs meaning we have margin to manage price fluctuations. 7) Our process can work with other biogenic waste products such as construction wood waste or agricultural wastes.
Technology - Tar and particulate fouling	1) Equipment with fouling tendencies will be designed with online flushing or backwash capacities or with bypasses to clean the equipment on-line. 2) A robust spare parts strategy will be developed to ensure cleaning and repair is prompt.

	3) Guard beds or filters will be provided upstream of equipment that cannot be taken offline and to protect catalyst.
Supply chain and Delivery - Material Delivery - Quality of goods - Labour availability	1) Complete a market enquiry based on preliminary design into to material availability and establish project schedule and float. 2) We can accelerate production based on providing incentives if/ when required. 3) Develop an expediting strategy, managed through disciplined approach to engineering/ engineers. 4) Clearly defined inspection steps on test ITPs for each piece of equipment. 5) Pre-inspection meetings for all critical equipment at supplier shop 6) Resident inspectors for critical equipment.
Regulatory Approval / Stakeholder Consultation (risk delays getting approvals)	1) Engagement on regulations with Canadian provincial governments has already begun. Decision to build in Alberta was partly instructed by regulatory review conducted by McCarthy Tetrault LLP of the CCS regulatory and sequestration site readiness in British Columbia. 2) Indigenous consultations started early and a Memorandum of Understanding is already signed with the Fort Nelson First Nation for access to fibre and rights to build a pellet plant sized to feed the first two production trains. 3) Chose a site in the Alberta Industrial Heartland which is already industrial zoned and is where NWCP (H2N founder and owner) built the Sturgeon Refinery and Alberta Carbon Trunk Line and know the process and people well. 4) Engage EIA consultant to facilitate the permit approval process. 5) Incorporate EIA and permit process into the project schedule and gate approval process. 6) Progress permitting with preliminary engineering to mitigate delays 7) Link any engineering or construction activities to applicable permits
CO2 sequestration site	1) Building in Alberta minimizing risk because of existing CCS rules and regulations (https://open.alberta.ca/publications/2011_068) 2) NWCP, one of H2N's founders has an existing relationship with and ownership stake in Enhance, an existing CO2 sequestration company operating in the region of Alberta we plan to build in. 3) Alberta has a public and known process in place to develop CCS Hubs and hub managers that will be open assets available to any company wishing to sequester. 25 companies have been approved for exploratory permits and several more sites should be on stream before our opening in 2027 (https://www.alberta.ca/carbon-capture-utilization-and-storage-overview.aspx).

Government support in the form of grants/ tax credits	1) We believe we qualify for the announced Canadian Federal Investment Tax Credits for CCUS and Clean Tech (including clean hydrogen production). With these ITC's 30-50% of our capital equipment costs would be covered. While we have included these ITC's in the economics presented in this application we have done it at a conservative rate below the level we believe we will qualify for. 2) We have applied for, and will continue to apply for, government grants such as the Canadian Net Zero Accelerator and Energy Innovation Program. Our economics are not predicated on any of these applications being successful. 3) For future US builds the Q45 tax credit and hydrogen subsidies in the Inflation Reduction Act likely apply to our process.

2. Durability

a. Describe how your approach results in permanent CDR (> 1,000 years). Include citations to scientific/technical literature supporting your argument. What are the upper and lower bounds on your durability estimate?

H2N plans to sequester CO2 in deep saline aquifers with permanence over 1000 years in Alberta because the province has established Carbon Sequestration Tenure Regulations for CO2 storage and has an approved process for awarding CO2 sequestration leases. Under these regulations the lessee must have an approved plan for permanence for 15-years and pays a fee per tonne of CO2 injected into a Post closure Stewardship Fund to mitigate against reversals. At the end of the 15-year lease, the Province assumes accountability for the long-term storage and durability. The final disposal location is not confirmed at this time, but H2N's founding partner has vast experience in CO2 injection (see response 3d).

These aquifers are capped by thick shale formations which function as an impermeable seal. The majority of saline aquifers in Western Canada were tested for oil and gas, found to be water bearing and are now being utilized for CO2 storage. The data gathered by the oil industry is vital to proving the technical competence of these storage zones.

Local-scale characterization efforts of saline aquifers for CO2 storage have taken major steps with the success of the Shell Quest project and the technical approval of six other potential storage hubs in Alberta. Shell Quest has sustained safe, and reliable operation since initiating first injection in 2015; to date they have stored 6.8 million tonnes of CO2 into the Basal Cambrian Sand, a deep saline aquifer zone. Injection is an approximate depth of 1500-2000 meters and the Basal Cambrian Sand in this area is capped by the Lower Marine Sand of the Earlie Formation – a transitional heterogeneous clastic interval overlain by a Middle Cambrian Shale zone.

Saline aquifers avoid a major risk in Alberta as they will avoid the presence of legacy wellbores or the future potential of hydrocarbon exploration.

Citing: *Application of Canadian Standards Association guidelines for geologic storage of CO2 toward the development of a monitoring,verification, and accounting plan for a potential CCS project at Fort Nelson, British Columbia, Canada James A. Sorensena*, Lisa S. Botnena, Steven A. Smitha, Charles D. Goreckia, Edward N. Steadmana, John A. Harjua a Energy & Environmental Research Center, 15 North 23rd Street, Stop 9018, Grand Forks 58202-9018, United States*

b. What durability risks does your project face? Are there physical risks (e.g. leakage, decomposition and decay, damage, etc.)? Are there socioeconomic risks (e.g. mismanagement of storage, decision to consume or combust derived products, etc.)? What fundamental uncertainties exist about the underlying technological or biological process?

Durability risks for CO2 storage are similar with respect to existing reservoir development and management for oil and gas production. This extensive experience has aided Alberta and Southern U.S. gulf states to adopt CO2 rules and regulations sooner than other regions. Identified durability risks the project faces with respect to CO2 storage are, to name a few: migration along a legacy well, migration along an injection well due to poor cement bond or corrosion, migration along a rock pathway due to erosion processes. These issues have been well studied in the Shell Quest Project (Modelling of CO2 Leakage from CCS Overlying Formations – Quest CCS Monitoring Evaluation by Jeff Duer, paper SPE-187100-MS). Under the Alberta Governments' Carbon Sequestration Tenure Management process, 25 companies have been approved for exploratory permits to develop CCS hubs. H2N believes the extensive geological and well design testing completed by these companies, under the regulations of Alberta, will result in proven de-risked sequestration and monitoring processes available at third-party CO2 hubs H2N intends to use for CO2 storage.

3. Gross Removal & Life Cycle Analysis (LCA)

a. How much GROSS CDR will occur over this project's timeline? All tonnage should be described in **metric tonnes** of CO_2 here and throughout the application. Tell us how you calculated this value (i.e., show your work). If you have uncertainties in the amount of gross CDR, tell us where they come from.

Gross tonnes of CDR over project lifetime	15,293,450 tonnes cumulative CO2 removal from the first train (50-year life); This equates to 0.5 gigatonnes of avoided emissions from four Hubs over their 50 year lifespan.
Describe how you calculated that value	Each production train is estimated to avoid the emission of 305,869 tonnes gross from the burning or rotting of residual forestry fibre each year. Each train has a 50-year life. H2N plans to build out four Hubs with eight production trains each for a total of 32 trains.

b. How many tonnes of CO_2 have you captured and stored to date? If relevant to your technology (e.g., DAC), please list captured and stored tons separately.

None to date from this project. H2N founder North West Capital Partners have invested in, built or operated projects that sequester over four MtCO2e/ yr and have sequestered over 40 Mt to date. These projects include the Alberta Carbon Truck Line, Sturgeon Refinery, Enhance Energy and Weyburn-Midale.

c. If applicable, list any avoided emissions that result from your project. For carbon mineralization in concrete production, for example, removal would be the CO_2 utilized in concrete production and avoided emissions would be the emissions reductions associated with traditional concrete production. Do not include this number in your gross or net CDR calculations; it's just to help us understand potential co-benefits of your approach.

We have applied 100% allocation of the lifecycle emissions to the CO2 sequestered in the calculations for this application and do not include the avoided emissions from the use of the hydrogen (displacing diesel, grey or blue hydrogen or natural gas); ash (for cement production); or other biproducts (clay for soil enhancement, nitrogen for fertilizer, sulphur for chemicals). The avoided emissions through displacement of fossil fuels with our hydrogen (rated at a carbon intensity of zero) ranges from 48,500 tonnes per year (for natural gas) to 118,000 tonnes per year (for diesel).

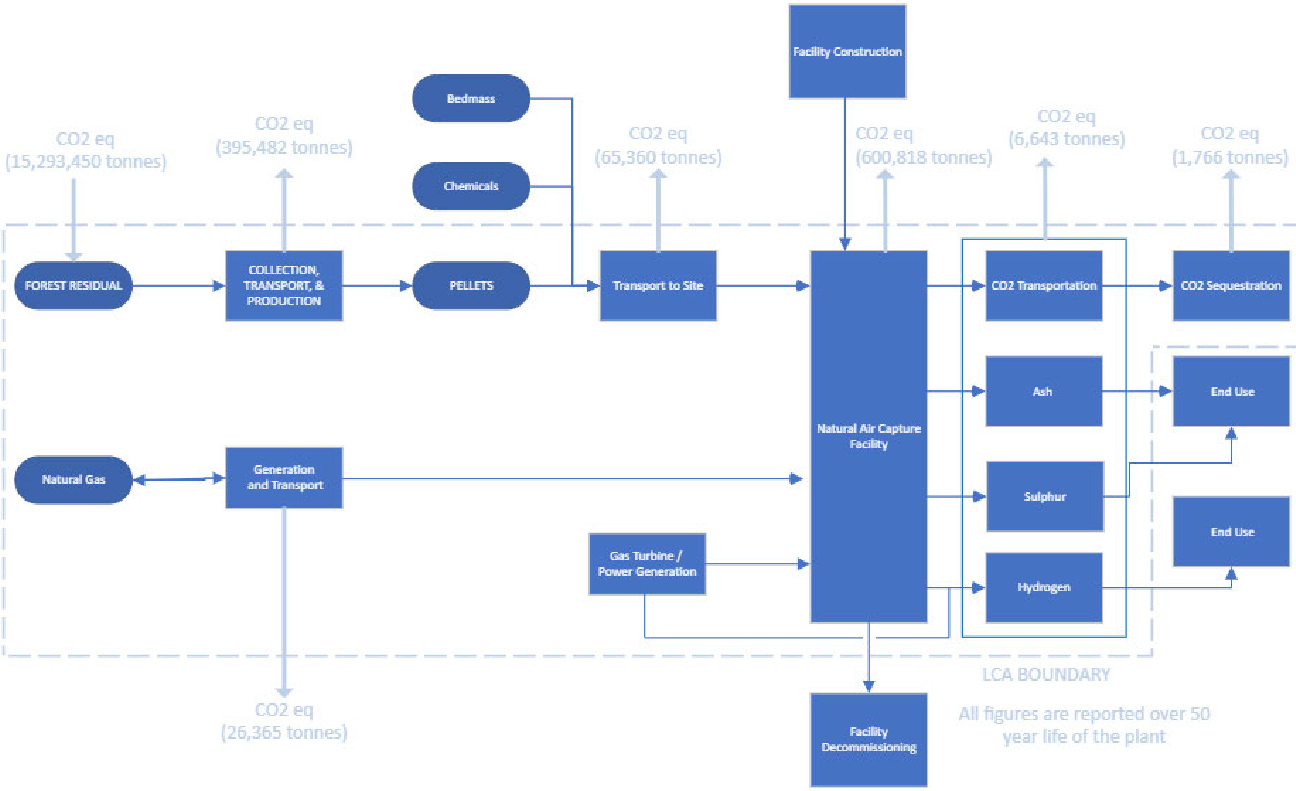
d. How many GROSS EMISSIONS will occur over the project lifetime? Divide that value by the gross CDR to get the emissions / removal ratio. Subtract it from the gross CDR to get the net CDR for this project.

Gross project emissions over the project timeline *(should correspond to the boundary conditions described below this table)*	1,096,440 tonnes (first train)
Emissions / removal ratio *(gross project emissions / gross CDR–must be less than one for net-negative CDR systems)*	0.07
Net CDR over the project timeline *(gross CDR - gross project emissions)*	14,197,010 tonnes (first train)

e. Provide a process flow diagram (PFD) for your CDR solution, visualizing the project emissions numbers above. This diagram provides the basis for your life cycle analysis (LCA). Some notes:

- The LCA scope should be cradle-to-grave
- For each step in the PFD, include all Scope 1-3 greenhouse gas emissions on a CO_2 equivalent basis

- Do not include CDR claimed by another entity (no double counting)
- For assistance, please:
  - Review the diagram below from the CDR Primer, Charm's application from 2020 for a simple example, or CarbonCure's for a more complex example
  - See University of Michigan's Global CO_2 Initiative resource guide
- If you've had a third-party LCA performed, please link to it.



f. Please articulate and justify the boundary conditions you assumed above: why do your calculations and diagram include or exclude different components of your system?

Boundary includes all Scope 1 and 2 emissions for the facility and Scope 3 emissions for the CO2 sequestration. We include all sinks and sources relating to the operation of the facility including: the carbon sequestered in the feedstock; transportation emissions to move feedstock and inputs to site and take outputs and wastes from site; facility energy use emissions and CO2 sequestration emissions. We have excluded facility construction, demolition, embedded carbon in the equipment and materials and long-run forest health impacts. As per the instructions it does not include the scope 3 emissions avoided through end use of the co-products.

g. Please justify all numbers used to assign emissions to each process step depicted in your diagram above. Are they solely modeled or have you measured them directly? Have they been independently measured? Your answers can include references to peer-reviewed publications, e.g. Climeworks' LCA paper.

Process Step	**CO_2(eq) emissions over the project lifetime (metric tonnes)**	**Describe how you calculated that number. Include references where appropriate.**
GENERAL Notes		Facility material and energy balance data has been provided by H2N EPC developed by Hatch and/or estimated internally by H2N. LCA has been completed by Le-ef, a 3rd party consultant.
Avoid Emissions through business as usual treatment of forest residuals	-15,293,450	Avoided emissions has been calculated as the mid-point of two 'business as usual' baseline options 1) combustion of forestry and mill residuals in slash piles or hog fuel burners; 2) landfilling of forestry and mill residuals. The calculation of avoided emissions from the use, rather than combustion or landfilling of forestry residuals uses the dry wood combustion factor in the British Columbia Government's Best Practices Methodology for Quantifying GHG Emissions (Table 1, p9) and the methodology for calculating the emissions from wood waste landfills from the Alberta Emission Handbook 2019.
Forest and Pellet Manufacturing	395,482	Calculated from the Drax Carbon Calculator that is approved for use in UK/ EU ETS schemes. (7,910 tCO2e/yr x 50 years)
Bedmass & Chemical Transport	65,360	Emissions calculated using emission factors from the MNP study (with GHG analysis conducted by Le-ef) for the BC Government and Business Council of BC of 36.6 gCO2e/ tonne/ km (tkm). Transport distance estimated based on known local supplier. (1,307 tCO2e/yr x 50 years)
Natural Gas (upstream)	26,365	Upstream NG extraction and processing emissions are calculated using the factors in the Alberta Emission Handbook multiplied by H2N NG consumption. (527 tCO2e/yr x 50 years)
Electricity	0	It is assumed all the power needs will be provided via a hydrogen-fueled gas turbine with top-up steam turbine or renewable electricity purchase if necessary.

Facility (total emissions)	600,818	Facility emissions are just from natural gas use and were calculated by multiplying the total natural gas consumed by the combustion emission factor of 1928 gCO2e/ m3 published in the Alberta Emissions Handbook. (12,016 tCO2e/yr x 50 years)
CO2 Sequestration	1,766	Calculated using an emission factor of 4.2 gCO2e/tkm. (Le-ef calculation based on the Enbridge website data on pipeline emissions vs Railway Association Canada values). (35 tCO2e/yr x 50 years)
Ash, Slag, Sulphur Transport	6,599	Emissions calculated using emission factors from the Emissions calculated using emission factors from the MNP study (with GHG analysis conducted by Le-ef) for the BC Government and Business Council of BC of 36.6 g CO2e/tkm. Transport distance estimated based on known local supplier. (132 tCO2e/yr x 50 years)
H2 Transport	50	Pipeline emission factor of 4.2 gCO2e/tkm has been used.
Total	1,096,440	(21,929 tCO2e/yr x 50 years)
Facility Construction	Not Included	At this early stage of development, H2N does not have the details to estimate construction emissions. H2N intends to develop these as the construction execution plan materializes with contactors.
Facility Deconstruction	Not Included	Similarly, H2N does have the level of detail required to incorporate decommissioning emissions into the LCA. H2N intends to include these as project definition grows.
Co—product end use	Not Included	Per the instructions, the LCA boundary does not include the avoided emissions possible from use of our co-products to displace higher emitting alternatives.

4. Measurement, Reporting, and Verification (MRV)

Section 3 above captures a project's lifecycle emissions, which is one of a number of MRV considerations. In this section, we are looking for additional details on your MRV approach, with a particular focus on the ongoing quantification of carbon removal outcomes and associated uncertainties.

a. Describe your ongoing approach to quantifying the CDR of your project, including methodology, what data is measured vs modeled, monitoring frequency, and key assumptions. If you plan to use an existing protocol, please link to it. Please see Charm's bio-oil sequestration protocol for reference, though note we do not expect proposals to have a protocol at this depth at the prepurchase stage.

> The data presented in this application is modelled because we are not operating yet.
>
> We hired Le-ef, a GHG modelling and carbon consultancy firm with deep North American experience to develop our LCA based on our FEL1 engineering study by Hatch, a globally recognized engineering consultancy. Hatch used data from the techno-economic study provided by SunGas. Le-ef used UNFCCC global warming potentials and emissions factors from the most applicable Canadian regulations, data sets or offset protocols. Conservative estimates have been used for facility energy use, operating run-time, methane and CO2 leakage rates.
>
> Once operational, we will update the LCA to real data. We will baseline the business-as-usual emissions against our real mix of wood feedstocks and use real travel distances, facility energy use and CO2 volumes sequestered. We will update factors in our LCA calculations with the latest UNFCCC data and any updated methodologies in regulations or offset protocols we are using for emission factors or producing credits under. The Canadian and BC Governments under their frameworks (Canada's Greenhouse Gas Offset Credit System/ BC Offset Protocol Policy) are working on updated CCUS protocols and the BC Government is working on an Avoided Emissions protocol that is anticipated to include a methodology for the avoidance of emissions through the diversion of forestry and mill residual wood wastes.
>
> The monitoring of the permanence of the sequestration will be the responsibility of our sequestration partner and the Alberta Government. In Alberta the province has established Carbon Sequestration Tenure Regulations for CO2 storage that allows 15-year leases subject to the approval of a MRV plan. Under these regulations the lessee pays a fee per tonne of CO2 injected into a Post-closure Stewardship Fund and at the end of the 15-year lease, the Province assumes the accountability for.

b. How will you quantify the durability of the carbon sequestered by your project discussed in 2(b)? If direct measurement is difficult or impossible, how will you rely on models or assumptions, and how will you validate those assumptions? *(E.g. monitoring of injection sites, tracking biomass state and location, estimating decay rates, etc.)*

> We plan to work with a proven injection and storage partner who has been granted a sequestration lease by the Alberta Government that meets the Government's MRV practices (https://open.alberta.ca/publications/2011_068) with respect to durability – such as Enhance Energy. We plan to inject into saline aquifers - a proven CO2 sequestration reservoir type with 1000+ years of

permanence. We will ensure our sequestration partner is undertaking practices similar to those already employed by Shell Quest in their injection into a saline aquifer in Alberta - monitoring: the composition and flow of the injection stream; the CO2 plume development inside the storage complex; the pressure development inside the storage complex; the injection well integrity; the geological seal integrity; any hydrosphere impacts; any CO2 emissions into the atmosphere.

c. This tool diagrams components that we anticipate should be measured or modeled to quantify CDR and durability outcomes, along with high-level characterizations of the uncertainty type and magnitude for each element. We are asking the net CDR volume to be discounted in order to account for uncertainty and reflect the actual net CDR as accurately as possible. Please complete the table below. Some notes:

- In the first column, list the quantification components from the Quantification Tool relevant to your project (e.g., risk of secondary mineral formation for enhanced weathering, uncertainty in the mass of kelp grown, variability in air-sea gas exchange efficiency for ocean alkalinity enhancement, etc.).
- In the second column, please discuss the magnitude of this uncertainty related to your project and what percentage of the net CDR should be discounted to appropriately reflect these uncertainties. Your estimates should be based on field measurements, modeling, or scientific literature. The magnitude for some of these factors relies on your operational choices (i.e., methodology, deployment site), while others stem from broader field questions, and in some cases, may not be well constrained. We are not looking for precise figures at this stage, but rather to understand how your project is thinking about these questions.
- See this post for details on Frontier's MRV approach and a sample uncertainty discount calculation and this Supplier Measurement & Verification Q&A document for additional guidance.

Quantification component Include each component from the Quantification Tool relevant to your project	**Discuss the uncertainty impact related to your project** Estimate the impact of this component as a percentage of net CDR. Include assumptions and scientific references if possible.
Storage	Negligible – sequestered tonnes will be directly measured
Leakage Storage monitoring and maintenance	Negligible – Firstly, we intend to inject into proven CO2 transportation systems and reservoirs close to our facility meaning short pipeline distances. Secondly, the Alberta Government Tenure Regulations require approved MRV policies and practices and move the long term durability burden onto the government in exchange for payments into a Post closure Stewardship Fund to be used to mitigate any losses and keep projects whole
Feedstock storage counterfactual Feedstock use counterfactual	Low – H2N's LCA takes into account the counterfactual of what would have happened to the fibre we plan to utilize for our first plant. Once the plants are up and running direct measurement and monitoring of actual feedstocks used to

	make the pellets will be used to determine actual LCA. Our business model is predicated on revenues from the environmental attributes generated by preventing the counterfactual case of the carbon returning quickly to atmosphere through burning or rotting of the fibre. We are not therefore incentivized to use fibre that would otherwise have higher value use and/or have a better emissions counterfactural.
Indirect land-use change	Negligible – on the positive side we believe our business model will help support improved management of North America's forests in the long run and support the forests adapting to climate change. Both of these factors is evidenced to increase carbon sequestration in forests, but we have not factored any of this into our LCA calculations. On the negative side, in certain uneconomical harvest regions, our model enables increased forest lumber operations - by providing a market for the residual fibre, lumber logging becomes economic. This could increase forestry activity which may have a short-term impact on carbon released to atmosphere. Over the long term however this likely results in more long-lived wood products which sequester carbon and a net-positive carbon balance as the forest regrows and sequesters more carbon.
Materials	Low – our LCA does not currently factor in the embodied carbon of equipment or materials. With a 50-year H2N plant life, the embodied carbon in the equipment will be amortized over a long period and will not make a meaningful difference to net annual sequestration. Because of our gasification process the embodied carbon in our bed materials is either captured through the gasification, or is embodied in the ash waste material or leftover clay material. We believe the clay can be used as a soil enhancer and depending on the exact chemical make-up the ash can either also be spread on soil or used to displace higher embodied forms of ash used in cement production.
Energy	Low - our LCA incorporates the energy balance from our FEL1 engineering study. As we improve our engineering we expect our modeled energy use to decline as the FEL1 is conservative. Furthermore, it is out intent to use our co-product hydrogen as a major energy source removing the need for all grid electricity and a proportion of natural gas use.

d. Based on your responses to 4(c), what percentage of the net CDR do you think should be discounted for each of these factors above and in aggregate to appropriately reflect these uncertainties?

For our first plant where the fibre feedstock is known and the sequestration reservoirs and rules are established we believe the cumulative impacts of the factors above is less than 10%.

e. Will this project help advance quantification approaches or reduce uncertainty for this CDR pathway? If yes, describe what new tools, models or approaches you are developing, what new data will be generated, etc.?

Potentially yes, by developing a BiRCS project along a timeline the same as the Canadian and BC Governments are developing CCS and Avoided Emissions Protocols under their offset frameworks (Canada's Greenhouse Gas Offset Credit System/ BC Offset Protocol Policy), and through the development process we can work with them to help create more accurate profiling of and measurement of forestry residuals and waste biomass to sequestration.

Furthermore, with our intent to sell our co-product hydrogen into fuel markets to displace diesel or natural gas we can potentially help develop new biofuel/ bio-energy/ BiRCS methodologies and baselines for regulations such as the BC Low Carbon Fuel Standard and Canadian Clean Fuel Regulations. We are currently working with GHGenius, the model used by the BC Low Carbon Fuel Standard to this end.

f. Describe your intended plan and partners for verifying delivery and registering credits, if known. If a protocol doesn't yet exist for your technology, who will develop it? Will there be a third party auditor to verify delivery against that protocol or the protocol discussed in 4(a)?

Le-ef who developed our LCA but have also advised clients on the development of offsets under existing protocols; credits under government regulations and the development of new protocols.

There is no current protocol we are aware of that aligns well with our business model but our initial sales pathways do not require them. We intend to sell the CDR tonnes and/or hydrogen with CDR attributes attached from the first train either to a natural gas utility under BC's renewable gas mandate or into the BC Low Carbon Fuel Standard. These systems have their own fuel approval/ credit generation approaches.

The Canadian and BC Governments under their frameworks are working on updated CCS protocols and the BC Government is working on an Avoided Emissions protocol that is anticipated to include a methodology for the avoidance of emissions through the diversion of forestry and mill residual wood wastes. It is anticipated these protocols will meet our needs. If they ultimately do not meet our needs, or if credit buyers have different needs, we will work with independent protocol developers such as Verra and use third-parties to verifier, audit and validate the CDR quantities (e.g. Brightspot Climate, ICF Consulting Canada, or Tetra Tech).

5. Cost

We are open to purchasing high-cost CDR today with the expectation the cost per tonne will rapidly decline over time. The questions below are meant to capture some of the key numbers and assumptions that you are entering into the separate techno-economic analysis (TEA) spreadsheet (see step 4 in Applicant Instructions). There are no right or wrong answers, but we would prefer high and conservative estimates to low and optimistic. If we select you for purchase, we'll work with you to understand your milestones and their verification in more depth.

a. What is the levelized price per net metric tonne of CO_2 removed for the project you're proposing Frontier purchase from? This does not need to exactly match the cost calculated for "This Project" in the TEA spreadsheet (e.g., it's expected to include a margin), but we will be using the data in that spreadsheet to consider your offer. Please specify whether the price per tonne below includes the uncertainty discount in the net removal volume proposed in response to question 4(d).

$398 / tonne CO_2 does not include an uncertainty discount

b. Please break out the components of this levelized price per metric tonne.

Component	Levelized price of net CDR for this project ($/tonne)
Capex	$241
Opex (excluding measurement)	$157 (net of H2 sales)
Quantification of net removal (field measurements, modeling, etc.)[2]	Part of carbon storage lessee cost
Third party verification and registry fees (if applicable)	Not meaningful
Total	$398

c. Describe the parameters that have the greatest sensitivity to cost (e.g., manufacturing efficiencies, material cost, material lifetime, etc.). For each parameter you identify, tell us what the current value is, and what value you are assuming for your NOAK commercial-scale TEA. If this includes parameters you already identified in 1(c), please repeat them here (if applicable). Broadly, what would need to be true for your approach to achieve a cost of $100/tonne?

Parameter with high impact on cost	Current value (units)	Value assumed in NOAK TEA (units)	Why is it feasible to reach the NOAK value?
Productivity Factors (construction)	0.8	0.9	Because the technology is already proven, H2N's focus is not on technology development but assembly line style construction to lower capital

[2] This and the following line item is not included in the TEA spreadsheet because we want to consider MRV and registry costs separately from traditional capex and opex.

			requirements. Priority will be on standardization and factory-built modular construction starting Train 1 onwards;
Commodity Prices (steel, copper etc)	n/a	n/a	H2N intends to enter into long term supply chain agreements with manufacturers and distributors to reduce cost of goods.
Engineering Costs	100%	65%	Each train will be identical, reducing engineering and owners costs.
Operating and Material Costs	100%	80%	Economies of scale can be found on operating materials and costs
Labour Costs	100%	50%	Subsequent trains do not require the same level of employees as the first, and head office staff costs are divided across more trains.
Facility Run Time	90%	95%	As we learn and improve and as staff learn and improve we would expect less facility downtime.

d. What aspects of your cost analysis are you least confident in?

The cost estimates for utilities and offsites and the OSBL (piperack, undergrounds etc) work were included in FEL1 using factored estimates, as such, are least verified. However, the H2N team recently completed the construction of a major refinery which utilizes similar equipment so the confidence in the non-FEL1 infrastructure estimates are higher than for average developers.

e. How do the CDR costs calculated in the TEA spreadsheet compare with your own models? If there are large differences, please describe why that might be (e.g., you're assuming different learning rates, different multipliers to get from Bare Erected Cost to Total Overnight Cost, favorable contract terms, etc.).

The CDR costs in the TEA spreadsheet are much higher compared with our own model. For capital costs, the main difference is the amount of contingency and owners costs. H2N is using a 30% contingency calculated off total base cost (project and process). This was the recommended contingency from the EPC based on AACE standards. H2N has also used 10% owner's costs versus 7% in TEA. H2N feels a higher owner's cost is expected in a project of this size. H2N intends to have higher capital savings or learning rates than those used in the TEA. As H2N intends to standardize and modularize the design, we expect to see large reductions in engineering, owners cost and contingency.

Our internal modelling of the net CDR cost benefits from the revenue from our hydrogen production, which reduce the net CDR cost by as much as $150 per tonne. Please see supplementary information attached.

f. What is one thing that doesn't exist today that would make it easier for you to commercialize your technology? (e.g., improved sensing technologies, increased access to X, etc.)

More mature and stable carbon markets. In Canada there are numerous regulated and voluntary carbon markets in development, and others with increasing stringency and/or market participation that we believe will in time support our economics. Today the BC LCFS is only market with a known credit price over our threshold.

6. Public Engagement

In alignment with Frontier's Safety & Legality criteria, Frontier requires projects to consider and address potential social, political, and ecosystem risks associated with their deployments. Projects with effective public engagement tend to:

- Identify key stakeholders in the area they'll be deploying
- Have mechanisms in place to engage and gather opinions from those stakeholders, take those opinions seriously, and develop active partnerships, iterating the project as necessary

The following questions help us gain an understanding of your public engagement strategy and how your project is working to follow best practices for responsible CDR project development. We recognize that, for early projects, this work may be quite nascent, but we are looking to understand your early approach.

a. Who have you identified as relevant external stakeholders, where are they located, and what process did you use to identify them? Please include discussion of the communities potentially engaging in or impacted by your project's deployment.

H2N will construct the first Hub near Edmonton, Alberta in an area known as Alberta's Industrial Heartland ('AIH') that our founder NWCP has already built on and that is already zoned for Heavy Industrial development. The process used to identify external stakeholders in the AIH has been well established by Regulators and governing bodies, and by several major industrial developments existing within the area.

For the H2N plant, the Alberta Energy Regulator ('AER') is the single regulator. Their process dictates a single integrated application which is distributed to other regulatory entities as appropriate. These may include Alberta Environment & Parks, Federal Impact Assessment Agency, Environment and Climate Change Canada, and Alberta Transportation. As part of the AER application, a detailed Public Involvement Plan ('PIP') is submitted for review and approval.

In addition to those regulatory bodies involved be the AER, local Indigenous Nations and other relevant external stakeholders that would be engaged include:

- AIH Association, a collaboration of the municipalities who areas the AIH overlaps.
- Industrial operators proximate to the site and within the AIH, through direct contact and involvement with the Northeast Capital Industrial Association.
- Residential and landowner stakeholders proximate to the site per processes laid out by the AER.
- Canadian National Railway as the rail service provider to the area.
- The Alberta Electric System Operator related to connection to necessity power supply.
- The AER related to pipelines necessary to connect the facility to services and markets.
- Investors and the financial sector.
- The environmental not for profit sector.
- Not for profit climate/ clean economy organizations such as The Transition Accelerator.
- The media.

In addition, we will engage stakeholders, municipalities and the Indigenous Nations in the communities where the pellet plants and forestry activities are located.

b. If applicable, how have you engaged with these stakeholders and communities? Has this work been performed in-house, with external consultants, or with independent advisors? If you do have any reports on public engagement that your team has prepared, please provide. *See Project Vesta's community engagement and governance approach as an example and Arnestein's Ladder of Citizen Participation for a framework on community input.*

To date, the only engagement that has been conducted is with the Fort Nelson First Nation (FNFN) and Northern Rockies Regional Municipality (NRRM) along with the BC Provincial and Canadian Federal Governments up to the ministerial level and Canadian National Railway. Engagement has been primarily performed by H2N employees with some political lobbying conducted with external consultants.

The FNFN and NRRM, are respectively the Indigenous Nation and municipal council in the Fort Nelson area where the first pellet plant and associated forestry operations will be. Both parties are fully supportive of the climate and economic opportunities presented by our project. Peak Renewables, our founder and partner on the forestry and pellet operations has a Memorandum of Understanding with the Fort Nelson First Nation and H2N has released a joint press release with them and our plans are profiled on the NRRM website (https://www.northernrockies.ca/en/news/fnfn-and-h2n-investigating-new-hydrogen-facility.aspx).

The engagements with governments have been designed to generate higher level support for our concept and have focused on ensuring we are eligible for the Federal CCUS and Clean Tech Investment Tax Credits and that the BC Low Carbon Fuel Standard and Proposed Natural Gas Utility GHG Cap rules are eligible markets for us to sell CCS credits and/or negative hydrogen fuel into. In general government officials are supportive of the project.

c. If applicable, what have you learned from these engagements? What modifications have you already made to your project based on this feedback, if any?

Following engagement with the BC Government (and the regulatory review conducted by McCarthy Tetrault LLP) we determined that BC's existing CCS rules and regulations were not sufficient to gain timely access to sequestration and were not recognized federally to be eligible for the CCS investment tax credits unlike Alberta. H2N thus pivoted to relocate the first H2N hub to Alberta into the mature Alberta Industrial Heartland CCS market (the pellet plant remans in Fort Nelson). Engagements with FNFN and NRRM have helped us understand some of the public facing challenges we may encounter and to prepare for them.

d. Going forward, do you have changes to your processes for (a) and (b) planned that you have not yet implemented? How do you envision your public engagement strategy at the megaton or gigaton scale?

Now the new Premier of Alberta (announced October 6th) is in place and as the new Government begins to be formed, we will begin focused engagement with them.
As we scale up, we may need to engage in public consultation to: distance ourselves from some of the (largely untrue) stories that pellets used for bioenergy are being produced from valuable, healthy, standing trees in BC; show how managing forests for wood products can support healthier forests that sequester more carbon; and demonstrate the safety and benefits of hydrogen as a clean fuel.

7. Environmental Justice[3]

As a part of Frontier's Safety & Legality criteria, Frontier seeks projects that proactively integrate environmental and social justice considerations into their deployment strategy and decision-making on an ongoing basis.

a. What are the potential environmental justice considerations, if any, that you have identified associated with your project? Who are the key stakeholders? Consider supply chain impacts, worker compensation and safety, plant siting, distribution of impacts, restorative justice/activities, job creation in marginalized communities, etc.

Environmental and social justice considerations include:

- The source of fibre we use as feedstock.

[3] For helpful content regarding environmental justice and CDR, please see these resources: C180 and XPRIZE's Environmental Justice Reading Materials, AirMiners Environmental and Social Justice Resource Repository, and the Foundation for Climate Restoration's Resource Database

- The communities in which the pellet and H2N plants are built and associated job and economic opportunities.
- Pollution risks from the pellet and hydrogen plants.
- The supply chain for, and materials that go into, the heavy equipment and where it is manufactured.
- Worker safety in the forestry and plant operations.

b. How do you intend to address any identified environmental justice concerns and / or take advantage of opportunities for positive impact?

H2N's Hub and spoke model provides forestry-based employment in underserved Indigenous and remote communities that in often suffer high levels of unemployment due to declining traditional rural industries. Furthermore, these forestry jobs are more secure because they are tied to the transition of the industry away from products less in demand, like pulp and paper, and towards future proof sectors like bio-energy and CDR. We have also signed up to Canada's 50-30 equity, diversity and inclusion target.

For our fibre feedstock, we are incentivized to use residual and waste fibre, not standing trees, to maximize CDR and revenues. We can however underpin the economics of the lumber industry to allow jobs to be created in that sector in these rural communities. Furthermore, we prevent slash-burning and its associated air pollution, and plan to replant with climate resilient species to improve forest health and support carbon uptake and climate adaptation.

The H2N Hubs are a further 'just transition' opportunity, with jobs requiring skills from the traditional energy industries. By building initial the AIH we can access fossil-energy workers and as we expand to four Hubs we can offer these high-wage jobs in other parts of the country. Our intention is to use unionized workers at our plants to support a safe and well-compensated workplace.

We support reconciliation with Indigenous peoples through our intention to partner with the local Indigenous Nations on the ownership of forestry tenures, and equity ownership in the plants, as well as the associated jobs as demonstrated by our MoU with Fort Nelson First Nation.

The pellet plant and H2N facility will meet or exceed environmental regulations and guidelines (ambient air quality/ surface water quality guidelines). Emissions and effluents from the facility will be modelled during the Environmental Impact Assessment to ensure H2N has a minimal impact.

8. Legal and Regulatory Compliance

a. What legal opinions, if any, have you received regarding deployment of your solution?

H2N has engaged legal services of McCarthy Tetrault LLP to assess the legal and regulatory hurdles involved with building a hydrogen/CCS plant in British Columbia. H2N's team includes the legal

counsel with NWCP with experience on a number of projects built in Alberta, including CCS. H2N will retain legal services through the regulatory and EIA development phase.

b. What permits or other forms of formal permission do you require, if any, to engage in the research or deployment of your project? What else might be required in the future as you scale? Please clearly differentiate between what you have already obtained, what you are currently in the process of obtaining, and what you know you'll need to obtain in the future but have not yet begun the process to do so.

We do not need any permits for research as all the individual technologies are proven. For the first hub in Alberta, H2N requires an operating license through the Alberta Energy Regulator (see Q6a); and the project will need to be registered and approved by the Alberta Boiler Safety Association, and municipal approvals will also be required for local requirements such as compliance under the building codes. H2N will begin the process for obtaining permits or licenses in Q2 of 2023 beginning with stakeholder consultation and site assessments (geotechnical, vegetation, wildlife).

c. Is your solution potentially subject to regulation under any international legal regimes? If yes, please specify. Have you engaged with these regimes to date?

It is H2N's understanding that the first Hub and associated CDR or product sales will not be subject to international legal regimes. We are planning a United States location for a future Hub and at that point H2N will engage with consultants/ legal services knowledgeable with the local, state and federal regulations.

d. In what areas are you uncertain about the legal or regulatory frameworks you'll need to comply with? This could include anything from local governance to international treaties. For some types of projects, we recognize that clear regulatory guidance may not yet exist.

There is limited uncertainty for the plant - the technologies H2N plans to use are all proven; building in Alberta provides a known regulatory regime for the building and operating of a facility of this type and the sequestration of CO2; and the team has experience of building major facilities in this region. We do intend to use a hydrogen fuel gas turbine to generate internal power and the emission regulations for hydrogen fired equipment is not certain at this time. We will address this issue with our engineering consultant, turbine vendor and regulatory bodies in next phase of engineering.

e. Do you intend to receive any tax credits during the proposed delivery window for Frontier's purchase? If so, please explain how you will avoid double counting.

Some of our equipment qualifies for the Canadian CCUS Investment Tax Credit and Canada is also developing a Clean Tech ITC that will include credit for hydrogen production equipment. The exact details of this are not known. Neither of these ITCs create any double counting issues.

9. Offer to Frontier

This table constitutes your **offer to Frontier**, and will form the basis of contract discussions if you are selected for purchase.

Proposed CDR over the project lifetime (tonnes) *(should be net volume after taking into account the uncertainty discount proposed in 4(c))*	1,130 tonnes
Delivery window *(at what point should Frontier consider your contract complete? Should match 1(f))*	The second half of 2027
Levelized Price (\$/metric tonne CO_2) *(This is the price per tonne of your offer to us for the tonnage described above)*	\$398/ tonne

Application Supplement: Biomass

(Only fill out this supplement if it applies to you)

Feedstock and Physical Footprint

1. What type(s) of biomass does your project rely on?

Our feedstock will be harvest and saw mill residuals and wood waste: tree-tops, branches, firekill and off-species that are usually left in the woods and not utilized by the wood products industry; and saw mill residuals such as chips and sawdust. We can also utilize construction wood waste. The material is collected rather than left to rot, landfilled or be burnt and brought to regional pellet mills for processing.

2. How is the biomass grown (e.g., kelp) or sourced (e.g., waste corn stover)? Do you have supply agreements established?

See Q1 for feedstock sourcing. In terms of supply agreements, Peak Renewables is a founder, 50% owner and the feedstock supplier to H2N. Peak has an MoU in place with Fort Nelson First Nation for access to fibre and permission to build a pellet plant on the disused oriented strand board mill site on their traditional territory that Peak already owns.

The pellet mill in Fort Nelson will produce enough pellets to supply the first two production trains at the Alberta H2N Hub. Peak also owns disused mill sites and has access to forestry tenures at sites in Chetwynd and Mackenzie, British Columbia and Prince Albert, Saskatchewan.

If H2N needed feedstock beyond the capacity of Peak to supply, there is a global market for pellets and our business model is built on paying the global market price for them.

3. Describe the logistics of collecting your waste biomass, including transport. How much carbon emissions are associated with these logistics, and how much does it cost? How do you envision this to evolve with scale?

Harvest residuals are usually left in the cut block and need to be transported out of the forest and to the pellet mill. Mill residuals are a waste that is currently removed from site for disposal or use.

The emissions of retrieving and processing the biomass are included within our LCA (7,910 tonnes/year up to and including conversion into pellets) and the cost of it is embedded in the pellet price in our model. We estimate we can ship pellets 1750km economically opening up many feedstock locations, helping us manage access and cost.

As we scale there are several factors that could affect the emissions and economics of the biomass:

● Economies of scale if the pellet plants can be built to produce enough pellets for more than one production train. ● Over time, and for sites beyond Fort Nelson, transportation emissions may increase as we travel further from the pellet plant to access biomass (due to less forestry activity close by) and as the pellet plants may be further from the Hub. ● In the US, the fibre markets are predominantly managed forests with predictable growth/ cutting patterns creating a more stable emissions and cost profile for our proposed US Hub.

4. Please fill out the table below regarding your feedstock's physical footprint. If you don't know (e.g. you procure your biomass from a seller who doesn't communicate their land use), indicate that in the table.

	Area of land or sea (km^2) in 2022	**Competing/existing project area use (if applicable)**
Feedstock cultivation	Each process train will require about 500,000 m^3 of fibre per year. This is the residuals from about 2,850 hectares of forestry activity	Because we use harvesting and mill residuals, we co-exist rather than compete with the lumber sector that utilizes the high value wood.
Processing	The pellet plant and associated feedstock storage yards is on industrial land utilizing approximately 0.1-0.15 km^2 The H2N Hub will be approx 0.09 km^2 per train.	Pellet plant is on the site of a disused OSB mill with existing feedstock yards. Site has been shut down for 15 years with no alternative uses proposed. H2N plant is on industrial zoned land in the Alberta Industrial Heartland. Exact site location still being negotiated.
Long-term Storage	Peak will have 7-10 days of feedstock in on-site storage H2N will have 7 days of on-site pellet storage (~6,000 tonnes per train).	

Capacity

5. How much CDR is feasible globally per year using the biomass you identified in question 1 above? Please include a reference to support this potential capacity.

Our approach provides the maximum sequestration potential from the biomass specified in Q1. The solid wood market sustainably harvests over 600 million m3 of logs in Canada and United States annually. From the raw logs, 50% of this fibre ends up as mill residuals (sawdust and chips) and there is

a further 200 million m3 of residual fibre also from the harvest area which currently is uneconomical to extract and is burned in slash piles or rots (tree tops, branches and other marginal waste fibre). All combined, these residuals contain over 400 million tonnes of CO_2 which ultimately ends up back in the atmosphere squandering the hard work done by the tree to concentrate CO_2 from 400 parts per million to 50% carbon. Our process could avoid most of these emissions and instead sequester that carbon.

Additionality and Ecosystem Impacts

6. What are applications/sectors your biomass feedstock could be used for other than CDR? (i.e., what is the counterfactual fate of the biomass feedstock)

The harvesting and mill residuals we are targeting are currently waste streams or in some cases converted into pellets and shipped globally for electricity production or used to produce electricity at mills. Previously some was used for pulp and paper production or OSB before those industries went into decline and portions would have been left behind or burnt at the roadside

The avoided emissions from the business-as-usual case where the material is wasted ranges from 450,457 tCO_2e/yr where the material is combusted in a slash pile or a hog fuel boiler; to 304,775 tCO_2e/yr where the material is landfilled.

7. There are many potential uses for waste biomass, including avoiding emissions and various other approaches to CDR. What are the merits and advantages of your proposed approach in comparison to the alternatives?

Today, gasification with the sequestration of the CO_2 is the most climate friendly use of the material. Other uses for the fibre all end up with the carbon from the wood being released back to atmosphere. For example, our analysis suggests that when pellets are shipped to Europe for electricity production the lifecycle emissions are $2tCO_2e$ per tonne of pellets. By gasifying them domestically and sequestering the carbon, the emissions are $-1.5tCO_2e/t$. As post-combustion CCS improves the lifecycle emissions of use in bioenergy + CCS plants will come down, but we believe we will remain best-in-class because of the co-product hydrogen we produce that can also be used to displace fossil fuels and avoid further emissions.

We hope that by providing an economic underpinning for the forestry industry we can support the development of other climate friendly outcomes like engineered mass timber construction; lignin and other bioeconomy products. Without a stable forestry market for lumber and for harvest and mill residuals, these other markets will struggle to develop.

8. We recognize that both biomass production (i.e., growing kelp) and biomass storage (i.e., sinking in the ocean) can have complex interactions with ecological, social, and economic systems. What are the

specific, potential negative impacts (or important unknowns) you have identified, and what are your specific plans for mitigating those impacts (or resolving the unknowns)?

By providing an economic underpinning for the continuation or expansion of the lumber industry it is possible that we facilitate more forestry activities. While this can provide important positive economic impacts to Indigenous and remote communities, there are potential land-base, biodiversity and ecological impacts if the forestry activity is not conducted in a sustainable manner. We will operate with, and only work with partners who operate with, the highest standards of certifiable sustainable forestry practices.

For example, in Fort Nelson all harvesting activities will be done in conjunction with the Fort Nelson First Nation utilizing the Land Management Framework (LMF) that fully incorporates the highest levels of sustainability focused on FNFN values and treat rights incorporating cultural, social and environmental values. The LMF ensures the protection of treat rights as well as cultural values, management of species at risk, riparian values, biodiversity and old forest retention in full consideration of existing FNFN land users (trappers etc.).

Forest harvesting will continue to ensure healthy forests and reduce the risk of devastating fires and insect outbreaks by allowing the historically natural age class distributions to once again be prevalent.

Furthermore, silviculture plans and replanting will take into account forest health and diversity including consideration of species more resilient to future climates.

Application Supplement: Geologic Injection

(Only fill out this supplement if it applies to you)

Feedstock and Use Case

1. What are you injecting? Gas? Supercritical gas? An aqueous solution? What compounds other than C exist in your injected material?

The injection will be supercritical fluid. The CO_2 will have a minimum purity of 95vol% with<4vol% (CH_4, CO, Nitrogen, Argon).

2. Do you facilitate enhanced oil recovery (EOR), either in this project or elsewhere in your operations? If so, please briefly describe.

H2N will not be facilitating EOR.

Throughput and Monitoring

3. Describe the geologic setting to be used for your project. What is the trapping mechanism, and what infrastructure is required to facilitate carbon storage? How will you monitor that your durability matches what you described in Section 2 of the General Application?

H2N will be injecting into saline aquifers in Alberta via CO_2 pipeline infrastructure. These aquifers lie in isolation below the oil and gas bearing thick shale formations which act as an impermeable cap. The specific recipient aquifer will be defined through an evaluation and procurement cycle. Most of these aquifers in Alberta have had extensive testing and study through the oil and gas industry using petrophysics, drilling core, drill samples and actual fluid testing which allows scientists and governments to prove safe storage capacity.

Planned depth of injection will be 1500-2000m. Approved projects in Alberta require monitoring wells to detect CO_2 plume lateral movement and ensure vertical containment within the reservoir. Injection rates and pressures must also be kept within Alberta approval guidelines to ensure reservoir and cap rock integrity is maintained without induced fracturing.

Following separation of the post-gasification process gas into CO_2 and H_2, CO_2 is conditioned at the H2N Hub in preparation for sequestration. The separated CO_2 is first treated to reduce the sulphur content to pipeline specification then dehydrated prior to compression to a supercritical transportable liquid state. From the H2N plant the CO_2 is pumped to the injection wellhead and injected still in the aqueous state at pressure.

H2N will be using a 3rd party to inject and monitor the CO_2 following the Alberta Regulation 68/2011 Mines and Mineral Act for Carbon Sequestration Tenure Regulation. As per 68/2011, H2N will also be required to pay, directly or indirectly, into the Post-closure Stewardship Fund on a per tonne basis for injected CO_2. The Stewardship fund was established and is maintained by the provincial ministry to mimic closure regulations of oil and gas reservoirs. Shell Quest, and other approved Alberta sequestration hubs, including Enhance Energy, are mandated to follow the existing monitoring and post closure regulations as part of the permit to operate. H2N will require compliance monitoring and reporting for all parties contracted to perform final injection.

4. For projects in the United States, for which UIC well class is a permit being sought (e.g. Class II, Class VI, etc.)?

Not applicable at this time.

5. At what rate will you be injecting your feedstock?

CO_2 injection will be 53 tonnes per hour for the first production train.

Environmental Hazards

6. What are the potential environmental impacts associated with this injection project, what specific actions or innovations will you implement to mitigate those impacts? How will they be monitored moving forward?

H2N supports, and references, the environmental impact assessment used for the Shell Quest project currently in operation near the site of our first Hub; there are 9 potential threats to containment detailed in that study:

1) Migration along a legacy well (no risk, CO_2 hubs are not permitted in legacy Oil and Gas wells).

2) Migration along an injection well due to a subsequently degraded cement bond or corrosion of the casing (current design best-practices and regulations uphold well casing integrity).

3) Migration along a deep monitoring well (limited risk, deep monitoring wells drilled to date, in the vicinity of the injection wells, terminate above the seal with the goal to detect CO_2 or brine migrating above the storage complex).

4) Migration along a rock matrix pathway due to unexpected changes in the depositional environment or erosional processes (avoid with optimal use of natural barriers).

5) Migration along a fault that extends out of the BCS storage complex and provides a permeable pathway (no evidence of faults with throws greater than 15 m crossing the seal complex from 2D and 3D seismic data covering the full area).

6) Induced stress re-activates a fault creating a new permeable pathway out of the BCS storage complex (pre-existing sealing faults may re-activate due to stress but any decrease in shear stress

will stabilize the fault making re-activation less likely).

7) Induced stress opens fractures (increased pressures and decreased temperatures may initiate localized fractures that propagate vertically to create a new permeable pathway out of the BCS storage but occurrence of any such fracturing does not constitute a threat to containment as ultimate CO_2 reservoir pressure won't exceed 12% of BCS fracture extension pressure).

8) Acidic fluids erode geological seals (injected CO_2 will acidify formation fluids which may react in contact with geological seals to enhance local permeability but reduce overall permeability within the seal).

9) Third Party Activities may induce environmental changes that cannot be distinguished from the potential impacts of CO_2 storage that might trigger a perceived loss of containment from the BCS storage complex.

There are no other third-party CCS projects proposed in the vicinity of the Quest Project. Any new CCS project would be accessed on the impact created by the overall pressure increase in the BCS.

A conceptual site model (CSM) of the Quest Project SLA does not foresee a pathway connecting the source to any receptor (Figure 3-8). Hence, no pathway has been identified through which saline brine from the injection interval may reach aquifers above the base of the groundwater protection zone. Furthermore, pressures are too low for BCS brine to be lifted to above the BGWP zone.

In conjunction with well head monitoring, deep monitoring wells situated over the cap layer are used ongoingly to detect fugitive CO_2 releases from the storage complex. H2N, or third-party CCS operators contracted by H2N, will abide by Alberta hub approval regulations stipulating monitoring and reporting requirements.

7. What are the key uncertainties to using and scaling this injection method?

CO_2 injection and permanent storage is underway in Alberta at scale through Shell Quest and, most recently, the Alberta Carbon Trunk Line (ACTL) and Enhance Energy. The injection technology has no significant uncertainties remain for outside of the standard liability obligations the well owner assumes and ultimately transfers to the provincial government under the . H2N will be injecting under the established regulations for industrial sequestration which are well founded. The H2N team was one of the first to inject CO_2 in Alberta at scale as the founder of Enhance Energy and participated in early regulatory adoption of CO_2 best practices.