Technical Feasibility of Offshore Natural Gas and Gas Liquid Development Based on a Submarine Pipeline Transportation System

Offshore Newfoundland and Labrador

Final Summary Report

Submitted To:

Government of Newfoundland and Labrador
Department of Mines & Energy
Petroleum Resource Development Division

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1 EXECUTIVE SUMMARY

This report summarizes the Gas Pipeline Study conducted on behalf of the Government of Newfoundland and Labrador, Department of Mines and Energy. The work involved a detailed review of the technical and economic aspects of developing the offshore natural gas and associated liquid resources of Newfoundland and Labrador. The study focussed mainly on the gas and gas liquids of the Grand Banks area, the pipeline option for commercially developing the resources and the utilization of the gas for power generation on the island of Newfoundland.

A detailed scope of work was presented both in the Department of Mines and Energy (2000) Request for Proposal and the proposal submitted by the Pan Maritime - Kenny, IHS Energy Alliance (2000). The study was broken down into several major components as follows:

Task	Description	Responsibility
1	Resource Evaluation	Well Service Technology
2	Iceberg Risk and Routing Considerations	C-CORE
3	Pipeline Design and Cost Estimate	Pan Maritime-Kenny (PMK)
4	Facilities Cost Estimates and Economic Analysis	IHS Energy Group Economics and Consulting

The work of the study concludes that the natural gas resources evaluated can be developed economically using a pipeline system to export gas from offshore Newfoundland to Eastern Canada and on to the US. A sustainable production rate of at least 700 million standard cubic feet per day is required in order to maintain the economics of the system. The extent and availability of the resources identified in the study must be confirmed prior to beginning any pipeline project, especially those in the North White Rose field, and a basin-wide co-operative approach will be necessary for economic resource development.

The study further concludes that the optimum route for the gas export pipeline from the Grand Banks into Bull Arm is a northern route into deep water (> 200 m) and then an overland route to Come by Chance. The export pipeline route to the US would be a subsea route from Come by Chance into Country Harbour, Nova Scotia and then an onshore route paralleling the existing Maritimes & Northeast pipeline route into Boston.

This report presents an overview of each of the components, presents major conclusions and recommendations, and discusses requirements for further work that will need to be conducted to develop natural gas and make the construction of a subsea pipeline transportation system offshore Newfoundland a reality.

2 INTRODUCTION

The main objective of this study was to establish if the development of natural gas from the Jeanne d'Arc Basin via a marine pipeline was technically and economically feasible and under what conditions. The area is principally an oil prone area and thus the development needs to take due consideration not to compromise oil recovery at the expense of gas extraction.

The following primary (oil) fields were included in this investigation:

- Hibernia
- Terra Nova
- White Rose
- Hebron

In addition, certain secondary fields (via tiebacks) were included to extend the life of the primary field extraction and enhance a 15-year gas production life, thus justifying the installation of a pipeline export system. The secondary fields considered were as follows:

- North Ben Nevis
- North Dana
- South Mara
- Springdale
- Trave

In all 5.34 trillion cubic feet (TCF) of gas was considered to be technically recoverable for the purposes of this study. However, once field development and operating costs were considered 4.82 TCF of the resource is economically recoverable as summarised in Table 2.1.

Table 2.1 Total Gas Resource and Economically Recoverable Resource by Field

	Gas Resource	
Field	**Total**	**Economic***
	(BCF)	**(BCF)**
Hebron/Ben Nevis	390	108
Hibernia	1404	1404
North Ben Nevis	134	134
North Dana	481	481
South Mara	150	150
Springdale	241	103
Terra Nova	264	264
Trave	31	0
White Rose	2246	2178
Total	**5341**	**4822**

The study determined that the sustainable economic natural gas extraction rate needed to support the gas development was not less than 700 million cubic feet per day (MMscfd) through a 36" pipeline. This rate gave sufficient cash flow to justify the development and a long enough period to be able to amortise an export pipeline system. A pre-tax internal rate of return (IRR) hurdle rate of 20% was used for each field development to determine if the project could proceed. As a result, development of the Trave Field was excluded from all the cases.

The economics were run for the **Oil Only Scenario** and then as a combined **Oil and Gas Scenario** for each gas development case. The difference between the two scenarios gave us the viability for gas development.

For each first gas sales date (2005, 2010, and the 2015) gas development scenarios were created for each field. The scenarios were based on the recoverable resources, production profile, production facilities, method of development and timing. Although field economics benefit from earlier start dates because of discounting with time, the fields were burdened with lower production rates because of oil development priorities and forecast lower gas prices. The economic analysis should be revisited, subsequent to this report, as current information on oil and gas resources and development methods become available.

In reality, outside influences such as the US natural gas market, the timing of competing projects to supply that market, and the changes in demand due to the limited supply of gas over the next 5 years will be the controlling influence. Put another way, if the market does not perceive the gas supply at a "reasonable price" will be available, capital investment decisions will permanently change the natural gas demand outlook – i.e. a move to coal and nuclear for power generation, industrial users relocate to countries with lower energy prices. Also, as the industry continues to drill in the basin it is also likely more gas resources will be discovered between now and the decision to proceed with natural gas development in Newfoundland.

The principal conclusions for this study are as follows:

- The natural gas resources defined in this study are economic to develop using an export pipeline to Eastern Canada and the US even with a reasonably conservative (low) commodity pricing scenario.
- The sustainable economic natural gas production rate needed to support gas development via a marine pipeline is not less than 700 MMscfd.
- Before any pipeline project could proceed, the resources identified need to be confirmed. The most important of these being the resources in the North White Rose Field since the field accounts for over 40 percent of the resources included in the study.
- To date there is no single known field with gas resources large enough to support the cost of installation of a marine gas pipeline from the Grand Banks to markets in Eastern Canada and the U.S. So the natural gas development will need a basin-wide co-operative approach.
- Delivery of gas for domestic use for power generation, industrial, commercial, and residential is not economically feasible without integral development for delivery to Eastern Canada and the US. This is due to the small size of the potential domestic market and the resulting high unit cost of bringing the gas to shore combined with the cost of installing a gas pipeline from the Grand Banks to Come-by-Chance.
- Based upon the length of time it takes to confirm resources, plan and implement a co-ordinated natural gas development project, 2005 in not a realistic first gas date. A start date of 2007 or 2008 is likely to be the earliest practical time.
- The timing of other major projects to deliver gas into the US should be considered when finalising the first gas date.
- Discovery of additional non-associated gas will improve the economics of development of the natural gas resources and accelerate the timing.

3 METHODOLOGY

3.1 General

To date, only one field – Hibernia – has been brought into production offshore Newfoundland and Labrador. Hibernia came on-stream in November 1997. Terra Nova is currently under development and is due to begin production during the second quarter of 2001. A third field, White Rose, has a first oil target in late 2003 – 2004. There have also been numerous other discoveries.

As indicated in the Well Service Technology (2000) report, summarised in Appendix 1, offshore development has focused on the area's oil resources, primarily due to the lack of gas infrastructure. It is however, the purpose of this report to determine the economic feasibility of developing the gas resources based on a submarine pipeline transportation system.

For the Base Reference Case gas sales are projected to start in 2015. This assumes that gas will initially be utilized to enhance oil production (see Well Service Technology (2000) for detailed analysis of reservoir characteristics and production scenarios). The year 2015 was selected as the Base Case during the resource evaluation as this was the basis for no loss of oil production. **For the rest of the report the 2015 first gas production case will be referred to as the Base Case**. Other earlier gas cases (2005 and 2010) were evaluated but only the 2010 Case is reviewed in this report to assess the advantages and challenges compared to the Base Case. Discussion of the 2005 Case is omitted since it is not a practical possibility from the standpoint of the time required to design and build the pipelines and develop the fields to begin gas sales.

3.2 Objectives

The objectives of this study encompass the analysis of various Grand Banks natural gas resource development schemes, including methods of processing, transporting (via pipeline) the gas to market and the demand for such gas while maximising the recovery of the crude oil resource.

3.3 Discussion

For each of the major fields – Hibernia, Terra Nova, White Rose and Hebron - scenarios were developed for both oil and gas production following the production profiles developed prior to economic analysis and described in the Well Service Technology (2000) report. For each of the major field developments, the base option calls for oil to be the primary focus with gas re-injected. Gas sales production is secondary to maximising recovery of a field's oil resource. Two options were considered for the gas production:

- **Full Gas Processing** Offshore, sending "commercial specification" gas to the onshore terminal at Come by Chance.
- Partial gas treatment offshore sending **Dense Phase** gas to Come by Chance for onshore processing.

Onshore Gas Processing involves both the dehydration of the gas, so gas hydrates do not form in the export systems, and "hydrocarbon dew pointing" to a point where hydrocarbon liquids do not drop out in the export pipeline systems. Any liquids removed on the platform are assumed to be spiked into the crude oil for export. Additional gas liquids could be extracted onshore, if deemed economic, before the gas is sent to the local market, the Canadian maritime provinces, or the Northeast United States.

Dense Phase export involves dehydration offshore then compression of the gas to a pressure that the fluid in all points in the pipeline system are maintained above the hydrocarbon dew point.

The prefered process can only be decided once one knows the reservoir characteristics and compositions of the natural gas from **all** the fields.

The **Dense phase** option has some advantages with respect to landing a "wet" gas onshore for recovery of natural gas liquids (NGL's), should there be a local market. The disadvantage of this option is the pipeline must be operated at a higher pressure (more expensive) and has to have substantial liquids receiving facilities (slugcatcher) to cope with operational interruptions of the pipeline. Furthermore it requires a totally co-ordinated approach to development and control operations as all primary field owners will have to keep the gas in the dense phase, whatever the composition of the well fluids and whatever operational difficulties they might be facing. This is quite different to the operational approach of oil production platforms where downtime is not a serious problem as it can be made up through increased production later. Most Natural Gas contracts do not deem this to be acceptable for uninterruptible supply.

In **Offshore Gas Processing** the variations in operations and well fluids can be catered for and the primary field operation requirements are much more flexible, a more acceptable situation considering most of the fields are oil production facilities. This allows significant variations in the future fields developed as seems evident in fields found to date. The four primary fields range from heavy, to medium gravity oil to gas condensate deposits.

For these reasons **Offshore Gas Processing** with no additional onshore hydrocarbon processing has been chosen as the basis of this study and all results presented in this report reflect that option. This decision in no way mandates the final choice and is purely chosen to be a conservative workable option.

Other variations evaluated include:

Hibernia – gas exports were modelled via a northern or central (Newfoundland) pipeline route as the main options available to land gas in Newfoundland (Figure 3.3.1). Only the Northern Route costs are presented in this report since that is the route C-CORE identified as the best option, in terms minimising the risk of damage from iceberg scour, at justifiable additional cost.

Many different development options were screened for the fields, including floating production storage and offloading (FPSO) vessels, gravity based structures (GBS's) and sub-sea tiebacks.

Four fields were considered primary fields while all other fields, apart from the Laurentian Sub-basin prospects, were developed as tiebacks to primary fields and thus are considered secondary fields.

Six additional (secondary) fields have been assumed developed via a tieback to one of the primary fields. These include:

- North Ben Nevis to Hibernia (Base and 2010 Cases)
- Ben Nevis/West Ben Nevis to Hebron (Base Case) to Hibernia (2010 Case)
- North Dana to White Rose (Base and 2010 Cases)
- South Mara to Hibernia (Base and 2010 Cases)
- Trave to White Rose (Base and 2010 Cases)
- Springdale to Terra Nova (Base and 2010 Cases)

A full review of tiebacks is explained in the Well Service Technology (2000) report and varies according to the gas case used to best fit the production limitations selected in this study.

Semi-submersible and FPSO options were also considered for North Dana but are not presented here.

For the secondary fields, development scenarios were based upon development of gas and condensate production.

The following options and processing capacities are presented in this report:

- Base Case (2015)
- 2010 Case
- 2005 Case
- 2010 Case with Laurentian Sub-basin prospects

It should be noted that the options presented in this report reflect credible and consistent options. The selections do not reflect the optimum or actual method to be used for development.

The final choice of development is a complex choice and will be based upon much more information, data and additional work that needs to be performed by the operators, not least of which is confirmation of the natural gas resources, reservoir and fluid data from additional exploratory and appraisal wells.

The Hibernia project started development in 1993 with first production in November 1997. The platform consists of three separate components: topsides, gravity base structure (GBS) and an offshore loading system. The topsides consists of five modules which accommodate all of the drilling and producing equipment as well as all of the living quarters for approximately 185 staff. These five modules include process, wellhead, mud, utilities and accommodations.

A gravity-based structure constructed of concrete supports the topsides. It has a storage capacity of 1.3 MMBBL of crude oil and was specially designed to withstand the harsh environment of offshore Newfoundland, allowing for year-round operations.

The offshore loading system is used to transfer oil from the platform to shuttle. A second, completely duplicate system provides backup if needed.

Terra Nova is the second field (as well as the second largest oil field to be discovered off the Grand Banks) being developed offshore Newfoundland. Terra Nova is being developed with a floating production, storage and offloading (FPSO) vessel with first oil modelled to start during late second quarter of 2001. More recent announcements indicate first oil production will be delayed to the end of 2001.

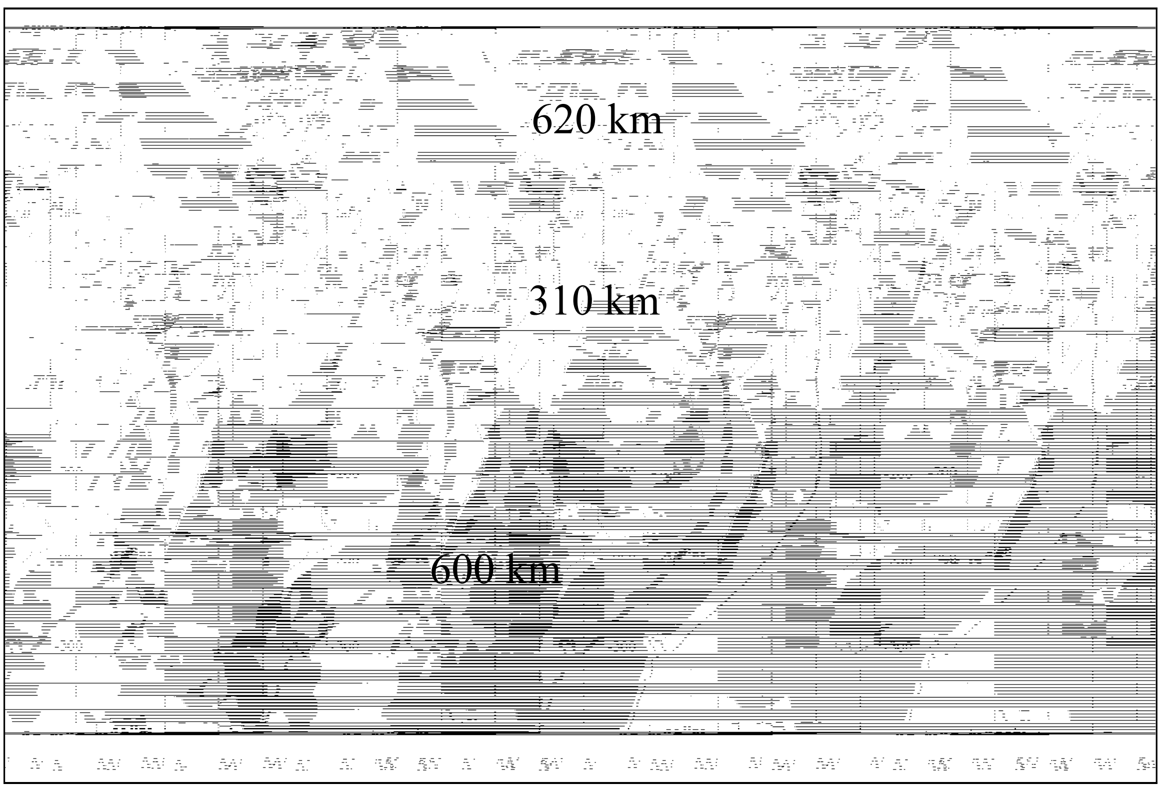
White Rose will likely be the third development offshore Newfoundland and Labrador; first oil is expected in 2004. Operator Husky has selected an FPSO similar to that being used for Terra Nova as the preferred method for phase 1 (oil development).

Based on the pipeline risk analysis due to iceberg scour conducted by C-CORE, which is presented in C-CORE (2000) and summarised in Appendix 2, three routes were considered to transport gas from the Grand Banks fields to Newfoundland, as shown in Figure 3.3.1:

- The 620 kilometre (km) **Northern Route** is protected by deep water and requires limited trenching. This route was considered by C-CORE to be the preferred route due to the significant amount of trenching required along the two other pipeline routes.
- The **Central Route** is shorter offshore (310 km) but exposed to icebergs and requires significant trenching.
- The 600-km **Southern Route** has moderate iceberg exposure and requires significant trenching.

The above listed pipeline lengths are consistent with the C-CORE report using Hibernia as the “head of pipeline” for Grand Banks natural gas development. The reason the Hibernia platform was used was to benefit from the fixed structure that is in operation.

Figure 3.3.1 Preliminary Landing Pipeline Routes Considered



For the main export route options the following pipeline segments were reviewed as shown in Figure 3.3.2.

Overland gas export routes included:

- Come by Chance to Port aux Basques (558 km) -- Route 6
- Sydney to Country Harbour (190 km) -- Route 10
- Country Harbour to Boston (1,100 km) -- Route 11**(Selected as study basis)**

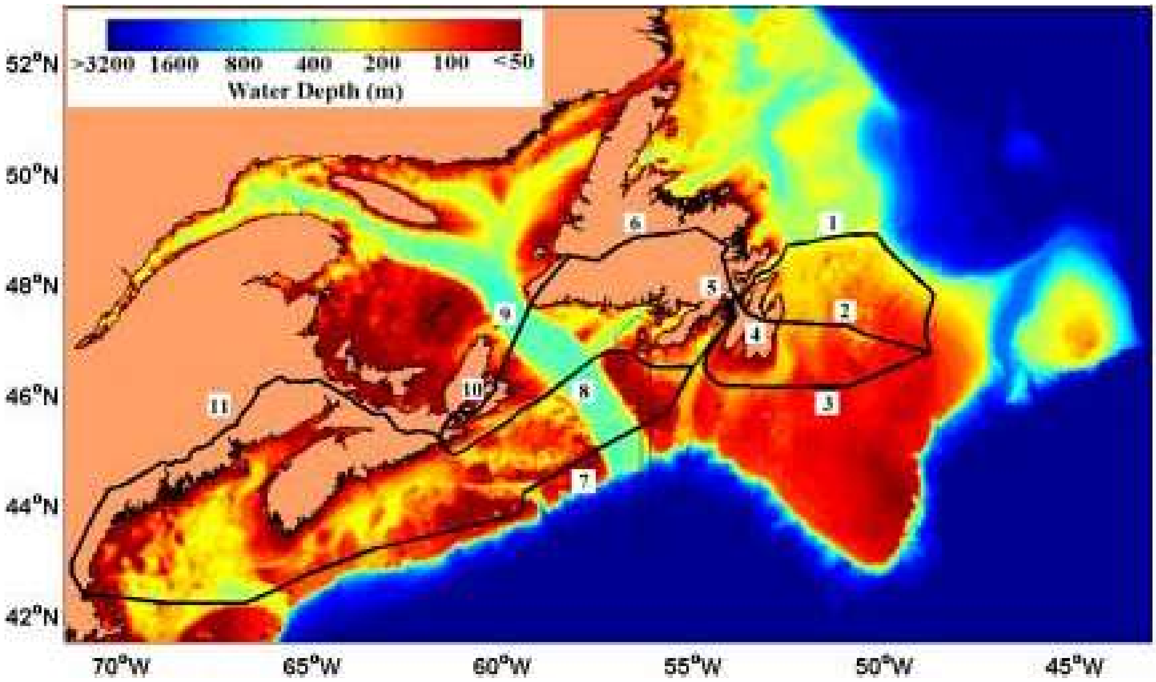
Offshore export pipeline routes included:

- Boston Route (1,620 km) runs from Come by Chance in Trinity Bay down the Scotian Shelf, making landfall at Boston-- Route 7
- Country Harbour Route (771 km) runs from Come by Chance to Country Harbour, Nova Scotia-- Route 8 **(Selected as study basis)**
- Sydney Route (172 km) runs from Port aux Basques to Sydney -- Route 9

The combination of export routes #8 (Come by Chance to Country Harbour) and #11(Country Harbour to Boston) were used in this economic analysis. Although the cost of that export route is estimated by the study group to be $2.9 billion (Canadian), which is considerably more expensive to construct than the direct offshore Come by Chance to Boston line, it was selected for the following reasons:

- The onshore part of the route (#11) follows the existing Maritimes & Northeast Pipeline right-of-way so the regulatory review process and right-of-way issues should be minimal compared to the other routes.
- The onshore route could also provide gas to the Canadian Maritime Provinces.
- The difficulty and cost of the offshore pipeline approach into the Boston area could be much greater than estimated. Regulatory issues or actions could protract the regulatory review of the offshore route by environmental groups.

Figure 3.3.2 Import and Export Route Options Considered



4 COST ESTIMATION METHODOLOGY AND DISCUSSION

4.1 Cost Analysis

4.1.1 Facilities

Costs for offshore and sub-sea facilities and infield and intra-field pipelines were calculated using IHS Energy Group's proprietary software, ***QUE$TOR Offshore***. Costs for the export compression were calculated using ***QUE$TOR Onshore***.

To ensure ***QUE$TOR*** gave credible results in the very unique environment offshore Newfoundland, IHS Energy performed a benchmarking exercise on the cost database and calculated results by simulating the Hibernia and Terra Nova facilities. Additional account was taken of previous work undertaken by the Government and other consultants in estimating likely future GBS costs. The resulting cost estimates calculated were then audited by an independent third party to ensure adequacy, consistency and credibility in the Newfoundland environment.

Significant work was done in estimating the strengthening requirements due to ice and the protection requirements of sub-sea equipment from iceberg scour. Table 4.1.1 provides a summary of the main cost estimates generated by IHS Energy Economics and Consulting Business.

Table 4.1.1 Total Capital Costs Summary

	Total Costs (MM $CAN)			
Case	**GAS (Incremental)**	**Pipeline to Shore**	**Pipeline to Market**	**Terminal**
Hibernia	168.0	794.8	2923.8	69.0
Terra Nova	196.0			
White Rose	1323.0			
Hebron	51.0			
N.Ben Nevis tied back to Hibernia	81.1			
Springdale tied back to Terra Nova	71.9			
South Mara tied back to Hibernia	74.8			
North Dana tied to back to White Rose	112.9			
Trave tied back to White Rose	64.9			
Laurentian - LB01	1068.1			
Laurentian – LB02	834.6			
Laurentian – LB03	1062.4			

Notes: 1. Facilities include drilling, structure, topsides, subsea and intra/inter field flowlines.
2. New well costs included, well conversion costs excluded.
3. Trave subsequently excluded from development consideration.

4.1.2 Pipelines

The Grand Banks to Newfoundland Pipeline and Gas Export Pipelines were estimated separately, details of which are presented in the Pan Maritime - Kenny (2000a) "Cost and Schedule Estimates" report and summarised in Appendix 3. Based on the pipeline routes presented by C-CORE (2000) and the associated cost estimates, the pipeline cost estimates used in the IHS economic analysis are shown in Table 4.1.2.

Table 4.1.2 Landing and Export Pipeline Costs

Route	MM C$
Northern Import Route (Grand Banks to Come by Chance)	**795**
Central Import Route (Grand Banks to Come by Chance)	933
Southern Import Route (Grand Banks to Come by Chance)	758
Onshore Export (Come by Chance to Boston) #6,9,10,11	3824
Direct Boston Export (Come by Chance to Boston) #7 (Excludes landfall costs)	1579
Off/Onshore Export (Come by Chance to Boston) #8,11	**2924**
Laurentian Prospect to Come by Chance	477
Laurentian Prospect to Direct Boston Export #7	50
Come by Chance to Holyrood Spur	128

Notes: 1. Selected routes for the study are in bold. Total cost is $3,719 MM.
2. Excludes terminal cost of $69 MM.
3. All lines are 36" in diameter.

5 ECONOMICS METHODOLGY & DISCUSSION

5.1 Economic Analysis

The economic modelling used in this study was performed using IHS Energy Group's Proprietary software ***AS$ET***.

AS$ET is a portfolio and scenario modelling system ideal for performing complex studies of this sort. Each option for each field can be modelled and the results stored and switched on or off to calculate the results of a multitude of combinations. In this way, once built the model can continuously be updated and options re-analysed with relative ease.

Pre-tax analysis was run for the Base Case, 2010 Case, and 2005 Case. Development of the Laurentian Sub-basin prospects and Trave were excluded from the three cases since they did not meet the 20% pre-tax IRR hurdle rate based upon the development scenarios selected. For all three cases field operation was curtailed using an economic limit triggered by the first year of negative operating cash flow. Table 2.1 shows that 519 billion cubic feet (BCF) or 10 percent of the gas resource is uneconomic to recover. Most of the uneconomic reserves are in the Hebron/Ben Nevis and Springdale fields.

Standard output tables were generated for composing the net present values at various discount rates for all cases and these tables are included in the following text. In addition, sensitivities to net present value were run on prices, capital expenditures and operating costs.

5.2 Initial Modeling Scenarios

During the early stages of this study, seven initial scenarios were generated to be able to establish the sustainable production rates from the basin. The field deliverabilities allowed for a 22-year plateau for each of the 500 MMCFD pipeline scenarios. When the pipeline capacity was increased to 1000 MMCFD only the year 2015 start date could reach the plateau. The plateau was then maintained for 8 years. The cases were as follows:

- "Preliminary Base Case" – Gas sales in 2015, 500 million cubic feet per day (MMCFD) from all fields (excluding Laurentian prospects)
- Gas sales in 2015, 1000 MMCFD from all fields (excluding Laurentian prospects)
- Gas sales in 2005, 500 MMCFD from all fields (excluding Laurentian prospects), with accelerated blow down (oil) in White Rose
- Gas sales in 2010, 500 MMCFD from all fields (excluding Laurentian prospects), with accelerated blow down (oil) in White Rose
- Gas sales in 2005, 1000 MMCFD from all fields (excluding Laurentian prospects), with accelerated blow down (oil) in White Rose
- Gas sales in 2010, 1000 MMCFD from all fields (excluding Laurentian prospects), with accelerated blow down (oil) in White Rose
- Gas sales in 2010, 1000 MMCFD from all fields, including Laurentian prospects and accelerated blow down (oil) in White Rose

In all, a total of 274 field scenarios were initially reviewed.

5.3 Final Modelling Scenarios

After finishing the initial screening, it was concluded that a total gas production rate of around 700 MMCFD was more desirable from both the economics and the production period. The rate was based on the current natural gas resource estimates and the premise any export pipeline system will need at least 15 years of production volumes at plateau rates to build the export pipeline system.

As a result 4 basic scenarios were modelled and are presented in this report:

- **Base Case** – Gas sales in 2015, 700 MMCFD from all fields (excluding Laurentian prospects).
- **Gas sales in 2010**, 700 MMCFD from all fields (excluding Laurentian prospects), the acceleration of the White Rose North pool gas blow down represents a potential loss of 9 million barrels of recoverable oil.
- **Gas sales in 2005**, 600 BCFD from all fields (excluding Laurentian prospects), the acceleration of the White Rose North pool gas blow down represents a potential loss of 49 million barrels of recoverable oil.
- **Gas sales in 2010**, 700 BCFD from all fields (**including Laurentian** prospects), with accelerated blow down (oil) in White Rose. **Note** this case was run pre-tax only. The Laurentian Sub-basin prospects development did not meet the 20 percent pre-tax economic hurdle rate. Therefore the case was dropped.

On a pre-tax basis, the total estimated capital and operating costs to develop and produce the 4.82 trillion cubic feet (T) of economically recoverable natural gas resources identified in this study is $C10 billion. Table 5.3.1 provides the breakdown between the field development, operation, pipeline, and terminal costs for both capital (CAPEX) and operating (OPEX) costs.

Table 5.3.1. Base Case – Incremental Gas Development Capital and Operating Costs Nominal Year 2000 Dollars (royalties and taxes excluded)

	CAPEX	OPEX *	Total Cost
	($Cmm)	($Cmm)	($Cmm)
Fields	2078.6	3349.4	5428.0
Northern Import Pipeline	794.8	247.5	1042.3
Terminal & Export Pipelines	2992.8	694.9	3687.7
	5866.2	**4291.8**	**10158.0**

* Figures based on an economic limit

No escalation or inflation

The terminal costs included in Table 5.3.1 include piping and compression only.

Table 5.3.2 provides a summary of the 4.82 TCF of economically recoverable natural gas resources by field for the Base Case. This compares to the total recoverable resources for the Grand Banks of 5.34 TCF as defined in the Well Service Technology (2000) report. The natural gas resources in White Rose account for forty-five percent of the total. The combination of the White Rose and Hibernia fields represents almost three-quarters of the total economically recoverable gas resources. The condensdate for Hibernia reflect only the NGL's from the cessation of oil production as NGL's are currently recovered in Hibernia's oil phase.

Table 5.3.2 Base Case Economically Recoverable Resources by Field

	Economic Resources Recovered *	
Field	**Gas**	**Condensate**
	(BCF)	**(mmb)**
Hebron FPSO	108.0	1.3
Hibernia	1404.0	13.3
North Ben Nevis	134.0	4.5
North Dana	481.0	12.6
South Mara	150.0	7.4
Springdale	103.0	0.0
Terra Nova	264.0	16.9
White Rose	2178.0	81.7
Total	**4822.0**	**137.7**

* Figures based on an economic limit

No escalation or inflation

Trave field development not used – it did not meet the 20% pre-tax IRR hurdle rate

5.4 Gas Processing

The gas, when landed at Come by Chance, could be further processed to remove additional natural gas liquids (NGL's) by adding additional processing facilities. The additional processing is generally an economic issue driven by the differential between the price of crude oil/NGL and natural gas. If the gas price is high and the oil price is not, the light hydrocarbon fraction is generally left in the gas to increase the gas volume and BTU content. If the gas price is low and the liquids price is high then it is profitable to remove the NGL's.

This study does not address the level of additional onshore gas processing. The CAPEX and OPEX for the Come by Chance terminal for the export pipeline do not include facilities for NGL's recovery. At this stage there are too many unknowns both in development and compositions to address the level of liquids production, thus they have not been addressed here. As more information is known, then this issue should be revisited to establish the potential and economic benefits for further gas processing onshore.

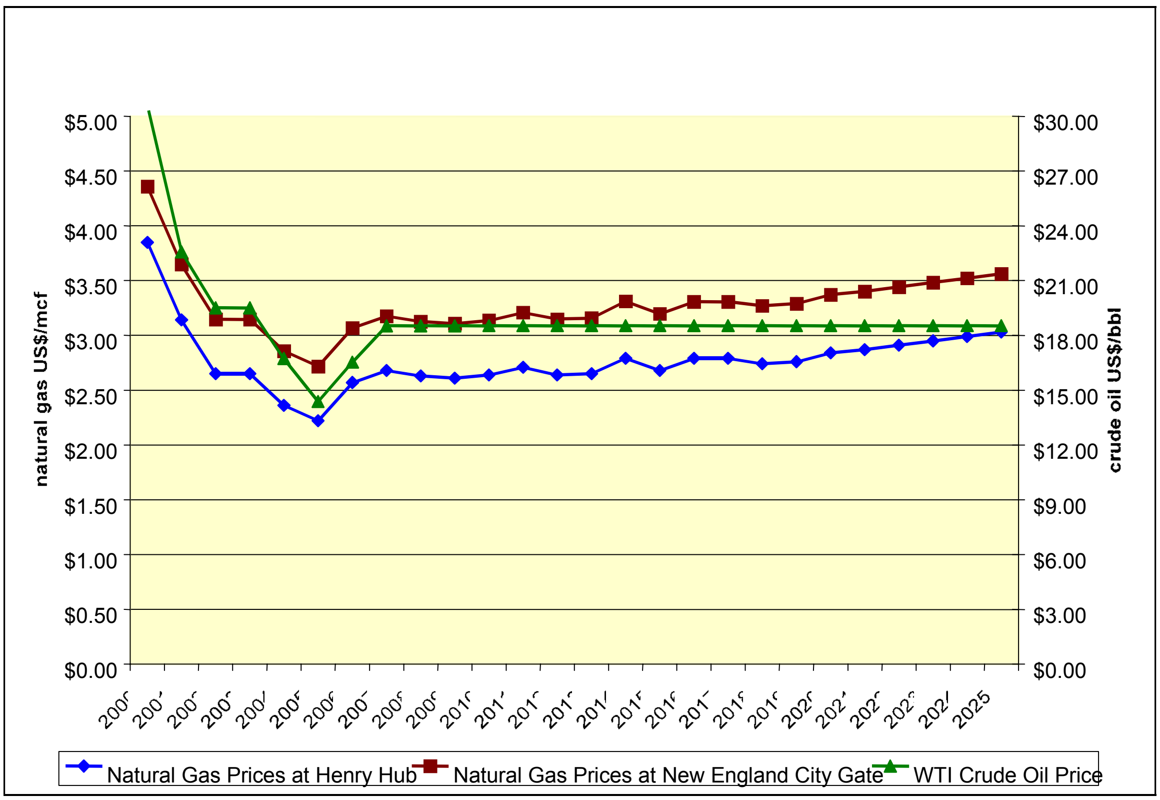
At Come by Chance, the gas is compressed for pipeline delivery for local use or for sale through the main export pipeline to eastern Canada and the US.

5.5 Economic Assumptions

Once the various development options and cost estimates were generated, unburdened (i.e., no fiscal terms or financing applied) economics were run on each of the cases to evaluate the overall viability of the cases. After review of these cases, the following fiscal terms were applied:

- Exchange rate = C$1.43 = US$1.00 held flat over life.
- Gas price = March 2000 ICF Consulting (interim) study, “A Market Analysis of Natural Gas Resources Offshore Newfoundland” (see Figure 5.5.1).
- Oil price = March 2000 ICF Consulting (interim) study, “A Market Analysis of Natural Gas Resources Offshore Newfoundland” (see Figure 5.5.1).
- No inflation (current dollars).
- Discount date = 1/1/2001.

Figure 5.5.1 Oil and Natural Gas Price Forecast (2000 Constant Dollars)



Source - “A Market Analysis of Natural Gas Resources Offshore Newfoundland”

It should be noted that the forecasts used in this study heavily influence the relative economics between the cases investigated. Should oil prices remain higher than forecast then the relative economics for gas would look more attractive for domestic consumption. Should the gas price remain more static in real terms, i.e. the US becomes more reliant on imported LNG, then the earlier gas cases (i.e. 2010 and earlier) will look considerably more attractive. Because the reliability of future price prediction is a highly uncertain art, due consideration as to the sensitivity of the economic results should be considered before the timing of gas start can be decided. The timing should be more properly oriented around issues such as clashing with other major new supplies, losing oil production if gas is brought on too early, or extending gas operations past the last oil production date for a platform.

5.6 Base Case Scenario

The Base Case assumes initial gas sales in 2015 (with the exceptions noted previously) using a rate of 700 MMCFD. The Trave field was excluded since it failed to meet the IRR pre-tax hurdle rate. Figure 5.6.1 below shows the combined gas production profile for the Base Case, based upon a minimum oil loss philosophy over the gas extraction period.

Figure 5.6.1: Base Case Natural Gas Production Profile

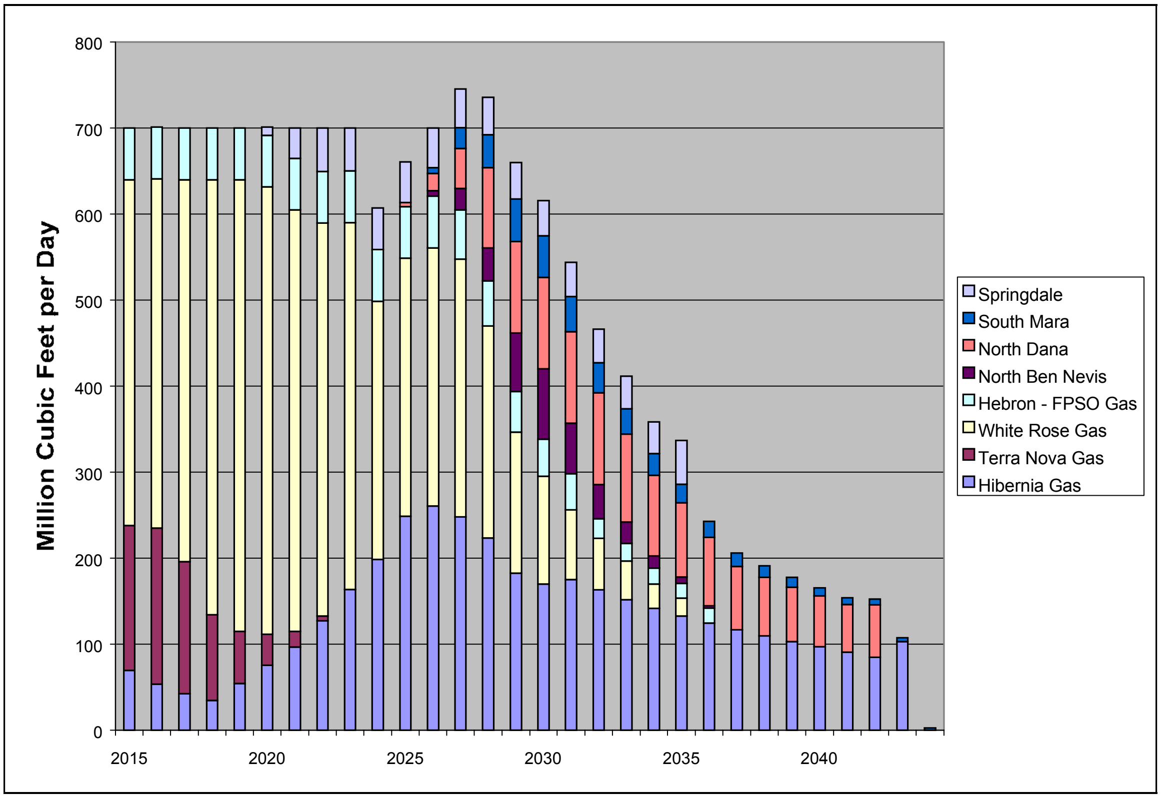


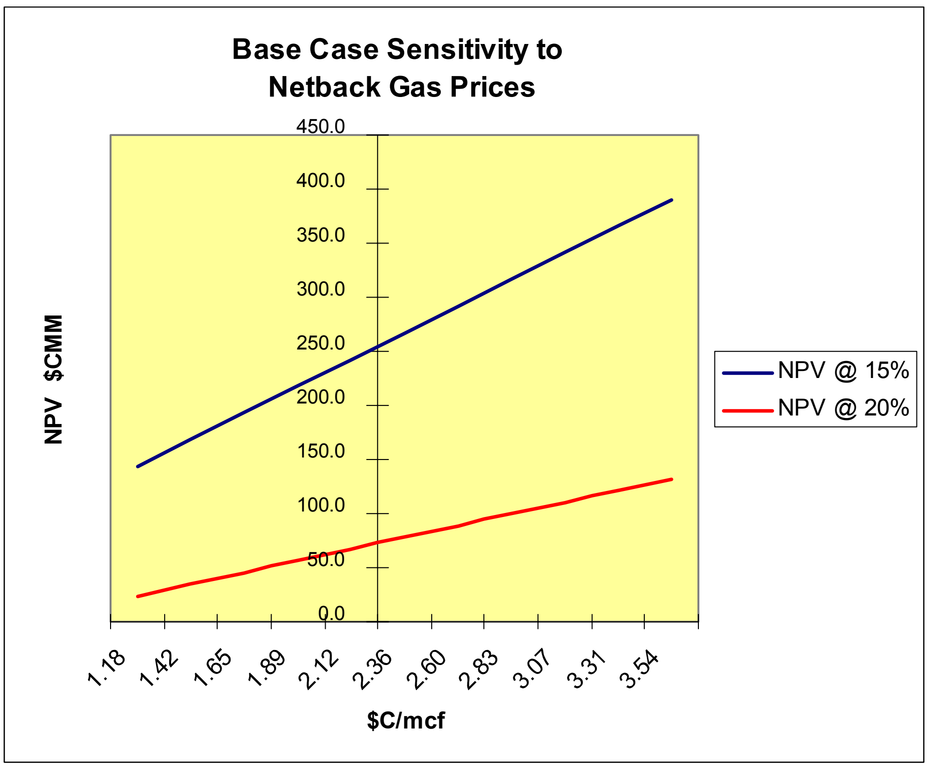
Table 5.6.1 summarises the cash flow and net present value of each field for the Base Case incremental gas sales on a pre-tax basis.

TABLE 5.6.1 Base Case Pre-tax Incremental Gas Field Development Economics

Field	NPV @ 0%	NPV @ 10%	NPV @ 15%	NPV @ 20%	IRR
	($Cmm)	($Cmm)	($Cmm)	($Cmm)	(%)
Hebron FPSO	195.6	37.1	17.0	8.0	74.3
Hibernia	1817.8	155.6	48.9	15.0	31.4
North Ben Nevis	308.1	15.7	3.8	1.0	49.9
North Dana	1309.5	52.1	11.7	2.8	49.9
South Mara	387.1	17.1	4.0	1.0	50.0
Springdale	136.9	11.5	3.3	0.9	32.2
Terra Nova	639.9	125.2	58.3	27.9	95.4
White Rose	4337.7	425.7	120.1	21.2	22.8
	9132.6	**840.0**	**267.1**	**77.8**	

Figure 5.6.2 illustrates that the natural gas price has a significant affect on the incremental gas development economics.

Figure 5.6.2 Base Case Pre-tax Incremental Gas Sensitivities



Netback prices in Figure 5.6.2 are based upon the average price across the gas production period for gas leaving Hibernia, with a C$2.62/mcf tariff contribution to attribute for the cost of the landing and export pipelines (15% return on capital).

Figure 5.6.3 presents the Newfoundland Wellhead oil and gas prices, in Canadian dollars, based upon the average price for gas leaving Hibernia with a C$2.62/mcf tarriff contribution to attribute for the cost of the landing and export pipelines.

Figure 5.6.3 Newfoundland Wellhead Oil and Gas Prices (CAD)

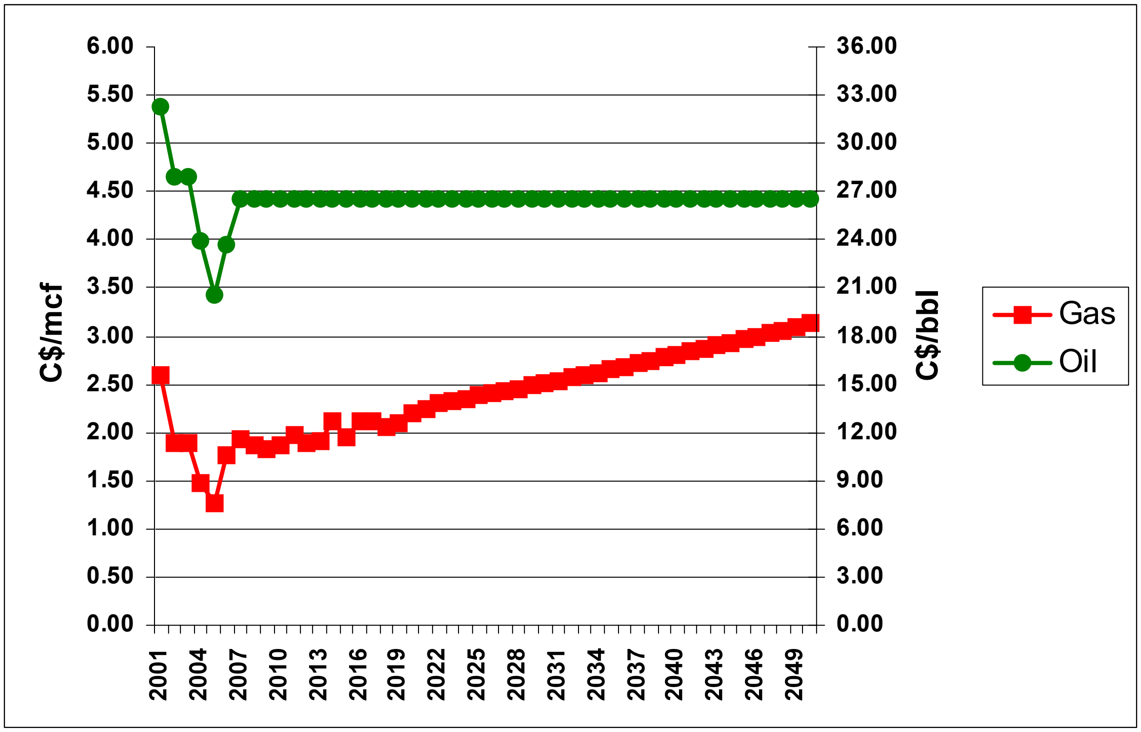
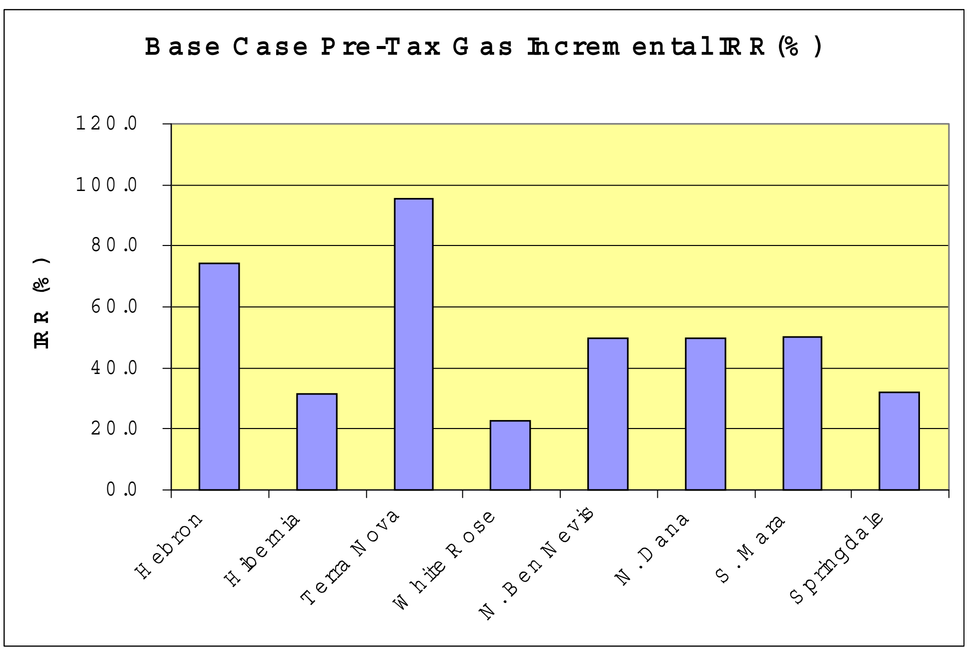


Figure 5.6.4 presents the pre-tax gas incremental internal rate of return for the Base Case.

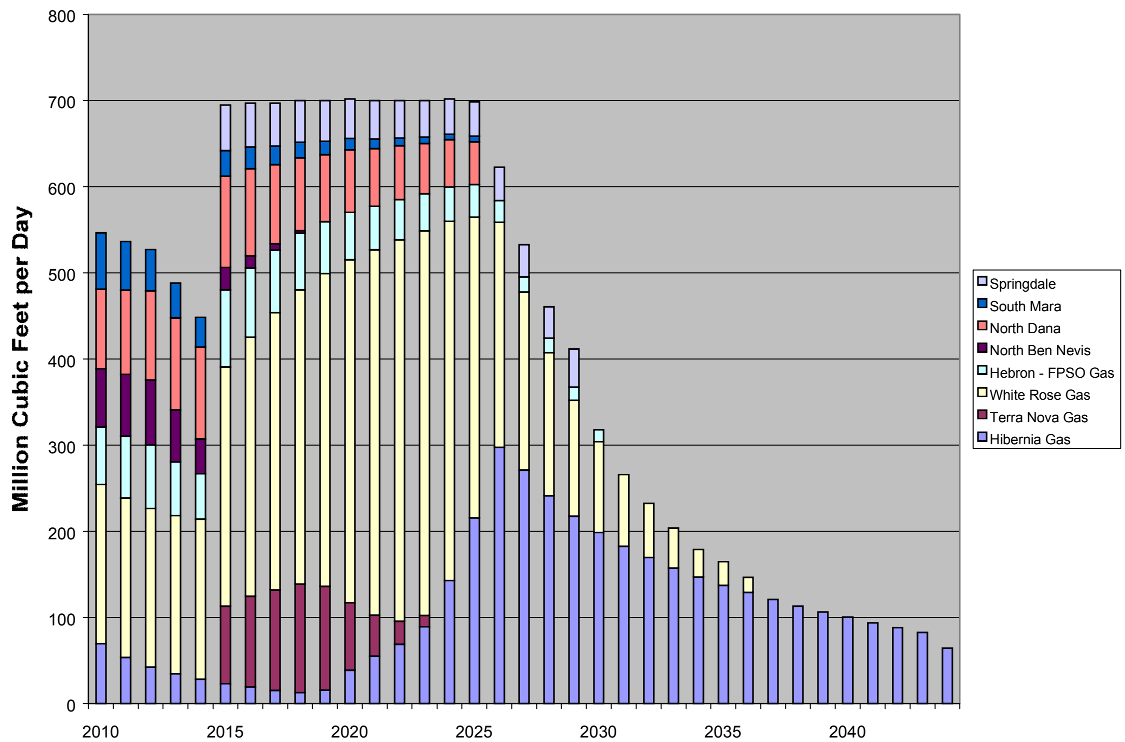
Figure 5.6.4 Base Case Pre-tax Gas Incremental IRR(%)



5.7 2010 Case

The 2010 case reaches the 700 MMCFD production plateau in 2015. The White Rose field production profile used imposed a 300 MMCFD gas processing limit for the first 5 years so the total production does not reach the 700 MMCFD plateau until the sixth year. Figure 5.7.1 shows the combined gas production profile for the 2010 case.

Figure 5.7.1 2010 Case Natural Gas Production Profile



As a result of the production profile used for the case, which takes 5 years to reach the production plateau, and the price forecast used (see section 5.5) the 2010 Case NPV(0) economics look marginally worse than the Base Case. NPV's at 10,15 and 20% demonstrate the benefits derived from the earlier start date. More work is needed to establish how White Rose may better be exploited with minimum loss of oil and what appropriate processing limit should be used before any final decisions can be made. Table 5.7.1 summarises the cash flow and net present value of each field for the 2010 case incremental gas sales on a pre-tax basis.

Table 5.7.1 2010 Case Pre-tax Incremental Natural Gas Field Development Economics

Field	NPV @ 0%	NPV @ 10%	NPV @ 15%	NPV @ 20%	IRR
	($Cmm)	($Cmm)	($Cmm)	($Cmm)	(%)
Hebron FPSO	475.7	117.1	61.5	33.3	75.7
Hibernia	1706.0	134.5	36.2	5.2	22.0
North Ben Nevis	240.7	71.9	40.9	23.7	92.7
North Dana	1065.0	225.1	113.0	59.3	87.2
South Mara	315.2	81.8	44.6	25.1	97.7
Springdale	293.1	39.2	15.3	6.2	52.2
Terra Nova	630.7	105.5	45.2	19.8	55.3
White Rose	3993.3	607.2	200.4	30.1	21.7
	8719.7	1382.3	557.1	202.7	

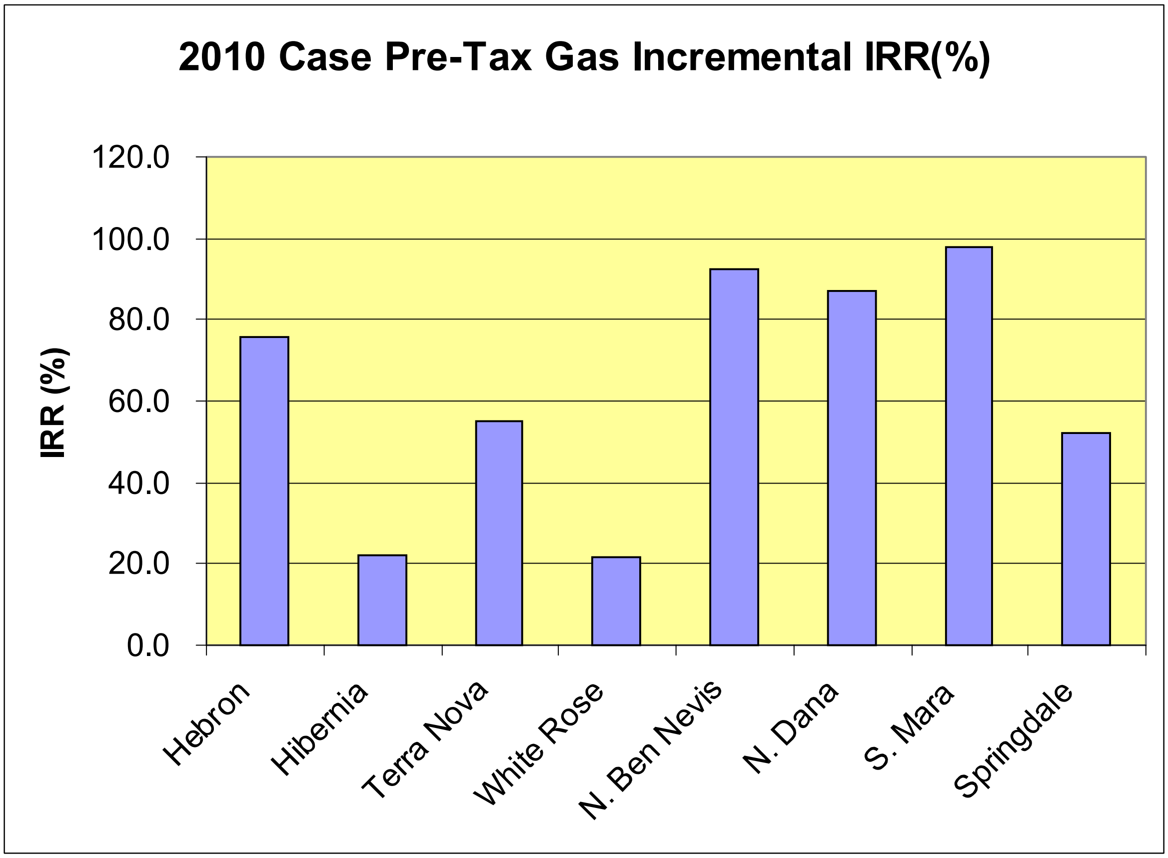
Discount Date = 1-1-2001

Figures based on an economic limit

No escalation or inflation

Figure 5.7.2 presents the pre-tax gas incremental internal rate of return for the 2010 case.

Figure 5.7.2 2010 Case Pre-tax Gas Incremental IRR(%)



2010 Case Scenario with Laurentian Sub-basin Prospects

The study looked at three independent developments for Laurentian fields, comingling at the largest platform. Given the lack of any discoveries at this stage, the Laurentian resource sizes estimated are considered very marginal. The Laurentian Sub-basin will require more in-depth location, resources and cost analysis and a different integrated development plan if it is to become economic. Results are presented in Table 5.7.2.

Table 5.7.2 2010 Case (with Laurentian prospects) Pre-tax Incremental Natural Gas Development Economics

	Recoverable Gas	Revenue	CAPEX	OPEX	NPV@ 0%	NPV@ 10%	NPV@ 15%	IRR
	BCF	MM $ Can	MM $ Can	MM $ Can	MM $ Can	MM $Can	MM $ Can	%
Prospect 1	1235.6	3414.1	1068.1	1197.0	1149.1	-29.1	-120.4	9.2
Prospect 2	717.3	1947.7	834.6	873.0	240.1	-135.1	-147.7	3.6
Prospect 3	1342.0	4087.2	1062.3	1430.2	1594.7	-88.6	-108.6	7.2
Laurentian Sub-basin	**3294.9**	**9449.0**	**2965.0**	**3500.2**	**2983.9**	**-252.8**	**-376.7**	**7.7**

Discount Date = 1-1-2001

Figures based on an economic limit

No escalation or inflation

6 REQUIREMENTS FOR FURTHER WORK

Since this study is a preliminary technical and economic feasibility analysis, further work is required to examine the following parameters in greater detail:

- The subsea pipeline was routed without an actual route survey. Therefore, one does not have a clear idea of potential problem areas such as large boulders, excessive free spans and bedrock outcrops. Following a detailed route survey the preliminary C-CORE route, which is based on iceberg scour risk alone, will be modified.
- More environmental data is needed as well as a thorough examination of trenching equipment capable of trenching pipelines in water depths up to 200 m. For purposes of this study, environmental data was obtained for the Hibernia, Terra Nova and White Rose offshore development projects. A discussion was also held with Royal Boskalis, the contractor responsible for construction of the Terra Nova Glory Holes. For purposes of this study, it was assumed that the soil conditions along the proposed route were similar to the soil conditions at other offshore production sites such as Hibernia and Terra Nova.
- There is a need to examine in greater detail the use of a 100 year return period for iceberg risk. If the target risk level is modified, then it may be possible to route the pipeline in shallower water and/or trench a shorter length. This will obviously have some cost implications.
- The issue of head of pipeline must be addressed. It was assumed for purposes of this project that a head of pipeline was preferable and the location would be the Hibernia structure. This assumption is logical since the only existing fixed facility is the Hibernia structure. However, it is not known if the Hibernia GBS would be available in the event of project go-ahead.
- Specific details are required regarding the product to be transported by the subsea pipeline. For purposes of this study, several assumptions have been made regarding the product type and these assumptions have to be checked and modified as necessary.
- The line sizing work will need to be refined once additional geotechnical, environmental and gas composition information is obtained in the future.
- Substantial additional information and work to confirm reserves, reservoir properties, modelling and fluid compositions is required.

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Appendix 1 - Well Service Technology

Natural Gas Pipeline Feasibility Study - Resource Evaluation

Executive Summary

General

Development of Newfoundland's offshore resources has concentrated to date on oil developments, mainly because of the lack of gas infrastructure. The first two developments, Hibernia and Terra Nova, are both using their gas inkind for pressure maintenance and gas displacement. The Hibernia field has both solution gas and gas-cap gas associated with its gas reserves. For gas conservation and oil recovery reasons, the produced gas is being re-injected into the gas cap, which displaces the oil to downdip producers. Under the current development plan, gas would become available for sales after the producers, under gas injection support, become uneconomic. At this point the gas block(s) can be blown-down if the pressure drop has no adverse effect on the remaining field performance. The Terra Nova field has only solution gas, as no gas cap has been identified. Solution gas re-injection is into an updip oil column in one of the fault blocks. Gas breakthrough and a total gas balance are issues facing the development of Terra Nova, which will in turn affect the timing for gas availability (sales). A Grand Banks natural gas development would enhance the reservoir management and depletion strategies available for both projects.

The acceleration of gas sales from these projects is subject to many issues and considerations, the main one being oil conservation. It must be demonstrated that the oil reserves are not jeopardized in any way, by changing the depletion strategies to allow the early sale of gas from these projects. Future oil developments (Hebron, White Rose South) must also consider gas injection as one of the depletion plan options, as this may enhance oil recovery. However, a natural gas development would provide alternatives to the oil depletion strategy and may ultimately improve project economics. A larger gas field such as White Rose North, would provide a more flexible gas resource, and would be a necessary element for any future gas development project.

Objectives

The purpose of this part of the study was primarily threefold:

- To establish the Newfoundland offshore gas resource basis, through the identification, quantification and categorization of the relevant static and dynamic reservoir information. This was accomplished by the probabilistic modelling of the resources base and quantification of the field and pool resources according to their relative insitu nature.
- To evaluate the benefits of solution gas re-injection into the Terra Nova and Hibernia fields. This exercise was aimed at reviewing the justification behind the gas injection options for each field and the implications for changes to their existing plans.
- To forecast individual field and cumulative gas and gas liquid production profiles and to assist in determining the economic threshold for an offshore pipeline to deliver gas to market.

Summary, Conclusions and Recommendations

Summary

The offshore Newfoundland gas and NGL resources were estimated to be 150.5 10^9 Sm^3 (5.34 tcf) and 50.3 10^6 Sm^3 (317 mmbbl) respectively. The majority of the gas resources (67%) are held in the White Rose and Hibernia fields and it is the timing of gas from these two projects that, to a large degree, will dictate the offshore gas development schedule. Most of the gas (76%) is associated with oil and is therefore considered secondary in development priority.

Both Hibernia and Terra Nova should benefit from high gas displacement efficiency through gravity drainage and near-miscible behaviour. The only threat to poor recovery under both gasflood schemes appears to be their vertical conformance or gasflood stability. If this can be properly managed then gas injection should be successful in both fields with recoveries equal to or greater than water injection.

The Base Case cumulative profile follows ideal reservoir management practices and begins in 2015, when the major developments commence gas blowdown. Under this scenario gas capacity can be maintained for 15 years at 19.7 10^6 Sm^3/d (700 mmscfd). To start gas sales earlier requires that most of the secondary fields be accelerated and that the White Rose N-22 pool be blowndown prematurely, with a possible loss in oil recovery. To achieve and maintain larger pipeline capacities additional discoveries are required. Based on a prospect evaluation of the Laurentian Sub-Basin a cumulative gas profile with a plateau of 28.2 10^6 Sm^3/d (1000 mmscfd) could be met for a period of 16 years.

Conclusions

The main conclusion drawn from this study were as follows:

Gas and NGL Resources

- Probabilistic modelling of the discovered gas resources gave a P50 estimate of 150.5 10^9 Sm^3 (5.34 tcf). This value is slightly higher than that estimated by the C-NOPB mainly due to the inclusion of solution gas in several of the fields. The P50 NGL resources were estimated to be 50.3 10^6 Sm^3 (317 mmbbl). The gas and NGL resources were normally distributed with a fairly short range. This would imply that if additional resources were required to meet the economic threshold, then new discoveries would most likely be required.

- Most of the gas resources (67%) are held in two fields. White Rose is the most significant contributor at 41%, followed by Hibernia at 26%. It is the timing of gas from these two projects, that will to a large degree dictate the schedule for gas development offshore Newfoundland.

- The majority of the gas (76%) is associated with oil in one form or another (i.e. solution gas or gas cap gas). This gas is considered secondary in development priority behind the oil, as acceleration of the gas ahead of or in parallel with the oil, will in most cases have an adverse impact on the oil recovery and performance. This has significant implications on the mode and timing of a future gas development, with the oil phase dictating the timing of the gas phase.

- The other 24% of the gas is categorized as non-associated gas and is unencumbered with any oil development.

Gas Injection Benefits

- The information available on Hibernia would indicate that gas injection should benefit from a high displacement efficiency through gravity drainage and near-miscible behaviour. Black-oil simulation of water and gas injection showed water injection to be marginally superior (47 vs. 41%), without, however, the compositional benefits considered. Long core displacement tests and compositional sector modelling indicated that near-miscible behaviour should contribute significantly to the recovery. The MMP was estimated to be above 40 MPa. The only threat to poor recovery under this scheme appears to be its vertical conformance or gasflood stability. If this can be properly managed then gas injection should be successful in Hibernia with recoveries equal to or higher than water injection.

- Similarly, Terra Nova should benefit from high gas displacement efficiency through gravity drainage and near-miscible behaviour. This is mainly attributed to the rich injection gas composition estimated for the development. Fluid characterization indicated a MMP of approximately 34.5 MPa. Compositional modelling of the C-09 block indicated a recovery under gas injection of 50%, compared to 36-38% achieved by water injection. The only threat to poor recovery under this scheme appears to be its vertical conformance or gasflood stability. If this can be properly managed then gas injection should be successful.

- Both projects are committed to gas injection and will most likely exhaust all mitigating options if gasflood performance is poor. This is a normal occurrence in offshore developments where produced gas must be used in-kind. Through proper reservoir management and well intervention programs, recovery schemes can be maintained and often improved upon.

- To convert either Hibernia or Terra Nova from gas to water injection would require significant capital investment in well conversions, re-completions and possibly sidetracks. Terra Nova would most likely require more capital as the sub-sea design would have to be changed as well to allow water injection into the NW drill centre.

Gas Sales Availability

- Because of the dependency of several of the pools to the oil-phase development, the oil production profiles had to be established first in order to determine the timing and of the gas phase (final blowdown) and the amount of gas available during the oil phase. From this evaluation it was determined that no significant gas volumes would be available from the primary gas resources prior to blowdown for each field, which under ideal reservoir management occurs at the end of oil and/or condensate recovery.

- The main two fields, White Rose and Hibernia, do not commence blowdown until 2015 and 2019 respectively. Terra Nova could begin blowdown of its injected gas in 2015 and the Ben Nevis L. Hibernia could commence following its gas cycling period in 2010. Acceleration of the blowdown period(s) could have negative effects on the oil phase performance and recovery.

Prospect Evaluation

- Three Laurentian sub-basin prospects were evaluated as possible add-ons to the existing resource base. The three prospective structures are similar to those found in the gas bearing Sable sub-basin. The prospects range in size from 21.6 10^9 Sm^3 (0.77 tcf) to 38.9 10^9 Sm^3 (1.36 tcf), and collectively sum to 96.2 10^9 Sm^3 (3.4 tcf). Each prospect had production forecasts built based on deliverability estimates from analogue fields.

Production Forecasting

- Production forecasts for the blowdown of each pool were generated using material balance techniques, incorporating all of the relevant PVT, aquifer, deliverability and completion data. The individual performance profiles were then combined using a production forecasting tool honouring the field centre capacities and the gathering system constraints.

- The Base Case cumulative gas production profile follows ideal reservoir management practices and begins in 2015, when the major developments commence gas blowdown. A plateau period can be maintained at 19.7 10^6 Sm^3/d (700 mmscfd) for a period of 15 years starting in 2015.

- To start gas sales in 2005 requires that most of the secondary fields be accelerated and for the White Rose N-22 pool begin blowdown without secondary oil recovery. Loss in oil recovery is a potential issue under this scenario. A plateau rate of 16.9 10^6 Sm^3/d (600 mmscfd) can be maintained for a period of approximately 17 years beginning in 2005.

- Beginning gas sales in 2010 also requires that the blowdown of White Rose N-22 be accelerated forward. A minor loss in oil recovery is possible under this scenario. A plateau rate of 19.7 10^6 Sm^3/d (700 mmscfd) can be maintained for a period of 15 years beginning in 2010.

- Although White Rose and Hibernia can supply significant gas production, additional discoveries are required to adequately maintain larger pipeline capacities. The Laurentian sub-basin, Flemish Pass and Jeanne d'Arc Basins and other prospective basins have the potential to supply these additional resources.

- With the 3 Laurentian sub-basin prospects added to the Grand Banks resource base, an export pipeline capacity of 28.2 106 Sm3/d (1000 mmscfd) can be reached in 2010 and maintained for 16 years.

Recommendations

The following recommendations are made related to the findings from this study:

- This evaluation should be updated periodically to incorporate new production data (field performance) and any newly released field development information that may relate to gas sales issues (i.e. White Rose and Hebron development plans). Any new discoveries should be added to the analysis and cumulative production profiles.
- Any additional production forecasts incorporating new start dates, pipeline capacities or gathering system capacities should be performed by WST, as the necessary tools and procedures are in place for properly generating the cumulative profiles.
- The NGL resource estimates should be more rigorously evaluated taking into account the range of compositional change within the reservoir, likely process cut for liquids recovery, condensate recovery estimates and gas shrinkage.
- Following the completion of the Hibernia miscible feasibility study, required by the DPA approval, the benefits of gas injection should be re-evaluated.

Appendix 2 - C-CORE

Iceberg Risk and Routing Considerations for Grand Banks and Export Pipelines

Executive Summary

Background

Iceberg risk is a significant factor in assessing the feasibility of constructing a pipeline to transport natural gas on the Grand Banks to markets. Various import pipeline routes, carrying gas from the Grand Banks to Newfoundland, and export routes, carrying gas from Newfoundland to Nova Scotia and New England were considered.

Objectives

The objective of the study was to analyze a number of import and export gas pipeline routes and optimize them with respect to iceberg risk, seabed conditions, pipeline length and seabed slope. Based on this analysis, a preferred route was selected, and the required trenching length and depth for iceberg risk mitigation was estimated. The role of iceberg management techniques for the potential reduction of iceberg risk was also discussed.

Methodology

The first step in the analysis was to establish a target safety or reliability level associated with iceberg damage for each pipeline. A target return period of 100 years for iceberg damage was considered over the entire length of each import and export pipeline.

A statistical analysis, accounting for variations in iceberg frequency, size, speed, scour depth and water depth was developed to predict the frequency at which a 1m diameter pipeline, either resting on the seabed or buried below the mudline, would be affected by an iceberg. The risk for a pipeline route was calculated by breaking down the pipeline route into subsections and calculating the risk for each subsection based on the local conditions, considering whether the pipeline was buried and the depth of burial. The total risk for a pipeline was the sum of the risks for the various subsections.

The risk of damage for a pipeline resting on the seabed was determined from the frequency with which iceberg keels would cross the pipeline within 1m of the seabed and the frequency at which a scouring iceberg (an iceberg with its keel dragging on the seabed) would cross the pipeline. The risk for a pipeline buried below the mudline was determined from the probability that an iceberg would scour deep enough to strike the pipeline or cause excessive loads on the pipeline due to the disturbance of soil underneath the scouring iceberg. All of these events were considered to result in pipeline failure.

Particularly on the northeastern Grand Banks, effective iceberg management techniques may be applied to reduce the risk of pipeline damage. State-of-the-art methods are outlined in the report.

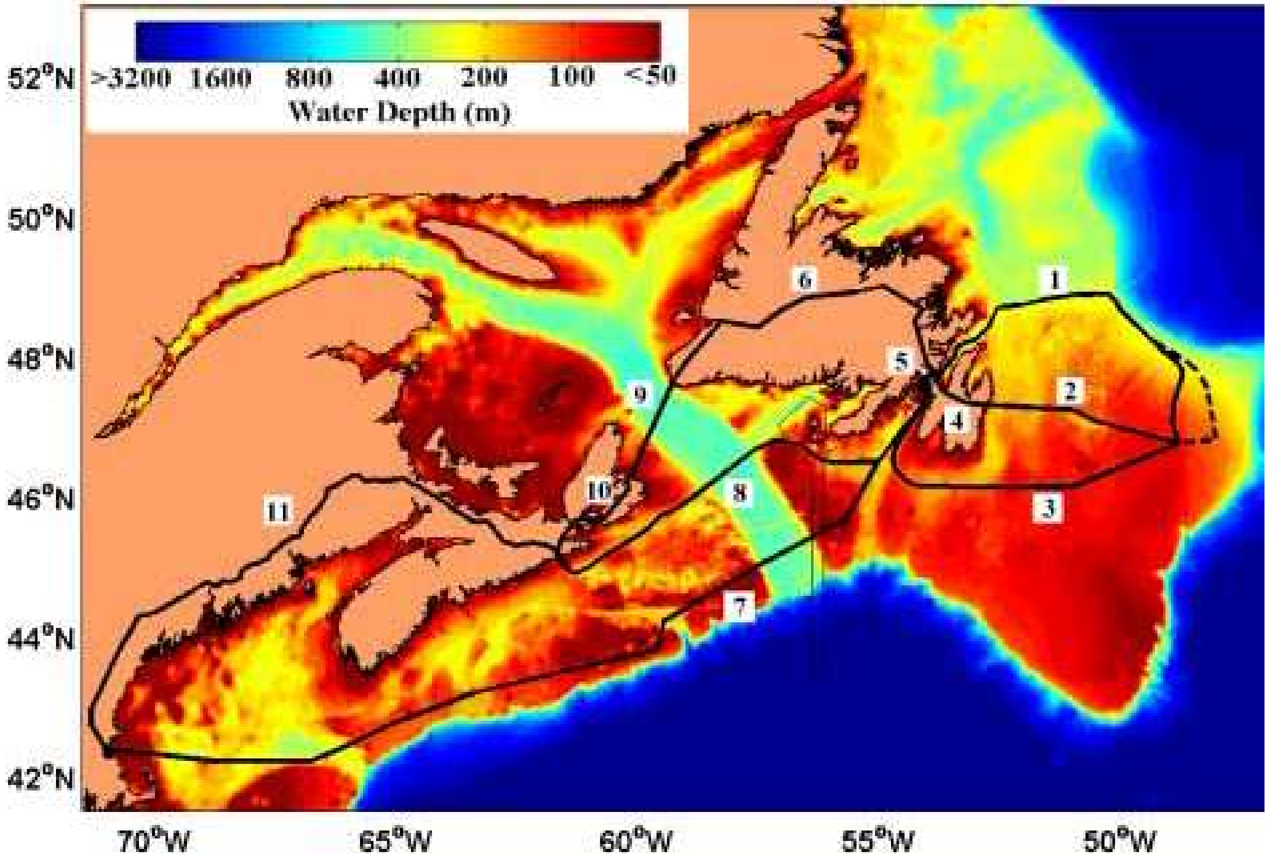
Results

Three import pipeline routes, three overland routes and three export routes were considered. The routes are illustrated in the following figure, and pipeline lengths and estimated trenching requirements are given in the following table.

The most favourable of the three import pipeline routes (routes 1-3) was the northern route. The direct and southern routes required trenching along their entire lengths to meet target safely levels. The seabed conditions along these pipeline routes may be difficult for trenching due to the presence of bedrock and the potential presence of a tough hardpan layer. Of the three export pipelines (routes 7-9) only one, passing over the St. Pierre Bank, required any significant trenching. The choice of export pipeline route is expected to be made on other strategic and economic concerns, thus no recommendation will be made on export routes.

Pipeline Lengths (and Estimated Trenching Requirements for Offshore Pipelines)

Route	Length	Trenching(Length and Depth)
Import Pipeline Routes		
1. Northern Route	620 km	110 km, 3m
2. Direct Route	310 km	All, 3m
3. Southern Route	600 km	All, 3m
Newfoundland Overland Routes		
4. Bay Bulls to Come By Chance	113 km	N/A
5. Bull Arm to Come By Chance	9 km	N/A
6. Come By Chance to Port aux Basques	558 km	N/A
Export Pipeline Routes		
7. Boston Route	1620 km	133 km, 1m
8. Country Harbour Route	771 km	3 km, 1m
9. Sydney Route	172 km	0
Mainland Overland Routes		
10. Sydney to Country Harbour	190 km	N/A
11. Country Harbour to Boston	1100 km	N/A
Notes: Pipeline trenching specifications are for iceberg risk mitigation of marine pipelines only, and do not account for other considerations (i.e. regulatory requirements). The trench depth includes a 1m allowance for the pipeline and concrete cover, and any additional clearance below the mudline.		



Import, Export and Overland Pipeline Routes

The direct route option for the import pipelines has the obvious advantage of having the shortest length. However, the scour rate is likely to be high and trenching is likely to be difficult along this route. The majority of the northern route is in water sufficiently deep that trenching is not required for iceberg risk mitigation. The trenching required for the protection of the initial portion of this route is likely to get easier as the pipeline progresses off the more shallow portions of the Grand Banks. These factors were considered when recommending the northern route over the direct route. However, it should be noted that the extent of hardpan on the Grand Banks is still largely unknown. Also, most research on iceberg scour rates has been in response to industry needs, thus little work has been done outside the Jeanne d'Arc basin. Additional geotechnical and geophysical surveys, particularly along the northern and direct routes, are recommended to provide hard data on scour rates and hardpan presence.

Appendix 3 - JP Kenny / Pan Maritime

Design Basis, Gas Flow Analysis, Subsea Pipeline Mechanical Design

Executive Summary

DESIGN BASIS OVERVIEW

Grand Banks Field Coordinates

Table 1 presents coordinates of the various resource fields located on the Grand Banks. It must be emphasized that these co-ordinates are preliminary and are used for purposes of this study only.

Table 1 - Resource Field Coordinates

Reservoir	Latitude	Longitude
Hibernia	468 45’ 01.25’’ N	488 46’ 54.68’’ W
Terra Nova	468 28’ 31.69’’ N	488 28’ 51.34’’ W
White Rose	468 48’ 26.24’’ N	488 01’ 22.65’’ W
Hebron	468 32’ 33.95’’ N	488 31’ 45.47’’ W
Ben Nevis	468 34’ 39.74’’ N	488 21’ 09.84’’ W
North Ben Nevis	468 40’ 53.57’’ N	488 25’ 18.60’’ W
South Mara	468 42’ 01.07’’ N	488 32’ 19.63’’ W
North Dana	478 12’ 43.60’’ N	478 36’ 12.62’’ W
Trave	468 56’ 17.56’’ N	478 58’ 09.74’’ W

Bathymetric Data

Bathymetric data for the Grand Banks and along the intended pipeline route was obtained from C-CORE and from published information pertaining to the Hibernia, Terra Nova and White Rose development projects.

Water depths for the development areas off the east coast of Newfoundland range from a minimum of about 80 m for Hibernia to a maximum of about 130 m for the planned White Rose development. The Terra Nova field is located in an intermediate water depth of about 90m. The C-CORE routing report contains detailed bathymetric information for the three import pipeline routes as well as the export routes from Argentia to Boston.

Environmental Data

Published environmental design criteria were obtained for the Hibernia, Terra Nova and White Rose field developments. A comparison was made between the three data sets and the data used as input for the engineering design of the Grand Banks Gas Pipeline are summarised in Table 2 below. Table 3 contains selected preliminary environmental design criteria for the Sable Offshore Energy Project used for the design of the US export pipeline from Newfoundland to Boston. The maximum and significant wave heights in Table 3 are average values of the 6 different Sable Island fields (Venture, South Venture, Thebaud, Alma, Glenelg and North Triumph).

Table 3 - Environmental Design Criteria - Grand Banks Area

Parameter	Return Period (Years)		
	1	10	100
Significant Wave Height	11 m	13.2 m	16 m
Peak Period	14.1 s	15.5 s	17.0 s
Maximum Individual Wave Height	20.7 m	25.1 m	30.4 m
Period of Maximum Wave	12.5 s	13.5 s	15.0 s
Current speed 20 m below surface	1.00 m/s	1.15 m/s	1.30 m/s
Direction (to) of near surface current	W	W	W
Current speed 45 m below surface	0.86 m/s	0.97 m/s	1.09 m/s
Direction (to) of mid-depth current	SW	SW	SW
Current speed 70 m below surface	0.70 m/s	0.83 m/s	0.96 m/s
Direction (to) of near bottom current	SE	SE	SE
Water Temperature	Maximum ~ 3ºC, Minimum ~ -1.7ºC		
Water Salinity	~ 33.0 ppt @ 50 m		

Table 4 - Environmental Data - Sable Offshore Energy Project

Parameter	100 Year Return Period Values
Average Significant Wave Height	13.1 m
Average Maximum Wave Height	21.6 m
Period Range for Max. Waves	14 - 19 s
Near Bottom Current Velocity	S

Geotechnical Criteria

Published geotechnical information for the Grand Banks was reviewed for an indication of the soil conditions and the degree of difficulty to be expected in trenching the gas pipeline. The geotechnical information reviewed comprised soil boring data for the Hibernia and Terra Nova offshore projects, soil conditions encountered during construction of the Terra Nova Glory Holes and a discussion with the Glory Hole contractor (Royal Boskalis).

Hibernia design stratigraphies from the seabed surface to about five meters below surface are characterised by a thin loose surficial sand layer overlying a dense sand/gravel layer. With increasing depth the seabed is characterised by dense to very dense sand with intermittent stiff clay layers. The Hibernia Development Plan Update states that for the analysis of the GBS skirt penetration, a soil friction angle of 45° and a total soil unit weight of 20.5kN/m^3 were used.

Soil conditions at the Terra Nova site are similar to conditions at the Hibernia site with a thin layer of loosely packed coarse sand at the seabed surface overlying a layer of dense to very dense sand/sand and gravel to a depth of about 2 m. A “hard pan” layer is located from about 2m to 4m below the seabed surface. With increasing depth, the stratigraphy changes from mainly sand to intermittent dense sand/stiff clay layers with varying thickness (2m to 18m). The reported friction angle of the near surface (< 2m) sand layer is about 40º while the average shear strength of the stiff clay from the five soil borings is on the order of 120kPa.

Royal Boskalis, the Terra Nova glory hole contractor, was also questioned with respect to possible difficulties in trenching the subsea pipelines. Royal Boskalis stated that if soil conditions along the intended pipeline route were similar to the Grand Banks soil conditions, there should be no major difficulties encountered during trenching operations in water depths up to about 100 m. This is based on the assumption that trenching up to this water depth will be carried out using similar equipment as that used to construct the five Terra Nova Glory Holes. The Glory Holes were constructed using Suction-Dredge technology in water depths of 85-90 m. However, use of this technology is not feasible at water depths much greater than 100 m. Therefore, further work is required to investigate trenching techniques in water depths greater than 100m.

GAS FLOW ANALYSIS

Summary

A pipe sizing analysis has been performed to evaluate required pipeline diameters for flowrates of 0.5, 1.0 and 1.5 BSCFD.

For a flowrate of 1 BSCFD (1 billion standard cubic feet per day), a 36-inch pipeline will be adequate to transport the gas from the Grand Banks to the "Come by Chance" terminal in Newfoundland, with a discharge pressure of 150 bara and an arrival pressure of 70 bara. Similarly, with 70 bara arrival pressure at the Boston terminal, approximately 200 bara would be required at the "Come by Chance" terminal in Newfoundland for a 36-inch pipeline.

For the onshore route from "Come by Chance" to "St. Stephen" (near the Canada-U.S. border), a maximum discharge pressure of 200 bara would be required at "Come by Chance" to meet the arrival pressure of 70 bara at "St.Stephen".

From "St.Stephen" to Boston (Drakut), to obtain an arrival pressure of 70 bara, a maximum discharge pressure of 130 bara is required downstream of the compressor station at "St.Stephen".

The viability of the proposed 36" system was also assessed with respect to pressure and throughput criteria. Two-phase liquid – gas transportation of oil with low gas content, and transportation of gas with small liquid loadings were considered. Typical gas-oil ratios and densities of Hibernian and Terra Nova oils were used in the assessment of oil flow in the presence of gas. Selected post-2015 projected natural gas and NGL production profiles data were used for assessing gas transportation in the presence of NGL.

Use of the 36" Northern Route to transport Hibernia and Terra Nova oil with some gas pipeline is likely to be restricted to oil rate of less than 200,000 bbl/d because of pressure limitation.

In later field life when gas is transported via the 36" pipeline, up to 1.0 BSCFD may be delivered along with associated NGL. The dominant flow regime expected during steady operations during this period is segregated flow. Although no slugging problem is expected during normal operation, removal of liquid from the pipeline by pigging may entail requirement of large on-shore liquid handling facility.

Consideration of Laurentian Sub-Basin Reserves

Based on a flowrate of 400MMSCFD, a 26-inch pipe is required to transport gas from LSB to the Come By Chance terminal in Newfoundland.

The proposed 36-inch pipeline for the Newfoundland to Boston offshore route will be too small to transport 1.4 BSCFD of combined gas from Grand Banks and LSB. Consequently, either a larger pipe diameter is used or depending on the timing of the gas start-up at both LSB and Grand Banks, the 36-inch pipe may be adequate. This is dependent on a maximum of 1BSCFD of gas flowing through the pipeline at any period of time.

Recommendations

It is recommended that a further detailed analysis be carried out when more data is available from the fields, and when all the routing are confirmed.

The presence of produced water in the pipeline should be investigated and an appropriate thermal analysis performed to assess potential issue of liquid drop out (single phase gas option) and hydrate formation.

PIPELINE MECHANICAL DESIGN

Summary

The main objectives of the pipeline mechanical design were:

- To determine the required pipeline properties (wall thickness, diameter, steel grade) for all preliminary pipeline routes based on variations in water depths.
- To design the pipeline to have sufficient negative buoyancy to be stable under environmental and current loading.
- To determine the concrete coating thickness for the pipeline to be stable under environmental wave and current loads accounting for water depth changes along the preliminary routes.
- To determine the minimum required wall thickness for the onshore pipeline.
- To determine the required pipe wall thickness for the Laurentian Sub-Basin (LSB) routes.

The required pipeline wall thickness was determined for all offshore pipeline routes and the LSB routes to satisfy the pressure containment and external pressure collapse criteria in accordance with DNV '96.

The on-bottom stability analysis was performed for the offshore pipelines and the concrete coating requirements were determined. This stability analysis was performed using JP Kenny's in-house program "Pipecalc – On-bottom stability module".

Excluding the LSB to Come By Chance route (route for transportation of gas reserves from the Laurentian Sub Basin, located off the South Coast of Newfoundland, to Come by Chance), the offshore pipeline outside diameter (OD) is constant throughout the route and is equal to a standard 36-inch API pipe (914.4mm). The LSB to Come By Chance route is a standard API 26-inch pipe (660.0mm).

The onshore pipeline routes have been split into zones depending on the appropriate ASME B31.8 location class. The minimum required wall thickness have been determined for these zones.

This report has been prepared for the purpose of preliminary feasibility and cost estimating. Further analysis will be required for more detailed design activities.

Conclusions

Conclusions are as follows:

- The selected wall thickness of 30.2mm for the gas export pipeline satisfies the bursting, pressure collapse criteria and corrosion allowance.
- Review of local buckling for the combined action of internal or external pressure, axial force and bending moment has confirmed the suitability of the pipeline wall thickness selected.
- The pipeline is trenched at water depths up to 200m. A nominal 40mm concrete coating is applied to the pipeline at deeper water depths since iceberg risk is reduced and trenching is not necessary.

Recommendations

Offshore Pipeline (Hibernia to Newfoundland, Newfoundland to Boston / Newfoundland to Country Harbour, Nova Scotia)

It is recommended that:

- 30.2mm wall thickness is used throughout the offshore pipeline route except where buckle arrestors are required;
- Buckle arrestors are required at water depths greater than 200m i.e. all exposed pipe;
- The optimum size and spacing of buckle arrestors shall be confirmed following further calculations;
- For water depths greater than 200m, a nominal concrete coating (40mm) should be applied to the pipeline for stability purposes;
- The pipeline is trenched in water depths less than 200m to aid stability and to prevent iceberg incursion and scour;
- A review of the present analyses should be performed in the event that adjustments to the pipeline routes are made that result in significant changes in water depths;
- A review of the stability and wall thickness requirements should be performed if revised environmental data is obtained.

Onshore Pipeline

It is recommended that:

- The wall thickness for the onshore pipelines route varies from 28.22mm to 50.8mm depending on the location class associated.
- A review of the wall thickness requirements should be performed once the location classes have been finalised.