STUDY REPORT

econext, Energy NL, and OilCo

Feasibility of Blue Hydrogen Production in Canada's Offshore Oil and Gas Industry

Study Report

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1 Executive Summary

Newfoundland and Labrador has extensive natural gas resources offshore. The province considers 12.6 trillion cubic feet of natural gas discovered but undeveloped (REF 1) with significant additional resource potential identified through independent resource assessments (REF www.oilconl.com). To this point in the NL oil and gas industry, existing operations have been separating natural gas from the produced oil and reinjecting the gas into subsurface reservoirs.

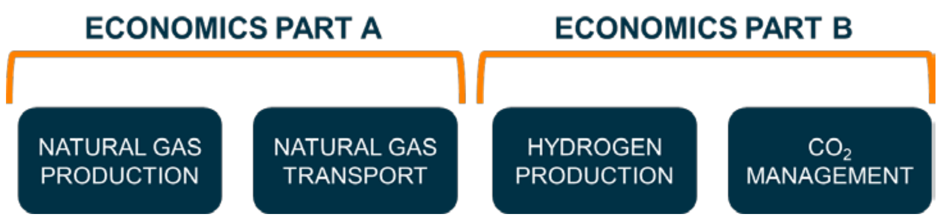
In 2018, the government of Newfoundland and Labrador released Advance 2030 – A Plan for Growth in the Newfoundland and Labrador Oil and Gas Industry. This document notably contained a mid-term (2022) focus area of development of a natural gas development plan. It also included long-term (2030) focus areas of commercial natural gas production and development of a world class energy cluster including energy sources such as hydrogen.

In 2020, The Premier of Newfoundland and Labrador appointed the Premier's Economic Recovery Team (PERT). In May, 2021 the PERT report titled The Big Reset was submitted. Relevant to this study, the PERT report specifically outlines the transition to a green economy and the role that low-emission oil and gas development and associated production of blue hydrogen can play (REF 2).

The Canadian federal government is also active with initiatives focused on low carbon hydrogen centred around the Hydrogen Strategy for Canada published in December 2020 (REF 16). This strategy notes development of low-carbon hydrogen as a strategic priority for Canada. The 2050 vision within this strategy includes placement of Canada as one of the top 3 global clean hydrogen producers with Canadian hydrogen sector revenue greater than $50 billion. One of the key principles noted from the strategy development was focus on creation and implementation of large scale projects that could be promoted and highlighted internationally.

The development concepts outlined in this study could support the 2022 and 2030 focus areas from the Advance 2030 Plan as well as the green energy transition strategies included in the PERT report. Additionally, the concepts and analysis presented fit well with the Hydrogen Strategy for Canada (REF 16) and the Feasibility Study of Hydrogen Production, Storage, Distribution, and Use in Newfoundland & Labrador (REF 18) . The significant natural gas resource base included in this study combined with the associated scalable hydrogen production could create the foundation for a large scale project as noted within the Hydrogen Strategy for Canada and the regional deployment hub theme discussed in the Feasibility Study of Hydrogen Production, Storage, Distribution, and Use in Newfoundland & Labrador. This type of development could allow near-term energy demands to be met with a combination of natural gas and hydrogen supply. Hydrogen production increases could be developed in coordination with development of the global hydrogen market.

For this report, Aker Solutions studied the production of blue hydrogen from natural gas. In a blue hydrogen process utilizing Steam-Methane Reforming (SMR), natural gas reacts with steam to generate hydrogen and CO_2. Rather than release the CO_2 to the atmosphere, it is captured, compressed, and permanently stored. The Come-By-Chance refinery has been producing hydrogen for 40+ years using SMR but without the CO_2 capture and storage element included in this study. The primary elements of this study include:



1.1 Natural Gas Production Summary

Aker Solutions were provided with natural gas resource basis information for two offshore areas – the Jeanne d'Arc basin (*Brownfield* concept area) where the current operating assets offshore NL reside, and the West Orphan basin (*Greenfield* concept area), which has been subject to independent resource assessments managed by OilCo. For both areas, conceptual details of a gas processing hub were investigated. The Brownfield concept includes conceptual tie-backs from the SeaRose FPSO and the Hibernia GBS plus independent subsea resource connections. Terra Nova and Hebron natural gas resources were excluded in consultation with client based primarily on smaller resource estimates and distance from the concept processing hub. The Greenfield concepts consider new subsea infrastructure to deliver gas to the processing hub.

Table 1-1: Natural Gas Production and Pipeline Summary

NG Option	NG Volumes	Hub Facility	NG Peak Production Rate	Operational Life	Pipeline Size	Pipeline length
Brownfield	4.0 TCF	FPSO	650 mmscfd	20 yrs	26"	600km
Greenfield 1	5.0 TCF	FPSO	650 mmscfd	30 yrs	26"	450km
Greenfield 2	10.0 TCF	FPSO	1,300 mmscfd	30 yrs	30"	450km

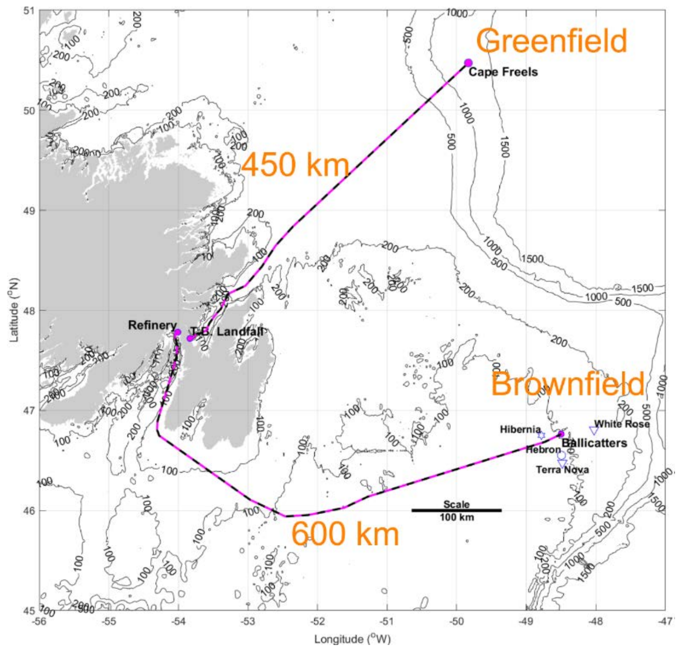


Figure 1-1: Preferential Pipeline Routes

For both concept areas, a new processing hub treats the natural gas, compresses it, and directs it to shore via a new pipeline. Aker Solutions engaged C-CORE to assess and advise preferential pipeline routes from the processing hub to shore with respect to iceberg impact risk analysis. The analysis indicates that there is a quantified iceberg impact risk to be managed for the 600 km Brownfield pipeline route while the 450 km Greenfield pipeline route indicates no iceberg impact risk due to the deeper water along the route. Please reference the complete C-CORE report in Appendix A for additional details. As seen in Figure 1-1 above, the Brownfield and Greenfield pipelines take different marine routes to shore however they both terminate at the same onshore facilities location.

The natural gas arriving on shore is split into a stream available for hydrogen production and a stream available for gas sales. The portion of the delivered gas utilized for hydrogen production was determined based on industry research of reasonable hydrogen plant capacity and the natural gas required as a feed stock to that plant. 85 mmscfd of natural gas (equivalent to 15% or less of the delivered natural gas) is required for the hydrogen production outlined in this study leaving a considerable amount for alternative utilization or future additional hydrogen production. These alternative uses could include export sale as LNG, power generation, industrial heating, etc. The concepts in this study include co-located CO_2 capture and storage infrastructure that could be scaled to manage the CO_2 associated with the alternative gas uses noted above.

1.2 Hydrogen Production and CO_2 Management Summary

Air Liquide Engineering and Construction (*Air Liquide*) were engaged to provide preliminary information on blue hydrogen production equipment. The proposed plant produces 250 million standard cubic feet per day (mmscfd) of hydrogen. This is equivalent to 600 Te/d. Similar to the existing hydrogen plant in Come-By-Chance, the base technology is Steam-Methane Reforming (SMR). Offshore hydrogen production was considered in the early screening phase of this study. It was removed from consideration primarily due to installation space demands.

Along with feeding natural gas to the SMR as hydrogen feed stock, the natural gas is also used as fuel to heat the catalytic SMR process. The CO_2 generated from the steam / natural gas reaction is captured within the hydrogen production equipment process. The CO_2 that results from burning fuel gas for heat in that process is also captured using an amine based flue gas carbon capture process. This combined CO_2 capture results in greater than 95% of the generated CO_2 being captured instead of released to the environment.

The combined CO_2 stream is compressed and sent back offshore to an injection well for permanent storage. Overall, 2 million tonnes per year of CO_2 is stored between 2000 and 4000 meters beneath the sea bed. To accommodate this flow, a CO_2 return pipeline from shore follows a path similar to the gas delivery line to an injection site near the offshore gas processing hub.

Table 1-2: Hydrogen Production and CO_2 Management Summary

H_2 Option	Operational Life	H_2 Production Rate	CO_2 Capture (million)	CO_2 Storage	Storage Pipeline Size	Pipeline Length
Brownfield	20 yrs	600 Te/d	2 MTPA	Brownfield	14"	600km
Greenfield	30 yrs	600 Te/d	2 MTPA	Greenfield	14"	450km

Hydrogen gas of the quality produced with this process has several downstream distribution options. The optimal product form to export hydrogen to international markets is outside the scope of this study. However, converting hydrogen to a liquid form – for example ammonia or methanol – has the benefit of avoiding high pressure storage and transport. Post production conversion of hydrogen gas to ammonia for storage and export is discussed in this study along with indicative cost impacts.

1.3 Onshore Facilities Concept Location

Large scale decarbonization initiatives and hydrogen fuel developments are trending to be developed in existing industrialized areas with marine access. Four areas that were notable in researching for this study were Net Zero Teesside (www.netzeroteesside.co.uk) and Zero Carbon Humber (www.zerocarbonhumber.co.uk) in the UK plus the Mongstad refinery area (www.equinor.com/en/what-we-do/terminals-and-refineries/mongstad.html) and Northern Lights (www.norlights.com) in Norway.

The existing marine, industrial, and processing facilities located at the intersection of Trinity Bay and Placentia Bay, NL made this area attractive at a concept level to base the onshore infrastructure for this study. This area encompasses a combination of natural and built infrastructure elements that could be optimized within the scope of the developments outlined in this study.

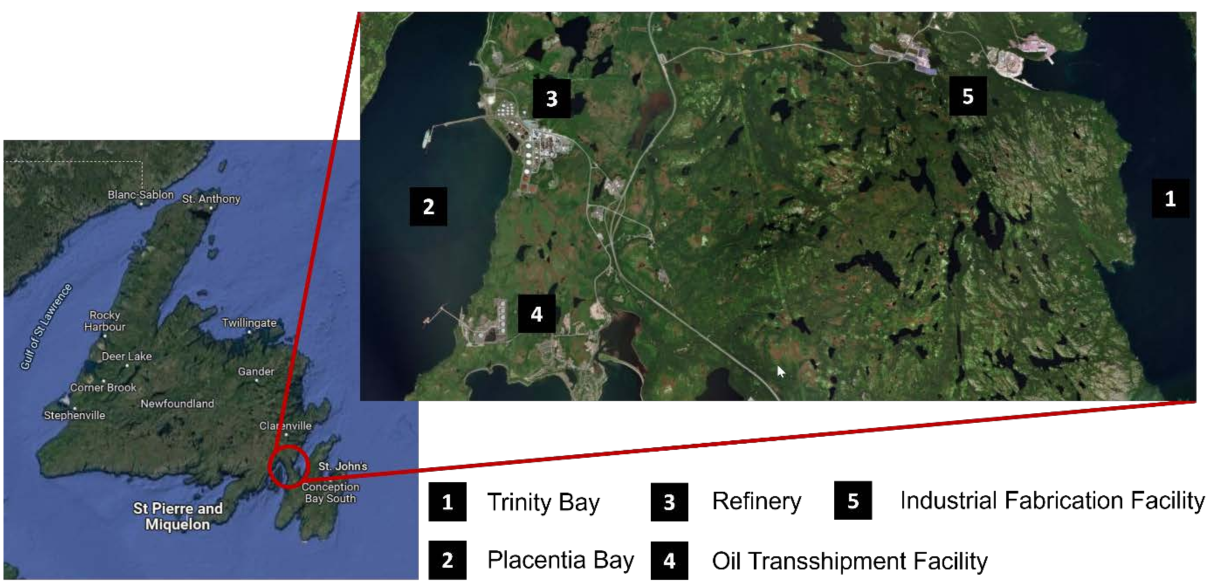


Figure 1-2: Onshore Facilities Concept Location

1.4 Economic Analysis Summary

The economic analysis for this study took a two-part approach:

Part A: Development of a natural gas supply and associated natural gas price to feed the blue hydrogen production process

Part B: Hydrogen production and associated CO_2 management based on the natural gas supply inputs developed in Part A

The Part A output for natural gas supply cost is summarized in the following table:

Table 1-3: Natural Gas Supply Cost Analysis

Development Option	NG Price (CAD / mscf)	CAPEX & OPEX	Royalties &Taxes
Brownfield	$11.96	72%	28%
Greenfield 1	$9.38	74%	26%
Greenfield 2	$6.71	76%	24%

The Part B output for hydrogen production and CO_2 management cost is summarized in the following table:

Table 1-4: Hydrogen Production Cost Analysis

Development Option	Hydrogen Price (CAD/kg)	CAPEX & OPEX	NG	Taxes
Brownfield	$6.41	64%	26%	10%
Greenfield 1	$5.27	65%	25%	10%
Greenfield 2	$4.89	71%	19%	10%

This study provides an un-optimized economic assessment of natural gas development and subsequent blue hydrogen production in the context of the NL resource potential. The production scale and time horizons considered provide an opportunity for further analysis of the associated concept elements. This subsequent analysis should focus on technical optimization and industrial synergy opportunities. Additionally, review and scenario testing of jurisdictional incentives for long term emissions reduction developments (such as the Government of Canada CCUS Tax Credit) should be applied. This will allow further understanding of the feasibility and competitiveness of such developments in the context of future low-carbon energy supply and demand.

1.5 Study Output Analysis

The following are key highlights from the study output:

- The technical elements of the blue hydrogen developments contained in this report are established and operational in various regions and are not dependent on significant technology development
- Blue hydrogen price is heavily influenced by the feed natural gas price where NL appears on the competitive end of the IEA range with the Greenfield natural gas source
- The CAPEX / OPEX component of the NL scenarios is higher than this component for the IEA regional data however the IEA data shows the same CAPEX / OPEX across all regions - this should be better understood before considering a direct comparison
- The Royalties / Taxes portion of the derived natural gas price is significant (24-28%) and should be reviewed for opportunities to increase competitiveness of both the natural gas sales as well as the associated blue hydrogen cost
- Coordination of a blue hydrogen development should maximize synergy and cooperation benefits that can be assembled through strategic port, industrial, refining, and government partnerships
- The scale of blue hydrogen production potential utilizing NL natural gas resources is significant and warrants investigating NL participation and placement within an international supply hub system
- The IEA coordinated Hydrogen Initiative within the Clean Energy Ministerial (of which Canada is a participant) includes a Global Ports Hydrogen Initiative where a development of this potential could be addressed (www.cleanenergyministerial.org/initiatives-campaigns/hydrogen-initiative/)
- Both the natural gas and hydrogen production aspects of the developments considered in this report could support recent Canada / Germany and Canada / Netherlands announcements related to energy cooperation

1.6 Go-Forward Recommendations

The following areas emerged as clear candidates for subsequent review to further evaluate the associated opportunities and challenges:

- Structured technical and economic review of the downstream hydrogen value chain to further develop the overall value proposition for NL blue hydrogen production
- Technical and economic review of the power consumption requirements and power supply potential associated with a blue hydrogen development to recommend an optimized approach

- Asset specific cooperation to better optimize synergy and mutual benefit considerations in a development of this scale
- Broader lens study of the potential that delivering NL natural gas to shore provides from an economic and emissions reduction potential when employed for domestic and export use (i.e. study opportunities for NL supplied natural gas to displace existing higher emitting fuel sources at a regional, national, and international level)
- Study of the additional economic and emissions reduction opportunity that third party CO_2 compression and permanent storage could provide considering the CO_2 storage infrastructure associated with a blue hydrogen development
- Scope specific study of the CO_2 transport and storage elements explored in this study to optimize and better understand that component
- Follow-up concept study focused on technical and economic optimization opportunities (i.e. narrowed list of development concepts, application of potential government incentives, etc.)

2 Acknowledgements

This report was prepared by Aker Solutions in St. John's, NL supported by Aker Solutions professionals in Norway and the UK. Aker Solutions delivers integrated solutions, products, and services to the global energy industry. We enable low-carbon oil and gas production and develop renewable solutions to meet future energy needs. By combining innovative digital solutions and predictable project execution, we accelerate the transition to sustainable energy production.

A large group of industry professionals contributed to this study and Aker Solutions would like to acknowledge the contributions of Growler Energy, Recovery Factory, C-CORE, and Air Liquide Engineering and Construction.

Finally, Aker Solutions would like to acknowledge the support provided throughout the study by econext, OilCo, and Energy NL.

NOTE: The interface with existing facilities and operations discussed in this study are presented for concept consideration only. No direct technical interface was conducted between this study and the Operators of the noted facilities and therefore no endorsement by the Operators or technical alignment should be assumed.

3 Definitions and Acronyms

Table 3-1: Definitions and Acronyms

Acronym	Definition
ACC	Aker Carbon Capture
API	American Petroleum Institute
Barg	Pressure measurement; 1 barg = 100 kPag
Bbls	Barrels
BFW	Boiler Feed Water
BOPD	Barrels Oil Per Day
C	Celsius
CH_4	Methane
C-NLOPB	Canada-Newfoundland and Labrador Offshore Petroleum Board
CO_2	Carbon Dioxide
CO	Carbon Monoxide
CWI	Carbonated Water Injection
DEH	Direct Electric Heating
FLNG	Floating Liquified Natural Gas
FPSO	Floating Production, Storage, and Offloading vessel
GBS	Gravity Base Structure
H_2	Hydrogen
H_2O	Water / Steam
HP	High-Pressure
HSC	Hydrogen Strategy for Canada
HSE	Health, Safety, and Environmental
ID	Inner Diameter
IEA	International Energy Agency
ITS	Integrated Template Structure
J-T	Joule-Thompson – cooling effect from gas expansion
kg/hr	Kilograms per Hour
Kms	Kilometres
kW	Kilowatts
LNG	Liquified Natural Gas
LOHC	Liquid Organic Hydrogen Carriers
LP	Low-Pressure
LPG	Liquified Petroleum Gas
M	Meter
MJ/L	Mega-Joules per liter (energy density)

Acronym	Definition
Mscf	Thousand Standard Cubic Feet
Mmscfd	Million Standard Cubic Feet Per Day (standard gas flow rate)
MPa	Megapsacals; 1 MPa = 1000 kPa
MTPA	Metric Tonnes Per Annum (Year)
MW	Megawatts
NG	Natural Gas
NGL	Natural Gas Liquids
NL	Newfoundland and Labrador
NOx	Oxides of Nitrogen (as atmospheric pollutants)
OD	Outer Diameter
PERT	Premier's Economic Recovery Team
POB	People On Board
PSA	Pressure Swing Adsorber
SMR	Steam-Methane Reformer
TCF	Trillion Cubic Feet
Te/d	Metric Tonnes per Day
TRL	Technical Readiness Level
UK	United Kingdom
USA	United States of America
WAG	Water Alternating Gas (reservoir injection)

4 Figures and Tables

5 Introduction

In May 2021, *The Big Reset* report was issued by the Premier of Newfoundland and Labrador's Economic Recovery Team (PERT). The report recognized that the contribution of Oil and Gas to the Newfoundland and Labrador economy will diminish as our province targets the Net-Zero goals set by the government.

As such, one of the key areas of the PERT report was to build a greener, technologically advanced economy. One of the recommendations from the report related to this key area was to ***Kick-Start Hydrogen Development.*** The global economy is investing billions of dollars to transition to hydrogen energy and the PERT report recommends that NL explore the opportunities for this investment.

Hydrogen is the most abundant element in the universe. Traditionally, hydrogen has been produced to meet the needs of oil refineries, including NL's own Come-By-Chance refinery. Refineries use the off gases created in their processes to feed a Hydrogen Steam-Methane Reformer (SMR). The reformer uses the hydrocarbon gas, as well as steam, to generate hydrogen and carbon dioxide. A very basic representation of this can be shown assuming methane (CH_4) is fed to the reformer.

$$CH_4+2H_2O \rightarrow 4H_2+CO_2 \qquad (1)$$

As the equation shows, one part methane reacts with two parts water (steam) to generate four parts hydrogen and one part carbon dioxide (CO_2). The hydrogen generated is used in refinery processes for making gasoline, diesel, and other products. The CO_2 generated is of no use to a refinery and, as a result, it was historically released into the atmosphere. CO_2 is a greenhouse gas; as a result, in recent years, hydrogen generated by this method has been assigned the term "grey" hydrogen. This is in contrast to "green" hydrogen.

"Green" hydrogen refers to hydrogen that is formed from the electrolysis of water. A basic equation for this is shown below.

$$2H_2O \rightarrow 2H_2+O_2 \qquad (2)$$

Electrolysis uses electricity to split water into hydrogen and oxygen. As the equation indicates, no CO_2 is generated from this process. Water is the feed stock and renewable electricity is the energy source required to achieve the hydrogen separation.

This study assesses the production of "Blue" hydrogen utilizing offshore natural gas as the feed stock and energy source. Blue hydrogen follows the same reaction as described in equation (1) above, but the CO_2 generated is captured and permanently stored. As a result, the greenhouse gas emissions for each kilogram of hydrogen generated is significantly reduced relative to grey hydrogen. Figure 5-1 below gives a breakdown of hydrogen generated in the USA (REF https://clearpath.org/tech-101/hydrogen-101/).

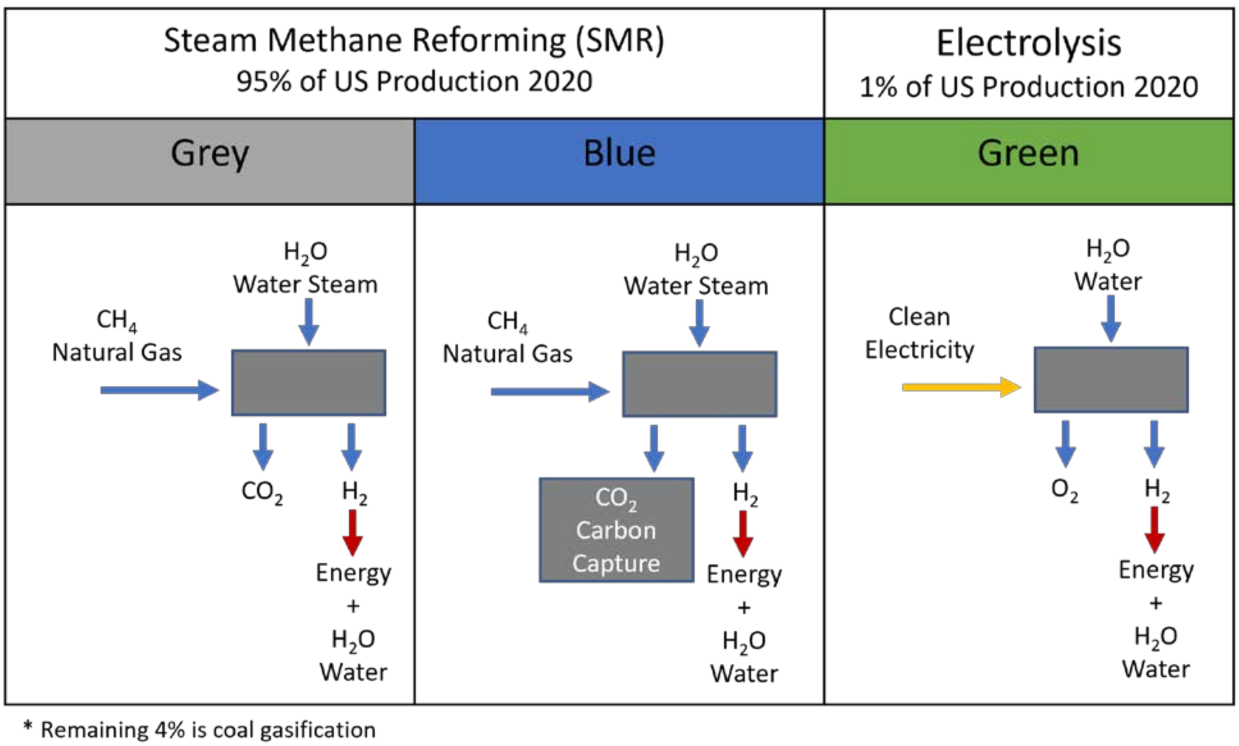


Figure 5-1: Breakdown of Hydrogen Generated in the USA

To this point in the Newfoundland and Labrador Oil and Gas industry, all gas recovered during oil production has been reinjected back into the reservoir, utilized for fuel in offshore oil production facilities, or flared in accordance with offshore process condition demands. The result is that the existing developments offshore NL have significant associated gas that could potentially be commercialized. This identified resource opportunity is currently being promoted by LNG Newfoundland and Labrador Limited (www.lng-nl.com).

Along with the associated gas from existing oil developments, significant additional hydrocarbon resources have been estimated through independent resource assessments managed by OilCo.

Bringing Newfoundland and Labrador's natural gas to shore presents an opportunity to develop this energy resource for both traditional utilization as well as production of low-carbon blue hydrogen. In July 2021, this opportunity was recognized by OilCo (www.oilconl.com), as well as its partners, econext (www.econext.ca), and Energy NL (www.energynl.ca) . This group called for proposals on the Feasibility of Blue Hydrogen Production in Canada's Offshore Oil and Gas Industry.

Aker Solutions submitted a comprehensive proposal anchored in local expertise, industry and academic partnerships, and broader corporate experience and were ultimately awarded the scope.

5.1 Scope

As a part of the successful bid, Aker Solutions were asked to break the scope down into the following services:

1. Identify and Assess. This covers the early phase of the study, whereby the team investigates:
    a. Established and emerging hydrogen technologies and their applicability to Canada's east coast offshore oil and gas industry;
    b. The infrastructure requirements associated with the identified technologies; and
    c. Future re-purposing opportunities, and opportunities / interdependencies with carbon capture and storage, electrification, additional gas development, technologies, etc.
2. Using the information obtained, prepare a report that will identify / provide:
    a. Opportunities and challenges (technical and commercial constraints) for blue hydrogen production in Canada's east coast offshore oil and gas industry.
    b. Information and technology gaps, new infrastructure required, and innovations needed to enable blue hydrogen production in Canada's east coast offshore oil and gas industry; and
    c. An economic analysis that explores the incremental value of blue hydrogen to potential natural gas development scenarios in Canada's east coast offshore oil and gas industry.

Specific to the carbon capture and storage evaluation conducted as a part of the overall study, the report shall:

1. Highlight and describe small scale post-combustion CO_2 capture facilities currently in place for gas turbines.
2. Identify technologies currently available or in progress that are modular and have the ability to be installed on an FPSO. This will include identifying metrics such as package dimensions and weight, power requirements, CO_2 capture rate, etc.
3. Identify challenges with applying this technology to an FPSO including space and weight limitations, parasitic load (heat and power) challenges related to CO_2 handling, J-T effects, CO_2 purity expected in injection stream, phase transitions and interactions with other gasses / fluids, etc.
4. Include a schematic of an FPSO conceptualizing how flue gas would be brought to a capture facility and where compression would be added to the produced CO_2 to pressurize the CO_2 for delivery to a well for injection.
5. Describe possible CO_2 injection concepts / scenarios (i.e. dissolved CO_2 injected via water injector, WAG, etc.)
6. Identify HSE elements that will be affected by the process including flaring, gas exposure, personnel required, etc.
7. Provide a high-level summary of the supply chain capabilities and competencies likely required for implementation.

5.2 Study Methodology

The study methodology was organized into the following phases:

1. IDENTIFY	▪ Core Technology Identification ▪ Infrastructure Identification ▪ Cross-Initiative Screening ▪ Concept Short-List / Workshop
2. ASSESS	▪ Core Technology Assessment ▪ Infrastructure Assessment ▪ Economics Assessment
3. COMMUNICATE	▪ Report Preparation ▪ Report and Presentation

Figure 5-2: Study Phases

In the Identify phase, various development concepts were considered to address the scope requirements of this study. At the end of this phase, a workshop was held with client representatives and the following alignment was achieved:

- Natural Gas Production - Brownfield
    - Central hub located in the Jeanne d'Arc basin for tie-in to existing resource assets
    - Floating hub facility basis for capital efficiency & process design certainty
    - Resource basis to be advised by OilCo (4.0 TCF determined post-workshop)
- Natural Gas Production - Greenfield
    - Floating facility in West Orphan basin
    - Resource basis of 10 TCF
- Natural Gas Transport
    - Pipeline transport
    - Pipeline routes guided by C-CORE preferential pipeline routes based on iceberg risk assessment
- Hydrogen Production

- Natural Gas Reforming Process
    - Steam Methane Reforming
    - Auto-Thermal Reforming
- Industrial suppliers engaged for guidance on technology selection for this application
- Staged capacity increase approach built on blocks of production

In the Assess phase, the study team developed the technical and economic aspects of the areas noted above.

The goal for the study team was to investigate various technologies available for production of blue hydrogen, and determine a realistic configuration, considering the equipment footprint required and CO_2 storage capabilities.

At a high-level, the possibility of producing hydrogen offshore (via a re-purposed current asset or a new build) was considered. The benefit of offshore hydrogen production and carbon capture would be the minimization of subsea pipelines to shore. Only a hydrogen line would be required for this case – the CO_2 captured offshore would be injected and stored in a drilled reservoir.

This was compared to onshore production of blue hydrogen. For this case, natural gas is transported to shore via pipeline and the CO_2 captured is returned to an offshore reservoir for injection and permanent storage. This option provides more physical space for hydrogen production equipment but requires more pipelines to deliver natural gas to shore and return CO_2. A further benefit with this arrangement is the flexibility to sell natural gas to market. See www.lng-nl.com for information regarding a proposed LNG development utilizing NL offshore gas.

Once the high-level layout was determined, Aker Solutions and its partners studied the components required to build up the facilities. This included investigation into:

- The daily rate of natural gas available. This is highly dependent on the volume of gas reserves and the draw down rate from the reservoir.
- For this, Brownfield and Greenfield options were studied.
    - Brownfield considers using gas that has been reinjected into the existing offshore developments. For the purposes of this study, the White Rose field, the Hibernia field, and a previously drilled but not developed field (Ballicatters) were considered. The provided gas availability profiles equated to 4.0 trillion cubic feet (TCF).
    - Greenfield considers using gas from a new development. The West Orphan Basin (Cape Freels) is an undeveloped area with significant hydrocarbon potential per OilCo managed independent resource assessments. This area is located north-

west of the existing offshore developments. This resource is assumed to be 10 TCF of gas as an input provided for this study.

- The offshore processing capability required, and the associated vessel requirement. This aided in the evaluation of whether existing offshore assets could be repurposed, or if a new build (floating or gravity base) would be required.
- Based on the availability of gas, the assumed hydrogen production rate, and the associated CO_2 captured, subsea pipelines were sized. The length of these lines varies between the Brownfield option and the Greenfield option.
- The sizing for hydrogen production and CO_2 capture / compression was based on equipment with a high technology readiness level (TRL). Reputable vendors were engaged throughout the study period to provide sizing, auxiliary equipment requirements, and preliminary pricing.

From this analysis, a cost estimate was developed. This was used to develop an economic analysis as described below.

5.2.1 Economic Methodology

The economic evaluation for this study is broken down into a two-part approach.

Part A – Natural Gas Supply for Blue Hydrogen Production

This first part of the analysis focuses on determining a sale price for natural gas for each of the development scenarios. A Net Present Value analysis was completed using a discounted rate (or minimum acceptable rate of return) of 10%. Key variables include: natural gas location, production life, production rate and recoverable volumes of gas. Key inputs include CAPEX, OPEX, Taxes and Royalties. The natural gas sale prices derived from the analysis will then be used as the natural gas purchase price in the hydrogen production economic analysis in Part B.

Part B – Hydrogen Production with Carbon Capture and Storage

The natural gas pricing determined in Part A was used as an input into the hydrogen production + CCS analysis to determine a minimum sale price for hydrogen for each of the natural gas development scenarios. A Net Present Value analysis was completed using a discounted rate of 10%, the same minimum acceptable rate of return used in Part A.

Key variables include natural gas supply, CO_2 storage location, and production life. Key inputs include CAPEX, OPEX, Natural Gas Cost, and Taxes. Based on this analysis, a hydrogen sale price was established for each of the natural gas supply options.

The benefit of this methodology is that it provides a price for natural gas for each of the agreed scenarios studied and shows the incremental value of producing hydrogen for each option. The method also provides the flexibility to vary the natural gas feed for hydrogen production – in other words, the analysis does not require 100% of the natural gas delivered to shore to be converted into hydrogen.

As part of the analysis, the levelized cost of hydrogen production was also calculated at a discount rate of 8%. This was used for comparison with publicly available hydrogen cost data for information only.

This study uses a Canadian dollar exchange rate of $0.79 USD per $1.00 CAD for all conversions between Canadian and United States dollars.

5.2.2 Estimate Methodology

The estimates developed for this study align with the Aker Solutions Master Estimating Procedure as well as Aker Solutions Cost Basis for Concept Estimates. The estimates developed are classified by Aker Solutions as PEM 1A – Opportunity Appraisal for project feasibility or concept phase (similar to AACE Level 5) with level of accuracy +/- 50%.

The overall estimate development relied on the utilization of several independent databases and knowledge within Aker Solutions which produce consistent and verifiable concept level factored estimates. Air Liquide was also engaged for their hydrogen production expertise and supported the overall estimate development in this area. All estimates are based on non-optimized concept selection with estimate definition and detail aligned with the level of technical and execution information available.

5.3 Core Study Inputs

Several key inputs were used to develop the concept for this study and estimate the economics. These include:

- Natural gas resource basis for Brownfield and Greenfield scenarios was provided by OilCo
- Preferential pipeline routes with respect to iceberg impact risk assessment were provided by C-CORE (See Appendix A)
- IEA published reports and associated basis data
- Third party equipment technical and commercial information

NOTE: The interface with existing facilities and operations discussed in this study are presented for concept consideration only. No direct technical interface was conducted between this study and the Operators of the noted facilities and therefore no endorsement by the Operators or technical alignment should be assumed.

6 Complete System Overview

As described above, two sources of gas to shore are considered for this scope, a Brownfield option that sources gas from the existing Hibernia, White Rose, and Ballicatters fields, and a Greenfield option that develops a concept gas field, that has not been developed to this point. The sub-sections here provide a summary of both the Brownfield and Greenfield options.

It was also mentioned that hydrogen development offshore was considered. It was determined that adding hydrogen technology offshore was not feasible. The third party vendor used to provide preliminary input for this report estimated that the footprint for the hydrogen plant alone would be outside the footprint that typical offshore facilities can accommodate. Many other services (boiler feed water, drying, compression, etc.) are required. As a result, offshore production of hydrogen was screened out.

6.1 Brownfield Scenario

Figure 6-1: Brownfield Concept (Not To Scale)

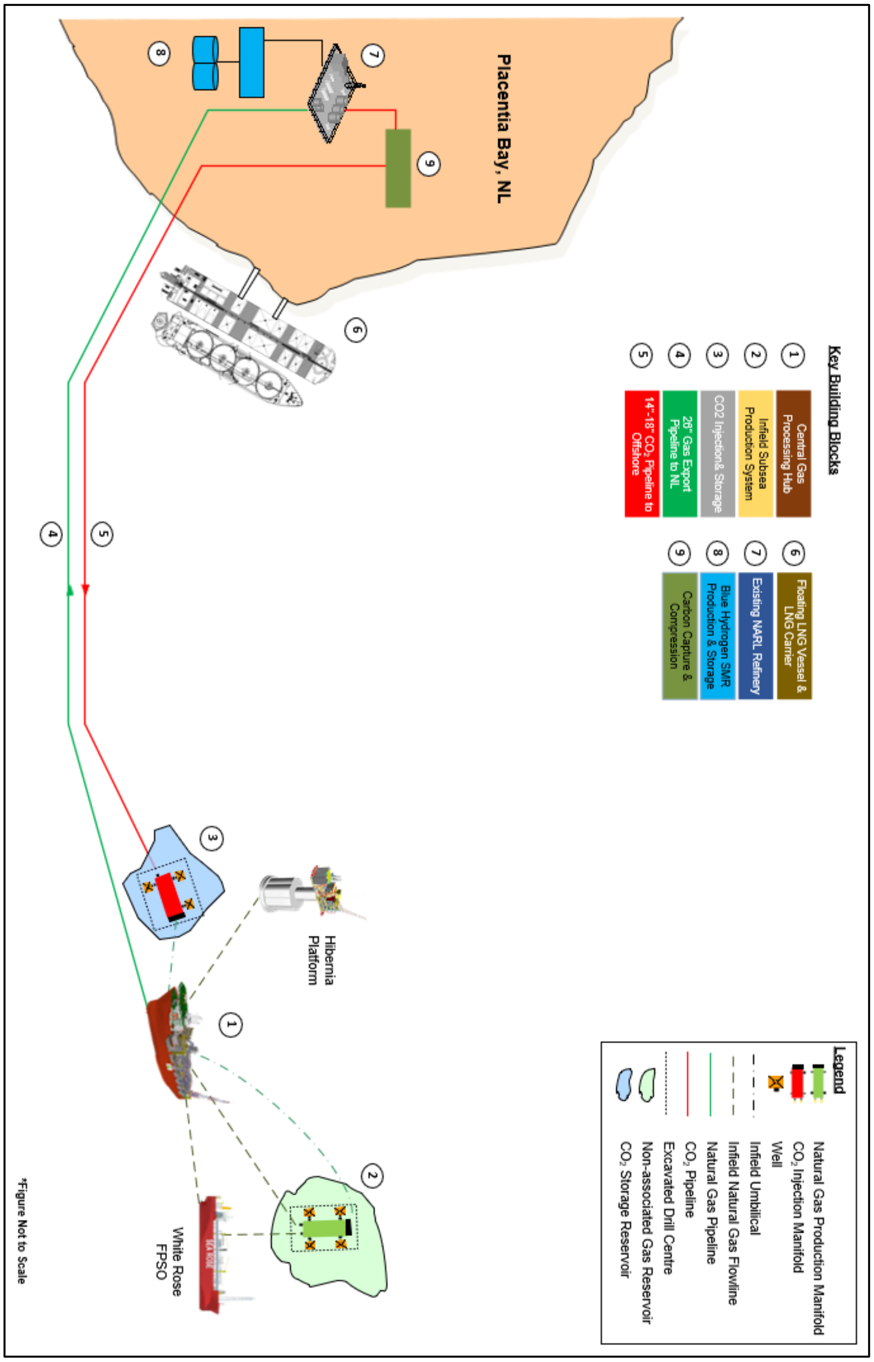


Figure 6-2: Brownfield Overview (Not To Scale)

Please note that Figure 6-2 is provided to give a concept system overview and is not intended to be geographically accurate. Please refer to Figure 1-1 for geographic pipeline routing perspective.

As the figure indicates, a central offshore hub will be constructed that receives gas from three sources:

- The existing White Rose field. This gas will be fed direct from the SeaRose FPSO.
- The existing Hibernia field. This gas will be fed direct from the Hibernia GBS.
- A new development in the basin with known gas resources (Ballicatters). This gas will be fed direct from a new subsea gas manifold.
- A tie-back will be considered for all three – from the development to the new processing hub.

The central hub will process up to 650 mmscfd of gas from the three sources. Gas from the sources will be of varying quality – gas from the operators may be at its dewpoint or dried. Gas from a new development will go direct to the new hub, with no prior processing. It will contain approximately 30 Bbls of condensate for every 1 mmscf of gas delivered.

The water depth around the hub will be approximately 100-meters.

Since condensate and water is expected in the gas to the hub, processing and drying of the gas will be included on the new hub, prior to export to shore. The hub will also include condensate storage for the purpose of sale for any condensate not removed by existing gas contributing facilities.

Once the natural gas has been treated and dried on the new hub, it will be compressed and sent through a subsea pipeline to shore via Placentia Bay for termination near the Come-By-Chance refinery. C-CORE evaluated the optimal route from the Jeanne d'Arc basin to the refinery area, considering an iceberg contact model. As a result, a 600 km pipeline route was selected.

Based on the availability of gas from the operators, the offshore hub is expected to come online in 2027 with gas from Hibernia and White Rose.

Production will increase with the addition of Ballicatters in 2029. At peak rates (around 2032), 650 mmscfd will be achieved via:

- 200 mmscfd from Hibernia.
- 250 mmscfd from SeaRose.
- 200 mmscfd from Ballicatters

The provided profile equates to 20-years of production.

Natural gas arriving on shore will be routed to two places:

- For sale to international market. The details of how post-arrival natural gas is distributed for sale is outside the scope of this study.
- To a newly developed hydrogen plant with carbon capture.

Conceptual details of the hydrogen production facility are as follows:

- 2 million MTPA of CO_2 generated. This is based on known compression capability of a leading compressor vendor.
- The CO_2 generated is assumed to be derived from both the steam-methane reaction (65%) and combustion products from the heat required to drive the reaction (35%).
- Based on the CO_2 assumptions:
  - 250 mmscfd or 600 Te/d of hydrogen is produced.
  - 73 mmscfd of natural gas is fed to the stream-methane reformer.
  - 12 mmscfd of natural gas is fed to the reformer furnace to provide heat to the reaction.
  - Approximately,115,000 kg/hr of steam is required to feed the reaction.
- A total of 85 mmscfd of natural gas is consumed to generate the hydrogen. Note that this is well below the gas available and delivered from offshore. This allows opportunity to scale up hydrogen production, if desired.

There are several ways to store the hydrogen produced. These include but are not limited to:

- Compressed gas storage.
- Liquid hydrogen (cryogenic) storage.
- Liquid ammonia storage.

This study does not provide detailed evaluation of hydrogen storage options. High-level concepts are explored and qualitative comparison is provided. For information purposes, the levelized cost per kg of blue hydrogen produced is presented for comparison with publicly published data. In addition, the indicative costs related to ammonia conversion are provided.

As mentioned, CO_2 will be generated from two sources. The hydrogen technology included in this study includes CO_2 capture from the reaction process using cryogenics. The CO_2 from combustion will be captured by an amine absorption circuit.

All CO_2 captured will be treated to pipeline quality, combined, and compressed into dense phase by the onshore compressors. At that point, the dense phase CO_2 will flow through a subsea pipeline dedicated to CO_2 return to a subsea injection site near the gas processing hub (approximately 600 kms). The subsea pipeline and on shore compressors will be designed such that the CO_2 remains in dense phase for the entire length of the flowline. In dense phase, the CO_2 takes up much lower volume than CO_2 in the gas phase. Also, the dense phase properties provide benefits for CO_2 injection.

A range of CO_2 injection depths were explored for the Brownfield site. For the first, the depth of the well will be such that a reservoir with adequate porosity and permeability is reached. This will allow for long term storage of the CO_2. A second option will explore injection into Hibernia's non-oil formation. For both injection options, the CO_2 pressure of around 100 barg at the seabed is required for injection into the reservoir.

For both injection cases, the analysis was completed so that dense phase CO_2 arrives near the new hub at about 100 barg pressure. Based on the injection pressure required, and the static head that the dense phase CO_2 will provide, subsea boosting of the CO_2 is not required.

Note that a sensitivity is presented for additional capacity in the CO_2 return flowline. Although the study is conducted around 2 million MTPA of CO_2 returned, a sensitivity is included exploring a CO_2 pipeline capable of handling 4 million MTPA. This allows for two potential revenue streams:

- Expansion of the hydrogen production facility / CO_2 capture equipment. An additional train of production can be added at a later date, without changing the subsea CO_2 line.
- The Northern Lights project in Norway (www.norlights.com) is designed to receive CO_2 from industrial emitters and transport this CO_2 via subsea pipeline to a subsea injection well for permanent storage. The CO_2 transport and storage infrastructure within this concept development could be considered for a North American version of the Longship Project (https://langskip.regjeringen.no/longship/) which Northern Lights is a component of.

In order to add the additional capacity and maintain the same onshore CO_2 compressors, the CO_2 return line is increased from 14" OD (for the 2 million MTPA case) to 18" OD (for the 4 million MTPA case).

6.2 Greenfield Scenario

Figure 6-3: Greenfield Concept (Not To Scale)

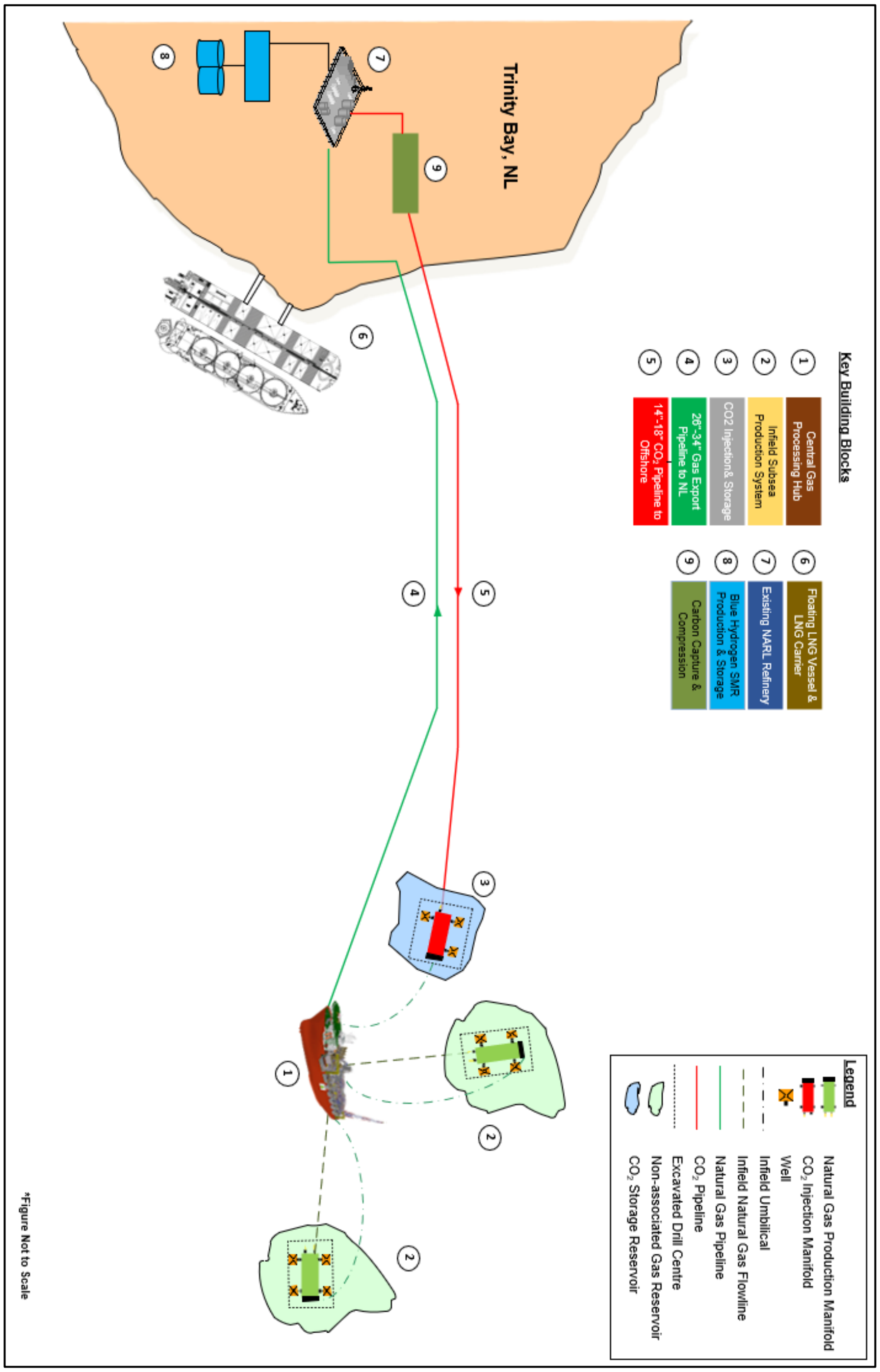


Figure 6-4: Greenfield Overview (Not To Scale)

Please note that Figure 6-4 is provided to give a concept system overview and is not intended to be geographically accurate. Please refer to Figure 1-1 for geographic pipeline routing perspective.

The Greenfield option has similarities to the Brownfield option, but with notable differences. The gas development for the Greenfield option is a new development. Concept gas reserves of 10 TCF were provided for this option. This larger resource size allowed two production rate scenarios for Greenfield to be assessed, 650 mmscfd and 1300 mmscfd.

As indicated in Figure 6-4, the subsea developments link direct to a gas processing hub. Each subsea center will have a tie-back to the gas processing hub. The same wet gas that was assumed for the Brownfield option, with 30 Bbls of condensate per mmscf, will be delivered from subsea centers to the central hub for processing. All drying, condensate storage, etc., will be contained within the gas processing hub to treat the gas to pipeline quality. Note that the water depth in the West Orphan area is much deeper than the Brownfield option – approximately 1250 meters of water.

Once treated, the dry gas will be compressed and sent through a subsea pipeline to shore via Trinity Bay for termination near the Come-By-Chance refinery. The same pipe size (26" OD) is considered for the 650 mmscfd Greenfield case. The Greenfield pipeline route from the West Orphan basin to the Come-By-Chance refinery area via Trinity Bay results in a length of 450 km with no identified iceberg risk due to the water depth along the route. This pipeline route includes a relatively short overland portion from landfall to the refinery which is discussed in the C-CORE report in Appendix A.

To handle the additional Greenfield case of 1300 mmscfd production, the natural gas pipeline OD will increase to 34".

The onshore facilities assumed for the Brownfield option will be the same in the Greenfield option. The concept design for the hydrogen production facilities and the hydrogen handling options will be applied to both scenarios.

The onshore CO_2 capture will be the same for both options as well, utilizing both the cryogenics and the amine capture. The compressed CO_2 will be returned to an injection site near the Greenfield hub for this option – approximately 450 kms from shore. The quantity of CO_2 returned will be the same as assumed for the Brownfield option, with the option to deliver either 2 million MTPA (14" OD pipeline) or 4 million MTPA (18" OD pipeline).

Since there are no existing producing reservoirs for this case (like the Hibernia non-Oil reservoir considered for the Brownfield case), only injection into a reservoir with adequate porosity and permeability is considered. Since the water depth is 1250 meters for this option, the additional head pressure will result in a CO_2 pressure at the seabed of 230 barg. This is adequate pressure to inject into the reservoir, without subsea boosting.

7 Natural Gas Production

7.1 Subsea System

The gas processing hub considered for both the Brownfield and Greenfield scenarios is a floating facility. A floating production facility is supported by subsea system infrastructure to supply the natural gas resource. Subsea systems carry the benefit of flexibility of resource access and expansion capability. The subsea system will consist of a number of well centers connected via dedicated flowlines along the sea floor and finally a riser connecting to the production facility. Each of the drill centers will be connected to an umbilical to provide control, chemicals, and hydraulics. It is assumed each of the drill centers will be located between 5-25 km from the process hub.

The infield production flow assurance needs to mitigate risks to issues such as:

- Hydrate formation risk mitigation.
- Wax formation risk mitigation.
- Scale formation mitigation.
- Sand production and erosional risk.

To mitigate some of the risks above, direct electrical heating (DEH) has been selected for this development. Other options exist including chemical injection strategy. However, electrical heating does offer a robust solution and is regarded as an operationally friendly solution. It is assumed no heating power is required for the flowlines during normal production, electrical heating will only be required under shutdown and start-up.

7.1.1 Greenfield

For the Greenfield development of 650 mmscfd gas production, about 10 wells will be required. To take advantage of the additional gas volume in the West Orphan area resource basis, the number of wells will increase to 19 for 1300 mmscfd production. The subsea equipment is very dependent on the subsurface requirements, even then there are further optimizations that can be undertaken. The following describes the architecture that has been assumed for this development.

For the 10 well case, 3 drill centers are assumed comprising each of a 4-slot Integrated Template Structure (ITS) housing 4 Christmas Trees and the production manifold. Two slots will be spare for potential future drilling. An umbilical will provide controls, hydraulics and chemicals to the subsea system.

For the 19 well option, 5 well drill centers are assumed comprising each of 4-slot Integrated Template Structure (ITS).

7.1.2 Brownfield

For the Brownfield option, a maximum of 200 mmscfd will need to come from subsea (Ballicatters), needing about 3 wells. For this case, 1 drill center is assumed comprising of a 4-slot Integrated Template Structure (ITS) which can house up to 4 Christmas Trees.

In 2038, once the SeaRose FPSO is assumed off station, an additional 200 mmscfd will be produced from the White Rose field through a subsea development. This needs about 3 wells. For this case, 1 drill center is assumed comprising of a 4-slot Integrated Template Structure (ITS) which can house up to 4 Christmas Trees.

7.2 Connection to Existing Production Facilities (Brownfield)

The interface with existing facilities and operations discussed in this section are presented for concept consideration only. No direct technical interface was conducted between this study and the operators of the noted facilities and therefore no endorsement by the operators or technical alignment should be assumed.

The production hub will be conceptually connected to the Hibernia GBS production facility and SeaRose FPSO via subsea tie-backs. These will be about 25 km away from the production hub. Hibernia will provide up to 200 mmscfd and SeaRose will provide up to 250 mmscfd.

The following proposed concepts have been assumed for this study and directionally provide a robust solution.

- The gas from SeaRose will be dehydrated (water removed), but due to the possibility of condensate drop-out, the gas will be transferred in dense phase avoiding liquid drop out and hence associated flow assurance issues during normal operation.
- Limited dew pointing is carried out on the gas from Hibernia. To avoid liquid drop and associated flow assurance issues the gas will be transferred dense phase. As the gas contains water, the hydrate mitigation approach will be with the use of Direct Electrical Heating. It is assumed no heating power is required for the flowlines during normal production, electrical heating will only be required under shutdown and start-up.

7.3 Hub Processing Facility

An FPSO (Floating Production Storage and Offloading) production facility has been selected as the base concept as there are analogues in the same vicinity (Terra Nova and SeaRose FPSO) and in similar environments e.g. North Sea. For the shallow water Brownfield option, the GBS type facility is also a credible alternative facility. As an additional alternative, a circular FPSO could be considered.

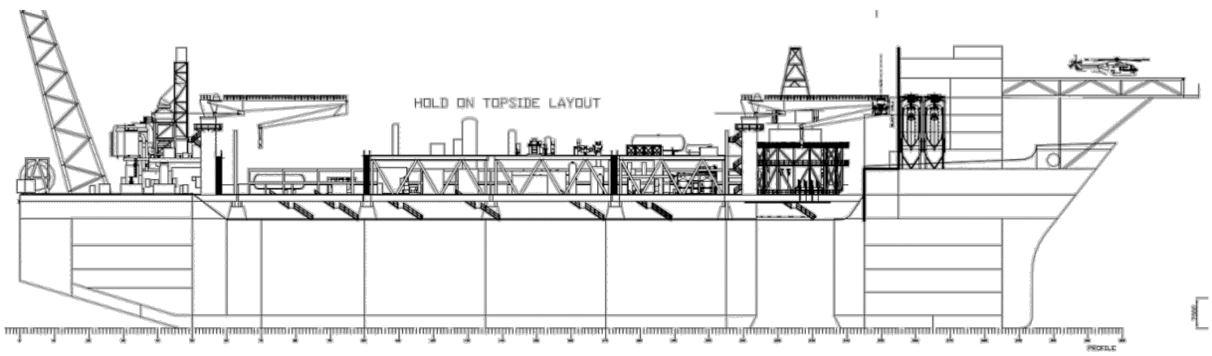


Figure 7-1: Typical Gas Processing FPSO

From a capacity perspective, the Skarv FPSO is an analogue in the Norwegian North Sea that can handle a similar capacity to the proposed Greenfield and Brownfield 650 mmscfd capacity case.

Skarv FPSO's key information:

- 875,000 barrels of storage capacity
- 670 mmscfd gas production capacity
- 86,000 BOPD oil production capacity

(REF https://www.bp.com/en/global/corporate/news-and-insights/press-releases/bp-begins-production-from-skarv-field-norway.html).

The connection between the FPSO and the subsea tie-backs and pipeline is through a buoy at the lower portion of the turret. The buoy provides the mooring point for the FPSO, and the pathway for gas and fluids that flow to and from the FPSO. The buoy has a quick-disconnect feature, allowing the FPSO to safely disconnect and leave the area quickly in an emergency situation such as in case of an iceberg.

The produced fluids (unprocessed, partially processed) will first pass to the reception facilities. Multiphase fluids will be separated, inlet conditioning will occur to enable processing of the gas and fluids. The water in the gas will be removed, typically using a glycol dehydration unit, this will eliminate potential hydrate issues and reduce corrosion inside the gas pipeline. The resulting gas will be compressed and hydrocarbon dew pointed to maximize condensate production on the floater and ensure no hydrocarbon liquid drop out occurs in the gas before sending it to shore through the gas export pipeline. An alternative to meet the dew point (both hydrocarbon and water) can also be done through a turboexpander, meaning some of the energy lost through expansion can be recovered through the re-compressor on the same shaft.

The dry gas will be compressed into the dense phase with the aim of stopping any liquid drop out in the gas pipeline causing operational issues. Dense phase transfer has several benefits:

- Transport of gas at high pressures over long distances, especially when intermediate compressor booster stations are not feasible (offshore). Dense phase operation eliminates the problems associated with multiphase flow operation of long, large diameter pipelines.
- Dense phase allows for reasonable flexibility with respect to gas composition, limited hydrocarbon dewpointing / natural gas liquid (NGL) recovery.

Typically, NGL processing is not handled offshore due to extra processing and storage requirements. The assumption is that the quantity of NGLs will not impact gas processing and condensate stabilization.

The condensate produced will be stabilized to meet tanker export quality and stored in tanks before offloading. As per existing facilities, tandem offloading of condensate to a tanker is assumed. However, use of buoy based offloading could be an option, reducing the risk of collision.

Produced water will be separated from the hydrocarbon streams, cleaned to meet the C-NLOPB guidelines, and discharged to the sea.

For the Greenfield 650 mmscfd case, approximately 19,500 barrels of condensate/water will be removed from the gas stream produced. As a comparison, AkerBP's Skarv FPSO produces about 86,000 barrels per day and has a storage capacity of 875,000 barrels, allowing for about 10 days storage. Even for the Greenfield 1300 mmscfd case, only 39,000 barrels of condensate/water would be produced per day, meaning the hull storage capacity is more than sufficient.

7.3.1 Utility and Support Systems

To support operations, several utility and support systems will be on the FPSO, including:

- Chemical storage and injection
- Cooling and heating systems
- Hydraulic/pneumatic systems including inert gas

- Instruments/electrical rooms
- Fuel gas
- Electrical power generation/distribution
- Flare
- Water treatment
- Jet and diesel
- Firewater
- Fire protection
- Potable water
- Ballast
- Drains
- Metering
- Accommodations
- Helideck

Power generation is in the order of 90 MW for the 650 mmscfd case and 170 MW for the 1300 mmscfd case. A 3 x LM6000 has been considered for the 650 mmscfd case and 4 x LM6000 for the 1300 mmscfd case. (REF www.ge.com/gas-power/products/gas-turbines/lm6000)

To improve efficiency and reduce carbon emissions, the power generating gas turbine will have a heat recovery system and exhaust gas carbon capture units. The proposed carbon capture units will be amine based. Further details on carbon capture units is covered in section 11.

The topside facility could capture about 0.5 million MTPA of CO_2 for the 650 mmscfd case and about 0.8 million MTPA for the 1300 mmscfd case. The captured CO_2 will be compressed, dehydrated, oxygen removed, liquefied, and pumped, sending the liquid CO_2 subsea and connecting into the subsea CO_2 line from shore. The comingled fluids will continue to the subsea CO_2 injection wells.

For the 650 mmscfd case, the topside weight will be approximately 20,000 tonnes. As expected this is closely aligned with the Skarv FPSO.

For the 1300 mmscfd case, the topside weight will be in the region of 35,000 tonnes. For an FPSO, this is not large. There are Floating Liquified Natural Gas (FLNG) facilities which are in the region of 70,000 tonnes, 432 m x 66 m (Coral FLNG). The Ichthys Gas Production facility offshore, which is based on a semi, has a topside weight of 71,000 tonnes for 1700 mmscfd of production. Based on environmental conditions offshore Newfoundland, a topside weight up to 50,000 tonnes is potentially credible.

8 Natural Gas Transport

The natural gas stream would be transported as high pressure dense phase fluid. The natural gas stream will be hydrocarbon dew point controlled to reduce the risk of hydrocarbon liquid drop out in the pipeline.

It is anticipated that there will be no hydrogen sulfide (H_2S) in the gas stream. However, a small percentage of CO_2 is expected in the natural gas stream which in the presence of water could form corrosive carbonic acid. In addition, natural gas in the presence of water could form hydrates which could potentially plug the pipeline system.

The natural gas stream would need to be dehydrated to reduce the risk of corrosion, hydrate formation, and fluid flow inefficiencies. Alternative water management methods could be considered to achieve similar risk reduction.

8.1 Brownfield Scenario

For the Brownfield scenario, the routing is expected to be the southern route through Placentia Bay and outwards to the Jeanne d'Arc Basin oil and gas facilities for a total distance of 600 kilometers.

The flow rate for the natural gas pipeline will be based on the amount of natural gas expected for the gas development scenario (650 mmscfd). The pipeline pressure is expected to be approximately 200 barg at the offshore inlet location and approximately 90 barg at the onshore outlet. The required outside diameter of the pipeline is anticipated to be 26 inches. The resulting inside diameter will be a function of the wall thickness which will vary depending on the strength of the carbon steel chosen for the pipeline. Higher strength steels will enable a thinner wall section and thus larger inside diameter for a given outside diameter.

8.2 Greenfield Scenario

For the Greenfield scenario, the routing is expected to be the northern route through Trinity Bay and outwards to the Orphan Basin resource area for a total distance of 450 kilometers.

The flow rates for the natural gas pipeline will be based on the amount of natural gas expected for the respective scenario (650 mmscfd or 1300 mmscfd). The pipeline pressure is expected to be approximately 200 barg at the offshore inlet location and approximately 90 barg at the onshore outlet. The 1250 meter elevation change between the inlet and outlet will affect the available pressure for fluid movement as the hydrostatic pressure of the natural gas will have to be overcome. Consequently, even though the Greenfield pipeline is shorter than the Brownfield pipeline, the increased water depth offsets some of the benefits of the shorter distance and it is anticipated that the pipeline diameter will be the same for the Brownfield and the Greenfield 650 mmscfd scenarios.

The outside diameter of the pipeline is anticipated to be 26 inches for the lower flow rate (650 mmscfd) and 34 inches for the higher flow rate (1300 mmscfd).

Table 8-1: Options for Natural Gas Pipelines

		Brownfield	Greenfield	
Flow Rate	mmscfd	650	650	1300
Pipeline Length	km	600	450	450
Pipeline Inlet Pressure	Barg	200	200	200
Pipeline Outlet Pressure	Barg	90	90	90
Height Differential	m	100	1250	1250
Pipeline OD	Inches	26	26	34
Pipeline ID	Inches	24.5	24.5	32.0

9 Natural Gas Receiving

Natural gas will enter the onshore facilities at high pressure. The gas has been dehydrated and dew pointed therefore no liquid drop out will occur and no need for slug catching facilities.

Pigging facilities will be provided to allow for inspection pigging.

The gas entering the facility will be heated and dropped down in pressure before it enters the hydrogen production unit. A portion of the 650 mmscfd gas that arrives onshore will be routed through a heater to bring the gas temperature to a point suitable for feeding the hydrogen plant package.

The balance of natural gas that arrives on shore will be available for sale to market. Details of the sale of natural gas is outside the scope of this study.

9.1 Utilities and offsites

Onshore facilities will be standalone, however the proposed facility could be co-located adjacent the Come-By-Chance refinery where there could be an opportunity for synergies.

Facilities expected to support hydrogen production include:

- Buildings to house for example the control room, electrical and instrumentation rooms, workshops and stores, catering facilities, offices/admin, guard house, car park, roads, security fence, accommodation.
- Fuel gas
- Electrical power
- Potable water
- Waste water treatment
- Storm water
- Cooling water or air coolers
- Air Separation Unit and storage
- Telecoms
- Security
- Demineralized water and BFW treatment
- Firewater
- Raw water
- Hydrocarbon closed drains
- Service Water
- Chemicals
- Steam system
- Water Treatment – process contaminated water, contaminated surface water, sanitary
- Storage tanks
- Flare
- Chemical handling
- Waste/disposal

10 Hydrogen Production

Around 85 mmscfd of the 650 mmscfd that arrives on shore will be fed to the hydrogen plant. This gas is heated from the expected 0 to 5 Celsius, to meet the hydrogen plant requirements.

As noted in the Introduction, two gas streams are required in the hydrogen production process, one for the reaction with steam to form hydrogen, and another to heat the furnace that drives the reaction.

The gas fed to the hydrogen plant is further split into an 85/15 ratio. 85% of the heated gas feeds the Steam-Methane Reformer (SMR) and 15% of the heated gas is used as trim fuel to fire the SMR furnace. A furnace temperature of 850 C is required to support the reaction. The plant proposed has the potential to produce 250 mmscfd of hydrogen.

Figure 10-1 below gives an overview of the Air Liquide Steam-Methane Reforming technology that is considered for this study. (REF www.engineering-airliquide.com/technology-handbook)

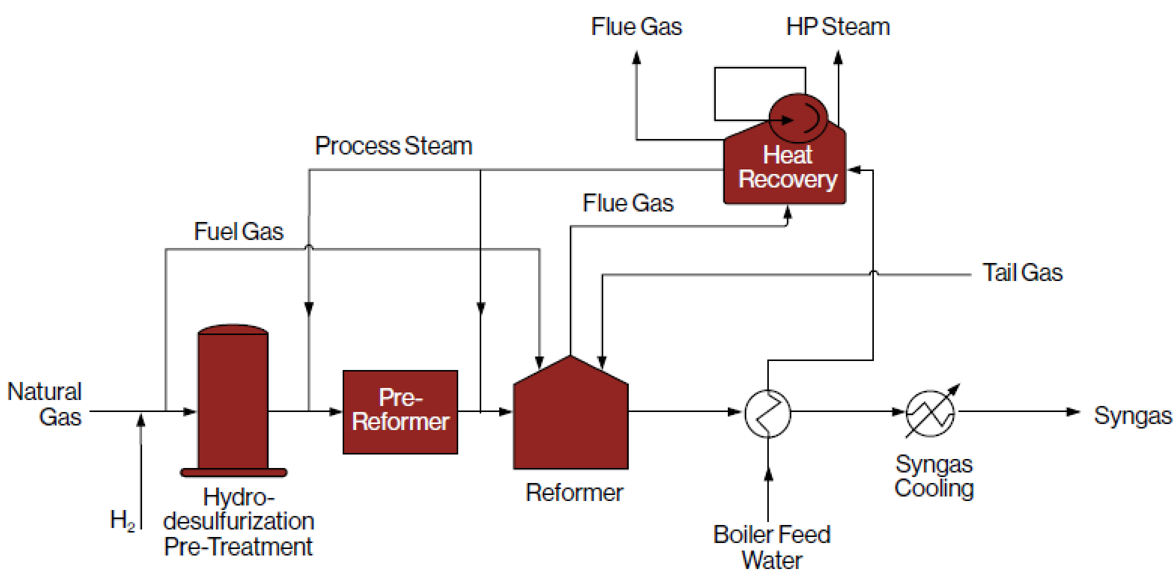


Figure 10-1: Air Liquide Steam-Methane Reforming Summary

The stages within the Air Liquide SMR package include:

- Pre-Treatment / Desulfurization: Impurities are detrimental to the hydrogen reaction and the life of the SMR catalyst. As a result, a pre-treatment step is included to remove trace amount of sulfur.

- Pre-Forming: A pre-forming step is included to convert larger chain hydrocarbons (for example, butane) to methane. This step makes the SMR more efficient and reduces the size of the reformer.
- SMR Furnace: Steam is added to the purified natural gas, and fed to the reaction furnace. The furnace contains hundreds of vertical catalyst tubes, filled with a catalyst that supports the Syngas reaction described in equation (1), Section 5. Natural gas is also used to fire the furnace and bring the catalyst tubes to the target temperature.
- Steam Generation Convection Section: Due to the heat required to drive the reaction, the flue gas from the SMR furnace is very hot (> 1000 C). Boiler Feed Water is fed to coils in the convection section of the furnace. This results in the generation of high-pressure steam. This is the same steam that is used as a feed to the reaction – overall, the SMR unit is a net steam exporter.
- Shift Reactors: Downstream of the SMR unit, additional catalyst vessels are utilized (after cooling) to shift the reaction toward more generation of hydrogen. This step also removes any carbon monoxide (CO) that is generated.
- Pressure-Swing Adsorption (PSA): In order to get the hydrogen product to the quality required for compression / storage, a Pressure-Swing Adsorber is required. This unit captures the trace amounts of CO_2, CO, nitrogen, and hydrocarbons. The result is hydrogen that is >99.9% quality.

Air Liquide also provide their Cryocap™ H_2 Process, for the recovery of CO_2 from the Syngas represented as the outlet stream in Figure 10-1. A summary of the Cryocap™ H_2 Process is given in Figure 10-2. (REF www.engineering-airliquide.com/technology-handbook)

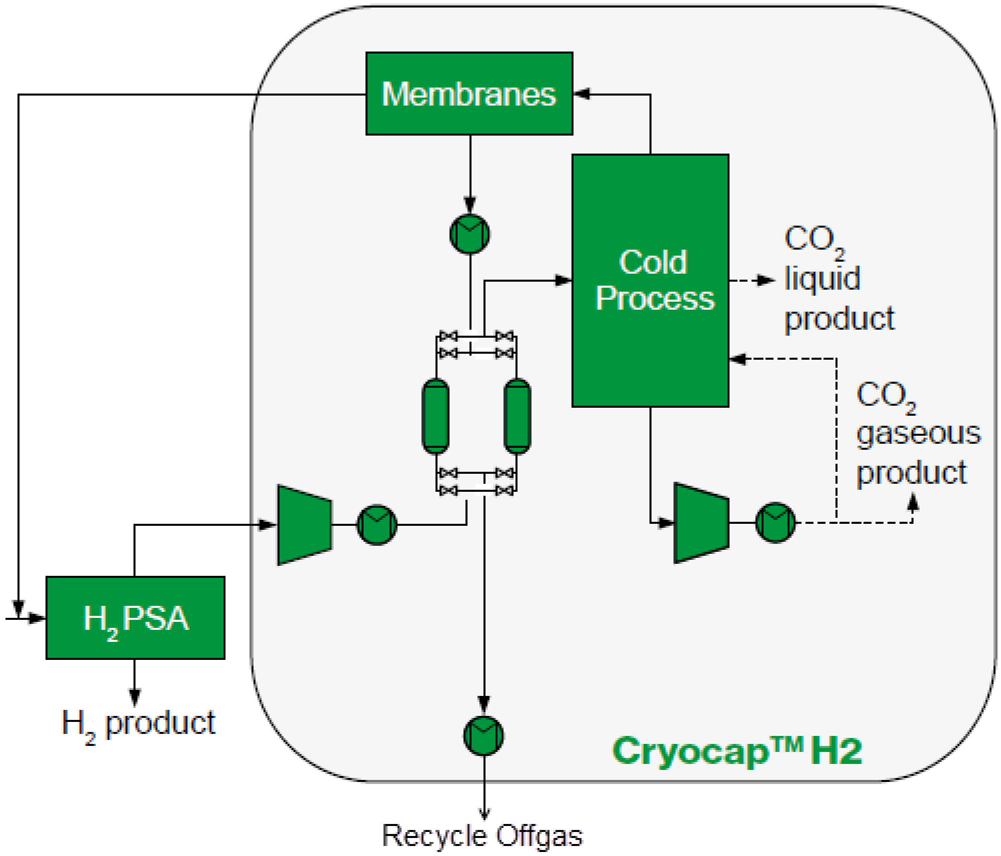


Figure 10-2: Air Liquide Cryocap™ H2 Summary

The stages within the Air Liquide Cryocap™ H_2 package include:

- Cryogenic CO_2 Separation: About 65% of the CO_2 potential in a hydrogen plant is due to the Syngas reaction described in equation (1). Air Liquide developed Cryocap™ H_2 as a means to capture the CO_2 released when hydrogen is formed. After the purified hydrogen stream is removed in the Pressure-Swing Adsorber, the CO_2 rich offgas is sent through an extreme cold process, that results in two very pure CO_2 product streams (one liquid and one gas).
- For a 250 mmscfd hydrogen plant, approximately 1,200,000 MTPA of CO_2 is formed due to the hydrogen reaction.
- Note that the capture of CO_2 that formed in the reaction furnace is covered in the next section of this report.

10.1 Hydrogen Quality

The hydrogen product from the Pressure-Swing Adsorber is very high quality (>99.9%), and leaves the adsorber at 25 barg and 30 C for the purposes of this study. Small trace amounts (ppm levels) of methane, CO_2, CO, and nitrogen will be in the hydrogen stream.

Hydrogen of this quality is ready for downstream use without the requirement for any additional treatment.

10.2 Steam Generation

As noted above, the Steam-Methane Reformer is a net steam exporter. Steam generated is more than enough to meet the steam/carbon ratio required to drive the syngas reaction.

Options for the additional steam produced in the SMR will be explored in the Power Demand section of this report.

10.3 Support Services

Along with the base Steam-Methane Reformer with the Cryocap™ H_2 technology, numerous other utilities and services are required to complete the system. These are listed in section 9.1 above. There is potential to share some of these services with other operators in the Placentia Bay area, most notably the Come-By-Chance refinery. The refinery is in the process of being repurposed to process biofuels. Some of the equipment / capacity originally intended for the oil refining operation may not be utilized going forward. A new development like a hydrogen plant could potentially access some of this under-utilized capacity.

The refinery would likely consider delivery of natural gas to Placentia Bay a benefit. Fuel cost is one of the major expenses for a refinery – a consistent source of fuel gas, which has a lower carbon footprint than the typical fuel oil used, would likely be advantageous.

Additionally, the refinery could consider using the hydrogen produced from the proposed blue hydrogen facility with CCS, as opposed to the existing hydrogen production without CCS, which could potentially reduce their operating cost and associated CO_2 emissions.

Finally, another potential synergy with the Come-By-Chance site is the deep water jetty and marine interface infrastructure. Large commercial shipping has long navigated in and out of Placentia Bay utilizing established regulations and procedures. If the capacity is available, the jetty and associated infrastructure could be considered for incorporating hydrogen export and / or CO_2 import (for storage) capability.

10.4 Plant Footprint

The onshore equipment described in this section requires a significant amount of physical space. A hydrogen plant alone of this capacity could require approximately 200 m x 100 m of footprint space. Once other processes are factored in, a large industrial site would result. The other processes (as described throughout this report) include:

- Natural gas receiving and preheating.
- Boiler feed water plant.
- Administration, maintenance, electrical, and operations buildings.
- CO_2 compression package.
- Flare system.

This is just a high level overview of major equipment. This space requirement further supports the selection of the refinery area as a location. Crown land is available in the area that could potentially be used to accommodate this onshore development.

11 CO_2 Capture

11.1 Post-Combustion Offshore

Offshore oil and gas facilities use significant amounts of electrical power. This is typically generated on the platform by natural gas driven gas turbines. These turbines are typically aero derivative units with a power output between 20 MW AND 40 MW. Like the power generators in offshore Newfoundland and Labrador, these units are mainly simple cycle generators and do not use the heat in the exhaust to generate steam for a steam turbine.

The turbine exhaust contains approximately 4% CO_2. A turbine generating 20 MW of power will emit approximately 100 000 MTPA of CO_2. Large emissions of CO_2 are no longer desirable and operators are investigating ways to significantly reduce emissions.

There are a number of ways to achieve this including;

- Combined cycle power generation
- Post combustion CO_2 capture
- Power from land
- Offshore wind
- Hydrogen from land

For this study, post combustion CO_2 capture is selected for the new offshore installations.

Figure 11-1 Typical Two Gas Turbine Arrangement with CO2 Capture

There is an enormous amount of research and development activity associated with CO_2 capture. Most of this work is associated with capture onshore. The technology available includes:

- Chemical absorption by amine
- Physical absorption
- Adsorption onto fixed bed
- Chilled ammonia
- Oxy fuel combustion

Chemical absorption of CO_2 by amine has come farthest in industrial onshore applications and there are several international projects applying this technology including the Quest project in Alberta and the Norcem project in Norway.

There has been less focus on offshore CO_2 capture likely due to a lower market potential. Offshore capture plants have a number of technical challenges including:

- Floating platform movement
- Available space
- Equipment weight
- Equipment size
- Safety

Figure 11-3 presents a typical floating production unit with CO_2 capture. Like onshore facilities, chemical CO_2 absorption by amine has come the farthest in development for offshore use. This study is aware of two companies developing systems for delivery. This study assumes that offshore post combustion will use available amine based absorption technology for the new gas processing hubs considered.

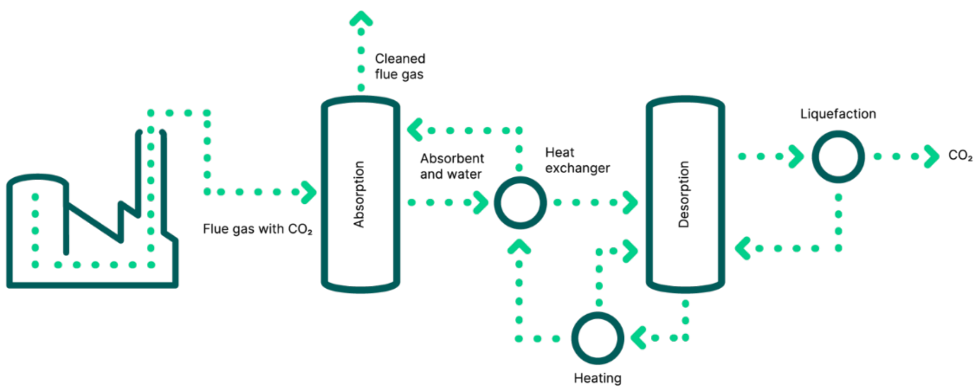


Figure 11-2 Flowsheet for Amine Based Post Combustion CO2 Removal

Figure 11-2 presents a simplified flow diagram for the absorption process. The flue gas from the gas turbine passed through the absorption column and up to 95% of the CO_2 is captured. Absorbent leaves the bottom of the column and is sent to the desorption column for regeneration. The product CO_2 leaves the top of the column at 1 barg. The desorption process requires significant amounts of heat. The product CO_2 then needs to be compressed, liquified, and sent to an underground storage. These systems are all very similar independent of supplier but vary in the details of the design. Key items of the design which vary from supplier to supplier include:

- Absorbent composition and characteristics
- Absorption column mass transfer equipment
- Flue gas wash systems
- Absorbent reclaiming requirements and systems
- Heat integration
- Layout
- Weight
- CO_2 compressor system design
- CO_2 dehydration system design

The CO_2 compressor system design depends on the flow rate and discharge pressure required. Offshore designs typically use a combination of screw and reciprocating machines.

Figure 11-3 FPSO with CO_2 Capture

Figure 11-4 demonstrates the Aker Carbon Capture modular design and Figure 11-5 shows how this module could be placed on a floating production unit.

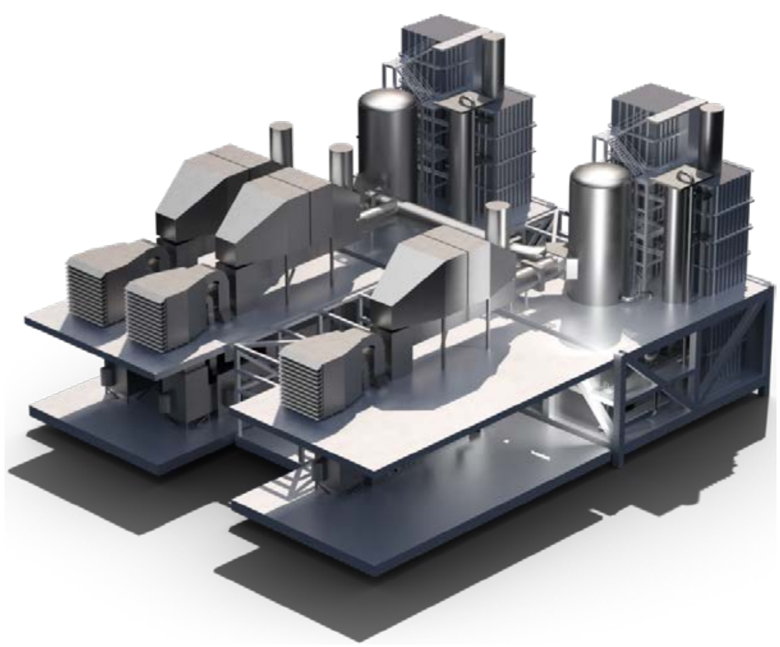


Figure 11-4 Offshore Modular Design by Aker Carbon Capture

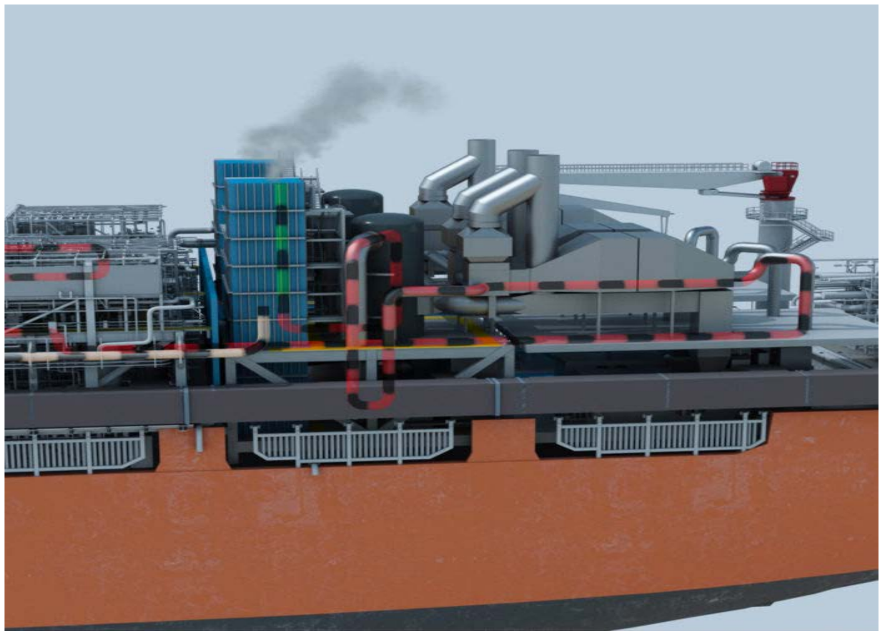


Figure 11-5 ACC Modules Placed on a Floating Production Facility

All the figures presented in this section were provided by Aker Carbon Capture (ACC) (www.akercarboncapture.com)

The CO_2 captured must be disposed of safely. This is normally achieved by injection of dense phase CO_2 into aquifers. Alternatively, it can be injected into oil reservoirs to enhance oil production. The CO_2 can be dissolved into water on the FPSO and injected with water into a reservoir.

CO_2 in various phases and alone or mixed with water or natural gas can be used to enhance or increase oil production. The most storage and additional oil recovery is when CO_2 is injected by itself or in a water-alternating-CO_2 scenario (WAG - water alternating gas), being miscible with oil at most offshore reservoir conditions. The water provides conformity and better sweep efficiency. Based on reservoir/block size and characterization (fractured, stratified, permeability, porosity), conditions (pressure, temperature), and oil quality along with the volumetric flow rate of CO_2 and its purity (based on capture technique), there are various other ways CO_2 can be utilized for enhanced oil recovery. As mentioned, CO_2 can be injected in its dense phase or alternating slugs of CO_2 and water (CO_2 WAG). CO_2 may be added to natural gas if the natural gas is being re-injected. In some cases, this can enrich the natural gas so that it becomes miscible, or more readily mixes with the oil. Again, this can be injected to gas flood the reservoir or in a WAG operation. CO_2 can be mixed with the water phase for carbonated water injection (CWI). This method is advantageous when the volume of CO_2 available is low. Dissolved CO_2 preferentially transfers from the water to the oil phase, swells the oil and can reconnect immobile, hard to recover oil. CO_2 can interact with facility / pipe / well materials, aqueous and reservoir rock and these interactions should be taken into consideration.

CO_2 capture will have safety implications for the FPSO. CO_2 is an inert gas and will not present a fire risk to a platform. However, CO_2 is toxic at high concentration and will also cause asphyxiation if oxygen concentrations are too low. The issues presented by CO_2 are familiar to FPSO operators processing natural gas and oil. The safety level of the FPSO will not be significantly affected by CO_2 systems.

The capture system will contain significant volumes of liquid absorbent. This liquid may degrade over time and must be cleaned by reclamation. Reclamation will generate a slurry waste which must be transported to land for disposal. Chemicals may also be required to reduce corrosion in the system. These chemicals should not be emitted to sea. Some absorbents are more toxic to the ocean than alternatives. Suppliers have developed absorbents that have very low degradation rates and minimal impact on sea life. These absorbents should be selected for offshore use, even if they have a slightly higher heat consumption.

There are several suppliers of CO_2 capture technology. However, few companies have developed offshore, modular concepts applicable to FPSOs. The market situation for this technology is difficult to predict. If the market grows, then it is expected that more suppliers will develop offshore concepts.

A modular carbon capture solution was also considered for the existing offshore developments in NL offshore. As the figures in this section illustrate, adding a large module like this to an existing facility is a complex task. The following section discusses addition of post-combustion carbon capture on existing facilities.

11.2 Retrofitting Existing Offshore Facilities

There are no offshore post combustion CO_2 capture facilities in operation today. This includes new build and retrofit systems. Several designs are developed for future installation and potential modifications.

CO_2 emissions are reduced by alternative methods which include:

- Power from shore / low carbon electrification

- Improved turbine efficiency
- Retrofitting combined cycle systems
- Reduced flaring and closed flare systems
- VOC recovery

Aker Solutions are also progressing development of subsea power generation technology as a potential alternative to existing gas turbine power generation. This technology would generate electricity offshore on the seabed utilizing available natural gas with integrated CO_2 separation. The separated CO_2 could be permanently stored in offshore subsurface reservoirs thereby providing natural gas fueled power generation for offshore facilities with zero emissions.

11.2.1 Existing Offshore CO_2 Removal Systems

There are several offshore facilities throughout the world with CO_2 removal from natural gas. The process is very similar to post combustion capture with the main difference being the operating pressure of the absorption unit. The post combustion absorber operates at about atmospheric pressure and has a low partial pressure of CO_2 (under 0.05 bar). The natural gas absorber operates at elevated pressure normally over 50 barg resulting in the partial pressure of CO_2 being significantly higher (over 2 bar). The high partial pressure gives real advantages including:

- Small absorber diameter
- Reduced de-sorber diameter
- Reduced absorbent circulation rates
- Reduced heat consumption
- Lower foot print
- Alternative absorbent types

Most existing offshore CO_2 capture units are catch and release. The carbon dioxide is removed from the natural gas to achieve the required export gas specification. The CO_2 is released to the atmosphere locally resulting in no environmental benefit or CO_2 emissions reduction. However, there is considerable operating experience that can be directly applied to future projects.

Aker Solutions has experience installing an offshore CO_2 capture and sequestration system at the Sleipner installation in Norway. Equinor captured and sequestered over 1 million MTPA of CO_2 since 1996. The captured CO_2 is injected into a porous/high permeability offshore formation for geological storage. Similar is being considered in this feasibility study.

Figure 11-6 below provides a visual of the Sleipner installation.

Figure 11-6 The Sleipner field in the North Sea. (Photo: Harald Pettersen / Equinor ASA)

11.2.2 Design Challenges for Application on Existing Facilities

Retrofitting post combustion CO_2 capture and storage systems has proven to be a challenging problem. There are hundreds of offshore facilities in operation throughout the world which combust hydrocarbons. Gas turbines and motors are used to drive compressors and generate electrical power. The associated CO_2 emissions are a problem for the operators. Most operators have very stringent goals and need to significantly reduce CO_2 emissions.

The key challenge is space. Figure 11-7 and Figure 11-8 present the layout of a typical floating offshore production facility (FPSO). It is assumed that the facility will have three aeroderivative gas turbines. The blue items identified as 'GEN' are the gas turbines. The green area identified as CC are the CO_2 capture modules. The figures show that the CO_2 capture modules will take up a similar area to the power generation turbines. In this example, the CO_2 compression is in the process area.

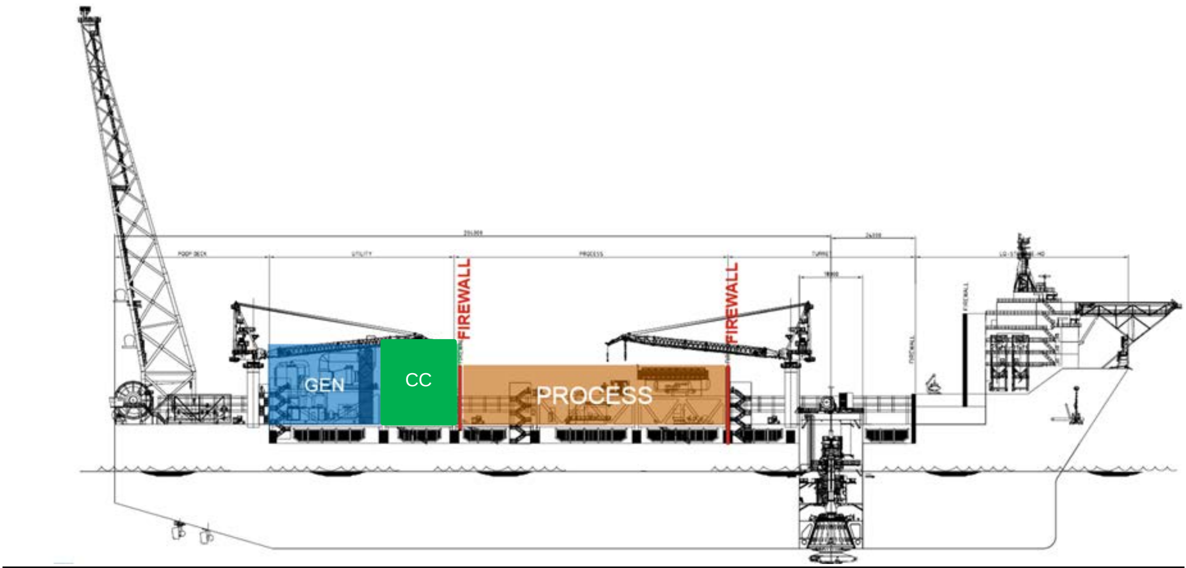


Figure 11-7 FPSO Lay Out with Post Combustion CO_2 Capture

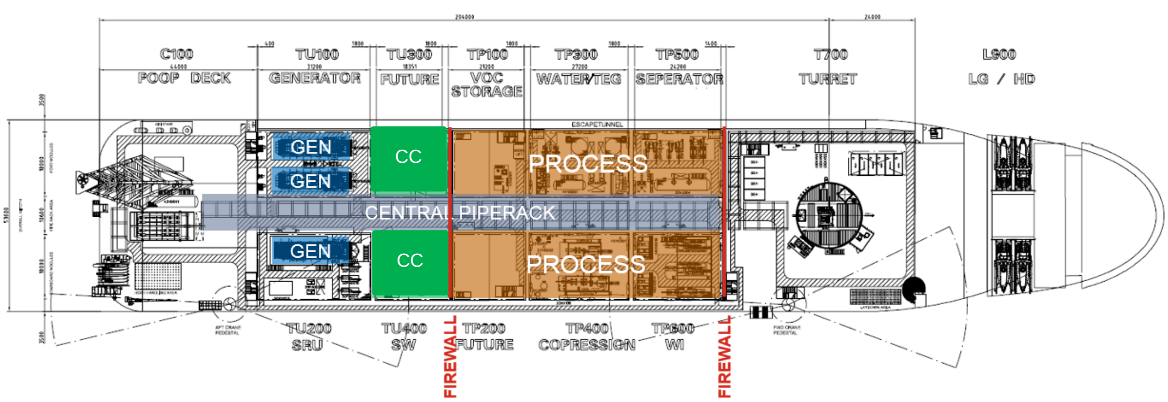


Figure 11-8 FPSO plan with Post Combustion CO_2 Capture

To be able to retrofit a facility, a topside must have the area available greater than the existing area used for power generation. Very few of the existing facilities have this area available. The CO_2 capture unit also requires heat and this heat is typically provided by waste heat recovery from the turbine exhaust. The waste heat recovery unit will therefore require modification. Figure 11-9 shows a gas turbine with horizontal waste heat recovery unit. The blue section demonstrates the increase in size required if CO_2 capture is required.

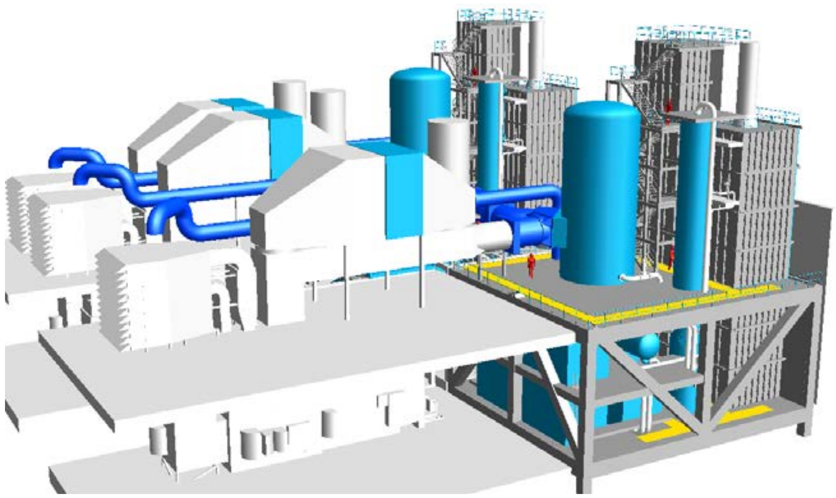


Figure 11-9 Retrofitting CO_2 Capture Modification to waste heat recovery

Aker Solutions has investigated retrofitting CO_2 capture to existing fixed installations including the Draugen platform in Norway. Figure 11-10 is a photograph of the production facility.

Figure 11-10 The Draugen platform (www.norskpetroleum.no)

Draugen operates with three parallel gas turbines for power generation and will require a large module for CO_2 capture. There is no available space topside for the module so it was conceptually placed as a hang-off on the side of the platform as shown in Figure 11-11.

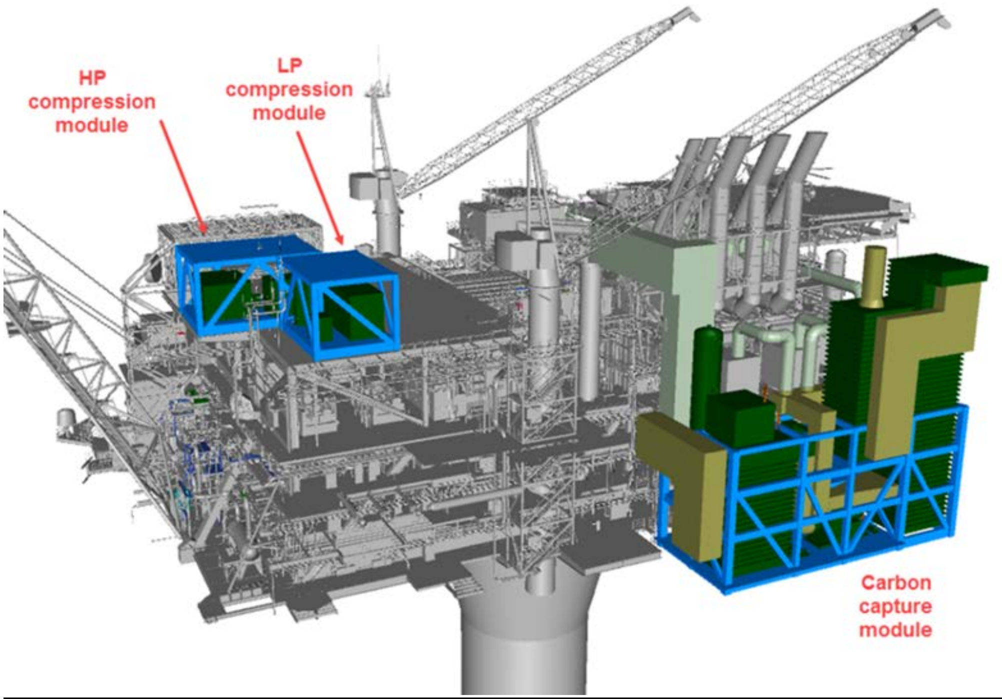


Figure 11-11 Draugen Platform modified for Carbon Capture

11.2.3 Power Demand Considerations

The CO_2 capture unit will require utilities, power and heat. These must be supplied from the existing facility. In many cases, these utilities may not be available and modifications will be required.

Table 11-1 presents example heat and electrical power required to capture CO_2 from a gas turbine generating 30 MW of electrical power. The capture plant will require 14 MW of heat and 2.2 MW of electrical power. The heat is required to regenerate the absorbent. The electrical power is mainly required for CO_2 compression. There are also numerous smaller consumers including fans, pumps and heaters.

Table 11-1: Example Utility Requirements for CO_2 capture 30 MW turbine

Main Case	Unit	Amount
Electrical power generation per turbine	MW	30
Flue gas temperature upstream WHRU	°C	525
Flue gas temperature downstream WHRU	°C	212/250 norm/max
CO_2 emissions per turbine	tonnes/hour	3.4
CO_2 captured/injected per turbine	tonnes/hour	14
CO_2 concentration in exhaust from turbine	%vol	3.6
Fan duty per turbine	MW	0.5
CO_2 compression duty per turbine	MW	1.5
Total electrical power require	MW	2.2
Total heat power required	MW	14

The extra heat will be supplied by modifying/extending the waste heat recovery unit. Figure 11-9 demonstrates how this can be achieved in a horizontal waste heat recovery unit.

The extra electrical power must be supplied by the existing system. Installation of extra electrical generators is probably not possible. If electrical power is not available, the operation of the facility must be changed to reduce power consumption of the existing systems.

The capture plant will also require connection to several utility systems including:

- Cooling
- Compressed air
- Nitrogen
- Chemical injection
- Chemical storage
- Vent/flare
- Drain
- Fire water
- Control system

Previous studies have indicated that it is normally possible to tie in to these existing systems with little impact.

11.3 CO_2 Capture from Hydrogen Production Process - Onshore

As described in Section 10.0 of this report, the Steam-Methane reforming process selected for hydrogen generation has two separate CO_2 streams:

- CO_2 capture from the syngas
- Post-Combustion CO_2 capture from the SMR furnace

The carbon capture technology selected for the offshore flue gas on the new floating facility will be very similar to that used in the onshore post combustion CO_2 capture. The effluent from the SMR furnace will be directed to an onshore amine absorption unit, and a similar flow path described in Figure 11-2 will be followed.

Based on the 250 mmscfd of hydrogen produced, around 75,000 kg/hr of CO_2 is produced due to the fuel gas combustion in the SMR. 95% of this is captured by the amine process.

The CO_2 captured via an amine process is "wet" (i.e. it contains some of the water that was a combustion product in the SMR as well). In order to prepare the CO_2 for pipeline transport and underground storage, the CO_2 needs to be dried, using an onshore dehydration unit. Once this stream is dried, it can be commingled with the CO_2 recovered in the syngas process and compressed for transport.

11.4 CO_2 Compression on Land

Large scale CO_2 will be produced on land by the blue hydrogen production facility. The CO_2 flow rate will be up to 2 million MTPA. The compressor discharge pressure will be around 200 barg, resulting in CO_2 in the dense phase.

Large scale CO_2 compression systems are operating internationally with rates over 1 million MTPA. This is seen as an expanding market and compressor system suppliers are developing larger and more efficient systems. Compressor units with capacities over 2 million MTPA are now available.

Integral gear compressors dominate the market and give the best combination of cost and efficiency. There are several suppliers that can supply this technology. The main advantages of this technology are:

- Multiple shafts allowing optimal speed for each stage
- Up to 8 compressor stages
- High efficiency
- Inlet pressures as low as 0.4 barg acceptable

- Discharge pressure over 200 barg available
- Can operate in CO_2 dense phase
- Supplied as complete module with coolers and scrubbers
- Water cooled
- Can be combined with dense phase pump
- Heat integration possible
- CO_2 treatment possible between compression stages
- Capacities up to 2 million MTPA
- Duties up to 50 MW

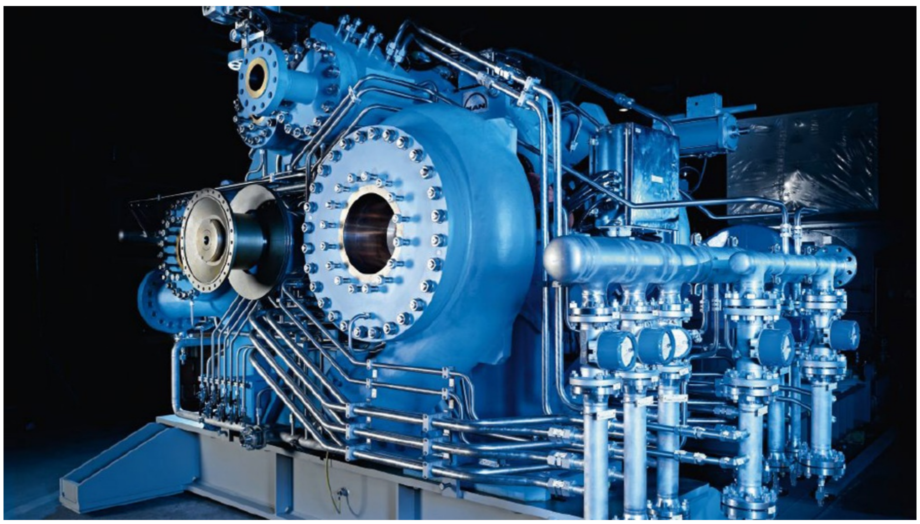


Figure 11-12 Integral Gear Compressor Suitable for CO_2 Compression

Figure 11-13 Integral Gear Compressor Suitable for CO_2 Compression

Figure 11-14 Integral Gear Compressor Suitable for CO_2 Compression

11.5 CO_2 Emissions Summary – Natural Gas Production

The summary Table 11-2 below shows the high level breakdown of the CO_2 emissions and carbon intensity for each of the natural gas production options analyzed. Each option only considers emissions created from the power generating gas turbine which will have a heat recovery system and exhaust gas carbon capture unit. Total emission are based on 100,000 MTPA per 20 MW of power required and capture is assumed at 95% through amine based absorption technology. Carbon intensity was calculated by dividing the total lifetime emissions by total lifetime production. No emissions are considered for the onshore gas receiving as any required power is assumed to be from grid supplied hydro power.

Table 11-2: CO2 Emissions and CI - NG Production

NG Option	NG Production - CO_2 (MTPA)			Carbon Intensity kg CO_2/mmscf
	Produced	Captured	Released	
Brownfield	450,000	427,500	22,500	113
Greenfield 1	450,000	427,500	22,500	135
Greenfield 2	850,000	807,500	42,500	128

11.6 CO_2 Emissions Summary – Hydrogen Production

The summary Table 11-3 below shows the high level breakdown of the CO_2 emissions for each of the hydrogen production options analyzed. Each option considers emissions created from the hydrogen feed and fuel gas as well as the emissions associated with the production of the required natural gas. For the recovery of CO_2 from the feed gas, a capture rate of 99% is assumed using the Air Liquide Cryocap™ H_2 Process. For the recovery of CO_2 from the fuel gas, a capture rate of 95% is assumed using amine based absorption technology. No further emissions are considered for hydrogen production as additional power requirements are assumed to be from grid supplied hydro power.

Table 11-3: CO_2 Emissions and CI - Hydrogen Production

Hydrogen Option	Hydrogen Production - CO_2 (MTPA)			NG - CO_2 Emissions (MTPA)	Total CO_2 Emissions (MTPA)	Carbon Intensity (kg CO_2/kgH_2)
	Produced	Captured	Released			
Brownfield	1,875,735	1,830,756	44,979	3,490	48,469	0.22
Greenfield 1	1,875,735	1,830,756	44,979	4,188	49,167	0.22
Greenfield 2	1,875,735	1,830,756	44,979	3,956	48,935	0.22

12 CO_2 Transport

Globally, CO_2 pipelines have been in use for many years both onshore and offshore. The design and operation has a proven success record and utilizing CO_2 pipelines to transport CO_2 from onshore NL to offshore NL is expected to be technically feasible.

CO_2 will react with water to form carbonic acid which is corrosive to pipelines made from carbon steel. Consequently, to reduce the risk of pipeline corrosion, the CO_2 will need to be dehydrated to a quality that has low to no water content.

If water and hydrocarbons are both present in the CO_2 pipeline, there is a risk that formation of hydrates could occur and potentially plug the system.

Overall, making the CO_2 product as pure as reasonably possible (i.e. removal of contaminants) will reduce risk associated with pipeline operations.

It is important that experts in pipeline design and operations work with experienced management teams to ensure the CO_2 pipeline is designed, constructed, and operated in a safe and environmentally sound manner. Industry experience has demonstrated that CO_2 pipelines can be constructed and operated to meet or exceed high standards.

The risk is manageable and CO_2 pipelines are often considered to be in a similar category to hydrocarbon pipelines such as natural gas or petroleum liquid pipelines. Unlike hydrocarbons, CO_2 is not flammable. However, if there is a leak in the proximity to humans there is a danger to humans from exposure that could lead to injury or death from toxicity or asphyxiation. The risk to humans is more relevant to onshore pipelines in populated areas rather than pipelines in an offshore subsea environment.

With respect to offshore NL, there is additional risk of an iceberg impact with the pipeline and appropriate risk assessment would need to be completed and risk mitigation measures implemented. To mitigate this risk, the C-CORE model used for the best route to bring natural gas to shore (which considered iceberg scour as the main input) is also applied to the CO_2 return pipeline. The Brownfield pipeline route has a quantified iceberg risk to be managed. The Greenfield route indicates no iceberg impact risk due to the water depth. Please reference the complete C-CORE report in Appendix A for additional information.

At atmospheric pressures, CO_2 is in a gas phase at temperatures higher than minus 78 degrees Celsius – below that temperature it is in a solid phase (dry ice). To transport CO_2 in a pipeline, it is more efficient to compress the CO_2 to higher densities and transport as a dense phase liquid, or dense phase fluid (supercritical fluid), rather than in a low density gas phase. For the typical range of pipeline pressures above 74 barg, in order to keep the fluid in a liquid dense phase or super critical fluid phase, the CO_2 temperature has to be above approximately minus 50 degrees Celsius. At temperatures below approximately minus 50 degrees Celsius the CO_2 will turn to a solid at these typical higher pipeline pressures. The phase diagram for CO_2 (see Figure 12-1 below) should be reviewed to know what phase (solid, vapor/gas, liquid, liquid dense, and Supercritical) the CO_2 will be in for a combination of pressures and temperatures.

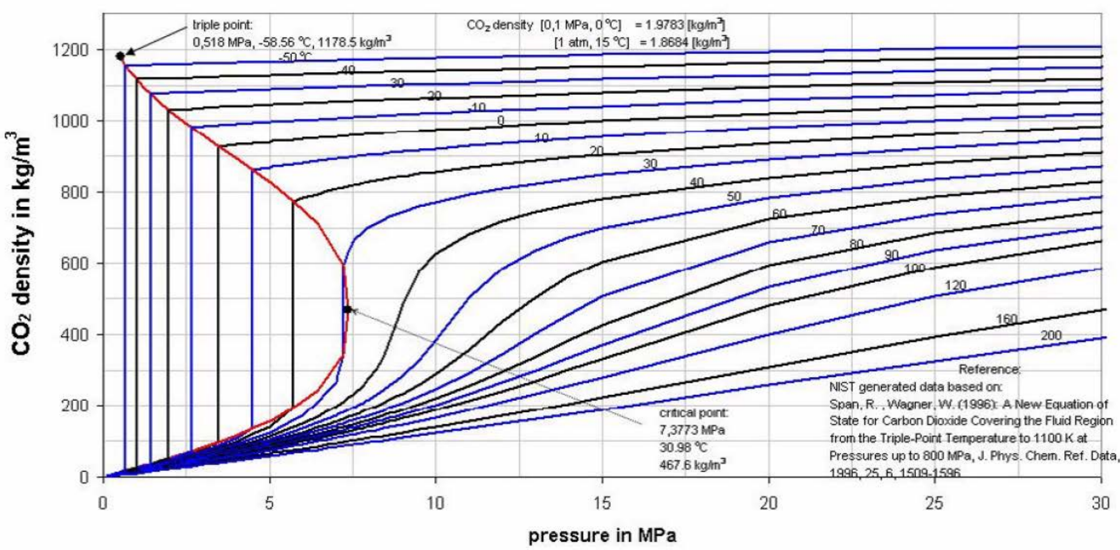


Figure 12-1: CO2 Phase Diagram (van der Meer et al. 2009)

12.1 Brownfield CO_2 Pipeline

For the Brownfield scenario, it is anticipated the CO_2 pipeline would follow a similar routing that C-CORE proposed for the natural gas pipeline from the Jeanne d'Arc basin to Placentia Bay. The length will be approximately 600 kilometers.

The flow rates for the CO_2 pipeline will be based on the amount of CO_2 expected from the hydrogen plant explained in section 10. The preliminary sizing considers the 2 million MTPA of CO_2 from the 250 mmscfd hydrogen plant. However, this study also considers the opportunity to expand the CO_2 return to up to 4 million MTPA. The larger CO_2 return line provides the flexibility to expand the onshore hydrogen production, or to receive CO_2 from other industries looking for CO_2 storage capacity.

The pipeline pressure is expected to be approximately 200 barg at the onshore inlet location and approximately 97 barg at the outlet. Due to the shallow water depth of approximately 100 meters, the CO_2 hydrostatic head pressure on the outlet pressure will be approximately 9 bar resulting in a 106 barg pipeline outlet pressure at the seabed. The required inside diameter of the pipeline is anticipated to be approximately 12 inches for the lower flow rate (2 million MTPA) and 15.3 inches for the higher flow rate (4 million MTPA). The outside diameter is anticipated to be 14 inch and 18 inch for the lower and higher flow rate respectively. The resulting inside diameter will be a function of the wall thickness which will vary depending on the strength of the carbon steel chosen for the pipeline. Higher strength steels will enable a thinner wall section and thus larger inside diameter for a given outside diameter.

12.2 Greenfield CO_2 Pipeline

For the Greenfield scenario, it is anticipated the CO_2 pipeline would follow a similar routing that C-CORE proposed for the natural gas pipeline from the Cape Freels area of the West Orphan basin to Trinity Bay. The length would be approximately 450 kilometers.

The flow rates for the CO_2 pipeline will be based on the amount of CO_2 expected from the hydrogen plant explained in section 10. The preliminary sizing considers the 2 million MTPA of CO_2 from the 250 mmscfd hydrogen plant. However, this study also considers the opportunity to expand the CO_2 return to up to 4 million MTPA. The larger CO_2 return line provides the flexibility to expand the onshore hydrogen production, or to receive CO_2 from other industries looking for CO_2 storage capacity.

The pipeline pressure is expected to be approximately 200 barg at the onshore inlet location and approximately 122 barg at the outlet based on friction losses only. The changing elevation between the inlet and outlet will affect the outlet pressure. The outlet is on the seabed in 1250 meter water depth resulting in 110 bar of hydrostatic pressure due to the CO_2 fluid in the pipeline. This pressure is added resulting in an outlet pressure of 233 barg from the CO_2 pipeline at the seabed.

The required inside diameter of the pipeline is anticipated to be approximately 12 inches for the lower flow rate (2 million MTPA) and 15.3 inches for the higher flow rate (4 million MTPA). The outside diameter is anticipated to be 14 inch and 18 inch for the lower and higher flow rate respectively.

Table 12-1 below summarizes the sizing of the Brownfield and Greenfield cases, for both the base 2 million MTPA, and the 4 million MTPA sensitivity case.

Table 12-1: CO2 Pipeline Sizing Analysis

		Brownfield		Greenfield	
Flow Rate Capacity (millions)	MTPA	2.0	4.0	2.0	4.0
Pipeline Length	km	600	600	450	450
Pipeline Inlet Pressure	barg	200	200	200	200
Pipeline Outlet Pressure (friction losses only)	barg	97	97	122	122
Height Differential	m	100	100	1250	1250
Hydrostatic CO2 Pressure differential	barg	9	9	110	110
Pipeline Outlet Pressure	barg	106	106	233	233
Pipeline OD	inches	14	18	14	18
Pipeline ID Required	inches	12.0	15.3	12.0	15.3

13 CO_2 Storage

For this study, CO_2 storage location adjacent to the associated gas production was considered to avail of available seismic and well log information. A recognized optimization opportunity is a scope specific study of CO_2 transport and storage focused on the region explored in this study to optimize and better understand that component.

CO_2 storage requires a reservoir with storage capacity of adequate rock porosity and permeability and a trap or seal to contain the CO_2 as it would contain reservoir fluids of gas, oil, and water. While considering the storage potential of CO_2 in the subsurface in the pore space between the rock/sand grains, it is important to consider the overall storage capacity of the reservoir (porosity) and how easy it is for fluids to flow through the interconnected pore space (permeability). Further, the depth of the water and true vertical depth of the reservoir formation changes the temperature and inherent hydrostatic pressure based on overburden and pore fluids. The pore fluid pressure may deviate from the theoretical hydrostatic pressure based on communication between the layers and changes in the depositional setting over geological time. Likewise, temperatures may deviate as well.

Assessing the basin stratigraphy, the Jeanne d'Arc basin (Brownfield location) is separated from the Orphan basin (Greenfield location) by the Labrador Greenland rift event that pulled apart the two basins back during the lower Cretaceous-Aptian period. The basin depositional setting is similar with differences due to location and erosion events. Reservoir quality rock in this area is generally found in sandstone formations deposited in a fluvial, near shore face, or shore face depositional setting. The major hydrocarbon reserves are found in the Jeanne d'Arc basin in the early Cretaceous period in the Hibernia, Ben Nevis, and Avalon sandstone formations. Late Cretaceous sandstone formations include Fox Harbour and Otter Bay. In both the Jeanne d'Arc and Orphan basin, saline aquifers have been shown seismically and through exploration wells to exist in Paleocene, Eocene, and Oligocene tertiary sands. Depending on geographic location, geologic events, and specific depositional setting/erosion, the geologic time periods and rock lithology may exist at different true vertical depths (TVD) introducing uncertainty in formation properties.

Based on seismic and well log information, and given uncertainty in formation quality, the following assumptions were used in determining the injectivity of CO_2 into plausible formations.

- A pressure gradient of 0.11625 bar/m was used based on hydrostatic pressure gradients and well data (REF https://oilconl.com/licensing-rounds/2016-eastern-newfoundland-region-nl-02-en/)
- The thermal gradient adjusted with well temperatures were used to determine the temperature profile at the interested depths, shown in the table below
- A vertical injection well was assumed with 4" tubing

- Tubing head pressures were based on delivered pressures as discussed in Section 8
- Beggs & Brill was assumed for well bore hydraulics
- Peng Robinson equation of state was used to account for CO_2 density
- The hydrostatic pressure of seawater (980, 12256 kPa for 100 and 1250 m of water, respectively) were added to the reservoir pressures shown below for the Greenfield (West Orphan) and Brownfield (Jeanne d'Arc) cases.
- A 25 m high aquifer filled with 35,000 ppm salt with a 450 acre (182 hectare) area or 1.7 km diameter area around the well was assumed.
- To account for uncertainty, three permeabilities were examined (100, 800 1500 mD)

Table 13-1 below summarized the expected CO_2 injection rates at various depths for both the Greenfield and Brownfield cases.

Table 13-1: CO_2 Injection Rates at Varying Reservoir Depths

	Depth (TVDm)	Pressure (bar)	Temperature (°C)	Permeability (mD)	Possible CO_2 Injection Rate (1000 Sm^3/day)	Possible CO_2 Injection Rate (Mt/yr)
Greenfield 1250 m water THP = 233 bar	2000	233	65	100 - 1500	1800 - 2100	1.2 - 1.4
	3000	349	90		1450 - 1600	0.97 - 1.1
	4000	465	120		1100 - 1300	0.74 - 0.87
	5000	581	160		900 - 1000	0.60 – 0.67
Brownfield 100 m water THP = 105 bar	2000	233	65	100 - 1500	1450 - 1700	0.97 – 1.14
	3000	349	90		1050 - 1250	0.70 – 0.84
	4000	465	120		700 - 850	0.47 – 0.57
	5000	581	160		Not possible	

Based on the delivery pressure for the Brownfield case, it is possible to inject CO_2 into formations as deep as 4000 m and meet the target of 2 million MTPA CO_2 injection. Shallower formations are easier to inject into based on lower frictional losses in the well and a lower reservoir pressure to overcome.

14 Power Demand Review

To undertake a project of this magnitude, significant power is required, both offshore on the gas processing facility and onshore at the hydrogen plant location.

14.1 Offshore Power Demand

As mentioned in section 7, the gas processing floating facility will require approximately 90 MW of power for the 650 mmscfd natural gas to shore option. This applies to both the Greenfield and Brownfield options. To take advantage of the larger gas inventory in the Cape Freels area, 170 MW of power is required on the larger floater facility that supports 1300 mmscfd of natural gas to shore.

These power generators will be fueled by the same gas that is treated and prepared to pipe to shore. The flue gas from the power generators will be routed to carbon capture units installed on the new floating facilities, where the CO_2 will be removed, compressed, and routed to the same injection well planned for the CO_2 return from the onshore hydrogen plant.

14.2 Onshore Power Demand

The Steam-Methane Reforming process will require a large power demand. Power is considered for:

- Preheating the natural gas that arrives on shore. It is expected that the gas that arrives on shore will be at the sea bed temperature (assumed to be 0 Celsius). The hydrogen plant requires that the gas be preheated to 5 Celsius before entering the package. As a result, a 2 MW electric heater is included in the design, that takes the full stream of natural gas required for the 250 mmscfd hydrogen plant and increases it to the 5 Celsius target.
- The power required to run the hydrogen production equipment is estimated at 30 MW
- The captured CO_2 for both the Brownfield and Greenfield options are compressed to 200 barg to achieve the offshore injection pressure.
- Approximately 25 MW of power is required to operate the CO_2 compressors.
- A further 10 MW of power is assumed for the miscellaneous operations that are required to support the facility:
    - A boiler feed water plant to ensure the water quality meets the target steam requirements.
    - Various support buildings, such as administration, control rooms, maintenance shops, etc.
    - Heat trace requirements for freeze protection.

Table 14-1 below provides a high level summary of the power demand on shore.

Table 14-1:Hydrogen Plant On-Shore Power Demand

Service	Unit	Amount
Hydrogen Plant	MW	30
CO_2 Compression	MW	25
Pre-Heating of Natural Gas	MW	2
Ancillaries	MW	10
Total Power Demand	**MW**	**67**

Overall, around 70 MW of power is required for the onshore blue hydrogen facility. NL Hydro published industrial power rates equate to approximately 5.91 cents/kWh (REF 17). Thus, to deliver 70 MW of power consistently, the annual power cost is approximately $35-million. Follow-on study of the concepts introduced in this study should explore potential power supply cost incentives and efficiencies that could be negotiated.

An alternative that should be explored, should the blue hydrogen concept move forward, is the use of steam turbines to generate power. As noted in the hydrogen generation section of this report, the Steam-Methane Reformer is a net producer of steam. Steam is fed to the reactor tubes to make hydrogen, but the excess heat that remains in the furnace (in the heater convection section) is recovered to generate steam.

Boiler feed water is fed through tubes in the convection section of the furnace, which results in a net export of steam. There are options within the design of the SMR that provide further fuel gas firing in the convection section, therefore generating more steam. More capital would be required up front, but it is possible that additional steam generation and steam turbines could be included in the concept, thereby eliminating the need to purchase power from the grid.

Generating more steam does result in an iterative process. More fuel is required to generate the steam, which would be supplied from the natural gas that arrives on shore. The burning of more natural gas will result in additional CO_2 load on the carbon capture units, and additional CO_2 compression.

The power balance and the optimal path forward is a potential future study. At this conceptual stage, it is sufficient to say that an opportunity exists to optimize the power demand and supply options, and it should be explored in future project phases.

15 Economic Analysis

15.1 Natural Gas Supply for Blue Hydrogen Production

Access to a cost effective and reliable natural gas source is considered a key component of hydrogen production. Currently, NL has no access to natural gas and therefore the first part of the hydrogen feasibility analysis focuses on securing a reliable source of natural gas as required for the SMR process of hydrogen production. Three development scenarios to import gas to shore from offshore NL were evaluated. These include a 20-year Brownfield development (650 mmscfd) and two 30-year Greenfield developments (650 mmscfd & 1,300 mmscfd). Table 15-1 below summarizes the governing parameters for each of the three scenarios to produce NG and transport to onshore.

Table 15-1: Natural Gas Production and Pipeline Summary

NG Option	Capital Cost $M CAD	NG Volumes	Facility	NG Production Rate	Operational Life	Pipeline Size	Pipeline length
Brownfield	$9,875	4.0 Tcf	FPSO	650 mmscf/d	20 yrs	26"	600km
Greenfield 1	$9,207	5.0 Tcf	FPSO	650 mmscf/d	30 yrs	26"	450km
Greenfield 2	$14,197	10.0 Tcf	FPSO	1,300 mmscf/d	30 yrs	30"	450km

A conceptual estimate was compiled for each of the scenarios and from this, a high-level economic evaluation was performed for each scenario using Net Present Value (NPV) analysis. This analysis considered a discount rate of 10% (minimum rate of return) to determine a minimum acceptable sale price for natural gas. The main inputs to economic analysis include CAPEX, OPEX, Royalties and Taxes. The results of the analysis indicate that a unit price for natural gas would be in the range of $7 to $12 / mscf. The production cost of the natural gas (CAPEX / OPEX) accounts for approximately 74% ($5.10 - $8.70 / mscf) of the overall cost while the Royalties / Taxes make up roughly 26% ($1.60 - $3.30 / mscf). A natural gas development would require capital investment of around $9 - $14 Billion CAD. Additional markets for natural gas would be necessary as only 85 mmscfd of the produced natural gas would be required for the hydrogen production development reviewed for this study. The table below summarizes the results for the natural gas price for each development option as well as the percentage breakdown of the gas price into the major components: CAPEX / OPEX and Royalties / Taxes.

Table 15-2: Natural Gas Supply Cost Analysis - % Breakdown

Development Option	NG Price ($CAD/mscf)	CAPEX & OPEX	Royalties & Taxes
Brownfield	$11.96	72%	28%
Greenfield 1	$9.38	74%	26%
Greenfield 2	$6.71	76%	24%

Table 15-3: Natural Gas Supply Cost Analysis - $ Breakdown

Development Option	NG Price ($CAD/mscf)	CAPEX & OPEX	Royalties & Taxes
Brownfield	$11.96	$8.65	$3.31
Greenfield 1	$9.38	$6.90	$2.47
Greenfield 2	$6.71	$5.13	$1.58

The initial results from the high-level evaluation indicate that from a gas price and capital investment perspective, a Greenfield natural gas development looks more favourable. These results are influenced largely by the pipeline length, recoverable volumes and production rate of natural gas.

As seen in the natural gas price breakdown charts above, Taxes / Royalties represent a significant portion of the total price. In all options Taxes / Royalties are more than 30% of the CAPEX / OPEX cost and represent approximately 24% to 28% of the overall natural gas price. The NL Offshore Natural Gas Royalty Regime as well as the taxes are areas that require further analysis / review due to the overall impact on the final natural gas sale price. Higher production cost equates to a higher natural gas base cost which in return will generate higher taxes and demand more royalties, therefore in this type of analysis the compound effect could make projects look uneconomic by demanding a higher final sale price for natural gas which is not competitive in today's markets. The sale prices generated above for natural gas are the values which will be assigned to the hydrogen production + CCS economic evaluation.

15.2 Hydrogen Production with Carbon Capture and Storage

For the Hydrogen + CCS, one facility design option was considered for the hydrogen production and carbon capture while the associated CO_2 storage location was determined to be in the area matching the NG source. The CO_2 storage location will be in close proximity to the NG processing facility and both the NG and hydrogen production facilities will utilize the same storage location and subsea infrastructure. Table 15-4 below summarizes the governing parameters for each of the three scenarios to produce Hydrogen + CCS.

Table 15-4: Hydrogen Production and CO_2 Management Summary

Hydrogen Option	Capital Cost $M CAD	Facility Type	Operational Life	Hydrogen Production Rate	CO_2 Capture (million)	CO_2 Storage Area	CO_2 Pipeline Size	CO_2 Pipeline Length
Brownfield	$5,155	SMR + CCS	20 yrs	600 tonnes/d	1.9 MTA	BF	14"	600km
Greenfield 1	$4,683	SMR + CCS	30 yrs	600 tonnes/d	1.9 MTA	GF	14"	450km
Greenfield 2	$4,683	SMR + CCS	30 yrs	600 tonnes/d	1.9 MTA	GF	14"	450km

Conceptual estimates were developed for the hydrogen production + CCS considering the Brownfield and both Greenfield options for natural gas supply. CO_2 storage for each case is assumed to be in the area of the natural gas supply. Based on a production rate of 600 tonnes H_2/day, the hydrogen + CCS development would require capital investment of around $4.7 - $5.2 billion CAD. A significant portion the cost is related to the CO_2 storage which accounts for approximately 45-50% of the overall capital investment, while the Hydrogen production and carbon capture accounts for approximately 50-55%. The main inputs in the economic analysis include CAPEX, OPEX, Natural Gas Price, and Tax. The analysis applied a discount rate of 10% (minimum rate of return) to determine a minimum sale price for hydrogen. The table below summarizes the hydrogen sale price results for the development options as well as the percentage breakdown of the hydrogen price into the 4 major components: CAPEX, OPEX, Natural Gas and Taxes.

Table 15-5: Hydrogen Production Cost Analysis

Development Option	Hydrogen Price ($CAD/kg)	CAPEX	OPEX	NG	Taxes
Brownfield	$6.41	49%	15%	26%	10%
Greenfield 1	$5.27	49%	16%	25%	10%
Greenfield 2	$4.89	53%	18%	19%	10%

Based on a hydrogen daily production rate of 600 tonnes/day the results of the evaluation indicate pricing for hydrogen in the range of \$4.89/kg and \$6.41/kg CAD. As seen in the table above the natural gas price is an influential part of the hydrogen production, accounting for 19% to 26% of the overall unit cost.

The recommended CO_2 storage area is a major contributor to the overall capital cost of the CCS portion of the project, due to its geographical location. The recommended offshore storage area requires a 450 - 600 km, 14" pipeline to transport CO_2 from the onshore hydrogen facility to a location offshore Newfoundland near the gas recovery site. One option to potentially recover some of this cost would be to pre-invest in a pipeline with additional capacity to transport and store CO_2 from other sources.

The cost of increasing the CO_2 transport and storage from approximately 2.0 million MTPA to 4.0 million MTPA (14" to 18" pipeline) was reviewed and would result in an incremental capital cost of approximately \$900M - \$1,000M. Additional infrastructure such as CO_2 temporary storage and establishing an import terminal would also have to be considered in the overall assessment depending on the potential sources of CO_2. A larger capacity CO_2 pipeline could support local projects (LNG, additional Hydrogen etc.) and industries (i.e. Come-By-Chance refinery, Holyrood power generation) in dealing with CO_2 emissions as well as the possibility of importing of CO_2 for storage, similar to the Northern Lights Project in Norway. With recent carbon taxation forecasts (\$170/tonne in 2030) and the associated national emissions reduction targets, this could be a viable option to help with emissions reduction. Further CO_2 storage market analysis/evaluation would have to be performed while considering the additional capital investment required.

15.3 Hydrogen Storage & Ammonia Production

With the limited domestic use for hydrogen within the province, and the predicted global demand for clean energy solutions, regional and international trade in hydrogen will become an important part of the overall development model for locally produced hydrogen. Newfoundland and Labrador has the natural resource base plus advantageous geographic features and location to fully participate in an international hydrogen fuel supply chain. The storage and transportation of large volumes of hydrogen is a developing industry. Currently the most developed and economic solution for hydrogen distribution is via pipeline. Due to our geographical location, an alternative for transporting mass produced hydrogen is conversion to ammonia. The ammonia industry is far more established and proven in the area of storage and transportation and ammonia can also be reconverted back to hydrogen for end use consumption.

The production of 1 tonne of ammonia requires approximately 177 kg of hydrogen. Therefore if 100% of the hydrogen were to be converted to ammonia it would result in approximately 3,390 tonnes/day or 1.24 million tonnes/year.

High level costs for ammonia conversion were calculated based on data established and published by the IEA (REF 15). It is estimated that the capital cost for converting 100% of the hydrogen produced to ammonia, establishing an export terminal with storage (35,000 tonnes), and purchasing 2 ships for transportation (26,000 tonnes/ship) would cost approximately $1.5 Billion CAD.

Additionally, Figure 15-1 below (REF 13) produced by the IEA compares the cost (USD/kg) of delivering hydrogen gas by pipeline as well as the liquid hydrogen, LOHC and ammonia by ship. Based on this information the cost per kg of H_2 would increase by approximately $1.60 CAD to convert to ammonia, transport by ship and re-convert to H_2 at a receiving terminal.

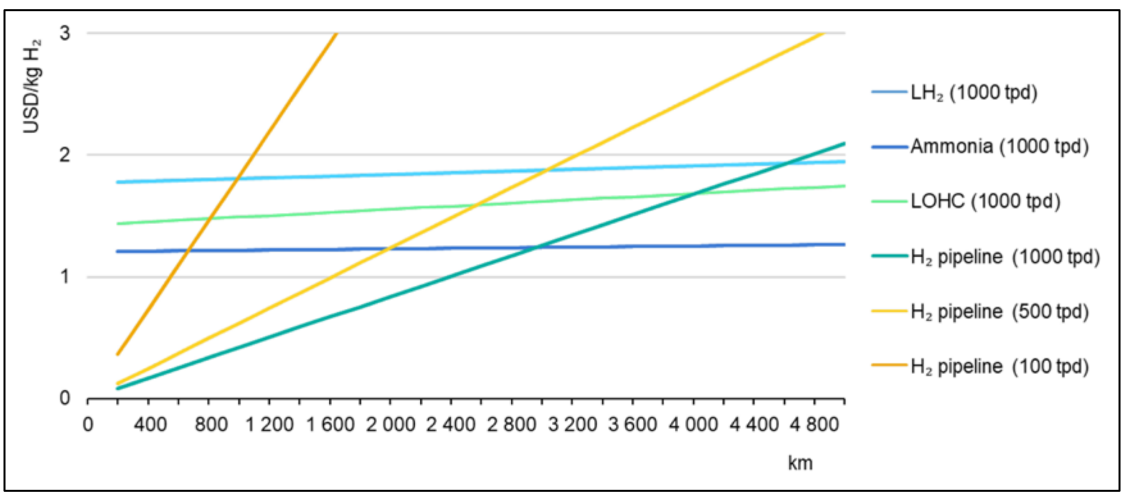


Figure 15-1: Costs of Delivering Hydrogen, 2030 IEA

Table Notes: GH2 = gaseous hydrogen. LH2 = liquefied hydrogen. LOHC = liquid organic hydrogen carrier, tpd = tonnes per day. Includes conversion, export terminal, shipping, import terminal and reconversion costs for each carrier system. Storage costs are included in import and export terminal expenses. The pipeline cost assumes construction of a new pipeline. Sources: Based on IAE (2016); Baufumé (2013).

15.4 NL Blue Hydrogen versus National/Global Hydrogen Production

Various publicly available sources of data for hydrogen production + CCUS indicate a range of unit production costs while providing little to no detail or explanation of how the values were calculated. Due to the number of variables and lack of detail, only high level comparisons are possible and a further in-depth analysis would have to performed to fully understand any differences in cost forecast.

The Hydrogen Strategy for Canada (HSC) - December 2020 (REF 16) compares bulk hydrogen production cost from different pathways from a range of international and Canadian studies. The report indicates the cost (year 2020 / 2030) for hydrogen produced using SMR + CCUS is in the range of approximately $1.00/kg to $4.10/kg CAD ($0.79/kg to $3.23/kg USD). Figure 15-2 below contained in the HSC compares hydrogen production pathway costs for 2020, 2030 and 2050.

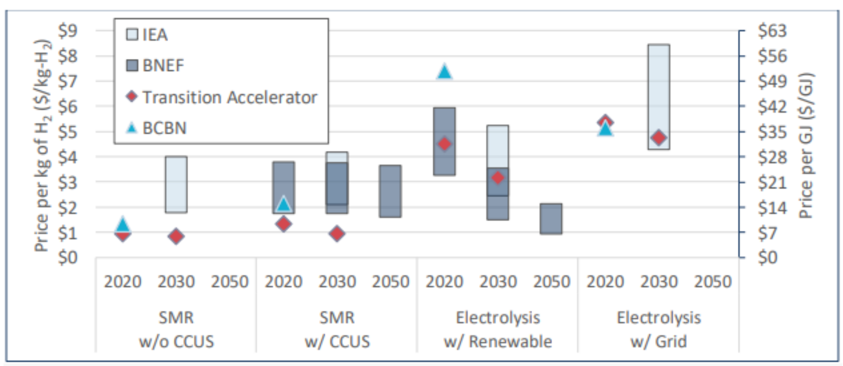


Figure 16 – Comparison of Hydrogen Production Pathway Costs 2020, 2030, and 2050[1,2,3,4]

[1] IEA. 2019. The Future of Hydrogen: Seizing Today's Opportunities.
[2] Asia Pacific Energy Research Centre, "Perspectives on Hydrogen in the APEC Region.pdf," Jun. 2018 [Online]. Available: https://aperc.ieej.or.jp/file/2018/9/12/Perspectives+on+Hydrogen+in+the+APEC+Region.pdf
[3] BCBN BC Hydrogen Study, Zen and the Art of Clean Energy Solutions Inc., 2019
[4] BloombergNEF: Hydrogen Economy Outlook, March 20, 2020,

Figure 15-2: Hydrogen Production pathway costs 2020, 2030 and 2050 (REF 16)

The IEA is a main source of publicly available data on hydrogen production + CCUS and indicates a levelized cost range of roughly $1.50/kg to $2.40 USD ($1.90 to $3.00 CAD/kg) for hydrogen produced from natural gas with CCUS. Figure 15-3 below published by the IEA (REF 14) compares hydrogen production costs using natural gas for various regions of the world. This chart shows a breakdown of cost into the three major categories: CAPEX, OPEX and Natural Gas.

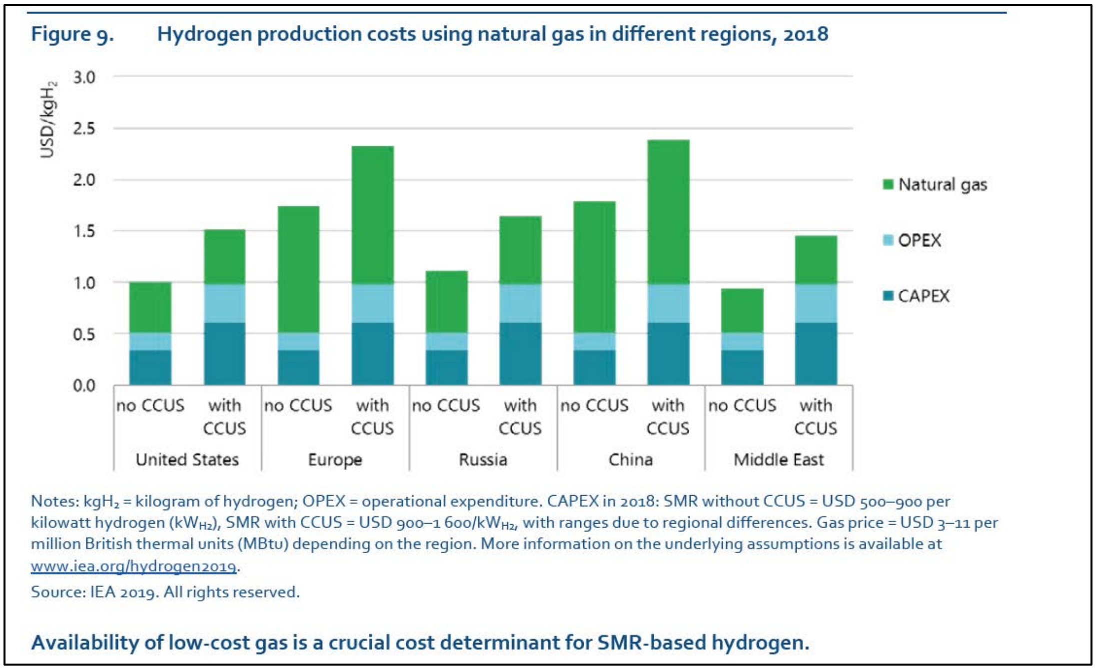


Figure 15-3: Hydrogen Production Costs in Different Regions

To compare NL blue hydrogen to the HSC and IEA values for hydrogen production from other regions, the levelized cost of NL blue hydrogen was re-calculated at a discount rate of 8%, consistent with IEA/HSC and the corporate tax was removed. The result is a levelized cost for hydrogen between \$3.92/kg and \$5.30/kg CAD. This equates to approximately \$3.09/kg to 4.17/kg USD. The levelized energy cost of hydrogen for the development options reviewed is summarized in Table 15-6 below and represented for both CAD and USD:

Table 15-6: Levelized Cost of NL Blue Hydrogen (Discount Rate 8%)

Development Option	Cost CAD$	Cost USD$
Brownfield	$5.30	$4.17
Greenfield 1	$4.30	$3.38
Greenfield 2	$3.92	$3.09

Figure 15-3 indicates that all regions have the same CAPEX ($0.61/kg USD) and OPEX ($0.37/kg USD) for hydrogen production with CCS. The natural gas cost is the one variable which differs in all regions and is between $0.54/kg and $1.40/kg USD. Figure 15-4 below shows the levelized cost breakdown for the hydrogen for the three options compared with the IEA and HSC values in USD.

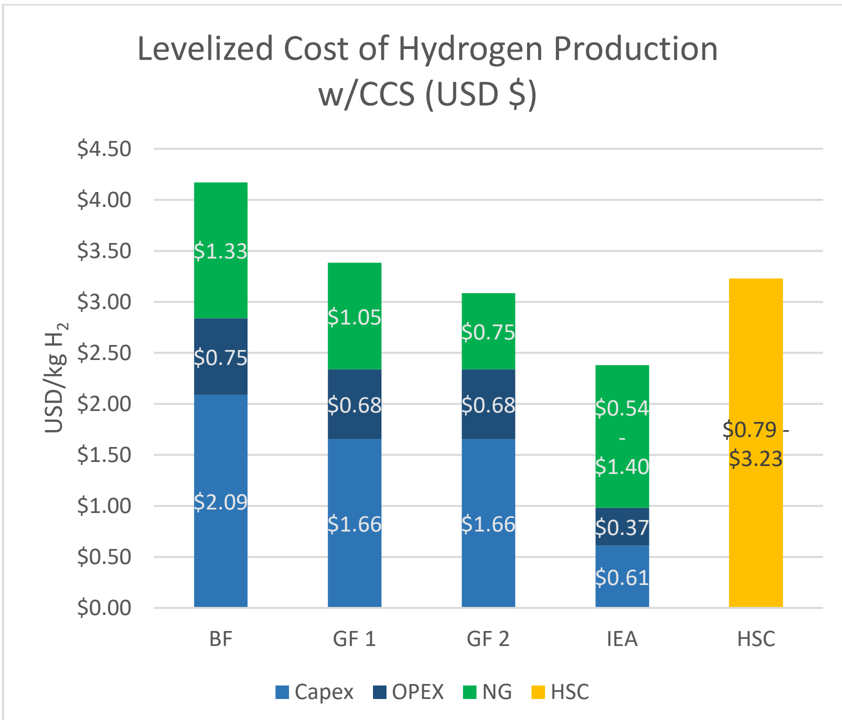


Figure 15-4: NL Blue Hydrogen vs IEA / HSC – Levelized Comparison – USD

High level observations indicate the levelized costs for locally produced hydrogen using offshore gas is above the range of hydrogen production costs published by the IEA but within range of the HSC values for the Greenfield options. Significant difference is seen in the CAPEX and OPEX values when comparing to the IEA values. The majority of this delta is most likely due to the geographical storage location of the CO_2 which requires significant infrastructure to transport CO_2 450-600km offshore NL. Overall the NG costs are within the range of the IEA published values, being higher than those seen in the United States, Middle East and Russia but below the values for Europe and China.

More detail and further analysis are needed to entirely understand how NL produced blue hydrogen compares to national and global blue hydrogen production. The data from all sources would have to be thoroughly reviewed and validated to fully understand the price deltas.

16 Downstream Hydrogen Value Chain Review

Hydrogen production, storage, transmission, handling, and consumption, as well as the manufacturing of the associated infrastructure, has many overlaps with existing industrial sectors, including the oil and gas industry. This provides a variety of options for an energy transition via hydrogen as many of the skills, jobs, infrastructure, assets, and businesses could be transferable (REF 3). Figure 16-1 below demonstrates the variety of possible blue hydrogen pathways that could exist, from feedstocks and inputs to storage options and end-uses.

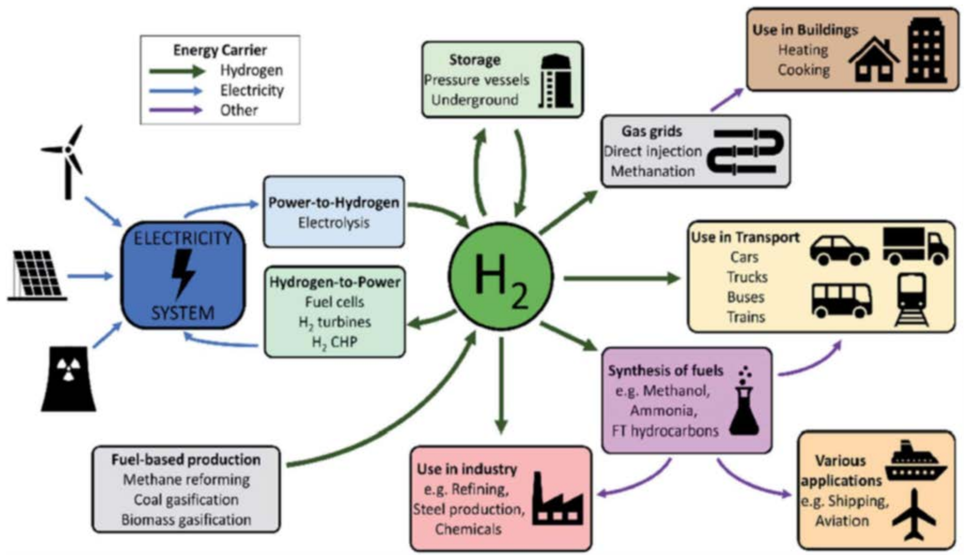


Figure 16-1: Potential Uses of Hydrogen

As shown, a wide variety of pathways are available for a blue hydrogen future. This means that a variety of technologies exist not only in production methods, but also storage, transmission, distribution, and possible end-uses. The following sections highlight the diversity of these technologies, as well as the potential end-use cases, and specifically speak to how this might come to fruition in Newfoundland and Labrador.

16.1 Storage, Transmission, and Distribution

Hydrogen's energy per unit mass is three times that of gasoline, however on a volume bases it is reversed; liquid hydrogen's energy density is roughly four times less than that of gasoline (REF https://www.energy.gov/eere/fuelcells/hydrogen-storage#:~:text=On%20a%20mass%20basis%2C%20hydrogen,44%20MJ%2Fkg%20for%20gasoline). As such, for hydrogen to become a competitive energy carrier in a low-carbon future, its energy density by volume must increase. This means that the same amount of hydrogen energy needs to occupy less space. This can be done in a variety of ways; the first set of transformations involve altering hydrogen's physical properties via compression or liquefaction (REF 3). Compression is one basis of hydrogen storage. Alternatively, hydrogen can be chemically converted into other intermediates, such as sorbents, metal hydrides, and liquid organic or chemical hydrogen (REF https://www.energy.gov/eere/fuelcells/hydrogen-storage).

Hydrogen conversion can be useful when there are supply-chain advantages, such as utilizing existing infrastructure, to meet an existing demand, and/or to improve the physical properties for easier storage and safer handling (REF 3). Table 16-1 (REF 3, REF 4) below demonstrates the different physical properties various hydrogen or hydrogen-derived mediums present, with details regarding the required infrastructure, conversions, and potential losses in the subsequent sections.

Table 16-1: Properties of Hydrogen in Various States

Medium	State	Operating Temperature (˚C)	Operating Pressure (MPa)	Energy Density (MJ/L)
Compressed Hydrogen	Gas	15 to 25	35 to 70	4.9
Cryo-Compressed Hydrogen	Supercritical Fluid	-240 to -200	50 to 100	4.0
Liquified Hydrogen	Liquid	-253	0.1 to 0.4	6.4
Ammonia	Liquid	-35 to 5	0.1 to 2.0	16.9
Methanol	Liquid	15 to 25	0.1	11.5
Liquid Organic Hydrogen Carriers	Liquid	15 to 25	0.1	7.0
Metal Hydrides	Liquid or Solid	15 to 25	0.1	13.2

In the following sections, it is critical to note that with each transformation or conversion discussed, there are energy losses, as well as infrastructure and energy requirements that play a role in its suitability for a specific use. As a result, the medium in which hydrogen is stored, transported, and distributed heavily relies on what its end-use will be, and where that end use is, since each medium presents a variety of strengths and weaknesses.

16.1.1 Compressed Gaseous Hydrogen

Compressed gaseous hydrogen is a form of physical storage that is widely adopted today. It involves passing hydrogen gas through a compressor to pressurize it anywhere from 350 bar to 700 barg. Various compressor technologies exist, including reciprocating, rotary, ionic, and centrifugal compressors (REF https://www.energy.gov/eere/fuelcells/gaseous-hydrogen-compression), with emerging compressor technologies such as metal hydride and electrochemical compressors also being explored (REF 3). Each compressor technology uses different techniques to compress the gas, resulting in different compression ratios (ratio of pressure at the outlet of the compressor over the pressure at the inlet) and throughput (rate of compression) (REF https://www.energy.gov/eere/fuelcells/gaseous-hydrogen-compression). Each compressor technology also has its own energy requirements to power the process. As such, the use of one type of compressor over another comes down to what the priorities are for a given application.

Upon compression, there are options on how hydrogen gas can be stored, such as pressure vessels or in geological formations. Pressure vessel storage utilizes specially designed high-pressure vessels, which have lower capital costs than other storage systems and are quicker to deploy and install (REF 5). Meanwhile, geological formations are among the most commonly used natural gas storage techniques and could be modified to accommodate hydrogen storage by plugging microporous spaces to decrease hydrogen depletion and losses (REF 6). This storage method involves boring a hole down to storage depths and using solution mining techniques to dissolve the salt to extract, and replacing it with gaseous hydrogen (REF 6). This is an area requiring further research in Newfoundland and Labrador, but has the potential to offer bulk gaseous hydrogen storage that does not comprise the same terrestrial footprint as storage vessels since it is underground.

If hydrogen end-use requires transport, compressed hydrogen gas can be distributed using pipelines, compressed gas ships, or tube-trailer trucks, each presenting their own strengths and weaknesses. For example, pipeline distribution is a cost-effective method for high-volume compressed hydrogen gas transmission due to its low operational costs and long lifespan (REF 7). This is especially appealing in jurisdictions that have existing natural gas pipeline infrastructure that can be repurposed for hydrogen gas or used in a blended network with natural gas (REF 3). Limitations with hydrogen pipelines include their capital cost, which are more expensive than natural gas pipelines due to hydrogen-specific welds required to reduce leaking and specific pipe materials needed to minimize hydrogen embrittlement effects, and that as distance increases so does the capital cost. Tube-trailers, however, offer distribution options for local-end use, such as fueling hydrogen-powered vehicles, but can be limited by safety and regulatory limits with respect to the weight of transported hydrogen (REF 3). Compressed gas carriers provide an opportunity to distribute to international markets, especially considering the deep waters of Placentia Bay, NL. However, multiple ships would need to be dedicated to round-the-clock hydrogen service.

In terms of the hydrogen storage, which is required as a buffer for the compressed gas shipping option, opportunities exist in exploring composite materials for the high-pressure vessels, which are typically made from steel, to reduce weight limitations (REF 5).

16.1.2 Liquid Hydrogen

Liquid hydrogen, also known as cryogenic hydrogen, is achieved by cooling hydrogen to -253˚C, with highly insulated storage vessels used to store the hydrogen afterwards (REF https://www.sciencedirect.com/topics/engineering/cryo-compressed-hydrogen). Liquid hydrogen, as noted in Table 16-1 above, has a better energy density than that of compressed hydrogen, meaning it can yield the same power output while occupying less space, making it more ideal for long-haul transmission, especially in scenarios where weight and volume optimization is key. This includes in liquefied tanker trucks, or in a similar fashion to liquid natural gas (LNG), liquefied carriers (REF https://global.kawasaki.com/en/hydrogen/#:~:text=Kawasaki%20will%20introduce%20the%20world's,first%20LNG%20carrier%20in%201981.). The world's first large international shipment of liquefied hydrogen, in the Suiso Frontier developed by Kawasaki Heavy Industries, left an Australian port the evening of January 28, 2022, and aims to demonstrate the future of liquefied hydrogen shipping transport in the hydrogen supply-chain (REF https://www.maritime-executive.com/article/suiso-frontier-departs-australia-with-first-liquid-hydrogen-shipment). A major issue with liquid hydrogen is the boil-off effect. Since the liquid hydrogen is stored at cryogenic temperatures, any localized warming above the -253 C storage temperature will result in some of the hydrogen changing to the gas phase. This effect is more pronounced in smaller tanks with higher surface-to-volume ratios (REF https://www.energy.gov/eere/fuelcells/liquid-hydrogen-delivery), and further contributes to losses. An opportunity with the boil-off effect is for it to be recovered and stored in gaseous form, minimizing losses, or to use the boil-off gas as fuel for the carrier ship, assuming it has hydrogen fuel compatibility (REF 3).

16.1.3 Cryo-Compressed Hydrogen

Cryo-compressed hydrogen is a combination of compressed and cryogenic hydrogen, and it requires pressurized hydrogen stored at extremely low temperatures (REF https://www.sciencedirect.com/topics/engineering/cryo-compressed-hydrogen). Combining attributes aims to improve on the disadvantages of both compressed and liquid hydrogen transport and storage, specifically compressed hydrogen's high volumes and compression requirements, and to minimize the boil-off effect of liquid hydrogen (https://www.sciencedirect.com/topics/engineering/cryo-compressed-hydrogen). The cryo-compressed hydrogen state is achieved using a cryo-compressor, and specialized storage vessels that are extremely well insulated, that are also capable of being pressurized. Studies are showing that this option for hydrogen storage offers feasible costs, and scales well (REF 4). Similar to compressed and liquid hydrogen, once in storage vessels, cryo-compressed hydrogen can be used in stationary storage applications, or in mobile applications via cryo-compressed tanker trucks, or carrier tankers (REF 3).

16.1.4 Methanol

While hydrogen can have its physical properties altered (compressed, liquefied, or cryo-compressed), it can also be chemically converted into other intermediates, such as methanol. In simple terms, methanol (CH_3OH) (REF https://www.methanol.org/about-methanol/) is created by combining hydrogen and carbon dioxide, with the carbon dioxide originating from a variety of places, including the atmosphere (REF https://www.blue.world/renewable-methanol/). Once methanol is formed, it can be stored in tanks, and can be transported and distributed like other liquid fuels, via tanker trucks or carrier ships. Methanol storage is easy and stable given its liquid state in ambient conditions, making transport affordable and with negligible losses. For example, its storage and transport can be estimated to have an efficiency of 95%. Additionally, there are a lot of opportunities that exist when hydrogen is converted to methanol; methanol is already a widely used feedstock (formaldehyde, acetic acid, propene, etc.), meaning existing production, storage and distribution technologies and pathways can be utilized (REF https://www.blue.world/renewable-methanol/). Also, it can be integrated into existing infrastructure with minor modifications, meaning that converting the methanol back to hydrogen is not always necessary, instead, methanol itself can be the end-use fuel. Methanol fuel adoption is becoming more common across the globe, as seen by Maersk's purchase of 12 methanol-fueled container vessels. One factor to be accounted for in methanol use is its carbon content, resulting in some carbon emissions when burned.

16.1.5 Ammonia

Ammonia, like methanol, is another chemical intermediate, or end-use fuel option for a hydrogen economy. Ammonia is the most developed long-distance hydrogen transmission medium, with numerous routes in operation (REF 7). Like methanol, ammonia (NH_3) can be formulated by combining hydrogen (H_2) with an existing atmospheric gas, nitrogen (N_2) through the Haber-Bosch process (REF 3), which is relatively cheap and efficient, although losses are expected. The same is also true for the dehydrogenation process, if hydrogen is the targeted end-use, with a resulting yield of 0.176 tonnes-H2/tonne-NH3 (REF 7). Ammonia also has an existing market as a product (chemical fertilizer, refrigerant gas, etc.), and is also being explored as a fuel itself, with specific applicability in the marine sector (REF https://www.rechargenews.com/energy-transition/more-than-85-of-export-oriented-low-carbon-hydrogen-projects-plan-to-ship-ammonia-not-h2/2-1-1144059), potentially removing the need for converting back to hydrogen, minimizing the associated inefficiencies. This means existing means of ammonia storage, transport, and distribution exist and can be capitalized on, whether ammonia is to be used as a hydrogen carrier, or as a fuel. However, it is important to mention ammonia's drawbacks, which include it being treated as a toxic chemical requiring regulation due to the risk of potential spillage, as well as its high ignition point and the release of nitrous oxides when burning (REF https://www.rechargenews.com/energy-transition/more-than-85-of-export-oriented-low-carbon-hydrogen-projects-plan-to-ship-ammonia-not-h2/2-1-1144059). While there is no carbon in ammonia, and inherently is not released when burned, nitrogen oxides are estimated to have a global warming potential that is 265+ times that of carbon dioxide (https://www.epa.gov/ghgemissions/understanding-global-warming-potentials#:~:text=Nitrous%20Oxide%20(N2O,than%20100%20years%2C%20on%20average.). Despite its drawbacks though, ammonia is integrated into approximately 85% of all the hydrogen export market capacity across the globe (REF https://www.rechargenews.com/energy-transition/more-than-85-of-export-oriented-low-carbon-hydrogen-projects-plan-to-ship-ammonia-not-h2/2-1-1144059).

16.1.6 Liquid Organic Hydrogen Carriers

Liquid organic hydrogen carriers (LOHC) are additional hydrogen intermediates that can be used for better storage and transport properties. LOHCs are organic compounds in liquid or semi-solid state that store hydrogen through catalytic hydrogenation and dehydrogenation processes (REF 8). An example of this is hydrogen that is reacted with toluene to form the LOHC methylcyclohexane (MCH), a liquid at ambient temperatures and pressures that provides easy storage and transport using existing fuel infrastructure with minimal losses for long-term storage (REF https://www.csiro.au/en/work-with-us/ip-commercialisation/hydrogen-technology-marketplace/lohc-toluene-methylcyclohexane). Drawbacks specifically to MCH include the high temperatures required for hydrogenation and dehydrogenation, and that toluene and MCH are both toxic substances. In comparison to the previously mentioned mediums for hydrogen storage, LOHC still remains to be in the research and development stage, with only small prototypes being explored globally, but with improvements may prove to be a strong storage medium due to its improved handling capabilities (REF 3).

16.1.7 Metal Hydrides

An emerging means of hydrogen storage, with one of the best energy density characteristics, is metal hydride storage. Metal hydrides are formed when hydrogen bond with metal atoms, which result in stable, liquid or solid-state, compounds (REF 3). While this method of hydrogen storage is among the least developed, it offers a wide range of opportunities that are currently studied today, including improving hydrogen storage density, adsorption and absorption kinetics, and overarching process efficiencies (REF https://www.energy.gov/eere/fuelcells/metal-hydride-storage-materials). With improvements in these areas, and as research and adoption continue to develop, metal hydrides can become a key component to hydrogen storage and transport, especially in road/terrestrial distribution (REF 5).

16.2 Hydrogen Utilization

There has been a major increase in both interest and investment in hydrogen in recent years, with 30 countries releasing hydrogen roadmaps and a worldwide government investment of $70 billion USD in public funding [REF 9]. For countries with ambitious carbon emission reductions targets (for example, Canada has committed to net-zero by 2050), hydrogen is a potential pathway towards reducing emissions in hard-to-abate sectors, such as heavy industries with huge energy needs to process heat from burning fossil fuels, or electrification of grids with few carbon neutral options. Hydrogen provides a solution to both challenges since it has the versatility to be stored, shipped and consumed as a high energy fuel with the benefit of low carbon intensity, or reconverted to electricity in a fuel cell. Hydrogen can also replace grey hydrogen as a feedstock in industrial processes, further penetrating the heavy industry market with clean fuel. In short, hydrogen's potential, while not yet fully realized, is undeniable and will serve as a key player in global decarbonization efforts.

Newfoundland and Labrador, with its abundance of resource potential and geographic location on the eastern North American seaboard, is well-positioned to participate in the global trade of hydrogen. While domestic use will be limited (this will be discussed later in this section), there is a significant opportunity to export. The following section will highlight some of the utilization options for hydrogen produced in NL. The section is not exhaustive; further study of hydrogen export strategy from NL is recommended as an overall view of all hydrogen supply chains. Export strategies will focus on marine transportation and transshipment and will touch on the predominant options: liquid hydrogen, ammonia, liquid organic hydrogen, and methanol as a possible marine fuel. Please note that the cost-optimal solution depends on the targeted end-use, with deciding factors including fuel-type requirements, the need for reconversion, and purity requirements.

16.2.1 Domestic Use

There is limited infrastructure in NL associated with the use of hydrogen or natural gas for domestic use. There is no natural gas pipeline network in the province; the only significant use of natural gas as an energy source is in the offshore oil and gas sector for facility power generation.

NL has had very little domestic production and utilization of hydrogen and has seen near-term decline of its use in those facilities. The Come-By-Chance refinery produces hydrogen for its processes through SMR reformation; the facility has since been rebranded as Braya Renewable Fuels and will continue to produce hydrogen to support production of low-emission fuels for the aviation and long-haul trucking industry.

[REF https://markets.businessinsider.com/news/stocks/come-by-chance-refinery-now-braya-renewable-fuels-introduces-new-executive-team-1031177953].

The Ramea Wind-Hydrogen-Diesel system used hydrogen created from wind energy as a fuel in an off-grid electricity application but has since been decommissioned. The project, implemented in 2009, did not operate as intended, encountering technical issues associated with the combustion of hydrogen and sizing/efficiency issues with the existing diesel plant.

Aside from the two applications above, there are no other significant users of hydrogen within the province.

The Canada Energy Regulator publishes energy futures data based on energy end-uses [REF 10]. Figure 16-2 illustrates the energy trends in NL from 2022 to 2050 by major energy sources under an Evolving Policies Scenario. The Evolving Policies Scenario assumes the implementation of policy making and action that will reduce emissions from the energy system at a pace that will meet federal emissions targets.

At first glance, the first most notable trend is an overall projected decrease in energy consumption in the province. There are multiple contributors to this trend, including the electrification of light-vehicle transportation (and the resulting efficiencies), the carbon abatement of offshore oil & gas production, and a general decrease in the population of Newfoundland and Labrador. The Newfoundland and Labrador population dropped by 1.8% from 2016-2021, most notably in the rural areas of the province [REF https://census.gc.ca/census-recensement/index-eng.cfm].

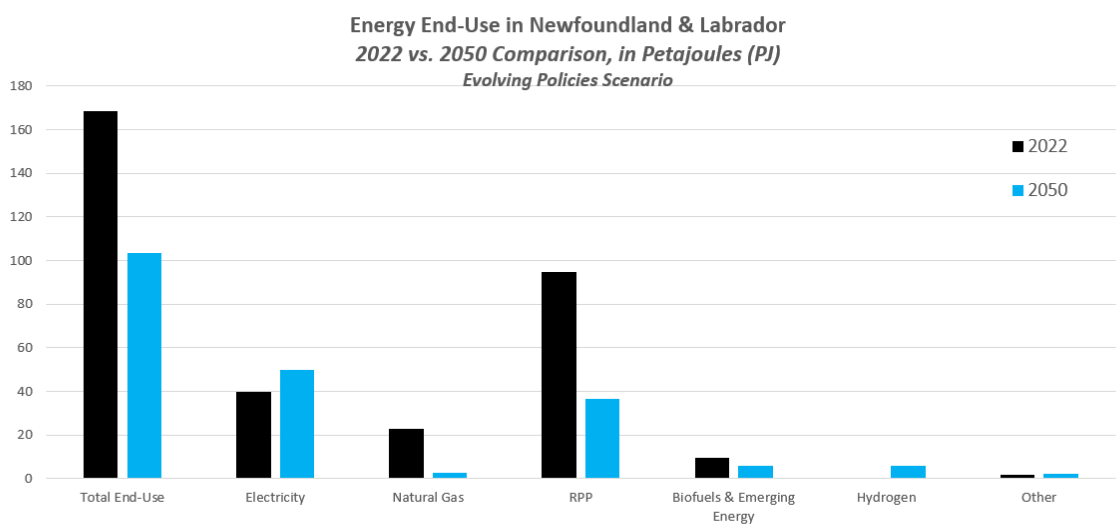


Figure 16-2: Energy Use in NL

Hydrogen utilization in Newfoundland and Labrador is expected to increase by 6% of total energy usage from 2022 to 2050 under the Evolving Policies Scenario. With the expected growth of the mining sector and corresponding increase in utilization of medium-heavy duty vehicles, this is likely the focus area for domestic growth of hydrogen.

16.2.2 Regional Use – Export to the Maritimes

While the growth in domestic demand for hydrogen in Newfoundland and Labrador is modest, this is not the case for both forecasted regional and national demand. Previous studies of hydrogen potential in the Maritimes [REF 6] showed that hydrogen has the potential to deliver up to 22% of end-use energy demand in the region by 2050, which could be in-large part supplied by Newfoundland and Labrador. In the Evolving Policies Scenario, demand for hydrogen in the Maritimes is expected to increase to 1,790 tonnes per day [REF 6]; this represents a close proximity, high-value opportunity for Newfoundland and Labrador hydrogen. Note that the 250 mmscfd plant proposed for this study represents only 600 tonnes per day.

There is extensive natural gas pipeline infrastructure in the Atlantic Canadian region that connects the Maritimes to Northeast United States market; this would be a logical connection point to both Canadian and American markets for Newfoundland and Labrador hydrogen output. Figure 16-3 provides an overview of the current pipeline infrastructure in the Maritimes.

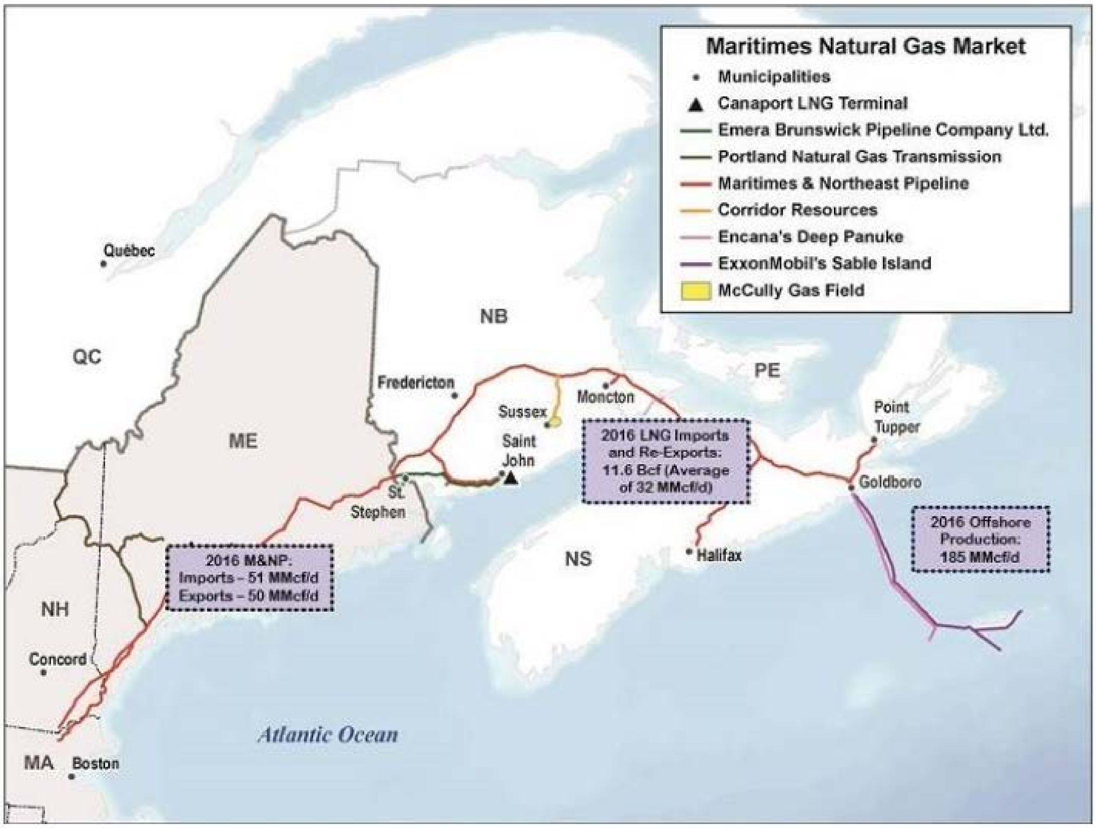


Figure 16-3: Maritime Natural Gas Pipelines

The Saint John LNG terminal, approximately 1,520 km from Arnold's Cove, NL, has been the main source of regional natural gas input in the Maritimes since the decommissioning of gas fields off the Nova Scotia coast. The terminal has a maximum send out capacity of 1.2 billion cubic feet or 28 million cubic metres of natural gas per day and is equipped to regasify imported LNG and supply the region via the Maritimes and Northeast pipeline [REF www.saintjohnlng.com]. The capacity of the facility should be able to accommodate the entire volume of hydrogen produced from offshore NL natural gas, assuming that the facility could be adapted to regasify and mix hydrogen in the pipeline network. Further study would be required but remains a regional opportunity for hydrogen utilization.

From a transportation perspective, the 1,520 km distance may challenge the economic threshold for a subsea pipeline. An in-depth analysis of this option is beyond the scope of this study; however, further study of regional hydrogen export strategy is recommended. It should be noted that there are inherent advantages of regional pipeline infrastructure, especially in scenarios with access to long term, carbon neutral energy supplies. Compared to electrical transmission lines, pipelines can transmit 10 times the energy at 1/8th the cost [REF 9]. They also serve as both a transmission and storage solution for energy.

Marine shipment from Arnold's Cove, NL to Saint John, NB via liquified hydrogen is a viable option for regional transshipment, as well, especially since regasification is already a function of their receiving facility. Figure 16-4 depicts the Suiso Frontier, the first liquified hydrogen carrier; the vessel is designed to transport 1,250 m^3 of liquid hydrogen over a 9,000 km journey from Australia to Japan. While this is slightly undersized for anticipated outputs from NL blue hydrogen production as described in this study, size and capacity of future carriers are expected to increase to 160,000 m^3 of liquid hydrogen as a part of the future global hydrogen supply chain network (REF 11).

Figure 16-4: Suiso Frontier Hydrogen Carrier

16.2.3 Regional Use – Marine Clean Fuel Hub

Newfoundland and Labrador's geographic position is not only advantageous from a proximity to European market perspective, but is also in strategic proximity to major marine traffic between North American and European markets. Many commercial ships pass by Newfoundland and Labrador daily, predominantly on-route to the St. Lawrence Seaway and major ports in the Northeast United States [REF www.dfo-mpo.gc.ca/oceans/publications/nfld-atlas-tnl/page07-eng.html#traffic]. This strategic position presents marine refueling using clean fuels as a possible use and opportunity for Newfoundland and Labrador hydrogen.

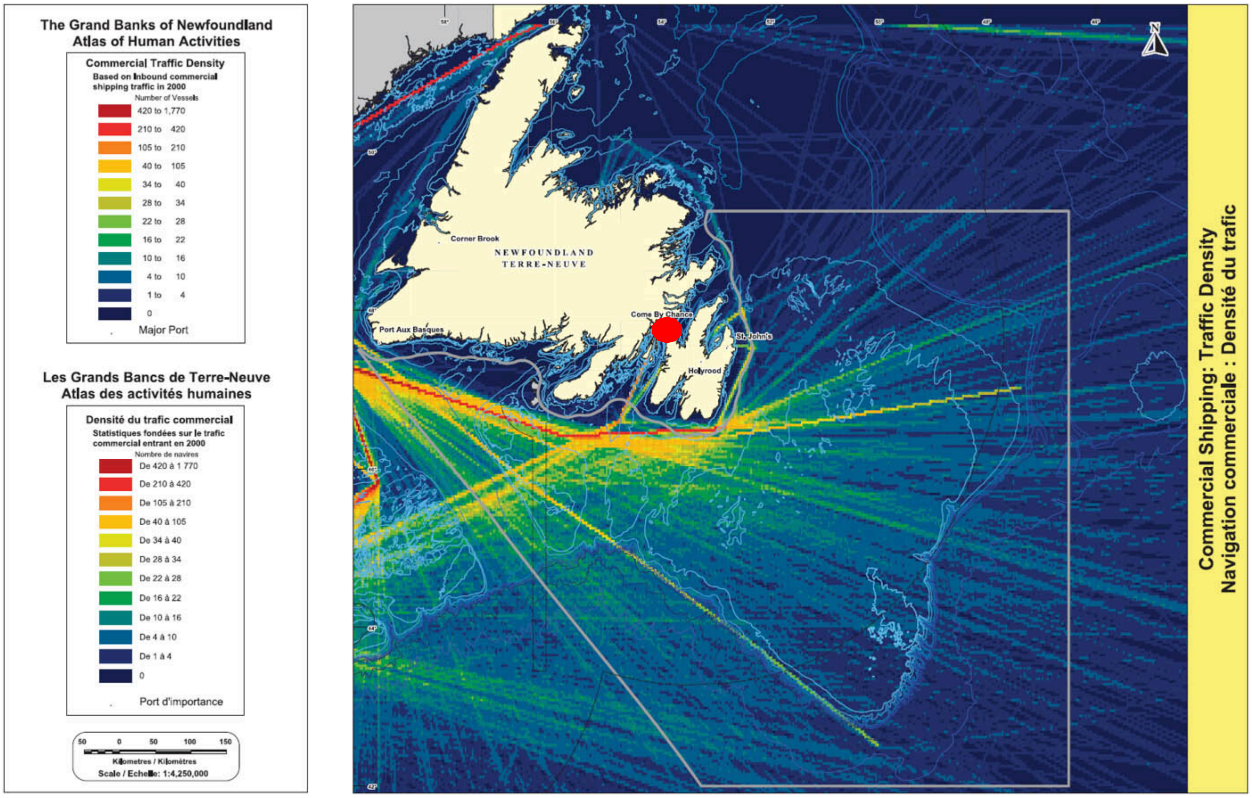


Figure 16-5: Commercial Shipping Density Map

There is a growing interest in the shipping industry to find low emission fuel sources. Danish firm Maersk recently announced an order of eight large ocean-going vessels that will have the ability to run on carbon-neutral methanol through employing liquid gas injection. As a true transition-era measure, Maersk's ships will be able to run on both traditional marine fuels and methanol; this is to mitigate against the supply risk associated with sourcing a regular and reliable supply of methanol. Methanol is another potential hydrogen derivative that can be used as a carrier, as well as a clean fuel. However, because of its carbon content, it should be noted that there are some carbon emissions associated with methanol as a fuel, although the emissions are significantly lower than traditional marine fuels. The greatest advantage of this approach, and likely a key part of Maersk's decision making, is that it utilizes the same well-known, operated and maintained engines with only slight modifications. Bunkering standards for methanol are virtually identical for traditional marine fuels, so most of the business operations remain the same.

Sourcing and supply of a large, consistent methanol source that can service the fleet remains one of the key risks. This presents an opportunity for further study and exploration in Newfoundland and Labrador. Blue hydrogen is an ideal fit for methanol production since both hydrogen and carbon dioxide, two key components of the process, are included in the process.

16.2.4 International Use – Export to European Markets

Newfoundland and Labrador's proposed hydrogen ports are within 4,500 km of Rotterdam and other major European ports. Europe is considered one of the strongest markets for hydrogen; hydrogen demand in Europe alone is expected to reach 45 million MTPA by 2050 [REF 12]. Marine shipment distances from NL are competitive with other regions vying to supply Europe with hydrogen, including Asia, the Middle East and Iceland. In short, with a rich supply of blue hydrogen, there is a major opportunity to supply the European market. The scale of this opportunity is significant; as noted in [REF 6], capturing as little as 5% of the European hydrogen market is a $9 Billion annual opportunity (8,000 tonnes H_2/day at $3/kg H_2).

Transporting energy over long trade routes between Canada and Europe is easier and more cost-effective as a chemical fuel. Transportation of chemical fuels is beneficial due to their higher energy density, reduced losses during transport, and ability to provide direct transmission throughout wide-scale networks. For that reason, it is likely that two methods of shipment will be preferred from Newfoundland and Labrador to European markets: Ammonia and Liquid Organic Hydrogen Carriers (LOHC).

Ammonia is by far the most mature and developed market for hydrogen in the world today. The existing market for ammonia is currently 180 million MTPA, largely driven by its use in fertilizers and production of derivatives, such as urea [REF 9]. At present, most of the hydrogen supply via ammonia is produced using SMR methods without carbon capture, so decarbonization of this industry alone will have a significant impact on global carbon emissions.

Ammonia's energy density allows for efficient marine transportation of hydrogen. With a relatively high boiling point temperature compared to liquid hydrogen, boil off is not a major concern. Using ammonia in liquid form at relatively low pressures has the advantage of an energy density 1.5 times that of liquefied hydrogen, therefore, requires far fewer ships to transport the same amount of energy. Ammonia is versatile; it can be used as a fuel in its current state, or it can be converted back to hydrogen through a dehydrogenation process. The latter results in some loss in energy efficiency and increased cost of supply, but still remains a viable option over long shipping routes.

With the interest in the expanded role of hydrogen as an energy storage and delivery solution, there's been increased interest in pursuing various uses for the fuel. Nuclear-averse nations, such as Japan and Germany, are particularly keen on using ammonia in power generation, while South Korea has announced plans to blend ammonia into its thermal plants. Research on the potential generation and use of ammonia for powering off-grid facilities, such as offshore oil and gas facilities, have garnered increased research interest.

Ammonia may also play a role in marine transport. Manufacturers, such as Wartsila, are experimenting with ammonia as a marine fuel, developing internal combustion engines for ships to run on dual fuel, similar to Maersk's methanol approach. Coupled with the lower energy required to produce ammonia and the ability to burn ammonia without carbon emissions, this makes ammonia a viable hydrogen-based fuel for marine applications. Management of the associated NOx emissions when ammonia used as a fuel would need to be fully considered as well from a CO_2(eq) emissions perspective.

As stated previously, chemical storage of hydrogen provides a means of overcoming the low temperature/high pressure requirements for shipment of hydrogen to a practical degree. Significant research in finding new chemical pathways for shipping hydrogen have been prevalent, including research on using Liquid Organic Hydrogen Carriers (LOHC) for hydrogen use.

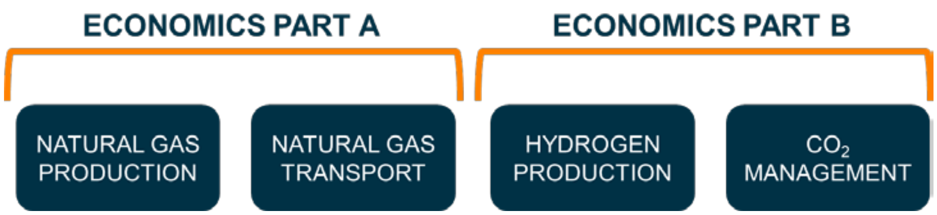
LOHCs are easily transported chemical compounds that can be reversibly hydrogenated. Hydrogen is chemically bound to liquid compounds so that it can be transported at atmospheric pressure like many other diesel-like substances. One of the biggest advantages of LOHC is that any equipment or infrastructure designed for storage of diesel can be easily retrofitted to handle other organics. One noteworthy advantage from a Canadian perspective is that LOHCs behave like diesel in cold climates, so are adaptable to all regional / environmental settings. For these reasons, LOHC can be transported and stored for a multitude of applications including off-grid and offshore. Research into many uses of LOHCs as an energy source are ongoing.

One of the key drawbacks of LOHCs is that high temperatures are required for the dehydrogenation process, which significantly increases the supply costs. Generally speaking, LOHC requires a fairly large scale production to make economic sense, which would apply to the scenario studied in this report.

In summary, there are multiple supply options for both regional and international export scenarios. Further study is required and should incorporate a broad Newfoundland and Labrador strategic view of hydrogen export.

17 Study Output Analysis

This study performed a cross-section analysis of blue hydrogen production utilizing Newfoundland and Labrador offshore natural gas resources. This was a complex analysis that explored the technical considerations of the elements best depicted by the following:



The following are key highlights from the study output:

- The technical elements of the blue hydrogen developments contained in this report are established and operational in various regions and are not dependent on significant technology development
- Blue hydrogen price is heavily influenced by the feed natural gas price where NL appears on the competitive end of the IEA range with the Greenfield natural gas source
- The CAPEX / OPEX component of the NL scenarios is higher than this component for the IEA regional data however the IEA data shows the same CAPEX / OPEX across all regions - this should be better understood before considering a direct comparison
- The Royalties / Taxes portion of the derived natural gas price is significant (24-28%) and should be reviewed for opportunities to increase competitiveness of both the natural gas sales as well as the associated blue hydrogen cost
- Coordination of a blue hydrogen development should maximize synergy and cooperation benefits that can be assembled through strategic port, industrial, refining, and government partnerships
- The scale of blue hydrogen production potential utilizing NL natural gas resources is significant and warrants investigating NL participation and placement within an international supply hub system
- The IEA coordinated Hydrogen Initiative within the Clean Energy Ministerial (of which Canada is a participant) includes a Global Ports Hydrogen Initiative where a development of this potential could be addressed (www.cleanenergyministerial.org/initiatives-campaigns/hydrogen-initiative/)
- Both the natural gas and hydrogen production aspects of the developments considered in this report could support recent Canada / Germany and Canada / Netherlands announcements related to energy cooperation

18 Go-Forward Recommendations

This concept feasibility study took a comprehensive view of four large scale development elements indicated above (natural gas production, natural gas transport, hydrogen production and CO_2 management).

The following areas emerged as clear candidates for subsequent review to further evaluate the associated opportunities and challenges:

- Structured technical and economic review of the downstream hydrogen value chain to further develop the overall value proposition for NL blue hydrogen production
- Technical and economic review of the power consumption requirements and power supply potential associated with a blue hydrogen development to recommend an optimized approach
- Asset specific cooperation to better optimize synergy and mutual benefit considerations in a development of this scale
- Broader lens study of the potential that delivering NL natural gas to shore provides from an economic and emissions reduction potential when employed for domestic and export use (i.e. study opportunities for NL supplied natural gas to displace existing higher emitting fuel sources at a regional, national, and international level)
- Study of the additional economic and emissions reduction opportunity that third party CO_2 compression and permanent storage could provide considering the CO_2 storage infrastructure associated with a blue hydrogen development
- Scope specific study of the CO_2 transport and storage elements explored in this study to optimize and better understand that component
- Follow-up concept study focused on technical and economic optimization opportunities (i.e. narrowed list of development concepts, application of potential government incentives, etc.)

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9) Hydrogen Insights: A perspective on hydrogen investment, market development and cost competitiveness, February 2021
10) Canada's Energy Future 2021
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13) IEA - Global Hydrogen Review - 2021
14) IEA – The Future of Hydrogen – 2019
15) IEA – Global Hydrogen Review – 2021 - Assumptions Annex
16) Natural Resources Canada – Hydrogen Strategy for Canada
17) Newfoundland and Labrador Hydro – Schedule of Rates, Rules, and Regulations (estimate based on 2021 document utilizing Industrial – Firm rates)
18) Feasibility Study of Hydrogen Production, Storage, Distribution, and Use in Newfoundland & Labrador

Appendix A – C-CORE Pipeline Route Study

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Blue Hydrogen & CCUS Feasibility Study – Pipeline Route Study

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Project Team

Tony King (Project Manager)

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Aker Solutions Canada Inc.	Steve Penton	1 (pdf File)

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Iceberg contact rates were assessed for pipelines from a landfall in Trinity Bay to the West Orphan Basin (Cape Freels) and the Come by Chance Refinery in Placentia Bay to the Jeanne d'Arc (Balicatters). Contact rates were estimated for the scenario of minimal pipeline burial (pipe crown flush with the seabed) and the pipe laid on the seabed. The analysis used output from a Monte Carlo iceberg contact model. The iceberg risk analysis indicates no iceberg risk for the selected 425.9 km pipeline route from the Trinity Bay landfall to the West Orphan Basin. The low risk is due to the deep water along the route. The 605.4 km pipeline route from the Come by Chance Refinery to the Jeanne d'Arc (Ballicaters) has annual iceberg contact rates of 0.0065 yr^{-1} and 0.065 yr^{-1} (154 and 15.4 year return periods) for a pipeline with minimal burial and laid on the seabed, respectively. If ice management activities conducted in the Jeanne d'Arc for support of production facilities are considered, these contact rates are halved. Recommended work include seabed surveys and investigations along the selected routes, as well as data collection for further development of the Monte Carlo iceberg contact model. Additional assessment of ice management for reduction of iceberg risk may also yield benefits.

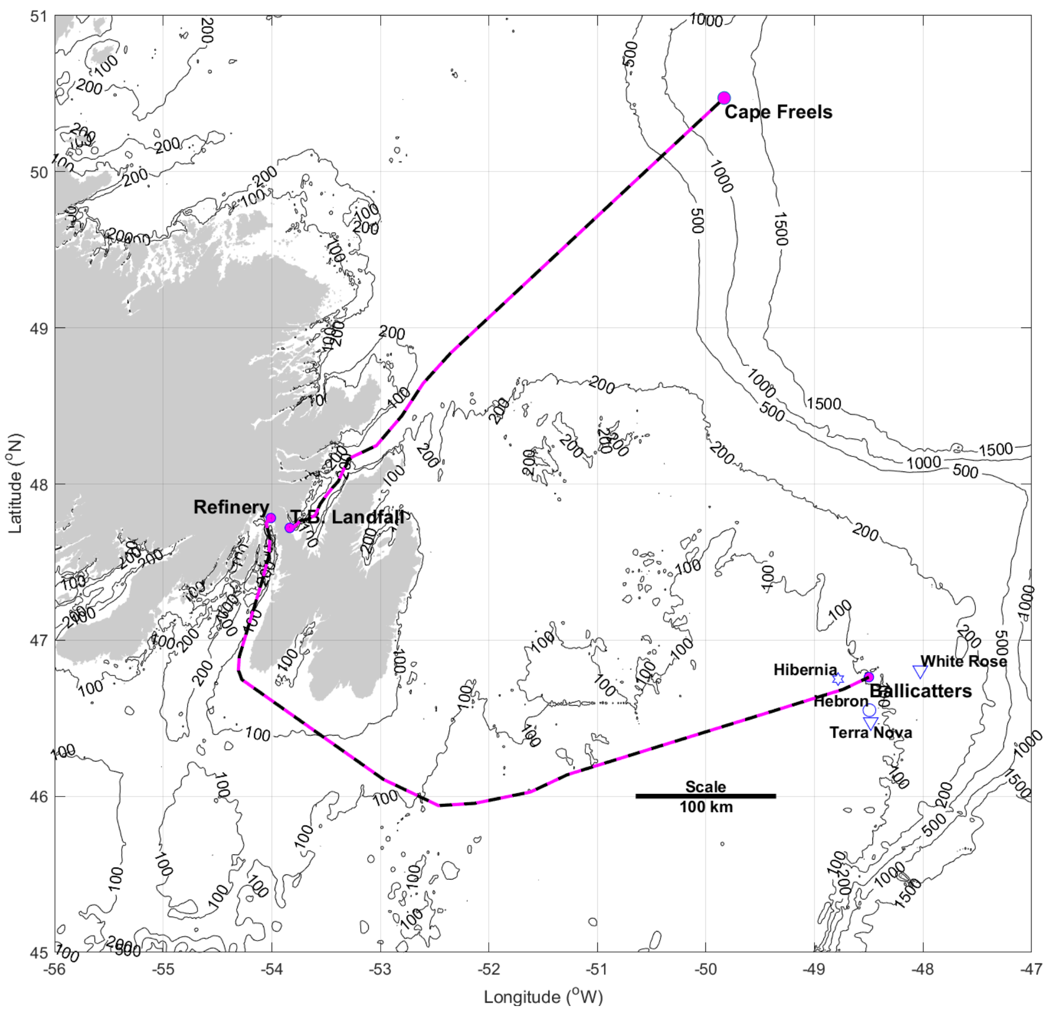

Figure 1. Selected pipeline routes

1 Introduction

1.1 Background

The pipeline routing study presented here was prepared to support Aker Solutions' Blue Hydrogen & CCUS Feasibility Study. Two pipeline routes are considered, connecting the Come by Chance oil refinery and:

- the West Orphan Basin; and
- the Jeanne d'Arc Basin.

The West Orphan Basin pipeline landfall in Trinity Bay is assumed to be the same as was used for the cable iceberg risk analysis for the Aker Solution FPSO Electrification study (C-CORE, 2020) and for the analysis presented here will terminate at the Cape Freels (Ephesus) prospect in the Orphan Basin. The Jeanne d'Arc pipeline route starts at the Come by Chance refinery and is assumed to end at the Ballicatter wellsite.

1.2 Objectives

The objective is to select the two pipeline routes and estimate iceberg contact rates for the case of minimal pipeline burial (pipeline crown flush with seabed) and the pipeline laid on the seabed.

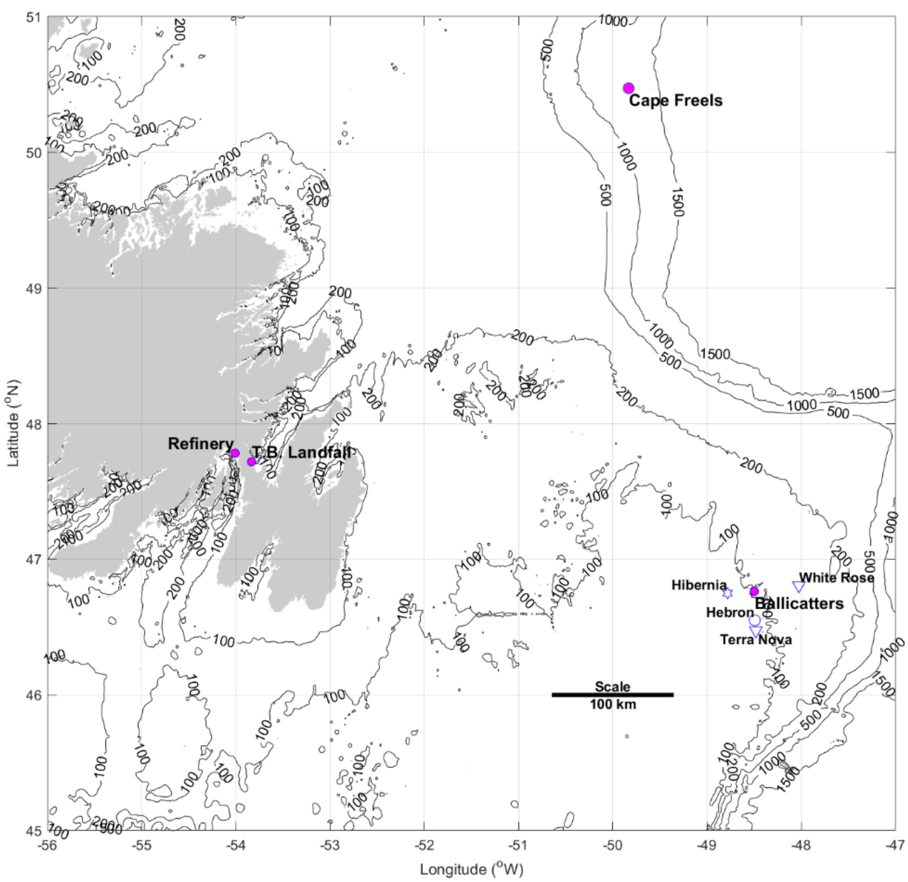

Figure 1. Proposed pipeline routes start and end points

2 Methodology

2.1 Iceberg Contact Model

The iceberg risk analysis uses output from a Monte Carlo drift-based iceberg contact model that simulates the distribution of iceberg groundings and incidences where iceberg keels are close enough to the seabed to contact subsea facilities (King, 2012; King et al., 2016). Modelled icebergs are introduced just north of the Grand Banks (49.5°N) and assigned waterline lengths, masses and drafts based on distributions derived from observed data. Modelled icebergs are then moved onto the Grand Banks in discrete time steps (i.e. 1 hour) using a drift algorithm that incorporates observed and modeled iceberg drift data. At each time step, iceberg drafts are checked against water depths. Where iceberg drafts are greater than water depths, icebergs are considered grounded, designated immobile, and the grounding locations are saved. In the case of free-floating icebergs (draft less than water depth), the drift algorithm calculates new iceberg locations for the next time step. Locations where free-floating icebergs keel are within a specified distance of the seabed (i.e. 10 m) may also be also saved for calculating contact rates with subsea structures, although this is typically done only for simulations covering smaller areas due to the large amount of data produced and additional computation time. Iceberg locations for all time steps are also saved. As the simulation progresses, the mass of each iceberg is reduced to simulate the melting process and drafts are reduced accordingly. Icebergs are observed to roll and change drafts, so modelled iceberg drafts are occasionally changed within the constraints of the mass/draft relationship and likely magnitudes of draft changes based on modelling (King et al., 2016) to simulate rolling events. Once an iceberg's mass decreases to a specified minimum value (2,000 tonnes, roughly equivalent to a bergy bit) the simulation is terminated for that iceberg. Model results are processed into bins measuring 0.01° square, and the many simulations must be run to ensure that a sufficient number of icebergs drift into all regions of the model and that results are reproducible. The sample model output shown in Figure 2 used 3.6 billion simulated icebergs, requiring several weeks (and computers) to generate. These model results also incorporate an updated iceberg waterline length distribution and iceberg length/mass/draft relationships (King, 2021). The modeled iceberg grounding density (total number per 0.01°cell) was converted to an iceberg gouge formation rate using results from the 2004 repetitive seabed mapping program (Sonnichsen and King, 2011). As can be seen in Figure 2, the grounding rate is not uniform. Based on the gouge population observed in the 2004 multibeam data, the modeled iceberg groundings are broken down into furrows (⅔) and pits (⅓). The furrowing iceberg pipeline crossing rate, n_f, was calculated using:

$$n_f = \frac{2}{\pi}\rho_f L_p \overline{L_f} \tag{1}$$

where ρ_f is the furrow formation rate, L_p is the pipeline length (or segment length), and $\overline{L_f}$ is the mean furrow length (650 m). This equation assumes a uniform distribution of furrow direction (equally likely from any direction). The pitting iceberg crossing rate was calculated using:

$$n_p = \rho_p L_p \overline{D_p} \tag{1}$$

where ρ_p is the pit formation rate, L_p is the pipeline length (or segment length), and $\overline{D_p}$ is the mean pit diameter (50 m).

Free-floating iceberg contacts for pipelines laid on the seabed were estimated using the observation that for iceberg risk analyses for pipelines on the Grand Banks that furrowing and pitting contacts account for approximately 10% of total contacts (i.e. see King, 2019). Hence, the iceberg contact rate for a pipeline laid on the seabed was estimated by multiplying the scouring (furrowing and pitting) crossing rate by a factor of 10.

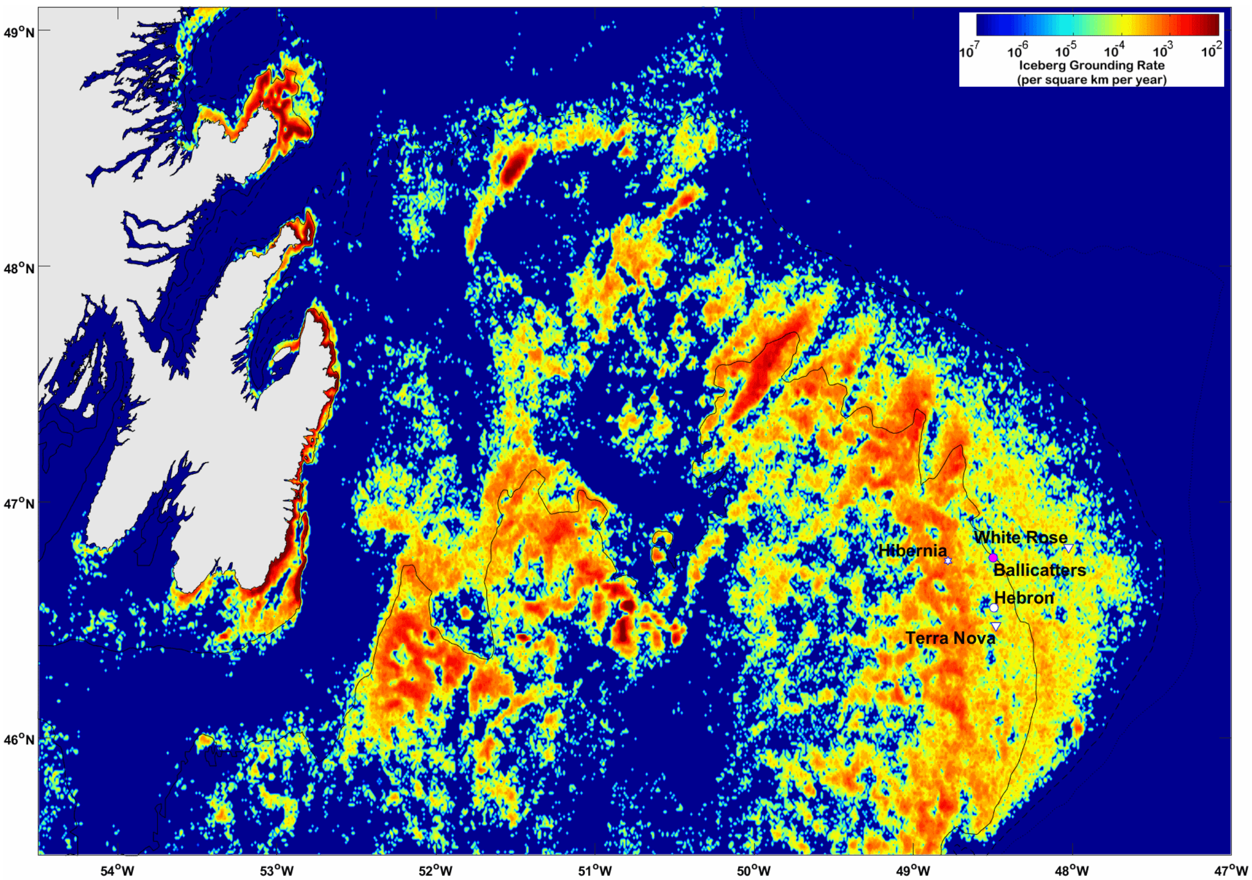

Figure 2. Modelled iceberg grounding rates

3 West Orphan Basin Pipeline Route Analysis

3.1 Overland Route Portion

The initial portion of the pipeline route from the Come by Chance refinery, located in Placentia Bay, to the West Orphan Basin crosses over the isthmus to Trinity Bay (see Figure 3). The assumed landfall is at Salmon Point, as was used for the Aker Solutions FPSO Electrification study (C-CORE, 2021). An option for routing a pipeline to this location is to go east of the refinery about 1.5 km where the Newfoundland Trailway passes underneath the Trans-Canada Highway (TCH), see Figure 4. The pipeline route can then run southeast parallel to the Trailway for a distance of approximately 9 km, after which it turns east for a distance of 6 km to reach the landfall at Salmon point, or alternatively, a landfall location at Little Southern Harbor can be reached at a distance of about 3.5 km. This gives an overland route with a total length of 14 to 16.5 km (or possibly longer to avoid local features).

Another option is, after passing beneath the TCH, turn north and run parallel to the TCH for a distance of 2.2 km to the entry for the Bull Arm Fabrication Site. The pipeline route can then run parallel to access road for a distance of approximately 7 km to reach a landfall location near Mosquito Cove at the Bull Arm Fabrication Site. This gives an overland route with a total length of just under 11 km. However this option does require lengthening the subsea pipeline route an additional 11 km to reach the Mosquito Cove landfall, requiring an additional 5.5 km of pipeline length overall when including the additional subsea portion. However, this route does have the advantage of minimizing disruption to the Trailway (a provincial park), and using an existing access road and brownfield site for accessing the Trinity Bay landfall.

Figure 3. Pipeline landfall and isthmus crossing options

Figure 4. NL Trailway TCH underpass near Come by Chance refinery

3.2 Landfall to Orphan Basin

The pipeline route from the landfall at Salmon Point to the Cape Freels (or Ephesus) prospect in the West Orphan Basin follows the same route as was used for the Aker Solutions FPSO Electrification study (C-CORE, 2021). The differences between results shown here and the C-CORE (2021) study is that the results given here are based on the updated Monte Carlo iceberg contact model and the 2021 study used a geometric iceberg grounding model which did not use the updated iceberg waterline length or length/mass/draft relationships. Both of these differences would contribute to reduced calculated iceberg risk for this analysis.

Figure 5 shows the initial portion of the pipeline route from the Trinity Bay landfall to the West Orphan Basin with modelled iceberg grounding rates. Markers ('o') are included every 10 km. The model predicts no iceberg groundings along this portion of the route, thus there is no risk from scouring (furrow and pitting) or free-floating icebergs, and thus no iceberg risk to a pipeline with minimal trenching (crown flush with the seabed) or laid directly on the seabed.

Figure 6 shows the full 425.9 km pipeline route (markers every 25 km). Figure 7 shows the water depth profile along the route. The figure shows the deep water along the Trinity Bay portion of the route, responsible for the low iceberg risk along this route.

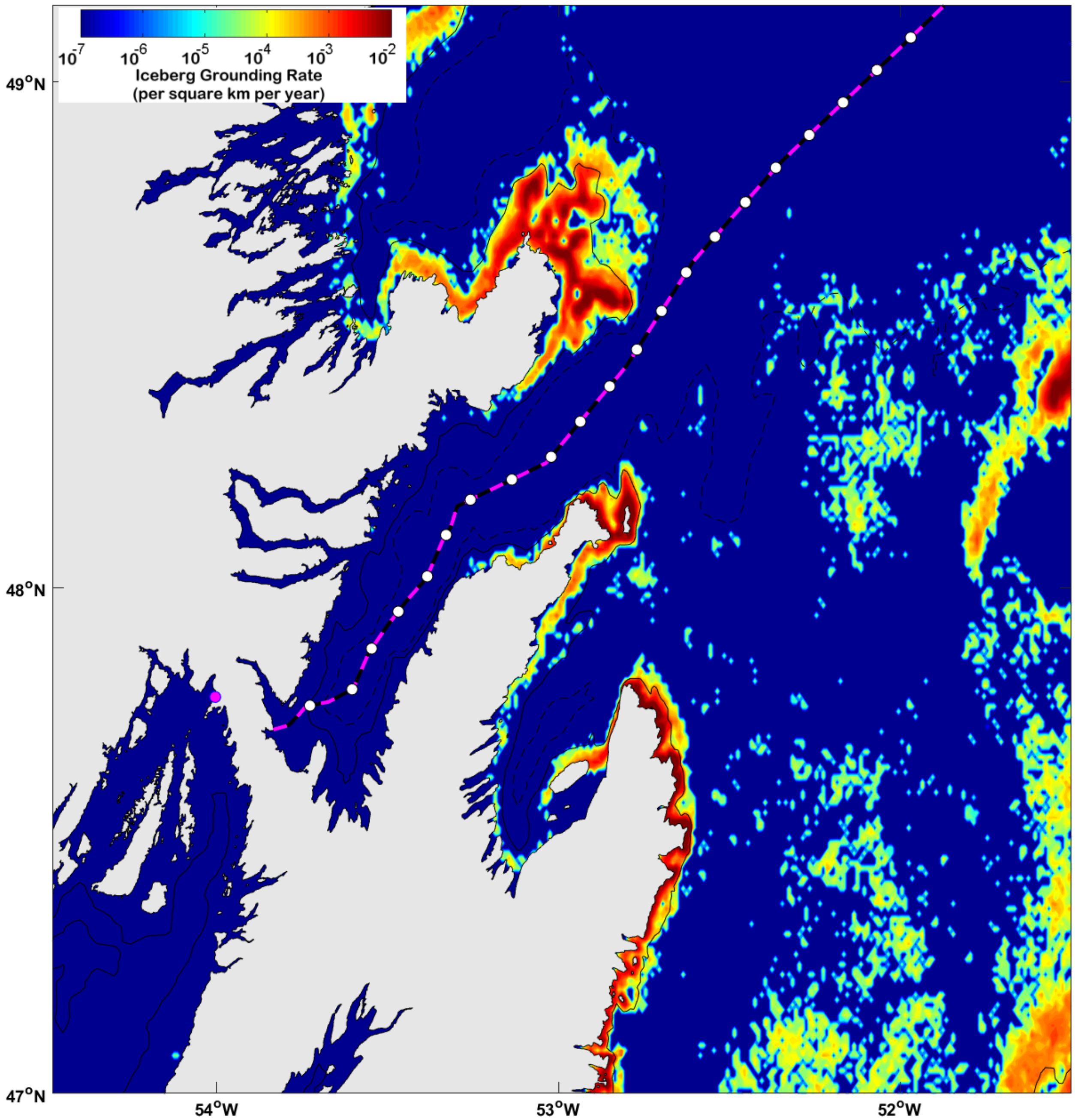

Figure 5. Initial portion of pipeline route from Trinity Bay landfall to West Orphan Basin ('o' every 10 km), with modelled iceberg grounding rates

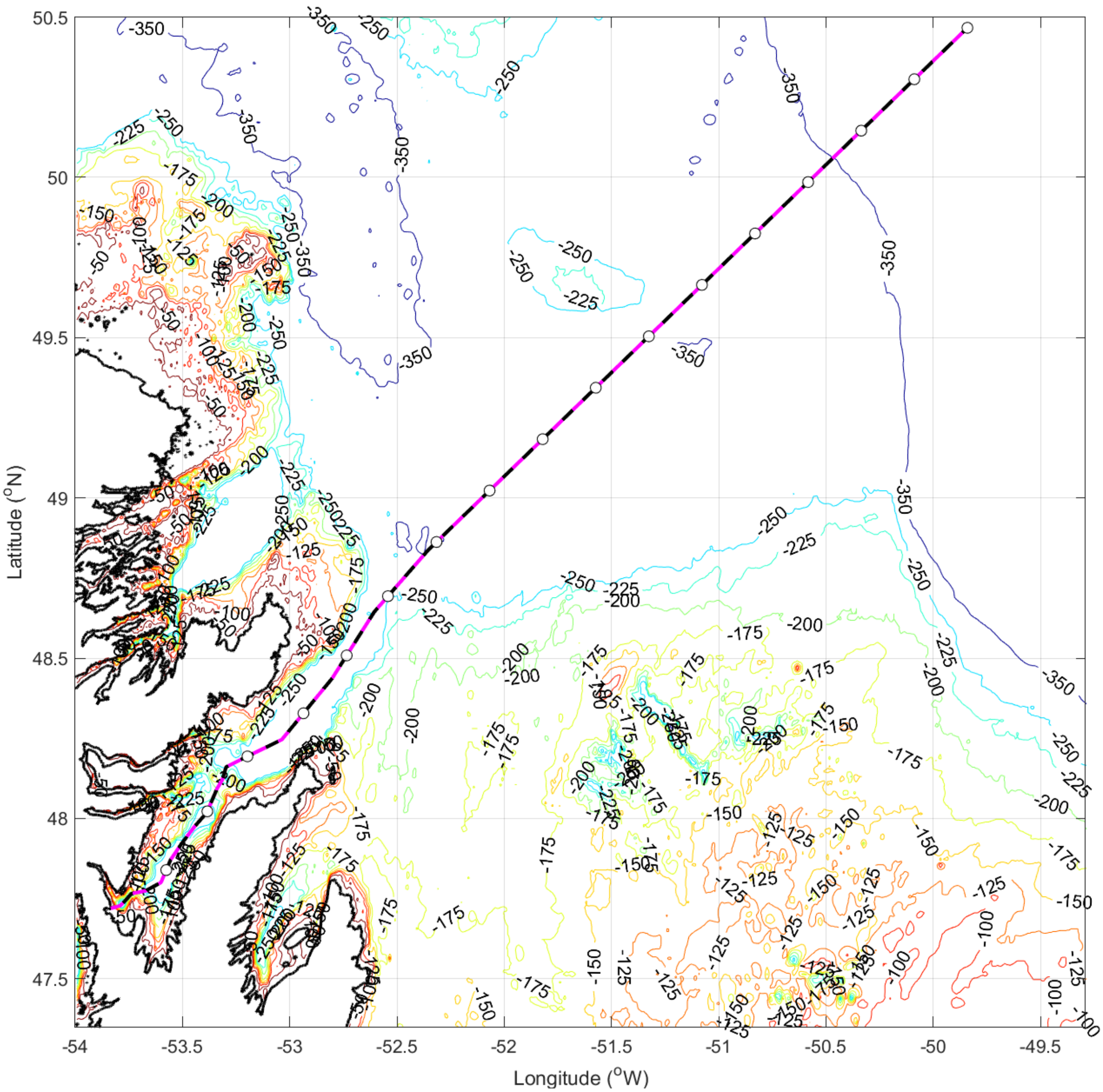

Figure 6. Pipeline route from Trinity Bay landfall to West Orphan Basin ('o' every 25 km)

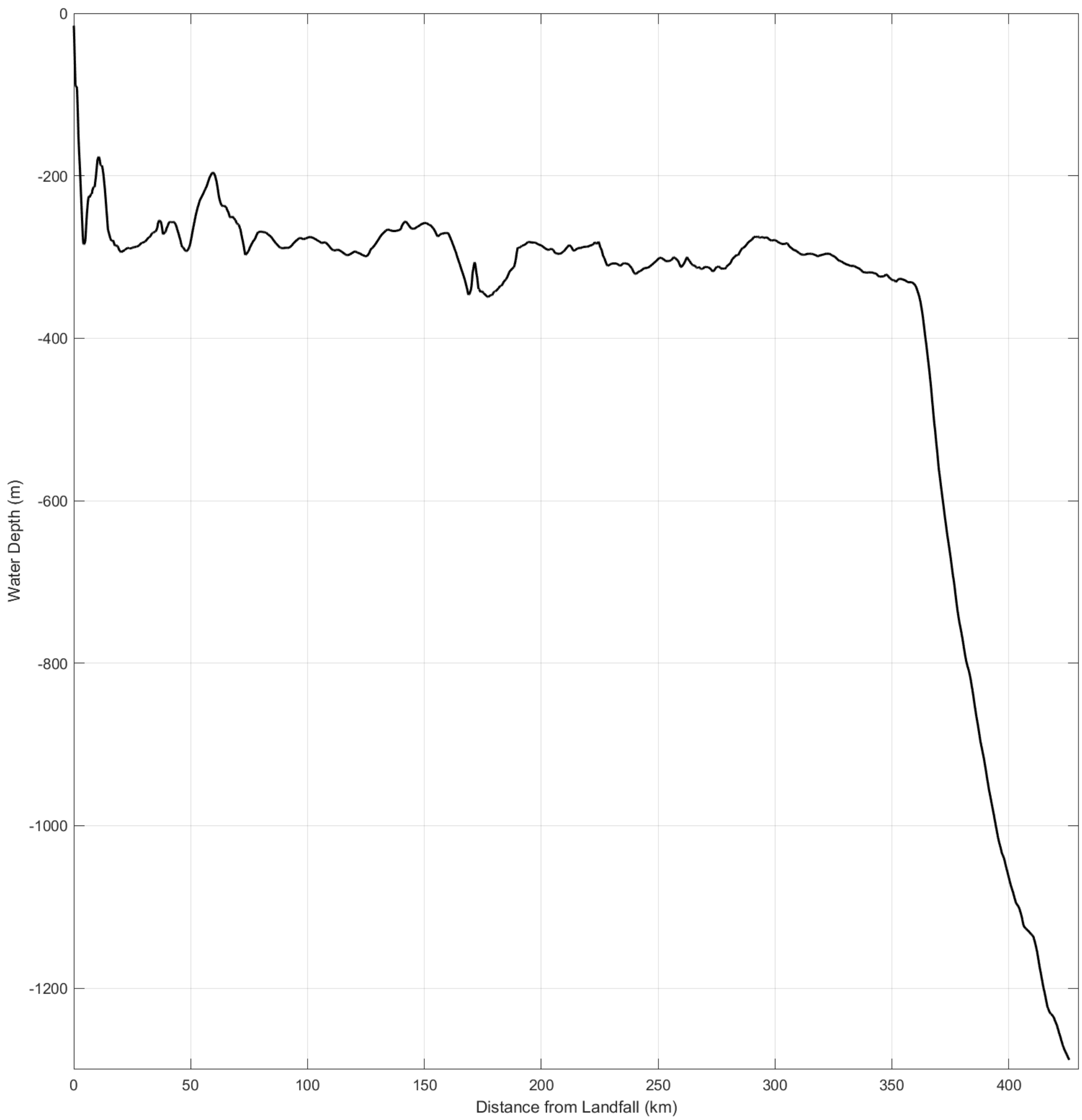

Figure 7. Water depth profile along pipeline route from Trinity Bay landfall to West Orphan Basin

4 Jeanne d'Arc Pipeline Route Analysis

Various options were considered for the pipeline route from the refinery to the Jeanne d'Arc (Figure 8). The route out of Placentia Bay was the same for all cases, avoiding close proximity to the Cape St. Mary's Ecological Reserve at the mouth of Placentia Bay. The three routes considered were selected to minimize iceberg risk and pipeline route length. Option 1 (605.4 km) goes to the bottom of the Avalon Channel to avoid a zone of high iceberg risk on the east side of the Avalon Channel and then goes a direct path to the Ballicater site, with a slight deviation to avoid Hibernia and Hibernia South (and connecting flowlines). Option 2 (571.9 km) takes a slightly more direct route, shirting north of the Virgin Rocks (a protected area) and running just north of Hibernia before going to Balicatters. Option 3 (576.3 km) takes a similar route but passes just south of the Virgin Rock, also avoiding Hibernia and Hibernia south.

More detailed plots show routes with distance markers every 25 km (Figure 9, Figure 13 and Figure 17), water depths along routes (Figure 10, Figure 14 and Figure 18), scour (furrow and pit) crossing rates (Figure 11, Figure 15 and Figure 19) and cumulative iceberg risk along the route, from landfall (Figure 12, Figure 16 and Figure 20).

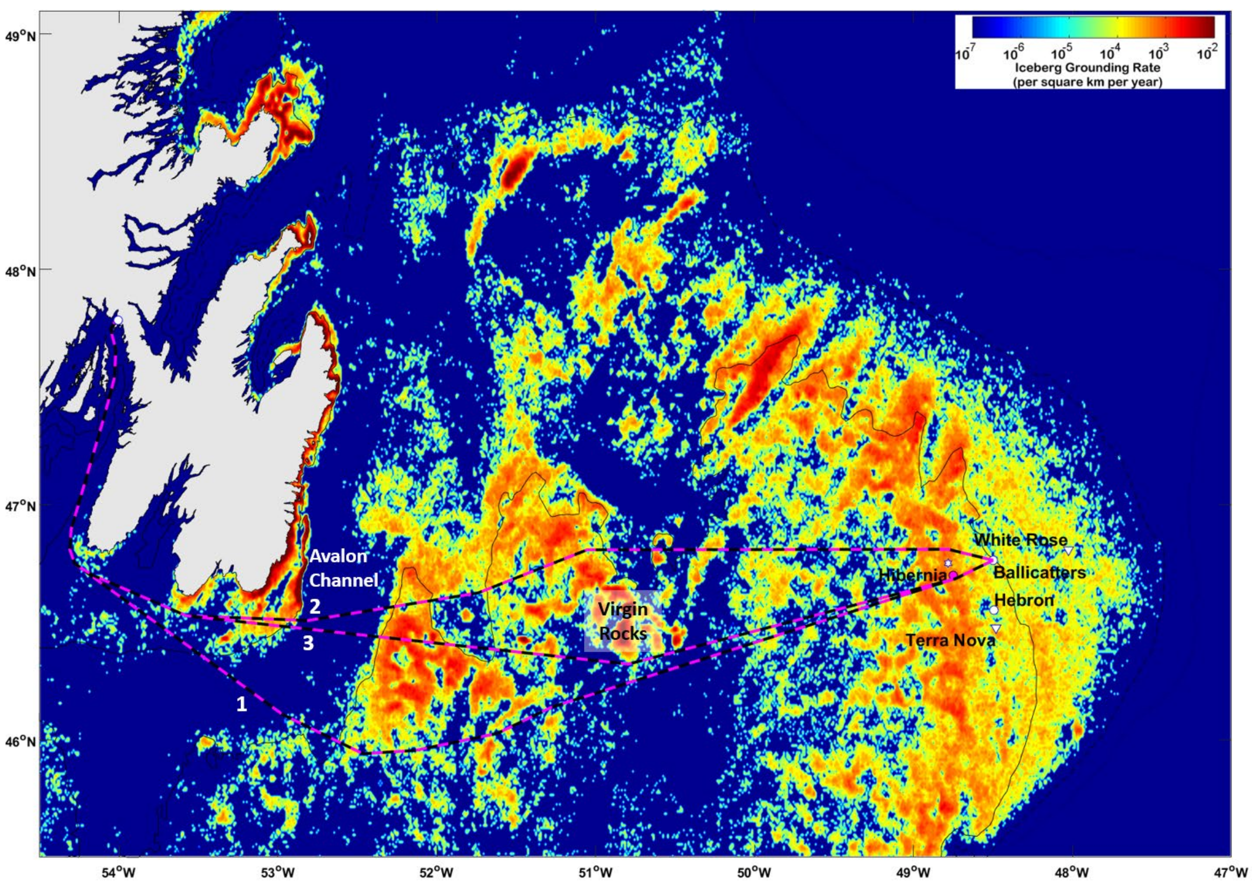

Figure 8. Routes considered for refinery to Jeanne d'Arc

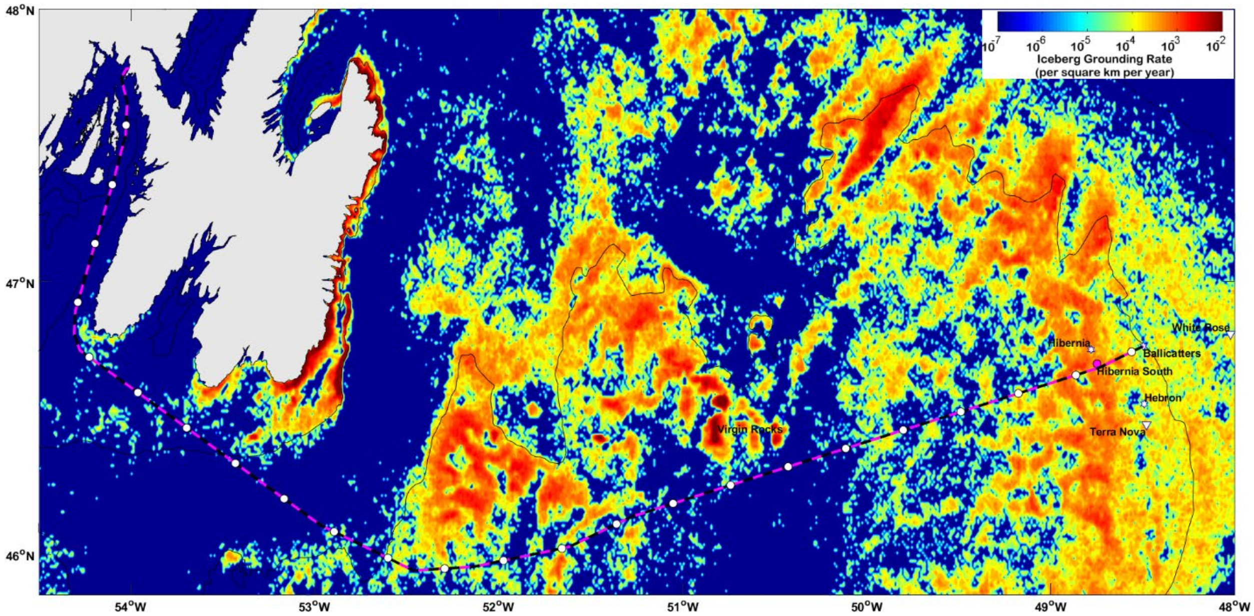

Figure 9. Jeanne d'Arc route option 1 ('o' every 25 km)

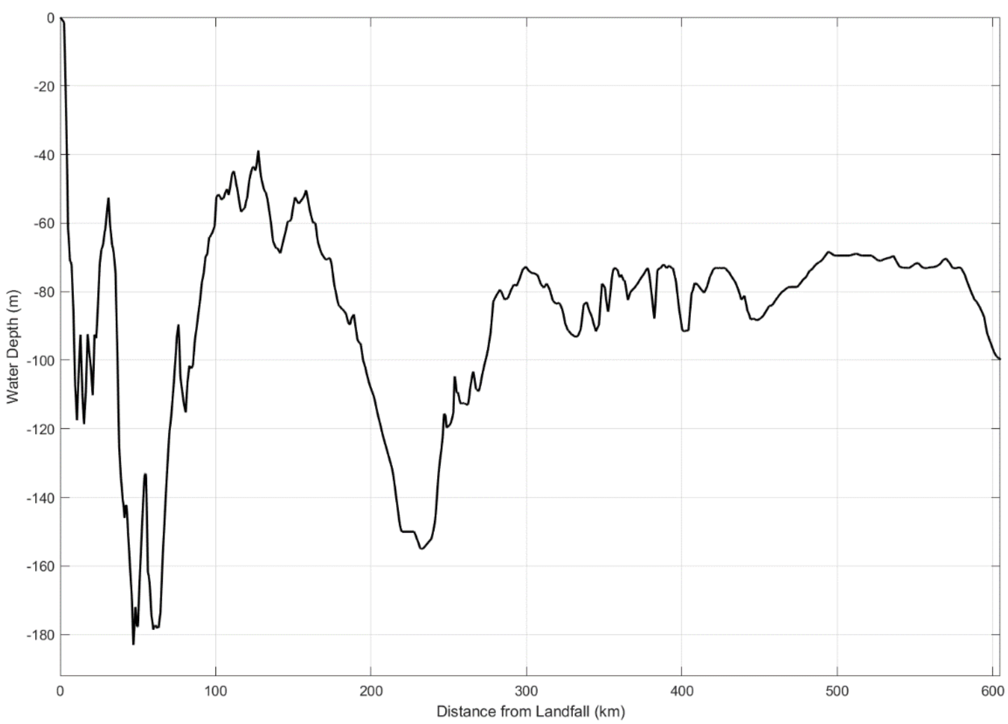

Figure 10. Water depth profile along Jeanne d'Arc route option 1

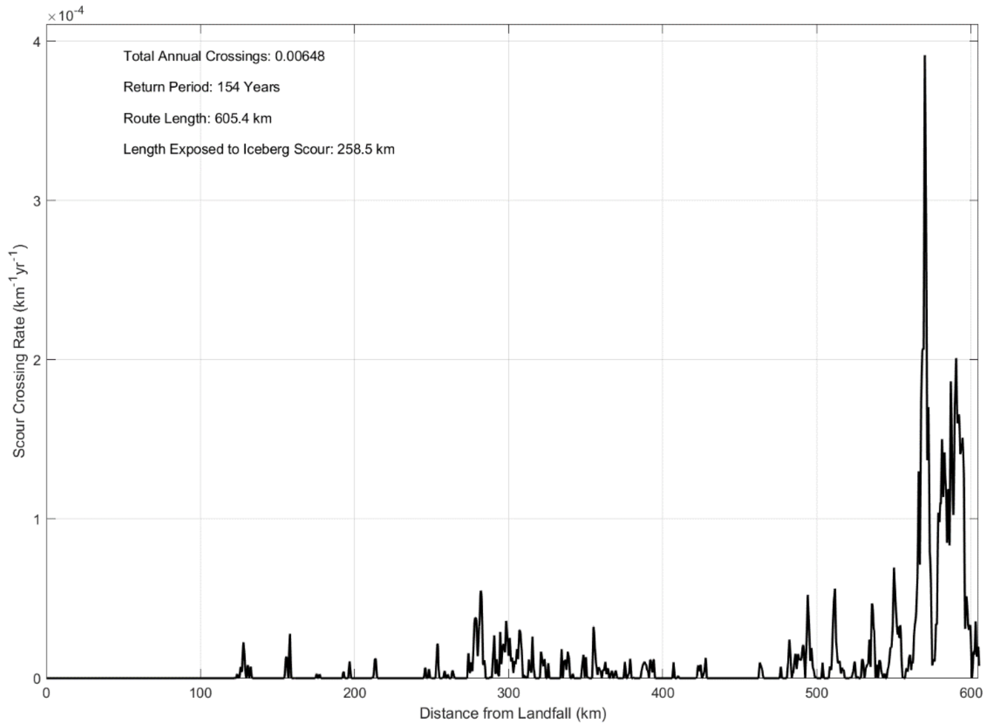

Figure 11. Scour (furrow and pit) pipeline crossing rates along Jeanne d'Arc route option 1

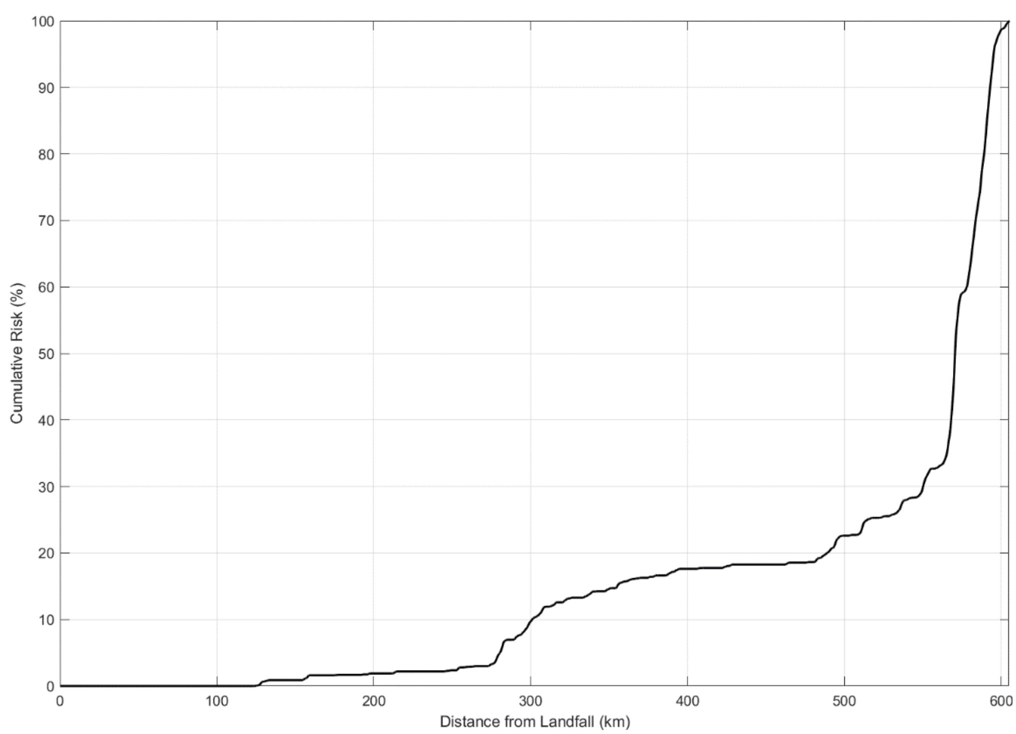

Figure 12. Cumulative iceberg pipeline risk, starting at landfall, Jeanne d'Arc route option 1

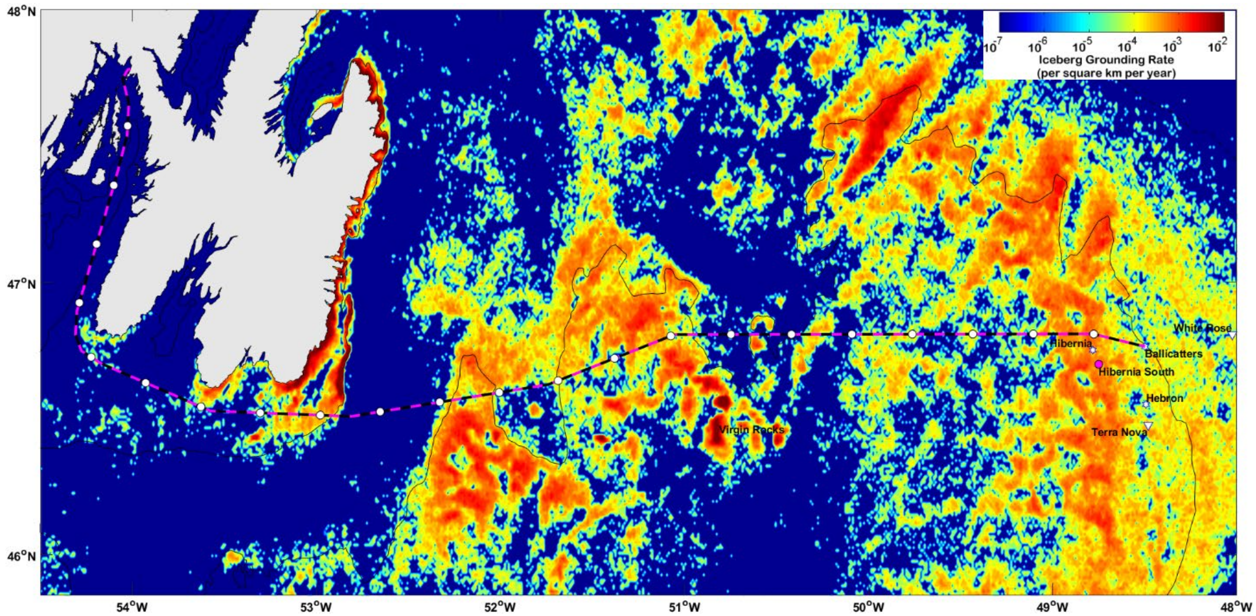

Figure 13. Jeanne d'Arc route option 2 ('o' every 25 km)

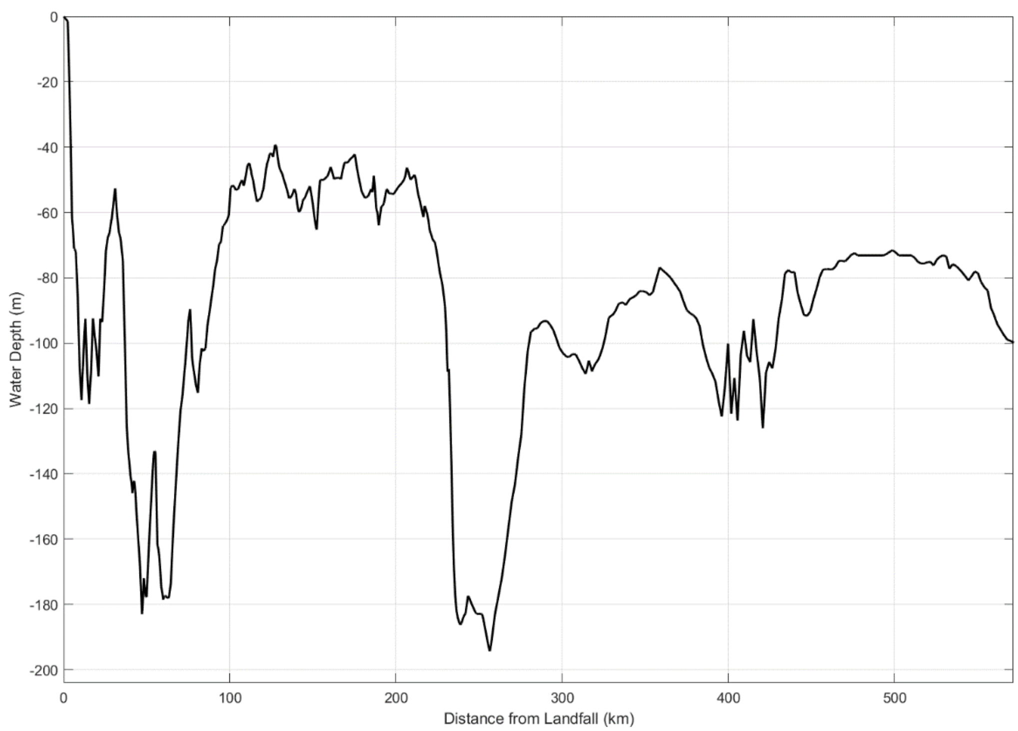

Figure 14. Water depth profile along Jeanne d'Arc route option 2

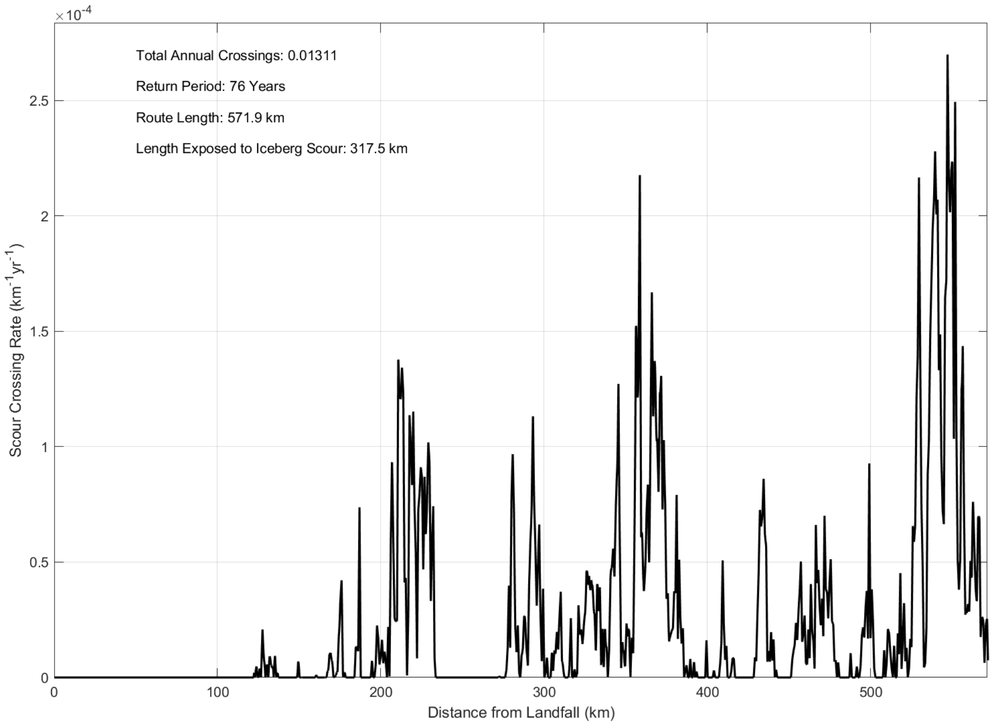

Figure 15. Scour (furrow and pit) pipeline crossing rates along Jeanne d'Arc route option 2

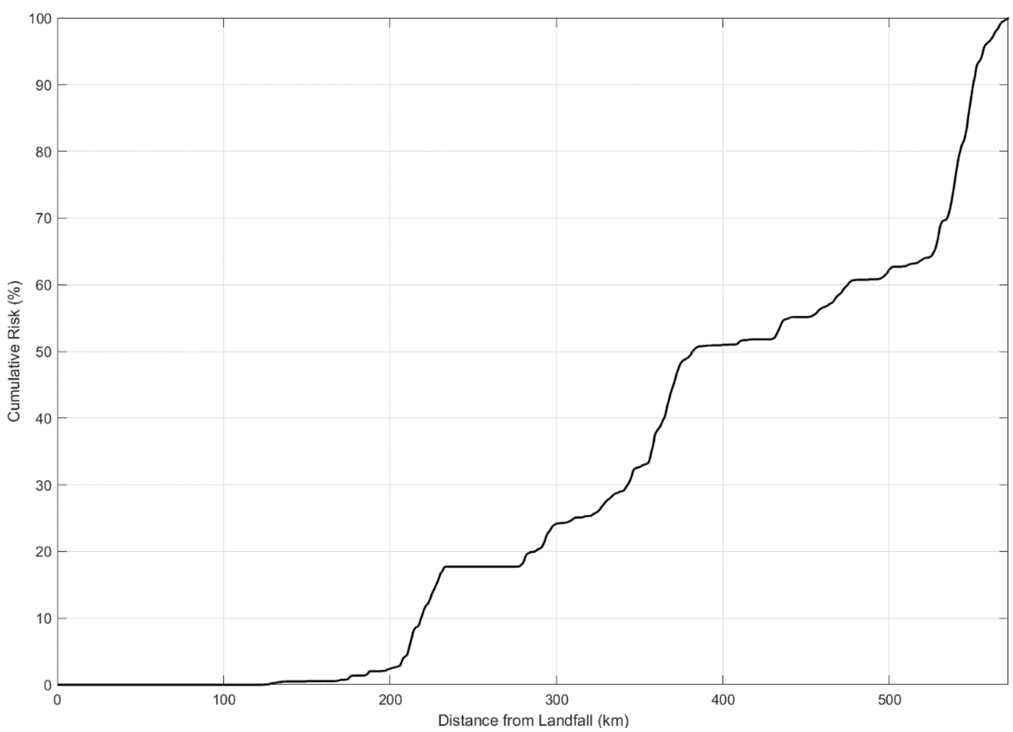

Figure 16. Cumulative iceberg pipeline risk, starting at landfall, Jeanne d'Arc route option 2

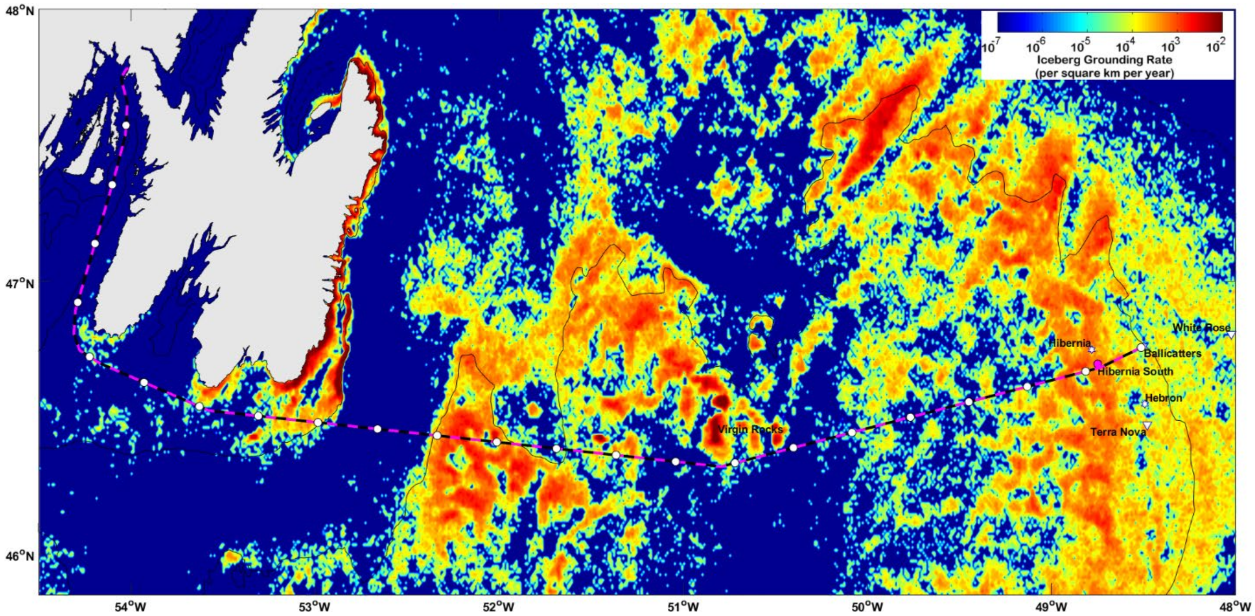

Figure 17. Jeanne d'Arc route option 3 ('o' every 25 km)

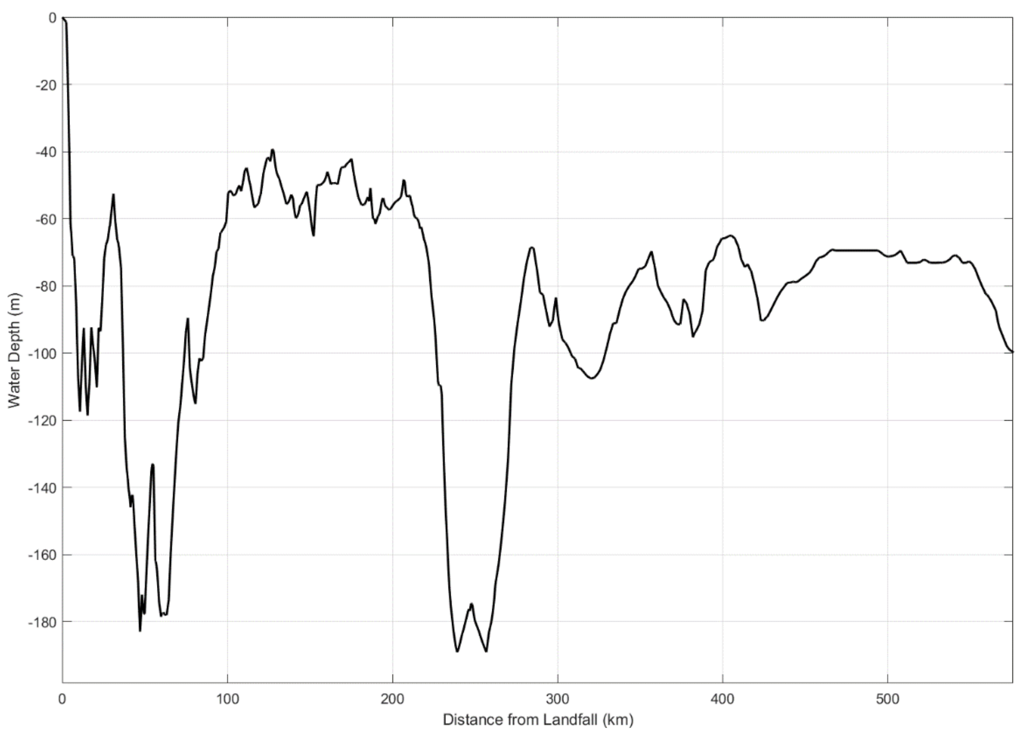

Figure 18. Water depth profile along Jeanne d'Arc route option 3

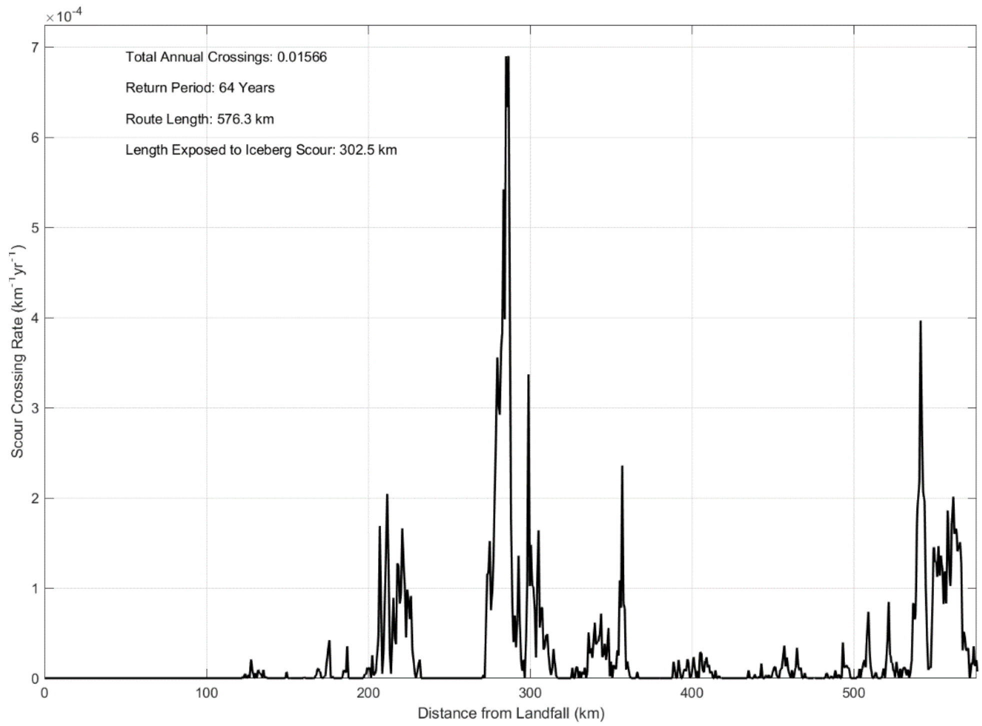

Figure 19. Scour (furrow and pit) pipeline crossing rates along Jeanne d'Arc route option 3

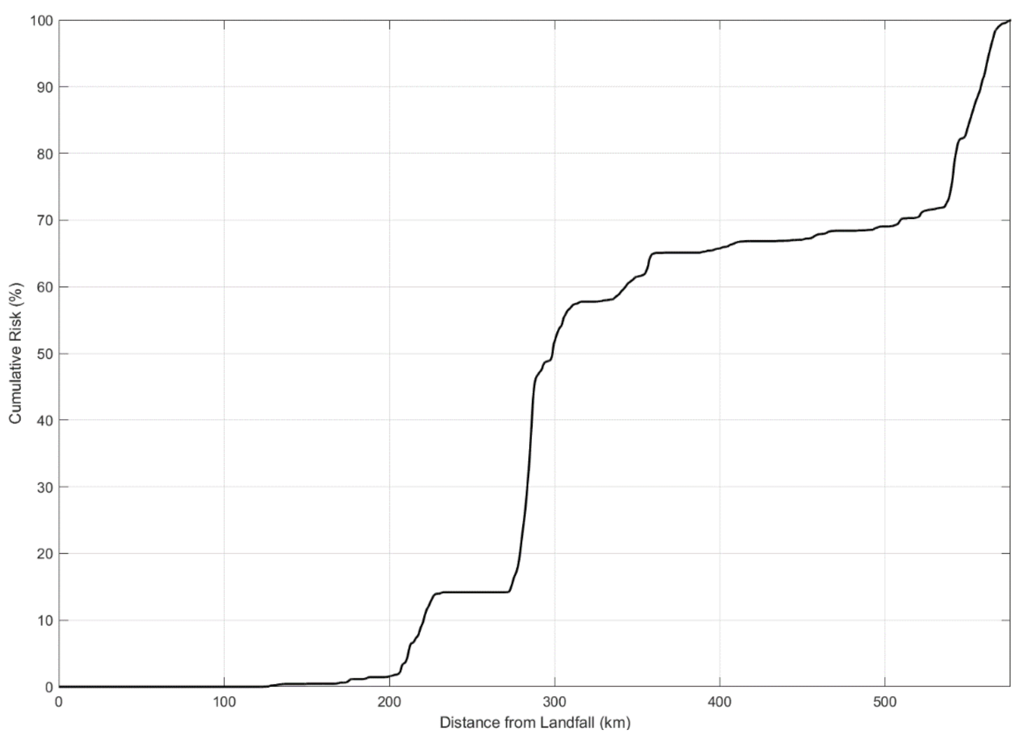

Figure 20. Cumulative iceberg pipeline risk, starting at landfall, Jeanne d'Arc route option 3

Table 1 summarizes the analysis results for the various routes considered. The differences in the lengths of the routes are relatively minor, with the longest route less than 6% longer than the shortest route. However, the differences in the iceberg contact rates are substantial, with the longest route having less than 50% of the iceberg contact of the alternatives. Given the minor difference in route length, route option 1 would appear to be the best alternative.

It should be noted that the iceberg contact rates in Table 1 do not include the influence of ice management. An ice management success rate of 85% has been estimated for an excavated drill center in 110 m water depth (King et al., 2016). As can be seen in Figure 12, 70% of the iceberg risk along route option 1 is accrued in the last 55 km of the pipeline route. This portion of the pipeline route passes between Hibernia and Hebron (both of which have their own ice management programs), headed towards the Ballicater site, where presumably there will be a surface facility which will also have some level of ice management. This section of the pipeline route will benefit from ice management activities already in place for surface facilities, and any incremental ice management on behalf of the pipeline will only further reduce iceberg risk. If it is conservatively assumed the iceberg risk along this section of the pipeline route is reduced by 70%, the total iceberg risk to the pipeline is reduced 50%. This will reduce the annual iceberg contact rate for the pipeline with minimal burial to 0.0033 yr^{-1} (return period 300 years) or 0.033 yr^{-1} (return period 30 years) for a pipeline laid on the seabed, without significant additional ice management effort. Further reductions in iceberg risk are possible, and could be obtained with additional ice management effort.

Table 1. Iceberg contact rates with Jeanne d'Arc pipeline route options (values in brackets are return periods, in years), no ice management

Route Option	Length (km)	Length Exposed to Iceberg Risk (km)	Annual Contact Rate, Minimal Burial (yr^{-1})	Annual Contact Rate, Pipe on Seabed (yr^{-1})
1	605.4	258.5	0.0065 (154)	0.065 (15.4)
2	571.9	317.5	0.0131 (76)	0.131 (7.6)
3	576.3	302.5	0.0157 (64)	0.157 (6.4)

5 Conclusions and Recommendations

5.1 Conclusions

The iceberg risk analysis indicates no iceberg risk for the selected pipeline route from the Trinity Bay landfall to the West Orphan Basin. The low risk is due to the deep water along the route. The selected route for the Come by Chance Refinery to Jeanne d'Arc has annual contact rates of 0.0065 and 0.065 yr^{-1} (154 and 15.4 year return period) for a pipeline with minimal burial and laid on the seabed, respectively. If ice management activities conducted in the Jeanne d'Arc are considered, these contact rates are halved.

5.2 Recommendations

Recommended activities to refine the analysis presented here are:

- To conduct a seabed survey of the pipeline route in Trinity Bay and landfall(s) to assess potential iceberg scour activity. The Monte Carlo iceberg contact model predicts no iceberg scour risk near the landfall, but this may not be correct as icebergs have been observed deep in Trinity Bay. This would also assist in detailed pipeline routing for the pipeline landfall. Further consideration of Trinity Bay landfall locations (Salmon Point/Little Southern Harbour versus a landfall near or at Mosquito Cove) and associated overland routes is also warranted.
- A seabed survey along the Jeanne d'Arc pipeline route to verify iceberg scour density and other seabed features and hazards, as well as geotechnical investigations to assess the feasibility of shallow trenching.
- On-going collection of iceberg data to better characterize the changing iceberg regime and resulting changes in iceberg risk. This includes collection of iceberg profile data to define the iceberg length/mass/draft relationships with a higher degree of confidence and assess potential changes over time, as well as changes in waterline length distributions, iceberg frequency and development of a source-to-sink model of iceberg occurrence to facilitate prediction of changes in iceberg risk on the Grand Banks.
- Given that the majority of the iceberg risk is concentrated along a relatively short portion of the pipeline route, further assessment of ice management to reduce iceberg risk is warranted.

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