NATURAL GAS UTILIZATION STUDY:

OFFSHORE NEWFOUNDLAND

1998

Prepared for:

Atlantic Canada Opportunities Agency
and
Newfoundland Ocean Industries Association

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1. SUMMARY AND CONCLUSIONS

1.1 Introduction

The purpose of this study is to quantify the natural gas resources of Newfoundland, identify production and transportation options and lay out the terms of reference of a follow up study. The present study (Phase I) is characterized as a scoping study while Phase II will be a comprehensive examination of critical issues. The ultimate objective is to create a development strategy for Newfoundland natural gas.

1.2 Global Setting

Natural gas is rapidly growing in global importance both as an energy source and as a feedstock for downstream industry. In terms of energy equivalence, natural gas now represents almost 60% of the contribution made by oil. This growth is driven by general economic expansion and the environmental premium placed on natural gas which is far less polluting than its main fossil fuel rivals of oil and coal. New use is dominated by the power generation sector.

The natural gas industry is also evolving rapidly as new reserves are established and long distance transportation options are developed mainly through the use of pipelines and LNG[1] carriers. As a result, the industry is now global in scope and is developing characteristics which are quite distinct from those of the traditional oil business. This requires business and governmental responses which are specific to the natural gas industry.

On a global scale, reserves of natural gas are abundant and growing. Proven world reserves now stand in excess of 5000 Tcf, 70% of which is in the CIS and Middle East regions. In contrast to the distribution of reserves, production and consumption are dominated by the industrialized countries of North America and Western Europe.

This “disconnect” between markets and reserves has major implications including:

- The need to develop cost effective long-distance transportation technologies and delivery systems;

- The location or re-location of downstream industries closer to reserves.

The abundance of reserves and the development of the international trade in natural gas suggest that gas prices will be under downward pressure for the foreseeable future. Natural gas is increasingly in direct competition with other fossil fuels and gas supplies from different sources are competing with each other, i.e. there is gas/gas competition.

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[1] **See Appendix B for Abbreviations and Conversion Factors used in this report.**

1.3 Findings

1. The natural gas resource base for the Province currently is estimated to total 61.9 Tcf, comprising 8.2 Tcf of Discovered Resources and 53.7 Tcf Undiscovered Resources. Of the Discovered Resources, 4.2 Tcf is on the Labrador Shelf and 4.0 Tcf is in the Jeanne d'Arc Basin on the Grand Banks.

2. The Discovered Resource estimates for the Jeanne d'Arc Basin are probably low and may be increased to 5.2 Tcf with reasonable confidence. In the near term, the resources of the Jeanne d'Arc represent the best opportunity for development.

3. The major discoveries in Jeanne d'Arc Basin are dominantly oil and associated natural gas. Reservoir depletion schemes must take account of both petroleum forms, with oil usually taking precedence. Natural gas from the first two probable developments - Hibernia and Terra Nova - is currently slated for re-injection into the reservoirs for pressure maintenance and will be available for export from the fields only when no longer required for this purpose.

4. Accurate resource estimates are a fundamental requirement for valuation, strategic management and development purposes. Current estimates of Undiscovered Resources are badly out of date and need to be redone on a priority basis so that a more complete picture of the development potential of the industry can be obtained. Within the Jeanne d'Arc Basin, the current study estimates that the Undiscovered Resources are 19 Tcf. Further, it is suggested that the majority of these resources may be contained in 3 very large fields (> 100 MM boe) and 20 large fields (between 25 and 100 MM boe) which are still to be discovered.

5. The Hibernia development could play a pivotal role in the development of the natural gas resources of fields within a radius of approximately 50 km around the platform. A preliminary economic analysis of a Hibernia-related development, based on associated gas from Hibernia and other oil fields in the vicinity, shows the potential for positive rates of return. The economic viability of this development is considerably enhanced by the cost contribution of the associated oil developments.

6. A preliminary economic analysis of stand-alone gas development in the Jeanne d'Arc basin does not show a positive rate of return based on the cost/price assumptions used in this study.

7. Potential onshore natural gas developments in the Western Newfoundland Basin show very positive economics. Currently, this is a established exploration play but no economic deposits have yet been discovered. The play is in an early exploratory or wildcat phase.

8. The royalty regimes for natural gas, onshore and offshore, are unclear. Current global trends are to design gas-specific regimes which reflect the particular requirements of gas developments. Newfoundland will have to act accordingly if gas developments are to be encouraged.

9. Various transportation options were examined including pipelines, LNG, methanol and CNG. Of these options, only pipelines and LNG are in common use. Unit costs of pipelines are clearly superior to LNG. Methanol and CNG demonstrate unit costs which are similar to pipelines but these are largely theoretical at present.

10. The pipeline option for the Jeanne d'Arc Basin has certain challenges to overcome. These include a resource base which is insufficiently defined at present to support an assumed throughput in the order of 500 mmcf per day as well as questions of reliability due to possible iceberg damage. The local market, at least initially, is too small to absorb the assumed value of pipelined gas requiring the excess to be sold outside of the Province. Where the royalty take is likely to be low, as on the Grand Banks, economic benefits will be derived dominantly through value-added downstream activity within the Province.

11. Some of the innovative process and transportation technologies show promise and their scale is more in keeping with the discovered resource base, local participation in development and the ability of the local markets to absorb their deliveries. Of most interest are transportation options which are modular and scalable. Active participation by the Newfoundland community in helping to develop promising technologies is suggested as a means to ensure that Newfoundland issues are addressed, to ensure early availability to Newfoundland and as a Newfoundland export of know-how and technology. The Newfoundland community currently has considerable infrastructure and human resource capabilities for developing technology for northern marine development areas. These advantages include world-class research and testing facilities and the presence of leading oil and engineering companies.

12. The Discovered Resources offshore Labrador are in very high quality reservoirs. Currently, they are at technical and economic frontiers of development. A Labrador-specific solution should be sought to achieve the accelerated development of these resources.

1.4 General Conclusion - Phase I Study

Newfoundland's natural gas resources are valuable and potentially capable of supporting significant industrial initiatives. While the discovered resources are not yet large on a world scale, the undiscovered potential holds significant promise for both the Newfoundland offshore and onshore areas. The location and operating environment for the offshore resources means that successful development will require effort, innovation and wise decisions on the part of all stakeholders. Development will not happen "naturally" because of overwhelming competitive advantages.

The implication of the above is that Newfoundland will have to carefully identify and exploit development opportunities which make economic sense and where Newfoundland is competitive. In terms of Phase II tasks, this means a systematic review of each requirement of the natural gas value chain - from well head to market - to identify challenges and opportunities so that appropriate action can be taken.

1.5 Phase II

The natural gas Value Chain (Figure 1.1) illustrates the main organizational components of the industry and their probable evolution time. Opportunities and challenges exist in each component and a number of general "Actions" are proposed to address these.

The ultimate objective of Phase II is the development and implementation of a Strategic Plan for Newfoundland's natural gas resources. The elements of such a plan are illustrated by Figure 1.2

Phase II is visualized as a strategic planning process within which there is a series of inter-related tasks to be performed. Figure 1.3 presents the proposed tasks and their timing.

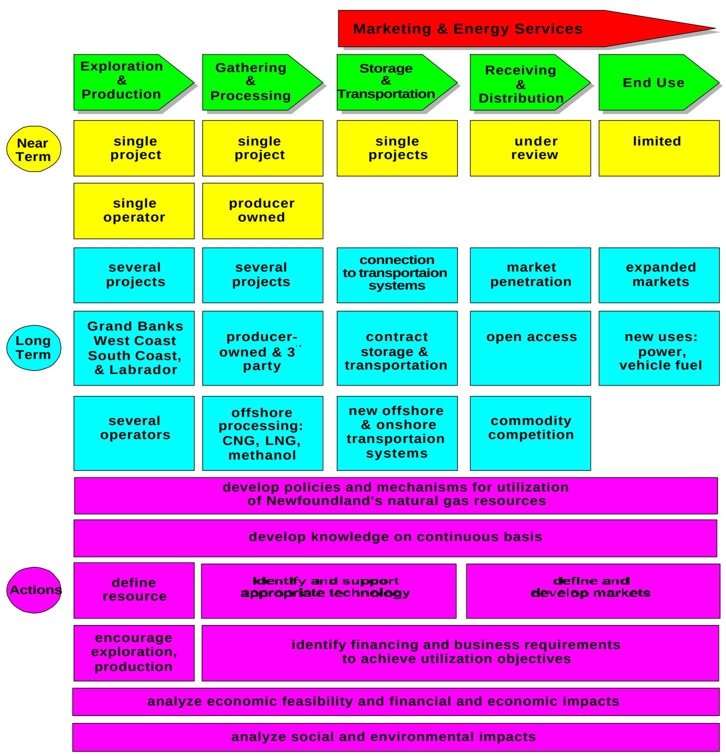

Figure 1.1 Natural Gas Value Chain - Phase II Actions

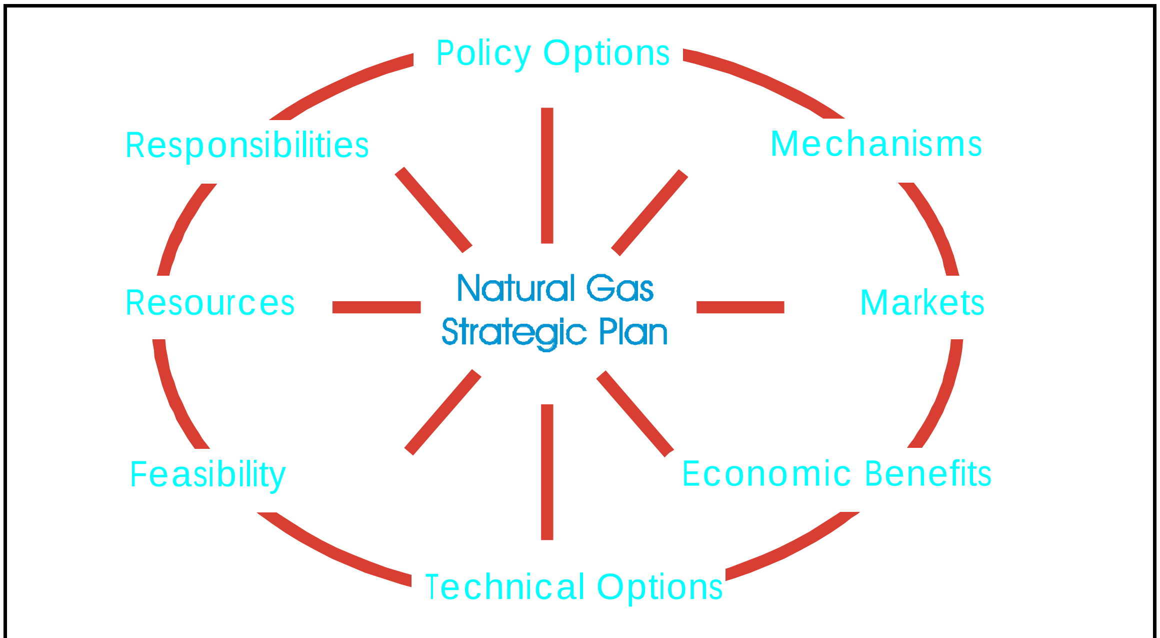

Figure 1.2 Elements of a Natural Gas Strategic Plan

Work Packages		1998	1999	2000	2001
101	Develop Planning and Coordination Process	*continuous process*			
201	Develop Natural Gas Policy	*final*			
202	Establish Natural Gas Royalty Regime	*final*			
203	Investigate Options for Increasing Exploration and Development	*final*			
204	Review Mechanisms for Financing and Operating		*update 1*		*update 2*
205	Identify Opportunities for Natural Gas Utilization	*continuous process*			
206	Identify and Analyze Markets	*continuous process*			
301	Update Estimates of Discovered Resources	*update 1*		*update 2*	
302	Update Estimates of Undiscovered Resources	*update 1*		*update 2*	
401	Review Natural Gas Production Options	*update 1*		*update 2*	
402	Develop Natural Gas Transportation Options	*continuous process*			
403	Conduct Economic Research and Analysis	*continuous process*			
404	Conduct Social and Environmental Impact Analysis			*continuous process*	

Figure 1.3: Work Packages and Timing Phase II

2. BACKGROUND

2.1 Purpose and Scope

The purpose of the study is to quantify the gas resources of Newfoundland, identify production and transportation options and lay out the Terms of Reference for a follow-up study. The present study (Phase I) is characterized as a scoping study while Phase II will be comprehensive examination of critical issues. The ultimate objective is to create a development strategy for Newfoundland industry.

This report was commissioned by the Newfoundland Ocean Industries Association (NOIA) and the Atlantic Canada Opportunities Agency (ACOA). The Terms of Reference were developed by NOIA and ACOA who also provided supervision of the study through a Steering Committee. The Departments of Industry, Trade and Technology and Mines and Energy of the Newfoundland and Labrador Government were also represented on the Steering Committee.

The study was carried out by an alliance of independent consultants under the lead of the principal contractor, Imperial Venture Corp of St. John's, Newfoundland. The study team and their principal areas of expertise are as follows:

Steven M. Millan, P.Geol. - *Project Leader, Resource Assessments*

Gus Cammaert, Ph.D, P.Eng. - *Development and Transportation Options*

Lorne Spracklin, M.A. - *Project Economics*

Pedro van Meurs, Ph.D - *Global Economics, Fiscal Regimes*

The level of effort for the study was approximately $25,000 and it was conducted over a period of approximately eight weeks in May and June 1998.

Information for the study was derived mainly from public domain sources augmented, where appropriate, from the consultants' databases. Proprietary cash-flow (van Meurs) and cost models (Cammaert) were used for analysis.

The report is organized into the following main sections:

- **Summary and Conclusion**
- **Background**
- **Resource Endowment**
- **Production Systems**
- **Transportation Systems**
- **Preliminary Project Economics**
- **Phase II - Terms of Reference**

2.2 Natural Gas in a Global Setting

2.2.1 Resources

Natural gas is rapidly gaining importance both as a source of energy and as a feedstock for industry. This growth is being driven by a number of factors including:

- growing energy demand from an expanding world economy;
- an abundant resource base;
- environmental pressures for the use of gas which is a relatively "*clean*" fuel in comparison to oil or coal;
- improving technologies for the production, transportation and conversion of natural gas.

Excluding the former Soviet Union, in 1996 gas production grew at 4.9% to 215 Bcf[1] per day. In newly developing economies, consumption in 1996 grew by 10% in Latin America, over 8% in the Middle East and 7.5% in Asia with new use dominated by the power generation sector. Even in the more mature markets of North America and Western Europe, growth continues at over 3% per year as traditional oil and coal-burning facilities are replaced with cleaner burning gas. On the whole, power generation holds a 26% share of world gas consumption and will soon pass industry (28.5%) as the leading user of gas.

Traditionally, natural gas was treated as a secondary product of the "oil" business. Its discovery was most often incidental or accidental to the search for oil and relatively few exploration wells were specifically intended to search for gas. In spite of this, the natural gas reserves base has continued to grow from 50% of oil reserves in 1970 to approximately 100% today (Figure 2.1). A strong argument can be made that a specific gas-directed exploration strategy would dramatically increase the gas resource estimates which are currently in place.

[1] **See Appendix B for Abbreviations and Conversion Factors used in this report.**

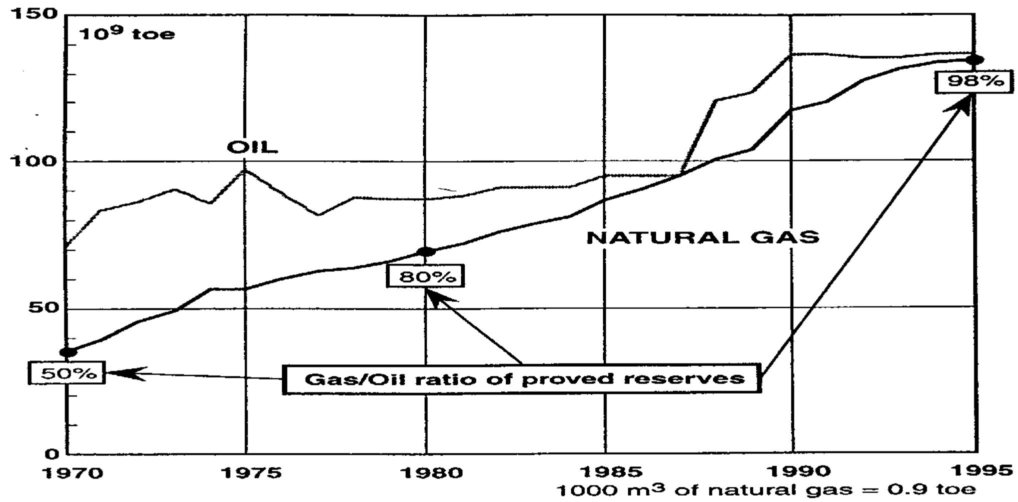

Figure 2.1: Proved Reserves of Oil and Natural Gas in the World.
(source: after Cornot-Gandolphe and Chabrelie, 1995 in Rojey, et al, 1997)

In terms of energy equivalence, gas production has gained steadily on oil. Between 1970 and 1994 (Figure 2.2) world gas production grew from 37% to 58% of oil. Despite this growth in production, gas reserves continue to grow faster than the world gas market. As a consequence, the reserves-to-production ratio for gas now stands at over 65 years, while that for oil is at 45 years. While this is reassuring from a security of supply viewpoint, it means that there are vast shut-in reserves that governments and industry are anxious to monetize. Moreover, gas production is still growing faster than consumption and over 5 Bcfd is being flared, due to lack of markets, with environmental and resource conservation implications.

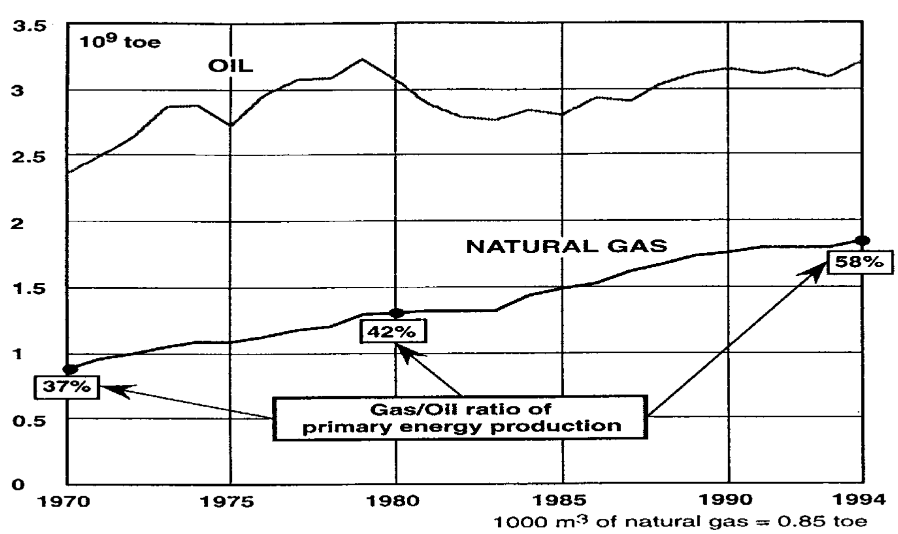

Figure 2.2: Marketed Production of Oil and Natural Gas in the World.
(source: after Cornot-Gandolphe and Chabrelie, 1995 in Rojey et al, 1997)

Geographically, gas discoveries have been made in more than 80 countries including every continent. Countries with significant gas reserves are more numerous than those with significant oil reserves. The global proven reserves picture is dominated by the Commonwealth of Independent States (CIS) with 40% of the world's reserves and the Middle East with 30% (Table 2.1).

Significantly, the industrialized countries of North America and Western Europe, which are large producers and users of gas, only account for just over 10% of proven reserves among them. These western industrialized countries currently account for 44% of world production and just over 50% of natural gas consumption.

Exploration over the past 20 years has yielded much more favourable results in Latin America, Africa, the Middle East, Asia and the CIS than in the western developed countries. Moreover, as these countries are less thoroughly explored than the industrialized countries, their upside potential for reserves additions is probably greater.

Within individual geographic regions, new discoveries are tending to be made in more and more "difficult" areas. For example, in North America, major additions to reserves have been made in frontier and deep offshore locations; in Europe there is the growing importance of the North Sea; in the CIS the major resources are in Siberia. From 1970 to 1990 some 70% of net reserves additions were made in areas which are at the technological and economic frontiers.

Table 2.1: Regional Distribution of Proven Natural Gas Reserves[2]
(source: Rojey, et al, 1997)

Region	***Proven Reserves (Tcf)***	***Ranking***	***Percentage Of World Reserves***
North America	*244*	*6*	*5.0%*
Latin America	*275*	*5*	*5.3%*
Western Europe	*222*	*7*	*4.2%*
CIS	*2,114*	*1*	*40.0%*
Eastern Europe	*25*	*8*	*-*
Africa	*318*	*4*	*6.0%*
Middle East	*1,588*	*2*	*30.0%*
Asia/Oceania	*501*	*3*	***9.5%***
Total	***5,288***		

[2] **Reserves numbers in this report have been derived from a variety of sources. Totals will not always be reconcilable from figure to figure due to rounding errors and differing vintages of data and geographical boundaries.**

In summary:

- On a global scale there are abundant and growing reserves of natural gas, dominated by the reserves of the CIS and the Middle East.
- There is a widening imbalance between the discovery of major reserves and the location of major markets.
- Discoveries of new reserves are increasingly being made in areas with severe operating conditions.
- The industrialized countries are major producers and users of natural gas but their reserves base and resource potential is relatively small. Thus, on a regional basis, they will be the first to encounter growth constraints due to a lack of resources from within the region. ***This situation may place a premium on Newfoundland's gas reserves from regional interests with security of supply concerns.***

Within the supply/demand context described above, two important trends are foreseen:

1. the development of more efficient technologies, operating and business practices designed to reduce the costs of production, processing and transport;

2. the location or relocation of value-added activities as close to natural gas reserves as possible.

2.2.2 International Gas Market Developments

Gas is far more costly to transport than oil on an energy equivalent basis. Most gas is transported either by pipelines or in liquid form as LNG. As a result, gas production is market-limited and only those gas reserves which are close to large markets can be produced on a commercial scale with relatively low reserve-production ratios. Other gas reserves in the world essentially remain under-produced or "*shut-in*" waiting for markets or new and cheaper transport technologies to develop. In these cases, reserve-production ratios are often very high. The following tables divide the world gas reserves in these two categories, based on data for the year 1996.

The tables show that almost half the world gas production comes from only about 8% of the world gas reserves while about 92% of the world gas reserves are under-produced or simply shut-in.

Development of Newfoundland's gas resources must be seen in the context of worldwide competition from about 40 nations in the world. These countries have a total of over 5000 Tcf of gas reserves available, and are also trying to develop their resources. In order to be successful in gas development, Newfoundland must therefore search for the specific types of developments and markets in which the Province would have a natural advantage.

2.2.3 World Gas Price Development

The large amount of gas that is being under-produced or shut-in creates a significant gradual downward pressure on gas prices. During the 1970's and 1980's, domestic gas reserves in the United States and Europe were relatively scarce in relation to demand, while at the same time, the large untapped gas resources in Asia, the Middle East, Latin America and Africa could not be brought into production economically in order to compete in these markets.

As a result, a pricing system developed in these markets linking gas prices primarily to alternative energy sources (crude oil, fuel oil, diesel fuel, coal, etc.). Gas was usually sold at the city gate at a slight discount to oil products. However, as a result of the gradually improving technology and cost reduction related to long distance gas transmission, a pattern of direct gas-gas competition has emerged. This happened first in North America in the 1970's and 1980's and gas-gas competition has now also been introduced in the UK.

With the liberalization of gas markets in Western Europe through the Common Market, it is expected that in continental Western Europe gas-gas competition will become stronger, with gas resources from Norway, Russia, West Asia, the Middle East and North Africa all competing for the European market. It is expected that gas prices in Europe will fall by about 25-30% from 1997 levels as a result.

Table 2.2: Low Reserve/Production Areas
(source: van Meurs, 1998)

Area	Production (Tcf/y)	Reserves (Tcf)	R/P Ratio
Canada	5.83	68.5	11.7
USA	19.08	166.1	8.7
Argentina	1.02	22.7	22.2
Europe (except Norway)	9.39	139.3	14.8
Thailand	0.43	7.0	16.3
Japan	0.07	1.1	15.7
South Africa	0.07	0.8	11.6
Total	**35.89**	**405.5**	**11.3**

Japanese gas consumption was largely based on imported LNG which was expensive to produce and transport to Japan. Typically, it was purchased at a premium relative to crude oil. However, with the emergence of South Korea and Taiwan as important buyers of LNG in Asia, the markets have become more competitive and gas-gas competition has now emerged among many possible LNG development opportunities to serve this market. The gradual reduction in LNG tanker transport cost now makes it possible for Middle East gas producers to compete in the East Asian markets while, at the same time, gas transported by pipeline may become another important source of gas supplies in East Asia.

Table 2.3: High Reserve/Production Areas
(source: van Meurs, 1998)

Area	***Production (Tcf/y)***	***Reserves (Tcf)***	***R/P Ratio***
Mexico	*0.99*	*63.9*	*64.5*
Trinidad	*0.30*	*16.1*	*53.7*
South America (except Argentina)	*1.55*	*181.7*	*117.2*
Norway	*1.45*	*105.9*	*73.0*
Africa (except South Africa)	*3.10*	*332.6*	*107.3*
Russia	*19.81*	*1717.2*	*86.7*
West Asia, Ukraine	*1.98*	*207.2*	*104.6*
Middle East	*5.17*	*1742.2*	*337.0*
Australia	*1.00*	*115.0*	*115.0*
Asia (except Japan and Thailand)	*6.39*	*335.9*	*52.6*
Total	***41.74***	***4,817.7***	***115.4***

An important long-term trend in the world gas markets is therefore increased worldwide connection of gas resources and markets through lower cost pipelines and LNG transport schemes, and as a consequence, increased gas-gas competition. As a result, it is expected that gas markets will increasingly "*disconnect*" from the oil market and the enormous gas resources in the world will result in downward pressure on gas prices relative to oil.

Possible gas developments in Newfoundland must be viewed not only from the perspective of market competition with oil but also from the perspective of other gas projects which compete for the same markets or result in the production of the same products.

2.2.4 Fiscal Systems For Gas

Gas is increasingly developing as an energy source with its own economic development, marketing and financing patterns quite separate from oil. International environmental accords are giving additional impetus to the increasing use of natural gas.

As a result, some governments have started to respond to the fact that gas is an energy source with very different characteristics from oil. Accordingly, fiscal systems are now being developed for gas which are different from oil. Most gas terms involve a lower governmental take than for oil.

The strongest case of a country adopting a concerted policy of offering substantially more favorable terms for gas than for oil is Indonesia. Indonesia accepts a government take which ranges from 30% to 17% lower than for oil. Given that gas development in Indonesia has a low netback to the producer, the policy appears entirely rational. Indonesia also has an aggressive policy of promoting the export of LNG.

Within Canada, Manitoba is the only province which offers a substantial incentive for natural gas by fixing the royalty level at 12.5% as compared to the marginal oil royalty rate of 24.75%. This results in a drop of 15% in government take.

Next in line is Australia whose onshore State regimes exhibit a government take which is roughly 14% lower for gas than for oil. This is because the commonwealth excise tax which applies to cumulative oil production above 30 MMbbl does not apply to natural gas, LNG or LPG.

The same fiscal regime which applies to both France and St. Pierre and Miquelon offers a government take which is also just under 14% lower for gas than for oil. This is partially accomplished by a royalty free gas production of up to 29 MMcf/d with a royalty of only 5% in excess of this amount, as opposed to a sliding scale oil royalty whose marginal rate is 12%.

Trinidad & Tobago is another country which has adopted a clear policy and implementation plan of encouraging natural gas development over the past decade. As the Supplemental Petroleum Tax and the Petroleum Levy do not apply to natural gas, the government take in the case of a natural gas development is almost 14% lower than for oil. ***The success of this strategy was recently witnessed by a Newfoundland trade mission to that country in April of this year.***

This trend is increasing and recently a number of other potential LNG exporting countries have taken steps to introduce significant incentives for gas development. These countries include Qatar, Yemen, and Papua-New Guinea. In addition, Iran has recently concluded a contract with the oil company Total under terms that greatly stimulate gas development.

The fact that both Qatar (with 300 Tcf of gas reserves) and Iran (with 812 Tcf of gas reserves) are taking aggressive steps to make their gas resources economically attractive, indicates that even the huge gas reserves in the Middle East may become increasingly part of a new worldwide pattern of gas-gas competition.

An interesting case for Newfoundland is that Alaska recently passed a new law which dramatically changes the fiscal terms applicable to gas for LNG exports. This now may become the basis for an Arco-led consortium for the production of Prudhoe Bay gas for exports.

It is important to realize, therefore, that it is unlikely that gas development will come about in Newfoundland unless the Province joins the worldwide trend of offering fiscal terms for gas which are substantially more attractive than for oil. The assessment of the Province's competitive position will require the analysis of a variety of factors affecting the value of the resource to prospective developers and resource owners. A key factor is the fiscal regime.

2.3 Regulatory Setting

Management of the offshore hydrocarbon reserves rests with the Canada Newfoundland Offshore Petroleum Board (CNOPB) which administers mirror legislation of the Governments of Canada and the Government of Newfoundland and Labrador. Onshore resources fall under Provincial jurisdiction. In both cases, Legislation covering such major aspects as land tenure, fiscal take, exploration and production operations, are in place. In general, oil developments were contemplated in the drafting of the various pieces of Legislation and usually natural gas is included under the definition of petroleum. Generic royalty regimes have been announced for both the onshore and offshore areas. These regimes have not yet been put into regulations. Whether these systems will apply to oil only or extend to gas is unclear.

As discussed elsewhere, gas specific legislation is advisable where there are clear differences in the development characteristics of oil and gas. Within a competitive investment setting, having an explicit competitive regime for natural gas would be expected to encourage exploration and development by improving potential rewards and providing a firm foundation of established legislation in the assessment of risk factors by the private sector.

3. RESOURCE ENDOWMENT

This section of the report presents an estimate of the natural gas resources of Newfoundland and Labrador within the context of a general discussion on resource estimates. Estimates of natural gas liquids are not specifically addressed.

3.1 Introduction

A resource estimate is a fundamental piece of information for resource valuation and strategic management and development decisions. Yet resource estimations are replete with technical, definitional, methodological and forecasting difficulties. In addition, resource estimates are often used in a political sense to defend or attack a particular negotiating position.

It is necessary, therefore, to look behind any resource estimate numbers to see how they were derived, how they are defined and, finally, how much weight should be given to them. Ultimately, resource estimates are just that - estimates or approximations. As such, resource estimates will change over time as the information base changes and interpretations are revised.

In general, the quality of resource estimates is controlled by the following factors:

- available data base in the subject area;
- body of knowledge from analogous areas elsewhere;
- capability of the estimators;
- validity of modeling and other estimating techniques.

Every resource estimate is qualified (explicitly or implied) by a level of confidence. This may be expressed by stating a range of resource numbers or giving a probability factor to qualify an estimate. Unfortunately, the terms used are often cumbersome and there is no universally accepted norm.

3.2 Definitions and Scope

This report deals with conventional natural gas resources only. While the Newfoundland and Labrador area has significant potential unconventional gas resources in the form of coalbed methane and, especially, natural gas hydrates, these are beyond the scope of the current report.

The terminology and definitions in this report generally follow the usage of the Canadian Gas Potential Committee (1997) Report. A simplified scheme has been used in which the resources are segregated into “Discovered” and “Undiscovered” categories in the various geological basins of the Province. Reference is made to the following terms in this report:

- Discovered Gas Resources are defined as gas and related substances initially contained in known accumulations that have been penetrated by a wellbore (comprising both recoverable and unrecoverable).

- Undiscovered Gas Potential refers to the quantities of gas and related substances which are estimated, at a particular time, to exist in accumulations still to be discovered.

- Total Gas Endowment is the total of Discovered and Undiscovered Gas Resources in a particular geological basin.

- Established Reserves are reserves recoverable under current technology and economic conditions which have been proven by drilling, testing or production plus contiguous recoverable reserves interpreted to exist with reasonable certainty from geological, geophysical or similar information.

- Associated Gas is natural gas that overlies and is in contact with crude oil in a reservoir, at original reservoir conditions. In this report, Solution Gas is included in the associated gas category. Solution Gas is natural gas which is dissolved in crude oil in a reservoir at original reservoir conditions and is normally produced with the crude oil.

- Non-Associated Gas is natural gas found in a reservoir in which no crude oil is present at reservoir conditions.

3.3 Resource Estimates

As noted previously, a fundamental input to any resource estimate is access to current data. Due to proprietary considerations, governmental regulatory bodies are the only groups with full access to all current data. These groups, therefore, have traditionally taken responsibility for producing resource estimates on a timely basis as a primary function of their duty as resource managers.

With regard to Discovered Resources, the CNOPB reviews and publishes their estimates on an annual basis and these number have been used in this report as seen in Table 3.1. The currency of estimates of Undiscovered Resources is far less satisfactory, with most published assessment work being a decade or more out of date.

In this report, information from a variety of published sources was used, with the principal source being noted on Table 3.1 for each basin. In some cases, published estimates have been modified in the light of recent information or experience of the reviewers. The location of the various basins has been taken from a recent presentation by Drummond and is shown in Figure 3.1.

In summary, the Total Natural Gas Endowment for Newfoundland and Labrador is estimated at 61.9 Tcf in place. Of this, 8.2 Tcf is in the category of Discovered Resources comprising 4.2 Tcf on the Labrador Shelf and 4.0 Tcf in the Jeanne d'Arc Basin on the Grand Banks. ***Early performance figures from the Hibernia field strongly suggest the current "official" resource estimate is conservative. On this basis it would be reasonable to increase the Discovered Resources of the Jeanne d'Arc Basin by 30%, to about 5.3 Tcf.***

The Discovered Resources of the Labrador Shelf are in extremely high quality reservoirs. Currently, however, they are at an economic and technical frontier. Since there is little new information from Labrador, current resource estimates are considered adequate. Special circumstances or new technologies could trigger the possibility of an economic development in the Bjarni/North Bjarni area and this possibility should be assessed from time to time. *Specific development work directed at the Labrador resources could hasten their development and form the basis for the export of Newfoundland developed know-how to other similar frontier regions.*

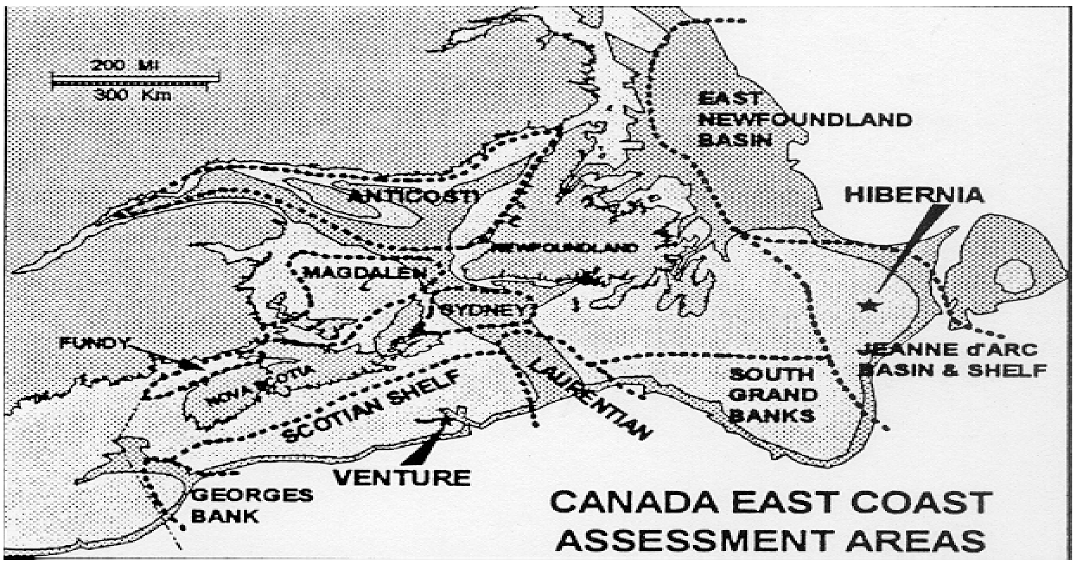

Figure 3.1:	Canada Maritime Region Assessment Areas (source: Drummond, 1998)

At present, the Jeanne d'Arc Basin holds the key to gas development since this is the only basin where there are discovered resources which are potentially developable under current technology and economic conditions. Current estimates of the resource potential of the basin are out of date and probably low in the light of improved exploration and producing technologies and new play concepts. To reflect this, an undiscovered resource estimate of 19 Tcf is presented based on an increasing probability that earlier high-side estimates will be achieved. It is obvious that new resource estimates for the basin are needed on a priority basis if development planning by governments and industry is to have a firm foundation. In view of the current flow of new exploration and production data, this process of resource estimation must be ongoing.

It is noted that while resource estimates by different reviewers seem to be achieving a certain degree of coincidence, this does not mean that they are "correct". Rather, it is suspected that the estimates are mostly projections of numbers from outdated common sources by reasonable people using similar techniques. What is required is a reworking from the "bottom up", applying geological judgement and statistical modeling to the current database.

Resource estimates for Western Newfoundland (onshore and offshore), White Bay and the Laurentian and Sydney Basins, are either non-existent or out-of-date. In view of the exploration interest by companies in the West and South Coast areas, as well as the maritime boundary issue with Nova Scotia, it would be prudent to assess the resources of these areas on an urgent basis. The geochemistry and thermal histories of these areas suggests that there is a high probability of natural gas in some basins. Consideration of proximity to markets and operating conditions would give these basins an advantage over the Grand Banks, if discovered volumes were large enough.

Table 3.1: Working Resource Estimates	
I. Discovered Resources	***Tcf***
a. Labrador Shelf - CNOPB estimate	***4.2***
b. Jeanne d'Arc - CNOPB estimate reasonable chance of 5.2 Tcf through extensions to discovered fields	***4.0***
Totals	***8.2***
II. Undiscovered Resources	
a. Labrador Shelf - NEB/Drummond	***6.0***
b. East Newfoundland basin - Drummond	***13.1***
c. Jeanne d'Arc - Drummond/MIllan	***19.0***
d. South Grand Banks - Drummond	***3.2***
e. Laurentian Basin (50% Newfoundland) - Drummond	***8.9***
f. Anticosti/Western Newfoundland - Millan	***3.5***
Totals	***53.7***
Total Endowment Discovered and Undiscovered	***61.9***

A mechanism is needed to ensure that quantity resource estimates are produced on a timely basis. The Canadian Gas potential Committee provides a useful model of a collaborative process which brings together stakeholders from industry, government and academia to produce unbiased estimates of high technical quality on a regular basis. An adaptation of this model for Newfoundland is proposed, covering both oil and natural gas resources.

3.4 Gas versus Oil

Exploration to date has concentrated on oil, not natural gas. Similarly, earlier resource estimates have considered gas as an adjunct to oil. This approach may well have skewed the results towards oil and placed the gas estimates on the pessimistic side. Deeper parts of the Jeanne d'Arc (ie. to the North) may be gas prone according to recent geochemical work and a gas specific exploration program would probably result in increased discoveries and an enhanced resource base.

To date, approximately 70% of the natural gas discovered in the Jeanne d'Arc Basin is associated with oil. This means that any reserve depletion scheme must account for the effective recovery of both oil and gas, usually with precedence being given to the oil. As a consequence, the rate of natural gas production is dependent on the rate of oil production and gas will only become available when it is not needed for pressure maintenance.

This is currently the case with both Hibernia and Terra Nova developments where gas is needed for re-injection under the present understanding of reservoir performance. With increasing production history this understanding may change. It is noted that in certain cases, associated gas cannot be re-injected and its disposal is a cost. Having a way to utilize the gas resource would be of benefit to both resources and the overall economic return of the area.

The Whiterose field contains major quantities of both oil (178 MMbbls) and gas (1.5 Tcf) in various reservoirs and fault blocks. It may well be an ideal candidate for an innovative combined oil/gas development.

3.5 Resource Distribution

In addition to the estimated overall volume of resources, the distribution of those volumes into discrete fields of various sizes is an important economic/developmental consideration. Obviously, it is better to have a given resource volume distributed into a small number of large fields rather than a large number of small fields.

In a given basin, field sizes tend to follow a log-normal distribution. For the Jeanne d'Arc Basin, the largest field sizes are defined by such major fields as Hibernia, Terra Nova, Hebron and Whiterose (Table 3.2, Chipman 1997). Estimates by the GSC (1992) for the main play-group of the Jeanne d'Arc suggest the following distribution of reserves:

Size Class	**Predicted**	**Discovered**
> 100 MMbbl	*7*	*4*
between 25 and 100 MMbbl	*23*	*3*
< 25 MMbbl	*445*	*7*

The GSC notes that the two size classes above 25 MMbbl contain 2/3 of the resources associated with the main play group in the Jeanne d'Arc Basin. These distribution patterns suggest that there are 3 or more fields containing more than 100 MMbbl oil or oil equivalent still to be discovered plus 20 fields in the range or 25 to 100 MMbbl oil or oil equivalent awaiting discovery.

In the West Coast area of Newfoundland, offshore structures in the Hibernia size range have been mapped by geophysics, while onshore fields in the 25 to 100 MMboe class are targeted by current early exploration efforts. This basin is largely untested with only 4 modern deep wells having been drilled to date, one of which was a geological success.

3.6 Geographical Considerations

Important geographical considerations are:

- the clustering of pools to enable the development and use of common infrastructure.
- the operating environment, especially such factors as wind, sea-state, water depth, pack ice and icebergs.
- distances to nearest landfall and to markets.

On the basis of geographical considerations, the resources of Newfoundland and Labrador fall into the following area classes, listed in order of decreasing severity of the operating environment:

- The Labrador Shelf.
- The Grand Banks.
- The West and South Coast offshore basins.
- The West Coast onshore.

3.7 Conclusions

In the near term, natural gas development interest is focussed on the Jeanne d'Arc Basin where gas resources of between 4.0 and 5.2 Tcf have been discovered. It is estimated that a further resource of 19 Tcf remain to be discovered in this basin. In this basin, approximately two thirds of the discovered resources are contained in large fields (>100 MMboe) and it is predicted that 3 additional fields of this size class remain to be discovered.

The probable development sequence in the Jeanne d'Arc Basin is, in order of development; Hibernia, Terra Nova, Whiterose, Hebron/Ben Nevis. In all of these fields, the natural gas resource is associated with oil and in all fields except Whiterose, the oil resource dominates the natural gas resource. As a consequence, the natural gas resource is tied to oil in terms of rate of production and timing of gas rates to markets.

At present, Hibernia is the only field in production and it is in the early stages of the production cycle. The reservoir depletion scheme currently requires the re-injection of natural gas for pressure maintenance purposes to improve oil recovery. This effectively means that natural gas is not currently available for sale. It is anticipated that in the order of 24 months of production history will be required to adequately judge whether or not the current scheme can be modified to make natural gas available for sales.

The Terra Nova development plan also contemplates re-injecting the associated gas which will be produced with the oil. There is no basis, on publicly available information, to assume that the Terra Nova proponents will adopt another reservoir management plan, prior to developing an historical database from actual production experience.

Table 3.2: Discovered Resources* - Northeast Grand Banks and Labrador Shelf region. (source: Chipman, 1997)						
Field	***Oil***		***Gas***		***NGLs***	
Northeast Grand Banks:	***m^3 x 10^6***	***MMbbl***	***m^3 x 10^9***	***Bcf***	***m^3 x 10^6***	***MMbbl***
Hibernia	*106.0*	*666*	*28.7*	*1,017*	*17.7*	*111*
Terra Nova	*64.6*	*406*	*7.6*	*269*	*2.2*	*14*
Hebron	*31.0*	*195*	-	-	-	-
Whiterose	*28.4*	*178*	*42.7*	*1,509*	*9.2*	*58*
West Ben Nevis	*4.0*	*25*	-	-	-	-
Mara	*3.6*	*23*	-	-	-	-
Ben Nevis	*3.0*	*19*	*6.5*	*229*	*4.7*	*30*
North Ben Nevis	*2.9*	*18*	*3.3*	*115*	*0.7*	*4*
Springdale	*2.2*	*14*	*6.7*	*236*	-	-
Nautilus	*2.1*	*13*	-	-	-	-
South Tempest	*1.3*	*8*	-	-	-	-
Fortune	*0.9*	*6*	-	-	-	-
South Mara	*0.6*	*4*	*4.1*	*144*	*1.2*	*8*
East Rankin	*1.1*	*7*	-	-	-	-
North Dana	-	-	*13.3*	*470*	*1.8*	*11*
Trave	-	-	*0.8*	*30*	*0.2*	*1*
SUBTOTALS	***250.6***	***1,576***	***113.7***	***4,019***	***37.7***	***237***
Labrador shelf:						
North Bjarni	-	-	*63.3*	*2,235*	*13.1*	*82*
Gudrid	-	-	*26.0*	*920*	*1.0*	*6*
Bjarni	-	-	*24.3*	*859*	*5.0*	*31*
Hopedale	-	-	*3.0*	*105*	*0.4*	*2*
Snorri	-	-	*3.0*	*105*	*0.4*	*2*
SUBTOTALS	**-**	**-**	***119.6***	***4,224***	***19.9***	***123***
TOTAL (March 31/93)	***250.6***	***1,576***	***233.3***	***8,243***	***57.6***	***360***
*****expressed at the 50% probability of occurrence						

In Whiterose, the natural gas resource exceeds the oil resource on an energy-equivalent basis but probably not on economic value. In addition, the resources are contained in a number of compartments with differing oil/gas relationships. Whiterose therefore may be a candidate for an innovative co-production scheme for both oil and natural gas.

Current uncertainties regarding the value and timing of marketable natural gas makes the feasibility of development/transportation schemes difficult to ascertain. This is especially true for large inflexible systems, such as pipelines, and suggests that a modular, scalable development holds certain theoretical advantages. While such modular designs have been developed, they have little or no track record.

4. PRODUCTION SYSTEMS

This section of the report is intended to present an overview of natural gas production systems. It begins with a classification of natural gas types, depending mainly on composition. This is followed by a discussion of offshore production facilities (fixed and floating platforms and subsea systems). The section closes with a summary of the processing requirements for compressed natural gas (CNG), liquefied natural gas (LNG), and natural gas chemicals.

To a large extent, this portion of the report is based on a recent text entitled "Natural Gas - Production, Processing, Transportation" (Rojey et al, 1997). All figures and tables are reproduced from this text, unless indicated otherwise.

4.1 Introduction

Three types of natural gas are generally identified:

- Non-associated gas which is not in contact with oil.
- Gas-cap associated gas overlying the oil phase in the reservoir.
- Associated gas "*dissolved*" in the oil at reservoir conditions (also known as *"solution gas"*).

Note that this classification sometimes obscures situations that could be very different within a given category of gas. Some gas-cap reservoirs are relatively marginal, whereas others, in terms of energy equivalence, represent gas reserves that are larger than those of the underlying oil.

The gas/oil ratio (ratio of the volume of gas to the volume of oil at normal standard conditions of temperature or pressure) of the oil reservoirs can vary in considerable proportions, from a less than 1 cf to more than 150 cf of associated gas per cf of oil at the separator.

The following phases of natural gas depend on temperature and pressure in the reservoir and at the surface:

- *"Dry gas"*, that does not form a liquid phase at production conditions.
- *"Wet gas*", forming a liquid phase during production at surface conditions.
- "*Condensate gas"*, forming a liquid phase in the reservoir during production.

A further classification of natural gas is by its hydrogen sulfide content:

- A "*sweet*" gas generally has less than 1% hydrogen sulfide and a sour gas has greater than 1%.

The composition of gases from several fields on the Grand Banks and offshore Labrador (the North Bjarni field) is presented in Table 4.1. This shows that all of the gas in this sample is a high-quality "sweet" gas, with no hydrogen sulfide present in any of the analyses and low concentrations of carbon dioxide. The gases are also dry.

Table 4.1: Composition of Gases, Grand Banks and Offshore Labrador (source: ACOA)					
Field	***Hibernia***	***Hibernia***	***Whiterose***	***Springdale***	***N. Bjarni***
Formation	***Hibernia***	***Ben Nevis***	***Whiterose***		***Bjarni***
Ethane and higher hydrocarbon s	*13.43%*	*12.10%*	*9.11%*	*7.91%*	*14.62%*
Hydrogen sulfide	*0.00%*	*0.00%*	*0.00%*	*0.00%*	*0.00%*
Carbon dioxide	*0.98%*	*0.26%*	*1.42%*	*0.56%*	*0.55%*

4.2 Chemical Composition

The chemical composition of natural gas is a most important factor, because it determines the processing that the gas will have to undergo. Hydrogen sulfide raises the most critical problems but is not an issue in the Newfoundland gases tested to-date.

The production of natural gas often encounters difficulties connected with the plugging of pipelines by the deposition of crystals, first thought to be ice crystals. These crystals are in fact hydrates of natural gas which can appear far above the temperature at which ice is formed. They are inclusion compounds which result from the combination of water with some of the components of natural gas (primarily methane).

To prevent pipe plugging, production and transport installations must be protected from the risks of hydrate formation. One way to achieve this is to dry the natural gas. If this is not feasible, temperature and pressure conditions must be created to prevent the formation of hydrates, otherwise an inhibitor must be introduced.

4.3 Production Facilities

When gas is produced offshore the separation of liquid fractions and the removal of water and sour gases cannot be carried out economically under water before the production flow is sent into the pipeline. Water and certain hydrocarbons are therefore present in liquid fractions and natural gas must then be transported in multi-phase flow. In this case, a solid phase of hydrates may be formed from some of the components present, plugging the flow lines.

After collection, the gas is processed on a platform or onshore. The equipment required for offshore production is often divided between a central platform and satellite platforms. The need to cut costs has led to the simplification of satellite platforms by automation, with control performed from the central platform, and by carrying out most of the gas processing on the central platform. To increase gas production and to offset the reservoir pressure decrease, it is necessary to install a compressor that is generally placed on the central platform as well. Subsea production systems are designed to replace satellite platforms or even ultimately the central platform, by transferring all processing to onshore facilities. The design of the platforms, and of the installations placed on the deck, has also evolved considerably.

The choice of production system to be used offshore Newfoundland consists of the following three alternatives (Figure 4.1):

1. A gravity base platform.
2. Floating production system with subsea completion.
3. Subsea system with satellite field tie-ins to a host platform.

Many of the considerations related to the choice of production system are common for both oil and gas production, and the main factors are summarized below.

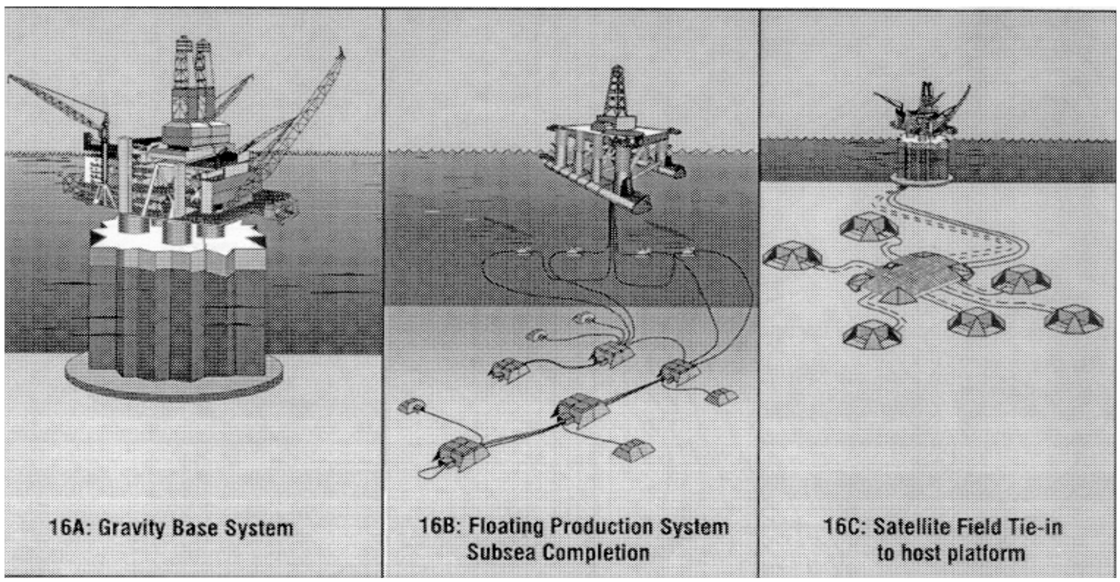

Figure 4.1 Oil and Gas Production Systems for Offshore Newfoundland (source: Chipman, 1997)

4.3.1 Fixed Platform Production

A gravity base system (GBS), as in the case of the Hibernia platform, can be designed to withstand iceberg collisions and pack ice action. However, it requires a large resource base to justify its use. The recoverable gas resources of the Grand Banks fields are likely insufficient to support such a system. However**, *where oil production has justified the installation of a GBS, as is obviously the case for Hibernia, the future production of gas on the same platform is a viable and attractive option, provided that deck space and weight considerations can be met.***

The GBS alternative is also preferred where a large number of wells need to be drilled. The storage space available for LNG, natural gas liquids, or methanol and other chemicals, is generally much larger than that on floating systems. A bottom-founded system will generally have higher operating efficiency than a floater, and it will also solve possible motion-related problems with process equipment. For processes that require larger and heavier items of equipment, a GBS provides far greater topside load capacity. However, in areas of greater water depths, as for offshore Labrador, GBS designs will not likely be viable because of the high capital costs, and the difficulty of incorporating adequate resistance to very large icebergs.

4.3.2 Floating Platform Production

***Outside of the Hibernia field development, it appears that there will be heavy reliance on floating and subsea technology, given the expected resources of both oil and gas fields on the Grand Banks*.**

Floating production systems (whether they are monohull or semi-submersible based) can be disconnected and moved off location in the face of iceberg or pack ice threat. This requires costly disconnect systems, however, and greater potential downtime. Topside load capacity, and storage volume, is reduced. However, one main advantage of a floating production system is that it can be justified for the development of smaller gas fields, and it can even be used to exploit several small fields sequentially, or simultaneously. A floating system can also be used as a satellite development to a larger field.

***Floating systems have not been used to date for LNG or methanol production. However, several promising designs have been developed which merit further study for application to offshore Newfoundland gas fields*;** these are reported on in the chapter which follows.

4.3.3 Subsea Production

Production by subsea wellheads and transport of the gas at the seabed make it possible to eliminate fixed or floating platforms. These solutions are nevertheless faced with major technical difficulties; they require complex installation procedures, as well as elaborate remote control systems for the subsea wellheads.

An example of a subsea production system for deep waters and long distance tiebacks is the Mensa development in the Gulf of Mexico (Figure 4.2).

Mensa's subsea manifold is located over 60 mi from the host platform West Delta 143. The 12-in export pipeline is fitted with a termination sled, and there is also an electrical distribution structure to terminate the power/signal umbilical and also to locate a booster to provide signal enhancement. Three 6-in 5-mi flowlines connect infield wells to the manifold.

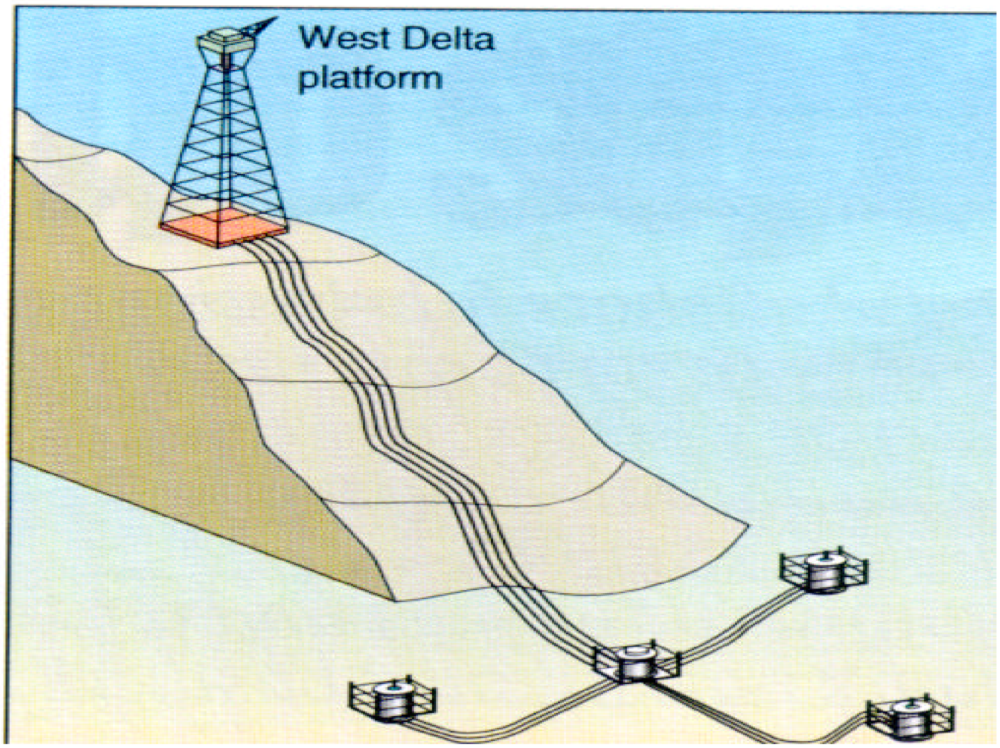

Figure 4.2: Mensa Subsea Production System
(source: Sasanow, 1997)

Special measures were taken to reduce the problem of hydrate formation, through continuous glycol dousing.

4.4 Processing Requirements

The processing of natural gas consists of the separation of some of the components present at the well exit, such as water, acid gases and heavy hydrocarbons, to adjust the gas to transport or commercial specifications. The distribution of these operations between the field and the delivery point is dictated by economic considerations. It is usually preferable to conduct on the production platform only operations that make the gas transportable.

Figure 4.3 shows the main processing operations for dry gas like that which occurs on the Grand Banks. The first step separates the liquid fractions that may be contained in the well stream - the liquid hydrocarbon fraction and uncombined water. The next processing step depends on the transport system adopted. Natural gas and its different fractions can be transported in various forms:

- compressed natural gas (CNG) via pipeline or ship;
- liquefied natural gas (LNG), by ship;
- liquefied petroleum gas (LPG), by pipeline or ship;
- chemicals (methanol, ammonia, urea), by ship.

Each of these transport methods implies a succession of steps and constitutes a gas chain. The various gas chains are discussed in greater detail in the next section.

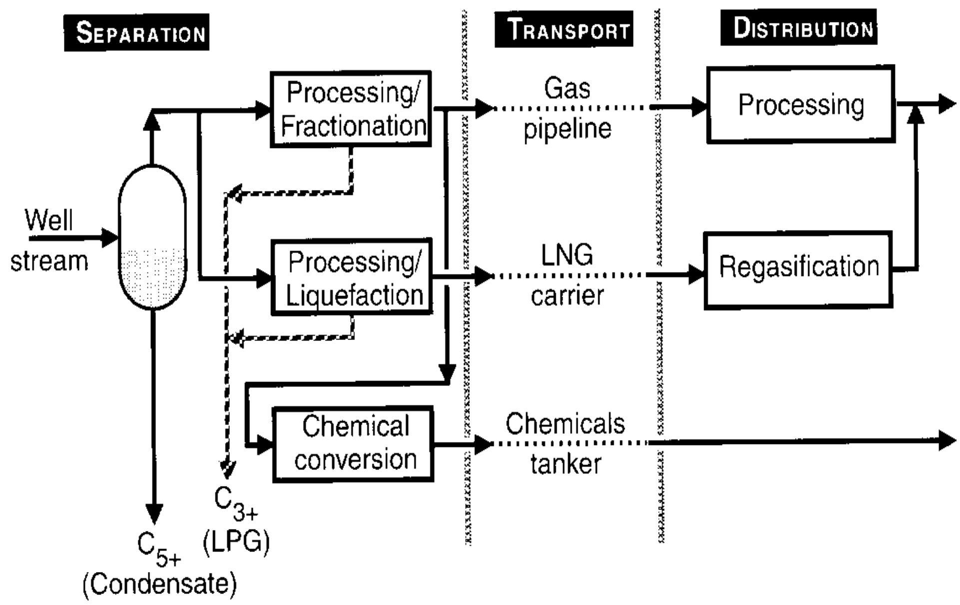

Figure 4.3: Processing Operations (Dry Gas or Condensate Gas) (source: Rojey et al, 1997)

During processing it may be necessary to remove at least partially:

- hydrogen sulfide (H_2S), which is toxic and corrosive;
- carbon dioxide (CO_2), which is corrosive, has no heating value and can crystallize in cryogenic processes;
- mercury, toxic and corrosive, mainly with aluminum-based alloys;
- water, leading to the formation of hydrates and corrosion;
- heavy hydrocarbons, condensing in the transport systems;
- nitrogen, with no heating value.

4.4.1 Compressed Natural Gas

Natural gas must be compressed at high pressure before it can be transported by pipeline. The transport of compressed gas by ship has been so far rejected for economic and safety reasons, but recent technical developments may offer breakthroughs (*see next section*).

For pipeline transport, the transport specifications are aimed at preventing the formation of a liquid phase, the clogging of the line by hydrates, and excessive corrosion. A maximum value is usually imposed on the water and hydrocarbon dew-point temperatures. For a commercial gas, the specifications are more severe and also include a range limited by heating value. The maximum hydrogen content in a processed gas is usually limited to very low values.

Owing to the differences between transport specifications and commercial specifications, further treatment may be required after the transport step, before the gas is sent into the distribution network. The processing carried out to meet transport specifications may be accompanied by fractionation, to obtain a liquid fraction containing LPG (propane and butane) and possibly ethane, if it appears advantageous to upgrade this liquid fraction separately. In some specific cases, nitrogen separation may be necessary, and helium recovery may also be required if it is present in the gas.

If the natural gas is to be liquefied, prior processing must eliminate possible crystallization in the heat exchangers of the liquefaction plant. Fractionation between methane and the heavier hydrocarbons is usually carried out during liquefaction. Accordingly, the gas obtained after regasification of the LNG reaching the receiving terminal can normally be sent directly into the distribution network.

4.4.2 Liquefied Natural Gas

Liquefied natural gas must remain liquid at atmospheric pressure. The temperature at which natural gas is stored in liquefied form is close to the boiling point of methane. The gas is liquefied under pressure, then subcooled to be kept liquid at atmospheric pressure.

Liquefaction is carried out at a pressure determined by economic factors. A higher pressure reduces the energy required to liquefy the natural gas, since the temperature range during the liquefaction process rises. Natural gas is liquefied over a temperature interval owing to the presence of hydrocarbons other than methane. The initial liquefaction temperature is higher with increasing contents of heavy hydrocarbons. For instance, it may begin at around -10^{o}C and continue to a temperature close to the vapor-liquid equilibrium temperature of methane under pressure (around -100^{o}C). The third liquid phase obtained is then subcooled to the boiling point of LNG at atmospheric pressure.

Small units processing up to 100 MMcf/d of natural gas provide storage capacities to meet variable demand needs (peak-shaving plants), by storing LNG in low- and medium-consumption periods, and by re-vaporizing it during peak periods. The refrigeration cycle used for such a plant has to remain simple. It is generally a single cycle operating either with a mixed refrigerant, or with a permanent gas such as nitrogen refrigerated by expansion in a turbine and, after heat exchange, recompressed and recycled.

Various concepts for gas liquefaction offshore and in "*difficult areas*" have not hitherto been applied for economic reasons. One of the most attractive concepts involves the transportation of liquid nitrogen on the carrier return route, the vaporization of the nitrogen being used to liquefy the natural gas. This operation can be performed directly on the carrier, with the nitrogen discharged to the atmosphere. Liquid nitrogen is obtained onshore by air fractionation, exploiting the refrigeration produced by the vaporization of LNG (Figure 4.4). This system is referred to as the "*cold-box shuttle."*

The cold ambient temperatures of the local operating environment is a positive element for any cryogenic scheme.

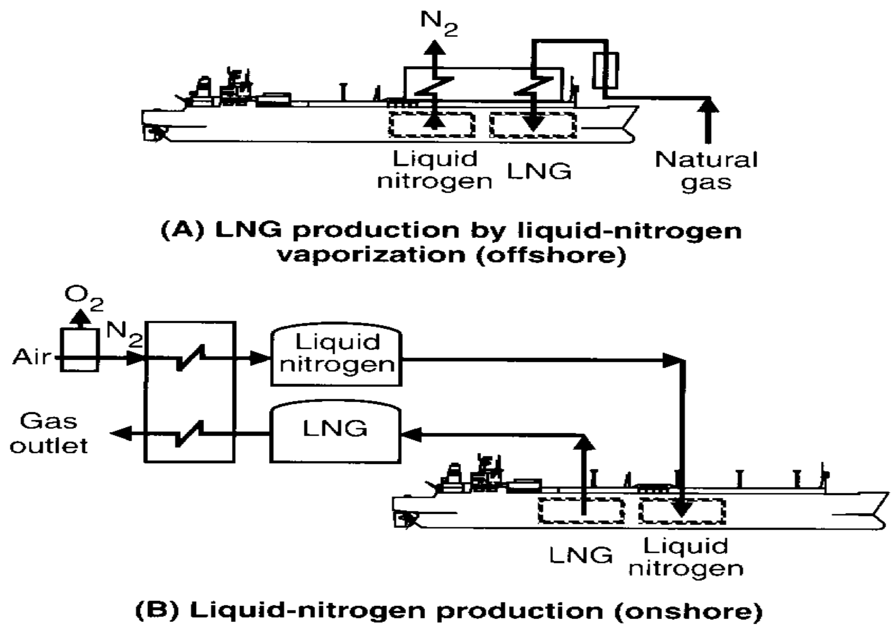

Figure 4.4: Natural Gas Liquefaction by the "*Cold Box Shuttle*"
(source: Rojey et al, 1997)

4.4.3 Natural Gas Chemicals

Methane can be transformed by chemical conversion to a liquid at ambient conditions. The desired product is usually a fuel that is easy to transport and use: gasoline, kerosene or gas oil. This operation can be achieved by using different routes, as illustrated in Figure 4.5.

With the exception of methanol synthesis, a widely industrialized process, methane chemical conversion has not been applied to a large extent. The difficulty of activating methane chemically makes such operations relatively complex and expensive.

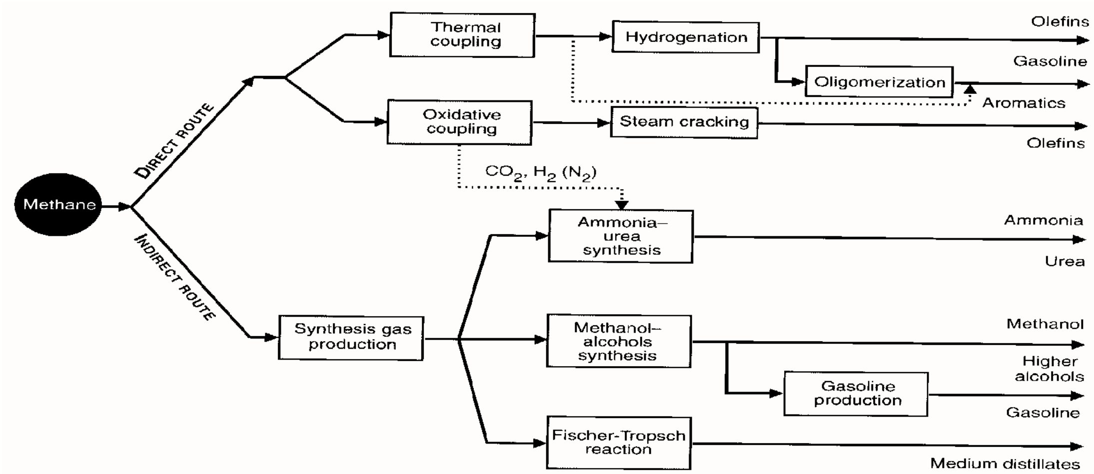

Figure 4.5: Routes for the Chemical Conversion of Methane.
(source: Rojey et al, 1997)

At the present time, the only route applied industrially is the so-called indirect route involving the production of a synthesis gas, a mixture of carbon monoxide and hydrogen. After adjusting the composition of this mixture, two alternatives are available:

1. Direct synthesis of liquid hydrocarbons.
2. Synthesis of methanol or a mixture of methanol and higher alcohols which can either be incorporated directly in the fuels, or converted in a second step to liquid hydrocarbons or others.

The direct route involves an attempt to convert the methane directly to liquid hydrocarbons (oxidative coupling or thermal coupling) without transiting through a mixture of carbon monoxide and hydrogen.

In the future, the market for the chemical conversion of natural gas could grow considerably, either in a situation of higher crude-oil prices, or if technical advances improve the profitability of the processes. The upgrading of methane in the form of chemicals may offer an attractive alternative to natural gas transport by pipeline.

4.5 Conclusions

The natural gas which is commonly found on the Grand Banks or offshore Labrador is a high quality sweet gas, with no hydrogen sulfide, and low concentrations of carbon dioxide. Both associated and non-associated gases are present.

Given the expected resources in the gas fields of the Grand Banks, it is likely that there will be heavy reliance on floating and subsea technology in the future. Floating systems have not been used for LNG or methanol production to date, however. Production by subsea wellheads and transport at the seabed is faced with major technical difficulties, but offers major potential for the future.

5. TRANSPORTATION SYSTEMS

This chapter on transportation systems covers the technology and costs of alternative means of transporting offshore natural gas. The traditional transportation modes in the past have been pipelines and LNG carriers, but new technologies of methanol and CNG transport are currently under development.

5.1 Introduction

Natural gas is currently transported either by pipeline in the form of compressed gas or after liquefaction, by LNG carrier in the liquid state. It can also be transformed by chemical conversion.

Figure 5.1 shows the different "*gas chains*" that encompass production, transportation and distribution.

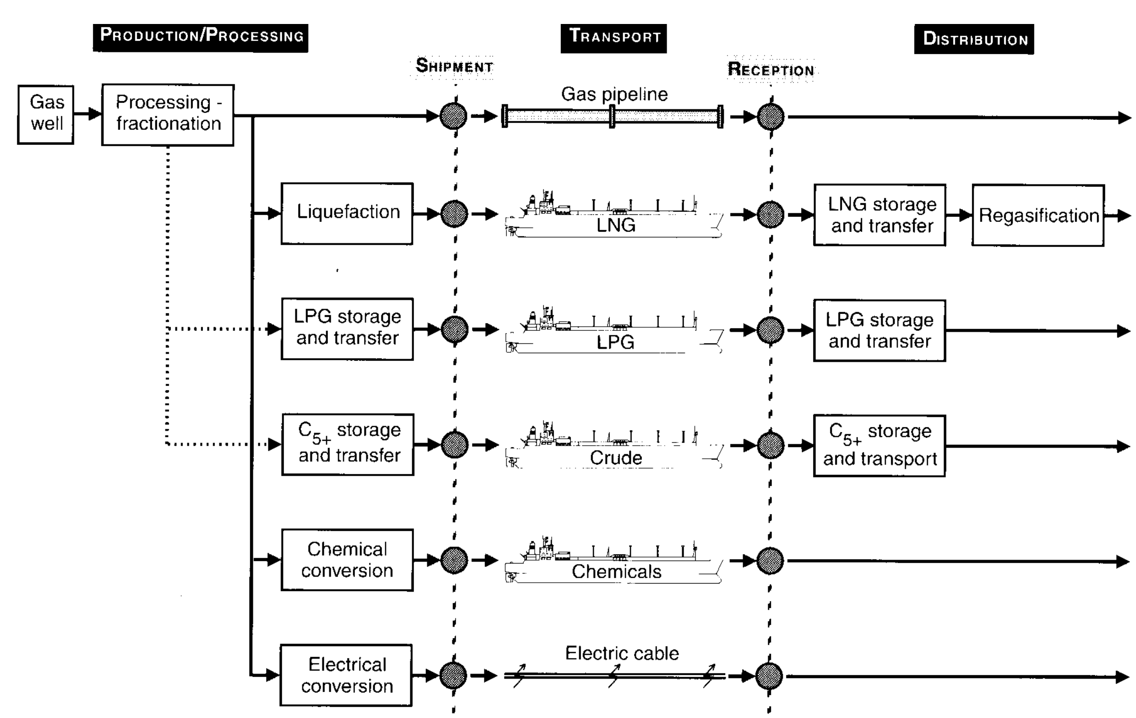

Figure 5.1: Gas Chain for Production, Transport and Distribution (source: Rojey et al, 1997)

Pipeline transport is the simplest solution, but requires the installation of a network of pipelines connecting the production and receiving points.

Transport by LNG carrier requires liquefaction of the natural gas, which is transported in the liquid phase at atmospheric pressure at about -160°C. The transport by ship of pressurized natural gas was investigated at one time, but has so far been discounted for reasons of cost and safety.

It is possible to transform the natural gas chemically into a liquid product at ambient conditions, such as methanol or gasoline. Until recently this alternative was faced by technical and economic obstacles but is now again attracting interest. It is also possible to convert the combustion heat of natural gas into electrical energy and transport the energy by subsea cable. Owing to the relatively high costs involved, this solution has not been applied so far on a large scale. However, power generation using natural gas as a primary energy source is spreading today. Modern combined-cycle power plants have very high efficiencies and are also favored by environmental legislation.

If the natural gas contains a significant amount of hydrocarbons other than methane (in the form of condensate gas or associated gas), the separation and separate transport of the heaviest fraction (LPG) is quite common.

5.2 Transportation Systems

5.2.1 Pipeline Transport

The growth of natural gas transport by pipeline has led to the establishment of a large network of pipelines throughout the world. The total length of the world's gas pipelines is about twice the length used to transport crude oil, and is more than 600,000 mi.

Table 5.1 lists the figures for the international natural gas trade, indicating the quantities transported annually by pipeline and LNG carriers. Note that the share of LNG rose from about 6 to 24% between 1970 and 1994.

Table 5.1: International Natural Gas Trade (Tcf/y)
(Source: Rojey et al, 1997)

Year	*1970*	*1975*	*1980*	*1985*	*1990*	*1994*
Pipelines	*1.52*	*3.96*	*6.28*	*6.28*	*8.31*	*9.71*
LNG carriers	*0.09*	*0.46*	*1.11*	*1.80*	*2.55*	*3.10*
Total	*1.61*	*4.42*	*7.10*	*8.08*	*10.86*	*12.81*

The design of gas pipelines presents some major challenges, however, new software packages and ample experience have provided a systematic design basis.

An important early task is the selection of a pipeline route. Rough seabeds, hard or very soft soils, boulder fields and iceberg scours, are areas to be avoided. The choice of landfalls and platform approaches are important. Suitable pipeline materials need to be investigated in conjunction with fluid properties and temperatures. There is a choice between rigid pipe and flexibles, carbon steel, stainless steel, as well as clad and lined pipes. The designer needs to consider materials for anti-corrosion coatings, concrete coatings, field joints, thermal insulation and anodes. In addition to the hydrate problems identified earlier, the pipeline must be designed for high flowline pressures and stability at the seabed.

One of the principal reasons why gas pipelines can be constructed quickly and economically is the development of large and efficient pipelay vessels (Heerema, 1998). One such vessel is the "Solitaire" owned by the Allseas Group SA (see Figure 5.2).

The vessel is capable of a sustained lay rate of about 4 mi per day, and can install pipeline of all sizes, up to 26 in and higher. It relies on dynamic positioning, so that anchor handling vessels are not required. Because of the length of the vessel, pitch motions are minimized. Welding operations are totally automated, and pipelines can be installed in water depth exceeding 3000 ft.

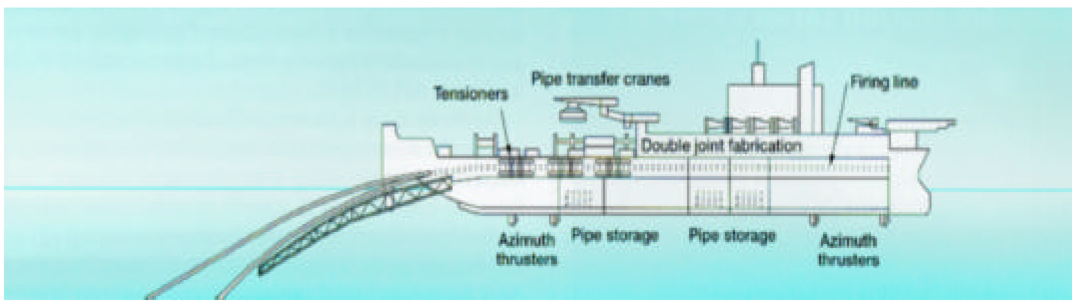

Figure 5.2: Solitaire Pipelay Vessel
(source: Heerema, 1998)

5.2.2 LNG Transport

An LNG transport chain includes the following main steps (Figure 5.3):

- Processing and pipeline transport to the coast. These operations are similar to those conducted in the gas-pipeline transport system.
- Processing of the gas produced to meet liquefaction specifications.
- Liquefaction of the gas, possibly accompanied by fractionation.
- Storage and loading (shipping terminal).
- Transport by LNG carrier.
- Reception and storage.
- Regasification.

An alternative to this gas chain is offshore liquefaction but this has not been implemented to date.

From the outset, two LNG shipment concepts have coexisted; one using integrated tanks and the other using self-supporting tanks. LNG carrier capacities have evolved significantly over the years. A typical figure today is 125,000 m^3 (4.4 MMcf) of LNG. LNG ships are constructed with a double hull. The inner hull gives added protection from collision and the void space between the inner and outer hull can be used for ballast water.

In the integrated-tank technology, the forces exerted by the LNG cargo are transmitted by a metallic membrane to the ship's hull, through rigid load-bearing insulation (Figure 5.4). In the Technigaz concept, the tanks are made of a flexible stainless steel membrane, which rests on the hull via an insulator and a secondary barrier designed to protect the cargo tanks from any LNG leakage. Twelve LNG carriers have been built (total capacity 50 MMcf of LNG) using the Technigaz technique.

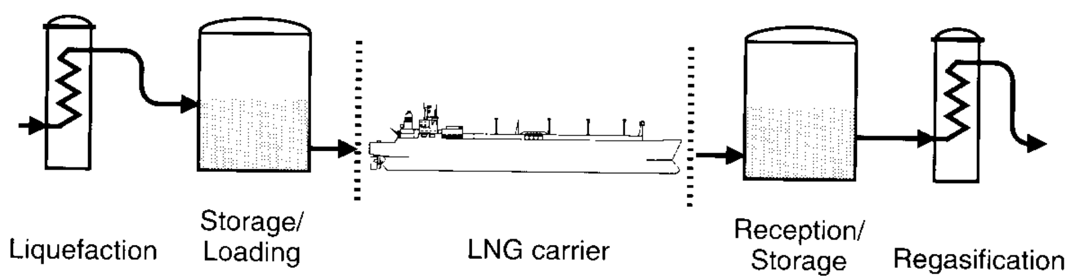

Figure 5.3: LNG Transport System
(source: Rojey et al, 1997)

In carriers with self-supporting tanks, the LNG reservoirs completely withstand the stresses generated by the weight of LNG that they contain. The Norwegian company Moss Rosenberg introduced the concept of spherical self-supporting tanks. The LNG is contained in four to six spherical tanks (Figure 5.5). The spheres are insulated but a gap is maintained between the tanks and the insulation. This space is filled with dry air which, if required, can be replaced by inert gas (nitrogen). Each tank is supported by a cylindrical skirt that rests on the hull of the carrier. A second safety barrier is placed at the base of the tanks to protect the hull of the ship against any LNG leakage. This design has been adopted by various Japanese shipbuilders. Forty-five ships have been built to this design (with a total capacity of 194 MMcf of LNG).

5.3 Assessment of Risks

The assessment of risks is a particularly important aspect in the evaluation of transportation options of the Grand Banks.

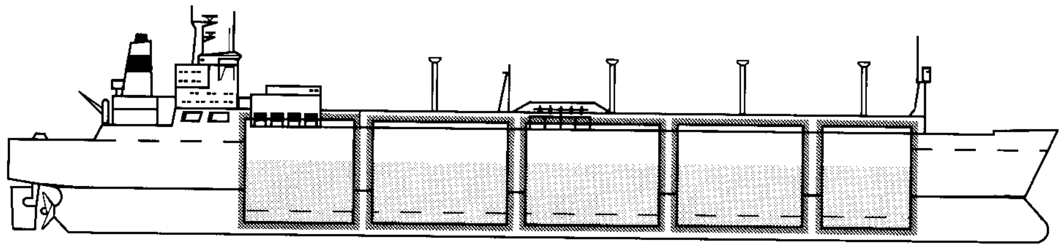

Figure 5.4: LNG Carrier with Gaz Transport Membrane
(source: Rojey et al, 1997)

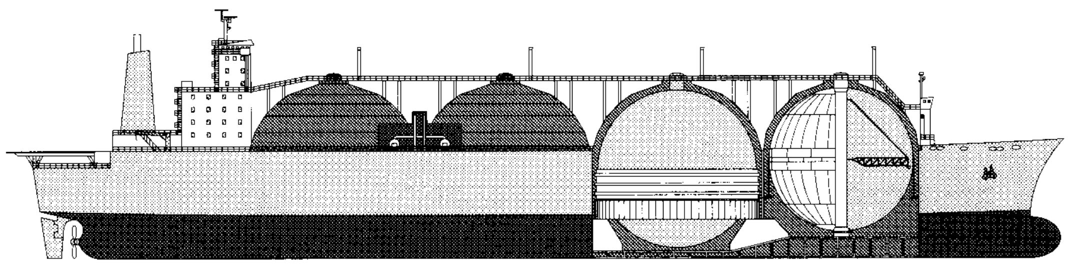

Figure 5.5: LNG Carrier with Moss Rosenberg Self-supporting Tanks
(source: Rojey et al, 1997)

For fields of the size contemplated, pipelines would likely be the preferred option if the Grand Banks were located in some other part of the world. Iceberg threat is the principal obstacle to development; in other areas corrosion and mechanical damage are the main risk considerations, but solutions to these problems are now almost routine.

A gas pipeline from the Grand Banks to shore will be at least 250 mi long, depending on the route and the landfall. One method of protecting a pipeline from iceberg scour is burial, but this will be prohibitively expensive and the presence of exposed rock along the route will preclude burial in certain sections. Iceberg management, through towing or even iceberg destruction, will very likely not be feasible, considering the size of the area which must be patrolled, and the lack of success with the towing and blasting of icebergs to date.

It seems likely that the only reasonable, and economical method of iceberg hazard mitigation is the following:

- Careful selection of a pipeline route to follow natural trenches or low areas of the seabed.

- Effective design of shutdown systems along the pipeline route, which can close down the pipeline when pressure losses are detected.

- Testing and implementation of pipeline repair techniques in the event that pipeline damage does occur.

Vessels that are used for natural gas transport (whether the gas is in the form of LNG, CNG or methane) also must face the iceberg threat, but the technology for iceberg detection from land, planes and ships has advanced considerably. The detection of small iceberg masses, especially during storms, has remained a difficult problem, but with careful design of ice-resistant bows and double-skin hull construction, the hazards of potential impact can be minimized.

5.4 Benchmark Production and Transportation Systems

A brief review of the literature was carried out, together with an assessment of new technologies, some of which are not published, but which are described in reports forwarded to local industry and government departments.

This review is by no means exhaustive, owing to the limitations in schedule and budget. In particular, projects and technologies with particular relevance to East Coast gas developments were investigated. The information gathered was also essential to the analysis of investment costs which follows.

5.4.1 Offshore Gas Pipeline for Multi-field Development

The AMOCO-operated Central Area Transmission System (CATS) is a pipeline and processing facility which connects the central North Sea hydrocarbon fields directly to the UK gas market (see Figure 5.6). This project is particularly relevant because the pipeline is of similar length to that needed for the Grand Banks. The pipeline portion became operational in 1993 at a cost of £400 million. Its 1.68 Bcf/d capacity is now fully contracted out. The pipeline is 36 in diameter and 250 mi in length. The published cost is equivalent (in US$ at today's foreign exchange rates, and ignoring inflation) to a unit construction cost of $72,400 per in-mi.

A decision was made early on in the CATS project to make the pipeline as big as possible, to cope with undeveloped fields coming on stream at a later date. This year, CATS is expected to carry about 20% of the entire UK gas production.

The pipeline must withstand the hostile conditions of the Central North Sea, and is made of high-strength steel with a maximum wall thickness of 1 in. For extra protection and weight it is coated with concrete on the outside. The pipe's interior is lined with an epoxy film to reduce friction and abrasion.

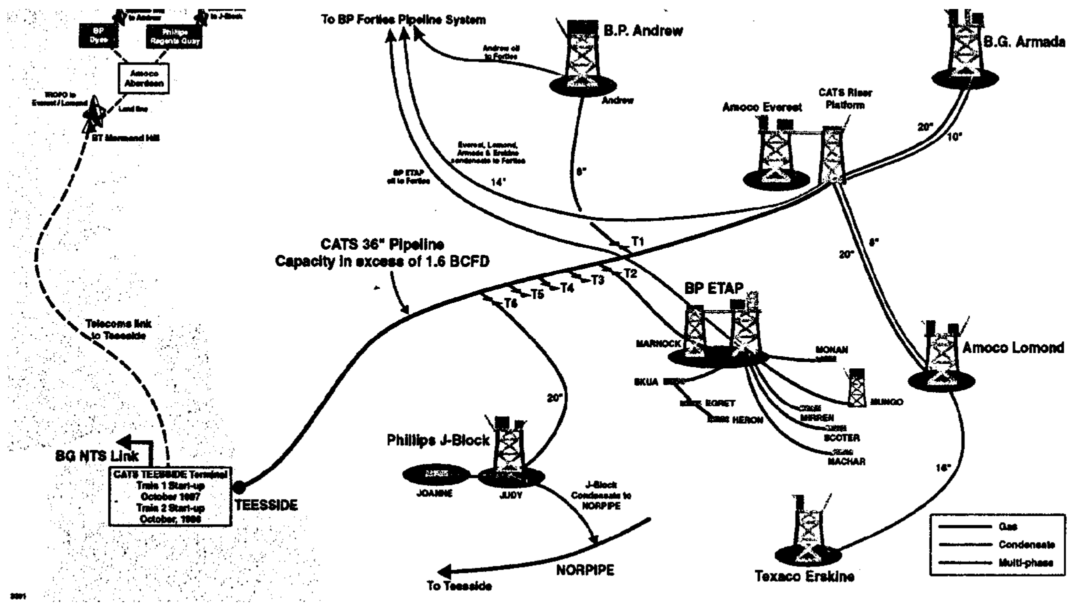

Figure 5.6: The CATS Pipeline and Infrastructure
(source: Anon., 1997)

5.4.2 Floating LNG Plant

Mobil Technology Co. has developed a unique floating LNG plant design. The result is a production, storage and offloading platform to produce 6 MMt per year of LNG and up to 55,000 bbl/d of condensate from 1 Bcf/d of feed gas. At an estimated cost of $6 billion, the unit cost of the facility is $20.50 per Mcf/y. The design team estimates that the LNG platform has potential cost saving of around 25% over conventional onshore facilities (Bhattacharjee et al, 1997).

All production and off-loading equipment is supported by a square donut-shaped hull (Figure 5.7), which is spread-moored. It was designed primarily for locations in the Pacific Rim, with water depths up to 650 ft. The hull is constructed of reinforced concrete.

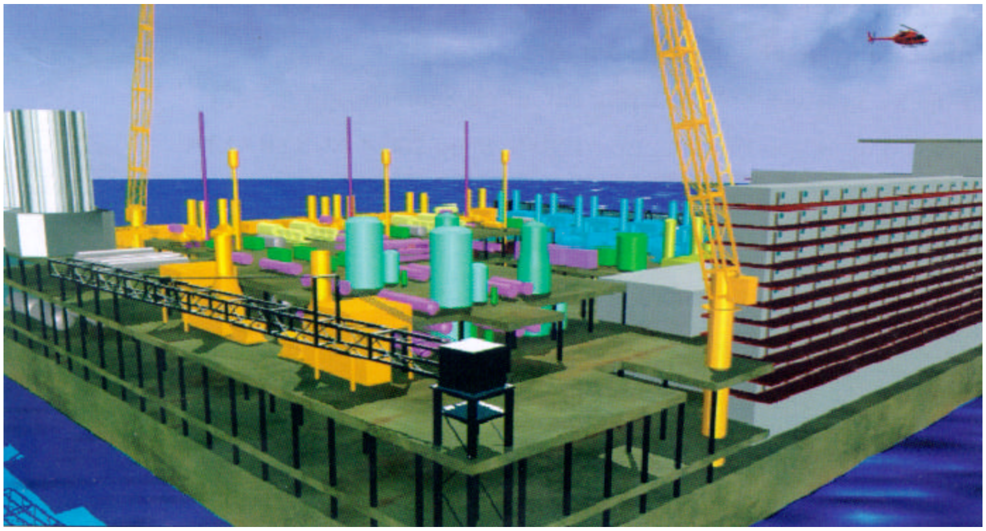

Figure 5.7: Floating LNG Plant
(source: Bhattacharjee, 1997)

Taking gas from subsea wells, the floating plant produces, stores and offloads LNG and condensates. It does not perform drilling and workovers, but otherwise is fully self-sufficient. Using a single refrigerant process, the facility is able to handle gas containing up to 15% CO_2, 100 ppm H_2S, and 55 bbl of condensate per Bcf of gas.

The barge and its mooring were designed around a fairly severe Pacific Rim environment. The environmental forces will be very large, compared to what is typical for FPSOs, since the barge has 165-m long sides. To anchor such a large barge in the shallow waters of the Grand Banks may be a problem.

5.4.3 LNG Technology for Marginal Fields

BHP Petroleum Pty. Ltd. has unveiled a new LNG process claimed to make the development of marginal and offshore projects viable. It enables LNG production at volumes as low as 1 MMt per year. The process is based on the conventional nitrogen cycle that has been successfully employed by Linde AG in small, peak shaving LNG plants.

Its attractions for offshore LNG production is its simple design using a single refrigeration cycle, with relatively few equipment items. However, the nitrogen cycle's inefficiency at this scale is a barrier - it requires three times more power than a comparable baseload LNG plant.

BHP has designed a topsides layout with the Compact LNG process and storage tanks on a GBS, specifically for the Timor Sea. According to a published article (Anon, 1998), "Compact LNG technology may one day be used for floating LNG facilities. However, floating facilities require the future development of a safe and reliable cryogenic offloading system for the transfer of LNG".

5.4.4 CNG Shuttle with Power Generation

A report has been prepared by Cimarron Engineering Ltd. of Calgary, on the transport of CNG from the Grand Banks to the island of Newfoundland (Cimarron, 1998).

The solution basically consists of storing CNG in pressure vessels made from composite reinforced steel line pipe. These pressure vessels are contained in the hold of a ship, and are integrately connected so that processing of the gas can be done while the ship is en route. The development of composite pressure vessels has reduced the problem of excessive weight. The composite system increases steel toughness and retards rupture characteristics so that high safety factors can be attained.

On arrival at the unloading dock, the processed gas will be discharged at a simplified LNG facility. Discharging of high-pressure refrigerated gas will allow for a very simple cryogenic system.

A feasibility analysis was carried out to investigate a power generation option for the Placentia Bay region. Specifically, a power plant producing 285 MW of electricity would require about 50 MMcf/d of fuel gas (with plant efficiency of about 80%). The associated liquefaction plant would have a capacity of about 70 MMcf/d. Three CNG shuttle ships would be required, each carrying about 100 MMcf at 2000 psi. The round trip would take about 72 hours. It was estimated that the cost of three vessels, including containment systems and process equipment will be about $180 million, and the onshore facilities about $360 million.

5.4.5 Gas Transport with "Coselle" CNG Carrier

The Calgary firm of Cran and Stenning Technology have applied for worldwide patents on a new type of pressure vessel which may radically change the economics and safety of CNG transport (Cran and Stenning, 1998). The Coselle containment system consists of several miles of small diameter pipe coiled into a carousel (hence the word "*coselle*"). Figure 5.8 shows a CNG carrier with both a coselle and a traditional pressure bottle containment system.

The coselle pressure vessel is claimed to have the potential to significantly lower the cost of CNG marine transport. The ships are double-hulled carriers filled with coselles. The pressure vessels represent about half of the total ship capital cost and so their design and cost are of critical importance. The vessels are estimated to cost about $100 to $125 million each - each vessel has a capacity of about 300 MMcf of export gas.

The advantages of CNG transport are numerous. The onshore facilities are modest (dehydration and compression). The threshold volume for start-up is much smaller than for LNG and capacity can expand in step with growing demand. The ship can be built in reasonably-sized shipyards so prices will be competitive. The "*low-tech*" nature of a CNG project also provides industrial benefits to the host country. Loading and unloading problems are minimized.

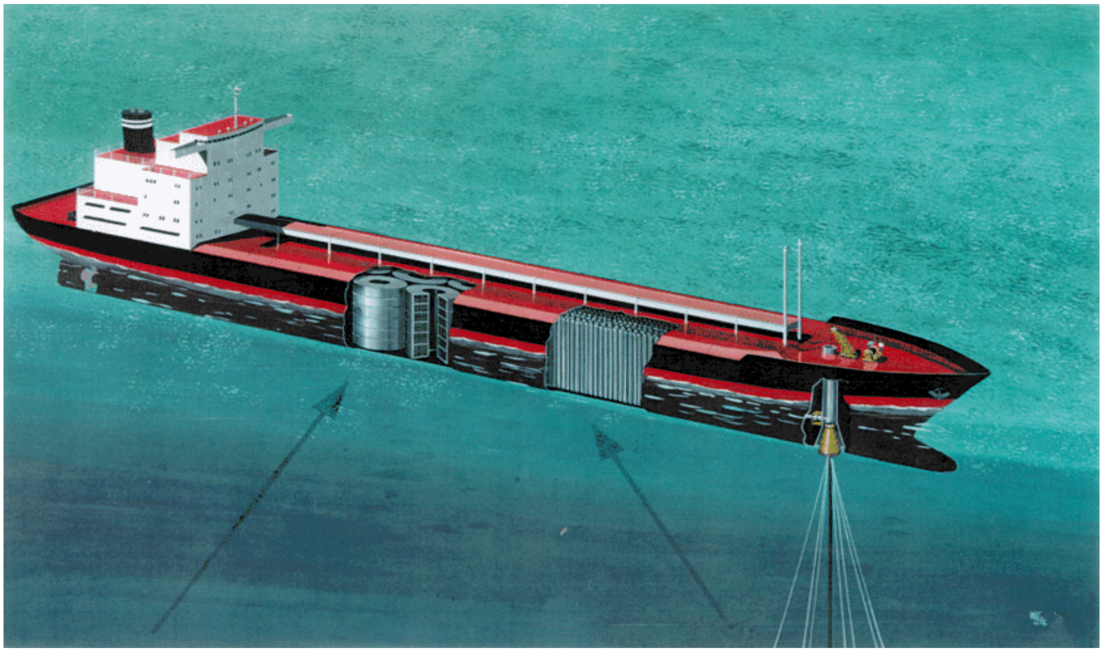

Figure 5.8: CNG Carrier
(source: Cran and Stenning, 1998)

5.4.6 Enhanced Gas-to-Liquids Technology

A growing inventory of gas reserves in Atlantic waters is prompting exploration groups in north-west Europe to study prospects for commercial recovery from deep and distant locations with no existing infrastructure (Frazer, 1997).

Texaco has an agreement to study applications of enhanced gas-to-liquids technology developed by the Tulsa-based company Syntroleum from the Fischer-Tropsch process pioneered in Germany in the 1920's. Syntroleum claims its compact units can be packaged for use offshore on fixed platforms or floating production installations.

Calculations by energy analysts at Wood Mackenzie suggest that "the economics of gas-to-liquids technology are starting to rival typical investments in LNG."

5.4.7 Methanol Conversion and Transportation

Solco Energy AS of Norway has developed a new floating production system that converts natural gas to methanol. Most of the existing methanol technologies require large volumes of pure oxygen in combination with open flame burners. This makes them relatively unsafe for offshore applications, and additional weight, size and motion sensitivity problems are also involved (Solco, 1997).

Solco's process is based on new convection reformer technology that was originally developed for the ammonia and fuel cell industries. The technology has been proven at a pilot test plant in Houston, and work is presently underway on the detailed design of a Methanol Production System Vessel (MEPS). The vessel will be able to process both crude oil and methanol at the same time, so that associated gas can be recovered and utilized economically.

A preliminary design has been developed by Solco, from which the unit cost and performance data used below has been derived. The assumed gas production is 80 MMcf/d, and methanol production 2700 t/d. The total capital cost of the floating production system is estimated to be $500 million. This translates into a unit cost of production of about $17.00 per Mcf/y.

One of the potential benefits of the methanol conversion process is that the methanol can be converted to olefins, which are a basic chemical feedstock in the production of ethylene and propylene. These materials are in turn the starting materials for most of the world's chemicals and plastic industries. It has been estimated by Solco that a methanol-to-olefins plant in Newfoundland would cost approximately $2 billion to build; it would create up to 3,000 construction jobs in the first 2-3 years, and up to 800 long term jobs. Methanol can also be used in fuel cells, which can generate electricity without combustion.

5.5. Capital Investment Comparisons

An Excel spreadsheet model was developed to calculate capital investment costs to bring natural gas to shore from the Grand Banks. No exploration or production costs are included. The main assumptions, input data and results of the cost model are discussed below.

Four different alternatives are considered:

- Transportation of gas by pipeline to shore.
- Floating LNG plant, shipment of LNG by LNG carrier.
- Floating methanol plant, shipment by tanker.
- Compressing the gas and shipment of CNG by CNG carrier.

It is assumed that the gas is brought to shore in the Argentia/Long Harbour area.

5.5.1 Basis of Cost Model

All capital costs were estimated on the basis of reasonable assumptions of typical current costs. Cost figures are based on a study by van Meurs & Associates Limited (1997), and the references quoted for the projects described above. It must be stressed that the costs are order-of-magnitude only and in some cases it is doubtful whether the unit costs can be scaled up or down for various gas flows.

Pipeline Transportation

It is assumed that the gas is compressed and conditioned on an existing platform. Some conditioning is required onshore, but otherwise the gas goes straight into a distribution system (not costed).

Pipeline costs are very different for various projects. The pipeline costs estimated in this report apply only to the main line from the gas field or gas fields to the liquefaction plant or distribution system onshore. Costs depend on the diameter of the line, the length of the line and the nature of the seabed. The costs of offshore lines is higher than for onshore lines and difficult seabed conditions increase costs.

The assumptions for pipeline design and costs have been checked against several recently completed projects such as the CATS project described above. The published cost of the CATS pipeline is equivalent (in US$ at today's foreign exchange rates, and ignoring inflation) to a unit construction cost of $72,400 per in-mile. The report by van Meurs & Associates assumes unit cost of $80,000 per in-mile and this figure is used here.

A standard compressed gas pipeline formula was incorporated in the spreadsheet which calculates the required pipeline diameter for a specified total flow and pipeline length. The pipeline is assumed to be 310 mi long. The costs of gas processing and receiving are arbitrary - these are generally the lowest of any system considered.

LNG Transportation

It is assumed that the LNG system includes a floating liquefaction/storage platform which is linked to a fixed or floating platform which produces the gas. The floating platform processes and liquefies the gas and transfers the gas to LNG carriers.

The cost of the floating LNG plant is based on the projected cost of the Mobil plant design described in the previous section (although it is uncertain whether the unit costs are reasonable for smaller throughputs).

The cost model uses the concept of "*standard*" ships. A "*standard*" LNG carrier has 4.4 MMcf of LNG capacity, and an average speed of 17.5 knots. The cost of a standard ship was assumed to be $250 million. The tonnage that can be transported depends on the distance and the composition of the gas. Some of the volume "boils off" during transport in order to keep the gas at very low temperatures and some of it needs to be maintained as ballast.

The shipping distance to Argentia from the Grand Banks is taken as 310 mi (identical to the pipeline length), which results in a return voyage time of 7.3 days, with an allowance for mooring, loading and unloading time.

Methanol Transportation

The costs of a floating methanol plant are based on the estimates provided by Solco Energy AS. Since the plant can process gas and oil at the same time, it was arbitrarily decided that 25% of the capital costs can be attributed to the production of natural gas. Naturally, this assumption has a major impact on the results.

It is also assumed that the chemical carriers have a 25,000-ton capacity, and the same operating characteristics as the LNG carriers, with less time required for loading and unloading. The vessels are assumed to cost about $75 million each.

CNG Transportation

The unit costs of CNG shipment are based on figures provided by Cran and Stenning.

It is assumed that the natural gas is conditioned and compressed on an existing platform which produces or collects the gas. The gas is then transferred to a CNG vessel, which brings the CNG to a receiving terminal. The CNG vessels are each estimated to hold about 320 MMcf of gas, and are estimated to cost $125 million. Their operating characteristics are assumed to be similar to those of the chemical carriers.

5.5.2 Cost Comparison Summary

The total investment cost for a transportation system, including provision for processing, loading and receiving, are summarized in the tables that follow (Tables 5.2 to 5.6).

Five levels of gas throughput are analyzed, starting with a flow of 100 MMcf/d (for a small single field operation) to a maximum of 500 MMcf/d (equivalent to a multi-field operation on the Grand Banks). The tables show the breakdown for three major cost elements, and also the size of pipeline or number of vessels involved in each delivery system.

For example, a daily flow rate of 100 MMcf/d will require a 14-in pipeline, a single LNG carrier, a single methanol tanker or two CNG carriers. (Note that no attempts have been made to optimize pipeline or vessel sizes, or tanker storage requirements at the front or back end of the system.)

The total costs need to be considered with care, and at this level of analysis they are suggestive of trends and overall comparisons only. The costs shown in the tables are expressed as unit costs in Table 5.7, and in the graph in Figure 5.9.

The general conclusions that can be drawn from this first-level analysis are as follows:

- The use of a floating LNG plant and one or more LNG carriers is in all likelihood prohibitively expensive for a Grand Banks development. LNG transportation costs are 4 to 6 times higher than lower-cost alternatives.

- Except for single-field developments, pipelines are the lowest-cost option. Pipeline unit investment costs drop significantly with the size of the development.

- Methanol and CNG shipment are competitive with pipelines over the range of flows modeled. The number of ships required at the higher flows, however, may cause significant logistics problems.

Table 5.2: Capital investment for gas transportation system, 100 MMcf/d ($ million)				
	Pipeline	***LNG***	***Methanol***	***CNG***
Processing and Loading	*21*	*775*	*155*	*21*
Transportation	*348*	*225*	*75*	*250*
Receiving	*25*	*41*	*50*	*50*
Total	*394*	*1042*	*280*	*321*
Transportation System	*14-in pipeline*	*1 LNG carrier*	*1 tanker*	*2 CNG carriers*

Table 5.3: Capital investment for gas transportation system, 200 MMcf/d ($ million)				
	Pipeline	***LNG***	***Methanol***	***CNG***
Processing and Loading	*41*	*1,550*	*310*	*41*
Transportation	*447*	*225*	*75*	*375*
Receiving	*25*	*83*	*50*	*50*
Total	*514*	*1,858*	*435*	*466*
Transportation System	*18-in pipeline*	*1 LNG carrier*	*1 tanker*	*3 CNG carriers*

Table 5.4: Capital investment for gas transportation system, 300 MMcf/d ($ million)				
	Pipeline	***LNG***	***Methanol***	***CNG***
Processing and Loading	*62*	*2,325*	*465*	*62*
Transportation	*497*	*225*	*150*	*500*
Receiving	*25*	*124*	*50*	*50*
Total	*584*	*2,675*	*665*	*612*
Transportation System	*20-in pipeline*	*1 LNG carrier*	*2 tankers*	*4 CNG carriers*

Table 5.5: Capital investment for gas transportation system, 400 MMcf/d ($ million)				
	Pipeline	***LNG***	***Methanol***	***CNG***
Processing and Loading	*83*	*3,101*	*620*	*83*
Transportation	*547*	*450*	*150*	*625*
Receiving	*25*	*165*	*50*	*50*
Total	*655*	*3,716*	*820*	*758*
Transportation System	*22-in pipeline*	*2 LNG carriers*	*2 tankers*	*5 CNG carriers*

Table 5.6: Capital investment for gas transportation system, 500 MMcf/d ($ million)				
	Pipeline	***LNG***	***Methanol***	***CNG***
Processing and Loading	*103*	*3,876*	*775*	*103*
Transportation	*597*	*450*	*225*	*750*
Receiving	*25*	*207*	*50*	*50*
Total	*725*	*4,533*	*1,050*	*903*
Transportation System	*24-in pipeline*	*2 LNG carriers*	*3 tankers*	*6 CNG carriers*

Table 5.7: Unit Investment Costs for Various Transportation Options ($Mcf/d)				
	Pipeline	**LNG**	**Methanol**	**CNG**
100 MMcf/d	*39.40*	*104.20*	*28.00*	*32.10*
200 MMcf/d	*25.70*	*92.90*	*21.80*	*23.30*
300 MMcf/d	*19.50*	*89.10*	*22.20*	*20.40*
400 MMcf/d	*16.40*	*92.90*	*20.50*	*19.00*
500 MMcf/d	*14.50*	*90.70*	*21.00*	*18.10*

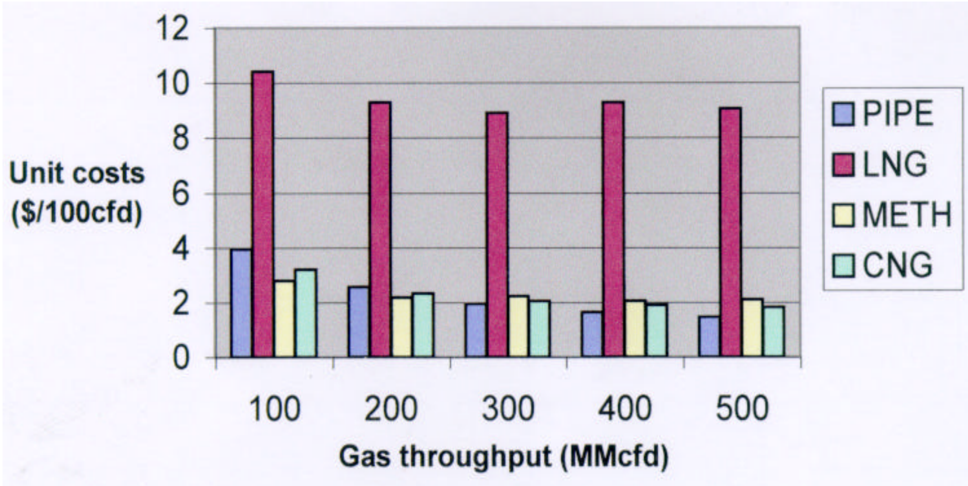

Figure 5.9: Unit Capital Investment Costs for Gas Transport from the Grand Banks.

5.6 Conclusion

It is reasonably clear from the analysis that has been carried out that offshore liquefaction of gas, and transport by LNG carrier, is not a viable economic option.

A gas pipeline to shore would normally be the most effective and economical solution, but only at the largest possible pipeline diameter to carry the maximum gas flow. This requires a substantial investment, and the threat of iceberg damage reduces the attractiveness of this option.

Methanol conversion and CNG transport by ship are options to be considered, but the technology for both remains to be proven for offshore applications. The design for a single floating production system for both oil and methanol has been developed, and this appears very promising for fields like Whiterose. CNG transport has significant merit, especially for early field development, or the exploitation of associated gas from an existing platform. The design of a CNG transport system is relatively "low-tech", and Newfoundland could play a pivotal role in its development.

6. PRELIMINARY PROJECT ECONOMICS

6.1 Introduction

6.1.1 Purpose

This section presents the results of preliminary economic analysis of natural gas potential in the Province of Newfoundland taking into account such factors as resource size, timing, development and operating costs, prices, and fiscal systems. The purpose of the analyses is not to determine project viability; it is intended to determine whether there is sufficient justification on an economic basis to proceed with further work toward successfully establishing a natural gas industry in the province.

The word preliminary is emphasized. The analyses presented are intended as a first look at the economics of natural gas production in the region. There is little in the way of published data on natural gas development in either the offshore or onshore area of Newfoundland that would enable a thorough and complete economic assessment. Since many of the factors, particularly costs, are not available, estimates based on industry norms were used.

6.1.2 Projects Analyzed

Four hypothetical natural gas projects were analyzed - two in the Jeanne d'Arc basin area of the Grand Banks, and one each in the offshore and onshore area of the west coast of Newfoundland. The assumed characteristics of these projects are more fully described below.

For reference purposes, each of the four projects analyzed are labeled as follows:

- Hibernia Platform Related;
- New Production Facility Related;
- Offshore Western Newfoundland;
- Onshore Western Newfoundland.

6.1.3 Methodology

The analyses presented in this report utilize generally accepted discounted cash flow techniques using a computer cash flow model and data bases developed by van Meurs & Associates Limited for use in the oil and gas industry. The data bases developed by van Meurs & Associates Limited were further supplemented for use here by discussions with officials of the CNOPB and the Newfoundland Department of Mines and Energy and from the files of Imperial Venture Corp. For each of the four projects, base case production and cost profiles are developed. Three cost and three price sensitivities (for a total of nine cases) were run for each project. The price levels used are price levels at the point of discharge from the production platform.

Cost Sensitivities

- 70% of base case costs,

- Base case costs,
- 130% of base case costs.

Price Sensitivities

For the purposes of sensitivity analysis, the following gas prices at the production facility have been assumed;

- US$1.18 per Mcf,
- US$1.48 per Mcf,
- US$1.78 per Mcf.

The Canadian equivalents of the US prices were assumed to be C$1.60, C$2.00, and C$2.40, respectively.

For base case analyses, the US$1.48 per Mcf price scenario was used.

6.2 General Assumptions

6.2.1 Economic Indicators

For purposes of this study, the Rate of Return (ROR) is used as the main indicator of relative project attractiveness.

The rate of return on the project before the application of any financing is called the project rate of return on total capital. The higher the rate of return, the more profitable the investment. While it is difficult to say what rate of return a particular company might accept on any individual project, it is probably fair to say that because of the inherent risks in a frontier area, the oil and gas industry is typically looking for a project rate of return of 25% or more.

6.2.2 Fiscal System

Two components of the overall fiscal system are included in the analysis undertaken in this study, namely, income tax, at both the federal and provincial levels, and provincial royalties.

The corporate income tax rates currently applicable at the federal and provincial levels are 28% and 14%, respectively. There is an additional 4% surcharge on federal taxes payable. The combined rate is 43.12%. In the Province of Newfoundland, both federal and provincial income taxes are calculated and payable on the basis of the same taxable income. In calculating taxable income, exploration may be depreciated at 100%. Development wells are depreciated at 30%, on a declining balance basis. Facilities are depreciated at 30% from the start of production. Well intangibles are depreciated at 25%, also from the start of production. Royalties are not deductible, but there is a 25% resource allowance instead.

Royalties are payable to the Province of Newfoundland in both the onshore and offshore areas. The royalty regime for petroleum production is not yet in regulation form. The terms and conditions of the royalty system have been made public, however.

Based upon these public announcements, it is assumed for purposes of this study that the terms and conditions applicable to petroleum production in the onshore and offshore areas, including that for natural gas, are as follows:

Table 6.1: Generic Onshore Royalty Terms (source: NF Department of Mines & Energy)	
Royalty Holiday	*First 2 MMbbl equivalent*
Basic Royalty	*5%*
Net Royalty ***Tier 1*** *Rate* *Return Allowance*	 *20%* *5% plus long term bond rate*
Tier 2 *Rate* *Return Allowance*	 *5%* *15% plus long term bond rate*

Table 6.2: Generic Offshore Royalty Terms (source: NF Department of Mines & Energy)	
Basic Royalty	
Until the earliest of: *(I) 20% of reserves* *(ii) 50 MMbbl or equivalent* *(iii) Simple Payout*	 *1%*
(I) 100 MMbbl or equivalent cumulative production *(ii) Simple Payout*	 *2.5%*
Next 100 MMbbl or equivalent	*5%*
Thereafter	*7.5%*
Net Royalty ***Tier 1*** *Rate* *Return Allowance*	 *20%* *5% plus long term bond rate*
Tier 2 *Rate* *Return Allowance*	 *5%* *15% plus long term bond rate*

It is assumed that these fiscal terms and conditions will apply for the life of the projects analyzed. For purposes of the analyses here the long term bond rate is taken to be 7% over the life of the projects.

6.2.3 Escalation Rate

All costs and prices are escalated by 3% per year. This means that all cost and price levels were assumed constant in real terms over the course of the analytical period. All estimates were done in real 1998 dollars. All cash flows were done in current dollars in order to calculate the various tax impacts.

6.2.4 Proponents Taxable Position

For Newfoundland, it is assumed that the projects can be launched under “consolidated” terms or on a full flow-through basis. This assumes that the investors are in a taxable position elsewhere in the country and can immediately deduct costs from taxable income for tax purposes, subject to any applicable rules with respect to the start of depreciation for assets.

6.2.5 Financing

For all projects analyzed, 100% equity financing was assumed. This means that the economics including taxation is calculated without any deductions for interest expenses.

6.2.6 Exchange Rate

The Canada - United States exchange rate is assumed at US$1.00 is equal to C$1.35 over the life of the projects analyzed.

6.3 Project Descriptions

6.3.1 Overview

The first two of the natural gas projects analyzed are assumed to take place in the Jeanne d’Arc Basin in the east coast Newfoundland offshore area. The third and fourth projects are assumed to occur in the western portion of the province, one in the offshore area and a second in the onshore area. Of the two projects in the Jeanne d’Arc Basin, one is assumed to produce natural gas from fields accessible either directly or via gathering lines from the Hibernia platform. The cost of the existing platform, facilities and wells are assumed not to accrue to natural gas. Only those costs specified below are assumed to apply to natural gas production. The second project analyzed for the Jeanne d’Arc Basin is assumed to be a new facility other than that related to the Hibernia platform. Again, however, there is assumed to be shared costs and those specified below are those costs that accrue to natural gas production. Neither of the two projects are necessarily dependant entirely upon existing discovered resources or that either is necessarily operating alone in the region. No start date is specified. Since the economics are calculated on a go forward basis, the results presented here would not be affected by changes in start date.

Since the purpose of this study is to take a first look at the economics of gas production, the existence of a transportation system is assumed to exist.

6.3.2 Production Profiles

Table 6.3 presents details on assumptions related to natural gas reserves, peak production, years at peak production, and annual production decline rates used in developing the production profile for each of the four projects analyzed.

Table 6.3: Base Case Production Profiles Assumptions

Area	*Field Size (Bcf)*	*Max. Annual Production (Bcf)*	*No. of Years at Peak*	*Rate of Decline (%)*
Grand Banks - Hibernia Platform Related	*1,600*	*144*	*7*	*8.5%*
Grand Banks - New Production Facility Related	*1,400*	*140*	*6*	*8.5%*
Offshore Western Newfoundland	*1,500*	*155*	*6*	*8.5%*
Onshore Western Newfoundland	*1,000*	*84*	*6*	*8.5%*

6.3.3 Cost Assumptions

This section provides details on base case capital, operating and transportation cost assumptions associated with each of the four projects. Unless otherwise specified, all costs are expressed in millions of Canadian dollars.

Capital costs are categorized as either exploration or development costs. Exploration costs are in turn subdivided into geophysical costs and exploration well costs. Development costs are subdivided into development wells costs, platform costs, facility costs, and gathering pipeline costs.

Table 6.4 & 6.5 present details on the base case exploration and development cost assumptions for each project analyzed. Each cost category is subdivided along lines described above.

Operating costs were subdivided into two subcategories - fixed and variable. Annual fixed operating costs were taken as a percentage of installed capital. These percentages are detailed in Table 6.6. Variable operating costs of $0.03 per Mcf were assumed.

6.4 Results of the Analyses

6.4.1 Base Case Results

Table 6.7 presents the results of the analyze of the four projects for the base case assumptions. The price assumed is US$1.48/Mcf. At a 25% hurdle rate, only the onshore project passes the test. If 20% were in fact the hurdle rate, then the Hibernia platform related production would also result in positive economics. Both the Grand Banks - New Production Facility Related and the Offshore Western Newfoundland projects are non-starters under the base case assumptions.

Table 6.4: Base Case - Exploration Cost Assumptions

Area	***Geophysical***		***Exploration Wells***	
	Cost Per Year	***No. of Years***	***No. of Wells***	***Cost Per Well***
Grand Banks - Hibernia Platform Related	-	-	-	-
Grand Banks - New Production Facility Related	*$3.0*	*2*	*1*	*$40*
Offshore Western Newfoundland	*$2.0*	*2*	*3*	*$20*
Onshore Western Newfoundland	*$2.0*	*2*	*3*	*$6*

Table 6.5: Base Case Development - Cost Assumptions

Area	***Development Wells***		***Platform Cost***	***Facilities Cost***	***Gathering Lines Cost***	***Total Costs***	
	No. of Wells	***Cost Per Well***				***Total***	***$/Mcf***
Grand Banks - Hibernia Platform Related	*4*	*$30*	-	*$270*	*$250*	*$640*	*$0.40*
Grand Banks - New Production Facility Related	*10*	*$30*	*$420*	*$570*	*$250*	*$1,540*	*$1.10*
Offshore Western Newfoundland	*12*	*$10*	*$270*	*$660*	-	*$1,050*	*$0.70*
Onshore Western Newfoundland	*14*	*$5*	-	*$110*	-	*$180*	*$0.18*

6.4.2 Cost Sensitivities

Given the data constraints and uncertainties associated with the oil and gas industry, two cost sensitivities were undertaken - plus and minus 30% around the base case. The results of these sensitivities are presented in Table 6.8. Of course, as one would expect, cost reductions or increases have a significant effect on project economics.

Table 6.6: Base Case - Operating Cost Assumptions (C$ million)		
Area	***Platform***	
	Fixed (% of Capital)	***Variable ($'s /Mcf)***
Grand Banks - Hibernia Platform Related	*6.2%*	*$0.30*
Grand Banks - New Production Facility	*6.2%*	*$0.30*
Offshore Western Newfoundland	*7.0%*	*$0.30*
Onshore Western Newfoundland	*5.0%*	*$0.30*

Table 6.7: Base Case - Rate of Return - Nominal	
Area	***Rate of Return***
Grand Banks - Hibernia Platform Related	*24%*
Grand Banks - New Production Facility Related	*3%*
Offshore Western Newfoundland	*11%*
Onshore Western Newfoundland	*54%*

Table 6.8: Cost Sensitivities - Rate of Return - Nominal %			
Area	***Rate of Return***		
	70% of Base	***Base Case***	***130% of Base***
Grand Banks - Hibernia Platform Related	*32%*	*24%*	*19%*
Grand Banks - New Production Facility Related	*11%*	*3%*	*0% or less*
Offshore Western Newfoundland	*17%*	*11%*	*5%*
Onshore Western Newfoundland	*67%*	*54%*	*44%*

6.4.3 Price Sensitivities

Table 6.9 presents the results of sensitivities carried out on price. For purposes of the analyses presented here, two additional price scenarios were undertaken, namely, US$1.70 and US$2.30.

Table 6.9: Price Sensitivities - Rate of Return - Nominal, %			
Area	***Rate of Return***		
	US$1.18	***US$1.48***	***US$1.78***
Grand Banks - Hibernia Platform Related	*19%*	*24%*	*28%*
Grand Banks - New Production Facility Related	*0% or less*	*3%*	*7%*
Offshore Western Newfoundland	*6%*	*11%*	*14%*
Onshore Western Newfoundland	*44%*	*54%*	*63%*

Further results combining the price and cost sensitivities are provided in Table 6.10 to 6.13 inclusive for each of the four projects analyzed.

Table 6.10: Rate of Return - Nominal Hibernia Platform Related, %			
Cost Scenario	***Price Scenario***		
	US$1.18	***US$1.48***	***US$1.78***
70% Base Case Costs	*26%*	*32%*	*37%*
Base Case Costs	*19%*	*24%*	*28%*
130% Base Case Costs	*14%*	*19%*	*22%*

Table 6.11: Rate of Return - Nominal New Production Facility Related, %			
Cost Scenario	***Price Scenario***		
	US$1.18	***US$1.48***	***US$1.78***
70% Base Case Costs	*6%*	*11%*	*15%*
Base Case Costs	*0% or less*	*3%*	*7%*
130% Base Case Costs	*0% or less*	*0% or less*	*1%*

Table 6.12: Rate of Return - Nominal Offshore Western Newfoundland, %			
Cost Scenario	***Price Scenario***		
	US$1.18	***US$1.48***	***US$1.78***
70% Base Case Costs	*13%*	*17%*	*20%*
Base Case Costs	*6%*	*11%*	*14%*
130% Base Case Costs	*1%*	*5%*	*9%*

Table 6.13: Rate of Return - Nominal Onshore Western Newfoundland, %			
Cost Scenario	***Price Scenario***		
	US$1.18	***US$1.48***	***US$1.78***
70% Base Case Costs	*56%*	*67%*	*78%*
Base Case Costs	*44%*	*54%*	*63%*
130% Base Case Costs	*36%*	*44%*	*53%*

6.5 Conclusions

The following conclusions and observations are drawn from the preceding analyses:

- ***The results of these very preliminary economic analyses provide cause for hope and cautious optimism, but the results are not spectacular. Only the onshore area provides reasonable returns under the circumstances assumed.***

- ***The issue of transportation is of critical importance and offers a unique challenge for the development of a natural gas industry.***

- ***It is fair to conclude from the above analyses that discoveries of natural gas on or near shore in the west coast portion of the island in commercial quantities will likely be developed.   In general, issues relating to the operating environment and proximity to markets make the west coast area more attractive.***

- ***Further economic analysis is necessary. There is no substitute for good and reliable data upon which to base the economic analysis and such was not available to this study. Furthermore, project viability analyses need to be complimented with net income benefits analyses particularly in connection with policy development, royalty regime development, and opportunities identification.***

7. PHASE II TERMS OF REFERENCE

7.1 Introduction

The overall purpose of the Natural Gas Utilization Study is to create "*a Natural Gas Development Strategy for Newfoundland Industry*." The current Phase I was designed as a scoping study based on a high level review of existing information. A key output of Phase I is to propose Terms of Reference for a comprehensive and detailed Phase II study which is characterized by the project proponents as an "*in-depth study of downstream gas issues associated with the exploitation of the Grand Banks natural gas resource*". Furthermore, the proponents have stated that major areas of study for Phase II would include the following:

- **Options for gas utilization.**
- **Newfoundland benefits opportunities.**
- **Financial and economic impact analysis.**
- **Engineering and economic constraints.**
- **Stakeholder considerations.**
- **Atlantic Canadian development approach.**

7.2 General Conclusion of Phase I

Newfoundland's natural gas resources are valuable and potentially capable of supporting significant industrial initiatives. While the discovered resources are not yet large on a world scale, the undiscovered potential holds significant promise for both the Newfoundland offshore and onshore areas. The location and operating environment for the offshore resources means that successful development will require effort, innovation and wise decisions on the part of all stakeholders. Development will not happen "naturally" because of overwhelming competitive advantages.

The implication of the above is that Newfoundland will have to carefully identify and exploit development opportunities which make economic sense and where Newfoundland is competitive. In terms of Phase II tasks, this means a systematic review of each requirement of the natural gas value chain - from well head to market - to identify challenges and opportunities so that appropriate action can be taken.

7.3 The Natural Gas Value Chain

The main components of the industry are illustrated by the natural gas value chain. (Figure 7.1, Source: Stedman 1998). This figure further illustrates, with particular reference to Nova Scotia, how the organization of activities within the value chain are likely to evolve over time.

The natural gas value chain is used here as an organizational concept for Phase II. Phase II is visualized as a series of inter-related tasks within an ongoing strategic management process.

In the near-term, the value chain is dominated by a single project, with a single operator and limited markets. In the longer term, a more complex arrangement may evolve with several projects, multiple operators, third party facilities and expanded markets. The evolution of activities, over time, will be strongly influenced by government policies and actions addressing such key issues as local and regional benefits; gas exports verses local value-added activities; vertical integration versus downstream competition, incentives, fiscal take and regulatory several projects, multiple operators, third party facilities and expanded markets. The evolution of activities, over time, will be strongly influenced by government policies and actions addressing such key issues as local and regional benefits; gas exports verses local value-added activities; vertical integration versus downstream competition, incentives, fiscal take and regulatory burden.

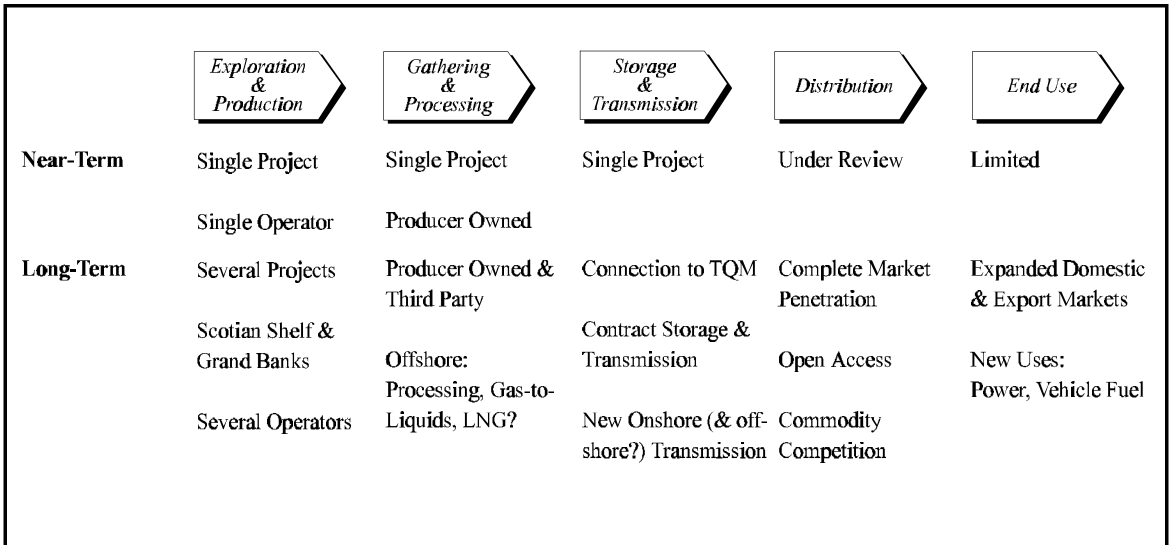

Figure 7.1 The Natural Gas Value Chain
(Source: Stedman, 1998 Novagas Canada Ltd.)

7.4 Comments Arising from Phase I

The following is a summary of the results and conclusions arising out of the current Phase I study:

1) The natural gas industry is evolving rapidly driven by its value as a clean source of energy and as a starting point for a variety of industrial processes. This evolution involves all components of the natural gas value chain including technology developments, regulatory systems, financial and business arrangements and markets.

Markets are seen to be the key to any development of Newfoundland’s natural gas resources and this aspect was not included in Phase I. The markets will determine such critical elements as demand volume, price, timing, product state and location. These elements, in turn, will determine the economic feasibility of various development options.

2) With regard to timing, natural gas developments could occur within five years. Given the long lead times of various key developmental issues, Phase II is timely and should be initiated as soon as possible.
Phase II will be conducted within the context of a steadily evolving situation. Consequently it is important that the appropriate administration infrastructure is in place to track changes and capture opportunities on a continuing basis.

3) The natural gas resource base of Newfoundland is currently poorly defined for the following main reasons:

- Exploration, even in the Jeanne d’Arc Basin is still at an immature stage.
- There is little production history.
- Undiscovered resource potential estimates are either nonexistent or out of date.

Since the resource base is the fundamental input in an industrial strategy based on that resource, Phase II must address the above issues in terms of:

- Possible ways to accelerate exploration.
- Mechanisms to ensure that high-quality resource estimates are produced on a timely basis.
- Mechanisms to review production/reservoirs performance data as a strategic input for the development of a natural gas industry.

4) On a global scale, gas reserves are plentiful and growing. Market growth, though positive, is not keeping up with the growth of reserves due to the locational separation of major reserves from major markets and the high cost of transport. Long-term price trends for natural gas are downward.

Key issues arising from the above, which should be addressed in Phase II include:

- Ongoing mechanisms for tracking technology developments of particular relevance to Newfoundland and taking an active role in their development where feasible and strategic.

- Models and trends for financing major natural gas developments and transportation systems including the roles of governments, the private sector resource developers, third party transportation systems, alliances and other cooperative mechanisms. This task may be enhanced by case studies of specific gas-based developments analogous to Newfoundland such as Trinidad and Tobago.

5) The trends in major reserves additions is for these to be located in more and more difficult operating environments such as very deep water or in arctic regions. This trend represents a market opportunity for technology designed to improve the feasibility or cost of accessing such "*difficult*" reserves.

Newfoundland has significant capabilities to address many of the technological issues affecting the development of its natural gas resources eg. conversion at sea, marine transportation, iceberg scour, etc. These capabilities include research and development infrastructure, fabrication facilities and human resources both local and through the presence of major international exploration and production and engineering firms in the Province.

Taking a lead role in key technology development has the following potential benefits:

- Newfoundland issues are specifically addressed on a priority basis.
- Newfoundland has early access to the technology giving a competitive lead.
- Wealth is created through the export of technology and high level services.

Several promising technologies were identified in Phase I. These, and other potential solutions need to be examined in a more definitive matter in Phase II.

6) Newfoundland's natural gas resources will be developed in the context of increasingly global competition. Recent trends are for governments to review their fiscal systems in view of the specific requirements of the natural gas industry and the globally competitive situation.

It is recommended that Phase II should review the fiscal regulatory regimes in Newfoundland and make recommendations on changes which would produce a modern, competitive system.

While the fiscal regime is a key issue, it is by no means the only governmental element which affects the resource. The recommended Phase II review may possibly be extended to include the identification of other key government factors and their effects - positive or negative - on the competitive position of Newfoundland's resources.

7) Very preliminary project economics analyses were conducted in Phase I. The validity of these analyses is constrained by the very preliminary nature of the input data. Phase II should redo these analyses based on rigorously derived data on all critical elements including sales price, transportation tariffs, facilities cost, and wellhead price, etc.

7.5 Phase II in the Context of the Natural Gas Value Chain

Charles Steadman's diagram (Section 7.3) has been modified in figure 7.2 for application to Newfoundland and Phase II. In particular, certain general actions are proposed which encompassed a series of interrelated- Phase II tasks.

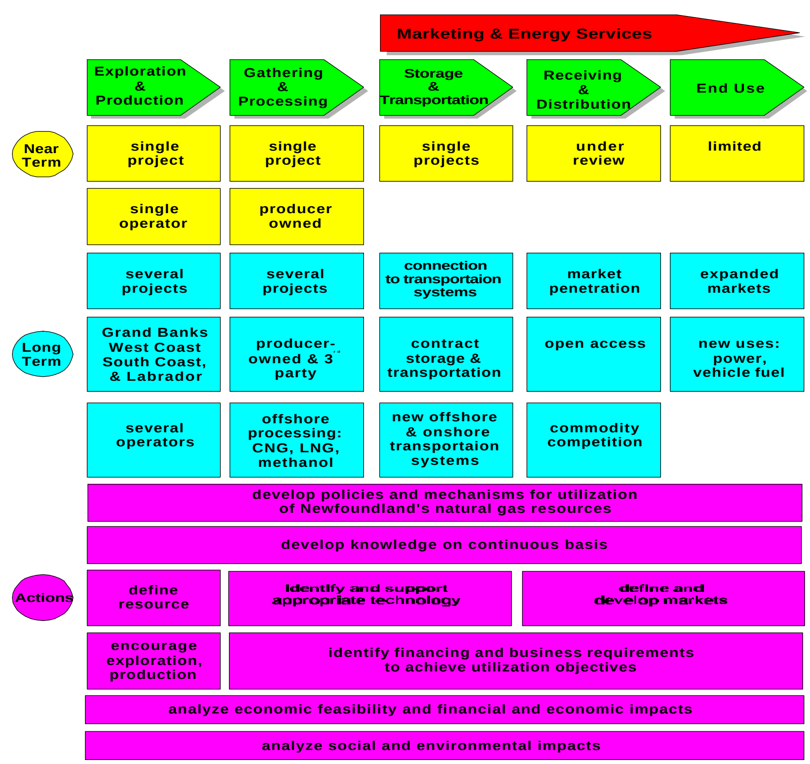

Figure 7.2 Natural Gas Value Chain - Phase II Actions

The Ultimate objective of Phase II is, presumably, the development and implementation of a Strategic Plan for Newfoundland's natural gas resources. The elements of such a plan are illustrated by Figure 7.3.

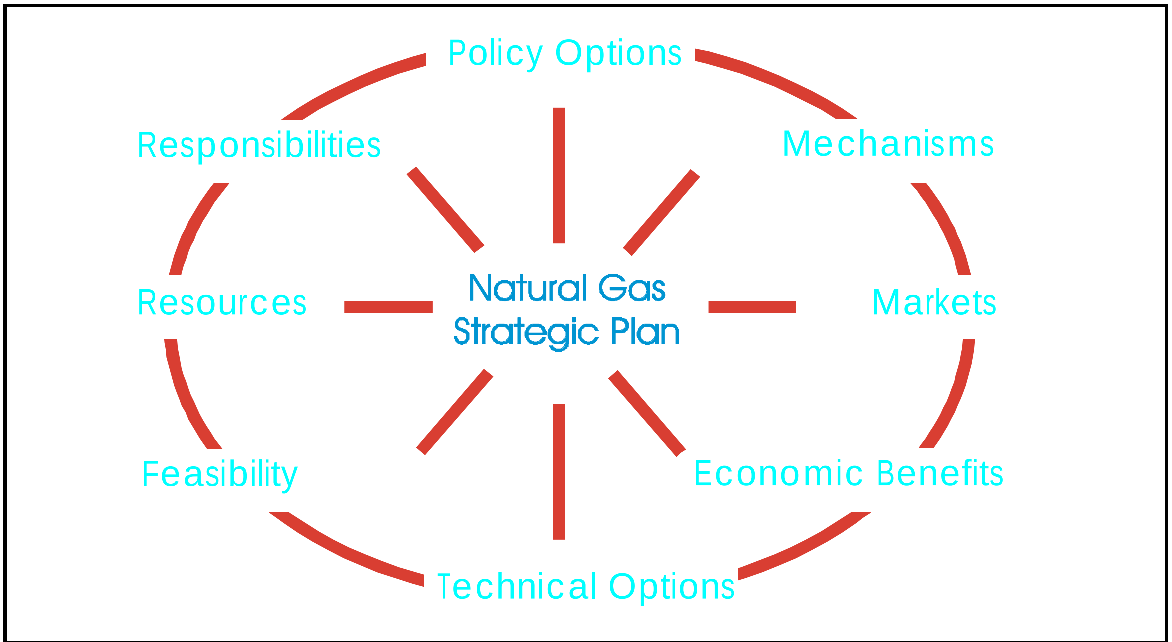

Figure 7.3 Elements of a Natural Gas Strategic Plan

Phase II Tasks have been identified and outlined in the following Section. The initial work Package, numbered 101, is to define the operating mechanism and structure to coordinate planning activities and actions on an ongoing basis. This is seen as essential to achieving a sustained, productive effort.

The additional tasks deal with specific issues of resource estimates, regulations, technology and economic analysis. In many cases the proposed tasks are similar to those described by the study proponents in the project document.

Suggested level of effort is given on a relative scale. Most of the tasks can be performed at various levels of expenditure according to budget, input details and output accuracy requirements. In general, the evolving nature of the industry, both globally and in Newfoundland, requires tasks to be redone over time with increasing sophistication.

7.6 Phase II Organization and Task Description

The Phase II organizational scheme is shown graphically in Figure 7.4 while the individual Work Packages are described in the following pages.

Work Packages		1998	1999	2000	2001
101	Develop Planning and Coordination Process	*continuous process*			
201	Develop Natural Gas Policy	*final*			
202	Establish Natural Gas Royalty Regime	*final*			
203	Investigate Options for Increasing Exploration and Development	*final*			
204	Review Mechanisms for Financing and Operating		*update 1*		*update 2*
205	Identify Opportunities for Natural Gas Utilization	*continuous process*			
206	Identify and Analyze Markets	*continuous process*			
301	Update Estimates of Discovered Resources	*update 1*		*update 2*	
302	Update Estimates of Undiscovered Resources	*update 1*		*update 2*	
401	Review Natural Gas Production Options	*update 1*		*update 2*	
402	Develop Natural Gas Transportation Options	*continuous process*			
403	Conduct Economic Research and Analysis	*continuous process*			
404	Conduct Social and Environmental Impact Analysis			*continuous process*	

Figure 7.4: Work Packages and Timing Phase II

NATURAL GAS UTILIZATION STUDY **Work Package Breakdown - Phase II Study**		
No: *101*	**Title:** ***Develop a Process to Focus and Coordinate Natural Gas Development Planning.***	**Priority:** *High*

Status:

Responsibilities are Shared among various stakeholders at both policy and working levels. The present study is a model of collaborative planning at a working level. Process and infrastructure needs to be established on a semi-permanent basis to stimulate and coordinate planning functions for natural gas development.

Scope:

- *Develop models and analyze the feasibility of developing a collaborative process to focus and coordinate planning functions for natural gas development.*
- *Negotiate "buy-in" to the preferred process by stakeholders.*
- *Implement process and delivery structure.*

Level of Effort:	**Notes:**
Significant	*This activity is vital to ensuring ongoing planning efforts and implementation of recommendations.*

NATURAL GAS UTILIZATION STUDY **Work Package Breakdown - Phase II Study**		
No: *201*	**Title:** ***Develop a Natural Gas Policy***	**Priority:** *Medium*

Status:

Policy development is a necessary prerequisite to strategic planning and program implementation. A comprehensive natural gas policy integrated with an overall energy policy needs to be developed for the Province.

Scope:

- *Define resource management objectives.*
- *Describe current policies.*
- *Identify policy gaps.*
- *List and analyse options.*
- *Consult with stakeholders.*
- *Choose most appropriate policy.*
- *Develop mechanisms for implementation.*

Level of Effort:	**Notes:**
Significant	*This is seen as an ongoing process which needs to be updated on an annual basis.*

NATURAL GAS UTILIZATION STUDY **Work Package Breakdown - Phase II Study**		
No: *202*	**Title:** ***Establishment of a Natural Gas Royalty Regime***	**Priority:** *Medium*

Status:

To date project-specific oil royalty regimes have been put in place for Hibernia and Terra Nova. Generic royalty regimes for future developments onshore and offshore have been announced but not put in regulation form. It is unclear whether these regimes extend to natural gas. Indications are that they do not.

Scope:

- *Options identification, including review and recommend changes in the fiscal systems, onshore and offshore, to reflect the special requirements of natural gas, as distinct from oil.*
- *Review royalty modification that may reflect difficulty of exploiting gas resources in different regions.*
- *Industry consultation.*
- *System selection and design.*
- *Royalties versus benefits optimization.*
- *Undertake associated research and analysis including supporting data base and model development and maintenance.*
- *Regulation preparation and publication.*
- *Proportion.*

Level of Effort: *Significant*	**Notes:** *This is seen as an ongoing process which needs to be updated on an annual basis.*

NATURAL GAS UTILIZATION STUDY Work Package Breakdown - Phase II Study		
No: *203*	**Title:** ***Investigate Options for Increasing Exploration and Development***	**Priority:** *Medium*

Status:

Exploration is necessary to a viable industry. Levels of exploration in recent years have been less than adequate.

The natural gas industry is evolving rapidly and is increasingly competitive on a global scale. To be successful Newfoundland must be selective and competitive.

Scope:

- *Undertake a study to identify factors and constraints affecting the decision to explore in Newfoundland including land tenure, fiscal regimes, and other regulatory matters.*
- *Review and recommend changes in overall legislation impacting on natural gas development to ensure that the legislative package is appropriate to the objectives of stakeholders.*
- *Investigate the reasons for the long time between discovery, development and identify mitigating actions.*
- *Consultation with industry including identification of factors, influencing their decision to explore.*
- *Program Identification.*
- *Program implementation.*
- *Promotion.*

Level of Effort:	**Notes:**
Moderate	*Essential to carry out this investigation at outset of next phase.*

NATURAL GAS UTILIZATION STUDY **Work Package Breakdown - Phase II Study**		
No: *204*	**Title:** ***Review Mechanisms for Financing and Operating Natural Gas Developments***	**Priority:** *Medium*

Status:

Current process is centered on individual operators. As the industry grows, a variety of collaborate arrangements may be required to raise the required capital, induce competition and provide the necessary infrastructure. Financing of developments and associated infrastructure is a major constraint to the pace of development.

Scope:

- *Review established and evolving models for financing and operating the various requirements of the gas industry.*
- *Examine in detail one or more potential analogue eg. Trinidad & Tobago*
- *Recommend appropriate models and mechanisms for Newfoundland.*

Level of Effort: *Moderate*	**Notes:** Regular updating is required.

NATURAL GAS UTILIZATION STUDY **Work Package Breakdown - Phase II Study**		
No: *205*	**Title:** ***Identification of opportunities for Natural Gas Utilization within Newfoundland and Labrador***	**Priority:** *High*
Status: *Natural gas utilization within the Province is key to the maximization of local benefits. The use of natural gas is currently constrained by unavailability in the Newfoundland market. Potential benefits from natural gas exploitation may result from downstream activities.*		
Scope: • *Ongoing opportunity identification including opportunities and trends.* • *Ongoing opportunity assessment including model and data base development and maintenance.* • *Program identification, assessments and reassessment.* • *Program implementation.* • *Promotion.* • *Continuous reevaluation and reassessment of opportunities and challenges.*		
Level of Effort: *Moderate*	**Notes:** *Ongoing process.*	

NATURAL GAS UTILIZATION STUDY Work Package Breakdown - Phase II Study		
No: 206	**Title:** ***Identify and analyze markets for Newfoundland's natural gas and gas-derived products***	**Priority:** *High*
Status: *Markets for Newfoundland's natural gas and gas-derived products are the key factor in determining the viability and characteristics of the industry within an environment of open competition.*		
Scope: • *Identify market characteristics and trends for gas and products.* • *Identify Newfoundland's competitive position and any special situations which may have particular positive or negative effects.* • *identify market development opportunities.* • *identify regional synergies, if present.* • *Use demand-side output in supply-side decision making.* • *identify alliances and mechanisms which might assist in market penetration.*		
Level of Effort: *High*	**Notes:** *Ongoing process.*	

NATURAL GAS UTILIZATION STUDY Work Package Breakdown - Phase II Study		
No: *301*	**Title:** ***Update Estimates of Discovered Resources***	**Priority:** *High*
Status: *Natural gas resource estimates are updated annually by CNOPB.*		
Scope: • *Ensure updated estimates are incorporated in ongoing development planning.* • *Monitor changes and incorporate as required.*		
Level of Effort: *Low*	**Notes:** *This is seen as an ongoing process which needs to be updated on an annual basis.*	

<table>
<tr><td colspan="3">NATURAL GAS UTILIZATION STUDY
Work Package Breakdown - Phase II Study</td></tr>
<tr><td>No:
302</td><td>Title:
Update Estimates of Undiscovered Resources</td><td>Priority:
High</td></tr>
<tr><td colspan="3">Status:

Estimates of undiscovered resources are badly out of date.</td></tr>
<tr><td colspan="3">Scope:

• Undertake comprehensive review of potential resources.

• Develop a process to undertake these tasks and update results on an ongoing basis.

•
Adopt the following sequence in the evaluation:

1. Jeanne d'Arc and the Grand Banks
2. Western and southern Newfoundland
3. Laurentian basin
4. Labrador</td></tr>
<tr><td>Level of Effort:
Significant</td><td colspan="2">Notes:
This is seen as an ongoing process which needs to be updated on an annual basis.</td></tr>
</table>

NATURAL GAS UTILIZATION STUDY Work Package Breakdown - Phase II Study		
No: *402*	**Title:** ***Develop Natural Gas Transportation Options***	**Priority:** *High*

Status:

Pipelines and LNG carriers represent the state-of-the-art in current technology of natural gas transport. However, pipelines are likely only economically feasible if they are designed for multi-field flows, and they are susceptible to damage and interruption from scouring icebergs. A floating LNG plant and LNG carriers will probably be prohibitively expensive, as they can only be justified for large gas fields at considerable distances from a receiving terminal. It is possible, however, that further developments in pipeline and LNG technology may be more suitable for application on the Grand Banks. Methanol and CNG are promising new technologies which warrant further study.

Scope:

- *Review pipeline technology especially with respect to iceberg protection, emergency shutdown procedures, and repair methods.*
- *Monitor developments in floating LNG plants suitable for small-sale installations and the potential application of "cold box shuttle" and similar techniques that may allow processing on the transport vessel.*
- *Review methanol conversion and other gas-to-liquid conversion processes, with a view to possible adaptation for the Newfoundland offshore.*
- *Review and evaluate the options proposed for CNG transport, with respect to processing, conditioning and compression requirements, vessel and containment design, and receiving terminal requirements.*
- *Assemble unit cost data for modules of the processing, loading, transporting, unloading and storage components of the various gas chains.*
- *Identify specific development opportunities for Newfoundland, for specific application to local conditions, and also which have export opportunities.*

Level of Effort: *Significant*	**Notes:** *This is seen as an ongoing process that needs to be updated on a regular basis.*

NATURAL GAS UTILIZATION STUDY **Work Package Breakdown - Phase II Study**		
No: *401*	**Title:** ***Review Natural Gas Production Options***	**Priority:** *High*

Status:

Natural gas production by floating or subsea systems is seen as the most likely option for offshore Newfoundland, considering the size of the fields, and the nature of the operating environment. Although bottom-founded platforms have clear advantages in terms of topsides capacity, storage volumes and other factors, their use will likely be restricted to oil production in the first instance, with later expansion or substitution for gas production. Continuous developments in processing techniques, such as subsea separation, gas-liquid conversion, etc., warrant regular reviews.

Scope:

- *Review advances in floating facility designs, especially those that permit easier loading and unloading operations, quick-disconnect features, etc.*
- *Conduct a thorough review of advances in subsea technology for gas production, especially in terms of systems that offer remote operation from shore or distant platforms, and operation in deep waters with iceberg threats.*
- *Review advances in processing options that can be exercised on transporting vessels.*
- *Review advances in process technology that have particular relevance to small-scale and early development.*
- *Build up a database of unit costs for various types of process equipment and production facilities.*
- *Build up a file of project descriptions which are relevant to possible future implementation for the Newfoundland offshore.*

Level of Effort:	**Notes:**
Significant	*This seen as an ongoing process that needs to be updated on an regular basis.*

NATURAL GAS UTILIZATION STUDY Work Package Breakdown - Phase II Study		
No: *403*	**Title:** ***Economic Research and Analysis Support***	**Priority:** *Medium*

Status:

Ongoing economic analysis including project viability and net income benefits analysis is essential. There is no substitute for good and reliable data upon which to base economic analysis. Project viability analysis needs to be complimented with net income benefits analysis particular in connection with policy development, royalty regime development and opportunity identification.

Scope:

- *Identification of areas where economic analysis support is required.*
- *Identification of data requirements.*
- *Ongoing program of data collection as required.*
- *Ongoing model and data base development and/or enhancement.*
- *Provision of ongoing support as required.*

Level of Effort:	**Notes:**
Moderate	*Ongoing exercise.*

NATURAL GAS UTILIZATION STUDY **Work Package Breakdown - Phase II Study**		
No: *404*	**Title:** ***Conduct Social and Environmental Impact Analysis***	**Priority:** *Moderate*
Status: *Social and Environmental effects are integral to any development of a natural gas industry and are a fundamental input to the decision-making process.*		
Scope: • *Conduct a general review of analogous projects to develop a relevant database.* • *Identify critical issues and determine a program for their management.* • *Include social and economic data collection in other task activities.*		
Level of Effort: *Moderate*	**Notes:** *Ongoing exercise.*	

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APPENDIX A - GLOSSARY

Associated Gas:	Natural gas that overlies and is in contact with crude oil in the reservoir, at original reservoir conditions. Also referred to as *gas-cap gas*.
Condensate:	A mixture comprising pentanes and heavier hydrocarbons recovered as a liquid from field separators, scrubbers or other gathering facilities or at the inlet of a processing plant before the gas is processed.
Discovered Gas Resources:	Those quantities of gas and related substances that are estimated, at a particular time, to be initially contained in known accumulations that have been penetrated by a wellbore. Also known as **Initial Gas in Place**. They comprise those quantities that are recoverable from known accumulations and those that will remain unrecoverable.
Established Reserves:	Those reserves recoverable under current technology and present and anticipated economic conditions, specifically proved by drilling, testing or production, plus that portion of contiguous recoverable reserves that is interpreted, from geological, geophysical or similar information, to exist with reasonable certainty. This term has been used historically in Canada, particularly by regulatory agencies, and typically comprises proved reserves plus a portion of probable reserves.
Established Exploration Play:	An **Exploration Play** that has been demonstrated to exist by the discovery of one or more pools.
Exploration Play:	A geological configuration, within a defined area which combines source rock, reservoir, trap, migration and preservation in such a way that the critical factors that control the occurrence of oil and gas are essentially similar.
Gas Endowment:	Total quantity of **Discovered Gas Resources** and **Undiscovered Gas Resources**. See ***Gas Resources***.
Gas Resources:	The total quantities of gas and related substances that are estimated, at a particular time, to be contained in, or that have been produced from, known accumulations, plus those estimated quantities yet to be discovered.
Hydrocarbon Liquids:	Those hydrocarbon components that can be recovered from natural gas as liquids, including but not limited to ethane, propane, butanes, pentanes plus, condensate, and small quantities of non-hydrocarbons.

Natural Gas (Gas):	A mixture of the lighter hydrocarbons that exists either in the gaseous phase, or in solution in crude oil in reservoirs, and are gaseous at atmospheric conditions. Natural Gas may contain sulphur or other non-hydrocarbon compounds.
Non-associated Gas:	Natural gas found in a reservoir in which no crude oil is present at reservoir conditions.
Petroleum:	A naturally occurring mixture consisting predominately of hydrocarbons in the gaseous, liquid or solid phase.
Reserves:	A general term related to the estimated recoverable quantities, at a particular time, from a petroleum reservoir. As these quantities may be initial or remaining, raw or marketable, crude oil or natural oil or natural gas and related products, the term requires further definition when used.
Solution Gas:	Natural gas that is dissolved in crude oil in the reservoir at original reservoir conditions and is normally produced with the crude oil.
Undiscovered Gas Potential:	Those in-place quantities of gas and related substances that are estimated, at a particular time, to exist in accumulations yet to be discovered.

APPENDIX B - CONVERSION FACTORS AND ABBREVIATIONS

1. Gas Conversion Factors

1 cubic foot gas	= 0.0283 cubic meter gas
	= 0.00005 cubic meter LNG
	= 0.00019 barrel oil equivalent
1 ton LNG	= 1,379 cubic meter gas
	= 2.2 cubic meter LNG
	= 2.47 cubic meter LNG
	= 9.53 barrel oil equivalent

2. Other Conversion Factors

1 mile	= 1.609 kilometers
1 nautical mile	= 1.852 kilometers
1 inch	= 25.4 millimeters
1 pound per sq in	= 6.894 kiloPascals
1 ton	= 0.907 metric tonne

3. Common Abbreviations

bbl	- barrel
bbl.d	- barrels per day
boe	- barrels oil equivalent
Bcf	- billion cubic feet
cf	- cubic feet
CIS	- Commonwealth Independent States
CNG	- compressed natural gas
CO_2	- carbon dioxide
.d	- per day
GBS	- gravity base system
GOR	- gas/oil ratio
H_2S	- hydrogen sulfide
km	- kilometer
LNG	- liquefied natural gas
LPG	- liquefied petroleum gas
Mcf	- thousand cubic feet
mi	- miles
Mmbbl	- million barrels
Mmboe	- million barrels oil equivalent
MMBtu	- million British thermal unit
MMcf	- million cubic feet
MW	- megawatt
NGL	- natural gas liquid
t	- tons
Tcf	- trillion cubic feet
toe	- tons oil equivalent