Mackenzie Delta LNG Pre-Feasibility Study

REVISED Final Report

Government of Northwest Territories

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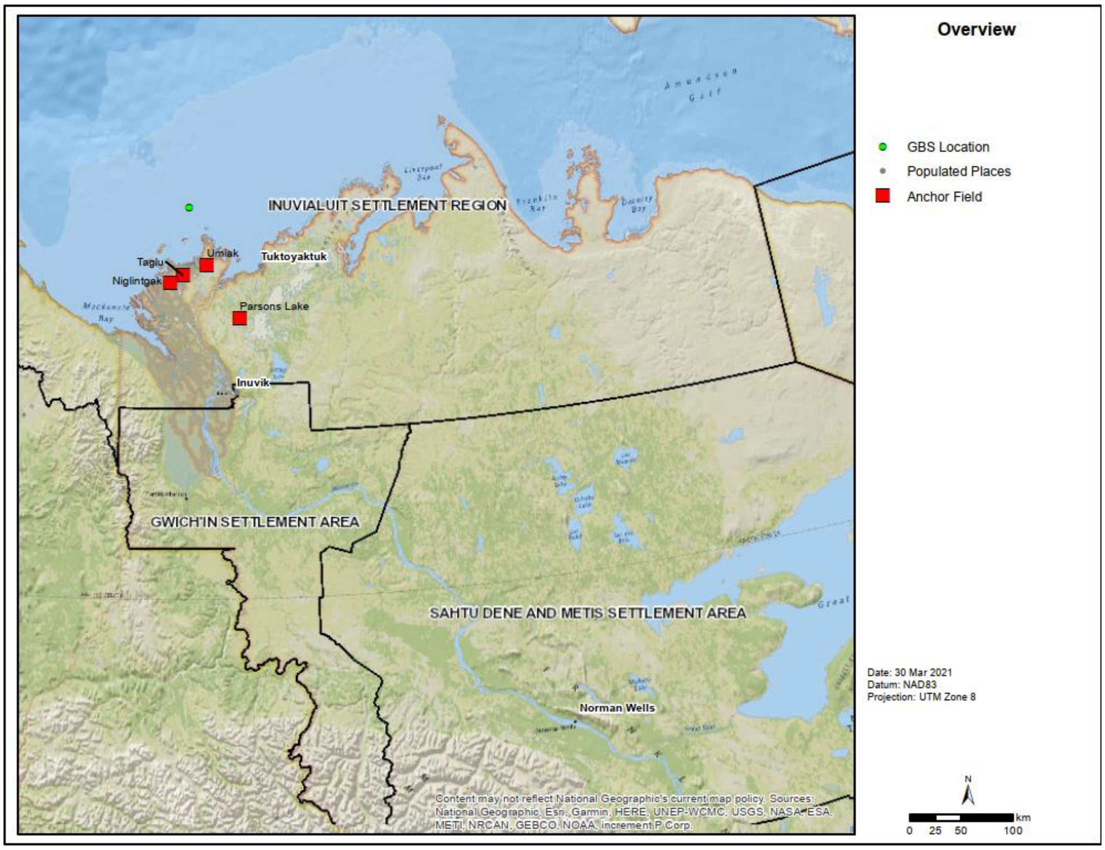
Executive Summary

The Government of the Northwest Territories (GNWT) is interested in better understanding the economics of developing conventional onshore natural gas reserves located in the Mackenzie Delta region of the Northwest Territories (NWT). The Mackenzie Delta contains substantial proven onshore conventional natural gas reserves that could be developed for export that would provide economic benefits to the Inuvialuit Settlement Region, NWT and Canada. The study concept is called "Mackenzie Delta Liquified Natural Gas" or MDLNG Project.

The MDLNG Project is based on the development and production of onshore gas and condensates in the Mackenzie Delta for delivery by onshore and offshore pipelines to gas liquefaction and hydrocarbon facilities on Gravity Based Structure(s) (GBS) located approximately 31 km offshore. From the offshore facilities, the LNG and condensate will be shipped by separate specialized icebreaking tankers to export markets. The LNG production target is 4 Million tonnes per year (MTPA) over a period of 20 years.

An alternative is to ship the condensate via a new pipeline to Enbridge's Line 21 at Norman Wells which in turn will transport the condensate to Alberta and other markets. The natural gas would still be transported to an offshore LNG facility for liquefaction and shipped in specialized ice breaking tankers to export markets.

The following map Executive Summary Figure -1 provides the location for the fields and the GBS location in relation to major centres such as Tuktoyaktuk, Inuvik and Norman Wells.



Executive Summary Figure -1 Overview Map

This pre-feasibility study includes the following:

- Upstream Supply Forecast, Field Development Plan Scenarios and Cost Estimates
  - Option 1 – natural gas and condensate pipelines to offshore GBS(s)
  - Option 2 – natural gas pipeline to offshore GBS (LNG), condensate pipeline to Norman Wells
- Offshore GBS Facilities and Costs
- Shipping and Tanker Requirements and Costs
- Project Economic Assessment

Background

Projects to exploit the large natural gas reserves in the Beaufort Sea and Mackenzie Delta region of the Northwest Territories were first proposed in the 1970's. In 2004, a consortium of producers led by Imperial Oil proposed the Mackenzie Gas Pipeline project (MGP). The MGP was designed to transport approximately 1,200 million cubic feet per day (MMcfd) of natural gas from the Mackenzie Delta, via a natural gas pipeline, to Alberta. The MGP underwent an extensive regulatory process by the National Energy Board (NEB, now called Canada Energy Regulator).

The NEB and the Joint Review Panel (JRP) evaluated the impact on the communities and environment conducting a detailed review of the natural gas fields, gathering pipelines, processing facilities and pipelines (both natural gas and natural gas liquids (NGL)) that were required for the project. It was approved by the NEB and was granted federal cabinet approval in March 2011. Due to market factors, the consortium decided to abandon the MGP project in 2017.

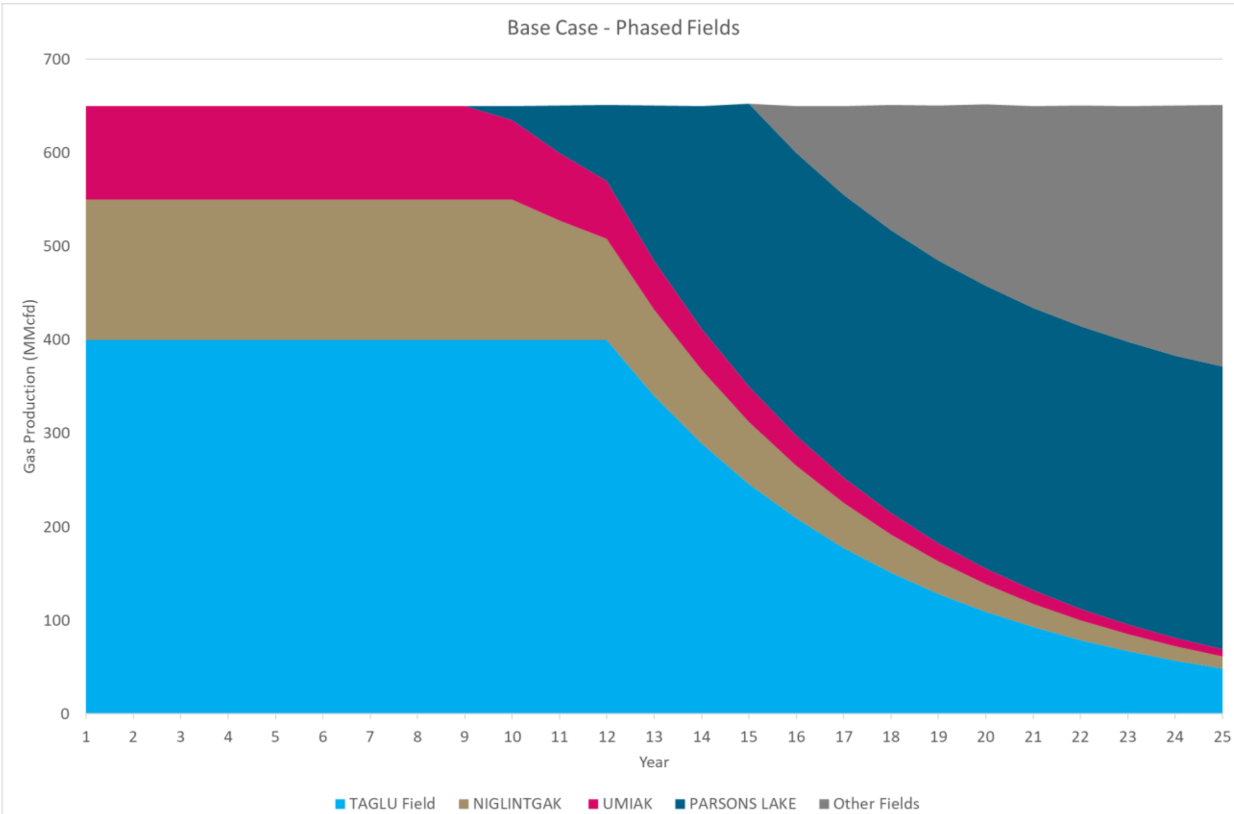
The technical information about the natural gas fields, gathering pipelines and processing facilities that was developed for the MGP project, supplemented with new information provided by MGM Energy (MGM) and Nytis Exploration Company Canada Ltd. (Nytis), is used as the basis for the natural gas supply and field development in this study. However, there are two significant differences with the MDLNG project:

- The volumes are approximately half, the MGP initial volume was 1,200 MMcfd versus the MDLNG is only 650 MMcfd.
- The operating pressure of the MGP was 18.7 megapascals (2710 pounds per square inch) versus the pressure for the liquefaction facility is only 3.5 megapascals (500 pounds per square inch) which reduces the required compression at the conditioning and process facilities and the wall thickness of the pipelines.

Study Findings and Conclusions:

Natural Gas Resources

There is enough natural gas currently discovered to support the MDLNG project for a period of more than 20 years. The discovered natural gas resource assessment for the Mackenzie Delta is 8.0 Trillion Cubic Feet (Tcf) with an expected additional potential undiscovered resource of 11.1 Tcf. The resource information is sourced from: Anchor fields from the field interest holders (per MGP), the National Energy Board 2014 Conventional Resource Assessment, and from information provided by MGM and Nytis. For the pre-feasibility study only the discovered natural gas resources have been used. The forecast deliverability for the Base Case production is shown in Executive Summary Figure -2:



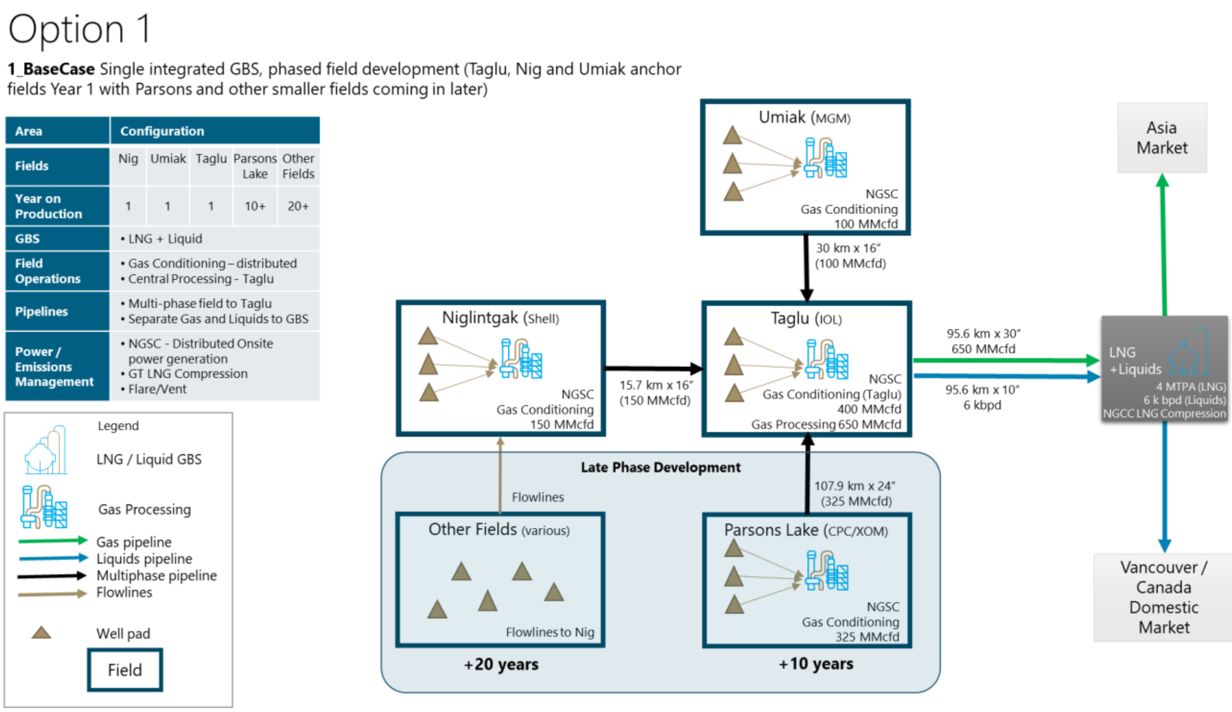
Executive Summary Figure -2 Base Case - Phased Fields

Technical Feasibility

The MDLNG project is technically feasible. Natural gas production facilities and associated pipelines have been operating safely in Arctic climates such as Alaska and Russia for over forty years. Russia has shipped LNG in arctic waters since 2017 using LNG and Condensate Ice Breaking Carriers. The ice breaking carrier technology proposed in this pre-feasibility study is based on Russia's operating experience.

This study determined that the GBS (LNG) needs to be equal to or greater in length than the LNG carrier to protect the carrier during winter loading. Based upon this size requirement and by having the gas processing (CO_2, mercury removal and dehydration) onshore, a single GBS could meet liquefaction and storage requirements for the LNG and condensate. With only one GBS required offshore that can manage both the LNG and Condensate, the economics, at this time, do not support Option 2.

Executive Summary Figure -3 presents a summary of the timing and general description of the facilities for the Base Case Option 1.



Executive Summary Figure -3 Option 1 – Base Case

Capital and Operating Costs

As seen in Executive Summary Table -1 and Executive Summary Table -2, the initial capital cost for the Base Case Option 1 is estimated to be CAN$8,258 million with a total capital cost over the 20-year period of CAN$11,351 million. The initial capital cost for Option 2 is estimated to be CAN$9,375 million with a total capital cost of CAN$12,468 million. The initial capital cost of Base Case Option 1 is CAN$1,117 million less expensive in capital cost and has CAN$111 million less in annual operating expenses compared to Option 2. As a result, Option 1 is the preferred economic option.

Executive Summary Table -1: Option 1 Base Case

Cost Element	CAPEX 2021 CAN$ Million	OPEX 2021 CAN$ Million/Year
Initial Field Development	2,768	69
Gathering	146	3
Base Case Onshore Export Pipelines	518	12
Base Case Offshore Export Pipelines	515	1

Cost Element	CAPEX 2021 CAN$ Million	OPEX 2021 CAN$ Million/Year
Single GBS (LNG & O)	4,311	198
Shipping LNG	0	292
Shipping Condensate	0	28
Initial Base Case Cost	8,258	603
Future Base Case Cost	3,093	77
Total Base Case Cost	11,351	680

Executive Summary Table -2: Option 2 NGL South Pipeline

Cost Element	CAPEX 2021 CAN$ Million	OPEX 2021 CAN$ Million Year
Initial Field Development	2,768	69
Initial Gathering	146	3
Natural Gas Onshore Export Pipeline	389	9
Natural Gas Offshore Export Pipeline	477	1
Condensate Onshore Export Pipeline	1,266	142*
GBS LNG	4,329	198
Shipping LNG	0	292
Initial Option 2 Cost	9,375	714
Future Option 2 Cost	3,093	77
Total Option 2 Cost	12,468	791

Note: *Includes the transportation toll to get from Norman Wells to Edmonton.

Comparison with Other LNG Projects

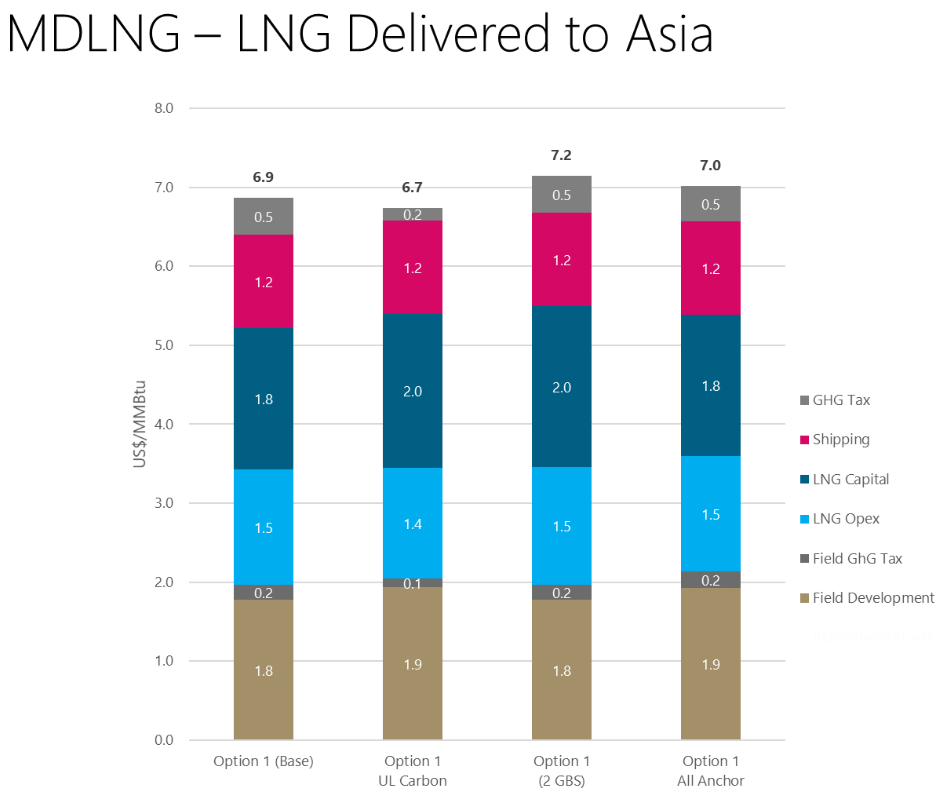
As seen in Executive Summary Table -3, the delivered cost of LNG to Asian markets (US$ 6.9 to 7.2 MMBtu) is within the range of other North American LNG projects. MDLNG provides a lower delivered cost than projects such as Sabine Pass (US$ 7.9 MMBtu) and Corpus Christi (US$ 8.4 MMBtu). The delivery time is also shorter than the US Gulf coast, even during the winter.

Executive Summary Table -3: Project Comparison for Delivered Cost to China

Comparatble LNG Projects	Delivered Cost to Asia (US$/MMBtu)	Average Distance to Chinese Port (Days)
Qatar New Mega trains	4.5	≈ 12
Arctic LNG - 2	5.9	≈ 20
LNG Canada	6.9	≈ 11.5
Mozambique Onshore	7.2	≈ 13.5
Illustrative USGC (Permian supply + $550/t EPC)	7.1	≈ 24
Illustrative USGC (HH supply + $550/t EPC)	7.1	≈ 24
MDLNG Option 1	**6.9 -7.2**	**≈ 15 (Winter)/11 (Summer)**
Sabine Pass Trains 2 - 5	7.9	≈ 24
Corpus Christi Trains 1 - 2	8.4	≈ 24

Note: USGC is the United States Gulf Coast. HH is Henry Hub. EPC is Engineering, Procurement and Construction.

Executive Summary Figure -4 presents the cost by segment to arrive at the Delivered Cost to Asia.

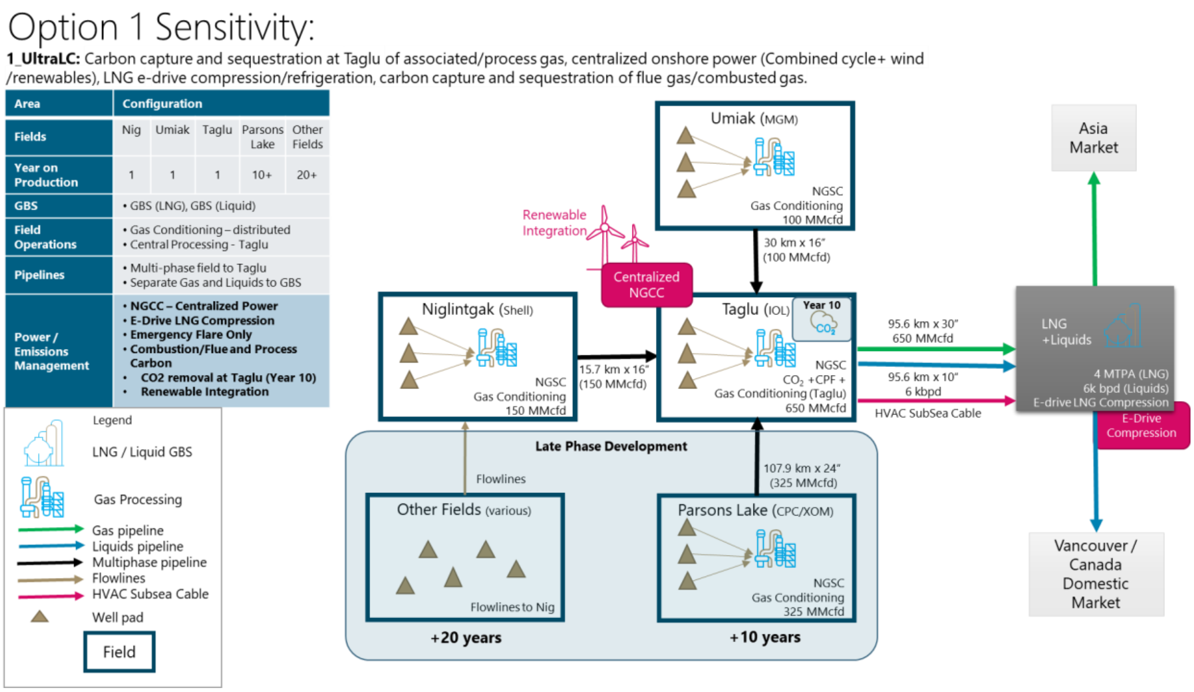


Executive Summary Figure -4 Delivered Cost Breakdown

GHG Reduction

An alternative to the base case that integrates best available technology for reducing GHG emissions includes electrification of onshore and offshore compression and combined cycle gas turbine electrical generation in the initial build, followed by implementation of carbon capture and storage (CCS) after 10 years of operation. Based upon the current forecast for carbon taxes (presently targeted to reach $170 per tonne in 2030), pursuing reduced GHG emissions via carbon capture and storage would reduce the delivered cost of the Project and is a clear benefit; however a reservoir to store the CO_2 needs to be identified (is outside Advisian's scope of work). As shown in Figure 4, the Base Case ultra-low carbon case reduces the landed cost by approximately US$0.3/MMBtu while establishing a low carbon intensity pathway.

Executive Summary Figure -5 presents a summary of the timing and general description of the facilities for the Base Case "Ultra-Low Carbon" Option.



Executive Summary Figure -5 Option 1 Sensitivity – Full Carbon Capture with Renewables

Conclusion

This pre-feasibility study finds that the MDLNG Project is technically and economically feasible. The upstream facilities need to be staged such that the supply nearest to the offshore GBS, Niglintgak, Taglu and Umiak, are developed initially with Parsons Lake and smaller fields added later to offset field declines at Niglintgak, Taglu and Umiak. A detailed analysis of the production should be undertaken, particularly with respect to the condensate production. A study could be undertaken to determine if re-injection of the condensate is feasible to eliminate the cost of transporting the condensate.

By locating the gas processing onshore and designing high efficiency facilities that are CCS ready, the CO_2 intensity of the LNG product will be substantially below the global average resulting in enhanced economic performance. A single GBS that provides natural gas liquefaction, storage and loading facilities for both the LNG and condensate is recommended.

At this early phase there is significant uncertainty in the capital and operational costs. This estimate is considered by Advisian to be an AACE Class 5 estimate (-30%/+50%). The landed cost of LNG from this project in Asian markets, although at the high end of the range of competing global projects, will be competitive with other proposed North American projects.

Acronyms and Abbreviations

Acronym/abbreviation	Definition
B	Billion
BAT	Best Available Technology
BEP	Best Environmental Practices
bbl	1 Oil Barrel
bbl/d	Barrels of Oil Per Day
Bcf	Billion Cubic Feet / Per Day
BOG	Boil Off Gas
bpd	Barrels Per Day
BTU/cf	British Thermal Unit / Cubic Feet
CAPEX	Capital Expenditures
CCR	Central Control Room
CAD	Canadian Dollar
CAN$	Canadian Dollar
CER	Canadian Energy Regulator
CCS	Carbon Capture and Storage
CGPF	Central Gas Processing Facility
CO^2	Carbon Dioxide
CSSC	Hudong-Zhonghua Shipbuilding
DSME	Daewoo Shipbuilding & Marine Engineering
ECCC	Environment and Climate Change Canada
EPC	Engineering, Procurement and Construction
FOC	Fibre Optic Communications Cable
FY	First Year Ice
GBS	Gravity Based Structure
GBS (O)	Gravity Based Structure (Oil)
GBS (LNG)	Gravity Based Structure (Liquid Natural Gas)

Acronym/abbreviation	Definition
GCF	Gas Conditioning Facility
GHG	Greenhouse Gas
GHGPA	Greenhouse Gas Pollution Pricing Act
GNWT	Government of the Northwest Territories
ha	Hectare (100 hectares in one square kilometre)
Hanjin	Hanjin Heavy Industries and Construction
HDD	Horizontal Directional Drilling
HH	Henry Hub
HHI	Hyundai Heavy Industries
HHV	Higher Heating Value
HSHI	Hyundai Samho Heavy Industries
IAA	Impact Assessment Act
ISO	International Standards Organization
ISR	Inuvialuit Settlement Region
JRP	Joint Review Panel
km	Kilometre
knots	Knot is Unit of Speed = 1 Nautical Mile
kbpd	Thousand barrels per day
LNG	Liquified Natural Gas
LNGC	Liquefied Natural Gas Carrier
m	Metre
m^2	Metre Squared
m^3	Cubic Metre
m/s	Metre Per Second
Mcf	One Thousand Cubic Feet (Measurement of Natural Gas)
MDLNG	Mackenzie Delta Liquified Natural Gas Pre-Feasibility Study
Mbbl/D	Thousand Barrels of Oil Per Day

Acronym/abbreviation	Definition
MGP	Mackenzie Gas Pipeline
MGM	MGM Energy
MHI	Mitsubishi Heavy Industries
MM	Million
MMbbl	Million Barrels (oil reserves)
MMBtu	Metric Million British Thermal Unit (Measurement of Natural Gas)
MMcfd	Million Cubic Feet Per Day
MTPA	Million Metric Ton Per Annum (Weight of LNG)
MOP	Maximum Operating Pressure
MPa	Megapascal (1 MPa = 150 psi)
MY	Multi Year Ice
MW	Mega Watt
NEB	National Energy Board
NGL	Natural Gas Liquids
NGCC	Natural Gas Combined Cycle
Nig	Niglintgak
nm	Nautical Mile
NPS	Nominal Pipe Size
NPV	Net Present Value
NWT	Northwest Territories
OPEX	Operational Expenditures
PPMV	Parts Per Million Volume
PC3	Polar Class 3
PV	Present Value
SHI	Samsung Heavy Industries
t	Tonne
Tcf	Trillion Cubic Feet

Acronym/abbreviation	Definition
USGC	United States Gulf Coast
US$	United States Dollar
USD	United States Dollar
VSM	Vertical Support Member

1 Introduction

The Government of the Northwest Territories (GNWT) is interested in better understanding the economics of developing the conventional natural gas reserves located in the Mackenzie Delta region of the Northwest Territories (NWT). The Mackenzie Delta contains substantial proven publicly owned conventional natural gas reserves that could be developed for export and would provide economic benefits to the Inuvialuit Settlement Region, NWT and Canada. The study concept is called "Mackenzie Delta Liquified Natural Gas" or MDLNG Project. The Base Case is located entirely within the Inuvialuit Settlement Region (ISR), as shown in Figure 1-1 below.

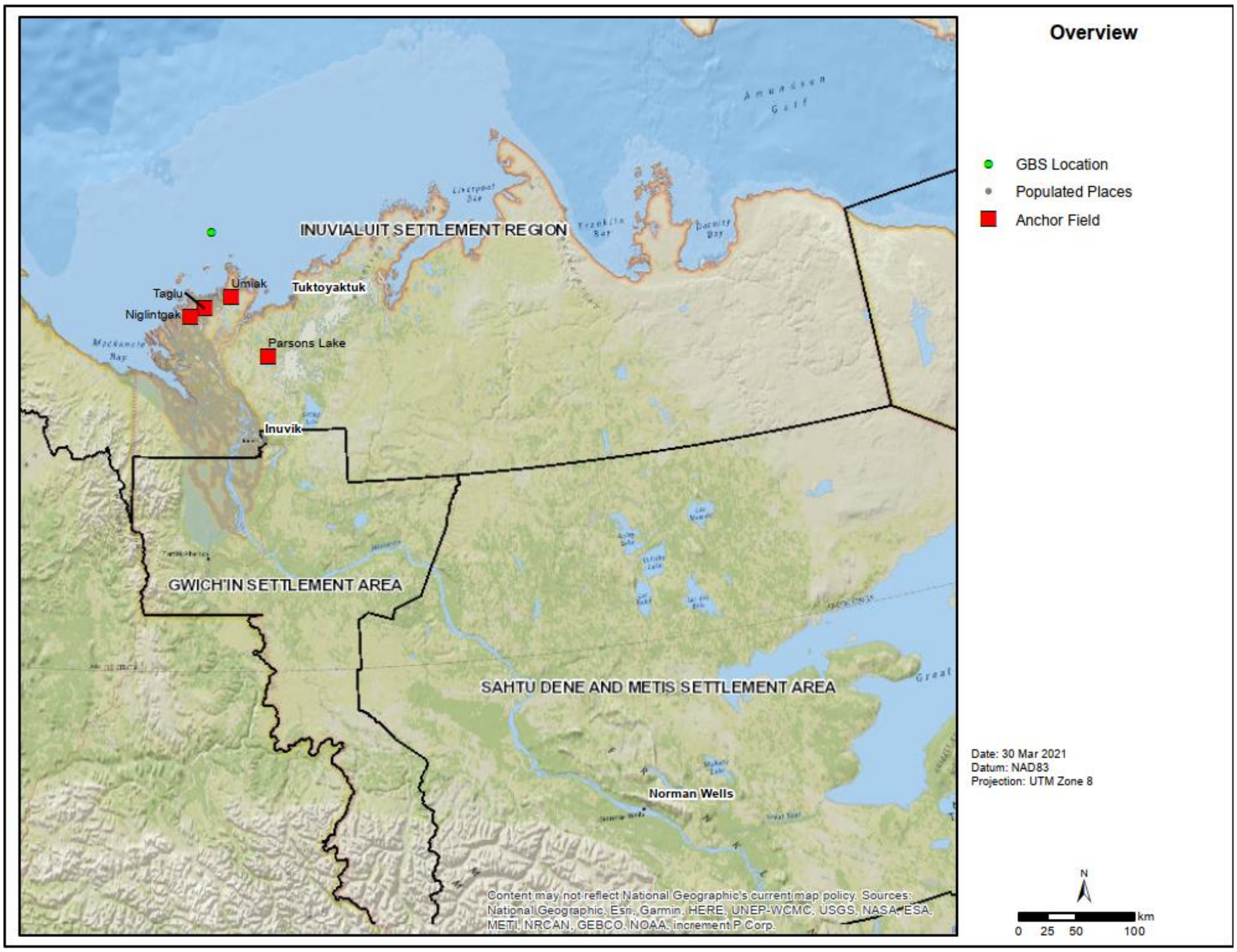


Figure 1-1 Overview Map

The primary MDLNG concept is the development of onshore hydrocarbons for delivery to gas liquefaction and hydrocarbon export facilities located approximately 31 km offshore. From the offshore export facilities, the LNG and condensate would be shipped by separate specialized icebreaking tankers to markets.

An alternative is to build a condensate pipeline to Norman Wells to interconnect with Enbridge's Line 21 which in turn would transport the oil to Alberta and other markets. The natural gas would be transported to the LNG facility to be shipped in specialized ice breaking tankers to market.

The original scope of work assumes that there would be a requirement for a Gravity Based Structure (GBS) for LNG and a GBS Oil (O) for condensate.

The deliverables for this MDLNG pre-feasibility study consist of the following:

1. Upstream Field Development Plan and Cost Estimates

- A description and schematics showing the main facilities at the core fields and any other facilities downstream of the core fields but upstream of the inlet to the offshore facilities.
- Maps showing the pipeline gathering system and export pipelines configuration and route.
- An associated screening level (Class 5 equivalent -30%/+50%) cost estimate, showing total cost estimate and unit cost (e.g. $/Mcf or $/bbl), together with breakdown by project component.
- In addition to the capital cost estimate, an estimate of OPEX and cost estimating assumptions.

2. Offshore Structures

- A description of the GBS design, identifying the different options where applicable, and including simple drawings.
- Screening level (Class 5 equivalent) cost estimate, showing total installed capital cost estimate range and associated OPEX estimates.

3. Shipping Study

- A description of the results of the shipping study including applicable drawings and maps. The methodologies used to generate key information, such as screening-level LNG carrier and condensate/ oil tanker design, estimated number of LNG carriers and condensate/oil tankers required for the project and estimated number of shipments per month.
- A screening-level cost estimate including the items outlined in the scope description above.

4. Cost Estimation Summary

- A summary of cost estimate information generated in all three scopes, covering both CAPEX and OPEX resulting in an "all-in" screening level development cost for the MDLNG concept. These costs are expressed in 2021 Canadian dollars (CAN$).

5. Economic Evaluation

- A high-level economic evaluation of the options.

- A simple pre-tax economic assessment of the MDLNG concept comparing the estimates of total costs against expected revenue per Mcf/MMBtu and per bbl.
- Sensitivities will be run based on the range of total capital / operating costs.
- A 'landed' price of LNG (US$/MMBtu).

6. Conclusions

- A summary of the conclusions for the report and potential future studies.

2 Upstream Field Development

2.1 Supply

The upstream field development is based in a large part on the field development plans for the Mackenzie Gas Pipeline (MGP) project. The initial phase of the MGP relied on the discovered onshore natural gas with anchor facilities located at Niglintgak, Taglu and Parsons Lake. These same locations have been used in this study because the facility designs and the location rationale were previously approved by the National Energy Board (NEB, now called the Canadian Energy Regulator). This information was supplemented with new information provided by MGM Energy (MGM) and Nytis Exploration Company Canada Ltd. (Nytis).

There are two primary options related to the transportation of condensate. Option 1 has the condensate going to an offshore GBS storage facility to be exported by ice breaking tankers. Option 2 ships the condensate by pipeline south to Norman Wells and then on to markets using existing pipelines. Both Options have the natural gas converted to LNG on an offshore GBS for shipment to Asian markets. For the various options, sensitivities were evaluated related to:

- Different timing and locations for the supply of natural gas
- Different carbon capture and power generation
- The production and transportation of oil in addition to the condensate.

The sensitivities are described in Appendix A with the results summarized in Section 6: Economic Evaluation.

2.1.1 Hydrocarbon Reserves

The following table provides the breakdown for individual discovered fields with respect to gas, condensate and oil reserves. Producers for individual fields are identified where the information is known. The information in Table 2-1 is sourced from the field interest holders (per MGP), the NEB, 2014 Conventional Resource Assessment and from information provided by MGM Energy Corp. (MGM) and Nytis Exploration Co. LLC (Nytis). Although oil reserves were identified for the MGP project, the producers did not include any oil production. MGM did not include the oil reserves in their economics for the Umiak field nor did Nytis in their evaluation of the Garry field.

Table 2-1: Hydrocarbon Reserves

Field Name	Owner	Gas Bcf	Condensate MMbbl	Oil MMbbl
Anchor Fields				
Taglu	Imperial Oil	2,898	30.5	0.0
Parsons Lake	Conoco Phillips/ExxonMobil	2,257	23.9	1.2
Niglintgak	Shell	912	0.3	9.4

Field Name	Owner	Gas Bcf	Condensate MMbbl	Oil MMbbl
Sub-total		**6,067**	**54.7**	**10.6**
Additional Fields				
Langley, Olivier, Ellice	MGM	584	0.0	0.0
Umiak	MGM	525	12.0	33.2
Garry	Chevron/Nytis	220	2.68	40.3
Hansen	Imperial Oil	191	1.27	3.2
Titailik	Imperial Oil	59	0.0	0.0
Ya Ya	Shell	115	0.5	0.0
Malik	Imperial Oil	40	0.0	0.0
Kumak South	Shell	28	0.15	11.4
Unipkat	Shell/MGM	109	0.0	28.1
Ivik	Imperial Oil/Nytis	19	0.0	6.0
Sub-total		**1890**	**16.6**	**122.2**
Grand Total		**7,957**	**71.3**	**132.8**

The new fields that have been added are located on the map below:

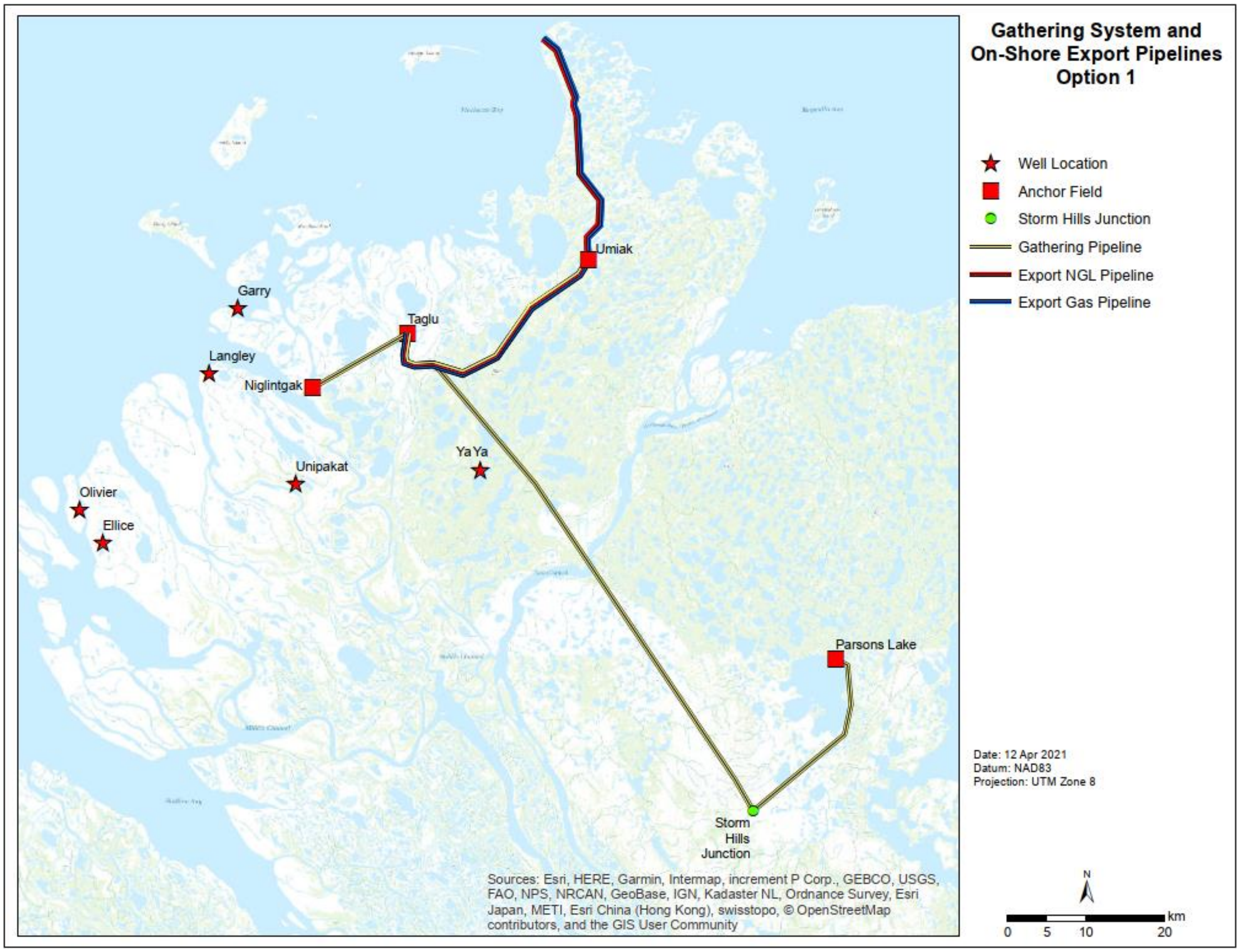


Figure 2-1 MDLNG Gathering System and Onshore Export Pipelines

In 2004, Sproule reported that the expected undiscovered onshore reserves in the delta region could provide an additional 11.138 Tcf (Trillion Cubic Feet) as presented in the Table 2-2.

Table 2-2: Undiscovered Onshore Reserves Table

Region	Natural Gas Bcf	NGL MMbbl
Taglu	6,713	112.4
Ivik	1,272	16.5

Region	Natural Gas Bcf	NGL MMbbl
Parsons Lake	1,629	25.9
Tuk	49	0.1
Mayogiak	18	0
Atkinson Point	83	0
South Delta Parson	547	8.7
South Delta other Mesozoic	431	3.7
South Delta Paleozoic	396	3.4
Total	**11,138**	**170.7**

2.1.2 Gas Deliverability

Currently, it is unknown which producers would initially support the MDLNG project; therefore, a number of options are evaluated. With each of the gas deliverability cases, the associated NGL production is also forecast.

Each gas field has multiple zones within the field. How the zones are developed will be a decision that an individual producer will make as they develop the field. For this study, each field has been treated as a single production area. The deliverability forecasts have been developed using a simple volumetric calculation for each field. The assumption being that a field can produce at the planned capacity until 60% of the field has been depleted at which time the production will decline at a rate of approximately 15%/year. More detailed modelling for each reservoir will need to be done in future phases of the project. For the non-anchor fields, the daily production capacity was calculated by dividing the field reserves by 7,300 (20 years x 365 days/year).

The associated condensate production was also developed using a simple volumetric calculation. The condensate production forecasts will need more study using other reservoir models to better define the production. The condensate production forecasts by field presented in the MGP filings would indicate a faster decline rate than is presented using the simple model. In all cases, the initial condensate production is 6,500 bbl/d or less.

2.1.2.1 Base case

The initial deliverability assumes that Niglintgak, Taglu and Umiak will provide the gas for the Project. Production will be held constant for the first 10 years and then Parsons Lake production will be added to make up for anticipated declines in Niglintgak, Taglu and Umiak. Parsons Lake will reach full production capacity by year 15. The other fields beginning with Langley, Olivier and Ellice are forecast to come onstream in year 17 with all of the discovered fields in production by year 20. Figure 2-2 illustrates the phased production from the fields for the Base Case.

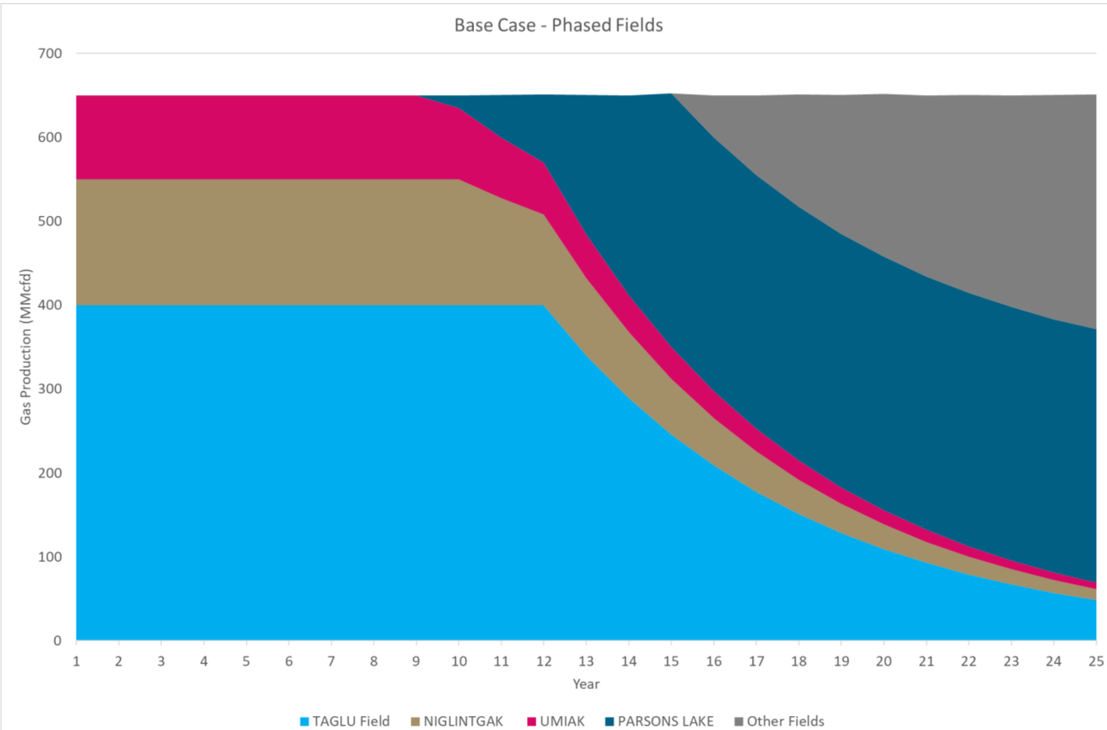


Figure 2-2 Base Case – Phased Fields

The associated production of condensate for the base case is presented below. Only Taglu and Umiak have any material production of condensate in the early years. Niglintgak has negligible condensate production. The production of condensate from Parsons Lake is not smooth as the natural gas builds up to match the declines in the northern fields. The actual production would depend upon which development wells and zones were brought on in the early years.

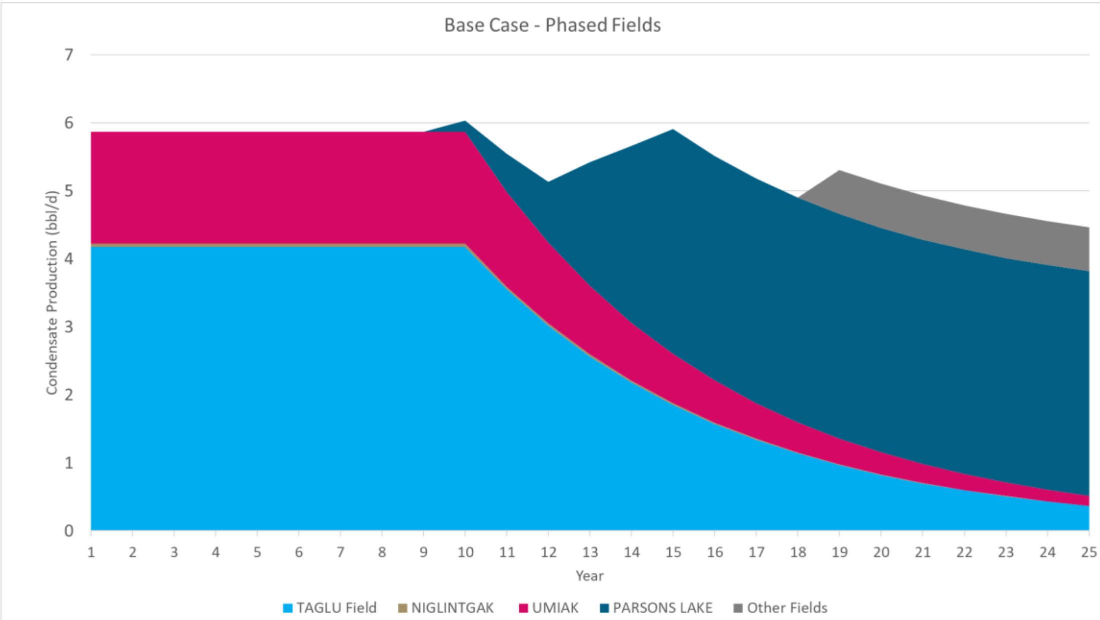


Figure 2-3 Base Case – Condensate Profile

2.1.2.2 All fields

With the expected onstream date for the MDLNG Project being approximately 2030, there is the potential that all the producers in the region will want to have their fields participate, so production from each field would be prorated to meet the required capacity (see Figure 2-4).

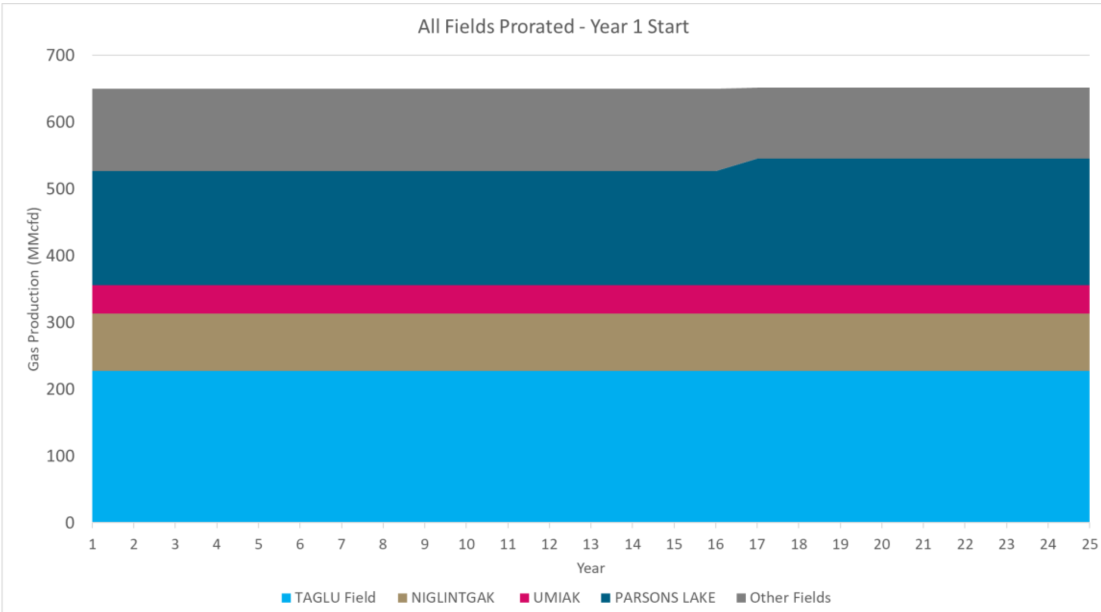


Figure 2-4 All Fields Prorated – Year 1 Start

The condensate production for the All Fields Prorated with a year 1 start is presented in Figure 2-5:

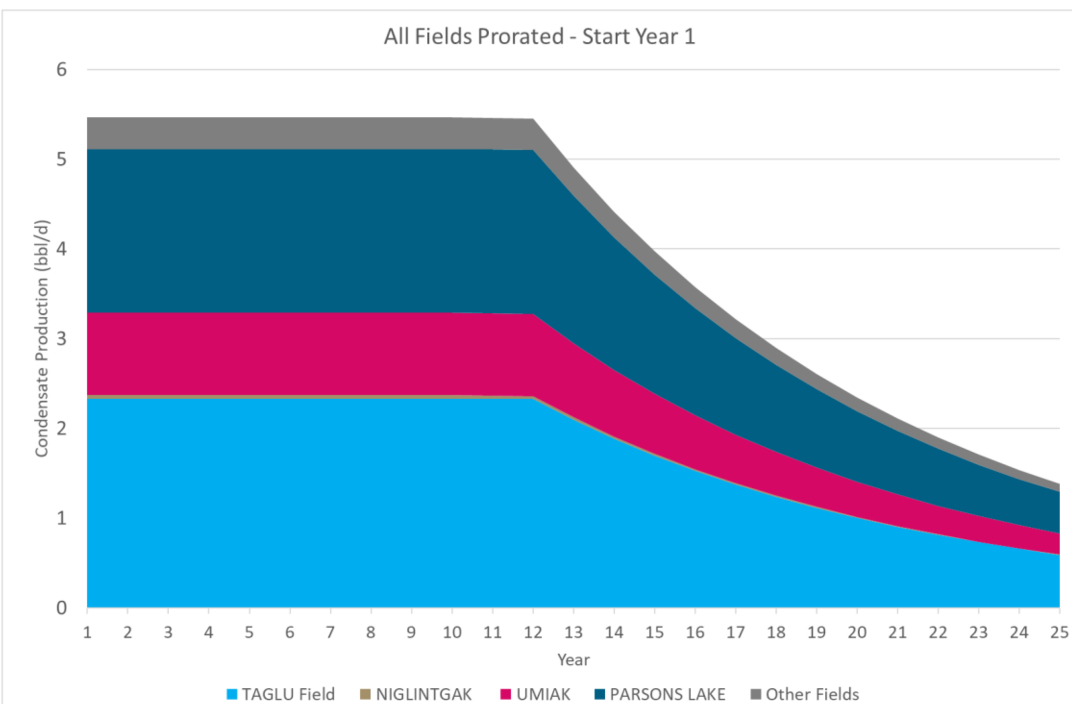


Figure 2-5 Condensate Production for All Fields Prorated – Year 1 Start

2.1.2.3 Anchor Fields

As another sensitivity to the production and costs, a production profile assuming that the Parsons Lake comes onstream at the same time as Niglintgak, Taglu and Umiak was developed. The combined production from these fields would need to be prorated down to meet the 650 MMcfd production requirement.

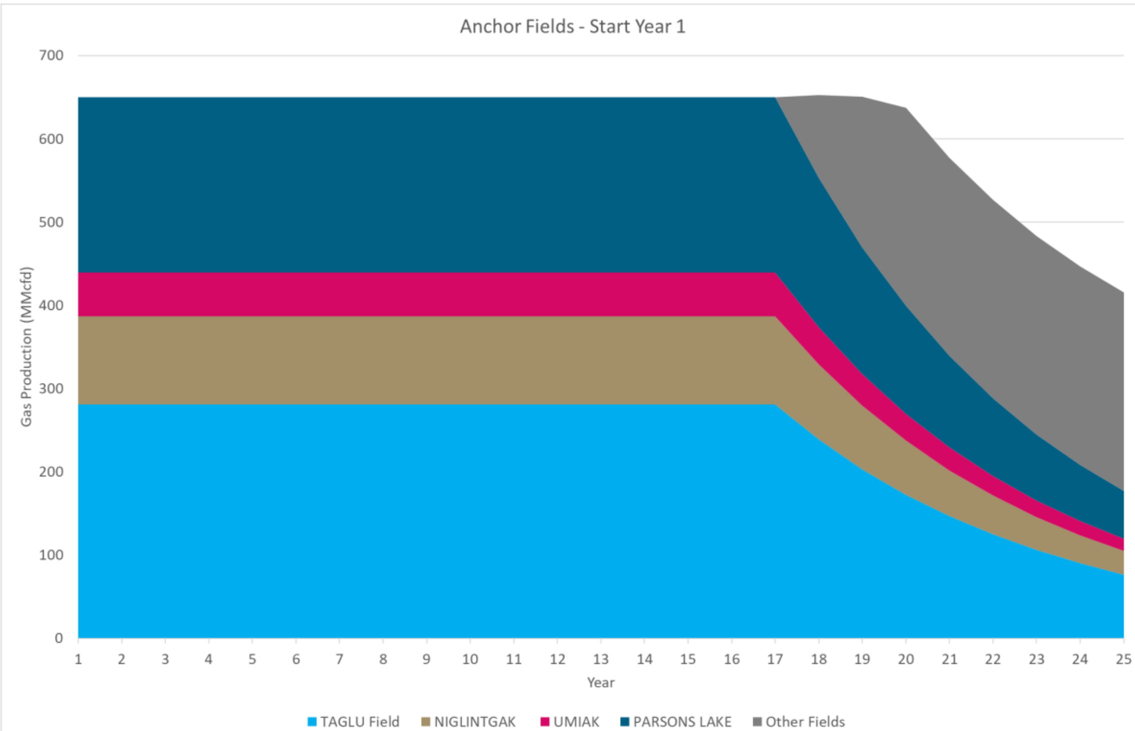


Figure 2-6 Anchor Fields – Year 1 Start

The associated production of condensate for the Anchor Fields all starting in year 1 is presented in Figure 2-7.

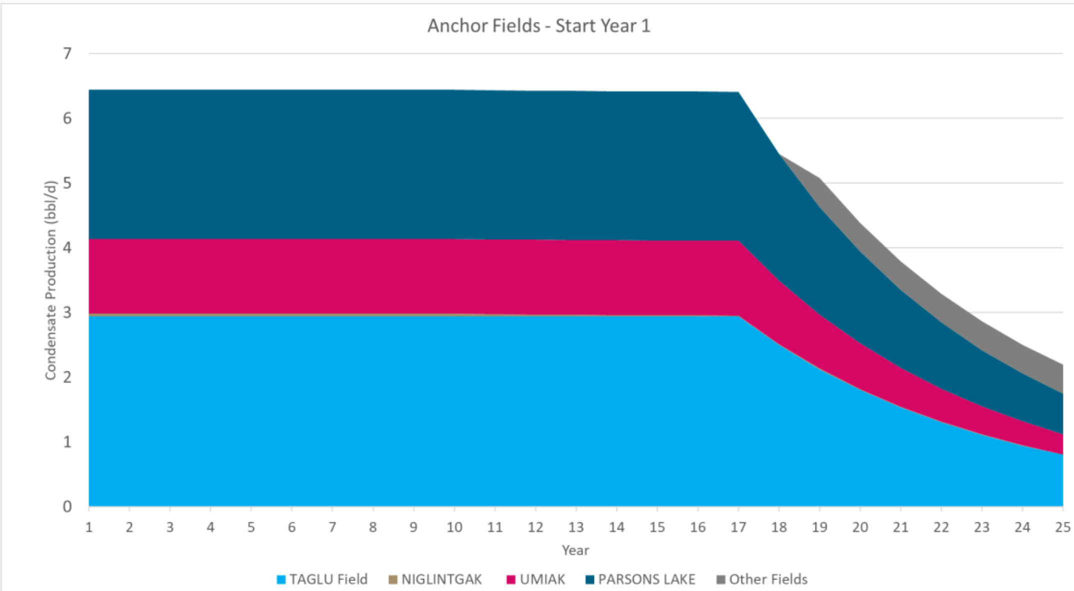


Figure 2-7 Associated Production of Condensate for Anchor Fields – Year 1 Start

2.2 Field Development

This section provides a general overview of the onshore field development. The field development for the upstream well pads, flow lines, conditioning facilities and gathering lines was extensively described in the MGP application. The facility construction, in the MGP application, considered arctic conditions and detailed mitigation plans for minimizing the impact to the permafrost were developed. Those construction techniques and considerations were relied upon in the development of the capital cost estimates for the field development.

As this region has permafrost throughout, the facilities and pipelines are designed to have the least impact possible to the permafrost. To achieve this, multiple production wells are proposed to be directionally drilled from well pads that are built on elevated pile foundations. The flow lines are proposed to be above ground and insulated as the gas production will be much warmer than the ground. The conditioning facilities and Central Gas Processing Facility will also be built to reduce the impact on the permafrost. In the case of Niglintgak, the proposed conditioning facility is built on a barge. The gathering lines from the conditioning facilities to the Central Gas Processing Facility will be buried with these multiphase product pipelines operating at a temperature of -1° C. Similarly, the export pipelines (both gas and condensate) will be buried with the temperature of the gas and condensate leaving the Central Gas Processing Facility at a temperature of -1° C.

2.2.1 Field Development and Gas Conditioning Facilities

The field development for each anchor field includes:

- Number of well pads with several production wells
- Gas conditioning facility
- Disposal well(s)
- Above-ground flow lines from the well pad to the gas conditioning facility
- Supporting infrastructure

The gas conditioning facilities for each of the anchor fields will separate, dehydrate, cool and meter the production in preparation for delivery into the gathering pipeline. Equipment located on the site will typically include:

- An inlet separator
- Dehydration equipment
- Gas compression equipment (future)
- Refrigeration equipment
- Safety and control systems, including a flare system communications equipment
- Utility systems, including:
  - Electrical power generation equipment a circulating heat medium
  - Fuel gas

Gas conditioning facilities will process the reservoir fluids from the well-site facilities to meet the specifications of the gathering pipelines, which will then transport the co-mingled gas and liquids directly to the Central Gas Processing Facility located at Taglu. Gas conditioning facilities will be designed for remote, unstaffed operations and will be accessible by helicopter, fixed-wing aircraft, winter road and barge. Living quarters will be provided for operations and maintenance staff when on site.

The gas conditioning facility for Taglu will be incorporated into the Central Gas Processing Facility located in the Taglu area.

2.2.1.1 Field Development

Niglintgak Field Development

Originally Shell considered two options for their gas conditioning facility (a barge-based option and a land-based option). Shell ultimately chose the barge-based option for cost and environmental reasons. For the purpose of this pre-feasibility study, only the barge-based option is considered.

The Niglintgak gas conditioning facility would be located near the southern end of Niglintgak Island in the Mackenzie Delta, within the Kendall Island Bird Sanctuary. The field is located approximately 120 km northwest of Inuvik and 85 km west of Tuktoyaktuk.

The field development will include:

- Three well pads (north, central and south)
  six to 12 production wells

- A gas conditioning facility
- A disposal well
- Flow lines
- A remote drilling sump
- Supporting infrastructure
- Helipadd

The Niglintgak field development flow lines and gathering pipeline traverses four major river crossings (one for the flow lines, 3 for the gathering pipeline) which have been assumed to be installed by horizontal directional drilling (HDD).

The initial field development will involve drilling four wells from the proposed north pad and one well from each of the proposed central and south pads. Three well pads will be needed to access the full resource, because of its shallow depth. Up to six additional wells might be drilled from the proposed pads, depending on the production performance of the initial development wells.

Elevated steel pads will be installed on steel piles at each well pad to support the drilling rig and its equipment. The pads will be about 2 to 3 m above ground and will have spill containment capability. The pad size will range from 45 by 75 m to 75 by 90 m. The pads will have sufficient area to support well-workover operations. The piles will be installed in holes drilled with truck-mounted auger rigs and will be frozen in place. The pads will remain in place for the production life of the wells.

Steel pads and walkways covering an area of 100 by 100 m will also be provided for the well pad facilities.

An ice pad will be constructed adjacent to each well pad for the drilling camp and equipment laydown during winter drilling and construction activities.

Each well pad in the Niglintgak field, including the ice pad and well pad facilities, will require a total area of about 6 hectares (ha).

Taglu Field Development

The Taglu field is located near the northern margin of the Mackenzie Delta, about 120 km northwest of Inuvik and about 70 km west of Tuktoyaktuk. The centroid of the field and the proposed site of the Taglu development is located near the confluence of the Kuluarpak and Harry channels of the Mackenzie River, and lies within the Kendall Island Bird Sanctuary.

The Taglu development concept was assessed as an integral component of the Mackenzie Gas Pipeline Project and is also considered an integral component of the proposed MDLNG Project. Opportunities to obtain synergies with the other anchor gas fields and take advantage of coordinating infrastructure requirements for the MDLNG Project were considered.

The Taglu field is expected to be developed in stages. When complete, the following will be located on a common site:

- A well pad consisting of 10 to 15 production wells

- One or two disposal wells
- A Central Gas Processing Facility (processes all gas prior to gas and liquids entering the export pipelines)
- supporting infrastructure, including an airstrip

The well pad is located next to the Central Gas Processing Facility (CGPF) such that the flow line from the well pad to the CGPF is only a couple of hundred metres in length and is considered part of the well pad. The Central Gas Processing Facility at Taglu eliminates the requirement for a conditioning facility at Taglu therefore eliminating the requirement for a gathering pipeline.

The initial field development will involve drilling five to seven production wells from a single well pad. Full field development will require drilling an additional three to eight production wells from the same well pad within 10 years of start-up.

The conceptual design is based on pile-supported elevated structures, using ad-freeze piles. The piles, which are set in drilled holes and frozen in place, elevate the structures to the required height and provide free airflow between the gravel and heat sources, maintaining the ground temperature. Ground temperature is important in determining the time required to develop the desired ad-freeze or freeze back strength.

Infrastructure will be required to provide access to the Taglu site all year to support the construction and operations phases of the development. This will include:

- A river barge dock
- An all-weather road within the plot area to provide access between the barge landing site, airstrip, well pad and CGPF pad
- Winter road from Tununuk Point to transport gravel, drilling equipment and other site supplies
- a permanent airstrip to transport equipment and personnel by aircraft
- a permanent helicopter pad for use in the shoulder seasons when the airstrip might be inaccessible because of flooding

Umiak Field Development

The Base Case field development plan for Umiak envisions an Umiak gas conditioning facility located at C-16, with the N-16 well connected to the gas conditioning facility via an above ground pipeline supported on vertical support members (VSMs). There will be 2 or more wells located at the gas conditioning facility where the natural gas, natural gas liquids (NGLs), and water will be separated. The water will be reinjected into a disposal well. The natural gas and NGLs will be dehydrated in separate processes, the former by mol sieve dehydration, the latter through a stripping column. These streams are cooled, recombined and sent in a common buried export pipeline approximately 30 km to Taglu, the location of the Central Gas Processing Facility. At the Umiak gas conditioning facility there will be process utilities consisting of a fuel gas system, power generation, emergency power generation, utility heating, heat tracing, potable water, instrument air, fire suppression, diesel system, drain system, waste handling and chemical injection systems.

Infrastructure will be required to provide access to the Umiak site all year to support the construction and operations phase of the development. This will include:

- Barge landing site including dock and storage pad
- Helipad
- Roads
- Permanent foundations
- Maintenance building
- Cold storage building
- Heated storage building
- Vehicle fuel storage
- Temporary construction camp
- Fencing and lighting
- Accommodations, telecommunication and control room

Site construction would take place over 3 winters.

Parsons Lake Field Development

The main production facilities at the Parsons Lake field will be located on two main gravel pads, the most northerly and larger of the two near the northeast shore of Parsons Lake.

This north pad will be built first. The gas conditioning facility for the Parsons Lake field will be located there. Two injection wells for disposing of drilling cuttings, produced water and other waste from the field will also be located on the north pad. The connection to the Parsons Lake Gas Conditioning Facility to the proposed gathering system pipeline extending to the Central Gas Processing Facility (located at Taglu) will also be located at the north pad.

Based on the original permit application, the second, smaller well pad would be constructed about five or six years after construction of the north pad and will be located about 14 km from it, south of Parsons Lake. An elevated, two-phase flow line will transport natural gas from the south pad to the north pad's gas conditioning facility. The preferred configuration is to have the main facilities at the north pad, with a minimally equipped facility at the south pad, because:

- The bulk of the production comes from north pad wells
- The overall cost is reduced by using the available future gas conditioning capacity at the north pad
- The overall land area required for the facilities is less

This configuration assumes a complete gas conditioning facility at the north pad, consisting of inlet separation, compression, dehydration and product chilling units. Although locating the gas conditioning facility at the north pad requires a flow line from the south pad to the north pad, the advantages of this configuration outweigh the disadvantages.

Nine producing wells are expected to be located on the north pad, although space has been reserved for drilling about 10 additional wells. The south pad is expected to require three producing wells, although space has been reserved for drilling about four additional wells. Although additional wells are planned to be drilled on both the north and south pads, the final number of wells will depend on the drilling and production results.

The north pad will be built on granular material about 1.5 m thick. All heated buildings and equipment outside the buildings will be supported on steel pipe piles. The piles will be an ad-freeze type installed in oversized holes filled with sand slurry.

The south pad will be built on ice pads and will have only a small area of granular material around the wellheads. All other buildings and equipment will be supported on steel pipe piles and will be connected by walkways.

Infrastructure required will include:

- Helicopter pads will be at the north pad, south pad and satellite wells.
- Roads - The north pad will have a permanent access road connecting it to Parsons Lake.
- Dock - A floating dock will likely be built on Parsons Lake at the north pad. The dock is designed to handle the docking and unloading of a float plane.
- Airstrip - An all-weather airstrip approximately 1,500 m long by 50 m wide was planned by the field Owners in their original field development plan. The airstrip will be able to handle aircraft up to the size of a C-130 Hercules cargo transport and would be located in the vicinity of the north pad.
- Accommodation Facilities - The north pad will have permanent accommodation facilities for about 28 people. During construction, a temporary 150-person camp will be located at the north pad.

Other fields

The other fields have been assumed to require only a drilling pad, development wells and above ground flow lines to the nearest conditioning plant.

2.2.1.2 Central Gas Processing Facility

The onshore gas processing facility will use gas from the other fields in any combination to supply the 4 MTPA offshore LNG plant. Condensate stabilization is also included in the process. Processed gas (meeting the LNG specification) and stabilized condensate will be exported to offshore GBS(s) in separate pipelines.

Nominally, the gas processing facility will process about 650 MMcfd gas to support 4 MMTPA LNG production and provide fuel for the offshore operation.

Overall, the gas from the fields is very lean and even unprocessed gas does not exceed the maximum LNG Higher Heating Value (HHV) of 1,170 BTU/cf. As a result, only a relatively small amount, about 6,500 bpd of condensate, must be removed to meet the C5+ spec in the LNG product.

The gas is not suitable for direct liquefaction because of the CO_2 content. This must be less than 50 PPMV. For CO_2 management, it is advantageous to remove CO_2 at the onshore Central Gas Processing Facility. The offshore LNG plant would then default only to liquefaction.

The Central Gas Processing Facility (CGPF) will include the following:

- Inlet separation and liquids stabilization
- CO_2 removal (amine)
- Dehydration and mercury removal (solid bed adsorption)
- Propane refrigeration
- Inlet or outlet compression (if required)
- Safety and control systems, including a flare system communications equipment
- Utilities and Offsites (including power generation)

The CGPF is designed to allow CO_2 capture and storage, based on the assumption that an acceptable storage reservoir can be found to inject the CO_2. This presents a potential project benefit because the cost of the additional facilities offsets carbon emissions and would eliminate most carbon tax. Included in this concept is the generation of power which would be sent to the GBS to run electric compressors, reducing the carbon footprint even further.

2.2.1.3 Gathering System Pipelines

The gathering system is comprised of pipelines and associated facilities extending from each of the individual field's gas conditioning facilities and connecting to the Central Gas Processing Facility. The fully developed gathering system for Option 1 is presented in the Figure 2-8 below.

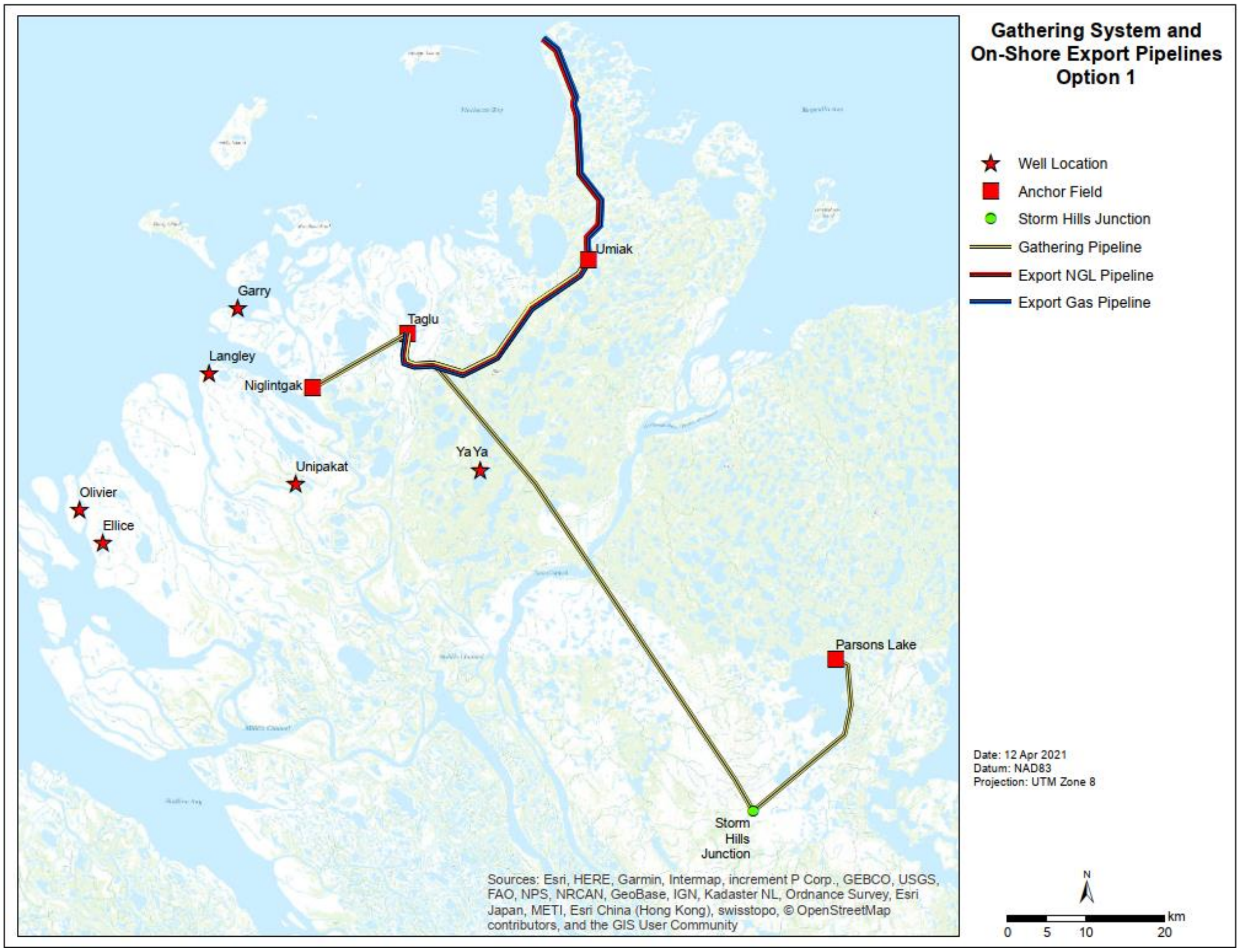


Figure 2-8 Gathering System and Onshore Export Pipelines Option 1

The design of the gathering pipelines is based on the gas production volumes from four anchor fields and other potential gas sources in the Mackenzie Delta. For the purposes of this pre-feasibility study, receipt locations for volumes received from other potential sources are assumed to flow into the nearest anchor gas conditioning facility.

The selected gathering pipeline consist of about 153.6 km of buried NPS 16 and NPS 24 pipelines. These include:

- 15.7 km, NPS 16, X52 pipe, 9.93 MPa MOP for the Niglintgak lateral
- 107.9 Km, NPS 24, X52 pipe, 9.93 MPa MOP for the Parsons Lake lateral
- 30 km, NPS 16, X52 pipe, 9.93 MPa MOP for Umiak lateral

The Niglintgak and Parsons Lake laterals follow the route that was selected in the MGP study. The route for the Umiak lateral follows the route for the export pipelines to the GBS.

Receipt meter stations for the gathering pipelines are located at each anchor field gas conditioning facility. Gas and liquids will be metered separately, using allocation meters designed to the same standards as custody-transfer meters. Pigging facilities and block valves are included at each site.

2.2.1.4 Export Pipelines

Option 1

As seen in Figure 2-9, the export pipelines for Option 1 are 95.6 km in length, (30.8 km offshore and 64.8 km onshore) with an NPS 30 natural gas pipeline and an NPS 10 condensate pipeline. The onshore portion of the export pipelines is buried and runs from the CGPF located at Taglu to the shore crossing on the North Point on Richards Island. The shallow sea along the coast influenced the location for the shore crossing. With sea ice being present for at least nine months of the year, it was assumed that winter construction of the offshore pipelines, from the shore crossing to a water depth of approximately 6 metres, would be required.. The selected shore crossing provides the least amount of winter sea ice construction (10 km). The onshore route to the shore crossing was selected to minimize the crossing of water bodies and pingos (ice-cored hills). The offshore portion of the pipeline starts with a shore crossing at North Point on Richards Island out to the proposed LNG offloading GBS platform (see Appendix B for more details). For the export pipelines, three cases were evaluated:

- Case 1: has two GBS platforms, one for LNG processing / offloading and one for condensate/oil offloading and has two pipelines; one gas pipeline and one condensate/oil pipeline.
- Case 2 Base Case: has one GBS platform that will offload both LNG and condensate/oil and has two pipelines; one gas pipeline and one condensate/oil pipeline.
- Case 3: this case is identical to Case 2 with the addition of a power cable from Taglu to the GBS.

It was assumed that a fibre optic communications cable (FOC) will also be needed for each case and will be installed bundled to the gas pipeline.

The selection of the pipeline route and the location of the GBS is based upon the requirement for the GBS to be located in a water depth of at least 15 metres. The GNWT's proposed location (Isserk E-27 well, a sacrificial beach island) does not meet the criteria because the water depth at that location is only approximately 12 metres.

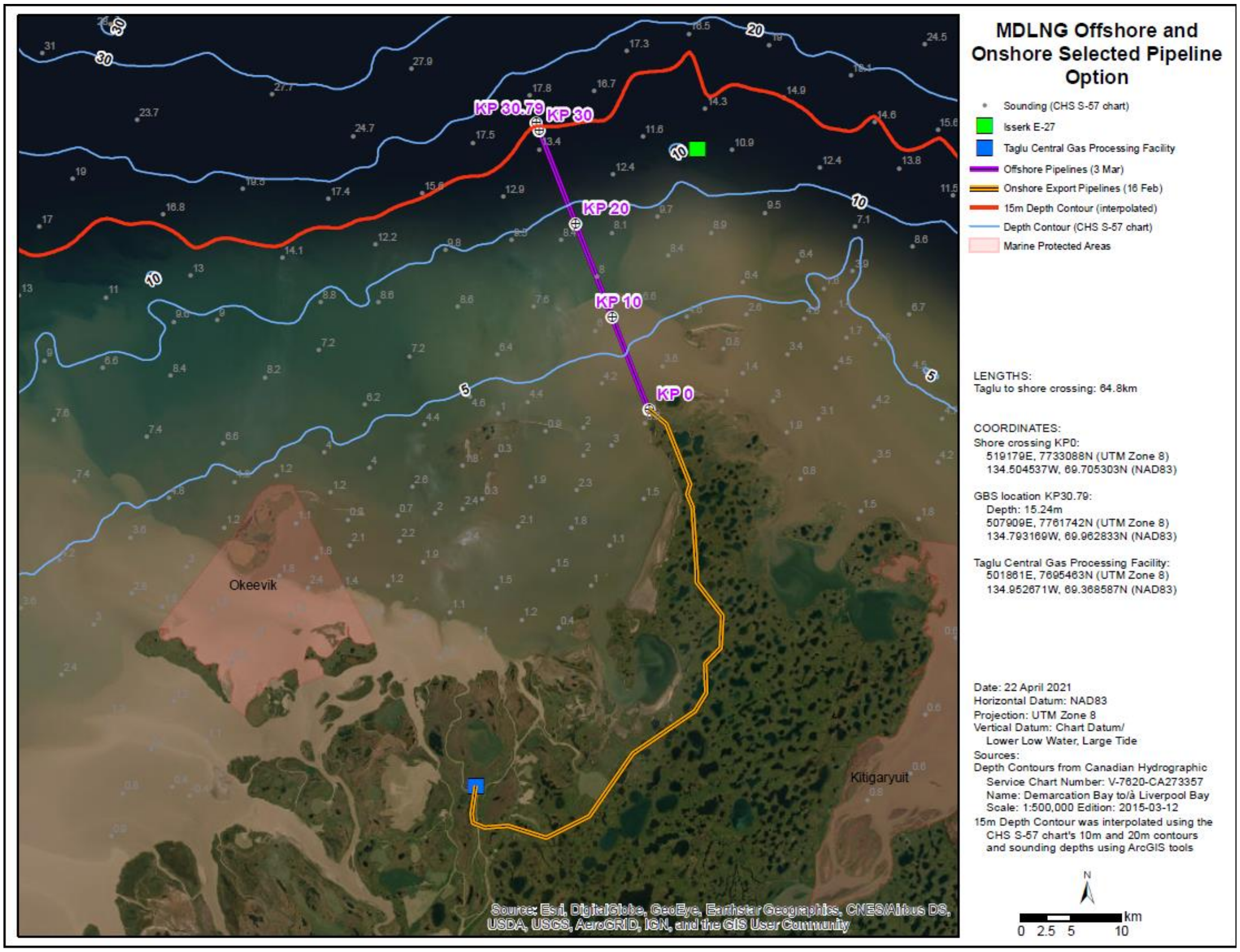


Figure 2-9 MDLNG Export Pipelines Offshore and Onshore to a single GBS

Option 2

Option 2 (Figure 2-10) has the same 95.6 km NPS 30 natural gas pipeline to the proposed LNG offloading GBS platform as Option 1, with an additional onshore 633 km NPS 10 buried condensate pipeline going south from Taglu along the original routing of the MGP project to Norman Wells. For this option, it is assumed that a FOC will be installed on both the natural gas pipeline to the GBS and on the NGL pipeline to Norman Wells.

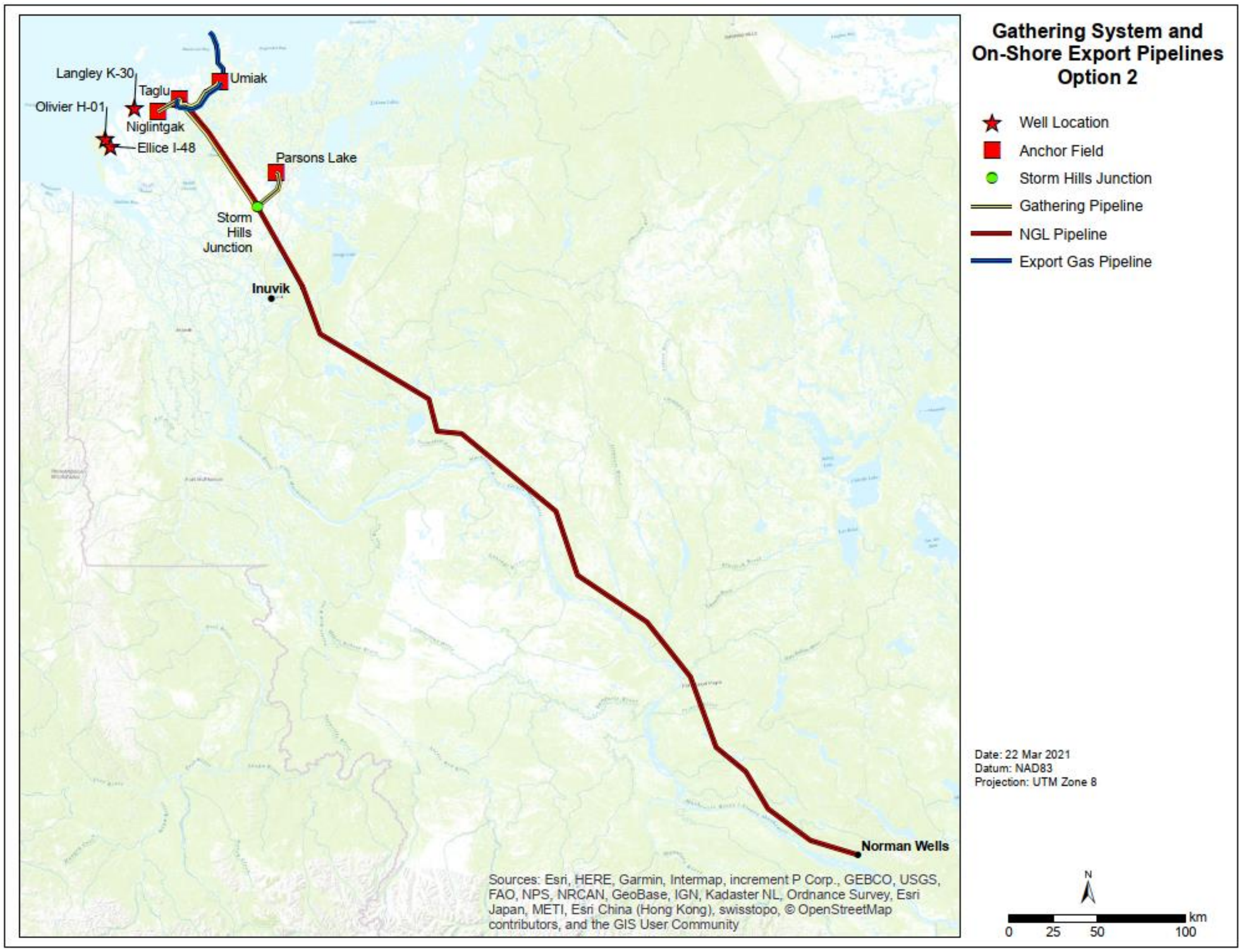


Figure 2-10 Gathering System and Onshore Export Pipelines Option 2

From Norman Wells, the condensate will enter Enbridge's Line 21. Line 21 is approximately 868 kms in length extending from Norman Wells to Zama Lake in Alberta, where it interconnects with the 775 km Rainbow Pipeline (owned by Plains Midstream) that transports product to Edmonton (see Figure 2-11). Enbridge operates Line 21 (the Norman Wells Pipeline) which is a NPS 12 pipeline with a design capacity of 50,000 barrels per day. The transportation tariff and tolls are regulated by the CER. The average daily delivery of oil to Zama from Norman wells for 2021 is forecast to be approximately 7,500 bbl/d. The current transportation toll on Line 21 is $21.4/bbl. The Rainbow Pipeline has sufficient capacity to transport the forecast MDLNG condensate volumes. Rainbow Pipeline does not have a published transportation toll, the tolls are market based. As the distance is approximately the same, the same transportation toll as Line 21 was assumed for the Rainbow Pipeline toll.

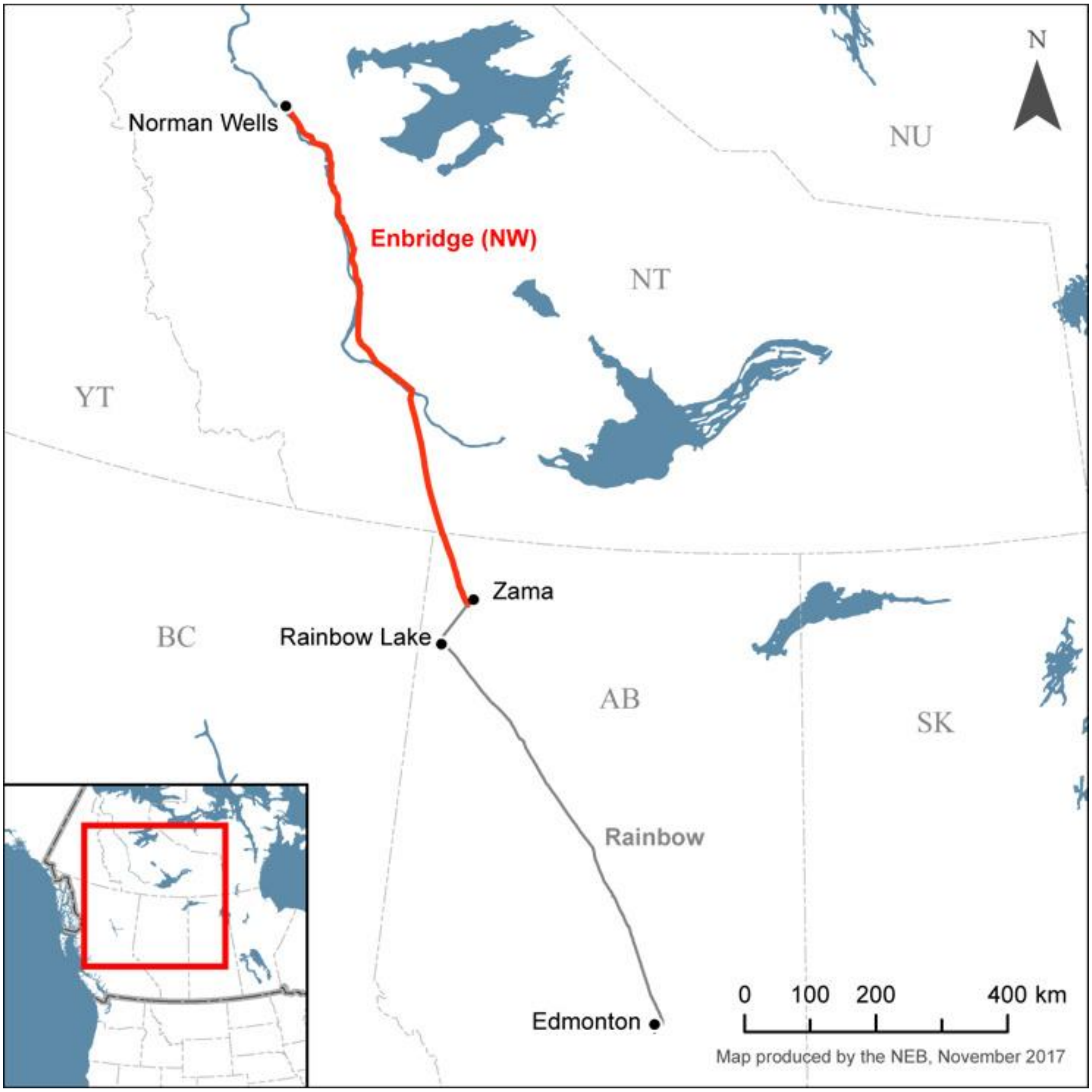


Figure 2-11 Norman Wells to Edmonton, Alberta

2.3 Cost Estimates for Field Development

2.3.1 Capital Cost Estimate for Field Development and Gathering

The capital cost estimates for field development for Niglintgak, Taglu and Parsons Lake are based on the conceptual design of the original permit applications submitted by the individual field owners for the MGP Project in 2004. The Umiak Field development costs are based upon information provided by MGM.

For the other smaller fields, an average cost per MMcfd of capacity is used that reflects the cost of well pads, drilling and completion of development wells, and flow lines. The smaller fields are assumed to use the gas conditioning facilities at the anchor locations.

With some variation, the capital cost estimate for each of the anchor fields includes costs for:

- Regulatory application preparation
- Well pads, drilling and completions
- Project management
- Design, procurement and construction of production facilities and flow lines
- Pre-commissioning

At each of the locations, the unit costs presented in Table 2-3 were used to develop the estimate.

Table 2-3: Upstream Cost Basis

Component	Unit	2021 CAN$ MMM
Development Well	$/well	40
Well Pad	$/pad	26
Flow line	$/diameter-inch-km	0.25
Conditioning Plant	$/MMcfd	1.3
Central Gas Processing Facility	$	800

Table 2-4 below summarizes the Capital Cost Estimate (CAPEX) for the Field Development and Gathering System, including the Central Gas Processing Plant at Taglu for the Base Case.

Table 2-4: CAPEX for Field Development and Gathering Systems to Taglu

Field	Field Development 2021 CAN$ MM	Gathering System to Taglu 2021 CAN$MM	Processing Facility 2021 CAN$MM	Total 2021 CAN$MM
Initial CAPEX				
Niglintgak	727	50	Processed at Taglu	777
Taglu	903	Not required	800*	1,703
Umiak	338	96	Processed at Taglu	434
Subtotal Initial CAPEX	**1,968**	**146**	**800**	**2,914**
Future CAPEX Additions				
Niglintgak	0	0	0	
Taglu	201	0	0	201
Umiak	0	0	0	0
Parsons Lake**	1,391	518		1,909
New fields***	983	Fields go to existing Anchor conditioning facilities	Processed at Taglu	983
Subtotal Future CAPEX	**2,575**	**518**	**0**	**3093**
Total CAPEX	**4,543**	**664**	**800**	**6,007**

*Conditioning costs are included in the processing plant cost.

**Parsons Lake production (costs) is deferred until Niglintgak, Taglu and Umiak begin declining production in year 10 of the project.

***For new fields (other fields identified in table 2-1) that would be required to supplement the decline on the initial fields, only wells, well pads and flow lines to existing anchor conditioning facilities were added. These fields do not come onstream until year 17 in the base case.

Future CAPEX additions at Taglu are for drilling additional wells and compression to maintain deliverability.

2.3.2 Operating Cost Estimate for Field Development and Gathering System

Periodic major maintenance activities and well interventions are included in developing the average annual cost estimate over the life of the facility.

The OPEX costs include:

- Well pad operations, including periodic well interventions and routine maintenance
- On-site and off-site operations and maintenance staff

- Routine and major maintenance costs for production facilities
- All consumables, goods and materials for well pads, flow lines and the gas conditioning facilities
- Routine inspections
- Accommodation and catering for on-site personnel
- Logistics and transportation support
- Property taxes, access fees and insurance
- Management and administration (local and head office)
- Abandonment and reclamation

Fuel gas will be supplied from the processed gas stream leaving the facility and is included as gas shrinkage, not as an operating cost.

Table 2-5 summarizes the OPEX costs for the Field Development and Gathering System, including the Central Gas Processing Plant at Taglu.

Table 2-5: Summary of OPEX for Field Development and Gathering System to Taglu

Plant	Field Development 2021 CAN$ Millions/year	Gathering System 2021 CAN$ Millions/year	Total Field and Gathering OPEX 2021 CAN$ Millions/year
Initial OPEX			
Niglintgak	18	1	19
Taglu	43	Not applicable	43
Umiak	8	2	10
Subtotal Initial OPEX	**69**	**3**	**72**
Future OPEX Additions			
Niglintgak	0	0	0
Taglu	5.0	0	5.0
Umiak	0	0	0
Parsons Lake	35	13.0	48
New fields*	25	0	25
Subtotal Additional OPEX	**64**	**13**	**77**
Total OPEX	**134**	**16**	**150**

Plant	Field Development 2021 CAN$ Millions/year	Gathering System 2021 CAN$ Millions/year	Total Field and Gathering OPEX 2021 CAN$ Millions/year
OPEX is added when the CAPEX is added. Parsons Lake comes onstream in year 10 of the project. New fields come onstream in year 17.			

2.3.3 CAPEX and OPEX for the Export Pipeline Options

The CAPEX cost and OPEX for the export pipelines related to study Options 1 and 2 are summarized in Table 2-6.

Table 2-6: CAPEX and OPEX Summary

COMPONENT	Onshore CAPITAL COST 2021 CAN$ Millions	Offshore CAPITAL COST 2021 CAN$ Millions	TOTAL CAPITAL COST $2021 Millions	AVERAGE YEARLY O&M 2021 CAN$ Millions	COMMENTS
Option 1	518.4	514.9	1,034.3	13	Gas Pipeline Onshore 64.8 km NPS 30 Offshore 30.8 km NPS 30; Condensate Pipeline Onshore 64.8 km NPS 10 Offshore 30.8 NPS 10
Option 2 Gas Pipelines	388.8	477.5	866.3	10	64.8 km + 30.8 km NPS 30
Option 2 Onshore NGL Pipeline	1,266.0	N/A	1,266.0	142	633 km NPS 10 Includes the transportation tolls from Norman Wells to Edmonton

3 Offshore Structures

Hydrocarbons produced from onshore upstream field developments will be sent to offshore facilities via subsea pipelines. The MDLNG offshore facilities will be installed at a remote location where harsh weather conditions are frequent (see Figure 2-9). Condensate will be stored offshore and loaded onto Polar Class condensate tankers (Option 1 only). Pre-treated gas will be liquified, stored and exported using Polar Class LNG carriers (both Options). Utilities, including power generation and crew accommodation will also be required on the MDLNG offshore facilities to support operations and guarantee autonomy due to the significant distance to shore and the lack of other nearby infrastructures.

A GBS will be used to support the MDLNG offshore facilities due to the specific bathymetry and arctic environment of the Beaufort Sea. Two options are considered for the MDLNG development:

- Two separate GBS(s): one for oil/condensate (GBS (O)) and one for LNG (GBS (LNG)); or
- One single GBS for both oil/condensate and LNG.

3.1 Site Selection

3.1.1 Water Depth and Seabed Conditions

The GBS must be installed at a location with sufficient water depth to allow GBS installation and subsequent safe navigation of ships (LNG carrier (LNGC)) and oil/condensate carriers. Preliminary ship information indicates that vessel drafts would be approximately 11.7 m, and therefore a typical and likely conservative draft of 12 m will be assumed for both LNGC and oil/condensate carriers.

Following international guidelines for navigation and depending on site-specific environmental conditions, it is estimated that a water depth of ≈15 m-15.5 m should be allowed for approach channel, swing basin and berth pocket.

The continental shelf has a gentle slope with water depth increasing from -10 m to -15 m over approximately 6 to 8 km and from -15 m to -20 m over approximately 4 to 5 km. Although extensive geotechnical data from previous industry activity are likely to be available for the region, at this stage of the Project development it is assumed that a suitable location with adequate foundations to support the GBS can be identified. Referring to the exploration structures installed in the 1970s and 1980s, the Mackenzie Delta is known to have variable and weak soil conditions and therefore the top 3-5 m of weaker material and sediments will likely be removed and replaced with more competent material and cleaner sand, prior to the GBS installation.

It should be noted that the uncertain foundation conditions are a significant factor and will likely control the final site selection.

3.1.2 Ice Conditions

The MDLNG offshore facilities will be installed in the landfast ice zone of the Beaufort Sea which extends to a water depth of approximately 20 m during the winter months. This region is made of First Year (FY) ice with ice beginning to grow in late September and reaching a maximum thickness of 1.9 m in late April. The ice breaks up in early July and open drift ice conditions would normally develop earlier than Alaska, i.e., generally in early summer, because of the local geography and outflow from the Mackenzie River. Historically, there were pack ice incursions throughout the open water season, but the pack ice edge has been some distance offshore in recent years.

Ice-classed vessels will be required all year round to reach the MDLNG offshore facilities and load oil/condensate and LNG. It is expected that three support vessels/icebreakers will be used for year-round operations at the terminal to maintain the approach, swing basin and berth pocket free of ice and assist carriers to berth at the terminal. The three support vessels will need to be Polar Class icebreakers; 1 Primary Icebreaker (PIB), 1 Harbour Icebreaker (HIB) and 1 Escort Icebreaker (EIB). At least one support vessel will be required to assist in manoeuvring at the terminal and there will likely need to be an escort vessel to support year-round transits around Point Barrow where challenging conditions can be expected.

In mid-winter the ice will re-freeze very quickly after being broken. This can be an issue for using a single channel as the constant breaking of ice and the subsequent re-freezing causes more difficult transit conditions. This could include potential ice blocks being forced under the vessels while under way. Preliminary global ice horizontal load calculations to estimate the GBS hull scantlings and ballast volume and weight required by GBS, in accordance with ISO 19906, A.8.2.4.3.3 Global Pressure for Sea Ice, indicate that, based on a level ice of 2.0 m thickness, a uniform lateral load of 2 MN/m (Meganewton/metre) could be expected. This is appropriate for seasonal FY ice, however the GBS will be exposed to much thicker Multi Year (MY) ice when assessing ice conditions on a longer term and statistical basis. Contact with MY ice will result in higher loads which can be derived as approximately 5 MN/m. Ultimately, a detailed analysis based on statistical modeling and Monte Carlo type analyses will be required to establish design loads for the GBS.

3.1.3 Wind and Waves

Existing literature available in the public domain indicate that extreme winds (refer to *"Overview of Historical Canadian Beaufort Sea Information" by G.W. Timco and R. Frederking, NRC Canadian Hydraulics Centre, Technical Report CHC-TR-057 February 2009*) can be quite high in the Beaufort Sea, i.e., 100-year return period wind speed (1-hour) is approximately 60 knots (gust speed is 80 knots). These extreme wind speeds are in-line with classification societies' requirements for the design of offshore structures in harsh environment and therefore are not anticipated to be an issue for the GBS design.

Waves are only relevant during summer months and are benign, (i.e., < 2 m) with probably very short periods due to limited fetch, therefore it is expected that LNGCs and condensate tankers will be able to berth at the terminal and remain moored in most wave conditions. However, since the ice pack edge has been observed to be quite far north in late summers of recent years, wave conditions may become more adverse in the future and therefore a metocean study is recommended to confirm design and operability requirements as part of the next phase of the project development.

3.1.4 1 GBS versus 2 GBS

There is an opportunity to combine GBS(O) and GBS(LNG) with some significant cost savings.

Installing two GBS could present some flexibility in terms of operations, e.g., both Polar Class LNGC and condensate tanker could load simultaneously at the terminal. In this case, the fleet of support vessels would likely need to be doubled. GBS(O) and GBS(LNG) could be installed next to each other and present synergies including accommodation, power generation, loading facilities (e.g. oil/condensate might be loaded from GBS(LNG)). If installed adjacent to each other, the two GBS platforms could provide improved protection from both mobile ice and open water conditions during high wave events. The optimum configuration would require a more detailed study of ice movement direction throughout the year and open water wave conditions. These potential benefits briefly discussed would be outweighed by the significantly higher capital and operating expenditures of two GBS.

The conceptual design prepared for MDLNG shows that a single "combined" GBS with overall dimensions 340m x 80m x 33.5m would have sufficient storage capacity (oil/condensate and LNG) and sufficient deck space for liquefaction, power generation, utilities, accommodation, mooring and loading facilities. The combined GBS would also allow both Polar Class LNGC and condensate tanker to berth and load condensate and LNG at a single loading platform.

Therefore, Advisian recommends to design, fabricate and install only one GBS. This recommendation has been adopted as part of the Option 1 Base Case.

3.2 Material Selection: Concrete versus Steel

Preliminary cost estimates prepared by Advisian (and supported by previous GBS studies in North America and benchmarking against existing assets) indicate that concrete costs are significantly higher than steel, i.e., more than twice as expensive.

It is anticipated that a steel GBS would be fabricated in Asia (China, South Korea or Singapore) and towed to site. There are only a few shipyards with experience in GBS construction that could take on the large LNG GBS. China and South Korea are the likely candidates.

Keppel and Sembcorp in Singapore have developed some GBS designs but lack experience in construction of these conceptual designs. For costing purpose, Advisian considered steel GBS fabrication in South Korea, since Chinese yard costs may not be significantly lower and carry higher risk factors. It is however noted that fabrication of topside modules could be done at a Chinese yard with integration to hull either in South Korea or China.

Concrete has been the material of choice for the current LNG industry GBS experience. The one operational LNG GBS in Adriatic Sea (i.e., Adriatic LNG Terminal) and the 3 GBS currently in construction for Novatek Arctic LNG 2 in Russia are all concrete. Novatek Arctic LNG 2 is a very large-scale project with circa 20MTPA LNG production which justified the development of a purpose-built yard at Belokamenka, near Murmansk for the construction of the 3 GBS and installation of topside modules. The tow distance from Belokamenka to the Gydan Peninsula where Novatek Arctic LNG 2 is being developed is approximately 1,000 nautical miles (nm).

Towing distance from both Russia and Newfoundland to Mackenzie Delta would be 3 times (about 3,000 nm) longer than the distance between Belokamenka to the Gydan Peninsula, and ice conditions would be challenging. In comparison, towing distance from South Korea would be approximately 4,000 nm but the majority of the towing route is over warm water with no threat of ice incursions during the tow window. More importantly, a steel GBS has a much lower lightship draft and is able to support the substantial topside weight during the tow condition. This is important for the shallow water tow route around Point Barrow to the Mackenzie Delta.

Table 3-1 presents a comparison of GBS concrete versus steel with a list of pros and cons to support the decision on material selection.

Table 3-1: Concrete vs Steel GBS Comparison

GBS Hull Structures	Concrete	Steel
Pros	• High weight and displacement minimize additional ballast • Good resistance to local ice loads • Superior cryogenic behaviour • Slower thermal response and better insulation • Reduced maintenance costs • Good impact resistance • Excellent fatigue life • Resistance to buckling	• Far East has large drydocks and fabrication capabilities • Competitive international tendering • Shallow lightship draft supports additional topsides for tow and installation • Materials and scantlings proven for Arctic deployment • Traditional engineering and construction and similarity with LNG/LPG carriers • More likely to be able to be floated off site during decommissioning in this water depth range given the float in draft and weight. • Not subject to freeze and thaw damage • Prestressing not required
Cons	• High displacement and draft restrict topside weights, tow route and installation • Concrete construction in North America (or even Russia) not competitive with Asian steel fabrication • New site development required for graving dock • Long and exposed tow route	• Additional ballast required to achieve required on-bottom weight • Shipbuilders will lack experience in LNG GBS construction and therefore will rely on shipbuilding experience to build a bespoke GBS • Lack of track-records • Long tow route but easier navigation

Considering the significant cost savings discussed above, Advisian recommends considering a steel GBS hull. This is further supported by the comparison presented in the Table 3-1 above which clearly indicates that having access to Asian shipyards' fabrication capabilities and capacities present significant advantages for construction and installation.

3.3 Terminal Concept

3.3.1 Storage Capacities and Offtake Frequencies

Storage capacities for oil/condensate and LNG are in the first instance based on approximately 1.5 times the storage capacity of Polar Class LNG carriers and Polar Class condensate tankers, which are anticipated to visit the terminal (i.e., approximately 500,000 bbls (circa 80,000 m^3) of oil/condensate and 260,000 m^3 of LNG).

Annual LNG production is estimated as 4 MTPA resulting in approximately 50 LNG cargo offtakes per year or one cargo every 7 days with a typical 170,000 m^3 Polar Class LNGC. With an LNG storage capacity of 260,000 m^3, the GBS would have approximately 3.5 days of buffer to mitigate risks of LNGC arrival delays at the terminal.

Condensate production is estimated to be in the order of 6,500 bbls/d resulting in a frequency of approximately 30 days. It is assumed that the Condensate tankers will coordinate with the LNG carriers such that the LNG carrier will act as an ice breaker for the Condensate tanker eliminating the need for a separate ice breaker to escort the Condensate tanker.

3.3.2 Mooring and Loading Facilities

It is recommended that berthing and mooring of Polar Class LNGC and condensate tanker would be done directly alongside the GBS.

It is assumed that both Polar Class LNGC and condensate tanker will approach the terminal supported by a minimum of three Polar classed icebreakers, and then berth and moor to the GBS using their own mooring lines. The length of the GBS, i.e., 340 m, is deemed sufficient to accommodate Polar Class LNGC and condensate tanker, however mooring analysis will be required as part of the Project development future phases to confirm the mooring layouts.

Both Polar Class LNGC and condensate tanker need to be protected from any potential moving ice. Since the GBS is planned to be installed within the landfast ice zone, ice may be slow moving or stationary during the winter months. However, there will be moving ice during freeze-up, break-up and the nominally open water season when there may be drifting ice. The GBS will need to be orientated to maximize protection to the vessels. It is envisaged, at this stage, that an orientation east-west for the GBS with vessels berthing and loading at the southern side (i.e., "shore" side) would be suitable.

Four LNG loading arms and two oil/condensate arms are likely to be required to allow transfer within reasonable laytime.

Polar Class LNGC and condensate tanker can load from both sides (i.e., portside and starboard) so the vessels can approach the terminal from either end of the GBS. It is also assumed that the vessels can navigate backwards as a “double acting” mode. The capability to navigate ahead and astern provides maximized flexibility to select best and easiest way to arrive and depart to and from loading berth. See Figure 3-1 and Figure 3-2.

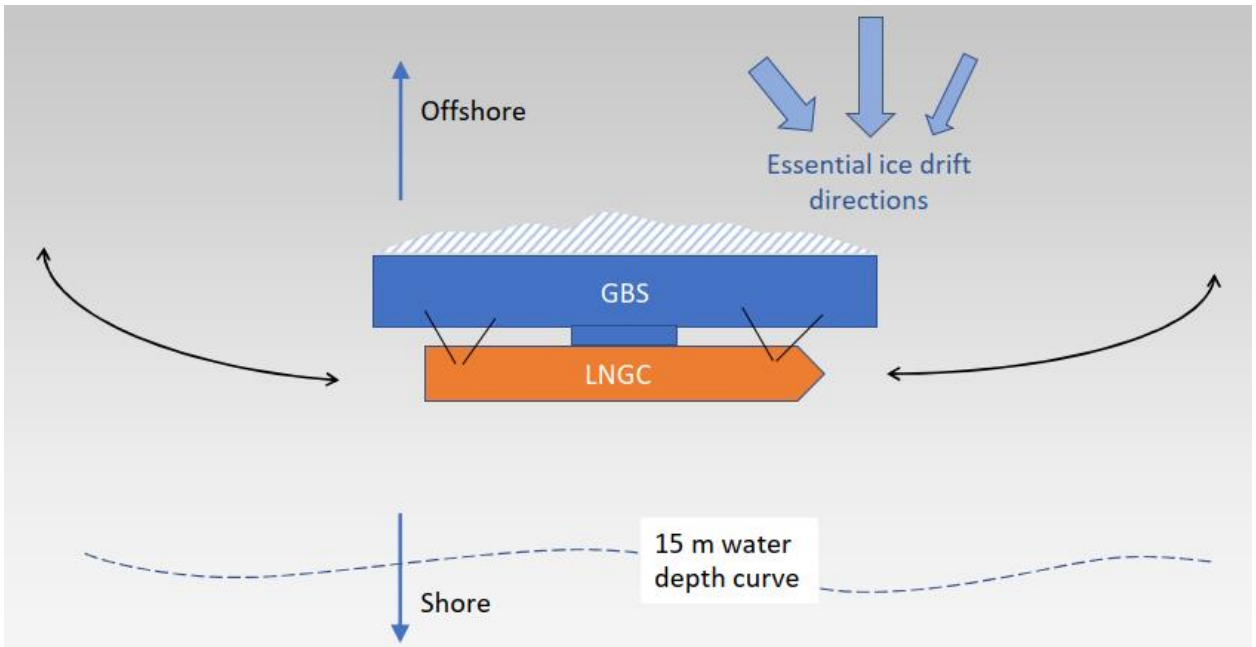


Figure 3-1 Sketch of Terminal Layout

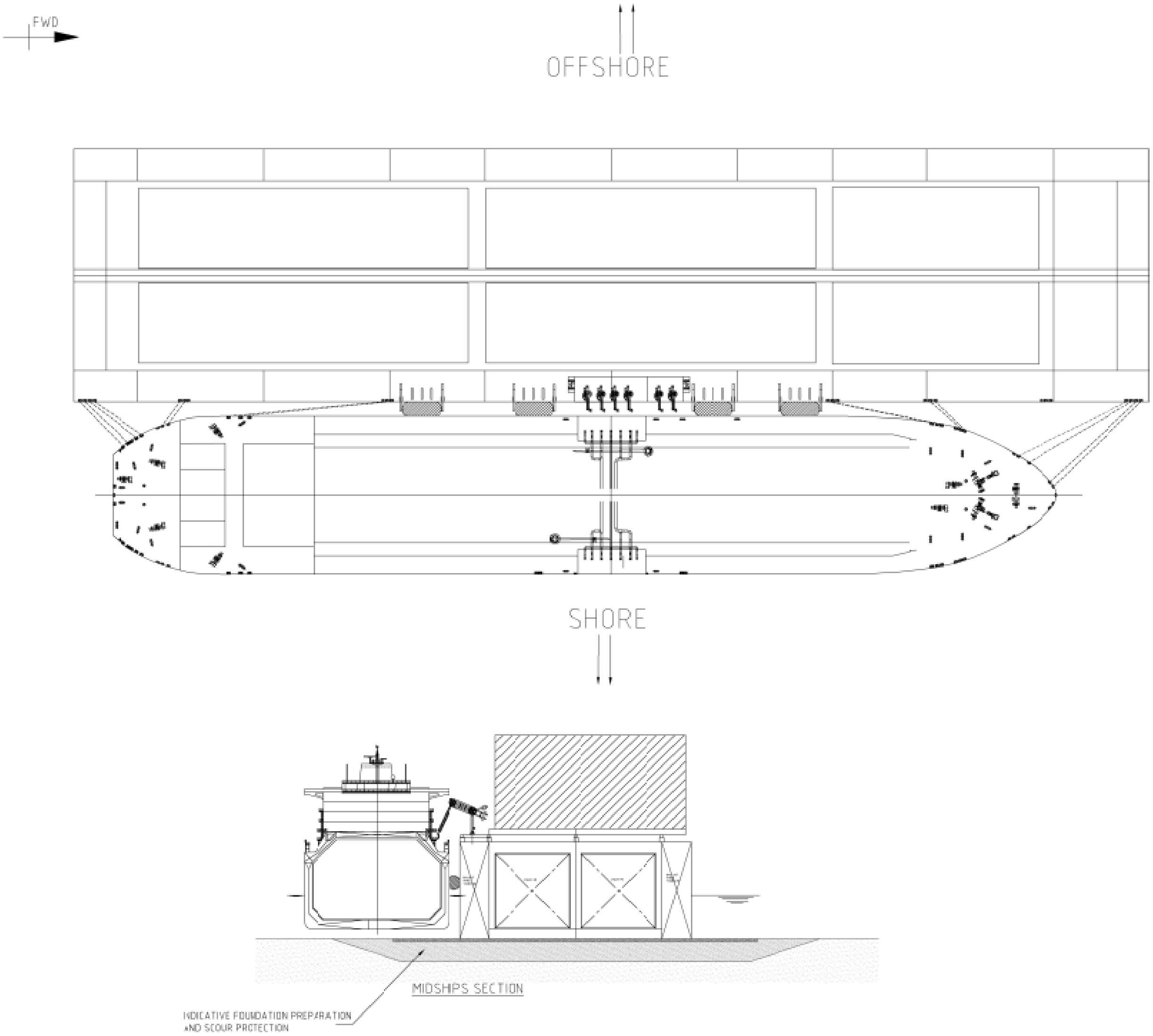


Figure 3-2 LNGC mooring layout at terminal

3.3.3 GBS Topsides and Process Facilities

LNG liquefaction, with an initial production capacity of 4MTPA shall be installed on the GBS. As part of this pre-feasibility study, it has been assumed that gas pre-treatment, including all processes upstream of NGL extraction, is available onshore.

Considering the ambient air temperatures, it is envisaged that 4 x 1MTPA Single Mixed Refrigerant units should be suitable with air coolers which are expected to be the limiting factor in final nameplate production capacity.

The following systems will be installed on the GBS:

- 4 x Gas turbines (nominally PGT25+G4 units) directly driving each liquefaction train
- Refrigerant storage
- BOG and fuel gas system
- Pressure relief, blowdown systems and flare
- Fire protection and safety systems
- General utilities (air, nitrogen, water systems)
- Electrical power generation and distribution systems for LNG production operations, black start of the facility and emergency operation
- Accommodation and Central Control Room (CCR) incorporating marine and production operations monitoring and control
- LNG transfer systems and loading arms
- Oil/condensate transfer systems and loading arms
- Cranes and other material handling facilities

The preliminary plot plan presented in Figure 3-3 has been developed as part of the pre-feasibility study and considers process and safety requirements. The total GBS deck area is approximately 27,200 m^2 (340 m x 80 m) and proves to be sufficient for installation of the foreseen equipment and systems since no space and layout optimization (e.g., stacking) was considered.

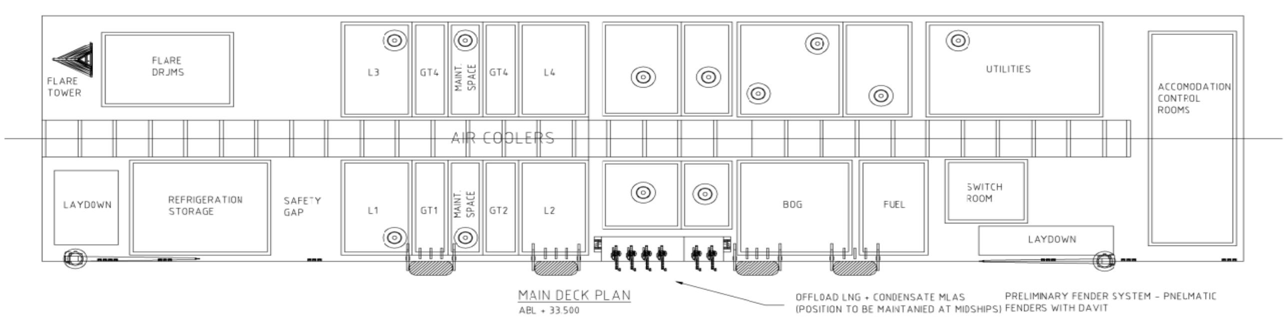


Figure 3-3 Preliminary GBS Topsides Layout

3.4 Construction and Installation Considerations

3.4.1 Shipyards

A review of shipyards worldwide with experience of building membrane-type LNGCs has been performed by Advisian. The shipyards identified below in Table 3-2 have experience building LNGCs and are licensed to construct membrane tanks, along with having drydocking facilities with the dimensions to allow the building steel hull GBS. Advisian's review checked the shipyard crane capacities, topsides fabrication and integration experience.

Other shipyards have capabilities to build LNGCs but have limited experience in topside integration. Table 3-2 presents a list of suitable shipyards with the capability to build a steel hulled LNG GBS.

Table 3-2: Shipyards

Yard	Country	Dock Name	L [m]	B [m]	D [m]	Crane Capacity [tonne]	Membrane System	Topside Integration
CSSC	China	-	380	92.0	-	-	No96	Yes
MHI	Japan	Building	990	100.0	14.5	-	No96	Yes
MHI	Japan	Repair	400	100.0	14.5	-	No96	Yes
Hanjin	Philippines	Dry Dock No. 5	370	100.0	12.5	600	No96, MKIII	No
Hanjin	Philippines	Dry Dock No. 6	550	135.0	13.5	600	No96, MKIII	No
DSME	South Korea	No.1	530	131.0	14.5	900	No96	Yes
HHI	South Korea	Dry Docks No. 3	672	92.0	13.4	1290 & 10k	MKIII	Yes
HSHI	South Korea	No. 1 Dock	500	100.0	13.0	2x600	MKIII	Yes
HSHI	South Korea	No. 2 Dock	594	104.0	13.0	2x900	MKIII	Yes
SHI	South Korea	Dock No. 3	640	97.5	12.7	3600	MKIII	Yes

Shipyard Abbreviations:
L: Length
B: Beam
D: Depth
CSSC: Hudong-Zhonghua Shipbuilding
MHI: Mitsubishi Heavy Industries
Hanjin: Hanjin Heavy Industries and Construction
DSME: Daewoo Shipbuilding & Marine Engineering
HHI: Hyundai Heavy Industries
HSHI: Hyundai Samho Heavy Industries
SHI: Samsung Heavy Industries

3.4.2 Tow and Transport

GBS towing and installation would be in the late July to August and early September window when ice break-up has occurred, and open water conditions prevail. The tow around Point Barrow and Alaska will be the critical entry constraint.

It is foreseen that the GBS could be built in South Korea or China. A GBS displacement of approximately 270,000 tonnes is estimated meaning that a wet tow would probably be required as there are currently no vessels that are large enough for a dry tow. The average speed for the tow is assumed to be 4-6 knots based on tow performed for similar size vessels. The total towing distance is close to 4,000 nm, transiting offshore Japan and Sakhalin, though the Bering Sea, along the coast of Northwest Alaska, around Point Barrow and finally arriving at Mackenzie Delta. A minimum duration of four to six weeks for the entire voyage can be expected.

As installation window is likely to be very limited, critical contingencies on construction and tow durations will have to be made when developing Project schedule, since GBS arriving late at site could mean a 10-12 months Project start-up delay.

3.4.3 Seabed Preparation

The Mackenzie Delta is known to have variable and weak soil conditions and a detailed site investigation program will be required as part of the final site selection process. For this study, it has been assumed that the top 3-5 m of weaker material and sediments are removed and replaced with more competent material and cleaner sand, prior to the GBS installation. This would be consistent with previous foundation procedures for exploration activities in the 1980s.

3.4.4 Ballasting

The GBS will require a substantial amount of ballast to achieve the on-bottom weight and foundation stability against multiyear ice loads that may be expected.

It may be possible to use dredged sand, as this was used in the earlier exploration days for the construction of artificial sand islands and also to provide the sand core for the Molikpaq exploration platform. Similar sand material could be used for the ballast compartments and could potentially use material from existing relic artificial islands. This would be dredged sand pumped hydraulically into the GBS hull ballast tanks.

3.5 GBS Concept Summary

The following Table 3-3 presents the main characteristics of the MDLNG GBS concept.

Table 3-3: GBS Concept

Item	Description
Hull material	Steel
Overall dimensions	340 m x 80 m x 33.5 m
Hull Lightweight	150,000 tonnes
Topside weight	120,000 tonnes
Ballast Volume	260,000 m^3
Shipyard	Preferably South Korea
LNG production	4 MTPA

Item	Description
LNG storage	~260,000 m^3
Oil/condensate storage	~80,000 m^3
Mooring	To GBS – suitable for 170,000 m^3 Polar Class LNGC and 44,000 DWT Polar Class condensate tanker
Loading	4 loading arms for LNG transfer and 2 loading arms for oil/condensate. 1 LNG offtake expected every 7 days on average, and maximum 1 oil/condensate offtake every 30 days.
Liquefaction Facilities	4 x 1 MTPA Single Mixed Refrigerant units
Cooling system	Air cooling
Power generation	4 x Gas turbines with direct drive
Accommodation	140 Persons on Board (POB)
Support vessels	3 x Polar Class Icebreakers
GBS tow	4-6 knots towing speed with expected duration 4 to 6 weeks. Wet tow from Far East Asia to Mackenzie Delta, via Sea of Japan, Sea of Okhotsk, Bering Sea, Chukchi Sea and Beaufort Sea
GBS installation	3 X Polar Class Icebreakers (HIB, PIB, EIB)

Figure 3-4 presents the proposed preliminary layout for the GBS.

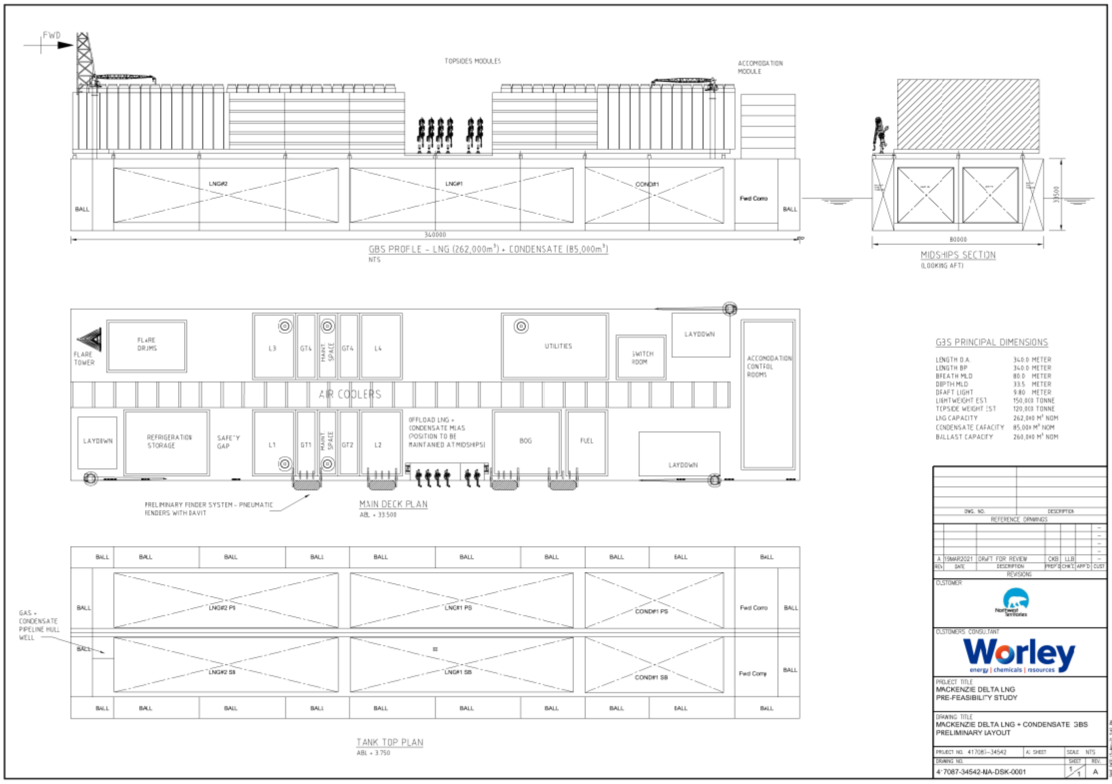


Figure 3-4 Mackenzie Delta LNG and Condensate GBS Preliminary Layout

For Option 2, the condensate goes by pipeline to Norman Wells eliminating the need for condensate storage and loading on the GBS. As the size of the GBS would need to stay the same to ensure protection for the LNG carriers during the winter, the storage space that would have been used by the condensate can be used for additional LNG storage. That increases the LNG storage capacity from 260,000 m^3 to 376,000 m^3 which provides more flexibility for the LNG carriers.

3.6 Cost Estimate for GBS

3.6.1 Capital Costs

The capital costs for the GBS options are presented in Table 3-4.

Table 3-4: Capital Cost Table

Component	Single GBS (LNG+ O) 2021 CAN$ Million	2 GBS: GBS (LNG) +GBS (O) 2021 CAN$ Million	Single GBS (LNG) 2021 CAN$ Million
GBS Hull	1,325	1,919	1,344*
GBS Topsides	2,888	2,952	2,887

Component	Single GBS (LNG+ O) 2021 CAN$ Million	2 GBS: GBS (LNG) +GBS (O) 2021 CAN$ Million	Single GBS (LNG) 2021 CAN$ Million
Installation	98	183	98
Total	**4,311**	**5,054**	**4,329**

*LNG storage increased from 260,000 m^3 to 376,000 m^3 using the space that was taken up by the oil storage.

3.6.2 Operating Costs

The operating costs for the GBS options are presented in Table 3-5.

Table 3-5: Operating Cost Table

Annual Cost 2021 CAN$				
O&M				
	Qty.	***Unit***	***$/day***	**Total**
Crew	140	Persons on Board	87,500	63,875,000
Catering	140	Persons on Board	63	3,219,300
Hull Maintenance Budget			7,500	2,737,500
Topsides Maintenance Budget				86,662,500
Crew Transfer				
	Qty.	***Unit***	***$/flight***	
Chopper to Shore	10	flights/month	25,000	3,250,000
Airfares		flights/person	3,750	6,825,000
Misc. (Insurance Management, Fleet Management, Supply, Logistic, etc.)				16,656,880
Subtotal				***183,225,680***
Ice Management				
	Qty.	***Unit***	***$/month***	
Polar Class Ice Breakers	12	month	1,250,000	15,000,000

Annual Cost 2021 CAN$	
Subtotal	***15,000,000***
Subtotal Annual Cost	**198,225,680**
Total Cost (excl. contingency)	**198,225,680**

4 Shipping Study

The shipping study in Appendix C assesses the ice conditions along the transportation route and at the GBS. The report analyses the reference ice-capable LNG carriers and condensate tankers, as well as the transportation scenarios to markets from the GBS. The ice management fleet at the GBS is described with recommended ice management operations. Below is a high-level summary of the information contained in Appendix C.

4.1 Summary of Shipping Options

For the transit simulation, ice profiles are assigned to different legs of the transit route defined in Figure 4-1. The ice profiles for the legs are derived from ice conditions for various sea areas/segments, using the information presented in Appendix C. The ice conditions required for transit simulation are generated for every sea leg/segment for average type of winter.

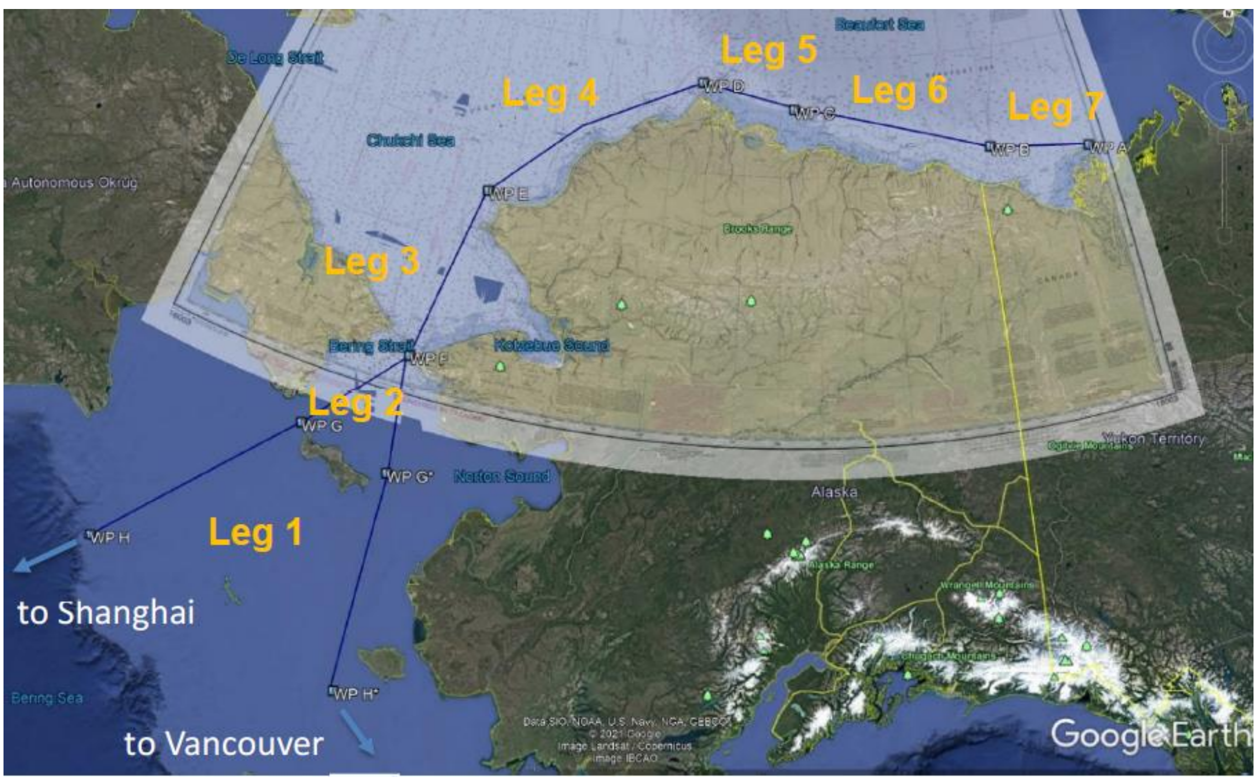


Figure 4-1 Carrier Route for Transit Simulation

Monthly ice profiles were generated for an average year for the transit simulation. In general, it should be noted that the ice profiles did not account for multi-year ice. It was assumed that multi-year ice floes are avoided with "tactical navigation".

Using “tactical navigation” means that the ice profile is modified to avoid the largest ridges and use ice of a lower concentration. In real practice, this is achieved by choosing the most optimal route in the ice using current satellite images, detailed ice charts and forecasts.

The following assumptions for transit simulation in ice conditions have been made:

- Open water service speed for both ballast and loaded conditions are considered the same (19.5 knots for LNG carrier and 13.5 knots for oil/condensate tanker).
- The simulations for both types of vessels have been done at design draft, it has been assumed that the ice going capability does not differ significantly at ballast draft.
- Speed limit when operating astern (12 knots for LNGC and 11 knots for tanker) has been set for the simulation (this is based on practical full-scale experience of safe handling of ships stern first in ice).

There are additional operational assumptions that influence the resulting total roundtrip time. The roundtrip cycle is:

Loading – Unmooring – Loaded voyage – Delays – Mooring – Unloading –

Unmooring – Ballast voyage – Delays – Mooring – Loading - … etc.

The following assumptions are used for LNG carrier:

- Loading time: 48 hours
- Discharging time: 30 hours
- Mooring/unmooring time in summer 4 hours/roundtrip
- Mooring/unmooring time in winter 6 hours/roundtrip
- Other delays in summer 15 hours/one/way trip
- Other delays in winter 25 hours/one/way trip

Loading and discharging time includes waiting for a given slot in harbours, custom procedures, receiving permissions, etc.

Other delays are added to account for: bad weather, pilot boarding, and in this study the time required to overcome the approach area through the shear zone and fast ice to the GBS (assumes 10 hours).

Yearly production of LNG is 4.0 MTPA, with density 0.45 t/m^3 and it is assumed that monthly production is constant.

Assumptions which are used for condensate tanker:

- Loading time: 36 hours
- Discharging time: 24 hours
- Mooring/unmooring time in summer 4 hours/roundtrip
- Mooring/unmooring time in winter 6 hours/roundtrip
- Other delays in summer 15 hours/one/way trip

- Other delays in winter 25 hours/one/way trip

Yearly production of condensate is around 360,000 t (based on maximum level of 10 000 barrels/day and cargo density 0.65 t/m^3) and it is assumed that monthly production is constant.

GBS additional storage (in addition to buffer storage needed to load one vessel) both for LNG and condensate is calculated to assure smooth yearly transportation during longer roundtrip times in the wintertime.

The initial transit study has shown that for the export of 4 MTPAof LNG from the Mackenzie Delta to China, five specialized icebreaking LNG carriers (similar to YamalMax type) are required and can operate on this route year-round in average winter conditions. The actual calculated maximum number of LNGCs during the winter months is 4.7.

An option to reduce the number of icebreaking LNG carriers by transferring the LNG to ocean-going LNG carriers at Dutch Harbor during the winter was considered. Although the number of Icebreaking LNG carriers could be reduced to 3 from 5, additional carriers would need to be added during the summer or the amount of LNG storage would need to be increase from 260,000 m^3 to 448,000 m^3. During the winter, there would be an additional cost for 3 ocean going LNG carriers. This option could be considered in future phases of the project (see Appendix C for more details).

For the export of condensate from the Mackenzie Delta to Vancouver, one ice going product tanker (similar to Boris Sokolov type) is required.

4.1.1 LNG Shipping

The LNG carriers used for this study are based upon the Yamal LNG carrier, Figure 4-2 which are ice class rated as Polar Class 3 (PC3). The design is dedicated for efficient navigation both in difficult ice conditions and on long open water voyages. The net cargo capacity of these vessels is 170,000 m^3 which is a standard volume for modern conventional LNG carriers.

Figure 4-2 Yamal LNG Carrier Image

The icebreaking carriers would make the full round trip to Shanghai (used for transit calculation). This will require 5 icebreaking LNG carriers to transport 4 MTPA. Figure 4-3 presents the transportation system simulation results for 4 MTPA LNG production using the reference YamalMax LNGC for an average winter. The orange line represents production, which is a constant. The green line represents the required GBS storage (including buffer and additional storage). The bar lines represent cargo loaded in the fleet. The black dots represent the number of vessels required in the fleet each month once storage is considered. The number of vessels per month is intentionally left as non-integer numbers to provide the month-to-month sensitivity and to show the effect of additional storage on the fleet. As can be seen, more icebreaking LNG carriers will be needed in the winter. The simulation below only uses 4.7 LNG carriers during the winter, if all 5 LNG carriers were used to their full capability during winter, 4.24 MPTA could be transported, resulting 4 MPTA being delivered to Asia

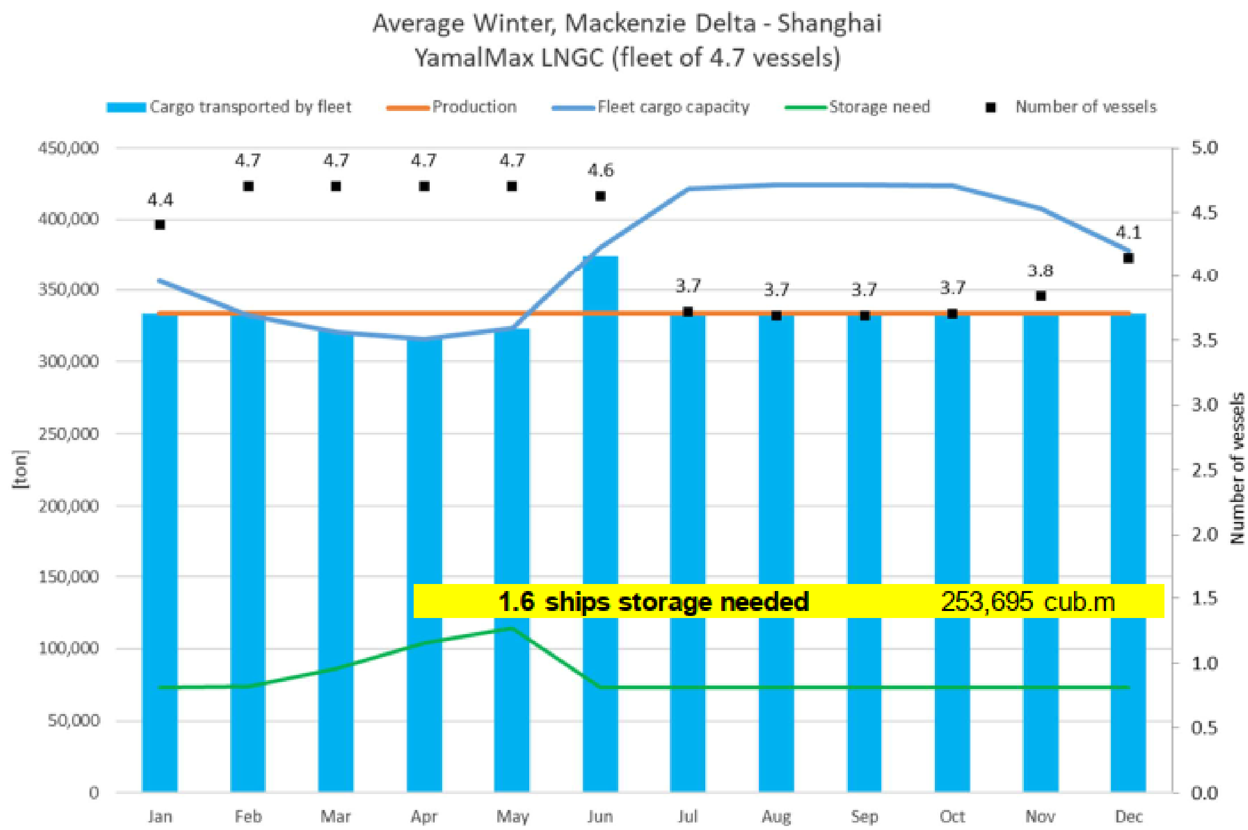


Figure 4-3 Transportation capability analysis for average winter, 4 MTPA of LNG, year-round to Shanghai, YamalMax LNGC, one GBS storage limit.

4.1.2 Oil/Condensate Shipping

The condensate carrier is based upon the Boris Sokolov carrier which is ice class rated as PC3. described in Figure 4-4. The Boris Sokolov is a product tanker with five separate cargo holds. The vessel is specifically dedicated for transportation of gas condensate from Arctic areas to markets. As an extra feature, the vessel can transport fuel oil for other needs in its fore storage tank (1,400 m^3) during ballast voyage to Arctic waters.

Figure 4-4 Arctic condensate tanker Boris Sokolov during delivery ice trials in 2019 (Source: Aker Arctic)

The Icebreaking condensate carriers would make the full round trip to Vancouver. This will require one icebreaking condensate carrier to transport 0.377 MMTPA of condensate as presented in Figure 4-5.

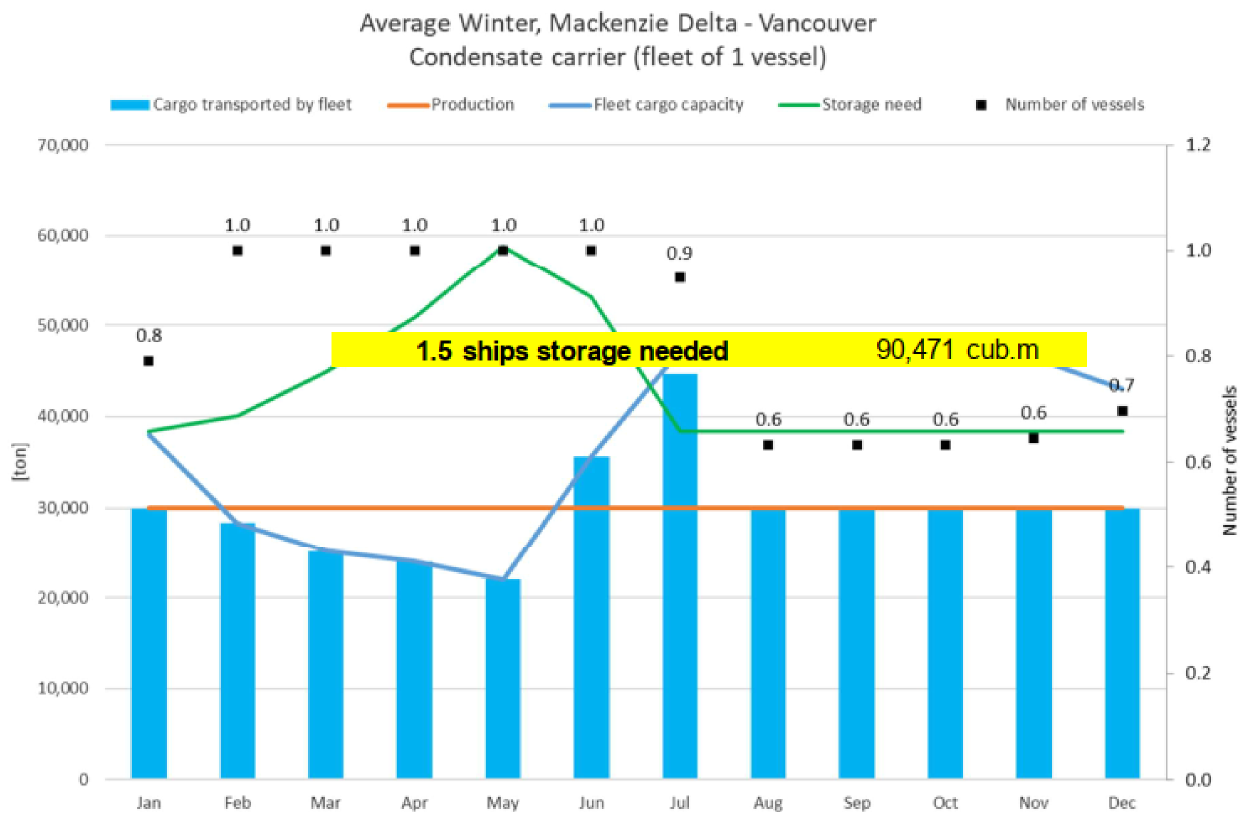


Figure 4-5 Transportation capability analysis for average winter, 0.36 MTPA of gas condensate, year-round to Vancouver, Boris Sokolov type tanker.

4.1.3 Ice Management

For ice management at the GBS, three types of icebreakers are required:

- HIB: Harbor Icebreaker – smaller icebreaker for flushing the area around the GBS to allow the LNG and condensate carriers a clear path to the loading facilities. See Figure 4-6.
- PIB: Primary Icebreaker – primary ice breaker to break the ice channel to the GBS. See Figure 4-7
- EIB: Escort Icebreaker – A heavy-duty icebreaker for escorting in hard ice conditions, such as multi-year ice. The EIB can be used for escorting either the LNG Carrier or Condensate tanker along the route between the GBS and the Bering Sea. See Figure 4-8.

Figure 4-6 Harbour Icebreaker "Ob" operating nowadays at the Sabetta LNG GBS (source: Atomflot)

Figure 4-7 SFC Sakhalin icebreaker (Source: FESCO)

Figure 4-8 Escort Icebreaker (Source: Aker Arctic)

4.1.3.1 Ice Management Operations

The typical Ice Management Vessel operations and duties are described in detail in Appendix C: Transit and Ice Management Study.

4.2 Cost Estimates Shipping

The shipping costs for the LNG and oil/condensate are summarized in Table 4-1.

Table 4-1: Cost Estimate Table

Cost Element	5 LNG Carriers 2021 CAN$ MM	1 Condensate Carrier 2021 CAN$ MM
Fuel Cost	114.4	10.7
Fixed Operational Cost	54.8	7.1
Ice Breaker Assistance Cost	0	0
Capital Cost	2,000	162.5
Lease Cost*	122.4	10.0
Total Annual Cost	291.6	27.8
Delivered Product	3.78 MT**	0.36 MT
Cost per Tonne	77.2	77.2

*Lease cost is based upon a 20-year lease for the carriers. The Lease cost is used in the economic model.

**Delivered product is 4 MTPA produced at the GBS less LNG used as fuel to the delivery point in Asia.

4.3 Ice Management Costs

The ice management (IM) requires three icebreakers at the GBS. The three ice breakers are identified as:

- HIB: Harbor Icebreaker
- PIB: Primary Icebreaker
- EIB: Escort Icebreaker

The cost of assisting the carriers are at the minimum level during the open water season and increase gradually towards the winter reaching the maximum level typically in January. Costs start to decrease in the middle of spring, first steadily and then, around June, rapidly reaching the minimum level again when all of the ice has melted. Ice drifting during autumn, when the ice cover is not yet thick and stable, may on occasion require additional work and costs. In addition, during the ice melting season and Mackenzie River flooding, ice drifting may occasionally be caused from the shore towards offshore requiring additional efforts by the IM vessels. However, these events are not considered challenging for the IM vessels to manage but occasionally operational costs can be expected to increase

The operating costs for the icebreakers vary between the winter and summer season as described in Table 4-2. These costs are included as OPEX costs for the GBS.

Table 4-2: Ice Management Cost Table

Type	Element	Winter Season (6 months)			Summer Season (6 months)		
Cost Element	Units	HIB	PIB	EIB	HIB	PIB	EIB
IM at Terminal	Hours	60	60	24	24	0	0
Escorting and IM outside Terminal	Hours	0	0	200	3.4	3.2	3.2
Standby	Hours	672	672	508	26.1	27.3	27.3
Fuel consumption	Tons	151	276	1443	231	365	440
Fuel Cost	CAN$	79,040	144,906	757,554	121,067	191,544	231,200
Fixed Monthly Cost [1]	CAN$	225,000	247,500	247,500	97,500	107,250	39,000
Total Monthly cost per vessel	CAN$	304,040	392,406	1,005,054	218,567	298,794	270,200
Total Monthly Cost for all IM	CAN$		1,701,500			787,561	
[1] Salaries, insurances, etc.							

5 Cost Estimate Summary

The cost estimate summary on a rolled-up basis is presented in the Table 5-1 below for the total costs for Option 1 Base Case.

Table 5-1: Option 1 Base Case

Cost Element	CAPEX 2021 CAN$ Million	OPEX 2021 CAN$ Million/Year
Initial Field Development	2,768	69
Gathering	146	3
Base Case Onshore Export Pipelines	518	12
Base Case Offshore Export Pipelines	515	1
Single GBS (LNG & O)	4,311	198*
Shipping LNG	0	292
Shipping Condensate	0	28
Initial Base Case Cost	8,258	603
Future Base Case Cost	3,093	77
Total Base Case Cost	11,351	680

*Includes the Ice Management costs at the GBS.

Table 5-2 presents CAPEX and OPEX for Option 2.

Table 5-2: Option 2 South Pipeline

Cost Element	CAPEX 2021 CAN$ Million	OPEX 2021 CAN$ Million/Year
Initial Field Development	2,768	69
Initial Gathering	146	3
Natural Gas Onshore Export Pipeline	389	9
Natural Gas Offshore Export Pipeline	477	1
Condensate Onshore Export Pipeline	1,266	142*

Cost Element	CAPEX 2021 CAN$ Million	OPEX 2021 CAN$ Million/Year
GBS LNG	4,329	198**
Shipping LNG	0	292
Initial Option 2 Cost	9,375	714
Future Option 2 Cost	3,093	77
Total Option 2 Cost	12,468	791

*Include the transportation toll to get from Norman Wells to Edmonton.

**Includes the Ice Management costs at the GBS.

In addition to the two Options identified above, sensitives to phasing of different fields and the impact of potential carbon sequestration at Taglu were developed. Table 5-3 summarizes the Upstream CAPEX (field development, conditioning facilities and CGPF) for the different sensitives. The facilities downstream of the CGPF are not considered in the table below.

Table 5-3: Summary of Upstream CAPEX Options

Options	Option	Initial CAPEX 2021 CAN$ MM	Future CAPEX 2021 CAN$ MM	Total CAPEX 2021 CAN$ MM
Option 1	Base Case	2,914	3,093	6,007
	2 GBS	2,914	3,093	6,007
	Low Carbon	2,914	3,768	6,682
	Ultra-Low Carbon	3064	4,791	7,855
	All Fields	4,674	1,017	5,812
	Anchor Fields	3,732	1,973	5,706
	Base Case Oil	3,123	3,093	6,216
Option 2	Pipeline to Norman Wells	2,914	3,093	6,007
	NW Pipeline Oil	3,123	3,093	6,216

5.1 High-Level Project Schedule

The project is currently in the conceptual stage of develop. The following chart is a high-level schedule that identifies the major activities that are required to have the MDLNG project onstream by 2030.

Table 5-4: *High-level Schedule Table*

	Project Development	Project Validation (Feasibility Study)	Project Regulatory	Project Commitment	Project Implementation	Operations
Dates	**2021**	**2022-2023**	**2024**	**2025**	**2026 -2030**	**2030**
	- Business plan developed - Organization - Funding - Management Structure - External Resource Plan - Policies & Procedure Plan - Project Execution Plan - Financial Plan - Critical Risk assessment - Determine Project ownership, finance and operating strategy	- Begin Stakeholder Engagement, Environmental Screening & Route Definition - Develop and submit export application - MOU(s) with potential off takers - Pre-FEED engineering - Develop Class 4 estimate - Develop and submit regulatory application	- Regulatory hearing process - Determine ownership, finance and operating terms - FEED engineering - Definitive off-take agreements	- Participants Commit to Project - Regulatory Hearing Process - Complete FEED Engineering - Class 3 Estimate - Start Detailed Design - Project financing	- Regulatory approval received - Construction begins - Complete Detailed Design - Operating organization - Begin construction of upstream facilities - Begin construction of GBS - Begin construction of Ice breaking LNG and Condensate Carriers - Begin construction of Ice breakers for ice management	- Commence operations

6 Economic Evaluation

6.1 Summary

There were two main options:

- Option 1 – natural gas and condensate pipelines to offshore GBS(s)
- Option 2 – natural gas pipeline to offshore GBS (LNG), condensate pipeline to Norman Wells

For Option 1, alternatives were evaluated for variations on field development production timing, liquids and/or oil processing, export pipeline connections from Taglu Central Gas Processing Facility to the GBS, LNG compression power source, power/energy and CO_2 management configurations. The LNG only case (1_LNG) excludes the associated liquids capital and operating expenses from the CGPF through shipping to highlight the additional costs associated with liquids handling.

Both Option 1 and 2 considered adding oil production as a variation to see if that would improve the economics.

The options evaluated are summarized in Table 6-1. Production profiles scenarios each for the Base Case, All Fields and Anchor are detailed in Section 2.1.2. Schematics detailing each of the options and sensitivity cases can be found in Appendix A.

Table 6-1: Options Evaluated and Summary Table

#		Focus Decisions → Strategic Themes ↓	Phasing	Oil / Liquids Processing	GBS Connection	GBS Configuration	LNG Compression Power	Export	Electricity / Power	Carbon Management
#	**Decision Inputs**		- Nig, Taglu & Umiak, Parsons L, other later (Base Case) - All Fields (Year 1) prorated - Anchor Fields (Yr 1) prorated, other fields later	- Liquids (Condensate) - Liquids + Oil	- Gas - Liquids - Multi-Phase Pipeline - Subsea Power Cable	- Combine LNG/ Liquids - Separate Platforms for LNG/ Liquids	- Gas Turbine - Electric Drive	- LNG GBS - Vessel - Liquid GBS - Vessel - Taglu - Pipeline to Norman Wells	- Centralized NGCC - Distributed NGSC - Renewables Integration	- Associated CO2 (capture & sequester process gas (CCS)) - NGCC Flue Gas
1		**1_BaseCase**	- Nig, Taglu & Umiak (Yr 1), Parsons L, others later	Liquids (Condensate)	- Gas Pipeline - Liquids Pipeline	Combine LNG/Liquids	· Gas Turbine	- LNG Vessel - Liquid Vessel	- Dist. Power Gen GBS & Field	Vented CO2 Flare (emergency)
2		**1_2GBS**	- Nig, Taglu & Umiak (Yr 1), Parsons L, others later	Liquids (Condensate)	- Gas Pipeline - Liquids Pipeline	· 2 GBS each for LNG/Liquids	· Gas Turbine	- LNG Vessel - Liquid Vessel	- Dist. Power Gen GBS & Field	Vented CO2 Flare (emergency)
3	Option 1	**1_LowCarb**	- Nig, Taglu & Umiak (Yr 1), Parsons L, others later	Liquids (Condensate)	- Gas Pipeline - Liquids Pipeline	Combine LNG/Liquids	· Gas Turbine	- LNG Vessel - Liquid Vessel	- Dist. Power Gen GBS & Field	·Associated CO2 CCS
4		**1_UltraLC**	- Nig, Taglu and Umiak (Yr 1), Parsons L, others later	Liquids (Condensate)	- Gas Pipeline - Liquids Pipeline - Subsea Power Cable	Combine LNG/Liquids	· Electric Drive	- LNG Vessel - Liquid Vessel	-Centralized NGCC -Renewables	·Associated CO2 CCS ·NGCC Flue Gas (CCS)
5		**1_AllField**	- All fields Year 1 - prorated	Liquids (Condensate)	- Gas Pipeline - Liquids Pipeline	Combine LNG/Liquids	· Gas Turbine	- LNG Vessel - Liquid Vessel	- Dist. Power Gen GBS & Field	Vented CO2 Flare (emergency)

		Focus Decisions → Strategic Themes ↓	Phasing	Oil / Liquids Processing	GBS Connection	GBS Configuration	LNG Compression Power	Export	Electricity / Power	Carbon Management
6		**1_Anchor**	- Nig, Taglu, Umiak & *Parsons L (Yr 1)*, others later	Liquids (Condensate)	- Gas Pipeline - Liquids Pipeline	Combine LNG/Liquids	· Gas Turbine	- LNG Vessel - Liquid Vessel	- Dist. Power Gen GBS & Field	Vented CO2 Flare (emergency)
7		**1_LNG**	- Nig, Taglu, Umiak & Parsons L (Yr 1), others later	Liquid Costs excl.	- Gas Pipeline	LNG	· Gas Turbine	- LNG Vessel	- Dist. Power Gen GBS & Field	Vented CO2 Flare (emergency)
8		**1_BC_Oil**	- Nig, Taglu & Umiak (Yr 1), Parsons L and others later	Liquids + Oil	- Gas Pipeline - Liquids Pipeline	Combine LNG/ Liq + Oil	· Gas Turbine	- LNG Vessel - Liquid Vessel	- Dist. Power Gen GBS & Field	Vented CO2 Flare (emergency)
9	Option 2	**2_PipeNW**	- Nig, Taglu & Umiak (Yr 1), Parsons L, others later	Liquids (Condensate)	· Gas Pipeline	LNG Only GBS	· Gas Turbine	- LNG Vessel - Liq. Pipeline to Norman Wells	- Dist. Power Gen GBS & Field	Vented CO2 Flare (emergency)
10		**2_PNW_OIl**	- Nig, Taglu & Umiak (Yr 1), Parsons L, others later	Liquids + Oil	· Gas Pipeline	LNG Only GBS	· Gas Turbine	- LNG Vessel - Liq. + Oil Pipeline to Norman Wells	- Dist. Power Gen GBS & Field	Vented CO2 Flare (emergency)

6.2 Project Assumptions

The analysis relies on several input assumptions, as stated in the following Table 6-2. These are generally financial assumptions to which the results may be sensitive.

Table 6-2: Input Assumptions

Parameter	Value	Source/Comment
Discount Rate	10%	
Modelled Period	2030–2054	
US Exchange Rate	1.25	Bank of Canada 02-2021
Currency	2021 CAN$	
Inflation Index	2003 1.45	Statistics Canada
Natural Gas Forecast	US$ 3/MMBtu	Sproule 02-2021
LNG Futures	US$ 10/MMBtu	Delivered to Asia
Condensate Forecast	CAN$ 60/bbl (Edmonton)	Sproule 02-2021-02
Pipeline Tariff Rate	CAN$ 42.82/bbl	Tolls for Line 21 and Rainbow pipeline
Carbon Price	CAN$170 t CO2e	Government of Canada
GHG Emissions		
Scope 1	0.054 t CO_2e/Mcf	Field gas consumption, power generation
LNG INTENSITY TARGET	0.16 t CO_2e/t LNG	Government of British Colombia

6.3 CO_2/GHG Issues

6.3.1 Carbon Pricing

Sources of greenhouse gas emissions (GHG) considered within the evaluation include field gas combusted for power generation and associated gas from processing. These are considered Scope 1 emissions, which are those emissions that are generated on site or directly through operations. Carbon pricing for industrial emitters for the Government of NWT is governed under the Petroleum Products and Carbon Tax Act and Regulation, in compliance with the Government of Canada, Greenhouse Gas Pollution Pricing Act (GHGPA).

The Federal output-based pricing system (OBPS) for large industrial emitters is designed to enable large emitters to maintain their global competitive position and reduce carbon leakage risk by setting a performance standard based on GHG emissions emitted for each unit of output and providing an incentive to cut carbon pollution (Government of Canada, 2021a).

The Government of Canada introduced the *Impact Assessment Act* (IAA) in August 2019. Included in the IAA is an assessment of the extent to which a given project is expected to hinder or contribute to Canada's climate change commitments and goals. Canada's current target under the Paris Agreement is to reduce greenhouse gas (GHG) emissions by 30% below 2005 levels by the year 2030. Additionally, Canada is aspiring to achieve net-zero emissions by 2050.

Among many other elements of assessment, the IAA considers integration of GHG-related best available technologies (BAT) and best environmental practices (BEP). BAT/BEP are defined as "the most effective technology, technique or practice economically achievable for reducing GHG emissions" (ECCC, 2020). Accordingly, approval subject to the IAA could be anticipated to consider a high cut off value as a condition of as BAT requirements and alignment with overall climate change commitments (JWN, 2019).

The global range for GHG intensity for LNG facilities lies between 0.15 and 0.44 t CO_2e/t LNG based on current technology and development (JWN, 2019). LNG facilities within Canada are projecting world leading intensity rates through electrification as low as 0.06 t CO_2e/t LNG.

It is expected that the future policy for NWT would emulate LNG standards in other Canadian jurisdictions. This study uses the performance intensity rate of 0.16 t CO_2e/t LNG, as applied under the Liquefied Natural Gas Environmental Incentive Program for the province of British Colombia under the Greenhouse Gas Industrial Reporting and Control Act (GGIRCA).

For the purposes of this analysis, pricing of GHG emissions is assumed to be consistent with the OBPS, where emissions above the benchmark intensity are subject to tax and those below are subject to a credit. It is anticipated that operations would be not be anticipated to start before 2030, therefore the price of carbon is set according to the current indicated policy of $170 per t $C0_2$e in 2030 under the GHGPA.

6.3.2 Greenhouse Gas Emissions

Annual GHG emissions were calculated using the estimated CO_2 removed from process gas and natural gas combustion and flue gas. CO_2 content will vary depending on field, the factors presented in Table 6-3 were applied for each of the developed fields. Figure 6-1 provides the associated emissions by field. Parsons Lake with the highest CO_2 content in the natural gas emits the highest amount of CO_2.

Table 6-3: Associated Gas CO2e recovered factors by field

Field	t CO2/MMcf of natural gas
Taglu	0.15
Niglintgak	0.51
Parsons Lake	1.72
Umiak	0.12
Other Fields	0.51

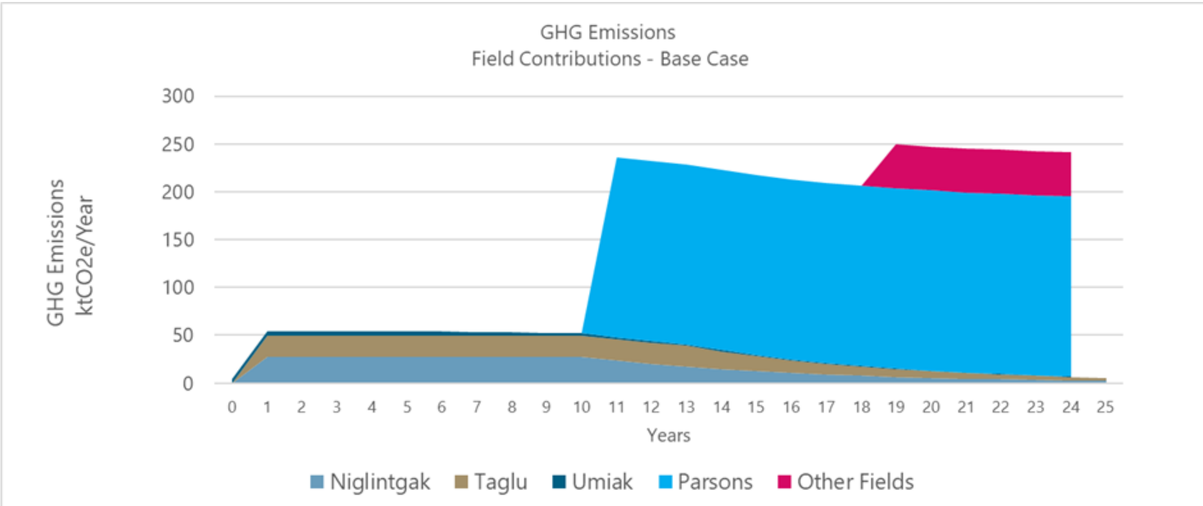


Figure 6-1 Lifecycle Associated Gas Emissions by Field

Table 6-4 provides the power generation, demand and emissions assumptions for the GHG emissions from the turbines required for field and GBS required power and compression.

Table 6-4: Field and LNG Power and GHG Emission Basis

Item	Units	Base Case (Distributed)	Low Carbon (1_LowCarb)	Ultra Low Carbon (1_UltraLC)
LNG Power & Compression Capacity	MW	183	183	192
Wind Capacity	MW average	-	-	13
Total NG Based Power Demand		183	183	179
Onshore Fuel Gas Use	MMcfd	35	35	35

In the model, carbon capture and sequestration are implemented in year 10 for the Option 1 Low Carbon and Option 1 Ultra Low Carbon cases. The model includes associated capital expenditures (wells, compression, electric drives for liquidation, power generation, power transmission), operating expenses, field gas use and reduced carbon taxes owed.

Figure 6-2 provides a breakdown of the GHG emission contributors and reduction potential from the Base Case and the Ultra-Low Carbon option. Offshore power and onshore gas consumption contribute the largest amount of greenhouse gas emissions over the life of the project, while the greatest reduction potentials come from increased energy efficiency and carbon capture technology for post-combustion emissions. The Low Carbon Option only considers carbon sequestration for the Acid Gas/Associated Gas.

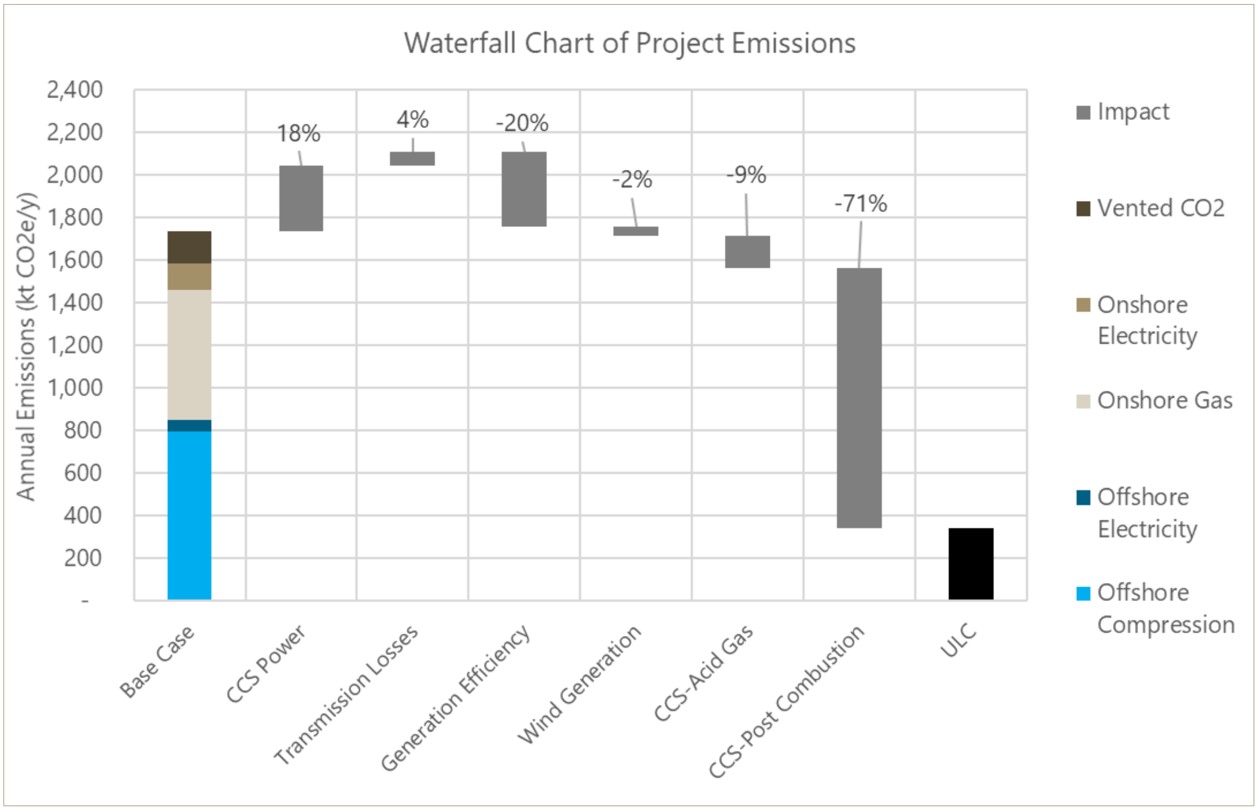


Figure 6-2 Waterfall chart of emission contributors

All remaining options and sensitivity cases assume that greenhouse gas emissions are vented and priced based on Canada's carbon tax rate of $170 tonne in 2030 for all emissions greater than 0.16 t CO_2/t LNG. The predicted emissions profile relative to the OBPS benchmark of than 0.16 t CO_2/t LNG for the different options are shown in Figure 6-3 below:

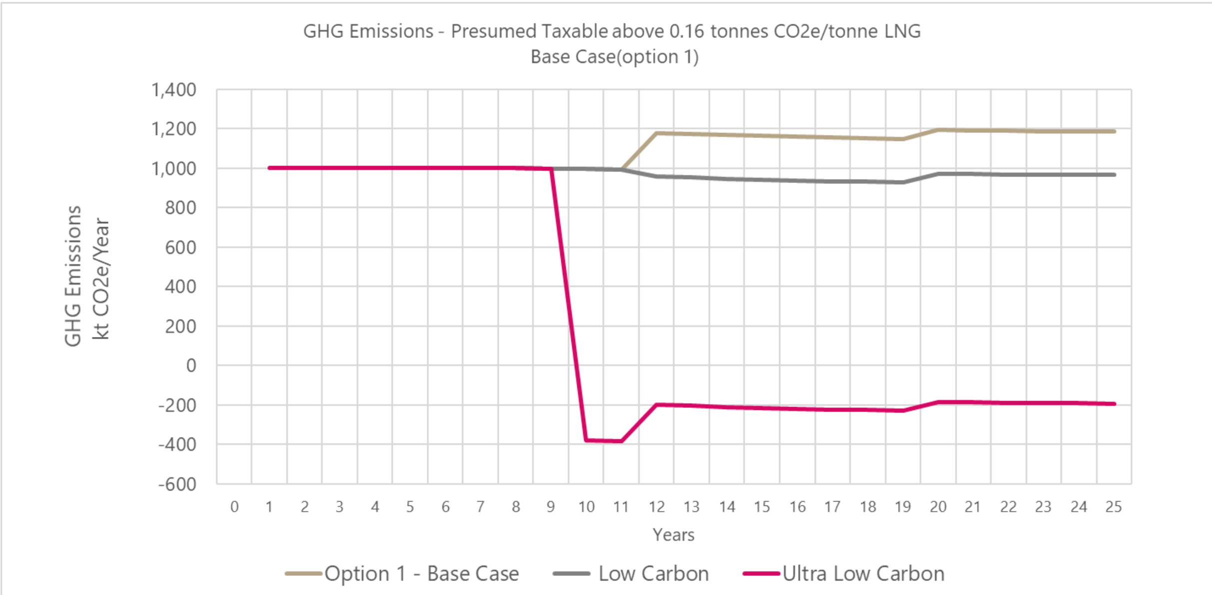


Figure 6-3 Lifecycle GHG Emission Profiles

It should be noted that these two sources (CO_2 extracted from the gas stream and CO_2 sequestered from the flue gas at Taglu) are expected to represent the large majority of emissions but do not represent all the GHG emissions expected from the project. Additional sources would also include fugitive emissions, emergency flaring, fuel consumption for shipping, equipment, vehicles, and other sources.

6.4 Financial Summary Results

6.4.1 Financial Present Value (PV)

Results are depicted graphically in Figure 6-4 showing the project costs on a Present Value (PV) basis in dollars for each of the options. Figure 6-4, shows the total cost for each of the options.

Figure 6-4 PV Costs (CAN$) up to 2054 – Individual Options

Figure 6-5 shows the marginal comparison of Option 1 to its sensitivity cases on a Present Value (PV) cost basis. Option 1(1_BaseCase), outperforms all cases aside from the low carbon cases (1_LowCarb, 1_UltraLC). The LNG only case (1_LNG) excludes the associated liquids capital and operating expenses from the CGPF through shipping to highlight the additional costs associated with liquids handling.

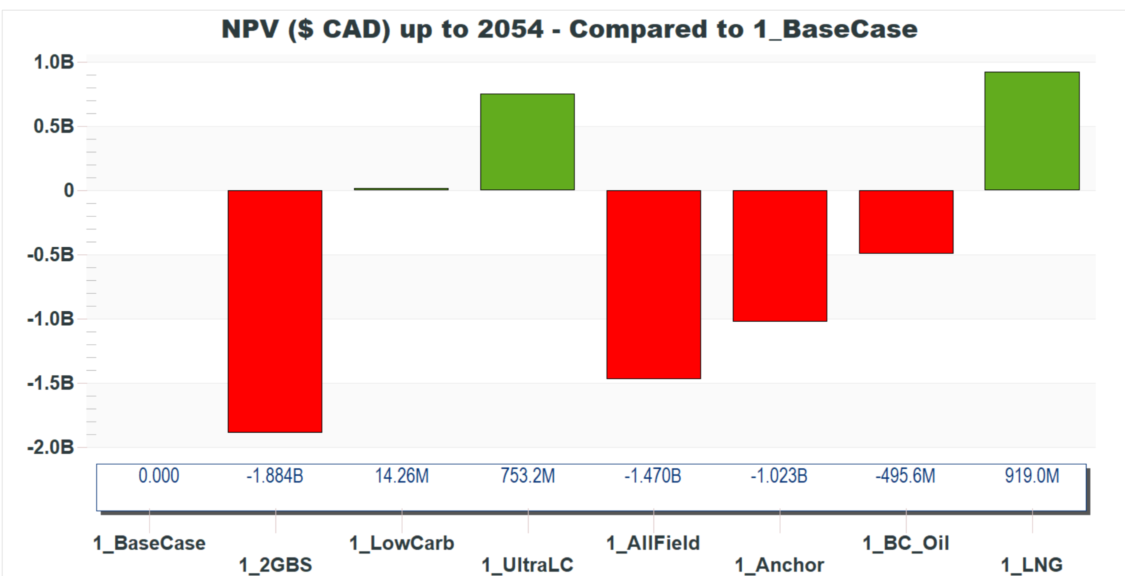


Figure 6-5 PV Production Costs to 2054 – Marginal Comparison of Option 1 Base Case and Sensitivity Cases

The following observations can be made:

- There are significant additional capital and operating expenses associated for the second GBS with the two GBS case (1_2GBS).
- The increase in costs for the All Field and Anchor cases (1_AllField, 1_Anchor) are associated with the additional upfront capital required for the early production timing.
- Additional costs for capital and operating expenses associated with centralized power, renewables and carbon capture and sequestration are offset by a significant reduction in GHG carbon taxes over the life of the project with the ultra-low carbon case.

6.4.2 Landed Cost Comparison

Figure 6-6 provides the total landed cost for each option in USD $/MMBtu. Landed costs are presented in USD for benchmark comparison to international markets. Total costs are split into the following:

- Field Development - costs required to develop the field and deliver to the GBS/LNG facilities including development wells, flow lines, conditioning facilities, gathering pipelines, central gas processing facility, and export pipelines,
- LNG OPEX - costs to maintain and support the GBS including costs for ice management,
- LNG CAPEX - costs of the GBS Hull, LNG liquefaction, LNG storage and loading, liquids handling facilities and all other equipment (power generation, accommodations, and utilities) on the GBS.
- Shipping - cost to transport LNG or liquids to market
- GHG Taxes - greenhouse gas taxes are the net taxes paid for each option over the life of the project.

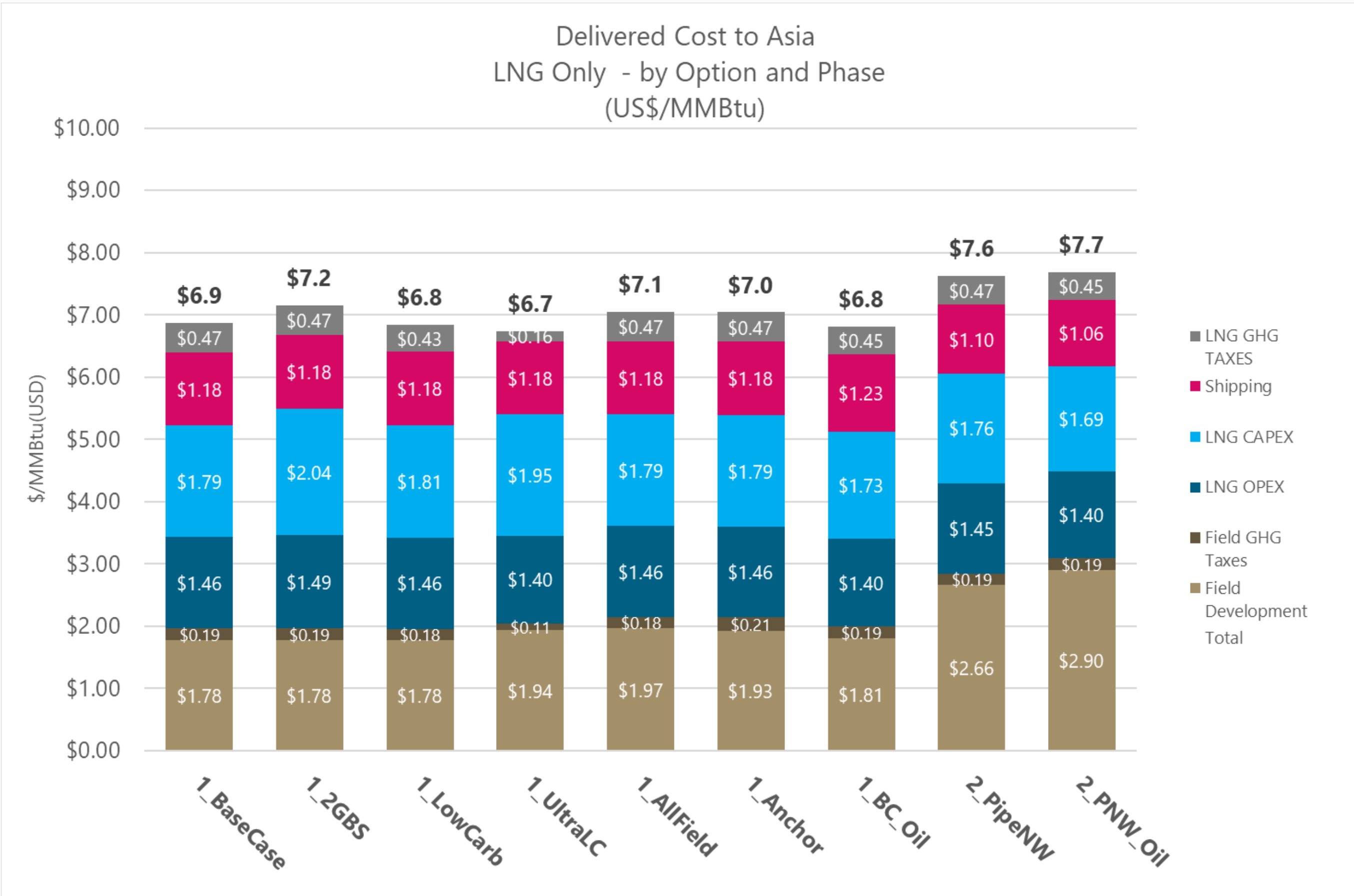


Figure 6-6 Delivered Cost to Asia – LNG Only

Figure 6-7 Provides the cost comparison between Option1 transporting condensate by ship versus Option 2 shipping condensate by pipeline. The Handling cost for Option 1 is the cost for the Export Pipeline, storage and loading facilities at the GBS related to the condensate, with the transport cost being the cost of transporting the condensate by ship to market. For Option 2 the transport costs include all costs downstream of the CGPF to the market.

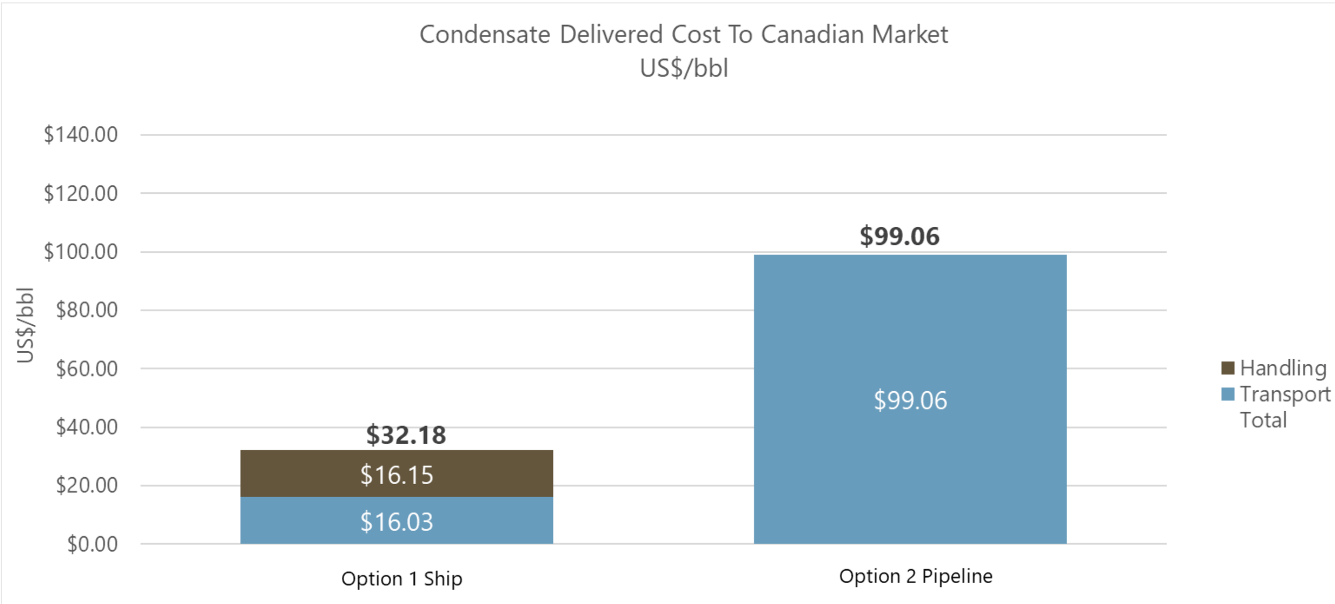


Figure 6-7 Condensate Delivered Cost

Based upon a price of US$ 10/MMBtu as forecast by Sproule, the MDLNG project even at US$ 7.7 MMBtu would generate a positive profit. For the condensate, the cost of US$ 32.18/bbl (CAN$ 40.22/bbl) would be a positive contribution at the forecast value of CAN$ 60/bbl. With the much higher capital investment and high transportation tolls makes Option 2 uncompetitive in the market.

7 Conclusions

This pre-feasibility study Indicates that the MDLNG Project is technically and economically feasible. The Mackenzie Delta contains substantial proven onshore conventional natural gas reserves that could be developed for export that would provide economic benefits to the Inuvialuit Settlement Region, NWT and Canada.

The upstream facilities need to be staged such that the supply nearest to the offshore GBS (Niglintgak, Taglu and Umiak) are developed initially with Parsons Lake and smaller fields added later in the project to offset field declines at Niglintgak, Taglu and Umiak. By locating the gas processing onshore and designing the facilities for carbon capture and storage (CCS) the carbon footprint will be reduced. A single GBS that liquifies the natural gas, provides storage and loading facilities for the LNG and condensate is recommended.

The landed cost of LNG in Asian markets although at the high end of the range, will be competitive with other North American projects particularly if CCS is successful.

A more detailed feasibility evaluation of the transportation of LNG and gas condensates from the Mackenzie Delta would include the following studies:

- Detailed reservoir simulations for each of the fields to confirm the gas deliverability forecasts.
- As part of the detailed reservoir simulations, condensate production profiles should be developed that are consistent with the natural gas production profiles.
- An analysis of potentially re-injecting the condensate back into the reservoirs to eliminate the requirement for shipping condensate.
- An analysis of the feasibility of using Wind and Solar as potential power sources to reduce the carbon footprint at the conditioning facilities.
- An analysis of potential locations for carbon storage.
- An assessment of external risks (regulatory, ESG, and political).
- Deeper risk assessment of multi-year ice influence on the safety of navigation and optimal routes in ice.
- Consideration of different design concepts for ice breaking LNG carriers (with extreme ice bow, bulbous ice bow, etc.).
- A more detailed analysis of trans-shipment issues (with a comparison of different transportation schemes and destinations).
- Transit simulation for winters with greater than normal ice conditions would provide a more accurate evaluation of the required storage volumes for LNG and condensate.

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Appendix A
Project Option Details

Mackenzie LNG Pre-Feasibility Study

Options Review

31-03-2021

Rev 1

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Options

Options Review

Option 1:

- 1_BaseCase Single integrated GBS, phased field development (Taglu, Nig and Umiak anchor fields Year 1 with Parsons and other smaller fields coming later)
- Sub-options – same as 1-BaseCase with following sensitivities:
  - 1_2GBS : Two GBS, one for LNG and second for condensate handling
  - 1_LowCarb: Carbon capture and sequestration of associated/process gas at the Central Gas Processing Facility
  - 1_UltraLC: Carbon capture and sequestration of associated/process gas, centralized onshore power (Combined cycle+ wind /renewables), LNG e-drive compression/refrigeration, carbon capture and sequestration of flue gas/combusted gas.
  - 1_AllField: All fields producing from Year 1 (Taglu, Nig and Umiak anchor fields, Parsons Lake and other smaller fields).
  - 1_BC_Oil: With oil processing facilities at production fields

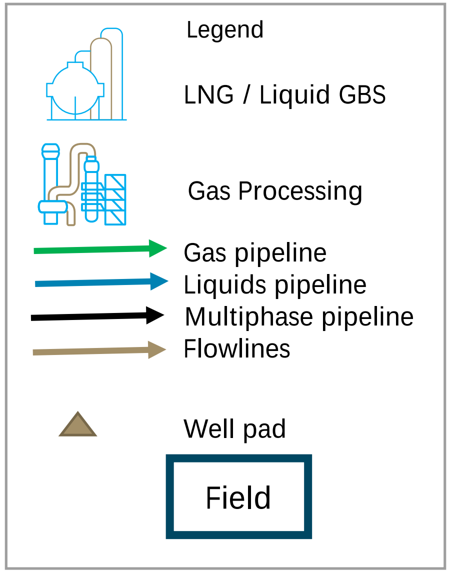
Option 2:

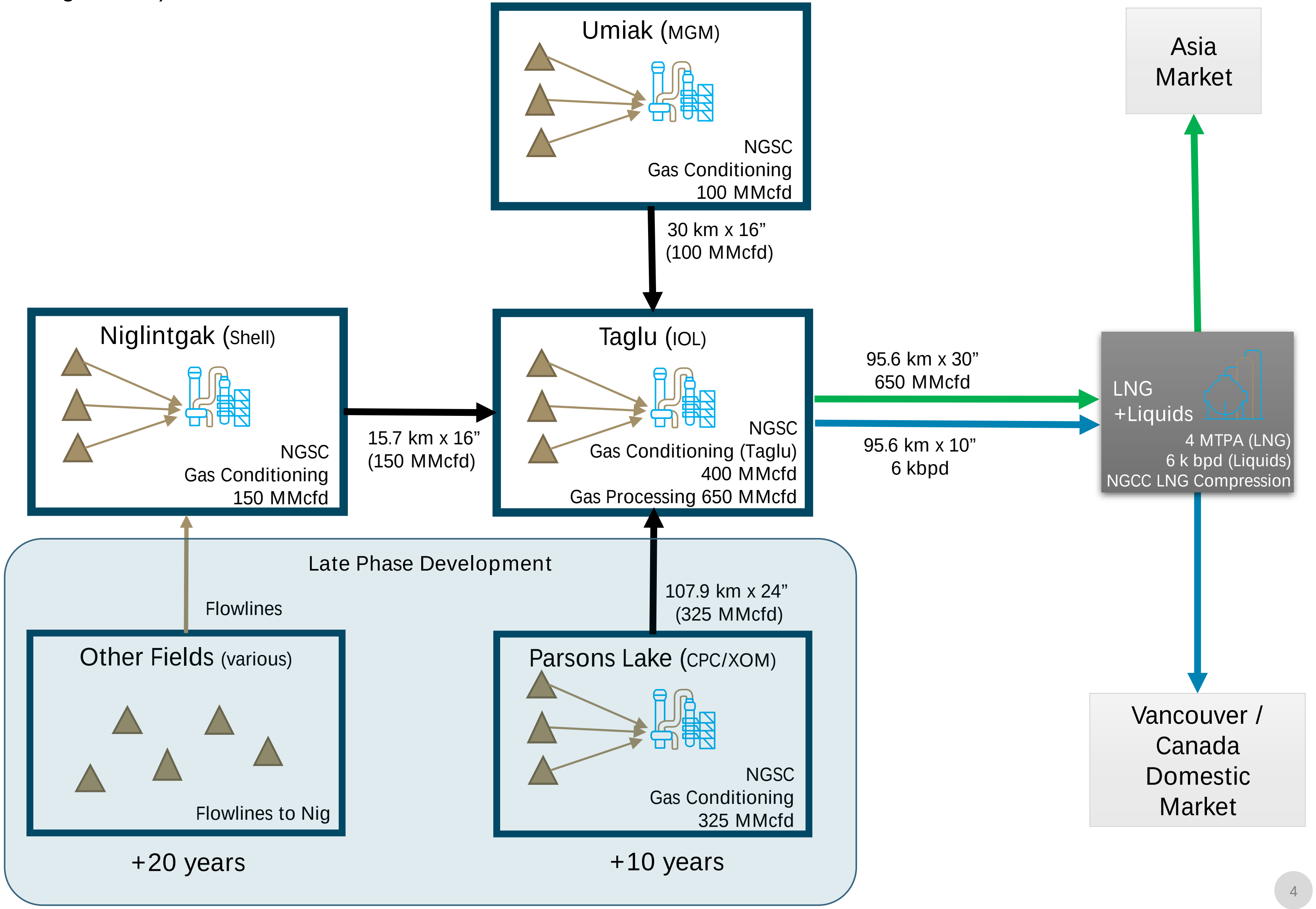
- 2_PipeNW Single GBS (LNG), condensate goes south to Norman Wells, phased field development (Taglu, Nig and Umiak anchor fields Year 1 with Parsons and other smaller infields coming later)
- Sub-Options same as 2_PipeNW with following Sensitivities:
  - 2_PNW_Oil: With oil processing facilities

Option 1

1_BaseCase Single integrated GBS, phased field development (Taglu, Nig and Umiak anchor fields Year 1 with Parsons and other smaller fields coming in later)

Area	Configuration				
Fields	Nig	Umiak	Taglu	Parsons Lake	Other Fields
Year on Production	1	1	1	10+	20+
GBS	• LNG + Liquid				
Field Operations	• Gas Conditioning – distributed • Central Processing - Taglu				
Pipelines	• Multi-phase field to Taglu • Separate Gas and Liquids to GBS				
Power / Emissions Management	• NGSC - Distributed Onsite power generation • GT LNG Compression • Flare/Vent				

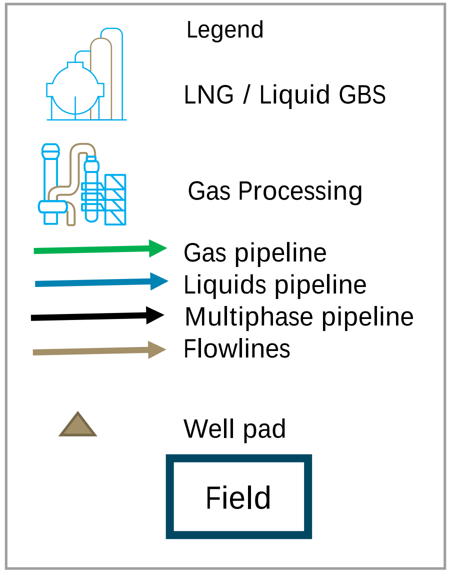


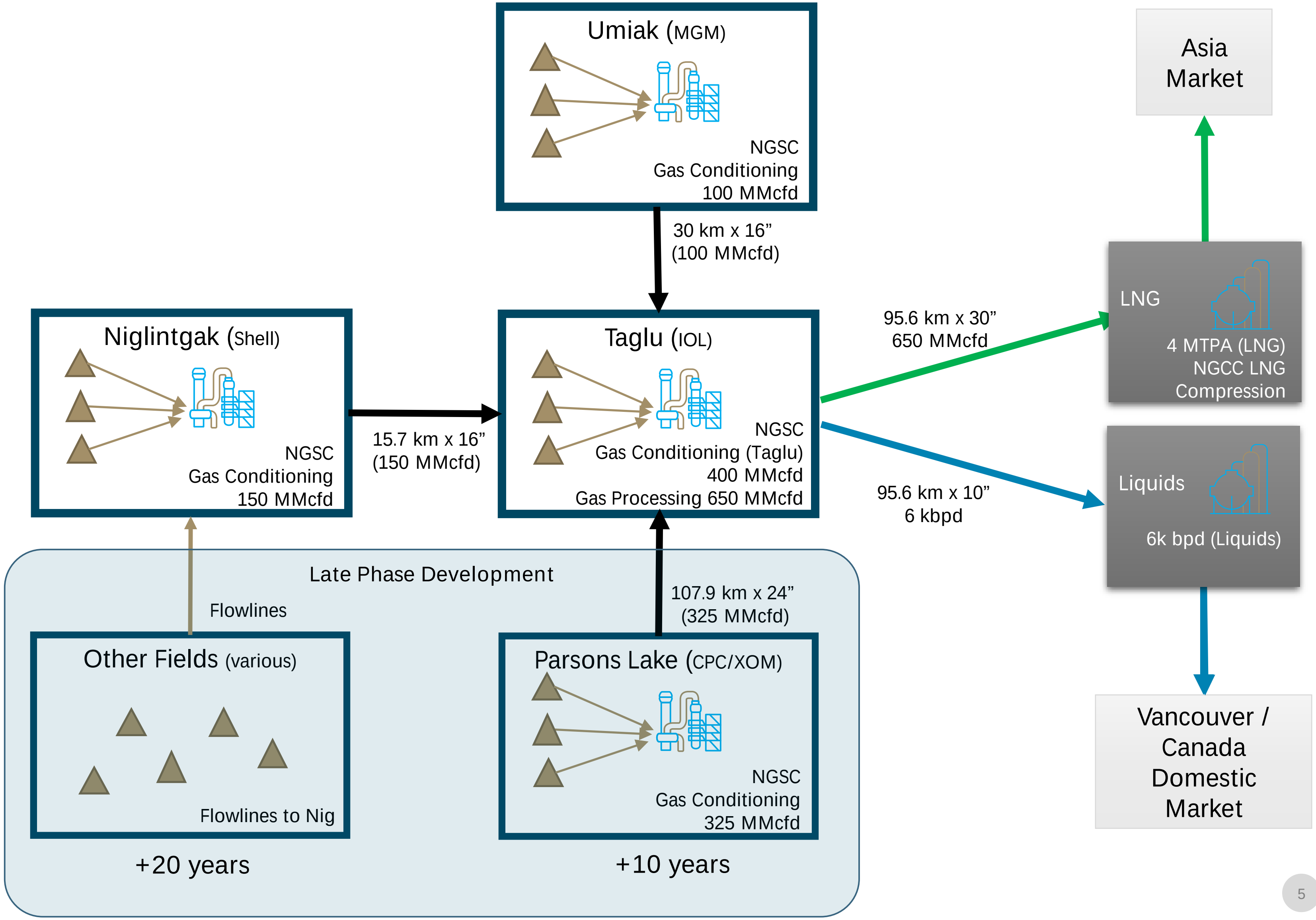


Option 1 Sensitivity

1_2GBS : Two GBS, one each for LNG and second for liquid handling

Area	Configuration				
Fields	Nig	Umiak	Taglu	Parsons Lake	Other Fields
Year on Production	1	1	1	10+	20+
GBS	• GBS (LNG), GBS (Liquid)				
Field Operations	• Gas Conditioning – distributed • Central Processing - Taglu				
Pipelines	• Multi-phase field to Taglu • Separate Gas and Liquids to GBS				
Power / Emissions Management	• NGSC - Distributed Onsite power generation • GT LNG Compression • Flare/Vent				

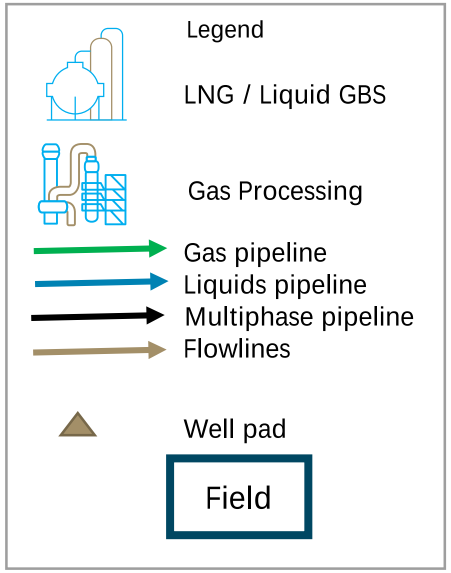


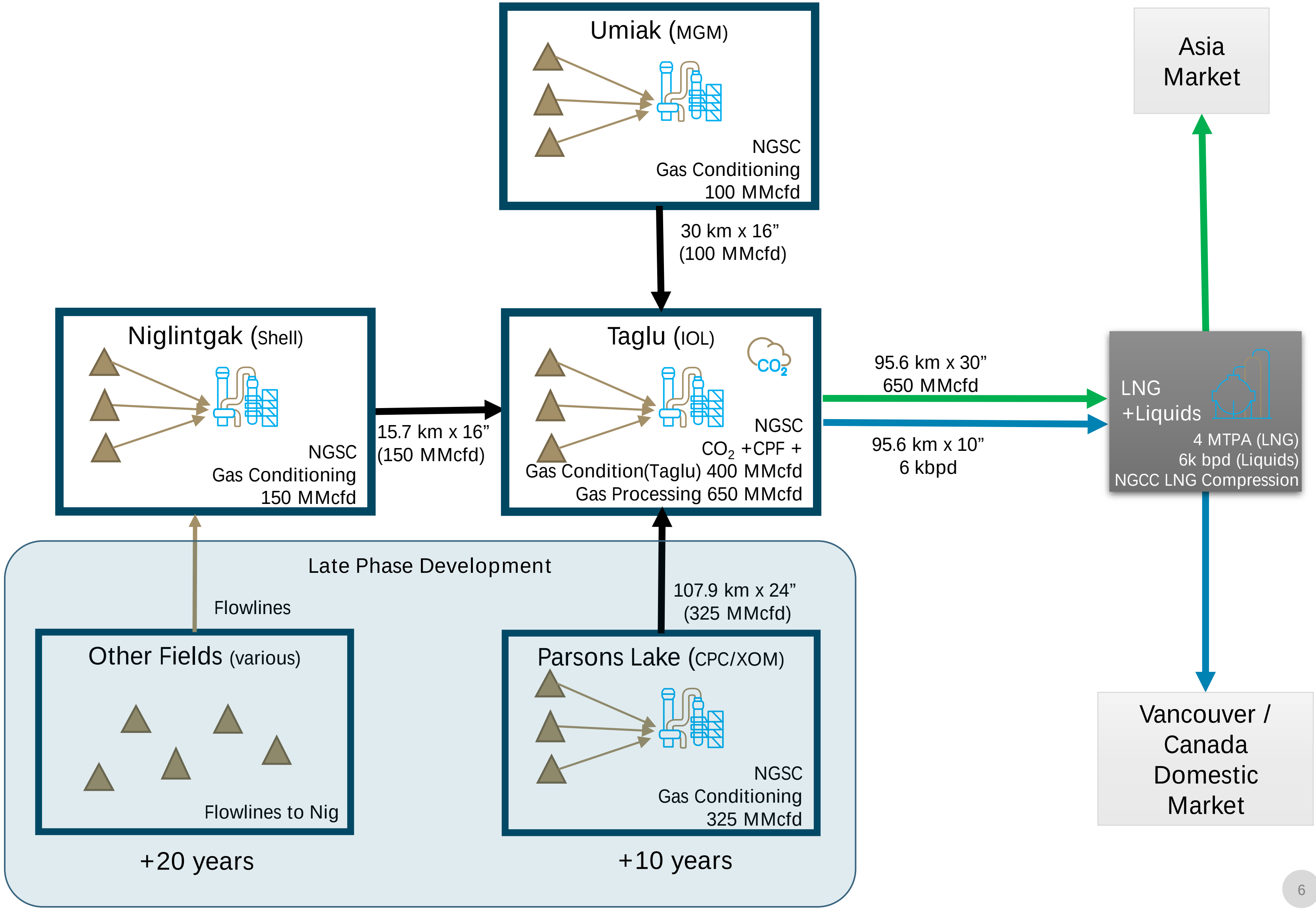


Option 1 Sensitivity:

1_LowCarb: Carbon capture and sequestration of associated/process gas

Area	Configuration				
Fields	Nig	Umiak	Taglu	Parsons Lake	Other Fields
Year on Production	1	1	1	10+	20+
GBS	• GBS (LNG), GBS (Liquid)				
Field Operations	• Gas Conditioning – distributed • Central Processing - Taglu				
Pipelines	• Multi-phase field to Taglu • Separate Gas and Liquids to GBS				
Power / Emissions Management	• NGSC - Distributed Onsite power generation • GT LNG Compression • Flare/Vent • Process Carbon • CCUS at Taglu (Year 10)				

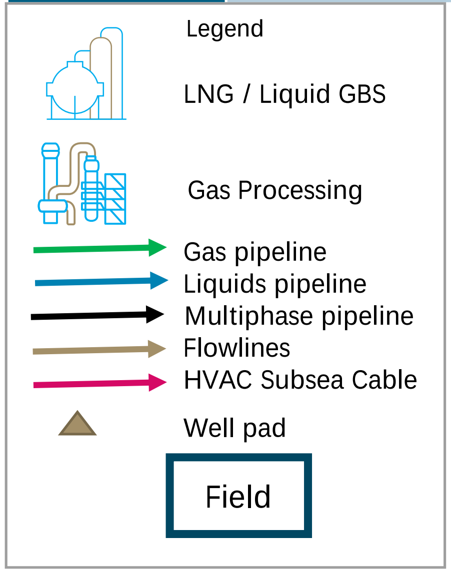


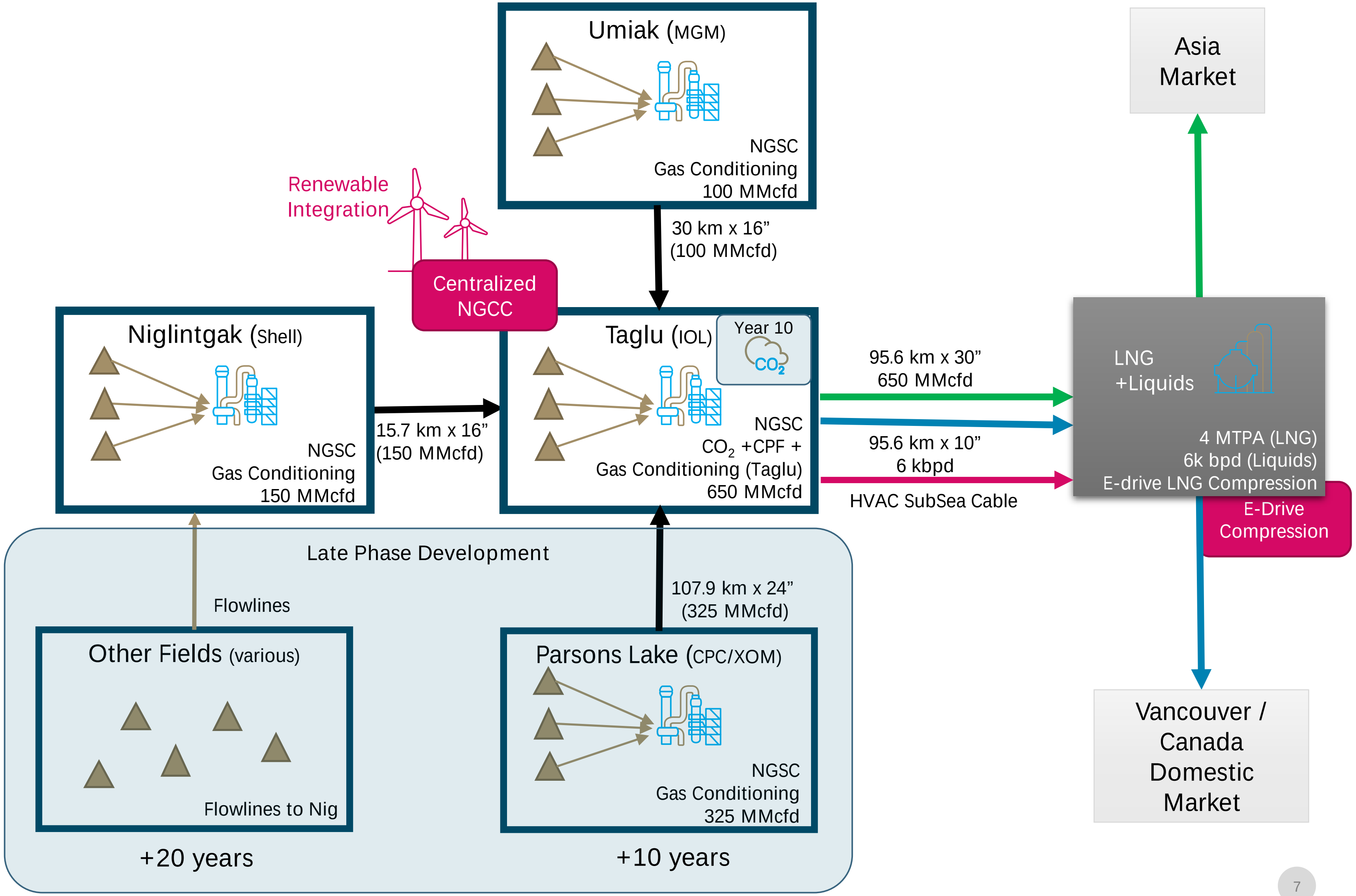


Option 1 Sensitivity:

1_UltraLC: Carbon capture and sequestration at Taglu of associated/process gas, centralized onshore power (Combined cycle+ wind /renewables), LNG e-drive compression/refrigeration, carbon capture and sequestration of flue gas/combusted gas.

Area	Configuration				
Fields	Nig	Umiak	Taglu	Parsons Lake	Other Fields
Year on Production	1	1	1	10+	20+
GBS	• GBS (LNG), GBS (Liquid)				
Field Operations	• Gas Conditioning – distributed • Central Processing - Taglu				
Pipelines	• Multi-phase field to Taglu • Separate Gas and Liquids to GBS				
Power / Emissions Management	• NGCC – Centralized Power • E-Drive LNG Compression • Emergency Flare Only • Combustion/Flue and Process Carbon • CO2 removal at Taglu (Year 10) • Renewable Integration				

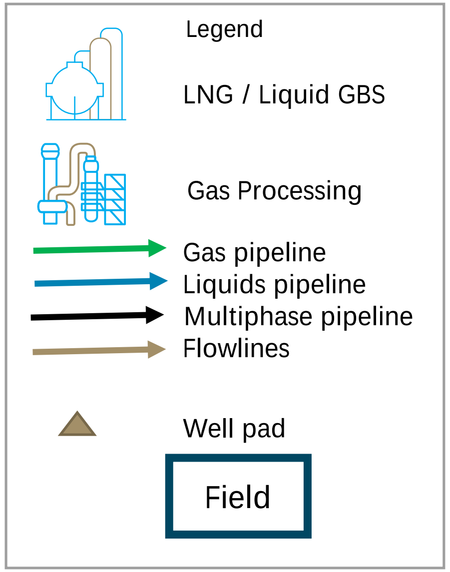


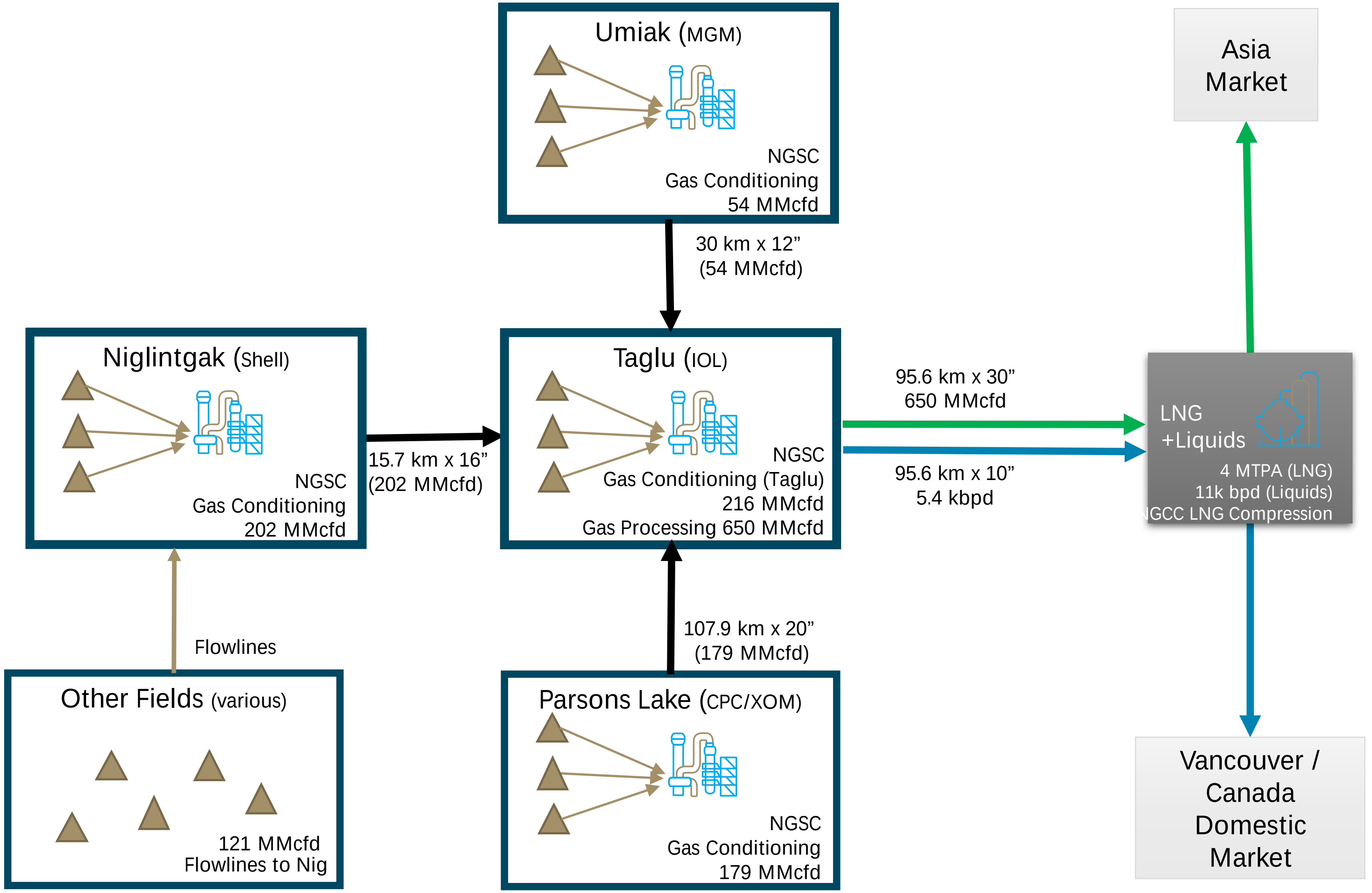


Option 1 Sensitivity:

1_AllField: All fields producing from Year 1 (Taglu, Nig and Umiak anchor fields, Parsons Lake and other smaller fields).

Area	Configuration				
Fields	Nig	Umiak	Taglu	Parsons Lake	Other Fields
Year on Production	1	1	1	1	1
GBS	• LNG + Liquid				
Field Operations	• Gas Conditioning – distributed • Central Processing - Taglu				
Pipelines	• Multi-phase field to Taglu • Separate Gas and Liquids to GBS				
Power / Emissions Management	• NGSC - Distributed Onsite power generation • GT LNG Compression • Flare/Vent				

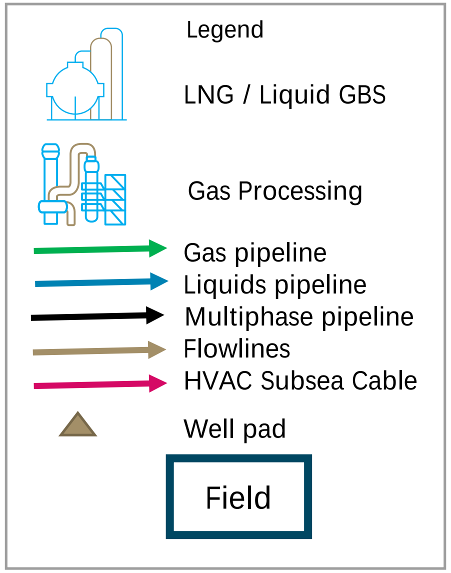


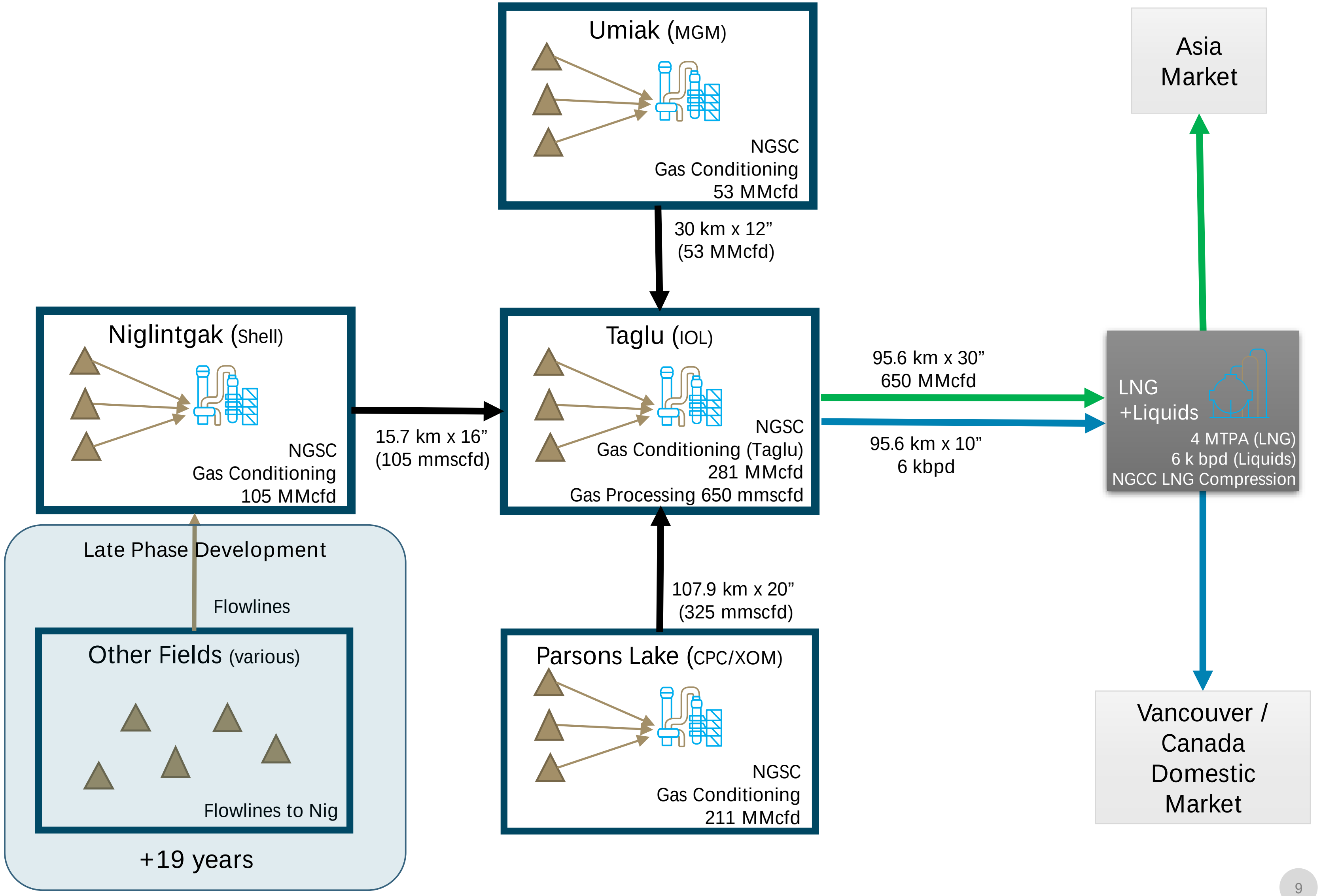


Option 1

1_Anchor Single integrated GBS, Anchor fields (Taglu, Nig, Umiak and Parsons Lake) develop Year 1 and other smaller fields coming in later)

Area	Configuration				
Fields	Nig	Umiak	Taglu	Parsons Lake	Other Fields
Year on Production	1	1	1	1	20+
GBS	• LNG + Liquid				
Field Operations	• Gas Conditioning – distributed • Central Processing - Taglu				
Pipelines	• Multi-phase field to Taglu • Gas and Liquids to GBS				
Power / Emissions Management	• NGSC - Distributed Onsite power generation • GT LNG Compression • Flare/Vent				

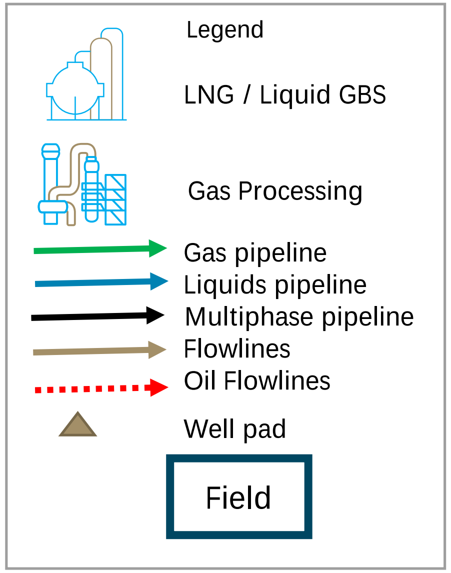


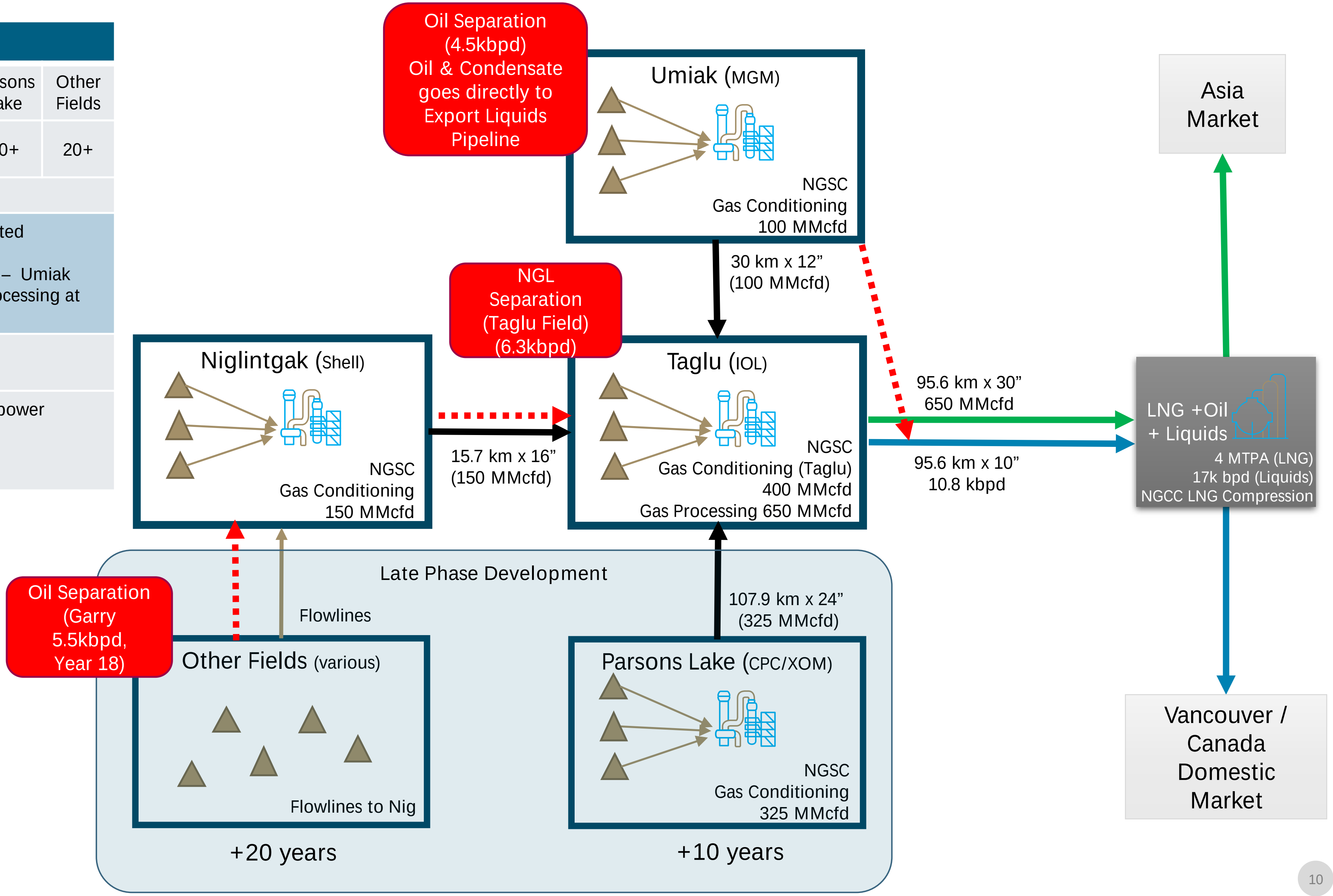


Option 1 Sensitivity:

1_BC_Oil: With oil processing facilities

Area	Configuration				
Fields	Nig	Umiak	Taglu	Parsons Lake	Other Fields
Year on Production	1	1	1	10+	20+
GBS	• LNG + Liquid				
Field Operations	• Gas Conditioning – distributed • Central Processing – Taglu • Oil Separation/stabilization – Umiak and Garry Fields, NO oil processing at Taglu CPF				
Pipelines	• Multi-phase field to Taglu • Gas and Liquids to GBS				
Power / Emissions Management	• NGSC - Distributed Onsite power generation • GT LNG Compression • Flare/Vent				

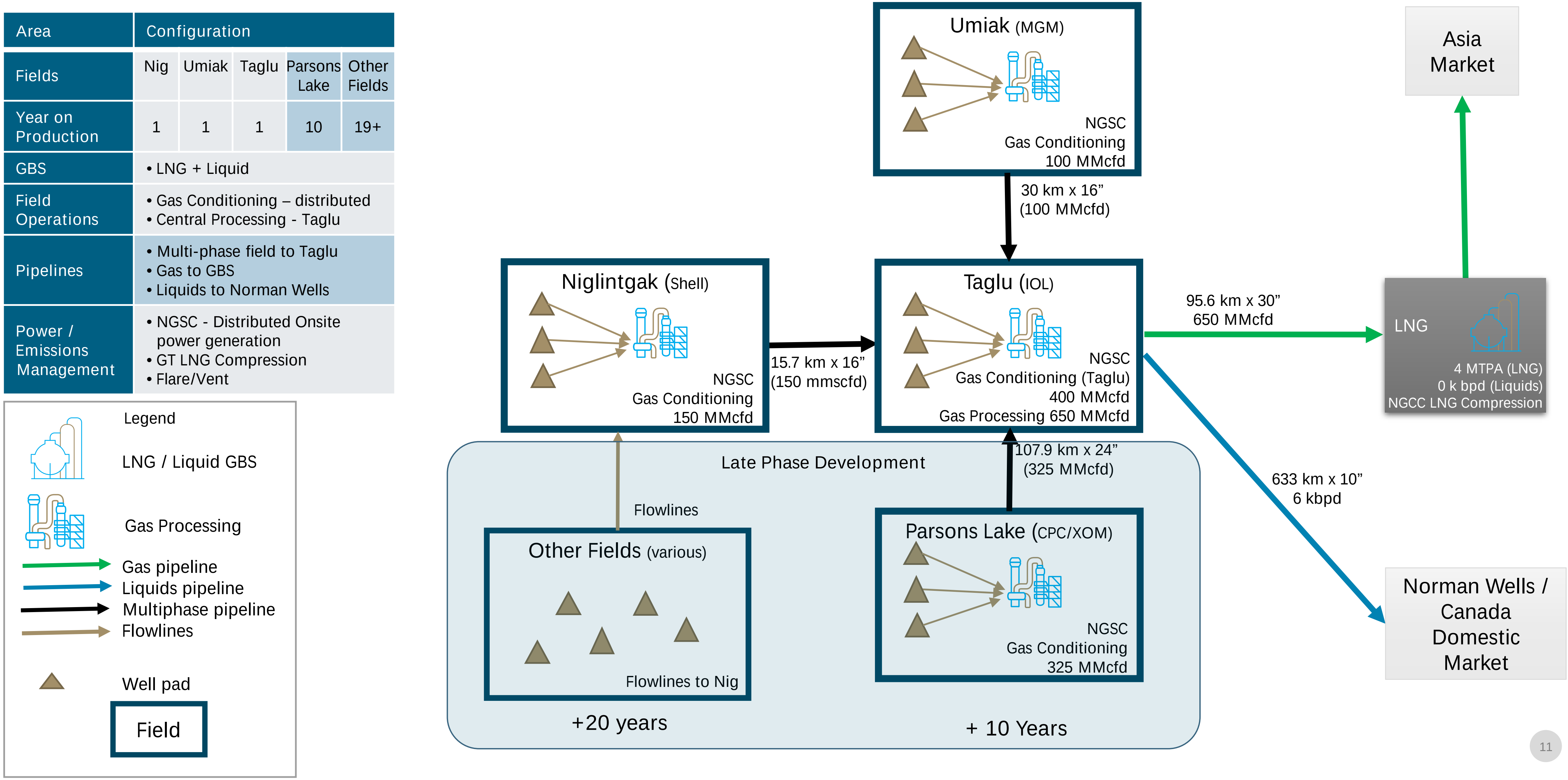




Option 2:

2_PipeNW Single integrated GBS, liquids go south to Norman Wells, phased field development.

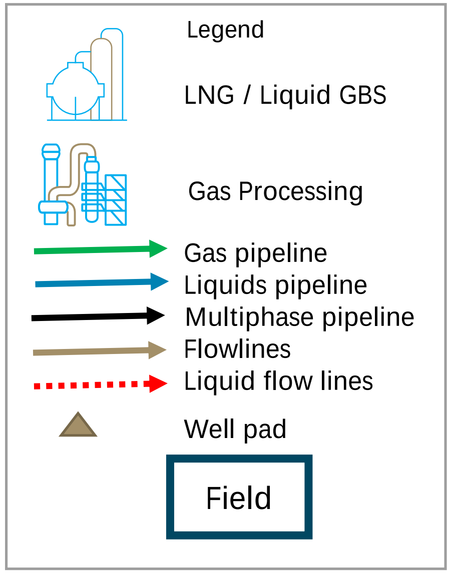
Area	Configuration				
Fields	Nig	Umiak	Taglu	Parsons Lake	Other Fields
Year on Production	1	1	1	10	19+
GBS	• LNG + Liquid				
Field Operations	• Gas Conditioning – distributed • Central Processing - Taglu				
Pipelines	• Multi-phase field to Taglu • Gas to GBS • Liquids to Norman Wells				
Power / Emissions Management	• NGSC - Distributed Onsite power generation • GT LNG Compression • Flare/Vent				

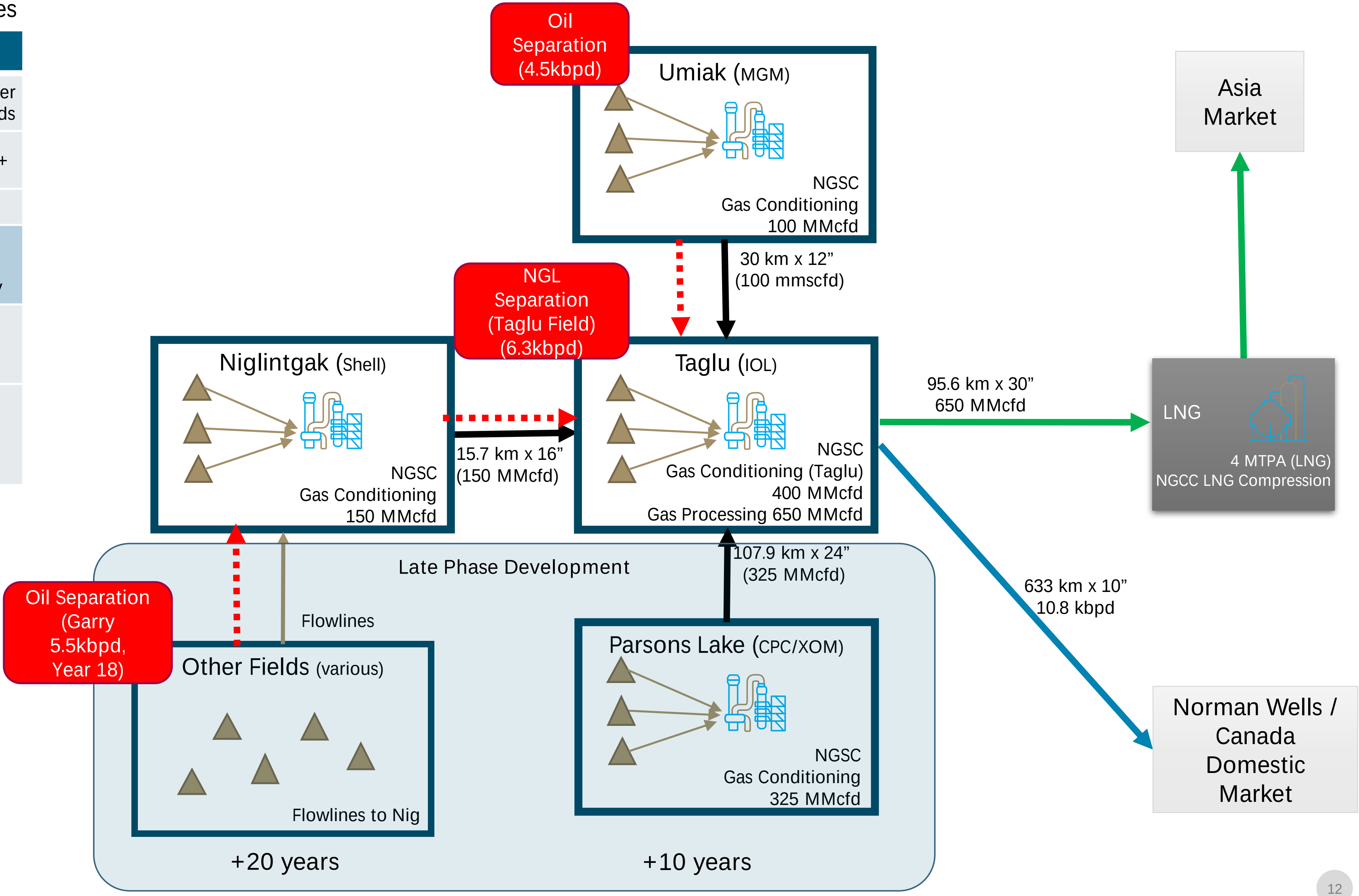


Option 2 Sensitivity:

2_PNW_Oil: With oil processing facilities

Area	Configuration				
Fields	Nig	Umiak	Taglu	Parsons Lake	Other Fields
Year on Production	1	1	1	10	19+
GBS	• LNG + Liquid				
Field Operations	• Gas Conditioning – distributed • Central Processing – Taglu • Oil Processing – Umiak & Garry				
Pipelines	• Multi-phase field to Taglu • Gas to GBS • Liquids to Norman Wells				
Power / Emissions Management	• NGSC - Distributed Onsite power generation • GT LNG Compression • Flare/Vent				





Appendix B
Offshore Pipeline Report

Mackenzie Delta Liquified Natural Gas – Prefeasibility Study
Offshore Pipeline Execution, CAPEX & OPEX

1 INTRODUCTION

The Government of the Northwest Territories (GNWT) is interested in better understanding the project economics of developing the conventional natural gas reserves located in the Mackenzie Delta region of the Northwest Territories (NWT). The Mackenzie Delta contains substantial proven publicly owned conventional natural gas reserves that could be developed for export that would provide immediate economic benefit to the Inuvialuit Settlement Region, NWT and Canada. The study concept is called "Mackenzie Delta Liquified Natural Gas" or MDLNG.

The primary MDLNG concept is the development of onshore hydrocarbons for delivery to gas liquefaction and hydrocarbon export facilities located approximately 30 km offshore. From the offshore export facilities, the LNG and oil would be shipped by separate specialized icebreaking tankers to markets.

An alternative would be to build an oil pipeline to Norman Wells to interconnect the Enbridge's Line 21 which in turn would transport the oil to Alberta and on to other markets. The natural gas would still be transported to the offshore LNG facility to be shipped in specialized ice breaking ships to market [Ref. 1].

1.1 Background

The purpose of this memorandum is to provide desk top conceptual level design, capital cost estimate and operating cost estimate for the offshore pipeline component associated with the project. The two options for are: (1) Option 1 which includes an offshore gas pipeline and an offshore condensate/oil pipeline; (2) Option 2 which only includes an offshore gas pipeline. While the base case for Option 1 is two separate GBS's (LNG and liquids), a variation looked at a single combined GBS case where the pipelines are directed to a single LNG + liquids GBS. There is another variation to Option 1 which includes an offshore power cable to the LNG GBS [Ref. 1]. The offshore pipeline battery limits for both pipelines are the Richards Island North Point shore crossing surfacing point and the offshore GBS riser tie-ins. The overall targeted estimate accuracy is a screening level, Class 5 estimate. A preliminary pipeline design and construction execution plan for the offshore pipeline was developed and is provided as the basis of estimate.

This document summarizes the work completed to develop the capital cost estimate and operational cost estimate for the offshore portions of the MDLNG gas pipeline, condensate/oil pipeline, and power cable (combined as required for the appropriate cases of interest). Intecsea's past involvement in several projects of a similar nature in the Canadian and Alaskan Beaufort seas have helped facilitate the cost estimate preparation. Contractors and vendors were not contacted to provide detailed budgetary quotes for the line pipe materials and construction activities, rather, in-house data compiled from previous project experience and contractor estimates was used to develop the costs for specific construction activities.

It should be noted that:

- Sea ice is the primary constraint in the area and is present for at least nine months of the year. In addition to governing the design of potential offshore route options, sea ice influences the potential construction methods and most of the operating support considerations for field development and pipeline operations. Other factors, such as the area's low winter temperatures, the potential presence of permafrost, pressure ridge ice keel grounding, the short seasonal construction window, and significant environmental constraints have strong influences on the development of offshore pipelines and their cost.
- All scheduling referenced in this document are subject to change as the MDLNG project develops and are based on an assumed winter construction from the sea ice for the shore crossing and near shore section of the offshore pipeline, and an assumed summer open water construction season for the remaining offshore section out to the GBS, as outlined in Section 4;
- Assumptions have been made where applicable design work has not yet been completed. Although the assumptions have been made in an attempt to provide costs that are as complete as possible, they also introduce a level of uncertainty in the preliminary estimate and should be updated to reflect the results of applicable engineering analyses as design work is completed.
- Portions of historical in-house data used in these estimates have not been confirmed with as-built costs.
- The construction execution plan presented is preliminary and high level. No construction contractors were consulted during its development. When appropriate, it is recommended that the proposed offshore pipeline construction execution plan be reviewed by competent pipeline installation and trenching contractors.
- The construction execution plan presented here, and the associated capital costs, may change based on any new survey data collected, and based on installation and trenching contractors input and capabilities.
- The chosen pipeline trench depth along the offshore route has been assumed based on engineering judgement and limited available public data (see Section 3.3). To further refine the required trench depth and the associated cost, it is recommended to complete a detailed seabed ice gouge study by requesting data from survey companies or operators who have completed seabed surveys in the Canadian Beaufort Sea.

1.2 Summary

The GNWT MDLNG study entails an offshore pipeline component from a shore crossing at North Point on Richards Island out to the proposed LNG offloading GBS platform. Option 1 entails an offshore gas pipeline and an offshore condensate/oil pipeline. Option 2 only has an offshore gas pipeline. The overall cases reviewed in this offshore pipeline study are provided below:

- Case 1: has two GBS platforms, one for LNG processing and offloading and one for condensate/oil offloading and has two pipelines; one offshore gas pipeline and one offshore condensate/oil pipeline. This case is identified as Option 1 in the GNWT RFQ.

- Case 2: has one GBS platform and has a single offshore gas pipeline. This case is identified as Option 2 in the GNWT RFQ.

- Case 3: has one GBS platform that will offload both LNG and condensate/oil, and has two pipelines; one offshore gas pipeline and one offshore condensate/oil pipeline. This case is identified as an alternate of Option 1 in the GNWT RFQ.

- Case 4: this case is identical to Case 3 with the addition of a subsea power cable from shore to the GBS. This case is identified as an alternate of Option 1 in the GNWT RFQ.

It was assumed that a fibre optic communications cable (FOC) will also be needed for each case and the offshore portion will be installed bundled to the gas pipeline. This section summarizes the design, the construction plan, operation and maintenance requirements, and the resulting CAPEX and OPEX for the offshore pipeline cases outlined above.

1.2.1 Pipeline Design

The offshore pipeline route runs from the northwest corner of North Point on Richards Island along a straight-line route to the GBS located just beyond the 15m water depth contour. The total route length is approximately 30.8 km. For Option 1, both the export gas pipeline and the export condensate/oil pipeline will be installed in the same offshore trench. An armored subsea FO communications cable approximately 25mm in diameter will be installed bundled to the gas line of each option. For Case 4, it was assumed the power cable will need to be installed into its own offshore trench to prevent potential heat and CP interference impacts to the pipelines. Further details on the offshore pipeline design can be found in Section 3.

Table 1-1: Export Pipeline Design

<table>
<tr><th rowspan="2">Parameter</th><th colspan="3">Option 1</th><th colspan="2">Option 2</th></tr>
<tr><th colspan="2">Export Gas Pipeline</th><th>Condensate/Oil Pipeline</th><th colspan="2">Export Gas Pipeline</th></tr>
<tr><td>Steel Grade</td><td colspan="2">X52</td><td>X52</td><td colspan="2">X52</td></tr>
<tr><td>Pipe Outside Diameter</td><td colspan="2">762 mm
(30.00 in)</td><td>273 mm
(10.75 in)</td><td colspan="2">762 mm
(30.00 in)</td></tr>
<tr><td>Pipe Wall Thickness</td><td colspan="2">38.1 mm
(1.500 in)</td><td>15.1 mm
(0.594 in)</td><td colspan="2">38.1 mm
(1.500 in)</td></tr>
<tr><td>Fusion Bonded Epoxy (FBE) Anti-corrosion Coating</td><td colspan="2">0.4mm
(16 mils)</td><td>0.4mm
(16 mils)</td><td colspan="2">0.4mm
(16 mils)</td></tr>
<tr><td>Concrete Weight Coating[1]</td><td>0 mm
(0 in)</td><td>38.1 mm
(1.5 in)</td><td>0 mm
(0 in)</td><td>0 mm
(0 in)</td><td>38.1 mm
(1.5 in)</td></tr>
</table>

Parameter	Option 1			Option 2	
	Export Gas Pipeline		Condensate/Oil Pipeline	Export Gas Pipeline	
Anode Size	124.9 kg	77.2 kg	44.9 kg	124.9 kg	77.2 kg
Total Length	10 km	20.8 km	30.8 km	10 km	20.8 km
Pipe Weight in Air[2]	457.9 kg/m	955.7 kg/m	96.4 kg/m	457.9 kg/m	973.2 kg/m
Submerged Specific Gravity (SG)[2]	1.45	1.7	1.6	1.45	1.7

Notes:

1. CWC density is 3044kg/m3 (190lb/ft3).
2. FOC not included in the weights and SGs.

The pipeline steel grade and the wall thickness were chosen for strain compliant pipe in an effort to reduce the required trenched depth due to seabed ice gouging. The X52 grade typically allows for lower yield to ultimate ratios, and the diameter to wall thickness ratio chosen will allow for a higher bending strain capacity.

The pipeline offshore trench design was assumed based on the expected 100-year return period ice gouge depths, sub-keel separation and trenching tolerances. For the Option 1 cases, it was assumed the 10in line would not affect the trench depth but would affect the trench width of the summer installed segment. Further details on the trench design can be found in Section 3.3.

Table 1-2: Offshore Target Trench Depths

KP Section	Segment Length (km)	Option 1		Option 2	
		Target Trench Depth (m)	Trench Volume (m^3)	Target Trench Depth (m)	Trench Volume (m^3)
0-2.5	2.9	2.9	40,354	2.9	40,354
2.5-5	3.4	3.7	103,874	3.7	103,874
5-6.2[1]	3.7	4.3	147,949	4.3	147,949
6.2[1]-10	12.2	4.3	874,020	4.3	662,316
10-15.0	8.3	5.7	902,002	5.7	711,494

Notes:

1. On-ice construction section is from the shoreline to 6.3m WD and the open water construction segment is from 6.2m WD to the GBS (15m WD).
2. For Case 4, the required power cable trench depth was assumed to be 1 m less than the pipeline trench depth.

Upheaval buckling and permafrost thaw settlement risks to the offshore pipeline were considered minimal due to the pipeline's inlet operating temperature being approximately -1°C. The strudel scour risk to the pipeline at this location is not fully known due to the lack of data. The risk of strudel scours is thought to be low due to the lack of major river channels and therefore river drainage around North Point, the relatively deep trench depths and the low pipeline operating temperatures.

1.2.2 Construction Plan

The chosen construction plan for the offshore segments of the pipelines is to install the shore crossing and the first 10km offshore during the winter season from the sea ice. The chosen shore crossing method is an open cut trench. For Option 1 (Cases 1, 3 and 4) the 30in gas line and 10in condensate line will be installed as a bundle. The ice will be thickened to support the construction activities, the trench will be excavated through a slot cut in the ice, the pipeline(s) will be installed and then the trench will be backfilled. The end of the winter installed pipeline(s) will have a recovery head attached to it and during the summer open water season the end of the pipeline(s) will be recovered by the laybarge. The remaining 20.8 km of offshore trench will be excavated during the open water season using a cutter suction dredge and the two pipeline(s) will be installed individually into the same trench using a shallow water laybarge. For Case 4, the power cable will be installed into its own trench 100m from the pipelines; it will be installed using a cutting blade and jetting tools that trench and backfill in one pass.

The pipeline and power cable GBS approaches assumed for this study will be handled through a pipeline casing installed from inside the GBS out to the pipeline trench. A short length of pipeline will be installed into the subsea trench offshore. Once the casing is installed, the short length pipelines will then be pulled into the casing. After the end is near the other exiting offshore pipeline segment, a midline tie-in will be completed. As the remaining portion of the pipelines are pulled into the casing the slack from the midline tie-in will be removed. Further details on the GBS approach method can be found in Section 4.4.

The high-level construction schedule to complete the offshore pipeline installation is given below. This is applicable for all cases. The offshore pipeline schedule is also reflected in the overall project schedule.

Year 1	
January – October	Fabricate and deliver line pipe to Tuktoyaktuk
August – October	Install GBS(s)
October - November	Double joint line pipe
Year 2	
January – March	On-ice winter trenching and installation
June – August	Mobilize CSD, lay barge spread, and necessary support vessels
July – September	Direct Pipe in preparation for tie-ins
August	Excavate trenches with the CSD
August – September	Pick-up and tie-in; lay pipeline(s) and cable (Case 4) from on-ice section to the GBS
August – October	Backfill of the pipeline(s) using CSD
September - October	Complete GBS tie-in(s)
October	Complete cleaning, gauging and hydrotest

October	Demobilize all vessels

1.2.3 Operations and Maintenance

The general operations and maintenance requirements such as monitoring temperature and pressure, mass balance and in-line inspection for the gas and condensate lines will be the same as for the onshore pipeline segments. The main requirement unique to the offshore segment of the pipeline(s) are the yearly bathymetry surveys. The bathymetry surveys will identify if seabed ice gouging or significant seabed erosion has occurred over the pipeline route. If river overflood does occur over the pipeline route, then the route will require yearly helicopter aerial surveys to map drain features in the ice during breakup. Then in the open water season, these locations will be surveyed to identify if a strudel scour has occurred. Further information on the operations and maintenance requirements for the offshore pipeline(s) can be found in Section 5.

1.2.4 CAPEX

The CAPEX cost summary for the GNWT MDLNG study Options 1 and 2 including the subsequent Option 1 cases are provided in Table 1-3 below. The cost breakdown can be found in Section 6 and the detailed cost spreadsheets are in Appendix A. The main cost assumptions are given in Section 6.1 and the main exclusions are given in Section 6.2.

Table 1-3: CAPEX Summary

Case	Option 1	Option 2	Option 1	Option 1
	Case 1	Case 2	Case 3	Case 4
CAPEX Item	**$1,000 CAD**	**$1,000 CAD**	**$1,000 CAD**	**$1,000 CAD**
Materials	60,338	51,528	60,338	122,058
Materials Transportation	45,904	41,296	45,904	46,246
Surveys	5,719	5,719	5,719	5,753
Vessel Upgrades	103,421	103,421	103,421	103,421
Offshore Trenching & Backfilling	40,944	34,961	39,463	39,463
Offshore Installation	55,905	42,466	55,905	68,835
Ice Management and Support	42,651	42,651	42,651	42,651
On-ice Installation	74,804	70,557	74,804	75,479
Offshore Pre-commissioning	5,467	4,556	5,467	5,467
Onshore Construction Camp	29,160	29,160	29,160	29,160
Engineering, Permitting Support, Proj/Const Mgmt	55,718	51,158	52,041	61,125
Total	**520,031**	**477,472**	**514,873**	**599,659**

1.2.5 OPEX

The OPEX cost summary for the GNWT MDLNG study Options 1 and 2 including the subsequent Option 1 cases are provided in Table 1-4 below. The cost breakdown can be found in Section 8 and the detailed cost spreadsheets are in Appendix B. The main cost assumptions and exclusions are given in Section 8.

Table 1-4: OPEX Summary

Case	Option 1		Option 2	
	Annual	Lifetime[1]	Annual	Lifetime[1]
OPEX Item	**$1,000 CAD**	**$1,000 CAD**	**$1,000 CAD**	**$1,000 CAD**
Operational Pigging	184	3,670	139	2,766
External Surveys	1,114	22,289	1,114	22,289
Inspection Evaluation	50	1,000	50	1,000
Chemical Injection[2]	0	0	0	0
Total	**1,348**	**26,959**	**1,303**	**26,055**

Notes:

1. Assumes a 20-year design life
2. No chemical injection costs where included. It was assumed any requirements will be covered in the onshore scope.

1.3 Recommendations

Based on the results of the study, the following are recommended:

- Geophysical surveys should be completed yearly along the potential routes to the offshore GBS(s). Geophysical surveys are needed to provide detailed seafloor mapping that would include seabed ice gouging and strudel scouring. Yearly surveys are needed to aid in determining the return period seabed ice gouge and strudel scour. Geotechnical surveys are required to help identify the soil conditions along the route for design and construction purposes.

- It is recommended to complete yearly overflood surveys as well as helicopter overflight surveys. The overflood surveys will help map the extent of the overflood and the overflight surveys will help to identify drain features in the sea ice near the proposed offshore route. Subsequent open water bathymetry surveys should be completed to identify the extent of seabed strudel scouring.

- For the study, the assumed GBS approach is by installation of casing/pull tubes using the Direct Pipe method for the pipelines and cable. Suring the next phase it is recommended to complete a GBS approach/riser study to evaluate various different methods and options.

- With the inlet temperature of the onshore pipelines being -1°C and with the pipelines being buried onshore in permafrost, there is a risk to the pipeline offshore where there is no permafrost. If the pipeline is installed in permafrost that is colder than -1°C, then as the gas traverses through the onshore pipeline, it will become colder by the time it reaches the offshore pipeline segment. In the offshore trench the pipeline is surrounded by saturated soils that could freeze as the cold gas traverses through the pipeline. This could result in frost heave. This should be reviewed during the next phase of the project.

- The trench depths provided in this study are based on assumptions. To optimize the trench depth requirements, it is recommended to complete a series of studies during the next phase of the project. These would include seabed ice gouge data gathering, determination of return period seabed ice gouging, and pipeline FE analyses using the return period data to determine the sub gouge depth of influence and effects on the pipeline(s).

- For the winter construction on-ice segment, the 30in gas pipeline by itself weighs ~681 kg/m. This is ~74kg/m heavier than any pipeline system installed in the winter from the sea ice to date and is much heavier than any pipeline installed in the winter from floating sea ice to date. However, previous studies on similar projects have shown pipeline installation from the sea ice is still feasible. During the next phase, it is recommended to complete a winter installation study to review the sea ice requirements and complete a pipeline FE installation analysis showing the support requirements. The sea ice study can also include reviewing sea ice stability to identify the potential risk of sea ice moving during the on-ice construction.

- With the current onshore pipeline inlet temperature being -1°C, the risk of upheaval buckling is very low resulting in no real backfill thickness requirement. As a means to reduce construction costs, during the next phase it is recommended to review if backfilling of the trench is necessary. It should be noted that a lack of backfill in the trench could cause ice wallowing (where the ice keel is trapped in the trench due to the depth of the keel and moves vertically with waves and tides) to preferentially occur over the pipeline(s).

- It is recommended that the need to ice strengthen and winterize construction vessels that do not normally operate in polar regions be reviewed during the next design phase. Ice strengthening and/or winterization of the construction vessels may not be necessary to the level currently provided for in the current cost estimates.

- The pipeline route crosses a zone that encompasses a travel corridor used by Beaufort beluga to move into, out of, and amongst the various bays of the Mackenzie Estuary. Certain vessel activities are allowed during whaling seasons. However, the expected construction activities have never been done before in the Canadian Beaufort Sea. The proposed construction activities should be reviewed with indigenous communities and governmental agencies in future phases of the project.

- The summer installation window is based on regional sea ice data. For the next phase of the project, it is recommended to complete a sea ice and construction vessel study that focuses on open water construction season length that can be achieved based on the types of vessels to be used.

- In order to help accommodate the proposed pipeline installation, the following infrastructure modifications are recommended:
    - Dredge Tuktoyaktuk port facilities to provide access for larger vessels and barges.
    - Port upgrades to accommodate bulk freighters as well as trenching, installation, and support vessels.
    - Increase fuel storage capacity for on-ice construction equipment and marine vessels.
    - Expansion of material (pipe) storage and construction areas.

  In addition to these recommended infrastructure upgrades, it may also be necessary to review/upgrade the personnel accommodations in the area. Note that camp loading scenarios should be evaluated in future design phases.

- During future phases of the project, it is recommended to complete a more detailed cost estimate that would entail requests for budgetary quotes, consultations with construction contractors and review of alternative delivery routes and methods, such as shipping to Skagway and trucking line pipe to site.

2 ACRONYMS & TERMS

A&R - Abandonment and Recovery

AHTS - Anchor Handling Tug Supply Vessels

CAPEX - Capital Expenditure

CSD - Cutter Suction Dredge

CWC - Concrete Weight Coating

D - Diameter (pipeline)

DOC - Depth of Cover

FBE - Fusion Bonded Epoxy

FE - Finite Element

FJC - Field Joint Coating

FOC - Fibre Optic Cable

GBS - Gravity Base Structure

ILI - Inline Inspection

LDS - Leak Detection System

LLI - Long Lead Items

LS - Lump Sum

MDLNG - Mackenzie Delta Liquefied Natural Gas

MEG - Monoethylene Glycol

MeOH - Methanol

MFL - Magnetic Flux Leakage

NDE - Non-Destructive Examination

NTS - Not to Scale

OD - Outer Diameter (pipeline)

OPEX - Operating Expenses

PU - Polyurethane

PWHT - Post-Weld Heat Treatment

RFQ - Request for Qualifications

SAW - Submerged Arc Welded (linepipe)

SG - Specific Gravity

t - wall thickness (pipeline)

TIC - Total Installed Cost

TSHD - Trailing Suction Hopper Dredge

UT - Ultrasonic Testing

WD - Water Depth

WPQ - Welding Performance Qualifications

WT - Wall Thickness (pipeline)

3 PIPELINE DESIGN

For Option 1, two pipelines are needed. A 30in diameter gas pipeline and a 10in condensate/oil pipeline. The pipeline operating inlet temperatures for both lines is -1°C [Ref. 4] to prevent thaw subsidence along the onshore route. Therefore, it was assumed the offshore pipelines will have minimal temperature differential during operations. The inlet operating pressures of both lines is expected to be less 68.9 bar (1000psi) [Ref. 3].

3.1 Offshore Pipeline Route

The onshore gas will be treated at the Taglu Central Gas Conditioning Facility after which the gas will be sent via an onshore buried pipeline to a shore crossing located at North Point on Richards Island. The onshore/offshore isolation joint will be located approximately 100m onshore from the MSL shoreline and is identified as offshore pipeline KP 0.0. This isolation joint will separate the onshore and offshore cathodic protection systems. From the isolation joint 100m onshore, the offshore pipeline route will be a straight-line route to the offshore GBS LNG facility. For Option 1, the condensate/oil pipeline will be installed along the same route and in the same offshore trench as the gas line. The approximate length of the offshore route segments is 30.79km. The route is shown in Figure 1.

Figure 1: MDLNG Offshore Pipeline Route [Ref.5]

The profile of the offshore pipeline route is provided in Figure 2 below.

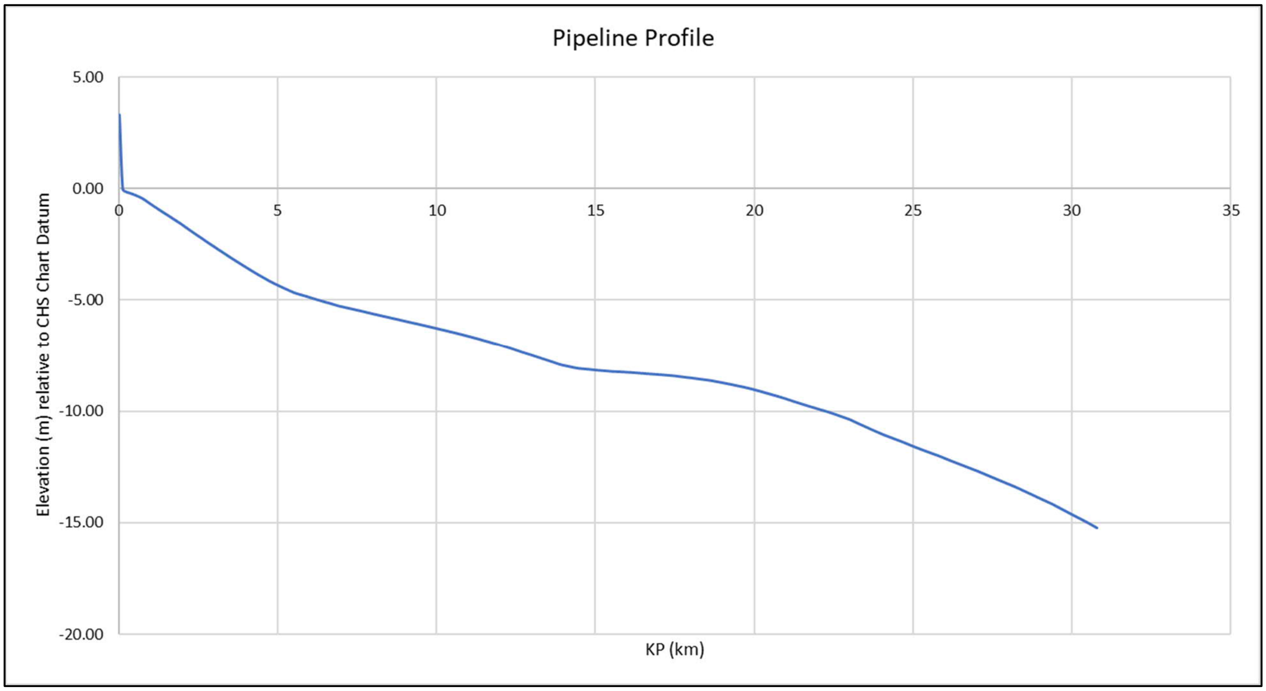


Figure 2: MDLNG Offshore Pipeline Route Profile [Ref. 6]

The shore crossing shown in Figure 1 at North Point was chosen due to the shoreline there appearing to have less morphological changes over time. It also allows for a shorter offshore route out to the ~15m water depth contour while avoiding Pullen Island. With limited available public data along the route, a pipeline routing study should be completed during a future phase of the project to review routing alternatives.

3.2 Pipeline Mechanical Design

In an effort to reduce the offshore trenching requirement, the offshore pipeline designs are assumed to be a limit state strain-based design. Based on similar strain-based designs for offshore Arctic pipelines, the grade of steel was chosen to be API 5L grade L380 (X52) [Ref.7]. This grade of steel generally allows for lower yield to ultimate ratios which are beneficial for pipelines expecting high bending strains.

The offshore gas pipeline diameter chosen for this study is nominal 30-inch, and the chosen diameter for Option 1's condensate line is nominal 10-inch. Each of the offshore pipelines were assumed to have 0.41mm (16 mils) of FBE anti-corrosion coating along the entire length of the offshore segments. The wall thickness for each was chosen based on common sizes and achieving a D/t (pipe diameter to wall thickness) ratio of 20 or less. Based on past similar Arctic subsea limit state design projects, the chosen D/t ratio will provide adequate strain capacity.

For trenched pipelines, it is important that they have a specific gravity that will allow them to settle and be stable at the bottom of the trench during the trenching, mainly backfilling, activities. For this study, the SG of the pipelines was chosen based on past projects and engineering judgement. For the on-ice construction portion of the route, a SG of 1.45 was chosen for the gas pipeline. This SG balances the pipeline weight in air with that of the pipeline being stable at the trench bottom during construction. The weight of the pipeline can impact the installability of the pipeline from the sea ice due to potential weight limitations on the sea ice and capacity of sideboom supports. Installation of the pipeline from the sea ice is discussed in more detail in Section 4.2.

For summer construction, the dredge backfilling activities are expected to fluidize the trenching spoils in the trench water column such that the SG requirement for that segment of the pipeline will be in the range of 1.6 to 1.7. To increase the gas pipelines SG along this segment of the offshore route, a concrete weight coating (CWC) of 38.1mm (1.5in) was assumed.

A high-level cathodic protection calculation using DNVGL-RP-F103 [Ref. 8] was completed to identify the anode material requirements. It was assumed the pipelines will have bracelet style anodes at a spacing of 8 joints and will have molded anode tapers/fill to allow for ease of installation through roller cradles and boxes. The assumed field joint coatings for the FBE coated pipe was FBE, and for the CWC line pipe was FBE with a polyurethane (PU) fill.

Table 3-1: Offshore Pipeline Design

Parameter	Option 1			Option 2	
	Export Gas Pipeline		Condensate/Oil Pipeline	Export Gas Pipeline	
Steel Grade	X52		X52	X52	
Pipe Outside Diameter (OD)	762 mm (30.00 in)		273 mm (10.75 in)	762 mm (30.00 in)	
Pipe Wall Thickness	38.1 mm (1.500 in)		15.1 mm (0.594 in)	38.1 mm (1.500 in)	
FBE Anti-corrosion Coating	0.4mm (16 mils)		0.4mm (16 mils)	0.4mm (16 mils)	
Concrete Weight Coating[1]	0 mm (0 in)	38.1 mm (1.5 in)	0 mm (0 in)	0 mm (0 in)	38.1 mm (1.5 in)
Total Length	10 km	20.8 km	30.8 km	10 km	20.8 km
Pipe Weight in Air[2]	681.4 kg/m	955.7 kg/m	96.4 kg/m	681.4 kg/m	973.2 kg/m
Submerged SG[2]	1.45	1.7	1.6	1.45	1.7
Anode Mass	124.9 kg	77.2 kg	44.9 kg	124.9 kg	77.2 kg

Notes:

1. CWC density is 3044kg/m3 (190lb/ft3).
2. FOC not included in the weights and SGs.

A Fibre Optic Cable for communications is also required to be installed along the same offshore route. Details on the FOC design were not available at the time of this work, and therefore the FOC was assumed to be an armored subsea 24 strand FOC with a 1in diameter.

For Option 1 Case 4, a power cable is required to be installed from the shoreline to the GBS. The power cable requirements and therefore its size was unknown at the time of this study. It was assumed this line would be installed in a separate trench 100m to the side of the pipelines to avoid pipeline thermal and CP interference issues.

3.3 Trenching Requirements

Offshore Arctic pipelines are subjected to external loading risks such as seabed ice gouge and strudel scours and are generally trenched for protection. Burial of offshore pipelines that operate at higher than ambient temperatures can also introduce the risk of upheaval buckling or permafrost thaw settlement.

3.3.1 Trenching definitions

The following are the definitions for the trenching terms used for the GNWT LNG offshore pipeline design work:

- Depth of Cover: Vertical distance between top of pipe and original undisturbed seabed elevation. This term is used when the pipeline target trench depth is governed by scouring events such as ice gouge or strudel scours. For ice gouge, the DOC requirement will be the 100yr design ice gouge depth + the sub ice keel separation.
- Backfill Thickness: Vertical distance between top of pipe and the top of backfill elevation directly over the pipe. This term is used when the pipeline target trench depth is governed by upheaval buckling.
- Target Trench Depth: The trench depth (trench bottom elevation) which the trenching equipment will target. The actual target trench depth will be a range, and therefore a slight over excavation is required to be in the midpoint of the range.
- Seabed Smoothing: The virtual smoothing of the seabed such that the target trench depth remains the same over a long distance to avoid having too much local variance in the target trench depth. Seabed smoothing should be accounted for in the design target trench depth.
- Survey Errors: The bathymetry (seabed) survey, the trench depth survey, the top of pipe survey and the backfill elevation survey will all have an error associated with them. This error should be accounted for in the design target trench depth.
- Trenching Tolerance: Trenching tolerance is defined as the summation of the seabed smoothing, survey errors and over-excavation that is added to the minimum required Depth of Cover or backfill thickness in order to determine the required target trench depth. For the purposes of this study, the trench tolerance was assumed to be 1m.

For this study, the depth of cover will be greater than the backfill thickness requirement. Therefore, the 'target trench depth' along the route will be the summation of the required depth of cover, trenching tolerances and the pipeline diameter.

3.3.2 Seabed Ice Gouge

Irregular ice keels beneath floating sea ice pressure-ridges can periodically contact the seabed and form gouges (Figure 3). During wintertime, wind and currents push the ice sheet forming pressure ridges. Keels form beneath these pressure ridges, extending to the seabed, and are moved with the ice sheet along with other entrapped ice features. Residual sea ice features with deep drafts may also be present year-round in the study area. This moving ice may gouge the seabed over long distances as it is moved into shallower water. It is also possible for isolated ice features to gouge the seafloor during the summer open water season, as they are pushed by winds and current.

The 100-year annual return period ice gouge depths were assumed based on Intecsea's experience from previous projects and engineering judgement. The assumed 100yr return design ice gouge depths are based on water depth ranges and are given below:

- WD = 0 – 2.5m, 100yr ice gouge depth = 0.6m
- WD = 2.5 – 5m, 100yr ice gouge depth = 1.4m
- WD = 5 – 10m, 100yr ice gouge depth = 2.0m
- WD = 10 – 15m, 100yr ice gouge depth = 3.4m

For a given incision depth, it is possible to quantify the extent of soil movement below the ice keel. As the ice keel passes, the soil is pushed laterally and downward, with the lateral component being on the order of 6 to 8 times greater than the downward component. If the pipeline alignment passes through areas of active ice gouging, the amount of displacement must be evaluated. The pipeline depth of cover must be such that the resulting pipeline bending strains induced by the design ice gouge are within allowable values. For the purposes of this study, no pipeline seabed ice gouge analysis was completed. Because there will be limited pipeline differential temperature during operations (a relatively low operating temperature), during a seabed ice gouge, the associated pipeline feed in from locked in differential temperature will be minimal. Therefore, the required sub ice keel separation was assumed to be 0.5m for the purposes of this study.

Figure 3: Gouging Ice Keel over Buried Pipeline

3.3.3 Strudel Scour

Offshore of Arctic river deltas, the floodwaters due to terrestrial snow melting and river overflood precede the break-up of bottomfast sea ice. As the freshwater advances across the sea ice, the floodwater drains through cracks (e.g. tidal cracks) and holes (e.g. seal breathing holes) in the sea ice as a water jet with enough velocity to scour the seafloor through hydrodynamic erosion (Figure 4). This phenomenon is termed strudel scour.

Strudel scours usually occur in 1.5 to 6 m water depths offshore Arctic river deltas and the deepest scour depressions are generally found in shallow water (e.g., 1.5 to 3 m deep) where the strudel jet is sufficiently powerful to erode and excavate the seafloor sediments immediately below the ice. A prerequisite to large strudel scours forming is that the ice needs to be floating; there must be open water between the bottom of the ice and seabed. If the "gap" is too large, the strudel jet will not have sufficient power for significant soil erosion. In general, large strudel scours do not form within the bottomfast ice zone, which is typically within the 1.5 m water depth contour.

If a strudel scour occurs on top of the pipeline alignment, there is a potential for the pipeline to lose required support beneath. If soil is eroded from beneath the pipeline, the pipeline will span the scour length. The proposed pipelines must be designed to resist the expected loads of a potential strudel scour event.

The risk of a significant strudel scour occurring over the proposed pipeline route is not fully known due to the general lack of overflood and strudel scour survey data along or in the region of the proposed pipeline route. However, given the routes location generally away from the main Mackenzie Delta river channels, it is expected the risk is low. This will need to be confirmed during the next phases of the project. The pipeline operating temperature of the pipeline (inlet at -1°C) also reduces the risk of a strudel scour impacting the pipeline integrity.

Generally, a heated pipeline will develop a thaw bulb around the pipeline. During the winter this thaw bulb can affect the integrity of any grounded or near grounded sea ice above the trenched pipeline. This degraded sea ice can cause strudel scours to preferentially occur over the pipeline route. Given the low operating temperature of the pipeline, this risk is greatly reduced.

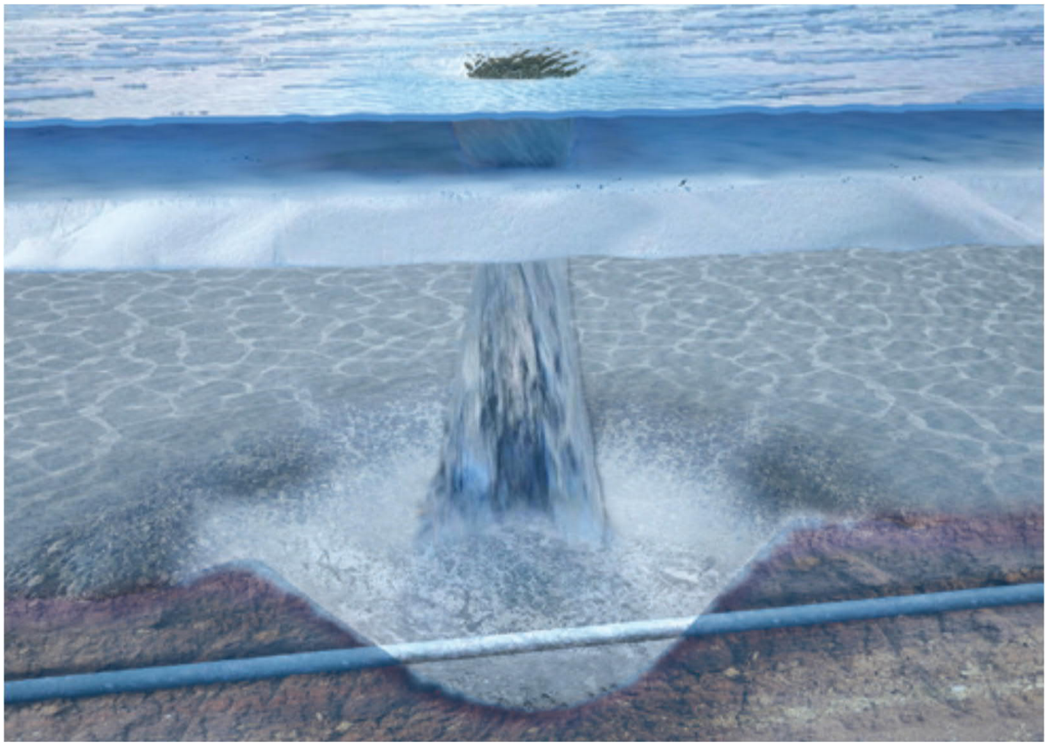


Figure 4: Strudel Scour over Buried Pipeline

3.3.4 Upheaval Buckling

When a pipeline is installed in an excavated trench and backfilled, the pipeline will be axially restrained along its length away from its surfacing points at the ends due to the frictional restraining forces of the surrounding soil. Once the axially restrained pipeline is put into operation, compressive forces due to the differential temperature and pressure will develop in the axially restrained pipeline. At local trenched pipeline (vertical) imperfections (also known as props), an effective vertical (upheaval) component of the pipeline compressive force can result, with sufficient upward force to exceed the normal restraint provided by the pipeline's submerged weight, bending stiffness and the backfill soil overburden. The trenched pipeline experiencing this force may displace vertically as this is the path of least resistance. This potential vertical instability and displacement is termed upheaval buckling. If this displacement is significant, it could risk the integrity of the pipeline or leave it exposed to other environmental loading conditions above the seabed. With the expected low design differential temperatures and pressures of the proposed pipelines, upheaval buckling is not a concern and is not considered to be one of the driving design considerations governing trench depth.

While minimal backfill thickness will be required on top of the pipelines to prevent upheaval buckling, it has been assumed that all of the trenching spoils taken out of the trench is required to be put back into the trench as backfill. The backfill will reduce the risks associated with ice wallowing.

3.3.5 Permafrost Thaw Settlement

Subsea permafrost is generally defined as soil that remains at or below 0ºC for at least two consecutive years. Depending on local soil pore water salinity, the permafrost could be frozen or unfrozen. Thaw-stable permafrost is generally found in well drained coarse sediments that contain little or no ice. Thaw-sensitive (unstable) permafrost is generally found in finer sediments that can contain large amounts of ice. The percentage of pore water forming ice crystals in marine soils varies with its temperature, salt content, and soil type. Laboratory testing of soil boring samples is typically required to define permafrost thaw consolidation characteristics.

In the Arctic, permafrost will be most prevalent onshore and in the shallow water near shore, and as such may be a concern at shore crossings. Offshore permafrost soils generally occur in the Beaufort Sea nearshore areas where bottomfast ice forms during the winter. Beyond the boundary of bottomfast ice, the permafrost profile typically declines rapidly. Alternatively, frozen soils may remain subsea following erosion of a shoreline and over a long period of time this can result in pockets of remnant relatively shallow permafrost further offshore. A warm pipeline trenched within or near ice-rich permafrost material will induce thaw subsidence due to a heat bulb developing around the pipeline. The extent of the heat bulb, the soil type, moisture/ice content, and the stratigraphic profile are the primary factors that determine the potential for differential settlement along the pipeline alignment. Differential settlement along the alignment can induce significant axial bending strain in the pipeline(s).

While there is expected to be permafrost along the offshore pipeline route, especially at the shore crossing, the pipeline's operating temperature will result in a minimal thaw bulb. The risk of significant permafrost thaw pipeline differential settlement is considered low. Therefore, at this time it was assumed there will be no need for permafrost thaw settlement mitigation methods such as thaw stable gravel and thermal syphons at the shore crossing.

3.3.6 Trench Design

The required trench depth for the pipeline(s) along the route have been assessed with regards to seabed ice gouge. The route trench depths presented in this section are the predicted depths required to avoid excessive bending strains in the pipeline due to seabed ice gouge.

Pipeline trench cross-section definitions are shown in Figure 5.

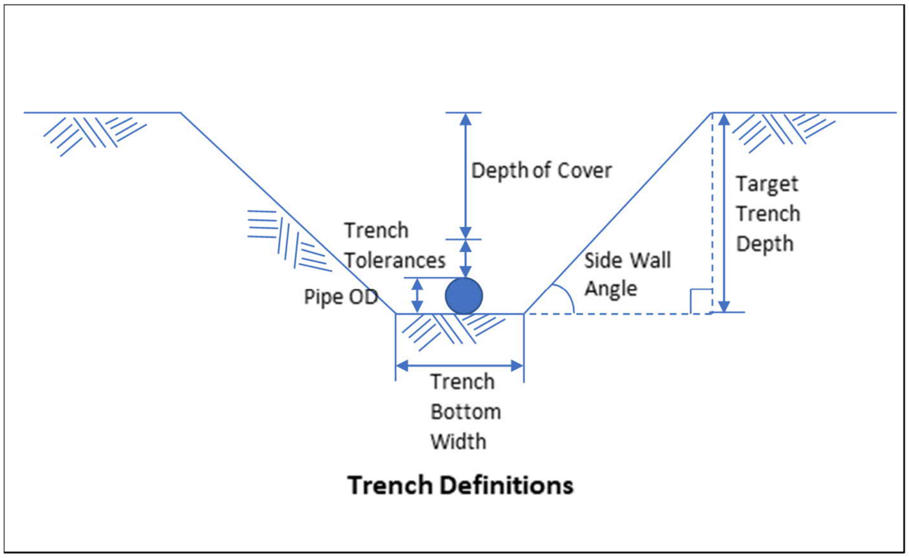


Figure 5: Typical Seabed Trench Profile Definitions (not to scale)

The trench cross-section for the on-ice winter construction assumes the trenching is completed by conventional backhoes and the ice slot width of 2m governs the trench bottom width. The trench cross-section for the open water season trenching assumes the trenching is completed using a cutter suction dredge where the pipelines will be individually installed on the trench bottom. This requires a trench bottom width of approximately 9m for the gas line and condensate line (Option 1) and 5m for the lone gas line (Option 2). The 9m trench bottom width for Option 1 allows for a 5m spacing between the two pipelines (Figure 6) that should not slow the pipeline installation down significantly.

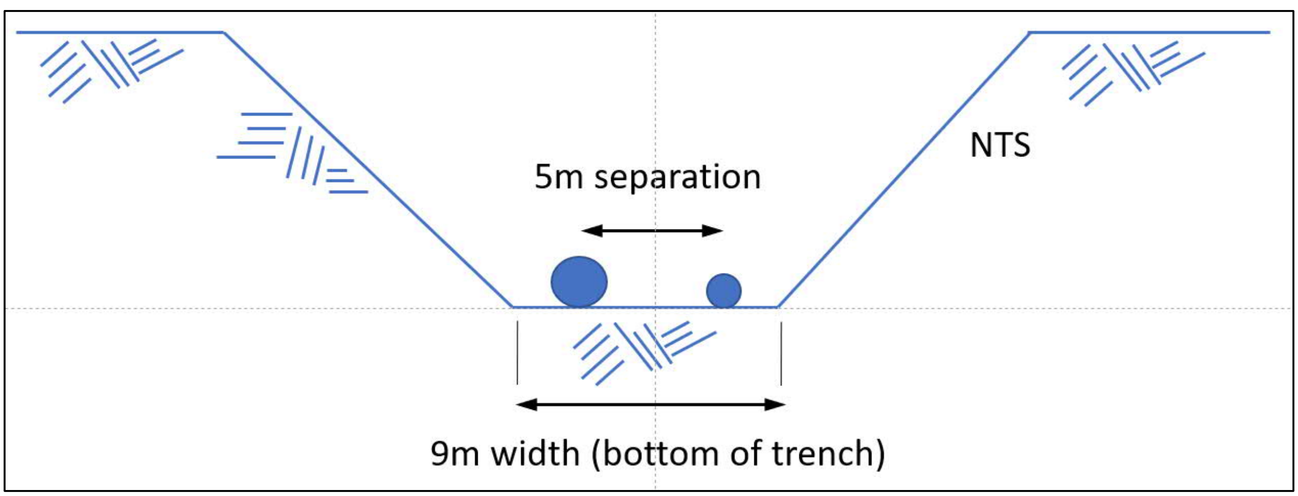


Figure 6: Typical Seabed Trench Profile Showing Two Pipelines of Option 1

The trench side wall angle was assumed based on past project experience and engineering judgement for silty sand to sandy silt. For the summer installation, the trench sidewalls are assumed to be 30° on average. For the winter installation from the sea ice, the sidewalls will vary from near vertical at the shore crossing to 30° further offshore. Over the first portion of this length (0-2.5m WD), the trench sidewalls are assumed to be at 45°. Trench sidewall stability in the soils encountered along the pipeline route will need to be confirmed during future phases of the project using the geotechnical information collected along the route. Additionally, trench sidewall erosion and the duration that such a trench could remain open on the seabed (natural infilling) should be confirmed, considering metocean conditions along the route and in-situ soils.

To determine the trench volume along the offshore pipeline route for both Options, the following were considered:

- Required depth of cover
- Trenching tolerances
- Pipeline diameter
- Trench bottom width
- Side slope angle

The estimated trench depths and associated trenching volumes for the different route segments are listed in Table 3-2 below for Option 1 and in Table 3-3 for Option 2. The trench dimensions and the target trench depths provided are preliminary and will need to be updated when site specific geotechnical data is available.

Table 3-2: Pipeline Trench Requirements for Option 1 (Gas and Condensate Pipelines)

Water Depth Range (m)	Route Length (km)	Depth of Cover (m)[1]	Trenching Tolerances (m)	Pipeline Diameter (m)[2]	Target Trench Depth (m)[4]	Trench Bottom Width (m)	Trench Side Slope (°)	Trench Volume (m^3)
0-2.5	2.9	1.1	1	0.76	2.9	2	45	40,354
2.5-5	3.4	1.9	1	0.76	3.7	2	30	103,874
5-6.3[3]	3.7	2.5	1	0.76	4.3	2	30	147,949
6.3[3]-10	12.2	2.5	1	0.84	4.3	9	30	874,020
10-15.0	8.3	3.9	1	0.84	5.7	9	30	902,002

Notes:
1. Depth of cover is the 100yr ice gouge + sub ice keel separation.
2. Pipeline diameter is 30in for the on-ice construction section and 33in for the summer installation section.
3. On-ice construction section is from the shoreline to the 6.3m WD and the open water construction segment is from the 6.3m WD to the GBS (15m WD).
4. The target trench depths were rounded to the nearest 10th of a metre.

For the Option 1 Case 1, the two pipelines will be separated approximately 3km from the two platforms and will go into separate trenches. This assumes the centre of the two GBS structures are 440m apart from each other. For this case, an additional 132,269 m^3 of trench volume is required.

For the Option 1 Case 4, the assumed power cable trenching requirements is the DOC in Table 3-2. This is due to the cable physical flexibility and trenching/installation method limitations (See Sections 4.2.6 and 4.3.3).

Table 3-3: Pipeline Trench Requirements for Option 2 (Gas Pipeline)

Water Depth Range (m)	Route Length (km)	Depth of Cover (m)[1]	Trenching Tolerances (m)	Pipeline Diameter (m)[2]	Target Trench Depth (m)[4]	Trench Bottom Width (m)	Trench Side Slope (°)	Trench Volume (m^3)
0-2.5	2.9	1.1	1	0.76	2.9	2	45	40,354
2.5-5	3.4	1.9	1	0.76	3.7	2	30	103,874
5-6.3[3]	3.7	2.5	1	0.76	4.3	2	30	147,949
6.3[3]-10	12.2	2.5	1	0.84	4.3	5	30	662,316
10-15.0	8.3	3.9	1	0.84	5.7	5	30	711,494

Notes:

1. Depth of cover is the 100yr ice gouge + sub ice keel separation.
2. Pipeline diameter is 30in for the on-ice construction section and 33in for the summer installation section.
3. On-ice construction section is from the shoreline to the 6.3m WD and the open water construction segment is from the 6.3m WD to the GBS (15m WD).
4. The target trench depths were rounded to the nearest 10^{th} of a metre.

4 CONSTRUCTION PLAN

The GBS is situated within the Mackenzie River Delta region of the Canadian Beaufort Sea, in approximately 15 m of water. This area is ice covered throughout most of the year and is prone to intrusion from multi-year ice. Because of this, the physical environment of the region has a major effect on the installation methodologies for the proposed offshore pipeline options.

The pipeline installation methodology is based on the following main assumptions. Additional assumptions can be found in the subsections for the proposed winter and summer construction methods:

- The offshore pipeline installation will be split into two installation methods: the first 10km of pipeline from the shore will be trenched and installed in the winter from the sea ice and the remaining 20.8 km will be trenched and installed during the summer open water season.
- Marine transportation via the east coast of Canada is considered to be unlikely given the prevalence of year-round ice coverage, navigability restrictions, and limited shore-based infrastructure. Furthermore, it is unlikely that materials would be procured from the area. Major equipment and material are assumed to arrive from the Pacific through the Bearing Strait and into the Arctic Ocean.
- For the purpose of this study, it has been assumed that the pipelines will be installed after the GBS installation and will tie into the GBS risers using the Direct Pipe structure approach method. Pipeline tie-ins at the GBS are assumed to take 4 days per tie-in.
- Pipeline recovery and layaway was assumed at the location between the winter installed segment and the summer installation. It was assumed to take 2 days for the recovery and tie-in.
- The start date for open water operations in the Beaufort Sea is usually controlled by the date that the ice clears Point Barrow, Alaska. For the purpose of this study it has been assumed that no offshore construction will begin before August 2nd and must end not later than October 17th.
- The pipeline route is in a travel corridor used by Beaufort beluga to move into, out of, and amongst the various bays of the Mackenzie Estuary. It is assumed that the summer offshore trenching and pipelay activities will be permitted, and that construction work in the Canadian Beaufort would not be stopped due to whale transits and/or whaling season.
- This study has assumed that no equipment will be overwintered. Given the existing and forecasted demand for primary trenching and pipelay equipment as well as support vessels, it is unlikely that contractors would be interested in the associated downtime and maintenance required to overwinter equipment.
- For the purpose of this installation assessment, the maximum water depth for on-ice construction on floating ice is restricted to 10.0 m and the maximum length that can be completed in a single winter season is assumed to be 10 km.
- It is assumed that all vessels and other floating equipment sent to the Arctic will be winterized and have strengthened hulls to withstand ice incursions as this project will push the boundaries of the open water construction season window.

- It is assumed the pipelines will be double jointed and have anodes put on them prior to hauling them out onto the ice for the winter installation or loading them onto pipe haul barges for the summer installation.
- In the Canadian Beaufort, there are several safe havens along the pipeline route where vessels can move for protection from ice. For typical smaller ice events, the ice may be managed and/or the vessels can simply move to an area where ice is not present and not forecasted to be present.
- For Option 1, the pipelines are assumed to be installed in the same trench. The pipelines in the on-ice section will be bundled. For the summer trench and installation, a pipeline spacing of 5.0 m has been assumed. This spacing will slow the installation rate.
- The 30in outer diameter (OD) pipeline wall thickness is 1.500 in and, in general, this requires special attention regarding weldability. The Canadian pipeline standard, CSA Z662 [Ref.9], requires post-weld heat treatment (PWHT); however, based on previous offshore projects involving thick-walled pipelines, PWHT requirements should be determined as part of the welding procedure qualification. It was assumed that the project's welding procedure will use either low hydrogen or automatic welding processes as well as proper full wall thickness preheat to avoid the necessity of PWHT for the proposed pipelines.

Table 4-1 provides a breakdown of the length of each segment of the route for the pipelines and the Case 4 power cable based on the preferred method for trenching, installation, and backfilling for the given water depth ranges. The on-ice power cable trenching and installation is limited to grounded sea ice.

For the summer construction, it is recommended that each vessel used will be required to have a minimum of Polar Class 6. If the required vessel does not meet the requirements of Polar Class 6 or greater, then it is recommended that they will be ice strengthened and winterized prior to being mobilized to the project site. For safety concerns, the vessels will need to handle the expected ice loads if they were to get trapped in ice.

Table 4-1: Summary of Construction Methods

Line Type	Range of Water Depths (m)	Trenching/ Backfilling Method	Installation Method	Length of Line (km)
Pipelines	0 – 6.3[(1)]	On-Ice, Conventional Equip/Backhoes	On-Ice, Conventional Equip/Sidebooms	10
	6.3 – 15	CSD	Shallow Water Laybarge	20.8
Power Cable (Option 1 Case 4)	0 – 2.5[(1)]	On-Ice, Large Blade trencher	On-Ice, Large Blade Trencher	2.9
	2.5 – 15	Post-lay Mechanical/Jetting	Reel Lay Vessel	27.9

Notes:

1. On-ice installation was limited to a maximum length of 10 km.

The high-level construction schedule to complete the offshore pipeline installation is given below. It is estimated that the trenching and installation of the pipeline(s) can be completed in one winter and summer season. This is applicable for all cases.

Year 1	
January – October	Fabricate and deliver line pipe to Tuktoyaktuk
August – October	Install GBS(s)
October - November	Double joint line pipe
Year 2	
January – March	On-ice winter trenching and installation.
June – August	Mobilize CSD, lay barge spread, and necessary support vessels.
July – September	Direct Pipe in preparation for tie-ins.
August	Excavate trenches with the CSD.
August – September	Pick-up and tie-in; lay pipeline(s) and cable (case 4) from on-ice section to the GBS.
August – October	Backfill of the pipeline(s) using CSD.
September - October	Complete GBS Tie-in(s).
October	Complete cleaning, gauging and hydrotest
October	Demobilize all vessels.

4.1 Shore Crossing Method

The pipelines for each Option will transition from onshore to offshore through a shore crossing. The shore crossing will use a vertical sweep lay within a sloped open cut excavation corridor. It is assumed that the trench walls near the shore crossing will remain nearly vertical since the near shore and shore crossing permafrost soils are expected to remain frozen during construction. The construction of the pipeline shore crossing trench, and the pipeline installation at the shore crossing, will be completed in the winter using conventional trenching equipment operating from ice roads and the sea ice. An independent on-ice trenching spread will begin excavation at the shore crossing location and will work its way offshore. Based on previous near shore projects where the construction was completed in the winter from the sea ice, the winter excavated trench is expected to remain dry out to a water depth of 1.5 metres or less.

The shore crossing trench assumptions for this study are given below:

- Given the pipeline operating temperatures, the shore crossing trench was assumed to not require over-excavation to allow for the placement of thaw stable gravel and thermal siphons.
- The shore approaches will be completed in the winter construction season to limit environmental damage.

- The pipelines offshore-onshore isolation joint is assumed to be 100 m from the MSL waterline to account for shoreline erosion and potential ice ride up onshore.

4.2 Winter On-ice Construction Plan

Based on standard industry practices and past experience, on-ice construction is limited by the stability of the floating ice. Floating ice that is exposed to dynamic ocean events may not provide a stable work surface for on-ice construction activities as the ice may fracture or move during construction. For areas that are sheltered by land masses or in proximity to stable grounded, land-fast, or bottom-fast ice, the risk of the ice becoming unstable is reduced. For the purpose of this installation assessment, the following assumptions have been made for on-ice construction:

- On-ice construction is restricted to the first 10 km of offshore. This is generally based on the offshore pipeline lengths previously completed from ice work platforms.

- The sea ice is stable enough to complete 10km of trench excavation and pipeline installation from the sea ice in the winter. The first half of the route near shore has islands to the east and to the southwest that will help stabilize the ice sheet.

- Ice thickening is assumed to be able to begin in mid to late December. A total of ~2.75m of ice thickness is required for the floating section.

- On-ice construction on artificially thickened grounded ice can begin in early February.

- On-ice construction and all associated equipment and personnel must be finished and off the ice by May 1st.

- Due to the weight of the pipeline bundle, additional sideboom pipelayers will be needed for 3 of the installation supports where sidebooms will be located on each side of the trench with a spreader bar holding the pipeline support.

The overall construction strategy is to use the winter construction season to its maximum advantage, allowing the use of conventional and adapted onshore construction equipment and techniques. The winter season construction, using backhoes and side-booms, was chosen due to the proven track record, relative ease of construction, and to reduce permitting issues (as compared to summer installation). The stable ice surface creates a staging location along the ice slot where the pipeline can be constructed and staged for installation. Conventional trenching and flowline installation equipment can complete the trenching and pipeline installation from the ice surface.

The abbreviated on-ice construction sequence is as follows:

- Prepare a stable ice work surface along the proposed route;
- Cut a slot into the ice work surface;

- Excavate the trench using extended reach backhoes;
- Prep ice for pipeline work;
- Fabricate the pipeline;
- Install the pipeline in the trench; and
- Backfill the trench.

4.2.1 Activity 1: Ice Road Construction and Ice Thickening

To create a stable work surface for the offshore pipeline installation, the sea ice will be thickened along the offshore route to a sufficient thickness to support the construction equipment. The ice work surface will be prepared and maintained (constant clearing and resurfacing) along the offshore pipeline route for the duration of all pipeline winter construction activities. The primary ice work surface will be built approximately 120 m wide along the pipeline route where pipeline construction and installation will take place.

It is estimated that the ice can be thickened at the rate of 2.5 to 5 cm per day by flooding, based on historical ice construction data in Alaska. This rate can be further increased in areas where the ice is to be made bottom-fast by sequentially adding layers of ice chips from nearby freshwater basins and flooding the work surface. The required ice thickness to support the equipment is expected to be minimum 2.75 m. The work surface prepared for the offshore route will be maintained for the duration of the construction activities.

Construction of the ice roads and thickening of the ice will begin as soon as the natural sea ice is able to support the ice thickening equipment. This is expected to be mid to late December.

4.2.2 Activity 2: Ice Cutting and Slotting

The ice will be slotted using ice cutters / trenchers (Figure 7) and moved away from the slot area using front-end loaders. The ice spoils along floating sea ice sections will need to be stored on grounded ice, and as such, the ice will be transported to temporary storage locations on grounded ice using earth moving equipment (loaders and haulers). These activities will largely be performed during February and March.

Figure 7: Cutting of the Ice using Ditch Witch Cutter

4.2.3 Activity 3: Trenching

The trench for the pipeline will be made along the proposed route. Trenching activities will be performed from February on into April. Backhoes, front-end loaders and other earth-moving equipment will constitute the main equipment to excavate the trench.

Similar to the ice spoils, the material removed from the trench on floating sea ice will need to be stored on grounded ice. Loaders and haulers will be used to load and transport the trenching spoils to temporary storage locations on grounded ice. The spoils will remain there until it can be used as backfill.

Traditional surveying will be conducted to verify that the desired trench depth has been achieved. The survey results, together with the project's bathymetric survey, will serve as the basis for the as-built records of the construction activities.

Trenching from the ice involves the use of conventional backhoes equipped with pontoon tracks that will straddle the ice slot and excavate the trench to the desired trench depth (Figure 8). To ensure compliance with the design depth of cover and trench bottom roughness requirements, the trench will be surveyed just prior to the pipeline installation and, if required, the trench will be cleaned out.

The construction plan proposed is intended to allow a continuous trenching, pipe laying and backfilling program. To ensure this, the base case construction plan is to start excavation at various locations, with multiple independent trenching spreads. Each spread will include a backhoe and other earth-moving equipment required to excavate the trench. The actual number of trenching spreads that make up the trenching programs will be determined by the contractor based on the construction schedule.

Figure 8: Trenching from the Ice using Extended Reach Backhoe

4.2.4 Activity 4: Pipeline Site Preparation

The site preparation for pipeline make-up and installation activities occurs during February and March. Construction activities include set up of the material and line pipe storage areas and the stringing of the double joints. Tracked equipment and graders will be used to produce a level ice surface where joints of line pipe can be welded to form strings. The sea ice work surface is typically capped with freshwater ice for durability under the equipment loadings. Trucks, small cranes and sidebooms will be used to stage the double joints for welding.

4.2.5 Activity 5: Pipe String Make-Up (Welding)

Pipeline string make-up commences as soon as the work site has been prepared and the pipe is delivered. In order to limit the on-ice welding time and the number of field joints, it has been assumed that all coated pipe has been double jointed prior to arrival. The assumed period for the majority of the pipeline joint make up is March.

Pipe string fabrication will make use of standard cross-country techniques with qualified and approved welders and welding procedures. Pipe will be strung out along the length of the pipeline route and several mobile welding stations will be used in sequence to complete welding of the pipe strings (Figure 9). The pipeline is assumed to be made up in ~3 km long strings and each section will be tied in when the installation spread approaches the next string.

Non-destructive examination (NDE) crews follow after the firing line to inspect each weld for defects. Inspection includes visual examination as well as automatic ultrasonic inspection. After being cleared by inspection, each weld will have its required field joint coating applied. As each string is completed, the crews return to start a new string, until all of the pipe strings are completed.

Once the pipeline strings are made up, they will be placed on skids in a position where the pipeline can easily be installed into the trench. For Option 1, the pipelines will be bundled together using spacers and straps. This activity also includes the additional time, equipment, and personnel required to install the fibre optic communications cable (FOC). It is assumed that the FOC can be installed to keep pace with the bundling process.

Figure 9: On-Ice Welding of Pipeline

4.2.6 Activity 6: Pipeline Installation

The on-ice installation will start from the shore crossing location and progress offshore. The initial pipeline string will be installed using cranes and the sideboom pipe-layer installation spread (Figure 10). Pipeline installation will follow immediately behind the clean out trenching spread. Sideboom pipe-layers will be used to lower the pipeline through the slot and into the trench. The pipeline installation will be performed in March and April.

Each segment will be lowered into the trench as the sidebooms move along the ice with roller cradles supporting the pipeline(s). Due to the weight of the 30in gas pipeline and risks associated with undermining of the grounded sea ice, a spreader bar will be used to maintain adequate clearance between the edge of the ice slot and the sidebooms. This clearance is required to ensure the sidebooms can handle the expected loads and are not on undermined ice (are beyond the cantilevered ice hinge point). A total of 5 supports are assumed to be needed to install the pipeline. The trailing 3 will need to have a spreader bar with sidebooms on each side of the ice slot.

For Option 1, Case 4, the power cable trenching and installation will be an all-in-one activity. A large trencher with a cutting blade will be used to both excavate the cable trench through the grounded ice and installing the cable as it moves along the route. This is done using a cable guide connected to the trenching blade. The cable will be on a spool inside a heated enclosure that will feed into the cable guide on the trencher. This method will be limited to the grounded ice section (2.5m water depth) due to the trenching blade length and the ice stability risk associated with having parallel ice slots. An abandonment pit through an opening in the sea ice will be excavated where the cable end will be laid into. The cable end will be recovered during summer construction, and the summer segment will be spliced into the winter segment to initiate the summer cable lay.

Figure 10: Lowering of Pipeline through Ice Slot into Trench

4.2.7 Activity 7: Backfilling the Trench

Once a segment of the installed pipeline's depth of cover and trench bottom roughness is confirmed, the trench segment will be backfilled. Backfilling will start shortly after pipeline installation and will continue until about two weeks after pipeline installation. The backfill material used will be the material that was excavated from the trench. The trench spoils will be transported from the windrow temporary storage site or a remote site on bottom-fast ice and placed in the trench. Backfilling of the trench will be performed with earth-moving equipment such as haulers, front-end loaders and backhoes to push and place the spoils into the trench (Figure 11).

When the trench spoils are excavated and stored on the ice, they will freeze. Frozen spoils to be used as backfill must first be milled or otherwise reworked to limit the size of frozen soil blocks dropped onto the pipelines and reduce the voids in the backfill. Once the soil spoils are placed into the trench as backfill, the ice spoils will be evenly distributed over the width of the ice slot on top of the soil backfill. Based on previous projects, it is assumed that all excavated materials must be returned to the trench. The last 300m of the winter trench will not be backfilled to allow for recovery during the summer open water season.

Figure 11: Backfilling of Trench

4.3 Summer Open Water Construction Plan

For the purposes of this assessment, open water refers to conditions in which the ice coverage is less than one tenth (< 1/10th). Interruption in trenching or pipelay operations would be caused by an intrusion of ice into the operating area. An ice intrusion is considered any ice coverage that has moved into the area that is greater than the desired operating concentration. Intrusions generally consist of first year ice floes that have broken free from the land-fast ice or multi-year floes drifting south from the polar pack ice.

Canadian Beaufort Sea ice conditions have been summarized as follows:

- First year ice grows from initial freeze-up beginning in October until November when the coverage typically exceeds 9/10^{ths}.
- Ice-thickness continues to increase until May when the average annual ice growth is around 1.9 m at its maximum thickness.
- Spring breakup usually begins sometime between May and June, with the warm weather and offshore winds working together to remove the land-fast and seasonal pack ice that has grown throughout the winter.
- The GNWT LNG offshore project area is typically ice-free by mid to late July and open-water conditions (< 1/10th coverage) continue until late September early October.

It is assumed that vessels will be escorted by an ice breaker around Point Barrow through the ice in early August to the project site. All non-ice class vessels are assumed to have ice strengthening to allow operation in ice concentrations up to 1/10th (this will allow operation in the “Open Water Season”) and to ensure limited vessel damage in the event the vessel becomes entrapped in ice.

The pipelay operation is more sensitive to wave and ice conditions in comparison to trenching and backfilling. As such, the construction window for the pipelay is expected to be less than the construction window for the trenching.

In the Canadian Beaufort, the assumed open water construction season is ~77 days. The total potential days of work based on open water operating season will be less than this to account for lost operational time for pipeline abandonment and recovery, and waiting on weather (WOW).

Any ice invasion into the working area could potentially affect both pipelay and trenching/backfill operations. Pipelay operations are more sensitive to environmental conditions (waves and ice) and would result in the need to abandon and recover the pipeline. It was assumed that a pipeline abandonment and recovery would take ~2 days for a lay barge. Abandonment would occur as a result of severe environmental conditions such as significant sea states or ice ingress during construction. For the pipelay/installation, 2 abandonments (at 2 days each) were included for unexpected pipeline abandonment and recovery.

The construction activities may also be impacted by the weather (sea states, fog, etc.) and sea ice floes. The following was assumed for the Waiting on Weather (WOW) impact to the construction activities:

- Pipelay/Installation: an additional 20% time loss has been included for severe metocean conditions, as well as waiting on the ice to clear in the event of an ice incursion.
- Trenching and Backfilling: An additional 15% time loss has been included for severe metocean conditions, as well as waiting on the ice to clear in the event of an ice incursion.

The total assumed operating time in days is provided in Table 4-2 below. Downtime due to ice ingress could potentially be reduced using a combination of icebreakers and smaller ice management vessels for ice management during the pipelay and trenching operations. In addition, the construction/installation vessels are recommended to have some ice strengthening/class. For the pipelaying operation, if large ice floes or ice fragments approach, pipelay operations will have to be suspended. The ice management vessels will support where they can to allow the pipelay vessel to abandon the pipeline on the seafloor and move out of the area.

Table 4-2: Assumed Operational Time

Operation	Open Water Operating Season	Average Operating Season (Days)	Operational Time Loss (days)			Total Operating Time (days)
			Pipeline A&R Due to Severe Environmental Conditions	Whaling(3)	WOW (4) Trenching (15%) Pipelay (20%)	
Trenching and Backfilling (1)	August 2(2) – October 17	77	0	0	12	65
Pipelay / Installation (1)	August 2(2) – October 17	77	4	0	15	58

Notes:

1) Pipelay operations are more sensitive to wave and ice conditions in comparison to trenching and backfilling.
2) Pt. Barrow cannot be cleared before August 2nd, this does not include time required to transit to field.
3) Operations are assumed to experience no impacted from whaling operations.
4) Waiting on weather (WOW) includes time loss due to extreme metocean conditions as well as interruptions due to sea ice.

4.3.1 Pipelay Method

The conventional S-lay pipeline installation technique is considered to be the more reliable installation option to use for the GNWT LNG offshore pipeline installation (Figure 12). Conventional S-lay barges use track-type tensioners to apply tension to the pipeline and thereby control the pipe stress and curvature in the sagbend. A stinger is used to control the curvature in the overbend region as the pipe departs with the lay barge.

Due to the water depths of the pipeline route, the summer pipeline installation will need to be completed by an anchored pipelay barge. Several contractors could potentially supply suitable pipelay barges; however, most of these vessels would likely require ice strengthening and winterization. The majority of the existing shallow water pipelay barges are old, their hulls unable to handle ice loadings, and are ill-equipped for Arctic operations. Few shallow water barges have been built in recent years and anything that was will likely require hull strengthening.

An anchored lay barge would need to be escorted by a pair of ice class anchor handling tug supply vessels (AHTS) as well as an icebreaking support vessel. The icebreaker is required to allow for early entrance into the project site, to mitigate any ice incursions that may occur while the AHTS are occupied moving the barge's anchors and to allow for a late exit out of the project area.

The required vessel tension to install the proposed pipelines was not determined during this study. While the pipeline sizes and weights are significant, and will limit the number of available vessels that can install the pipelines, the relatively shallow water depths means that anchor laybarges capable of installing these lines do exist. It is recommended to complete a static installation analysis during the next phase of work to get an estimate for the required top tension.

The proposed shallow water offshore anchored lay barge S-lay installation spread requires the following vessels:

- Conventional second generation lay vessel/barge with a stinger;
- Two ice-strengthened or icebreaking anchor handling tugs;
- Two pipe shuttle barges;
- One pipelay survey vessel with an underwater remotely operated vehicle (ROV) with camera;
- An icebreaker (Polar Class 4 or stronger); and
- One supply/crew boat.

Figure 12: Typical S-Lay Laybarge

4.3.2 Trenching and Backfilling Method

The most common hydraulic dredges used for the excavation of pipeline trenches are cutter suction dredges (CSD), and trailing suction hopper dredges (TSHD). Because of their operating draft, dredges of this type are often limited to water depths greater than 6 m. The CSD excavates the trench with a rotating cutter head on the end of a ladder extended to the seabed (Figure 13). The CSD sweeps the cutter head back and forth while advancing longitudinally using spud piles. Because of the sweeping motion of the vessel, the trench tends to be wide. The cutter head breaks the soil and pumps the soil/water slurry through a pipe up the ladder and through a discharge pipe. The end of the discharge pipe is typically located within a few hundred metres from the dredge and is moved frequently to prevent excessive dredged spoil from accumulating in one area. CSDs are typically limited to a maximum 30-35 m combined trench and water depth. TSHDs excavate the trench by lowering a suction head to the seabed and pumping the trenching spoils into a hopper in the vessel's hull. When the hopper is full, the suction head is raised, and the vessel sails to a designated spoil storage area to empty the hopper. The dredge then returns to the pipeline route and continues dredging. Internationally available TSHDs can reach up to 155 m combined water and trench depth; however, Canadian flagged vessels are generally smaller, with a maximum depth of approximately 33 m.

When some soils are dredged and discharged (such as silts) using hydraulic dredging, more sediment is suspended in the water column than through mechanical excavation methods. This would need to be evaluated from an environmental impact perspective. Special consideration may also need to be given to areas where ice-bonded permafrost may be encountered. A CSD can achieve an average excavation rate of approximately 2750 m^3/hr., whereas a TSHD achieves approximately 1000 m^3/hr. These excavation rates are averages; actual excavation rate can vary significantly depending on soil type and the presence of boulders.

Given the target trench depths required along route (2.9 m – 5.7 m), hydraulic dredging with a CSD is the preferred trenching method for the summer construction segment of the route. CSDs are available from a number of companies worldwide and there is past operational experience in the Canadian Beaufort as well as the Russian Arctic. However, there are a very limited number of ice classed CSDs currently available. Depending on the CSD that is selected, the hulls of the dredge and its potential support vessels may require upgrading.

The CSD can re-dredge the stored trenching spoils and re-deposit them over the pipeline(s) as backfill. Due to the shallow water depths and relatively fast excavation rates required, a CSD is also preferred to complete the backfilling of the trenches. Excavated material can be placed back into the trench through the CSD's discharge pipe, which can be placed within a couple hundred metres of the CSD. In order to control sediment dispersion, it is proposed that the discharge pipe is submerged and controlled by a support vessel so that the end of the discharge pipe is held within the excavated trench, or as close as possible. If the desired control of spoils cannot be achieved with this method, a fall pipe vessel may be required. This method will need to be reviewed by a dredging contractor in future phases. For scheduling and costing purposes, the backfill rate for the CSD is assumed to be 5000 m^3/hr.

The proposed shallow water offshore trenching spread requires the following vessels:

- Cutter Suction Dredge;
- One trenching survey vessel with an ROV;
- An icebreaker (Polar Class 4 or stronger); and
- One support/supply/crew boat.

Figure 13: Typical Cutter Suction Dredge

4.3.3 Power Cable

For Option 1 Case 4, a power cable is to be installed from the shore crossing to the GBS. The first 2.9km of the power cable from shore will be installed from the sea ice. The cable end will be recovered from a winter abandonment pit during the summertime, and the summer segment will be spliced into the winter segment to initiate the summer cable lay. A cable lay vessel will then install the cable on the seafloor up to the GBS. A subsea mechanical excavator jetting machine will then lower the cable into the seabed to the required depth of cover. The subsea cable machine will excavate, lower and backfill the cable all in one pass. Due to the required depth of cover for the cable, there will be a limited number of subsea cable burial machines that can complete the cable burial in the deeper section of the route.

4.4 GBS Approach Method

For the purposes of this study, "Direct Pipe" is the preferred GBS approach method and tie-in concept. The procedure involves thrusting and boring a pull-tube a short distance under the GBS to the edge of its footprint and continuing to the offshore pipeline trench. This can be used to create a bell mouthed J-tube to facilitate pipeline pull-in to the structure, as depicted in Figure 14.

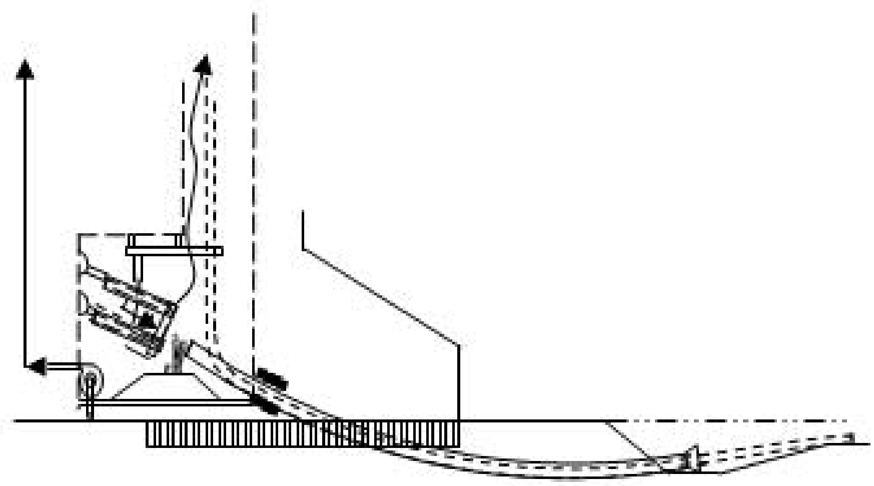


Figure 14: Typical Bell Mouthed J-Tube Connection to GBS Base

The current methodology, assumes that the pipelines for each option will be trenched, installed, and backfilled to permit recovery for the GBS tie-in. The trenched pipeline will stop approximately 300 m before the GBS touchdown zone and a length of the pipe (approximately 150 m) will be left exposed (with the trench intentionally not backfilled) so that it is possible to recover the end of the pipeline.

With the GBS installed in the previous open water construction season, there will be time for the Direct Pipe casings to be completed prior to the following open water construction season when the pipelines are installed. After the installation barge completes the offshore pipeline installation, the pipeline tie-ins will begin. A bell mouth will be attached to the end of the J-tube (pull-tube) and a pull-cable will be lowered through it and lifted up to the barge. Pipeline pull-in will commence from the stationary position while the pipe string is pulled back into the J-tube under appropriate tension. Once a sufficient length of pipe has been pulled into the platform, the previously installed pipeline will be recovered to the deck of the barge so that the two lengths of pipe can be welded together. The now completed pipeline will be lowered back into the trench while the excess slack is pulled through the platform's J-tube.

For this study, it was assumed that each pipeline for Option 1 will have its own casing. There is the possibility of oversizing the J-tube to allow for more than one pipeline to be pulled through. This single J-tube option generally has issues with tie-ins at the GBS deck level. Additionally, the pipelines would need to be stacked on top of each other on the subsea end. As a result, two J-tubes (one for each line) are preferred for Option 1.

For Option 1 Case 4, the power cable will have its own casing. The cable will be installed in a similar manner as the pipelines, with the end of the cable being pulled in, while the offshore segment is lowered into the trench.

5 OPERATIONS AND MAINTENANCE

In addition to routine meter, pump, and valve operations, the main focus of the operating procedures for both proposed options will be to monitor the integrity of the offshore pipelines. Monitoring will involve a continual review of flow properties, pressure based monitoring, and various types of inspections. A pipeline inspection philosophy is vital to successful operations. An inspection plan should optimize the amount of useful information that can be gained from inspection surveys and pigging schedules and must take into account the criticality of the various systems in the field. If test results are satisfactory, it can generally be inferred that the system is fit for service. When degradation is discovered, these areas may be designated for further evaluation or may be severe enough to warrant immediate corrective repairs.

The offshore segment of the pipelines is a continuation of the onshore segments. Therefore, the operations and maintenance requirements for the offshore gas and condensate pipelines regarding flow assurance, maintenance pigging and internal corrosion monitoring are no different than the onshore operations and maintenance requirements. The unique operations and maintenance requirements for the offshore segment are provided below:

- River flood gauge monitoring for determining timing of river overflood in spring of each year. This would be followed by annual over-flights to find strudel drain features in the sea ice.

- Annual bathymetry surveys along the offshore pipeline route to a km each side of the route. The survey will identify seabed ice gouge and strudel scours that have occurred near the pipeline route. The data can be used to further quantify the risks to the pipeline. The backfill elevation over the pipeline will also be recorded. Low backfill areas can cause ice wallowing.

- Annual cathodic protection surveys using reference cells at the shore crossing and GBS are required to ensure the pipeline is protected from external corrosion.

- Annual continuity check surveys at the shore crossing and GBS riser isolation joints to ensure the offshore pipeline CP system is isolated form the GBS facilities and onshore pipeline.

- Pigging Surveys:

    - Caliper Pigging: Prior to startup and prior to every wall thickness pigging and 3-D geometry pig survey to ensure safe passage of smart pigs.

    - Wall Thickness Measurement: The same wall thickness measurement pig run for the onshore can be run for the offshore. Due to the offshore gas pipeline wall thickness of 38.1mm (1.5in), a UT wall thickness measurement pig is required. A base line survey is needed before startup, then on or shortly after year 1 of operation flowed by one within every 5 years thereafter. The wall thickness pig can measure internal and external corrosion.

- Smart Pig: Geometry mapping smart pigging is required to review the offshore pipeline profile for movement. The mapping pig can be run with the wall thickness measurement pig. A base line survey is needed before startup, then on or shortly after year 1 of operation flowed by one within every 5 years thereafter. Additionally, if a significant ice gouge or strudel scour has been surveyed over the pipeline route, a mapping pig survey will need to be completed.

6 CAPEX

Intecsea's past involvement in several projects of a similar nature in the Beaufort Sea and the Canadian East Coast has helped facilitate the cost estimate preparation. Contractors were not contacted to provide detailed budgetary quotes for the construction activities. As such, in-house data compiled from previous project experience and contractor estimates was used to develop the costs for specific construction activities. It should be noted that:

- Assumptions have been made where applicable design work has not yet been completed. Although the assumptions have been made in an attempt to provide costs that are as complete as possible, they also introduce a level of uncertainty in the preliminary estimate and should be updated to reflect the results of applicable engineering analyses as design work is completed.
- Portions of the historical in-house data used in these estimates have not been confirmed with as-built costs.
- If costs were taken from older data, the costs were factored up to 2021 values. Costs in USD were factored by 1.26 to get CAD costs. The costs shown in this section are the factored costs.

6.1 Cost Assumptions

The following list of assumptions was used to develop the cost estimates:

- Material costs are based on previous vendor estimates and factored historical data from past projects.
- All material costs for the offshore pipelines, including line pipe steel, coating, and anodes include a 5% increase for spares and wastage incorporated as an increased length of line pipe rounded to the nearest standard 40 ft (12.2 m) line pipe joint.
- Minor consumable and miscellaneous offshore flowline materials such as temporary flanges, fittings, valves, and weld consumables are included as 1% of the total materials cost.
- All line pipe is assumed to be manufactured in Japan and transported to an FBE and CWC facility in Southeast Asia. The coated line pipe is then shipped from Southeast Asia to the onshore staging site at the Tuktoyaktuk Port area via ocean going freighter.
- It was assumed the offshore pipeline will be brought to an onshore line pipe storage facility near Tuktoyaktuk, NT, the summer before the winter installation. Line pipe joints will be double jointed and will have the anodes installed there. They will remain stored there until they are transport to the ice during the winter installation or transferred to pipe haul barges during the following summer installation.
- Based on the information provided, the line pipe material will not need to be designed for sour service.
- The cost of sea and land-based transportation for all equipment and materials is based on vendor information from past projects and other historical in-house data.
- Winter on-ice construction method and costs are based on past projects and in-house cost data. No budgetary quotes were obtained from contractors for construction activities.

- Mobilizations and demobilizations will be required once for a single summer construction season. Over-wintering of proposed construction equipment and offshore construction vessels has not been considered.
- All on-ice construction activities assume that personnel spreads are independent for each construction activity and that all operations are 24 hours, requiring 2 complete personnel spreads working in 12-hour shifts. Optimizations among shared personnel spreads have not been considered at this stage.
- Vessels and equipment are assumed to be mobilized from various locations, including, but not limited to Alaska, the Gulf of Mexico and Northern Europe, depending on the activity.
- Mobilization and demobilization durations for personnel and equipment have been assumed based on previous project experience. Potential additional costs for project-specific personnel training have been neglected.
- It was assumed that there will be an ice road built between the Inuvik-Tuktoyaktuk highway and the shore crossing at North Point as part of the onshore pipeline construction. The line pipe double joints will be transported to a storage location at the shore crossing on the sea ice. Alternatively, an ice road could be considered from Tuktoyaktuk to the offshore construction site; the feasibility and routing would need to be confirmed.
- The offshore pipelay season in the is assumed to be between August and October, approximately 77 days.
- All construction and installation activity durations are based on the Execution Schedule.
- All vessel day rates include the cost for time charter, fuel, and consumables.
- Ice strengthening or winterization will be required for any vessel to work in the Beaufort Sea.
- Ice management vessels, ice/weather monitoring, and helicopter services are assumed to be required throughout the duration of active construction and installation periods.
- All vessel, equipment and manpower requirements are available at the time they are needed. There are a limited number of ice-classed vessels suitable for offshore arctic trenching, construction, and installation. Therefore, consultation with contractors regarding future vessel construction plans and the feasibility of substantially modifying existing vessels should be further investigated.
- All progression, advancement rates and durations for offshore construction activities (trenching, pipelay, cable lay, etc.) and on-ice (ice road construction, ice cutting and slotting, on-ice welding, etc.) construction activities are based on in-house data and previous project experience.
- Engineering design, permitting support, project management, construction management and logistics have been included as percentage of the total installed cost subtotal.
- No contingency was included as part of the CAPEX estimate.
- Further detailed cost estimate assumptions are provided in the subsections below.
- All costs are in 1st quarter 2021 Canadian dollars (CAD).

6.2 Exclusions

The following items are excluded from the cost estimate:

- Owner/operator costs including the project team, owners engineering, and third-party verifications.
- Owner/operators financing (including interest during construction and bank guarantees), taxes, insurance, licensor fees and royalties, permits, customs and import duties.
- Environmental impact assessment or expenditures.
- Regulatory and permitting costs.
- Costs associated with potential project delays for permitting or environmental issues are not included.
- Land costs or pipeline right-of-way (ROW) easements.
- Lease and / or other costs related to offshore projects.
- Currency fluctuations and escalation.
- Security throughout construction.
- Warehouse spares.
- Emergency, fire and spill response personnel/transportation/equipment.
- No costs have been included for hydrotest water procurement and disposal. It is assumed this will be pushed back to shore and disposed of with the onshore hydrotest water.
- A suite of pipeline, FOC and power cable repair tools.
- Infrastructure upgrades at proposed construction sites.
- No costs for the onshore facilities (such as a shore crossing valve) have been included for the offshore pipeline costs.
- Potential additional costs such as project-specific personnel training have not been included.

6.3 Materials

The unit cost of pipeline materials, including the carbon steel line pipe, FOC, sacrificial aluminum anodes, and FBE were obtained and factored from previous studies where budgetary quotes had been obtained.

Table 6-1: Material Cost Breakdown

Category	Item	Cost Basis	Cost (CAD)
Pipeline	Seamless API Spec 5L X52	mT	$2,400
	Welded (SAW) API Spec 5L X52	mT	$1,900
	External Anti-corrosion Coating - Fusion Bonded Epoxy (FBE)	m^2	$28.00

Coatings, Anodes, and Insulation	Concrete Weight Coating – (CWC)	kg	$0.85
	Sacrificial Anodes	kg	$7.15
Fibre Optic Cable	1in Diameter Armored Fibre Optic Cable for Offshore	m	$15.15
Power Cable	Armored Offshore Power Cable	m	$1,890
Anode Taper	10in PU Anode Taper	each	$136.68
	30in PU Anode Taper	each	$421.43
Bundle Spacers/Straps	Custom Molded Spacer and Large Rachet Straps	Every 6.1m	$193.63
Miscellaneous	Miscellaneous materials (flanges, weld consumables, field joints etc.) have been included as a percent of the total material costs.	%	1

6.4 Materials Transport

To establish transportation costs, it is assumed that the line pipe will be purchased from a pipe mill in Japan and shipped to Southeast Asia to be coated. After coating, the pipe would be shipped via freighters from Southeast Asia to Kugmallit Bay where the line pipe would be transferred at sea to smaller more maneuverable pipe haul barges and then be brought to an onshore line pipe storage facility near Tuktoyaktuk, NT. Once construction begins, the line pipe would be loaded onto pipe haul vessels and brought to the pipelay vessel in the field. Where necessary, the freighters would be supported by icebreakers and ice management vessels (note that ice-conditions vary from year-to-year and ice breaking or management vessels may or may not be required).

The line pipe will be stored at the temporary storage facility until it is ready to be transported by truck to the on-ice construction site, or by barge to the pipelay vessel. The estimated quantity of pipeline stored for Option 1 is approximately 31,500 mT, and the estimated area required for storage is 18,000 m^2. The estimated quantity of pipeline stored for Option 2 is approximately 28,400 mT, and the estimated area required for storage is 16,000 m^2.

The costs shown in Table 6-2 are included as specific handling events in this cost estimate. Noted transportation assumptions and uncertainties include:

- It was assumed that land would be available at Tuktoyaktuk port that could be used for the temporary storage of the coated pipe. For the purpose of this estimate, it has been assumed that a storage area will be used to store line pipe for 180 days for the winter installed line pipe and 360 days for the summer installed line pipe.
- Freighter and vessel day rates include the cost for time charter and bunker fuel.
- All marine materials shipping assumes a travel speed of 14 knots.

- All proposed transport vessels are assumed to be available on the charter market when required. However, charter companies should be engaged at the earliest opportunity to determine the availability of applicable vessels and the interest of the associated ship owners.
- The material transport for the FOC to be installed from the sea ice is assumed to be overland on truckable spools. The FOC for the summer installation will be on one spool that is brough to site by the pipelay barge.

Table 6-2: Transportation Cost Breakdown

Category	Item	Cost Basis	Cost (CAD)
Marine Shipping to Coating Plant	Mobilize/demobilize standard bulk freighter	day	$ 41,004
	Load bare line pipe onto standard freighter in Japan	mT	$ 11.85
	Ship line pipe via standard bulk freighter to coating plant in Southeast Asia	day	$ 41,004
	Offloading line pipe at coating plant in Southeast Asia	mT	$ 11.85
Marine Shipping to Tuktoyaktuk	Mobilize/demobilize freighter	day	$ 41,004
	Load coated line pipe onto freighter in Southeast Asia	mT	$ 11.85
	Ship coated line pipe via freighter from coating plant to Kugmallit Bay	day	$ 41,004
	Mobilize/demobilize Arctic (ice-class) near-shore shuttle barge	day	$ 17,085
	Barge coated line pipe to receiving terminal in Tuktoyaktuk, NT	day	$ 22,780
	Offload barge into temporary storage facility in Tuktoyaktuk, NT	mT	$ 22.78
Pipe Storage	Temporary storage yard charges Tuktoyaktuk, NT	m^2/day	$ 5.70
Transfers During Offshore Pipelay	Mobilize/demobilize Arctic (ice-class) offshore shuttle barge	day	$ 17,085
	Load offshore shuttle barge for transfer to pipelay vessel	mT	$ 22.78
	Shuttle line pipe to barge for offshore installation in Beaufort Sea	day	$ 22,780
Transfers During On-Ice Construction	Transfer coated line pipe to pipeline ROW via truck on ice roads to on-ice Construction Site	Truck/day	$ 854
Fibre Optic Cable	Transport fibre optic cable for summer install (one larger reel)	reel	$ 56,950
	Transport fibre optic cable for winter install (truck-able reels)	reel	$ 28,475

6.5 Design, Pre-Construction, and Construction Surveys

The cost estimate includes a cost for helicopter over-flood surveys during the design phase of the project, as well as for helicopter services for the duration of the offshore construction. These services are estimate at a cost of $22,780/day.

During the Pre-FEED, FEED, and detailed design phases of the project, a survey vessel will conduct geophysical and bathymetric surveys. Every year a geophysical survey should be completed for the trenched segments of the pipeline routes to provide yearly ice gouge data and, where required, strudel scour data. The survey vessel is assumed to mobilize from Anchorage at a rate of $53,305/day and operate at a rate of $88,842/day. This vessel will also be equipped to complete refractive sub-bottom profiling and carry geotechnical survey equipment for use during the survey season. The geotechnical program assumes that a sample will be taken every 1 km at a rate of 5 samples per day for Pre-FEED and then one every 4km at FEED. It is assumed, the detailed design phase will not require an additional geotechnical surveys or refractive sub-bottom surveys. The geotechnical equipment cost is estimated at a lump sum (LS) mob/demob cost of $17,085 and a working rate of $34,170/day. Due to the reduced survey requirements for the detailed design phase, the survey vessel cost was adjusted to a mobilization rate of $41,004/day and operational rate of $68,340/day. In addition to the primary design surveys, interphase geophysical surveys will need to be conducted leading up to the proposed construction seasons. The costs for these interphase surveys are not included in this cost estimate.

Surveys will be required before, during, and after construction / installation. For the purpose of this cost estimate, the following surveys have been included:

- Pre-construction (Pre-trenching) – included as part of the recommended design, preconstruction, and construction surveys.
- Pre-lay (Post-trenching) – included as part of the trenching costs or pipelay costs.
- As-laid – included as part of the pipelay costs.
- As-backfilled – included as part of the recommended construction surveys. This survey will be used to establish as baseline for backfill conditions prior to start up.

The proposed pre-construction and as-backfilled survey vessel equipped with the necessary equipment is assumed mobilized from Anchorage AK at a rate of $49,205/day for mob/demobilization and $82,008/day during survey.

6.6 Vessel Procurement and Upgrades

Given the potential ice conditions and low temperatures even during the summer months, it is recommended that the non-ice class vessels operating in the Beaufort Sea be ice strengthened and winterized. It is recommended that the need to ice strengthen and winterize construction and support vessels that do not normally operate in polar regions be reviewed during the next design phase. It was assumed that ice strengthening, and winterization upgrades can be completed on existing vessels and new build vessels would not be required.

The costs for ice strengthening and winterization upgrades are assumed to be approximately 10% of the European new build value, as shown in Table 6-3. These costs include not only the direct cost of vessel upgrades, but also the contractor mark-up for lost operational time while the vessel is in dry dock. These upgrades, if required, would take place prior to mobilization to Canada. Depending on the market conditions during the proposed retrofitting time, these costs may vary significantly with the opportunity cost for the vessel owner/operator. As such, these costs should be treated as order of magnitude costs and the feasibility of upgrading existing vessels should be further evaluated in future design phases with vessel owners/operators.

Table 6-3: Vessel Modifications

Vessel		New Build Cost	Arctic Modify	Modification Costs	Number of Vessels
		$1,000 CAD	%	$1,000 CAD	
Trenching and Backfilling	CSD	170,850	10	17,085	1
Pipelay	Anchored Lay Barge	218,232	10	21,823	1
	Pipelay Support Vessel	205,020	10	20,502	1
Support	Anchor Handling Tug / Work Boat	82,716	10	8,272	2
	Pipe Carrier	62,303	10	6,230	2
	Supply Vessels / Crew Boats	74,035	10	7,403	2

6.7 Offshore Construction

This section reviews the summer offshore pipeline construction costs. The recommended support fleet (ice breakers, anchor handling tugs, and work boats) costs do not account for any synergies with other aspects of the project.

6.7.1 Trenching and Backfilling

The trenching/backfilling involves the use of a cutter suction dredge (CSD). For the purpose of this estimate, the following assumptions have been made:

- The CSD will be mobilized from northern Europe. Vessel transit speeds have been assumed at 10 knots. The CSD will be mob/demobilized at a rate of $205,020/day and operated at an estimated rate of $341,700/day in the Canadian Beaufort Sea.

- One (1) workboat / crew boat / small support vessel will be required for the CSD throughout the duration of the trenching and backfill seasons. The workboat will be mob/demobilized from Anchorage AK at a rate of $20,200/day and operated at an estimated rate of $30,300/day in the Canadian Beaufort Sea.
- One (1) ROV equipped survey vessel will be required for the CSD to monitor trenching and backfilling throughout the construction season. The ROV vessel(s) will be mob/demobilized from the Anchorage AK at a rate of $50,500/day and operate at a rate of $75,750/day.

6.7.2 Offshore Pipeline Installation

The installation cost estimates for Options 1 and 2 are based on using a double-joint pipelay barge to lay the pipelines. The anchored pipelay barge will be mob/demobilized from the Gulf of Mexico at a rate of approximately $250,000/day and operate at a rate of $500,000/day. These rates include two ice class anchor handling tugs. In addition to pipeline installation, the pipelay barge will be used to complete the GBS tie-in(s).

The following assumptions have been used to estimate the total installation time using the shallow water pipelay barge:

- Tie-in and lay always will be required where the pipeline must be recovered from previous offshore pipelay or on-ice construction seasons.
- The anchored lay barge(s) will operate at the following rates:
  - 1.5 km/day for the 30-inch OD pipe
  - 3.0 km/day for the 10-inch OD pipe
- Required anchored barge to complete tie-in(s) at the GBS has been included as additional lay barge time.
- Abandonment and recovery allowances have been included as additional lay barge time.
- Installation downtime due to inclement weather has been estimated at 20% for the standard pipelay operations.
- One (1) workboat will support the anchored lay barge. The vessel is intended to serve as a crew boat / support vessel throughout the duration of the season. The workboat was assumed to be mob/demobilized from the Anchorage AK at a rate of $20,200/day and operate at a rate of $30,300/day.
- One (1) ROV equipped survey vessel will be required to monitor the pipelay operations and touch down conditions. The ROV vessel was assumed to be mob/demobilized from the Anchorage AK at a rate of $50,500/day and operate at a rate of $75,750/day.
- No trenched pipeline span remediation costs were included.

6.7.3 Power Cable Lay and Burial

The installation cost estimates for the Option 1 Case 4 with the power cable assume that one vessel is required to complete both the cable lay onto the seabed and the burial using the subsea cable trenching machine. The cable lay vessel along with the trenching machine, will be mob/demobilized from the Gulf of Mexico at a rate of approximately $140,097/day and will operate at a rate of $233,495/day. For the duration, it was assumed it will take 1 day to recover and splice into the abandoned cable, 2 days to lay the cable out to the GBS and 4 days to complete the cable trenching. It will take 4 days to make the power cable tie-in to the GBS.

6.7.4 Direct Pipe for GBS Tie-in

The Direct Pipe estimates to complete the GBS tie-in(s) were based on the following assumptions:

- Design (for installation and support section)
  - Each individual pipeline will require a 300 m long, 50-inch diameter carrier pipe to complete the proposed Direct Pipe casings.
  - Water depth at all Direct Pipe installations is 15 m.
  - Progress rates (~20 m/day).
- Mob/demobilization
  - Mobilization distance from Calgary to Tuktoyaktuk of approximately 2,500 km.
  - Equipment, personnel, and carrier pipe mobilizations are included as lump sum costs:
    - Equipment mob/demob is $1,195,950 LS.
    - Carrier pipe delivery and personnel mob/demob costs are $623k LS per casing.
- Crew and equipment operating
  - A 12-person crew, including 2 inspectors will be used to complete the proposed Direct Pipe casing installations.
  - All required equipment and fuel are included in the operational day rate. This includes costs for communications, water, cutting disposal, etc.
  - All-inclusive day rate of $273,360/day.

6.7.5 Ice Management and Support

It is recommended that one heavy icebreaker, one light icebreaker (multi-purpose support vessel), weather/ice monitoring, and helicopter support (multi-purpose) be onsite throughout the duration of the summer offshore pipeline construction and installation. No synergies with other offshore construction activities were accounted for in determining the ice management and support requirements. The ice management costs included in offshore pipeline CAPEX are provided below.

- Heavy ice breaker with a $132,124/day mob/demob rate, mobilized from Northern Europe and a $164,016/day work rate.
- Light MPV ice breaker $86,564/day mob/demob rate, mobilized from Northern Europe and a $107,066/day work rate.
- Weather and sea ice monitoring at $17,085/day.
- Helicopter services at $22,780/day,

6.8 On-Ice Construction Activities

The methodology used to develop a cost for each of the proposed on-ice construction activities was based on identifying the means (equipment and personnel), progression rate, and duration for each of the activities. Equipment and personnel requirements were selected so that the on-ice pipeline installation could be completed within single winter season construction period.

Construction of on-ice pipelines in the winter from a shore-fast ice surface is divided into two sets of activities: civil works and pipeline fabrication / installation. Civil works include construction of ice platforms (roads), thickening of the ice platform to form a bearing surface, making ice slots by cutting and removing ice blocks, excavation of an offshore trench into which the pipeline is lowered, and backfilling of the trench. Pipeline fabrication and installation will include pipe string make-up/bundling, pipeline installation, and hydrostatic testing.

The following assumptions are applicable to all on-ice construction and installation activities:

- Mobilization and demobilization of equipment and personnel has been included on a per activity basis. These line items reflect the cost to mobilize and demobilize land-based construction equipment, trenching spreads, and required materials.
- Mobilization of required on-ice equipment will start early to mid-November and extend through until January while demobilization will most likely start in March and continue into May.
- Equipment mobilization rates assume the equipment stays on site for the entire duration that the equipment is required.
- Personnel mob/demobilization rates reflect an assumed shift rotation of 30 days. For the purpose of this estimate, construction crews are assumed to be independent to capture the maximum potential mobilization and demobilization cost. Mobilization is assumed to be from Alberta. The cost of return airfare for all on-ice construction and installation personnel has been assumed to be approximately $1,700 per mob/demobilization.
- For Option 1, the ice work, trenching, pipelay and backfilling will not be affected by the addition of the 10-inch line.

The durations, mob/demobilizations day rate costs, and functional rate costs are shown in Table 6-4 for the main on-ice activities. The activities noted in the table are described briefly below.

Table 6-4: Average On-ice Construction Rates for Main Activities

Activity	Duration (Days)	Average Mob/Demob Cost	Average Functional Rate
1-1: Grounded Ice Road Construction and Ice Thickening	70	$44,421/day	$91,120/day
1-2: Floating Ice Road Construction and Ice Thickening	80	$44,421/day	$91,120/day
1-3: Grounded Ice Road Maintenance		-	$44,421/km
1.4: Floating Ice Road Maintenance		-	$56,950/km
2: Ice Cutting and Slotting	30	$54,672/day	$91,120/day
3-1: Primary Trenching	35	$91,120/day	$170,850/day
3-2: On-going Trench Cleanout	20	$45,560/day	$85,425/day
4: Pipe Make-up Site Preparation	25	$45,560/day	$91,120/day
5-1: Standard Welding Option 1	28	$95,676/day	$261,970/day
5-1: Standard Welding Option 2	20		
5-2: Pipeline Make-up Option 1	21	$28,475/day	$56,950/day
5-2: Pipeline Make-up Option 2	18		
5-3: FOC Install/bundling	21	$11,390/day	$19,363/day
6-1: Pipeline Installation	22	$91,120/day	$216,410/day
6-2: Shore Crossing Install	4	$28,475/day	$56,950/day
7: Backfilling the Trench	30	$62,645/day	$125,290/day

6.8.1 Activity 1: Ice Road Construction and Thickening

The ice work surface (platform) will be prepared and maintained for the duration of all winter construction activities. The 240 m wide ice-platform will need to be thickened and made structurally sound to permit the safe use of the construction equipment. The floating ice is assumed to be thickened by pumping seawater to a minimum thickness of 2.75 m and capped with freshwater sourced locally. This thickness will be achieved before the end of natural ice thickening, so the actual thickness will be greater than 2.75m.

In addition to the ice platform over the pipeline route, an ice platform at the shore crossing will be constructed as a storage location for spoils and equipment/materials. For this pad, it was assumed to take an additional 6 days at a $44,421/day rate.

Maintenance of the ice work surface will be conducted by a reduced spread for the duration of on ice construction activities. For the storage pad ice maintenance, an additional kilometre was included for the maintenance length.

6.8.2 Activity 2: Ice Cutting and Slotting

Slots will be cut in the ice using ice cutters / trenchers. The ice will be cut into approximately six-foot by six-foot blocks and removed using backhoes. The blocks will be moved by front-end loaders to locations away from the construction activities.

It has been assumed that the minor differences in ice thickness along the route do not significantly affect the ice cutting and slotting rate.

6.8.3 Activity 3: Trenching

The trench will be excavated using backhoes. This method of construction is proposed to allow a continuous trenching, pipe-laying, and backfilling program. The base case construction plan is to start excavation at various locations with independent trenching spreads. For the purpose of this estimate, trenching operation costs are based on 4 trenching spreads and with the trench having the dimensions provided in Table 3.2 and Table 3.3.

Backhoes, front-end loaders and other earth-moving equipment will constitute the main items of equipment to excavate the trench. It is assumed that the same trenching spreads will be used for the entirety of each route. In addition to the primary excavation spread, 2 trenching spreads have been included for ongoing trench cleanup between the initial excavation and pipelay.

Loaders and haul trucks will be used to move the trenching spoils from the floating ice section back onto bottom fast ice for storage. The spoils haul spread is $11,390/day and will last the entire time of the primary trenching.

6.8.4 Activity 4: Pipeline Site Preparation

Tracked equipment and graders will be used to produce a level ice surface where joints of line pipe can be welded to form strings. The ice pad will be used to store line pipe and completed pipeline strings, which are assumed to be up to 3000 metres long.

6.8.5 Activity 5: Pipe String Make-up (Welding)

In order to limit the on-ice welding, field joint and anode attachment time, it has been assumed that all coated pipe has been double jointed, and anode have been attached with their tapers prior to arriving at the on-ice location. This is also applicable for the summer installation line pipe. The cost for the offsite welding and FJC is $4556/joint for the 30in line and $1367/joint for the 10in line. The cost for anode installation including tapers is $854/anode.

The strings will be fabricated on the ice platform close to the trench. Fabrication will make use of standard cross-country techniques with qualified and approved welders and welding procedures. Pipe double joints will be strung out along the length of the construction pad, and several mobile welding stations will be used in sequence to complete welding of the pipe strings. Non-destructive testing (NDT) and field jointing will be completed following welding.

Pipeline make-up will consist of completing the on-ice tie-ins between pipe stings, staging of the pipe string and bundling the fibre optic cable to the 30in pipe. For Option 1, this will also include bundling of the 10in line to the 30in line. The rate includes the time, equipment, and personnel required to install the fibre optic cable. It is assumed that the FOC can be installed to keep pace with the on-ice installation process.

6.8.6 Activity 6: Pipeline Installation

Pipeline installation will follow at the shore crossing immediately behind the clean out trenching spread. To initial the shore crossing, two cranes along with the pipelay spread will place the pipeline(s) into the shore crossing trench. After which, the installation spread will use sideboom pipe-layers to lower the bundle through the slot and into the trench. Each segment will be lowered into the trench as the side booms move along the ice with flat bottom rollers cradles supporting the pipeline bundle. Where required, a spreader bar will be used to maintain the necessary clearance between the side booms and the edge of the ice slot.

For the purpose of this cost estimate, all equipment and personnel required for the pipeline installation are assumed to be mobilized at the start of pipelay. For the shore crossing a LS cost of $569,500 was assumed to account for requirements such as a saltwater plug and revegetation of the tundra.

For Option 1 Case 4, the power cable will be installed into its own trench 100m to the side of the pipeline trench. The length of this trench will be 2.9km. The mob/demob rate for the trenching spread is 17,085/day and the operating cost is $34,170/day. The duration of the cable installation is 14 days due to expected permafrost.

6.8.7 Activity 7: Backfilling

Trench spoils will be transported to a location on grounded ice so that the additional weight does not influence the integrity of the floating ice. The storage of backfill material away from the trench reduces the backfilling rate for floating ice; however, this could be mitigated by using more earth moving equipment to haul the trench spoils to the backfill site.

Backfilling of the trench will be performed by earth-moving equipment. It is assumed that all excavated materials must be returned to the trench. Loaders and haul trucks will be used to move the trimmed trenching spoils from the storage ice sections back into the trench. The spoils haul spread to get the spoils from the storage location to the side of the trench is $11,390/day and will last the entire time of the backfilling. No gravel backfill has been assumed required for local high points of the installed pipeline.

Once the on-ice pipeline is installed and backfilled, it will be filled with nitrogen and pressure tested. The final hydrotest to satisfy applicable regulations and codes will be completed when the entire offshore line is installed.

6.9 Hydrotesting and Dewatering

The primary hydrotesting and dewatering activities and assumptions for the offshore pipelines are provided below:

- The pre-commissioning spread is estimated at a cost of $455,600/day. As all hydrotesting will be performed from the GBS, standby vessel time has not been included. This spread will also be required to dewater and dry the gas pipelines post-hydrotest; the same day rate of $455,600/day will be applied.
- No costs have been included for the disposal of the hydrotest water after testing is complete.
- De-water and drying will be performed for the gas pipeline only.
- Hydrotest and dewatering durations are shown below in Table 6-5 and are based on past project experience.

Table 6-5: Offshore Pre-commissioning Durations

Pipeline Option	Pipeline Length	Flooding, Cleaning and Gauging	Hydrotesting	Dewatering and Drying[2]	Hydrotest Volumes[1]
Option 1	30.8 km	4 days	3 days	5 days	11,374 m^3
Option 2	30.8 km	3 days	2 days	5 days	11,374 m^3

Notes:
1. Volumes assume that the largest lines are tested first, and fluid is then cycled through the other lines for testing.
2. Gas line only.

6.10 Long Lead Items

A long lead item (LLI) is defined as any item that takes longer than six (6) months from the placement of the order to arrival at the project site. Potential long lead items identified for this project are tabulated below in Table 6-6. All items and quantities are based on current estimates and should be refined during future phases. Due to the remoteness of the area, it is important to have a subsea pipeline repair system near the project.

Table 6-6: Potential Long Lead Items

Item Description	Quantity
Carbon Steel Line Pipe (API Spec 5L Grade X52)	25,193 mT
Pipeline Repair System	TBD
Winterization of Vessels	A number of vessels would likely need be ice strengthened/winterized before mobilizing. This could take several months to complete for some of the vessels.
Reserve CSD for Construction Season	Will need the vessel for a specific installation window.

Reserve Lay Barge(s) for Installation Season	Will need the vessel for a specific installation window.

6.11 Engineering, Project Management, and Contingency

6.11.1 Engineering, Procurement and Construction Management

Engineering, procurement and construction management costs for this study have been assumed as 10% of the total installed cost (TIC). This includes inspection and construction management cost to cover all materials fabrication, transportation, pipeline field construction, and as-built documentation activities.

6.11.2 Logistics

Logistics to support the project and facilitate the transportation of materials, equipment, and personnel throughout the duration of the project has been assumed as 2% of the TIC.

6.11.3 Contingency

The offshore pipeline CAPEX costs are based on the expected materials and construction requirements as presently envisioned at this conceptual phase. Known and reasonably expected cost increases due to factors such as materials excess and wastage, normal weather, and mechanical downtime are included in this cost estimate.

Both cost increases and decreases are anticipated from the estimated preliminary cost due to changes as more detailed design and construction planning are performed, and as the actual procurement and construction activities progress.

For the purpose of this estimate, no contingency was included.

7 CONSTRUCTION SCHEDULE

The above basis of estimate was used to generate an overall high-level project development schedule that can be found in Appendix C. The schedule is valid for all options and cases as there is little difference between them. The schedule provided only reviews the significant items or milestones at a high level. The schedule was split into the following 4 different sections:

- Project Management and Surveys
- Materials and Double Jointing
- GBS Installation and On-ice Construction
- Summer Construction Work

7.1 Project Management and Surveys

The Project Management and Survey section contains the following 3 elements:

- Project Management: This covers the following activities that start with the concept and continues on until hand over to operations: Engineering, Project Management, Permitting, Procurement and Construction Management.
- Open Water Surveys: These are the geophysical surveys completed each up to and after the construction of the pipeline. These will be complete in August during the open water season.
- Strudel Scour Flyover Surveys: These are the aerial surveys completed during the river overflood, which generally occurs in early July, that will map drainage features in the sea ice in the area of the pipeline route.

7.2 Materials and Double Jointing

The Materials and Double Jointing section contains the following 5 elements:

- Line Pipe Order: This is a milestone date when the line pipe will be ordered. This date is assumed based on past projects and should be confirmed once budgetary quotes are received from pipe mills and coating yards.
- Line Pipe Fabrication and Coating: It was estimated that the line pipe fabrication and coating will take about 8 months. This duration was assumed based on past projects and should be confirmed once budgetary quotes are received from pipe mills and coating yards.

- Materials Shipment to Tuktoyaktuk: The shipment of the coated line pipe is expected to take close to 2 months for it to get to Kugmallit Bay and for the pipe to be offloaded onto smaller barges to be brought into the Tuktoyaktuk port.

- Testing and WPQs: The received pipe material will need to be tested and WPQs will need to be developed prior to double jointing the line pipe. It is important to note that the welding requirements will be stricter than normal due to limit strain design requirements.

- Pipeline Double Jointing: Once the WPQs have been completed then the line pipe will be double jointed. This will include the welding, NDE, FJC, anode and anode taper installation.

7.3 GBS Installation and On-ice Construction

The GBS Installation and On-ice Construction section contains the following 4 elements:

- GBS Installation: The current plan has the GBS installed the summer before the pipeline. This will allow for the GBS tie-in to be completed in the same season as the pipelay. This is to help prevent a second pipelay mobilization.

- Pipe Transport to Site: Once an onshore ice road is built from the Tuktoyaktuk highway to the project site, double jointed line pipe will be trucked over and stored.

- Ice thickening: The key on-ice activity is the building of the sea ice platform that all of the on-ice construction will be completed from. Once the offshore ice is stable enough to support ice thickening equipment, the ice thickening will start. This is expected to start in mid-December and will continue on into late February early March.

- On-ice Construction: Once the nearshore ice is grounded then the on-ice construction can begin. The on-ice construction includes the shore crossing construction, ice slotting, trench excavation, pipeline stringing/welding/bundling, pipeline installation and backfilling. For Option 1 Case 4 this will also include the first 2.9km of the power cable installation.

7.4 Summer Construction Work

The Summer Construction Work section contains the following 7 elements:

- GBS Direct Pipe Installation: This is the construction of the GBS approach pull tube installations by the Direct Pipe method. They will need to be completed before summer pipelay gets to the GBS.

- Excavate the Trench using the CSD: The summer installation window is short, so it is important for the CSD to start as soon as the sea ice permits. The trenching is expected to take about a month.

- Pipelay: The pipelay will start as soon as the CSD has completed a few kilometres of the trench. The pipelay barge will pick up the winter installed pipeline end and lay-away. The pipelay is expected to take a little less than a month to complete.

- Cable Lay: With the pipelay waiting for the CSD to excavate a few km, the cable lay vessel can initiate the cable lay and get ahead of the pipelay to avoid interference with the pipelay anchor spread. The cable lay is expected to take about 3 weeks to complete.

- GBS Tie-in's: Once the cable lay reaches the GBS, the cable can be tied into the GBS by pulling the cable into a completed Direct Pipe casing. This is expected to happen well before the pipelay reaches the GBS. Once the pipelay reaches the GBS, the pipeline(s) will be tied into the GBS by pulling the pipeline(s) into the completed Direct Pipe casings.

- Backfilling: The trench backfilling will start as soon as the trench excavation is completed. Once the CSD completes the trench to the GBS, it will go back to the start of the trench and will start backfilling in behind the pipelay. Backfilling is expected to take about 3 weeks to complete.

- Once all the tie-ins are complete and the trench is backfilled, the pipeline will be cleaned, gauged and hydrotested. This is expected to take a week or two. The vessels will leave the area before the hydrotest to ensure they are able to get around Barrow before the ice sets in.

8 OPEX

The operating cost estimate in Appendix B includes the cost for the offshore pipeline inspection and operation; the methodology for this has been described in Section 5. Operational costs estimated for this project do not include contingencies. The OPEX is provided on a per annum basis as well as for the length of the project's assumed design life of 20 years.

8.1 Leak Detection System

The majority of the leak detection system operational requirements are assumed to be monitored by the operations staff. Once the systems are installed, tested, and shown to be operating correctly, the operational staff will be capable of responding to warnings, alarms, and LDS system output when required. As such, no additional operating costs have been included for monitoring pressure, temperature, mass balance, etc.

8.2 Operational Pigging

Various pigging inspections are recommended for offshore pipeline(s). The frequency for each of the proposed pigging activities is summarized in Table 8-1 as well as in Section 5. All assumed frequencies should be confirmed based on operational performance.

Table 8-1: Pigging Frequency Summary

<table>
<tr><th rowspan="2">Pipeline</th><th colspan="2">Pigging Frequency by Operation</th></tr>
<tr><th>In-Line Inspection</th><th>Pipeline Cleaning</th></tr>
<tr><td>Option 1 – 30inch Gas Line</td><td rowspan="3">Prior to start up (base line), after first year, and then every 5 years afterwards</td><td>Yearly</td></tr>
<tr><td>Option 1 – 10.75inch Condensate Line</td><td>Quarterly</td></tr>
<tr><td>Option 2 – 30inch Gas Line</td><td>Yearly</td></tr>
</table>

8.2.1 Internal Pipeline Inspection

The in-line inspection (ILI) costs assume the schedule provided in Table 8-1. ILI costs will include engineering and management, pigging equipment mobilization and demobilization.

Wall thickness measurements can be taken using either magnetic flux leakage (MFL) pigs or ultrasonic technique (UT) pigs. MFL pigs are generally the preferred method of detecting metal loss, however their operability is limited based on the wall thickness; the standard maximum wall thickness for MFL pigs is accepted at 1.00 in for offshore pipelines. The alternative method, UT pigging, can operate with almost no limitation on wall thickness. Based on the proposed pipelines, the inspection of the 10.75-inch line can be completed by MFL pigs and the larger 30-inch pipelines will need to be inspected using UT pigs. For the gas line, it will be necessary to surround the UT pig with a fluid (MEG or MeOH) to ensure that the sensors are able to properly measure wall thickness.

For the purpose of this estimate the following assumptions have been made for ILI costs:

- The pigs would be specially designed to be able to inspect each pipeline route in a single run (batteries, memory capacity, etc.);
- The cost only includes the length of the offshore pipeline;
- Calliper pigs are run in the pipeline before the WT and geometry (XYZ mapping) pigs are run;
- Wall thickness and geometry pigs are combined into one pig train;
- The tool speed is assumed at 1 m/s; and
- Based on the recommended frequency and a 20-year design life, the per annum ILI cost is considered to be 25% of the cost of a single ILI run.

8.2.2 Pipeline Cleaning

For the purposes of this study, the pipelines will be cleaned using steel-body brush pigs. For the purposes of the OPEX estimate, the following have been assumed:

- Pigs will be brought out to facilities on supply boats. As such, the cost of transporting them from shore was not included.
- A year's supply of pigs will need to be stored on the platforms since it will not be possible to transfer the reusable pigs back to the platform outside of the open water season.
- The 10in cleaning pig lifespan is 4 runs/pig and the 30in cleaning pig lifespan is 6 runs/pig.
- 30in cleaning pig is $10,382 and replacements are $8,281/each.
- 10.75in cleaning pig is $2,448 and replacements are $1,903/each.

8.3 Pipeline Surveillance

The cost assumptions for the pipeline inspections are provided in the sections below. For the external pipeline inspection and the operational surveys, an annual project management and engineering cost of $250k was assumed for Option 3 and $150k was assumed for Options 1, 2 and 4.

8.3.1 Aerial Survey

Aerial surveillance will include leak detection monitoring while conducting strudel scour erosion monitoring during spring over-flood (June) and the open water / broken ice season. OPEX costs are based on the following assumptions:

- Aerial surveys are assumed to be conducted using either fixed-wing aircraft or helicopter with a rental day rate of $20,000;

- For Options 1, 2, and 4, the aerial surveillance for leak detection is assumed to be included as part of the standard crew and material transportation operations between the shorebase and the platforms. Therefore, this has not been included within the OPEX estimate; and
- Flowline aerial surveys for the onshore pipeline sections are considered to be outside the scope of the offshore OPEX. Therefore, no cost has been included to survey the onshore sections.

8.3.2 Operational Surveys

During the operational life of the MDLNG offshore pipeline(s), it is assumed that a geophysical survey (multi-beam and side scan) will be required every year to monitor the bathymetry (trench backfill elevation), strudel scour, and ice gouging in the region. The operational survey assumptions are as follows:

- A dedicated vessel is mobilized from Anchorage AK at a rate of $41,004/day;
- The vessel has an assumed working rate of $68,340/day; and
- A cost of $15,000 for post-inspection processing and analysis.

It was also assumed the survey vessel will not need to be winterized or ice strengthened.

8.4 Chemical Injection

Chemical injection requirements have not been included in the offshore pipeline OPEX. It was assumed that the requirements would be covered in the onshore pipeline OPEX since the offshore is the continuation of the onshore pipeline(s).

9 REFERENCES

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3. Paulin, Mike (Intecsea) email, “FW: 417011-34542 / Mackenzie Project Biweekly report/ For week ending Feb 5, 2021”, sent 9-Feb-21

4. Paulin, Mike (Intecsea) email, “FW: Pipeline Alignments”, sent 22-Feb-21

5. Worley, ”MDLNG Offshore and Onshore Selected Pipeline Option”, 3 March 2021.

6. Paulin, Mike (Intecsea) email, “FW: CHS S-75 nautical chart option”, sent 4-Mar-2021

7. API, “Line Pipe” API Specification 5L, Forty-Sixth Edition, April 2018, Errata 1, May 2018.

8. DNVGL, “Cathodic Protection of Submarine Pipelines” DNVGL-RP-F103, July 2016.

9. CSA Standards, “Oil and Gas Pipeline Systems” Z662-11.

Appendix A

Offshore Pipelines CAPEX Estimates

11-Mar-21

Case		Cost Case 1	Cost Case 2	Cost Case 3	Cost Case 4
		GNWT: MDLNG - Option 1 with 2 GBSs - Offshore Gas and Condensate Pipelines with 2 GBSs	**GNWT: MDLNG - Option 2 - Offshore Gas Pipeline with 1 GBS**	**GNWT: MDLNG - Option 1 with 1 GBS - Offshore Gas and Condensate Pipelines with 1 GBS**	**GNWT: MDLNG - Option 1 with 1 GBS and power cable - Offshore Gas and Condensate Pipelines with 1 GBS and power cable**
CATEGORY TOTALS		**$1,000 CAD**	**$1,000 CAD**	**$1,000 CAD**	**$1,000 CAD**
1	Materials	60,338	51,528	60,338	122,058
2	Materials Transportation	45,904	41,296	45,904	46,246
3	Design, Preconstruction, and Construction Surveys	5,719	5,719	5,719	5,753
4	Vessel Procurement and Upgrades	103,421	103,421	103,421	103,421
5	Offshore Trenching and Backfilling	40,944	34,961	39,463	39,463
6	Offshore Installation	55,905	42,466	55,905	68,835
7	Ice Management and Support	42,651	42,651	42,651	42,651
8	On-ice Installation	74,804	70,557	74,804	75,479
9	Offshore Precommissioning	5,467	4,556	5,467	5,467
10	Onshore Construction Camp	29,160	29,160	29,160	29,160
11	Engineering, Permitting Support, Project/Construction Management, and Contingency	55,718	51,158	52,041	61,125
GRAND TOTAL		**520,031**	**477,472**	**514,873**	**599,659**

GNWT: MDLNG - Option 1 with 2 GBSs - Offshore Gas and Condensate Pipelines with 2 GBSs — 11-Mar-21

ID	Item	Unit Metric	Unit Cost CAD$	Quantity Metric	Mobilization / Demobilization Days	Unit Duration Days	Base Cost CAD	Escalated Cost CAD $1,000	Base Cost CAD $1,000
1.0	**Materials**								
	Pipeline Components								
	Gas Pipeline - 30 in OD x 1.5 in WT (Welded, API Spec5L X52)	mT	$ 1,900	21,990			$ 41,780,384	$ 41,780,384	$ 41,780
	Condensate pipeline - 10.75 in OD x 0.594 in WT (Seamless, API Spec5L X52)	mT	$ 2,400	3,103			$ 7,447,373	$ 7,447,373	$ 7,447
	Coatings, Anodes, and Insulation								
	External anti-corrosion coating - Fusion Bonded Epoxy (FBE)	sm	$ 28.00	105,138			$ 2,943,864	$ 2,973,302	$ 2,973
	Sacrificial anodes	kg	$ 7.15	48,121			$ 344,063	$ 347,504	$ 348
	Concrete weight coating (CWC)	kg	$ 0.85	6,376,688			$ 5,420,185	$ 6,173,591	$ 6,174
	10in Anode Tapers	anode	$ 120	342			$ 41,040	$ 46,745	$ 47
	30in Anode Tapers	anode	$ 370	352			$ 130,240	$ 148,343	$ 148
	Bundle spacers and straps	each	$ 170	1,721			$ 292,548	$ 333,212	$ 333
	Fiber Optic Cable								
	Fiber optic cable for offshore	m	$ 15.00	21,829			$ 327,435	$ 330,709	$ 331
	Fiber optic cable for on-ice (truck-able reels)	m	$ 15.00	10,494			$ 157,406	$ 158,980	$ 159
	Miscellaneous - 1% of materials								
	Miscellaneous materials (flanges, FOC splice kits, weld consumables, field joints, etc.)	% of materials	1%				$ 588,845	$ 597,401	$ 597
	SUB-TOTAL								$ 60,338
2.0	**Materials Transportation**								
	Logistics - Marine Based Transport to Beaufort Sea								
	Marine Shipping to Coating Plant (Japan to SE Asia)								
	Manufactured line pipe	mT	$ -	25,093					
	Mobilize local standard bulk freighters	day	$ 36,000	2	2		$ 144,000	$ 164,016	$ 164
	Port Fee: Load bare line pipe onto standard freighters	mT	$ 10.4	25,093			$ 260,965	$ 297,239	$ 297
	Ship line pipe via standard bulk freighter to coating plant (includes unloading time)	day	$ 36,000	2		15	$ 1,080,000	$ 1,230,120	$ 1,230
	Port Fee: Offloading line pipe at coating plant	mT	$ 10.4	25,093			$ 260,965	$ 297,239	$ 297
	Demobilize standard bulk freighters	day	$ 36,000	2	9		$ 648,000	$ 738,072	$ 738
	Coat pipe	-	$ -	-					
	Marine Shipping to Beaufort Sea (SE Asia to Kugmallit Bay)								
	Mobilize local freighters	day	$ 36,000	2	2		$ 144,000	$ 164,016	$ 164
	Port Fee: Load coated line pipe onto freighters	mT	$ 10.4	31,522			$ 327,828	$ 373,396	$ 373
	Ship coated line pipe via freighter from coating plant to offshore unloading area Canadian Beaufort (includes unloading time)	day	$ 36,000	2		26	$ 1,872,000	$ 2,132,208	$ 2,132
	Mobilize pipe barges from Anchorage	day	$ 15,000	3	19		$ 855,000	$ 973,845	$ 974
	Demobilize freighters	day	$ 36,000	2	20		$ 1,440,000	$ 1,640,160	$ 1,640
	Barge coated line pipe to receiving terminal in Tuktoyaktuk, Norwest Territories	day	$ 20,000	3		12	$ 720,000	$ 820,080	$ 820
	Port Fee: Offload barge into temporary storage facility in Tuktoyaktuk, Norwest Territories	mT	$ 20	31,522			$ 630,439	$ 718,070	$ 718
	Demobilize pipe barges back to Anchorage	mT	$ 15,000	3	19		$ 855,000	$ 973,845	$ 974
	Transfers								
	Offshore Pipelay								
	Mobilize barge (offshore installation only)	day	$ 15,000	2	19		$ 570,000	$ 649,230	$ 649
	Load shuttle barge for transfer to pipelay vessel (offshore installation only)	mT	$ 20	23,271			$ 465,423	$ 530,117	$ 530
	Shuttle line pipe to barge for offshore installation (offshore installation only) in Beaufort Sea	day	$ 20,000	2		35	$ 1,391,600	$ 1,585,032	$ 1,585
	Demobilize barge (offshore installation only)	day	$ 15,000	2	19		$ 570,000	$ 649,230	$ 649
	On-ice Construction								
	Port Fee: Load coated line pipe onto trucks	mT	$ 20	8,251			$ 165,016	$ 187,953	$ 188
	Mob/Demob 20 Trucks from Alberta	truck/day	$ 750	20		6	$ 90,000	$ 102,510	$ 103
	Transfer coated line pipe to pipeline Right-of-Way via truck (on-ice construction only) to on-ice construction Site	truck/day	$ 750	344			$ 257,837	$ 293,676	$ 294
	Unload coated line pipe at project site	mT	$ 20	8,251			$ 165,016	$ 187,953	$ 188
	Miscellaneous Materials								
	Transport Fiber optic cable for offshore	LS	$ 50,000				$ 50,000	$ 56,950	$ 57
	Transport Fiber optic cable for on-ice (truck-able reels)	LS	$ 25,000				$ 25,000	$ 28,475	$ 28
	Tuktoyaktuk Port Storage Site (Winter line pipe)	m2/day	$ 5	5,495		180.0	$ 4,945,652	$ 5,633,098	$ 5,633
	Tuktoyaktuk Port Storage Site (Summer line pipe)	m2/day	$ 5	12,427		360.0	$ 22,368,298	$ 25,477,492	$ 25,477

GNWT: MDLNG - Option 1 with 2 GBSs - Offshore Gas and Condensate Pipelines with 2 GBSs									11-Mar-21
ID Item	**Unit** **Metric**	**Unit Cost** **CAD$**	**Quantity** **Metric**	**Mobilization / Demobilization** **Days**	**Unit Duration** **Days**	**Base Cost** **CAD**	**Escalated Cost** **CAD $1,000**	**Base Cost** **CAD $1,000**	
SUB-TOTAL								$ 45,904	

GNWT: MDLNG - Option 1 with 2 GBSs - Offshore Gas and Condensate Pipelines with 2 GBSs | 11-Mar-21

ID	Item	Unit Metric	Unit Cost CAD$	Quantity Metric	Mobilization / Demobilization Days	Unit Duration Days	Base Cost CAD	Escalated Cost CAD $1,000	Base Cost CAD $1,000
3.0	**Design, Preconstruction, and Construction Surveys**								
	Recommended Design Surveys								
	Pre-FEED Surveys								
	Spring over flood helicopter survey - strudel flight	day	$ 20,000	1		1	$ 20,000	$ 22,780	$ 23
	Mob/demob vessel to perform summer geophysical, bathymetry survey, and refractive sub-bottom profiling	day	$ 46,800	1	16		$ 748,800	$ 852,883	$ 853
	Summer geophysical, bathymetry survey, and refractive sub-bottom profiling	day	$ 78,000	1		11	$ 858,000	$ 977,262	$ 977
	Geotechnical Equipment mob/demob	LS	$ 15,000	1			$ 15,000	$ -	$ -
	Summer geotechnical (borehole survey)	day	$ 30,000	1		7	$ 210,000	$ 239,190	$ 239
	FEED Surveys								
	Spring over flood helicopter survey - strudel flight	day	$ 20,000	1		1	$ 20,000	$ 22,780	$ 23
	Mob/demob vessel to perform summer geophysical, bathymetry survey, and refractive sub-bottom profiling	day	$ 46,800	1	16		$ 748,800	$ 852,883	$ 853
	Summer geophysical, bathymetry survey, and refractive sub-bottom profiling	day	$ 78,000	1		6	$ 468,000	$ 533,052	$ 533
	Geotechnical Equipment mob/demob	LS	$ 15,000	1			$ 15,000	$ -	$ -
	Summer geotechnical (borehole survey)	day	$ 30,000	1		2	$ 60,000	$ 68,340	$ 68
	DETAILED Surveys								
	Spring over flood helicopter survey - strudel flight	day	$ 20,000	1		1	$ 20,000	$ 22,780	$ 23
	Mob/demob vessel to perform summer geophysical survey	day	$ 36,000	1	16		$ 576,000	$ 656,064	$ 656
	Summer geophysical survey	day	$ 60,000	1		4	$ 240,000	$ 273,360	$ 273
	Interphase Geophysical Surveys								
	Preconstruction Surveys								
	Mob/demob vessel to perform offshore pre-construction survey	day	$ 43,200	1	16		$ 691,200	$ 787,277	$ 787
	Conduct offshore preconstruction survey - Beaufort	day	$ 72,000	1		1	$ 72,000	$ 82,008	$ 82
	As-backfilled Survey								
	Mob/demob vessel to perform offshore as-backfilled	day	$ -						
	Conduct offshore as-backfilled survey	day	$ 72,000	1		4	$ 288,000	$ 328,032	$ 328
	SUB-TOTAL								$ 5,719
4.0	**Vessel Procurement and Upgrades**								
	Winterization and Arctic Modifications								
	Trenching and Backfilling								
	Cutter Suction Dredger (CSD)	LS	$ 15,000,000	1			$ 15,000,000	$ 17,085,000	$ 17,085
	Pipelay								
	Anchored Lay Barge	LS	$ 19,160,000	1			$ 19,160,000	$ 21,823,240	$ 21,823
	Pipelay Support Vessel	LS	$ 18,000,000	1			$ 18,000,000	$ 20,502,000	$ 20,502
	Support Vessels								
	Anchor Handling Tug / Work Boat	LS	$ 7,350,000	2			$ 14,700,000	$ 16,743,300	$ 16,743
	Pipe Carrier	LS	$ 5,470,000	2			$ 10,940,000	$ 12,460,660	$ 12,461
	Supply Vessels / Crew Boats	LS	$ 6,500,000	2			$ 13,000,000	$ 14,807,000	$ 14,807
	SUB-TOTAL								$ 103,421
5.0	**Offshore Trenching and Backfilling**								
	Mobilization/Demobilization								
	Mob/demob cutter suction dredger (CSD) - Trenching and Backfilling	day	$ 180,000	1	90		$ 16,200,000	$ 18,451,800	$ 18,452
	Trenching and Backfilling								
	Trench and backfill using cutter suction dredger (CSD)	day	$ 300,000			47.7	$ 14,312,183	$ 16,301,576	$ 16,302
	Monitor During Trenching and Backfilling								
	Mob/demob vessel to serve as workboat / crew boat / support vessel	day	$ 20,000	1	16		$ 320,000	$ 323,200	$ 323
	Workboat / crew boat / support vessel	day	$ 30,000			48	$ 1,431,218	$ 1,445,530	$ 1,446
	Mob/demob vessel for ROV monitoring of trenching and backfill activities	day	$ 50,000	1	16		$ 800,000	$ 808,000	$ 808
	ROV monitoring of trenching and backfill activities	day	$ 75,000			48	$ 3,578,046	$ 3,613,826	$ 3,614

ID	Item	Unit Metric	Unit Cost CAD$	Quantity Metric	Mobilization / Demobilization Days	Unit Duration Days	Base Cost CAD	Escalated Cost CAD $1,000	Base Cost CAD $1,000
	SUB-TOTAL								$ 40,944
6.0	**Offshore Installation**								
	Anchored Lay Barge								
	Anchored barge mob/demobilization (includes 2 anchor handling/tow tugs)	day	$ 250,000	1	90		$ 22,500,000	$ 22,500,000	$ 22,500
	Anchored barge operational time (includes 2 anchor handling/tow tugs)	day	$ 500,000	1		27	$ 13,395,000	$ 13,395,000	$ 13,395
	Anchored barge operational time - GBS tie-in (includes 2 anchor handling/tow tugs)	day	$ 500,000	1		8	$ 4,000,000	$ 4,000,000	$ 4,000
	GBS Direct Pipe								
	Direct Pipe equipment mob/demobilization	LS	$ 1,050,000	1			$ 1,050,000	$ 1,195,950	$ 1,196
	Pipe delivery, misc. equipment, and personnel mob/demobilization	LS	$ 1,094,000	1			$ 1,094,000	$ 1,246,066	$ 1,246
	Operational day rate for equipment and crew	day	$ 240,000			32	$ 7,680,000	$ 8,747,520	$ 8,748
	Support Vessels and Activities								
	Mob/demob vessel to serve as workboat / crew boat / support vessel	day	$ 20,000	1	16		$ 320,000	$ 323,200	$ 323
	Workboat / crew boat / support vessel	day	$ 30,000	1		35	$ 1,043,700	$ 1,054,137	$ 1,054
	Mob/demob vessel for survey throughout construction and ROV survey of pipelay activities	day	$ 50,000	1	16		$ 800,000	$ 808,000	$ 808
	Survey throughout construction and ROV monitoring of pipelay activities	day	$ 75,000	1		35	$ 2,609,250	$ 2,635,343	$ 2,635
	SUB-TOTAL								$ 55,905
7.0	**Ice Management and Support**								
	Heavy Icebreaker								
	Mob/demobilize heavy icebreaker	day	$ 116,000	1	85		$ 9,860,000	$ 11,230,540	$ 11,231
	Heavy icebreaker on duty	day	$ 144,000	1		77	$ 11,088,000	$ 12,629,232	$ 12,629
	Light Icebreaker and Ice Monitoring								
	Mob/demobilize light icebreaker	day	$ 76,000	1	85		$ 6,460,000	$ 7,357,940	$ 7,358
	Light icebreaker on duty	day	$ 94,000	1		77	$ 7,238,000	$ 8,244,082	$ 8,244
	Weather/Ice monitoring during construction season	day	$ 15,000	1		80	$ 1,200,000	$ 1,366,800	$ 1,367
	Helicopter services	day	$ 20,000	1		80	$ 1,600,000	$ 1,822,400	$ 1,822
	SUB-TOTAL								$ 42,651
8.0	**On-ice Installation**								
	Project Management and Support								
	General Support Throughout On-ice Construction	day	$ 62,000	160			$ 9,920,000	$ 11,298,880	$ 11,299
	Arctic Civil Works								
	Activity 1: Ice Road Construction and Ice Thickening — **24 hour operation (double shift)**								
	Grounded Ice Road Construction								
	Mob/demobilize construction crews and supervising personnel	person	$ 1,500	45	3		$ 202,500	$ 230,648	$ 231
	Mob/demobilize construction and maintenance equipment	day	$ 39,000		10		$ 390,000	$ 444,210	$ 444
	Grounded ice-road construction	day	$ 80,000			70	$ 5,600,000	$ 6,378,400	$ 6,378
	Grounded ice pad construction for equipment staging and trench spoils	day	$ 39,000			6	$ 234,000	$ 266,526	$ 267
	Floating Ice Road Construction								
	Mob/demobilize construction crews and supervising personnel	person	$ 1,500	45	3		$ 202,500	$ 230,648	$ 231
	Mob/demobilize construction and maintenance equipment	day	$ 39,000		10		$ 390,000	$ 444,210	$ 444
	Floating ice-road construction	day	$ 80,000			80	$ 6,400,000	$ 7,289,600	$ 7,290
	Maintenance								
	Grounded ice storage pad maintenance	km	$ 39,000	1.00			$ 39,000	$ 44,421	$ 44
	Grounded ice-road maintenance	km	$ 40,000	2.90			$ 116,000	$ 132,124	$ 132
	Floating ice-road maintenance	km	$ 50,000	7.10			$ 355,000	$ 404,345	$ 404
	Activity 2: Ice Cutting and Slotting — **24 hour operation (double shift)**								
	Mob/demobilize construction crews and supervising personnel	person	$ 1,500	35	1		$ 52,500	$ 59,798	$ 60
	Mob/demobilize construction and maintenance equipment	day	$ 48,000		10		$ 480,000	$ 546,720	$ 547
	Cut slots in ice using trenchers, remove blocks using backhoes, and re-position blocks away from slots using front-end-loaders	day	$ 80,000			30	$ 2,400,000	$ 2,733,600	$ 2,734

ID Item	Unit Metric	Unit Cost CAD$	Quantity Metric	Mobilization / Demobilization Days	Unit Duration Days	Base Cost CAD	Escalated Cost CAD $1,000	Base Cost CAD $1,000
Additional trucks and loader to remove ice from floating ice section to grounded ice section	day	$ 17,000			30	$ 510,000	$ 580,890	$ 581
Activity 3: Trenching and Cleanout **24 hour operation (double shift)**								
Primary								
Mob/demobilize construction crews and supervising personnel	person	$ 1,500	36	2		$ 108,000	$ 123,012	$ 123
Mob/demobilize construction and maintenance equipment	day	$ 80,000		10		$ 800,000	$ 911,200	$ 911
Primary excavation using 4 spreads	day	$ 150,000			35	$ 5,250,000	$ 5,979,750	$ 5,980
Additional trucks to haul spoils from floating ice to grounded ice storage site	day	$ 10,000			35	$ 350,000	$ 398,650	$ 399
On-going Cleanout Prior to Pipelay								
Mob/demobilize construction crews and supervising personnel	person	$ 1,500	17	2		$ 51,000	$ 58,089	$ 58
Mob/demobilize construction and maintenance equipment	day	$ 40,000		10		$ 400,000	$ 455,600	$ 456
On-going trench cleanup using 2 spreads	day	$ 75,000			20	$ 1,500,000	$ 1,708,500	$ 1,709
Arctic Pipeline Installation								
Activity 4: Pipeline Make-Up Site Preparation **12 hour operation (single shift)**								
Mob/demobilize construction crews and supervising personnel	person	$ 1,500	40	1		$ 59,652	$ 67,943	$ 68
Mob/demobilize construction and maintenance equipment	day	$ 40,000		10		$ 400,000	$ 455,600	$ 456
Set-up on ice work site and string line pipe	day	$ 80,000			25	$ 2,000,000	$ 2,278,000	$ 2,278
Activity 5: Pipe String Make-Up (Welding) **24 hour operation (double shift)**								
Offsite Welding and Preparation								
Double joint (Weld/NDE/FJC) 10in line pipe	joint	$ 1,200	1,326			$ 1,591,200	$ 1,812,377	$ 1,812
Double joint (Weld/NDE/FJC) 30in line pipe	joint	$ 4,000	1,326			$ 5,304,000	$ 6,041,256	$ 6,041
Install sacrificial anodes	anode	$ 750	229			$ 171,837	$ 195,722	$ 196
On-ice Welding								
Mob/demobilize construction crews and supervising personnel	person	$ 1,500	75	1		$ 112,500	$ 128,138	$ 128
Mob/demobilize welding equipment spread	day	$ 84,000		10		$ 840,000	$ 956,760	$ 957
Weld/NDE pipelines on-ice	day	$ 230,000			28	$ 6,440,000	$ 7,335,160	$ 7,335
Field joint coating	joint	$ 150	862			$ 129,300	$ 147,273	$ 147
String Make-Up **24 hour operation (double shift)**								
Pipelines								
Mob/demobilize construction crews and supervising personnel	person	$ 1,500	15	1		$ 22,500	$ 25,628	$ 26
Mob/demobilize equipment spread	day	$ 25,000		10		$ 250,000	$ 284,750	$ 285
Prepare pipe strings (tie-in to previous strings, bundling, etc.)	day	$ 50,000			21	$ 1,050,000	$ 1,195,950	$ 1,196
Fiber Optic Cable								
Mob/demobilize fiber optic cable installation crew	person	$ 1,500	6	2		$ 18,000	$ 20,502	$ 21
Mob/demobilize Fiber optic cable installation equipment	day	$ 10,000		10		$ 100,000	$ 113,900	$ 114
Install fiber optic cable	day	$ 17,000			21	$ 357,000	$ 406,623	$ 407

GNWT: MDLNG - Option 1 with 2 GBSs - Offshore Gas and Condensate Pipelines with 2 GBSs 11-Mar-21

ID Item	Unit Metric	Unit Cost CAD$	Quantity Metric	Mobilization / Demobilization Days	Unit Duration Days	Base Cost CAD	Escalated Cost CAD $1,000	Base Cost CAD $1,000
Activity 6: Pipeline Installation **24 hour operation (double shift)**								
Lay Pipeline - Grounded Ice								
Mob/demobilize construction crews and supervising personnel	person	$ 1,500	45	1		$ 67,163	$ 76,499	$ 76
Mob/demobilize equipment for pipeline installation	day	$ 80,000		10		$ 800,000	$ 911,200	$ 911
Lower bundle into excavated trench on grounded ice using 7 long reach side booms	day	$ 190,000			6	$ 1,140,000	$ 1,298,460	$ 1,298
Lay Pipeline - Floating Ice								
Mob/demobilize construction crews and supervising personnel	person	$ 1,500	45	1		$ 67,163	$ 76,499	$ 76
Mob/demobilize equipment for pipeline installation	day	$ 80,000		10		$ 800,000	$ 911,200	$ 911
Lower bundle into excavated trench on grounded ice using 7 long reach side booms	day	$ 190,000			16	$ 3,040,000	$ 3,462,560	$ 3,463
Shore Crossing								
Mob/demobilize additional personnel for crane operations	person	$ 1,500	6	1		$ 9,000	$ 10,251	$ 10
Mob/demobilize equipment	day	$ 25,000		10		$ 250,000	$ 284,750	$ 285
Operations	day	$ 50,000			4	$ 200,000	$ 227,800	$ 228
Saltwater plug and Shore Crossing Revegitation	LS	$ 500,000	1			$ 500,000	$ 569,500	$ 570
Activity 7: Backfilling the Trench **24 hour operation (double shift)**								
Mob/demobilize construction crews and supervising personnel	person	$ 1,500	37	1		$ 55,620	$ 63,351	$ 63
Mob/demobilize backfilling equipment from Prudhoe	day	$ 55,000		10		$ 550,000	$ 626,450	$ 626
Backfill trench	day	$ 110,000			30	$ 3,300,000	$ 3,758,700	$ 3,759
Additional trucks and loaders to haul spoils back to floating ice from grounded ice storage site	day	$ 10,000			30	$ 300,000	$ 341,700	$ 342
SUB-TOTAL								$ 74,804
9.0 Offshore Precommissioning								
Export								
Flooding, cleaning, and gauging	day	$ 400,000			4	$ 1,600,000	$ 1,822,400	$ 1,822
Hydrotesting	day	$ 400,000			3	$ 1,200,000	$ 1,366,800	$ 1,367
De-water and drying	day	$ 400,000			5	$ 2,000,000	$ 2,278,000	$ 2,278
SUB-TOTAL								$ 5,467
10.0 Onshore Construction Camp								
Construction and Operation								
Operational cost for accommodations	person-days	$ 400	72,900			$ 29,160,000	$ 29,160,000	$ 29,160
SUB-TOTAL								$ 29,160
11.0 Engineering, Permitting Support, Project/Construction Management, and Contingency								
Percent of TIC Costs								
Engineering design, Procurement, Project/Construction management - 10% of all subtotals	% of all subtotals	10%				$ 42,384,105	$ 46,431,312	$ 46,431
Logistics - 2% of all subtotals	% of all subtotals	2%				$ 8,476,821	$ 9,286,262	$ 9,286
Contingency								
Offshore pipeline contingency - 0% of total cost	% of total cost	0%				$ -	$ -	$ -
SUB-TOTAL								$ 55,718
12.0 Total Cost								
Total	$CAD					$ 474,701,978	$ 520,030,693	$ 520,031
SI cost metric	$CAD/km	30.8 km						$ 16,890
US cost metric	$CAD/mile	19.1 mi						$ 27,181

GNWT: MDLNG - Option 2 - Offshore Gas Pipeline with 1 GBS — 11-Mar-21

ID	Item	Unit Metric	Unit Cost CAD$	Quantity Metric	Mobilization / Demobilization Days	Unit Duration Days	Base Cost CAD	Escalated Cost CAD $1,000	Base Cost CAD $1,000
1.0	**Materials**								
	Pipeline Components								
	Gas Pipeline - 30 in OD x 1.5 in WT (Welded, API Spec5L X52)	mT	$ 1,900	21,990			$ 41,780,384	$ 41,780,384	$ 41,780
	Coatings, Anodes, and Insulation								
	External anti-corrosion coating - Fusion Bonded Epoxy (FBE)	sm	$ 28.00	77,402			$ 2,167,262	$ 2,188,934	$ 2,189
	Sacrificial anodes	kg	$ 7.15	32,763			$ 234,255	$ 236,598	$ 237
	Concrete weight coating (CWC)	kg	$ 0.85	6,376,688			$ 5,420,185	$ 6,173,591	$ 6,174
	30in Anode Tapers	anode	$ 370	352			$ 130,240	$ 148,343	$ 148
	Fiber Optic Cable								
	Fiber optic cable for offshore	m	$ 15.00	21,829			$ 327,435	$ 330,709	$ 331
	Fiber optic cable for on-ice (truck-able reels)	m	$ 15.00	10,494			$ 157,406	$ 158,980	$ 159
	Miscellaneous - 1% of materials								
	Miscellaneous materials (flanges, weld consumables, field joints, etc.)	% of materials	1%				$ 502,171.67	$ 510,175	$ 510
	SUB-TOTAL								$ 51,528
2.0	**Materials Transportation**								
	Logistics - Marine Based Transport to Beaufort Sea								
	Marine Shipping to Coating Plant								
	Manufactured line pipe	mT	$ -	21,990					
	Mobilize local standard bulk freighters	day	$ 36,000	2	2		$ 144,000	$ 164,016	$ 164
	Port Fee: Load bare line pipe onto standard freighters	mT	$ 10.40	21,990			$ 228,693	$ 260,481	$ 260
	Ship line pipe via standard bulk freighter to coating plant (includes unloading time)	day	$ 36,000	2		15	$ 1,080,000	$ 1,230,120	$ 1,230
	Port Fee: Offloading line pipe at coating plant	mT	$ 10.40	21,990			$ 228,693	$ 260,481	$ 260
	Demobilize standard bulk freighters	day	$ 36,000	2	9		$ 648,000	$ 738,072	$ 738
	Coat pipe	-	$ -	-					
	Marine Shipping to Beaufort Sea								
	Mobilize local freighters	day	$ 36,000	2	2		$ 144,000	$ 164,016	$ 164
	Port Fee: Load coated line pipe onto freighters	mT	$ 10.40	28,403			$ 295,396	$ 336,456	$ 336
	Ship coated line pipe via freighter from coating plant to offshore unloading area Canadian Beaufort (includes unloading time)	day	$ 36,000	2		26	$ 1,872,000	$ 2,132,208	$ 2,132
	Mobilize pipe barges from Anchorage	day	$ 15,000	3	19		$ 855,000	$ 973,845	$ 974
	Demobilize freighters	mT	$ 36,000	2	20		$ 1,440,000	$ 1,640,160	$ 1,640
	Barge coated line pipe to receiving terminal in Tuktoyaktuk, Norwest Territories	day	$ 20,000	3		12	$ 720,000	$ 820,080	$ 820
	Port Fee: Offload barge into temporary storage facility in Tuktoyaktuk, Norwest Territories	day	$ 20.00	28,403			$ 568,070	$ 647,032	$ 647
	Demobilize pipe barges back to Anchorage	mT	$ 15,000	3	19		$ 855,000	$ 973,845	$ 974
	Transfers								
	Offshore Pipelay								
	Mobilize barge (offshore installation only)	day	$ 15,000	2	19		$ 570,000	$ 649,230	$ 649
	Load shuttle barge for transfer to pipelay vessel (offshore installation only)	mT	$ 20	21,250			$ 425,008	$ 484,084	$ 484
	Shuttle line pipe to barge for offshore installation (offshore installation only) in Beaufort Sea	day	$ 20,000	2		21	$ 834,400	$ 950,382	$ 950
	Demobilize barge (offshore installation only)	day	$ 15,000	2	19		$ 570,000	$ 649,230	$ 649
	On-ice Construction								
	Port Fee: Load coated line pipe onto trucks	mT	$ 20	7,153			$ 143,062	$ 162,947	$ 163
	Mob/Demob 20 Trucks from Alberta	truck/day	$ 750	18		6	$ 81,000	$ 92,259	$ 92
	Transfer coated line pipe to pipeline Right-of-Way via truck (on-ice construction only) to on-ice construction Site	truck/day	$ 750	301			$ 225,750	$ 257,129	$ 257
	Unload coated line pipe at project site	mT	$ 20	7,153			$ 143,062	$ 162,947	$ 163
	Miscellaneous Materials								
	Transport Fiber optic cable for offshore	LS	$ 50,000				$ 50,000	$ 56,950	$ 57
	Transport Fiber optic cable for on-ice (truck-able reels)	LS	$ 25,000				$ 25,000	$ 28,475	$ 28
	Tuktoyaktuk Port Storage Site (Winter line pipe)	m2/day	$ 5	4,804		180	$ 4,324,041	$ 4,925,083	$ 4,925
	Tuktoyaktuk Port Storage Site (Summer line pipe)	m2/day	$ 5	10,992		360.0	$ 19,786,222	$ 22,536,507	$ 22,537
	SUB-TOTAL								$ 41,296
3.0	**Design, Preconstruction, and Construction Surveys**								

GNWT: MDLNG - Option 2 - Offshore Gas Pipeline with 1 GBS | 11-Mar-21

ID	Item	Unit Metric	Unit Cost CAD$	Quantity Metric	Mobilization / Demobilization Days	Unit Duration Days	Base Cost CAD	Escalated Cost CAD $1,000	Base Cost CAD $1,000
	Recommended Design Surveys								
	Pre-FEED Surveys								
	Spring over flood helicopter survey - strudel flight	day	$ 20,000	1		1	$ 20,000	$ 22,780	$ 23
	Mob/demob vessel to perform summer geophysical, bathymetry survey, and refractive sub-bottom profiling	day	$ 46,800	1	16		$ 748,800	$ 852,883	$ 853
	Summer geophysical, bathymetry survey, and refractive sub-bottom profiling	day	$ 78,000	1		11	$ 858,000	$ 977,262	$ 977
	Geotechnical Equipment mob/demob	LS	$ 15,000	1			$ 15,000	$ -	$ -
	Summer geotechnical (borehole survey)	day	$ 30,000	1		7	$ 210,000	$ 239,190	$ 239
	FEED Surveys								
	Spring over flood helicopter survey - strudel flight	day	$ 20,000	1		1	$ 20,000	$ 22,780	$ 23
	Mob/demob vessel to perform summer geophysical, bathymetry survey, and refractive sub-bottom profiling	day	$ 46,800		16.0		$ 748,800	$ 852,883	$ 853
	Summer geophysical, bathymetry survey, and refractive sub-bottom profiling	day	$ 78,000	1		6	$ 468,000	$ 533,052	$ 533
	Geotechnical Equipment mob/demob	LS	$ 15,000	1			$ 15,000	$ -	$ -
	Summer geotechnical (borehole survey)	day	$ 30,000	1		2	$ 60,000	$ 68,340	$ 68
	DETAILED Surveys								
	Spring over flood helicopter survey - strudel flight	day	$ 20,000	1		1	$ 20,000	$ 22,780	$ 23
	Mob/demob vessel to perform summer geophysical survey	day	$ 36,000	1	16		$ 576,000	$ 656,064	$ 656
	Summer geophysical survey	day	$ 60,000	1		4	$ 240,000	$ 273,360	$ 273
	Interphase Geophysical Surveys								
	Preconstruction Surveys								
	Mob/demob vessel to perform offshore pre-construction survey	day	$ 43,200	1	16		$ 691,200	$ 787,277	$ 787
	Conduct offshore preconstruction survey - Beaufort	day	$ 72,000	1		1	$ 72,000	$ 82,008	$ 82
	As-backfilled Survey								
	Mob/demob vessel to perform offshore as-backfilled	day	$ -						
	Conduct offshore as-backfilled survey	day	$ 72,000	1		4	$ 288,000	$ 328,032	$ 328
	SUB-TOTAL								$ 5,719
4.0	**Vessel Procurement and Upgrades**								
	Winterization and Arctic Modifications								
	Trenching and Backfilling								
	Cutter Suction Dredger (CSD)	LS	$ 15,000,000	1			$ 15,000,000	$ 17,085,000	$ 17,085
	Pipelay								
	Anchored Lay Barge	LS	$ 19,160,000	1			$ 19,160,000	$ 21,823,240	$ 21,823
	Pipelay Support Vessel	LS	$ 18,000,000	1			$ 18,000,000	$ 20,502,000	$ 20,502
	Support Vessels								
	Anchor Handling Tug / Work Boat	LS	$ 7,350,000	2			$ 14,700,000	$ 16,743,300	$ 16,743
	Pipe Carrier	LS	$ 5,470,000	2			$ 10,940,000	$ 12,460,660	$ 12,461
	Supply Vessels / Crew Boats	LS	$ 6,500,000	2			$ 13,000,000	$ 14,807,000	$ 14,807
	SUB-TOTAL								$ 103,421
5.0	**Offshore Trenching and Backfilling**								
	Mobilization/Demobilization								
	Mob/demob cutter suction dredger (CSD) - Trenching and Backfilling	day	$ 180,000	1	90		$ 16,200,000	$ 18,451,800	$ 18,452
	Trenching and Backfilling								
	Trench and backfill using cutter suction dredger (CSD)	day	$ 300,000			34	$ 10,303,575	$ 11,735,772	$ 11,736
	Monitor During Trenching and Backfilling								
	Mob/demob vessel to serve as workboat / crew boat / support vessel	day	$ 20,000	1	16		$ 320,000	$ 323,200	$ 323
	Workboat / crew boat / support vessel	day	$ 30,000			34	$ 1,030,358	$ 1,040,661	$ 1,041
	Mob/demob vessel for ROV monitoring of trenching and backfill activities	day	$ 50,000	1	16		$ 800,000	$ 808,000	$ 808
	ROV monitoring of trenching and backfill activities	day	$ 75,000			34	$ 2,575,894	$ 2,601,653	$ 2,602
	SUB-TOTAL								$ 34,961

GNWT: MDLNG - Option 2 - Offshore Gas Pipeline with 1 GBS 11-Mar-21

ID	Item	Unit Metric	Unit Cost CAD$	Quantity Metric	Mobilization / Demobilization Days	Unit Duration Days	Base Cost CAD	Escalated Cost CAD $1,000	Base Cost CAD $1,000
6.0	**Offshore Installation**								
	Anchored Lay Barge								
	Anchored barge mob/demobilization (includes 2 anchor handling/tow tugs)	day	$ 250,000	1	90		$ 22,500,000	$ 22,500,000	$ 22,500
	Anchored barge operational time (includes 2 anchor handling/tow tugs)	day	$ 500,000	1		17	$ 8,430,000	$ 8,430,000	$ 8,430
	Anchored barge operational time - GBS tie-in (includes 2 anchor handling/tow tugs)	day	$ 500,000	1		4	$ 2,000,000	$ 2,000,000	$ 2,000
	GBS Direct Pipe								
	Direct Pipe equipment mob/demobilization	LS	$ 1,050,000	1			$ 1,050,000	$ 1,195,950	$ 1,196
	Pipe delivery, misc. equipment, and personnel mob/demobilization	LS	$ 547,000	1			$ 547,000	$ 623,033	$ 623
	Operational day rate for equipment and crew	day	$ 240,000			16	$ 3,840,000	$ 4,373,760	$ 4,374
	Support Vessels and Activities								
	Mob/demob vessel to serve as workboat / crew boat / support vessel	day	$ 20,000	1	16		$ 320,000	$ 323,200	$ 323
	Workboat / crew boat / support vessel	day	$ 30,000	1		21	$ 625,800	$ 632,058	$ 632
	Mob/demob vessel for survey throughout construction and ROV survey of pipelay activities	day	$ 50,000	1	16		$ 800,000	$ 808,000	$ 808
	Survey throughout construction and ROV monitoring of pipelay activities	day	$ 75,000	1		21	$ 1,564,500	$ 1,580,145	$ 1,580
	SUB-TOTAL								$ 42,466
7.0	**Ice Management and Support**								
	Heavy Icebreaker								
	Mob/demobilize heavy icebreaker	day	$ 116,000	1	85		$ 9,860,000	$ 11,230,540	$ 11,231
	Heavy icebreaker on duty	day	$ 144,000	1		77	$ 11,088,000	$ 12,629,232	$ 12,629
	Light Icebreaker and Ice Monitoring								
	Mob/demobilize light icebreaker	day	$ 76,000	1	85		$ 6,460,000	$ 7,357,940	$ 7,358
	Light icebreaker on duty	day	$ 94,000	1		77	$ 7,238,000	$ 8,244,082	$ 8,244
	Weather/Ice monitoring during construction season	day	$ 15,000	1		80	$ 1,200,000	$ 1,366,800	$ 1,367
	Helicopter services	day	$ 20,000	1		80	$ 1,600,000	$ 1,822,400	$ 1,822
	SUB-TOTAL								$ 42,651
8.0	**On-ice Installation**								
	Project Management and Support								
	General Support Throughout On-ice Construction	day	$ 62,000	160			$ 9,920,000	$ 11,298,880	$ 11,299
	Arctic Civil Works								
	Activity 1: Ice Road Construction and Ice Thickening **24 hour operation (double shift)**								
	Grounded Ice Road Construction								
	Mob/demobilize construction crews and supervising personnel	person	$ 1,500	45	3		$ 202,500	$ 230,648	$ 231
	Mob/demobilize construction and maintenance equipment	day	$ 39,000		10		$ 390,000	$ 444,210	$ 444
	Grounded ice-road construction	day	$ 80,000			70	$ 5,600,000	$ 6,378,400	$ 6,378
	Grounded ice pad construction for equipment staging and trench spoils	day	$ 39,000			6	$ 234,000	$ 266,526	$ 267
	Floating Ice Road Construction								
	Mob/demobilize construction crews and supervising personnel	person	$ 1,500	45	3		$ 202,500	$ 230,648	$ 231
	Mob/demobilize construction and maintenance equipment	day	$ 39,000		10		$ 390,000	$ 444,210	$ 444
	Floating ice-road construction	day	$ 80,000			80	$ 6,400,000	$ 7,289,600	$ 7,290
	Maintenance								
	Grounded ice storage pad maintenance	km	$ 39,000	1.00			$ 39,000	$ 44,421	$ 44
	Grounded ice-road maintenance	km	$ 40,000	2.90			$ 116,000	$ 132,124	$ 132
	Floating ice-road maintenance	km	$ 50,000	7.10			$ 355,000	$ 404,345	$ 404
	Activity 2: Ice Cutting and Slotting **24 hour operation (double shift)**								
	Mob/demobilize construction crews and supervising personnel	person	$ 1,500	35	1		$ 52,500	$ 59,798	$ 60
	Mob/demobilize construction and maintenance equipment	day	$ 48,000		10		$ 480,000	$ 546,720	$ 547
	Cut slots in ice using trenchers, remove blocks using backhoes, and re-position blocks away from slots using front-end-loaders	day	$ 80,000			30	$ 2,400,000	$ 2,733,600	$ 2,734
	Additional trucks and loader to remove ice from floating ice section to grounded ice section	day	$ 17,000			30	$ 510,000	$ 580,890	$ 581

GNWT: MDLNG - Option 2 - Offshore Gas Pipeline with 1 GBS									11-Mar-21
ID	**Item**	**Unit Metric**	**Unit Cost CAD$**	**Quantity Metric**	**Mobilization / Demobilization Days**	**Unit Duration Days**	**Base Cost CAD**	**Escalated Cost CAD $1,000**	**Base Cost CAD $1,000**
	Activity 3: Trenching and Cleanout — **24 hour operation (double shift)**								
	Primary								
	Mob/demobilize construction crews and supervising personnel	person	$ 1,500	36	2		$ 108,000	$ 123,012	$ 123
	Mob/demobilize construction and maintenance equipment	day	$ 80,000		10		$ 800,000	$ 911,200	$ 911
	Primary excavation using 4 spreads	day	$ 150,000			35	$ 5,250,000	$ 5,979,750	$ 5,980
	Additional trucks to haul spoils from floating ice to grounded ice storage site	day	$ 10,000			35	$ 350,000	$ 398,650	$ 399
	On-going Cleanout Prior to Pipelay								
	Mob/demobilize construction crews and supervising personnel	person	$ 1,500	17	2		$ 51,000	$ 58,089	$ 58
	Mob/demobilize construction and maintenance equipment	day	$ 40,000		10		$ 400,000	$ 455,600	$ 456
	On-going trench cleanup using 3 spreads	day	$ 75,000			20	$ 1,500,000	$ 1,708,500	$ 1,709
	Arctic Pipeline Installation								
	Activity 4: Pipeline Make-Up Site Preparation — **12 hour operation (single shift)**								
	Mob/demobilize construction crews and supervising personnel	person	$ 1,500	40	1		$ 59,652	$ 67,943	$ 68
	Mob/demobilize construction and maintenance equipment	day	$ 40,000		10		$ 400,000	$ 455,600	$ 456
	Set-up on ice work site and string line pipe	day	$ 80,000			25	$ 2,000,000	$ 2,278,000	$ 2,278
	Activity 5: Pipe String Make-Up (Welding) — **24 hour operation (double shift)**								
	Offsite Welding and Preparation								
	Double joint (Weld/NDE/FJC) 30in line pipe	joint	$ 4,000	1,326			$ 5,304,000	$ 6,041,256	$ 6,041
	Install sacrificial anodes	anode	$ 750	118			$ 88,500	$ 100,802	$ 101
	On-ice Welding								
	Mob/demobilize construction crews and supervising personnel	person	$ 1,500	75	1		$ 112,500	$ 128,138	$ 128
	Mob/demobilize welding equipment spread	day	$ 84,000		10		$ 840,000	$ 956,760	$ 957
	Weld/NDE pipelines on-ice	day	$ 230,000			20	$ 4,600,000	$ 5,239,400	$ 5,239
	Field joint coating	joint	$ 150	431			$ 64,650	$ 73,636	$ 74
	String Make-Up — **24 hour operation (double shift)**								
	Pipelines								
	Mob/demobilize construction crews and supervising personnel	person	$ 1,500	15	1		$ 22,500	$ 25,628	$ 26
	Mob/demobilize equipment spread	day	$ 25,000		10		$ 250,000	$ 284,750	$ 285
	Prepare pipe strings (tie-in to previous strings, bundling, etc.)	day	$ 50,000			18	$ 900,000	$ 1,025,100	$ 1,025
	Fiber Optic Cable								
	Mob/demobilize fiber optic cable installation crew	person	$ 1,500	6	2		$ 18,000	$ 20,502	$ 21
	Mob/demobilize Fiber optic cable installation equipment	day	$ 10,000		10		$ 100,000	$ 113,900	$ 114
	Install fiber optic cable	day	$ 17,000			21	$ 357,000	$ 406,623	$ 407
	Activity 6: Pipeline Installation — **24 hour operation (double shift)**								
	Lay Pipeline - Grounded Ice								
	Mob/demobilize construction crews and supervising personnel	person	$ 1,500	45	1		$ 67,163	$ 76,499	$ 76
	Mob/demobilize equipment for pipeline installation	day	$ 80,000		10		$ 800,000	$ 911,200	$ 911
	Lower bundle into excavated trench on grounded ice using 7 long reach side booms	day	$ 190,000			6	$ 1,140,000	$ 1,298,460	$ 1,298
	Lay Pipeline - Floating Ice								
	Mob/demobilize construction crews and supervising personnel	person	$ 1,500	45	1		$ 67,163	$ 76,499	$ 76
	Mob/demobilize equipment for pipeline installation	day	$ 80,000		10		$ 800,000	$ 911,200	$ 911
	Lower bundle into excavated trench on grounded ice using 7 long reach side booms	day	$ 190,000			16	$ 3,040,000	$ 3,462,560	$ 3,463
	Shore Crossing								
	Mob/demobilize additional personnel for crane operations	person	$ 1,500	6	1		$ 9,000	$ 10,251	$ 10
	Mob/demobilize equipment	day	$ 25,000		10		$ 250,000	$ 284,750	$ 285
	Operations	day	$ 50,000			4	$ 200,000	$ 227,800	$ 228
	Saltwater plug and Shore Crossing Revegitation	LS	$ 500,000	1			$ 500,000	$ 569,500	$ 570
	Activity 7: Backfilling the Trench — **24 hour operation (double shift)**								
	Mob/demobilize construction crews and supervising personnel	person	$ 1,500	37	1		$ 55,620	$ 63,351	$ 63

GNWT: MDLNG - Option 2 - Offshore Gas Pipeline with 1 GBS 11-Mar-21

ID	Item	Unit Metric	Unit Cost CAD$	Quantity Metric	Mobilization / Demobilization Days	Unit Duration Days	Base Cost CAD	Escalated Cost CAD $1,000	Base Cost CAD $1,000
	Mob/demobilize backfilling equipment from Prudhoe	day	$ 55,000		10		$ 550,000	$ 626,450	$ 626
	Backfill trench	day	$ 110,000			30	$ 3,300,000	$ 3,758,700	$ 3,759
	Additional trucks and loaders to haul spoils back to floating ice from grounded ice storage site	day	$ 10,000			30	$ 300,000	$ 341,700	$ 342
	SUB-TOTAL								$ 70,557
9.0	**Offshore Precommissioning**								
	Export								
	Flooding, cleaning, and gauging	day	$ 400,000			3	$ 1,200,000	$ 1,366,800	$ 1,367
	Hydrotesting	day	$ 400,000			2	$ 800,000	$ 911,200	$ 911
	De-water and drying	day	$ 400,000			5	$ 2,000,000	$ 2,278,000	$ 2,278
	SUB-TOTAL								$ 4,556
10.0	**Onshore Construction Camp**								
	Construction and Operation								
	Operational cost for accommodations	person-days	$ 400	72,900			$ 29,160,000	$ 29,160,000	$ 29,160
	SUB-TOTAL								$ 29,160
11.0	**Engineering, Permitting Support, Project/Construction Management, and Contingency**								
	Percent of TIC Costs								
	Engineering design, Procurement, Project/Construction management - 10% of all subtotals	% of all subtotals	10%				$ 38,828,591	$ 42,631,464	$ 42,631
	Logistics - 2% of all subtotals	% of all subtotals	2%				$ 7,765,718	$ 8,526,293	$ 8,526
	Contingency								$ -
	Offshore pipeline contingency - 0% of total cost	% of total cost	0%				$ -	$ -	$ -
	SUB-TOTAL								$ 51,158
12.0	**Total Cost**								
	Total	$CAD					$ 434,880,218	$ 477,472,401	$ 434,880
	SI cost metric	$CAD/km	30.8 km						$ 14,124
	US cost metric	$CAD/mile	19.1 mi						$ 22,731

GNWT: MDLNG - Option 1 with 1 GBS - Offshore Gas and Condensate Pipelines with 1 GBS — 11-Mar-21

ID	Item	Unit Metric	Unit Cost CAD$	Quantity Metric	Mobilization / Demobilization Days	Unit Duration Days	Base Cost CAD	Escalated Cost CAD $1,000	Base Cost CAD $1,000
1.0	**Materials**								
	Pipeline Components								
	Gas Pipeline - 30 in OD x 1.5 in WT (Welded, API Spec5L X52)	mT	$ 1,900	21,990			$ 41,780,384	$ 41,780,384	$ 41,780
	Condensate pipeline - 10.75 in OD x 0.594 in WT (Seamless, API Spec5L X52)	mT	$ 2,400	3,103			$ 7,447,373	$ 7,447,373	$ 7,447
	Coatings, Anodes, and Insulation								
	External anti-corrosion coating - Fusion Bonded Epoxy (FBE)	sm	$ 28.00	105,138			$ 2,943,864	$ 2,973,302	$ 2,973
	Sacrificial anodes	kg	$ 7.15	48,121			$ 344,063	$ 347,504	$ 348
	Concrete weight coating (CWC)	kg	$ 0.85	6,376,688			$ 5,420,185	$ 6,173,591	$ 6,174
	10in Anode Tapers	anode	$ 120	342			$ 41,040	$ 46,745	$ 47
	30in Anode Tapers	anode	$ 370	352			$ 130,240	$ 148,343	$ 148
	Bundle spacers and straps	each	$ 170	1,721			$ 292,548	$ 333,212	$ 333
	Fiber Optic Cable								
	Fiber optic cable for offshore	m	$ 15.00	21,829			$ 327,435	$ 330,709	$ 331
	Fiber optic cable for on-ice (truck-able reels)	m	$ 15.00	10,494			$ 157,406	$ 158,980	$ 159
	Miscellaneous - 1% of materials								
	Miscellaneous materials (flanges, FOC splice kits, weld consumables, field joints, etc.)	% of materials	1%				$ 588,845	$ 597,401	$ 597
	SUB-TOTAL								$ 60,338
2.0	**Materials Transportation**								
	Logistics - Marine Based Transport to Beaufort Sea								
	Marine Shipping to Coating Plant (Japan to SE Asia)								
	Manufactured line pipe	mT	$ -	25,093					
	Mobilize local standard bulk freighters	day	$ 36,000	2	2		$ 144,000	$ 164,016	$ 164
	Port Fee: Load bare line pipe onto standard freighters	mT	$ 10.4	25,093			$ 260,965	$ 297,239	$ 297
	Ship line pipe via standard bulk freighter to coating plant (includes unloading time)	day	$ 36,000	2		15	$ 1,080,000	$ 1,230,120	$ 1,230
	Port Fee: Offloading line pipe at coating plant	mT	$ 10.4	25,093			$ 260,965	$ 297,239	$ 297
	Demobilize standard bulk freighters	day	$ 36,000	2	9		$ 648,000	$ 738,072	$ 738
	Coat pipe	-	$ -	-					
	Marine Shipping to Beaufort Sea (SE Asia to Kugmallit Bay)								
	Mobilize local freighters	day	$ 36,000	2	2		$ 144,000	$ 164,016	$ 164
	Port Fee: Load coated line pipe onto freighters	mT	$ 10.4	31,522			$ 327,828	$ 373,396	$ 373
	Ship coated line pipe via freighter from coating plant to offshore unloading area Canadian Beaufort (includes unloading time)	day	$ 36,000	2		26	$ 1,872,000	$ 2,132,208	$ 2,132
	Mobilize pipe barges from Anchorage	day	$ 15,000	3	19		$ 855,000	$ 973,845	$ 974
	Demobilize freighters	day	$ 36,000	2	20		$ 1,440,000	$ 1,640,160	$ 1,640
	Barge coated line pipe to receiving terminal in Tuktoyaktuk, Norwest Territories	day	$ 20,000	3		12	$ 720,000	$ 820,080	$ 820
	Port Fee: Offload barge into temporary storage facility in Tuktoyaktuk, Norwest Territories	mT	$ 20	31,522			$ 630,439	$ 718,070	$ 718
	Demobilize pipe barges back to Anchorage	mT	$ 15,000	3	19		$ 855,000	$ 973,845	$ 974
	Transfers								
	Offshore Pipelay								
	Mobilize barge (offshore installation only)	day	$ 15,000	2	19		$ 570,000	$ 649,230	$ 649
	Load shuttle barge for transfer to pipelay vessel (offshore installation only)	mT	$ 20	23,271			$ 465,423	$ 530,117	$ 530
	Shuttle line pipe to barge for offshore installation (offshore installation only) in Beaufort Sea	day	$ 20,000	2		35	$ 1,391,600	$ 1,585,032	$ 1,585
	Demobilize barge (offshore installation only)	day	$ 15,000	2	19		$ 570,000	$ 649,230	$ 649
	On-ice Construction								
	Port Fee: Load coated line pipe onto trucks	mT	$ 20	8,251			$ 165,016	$ 187,953	$ 188
	Mob/Demob 20 Trucks from Alberta	truck/day	$ 750	20		6	$ 90,000	$ 102,510	$ 103
	Transfer coated line pipe to pipeline Right-of-Way via truck (on-ice construction only) to on-ice construction Site	truck/day	$ 750	344			$ 257,837	$ 293,676	$ 294
	Unload coated line pipe at project site	mT	$ 20	8,251			$ 165,016	$ 187,953	$ 188
	Miscellaneous Materials								
	Transport Fiber optic cable for offshore	LS	$ 50,000				$ 50,000	$ 56,950	$ 57
	Transport Fiber optic cable for on-ice (truck-able reels)	LS	$ 25,000				$ 25,000	$ 28,475	$ 28
	Tuktoyaktuk Port Storage Site (Winter line pipe)	m2/day	$ 5	5,495		180.0	$ 4,945,652	$ 5,633,098	$ 5,633
	Tuktoyaktuk Port Storage Site (Summer line pipe)	m2/day	$ 5	12,427		360.0	$ 22,368,298	$ 25,477,492	$ 25,477

GNWT: MDLNG - Option 1 with 1 GBS - Offshore Gas and Condensate Pipelines with 1 GBS										11-Mar-21
ID	Item	Unit Metric	Unit Cost CAD$	Quantity Metric	Mobilization / Demobilization Days	Unit Duration Days	Base Cost CAD	Escalated Cost CAD $1,000	Base Cost CAD $1,000
	SUB-TOTAL								$ 45,904

GNWT: MDLNG - Option 1 with 1 GBS - Offshore Gas and Condensate Pipelines with 1 GBS										11-Mar-21
ID	**Item**	**Unit Metric**	**Unit Cost CAD$**	**Quantity Metric**	**Mobilization / Demobilization Days**	**Unit Duration Days**	**Base Cost CAD**	**Escalated Cost CAD $1,000**	**Base Cost CAD $1,000**	
3.0	**Design, Preconstruction, and Construction Surveys**									
	Recommended Design Surveys									
	Pre-FEED Surveys									
	Spring over flood helicopter survey - strudel flight	day	$ 20,000	1		1	$ 20,000	$ 22,780	$ 23	
	Mob/demob vessel to perform summer geophysical, bathymetry survey, and refractive sub-bottom profiling	day	$ 46,800	1	16		$ 748,800	$ 852,883	$ 853	
	Summer geophysical, bathymetry survey, and refractive sub-bottom profiling	day	$ 78,000	1		11	$ 858,000	$ 977,262	$ 977	
	Geotechnical Equipment mob/demob	LS	$ 15,000	1			$ 15,000	$ -	$ -	
	Summer geotechnical (borehole survey)	day	$ 30,000	1		7	$ 210,000	$ 239,190	$ 239	
	FEED Surveys									
	Spring over flood helicopter survey - strudel flight	day	$ 20,000	1		1	$ 20,000	$ 22,780	$ 23	
	Mob/demob vessel to perform summer geophysical, bathymetry survey, and refractive sub-bottom profiling	day	$ 46,800	1	16		$ 748,800	$ 852,883	$ 853	
	Summer geophysical, bathymetry survey, and refractive sub-bottom profiling	day	$ 78,000	1		6	$ 468,000	$ 533,052	$ 533	
	Geotechnical Equipment mob/demob	LS	$ 15,000	1			$ 15,000	$ -	$ -	
	Summer geotechnical (borehole survey)	day	$ 30,000	1		2	$ 60,000	$ 68,340	$ 68	
	DETAILED Surveys									
	Spring over flood helicopter survey - strudel flight	day	$ 20,000	1		1	$ 20,000	$ 22,780	$ 23	
	Mob/demob vessel to perform summer geophysical survey	day	$ 36,000	1	16		$ 576,000	$ 656,064	$ 656	
	Summer geophysical survey	day	$ 60,000	1		4	$ 240,000	$ 273,360	$ 273	
	Interphase Geophysical Surveys									
	Preconstruction Surveys									
	Mob/demob vessel to perform offshore pre-construction survey	day	$ 43,200	1	16		$ 691,200	$ 787,277	$ 787	
	Conduct offshore preconstruction survey - Beaufort	day	$ 72,000	1		1	$ 72,000	$ 82,008	$ 82	
	As-backfilled Survey									
	Mob/demob vessel to perform offshore as-backfilled	day	$ -							
	Conduct offshore as-backfilled survey	day	$ 72,000	1		4	$ 288,000	$ 328,032	$ 328	
	SUB-TOTAL								$ 5,719	
4.0	**Vessel Procurement and Upgrades**									
	Winterization and Arctic Modifications									
	Trenching and Backfilling									
	Cutter Suction Dredger (CSD)	LS	$ 15,000,000	1			$ 15,000,000	$ 17,085,000	$ 17,085	
	Pipelay									
	Anchored Lay Barge	LS	$ 19,160,000	1			$ 19,160,000	$ 21,823,240	$ 21,823	
	Pipelay Support Vessel	LS	$ 18,000,000	1			$ 18,000,000	$ 20,502,000	$ 20,502	
	Support Vessels									
	Anchor Handling Tug / Work Boat	LS	$ 7,350,000	2			$ 14,700,000	$ 16,743,300	$ 16,743	
	Pipe Carrier	LS	$ 5,470,000	2			$ 10,940,000	$ 12,460,660	$ 12,461	
	Supply Vessels / Crew Boats	LS	$ 6,500,000	2			$ 13,000,000	$ 14,807,000	$ 14,807	
	SUB-TOTAL								$ 103,421	
5.0	**Offshore Trenching and Backfilling**									
	Mobilization/Demobilization									
	Mob/demob cutter suction dredger (CSD) - Trenching and Backfilling	day	$ 180,000	1	90		$ 16,200,000	$ 18,451,800	$ 18,452	
	Trenching and Backfilling									
	Trench and backfill using cutter suction dredger (CSD)	day	$ 300,000			44.4	$ 13,320,165	$ 15,171,668	$ 15,172	
	Monitor During Trenching and Backfilling									
	Mob/demob vessel to serve as workboat / crew boat / support vessel	day	$ 20,000	1	16		$ 320,000	$ 323,200	$ 323	
	Workboat / crew boat / support vessel	day	$ 30,000			44	$ 1,332,017	$ 1,345,337	$ 1,345	
	Mob/demob vessel for ROV monitoring of trenching and backfill activities	day	$ 50,000	1	16		$ 800,000	$ 808,000	$ 808	
	ROV monitoring of trenching and backfill activities	day	$ 75,000			44	$ 3,330,041	$ 3,363,342	$ 3,363	

GNWT: MDLNG - Option 1 with 1 GBS - Offshore Gas and Condensate Pipelines with 1 GBS										11-Mar-21
ID	**Item**	**Unit** **Metric**	**Unit Cost** **CAD$**	**Quantity** **Metric**	**Mobilization / Demobilization** **Days**	**Unit Duration** **Days**	**Base Cost** **CAD**	**Escalated Cost** **CAD $1,000**	**Base Cost** **CAD $1,000**
	SUB-TOTAL								$ 39,463
6.0	**Offshore Installation**								
	Anchored Lay Barge								
	Anchored barge mob/demobilization (includes 2 anchor handling/tow tugs)	day	$ 250,000	1	90		$ 22,500,000	$ 22,500,000	$ 22,500
	Anchored barge operational time (includes 2 anchor handling/tow tugs)	day	$ 500,000	1		27	$ 13,395,000	$ 13,395,000	$ 13,395
	Anchored barge operational time - GBS tie-in (includes 2 anchor handling/tow tugs)	day	$ 500,000	1		8	$ 4,000,000	$ 4,000,000	$ 4,000
	GBS Direct Pipe								
	Direct Pipe equipment mob/demobilization	LS	$ 1,050,000	1			$ 1,050,000	$ 1,195,950	$ 1,196
	Pipe delivery, misc. equipment, and personnel mob/demobilization	LS	$ 1,094,000	1			$ 1,094,000	$ 1,246,066	$ 1,246
	Operational day rate for equipment and crew	day	$ 240,000			32	$ 7,680,000	$ 8,747,520	$ 8,748
	Support Vessels and Activities								
	Mob/demob vessel to serve as workboat / crew boat / support vessel	day	$ 20,000	1	16		$ 320,000	$ 323,200	$ 323
	Workboat / crew boat / support vessel	day	$ 30,000	1		35	$ 1,043,700	$ 1,054,137	$ 1,054
	Mob/demob vessel for survey throughout construction and ROV survey of pipelay activities	day	$ 50,000	1	16		$ 800,000	$ 808,000	$ 808
	Survey throughout construction and ROV monitoring of pipelay activities	day	$ 75,000	1		35	$ 2,609,250	$ 2,635,343	$ 2,635
	SUB-TOTAL								$ 55,905
7.0	**Ice Management and Support**								
	Heavy Icebreaker								
	Mob/demobilize heavy icebreaker	day	$ 116,000	1	85		$ 9,860,000	$ 11,230,540	$ 11,231
	Heavy icebreaker on duty	day	$ 144,000	1		77	$ 11,088,000	$ 12,629,232	$ 12,629
	Light Icebreaker and Ice Monitoring								
	Mob/demobilize light icebreaker	day	$ 76,000	1	85		$ 6,460,000	$ 7,357,940	$ 7,358
	Light icebreaker on duty	day	$ 94,000	1		77	$ 7,238,000	$ 8,244,082	$ 8,244
	Weather/Ice monitoring during construction season	day	$ 15,000	1		80	$ 1,200,000	$ 1,366,800	$ 1,367
	Helicopter services	day	$ 20,000	1		80	$ 1,600,000	$ 1,822,400	$ 1,822
	SUB-TOTAL								$ 42,651
8.0	**On-ice Installation**								
	Project Management and Support								
	General Support Throughout On-ice Construction	day	$ 62,000	160			$ 9,920,000	$ 11,298,880	$ 11,299
	Arctic Civil Works								
	Activity 1: Ice Road Construction and Ice Thickening **24 hour operation (double shift)**								
	Grounded Ice Road Construction								
	Mob/demobilize construction crews and supervising personnel	person	$ 1,500	45	3		$ 202,500	$ 230,648	$ 231
	Mob/demobilize construction and maintenance equipment	day	$ 39,000		10		$ 390,000	$ 444,210	$ 444
	Grounded ice-road construction	day	$ 80,000			70	$ 5,600,000	$ 6,378,400	$ 6,378
	Grounded ice pad construction for equipment staging and trench spoils	day	$ 39,000			6	$ 234,000	$ 266,526	$ 267
	Floating Ice Road Construction								
	Mob/demobilize construction crews and supervising personnel	person	$ 1,500	45	3		$ 202,500	$ 230,648	$ 231
	Mob/demobilize construction and maintenance equipment	day	$ 39,000		10		$ 390,000	$ 444,210	$ 444
	Floating ice-road construction	day	$ 80,000			80	$ 6,400,000	$ 7,289,600	$ 7,290
	Maintenance								
	Grounded ice storage pad maintenance	km	$ 39,000	1.00			$ 39,000	$ 44,421	$ 44
	Grounded ice-road maintenance	km	$ 40,000	2.90			$ 116,000	$ 132,124	$ 132
	Floating ice-road maintenance	km	$ 50,000	7.10			$ 355,000	$ 404,345	$ 404
	Activity 2: Ice Cutting and Slotting **24 hour operation (double shift)**								
	Mob/demobilize construction crews and supervising personnel	person	$ 1,500	35	1		$ 52,500	$ 59,798	$ 60
	Mob/demobilize construction and maintenance equipment	day	$ 48,000		10		$ 480,000	$ 546,720	$ 547
	Cut slots in ice using trenchers, remove blocks using backhoes, and re-position blocks away from slots using front-end-loaders	day	$ 80,000			30	$ 2,400,000	$ 2,733,600	$ 2,734

GNWT: MDLNG - Option 1 with 1 GBS - Offshore Gas and Condensate Pipelines with 1 GBS 11-Mar-21

ID Item	Unit Metric	Unit Cost CAD$	Quantity Metric	Mobilization / Demobilization Days	Unit Duration Days	Base Cost CAD	Escalated Cost CAD $1,000	Base Cost CAD $1,000
Additional trucks and loader to remove ice from floating ice section to grounded ice section	day	$ 17,000			30	$ 510,000	$ 580,890	$ 581
Activity 3: Trenching and Cleanout **24 hour operation (double shift)**								
Primary								
Mob/demobilize construction crews and supervising personnel	person	$ 1,500	36	2		$ 108,000	$ 123,012	$ 123
Mob/demobilize construction and maintenance equipment	day	$ 80,000		10		$ 800,000	$ 911,200	$ 911
Primary excavation using 4 spreads	day	$ 150,000			35	$ 5,250,000	$ 5,979,750	$ 5,980
Additional trucks to haul spoils from floating ice to grounded ice storage site	day	$ 10,000			35	$ 350,000	$ 398,650	$ 399
On-going Cleanout Prior to Pipelay								
Mob/demobilize construction crews and supervising personnel	person	$ 1,500	17	2		$ 51,000	$ 58,089	$ 58
Mob/demobilize construction and maintenance equipment	day	$ 40,000		10		$ 400,000	$ 455,600	$ 456
On-going trench cleanup using 2 spreads	day	$ 75,000			20	$ 1,500,000	$ 1,708,500	$ 1,709
Arctic Pipeline Installation								
Activity 4: Pipeline Make-Up Site Preparation **12 hour operation (single shift)**								
Mob/demobilize construction crews and supervising personnel	person	$ 1,500	40	1		$ 59,652	$ 67,943	$ 68
Mob/demobilize construction and maintenance equipment	day	$ 40,000		10		$ 400,000	$ 455,600	$ 456
Set-up on ice work site and string line pipe	day	$ 80,000			25	$ 2,000,000	$ 2,278,000	$ 2,278
Activity 5: Pipe String Make-Up (Welding) **24 hour operation (double shift)**								
Offsite Welding and Preparation								
Double joint (Weld/NDE/FJC) 10in line pipe	joint	$ 1,200	1,326			$ 1,591,200	$ 1,812,377	$ 1,812
Double joint (Weld/NDE/FJC) 30in line pipe	joint	$ 4,000	1,326			$ 5,304,000	$ 6,041,256	$ 6,041
Install sacrificial anodes	anode	$ 750	229			$ 171,837	$ 195,722	$ 196
On-ice Welding								
Mob/demobilize construction crews and supervising personnel	person	$ 1,500	75	1		$ 112,500	$ 128,138	$ 128
Mob/demobilize welding equipment spread	day	$ 84,000		10		$ 840,000	$ 956,760	$ 957
Weld/NDE pipelines on-ice	day	$ 230,000			28	$ 6,440,000	$ 7,335,160	$ 7,335
Field joint coating	joint	$ 150	862			$ 129,300	$ 147,273	$ 147
String Make-Up **24 hour operation (double shift)**								
Pipelines								
Mob/demobilize construction crews and supervising personnel	person	$ 1,500	15	1		$ 22,500	$ 25,628	$ 26
Mob/demobilize equipment spread	day	$ 25,000		10		$ 250,000	$ 284,750	$ 285
Prepare pipe strings (tie-in to previous strings, bundling, etc.)	day	$ 50,000			21	$ 1,050,000	$ 1,195,950	$ 1,196
Fiber Optic Cable								
Mob/demobilize fiber optic cable installation crew	person	$ 1,500	6	2		$ 18,000	$ 20,502	$ 21
Mob/demobilize Fiber optic cable installation equipment	day	$ 10,000		10		$ 100,000	$ 113,900	$ 114
Install fiber optic cable	day	$ 17,000			21	$ 357,000	$ 406,623	$ 407

GNWT: MDLNG - Option 1 with 1 GBS - Offshore Gas and Condensate Pipelines with 1 GBS | 11-Mar-21

ID	Item	Unit Metric	Unit Cost CAD$	Quantity Metric	Mobilization / Demobilization Days	Unit Duration Days	Base Cost CAD	Escalated Cost CAD $1,000	Base Cost CAD $1,000
	Activity 6: Pipeline Installation **24 hour operation (double shift)**								
	Lay Pipeline - Grounded Ice								
	Mob/demobilize construction crews and supervising personnel	person	$ 1,500	45	1		$ 67,163	$ 76,499	$ 76
	Mob/demobilize equipment for pipeline installation	day	$ 80,000		10		$ 800,000	$ 911,200	$ 911
	Lower bundle into excavated trench on grounded ice using 7 long reach side booms	day	$ 190,000			6	$ 1,140,000	$ 1,298,460	$ 1,298
	Lay Pipeline - Floating Ice								
	Mob/demobilize construction crews and supervising personnel	person	$ 1,500	45	1		$ 67,163	$ 76,499	$ 76
	Mob/demobilize equipment for pipeline installation	day	$ 80,000		10		$ 800,000	$ 911,200	$ 911
	Lower bundle into excavated trench on grounded ice using 7 long reach side booms	day	$ 190,000			16	$ 3,040,000	$ 3,462,560	$ 3,463
	Shore Crossing								
	Mob/demobilize additional personnel for crane operations	person	$ 1,500	6	1		$ 9,000	$ 10,251	$ 10
	Mob/demobilize equipment	day	$ 25,000		10		$ 250,000	$ 284,750	$ 285
	Operations	day	$ 50,000			4	$ 200,000	$ 227,800	$ 228
	Saltwater plug and Shore Crossing Revegitation	LS	$ 500,000	1			$ 500,000	$ 569,500	$ 570
	Activity 7: Backfilling the Trench **24 hour operation (double shift)**								
	Mob/demobilize construction crews and supervising personnel	person	$ 1,500	37	1		$ 55,620	$ 63,351	$ 63
	Mob/demobilize backfilling equipment from Prudhoe	day	$ 55,000		10		$ 550,000	$ 626,450	$ 626
	Backfill trench	day	$ 110,000			30	$ 3,300,000	$ 3,758,700	$ 3,759
	Additional trucks and loaders to haul spoils back to floating ice from grounded ice storage site	day	$ 10,000			30	$ 300,000	$ 341,700	$ 342
	SUB-TOTAL								$ 74,804
9.0	**Offshore Precommissioning**								
	Export								
	Flooding, cleaning, and gauging	day	$ 400,000			4	$ 1,600,000	$ 1,822,400	$ 1,822
	Hydrotesting	day	$ 400,000			3	$ 1,200,000	$ 1,366,800	$ 1,367
	De-water and drying	day	$ 400,000			5	$ 2,000,000	$ 2,278,000	$ 2,278
	SUB-TOTAL								$ 5,467
10.0	**Onshore Construction Camp**								
	Construction and Operation								
	Operational cost for accommodations	person-days	$ 400	72,900			$ 29,160,000		$ 29,160
	SUB-TOTAL								$ 29,160
11.0	**Engineering, Permitting Support, Project/Construction Management, and Contingency**								
	Percent of TIC Costs								
	Engineering design, Procurement, Project/Construction management - 10% of all subtotals	% of all subtotals	10%				$ 42,250,183	$ 43,367,253	$ 43,367
	Logistics - 2% of all subtotals	% of all subtotals	2%				$ 8,450,037	$ 8,673,451	$ 8,673
	Contingency								
	Offshore pipeline contingency - 0% of total cost	% of total cost	0%				$ -	$ -	$ -
	SUB-TOTAL								$ 52,041
12.0	**Total Cost**								
	Total	$CAD					$ 473,202,048	$ 485,713,237	$ 485,713
	SI cost metric	$CAD/km	30.8 km						$ 15,775
	US cost metric	$CAD/mile	19.1 mi						$ 25,387

GNWT: MDLNG - Option 1 with 1 GBS and power cable - Offshore Gas and Condensate Pipelines with 1 GBS and power cable — 11-Mar-21

ID	Item	Unit Metric	Unit Cost CAD$	Quantity Metric	Mobilization / Demobilization Days	Unit Duration Days	Base Cost CAD	Escalated Cost CAD $1,000	Base Cost CAD $1,000
1.0	**Materials**								
	Pipeline Components								
	Gas Pipeline - 30 in OD x 1.5 in WT (Welded, API Spec5L X52)	mT	$ 1,900	21,990			$ 41,780,384	$ 41,780,384	$ 41,780
	Condensate pipeline - 10.75 in OD x 0.594 in WT (Seamless, API Spec5L X52)	mT	$ 2,400	3,103			$ 7,447,373	$ 7,447,373	$ 7,447
	Coatings, Anodes, and Insulation								
	External anti-corrosion coating - Fusion Bonded Epoxy (FBE)	sm	$ 28.00	105,138			$ 2,943,864	$ 2,973,302	$ 2,973
	Sacrificial anodes	kg	$ 7.15	48,121			$ 344,063	$ 347,504	$ 348
	Concrete weight coating (CWC)	kg	$ 0.85	6,376,688			$ 5,420,185	$ 6,173,591	$ 6,174
	10in Anode Tapers	anode	$ 120	342			$ 41,040	$ 46,745	$ 47
	30in Anode Tapers	anode	$ 370	352			$ 130,240	$ 148,343	$ 148
	Bundle spacers and straps	each	$ 170	1,721			$ 292,548	$ 333,212	$ 333
	Power Cable								
	Power cable for offshore	m	$ 1,890.00	21,836			$ 41,269,798	$ 41,269,798	$ 41,270
	Power cable for on-ice (truck-able reels)	m	$ 1,890.00	10,497			$ 19,839,920	$ 19,839,920	$ 19,840
	Fiber Optic Cable								
	Fiber optic cable for offshore	m	$ 15.00	21,829			$ 327,435	$ 330,709	$ 331
	Fiber optic cable for on-ice (truck-able reels)	m	$ 15.00	10,494			$ 157,406	$ 158,980	$ 159
	Miscellaneous - 1% of materials								
	Miscellaneous materials (flanges, FOC splice kits, weld consumables, field joints, etc.)	% of materials	1%				$ 1,199,943	$ 1,208,499	$ 1,208
	SUB-TOTAL								$ 122,058
2.0	**Materials Transportation**								
	Logistics - Marine Based Transport to Beaufort Sea								
	Marine Shipping to Coating Plant (Japan to SE Asia)								
	Manufactured line pipe	mT	$ -	25,093					
	Mobilize local standard bulk freighters	day	$ 36,000	2	2		$ 144,000	$ 164,016	$ 164
	Port Fee: Load bare line pipe onto standard freighters	mT	$ 10.4	25,093			$ 260,965	$ 297,239	$ 297
	Ship line pipe via standard bulk freighter to coating plant (includes unloading time)	day	$ 36,000	2		15	$ 1,080,000	$ 1,230,120	$ 1,230
	Port Fee: Offloading line pipe at coating plant	mT	$ 10.4	25,093			$ 260,965	$ 297,239	$ 297
	Demobilize standard bulk freighters	day	$ 36,000	2	9		$ 648,000	$ 738,072	$ 738
	Coat pipe	-	$ -	-					
	Marine Shipping to Beaufort Sea (SE Asia to Kugmallit Bay)								
	Mobilize local freighters	day	$ 36,000	2	2		$ 144,000	$ 164,016	$ 164
	Port Fee: Load coated line pipe onto freighters	mT	$ 10.4	31,522			$ 327,828	$ 373,396	$ 373
	Ship coated line pipe via freighter from coating plant to offshore unloading area Canadian Beaufort (includes unloading time)	day	$ 36,000	2		26	$ 1,872,000	$ 2,132,208	$ 2,132
	Mobilize pipe barges from Anchorage	day	$ 15,000	3	19		$ 855,000	$ 973,845	$ 974
	Demobilize freighters	day	$ 36,000	2	20		$ 1,440,000	$ 1,640,160	$ 1,640
	Barge coated line pipe to receiving terminal in Tuktoyaktuk, Norwest Territories	day	$ 20,000	3		12	$ 720,000	$ 820,080	$ 820
	Port Fee: Offload barge into temporary storage facility in Tuktoyaktuk, Norwest Territories	mT	$ 20	31,522			$ 630,439	$ 718,070	$ 718
	Demobilize pipe barges back to Anchorage	mT	$ 15,000	3	19		$ 855,000	$ 973,845	$ 974
	Transfers								
	Offshore Pipelay								
	Mobilize barge (offshore installation only)	day	$ 15,000	2	19		$ 570,000	$ 649,230	$ 649
	Load shuttle barge for transfer to pipelay vessel (offshore installation only)	mT	$ 20	23,271			$ 465,423	$ 530,117	$ 530
	Shuttle line pipe to barge for offshore installation (offshore installation only) in Beaufort Sea	day	$ 20,000	2		35	$ 1,391,600	$ 1,585,032	$ 1,585
	Demobilize barge (offshore installation only)	day	$ 15,000	2	19		$ 570,000	$ 649,230	$ 649
	On-ice Construction								
	Port Fee: Load coated line pipe onto trucks	mT	$ 20	8,251			$ 165,016	$ 187,953	$ 188
	Mob/Demob 20 Trucks from Alberta	truck/day	$ 750	20		6	$ 90,000	$ 102,510	$ 103
	Transfer coated line pipe to pipeline Right-of-Way via truck (on-ice construction only) to on-ice construction Site	truck/day	$ 750	344			$ 257,837	$ 293,676	$ 294
	Unload coated line pipe at project site	mT	$ 20	8,251			$ 165,016	$ 187,953	$ 188
	Miscellaneous Materials								
	Transport Power cable for offshore	LS	$ 150,000				$ 150,000	$ 170,850	$ 171
	Transport Power cable for on-ice (truck-able reels)	LS	$ 150,000				$ 150,000	$ 170,850	$ 171

GNWT: MDLNG - Option 1 with 1 GBS and power cable - Offshore Gas and Condensate Pipelines with 1 GBS and power cable									11-Mar-21
ID Item	Unit Metric	Unit Cost CAD$	Quantity Metric	Mobilization / Demobilization Days	Unit Duration Days	Base Cost CAD	Escalated Cost CAD $1,000	Base Cost CAD $1,000
Transport Fiber optic cable for offshore	LS	$ 50,000				$ 50,000	$ 56,950	$ 57
Transport Fiber optic cable for on-ice (truck-able reels)	LS	$ 25,000				$ 25,000	$ 28,475	$ 28
Tuktoyaktuk Port Storage Site (Winter line pipe)	m2/day	$ 5	5,495		180.0	$ 4,945,652	$ 5,633,098	$ 5,633
Tuktoyaktuk Port Storage Site (Summer line pipe)	m2/day	$ 5	12,427		360.0	$ 22,368,298	$ 25,477,492	$ 25,477
SUB-TOTAL								$ 46,246

ID	Item	Unit Metric	Unit Cost CAD$	Quantity Metric	Mobilization / Demobilization Days	Unit Duration Days	Base Cost CAD	Escalated Cost CAD $1,000	Base Cost CAD $1,000
3.0	**Design, Preconstruction, and Construction Surveys**								
	Recommended Design Surveys								
	Pre-FEED Surveys								
	Spring over flood helicopter survey - strudel flight	day	$ 20,000	1		1	$ 20,000	$ 22,780	$ 23
	Mob/demob vessel to perform summer geophysical, bathymetry survey, and refractive sub-bottom profiling	day	$ 46,800	1	16		$ 748,800	$ 852,883	$ 853
	Summer geophysical, bathymetry survey, and refractive sub-bottom profiling	day	$ 78,000	1		11	$ 858,000	$ 977,262	$ 977
	Geotechnical Equipment mob/demob	LS	$ 15,000	1			$ 15,000	$ 17,085	$ 17
	Summer geotechnical (borehole survey)	day	$ 30,000	1		7	$ 210,000	$ 239,190	$ 239
	FEED Surveys								
	Spring over flood helicopter survey - strudel flight	day	$ 20,000	1		1	$ 20,000	$ 22,780	$ 23
	Mob/demob vessel to perform summer geophysical, bathymetry survey, and refractive sub-bottom profiling	day	$ 46,800	1	16		$ 748,800	$ 852,883	$ 853
	Summer geophysical, bathymetry survey, and refractive sub-bottom profiling	day	$ 78,000	1		6	$ 468,000	$ 533,052	$ 533
	Geotechnical Equipment mob/demob	LS	$ 15,000	1			$ 15,000	$ 17,085	$ 17
	Summer geotechnical (borehole survey)	day	$ 30,000	1		2	$ 60,000	$ 68,340	$ 68
	DETAILED Surveys								
	Spring over flood helicopter survey - strudel flight	day	$ 20,000	1		1	$ 20,000	$ 22,780	$ 23
	Mob/demob vessel to perform summer geophysical survey	day	$ 36,000	1	16		$ 576,000	$ 656,064	$ 656
	Summer geophysical survey	day	$ 60,000	1		4	$ 240,000	$ 273,360	$ 273
	Interphase Geophysical Surveys								
	Preconstruction Surveys								
	Mob/demob vessel to perform offshore pre-construction survey	day	$ 43,200	1	16		$ 691,200	$ 787,277	$ 787
	Conduct offshore preconstruction survey - Beaufort	day	$ 72,000	1		1	$ 72,000	$ 82,008	$ 82
	As-backfilled Survey								
	Mob/demob vessel to perform offshore as-backfilled	day	$ -						
	Conduct offshore as-backfilled survey	day	$ 72,000	1		4	$ 288,000	$ 328,032	$ 328
	SUB-TOTAL								$ 5,753
4.0	**Vessel Procurement and Upgrades**								
	Winterization and Arctic Modifications								
	Trenching and Backfilling								
	Cutter Suction Dredger (CSD)	LS	$ 15,000,000	1			$ 15,000,000	$ 17,085,000	$ 17,085
	Pipelay								
	Anchored Lay Barge	LS	$ 19,160,000	1			$ 19,160,000	$ 21,823,240	$ 21,823
	Pipelay Support Vessel	LS	$ 18,000,000	1			$ 18,000,000	$ 20,502,000	$ 20,502
	Support Vessels								
	Anchor Handling Tug / Work Boat	LS	$ 7,350,000	2			$ 14,700,000	$ 16,743,300	$ 16,743
	Pipe Carrier	LS	$ 5,470,000	2			$ 10,940,000	$ 12,460,660	$ 12,461
	Supply Vessels / Crew Boats	LS	$ 6,500,000	2			$ 13,000,000	$ 14,807,000	$ 14,807
	SUB-TOTAL								$ 103,421
5.0	**Offshore Trenching and Backfilling**								
	Mobilization/Demobilization								
	Mob/demob cutter suction dredger (CSD) - Trenching and Backfilling	day	$ 180,000	1	90		$ 16,200,000	$ 18,451,800	$ 18,452
	Trenching and Backfilling								
	Trench and backfill using cutter suction dredger (CSD)	day	$ 300,000			44.4	$ 13,320,165	$ 15,171,668	$ 15,172
	Monitor During Trenching and Backfilling								
	Mob/demob vessel to serve as workboat / crew boat / support vessel	day	$ 20,000	1	16		$ 320,000	$ 323,200	$ 323
	Workboat / crew boat / support vessel	day	$ 30,000			44	$ 1,332,017	$ 1,345,337	$ 1,345
	Mob/demob vessel for ROV monitoring of trenching and backfill activities	day	$ 50,000	1	16		$ 800,000	$ 808,000	$ 808
	ROV monitoring of trenching and backfill activities	day	$ 75,000			44	$ 3,330,041	$ 3,363,342	$ 3,363

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ID	**Item**	**Unit Metric**	**Unit Cost CAD$**	**Quantity Metric**	**Mobilization / Demobilization Days**	**Unit Duration Days**	**Base Cost CAD**	**Escalated Cost CAD $1,000**	**Base Cost CAD $1,000**	
	SUB-TOTAL								$ 39,463	
6.0	**Offshore Installation**									
	Anchored Lay Barge									
	Anchored barge mob/demobilization (includes 2 anchor handling/tow tugs)	day	$ 250,000	1	90		$ 22,500,000	$ 22,500,000	$ 22,500	
	Anchored barge operational time (includes 2 anchor handling/tow tugs)	day	$ 500,000	1		27	$ 13,395,000	$ 13,395,000	$ 13,395	
	Anchored barge operational time - GBS tie-in (includes 2 anchor handling/tow tugs)	day	$ 500,000	1		8	$ 4,000,000	$ 4,000,000	$ 4,000	
	Power Cable Lay									
	Cable lay vessel mob/demobilization	day	$ 123,000	1	50.0		$ 6,150,000	$ 7,004,850	$ 7,005	
	Cable lay time, including trenching	day	$ 205,000	1		11	$ 2,255,000	$ 2,568,445	$ 2,568	
	GBS Direct Pipe									
	Direct Pipe equipment mob/demobilization	LS	$ 1,050,000	1			$ 1,050,000	$ 1,195,950	$ 1,196	
	Pipe delivery, misc. equipment, and personnel mob/demobilization	LS	$ 1,641,000	1			$ 1,641,000	$ 1,869,099	$ 1,869	
	Operational day rate for equipment and crew	day	$ 240,000			42	$ 10,080,000	$ 11,481,120	$ 11,481	
	Support Vessels and Activities									
	Mob/demob vessel to serve as workboat / crew boat / support vessel	day	$ 20,000	1	16		$ 320,000	$ 323,200	$ 323	
	Workboat / crew boat / support vessel	day	$ 30,000	1		35	$ 1,043,700	$ 1,054,137	$ 1,054	
	Mob/demob vessel for survey throughout construction and ROV survey of pipelay activities	day	$ 50,000	1	16		$ 800,000	$ 808,000	$ 808	
	Survey throughout construction and ROV monitoring of pipelay activities	day	$ 75,000	1		35	$ 2,609,250	$ 2,635,343	$ 2,635	
	SUB-TOTAL								$ 68,835	
7.0	**Ice Management and Support**									
	Heavy Icebreaker									
	Mob/demobilize heavy icebreaker	day	$ 116,000	1	85		$ 9,860,000	$ 11,230,540	$ 11,231	
	Heavy icebreaker on duty	day	$ 144,000	1		77	$ 11,088,000	$ 12,629,232	$ 12,629	
	Light Icebreaker and Ice Monitoring									
	Mob/demobilize light icebreaker	day	$ 76,000	1	85		$ 6,460,000	$ 7,357,940	$ 7,358	
	Light icebreaker on duty	day	$ 94,000	1		77	$ 7,238,000	$ 8,244,082	$ 8,244	
	Weather/Ice monitoring during construction season	day	$ 15,000	1		80	$ 1,200,000	$ 1,366,800	$ 1,367	
	Helicopter services	day	$ 20,000	1		80	$ 1,600,000	$ 1,822,400	$ 1,822	
	SUB-TOTAL								$ 42,651	
8.0	**On-ice Installation**									
	Project Management and Support									
	General Support Throughout On-ice Construction	day	$ 62,000	160			$ 9,920,000	$ 11,298,880	$ 11,299	
	Arctic Civil Works									
	Activity 1: Ice Road Construction and Ice Thickening **24 hour operation (double shift)**									
	Grounded Ice Road Construction									
	Mob/demobilize construction crews and supervising personnel	person	$ 1,500	45	3		$ 202,500	$ 230,648	$ 231	
	Mob/demobilize construction and maintenance equipment	day	$ 39,000		10		$ 390,000	$ 444,210	$ 444	
	Grounded ice-road construction	day	$ 80,000			70	$ 5,600,000	$ 6,378,400	$ 6,378	
	Grounded ice pad construction for equipment staging and trench spoils	day	$ 39,000			6	$ 234,000	$ 266,526	$ 267	
	Floating Ice Road Construction									
	Mob/demobilize construction crews and supervising personnel	person	$ 1,500	45	3		$ 202,500	$ 230,648	$ 231	
	Mob/demobilize construction and maintenance equipment	day	$ 39,000		10		$ 390,000	$ 444,210	$ 444	
	Floating ice-road construction	day	$ 80,000			80	$ 6,400,000	$ 7,289,600	$ 7,290	
	Maintenance									
	Grounded ice storage pad maintenance	km	$ 39,000	1.00			$ 39,000	$ 44,421	$ 44	
	Grounded ice-road maintenance	km	$ 40,000	2.90			$ 116,000	$ 132,124	$ 132	
	Floating ice-road maintenance	km	$ 50,000	7.10			$ 355,000	$ 404,345	$ 404	
	Activity 2: Ice Cutting and Slotting **24 hour operation (double shift)**									

ID	Item	Unit Metric	Unit Cost CAD$	Quantity Metric	Mobilization / Demobilization Days	Unit Duration Days	Base Cost CAD	Escalated Cost CAD $1,000	Base Cost CAD $1,000
	Mob/demobilize construction crews and supervising personnel	person	$ 1,500	35	1		$ 52,500	$ 59,798	$ 60
	Mob/demobilize construction and maintenance equipment	day	$ 48,000		10		$ 480,000	$ 546,720	$ 547
	Cut slots in ice using trenchers, remove blocks using backhoes, and re-position blocks away from slots using front-end-loaders	day	$ 80,000			30	$ 2,400,000	$ 2,733,600	$ 2,734
	Additional trucks and loader to remove ice from floating ice section to grounded ice section	day	$ 17,000			30	$ 510,000	$ 580,890	$ 581
	Activity 3: Trenching and Cleanout **24 hour operation (double shift)**								
	Primary								
	Mob/demobilize construction crews and supervising personnel	person	$ 1,500	36	2		$ 108,000	$ 123,012	$ 123
	Mob/demobilize construction and maintenance equipment	day	$ 80,000		10		$ 800,000	$ 911,200	$ 911
	Primary excavation using 4 spreads	day	$ 150,000			35	$ 5,250,000	$ 5,979,750	$ 5,980
	Additional trucks to haul spoils from floating ice to grounded ice storage site	day	$ 10,000			35	$ 350,000	$ 398,650	$ 399
	On-going Cleanout Prior to Pipelay								
	Mob/demobilize construction crews and supervising personnel	person	$ 1,500	17	2		$ 51,000	$ 58,089	$ 58
	Mob/demobilize construction and maintenance equipment	day	$ 40,000		10		$ 400,000	$ 455,600	$ 456
	On-going trench cleanup using 2 spreads	day	$ 75,000			20	$ 1,500,000	$ 1,708,500	$ 1,709
	Arctic Pipeline Installation								
	Activity 4: Pipeline Make-Up Site Preparation **12 hour operation (single shift)**								
	Mob/demobilize construction crews and supervising personnel	person	$ 1,500	40	1		$ 59,652	$ 67,943	$ 68
	Mob/demobilize construction and maintenance equipment	day	$ 40,000		10		$ 400,000	$ 455,600	$ 456
	Set-up on ice work site and string line pipe	day	$ 80,000			25	$ 2,000,000	$ 2,278,000	$ 2,278
	Activity 5: Pipe String Make-Up (Welding) **24 hour operation (double shift)**								
	Offsite Welding and Preparation								
	Double joint (Weld/NDE/FJC) 10in line pipe	joint	$ 1,200	1,326			$ 1,591,200	$ 1,812,377	$ 1,812
	Double joint (Weld/NDE/FJC) 30in line pipe	joint	$ 4,000	1,326			$ 5,304,000	$ 6,041,256	$ 6,041
	Install sacrificial anodes	anode	$ 750	229			$ 171,837	$ 195,722	$ 196
	On-ice Welding								
	Mob/demobilize construction crews and supervising personnel	person	$ 1,500	75	1		$ 112,500	$ 128,138	$ 128
	Mob/demobilize welding equipment spread	day	$ 84,000		10		$ 840,000	$ 956,760	$ 957
	Weld/NDE pipelines on-ice	day	$ 230,000			28	$ 6,440,000	$ 7,335,160	$ 7,335
	Field joint coating	joint	$ 150	862			$ 129,300	$ 147,273	$ 147
	String Make-Up **24 hour operation (double shift)**								
	Pipelines								
	Mob/demobilize construction crews and supervising personnel	person	$ 1,500	15	1		$ 22,500	$ 25,628	$ 26
	Mob/demobilize equipment spread	day	$ 25,000		10		$ 250,000	$ 284,750	$ 285
	Prepare pipe strings (tie-in to previous strings, bundling, etc.)	day	$ 50,000			21	$ 1,050,000	$ 1,195,950	$ 1,196
	Fiber Optic Cable								
	Mob/demobilize fiber optic cable installation crew	person	$ 1,500	6	2		$ 18,000	$ 20,502	$ 21
	Mob/demobilize Fiber optic cable installation equipment	day	$ 10,000		10		$ 100,000	$ 113,900	$ 114
	Install fiber optic cable	day	$ 17,000			21	$ 357,000	$ 406,623	$ 407

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	Activity 6: Pipeline Installation **24 hour operation (double shift)**								
	Lay Pipeline - Grounded Ice								
	Mob/demobilize construction crews and supervising personnel	person	$ 1,500	45	1		$ 67,163	$ 76,499	$ 76
	Mob/demobilize equipment for pipeline installation	day	$ 80,000		10		$ 800,000	$ 911,200	$ 911
	Lower bundle into excavated trench on grounded ice using 7 long reach side booms	day	$ 190,000			6	$ 1,140,000	$ 1,298,460	$ 1,298
	Lay Pipeline - Floating Ice								
	Mob/demobilize construction crews and supervising personnel	person	$ 1,500	45	1		$ 67,163	$ 76,499	$ 76
	Mob/demobilize equipment for pipeline installation	day	$ 80,000		10		$ 800,000	$ 911,200	$ 911
	Lower bundle into excavated trench on grounded ice using 7 long reach side booms	day	$ 190,000			16	$ 3,040,000	$ 3,462,560	$ 3,463
	Shore Crossing								
	Mob/demobilize additional personnel for crane operations	person	$ 1,500	6	1		$ 9,000	$ 10,251	$ 10
	Mob/demobilize equipment	day	$ 25,000		10		$ 250,000	$ 284,750	$ 285
	Operations	day	$ 50,000			4	$ 200,000	$ 227,800	$ 228
	Saltwater plug and Shore Crossing Revegitation	LS	$ 500,000	1			$ 500,000	$ 569,500	$ 570
	Power Cable Installation **12 hour operation (single shift)**								
	Mob/demobilize construction crews and supervising personnel	person	$ 1,500	15	1		$ 22,500	$ 25,628	$ 26
	Mob/demobilize equipment for cable installation	day	$ 15,000		10		$ 150,000	$ 170,850	$ 171
	Install power cable	day	$ 30,000			14	$ 420,000	$ 478,380	$ 478
	Activity 7: Backfilling the Trench **24 hour operation (double shift)**								
	Mob/demobilize construction crews and supervising personnel	person	$ 1,500	37	1		$ 55,620	$ 63,351	$ 63
	Mob/demobilize backfilling equipment from Prudhoe	day	$ 55,000		10		$ 550,000	$ 626,450	$ 626
	Backfill trench	day	$ 110,000			30	$ 3,300,000	$ 3,758,700	$ 3,759
	Additional trucks and loaders to haul spoils back to floating ice from grounded ice storage site	day	$ 10,000			30	$ 300,000	$ 341,700	$ 342
	SUB-TOTAL								$ 75,479
9.0	**Offshore Precommissioning**								
	Export								
	Flooding, cleaning, and gauging	day	$ 400,000			4	$ 1,600,000	$ 1,822,400	$ 1,822
	Hydrotesting	day	$ 400,000			3	$ 1,200,000	$ 1,366,800	$ 1,367
	De-water and drying	day	$ 400,000			5	$ 2,000,000	$ 2,278,000	$ 2,278
	SUB-TOTAL								$ 5,467
10.0	**Onshore Construction Camp**								
	Construction and Operation								
	Operational cost for accommodations	person-days	$ 400	72,900			$ 29,160,000		$ 29,160
	SUB-TOTAL								$ 29,160
11.0	**Engineering, Permitting Support, Project/Construction Management, and Contingency**								
	Percent of TIC Costs								
	Engineering design, Procurement, Project/Construction management - 10% of all subtotals	% of all subtotals	10%				$ 49,646,714	$ 50,937,400	$ 50,937
	Logistics - 2% of all subtotals	% of all subtotals	2%				$ 9,929,343	$ 10,187,480	$ 10,187
	Contingency								
	Offshore pipeline contingency - 0% of total cost	% of total cost	0%				$ -	$ -	$ -
	SUB-TOTAL								$ 61,125
12.0	**Total Cost**								
	Total	$CAD					$ 556,043,200	$ 570,498,883	$ 570,499

GNWT: MDLNG - Option 1 with 1 GBS and power cable - Offshore Gas and Condensate Pipelines with 1 GBS and power cable									11-Mar-21
ID Item	Unit Metric	Unit Cost CAD$	Quantity Metric	Mobilization / Demobilization Days	Unit Duration Days	Base Cost CAD	Escalated Cost CAD $1,000	Base Cost CAD $1,000	
SI cost metric	$CAD/km	30.8 km						$ 18,529	
US cost metric	$CAD/mile	19.1 mi						$ 29,819	

Appendix B

Offshore Pipelines OPEX Estimates

15-Mar-21

Estimated OPEX for GNWT MDLNG Offshore Pipelines **TOTALS**	**MDLNG Option 1** **Annual**		**Lifetime**		**MDLNG Option 2** **Annual**		**Lifetime**	
	$1,000 CAD				**$1,000 CAD**			
Operational Pigging								
Caliper Pigging	$	37.3	$	745.0	$	35.8	$	715.2
Wall Thickness Measurement / Geometry Pigging	$	142.5	$	2,850.0	$	100.8	$	2,016.0
Pipeline Cleaning	$	3.8	$	75.5	$	1.8	$	35.2
External Surveys								
Survey Planning	$	150.0	$	3,000.0	$	150.0	$	3,000.0
ROV Survey	$	-	$	-	$	-	$	-
Operational Surveys	$	964.4	$	19,288.5	$	964.4	$	19,288.5
Inspection Evaluation								
Evaluation of yearly inspection results	$	50.0	$	1,000.0	$	50.0	$	1,000.0
Chemical Injection								
Chemicals	$	-	$	-	$	-	$	-
Transportation	$	-	$	-	$	-	$	-
GRAND-TOTAL	**$**	**1,348**	**$**	**26,959**	**$**	**1,303**	**$**	**26,055**

AMAULIGAK FEL-1 PIPELINES STUDY
OPEX REPORT

Route Option 1 OPEX Estimate

15-Mar-21

MDLNG Option 1																	
ID	**Item**	**Unit**	**Unit Cost**	**Quantity**	**Mobilization / Demobilizations**	**Unit Duration**	**Annual Cost**	**Annual Cost**	**Input**	**Input**	**Input**	**Input**	**Input**	**Input**	**Input**	**Input**	**Input**
		Metric	**CAD$**	**Metric**	**Days**	**Days**	**CAD**	**CAD $1,000**	-	-	-	-	-	-	-	-	-
1.0	**Operational Pigging**																
	In-Line Inspection (ILI)																
	Caliper Pigging																
	Mob/demob of caliper pigging equipment	per skid	$ 25,000	2			$ 12,500	$ 13									
	Mob/demob technicians	LS	$ 5,000	1			$ 1,250	$ 1									
	Caliper pig rental - 30" x 31 km	LS	$ 54,000	1			$ 13,500	$ 14									
	Caliper pig rental - 10.75" x 31 km	LS	$ 40,000	1			$ 10,000	$ 10									
	Wall Thickness Measurement / Geometry Pigging																
	Mob/demob of ILI pigging equipment	per skid	$ 30,000	2			$ 15,000	$ 15									
	Mob/demob inspection technicians	LS	$ 10,000	1			$ 2,500	$ 3									
	Inspection skid rental - 30.0" x 31 km	LS	$ 350,000	1			$ 87,500	$ 88									
	Inspection skid rental - 10.75" x 31 km	LS	$ 150,000	1			$ 37,500	$ 38									
	Pipeline Cleaning																
	Steel body cleaning pig 10.75" (condensate pipeline)	per year	$ 2,012	1			$ 2,012	$ 2	$ 2448 / pig	4 runs/yr	4 runs/pig	4 replacements	$ 1903 / replacements	20 yrs	1 units		
	Steel body cleaning pig 30" (gas pipeline)	per year	$ 1,761	1			$ 1,761	$ 2	$ 10382 / pig	1 runs/yr	6 runs/pig	3 replacements	$ 8281 / replacements	20 yrs	1 units		
	SUB-TOTAL							$ 184									
2.0	**External Surveys**																
	Survey Planning																
	Project management and engineering	LS	$ 150,000	1			$ 150,000	$ 150	1 units								
	Operational Surveys																
	Mob/demob vessel to perform summer geophysical (side scan / multi-beam) survey	day	$ 41,004		16		$ 656,064	$ 656									
	Geophysical (side scan / multi-beam) survey	day	$ 68,340			4	$ 273,360	$ 273									
	Post-inspection processing and analysis	LS	$ 15,000	1			$ 15,000	$ 15	1 units								
	Aerial survey	day	$ 20,000			1	$ 20,000	$ 20	1 surveys/yr								
	SUB-TOTAL							$ 1,114									
3.0	**Inspection Evaluation**																
	Evaluation of yearly inspection results	LS	$ 50,000	1			$ 50,000	$ 50	1 units								
	SUB-TOTAL							$ 50									
4.0	**Chemical Injection**																
	Chemicals																
	Transportation																
	SUB-TOTAL							$ -									

Route Option 2 OPEX Estimate

15-Mar-21

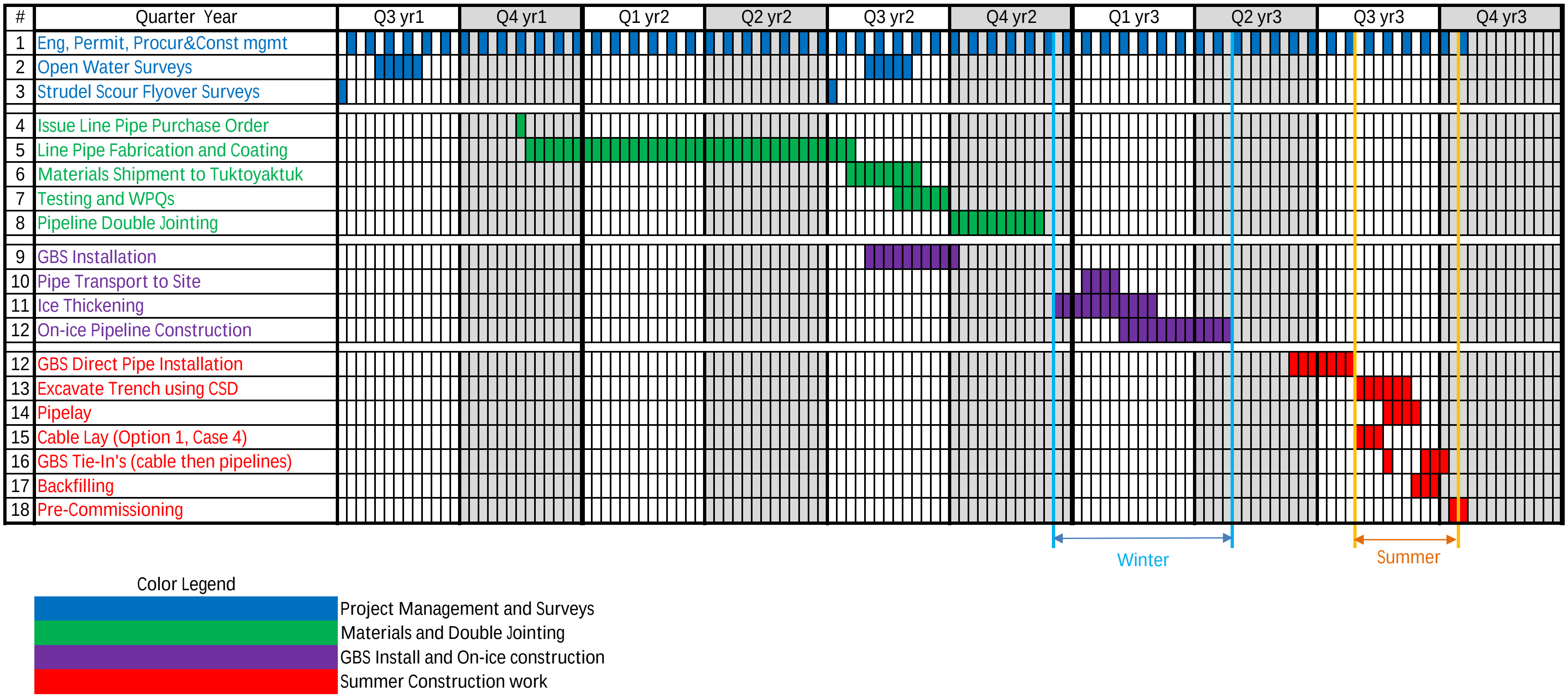
MDLNG Option 2

ID	Item	Unit	Unit Cost	Quantity	Mobilization / Demobilizations	Unit Duration	Annual Cost	Annual Cost	Input	Input	Input	Input	Input	Input	Input	Input	Input
		Metric	CAD$	Metric	Days	Days	CAD	CAD $1,000	-	-	-	-	-	-	-	-	-
1.0	**Operational Pigging**																
	In-Line Inspection (ILI)																
	Caliper Pigging																
	Mob/demob of caliper pigging equipment	per skid	$ 25,000	2			$ 12,000	$ 12									
	Mob/demob technicians	LS	$ 5,000	1			$ 1,200	$ 1									
	Caliper pig rental - 30" x 31 km	LS	$ 54,000	1			$ 12,960	$ 13									
	Caliper pig rental - 10.75" x 31 km	LS	$ 40,000	1			$ 9,600	$ 10									
	Wall Thickness Measurement / Geometry Pigging																
	Mob/demob of ILI pigging equipment	per skid	$ 30,000	2			$ 14,400	$ 14									
	Mob/demob inspection technicians	LS	$ 10,000	1			$ 2,400	$ 2									
	Inspection skid rental - 30.0" x 31 km	LS	$ 350,000	1			$ 84,000	$ 84									
	Pipeline Cleaning																
	Steel body cleaning pig 30" (gas pipeline)	per year	$ 1,761	1			$ 1,761	$ 2	$ 10382 / pig	1 runs/yr	6 runs/pig	3 replacements	$ 8281 / replacements	20 yrs	1 units		
	SUB-TOTAL							$ 138									
2.0	**External Surveys**																
	Survey Planning																
	Project management and engineering	LS	$ 150,000	1			$ 150,000	$ 150	1 units								
	Operational Surveys																
	Mob/demob vessel to perform summer geophysical (side scan / multi-beam) survey	day	$ 41,004		16		$ 656,064	$ 656									
	Geophysical (side scan / multi-beam) survey	day	$ 68,340			4	$ 273,360	$ 273									
	Post-inspection processing and analysis	LS	$ 15,000	1			$ 15,000	$ 15	1 units								
	Aerial survey	day	$ 20,000			1	$ 20,000	$ 20	1 surveys/yr								
	SUB-TOTAL							$ 1,114									
3.0	**Inspection Evaluation**																
	Evaluation of yearly inspection results	LS	$ 50,000	1			$ 50,000	$ 50	1 units								
	SUB-TOTAL							$ 50									
4.0	**Chemical Injection**																
	Chemicals																
	Transportation						$ -										
	SUB-TOTAL							$ -									

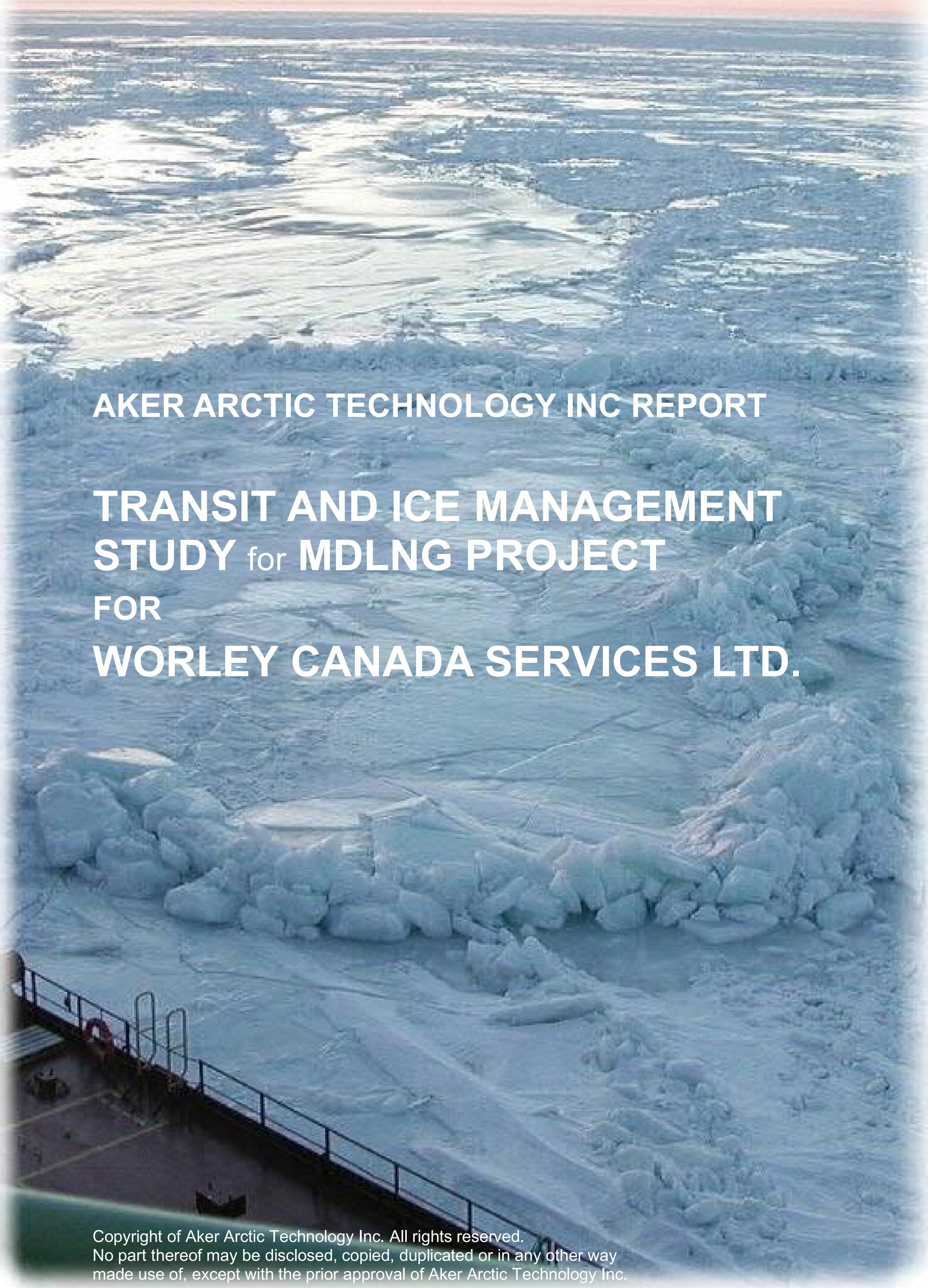
Appendix C

Offshore Pipelines Schedule

GNWT MDLNG Offshore Pipeline Schedule



Appendix C
Aker Arctic Report



Aker Arctic

AKER ARCTIC TECHNOLOGY INC REPORT

TRANSIT AND ICE MANAGEMENT STUDY for MDLNG PROJECT

FOR

WORLEY CANADA SERVICES LTD.

Name of document: Transit and Ice Management study for MDLNG Project	
Document Responsible: Ruiz de Almiron de Andres Cayetana	**Document Co-Author(s):** Idrissova Sabina; Saarinen Sami; Shtrek Alexey; Lindholm Mauri
Document Reviewer: Hovilainen Mika	**Document Approver:** Ruiz de Almiron de Andres Cayetana
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Client: Worley Canada Services Ltd. / Hale Jim	
Revision remarks: Updated after comments to Revision B. English proofed.	

Summary:

This initial transit study's findings are:

That for the export of 4 Mtpa of LNG from the Mackenzie Delta to China, five specialized icebreaking LNG carriers (similar to the YamalMax type) are required which can operate on this route year-round, and through an average-type winter. With limited storage capacity (one GBS, 270,000 m^3), the actual calculated maximum number of LNGCs during winter months is 4.7, and the cost of transportation is approximately USD 62/ton (about USD 1.16/MMBtu).

For the export of comingled oil/condensate from the Mackenzie Delta to Vancouver, one ice-going product tanker (similar to the Boris Sokolov type) is required for a production rate of 10,000 bbl/day, the required storage volume is about 90,000 m^3 and the cost of transportation is about USD 61.5/ton. For a production rate of 30,000 bbl/day, three condensate tankers are required, with the condition that icebreaker assistance is provided during the four to five months of an average-type winter. The required storage volume in this case is about 140,000 m^3; the actual maximum number of condensate tankers is 2.5 for an average winter, with the cost of transportation being approximately USD 63.5/ton.

An Ice Management fleet of three icebreakers is proposed to assist the LNG carriers and condensate tankers at MDLNG GBS. The associated operational costs are approximately USD 12 million/year. The proposed fleet and costs presented here are based on a maximum capacity required scenario, covering all key aspects affecting IM needs. The IM fleet proposal should be updated at a later stage when the final transportation parameters are agreed.

Keywords:

Transit Study

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ABBREVIATIONS

BOR .... Boil-off Rate (natural boil-off rate of LNG cargo)
CAPEX .... Capital Expenses
CCS .... Cargo Containment System
CT .... Condensate Tanker
DAS .... Double Acting Ship
DOLPHIN (breasting d.). Marine structure for taking berthing loads from ship's side
DOLPHIN (mooring d.)..... Structure serving as fixing point for ship's mooring ropes
EIB .... Escort Icebreaker
EFL .... Extended Flaw Lead
GA .... General Arrangement
GBS .... Gravity Based Structures
GNWT .... Government of the Northwest Territories
HB .... Hanna Shoal
HIB .... Harbour Icebreaker
IBT .... Icebreaking Tug
IM .... Ice Management
IMV .... Ice Management Vessels
ITF .... International Transport Workers' Federation
LFI .... Landfast Ice
LNG .... Liquefied Natural Gas
LNGC .... Liquefied Natural Gas Carrier
MDLNG .... Mackenzie Delta LNG project
MDO .... Marine Diesel Oil
MMBtu .... Millions of British thermal units
Mtpa .... Million Tonnes Per Annum
MUSD .... Million US dollars
OPEX .... Operating Expenses
OW .... Open Water
P&I .... Protection and Indemnity
PB .... Point Barrow
PIB .... Primary Icebreaker
TCC .... Total Crew Cost
STS .... Ship To Ship

1 BACKGROUND

The Mackenzie Delta of the Northwest Territories (NWT) contains substantial proven publicly-owned conventional natural gas reserves that could be developed for export, providing immediate economic benefit to the Inuvialuit Settlement Region, NWT and Canada. This concept is called “Mackenzie Delta Liquefied Natural Gas” or MDLNG, and it meets the requirements of the Government of the Northwest Territories’ (GNWT) ‘Petroleum Resource Strategy’.

This shipping study assess the ice conditions along the transport route and at the offshore GBS located at a base case site off the shore of the Mackenzie Delta in the Canadian Beaufort Sea. It analyses the reference ice-capable LNG carriers and oil / condensate tankers, as well as the transportation scenarios to markets from the GBS. An ice management fleet and recommended ice management operations are also presented.

2 ICE CONDITIONS ALONG THE ROUTE

This section provides an overall description of the ice conditions along the anticipated transportation route through the Chukchi, Bering and Beaufort Seas. This overall description is then used to define the ice profiles for the transit simulation. In addition, information on specific areas along the route with respect to the worst-expected ice conditions is also presented. The specific ice conditions in the coastal area of the Mackenzie Delta where the location of the Gravity Based Structure (GBS) is planned are described; and ice management will be evaluated.

2.1 GENERAL DESCRIPTION OF ICE FORMATION

Descriptions of ice formation for the Chukchi, Bering and Beaufort Sea areas are described in the following section. The general location of the sea areas is indicated in Figure 2-1.

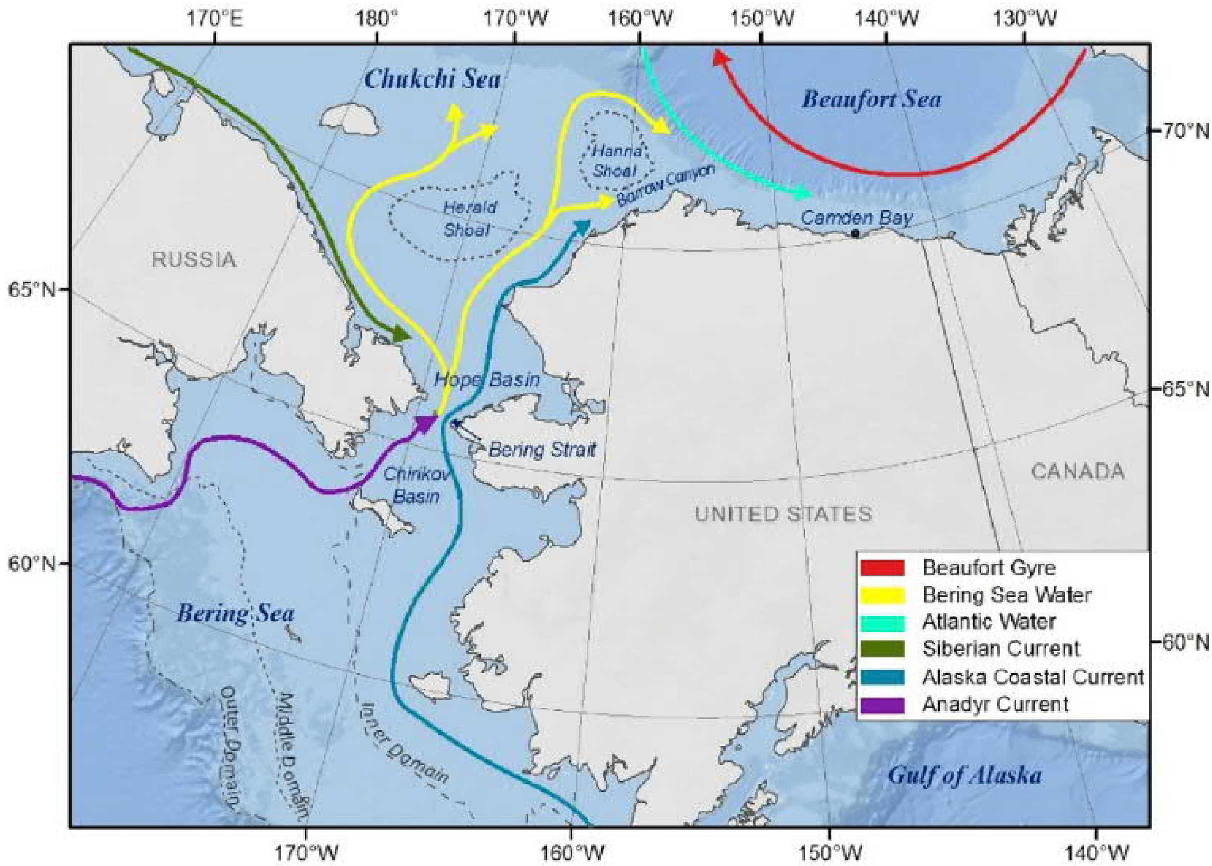


Figure 2-1 – Overview of sea areas (Kuletz, et al., 2019)

2.1.1 THE BEAUFORT SEA

This chapter describes general ice conditions in the Beaufort Sea. Emphasis is given to the southern parts of the sea over which the transportation route is expected. An overview map of the Beaufort Sea area is shown in Figure 2-2.

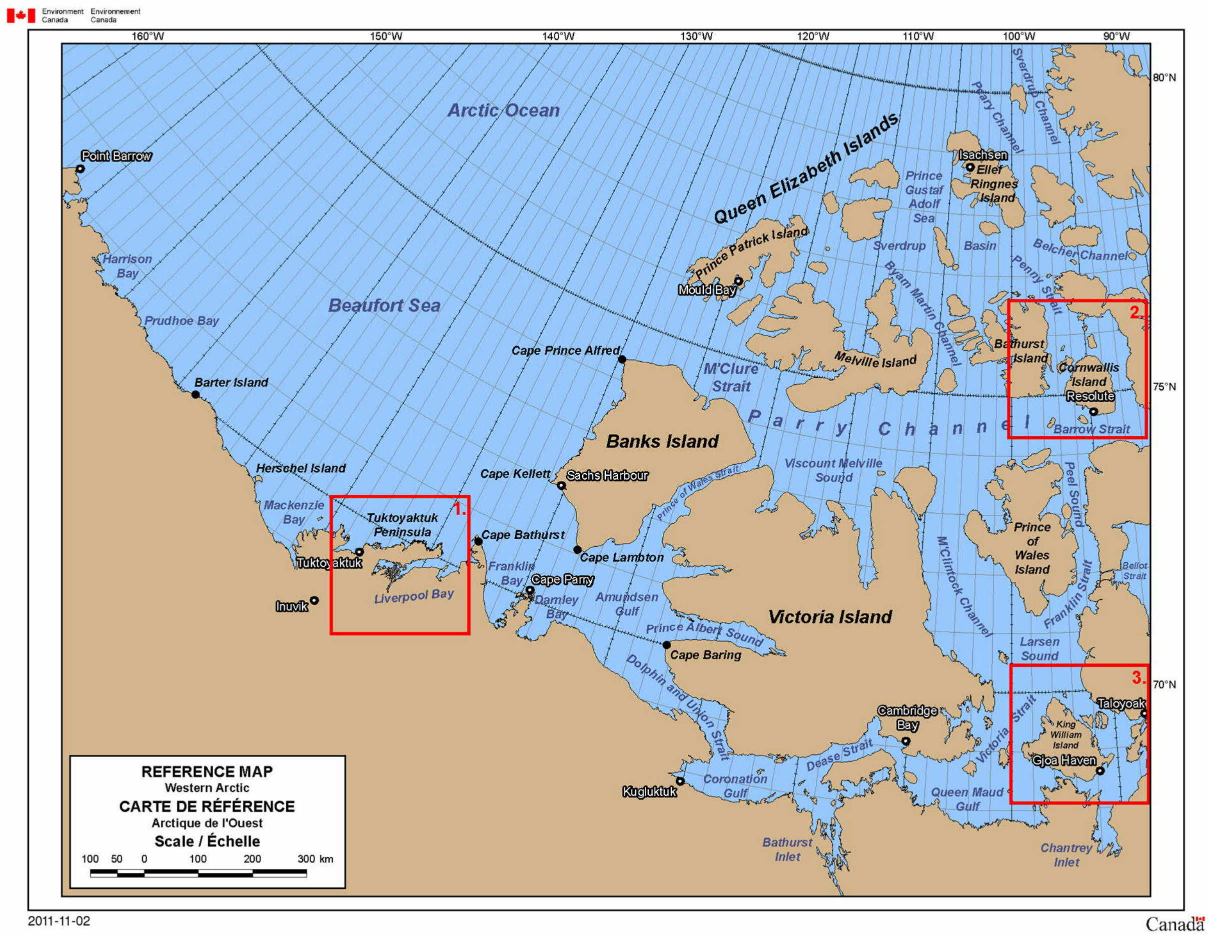


Figure 2-2 – Overview of the Beaufort Sea (CIS, 2021)

2.1.1.1 METEOROLOGY AND OCEANOGRAPHY

Air temperature

The yearly mean air temperature in the Beaufort Sea area is low: below −10 °C. Typically, sub-zero temperatures prevail from late September until the end of May. The average temperature during the coldest months (January and February) is close to −30 °C, while the extreme minimum can reach −50 °C. The daily average, minimum and maximum temperatures at Tuktoyaktuk (see Figure 2-2) are shown in Figure 2-3 and Figure 2-4. The temperature regime at Tuktoyaktuk is representative of the Beaufort Sea's coastal areas.

Winds

Winds strongly influence the ice conditions in the Beaufort Sea. Northwesterly winds may press the pack ice against the shore or landfast ice and induce significant ice deformation; while during offshore winds, a lead may develop along coastal areas.

The prevailing wind direction is from north-northwest in winter and from the east in summer. The average wind speed is about 6 m/s. The strongest winds blow from the northwest with a maximum gust speed of about 40 m/s.

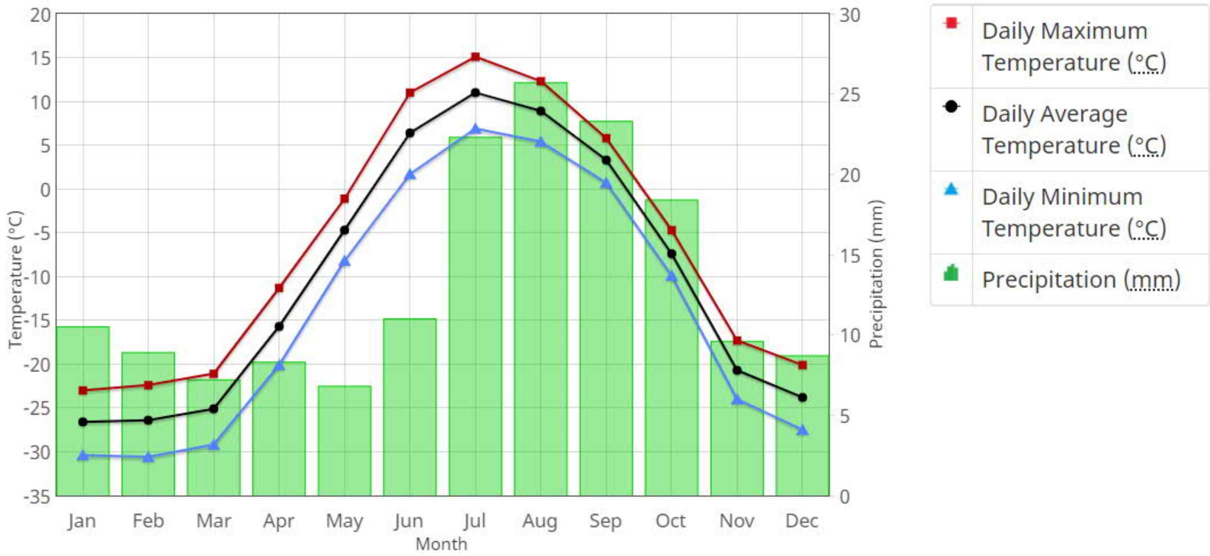


Figure 2-3 – Temperature and Precipitation Graph for 1971 to 2000 Canadian Climate Normals TUKTOYAKTUK A (CIS, 2021)

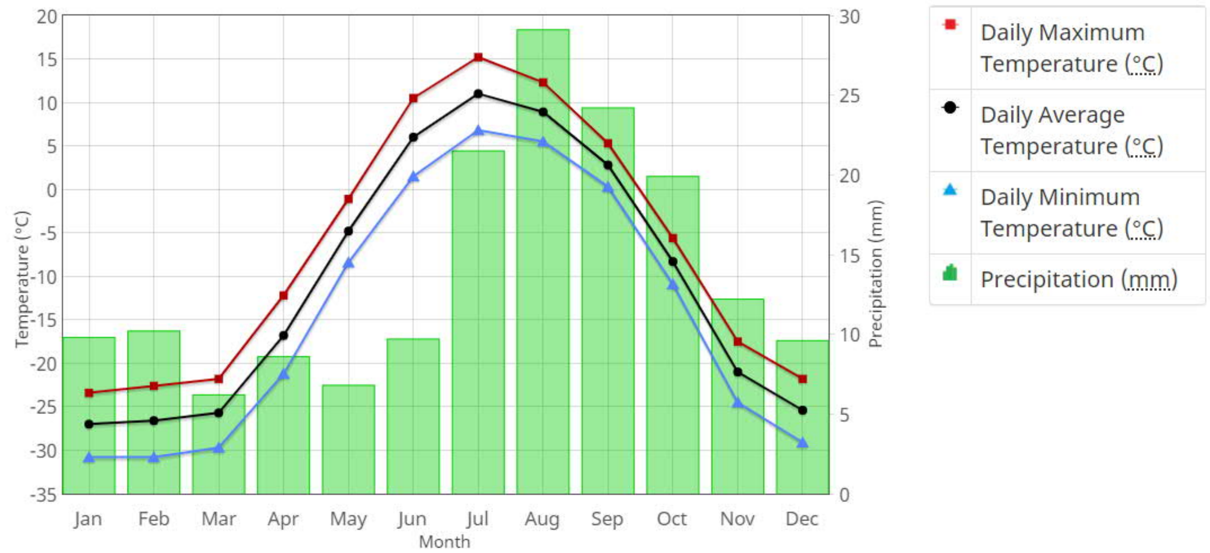


Figure 2-4 – Temperature and Precipitation Graph for 2000 to 2010 Canadian Climate Normals TUKTOYAKTUK A (CIS, 2021)

Bathymetry

A bathymetric map of the Beaufort Sea is shown in Figure 2-5. Most of the sea consists of the deep Canadian Basin with water depths down to 4000 m. However, the Alaskan and Canadian mainland coasts have an extensive continental shelf with a 100 m depth contour about 80 to 130 km offshore (except near Herschel Island where it is only about 20 km offshore).

Sea currents

The Beaufort Gyre dominates the current regime in the Beaufort Sea. The clockwise rotation of the Gyre results in an east to west flow in the southern Beaufort Sea, and is presented in Figure 2-6. The mean speed of Beaufort Gyre is 0.02 to 0.03 m/s, whereas in the southern Beaufort Sea, the speed is typically 0.05 to 0.1 m/s. However, surface currents are affected by wind and they can reach speeds of 0.5 m/s. Tidal currents are weak in the area due to the small tidal range (generally 0.1 to 0.3 m).

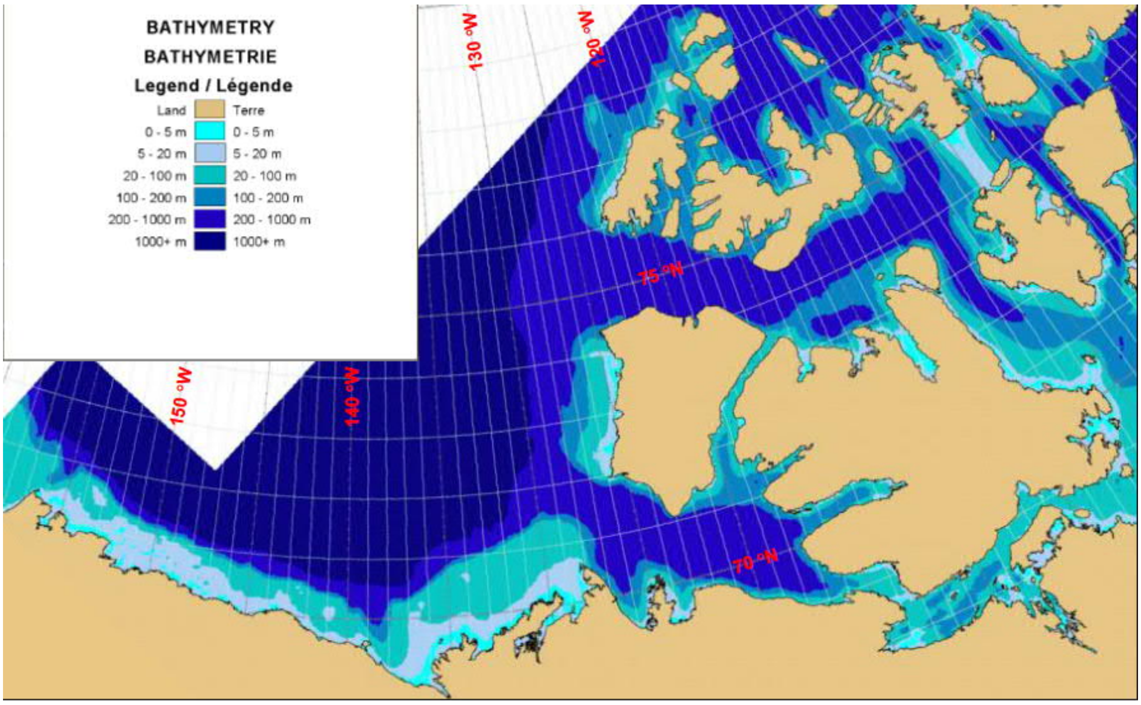


Figure 2-5 – Bathymetry of the Beaufort Sea (Source: Aker Arctic Technology Inc)

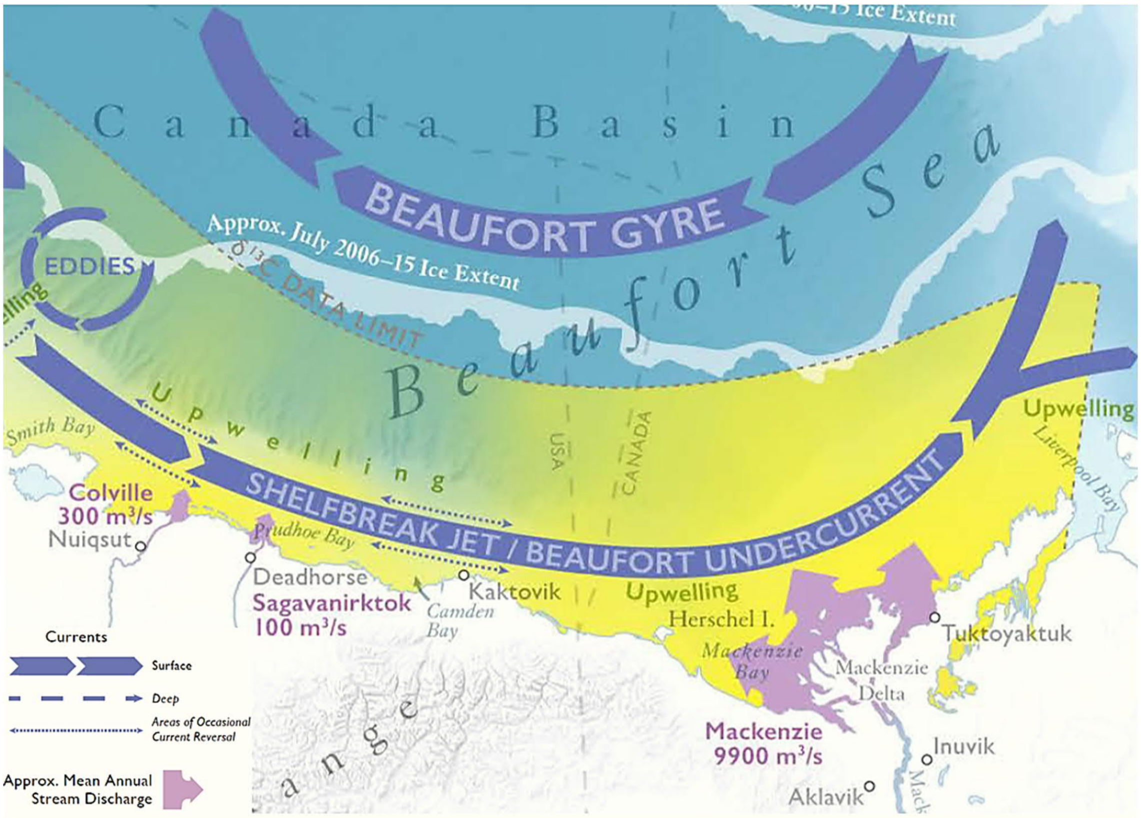


Figure 2-6 – Sea currents (Smith, et al., 2017)

Waves

The wave regime in the Beaufort Sea is determined mainly by the ice cover, which limits the wind fetch. The average significant wave height is less than 1.0 m, with an extreme value of 6.3 m.

2.1.1.2 ICE CONDITIONS

Ice season

New ice formation in the Beaufort Sea begins among multi-year ice floes in the polar pack during September, and then spreads southwards. In the southern Beaufort Sea, freeze-up begins normally at the beginning of October. By the end of October, the sea is usually totally ice-covered with a concentration above 9/10th. The variation of freeze-up patterns between a mild and a severe year is about one month. For example, the formation of a total ice cover in the Beaufort Sea may occur from late September to early November.

The ice melt begins in Mackenzie Bay (see Figure 2-2 and see Figure 2-6) in June and an open water area develops quickly there. The fast ice along the Canadian coast fractures in July, and by the end of the month the area from Mackenzie Bay to Cape Bathurst (see Figure 2-2) is open. West of Mackenzie Bay, along the Alaskan coast, a narrow lead normally develops close to the shore during July. However, open drift ice conditions do not develop along the coast until the first half of August and an open water route may not develop until the beginning of September.

The variations in the ice cover between different types of ice conditions are considerable. During severe ice conditions, northwesterly winds push the Arctic pack ice against the shore, and high concentrations of multi-year ice may be present throughout the summer. In this case, the complete break-up of fast ice can be delayed until August. During mild ice conditions, an open water route along the Alaskan and Canadian coasts can develop late in July, and the route can stay open until October.

The summer season in the Beaufort Sea can be defined as a period of open pack ice conditions when the average ice concentration remains, for example, under 5/10th. The length of the summer season varies from 0 to 120 days and is 60 to 70 days on average.

Ice zones

In winter, the Beaufort Sea ice cover is divided into three ice zones, as shown in Figure 2-7:

- landfast ice zone
- transition zone
- polar pack ice zone

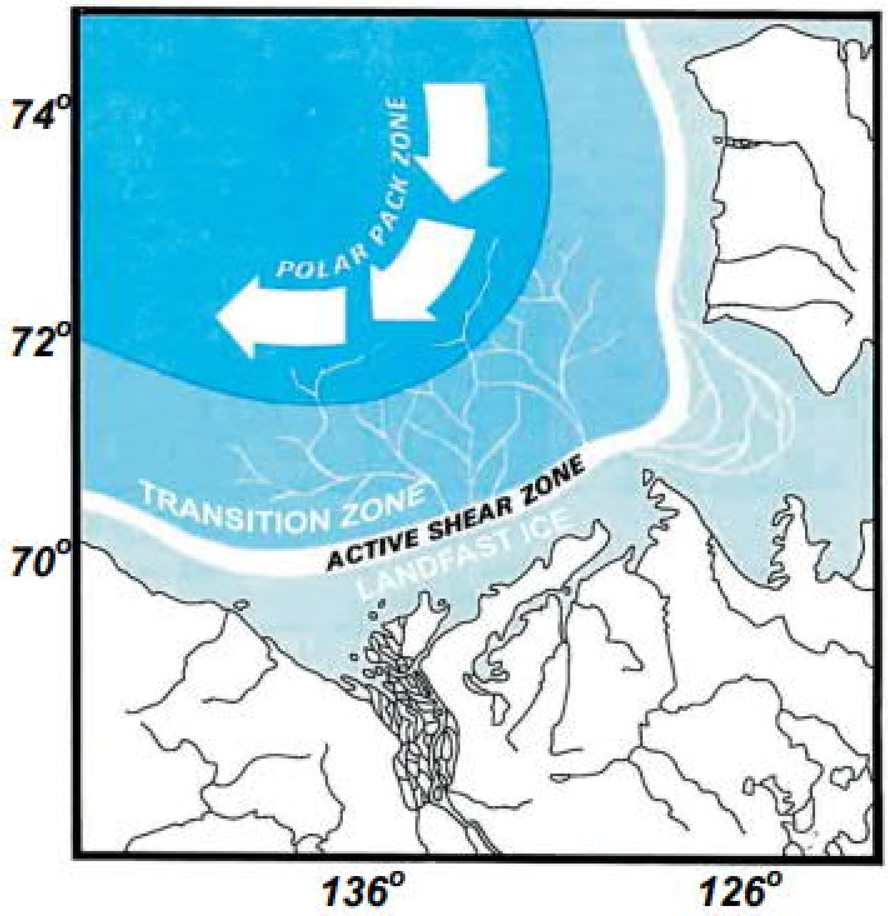


Figure 2-7 – Ice zones in the Beaufort Sea (Fissel, et al., 2012)

Ice cover characteristics

The annual growth landfast ice begins in September and October, with the appearance and development of new ice, intermixing with shoreward advancing pack ice that has survived at least one annual melt season. During this process, the offshore edge of the zone irregularly advances seaward and retreats through alternating steps of growth and deformation, until its outer boundary becomes stabilized in early winter in waters close to the 20 m bathymetric contour. Stabilization is produced by physical contact between the sea floor and deep ice keels embedded in the outer portion of the landfast ice. These deep keels are produced by strong interactions between the landfast ice and adjacent portions of the gyral pack ice, which also increases its areal extent and thickens during the fall and winter months. A well-developed flaw or "active shear lead" with widths ~10 km can usually be seen seasonally marking the outer limits of the landfast ice.

The fast ice normally reaches its annual maximum thickness in the middle of May. During average winters, this can be 170 to 180 cm in the southern Beaufort Sea. Ice growth curves for three different locations are shown in Figure 2-8. In the transition zone the average level ice thickness is less than the fast ice thickness. This reflects in the presence of different stages of ice development in the mobile pack ice. New ice is produced throughout the winter in the leads that are formed between mobile ice floes.

Landfast ice thickening does not extend any further, and in early summer it begins to melt. The thickest level ice is primarily found in the old ice dominated regions of the gyral zone.

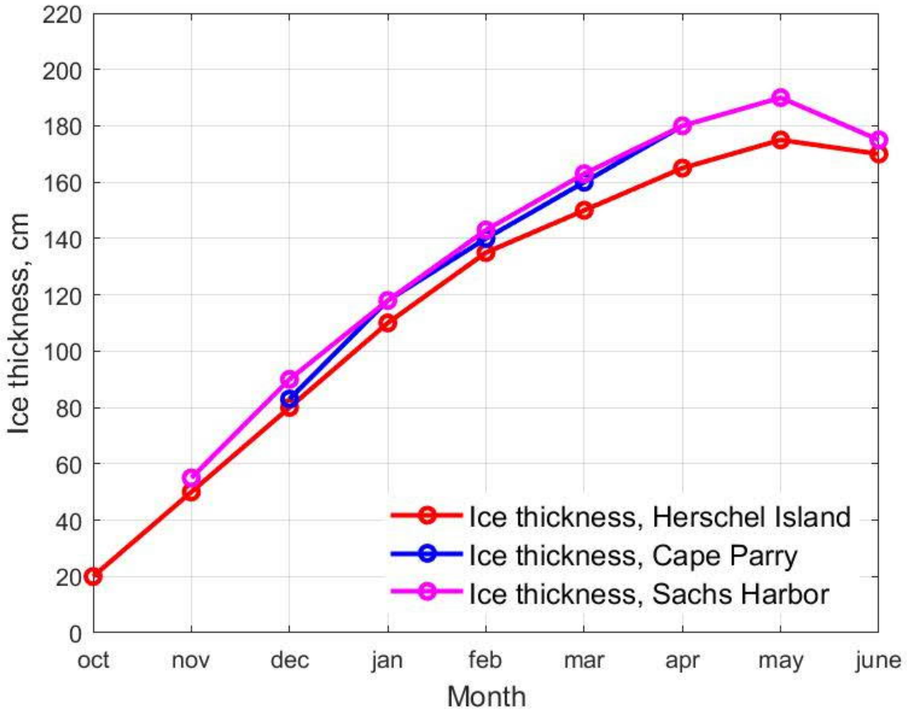


Figure 2-8 – Ice growth at Herschel Island, Cape Parry and Sachs Harbor for average winters (Source: Aker Arctic Technology Inc)

Ice drift

The ice drift is dominated by winds. However, the general ice drift pattern follows the current in the Beaufort Gyre, resulting in an average ice drift from east to west in the southern Beaufort Sea. The average ice drift speed is 0.2 m/s in summer and 0.05 m/s in winter. The maximum drift speeds are 1.0 m/s and 0.6 m/s, respectively.

Ice ridges

Ice ridging is very intensive in the transition zone. The seasonal variation of the ridge frequency is significant. In early winter, the frequency is typically less than 5 ridges/km, but grows to 10 to 15 ridges/km by February.

The total ridge thickness (sail and keel height) is typically 6 to 9 m, with a maximum thickness of over 30 m for first year ice. The total thickness of multi-year ridges found in the area is typically 10 to 15 m, with a maximum thickness of about 40 m.

Ridging in the polar pack ice zone is significant but less intensive than in the transition zone. The ridge frequency in the polar pack ice is typically 5 to 10 ridges/km. The ridge thickness is the same as in the transition zone. The amount of multi-year ice ridges is high due to high multi-year ice concentration).

First-year ridges are found also in the landfast ice zone, beyond the 5 m water depth contour. They are formed in early winter before the ice becomes landfast. The ridge frequency is typically 2 to 5 ridges/km. Grounded ice ridges ('stamukhi') are common in water depths of less than 15 m, but they are observed in water depths of up to 20 m.

Occurrence of multi-year ice

Most of the Beaufort Sea's multi-year ice is found in the polar pack ice zone where the multi-year ice coverage is 7/10th to 10/10th throughout the year. The transition zone is mostly covered by first-year ice, but also includes areas with multi-year ice. The typical multi-year ice coverage within the transition zone varies from 0/10th to 3/10th (in winter).

In summer, the edge of the polar pack ice usually lies 150 to 200 km offshore, but during northerly and northwesterly winds multi-year ice is pushed southwards towards coastal areas. In summer, the multi-year ice coverage in the southern Beaufort Sea varies from 0/10th to 3/10th. However, the coverage can be much higher locally, although concentrations above 3/10th are uncommon.

The mean coverage near the Canadian coast varies from 0/10th to 1/10th and is typically 0.3/10th to 0.5/10th. The coverage near the Alaskan coast is typically 1/10th to 3/10th and during major multi-year ice incursions, the coverage may approach 10/10th. The typical distribution of multi-year ice concentration in summer is shown in Figure 2-9. It should be noted that multi-year ice does not reach the nearshore areas every year. Multi-year ice is observed at a specific coastal location once every 3 to 5 years.

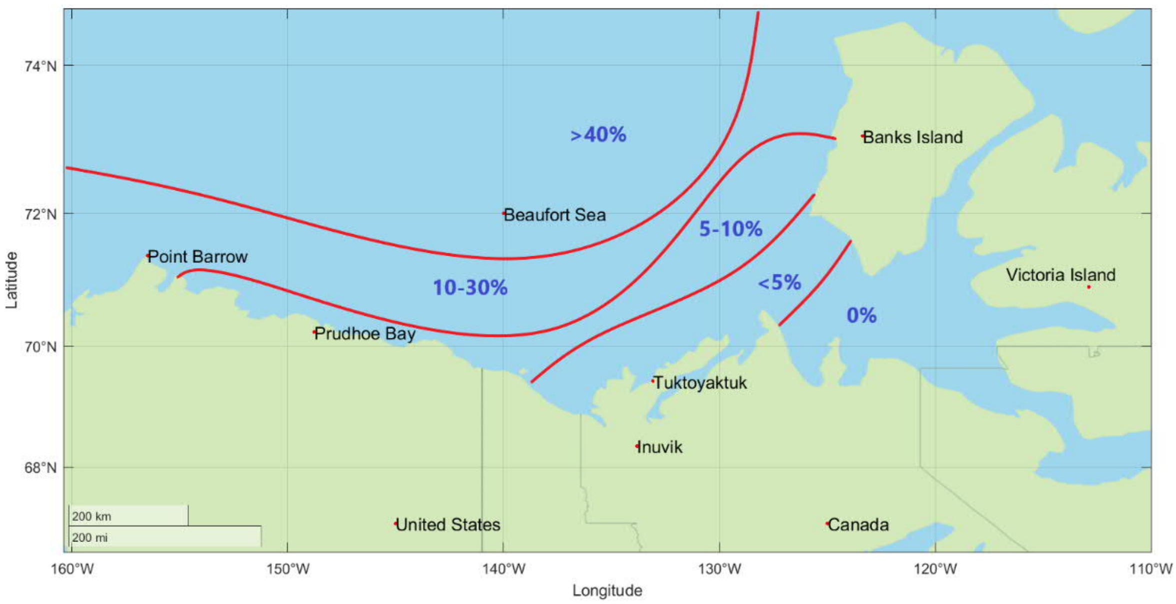


Figure 2-9 – Typical distribution of multi-year ice concentration in summer (Source: Aker Arctic Technology Inc)

Polynyas

There is one recurring polynya in the Beaufort Sea, located north of Cape Bathurst ('Cape Bathurst Polynya'), presented in Figure 2-10). The extent of the polynya is highly variable, depending on the prevailing wind direction. In addition, a shore lead may develop off the mainland coast and the west coast of Banks Island (see Figure 2-10) in winter during strong offshore winds.

Figure 2-10 – Sea ice advance in the Beaufort Sea (Smith, et al., 2017)

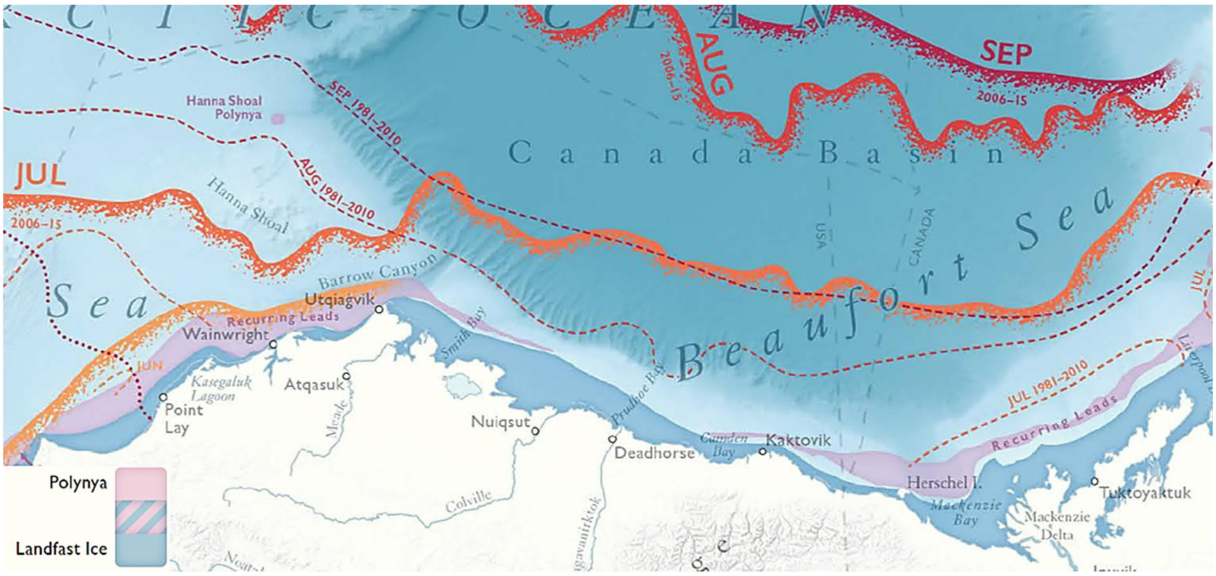


Figure 2-11 – Sea ice retreat in the Beaufort Sea (Smith, et al., 2017)

2.1.1.3 Summary for the Beaufort Sea

The following section provides summary tables of key ice information for the Beaufort Sea (Table 2-1-Table 2-4).

Table 2-1 – Ice season in the Beaufort Sea for an average winter

Beginning of freeze-up	Average Latest Earliest	Early October Late October Late September
Formation of 9+/10th ice cover	Average Latest Earliest	Mid October Early November Late September
Beginning of break-up of ice	Average Latest Earliest	Late July Mid August Early July
Clearing of most ice	Average Latest Earliest	Early September No clearance Mid August
Length of summer season (ice concentration less than 5/10th)	Average Latest Earliest	60-70 days 100-120 days 0-30 days

Table 2-2 – Ice drift speed in the Beaufort Sea, m/sec

Season	Magnitude	Drift speed
summer	Average Max	0.2 1.0
winter	Average Max	0.05 0.6

Table 2-3 – First-year ice properties in the Beaufort Sea

Quantity	Unit	Value	
Level ice			
Thickness (annual maximum)	cm	Average Min Max	170-180 150 200
Rafted ice			
Thickness (annual maximum)	cm	Max	450-600
Ridges			
Number of ridges per km • Transition zone • Polar pack zone • Fast ice zone	1/km	 Typical Typical Typical	 10-15 5-10 2-5
Consolidated layer, thickness (annual maximum)	cm	Average	300-350
Keel, depth	m	Typical Max	5-7 25-30
Sail, height	m	Average Max	1.5 5

Stamukhi (grounded hummocks) are common in water depths less than 15 m, though observed in water depths up to 20 m. Grounded hummocks (or parts of them) may start floating in late spring.

Table 2-4 – Multi-year ice properties in the Beaufort Sea

Quantity	Unit	Value	
Level ice			
Thickness (in polar pack ice)	cm	Average Typical Max	320 200-250 400-500
Ridges			
Number of ridges per km • Transition zone • Polar pack zone	1/km	 Typical Typical	 10-15 5-10
Keel, depth	m	Typical Max	5-10 35
Sail, height	m	Typical Max	4-6 10-12

The concentration of multi-year ice in the polar pack zone is around 7/10th, and near the Alaskan coast 1/10th-3/10th. A floe size can reach a maximum 20-50 km offshore and up to 3.6 km in nearshore areas, though a typical floe size in a nearshore region is closer to 1 km.

2.1.2 THE CHUKCHI SEA

The Chukchi Sea is a shallow marginal sea in the Arctic Ocean. It is located between the Chukotka Peninsula (Russia) and Alaska. It is limited by the Bering Strait to the south, Point Barrow to the northeast and Wrangel Island to the northwest. The northern limit is roughly on a line joining Point Barrow and Wrangel Island. A reference map is shown in Figure 2-12.

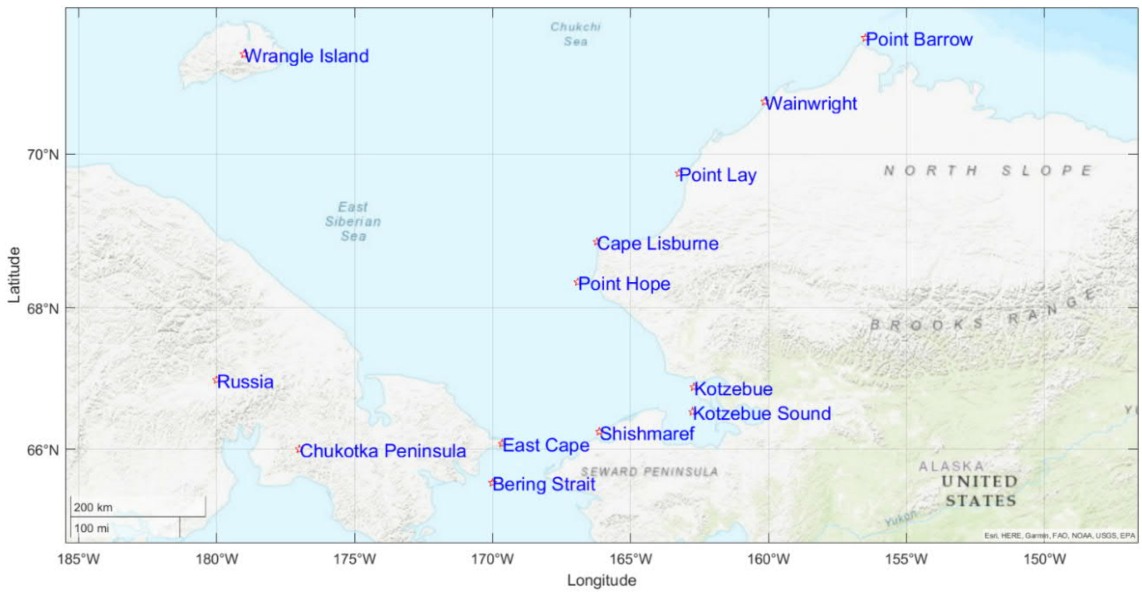


Figure 2-12 – The Chukchi Sea (Source: Aker Arctic Technology Inc)

The ice conditions in the Chukchi Sea are similar to those in the Beaufort Sea, especially in the northeastern part (between Cape Lisburne and Point Barrow, shown in Figure 2-12). However, there is a decrease of multi-year ice occurrence and ice thickness when going southwards.

2.1.2.1 METEOROLOGY AND OCEANOGRAPHY

Air temperature

The yearly mean air temperature in the Chukchi Sea area is low: ranging from −5 °C in the southern part to −12 °C in the northeastern part of the sea. Typically, sub-zero temperatures prevail from October to May. The average temperature in the coldest month is about −20 °C in the south and −27 °C in the northeast. The extreme minimum temperature in coastal areas is from −47 to −48 °C, while in open sea areas it is about −40 °C. The monthly average, minimum and maximum temperatures at Point Barrow and Kotzebue are shown in Figure 2-13 and Figure 2-14.

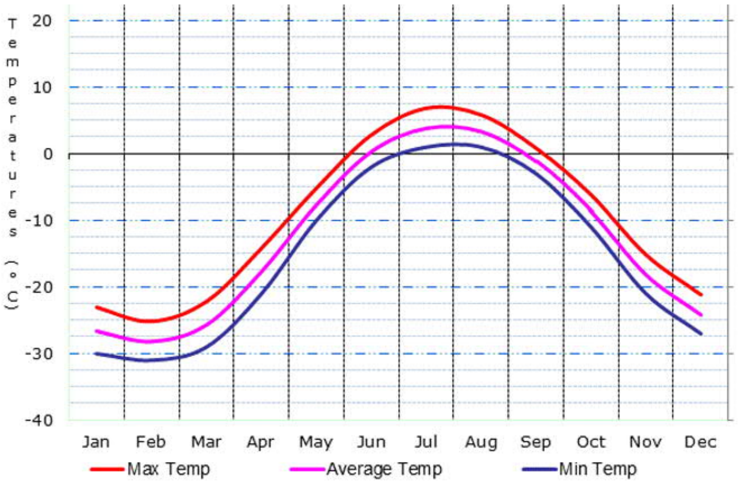


Figure 2-13 – Monthly air temperatures at Point Barrow (Climatemps, 2021)

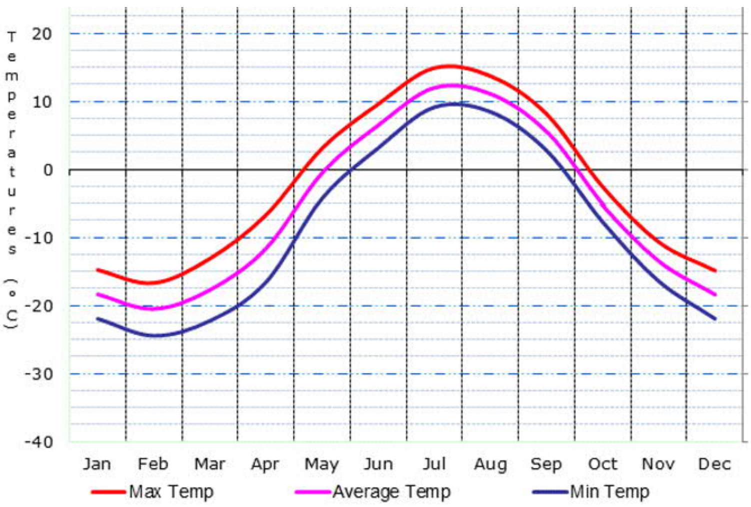


Figure 2-14 – Monthly air temperatures at Kotzebue (Climatemps, 2021)

Winds

The average wind speed along the Alaskan coast is 4 to 6 m/s throughout the year. Extreme wind speeds exceed 25 m/s. The prevailing wind direction is mostly from north-northeast throughout the year. The only exception to this occurs in the southern part of the sea in summer when the prevailing winds are from south to west.

Bathymetry

The Chukchi Sea is a shallow marginal sea of the Arctic Ocean with water depths less than 100 m. Over half of the total area is occupied by depths less than 50 m. A bathymetric map of the Chukchi Sea is shown in Figure 2-15.

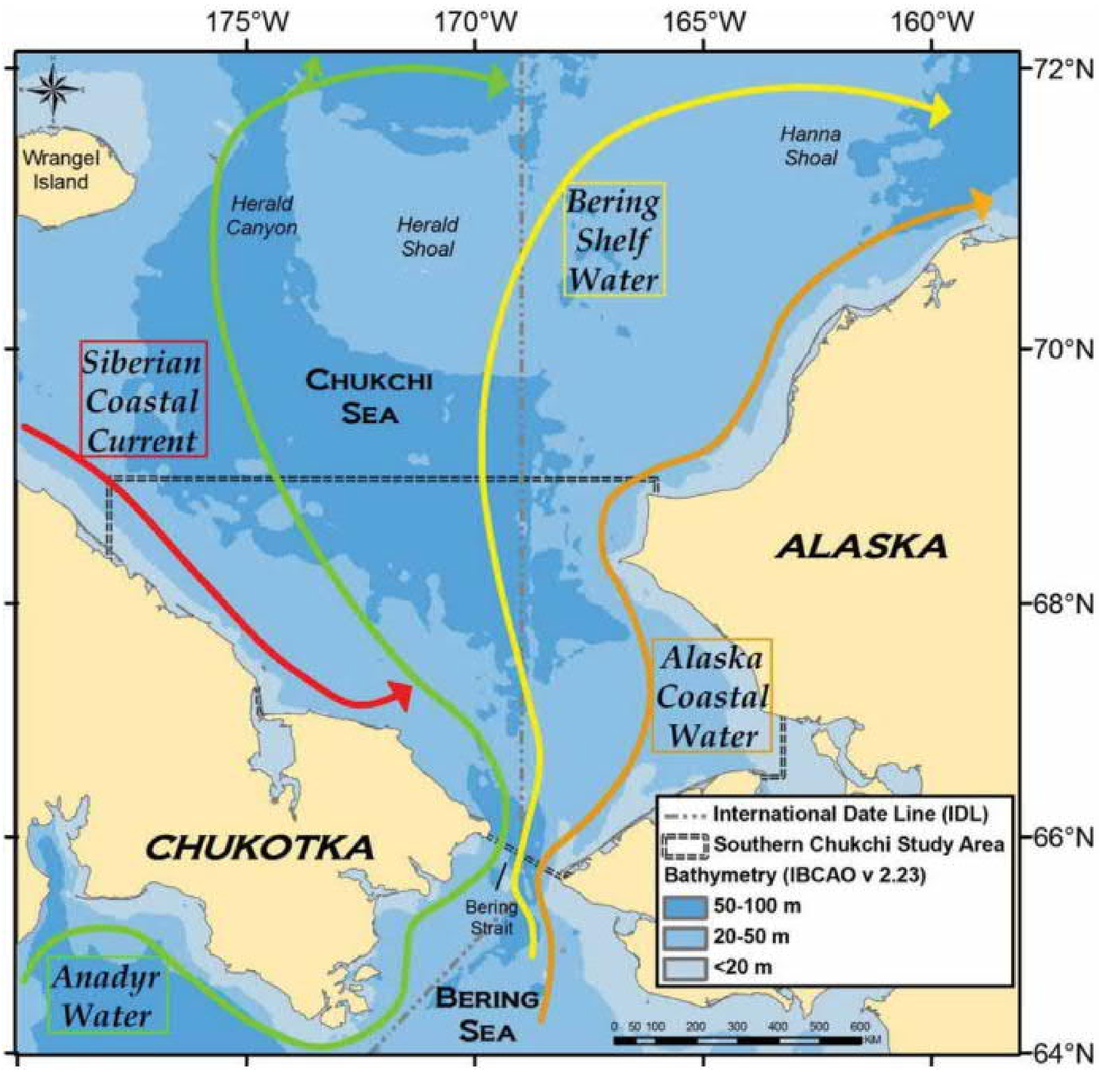


Figure 2-15 – Bathymetry of the Chukchi Sea (Clarke, et al., 2013)

Sea currents

The current pattern in the Chukchi Sea is complex. Generally, the currents flow southeastward along the Russian coast and northwards along the Alaskan coast. The flow through the Bering Strait is generally from south to north. Maximum current speed in the Bering Strait is 1.5 m/s in summer.

2.1.2.2 ICE CONDITIONS

Ice season

New ice formation in the northern parts of the Chukchi Sea normally begins in late October. Typically, the whole sea area is ice covered by mid-November. In severe years, freeze-up may start as early as late September in the area between the Russian mainland and Wrangel Island, in early October along the Alaskan coast close to Point Barrow, and in mid-October in the southern parts of the sea. In mild years, freeze-up may not begin until late November or early December in the whole sea area.

During average winters, the ice starts to break-up in mid-June in the southern part of the sea. The entire Alaskan coast is ice-free by late June. Generally, most of the sea is ice free in August and September. However, low concentrations of ice can be found in the very northern parts of the sea throughout the summer. Typically, the Chukchi Sea remains ice-covered from mid-November to mid-June.

Fast ice

The average fast ice extent along the Alaskan coast varies from 5 to 40 km. The extreme value can reach 70 km between Cape Lisburne and Wainwright. The Kotzebue Sound is usually covered by landfast ice. The annual maximum fast ice width is reached by February to March. The typical fast ice extent is shown in Figure 2-16 and Figure 2-17.

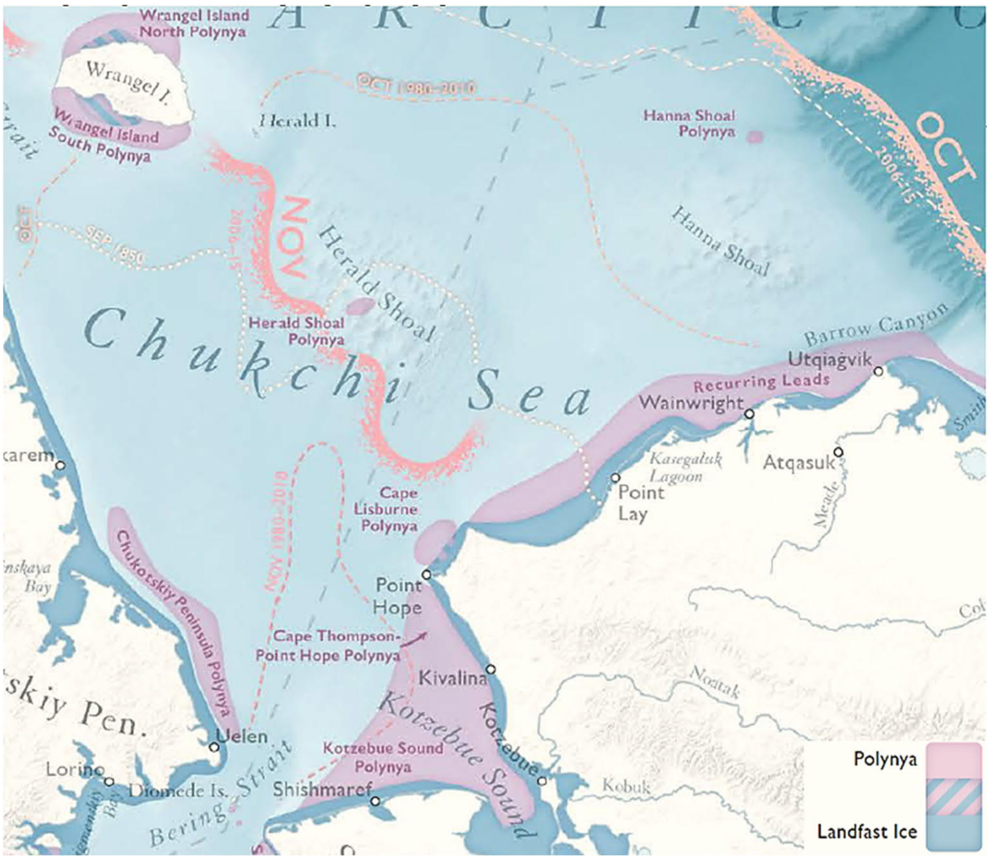


Figure 2-16 – Sea ice advance in the Chukchi Sea (Smith, et al., 2017)

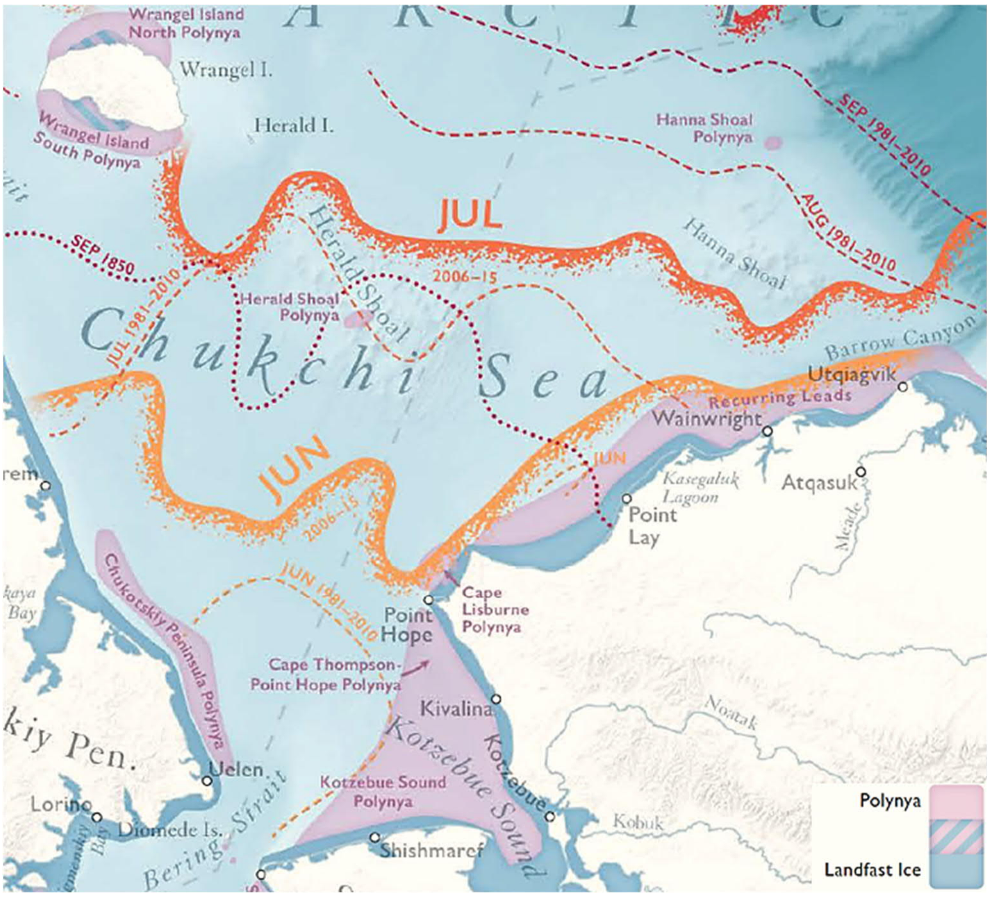


Figure 2-17 – Sea ice retreat in the Chukchi Sea (Smith, et al., 2017)

Ice thickness

The fast ice thickness normally reaches its annual maximum in May. During average winters, the maximum ice thickness reaches about 150 cm in the northeastern Chukchi Sea. In severe winters, the ice thickness may reach 185 cm. In the southern Chukchi Sea, the annual maximum thickness is about 30 cm less than in the northeast. The extreme level ice thickness in the northern Chukchi Sea can be as high as 210 cm. The ice growth curve for an average year at Point Hope is shown in Figure 2-18.

Figure 2-18 – Ice thickness for an average winter, Point Hope (Source: Aker Arctic Technology Inc)

Ice drift

In general, ice drifts southeastwards along the Russian coast towards East Cape (see Figure 2-12) then turns north before reaching the Bering Strait area. The general ice drift direction in the central and eastern Chukchi Sea is from south to north. The average and maximum drift speeds are assumed to be 0.2 m/s and 1.0 m/s, respectively.

Ice ridges

Intensive ice ridging occurs along the Alaskan coast in the shear zone between fast ice and mobile pack ice, especially in the areas from Point Hope to Point Barrow and from Shismaref to the Bering Strait (see Figure 2-12). The area close to Point Barrow is always heavily ridged as a result of prevailing northerly/north-easterly winds and the pressure formed by the Beaufort Gyre. In mid-winter, ridge frequency is typically 5 to 10 ridges/km in the coastal shear zone, about 5 ridges/km in the mobile pack ice, and 2 to 3 ridges/km in the landfast ice. Locally, ridge frequencies can be higher and large areas can be totally ridged. In general, the ridge frequency is slightly higher in the northern part than in the southern part of the sea.

The total ridge thickness (sail and keel height) is typically 6 to 9 m and the estimated maximum thickness is about 25 m for first-year ice. The total thickness of multi-year ridges found in the area is typically 10 to 15 m and the estimated maximum thickness about 30 m. Grounded ice ridges (‘stamukhi’) are common in water depths of less than 10 m, but they are also observed in water depths up to about 20 m.

Occurrence of multi-year ice

Most of the multi-year ice found in the Chukchi Sea originates from the Arctic Ocean. The Beaufort Gyre feeds multi-year ice into the Chukchi Sea between Point Barrow and Wrangel Island. Also, some multi-year ice may form on the southern side of Wrangel Island during several consecutive cold summers.

In winter, the multi-year ice concentration in the northern part of the sea is about 2/10th to 3/10th on average and the maximum concentration is 5/10th to 8/10th. The amount of multi-year ice decreases rapidly when going southwards, and multi-year ice floes are rarely transported all the way to the Bering Strait area. Multi-year ice occurrence in the Chukchi Sea is shown in Figure 2-19.

The typical multi-year ice floe size in the Chukchi Sea is about 500 m across, but vast floes of up to 10 km across are also quite common. The thickness of the multi-year ice floes is typically 2 to 2.5 m.

Polynyas

A significant recurring polynya (or flaw lead) in the Chukchi Sea opens between the fast ice and the mobile pack ice in the area from Cape Lisburne to Point Barrow ("Cape Lisburne Polynya") during offshore winds in spring. In the northeast part of the Bering Strait, the Kotzebue Sound Polynya is located (Figure 2-16). Although polynya does occur in the Kotzebue Sound, it is not very sensitive to the north-easterly wind, unlike the Cape Lisburne Polynya (Figure 2-16).

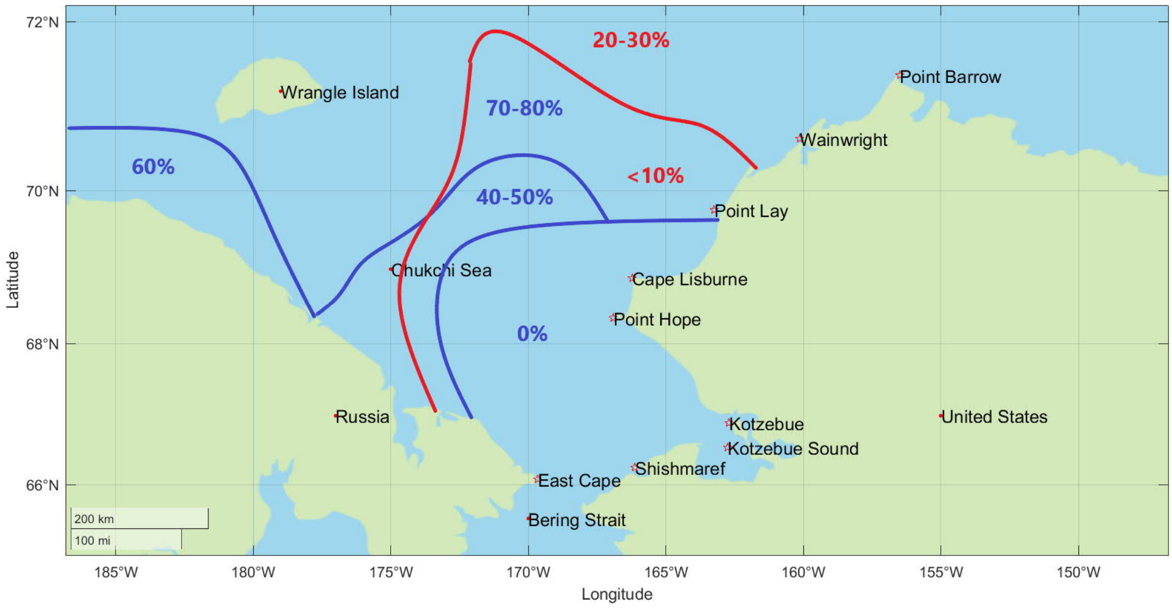


Figure 2-19 – Average (red) and maximum (blue) multi-year ice concentrations in the Chukchi Sea in April (Source: Aker Arctic Technology Inc)

2.1.2.3 Summary for the Chukchi Sea

The following section provides summary tables of key ice information for the Chukchi Sea (Table 2-5-Table 2-8).

Table 2-5 – Ice season in the Chukchi Sea for an average winter

		Southeastern Alaskan coast from Bering Strait to Point Hope	Northeastern Alaskan coast from Point Hope to Point Barrow
Freeze-up	Average Latest Earliest	Mid November Early December Mid October	End of October Late November Early October
Break-up	Average Latest Earliest	Mid June Mid July End of May	Late June Late July Early June
Number of ice days (per year)	Average Latest Earliest	210 170 270	235 190 285

Table 2-6 – Ice drift speed in the Chukchi Sea, m/sec

Season	Magnitude	Drift speed
summer	Average Max	0.2 1.0

Table 2-7 – First-year ice properties in the Chukchi Sea

Quantity	Unit	Value	
Level ice			
Thickness (annual maximum), Point Hope	cm	Average Min Max	140 100 185
Thickness, extreme in Northern Chukchi Sea		Extreme	210
Rafted ice			
Thickness (annual maximum)	cm	Max	450-600
Ridges			
Number of ridges per km • Fast ice zone • Shear zone • Pack ice zone	1/km	 Typical Typical Typical	 2-3 5-10 5
Keel, depth	m	Typical Max	5-7 25
Sail, height	m	Average Max	1.5 4

Stamukhi (grounded hummocks) are common in water depths less than 10 m, though observed in water depths up to 20 m. Grounded hummocks (or parts of them) may start floating in late spring.

Table 2-8 – Multi-year ice properties in the Chukchi Sea

Quantity	Unit	Value	
Level ice			
Thickness (in polar pack ice)	cm	Typical	200-250
Ridges			
Number of ridges per km Polar pack zone	1/km	Typical	5
Keel, depth	m	Typical Max	5-10 25
Sail, height	m	Typical Max	3-4 7

The average concentration of multi-year ice in the northern Chukchi Sea is 2/10th, and the maximum is 5/10th-7/10th. The amount of multi-year ice decreases rapidly towards the south, with practically no multi-year ice in the Bering Strait area. Multi-year ice incursion is in coastal areas close to Point Barrow during summer (occasionally, the concentration may approach 10/10th).

2.1.3 THE BERING SEA

The Bering Sea is a seasonally frozen sea area limited by the Bering Strait to the north, the Aleutian Islands to the south, Russia to the west and Alaska to the east. A reference map is shown in Figure 2-20.

Figure 2-20 – Reference map of the Bering Sea (Source: Aker Arctic Technology Inc)

2.1.3.1 METEOROLOGY AND OCEANOGRAPHY

Air temperature

The yearly mean air temperature in the Bering Sea varies from −5 °C at the Bering Strait in the north to +5 °C at the Aleutian Islands in the south. Typically, sub-zero temperatures prevail from October to May in the northern part of the sea (north of latitude 60 °N). The average temperature during the coldest month (February) is about −15 °C in areas close to the Bering Strait and about zero degrees at the Aleutian Islands.

During the winter months (November to March) the temperatures in areas close to the Bering Strait are about 10 °C lower than at St. Matthew's Island (approximately on latitude 60 °N). The extreme minimum temperature in coastal areas in the northern Bering Sea is about −40 °C. The monthly average, minimum and maximum temperatures at Nome and St. Paul Island are shown in Figure 2-21 and Figure 2-22.

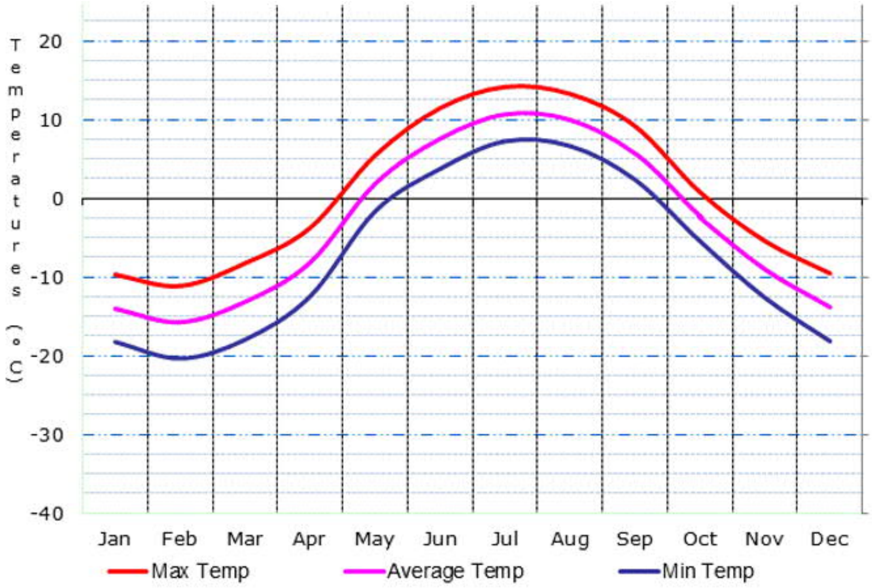


Figure 2-21 – Monthly air temperature at Nome (Climatemps, 2021)

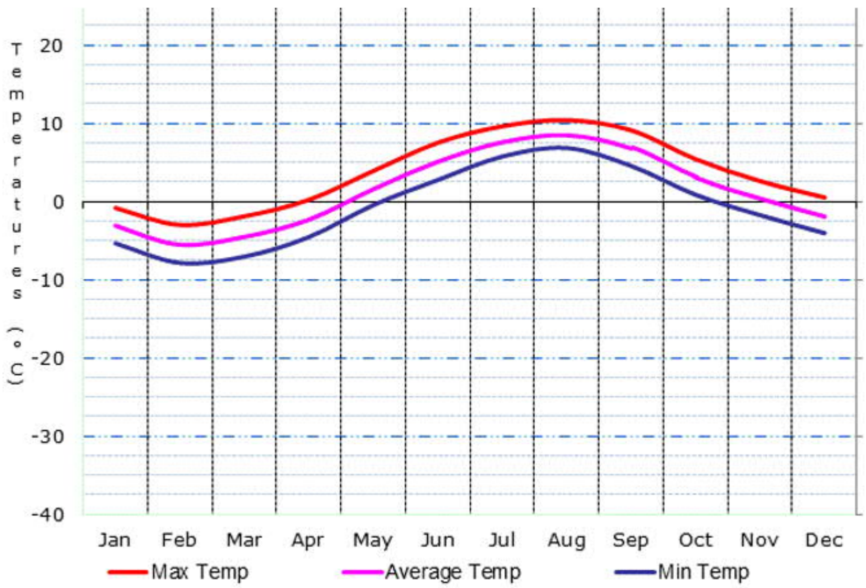


Figure 2-22 – Monthly air temperatures at St. Paul Island (Climatemps, 2021)

Winds

Northerly-north-easterly winds prevail in the whole sea area from September to May. In summer, the prevailing wind direction is from south-southwest. The average wind speed is 8-10 m/s in winter (November-April) and 4-6 m/s in summer (June-August). The extreme wind speed exceeds 25 m/s.

Bathymetry

The northeastern Bering Sea is shallow with water depths of less than 100 m. This is the area where the Bering Sea ice cover appears. The 100 m depth contour lies approximately on the line between Unimak Island and Cape Navarin. The deep Navarin Basin occupies most of the southwestern Bering Sea, where water depths exceed 3000 m. The bathymetric map of the Bering Sea is shown in Figure 2-23.

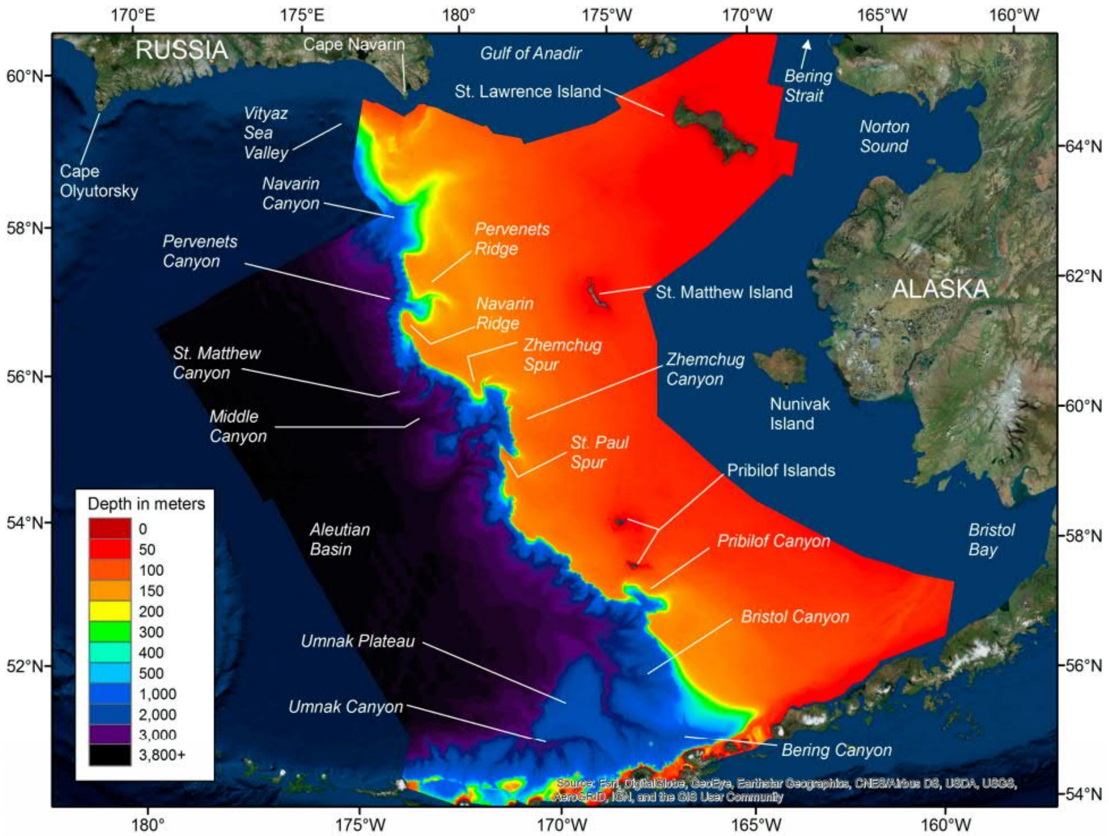


Figure 2-23 – Bathymetry of the Bering Sea (Zimmermann & Prescott, 2018)

2.1.3.2 ICE CONDITIONS

Ice season

The freeze-up begins from the northern parts of the Bering Sea (the Bering Strait area and Norton Sound) typically in late November. The ice edge proceeds gradually southwards and reaches the line between Nunivak Island and Cape Navarin by mid-December, St. Matthew's Island by mid-January and the maximum ice extent is reached in February. In severe years, freeze-up begins about three weeks earlier and in mild years about one month later than in an average year. The annual ice extent is shown in Figure 2-24 and Figure 2-25.

The ice edge starts to retreat northwards in March. During average winters, the ice edge passes St. Matthew's Island in late May or early June and the whole Bering Sea becomes ice-free in late June. During mild winters, the sea becomes ice-free in early June, while during severe winters the final ice clearance would not be until early July.

Practically all the ice in the Bering Sea is first-year ice. However, a few multi-year ice floes may drift through the Bering Strait into the northern Bering Sea. The multi-year ice concentrations are negligible. The ice in the Bering Sea stays mobile throughout the winter, except for a narrow landfast ice zone. Generally, the ice drifts from north to south with the prevailing winds. Most of the Bering Sea ice is formed in the northern parts around St. Lawrence Island and Norton Sound, where wind driven polynyas are a major source of ice formation.

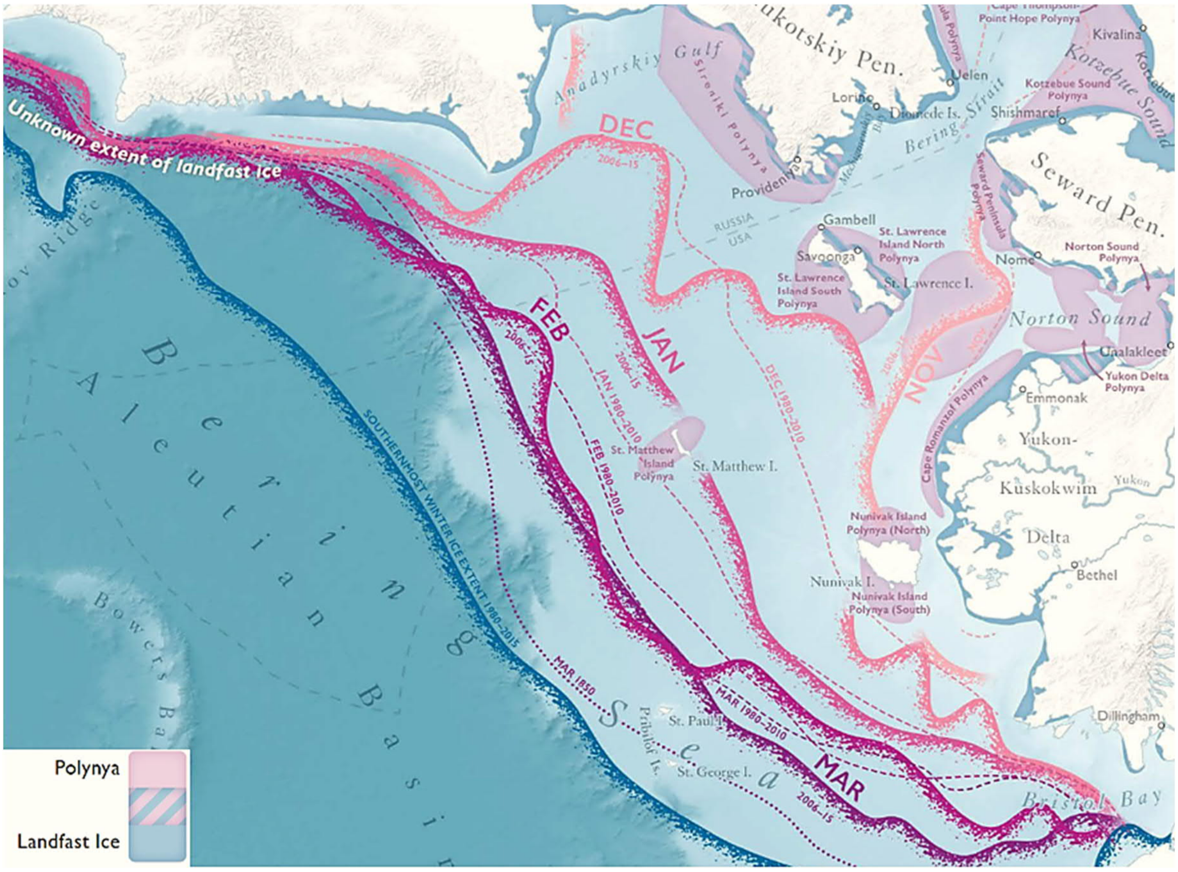


Figure 2-24 – Sea ice advance in the Bering Sea (Smith, et al., 2017)

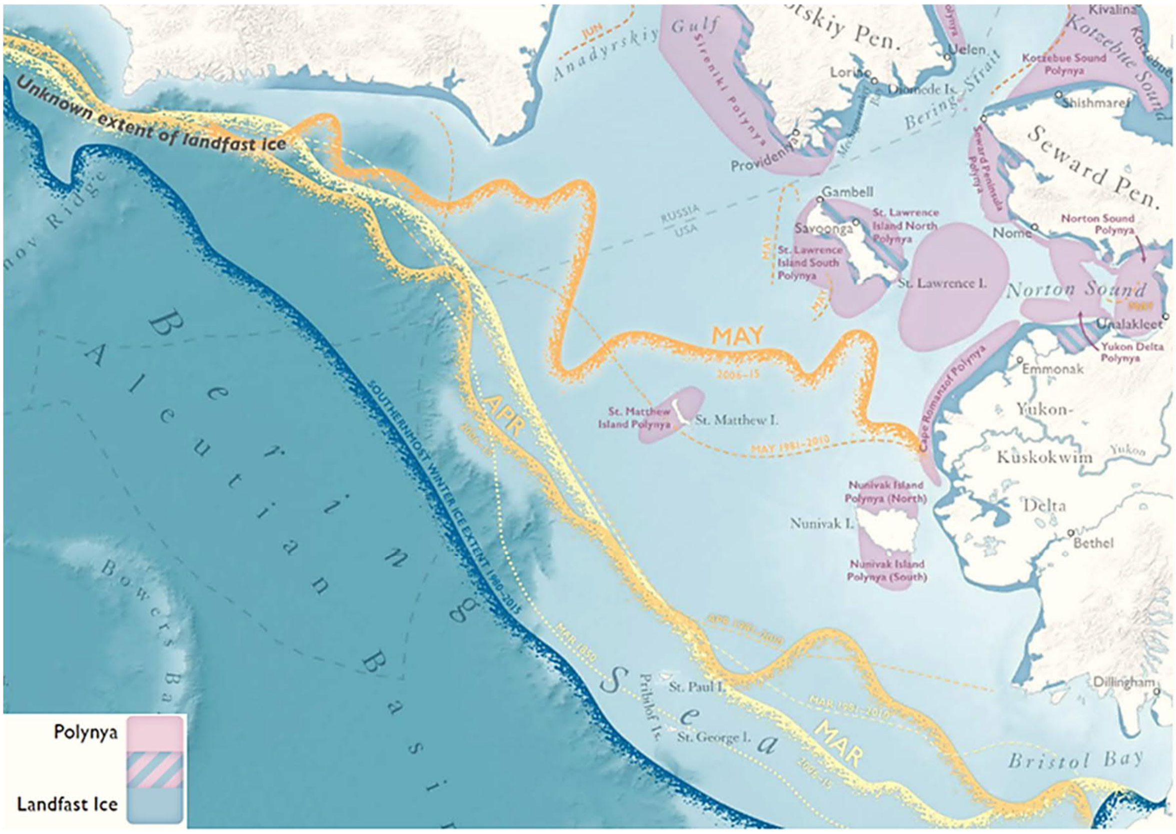


Figure 2-25 – Sea ice retreat in the Bering Sea (Smith, et al., 2017)

The ice concentration in mid-winter is close to 10/10th north of St. Lawrence Island and in the Norton Sound, 3/10th to 8/10th south of St. Matthew's Island and 8/10th to 10/10th between the mentioned areas. Typical ice floe sizes range from 500 m to several kilometers north of St. Lawrence Island, and less than 500 m south of St. Lawrence Island.

Fast ice

The average fast ice extent along the Alaskan coast varies typically from 3 to 30 km. The extreme value is 40 to 50 km in the southern and eastern Norton Sound and offshore Yukon Delta. In some years, the fast ice width is only 0 to 3 km on the coast from the Bering Strait to northern Norton Sound. The annual maximum fast ice width is reached from February to March. The fast ice extent along the Alaskan coast is shown in Figure 2-24 (Smith, et al., 2017).

Ice thickness

The fast ice normally reaches its annual maximum thickness in March. In average years, the maximum thickness reaches about 90 cm. In severe winters, the fast ice may reach a thickness of 150 cm. The ice growth curve for Mekoryuk Bay (Nunivak Island in Figure 2-23) is shown in Figure 2-26.

The pack ice in the Bering Sea is considerably thinner than the landfast ice. This reflects the presence of different stages of ice development in the pack ice. The maximum annual level ice thickness is about 50 to 60 cm in average years and 90 to 100 cm in extreme years for most of the ice cover in the Bering Sea. Between

St. Lawrence Island and the Bering Strait, the level ice thickness reaches 80 cm in average years and 120 cm in severe years.

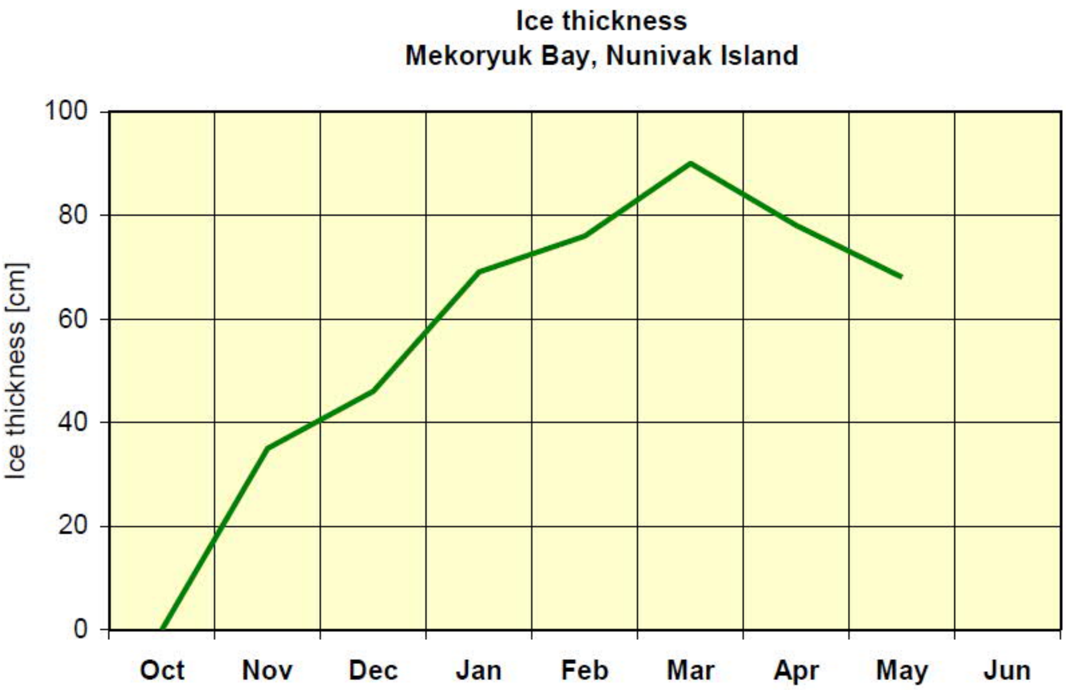


Figure 2-26 – Ice growth at Mekoryuk Bay (Nunivak Island) for an average winter (Source: Aker Arctic Technology Inc)

Ice ridges

Ice ridges are a common feature in the Bering Sea. The ridge frequency in mid-winter is commonly 5 to 10 ridges/km. The total thickness of a ridge is typically 5 to 6 m and the extreme thickness is estimated to be about 20 m.

In the Bering Sea an "ice dam" forms between St. Lawrence Island and the Siberian mainland causing severe ridging west of the Island.

Occurrence of multi-year ice

Multi-year ice floes can occasionally drift through the Bering Strait to the Bering Sea. However, the occurrence of multi-year ice in the Bering Sea is very rare and the concentrations are negligible. Occasional multi-year ice floes have been observed as south as St. Lawrence Island.

Polynyas

Several significant wind-driven polynyas are found in the Bering Sea. They are located south of St. Lawrence Island, to the northern side of Norton Sound, south of Nunivak Island and in Kuskokwim and Bristol Bays (Figure 2-25). The St. Lawrence Island and Norton Sound polynyas are focal points for ice production in the Bering Sea.

2.1.3.3 Summary for the Bering Sea

The following section provides summary tables of key ice information for the Bering Sea (Table 2-9 and Table 2-10).

Table 2-9 – Ice season in the Bering Sea for an average winter

		Central St. Lawrence Island to latitude 58.5-62 deg N	Northern Bering Strait to St. Lawrence Island, Norton Sound
Freeze-up	Average Latest Earliest	Mid December Mid February Late November	Late November Late December Early November
Break-up	Average Latest Earliest	Early June Late June Mid March to Mid April	Mid June Early July Mid May
Number of ice days (per year)	Average Latest Earliest	175 30-60 210	200 140 240

Table 2-10 – First-year ice properties in the Bering Sea

Quantity	Unit	Value	
Level ice			
Thickness (annual maximum) Landfast ice	cm	Average Max	90 150
Thickness (annual maximum) Pack ice, typical	cm	Average Max	50-60 90-100
Thickness (annual maximum), Pack ice (between St. Lawrence Island and Bering Strait)		Average Max	80 120
Rafted ice			
Thickness (annual maximum)	cm	Average	190
Ridges			
Number of ridges per km, pack ice	1/km	Typical	5-10
Consolidated layer, thickness (annual maximum)	cm	Typical	180
Keel, depth	m	Typical Max	3.5 15
Sail, height	m	Average Max	1.0-1.5 2.9

2.2 MULTI-YEAR ICE

This section describes an analysis of assessing the risk of multi-year ice interaction through an understanding of the presence of multiyear ice along the expected transit route. The understanding presented in the section is a result of studying ice charts and current literature.

From the assessment of overall ice conditions in the general seas of transit in the ice charts, the main challenge from multi-year ice lies in the region of the Beaufort Sea/Chukchi Sea. The main area of concern is around Point Barrow located on the northernmost point of Alaska (Figure 2-12). In the last 10 years, there have been occasions where a short passage around Point Barrow would involve interaction with multi-year ice.

Observations of the ice conditions at Point Barrow over approximately the last 10 years show ice dominantly presents between November and July (Figure 2-27). Within the total ice concentrations are concentrations of old ice (Figure 2-28). Old ice is considered to include second-year and multi-year ice. This implies there is an intrusion of multi-year ice against Point Barrow, causing a so-called “blocking” ice event. Due to the prevalence of such cases over the past 10 years, and the likelihood of facing them in future, full consideration regarding ship interaction with multi-year ice must be given.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2009	-	-	-	-	-	-	-	-	0	0	98	98
2010	98	98	98	98	98	98	98	0	0	0	98	98
2011	98	98	98	98	98	98	70	0	0	0	98	98
2012	98	98	98	98	98	98	98	70	0	0	98	98
2013	98	98	98	98	98	98	98	50	0	0	98	98
2014	98	98	98	98	98	98	98	0	0	0	98	98
2015	98	98	98	98	98	98	20	0	0	0	98	98
2016	98	98	98	98	98	98	98	50	0	0	98	98
2017	98	98	98	98	98	98	0	0	0	0	0	98
2018	98	98	98	98	98	98	98	70	0	0	98	98
2019	98	98	98	98	98	98	0	0	-	-	-	-
	98	denotes a concentration of 9+/10										

Figure 2-27 – Recent total ice concentration around Point Barrow (Source: Aker Arctic Technology Inc)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2009	-	-	-	-	-	-	-	-	0	0	1	20
2010	70	70	90	1	40	1	40	0	0	0	1	10
2011	0	0	0	0	0	20	0	0	0	0	1	50
2012	60	60	70	80	50	1	70	20	0	0	0	0
2013	0	0	0	0	0	0	0	0	0	0	40	30
2014	80	50	80	10	10	10	30	0	0	0	10	0
2015	0	0	0	80	40	1	0	0	0	0	1	40
2016	50	20	0	0	0	1	10	1	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	0	0
2018	1	0	0	0	50	60	0	20	0	0	50	90
2019	90	1	20	10	1	1	0	0	-	-	-	-
	1	denotes trace amount										

Figure 2-28 – Recent total old ice concentration around Point Barrow (Source: Aker Arctic Technology Inc)

Current geophysical studies using satellite imagery provide an understanding of a formation of what is deemed the “Multi-Year Gateway” or the “Barrow Arch” that forms around Point Barrow. The phenomenon is a result of multiple interacting features that ultimately release multi-year ice towards Point Barrow. Bathymetry around Point Barrow contains two major shoals (Harrison Bay Shoal and the Hanna Shoal) that create stable anchors against Beaufort drift pack ice, resulting in multi-year ice flowing out of the pack in a gateway between the two.

The first shoal to the east of Point Barrow, the Harrison Bay Shoal, is located some nautical miles off the coast of the North Slope. It presents a northerly extension of the landfast ice and provides a stable point of ice against Beaufort

Gyre driven pack ice, due to the shallow draft and the resulting potential grounded ice features. The second shoal to the northwest of Point Barrow, the Hanna Shoal, provides a stable point against the pack ice with shallow depths. In between the two shoals is mainly a region of the Chukchi Sea, primarily west of Point Barrow (Figure 2-29).

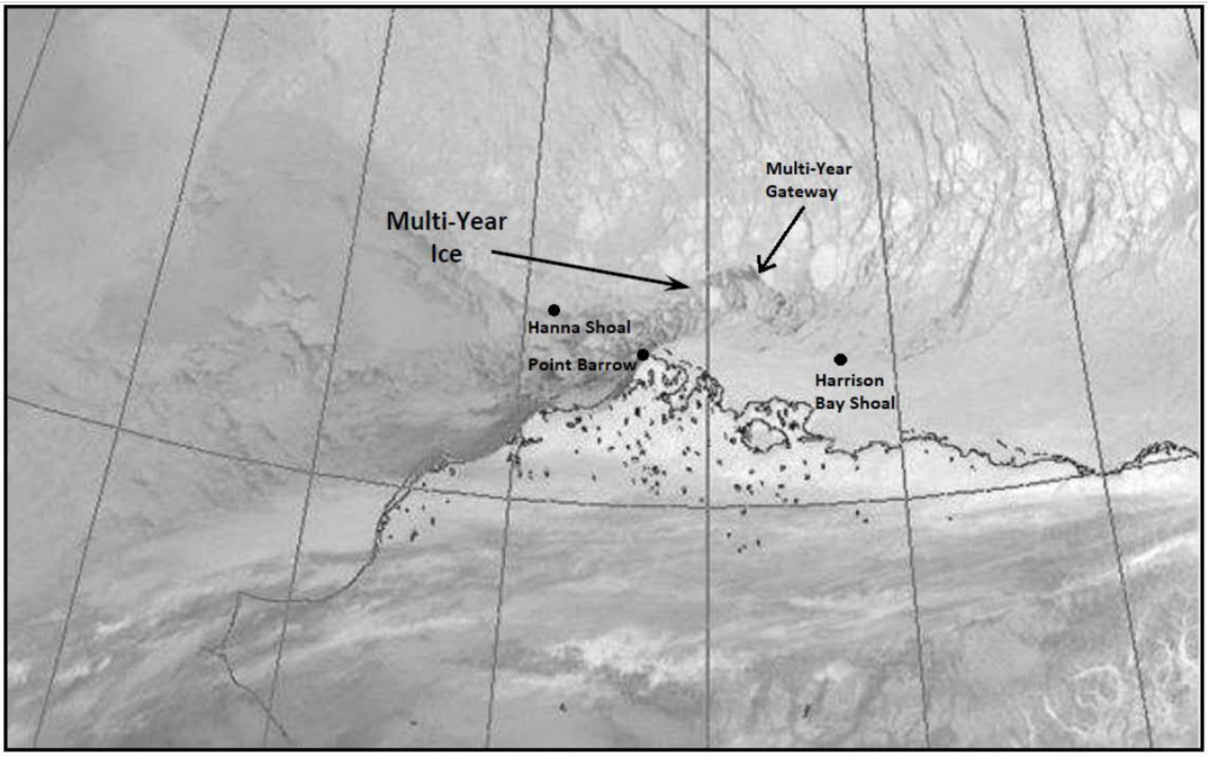


Figure 2-29 – Multi-Year Gateway diagram regarding the locations of major shoals and Point Barrow (Source: Aker Arctic Technology Inc)

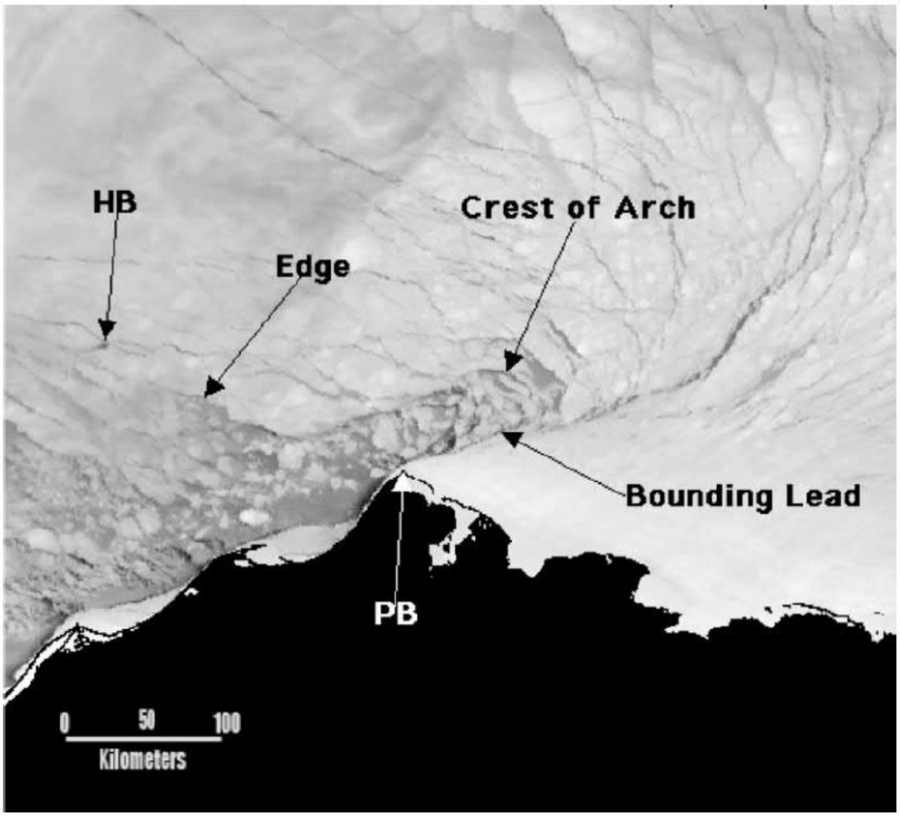


Figure 2-30 – Further detail of the Multi-Year Gateway (PB=Point Barrow, HB=Hanna Shoal) (Source: Aker Arctic Technology Inc)

Looking more locally around Point Barrow (PB) in Figure 2-30, the flaws create a zone of a mix of open water and ice, but with large components of multi-year ice from the polar pack. A bounding lead is usually formed from Point Barrow and along the landfast ice and northeast during these occurrences. The other edge is held by the region around Hanna Shoal (HB). The resulting gateway is represented in the Barrow Arch that would push out multiyear ice floes as the polar pack moves. Overall, the points near Point Barrow present a risk of multi-year ice interaction.

The process, where the coastal flaw lead evolves into a multi-year gateway and where the multi-year ice transfers into the sea, may be subdivided into four events:

– Flaw Lead. A flaw lead develops off the northeast coast of the Chukchi Sea when sustained easterly winds drive the pack ice offshore (Figure 2-31). The width of the lead can range from less than a kilometer to more than 250 km, and the lead can persist for periods that range from less than a day to more than a month.

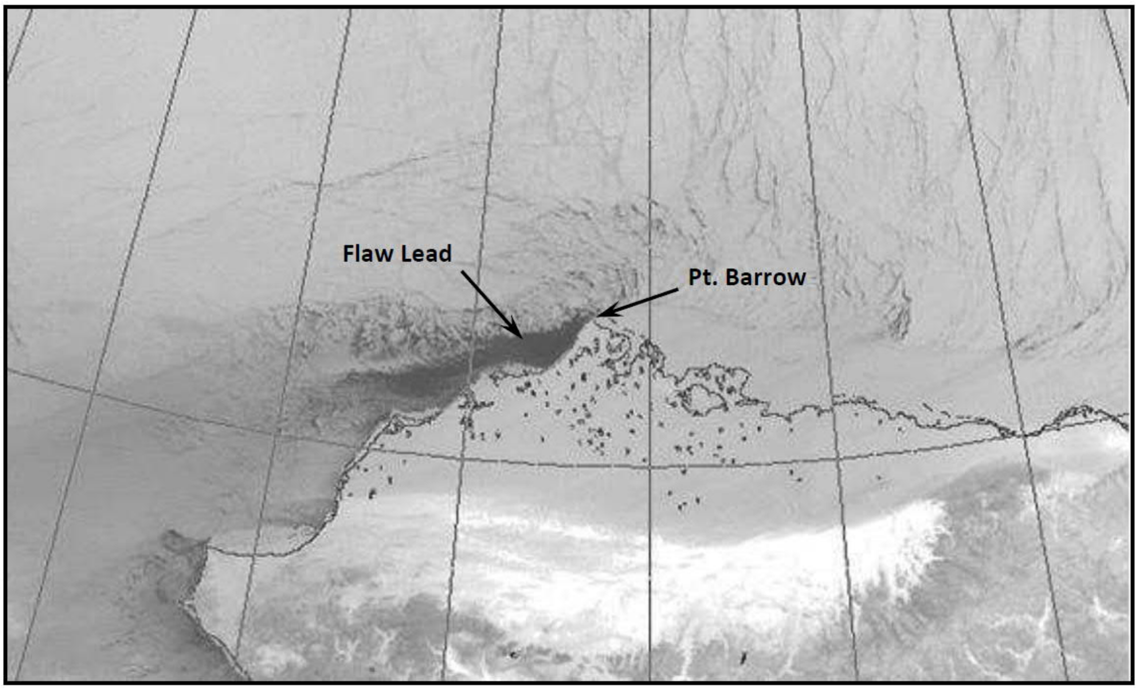


Figure 2-31 – Example of Flaw Lead on January 22, 2013 (Ward, et al., 2015)

– Extended Flaw Lead (EFL). An EFL results when the flaw lead extends to the north and east of Point Barrow (Figure 2-32). This northward extension is caused by westward movement of Beaufort Sea pack ice, which in turn is caused by easterly winds.

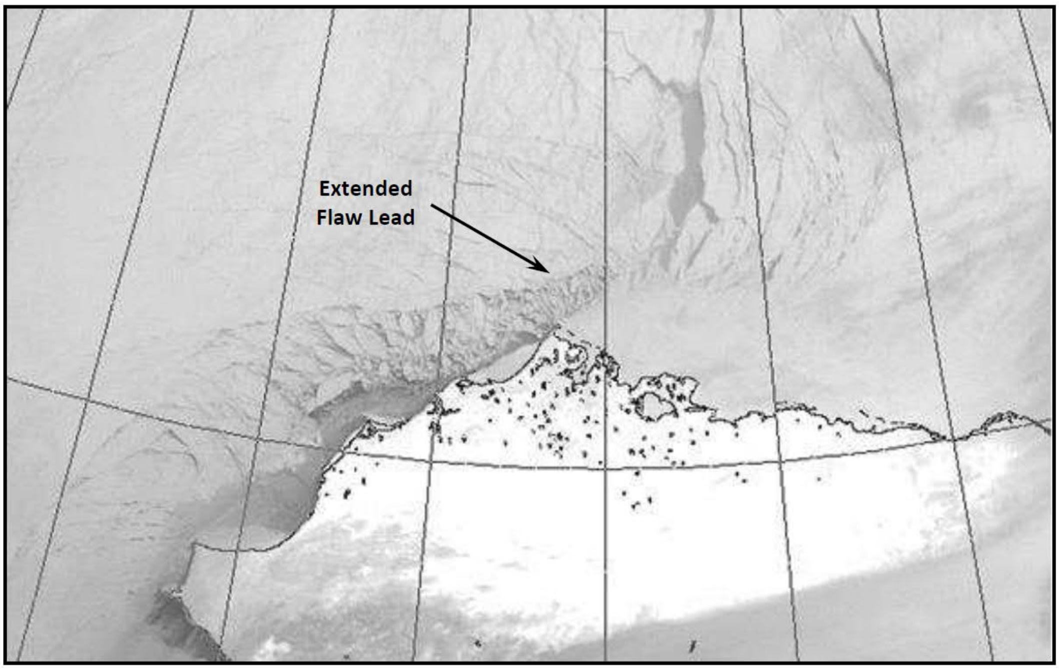


Figure 2-32 – Example of Extended Flaw Lead on February 5, 2013 (Ward, et al., 2015)

– Multi-Year Ice in EFL. Multi-year ice features can enter the EFL if the lead extends sufficiently far north to intersect the southern boundary of such ice (Figure 2-29).

– Multi-Year Gateway. A multi-year gateway exists when multi-year features that have entered the EFL are advected into the region south and west of Point Barrow (Figure 2-33).

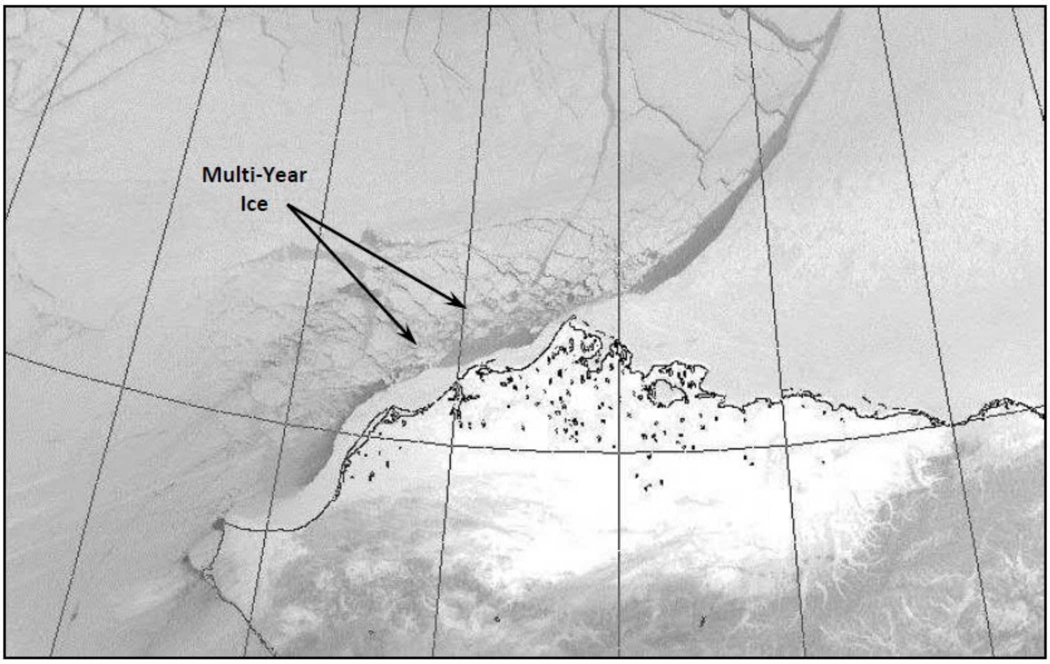


Figure 2-33 – Example of Multi-Year Gateway on March 28, 2012 (Ward, et al., 2015)

The frequency of the stages of development up until the passage of multi-year ice into the gateway is summarized in Figure 2-34, where the number of days of occurrence per yearly winter over 21 years is shown.

For each of these twenty-one winters, all available data were reviewed on a daily basis from December 1 through April 30 to quantify the occurrence of each of the four events that produce the multi-year gateway. It should be noted that each event represented a necessary, but not sufficient condition for the existence of the next event. If multi-year ice was found to be entering the EFL but not reaching the region south and west of Point Barrow, for example, positive occurrences were logged for the existence of the flaw lead, the EFL, and multi-year ice entering the EFL, but not for the multi-year gateway.

Green rows in Figure 2-34 are years of multi-year ice in the gateway and red is a non-occurrence year. All multi-year ice incursions into the Chukchi Sea during the 21-winter study period occurred via the multi-year gateway. The only exception took place in November 2010, when a large-scale southerly advance of pack ice introduced a small concentration of multi floes into the region south and west of Point Barrow. The result shows that in 14 of the 21-year ice flows to Point Barrow from the gateway, and for 15 out of 21 years that multiyear ice was experienced at Point Barrow. Therefore, from a ship specification perspective, the evaluation of these situations is very important. Further detailed investigation should be made regarding ice conditions during these occurrences, together with an evaluation of the probability of encountering multi-year ice.

Winter	Flaw lead	EFL	Multi-Year Ice Enters EFL	Multi-Year Gateway(1)
1993-94	57	39	16	5
1994-95	36	22	9	0
1995-96	42	30	20	3
1996-97	46	29	23	6
1997-98	68	43	33	23
1998-99	34	25	14	5
1999-00	55	41	30	13
2000-01	74	59	33	16
2001-02	47	35	20	8
2002-03	57	29	6	0
2003-04	57	49	20	10
2004-05	51	36	16	0
2005-06	42	31	29	20
2006-07	52	48	7	0
2007-08	49	34	17	0
2008-09	45	31	18	8
2009-10	59	43	24	14
2010-11(2)	35	28	5	0
2011-12	45	32	24	14
2012-13	66	52	0	0
2013-14	40	31	23	15
Avg	50	37	18	7
Max	74	59	33	23
Min	34	22	0	0

Figure 2-34 – Daily occurrences over 21 winter seasons of different stages of development leading to the Multi-Year Gateway (Ward, et al., 2015)

(1) The 14 years in which the Multi-Year Gateway was active are highlighted in green, while the 7 years in which it was inactive are highlighted in red.

(2) In November 2010, multi-year ice entered the region of Point Barrow when the pack ice moved south rather than via an EFL.

2.3 MACKENZIE DELTA

There are several studies available on sea ice and physical oceanographic conditions of the Mackenzie Delta area. Most of the well documented data were collected during the 1970's and 1980's. However, some more recent studies on the assessment of sea ice conditions were conducted by the Canadian Ice Service, Kavik-Axys study for Devon, by the National Oceanic and Atmospheric Administration (NOAA) etc. Thus, the description of ice conditions in the Mackenzie Delta presented in this chapter covers both historically collected and analyzed data, and the last available studies.

2.3.1 STUDY AREA

The study area covers the offshore waters from Herschel Island in the west to Cape Bathurst in the east, and stretches northwards from the coastline to the southern boundary of the polar pack (Figure 2-35). Special attention is given to the nearshore waters that are covered by landfast ice in winter, where a possible location for the GBS is considered. This area is typically bounded by a 20m water depth contour and falls south of 70°N.

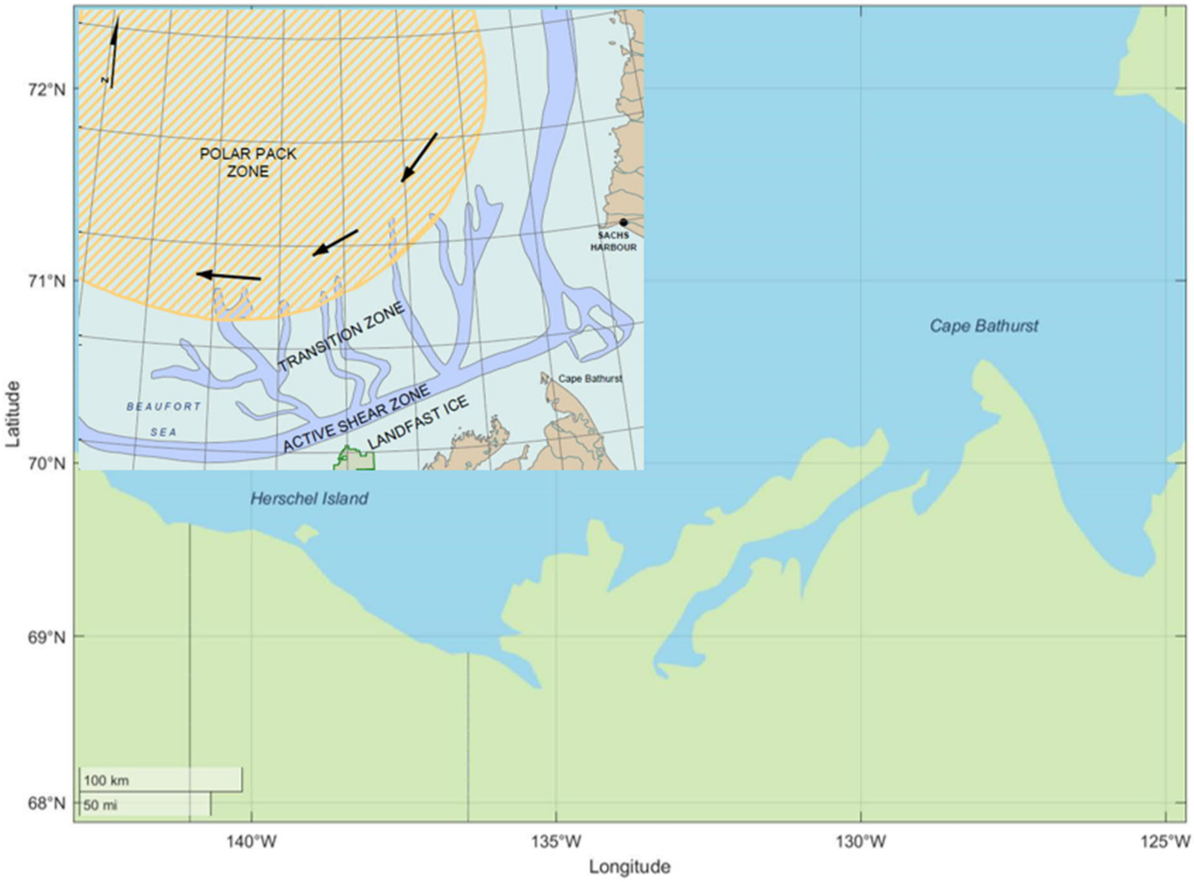


Figure 2-35 – Study area (reproduced from (KAVIK-AXYS, 2004)

2.3.2 AIR TEMPERATURE

The climate of the Mackenzie Delta and the Beaufort coast is dry and cold. Ice and snow cover persist for 6 to 9 months of the year. The average annual mean daily air temperature is approximately -10°C, and the average mean daily maximum and minimum temperatures for the year are -7.5°C and -15°C. Summer temperatures typically range from 4.5 to 8.5°C and the winter mean temperature is –26.5°C.

2.3.3 WINDS AND CURRENTS

Currents on the Beaufort Sea's inshore continental shelf are controlled by winds and modified by the Mackenzie River outflow, interactions with the underlying water layer and local bathymetry. In the absence of strong winds, the Mackenzie River discharge is the dominant factor influencing currents.

The Mackenzie River's discharge into the Beaufort Sea dominates circulation and water properties at a peak from mid-May to mid-June. It continues to dominate circulation through the summer months of ice breakup and open water conditions. Mackenzie River water, after mixing with shelf waters, can be detected at much greater distances from the river mouth, extending as much as 400 km from the shore.

In early summer, the Mackenzie River's discharge peaks, and the outflow creates maximum current velocities that can be greater than 0.5 m/s. Later in the summer and fall, the currents that are associated with the river's discharge progressively decrease. Apart from the influence of this discharge, surface currents in the nearshore areas of the Beaufort Sea are controlled by variations in wind direction and speed during the open water season.

During the winter months, relatively strong northwesterly winds dominate the Mackenzie basin. Large, cold high-pressure areas migrate over the Beaufort Sea to the mainland, remaining over the region for long periods of time. In the summer, warm, southwesterly flows settle over the area, which combined with the presence of the sun, bring warmer temperatures, as presented in Figure 2-36.

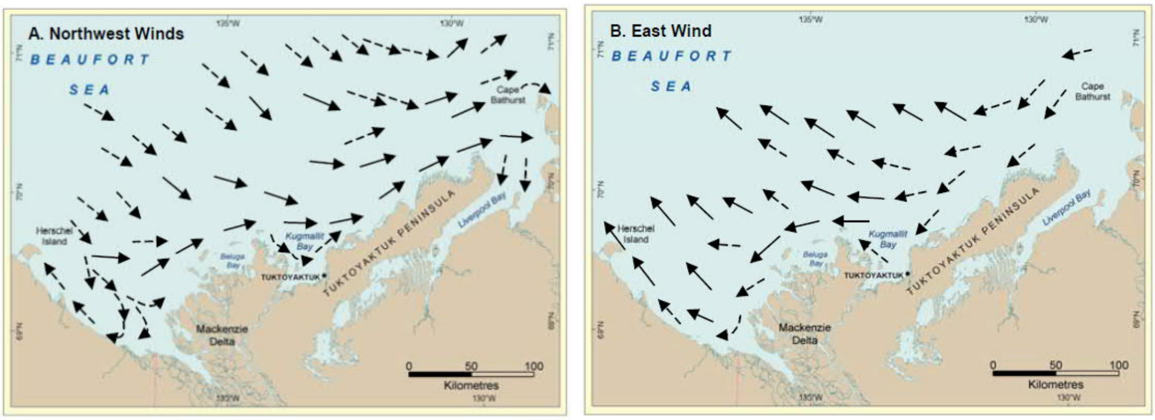


Figure 2-36 – Northwest and east winds in the Mackenzie Delta (Fissel, et al., 2012)

An analysis of 14 years (1994–2007) of wind data measured at Pelly Island on the Mackenzie Shelf shows that winds blowing from the east occur most frequently; nearly twice as often as winds blowing from the west-northwest. However, the strongest winds (those exceeding 12 m/s) nearly always blow from the west-northwest, with a maximum recorded wind speed of 24 m/s. The surface currents generated by the two dominant wind directions generally track the wind direction with a 15–30º rightward deflection. Current speeds are ~2–3% of the wind speed with typical speeds of 0.25–0.4 m/s (up to 0.8 m/s) (Fissel, et al., 2012).

2.3.4 BATHYMETRY

The Mackenzie Shelf at Mackenzie estuary is extremely shallow and flat, with a 10 m isobath occurring as far as 35 km offshore (Figure 2-37). Discontinuous sub-sea bottom permafrost is found throughout. To the north of the Mackenzie Shelf, the sea bottom slopes sharply to depths of greater than 3000 m. This shelf break occurs between the 80 and 120 m isobaths, which is approximately 120 km offshore.

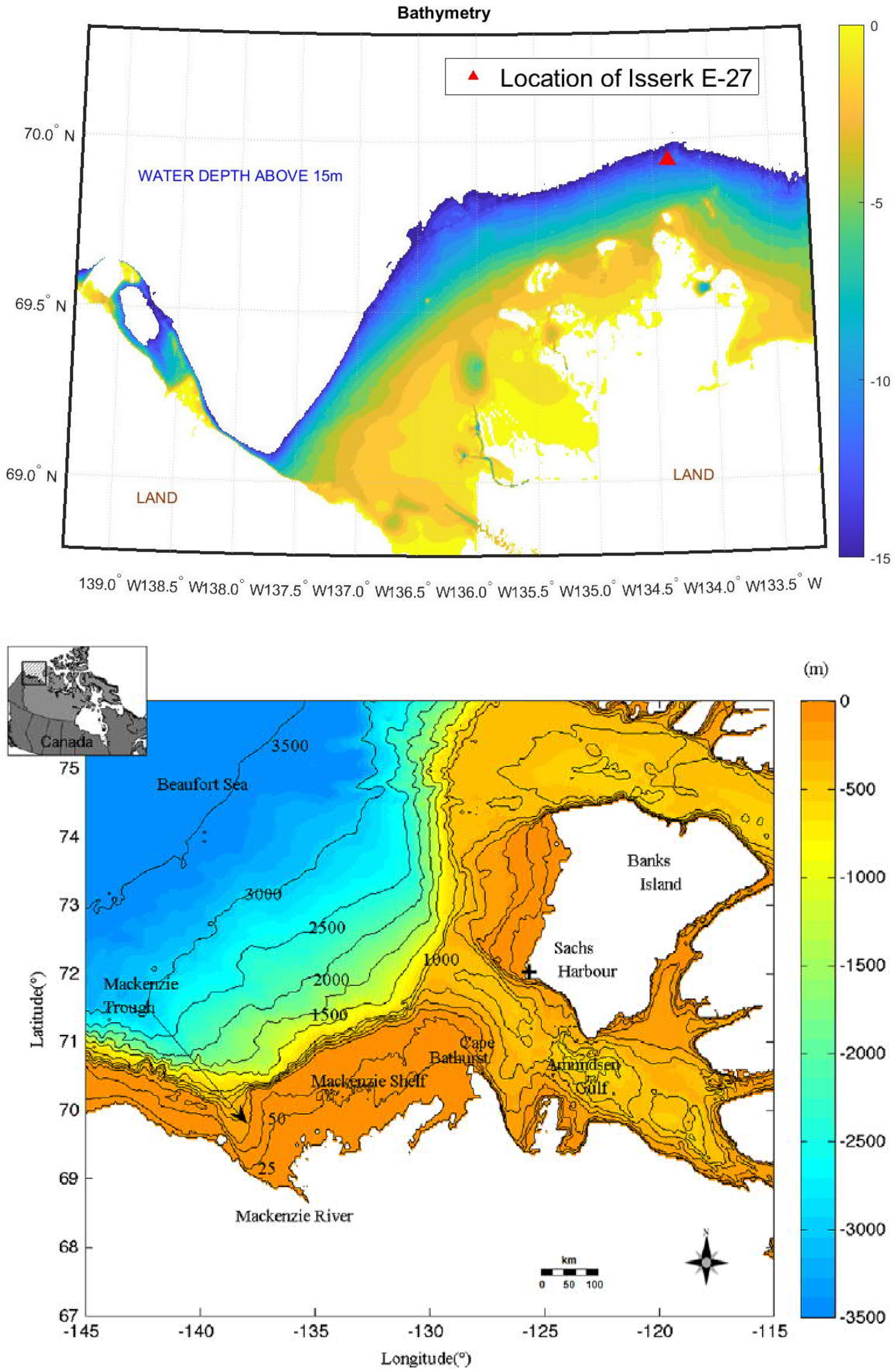


Figure 2-37 – Bathymetry in the Mackenzie Delta (GEBCO, 2020; Mustapha, et al., 2016)

2.3.5 LANDFAST ICE

2.3.5.1 Growth of landfast ice

The first ice formation in the channel mouths of the Mackenzie River, and in the sheltered bays and coastal shallows of the Beaufort Sea, is normally seen in early to mid-October. This new ice cover rapidly extends seaward to water depths of 5 to 10 m as the sea surface cools throughout October and November. In Mackenzie Bay and the coastal areas towards the east, the presence of low salinity surface water caused by river outflow tends to enhance freeze-up. Further offshore, freezing of the sea surface is often delayed by a few days due to higher salinity surface waters.

From initial freeze-up to early November, the landfast ice cover that forms along exposed sections of the coastline (like those off Pullen Island) is quite unstable. Ice movements of a few kilometers per day can occur outside the shelter of protected bays and islands, leads can open and close, and strong southerly or easterly winds can break large sections of the newly forming landfast ice cover away and move it offshore. Average ice drift speeds are in the order of 5–10 cm/sec, with extremes in the range of 50 cm/sec or more. Some rafting and low relief rubble is normally seen in these nearshore parts of the landfast ice, due to relative movements that occur within it as it forms. As freeze-up continues through mid-November and into December, the landfast ice progressively grows seaward.

By mid-December, the landfast ice edge has typically extended further seaward to water depths of about 15 m. The rate of offshore progression of the landfast ice edge and the number of growth steps varies from year to year and depends on the prevailing air temperature, wind and ice conditions. Weather events that involve strong winds from the north or west tend to push the offshore pack ice against the outer edge of the growing landfast ice cover, which in turn creates pressure ridges along its seaward boundary. Some of these ridges are large enough to have keels that ground on the sea floor, stabilizing the landfast ice cover shoreward of the grounded ridge areas.

The outer edge of the landfast ice normally stabilizes near the 20 m water depth contour in late December to mid-January, where it is anchored by bands of grounded ridges. These zones form as a consequence of the freeze-up process in the Beaufort Sea.

Constrained by bathymetric effects, the stability of the landfast ice extent in the Beaufort Sea has been observed over the past several decades. Based on the conducted studies, the dates of significant changes in the landfast ice in the Beaufort Sea were examined (Table 2-11).

Based on the studies conducted by (Danielewicz & Pilkington, 1980) it was found that, on average, the floating zone of the landfast ice extends to about a 20 m isobath. Later, Radarsat imagery acquired in 1996–2004 across the eastern Chukchi Sea to the western Beaufort Sea, showed broad stable extensions of landfast sea ice, which did not show any significant difference from the 1970s (Nghiem, et al., 2014). From recent available studies with the application of Resolution Imaging Spectroradiometer images it was observed that the lead in 2013 and the landfast ice edge in 2012 were both found to form a 25 m isobath by a bathymetry conformity analysis with data from the International Bathymetric Chart of the Arctic Ocean (Nghiem, et al., 2014).

Table 2-11 – Dates of significant changes in the landfast ice in the Beaufort Sea

Date	***Event***
Early October	New ice growth begins
Late October	Open water rare
Mid November	Stable shorefast ice with light ridging
Late December	Shorefast ice extends to 20 m isobath with moderate ridging
Late January	Fast ice at maximum extent, severe ridging at interface with pack ice
Late May	Rivers flood onto nearshore fast ice
Mid June	First appearance of surface melt pools
Late June	First openings in shorefast ice
Early July	End of stable ice
Late July	Ice free to 10 m isobath
Source: (Danielewicz & Pilkington, 1980)	

The extent of landfast ice for the years 1973 to 1979 (maximum extent in May and June), and 1997-2002 is shown in Figure 2-38.

Although the specifics of the landfast ice growth patterns in the Beaufort Sea vary annually, the outer edge of the landfast ice tends to stabilize near the 20 - 25 m water depth contour in most years. The maximum extent of the landfast ice cover can be reached anytime between early January and mid to late March. However, once reached, the overall position of the landfast ice edge generally changes little, even though flaw leads continually open and close along its outer boundary.

The surface topography of the landfast ice is generally smooth out to water depths of 6–8 m. Beyond this depth, it progressively becomes more heavily deformed with rafted areas, pressure ridges and rubble. The landfast ice can be extremely rough near its outer edge, in water depths between 15 m and 20 m (KAVIK-AXYS, 2004).

During the winter, a system of shore leads, which open and close, and a polynya which forms in the vicinity of Cape Bathurst, run parallel to the mainland coast and the west coast of Banks Island.

a)

b)

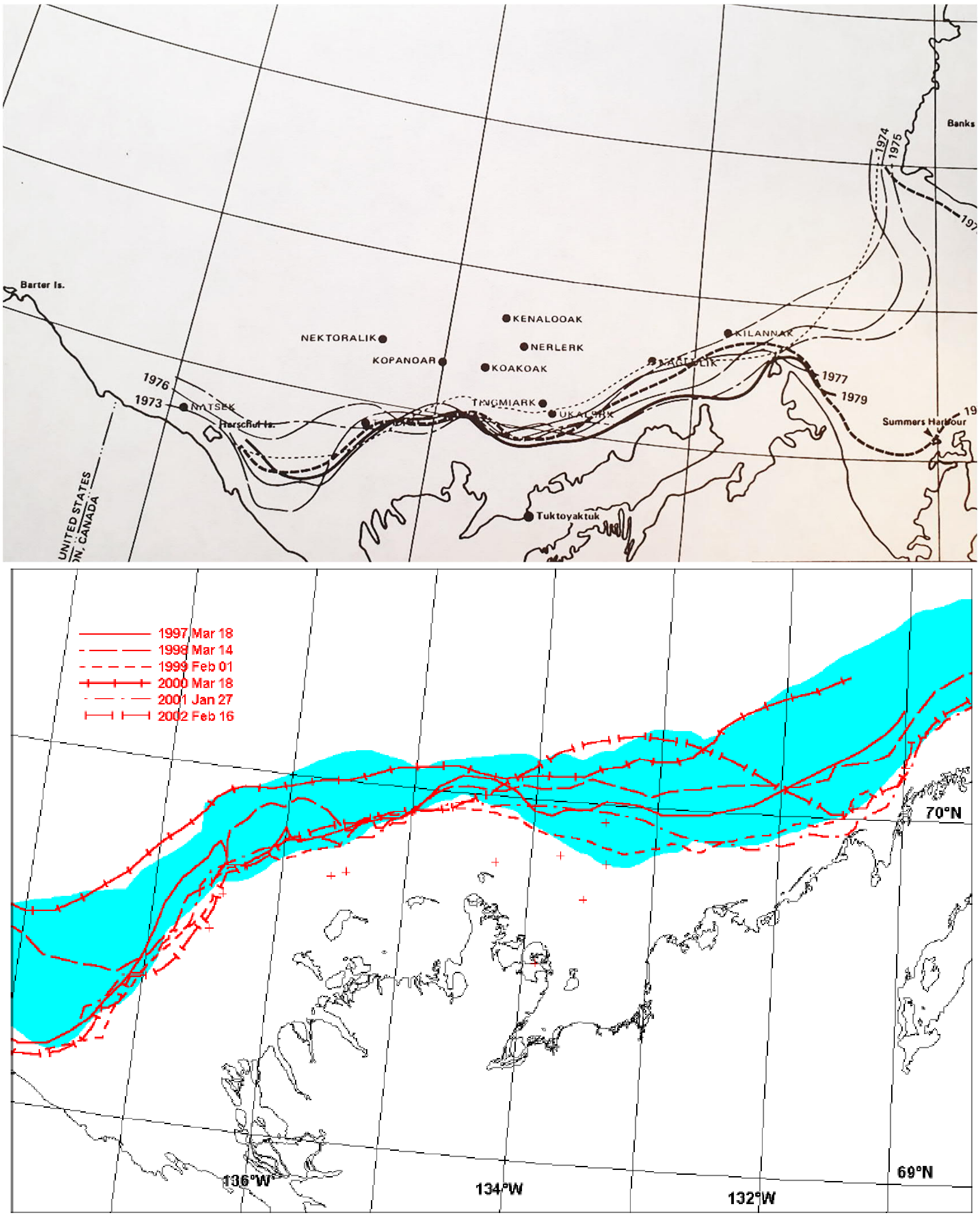
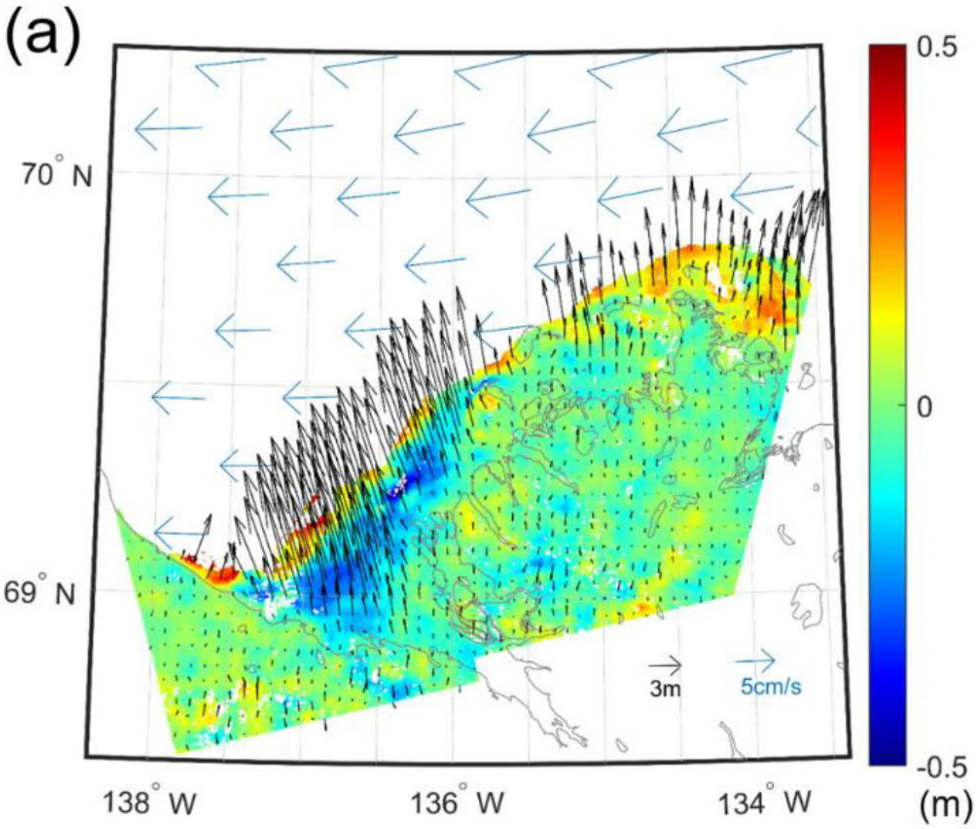


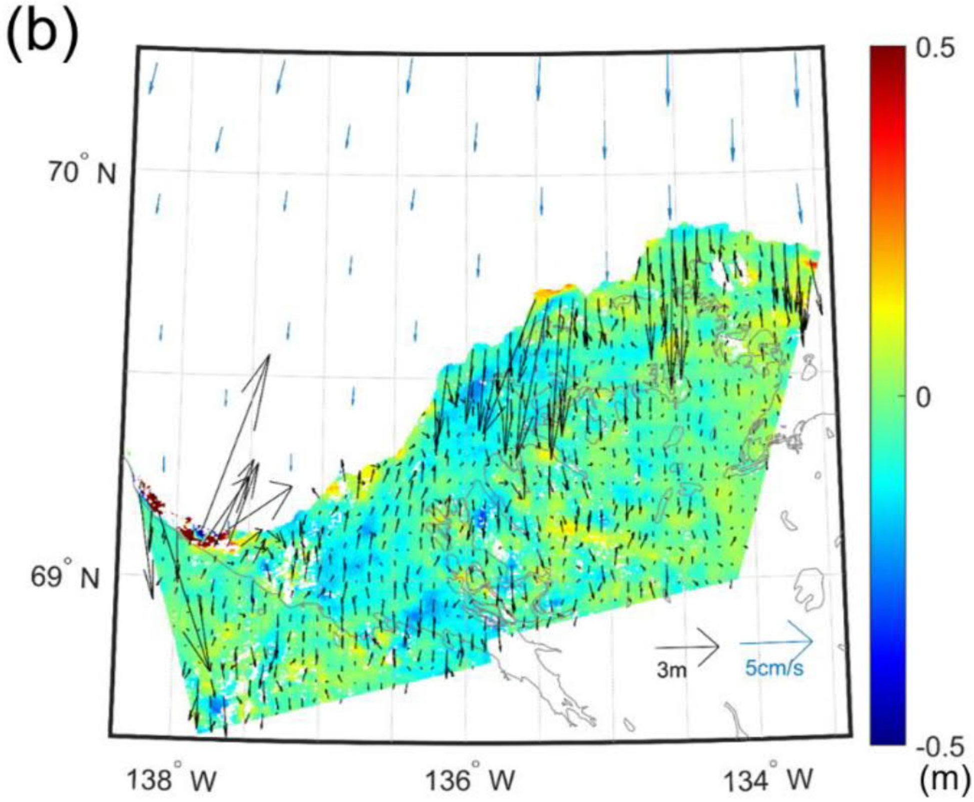
Figure 2-38 – Maximum landfast ice extent in winter, from the winters of a) 1973 to 1979 and b) 1997-2002 (Danielewicz & Pilkington, 1980; KAVIK-AXYS, 2004)

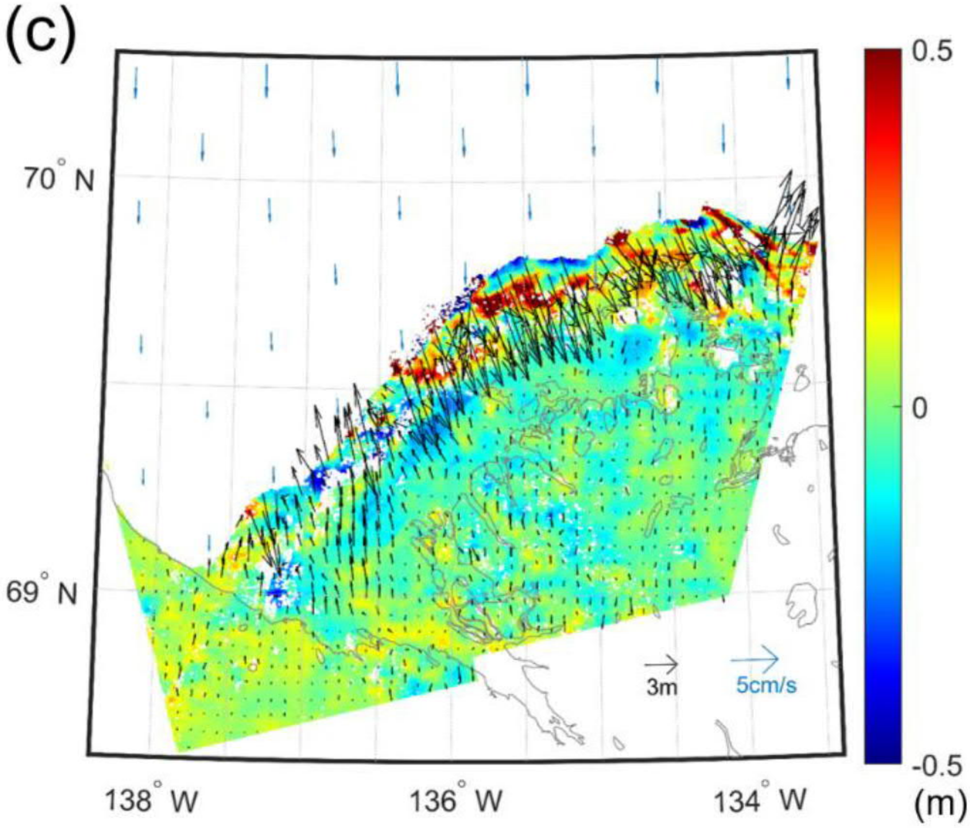
Extensive study was conducted (Choe, et al., 2020) for an investigation into the growth and displacement of landfast ice along the shoreline of the Mackenzie Delta. Three-dimensional (3D) offsets of the landfast ice were reconstructed on the same dates during the November 2017-April 2018 and 10 October 2018-May 2019 annual cycles. The results showed horizontal and vertical displacements of floating landfast ice caused by ice breakups and pressure ridges which are mainly driven by drift sea ice motions and the Mackenzie Delta discharges.

Figure 2-39 shows the results provided by (Choe, et al., 2020) which describes the movements of the landfast ice during the 2017-2018 cycle compared to the average daily motions of drift sea ice during the same period. In January 2018, the floating landfast ice showed horizontal displacements towards the northwest, which are consistent with the direction of the Mackenzie Delta discharges towards the Beaufort Sea and the drift sea ice motions heading west along the coastline (Figure 2-39a).

In late January to early March 2018, sudden upward vertical offsets of >0.5 m were observed during 12- and 24-day intervals (Figure 2-39b and Figure 2-39c). These were considered to be pressure ridges formed by the collision between landfast ice and drift sea ice. The drift sea ice motions were confirmed to move towards the land from the north during the same periods. Overall, the floating landfast ice changes for the 2017-2018 cycle are characterized by the horizontal offsets heading northwest and the vertical downward offsets expanding towards the Beaufort Sea's coasts out of the Mackenzie River mouth (Figure 2-39d).




(b)
70° N
69° N
138° W
136° W
134° W
3m
5cm/s
0.5
0
-0.5
(m)


(c)
70° N
69° N
138° W
136° W
134° W
3m
5cm/s
0.5
0
-0.5
(m)

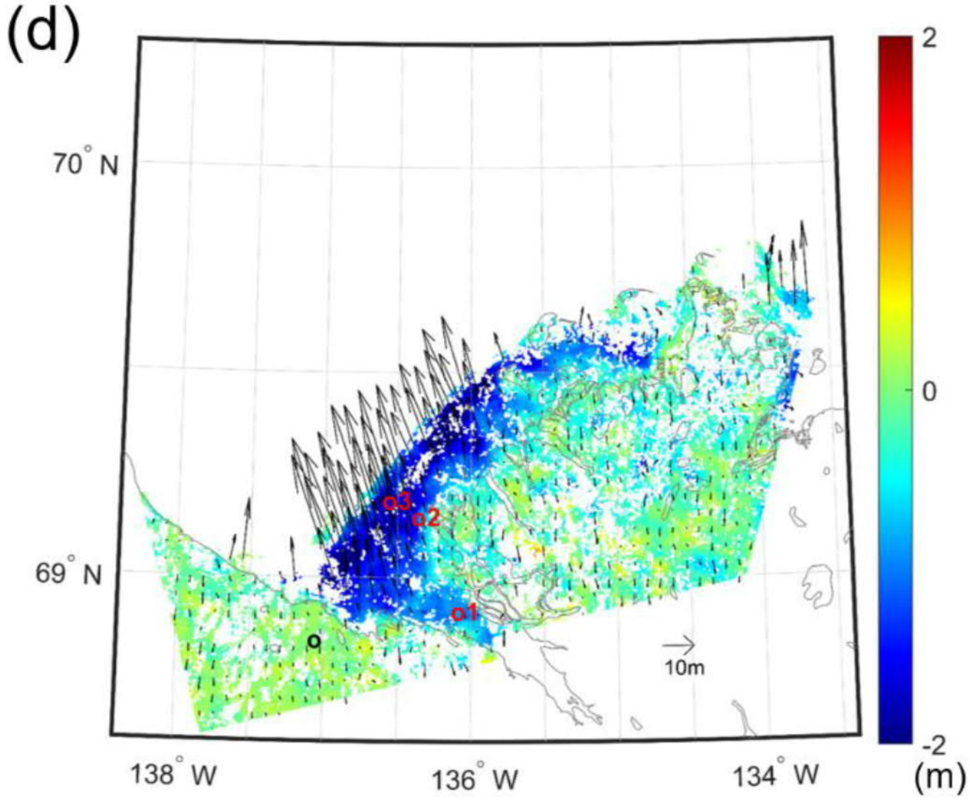


Figure 2-39 – Time of measurements (a) 2018/01/13-2018/01/25. (b) 2018/01/25-2018/02/06. (c) 2018/02/06-2018/03/02. (d) Total cumulative offsets between 2017/11/26 and 2018/04/07 (Choe, et al., 2020)

The colour bars in Figure 2-39 represent vertical offsets, and the black arrows represent horizontal offsets reconstructed from east-west and north-south offsets. The pale blue arrows represent the averaged drift sea ice motions during the same period. Note that the sizes of the arrow scale bars vary relative to the changes for each period. The red (landfast ice; LFI 1-3) circles represent the spots for time-series analysis.

As a result, it was found that LFI 1, formed close to the land, showed little variation in north-south and east-west offsets, similarly to the land. Only vertical offsets of ~-1 m. LFI 2 and LFI 3, close to the seaward edge, showed faster growth, particularly in November to January, and reached up to ~2.5 m.

The horizontal displacements towards north are likely affected by freshwater discharges from the Mackenzie River and surrounding channels flowing into the Beaufort Sea. The horizontal displacements towards west correspond to drift sea ice motions mostly heading west, which are driven by wind and ocean currents. The time-series analysis revealed the most significant growth and displacement of landfast ice occurs between November and January.

2.3.5.2 THICKNESS OF LANDFAST ICE

Shorefast ice generally begins to grow in shallow waters and sheltered bays. The landfast ice grows in thickness at a rate of about 1 cm per day throughout the Beaufort Sea until just prior to breakup. The mean thickness of the landfast ice based on (Danielewicz & Pilkington, 1980) is presented in Figure 2-40.

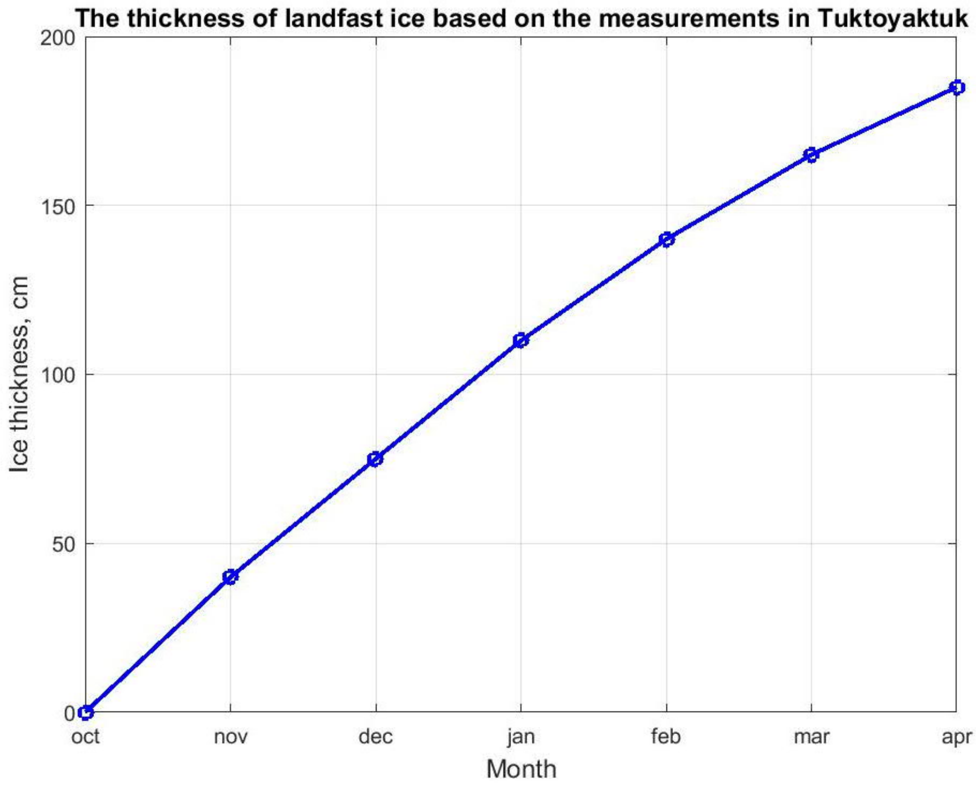


Figure 2-40 – Mean thickness of landfast ice (reproduced from (Danielewicz & Pilkington, 1980))

More recent available landfast ice growth curves and thickness values that are representative of the ice cover near Tuktoyaktuk for the period of 1991/92 to 2001/02 are presented in Figure 2-41.

This figure includes:

- mean ice thickness from measurements at Tuktoyaktuk over the 1961 to 1990 period, provided by a Canadian Ice Service (CIS) program,
- minimum and maximum bounds for level ice thicknesses in the landfast ice zone, based on industry studies carried out during the 1970s and the early 1980s (EIS curves),
- estimated ice growth curves and ice thickness values for each winter from 1991/92 to 2001/02, based on air temperatures measured in Tuktoyaktuk by Environment Canada.

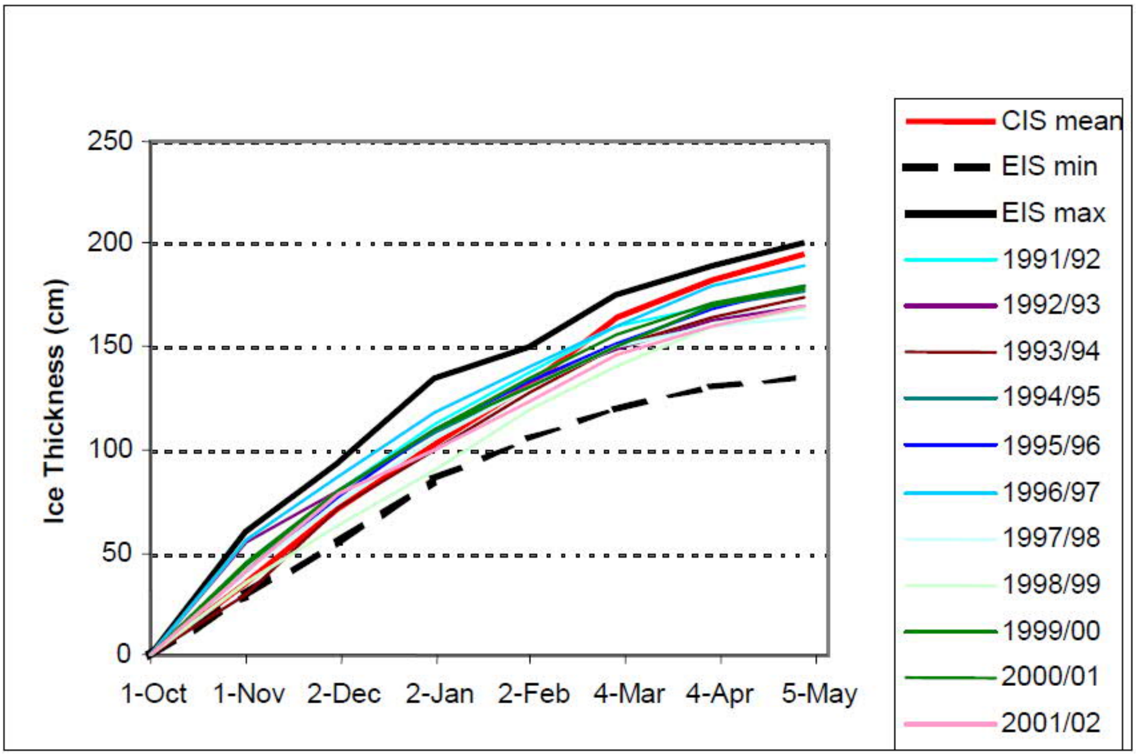


Figure 2-41 – Different data sources of landfast ice measurements (KAVIK-AXYS, 2004)

Based on this data, it is reasonable to expect typical ice thickness values of 0.8 m, 1.2 m and 1.6 m in the Beaufort Sea's nearshore landfast ice by mid-December, late January and mid-April, respectively. Maximum ice thickness values of almost 2.0 m are predicted from the growth curves for colder years.

However, as was discussed previously and presented in Figure 2-39, rubble and ridge formation often occur in the Mackenzie Delta, and the ice thickness significantly increases.

2.3.5.3 Break-up period

Break-up in the nearshore waters of the Canadian Beaufort Sea normally begins in early to mid-June, with near total ice clearance typically seen in water depths to about 20 m by late July. Significant melting first occurs immediately adjacent to the shoreline and is enhanced by Mackenzie River discharge and flooding of the ice surface in early June. The fracturing of the ice barrier is followed by the disintegration of the ice sheet north of Pullen and Richards Island. As a result, these areas, typically, remain ice covered later. Large sections of the landfast ice cover tend to fracture off from the outer edge and then drift northwards during this period. The ice break-up process normally clears all ice from the southern areas by mid-July and from the more northerly parts of Devon's leases by late July. The most western point of Devon's lease area lies about 140 km west of Tuktoyaktuk, while the northern limit of the eastern part the lease area is roughly 50 km north of Tuktoyaktuk. The ice sheet fractures into floes, which may be tens of kilometers in diameter, which then drift offshore under the influence of easterly winds (KAVIK-AXYS, 2004).

2.3.5.4 Open water period

The open water period in the southern Beaufort Sea usually lasts for about three months, from mid to late July until early to mid-October, as presented in Figure 2-42. During this period, large areas of open water are common in the nearshore coastal zone. However, pack ice can move into the Beaufort Sea's shallow waters under the influence of winds from the northerly quadrants. Pack ice intrusions occur most commonly in fall. These ice intrusions can quickly bring first year ice and multi-year floes from the northerly polar pack into the Beaufort Sea's coastal waters where the heavier floes within this pack ice generally ground in water depths between 12 m and 20 m (KAVIK-AXYS, 2004).

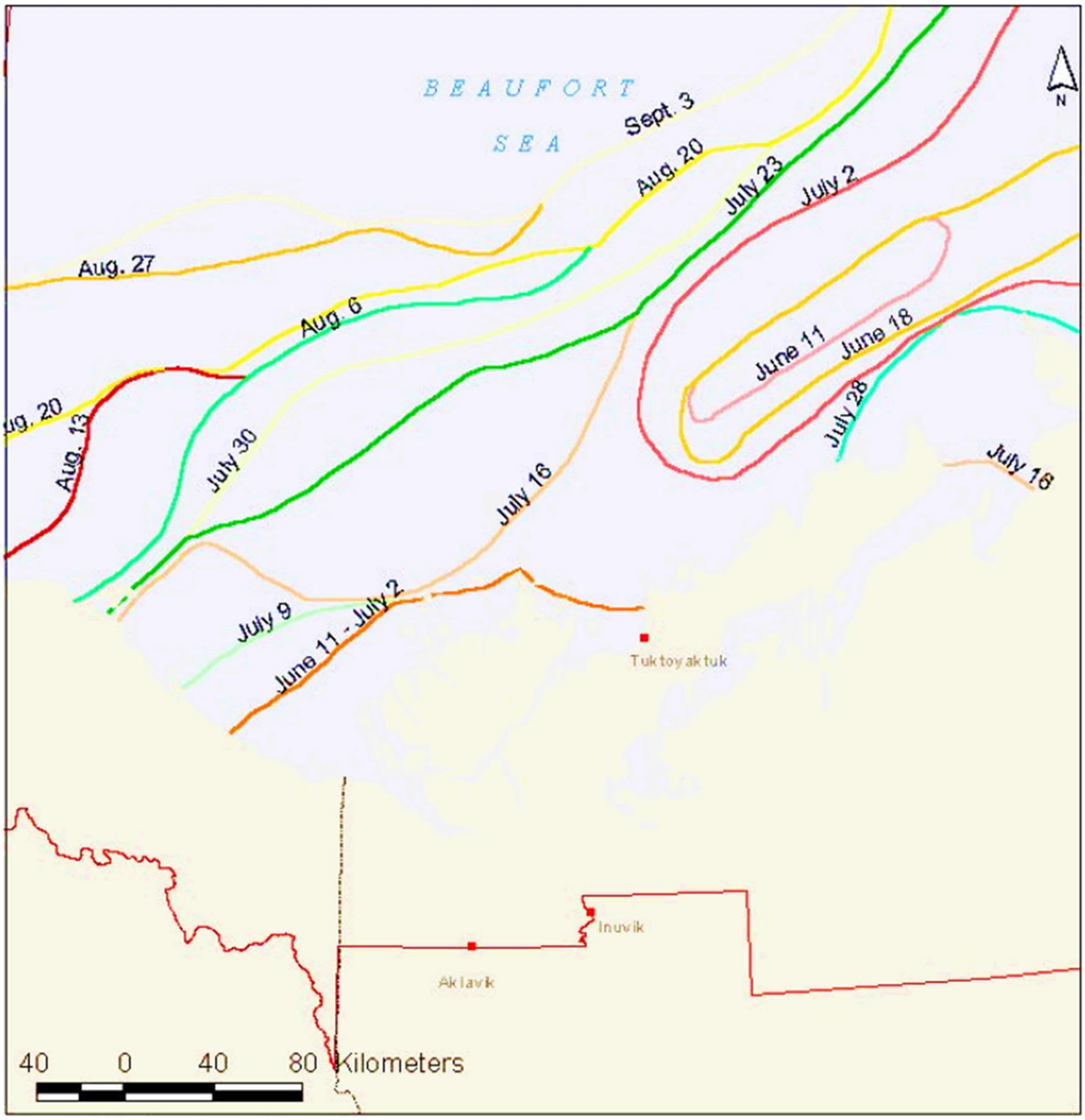


Figure 2-42 – Ice clear dates in the Mackenzie Delta (Melnyk, 2001)

2.3.5.5 Ridges

The ice cover is generally smooth in the landfast ice zone with water depths to 5–6 m. Beyond this water depth, ridging in the landfast ice becomes more common, with the frequency of ridges and rubble ice features increasing with distance offshore. Typically, the ice cover in water depths from 5–10 m is lightly to moderately ridged, with 2–10 ridges/km. In water depths from 11–15 m, the frequency of ridges and rubble areas is higher, in the range of 10–30 ridges/km. At the outer edge of the landfast ice, in 15–20 m of water, ridging is generally severe. Here, ridge frequencies of 30–50 ridges/km are not uncommon and extensive areas of level ice are rarely seen (KAVIK-AXYS, 2004).

Upward looking sonar measurements in waters beyond the landfast ice off the Mackenzie Delta suggest that ridges with a draft greater than 20 m occupy only 0.1% of the ice surface. If a typical ridge section is assumed to be in the order of 100 m wide, this corresponds to approximately one such ridge per 100 km of ice.

2.3.6 SUMMARY OF ICE CONDITIONS IN THE MACKENZIE DELTA

Summer (July-September)

In the summer, the area is generally ice free as presented in Figure 2-43.

Early winter (October-December)

The freeze-up starts generally in early October from the shore and 100% ice cover develops during the month. In November the ice at shore stabilizes and forms an area of landfast ice. In early winter the ice cover is mostly thin first-year ice with a thickness of 30-70 cm. The maximum level ice thickness reaches about 90 cm by the end of December in average years and 120 cm in severe years.

Ice deformation in the landfast ice zone is limited and is formed in early winter before the ice becomes landfast. Typical ridge frequency is assumed to be 2-5 ridges/km. Grounded ice ridges are common in water depths less than 15 m but can be observed in water depths up to about 20 m.

Mid winter (January-March)

The landfast ice gradually extends to deeper water, and by March it generally reaches the 20 m isobath. The level ice thickness reaches about 150 cm in March during average years and about 180 cm in severe years. Extensive shear ridging occurs at the landfast ice edge, between the landfast ice and pack ice.

Late winter/Early summer (April-June)

The late winter ice conditions are similar to those of mid-winter, except for an increase in ice thickness. Also, the landfast ice may extend to water depths up to about 30 m. The maximum annual level ice thickness is reached normally in April-May and is about 180 cm in average years and 200 cm in severe years.

In June, the landfast ice melts and starts fracturing. The nearshore areas off Prudhoe Bay and Tuktoyaktuk have broken up typically by early to mid-July.

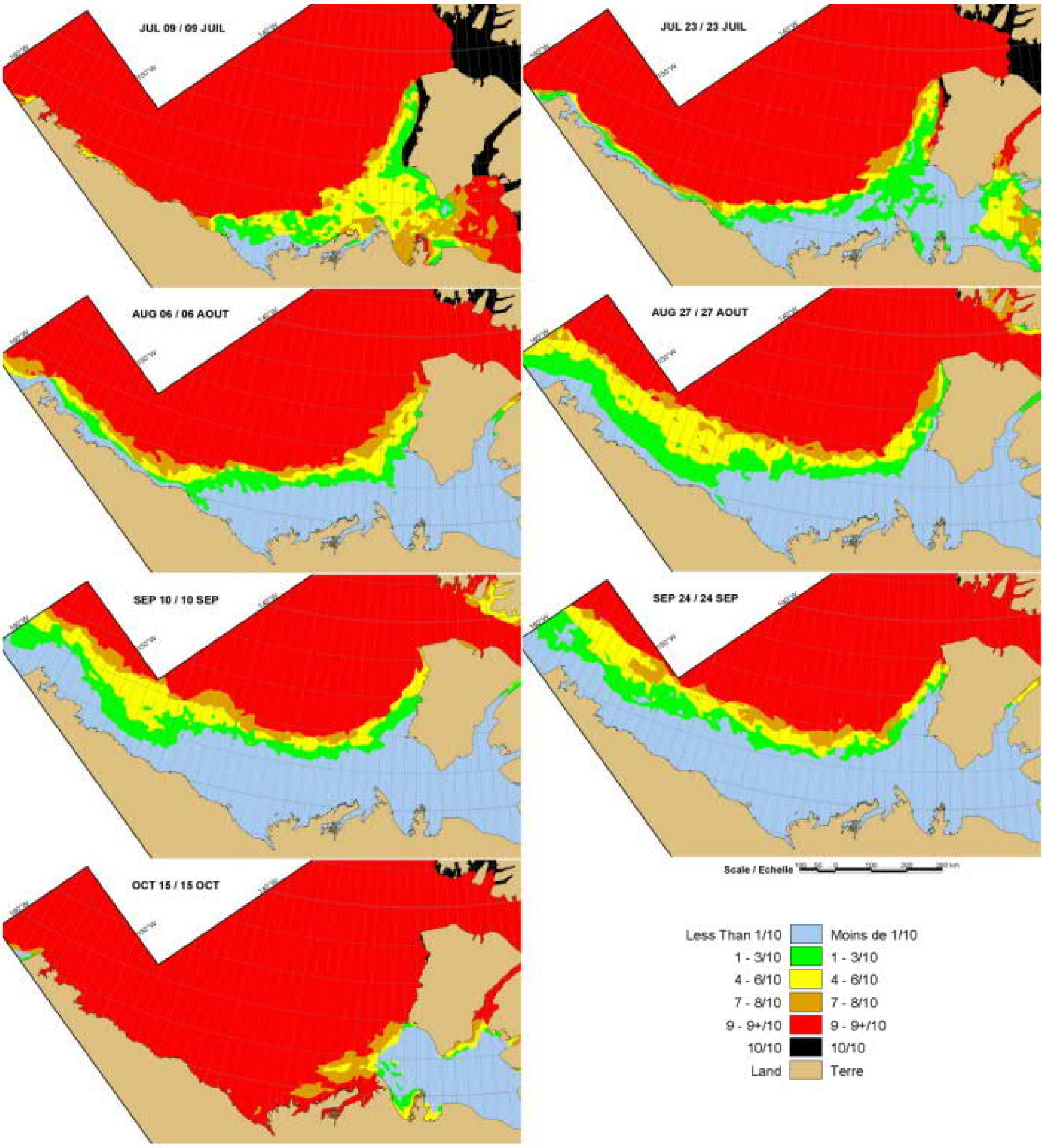


Figure 2-43 – Median (1971–2000) distributions of ice concentration in the Beaufort Sea at weekly intervals between 25 June and 15 October (Fissel, et al., 2012)

3 ICE PROFILES

For the transit simulation, ice profiles are assigned to different legs of the transit route defined in Figure 3-1. The ice profiles for the legs are derived from ice conditions for various sea areas / segments, using the information presented in the previous sections. The ice conditions required for transit simulation are generated for every sea leg / segment for an average type of winter.

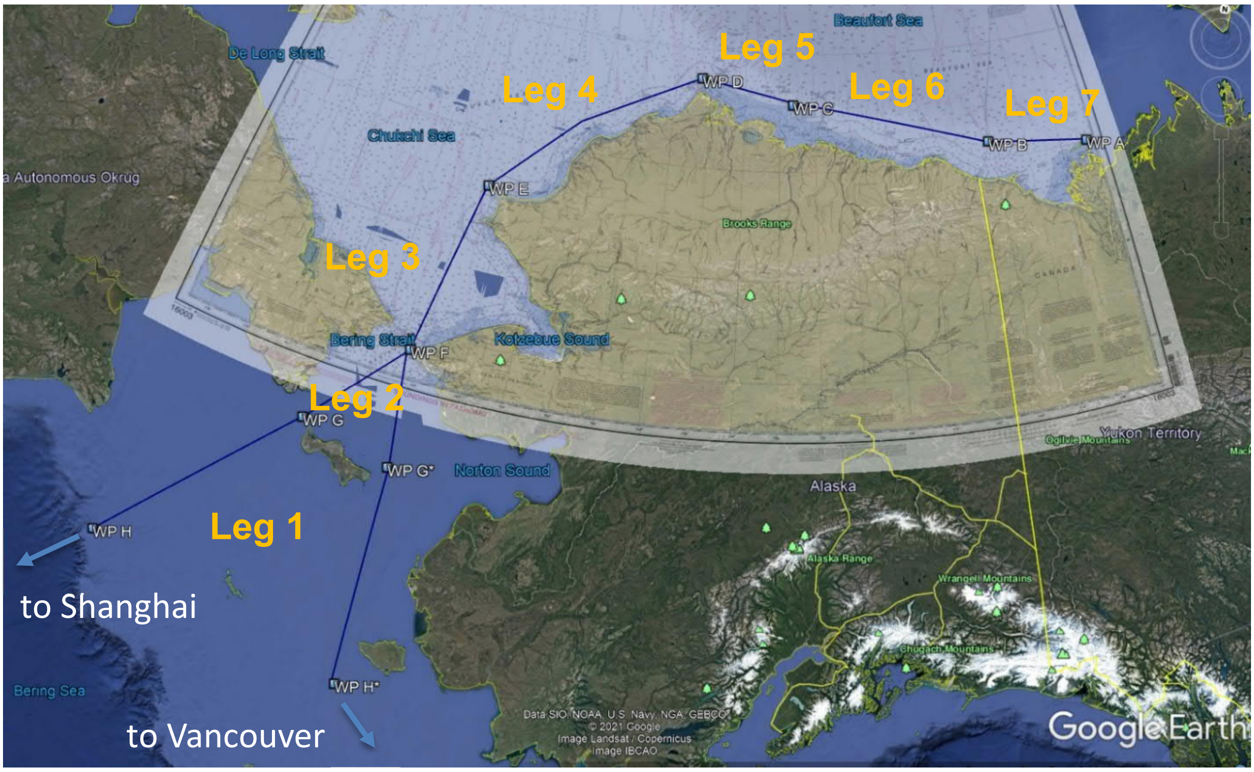


Figure 3-1 – Scheme of the route to the Mackenzie Delta for generation of typical ice profiles (Source: Aker Arctic Technology Inc)

Based on a review of the ice conditions presented in the previous section, discrete ice profiles for the following segments are determined:

- Bering Sea Central – from way points H (60°15'N, 178°50'W) or H*(60°15'N, 178°50'W), representing maximum distribution of compacted ice cover in central part of the Bering Sea for average winter, to way points G (64°00'N, 172°10'W) or G*(63°30'N, 168°00'W), located close to St. Lawrence Island.
- Bering Sea North – from way points G or G* to the Bering Strait (way point F - 65°45'N, 168°30'W).
- Chukchi Sea South – from the Bering Strait to Cape Lisburne (way point E - 69°0'N, 167°0'W).
- Chukchi Sea Northeast – from Cape Lisburne to Point Barrow (way point D - 71°40'N, 156°30'W).
- US Beaufort Sea West – from Point Barrow to Harrison Bay (way point C - 71°15'N, 151°10'W).
- US Beaufort Sea East – from Harrison Bay to way point B (70°20'N, 140°10'W).
- Canadian Beaufort Sea – from way point B to way point A (70°00'N, 134°15'W) near to proposed location of the Mackenzie Delta GBS(s).

Monthly ice profiles shown in Table 3-1 are generated for an average year for the transit simulation of the Mackenzie Delta LNG project.

In general, it should be noted that these ice profiles do not take into account multi-year ice. At this stage it is assumed that multi-year ice floes are avoided using 'tactical navigation'.

Using 'tactical navigation' means that the ice profile is slightly modified so that the vessel will avoid the largest ridges and use open water leads in ice of lower concentration. In real practice, this is achieved by choosing the most optimal route in ice using current satellite images, detailed ice charts and forecasts. Not increasing the distance travelled in ice using tactical navigation the simulation adjusts the concentration of ice encountered, reduces the mean ridge thickness (by 50% from maximum) and reduces the ridges per kilometer (by 50%).

Table 3-1 – Ice profiles for the route 'Mackenzie Delta - Bering Sea ice edge' for an average year

Leg No	**Unit**	**Leg 1**	**Leg 2**	**Leg 3**	**Leg 4**	**Leg 5**	**Leg 6**	**Leg 7**
Waypoints		H-G, H*-G*	G (G*)-F	F-E	E-D	D-C	C-B	B-A
Sea area name		Bering Sea, central	Bering Sea, north	Chukchi Sea, south	Chukchi Sea, northeast	US Beaufort Sea, west	US Beaufort Sea, east	Canadian Beaufort Sea
Length	[nm]	285	145	200	270	110	230	120
January								
Max. level ice thickness	[m]	0.2	0.4	0.7	0.8	1.1	1.1	1.1
Concentration	[%]	80	95	95	98	98	98	98
Mean ridge thickness	[m]	0	3	5	6	6.5	6.5	6.5
Ridges per kilometer	[1/km]	0	4	5	5	8	8	8
February								
Max. level ice thickness	[m]	0.4	0.6	0.9	1.1	1.3	1.3	1.3
Concentration	[%]	90	98	95	98	98	98	98
Mean ridge thickness	[m]	3	4	6	7	8	8	8
Ridges per kilometer	[1/km]	5	5	5	8	8	12	12
March								
Max. level ice thickness	[m]	0.5	0.7	1.1	1.3	1.5	1.5	1.5
Concentration	[%]	90	98	95	98	98	98	98
Mean ridge thickness	[m]	4	4.5	6	7	8	8	8
Ridges per kilometer	[1/km]	7	7	5	8	10	12	12
April								
Max. level ice thickness	[m]	0.5	0.8	1.3	1.5	1.6	1.6	1.6
Concentration	[%]	90	95	95	98	98	98	98
Mean ridge thickness	[m]	4	5	6	7	8	8	8
Ridges per kilometer	[1/km]	3	7	5	8	10	12	12
May								
Max. level ice thickness	[m]	0.4	0.8	1.3	1.6	1.7	1.7	1.7
Concentration	[%]	50	80	80	90	95	95	95
Mean ridge thickness	[m]	0	4	6	7	8	8	8
Ridges per kilometer	[1/km]	0	3	5	8	10	12	12
June								
Max. level ice thickness	[m]	0	0.4	0.7	1.0	1.5	1.5	1.2
Concentration	[%]	0	50	60	80	90	90	30

Mean ridge thickness	[m]	0	0	4	5.5	8	8	0
Ridges per kilometer	[1/km]	0	0	3	4	8	10	0
July								
Max. level ice thickness	[m]	0	0	0	0	1.0	1.0	0.8
Concentration	[%]	0	0	0	0	70	50	10
Mean ridge thickness	[m]	0	0	0	0	6	0	0
Ridges per kilometer	[1/km]	0	0	0	0	4	0	0
August								
Max. level ice thickness	[m]	0	0	0	0	0.5	0	0
Concentration	[%]	0	0	0	0	50	0	0
Mean ridge thickness	[m]	0	0	0	0	0	0	0
Ridges per kilometer	[1/km]	0	0	0	0	0	0	0
September								
Max. level ice thickness	[m]	0	0	0	0	0	0	0
Concentration	[%]	0	0	0	0	0	0	0
Mean ridge thickness	[m]	0	0	0	0	0	0	0
Ridges per kilometer	[1/km]	0	0	0	0	0	0	0
October								
Max. level ice thickness	[m]	0	0	0	0	0.15	0.15	0.15
Concentration	[%]	0	0	0	0	80	80	80
Mean ridge thickness	[m]	0	0	0	0	0	0	0
Ridges per kilometer	[1/km]	0	0	0	0	0	0	0
November								
Max. level ice thickness	[m]	0	0	0.2	0.3	0.5	0.5	0.5
Concentration	[%]	0	0	80	90	95	95	95
Mean ridge thickness	[m]	0	0	0	0	4	4	4
Ridges per kilometer	[1/km]	0	0	0	0	3	3	3
December								
Max. level ice thickness	[m]	0	0.2	0.4	0.5	0.8	0.8	0.8
Concentration	[%]	0	85	95	95	95	95	95
Mean ridge thickness	[m]	0	0	3	4	5	5	5
Ridges per kilometer	[1/km]	0	0	3	3	5	5	5

4 VESSELS DEFINITION

4.1 BASELINE LNG CARRIER

As a baseline for the LNG carrier, *Christophe de Margerie* type LNGC is selected. The design is dedicated for efficient navigation both in difficult ice conditions and on long open water voyages. This vessel type is generally referred to as YamalMax LNGC. Operational experience of using YamalMax type for LNG transportation in the Arctic with the reasoning for selection of this type as baseline LNG carrier for MDLNG is provided in section 4.4.

A general arrangement of the reference vessel is presented in Figure 4-1 and photos of YamalMax type LNG carrier *Christophe de Margerie* are shown in Figure 4-2.

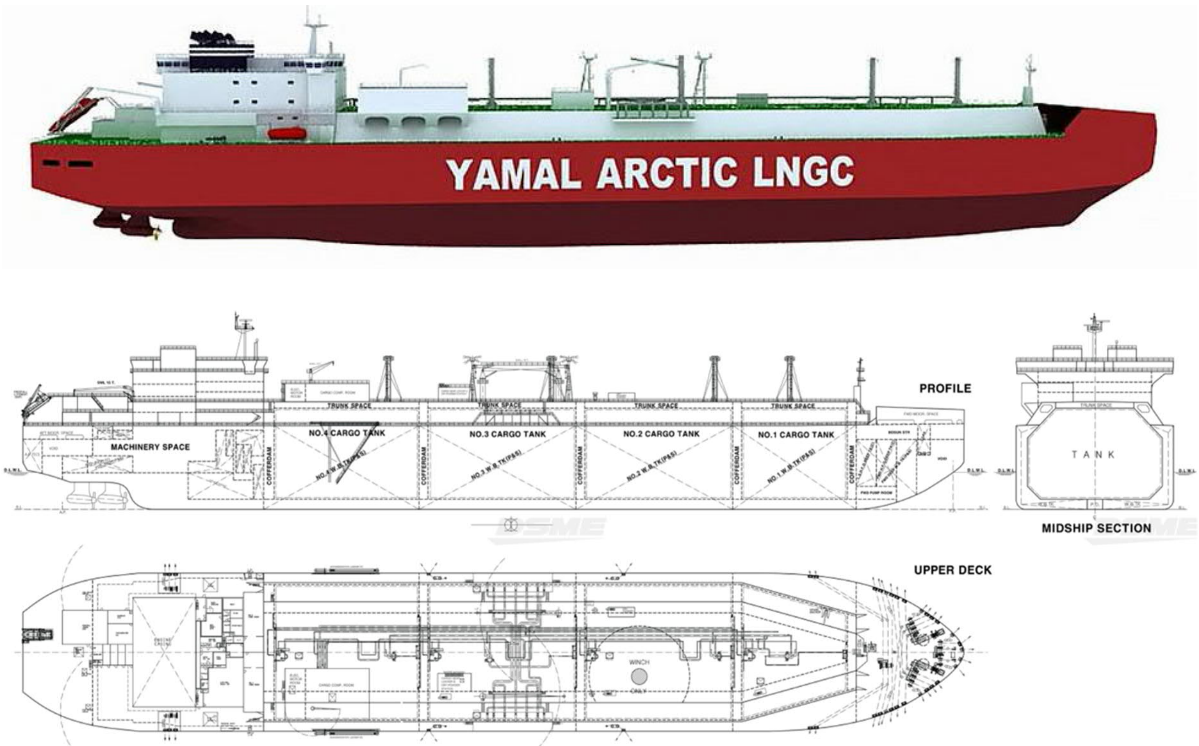


Figure 4-1 – Arctic LNG Carrier, type YamalMax, an artist's impression and a general arrangement plan of the existing design (RINA, 2017)

Main characteristics of the reference vessel based on YamalMax type LNGC are presented in Table 4-1.

The net cargo capacity of the reference vessel is 170,000 m³, which is the standard volume for modern conventional LNG carriers.

The propulsion system consists of three 15 MW azimuthing propulsion units, which are currently the highest-powered ice-strengthened podded propulsion units in service. The concept is of a double acting type: the stern is optimized for icebreaking and ridge crossing, and the bow is a compromise between efficient open water operation and some icebreaking capability, and can be considered a moderate icebreaking bow. Description of double acting principle is given in Section 4.3.

Figure 4-2 – YamalMax type LNG carrier *Christophe De Margerie* during delivery ice trials in 2017 (Source: Aker Arctic)

Table 4-1 – Proposed main characteristics of reference vessel based on YamalMax type LNGC

Parameter	Unit	Value
Ice class	-	PC3
Four cargo tanks, total volume	m^3 (filling %)	172,600 (100%) 170,000 (98.5%)
Length overall	m	abt. 300
Breadth[1]	m	50.0
Depth, to upper deck/trunk deck	m	26.5/33.8
Draught, design (T_d)	m	11.7
Draught, ice-going (T_{ice})	m	12.0
Draught, scantling (T_s)	m	13.0
Draught, ballast in OW (T_A/T_F)	m	abt. 11/10
Ice-going concept	diesel-electric propulsion with three azimuthing propulsion units	
Hull form	Ice bow, Double Acting Ship	
Deadweight[2] at T_d	t	abt. 81,000
Lightweight	t	abt. 47,000
Ballast tanks	m^3	70,000
Propulsion machinery: azimuthing electric propulsion units, (“Azipod” units)	MW	3×15
Service speed[3]	kn	19,5
Power plant: six diesel generator sets (several alt’s)	MW	min. about 64
Voltages		6,600 V / 690 V / 440 V /230 V, 24 VDC
Other gensets: harbour genset emergency genset	kW	 abt. 800 abt. 700

[1] alt. hull concepts with lesser breadth exist
[2] LNG cargo with density 0.45 t/m[3] about 77,000 t, other DWT 4,000 t
[3] with 21% sea margin

Auxiliary steam boilers:	-	2 oil-fired boilers 6 exhaust gas boilers
Complement/cabins:		up to 45
Active crew[4]	person	30-35
Cargo containment[5]	-	GTT's NO.96 GW
Boil-off Rate (BOR)[6]	%/day	guaranteed 0.12/day
Cargo pumps, capacity (head): submerged electric type	m^3/h (mLC)	8×2000 (170)
Stripping/spray pumps, capacity (head): submerged electric type	m^3/h (mLC)	2×60 (170)
Fuel gas pumps, capacity (head): submerged electric type	m^3/h (mLC)	2×20 (210)
Emergency cargo pump, capacity (head): portable electric	m^3/h (mLC)	550 (150)
Gas Combustion Unit, capacity:	t/h	abt. 5
Low duty (boil-off) compressors:	m^3/h	2×4000
High duty compressors:	m^3/h	2×35,000
Inert gas plant:	m^3/h	17,000
Nitrogen gas plant	m^3/h	2×200
In addition, various gas heaters:	for fuel gas, vapor return, forcing vaporizer, LNG vaporizer	
Cargo containment system/cofferdam steel bulkhead heating:	thermal oil heating (as required for the membrane CCS)	

Icebreaking performance of YamalMax type LNG carriers according to design specification:

- The vessel shall be able to break level ice of 500 kPa flexural strength of minimum 1.5 m thickness continuously at a speed of 2 knots bow first.
- In stern first mode the vessel shall be able to break level ice of 500 kPa flexural strength of minimum 1.5 m thickness at a speed of 5 knots and

[4] depending on the season, operator and need for extra persons onboard like trainees, ice personnel and visitors
[5] with improved insulation system with glass wool filled insulation boxes
[6] in IMO standard conditions; The actual BOR in cold environment shall be less, below 0.10 % per day

maintain a continuous speed (2 knots) in minimum 2.1 m level ice thickness. The requirements are met in the design Arctic draught and in ballast conditions.

- The vessel shall be able to operate with continuous motion in brash ice up to 8 m thickness in shallow water depth down to 15 m and shall achieve a speed of 4 knots in brash ice up to 4 m thickness.
- The vessel shall be able to operate in and penetrate through ice ridges up to 15 m keel depth without getting stuck.
- In addition, there are requirements for minimum turning circles in ice.

Christophe de Margerie is the flag ship of the existing fleet of 15 vessels that serve the LNG transportation of the Yamal LNG project (Table 4-2).

Table 4-2 – Full list of YamalMax type LNG carriers

Name	***Construction completed***	***Shipyard***	***Operator***
Christophe de Margerie	November-16	DSME	Sovcomflot
Boris Vilkitskiy	November-17	DSME	Dynagas
Fedor Litke	November-17	DSME	Dynagas
Eduard Toll	December-17	DSME	Teekay/CLNG
Vladimir Rusanov	January-18	DSME	MOL/CSDC
Rudolf Samoylovich	August-18	DSME	Teekay/CLNG
Vladimir Vize	October-18	DSME	MOL/CSDC
Georgiy Brusilov	November-18	DSME	Dynagas
Boris Davydov	December-18	DSME	Dynagas
Nikolay Zubov	January-19	DSME	Dynagas
Nikolay Yevgenov	April-19	DSME	Teekay/CLNG
Vladimir Voronin	July-19	DSME	Teekay/CLNG
Nikolay Urvantsev	July-19	DSME	MOL/CSDC
Georgiy Ushakov	September-19	DSME	Teekay/CLNG
Yakov Gakkel	November-19	DSME	Teekay/CLNG

4.2 BASELINE OIL/CONDENSATE TANKER

As a baseline for the oil/condensate tanker, the product tanker *Boris Sokolov* is selected. A general arrangement of the reference vessel is presented in Figure 4-3.

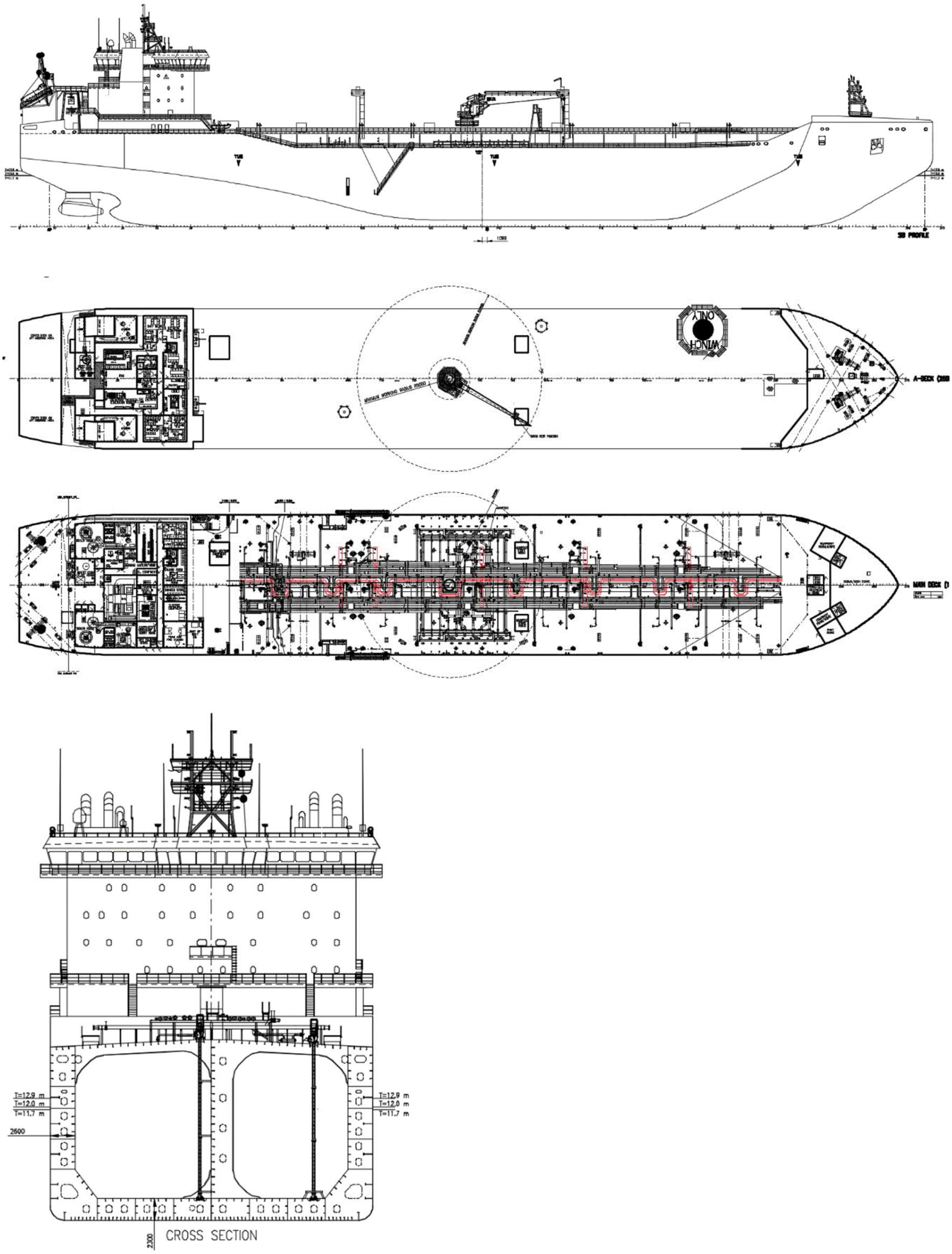


Figure 4-3 – Reference Arctic condensate tanker of *Boris Sokolov* type

Photos of the tanker *Boris Sokolov* from ice trials in the Kara Sea are shown in Figure 4-4.

Figure 4-4 – Arctic condensate tanker *Boris Sokolov* during delivery ice trials in 2019 (Source: Aker Arctic)

Boris Sokolov is a product tanker with respective cargo handling features including five cargo segregates. The cargoes can be clean or dirty oil products, from condensate oil to crude oil. However, the vessel is specifically dedicated for transportation of gas condensate oil from Arctic areas to the markets. As an extra feature, the vessel can transport fuel oil (MDO) for other needs in its fore storage tank (1,400 m^3) during ballast voyages to Arctic waters.

In Table 4-3 below a dedicated condensate oil tanker based mainly on the features of the *Boris Sokolov* is described.

Table 4-3 – Main characteristics of reference Arctic Condensate Tanker

Parameter	**Unit**	**Value**
Ice class	-	PC3
Cargo tanks, five pairs of cargo tanks, one pair of slop tanks (suited for cargo oil)	total, m^3	abt. 60,000
Hull form	moderate ice bow, Double Acting Tanker hull	
Length overall	m	abt. 214
Breadth	m	34.0
Depth, to upper deck	m	18.3
Draught, design	m	11.7
Draught, ice-going (T_{ice})	m	12.0
Draught, scantling (T_s)	m	12.9
Draught, ballast, in open water (T_A/T_F)	m	9.0/8.7
Draught, ballast, in ice condition, min. T_A	m	10
Cargo segregates (suggested one):	dedicated for gas condensate or other oil product	
Ice-going concept	diesel-electric propulsion with two azimuth propulsion units	
Deadweight[7]	t	up to 43,000
Lightweight	t	abt. 21,000
Propulsion machinery azimuthing electric propulsion units, (“Azipod” units)	MW	2×11
Service speed[8]	kn	13

[7] with gas condensate cargo, density 0.65 t/m^3: cargo 39,000 t, other DWT 4,000 t
[8] typical and economical service speed (max. propulsion power resulted from ice-navigation needs, would provide far higher open water speed which non-essential)

Power plant[9]	total, MW	31-32
Voltages:		6,600 V / 690 V / 440 V /230 V, 24 VDC
Other gensets: Harbour genset Emergency genset	kW	 abt. 800 abt. 700
Auxiliary steam boilers: oil-fired boilers exhaust gas boilers	t/h	 2×6 4×1.5
Cargo tank heating:		Thermal oil heating
Cargo and slop pumps[10]	m^3/h	10×800 and 2×300
Complement/cabins:	person	Up to 30 cabins/persons + 1 riding crew or Suez workers' cabin for 6 p.
Active crew[11]	person	20-25

Icebreaking performance of the *Boris Sokolov* tanker according to design specification:

- In first-year level ice with a flexural strength of 500 kPa, the vessel can achieve 2 kn in 1.8 m level ice stern first, and 2 kn in 1.5 m level ice bow first with 100% propulsion power of 2×11 MW of the azimuthing thrusters.
- In up to 4 m of brash ice the vessel can achieve a continuous speed stern first.
- The vessel can penetrate ridges up to 15 m without getting stuck stern first.
- In addition, there are requirements for minimum turning circles in ice.

Two condensate tankers, *Boris Sokolov* and her half-sister *Yuriy Kuchiev,* are currently serving the Yamal LNG project, together with 15 YamalMax LNG carriers.

It should noted that the condensate tanker *Yuriy Kuchiev* has been built to the same specification as *Boris Sokolov,* but at another shipyard having limitations in its building dock. Therefore, the latter vessel has slightly different main dimensions (a longer but narrower hull).

[9] comprising of four diesel generator sets (several maker alt's)
[10] electric driven, of deep-well type
[11] depending on the season, operator and need for extra persons onboard like trainees, ice personnel and visitors

4.3 DOUBLE ACTING SHIP CONCEPT IN GENERAL

The Double Acting Ship (DAS) concept is designed to run ahead in open water and astern in heavy ice conditions. The actual bow form can be optimized for the selected route to achieve superior ice going performance when running astern, reducing the need of icebreaker assistance.

The benefit from this freedom in bow form design is that the Double Acting Ships display much better open water performance than conventional ice going vessels. The propulsion power needed to break ice in DAS mode in difficult ice conditions is drastically less than that needed for ordinary bow-first mode.

In practice, in less severe ice conditions a Double Acting Ship can achieve higher speed bow first until a certain threshold speed or ice thickness is achieved. In thicker ice it becomes much more economical to navigate the vessel in stern ahead mode – which is often the only way to proceed when facing the most severe conditions such as heavily ridged ice and/or in a compressive ice pack.

To date, 37 DAS concept vessels have been built and all, but two Aframax tankers, were designed for operation in Russian Arctic waters. These two Aframax crude oil tankers were designed for the most demanding ice conditions of the Baltic Sea. One of them, an aged tanker *Tempera* has been modified into an FPSO unit. Its sister vessel *Mastera* is still in service in the Baltic Sea.

Currently, three Double Acting Ships are under construction: One 69,000 dwt Arc6 ice class shuttle tanker and two Arc7 ice class LNG carriers for Arctic LNG 2 project. There are in total 21 new LNGC's ordered: 15 from Samsung/Zvezda (new Arctic LNGC concept design by Samsung) and 6 from DSME (new Arctic LNGC concept design by Aker Arctic).

4.4 EXISTING EXPERIENCE OF YEAR-ROUND EXPORT OF LNG FROM THE ARCTIC REGION

The first occasional transit voyages of LNG carriers along the NSR took place in 2012, but year-round export of LNG from the Arctic began only after the start of production from the Yamal LNG plant with export from Sabetta seaport.

Currently, Yamal LNG Project provides the production of not less than 16.5 million tons of LNG per year and its marine transportation from export terminal in the port of Sabetta, located in the Ob Gulf of the Kara sea. As mentioned in section 4.3, 15 Arctic LNG carriers of Arc7 ice class with a capacity of about 172,000 m^3 were specially built for the export of LNG from Sabetta. At the same time, in case of additions fleet needs for transportation and ice conditions, ships of lower ice classes are also used for the export of LNG from Sabetta in summer period of navigation.

The original trade pattern of the fleet comprises LNG transportation to the west (year-round) and to the east (on a seasonal basis - around six months of the year) from the Yamal LNG plant in Sabetta, located on the Yamal peninsula. The destinations so far have been distant gas terminals in Europe and the Far East, ship-to-ship (STS) transfer operations in Norwegian waters, and lately in a fjord near Murmansk. In several European ports, a great number of shiploads have been transferred to an open water LNG carrier via piping on the pier or via intermediate storage on shore, another way of performing STS.

The level of icebreaking capability (1.5 m in level ice ahead and 2.1 m astern) was chosen to allow these ships to navigate year-round from Sabetta in western direction through the south-western part of the Kara Sea, and for about 6 months (from July to December) eastward along the Northern Sea Route (NSR). Icebreaker support was originally presumed only inside the Ob Gulf. Figure 4-5 shows the actual data on number of voyages of LNG carriers and condensate tankers from Sabetta (with tracks and destinations) made in 2020.

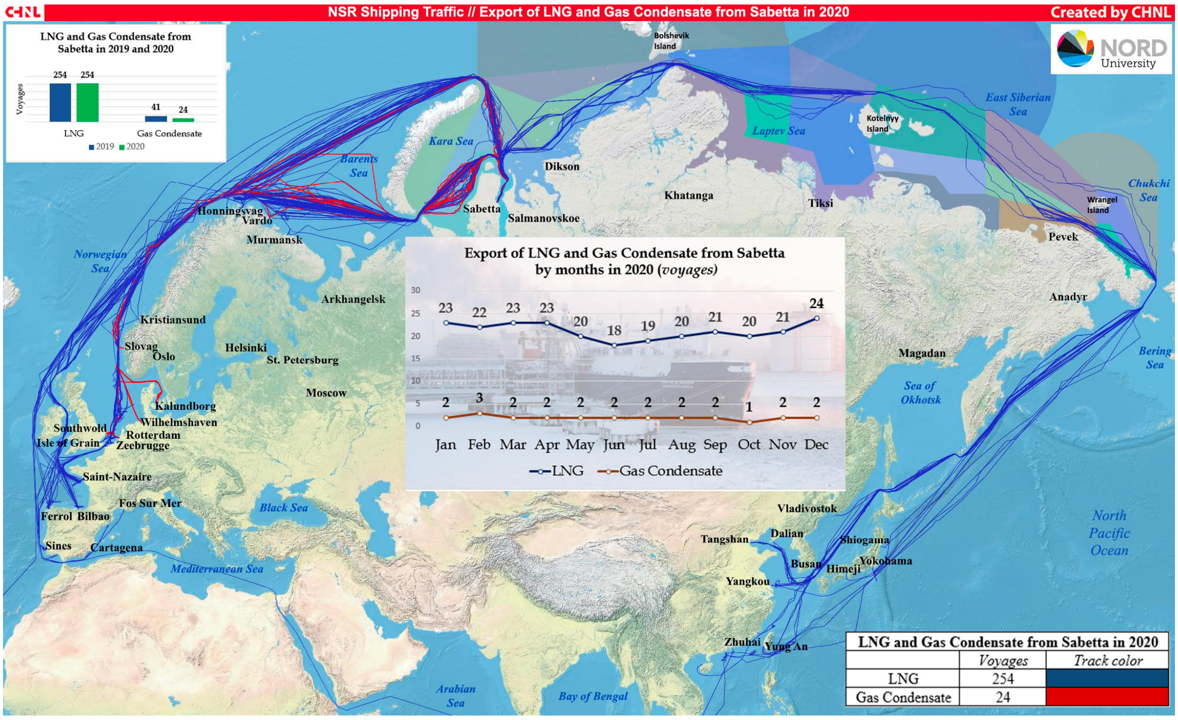


Figure 4-5 – Export of LNG and gas condensate from Sabetta in 2020 (CHNL, 2020)

Navigation in ice through the summer season takes place independently both to the east and west, as well as to the west in the winter season. In the winter season, eastbound trade is difficult, even when assisted. The first generation of icebreaking LNG carriers were not designed for eastbound trade during the winter navigating season and their hull form is not well suited for efficient icebreaker escort using existing large line icebreakers.

At the same time, Novatek company (operator of Yamal LNG) has organized several experimental voyages of YamalMaxes in an attempt to extend the navigation period eastward.

In May 2020, Novatek performed very early experimental eastbound transportation of LNG along the NSR. Arc7 ice-class LNG carrier *Christophe de Margerie* of Sovcomflot left the port of Sabetta on 18 May 2020 and successfully transited the Eastbound ice-covered part of the Northern Sea Route (NSR) and reached the Bering Strait in only 12 days. The voyage took place before the traditional start of the summer navigation season in average ice conditions, with the maximum ice thickness on the route reaching 1.3 meters. On May 24, next LNGC *Vladimir*

Voronin with cargo left the port of Sabetta, and completed NSR transit on June 2, being supported by nuclear icebreakers at some areas of NSR.

In AARI publication (Sokolova, et al., 2020) on the example of the pair *Christophe de Margerie* and *Vladimir Voronin* and one more pair *Georgy Brusilov* and *Vladimir Rusanov*, followed a month later, a comparative analysis was made for two modes of navigation: independent and under icebreaker escort. The results of the detailed analysis did not reveal sufficient differences in time and service of LNG carriers, navigating independently or under icebreaker escort in those ice conditions, which were developed by the beginning of summer navigational season.

In the beginning of 2021 attempts were continued with very late experimental voyages of LNG carriers to Asia via the NSR.

On 5 January 2021, *Christophe de Margerie* left the Port of Sabetta with a cargo of liquefied natural gas from the Yamal LNG project and headed east for the Port of Jiangsu in China. In 10 days and 21 hours, the vessel completed the voyage along the Northern Sea Route without icebreaker support, reached Cape Dezhnev. On 26 January, the tanker arrived Jiangsu, where she successfully discharged the LNG and set off on ballast passage.

Christophe de Margerie was followed by *Nikolay Evgenov* on January 6 (arrived at the port of Pyeongtaek on January 27). Both vessels crossed the eastern sector of the NSR without icebreaker support. There was also a ballast voyage of LNGC *Nikolay Zubov*, which left the port of Dalian on December 25, 2020 and entered the water area of the NSR along Cape Dezhnev on January 6. The vessel arrived at the port of Sabetta on January 18, also without icebreaker support.

A latest transit voyage of Yamalmax LNGC from Asia to Sabetta was made in February with icebreaker escort. On February 7, around Cape Dezhnev, the nuclear-powered icebreaker *50 Let Pobedy* took the *Christophe de Margerie* under escort, and the vessels began NSR transit westward. The maximum ice thickness on the convoy route reached up to 1.5 meters. The average speed of the convoy was 8.6 knots. On February 19, *Christophe de Margerie* arrived in the port of Sabetta.

One of the main goals of these experimental voyages is to collect operational experience and study the conditions of year-round operation in the eastern part of the Russian Arctic.

At the moment, Novatek has been expanding its liquefied natural gas production in the Gulf of Ob with construction of the Arctic LNG 2 production site, located in the Gydan Peninsula across the Gulf of Ob, as well as in Sabetta. In the future, transportation from Yamal LNG will focus on the west-bound route to Europe, and from Arctic LNG 2 on the east-bound route to Asia along the NSR. The new Arc7 design should allow transportation year-round on this challenging itinerary. The target is to transport LNG with special vessels through ice-covered areas to reshipping terminals in Kamchatka and Murmansk, and from there with open water vessels further to the market.

Figure 4-6 – Logistic scheme of near future LNG export from Russian Arctic

The next generation icebreaking LNG carrier concept design proposed by Aker Arctic comes with improved transport economies, no seasonal limitations and higher cargo turnaround than the previous generation of ships.

Compared to the previous generation LNG carrier, the size has been adjusted. The new vessel will be about 47 meters wide and almost 300 meters long. Nonetheless, the ice-optimized hull has a higher block coefficient, which means that the cargo capacity remains the same 170,000 m³, despite the narrower hull.

Hence, the new LNGC design for Arctic LNG 2 project is optimized for a specific route with predominant operation in ice conditions and cannot be recommended as reference design for this initial stage of MDLNG study, which does not consider in detail the possibility of transshipment of LNG, presuming direct delivery to markets as basic case.

5 TRANSIT ANALYSIS ALONG THE SHIPPING ROUTES

To analyze the capability of the considered cargo vessel types (icebreaking LNG carrier and oil/condensate tanker) to maintain a certain speed in the specified routes from the Mackenzie Delta in the Canadian Beaufort Sea to Shanghai (for a LNG carrier) and to Vancouver (for an oil/condensate tanker), transport simulations are performed. A simulation tool developed by Aker Arctic is applied to determine the average speed of the vessel through the different ice conditions encountered on the route, depending on the ice performance of the ship. The simulations for the routes are done on a monthly basis for an average type of winter.

A further calculation of vessel roundtrip times is made, considering loading and unloading, mooring and other waiting times. Longer roundtrip times during mid-winter months dictate the size of the fleet (number of vessels in the fleet). The fleet size needs to be sufficient to transport the yearly production of LNG and comingled oil/condensate from the Mackenzie Delta GBS. In this calculation, LNG and oil storage is assumed to help with the wintertime transport, and a certain amount of storage volumes are allowed.

In the following sections, all calculation assumptions and results of cargo carrying capability are explained and presented.

5.1 METHODOLOGY

The ice profiles represent the ice conditions the vessel meets along the route legs. They are prepared based on data referred to in Section 1. In the ice profiles, variations of level ice thickness and ice ridge size and density correspond to measured ice distribution in natural ice fields. An example of a generated ice profile for a 15 km segment made by simulation tools can be seen in Figure 5-1. It was generated with the following properties:

Level ice thickness	1.5	m
Concentration	98	%
Mean ridge thickness	8	m
Ridge density	7	1/km

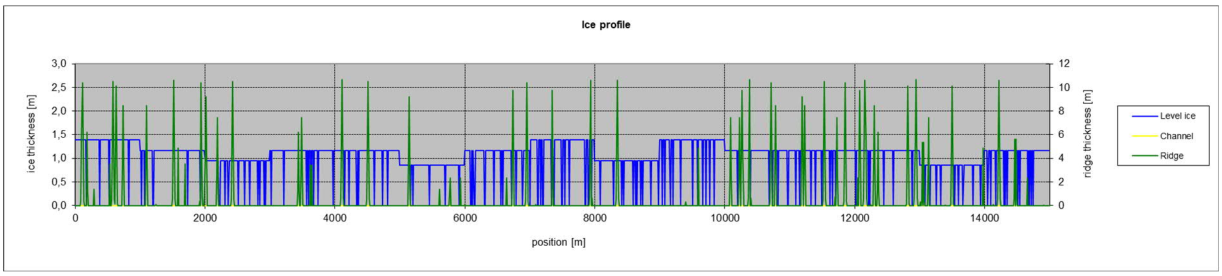


Figure 5-1 – Example of ice profile

Average vessel speed through the generated ice profile is calculated by a simulation based on the net thrust and ice resistance of the vessel. The force balance of thrust and resistance is determined at small time steps. The simulated speed profile for the generated ice profile above is shown in Figure 5-2. The profile was simulated for reference vessel astern-mode, and the average speed is 2.4 m/s (4.7 knots).

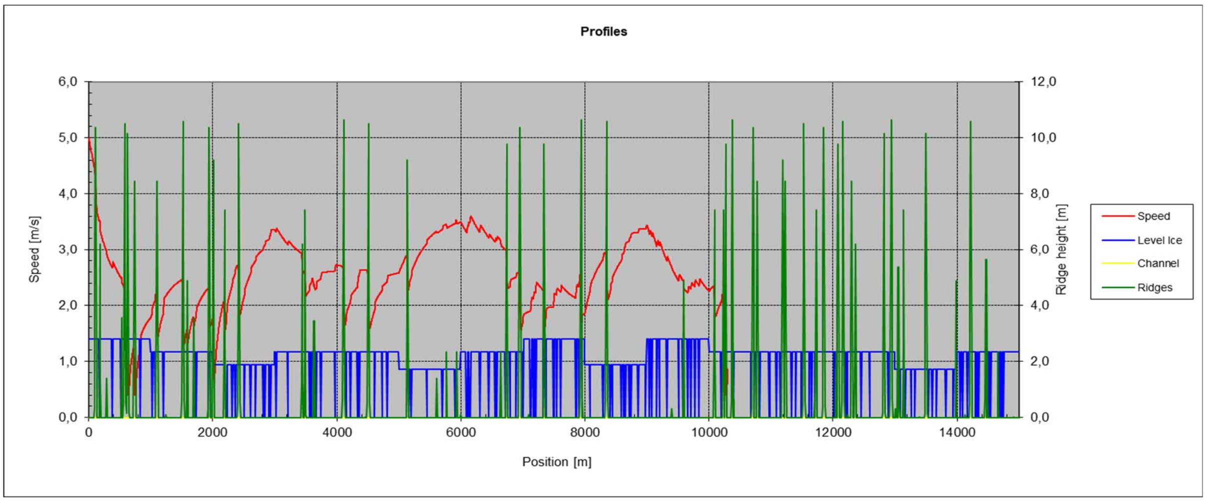


Figure 5-2 – Example of simulated speed of a vessel through example ice profile

Tactical navigation factors are also estimated in the speed simulation. This means that the ice profile is slightly modified so that the vessel will avoid the largest ridges and use open water leads in lower concentration ice. These factors will give more accurate average speed estimations.

Since the vessels utilize double acting operation, ahead/astern capability and related speed is computed separately. Operation mode at faster speed is selected and utilized in roundtrip time calculations.

5.2 INPUTS AND ASSUMPTIONS

The following assumptions for transit simulation in ice conditions have been made:

- Open water service speed for both ballast and loaded conditions are considered the same (19.5 knots for LNG carrier and 13.5 knots for oil/condensate tanker).
- The simulations for both types of vessels have been done at design draft; it has been assumed that the ice going capability does not differ significantly at ballast draft.
- Speed limit when operating astern (12 knots for LNGC and 11 knots for the tanker) has been set for the simulation (this is based on practical full-scale experience of safe handling of ships, stern first in ice).

There are additional operational assumptions that influence the resulting total roundtrip time. Roundtrip cycle is:

Loading – Unmooring – Loaded voyage – Delays – Mooring – Unloading – Unmooring – Ballast voyage – Delays – Mooring – Loading - … etc.

The following assumptions are used for the LNG carrier:

Loading time	48	hours

Discharging time	30	hours
Mooring / unmooring time in summer	4	hours/ roundtrip
Mooring / unmooring time in winter	6	hours/ roundtrip
Other delays in summer	15	hours/ one way trip
Other delays in winter	25	hours/ one way trip

Loading and discharging time also includes waiting for given slots in harbours, customs procedures, receiving permissions, etc.

Other delays are added to account for bad weather, pilot boarding, and, in this study, the time required to navigate the approach area through shear zone and fast ice to the GBS (preliminarily assumed as 10 hours).

Yearly production of LNG is 4.0 million tons, with a density of 0.45 t/m^3, and it is assumed that monthly production is constant.

Assumptions which are used for the condensate tanker:

Loading time	36	hours
Discharging time	24	hours
Mooring / unmooring time in summer	4	hours/ roundtrip
Mooring / unmooring time in winter	6	hours/ roundtrip
Other delays in summer	15	hours/ one way trip
Other delays in winter	25	hours/ one way trip

Yearly production of condensate is around 360,000 tons (based on a maximum level of 10,000 barrels/day and a cargo density of 0.65 t/m^3) and it is assumed that monthly production is constant.

GBS additional storage (in addition to buffer storage needed to load one vessel), both for LNG and condensate, is calculated when needed to assure smooth yearly transportation during longer roundtrip times in wintertime. For the base case of using only one GBS in the project, according to information provided by the Client it is assumed that LNG storage is limited to a maximum volume of 270,000 m^3.

5.3 SIMULATION RESULTS

5.3.1 AVERAGE SPEED ALONG ICE ROUTE

5.3.1.1 YAMALMAX CLASS LNGC

Average speeds for each leg of the considered transportation route for the YamalMax type LNG carrier are presented in Figure 5-3. As can be seen from the results of ice transit simulation, in an average winter the LNG carrier is able to operate independently at speeds exceeding 6 knots, even on the most difficult legs. Icebreaker assistance is assumed to be provided only on the approach to the GBS.

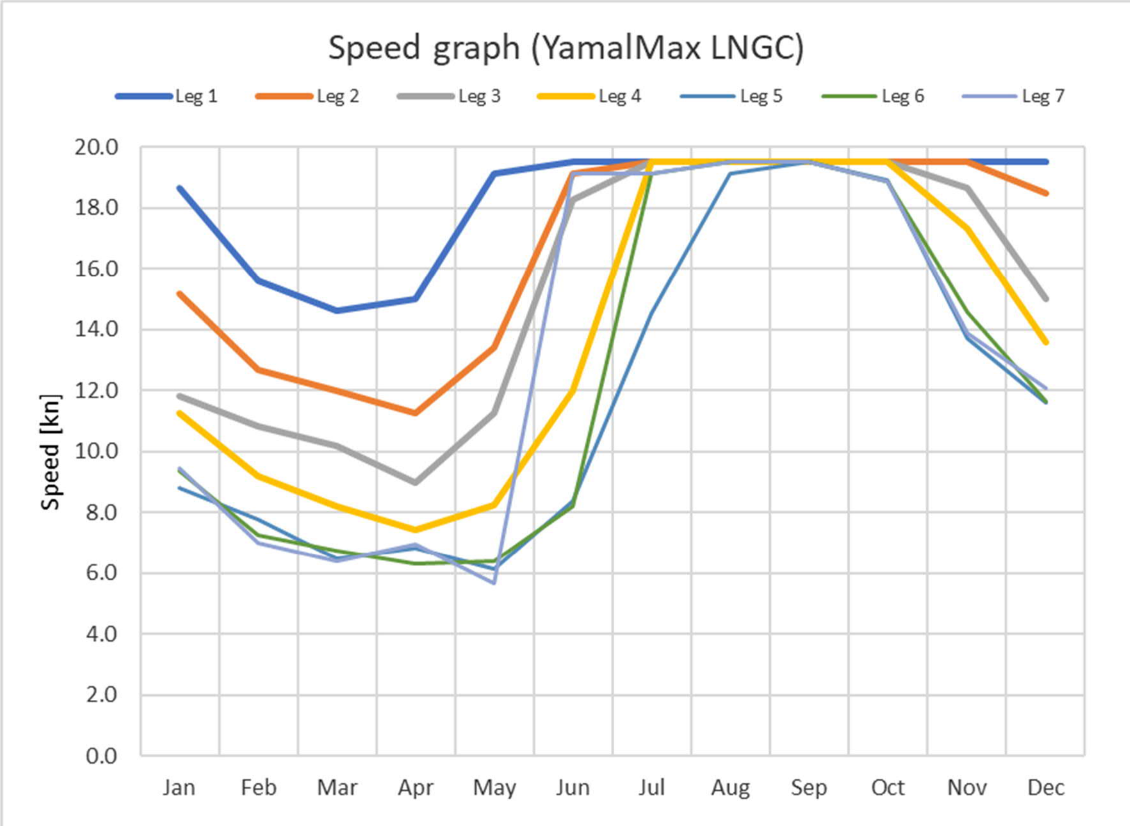


Figure 5-3 – Average speeds for YamalMax type LNGC (average winter)

5.3.1.2 OIL/CONDENSATE TANKER

Average speeds for each leg of the considered transportation route for the *Boris Sokolov* type tanker (taken as reference oil/condensate tanker) are presented in Figure 5-4. As follows from the obtained results of ice transit simulations, in average ice conditions, the average speed is below 3 knots (which practically means that the vessel is unable to safely operate independently) for five months (February-June) on Legs 5-6 and for four months (February-May) on Leg 7.

In this initial study, for further calculations, a basic possible scenario is used when the condensate tanker moves independently at its lowest achievable speed. If the ship gets stuck in ice, there is the possibility of it being taken under escort by the primary icebreaker located at the GBS site or by a passing-by LNG carrier.

In principle, it is also possible to organize a joint convoy when a smaller-sized tanker is moving in the channel behind a YamalMax type LNG carrier. There was such a practical navigational case of the LNGC *Boris Davydov* and the tanker *Boris Sokolov* engaging in a joint voyage along the Northern Sea Route from the Bering Strait to Sabetta from December 2018 to January 2019. However, at this stage of the study it is rather difficult to estimate the total effect of such joint ventures on the whole cargo transportation scheme.

As an optional case scenario of more intensive tanker traffic for the above mentioned months and legs, an assessment of average speeds of a tanker escorted by one leading icebreaker was made (Figure 5-5).

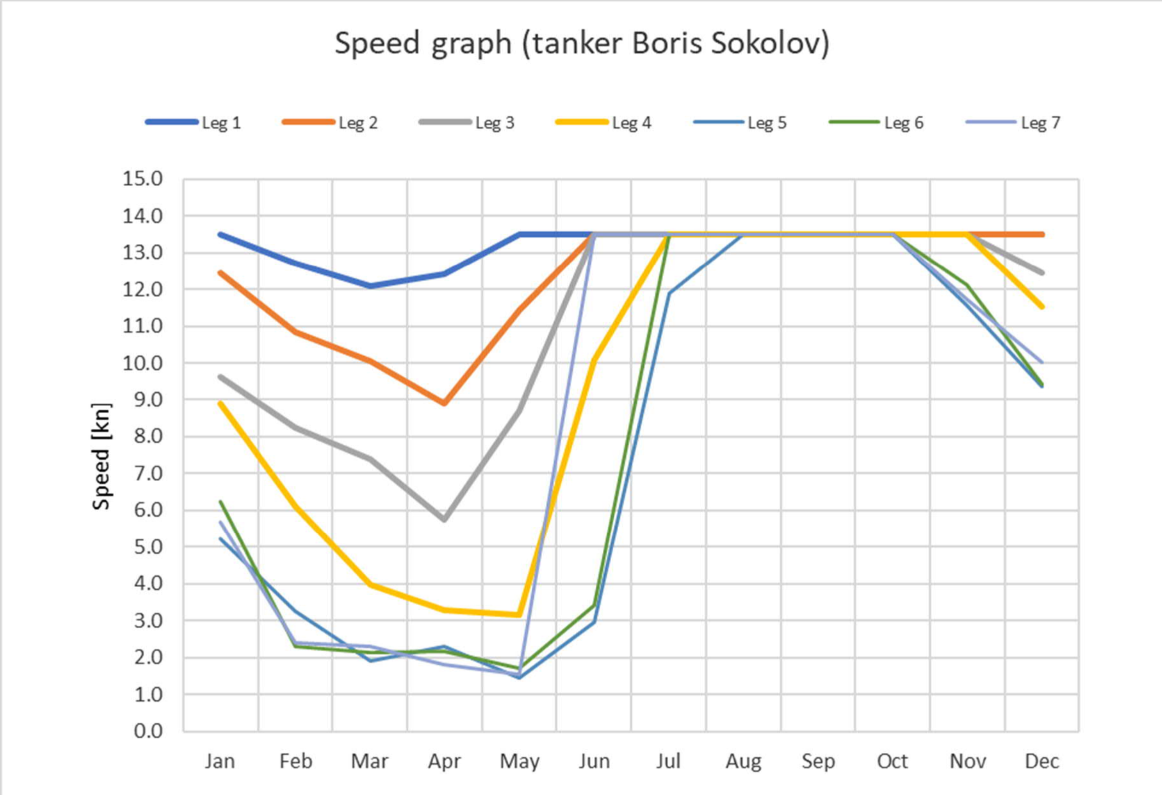


Figure 5-4 – Average speeds for tanker *Boris Sokolov* (average winter)

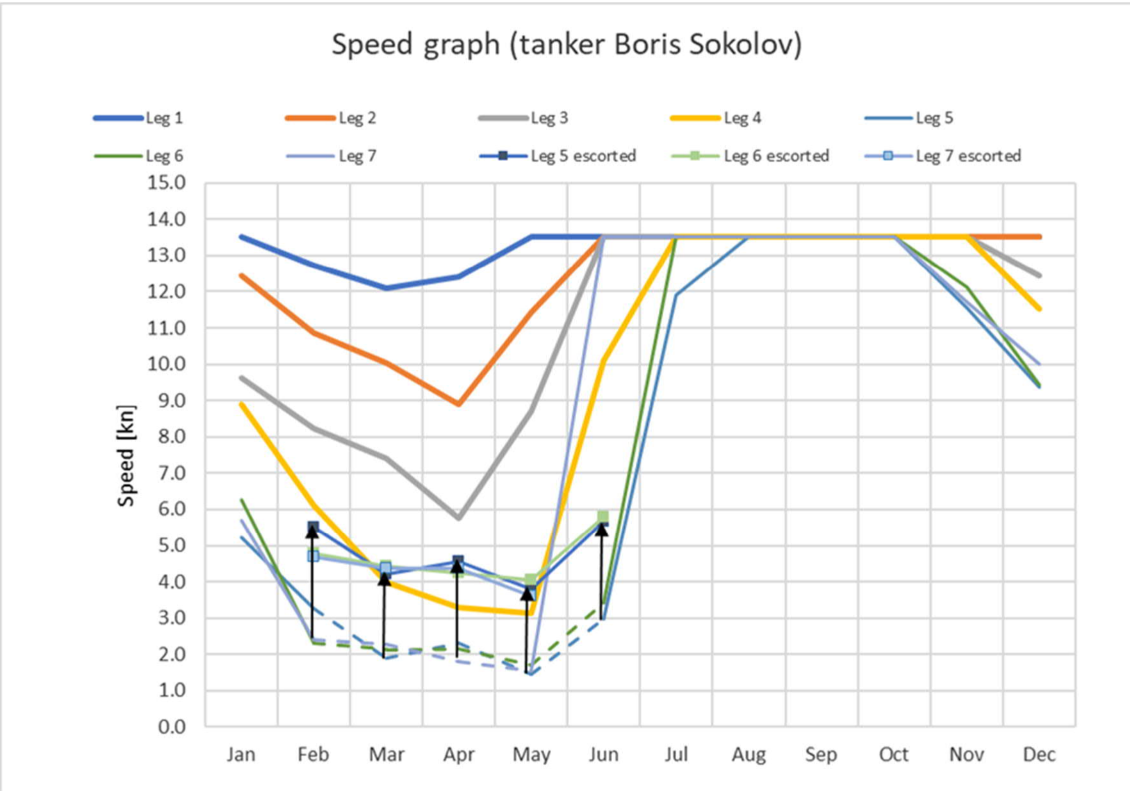


Figure 5-5 – Average speeds for tanker *Boris Sokolov* (average winter) with possible icebreaker escort

Using icebreaker assisted navigation allows an increase in average speeds by approximately 2.5 knots, as shown by arrows in Figure 5-5.

5.3.2 MONTHLY ROUNDTRIP TIMES

5.3.2.1 YamalMax class LNGC

Calculated monthly average values for the duration of a roundtrip voyage on the considered transportation route to Shanghai for a YamalMax type LNG carrier, as well as the average speed of movement along the route, are presented in Figure 5-6.

The measured length of open water on the route from the point of maximum distribution of ice (end of the ice route - Waypoint H in Figure 3-1) to Shanghai is 3300 nm.

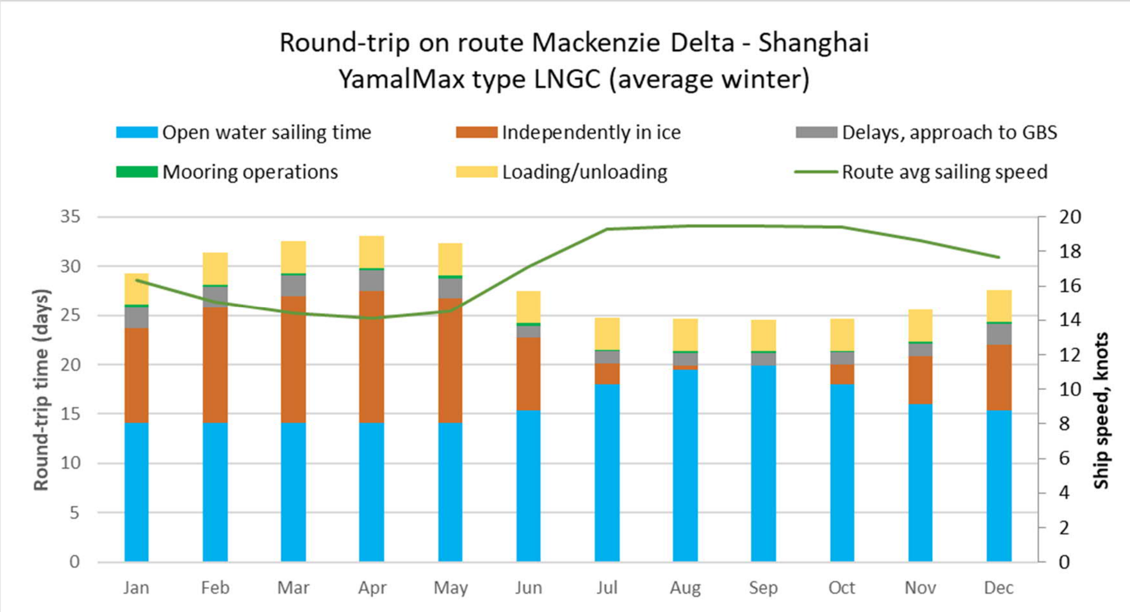


Figure 5-6 – Roundtrip times and average speeds for YamalMax type LNGC (average winter)

5.3.2.2 Oil/Condensate tanker

Calculated monthly average values for the duration of a roundtrip voyage and average speeds on the considered transportation route to Vancouver for the *Boris Sokolov* type tanker are presented in Figure 5-7 (for the base case of mainly independent navigation) and in Figure 5-8 (for the case with possible icebreaker escort). It could be seen that almost up to 10 days of icebreaker assistance per one roundtrip would be required for the hardest months.

The measured length of the open water route from the point of maximum distribution of ice (end of the ice route - waypoint H* in Figure 3-1) to Vancouver is 2000 nm.

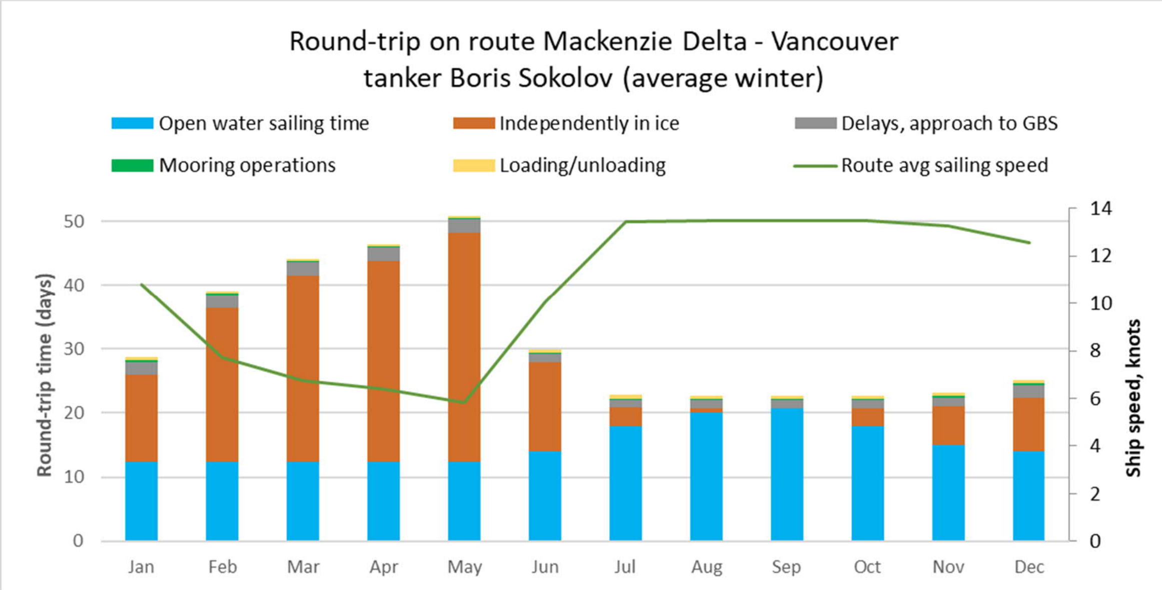


Figure 5-7 – Roundtrip times and average speeds for *Boris Sokolov* type tanker (average winter)

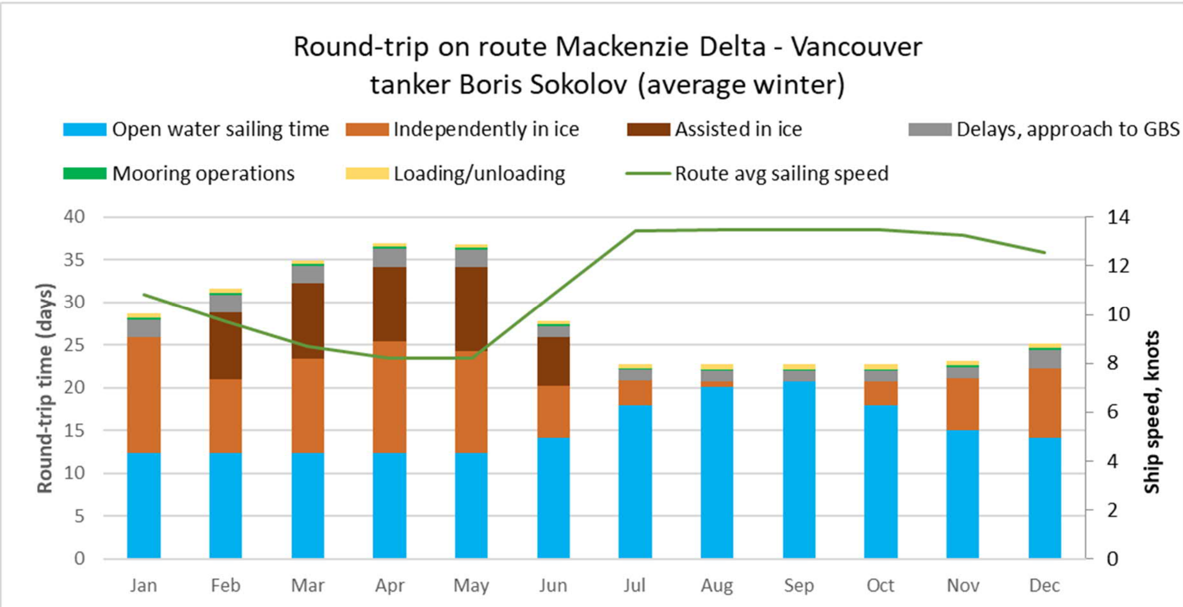


Figure 5-8 – Roundtrip times and average speeds for *Boris Sokolov* type tanker (average winter) with possible icebreaker escort

5.3.3 CARGO TRANSPORT CAPACITY, FLEET SIZE AND STORAGE NEEDED

5.3.3.1 TRANSPORTATION OF 4 MTPA OF LNG

The graph in Figure 5-9 shows the transportation system simulation results for a 4 Mtpa LNG production rate using the reference YamalMax LNGC for an average winter. As was noted during discussions with the Client, in the case of only one GBS being used, the limiting storage volume is 270,000 m³.

In the graph below and following sections, the orange line represents production, which is constant for a given case. The green line represents the required GBS storage (including buffer and additional storage). The bar lines represent cargo loaded in the fleet. The black dots represent the number of vessels required in the fleet each month, once the onshore storage is considered. The number of vessels per month is intentionally left as non-integer numbers, to precisely show the fleet demand. Fleet size is presented as decimal numbers to get idea of the month-to-month sensitivity and to show the effect of additional storage on the required fleet. As can be seen, more icebreaking LNG carriers will need to be used in the winter, which will affect the total fuel consumption of the LNGC fleet during the year.

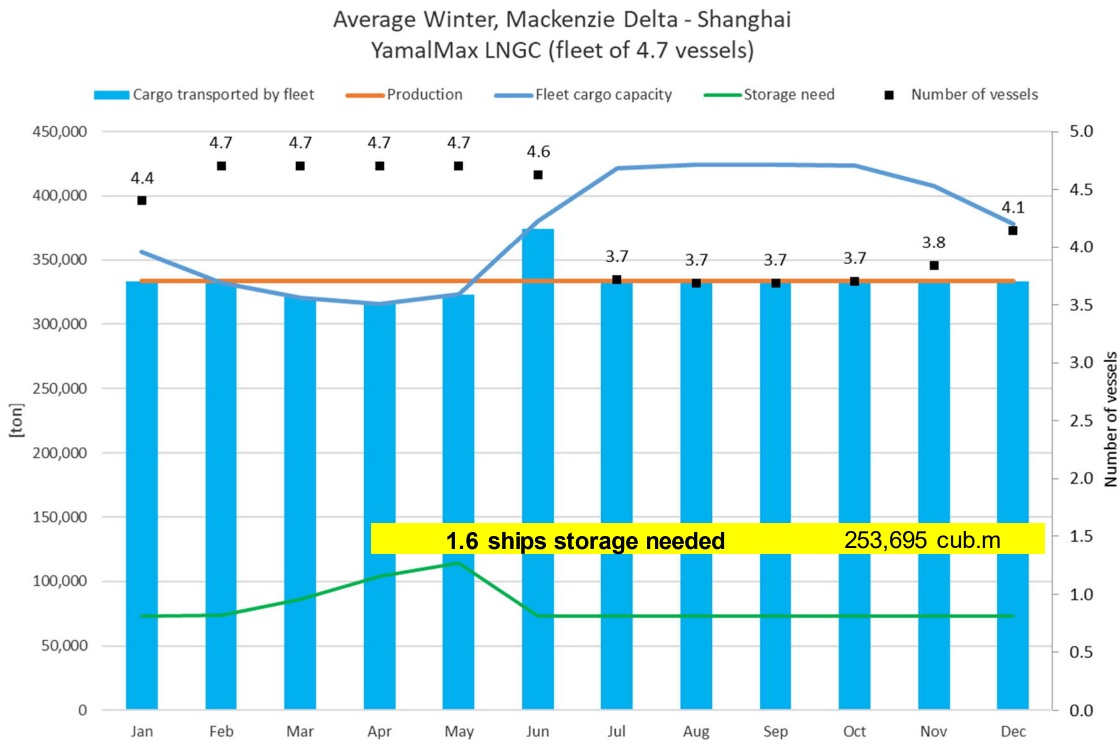


Figure 5-9 – Transportation capability analysis for average winter, 4 Mtpa of LNG, year-round to Shanghai, YamalMax LNGC, one GBS storage limit

The results indicate that:

– 4.7 vessels are required in the fleet.
– 1.6 vessel cargo capacity is required for storage (254k m³ of LNG) at the GBS (including buffer capacity needed for the loading of one LNGC).

To investigate the impact of an optimized transportation scheme which includes using a shorter route during the winter-spring period, an additional transportation system simulation was made with the following adjustments. It was assumed that during the half-year period (from December to May) icebreaking LNG carriers operate on the route from the Mackenzie Delta to Dutch Harbour (a possible point where safe transshipment to conventional LNG carriers could be organized), while direct transportation by icebreaking LNGCs to Shanghai is carried out during the remaining 6 months (from June to November).

As can be seen from Figure 5-10, the use of such a logistic scheme will reduce the required number of icebreaking LNGCs to 3 units. At the same time, additional storage to the amount of 450k m^3 will be required only in the summer period. Some reduction in the storage volume is possible; for example, when using low ice class LNG carriers during the open water season (as is widely practiced in the Yamal LNG project).

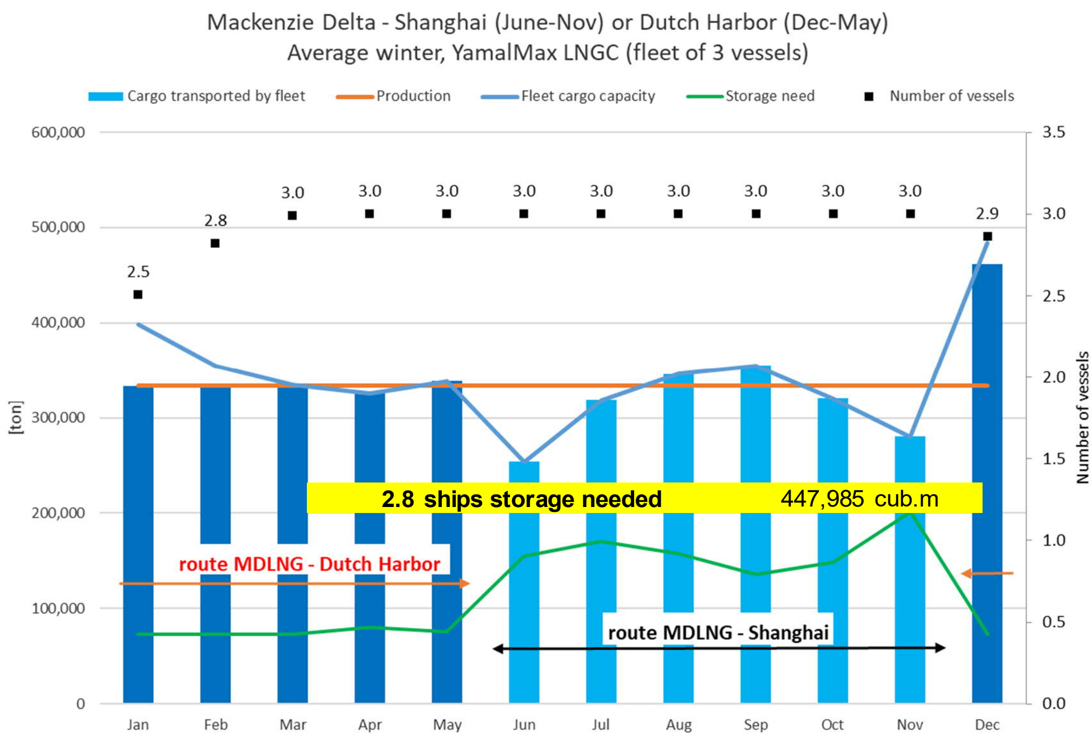


Figure 5-10 – Transportation capability analysis for average winter, 4 Mtpa of LNG, December-May to Dutch Harbour and June-November to Shanghai, YamalMax LNGC

Further transportation from the transshipment area by conventional LNG carriers, as well as the issues of organizing transshipment of LNG cargo are beyond the scope of this Study and are the subject of additional work to optimize the transport scheme at the next stages of the Project.

5.3.3.2 OIL/CONDENSATE TANKER

Figure 5-11 presents the transportation system simulation results for 0.36 Mtpa of gas condensate production level (based on production rate 10,000 bbl /day) using the reference *Boris Sokolov* type tankers for an average winter.

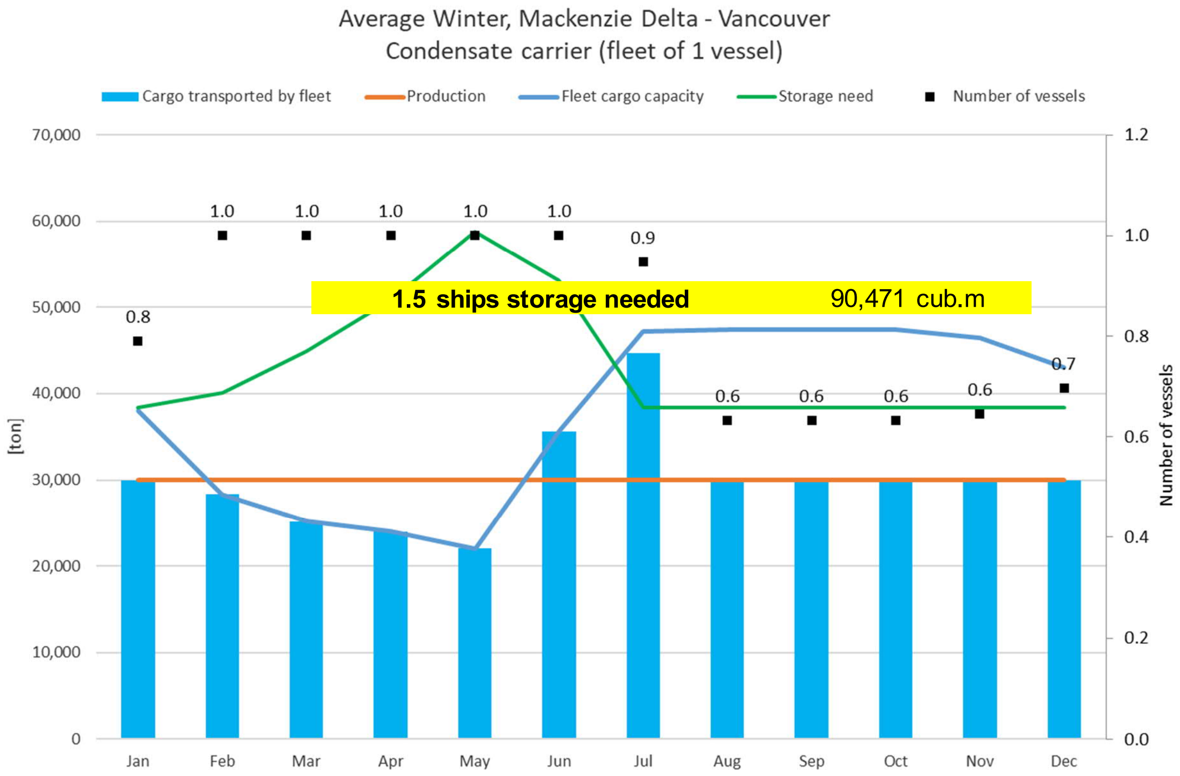


Figure 5-11 – Transportation capability analysis for average winter, 0.36 Mtpa of gas condensate, year-round to Vancouver, *Boris Sokolov* type tanker

The results indicate that:

– 1 vessel is required in the fleet.
– 1.5 vessel cargo capacity is required for storage (90,000 m³ of storage for gas condensate) at the GBS (including buffer capacity needed for loading of one tanker).

The graph in Figure 5-12 presents the transportation system simulation results for 1.1 Mtpa of gas condensate production level (based on production rate of 30,000 bbl /day) using the reference *Boris Sokolov* type tankers for an average winter.

The results indicate that:

– 2.5 vessels are required in the fleet.
– 2.3 vessel cargo capacity is required for storage (138,000 m³ of storage for gas condensate) at the terminal (including buffer capacity needed for loading of one tanker).

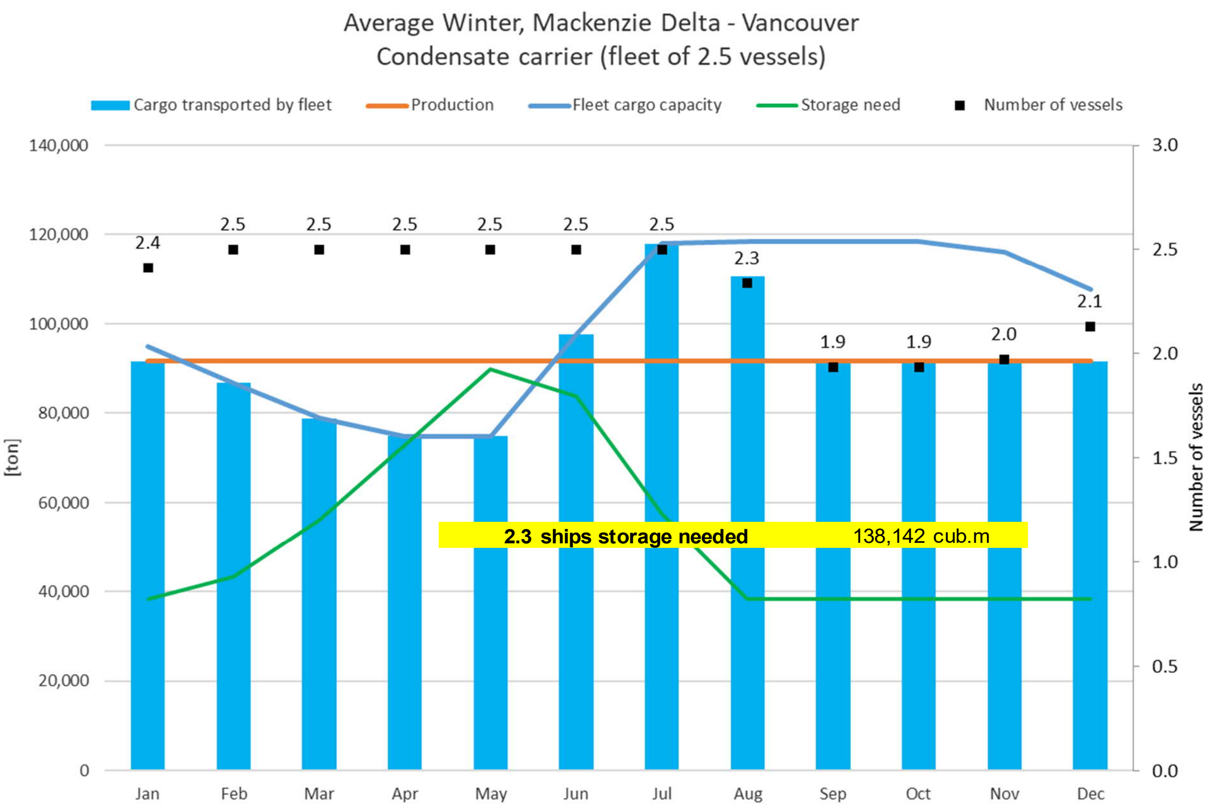


Figure 5-12 – Transportation capability analysis for average winter, 1.1 Mtpa of gas condensate, year-round to Vancouver, Boris Sokolov type tanker

5.3.4 CAPITAL COST ESTIMATES (CAPEX)

For the icebreaking LNG carriers, the reference newbuilding price of the *Christophe de Margerie* is used. For the gas condensate tanker, the reference newbuilding price of the tanker *Boris Sokolov* is used. Reference prices are adjusted to current market level, rounded, and relevant to the construction of a small series of similar vessels in South Korea or China.

Capital costs or financing costs in this study is simply calculated based on the estimated newbuild price, term of payment, interest rate and residual value of the vessel.

– Newbuild price for icebreaking PC3 polar class YamalMax type LNG carrier is USD 320 million.
– Newbuild price for ice-going PC3 polar class gas condensate tanker of *Boris Sokolov* type is USD 130 million.
– Term of payment is 20 years at 2% interest rate.
– Residual value of the vessels is 0% of newbuild price.
– Yearly effect (lowering of costs) of residual value is simply calculated by dividing the residual value by the term of payment years (instead of discounting the future income into today's value).

5.3.5 OPERATING COST ESTIMATES (OPEX)

5.3.5.1 BASIC ASSUMPTIONS FOR OPEX CALCULATIONS

An estimation of operational expenses for ships is, as a rule, required when solving various ship design optimization tasks. Using these calculations, the efficiency of various Arctic or freezing-sea transportation schemes and various design options of ice going vessels is compared. For various tasks, different degrees of detail for calculations could be used.

Operational expenses (OPEX) in a general case include the following main items:

- Fixed expenses associated with the maintenance of ships in operation (crew expenses, insurance, technical services, repair, drydocking, management etc.).
- Running (roundtrip based) expenses, including fuel expenses, port/waterway/canal dues and fees for possible icebreaker support.

For this study, the following OPEX structure is proposed for estimating the cost of transportation of LNG and gas condensate from the Mackenzie Delta. The estimates below are based on available and public statistical data, as well as previous estimates of operating costs for LNG carrier and oil tanker types of vessels.

5.3.5.2 FIXED OPERATIONAL COSTS

- Crew expenses: includes the salary of ship crew members, taking into account overtime and vacation, training, travel and medical care, social taxes & payments, food provision, etc. The level of salary is usually determined in accordance with the International Transport Workers' Federation (ITF, 2020) uniform Total Crew Cost (TCC) Agreement, based on the standard crew list for the type of vessel under consideration, the other components are taken into account by a relative coefficient. It was assumed that the crew number is 35 for icebreaking type LNGC and a crew of 25 persons – for gas condensate tanker, average value of expenses for crew and provision - about USD 220 / person per day.
- Insurance expenses: includes Hull and Machinery (H&M) insurance (can be taken at the annual amount of 0.3% of ship construction cost) and insurance at the P&I (Protection and Indemnity) club costs of this type of insurance (can be assumed as USD 3.5 per 1000 tons of deadweight per day).
- Technical services, spare parts, maintenance: usually assumed this should depend on the degree of complexity of the vessel, which generally for ice class vessels can be expressed by statistical dependence as lightweight.
- Repairs, drydocking, class surveys: a rough estimation of this component is done based on reference data of the cost of drydocking cargo vessels equipped with azimuthing propulsion units.
- Management expenses: the costs of the operation of the vessel, the need for its maintenance by onshore personnel: superintendents, accountants, commercial department activities, marketing, etc. (proposed to assume that this item amounts to 15% of operational expenses).

Results of tentative calculation of fixed OPEX items (without fuel expenses) for YamalMax LNGC and Boris Sokolov type tanker are presented in Table 5-1.

Table 5-1 – Calculation of fixed OPEX items for YamalMax LNGC and *Boris Sokolov* type tanker, USD / day

Type of vessel	Unit	YamalMax type LNG carrier	Boris Sokolov type tanker
Crew		35	25
Maximum DWT		83,000	40,000
Lightweight	ton	47,000	21,100
Construction cost	MUSD	320	130
Calculation of average daily fixed costs			
• Insurance (H&M+P&I)	USD/day	2915	1206
• Crew and provision	USD/day	7700	5500
• Service and maintenance	USD/day	3960	1677
• Repairs, docking, class surveys	USD/day	6000	5000
• Management, other	USD/day	3086	2007
Total fixed operational expenses	USD/day	23,661	15,390
Rounded values of daily fixed OPEX	USD/day	**24,000**	**15,500**

5.3.5.3 ROUNDTRIP BASED OPERATIONAL COSTS

- Fuel expenses are obtained by multiplying the total fuel consumption during a roundtrip voyage from the transit simulation (calculated separately for different modes of operation – open water navigation, navigation in ice, mooring operations, loading, unloading, idle), by the fuel's price. The cost of lubrication oil is considered as an addition of 1% to the fuel cost. For YamalMax type LNG carriers, equipped with engines using LNG as a fuel, consumption of pilot fuel (MDO) is not calculated separately for each mode of operation, but considered as an addition of 2% to the total fleet fuel cost.
- Icebreaker support fee in this study has been calculated based on the minimum estimate of the possible charter rate of a linear (escort) icebreaker (USD 45,000/day, based on available reference data for the Russian Arctic and freezing seas), including the required period of obtaining an icebreaker to escort the gas condensate tanker.
- No roundtrip base costs regarding fees and port expenses have been considered in this study.

Fuel consumption is estimated by dividing the total roundtrip operation time into smaller components having their own share of consumption. The following different operation modes are used:

- Open water navigation
- Independent navigation in ice
- Icebreaker assisted navigation in ice
- Loading and unloading
- Icebreaker assisted navigation in ice
- Waiting, idle and off hire time

Time spent in different operational modes is based on transit simulation results and other operational assumptions explained in Section 5.2.

Each type of vessel has its own consumption figures (of LNG or MDO) based on power or other technical properties. Fuel consumption figures used are presented in Table 5-2.

Table 5-2 – Fuel consumption values for an OPEX calculation

Mode of operation		YamalMax LNGC	Condensate tanker
Open water navigation (at open water service speed)	ton / hour	7.54	1.65
Independent navigation in ice	ton / hour	6.40	2.86
Icebreaker assisted navigation in ice	ton / hour	-	2.57
Consumption, loading	ton / hour	0.435	0.12
Consumption, discharging	ton / hour	1.697	0.75
Mooring & unmooring	ton / hour	1.37	0.83
Waiting & idle, off hire	ton / hour	0.22	0.12

The resulting total fuel consumption for the fleet is calculated based on the assigned number of vessels in each month and their corresponding operation modes during the whole year. Fuel consumption for the idle vessels (those ships in the fleet that are not assigned for monthly transportation) is also considered with consumption in the “off hire” figure.

An average fuel price of USD 400/ton for LNG is used, considering that LNG cargo is used as fuel on loaded and ballast voyages. For MDO, an average fuel price of USD 600/ton is used, and assumed as the main fuel type for condensate tankers.

5.3.6 TRANSPORTATION COST SUMMARY

In Table 5-3 all cost components have been summed up and a summary of cost comparison results is presented. The most interesting figures are at the bottom of the table:

– Costs per ton: total costs divided by the amount of delivered cargo tons.
– OPEX per ton: total operating costs divided by the amount of delivered cargo tons.
– CAPEX per ton: total capital costs divided by the amount of delivered cargo tons.

Total fleet costs are calculated based on the rounded fleet size, and not the actual calculated fleet, as indicated in Figure 5-9 for LNG carriers and in Figure 5-11 and Figure 5-12 for condensate tankers. As the number of vessels is rounded, the possible difference in CAPEX is not reflected in Table 5-3. At the same time, the difference in the required number of vessels can have a greater impact in heavy winter ice conditions.

For LNG transportation, the volume of delivered cargo is the volume of loaded LNG, less the amount of cargo used as fuel for ship propulsion.

The resulting final transportation cost for LNG and gas condensate cargoes is the initial estimate of the level of expenses for seabound transportation from the Mackenzie Delta, excluding other costs associated with the port and service infrastructure.

Table 5-3 – Summary of calculations of transportation costs (average winter)

Vessel type		**YamalMax LNGC**	**Condensate tanker**		unit	Notes
Destination		Shanghai	Vancouver			
Cargo Transport	Number of vessels	5	1	3	pcs	required number of ship rounded
	Loaded cargo	4.0	0.36	1.1	Mton	
	Required storage volume	253,695	90,471	138,142	m^3	
	Total fuel consumption	222,217	14,100	36,822	ton/year	
	Fuel price	400 (LNG)	600 (MDO)	600 (MDO)	$/ton	current level bunker prices of LNG and MDO
	Cost of pilot fuel and lube oil	2667	85	221	k$/year	+2% of cost for pilot fuel, +1% for lube oil
Fuel cost	**Total fuel cost for fleet**	**91.55**	**8.54**	**22.31**	**M$/year**	
	Daily fixed costs	24,000	15,500	15,500	$/day, avg	max estimate
Fixed operational costs	Total one ship for year	8.76	5.66	5.66	M$/year	
	Total for fleet	**43.8**	**5.7**	**17.0**	**M$/year**	
Icebreaker assistance costs	Estimated charter rate			45,000	$/day	estimated market value
	Total for required period	-	-	**6.8**	**M$/year**	1 escort IB for 5 months
Capital costs	Building cost of ship	320	130	130	M$	
	Term of payment	20	20	20	years	
	Interest rate	2%	2%	2%		
	Residual value of ship	0	0	0	M$	0% of newbuild price
	Total one ship	19.6	8.0	8.0	M$/year	
	Total for fleet	**97.9**	**8.0**	**23.9**	**M$/year**	
TOTAL YEARLY COST	OPEX costs (+IB cost)	135.35	14.20	46.04	M$/year	
	CAPEX costs	97.9	8.0	23.9	M$/year	
	Total yearly cost	**233.2**	**22.2**	**69.9**	**M$/year**	
	Delivered cargo per year	3.777	0.36	1.10	Mtpa	
	Costs per tonne	**61.75**	**61.53**	**63.53**	**$/t**	approx. 1.16 $/MMBtu for LNG
	OPEX/tonne	**35.84**	**39.45**	**41.85**	$/t	
	CAPEX/tonne	**25.91**	**22.08**	**21.68**	$/t	

6 ICE MANAGEMENT

The Ice Management (IM) procedures and examples of applicable IM vessels for the MDLNG GBS are studied in the following sections. The proposed IM fleet should be considered as tentative at this stage. This is because all affecting factors, especially the ability of the logistical chain to tolerate disturbances, is not known yet. The IM fleet can be updated/adjusted to meet the requirements of marine transportation at a later state when all key factors are known. The possibilities to combine duties of different IM vessels, not only at the GBS site but also along the routes of the LNG carriers and condensate tankers, are also discussed.

It is important to understand that the ice conditions in the MDLNG GBS region (and along the route between the GBS and the Bering Sea) vary significantly depending on the severity of the seasons and years. There may be a duration several years long when the ice conditions can be characterized as “mild” or “average” and a severe period may, for example, occur only once every seven to nine years. This phenomenon, and especially how it is considered in the design of the overall LNG logistical chain, is one of the key challenges regarding selection and design of the vessels. Designing the vessels (cargo vessels and assisting vessels) for the most severe ice conditions often leads to a high number of significantly expensive vessels whose full performance is needed only few times during the project lifetime. And still, because the most difficult ice conditions or “ice events” during the project lifetime cannot be known in advance, a 100% guarantee for their performance cannot be given.

6.1 BASIC ASSUMPTIONS

The following assumptions are used as a basis to define the proposed IM fleet.

<u>Ice conditions at the GBS</u>

The ice conditions in the GBS area are considered as “difficult” when typically occurring in February-March of a hard winter. The representative level ice thickness is 2 m. The GBS basin near the docking area has a thick brash ice layer. The GBS basin and surrounding area may occasionally include multi-year ice fragments.

<u>Required assistance</u>

LNG Carriers (LNGC) and Condensate Tankers (CT) are both equipped with azimuth thrusters enabling good maneuverability in ice (and in open water). During berthing the carriers can control their stern with these thrusters. At a minimum, assistance is needed at the bow only (see Section 6.3.2). The LNGC and CT can both arrive and depart from the GBS without assistance. However, if the shear zone between dynamic sea ice and the landfast ice is compressive and/or heavily ridged, assistance can be arranged to pass it more easily.

Assisting IM Vessels

It assumed at this stage that all IM vessels can use MDO or LNG as a fuel (i.e. “dual fuel” machinery). Their bunkering is arranged from the GBS and they can navigate in the summer season to Dutch Harbour independently without re-fueling on the route. It may be beneficial to arrange some maintenance/repair services for IM vessels at the GBS; the possibilities to arrange such services should be evaluated at a later stage.

The IM vessels can be equipped for various additional duties; e.g: supply, stand-by, firefighting, oil combatting or spillage response, EER tasks, etc. The requirement for these tasks and modification to the IM vessels to make them fit for purpose should be evaluated at a later stage.

The GBS location, orientation and layout

The GBS is in 15-metre-deep waters of the coastal region, typically inside the fast ice zone. The GBS is an elongated rectangular structure with its berth integrated at the shore-side, thus providing good protection from offshore drifting. It can be approached straight wise from both ends of the BGS (see Figure 6-12).

Ship GBS visit frequency

The LNG carriers visit the GBS once per week and the condensate tanker visits the GBS once every two weeks. Thus, 6 vessels visit the GBS per month.

6.2 ICE MANAGEMENT VESSELS

A set of applicable Ice Management Vessels (IMV), i.e. Primary, Harbor, and Escort Icebreakers, for assisting LNGC and condensate tankers during their MDLNG GBS visits are introduced in the sections below. Based on the performance of these vessels, the key tasks and IM techniques used in assisting are described later in Section 6.3.

The newbuilding price estimations given in the following sections should be treated as very rough and only indicative. The real new-building price depends on multiple factors such as building country, current order book, unique design and outfitting of the vessel, etc. The given estimates, however, provide a first insight to the price level of the ship in question and can be used, for example, for overall budgetary purposes.

6.2.1 PRIMARY ICEBREAKER

The Primary Icebreaker is intended for various tasks. This vessel can manage large ice features and grounded ridges in front of the GBS and maintain the approach/departure channels to/from the GBS through the shear zone and the fast ice zone. It can escort the LNG Carriers through the shear zone and fast ice, and lead them to, and away from, the GBS location. The vessel is maneuverable and thus capable of managing significant amounts of brash ice formed in the GBS basin and in the jetty area near the GBS.

The Primary Icebreaker forms the core of the IM Fleet. It is essentially used to assist the LNG Carriers and condensate tankers during their GBS visits, and has the capability to perform other IM tasks. The Primary Icebreaker is supported at the GBS basin by the Harbour Icebreaker (Section 6.2.2). Outside the GBS, especially during hardest ice seasons, it is supported by the Escort Icebreaker (see Section 6.2.3). The primary icebreaker provides flexibility and certainty in assisting tasks at the MDLNG GBS because it can perform many tasks and can be adopted for several duties.

The vessel design would be based on the Aker ARC 130A concept. The icebreakers *Aleksandr Sannikov* and her sister, *Andrey Vilkitsky* were both built based on this concept. Today they assist oil tankers at the Novy Port oil loading tower in the southern Ob Bay (North Russia). A drawing and photo of the *Aleksandr Sannikov* are presented in Figure 6-1 and Figure 6-2.

Approximate main parameters and an indicative price estimate for the Primary Icebreaker proposed for MDLNG GBS are as follows:

Length	122 m
Beam	25 m
Draught	8 m
Propulsion	2 azimuth drives at the stern, 1 azimuth drive at the bow
Propulsion power	22 MW
Ice class	PC 2
Ice performance:	2 knots in 2 m thick level MY-ice. 4 knots with good maneuverability in 7 m thick brash ice.
Indicative newbuilding price:	USD160 million

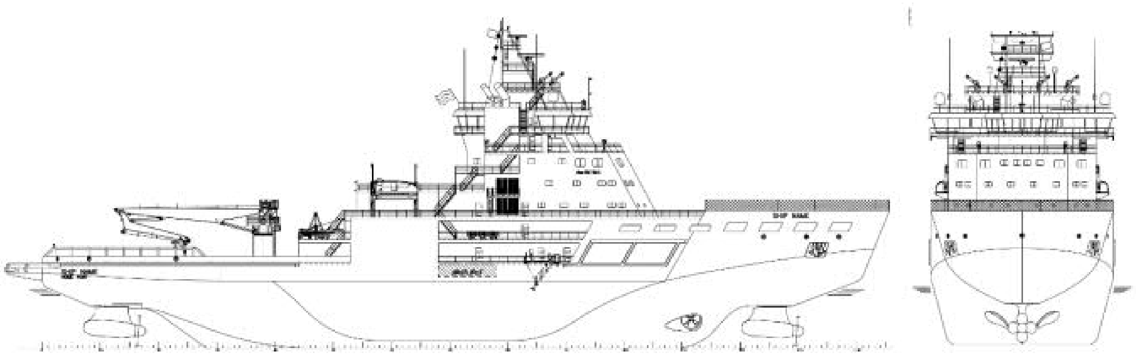


Figure 6-1 – Example GA of Primary Icebreaker

Figure 6-2 – *Aleksandr Sannikov* at Novy Port loading tower (Ob Bay, North Russia, Source: Gazpromneft Shipping)

Another example of an icebreaker that could be used as a design reference for the MDLNG GBS Primary Icebreaker is presented in Figure 6-3. This alternative could be applied, especially if multi-year ice operations are emphasized. The power of this variant is again split between two stern-located azimuthing propulsion units, but there is no thruster at the bow. This enables a higher speed in bow-first operations in MY ice. The concept would be based on an uprated variant of the *SCF Sakhalin* (originally *FESCO Sakhalin*) which has been operating as a support icebreaker off Sakhalin since its delivery in 2005. Today (i.e. winter 2020 - 2021) the vessel is assisting at the Prirazlomnoya Platform located in the Pechora Sea (Northern Russia).

Figure 6-3 – *SFC Sakhalin* icebreaker (Source: FESCO)

6.2.2 HARBOUR ICEBREAKER

The harbor icebreaker can perform regular tug-boat tasks and easier icebreaking duties at the GBS basin. It has good maneuvering capability in brash ice enabled by azimuth thrusters. It is designed to push and pull carriers or tankers during their GBS visits (presented in 6.3.2), clear the jetty area of brash ice by “flushing” (see Figure 6-10) and perform other close-distance assisting operations inside the GBS basin and near the berths and carriers/tankers safely.

An example of a Harbor Icebreaker is presented below. It is dedicatedly designed for efficient assisting tasks, e.g. pushing and pulling of large carriers in a demanding environment. She has two azimuth thrusters at the stern and two at the bow providing high maneuvering performance and capability to perform close-distance IM operations on a year-round basis at the MDLNG GBS. It has limited capability to operate in thick level ice outside the GBS basin during most difficult ice seasons.

The main parameters (approximates) and rough price indication for the Harbor Icebreaker proposed for MDLNG GBS are given below. The vessel design would be based on the Aker ARC 124A. The icebreaker *Ob* was designed based on this concept. *Ob* is assisting YamalMax LNG Carriers in Sabetta LNG GBS (Northern Ob Bay, North Russia) today. A drawing and photo of this icebreaker are presented in Figure 6-4 and Figure 6-5.

Proposed main characters of MDLNG GBS Harbour Icebreaker:

Length	abt. 90 m
Beam	abt. 20 m
Draught	abt. 7.5 m
Propulsion	2 azimuth drives at stern, 2 azimuth drives at the bow
Propulsion power	12 – 14 MW

Ice class	PC 3 Icebreaker
Ice performance:	2 knots in 1.7 m FY ice
	4 knots in 4 thick brash ice

Indicative newbuilding price: USD 110 million

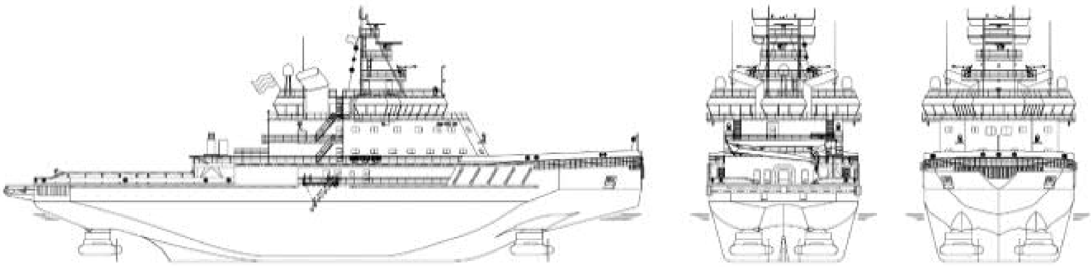


Figure 6-4 – GA drawing of Aker ARC 124A

Figure 6-5 – Harbour Icebreaker "*Ob*" operating currently at the Sabetta LNG GBS (source: Atomflot)

6.2.3 ESCORT ICEBREAKER

A heavy-duty icebreaker concept for continuous escorting in hard ice conditions, which may include multi-year ice, is presented below. This vessel can be used for LNG Carrier and condensate tanker escorting on a year-round basis in all anticipated ice conditions along the route between MDLNG GBS and the Bering Sea. She has no thrusters at the bow, which enables high-speed, bow-ahead operations in severe ice conditions. The vessel has two azimuth thrusters at the stern to provide maneuvering capability, and the ability to prepare channels for the carrier. In addition, she has one larger shaft line propeller to provide additional boost forwards. By using her mass (inertia), she can demolish grounded ridges and open channels through difficult ice segments (formed, for example, to the shear zone between landfast ice and dynamic sea ice) and in areas where multi-year ice exists.

The maneuvering capability of the Escort Icebreaker is inferior to the maneuvering capability of Primary and Harbour Icebreakers, thus it is not feasible for towing and pushing of the carriers/tankers or other specific IM tasks requiring Azimuth thruster(s) at the bow (ref. example in Figure 6-10). However, an Escort Icebreaker can be used efficiently to break all kinds of ice around the GBS if needed (as described in Figure 6-15).

The main parameters (approximates) for the Escort Icebreaker proposed for MDLNG GBS are listed below. The vessel design would be based on the Aker ARC 143 concept initially designed for escorting “YamalMax” LNG Carriers on a year-round basis on the Northern Sea Route. No real-life example of this icebreaker exists yet. A drawing and artistic impression of the vessel are presented in Figure 6-6 and Figure 6-7.

The proposed main characteristics, together with a rough newbuilding price indication for the Escort Icebreaker operating in the MDLNG GBS region and on the carrier routes through the Beaufort and Chukchi Seas are presented below.

Estimated main parameters of Escort Icebreaker:

Length	160 m
Beam	34 m
Draught	9 m
Propulsion	Two azimuth drives and one shaft line propeller at the stern
Propulsion power	40 MW
Ice class	PC 2
Ice performance:	2 knots in 3 m multi-year ice

Indicative newbuilding price: USD 300 million (this estimation should be considered very rough and preliminary and representing an “international ship price” due to the ship in question being unique and no adequate price reference is available).

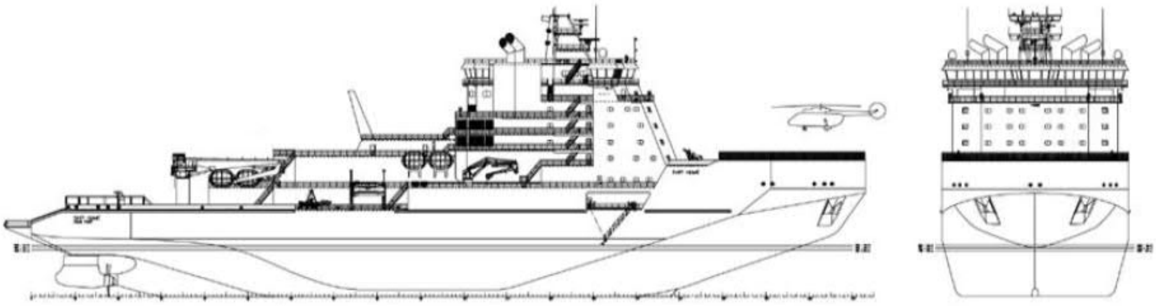


Figure 6-6 – GA of Escort Icebreaker

Figure 6-7 – Artist impression of the Escort Icebreaker (Source: Aker Arctic)

6.3 ICE MANAGEMENT OPERATIONS

Typical IMV operations and duties are presented in this section. The presented duties can be performed efficiently with the vessels introduced in the previous sections. In principle, some of these operations can also be performed with other types of icebreaker, but with lower efficiency and safety. On the other hand, some IMV techniques, like “flushing” for example, require azimuth thrusters, and such operations cannot be performed appropriately without them.

6.3.1 PREPARATIONS FOR CARRIER ARRIVAL

The ice from the GBS basin is broken to small floes, as described in Figure 6-8, in readiness for carrier and assisting vessel maneuvers. This enables the vessels to operate with less resistance, thus making operations quicker and safer. The preparations for a carrier’s arrival should not be started too early, as to avoid re-freezing of the area before the vessel arrives. A photograph of an area being prepared is shown in Figure 6-9.

A specific preparation task is presented in Figure 6-10. The drawing describes two methods of clearing ice away from dolphins in order for the final stages of carrier berthing to be completed easily: The Harbor Icebreaker (HIB) uses her azimuth thrusters to “flush” the side of the breasting dolphin. This is done because ice tends to squeeze between the carrier and the dolphin when the carrier is moored. Ice also accumulates and freezes to the sides of dolphins making the finalization of the berthing of the carrier very difficult. Therefore, it is important to clear as much ice as possible from the area near the dolphins before the carrier arrives. Furthermore, it should be noted that this flushing task can only be performed appropriately by vessels equipped with two or more azimuth thrusters.

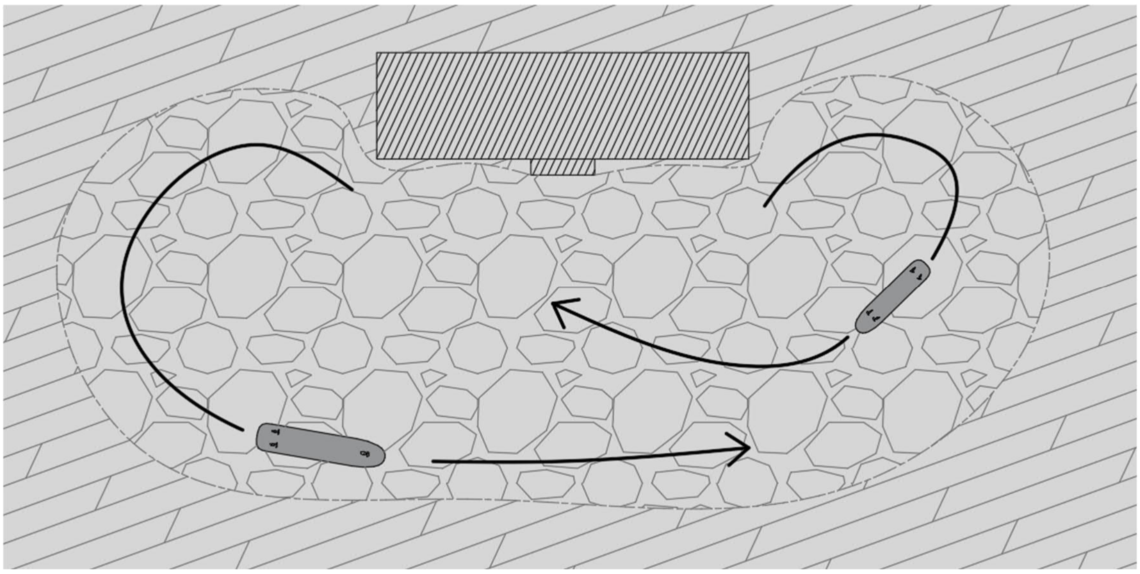


Figure 6-8 – HIB breaking ice at the GBS basin before the LNG Carrier arrives.

Figure 6-9 – Breaking ice before carrier arrival in the Eastern Gulf of Finland (Source: Aker Arctic)

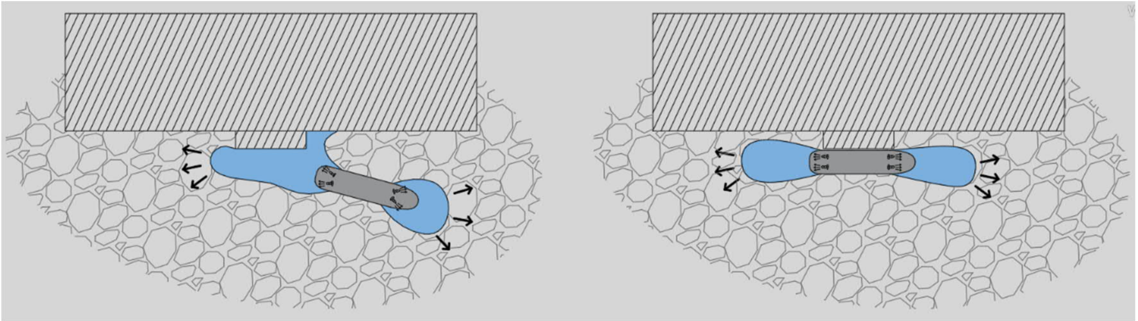


Figure 6-10 – Clearing the mooring location of the carrier by flushing. Harbour Icebreaker uses her azimuth thrusters to push ice away.

Figure 6-11 – Harbour tug is clearing the dolphins of ice by flushing with her azimuth thrusters, Eastern Gulf of Finland (Source: Aker Arctic).

6.3.2 VESSEL APPROACH, BERTHING AND DEPARTURE

The MDLNG GBS enables carrier approach, berthing and departure in a straightforward manner without any difficult maneuvers. In principle, the carrier does not need to be turned during GBS visits, and assistance is needed only at the final stages of berthing.

The possible tracks of the carrier arrival are described in Figure 6-12: The carrier may approach bow or stern-first to the GBS. It is recommended that the final stage of berthing is done stern-first however, as the stern-control of the carriers is better and because the carrier may then utilize her own azimuth thrusters to clear ice beside the breasting dolphin (see Figure 6-13).

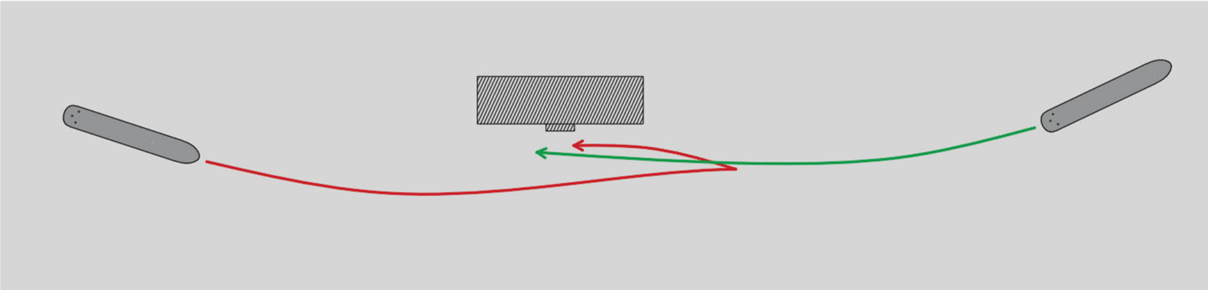


Figure 6-12 – Approach schemes. Red curve: Bow-first approach; Green curve: Stern-first approach.

The berthing of the carrier is described in Figure 6-13. The carrier approaches the mooring location stern-first. If there is still too much ice beside the breasting dolphin, the carrier may use one of her azimuth thrusters to clear it once again. It may be reasonable, for safety reasons, to attach the Harbour Icebreaker to the bow of the carrier to ensure that the bow of the carrier does not swing towards the GBS (this can be possible especially during a hard ice season when brash ice pressure may push the bow towards the GBS).

When the carrier has reached the correct position, the final movement sideways (side-first) is assisted by the Harbour Icebreaker, which pushes the carrier gently from the bow. The stern of the carrier does not need pushing because her own thruster(s) can be used to move the stern towards the GBS.

Carrier departure is illustrated in Figure 6-14. The Harbour Icebreaker is attached to the bow of the carrier and pulls the carrier away from the GBS. The carrier uses her own thrusters simultaneously to move the stern further from the GBS. When the carrier is at a safe distance from the GBS, the towline is released, and the carrier can start to navigate without support.

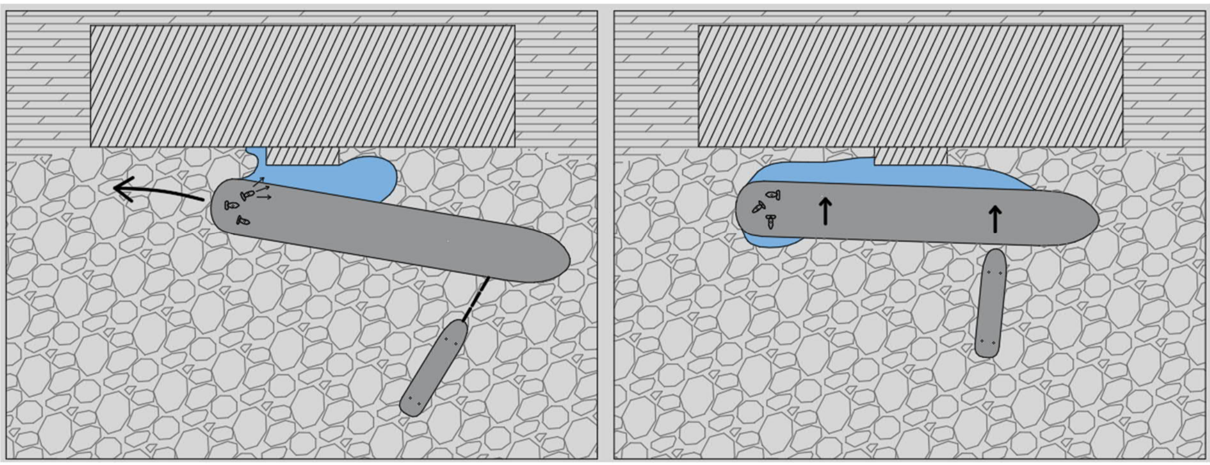


Figure 6-13 – Berthing of the LNG Carrier. The carrier flushes ice away from the breasting dolphin. Blue color illustrates open water or very loose rubble.

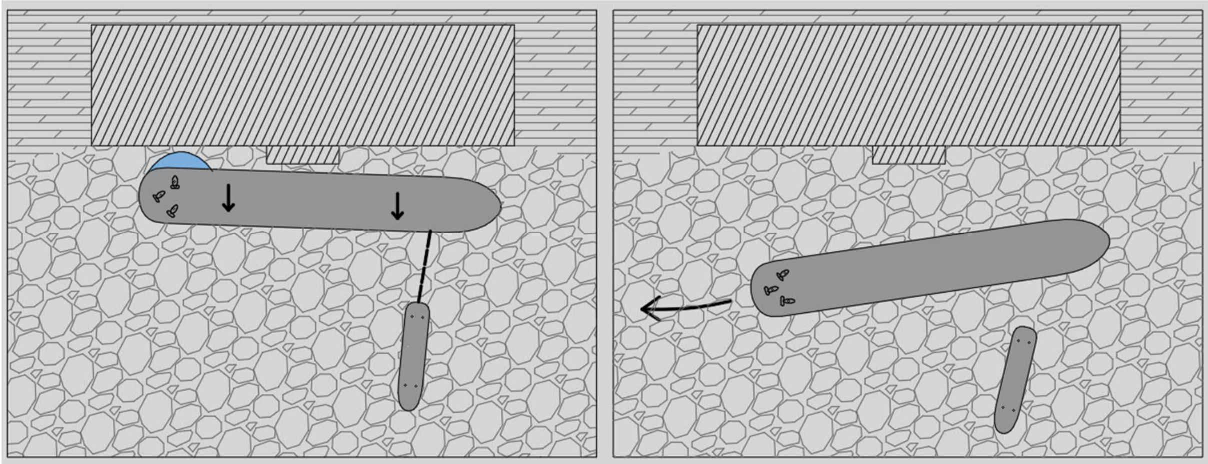


Figure 6-14 – Carrier departure. Harbour Icebreaker pulls the carrier by the bow and the carrier's own thrusters provide thrust for the stern to move the carrier further from the GBS.

6.3.3 ADDITIONAL IM DUTIES

In addition to IM procedures described in previous sections, there are other tasks which can be done to aid the LNG Carrier's GBS visits and navigation near the GBS. Unnecessary icebreaking, especially during the freezing season, in the area should be avoided as this actually increases the amount of ice. However, examples of these additional IM tasks are described below.

Figure 6-15 presents one example of an IM procedure that could be used to decrease the amount of ice and consequent ice pressure in the GBS basin: A larger (i.e. Escort or Primary) icebreaker moves slowly along the fast ice edge of the GBS basin and a smaller (i.e. Harbour or Primary) icebreaker follows so that brash ice is bushed sideways towards the track of the larger icebreaker. The smaller icebreaker may use her azimuth thrusters to improve ice movements.

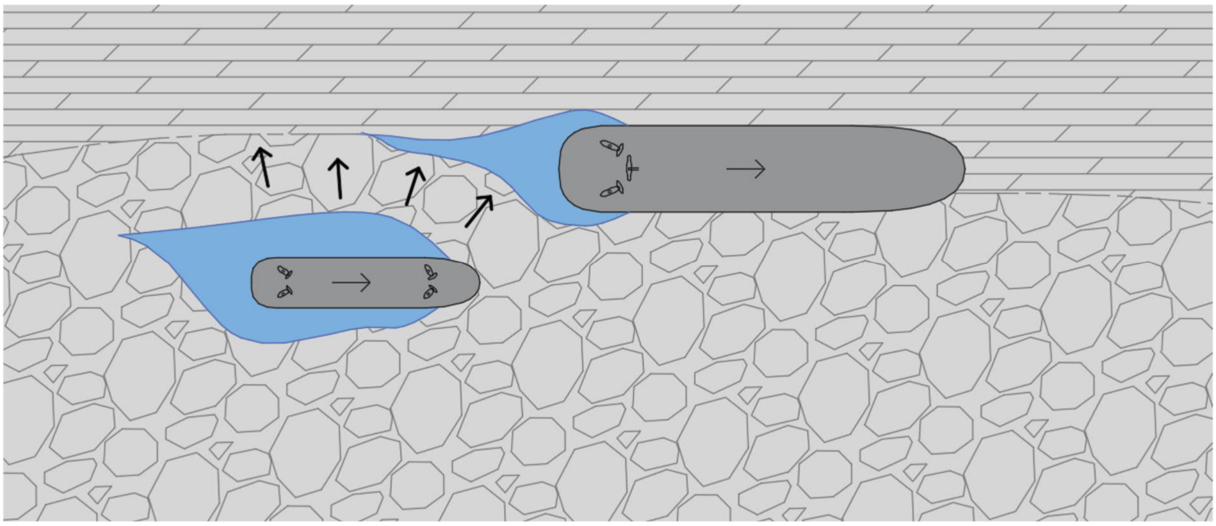


Figure 6-15 – Preparing more space for brash ice to relieve ice pressure inside the GBS basin.

Another example of an additional IM task is presented in Figure 6-16. The Escort (or Primary) icebreaker proceeds slowly in level ice or ridged zone and flushes sideways with her thrusters. The propeller flow pushes broken ice further below the ice cover and may even break level ice beside the icebreaker. In ridges, the ice blocks at the underwater part (i.e. “keel”) of the ridge are also pushed sideways. This decreases the buoyancy supporting the upper part of ridge (i.e. “sail”) thus causing its easier collapse. Eventually, a wide channel of loose ice is formed, enabling easier carrier navigation through it. This assisting method can, for example, be applied when escorting a carrier through a shear zone located between the landfast ice and dynamic sea ice. This zone is often heavily ridged and thus difficult to navigate for the carrier.

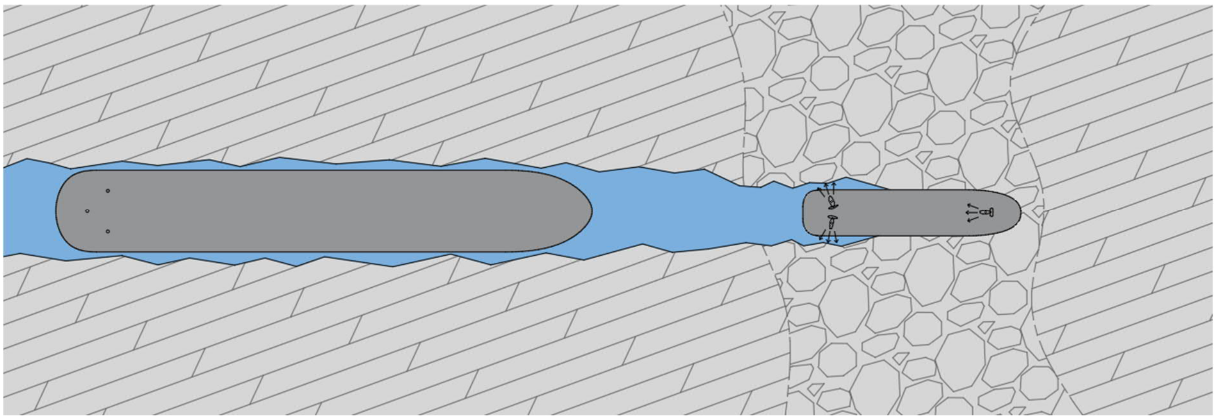


Figure 6-16 – Escorting the LNG Carrier outside the GBS area.

It is possible that ice will drift occasionally from the shore side towards the GBS. The cause of this phenomenon is not fully understood, but it seems to be related to the Mackenzie River flooding: Ice melts in the river and starts to drift finally to the sea. Landfast ice may start to break into floes and fragments at the same time. These floes may then drift to the GBS from the unprotected direction. In such a case, IM may be needed to break ice floes even smaller and push and flush them so that the amount of drifting ice entering the GBS basin and jetty is minimized.

It can be assumed that the above-described event does not critically disturb GBS operations. This is because the ice is soft and at its melting state, the concentration of ice is relatively low, and floes are small and easy to break even smaller. In addition, it can be assumed that these events are also rare. However, if this event is more severe than expected and more difficult to manage with icebreakers, interruption to GBS operations may be required. This downtime should, however, be assumed as relatively short.

6.4 IM FLEET AND COSTS

6.4.1 PROPOSED IM FLEET

The proposed Ice Management Vessels (IMV) and their duties are summarized in the table below. The duties are based on the tasks presented in Section 6.3 and performance of the vessels introduced in Section 6.2.

It should be noted that the presented IM fleet composition is based on a maximum capacity required scenario, covering all key aspects affecting IM needs. In principle, this means that that the proposed fleet is capable of taking care of assisting operations in all realistically anticipated ice conditions in the immediate and adjacent GBS regions, without causing disturbances to marine transportation.

For example, if two to three days of delays in transportation can be tolerated, the IM requirements can be decreased, and the IM fleet may be comprised of lighter icebreakers or tugs. This naturally means that the newbuilding prices of the ships can be reduced. Alternative fleet compositions and the possibilities to reduce IM requirements are further discussed in Section 6.5.

In addition, the IM fleet is composed such that vessels can be used for multiple tasks, thus enabling the replacement of one vessel by another if needed (ref. “primary” and “secondary” tasks in Table 6-1).

Table 6-1. Tasks of the proposed vessels in IM Fleet

	Ref. drawing	HIB	PIB	EIB
IM, fairways	6-16	-	S	P
IM, GBS basin	6-8	P	P	P/S [1]
IM, jetty	6-10	P	S	-
Pushing (carrier berthing)	6-13	P	S	-
Towing (carrier depart)	6-14	P	P	S
Escorting outside GBS	6-16	-	S	P
Brash ice management	6-15	P	P	P
Drifting ice management	-	S	P	P

HIB: Harbour Icebreaker
PIB: Primary Icebreaker
EIB: Escort Icebreaker
P: Primary task - full capability to perform the task.
S: Secondary task – can perform the task if required, but with reduced efficiency.
1) Straightforward ice breaking further from the jetty/GBS.

6.4.2 OPERATIONAL COSTS

The operational costs for the IM vessels are presented in Table 6-2 and

Table 6-3. The following should be noted regarding the presented cost estimates:

- The cost estimates are rough and correspond to the basic assumptions, tasks and vessels described in earlier sections and distribution of duties described in Table 6-1. No costs associated to the escorting of condensate tankers on their routes (ref. Table 5-3) are included in these estimates.
- Marine Diesel Oil (MDO) is assumed to be USD 400/ton.

- The LNG price is not estimated due to its pricing-principle of “for own purposes” (the market value of about USD 400/ton can be applied also for the LNG). LNG consumption, if the IMVs are used in gas-mode, is given in the table.
- It is assumed that the IMVs can bunker (either LNG or MDO) from the GBS, thus they do not need to leave the GBS for bunkering.
- No capital assets, associated interest costs, etc. are included in the estimations.
- In stand-by/Idle -mode the IMVs are parked using no power for navigation (only power required for heating etc. is in use).

The costs of assisting the carriers are at their lowest during the open water season and increase gradually towards the winter, reaching a maximum typically in January. Correspondingly, costs start to decrease in the middle of spring, at first steadily and then, around June, rapidly reaching minimum level again when all the ice has melted. Ice drifting during autumn, when the ice cover is not yet thick nor stable, may cause occasional additional work and costs. In addition, the ice melting season and Mackenzie River flooding, may cause occasional offshore ice drifting requiring specific efforts by the IM vessels. However, these events are not considered to be especially challenging for the IM vessels to manage, but some occasional increase in operational costs can be expected.

The operational costs of IM during difficult months (approximately from January to April) in an average winter are presented in the Table 6-2. In hard winters, the costs are slightly higher, and the length of the period can be assumed as one to two months longer. Correspondingly, in easy winters the difficult period is shorter, and costs are slightly lower.

Table 6-2 – Monthly duration of tasks and associated monthly costs of the whole IM fleet. Hard months (January-April) in average winter.

		HIB	PIB	EIB
IM at the GBS	Hours/month	60	60	24
Escorting and IM outside the GBS	Hours/month	0	0	200
Stand-by	Hours/month	672	672	508
Fuel (MDO) consumption	tons/month	151	276	1443
Comparable LNG consumption	tons/month	130	238	1244
Fuel (MDO) & lubrication costs	USD/month	63,232	115,925	606,043
Fixed monthly costs (1	USD/month	180,000	198,000	198,000
Total monthly costs per vessel	USD/month	243,232	313,925	804,043
All total	USD/month	1,361,200		

HIB = Harbour Icebreaker, PIB = Primary Icebreaker, EIB = Escort Icebreaker

1) Salaries, insurances, etc.

It can be assumed that HIB and PIB are partly deployed for carrier assistance in the open water season. Therefore, the EIB can be assumed as completely idle, causing only minimal costs during this season. Based on these assumptions the level of assisting costs at the MDLNG GBS are presented in the

Table 6-3. This includes assisting and securing with the Harbour Icebreaker, the Carrier berthing and departing from the berth, stand-by mode, as well as one roundtrip for each IMV (including EIB) during summer to Dutch Harbour for inspection/maintenance etc. The Primary Icebreaker is assumed to stay on stand-by and ready to secure operations if the Harbour Icebreaker is away or unable to take care of her duties.

Table 6-3 – Monthly duration of tasks and associated costs of the whole IM fleet. Open Water season (approx. July to September).

		HIB	PIB	EIB
IM duties at the GBS	Hours/month	24	0	0
Travels	Days/month	3,4	3,2	3,2
Stand-by (or idle)	Days/month	26,1	27,3	27,3
Fuel (MDO) consumption	tons/month	231	365	440
Corresponding LNG consumption	tons/month	199	315	380
Fuel (MDO) & lubrication costs	USD/month	96,854	153,235	184,960
Fixed monthly costs (1	USD/month	78,000	85,800	31,200
Total monthly costs per vessel	USD/month	174,854	239,035	216,160
All total	USD/month	630,049		

HIB = Harbour Icebreaker, PIB = Primary Icebreaker, EIB = Escort Icebreaker

1) Salaries, insurances, etc.

Thus, as a conclusion, the monthly costs of assisting the LNG carriers and condensate tankers at the MDLNG GBS are at their lowest level of around USD 600,000/month, typically over the three (open water) months. Correspondingly, costs will be at their highest level, about USD 1.3 million/month, for approximately four months of the hardest ice seasons. In an average year, the total costs are considered to be approximately USD 12 million/year.

It should be noted that the presented costs are tentative and based on cautiously highest assumptions. The IM fleet composition, the IM vessel parameters as well as associated costs should be updated/adjusted at a later stage when more detailed information on the overall logistics is available.

6.5 DISCUSSION

6.5.1 LOGISTICS FLEXIBILITY AND ALTERNATIVE IM VESSELS

As mentioned before, the proposed IM fleet (see Section 6.2) is based on a maximum capacity required scenario : the proposed fleet is defined to assist the carriers at the GBS, as well as outside the GBS (specifically at the Shear Zone, that may consist of heavy ridging and compression) to avoid delays in marine logistics.

If the overall transportation system has an inbuilt flexibility and IM-related delays in marine logistics are tolerated, the IM Fleet requirements and the capital expenditures associated, can be decreased. An increase of the LNG buffer storage capacity at the GBS probably provides the most reasonable opportunity to increase the tolerance of delays in transportation and IM requirements. Accordingly: The larger the storage capacity, the smaller the requirements for the IM fleet.

The vessel concept that could be applied in MDLNG GBS area is presented below. This is the PC4 Icebreaking Tug (IBT) equipped with two azimuth thrusters. Her capability to assist the carriers in easier seasons inside the GBS (in brash ice conditions) can be assumed appropriate, but during harder seasons difficulties are foreseen. The benefits associated to this tug-concept are her handiness in open water and easy ice conditions as well as lower costs (CAPEX and OPEX). It may be possible to upgrade the design for more difficult ice conditions and a higher ice class. In addition, the vessel could possibly be designed so that she could visit Tuktoyaktuk.

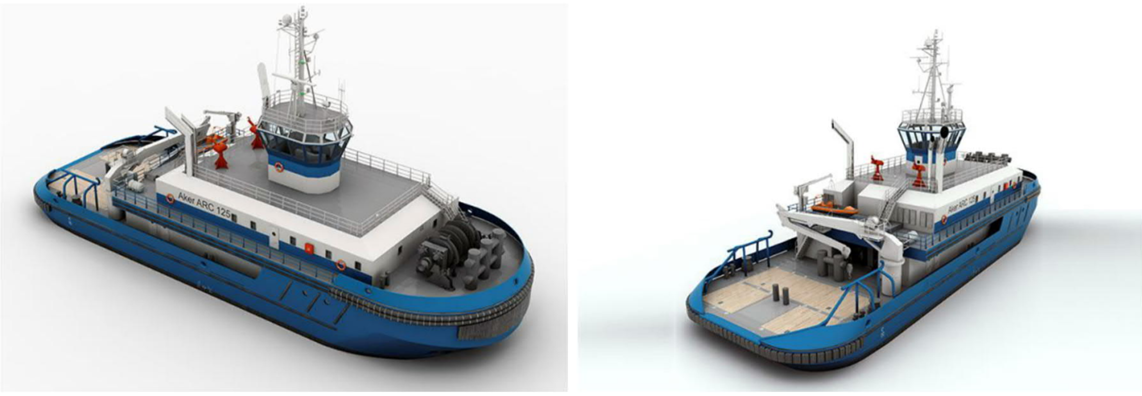


Figure 6-17 – Aker ARC 125 Icebreaking Tug.

The Escort Icebreaker has impressive icebreaking capability when assumed to be operating in the hardest ice conditions of the Beaufort and the Chukchi Seas. However, it can be assumed as too large and powerful a concept for efficient vessel assistance duties near the GBS. It lacks the maneuverability of a smaller tug and is too large to perform tug duties efficiently for carrier vessels without an increased risk of causing damage. Furthermore, using the Escort Icebreaker for such duties would not be cost effective.

As described earlier in this report however, the condensate tanker also needs icebreaker assistance in difficult ice conditions on her transit between the GBS and

Point Barrow. It may be possible to combine assisting services so that one Escort Icebreaker can assist carriers during voyages in the Beaufort Sea, including the ridged Shear Zone near the GBS. This may require some additional flexibility of the transportation system. It should be noted in this connection that, even if the LNG carriers are able to navigate independently in the region, they still benefit from assistance: they may follow the icebreaker (or use the tracks of an icebreaker) using less propulsion power than required for independent navigation.

In conclusion, the Ice Management vessels and fleet composition at the MDLNG GBS should be optimized at a later stage when more information on the factors affecting it is available.

6.5.2 ALTERNATIVE GBS CONFIGURATIONS

The key idea of ice protection at MDLNG GBS is that it is capable of protecting itself. This means that the GBS is big enough to provide appropriate shelter from ice drifting from offshore (which is assumed to occur relatively often, especially before the landfast ice is not fully developed and during melting seasons). However, if the GBS does not completely cover the whole length of the carrier (and with some surplus) then the drifting ice will hit the sides of the carriers directly, thereby causing high stress loads. The loading of the carrier cannot take place during such an event without additional ice protection structures.

In principle, protection for the GBS does not need to be a totally solid structure, but in can consist of several individual blocks located close to each other. In fact, as illustrated in Figure 6-18, these blocks may provide even better protection against ice drifting from different directions than just one solid block. Naturally, the distance between the blocks should be sufficient to prevent ice penetrating intensively through them. If needed, some additional structural elements could be used to fill the gaps totally or partially without a significant increase in building costs. The layout example on the right side of Figure 6-18 presents an arrangement where the outer blocks are slightly angled towards the GBS basin in order to improve protection, and additional structures have been installed between the gaps. The breasting dolphin is located further from the GBS, which opens additional space for brash ice to be pushed during carrier arrival. The outer blocks have not been angled too much, preserving straightforward and safe access and departure ability for the carriers.

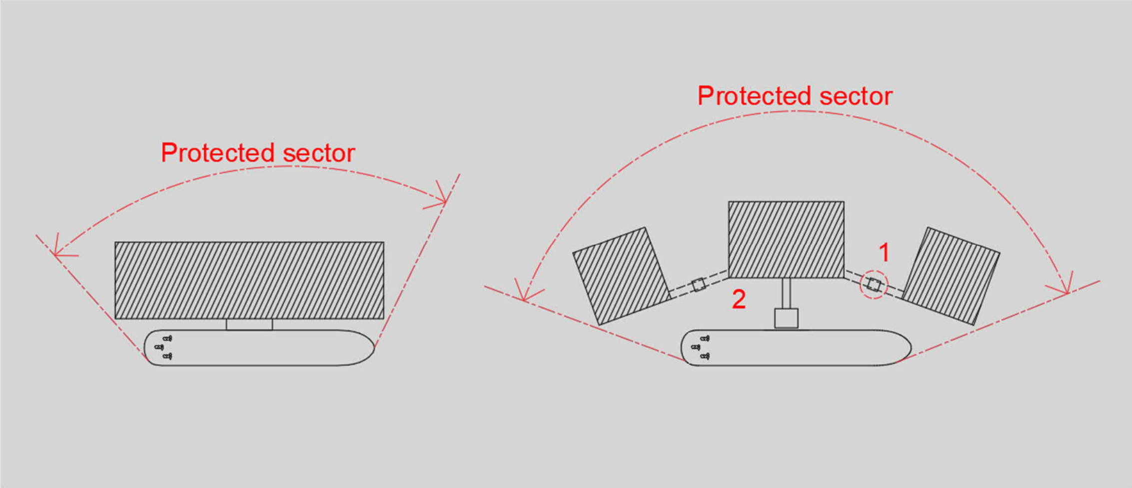


Figure 6-18 – Comparison of different GBS layout alternatives.

The layout on the right provides better protection against ice drifting from divergent directions. 1) Possible additional structure to prevent ice drifting through the gap between the GBSs; 2) additional area for brash ice to be moved during carrier arrival.

In principle, the GBS complex layout and its ice protection capability, as well as its suitability for carrier visits, can be further studied and optimized at a later stage when the possible layout options, sizes, geometries and other possible limitations and restrictions are known.

7 CONCLUSIONS

This initial transit study's findings are:

That for the export of 4 Mtpa of LNG from the Mackenzie Delta to China, five specialized icebreaking LNG carriers (similar to the YamalMax type) are required which can operate on this route year-round, and through an average-type winter. With limited storage capacity (one GBS, 270,000 m^3), the actual calculated maximum number of LNGCs during winter months is 4.7, and the cost of transportation is approximately USD 62/ton (about USD 1.16/MMBtu).

For the export of comingled oil/condensate from the Mackenzie Delta to Vancouver, one ice-going product tanker (similar to the Boris Sokolov type) is required for a production rate of 10,000 bbl/day, the required storage volume is about 90,000 m^3 and the cost of transportation is about USD 61.5/ton. For a production rate of 30,000 bbl/day, three condensate tankers are required, with the condition that icebreaker assistance is provided during the four to five months of an average-type winter. The required storage volume in this case is about 140,000 m^3; the actual maximum number of condensate tankers is 2.5 for an average winter, with the cost of transportation being approximately USD 63.5/ton.

It can be assumed that three IM vessels are required to assist the LNG carriers and condensate tankers. The total operational costs of assisting are approximately USD 12 million/year. The greatest IM efforts are needed typically between January and April, and less during open water season, approximately from July to October. The proposed IM fleet and costs presented should be considered tentative. The IM fleet proposal should be updated at a later stage when the final logistical parameters are agreed.

As a proposal for a more detailed feasibility evaluation of transportation of LNG and gas condensate from the Mackenzie Delta, we recommend carrying out the following further studies:

- deeper risk assessment of multi-year ice influence on safety of navigation and optimal routes in ice;
- consideration of different design concept options for icebreaking LNG carriers (with an extreme ice bow, bulbous ice bow, etc.);
- investigation of transshipment issues (with comparison of different transportation schemes and destinations);
- transit simulations for severe types of winter (with more accurate evaluations of required storage volumes for LNG and condensate oil).

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