Decision 2001.01

November 26, 2001
St. John's, Newfoundland
Canada

Application for Approval

White Rose Canada-Newfoundland
Benefits Plan

White Rose Development Plan

Graphics were modified from originals provided by Husky Oil Operations Ltd.

ISBN: 0-921569-35-1

CANADA-NEWFOUNDLAND
OFFSHORE
PETROLEUM
BOARD

November 27, 2001

The Honourable Ralph Goodale
Minister of Natural Resources Canada
Government of Canada
580 Booth Street
Ottawa, ON
K1A 0E4

The Honourable Lloyd Matthews
Minister of Mines and Energy
Government of Newfoundland and Labrador
P.O. Box 8700
St. John's, NF
A1B 4J6

Dear Ministers:

The Canada-Newfoundland Offshore Petroleum Board has considered the White Rose Canada-Newfoundland Benefits Plan ("Benefits Plan") and the White Rose Development Plan ("Development Plan") submitted on January 15, 2001 by Husky Oil Operations Limited on behalf of itself and Petro-Canada.

As you are aware the Board has taken a decision to approve the Benefits Plan, subject to conditions described in the attached report, in advance of a decision on the Development Plan. We thank you and your officials for worthwhile contributions during consultation on the Benefits Plan. Our decision to approve the Development Plan, subject to conditions described in the attached report, is a fundamental decision which is hereby submitted to you for your consideration.

On behalf of the Board, I am pleased to submit herewith our report setting forth the Board's approvals in respect thereto.

Respectfully submitted,

H.H. Stanley
Chairman and CEO

Fifth Floor, TD Place, 140 Water Street, St. John's, Newfoundland, Canada. A1C 6H6
Telephone (709) 778-1400 Telecopier (709) 778-1473

Decision 2001.01
Table of Contents

CHAPTER 1: DECISION SUMMARY

1.1 INTRODUCTION

This report constitutes the decision of the Canada-Newfoundland Offshore Petroleum Board (the Board) concerning the application by Husky Oil Operations Limited and its partner (the Proponent) for approval of its plans for the development of the White Rose oil field (the Development). In March 2000, the Proponent submitted a Project Description to the Board. This submission initiated the federal environmental assessment process under the *Canadian Environmental Assessment Act* (CEAA). In October 2000, the Proponent filed a Comprehensive Study Report and after thorough review, the Federal Minister of the Environment accepted the Comprehensive Study Report on June 11, 2001. As required by the Accord Acts[*], the Proponent has submitted both a White Rose Canada-Newfoundland Benefits Plan (the Benefits Plan) and a White Rose Development Plan (the Development Plan) along with other documents in support of its Application. The Board is required under the Accord Acts to approve the Benefits Plan before approving the Development Plan.

In considering these plans, the Board appointed a Public Review Commissioner under the Accord Acts. The Commissioner held public meetings and provided a report containing 32 recommendations. The Board considered these recommendations and consulted relevant Government departments and agencies as it developed its decision regarding the Application.

The Board has approved both the Benefits Plan and the Development Plan subject to the conditions set out in this Decision Report.

1.2 THE WHITE ROSE CANADA-NEWFOUNDLAND BENEFITS PLAN DECISION

The Accord Acts contain provisions designed to ensure that the resources off the coasts of Newfoundland & Labrador (the Province) are developed in such a way that benefits accrue to Canada and in particular to the Province. Two fundamental principles are embodied in the Accord Acts for this purpose. The first requires that Canadian enterprises and individuals be provided a full and fair opportunity to participate in the supply of goods and services to offshore oil and gas activities with first consideration being given to those located within the Province provided they are competitive in terms of fair market price, quality and delivery and the second requires that first consideration for training and employment be given to residents of the Province.

[*]Canada-Newfoundland Atlantic Accord Implementation Act, S.C. 1987, c.3 and the Canada-Newfoundland Atlantic Accord Implementation Newfoundland Act, R.S.N. 1990, c.C-2. Where specific references are made in this Report to the Act, they are to the Act shown first in this footnote.

The Proponent has presented a Benefits Plan which addresses these principles.

The Board's assessment of the Proponent's Benefits Plan was guided by the requirements of the Legislation* in the five areas noted below.

Office in the Province
The Proponent opened its East Coast Regional Office in St. John's in November 1997. This office is described as being responsible for managing all operational aspects of the Proponent's programs on the Grand Banks. The Board is generally satisfied that the organization established by the Proponent has appropriate levels of decision making to manage the construction and operation of the Development.

Employment
The Board recognizes there are two distinct phases of the activity associated with the White Rose Development, the project and operations phases, each of which offers different types of employment opportunities. The project phase provides an opportunity for the employment on a short-term basis of a workforce skilled in engineering, fabrication and construction. The operations phase provides more lead time for training personnel with the requisite basic skills and offers opportunities for long-term employment. As a condition of its approval, the Board requires the Proponent to address the human resources needs of both phases of the Development. This Human Resources Plan will outline participation in the Development by Canadian and Newfoundland & Labrador residents.

The Board is generally satisfied that the Proponent's employment-related policies meet the requirements of the Legislation for the employment of Canadians, and in particular residents of the Province, in all phases of the Development.

Research & Development and Education & Training
The Legislation requires expenditures for research and development and education and training in the Province. The Board will establish parameters, criteria, and target levels for such expenditures. It is a condition of approval that the Proponent submit a plan to the Board that will address the statutory obligation for expenditures in this area.

Goods and Services
It is the Board's assessment that, overall, the policies and procedures related to the acquisition of goods and services for the Development, described in the Benefits Plan, are consistent with the statutory requirements to give full and fair opportunity to Canadian suppliers and first consideration to goods and services provided from within the Province. Nevertheless, the Board has attached several conditions to its approval in the areas of: contractor/subcontractor obligations, reports concerning contracting activity, forecasts of Development activity, competitive markets in Canada and the Province, and bid evaluation.

---

*In this Report, Legislation means either the Accord Acts or the Regulations thereunder, or both.

Disadvantaged Individuals and Groups
As a condition of approval, the Board requires the Proponent to submit a report for approval by the Board describing its approach to affirmative action as contemplated in section 45(4) of the Legislation. The report should include specific initiatives.

Monitoring and Reporting
An important factor governing the procedures for monitoring and reporting is the need for the Board, Governments and the public to know and understand the nature and level of economic activity associated with the Development that is occurring in Canada and in the Province. The Board also has an obligation as the regulator to ensure that the Proponent's commitments are met. To this end, the Board has attached a number of conditions to its approval with respect to reporting.

It is the decision of the Board that the White Rose Canada-Newfoundland Benefits Plan is approved subject to the conditions set out herein.

1.3
THE WHITE ROSE DEVELOPMENT PLAN DECISION

The White Rose Development Plan sets out the Proponent's interpretation of the geology and reservoir characteristics of the White Rose oil field, provides estimates of hydrocarbon reserves, describes the approach and facilities the Proponent plans to use to recover those reserves, and includes a description of the environmental parameters governing the design of facilities.

The Board's responsibility in reviewing this plan is to ensure that hydrocarbons are produced in accordance with good oil field practice with due regard for the efficient recovery of the resource and the prevention of waste; that the facilities are designed to operate safely throughout the expected life of the field; that a responsible approach is taken to environmental protection; and, that the safety of personnel is a primary consideration at all times.

The Proponent proposes to develop the South Avalon oil pool using a steel Floating Production Storage Offloading vessel (FPSO) in conjunction with seabed completions. The design rate is 15 900 m^3/d (100,000 bopd).

The Board's overall response to the Development Plan has been positive. The work submitted by the Proponent was judged to be thorough and comprehensive, and the concepts, approaches, and preliminary designs have been accepted. This initial approval will be followed by more detailed analyses as plans evolve and other specific approvals by the Board are required for the execution of various components of the actual work. Det Norske Veritas has been appointed as Certifying Authority for the Project and will conduct such reviews of the design and surveys of the construction of the facilities as are necessary to enable it to issue a Certificate of Fitness attesting that the facilities have been designed in compliance with the applicable Legislation and are suitable for their intended purpose.

Conservation of the Resource

The White Rose field is located on the eastern margin of the Jeanne d'Arc Basin and comprises several fault bounded blocks and hydrocarbon pools. The presence of hydrocarbons in several of the major fault blocks has been confirmed by the exploration and delineation drilling. The Proponent proposes to develop the oil reserves contained in the South Avalon pool and in later years, to augment this production with oil production from the North and West Avalon pools and natural gas, provided it is economically viable to do so.

The Board believes the Proponent's Development Plan is appropriate given the present state of knowledge of the resource but has established several conditions to its approval of the portion of the Development Plan concerned with the conservation of the resource.

Safety of Operations

The Board has considered the safety of the production system as a whole and its components, including its structures, facilities, equipment, operating procedures and personnel.

The Board has several conditions on its approval including those related to: requirement for a Safety Plan with each application for a development work authorization; requirement for the development and documentation of detailed operations procedures; requirement for the submission of a training proposal with respect to individuals employed on the FPSO and support craft; disconnect procedures; demonstration that the best practicable evacuation technology will be used on the production and drilling installations; and approval for the configuration of the support vessel fleet and specification for standby vessels prior to contracting for these vessels.

Protection of the Environment

Through the required approval of the Proponent's Environmental Protection Plan and its associated Environmental Effects Monitoring Plan, the Board will ensure that the facilities are operated in an environmentally safe manner. All routine discharges from the platform will be required to meet regulatory standards. The Board has attached several conditions to its approval to ensure the adherence to existing environmental standards. Conditions include those related to: greenhouse gas emissions; production discharges; chlorine use; and the injection of produced water.

It is the decision of the Board that the White Rose Development Plan is approved subject to the conditions set out herein.

CHAPTER 2: INTRODUCTION

2.1 INTRODUCTION

Proponents of development projects in the Newfoundland Offshore Area are required, under the *Canada-Newfoundland Atlantic Accord Implementation Act* and the *Canada-Newfoundland Atlantic Accord Implementation Newfoundland Act*, to obtain approval of development plans for projects offshore Newfoundland and Labrador from the Canada-Newfoundland Offshore Petroleum Board (the Board). Before approving a Development Plan, the Board must have approved a Canada-Newfoundland Benefits Plan for the development project.

This Report (Decision 2001.01) sets out the Board's decision with respect to the White Rose Development Application (the Application), comprising both the White Rose Canada-Newfoundland Benefits Plan and the White Rose Development Plan. The Board's approval is subject to conditions set out in this Report.

The conditions to the Board's approval should be read in the context of the supporting narrative regarding the manner in which the Proponent has proposed to carry out the White Rose Development. The Board's judgment of the Proponent's compliance with its undertakings and with the conditions which the Board has established will be made in consideration of the narrative.

2.2 THE HISTORY OF THE WHITE ROSE PROJECT

The White Rose field was discovered in 1984 by the drilling and testing of the Husky et al Whiterose N-22 exploratory well. Following the initial discovery, eight additional wells were drilled to define the structure and three seismic surveys (including the main PGS 97 3-D survey shot in 1997 and used extensively) were conducted. The wells and seismic surveys helped to confirm the presence of significant quantities of oil in the Avalon Formation.

The White Rose Significant Discovery Area consists of both oil and gas accumulations, including those in the South Avalon pool, the North Avalon pool, the West Avalon pool and the Hibernia Formation, the Eastern Shoals Formation and the South Mara member of the Banquereau Formation. The White Rose Development focuses on the South Avalon pool which in the Proponent's estimation covers approximately 40 km^2, and contains an estimated 36 x 10^6 m^3 (230 million barrels) of recoverable oil at a 50 percent probability level (P50 reserves). The North and West Avalon pools are considered in the Application but are deferred developments. The Proponent's current estimates of potential recoverable P50 oil resources from the North and West Avalon pools total 12.8 x 10^6 m^3 (82 million barrels). If additional evaluation determines that economically recoverable reserves exist in the North and West Avalon pools, the Proponent intends to tie these pools into the White Rose oilfield development infrastructure, thus extending the production plateau. The exploitation of gas resources is not proposed in the Application.

At present, the White Rose Significant Discovery Area incorporates thirteen Significant Discovery Licences (SDL) with two different interests (Table 1). The average non-weighted interests in the White Rose Significant Discovery Area are as follows:

Husky Oil Operations Ltd.	77.1 percent
Petro-Canada	22.9 percent

Table 1: White Rose Significant Discovery Licences

Relevant Discovery	Relevant Licence	Current Hectarage	Interest Holders (* Representative)	Percent Interest	Effective Date
Whiterose N-22	SDL No. 1018	1 062	Husky Oil Operations Ltd.* Petro-Canada	90.00 10.00	February 16, 1990
Whiterose N-22	SDL No. 1019	1 416	Husky Oil Operations Limited* Petro-Canada	90.00 10.00	February 16, 1990
Whiterose N-22	SDL No. 1020	1 062	Husky Oil Operations Limited* Petro-Canada	90.00 10.00	February 16, 1990
Whiterose N-22	SDL No. 1021	708	Husky Oil Operations Limited* Petro-Canada	72.50 27.50	February 16, 1990
Whiterose N-22	SDL No. 1022	708	Husky Oil Operations Limited* Petro-Canada	72.50 27.50	February 16, 1990
Whiterose N-22	SDL No. 1023	353	Husky Oil Operations Limited* Petro-Canada	90.00 10.00	February 16, 1990
Whiterose N-22	SDL No. 1024	1 767	Husky Oil Operations Limited* Petro-Canada	72.50 27.50	February 16, 1990
Whiterose N-22	SDL No. 1025	5 648	Husky Oil Operations Limited* Petro-Canada	72.50 27.50	February 16, 1990
Whiterose N-22	SDL No. 1026	2 471	Husky Oil Operations Limited* Petro-Canada	72.50 27.50	February 16, 1990
Whiterose N-22	SDL No. 1027	1 765	Husky Oil Operations Limited* Petro-Canada	72.50 27.50	February 16, 1990
Whiterose N-22	SDL No. 1028	12 355	Husky Oil Operations Limited* Petro-Canada	72.50 27.50	February 16, 1990
Whiterose N-22	SDL No. 1029	2 824	Husky Oil Operations Limited* Petro-Canada	90.00 10.00	February 16, 1990
Whiterose N-22	SDL No. 1030	1 412	Husky Oil Operations Limited* Petro-Canada	90.00 10.00	February 16, 1990

Note: as of October 5, 2001

The South Avalon pool, located only in the southern part of the Significant Discovery Area, may extend onto Exploration Licence 1045, which is held by Husky (70 percent) and Petro-Canada (30 percent).

2.3 A DESCRIPTION OF THE WHITE ROSE PROJECT

The Proponent proposes to develop the White Rose oilfield, using subsea wells in conjunction with a steel Floating Production Storage Offloading vessel, which in the Proponent's assessment represents the most economically viable way to develop the field.

The White Rose field is located approximately 350 km east of St. John's, on the eastern edge of the Jeanne d'Arc Basin. The South Avalon oil pool, which contains most of the oil reserves, is in an area where the water depth ranges between 115 and 130 meters. The total recoverable oil resources in the field are estimated, and expressed at a 50 percent probability level by the Board, to be $45x10^6$ m^3 (283 million barrels). Most of the hydrocarbons contained in the Avalon Formation, pressure measurements and fluid contacts indicate that the oil and gas accumulation in the Avalon Formation is divided into three separate pools, each with an associated gas cap: the South Avalon pool, the North Avalon pool and the West Avalon pool. The E-09 well, drilled in 1987-88, encountered over 90 meters of net oil pay in the South Avalon oil pool. The main Avalon reservoir is a sequence of clean, fine to very fine grained sandstones that were deposited about 110 million years ago in the Early Cretaceous. The South Avalon pool will be developed first. The Proponent has stated that if additional evaluation determines that economically recoverable reserves exist in the North and West pools, then the Proponent intends to ultimately tie these pools into the White Rose oilfield development infrastructure, thus extending the production plateau. This would occur approximately 4 to 5 years into the production life of the field. In terms of natural gas, the Board estimates, at a 50 percent probability, that the field contains recoverable resources of $76.7x10^9$ m^3 (2.7 tcf). The Proponent estimates that the field contains 50.8 $x10^9$ m^3 (1.8 tcf). As noted earlier, the Proponent does not propose in the Application to exploit the natural gas resources.

Development of the White Rose oilfield will include development drilling and the engineering, procurement, construction, modification, installation, commissioning and operation of a FPSO and associated facilities. The crude oil will be delivered to market using shuttle tankers either directly or via a transshipment facility.

The Proponent evaluated eight production system concepts for the Development, including a Gravity Base Structure (GBS). The Proponent's most recent estimates indicate the cost of a GBS-based field development ($3.2 billion CDN) exceeds that of the proposed FPSO-based development by approximately $1.1 billion. The Proponent has concluded that the steel FPSO is the most economically viable way to develop the White Rose field. The Proponent has chosen to develop the field using a new-build, steel FPSO moored by means of a disconnectable turret. The vessel will be based upon a tanker design.

Wells will be drilled from one or more semi-submersible drilling units. The depletion plan calls for 21 wells (eight horizontal production wells, six deviated water injection wells, five horizontal water injection wells, and two deviated gas injection wells). To maximize oil production, reservoir pressure will be maintained by injecting water into the 11 strategically placed wells. Produced gas will be conserved by re-injecting into the northern part of the field.

Current planning anticipates four production wells, five water injection wells and one gas injection well will be drilled and tied in before first oil production. As currently foreseen, drilling would continue over a two-year period after first oil until the reservoir is fully developed. Ongoing reservoir management may require further production optimization wells in the pool over the life of the Project.

Wells are presently expected to be tied into subsea manifolds with flowlines and connected to the FPSO through flexible marine risers. It is anticipated that gas lift will be the artificial lift method used to optimize oil production later in the life of the field. Provisions for gas lift equipment will be included in the initial completion design of the wells.

The peak production design capacities for the FPSO are: oil production of 15 900 m^3/d (100,000 bopd); water production of 28 000 m^3/d (180,000 bpd), and gas production (including lift gas) of 4.2×10^6 m^3/d (148.3 mmscf/d). To allow for system downtime, the average annual capacity is estimated by the Proponent to be 92 percent of these rates. At this efficiency, an average oil plateau rate of 14 628 m^3 /d (92,000 bopd) is expected for four years. An extended plateau period may be possible with development of the deferred resources from the West and North Avalon pools.

A typical subsea solution for floating production facilities consists of templates, manifolds, flowlines, umbilicals and risers. Projects on the Grand Banks also include some form of iceberg scour protection for their subsea installations. For the White Rose Development, the main method of iceberg scour protection will be glory holes, with the possibility of implementing other solutions at strategic locations to optimize field layout. It is anticipated that three or four drill centers located in glory holes will be required to access the oil reserves in the South Avalon pool.

The proposed schedule foresees the first shuttle tanker load of oil being produced in third quarter 2004. Depletion of the South Avalon pool reserves will take about 12 years.

2.4
THE BOARD'S AUTHORITY

In February 1985, the Governments of Canada and of Newfoundland & Labrador signed the Atlantic Accord which provided for the establishment of a joint-management regime respecting oil and gas exploration and development in the Newfoundland Offshore Area, including the formation of the Canada-Newfoundland Offshore Petroleum Board. Each Government enacted legislation to implement the Atlantic Accord.

Under the Legislation, before any development activity can proceed in the offshore area, the Proponent is required to submit for Board approval a Development Plan and a Canada-Newfoundland Benefits Plan. As part of the Board's review and approval process, the Accord Acts require the Board to conduct a public review of a Development Application unless the Board is of the opinion that it is not in the public interest to do so. The conduct of a public review is subject to any joint Ministerial directive which may be issued and to any terms of reference which may be established by the Board pursuant to the Legislation.

In addition to the Board's authority under the Legislation, the Board also has a responsibility under the *Canadian Environmental Assessment Act* (CEAA) to ensure that an environmental assessment of any proposed development is conducted.

2.5
THE BOARD'S DEVELOPMENT APPLICATION GUIDELINES

To assist Proponents of offshore hydrocarbon development projects in preparing development applications, the Board published, in 1988, its *Development Application Guidelines: Newfoundland Offshore Area* which describe the information required by the Board to process a development application and the review process followed in considering such an application.

The Guidelines specify that for all development applications three basic documents should be submitted by the Proponent:

- a Development Plan;
- a Canada-Newfoundland Benefits Plan; and,
- a Development Application Summary.

The Guidelines also provide for the submission of a Socio-Economic Impact Statement and an Environmental Impact Statement in the event the Board should determine that such documents are necessary to carry out a comprehensive review of the development application.

2.6
THE APPROVAL PROCEDURE FOR THE WHITE ROSE PROJECT

The Board informed the Proponent of the White Rose Project, early in the planning stages of the Project, that a public review of the proposed development of the White Rose oil field would be required to complement its own internal review.

The Proponent submitted in March 2000 the "White Rose Oilfield Project Description". The submission of this document to the Board initiated the federal environmental assessment process under the *Canadian Environmental Assessment Act* (CEAA) and the Development Application review process under the Accord Acts.

In October 2000, the Proponent filed the "Comprehensive Study Report" required under the CEAA. This Report describes the Development and its potential environmental effects, including cumulative effects. The White Rose Development Application was filed with the Board on January 15, 2001 and forwarded to the Public Review Commissioner appointed by the Board under the Accord Acts on March 16, 2001. The Board also forwarded the Development Application to several departments in the Governments of Canada and of Newfoundland and Labrador and conducted its own completeness and internal reviews as required by the Development Application Guidelines.

On June 11, 2001, the Federal Minister of Environment adopted the Comprehensive Study Report. The Commissioner began public review sessions on July 11, 2001 and submitted his report to the Board and Ministers in September 2001.

The response to the Commissioner's report and the results of the Board's internal review are reflected in this Decision Report.

2.7
THE WHITE ROSE DEVELOPMENT APPLICATION

The White Rose Development Application, which was filed with the Board on January 15, 2001, is composed of six main documents:

- Project Summary – an overview of all aspects of the plans to develop the White Rose field including engineering, economic, environmental and socio-economic considerations;
- Volume 1 Canada-Newfoundland Benefits Plan – a description of the Proponent's commitments and plans for the participation of Canadian, in particular Newfoundland and Labrador, businesses and the employment of Canadians, in particular residents of Newfoundland and Labrador, in the Development;
- Volume 2 Development Plan – a description of the reservoir depletion, development drilling, facilities, development and operating plans for White Rose;
- Volume 3 Environmental Impact Statement (Comprehensive Study Part One (issued October 2000)) – a description of the physical and biological environments of the White Rose area and the impacts of the Development on them;
- Volume 4 Socio-Economic Impact Statement (Comprehensive Study Part Two (issued October 2000))– a description of the socio-economic conditions in the predicted impact areas and the socio-economic impacts of the Development; and
- Volume 5 Safety Plan and Concept Safety Analysis.

The Proponent also filed with the Board numerous Part II documents which were used to prepare the White Rose Development Application.

The White Rose Oilfield Development Application Supplemental Report was submitted in March 2001 in response to information requested by the C-NOPB in a letter dated February 27, 2001. This information was requested after the Board had conducted its completeness review of the Development Application itself. Also, and in response to additional information requests from the White Rose Public Review Commissioner, Husky submitted a supplementary document in June 2001. The Commissioner had sought clarification on the differences between the use of a GBS and FPSO and had posed questions on the industrial benefits that will flow to Newfoundland & Labrador from the Development. The Board also received a July 4, 2001 letter from the Proponent's contractor, Maersk, outlining the proposed flow measurement and metering philosophy for the Project After the public review hearings, the Board received from the Proponent a letter dated October 16, 2001 concerning the White Rose South Avalon depletion plan updates; a letter dated October 17, 2001 concerning the facilities update; and, a letter dated October 18, 2001 concerning the Test Separator.

2.8
OTHER INFORMATION CONSIDERED BY THE BOARD

In addition to the information contained in the Development Application and supplementary submissions, the Board considered the following in its review of the Application:

- Report of the Public Review Commissioner for the White Rose Development Application;
- public review submissions and responses by the Proponent;
- the January 2001 Report of the C-NOPB and GSC about the resource potential of the Jeanne d'Arc Basin and surrounding area;
- papers from various NOIA Conferences;
- input of other Government Agencies; and,
- internal Board assessments.

The Commissioner's recommendations which are within the Board's jurisdiction and which pertain to the Board's decisions regarding the White Rose Canada-Newfoundland Benefits Plan or the White Rose Development Plan are addressed in this report.

The Board's staff also consulted with those departments and agencies of the Governments of Canada and of Newfoundland & Labrador having responsibilities related to offshore oil and gas activities. The advice and assistance provided by these parties in reviewing the Application contributed to the consideration of the Commissioner's Report and to this Decision Report. The Board intends to continue consultations with these departments and agencies as it carries out its regulatory duties with respect to the Project.

During its review of the Application, the Board's staff held discussions with the Proponent to clarify certain aspects of the Development Application.

CHAPTER 3:
THE WHITE ROSE CANADA-NEWFOUNDLAND BENEFITS PLAN DECISION

3.1
INTRODUCTION

The requirements for a Canada-Newfoundland Benefits Plan are set out in Section 45 of the Accord Acts. The White Rose Benefits Plan was the subject of public hearings as one part of the review process established for the overall White Rose Development Application. The White Rose Commissioner's Report contained a number of Benefits recommendations.

The Legislation establishes four broad areas of responsibilities for the Board. These are:

- **Resource Management**:
  To ensure maximum recovery of hydrocarbon reserves through the use of good reservoir management practice;
- **Safety**:
  To ensure that drilling and production installations are designed, constructed and operated in a manner that minimizes the possibility of injury to workers;
- **Environment**:
  To ensure that operations minimize any adverse impacts on the environment;
- **Economic Benefits**:
  To ensure that workers and businesses in Newfoundland & Labrador and Canada have an opportunity to participate in economic activity associated with the development and production of offshore hydrocarbon resources.

In the areas of Resource Management, Safety and Environmental Protection, the responsibilities of the Board, as set out in the Legislation, establish the Board's role as an Independent Regulator. In these three areas, the Legislation confers on the Board broad authority to regulate, monitor and seek remedies from offshore operators. This authority is similar to that given to other regulatory agencies in Canada, such as the National Energy Board, and the Alberta Energy and Utilities Board.

In the area of Economic Benefits, the Legislation does not confer any authority on the Board to require or set specific Newfoundland & Labrador or Canadian content targets. However, the Board is proactive with operators in seeking out Newfoundland & Labrador and Canadian suppliers and has been successful in ensuring that local content is a factor that operators take into consideration when selecting suppliers.

The public review of the White Rose Project and feedback the Board has received from other public sources suggest the Board should take a more central role in economic development activity. The Commissioner has made some recommendations in his report suggesting the Board make certain benefit achievements a condition of any approval of the White Rose Benefits Plan. The Board has not done so. This should not be interpreted as either disagreement or agreement on the Board's part with these recommendations made by the Commissioner. The Board has no authority to implement such recommendations. Therefore, this Benefits Plan Decision has not addressed these recommendations; other than to indicate where and how they fall outside the Legislation.

3.2
BENEFITS PROVISIONS OF THE ATLANTIC ACCORD LEGISLATION

The Commissioner's Report recommended [4.5][*] that the Board, after considering the Report, release a definitive statement as to how it interprets and applies the provisions of the Atlantic Accord and the Legislation. Part A of Chapter 3 of this Decision Report constitutes the Board's response to that recommendation by the Commissioner. It describes the Board's approach. Where that approach differs from the Commissioner's interpretation and/or approach, the difference is explained. For ease of reference, the Benefits provisions of the Accord Acts (section 45) have been reproduced as Appendix C to this Decision Report.

3.2.1
Atlantic Accord & Legislation – Interaction

The Legislation is based on the Atlantic Accord. Section 17(1) of the Accord Acts reads *"The Board shall perform the duties that are conferred or imposed on the Board under the Atlantic Accord or this Act"*. On this basis the Commissioner asserts the Board has the "responsibility and the primary authority" to ensure that appropriate economic Benefits are delivered to Newfoundland & Labrador and Canada; and that the Board has "exclusive jurisdiction", "very broad latitude" and "discretion" to determine the principles and substance of Benefits Plans.

The Board is cognizant of the Atlantic Accord, and of section 17(1) of the Act, which requires it to take the Accord into account. The Board has done this, and notes that in respect of benefits, both the Accord and the Legislation are essentially the same. Both require that Benefits Plans be designed to ensure that, for goods and services, opportunities are made available to Newfoundland & Labrador and Canadian participants. There is no requirement in the Accord or the Legislation that Benefits Plans be designed to ensure that economic Benefits are delivered to Newfoundland & Labrador and Canada. This is particularly the case for goods and services, which are subject to an overriding qualification relating to market competition.

The following table compares the provisions of the Accord and the Legislation for goods and services and employment. This comparison shows the similarities in respect of these categories of benefits; both are essentially the same. It is not possible therefore to use the Accord to broaden or enlarge the provisions of the Legislation.

[*] Square brackets are sometimes used in this Report to identify a recommendation by the Commissioner. The bracketed number corresponds to the Commissioner's recommendation.

Accord		Legislation
Section 51: The Legislation implementing the Accord shall provide … manufacturers, consultants, contracting and service companies in Newfoundland & Labrador and other parts of Canada with a full and fair opportunity to participate in the supply of goods and services …		Subsection 45(1): … Canada-Newfoundland Benefits Plan means a Plan … for providing manufacturers, consultants, contractors and service companies in the Province and other parts of Canada with a full & fair opportunity to participate on a competitive basis in the supply of goods and services. Note: Act adds "on a competitive basis".
Section 51: … The Board shall seek to ensure that first consideration is given to services provided from within Newfoundland & Labrador, and to goods manufactured in Newfoundland & Labrador, where such goods are competitive in terms of fair market price, quality and delivery ….		Paragraph 45(3)(d): First consideration shall be given to services provided from within the Province and to goods manufactured in the Province, where those services and goods are competitive in terms of fair market price, quality and delivery.
Section 51: … ensure that individuals resident in Newfoundland & Labrador are given first consideration for training & employment …		Paragraph 45(3)(b): … Individuals resident in the Province shall be given first consideration for training & employment …

3.2.2
Application of the Benefits Provisions of the Legislation

Section 45 of the Accord Acts contemplates five (5) categories of Benefits, as follows:

- office in the Province;
- employment & training;
- research & development and education & training;
- goods & services; and,
- opportunities for disadvantaged individuals or groups.

As will be seen, the Legislation is specific for certain categories of Benefits, leaving no latitude to the Board to determine how the Accord Acts should be interpreted. For other categories of benefits, latitude is left to the Board to set parameters and criteria for implementation.

3.2.2.1
Office in the Province

The statutory requirement with respect to the establishment of an office in the Province is as follows:

> **45(3)(a) … before carrying out any work or activity in the offshore area, the corporation or other body submitting the plan shall establish in the Province an office where appropriate levels of decision-making are to take place;**

This requirement is straightforward. It is intended to ensure that an operator establishes an office in the Province with appropriate decision making authority. For example, the Board would not consider any application for an exploration drilling, development or production activity from an operator who did not have an office with appropriate levels of decision-making in the Province.

3.2.2.2
Employment & Training

The statutory requirements related to the employment of Canadian and Newfoundland & Labrador residents are summarized by the following excerpts from the Legislation:

> **45(1) Canada-Newfoundland Benefits plan means a plan for the employment of Canadians and, in particular, members of the labour force of the Province…**
>
> **45(3)(b) … consistent with the <u>Canadian Charter of Rights and Freedoms</u>, individuals resident in the Province shall be given first consideration for training and employment in the work program for which the plan was submitted and any collective agreement entered into by the corporation or other body submitting the plan and an organization of employees respecting terms and conditions of employment in the offshore area shall contain provisions consistent with this approach;**

These requirements are intended to ensure that first consideration for employment opportunities arising from the conduct of exploration, development or production activity in the work program for which the Plan was submitted is provided to residents of the Province. For the purpose of administering these requirements, the Board relies on definitions established in other legislation as follows:

Canadian – A person who was born in Canada and who has not relinquished his/her Canadian Citizenship; or, a person who has been granted Canadian citizenship; or, a person who has been granted permanent resident (landed immigrant) status in Canada.

Newfoundland & Labrador Resident – A Canadian citizen (or landed immigrant) who meets the residency requirements of the Newfoundland & Labrador Election Act: i.e., a person who has resided in the Province for the immediately preceding six-month period.

In assessing employment plans associated with the work, the Board considers efforts by the Proponent and its contractors to recruit Newfoundland & Labrador residents and other Canadians for work outside of Canada on the Project. The Board also takes into consideration the duration of the work in reviewing employment plans associated with the conduct of the work.

Contractors proposing to use non-Canadian personnel in Canada must also satisfy the requirements of the *Canada Immigration Act*. The Board works closely with Human Resources Development Canada (HRDC) to ensure the requirements of the Immigration Act and the Legislation are observed.

The ‘first consideration’ provision of the Legislation clearly requires that the Proponent and its contractors look first to the Newfoundland & Labrador labour market to meet their human resource requirements. Employers have the right to establish, in advance of the recruitment process, the qualifications required of candidates for employment. However, the ‘first consideration’ requirement means that once the qualifications for a position have been established, a Newfoundland & Labrador resident who meets these qualifications must be given employment preference over non-residents.

The Proponent must further ensure that any collective agreement entered into respecting terms and conditions of employment shall contain provisions consistent with the first-consideration provisions for employment and training. In discharging its responsibilities in this area, the Proponent must identify its labour requirements in a timely manner and make provision for the training and upgrading of Newfoundland & Labrador residents to become qualified for the employment opportunities arising from the Project. The Proponent and its contractors must develop systems and maintain detailed records of their recruitment and staffing activities to demonstrate to the Board that their decisions are consistent with the requirements of the Legislation. Human Resource Plans must be available for Board review within a reasonable period after project approval and/or sanction, and periodically during the life of the Project.

Safety is always a consideration. In some cases, a candidate may have the qualifications, but not the necessary work experience with specialized processes or equipment. In these instances, safety becomes the determining factor. For longer-term activities, a “shadowing” approach is often required whereby residents otherwise meeting the qualifications are given an opportunity to acquire the experience and eventually progress into the position. For short-term activity, this approach is usually not feasible.

3.2.2.3
Research & Development and Education & Training

The statutory requirement for expenditures related to research and development and education and training in the Province is as follows:

> **45(3)(c) … expenditures shall be made for research and development to be carried out in the Province and for education and training to be provided in the Province;**

Since the Legislation simply requires that expenditures be made for these purposes in the Province, latitude is left to the Board to establish parameters and criteria for such expenditures.

This statutory requirement is intended to ensure that the Proponent describes its plans and financial commitments to research & development and education & training in the Province. The amount of financial contribution in this area is expected to be consistent with national norms for such expenditures by the private sector. For the development phase, such norms might include the national average level of such expenditures by the private sector as a percentage of capital investment. For the operations phase, it might include the national average level of expenditures by the private sector as a percentage of revenue. While the expenditures must be "in the Province", Canada Custom and Revenue Agency criteria could be used as a guide to eligible expenditures. Expenditures for research & development and education & training are viewed by the Board to be strategically important contributions to the growth and development of the research and development and education and training capacity in the Province.

3.2.2.4
Goods and Services

The statutory requirements related to the provision of goods and services are contained in the following excerpts from the Legislation:

> **45(1) Canada-Newfoundland Benefits Plan means a plan ... for providing manufacturers, consultants, contractors and service companies in the Province and other parts of Canada with a full and fair opportunity to participate on a competitive basis in the supply of goods and services used in any proposed work or activity referred to in the Benefits plan.**
>
> **45(3)(d) First consideration shall be given to services provided from within the Province and to goods manufactured in the Province, where those services and goods are competitive in terms of fair market price, quality and delivery.**

For goods and services the Legislation affords no scope for latitude on the Board's part as to how it should be implemented. The Legislation requires that a plan be presented which prescribes a competitive process. It does not contain any authority to establish local content targets, or to require the Proponent to establish such targets. Further, the Legislation makes no provision for specific remedies in the event the Proponent fails to follow-up on a commitment it has made.

The Board has always acted on the basis that, for the provision of goods and services, section 45(1) of the Legislation defines a Benefits Plan as *"a plan ... for providing manufacturers, consultants and contractors and service companies in the Province and other parts of Canada with* ***a full & fair opportunity to participate on a competitive basis in the supply of goods and services*** *..."*. (Emphasis added). Despite a widespread public perception to the contrary, this provision cannot be enlarged or interpreted to ensure that any specific level of economic benefits are delivered in the domestic economy. It directs that a full and fair opportunity to participate based on a competitive process be assured to Newfoundland & Labrador and Canadian entities.

This approach is reinforced and elaborated by paragraph 45(3)(d) of the Legislation which requires that *"****first consideration*** *shall be given to services provided from within the Province, and to goods manufactured in the Province****, where those services and goods are competitive in terms of fair market price,***

quality and delivery". (Emphasis added). Again, the Legislation is clear. For goods and services, it stipulates that where they are competitive in terms of fair market price, quality and delivery, first consideration will be accorded for services supplied from, and goods manufactured in, Newfoundland & Labrador.

In summary, the Legislation specifies a process and the right of Newfoundland & Labrador and Canadian businesses to participate on a competitive basis; it does not specify any particular outcome of that process.

The Board views this legislative direction as prescriptive. Accordingly the Board is not able to accept a widely held view that it has broad latitude and discretion to determine the outcome of Benefits Plans in respect of the provision of goods and services, especially the establishment of specific Benefits targets.

In a discussion of project economics, the Commissioner asserts that the project rate-of-return is higher and has more upside potential than indicated in the Development Application. On this basis, the Commissioner concludes that the Proponent can undertake early gas delineation drilling, pre-invest for gas production and implement "pro-active" Benefits programs.

The Commissioner's observations in respect of gas delineation wells and pre-investment for gas production are dealt with in the Development Plan Decision Report. The issue at hand is the Commissioner's view as to the relationship between the marginality or viability of a project and "Benefits".

In respect of "Benefits", the provisions of the Legislation are indifferent to the marginality or viability of a project. If a developer chooses, for whatever reasons, to proceed with a project which has a low rate-of-return, section 45, the Benefits provisions of the Legislation, would apply to that project in exactly the same manner as to a project which has a high rate-of-return. There is no scope in the Legislation to vary the application of section 45 on the basis of a project's rate-of return. Accordingly, section 45 does not raise any requirement to assess the economics of a project. In the Board's overview of any project, the standards on which a project are judged will not be altered on the basis of the profitability of the project. It is the Board's view that a common high standard must be met by all projects, notwithstanding the economics.

The Commissioner's Report states that competition should not be interpreted to mean the lowest price resulting from an international bidding process, and that such an interpretation is not consistent with the objectives of the Legislation.

One conclusion emerging from this reasoning is that bidding would be restricted to Canada and Newfoundland & Labrador. The Legislation require a full and fair opportunity for businesses in Newfoundland & Labrador and Canada to participate in a competitive process. If it was intended that the process be restricted to the domestic market, such language in the Accord and Legislation would be redundant. But the language is there, and this can lead only to a conclusion that there was not an intent to limit the competitive process to the domestic market.

It is noteworthy that for the Terra Nova Project the Benefits Agreement negotiated by the Government of Newfoundland & Labrador contained a provision that Benefits be subject to an internationally competitive bidding process. Also, the Terra Nova Panel Report noted such an international policy had been an explicit part of Newfoundland & Labrador policy dating back to 1977. The Terra Nova panel concluded that *" ... it is a policy that makes economic sense*". The Terra Nova panel also observed on this issue *"... to be successful, the skills developed in Newfoundland & Labrador, the **quality** of work and the **price** at which the products can be delivered **must be at least equal to, but preferably better than, that offered by competitors.**"* (Emphasis added).

The Commissioner's Report notes that in an international bidding process suppliers from some countries may benefit from subsidies, and therefore the competition may not be fair. This could happen. However, the Board notes that such matters are covered by competition laws and by international trade agreements, all of which have elaborate and well-developed appeal and tribunal processes to which an aggrieved Canadian supplier may resort. These are the appropriate processes in Canada for handling instances of unfair competition, whether that competition is international or domestic.

During the public hearings many expressed the view that "local content" must be one of the evaluation criteria in the bid selection process. This implies an extra margin or advantage, which would be applied to a domestic bid over a foreign bid, i.e., a local preference policy.

As already noted, there is no provision in the Legislation for such an approach. The Terra Nova panel observed that domestic bids should be **at least equal** to foreign bids. The Legislation does require first consideration for services provided from within the Province, and to goods manufactured in the Province; a process which can be defined by the "at least equal" criterion. As well, in those instances where it can be demonstrated that a competitive market exists in Newfoundland & Labrador for the supply of a good or service, the first consideration provision may result in a competition limited to the Newfoundland & Labrador market.

It is not accurate to say that local content is never a criterion used in the bid selection process. In some cases, it can become the most important criterion for the operator such as, for instance, in the case of frequent maintenance items; or, where the development of local capacity is central to the long-term servicing and development of the offshore industry.

The Commissioner's Report focuses on "targets" "quantifiable objectives" "specific goals" or "specific Benefits targets". The Report is somewhat ambivalent on this issue, emphasizing that "targets are not **quotas** … but rather **management tools**" (emphasis added). It goes on to say the targets would be the Proponent's own best estimates of what can be achieved in terms of Canada-Newfoundland Benefits, i.e., they would not be imposed. Nevertheless the Report recommends these estimates be expressed as *"... quantifiable objectives, of what Benefits the Proponent expects will be achieved ...".*

Targets, however worded, present difficulties because, in respect of goods and services, the Legislation precludes, via its prescription of a competitive process, the imposition of targets. It does not give the Board any scope or latitude to specify the achievement of defined outcomes.

This feature of the Legislation seems to be at the root of much of the concern expressed in the public hearings. There is a widespread misconception that:

- the Atlantic Accord intended some measure of "preference" for Newfoundland & Labrador/Canada goods & services; and
- the Legislation contains or prescribes a measure of "preference" for Newfoundland & Labrador/Canada goods & services.

This misconception is often expressed as a duty on the Board's part to maximize Newfoundland & Labrador/Canada content in projects. There was a clear consensus on this in many of the presentations during the public hearings. But, as has been noted, the Legislation is prescriptive in this area; and is prescriptive in a manner which precludes consideration of preference and any requirement for content targets. Not only is there no legislative obligation to introduce such a local preference policy, the wording of the Legislation prevents the use of requirements which would have that effect. The Legislation prescribes a <u>competitive</u> process.

Where the legislative prescription is so clear, there is generally no need to look to other documents to assist with its interpretation. However, as noted earlier, both the Accord and the Legislation are essentially the same on these points. Neither contains any reference to **maximizing** Benefits. Both specify "first consideration" for services provided from, and goods manufactured in Newfoundland & Labrador where they are **competitive**. The Accord and the Legislation are similar on these points.

Notwithstanding the clear wording in both the Accord and the Legislation, the Board works with operators to ensure that goods and services are sourced from Newfoundland & Labrador and Canada to the maximum extent possible. With respect to the statutory requirements governing the provision of goods and services, the Board expects the Proponent to apply the following general principles in making its decisions related to the procurement of goods and services:

- for products and services normally acquired on an international competitive bidding basis, potential Newfoundland & Labrador and Canadian suppliers will be given a full and fair opportunity to participate in the procurement process. While the statutory requirements do not afford Canadian and Newfoundland & Labrador suppliers an unfettered right to bid, the Board expects that domestic suppliers who have expressed an interest will be given an opportunity to qualify to bid; and, if successful, a full and fair consideration in the bidding process. The Board accepts that the Proponent has the ability to limit the number of vendors invited to bid through a prequalification process, and that it would be unfair to expose vendors to the costs of preparing a bid where they have already been assessed to be unqualified to provide the required goods or services on the basis of quality and/or delivery criteria;

- the manner in which bids are packaged or structured can affect the ability of some suppliers to participate in the bidding process. This can be a particular problem for smaller suppliers. The Board expects the Proponent, to the extent reasonably possible, to structure and size its bid packages in such a manner that bidders in the Province have a full and fair opportunity to participate in the bidding process; and,
- where there is a sufficient number of qualified and competitive suppliers in the domestic market, the Board expects that the Proponent and its major contractors will normally limit the bidding process to that market.

In each procurement decision, the Proponent must ensure that 'first consideration' is given to Newfoundland & Labrador suppliers who are competitive in terms of fair market price, quality and delivery. In this regard, the Board considers fair market price to be the best price tendered by qualified vendors who have each been provided the same information regarding the Proponent's requirements, and with the same reasonable time in which to respond.

It is also important that in assessing the bids, the prices at which the goods and services were tendered by competing bidders be evaluated in an objective and unbiased manner. The Proponent and its contractors are expected to keep sufficiently detailed records to demonstrate to the Board that their procurement process and decisions are consistent with the requirements of the Legislation. The Board will audit the systems and procedures associated with the procurement process.

3.2.2.5
Disadvantaged Individuals or Groups

The statutory provision, which addresses the Board's obligations with respect to disadvantaged individuals or groups, is as follows:

> **45(4) The Board may require that any Canada-Newfoundland Benefits plan include provisions to ensure that disadvantaged individuals or groups have access to training and employment opportunities and to enable such individuals or groups or corporations owned or cooperatives operated by them to participate in the supply of goods and services used in any proposed work or activity referred to in the Benefits plan.**

A Benefits Plan is required to ensure that provisions are established to ensure disadvantaged groups and individuals have access to training and employment opportunities. In this context the provision of paragraph 45(3)(b) which stipulates that a collective agreement may not frustrate access to training and employment opportunities for residents of the Province, would apply equally to disadvantaged individuals.

Proponents are expected to be proactive in this regard in their plan. In the context of the plan disadvantaged groups and individuals are considered to include: women, aboriginal groups, persons with disabilities and members of visible minorities. The Proponent is expected to review and assess models such as the federal *Employment Equity Act* and other models as appropriate in preparing its action plans in this regard. Such plans will normally encompass affirmative action measures with an explicit objective to increase the participation of disadvantaged groups and individuals.

3.2.3 Monitoring and Reporting

In order to ensure that processes established in a Benefits Plan for a project are followed, the Board establishes comprehensive monitoring and reporting procedures with a proponent. These monitoring procedures include the review of contract procurement forecasts provided by a proponent, wherein a selection of contracts and procurements is identified and monitored.

This process includes a review of selected contracts and procurements at the prequalification, bid list and award stages. The Proponent also provides quarterly reports with respect to expenditures, all procurement and contracting decisions in excess of $100,000, along with comprehensive employment reports and an annual report. The Board will, in its monitoring and reporting procedures, require information which provides a cumulative assessment of Benefits Plan achievements. Section 119 of the Legislation places some limitations on the extent to which some of the information may be released. However, the Board will, in designing the monitoring and reporting procedures, take care to ensure to the fullest possible extent that all information in which there is a legitimate public interest will be reasonably available.

3.2.4 Conclusion

In the foregoing Part, which has been presented as a response to Recommendation 4.5 of the Commissioner's Report, the Board has explained the meaning and application of the Benefits provisions of the Legislation. These matters occupied a significant part of the White Rose Public Review process and the Commissioner's Report. In this context, the Board believes that a clear explanation of the meaning and application of the Benefits provision of the Legislation will be useful to participants in the industry, and will inform the broad public debate on the issue. It is the Board's view that clarity on the Benefits provisions of the Legislation is important for all who have a stake in the development of the offshore industry, including Governments, workers, the supply community and the offshore operators.

All participants in this dynamic, emerging, new sector of the Newfoundland & Labrador economy have a need to understand the extent, and the limitations, of these Benefits provisions. Such an understanding is essential to formulating a successful approach to participation in the industry. In several areas, this Benefits

Plan Decision has broken new ground. This is the case, for example, in the areas of research and development and education and training and opportunities for disadvantaged individuals or groups. Also, in the areas of goods and services and employment, the Board believes this Decision Report has provided definition and precision to the Board's view of the provisions of the Legislation.

The Board will proceed in the coming months to revise its Benefits Guidelines along the lines described in this document.

PART B: THE WHITE ROSE CANADA-NEWFOUNDLAND BENEFITS PLAN DECISION

3.3
THE WHITE ROSE CANADA-NEWFOUNDLAND BENEFITS PLAN DECISION

The Board's assessment of this Benefits Plan was guided by the requirements of the Legislation. Within the limits of the Legislation, the Board, as an integral part of its review of the Benefits Plan, has considered the recommendations of the Commissioner. The Commissioner's recommendations related to the Benefits Plan are shown in Appendix B. The conditions which the Board has attached are an integral part of the Benefits Plan approval. These conditions are listed in Appendix A.

It is the decision of the Board that the White Rose Canada-Newfoundland Benefits Plan is approved subject to the conditions in this Benefits Plan Decision Report.

> **Condition 1:**
> **It is a condition of this approval that immediately upon its Project Sanction decision, the Proponent advise the Board in writing of the date of that decision.**

3.3.1
Office in the Province

This section describes the Board's assessment of the Proponent's plans to satisfy the legislative requirement to establish an office in the Province where appropriate levels of decision making are to take place.

The Proponent opened its East Coast Regional Office in St. John's in November 1997. This office is described as being responsible for managing all operational aspects of the Proponent's programs on the Grand Banks. Personnel based in this office have decision-making authority for all operations, including procurement. Activities at this office will include project management, engineering, operations management, procurement, geosciences and reservoir engineering, drilling operations, logistics and project communications.

The Proponent has clearly stated that it is committed to managing the White Rose Project from St. John's with all decision-making authority consistent with normal corporate business practices taking place in this office. The importance of having decision-making and key management functions in the local office is critical to an ability to focus on Benefits issues, local capabilities and sensitivities to local concerns.

The Proponent states its determination to elevate Canada-Newfoundland Benefits to a distinct position in White Rose corporate culture. The Proponent will hold internal workshops to encourage employees and contractors in engineering and procurement to pursue methodologies that will encourage participation. The results of these workshops will be reported to the Board.

The Board is generally satisfied that the Proponent has established an organization in the Province with appropriate levels of decision making to manage the construction and operation of the White Rose Project. It is further recognized that this organization will evolve through the various phases of the Project.

3.3.2
Employment

This section describes the Board's assessment of the Proponent's plans to satisfy the employment requirements of the Legislation.

The Proponent has committed to ensure that full and fair opportunity is provided to Canadians and first consideration to Newfoundland & Labrador residents for employment and training. It is critical in this process that the Proponent ensure that any collective agreement entered into respecting terms and conditions of employment shall not contain provisions that are inconsistent with or frustrate the first-consideration provisions for employment and training in the Legislation, or its provisions concerning opportunities for disadvantaged individuals or groups. The Proponent, through the provision of a Human Resource Plan, will outline participation in the Project by Canadian and Newfoundland & Labrador residents. The Proponent further undertakes that its Human Resource Plan will:

- identify the minimum training standards for all staff in the Project;
- collaborate with Governments and training institutions to identify existing or anticipated skills gaps and shortages in the labour pool;
- provide technical advice to training institutions in development and/or revisions to trades training programs; and,
- develop expenditure estimates associated with training needs.

The Proponent also stated its commitment to the following:

- early identification of human resource needs, including analysis of the need for foreign workers;
- pre-start-up training for key offshore personnel;
- specific offshore training in the Province;
- the use of existing training infrastructure in the Province; and,
- the use of Newfoundland & Labrador centres of excellence.

The Proponent stated clearly in its Benefits Plan the actions its contractors will put in place with respect to human resource planning activities. Also, contractor training will be subject to audit by the Proponent who will submit the results of these audits to the Board semi-annually, and will make them available on the White Rose website for public review.

The Board is generally satisfied that the Proponent's employment-related policies meet the requirements of the Legislation for the employment of Canadians, and in particular residents of the Province, in all phases of the Project.

3.3.2.1 Project Phase Employment

The Proponent cites that there is a high level of awareness within the federal government, provincial government, industry and training institutions, of the need to plan and prepare for future labour requirements. The Proponent indicates that, assuming there is no critical overlap between White Rose and other major projects, there will be no substantial shortage of Newfoundland & Labrador labour available to work on the Project.

The Proponent notes that conditions which dictate success of local staffing initiatives include:

- successful competitive bidding by Canadian and Newfoundland & Labrador facilities.
- competition for workers from other major projects.
- successful recruitment efforts by project contractors.
- a stable and equitable labour relations environment.

The Proponent states that the availability of qualified Canadian and Newfoundland & Labrador workers may be constrained by overlap with other major projects; and, to that extent it may be necessary to recruit foreign workers to meet this need.

The Board will monitor the contracting process during the construction phase with respect to employment of Canadian and Newfoundland & Labrador workers in the development to ensure that they adhere fully to the employment provisions of the Legislation.

3.3.2.2 Operations Phase Employment

The Proponent discusses human resource requirements for the producing operations phase of the Project and assesses that there should be no significant difficulties in meeting these requirements. The Proponent has stated its intention to provide a Human Resource Plan outlining participation by Newfoundland & Labrador engineers, geoscientists and other technical and non-technical disciplines, along with appropriate succession planning to maximize participation of Newfoundland & Labrador and other Canadian residents. The Board stresses the importance of thorough planning for employment in this phase of the development. It is the Board's expectation that this phase of employment will be given particular attention in the earlier noted Human Resource Plan.

Condition 2:
The Proponent submit to the Board, for approval, a comprehensive Human Resource Plan for the construction phase of the Project within 60 days of Project Sanction; and, for the operations phase, within one year of Project Sanction. These plans shall, among other items, include:

(i) hiring and training needs;

(ii) the time frame associated with employment opportunities for each phase; and,
(iii) estimates of expenditures associated with training requirements.

The Proponent shall report to the Board on the progress with respect to these plans on a regular basis as agreed with the Board. In both cases, the Proponent should provide reasonable and ample advanced notice to the Board of any anticipated requirements for foreign workers.

3.3.3
Research & Development and Education & Training

3.3.3.1
Research & Development

The Proponent has acknowledged that research & development (R&D) is an important component of its Canada-Newfoundland Benefits Plan for White Rose. The Proponent's support for R&D in the Province is described in the plan, and includes support for:

- The Centre for Cold Ocean Research & Engineering (C-Core);
- Memorial University Seismic Imaging Consortium (MUSIC);
- Newfoundland Environmental Industries Association (NEIA); and,
- Memorial University of Newfoundland (MUN).

To date, this support has included research in areas such as integrated ice management; subsea well iceberg prediction studies; seabird monitoring and donations of seismic information to Memorial University. Also, model tests for the White Rose FPSO were completed at the Institute for Marine Dynamics in St. John's earlier this year.

The Proponent has indicated its intention to continue to participate with other industry representatives in forums designed to identify R&D priorities which will advance the Province's offshore industry as a whole, and fit with the overall objectives of a sustainable petroleum economy. The Proponent has committed to conduct research workshops annually, which will result in a multi-year priority list and budget.

3.3.3.2
Education & Training

The Proponent acknowledges in its Benefits Plan the importance of education and training to the future of the oil and gas industry. Training requirements cover a broad spectrum from regulated industry health and safety requirements to skills development. The Proponent has committed to identify minimum training standards to staff all phases of the Project, and to collaborate with Government and training institutions to identify existing or anticipated skills gaps and shortages in the labour pool. Also, there is a commitment to provide technical advice to training institutions in the development and /or revisions to trades training programs.

In anticipation of the development and production stages of the White Rose Project, the Proponent is committed to:

- the early identification of human resource needs and the considered analysis of needs that involve foreign hiring at the contractor and subcontractor level;
- pre-start-up training for key offshore operations personnel;
- bringing discipline-specific, offshore operations training expertise to the Province;
- the use of existing training infrastructure in the Province; and,
- the use of established training "centres of excellence" in Newfoundland & Labrador.

The Proponent has committed in its Benefits plan to report on its performance and the performance of its contractors with respect to compliance with established plans and to report the results to the public and the Board semi-annually.

3.3.3.3
Summary – Research & Development and Education & Training

The Accord Acts requires expenditures for research & development and education & training in the Province. Hence, the Board has latitude to establish parameters and criteria for such expenditures. Accordingly, the Board will establish such parameters and criteria and a target level of expenditures. The Board acknowledges that the Proponent has addressed this matter substantially in its Benefits Plan. However, the Board believes that establishing quantifiable expenditure requirements in this regard is appropriate.

In establishing such requirements, the Board, when considering expenditures for those purposes by the Proponent and its contractors, will take into consideration national norms for private sector investment in research & development. For the development phase, such norms might include the national average level of such expenditures by the private sector as a percentage of capital investment. For the operations phase, it might include the national average level of expenditures by the private sector as a percentage of revenue. While the expenditures must be "in the Province", Canada Customs and Revenue Agency criteria could be used as a guide to eligible expenditures. Therefore, the Board attaches the following condition to the approval of the Benefits Plan:

> **Condition 3:**
> **Within 60 days of Project Sanction, the Proponent submit a plan to address the obligation in the Legislation that expenditures shall be made for research & development to be carried out in the Province and for education & training to be provided in the Province. The Board will review the Proponent's submission and establish an appropriate expenditure target. The Proponent shall report to the Board annually on the progress with respect to achievement of the established targets. The Board anticipates that for this Project, the target will not be less than $12 million during the pre-production stage.**

3.3.4
Goods and Services

The Proponent has committed to a broad set of policies and procedures with respect to providing full and fair opportunity for Canadian goods and services with first consideration to services provided from, and to goods manufactured, in the Province. This section assesses the adequacy of these policies and procedures.

3.3.4.1
Procurement Policies and Procedures

Key policies and procedures provided by the Proponent in its Benefits Plan include:

- sizing and design of bid packages, where appropriate, to fit capabilities of Canadian and in particular, Newfoundland & Labrador companies;
- development and use of a vendor database;
- investigation of labour and fabrication capabilities;
- early dissemination of information on the scope of work;
- open communication with all personnel and companies requesting non-proprietary information;
- presence of engineering, procurement and project management in Newfoundland & Labrador;
- assisting and advising on the development and implementation of transfer of technology and training programs for long-term cost effectiveness; and,
- to ensure the Benefits objective and commitments are achieved in all areas, the Proponent requires all contractors and subcontractors to comply with the Benefits principles, objectives and commitments contained in the Benefits Plan.

The Commissioner noted in his Report that there was some ambiguity at several points in the Benefits Plan with respect to the clarity of the commitment of subcontractors to comply with the obligations of the Proponent. The Board agrees with the Commissioner. The Proponent should address language in the Benefits Plan in this regard. Accordingly, the Board attaches the following condition to its approval of the Benefits Plan:

> **Condition 4:**
> **Upon Project Sanction, the Proponent review its commitment in the Benefits Plan with respect to the obligation of contractors and subcontractors to comply with the provisions of the approved Benefits Plan and submit for approval by the Board a definitive clarifying statement in this regard.**

It is the Board's assessment that, overall, the policies and procedures related to the acquisition of goods and services for the Development, described in the Benefits Plan, are consistent with the statutory requirements to give full and fair opportunity to Canadian suppliers and first consideration to goods and services provided from within Newfoundland & Labrador.

In the Board's view, increased participation in the design, fabrication, installation and servicing of the FPSO topsides and subsea systems, including subsea tree assembly and testing, in the Province, is strategically important.

The Board is aware that the Proponent has engaged in a significant level of pre-approval contracting activity. The Board has advised the Proponent that upon Project approval, contracting activity would be subject to review under the terms and conditions of the approved Benefits Plan, and attaches the following condition to its approval.

> **Condition 5:**
> **Within two months of regulatory approval, the Proponent submit to the Board a comprehensive report on its pre-approval contracting activity in sufficient detail for the Board to assess the extent to which the provisions of the Legislation and this Benefits Plan Decision have been met.**

In order to establish an effective measure of work to be completed in other parts of Canada and in the Province, the following conditions to the approval of the plan are established:

> **Condition 6:**
> **During the construction and operation of the White Rose Project, the Proponent provide, 30 days prior to the commencement of each quarter, quarterly forecasts of Project requirements, at a satisfactory level of detail, to the Board and to the public.**

> **Condition 7:**
> **For each work or activity which is to be executed in the Province and in the offshore area (or in another part of Canada), upon award of contract, the Proponent provide the Board with a complete and detailed description of the work commitments for the Province and Canada. The Proponent's performance will be measured against these commitments, and may be subject to independent verification.**

3.3.4.2
Bid Evaluation Framework

The Proponent described in its Benefits Plan the framework for evaluation of bids for goods and services for the Project. This framework can be summarized as follows:

- goods and services are to be acquired on a "Best Value" basis. The Proponent stressed that local industry must be encouraged to strive to provide goods and services that will compete effectively in a global marketplace. The Proponent also states that, consistent with the criteria for competitiveness outlined in the Legislation, "Best Value" is defined as a blend of total cost, quality, technical suitability, delivery and continuity of supply and service, where total cost is composed of initial purchase price plus operation and maintenance cost;
- the Proponent also indicated that where bids are essentially equal on a "Best Value" basis, first choice will be given to goods and services provided from Newfoundland & Labrador. The Proponent further

indicates that in all bidding processes, the level and quality of Newfoundland & Labrador Benefits, as well as technical and commercial considerations, shall be selection factors in awarding development contracts; and,

- the Proponent has further indicated in supplemental information that bid evaluations are structured on a case by case basis to meet the specific contract requirements and the weighting of criteria vary accordingly.

The Board believes that where there is a sufficient number of competitive suppliers in the domestic market for the supply of a good or a service, the first consideration provision of the Legislation may result in a competition limited to the domestic market. The Board will monitor closely the Proponent's performance in respect of this expectation.

The Proponent has established a Bid Committee to review Request for Proposal/Invitation to Tender documents and to develop appropriate evaluation plans. The Board is generally satisfied with the Proponent's approach to this important aspect of the Project. However, in order to ensure that appropriate systems and procedures with respect to project and operations contracting and procurement are in place, it is a condition of the Board's approval that:

Condition 8:
Upon Project Sanction, the Proponent establish systems and procedures, to the satisfaction of the Board and with particular attention to the calculation of Newfoundland & Labrador and Canadian content, to ensure the bid evaluation and reporting framework matches that which is described in the Benefits Plan. Further, the Proponent must establish, for approval by the Board, a methodology and a verification process for all Newfoundland & Labrador and Canadian content calculations by it and by its contractors and subcontractors.

3.3.5
Disadvantaged Individuals or Groups

The Proponent's approach to affirmative action, with respect to women, is substantially developed in the Benefits Plan. The Proponent and its contractors are committed to engaging in a yearly event to review achievements with stakeholders, and to track the actions and commitments that result from these meetings on an ongoing basis.

However, a Benefits plan is required to ensure that provisions are established to support the participation of disadvantaged groups and individuals in employment and the provision of goods and services for the Project. The provision in paragraph 45(3)(b) of the Legislation which stipulates that a collective agreement may not frustrate access to training and employment opportunities for residents of the Province, would apply equally to disadvantaged individuals.

The Proponent is expected to be proactive in this regard in its plan. In the context of the Benefits Plan, disadvantaged individuals and groups are considered to include: women, aboriginal groups, persons with disabilities and members of visible minorities. The Proponent is expected to review and assess models such as the federal *Employment Equity Act* and other models as appropriate in preparing its action plans in this regard. The Proponent's plans are deficient. Therefore, it is a condition of the approval of the Benefits Plan that:

> **Condition 9:**
> **Upon Project Sanction, the Proponent submit a report for approval by the Board describing its approach to affirmative action as contemplated in subsection 45(4) of the Legislation. This Report should include an assessment of the federal *Employment Equity Act* or other models as appropriate, and specific initiatives.**

3.4
MONITORING AND REPORTING

An important factor governing the procedures for monitoring and reporting is the need for the Board, Governments and the public to know and understand the nature and level of economic activity associated with the Project that is occurring in Canada, and in the Province.

The Proponent has stated it plans to report to the Board on a semi-annual basis with respect to the measured impact of benefits associated with employment, technology transfer, education and training, and research and development. The Proponent has also indicated that employment Benefits audits will be conducted at the end of each project phase or major milestone to determine if Benefits goals are being realized.

The Proponent describes its plans for Benefits reporting, both on its website and in public information material, including statistical information and updates with respect to: Labour statistics, Contract Awards and Economic Contributions. The Proponent further plans to implement a series of public forums, held twice each year, to discuss issues related to the Project with the public and with special interest groups. This will give participants a full opportunity to receive input respecting the Project and give the supply industry an opportunity to express its concerns and opinions to the Proponent.

While the Board views the intentions of the Proponent to report to the public to be positive initiatives, the Board believes it is necessary to report expenditures and employment information for the Development on a quarterly basis. The Proponent will be required to establish reporting systems and procedures to facilitate the accurate reporting of such information. The Proponent's acknowledgment of independent external audits of Canada-Newfoundland Benefits reporting, on an as-required basis, is noted.

> **Condition 10:**
> **The Proponent report on a quarterly basis, in a format satisfactory to the Board, expenditure and employment information, including Canadian and Newfoundland & Labrador content. Each quarterly report should also include an assessment of progress toward the achievement of Canada-Newfoundland Benefits commitments, as referenced in Condition 7. Such reports will be shared with the public. The Proponent should provide the results of internal audits completed with respect to Benefits reporting and**

an assessment of performance against identified contract goals to the Board and the public when complete.

The Proponent has provided Governments with updated plans and estimates for industrial benefits which it expects will accrue to Newfoundland and Labrador and to Canada, as a result of the construction and operation of the White Rose Development. The Proponent advised Governments that these are firm plans and the Proponent is confident they are realistic and achievable based on conditions existing at the time of preparation. The correspondence provided to Governments is attached as Appendix D.

The Board has been requested by the Provincial Government to acknowledge the Proponent's correspondence, "including specific reference to the firm plans which outline the Proponents' estimates and objectives related to industrial benefits". The Provincial Government has also requested that "the Board treat the plans, estimates and objectives provided therein as benchmarks, recognizing that benchmarks are not ceilings", and that the Board also monitor the benchmarks against actual performance. Finally, the Provincial Government has asked that "the Board specifically acknowledge the Proponents' undertaking ... to strive for an even greater level of benefits for Canada and, in particular, Newfoundland and Labrador". The correspondence from Government is also contained in Appendix D.

The Board is pleased to establish a monitoring and reporting process to track achievements against those anticipated in the Proponent's correspondence as a condition to its approval of the Benefits Plan.

Condition 11:
It is a condition of this Benefits Plan approval that the Proponent submit on a quarterly basis during the construction and operations phases of the Development a report describing its actual performance against the estimates provided in its correspondence contained in Appendix D of this Report. Any deviation between the benchmarks of estimates, plans and objectives and actual performance should be accompanied by explanatory notes in sufficient detail to allow assessment of the reasons for the deviation.

CHAPTER 4:
THE WHITE ROSE DEVELOPMENT PLAN DECISION

4.1
INTRODUCTION

Resource management is the essence or core feature of any Development Plan Decision. This statement is not meant to detract from the importance of other aspects of the decision such as safety, environmental protection or benefits. However, all of these are to some extent driven by the choice that is made in determining the general approach to the development of the hydrocarbon resources.

The legislative and regulatory philosophy, which guides this decision process is generally described as "Conservation of the Resource".

This aspect was dealt with in the "Report of the Public Review Commission for the White Rose Development Application" under the heading General Development Approach. The Terms of Reference for the Public Review asked the Commissioner to conduct a review of the White Rose Development Application which would include:

> "The general approach to the proposed and potential development and exploitation of the petroleum resources within the White Rose Significant Discovery Area;"

The Terms of Reference asked that the review include a consideration of matters within Chapters 4 through 9 of the C-NOPB *Development Application Guidelines*. Chapter 4 contains the guidelines for a "Development Plan".

Resource conservation is perhaps the most complex and technically challenging aspect of the Development Plan Decision, involving the integrated application of a wide array of geological and engineering factors. The Legislation stipulates that a central feature of the general approach must be the prevention of waste. The overriding principle here is one of good reservoir management practice. This principle, and the legislative requirement to prevent waste, must be the basis of the Board's decisions in this area.

Given the core nature of this decision, it commanded a lot of attention during the public hearings, and received extensive treatment in the Commissioner's Report. Two key issues which emerged were the choice of a production system, and treatment of the gas resource. It is in this context that the Board feels it is necessary to explain its approach to this aspect of the Development Plan Decision.

4.2
THE PRODUCTION SYSTEM

The Commissioner concluded that the Floating Production Storage and Offloading (FPSO) system is the "most cost effective" for the White Rose Project; and, recommends that, subject to certain operation and safety considerations, it be approved by the Board.

The Legislation requires that a Development Plan contain a description of "the production system and any alternative production systems that could be used …". The guidelines reflect the Legislation and direct further that the Proponent identify the system it has selected for the development.

The decision required of the Board is to approve or reject the system selected by the Proponent. There is no provision or authority in the Legislation for the Board to direct that a system other than the one selected by the Proponent be used. If the selected system does not meet the requirements of the Legislation, the only course open to the Board is to reject it.

The criteria which the Board must use in reaching a decision on a production system are defined in regulations. These criteria are:

- worker safety and environmental protection; and,
- maximum recovery of oil & gas from a pool or field.

A system which does not provide adequately for worker safety and environmental protection would not be acceptable under any conditions. It would be rejected by the Board.

As a general rule, in a field which contains both oil and gas, maximum recovery of both requires that the oil be produced first. The recovery of gas is not at risk if oil is produced first, whereas oil recovery can be reduced significantly if gas is produced first. This is a fundamental principle of good reservoir management practice.

Maximization of oil and gas recovery is primarily a geological and engineering decision. However, in some situations, it is necessary to consider economic factors. This arises when one production system may achieve a higher recovery factor than an alternative. But, if the value of the extra production is less than the extra cost associated with the system which has the higher recovery factor, a decision to use the higher cost system would be uneconomic, and therefore unacceptable. The Board does not have the authority to require a Proponent to make an uneconomic decision.

The FPSO versus GBS debate as it pertains to the White Rose Project is one of costs - $2.1 billion for the FPSO versus $3.2 billion for a GBS. Given the cost difference ($1.1 billion plus $500 million for decommissioning), the

Commissioner's conclusion that the FPSO is the most cost effective for the White Rose Project as currently configured, is consistent with the Board's view. In this context, the Board has determined there is no need for further financial or engineering analysis of the FPSO versus GBS issue in the context of the White Rose Project. Therefore, for this Project there is no requirement for a detailed economic or financial analysis. The system selected by the Proponent meets the worker safety and environmental protection criteria; is the most cost effective; and maximizes recovery.

The Commissioner was sensitive to the arguments presented on both sides of the FPSO versus GBS debate, and expressed the view that a consensus was required on the likely use of FPSO and GBS structures in the foreseeable future. In the Commissioner's view, an informed public debate on this issue would bring greater focus and impetus to all stakeholders in their various capacities in working towards common goals in terms of benefits. Specifically the Commissioner suggests a forum to address all aspects of the FPSO versus GBS question. It is a suggestion that the Board will pursue. However, in doing so, the Board is cognizant that future needs to a large extent will be dependent upon resources not yet discovered. As well, the industry focus is moving away from the relatively shallow waters of the Grand Banks and into the deeper waters of the Flemish Pass and areas off the south coast of Newfoundland. Bottom-founded structures will probably not be appropriate to the deepwater areas. Further, in those areas off southern Newfoundland where icebergs may be less of a consideration, other technologies could be considered. Therefore, any forum to examine differing production technologies for the offshore area, in the Board's view, must go beyond the FPSO versus GBS alternatives.

The Commissioner acknowledged the Proponent's commitment that the FPSO will be designed so that, with modifications, it can be used to export gas when an export infrastructure is available. The Commissioner concludes by recommending that the Board require the Proponent to drill a gas delineation well within six months of Project approval and, depending on the outcome of that well, pre-invest in a FPSO capability for export gas.

The Proponent describes the cost to modify the FPSO for gas export. These costs range from $75 million to $180 million. The cost of a delineation well would be about $30 million. This cost would be incurred on the assumption that a gas export infrastructure would be available in 2010 or 2016. In other words, it would require an investment of $100 to $200 million with no prospect of any return for six to twelve years. Further, the prospect of any return, even at these points in the future, is dependent upon an investor coming forward in the interim with an estimated $3.5 billion investment in gas export infrastructure. Such an investment would in turn be dependent upon other fields (some yet to be discovered) on the Grand Banks having, together with White Rose, 700 to 900 million cubic feet of gas per day available for export. Also, equipment installed now could be effectively obsolete before even being used. These factors present a difficult risk profile upon which to base a $100 to $200 million capital investment decision. The Board's conclusion is that to require pre-investment on the scale contemplated in such circumstances cannot be justified.

Concern was also expressed during the Public Hearing that White Rose gas might not be made available for export if gas transportation infrastructure was put in place. The Board, on its part, would expect in such circumstances that access to White Rose gas, subject to conservation considerations, would be realized through normal commercial negotiations. As discussed later, the Legislation does, however, provide the Board with authority to issue a Development Order should such a course of action be required.

4.3
PREVENTION OF WASTE

One of the central responsibilities of the Board is the prevention of waste in the development of the hydrocarbon resources of the Newfoundland Offshore Area. Waste as defined in section 154 of the Accord Acts includes:

- the inefficient or excessive use or dissipation of reservoir energy;
- the inefficient storage of petroleum above ground or underground;
- the escape or flaring of gas that could be economically recovered and processed or economically injected into an underground reservoir; or,
- the failure to use suitable artificial, secondary or supplementary recovery methods in a pool when it appears that such methods would result in increasing the quantity of petroleum ultimately recoverable under sound engineering and economic principles.

To meet this statutory requirement, the Board is guided in its decisions by the principles of good reservoir management and good production practice. At the risk of oversimplification, this often requires, in a field which contains both oil and gas, that the oil resources be produced first. This arises from the fact that the associated gas resources are necessary to maintain the reservoir pressure required to maximize oil recovery. The gas cap, and any solution gas that is re-injected is available for recovery after the oil.

There are significant examples of this starting with the Leduc discovery in Alberta in 1947. Blow down of the gas cap did not occur until some 40 years later. In Alberta, the Petroleum and Natural Gas Conservation Board was created in large part to avoid any repetition of the Turner Valley experience where the blow down of the gas cap left much of the underlying oil forever lost to recovery.

Premature production of the White Rose gas cap would lead to “waste” of the oil resource, and would not be permitted under the Legislation.

In the context of the White Rose Development Application, the application of the above principle has required consideration of the following matters:

- since the White Rose gas cap gas appears to be associated with the oil, it follows that commercial gas production must, for the most part, be deferred until oil recovery is substantially completed;
- a priority objective of development and delineation drilling must be to establish the extent of the oil resources in the North and West Avalon

pools. If economically recoverable oil resources are determined to exist in these areas, any consideration of gas development will have to be deferred until oil recovery is substantially completed. If the oil resources are shown to be uneconomic for recovery, the gas in this part of the field would be available for earlier development. As well, if any gas in the North Avalon pool exists as non-associated gas, it is important to identify the gas as such; and,

- in the absence of a development option for gas and to prevent waste, the White Rose Project will be required to re-inject produced gas into the reservoir to conserve it for future development.

4.4 THE GAS RESOURCE

There are two broad sets of factors which will determine the timing of commercial gas development in the Newfoundland Offshore Area –the size and nature of the resource and economic factors.

A study conducted by the Newfoundland Offshore Industries Association (NOIA) and Governments, of non-pipeline options was premised on an assumption that a proven recoverable gas resource threshold of 5 tcf is necessary to justify the investments required to commercialize Grand Banks gas. The Board is aware that the Province is doing further work to examine pipeline options, but is not aware of any conclusions of that work in terms of threshold resource levels that a pipeline option would require. The Proponent has indicated that the required threshold reserve is in the 7 to 10 tcf range. More specifically, the Proponent has concluded that 8.2 tcf will be required to support a $3.5 billion pipeline.

In the resource context, it is necessary to examine the size of the discovered gas resource on the Grand Banks, the type of gas (i.e. associated and non-associated) and its availability. The following table summarizes the Board's official estimate of the discovered gas resources on the Grand Banks.

Grand Banks Proven plus Probable (P50) Recoverable Gas Resources

Note: Numbers may not add to totals because of rounding

Field	Associated Gas Cap	Associated Solution Gas	Non-Associated Gas	Total Proven plus Probable Recoverable Gas Resources
White Rose	2.3 tcf	0.1 tcf	0.3 tcf	2.7 tcf
Hibernia	0.3 tcf	0.9 tcf	0.1 tcf	1.3 tcf
Terra Nova	0.0 tcf	0.3 tcf	0.0 tcf	0.3 tcf
Other	0.4 tcf	0.0 tcf	1.0 tcf	1.4 tcf
Total	**3.0 tcf**	**1.3 tcf**	**1.4 tcf**	**5.7 tcf**

The P50 resource estimates means there is a 50 percent probability that the gas resource is at least that large.

The 5.7 tcf estimate would appear to meet the 5 tcf threshold which the NOIA/Government non-pipeline study assumed. However, it is necessary to examine closely the distribution and characteristics of the gas resources described in the above table.

The total gas resource of 5.7 tcf is distributed across eight different fields. While 4.4 tcf is found at White Rose, Hibernia and Terra Nova, the remaining 1.3 tcf is distributed among five smaller fields. This factor led to the conclusion by the Commissioner that a Grand Banks gas development strategy must be basin-wide. If this were the only impediment, economic interest would in all likelihood motivate the license holders to develop such a strategy. In fact, there is already some movement in this direction as indicated by the study work initiated by the Proponent and the other license holders in the area.

However there is a second impediment which is related to the "associated" characteristic of the resource and which limits its availability for commercial development. Only 1.4 tcf of the estimated 5.7 tcf is "non-associated" and therefore potentially available for commercial development. This is far short of the 5 tcf threshold referenced in the NOIA/Government study or the Proponent's 8.2 tcf.

The remaining gas, 4.3 tcf, is all associated with oil. Associated gas is further divided into two types – gas cap and solution gas. Often, both are required for reservoir pressure maintenance in order to maximize oil recovery. To the extent the solution gas may not be required for this purpose, it would be available for export.

Solution gas is gas dissolved in the oil which is liberated under surface pressure conditions. Availability is always tied to the oil production rate. It represents a relatively small proportion (1.3 tcf) of the total resource estimate. At White Rose solution gas amounts to just 0.1 tcf. Even when it is not required for pressure maintenance, as is the case at White Rose, because it is tied to the rate of oil production it would not, by itself, be sufficient as the basis of a gas commercialization project.

Gas cap gas occurs in a pool overlying an oil accumulation. Its downward pressure on the oil is necessary to produce the oil to the surface. Examples have been cited earlier of instances in other parts of Canada where premature production of the gas cap have stranded forever significant volumes of oil. The statutory provisions of the Legislation concerning prevention of waste prohibit any consideration of such an approach in the Newfoundland Offshore Area.

The single largest known gas resource on the Grand Banks is the gas cap at White Rose. It is estimated to contain 2.3 tcf. In later sections of this Chapter there are detailed explanations of when that resource may be available for commercial development. This is the basis for the Commissioner's observation that White Rose has the potential to become the catalyst for commercial gas development on the Grand Banks. The Board concurs, but only when it can be made available without detriment to oil recovery.

The Commissioner notes as well the difference between the Board's estimate of the White Rose gas resource (2.7 tcf), and the Proponent's estimate (1.8 tcf). While this difference may be significant in a numerical sense, it has no material impact on the Board's decision. The Board has full confidence in the estimates produced by its reservoir engineering specialists, and these are the numbers which are considered by the Board in its decision-making process.

The Board is of the view that new exploration discoveries of non-associated gas will be required before a pipeline can be considered viable over the shorter term. In this regard, the Board notes that the January 2001 joint report of the C-NOPB and the Geological Survey of Canada assessed the total resource potential of the Jeanne d'Arc Basin and adjoining area at 18 tcf of which less than one third has been discovered to date. The estimated resource potential of non-associated gas is 4 tcf, of which only 1.4 tcf has been discovered to date. Gas from other areas of the Grand Banks may ultimately be necessary to trigger the desired development.

Consistent with the Board's views in respect of delineation drilling and gas resource development, it is appropriate to acknowledge the statutory powers which reside in the Board, officials and Ministers to revisit these issues in the event of significant delay and/or "waste".

Drilling Orders: Pursuant to section 76 of the Accord Acts, the Board may, with approval of Ministers (fundamental decision) make an order (subject to review by the independent Oil and Gas Committee) requiring the interest owner in relation to a significant discovery area, to drill a well. Consistent with directions as the Board may set in the order, the interest owner will be obligated to commence the drilling within one year of the order, or such longer period as is allowed. An order can be given where three years have passed since the termination of the well indicating the relevant significant discovery and can require only one well at a time in the relevant area. Non-compliance with the order could result in the Board canceling the interest, subject to review of such a cancellation order by the independent Oil and Gas Committee.

Development Orders: Pursuant to section 79 of the Accord Acts, the Board may, with approval of Ministers (fundamental decision), in an instance where a declaration of commercial discovery has been made, give notice to the owner of an interest (where commercial production of petroleum has not commenced) that the term of the interest will be reduced. The Board may thereafter give an order, where it is of the opinion that it is in the public interest (subject to review by the independent Oil and Gas Committee), reducing the term of the interest to three years or such longer period as is allowed, unless commercial production of petroleum commences. Non-compliance with the order would result in termination of the interest which would return the area to Crown Reserve status and allow the Board to offer the interest to other parties in a call for bids.

Production Orders: Pursuant to section 153 of the Accord Acts, the Chief Conservation Officer may, where he is of the opinion based on reasonable grounds that:

- the capacity exists to commence, continue or increase production of petroleum, and,
- an order in that regard would prevent "waste" (an industry term which relates generally to inefficient use of or escape of resources),

order commencement, continuation or increase of production at such rates and quantities as he believes are appropriate. Non-compliance with the order would constitute an offence under the Accord Acts.

While neither the Board, nor the Chief Conservation Officer (in the case of a production order) have in the past used the outlined order powers, they continue to be available in respect of both projects previously approved and will remain in force for the White Rose Project. These are the legislative mechanisms which allow the Board to “reclaim” resources where they are not used in the public interest or require drilling programs or production programs where projects are delayed or inappropriately carried out.

PART B: THE WHITE ROSE DEVELOPMENT PLAN DECISION

4.5 DEVELOPMENT PLAN DECISION

It is the decision of the Board that the White Rose Development Plan is approved, subject to the conditions established in this Development Plan Decision.

The Decision is in respect to the South Avalon pool development using subsea well technology and a steel Floating Production Storage and Offloading (FPSO) vessel as described in the Development Plan and accompanying submissions. An Annual Oil Production Rate of 5.8 10^6 m^3 (approximately 36.5 million barrels) based on a daily rate of 15 900 m^3/d (100,000 bopd) is also approved subject to conditions set out in this Development Plan Decision.

> **Condition 12:**
> **Compliance with the White Rose Benefits Plan and its conditions is a condition of this Development Plan approval.**

The Development Plan describes the Proponent's interpretation of the characteristics of the hydrocarbon reservoirs in the White Rose field, its estimates of the petroleum reserves and the approach it proposes to take to recover, or conserve, those reserves. It also includes a description of the facilities it proposes to install to produce the hydrocarbon resource, the parameters upon which its facilities design will be based, and the measures it proposes to undertake to ensure the safety of personnel and protection of the environment.

The Board has reviewed the Development Plan to ensure that it conforms to the requirements established by the Legislation. The Board's duties are to ensure that:

- the production facilities are designed and operated in full consideration of the safety of personnel and the protection of the natural environment; and,
- the resource is produced in accordance with good oil field practice, to maximize recovery and to prevent waste.

The Board notes that the White Rose Development Plan is based upon preliminary engineering studies and that, consequently, its approvals are related to the concepts, approaches and undertakings described in the Development Plan. As detailed design and operational planning proceed, it will be necessary for the Proponent to obtain the additional approvals that are set out in:

- the *Newfoundland Offshore Petroleum Installations Regulations;*
- the *Newfoundland Offshore Petroleum Drilling Regulations;*
- the *Newfoundland Offshore Area Petroleum Production and Conservation Regulations;*
- the *Newfoundland Offshore Area Petroleum Diving Regulations; and,*
- the draft *Petroleum Occupational Safety and Health Regulations – Newfoundland.*

Further, the *Newfoundland Offshore Certificate of Fitness Regulations* requires that a recognized Certifying Authority (CA) undertake a detailed examination of the design of facilities to ensure that they are fit for purpose and that they comply with the regulations. The Scope of Work for the CA must be submitted for Board approval. The Proponent has informed the Board that it has selected Det Norske Veritas (DNV) as the CA for the Project.

The remainder of this chapter presents the detailed results of the Board's review and is organized into three major areas: conservation of the resource, safety of operations, and protection of the environment. Each topic within these three broad areas will be introduced by describing first the Proponent's plans and proposals, then the main items of concern, including where applicable the recommendations of the White Rose Public Review Commission. Each topic concludes with the Board's assessment of the issue, including any conditions that it believes must be attached to its approval.

4.6
CONSERVATION OF THE RESOURCE

This section focuses on aspects of the White Rose Development Application which affect conservation of the resource. The statutes and regulations administered by the Board require that oil and gas resources be produced in accordance with good oil field practice, having proper regard for the efficient recovery of the resource and the prevention of waste. The Application presents the Proponent's interpretation of the geophysical and geological data, reservoir characteristics of the field, and the proposed approach to recovery of the oil reserves and the conservation of the gas resources.

In any oil or gas field development, it is impossible to resolve all of the geological, geophysical and reservoir ambiguities prior to proceeding with development. Despite the delineation drilling which has occurred in the White Rose field and subsequent studies, several uncertainties, which are discussed in the following sections of this Decision Report, may affect the depletion scheme to be employed and the recoverable reserves. The Proponent's plan provides for early resolution of these uncertainties and, in the Board's opinion, has sufficient flexibility to cope with any necessary changes.

The resource conservation aspects of the Application were reviewed utilizing the geoscientific interpretations and reservoir characteristics contained in the Application and its updates, and the Board's independent assessment. The Commissioner also addressed resource conservation aspects of the Application and made several recommendations. The following sections of the report present the Board's review and determinations.

4.6.1
Regional Geology

The C-NOPB has identified the primary reservoir interval in the White Rose field as the Ben Nevis Formation. However, based on recent data, the Proponent identifies this interval as the Avalon Formation. To minimize this nomenclature confusion, this document uses Avalon Formation as the reservoir name.

The Proponent has extensively detailed the regional geologic history of the Jeanne d'Arc Basin. In light of both the Board's and general industry understanding of the Basin, the Proponent's discussion is considered reasonable.

The following summary, extracted from various sources including: the Proponent's Development Plan Application, the Terra Nova Development Plan Application and the literature describes the regional geology of the Jeanne d'Arc Basin.

The White Rose field is located on the eastern margin of the Jeanne d'Arc Basin approximately 350 km east of St. John's and about 50 km from both the Hibernia and Terra Nova fields. The Jeanne d'Arc Basin is a northeast trending sedimentary basin bounded on the west by the Bonavista Platform, to the east by the Ridge Complex, and to the south by the Avalon Uplift. To the north, the Jeanne d'Arc Basin is bounded by the Cumberland Ridge.

The deposition sequence of sedimentary rocks in the basin was strongly controlled by regional tectonic events that have occurred on the North Atlantic continental margin. The initial deposition of sediments in the basin occurred during the rifting in Late Triassic to Early Jurassic time within a northeast trending rift graben. This was followed by a Jurassic post-rift phase, during which the area subsided and sediments with characteristics typical of marine environments, such as shale and limestone, were deposited. The organic-rich shale, limestones and marlstones of the Rankin Formation, which were deposited at the end of this phase, are of particular importance as they are considered to be the source rock for most of the oil generated in the basin.

A second phase of rifting oriented generally east-west, occurred in the Late Jurassic. The deposition of the fluvial sandstones and conglomerates of the Jeanne d'Arc Formation followed the uplift and erosion of the underlying Rankin Formation in this period. Basinward, the Jeanne d'Arc Formation grades into shales of the Fortune Bay Formation. Moving forward in time into the Early Cretaceous, braidplain and deltaic sandstones of the Hibernia Formation continued to fill the basin. Following this, a post-rift period of subsidence and deepening basin conditions occurred which is reflected by the "B" Marker and "A" Marker limestone, marine sandstones of the Catalina Formation and the Whiterose Formation shale.

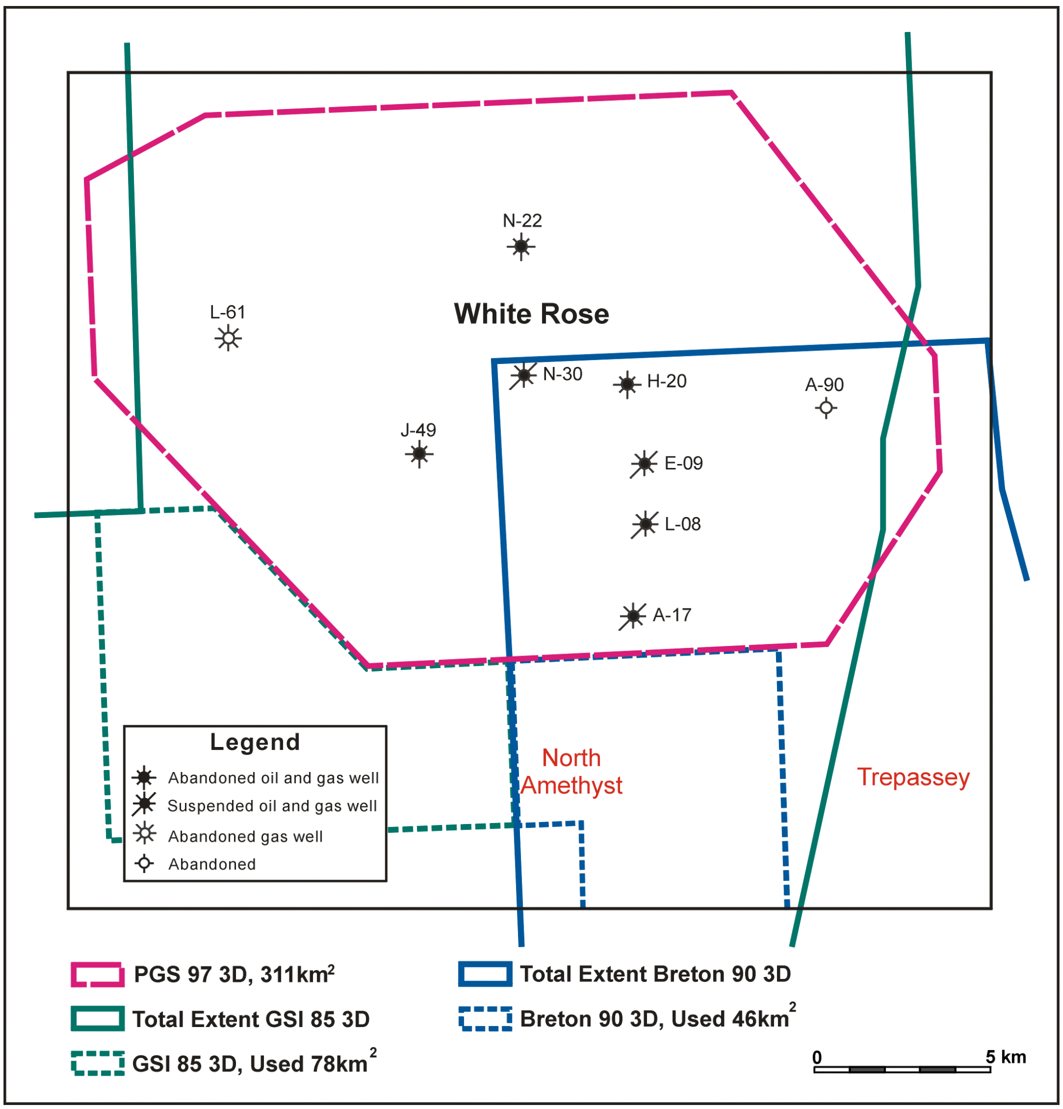
The final phase of rifting, a southwest-northeast extension, occurred in the mid-Cretaceous. During this time, the fluvial to marine sandstones of the Ben Nevis/Avalon Formations and basinward, the shales of the Nautilus Formation, were deposited.

Since the Late Cretaceous, the entire basin has undergone subsidence and the sediments deposited include fluvial-deltaic and deeper marine clastics and minor limestones. This was followed in the Quaternary by glaciation and the subsequent transgression of the ocean into the area.

4.6.2 Geophysical Interpretation

The interpretation of the White Rose field was conducted by the Proponent using three seismic surveys, PGS-97, Breton 1990 and GSI 1985, as shown in Figure 4.1. The first two are three-dimensional (3-D) seismic surveys and the GSI 1985 is a pseudo 3-D survey where data have been interpolated to produce a 3-D cube. The data were reprocessed and merged to a single data set for the interpretation of the field. Data quality is variable from good in the south to poor in the north, probably due to multiples, complex faulting and the presence of gas.

Figure 4.1 White Rose Complex 3-D Surveys

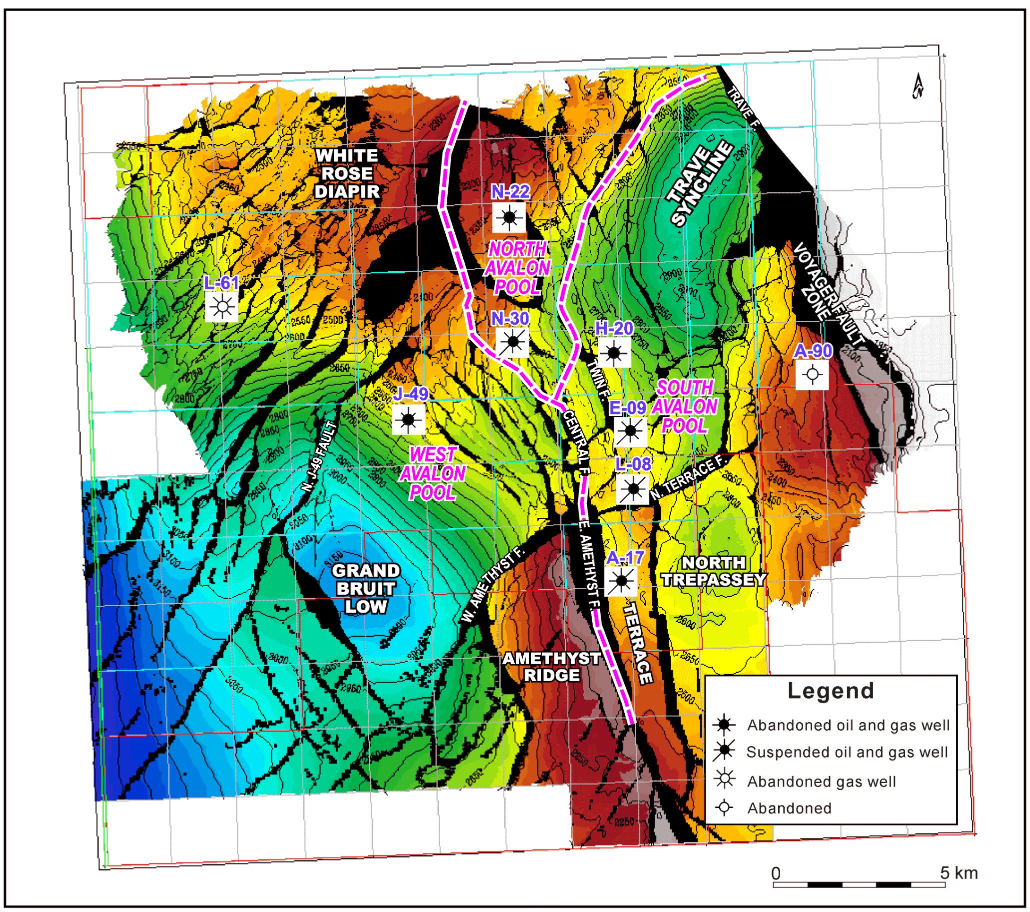


Source: after Husky 2001

The seismic data have been tied to eight wells in the field using synthetic seismograms and available vertical seismic profiles (VSP). The Proponent mapped three seismic markers, the Base Tertiary Unconformity, the Composite Marker and the mid-Kimmeridgian Unconformity over the entire area of the field. The Top Avalon Formation, which constitutes the top of the hydrocarbon-bearing reservoir, was mapped only in the eastern part of the field where the Marker is not highly affected by multiples and faulting. Interpretations by Board geophysicists concur with the Proponent's maps.

The Composite Marker map, at or near the base of the Avalon reservoir, is used to determine the distribution of the Avalon reservoir and to illustrate the structural framework separating the South, North and West Avalon pools. The major structural features surrounding the White Rose field are shown in Figure 4.2. The field is cut by north to south, northwest to southeast and northeast to southwest faults. The Proponent has attributed the development of these main features to tectonism and salt movement. The highly faulted area between the Amethyst Ridge and the White Rose diapir is more akin to salt withdrawal.

Figure 4.2 Regional Composite Marker Time Structure



Source: after Husky 2001

The Proponent has identified gas-charged sediments to the east of the Whiterose N-22 well. No structural maps of secondary reservoirs are included.

4.6.3
Geological Interpretation

The White Rose oil and gas field was discovered in November 1984 by the drilling and testing of the Husky/Bow Valley et al Whiterose N-22 well. Since then, eight delineation wells have been drilled on and around the structure. General statistics for each well are summarized in Table 4.1. The White Rose significant discovery area (SDA) was gazetted on June 15, 1987. The current SDA, significant discovery and exploration licences and wells are shown in Figure 4.3.

Figure 4.3 White Rose Significant Discovery Area and Land Interests

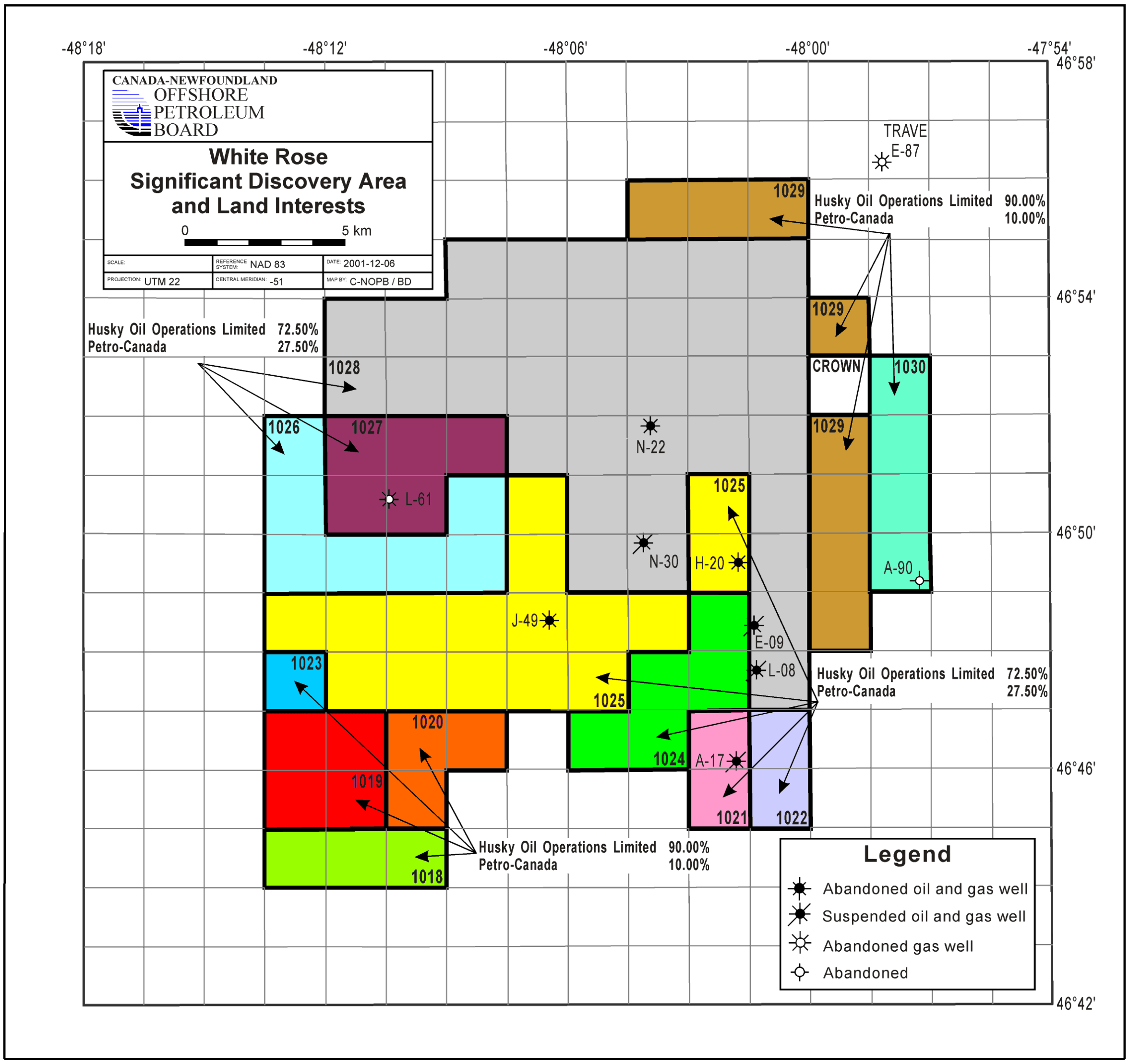


Table 4.1
White Rose Significant Discovery Area Well Summary

(Source: CANADA-NEWFOUNDLAND OFFSHORE PETROLEUM BOARD)

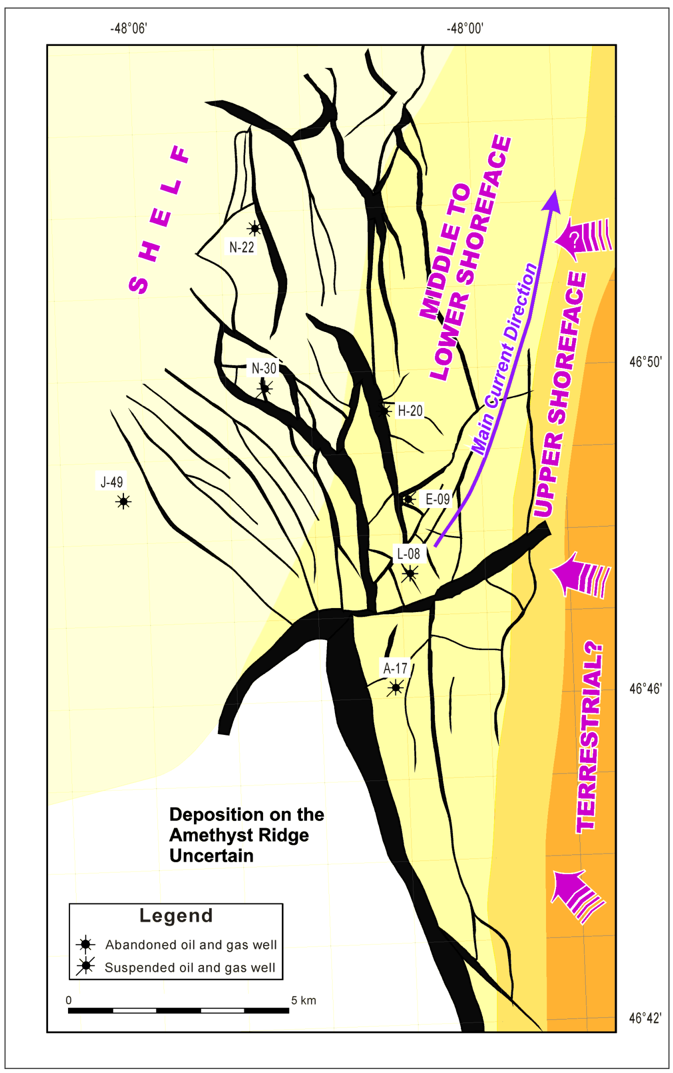
Well Name	Husky/Bow Valley et al Whiterose N-22	Husky/Bow Valley et al Whiterose J-49	Husky/Bow Valley et al Whiterose L-61	Husky/Bow Valley et al Whiterose E-09	Husky/Bow Valley et al Whiterose A-90	Husky et al White Rose L-08	Husky et al White Rose A-17	Husky et al White Rose N-30	Husky et al White Rose H-20
Location									
Latitude:	46 51 47.99 N	46 48 31.30 N	46 50 34.12 N	46 48 26.24 N	46 49 11.0 N	46 47 30.64 N	46 46 07.46 N	46 49 49.75 N	46 49 29.63
Longitude:	48 03 56.51 W	48 06 27.51 W	48 10 28.34 W	48 01 22.65 W	47 57 19.4 W	48 01 20.17 W	48 01 40.92 W	48 03 45.40 W	48 01 38.04
Classification:	Exploratory	Delineation	Delineation	Delineation	Delineation	Delineation	Delineation	Delineation	Delineation
Spud Re-Entry Date:	June 27, 1984	July 27, 1985	December 18, 1985 September 14, 1986 (DST and Abandon)	August 20, 1987 January 14, 1988 April 22, 1988	July 2, 1988	April 7, 1999	June 16, 1999	August 13, 1999	May 7, 2000
Log Datum:	27.4 mRT	22.9 mKB	22.9 mKB	23.0 mKB	22 mRT	25.0 mRT	25.0 mRT	25.0 mRT	26.4 mRT
Water Depth:	121.9 m	115.8 m	114.3 m	123.4 m	130 m	122.7 m	119.5 m	119.5 m	123.1 m
Total Depth:	4627.8 mRT	4561.4 mKB	3340.3 mKB	3810.9 m 3820.0 m 3970.0 m	3025 m	3130 m	3200 m	3290 m	3382 m
Termination Date:	January 4, 1985	December 11, 1985	March 26, 1986 October 2, 1986	November 11, 1987 February 22, 1988 July 1, 1988	August 9, 1988	June 13, 1999	August 4, 1999	October 14, 1999	June 25, 2000
Status:	Abandoned Oil and Gas Well	Abandoned Oil and Gas Well	Abandoned Gas Well	Oil and Gas Well Suspended	Abandoned	Suspended Oil Well	Suspended Oil Well	Suspended	Abandoned

The Proponent provided extensive description of the reservoirs at White Rose. The following reservoir description has been summarized from the various supporting documents submitted by the Proponent.

The White Rose structure comprises a broad, faulted and salt cored dome of Jurassic and Early Cretaceous sediments located on the eastern margin of the Jeanne d'Arc Basin. The structure is draped by Late Cretaceous and Tertiary sediments. Hydrocarbons have been recovered from four reservoirs in the White Rose structure: the Jeanne d'Arc Formation, the lower zone of the Hibernia Formation, the Avalon Formation, and the South Mara member of the Banquereau Formation.

Deposition of the Avalon Formation has been interpreted to be from a paleoshoreline to the east of the field. (Figure 4.4)

Figure 4.4 White Rose Complex – Paleogeography Late Aptian Time



Source: after Husky 2001

The White Rose Avalon Formation is divided into three pools, identified from separate oil/water and gas/oil contacts, and are separated by faulting and structural closure. Structurally, the White Rose Avalon pools reside in a complexly faulted area located west of the Voyager Fault Zone, and are situated above the deep seated Amethyst salt ridge and White Rose diapir.

The South Avalon pool has been defined by the H-20, E-09, L-08 and A-17 wells. The trap is a collection of 3 and 4 way closure fault blocks, bounded by major faults to the east, west and south. It has a stratigraphic limit at its northern extent, between E-09 and H-20, and a possible stratigraphic limit at its southern extent. The reservoir facies have been interpreted to be middle to lower shoreface.

The West Avalon pool includes the J-49 well. The trap is structural, and the reservoir consists of a thinner sequence of Avalon than the sequence drilled in the South Avalon pool. Elongated faults, oriented in a northwest to southeast direction, dissect the area into many narrow blocks.

The North Avalon pool includes the N-22 and N-30 wells and is located on the southeastern flank of the White Rose Diapir. The area is dissected by numerous faults trending mainly north-northwest to south-southeast and north-northeast to south-southwest. The North and South pools are separated by a structural low combined with reservoir quality degradation in the upper portions. The reservoir facies for both the West and North Avalon pools have been interpreted to be shelf.

Core interpretation suggests that the depositional environment was a marginal marine shoreface setting with frequent storm deposits. Numerous calcite concretions varying in dimensions are present, as layers of stratabound or scattered concretions. From the descriptions and log data, three layered models (a 2, 3 and 9 layered model) were developed, from which various reservoir models were subsequently derived.

The Proponent's layered geological models are considered to be reasonable and should be accepted. However, these models do not define the distribution of the various oil-water and gas-oil contacts across the field. This will be discussed further in a subsequent section.

4.6.4
Reservoir Characteristics

4.6.4.1
Formation Flow Tests

The Proponent conducted an extensive formation flow-testing program to evaluate productive performance, acquire fluid samples and establish reservoir parameters for reservoir studies. According to information provided by the Proponent, twenty-five drill stem tests (DSTs) were conducted in the White Rose field over the Avalon, Lower and Basal Hibernia, Wyandot Chalk, and Eastern

Shoals Formations and South Mara member of the Banquereau Formation. In addition to the DSTs, the Proponent collected an extensive set of wireline formation test data using Schlumberger's Modular Dynamic Tester (MDT) and ran production logs and multi-layer tests. The majority of the test data were acquired over the Avalon Formation.

According to the Proponent, the hydrocarbons encountered in the Avalon Formation are contained in three major pools (the South Avalon, the North Avalon and the West Avalon), with each pool containing an oil accumulation overlain by gas and underlain by a water leg. The gas-oil contacts have been drilled in all three pools, while the oil-water contact has been drilled in the West and South Avalon pools. Reservoir pressure data from DSTs and the MDT were used by the Proponent to determine pressure gradients and location of the gas-oil and oil-water contacts. The gas-oil and oil-water contacts currently used by the Proponent for the Avalon Formation pools are shown in Table 4.2.

Table 4.2
Avalon Formation: Proponent's Gas-Oil and Oil-Water Contacts

Pool	Gas-Oil Contact (mss)	Oil-Water Contact (mss)
South Avalon	2872	3009
North Avalon	3014	3073
West Avalon	3064	3127

The Proponent's analyses of the formation flow test data indicated the presence of wellbore damage causing flow restrictions and showed that the Avalon Formation contains low permeability sandstones (generally less than 100 mD). The Proponent notes that the production rates could be significantly increased by minimizing damage and that studies in progress indicate that the productivity of wells drilled horizontally into the Avalon Formation could be more than twice that of wells drilled vertically. The base case depletion plan calls for horizontal wells to improve production.

The Proponent noted that in addition to standard DSTs, vertical interference tests were run in the E-09 and L-08 wells to examine the impact of calcite cemented intervals on vertical communication within the reservoir. According to the Proponent, preliminary test analysis of L-08 DST 2 data indicates that major calcite cemented zones could either extend for 64 to 84 metres before vertical communication is seen around the zone, or have an effective vertical permeability of less than 0.5 mD.

The Proponent conducted several MDT vertical interference tests to assess vertical communication within the Avalon Formation. Results from these tests were compared with vertical to horizontal permeability ratios (kv/kh) measured from core to ensure that up-scaling routines from log scale to reservoir simulation scale were appropriate. The kv/kh ratios determined from the MDT tests indicated decreasing kv/kh ratios as the MDT interval increases. The average results are shown in Table 4.3.

Table 4.3 Summary of Average kv/kh Ratios	
Interval (m)	**Average kv/kh Ratio**
MDT 0.7 metre interval	0.37
MDT 2.4 metre interval	0.19
MDT 3.1 metre interval	0.06
Core plug scale	0.74

The Board notes the extensive formation flow-testing program conducted by the Proponent. The Board has conducted an independent review and interpretation of the Proponent's formation flow test data. While there are minor differences between the Board's interpretation and that of the Proponent, the Board concurs with the Proponent's assessment that the formation flow test data indicated significant wellbore damage which resulted in restricted flow and that the Avalon Formation contains low permeability sandstones. The Board believes the Proponent's assessment is reasonable for planning purposes.

The location of the gas-oil and oil-water contact will affect the computed reserves and may affect the location of development wells. The Board conducted an assessment of the data to define the contacts. There is good agreement between the Board's and the Proponent's gas-oil contacts. The Board, however carries a slightly deeper oil-water contact in the North and West Avalon pools, and a shallower contact in the South Avalon pool. The differences are not considered to be substantive. Given the complex faulting within the Avalon Formation, it is likely that other contacts may be encountered. However, the contacts presented by the Proponent are reasonable for planning purposes.

The Board acknowledges the extensive DST and MDT program conducted by the Proponent. Given the low permeability of the Avalon formation sandstones, well productivity is a key issue. The ability to achieve and sustain reasonable production rates from development wells will be critical to the success of the White Rose Project. The Proponent's plan to use horizontal wells offers the potential to achieve high production rates. However, the test data indicates that significant damage may be introduced by drilling operations, and it will be necessary to take measures to reduce damage to maximize production. Sustaining the production rates and achieving good recovery efficiency will depend on there being good vertical communication within the reservoir. This still presents a risk. However, the Board believes the Proponent has taken reasonable actions to assess the risk. The Board expects the Proponent to acquire information to further assess the degree of vertical communication early in the production phase through its data acquisition program, conducted in accordance with the Newfoundland Offshore Area Production and Conservation Regulations.

4.6.4.2
Petrophysics

The Proponent conducted a comprehensive logging and coring program while drilling the White Rose exploration and delineation wells. In the Application, the Proponent described the petrophysical interpretation of this data, including the assumptions and procedures used in the interpretation, and summarized the reservoir parameters derived for each of the sand units.

The Board has conducted an independent review of the petrophysical data and, based on its analyses, believes the interpretation of the available data presented by the Proponent to be reasonable.

4.6.4.3
Fluid Characteristics

During testing of the White Rose exploration and delineation wells, the Proponent conducted a thorough fluid sampling program. Analyses of the samples were conducted to define the fluid characteristics and select representative properties for engineering studies. For the Avalon Formation pools, the Proponent describes the characteristics of the oil and gas cap which, based on analyses of fluids recovered during testing of White Rose wells, it believes are present in each of the pools. It also presents an analysis of an Avalon Formation water sample recovered from the L-08 well drilled in the South Avalon pool and sea water proposed to be injected.

The Board has conducted a review of the fluid analysis conducted on fluid samples recovered from the Avalon Formation pools. In general, there is good agreement between the Board and Proponent. There are minor differences in the properties for the North Avalon pool. The Board based its properties on the oil sample from the Eastern Shoals Formation in the N-30 well that it believes to be in communication with the Avalon Formation. The Proponent based its properties on the South Avalon pool pressure volume and temperature (PVT) data as there were concerns with the integrity of the N-30 sample. These differences are not considered to be significant. The Board considers the Proponent’s oil, gas and water characterizations to be reasonable.

4.6.4.4
Core Analyses

In the Application, the Proponent presents a summary of the studies conducted on short plugs**,** full diameter cores and stacked cores cut from the cores recovered during exploration and delineation drilling, and the results of its analyses. These tests were conducted on cores from the Avalon Formation. Among other factors, these studies indicate the average water flood and gas flood residual oil saturations range from 20.2 to 38.9 percent and 21.9 to 40.9 percent, respectively. According to information provided by the Proponent in support of the

Application, a water flood residual oil saturation of 25.6 percent and a gas flood residual oil saturation of 40.1 percent were used in the Proponent's reservoir simulation studies. The Proponent noted work is continuing on the special core analyses. An extensive review of all special core analyses data will be conducted to identify any gaps in the data and to link the specific test results to the reservoir facies that are being identified as part of the geological modeling update.

The Board acknowledges that the Proponent has conducted a comprehensive core analyses program. The water flood residual oil saturation used by the Proponent in its reservoir simulation studies is reasonable. The gas flood residual oil saturation used by the Proponent, while not considered unreasonable, appears to be high. This would lead to lower oil recovery for gas flood depletion options. A review of the gas flood test data from two short stack core flood tests was conducted by the Board. The review indicated that both gas flood tests were conducted in an unstable regime and may have been susceptible to fingering and/or override effects. This factor will be investigated further as part of the coring program, pursuant to the *Newfoundland Offshore Area Petroleum Production and Conservation Regulations*.

4.6.5
Resource Estimates

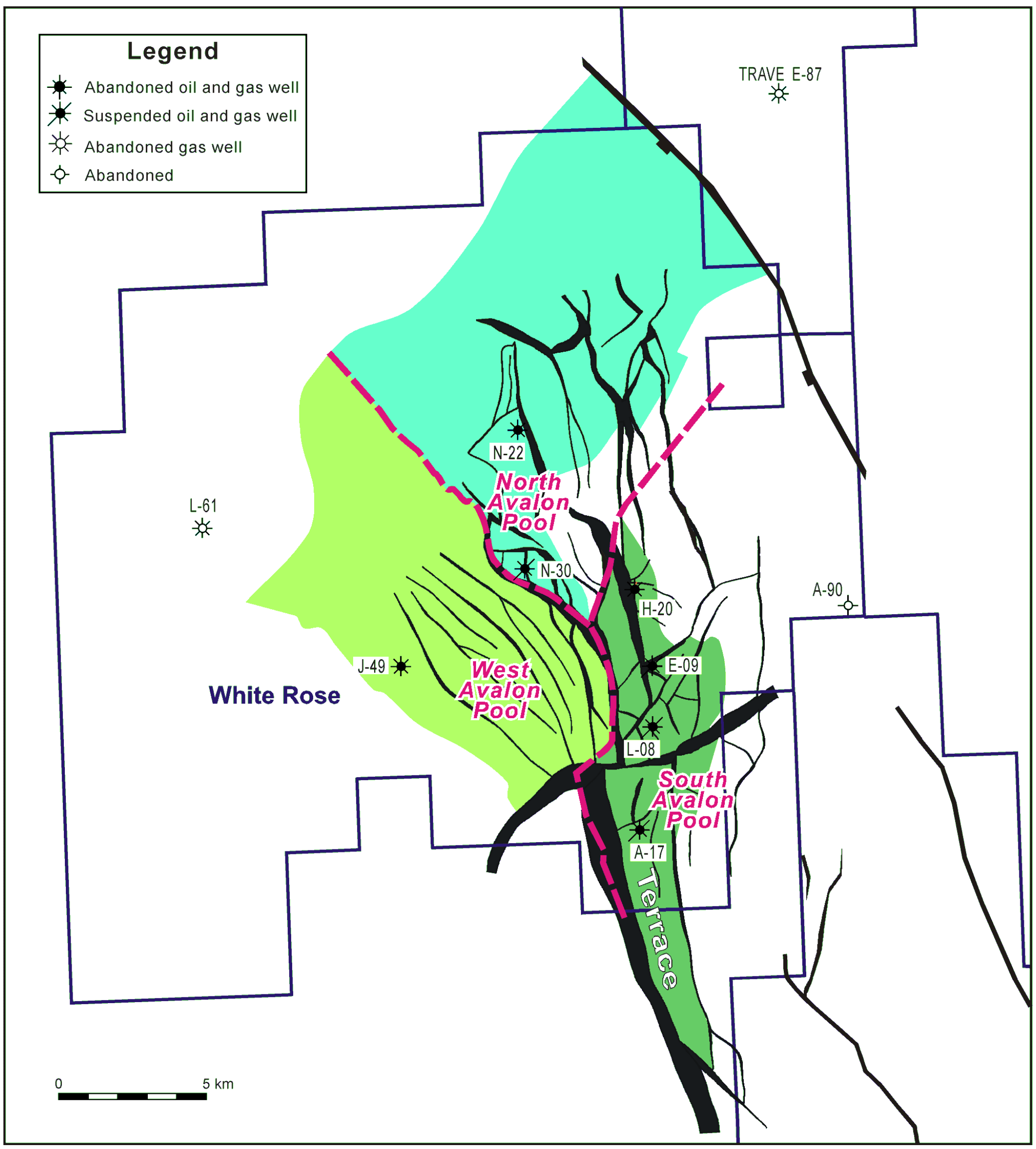
4.6.5.1
Original Oil and Gas-in-Place

In the Application submitted January 17, 2001, the Proponent presents a range of original oil and gas-in-place estimates for the Avalon Formation, which is the primary accumulation proposed for development at this time. The Hibernia Formation, Eastern Shoals Formation and South Mara member of the Banquereau Formation, are considered by the Proponent to be secondary zones with insufficient resources to make them economic. The Proponent also noted that two other zones, a Jurassic sandstone in the Whiterose E-09 well, and the Nautilus sandstone in the Whiterose N-22, well tested minor amounts of hydrocarbons. According to the Proponent, neither of these zones could be mapped and no resource estimates have been made. The extent of the three pools mapped by the Proponent in the Avalon Formation is shown in Figure 4.5 while the extent of the secondary pools is shown in Figure 4.6.

In March of 2001, the Proponent provided the document *"White Rose Oilfield Development Application Supplemental Report"* which, among other items, provided an update of the South Avalon pool reserve estimates incorporating data from the White Rose H-20 well. The Proponent provided a detailed description of the process, parameters and assumptions used to derive the oil and gas-in-place estimates for the Avalon pools. For the South and North Avalon pools, the Proponent used the gas-oil and water-oil contacts determined from wells drilled in these pools. However, for the West Avalon pool, the J-49 fluid contacts were used for fault block 15, while a range of fluid contacts were used for fault blocks 16 through 20 based on the J-49, N-30 and E-09 wells drilled in the West, North and South Avalon pools.

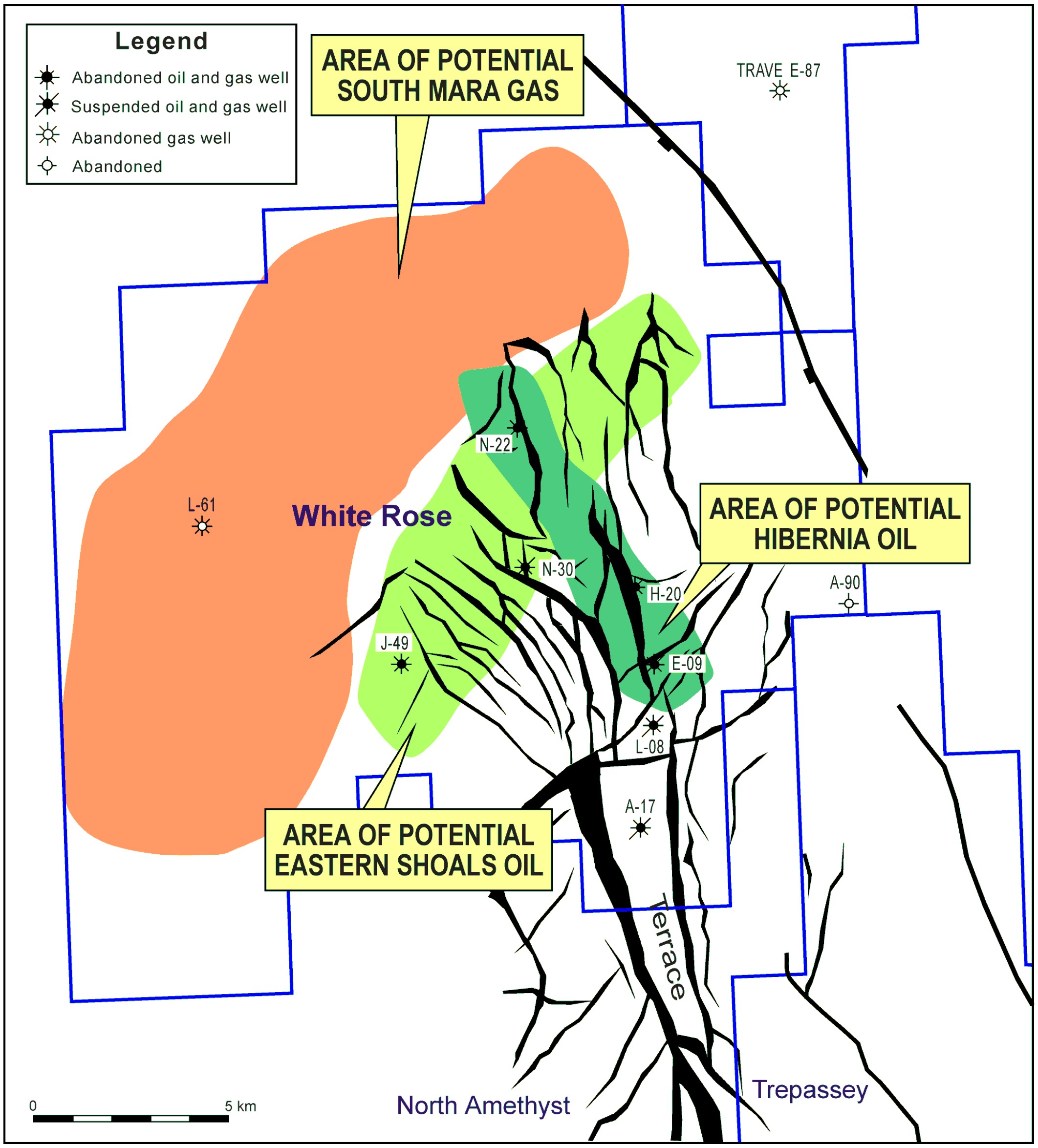
The Proponent used both deterministic and probabilistic procedures to estimate the oil and gas -in-place. In general, there was good agreement between the two approaches. The probabilistic numbers are presented. The oil-in-place estimate for the Avalon Formation is 178 10^6 m^3 (1,120 million barrels) while the gas cap gas-in-place estimate is 56 10^9 m^3 (2.0 tcf). This gas-in-place estimate is substantially less than the 89 $10^9 m^3$ (3.2 tcf) originally provided in Volume 2 of the Development Plan. Associated with the gas cap gas there is an estimated 11.9 10^6 m^3 (75 million barrels) of condensate-in-place.

Figure 4.5 White Rose Complex – Avalon Pools



Source: after Husky 2001

Figure 4.6 White Rose Complex – Secondary Pools



Source: after Husky 2001

In addition to the Avalon Formation original oil and gas-in-place estimates, the Proponent provided estimates for the Hibernia Formation, Eastern Shoals Formation and South Mara member of the Banquereau Formation. The Proponent's estimate of the Hibernia Formation oil-in-place ranges from 8 to 24 10^6 m^3 (50 to 151 million barrels), while the Eastern Shoals Formation oil-in-place is estimated to range from 6 to 9 10^6 m^3 (38 to 57 million barrels). According to the Proponent, these ranges are due mainly to uncertainty in pool extension and quality of sandstones. In the South Mara member, the Proponent estimates the original gas-in-place to range from 9 to 20 10^9 m^3 (0.3 to 0.7 tcf).

The Board conducted an assessment of the original oil and gas-in-place for the Avalon Formation pools, the Hibernia Formation and the South Mara member. In support of its assessment for the Avalon Formation, the Board undertook a review of the available geophysical, geological and engineering data. A comparison of the Board's and the Proponent's original oil and gas-in-place estimates for the Avalon Formation pools are provided in Table 4.4. (The P50 numbers in Table 4.4 indicate a 50 percent probability of occurrence of at least that in-place volume: correspondingly P90 and P10 numbers where used are in reference to low and high end estimates respectively.) There is good agreement between the Board and the Proponent respecting the original oil-in-place estimates for the total Avalon Formation. However, on a pool basis the Proponent carries a slightly higher oil-in-place estimate than that of the Board in the South Avalon pool, and significantly less in the North and West Avalon pools. As for the gas-in-place, the Board estimates are significantly higher than those of the Proponent for the Avalon Formation in general, and for the South and West Avalon pools specifically. There is good agreement between the Board and the Proponent for the North Avalon pool. There is no one factor that can account for the differences. Some of the observed differences include:

- the Board accounts for the gas resources in the southern portion of the Terrace block in the South Avalon pool. While the Proponent acknowledges the potential existence of these resources, they have been excluded from the Proponent's probabilistic resource estimates;
- in the South Avalon pool the Proponent carries a deeper oil-water contact than the Board, which partially accounts for the higher estimates of oil-in-place carried by the Proponent;
- in the North and West Avalon pools the Board carries a deeper oil-water contact than the Proponent, which partially accounts for the higher estimates of oil-in-place carried by the Board; and,
- the Proponent's base case for the West Avalon pool uses a range of gas-oil and oil-water contacts based on the N-30 and E-09 wells, except for the fault block containing the J-49 well which uses the contacts observed in this well. The Board uses the J-49 contacts, which results in higher volumes of gas-in-place.

Given the complex structural and depositional setting of the Avalon Formation in the White Rose field and the limited number of wells in the West and North area of the field, there are many plausible interpretations. Further drilling will clearly define fluid contacts and the oil and gas-in-place estimates in all pools. This drilling should be done in a timely manner to facilitate planning for the eventual exploitation of all of the oil and gas resources in the Avalon Formation pools.

The Board conducted an assessment of the oil-in-place in the Hibernia Formation and the gas-in-place in the South Mara member. These estimates are similar to those determined by the Proponent. While the Board has not conducted an assessment of the original oil-in-place for the Eastern Shoals Formation, it reviewed the assessment provided by the Proponent and believes it to be reasonable. A comparison of the Proponent's and Board's estimates is shown in Table 4.5.

Other hydrocarbons were encountered in the Jurassic sandstones in the Whiterose E-09 well, and Nautilus sandstone in the Whiterose N-22 well. The Board concurs with the Proponent that, based on current data, these accumulations could not be mapped. The Board expects the Proponent to evaluate further the potential of these accumulations prior to field abandonment.

The Board notes the difference between the Board and the Proponent in the oil and gas-in-place estimates. In the course of obtaining approval for the drilling program, pursuant to the *Newfoundland Offshore Petroleum Drilling Regulations*, the Proponent will be required to design the program to acquire additional information early in the development of the field to resolve areas of uncertainty surrounding these estimates. Also, should the results of drilling indicate any significant change in the premises upon which the present plan is based, the Proponent will be required to submit for the Board's approval an amended plan that takes this new information into account.

Condition 13:
Should the results of drilling indicate any significant change in the premises upon which the present Development Plan is based, the Proponent is required to submit for the Board's approval an amended plan that takes this new information into account. The Board will establish the date by which such a submission must be made considering the timing of the availability of new information.

Table 4.4
Avalon Formation Pools: Comparison of the Board's and Proponent's Original Oil and Gas-in-Place Estimates

	Avalon Formation Pool	Probability of Occurrence	C-NOPB	Proponent
Original Oil-in-Place ($10^6 m^3$)	South	P90	105.1	113.1
		P50	110.8	123.7
		P10	116.8	134.1
	North	P90	30.1	18.4
		P50	33.3	22.5
		P10	36.9	26.8
	West	P90	46.8	24.3
		P50	54.1	31.6
		P10	62.3	40.3
Total @ P50 ($10^6 m^3$)			**198.2**	**177.8**
(10^6 bbl)			**1247**	**1118**
Original Gas Cap Gas-in-Place ($10^9 m^3$)	South	P90	21.2	5.8
		P50	22.8	8.8
		P10	24.6	11.8
	North	P90	32.9	26.6

Table 4.4 Avalon Formation Pools: Comparison of the Board's and Proponent's Original Oil and Gas-in-Place Estimates				
	Avalon Formation Pool	**Probability of Occurrence**	**C-NOPB**	**Proponent**
		P50	36.8	33.2
		P10	41.7	41.5
	West	P90	25.1	10.7
		P50	29.0	14.3
		P10	33.5	19.2
Total @ P50 (10^9m^3)			**88.6**	**56.3**
(tcf)			**3.1**	**2.0**

Table 4.5 Avalon Formation Pools: Comparison of the Proponent's and Board's Original Oil And Gas-in-Place Estimates for Secondary Reservoirs			
Reservoir	**Avalon Formation Pool**	**Proponent Range**	**C-NOPB Range**
Hibernia	Original Oil-in-Place (10^6m^3)	8 to 24	13 to 28
South Mara	Original Gas-in-Place ($10m^3$)	9 to 20	6 to 24
Eastern Shoals	Original Oil-in-Place (10^6m^3)	6 to 9	No Estimate

4.6.5.2
Reserve Estimates

Assessment of the discovered oil and gas "Reserves" and "Resources" in oil and gas fields is an important function of the Board. It is important that the terminology it uses in relation to this section be clearly understood. The reader is referred to Appendix E, which describes the terminology used by the Board.

The Proponent's primary focus at this time is on development of the Avalon Formation oil reserves, specifically in the South Avalon pool. In the Development Application, the Proponent presented a detailed account of the assumptions and procedures used to estimate recoverable oil reserves for the Avalon pools. The Proponent used a probabilistic procedure to estimate reserves.

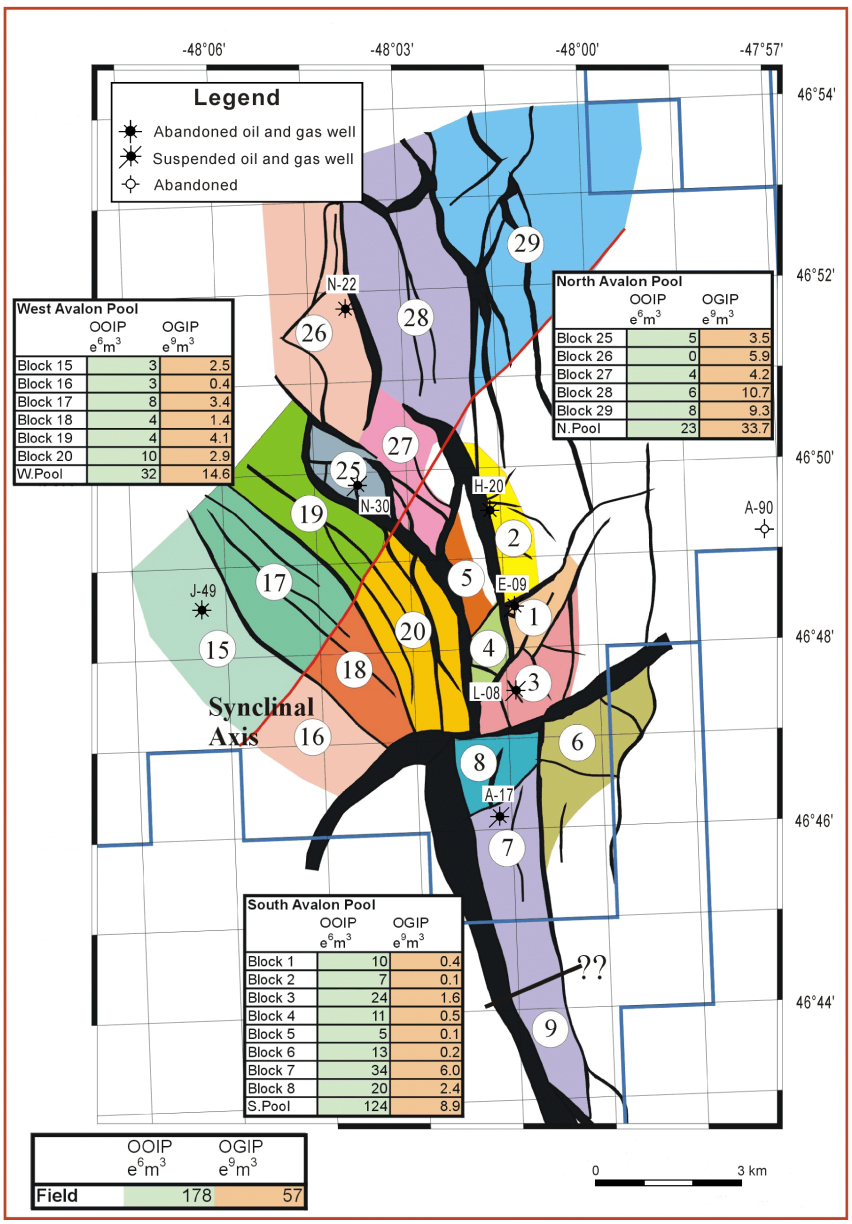
As the Proponent is proposing to develop the South Avalon pool, much of the work to assess reserves was focused on this pool. According to the Proponent, reservoir simulation studies carried out on the South Avalon pool determined a reference case recovery factor for the pool on a block-by-block and on a pool basis. Recovery factors for the West and North Avalon pools were selected based on reservoir performance observed in fault blocks in the South Avalon pool. The P50 recovery factors determined by the Proponent for the South, West and North Avalon oil pools respectively were 30.0, 23.6 and 24.7 percent.

For the South Avalon pool reserve estimates, the Proponent ran three cases as follows:

- downside case which excluded fault blocks 2, 5 and 6 (Figure 4.7);
- base case which excluded fault blocks 2 and 5; and,
- upside case which included all fault blocks in the South Avalon pool.

The final range of recoverable reserves reported by the Proponent for the South Avalon pool used the P90 volumes from the downside case, the P50 volumes from the base case and the P10 volumes from the upside case. For the North and West Avalon pools, the Proponent evaluated only fault block and total pool ranges.

Figure 4.7 Avalon Formation Oil and Gas in Place



Source: after Husky 2001

As the Proponent is proposing to develop only the White Rose Avalon oil accumulation at this time, these are referred to as reserves and are discussed below. The oil resources for the West and North Avalon pools are also discussed in this section of the report. The recoverable resource potential from the Avalon Formation gas along with other hydrocarbon accumulations is discussed in Section 4.6.9, “Deferred Development”.

A detailed review of the Proponent’s estimates of the White Rose field oil reserves and resources was carried out by the Board. The Board also conducted a review of the available geophysical, geological and engineering information; and reservoir simulation studies in support of its independent estimate of White Rose field Avalon Formation oil reserves. A comparison of the Board’s and Proponent’s reserve and resource estimates on the basis of the Board’s definitions is provided in Table 4.6. For the South Avalon pool, the Proponent’s P50 base case excluded fault blocks 2 and 5, the downside P90 case further excluded block 6 while the upside P10 case included all blocks.

There is good agreement between the Board and the Proponent respecting the original oil-in-place estimates for the total Avalon Formation; however, the Proponent carries higher oil reserves and resources estimates than the Board. The P50 oil reserves and resources for the Board and Proponent are 41.6 and 50.2 10^6m^3 (262 and 316 million barrels), respectively. For the South Avalon pool, the Board’s reserve estimate is 32.9 10^6m^3 (207 million barrels) while the Proponent carries 37.1 10^6m^3 (233 million barrels). The Proponent carries a slightly higher oil-in-place than the Board in the South Avalon pool, and significantly less in the North and West Avalon pools. Its oil reserves and resources, however, are higher than those estimated by the Board for all three pools. In the South Avalon pool, the Proponent carries more oil-in-place than the Board and that accounts for its higher reserves. The Proponent’s higher recovery factors provide the major explanation for its higher resources in the North and West Avalon pools.

Table 4.7 provides a comparison of the P50 recovery factors carried by the Board and Proponent for each pool. The Board based its recovery efficiencies on reservoir simulation studies conducted for the South**,** West and North Avalon pools. The Proponent based its recovery factors on reservoir simulation studies conducted only for the South Avalon pool. The current model carried by the Board indicates that the oil column in the West and North Avalon pools is about half as thick as that of the South Avalon pool. Also, the reservoir intervals containing the oil in the West and North Avalon pools are of poorer quality and consist of multiple intervals. Lower recovery factors would be expected under such conditions.

Table 4.6 Comparison of Avalon Formation Pools Oil Reserve and Resource Estimates (10^6 m^3)						
Avalon Formation Pool	**Probability of Occurrence**					
	P90		**P50**		**P10**	
	C-NOPB	**Proponent**	**C-NOPB**	**Proponent**	**C-NOPB**	**Proponent**
South Avalon Pool Oil Reserves	29.4	28.7	32.9	37.1	38.4	44.9
North Avalon Pool Oil Resources	1.4	4.2	2.3	5.3	3.4	6.6
West Avalon Pool Oil Resources	4.1	5.8	6.4	7.8	8.8	10.2

Table 4.7 Comparison of Avalon Formation Pools P50 Oil Recovery Factors		
Avalon Formation Pool	**P50 Case Oil Recovery Factor Percent**	
	C-NOPB	**Proponent**
South	29.7	30.0
North	6.9	23.6
West	11.8	24.7
Total Avalon Formation	**21.0**	**28.2**

4.6.6
Reservoir Exploitation

4.6.6.1
Exploitation Scheme

The Proponent is proposing to produce the oil reserves from the South Avalon pool. Development of the oil resources in the West and North Avalon pools will be considered at a later date. To assess and optimize the exploitation scheme for the South Avalon pool, the Proponent conducted three series of reservoir simulation studies as follows:

- South Avalon Pool Preliminary Model (November 1999). According to the Proponent, several of the reservoir simulation sensitivity analyses are based on this preliminary model developed in November 1999. It examined a waterflood in conjunction with gas injection into the south end of the Terrace block in the South Avalon pool that the Proponent now believes is isolated by faulting. The model did not include some faults incorporated in the current model. However, the Proponent contends that, despite the differences, the sensitivity work is still directionally valid;

- South Avalon Pool pre H-20 Model (March 2000). This model was created prior to drilling the H-20 well; and,
- South Avalon Pool post H-20 Model (August 2000). This model was created following drilling of the White Rose H-20 well and incorporated data acquired from the well. For this waterflood only case, all of the gas was injected into the North Avalon pool.

The Proponent also conducted a reservoir simulation study to assess the impact of storing gas from oil production in the South Avalon pool, on future recovery of North Avalon pool oil resources. A detailed summary of the assumptions and the results of the simulation studies was provided by the Proponent.

The Proponent examined four development options for the South Avalon pool. A comparison of the oil recovery factors and water and gas handling requirements for each case is provided in Table 4.8. The Proponent's preferred depletion scheme for the South Avalon pool is a water flood scheme with produced gas (net of fuel requirements) stored in the North Avalon pool. According to the information provided by the Proponent, in cases where all produced gas is re-injected into the South Avalon pool, oil recoveries are reduced significantly. For the partial re-injection cases, oil recoveries are not affected as significantly, but additional gas injection wells would be required to accommodate gas injection both within and outside the South Avalon pool. The Proponent noted that in all cases, re-injection of gas into the South Avalon pool increases gas-handling requirements due to earlier and more significant breakthrough volumes, and reduces project economics.

Table 4.8
South Avalon Pool: Oil Recovery Factors and Gas Handling Requirements for Alternative Development Options

Case	Recovery Factor (percent after 15 years)	Maximum Gas Rate ($10^6 m^3$)	Maximum Water Rate ($10^3 m^3$)
Water Flood only (Post H-20 Case)	41	2.8	23
Re-injection of gas into Terrace Block (November 1999 Model)	36	6.4 (capacity limited)	12
Re-injection of gas throughout the field(Pre-H-20 model)	34	10.1 (unconstrained)	19
Partial re-injection of gas throughout the field (Pre-H-20 model)	39	4.6	27

According to the Proponent, preliminary studies conducted on the North Avalon pool indicate that the area proposed for gas injection will be isolated from the oil leg by faults. The Proponent concludes that the oil leg in the North Avalon pool would not be impacted by gas injection. The Proponent conducted a reservoir simulation study to examine the impact of gas injection on the oil if the faults were not sealing. This study indicated a small amount of the in-place oil, approximately 5 percent, moved down into the water leg.

The Proponent reported that several reservoir simulation runs were performed to evaluate the impact of controllable and uncontrollable parameters. The controllable factors examined included oil and gas processing capacity and bottom hole operating pressure constraints for development wells. The greatest factor impacting on oil recovery from the South Avalon pool, with gas injection into the South Avalon pool, was gas processing capacity. Studies conducted by the Proponent indicated that at year 15, oil recovery could be reduced from 36 to about 32 percent if gas handling capacity was restricted to 3.5 10^6 m^3/d (124 mmscf/d). The uncontrollable parameters examined included vertical permeability, permeability barriers, reduced permeability in the water leg, non-sealing faults, sub-seismic faults (i.e. faults that cannot be identified using seismic data), and faults acting as flow conduits. With the exception of non-sealing faults, which indicated improved oil recovery, all other cases indicated that the recovery efficiency may be negatively affected by these factors. The presence of permeability barriers, which restrict communication and flow, exhibited the greatest potential to reduce oil recovery i.e. from the reference case 39 percent to about 25 percent.

The Board has conducted a reservoir simulation study to assess the depletion options for the Avalon Formation pools, and examine sensitivity to selected reservoir parameters. Reservoir simulation is a valuable tool to assess depletion options and provide input to estimating recovery efficiency. However, the reader is cautioned about comparing the recovery efficiencies from simulation studies such as shown in Table 4.8 to those used to estimate recoverable reserves and resources such as those shown in Table 4.7 presented in the previous section. It is the Board's view that the recovery efficiencies indicated from the referenced reservoir simulation studies are optimistic. The technical experts use judgment and take into consideration all factors, including reservoir simulation results, when assigning recovery efficiencies. The Board's reservoir simulation study concluded that the South Avalon pool is structurally not as well suited to gas injection as water injection. Gas injection resulted in lower oil recoveries. The study also assessed development of the North and West Avalon pools' oil resources. For the North Avalon pool, the Board's study concluded that due to faulting and the thin nature of the oil rim, oil development in this area may be marginal, and threshold economic reserves need to be established in order to screen fault blocks for development. The study also concluded that gas injection into the North Avalon pool could be managed without a major adverse impact on oil recovery and in the case of sealing faults without any adverse impact**.** It notes the West Avalon pool is highly stratified and faulted. Economic merits of development of the West Avalon pool need to be assessed through additional delineation drilling to properly understand and model the stratigraphy and reservoir properties in this area.

In relation to the proposed exploitation scheme, the Board concurs with the Proponent's proposed water flood scheme for exploitation of the South Avalon pool oil reserves and storage of gas, produced in association with the oil, into the

North Avalon pool. In implementing this scheme, to prevent oil movement into the South Avalon pool gas cap (which would lead to a reduction in oil recovery), it is important that the gas-oil contact be maintained at its current level through voidage balance and avoidance of gas production from the gas cap. If excessive production of South Avalon pool gas cap gas occurs, consideration will have to be given to injecting gas to maintain the gas-oil contact.

The Board acknowledges the potential reduction in oil recovery in the North Avalon pool if the faults are not sealing. However, the Board's and Proponent's current interpretation is that the faults are sealing. The Board believes that drilling a gas injection well in the North Avalon pool and monitoring the performance of the well, will provide information on the size of the oil and gas accumulation and the sealing nature of the faults. This information will be helpful to assess the economic development potential of the North Avalon pool oil resources. The Board also believes that, provided economic recovery of the North Avalon pool oil resources can be justified, any potential loss in oil recovery can be greatly reduced by initiating oil production as soon as possible following the start of gas injection. The Board will require the Proponent to assess the performance of the North Avalon pool under gas injection and also to assess the development potential of the oil resources early in the production phase and provide a report to the Board (see Section 4.3.9.6).

The Board notes the comprehensive sensitivity analyses conducted by the Proponent for both controllable and uncontrollable factors. From an uncontrollable factor perspective, in the Board's view, the greatest risk is flow performance. The Avalon Formation pools are complex and have permeabilities, an order of magnitude lower than the Hibernia and Terra Nova fields. The Proponent will need to assess and, as warranted, implement changes to its drilling, production and completion strategies to maximize recovery and sustain production.

The Board also notes that the Proponent is not proposing to develop fault blocks 2 and 5 in the South Avalon pool at this time. However, the Proponent's development drilling program provides for a pilot hole to be drilled into fault block 5. This, in conjunction with production performance data from the South Avalon pool, will provide information to assess the development potential of these fault blocks. It is the Board's view that extension of the proposed water flood into these fault blocks is covered by the current approval.

The Proponent's plan to place horizontal producers in the center of the oil column and displace the oil below the well via a bottom water flood, which is being done to reduce the risk of gas coning, could potentially leave a significant volume of "attic" oil trapped above the well. While concurring with the Proponent's plan, the Board nevertheless notes that, prior to termination of oil production activities, the Proponent is required by the *Newfoundland Offshore Area Petroleum*

Production and Conservation Regulations to examine opportunities to exploit this resource.

4.6.6.2
Development Well Requirements

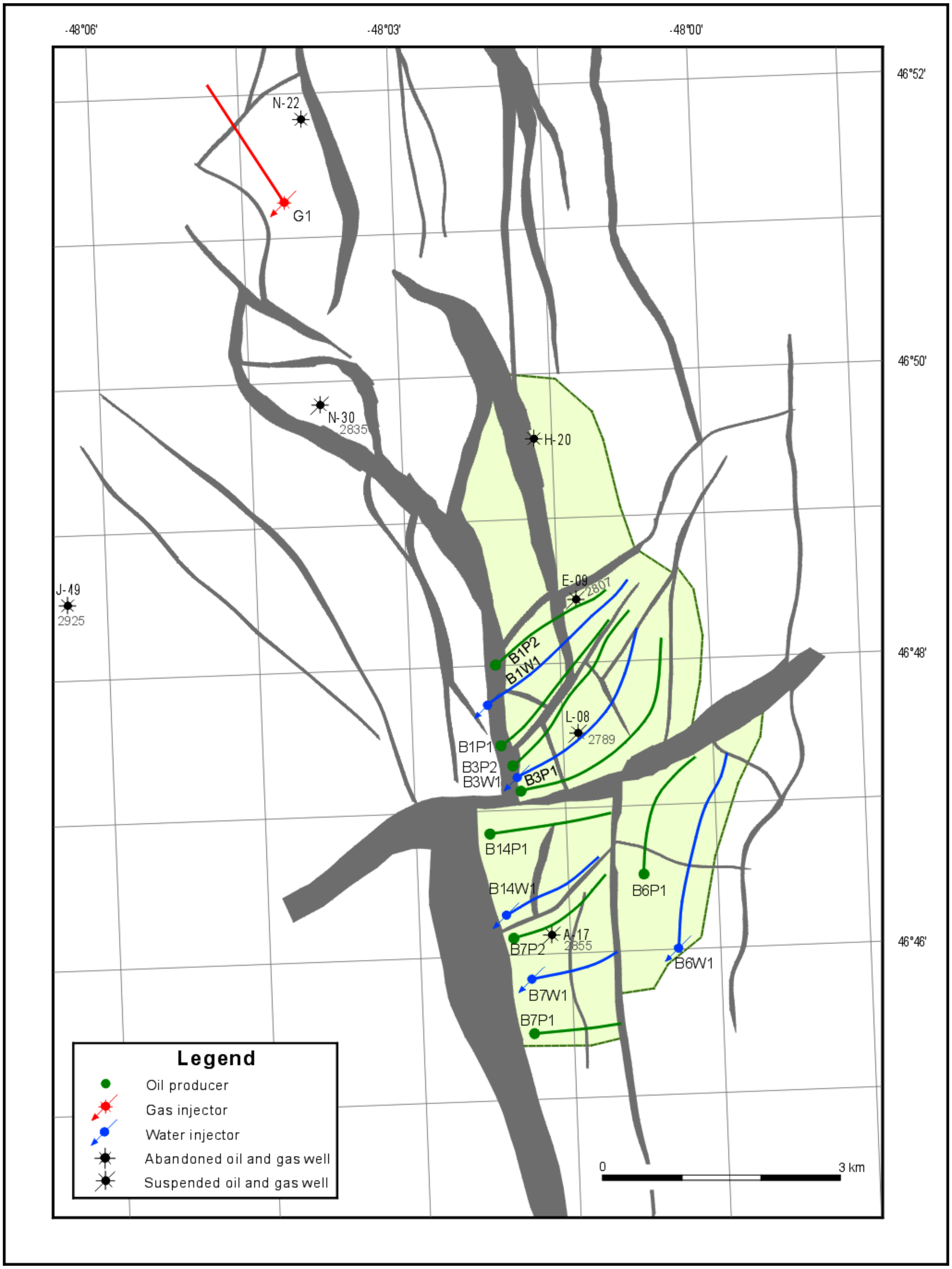
In the Development Plan, the Proponent noted that several reservoir simulation model runs were made to determine the horizontal well locations that would result in optimum oil recoveries. It was proposed to place horizontal water injection wells 50 metres below the oil-water contact to ensure dispersion of the injection water. Horizontal oil producers were placed to maximize recoveries while maximizing the time to water and gas breakthrough and minimizing the potential for gas coning. After accounting for information from the White Rose H-20 well, a total of eight production and five water injection wells were expected to be required to optimize reservoir performance. Two gas injection wells were also planned to dispose of gas produced in association with the oil. In total, 15 wells were proposed as shown in Figure 4.8. The Proponent noted that there was a potential need to drill up to 25 development wells, of which there would be 10 to 14 producing wells, six to eight water injection wells and two to three gas injection wells. The Proponent's plan is to drill the first gas injection well in the North Avalon pool N-22 area prior to production start-up and to have a second well completed shortly after production start-up. After monitoring the reservoir response, the Proponent will decide as to the number, timing and location of additional gas injectors, if required. Other potential locations for gas injector wells identified by the Proponent, include additional wells in the North Avalon pool, the West Avalon pool and the south end of the Terrace block in the South Avalon pool.

On October 16, 2001, the Proponent provided the Board with a revised development well layout and drilling schedule. According to the Proponent, the main risk areas associated with the well trajectories in the Development Application are as follows:

- drilling difficulty;
- injection water distribution assurance; and,
- reservoir uncertainty.

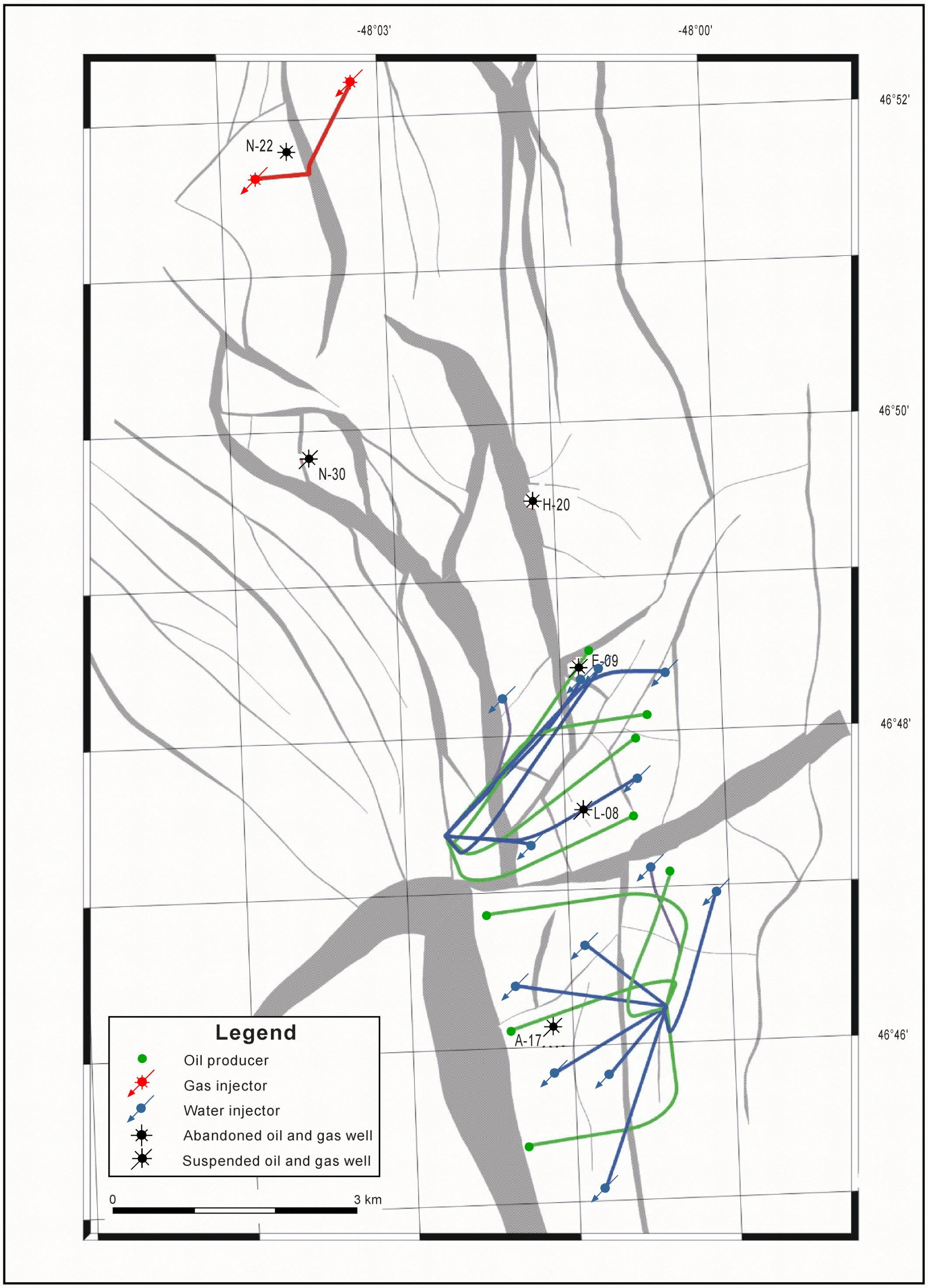
The Proponent noted that since the submission of the Development Application, the well layout has evolved to improve the implementation of the water flood development scheme from both an operations perspective and a risk perspective. The updated development well plan for the South Avalon pool development increases the well count to 21, of which eight are horizontal production wells, six are deviated water injection wells, five are shorter horizontal water injection wells and two are deviated gas injection wells. Two of the wells provide for pilot holes into undrilled fault blocks to verify hydrocarbon accumulations and reservoir quality. The locations for the revised development well configurations are shown in Figure 4.9.

Figure 4.8 South Avalon Pool Post H-20 Well Layout



Source: after Husky 2001

Figure 4.9 Updated South Avalon Pool Well Layout



Source: after Husky 2001

The Proponent notes the main characteristics of the updated well layout are:

- horizontal well trajectories do not have any curvature in the horizontal plane;
- horizontal well lengths have been minimized without risking recoveries;
- deviated water injection wells are used to ensure placement of water into sub-blocks where reserves are sufficiently large enough to justify a separate well;
- horizontal water injection wells with smart completions are used where a smaller sub-block does not have sufficient reserves to justify a separate injection well. The smart completions are limited to the control of a maximum of two sub-blocks to ensure high reliability;
- a combination of deviated injection wells and pilot holes are used to gather reservoir information that will assist in finalizing the location of horizontal production wells; and,
- the overall likelihood of achieving expected recoveries has improved as a result of reducing drilling, completion and injection water distribution risks.

According to the Proponent, the drilling sequence alternates early drilling between fault blocks to allow adequate time to utilize information from the initial well in a fault block (usually an injection well) to finalize the trajectory of the next well (usually a horizontal producer). This provides the best opportunity to maximize recoveries from that block. The Proponent's preliminary drilling sequence is given in Table 4.9, which describes the objectives for each of the wells and how the information acquired from the wells will be utilized to assist in decisions for subsequent wells.

The Proponent is not proposing development of the oil resources in the North and West Avalon pools or the White Rose field gas resources at this time. However, according to information presented by the Proponent, two to three development wells are expected to be required to recover oil from the North Avalon pool, and two to four development wells, with associated injectors will be required to deplete the West Avalon pool oil resources. The Proponent also estimates that eventually up to 10 additional wells may be required to develop White Rose gas resources.

The Board conducted an assessment of the development well requirements and locations for exploitation of the South Avalon pool oil reserves. The Board believes that the number and location of oil production and water injection wells proposed by the Proponent is reasonable. Because of the nature of the reservoir, there is a reliance on long reach horizontal wells to achieve and sustain reasonable oil production and water injection rates. Several of the wells are designed to drain more than one fault block. The Board believes that this is a reasonable approach to develop the oil reserves.

In respect of the two gas injectors proposed to conserve gas produced in association with oil production from the South Avalon pool, the Board's reservoir simulation studies suggest that to maintain an overall gas balance, more than two gas injectors may be required. The Board notes the Proponent has not ruled out more than two gas injection wells. The Proponent plans to monitor the reservoir response before deciding as to the number, timing and location of additional gas injectors. To conserve gas and minimize gas flaring, the Board believes that a second gas injector is required shortly after production is initiated to ensure that a backup gas injection well is available if problems should occur with a gas injection well. According to the drilling schedule presented by the Proponent, a second gas injection well would be the eleventh drilled or the first drilled following the initiation of production. However, if drilling is significantly behind schedule when production is initiated, the Board believes that the second gas injector well may have to be drilled earlier than scheduled. If gas cannot be conserved, the alternative will be forced curtailment of oil production.

The Board notes that resolution of uncertainties affecting the geological and geophysical interpretations may change the proposed well locations and the estimated number of wells required to deplete the oil reserves. These changes will be handled through the Drilling Program Authorization and Approval to Drill a Well issued by the Board.

The Board concurs with the Proponent that additional information and assessment is required prior to selecting development well locations for the West and North Avalon pools. In its subsea facility design, the Proponent is including provision for development wells in these areas if they can be economically justified. In relation to the estimated ten development wells to develop the gas resources, the Board believes, based on current information, the Proponent's estimate is reasonable. In any case, development of the West and North pool oil resources and the White Rose gas resources, will require a Development Plan amendment.

Table 4.9
Revised Preliminary Drilling Sequence for the South Avalon Pool (October 2001)

Order	Well Name	Glory Hole	Well Type	Well Objectives
1	B7VW3	South	Deviated Water Injector	Water injection support for southerly most producer (B7P1). Confirm reservoir structure, quality and contacts at the south end of the Terrace block. Information to optimize subsequent production and injection well trajectories in the Terrace Block starting with the B7P2 well.
2	B8VW1	South	Deviated Water Injector	Water injection support for the B8P1 well and possibly the B7P2 well. Confirm reservoir structure, quality and contacts at the north west side of the Terrace block. Information to finalize trajectory for the B8P1

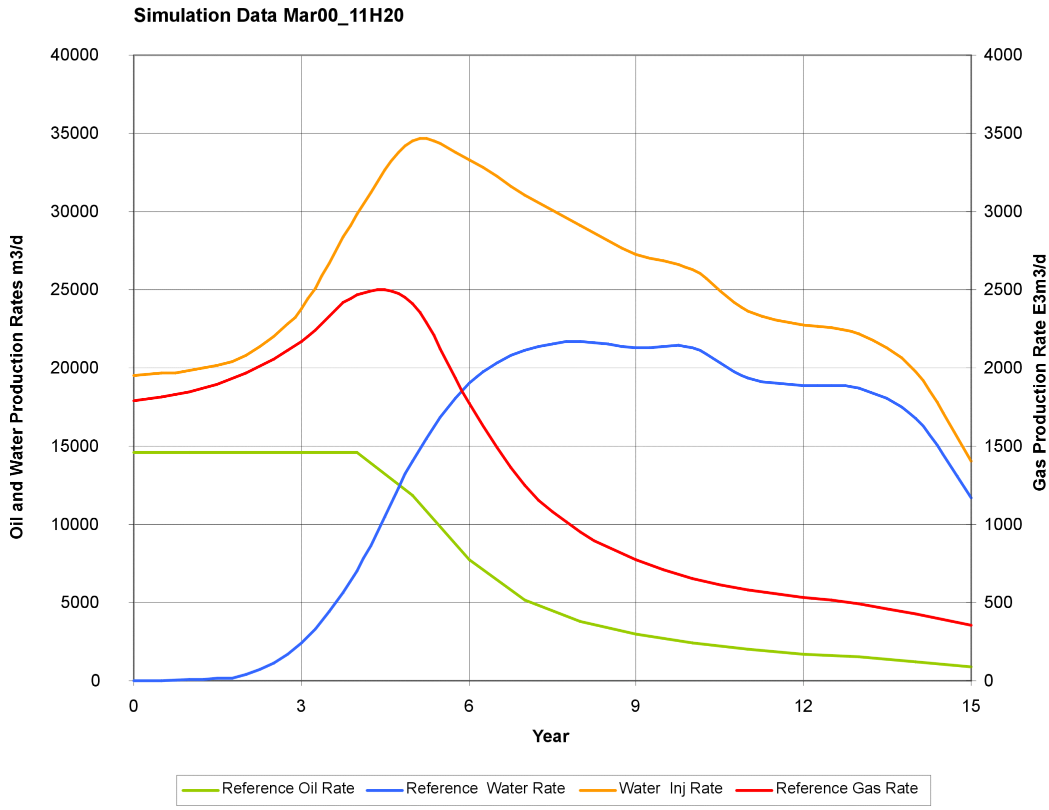
Table 4.9 **Revised Preliminary Drilling Sequence for the South Avalon Pool (October 2001)**				
Order	**Well Name**	**Glory Hole**	**Well Type**	**Well Objectives**
				well and possibly the B7P2 well
3	B7P2	South	Horizontal Producer	First production well – off set to A-17 delineation well
4	B8P1	South	Pilot to block 6 & Horizontal Producer	Verify hydrocarbons and reservoir quality in block 6 Second Production well
5	B26G1	North	Deviated Gas Injector	First gas injector Off set to N-22 exploration well Confirm reservoir structure and quality and provide information for finalizing the B28G1 gas injection well trajectory
6	B7VW1	South	Deviated Water Injector	Water injection support for the B7P1 and B7P2 wells
7	B7P1	South	Horizontal Producer	Third production well
8	B7VW2	South	Deviated Water Injector	Water injection support for the B7P1 and B7P2 wells
9	B3W1	Central	Horizontal Water Injector	Offset to L-08 delineation well Water injection support for the B3P1 and B3P2 wells Confirm structure, reservoir quality and pressure gradients for the sub-block east of the L-08 well. Information to finalize the trajectory for the B3P2 and B3P1 wells
10	B3P2	Central	Horizontal Producer	Fourth production well
Estimated First Oil On Board				
11	B28G1	North	Deviated Gas injector	Delineation well for eastward trends of the North Avalon pool Second gas injection well Confirm reservoir structure, quality and hydrocarbon pressure gradients east of the N-22 well. Information to be used for reducing risk of potential future North Avalon delineation wells
12	B3VW1	Central	Deviated Water Injector	Water injection support for the B3P1 and B3P2 wells Confirm reservoir structure, quality and hydrocarbon pressure gradients in the undrilled sub-block west of the L-08 well. Provide information on depositional trends towards the West Avalon pool. Information to be used for finalizing the B3P1 well trajectory and viability of delineating the West Avalon pool.
13	B3P1	Central	Horizontal Producer	Fifth production well
14	B8VW2	South	Deviated Water Injector	Additional water injection support for the B8P1 and possibly the B7P2 wells if required
15	B1P1-F	Central	Pilot to block 4 & Horizontal Producer	Confirm reservoir structure, quality and hydrocarbon pressure gradients in the undrilled sub-block west of the L-08 well Sixth production well

Table 4.9 Revised Preliminary Drilling Sequence for the South Avalon Pool (October 2001)				
Order	**Well Name**	**Glory Hole**	**Well Type**	**Well Objectives**
16	B1W1-F	Central	Horizontal Water Injector	Water injection support for the B1P1-F well
17	B1P1-A	Central	Horizontal Producer	Seventh production well
18	B4W1	Central	Horizontal Water Injector	Water injection support for the B1P1-A well
19	B11W1	Central	Horizontal Water Injector	Additional water injection support for the B1P1-A well
20	B6W1	South	Horizontal Water Injector	Depends on the pilot hole from the B8P1 well indicating sufficient oil volumes to justify development of this area. Confirm reservoir structure, quality and hydrocarbon pressure gradients in the undrilled sub-block south of the pilot hole well. Information to finalize trajectory of the B6P1 well Water injection support for the B6P1 well
21	B6P1		Horizontal Producer	Eighth production well

4.6.6.3
Production Forecast

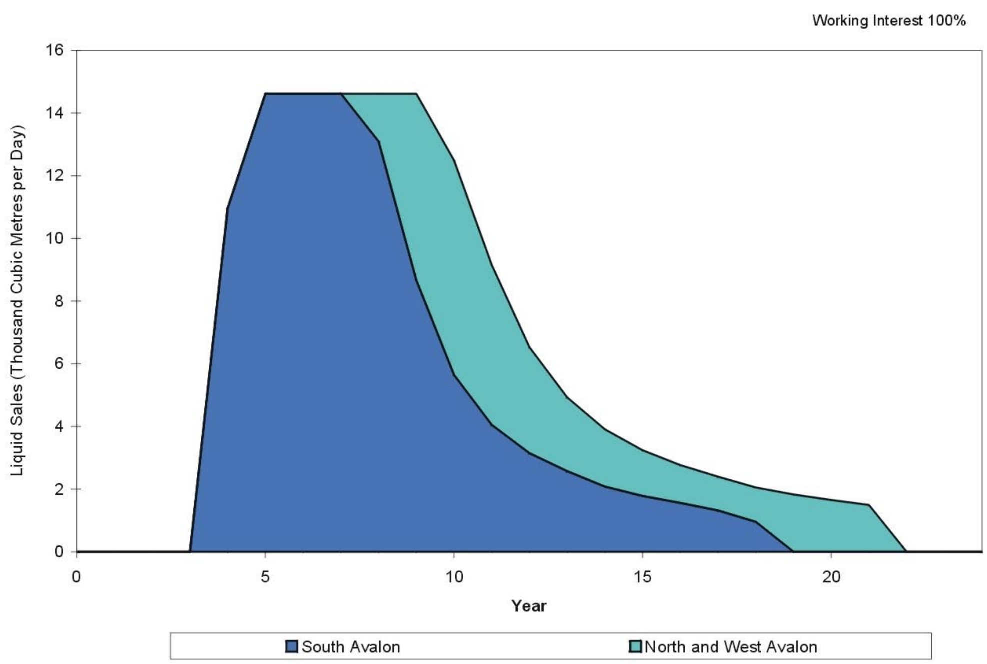
The Proponent's production and water injection forecast for its base case depletion strategy for the South Avalon Formation pool is provided in Figure 4.10. The forecast predicts that peak oil production of 14 628 m^3/d (92,000 bopd) will be maintained for four years and it will take 15 years to recover the oil reserves. According to the Proponent, the forecast is based on an operating efficiency of 92 percent, relative to a facility design rate of 15 900 m^3/d (100,000 bopd), and recoverable oil reserves of 36.2 $10^6 m^3$ (230 million barrels). Potential development of oil resources in the West and North pool could extend the plateau period as shown in Figure 4.11.

Figure 4.10 South Avalon Pool Production Forecast



Source: after Husky 2001

Figure 4.11 Plateau Period Extension Potential



Source: after Husky 2001

The authorization of oil and gas production rates is an important aspect of the Board's responsibilities under the legislation. The rates proposed by operators are assessed by the Board to ensure they are within safe operating limits for the facilities and will not adversely affect oil and gas recovery. In addition, the Board monitors production from fields and reservoirs to ensure that levels are consistent with the approved annual production rates and that good oil field practices are being observed. It is important for all stakeholders to understand clearly how certain rates are defined and administered.

The Board administers the following rates:

Annual Oil Production Rate (AOPR)
The Annual Oil Production Rate is the maximum annual oil or gas off-take rate authorized for a reservoir or field. It is approved by the Board as part of the Development Plan. This rate is defined by the plateau level of the production forecast and is based on the depletion strategy adopted for the field. This rate is usually expressed as an annual average daily production rate, in cubic metres per day. In approving this rate, the Board must be satisfied that it will not adversely affect oil or gas recovery. Any increase in this rate requires an amendment to the Development Plan. Such amendments also require the approval of both Ministers.

Facility Maximum Daily Production Rate (FMDPR)
The Facility Maximum Daily Production Rate is the oil or gas production rate at which the facility can maintain stable production operations with sufficient reserve capacity to accommodate operational upsets without exceeding the Maximum Safety Related Capacity of the platform. Typically, this is the design production rate for the processing facility, and it may be revised after production begins based on operating experience. There may be minor excursions above this rate during production operations, but these would only be of short duration.

The Board's Chief Safety and Chief Conservation Officers approve the Facility Maximum Daily Production Rate. In approving this rate, these officers give consideration to safety and resource management issues.

Maximum Safety Related Capacity (MSRC)
The Maximum Safety Related Capacity is the maximum oil or gas rate at which the platform may be operated. It is determined taking into account the safe operating limits of pressure relief, blow-down and flare systems, piping and equipment vibration, noise limits, cavitation, corrosion and erosion parameters. It provides a safety margin above the facility maximum daily production rate authorized for the facility, to allow for operational upsets. The maximum safety related capacity is expressed in cubic metres per day and is established by the Board's Chief Safety Officer. This rate may not be exceeded.

Well Rates
The Board may require operators to assess the impact of production rate of development wells on recovery efficiency and submit the results for review. The Board may set production rate limitations on wells to prevent waste. These limitations may be varied, as production information is acquired. The Board's Chief Conservation Officer establishes well rate limitations.

The Board considers the Proponent's South Avalon pool production and injection forecast to be reasonable and based on its own studies believes that the reservoir can support the oil production rate of 14 628 m^3/d (92,000 bopd) as described in the Proponent's submission. The Board notes that the Proponent's reservoir simulation studies suggest that oil recovery is not sensitive to an annual oil production rates up to 15 900 m^3/d (100,000 bopd) which is the proposed design oil processing capacity of the production facility. Therefore, the Board approves an annual oil production rate of 5.8 10^6 m^3 (approximately 36.5 million barrels) based on an average daily rate of 15 900 m^3/d (100,000 bopd).

The facility design rate of 15 900 m^3/d (100,000 bopd), subject to design certification, will become the Facility Maximum Daily Production Rate. Should the Proponent be able to demonstrate a higher sustainable daily safe throughput capability, through minor facility modifications ("debottlenecking") or otherwise, the approved rate could be subject to upward revision.

A Maximum Safety Related Capacity will be established based on operating performance.

The Board notes that the production of oil from the West and North Avalon pools could extend the plateau production period and the life of the field. Should the Proponent proceed with development of the oil resources in these pools, as previously noted, the Board will require a Development Plan amendment including a revised production forecast, which takes development of these areas into consideration. Also, the Board observes that the production forecast does not account for any natural gas liquids that will be produced when processing the gas for injection, particularly coned gas. The Board appreciates the difficulty in preparing the gas liquids production forecast given the uncertainty in some of the data. Nevertheless, it is important for the Board to have this information in order to discharge its duties.

4.6.6.4
Enhanced Recovery Scheme

The White Rose Commissioner requested additional information from the Proponent regarding the results of any studies undertaken to examine the use of methods, other than natural gas and water flood, to provide reservoir pressure maintenance. In response, the Proponent noted that alternative recovery mechanisms, other than water and gas injection, were evaluated and screened out early in the White Rose South Avalon pool depletion assessment. According to the Proponent, due to the initial reservoir pressure, reservoir temperature, large gas cap area and underlying water leg, miscible flooding was not considered a viable option. Polymer flooding and other types of viscous floods also are not considered viable due to the relatively low permeability of the reservoir. The Proponent considers carbon dioxide, compressed air or other gas injection options into the South Avalon pool, not viable because they could increase gas handling problems and require additional expensive gas compression facilities. These are relatively new and unproven technologies that do not have an historic offshore application. It is the Proponent's opinion that the alternative options would increase the development costs because of increased facilities requirements and higher operating costs without increasing overall oil recovery.

The Board concurs with the Proponent's opinion concerning alternative recovery mechanisms. However, consistent with the requirement of the *Newfoundland Offshore Area Production and Conservation Regulations*, the Proponent is expected to routinely assess the potential for enhanced recovery schemes throughout the producing life of the pool.

4.6.6.5
Gas Conservation

The Proponent's preferred option for gas conservation is to inject the produced gas into the gas cap areas of the North Avalon pool. The Proponent's plan is to drill the first gas injection well in the North Avalon pool. A second gas injection well is planned for the North Avalon pool and is expected to be available shortly after initiation of oil production.

The Board concurs with the Proponent's plan to conserve gas by re-injecting it into the North Avalon pool. However, because the potential exists for gas injection into the North Avalon pool to adversely affect oil recovery, the Board believes that the impact of gas injection needs to be thoroughly assessed early in the development. Also, as gas injection is not part of a depletion scheme to exploit the oil resources in the North Avalon pool and the gas is being injected for the purpose of gas storage, in accordance with legislation, the Proponent will be required to apply for a subsurface gas storage licence.

4.6.6.6
Reservoir Management

The Proponent notes that reservoir simulation is being used to evaluate and optimize proposed development scenarios and that the development well locations will be drilled based on this information, with updates using new data acquired during development drilling and production activities. The following issues will govern the Proponent's reservoir management objectives for the White Rose field:

- water injection should occur below the formation fracture pressure to optimize sweep efficiency;
- pool areas that are not in communication should be identified and steps taken to optimize recovery where possible; and,
- thief intervals or breakthrough points in horizontal wells should be identified and means of correction evaluated when necessary to optimize sweep efficiency.

According to the Proponent, proper data collection programs will be designed and implemented to meet reservoir management objectives. An overview of the data acquisition being considered by the Proponent, which includes well tests, pressure surveys, fluid sampling, coring, open hole logs and cased hole logs, is presented. In respect of performance monitoring, several variables- pool pressures, water cuts, gas-oil ratios, production rates and injection pressure- will be used to update reservoir simulation models. These models will be used to evaluate various scenarios to select infill well locations, design recompletions and manage voidage replacement with the goal of optimizing recoveries. The Proponent notes that production optimization is a broad topic involving reservoir, wellbore, subsea, and surface facility issues. The Proponent plans to optimize well completions, wellbore hydraulics and subsea and surface facilities during development planning considering the field production and injection conditions over the life of the field, and has made the following general comments regarding production optimization for the South Avalon pool:

- water injection will be used to replace production volumes and maintain reservoir pressures. The target voidage replacement ratio is 1.0;
- treatments on injectors or producers (to control production from, and injection into reservoir intervals) may be required in the event of premature water or gas breakthrough. Work will be evaluated on a case-by-case basis to determine if sweep efficiencies can be improved; and,
- increasing water cuts over time will cause a requirement for artificial lift in order to maintain production volumes. The wells will be completed to allow for gas lift.

According to the Proponent, there are several studies planned for the pre-production through to reservoir development and depletion phases. A comprehensive list of activities, as outlined in Section 6.9 Volume 2 of the Application, is provided by the Proponent. These activities are to be performed prior to pre-production drilling. The studies will include recommendations on how to capture and apply data from development drilling and field depletion performance. The Proponent states that these data will be used to improve the understanding of factors affecting performance and identify improvement opportunities.

On October 16, 2001, the Proponent provided further clarification on its formation evaluation principles and noted some of the basic principles, which are being used in developing the well formation evaluation requirements:

- LWD/MWD logs will be run on all wells. It is anticipated that as the Project proceeds it will be demonstrated that these logs may eliminate some of the wireline or TLC logging requirements;
- in addition to LWD/MWD, a standard logging package including Gamma Ray, Resistivity, Neutron, Density and directional measurements will be run on all wells until it can be demonstrated that some of these can be replaced by LWD/MWD;
- if LWD logs are determined to be unable to replace wireline logs, then the continued use of this form of data acquisition will be reassessed;
- image logs will be considered for pilot holes, and a portion of the other wells;
- core will be considered for the pilot holes and potentially for deviated wells in key undrilled blocks (providing hurdles for continuous sand are met);
- pressure gradient logs will be run in pilot holes, selected deviated wells and potentially intermediate sections of selected horizontal wells;
- the capability to capture fluid samples (including water) at the time of running pressure gradient logs will be available;
- production logs will not be run at the time of completion of the horizontal producers but will be considered for production wells with identified production performance problems on an as needed basis;
- initially, cement bond logs will be run prior to installation of the completion. As the Project proceeds the requirement for cement bond logging will be evaluated and potentially eliminated; and,
- service providers will be capable of providing other identified formation evaluation services that may be required on an ad hoc basis.

The Board believes that the data acquisition activities, which the Proponent describes, are consistent with the requirements of the *Newfoundland Offshore Area Petroleum Production and Conservation Regulations* and the *Newfoundland Offshore Petroleum Drilling Regulations*. Details of these programs will be subject to the approval of the Board as part of its Drilling Program and Production Operations authorization approval processes. The Board expects the Proponent to continue to investigate options to maximize recovery of the oil and gas resources. The Board notes the Proponent has identified optimization plans and planned studies through to pre-production drilling.

4.6.6.7
Summary – Reservoir Exploitation

The Board concurs with the Proponent's proposed exploitation plan for the South Avalon pool. However, the various interpretations and analyses, both by the

Proponent and by the Board, have indicated several factors that may affect the number and location of development wells and reservoir performance. These are:

- the sealing nature of the faults;
- the location of the oil-water contacts;
- the degree of vertical communication within the reservoir sandstones; and,
- production and injection performance of development wells.

Many of these factors are being studied by the Proponent prior to initiating development drilling. Each of these considerations affects both the reserve estimates and the exploitation strategy. The Board recognizes that ongoing studies and early drilling and production data could affect reserve estimates and exploitation strategy. The Board believes that the proposed exploitation scheme is reasonable. Gas injection into the North Avalon pool will conserve the gas for future production. However, the Board notes that the impact of gas injection on the North Avalon pool oil recovery needs to be re-assessed early in the development. The Board approves of the Proponent's proposed drilling plans and believes it is a reasonable approach. The Board acknowledges that resolution of uncertainties affecting the geological and geophysical interpretations may change the location and number of wells required to deplete the oil reserves. The Board believes the Proponent's production forecast is reasonable and approves an annual oil production rate of 5.8 $10^6 m^3$ (36.5 million barrels) based on an average daily rate of 15 900 m^3/d (100,000 bopd). However, the Board notes no production forecast has been provided for natural gas liquids, which will be produced when processing gas for injection and in association with any coned gas. It is important for the Board to have this information in order to discharge its duties. In terms of enhanced oil recovery, the Proponent must assess opportunities to improve oil recovery. The Proponent is continuing with studies and assessment to optimize the Development Plan. Several studies and activities are to be completed prior to pre-production drilling. The Board will review the results of these studies and activities.

It is a condition of the Board's approval that:

Condition 14:
The Proponent provide to the Board within 12 months following the initiation of sustained gas injection into the North Avalon pool, an assessment of the gas injection performance and its potential impact on recovery of oil resources in the North Avalon pool.

Condition 15:
The Proponent, prior to initiating oil production, provide a procedure acceptable to the Chief Conservation Officer for estimating the liquids produced in association with coned gas and report these estimates to the Board as part of the monthly production report.

Condition 16:
The Proponent provide to the Board, prior to initiating development drilling, a report summarizing the result of the activities and studies outlined in

Section 6.9 of the *White Rose Oilfield Development Application Volume 2: Development Plan*.

4.6.7
Field Hydraulics

The Proponent conducted well performance modeling, for both flowing and gas lift scenarios, based on the reservoir properties of the discovery and delineation wells. According to the Proponent, the flowing well model suggests that oil rates between 2 800 and 4 200 m^3/d (17,600 and 26,400 bopd) are possible from horizontal wells completed with 140-mm tubing. Also, the flow model indicates that oil wells will require artificial lift when water cut exceeds 40 percent.

The Proponent notes that 178 mm monobore completion may be employed in selected cases to facilitate higher production and injection rates where friction pressure loss from high velocity fluids is a concern. The Proponent plans to use 178 mm tubing for its injection wells and for its first four horizontal production wells, and to base its decisions on future production tubing size on experience gained from its first four production wells. A gas lift operating valve will be installed in all producing wells. The size of the injection lines to be chosen for each template will be based on an assessment of anticipated total injection rates and requirements for operating flexibility. The Proponent states that it will conduct further studies before finalizing its flowline sizes.

The Board notes that the Proponent has not conducted technical studies to optimize the field's hydraulic performance. These studies should assess flow performance from the reservoir to the process facilities and include an assessment of the effects of the proposed FPSO location on oil recovery. The Board will require submission of these studies prior to finalizing flowline design.

Condition 17:
Prior to finalizing the subsea flowline design, the Proponent submit for approval of the Chief Conservation Officer, the flowline sizes and the location of the FPSO, supported by the field hydraulic studies which provide an assessment of these factors on oil recovery.

4.6.8
Production System and Production Facilities Capabilities

The Proponent contracted Kvaerner SNC Lavalin Offshore (KSLO) to conduct a concept selection study to identify the potential alternatives for developing the White Rose Oilfield. According to the Proponent, eight alternatives were evaluated:

- steel ship-shaped Floating Production Storage Offloading (FPSO) facility;
- concrete FPSO facility;
- steel Semi-submersible facility with and without integrated storage;
- concrete Semi-submersible facility;

- concrete Gravity Base Structure (GBS);
- disconnectable concrete Tension Leg Platform (TLP);
- concrete barrier wall with a Floating Production Unit (FPU); and,
- steel Floating Production Drilling Storage Offloading (FPDSO) facility.

A comprehensive assessment was conducted on the options using criteria based on technical considerations, capital costs, construction time, concept maturity and deliverability, and risk considerations. The Proponent used a two stage screening process. Stage one involved a qualitative screening to eliminate options that were either undeveloped or clearly failed to satisfy primary technical criteria. The disconnectable concrete TLP, concrete barrier walls with FPU, and steel FPDSO facilities were eliminated at this stage. The assessment of the remaining five options concluded that the preferred production system for the White Rose oilfield development is a steel FPSO facility using subsea wells located in glory holes. According to the Proponent, the key factors contributing to the FPSO as a preferred option include the following:

- it is the most economically feasible way to develop the White Rose oilfield, taking into account feasibility, flexibility, deliverability, economic attributes, risk and safety and Canada-Newfoundland benefits;
- it has commercial and technical flexibility that is well suited to a complex field such as White Rose with technical challenges and reservoir uncertainties;
- it has a proven track record in harsh environments, with 20 units installed, or in construction in the last eight years;
- it can produce both oil and gas in sequential development;
- it has flexibility to tie in future fields;
- it offers the shortest time to First oil, thereby enhancing economics; and,
- it poses less of a challenge at decommissioning than a bottom-founded structure.

The Proponent noted the following further attributes of the steel FPSO option:

- it will provide an opportunity for continuous employment and a growing industry base for the Province;
- it will provide on a competitive basis the opportunity to develop the current capabilities of the Newfoundland workforce;
- it will increase competitive opportunities for the shipyard in Marystown;
- it will increase opportunities for facilities providing expertise in engineering, subsea and topside fabrication, drilling and supply services on a competitive global basis;
- it will establish and consolidate a proven and leading exportable technology in the Province for future developments off the east Coast of Canada and abroad; and,
- it will enable expertise and industry within the Province to keep pace with the trend in offshore oil and gas development throughout the world.

The Proponent stated that the GBS was ultimately discounted as an option on the following grounds:

- it is not economically viable for a field of the size of White Rose;
- of all options considered, it compares the most unfavorable with the steel FPSO option on cost and deliverability;
- it requires a long lead time;
- it presents problems for decommissioning and abandonment, and is not practical for relocation for further service at another site;
- there are insufficient oil reserves proven in the field to justify its use, and there is a high degree of uncertainty about the extent of further gas reserves yet to be proven;
- its forecast life-cycle cost is some $507 million more than the steel FPSO option; and,
- with a forecast negative return on investment, it is an option which owners will not be able to implement based on commercial and business considerations.

The Proponent also provided, in response to a request from the White Rose Commissioner, an economic assessment of the FPSO and GBS options, which incorporated revised cost estimates. There was a significant cost increase for the GBS. The results of the analysis are summarized in Table 4.10. The GBS relative to a FPSO increased the average cost per barrel by more than 50 percent. The Proponent's view is that a GBS is not a viable investment for the proposed White Rose Project and the Proponent would not proceed with this Project on the basis of a GBS. The Commissioner concurs with the Proponent that the FPSO is the most cost effective system for the White Rose Project.

Table 4.10
Proponent's Comparison of Capital Costs for FPSO and GBS

Cost Element ($million)	**FPSO**	**GBS**
Project Management	110	140
GBS Substructure	0	1080
GBS Topsides	0	1425
FPSO	960	0
Subsea/Pipelines/Offloading	250	100
Drilling and Completion	750	495
Total	**2070**	**3240**
Development Cost/bbl(excluding abandonment)	9.00	14.08

The Proponent's Development Plan provides preliminary design requirements for the White Rose FPSO and development wells and describes the proposed oil, water and gas production facilities to be installed on the FPSO. A summary of the Proponent's preliminary design requirements for the FPSO is provided in Table 4.11. The Proponent noted the design throughput of up to 18 000 m^3/d (113,000 bopd) was based on the technical and economic evaluations carried out to that point. According to the Proponent, an ongoing optimization program will be in place over the life of the field to capture potential incremental capacity up to 20 000 to 22 000 m^3/d (126,000 to 138,000 bopd) through debottlenecking, increased well performance, or the tying in of additional reserves from the North Avalon and West Avalon pools and other potential secondary pools.

Table 4.11
Preliminary Design Requirements for the White Rose FPSO

System	Capacity
Oil Production Rate	12 000 to 18 000 m^3/d
Water Production Rate	15 000 to 30 000 m^3/d
Total Fluids Production Rate	30 000 to 35 000 m^3/d
Gas Production Rate	3 to 7 $10^6 m^3$/d
Gas Injection Rate	3 to 7 $10^6 m^3$/d
Field Gas Lift Rate	3 to 7 $10^6 m^3$/d
Water Injection Rate	40 000 m^3/d
Oil Storage	110 to 135 $10^3 m^3$

On October 17, 2001, the Proponent provided further clarification on the design requirements for the FPSO, the turret system and the subsea system. The design requirements for the FPSO include:

▪ Oil Production Rate	15 900 m^3/d	100,000 bopd
▪ Water Production Rate	28 600 m^3/d	180,000 bpd
▪ Total Fluids Production Rate	33 000 m^3/d	208,000 bpd
▪ Total Gas Rate (including lift gas)	4.2 $10^6 m^3$/d	150 mmscf/d
▪ Maximum Total Gas Lift Rate	1.6 $10^6 m^3$/d	57 mmscf/d
▪ Peak Field Gas Injection Rate	3.7 $10^6 m^3$/d	131 mmscf/d
▪ Peak Field Water Injection Rate	44 000 m^3/d	277,000 bpd
▪ Oil Storage	148 $10^3 m^3$	930,000 bbls

A dual train gas compression system has been proposed instead of the single train gas compression system presented in the Development Plan Application.

A single test separator is proposed with the following capacities:

▪ Maximum Total Liquids	6 000 m^3/d	37,700 bpd
▪ Maximum Oil	6 000 m^3/d	37,700 bopd
▪ Maximum Water	4 500 m^3/d	28,400 bpd
▪ Maximum Gas	1.8 $10^6 m^3$/d	64 mmscf/d

The Proponent also described the FPSO turret system flexibility to accommodate future oil production from the deferred oil accumulations, gas production from the gas injection wells and export of gas. According to the Proponent, the turret is designed with two groups of passages, one interfacing with the topside and one interfacing with the subsea risers. Table 4.12 provides a listing of these. The turret has provisions to accommodate an additional production center, which can accommodate two production flowline risers, one water injection riser and one gas lift riser. While future production swivel passages will be physically included in the swivel stack, piping will not be connected to them until their final service is defined. The gas injection passage and swivel design will accommodate future gas production from the gas injection wells. However, as noted by the Proponent, it would be necessary to change some piping offshore. According to the Proponent, the spare production/export gas swivels are designed for future export of gas treated to meet typical pipeline specification. The Proponent notes space will be allocated and supports provided to allow retrofit of piping and a pig launcher/receiver between the future gas export riser and the swivel stack.

Table 4.12
Turret Provisions

Swivel Passages Interfacing to Topsides		**Risers Interfacing to Subsea**	
4	Production/Test	4	Production/Test
1	Water Injection	2	Water Injection
1	Gas Lift	2	Gas Lift
1	Gas Injection	1	Gas Injection
5+	Separate Chemical Injection	3	Multi-Line Umbilicals
2	Spare Production/Export Passages	4	Spare Slots

The Proponent notes that all parts of the subsea system are designed with flexibility for changing production requirements including additional wells, tie-in of new production centers and production of gas from the gas injection wells. To accommodate oil development in the West and North Avalon pools, the Proponent proposes to provide for the ability to install twin production risers and water injection and gas-lift risers. The Proponent will also conduct an electrical and hydraulic analysis to demonstrate that the control system is capable of controlling up to 33 production, gas injection and water injection wells.

In reviewing the material and explanations presented by the Proponent in defense of its position, the Board has concluded that the relative costs between the FPSO and GBS have been fairly determined.

It is not reasonable to believe that the $1.1 billion difference in the cost estimates between the FPSO and GBS could be closed by a more refined estimate. The difference is substantial even without considering abandonment costs for the GBS, which the Proponent has estimated at $500 million. Although certain technical publications have suggested there may be new processes and construction techniques that could reduce capital costs, such methods are unproven and there is no reason to expect that the costs could approach those associated with an FPSO. Consequently, the Board believes there would be no merit in pursuing a lengthy and costly process of re-examining potential GBS costs.

The Board has reviewed the proposed production system with respect to its potential effect on recovery of the oil and gas resources and has concluded that any minor incremental production gain based on possible lower abandonment economic limits with a GBS cannot be justified in comparison to large capital cost differences.

In terms of oil reserves for offshore oil fields in similar environments, the White Rose field is not considered to be large and based on the Board's current understanding of the data, there does not appear to be substantial oil resource upside potential.

The Proponent's desire to reduce capital exposure, as would be the case with a mobile FPSO vessel relative to a fixed GBS structure, and maintain flexibility under such circumstances is understandable.

The Board believes that the Proponent's plans for oil, gas and water processing are reasonable. Also, the Board believes that the Proponent's design reasonably provides for the production of deferred oil and gas resources. As previously noted, the FPSO can, if required, be modified to accommodate gas exports.

The Board acknowledges on July 4, 2001 the document *"Flow Measurement & Metering Philosophy"* outlining the proposed flow measurement and metering philosophy for the White Rose Project was received from Maersk, the Proponent's contractor. The document addressed the minimum requirements for all metering applications as required within the *"Guidance Note for Standards of Measurement in the Newfoundland Offshore Area, Draft October 2001"*. The Board notes that in accordance with the *Newfoundland Offshore Area Petroleum Production and Conservation Regulations*, the Proponent is required to submit details of the fluid metering and allocation procedures for review and approval by the Board's Chief Conservation Officer.

It is a condition of approval that:

> **Condition 18:**
> **No changes are to be made to the design requirements for the FPSO, the turret and the subsea system, from those set out in the Application and follow-up submissions which provide for accommodating future deferred oil and gas production, without the approval of the Board.**

4.6.9
Deferred Development

The Proponent addressed the following deferred developments in the Development Plan Application and the *White Rose Oilfield Development Application Supplemental Report*, March 2001:

- North Avalon oil;
- West Avalon oil;
- Eastern Shoals oil;

- Hibernia Formation oil; and,
- White Rose gas resources.

Each of the deferred developments is briefly reviewed in the following sections.

4.6.9.1
North Avalon Oil Deferred Development

The Proponent notes that the North Avalon pool is comprised of several fault blocks. According to information contained in the *White Rose Oilfield Development Application Supplemental Report*, March 2001, the gas-in-place in the gas cap ranges from 26.6 to 41.5 $10^9 m^3$ (0.9 to 1.5 tcf), while the oil-in-place ranges from 18.4 to 26.8 $10^6 m^3$ **(**115 to 169 million barrels**)**.

The Proponent plans to store excess gas from the South Avalon pool in the North Avalon pool gas cap for conservation purposes with gas injection being initiated as soon as the injection facilities are operational after the start of oil production. Gas injection may also be initiated in the gas cap of the South Avalon pool at a future time. By monitoring injection volumes and reservoir pressure changes, the Proponent believes it should be able to determine if significant portions of reservoir volumes are in communication and if the major faults mapped near the well are sealing.

Data obtained from development drilling will be used to update models to assist in confirming the placement of a second gas injection well and re-evaluate options for producing the oil resources. The reservoir quality is generally poorer than the South Avalon pool and recovery factors are expected to be lower. The Proponent's preliminary assessment is that recoverable oil resources range from 4.2 to 6.6 $10^6 m^3$ **(**26 to 41 million barrels**)** and that two to three production wells would be required to recover the oil if reasonable production rates can be achieved. Ideally, according to the Proponent, oil production wells will be drilled prior to the South Avalon pool coming off plateau production levels. The Proponent notes that any decisions on the viability or timing of drilling oil production wells will not likely be made until after initial reservoir response to the gas injection has been evaluated.

Consistent with good oil field practice, the Board believes that prior to producing the substantial gas cap gas resources of the North Avalon pool, the oil resources, to the extent it is economically viable to do so**,** should be exploited first. Otherwise, blow down of the gas cap could lead to a reduction in oil recovery. Also, it is the Board's view that identification and exploitation of the oil resources should occur as early as possible so as not to impede any future development of the gas resources.

As noted in Table 4.6, the Board's oil resource estimates are lower than the Proponent's. The Board acknowledges the uncertainty surrounding oil-in-place estimates and production characteristics of the North Avalon pool oil resources, and concurs with the Proponent that additional information and assessment is required prior to selecting development well locations. The Proponent is including in its subsea facility design provisions to accommodate possible development wells in this area. The Board believes that analysis of the data acquired from the South Avalon development drilling and North Avalon injection is necessary prior to making decisions respecting exploitation of the oil resource. The Board will require the Proponent to report on its findings and will pursue with the operator early development of the oil resources.

4.6.9.2
West Avalon Oil Deferred Development

The Proponent notes that the West Avalon pool is highly faulted and is comprised of several fault blocks with communication between the fault blocks unknown. The pool is expected to be of poorer reservoir quality than the South Avalon pool with reservoir quality improving on the east side of the pool.

According to information contained in the *White Rose Oilfield Development Application Supplemental Report*, March 2001, the gas-in-place in the gas cap ranges from 10.7 to 19.2 $10^9 m^3$ **(**0.4 to 0.7 tcf**),** while the oil-in-place ranges from 24.3 to 40.3 $10^6 m^3$ **(**153 to 253 million barrels**).** The Proponent's preliminary assessment is that recoverable oil resources range from 4.1 to 10.2 $10^6 m^3$ **(**26 to 64 million barrels**).** According to the Proponent, the southeastern end of the West Avalon pool has the best potential for economic oil production as it is closer to the South Avalon pool and likely to have better quality reservoir.

The Proponent estimates that, if reasonable production rates can be achieved, two to four oil production wells with associated injection wells will be required and noted that flexibility will be incorporated into the subsea system to allow potential future development of the southeastern area of the pool. Any decision to drill in the southeastern area will be dependent on drilling and production results from the South Avalon pool and excess FPSO production capacity.

The Proponent noted any decision to develop the western and northern area of the West Avalon pool would be dependent on drilling and production results from the southeastern area and information from the North Avalon pool. Ideally production wells would be drilled just prior to the South Avalon pool coming off plateau production. The Proponent is updating its geophysical and geological models and plans to conduct reservoir simulation studies to evaluate development options for the West Avalon pool, and to select potential locations for future drilling to prove up the West Avalon pool.

As noted in Table 4.6, the Board's oil resource estimates are lower than the Proponent's. The Board's views respecting early development of the West Avalon pool oil resources are similar to those noted for the North Avalon pool deferred development. Also, the Board believes that analysis of the data acquired from the South Avalon pool development drilling and production activities is necessary prior to making decisions respecting exploitation of the West Avalon pool oil resources. The Board notes the on-going geophysical, geological and reservoir modeling work being conducted by the Proponent to evaluate development options for the West Avalon pool and to select potential delineation well locations. The Board will require the Proponent to report on its findings and will be pursuing with the Proponent early development of the oil resources. The Proponent will be required to address in the report the proposed location and timing for drilling delineation wells to resolve geologic uncertainties.

4.6.9.3
Eastern Shoals Oil Deferred Development

The Eastern Shoals oil accumulation underlies portions of the West and North Avalon pools **(**see Figure 4.6**)**. According to information provided by the Proponent, the Eastern Shoals Formation oil-in-place is estimated to range from 6 to 9 10^6 m^3 **(**38 to 57 million barrels**)**. The Proponent notes that pressure data from the White Rose N-30 well indicated that the Eastern Shoals oil accumulation is in communication with the North Avalon pool and it is likely that the two oil accumulations would be produced concurrently if development proceeds in the future. Updated geologic and reservoir engineering models are being developed for the entire White Rose field by the Proponent, which will include the Eastern Shoals formation. The Proponent plans to develop models and assess various depletion options to assist in determining the potential feasibility of expanding the White Rose oil production to the North area of the field.

In the area of the White Rose N-30 well, the Board concurs with the Proponent's view that the Eastern Shoals oil accumulation is in communication with the Avalon formation. It is possible that the Eastern Shoals and North Avalon oil accumulations could be produced concurrently if development proceeds in the future. The Board acknowledges the ongoing work by the Proponent to assess development potential and will require the Proponent to report its findings. Additional information is required to assess the development potential of this accumulation**.** The Board expects the Proponent to design its drilling program, where practicable, to obtain information to better define the oil and gas in place and to assess its development potential.

4.6.9.4
Hibernia Formation Oil Deferred Development

At the request of the Board, the Proponent addressed this oil accumulation in the document *White Rose Oilfield Development Application Supplemental Report*, March 2001. According to the Proponent, the Hibernia Formation was not included as a deferred development in the Development Application as data gathered to date indicate that it is unlikely to be economically viable for development. The Proponent noted the following reasons:

- current estimates of original oil-in-place ranging from 8 to 24 10^6 m^3 (50 to 150 million barrels) will not likely justify economic development as the net pay is relatively thin and spread over a large area;
- the formation is considerably deeper than the Avalon Formation (600+ m) and would require additional wells to be drilled for depletion; and,
- formation permeabilities determined from drill stem test evaluations are very low (in the 10 mD range) and as a result, flow rates from the zone are also expected to be very low.

More detailed mapping and modeling of the formation will be carried out by the Proponent, and based on the results of the evaluations, a decision will be made as to whether or not it is reasonable to drill a delineation well.

The information provided by the Proponent, and the Board's own analyses, indicate that the Hibernia Formation contains significant quantities of oil. The Board acknowledges that the oil accumulation is contained in low permeability reservoir that exhibited a relatively low production rate, under 100 m^3/d (about 600 bopd), during drill stem testing. There is much uncertainty surrounding the development potential of the Hibernia Formation oil accumulation. The Board acknowledges the work planned by the Proponent and will require the results of the studies to be submitted to the Board. However, the Board believes that additional data is required to assess the development potential of these oil resources and, where practical, the production facilities should provide for exploitation of the resources. The Board notes that the Hibernia Formation oil accumulation is overlain by the Avalon formation. This presents an opportunity to drill selected pilot holes, planned for Avalon formation development wells, to sufficient depths to evaluate the Hibernia Formation or to deepen any depleted Avalon wells. The Board will require a through assessment of the production potential of the Hibernia Formation oil accumulation prior to approving field abandonment.

4.6.9.5
White Rose Gas Resources Deferred Development

The Proponent provided its technical and economic views respecting gas development in the following documents:

- White Rose Oilfield Development Application Volume 2: Development Plan, January 2001;
- White Rose Oilfield Development Application: Project Summary, January 2001;
- White Rose Oilfield Development Application Supplemental Report, March 2001;
- White Rose Oilfield Development Application: Response to Additional Information Requests from the White Rose Public Review Commission, June 2001; and,

- Deferred Development: White Rose Review Commission presentation, MR-059 July 25, 2001.

The Proponent addressed potential gas development from the perspective of the gas resources in the White Rose field and the regional gas resource potential. In the Deferred Development presentation MR-059, the Proponent's revised estimate for gas-in-place was 70.9 $10^9 m^3$ (2.5 tcf) with a recoverable gas resource of 49 $10^9 m^3$(1.8 tcf). In addition to gas cap gas, this estimate includes solution gas produced with the oil, and South Mara non-associated gas. The distribution of the gas resources is provided in Table 4.13.

Table 4.13
Proponent's P50 Estimates of White Rose Volumes
(from Deferred Development Presentation MR-059)

Pool	**Solution Gas Injected After Fuel ($10^9 m^3$)**	**Gas Cap Gas In Place Volumes ($10^9 m^3$)**	**Total ($10^9 m^3$)**	**Recoverable Assuming 70 percent RF ($10^9 m^3$)**
South White Rose	2.7	8.8	11.5	8.0
North White Rose	0.5	33.2	33.7	23.3
West White Rose	0.8	14.3	15.1	10.2
South Mara	N/A	10.6	10.6	7.4
Total $10^9 m^3$	**4.0**	**66.9**	**70.9**	**49.0**
Total tcf	**0.1**	**2.4**	**2.5**	**1.8**

The Proponent's view is that less than one-third of the above gas volume has been adequately delineated. According to the Proponent, four to six delineation wells, at an estimated cost of $120 million to $180 million would be required to increase the confidence in the resource estimates to the point that a decision to proceed with development could be made. The Proponent estimates that gas development would likely require in the order of 10 development wells, with associated glory holes and subsea systems, and states it may be possible to upgrade the FPSO to handle the additional gas volumes.

It is the Proponent's view that in order for oil recoveries to be maximized, reservoir pressures must be maintained and smearing of the oil leg into the gas cap should be avoided. Therefore, depletion of the gas resource should not commence until exploitation of the oil resource is well advanced. The Proponent believes that drilling and depletion of the oil legs, along with gas conservation monitoring, will provide valuable information as to the reservoir quality and compartmentalization in the gas cap areas. It plans to develop full field geologic and reservoir simulation models and update these models with information obtained from development drilling and production. The models will be used to assess the technical viability and appropriate timing for gas production.

In the documents *White Rose Oilfield Development Application: Project Summary* and *White Rose Oilfield Development Application: Response to Additional Information Requests from the White Rose Public Review Commission*, the Proponent discussed the commercial and business considerations related to gas development. According to the Proponent, the maximum gas potential of the White Rose field is far less than the threshold gas reserves required for commercial development of gas on the Grand Banks, which the Proponent estimates to be from 197 to 282 $10^9 m^3$ (7 to 10 tcf). In MR-059, the Proponent stated that in excess of 225 $10^9 m^3$ (8 tcf) and/or a higher gas price, would be required to reach an economic threshold. The Proponent's understanding of the estimated discovered gas volumes is shown in Table 4.14. Also, the Proponent noted that a series of studies on feasibility of natural gas development, coordinated by the Newfoundland Ocean Industries Association in conjunction with the federal and provincial Governments and end users, concluded that:

- the current natural gas prices being experienced are extraordinary and will return to more historic levels, experiencing moderate growth over the next 5 to 20 years;
- the potential domestic market for gas in Newfoundland is price competitive but has seasonal demand, with small size, and is geographically dispersed, and that the export market in the United States represents the most attractive opportunity for garnering economic benefit from Newfoundland natural gas from a market perspective;
- the majority of gas discovered to date in Newfoundland is associated with oil (solution and gas cap) and care is needed to avoid a compromise on ultimate oil recovery;
- precursors to a natural gas pipeline must be the confirmation of sufficient gas reserves, ensuring that the development sequence minimizes potential oil loss, ensuring that there are links with production profiles of both primary operations and secondary fields;
- the current total gas reserves discovered to date require confirmation; and,
- development will, in all likelihood, require basin-wide cooperation.

Table 4.14
Husky Oil Understanding of Discovered Gas Resources

Field	($10^9 m^3$)	(tcf)
White Rose (source DA Supplement)	49	1.8
Hibernia (source C-NOPB)	39.4	1.4
Terra Nova (source C-NOPB)	8.5	0.3
Other Pools (source C-NOPB)	36.6	1.3
TOTAL	**135.2**	**4.8**

Resources are volumes of hydrocarbons, expressed at P50 probability of occurrence, assessed to be technically recoverable that have not been delineated and have unknown economic viability (C-NOPB).

In its document *White Rose Oilfield Development Application: Project Summary,* the Proponent notes the future conditions necessary for White Rose gas development, which are summarized as follows:

- there must be a high degree of confidence in firm contracts for gas export to the United States market. Firm contracts will require proven reserves, committed transportation and firm prices;

- there must be a relatively high and stable gas price as Grand Banks gas will be a relative high cost resource to develop due to its remote location and lack of infrastructure. Current price forecasts are for Henry Hub prices in the US$2.50 to US$3.00 range in the medium to long term;
- to proceed with future gas development, industry must have a series of clearly delineated gas fields and associated gas that will support the ultimate sales contracts in the market place. While there are significant gas resources offshore Newfoundland, the Proponent notes that, according to the Newfoundland Ocean Industries Association, 76 percent of the gas resource occurs as solution gas in an oil pool, or as a gas cap over an oil pool. As such, the development and availability of these resources will depend on oil development and in most cases, will occur after oil resources have been depleted. The Proponent notes that in addition to the discovered gas resources, there is potential to discover more gas resources in the Jeanne d'Arc and in basins to the south. While this is encouraging, the regional gas supply is currently based for the most part on undiscovered resources, or resources that cannot be accessed until some time in the future; and,
- firm plans must be put in place for gas infrastructure such as a major pipeline connecting the Grand Banks to the North American pipeline grid. Equally important is proving up the gas reserves necessary to underwrite the infrastructure investment.

According to the Proponent, without existing infrastructure, gas development requires the accrual of additional gas resources, the delineation of which will be based on the long-term view of gas markets and pricing. A recent study, Purvin and Gertz 2001, concluded that the established gas resource estimates for the Atlantic Canada basins other than the Scotia Shelf, are insufficient to justify a major project at this time. In its document *White Rose Oilfield Development Application: Response to Additional Information Requests from the White Rose Public Review Commission*, the Proponent states it has initiated the activities summarized below:

- Husky Oil has completed a comprehensive inventory, identifying up to 135 10^9 m^3 (4.8 tcf) of discovered gas resources in the Jeanne d'Arc Basin. In addition, significant undiscovered potential in this and other basins in the Grand Banks region has been identified;
- Husky Oil has recently completed an initial assessment of the viability and cost of building a pipeline to connect Grand Banks gas to the North American pipeline grid. The study supported the technical feasibility of the pipeline and concluded a realistic schedule to be five years from project sanction of gas developments. The pipeline was estimated to cost $3.5 billion, resulting, as already noted, in the conclusion that 197 10^9 m^3 to 282 10^9 m^3 (7 to 10 tcf) of reserves need to be proven and a market secured before such a project can economically move forward. During the

hearing, the Proponent stated that 8.2 tcf and/or higher prices would be required to support a pipeline option;

- Husky Oil recently acquired four exploration licenses in the 2000 C-NOPB land sale. In Husky's opinion three of the four licenses acquired potentially contain 99 10^9 m^3 (3.5 tcf) of gas. They cautioned that each of the prospects have the usual exploration risk;
- in recognition of the conclusion that gas development on the Grand Banks will require a regional approach, Husky Oil is coordinating a study with five other major resource owners in the area. The study will further assess the natural gas resource potential of the Newfoundland offshore region, the proximity of the market and viability of gas development in a joint fashion; and,
- the White Rose Project Proponents undertook a study with Maersk to evaluate the capability of the White Rose FPSO to support the production and export of gas. The study has identified future modifications necessary to the production facility. The study has shown that the FPSO could be modified after six years of production to accommodate exports of 150 mmscf/d at a cost of $75 million. To modify the FPSO after 11.3 years of production to accommodate exports of 300 mmscf/d would cost $180 million. The vessel would have to come to shore for the retrofit with respective field production shutdowns of 12 and 16 weeks.

According to the Proponent, due to the time required to plan, obtain approvals, purchase equipment, and install gas infrastructure, any decisions on these projects must be based on a long-term view of gas markets. The Proponent's intention is to move forward with gas development when the necessary additional economically viable reserves are proven up and/or the required infrastructure is put in place to allow the gas development to proceed on an economically viable basis, and market confidence allows for incremental investments.

The Board has reviewed the information provided by the Proponent related to gas development. In terms of the gas resources in the White Rose field, most of the gas in the field is located in the gas cap overlying the Avalon Formation oil accumulations. The Board concurs with the Proponent's view that in order to maximize oil recoveries, reservoir pressure must be maintained and smearing of the oil leg into the gas cap, causing waste, which may occur as a result of producing the gas cap, should be avoided. It is the Board's view that this potential exists for the South, West and North Avalon pools. Typically, in such cases, good oil field practice dictates that oil production occurs first with gas production following at the later stage of oil depletion. Alternately, if performance indicates that the oil and gas are not in direct communication or that the oil cannot be economically produced, then there would be no reservoir constraints against gas development.

The Board believes that additional information is required before gas development can proceed. The drilling and depletion of the oil legs, along with gas injection monitoring, will provide valuable information on the reservoir quality and compartmentalization in the gas cap areas. The development wells will also provide information to better assess the White Rose gas resources.

The Proponent has stated that four to six delineation wells may ultimately be required to delineate the gas resources in the White Rose field. This possibly includes South Mara member delineation wells. The drilling of the North Avalon gas injection wells, a possible South Avalon gas injector, information from the South Avalon pool development wells and delineation wells drilled to evaluate the North and West Avalon pools oil resources, could provide much of the needed information. Consequently, specific to the Avalon pools, very few additional wells may be required to fully delineate the gas resources. No schedule is presented for drilling such wells. The Board believes that timely delineation of the resource needs to be undertaken in concert with proposed Avalon oil exploitation. Also, where practical, the subsea facilities, turret and gas handling systems should be designed to allow for possible change out or installation of equipment and space provided on the FPSO, to facilitate future gas exports. Should the future installation of such equipment be economically justifiable, an added benefit would likely be continued oil production beyond what otherwise might have been an abandonment economic limit.

Significant quantities of natural gas liquids are associated with the White Rose gas. Where practical, exploitation schemes need to be designed to ensure that recovery of this resource is maximized. The possible need for gas cycling to recover condensate prior to gas blow down would have to be assessed before the Board could consider any plan to produce the gas.

The Board notes that 76 percent of the discovered gas resources on the Grand Banks is associated gas that either exists as a gas cap overlying an oil pool, or as solution gas dissolved in oil that will be released from the oil during production. A summary of the gas resources by type is provided in Table 4.15. These associated gas resources, as is the case at Hibernia, may be required as part of the oil recovery scheme to maintain reservoir pressure or to increase the volumes of oil that can be recovered. In this regard, the Board concurs with the Proponent that development and availability of the gas resources will depend on oil development and in most cases, will occur after oil resources have been depleted. When solution gas resources are not being used as part of a pressure maintenance scheme to improve oil recovery and in the absence of gas markets, the Board policy, where practical, is to require the gas to be conserved by reinjection into a storage reservoir. For the South Avalon pool, the injection gas rate is expected to increase from an initial 1.5 to 2.5 10^6 m^3/d (53 to 88 mmscf/d) in year six declining thereafter to 0.5 10^6 m^3/d (17 mmscf/d) by year nine.

The Board notes that the January 2001 joint report of the Geological Survey of Canada and the C-NOPB assessed the resource potential of the Jeanne d'Arc Basin and surrounding area at 511 10^9 m^3 (18 tcf) of which less than one third has been discovered to date. The estimated non-associated resource gas potential is 111.7 10^9 m^3 (4.0 tcf) of which only 38.5 10^9 m^3 (1.4 tcf) has been discovered to date.

In terms of commercial gas development on the Grand Banks, the Board believes that, based on current resource estimates, the White Rose field, ultimately**,** will play a key role as it contains about 50 percent of the current discovered gas resources. Also, as the White Rose gas resources are associated with oil, it is desirable to exploit the oil resources as soon as possible. The Board will pursue with the Proponent early development of the North and West Avalon pool oil accumulation, if it can be economically justified. Wells drilled to produce the oil reserves in these areas would also assist in delineating the gas resource.

The Board notes that gas cycling to recover condensate prior to gas blow down would have to be assessed before the Board could consider any plan to produce the gas cap or any non associated gas.

Table 4.15
Summary of the P50 Discovered Recoverable Gas Resources by Type (10^9 m^3)

Note: Numbers may not add to totals because of rounding

Field	**Gas Type**		
	Associated Solution	**Associated Gas Cap**	**Non Associated**
Hibernia	26.4 (0.9)	9.8 (0.3)	2.6 (0.1)
Terra Nova	7.6 (0.3)	0	0
White Rose	3.8 (0.1)	64.3 (2.3)	8.6 (0.3)
Ben Nevis	0	2.4 (0.1)	6.5 (0.2)
North Ben Nevis	0	3.3 (0.1)	0
Springdale	0	0	6.7 (0.2)
South Mara	0	4.1 (0.1)	0
North Dana	0	0	13.3 (0.5)
Trave	0	0	0.8 (0.0)
Total	**37.8 (1.4)**	**83.9 (2.9)**	**38.5 (1.2)**

Source: C-NOPB

Development of the gas resources will require basin-wide cooperation, as there are insufficient resources in any one field to justify development. As already noted, Husky Oil is coordinating a study with five other major resource owners in the area to assess the natural gas resource potential of the Newfoundland offshore region, the proximity of the market and viability of gas development.

4.6.9.6
Summary Deferred Development

Several oil and gas accumulations exist in the White Rose field that may be exploited in the future using the production facilities proposed to deplete the White Rose South Avalon pool. Additional information is required before it can be determined if these oil accumulations, i.e., North and West Avalon pools, Hibernia Formation and Eastern Shoals Formation, can be economically developed.

For the oil accumulations, it is important that they be exploited with the proposed production system, as there are insufficient resources to justify stand-alone development.

The FPSO design provides for gas exports. Development of the gas resources could potentially extend life of the production facilities while also allowing for development of some of the marginal oil accumulations, thereby increasing oil recovery. However, gas development may also occur by way of a new and totally separate production facility.

Except for the South Mara gas accumulation, the information necessary to assess the development potential will be acquired from the South Avalon development drilling activities, including injection wells in the North Avalon pool, from any wells drilled into the North and West Avalon pools, production performance and future seismic evaluation. It will take time to assemble, interpret and act on all the information. The Board believes the key elements and sequence of events to ultimately provide for production of the deferred resources are:

- South Avalon pool development drilling to acquire reservoir information;
- production performance of the South Avalon pool and injection performance in the North Avalon pool;
- North and West Avalon pools - resolution of the development potential of the oil resources and the impact of gas production on recovery of these resources;
- early development of the Avalon oil accumulations in the North Avalon and West Avalon pools, if warranted, and subsequent production performance;
- sufficient capacity in the subsea, turret and topside facilities to accommodate development of the deferred resources; and,
- drilling, as ultimately necessary, to firm up gas resources.

None of the above, however, can occur in isolation of other considerations. These include the timing of future availability of gas from Hibernia and to a lesser extent from Terra Nova and new gas discoveries, preferably non-associated gas from new exploration drilling successes.

In relation to facilities to accommodate gas production, the facilities proposed for oil development should have the capability, by way of modifications, to accommodate gas export.

The Board notes that no depletion plan has been presented for development of the West and North Avalon pool, Eastern Shoals and Hibernia oil resources and the White Rose field gas resources. Should the Proponent elect to proceed with development of these resources, an amendment to the Development Plan will be required.

It is a condition of the Board's approval that:

Condition 19:
Within two years from initiation of production from the South Avalon pool, the Proponent submit a report, acceptable to the Board, on the following:

(i) an assessment of the development potential of the West and North Avalon oil pools and if warranted, proposals for drilling and evaluating the accumulations; and,
(ii) an updated evaluation of the White Rose field gas resources, along with a description of activities to be undertaken, including drilling schedule and locations for delineation or pre-development wells.

Condition 20:
Prior to any South Avalon pool development drilling operations, the Proponent submit an assessment of the extent to which any of the deferred resources can be evaluated using pilot holes.

4.6.10
Unitization

According to information presented by the Proponent, Husky oil is developing the White Rose oilfield with its co-venturer Petro-Canada with the average (non-weighted) interest of the co-venture parties in the White Rose Significant Discovery Area as follows:

- Husky Oil 77.1 percent
- Petro- Canada 22.9 percent

The White Rose Significant Discovery Area is comprised of thirteen significant discovery licenses with two different ownership interests. In addition, both parties have interest in Exploration Licenses in the region. The Significant Discovery Licenses in the White Rose field are shown in Figure 4.3. According to the Proponent, pooling agreements should not be a significant issue due to the uniform Working Interest over the portions of the field containing the majority of the reserves.

The Board notes that the extent of the White Rose South Avalon pool extends outside of the current Significant Discovery Area. The Board will review this item with the Proponent prior to initiation of production. Also, the Board notes that the working interests vary over the Significant Discovery Area. The Board believes that unitization of the White Rose Significant Discovery Area, including the area of the South Avalon pool outside the current significant discovery area, is important for conservation purposes and for effective administration of the regulations governing production of the resource.

Condition 21:
Prior to initiating production from the White Rose field, a unitization agreement among license holders for the White Rose Significant Discovery Area be submitted to the Chief Conservation Officer.

4.7
SAFETY OF OPERATIONS

This section describes the Board's review of the approach to safety of operations proposed by the Proponent in the Development Application and the Commissioner's recommendations related to human safety. The Board has considered the safety of the system as a whole and its components, including, to the extent information was available, its structures, facilities, equipment, operating procedures and personnel.

Pursuant to the Legislation, the Board must authorize all oil and gas activities in the Newfoundland Offshore Area. Before issuing an authorization, it must consider the safety of the activity as a whole, as well as the safety of its component parts.

The Board has established a safety assessment process to review applications to conduct such activities in a systematic and comprehensive manner. The objective of the assessment is to ensure that operators have considered all hazards of the activity and taken all the measures necessary to reduce the risks to a level that is as low as reasonably practicable (ALARP).

Before the Board issues an authorization, a review is conducted of the supporting information submitted by the applicant against checklists based on the Legislation and associated guidelines. The adequacy of the proposed safety management system is assessed. Pre-approval audits are undertaken that may include visits to installations, standby vessels and ancillary vessels. The applicant's communications, logistical support and other land-based facilities may also be visited.

The conduct of authorized activities is monitored for compliance with the applicable legislation and with conditions attached to authorizations by the Board. In discharging its responsibilities, the Board also monitors activities offshore through:

- reviewing daily operating reports;
- reviewing the minutes of meetings of the joint occupational health and safety committee on each installation;
- reviewing incident reports and investigating accidents and incidents; and,
- performing safety audits in the field and at applicant's offices.

The Board also advises applicants respecting the interpretation of regulations; and monitors the work of Certifying Authorities (CA) to ensure that their certification activities conform to the scope of work approved by the Board.

The Commissioner [5.1] recommended that the Board and Governments take appropriate action in accordance with their responsibilities with reference to the occupational health and safety issues raised. The Commissioner further recommended that the Board, as regulatory body, take the initiative. A forum which would include industry, labour, the relevant departments of Government and others interested in safety to review these matters in depth was suggested. Results of the forum and follow up action should be reported publicly.

The Board agrees that the draft regulations originally developed 11 years ago must be updated and enacted. The Board is fully supporting and is actively involved in the federal and provincial governments' current initiatives to develop clear and modern provisions for occupational health and safety under the Legislation. The fundamental rights of a worker to know about hazards in the workplace, to participate in occupational health and safety in the workplace and to refuse unsafe work are to be incorporated into such provisions. As part of this process, the Governments have stated there will be consultations where all stake holders including industry, labour, the relevant Departments of Government and others interested in safety will be asked to comment. The Board will ensure workers on offshore installations will have the opportunity to provide input into this process.

4.7.1
Design

In this section, various factors which have an impact on the design are discussed in the context of regulatory requirements and the Commissioner's recommendations.

The Proponent has stated that the White Rose Development Project is at the preliminary design stage. In addition, the analyses performed to date have assessed the basic design concepts, layout and intended operations with respect to safety and environmental hazards and risks. The Proponent has indicated that the results of a number of activities such as model tests, studies and decisions on systems will be incorporated into the detailed design.

The *Newfoundland Offshore Area Petroleum Production and Conservation Regulations* require that, before production operations may be authorized, the production installation shall have a Certificate of Fitness issued by a recognized Certifying Authority (CA). *The Newfoundland Offshore Certificate of Fitness Regulations* define the bodies which may act as a CA and require that a recognized CA undertake a independent examination of the design of facilities and survey the installation during construction and operation. The examination and survey by the CA shall ensure that the facilities and installation are fit for purpose, that they comply with the regulations and can be operated without posing threat to people or the environment. The CAs, all of whom have a long history as ship classification societies, bring a great deal of marine and industrial experience (including over 120 FPSOs operating in other jurisdictions) and knowledge from joint research projects into FPSOs. To ensure confidence in the Certificate of Fitness, the Board has to be satisfied with the level of review by the CA. This is determined through a review and approval of the Scope of Work under which the CA operates and through monitoring of the certification activities. The Board will monitor and audit the activities of the CA to ensure that it carries out its work in accordance with the approved Scope of Work.

The Commissioner [3.2] recommended that the Board consider the FPSO not as a mature technology, but as a maturing one, and furthermore that the FPSOs at Terra Nova and White Rose be closely monitored in relation to research on this technology ongoing elsewhere in the world and with particular focus on the aspects unique to our environment.

The Board acknowledges that to date there is no experience in operating an FPSO on the Grand Banks, and this is a technology which is maturing in the Newfoundland Offshore Area. However, any facilities to be used for petroleum operations on the White Rose field or other fields on the Grand Banks must be designed to operate safely and efficiently to minimize the risk to both personnel and the environment. The Board will continue to monitor FPSO research efforts through the operational phases of both the Terra Nova and White Rose Projects.

4.7.1.1
Design Standards for FPSO Vessel

A key design feature of the FPSO vessel proposed for the White Rose Project is its ability to disconnect from its moorings in the event of ice encroachment. The Proponent has also decided to design a vessel that is capable of independent self-propulsion. The FPSO vessel will be registered in Canada. When disconnected from its mooring system, the FPSO installation will be considered a "ship", as defined by the *Canada Shipping Act*, and consequently will fall under Transport Canada jurisdiction.

The current Memorandum of Understanding between the Board and Transport Canada (Ship Safety) describes the basis for cooperation between the two agencies and the means to establish an offshore regulatory regime within which marine safety is the prime concern. The *Canada Shipping Act* will apply to the hull of the FPSO vessel and all marine equipment (as defined within that Act) that is not part of the industrial process equipment. The FPSO vessel as a whole, including the marine and industrial plant, must also comply with the regulations under the Legislation, compliance with which will be verified by the Certifying Authority, Det Norkse Veritas.

If there is a variance between the two sets of regulatory requirements, the more rigorous requirement will take precedence. The Board will coordinate discussions related to these matters. Applications for acceptance of equivalencies to specific regulatory requirements, if submitted for review by the Proponent with appropriate documentation, will be considered by Board, and Transport Canada (Ship Safety), or both jointly, as is appropriate.

The Proponent states that one of the studies to be used in detailed design will be model tests carried out to establish the effects of physical environmental loading and assess the motion characteristics and station-keeping ability of the FPSO.

The Proponent has stated that all structures and equipment will be monitored routinely as a planned part of the maintenance program. Sensors and monitoring devices will be used as part of the program. Also as part of the overall monitoring program, the integrity of the following aspects of the FPSO will be monitored, using on-line monitoring systems; structural components, sub-structural components, equipment condition, corrosion rates, and vessel stability.

The Commissioner [5.4] recommended that the Board review the full results of all model testing on the proposed FPSO hull for White Rose and confirm that these results demonstrate its safety for the Grand Banks environment before approving the production system design. The Commissioner further recommended that ongoing monitoring of the structural integrity of the vessel be required.

The Certifying Authority will review, approve and monitor the Proponent's maintenance and monitoring program. The CA will also conduct periodic surveys of the FPSO to ensure compliance with the approved program, regulatory requirements and assess its fitness to operate safely without posing a threat to persons or the environment.

Given the complexity of the operation with its seabed components, its shipshape FPSO and the transport tankers, particular care must be taken. The Board will require the Proponent to keep the Board apprised of the design development, including the provision of key design philosophy documents, specifications and drawings. Therefore, it is a condition of the Board's approval that:

> **Condition 22:**
> **The Proponent submit to the Board within 90 days of Project Sanction a schedule of activities and decision points, including model tests, design analysis and design selection. The Proponent will submit selected test and study results to the Board as directed.**

4.7.1.2
Quality Management

The Proponent states in its Development Plan – Part I that it intends to implement a specific quality assurance system, across the whole development. It will be applicable to all contractors and suppliers in the conduct of their activities associated with the Project. *The Newfoundland Offshore Petroleum Installations Regulations* require an installation to be designed, constructed, installed and commissioned in accordance with standards respecting quality assurance published by the Canadian Standards Association. *The Newfoundland Offshore Certificate of Fitness Regulations* require the CA to determine whether the design, construction and installation are in accordance with the regulatory requirements.

The CA reviews the design and surveys the installation during all phases of its development to determine among other regulatory requirements compliance with the quality standards. Pursuant to these regulations, the Board's Chief Safety Officer is responsible for approving the Scope of Work for the CA where it is determined that such scope will provide the means for determining, among other things, that the installation has been constructed in accordance with an acceptable quality assurance program.

4.7.1.3
Physical Environmental Design Criteria

(i) **General**

The *Newfoundland Offshore Certificate of Fitness Regulations* require at Section 6(2)(b), that the Project's Certifying Authority determine "whether the environmental criteria for ... the site and the loads assumed for the installation are correct." Pursuant to the *Newfoundland Offshore Petroleum Installations Regulations*, the design of production installations, including subsea installations, which are intended for use in the Newfoundland Offshore Area must be consistent with elements of the Canadian Standards Association CAN/CSA S471-92, General Requirements, Design Criteria, the Environment, and Loads (the Code). This Code describes the loading conditions which different types of structure are expected to resist at specified levels of reliability.

A number of verification studies were undertaken to ensure that the margins of safety associated with this Code were consistent with those intrinsic in the other codes existing at that time and in general practice. The Code was developed by a committee of representatives from the offshore industry, offshore regulators, universities and research organizations. The committee considered other offshore codes available at the time and the uniqueness of the Canadian offshore environment in developing the Code. Therefore a design based on the Code will achieve the target level of safety presented in the Code. Design guidance takes into account reasonable extreme combination of environmental and other loads.

The Code requires that all loads on the structure or any of its parts during the construction, transportation, installation, operation, and decommissioning phases shall be considered in the design. Guidance is provided on the types of environmental conditions that exist offshore Canada. The Code requires that a realistic assessment of the environmental factors affecting the proposed offshore structure shall be made.

The loads due to various events are applied using load factors depending on the uncertainties associated with those loads. A larger load factor is used for loads that have greater uncertainties. The load factors given in the code were derived from the calibration studies conducted to support the Code's development. This ensures that the safety level is not compromised.

The Code provides for combinations of extreme events and loads. When designing for an extreme environmental event, the Code provides guidance on other companion environmental processes that must be considered along with the extreme environmental event. The Code provides factors for companion environmental processes, and notes that exceedence probabilities for companion environmental processes are dependent on local conditions. Combination of environmental loads with other loads are based on how likely or unlikely they occur together.

(ii) Meteorological and Oceanographic Design Criteria

The Board notes that CAN/CSA S471-92 requires that during the development of design parameters, a factor be applied to the calculated design loads to take into account the variability of these loads and load patterns, as well as any uncertainties which are inherent in the analysis of their effects. The Standard also requires that, when determining these loads, the simultaneous occurrence of environmental processes be taken into account. The manner in which this is done depends upon whether one environmental process is dependent on, independent of, or exclusive of another. Limiting environmental criteria for operations are reviewed by the Certifying Authority.

(iii) Sea Ice Design and Operating Criteria

The Proponent states that the FPSO vessel will be ice strengthened to operate in five-tenths concentration of 0.3m thick ice cover. The Proponent has not identified that the FPSO will be disconnected from moorings and risers when confronted by excessive sea ice. The *Newfoundland Offshore Area Petroleum Installations Regulations* require, at Section 54(1), that the Certifying Authorities determine that the FPSO vessel and the drilling unit are designed, constructed and established in such a manner that they will be able to:

> *withstand, without major damage, the ice loads to which [they] may be subjected ..., stay on location in the ice concentration and under the ice forces to which [they] may be subjected ..., and be moved from the production ... site in the ice concentration to which [they] may be subjected,*

and, at section 59(6), that their mooring systems;

> *incorporate a primary quick release system ... and at least one back-up system and have been demonstrated to be capable of permitting the quick release of the platform[s] from their moorings and risers."*

The Board observes that the Proponent has not fully articulated its criteria for operating in sea ice and is conducting model tests to substantiate these criteria. The Board expects the Proponent to provide the results of its investigations as they become more fully defined; these studies will be required to support the Safety Plan for operation of the facilities which the Proponent must submit for the

Board's approval in order to obtain authorization to begin production. The Board will pay close attention to the Certifying Authority's review of the FPSO vessel's ability to operate in 'design' ice concentrations and to disconnect and move away when more severe ice conditions are anticipated.

(iv) Iceberg Design and Operating Criteria

The Proponent proposes to install subsea wells and templates in open glory holes in the seabed with the top of the equipment a minimum of 2 to 3 metres below the mudline to avoid contact with scouring icebergs. It states that its ice management plan will provide for the orderly suspension of operations and the flushing of flowlines and risers, prior to the FPSO vessel moving offsite.

The Board believes that the Proponent's approach to the design, installation and operation of subsea flowlines can provide an acceptable degree of environmental protection and therefore accepts the concept, in principle. The Certifying Authority will be responsible for confirming that the Proponent's proposed design and operating arrangements are consistent with the CAN/CSA S471-92 *General Requirements, Design Criteria, the Environment, and Loads.*

The Proponent stated that the FPSO vessel "will disconnect from its mooring on the approach of an unmanageable iceberg of mass greater than 100,000 t". However, it also provided a July 24, 2001 clarification document to the Commissioner that stated that the vessel would be designed for an impact event associated with an undetected or undeflected iceberg with an annual probability of exceedence of 10^{-4} (a "ten-thousand-year event"). The Board notes that the two statements are not necessarily consistent since the severity of an "impact event" relates not only to the mass of the iceberg but also its speed and the precise nature of the collision (e.g., the degree to which the collision is off-center, the location of the point of impact, and the contact area between the ice and the hull).

The Board will require that the design criteria for glacial ice impact with the FPSO vessel be examined in detail by the Certifying Authority during its review of the design of the vessel, with particular attention to the detail of the methods used to calculate the probability of an iceberg incursion and the assumptions or calculations used in assessing the probability of detection of smaller pieces of glacial ice. For its part, the Board will examine this element of the CA's work closely during its monitoring of the CA's activities.

The Proponent has stated that the moorings and risers will be provided with emergency disconnect systems with central control and monitoring. The Proponent further states that these systems will require detailed investigations into the weather conditions and their effects to confirm environmental criteria for disconnection and reconnection. The Concept Safety Analysis notes that the provision of a "15 minute" disconnect time may not be optimal and a 1 hour disconnect time may be sufficient in cost benefit terms. The Board notes that the

FPSO's disconnect time will need to reduce the risk of iceberg impact to a level that is as low as reasonably practicable (ALARP).

The Commissioner [5.3] recommended that the Board require that the FPSO disconnect operation, including the quick disconnect in a simulated emergency situation, be thoroughly tested during commissioning. The Commissioner further recommends that regular practice disconnects, including complete disconnects from the spider buoy, be held at a frequency as determined by the Board but sufficient to allow operators to be comfortable with the procedure.

The Board will require a full regime of testing for the FPSO disconnect mechanism through independent verification at the manufacturing and commissioning stages. The regulations do not specify that an actual disconnect of the spider buoy be carried out in order to demonstrate its capability for quick release. However, the Board's Chief Safety Officer and the Certifying Authority must be satisfied that the primary release mechanism and the required backup systems are all functional before startup of production is approved. The need for the Proponent to conduct an actual release to further demonstrate the system will be determined after the detailed design, testing documentation and operating procedures for the turret have been submitted by the Proponent and considered by the Board.

In addressing the recommendation on regular practice disconnects, the Board will require this practice if it can be demonstrated it results in an increased level of safety. The Board therefore will be initiating further analysis of this matter using outside expertise as appropriate before making a decision to implement a requirement for regular practice disconnects of FPSO turrets in the offshore area.

The Board agrees that a conservative approach to ice management should be maintained in respect of offshore operations and notes that for many years the preparation and submission of ice management plans have routinely been required of operators of drilling or production installations in areas prone to ice encroachment. The Board monitors operators' implementation of these plans on a continuous basis when ice is present, as part of its ongoing monitoring of offshore operations. The Proponent's ice management plan will be a component of the Safety Plan for which the Board's approval must be obtained before production operations can begin.

In consequence of the foregoing it is a condition of the Boards approval that:

> **Condition 23:**
> **The Proponent shall, prior to commencing detailed design, demonstrate to the satisfaction of the Board that the FPSO's disconnect time will reduce the risk of iceberg impact to a level as low as reasonably practicable (ALARP). The Proponent shall provide a report for approval by the Board that describes how provision will be made for demonstration of and training for the disconnect procedure.**

4.7.2
Authorization of Construction and Installation Activities

The Proponent has proposed a strategy for the subsea component of the Project which may vary depending on the contractor chosen and the resources available. The Proponent has stated that the glory hole excavation will be dealt with as a stand-alone contract. Depending on their size, the manifolds may be installed either directly through the moonpool of a semi-submersible drilling unit or from the deck of a crane vessel with sufficient lifting capacity to lower them to the seafloor, where they could be picked up and placed by the drilling unit.

A dynamically positioned vessel, equipped for flexible pipe and cable installation, will be used to install the risers. Divers may be used for making the subsea connections. They may mobilize from a saturation diving facility on the vessel.

Wellheads will be installed in the glory holes through the moonpool of the drilling unit. Upon completion of the well-drilling operation, the drilling unit will also be used to install the wellhead xmas trees. Final connection of the wells to the manifolds by jumper spools will be carried out by divers.

If flexible flowlines are used, they can be spooled off a dynamically positioned lay vessel. If steel flowlines are used, they can be installed from a pipe lay barge or a dynamically positioned reel vessel. A survey will follow the installation of the subsea facilities.

The Board intends to administer its approval of these activities by grouping them into packages and to treat each as a program requiring separate development work authorization. The activities include the following:

- Glory Hole Excavation Program;
- Development Drilling Program, which may include the installation of the modular manifold centres;
- Subsea Production Systems Installation Program which will include installation of the riser buoy, risers, flowlines and umbilicals; and,
- Diving Program.

The specific regulatory requirements which apply to the various work activities may vary but the general requirements of the Legislation will apply to all work authorizations. The Board considers it important that a consistent approach be applied to safety management and environmental protection throughout the execution of construction activities. Therefore, it is a condition of the Board's approval that:

> **Condition 24:**
> **The Proponent submit with each application for a development work authorization, a Safety Plan for the approval of the Board's Chief Safety Officer.**

4.7.3
Operations

The operation of a complex processing facility such as that at the White Rose field depends both on the inherent safety incorporated into the design and construction of the facilities, and also on the presence of a skilled, well-trained workforce, all of whom are committed to safe operations. To ensure that the operations are conducted with due attention to safety, the Board also requires that the Proponent develop and adhere to safe operating procedures. These considerations are discussed in the following section.

4.7.3.1
Concept Safety Analysis

Section 43 of the *Newfoundland Offshore Petroleum Installations Regulations* requires the Proponent, at the time of submission of its Development Plan, to provide to the Board its definition of target levels of safety concerning its production installation, and a Concept Safety Analysis (CSA) respecting the installation. The Proponent submitted both documents as Volume 5 of its Development Application.

The CSA describes the results of the comparison between the two leading development options for the White Rose field, a steel FPSO and steel semi-submersible. The Proponent conducted a major hazards review on the preferred option FPSO vessel and evaluated whether the proposed development concept met the Proponent's stated target levels of safety. The Board notes that the Proponent's CSA proposes a number of recommendations to ensure that the target levels of safety are achieved. The CSA provides a list of recommended safety studies. The Proponent notes that additional safety studies will be required during detailed design but does not provide definite commitments in this regard. The Development Plan fails to provide either sufficient commitment to, or a strategy for, completing the detailed suite of safety studies required to support the design and provide the basis for the Safety Plan. The Board notes that the Terra Nova Project derived significant benefit from the development of a Safety Assessment Plan to plan, track and manage safety studies during the design of the Terra Nova FPSO and associated sub-sea facilities. The Board will require that it be informed of the actions which the Proponent proposes to take to satisfy recommendations of the safety studies, and that the Certifying Authority ensure that the recommendations have been properly satisfied.

The Board will require the Proponent to develop a plan to document and track the suite of safety studies required for detailed design at an early date and believes that the Plan should include the Proponent's schedule for satisfying the recommendations presented in its CSA. Further to this, the Board will require the Certifying Authority review this Plan, and the studies under it, to ensure appropriate safety assessment is undertaken and implemented in the design, construction, installation and operations phases of the Project.

The Board believes that a systematic and continuous approach to the elimination or reduction of risks to people, the environment, assets and production is required. The Board will require the Proponent to keep the Board apprised of the design development, including the provision of key design philosophy documents, specifications and drawings. Therefore, it is a condition of the Board's approval that:

> **Condition 25:**
> **(i) The Proponent submit a plan acceptable to the Board to document and track the suite of safety studies required for detailed design within 90 days of Project Sanction.**
> **(ii) The Plan include a schedule acceptable to the Board for satisfying the recommendations provided in the Proponent's Concept Safety Analysis.**

4.7.3.1.1
Location of Accommodation

The Board acknowledges that both fore and aft accommodations and the temporary safe refuge (TSR) have been used in other jurisdictions. The Concept Safety Analysis and the Development Plan fail to identify the need to engage in further study of the key issue of the location of the TSR prior to making a final decision on the design of the installation. The discussions in the CSA, related to TSR location are cursory including:

- the lack of adequate review of the effects of smoke and gas on critical systems;
- the effects of moving the vessel off the wind may induce on station keeping; and,
- tanker collision.

Experience has demonstrated the threat posed by smoke entering the TSR and associated evacuation systems, including both lifeboats and the helicopter deck. A similar threat is posed by gas ingress either into the TSR or around lifeboat stations and/or the helicopter deck. Therefore, it is a condition of the Board's approval that:

> **Condition 26:**
> **The Proponent shall, prior to commencing detailed design, demonstrate to the satisfaction of the Board that the location of the Temporary Safe Refuge (TSR) and evacuation systems, either at the bow or stern of the vessel, has reduced the risk to personnel to a level as low as reasonably practicable (ALARP).**

4.7.3.2
Safety Plan

The Proponent, in Volume 5 of its *Development Plan – Part I*, provides a preliminary Safety Plan which it undertakes to update and submit to satisfy the requirements of the *Newfoundland Offshore Area Petroleum Production and Conservation Regulations.* The Plan includes:

- a corporate safety management policy;
- an organizational structure;
- occupational health and safety considerations;
- training and qualifications of personnel;
- contingency and emergency plans;
- production and drilling operational procedures; and,
- a description of safety facilities and equipment.

The *Newfoundland Offshore Petroleum Production and Conservation Regulations* require that a Safety Plan must be approved by the Chief Safety Officer and a Certificate of Fitness issued by a recognized Certifying Authority before the Board authorizes an operator to begin oil production. The development of a Safety Plan commences with the safety studies conducted during detailed design and proceeds as the Proponent develops policies and procedures, selects equipment and defines personnel responsibilities to manage and reduce the level of risk associated with the Project. The Safety Plan must provide for a comprehensive systematic approach to safety management, and be continually updated during the life of the Project. All of the information that is required to be included in the Safety Plan is not available at the time of the submission of the Development Application. The Safety Plan is available for public review and comment and can be modified to take into account relevant contributions from public commentators. The Board will ensure that any comment offered is evaluated and, where appropriate, taken into account in the Plan.

The Board notes that its *Development Application Guidelines* and *Safety Plan Guidelines* provide guidance on the types of safety information that should be submitted by the Proponent in its Development Plan and Safety Plan. Prior to their publication, these guidelines were reviewed by interested parties and they are public documents about which relevant comment can be made for consideration by the Board.

The Safety Plan is intended to provide a comprehensive compilation of safety-related information regarding the production installation and its operation. The Board's *Safety Plan Guidelines* suggest in Section 3 (p. 13) that the "design features and equipment that are intended to eliminate identified hazards, reduce risk or mitigate consequences" be included in the plan and that "it should also describe ... provisions aimed specifically at the safety of personnel such as the temporary safe refuge, escape routes, lifesaving appliances, evacuation and rescue systems". Studies that evaluate the safety of these systems, and that demonstrate that the threat to personnel has been reduced to a level that is as low as reasonably practical, will be reviewed as part of the Safety Plan approval process. The Certifying Authority will also review safety studies and will monitor the "close out" of recommendations arising from these studies.

The Board notes that the Joint Occupational Health and Safety Committee which is required pursuant to the provincial *Occupational Health and Safety Act* provides a mechanism by which workers participate in the continuing development and the monitoring of the safety policies and procedures in the workplace; this may provide a model for worker participation for incorporation in the Safety Plan.

4.7.3.3
Operations & Maintenance Procedures

The Proponent notes in Volume 2 of its *Development Plan – Part I* in section 11.2 that operations and maintenance procedures will be developed specifically for the White Rose Project. The development of appropriate and accurate procedures has traditionally presented a challenge to operators of new installations. The Board notes that it will be monitoring the development of operating and maintenance procedures and will require the Proponent to provide the Board with an acceptable strategy for the development and tracking of this and other required documentation. This strategy should be developed early in the design phase such that it can be effectively implemented without the necessity of extensively reworking or having to develop procedures *ad hoc* after production has commenced. Pursuant to the *Newfoundland Offshore Area Petroleum Production and Conservation Regulations,* the Proponent is required to submit a procedure to ensure the safety of persons and the protection of the environment where the Proponent intends to conduct simultaneously with the production of petroleum:

- the drilling and completion of a well from the same drill center;
- a well operation from the same drill center; or,
- a construction or related activity.

The Commissioner [5.5] recommended that the Board require that the Proponent's operational safety planning, including its evacuation plans, consider the simultaneous occurrence of two or more extreme events, involving accidental events in combination with wind, sea and ice. The Commissioner further recommended that the ability of the FPSO to disconnect during heavy seas and high winds should also be assessed.

The Board notes that the simultaneous occurrence of two or more extreme events will be accounted for in the design as discussed in section 4.3.1.3, Physical Environmental Design Criteria. It is also apparent that contingency plans, including emergency evacuation plans, will need to be robust enough to address the possible simultaneous occurrence of accidental events in combination with heavy seas and ice/iceberg encroachment or other extreme events. Therefore, it is a condition of the Board's approval that:

Condition 27:
The Proponent shall, at least one year prior to the commencement of production operations, submit to the Board its strategy for the development and documentation of the detailed operations procedures necessary for the safe operation of the installation. The Proponent must also ensure that its contingency plans address the possibility of simultaneous occurrence of any combination of high winds, sea ice, icebergs and heavy seas with an accidental event.

4.7.3.4
Training and Qualifications

The Proponent's preliminary Safety Plan included a description of its proposed methodology for personnel selection, the mechanisms which it will use to ensure their continued competency, and the types of training which each individual will be required to undergo.

The Proponent states that a "marine group" with the appropriate Transport Canada qualifications will be onboard to operate the marine systems. The Board notes that the Proponent does not explicitly state that it intends to comply with the marine crewing requirements of the *Canada Shipping Act*.

The *Newfoundland Offshore Area Petroleum Production and Conservation Regulations* require that the Proponent submit for the Board's approval a Training Proposal consisting of a description of the training, qualifications and competencies of all individuals to be employed at its production facility, including individuals on support craft, along with a description of how the training will be provided and their competencies established.

The *Petroleum Occupational Safety and Health Regulations – Newfoundland* (Draft, compliance therewith is a condition for each work authorization in the Newfoundland Offshore Area) require all offshore personnel to be instructed and trained in the procedures to be followed by each employee in the event of an emergency; and to be informed of the location, use and operation of emergency and fire protection equipment.

The Board will audit the design of the Proponent's training program and its implementation for compliance with the above requirements and will consult advisory departments and agencies which have interests and expertise in this area respecting the design of its audit program.

Condition 28:
No later than one year prior to the scheduled installation of the FPSO vessel on location, the Proponent submit the Training Proposal required by the *Newfoundland Offshore Area Petroleum Production and Conservation Regulations* for the approval of the Board's Chief Safety Officer.

4.7.3.4.1
Offshore Installation Manager and Master Mariner

The operation of an FPSO on the Grand Banks as proposed for the White Rose Project by its very nature carries with it human safety and environmental hazards. These hazards arise from two broad sources and must be managed by personnel with appropriate skills, training and authority.

- Hazards are associated with oil and gas extraction and processing at high pressures and temperatures involving complex industrial operations in a confined space. The management of this enterprise requires one who has knowledge, expertise and experience in these industrial aspects of the operation and who has the necessary leadership qualities. This person is generally referred to as the Offshore Installation Manager (OIM).

- Hazards are associated with the marine environment in which the industrial undertaking is located. These include the hazards presented by the winds, waves and ice conditions of the Grand Banks. This requires the presence on the FPSO at all times of an experienced Master Mariner who can assume command after the industrial operation is shut down in a safe manner.

The reconciliation of the skill sets required to manage these hazards when the OIM and the Master Mariner are not one and the same person requires careful consideration.

For an FPSO with a disconnectable turret, such as is proposed for the White Rose Project, the difficult policy consideration which arises is who should make the decision in an emergency situation if and when the FPSO industrial operation should be shut down in preparation for disconnection – the OIM or the Master Mariner? This is the issue the Commissioner is addressing in his recommendation [5.2].

The Commissioner recommended the Board require that an experienced Master Mariner be the person responsible for the vessel integrity aspects of the White Rose FPSO and for issues of marine safety. The Commissioner further recommended that the Master Mariner have the authority to order the commencement of the disconnection process, including shutting down processing equipment and flushing lines, and to decide if and when the FPSO actually disconnects.

The Ocean Ranger Royal Commission devoted considerable attention to the issue of the command structure on a floating facility. Its discussion of this issue included the following:

- "To transfer full command in an emergency situation, or to expect lines of communication and authority to switch smoothly from one person to another in various types of emergencies, would seem to defy one of the most fundamental tenets of management." [Vol. 2, Chapter 5, page 63]; and,

- "When lives are at stake there should be no question regarding who is in charge. One person should be clearly in charge of the installation at all times." [Vol. 2, Chapter 11, page 167].

The Royal Commission went on to recommend:

> **132.** That
>
> (a) the offshore installation manager be the person in charge of the semisubmersible at all times and he be knowledgeable and experienced in both drilling and marine matters.

Government responded to the Royal Commission's recommendation with appropriate amendments to the Legislation.

Against this background, the position which the Board adopted for the Terra Nova FPSO is that the OIM is in complete charge of the FPSO at all times when it is connected to the moorings, including making the decision as to when petroleum production and processing activities are to be discontinued in readiness for mooring disconnect. This is the position which will also apply for the White Rose FPSO. This is consistent with the overriding requirement for a clear command structure and is consistent with the procedure followed in other jurisdictions where FSPOs with disconnectable mooring systems operate.

Consistent with the Royal Commission's recommendations, and those of the White Rose Commissioner, the Board concurs that more precision is required to:

- specify the role of the Master Mariner in the determination of when conditions may warrant the commencement of preparations for disconnection; and,
- specify the role of the Master Mariner in the disconnect operation.

The command structure for the FPSO should clearly require that in making decisions in relation to marine matters the OIM must seek the advice of the Master Mariner.

The Board will review the qualifications of the OIM and the Master Mariner, the command structure on the FPSO and the procedures in place for transfer of authority between the OIM and the Master Mariner (if they are not the same person) prior to approving the Safety Plan.

Further, the Board recognizes the essential role which the Master Mariner plays in the decision making process on all marine matters and in particular in an emergency circumstance that may lead to a decision to discontinue operations and disconnect from the moorings. Therefore in these circumstances, the Board will require the Master Mariner on board the FPSO to maintain an Official Log-Book and the List of the Crew as if the FPSO were a ship. In addition, the Master Mariner shall record in the Official Log-Book all recommendations made to the OIM on marine matters. Therefore it is a condition of the Board's approval that:

> **Condition 29:**
> **The command structure for the FPSO clearly require that in making decisions in relation to marine matters, the Offshore Installation Manager must seek the advice of the Master Mariner.**
>
> **Condition 30:**
> **The Master Mariner on board the FPSO shall maintain an Official Log-Book and the List of the Crew as if the FPSO were a ship. In addition, if not one and the same person, the Master Mariner shall record in the Official Log-Book all recommendations made to the Offshore Installation Manager on marine matters.**
>
> **Condition 31:**
> **The procedures should provide that initiation of the actual disconnection of the vessel shall be under the command of the Master Mariner.**

4.7.3.5
Safety Facilities and Equipment

(i) Evacuation Systems

The Proponent has not identified in detail the specific evacuation systems for its facilities nor does the Proponent commit to using the best practicable evacuation technology. As part of its development of the Safety Plan required by the *Newfoundland Offshore Area Petroleum Production and Conservation Regulations*, the Proponent will be required to demonstrate to the satisfaction of the Board that the best practicable evacuation technology available will be utilized on the FPSO vessel and on the drilling units used in developing the White Rose field. Therefore, it is a condition of the Board's approval that:

> **Condition 32:**
> **The Proponent demonstrate, to the satisfaction of the Board, that the best practicable evacuation technology is being used on the production and drilling installations prior to beginning operations in the field.**

(ii) Standby Vessels

The Proponent has not yet finalized the configuration of its support vessel fleet. Vessel(s) will be available at all times near the installation to perform standby duty as required by regulations. The standby vessels must meet the requirements of Transport Canada *TP 7920E the Standards Respecting Standby Vessels*. In addition to the general requirements of the Standards, the standby vessels should be designed for the specific duties envisioned for the chosen installation and be compatible with the evacuation systems and procedures to be employed on the installation. The vessel design must also consider the environment, particularly the sea ice and icing conditions in which the vessels will be required to operate. Features such as the propulsion and station keeping systems, the number of fast rescue craft and other types of rescue equipment, and the nature and size of first-aid facilities to be provided should be carefully considered. Consideration also should be given to the configuration of the support vessel fleet. The Proponent will be required to submit the functional specifications for the proposed standby vessels, along with a rationale for these specifications, to the Board for approval before contracting for these vessels. Therefore, it is a condition of the Board's approval that:

> **Condition 33:**
> **The Proponent obtain the approval of the Board for the configuration of the support vessel fleet and for the functional specifications for its proposed standby vessels prior to contracting for these vessels.**

4.7.3.6
Ice Management Plan

The Proponent states that it has developed a comprehensive ice management plan for exploratory operations, and describes in general terms the contents of this plan. The Proponent asserts that its past exploration drilling on the north-east Grand Banks has provided it with experience which will be useful in ice operations during development drilling and production operations for the White Rose Project.

The Proponent states that the FPSO, as well as any drilling units which may be operating in the field, will operate on the principle of iceberg avoidance. It further states that its ice management plan will provide for the orderly suspension of operations, and the flushing of production risers, prior to the FPSO vessel moving off site.

The Commissioner [5.6] recommended that the Board require that the Proponent's Ice Management Plan explicitly affirm the principle of avoidance of collisions with icebergs and establish prudent criteria for the mass of an approaching iceberg that would initiate disconnect procedures and an identified process to determine whether icebergs meet these criteria.

The Board notes that the preparation and submission of ice management plans have routinely been required of operators of drilling or production installations in areas prone to ice encroachment. The Board monitors operators' implementation of these plans on a continuous basis when ice is present, as part of its ongoing monitoring of offshore operations. Because of the inaccuracies of iceberg trajectory forecast models, these plans have incorporated ice avoidance procedures for installations and decision-making strategies for ice deflection, both of which have been based almost exclusively upon real-time iceberg observations. These procedures include protocols for assigning priorities to response actions, and therefore in the Board's view are sufficiently robust to cope with the multiple presence of potentially hazardous ice.

The acceptability of the ice management plan for the Project will be examined by the Board during its review of the Safety Plan. The Board agrees that a conservative approach to ice management should be maintained in respect of offshore operations. The Board will require that iceberg detection and deflection elements of the White Rose ice management plan are based upon a philosophy of avoiding all icebergs regardless of size and notes that the Proponent's statements to date are generally consistent with this philosophy. The Board will ensure that the ice management plan explicitly identifies the ice conditions in which the drilling and production installations are designed to operate, and the conditions in which disconnection of each installation and avoidance of ice is required. The Board expects that the Proponent's plan will include the provision of both enhanced ice detection equipment and surveillance procedures which will ensure that adverse ice conditions are detected in time to permit an orderly response. The Board will also ensure that the functional specifications for support vessels take into account the ice conditions in which these vessels are intended to operate. The Board will assess the effectiveness of the ice management plan as part of its regular monitoring of offshore operations.

4.8
PROTECTION OF THE ENVIRONMENT

This section describes the Board's review of the potential effects of the White Rose Project upon the natural environment, and of the measures which the Proponent plans to put in place to prevent or minimize these effects. The section concludes with a discussion of several associated issues raised by the Commissioner in his report. **The Project also has satisfied the environmental assessment requirements of the *Canadian Environmental Assessment Act*.**

4.8.1
Assessment under the Canadian Environmental Assessment Act

The White Rose Project was subject to a "Comprehensive Study" environmental assessment pursuant to the *Canadian Environmental Assessment Act* (CEAA). The Board, Environment Canada, Fisheries and Oceans, and Industry Canada were "Responsible Authorities" under CEAA and together were responsible for ensuring an environmental assessment of the Project consistent with that Act.

During the preparation of the Comprehensive Study, the Proponent undertook a public consultation program that included a series of open houses in Clarenville, Marystown, Arnold's Cove and St. John's, and a series of workshops with key stakeholders.

The Proponent submitted its Comprehensive Study documents in October 2000, and conducted workshops with fisheries and environmental organizations in November 2000. Following review of the Comprehensive Study documentation by federal and provincial agencies, a compendium of comments was provided to the Proponent in January 2001. The Proponent submitted supplementary documentation to address these comments in March 2001. The documentation was reviewed by the appropriate agencies and revised material was submitted in mid-April.

The finalized *White Rose Oilfield Comprehensive Study Report* (CSR) and its accompanying documentation was provided to the federal Minister of the Environment and to the Canadian Environmental Assessment Agency in April 2001. The Agency made the report available for public comment on April 25, 2001.

On June 11, 2001 the Minister of the Environment determined that the Project, as described with mitigation, was not likely to cause significant adverse environmental effects and referred it back to the Responsible Authorities for action. A copy of the Minister's communication to the Board is provided in Appendix F. If the Project proceeds, a "follow-up program" will be designed by the four Responsible Authorities to determine the effectiveness of mitigative measures and to verify the predictions of the environmental assessment.

The CSR presents an overview of the proposed Project and the surrounding environment, a summary of the potential environmental effects of the Project, a summary of consultations undertaken in relation to the Project, and recommendations with regard to mitigation measures designed to eliminate or reduce the significant environmental effects of the Project. These measures fall within the scope of the Environmental Protection Plan that must be approved prior to commencement of production operations (see section 4.8.6).

4.8.2
The Board's Assessment of the White Rose Project

The White Rose Project also was subject to assessment under the Accord Acts. Environmental protection matters were included in the terms of reference of the White Rose Public Review Commissioner and were discussed during the public hearings. The Board conducted its own internal review of the application in consideration both of the CEAA assessment and Commissioner's review. The results are described in the following sections.

4.8.3
Effects of Routine Discharges

Any hydrocarbon operation offshore generates routine discharges into the marine environment. The following sections discuss the principal discharges associated with project operations including those that received the greatest attention during the public hearings.

The minimum standards for treatment and disposal of wastes associated with offshore drilling and production are described in the 1996 *Offshore Waste Treatment Guidelines* (OWTG) co-published by the Board, the National Energy Board and the Canada-Nova Scotia Offshore Petroleum Board.

In response to a recommendation of the Terra Nova Project Environmental Assessment Panel, the three Boards initiated a formal review of the Guidelines. Since the beginning of the review, information on its progress, including minutes of all working group meetings, has been available on the Board's Website.

This work is nearing completion. A draft version for wider public comment is expected early in 2002. The Proponent must comply with the provisions of the 1996 Guidelines in the interim and those of the revised Guidelines when they are approved by the Board.

> **Condition 34:**
> **The Proponent provide in its Environmental Protection Plan that the treatment and disposal of wastes are consistent with the September 1996 *Offshore Waste Treatment Guidelines* and with revisions to these Guidelines following their approval by the Board.**

4.8.3.1
Greenhouse Gas Emissions

The Proponent estimates that its operations may emit approximately 370,000 tonnes (CO_2 equivalent) per year of "greenhouse gases", not including those associated with gas flaring during the initial start-up period and with upset conditions. This represents approximately 4.5 percent of the total estimated Newfoundland and Labrador emissions for the year 2000. The majority of the emissions are associated with the gas turbines used for power generation on the FPSO vessel. The Proponent has indicated that it intends to ensure emission reduction strategies are an integral part of the design of its facilities and has stated that the White Rose Project operations will be added to its corporate reporting under the Government of Canada's Voluntary Challenge program.

The Proponent has undertaken to evaluate the potential to reduce these emissions during the design of the production facilities. The Board will require a report on this evaluation at an early stage of project design. The Board believes that this evaluation should be periodically re-visited during the life of the Project in light of advances in technology and operating practices worldwide, and therefore will require that the Environmental Protection Plan include provisions to undertake this re-evaluation every three years following First Oil.

Condition 35:

(i) The Proponent, prior to finalizing the detailed design of the production facilities, evaluate and report to the Board the technical and economic feasibility of incorporating measures into the design of the facilities that will reduce the amount of greenhouse gases released from them.

(ii) The Proponent include as part of its Environmental Protection Plan provisions to re-evaluate this feasibility every three years following First Oil.

4.8.3.2
Drilling Discharges

The Proponent estimates that 21 wells drilled from three drill centres will be required to develop the White Rose South Avalon oil pool. The Proponent believes that drilling deviated, horizontal or similarly challenging well sections will require the use of a synthetic-based drilling fluid (SBF) similar or identical to that currently being used by the Hibernia and Terra Nova Projects. Other well sections will be drilled with a water-based fluid.

The Proponent included with its application a March 2001 supplementary document entitled *White Rose Oilfield Comparison of Drill Cuttings Disposal Options*. The document describes a detailed analysis of the technical and economic feasibility of three SBF cuttings management options:

- re-injection downhole;

- transportation ashore for treatment and disposal; and,
- on-site treatment and ocean discharge.

On-site treatment and discharge was the only option rated as both technically and economically feasible, and was selected by the Proponent as the preferred option.

The CSR and its supporting documentation predict that the biological zone of effects due to drilling discharges will be confined to within approximately 500 m of the drilling area.

The Proponent states in its Development Application that it will treat SBF cuttings to the levels specified in the 1996 OWTG and will comply with the revised Guidelines when they are published. It also states in its *White Rose Oilfield Comparison of Drill Cuttings Disposal Options* document that it will evaluate current best available technology for use and will consider emerging technologies as they are developed.

The Commissioner recommended [5.11] that should the Board approve ocean discharge of cuttings it require "that the lowest practical levels of residual (drilling and formation) fluids be obtained; that a complete record of release quantities and contaminant constituents be kept; that results of annual monitoring programs be released publicly and that treatment technology be reviewed annually and implemented where it can contribute to a continuous improvement approach to the control of pollutants."

The Board believes that the forthcoming edition of the *Offshore Waste Treatment Guidelines* will reflect best available proven technology in treatment of SBF drill solids. The Environmental Protection Plan for the development-drilling phase of the Project must be consistent with these guidelines (see section 4.8.3). Recording of drilling fluid constituent usage, and of overall release volumes, are required pursuant to existing Board guidelines.

The public release of detailed monitoring information submitted by operators is discussed in section 4.8.7.1.

The Board agrees that a continuous improvement approach to waste treatment is desirable and notes that such a philosophy is recommended in the current *Offshore Waste Treatment Guidelines*. While a formal annual examination of the state of the art in this technology may not be practical, the Guidelines already provide for a formal review, which includes an examination of the state of the art in treatment technology, every five years, unless compelling reasons to do so arise earlier. In the interim operators are expected to monitor improvements in treatment technology and implement them where feasible. Staff of Canada's regulatory Boards also endeavour to monitor international developments in the field. The Board considers this approach to be acceptable.

4.8.3.3
Production Discharges

Cooling Water

The Proponent states that cooling water used in the FPSO vessel will be chlorinated to control biological fouling and that chlorination is the only practicable method available. The CSR predicts that the effects due to the discharge of cooling water will be negligible.

The Board observes that some cooling water systems can be designed with a "feedback" monitoring system to minimize the amount of chlorine used, and that some cooling water may be useable as injection water for reservoir management. The Board will require the Proponent to investigate the feasibility of both these measures during the detailed design of its production facilities.

> **Condition 36:**
> **The Proponent investigate the feasibility of minimizing chlorine use by means of an in-line analyzer near the point of discharge which controls the quantity of chlorine that is added to the cooling water, and of using cooling water for water injection, and to provide for these measures in the design of its facilities unless otherwise approved by the Board in light of technical and economic considerations.**

Produced Water

Produced water is water that comes to the surface with produced petroleum and may contain a combination of water originally present in the subsurface formations and treated sea water that has migrated to producing wells from water injection wells. Produced water is treated, but nevertheless typically contains residual hydrocarbons, a variety of dissolved solids and may also contain traces of injection water treatment chemicals.

The Proponent proposes to treat produced water to meet levels recommended in the *Offshore Waste Treatment Guidelines* and discharge it into the ocean some three to five metres below the waterline of the FPSO vessel. The Proponent also indicates that it will comply with the provisions of the revised Guidelines. The CSR and its supporting documentation predict that the zone of influence of discharged produced water will be irregularly shaped but depending upon season could extend a maximum of 1.8 to 3.6 km down-current from the FPSO vessel, and will be limited to the uppermost part of the water column. Effects upon fish and fish habitat are predicted to be negligible.

The Proponent states in its application that it plans to investigate the feasibility of re-injecting some or all produced water rather than discharging it overboard. It also notes, however, that formation water samples it obtained during its delineation drilling program were contaminated by drilling fluid and that reliable compositional information for White Rose produced water therefore is not yet available. This information is a necessary component of the feasibility analyses described above.

The Commissioner recommended [5.12] that the Board "delay its approval of the White Rose produced water treatment system until the Proponent is able to prepare and submit an analysis providing sufficient technical and economic detail to allow the Board to make a determination of the effect of discharge of produced water." The Commissioner also recommended that if produced water were approved for discharge, that the Board require the use by the Proponent of best available proven technology for treatment of its oil content.

The Board believes that the CSR and its associated documentation provide an acceptable analysis of the potential effects of produced water discharge from the Project.

The Board believes, however, that produced water should be re-injected into subsurface formations if this is technically feasible and economically reasonable, and accepts that the lack of detailed compositional information presently impedes a complete assessment of this feasibility. The Proponent therefore should conduct this assessment following water production and submit the results to the Board promptly thereafter. In the meantime, it should provide in the topsides design of its FPSO vessel the capability for installing re-injection equipment.

The Board believes that the forthcoming edition of the *Offshore Waste Treatment Guidelines* will reflect best available proven technology in treatment of produced water that is discharged and will require that the Environmental Protection Plan for the Project be consistent with these guidelines (see section 4.8.3).

Condition 37:

(i) The Proponent provide in the design of the FPSO vessel topsides the capability for installing equipment for produced water re-injection.

(ii) The Proponent undertake and submit to the Chief Conservation Officer an analysis of the feasibility of produced water re-injection, following the recovery of sufficient volumes of produced water to permit such an analysis.

(iii) The Proponent proceed with re-injection of produced water if, in the opinion of the Chief Conservation Officer, it is technically feasible and economically reasonable to do so.

4.8.4
Effects of Accidental Discharges

The operation of a hydrocarbon production facility in a marine environment can lead to incidents in which hydrocarbons are accidentally discharged to the sea. The Proponent predicts that the probability of a large crude oil spill associated with its development drilling and production operations is low, but that smaller batch spills of ten cubic metres (63 barrels) or less may occur over the producing life of the field.

The Proponent states that the potential exists for significant seabird mortalities under some spill scenarios and that in the unlikely event of a major spill, temporary loss of access to fishing grounds and effects upon seafood marketability may result.

The Proponent points out that spill countermeasures are likely to be constrained by the harsh environment of the Grand Banks, and that it therefore emphasizes spill prevention measures. Nevertheless, the Proponent also has stated that its contingency plans for the Project will include provisions for spill surveillance and monitoring, for on-water response using equipment appropriate for the conditions likely to be encountered, and for appropriate training of response personnel.

The Board generally concurs with the Proponent's statements respecting offshore oil spills. A contingency plan for oil spill response is a required component of the Environmental Protection Plan and the adequacy of these contingency plans is reviewed by the Board prior to authorizing the corresponding activities.

4.8.5
Decommissioning and Abandonment

The Proponent's plans for abandonment of the various structures associated with its proposed operations are discussed in the following sections.

4.8.5.1
Floating Production, Storage and Offloading Vessel

The Proponent states that following depletion of the White Rose field the FPSO vessel will be decommissioned and made safe offshore. Wastes recovered during these operations will be transported to shore for treatment and disposal. All associated anchors and mooring lines or chains also will be removed from the field. The Proponent indicates that the precise disposition of the vessel cannot be predicted but ultimately will depend upon the condition of the vessel and the options available for its re-use.

The Board believes that the Proponent's plans for decommissioning the FPSO vessel are acceptable and notes that, under the requirements of the *Newfoundland Offshore Area Petroleum Production and Conservation Regulations*, approval of the Board is required prior to commencement of decommissioning.

4.8.5.2
Subsea Facilities

The Proponent states that individual wells will be abandoned as each is no longer useful. Production wells will be purged of hydrocarbons. All wells will be plugged, surface well equipment will be removed, and casing will be cut below the sea floor. Also, all subsea facilities, including flowlines, that are located on or above the undisturbed sea floor, will be removed during field abandonment. Trenched flowlines will be purged of hydrocarbons and left in place. Some equipment may protrude above the floor of the glory holes. The Proponent predicts that effects due to abandonment, and those associated with post-abandonment conditions, will be minor to negligible.

The Board acknowledges the Proponent's statements respecting abandonment of its development wells, and notes that pursuant to the *Newfoundland Offshore Petroleum Production and Conservation Regulations* the specific approval of the Board is required prior to the final abandonment of each well.

The Board believes that the proposed purging and abandonment in place of trenched flowlines likely will not result in significant adverse effects upon the natural environment nor interfere with other users of the seabed. However, this matter will be reviewed further at the time of abandonment, in consideration of regulations and national policies that exist at that time.

The *Newfoundland Offshore Area Petroleum Production and Conservation Regulations* require that the Environmental Protection Plan for the Project include plans for restoration of the site upon termination of production. The adequacy of these measures, including the minimization or elimination of interference with other legitimate users of the seabed, will be assessed in greater detail during review of the Plan.

The Board notes that the Proponent also will be required pursuant to the Accord Acts to seek the Board's approval prior to abandoning any subsea equipment in place on or below the sea floor.

4.8.6 Environmental Protection Plan

The *Newfoundland Offshore Area Petroleum Production and Conservation Regulations* require that, prior to production operations, the Board's Chief Conservation Officer approve an Environmental Protection Plan (EPP) for the Project. In cases like the proposed White Rose Project where significant development drilling occurs prior to production, the Board requires that a separate EPP for that phase of the Project be submitted as part of the application for Drilling Program Authorization.

The Proponent has stated that the White Rose Project will be governed by a comprehensive Health, Safety and Environment Loss Control Management System that will include the provision of:

- environmental training and awareness for offshore personnel;
- environmental performance targets;
- waste management plans for each offshore and onshore industrial facility;
- environmental effects monitoring programs;
- environmental compliance monitoring and reporting programs; and,
- optimization measures for the fishing industry.

The measures the Proponent describes are generally consistent with the requirements for an EPP contained in the *Newfoundland Offshore Area Petroleum Production and Conservation Regulations*.

Several topics of relevance to environmental protection planning attracted comment during the Commissioner's hearings and were the subject of several of his recommendations. These are discussed in more detail in the following sections.

4.8.6.1
The Precautionary Principle

The Board, in its decisions respecting the approval of activities in the Newfoundland Offshore Area, has adopted an approach consistent with the Government of Canada's approach and with the definition of the Precautionary Principle enunciated in Principle 16 of the *Rio Declaration on Environment and Development*:

> *When there are threats of serious or irreversible damage, lack of full scientific certainty must not be used as a reason for postponing cost effective measures to prevent environmental degradation.*

The Commissioner recommended [5.9] that "the Board require that the Precautionary Principle be fully integrated into both the planning and the operational decision-making for the White Rose Project and that the Board specifically require the use of best available technology in all aspects of the Project, including with respect to minimizing the discharge of pollutants."

The Board intends to continue its application of the Precautionary Principle in its future regulatory activities, including the review of the White Rose Environmental Protection Plan. The Board notes that the Principle focuses upon instances where there are "threats of serious and irreversible damage", and that even in these instances the applicability of preventative or mitigative measures must include considerations of cost effectiveness. Each potential application of best available technology therefore must be assessed on its own merits.

The Board's views respecting waste treatment and disposal are provided in section 4.8.3.

4.8.6.2
Environmental Assessment Methodology and Follow-Up

The environmental assessment for the White Rose Project, as described in section 4.8.1, was conducted in a manner consistent with both the Board's 1988 *Development Application Guidelines* and with the *Canadian Environmental Assessment Act* (CEAA). Several participants at the public hearings questioned the criteria that were used to define "significance" of environmental effects. The

Commissioner echoed these concerns and recommended [5.8] that the Board take them into account during the design of the follow-up program required pursuant to the CEAA, and that the Board "seek to achieve continuous improvement in impact assessment methodology, including the determination of significance criteria, through development of stringent guidelines for Proponents".

The Board observes that the methodology used in environmental assessment of the White Rose Project, including the significance criteria, was consistent with current practice and with guidance published by the Canadian Environmental Assessment Agency. As this methodology continues to evolve, the Board will continue to follow current standards as they are updated.

The Board believes that a fundamental part of the follow-up program for the White Rose Project will be the Environmental Effects Monitoring (EEM) program. It forms part of the Environmental Protection Plan that must be approved prior to commencement of production activities. The Board notes that the Hibernia and Terra Nova EEM programs, although informed by the environmental assessment processes that preceded them, focused upon the detection of environmental effects of far less magnitude than those associated with "significant" effects, and expects that the White Rose program will be similarly prudent in this regard.

4.8.6.3
Environmental Effects Monitoring – Seabirds

The Proponent states that it plans to design and implement an Environmental Effects Monitoring (EEM) program for the drilling and production phases of the Project. The EEM program will include provision for the collection of baseline data prior to the commencement of field development activities. The EEM program is an important component of the Environmental Protection Plan that must be approved prior to production operations.

The Commissioner referred to several comments raised during the public hearings respecting the desirability of monitoring effects upon seabirds as part of the EEM program. He observed that Government should take responsibility for "broad based research" but that the offshore industry also shared some responsibility for seabird monitoring. He recommended [5.13] that "the Board require the Proponent to conduct a program of research to establish the effects from its operations on marine birds in general, and specifically with respect to flares/lights, operational discharges and oil spills."

The Board agrees with the thrust of the Commissioner's recommendation and already has initiated work in this area. The Board believes that general research into effects of offshore petroleum operations upon seabirds is best approached through the Environmental Studies Research Funds (ESRF). The ESRF is funded through levies on petroleum-related licence holders, is managed by a joint

Government-industry-public management board, and publishes all its research reports. Several of its recent initiatives are relevant to this Recommendation.

In 2000 the ESRF published "*Seabird Attraction to Offshore Platforms and Seabird Monitoring from Offshore Support Vessels and Other Ships: Literature Review and Monitoring Designs*". The report, whose title is self-explanatory, described a study that was performed in 1999 by researchers at Memorial University and the University of New Brunswick following its suggestion to ESRF by the Board in 1998.

The Board also supported two seabird-related projects currently funded by ESRF:

- *Oil Pollution Seabird Mortality Assessment on the Sable Island Bank with Applications on the Grand Banks*, the development of a seabird carcass trajectory model and a seabird mortality assessment model; and,
- *Marine Bird and Mammal Monitoring Study,* a two-year program of monthly monitoring surveys using offshore supply vessels.

Finally, the ESRF management board has agreed, at the Board's suggestion, to budget funds in 2002 for a study of seabird attraction to offshore production installations. The work should build on the results of the work described above and on existing platform-based monitoring initiatives to evaluate and test instrumentation-based approaches for monitoring flare-related mortalities.

The Board considers these research initiatives to be adequate, but is willing to propose additional research to ESRF or to other research bodies as necessary to follow up or augment the results of these initiatives.

The Board notes that the operator of the Terra Nova Project has committed to, and currently is conducting, a seabird observation program using trained personnel at its offshore production site and plans to regularly make the resulting information publicly available. In addition, as part of its approved EEM program, it is reporting on seabird collisions with, or landings on, the FPSO vessel. The White Rose Proponent committed to the latter initiative in its application and to the former initiative during the public hearings.

The Board also observes that experience from the UK sector of the North Sea indicates that valid and credible seabird observation data can result from the use of industry personnel or their contractors, provided that those personnel are properly trained and that conduct of observations forms part of their core duties. The Board intends to monitor these portions of the Proponent's program and to consider alternatives to that program should it be found to be deficient.

4.8.7
Other Issues Raised During the Public Hearings

The Commissioner also offered recommendations respecting transparency of operations and access to information, cumulative environmental effects and regional environmental effects monitoring, and placement of third-party observers on offshore installations. These matters, while not necessarily specific to the proposed White Rose Project, are discussed in the following sections for completeness.

4.8.7.1
Transparency and Access to Information

Some participants in the public hearings expressed the view that the Board does not disclose sufficient information respecting environmental and safety matters. During the hearings, the restrictions placed upon the Board in this regard by the Accord Acts, specifically sections 119 and 115 respectively of the federal and provincial versions, were also noted.

The Commissioner recommended [5.7] that these sections of the Accord Acts be amended to allow the Board to disclose information where such disclosure would be "in the interest of public safety or the protection of the environment".

The Board notes that, notwithstanding the statements of some participants in the public sessions, it has summarized annual spill frequencies and volumes and the performance of waste treatment equipment in its annual reports, the four most recent of which are provided on its Web site. The Board now provides summary spill information directly in graphic and tabular form on its Web site, is consolidating the safety and environmentally-related information that presently is located in a variety of locations on its site, and plans to augment this new section with additional information on safety and environmental initiatives.

The Proponent committed in its application to make the results of its environmental effects monitoring (EEM) programs available to interested parties in the general public, and stated in a July 27, 2001 letter to the Commissioner its intent to make both EEM reports and environmental compliance monitoring information "publicly available to interested stakeholders in a timely manner".

The Board is restricted under the provisions of the Legislation from releasing detailed information on some safety and environmental matters without the consent of the operator. This includes a five-year confidentiality period respecting EEM program results. However, the Board is sensitive to the fact that information relevant to environmental protection and worker safety does have a significant public interest aspect. Such information for offshore projects should be reasonably available, at least to a level comparable to similar information from other industries. Therefore, the Board will require that the Safety Plans and the Environmental Protection Plans for White Rose include a section that describes how the Proponent intends to fulfill its commitment to make safety and environmentally-related information available to interested parties in the public. The Board also will pursue this matter with the operators of the Hibernia and Terra Nova Projects.

> **Condition 38:**
> **The Safety Plan and the Environmental Protection Plan each include a description, to the satisfaction of the Chief Safety Officer and the Chief Conservation Officer respectively, of the extent to which the Proponent will make safety and environmentally-related information available to the public.**

4.8.7.2
Cumulative Environmental Effects and Regional Monitoring

The environmental assessment of the White Rose Project included consideration of cumulative effects upon the environment likely to result from the Project in combination with other projects or activities that were, or were likely to be, carried out. These included the Hibernia and Terra Nova Projects, exploration activity, commercial fisheries, marine transportation and (for marine birds) hunting activities. The cumulative effects associated with the Project were predicted to be not significant.

The Commissioner noted that although the scope of cumulative effects assessment was consistent with CEAA guidance, some hearing participants had challenged its scope and its conclusions. He also referred to a March 2000 workshop that was proposed by the Board and sponsored by the Environmental Studies Research Funds (ESRF) and whose proceedings are published as ESRF Report 137, "*Workshop on Cumulative Environmental Effects and Monitoring on the Grand Banks and Scotian Shelf"*. He recommended [5.10] that the Board should follow up from this workshop by pursuing the issue of a regional monitoring program with the Department of Fisheries and Oceans (DFO), that such a program should incorporate public input and that the results should be made publicly available.

The Board notes that although a number of recommendation emerged from the workshop, its central recommendation was that DFO "take the lead in convening one or more follow-up meetings involving representatives from all relevant stakeholder groups to discuss how cumulative effects assessment should be pursued on a regional basis". This recommendation, accompanied by the workshop proceedings, was formally transmitted by the Chairperson of the ESRF Management Board to the Minister of Fisheries and Oceans in March 2001. The ESRF continues to consider the topic of cumulative effects as a priority for research and has funded several studies applicable to the topic since the workshop.

As noted during the workshop, DFO has responsibilities under the *Oceans Act* to lead initiatives relating to integrated management of Canadian ocean areas. The Board agrees that it is appropriate for DFO to lead the planning and development of regional programs to monitor the aggregate or cumulative effects upon the marine environment of all anthropogenic activities, including but not limited to the fishery, offshore petroleum exploration and production, marine transportation, hunting and coastal development. The Board will cooperate with DFO in any such initiatives.

In the meantime, should the White Rose Project proceed, the Board intends to pursue the topic of a regional monitoring program for effects that may be related to drilling and production activities in the Hibernia, Terra Nova and White Rose area of the northeast Grand Banks. Input from interested parties in industry, Government academia and the public will be a component of this effort.

The Board's approach to the release of information from these programs is discussed under section 4.8.7.1**.** The Board will request operators engaged in any regional monitoring initiatives to make the associated results available in a timely manner to interested parties.

4.8.7.3
Fishing Industry Agreements

The Proponent states that its Environmental Protection Plan will include fishing industry agreements and compensation procedures. It predicts that routine drilling and production activities will not significantly affect commercial fishery activities since the immediate White Rose area has not historically been heavily fished. The proposed safety zone, from which all unauthorized vessels will be excluded, represents a small fraction of the NAFO Unit Area 3Lt, the smallest fishing zone which contains the White Rose area. The Proponent points out the aggregate safety zones for Hibernia, Terra Nova and White Rose total some 34 km^2, less than 0.2 percent of the area of 3Lt.

The Proponent states that a large oil spill would be unlikely to significantly affect fish stocks, but that temporary loss of access to fishing grounds and effects upon seafood marketability may result from a major spill and that either of these effects could be significant.

The Proponent commits to engaging in an ongoing consultation process with fisheries interests during project operations, and to cooperate in this regard with other active operators on the Grand Banks.

The Commissioner recommended [5.14] that the Board require the oil and gas industry to provide funding for the Fish, Food and Allied Workers Union and the Fisheries Association of Newfoundland and Labrador to jointly hire a fisheries/petroleum industry liaison officer to advise them on offshore oil and gas issues related to the fishery and to assist both industries in cooperatively pursuing their respective activities. The Commissioner also offered observations concerning effects of seismic surveying and the need for compensation.

The Board agrees with the Commissioner's view that liaison between the offshore and fisheries industries is vital and accepts that an independent mechanism is required to assist both the industries understand and accommodate each other's operations. The Board has been pursuing such a liaison mechanism with offshore operators and with fisheries interests over the past several months and intends that these efforts be concluded in the near future.

With respect to seismic-related research the Board observes that an ESRF-sponsored workshop, whose proceedings were published as ESRF report 139 (*Proceedings of a Workshop to Develop Methodologies for Conducting Research on the Effects of Seismic Exploration on the Canadian East Coast Fishery, Halifax, Nova Scotia, 7-8 September 2000*), considered this matter as well as numerous other potential research items relating to effects of seismic exploration. The ESRF is undertaking several research initiatives consistent with the recommendations from the workshop, in consultation with Government, industry and fisheries interests. A Board representative currently chairs the working group overseeing these activities.

With respect to compensation the Board notes that the Accord Acts (e.g., section 162 of the federal Act) provide that in the event of a spill or debris the responsible operator is liable, without proof of fault or negligence, for all actual loss or damage incurred by any person as a result, up to a prescribed limit that has been set by regulation as $30 million. All persons to whose fault or negligence the spill or debris is attributable, or those legally responsible for them, are jointly and severally liable to the degree that fault or negligence is proven against them, without limit. The Board requires that a prospective operator of a drilling or production program provide the Board with unfettered access to funds for the purposes of the absolute liability provisions of the Accord Acts and assures itself that the operator has sufficient financial capability to respond to actions relating to claims of fault or negligence. Detailed information on these requirements are provided in the December 2000 *Guidelines Respecting Financial Responsibility Requirements for Work or Activity in the Newfoundland and Nova Scotia Offshore Areas* published jointly by the Board and the Canada-Nova Scotia Offshore Petroleum Board. The roles of the Boards in administering the compensation provisions of the Accord Acts are described in the September 1991 *Compensation Guidelines Respecting Damages Relating to Offshore Petroleum Activity*, also published by both Boards.

The Board took the view as early as its first decision respecting the Hibernia Project, *Decision 86.01*, that the best compensation program would be one developed jointly by the two industries. Representatives of Hibernia and of fishery interests subsequently undertook discussions that included the development of such a program. Board staff attended the meetings of this group to observe the process and to provide information on regulatory matters as required. A framework for a compensation program was developed that included a third-party dispute settlement mechanism for damage claims by a review board with appointees from both the fishery and offshore petroleum sectors. This claims settlement mechanism would be an alternative to seeking damages through court action or from the funds accessible to the Board under the Accord Acts.

Consensus amongst all parties was not achieved respecting all aspects of the program. However, sufficient progress was made that the Board was willing to accept the (then) current version of the program for the Hibernia Project, and more recently the Terra Nova Project, as an interim measure pending development of a document acceptable to all parties. The Board has exercised considerable patience in awaiting the conclusion of these discussions. The Board is acutely aware that the matter requires closure.

4.8.7.4
Third-Party Offshore Observers

Several participants in the public hearings expressed the view that independent observers should be placed upon offshore facilities. The Commissioner recommended [5.15] that the Board place an observer on each production facility on the Grand Banks "to monitor project interactions with the environment and to audit environmental management procedures". The Commissioner also observed that the duties of a C-NOPB observer could encompass matters such as spot checks of pollution control equipment and potential points of pollutant release; observation of surface slicks, third party audit of environmental management procedures and of seabird observations, and would provide additional experience in matters such as environmental effects monitoring.

The Board observes that some of the debate surrounding the need for observers involved, on the one hand, the contention that sufficient space exists to accommodate observers on offshore installations and that therefore there is no impediment to their employ, and on the other, that the industry is deserving of "trust" and therefore need not be held to this type of scrutiny. The Board respectfully suggests that neither argument is particularly relevant.

The Board believes that a crucial goal of the offshore regulatory structure is to ensure that personnel employed by offshore operators, and particularly members of the offshore workforce, are cognizant of the need to perform their duties in a safe and environmentally prudent manner, are competent to perform these duties, have the systems and procedures in place to enable this, and conscientiously follow these systems and procedures in practice. The operator carries the ultimate legal responsibility for this and the Board the duty to assure itself that this responsibility is properly and diligently discharged.

To ensure that this is the case, Board staff conducts a detailed review of operators' safety and environmental management systems prior to approving activities; monitors reports from offshore drilling and production operations on a daily basis; and conducts detailed safety and environmental audits offshore. The

Board currently employs five safety officers and one environmental officer who are charged with the latter duties.

An individual audit typically focuses intensely upon an element of the operator's management system and examines its performance in detail, through direct observation of activities, interviews with personnel, examination of records and in some cases collection of samples. Audits also include detailed checks on an operator's follow-up actions to previous safety or environmental incidents to ensure that factors that contributed to the incidents have been properly addressed. Although the operator is generally aware of the timing of an audit through arranging the auditor's transportation offshore, the subject of the audit is not revealed in advance. Conducting a three-day on-site audit can require over a week of advance research and preparation and follow-up often will require one or more weeks. A thorough modern safety or environmental audit therefore can require close to a person-month of activity, of which less than a week may actually be spent on an installation. It has been the Board's experience that completely auditing a drilling and production operation's environmental management system requires four to six separate audits per major installation and it notes that should the White Rose Project proceed additional resources may be required in its Environmental Affairs department to continue this level of oversight.

The Board stated in its Decision on the Terra Nova Development Application that it believed "in the interests of safety, personnel complements on offshore drilling and production facilities should be kept to the minimum necessary for prudent operations and has concluded that insufficient evidence has been presented to justify requiring the placement of additional, dedicated personnel on drilling or production platforms as observers" (*Decision 97-02* section 4.4.1, page 56). The Board observes that this philosophy is consistent with the practice in numerous other industries and jurisdictions and that the employment of regulatory personnel as full-time observers of industrial operations occurs only when there is evidence of pervasive and flagrant disregard for the regulatory system, of persistently poor operating practices, or both. The Board is satisfied that the existing reporting and auditing processes are working as intended and is unaware of any circumstances respecting Newfoundland offshore operations that would cause it to alter the position it stated in *Decision 97-02*. The Board wishes to emphasize, however, that should such circumstances arise, it is fully prepared to adopt a different regulatory approach, including consideration of full-time on-site oversight of the operations concerned.

Respecting spill observations the Board notes that the least effective observing position for detection of oil on the sea surface may well be on a surface installation, unless weather conditions are favourable and the spillage is observed when relatively close to the installation. Aerial observations are immeasurably superior when visibility conditions permit their conduct. Independent airborne pollution surveillance presently is conducted offshore Newfoundland by the Canadian Coast Guard. The results of this surveillance generally have been consistent with the notification reports operators are required to make to the Board. However, the Board will pursue with the Canadian Coast Guard the feasibility of enhancing this coverage.

Appendix A: Conditions of Approval of the White Rose Canada-Newfoundland Benefits Plan and the White Rose Development Plan

Condition 1:
It is a condition of this approval that immediately upon its Project Sanction decision, the Proponent advise the Board in writing of the date of that decision.

Condition 2:
The Proponent submit to the Board, for approval, a comprehensive Human Resource Plan for the construction phase of the Project within 60 days of Project Sanction; and, for the operations phase, within one year of Project Sanction. These plans shall, among other items, include:

(i) hiring and training needs;
(ii) the time frame associated with employment opportunities for each phase; and,
(iii) estimates of expenditures associated with training requirements.

The Proponent shall report to the Board on the progress with respect to these plans on a regular basis as agreed with the Board. In both cases, the Proponent should provide reasonable and ample advanced notice to the Board of any anticipated requirements for foreign workers.

Condition 3:
Within 60 days of Project Sanction, the Proponent submit a plan to address the obligation in the Legislation that expenditures shall be made for research & development to be carried out in the Province and for education & training to be provided in the Province. The Board will review the Proponent's submission and establish an appropriate expenditure target. The Proponent shall report to the Board annually on the progress with respect to achievement of the established targets. The Board anticipates that for this Project, the target will not be less than $12 million during the pre-production stage.

Condition 4:
Upon Project Sanction, the Proponent review its commitment in the Benefits Plan with respect to the obligation of contractors and subcontractors to comply with the provisions of the approved Benefits Plan and submit for approval by the Board a definitive clarifying statement in this regard.

Condition 5:
Within two months of regulatory approval, the Proponent submit to the Board a comprehensive report on its pre-approval contracting activity in sufficient detail for the Board to assess the extent to which the provisions of the Legislation and this Benefits Plan Decision have been met.

Condition 6:
During the construction and operation of the White Rose Project, the Proponent provide, 30 days prior to the commencement of each quarter, quarterly forecasts of Project requirements, at a satisfactory level of detail, to the Board and to the public.

Condition 7:
For each work or activity which is to be executed in the Province and in the offshore area (or in another part of Canada), upon award of contract, the Proponent provide the Board with a complete and detailed description of the work commitments for the Province and Canada. The Proponent's performance will be measured against these commitments, and may be subject to independent verification.

Condition 8:
Upon Project Sanction, the Proponent establish systems and procedures, to the satisfaction of the Board and with particular attention to the calculation of Newfoundland & Labrador and Canadian content, to ensure the bid evaluation and reporting framework matches that which is described in the Benefits Plan. Further, the Proponent must establish, for approval by the Board, a methodology and a verification process for all Newfoundland & Labrador and Canadian content calculations by it and by its contractors and subcontractors.

Condition 9:
Upon Project Sanction, the Proponent submit a report for approval by the Board describing its approach to affirmative action as contemplated in subsection 45(4) of the Legislation. This Report should include an assessment of the federal *Employment Equity Act* or other models as appropriate, and specific initiatives.

Condition 10:
The Proponent report on a quarterly basis, in a format satisfactory to the Board, expenditure and employment information, including Canadian and Newfoundland & Labrador content. Each quarterly report should also include an assessment of progress toward the achievement of Canada-Newfoundland Benefits commitments, as referenced in Condition 7. Such reports will be shared with the public. The Proponent should provide the results of internal audits completed with respect to Benefits reporting and an assessment of performance against identified contract goals to the Board and the public when complete.

Condition 11:
It is a condition of this Benefits Plan approval that the Proponent submit on a quarterly basis during the construction and operations phases of the Development a report describing its actual performance against the estimates provided in its correspondence contained in Appendix D of this Report. Any deviation between the benchmarks of estimates, plans and objectives and actual performance should be accompanied by explanatory notes in sufficient detail to allow assessment of the reasons for the deviation.

Condition 12:
Compliance with the White Rose Benefits Plan and its conditions is a condition of this Development Plan approval.

Condition 13:
Should the results of drilling indicate any significant change in the premises upon which the present Development Plan is based, the Proponent is required to submit for the Board's approval an amended plan that takes this new information into account. The Board will establish the date by which such a submission must be made considering the timing of the availability of new information.

Condition 14:
The Proponent provide to the Board within 12 months following the initiation of sustained gas injection into the North Avalon pool, an assessment of the gas injection performance and its potential impact on recovery of oil resources in the North Avalon pool.

Condition 15:
The Proponent, prior to initiating oil production, provide a procedure acceptable to the Chief Conservation Officer for estimating the liquids produced in association with coned gas and report these estimates to the Board as part of the monthly production report.

Condition 16:
The Proponent provide to the Board, prior to initiating development drilling, a report summarizing the result of the activities and studies outlined in Section 6.9 of the *White Rose Oilfield Development Application Volume 2: Development Plan*.

Condition 17:
Prior to finalizing the subsea flowline design, the Proponent submit for approval of the Chief Conservation Officer, the flowline sizes and the location of the FPSO, supported by the field hydraulic studies which provide an assessment of these factors on oil recovery.

Condition 18:
No changes are to be made to the design requirements for the FPSO, the turret and the subsea system, from those set out in the Application and follow-up submissions which provide for accommodating future deferred oil and gas production, without the approval of the Board.

Condition 19:
Within two years from initiation of production from the South Avalon pool, the Proponent submit a report, acceptable to the Board, on the following:
- **(i) an assessment of the development potential of the West and North Avalon oil pools and if warranted, proposals for drilling and evaluating the accumulations; and,**
- **(ii) an updated evaluation of the White Rose field gas resources, along with a description of activities to be undertaken, including drilling schedule and locations for delineation or pre-development wells.**

Condition 20:
Prior to any South Avalon pool development drilling operations, the Proponent submit an assessment of the extent to which any of the deferred resources can be evaluated using pilot holes.

Condition 21:
Prior to initiating production from the White Rose field, a unitization agreement among license holders for the White Rose Significant Discovery Area be submitted to the Chief Conservation Officer.

Condition 22:
The Proponent submit to the Board within 90 days of Project Sanction a schedule of activities and decision points, including model tests, design analysis and design selection. The Proponent will submit selected test and study results to the Board as directed.

Condition 23:
The Proponent shall, prior to commencing detailed design, demonstrate to the satisfaction of the Board that the FPSO's disconnect time will reduce the risk of iceberg impact to a level as low as reasonably practicable (ALARP). The Proponent shall provide a report for approval by the Board that describes how provision will be made for demonstration of and training for the disconnect procedure.

Condition 24:
The Proponent submit with each application for a development work authorization, a Safety Plan for the approval of the Board's Chief Safety Officer.

Condition 25:

(i) The Proponent submit a plan acceptable to the Board to document and track the suite of safety studies required for detailed design within 90 days of Project Sanction.

(ii) The Plan include a schedule acceptable to the Board for satisfying the recommendations provided in the Proponent's Concept Safety Analysis.

Condition 26:
The Proponent shall, prior to commencing detailed design, demonstrate to the satisfaction of the Board that the location of the Temporary Safe Refuge (TSR) and evacuation systems, either at the bow or stern of the vessel, has reduced the risk to personnel to a level as low as reasonably practicable (ALARP).

Condition 27:
The Proponent shall, at least one year prior to the commencement of production operations, submit to the Board its strategy for the development and documentation of the detailed operations procedures necessary for the safe operation of the installation. The Proponent must also ensure that its contingency plans address the possibility of simultaneous occurrence of any combination of high winds, sea ice, icebergs and heavy seas with an accidental event.

Condition 28:
No later than one year prior to the scheduled installation of the FPSO vessel on location, the Proponent submit the Training Proposal required by the *Newfoundland Offshore Area Petroleum Production and Conservation Regulations* for the approval of the Board's Chief Safety Officer.

Condition 29:
The command structure for the FPSO clearly require that in making decisions in relation to marine matters, the Offshore Installation Manager must seek the advice of the Master Mariner.

Condition 30:
The Master Mariner on board the FPSO shall maintain an Official Log-Book and the List of the Crew as if the FPSO were a ship. In addition, if not one and the same person, the Master Mariner shall record in the Official Log-Book all recommendations made to the Offshore Installation Manager on marine matters.

Condition 31:
The procedures should provide that initiation of the actual disconnection of the vessel shall be under the command of the Master Mariner.

Condition 32:
The Proponent demonstrate, to the satisfaction of the Board, that the best practicable evacuation technology is being used on the production and drilling installations prior to beginning operations in the field.

Condition 33:
The Proponent obtain the approval of the Board for the configuration of the support vessel fleet and for the functional specifications for its proposed standby vessels prior to contracting for these vessels.

Condition 34:
The Proponent provide in its Environmental Protection Plan that the treatment and disposal of wastes are consistent with the September 1996 *Offshore Waste Treatment Guidelines* and with revisions to these Guidelines following their approval by the Board.

Condition 35:
(i) The Proponent, prior to finalizing the detailed design of the production facilities, evaluate and report to the Board the technical and economic feasibility of incorporating measures into the design of the facilities that will reduce the amount of greenhouse gases released from them.
(ii) The Proponent include as part of its Environmental Protection Plan provisions to re-evaluate this feasibility every three years following First Oil.

Condition 36:
The Proponent investigate the feasibility of minimizing chlorine use by means of an in-line analyzer near the point of discharge which controls the quantity of chlorine that is added to the cooling water, and of using cooling water for water injection, and to provide for these measures in the design of its facilities unless otherwise approved by the Board in light of technical and economic considerations.

Condition 37:
(i) The Proponent provide in the design of the FPSO vessel topsides the capability for installing equipment for produced water re-injection.
(ii) The Proponent undertake and submit to the Chief Conservation Officer an analysis of the feasibility of produced water re-injection, following the recovery of sufficient volumes of produced water to permit such an analysis.
(iii) The Proponent proceed with re-injection of produced water if, in the opinion of the Chief Conservation Officer, it is technically feasible and economically reasonable to do so.

Condition 38:
The Safety Plan and the Environmental Protection Plan each include a description, to the satisfaction of the Chief Safety Officer and the Chief Conservation Officer respectively, of the extent to which the Proponent will make safety and environmentally-related information available to the public.

APPENDIX B: RECOMMENDATIONS OF THE WHITE ROSE PUBLIC REVIEW COMMISSIONER

The following recommendations are found in the Report of the Public Review Commissioner for the White Rose Development Application, dated September 2001. Decision Report 2001.01 references to these recommendations are shown bolded in brackets.

(GENERAL DEVELOPMENT APPROACH)

3.1 The Commissioner recommends that, subject to related recommendations on safety (5.2,5.3,5.4,5.5 and 5.6), the Proponent's preferred production system concept of a Floating Production Storage and Offloading system, (FPSO) and subsea completion system with flowlines and risers connected to a quick disconnect turret be approved by the Board for the White Rose development.

[Decision Report 2001.01: Section 4.5]

3.2 The Commissioner recommends that the Board consider the FPSO not as a mature technology, but as a maturing one, and furthermore that the FPSOs at Terra Nova and White Rose be closely monitored in relation to research on this technology ongoing elsewhere in the world and with particular focus on the aspects unique to our environment.

[Decision Report 2001.01: Section 4.7.1]

3.3 The Commissioner recommends that the Board approve the Proponent's deferred development plan for the oil resources of the White Rose Significant Discovery Area as presented during the public sessions and outlined in this chapter, provided that the Proponent is held to commitments made at the public review that there will be sufficient flexibility in the subsea system and turret to accommodate the plan; and provided that the White Rose oil development will not interfere with, or impede in any way, future gas development.

[Decision Report 2001.01: Sections 4.6.8 and 4.6.9]

3.4 The Commissioner recommends that the Board require the Proponent to provide for the eventual production of gas for export in its design of the FPSO topsides and facilities.

[Decision Report 2001.01: Sections 4.2, 4.6.8 and 4.6.9]

3.5 The Commissioner recommends that the Board require the Proponent to submit for the Board's approval a specific gas delineation program for the White Rose Significant Discovery Area, commencing with at least one delineation well within 6 months of Project approval.

[Decision Report 2001.01: Sections 4.2 and 4.6.9.6]

3.6 The Commissioner recommends that prior to the actual start of oil production (currently estimated for 2004) the Board review the information obtained from the recommended gas delineation program, and determine whether it would be appropriate to require the Proponent to undertake, at that time, the modifications required to the FPSO to enable it to export gas.

[Decision Report 2001.01: Section 4.2]

3.7 The Commissioner recommends that the Board require the Proponent to make White Rose gas available for export should gas transportation infrastructure be put in place.

[Decision Report 2001.01: Section 4.2]

3.8 The Commissioner recommends that when considering the Proponent's legitimate responsibilities under the Atlantic Accord and the relevant legislation, particularly its responsibilities relating to Canada/Newfoundland benefits, the Board not be influenced by the Proponent's suggestions that the Project is 'marginal'. The Commissioner has concluded that this is a Project with a good rate of return and considerable upside potential.

[Decision Report 2001.01: Section 3.2.2.4]

3.9 The Commissioner recommends that a complete project economic analysis be a required part of the Board's evaluation of future Development Applications.

[Decision Report 2001.01: Sections 3.2.2.4 and 4.2]

3.10 The Commissioner recommends that the Board not allow the Proponent's current contracting approach and schedule to influence the Board's decision-making in any way, whether regarding the selection of a particular production system, related contracts, or regarding the provision of Canada-Newfoundland Benefits.

[Decision Report 2001.01: Section 3.3.4.1]

3.11 The Commissioner recommends that all risks of delay or additional costs as a result of the contracting strategy employed by the Proponent be borne by the Proponent.

[Decision Report 2001.01: Section 3.3.4.1]

(BENEFITS AND THE CANADA-NEWFOUNDLAND BENEFITS PLAN)

4.1 The Commissioner recommends that the Board not approve the Canada-Newfoundland Benefits Plan, Volume I of the White Rose Development Application, for the reasons outlined in this chapter.

[Decision Report 2001.01: Section 3.3]

4.2 The Commissioner recommends that the Board invite the Proponent to re-write its Benefits Plan to correct the deficiencies identified by the Commissioner and to reflect the improvement suggestions outlined below. The Commissioner envisages that this can be done in consultation with the Board and the revised Benefits Plan can be resubmitted to the Board in a matter of a few weeks, without necessarily disrupting the Board's stated approval decision schedule for this fall. For ease of reference, the improvement suggestions include:

- provide, as an integral part of the Benefits Plan, realistic estimates, in terms of specific levels and quantifiable objectives, of what benefits the Proponent expects will be achieved through implementation of the Benefits Plan. These *quantifiable objectives* or *targets* should be express in terms such as dollar amount of goods and services procured, percentage of total dollars spent, percentage of construction contracts awarded, person-years of employment and/or similar quantifiable units. These targets represent thresholds to be strived for and subsequently are to be used as benchmarks against which progress can be measured. **[Decision Report 2001.01: Section 3.2.2.4]**;
- provide, as an integral part of the Benefits Plan, *tools* in the form of firm pro-active programs or initiatives that will be utilized by the Proponent and its contractors and subcontractors as they strive together to meet the stated quantifiable objectives or targets. There should be a list of these *tools* for each major category of benefits, namely: employment; education, training and technology transfer; goods and services; and research and development. **[Decision Report 2001.01: Section 3.2.2.4]**;
- provide, specific initiatives to promote training, recruitment, retention and promotion of women for the White Rose Project and amend the Benefits Plan to reflect the commitment to "defined objectives, quantifiable targets, and measured outcomes" contained in the

Proponent's June 8th Additional Information document. **[Decision Report 2001: Section 3.2.2.5]**;

- re-address the procurement and bid evaluation procedures for goods and services, and in particular, the Proponent's qualifiers 'internationally competitive', 'best value', 'essentially equal'. Local content must be included as one of the selection criteria in the definition of 'best value'.**[Decision Report 2001.01: Section 3.2.2.4]**;
- formally require all contractors and subcontractors operate as if they were the Proponent with all of its responsibilities and obligations under the Benefits Plan, and remove such catch-all escape clauses as require contractor's "to comply to a *reasonable* degree", "major contractors will be *encouraged* to conduct a thorough assessment of… local facilities", etc. **[Decision Report 2001.01: Section 3.3.4.1]**;
- provide specific research and development programs and expenditure commitment in line with a goal of creating the proper longer-term economic environment and business community appropriate to a "major oil and gas producer" or of developing a sustainable oil and gas industry. **[Decision Report 2001.01: Sections 3.2.2.3 and 3.3.3]**;
- update Chapters 5 and 6 of the Proponent's Benefits Plan with current information. For example, as mentioned earlier, Table 6.10-1 shows total labor requirements at approximately 12.2 million person-hours. Information presented in the June 8th response to the Commissioner provided tables totaling 21.9 million person-hours. These were subsequently corrected in Tables 4.1 and 4.2 shown in this chapter which total 19.3 million person-hours. It is most likely that Table 5.12-1, Consumables Requirements Summary and Table 5.12-2, Contracted Services Requirements Summary need similar updates. **[Decision Report 2001.01: Section 3.3.2]**;
- correct a variety of inconsistencies, such as the various references in the Plan to the fact that Canada-Newfoundland benefit considerations are part of the bid selection criteria whereas they are definitely not included in the best value definition; section 2.3.4 of the Plan ignores the Accord principle recognizing the right of Newfoundland and Labrador to be *the* principal beneficiary. The Company's position was corrected at the public sessions and this should be reflected in the Plan. **[Decision 2001.01: Section 3.2.2.4]**;

4.3 The Commissioner recommends that the Board require the Proponent to reflect the results of its new pro-active programs in its quantifiable objectives or targets for the Project and that, concurrent with the re-writing of the Benefits Plan, the Proponent and its contractors engage in an intensive effort to maximize the Canada/Newfoundland content in all major contract areas in the project phase in accordance with the provisions to be included in the new Plan.

[Decision Report 2001.01: Section 3.2.2.4]

4.4 The Commissioner recommends that the Board evaluate and make a decision on the Proponent's revised and re-submitted Canada-Newfoundland Benefits Plan prior to making a decision on the Development Plan.

[Decision Report 2001.01: Section 3.3]

4.5 The Commissioner recommends that the Board (after consideration of the Commissioner's interpretation of the Atlantic Accord and the Accord Acts, his advice on the Board's responsibilities in this area of Canada-Newfoundland benefits, and his advice on adoption of an improved system of benefits administration, as outlined in this Chapter 4) release publicly a definitive statement as to how the Board intends to interpret the Atlantic Accord and the Accord Acts and how the Board will implement or administer it benefits responsibilities, including requirements for, and evaluation of, the Benefits Plans.

[Decision Report 2001.01: Section 3.2]

4.6 The Commissioner recommends that the Board update Chapter 5 of its Development Application Guidelines entitled Canada-Newfoundland Benefits Plan, dated December 1988, so that these guidelines clearly specify these new Benefits Plan requirements and, in the appropriate level of detail, outline what is expected from Proponents.

[This matter is dealt with at Section 3.2.4 of this Decision Report. It is the Board's intention to begin an immediate review and update of the Development Application Guidelines.]

(HUMAN SAFETY AND ENVIRONMENTAL PROTECTION)

5.1 The Commissioner recommends that the Board and Governments take appropriate action in accordance with their responsibilities with reference to the occupational health and safety issues raised. The Commissioner further recommends that the Board, as the regulatory body, take the initiative. A forum which would include industry, labour, the relevant departments of Government and others interested in safety to review these matters in depth is suggested. Results of the forum and follow up action should be reported publicly.

[Decision Report 2001.01: Section 4.7]

5.2 The Commissioner recommends that the Board require that an experienced Master Mariner be the person responsible for the vessel integrity aspects of the White Rose FPSO and for issues of marine safety. The Commissioner further recommends that the Master Mariner have the authority to order the commencement of the disconnection process, including shutting down processing equipment and flushing lines, and to decide if and when the FPSO actually disconnects.

[Decision Report 2001.01: Section 4.7.3.4.1]

5.3 The Commissioner recommends that the Board require that the FPSO disconnect operation, including the quick disconnect in a simulated emergency situation, be thoroughly tested during commissioning. The Commissioner further recommends that regular practice disconnects, including complete disconnects from the spider buoy, be held at a frequency as determined by the Board but sufficient to allow operators to be comfortable with the procedure.

[Decision Report 2001.01: Section 4.7.1.3]

5.4 The Commissioner recommends that the Board review the full results of all model testing on the proposed FPSO hull for White Rose and confirm that these results demonstrate its safety for the Grand Banks environment before approving the production system design. The Commissioner further recommends that on-going monitoring of the structural integrity of the vessel be required.

[Decision Report 2001.01: Section 4.7.1.1]

5.5 The Commission recommends that the Board require that the Proponent's operational safety planning, including its evacuation plans, consider the simultaneous occurrence of two or more extreme events, involving accidental events in combination with wind, sea and ice. The Commissioner further recommends that the ability of the FPSO to disconnect during heavy seas and high winds should also be assessed.

[Decision Report 2001.01: Sections 4.7.1.3 and 4.7.3.3]

5.6 The Commissioner recommends that the Board require that the Proponent's Ice Management Plan explicitly affirm the principle of avoidance of collisions with icebergs and establish prudent criteria for the mass of an approaching iceberg that would initiate disconnect procedures and an identified process to determine whether icebergs meet these criteria.

[Decision Report 2001.01: Sections 4.7.3.6]

5.7 The Commissioner recommends that the Accord Acts be amended to allow the Board to disclose information in respect of which section 119 of the federal Accord Act and section 115 of the provincial Accord Act presently apply, where such disclosure is in the interest of public safety or the protection of the environment.

[Decision Report 01.01: Sections 4.8.7.1]

5.8 The Commissioner recommends that the Board take into account the concerns raised during the public sessions regarding the significance criteria and the resulting determination of significant effects in designing the follow-up program for the White Rose Project as required by the Canadian Environmental Assessment Act. The Commissioner further recommends that the Board seek to achieve continuous improvement in impact assessment methodology, including the determination of significance criteria, through development of stringent guidelines for Proponents.

[Decision Report 2001.01: Section 4.8.6.2]

5.9 The Commissioner recommends that the Board require that the Precautionary Principle be fully integrated into both the planning and the operational decision-making for the White Rose Project and that the Board specifically require the use of best available proven technology in all aspects of the Project, including with respect to minimizing the discharge of pollutants.

[Decision Report 2001.01: Section 4.8.6.1]

5.10 The Commissioner recommends that the Board, following up from its cumulative impacts workshop, pursue the issue of a regional monitoring program with the Department of Fisheries and Oceans. The regional monitoring program should incorporate public input and the results should be made available to the public.

[Decision Report 2001.01: Section 4.8.7.2]

5.11 The Commissioner recommends that should the Board approve the ocean disposal of drill cuttings, it should do so on conditions requiring that the lowest practical levels of residual (drilling and formation) fluids be obtained; that a complete record of release quantities and contaminant constituents be kept; that results of annual monitoring programs be released publicly and treatment technology be reviewed annually and implemented where it can contribute to a continuous improvement approach to the control of pollutants.

[Decision Report 2001.01: Section 4.8.3.2]

5.12 The Commissioner recommends that the Board delay its approval of the White Rose produced water treatment system until the Proponent is able to prepare and submit an analysis providing sufficient technical and economic detail to allow the Board to make a determination of the effect of discharge of produced water. The Commissioner further recommends that the Proponent be required to use best available proven technology to reduce the oil content to as low a level as practical if it is determined that produced water can be safely discharged into the ocean.

[Decision Report 2001.01: Section 4.8.3.3]

5.13 The Commissioner recommends that the Board require the Proponent to conduct a program of research to establish the effects from its operations on marine birds in general, and specifically with respect to flares/lights, operational discharges and oil spills.

[Decision Report 2001.01: Section 4.8.6.3]

5.14 The Commissioner recommends that the Board require the oil and gas industry to provide funding for FANL and FFAW to jointly hire a fisheries/petroleum industry liaison officer to advise them on offshore oil and gas issues related to the fishery and to assist both industries in cooperatively pursuing their respective activities.

[Decision Report 2001.01: Section 4.8.7.3]

5.15 The Commissioner recommends that the Board place a qualified observer on the White Rose FPSO and on other production facilities on the Grand Banks to monitor project interactions with the environment and to audit environmental management procedures.

[Decision Report 2001.01: Section 4.8.7.4]

Appendix C:
Benefits Provisions (Section 45) of the Atlantic Accord Legislation

45.(1) In this section, "Canada-Newfoundland benefits plan" means a plan for the employment of Canadians and, in particular, members of the labour force of the Province and, subject to paragraph (3)(d), for providing manufacturers, consultants, contractors and service companies in the Province and other parts of Canada with a full and fair opportunity to participate on a competitive basis in the supply of goods and services used in any proposed work or activity referred to in the benefits plan.

45.(2) Before the Board may approve any development plan pursuant to subsection 139(4) or authorize any work or activity under paragraph 138(1)(b), a Canada-Newfoundland benefits plan shall be submitted to and approved by the Board, unless the Board directs that that requirement need not be complied with.

45.(3) A Canada-Newfoundland benefits plan shall contain provisions intended to ensure that

45.(3)(a) before carrying out any work or activity in the offshore area, the corporation or other body submitting the plan shall establish in the Province an office where appropriate levels of decision-making are to take place;

45.(3)(b) consistent with the *Canadian Charter of Rights and Freedoms*, individuals resident in the Province shall be given first consideration for training and employment in the work program for which the plan was submitted and a collective agreement entered into by the corporation or other body submitted the plan and an organization of employees respecting terms and conditions of employment in the offshore area shall contain provisions consistent with this paragraph;

45.(3)(c) expenditures shall be made for research and development to be carried out in the Province and for education and training to be provided in the Province; and

45.(3)(d) first consideration shall be given to services provided from within the Province and to goods manufactured in the Province, where those services and goods are competitive in terms of fair market price, quality and delivery.

45.(4) The Board may require that any Canada-Newfoundland benefits plan include provisions to ensure that disadvantaged individuals or groups have access to training and employment opportunities and to enable such individuals or groups or corporations owned or cooperatives operated by them to participate in the supply of goods and services used in any proposed work or activity referred to in the benefits plan.

45.(5) In reviewing any Canada-Newfoundland benefits plan, the Board shall consult with both Ministers on the extent to which the plan meets the requirements set out in subsections (1), (3) and (4).

45.(6) Subject to any directives, issued under Subsection 42(1), the Board may approve any Canada-Newfoundland benefits plan.

APPENDIX D: BENEFITS LETTERS FROM GOVERNMENT AND PROPONENT

GOVERNMENT OF
NEWFOUNDLAND AND LABRADOR

Department of Mines and Energy
Office of the Minister

November 23, 2001

H.H. Stanley
Chairman and CEO
Canada-Newfoundland Offshore Petroleum Board
Fifth Floor, TD Place
140 Water Street
St. John's, NF
A1C 6H6

Dear Mr. Stanley:

Re: White Rose Development Plan Application

The Canada-Newfoundland Offshore Petroleum Board ("the Board") is presently considering a Development Plan Application ("DPA") submitted by Husky Oil Operations Limited and Petro-Canada ("the Proponents") for the development of the White Rose oilfield. A critical component of the White Rose DPA is the Canada-Newfoundland Benefits Plan ("the Benefits Plan").

The Accord Acts require the Board to consult with the provincial Minister of Mines and Energy and the federal Minister of Natural Resources on the extent to which the Benefits Plan meets the statutory requirements for such plans; these consultations have been ongoing and have been productive. The information provided and the request contained herein should be treated as part of that consultation process, notwithstanding that the request is for the Board to undertake an additional obligation which may not have been contemplated in your review of the Benefits Plan.

As you may be aware, the Proponents have undertaken, at their own risk, contracting activity in advance of an approved Benefits Plan. This has allowed the Proponents to establish firmer plans than provided earlier to the CNOPB for industrial benefits that should accrue to Newfoundland and Labrador and to Canada as a result of the construction, development and production of the White Rose Project. These updated plans have been shared with my officials and officials of the federal government. I attach, for your information, a letter from Mr. James S. Blair, dated November 20, 2001 (and other earlier correspondence from Husky Oil dated October 26, 2001), in which Husky Oil summarizes its updated and detailed plans to us in terms of achievable and measurable employment and expenditure benefits. The correspondence from Mr. Blair also indicates that Husky Oil will continue to proactively identify measures and initiatives aimed at increasing the level of Newfoundland participation

P.O. Box 8700, St. John's, Newfoundland, Canada, A1B 4J6, Telephone (709) 729-2920, Facsimile (709) 729-0059

even further, in keeping with the spirit and intent of the Atlantic Accord which provides that Newfoundland and Labrador shall be the principal beneficiary of the development of its offshore oil and gas resources. This provides considerable elaboration and clarification as to how the Proponents intend to execute the Benefits Plan submitted to the CNOPB.

The Board's obligation is to review the Benefits Plan provided by the Proponents and, if it is generally acceptable, approve it subject to appropriate conditions to address deficiencies identified by your review. My request to you is that the Board acknowledge the attached correspondence provided by the Proponents in your Benefits Plan Decision Report, including specific reference to the firm plans which outline the Proponents' estimates and objectives related to industrial benefits. Furthermore, I request that the Board treat the plans, estimates and objectives provided therein as benchmarks, recognizing that benchmarks are not ceilings. Consistent with this approach, I also request that the Board specifically acknowledge the Proponents' undertaking, contained in its correspondence dated November 20, 2001, to strive for an even greater level of benefits for Canada and, in particular, Newfoundland and Labrador, in all aspects of the project, including the topsides development phase, consistent with the provisions of the Atlantic Accord legislation.

I would also ask that the Board incorporate as a condition of the Benefits Plan approval that it will monitor the benchmarks against actual performance in assessing the success of the Proponents' efforts to maximize achievements flowing from the full and fair opportunity for Canadians, and first consideration for Newfoundlanders and Labradorians, to participate in the supply of goods and services and to undertake employment associated with the project. Such monitoring should include a regular and frequent review process, involving the Proponents, to identify any deviations from the benchmarks and a process to identify, as completely as possible, the reasons why performance did not match them. The information resulting from this review should be shared on a regular basis with officials of Natural Resources Canada and my Department.

I have made the federal Minister aware of the information I have provided to you and the request contained in this letter. I would ask that you consider this request in a timely fashion and advise me of your determination as soon as possible. If you should find yourself unable to accede to my request, I will so advise the federal Minister and ask that he join me in issuing a directive to the Board to like effect.

I look forward to hearing from you.

Yours very truly,

LLOYD G. MATTHEWS
Minister of Mines and Energy

Attach.

c: The Hon. Ralph Goodale
The Hon. Beaton Tulk

Husky Energy

707 8th Avenue S.W.
Box 6525, Station D
Calgary, Alberta, Canada
T2P 3G7

James S. Blair
Senior Vice-President and
Chief Operating Officer
Bus: (403) 298-6583
Fax: (403) 298-7133

November 20, 2001

Honourable Ralph Goodale
Minister of Natural Resources
Government of Canada
Natural Resources Canada
580 Booth Street, 21st Floor
Ottawa, Ontario K1A 0E4

Honourable Lloyd Matthews
Minister, Mines and Energy
Government of Newfoundland and Labrador
7th floor, 50 Elizabeth Avenue
St. John's, Newfoundland
A1A 1W5

Gentlemen:

Re: White Rose Project

We are writing to outline the employment and expenditure impact of our plan to carry out work in Newfoundland and Labrador and Canada for the various facets of the White Rose offshore oilfield development project. Noting of course that the implementation of this plan is dependent upon the CNOPB approval of the Benefits Plan, the Governments' approval of the Development Application and project sanction by the owners.

The White Rose project contracting strategy is based on obtaining fixed price lump sum contracts for all major components of the FPSO, subsea system, and glory holes excavation with the drilling rig contract based on a fixed dayrate (see attached schematic). Over the past several months, we have identified our preferred front end engineering and design (FEED) contractors with whom we plan to enter into final agreements given regulatory approval and owner project sanction.

The employment and expenditure summaries attached are based on information provided by these contractors and on internal Husky projections. The specific benefits provisions of the individual project components are outlined in correspondence to your officials dated October 26, 2001.

These firm plans reflect our most recent assessment of Newfoundland and Canadian commercially competitive capabilities, and we are confident that they are realistic and achievable based on conditions existing at the time of preparation. We are particularly pleased to note the Canada/Newfoundland fabrication, assembly and installation strategy for Topsides which will see over 80% of the person hours of work occur in Newfoundland with the balance being done elsewhere in Atlantic Canada.

Please note that Husky will continue to proactively identify measures and initiatives that will increase the level of Newfoundland and Canadian participation for all aspects of the project above and beyond that outlined herein. Moreover, as part of this effort, including with respect to the topsides element of the project, Husky will continue to identify measures aimed at increasing the level of Newfoundland participation in keeping with the spirit and intent of the Atlantic Accord which provides that Newfoundland be the principal beneficiary of the development of its offshore oil and gas resources.

Tables 1 and 2 reflect our most current plans for employment and expenditures for the development phase of the project. They cover the development phase for the FPSO and subsea systems assuming a first oil date of Q4 2004, and the complete development drilling and logistics program for a 21 well case (2002-2007). These plans continue to be refined as bid information is received but we are confident that they are realistic and achievable.

Operations phase employment and expenditure information is currently being refined as these services are currently under a bid process. Accordingly, we are providing you with our best estimates and objectives for employment levels as provided at the time of the public hearings.

We trust you will find this update informative and useful. In summary, the development strategy is designed to yield:

- Over 5.9 million person hours of direct employment in Newfoundland and over 1.3 million person hours of direct employment elsewhere in Canada;

- Over 400 long term, high quality jobs over the life of the field. When spin off effects are included, we estimate that the project will create an additional 1,000 jobs;

- Over the life of the project, an estimated $6.8 billion contribution to the GDP; and

- Approximately $1.4 billion in taxes and royalties.

As importantly, success on the White Rose project will demonstrate that smaller, but materially significant fields offshore Newfoundland can be developed economically, and with significant benefit to the local and national economy. The White Rose project can make a long term contribution to the Province's offshore petroleum industry by expanding the base of experienced individuals, businesses and research and training facilities, and building a proven track record of delivering a high quality product, on time and within budget.

Yours sincerely,

HUSKY OIL OPERATIONS LIMITED

James S. Blair
Senior Vice President and Chief Operating Officer

Attach.

White Rose Project Development Schematic

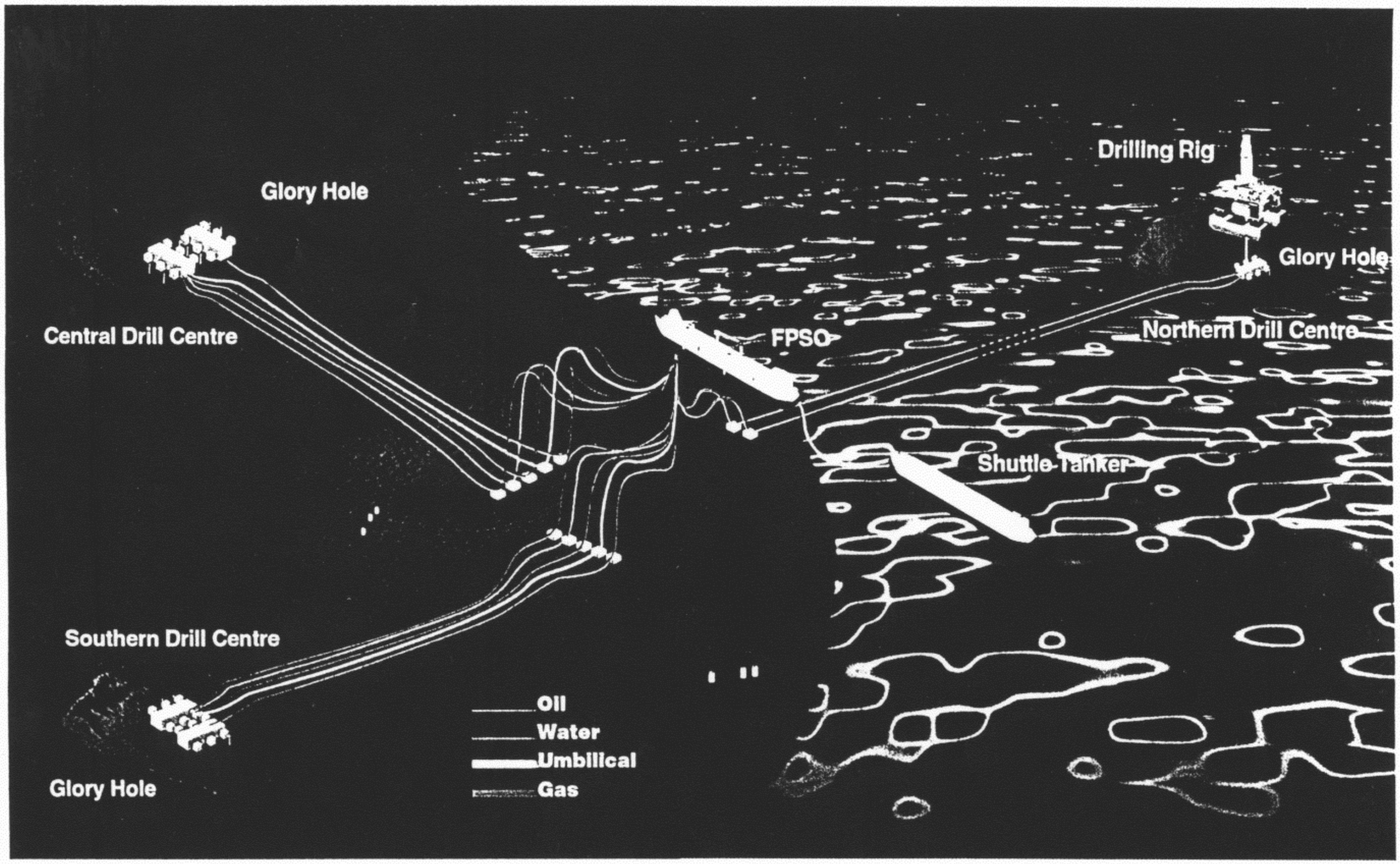


TABLE 1

Employment - Project Execution Phase
Estimated Direct Employment - Revised October 16, 2001
Commencing September 2001
PERSON HOURS

Project Component	Total Employment	NF Employment	Other Canadian Employment	International Employment
Husky Project Mgmt[1]	**536,000**	**478,000**	**38,000**	**20,000**
FPSO Project Mgmt[2]	**229,000**	**153,000**	**29,000**	**47,000**
FPSO Topsides[3]	**3,544,000**	**2,792,000**	**752,000**	**0**
FPSO Hull	**1,200,000**	**25,000**	**0**	**1,175,000**
FPSO Turret[4]	**478,000**	**66,000**	**0**	**412,000**
Subsea[5]	**1,460,000**	**360,000**	**5,000**	**1,095,000**
Drilling[6]	**2,005,000**	**1,103,000**	**501,000**	**401,000**
Logistics[6]	**913,000**	**885,000**	**28,000**	**0**
TOTAL[7]	10,365,000	5,862,000	1,353,000	3,150,000

Explanatory Notes on changes in estimates since public hearings. Information reflects activity commencing September 2001; based on first oil of Q4, 2004

The estimates provided are subject to DA approval and owner sanction, and are subject to the bid prices being held until such time as final contracts are executed. As well, the topsides fabrication strategy is contingent upon the successful conclusion of commercial arrangements for fabrication infrastructure within Newfoundland.

[1] **Project Management**: Previous total of 600,000, now 536,000 hours estimated.

[2] **FPSO Project Management**: Husky estimate based on overall man-hours and organization provided by Maersk

[3] **FPSO Topsides**: Excludes FEED.

[4] **FPSO Turret**: Revised to reflect bid information; Total (was 700,000, now 478,000). NF Employment (was 50,000, now 66,000). Pending further revisions to reflect additional turret passes.

[5] **Subsea**: Includes FEED and EPIC contracts and installation. NF employment has been changed to reflect bid information; total employment (was 1,200,000 now 1,460,000); NF employment (was 500,000, now 360,000)

[6] **Drilling and Logistics**: Estimates are based on 1999 and 2000 delineation drilling information. The seasonal nature of these two programs did not allow for meaningful succession planning. The development drilling and completions program will be a continuous process with practical succession planning. This should lead to increased Newfoundland content.
Drilling: 99 people average on rig; 21 wells drilled and completed; drilling total employment (was 1,600,000, now 2,005,000); drilling NF employment (was 800,000, now 1,103,000);
Logistics: 2.3 vessels 2002 - 2007; logistics total employment (was 980,000, now 913,000); logistics NF employment (was 840,000, now 885,000). Logistics estimates are for drilling program; no provision included for FPSO support during this period.

[7] **Overall total** employment estimate has been increased by 1,265,000 hours (now 10,365,000, was 9,100,000).

TABLE 2

Expenditure - Project Execution Phase
Estimated Project Expenditure - Revised October 16, 2001
Commencing September 2001
Canadian Dollars; in Thousands

Project Component	Total Expenditure	NF Expenditure	Other Canadian Expenditure	International Expenditure
Husky Project Mgmt[1]	**92,000**	**54,000**	**13,000**	**25,000**
FPSO Project Mgmt & Other Costs[2]	**102,000**	**66,000**	**5,000**	**31,000**
FPSO Topsides[3]	**661,000**	**251,000**	**165,000**	**245,000**
FPSO Hull	**215,000**	**0**	**1,000**	**214,000**
FPSO Turret[4]	**115,000**	**6,000**	**0**	**109,000**
Subsea [5]	**301,000**	**78,000**	**0**	**223,000**
Drilling[6]	**674,000**	**167,000**	**67,000**	**440,000**
Logistics[6]	**165,000**	**144,000**	**16,000**	**5,000**
TOTAL	2,325,000	766,000	267,000	1,292,000

[1] In addition to salaries and related employee costs, Project Management expenditures include computing requirements, office expenses, staff expenses, Certifying Authority costs, insurance, studies and project corporate overhead.

[2] Other costs include start-up and commissioning

[3] **FPSO Topsides**: Overall expenditure breakdown provided by AMKC, Excludes FEED,

[4] **FPSO Turret**: Pending further revisions to reflect final design requirements.

[5] **Subsea**: Based on 21 Wells;

[6] **Drilling and Logistics**:
Estimates are based on 1999 and 2000 delineation drilling information. The seasonal nature of these two programs did not allow for meaningful succession planing. The development drilling and completions program will be a continuous process with practical succession planning. This should lead to increased Newfoundland content.
Due to the service associated with the Drilling/Completion Program, the majority of the suppliers and rig contractor are international companies. Therefore the cost is assume Other and Not NF.
Drilling 99 people average on rig; 21 wells drilled and completed; 2.3 vessels

TABLE 3

Employment - Project Operations Phase
Estimated Direct Employment -
Estimates from July, 2001
(4^{th} Quarter 2004-2016)
PERSON HOURS

Project Component	Total Employment	NF Employment
Husky Project Mgmt	1,400,000	1,300,000
FPSO Operations	3,400,000	3,100,000
Drilling	400,000	200,000
Logistics	2,400,000	2,100,000
Well Interventions	900,000	500,000
Abandonment	200,000	100,000
Tankers	1,500,000	1,300,000
TOTAL	10,200,000	8,600,000

Husky Oil

Dr. William Roach
General Manager,
East Coast Development

Suite 801, Scotia Centre
235 Water Street
St. John's, Newfoundland
A1C 1B6

Phone: (709) 724-3900
Fax: (709) 724-3989

26 October 2001

Mr. Brian Maynard
Deputy Minister
Department of Mines and Energy
Natural Resources Building
7th Floor, 50 Elizabeth Avenue
St. John's, NF

Ref No.: MGM-0650

Dear Mr. Maynard:

File No.: 18.6.2

Re: White Rose Project

We are writing to provide you with up-to-date information on project contracting and the associated Canada/Newfoundland benefits for the White Rose project.

As you are aware our contracting strategy is based on obtaining fixed price lump sum contracts for all major components of the FPSO, subsea system, and glory holes excavation. The drilling rig contract will be based on a fixed dayrate. Over the past several months, we have identified our preferred front end engineering and design (FEED) contractors with whom we plan to enter final agreements given regulatory approval and owner project sanction.

The benefits information that follows is based on information provided by these contractors and on internal Husky projections. A summary of employment benefits and expenditures, listing relevant assumptions, is included.

These estimates represent our most recent evaluation of Newfoundland and Canadian content, and we are confident that they are realistic and achievable based on conditions existing at the time of preparation. Consistent with our operating philosophy, Husky will continue to proactively identify measures and initiatives that will increase the level of Newfoundland and Canadian participation over the life of the project.

FPSO (FEED Contractor – Maersk Contractors Newfoundland Ltd.)

In October, 2000, Maersk Contractors Newfoundland Ltd. was selected as the FEED contractor for the FPSO. They will continue in this role to year-end. As we indicated during the Public Hearings, the Owners will continue to evaluate leasing options for the FPSO, including the option of working with Maersk over the life of the field.

Hull (Preferred Contractor: Samsung Heavy Industries)

Samsung Heavy Industries of Koje-City, Korea completed the FEED phase on June 30, 2001, and commenced detailed design on July 1, 2001. Model tests were conducted during July through Oceanic Consulting Limited at the NRC Institute for Marine Dynamics in St. John's. A final commitment on the hull contract will be made following regulatory approval and Project Sanction by the owners.

In preparation for the hull procurement activity, Maersk undertook a comprehensive review of the Canadian procurement on previous shuttle tankers and the Terra Nova FPSO. Potential bidders were contacted to determine their interest in bidding work on the hull. As well, a detailed potential supplier list of 150 companies was developed based on consultations with the Canadian Shipbuilders Association, NOIA, Industry Canada and the owners.

In September, 2001, a Samsung procurement officer was located in the Maersk Contractors offices in St. John's. Maersk Contractors placed advertisements in both local and national newspapers advising the supply community that a representative from Samsung was available to meet to discuss supply opportunities. Over a 5-week period, 23 meetings were held with potential suppliers, and 285 bid packages were issued to 140 companies.

Turret and Mooring (Preferred Contractor: Single Buoy Moorings (SBM))

SBM-IMODCO of Houston has been awarded a FEED contract for the Turret and Mooring system for the FPSO. The scope of work includes model testing, which was done at the Institute for Marine Dynamics in St. John's during July and September, 2001.

With respect to the Canada/Newfoundland benefits package, once a final contract is executed with SBM, the company will establish a local engineering and procurement presence in St. John's in conjunction with its local engineering affiliate, Pan-Maritime. The Project Owners have required SBM to bid specific fabrication requirements here in the Province, including anchor piles and the Turret Equipment Room. SBM is also examining other potential fabrication opportunities for the Province. SBM has pre-qualified Newdock in St. John's and the FGN facility at Marystown for fabrication work.

In addition to the fabrication requirements associated directly with the White Rose Project, SBM-IMODCO has committed to fabricating a stock CALM (catenary anchor leg mooring) buoy in the Province as part of an overall vendor development initiative.

The CALM buoy constitutes the heart of a CALM system, which can be best described as an internationally accepted offshore system for the loading and/or offloading of tankers of all sizes. The present world market is some 10 to 15 CALM buoys a year.

With respect to employment and recruitment, SBM-IMODCO will employ between 3 and 5 local graduates and has agreed to recruit locally for up to 15 positions in the international operations of its Group's companies.

Topsides (Preferred Contractor: Aker Maritime Kiewit Contractors)

Following a competitive bid process, in April 2001, Husky announced that two bidders, Aker Maritime Kiewit Contractors (AMKC) and Single Buoy Moorings (SBM), were being carried forward in the final bidding phase for the FPSO Topsides. During this phase, AMKC was funded to advance engineering and design and refine the costs of a Canada/Newfoundland solution. SBM agreed to hold open their internationally based bid until October 1, 2001.

The AMKC FEED study was completed at the end of August 2001, and a lump sum pricing proposal was provided shortly thereafter. The proposed construction strategy is based on locating engineering and project management in St. John's, with fabrication being carried out in several yards in Newfoundland and Atlantic Canada. Although the location of specific work packages is subject to final confirmation, the plan would see approximately 2,078,000 person hours of fabrication and integration work undertaken in the province. Person hours associated with the current plan is summarized below.

Topsides	Location of Work	Person Hours
Engineering	St. John's, NF	500,000
Project Management	St. John's, NF	214,000
Fabrication/Integration	Newfoundland	2,078,000
Fabrication	Atlantic Canada	752,000
		TOTAL 3,544,000

Overall, Husky believes that this strategy, which would see over 80% of the person hours of work associated with Topsides occur in Newfoundland with the other 20% being done in Atlantic Canada, demonstrates our commitment to attaining a solution which meets the needs of the many stakeholders in the project.

Subsea:

Glory Hole Excavation (Preferred Contractor: Boskalis b.v.)

Through their work on the Terra Nova Project, Boskalis has established a local presence and relationships with a number of suppliers. Although the scope of excavation work is of relatively short duration (approximately 3 months), Boskalis has committed to seeking Canadian/Newfoundland crew for the operations. They will base a Project Manager here, as well as a Works Manager and Project Engineer. The company has committed to hiring 18 Newfoundland residents and Canadians out of a total complement of 45.

Subsea Production System: (Preferred Contractor: Coflexip Stena Offshore (CSO))

The White Rose project will enable CSO to build on the local base of operations that was established through the company's work on the Terra Nova project. CSO currently estimates that between 20 to 28 engineering and project management personnel will be based in Newfoundland to support the White Rose Project. Up to 12 additional staff will be required for the local supply base, as well as between two and four co-op students.

In terms of subcontracting activity, CSO has agreed to source:

- all eyeball ROV in Newfoundland
- 50%-75% of all divers in Newfoundland
- 50%-85% of all ROV crews in Newfoundland
- 30%-50% of all installation vessel crew in Newfoundland
- Marine survey vessels, equipment and labour from Atlantic Provinces

With respect to fabrication and assembly, the principle opportunities for Newfoundland/Canada will come in the following areas:

- Manifold frames, riser arches and pipeline spools
- Assembly of manifolds
- Concrete components – riser bases and protection mattresses
- System Integration Tests

As outlined in the public hearings, the subsea solution is "product-based" or based on proprietary technologies, and as such, means that fabrication of specialized flow lines and ancillary equipment cannot at present be carried out in Canada.

Drilling and Logistics (Under bid)

The drilling and logistics program is currently based on a 21 well case. Bids are currently being reviewed for a harsh environment class drilling rig required for year round operations. The scope of any possible refit is therefore yet to be determined and may present an opportunity for additional Newfoundland content.

The benefits estimates contained in the summary tables below are based on historical information on short term drilling programs. Husky is optimistic that with appropriate succession plans in place, higher levels of Newfoundland employment will be achieved.

Canada/Newfoundland Benefits Summaries

Tables 1 and 2 reflect our most current estimate of employment and expenditures for the development phase of the project. They cover the development phase for the FPSO and subsea systems (September 2001 to 4th quarter 2001) assuming a first oil date of Q4 2004, and the complete development drilling and logistics program for a 21 well case (2002-2007). These estimates continue to be refined as bid information is received.

TABLE 1
Employment - Project Execution Phase
Estimated Direct Employment - Revised October 16, 2001
Commencing September 2001
PERSON HOURS

Project Component	Total Employment	NF Employment	Other Canadian Employment	International Employment
Husky Project Mgmt[1]	536,000	478,000	38,000	20,000
FPSO Project Mgmt[2]	229,000	153,000	29,000	47,000
FPSO Topsides[3]	3,544,000	2,792,000	752,000	0
FPSO Hull	1,200,000	25,000	0	1,175,000
FPSO Turret[4]	478,000	66,000	0	412,000
Subsea[5]	1,460,000	360,000	5,000	1,095,000
Drilling[6]	2,005,000	1,103,000	501,000	401,000
Logistics[6]	913,000	885,000	28,000	0
TOTAL[7]	10,365,000	5,862,000	1,353,000	3,150,000

Explanatory Notes on changes in estimates since public hearings. Information reflects activity commencing September 2001; based on first oil of Q4, 2004

[1] **Project Management**: Previous total of 600,000, now 536,000 hours estimated.

[2] **FPSO Project Management**: Husky estimate based on overall man-hours and organization provided by Maersk

[3] **FPSO Topsides**: Excludes FEED.

[4] **FPSO Turret**: Revised to reflect bid information; Total (was 700,000, now 478,000). NF Employment (was 50,000, now 66,000). Pending further revisions to reflect additional turret passes.

[5] **Subsea**: Includes FEED and EPIC contracts and installation. NF employment has been changed to reflect bid information; total employment (was 1,200,000 now 1,460,000); NF employment (was 500,000, now 360,000)

[6] **Drilling and Logistics**: Estimates are based on 1999 and 2000 delineation drilling information. The seasonal nature of these two programs did not allow for meaningful succession planning. The development drilling and completions program will be a continuous process with practical succession planning. This should lead to increased Newfoundland content.
Drilling: 99 people average on rig; 21 wells drilled and completed; drilling total employment (was 1,600,000, now 2,005,000); drilling NF employment (was 800,000, now 1,103,000);
Logistics: 2.3 vessels 2002 - 2007; logistics total employment (was 980,000, now 913,000); logistics NF employment (was 840,000, now 885,000). Logistics estimates are for drilling program; no provision included for FPSO support during this period.

[7] **Overall total** employment estimate has been increased by 1,265,000 hours (now 10,365,000, was 9,100,000).

Table 2
Expenditure - Project Execution Phase

Estimated Project Expenditure - Revised October 16, 2001
Commencing September 2001
Canadian Dollars; in Thousands

Project Component	Total Expenditure	NF Expenditure	Other Canadian Expenditure	International Expenditure
Husky Project Mgmt[1]	92,000	54,000	13,000	25,000
FPSO Project Mgmt & Other Costs[2]	102,000	66,000	5,000	31,000
FPSO Topsides[3]	661,000	251,000	165,000	245,000
FPSO Hull	215,000	0	1,000	214,000
FPSO Turret[4]	115,000	6,000	0	109,000
Subsea [5]	301,000	78,000	0	223,000
Drilling[6]	674,000	167,000	67,000	440,000
Logistics[6]	165,000	144,000	16,000	5,000
TOTAL	2,325,000	766,000	267,000	1,292,000

[1] In addition to salaries and related employee costs, Project Management expenditures include computing requirements, office expenses, staff expenses, Certifying Authority costs, insurance, studies and project corporate overhead.

[2] Other costs include start-up and commissioning

[3] **FPSO Topsides**: Overall expenditure breakdown provided by AMKC, Excludes FEED, Execution strategy:

[4] **FPSO Turret**: Pending further revisions to reflect final design requirements.

[5] **Subsea**: Based on 21 Wells;

[6] **Drilling and Logistics:**
Estimates are based on 1999 and 2000 delineation drilling information. The seasonal nature of these two programs did not allow for meaningful succession planing. The development drilling and completions program will be a continuous process with practical succession planning. This should lead to increased Newfoundland content.
Due to the service associated with the Drilling/Completion Program, the majority of the suppliers and rig contractor are international companies. Therefore the cost is assume Other and Not NF.
Drilling 99 people average on rig; 21 wells drilled and completed; 2.3 vessels

Operations phase employment and expenditure information is currently being formulated as these services are currently under a bid process. Accordingly, we are able to provide you with our best estimates of the employment levels as were provided at the time of the public hearings.

Table 3
Employment - Project Operations Phase

Estimated Direct Employment -
Estimates from July, 2001
(4^{th} Quarter 2004-2016)
PERSON HOURS

Project Component	Total Employment	NF Employment
Husky Project Mgmt	1,400,000	1,300,000
FPSO Operations	3,400,000	3,100,000
Drilling	400,000	200,000
Logistics	2,400,000	2,100,000
Well Interventions	900,000	500,000
Abandonment	200,000	100,000
Tankers	1,500,000	1,300,000
TOTAL	10,200,000	8,600,000

Employment Equity and Diversity:

In June 2001, Husky provided the public review commissioner with additional information on our plans to implement employment equity and diversity initiatives for the White Rose project. As part of its human resources objectives, Husky strives to reflect the communities in which it operates. As well, Husky recognizes that skill shortages in Canada are becoming increasingly apparent in areas of importance to the oil and gas industry, and it is essential to look to new sources for critical skills. Across the organization, these objectives are being realized through corporate policies and initiatives, ranging from commitments to local recruitment to programs aimed at improving the participation and advancement of women and aboriginal groups.

For the White Rose Project, Husky is planning for diversity on several fronts. External expertise will be sought in the planning stages to help us assess diversity and gender issues relating to many aspects of the project, including: FPSO design; training, recruitment and retention issues; and contractor/sub-contractor policies; employment data collection and related initiatives. Based on this initial evaluation, Husky will identify areas where existing programs may be implemented (such as diversity awareness training) or, possibly, new programs (such as the Preparation program below) need to be developed.

With respect to employment measures, in our submission to the Public Review Commissioner, Husky provided a preliminary outline for a Diversity Employment Preparation Program designed to increase the participation in the offshore petroleum sector by individuals of the following designated groups: women; people with disabilities; Aboriginal persons; and visible minorities. Although details will be worked out in consultation with Husky's major contractors and other stakeholders over the coming months, the features of a program could include:

- initiatives targeted at youth to demonstrate to young people the range of career choices relating to the oil and gas industry;
- involvement of training institution in the development and delivery of programs;
- involvement of Husky's major contractors and suppliers, since these companies offer significant employment opportunities; and,
- a focus on long term employment opportunities.

Additional information on the program proposal, as set out in the June submission to the Public Review Commissioner, is attached for easy reference.

Summary

We trust you will find this update informative and useful. In summary, the development strategy outlined, if approved by the Governments and shareholders, will yield:

- Over 5.9 million person hours of direct employment in Newfoundland and over 1.3 million person hours of direct employment elsewhere in Canada

- Over 400 long term, high quality jobs over the life of the field; when spin off effects are included, we estimate that the project will create an additional 1,000 jobs.

- Over the life of the project, an estimated $6.8 billion contribution to the GDP (Based on a report, "An Analysis of the Economic Impact of the White Rose Project on the Newfoundland and Canadian Economies", prepared for Husky Energy by Dr. Wade Locke and Strategic Concepts, Inc., July 2001)

- Approximately $1.4 billion in taxes and royalties

As importantly, success on the White Rose project will demonstrate that smaller, but materially significant fields offshore Newfoundland can be developed economically, and with significant benefit to the local economy. The

White Rose project can make a long term contribution to the Province's offshore petroleum industry by expanding the base of experienced individuals, businesses and research and training facilities, and building a proven track record of delivering a high quality product, on time and within budget.

Yours sincerely,

Margaret E. Allan
for William Roach
General Manager, East Coast Development

Attachment

APPENDIX E:
DISCOVERED RESOURCE AND RESERVE TERMINOLOGY USED BY THE CANADA-NEWFOUNDLAND OFFSHORE PETROLEUM BOARD

Assessment of the discovered oil and gas **"Reserves"** and **"Resources"** in oil and gas fields is an important function of the Canada Newfoundland Offshore Petroleum Board. The following definitions are used by the Board:

> **"Discovered resources"** is used to describe those volumes of hydrocarbons that have been assessed to be technically recoverable, but have not been fully delineated and/or have uncertain economic viability. The volume of discovered resources includes that proven by drilling and testing and the interpretation of geological, geophysical or other information, and deemed to be technically recoverable. (For example, the natural gas and natural gas liquids in the Hibernia and Terra Nova fields, and the oil, natural gas and natural gas liquids in the undeveloped fields offshore Newfoundland and Labrador, are referred to as discovered resources.)
>
> **"Reserves"** is used to describe the portion of the oil-in-place or gas-in-place volumes identified by drilling and testing and the interpretation of geological and geophysical information, that are considered to be recoverable using current technology, and under present and anticipated economic conditions. (For example, the oil at Hibernia and Terra Nova classified as reserves.)

Since the assessment of reserves depends on the interpretation of data available at a given time, the reserves are further classified by the Board to reflect the uncertainty in the interpretation and the lack of detailed geological and reservoir data. The following classifications are used by the Board:

> **Proven Reserves**
> Hydrocarbons that have been confirmed by drilling and testing, or where sufficient geological and geophysical data exist to project the existence of hydrocarbons in adjacent fault blocks. A high confidence level is placed on recovery of these hydrocarbons.
>
> **Probable Reserves**
> Hydrocarbons that are projected to exist in fault blocks adjacent to those that have been tested by wells and into which the geologic trends may extend. Also, where fluid contacts have not been defined within the area drilled, these contacts may reasonably be projected to exist. However, additional drilling is required to substantiate the existence of hydrocarbons. These hydrocarbons may reasonably be expected to be recovered under normal operating conditions yet have a degree of risk,

either geologic or reservoir performance related, associated with their exploitation.

Possible Reserves
Hydrocarbons that may exist based on geophysics and the extension of geologic trends. However, due to the lack of adjacent wells located within the region and reservoir engineering and geologic data, these hydrocarbons cannot be assigned a lower risk classification.

The same classifications are used for both resources and reserves. However the primary difference in the case of discovered resource is the uncertainty as to the economic viability. In terms of the probabilistic approach the Board classifies P90 as proven, P50 as proven plus probable and P10 as proven plus probable plus possible. The P90 term implies a 90 percent probability of the value in question at least being realized. The P50 numbers are used for planning purposes as there is a 50 percent probability of that number being realized. The P10 estimates provide an upside potential but with only a 10 percent chance of being realized. There is always uncertainty in reserve estimation, particularly prior to production in offshore areas, as there are very few wells and no production experience. At this stage the objective is to define the reserve range and establish a base case for proceeding with development. As development wells are drilled and production information is acquired, the oil and gas-in-place estimates will be better defined and the recovery efficiency better understood. The estimates will change between the various categories as development proceeds, but generally should be within the range of the original estimate.

APPENDIX F: COMPREHENSIVE STUDY REPORT DECISION LETTER FROM MINISTER OF ENVIRONMENT TO C-NOPB

Minister of the Environment | Ministre de l'Environnement

Ottawa, Canada K1A 0H3

JUN 1 7 2001

Mr. Hal Stanley
Chairman and CEO
Canada-Newfoundland Offshore
Petroleum Board
5th Floor, TD Place
140 Water Street
St. John's NF A1C 6H6

Dear Mr. Stanley:

I am writing to advise you of my decision regarding the White Rose Offshore Oil Development project.

On April 18, the Canadian Environmental Assessment Agency and I received the comprehensive study report on the above-mentioned project from the Canada-Newfoundland Offshore Petroleum Board. The report was submitted on behalf of all the responsible authorities, namely the Board, Environment Canada, Fisheries and Oceans Canada, and Industry Canada.

Having taken into consideration the comprehensive study report and public comments filed pursuant to subsection 22(2) of the *Canadian Environmental Assessment Act*, I have concluded that the project, as described with mitigation, is not likely to cause significant adverse environmental effects. Environment Canada, Fisheries and Oceans Canada, and Industry Canada have reviewed the comprehensive study report, and have indicated their agreement with the recommendations and conclusions contained in the report. I am referring the project back to the Canada-Newfoundland Offshore Petroleum Board, Environment Canada, Fisheries and Oceans Canada, and Industry Canada for action under section 37 of the *Canadian Environmental Assessment Act*.

.../2

Canada

I recommend that the Board, along with Industry Canada, Environment Canada, and Fisheries and Oceans Canada, ensure that all mitigation measures and recommendations described in the comprehensive study report and appended documents are implemented. Considering the nature of the power that the Board may exercise in relation to the project, I also recommend that all responsible authorities jointly design and implement a follow-up program. Such a program should determine the effectiveness of measures taken to mitigate any adverse environmental effects, and verify the accuracy of the environmental assessment of the project.

In a few months, the Agency will be requesting, on my behalf, information on measures taken to mitigate the environmental effects of the project, as well as the details and results of the follow-up program. This information will assist the Agency in ensuring compliance with the *Canadian Environmental Assessment Act,* and will help to determine whether the environmental assessment validly predicted effects. I would appreciate the Board's co-operation in the supply of this information in a timely manner.

With respect to informing the public about the federal government's decision in this matter, I ask that your officials, in co-operation with the other responsible authorities, inform the public of the course of action being taken by the Board. Please be advised that the Agency will be issuing, on my behalf, a public notice of my determination.

Please accept my best wishes.

Yours sincerely,

David Anderson

David Anderson, P.C., M.P.

APPENDIX G: GLOSSARY

abandonment	The decommissioning of facilities and removal of offshore structures
ALARP	As low as reasonably practicable
AOPR	Annual Oil Production Rate
Associated gas	Gas that is in contact with oil. Associated gas may exist as a gas cap which overlays an oil accumulation or as solution gas which is dissolved in the oil under initial reservoir pressure and temperature conditions and released from the oil during normal processing of the oil at surface or when the pressure in an oil reservoir is reduced.
Biocide	A chemical substance that is lethal to some or all organisms
bopd	Barrels of oil per day
bpd	Barrels per day
Casing	Steel pipe used in oil and gas wells to seal off fluids from the borehole and to prevent the walls of the hole from caving in
C-Core	The Centre for Cold Ocean Research and Engineering
CEAA	Canadian Environmental Assessment Act
Certificate of Fitness	A certificate issued by a Certifying Authority stating that a design, plan or facility complies with the relevant regulations or requirements and is fit for its intended purpose
clastic	Pertaining to a rock or sediment composed principally of individual fragments or grains
completion	The activities necessary to prepare a well for the production of oil and gas or the injection of a fluid
conglomerate	A clastic sedimentary rock composed of fragments larger than 2 mm in diameter; the consolidated equivalent of gravel
core	A cylindrical boring of rock from which composition and stratification may be determined

CSA (a) Concept safety analysis. (b) Canadian Standards Association

CSR Comprehensive Study Report

cuttings Chips and small fragments of rock that are brought to the surface by drilling mud as it circulates

delineation well A well that is drilled to assess the aerial extent of an accumulation of petroleum

deltaic Pertaining to, or like a delta

development "Development" refers to all phases of the Project, from the decision to proceed with construction to abandonment of the field

DFO Department of Fisheries and Oceans

development well Well drilled for the purpose of production of oil or gas or for the injection or disposal of fluid into or from a petroleum reservoir

discovery well An exploratory well that encounters a new and previously untapped petroleum deposit; a successful wildcat well

DST Drillstem test

EEM Environmental effects monitoring

EPP Environmental Protection Plan

ESRF Environmental Studies Research Fund

exploration well A well drilled to find an oil- or gas-bearing formation

fault In the geological sense, a break in the continuity of rock types

First Oil Point when first shuttle tanker is filled with oil and disconnected from the offloading system

floating production system A monohull or semisubmersible vessel upon which equipment suitable for producing hydrocarbons is installed

flowline	(a) A pipeline that takes fluids from a single well or a series of wells to a gathering centre. (b) Seabed piping that connects field components such as wells, manifolds and riser bases
fluvial	Of or pertaining to a river
FMDPR	Facility Maximum Daily Production Rate
formation flow test	An operation to induce the flow of formation fluids to the surface of a well for the purpose of procuring reservoir fluid samples and determining reservoir flow characteristics
FPDSO	Floating Production Drilling Storage Offloading Facility
FPSO	Floating Production Storage Offloading vessel
FPU	Floating Production Unit
GBS	Gravity Base Structure
glory hole	A seabed excavation into which subsea equipment is installed
graben	A fault-bounded elongate crustal block that is lower in elevation relative to adjacent crustal blocks
Iceberg	A large piece of ice that has broken away from a glacier
iceberg scour	Seafloor trench caused by the ploughing action of a moving iceberg grounding on the ocean floor
impact area	The geographic area in which the human and natural environments may be affected by a project or activity
injection	The process of pumping gas or water into an oil-producing reservoir to provide a driving mechanism for increased oil production
injection water	Water pumped into the Formation to maintain reservoir pressure; offshore, injection water is filtered seawater treated with biocides, oxygen scavenging and scale inhibiting agents
KSLO	Kvaerner SNC Lavalin Offshore

logging	The systematic recording of data using a variety of specialized tools during and after the drilling of a well in order to ascertain the properties of the rocks and fluids of the formation through which the well is drilled
LWD	Logging while drilling
manifold	A piping arrangement containing the valving to divide a flow into several parts, combine several flows into one, or reroute a flow to one of several possible destinations
mD	Millidarcies of permeability
monohull	A single-hulled ship-shaped vessel
MSRC	Maximum Safety Related Capacity
MUN	Memorial University of Newfoundland
MUSIC	Memorial University Seismic Imaging Consortium
MWD	Measurement while drilling
NAFO	North Atlantic Fisheries Organization
natural gas liquids (NGLs)	Liquid hydrocarbons produced with natural gas that separate from the gas as a result of decreases in temperature and pressure
NEIA	Newfoundland Environmental Industries Association
non-associated gas	Gas which is not in contact with oil
OIM	Offshore Installation Manager
operations phase	The period following first oil until cessation of all oil production from the White Rose field
operator	When capitalized in this document, refers to Husky Oil
OWTG	1996 Offshore Waste Treatment Guidelines
permeability	The capacity of a rock to transmit a fluid
petrophysics	The study of reservoir properties using data obtained from various logging methods

porous	Used to describe a rock that contains void spaces
production platform	An offshore structure equipped to receive oil or gas from offshore wells where primary processing, compression and pumping are carried out before transportation of the oil or gas to shore
produced water	Water associated with oil and gas reservoirs that is produced along with the oil and gas.
project phase	The period beginning with regulatory approval of the Development Application and the Proponent's decision to execute White Rose Development and continuing until first oil
proponent	Husky Oil on behalf of all participating White Rose interest holders. Those White Rose asset owners who are sharing in the predevelopment costs and who have authorized Husky Oil to prepare a Development Application in its capacity as Operator
recoverable reserves	That part of the hydrocarbon volumes in a reservoir that can be economically produced
reservoir	A subsurface, porous, permeable rock body in which oil or gas has accumulated; most reservoir rocks are limestones, dolomites, sandstones, or a combination of these
rift	An elongate structural trough bounded by normal faults formed during crustal extension
riser	A flowline carrying oil or gas from the seabed to the deck of a production platform or a tanker loading platform
sandstone	Sedimentary rock composed of sand-sized particles.
SBF	Synthetic-based drilling fluid
scour	Seafloor erosion caused by strong currents, resulting in the redeployment of bottom sediments and formation of holes and channels
SDA	Significant Discovery Area
SDL	Significant Discovery Licence
sea ice	Any form of ice found at sea that originated from the freezing of sea water

sediment	Solid material, both mineral and organic, that is being or has been transported from its site of origin by air, water or ice
sedimentary rock	Rocks formed by the accumulation of sediment. The sediment may consist of rock fragments or particles, the remains of animals or plants, the product of chemical action or evaporation, or of mixtures of these materials
seismic	Pertaining to or characteristic of earth vibration. Also, process whereby information regarding subsurface geological structures may be deduced from sound signals transmitted through the earth
separator	A cylindrical or spherical vessel used to separate the components in mixed streams of fluids
shale	Sedimentary rock consisting dominantly of clay-sized particles, an appreciable amount of which are clay minerals
shuttle tanker	A ship with large tanks in the hull for carrying oil or water back and forth over a short route
source rock	Sedimentary rock in which organic material under pressure, heat and time was transformed into liquid or gaseous hydrocarbons (usually shale or limestone)
stock	A species, group or population that maintains and sustains itself over time in a definable area
tectonic	Of, or relating to the deformation of the earth's crust; the forces involved in, or producing, such deformation
template	A design pattern with built-in guides for specific equipment and structures to assure their usefulness
TLC	Tough logging conditions
TSR	Temporary Safety Refuge
White Rose Development	"Development" refers to all phases of developing the oil resource, from the decision to proceed with engineering and construction through to producing operations to abandonment of the field
tcf	Trillion cubic feet
topside (or topsides) facilities	The oil- and gas-producing and support equipment located on the top of an offshore structure

turret	A low, tower-like structure capable of revolving horizontally within the hull of a ship and connected to a number of mooring lines and risers. It allows the ship to rotate while connected to a fixed mooring system
umbilical	A conduit or group of conduits providing communications between a floating production facility and a facility located on the seafloor for the purposes of power and control
wellbore	The hole drilled by the drill bit
wellhead	The equipment installed at the top of the wellbore used to support the casing strings installed in the well and the rate of flow of fluids from the well