CONFIDENTIAL INFORMATION

GRAND BANKS GAS EXPORT PROJECT DETAILED FEASIBILITY STUDY

prepared for

Nalcor Energy

EnerSea Project No. ET-2009.03-01

Information Disclaimer and Confidentiality

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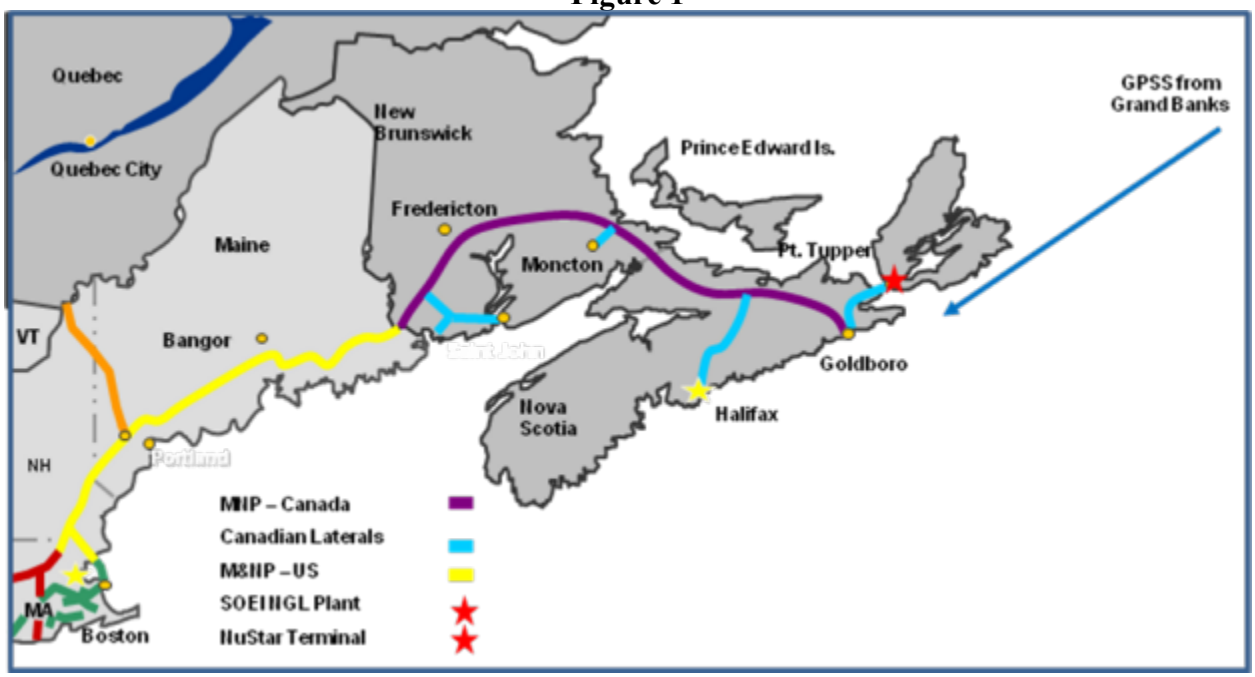
EXECUTIVE SUMMARY

EnerSea developed a Detailed Feasibility Study (DFS) in 2007 for Nalcor Energy (Nalcor) of a Gas Production and Storage Shuttle (GPSS) solution transporting Compressed Natural Gas (CNG) from the Grand Banks to a domestic location in Newfoundland. In April 2009, Nalcor commissioned EnerSea to evaluate the feasibility and commercial viability of the option for gas export from the same Grand Banks field to Nova Scotia with onward transport via onshore pipeline for sale to Canadian and United States gas markets as illustrated below in Figure 1. The existing facilities shown on the figure below would be modified as described in this report for delivery of CNG.

Figure 1



As industry continues to push the frontier boundaries of ultra-deep water and remote arctic locations, EnerSea Transport LLC has addressed these challenge by expanding the capability of its VOTRANS™ compressed natural gas (CNG) carrier into an "all-in-one" gas production and transport vessel called the Gas Production Storage Shuttle (GPSS™).

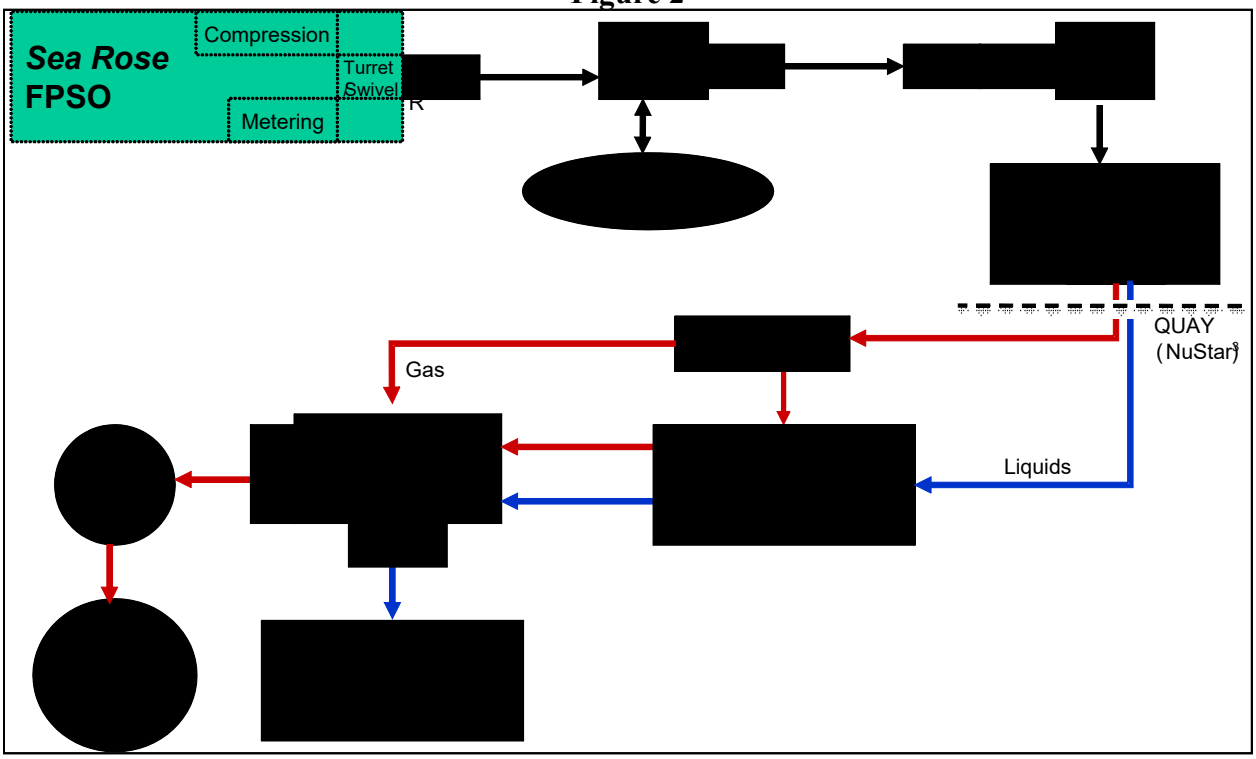
This shuttle vessel concept offers E&P operators the ability to eliminate much of the infrastructure traditionally required for remote gas field development, such as expensive pipelines in ice-prone areas, and dedicated production facilities.

The GPSS concept was adopted for this feasibility study for the specific Atlantic Canada operating conditions existing along the transit route between the field and the desired gas market. EnerSea has evaluated offshore loading system designs for use in this service that have been proven in both gas and oil operations with an extremely successful performance record in harsh environment oil and gas loading operations. The requirements and options for gas storage and processing at the delivery point have been assessed and defined to minimize the overall

transportation cost, while facilitating regular/consistent deliveries of gas and gas liquids to proposed gas offtakers. Together, these systems enable EnerSea to provide Nalcor with a robust, dependable and cost effective gas production and transport service.

The production, transport and delivery scenario for the natural gas and gas liquids is depicted in Figure 2.

Figure 2



Notes:

1. MNP indicates Maritimes & Northeast Pipeline
2. SOEI indicates Sable Offshore Energy NGL Plant operated by ExxonMobil
3. NuStar indicates the owner and operator for the terminal located at Pt. Tupper, Nova Scotia

GPSS Concept Description

The GPSS system was designed and evaluated for an initial production rate of approximately 200 million standard cubic feet per day (Mscfd) (ca. 5.66Mscm/d) and a maximum production rate of approximately 300 million standard cubic feet per day (Mscfd) of natural gas from the existing field development facility commingled with production direct from subsea wells.

The project concept will initially utilize three (3) GPSS units to produce, store and transport 200 Mscfd CNG to receiving facilities at NuStar's terminal at Point Tupper. A fourth ship may be introduced to support transport of cargos for a total field production rate of 300Mscfd (ca. 8.5Mscm/d). The GPSS units will be equipped to interact with the subsea field production systems to produce and store approximately 550Mscf (15.6Mscm) of gas and approximately 25,500 bbls (4,070m^3) of liquids (combined condensate and natural gas liquids, or NGLs,

methanol, and water) for transport to the delivery point located about 520 nm southwest of the field. The water depth of the field at the assumed GPSS loading terminal site is 120m.

The in-field production/loading system utilizes two (2) Submerged Turret Production (STP) systems similar to that designed and installed by Advanced Production Loading A/S (APL) for a number of FPSO facilities worldwide. The STP system is ideal for this application due to the specified high availability target. The STP buoy envisioned for the Grand Banks production will be greatly simplified as compared to the complex, multi-riser systems used with existing FPSO units.

EnerSea developed a conceptual definition for the subsea architecture and operating philosophy utilizing, to the extent possible, the existing subsea gas injection manifold.

Delivery terminal facilities were defined to offload, receive, meter and deliver natural gas to the MNP pipeline and to a VOLANDS™ storage facility. Further descriptions of each major delivery terminal component, company description and location are provided in Sections 2 and 4.

This study assumed the addition of a new dock to be built adjacent to NuStar's terminal in Pt. Tupper, Nova Scotia. Additional facilities and modifications are also evaluated in this study for offloading gas from the GPSS at the port, including cargo transfer equipment, such as gas loading arms and attendant piping, as well as process equipment related to VOTRANS's proprietary gas offloading system. The gas stream is delivered at a high rate from the GPSS after the shuttle is connected to the discharge terminal. Each shuttle is assumed to discharge its full cargo load within 24 hours. Gas and liquid cargos will be discharged and metered separately.

Part of the discharging cargo will be directed through a hydrocarbon (HC) liquids recovery unit, built and operated as part of this project before the resulting MNP-spec sales gas enters a "spur line" that connects to the MNP, allowing distribution of gas at rates up to the maximum daily delivery allocation. Gas discharged which exceeds the targeted daily delivery requirement will be routed to the VOLANDS storage facility. It is not expected that pipeline capacity (i.e. cushion or line pack) can be used as effective storage for the CNG gas delivery process – especially for rich gas deliveries.

Gas withdrawn from storage will be processed through the HC liquids recovery unit for export into the MNP spur and thus supports a steady state (ratable) delivery of sales gas. Gas is processed to MNP requirements and NGLs extracted accordingly. This study has also investigated the feasibility and commercial viability of transferring the ship's condensate cargo stream to SOEI for fractionation.

Conclusions

This feasibility study confirms that a GPSS solution is technically viable across the range of conditions examined to safely, reliably and efficiently transport gas from the supply to market locations defined. This study has developed the following technical conclusions regarding the major areas of investigation:

Subsea System Modification and Additions: No feasibility issues have been identified in connecting an export system to the existing subsea manifold. The existing subsea injection wells would require modification and re-working of their production trees and completion to be used as gas producers. Future wells can be completed in anticipation of the production/export requirement.

Ship: No feasibility issues have been identified for the ship, hull and containment.

Production and gas handling system: No feasibility issues have been identified for the production and gas handling system. Future engineering will be required to reflect the agreed field specifics, such as gas composition, production rates, flow assurance, reservoir modeling and production operations.

Loading System: The STP is proven in service in similar harsh environments for high pressure gas production/loading, so no feasibility issues have been identified.

Offloading Location: This study assumed Pt. Tupper as the specific location for the gas delivery port and VOLANDS storage facility. Additional screening and further evaluations will need to be performed in future development activities to confirm the relative technical and commercial attractiveness of this location compared to alternative sites.

Investigations pursued at a high level during this study indicate that Goldboro, Nova Scotia may be a very suitable alternative and may, in fact, limit the amount of new facilities/construction required to establish the features needed for delivery of the gas and liquids from the Grand Banks. Additional details regarding this alternative delivery option are included in Section 4.

Schedule: The schedule has been developed based on a goal of 1st gas from the field development in late 2014. The master schedule developed as part of this study indicates that this goal could be achieved, based on certain assumptions outlined in this report.

Recommendations

Given that gas and gas liquids are currently being re-injected into storage at a significant cost to the project stakeholders (both out of pocket and forgone revenues), there is a substantial financial incentive for the project to move forward as quickly as possible.

EnerSea has developed a GPSS pre-project development plan that defines the activities required to progress the project in parallel with the commercial activities leading up to project execution.

This report illustrates the unique capability that EnerSea's GPSS system can provide to the project's shareholders to create a robust, near-term solution for producing and delivering this challenging, but lucrative gas resource to markets.

The application of EnerSea's GPSS field development and transport solution also provides key advantages and opportunities as follows:

- Eliminate large fixed offshore infrastructure
- Minimize current FPSO constraints (compression and dehydration)

- Provide flexibility for changing rates and compositions over life of field
- Manage gas injection reservoirs through evacuation availability
- Limit the need for new injection wells
- Bring on new oil production with associated gas and condensate
- Tie-in production from new gas wells
- Provide an ideal solution in arctic and harsh environments
- No offshore personnel transport/transfers are required

EnerSea very much appreciates the opportunity to conduct this assessment, and we look forward to working with Nalcor further in this prospective effort. We recognize that challenging projects such as this one will require the creativity, perseverance and good cooperation amongst all shareholders in the project. EnerSea and our project partners are committed to working with you in that spirit.

1. BASIS OF STUDY

The general development and production parameters to be used in this assessment were defined and supplied by Nalcor, which is detailed in the Basis of Design (BOD) document included herein as Appendix 1. Abbreviations and acronyms used in this study are included herein as Appendix 2.

1.1 EnerSea Data Utilized in Study

In addition to the Nalcor-supplied information, EnerSea has contributed its own data and assumptions for this study as well as accessed information and preliminary engineering designs developed in its previous work to assist with the design of this study. EnerSea's input is detailed throughout this report.

1.2 Changes in Design Assumptions

It is recognized that certain of these data may be modified and/or better defined during subsequent phases of project development planning, characterization work and engineering studies. Modifications and refinements to the project inputs, as well as more detailed engineering and assessment work itself, can be expected to refine the results generated in this study and could result in commercial terms that are either higher or lower than those indicated by this report.

2. COMMERCIAL BASIS

The following section illustrates the life-of-field capital and operating costs and commercial basis for this project.

2.1 Estimated Cost of Service

Capital and operating costs were estimated and include costs for the GPSS fleet and ship operations, offshore loading terminal at the field and delivery terminal, inclusive of the VOLANDS storage facility, and gas handling equipment at the delivery site. EnerSea also estimated and included the costs for a gas processing plant at Pt. Tupper to extract NGLs. Table 1 below provides an effective production and transport tariff that is calculated using the capital and operating costs based on a 10% return on capital. The tariff is referenced to the start of the project execution phase, and indexed from that point in time forward.

Table 1

Project Scenario	Production Rate, Mscfd	Energy Content, Btu/scf [1]	Ship Size Mscf	Storage Size Mscf	CAPEX, MUSD	OPEX, MUSD/Yr	Fuel Gas, Mscfd	Transport Cost, USD/MMBtu
200 Mscfd Supply Case								
Base	200	1213	550	330	1814	43.7	11.6 [4]	**2.97**
300 Mscfd Supply Case (additive case) [4]								
Additive	300	1213	550	n/a [2]	432 [3]	57.9	16.7 [4]	**2.47 [5]**

Notes:
1. Average HHV of gas transported based on a 50/50 split between the reservoir and the FPSO. The HHV values for the reservoir and FPSO are included in the BOD.
2. No additional storage is required for 300 Mscfd Supply Case.
3. Ship capex (P50 case) only added to the cash flow stream in Year 5 (i.e. production Year 3).
4. Includes fuel gas used for GPSS fleet, VOLANDS and gas plant.
5. The "Additive" case tariff is calculated for the investments and cash flows over the entire life of the (two-phase) project, and thus provides a single tariff structure for all years. Based on the actual commercial structure that is eventually agreed, it is likely that a two-tiered tariff structure will be required that provides a slightly higher tariff (than this single tariff) for the initial production phase (200 Mscf/d) and a lower tariff for the higher production (300 Mscf/d) phase.

The complete GPSS project service includes all ships, facilities and services, from the reception of gas at the field's subsea manifold through the delivery of gas onshore to the outlet of the gas plant. Support for the subsea well production operations (via subsea well and manifold control equipment aboard the GPSS vessels) and related processing of produced fluids onboard the GPSS vessels will also be provided. The field operator will be responsible for all reservoir and subsurface well management and maintenance, and other subsea equipment up to the battery limit of the GPSS project. Fiscal metering is to be provided for custody transfer and performance tracking purposes. Produced fluids will be metered after arrival and separation on each of the GPSS units. Cargo fluids being discharged from the GPSS units will be fiscally metered on shore after treatment at the gas plant. All gas consumed as fuel shall be accounted. All products being delivered to clients shall be metered during delivery.

2.1.1 Basis for Capital & Operating Cost

The capital and routine operating and maintenance expenses are included for the following:

a) Subsea system
   - PLEM 1 and PLEM 2, inclusive of piles, weak links, tie-in spools, actuated valves
   - Steel flowline
   - Static umbilicals, inclusive SUTA, UTA and bend restrictors
   - Dynamic umbilicals (2 off 300m lengths), inclusive, end terminations and bend stiffener
   - Installation, inclusive mobilization and demobilization, dewatering and testing, contingencies and weather risk

b) Loading terminal, including:
   - Submerged Turret Buoys (STP) for 2 STP systems
   - Mooring and anchors for 2 STP systems
   - Risers and umbilical for 2 STP systems

c) Fleet of three (3) GPS shuttles, including:
   - Gas and liquids separation
   - Gas and liquids containment system
   - Subsea production system interfaces and controls
   - Gas handling and chilling system
   - Fiscal custody transfer meters
   - Safety systems
   - Vent/flare system

d) Delivery terminal modifications and facilities, including:
   - Loading port modifications and additions
   - Offloading arms
   - Ancillary piping and controls
   - CNG liquid displacement system
   - Automation, controls and instrumentation
   - Safety systems
   - Vent/flare system

e) VOLANDS, including:
   - Gas containment system
   - Enclosure/structure with insulation
   - Nitrogen generation, chilling and distribution system
   - CNG liquid displacement system (shared with delivery terminal)
   - Automation, controls and instrumentation
   - Safety systems
   - Vent/flare system (shared with delivery terminal)

f) Gas plant for NGL recovery
   - NGL separation system
   - Water treatment and rejection system
   - Turbo-expander and compressors
   - Fiscal custody transfer meters for gas and liquids

g) Overall operating and maintenance
h) Logistics, coordination, administration and overheads for the transport fleet, terminal facilities and services.

The capital cost breakdown for the following major components is included for the base case in Table 2 as follows:

Table 2

Major Capital Component	CAPEX, MUSD
Subsea manifold	27.2
Loading terminal	103.4
GPSS Fleet	1,298.0
Delivery Terminal	42.4
VOLANDS	136.7
Gas Plant (NGL recovery)	97.4
Engr, proj mgmt, ship comms.	108.9
TOTAL	**1,814.0**

Canadian crew costs are reflected in the start-up and operating cost estimates. However, at this time it is not possible to distinguish the influence of flag selection on the delivered cost of the GPSS units. With final commissioning assumed to take place in Newfoundland waters, there may be no cost penalty in adopting Canadian flag. The greatest impact is likely to be through a customs tariff on an "imported product" (the GPSS ships).

Please note that EnerSea has not included the cost for the following:

a) income tax or other taxes;
b) royalties and/or fees to local governments;
c) costs for domestic regulatory approvals, permits or fees (Note: EnerSea estimates that the costs for domestic regulatory approvals, permits and fees could be in the range of 5-10 M USD, based on previous discussions with Jacques Whitford); and,
d) miscellaneous site and project-specific items not presently defined.

2.1.2 General Tariff Assumptions

The following additional project assumptions apply to the above cases considered in this pre-feasibility study:

a) Vessel life: 30 years
b) Project Life: 20 years
c) Tariffs are based on production rate loaded at field
d) Costs are referenced to 1 June 2009 market data, cost estimates and assumptions.
e) Inflation of 2.2% has been assumed in the evaluations performed in this assessment.
f) Tariffs are referenced to 1 June 2009 and will be indexed to inflation and adjusted on an annual basis.
g) GPSS ships will be classed by the American Bureau of Shipping (ABS). The ships are expected to carry Canadian Flag.

2.2 Offloading Terminal, Fractionation and Transport Service Costs

EnerSea has worked with the business development and engineering teams of MNP, NuStar and ExxonMobil (SOEI operator) in an attempt to assess the costs for pipeline transport, discharge port access, and NGL fractionation, respectively, and other associated services.

EnerSea requested information from each of these parties in the form of Request for Information (RFIs). To date, we have not received responses to our requests, but will continue to follow-up and will provide to Nalcor as and when feedback is received.

EnerSea has included estimates (as tariffs per MMBtu) in Table 3 below for the following main facilities and operating requirements based on input received from these parties in 2005 and further discussions this year, and they have been adjusted as appropriate for changes in requirements.

Table 3

Additional Operating & Transport Costs	2014-2019	2020-2034
NuStar		
Gas delivery rate (Mscfd) [1]	185.4	278.8
Gas delivery energy content (Btu/scf)	1100	1100
NuStar Tariff (USD/MMBtu)	0.10	0.15
MNP		
MNP delivery Rate (Mscfd) [2]	173.9	261.6
MNP delivery energy content (Btu/scf)	1043	1043
MNP Tariff (USD/MMBtu) [2 3]	1.21	1.00
SOEI		
NGL delivery rate (Bbls/Day) [4]	11,055	16,602
SOEI Fractionation Cost [5]	JP-95	JP-95

Notes:
1. Gas delivered at the NuStar terminal subject to NuStar tariff.
2. Gas delivered into MNP pipeline subject to MNP tariff.
3. MNP tariff does not include free issue gas for compression fuel (estimated at 3%).
4. NGLs delivered to SOEI for fractionation subject to SOEI processing fee.
5. Ref section below for more info on JP-95. The rule of thumb cost for T&F (Transport and Fractionation) in the United States is USD 0.05 per gallon of liquid fractionated.

Infrastructure and services are required at the offloading terminal for port access, pipeline transportation of natural gas to northeast US markets and fractionation of NGLs. A description of the technical requirements for each major component of the delivery chain is described in Section 4. The entities and associated infrastructure and support required for this project are briefly summarized herein as follows:

2.2.1 NuStar Terminal

This study assumes that EnerSea will offload gas and NGLs at NuStar's Pt. Tupper terminal. NuStar Energy L.P. is a publicly traded, limited partnership based in San Antonio, Texas, with 8,491 miles of pipeline, 82 terminal facilities, four crude oil storage tank facilities and two asphalt refineries with a combined throughput capacity of 104,000 barrels per day. One of the

largest asphalt refiners and marketers in the U.S. and the second largest independent liquids terminal operator in the nation, NuStar also has operations in the United States, the Netherlands Antilles, Mexico, the Netherlands and the United Kingdom. More information on NuStar's Pt. Tupper Terminal is included on NuStar Energy L.P.'s web site at www.nustarenergy.com.

EnerSea has estimated and included in the capital costs the following major equipment and modifications that will be located at the NuStar terminal:

a) Delivery terminal modifications and facilities, including:
   - Loading port additions
   - Offloading arms
   - Ancillary piping and controls
   - CNG liquid displacement system
   - Automation, controls and instrumentation
   - Safety systems
   - Vent/flare system
b) VOLANDS, including:
   - Gas containment system
   - Enclosure/structure with insulation
   - Nitrogen generation, chilling and distribution system
   - CNG liquid displacement system (shared with delivery terminal)
   - Automation, controls and instrumentation
   - Safety systems
   - Vent/flare system
c) Gas plant for NGL recovery
   - NGL separation system
   - Water treatment and rejection system
   - Turbo-expander and compressors
   - Fiscal custody transfer meters for gas and liquids

EnerSea has also estimated operating expenses, reflected as a tariff in Table 3, for the following costs:

a) Ship docking services, such as tugs and pilots, for ship logistics in the port and port approach area
b) Land lease costs for the VOLANDS and gas plant.

2.2.2 SOEI Gas Liquids Fractionation

EnerSea has assumed that the SOEI gas fractionation facility can be utilized for processing and storage of these liquids for subsequent marketing. SOEI's Point Tupper fractionation plant fractionates natural gas liquids, which are separated at SOEI's Goldboro gas plant and transported via a buried pipeline to Point Tupper, near Port Hawkesbury on Cape Breton Island. The liquids are separated into propane, butane and condensate. SOEI's current processing capability is as follows:

- 20,000 barrels of liquid per day
- 7,000 barrels propane
- 3,000 barrels butane
- 10,000 barrels condensate

Both plants are part of the Sable Project, which is owned by ExxonMobil Canada Properties Ltd. (operator), Shell Canada Limited, Imperial Oil Resources, Pengrowth Energy Trust and Mosbacher Operating Ltd.

SOEI has indicated in past discussions that they may have processing capability to create propane (C_3) and butane (C_4) products from the NGL stream, dependent on future Sable exploration activities. Rail facilities also exist at this facility to ship these products on to market.

SOEI provided a proposal in 2005 that indicated the cost to perform these services would be negotiated and agreed according to JP-95 processing cost procedures, or other method that is mutually agreed. JP-95 is an industry guideline that has become the benchmark for the establishment of facility fees for the upstream processing industry. Each facility fee determination requires a set of negotiations to establish the circumstances for the fee applicable to that facility for that custom user. The guideline provides the following:

a) principles for conducting negotiations to establish an appropriate facility fee, and
b) relevant range to establish the boundaries for the determination of fees.

The determination of fees based on JP-95 has its foundation in the Jumping Pound formula. The formula application requires agreement by the parties on specific methodology. The calculations are simple, once the data is known.

EnerSea is not an expert on JP-95 tolling fees and as such has not included costs for NGL fractionation in this study. EnerSea recommends that Nalcor take advice from a consultant experienced in this area to establish an estimate for its economics. The rule of thumb cost for T&F (Transport and Fractionation) in the United States is USD 0.05 per gallon of liquid fractionated.

2.2.3 Maritimes & Northeast Pipeline system (MNP)

EnerSea has assumed that natural gas for export and sale will be transported from Pt. Tupper to the United States through the Maritimes & Northeast Pipeline (MNP) system. With 670 miles of pipeline (340 miles U.S.), Maritimes provides fuel for the northeast United States and Atlantic Canada - 600 million cubic feet per day of natural gas capacity on the Canadian side and 800 million cubic feet per day on the U.S. side.

MNP extends from Nova Scotia into New Brunswick, Maine, New Hampshire, and Massachusetts where it connects with Algonquin Gas Transmission's HubLine near Beverly, Massachusetts. There it provides a seamless link for Spectra Energy systems from offshore Nova Scotia to south Texas and the Gulf Coast. The Maritimes pipeline also connects to the North American pipeline grid at Dracut, Massachusetts. MNP has ownership interest as follows:

- Spectra Energy Transmission: 77.53%
- Emera, Inc: 12.92%
- ExxonMobil Corporation: 9.55%

A new pipeline spur from NuStar's terminal to MNP's existing pipeline near Goldboro would be required to transport natural gas into MNP's main trunkline to the US. Further compression facilities may be required along the system, depending on the level of other natural gas volumes contracted by MNP at the time of the Grand Banks project, which may affect the tariff in which M&NP will charge. EnerSea has included the pipeline tariff proposed that MNP proposed in 2005 in Table 3 above. In addition, MNP will require free issue gas for use as compression fuel for transport of natural gas along their system. This volume will depend on the system hydraulics and compression needs at the time, and would be approximately 3%.

2.3 Fuel Gas Usage

The GPSS system will utilize fuel gas from the produced gas stream to generate power for propulsion and ship's utilities, as well as for cargo processing and transfer. Fuel gas is also currently assumed to be used for the Delivery Terminal, Gas Plant, and VOLANDS storage facility. Some minor amounts of electricity from the local utility power system for the delivery terminal facilities may be required for the utility systems. EnerSea has assumed that fuel gas for the GPSS, Delivery Terminal and VOLANDS storage facility and utility power will be free-issued. The estimated fuel gas usage rates and electrical power have been calculated and are included in Table 4.

Table 4

Fuel Gas & Electricity Usage	2014-2019	2020-2034
Total Fuel Gas Consumption (MMBtu/Yr) [1]	3,730,788	5,507,744
Total Electricity Consumption (kW/Yr) [2]	124,875,309	181,468,671

Notes:
1. Fuel gas used for GPSS fleet, VOLANDS and gas plant.
2. Electricity used for delivery terminal, VOLANDS and gas plant.

2.4 Product Sales Volume Estimates

The product sales volumes are estimated in Table 5 below:

Table 5

Product Sales	2014-2019	2020-2034
Natural Gas		
Gas Sales Rate (MMBtu/Day) [1]	173.9	261.6
MNP delivery energy content (Btu/scf)	1,043	1,043
Liquids		
Propane (Bbls/Day) [2]	3,707	5,571
i-Butane (Bbls/Day)	727	1,092
n-Butane (Bbls/Day)	1,938	2,911
Condensate (Bbls/Day)	4,683	7,028

Notes:
1. Volume is referenced to entry into the MNP system at Pt. Tupper and requires deduction for MNP free issue fuel gas (estimated at 3%).
2. Includes small volume of ethane

2.5 Capital Cost Assessment

The capital costs for the export project are approximately 70% higher than those developed for the domestic delivery in the previous study. The primary reasons for these higher costs are as follows:

a) Inclusion of detailed assessment and costs for subsea system tie-in and manifold at a subsea gas injection manifold. The cost for this system was not included in the previous study.
b) Inclusion of two (2) buoys for the loading system vs. one (1) buoy assumed in the previous study. Two buoys were included to increase the overall system reliability and uptime.
c) The addition of one (1) GPS shuttle to the fleet, which is required for the longer voyage to Pt. Tupper (550 km vs. 320 km).
d) The design of the topsides and piping for the maximum gas rate of 300 Mscfd expected in year 5, (i.e. production year 5). Designing the system for the max expected gas rate will eliminate the requirement for GPSS modifications while in service prior to increasing the gas flow rate.
e) Change in gas composition and additional liquids handling capability onboard the GPSS, which is required due to the higher liquids content expected when taking gas directly from the N. Avalon reservoir.
f) Higher cost of NGL recovery plant, which will yield 3,000 to 6,000 Bbls per day of additional high-value NGLs.
g) Inclusion of an estimate for expansion of the NuStar port to receive CNG carriers that was not included in the previous (domestic) case.

The increased capital costs are balanced by the additional revenue and market liquidity for the natural gas and high-value NGLs generated. It is expected that a higher natural gas price can be

obtained in the US than can be obtained through negotiations with only one gas offtaker in Newfoundland.

2.6 Project Capital Risks and Probabilistic Impact Assessment

Cost estimating and project development schedule uncertainties are features of projects that industry benchmarking has highlighted as "containable" through early application of disciplined project management practices. Therefore, cost estimating and project development schedule uncertainties deserve considerable attention in pre-project development efforts. Accordingly, EnerSea has engaged DNV to lead a study of project risks related to the GPSS project development capital cost and schedule. A summary presentation of the DNV study and a description of the project risk assessment process are included herein as Appendix 3.

After the project risks were defined and ranked according to the agreed 5x5 risk matrix, DNV and EnerSea mapped the risks using a spreadsheet model for overall project capital costs. Estimates of the uncertainty and volatility of cost estimates were assessed as P10 and P90 costs for each of the elements reflected in the spreadsheet model. Correlations of dependency were assigned between the various pairs of elements. The CAPEX distribution without correlations between cost features was found to be unrealistically narrow, so only results including such correlations are being reported. The capital cost elements used in the model are shown in Appendix 3 with the assigned ranges for cost uncertainty and dependency correlations. Key conclusions of the project risk analysis related to the capital cost are included in Table 6 as follows:

Table 6

Project Scenario	CAPEX, MUSD	Transport Cost, USD/MMBtu
200 Mscfd Supply Case (exc. cost reduction)		
P10	1,630	**2.70**
P50 (Base)	1,814	**2.97**
P90	2,059	**3.33**
200 Mscfd Supply Case (Incl cost reduction)		
P10	1,529	**2.56**
P50	1,716	**2.83**
P90	1,953	**3.18**
300 Mscfd Supply Case[1] (excl cost reduction)		
P10	388 [1]	**2.25**
P50	432 [1]	**2.47**
P90	491 [1]	**2.76**
300 Mscfd Supply Casese[1] (Incl cost reduction)		
P10	365 [1]	**2.12**
P50	409 [1]	**2.35**
P90	466 [1]	**2.64**

Notes:
1. Additional ship capex (P50)

The largest cost risk drivers for the project are:

- Ship hull costs (i.e., a reflection of the intensity of the shipbuilding market at the time the ships are ordered)
- Cost of the premium line pipe used for CNG cylinders

It is encouraging to reflect on the cost uncertainty ranges applied to the elements in the CAPEX model because, while such wide ranges have been applied to the key cost drivers, the overall distribution is not disturbingly wide; even with market correlations being accounted. For example, the ship construction cost factor (a key driver) has been allowed to vary from $3,000/MT at P10 up to $6,000/MT at P90, as compared to the base P50 estimate of $3,800/MT from recent market evaluations. This represents a -20%/+60% range around a historic high in shipbuilding costs. The P10-P90 range for premium pipe supply costs was also assigned as -44% to +88% around a price ($1600/MT) that is 100% higher than the cost of the same pipe of material in 2002. Some cost features are assumed to have uncertainty ranges that could be 100% above the base estimate. Further, sampling in the Monte Carlo simulation process allows values to be picked up well outside of the P10-P90 range when log normal distributions are fit to the specified ranges.

The DNV team assessed the potential for "unknown-unknowns" as being a potential source for an additional "contingency" that should be applied on top of the ranges of uncertainties that were assigned to the cost features of the model. Their opinion was that, since the total system only incorporated proven technology components, the wide ranges of uncertainty applied to the cost elements provide adequate coverage for the "unknown-unknowns", as well as for cost increases that could be expected when building in features to enhance system "regularity" (e.g., adding redundant equipment and/or flow paths to ensure that gas delivery commitments can be met).

A more conservative perspective may consider/expect that one or more key elements of the project are simply missing from the budget prepared at this early stage for a new technology seeking its first application and would either push to include an allocation for unknown-unknowns or require that a relatively higher confidence level (e.g. at least 85% confidence) be used when assessing what to use as a budgetary estimate.

EnerSea identified specific cost saving features that it has identified to be implemented into projects, subject to additional technical work in FEED. Two areas allowing for substantial cost savings are:

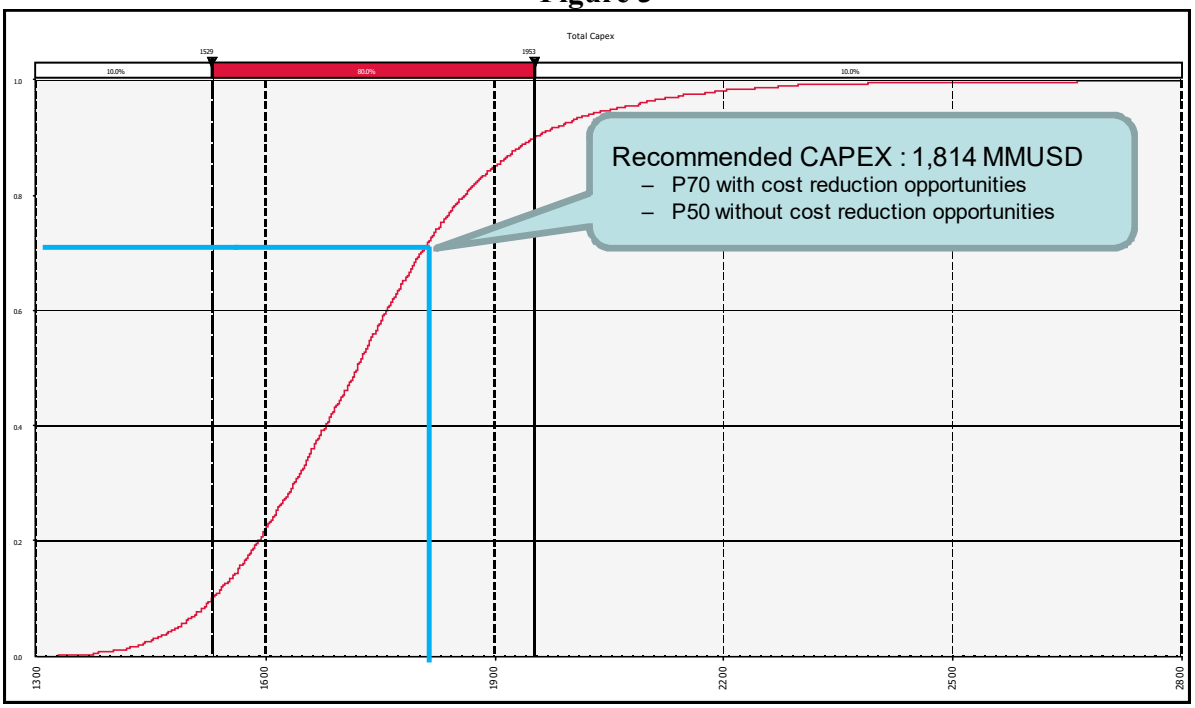
- Utilization of 48-inch cylinders instead of 42-inch cylinders on the GPSS and VOLANDS containment.
- Decreasing storage temperature from -30°C to -35°C or -40°C (labeled as "material technology" enhancement in DNV's project risk study).

Preliminary analysis of these cost savings features indicates that the design changes and technical requirements are attainable and EnerSea has decided to implement these changes on projects that have a reasonable FEED and pre-project development period. ABS has approved EnerSea's cylinder design up to 48-inch diameter and EnerSea has performed engineering work for other projects recently related to 48-inch cylinders. As such, EnerSea recommends that we incorporate this valuable cost saving feature into the ship design during FEED.

EnerSea recommends using the P70 (including cost reduction opportunities) estimate of capital costs as the baseline for tariff and economics calculations for this study. The capital cost of USD 1.814 billion also is approximately equal to the P50 estimate of capex without cost saving opportunities implemented.

Figure 3 below shows the cumulative probability curve and recommendation.

Figure 3



3. PROJECT PLAN AND SCHEDULE

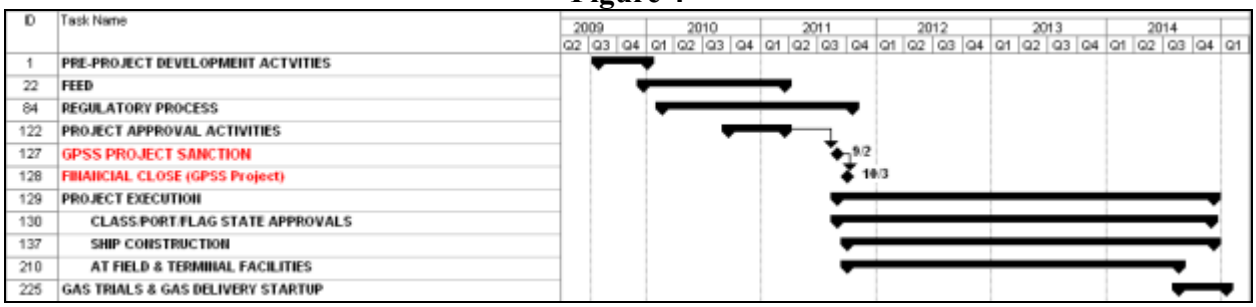
The preliminary Grand Banks Project Schedule reflects the level of information developed to date and the interdependencies of project activities. There are numerous activities to be completed prior to Final Investment Decision (FID) that will be important in establishing a definitive project development plan and to facilitate Nalcor's decision-making process. Completion of the following activities will provide Nalcor and EnerSea with sufficient levels of confidence in the technical, commercial and regulatory viability of the GPSS for the North Avalon field to sanction the Grand Banks project.

The schedule proposed below and all of its assumptions reflect an early start to pre-project development activities, which in any project is a prudent recommendation.

3.1 Schedule Basis

The schedule rollup illustrated in Figure 4 below is back-calculated from the goal of 1st gas from the full field development by December 2014. The detailed schedule in included as Appendix 4 herein.

Figure 4



The main assumptions for this schedule are as follows:

a) Nalcor moves forward with additional pre-project development activities, as described in the Pre-Project Development Plan, included herein as Appendix 5, during the period prior to commencement of FEED. These activities will be performed in parallel with Nalcor's commercial activities to create alignment between supply and market.
b) The FEED decision based on positive outcome of all of the above will be made by January 2010.
c) The schedule assumes that commercial negotiations will be conducted in parallel with the FEED activities to finalize the transportation agreement (and including the offloading terminal and gas liquids fractionation agreements) and the gas sale and purchase agreements as well as the work to secure any governmental approvals and other authorizations needed for project sanction.
d) The loading and offloading systems fabrication and installation schedule is not considered to be on the critical path and will commence as soon as necessary in advance of first vessel's operation.
e) The Regulatory process and schedule has been estimated based on results of the analysis completed by experts in Atlantic Canada. "Best" and "Worst" case scenarios have been

developed. "Project Release" triggers have been assigned to each major regulatory regime.

3.2 Project Schedule Risks and Probabilistic Impact Assessment

DNV facilitated two working sessions that allowed their analysts to document and appraise the various risks that are expected to challenge the timeliness and cost-effectiveness of the GPSS development for the Grand Banks gas export project. During the recent workshops, the risks defined and ranked according to the agreed 5x5 risk matrix established by the combined resources of Nalcor, EnerSea and DNV during the 2007 study were reviewed and adjusted by EnerSea and DNV to match the scope of the current project. Then, DNV mapped the risks over the entire project schedule. The deterministic project schedule prepared by EnerSea was streamlined to facilitate translation into the Pertmaster tool that DNV used for quantitative risk assessment, but all critical path schedule features were maintained.

One of the key input assumptions for the project schedule was FEED start date on January 2010.

Key conclusions of the project risk analysis related to the master schedule are as follows:

- Financial Close milestone (P50): 12 September 2011
- Start Gas Production (P50): 15 December 2014
- Full Gas Production (P50): 14 July 2015

The probabilistic estimates of the "Full Gas Production" milestone above can be compared to the deterministic schedule estimate by EnerSea of 5 January 2015

The largest schedule risk drivers for the project are:

- License holder alignment ("partner issues"),
- Financial closure processes,
- FEED start and FEED duration, which is driven largely by the regulatory process

3.3 Pre-Project Development

Pre-project development tasks will develop sufficient information and confidence to enter into and to be better prepared for project execution. These pre-project development activities (Pre-FEED and FEED) are further described and additional details, such as order of magnitude cost and schedule, are included in the Pre-Project development Plan included herein as Appendix 5. The proposed scope of work for the pre-project development plan is based on the following key activities:

- GPSS system design parameters that are advanced to each subsequent phase are flexible enough to accommodate an acceptable change in gas composition and rate, without substantial re-work in subsequent phases.
- Engineering and pre-project development activities do not advance at a faster rate than project information is available.

- GPSS system design information is developed to advance regulatory activity in the early stages to ensure regulatory approvals or project release triggers can be obtained within the GPSS schedule.
- GPSS will yield the greatest value, the earlier it is deployed.

3.3.1 Pre-FEED Activities

Pre-FEED activities will focus on developing information required to establish more confidence in the cost, schedule and technical requirements and to educate regulatory authorities and obtain feedback from those authorities and Class. The following objectives are defined for Pre-FEED:

- Confirm and update the GPSS concept based on reservoir information
- Prepare preliminary GPSS design;
- Support client in developing reservoir and flow assurance models,
- Prepare preliminary subsea system design and concept operations plan
- Assess and select delivery terminal location
- Perform preliminary HAZOP
- Submit and obtain input from regulatory authorities and Class;
- Develop preliminary regulatory roadmap
- Develop relevant permit applications and submit for approval.
- Develop detailed FEED plan and all documentation required to support FEED gate approval
- Select FEED subcontractors and prepare for FEED mobilization.

3.3.2 Project FEED

The FEED will be performed to develop the design and provide sanction level cost estimate and schedule required for the project. The FEED will also develop the regulatory permits required to provide sufficient confidence to Nalcor, the province and prospective financial lenders/investors to obtain project sanction and financial close for the project. The main objectives for the FEED are as follows:

- Develop GPSS ship design
- Obtain construction approval from ABS required for shipyard tender
- Complete subsea system design and tender required equipment
- Complete engineering and design for selected delivery terminal port(s)
- Complete engineering design activities for gas plant and NGL fractionation plant as required for selected port.
- Prepare for and initiate GPSS shipyard and long lead equipment tenders.
- Complete negotiations of ship-building contracts.
- Develop project sanction quality cost estimates.
- Complete regulatory activity to a “Project Release” level as indicated in various regulatory schedules.
- Commence Port and Flag State Approvals process.

- Develop and execute suite of agreements related to gas export, including, but not limited to:
  - CNG transport and storage agreement
  - Gas fractionation agreement
  - Pipeline delivery agreement
  - Gas Sales Agreements

3.4 Project Critical Path

EnerSea has focused its development efforts on items that will be on the critical path. EnerSea has developed plans for addressing these key critical path items with its partners (as appropriate) to ensure we can adequately estimate schedule and cost during the evaluation phase. EnerSea's plan to address these critical path items is discussed in more detail as follows:

3.4.1 Ship Construction and Delivery Schedule

Lead times and commitment horizons for equipment, materials, and shipyard slots will depend on the market at the time of order. One of the primary costs of a CNG ship is steel. Steel prices have been trending downward considerably in the second half of 2008 and now in the 1st half of 2009, due to reductions in steel pipe orders caused by the global financial crisis. The same trend exists now for ships, which is opening up ship yard capacity. In fact, some orders currently on the books of shipbuilders are being cancelled or could be expected to be acquired in the near to medium term. As such, EnerSea considers yard slots will be available for orders placed in the next 15-18 months. Beyond that, it is impossible to predict how the market will react to an improving economy.

3.4.2 Line Pipe

EnerSea has developed the line pipe specification used for CNG cylinder manufacture and working with three Japanese pipe mills has qualified their capabilities to supply pipe for EnerSea's projects. In conjunction with this qualification process, all three mills have manufactured pipe and plate that has been fabricated into test cylinders. These cylinders have been tested in EnerSea's prototype test program and in accordance with ABS requirements.

EnerSea has confirmed with each of these mills that the pipe can be manufactured in accordance with the schedule proposed herein based on award of pipe at project sanction.

3.4.3 CNG Cylinder Manufacture

EnerSea has developed the technical requirements for cylinder manufacture during its prototype testing program, inclusive development of pipe and head manufacture procedures, cylinder fabrication procedures and weld procedure qualifications with fabricators in the US, Korea and SE Asia.

EnerSea has received quotes for CNG cylinder fabrication from internationally recognized fabrication yards. Automatic welding equipment, procedures and personnel will be mobilized to the selected fabrication contractor's site. The Project Schedule incorporates this logistics plan.

3.4.4 Gas Handling Systems Fabrication

EnerSea developed the technical requirements for the gas handling system equipment. The Project Schedule assumes that the gas handling facilities will be built as modules for installation on to the GPSS decks.

This study assumes that the gas handling module will be built and installed in Newfoundland. After installation and testing of the cargo containment system, the ship will sail to Newfoundland for installation of the gas handling module, assuming that local fabrication resources and competitive pricing can be obtained for this activity.

EnerSea has identified qualified fabricators to assemble the equipment into modules. Due to the conventional nature of this module construction, EnerSea considers that there are many competitive fabricators capable of constructing this package.

3.4.5 Gas Trials

Gas Trials are required for final vessel classification. Initial gas trials for ship delivery purposes will be performed with nitrogen or other inert gas due to the challenges associated with obtaining natural gas in a compressed form similar in composition to the project-specific requirements. This aspect of ship delivery and release of shipyard responsibility must be considered in greater detail during further studies.

EnerSea considers that gas trials would ultimately be performed for final classification during commissioning of the 1st gas offtake and delivery from the specific project reservoir, which is similar to commissioning aspects of a normal FPSO installation.

3.4.6 Terminal Fabrication and Installation

Load-out, transportation and installation of the STP buoys and associated terminal equipment shall be performed according to Class and relevant industry standards. The methods for load out, transportation and installation of equipment for STP Subsea System are dependent on the types of ships selected for installation. Mobilization and de-mobilization is a critical cost element of the terminals installation and as such it is important that EnerSea and APL work together to identify installation ships that will be located in the area during the project phase. After these ships are identified, installation methods will be developed that are aligned with the cranes, lifting devices and capabilities of the specific installation ships selected and with the design parameters, schedule and location of destination site.

A detailed transportation schedule will be developed based on the location of the destination site, availability of cargo ships and access to sufficient crane capacity at the appropriate time. Arrangements for transport from fabrication yard to destination site will be planned to allow standardized transportation methods where possible, i.e. container or other means allowing equipment to be shipped on cargo liners. Heavy equipment like the STP Buoys and the anchors will be provided with purpose designed grillage/sea-fastening arrangements to suit the selected cargo ship. Mooring wire reels and riser/umbilical reels will be provided with reel cradles and be secured in line with the manufacturer's instructions.

4. PROJECT DEVELOPMENT SUMMARY

As industry continues to push the frontier boundaries of ultra-deep water and remote location, EnerSea Transport LLC has addressed the challenge by expanding the capability of its VOTRANS™ compressed natural gas (CNG) carrier into an "all-in-one" gas production and transport vessel called GPSS™ ("Gas Production Storage Shuttle").

This shuttle vessel concept offers E&P operators the ability to eliminate much of the infrastructure traditionally required for remote gas field development, such as expensive ultra-deepwater pipelines, and dedicated production facilities. Cost analyses have shown that a savings of approximately 20 – 25% in overall project capital costs for field production operations support, storage and transportation for a deepwater gas field development may be achieved across a broad range of application by employing the GPSS concept.

A feasibility study was completed by EnerSea with Kerr-McGee Corporation and the Research Partnership to Secure Energy for America (RPSEA) to develop the conceptual design and assess the technical and commercial viability of a gas production system for an ultra-deepwater gas reservoir in 2500m of water in the Gulf of Mexico.

The GPSS is analogous to a FPSO used in oil service with the added capability of transporting its gas product to market. It combines all of the features and advantages of the VOTRANS CNG carrier, including proprietary gas containment and gas handling technologies, with direct operational control and support for the subsea gas field and processing systems for the produced fluid onboard. The shuttle vessel concept also serves as a storage facility for gas and liquids and, when filled to capacity, disconnects from its production buoy/mooring to deliver the gas to market. Utilization of a tandem buoy configuration and multiple vessels operating in a shuttling fashion allows for uninterrupted production from remote fields. The GPSS project will initially utilize three (3) GPSS units to produce, store and transport CNG to NuStar's receiving terminal at Pt. Tupper. A fourth ship may be introduced to support transport of cargos for a field production rate of 300Mscfd (~8.5Mscm/d). The GPSS units will be equipped to interact with the subsea field production systems to produce and store up to 550Mscf (15.6Mscm) of gas and approximately 25,500bbls (4,070m^3) of liquids (combined condensate, methanol, and water) for transport to the market located about 520nm sailing distance west of the field. The harsh environment and 120m water depth at the field production/loading terminal site drive the recommended buoy loading system. A summary of the major components of the GPSS scenario are presented and discussed below:

EnerSea has developed the GPSS concept with several E&P companies over the last 6 years for various applications. The GPSS development history and status is summarized as follows:

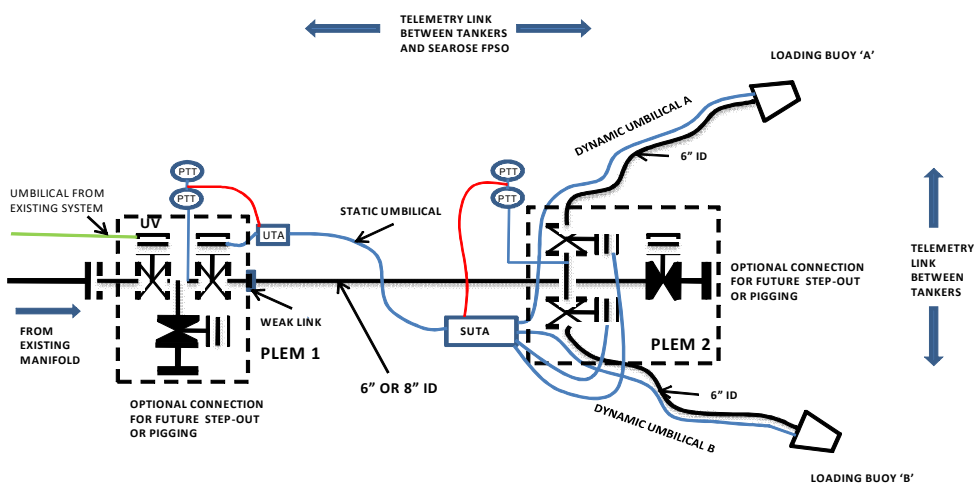
2003: Established concept (Kerr McGee – DWGOM)
2007: Technical Feasibility established (N. Sea)
2008: Preliminary HAZID completed (N. Sea)
2009: Developed Regulatory Roadmap with input from Norwegian Regulators

4.1 Gas Field Subsea Production Features

EnerSea commissioned JP Kenney to develop the conceptual definition for the subsea architecture and modifications required to create a production/export system at the field adjacent and connecting to a manifold, the details of which are included in Appendix 6 herein.

As shown in Figure 5 below, natural gas and associated liquids will flow approximately 2km from the subsea wells and or FPSO at the Manifold Center (MC) to a Pipeline End Manifold (PLEM) that serves as the riser base for an 8in. flexible pipe riser connecting to the STP buoy. Two (2) buoys at the offshore terminal means production operations from the field will not be interrupted when switching from one GPSS unit to the other. During change out of GPSS units, close coordination will be managed through a dedicated telemetry link with the FPSO to avoid any impairment of oil production and gas storage by the FPSO.

Figure 5
Conceptual Subsea Production/Export System



NOTES:
1. UMBILICALS INCLUDE HYDRAULIC TUBES, ELECTRICAL POWER AND SIGNAL AND CHEMICAL INJECTION TUBES (AS REQUIRED). HYDRATE INHIBITION WILL BE REQUIRED AND CORROSION INHIBITOR MAY BE INCLUDED, DEPENDING UPON CONDITION OF INCOMING GAS
2. THE UPSTREAM VALVE 'UV' IS CONTROLLED FROM FPSO VIA EXISTING SYSTEM
3. PLEM 1 MAY BE WITHIN OR WITHOUT GLORY HOLE, DEPENDING UPON SPACE AVAILABLE
4. PLEM 2 IS NOT IN A GLORY HOLE BUT IS PROVIDED WITH DROPPED OBJECT AND FISHING TRAWL PROTECTION
5. IT IS ASSUMED THAT LOADING BUOYS CONTAIN HIPPS SYSTEMS WITH ALL NECESSARY VALVING, SENSORS AND AUTONOMOUS CONTROL SYSTEM, CHEMICAL INJECTION AND BLOW-DOWN CONNECTIONS

It is assumed that the gas supply would be received by the GPSS from the gas field operator at a "gas production flange" on the downstream side of the MC. This supply would then be connected by an 8" jumper spool to a Pipeline End manifold, (PLEM 1) situated within the confines of the glory hole if possible. PLEM 1 contains two actuated valves, the first of which, designated UV, is controlled from the FPSO via the existing subsea control system. This facility enables the FPSO to shut off the gas export line in case of emergency or as otherwise required by operational considerations.

The second actuated isolation valve is controlled from either of the two GPSS shuttles via their respective dynamic umbilical, the Subsea Umbilical Termination Assembly (SUTA), the static umbilical and the Umbilical Termination Assembly (UTA). The UTA is connected to the valve by a hydraulic flying lead.

A dual pressure and temperature transducer is situated between the two isolation valves to enable monitoring the inlet parameters from the shuttle vessels. The transducers are connected to the UTA by an electrical flying lead (see red lines in the figure).

To facilitate future expansion by connection of alternative gas sources or potential pigging of the system an additional branch line has been included on PLEM 1 terminated by a closed valve and blind flange.

A weak link is included in the connection to the flowline to protect the system upstream in case the flowline is snagged by an anchor, iceberg or other hazard.

The flowline between PLEM 1 and PLEM 2 is approximately 2 km long flexible pipe in the base case (similar to the flowline from the FPSO to the manifold). PLEM 2 is a structure anchored to the seabed by suitable means from which the two risers, designated A & B in Figure 5, are connected to the two loading buoys. The PLEM and the equipment included are protected from dropped objects and fishing trawls by a suitable structure.

The system includes a hydraulically actuated isolation valve on each loading line, each controlled from its respective shuttle vessel via the dynamic umbilical, SUTA and hydraulic flying lead. Dual pressure and temperature transducers (PTT) are located on the header to provide monitoring capability on each vessel, connected to the SUTA by an electrical flying lead.

As on PLEM 1, an additional optional branch line has been included on PLEM 2 to facilitate future expansion or pigging operations.

To protect the system against potential hydrate formation, a chemical injection line is included in the umbilicals enabling methanol to be injected into either riser from PLEM 2 or into the flowline from PLEM 1.

As a general operating practice, when a GPSS shuttle is almost full, at a time and rate to be determined by the flow rate and water content of the gas being loaded, methanol should be injected from PLEM 2 to ensure complete dosing of the riser prior to closing the isolation valve. This will mitigate any hydrate formation even if the vessel is prevented from returning at the scheduled time by weather, mechanical breakdown or other unforeseen circumstance.

To ensure safe and efficient operation of the system a dedicated telemetry link should be established between the GPSS shuttles and the FPSO.

High Integrity Pressure Protection Systems (HIPPS) will be installed on top of the STP buoy to protect the GPSS shuttles from the reservoir pressure or gas pressure delivered by compression facilities on the FPSO. Flowing well stream pressure control will be managed by subsea chokes at the wells and the MC, as well as at a choke on top of the STP buoy. In general, flowing well

stream pressures and temperatures are kept at levels as high as practical throughout the flow path to the GPSS units so that much of the reservoir heat can be dissipated subsea.

A thermal hydraulic analysis has been performed to determine arrival conditions at the ship. The analysis indicates that if no significant pressure drop is induced subsea (e.g., at PLEM 1 or between the manifold center and the STPs), the arrival temperature at the GPSS units will be above 80ºC if the gas stream from the reservoir is flowing at approximately 200mmscfd through a flexible pipe flowline. However, in view of the high temperature of the supply gas, ~ 95-100ºC, it is recommended that an alternative employing unburied rigid steel pipe be substituted to increase the cooling capacity of the flowline. Initial estimates indicate that a subsea system employing the steel pipe option will cost about as much as the flexible flowline base case and is likely to offer some savings for cooling duty on the GPSS units. The costs for a steel flowline have been included in the capital costs. This will be investigated in much greater detail during FEED.

4.2 Production/Loading Terminal (STP buoy systems)

The loading system consists of a Submerged Turret Production (STP) buoy system, supplied by APL as illustrated in Figure 6. The STP system employs a conical moored buoy. The STP buoy connects the GPSS to the mooring system, when pulled into a mating cone in the GPSS hull. The buoy submerges to a depth of about 30m when the turret is disconnected.

The buoy incorporates a turret connected to the mooring and riser. The turret incorporates the following main components:

- Flexible riser (8”) connection
- PLEM umbilical connection
- Manifold Umbilical connection
- HIPPS for the gas production
- Junction Umbilical Termination Unit (UTA)

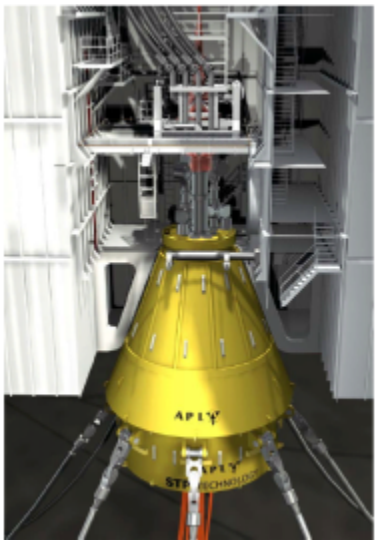


Figure 6

At the top of the turret, a flange and a Mate-able Quick Connect (MQC) plate assembly connect the vale and the junction UTA with the swivel and slip ring assembly located on the GPSS. STP equipment in the GPSS is located in a dedicated compartment. The pull-in winch and Hydraulic Power Unit are located on the GPSS deck.

The mooring system may be traditional chain-wire-chain, consisting of three clusters of two lines (110°/10° opening). Suction anchors are located on a radius of approximately 1km around the STP buoy.

4.3 Basic Logistics and Operability

The environmental criteria assumed for this study is based on the MSC database maintained by the Canadian government for the Canadian North Atlantic. While the sea states in this region are

very rough (to the extreme), there are large databases of experience of ships operating in the region. Globally, there is also significant experience by loading ships equipped with STP or STL systems. Therefore EnerSea is confident that the GPSS units, which will be equipped with appropriate dynamic positioning capability, will be able to load and offload in these weather conditions with a high degree of availability and uptime.

The specific met-ocean conditions at the offshore Loading Terminal area, as well as the full transit route, has been reviewed in greater detail using BMT-FM and their Simulation of Long-term Offshore Oil Production (SLOOP™) tool to assist with logistical assessment to determine the expected overall system availability and investigate sensitivities to provide guidance regarding the most influential aspects of the system configuration and operating scheme (ref Section 8 and Appendix 7 for details).

EnerSea will design its vessels and systems according to the specific metocean conditions expected to be encountered along the project's transit route to provide high reliability in its service.

The overall logistical operations for the Base Case are shown in Table 7 below. At 16 knots, open sea transit takes approximately 40% of each 7.21 day operating cycle. There is no appreciable transit time difference between the laden trip and the deadhead return voyage.

Table 7

Ship Size	Production Rate	Transit Speed	Connect at Field	Load	Disconnect at Field	Laden Voyage	Enter Port & Connect	Unload	Disconnect & Exit Port	Deadhead Voyage	Round Trip Time
Mscf	Mscfd	(knots)	(hrs)	(hrs)	(hrs)	(hrs)	(hrs)	(hrs)	(hrs)	(hrs)	(days)
550	200	16	4	64.5	2	34.4	6	24	4	34.4	7.21 (173hrs)
550	300	16	4	43.0	2	34.4	6	24	4	34.4	6.3 days 152 hrs

For initial sizing purposes, an ideal fleet utilization factor of 90% was assumed, which means that if the fleet operates perfectly it would have about 10% excess throughput capacity. This "utilization factor" provides additional time and flexibility for anticipated weather and port delays, in-service maintenance, bunkering, etc.

4.4 GPSS Vessel Specifics

EnerSea will deploy a fleet GPSS units designed to transport 550 Mscf (15.6 Mscm) each. The GPSS ships are designed to hold the CNG cylinders in a vertical orientation of its containment system. The GPSS uses EnerSea's proprietary Volume-Optimized gas handling and containment system aboard. Gas will be stored at approximately 1800 psig (125barg) and -30ºC. The ship holds containing the CNG containment cylinders will be insulated, inerted with nitrogen and refrigerated to offset environmental heat loads and thus maintain the temperature of the storage enclosure and gas cargo. The ships will be designed with a safety venting/relief system in accordance with ABS requirements.

Cargo gas will be used to provide fuel for propulsion, ship services and process requirements onboard the GPSS shuttles. This is far more cost effective and environmentally responsible than using expensive bunker fuel for these operations. A dual-fuel diesel electric system will be utilized to generate power to support these functions. The power can be shared very efficiently, since the peak power requirements for process work (gas loading and offloading) occurs when the ship is moored and propulsion needs are at a minimum. Conversely, when peak propulsion power is needed, the gas processing needs are at their minimum.

Propulsion systems in these vessels would support an average operational speed of 16 knots for the base case. A review of alternative cruising speeds and propulsion requirements can be examined and optimized in greater detail during subsequent studies. However, adopting higher speeds rapidly increases propulsion power requirements and fuel consumption.

The estimated fully-loaded operating draft of the GPSS shuttles will be approximately 10 meters. Draft allowances at the offloading port and along the transit route can be examined in greater detail during subsequent studies, but are not anticipated to pose any problems.

4.4.1 Ship Dimensions and Weights

A general arrangement for the GPSS is provided in Appendix 8. Key parameters for the design are included in Table 8 below:

Table 8

Design Parameter	Value	Units
Length Overall (LOA)	266.7	m
Beam	49	m
Depth	36.8	m
Draft (Lightship)	7.5	m
Draft (Full Load)	9.81	m
Full Load Displacement	98,584	MT

With a Block Coefficient (CB) estimated at 0.75, it is predicted that a 35MW power plant will cover all utility duties and allow a transit speed of 16 knots.

4.4.2 Draft Considerations of CNG Carriers

The weight and cost of the CNG cylinders are critical design features. EnerSea's optimized design allows a much greater volume of gas to be stored per unit mass of steel containment. This feature has the added benefit of allowing a lighter ship (hull) design to accommodate a given volume of gas, and has enabled EnerSea to design a gas carrier with a much shallower lightship draft than competing high-pressure CNG designed vessels (e.g. <7.5 m versus >10m). The deeper drafts in heavier CNG designs may create construction problems during shipbuilding and will also greatly restrict the possibility of finding dry docks capable of accepting such vessels for routine or emergency maintenance programs.

4.4.3 Service Life

The ship will be designed for a service life of 30 years in unrestricted ocean service, dependent on specific project requirements.

4.4.4 Engine and Propulsion Description

The GPSS units are specified to have a design service speed of 16 knots. Propulsion system requirements are established allowing a 20% sea margin with a clean bottom condition in calm and deep seas.

The GPSS will be a twin-screw ocean going vessel with dual fuel diesel electric propulsion, typically fueled by processed cargo gas. Twin tunnel thrusters may be utilized to provide dynamic positioning (DP-1) for maneuverability at loading facilities and receiving terminals. The GPSS will be designed such that offshore loading operations may be performed without assistance from marine support vessels.

Four to five (4-5) electric main generators power the GPSS and drive twin electric propulsion motors. Generators are also sized to include the duty required to power the gas handling systems used during gas transfer operations. The cargo handling system requires a considerable amount of power, which can be shared with the propulsion system as peak power demands for transit and loading/offloading operations occur at different times.

4.4.5 Flag & Port State Certification

The country of registry is selected based on the business requirements of the project and the ship owners. The overall design and construction of the GPSS will meet all generally accepted international maritime standards so as to allow Owners flexibility in selecting country of registry. However, in this project, Canadian flag is expected to be a requirement. Final requirements will established as the project advances through pre-Sanction activities.

4.4.6 Classification, Codes and Regulations

The GPSS (including hull, cargo systems, machinery and outfitting) are to be built under the survey of a classification society. For example, a plausible option would be to seek "class" from the American Bureau of Shipping (ABS), and to be classed and registered as ✠A1 ✠AMS Compressed Gas Carrier. The Classification would likely include the following notations:

AMS Compressed Gas Carrier;

b. ACCU - Indicates automatic centralized control from bridge and machinery room
c. SH-DLA - Built to plans approved to dynamic loading approach
d. SFA(N)- Spectral fatigue analysis for life of the CNGC
e. NIBS - Integrated bridge system for navigation
f. DPS-1 - System of thrusters, positioning instruments and control system to maintain position without assist
g. R2-S - Propulsion redundancy separated spaces
h. V-ship design will also consider Single Point Mooring, HHP, ES, Ice Class, and HM2ACCU dependent on future definition of project requirements.

4.4.7 Gas Cargo Containment System Design

The CNG cargo containment system consists of multiple Product Storage Tiers, the number of which is dependent on vessel carrying capacity and loading and offloading durations. Each of the Tiers is comprised of multiple pipe cylinders, clustered and connected by manifold piping. Each pair of transverse rows forms a Storage Tank, which is isolated with valves for segregation purposes. The Storage Tiers reside in four insulated cargo holds referred to simply as "holds". The holds are inerted with dry nitrogen and are equipped with refrigeration coils located at the top of each hold to maintain the internal temperature at -30ºC (-22ºF).

Table 9 summarizes the Cargo Storage functional requirements for the GPS shuttle.

Table 9
Gas Cargo Storage Functional Requirement

Design Parameter	Value	Units	Comments
Storage Capacity	550	Mscf	ca.537Mscf working storage capacity (excluding "permanent" heel)
Cylinders per ship	1848		ca. 31m^3 internal volume each (42"OD x ~38m long)
Product Storage Tiers	14		includes 1 tier dedicated to liquids storage (NGLs, condensate and water)
Cylinders per Storage Tier	132		3 tanks per tier
Cylinders per Tank	44		
Operating Pressure	125	Bar	
Design Pressure	135	Bar	Approximately 7% pressure range allowance between MAOP and PSV set point, including allowances for industry practice alarm response times and EG hydraulic head.
Operating Temperature	-22	˚F	-30˚C

The design utilizes vertically oriented tanks with manifold connections at the top and the bottom of the tanks. No flanged gas piping connections are located within the holds or below the main deck, consistent with guidelines in IGC code. A minimum clearance of 600mm is provided around the perimeter of the cargo holds for access and inspection. Spacing between adjacent cylinders and rows of tanks allow for manual inspection throughout.

The void space in the hold around the tanks will be filled with dry (chilled) nitrogen gas at a slight over-pressure.

Each storage tank will be located positively and restrained from horizontal displacements by horizontal beams and guides at the deck level and by chocked pedestals at the bottom. Lateral support will be provided in such a manner that allows the storage tanks to move vertically as required due to thermal and pressure variations. Final details for pipe supports and expansion arrangements to accommodate all deflections will be developed during FEED.

Hold covers are placed over each hold and bonded or welded to the hatch coaming. The covers will be fabricated from aluminum (or steel) and will be designed to resist pedestrian traffic loads, wind, pipe support loads, and green water.

All surfaces of the cargo holds exposed to ambient conditions will be insulated with polyurethane foam insulation flat panels and/or spray. Gas tight seals using a neoprene material will be provided around all pipe penetrations through the tops of the hatch covers. Design of the seals will allow for replacing the seals. The holds will be furnished with 610mm pressure/vacuum vents, set at 50mm of water (column - gage). The holds will be tested for tightness sufficient to hold a 1-inch (25mm) water column pressure for a period of 30 minutes.

4.4.8 Materials Design

The CNG cylinders will be manufactured of 42" x 20mm wall thickness modified API 5L X80 line pipe with toughness specs and Charpy values for low temperature service as specified in EnerSea's Line Pipe Specification (ET SPEC2003.07-01.001) and with semi-elliptical heads.

The cylinders are generally designed to have an acceptable probability of failure (POF) through 3 service lifetimes. In this case, the targeted minimum calculated lifetime would be at least 75yrs.

The heads will be manufactured of ASME-compliant high strength steel plate. The top head will have a formed or forged nozzle in the center for the gas inlet. The bottom head will have a similar nozzle in the center for the glycol displacement fluid outlet.

Manifold piping will be designed in accordance with ASME B31.3 (or equivalent) to be suitable for the gas handling and storage conditions. Stainless steel is specified for the gas-side flow paths. Long radius forged steel Y60 bends will be used in accordance with MSS SP75. Although use of flanges will be minimized, where required for maintenance and inspection ANSI 900 series weld neck ring joint flanges will be used with 316 stainless steel ring gaskets. All girth welds shall be 100% inspected by X-ray or equivalent technique.

EnerSea has qualified pipe materials from Nippon Steel Corporation, JFE and Sumitomo during its Prototype Test Program for fabrication of the CNG cylinder bodies.

4.4.9 Leak Detection

The GPSS and containment system will be extensively instrumented and continuously monitored for such items as pressure, temperature and fire and gas detection. The following methods will be used to determine the presence of a gas leak in the holds:

- Gas monitors
- Acoustic Emissions
- Temperature sensors

Crack development in the steel of the gas containment system will be monitored continuously to proactively detect and anticipate problems through the application of proven acoustic emissions (AE) instrumentation and monitoring. Periodic inspections as required by class will complement

the continuous AE monitoring. The use of AE systems is intended to prevent the occurrence of gas leaks caused by fatigue crack growth; however, when installed, AE sensors can also detect the sound of escaping gas at rates that could be too low for detection by traditional gas leak monitoring.

4.4.10 Containment System Construction and Integration

The storage tanks and all piping will be welded up to the first isolation valve. Each storage tank will be bottom supported on individual concrete pads, shaped and lined to properly support the end cap. All containment system valves will be located external to the hold area, and outside of the holds' hatch covers.

The storage cylinders are not planned to be coated internally or externally due to the use of ethylene glycol displacement systems and the dry nitrogen atmosphere inside the hold. Special studies will be performed during FEED, to confirm this assumption based on agreed gas quality and any potential requirements for handling corrosive contaminants during operations. Provisions will be made to protect the storage cylinders from abnormal corrosion during construction.

4.4.11 Operating Modes and Gas Handling Systems

The GPSS concept embodies four basic operating modes including Production/Loading, Transit (Full), Unloading, and Transit (Empty). EnerSea performed initial process design simulation to establish equipment lists and duties to develop costs for the proposed scenarios as presented herein. Preliminary work included dynamic simulation of the gas loading process focusing on conditions in cylinders downstream of a J-T valve that sends separated and dehydrated gas to the containment. To illustrate the gas operations, the following describes the gas handling systems and processes required for each mode. Relevant Process Flow Diagrams (PFDs) and equipment lists are included herein as Appendix 9.

4.4.11.1 Loading Mode

The GPSS connects to the STP buoy as defined for the Base Case herein. The flexible pipe riser from the PLEM to the STP will be used to transfer production from the subsea manifold onto the GPSS as operational control is passed over from the other GPSS. As flow starts, the produced fluid arrives at a pressure well above the targeted storage pressure. The gas stream coming from the subsea manifold reservoir can be substantially cooled during transfer through the subsea flowline and riser system, if rigid steel lines are used. EnerSea recommends the use of a relatively simple gas handling system for loading the cargo stream onboard the GPSS as illustrated in the PFDs included herein as Appendix 9.

After pressure let-down through the pressure-controlled HIPPS valve(s) on the STP buoy, the natural gas arriving on the GPSS is immediately separated from any liquid slugs and substantially dehydrated through a slug catcher and staged cooling and separation. Once dehydrated, the gas stream is directed to a J-T valve; then, routed through a manifold and switching valve system into the refrigerated CNG cargo containment system for shipment.

Initially, a substantial amount of chilling is available through the controlled pressure let-down to the pressure in essentially empty storage cylinders. As the pressure in the storage containers increases, the effect of auto-cooling at the J-T valve is diminished. At this stage of loading, the onboard refrigeration systems can be employed to ensure that heat-of-compression effects (temperature increase) within the containment are managed, without the need for liquid displacement operations. For this simple "blow in" operation, the CNG storage cylinders onboard will be filled in a phased process. If the high pressure supply gas has cooled down because the subsea system has been shut in for a substantial period, then the first charge of pre-cooled gas can be directed to the tier that is being used for fuel gas storage (because it will be at a high enough internal pressure to avoid excessive chilling from the cold start-up charge). As this tier approaches storage pressure, heat of compression will raise the internal temperature slightly above the target storage temperature and the reefer system will have had more time to be primed for service. Gas flow will then be switched to a second set of cylinders and loading will continue while the gas temperature in the first tier decreases as heat is extracted from the holds and the temperature of the gas starts to equalize with the hold temperature. As the second set of cylinders approaches their targeted storage pressure, the flow is directed to another set of cylinders (possibly all the remaining tiers on ship). Eventually, the gas flow is switched back to the first tiers (that have cooled back down to hold temperature) to "top them up" over the remainder of the planned loading time. At the end of the targeted loading time window, the ship will be filled to within a few percent of specified working capacity. If the other GPSS unit appears likely to be delayed in arriving for some reason, the operators can trim back the production rate to avoid a complete shut in and, possibly, "squeeze" a bit more gas into tiers that have had additional time to cool down.

The GPSS Loading PFD provided in Appendix 9 shows the process once the chiller downstream of the dehydration plant is in full operation. If the chiller is applied at full capacity at the start of flow, the flow stream temperature just downstream of the last J-T valve could fall below the temperature allowed for carbon steel pipe. Stainless steel piping is therefore provided on the gas side headers and fill-lines. Previous work has indicated that it is not necessary to provide any mechanical chilling until well after the loading process has started, and there has been no new information to indicate that this has changed.

The GPSS Loading PFD indicates the point of gas arrival on the ship. All elements of the steady-state simulation model are intended to ensure that the flow stream properties (including water saturation) are adjusted to provide expected arrival conditions on the GPSS, where the processing of produced fluids is modeled. The process is modeled to reflect that the liquids (especially, water) are removed from the gas cargo flow stream prior to storage in the CNG cylinders. The liquids are directed in bulk to a tier of dedicated liquid storage cylinders for delivery to shore for final processing. The liquids are not chilled prior to storage and free gas will evolve during (and after) loading into the tier. Depending on the final storage pressure and temperature within that tier, a substantial quantity of free gas may be available. Off-gas from the liquids tier will be directed to the gas storage tiers or the fuel gas treatment skid to allow it to be used as fuel for the GPSS.

A slug-catcher and fiscal meter will be installed upstream of the chillers and pair of valves that control flow into the CNG cargo cylinders.

Table 10 summarizes typical loading functional requirements for the GPSS.

Table 10
GPSS Loading Functional Requirements

Design Parameter	Value	Units	Comments
Base Initial Gas Loading Rate	200	Mscfd	GPSS gas handling sized to handle up to 300Mscfd
Max Water Vapor Content	292	Bbls/Day	Saturated at reservoir conditions
Arrival Pressure at GPSS	350	barg	HIPPS on STP ensures <135barg on board the GPSS
Arrival Temperature at GPSS	60	ºC	Upstream of the choke on the STP buoy

4.4.11.2 Transit (Full) Mode

The refrigerated CNG cargo containment system filled with CNG is maintained at a constant storage temperature and pressure during transit to the receiving terminal. Each hold has a refrigeration unit fixed on top through which a constant supply of fresh nitrogen is continuously supplied to keep both a slight positive pressure and target temperature range within the holds.

4.4.11.3 Cargo Unloading Mode

The CNG cargo is transferred out of the cargo containment system back to shore-based gas handling facilities through loading arm connections at the dock. The discharging gas cargo flowstream will be directed into a flowline designed for full pressure conditions and low temperature service with insulation to protect shore-side personnel and minimize heat gain during transfer to the gas plant and to the VOLANDS storage facility at the receiving port.

Once all Delivery Terminal connections have been “re-commissioned” and pressured up, the “bottom side” of all gas storage tiers are opened briefly to allow stored pressure to clean up any liquids accumulated in the bottom manifold. This flow stream will be directed through a let-down valve to the same system designed to handle the liquids discharged from the liquids storage tier. Once this initial purge is completed, gas cargo discharge is performed on a tier-wise basis (i.e., 132 cylinders or 3 tanks at a time) and is initiated by opening isolation valves and a primary flow-controlled discharge valve on the topside gas piping from storage.

Gas is displaced from the cylinders by pumping the displacement fluid (ethylene glycol/water – EG/H20) from a cold storage tank on shore. The gas product stream is transferred out of storage at constant pressure. The gas cargo flow stream is controlled at the desired off-loading pressure and off-loaded as a single gas phase stream. Table 11 summarizes the Cargo Unloading functional requirements for the GPSS.

Table 11
GPSS Cargo Unloading Functional Requirements

Design Parameter	Value	Units	Comments
Max Gas Unloading Rate	525	Mscfd	Based on a 24hr target for unloading the entire cargo charge (net of fuel gas)
Min Delivery Temperature	-30	˚C	
Delivery Pressure	124	Barg	VOLANDS storage pressure will be slightly lower, allowing for estimated pipeline losses

A shore-based glycol handling system is used to displace the gas from the Storage Tiers in the step-wise, cascading process during the unloading operation. The EG/H2O reservoir ("EG Storage Tank") is sized to store enough chilled displacement fluid (comprised of a mix of 60/40 EG/H2O) to support simultaneous GPSS discharging and VOLANDS charging operations. A chilling loop on the EG Storage Tank is sized to ensure that -30ºC Glycol is available at the start of discharge operations (i.e., chilling duty is averaged out over a full operational cycle to cover ambient heat gain as well as heat gained during displacement operations). EG enters each Storage Tier from the bottom nozzle and displaces the gas cargo out the top nozzle.

After approximately 95-97% of the cargo gas has been displaced from a Storage Tier, the top-side isolation valves on that tier are closed such that the remaining gas can be expanded to displace the glycol from the Storage Tier back into the EG Storage Tank. The gas remaining in the cylinders will be comprised of "fuel gas" and "permanent heel". It is intended that the "heel" quantity can be limited to about 3%, while the excess in one or more tiers is reserved for fuel for the return trip to the field.

The "raw" produced liquids flowstream coming off the ship is split with part going to storage in the VOLANDS unit in a tier dedicated for that purpose and part to the NGL recovery unit ("gas plant"). Liquids sent to the gas plant are commingled with the gas cargo stream for processing in the heater tower.

4.4.11.4 Transit (Empty) Mode

The residual gas and gas cargo containment system (the "holds") are maintained at a constant temperature of -30ºC as the GPSS returns to the field to pick up another load of production. Gas will be extracted from the higher pressure tier (or tiers) dedicated to fuel storage for the return trip.

4.4.12 Process and Utility Support Systems

There are a number of process and utility systems that are required to support the Storage, Loading, Transit, and Unloading operations. A brief description of these support systems follows.

4.4.12.1 Custody Transfer Metering

Custody transfer metering will be required onboard the GPSS top meter the gas and associated gas liquids (after separation). The Sales Gas Metering Package provides fiscal metering of the gas. The package consists of 2x100% meter runs. Each meter run consists of an ultrasonic flowmeter, pressure

and temperature measurement transducers and double isolation at the inlet and outlets. The package also includes analyzers to monitor the following properties of sales gas:

- Heating value
- Specific gravity
- Hydrocarbon dew point
- Composition (C1 to C8, C9+)
- CO2 content (as applicable)
- H2O content (as applicable)
- H2S and total sulfur (as applicable)

4.4.12.2 Refrigeration System

The Refrigeration System furnishes cooling duty to service the chilling loads for the GPSS facilities.

- During Loading Operations: Gas chilling; Cargo Hold refrigeration
- During Transit: Cargo Hold refrigeration
- During Unloading Operations: EG Chilling (shore-side)

This system uses an "Ozone Friendly" refrigerant having thermodynamic properties similar to Suva R 407 C. The system is designed to provide low-level refrigerant (-35ºC) with a high-level economizer (-21ºC) configuration. Refrigerant condensing uses a once-through air cooling system for heat rejection. Two refrigerant compressors will be used for refrigeration purposes.

4.4.12.3 Relief, Vent and Drains

The Relief, Vent and Drain System provide service to the GPSS at all times. The system includes separate high and low pressure relief, vent and knock-out vessels, a closed drain, an open drain and associated drain sump vessel(s). This system services the processing facilities as well as the Product Storage Tier relief and venting loads.

4.4.12.4 Electrical Power

All electrical power is supplied from the ship's main power generation system, which uses a dual fuel engine skid. An emergency generator is included as part of the GPSS Electrical Power system to service critical loads in event the main generators are unavailable for service.

Shore-side equipment is assumed to receive power as free-issue from the grid at the receiving port. An independent power supply may be considered as an option (during FEED) to support ship utilities when the GPSS units are at port.

4.4.12.5 Nitrogen Generation Unit

The Nitrogen Generation System shall be sized to meet the needs for Cargo Holds inert requirements and for purging the HP and LP Vent systems. O2 content will not exceed 5 Vol% and the water dew point at system pressure shall be less than -40°C (-40°F).

4.4.12.6 Fuel Gas System

Compressed Natural Gas (CNG) stored in the cargo cylinders can be used as a fuel gas for the Dual Fuel Diesel (DFD) generator drivers. Unless there is a substantial variation in gas composition from what is specified in the BOD, it is unlikely that Grand Banks gas will require costly adjustment to provide a suitable fuel gas.

The CNG required for such a system will be supplied from selected CNG tanks or tiers. During loading operations and laden transit, this gas has to be de-pressurized and heated from its storage conditions to be used as fuel. An electric pre-heater is used to heat the gas to 27°C, raising the temperature over the water dew point to prevent any hydrate formation. The gas is then passed through a pressure reduction valve and de-pressurized to 7.3 barg (105 psig). The sudden reduction in pressure leads to a temperature drop. The gas is then passed through a coalescer, to collect and drain off any liquids that might have formed. The dry fuel gas is then passed through a super-heater, which heats it to the required temperature 4.5°C.

Fuel Gas will be treated by a fuel gas conditioning skid which supplies the correct pressure, temperature, and quality gas required by the DFD generator drivers. Return voyage gas fuel supply will not involve significant depressurization. By planning to keep all fuel gas for the return voyage in a single tier (at a pressure higher than the other "empty" tiers), it is possible to avoid use of scavenging compression that could otherwise be required to ensure delivery above the 7.3 barg required by the DFD engines. The tier of higher pressure fuel gas will be the tier used when re-starting the loading process at the field.

4.4.13 Safety Systems

4.4.13.1 Emergency Shutdown System (ESD)

The Process Control System (PCS) and the Emergency Shutdown System (ESD) of the GPSS will be designed to utilize automation for the highest safety and reliability performance available through application of current technology, computing architecture and field instrumentation. These systems must be capable of operating independently for each ship and must interface with the facilities located at both the FPSO and N. Avalon manifold and the Delivery Terminal.

The ESD system will incorporate state-of-the-art technology. The alarm, annunciation, and ESD system will incorporate both gas detection and infrared fire sensors. The ESD systems will be designed to ensure protection of personnel and equipment by preventing equipment from being operated beyond its design limits. The ESD system logic will be programmed and the ESD equipment designed and installed to provide automated shutdown of equipment in such a manner as to result in a "fail safe" shutdown state. The ESD system will automatically shut down operations to a "fail safe" state in the event of loss of all electrical power, the loss of instrument air, the detection of gas, or the detection of fire.

Manual activation of the ESD system for total shutdown will also be provided for use by the operating personnel from within the central control room(s), from the ship's navigation/control bridge, and from other multiple remote ESD shutdown stations strategically located throughout the ship including the gas handling module area, the cargo containment areas, and the shore-side facilities.

4.4.13.2 Fire & Gas Detection

Fire and gas sensors will be provided throughout the process modules, in the cargo containment areas, in the ship's machinery space, and all locations that could have gas or hydrocarbon release. Such detection systems will be designed in compliance with typical standards used in offshore facilities and modern LNG carriers and will meet ABS requirements.

Detection of gas will sound an alarm and the safety panel located in the central control room will identify the location of the sensor that has detected gas. If a gas release is confirmed by more than one detector, the ESD systems will automatically shutdown the loading or unloading operation.

Detection of fire will sound an alarm, the ESD system will initiate shutdown, and the firewater pumps and spray deluge system will automatically activate.

4.4.13.3 Fire Protection and Fighting System

The fire protection system for the process facilities will be integrated with that of the ship. A firewater deluge and monitor supply will be provided designed in compliance with ABS and API offshore requirements. The system will be designed with looped firewater main and branched supply laterals designed to provide firewater from two alternate paths. Firewater pumps will be diesel driven and one spare will be provided. Firewater pumps will be separated and located in different location to minimize risk of the entire firewater supply being disabled from a single event occurring at or near the firewater pump location.

An inert gas system with redundant configuration will be provided to extinguish fires that might occur in the electrical power and engine room of the ship. Structural support steel will be passively protected by fire insulation coating materials.

4.4.13.4 Personnel Safety Systems

Emergency escape capsules will be provided at both the bow and stern of the GPSS with personnel capacity to evacuate all personnel from the ship in the event of an impending catastrophic equipment failure or fire. Life support and other safety equipment will be provided as required to comply with ABS rules and flag/port state regulations.

The general layout and arrangement of the facility will provide at least two escape routes, to allow personnel to leave an area that has developed an unsafe condition. General layout for the processing facility will follow the recommended practice given in API RP 14J.

4.4.14 Codes and Standards

The Gas Handling System facilities installed on the GPSS will be designed in compliance with industry Recommended Practices, Standards, and Specifications that are typically used in designing and operating offshore oil and gas production facilities (e.g., API, ABS, or DNV).

Cross references will be made with design requirements of the International Gas Code (IGC) and ABS CNG Carrier Guide.

4.5 Delivery Terminal Facilities and Operations

Delivery terminal facilities, assumed to be at Point Tupper, Nova Scotia were defined to offload, receive, meter and deliver natural gas to the MNP pipeline and to a VOLANDS™ storage facility. Additionally, gas processing for NGL recovery and propone and butane fractionation were also evaluated. The major components required to process the gas and NGLs and deliver the product to market are as follows:

- Newbuild ship berth
- Ethylene glycol tank and flowline to and from the offloading quay
- CNG flowline from the loading quay to the NGL recovery unit
- NGL flowline from the offloading quay to SOEI for fractionation
- Pipeline from the VOLANDS gas storage to MNP tie-in
- Fiscal custody transfer meters for natural gas transfer to MNP
- Fiscal custody transfer meters for NGLs transfer to SOEI
- MNP mainline transport to US markets (Dracut)
- Ship support services, such as tugs and pilots, for ship logistics in the port

EnerSea and Nalcor made a site visit to Point Tupper and had discussions with representatives from NuStar, SOEI, and MNP to confirm the viability of the location and investigate the facilities required for this project. The site visit is documented in photos included herewith as Appendix 10. Further descriptions of each major delivery terminal component are provided as follows:

4.5.1 CNG Shipping Terminal

This study assumed the use of a dock close to the NuStar's Pt. Tupper Terminal in Nova Scotia as shown in Figure 7. Additional facilities and modifications were evaluated in this study for offloading gas from the GPSS at the port, including cargo transfer equipment, such as gas loading arms and attendant piping, as well as process equipment related to VOTRANS proprietary gas offloading system. The NuStar site has space available for a new loading quay for CNG carriers, a VOLANDS unit, and the gas plant.

Figure 7

4.5.1.1 Shipping Terminal Operations Summary

The gas stream is delivered at a high rate from the GPSS after the shuttle is connected to the discharge terminal. Each shuttle is assumed to discharge its full cargo load (net of fuel gas) within 24 hours. Gas and liquid cargos will be discharged and metered separately.

The facilities required at port are as follows:

- Offloading arms
- Ancillary piping and controls
- Refrigerated Liquid Displacement System (with insulated liquid reservoir tank and off-gas recovery)
- Automation, controls and instrumentation
- Safety systems
- Vent/flare system
- Support facilities (water treating, inhibitor regeneration and storage, etc)

Because intermittent deliveries have been assumed in all cases, only a single port berth and a single set of gas offloading arms are required in order to support cargo offloading operations. Sparing will be carefully evaluated during FEED to minimize RAMS impact of this key link in the gas delivery system.

Gas loading arms which have been assumed for this project are illustrated herein as Appendix 11. These high-pressure arms are designed and manufactured by Emco Wheaton and are now installed and operational at terminals in the UK, Brazil, Kuwait and Argentina for offloading compressed natural gas (from regas LNG ships).

During transfer of cargos to shore-side facilities, the GPSS will be re-supplied (including a fresh supply of hydrate inhibitor).

4.5.1.2 Shipping Terminal Location – Pros and Cons

There are many advantages and disadvantages in using an existing facility. EnerSea evaluated the NuStar's Point Tupper terminal and can provide the following preliminary qualitative summary as follows:

- Pros:
  - Established terminal operation
  - NGL processing capability adjacent to terminal
  - Established products (condensate & NGL) storage and market
  - Foreign flagged vessels can be used
  - Located near major shipping routes for minimal marine vessel deviation
  - Deep water ports
  - Expansion plans could include CNG
- Cons:
  - Expansion plans will increase tanker traffic
  - Requires gas plant
  - Requires 50km spur line to Goldboro (M&NP)

4.5.2 CNG Storage

EnerSea evaluated the requirement for CNG storage at the port and determined that a land-based storage facility is an attractive feature to complement the marine gas transport system. EnerSea has adapted its proprietary VOTRANS technology to provide a unique gas storage facility for use where traditional underground (salt dome or reservoir) storage is not available. This VOLANDS™ (Volume Optimized Land-based Storage) system, as illustrated in Figure 9 can provide commercially advantageous storage quantities along with high cyclability and high delivery rates from a site convenient to gas receiving terminals and markets.

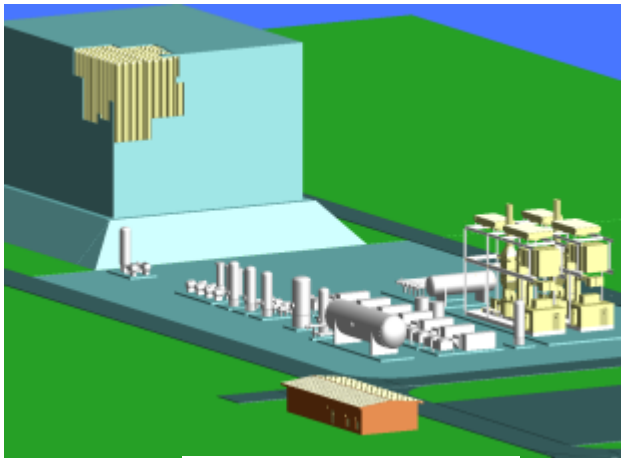


Figure 8

The VOLANDS facility will assist in receiving and storing the intermittently offloaded GPSS cargo at the Delivery Terminal. In this situation, where the market must receive a continuous or uninterrupted supply of gas, use of a VOLANDS storage facility enables the GPSS to offload its cargo more quickly and therefore increase the efficiency of the shipping operations. The higher marine efficiency thus allows for a reduction in fleet gas capacity (i.e. number of ships and or containment capacity per ship) otherwise required for continuous offloading. Gas will be redelivered from the VOLANDS unit on a ratable basis (assumed to be continuous) to the downstream gas offtaker.

The storage capacity is calculated based on the ship's gas cargo delivery volume (assuming a 24-hour offloading operation) less the daily average rate of gas sales (i.e. market demand) plus a small margin for operational flexibility. Additional capacity may also be provided by EnerSea, at additional cost, at the request of the gas customer if supplemental storage would be beneficial in managing the volumetric dynamics of their operation.

4.5.2.1 CNG Storage Operations Summary

Gas discharged from the ship which exceeds the targeted maximum daily delivery requirement will be routed to the VOLANDS storage facility. It is not expected that pipeline capacity (i.e. cushion or line pack) can be used as effective storage for the CNG gas delivery process, especially for rich gas deliveries.

Gas withdrawn from storage will be processed through the HC liquids recovery unit at a steady state (ratable) basis (and essentially constant pressure) prior to distribution via the MNP spur.

4.5.3 Gas Processing and NGL Recovery

In order to extract valuable NGLs from the gas stream and prepare the gas for transport on the MNP, system, natural gas will be processed to MNP requirements and NGLs extracted. Part of the discharging cargo will be directed through a HC liquids recovery unit before entering a “spur

line" that connects to the MNP allowing distribution of gas at rates up to the maximum daily delivery allocation.

EnerSea has included equipment required to perform a natural gas liquid (NGL) separation of the liquids stream coming off the ship and a storage tank for the NGL/condensate stream after the gas and MEOH/H_2O streams have been separated.

The cost of this new facility appears at this time to be justified at the current liquid price; however, this facility will be evaluated in more detail during FEED.

4.5.4 NGL Fractionation

EnerSea has assumed that the SOEI gas fractionation facility can be utilized for processing and storage of NGLs for subsequent marketing. SOEI's Point Tupper fractionation plant fractionates natural gas liquids into propane, butane and condensate.

The raw HC liquids cargo stream coming off the GPSS will be transferred into a temporary storage facility for ratable processing by SOEI at its existing gas fractionation plant as shown in Figure 9.

Figure 9

4.5.4.1 NGL Fractionation Location – Pros and Cons

There are many advantages and disadvantages in using an existing facility. EnerSea evaluated the use of SOEI's NGL fractionation plant and can provide the following preliminary qualitative summary as follows:

- Pros:
  - Established NGL plant
  - NGL processing capability adjacent to terminal
  - Excess capacity
- Cons:
  - Excess capacity will depend on NS exploration success
  - ExxonMobil's interest in negotiating gas processing volumes

4.5.5 Maritimes & Northeast Pipeline system (MNP)

EnerSea has assumed that the natural gas will be transported from Pt. Tupper to the United States through the Maritimes & Northeast Pipeline (MNP). A new pipeline spur approximately 50kms long would need to be installed from NuStar's terminal to interconnect with MNP's existing trunkline near Goldboro. The pipeline right of way exists and is currently used for SOEI's gas line from Goldboro to Point Tupper.

The natural gas would then flow into MNP's main trunkline to the US. Further compression facilities may be required along the system, dependent on other natural gas supply at the time of the Grand Banks project.

MNP extends from Nova Scotia into New Brunswick, Maine, New Hampshire, and Massachusetts where it connects with Algonquin Gas Transmission's HubLine near Beverly, Massachusetts.

4.5.5.1 MNP Use – Pros and Cons

There are many advantages and disadvantages in using an existing infrastructure. EnerSea evaluated the use of the MNP system can provide the following preliminary qualitative summary as follows:

- Pros:
  - Established pipeline
  - Excess capacity
  - Existing ROW for spur line
  - Cooperative and motivated
- Cons:
  - Excess capacity will depend on NS exploration and New Brunswick shale development success
  - Cost

4.5.6 Alternative Delivery Terminal Locations

Investigations pursued at a high level during this study indicate that Goldboro, Nova Scotia may be a very suitable alternative and, in fact, may limit the amount of new facilities/construction required to establish the features required for delivery of the gas and liquids from the Grand Banks. Some key aspects of this alternative delivery option are summarized as follows.

Natural gas from Sable Offshore Energy Project (SOEP) comes onshore near Goldboro, Nova Scotia. SOEI operate a gas plant nearby that processes the gas and sends a NGL stream via pipeline up to Point Tupper for fractionation. The Goldboro Gas Plant is located in Guysborough County, Nova Scotia and operates 24 hours a day, seven days a week and has a processing capability of up to 17 million cubic metres per day

EnerSea has considered establishing a port near this gas plant and utilizing the gas plant for gas processing, therefore obviating the need for a new gas plant, assuming SOEI has excess capacity. The NGLs could possibly be sent to Point Tupper in the existing pipeline, obviating the need for a new pipeline as well. There are many issues that have to be investigated before considering this option in greater detail, the greatest of which is whether there is suitable excess capacity in the gas plant and the pipeline. ExxonMobil stated their intentions to continue drilling offshore Nova Scotia; therefore, there will be a great deal of uncertainty on the answers to the question of capacity until drilling results are known.

Alternatively, if there is not sufficient spare capacity in the existing infrastructure, a new gas plant could be built at Goldboro or the SOEI plant expanded to handle the Grand Banks gas. A new liquids pipeline to Point Tupper may also be required. If substantially new infrastructure is required for the Goldboro option, then the only real issue that would need to be evaluated is whether a new-build port located near Goldboro might offer additional advantages, in terms of location, traffic or ease of port access.

Goldboro is the intended site for a new North American LNG delivery terminal and petrochemical industrial park, originally proposed (and approved) by Keltic Petrochemicals, Inc. and currently being progressed by Maple LNG Ltd (a unit of 4gas, a Dutch company). The proposed terminal complex is located very close to the SOEI Gas Plant and the MNP, as illustrated in Figure 10.

Figure 10

There are several positive reasons that would lead one to believe that this site may offer many advantages, such as:

- Final Environmental permit on March 2008; Permit to Construct issued in June 2008
- New terminal for import and storage of LNG at a site near Goldboro NS
- Two berths for vessels (length 345 m, beam 55 m and draught 12 m)
- Adjacent to the existing SOEI plant and the M&NP pipeline
- Design of the facilities will be based on a continuous operation, 24/7/365

The potential for synergy or conflicts with the Maple LNG initiative can be explored in greater detail prior to and during FEED.

5. PRELIMINARY PROJECT STAFFING PLAN

EnerSea has entered into strategic business relationships with the two of the leading gas ship owner/operators, Kawasaki Kisen Kaisha, Ltd. ("K"Line) and Tanker Pacific as well as with Mitsui & Co. (USA), Inc. These alliance partners are contributing their resources and capabilities to actively participate in and support EnerSea's transport projects and capabilities, including: vessel construction, ownership and operation; offshore storage facilities; and financing.

5.1 Project Management

EnerSea has developed an experienced team for execution of large international projects as can be seen below. EnerSea will be responsible for overall project management and will identify and employ world-class senior project management and project support personnel as required to oversee the critical activities. This team has been included in the design development for each project.

EnerSea's personnel have been involved with many world-class projects with responsibilities ranging from project engineering through project and asset management over a wide array of upstream and midstream production and infrastructure projects. This experience and the networks established by EnerSea's management team will be invaluable as we move forward on these projects.

EnerSea will develop a detailed project plan, inclusive of execution plan and staffing levels, during FEED.

5.1.1 Contracting Strategy

EnerSea will develop the overall project scope divided into various major components and will bid out major work packages whilst honoring the commitments set out under the Atlantic Accord. EnerSea will seek to appoint an EPC contractor, who shall be subject to the benefit commitments made by the proponent that will take project responsibility for engineering, procurement and construction for the major components.

5.1.2 GPSS Construction Period

During the ship construction, "K"Line will designate supervisor(s) to be dispatched to the shipyard to supervise construction. Several months prior to delivery, designated key crew members will also be dispatched to become familiar with the ship systems and to witness testing of the cargo systems in accordance with the CNGC Crew Training and Orientation Plan to be developed for project-specific requirements during FEED.

Procedures for the gas trial prior to delivery will be established by the shipyard for review and approval.

EnerSea and "K"Line will work with classification societies and regulators during all phases of vessel design, engineering, construction, commissioning and gas trials to ensure an efficient class approval and flag/port state approvals process.

5.2 Transport Service Management – Project Specific

EnerSea and "K"Line will form a Fleet Operations Management Team located onshore to manage fleet operations, logistics, port operations, supply, bunkering, client management, government and public relations and general administration during transport operations. EnerSea has included the following personnel for the shore-side Fleet Operations Team:

- EnerSea Project Company Services Team (Client & regional relations management)
- Fleet Manager
- Assistant Manager
- Port Captain
- Assistant Port Captain (2)
- Administration inclusive of Benefits Reporting & Local Procurement

5.3 Gas Loading and Offloading Terminal Operations

Operations of the Gas Loading Terminal and Gas Offloading Terminal will be the responsibility of the parties that own the assets.

6. SAFETY AND RISK ASSESSMENT

EnerSea always takes a proactive approach to safety and will ensure safety is the first priority in all of our plans and design. Safety is clearly an overriding issue with all natural gas systems, and with CNG transport carriers and associated operations. Multiple safety features and systems have been included in the VOTRANS design and operating procedures, many of which are extensions from existing gas facility design principles and practices. This section describes the safety analyses that have been undertaken to date that encompasses the design of EnerSea's V-ships on a general basis and as such would apply to most projects.

Key members of EnerSea's management team have spent the majority of their careers working with major E&P companies and have an ingrained attitude of safety. EnerSea has developed its technology with this same philosophy. A good example of this is the way in which the Company has validated its designs using Hazard Identification Reviews (HAZIDs) at various design stages from initial concept development through preliminary engineering.

EnerSea performed its first HAZID with DNV (Det Norske Veritas) in May 2001 focused on initial concept design of the containment system and gas handling system that would be hosted aboard a converted tanker. EnerSea's core team and contractors were the prime contributors and DNV performed a facilitation role for this HAZID. Detailed analysis was performed, hazards were identified and recommendations were made to mitigate these hazards. These recommendations were then incorporated into the next evolution of the design.

EnerSea held its second HAZID with ABS Consulting in August 2001 after further evolution of the design. In this HAZID, ABSC and ABS Class provided the majority of the review expertise along with EnerSea's core team only. It was clear that the risks were seen to be less than the DNV HAZID revealed due to incorporation of mitigation recommendations into the design.

A third HAZID was conducted in September, 2002 with ABS. Participants in this HAZID review included representatives from EnerSea, a "super major" under a technical cooperative agreement with EnerSea, Hyundai Heavy Industries, K-Line, Paragon Engineering Services, Alan C. McClure, Marsh Risk Consulting and ABS Class. Representatives from ABS Consulting facilitated the workshop. This HAZID resulted in a very positive decrease in the risks from previous HAZIDs due to incorporation of recommendations into the design and the evolution of the design.

The result of these exercises has been the development a core project Hazard Register that has been updated based on HAZIDs performed for specific projects as further described below.

6.1 Project-specific Hazard Register Update

EnerSea has maintained a Hazard Register as a "living document" throughout the technology development phase in accordance with ABS requirements in the AIP letter issued in 2003.

EnerSea updated the Hazard Register to reflect specific design and operating conditions for the previous study in 2007 evaluating a domestic market, inclusive of documenting appropriate mitigation measures in the VOTRANS design, and is included herein as Appendix 11 for

information. No reassessment was undertaken during this study since the scenarios were so similar.

The HAZID exercise provided an upper level assessment of the major risks associated with GPSS operation. The vessel, as currently defined for this phase of the project, can be expected to pose tolerable risks based on this initial risk ranking exercise. Those risks currently ranking as "intolerable" will be addressed through design evolution or further planned risk studies.

Several events identified in that HAZID study were found to be in the categories that require incorporation of reasonable risk reduction measures to preclude occurrence with mitigation measures to be applied in later design stages. Mitigation recommendations were generated during the previous HAZID studies which along with recommendations that will be generated during detailed design, further risk assessment and testing can be expected to reduce these risks to tolerable levels.

The latest HAZID performed for the GPSS scenario has confirmed the perception that no unmanageable hazards would block successful development and safe operation of the Grand Banks gas production system. However there are a number of issues that still need to be addressed prior to construction. In particular, the following general topics should be considered as primary objectives in the early phases of the project:

a) Even though the effectiveness of subsea cooling has allowed a substantial simplification of the loading system, it is still recognized that failure of a tube seal in the chiller could lead to serious consequences. Options for reducing the likelihood of failure and possibly the consequences will be explored early in FEED to ensure that tolerable risk level is achieved.

b) A substantially deleterious change in produced fluids composition has been acknowledged to have hazardous consequences. However, it is expected that future investigations for the project and reasonable monitoring practices at the FPSO will make the likelihood of seeing dangerous compositions being loaded by the GPSS remote.

c) Proper safety interlocks in the process control design will reduce the hazards associated with gas handling operations throughout.

d) Maritime operations in this harsh, subarctic environment will have to be performed to high standards of safety to manage the potential dangers to crews at acceptable levels.

e) The risk of "jet fire impingement" will be carefully assessed and minimized through Fire Risk Assessment and design practice. Recent studies indicate that jet fire scenarios are not likely to lead to catastrophic results. The event would be very dangerous to individuals directly exposed, but the pressures and durations of ignitable gas jets are relatively limited and localized. It is recommended that operating practices for personnel limit situations where individuals can be exposed to injuries by jet fire.

f) Current double-hull design features are expected to limit risks from grounding or collisions, but damage analyses are required to confirm effectiveness.

g) Proper training and advanced Human Factors design will limit the likelihood of maritime accidents.

h) Vent-relief systems design will be evaluated in Fire Risk Assessment during FEED and modified as necessary to reduce the likelihood of severe consequence to tolerable levels.

i) An uncontrolled gas leak in the STP room could have serious consequences and will be thoroughly investigated for the GPSS concept. It is noted that STP and gas STL's are operating safely worldwide.

j) Project specific engineering and metallurgical work will ensure that the cargo containment systems (esp. CNG and liquids storage cylinders) onboard and on shore will achieve adequately low risk levels.

k) Engine room redundancy can ensure that complete loss of power ("dead ship") would be a suitably remote possibility.

l) Automation of cargo transfer loading arms/hoses in port can limit personnel risks at that critical interface.

6.2 Risk Assessment Activities Completed to Date

ABS requires many safety and risk studies to be performed as each EnerSea project progresses. In the evolution of EnerSea's current projects and design, EnerSea has completed the following safety and risk studies:

- VOTRANS CNG Containment Structural Integrity Assessments
- Vessel HAZID Studies and HAZID Register
- Cold Jet Study for Containment System
- Comparative Risk Assessment between – CNG Vs LNG Carrier
- Vessel In-service Inspection Plan
- Gas Release/Dispersion Study
- Fire and Blast assessment
- Evacuation, Escape, and Rescue Study

Summaries of the results of these studies can be made available upon request.

7. LOGISTICS AND REGULARITY

EnerSea sanctioned a study to advance the process of investigating operational "regularity" for the production and export of gas from the Grand Banks to Nova Scotia. "Regularity" (also called "availability") combines consideration of reliability and efficiency. BMT Fluid Mechanics Limited (BMT-FM) was selected to perform the study because they developed and operate the SLOOP oil/gas field simulation software, which is well suited to this task. In this specialized task of the previous DFS work program, BMT-FM was supported by its sister company, BMT Reliability Consultants (BMT-RC; together, BMT), so that a stronger RAMS (Reliability, Availability, Maintainability Study) feature could be included. Modeling features developed in the previous study were incorporated in the present effort and report. The study has undertaken operational simulations of the gas production, marine export, and delivery to market through the construction of simple models representing key elements of the systems and processes involved, as well as the external factors (e.g., weather) affecting those operations. The models were generated through team interactions in a workshop and managed interchange of information as recorded in a "Modeling Notes" spreadsheet. These notes and the results of these simulations are presented in BMT's Report included in Appendix 7 herein.

Even with the inclusion of a simple RAMS assessment of key system elements, only a preliminary assessment of regularity can be achieved at this time. Still, the power of an event domain simulation program, like SLOOP, allows the generation of a great many perspectives on a complex operation. It is not the intent of this section to address all possible observations that can be gained by reviewing the data or report generated by BMT. The following subsections highlight the key points that EnerSea considers salient to this project at this time.

Regularity can be measured by the percentage of the time that the gas production target is achieved. This "success indicator" has two aspects:

1) the amount of time that 100% of the targeted daily rate is achieved, and

2) the amount of time that some percentage of the target is achieved.

It is important to note that "situation management" practices and responses which can be administered during actual operations will tend to greatly limit the impact of many of the factors/"impactors" accounted for in the current model. Therefore, it can be concluded that this early study is inherently conservative and the results for the base case and sensitivities are in some ways a "worst case" perspective – even though most charts prepared in the BMT report present "expected" values from a probabilistic database of outcomes. "Expected" results are the *mean* of the distribution of outcomes.

It should also be noted that while observations can be made from the generated results, it is premature to make absolute conclusions based on such a simplistic first pass at a complex problem. Further, the current modeling work has not addressed the economic value trade-offs for some of the key design features and operating strategies. All results are sensitive to the actual gas being produced and loaded at the field.

7.1 Modeling – Case Study Features and Assumptions

SLOOP is able to model and simulate operations for extremely complex production/export systems. The team adopted a relatively simplistic modeling approach due to the lack of maturity of the project development initiative and to facilitate interpretation of the results. The simulation workshop and follow up activities allowed the team to provide BMT with enough guidance and data to establish a model capable of providing substantial insight about what drives efficiency for the proposed operation and what may be achievable in terms of regularity and how much gas can be sold.

A substantial amount of effort has been expended to gather data and experiential perspectives on how the harsh sub-arctic environment of the location would be likely to impact operations. This included accessing the PERD Iceberg Sighting database, previous interactions with regionally experienced sea captains, and acquisition of a 50-year hindcast database for metocean conditions at the field and along the route into port. The vast hindcast database is not included as an appendix, but has been fully incorporated in the SLOOP analyses.

The shuttling operation reflects the use of three GPSS ships loading via two STP buoys at the field, as assumed in the BOD. For initial evaluations the shuttles are assumed to be subject to weather-induced delays and interruptions. The impact of planned dry-docking is minimized by an assumption that dry-docking will be scheduled to occur when the primary producer or consumer is taken down for substantial maintenance or upgrading. Simulations have been performed in which the RAMS features have been excluded so that results indicate more clearly the impact of environmental factors.

Route effects from storms, fog, ice, icing and icebergs were considered and modeled. BMT does an excellent job in addressing how the sub-arctic conditions impact operations. A serious attempt was made to reflect the influence of icebergs in the late spring season on sailing speeds. However, a somewhat conservative approach was adopted. A key early finding, according to feedback from experienced mariners in the region, has been that fog is not considered to affect open sea sailing speed.

Port entry and berthing limitations or delays have been modeled based on input from companies and ship captains familiar with the operating arena. Delays from pilot accessibility are modeled, as well as traffic delays due to interactions with ship traffic at the port. It is assumed that the GPSS units can enter port whenever necessary any time of day or night, but access can be randomly delayed as just noted.

Key aspects of the base production scheme as investigated are included in Table 12 below:

Table 12
GPSS Cargo Unloading Functional Requirements
(as used for SLOOP modeling)

Key Assumptions	Value	Comments
Gas production target	200 Mscfd (5.66Mscm/d)	Sensitivity to production rate is investigated
The reservoir is a "perfect supply" source		Targeted production rate is maintained whenever the FPSO is not injecting associated gas
Buoy connection Wave Limits (Hs)	5.5m	Range: 2.75 - 11m
Buoy connection Wind Limits	20.6m/s	Range: 10.3 - 41.2m/s
Number of GPSS ships	3	Fleet size is checked along with production rate sensitivity
Initial GPSS Ship gross cargo capacity:	590 Mscf (16.7 Mscm)	Sensitivities run on sizes from 80-120% (472-708Mscf)
GPSS Ship working cargo capacity:	560.5 Mscf	Allowing 5% of capacity dedicated to fuel & permanent heel
Ship's speed:	16knots	Range: 12 - 20knots
Iceberg avoidance: Speed reductions on route based on "sighting frequency"		
GPSS response on station		
• Level 1 (stop operations) for bergs	within 6nm	
• Level 2 (disconnect) for berg sighting	within 3nm	Sail to port if >2/3 full
Loading Limits: Gas Handling System	12m Hs	
GPSS Downtime (without and with mechanical failures at loading and unloading)		
Port Entry Delays:		
• Fog	1/30days in Feb & March	Range: 0-5 times per month
• Pilot and other traffic delays modeled with negative exponential on berth approach time	6 times per year	2h min, 8h mean, 36h max Bandwidth from 0% - 500%
Loading Limits: Gas Handling System	12m Hs	
RAMS delays:		
Key on-line process valves allowed to fail and be restored to service according to industry accepted database (Reference: OREDA database)		
Subsea HIPPS (at the manifold) assumed to be perfect due to extreme high consequence of failure and long repair time being likely to cause high simulation instability		
Valving on containment (ship and VOLANDS) assumed to be insignificant consequence due to high degree of segregation and redundancy (allowing by-pass and repair)		
Refrigeration failures have been assessed but appear to be relatively insignificant except to slow down loading or discharge operations.		

7.2 Key Results and Observations

The reader should keep in mind that the results are generated with an approximate, preliminary model so the trends in the sensitivity checks are probably more important than any individual result at this time. EnerSea has interpreted the set of results generated by BMT and provide the following comments to provide guidance for high level economic evaluations and strategic planning of efforts ahead.

No simulation case in this study exactly models the operating basis EnerSea is suggesting could be achieved once the lessons of the current simulation work have been properly included in the design. For example, the model reflects wave height limitations on the ability of pilots to board the ships coming into harbor, but open ocean weather data used to determine sea states that limit pilot access will yield conservative results as compared to sea conditions in Chedabucto Bay. Such conservatism on the input data appears to knock down performance predictions appreciably during the winter. Still, the study does provide good indications of what measures to address and features to incorporate in subsequent phases of project development.

Based on the current study, EnerSea suggests that a properly designed GPSS system should be able to achieve the targeted Base Case production rate at least 95% of the time annually in consideration of met-ocean conditions (i.e. no RAMS effects). When an optimized system design and practical operating/maintenance philosophies are implemented and modeled to limit the frequency and consequences of failures within the production and receiving/storage facilities, we might even expect to exceed 95% of that target on an annualized basis. However, seasonal variation is significant.

EnerSea decided to model a targeted gas sales rate of approximately 184Mscfd (5.22e6 scmd) for this study based on a targeted production rate of 200Mscfd with reductions for fuel consumption. The results in the following figures indicate month-by-month how much of the time the daily targets are achieved (as well as some ranges on daily delivery down to 90% of target). Data logging for the simulations in this study have been limited to tracking results for days when at least 90% of the targeted delivery rate is achieved.

In Figures 11 and 12, the seasonality of effects is highlighted with and without RAMS effects (i.e., mechanical systems failures). The deleterious effects of the severe winter weather and the spring iceberg seasons are distinct, but sensitivity studies give us some insight as to how to limit the impact of those environmental factors.

Figure 11
Comparison of variation of average gas loaded per month with and without equipment reliability

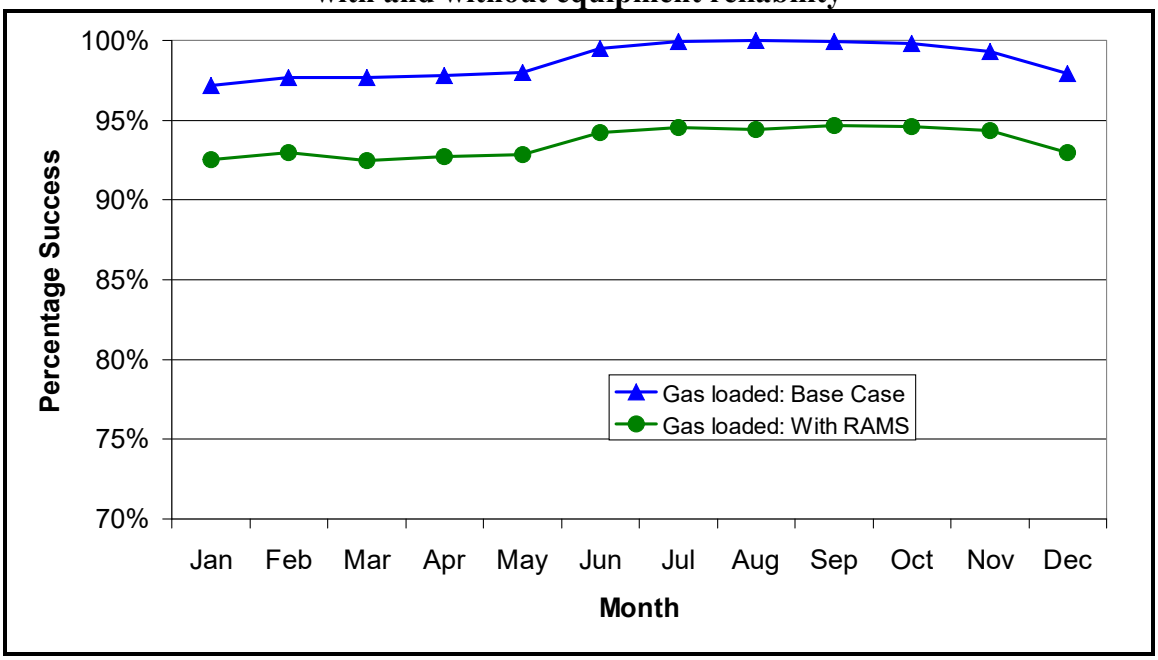
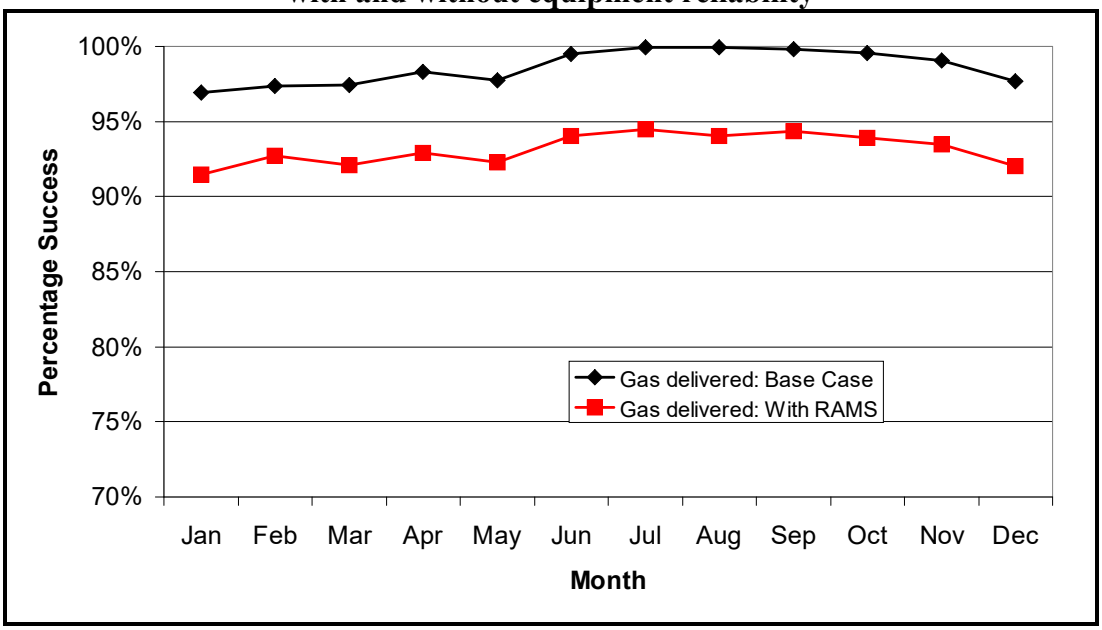


Figure 12
Comparison of variation of average gas delivered per month with and without equipment reliability



The likelihood of interruptions and the distribution of interruptions can be evaluated by consideration of Figures 13, 14 and 15. Even when RAMS effects are included, it can be noted that the GPSS units can be expected to be loading over 97% of the time annually. The difference

in the number and duration of interruptions caused by RAMS effects as compared to other sources can be seen in Figures 14 and 15. Whereas iceberg encroachment may be substantially beyond our control, RAMS impact can to a great extent be mitigated by proper design and operational management.

Figure 13
Variation of time spent loading gas per month with equipment reliability

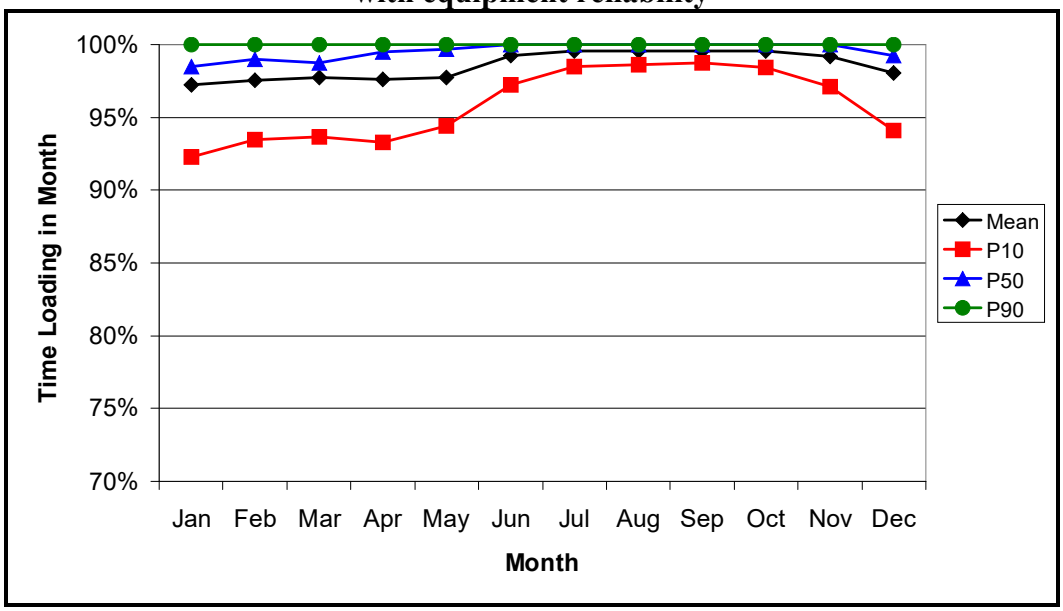


Figure 14
Frequency of Loading Interruptions

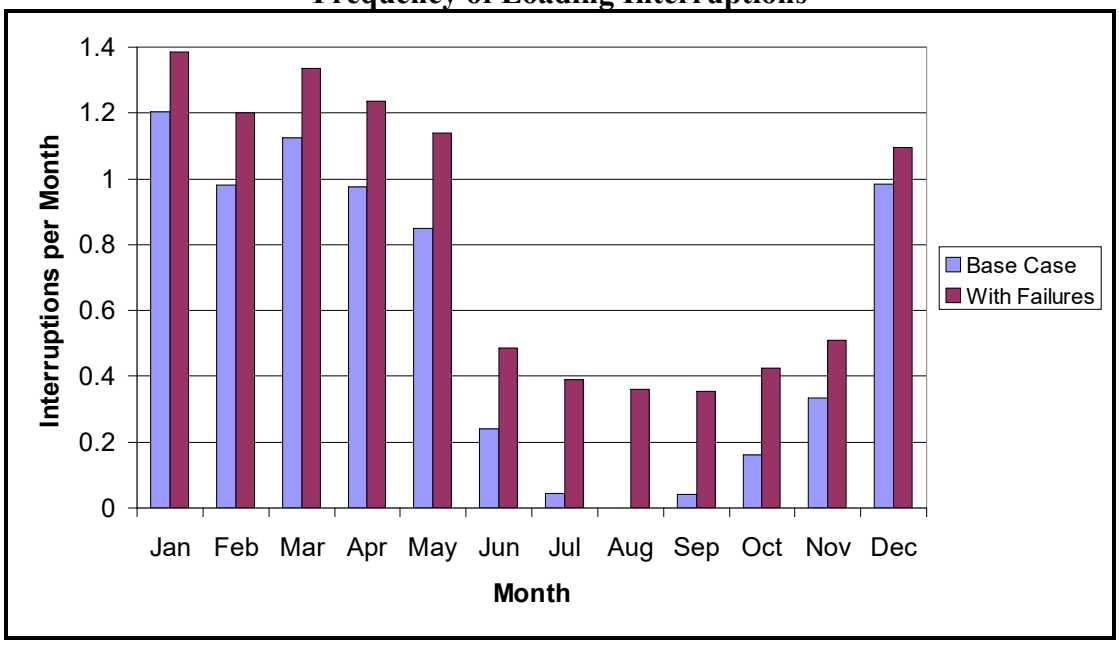
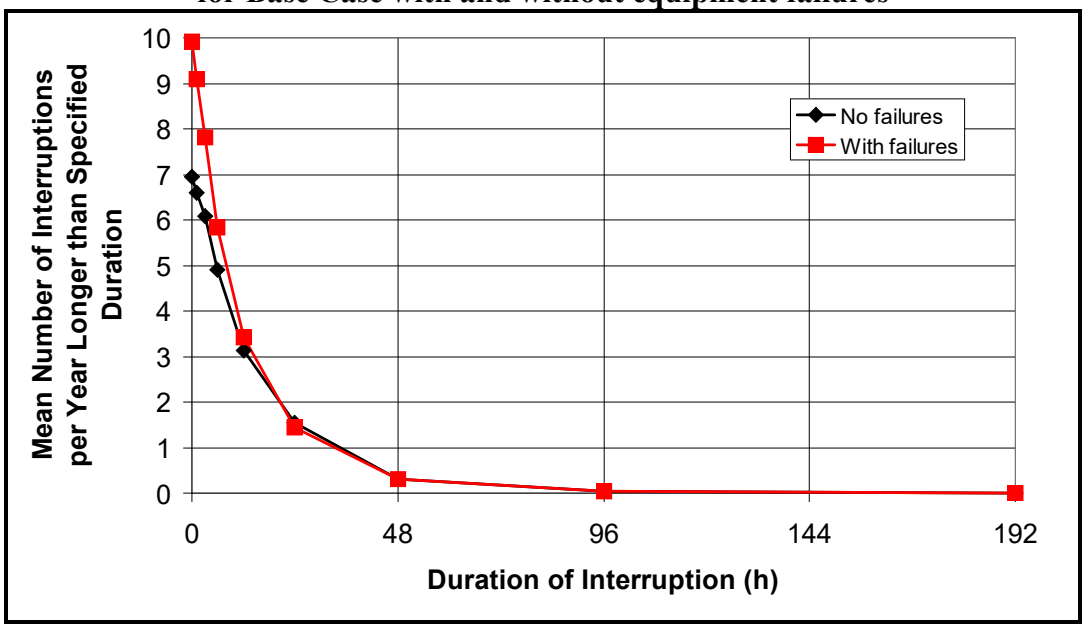


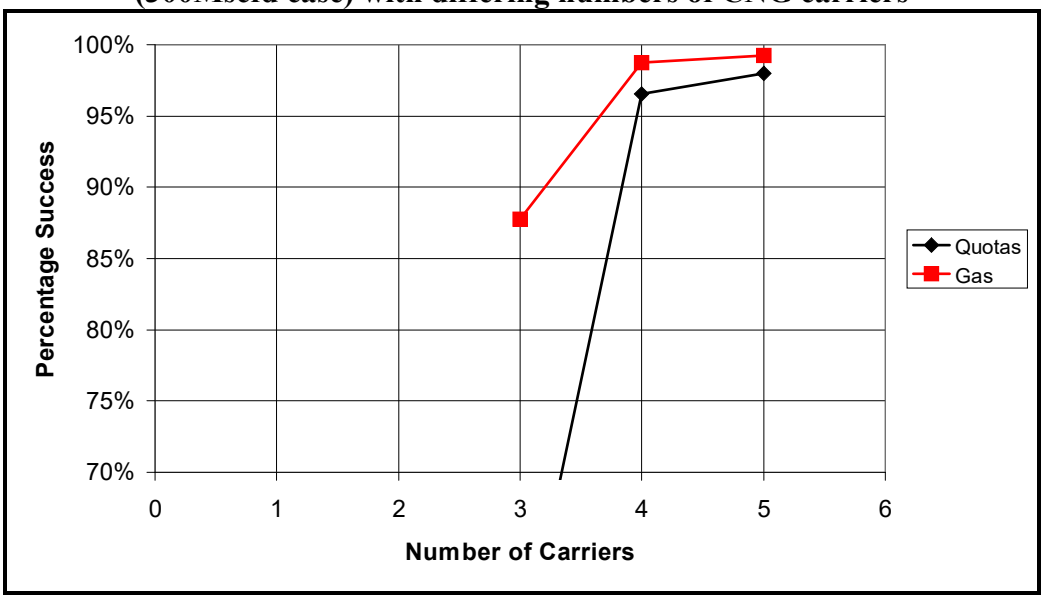
Figure 15
Frequency of loading interruptions by duration for Base Case with and without equipment failures



As presented in Figure 16, the mechanical failures only affect the short duration interruptions. Interruptions greater than 12 hours are predominantly caused by other sources (e.g., icebergs or harbour traffic). Once system design and operational practices are optimized, it should be possible to limit the expected number of loading interruptions substantially. EnerSea would target limiting unplanned interruptions to fewer than 4 per year total (excluding planned drydocking).

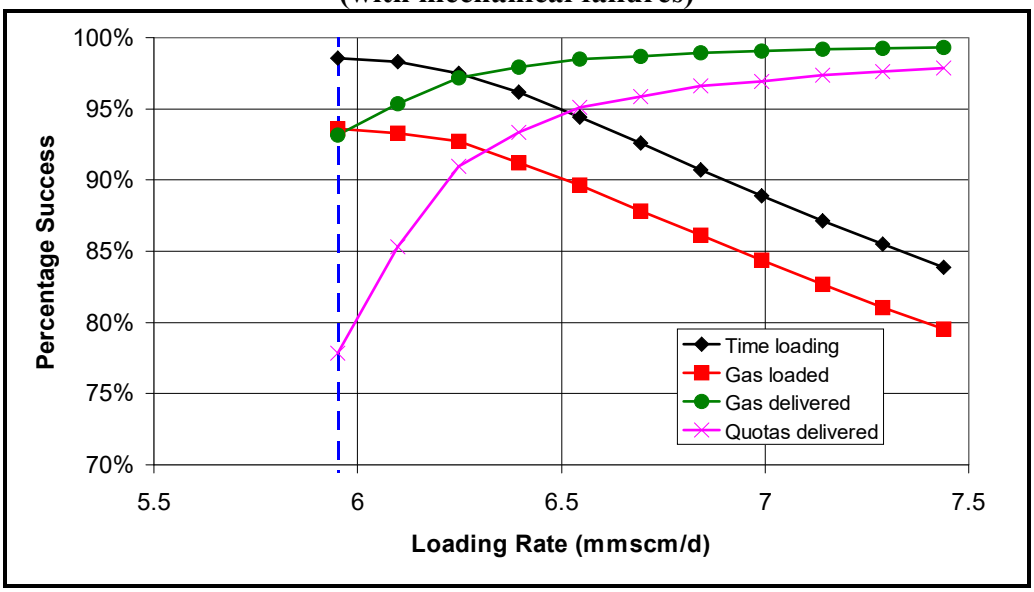
By examining Figure 16, it is easy to see that a fourth vessel will be required to support a production target of 300Mscfd. It is also apparent that a fifth ship could not be justified at that production rate.

Figure 16
Gas delivery statistics for a 50% increase in gas throughput (300Mscfd case) with differing numbers of CNG carriers



It is worth considering how a small increase in productivity from the field can affect the amount of gas delivered to market. Figure 17 indicates that a small supply rate increase dramatically improves that quantity of gas delivered by the GPSS fleet (and shore-side systems). A 5% increase in field production rate increases gas deliveries by about 6.6%, but increases the percent of time that the gas sales target is achieved by about 17%. The downside is that the loading process may be negatively impacted if the loading operations are not properly managed. The ships will fill up faster, leading to the potential for more loading interruptions. Increasing the production rate much above 5% (as a fixed higher rate, rather than as a temporary "catch up" capability) appears to rapidly diminish the time spent loading.

Figure 17
Variation of gas loading and delivery with gas loading rate
(with mechanical failures)



BMT has been able to model a conservative "iceberg response" philosophy, accounting for both the need to slow down if icebergs are present and the need to disconnect from the STP if an iceberg collision appears to be imminent. The simulation includes a speed reduction due to the presence of icebergs and the risk of collision with bergy-bits and growlers. However, the current study indicates that the logistical performance for this project is less sensitive as compared to early work that targeted deliveries to Newfoundland where most of the transit route is affected by icebergs. Figure 18 shows that there are a few days per month when quotas are missed due to iceberg encroachment, but there is very little impact on the amount of gas that would be delivered (even in May).

Figure 18
Proportion of quotas delivered with and without speed reduction due to iceberg presence (no mechanical failures)

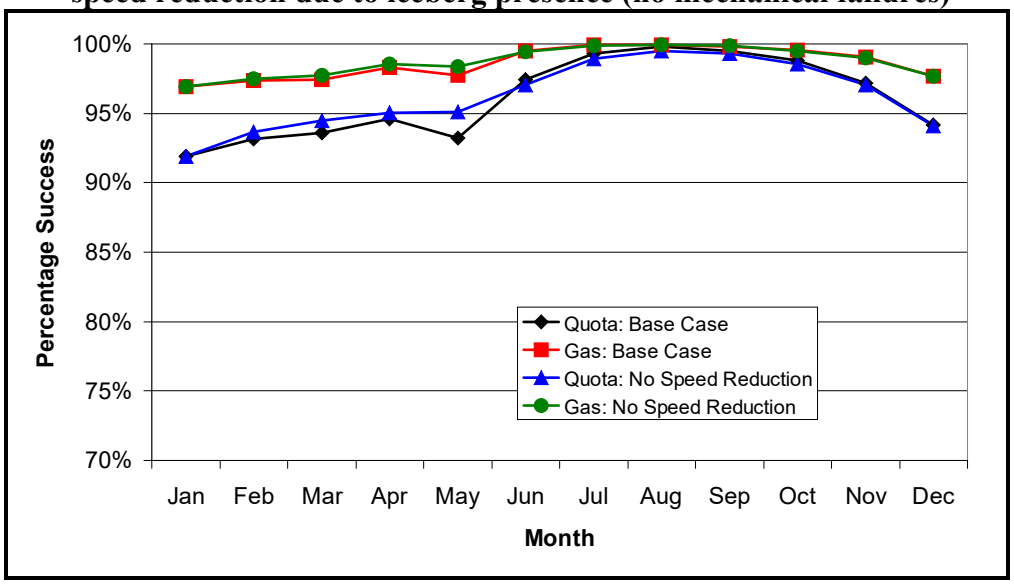
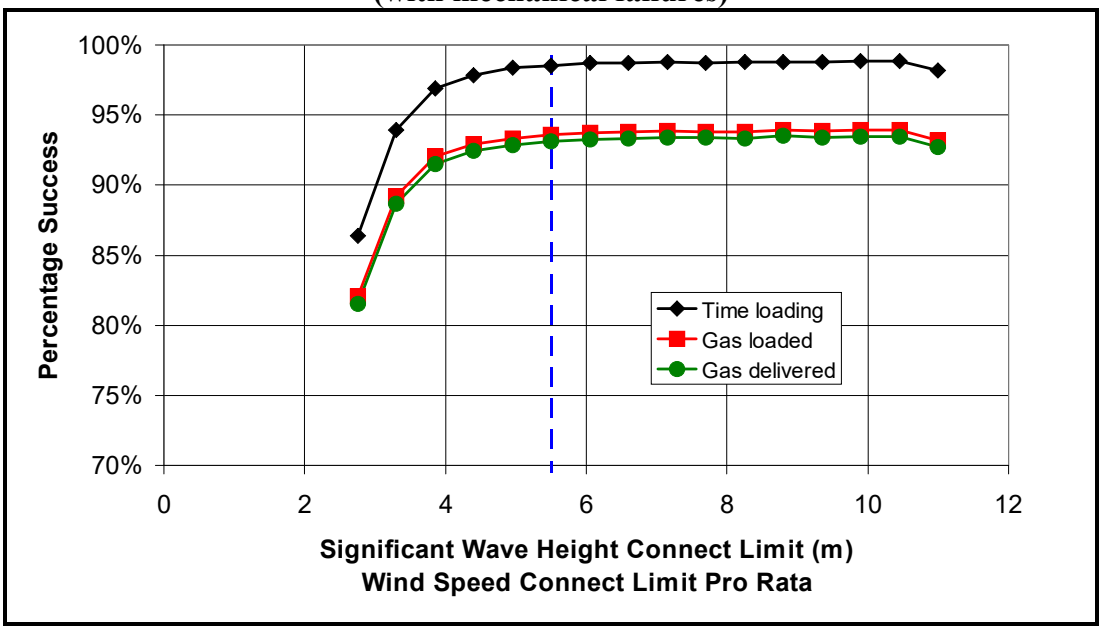


Figure 19 confirms that the sea state limit on the ability of the GPSS units to connect to the production terminals has a great impact, driving us to focus on the proven STP solution from APL.

Figure 19
Variation of gas loaded and delivered with loading buoy connect limits (with mechanical failures)



The sensitivity studies appear to confirm that the GPSS fleet can be configured with a slightly reduced capacity per ship (530-550Mscf versus 590Mscf in the base model) and that there is little to be gained by increasing its design speed above 16kts. There also appears to be some margin for speed reduction without serious consequence on performance. However, if the ship size is reduced by 10% and design speed was reduced by a couple of knots, we can expect that the performance would drop dramatically. This kind of "lopsided" or skewed influence pattern is common among several of the key performance drivers. Therefore, EnerSea decided to adjust the ship size only down to 550Mscf for the base case design and costs evaluated in this assessment while keeping the speed at 16kts for now. The sensitivity studies show that EnerSea's fleet and storage sizing philosophy is reasonable, even in this extremely harsh environment. It is obvious that system performance optimization will be an important step in FEED when the potential for reducing ship speed to 15kts can be confirmed in alignment with Nalcor's gas sales strategy.

8. GPSS OPERATIONAL CONSIDERATIONS

8.1 Fleet Operating Plan

"K"Line and EnerSea have generated a preliminary operations plan for several project-specific transport studies. The Fleet Operations Plan (FOP) also provides the basis for estimating OPEX for this core element of the gas export scenario. The FOP documents normal, contingency, emergency, and maintenance operations throughout the service life. This FOP will be updated in subsequent pre-project development activities to reflect the basis for the GPSS, specifically focused on modifications required for subsea control and production operations.

Basic elements and operating components of a VOTRANS ship are identical to the GPSS. The following section depicts the operational considerations for a GPSS operating in a transport project for reference and information only.

8.2 Inspection and Maintenance Onboard

The GPSS has been designed to facilitate access and workability for all elements that require regular inspection and maintenance. The machinery and facility blocks are spacious to facilitate these tasks.

ABS Consulting performed a study to address vessel Inspectability during previous VOTRANS development activities. The main objective of this study was to determine the level of cargo tank monitoring and inspection that would be required to provide a targeted reliability level. The starting point for this effort was a Vessel Inspectability workshop involving experienced mariners, ABS surveyors, and appropriate discipline engineers. The result is a Preliminary In-Service Inspection Manual. The Survey department of ABS also participated in the study and helped to generate a nominal In-Service Inspection Plan (ISIP) that will be the baseline for operating safety for any CNG transport project.

The arrangements of the cargo cylinders in the holds have been established through the inspectability assessment to ensure that surveyor/inspector access meets industry standards. Spacing of cylinders in the cargo holds has attracted considerable attention in design and study efforts to date. Even though there is no intention to repair cargo cylinders once the ship is in service, comfortable access to piping (esp. liquid manifolds) is also an important aspect during construction and in service.

A key feature of EnerSea's plan to ensure integrity of the gas containment system throughout the service life of each GPSS is the implementation of real-time, full-time Acoustic Emissions (AE) monitoring throughout. Every cargo manifold and a large statistically-determined number of the cargo cylinders will be wired with AE sensors. While in service, each ship will be acquiring continuous AE registration that will be compared against baseline AE "signatures" that were acquired during construction and commissioning. AE technology allows the onboard and shore-based operators (and through satellite connections, staff in headquarters) to track the evolution of fatigue damage in the cylinders and piping by "listening" to fatigue cracks growing. Steel structures fatigue and, in doing so, emit very high frequency signals which can be tracked to

assess structural integrity in detail. The application of AE technology is an important feature in EnerSea's plan to ensure the safety of the ships at all times.

With sensors distributed on manifolds, the AE can locate any significant fatigue crack development in every piping segment and at the ends of the CNG cylinders (far enough to "hear" well beyond the first girth weld). A strategic number of cylinders (probably 5 or 6) per tank will have at least one sensor placed on its mid-body to provide complete lineal coverage on about 10% of the cylinders onboard each ship. Every tank on a V-ship will be instrumented for AE monitoring with additional sensors distributed on the main piping and manifolds as well.

Since the CNG containment system is required to meet a very stringent probability of failure (POF) criteria by either ABS or DNV code, EnerSea undertakes a fully probabilistic approach to confirm compliance. AE monitoring complements a cylinder (& containment) design approach that targets the confirmation of a POF that is lower than the POF for gas ships already in service (for example, LNG and LPG carriers). The cylinders are designed to meet the POF target without ***any*** dependence on AE. Even if EnerSea's ship designs depended on AE to achieve or comply with the targeted POF, it is not necessary to deploy sensors on every cylinder. On the GPSS for this project, EnerSea would plan to instrument both top and bottom manifolds with AE sensors such that ***all*** cylinders on the ship will be monitored. Sensor placement would allow operators "to see" all of the manifold piping on every tank and past the first girth weld of each cylinder. Therefore, even without distributing any sensors on any of the cylinders, we would be able to inspect all of the most critical locations all of the time (24/7/365) by passive listening. Such a comprehensive inspection capability can be included in the fully probabilistic quantification of POF. The "extra" surveillance/inspection capability offered by AE provides extra layers of security against any form of fatigue failure because the AE systems can detect active cracks long before they become "critical".

8.3 Vessel Operations Management

8.3.1 Shore Organization

The CNG Technical Team (TCNG) in "K"Line will be responsible for the management of the maintenance and repair work of the Vessels. The Chief Technical Superintendent of TCNG will provide proper instructions to Technical Superintendents and the Vessel Master to carry out scheduled/ad-hoc maintenance work in accordance with the manual and procedures in "K"Line Safety Management System (KSMS) The general manager of "K"Line's Marine Safety Administration Group supervises the TCNG.

8.3.2 Vessel Crewing Policy

"K"Line's crewing policy is implemented to achieve safety of ship operations, cost competitiveness and compatibility placing utmost importance on the safety of ship operations. "K"Line will ensure that the vessel is manned with officers, engineers and ratings of the complement and nationalities as stated in this section.

8.3.2.1 Crew Management

"K"Line will ensure that ship crew will consist of a full complement of suitably qualified and experienced personnel. The Master, Officers and Ratings are provided for the Vessel, each of whom will be trained to operate the Vessel and equipment competently and safely at all times in accordance with good international ship management practice.

There will be on board at all times, personnel with a good working knowledge of the English language, to enable cargo operations at loading and off-loading site to be carried out efficiently and safely.

Additionally, all personnel onboard will have a good working knowledge of the customer's applicable standards and procedures for their respective areas of responsibility, and will be trained accordingly.

8.3.2.2 Crew Training

K-Line has developed a preliminary crew training and orientation plan. "K"Line will provide three Instructors, consisting of a Captain, Chief Officer and Chief Engineer, to investigate and prepare training materials for the CNGC training programs. These personnel will establish a special training course including the cargo-handling simulator for the Vessels. This program should commence about three years prior to the Vessel delivery.

"K"Line has maritime training facilities, specifically focused on gas shipping in Japan and the Philippines. K-Line will utilize its training facilities for the project, and costs for such training have been included in the operational cost estimates and resultant tariffs.

8.3.2.3 Crew Familiarization

"K"Line will arrange the appropriate officers, engineers and ratings to attend the Vessels during the final stage of the construction period, in order to familiarize them with the vessel and all gas systems, and to finalize operations manuals for the Vessel in service.

In addition, during this period, all officers, engineers and ratings will attend the above-mentioned training course provided by "K"Line, APL and any other manufacturers.

8.3.2.4 Certificates

All personnel onboard will hold valid licenses and certificates of competence, and endorsements where applicable, in accordance with the requirements of the law of the flag State [and port states]. In this project, it is assumed that the flag and port states will be Canada.

8.3.2.5 Crew Change Interval

The interval of crew alternation is normally dependent on the regulation of each Seaman's Union that seamen are affiliated with.

8.3.2.6 Crewing

Manning levels and full crew complement for the Vessel will be reviewed and approved based on the automation level of the machineries and the volume of maintenance work during the service.

8.3.3 Crew Complement

Canadian regulations require Canadian Officers and Ratings. "K"Line proposes a total of seven Ratings for the cargo part of the Vessels to allow three shifts a day during cargo loading/offloading operations and a day shift while the Vessels are at sea, in accordance with the International Ship Management and Operation Practice.

Officers	No.	Nationality	Duties
Master	1	Canadian	Commander of the Vessel (Master is to become certified as local pilot)
Chief Officer (Cargo Officer)	1	Canadian	Supervision of cargo handling, shipboard operation, maintenance work and personal management, DP monitoring during Loading,
First Officer	1	Canadian	Watch keeping of navigation and cargo operation
Second Officer	1	Canadian	
Third Officer	1	Canadian	
Chief Engineer	1	Canadian	Supervision of overall engine machinery and cargo handling equipment
First Engineer	1	Canadian	Engine watch
Second Engineer	1	Canadian	
Third Engineer	1	Canadian	
Jr. First Engineer (Gas Engineer)	1	Canadian	Supervision of overall cargo handling equipment, including AE systems and maintenance
Jr. Engineer (Gas)	2	Canadian	Shipboard O&M for cargo equipment including AE systems
Electrician	1	Canadian	Shipboard operations both engine and cargo part
Total	**13**		
Ratings	**No.**	**Nationality**	**Duties**
Bosun	1	Canadian	Maintenance work and cargo operation
Able Seaman	3	Canadian	Navigational watch and cargo operation
Ordinary Seaman	3	Canadian	Maintenance work and cargo operation
No.1 Oiler	1	Canadian	Maintenance work
Oiler	2	Canadian	Engine watch
Wiper	1	Canadian	Maintenance and cleaning work
Gas Oiler	3	Canadian	Engine Watch – Cargo
Chief Steward	1	Canadian	Catering service
Cook	2	Canadian	Catering service
Boy	2	Canadian	General service
Total	**19**		
Grand Total	**32**		

8.4 Scheduled Inspection and Dry-Docking Programs

EnerSea will work with the field operator and or EnerSea's client, Class, and regulators to schedule planned dry-dockings (4-5 weeks every 5 years) during periods when the field production facilities are undergoing annual shutdowns. Additionally, dry-dockings for fleets can be staggered to minimize the impact on field production.

8.4.1 Maintenance, Dry-docking and Inspection

EnerSea and "K"Line have developed the principles of maintenance management for the CNG ships that addresses the following issues:

- frequency and durations of dry-dockings
- purchasing and materials/equipment management system
- survey of yards suitable for dry-docking and major repairs
- type and arrangement of major equipment covered by in-service inspection and maintenance plans

Budgetary costs for in-service inspection and maintenance plans were estimated as a part of the operating expense and included in the Commercial section herein.

8.5 Sparing Philosophy

EnerSea has developed a sparing philosophy that will be applied to all projects.

8.5.1 Deployed Spares (on ship)

In general, the following equipment spares will be located onboard the ship for immediate use for emergency repair or maintenance:

TABLE 9 - EQUIPMENT SPARING GUIDELINES

EQUIPMENT TYPE	SPARING and CONFIGURATION GUIDELINE
Small Compressors (< 1500 hp)	2 X 100% units
Large Compressors (1500+ hp)	Multiple units with no spares
Pressure Vessels	No spares required.
Tanks	No spares required.
Filters	Multiple units with one spare
Shell & Tube Heat Exchangers	Multiple units with 10% excess area in each unit
Air Cooled Exchangers	Multiple units with 10% Excess Area In each Unit
Gas Chillers	Multiple units with 10% excess area in each unit
Seawater Supply Pump	Multiple units with no spares
Ethylene Glycol Pumps	Multiple units with no spares
Instrument Air Compressors	2 x 100% units
Nitrogen Generation Units	2 x 100% units (with independent operation assured)
Vent Scrubber Pump	1 X 100% units with no spares
Sump Pump	1 X 100% units with no spares
Slop oil transfer pump	1 X 100% units with no spares
Oily water transfer pump	1 X 100% units with no spares
Cargo valves and controls	Spares of replaceable components

8.5.2 Warehouse Spares

The following equipment spares may be selected for placement in a warehouse nearby the delivery terminal for delivery to the ships upon port calls for offloading. These spares will be selected, depending on project responsibilities and consequences of complete service interruption for extended periods.

- Major ship systems equipment/components as determined to require long delivery times for replacement (to be studied in detail during FEED)
- Mooring elements (one spare line and anchor; no spare buoys)

8.6 Mitigation Solutions for Unplanned Service Outrages

EnerSea has evaluated available solutions in the event of unplanned service outage. EnerSea considers that such service outages fall into two general and different categories – short term and long term events – and each of these has its own set of possible causes, responsibilities, and resulting costs, liabilities and potential mitigation procedures and remedies (both technical and commercial). There are project risk issues across the full value chain which may create such events, beginning at the supply reservoir itself, and risk mitigation strategies for potential events and their disruptions have been considered and included. Note that EnerSea is not proposing any measures at this time for reducing or eliminating any upstream or downstream causation of such disruption, but rather to consider ways in which deliveries may continue with no or minimum interruption. A discussion of each of these short and long term outages follows:

8.6.1 Short Term Outages (6 to ~72 hours)

- Causes: bunkering problem; small ship repair; minor terminal problem; gas supply (field / platform / pipeline) disruption; severe weather system.
- First line of defense: Planning & coordination. Communications procedures will be established such that as soon as any *potential* problem is identified, then the Project operator will be alerted, as well as any other relevant supply chain operators who may be able to assist with the issue. EnerSea's Project Operating Plan will have contingency plans in place, including training of crews and onshore support personnel, to anticipate and mitigate the potential event.
- System spare availability: EnerSea has included additional storage capacity in the fleet to provide additional flexibility and logistical support for project operations and to minimize potential disruptions. An additional 11% excess ship capacity has been included in the ship design that ideally could allow up to 21 hours overlap per vessel journey. This margin is intended to allow the transporter to contend with weather (winds, currents, etc.) factors, loading and unloading issues and minor equipment problems, etc. However, this same margin may be available to assist with events that might otherwise cause a disruption in deliveries.
- Spare ship propulsion: In addition to the above marine-based spare capacity, EnerSea has also designed its propulsion system to allow short duration increases in excess of 16 kts in good weather (i.e., the propulsion plant is designed to use only 80% of available

power to make 16kts in rough weather). This extra "speed on demand" will also allow greater flexibility and the ability to further reduce delivery disruptions.

- Spare loading and offloading capacity: EnerSea have designed the ship to handle up to 300 Mscfd for both loading and offloading loading and unloading operations. During the initial production phase (200 Mscfd), this additional capability will allow the GPSS to receive higher rates of gas from the field, or discharge higher rates of gas in the offloading terminal, and this flexibility may be valuable in helping to "catch up" in case of an event. This feature will be particularly effective in conjunction with any spare reservoir deliverability or linepack storage capacity that may be available at the respective loading and unloading terminals (see below).
- Reservoir storage: The FPSO can continue to inject gas into the reservoir whenever the GPSS units are unable to take gas from the field.
- Linepack capacity: The MNP spur pipeline is a potential source of linepack capacity. The design of this pipeline (diameter, operating pressure, compression, etc.) should be investigated during FEED to determine what optimum level of linepack should be built into the system. This feature could add significant flexibility to offloading operations and thus enhance the overall shipping logistics.
- Coordination of scheduled outages (FPSO and transport service): Planning and coordination of activities throughout the gas supply chain is a prudent operational practice, and one in which all members of the chain should see value. Being able to combine maintenance and repair activities (whether small repair requirements or major plant turnarounds/dry docking) will optimize delivery performance.

8.6.2 Longer Term Outages (longer than ~72 hours)

- Causes: larger ship repair; major terminal problem; substantial gas supply (field / platform / pipeline) disruption; major upstream or downstream maintenance turnaround; scheduled ship dry docking.
- First line of defense: Planning and preparation, as above.
- Similar series of mitigation solutions for short term outages, as above.
- Coordination of scheduled outages (e.g. with FPSO scheduled downtime; dry dockings)
- Planned reduction in capacity: if a longer term disruption is inevitable for any reason, EnerSea's transport operations can still deliver continuous volumes of gas, at reduced levels.
- Additional storage (VOLANDS, linepack): As mentioned above, additional storage capacity may be available through expanding the process and storage capabilities of the VOLANDS storage facility, as well as further exploitation (as possible and viable) of the downstream pipeline infrastructure for linepack storage utilization.

9. REGULATORY ISSUES

There are many regulatory and maritime authority approvals that will be required as this project moves forward. This section documents the understanding that EnerSea has developed to date.

9.1 GPSS Shipping Requirements: Maritime Authorities

Because ABS has taken the lead in establishing a solid foundation for acceptance of the new technology with North American regulatory bodies, EnerSea has specified that the Grand Banks GPSS ships will be built to ABS Class in accordance with their recently issued Guide for CNG Carriers (2005). ABS reviewed the V-ship design for the White Rose project in 2004 and confirmed that the design was aligned with the Approval in Principle issued in 2003.

9.1.1 Ship Classification: ABS

ABS accepted for Class-AIP (Approval in Principle) EnerSea's VOTRANS CNG Carrier based on the review of the submitted documentation and interaction with EnerSea in April 2003, provided certain issues were adequately addressed during future design stages and prior to obtaining vessel classification.

ABS Approval in Principle is a process by which ABS issues a statement that the proposed novel concept design complies with the intent of ABS Rules and IGC as applicable, subject to specified conditions. In order to achieve the Class-AIP, the proponent must identify all hazards related to the concept and compare them with existing marine practice to show that the risk created by novel concept is comparable to existing marine practice and would not pose any additional hazards.

ABS determined that EnerSea's design complies with ABS rules and IGC and that the VOTRANS carrier could receive a class certificate in accordance with ABS class rules when built.

EnerSea and its ship operator ("K"Line) have been investigating certain regulatory issues, such as class and Flag State approvals, in an ongoing process to develop our CNG capabilities. In particular, we have been engaged with key classification societies (esp., ABS) and prospective Flag States (e.g. Panama, Jamaica, Bahamas, etc.) for several years to advise them of the design and operational aspects of our CNG transport projects and to receive their regulatory guidance.

9.1.2 Canadian Maritime Authority

EnerSea does not expect any extraordinary challenges in gaining acceptance from Canadian maritime authorities. We have been in frequent communication with lead responsible representatives of Transport Canada over the past few years. In 2004, representatives from EnerSea and K-Line met with the regional technical lead, Mike Dwyer, to discuss his agency's oversight role. While no immediate "hard barriers" were noted, Mr. Dwyer was relatively non-committal as to the exact form of oversight and approval to be established. However, he acknowledged that the proactive track that EnerSea has adopted in communications with regulators and in developing/promoting the International Marine CNG Standards Forum has

greatly improved their ability to prepare for the tasks ahead. A process and schedule for review, construction oversight, and approval will be obtained from Transport Canada during the pre-project development phase in anticipation that the GPSS will be operating in Canadian waters under Canadian flag.

Mr. Dwyer has also confirmed that the competent technical approach adopted by ABS in creation of their Guide for Marine CNG is establishing a solid foundation for global acceptance of the new technology. This does not mean that Canadian regulators will accept ABS approval as the final word even though the technical resources at Transport Canada are somewhat dependent on external competence. Mr. Dwyer is aware that ABS and EnerSea are establishing the basis for design and ship approvals in recognition of the Formal Safety Assessment (FSA) guidelines from IMO. Transport Canada will be responsible for presenting the FSA to the world maritime community for any new technology introduced on the high seas through Canadian flag operations.

It may be expected that the vessel approvals will be handled under the delegation to class procedures agreed between Transport Canada (TC) and ABS for Convention ships. In these circumstances, ABS will undertake all plan approvals and construction inspections subject to TC audit. TC will require to “K”Line to perform a 'first inspection' of the vessel on arrival at the Canadian home port (or first port of arrival). The vessel will then revert to the delegated inspection for ongoing certification, as now seems to be the case for the Hibernia shuttle tankers.

In practice, there will almost certainly be some additional oversight by TC due to the unique nature of the vessel. Any risk assessments or variants to normal ABS rules will need to be agreed in advance by TC and potentially authorized throughout the mechanism of Decisions by the Board of Steamship Inspectors in Ottawa. It is seen as critical that TC representatives get motivated early and significant levels of interaction with ABS commenced in establishing TC’s acceptance of the ABS CNG Guide as a sufficient standard for ship approval in Canadian waters. Such motivation is likely to require substantial involvement and encouragement by Nalcor and the field operator and partners.

There is additional complexity due to the current status of the reform of the Canada Shipping Act, which was re-promulgated in late 2006. This affects a number of regulations, e.g. fire protection and lifesaving equipment. There will be a need to agree the regulatory basis for the design depending on the scheduling of keel laying and contract award. Recent precedent suggests that a 'build to SOLAS' philosophy will be accepted as a design philosophy, with additional Class and TC requirements to supplement areas in which SOLAS is silent or vague.

Although CNLOPB will have a keen interest in the viability and safety of the gas export technology, it is expected that Transport Canada will be recognized as the lead agency.

9.1.3 Canada Shipping Act

CNG shuttles will be required to comply with all requirements of the Canada Shipping Act, including such environmental aspects as disposal of bilge water at approved, designated disposal stations.

The Canada Shipping Act applies to all vessels in Canadian waters, with the exclusion of those powered by oars, and enables establishment of several regulations related to shipping in Canadian waters. These regulations include vessel traffic services areas, oil pollution prevention and safety work practices aboard vessels.

- Garbage Pollution Prevention Regulations prohibit the discharge of garbage including solid galley waste, food waste paper, rags, plastics, glass or similar refuge.
- Oil Pollution Prevention Regulations stipulate the requirement for installations capable of retaining oil residues on board for subsequent discharge to a reception facility and equipment that meets oily mixture discharge requirements as set out in the act. The fact that the GPSS vessels will be powered by cargo gas, rather than heavy fuel oil, will help to greatly reduce the potential likelihood and consequence of any spillage of such bunker oils both from the onboard storage/handling and also from bunkering operations which will be minimized. Air pollution emissions will also be greatly reduced due to the burning of relatively clean natural gas versus liquid bunker fuels.
- Pollution Prevention Regulations prohibits the disposal of pollutant substances identified in the regulations.
- Vessel Traffic Service Zones Regulations stipulate the requirements for communication with and adherence to marine regulators while navigating in applicable zones.

9.2 At Field and At Shore Regulatory Requirements

EnerSea Canada commissioned Jacques Whitford Limited (JW) to update its Regulatory Roadmap, which investigates the regulatory requirements of implementing long term deliveries of compressed natural gas (CNG) from gas reserves at White Rose to prospective gas delivery points along the eastern coast of Canada.

With respect to Project work at the Grand Banks field, the Canada-Newfoundland Offshore Petroleum Board (C-NOPB) may decide that the proposed Project is either a new development (which would require its own Development Plan) or a satellite development to the previously reviewed development, in which case, an amended Development Plan might be required.

The following regulatory agencies may have a mandated obligation with respect to the environmental regulatory review of the Project:

a) C-NOPB (Newfoundland and Labrador jurisdiction) – Atlantic Accord Act:
An amendment to the White Rose Development Plan may be required; amendments to other volumes of the Development Application may be required. The C-NOPB may be required to serve as a Responsibility Authority (RA) if a Canadian Environmental Assessment Act (CEAA) trigger applies and an environmental assessment is required pursuant to CEAA.

b) Canadian Environmental Assessment Agency – CEAA (Newfoundland and Labrador, and Nova Scotia jurisdictions):
In Newfoundland and Labrador, a Screening level environmental assessment may be required, depending on the determination of a trigger, or if a trigger doesn't exist, an addendum to the existing Comprehensive Study may be required, and

In Nova Scotia, a Comprehensive Study (or Panel) may be required;

c) National Energy Board – National Energy Board Act;

d) Transport Canada – Navigable Waters Protection Act (NWPA) (Nova Scotia jurisdiction)
Transport Canada administers Navigable Waters Protection Act permit requirements. If a Navigable Waters permit is required, Transport Canada will likely be an RA due to the NWPA trigger under CEAA. Transport Canada also administers TERMPOL (Chair of TERMPOL Review Committee)

e) Fisheries and Oceans Canada – Fisheries Act (Nova Scotia jurisdiction)
DFO administers the No Net Loss Fish Habitat policy pursuant to Section 35 of the Fisheries Act, and will be involved in negotiations for compensation for any harmful alteration, disruption or destruction of fish habitat. DFO will likely be an RA due to potential Fisheries Act trigger under CEAA;

f) Environment Canada – Canadian Environmental Protection Act (CEPA) and Fisheries Act (Nova Scotia jurisdiction)
Environment Canada administers the Ocean Disposal Permit requirements. Environment Canada will likely be an RA due to the potential CEPA trigger under CEAA. Environment Canada also administers Section 36 of the Fisheries Act, which prohibits the deposition of deleterious substances in fish-bearing waters.

g) Government of Nova Scotia (various departments and the Nova Scotia Utility Board).

JW completed a preliminary evaluation of the regulatory issues and provided an overview of the environmental regulatory requirements within Canada for this Project as included in Appendix 13 herein.

Appendix 1
Basis of Design

Appendix 2
Abbreviations and Acronyms

Appendix 3
Project Risk Assessment Summary
DNV

Appendix 4
Master Schedule

Appendix 5
Pre-Project Development Plan

Appendix 6
Subsea System Concept Report
JP Kenney

Appendix 7
SLOOP Report

Appendix 8
GPSS General Arrangement

Appendix 9
Process Flow Diagrams from HYSYS Models
Production Loading & Offloading
Gas Plant

Appendix 10

Site Visit Photos – Point Tupper (NuStar Terminal)

Appendix 11
Emco-Wheaton CNG Unloading Arms

Appendix 12
HAZID Register – Grand Banks

Appendix 13
Regulatory Roadmap