Ice problems related to Grand Banks petroleum fields
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Ice Problems Related to Grand Banks Petroleum Fields

submitted to

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National Research Council of Canada
on behalf of PERD Sub-Task 5.3 Oil & Gas

PERD/CHC Report 20-6

by

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November, 1997

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1.0 Introduction

Over the past several decades, the petroleum industry has carried out extensive exploration programs on the Grand Banks, which lies off the east coast of Newfoundland. To date, these efforts have resulted in a number of significant discoveries, including the Hibernia and Terra Nova oil fields. At the present time, *proven* oil and gas reserves in the Grand Banks region are estimated at 1.5 billion barrels of oil and 1 trillion cubic feet of gas, with *probable* reserve estimates being considerably higher. In recent years, there has been a reduced industry focus on the Grand Banks, which is consistent with the general decline in activity levels across the Canadian frontiers. However, development initiatives that began in the 1980's have continued, with the Hibernia project now being implemented and development of the Terra Nova field being aggressively pursued. As these Grand Banks development projects proceed and become operational, it is likely that smaller oil reserves such as the Whiterose and Hebron discoveries will be developed and tied into the region's production infrastructure. With development, it is also clear that further exploration will be stimulated on the Grand Banks, as evidenced by the renewal of exploratory drilling in 1997.

From an environmental perspective, the Grand Banks is generally recognized as one of the most hostile operating environments in the world, since it is influenced by a range of adverse factors. The primary environmental constraints include high waves, icebergs and sea ice, all of which have influenced the exploration approaches used to date and the design philosophies for the development systems being planned. Strong winds, structural icing, and poor visibility are also of concern, but are more important in terms of affecting operations than influencing design. In all cases, floating ice in the form of both icebergs and pack ice, has been viewed as the key environmental constraint for various Grand Banks development scenarios.

NRC, on behalf of PERD, has contracted B. Wright & Associates Ltd. to undertake an R&D planning study regarding ice-related problems on the Grand Banks, primarily as they influence the development of the smaller oil fields that have been discovered in the area. This report provides the results of the study, and has the objective of identifying and priorizing ice-related problems for oil fields like Whiterose, Hebron and Terra Nova, along with associated R&D needs. In keeping with PERD's new R&D planning philosophy, a scenario based approach has been used to focus on key design and operational issues. The relative importance of the different Grand Banks ice problems that are highlighted in this study have been assessed in terms of their impact on the cost and economics of potential developments, and on current perceptions about the safety and environmental acceptability of these projects.

2.0 Background

The Federal Energy Research and Development Program, which is coordinated by the Panel on Energy R&D (PERD), has been in place since the time of the first OPEC oil embargo in 1973. The program was established as part of the federal government's response to this oil supply crisis, with a view to conducting energy related R&D that in the longer term, would enhance the security of energy supplies for Canada, particularly oil. PERD funding reached maximum levels of about $170 million per year in the mid 1980's, but with recent federal budget cuts, has been reduced to annual levels of about $60 million. Currently, PERD's funding remains subject to downward pressures that are associated with government's fiscal restraint policies. In addition, new federal initiatives to reduce greenhouse gas emissions could lead to pressures for PERD to redistribute funds away from hydrocarbon fuels.

The objective of the PERD program is *to provide the science and technology that is required to support a diversified, economically and environmentally sustainable energy economy* in Canada. In terms of scope, the R&D that has been conducted under the auspices of PERD has addressed a variety of energy issues, ranging from the development of fossil fuels and renewable energy resources, to questions of energy efficiency and the impact of greenhouse gases on climate change. Since the program's inception, the majority of PERD's funding has been allocated to support internal R&D within various government departments and agencies.

Historically, PERD has directed a considerable amount of effort towards frontier oil and gas issues, with the objective of supporting research that will enhance Canada's ability to produce reserves from its harsh frontiers *in a safe, economically competitive and environmentally acceptable manner*. The frontier R&D initiatives that PERD has pursued encompass a wide range of environmental, geotechnical, marine engineering and transportation topics related to the development of oil and gas reserves in Canada's Beaufort Sea and MacKenzie Delta, Arctic Islands, and East Coast regions. Most of this R&D has been heavily oriented towards supporting government regulatory needs. This appears to have been an appropriate strategy for PERD's frontier program when industry activity levels were high, government needed the knowledge to implement regulations, and the expectation for economic frontier developments based on the technology being put in place by industry was high. However, smaller than expected frontier discoveries, high development costs and long development lead times, combined with falling oil prices and the poor economic conditions that have been experienced over the past decade, have led to a significant decline in industry's interest in the Canadian frontiers. From a PERD perspective, these factors have led to a de-emphasis in the frontier component of its program, with budget allocations for frontier R&D falling from roughly $20 million per year in the mid 1980's, to a present annual level of about $8 million.

These factors have also led PERD to reconsider the focus of its frontier program, away from research studies that support the regulation of assumed frontier developments, towards R&D thrusts that can make a difference in terms of lowering frontier development costs, mitigating technical risks, and creating the possibility of more economically attractive projects.

2.1 1992 Frontier Planning Study

Industry began to pursue this basic theme of focussing frontier R&D towards initiatives that could reduce the costs and risks of potential frontier development projects, through their representation on various PERD Committees in the late 1980s (CPA, 1990). However, the theme was more fully developed in late 1992, in a PERD sponsored *Research Planning Study for Canada's Frontier Oil and Gas,* conducted by K. R. Croasdale & Associates. This study focussed on a number of potential frontier development scenarios and was specifically aimed at defining the technology R&D opportunities that could improve the cost competitiveness of Canadian frontier projects. The study showed that some of these development scenarios could be cost competitive, particularly if focussed research could achieve technology uplift and lower costs. The underlying rationale for the study was to show that by improving the economics of potential frontier developments, or by triggering developments that appear uneconomic, Canada would benefit from the creation of additional wealth and the long term security of oil supply. The primary motivation for this initiative was to demonstrate the high importance of maintaining some of PERD's focus on priority frontier R&D issues, especially those that can lead to economically competitive frontier projects and wealth creation. Some of the key messages that were presented in this frontier planning study and still remain valid, are summarized as follows.

- in Canada, it is likely that oil and gas will continue to be a major energy source for decades to come, but conventional production from western Canada is in decline.

- since alternative oil sources such as those from the frontiers and oil sands are high in cost relative to imported oil, it is likely that unless development costs can be reduced, imports will eventually replace domestic production, with a very negative impact on Canada's balance of trade.

- at current oil prices, the value of already discovered frontier oil is in the order of tens of billions of dollars and, should these reserves be developed, they would eliminate high oil import costs, enhance Canada's energy security, and increase national wealth.

- existing knowledge and experience, in combination with focussed R&D, are the keys that can lead to economic, safe and environmentally acceptable frontier developments.

The Croasdale study examined a number of East Coast and Beaufort development scenarios from the perspective of how improved technology and knowledge could lower costs and in turn, create the possibility of frontier projects with viable economics. The relative economics of several Grand Banks oil development scenarios were considered, with some of the key results illustrated in Figure 2.1. As shown, one of the messages from the 1992 study was that these types of Grand Banks development projects can be economic with oil prices in the $15 to $20 range, particularly if focussed R&D can achieve technology uplift. This study also highlighted a number of topic areas where focussed R&D thrusts are warranted, on scenario by scenario basis, including ice problems related to Grand Banks petroleum fields. Although the potential for economic developments in Canada's frontiers was clearly demonstrated, questions about the attractiveness of these projects and their relative competitiveness in comparison with other world-wide investment opportunities, were not addressed.

2.2 1994 Frontier Competitiveness Study

In 1994, Natural Resources Canada carried out a study that considered the attractiveness of Canada's potential frontier development projects, in comparison to the opportunities offered by its international competitors. This evaluation, which was undertaken by the Economic and Financial Analysis Branch of Natural Resources Canada, was published in a 1994 report entitled *How Competitive is Canada in Attracting Petroleum Investment? - An International Comparison*. One of the key goals of this study was to assess whether Canada's fiscal system was too onerous compared to international alternatives and if so, how could it be changed to better compete with the fiscal regimes in other countries, to attract investment back to Canada. The work was prompted by the concern that overseas investment spending by Canadian petroleum companies had increased dramatically in the late 1980's and early 1990's, during a period of uncertain oil prices, economic recession and reduced oil company budgets. Over this period, there had also been a marked increase in the number of regions open for exploration and development, and new prospects in the former Soviet Union, Asia, Africa and South America far outweighed the investment capital that was available to oil companies.

The study focussed on oil rather than gas, and considered the competitiveness of potential oil field developments in a variety of countries against development opportunities in the Canadian frontiers. In an effort to assess the attractiveness of oil prospects which Canadian companies could expect to find in competing countries, typical oil pool sizes were assumed.

The fiscal systems that were in place in these countries were used for the analysis, ranging from the generic royalty and tax regimes in countries like Canada, the UK, Australia and Argentina, to a variety of Production Sharing Contracts in South East Asia, the Middle East and African countries. The Canadian frontier development scenarios and costs that were used in this work were based on Croasdale's 1992 frontier planning study.

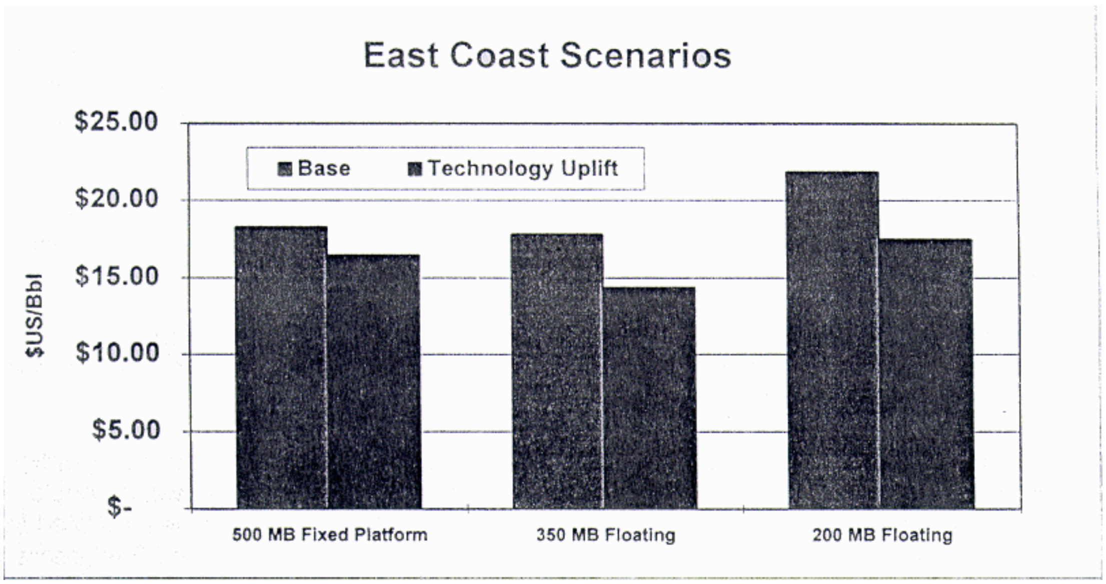


Figure 1: **The price required to obtain a 10% rate of return (after taxes &royalties) for several Grand Banks oil development scenarios, with and without "technology uplift", as presented in PERD's 1992 Frontier Planning Study.**

Some representative information and economic comparisons from this 1994 study are shown in Figures 2.2 to 2.6, with related comments given as follows.

- Figure 2.2 summarizes the range of typical oil pool sizes that should be expected in a variety of competing countries, in comparison to the oil field sizes reasonably expected in the Grand Banks and Beaufort Sea areas. The main point to recognize is that the oil fields discovered in these Canadian frontier regions are typically much larger than those in other competing areas and from this perspective, should be more attractive.

- Figure 2.3 shows typical cost per barrel breakdowns for a variety of international development opportunities. It may be seen that the per barrel costs for potential Canadian frontier projects is typically high, with the capital cost component of the large and small East Coast development scenarios (ie: fixed and floating production systems, respectively) being disproportionately large.

- Figures 2.4 through 2.6 highlight some of the development economics resulting from this study, and include the following assessment measures:

    - rate of return (ROR), which provides a measure of the after tax return on investment in a project

    - net present value (NPV) to total investment, which provides a measure of the efficiency of the invested capital

    - pay out to cost recovery, which provides a measure of the time period that risked funds are exposed to price, interest rate and political volatility

The results that are shown in Figures 2.4 to 2.6 suggest that potential oil field developments on the Grand Banks and in the Beaufort Sea may not be particularly attractive, compared to some of the other international opportunities that are available. Key conclusions that were drawn from this 1994 study are highlighted as follow.

- the impact of Canada's fiscal regime on the profitability of its potential frontier oil developments is minimal, and the fiscal system compares well with its competitors. (This conclusion was not necessarily accepted by industry as being appropriate, with the generic royalty regime recently introduced by Newfoundland recognized as a new and very positive factor, particularly in terms of removing uncertainties about the future fiscal climate for Grand Banks developments.)

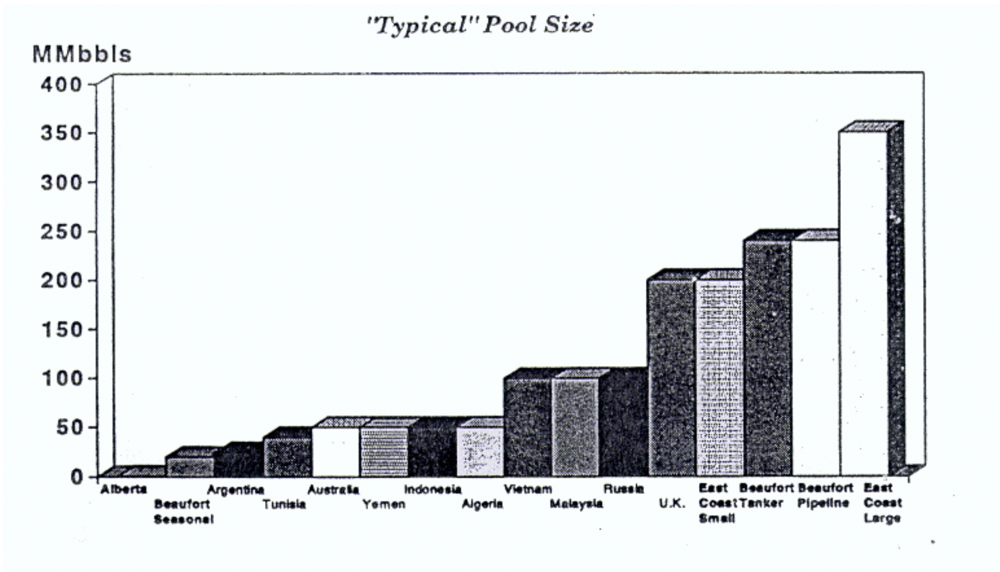


Figure 2.2: the range of typical oil pool sizes that should be expected in a variety of competing countries, in comparison to the oil field sizes reasonably expected in the Grand Banks (and Beaufort Sea) areas.

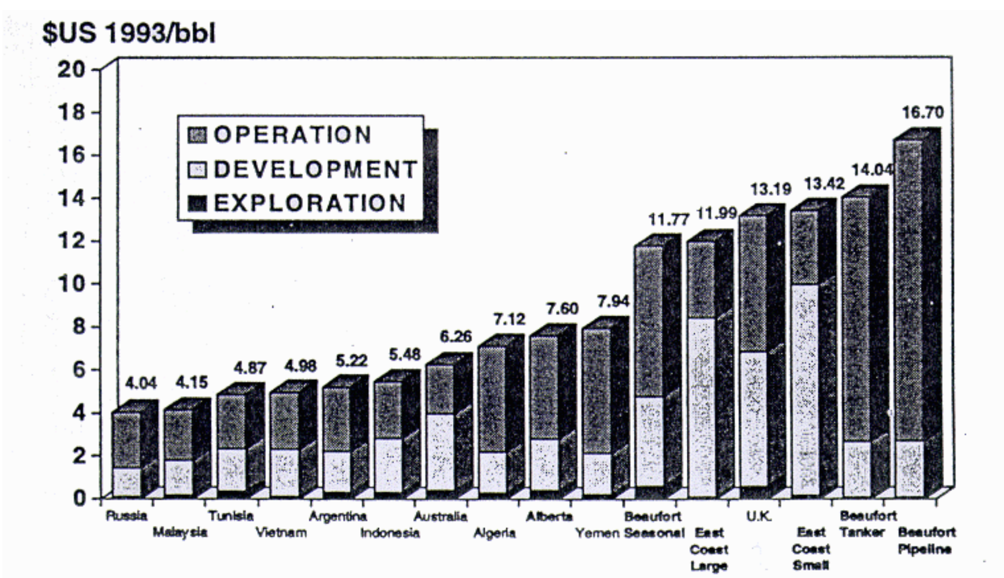


Figure 2.3: Typical cost per barrel breakdowns for a variety of international development opportunities, compared with potential Canadian frontier projects.

Figure 2.4:

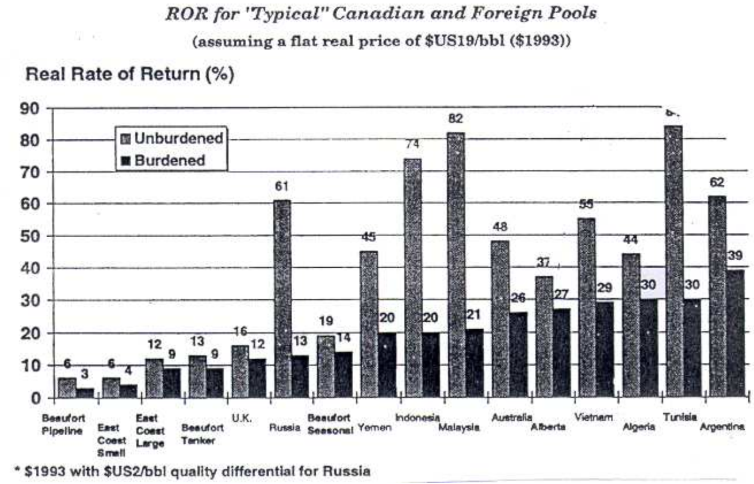


Figure 2.5:

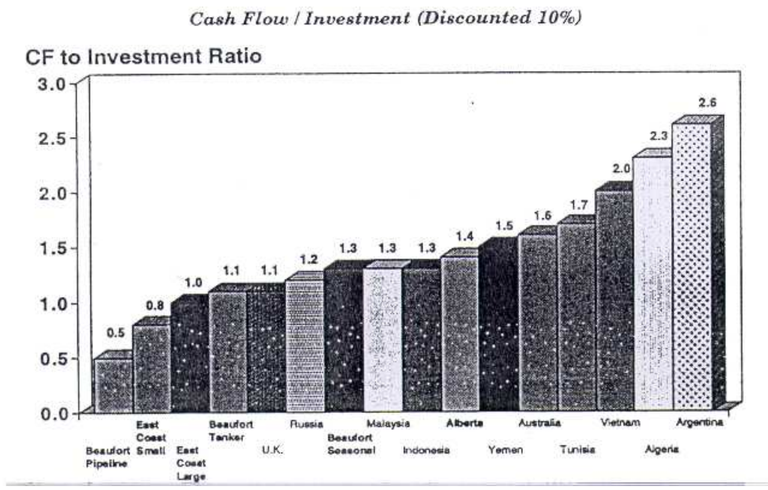
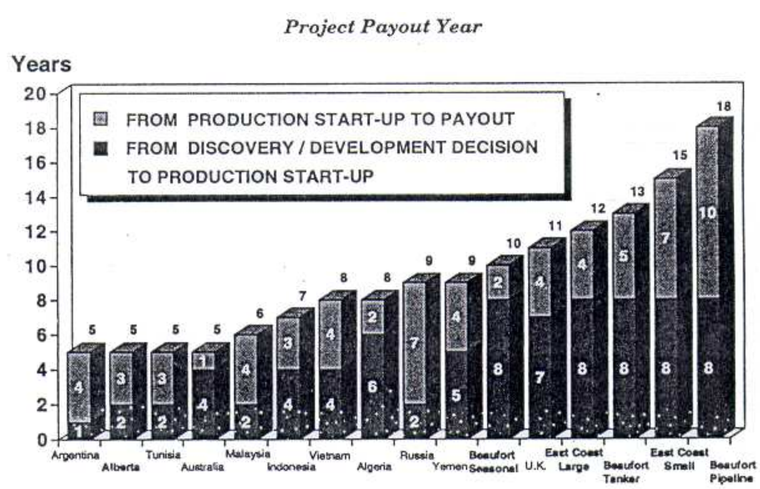


Figure 2.6:



- the high cost nature of Canadian frontier development projects and their long "on stream" lead times are the key factors which limit their profitability. The results of cost sensitivity analyses undertaken for the development of typical Canadian frontier pools suggest that a 25% reduction in capital costs would be needed to increase the RORs on these projects to the 15 to 20% real level, which is more competitive with foreign prospects.

- long frontier development time frames that are caused by factors such as regulatory requirements, the environmental assessment process and jurisdictional disputes have led many Canadian companies to pursue projects in other countries, where the time to first production and project pay out is reached more quickly. Any changes which Canada can make in its review and approval procedures would most likely improve its reputation in this regard.

- perceptions of technical risk, combined with the lack of any operational maturity in frontier development projects, make it difficult to attract companies that are looking for low cost, low risk, quick pay back situations. However, when the Hibernia project comes on stream, it is likely that oil companies will take closer look at the economics of other Grand Banks discoveries. These Grand Banks development prospects may be quite attractive when assessed from the perspective of already discovered pools, versus the economics of foreign prospects that incorporate exploration and political risk.

The comparative economics that were given in this 1994 government assessment strongly reinforced one of the key messages that was presented in the 1992 PERD frontier planning study, namely, the need to reduce the high costs of potential frontier development projects. However, the Natural Resources Canada study provided a number of other messages about the relative competitiveness of these frontier projects that are also important to recognize, including the effects of long lead times, perceptions of risk and fiscal regimes.

2.3 Recent Industry Perspectives

Despite concerns that have been expressed about the high cost, long lead time and relative competitiveness of potential frontier development projects in Canada, a new optimism has emerged about future oil developments on the Grand Banks, prompted by the initiation of the Hibernia project. Over the past several years, a number of oil companies have begun to follow courses of action and state public positions which clearly demonstrate their renewed interest in Grand Banks development opportunities. PetroCanada's Terra Nova project

initiative and Amoco's current exploration program on the Grand Banks are two key examples.
Some comments that have been recently made by key industry representatives are summarized as follows, to provide additional perspective in this regard.

April 1997 Presentation to NOIA by G. Bruce - Vice President of PetroCanada

- the Grand Banks is well on its way to becoming a major oil producing province, with PetroCanada's involvement in Hibernia, Terra Nova and other potential development projects considered to be a key component of the company's growth strategy and its future production portfolio.

- the Grand Banks region is very attractive to the oil industry for the following reasons:

  - it has proven to be an area where oil is found in large quantities, and at excellent finding rates

  - technology advancements that have been made over the past ten years, particularly with floating and subsea production systems, have resulted in very competitive development and operating costs

  - the new royalty regime that Newfoundland has established is profit sensitive and in PetroCanada's view, fair to all stakeholders

- the per barrel "find and development" cost for Grand Banks oil is actually less than for western Canada, and competes well with other international opportunities.

June 1997 Presentation to NOIA by R. Erickson - President of Amoco Canada

- Amoco is very optimistic about oil development prospects on the East Coast, and sees the initiation of the Hibernia project as a signal that the Grand Banks is poised to become a major oil producing area.

- Amoco's funding for their current exploration work on the Grand Banks reflects the development potential that is seen for the area and its high ranking relative to the company's other worldwide opportunities, including the production, refining and chemicals sectors.

- for Amoco to invest its capital efficiently in the competitive global marketplace, only high ranking prospects receive funding, with areas of high technical and/or nontechnical risk that do not present attractive business opportunities being discarded.

- factors that have contributed to a renewal of Amoco's interest in the Grand Banks region include:

    - the generic royalty regime that the Newfoundland government has recently established, and its effect on removing uncertainties about the future fiscal climate for developments in the area

    - efforts that government is now making to define a labour relations and local content framework for future developments in the area

- the other key issues that Amoco noted in this presentation include:

    - the importance of ensuring that Grand Banks oil discoveries can be quickly brought on stream, without undue delays that are caused by either technology limitations, the regulatory process, or policy issues

    - the pivotal role that innovative technology can play in reducing development project costs, enhancing economics, and making Grand Banks developments both viable and attractive

To provide some counterbalance to the bullish positions offered by PetroCanada and Amoco, it should be noted that Ian Doig, a well known oil analyst from Alberta, recently published the following views in a Calgary Herald article.

- the general perception in industry, government and the public sector is that the Grand Banks is a very hostile, high cost region for oil development with significant technical risks, despite the initiation of the Hibernia project.

- long development lead times (in the ten to fifteen years range) should be expected for future development projects in the area, because of jurisdictional wrangling, excessive regulation and the over zealous nature of the environmental assessment process.

- as long as these perceptions and constraints persist, most oil companies will avoid investments in potential Grand Banks development projects, and will direct their investment capital towards lower risk, quicker pay out opportunities, most of which are international.

3.0 Objectives

The goal of this study is to identify ice-related research initiatives that will be of benefit to oil field developments on the Grand Banks, in terms of reducing costs and improving economics, mitigating technical risks and increasing safety, and addressing any adverse perceptions of risk that may exist. This planning study is particularly important, given PERD's current budget restraints, the ongoing competition for diminishing PERD funds, and the need to select and priorize PERD research directions that can "make a difference" for potential development projects in Canada's frontiers.

The primary objectives of this study are:

- to identify the range of ice-related problems that are associated with potential Grand Banks oil field developments, with particular emphasis on the smaller oil reserves that have been discovered in the area to date.

- to assess the significance of these ice-related problems in technical and economic terms, in the context of representative Grand Banks development scenarios.

- to highlight the key ice problems related to Grand Banks petroleum fields and their relative priorities, for input to PERD's future R&D planning process.

4.0 Approach

The basic methodology that has been followed in this study work is highlighted in Figure 4.1. As shown, the approach that has been taken is subdivided into the following key tasks.

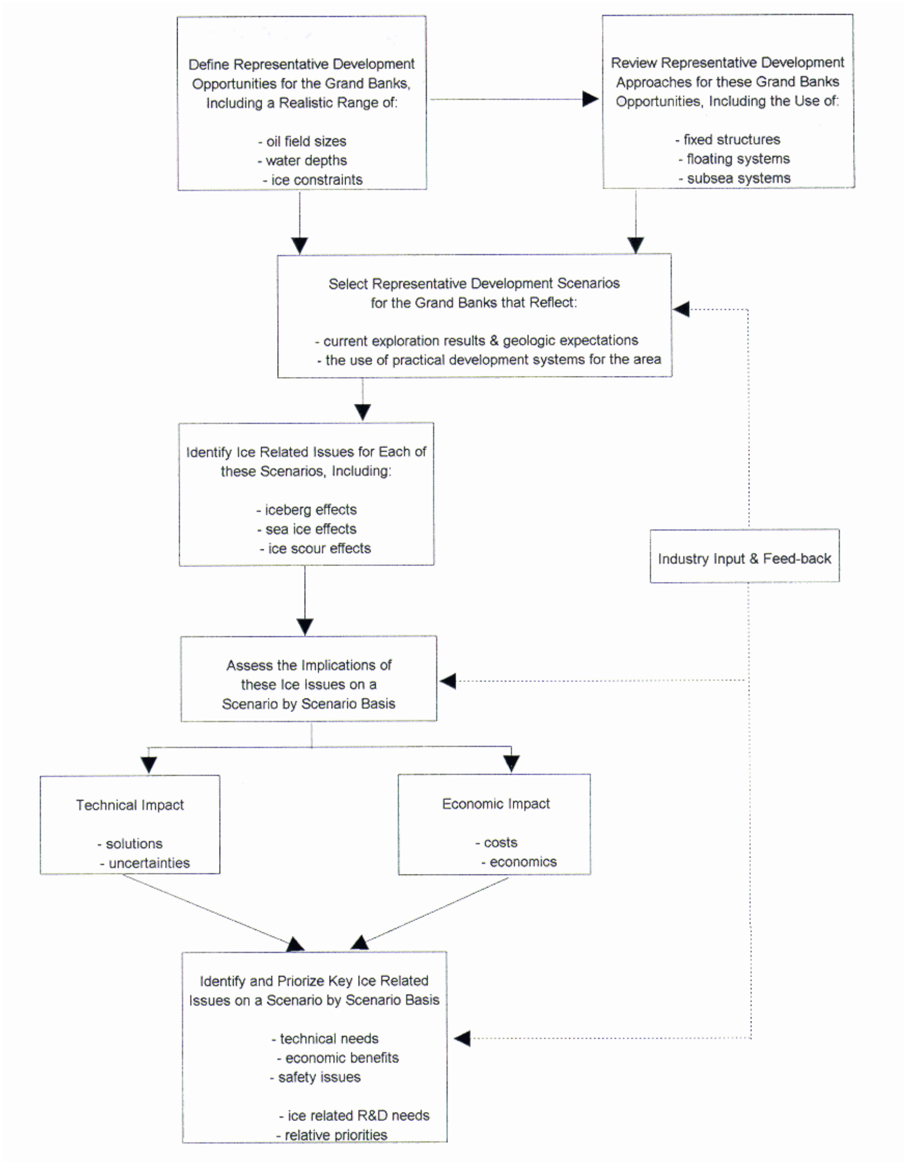
- a definition of representative "development opportunity scenarios" spanning the range of oil field sizes, water depths, and ice influences that should be reasonably expected on the Grand Banks, given current exploration results and geological expectations.

- a brief review of the various development approaches that could be used to pursue these "opportunity scenarios", and a selection of representative development system alternatives for each scenario.

- a discussion of the range of ice-related issues that should be recognized within the context of these different Grand Banks development scenarios, and their technical implications on a scenario by scenario basis.

- an evaluation of the significance of these ice-related problems for each development scenario in economic terms, and an assessment of the impact that technical advances in key "ice uncertainty" areas could have on costs, safety and perceptions of risk.

- an identification of the key ice-related research priorities and initiatives that would be of benefit in supporting the economic and safe development of oil fields in the Grand Banks area.



Although B. Wright & Associates Ltd. has been the primary contractor for this study, the work has been conducted on a joint basis, with K. R. Croasdale & Associates Ltd. and M. Fuglem of Memorial University, who ran most of the development project economics. C-CORE has also been involved, providing advisory input on an as-required basis.

In this study, a considerable amount of effort has been directed towards discussing Grand Banks ice problems and development issues with various industry, government and expertise group representatives. These interactions have been an important component of the work, since they have ensured that views on ice problem areas, different development approaches and costs, and technical risks were obtained from a wide range of stakeholders. These discussions have also led to a better appreciation for the current range of perceptions about potential Grand Banks field developments, the use of available technology, its limitations, the associated risks, and development project costs. A list of the organizations and individuals who have been contacted in conjunction with this study work is given in Table 4.1.

List of Organizations and Individuals Contacted

Organizations	Individuals	Topics Covered
Oil Companies		
Mobil Oil	W. Spring	ice problems & system costs
	G. Vance	ice problems & system costs
	D. McClelland	system costs
PetroCanada	G. Lever	ice problems & system costs
	P. Clark	ice problems & system costs
	K. Ng	ice problems & system costs
Husky	W. Shmink	ice problems & system costs
	C. Bailey	system costs
Amoco	K. Kennedy	ice problems
	D. Blanchet	ice problems & system costs
	K. Kovalski	system costs
Chevron	K. Roberts	system costs
	W. Bugno	ice problems
HMDC	J. Ransom	ice problems
	J. Henley	ice problems
Government Agencies		
NEB	B. Dixit	ice problems
CNOPB	D. Burley	ice problems
Specialist Groups		
Westmar	N. Allyn	ice problems
Sandwell	D. Masterson	ice problems & system costs
IFN	T. Brown	ice problems
Memorial	I. Jordaan	ice problems
Arctic Sciences	J. Marko	ice climate

Table 4.1:

5.0 Grand Banks Setting

5.1 Environment

The Grand Banks is located several hundred kilometres off the east coast of Newfoundland, covering an area of about 500,000 km that is centred at 46° N latitude and 51° W longitude. General water depths across much of the Banks are 150m or less, although the bathymetric contours tend to fall off rapidly on its flanks. Icebergs are well known as the most formidable environmental influence in the area, because of their size, mass and energy. The waters off Labrador and Newfoundland are often referred to as "iceberg alley" since high numbers of icebergs move through the area each year. Typically, more than 800 icebergs cross the 48th parallel annually, but there is considerable variability around this mean number from year to year. These icebergs are highly variable in terms of their size, mass, keel depth and shape and recognizing processes such as deterioration and calving, can be present in sizes ranging from a few metres to hundreds of metres, and masses varying from hundreds to millions of tonnes.

Large icebergs are of most importance in terms of the global forces that they may exert on structures, and the potential for damage to subsea facilities from deep iceberg keels. Bottom founded structures must be designed to withstand iceberg impact forces, while most floating structures must avoid them. Smaller glacial ice masses are also of concern to both fixed and floating systems, due to the high local impact loads that they can impose. Similarly, the presence of icebergs and small ice masses is an important consideration for vessels navigating or stationkeeping in the area, since high speed interactions may result in structural damage. Iceberg detection, monitoring and management techniques can be used to reduce the risk of iceberg and small ice mass interactions (eg: towing and water cannons) but often, these techniques lack reliability, particularly for the smaller ice masses and unstable berg forms. Additionally, when icebergs and small ice masses occur in combination with adverse wind, wave and visibility conditions, ice detection, monitoring and management can be difficult.

Sea ice is also an important consideration for any development systems that will be used on the Grand Banks, since these systems will unquestionably be exposed to sea ice over typical project lifetimes. Although sea ice is not an annual occurrence on the Grand Banks, it can be advected into the area from more northerly waters, where locally formed ice and pack ice moving southwards from the Labrador Sea can be found each winter. Typically, pack ice intrusions are experienced on the Grand Banks every several years, lasting anywhere from a week to a month or more. In the Flemish Pass and Flemish Cap areas, and on the northern part of the Grand Banks, pack ice occurrences can be more frequent. The sea ice comprising the mobile East Coast pack is normally thin, in the order of 0.5 to 1m, and is usually present in moderate concentrations, with floes that are tens of metres to hundreds of metres in extent. However, more extreme sea ice conditions can also occur which include thicker ice, larger floes, pressure ridges, rafted ice and small multi-year ice floe fragments. Small glacial ice masses and icebergs can also be contained within this East Coast pack ice.

A fixed platform would have to be capable of sustaining the forces associated with these sea ice conditions, both globally and locally, while most conventional floaters would normally avoid sea ice incursions by moving off location. In the case of purpose built floating vessels, capable mooring systems, combined with the occasional use of active ice management to reduce sea ice forces, would permit stationkeeping but would need a high level of reliability. Clearly, ice strengthened floating systems would also require effective and reliable protection against glacial ice masses that were embedded in the pack ice cover, to remain on location with confidence. The occurrence of sea ice will also have a strong influence on various marine operations, including tanker loading from fixed and floating production platforms, regional ship transits and resupply. However, the significance and consequences of sea ice encounters will depend upon the design and performance characteristics of the particular vessel and loading systems employed.

Here, it is also important to note that the wind and wave climate on the Grand Banks is not unlike the North Sea, with extreme maximum wave heights in the order of 30m. The area is often rough and experiences frequent occurrences of moderate to high seas and longer period swell, particularly during the fall and winter periods, when storms move through the region. Poor visibility caused by fog, low cloud cover, rain and blowing snow is also a common occurrence in the general area. In terms of technology, the offshore industry has shown that fixed or floating systems can be designed for safe and effective operations in this type of wave and weather environment. Monolithic gravity based structures and jackets are examples of existing bottom founded platforms, while semi-submersibles, ship-shape and tension leg systems represent some of the floating technology that is now in use. It is well known that relatively low cost production systems are available that would be operationally effective in the Grand Bank's wave and weather climate. *However, the presence of sea ice and icebergs, and the inability to reliably eliminate these ice threats limits the direct applicability of this conventional technology.*

5.2 Exploration

More than 100 exploration and delineation wells have been completed on the Grand Banks over the past twenty-five years, with 17 significant discoveries being made to date, primarily in the Jeanne d'Arc Basin. These wells have been drilled with conventional floating drilling equipment, designed for open water use. Since these drilling systems are not ice tolerant, most Grand Banks wells have been scheduled to avoid seasonal periods with the highest potential for iceberg encounters and sea ice incursions. Semi-submersibles have been the most common type of drilling system employed because of their superior performance characteristics in high seas, although drillships have also been used. Both types of systems have proven to be quite capable of effective drilling operations in the open water conditions experienced but as noted above, are not ice resistant. Although preferred operating windows have generally been selected for exploratory and delineation drilling work on the Grand Banks, it is well known that the presence of some icebergs has been unavoidable, even during these lower ice risk periods. As a result, the iceberg consideration has had a major influence on Grand Banks operations and has required the development of specialized equipment and novel operating procedures, designed to ensure safe and efficient drilling operations. In this regard, the Canadian oil industry has developed iceberg detection, management, alert and "vessel move-off" systems that are unique, and is in a well demonstrated position to drill cost effective exploration wells, with no major technical impediments. From an exploration perspective, improvements in the efficiency and reliability of iceberg and sea ice detection, forecasting and management systems would provide some benefits, but are by no means critical.

From a development perspective, the iceberg and sea ice constraints that are experienced on the Grand Banks are of much more consequence, since they have very significant design and operational implications for different production system alternatives. Although the equipment, procedures and experience base that have been developed through East Coast exploration operations provide a strong basis for planned development activities, better methods of coping with iceberg and sea ice problems will undoubtedly lead to improved development economics, and increased investor confidence.

5.3 Development

To date, two fundamentally different approaches have been considered for the development of Grand Banks oil reserves, as illustrated by the Hibernia and Terra Nova production systems. Schematics of these "generic" development approaches are shown in Figures 5.1 and 5.2. Both development schemes involve subsea flowlines, tanker loading facilities and shuttle tankers that will periodically move produced oil to market. However, the Hibernia approach is centred around the use of a fixed gravity based structure (GBS) which has integral oil storage and is designed to passively withstand all of the forces imposed by the environment, including those from extreme wave, iceberg and sea ice encounters. The benefit of this approach is that a fixed structure (with integral storage) will experience little, if any, production downtime due to adverse environmental conditions. However, the penalty is normally reflected by increased production facility costs, extended construction schedules, and longer time frames to "first oil".

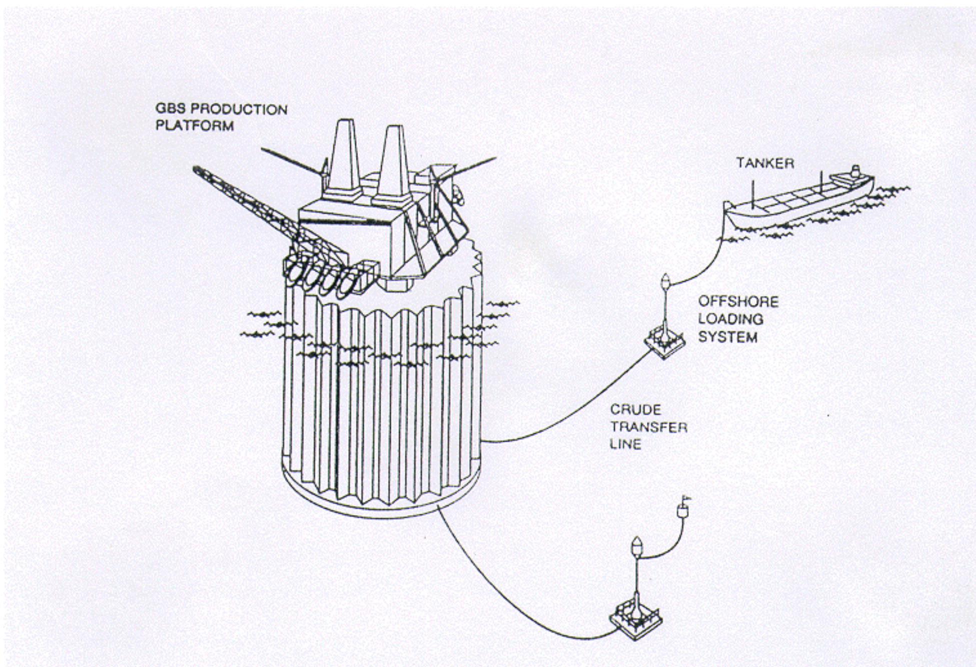


Figure 5.1: Sketch of Hibernia development system

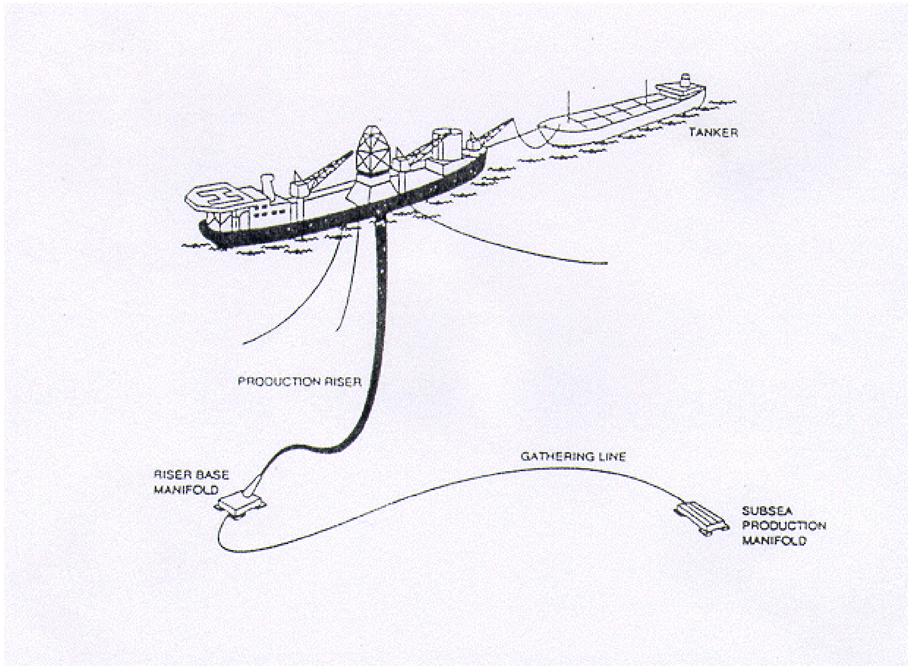


Figure 5.2: Sketch of proposed Terra Nova development system

The proposed Terra Nova development scheme involves a floating ship-shape production vessel with integrated storage and offloading systems (FPSO), that is designed to continue operations in most environmental conditions, but suspend production and if necessary, move off location, should extreme events occur. When iceberg or sea ice avoidance is required, the vessel's mooring lines and risers are lowered, and the FPSO simply moves off under its own power. This approach is based upon an "active design philosophy", and reflects a high level of confidence in the experience that has been developed with floaters during exploratory drilling activities, including the ice detection and management area. Generally, the advantage of an FPSO vessel is lower capital cost and quicker on-stream times, but the penalty is the potential for more downtime due to ice and waves, and the associated loss in production.

Both of these fixed and floating development approaches will involve the periodic transfer of stored oil from the production facility to ice strengthened double hull tankers via an offshore loading system, for subsequent transport to market. The tanker mooring and oil loading arrangement that will be periodically used at the GBS is located well below the waterline (when not in use), where it will be protected from most ice influences. At the FPSO, stored oil will be transferred to shuttle tankers that are periodically tandem moored to its stern, through a conventional mooring/loading arrangement. Clearly, tanker loading operations at both types of production facilities will be susceptible to iceberg and sea ice incursions. The shuttle tankers that are used within these developments will also be exposed to icebergs and sea ice during their transits to and from market and will be designed to contend with sea ice occurrences, but will have to avoid icebergs and small glacial ice masses (with the possible exception of very small features). Supply vessels working in the area will also be susceptible to the influences of sea ice and small ice mass occurrences.

Because the Grand Banks waters are relatively deep, the risk of seafloor scour is generally low. However, most of the subsea facilities that are associated with developments will have to be designed to accommodate the risk of iceberg scour, through placement within glory holes or trenches excavated on the seafloor. Here, it is important to note that iceberg scouring is a key constraint on pipeline transportation systems and therefore, on potential gas developments. If the sea floor was not subject to iceberg scouring, it is more likely that oil and gas pipelines would be used.

Decisions about the best type of development system for a given field are normally based upon an assessment of capital cost requirements, comparative economics and relative risks, which balance downtime, lost production and increased operating expenses for floaters against the increased capital cost and implementation schedules for fixed platforms.

6.0 Development Scenarios

In order to identify the range of ice-related problems that different Grand Banks development systems will have to contend with and in turn, assess their relative importance, representative development scenarios must first be defined. One approach is to select scenarios from existing Grand Banks discoveries and the specific development schemes now being considered, such as the Hibernia and Terra Nova projects. The other approach is to establish representative scenarios in a more generic manner, with the objective of spanning a wider range of field development possibilities. This latter approach has been adopted for this work, since it is considered to be more appropriate to PERD's R&D planning needs.

In basic terms, the definition of representative Grand Banks development scenarios involves the following two areas of consideration:

- the assumptions that are made about oil field sizes, the water depths in which they are located, and the severity of the ice conditions that these assumed field areas will be exposed to.

- the assumptions that are made about the particular development schemes that will be used to produce oil from these fields.

In this section of the report, the Grand Banks discoveries that have been made to date are briefly reviewed, to provide some background for the generic development opportunities that have been assumed. Based on these discoveries, a number of representative oil development opportunities are then defined. These generic cases are intended to span a realistic range of oil field size and water depth combinations that should be expected for future Grand Banks oil developments, in a parametric manner.

Since the ice conditions experienced in any given field location may influence the type of development approach that is selected for the field, key variations in the iceberg and sea ice climate seen across the Grand Banks are also highlighted. The development approaches that could be used to exploit these generic Grand Banks oil fields are then outlined, followed by a definition of representative Grand Banks development scenarios.

These composite scenarios combine oil field size, water depth and a particular development approach into a number of representative development cases that are used as a basis for the ice problems assessment work given in subsequent sections of this report.

6.1 Development Opportunities

6.1.1 Significant Discoveries

As outlined earlier, seventeen significant hydrocarbon discoveries have been made on the Grand Banks to date, in water depths ranging from 80m to 160m. These discoveries, together with estimates of their oil, gas and natural gas liquid reserves, are summarized in Table 6.1 Their geographical locations are shown in Figure 6.1. It may be seen that eight of these fields contain oil only, two are exclusively gas, and the remaining seven contain both oil and gas. Most of the proven oil reserves on the Grand Banks are located in the Hibernia, Terra Nova, Hebron and Whiterose fields, with the other existing oil discoveries being quite small. Here, it is also important to note that all of these fields lie in fairly close proximity to one another.

From a development perspective, it is clear that the amount of oil contained in any given field is a key factor. Obviously, the larger the oil reserve base the better. However, it is important to recognize that a variety of other reservoir factors also effect the attractiveness of potential field developments, and can strongly influence their cost. These factors include the fluid and production characteristics of the oil reservoirs comprising the field, the complexity of these formations in terms of structural style and trapping mechanisms, and the thickness, lateral extent and depth of the oil bearing zones. As an example, light high quality oil reserves that are concentrated over a small area, are located in a thick pay zone, and can be produced at high flow rates represent the most attractive situation. Typically, this type of oil field could be developed from one production platform, with a relatively small number of development wells. Alternatively, fields comprised of a variety of thin oil bearing zones that are spread over large lateral areas and are not capable of high flow rates are more difficult. A development scheme for this type of field would usually require many more producing and injector wells, and either multiple subsea well tie-backs to a production platform, or more than one platform. Clearly, these reservoir factors all play a very important role in the attractiveness of potential development projects, and on their costs and economics.

Each one of the oil fields discovered on the Grand Banks to date is different, and has its own unique reservoir characteristics. In general terms, these oil fields are not particularly simple. Typically, each field is comprised of several oil formations which are fairly large in areal extent, not particularly thick, and often complex in terms of faulting. Although individual well productivities for many of the larger Grand Banks fields are reasonably high, some of the smaller discoveries may have poorer flows. A few comments about the oil fields discovered to date (Chipman, 1997) are given as follows, to provide some feel for their characteristics.

Discovered Resources[1]	Newfoundland Offshore Area					
Field	Oil		Gas		NGLs[2]	
	m^3 x 106	million bbls	m^3 x 109	billion cu. ft.	m^3 x 10^6	million bbls
Hibernia[3]	106.0	666	28.7	1017	17.7	111
Terra Nova	64.4	406	7.6	269	2.2	14
Hebron	31.0	195	-	-	-	-
Whiterose	28.4	178	42.7	1509	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	-	-	-	-
King's Cove	1.6	10	-	-	-	-
South Tempest	1.3	8	-	-	-	-
East Rankin	1.1	7	-	-	-	-
Fortune	0.9	6	-	-	-	-
South Mara	0.6	4	4.1	144	1.2	8
North Dana	-	-	13.3	470	1.8	11
Trave	-	-	0.8	30	0.2	1

Table 6.1: Significant discoveries that have been made on the Grand Banks to date, together with estimates of their oil, gas and natural gas liquid reserves (from CNOPB, 1997)

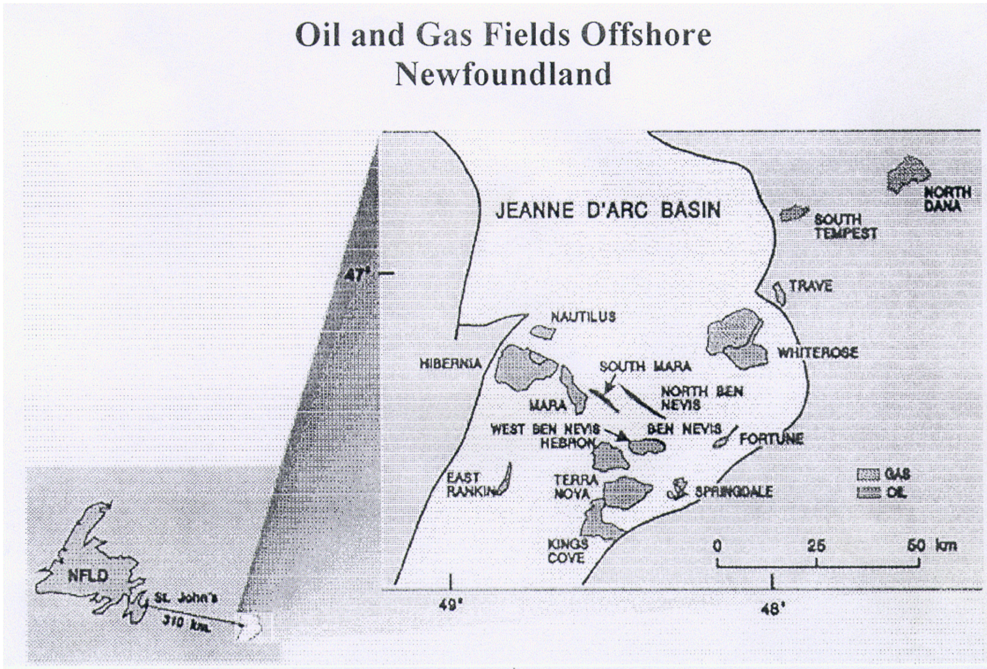


Figure 6.1: Geographical locations of Grand Banks discoveries (CNOPB, 1997)

Hibernia

Hibernia is the largest oil field that has been discovered on the Grand Banks, with estimated recoverable oil reserves of 666 million barrels, and an upside potential of nearly 1 billion barrels. This discovery is well recognized as major oil field by world class standards and as the lead development project, is also acknowledged as the key to stimulating further exploration and development on the Grand Banks. The following points should be noted.

- the extent, geometry and characteristics of the Hibernia oil field are quite well known from extensive delineation drilling, testing and seismic work.

- the field is comprised of four major hydrocarbon reservoirs, including the Hibernia formation, the Ben Nevis/Avalon reservoir, and the smaller Jeanne d'Arc and Catalina formations, all of which can be "reached" by wells drilled from the GBS with no need for separate subsea wells.

- the Hibernia field is located in about 80m of water and is roughly 10 x 10 km in areal extent, with its oil reserves lying between 2300m and 4200m below the sea floor, mostly in the Hibernia and Ben Nevis/Avalon formations.

- production rates as high as 30,000 BOPD and 12,000 BOPD are expected from individual development wells in the Hibernia and Ben Nevis/Avalon reservoirs respectively, with potential production from the field's smaller formations requiring further evaluation as development wells are drilled.

Terra Nova

Terra Nova is the second largest oil field that has been found on the Grand Banks to date, with estimated recoverable reserves of 405 million barrels and good upside potential for a larger reserve base. It is located about 40 km to the southeast of the Hibernia field and is also recognized as a substantial oil discovery by world class standards. Here, the following points should be noted.

- the nine wells that have been drilled in the Terra Nova field indicate significant oil reserves, although further delineation drilling is required in the field's far east section to confirm the reserve potential in this area.

- this field is comprised of the Terra Nova reservoir. which is the largest oil formation, and the smaller Beothuk formation, which is quite heavily faulted.
- the field is located in 93m of water and is about 8 x 10 km in lateral extent, with its oil reserves lying between 3200 and 3500m beneath the sea floor.

- production rates as high as 20,000 BOPD are expected from individual development wells in the Terra Nova reservoir.

Hebron & Whiterose

The Hebron and Whiterose oil discoveries, with current reserve estimates in the order of 150 to 200 million barrels, are the two more moderately sized oil fields that have been found on the Grand Banks. However, both fields require further delineation drilling to better define their reserve potential.

The Hebron field, with estimated recoverable oil reserves of 195 million barrels, is located in close proximity to Terra Nova, lying about 15 km to its northwest. It is believed to be the third largest oil field found in the Jeanne d'Arc Basin to date, but will require considerably more delineation. With regard to Hebron, the following points should be noted.

- the Hebron field is comprised of oil in the Jeanne d'Arc, Fortune Bay, Hibernia and Ben Nevis reservoirs, with the first three formations containing better quality oil.

- the West Ben Nevis and Ben Nevis discoveries, where oil has also been tested, are located in close proximity to Hebron's eastern flank, but appear to contain heavier, more viscous, poorer quality oil.

- geologically, the Hebron field is quite faulted, but involves relatively large simple fault blocks.

- the field is located in about 94m of water and is roughly 8 x 4 km in lateral extent, with its oil reserves lying between 1800 and 4400m below the sea floor.

- individual well productivities in the Hebron field are not well known without further delineation drilling, but will probably be in the 10,000 to 15,000 BOPD range.

The slightly smaller Whiterose field is located on the northeastern part of the Grand Banks, about 50 km away from the Hibernia and Terra Nova fields. Recoverable oil reserves from Whiterose are estimated at about 180 million barrels. Although five wells have been drilled in the field area to date, it is a large geological structure which has only been lightly delineated to date. The following points should be noted

- the Whiterose field is comprised of the South Mara, Ben Nevis/Avalon, Hibernia and/or Rankin oil reservoirs, with most of the oil being concentrated over a relatively small thick pay zone area in the Ben Nevis formation, which enhances its development potential.

- the field is located in roughly 110m of water and is about 7 x 5 km in lateral extent, with its oil formations located between 3000 and 3900m below the sea floor.

- since the permeability of the major Ben Nevis reservoir at Whiterose is relatively low, the field's development wells are not expected to be highly productive, with expected flow rates of 10,000 to 15,000 BOPD.

Minor Fields

In addition to the four major oil fields highlighted above, ten smaller oil discoveries have also been made on the Grand Banks. These minor fields, which include discoveries like Ben Nevis, Mara and King's Cove, are felt to collectively contain recoverable oil resources of about 130 million barrels. Typical reserve estimates for the smaller oil fields are in the 10 to 30 million barrel range, with well productivities expected to be quite low. Some of these reservoirs include fairly sizable quantities of gas and condensates while others, like the Trave and deeper water North Dana fields, are felt to contain gas and condensates exclusively. Since most of these smaller fields are the result of one discovery well only, their current oil reserve estimates are uncertain and could change considerably, should further delineation drilling be carried out.

There is no shortage of Grand Banks development opportunities, in addition to the Hibernia and Terra Nova oil fields. At a minimum, the Hebron and Whiterose fields each have a large enough resource base to qualify them as stand-alone development project candidates. The smaller fields do not appear to contain the oil resources to justify stand-alone development. However, they may be quite attractive as individual satellite fields tied back to an existing production facility, or in combination, when considered as candidates for simultaneous or sequential development. It is not unlikely that future exploration will also result in a number of new oil field discoveries, some of which may be quite sizable.

6.1.2 Generic Oil Fields

The range of reserves that have been found in the Grand Banks oil fields discovered to date, together with the water depths in which these fields are located, provide a basis for defining representative Grand Banks development opportunities. The generic oil field cases that have been selected for use in this study include:

- five different fields, with recoverable oil reserves of 50, 150, 250, 350 and 500 million barrels.

- four different water depths for each of these fields, 80, 100, 120 and 160m.

When parametrically combined, these representative oil field selections translate into twenty separate development opportunity cases. These twenty cases are intended to span a realistic range of oil reserve and water depth combinations that should be expected for future Grand Banks developments, in a parametric manner. Specific assumptions about the reservoir characteristics of these generic oil fields have not been made. However, typical oil field dimensions, well productivities and development drilling requirements have been established on the basis of current Grand Banks and other world wide experience, as outlined later in this report.

The prevailing industry view is that fields with recoverable oil reserves in the 200 to 300 million barrel range will be required to justify future Grand Banks developments. In addition, it is generally felt that floating production systems represent the only real alternative for these potential developments. Conventional industry wisdom also suggests that oil fields of at least 500 million barrels will be required to justify any more fixed structure developments, and that future discoveries of this size are unlikely. Industry also recognizes the potential for smaller Grand Banks oil resources to be economically tied back to existing facilities, but is seen as a longer term opportunity area. Here, it is interesting to note that in other areas of the world, oil fields of less than 100 million barrels are now being developed with floating systems. Fixed structures are also being used to develop more moderately sized fields, with reserves in the 200 million barrel range. In addition, the technology to produce satellite fields through subsea tie-backs has developed rapidly, and is routinely being used to develop small field reserves (10 to 50 million barrels) that are present around either fixed or floating production facilities.

The generic oil field cases defined for this study encompass a sufficiently wide range of Grand Banks development opportunities to allow all of these potential development alternatives to be considered. One challenge is to improve technology for Grand Banks developments to the point where relatively small oil field reserves can be economically produced, as is now being done in some of the more conventional open water areas of the world.

6.2 Ice Climate

It is clear that future developments on the Grand Banks will be exposed to different iceberg populations and sea ice occurrence frequencies, depending upon where they are located in the area. Because these ice conditions may influence the type of development approach that is ultimately selected for any given field, key variations in the iceberg and sea ice climate across the Grand Banks region are highlighted here. Obviously, oil fields that are situated in close proximity to one another and in similar water depths will not see much variation, at least in a statistical sense. However, more widely separated field areas may. For example, prospects that lie in deeper water areas towards the north and east sides of the Banks will experience more frequent and larger icebergs than in its shallower central and southern portions. This factor will effect the iceberg impact design loads used for fixed production structures, and will influence the downtime related to iceberg avoidance for floating production systems. Similarly, potential developments in the more northerly areas near Whiterose will be subjected to higher pack ice occurrence frequencies than those near Terra Nova and as a result, may incur substantially more sea ice related downtime. It is important to recognize these ice factors before considering various Grand Banks development alternatives.

6.2.1 Icebergs

Figure 6.2 shows iceberg densities across the Grand Banks, as derived from International Ice Patrol data (Fuglem, 1997). Although the iceberg occurrence statistics that are given in this figure are not intended as precise estimates, they do illustrate some of the major trends. The following points should be noted

- the distribution of iceberg densities on the Grand Banks does vary, with expected berg occurrence frequencies in the northern and eastern reaches of the area being about 50% higher than in its central and southern areas.

- some of the icebergs that are seen in these more exposed and deeper water portions of the Grand Banks will be large, because grounding will not filter them out.

- in short, iceberg populations that will influence the development of prospects in the general vicinity of Whiterose, the West Bonne Bay location where Amoco is now drilling, and along the east flank of the Grand Banks, may have a somewhat more pronounced effect on development schemes than those found near the Hibernia and Terra Nova oil fields.

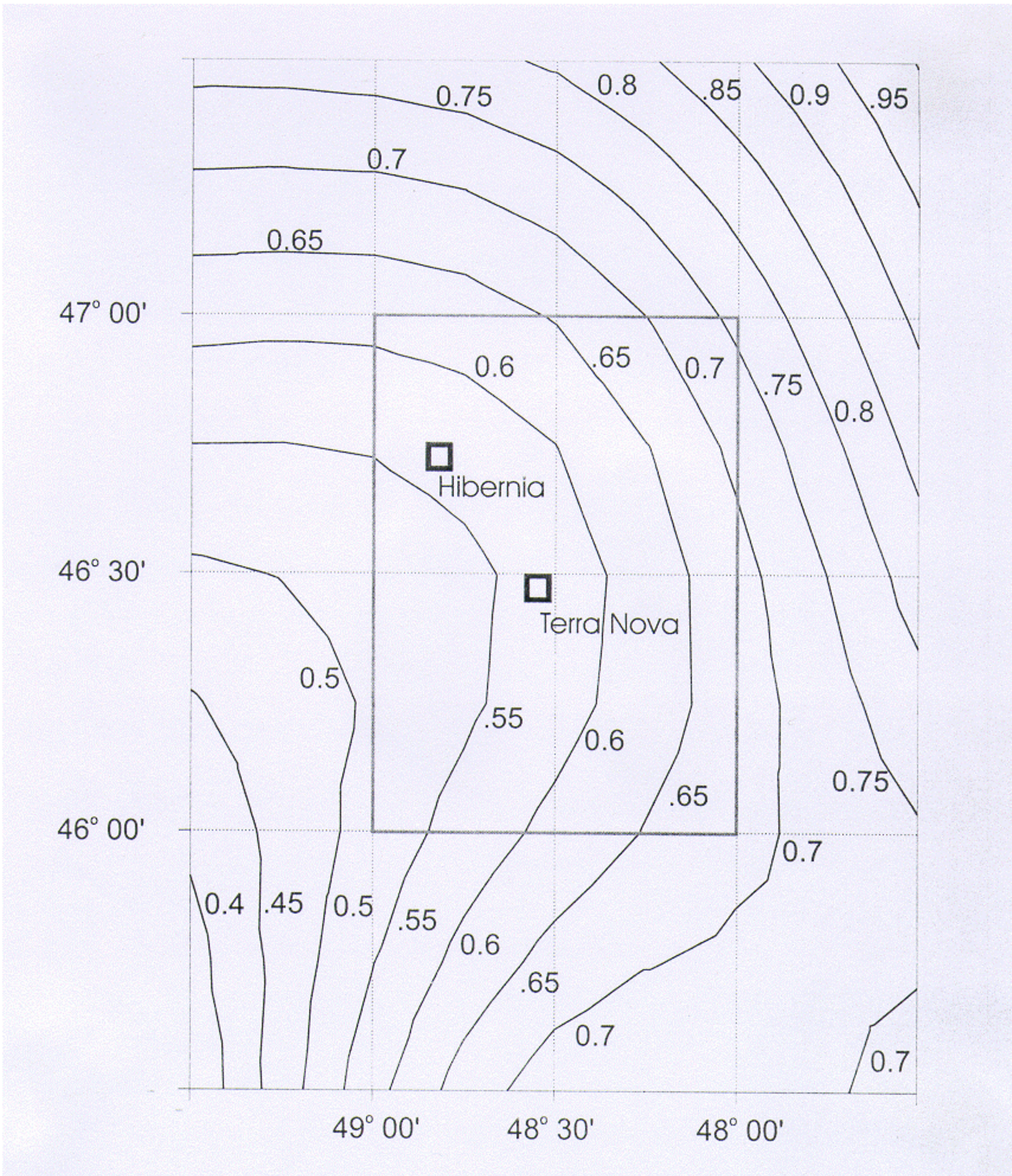


Figure 6.2: Average iceberg densities expected at any point in time across the Grand Banks, as derived from International Ice Patrol data from 1960 to 1974 (Fuglem, 1997)

6.2.2 Pack Ice

Figure 6.3 highlights some pack ice occurrence statistics for the Grand Banks, as presented in PetroCanada's recent Terra Nova Development Project Submission. These statistics are based upon Atmospheric Environment Service observations from 1963 to present, and show expected occurrence frequencies, durations and concentrations for pack ice intrusions, relative to the Terra Nova location. The distance scales given encompass most of the Grand Banks discoveries made to date. Here, the following points should be noted.

- pack ice occurrences in the immediate vicinity of Terra Nova are only expected in about one of four years, with mean occurrence durations of about two and a half weeks, and mean concentrations between 5 and 6/10ths.

- further to the north, towards the Hibernia and Whiterose fields, and to the east, pack ice intrusions are more frequent, with occurrence frequencies of about one of two years and mean durations of three to four and a half weeks.

- in some of the poorer ice years that have been experienced on the Grand Banks, pack ice has sometimes persisted for several months at potential development locations, often in concentrations as high as 7 to 9/10ths.

- the pack ice found on the Grand Banks is not particularly severe, typically containing first year ice type concentrations of about 3/10ths and many thin ice areas, but its movement rates can be very high.

- pack ice occurrences will have a more pronounced effect on oil field developments on the north and east portions of the Grand Banks like Whiterose, than the more southerly locations like Terra Nova.

The effect of variations in expected iceberg and pack ice conditions across the Grand Banks is not explicitly addressed for the development scenarios considered in this report. However, their impact on the design and operation of various development system alternatives for different water depths is recognized, and treated as a cost and downtime sensitivity.

The potential for long term climate related variations in Grand Banks iceberg and pack ice conditions over several decades (comparable to development project lifetimes) should also be noted here, in view of the global climate change and "presumed global warming" issue. Recent temperature data for the East Coast appears to indicate a cooling trend (Marko, 1995). It is conceivable that Grand Banks development systems which rely on minimal ice being present may have to contend with more ice than the long term averages would suggest.

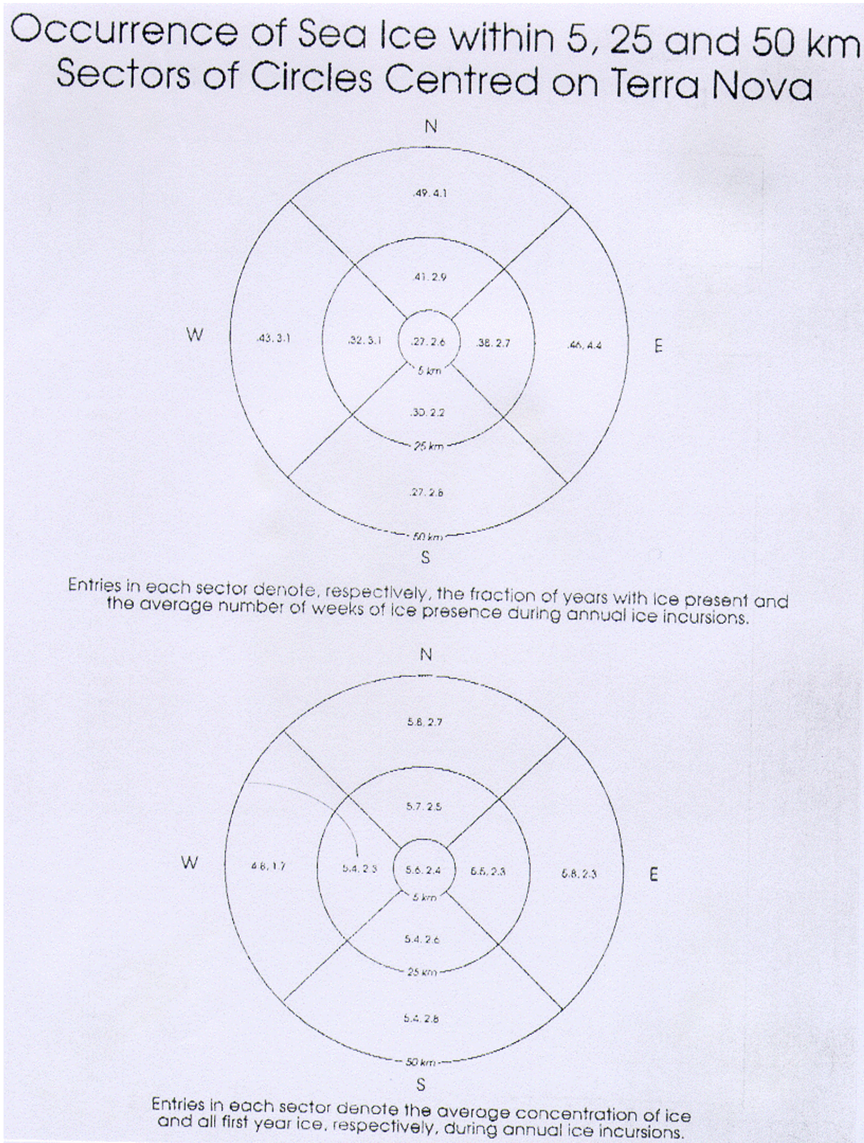


Figure 6.3a: Some pack ice occurencies statistics for the Grand Banks, as presented in PetroCanada's recent Terra Nova Development Project Submission (1997).

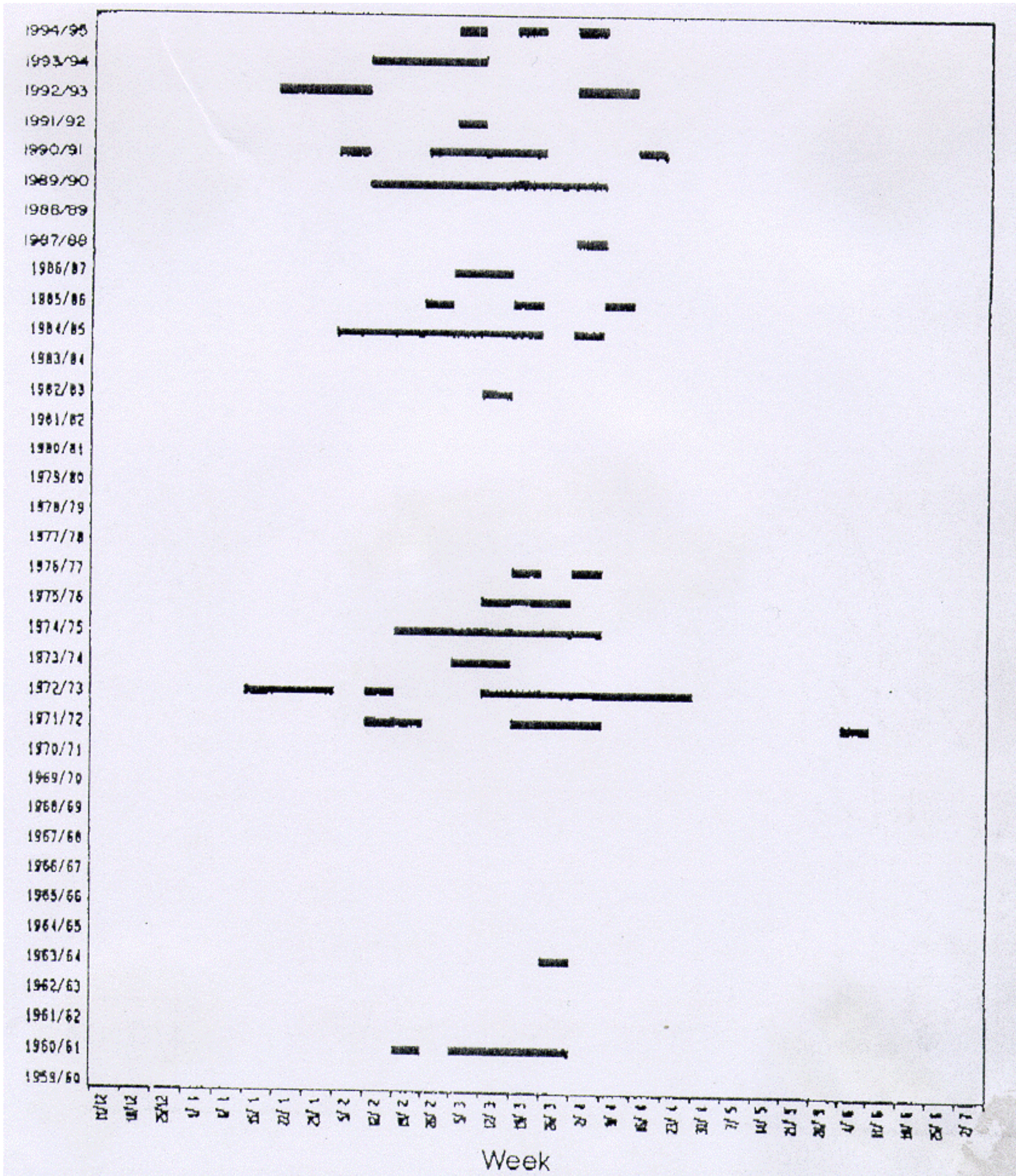


Figure 6.3b: Weekly instructions of all pack ice within 50 km of the Terra Nova location, from PetroCanada's recent Terra Nova development Project Submission (1997).

6.3 Development Approaches

6.3.1 General

Any offshore development project is comprised of a number of basic components. The major technical elements of a typical offshore development include:

- the production platform that is selected, either fixed or floating.

- the topsides facilities that are installed on the platform, including the production and accommodation modules and, in the case of fixed structures, the drilling module.

- the development wells that are drilled, including both producing and injector wells.

    - for fixed production structures, these wells are normally drilled from a drilling facility onboard the platform, after it has been installed in the field area

    - since floating production systems do not normally have drilling facilities, these wells are usually drilled from separate floating drilling vessels, often before the production system has been moored in the field area

- the subsea systems that may be required, including wellheads, manifolds and flowlines.
- the export approach that is adopted, either by pipeline or tankers, including:

    - any integral storage that is designed into the production platform or any of the separate field storage systems that may be put in place

    - the tanker loading system and tankers that are selected, should the marine export approach be used.

The cost of any offshore development project is strongly affected by the water depth in which it is located, the environmental conditions that it is exposed to, and the development approach selected. Platform costs are most sensitive to the operating environment, while subsea and export system costs are driven by both the operating conditions and the complexity and size of the development. Topsides and development drilling costs, which can be very high, are largely independent of the environment and are driven by process and reservoir requirements.

6.3.2 Development Options

Companies that are developing offshore oil fields have three main options. They can either build a fixed platform, deploy a floating production vessel, or install a subsea system for satellite fields that is tied back into an existing production facility. In conventional open water areas, the normal means of developing moderate to larger sized oil fields in shallow to intermediate water depths (out to about 100m) is to use a fixed platform, which is constructed of either steel or concrete. Fixed platforms are attached to the seafloor by piles or, in the case of gravity based structures, through their own weight. In open water, requirements for the structural strength and base shear resistance of fixed platforms are usually governed by the maximum wave loads expected. However, on the Grand Banks, fixed platforms will also have to withstand any iceberg collisions that may occur over their lifetime. The threat of icebergs virtually eliminates the possibility of using the type of light weight, low cost, multi-legged jacket or jack-up platforms that are commonly employed in conventional areas. This leaves fairly massive GBS structures as the only real fixed platform option for the Grand Banks.

One challenge for these GBS designs is to develop platform shapes that can effectively resist large iceberg impact loads, without attracting excessively high wave forces. On the Grand Banks, typical iceberg collision return periods for fixed structures are in the 10 to 15 year range and, in its northern and eastern areas, may involve maximum iceberg sizes up to 12 million tonnes. Over the central portion of the region, around the Hibernia and Terra Nova locations, water depths in the 80m to 90m range limit the maximum size of the design iceberg. As an example, the Hibernia platform was designed to withstand an iceberg impact energy which corresponds to a 6 million tonne berg moving at 0.6 m/sec. However, the massive size of this cylindrical GBS, along with its outer wall tooth design, represents a disadvantageous form for wave loads. As a result, both the design wave and iceberg loads for the Hibernia structure are very high, and are estimated to be very close to the same 1600 MN value. This design load level has resulted in a very capable GBS platform, but also a very costly one.

Improved structure concepts that provide good functionality for the platform’s topsides, storage, and its floating stability, while reducing both iceberg and wave loads, are desirable. These objectives have been pursued by Amoco in a recent Steel Stepped Gravity Platform design for the Grand Banks (Fitzpatrick & Kennedy, 1997). Their SSGP concept, shown in Figure 6.4, is optimized to reduce the effect of iceberg and wave loads on the platform and its foundation. By necking down the structure’s size through the waterline, design wave loads are reduced to about 1000 MN, while probabilistically derived iceberg impact design loads are estimated at roughly 900 MN (or lower). This fixed structure concept is considerably less costly than the Hibernia GBS platform, and appears to be a very attractive alternative for Grand Banks developments, in water depths out to about 100m.

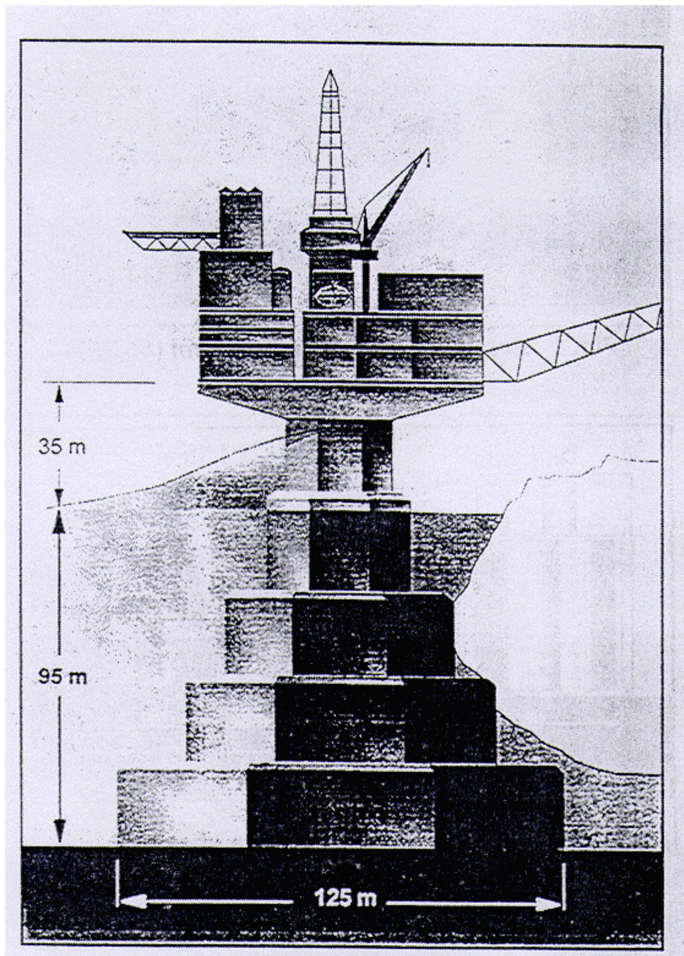


Figure 6.4: Amoco's recent Stepped Steel Gravity Platform design for a Grand Banks location in 95m of water (Fitzpatrick &Kennedy, 1997).

As water depths increase, floating development systems usually become a more cost effective option than using fixed production structures. Floating development systems consist of one or more surface vessels and a system of subsea wellheads, flowlines and manifolds, connected to the surface facility by risers. The use of floating vessels has become a well established means of developing offshore oil fields in a wide range of water depths. For example, the first oil produced in the British sector of the North Sea was brought on stream by a spread moored semi-submersible in 1975, at the Argyll field in 79m of water. Floating production vessels are based on semi-submersible or conventional ship-shape designs and unlike fixed structures, they are not particularly cost sensitive to water depth. Semi-submersibles have the advantage of reduced motions in high seas and their responses are not effected by changes in the wind and wave direction. However, because semis do not have onboard storage, produced oil must be continuously transferred to a separate storage vessel or to a pipeline. Ship-shape vessels have the advantage of being able to incorporate significant onboard oil storage and generally have greater surface areas and deck load capacities for their topsides. However, ship-shapes are more responsive to waves than semis, and usually need to weathervane into high seas to minimize their motions and maintain production. This requires a turret mooring system with a multi-pass fluid swivel arrangement to allow vessel rotation. Either type of vessel positions itself over subsea facilities and maintains location on a mooring system, often supplemented by dynamic positioning. These floating systems provide an attractive method of exploiting moderate to smaller sized oil fields in a range of water depths, but are more susceptible to hostile wind and wave conditions than fixed platforms.

Tension leg platforms are another option that should be mentioned for floating production. These platforms are tethered to the seafloor by a taut vertical mooring arrangement, and are often preferred for very deep water applications, in the order of several hundred metres or more. However, TLPs are not designed to be capable of easily moving off location and as a result, are not considered as a viable alternative for Grand Banks developments. This leaves semi-submersible and ship-shape vessels as the only real floating production candidates.

On the Grand Banks, these floating production vessels will be exposed to occasional iceberg and pack ice occurrences, as well as severe weather and wave events. These ice influences will also result in some downtime and from a structural design perspective, will require some level of ice strengthening on production vessels. Since the mode of operation for most floating systems will be to avoid icebergs and possibly, some heavy pack ice situations, a quick shut down, disconnect and vessel move-off capability will be important, to mitigate ice-related risks and minimize downtime. This quick disconnect requirement is a key technical challenge, particularly for turret moored vessels with a large number of production risers. However, the turret system that is now being designed for the Terra Nova FPSO is intended to enable orderly disconnect operations to be implemented over periods of four to five hours.

Here, the ice detection, ice alert and ice management procedures that have been developed during exploratory drilling operations on the East Coast should be noted, since they provide a strong experience base in this regard. To give some sense of the need for iceberg related disconnects, it is useful to quote some statistics from the Labrador Sea, where drilling started in 1971 and icebergs are more numerous than on the Grand Banks. In the first season, one drillship was used for 67 days. During this period, 167 icebergs were tracked, 10 were towed and one disconnect was required. From 1971 to 1982, there were 21 separate drilling vessel seasons (both drillships and semis), about 2,600 icebergs were tracked, more than 600 were towed, and there were a total of 13 disconnects. In terms of equivalences, this Labrador Sea experience is similar to about twenty years of production time with a floating system on the Grand Banks, and is quite comforting. However, it should also be recognized that Labrador drilling programs were designed to avoid the peak iceberg season and all pack ice occurrences in the area. Well suspension and vessel move-off times were also shorter, in the order of one to several hours, and the consequences of any unforeseen iceberg problems far less severe than in the production case.

The other key component of a floating development system which should be acknowledged is the subsea facilities that are required. These subsea facilities consist of a system of seafloor wellheads, manifolds and flowlines that feed oil to a riser base, from which it is carried to the production vessel through a number of risers. For sizable floating developments, these subsea facilities can be quite extensive, and may spread over distances of several kilometres or more. The areal dimensions of the individual components of these subsea systems are typically small, in the order of a few metres to a few tens of metres. However, interconnecting flowlines that are several kilometres or more are often required. On the Grand Banks, these subsea facilities will be exposed to the threat of scour from large deep draft icebergs. Scour frequencies for the area have been estimated at about 0.07 scours/km^2/year, with a maximum scour depth of 7m seen in 160m of water. Operationally, the occurrence of deep icebergs around a floating development which have the potential to scour may require subsea production facilities to be temporarily shut down, as a prudent precautionary response. Compared to floating production systems, fixed structure developments are highly compact and in most cases, do not involve any subsea facilities, with the exception of those that may be required to export oil.

Satellite oil fields can also be developed with subsea tie-backs to existing production facilities, either fixed or floating. The impetus for this type of development approach has sprung almost entirely from demand in the North Sea, where operators are constantly trying to find ways of making use of the processing capacity on their platforms. Small reservoirs that are located around producing fields have been accessed by subsea wells, with their oil being piped back to existing platforms over distances up to 10 km, for processing and subsequent export to market. This technology is developing rapidly, in terms of both piping distances and volumes.

In the future, it is likely that this type of subsea development approach will play an important role in exploiting some of the smaller oil reserves that are present on the Grand Banks, around larger fields which will be in production. Obviously, iceberg scour is a key consideration for this subsea development approach, particularly as pipeline tie-back lengths increase. The costs and more marginal economics that are normally associated with small reserve developments will magnify the importance of the iceberg scour consideration for this development scenario.

Single Well Oil Production Systems, which use a floating production vessel to extract oil from one or two wells drilled into small highly productive fields, have also gained recent popularity. The SWOPS approach produces oil from small fields over time frames of one to several years, and represents another alternative for some of the smaller Grand Banks oil fields. This type of production system is susceptible to the same iceberg and pack ice constraints as the larger floating developments. However, because the economics of SWOPS developments are considerably more fragile, the impact of ice related design costs and downtime events will be even more important.

Once a particular development approach is selected for oil production from an offshore field, the operator must decide on the most cost-effective means of moving it to market. In mature producing areas, most offshore installations are connected to subsea pipeline systems that carry produced oil to shore. However, in remote areas or in regions where there is little infrastructure in place, tankers are the common export approach. Tankers usually load oil from a single point mooring system (SPM) that is linked to a production facility's storage by a flowline, and transfers oil at high rates. There are many variations around this basic tanker loading approach, ranging from the use of permanent or "dynamic" storage vessels for semi and jacket platforms, through ship to ship transfers for FPSOs, to direct tanker loading from some fixed structures.

For Grand Banks oil developments, the tanker export approach is the preferred option, and will be used as part of the Hibernia and probable Terra Nova projects. Clearly, the design and operation of any tanker loading system at a Grand Banks production facility must recognize the iceberg and pack ice conditions that can be experienced in the area. In addition, export tankers must be designed and operated for safe and efficient transits through any of the glacial and sea ice conditions that are expected. These ice related factors have been accommodated in the Grand Banks tanker systems designed to date, through the use of ice-strengthened (Baltic Class 1A) double hull tankers of about 120,000 DWT. Notwithstanding these vessel design features, reliable detection and avoidance of icebergs and small glacial ice masses will be particularly important during tanker export system operations.

6.3.3 Representative Development Systems

For the purposes of this study, several representative development systems have been selected for the Grand Banks oil field cases identified in section 6.1.2, from a wide range of possible options. They are based on the use of conventionally accepted development approaches and are not significant departures from current technology. Accordingly, these systems represent realistic development approaches for the range of oil field cases under consideration. With regard to other development system options, there is enough commonality in the type of ice problems that will be experienced to be well demonstrated by the representative systems selected.

The development schemes that have been used as a basis for this study include specific fixed, floating and subsea production system concepts. They are summarized as follows.

Fixed Structure Development

- the fixed structure development scenarios considered here are based on the use of a large GBS platform that supports topsides facilities with production, accommodation and drilling modules, and has a substantial onboard storage capacity.

- although the GBS structure can, in principle, be constructed of either steel or concrete and can have any structural form, Amoco's SSGP platform concept has been used as the base case, rather than a Hibernia type concrete GBS.

- it has been assumed that all development drilling and work over operations are carried out from the GBS platform, without the need for any "far-field" subsea wells that are drilled from a separate drilling vessel and then tied back to the platform with flowlines.

- drilling advances which are constantly being made worldwide, such as the use of horizontal and multi-lateral wells, have been reflected in the number of development wells, well productivities and development drilling costs assumed.

- oil stored on the GBS is periodically transferred to an ice-capable shuttle tanker that moors to a loading system and loads oil over a period of about day. The loading system is connected to the platform by a high transfer capacity subsea flowline, and is submerged. Tanker loading operations near the platform are supported by at least one supply vessel for tendering and any as required ice management support.

- the number, carrying capacity, and turn-around time of the tankers comprising the export fleet are well matched to the GBS's storage capacity and there is a sufficient amount of excess onboard storage to accommodate a few days of wave or ice induced tanker loading downtime.

- the fixed structure development scenarios that are considered most seriously here involve the larger Grand Banks oil reserve cases (250, 350 and 500 million barrels). These fixed structure developments have been restricted to the 80m, 100m and 120m water depth cases, because platform costs in deeper waters would become prohibitive.

Floating Development System

- the floating development approach that has been selected for this work is based on the use of a moored ship-shape FPSO vessel which has dynamic positioning (DP) assist, with production and accommodation facilities on its deck, and a substantial amount of oil storage capacity within its hull.

- other floating development systems such as a semi-submersible production vessel used in combination with a separate floating storage vessel are possible, but would be more operationally cumbersome on the Grand Banks, particularly in ice. The philosophy adopted in this study is to minimize the number of development system components that are used and exposed to the ice environment.

- although various FPSO hull forms made from either steel or concrete are possible, a double hull ice strengthened steel vessel that is similar to the Terra Nova FPSO has been assumed. Appropriate FPSO vessel sizes have been determined in accordance with field reserve sizes considered, based on equivalent world wide experience.

- an FPSO that has an internal turret which houses its mooring system and production risers, allows the vessel to weathervane, and can be quickly disconnected has been assumed. External turret systems could also be used but they would not be protected by the FPSO vessel's hull, and would be vulnerable to ice.

- since development drilling and work over operations cannot be carried out from an FPSO, the use of a separate floating drilling vessel has been included in the floating production scenario. Again, current drilling technology (eg: horizontal wells) has been assumed, along with predrilled development wells to bring reserves on stream more quickly. New technology that will enable drilling and production operations from the same floating vessel is now being developed, but has not been considered here.

- subsea facilities for the floating development system are determined in accordance with the reserves, field extent and number of development wells assumed for each oil field scenario. Wellheads, manifolds and riser bases are assumed to be protected in seafloor glory holes, and flowlines given some scour protection by trenching.

- FPSO stationkeeping operations are assumed to be supported by ice capable supply vessels that are available to carry out any as required iceberg or sea ice management duties.

- oil stored on the FPSO is periodically transferred to an ice-capable shuttle tanker through a tandem mooring and loading arrangement located on the vessel's stern over a time period of about a day. These tandem tanker loading operations are also supported by supply vessels that are available in the field area, for tendering and any as required ice management support.

- as with the fixed structure development scenarios, it is assumed that the number, carrying capacity, and turn-around time of the export tankers are properly matched to the FPSO's storage, and there is enough excess storage onboard to accommodate a few days of wave or ice induced tanker loading downtime.

- this type of floating development approach is considered for all of the oil reserve and water depth combinations treated in this study, but is recognized as having marginal economics for the smaller oil field cases.

Small Subsea Development

- for the small Grand Banks oil field cases identified in this study, the most likely development approach involves the use of a subsea system of wells that are tied back to an existing production facility by a pipeline.

- floating systems would be used to drill the subsea wells and install other required subsea facilities, presumably outside of the ice season when potential icebergs or sea ice occurrences could result in some downtime and pose a threat to specialized equipment.

- again, it is assumed that all of the wells, flowlines, manifolds and pipelines required for this type of subsea development system will be designed with some protection against the potential threat of iceberg scouring.

7.0 Ice-Related Problems

In this section of the report, the range of ice-related problems that can influence different Grand Banks development approaches are outlined. These ice problems are presented in the context of the representative development scenarios defined in section 6, and their technical implications highlighted on a scenario by scenario basis. Although some of the more major iceberg and pack ice constraints have already been noted in earlier sections of this report, a more complete range of ice problems is identified here, in more specific detail. The effect of these ice-related problems on the cost and economics of various Grand Banks development alternatives is treated in the next section.

The ice issues that are discussed here relate to ice engineering problems of relevance to the design and operation of Grand Banks development systems. Since the exploratory drilling vessels that have been used to date have avoided all iceberg and sea ice encounters, there is little ice/structure interaction experience available for the Grand Banks, compared to areas like the Beaufort Sea. However, there is a considerable amount of practical operating experience with iceberg detection, forecasting and management systems, operational ice alert and avoidance procedures, and the Grand Banks environment itself.

It is clear that improvements in knowledge regarding design iceberg and small ice mass impact loads, operating efficiencies for floating systems in ice, iceberg scour, and scour protection methods would benefit potential development projects. For example, a better understanding of iceberg interaction behaviours and global impact loads, along with optimized structural designs to resist icebergs while minimizing storm wave forces, could significantly influence fixed platform costs. Similarly, more reliable ice detection and management methods could reduce (and ideally eliminate) the potential for iceberg and small ice mass impacts and high local loads, improve operating efficiencies for floaters, and provide more flexibility for the use of lower cost technology.

However, in the drive to conduct ice-related R&D that may reduce costs and make Grand Banks development opportunities more economically attractive, it is important not to lose sight of the need to maintain acceptable levels of safety and environmental impact. Since many of the ice design and operating criteria associated with Grand Banks development systems are treated in probabilistic terms, uncertainties and risk questions are of particular importance. Commonly held perceptions about various Grand Banks ice-related risks are also important to recognize. Misperceptions can lead to long technical exchanges during the regulatory review process, prompt strong public concerns and in turn, result in significant project delays. They can also steer investors away from potential Grand Banks development opportunities.

These observations should not be taken as an argument against R&D that is aimed at lower cost systems. On the contrary, they highlight the need to devise R&D initiatives which not only lead to lower costs, but also to reduced risk. These two attributes should be implicit in any recommended R&D thrusts. It is also important to note that R&D initiatives that address processes for which there is currently little experience (iceberg impacts) can only help in improving public confidence in new systems.

7.1 Fixed Structure Developments

The range of ice-related problems that are associated with fixed structure developments on the Grand Banks are summarized as follows. These problems are subdivided into key ice issue areas, and major technical considerations within each issue area identified.

- iceberg impact loads

  - full scale iceberg/structure interaction behaviour, failure pressures over large areas, and global iceberg impact loads
  - local iceberg impact loads
  - dynamic loading effects from iceberg impacts
  - probabilistic iceberg impact design loads, their uncertainties and reliability
  - iceberg statistics, including their occurrence frequencies and size, shape and drift speed distributions

- the relative benefit of different structure shapes

  - structure configurations to reduce iceberg impact loads
  - structure optimization to minimize both iceberg and wave design loads

- pack ice forces

  - (a minor issue for fixed structures compared with iceberg and wave loads)

- tanker loading in ice

  - detection and management of icebergs and small ice masses
  - stationkeeping and loading operations in moving pack ice, including the benefits of ice management support from standby vessels

  - preferred tanker loading systems for ice
  - potential ice damage to loading systems (when in use or on standby)
- tanker design and operations
  - ice strengthening requirements, primarily for small ice mass impacts
  - small ice mass detection and avoidance
  - preferred tanker designs for the combined ice and open water environment
  - tanker transit efficiencies in pack ice

More specific comments about these ice-related problem areas are given as follows. Many of these comments reflect the views that were presented in a 1992 scenario based *Review and Assessment of PERD and Other Ice/Structure Interaction Work* (Wright & Sandwell, 1992), and some of the key ice issue areas outlined in a more generalized sense in an *Environmental Research Planning Study for PERD 6* (Croasdale, 1994). These ice problems have also been discussed with various stakeholders as part of this study work, who are all in agreement with the problem areas but not necessarily their relative priorities.

7.1.1 Iceberg Impact Loads

Global Loads

- the need to resist potential iceberg impacts is recognized as the primary concern for fixed platforms on the Grand Banks and in all likelihood, will drive both the selection and design of these structures. Technical advances that could result in significantly smaller iceberg impact design loads than current levels would have a major impact in terms of reducing fixed structure costs.

- for example, the overall size and external “saw tooth” shape of the Hibernia GBS was selected to counteract iceberg impacts and the associated global loads, but its large waterline cross-section has also resulted in very high design wave loads. This GBS is a very costly structure.

- global iceberg impact load calculations for the Hibernia GBS assumed that icebergs would crush against the structure during the interaction process. Iceberg occurrence, size, shape and drift speed statistics were used in combination with glacial ice failure pressures measured over areas to $3m^2$ in the Pond Inlet indentation tests, as a basis for global design load predictions. Although probabilistic estimates of global iceberg impact loads were used to provide guidance, a maximum credible iceberg interaction load was ultimately selected for the GBS design.

- the probabilistic techniques applied in the Hibernia design work combined iceberg statistics with an ice crushing and energy balance model, that included the effects of eccentric impacts. Full scale iceberg failure pressures of 6 MPa were assumed over local to global areas, based on the fairly small scale Pond Inlet field test results.

- it was recognized that a considerable amount of conservatism was probably built into this iceberg impact load assessment approach, for the following reasons:

  - no information about large scale interaction behaviours and failure processes for iceberg/structure impacts is available, and the iceberg crushing mechanism assumed represents a worst case scenario

  - iceberg crushing pressures measured over relatively small areas may be quite high for the large area interactions expected in full scale, while different full scale iceberg failure and energy loss mechanisms (eg: fracture, calving, iceberg rotations, etc.) may result in substantially lower design load levels

  - hydrodynamic effects may play a “buffering” role during iceberg interactions

  - iceberg collisions are expected to be infrequent, with predicted return periods in the order of 10 to 15 years, and intuitively should not normally involve large iceberg high drift speed combinations

- more recently, probabilistic design loads have been developed for potential iceberg impacts with Amoco’s SSGP concept. The design iceberg load for the SSGP platform is at least two times lower than the value used for the Hibernia structure, for a more northerly, deeper water location (95m versus 82m). This reduction is primarily a consequence of:

  - the different size and form of the SSGP, despite its more exposed, slightly deeper water depth location

  - the use of lower iceberg crushing pressures over larger areas (4 MPa versus 6 MPa over a $25m^2$ area)

  - placing a higher degree of reliance on probabilistic load calculations methods and the resulting iceberg impact design load levels

- in terms of ice-related R&D, the importance of a recent research initiative, designed to obtain larger scale field information about iceberg failure pressures and pressure-area effects than the earlier Pond Inlet tests, should be recognized. In this project, which received funding from several oil companies and PERD, growlers and bergy bits were towed against a steep instrumented rock face on a small island off the Labrador Coast (C-CORE, 1995). Ice failure processes were documented and failure pressures measured for a considerable number of small ice mass impacts.

- the results of this work have provided useful data for both fixed and floating structure designs, but ice failures over very large areas ($>10m^2$) were not achieved. Further field tests involving larger area ice failures are important and are now being considered. It is imperative that any future field tests strive to simulate larger scale iceberg impacts. Although field projects of this nature are expensive, they are the only realistic way of making significant advances in our understanding of large scale iceberg failure processes and pressures.

- improved probabilistic methods have also been developed and applied to support fixed structure designs, primarily at Memorial University. These methods are now being refined and incorporated into their Canadian Offshore Design for Ice Environments (CODIE) initiative.

- the question of global iceberg impact loads is of clear importance for fixed structure developments, in terms of being a key design criteria and influencing platform cost. It is also important technical issue from a risk perspective, with commonly held views about platform vulnerability dating as far back as the sinking of the Titanic. However, because fixed structure developments are not considered likely by most oil companies, this ice issue area is not being aggressively pursued at the present time. As will be discussed later, the possibility of using the Hibernia GBS structure as a test location may offer a cost effective R&D opportunity. Clearly, this would be an important but very topical initiative, particularly with the platform's operators.

Local Loads

- the local ice loads that may be exerted during iceberg impacts are also an important consideration for the design of the outer shell of fixed (and floating) platforms, with concrete structures typically being less sensitive to local ice loading criteria than steel structures.

- although the question of local loads is a key ice issue area, the Pond Inlet tests and more recent field information obtained in the small glacial ice mass impact project off Labrador, have provided a relatively good information base on local pressure design criteria to scales of about $10m^2$.

- refinements in this ice problem area will not have the same level of impact on fixed platform costs as major advancements on the question of global iceberg loads, and are not considered as high a priority for fixed structure development scenarios. However, any field measurement projects directed towards an improved understanding of global iceberg impact loads and large scale pressure area effects would produce relevant local ice pressure information, and add to the current data base.

Dynamic Loads

- any dynamic loading effects that may be associated with iceberg impacts are largely unknown, other than the results provided by classical dynamics assessments. Structure and foundation responses will be manifested by larger deflections than if the nominal design load is applied as a static forces. A better understanding of global iceberg impact processes, large scale failure pressures, iceberg impact load time series, as well as the typical effective damping and stiffness of a structure, are required to better address this issue.

Iceberg Statistics

- the ice problems that have been outlined above focus on questions relating to iceberg failure pressures and design loads for fixed platforms. However, to properly estimate iceberg impact design loads for these fixed structures (particularly with probabilistic methods), a good statistical data base on iceberg occurrence frequencies and their size, shape and speed distributions is also required.

- the iceberg information that has been acquired to date provides a reasonable data base, but it is clear that additional data collection would be useful. For example, CSA code verification work carried out in 1994 showed a factor of five difference between the 10^{-2} and 10^{-4} iceberg design load for a representative Grand Banks platform, that was primarily driven by descriptions of the "extreme iceberg climate".

- in view of this, there are incentives for low cost, systematic data acquisition programs on icebergs in future years, to improve the existing data base. Better definition of the small ice mass climate is of less importance for fixed platform design but is very significant issue for floating development systems and tankers, as discussed later.

Miscellaneous

- there are other potential iceberg problems that should also be noted for fixed platform designs. For example, the possibility of peculiarly shaped iceberg sails interacting with the topsides deck of platforms should be recognized, but is specific to the particular design concept and its deck freeboard.

- the clearance behaviour of either failed iceberg ice or any pack ice that may be present during winter iceberg interactions is a consideration for specific structure designs. For example, the Hibernia GBS's external teeth could become plugged by brecciated ice accumulations during impacts, thereby eliminating their theoretical benefit.

7.1.2 Other Ice/Structure Interaction Considerations

Platform Geometry

- there are an endless range of fixed structure configurations that could be considered for the Grand Banks, ranging from the cylindrical "saw tooth" Hibernia GBS, through Amoco's "wedding cake" SSGP concept, to sloped conical structures.

- there are incentives to more thoroughly evaluate the relative advantages of different fixed structure configurations, in terms of their ability to resist iceberg impacts, trade-offs between iceberg and wave design loads, concept feasibility and cost.

- some directional analyses about the relative benefits of different structural forms in reducing iceberg impact loads have been presented in a recent paper (Croasdale & Metge, 1989). Although this information is good in concept, a number of designers have expressed concern about the practicality of some of the structure alternatives that appear to be attractive (eg: sloped structures), when considered solely from a global iceberg loading perspective.

- it is generally felt that any R&D that is directed towards fixed platform designs for the Grand Banks area should be carried out within industry, outside the realm of PERD's study program. However, PERD might address novel structure concepts and the ice load methods that are needed to calculate iceberg forces on various structure shapes.

Pack Ice Forces

- pack ice loads on fixed Grand Banks structures will be low in comparison with wave and iceberg impact forces, and as a result, are not seen as a significant design issue. Existing sea ice data and load estimation methods are considered to be adequate for any pack ice force assessments that may be required for fixed platform designs.

- pack ice influences, although infrequent, are viewed as being a far more important problem for tanker loading and vessel operations around fixed structures, and as a potential constraint for floating development systems.

7.1.3 Tanker Loading in Ice

Iceberg & Small Ice Mass Effects

- tanker loading operations carried out as part of fixed structure developments on the Grand Banks will be exposed to the potential threat of icebergs and small ice masses and at times, to moving pack ice conditions. The design of both the loading system and tankers must recognize these ice influences and operational procedures developed to contend with them.

- for the most part, the type of loading systems being considered for fixed structure developments involve oil transfer through a subsea flowline that runs from a J-tube in the base of a platform to a submerged loading arrangement, located well below the waterline when not in use. Tanker loading stations may be positioned at distances up to several kilometres from the platform.

- these loading systems, as typified by the Hibernia OLS which lies at a neutrally buoyant depth of about 40m below sea level, are accessed by the tanker on arrival. An oil transfer hose is pulled to the surface and connected to a manifold on the tanker, then loading operations initiated.

- when the OLS is not in use, the potential for iceberg keels colliding with the submerged system is of concern, although the likelihood is low. When loading operations are either being initiated or in progress, the tanker and oil transfer hose are more exposed to ice hazards, should they be present.

- if drifting icebergs and more particularly, small ice masses, are present around the loading station, an approaching tanker will have to make a decision about whether or not to moor up and begin oil transfer operations, or whether to wait until these hazards pass. If drifting icebergs and small ice masses occur when oil transfer is underway, decisions about suspending the loading operation and moving off may be triggered, through an ice alert procedure. Typical exposure periods for this type of operation will be limited to a day or two, because of the high oil transfer rate from the structure to the tanker, via the OLS.

- the detection, management and avoidance of icebergs and small ice masses is a very important consideration for tanker loading operations, to minimize the potential for downtime and reduce the risk of damage. Although tankers will be ice strengthened, these vessels and any oil transfer line will be at risk from unexpected iceberg and small ice mass collisions during operations. The fact that fixed structures will have large volumes of onboard oil storage will allow tankers to delay or suspend loading operations, and accept a considerable amount of downtime. However, once oil transfer begins, there will be considerable operational pressures to continue.

- iceberg detection and management is also an important consideration when tanker loading operations are not being carried out, to identify and deal with any deeper draft icebergs that may pose a potential threat to submerged loading facilities.

- from a more general Grand Banks development perspective, the importance of reliable iceberg detection and management techniques should be stressed, since improved technology in these areas would provide more flexibility for the design of any offshore systems, and enhance the safety of their operations.

- the potential threat of iceberg scour should also be mentioned in conjunction with the tanker loading consideration, with reference to the subsea flowline that runs from the structure to the loading facility. This iceberg scour problem area is highlighted later, in the more general context of subsea systems.

Pack Ice Effects

- although pack ice is not a major consideration for the design of fixed structures, its importance as an occasional operating constraint should not be underestimated. For example, a persistent pack ice intrusion on the Grand Banks could have a significant impact on the efficiency of oil transfer operations at a structure. Pack ice occurrences of more than a few days that precluded tanker loading operations would begin to cause production downtime, because the platform's oil storage tanks would be full. Relatively heavy pack ice conditions that lasted a month or more could significantly influence production on a fixed structure, oil delivery commitments and schedules, and cash flows.

- operationally, a tanker would "ease into" the pack ice situation that was present around a fixed structure, assess the level of difficulty in stationkeeping in the ambient conditions, and then make a decision about initiating oil loading operations.

- this is a prudent operating approach but in technical terms, is quite "seat of the pants". Past experience with vessel stationkeeping operations in the Beaufort Sea and in other ice infested areas suggests that tanker loading in moving Grand Banks pack ice may be a relatively straightforward operation.

- efforts to further assess the question of tanker stationkeeping and loading operations in moving Grand Banks pack ice conditions are warranted, including the benefits of ice management support from standby vessels. Work of this nature is required to:

    - evaluate expected pack ice forces levels
    - assess the need for ice management support
    - address concerns about tanker loading in pack ice and related downtime
    - highlight any potentially beneficial tanker and loading system design features

Preferred Loading Systems

- there are variety of tanker loading approaches that could be used on the Grand Banks, ranging from the Hibernia OLS, to the submerged turret loading systems (STLs) now being used in the North Sea. There are incentives to evaluate the relative advantages of these loading systems in Grand Banks ice conditions, and the trade-offs between concept feasibility, benefits and cost.

- it is generally felt that any R&D directed towards the design of tanker loading systems for the Grand Banks should be carried out within industry, and lies outside the scope of the PERD program. However, novel tanker loading concepts could be considered within some specific PERD studies, but as a low priority ice-related problem item.

7.1.4 Tanker Design and Operations

- the design and operation of the tankers that will be used to offload oil from fixed platforms and move it to market is also an important component of fixed development scenarios for the Grand Banks. Although these tankers will spend the vast majority of their time in open water conditions, they will also be exposed to iceberg and small ice mass occurrences, as well as occasional pack ice situations.

- tanker strengthening requirements, primarily for small ice mass impacts, represent a key issue area. Since hulls with the capability to withstand a full range of small ice mass collisions without any damage would be prohibitively expensive, some design compromises are required. For example, the Hibernia tankers are ice strengthened to Baltic Class 1A standards and accordingly, will be structurally capable in all pack ice conditions. Some incremental strengthening in their bow areas (CAC 2) has also been included to handle unforseen small ice mass collision events. The risk of occurrence of these collision events and the local ice load levels associated with them have been estimated on a probabilistic basis.

- however, uncertainties related to small ice mass collisions, along with standard marine operating practices, make iceberg and small ice mass avoidance a key. In this regard, the capability to detect icebergs and small ice masses during tanker transits in all weather sea state and pack ice conditions is a very important technical requirement.

- preferred tanker designs for mission profiles that will involve both open water and ice operating conditions is an issue, but is an industry concern. Issues regarding tanker strengthening needs and transit efficiencies in East Coast pack ice are considered to be well in hand, from past experience with vessel operations in sea ice. However, improvements in estimating small ice mass impact loads (as would be the outcome of continued experiments for floating production systems) will be important in better defining operational limits and transit efficiencies.

7.2 Floating Development Systems

The range of ice-related problems that are associated with floating development systems on the Grand Banks region are highlighted as follows. Again, these problems are subdivided by ice issue area, and the major technical considerations within each area identified.

- stationkeeping in bergy waters
    - iceberg and small ice mass detection and management
    - downtime levels related to iceberg and small ice mass occurrences
    - local ice loads from small ice masses, and the risk of damage
    - iceberg and small ice mass statistics, including occurrence frequencies and size, shape and movement distributions
    - ice design requirements for production vessels, including hull strengthening and quick release turret, riser and mooring systems

- stationkeeping in pack ice
    - downtime levels related to pack ice
    - pack ice forces on moored production vessels
    - ice management support and its benefits
    - pack ice statistics, including occurrence frequencies and characteristics

- iceberg influences on subsea systems
    - iceberg scour statistics and risks, and the scouring process itself
    - protection of subsea facilities against the risk of iceberg scouring

- tanker operations in ice

- loading operations in iceberg and pack ice conditions
- ice strengthening requirements, primarily for small ice mass impacts
- detection, management and avoidance of icebergs and small ice masses

More specific comments about these ice-related problems are given as follows. Since many problem areas are similar to those outlined for fixed structure developments, they are not reviewed in as much detail here. Again, the range of ice problems associated with floating development systems have been reviewed with various stakeholders as part of this study. Although there is general agreement with the ice issue areas, there are different perceptions about relative R&D priorities.

7.2.1 Stationkeeping in Bergy Waters

Potential Iceberg Impacts

- global loads that may be caused by iceberg impacts are not a significant design issue for the range of floating development systems now being considered, because floating production vessels will simply suspend operations and move off location to avoid them, when threatened. Downtime that may be caused by iceberg occurrences is of more concern, along with the ice detection, management and quick release systems that will be required to effectively operate floating production vessels in bergy waters.
- the potential for small glacial ice masses, either undetected or unavoidable, to cause high local ice loads on floating production vessels is of more significance for design. In this context, iceberg failure pressures, small ice mass interaction behaviours, and the risk of damage are all important issues.

- since iceberg avoidance is fundamental for most of the floating development concepts now under consideration, more reliable detection methods over a full range of glacial ice sizes is a key requirement. Similarly, improved iceberg management techniques for large through small ice masses is of high importance. Technical advances in these ice problem areas would lead to increases in both the efficiency and safety of floating development systems and, if highly reliable, could influence some aspects of overall system design.

- previous drilling operations on the Grand Banks and in the Labrador Sea, which have employed iceberg detection, forecasting and management systems, have provided invaluable experience with stationkeeping in bergy waters and iceberg avoidance techniques. However, further work which leads to improvements, particularly in the small ice mass detection and management area, are needed to support future floating development systems.

- a recent ESRF study entitled *Remote Sensing Ice Detection Capabilities - East Coast* (Rossiter et al, 1995) has reviewed current technology for iceberg and small ice mass detection, its capabilities and limitations, and future R&D needs. A key requirement that cannot yet be met is the "on-demand" detection of small ice masses, particularly in high sea states and in heavy pack ice conditions. The development of iceberg management techniques has not been pursued since drilling activities entered a hiatus in the mid 1980s. At the time, state -of-the-art iceberg management revolved around simple towing and deflection techniques, and success measures were debatable.
- for floating development systems, improved data bases that can be used to better define iceberg and small ice mass populations, occurrence frequencies, and size, shape and movement distributions are also needed for various design, operational, downtime and risk related considerations.

FPSO Vessels

- FPSO vessel, mooring and riser system designs will be primarily driven by the need to effectively stationkeep in the storm wave conditions expected on the Grand Banks, and by a variety of functional criteria governed by the development system's oil production, storage and topsides needs.

- the key ice-related design requirements for these production vessels include:

    - *hull strengthening for potential small ice mass impacts and sea ice*. Baltic Class 1A to CAC 2 hull strength levels developed for generic first year ice conditions are now being used in Grand Banks FPSO vessel designs. It is recognized that small ice masses moving at high speeds or driven by storm waves could challenge these hull strengths, but the use of double skin designs mitigate the risk of any consequential damage. The costs associated with currently envisioned ice strengthening levels are about 10% of a new vessel's capital cost and in a relative sense, are not particularly high (≈ $20 million).
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- *quick release turret, riser and mooring systems*. This is a very important ice-related requirement, and represents a new technology area for FPSOs. The Terra Nova turret system is unique and is being designed for orderly shut down, disconnect and FPSO move-off operations over a target time frame of 4 to 6 hours. A quick reconnect capability for the system (half a day to a day) is also a strong design requirement. This type of turret mooring and riser system is a costly component of a floating development system, in the order $200 million. Costs and complexities will rise for large oil field developments, as the number of production risers that are required increases.
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- improved information on small ice mass loads would be of benefit in FPSO hull design work, while improvements in iceberg and small ice mass detection and management techniques, and their reliability, may be useful in relieving costly quick release system requirements for these vessels. In this regard, a comprehensive operational simulator and risk model could be used to assess operating efficiencies, avoidance assumptions and required performance levels for ice detection and management, and ice tolerance.
- here, it should be noted that it is not only a production vessel, but also its mooring and riser systems, which are vulnerable to icebergs. Recognizing that typical catenary mooring spreads are in the order of 2 km, relatively large areas around floating production vessels will require protection from icebergs, including detection, monitoring, management and avoidance operations.

7.2.2 Stationkeeping in Pack Ice

- pack ice occurrences are relatively infrequent on the Grand Banks, although in poor ice years, they may result in substantial production downtime for floating development systems. The operational strategy now being considered for most floating platforms is to suspend production operations and move off location in the case of significant pack ice intrusions. For example, FPSO downtime evaluations being carried out in conjunction with the Terra Nova project are currently using a move-off criterion that is associated with pack ice concentrations of 5/10ths or more.

- pack ice related downtime events may be tolerable for large field developments in the central part of the Grand Banks like Terra Nova, where they are statistically projected to be infrequent and of short duration. However, further to the north around the

Whiterose discovery and/or for smaller oil fields that developed over fairly short time frames, potential pack ice related downtime is of much more consequence.

- efforts directed towards FPSO stationkeeping in pack ice are warranted, particularly in view of the successful operating experience with floating drilling systems in the Beaufort Sea, where the pack ice conditions are considerably more severe. From this experience, it is felt that pack ice forces on Grand Banks FPSOs should normally be low and in heavy pack ice conditions, could be kept to nominal levels with some ice management support. In this regard, stationkeeping and production efficiencies for many floating concepts could be improved, at relatively low cost.

- here, it is worthwhile noting that the mooring system capacity for most FPSO vessels now being considered for the Grand Banks is in the order of 1500 tonnes, to provide the capability to stationkeep in extreme wave conditions, and many will have DP assist. Expected pack ice force levels based on equivalent full scale experience should only be in the range of 10% to 20% of this mooring system capacity. FPSO response motions in pack ice should also be small, unlike those expected in storm waves. As long as internal turret systems are used on FPSOs and vessel drafts are considerable, ice clearance and the possibility of ice entanglement with mooring lines and risers should not be a concern.

- some physical modelling and analytic work has been carried out to evaluate ice force levels on a variety of moored platform concepts in moving pack ice. Although many of these studies have been directed towards floating development systems for other ice infested areas of the world, PetroCanada has recently carried out an ice model test series for the Terra Nova FPSO at NRC's IMD facility in Newfoundland. Model tests and analytic approaches are known to provide useful insights into the question of pack ice forces and moored vessel stationkeeping in pack ice. However, the use of full scale data and experience from previous floating system operation in ice is seen as a key.

- at the present time, there is enough information on Grand Banks pack ice conditions to carry out reasonable assessments of the probable performance capabilities and limitations of various floating production concepts, with and without ice management support, and to address the issue of their feasibility and practicality. However, some consideration should be given to improving the existing pack ice data base through systematic low cost data collection in conjunction with Grand Banks operations over the next few years.

7.2.3 Iceberg Influences on Subsea Facilities

Iceberg Scour Risks

- floating development systems will have a considerable array of subsea facilities, which will include wellheads, manifolds, flowlines and riser bases. The areal extent and "exposure" of these subsea systems will increase in approximate proportion to the size of the particular oil field being developed. It is well known that scouring of the sea floor by deep draft icebergs can occur on the Grand Banks but is quite rare. However, damage to subsea facilities could be very consequential in terms of cost, production downtime, and the potential for pollution. Precautions can be taken by designing quick shut-ins, automatic valves, and some level of protection for subsea facilities, used in combination with iceberg monitoring and management systems. The economic and risk trade-offs that are associated with protecting subsea facilities from the threat of iceberg scour make it a key ice problem, and related research would be valuable to support design and decision making.

- efforts to improve the iceberg scour statistics now available for the Grand Banks and their reliability are warranted, including scour frequencies, depths, widths, lengths and orientations. Expected scour return periods are particularly important in this regard.

Protection Methods

- methods that can be used to protect subsea facilities against the potential for iceberg scouring is also an important issue area. Most of the current protection approaches are based on scour avoidance, by placing subsea facilities within dredged glory holes and trenches. Preferred locations and routings that take advantage of any bathymetric shielding that may be available are also being considered.

- in order to provide a better basis for addressing improved subsea system protection methods, an improved understanding of the iceberg scouring process is needed. For example, driving force limitations and iceberg response motions that could result in rapid energy dissipation during scouring events merit further attention. The question of subsea scour disturbance is an accompanying issue. Research thrusts in these areas could be used to support the development of more cost effective protection methods, and related assessments of their reliability.

7.2.4 Tanker Operations in Ice

- the ice related tanker design and operations issues that are associated with floating development systems are analogous to those outlined in sections 7.1.3 and 7.1.4., for the fixed structure scenario. Again, the key ice issue areas include

  - loading operations in iceberg and pack ice conditions. With FPSO systems, oil transfer operations will typically be based on tanker loading in tandem from the stern of the FPSO vessel. This will provide an increased level of protection for tanker stationkeeping in ice conditions, compared to remote tanker loading arrangements like the OLS or STL systems.

  - tanker ice strengthening requirements, primarily for small ice mass impacts. The need for ice strengthening is related to a tanker's potential exposure to ice during both its loading and transit operations. High speed collision events while a tanker is in transit are of most concern..

  - iceberg and small ice mass detection, management and avoidance techniques. Clearly, reliable methods in these areas are required to support tanker loading and transit operations.

7.3 Subsea Development Systems

The ice problems that are directly related to subsea developments are less extensive than those associated with either the fixed or floating development scenarios, because surface facilities are not involved. Key ice problem areas include:

  - iceberg scour risks and protection methods
  - detection and management of deep draft icebergs

The technical components of these problem areas have already been highlighted, and will not be repeated here. However, the following points should be noted.

- the longer pipelines that may be needed to tie satellite oil fields back to an existing production facility, and the more marginal economics of this small field development approach, will increase the relative importance of the iceberg scour issue, including the question of risk and protection requirements, and related costs.

- although beyond the scope of this study, the feasibility and economics of the subsea pipeline systems that are now being considered for potential gas development on the Grand Banks will also be very sensitive to the risk of scour, and related protection requirements and costs.

- iceberg management techniques that are developed to protect subsea facilities may have a considerably greater focus on draft reduction than currently available methods. For example, C-CORE is now evaluating new techniques that involve mass removal from icebergs, in support of the recent gas pipeline (NAPP) proposal made by Tatham Offshore and its partners.

7.4 Miscellaneous

There are several other ice related problem areas that should be recognized here, which are relevant to all of the development scenarios discussed. These include:

- iceberg and pack ice forecasting
- the possible impact of global climate change on Grand Banks ice conditions
- ice effects on supply vessels and on safety and evacuation systems

A few comments about these additional ice issue areas are given as follows.

- iceberg and pack ice forecasting is not seen as a high priority issue by most operators. The potential benefits of better ice forecasting methods are well recognized, but the reliability of ice forecasts, along with the real time data needed to support them, is of high concern. From a practical operating perspective, the preferred approach is to detect and track icebergs and pack ice with the aid of simple persistence models. The reduction in emphasis on ice modelling and forecasting R&D that was recommended in a 1994 PERD planning study (Croasdale, 1994) is supported by this work.

- although most stakeholders view the potential effects of climate change on Grand Banks ice conditions as an irresolvable problem area, it is acknowledged as an issue. Periodic low cost reviews of the trends in observed ice conditions, similar to the recent scoping study that was sponsored by PERD (Marko, 1995), seem warranted. At a minimum, this type of initiative would put stakeholders in a position to respond to any concerns that may be raised.

- ice issues related to supply vessel operations in Grand Banks ice conditions are similar to many of those outlined for FPSO vessels and tankers. It should be recognized that supply vessels have successfully operated on the Grand Banks, off the east coast of Newfoundland and in the Labrador Sea since offshore operations commenced in the early 1970s.

- with regard to ice effects on safety and evacuation systems, icebergs should not be particularly problematic, due to the transient nature of their occurrences. However, development systems designed for use in the pack ice conditions that are occasionally experienced on the Grand Banks will have to recognize this constraint, in terms of the safety and evacuation methods employed.

The range of Grand Banks ice problems that have been identified for different development scenarios may appear extensive. In this regard, it is important to recognize that the Hibernia and Terra Nova projects have both demonstrated that development systems can be designed, and operations safely conducted, with the technology base currently available. However, there are a number of key ice problem areas in which R&D thrusts and improved information could provide significant benefits for future development systems. The implications of these ice problems on the cost and economics of different Grand Banks development alternatives are reviewed in the next section. This cost information, which is presented in the broader context of various development scenarios, provides a basis for priorizing important ice-related R&D thrusts.

8.0 Development Costs and Economics

In this section of the report, the implications of the ice problems that have been identified are considered, in terms of their influence on the costs and economics of possible Grand Banks development projects. The information given here is intended to provide some feel for the major cost components of different Grand Banks development scenarios, together with some perspective of the economic benefits that technical advances in key ice problem areas could have. The generic scenarios that were defined in section 6 have been used for this purpose. These include:

- developments that are based on the use of fixed structures, for oil field sizes of 50, 150, 250, 350 and 500 million barrels, located in water depths of 80m, 100m and 120m.

- developments that are based on the use of FPSO vessels, for oil field sizes of 50, 150, 250, 350 and 500 million barrels, located in water depths of 80m to 160m (or more).

- developments that are based on the use of subsea tie-backs to existing facilities over distances of 10, 20 and 30 km, for relatively small satellite oil fields 50, 150 and 250 million barrels in size, located in water depths of 80m to 160m.

As outlined earlier, these scenarios are intended to span a representative range of Grand Banks development opportunities and technology alternatives. They also reflect the range of oil reserves that have been found in Grand Banks fields to date, the water depths in which these fields are located, a reasonable array of development approaches, and input from industry. All of these scenarios assume that oil will be exported by tanker. Cases that involve small field developments with a fixed structure, or the use of subsea tie-backs for moderately sized fields, are recognized as highly improbable but have been included as parametric bounds.

8.1 System Components & Assumptions

In order to identify capital and operating costs (CAPEX and OPEX), the general scope of each development scenario was first established. As outlined in section 6.3.1, any offshore development project is comprised of a number of basic technical components. These include the project's development drilling activities, the topsides, subsea and export systems that are used, and the production structure or vessel itself. All are significant cost items.

Here, the first step was to determine the scope of the production systems that would be required for each development scenario, together with representative system configurations. This system definition work was based on current knowledge about offshore development systems worldwide, the experience of the authors, and input from a variety of industry sources. The scope of the Hibernia, proposed Terra Nova and possible Whiterose projects, along with the specific components of these development systems and their cost, provided valuable guidance in this regard. Each scenario was considered in terms of the following key components.

Oil Field Characteristics

- typical oil field dimensions and productivities were established on the basis of current information about the extent and properties of Grand Banks oil field reservoirs.

Development Drilling

- the number of development wells for each oil field case, including both producers and injectors, was estimated on the basis of current Grand Banks development approaches and relevant worldwide experience.

- here, the use of new technology (eg: horizontal and multi-lateral drilling) has been assumed, since advanced drilling techniques are now being routinely applied offshore. In general terms, this new drilling technology reduces the number of wells that are required, increases individual well productivities, and reduces development drilling costs.

- it is important to note that all of the development drilling (and work overs) activities for fixed development scenarios are assumed to be carried out from drilling facilities on the platform’s surface. In contrast, the development drilling and workover needs for the floating development cases will require the use of separate drilling vessels. This gives rise to higher drilling costs for the floating development approach.

Field Production Rates

- the field production rates that have been assumed are similar to those "needed" for equivalent worldwide developments, and are consistent with those planned for current Grand Banks development schemes.

- field production profiles were based on an initial production plateau that varied with the assumed field reserves, with production declines commencing when 50% of the field's reserve base had been produced, and declining at 15% per year thereafter. Ramp up time frames to peak production reflected a reasonable development drilling schedule, with pre-drilled wells assumed for the floating and subsea development scenarios.

Production Platform

- the production platforms that have been assumed as a basis for the representative field development scenarios include:

  <u>Fixed Structure Developments</u>

  - *the Stepped Steel Gravity Platform (SSGP) concept, with onboard storage volumes that are sufficient for the field production rates and tanker export systems assumed for each fixed development case.* Published cost estimates for this type of structure have been modified to reflect the effect of variations in water depth across the different field development scenarios, based on discussions with its designer (Fitzpatrick, personal communication). SSGP cost estimates have also been adjusted upwards in relation to published cost data, to incorporate some conservatism, accommodate input from companies other than Amoco, and present a more acceptable consensus view. Costs have also been allocated to cover the range of platform installation and removal operations that may be required.

  <u>Floating Development Systems</u>

  - *FPSO vessels with a quick release internal turret mooring and riser system, an oil offloading facility on their stern, and enough onboard storage to reasonably accommodate the production rates and tanker loading cycles associated with each floating development case.* Newbuild FPSO vessels have been assumed, with hull ice strengthening that is similar to the levels being carried for the Terra Nova FPSO. The vessel sizes and costs that have been used reflect current experience with floating systems in more conventional areas like the North Sea. However, the costs have been adjusted upwards, to include the incremental effect of ice strengthening needs, and the substantially higher cost of quick disconnect turrets. An allocation has also been provided for installation costs, primarily for the mooring (eg: piled anchors) and risers.

Topsides

- the scope and costs of the topsides facilities that have been assumed for each scenario are based on current Grand Banks development schemes, along with experiences with similarly sized fixed and floating development systems worldwide. The topsides costs used in this work reflect the benefits of ongoing industry initiatives for conventional offshore developments, which have reduced topsides weights and costs by optimizing layouts, improving production and reinjection processes, and so forth. Topsides costs for Grand Banks developments now envisioned by most of industry are considerably less than those associated with the Hibernia project.

- the FPSO vessels that are assumed in this work do not have onboard drilling facilities (although new technology is being developed in this regard). Two drilling rigs have been assumed for the larger reserve fixed structure cases, while only one rig has been assumed for the fixed structure scenarios involving smaller oil field reserves.

Subsea Facilities

- the only subsea systems that are associated with the fixed development scenarios considered here are flowlines, which lead from the platform to the tanker loading station, and the loading station itself. More extensive subsea facilities will be required for the floating development and satellite field tie-back scenarios, including subsea wells, flowlines, manifolds and riser bases.

- for the floating development scenarios, a rough rule of thumb that has been developed for Grand Banks projects, based on the number of subsea wells, has been used to determine “all-up” sea floor facility costs. This cost includes protection for all of the subsea systems in glory holes, with the exception of the flowlines, which are assumed to be run on the surface of the sea floor.

- wellhead and gathering costs for the subsea tie back case are similarly based, but include an incremental cost for a pipeline that runs from the satellite field back to a production facility, with some trenching to provide protection against iceberg scour.

Export System

- a simple per barrel tariff, based on industry input, has been used to derive oil export costs. This assumes a well developed tanker export system in the Grand Banks region.

Operations

- a wide range of operations are required to support the type of development scenarios under consideration here. These operations range from platform supply, fuelling and maintenance activities, through manning and shore base support requirements, to helicopter transport and ice management systems.

- the OPEX costs that have been used in this work are based on input from industry and represent those expected for ”reasonable” Grand Banks development schemes. These costs are largely fixed and will not decrease in proportion to the volume of oil that is produced from a given field. However, they have been adjusted on the basis of field size and are 20% higher for floating systems than for fixed developments, because of the stronger need for marine support, particularly for ice management.

8.2 Capital & Operating Costs

Tables 8.1 through 8.3 provide cost information for the various Grand Banks development scenarios considered in this study, and highlight some of the assumptions made. The CAPEX estimates contained in these tables are subdivided by development system component, while OPEX and export costs are given on a per barrel basis. Although there are a range of values from which any particular cost item could be selected, the estimates given here are intended to be as realistic as possible. They are not skewed upwards to incorporate conservatism nor are they as “optimistically low” as some of the more aggressive oil companies would assume. Most of the CAPEX items have lower costs than those suggested in the 1992 PERD Frontier

Planning Study, while the OPEX costs are substantially higher. Here, it is important to note that a considerable amount of effort was directed towards establishing these development scenario costs. To ensure that industry's views were properly reflected, the cost components and assumptions for each scenario were discussed in detail with a wide cross-section of oil companies representatives (see Table 4.1). Although there are some differences in opinion between various companies, the cost information summarized here is a reasonable consensus.

The costs that are provided in Tables 8.1 to 8.3 have been used as base case values for the comparative development economics given next. However, the simple per barrel cost totals shown in these tables are also a straightforward measure of the probable viability of each development scenario. For example, total per barrel costs that are in the $10 - $15 (Canadian) range suggest that a development project may have a reasonable chance of success, when factors such as the time value of money, taxes and royalties are taken into account. When the per barrel project costs begin to exceed this level, the economics for any development project will start to become much less attractive.

GBS System Cost Components

		Oil Field Reserves* (million bbls)					
		50	150	250	350	500	
Development drilling	- areal extent (km)	1 x 1	2.5 x 3	4 x 5	5 x 7	8 x 10	
	- # of wells	5	13	20	28	40	
	producers	3	8	12	17	25	
	injectors	2	5	8	11	15	
	- well productivity	10,000 to 15,000			15,000 to 25,000		
	- peak production	30,000	60,000	80,000	100,000	130,000	
	- total cost	75	195	300	420	600	15MM/well
	- years to deplete	7	12	15	18	23	
Structure & Topsides	- min storage (bbls)	600,000	600,000	800,000	850,000	1,000,000	
	- process capacity	30,000	60,000	80,000	100,000	130,000	
	- GBS substructure						
	- 80m	556	556	556	556	556	
	- 100m	695	695	695	695	695	
	- 120m	909	909	909	909	909	
	- topsides	300	400	500	600	750	
	- install/abandon	150	170	190	210	230	
	- total cost						
	- 80m	1006	1126	1246	1366	1536	
	- 100m	1145	1265	1385	1505	1675	
	- 120m	1359	1479	1599	1719	1889	
Loading System	- total cost	150	150	150	150	150	
Management & Engineering		140	170	190	240	300	
CAPEX	- 80m	1371	1641	1886	2176	2586	
	- 100m	1510	1780	2025	2315	2725	
	- 120m	1724	1994	2239	2529	2939	
CAPEX $/bbl	- 80m	27.42	10.94	7.54	6.22	5.17	
	- 100m	30.19	11.86	8.10	6.61	5.45	
	- 120m	34.49	13.30	8.96	7.23	5.88	
OPEX		312	600	940	1264	1776	
$/bbl		6.24	4.00	3.76	3.61	3.55	
Tanker tariff $/bbl		3.00	2.50	2.25	2.00	1.75	
Total $/bbl	- 80m	36.66	17.44	13.55	11.83	10.47	
	- 100m	39.43	18.36	14.11	12.22	10.75	
	- 120m	43.73	19.80	14.97	12.84	11.18	

Table 8.1:

Table 8.1

FPSO System Cost Components

		Oil Field Reserves* (million bbls)					
		50	150	250	350	500	
Development drilling	- areal extent (km)	1 x 1	2.5 x 3	4 x 5	5 x 7	8 x 10	
	- # of wells	5	13	20	28	40	
	producers	3	8	12	17	25	
	injectors	2	5	8	11	15	
	- well productivity	10,000 to 15,000			15,000 to 25,000		
	- peak production	30,000	60,000	80,000	100,000	130,000	
	- total cost	150	390	600	840	1200	$30MM/well
	- years to deplete	6	9	12	15	20	
FPSO vessel	- DWT (rough)	80,000	100,000	120,000	135,000	150,000	
	- storage (bbls)	400,000	550,000	700,000	800,000	1,000,000	
	- process capacity	30,000	60,000	80,000	100,000	130,000	
	hull	210	235	258	274	290	
	topsides	138	232	288	341	415	
	turret	100	125	150	175	200	
	installation	13	16	18	20	23	
	- total cost	461	609	715	810	928	
Subsea facilities	- total cost	75	195	300	420	600	$15MM/well
Management & Engineering		75	130	175	225	300	
CAPEX		761	1324	1790	2295	3028	
$/bbl		15.22	8.82	7.16	6.56	6.06	
OPEX		390	750	1175	1580	2220	
$/bbl		7.80	5.00	4.70	4.51	4.44	
Tanker tariff $/bbl		3.00	2.50	2.25	2.00	1.75	
Total $/bbl		26.02	16.32	14.11	13.07	12.25	

* any water depth between 80m and 160m

Table 8.2:

Subsea Tie-in of Small Field Reserves

Cost Basis	development drilling	30MM/well		
	subsea costs (all up)	15MM/well		
	pipeline tie-in costs	10MM		
	pipeline cost/km	3 x 8"	50 MM bbls	3.3 MM $
		3 x 10"	150 MM bbls	4.3 MM $
		3 x 12"	250 MM bbls	5.3 MM $
		includes umbilicals & 50% premium to trench lines against scour		

		Oil Field Reserves		
		50	150	250
Development drilling	- areal extent	1 x 1	2.5 x 3	4 x 5
	- # of wells	5	13	20
	produc	3	8	12
	injector	2	5	8
	- well productivity		10,000 to 15,000	
	- peak produ	30,000	60,000	80,000
	- total cost	150	390	600
	- years to de	7	12	15
Subsea facilities	subsea equip	75	195	300
	equipment m	15	15	15
	pipeline tie-in	10	10	10
	pipeline cost			
	- 10 km	48	58	68
	- 20 km	81	101	121
	- 30 km	114	144	174
CAPEX	- 10 km	283	653	978
	- 20 km	316	696	1,031
	- 30 km	349	739	1,084
CAPEX $/bbl	- 10 km	5.66	4.35	3.91
	- 20 km	6.32	4.64	4.12
	- 30 km	6.98	4.93	4.34

Process, OPEX and export tariff costs are determined by the production facility operator and cannot be reasonably specified here. As a result, the costs shown are CAPEX for the subsea system only.

Table 8.3:

The following points should be noted, on the basis of the cost information that is presented in these tables.

Fixed Structure Developments

- the CAPEX estimates that are given in Table 8.1 are relatively low in comparison to the Hibernia development project, typically by about 35% on a prorated oil field reserve basis. For the 500 million barrel development scenario, they are also less than the CAPEX estimates in the 1992 PERD Frontier Planning Study (Croasdale, 1992), by about 20%. This is a reflection of improvements in the development drilling and topsides engineering areas, and the lower costs of the SSGP type structure.

- development system CAPEX for the fixed structure scenarios given here is roughly apportioned as follows:

System Component	Cost	Influenced by Ice
Development Drilling	20-25%	no
Production Platform	30-40%	yes
Topsides Facilities	25-30%	no
Loading System	5-10%	yes
Management	10%	no

  In short, ice problems will have some level of influence on between 35% and 50% of the total capital cost of fixed structure developments on the Grand Banks.

- as expected, small oil field developments involving fixed production structures are not attractive while large field developments are. However, there appears to be some potential to develop fields in the 250 to 350 million barrel range with fixed platforms.

- in all cases, the effect of increasing water depth over the 80 to 120m range is not as significant an influence as one may expect. However, should relatively large iceberg impact design loads be carried for the deeper water locations, substantially higher structure costs may result.

- the direct effect of iceberg and occasional pack ice occurrences on the capital cost of a loading system is not particularly high in terms of a development project's overall CAPEX. These ice influences are of more consequence from the standpoint of tanker design, and loading and export system operations and efficiencies.

Floating System Developments

- the cost estimates that are given in Table 8.2 are comparable to those being carried for the Terra Nova and possible Whiterose development projects, on a prorated field reserve basis. However, the capital costs given here are somewhat lower than the CAPEX estimates in the 1992 PERD Frontier Planning Study, by about 25%.

- CAPEX for the floating development scenarios is roughly apportioned as follows:

System Component	Cost	Influenced by Ice
Development Drilling	35-40%	no
Production Vessel	15-20%	yes
Topsides Facilities	15-20%	no
Subsea Systems	20-25%	yes
Management	10%	no

  Again, ice problems will have some level of influence on between 35% and 45% of the total capital cost of floating development systems on the Grand Banks. However, their influence on FPSO operating efficiencies and potential downtime levels should also be recognized.

- there appears to be some potential for oil fields in the 150 to 200 million barrel range to be developed with floating production systems, while the larger field development cases also seem to be quite attractive.

Subsea Developments

- Table 8.3 only provides the capital cost of the subsea tie-in systems for the small oil field development scenarios. The CAPEX and OPEX costs that may be attributed to an existing facility that takes the oil, along with oil export costs, are not indicated. These other cost items are usually determined (or negotiated) once excess production capacity on a platform becomes available. A lower bound would assume that all of the facility's CAPEX has been paid off, leaving only its OPEX and the oil export costs, which would be in the $7 to $8 per barrel range.

- adding $7 to $8 to the CAPEX estimates shown in Table 8.3 suggests that small oil field developments should be viable with subsea tie-backs, as would be expected. The incremental capital cost associated with iceberg scour protection is the main ice issue.

8.3 Comparative Economics

To assess the economic implications of the ice problems that will influence these different Grand Banks development scenarios, some simple economics have been run. This economic assessment work involved the use a model that is currently under development at Memorial University, with support from the Canada-Newfoundland Offshore Development Fund (Fuglem, 1997). The model accepts CAPEX and OPEX estimates for development systems, related production profiles and oil export costs, but does not yet have the ability to include taxes and royalties or oil price and inflation forecasts. As a result, the information that is generated by the model allows relative economic comparisons between various development scenarios, in terms of constant, pre-tax, royalty free dollars. In essence, this model produces economic measures that represent the overall “size of the prize” for different Grand Banks development opportunities, before any government takes and risk factor adjustments.

It should be noted that the economics given in this study are not meant to be definitive. For example, they will not coincide with those developed by oil companies or government, which normally include various fiscal and risk factors. However, they are consistent across all of the development scenarios being considered, and can be used to obtain a sense of project viability and key sensitivities to technology improvements. This information can then be used to identify and priorize important ice-related R&D thrusts.

The economic modelling work and its assumptions, together with the model runs and results, are highlighted as follows.

Economic Indicators

To compare different systems, determine whether a given field development appears viable, and identify key sensitivities, a number of economic indicators were used. These indicators are highlighted below. Again, it should be noted that taxes, royalties and inflation have not been accounted for, and that a flat oil price of $20 US per barrel has been assumed in most model runs.

<u>Net Present Value (NPV)</u>

The NPV accounts for the time value of money and is the net cash flow over a project’s lifetime, both positive and negative, discounted to a particular rate of return. As such, it represents the total value of a project or the “size of the prize” in present day dollars. The discount rate that was assumed for this work is 10%.

Net Present Value per Barrel (NPV/bbl)

The NPV/bbl measure, calculated as a project's NPV divided by the number of barrels of oil produced (in some cases slightly less than the nominal field size) illustrates the project's overall NPV on a normalized per barrel basis.

Cash Flow Productivity Index

This is defined as a project's total operating revenue divided by its total capital expenditure (including developmental drilling costs). It is an index of the efficiency of invested capital and is an important indicator, considering limitations in any company's available capital and their desire to efficiently allocate investment funds to areas where they will generate the highest NPV.

Internal Rate of Return (IRR)

The IRR is defined as the discount rate which results in a project NPV of 0. This measure is an indicator of a project's economic robustness.

Payout Period

This is defined as the time at which a project's accumulated revenues equal its accumulated expenditures. From a company's perspective, the quicker the payout period the better, because the time period that risked funds are exposed to price, interest rate and political volatility is shorter.

These economic indicators have been computed for the scenarios given in Tables 8.1 and 8.2 and plotted as a function of field size, for various fixed and floating development system alternatives. The subsea tie-back development scenario for small oil fields was not modelled, because all of the system costs could not be well defined.

Model Overview & Assumptions

In the model, the economics for different development cases is determined by the magnitude and timing of capital, operating and transportation costs, and the revenues generated. Costs have been allocated according to the information given in Tables 8.1 and 8.2, which depend on field size and in the case of fixed structure developments, also vary with water depth. The capital costs are spread over a specified number of years from project start-up which depends on the development system used and the field size. It is assumed that the time to construct a fixed structure and its topsides is fairly constant (3.5 years), whereas the time required to put an FPSO system in place will increase with field size (2 years for small fields to 3.5 years for large fields). It should be noted that the resulting economics are reasonably sensitive to assumptions made about start-up schedules. The cost of developmental drilling is also spread over a number of years. Again, specified cost time lines are a function of the system used and field size. For the FPSO, it is assumed that drilling can start the first year (i.e. predrilling before the production vessel is installed on-site). For the GBS cases, it is assumed that drilling can only start once the platform is installed*. ∗

Production volumes are determined from the peak production rates that have been specified for each scenario, which vary with field size. Constant production rates at these peak levels are assumed during the first few years of a development, followed by a 15% per year decline once half the field reserves have been produced. Yearly revenues are computed as the amount of oil produced multiplied by oil price. Two criteria are used to terminate production and define a development project's effective lifetime. The first criterion is depletion of field reserves and the second is negative annual profit.

The operating costs are assumed to be constant during the peak production period and are progressively reduced thereafter, as production begins to decline. However, the operating costs are only decreased slightly in relation to the production decline, because most of the support logistics and personnel requirements will remain relatively constant. In addition, there are usually more difficulties with reservoir maintenance as a field ages and often an increased requirement for work overs and water and gas injection. OPEX costs vary with field size and for the fixed development scenarios are assumed to be 20% less than for the

∗ representative examples of the type of timing assumptions made about various CAPEX and OPEX expenditures are shown in Table 8.4. Detailed back-up for the all of the economics given in this report have been provided to NRC separately, and are available on request.

FPSO Scenarios

Development Drilling Costs ($MM)

Field Reserves	50	150	250	350	500
Year					
1	120	180	180	210	210
2	30	120	120	180	180
3		60	120	120	180
4		30	90	120	180
5			60	60	120
6			30	60	120
7				30	60
8				30	60
9				30	30
10					30
11					30

Operating Cost Profile* ($MM)

Field Reserves	50	150	250	350	500
Opex/year at peak rat	70	90	105	115	125
During subsequent	60	80	95	105	115
production years	60	80	95	105	115
	60	80	95	105	115
		75	95	105	115
		75	90	100	110
			90	100	110
			90	100	110
				95	110
				95	100
				95	100
					100
					90
					90
					90
Total OPEX	390	750	1175	1580	2220

* excluding insurance

Table 8.4:

floating system cases, largely because of lesser marine support requirements (eg: ice management). Tanker transportation costs to export produced oil are specified in terms of a cost per barrel. These per barrel transportation costs are assumed to decrease with increasing field size, as the use of more economical tanker export systems becomes more likely (eg: larger shuttle tankers).

With regard to system operating efficiencies, some very simple assumptions have been made. Any downtime that may be caused by mechanical failures has not been recognized and the effect of potential wave related downtime not fully acknowledged. For base case calculations, a constant downtime of 30 days per year has been specified for the FPSO system, while 0 days of downtime is assumed for the GBS. The influence of changing these downtime levels is considered by parametrically varying their values. Downtime is inserted at the beginning of each year of production. The effect of downtime is to delay production and defer production revenues. In the model, the depletion of reserves is stopped during downtime events and production of these reserves picked up at the end of the project. During downtime periods, the operating costs are maintained at their assumed levels.

Model Runs & Results

Economics have been run for the fixed and floating development scenarios, for each of the oil field reserve cases that have been defined (50, 150, 250, 350 and 500 million barrels). For the FPSO development approach, it is assumed that costs are relatively independent of water depth, and only one model run has been made for each reserve case. Since water depth will influence the capital cost of a GBS platform, three separate runs have been made for each fixed structure development scenario, with oil fields in 80m, 100m and 120m of water.

The results of these model runs are presented in Figure 8.1, for both the fixed and floating development system alternatives. Some of the key points to note are highlighted as follows.

- Grand Banks oil field developments involving reserves in the 150 to 200 million barrel range (or more) should not be unattractive. The NPVs that are shown for these oil reserve cases are considerable (in the order of $500 million) and leave room to accommodate substantial government takes.

- field developments with fixed structures become competitive with floating production systems for oil reserve cases in the 250 to 300 million barrel range, without taxes and royalties.

- the economics of fixed structure developments are not particularly sensitive to water depth variations over the 80 to 120m depth range. Fixed systems are more attractive than floating systems for larger oil fields involving reserves of 350 barrels or more.

- floating systems that work in a very efficient manner have the potential to develop small oil fields in the 100 to 150 million barrels range, on a pre-tax and pre-royalty basis. Very small oil field developments (in the order of 50 million barrels) have little chance of being economic, with either development approach.

- the other economic indicators shown also support these observations, with cash flow productivity indexes, IRRs and payout periods being quite reasonable. It is clear that these Grand Banks development opportunities represent substantial economic prizes, in absolute terms.

Model runs have also been carried out to determine the influence of different assumptions on these development economics, and to identify important sensitivities. For these runs, the main economic indicator that was used is the net present value per barrel. Since water depths do not have a major influence on the economics of fixed structure developments, the only GBS case considered is for an oil field location in 100m of water. Sensitivity analyses have been conducted for variations in CAPEX, drilling, OPEX and transportation costs, and are presented on single “spider plots”. Sensitivities to discount rate, project startup time, oil price, annual downtime levels and the year in which a major downtime event may occur were also determined. The effect of downtime can be quite important, particularly for FPSO systems developing small oil fields over relatively short time periods. Their operating efficiencies and revenue streams can be adversely effected during severe pack ice or iceberg years.

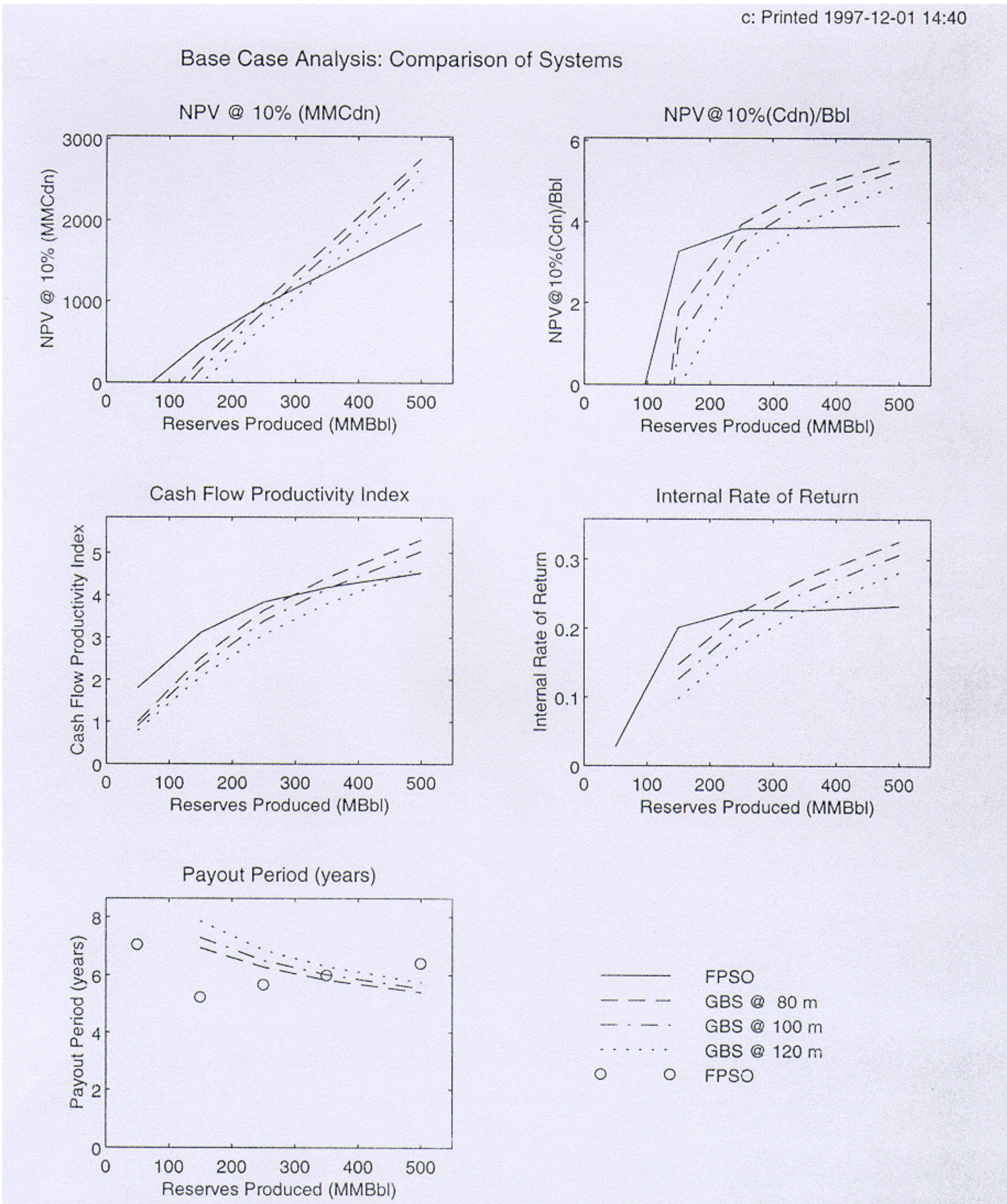
The results of sensitivity runs for the fixed and floating development scenarios are shown in Figures 8.2 to 8.4 and Figures 8.5 to 8.7, respectively. The following points should be noted.

- the spider plots Figures 8.2 and 8.5, which are based on a$20 US/bbl oil price and a 10% discount rate, show that variations in CAPEX have the single most significant effect on project economics. For example, for both the fixed and floating development systems, a CAPEX increase of 40% results in a decrease of roughly $500 million in NPV and in turn, a loss of viability for developments with reserves in the 150 to 200 million barrel range.

- sensitivities to changes in drilling, OPEX and transportation costs have little effect on the economics of fixed development scenarios. These factors are somewhat more influential for the floating system cases, where 40% increases in OPEX and drilling costs can mean NPV losses of several hundred million dollars.

- economic sensitivities to factors such as oil price, the assumed discount rate and start-up time frames, and downtime levels are considerable. Obviously, oil price has the most significant influence on economics. There are also clear benefits in having the ability to reduce a project's "time to first oil", by putting it on stream as quickly a possible.

downtime effects can also be quite important for the economics of these development scenarios, more so for the floating system cases. Tanker loading operations at fixed structures should only experience a few days of ice-related downtime annually, unless a heavy pack ice intrusion occurs. Available storage on GBS platforms will mitigate the impact of any loading downtime. However, should persistent pack ice conditions preclude loading operations for a few weeks in one of the first few years of a project, NPV losses of tens of millions of dollars could result.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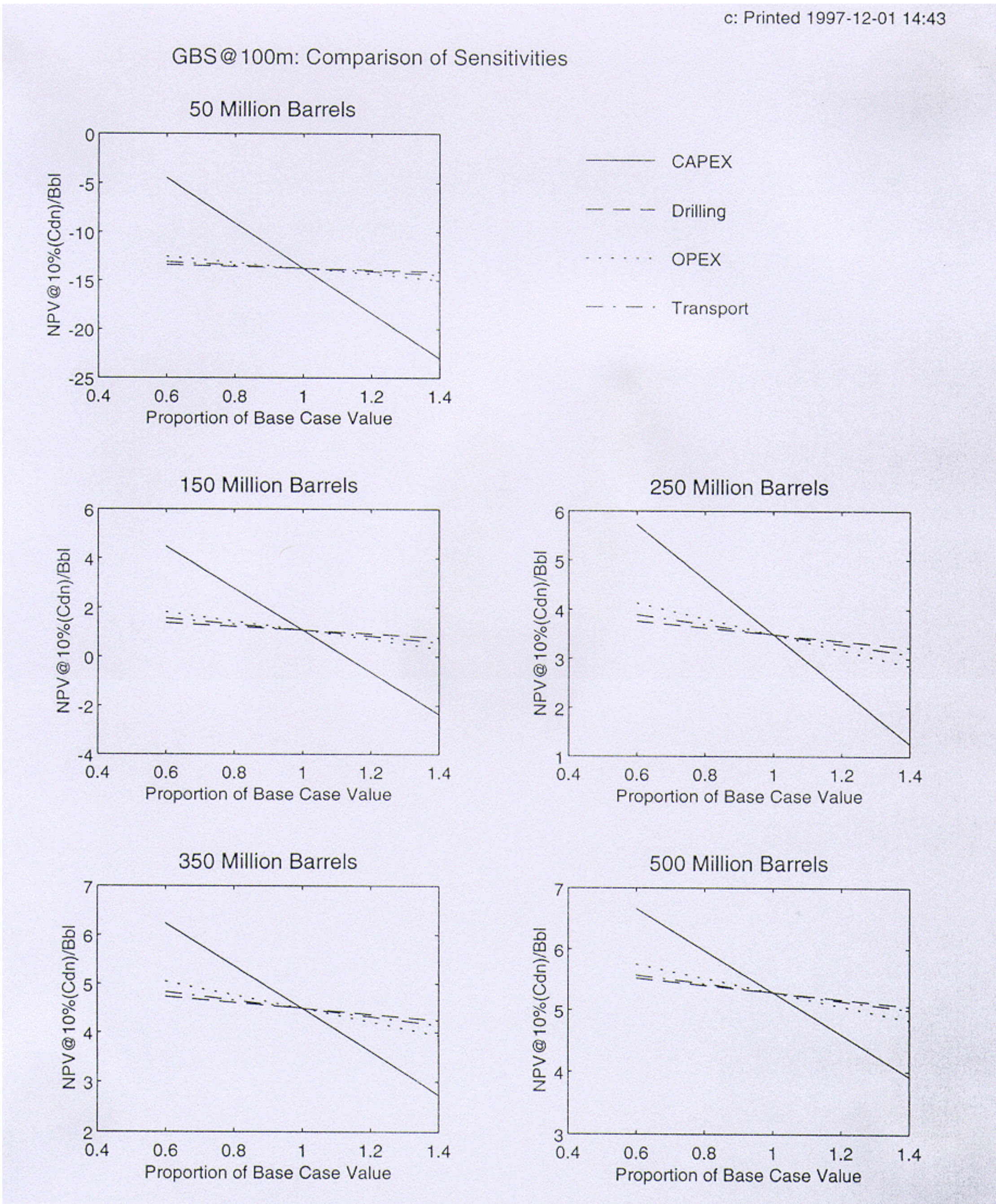
Base Case Analysis: Comparison of Systems
NPV @ 10% (MMCdn)
NPV @ 10% (MMCdn)
Reserves Produced (MMBbl)
NPV@10%(Cdn)/Bbl
NPV@10%(Cdn)/Bbl
Reserves Produced (MMBbl)
Cash Flow Productivity Index
Cash Flow Productivity Index
Reserves Produced (MBbl)
Internal Rate of Return
Internal Rate of Return
Reserves Produced (MMBbl)
Payout Period (years)
Payout Period (years)
Reserves Produced (MMBbl)
FPSO
GBS @ 80 m
GBS @ 100 m
GBS @ 120 m
FPSO

Figure 8.1:



c: Printed 1997-12-01 14:43
GBS@100m: Comparison of Sensitivities
50 Million Barrels
150 Million Barrels
250 Million Barrels
350 Million Barrels
500 Million Barrels
NPV@10%(Cdn)/Bbl
Proportion of Base Case Value
CAPEX
Drilling
OPEX
Transport

Figure 8.2:

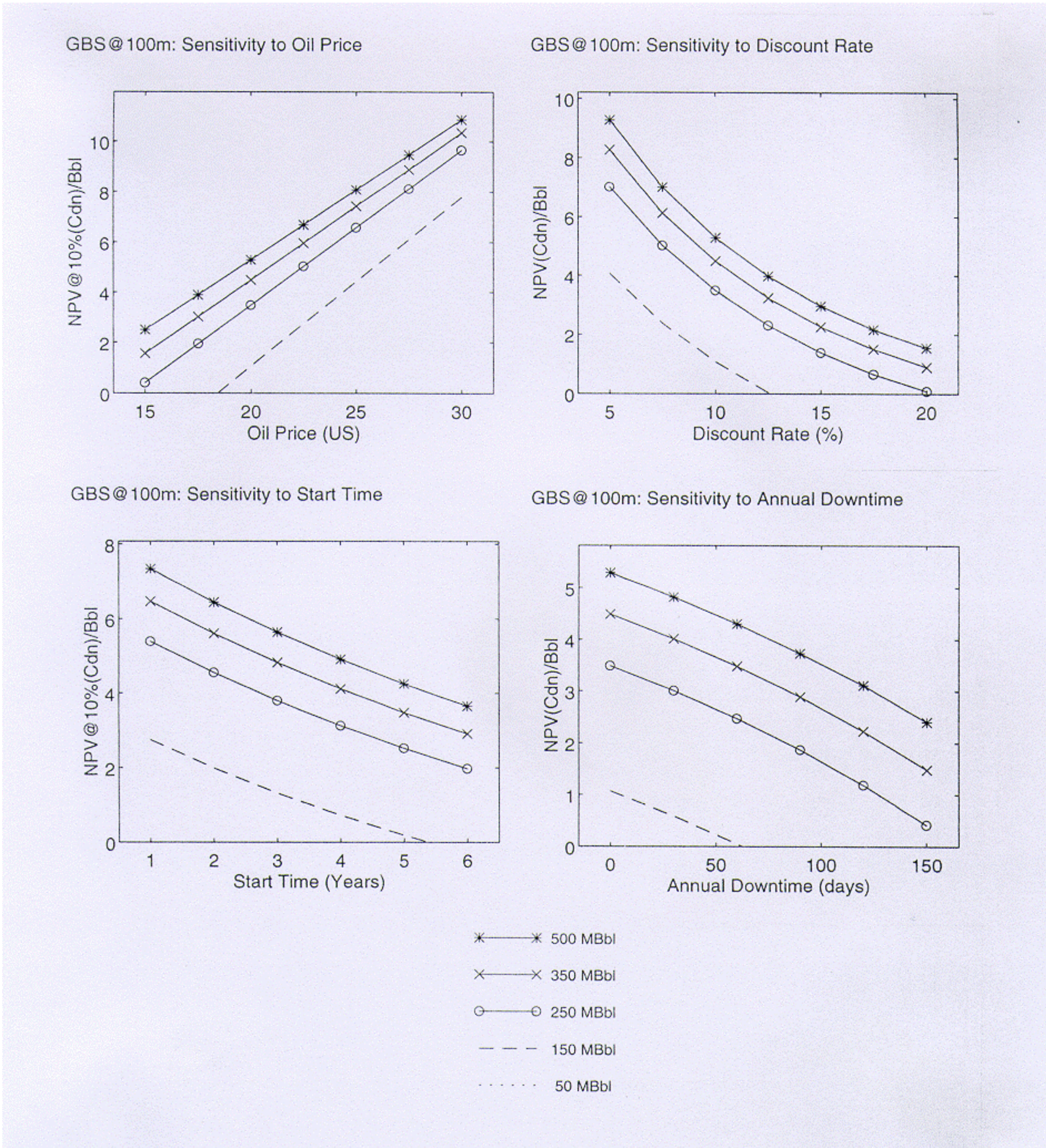

GBS@100m: Sensitivity to Oil Price
NPV@10%(Cdn)/Bbl
Oil Price (US)
GBS@100m: Sensitivity to Discount Rate
NPV(Cdn)/Bbl
Discount Rate (%)
GBS@100m: Sensitivity to Start Time
NPV@10%(Cdn)/Bbl
Start Time (Years)
GBS@100m: Sensitivity to Annual Downtime
NPV(Cdn)/Bbl
Annual Downtime (days)
500 MBbl
350 MBbl
250 MBbl
150 MBbl
50 MBbl

Figure 8.3:

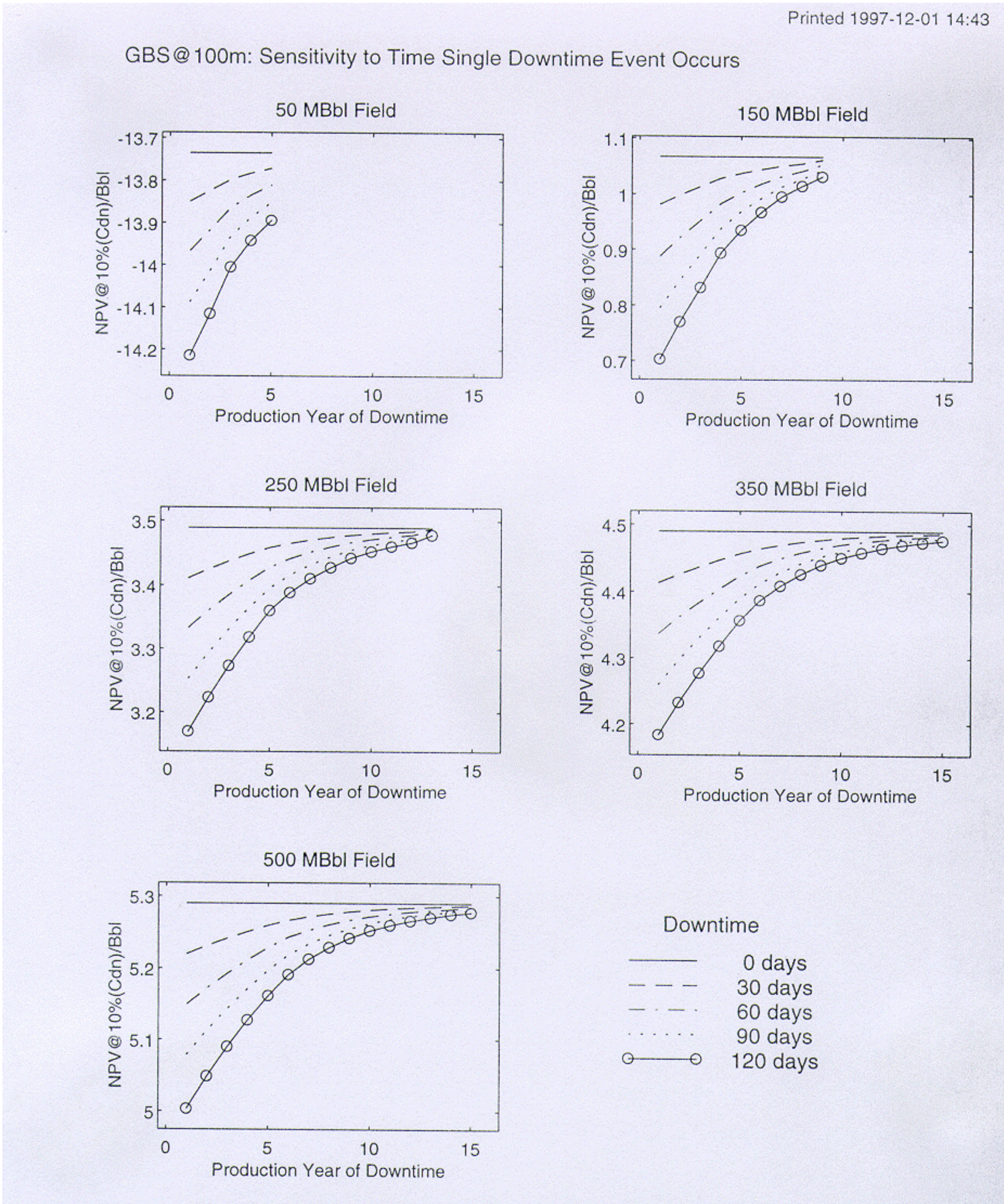

Printed 1997-12-01 14:43
GBS@100m: Sensitivity to Time Single Downtime Event Occurs
50 MBbl Field
150 MBbl Field
250 MBbl Field
350 MBbl Field
500 MBbl Field
NPV@10%(Cdn)/Bbl
Production Year of Downtime
Downtime
0 days
30 days
60 days
90 days
120 days

Figure 8.4:

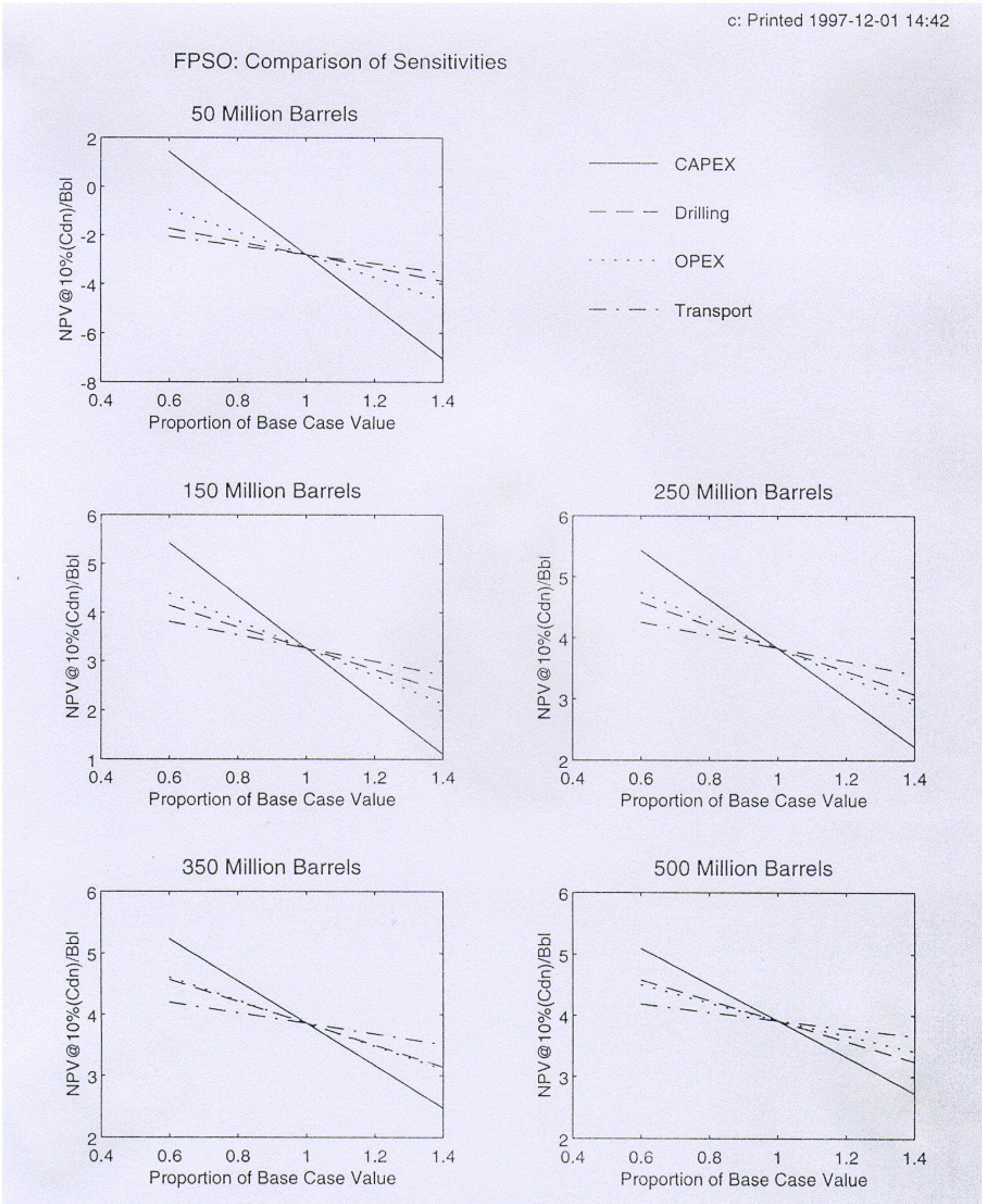
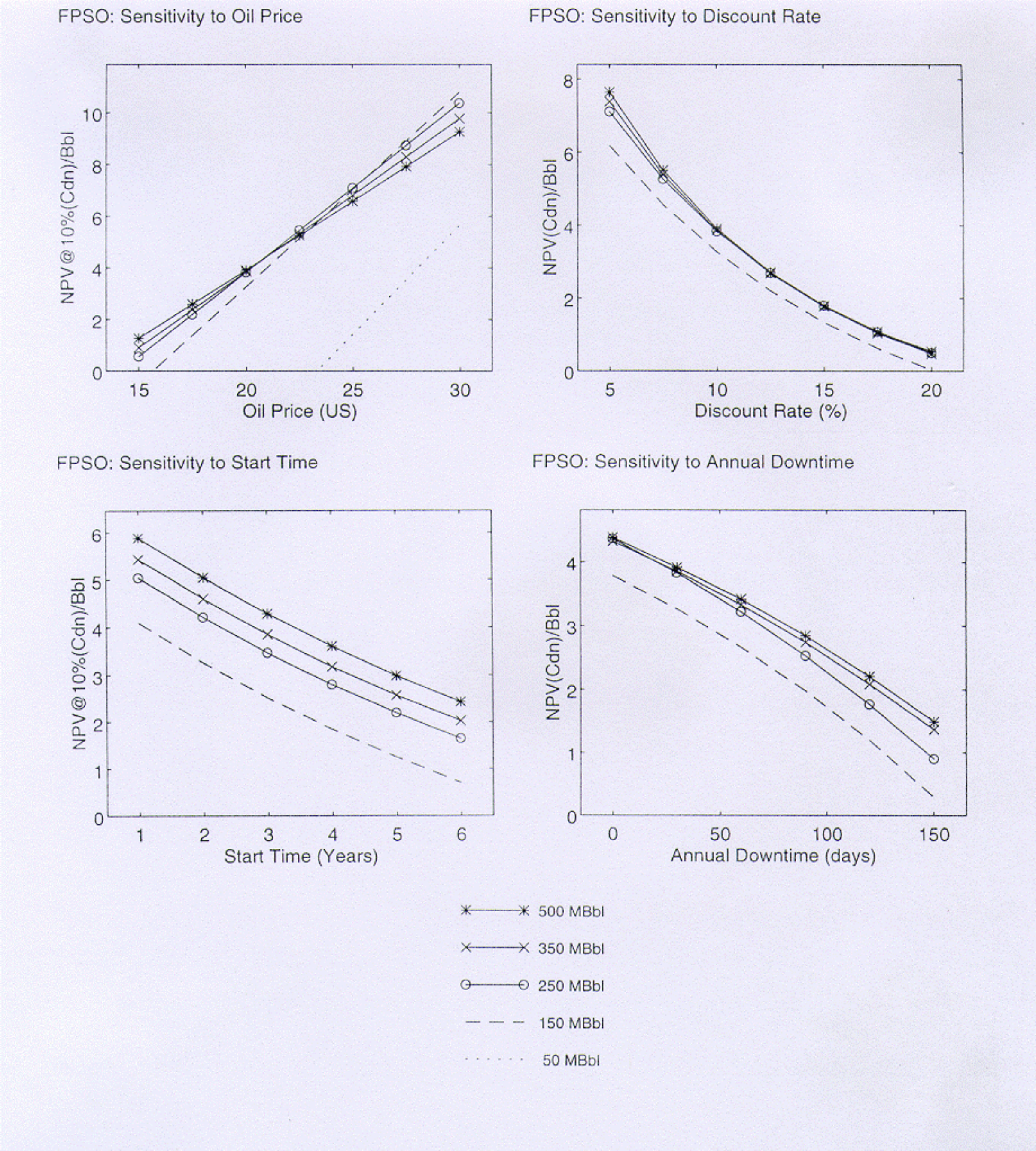
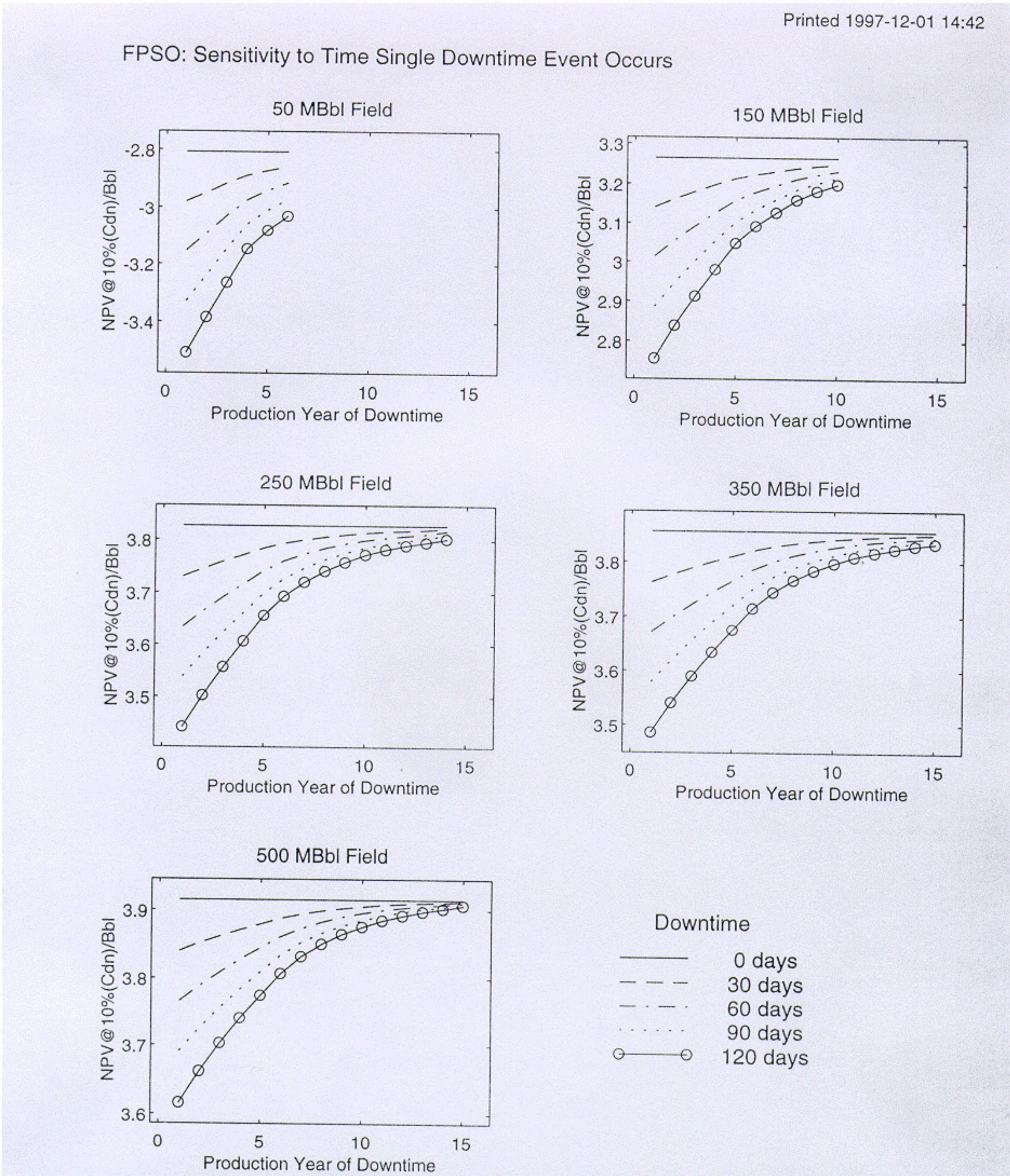

c: Printed 1997-12-01 14:42
FPSO: Comparison of Sensitivities
50 Million Barrels
150 Million Barrels
250 Million Barrels
350 Million Barrels
500 Million Barrels
NPV@10%(Cdn)/Bbl
Proportion of Base Case Value
CAPEX
Drilling
OPEX
Transport

Figure 8.5:



FPSO: Sensitivity to Oil Price
NPV@10%(Cdn)/Bbl
Oil Price (US)
FPSO: Sensitivity to Discount Rate
NPV(Cdn)/Bbl
Discount Rate (%)
FPSO: Sensitivity to Start Time
NPV@10%(Cdn)/Bbl
Start Time (Years)
FPSO: Sensitivity to Annual Downtime
NPV(Cdn)/Bbl
Annual Downtime (days)
500 MBbl
350 MBbl
250 MBbl
150 MBbl
50 MBbl

Figure 8.6:



Printed 1997-12-01 14:42
FPSO: Sensitivity to Time Single Downtime Event Occurs
50 MBbl Field
150 MBbl Field
250 MBbl Field
350 MBbl Field
500 MBbl Field
NPV@10%(Cdn)/Bbl
Production Year of Downtime
Downtime
0 days
30 days
60 days
90 days
120 days

Figure 8.7:

- FPSO stationkeeping operations are more susceptible to ice, and annual ice-related downtimes could be substantially higher than a few days, particularly in heavy iceberg or pack ice years. Assumed downtime levels have a considerable influence on FPSO system economics, particularly for the small field development cases. For example, if FPSO production operations were interrupted by a several month pack ice intrusion during the first year or two of a 150 million barrel field development, an NPV loss of about $100 million would result.

8.4 Implications

Based on the cost and economic information outlined above, it is evident that there is good potential for a number of Grand Banks development scenarios to be quite viable. However, assessing the direct implications of different ice-related problems on the economics of these development alternatives is not straightforward. Clearly, improved understandings in a variety of ice issue areas would be beneficial in increasing the potential for more cost effective system designs and operations, and creating higher levels of comfort with the "doability" and safety of Grand Banks development projects. The relative value of better knowledge or improved technology for ice would also increase as the economics of a particular development became more marginal.

Although judgemental, Tables 8.5 through 8.7 highlight some of the more important cost and economic implications of key Grand Banks ice problems for different development scenarios, and provide a few related comments. This information is not intended to be precise, but does give some perspective of the incentives for ice-related R&D in support of future development opportunities on the Grand Banks.

Fixed Structure Development Scenario

System Component	***Ice Issue***	***Importance***	***Economic & Other Implications***
Fixed platform			
	Iceberg impact load levels and optimization for design iceberg and wave events	Deterministic impact loads due to large icebergs are now conservatively estimated. Probabilistic load levels are considerably lower, but are sensitive to assumptions about iceberg statistics. Better knowledge of iceberg impact loads would allow potential cost reductions for future structure designs, and more comfort during their deployments.	Several hundred million in structure CAPEX. Several hundred million in project NPV. Shorter construction periods and Higher levels of comfort with fixed platforms and associated risks.
Tankers			
- hull strengthening	Collisions with small icebergs	Small ice mass occurrence frequencies, collision mechanics and loads are not well known, leading to uncertainties in strengthening requirements, risk assessments and operating criteria.	About 10% of vessel hull cost (ten to thirty million in CAPEX). Effect on export tariffs is small. More important issue in terms of risk, reliability and safety.
- ice detection & avoidance	Collisions with small icebergs	Current limitations/uncertainties in on-demand small ice mass detection capabilities may result in overly conservative design and operating critera. Good small ice mass management capabilities during tanker loading operations will reduce downtime.	Little direct impact in terms of costs. Reduced risks and improved operating efficiencies with more reliable all weather small ice mass detection, avoidance and management capabilities.
- loading in pack ice	Downtime due to prolonged pack ice intrusions	Inability to carry out stationkeeping and loading operations in heavy pack ice may lead to lengthy production downtime when GBS storage is full.	Tens of millions in project NPV if lengthy ice downtime occurs in first few years. Daily losses of one to two million dollars in "upfront revenues". More confidence will reduce risk perceptions.
Other		*It is clear that a reduction in development drilling and topsides costs would have a very significant and positive effect on project economics.*	

Table 8.5:

Floating Development System Scenario

System Component	***Ice Issue***	***Importance***	***Economic & Other Implications***
FPSO Vessel & Tankers			
- hull strengthening	Collisions with small icebergs	Small ice mass occurrence frequencies, collision mechanics and loads are not well known, leading to uncertainties in strengthening requirements, risk and downtime assessments, and operating criteria.	About 10% of vessel hull cost (ten to thirty million in CAPEX). Potentially less downtime at one to two million per day in lost upfront revenue and tens of millions in project NPVs. Higher levels of comfort with floating systems and the associated risks.
- ice detection & management	Collisions with small icebergs	Current limitations/uncertainties in small ice mass detection and management capabilities may result in overly conservative designs and operations, and considerable downtime. Improved and more reliable methods are required.	Reduced risks and improved operating efficiencies with more reliable all weather small ice mass detection and management capabilities. Higher levels of comfort with floating systems and the associated risks.
- stationkeeping in pack ice	Downtime due to prolonged pack ice intrusions	Inability to carry out FPSO stationkeeping and tanker loading operations in heavy pack ice may lead to lengthy periods of downtime. Experience with floating sytems in other ice-infested areas suggests that operations in pack ice should be "doable".	Tens of millions in project NPV if lengthy ice downtime occurs in first few years. Daily losses of one to two million dollars in "upfront revenues". More confidence will reduce risk perceptions.
Subsea Facilities			
	Damage from scouring icebergs	Floating development systems will require extensive subsea facilities. The potential for scour related damage must be reliably estimated anf if needed, cost effective scour protection methods devised.	Tens of million in subsea system CAPEX. Up to a hundred million in project NPVs.
	Managing deep draft icebergs that threaten facilities	Reliable methods of identifying and managing large deep draft icebergs would be beneficial for subsea developments, in terms of mitigating iceberg scour risks.	Higher levels of comfort with subsea systems and the associated risks. Potentially less production downtime because of preventative subsea system shut downs when large icebergs move into the field area.
Other			
		It is clear that a reduction in development drilling, topsides and subsea equipment costs would have a very significant and positive effect on project economics.	

Table 8.6:

Subsea Development Scenario

System Component	Ice Issue	Importance	Economic & Other Implications
Subsea Facilities			
	Damage from scouring icebergs	These development systems will require subsea facilities and relatively long pipelines. The potential for scour related damage must be reliably estimated anf if needed, cost effective scour protection methods devised.	Tens of millions to a hundred or more million in subsea and pipeline system CAPEX. Up to a hundred million in project NPVs. Higher levels of comfort with subsea developments and the associated risks.
	Managing deep draft icebergs that threaten facilities	Reliable methods of identifying and managing large deep draft icebergs would be beneficial for subsea developments, in terms of mitigating iceberg scour risks.	Potentially less production downtime because of preventative system shut downs when large icebergs move close to subsea facilities and pipelines. Minimal impact in terms of project economics unless reliability is nearly 100%, but a valuable operational tool to mitigate risk.
Other		*It is clear that a reduction in development drilling, subsea equipment and pipelining costs would have a very significant and positive effect on project economics.*	

Table 8.7:

9.0 Ice Research Requirements

In this section of the report, key areas in which ice-related research would be of benefit for potential Grand Banks oil field developments are summarized. Recommendations for specific R&D initiatives are also presented, with priorities identified on the basis of technical need, economic benefit, and safety and risk considerations. Because these ice-related problems and research needs have already been referred to throughout the report, they are only presented in summary form here.

The issue of assigning priorities to R&D needs is a difficult one and tends to be "company specific". For example, a company that is committed to building and operating a floating development system will attach the highest priorities to research needs for this type of system, and will have little interest in R&D relating to fixed platforms. Alternatively, a company that is involved with the Hibernia project will see higher priorities for research relating to tanker transportation and loading, and in the longer term, for R&D relating to seafloor scour issues for subsea tie-backs. New operators just entering the exploration phase may well be interested in R&D that supports the optimization of fixed structures, so that they can be economically used on the smallest posible field size.

The priorities for PERD R&D need to recognize this range of views. Here, this consideration has been treated by assigning short and longer term research priorities where necessary, as discussed in section 9.2.

9.1 R&D Needs & Priorities

Fixed Structure Developments

The key ice-related problems and R&D needs for fixed structure developments are highlighted in Table 9.1, along with related priorities. The primary areas of consideration include:

- optimizing fixed structure designs for icebergs and waves
- iceberg impact design loads
- tanker hull strengthening requirements for ice
- small ice mass detection and avoidance
- tanker loading operations in pack ice

Table 9.1:

9.1:

Fixed Structure Development Scenario

System Component	Ice Issue	R&D Needed	Relative Priority	Comments
Fixed platform				
	Iceberg impact loads	Real world iceberg impacts with a fixed structure (such as the Hibernia GBS)	ML - short term H - longer term	This could well become a higher priority in the longer term. Obviously, a JIP item.
		Continued measurements of ice failure pressures over large areas (eg: follow-up to C-CORE's tests)	ML - short term H - longer term	Larger area failures than those achieved in the C-CORE project are important. PERD's transportation group is now involved with new R&D initiatives in this area (1).
	Iceberg statistics	Data collection to improve iceberg statistics (occurrence frequencies, masses, shapes & speeds) for probabilistic iceberg impact load analyses	M	This will be an ongoing part of industry's current & future operations on the Grand Banks, but enhancements are possible (2). Close cooperation with industry will be required here.
Tankers				
	Ice strengthening requirements	Continued measurements of ice failure pressures over large areas (eg: follow-up to C-CORE's tests)*	MH	Comments as above in (1).
		Instrumented ship impact tests with growlers and bergy bits (eg: dedicated trials with the Terry Fox icebreaker)*	H	Also an initiative being considered within PERD's transportation group, as a longer term item to consider for support in 1998 as a JIP.
	Small ice mass statistics	Data collection to improve small ice mass statistics (occurrence frequencies, masses, shapes & speeds), and better understand their genesis, deterioration and lifespans*	H	Comments as above in (2).
	Iceberg detection	Continued R&D to improve "on-demand" iceberg detection methods and assess their reliability and limitations, with emphasis on small ice masses (eg: follow-up to the 1995 ESRF study)*	VH	Remote sensing R&D and evaluations from the Hibernia GBS could be supplemented, but this is outside of ISIAC's scope.
	Iceberg management	R&D to improve iceberg management methods and their reliability (to support tanker loading operations), with emphasis on small icebergs and bergy bits*	H	Close cooperation with operators will be required here.
	Loading operations in pack ice	An evaluation to assess the practicality and limitations of tanker loading operations in pack ice, and the benefits of ice management support*	M	Use of full scale experience with in-ice operations in other areas is important here, such as that documented in a recent Arctic Tanker Loading JIP study supported by PERD.

* these R&D needs are also relevant to the floating development scenario.

A key question for the fixed development scenario is whether or not a GBS platform can be designed for the Grand Banks area that is relatively low in cost, easy to construct, and will perform in a safe and effective manner. This consideration is largely driven by the magnitude of the iceberg impact design load that is selected. If low cost GBS platforms can be developed for the area (like the SSGP concept), then a variety of other benefits would accrue, including lower development drilling costs, eliminating the requirement for extensive subsea facilities, and less potential production downtime compared to floating systems. All of these factors would have the run-on effect of enhancing the economics of a project.

Although there are opportunities and incentives to further optimize fixed platform designs, this is not seen as priority in the short term. Most of the prospective oil fields on the Grand Banks are not very large, and conventional wisdom, combined with project economics, now favour the use of potentially lower cost floating development systems. Before too much effort is taken to optimize structure designs, it is clear that iceberg impact loads should be more reliably understood. In this regard, research related to global iceberg loads have been given a moderate priority in the short term and a higher priority in the longer term, particularly full scale observations of the iceberg/structure interaction process. It is clear that the presence of the Hibernia GBS platform provides an opportunity to carry out a research program of this nature. Some thought should be given to promoting this type of R&D initiative, but over the several years, once the Hibernia operation has become routine.

The importance of ice research relating to the tanker component of the fixed development scenario has also been recognized, and is of generic relevance to all Grand Banks systems. Related R&D will not have a large impact on project economics, but is of more importance from a risk and safety perspective. Research initiatives that are directed towards the issue of potential tanker collisions with small undetected ice masses during either transit or loading operations loads are key. In this regard, an improved knowledge of local ice impact loads and ice detection and management methods, particularly for small glacial ice features, are all of high importance.

Some research into the question of tanker loading operations in moving pack ice conditions is also warranted, because lengthy pack ice occurrences could result in significant production downtime on a fixed platform. Clearly, there will always be both operational and scheduling pressures to continue tanker loading operations in most ice conditions. However, this issue is of more importance for the more northerly areas of the Grand Banks where more pack ice can be experienced. It is also of more importance in terms of the economics of smaller oil field developments, where potential production losses in the first few years of a project would be less tolerable.

Floating Development Systems

The key ice issues and ice research needs for floating development systems are highlighted in Table 9.2, along with related priorities. The primary areas of consideration include:

- iceberg and small ice mass detection and management methods
- minimizing ice-related downtime levels
- FPSO and tanker hull strengthening requirements
- FPSO stationkeeping and tanker loading operations in pack ice
- iceberg scour risks and protection methods for subsea systems

For this type of development scenario, priority R&D initiatives should be directed towards minimizing risks, achieving a good balance between the potential for ice-related downtime and a system's tolerance to ice, and reducing some of the perceptions of risk that are associated with floating systems. It is also important to confirm, test and improve the technology that is being proposed and in the longer term, to develop novel design and operational approaches that can provide significant ice tolerance for these systems.

Potential collisions with icebergs that are too small to be detected and managed is the highest priority issue for floating development systems on the Grand Banks. This applies to both floating production vessels and export tankers. More information is needed on small ice mass occurrences and ice detection and management limits, to avoid overly conservative designs and operating procedures. In addition, current knowledge levels in these areas do not allow meaningful risk assessments, which are of high importance for technical decision making, safety and regulation. Since floating systems are the most likely means of development for small Grand Banks fields, R&D is required to better define small ice mass statistics, collision mechanics and load levels, and to improve detection and management systems. All of these research areas deserve higher priorities than any other topics. R&D initiatives that relate to improved iceberg forecasting methods are not identified here, because more research in this area is not seen as a priority need, due to the limited operational practicality of relying on iceberg trajectory forecasts.

Pack ice effects on floating production vessels and tanker loading operations are also an issue of concern. Since vessels have the flexibility to move off location and avoid severe pack ice conditions, this is not a safety issue. However, some Grand Banks areas can experience lengthy pack ice intrusions in poor years, and significant periods of production downtime could result. Because of this, research into the question of FPSO stationkeeping and tanker loading operations in moving pack ice conditions is also warranted. Since operators will rely ble 9.2:

Floating Development System Scenario

System Component	Ice Issue	R&D Needed	Relative Priority	Comments
FPSO Vessels & Tankers				
	Ice strengthening requirements	Continued measurements of ice failure pressures over large areas (eg: follow-up to C-CORE's tests)*	H	Larger area failures than those achieved in the C-CORE project are important. PERD's transportation group is now involved with new R&D initiatives in this area, but this a longer term JIP item.
		Instrumented ship impact tests with growlers and bergy bits (eg: dedicated trials with the Terry Fox icebreaker)*	H	Also an initiative being considered within PERD's transportation group. Again, a longer term item to consider for support in 1998 as a JIP.
	Small ice mass statistics	Data collection to improve small ice mass statistics (occurrence frequencies, masses, shapes & speeds), and better understand their genesis, deterioration and lifespans*	H	This will be an ongoing part of industry's current & future operations on the Grand Banks, but enhancements are possible. Close cooperation with indusry required.
	Iceberg detection	Continued R&D to improve "on-demand" iceberg detection methods and assess their reliability and limitations, with emphasis on small ice masses (eg: follow-up to the 1995 ESRF study)*	VH	Remote sensing R&D and evaluations from the Hibernia GBS could be supplemented, but this is outside of ISIAC's scope.
	Iceberg management	R&D to improve iceberg management methods and their reliability (to support tanker loading operations), with emphasis on small icebergs and bergy bits*	VH	Close cooperation with operators will be required here.
	FPSO stationkeeping and tanker loading operations in pack ice	An evaluation to assess the practicality and limitations of FPSO and tanker loading operations in pack ice, and the benefits of ice management support*	H	Use of full scale experience with in-ice operations in other areas is important here, such as that documented in a recent Arctic Tanker Loading JIP study supported by PERD.
Subsea Facilities				
	Iceberg scour risks and protection methods	An evaluation of current knowledge regarding scour risks, processes and protection methods for the Grand Banks, including uncertainties and required R&D directions*	H	Care should be taken to extend rather than duplicate recent work carried out by PetroCan for Terra Nova.
	Deep draft iceberg management	R&D to identify and develop feasible methods of managing large icebergs, including mass removal for draft reduction*	M	Similar work being considered for the North Atlantic Pipeline Project should be recognized here.

* these R&D needs are all relevant to the fixed and subsea development scenario.

Table 9.2:

more on remote sensing and ice edge tracking than on forecasts, additional research on ice edge forecasts is not a high priority item in this regard.

As part of any floating development system, extensive subsea facilities will be required, raising a variety of questions related to the potential for iceberg scour. The risk of damage to subsea systems needs to be predicted with a high degree of confidence. R&D to improve assessments of iceberg scour risk and the effects of different scour protection methods on risk is required. If scour protection is needed, then lower cost arrangements should be developed. These comments also apply to the R&D needs identified for the subsea development scenario, which are shown in Table 9.3.

9.2 Recommended R&D Initiatives

There are a number of key ice-related R&D thrusts that should be considered to support future Grand Banks oil field developments, including both short and longer term initiatives. Priority research directions that are recommended here are highlighted as follows.

Longer Term Needs

- *an improved understanding of small ice mass impact loads on floating vessels, and of global iceberg impact loads on fixed structures.*

  - R&D initiatives to address the question of small ice mass loads are already underway, and should be supported. Two key examples are the instrumented barge impact tests now being pursued by IMD as a follow-up to C-CORE's offshore Labrador field project, and controlled collisions of an instrumented hull (the Terry Fox icebreaker) with growlers and bergy bits. With reference to the IMD initiative and its objectives, any future field work should ensure that large area ice failures are achieved. With reference to a possible project with the Terry Fox, it is likely that only small area ice failures would be seen. However, this latter approach should be relatively inexpensive and quick to carry out, and would provide "real world results" for vessel collisions with small ice masses that would be very credible.

  - R&D initiatives to address the question of global iceberg impact loads should first focus on the full scale iceberg interaction process itself, because this is

Subsea Development Scenario

System Component	Ice Issue	R&D Needed	Relative Priority	Comments
Subsea Facilities				
	Iceberg scour risks and protection methods	An evaluation of current knowledge regarding scour risks, processes and protection methods for the Grand Banks, including uncertainties and required R&D directions	H	Care should be taken to extend rather than duplicate recent work carried out by PetroCan for Terra Nova.
	Deep draft iceberg management	R&D to identify and develop feasible methods of managing large icebergs, including mass removal for draft reduction	M	Similar work being considered for the North Atlantic Pipeline Project should be recognized here.

Table 9.3:

not well understood and will control the resultant load levels. Observations of small icebergs towed against the Hibernia GBS would be an invaluable first step in this regard.

Industry acknowledges the importance of these ice loading issues and is generally supportive of the need for related R&D work over the next few years. However, industry's present focus on floating developments for small to moderately sized Grand Banks oil field developments and the iceberg avoidance problem, in combination with the high cost of full scale ice load projects, tends to limit the current level of enthusiasm. R&D initiatives of this nature are more likely candidates for success in the longer term, when more momentum has built for various Grand Banks development opportunities, and cooperative industry funding and logistic support may be easier to come by. Smaller, more stepwise R&D initiatives that are directed towards several key ice issue areas in which little new work has been done since the 1980's (except within the Terra Nova Project) are considered to be better short term R&D choices.

Short Term Needs

- *an improved understanding of iceberg detection and management methods and their limits, particularly for small ice masses*

- *improved statistics on icebergs, particularly on small ice mass occurrences, sizes and geometries*

- *an improved understanding of the potential for FPSO stationkeeping and tanker loading operations in pack ice*

- *an improved understanding of iceberg scour risks and scour protection methods*

The need for these four short term R&D initiatives has been reviewed with various industry representatives, and the nature of the most immediate work requirements discussed. One of the criticisms expressed by industry about past R&D planning studies was that key research needs were identified in fairly general terms, but that specific studies were not suggested.

Here, recommended work scopes for these four short term ice-related research initiatives have been developed, and are provided in Attachment 1. These recommended studies are intended to be initial steps in pursuing high priority ice-related R&D directions that are important in terms of supporting future Grand Banks developments. The four work scopes have all been reviewed by industry representatives and, although there is general agreement with the R&D thrusts and their scopes, it was quite clear that different companies do not necessarily see the same relative priorities.

9.3 Communication & Collaboration

Although there was little activity on the Grand Banks from the mid 1980s to the early 1990s, the Hibernia project and PetroCanada's recent Terra Nova field development initiatives have prompted a strong and renewed level of industry interest in the area. Over the past decade, some ice-related research work has been carried out but often, these R&D efforts have not been well communicated and have been fragmented, with the exception of a few of the studies carried out by lead operators.

In the future, it is clear that good communication of PERD's ice-related R&D initiatives and their results will be important. In this regard, close cooperation with Grand Banks operators and other stakeholders is an important consideration, with a view to obtaining ongoing input and feedback, avoiding duplication and opening up avenues for R&D collaboration.

To ensure that PERD's R&D initiatives are well known and to promote the potential for collaborative R&D, the following range of actions should be considered.

- better communication regarding the R&D programs that have been and are now being carried out, through:
  - informal networking with key players, including the oil companies and active R&D groups like C-CORE and Memorial University's Ocean Engineering department. (the range of ice work being conducted within MUN's CODIE program is a good example).
  - periodic working group sessions with key Grand Banks stakeholders that do not involve formalized presentations of R&D results, but are more "hands-on" scenario based discussions

- pursuing opportunities for collaborative ice-related R&D projects with active Grand Banks operators who have offshore logistics support in place, as suggested in some of the work scopes that are outlined in Attachment 1

- recognizing possible R&D synergies with ice research needs in other regions of the world∗, and pursing opportunities to lever PERD funding.

∗ For example, FPSO stationkeeping and tanker loading operations in moving pack ice is an important consideration for potential developments in the Russian offshore, while scour risk assessment methods have become an important issue for new developments in the nearshore waters of the Alaskan Beaufort Sea.

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Abstract

Over the past several decades, the petroleum industry has carried out extensive exploration programs on the Grand Banks, which lies off the east coast of Newfoundland. To date, these efforts have resulted in a number of significant discoveries. This report is a R&D planning study regarding ice-related problems on the Grand Banks, primarily as they influence the development of the smaller oil fields that have been discovered in the area. The report provides the results of the study, and has the objective of identifying and priorizing ice-related problems for oil fields like Whiterose, Hebron and Terra Nova, along with associated R&D needs.

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