EXECUTIVE SUMMARY

This volume presents the technical information in support of the Development Plan Application for the Sable Offshore Energy Project. The Project consists of six gas fields that have currently been identified as being suitable for initial development: Venture, South Venture,Thebaud, North Triumph, Alma and Glenelg.

The six fields of the Sable Offshore Energy Project were discovered between 1972 and 1986, and are estimated to contain approximately 85 billion cubic metres (3 TCF) of recoverable gas. Hydropressured and overpressured gas accumulations occur in Late Jurassic and Early Cretaceous porous sandstone reservoirs at depths of 2,800 to 5,000 metres below sea level. Reservoir sandstones are interpreted to be of deltaic and shallow marine origin, associated with a large, ancient delta system which was deposited in the vicinity of the present Sable Island area. Repeated delta advance and retreat resulted in a thick, vertically stacked succession of coarsening upward delta progradation cycles. Marine flooding events provided the shale seals to individual sandstone reservoirs, and gas accumulations are associated with rollover anticlines on the downthrown side of major down to the basin growth faults. Reservoirs have zonal average porosities of up to 20 percent, and permeabilities up to 300 millidarcies. The occurrence of pervasive gain-coating chlorite is characteristic of many of the reservoirs, and is believed to have preserved high porosities at great depth by inhibiting the development of quartz cement. Individual sandstone reservoirs in the six project fields are generally in the range of 20 to 35 metres in thickness.

The current subsurface database discussed in this volume, consists of well information such as logs, cores and drillstem tests from the existing exploration and delineation wells, as well as 2D, and some 3D seismic data acquired during the 1980 s. Petrophysical, Geological and Geophysical studies were conducted during the 1980 s, and early 1990 s. Analyses to date, indicate that modern 3D seismic will significantly improve the ability to map reservoir distribution and quality. Plans are in place for the acquisition of 3D seismic in 1996. Future Geoscience studies will focus on the integration of new 3D seismic data with wellbore data to generate comprehensive geologic and reservoir models for optimized field depletion and reservoir management.

The reservoir engineering section within this volume describes the data used in the development of reservoir characterizations for the purpose of individual field and project simulation studies. The individual field simulation studies were conducted to generate depletion plans. The depletion plans included the predicted number of required development wells, well offtake rates, well locations, completion details and the overall field deliverability and recovery efficiency. The integration of the individual field simulation models with a surface network simulator provided the tool necessary for the study of alternative project development options.

This volume presents the current Project plan that was developed through multiple simulation iterations with full account for the surface, subsurface and market sales gas rate constraints. The current plan begins development with production from Thebaud, Venture and North Triumph and phases in the other fields to maintain a production rate of 11.3 E6M3/d for 16 to 17 years. The simulated event sequence indicates an initial high level of activity for the start of production, with five Venture wells, four Thebaud wells and three North Triumph wells assumed to be predrilled. In production years five through eight, the remaining four Venture wells, two wells in South Venture and five wells each in Alma and Glenelg are added, as required, to maintain the desired level of sales gas.

Drilling and Completion planning activities, incorporates the use of two cantilever jack-up drilling rigs capable of working year round in all water depths associated with the Project fields. The pre-drilling of 12 of the 28 wells planned for the Project commences using both rigs prior to platform installation. The current plan envisages the use of both water-base and oil-base fluids for different sections of the hole depending on well-bore angle, hole stability and total depth of the well.

The current well completion design uses a step-monobore concept allowing for the flexibility to provide up to 5 inch tubing for deep high-pressure zones and 7 inch tubing for the shallower lower-pressured zones as required for deliverability. All wells are planned to contain subsurface safety control valves, polished-bore receptacles and non-damaging packer fluid. The wellhead is planned as a standard configuration with the capability to sever and seal against wireline or coiled tubing. All completions, testing and major workovers are currently planned to be performed by the jack-up drilling rig(s).

When fully developed, the production facilities for the current development plan will include up to six production platforms and an accommodation platform. The central facilities at Thebaud will be continuously manned, and include wellheads, production and processing equipment and an adjacent accommodation platform. The remaining fields, Venture, North Triumph, South Venture, Glenelg and Alma will be developed with normally unmanned satellite platforms. These satellites will support wellheads and minimal processing facilities and be equipped with emergency shelters only. The satellite platforms will be tied-back to the Thebaud platform via subsea interfield flowlines. A single subsea production gathering pipeline will transport the gas from Thebaud to an onshore natural gas processing plant, with its related facilities, in the Country Harbour area. This plant is anticipated to deliver a sales gas volume of 11.3 E6M3/d into the Maritimes and North East Pipeline, supplying markets in Canada and the eastern United States. Natural gas liquids extracted from the produced gas will be fed by buried pipeline to liquid processing, storage, and shipping facilities in the Point Tupper area.

This volume also describes the facility construction and installation philosophy. The objective is to establish a management structure and Project execution plan that will assure a quality product at low cost within an acceptable schedule. The current Project schedule has first gas production by the end of 1999.

The principle associated with the decommissioning and abandonment activities is that such activities will be undertaken in accordance with the regulatory requirements applicable at the time of such activities. Furthermore, abandonment plans will be submitted to the appropriate regulatory authorities for approval prior to abandonment.

The Environmental, Health and Safety Management (EHSM) system proposed for the Project is described in the Development Plan, together with the major steps in the system s development. Key components of the Environmental, Health and Safety Management system include the Project s Safety Plan, the Environmental Protection Plan (EPP) and Contingency Plans. Together these provide the framework for managing and improving operations, in terms of personnel and public safety and protection of the environment consistent with the SOEP Project Principles, including:

¥ We will develop this Project with meticulous attention to safety, ensuring that risks to both employees and the public are as low as reasonably possible.
¥ We will meet or exceed Canada s tough standards for environmental protection.
¥ We will respect the environmental significance of Sable Island, and the Gully.

The policies, standards and practices of the Project are being developed consistent with a philosophy founded on three beliefs:

- ¥ All environmental, health and safety incidents are preventable.
- ¥ Environmental, health and safety objectives must never be sacrificed for expediency.
- ¥ Environmental, health and safety objectives are an integral part of operations objectives.

The Safety Plan is being developed with a deliberate, systematic and efficient approach, ensuring Project activities are planned, organized, executed and maintained in a manner that achieves safety and protects the environment. The Environmental Protection Plan will provide detailed guidance for Project personnel, on how to eliminate or minimize any adverse environmental effects from the Project. In addition, Contingency Plans are being developed to ensure the safety of Project personnel and the public, and to protect both the environment and the Proponents investment by establishing procedures for responding to emergency situations. These deal with the response to, and mitigation of, accidental events affecting the safety of personnel and the public or the integrity if the facilities, and the response to, and mitigation of, accidental release of hazardous substances. An important component of the plans will be coordination with existing industry and government plans, facilities and equipment.

The subject of Project liability and compensation is also addressed in this volume. Liability may be imposed upon a party responsible for an incident or activity that has impacted the environment while conducting offshore operations. The Accord legislation as well as fisheries, shipping and other legislation may impose liability for impacts to the environment arising from offshore operations. Voluntary compensation plans and government policy may also establish a basis for liability and compensation. As part of the Project strategy to address compensation, environmental degradation community concerns and financial responsibility matters, a fisheries compensation plan will be filed during activities leading up to construction of facilities for the Project. Fisheries industry consultation will be ongoing in preparing the plan. Community concerns relating to the environment have been recorded as part of the pre-filing public consultation program and have been used as input in certain Project decisions. Evidence of financial responsibility to address prescribed liabilities that may be incurred in conducting the Project will be provided prior to the commencement of the specific offshore activity in respect of which the applicable financial requirement relates.

The current development strategy is based on present estimates of gas reserves, based primarily on exploration seismic data and current projections of future market conditions. As new seismic data, reanalysis of old data and new engineering studies become available, the development scheme may be altered in significant ways. For example, the number of wells and/or the sequence of fields may be adjusted during the life of the Project or new discoveries may be added. The plan must have sufficient flexibility to also incorporate advances in technologies and the integration of more accurate real-time information about winds, waves and currents in the offshore region. Flexibility in responding to these conditions is a key element in the Project development and will be needed in its ongoing regulation.

PREFACE

This **Development Plan Application** (DPA) is **Volume 2** of five documents comprising an application for approval of the **Sable Offshore Energy Project**. These documents are:

Volume 1	Project Overview
Volume 2	**Development Plan Application**
Volume 3	Environmental Impact Statement
Volume 4	Socio-Economic Impact Statement
Volume 5	Canada-Nova Scotia Benefits Plan

The purpose of each volume is:

Volume 1 Project Overview:

To summarize the application and to provide a description of the Project in sufficient detail to satisfy readers interested in a general review.

Volume 2 Development Plan Application:

To describe the gas reservoirs, development strategy, proposed facilities, and Project environmental and safety management.

Volume 3 Environmental Impact Statement (EIS):

To describe the physical and biological environment surrounding the Project, assess potential impacts and identify ways to minimize them.

Volume 4 Socio-Economic Impact Statement (SEIS):

To describe the socio-economic environment of Nova Scotia, with particular emphasis on the Country Harbour and Strait of Canso areas; to assess potential socio-economic impacts and discuss ways to minimize them and to maximize potential benefits; to estimate the economic impacts from the Project.

Volume 5 Canada-Nova Scotia Benefits Plan:

To describe how the Project plans to promote the natural flow of benefits from the Project to Nova Scotia and Canada.

The **Sable Offshore Energy Project** Proponents are: Mobil Oil Canada Properties (Mobil), Lead Operator, Shell Canada Limited (Shell), Joint Operator, Petro-Canada, Imperial Oil Resources Limited (Imperial) and Nova Scotia Resources Limited(NSRL).

The Project is currently planned for development in conjunction with a sales gas pipeline, the **Maritimes and Northeast Pipeline Project**, to be built from the gas plant at Country Harbour through Nova Scotia, New Brunswick and the New England states by a consortium of Canadian and American companies. The Proponents are: Westcoast Energy, Inc., Panhandle Eastern Corporation, Mobil Oil Canada Properties and

TABLE OF CONTENTS

TABLE OF CONTENTS

TABLE OF CONTENTS

TABLE OF CONTENTS

Figures

FIGURES cont d.

6.0 Construction and Installation

10.0 Safety Plan

—TABLES—

1 PROJECT OVERVIEW

1.1 Introduction

The Scotian Shelf, located in the Nova Scotia offshore region, has been a focus of study and exploration by the oil and gas industry for the past 50 years. Early geological studies of this subsea region predicted the presence of sediments similar to those found in the petroleum rich Gulf Coast of the United States. In the late 1960's, the first successful test wells were drilled in the Sable area leading to initial discoveries of natural gas in sandstone reservoirs that marked the beginning of intensified exploration. During this exploratory period, a total of 125 test wells were drilled in the Nova Scotia offshore region, 121 of these in the Scotian Basin. Some eighty-eight separate geologic structures have been tested.

The Geological Survey of Canada (GSC) and the Canada-Nova Scotia Offshore Petroleum Board (CNSOPB) have estimated the total potential gas resources for the Scotian Shelf at 512 billion cubic metres. Actual discovered gas reserves amount to about one third of the estimated total resources. Most of the discovered gas is located in the vicinity of Sable Island where gas pools are estimated to contain 142 billion cubic metres of recoverable gas. The size of this resource base can be measured against the total Canadian consumption which in 1993 was approximately 62 billion cubic metres.

There is significant demand predicted for competitively priced natural gas in the Maritimes and in the northeastern United States. Both Atlantic Canada and the densely populated northeastern US region have substantial growth potential, due in part to increasing environmental concerns. Clean burning natural gas is expected to continue to find increased markets. The combination of a rich resource base, advances in gas supply technology and increasing market requirements for this environmentally favourable energy source provide the foundation for the Sable Offshore Energy Project (SOEP).

This Development Plan Application (DPA, Volume 2) and its supporting documents (Environmental Impact Assessment, Socio-Economic Impact Assessment and Benefits Plan, Volumes 3-5) propose development of these reserves. A summary of the application and supporting documents is found in Volume 1. The DPA is divided into two major parts: Part 1 is a detailed description of the Project and the reservoirs to be developed, and Part 2 is a bibliography of reports and internal correspondence that support the submission. These documents will be made available to the Canada-Nova Scotia Offshore Petroleum Board upon request. This submission has been prepared pursuant to the requirements of the *Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act* and the *Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation (Nova Scotia) Act* .

1.2 Project Scope and Timing

From the mid 1960's through to the late 1980's, significant deposits of natural gas were discovered in the porous sandstone rocks underlying the Sable Island area, approximately 160 to 300 km off the east coast of mainland Nova Scotia. Six gas fields have currently been identified as being suitable for development: Venture, South Venture, Thebaud, North Triumph, Glenelg and Alma. These fields contain about 85 billion cubic metres of recoverable gas reserves. The fields lie 10 to 40 km north of the edge of the Scotian Shelf in water depths between 20 and 80 metres, as shown in **Figure 1-1**. The Sable Offshore Energy Project proposes to develop these six natural gas reservoirs.

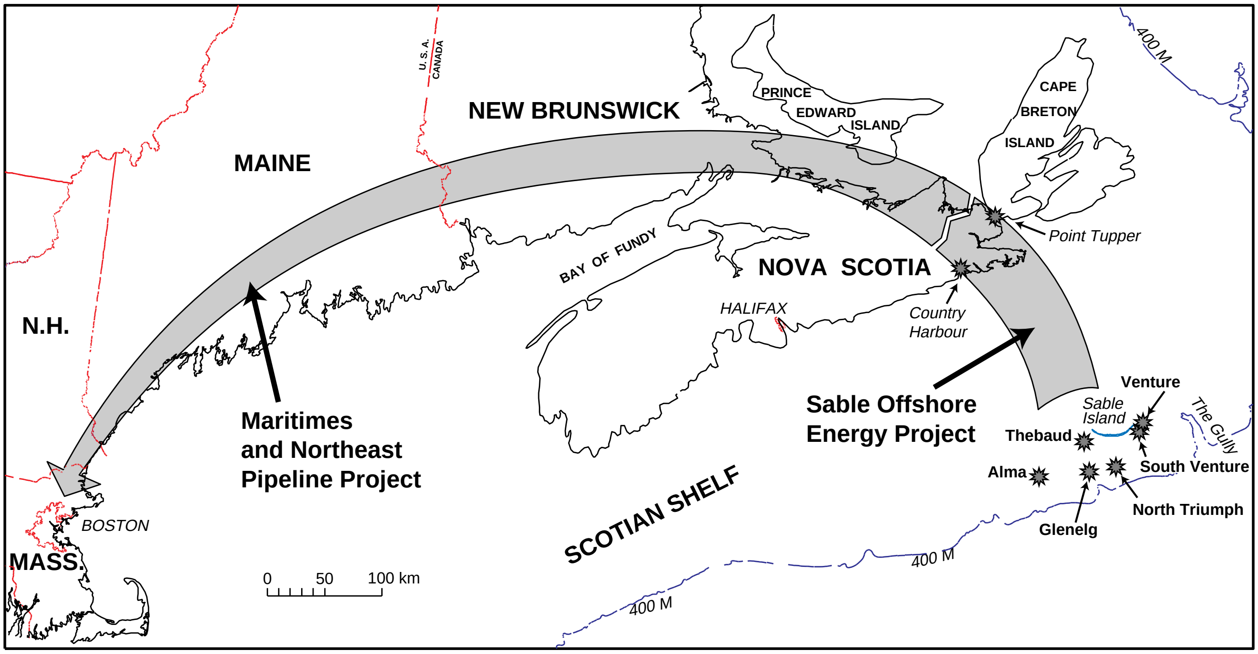


Figure 1-1: Current Development Plan Summary

The Project requires offshore and onshore facilities for production, transmission and processing of natural gas. Gas and associated natural gas liquids from offshore production platforms would be collected and brought ashore via a submarine pipeline to a gas plant located near Country Harbour, Guysborough County, Nova Scotia. Natural gas liquids would be transported by an onshore gathering line to the Point Tupper area of Richmond County, Nova Scotia for further processing and shipping. The degree of processing at the Point Tupper facility will be determined during the Front End Engineering Design process, following further marketing studies. The processed natural gas would be transported to Canadian and US markets through a pipeline proposed via Nova Scotia and New Brunswick to tie into the existing North American gas pipeline grid in the northeastern United States.

The Project includes:

- Offshore wells: engineering, drilling, completion, production and maintenance;
- Offshore production platforms: engineering, fabrication, installation, operation and maintenance;
- Interfield gathering lines, main subsea gathering lines and onshore natural gas liquids gathering lines: engineering, fabrication, installation, operation and maintenance;
- Onshore facilities for processing the natural gas and liquids: engineering, construction, operation and maintenance;
- Project management: including implementation of the Benefits Plan, Safety Plan, Environmental Protection Plan and Contingency Plans; and
- Decommissioning and abandonment of facilities at the conclusion of the Project.

The current development plan specifies six gas fields for development, which will be phased to maintain a sales gas volume of 11.3 million cubic metres per day for approximately 16 years. Compression and well recompletions will be implemented as appropriate to maximize gas recovery as the field pressure declines. The life cycle of the **Sable Offshore Energy Project** begins with development, followed by construction, production and finally abandonment and reclamation. The Project is expected to last at least 25 years from the initial gas flow at the end of 1999. The facilities will be designed so that with proper inspection, maintenance and repairs, they can be used beyond the projected Project term. This will support subsequent development at satellite fields and future exploratory discoveries by the Project.

The current development plan has 28 wells at the six gas fields, drilled over the Project life to maintain the sales gas rate. Jack-up drilling rigs capable of year-round operation are planned for use. These rigs must be certified for safe operation in water depths to 90 metres and for environmental conditions found in the Project area. The number and sequence of wells will be subject to adjustment throughout the Project life, depending on drilling results, production performance and market conditions.

One platform located at each of the six fields is currently envisioned for full development of the Project **(Figure 1-2)**. The Thebaud platform providing the central facilities for gathering, dehydration and future compression of the gas from the satellite fields in addition to wellhead and production facilities. Remote monitoring and control of the other field platforms would also be conducted from the Thebaud platform. This figure illustrates a separate living quarters platform at Thebaud linked to the production platform by a walkway.

The satellite platforms currently envisaged for Venture, North Triumph, Glenelg and Alma will be unmanned wellhead and production facilities, each equipped with emergency living quarters and a helideck. All platforms have safety, fire protection and evacuation systems designed to meet or exceed Project standards and codes and local regulations. Ships and boats will be excluded from a 500 metre radius safety zone around all platforms.

The South Venture field would be developed using a minimum wellhead support structure and tied-back to the Venture platform. It is also possible that South Venture could be developed using extended reach wells drilled from the Venture platform. This decision is to be made at the time South Venture production is required to sustain production rates.

Gas, condensate and water produced at the satellite platforms would be transported through a system of buried subsea flowlines to the Thebaud platform . A 200 metre no-anchor zone would be established around subsea gathering lines.

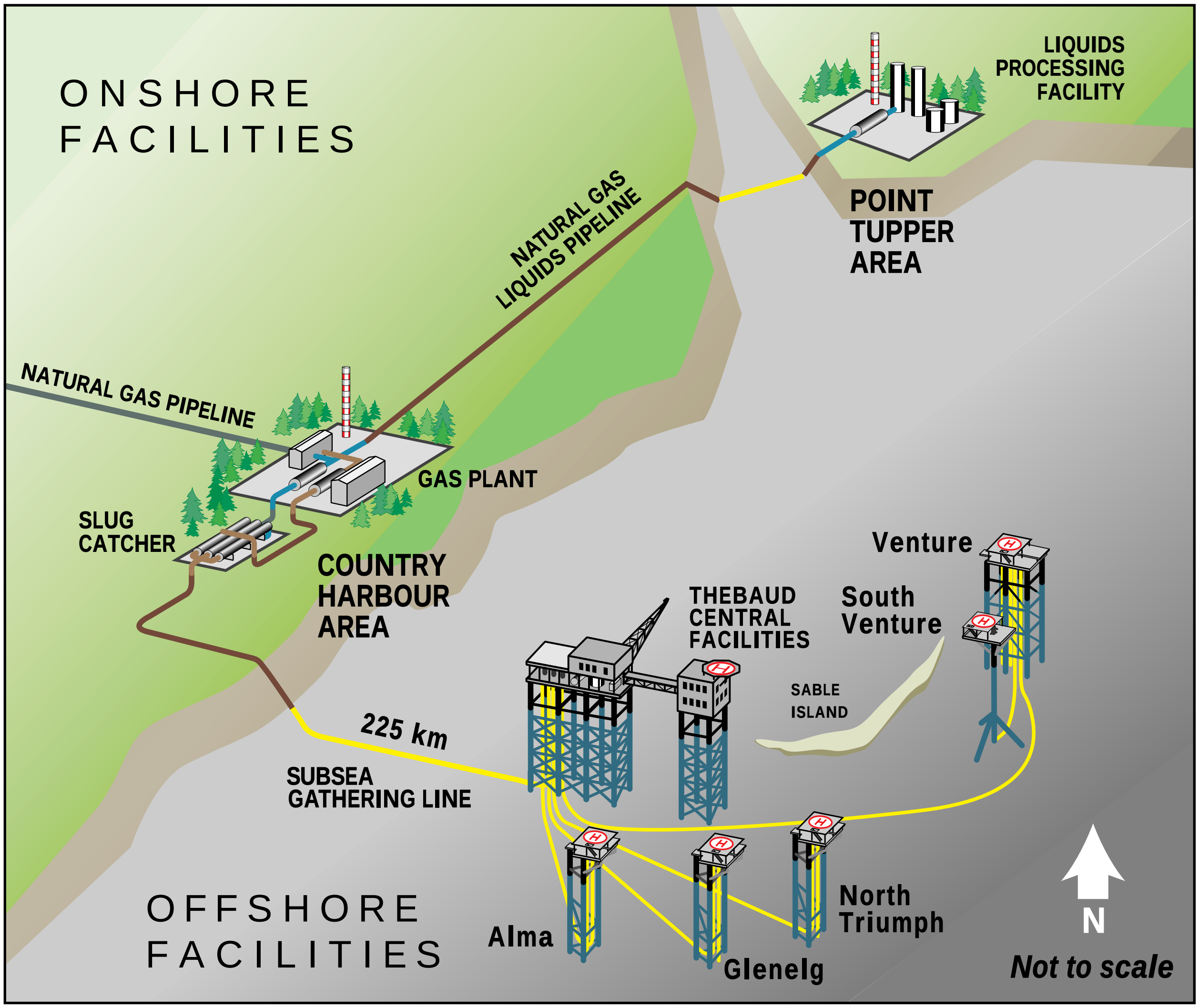


Figure 1-2: Project Facilities

At the Thebaud platform, unprocessed gas would be separated and dehydrated. The produced water would be treated to specified standards and then discharged to the sea. The gas and associated natural gas liquids would then be recombined and transmitted via a subsea gathering line to landfall in the Country Harbour area, Guysborough County, Nova Scotia and a gas processing plant located nearby. Gas conditioning to meet sales gas specifications would be completed at the gas plant and sales gas would be delivered by existing and proposed pipelines to areas of Atlantic Canada and the northeastern United States. Natural gas liquids would be sent by onshore pipeline to a handling facility near Point Tupper, Richmond County, Nova Scotia. At this site, the natural gas liquids would be further processed and prepared for shipping.

Table 1.1 summarizes the development plan presented in this application.

Table 1.1: Current Development Plan Summary

Sales Gas:	**Plateau Rate:**	11.3 E6M3/d		
	Plateau:	16 years		
	Life:	25 years minimum		
Raw Gas Reserves:	129.3 E9M3 Mean Value			
Platforms:	**Type**	**Site**		**Design Rates (E3M3/d)**
	Central	Thebaud (Inlet)		6230
	Central	Thebaud (Six Field)		12750
	Satellite	Venture		7080
	Satellite	North Triumph		3680
	Wellhead	South Venture		1840
	Satellite	Alma		3680
	Satellite	Glenelg		3680
Development Wells:	**Field**	**Number**		
	Thebaud	4		
	Venture	9		
	North Triumph	3		
	South Venture	2		
	Alma	5		
	Glenelg	5		
	Total	28		
Offshore Pipelines:	**Length (Km)**	**Diameter (mm)**	**Wall Thickness (mm)**	**Max. Operating Pressure (KPa)**
Thebaud - Shore	225	609	15.9	11,725
Venture - Thebaud	56	457	12.7	13,800
North Triumph - Thebaud	35	324	12.7	13,200
South Venture - Venture	5	219	12.7	14,140
Alma - Thebaud	50	324	12.7	13,200
Glenelg - Thebaud	32	324	12.7	13,200
Slugcatcher:	**Location:**	Country Harbour Area		
	Type:	Multipipe		
	Liquid Capacity:	2385 m3		
Gas Plant:	**Location:**	Country Harbour		
	Type:	Turboexpander /Natural Gas Dewpointing		
	Products:	Sales Gas, NGL mix		
NGL Transmission Pipeline:	**Location:**	Country Harbour to Point Tupper		
	Size:	219 mm		
	Length:	67 km		
	Wall Thickness:	6.4 mm		
	Max. Op. Pressure:	6900 KPa		
NGL Processing:	**Location:**	Point Tupper		
	Type:	Fractionation / Stabilization		
	Products:	LPG Mix, Condensate		

The Project has two main phases:

Initial Development Phase:	Development drilling to prepare initial production wells Construction of Project facilities Development of drilling and construction of facilities for additional production sites
Production Phase:	Gas production and processing

As shown in the Project schedule, **Figure 1-3**, the Proponents intend to make the final decision to proceed in 1997, with gas production from the first phase of the Project by late 1999. Drilling and construction in the current proposal would start at Thebaud, Venture and North Triumph. During the Production Phase, fields would be developed as required to maintain the sales gas rate of 11.3 million cubic metres per day. Construction at the South Venture, Glenelg and Alma fields is currently planned for 2004-2007. The Sable Project is projected to last until the year 2025. Project facilities will be designed so that with proper inspection, maintenance and repairs, they can be used well beyond the current Project life. This enables subsequent development at existing satellite fields and further exploratory discoveries to be incorporated into the Project as warranted.

The timing of these Project elements may be adjusted during the life of the Project in order to respond to evolving market conditions and additional information from field and design studies, as well as exploration successes.

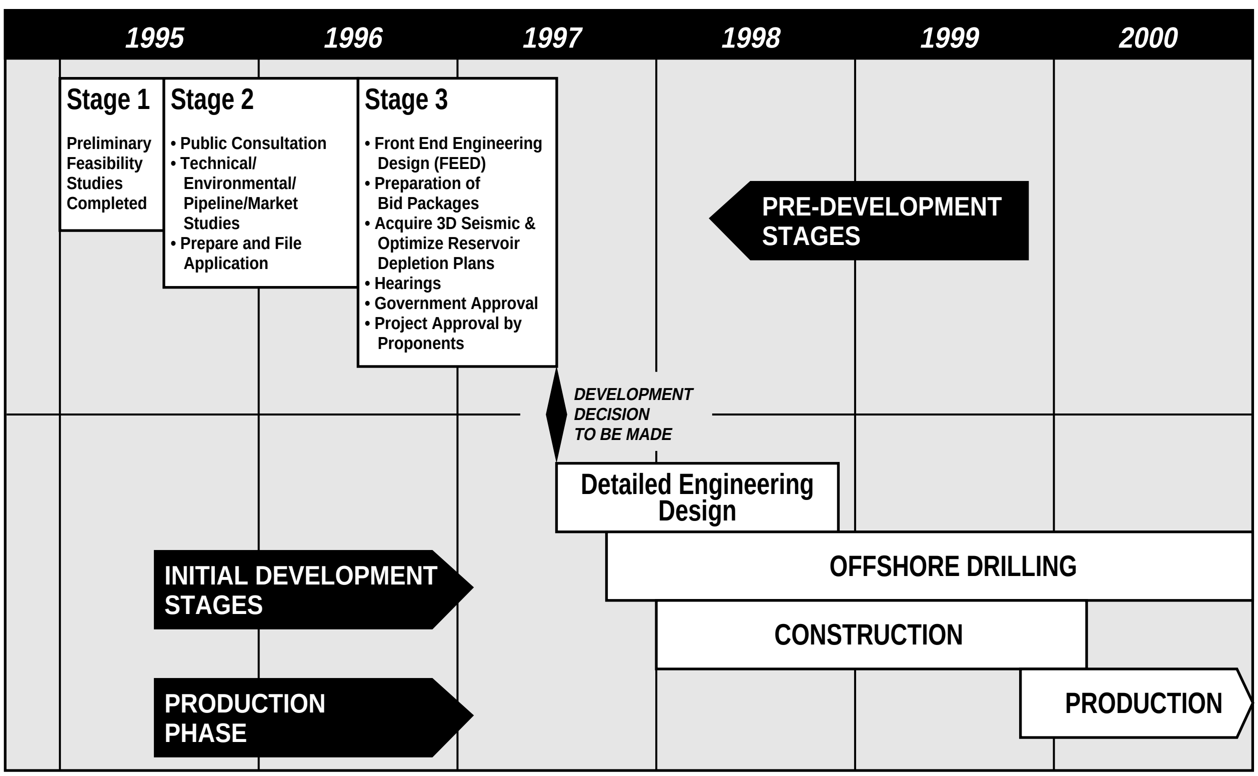


Figure 1-3: Proposed Project Schedule

1.3 Project Development Strategy

In offshore development, the Project plan must, at the outset, be flexible to accommodate all likely contingencies since unanticipated changes may be costly and are often extremely difficult to accommodate. The development approach adopted for this Project relies on the use of multi-disciplinary teams to evolve the Project design as information becomes available.

The current development plan is based on estimates of gas reserves, established primarily from exploration seismic data and current projections of future market conditions. As new seismic data, reanalysis of old data and new engineering studies become available, the development scheme may be altered in significant ways. For example, the number of wells and/or the sequence of fields may be adjusted during the life of the Project or new discoveries may be added. The plan must have sufficient flexibility to also incorporate advances in technologies and the integration of more accurate real-time information about winds, waves and currents in the offshore region. Flexibility in responding to these conditions is a key element in the Project development and will be needed in its ongoing regulation.

As illustrated in Figure 1-4, a wide range of alternatives were considered during the early stages of the Project. In the early 1980's, Mobil submitted a development proposal for natural gas for the Venture Field. Preliminary studies of other development options, including generating electrical power from the natural gas, the feasibility of applying Liquid Heavy Gas (LHG) technology, and the potential transportation of gas as a Liquified Natural Gas (LNG) have also been evaluated.

The criteria used in assessing the potential alternatives included the following:

- safety
- environmental protection
- economic criteria
- capital cost and cost uncertainty
- operating and maintenance costs
- reliability and availability of facilities
- complexity of operations
- operating flexibility
- pipeline route
- ease of expansion
- Canada - Nova Scotia benefits
- regulatory requirements

The following sections of the Development Plan Application identify alternatives that could be incorporated into the Project design during the development phase. These are identified as Development Alternatives. The application also presents alternatives that preliminary studies indicate are unsuitable, for economic, environmental, safety or technological reasons. These are identified as Eliminated Alternatives.

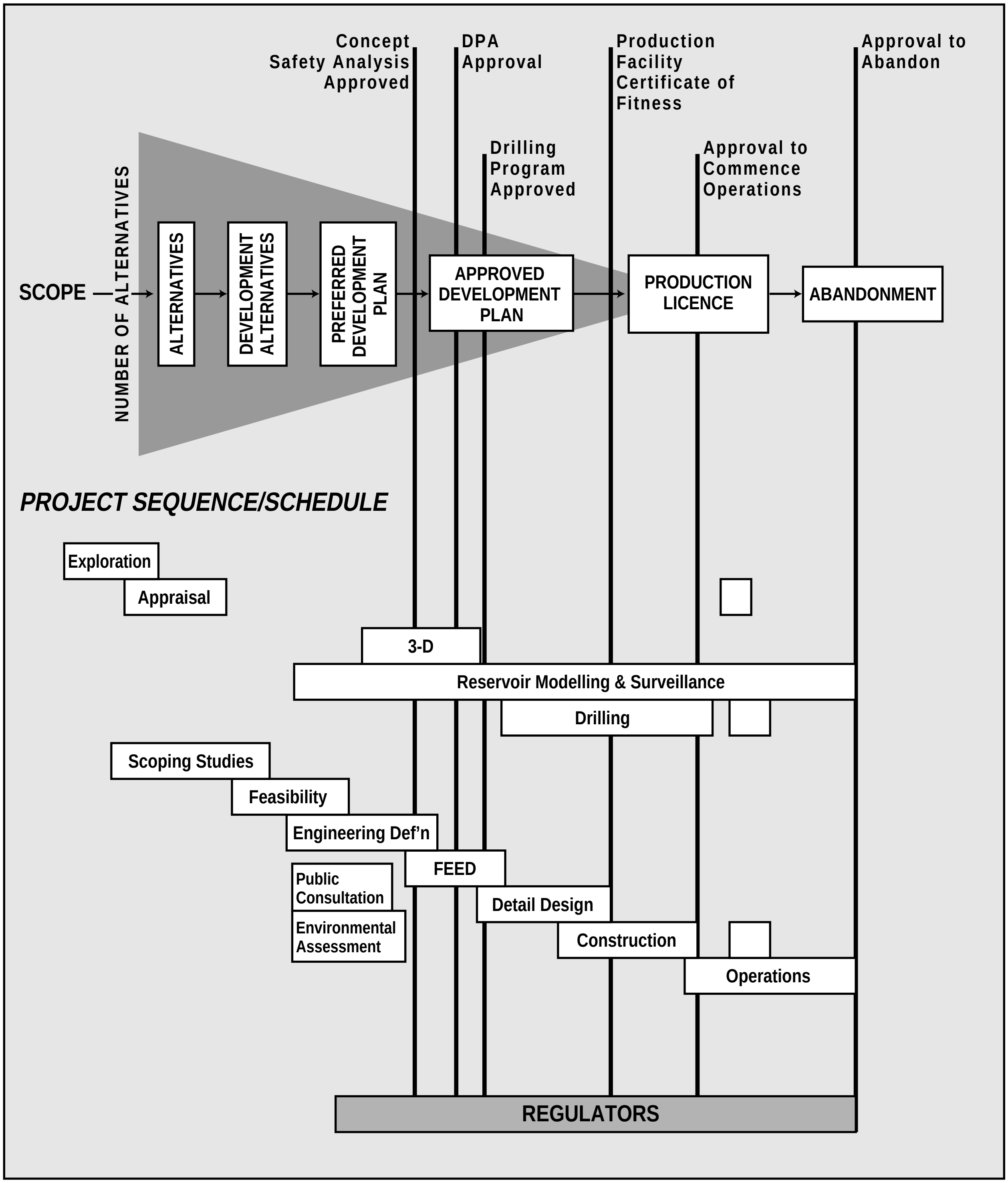


Figure 1-4: Project Development Process

The Project schedule of activities shown in **Figure 1-5** indicates that many activities are being conducted concurrently. Therefore, as information becomes available, the Project scope will continue to be refined. This approach allows the Project team to make increasingly precise decisions about Project options, such as the need for further data acquisition or the implementation of new or emerging technologies for the purpose of maximizing reserves recovery. This process of refinement of the Project scope through the integration of information throughout the development is expected to produce the most responsive and cost-effective development plan.

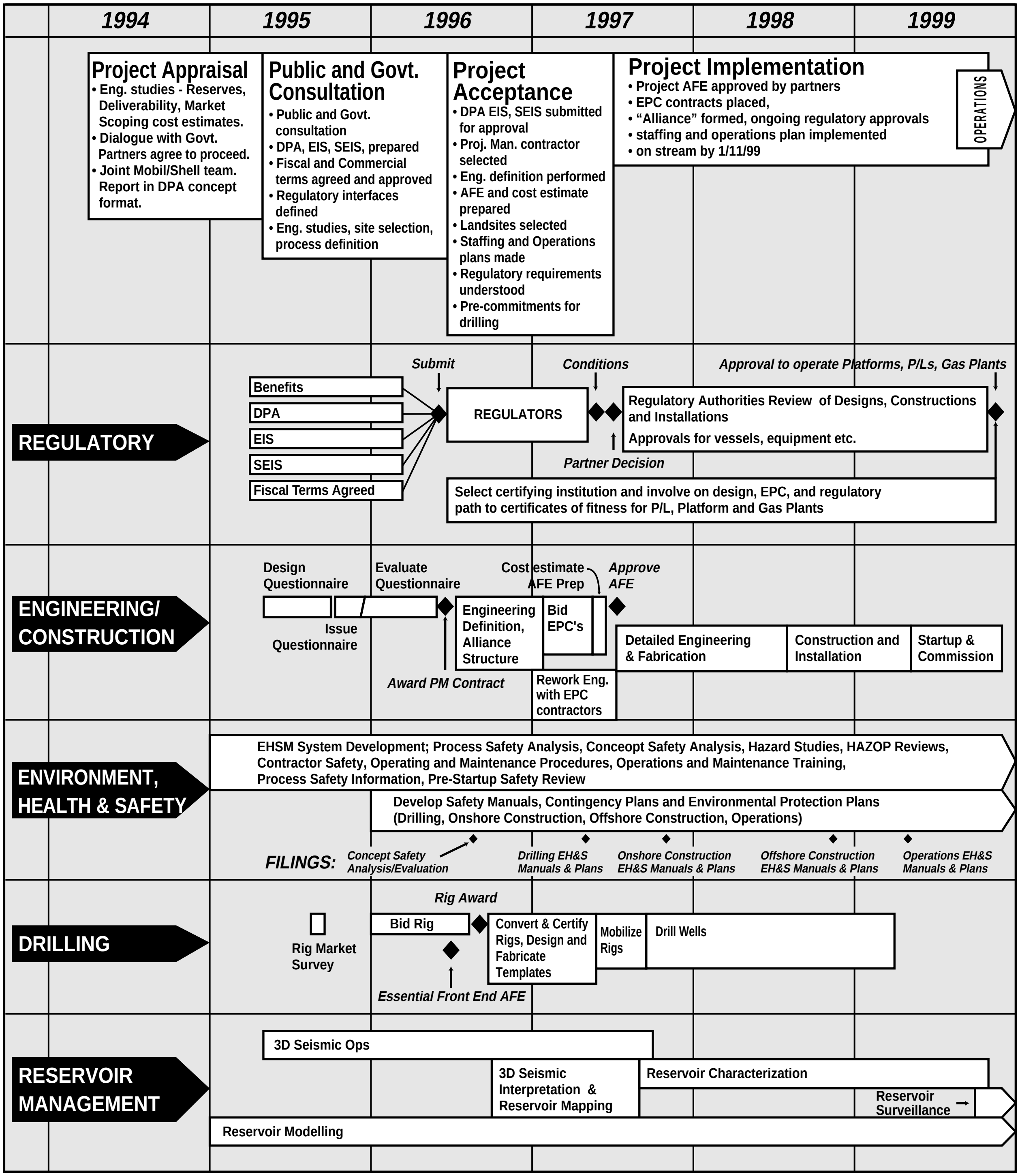


Figure 1-5: Schedule of Project Activities

1.4 Project Management

1.4.1 Project Management Approach

The Sable Offshore Energy Project management approach relies on the use of multi-disciplinary teams with common goals to successfully integrate the knowledge, skills and experience of Project personnel and participating contractors. Initially, the Project team will consist of employees from the Proponent's companies and the selected engineering contractor(s). The use of multi-disciplinary teams allows for better integration of information in the refinement of Project design which results in shorter time between discovery to gas sales. As production facilities are better matched to the expected reservoir potential, investment is optimized. During Front End Engineering Design (FEED), the team will also seek the participation of specialists in environmental engineering, hazard and risk analysis, drilling, construction, and other areas. Specialists in these areas will assure standards of health, safety and environmental protection are maintained.

Following Project approval and the decision to proceed, the current plan envisages operations conducted through a single entity, such as an operating company or a joint venture. The successful history of joint ventures in the petroleum industry will provide experience and direction in developing sound management structure and effective, incentive-based relationships with contractors.

1.4.2 Project Principles and Guidelines

The Sable Offshore Energy Project is a complex undertaking, involving five Project participants, many contractors and suppliers, and hundreds of individuals. In order to provide common guidance to all of the people involved, the Proponents have established a set of Project Principles as shown in Figure 1-6. The principles address four major areas:

- Business Principles
- Responsible Development Principles
- Compensation and Benefits
- Project Ethics

SOEP Project Principles

Business

Guiding Principle:

Our Project is market driven and must be competitive with other North American energy alternatives.

Guidelines

- Our Project will be competitive with energy alternatives available to our companies and to our customers. We will deliver our product at the right price and time.
- Our Project will connect with the North American gas pipeline system to provide both domestic and export market access and alternatives to gas buyers and sellers.
- We will target all markets along our pipeline route on a basis of economic justification, with the expectation that areas along the route which are currently unserved will be developed as it becomes economically viable to do so.
- Our Project will be a stand-alone investment without any reliance on government funding.
- We will access technology, goods and services on an internationally competitive basis.

Responsible Development

Guiding Principle:

We will implement and operate the Project in an efficient manner, seeking win/win outcomes in our relations with all stakeholders - government, public and investor.

Guidelines

- We will honor the Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act, and other relevant legislation, ensuring that we do so in a cost-effective and timely manner.
- We will develop this Project with meticulous attention to safety, ensuring that risks to both employees and the public are as low as reasonably possible.
- We will meet or better Canada's standards for environmental protection.
- We will respect the environmental significance of Sable Island, and the Gully.
- Our relationship with the governments will be non-partisan.
- Our communications with the public will be open, proactive and two-way. We will strive to establish good, long-term relationships with the communities with whom we interact.
- The need to provide an adequate return to our investors, commensurate with the size and risk of the investment, will underlie all of our business decisions.

Compensation and Benefits

Guiding Principle:

We will provide full and fair opportunity for all stakeholders to share in the economic benefits flowing from the Project.

Guidelines

- Our procurement policies will be driven by the concept of "best total value", and will adhere to the requirements of applicable legislation.
- We will encourage the development of a long term industrial support base for the Project in Nova Scotia and Canada.
- We will strive to coexist with, and have a minimum impact on, existing fishing, aquaculture, forestry, agricultural and other businesses.
- Where appropriate, we will provide compensation for services provided, property utilized, and other potential business impacts occurring due to the Project.

Project Ethics

Guiding Principle:

We hold ourselves and our contractors to the highest standards of business ethics and professional performance.

Guidelines

- We will carry out our business in an open, fair, and forward-thinking manner, while respecting legal and commercial considerations.
- We respect every person directly or indirectly associated with this Project and will provide them an opportunity for involvement in formulating our development plan.
- We will employ Quality Assurance and Continuous Improvement practices in all of our Project activities.

September 19,1995

Figure 1-6: Project Principles and Guidelines

1.4.3 Proponent's Experience

Mobil and Shell are providing technical, business, safety and environmental leadership to the Project's engineering and management team. Substantial work was completed for the proposed Venture Project in the 1980's, much of which is incorporated into the development plan for the Sable Offshore Energy Project. The Proponents have also drawn upon their considerable experience though their international affiliates in offshore developments in the North Sea and the Gulf of Mexico.

Mobil and its affiliates produce 48 billion cubic metres of natural gas per year worldwide. Shell and its affiliates produce 71 billion cubic metres annually, much of this from wells in the Gulf of Mexico where the daily production rate is three times that planned for the Sable Offshore Energy Project.

Shell's development of deep water as well as shallow water gas resources in the Gulf region has required technological innovations in drilling and production operations that may be adapted to the shallow water Sable fields. Mobil is also a leader in offshore development on a global scale. In Mobile Bay, an environmentally sensitive area of the Gulf Coast, Mobil has successfully operated for a decade using production facilities similar to those proposed for the Sable Project. Mobil also has extensive experience using unmanned platform facilities more than 100 km offshore in the North Sea. The use of satellite technology, unmanned platforms and jack-up rigs are expected to increase the cost-effectiveness and safety of the Sable Offshore Energy Project. The North Sea experiences provide a source of information about a northern climate comparable to the waters offshore Nova Scotia.

1.5 REGULATORY OVERVIEW

A number of regulatory authorities are responsible for representing the interests of the people of Nova Scotia and Canada in the management of natural resources. These interests include the equitable access to natural gas and other resources, protection of the environment, and sharing of the economic benefit from the production of natural resources via economic activity and through the collection of royalties and tax revenues. This submission addresses regulatory guidelines based on energy policy established in key legislation.

Primary Legislation

The Sable Offshore Energy Project will be regulated by a number of federal and provincial agencies. Relevant legislation includes:

- Canada - Nova Scotia Offshore Petroleum Resources Accord Implementation Act
- Canada - Nova Scotia Offshore Petroleum Resources Accord Implementation (Nova Scotia) Act; (these two acts are jointly known as the Accord Acts)
- National Energy Board Act
- Nova Scotia Energy and Mineral Resources Conservation Act
- Nova Scotia Pipeline Act.

The following three agencies have indicated that they are the responsible regulatory authorities for regulating various aspects of the Project:

- Canada - Nova Scotia Offshore Petroleum Board
- National Energy Board
- Nova Scotia Energy and Mineral Resources Conservation Board

These agencies are developing a coordinated regulatory process for a collaborative approach to the effective and efficient regulation of the Project.

Environmental Review

Several government departments and agencies have indicated they are responsible for review of the Project's environmental and socio-economic impacts:

- Canadian Environmental Assessment Agency
- Natural Resources Canada
- Nova Scotia Department of the Environment
- Nova Scotia Department of Natural Resources
- National Energy Board
- Canada-Nova Scotia Offshore Petroleum Board

In order to coordinate their efforts, these agencies are developing a Memorandum of Understanding to carry out joint environmental assessment reviews of the Sable Offshore Energy Project. A five member panel is anticipated to be appointed to hold public hearings for the Sable Project and to prepare a report with recommendations to the responsible government agencies.

2.0 GEOLOGY, GEOPHYSICS AND PETROPHYSICS

The **Sable Offshore Energy Project** will produce natural gas from porous sandstone reservoirs which lie deep under the sea floor of the Sable Island area. This chapter is a description of these reservoirs, and is divided into two parts.

The first part is a regional overview. This includes a general introduction to the geological history of the Sable area. It also describes the methodology used to determine the size and nature of the reservoirs.

The second part is a field-by-field description of gas accumulations currently included in the Project. It contains a summary of the structure, stratigraphic setting, and gas in place (GIP) estimates for each of the six **Sable Offshore Energy Project** fields: Thebaud, Venture, North Triumph, South Venture, Glenelg, and Alma.

2.1 Geological Interpretation and Reservoir Description

2.1.1 Regional Structural Setting

The Scotian Shelf is a narrow (125 to 225 kilometre wide) north-easterly trending continental margin which extends 800 kilometres from the Northeast Channel to the Laurentian Channel. **Figure 2.1.1.1** illustrates the location of the Scotian Shelf.

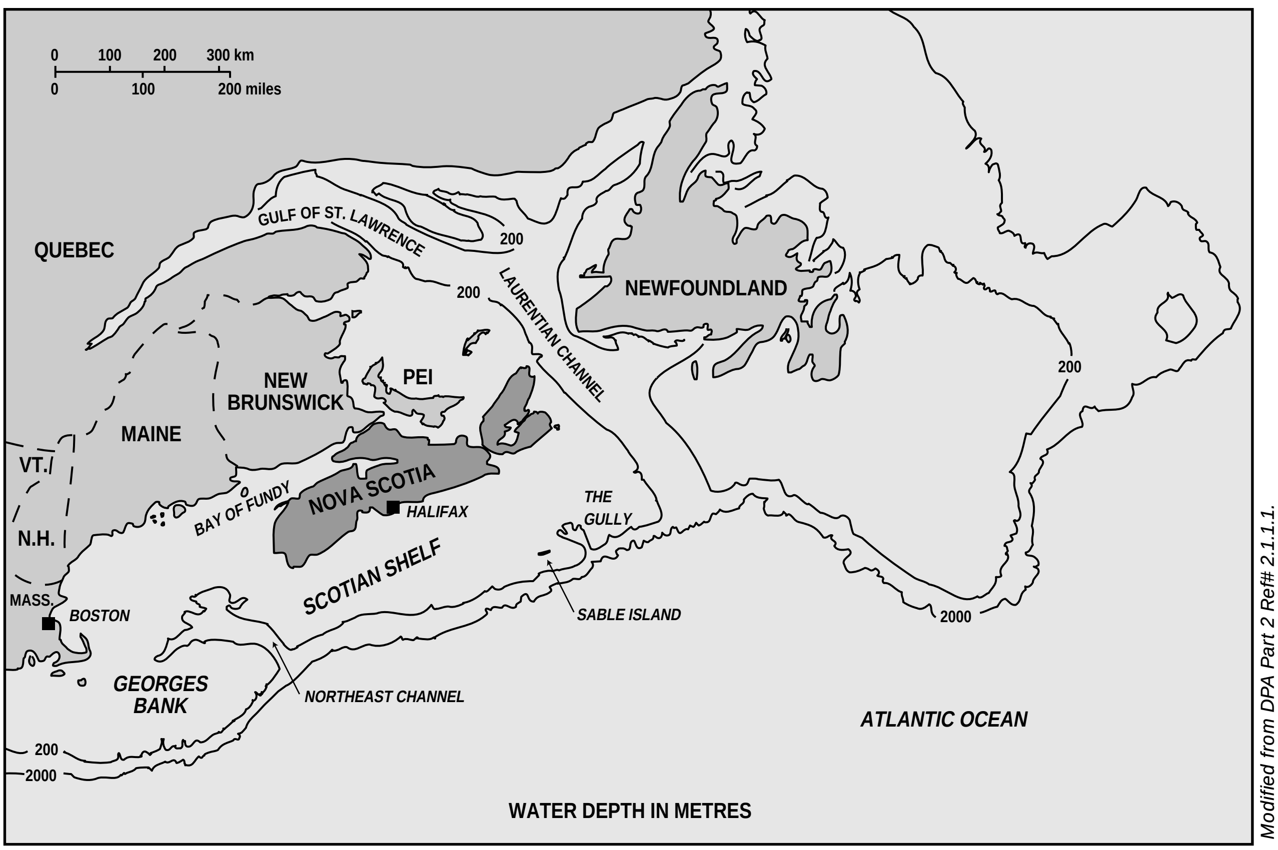
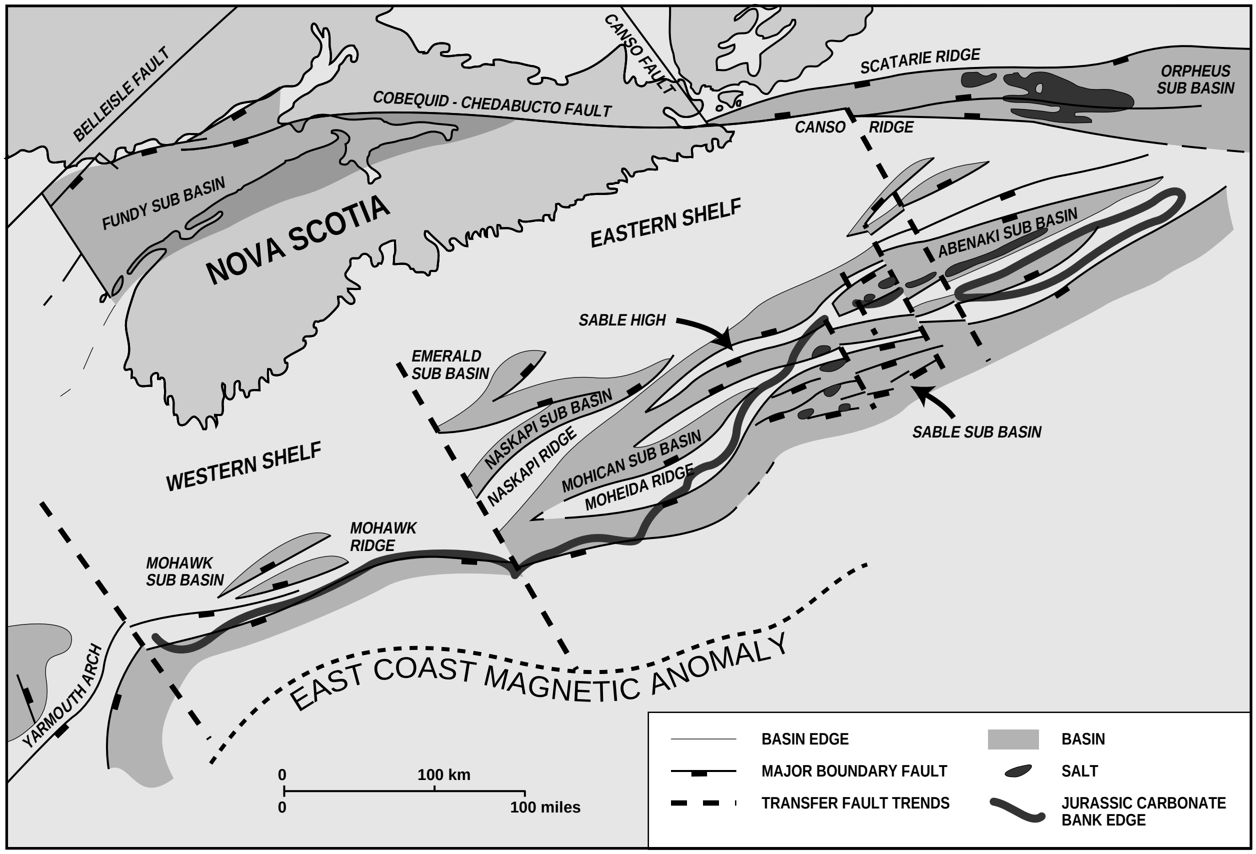


Figure 2.1.1.1: Location of the Scotian Shelf

The post-Palaeozoic geologic history of this area consists of continental extension and rifting, followed by ocean opening and the development of a passive continental margin. Extension faulting during the rifting stage, beginning in the Late Triassic and terminating in the Early Jurassic with the separation of Africa from North America, created a network of basement ridges and basins, collectively termed the ‘Scotian Basin.’ The gas fields lie within one of these basins, the ‘Sable Subbasin.’ **Figure 2.1.1.2** illustrates the tectonic elements of the Scotian Basin. A detailed discussion of the structural setting of the Scotian Basin is found in Part Two (**DPA - Part 2, Ref. # 2.1.1.1. through 2.1.1.5**).

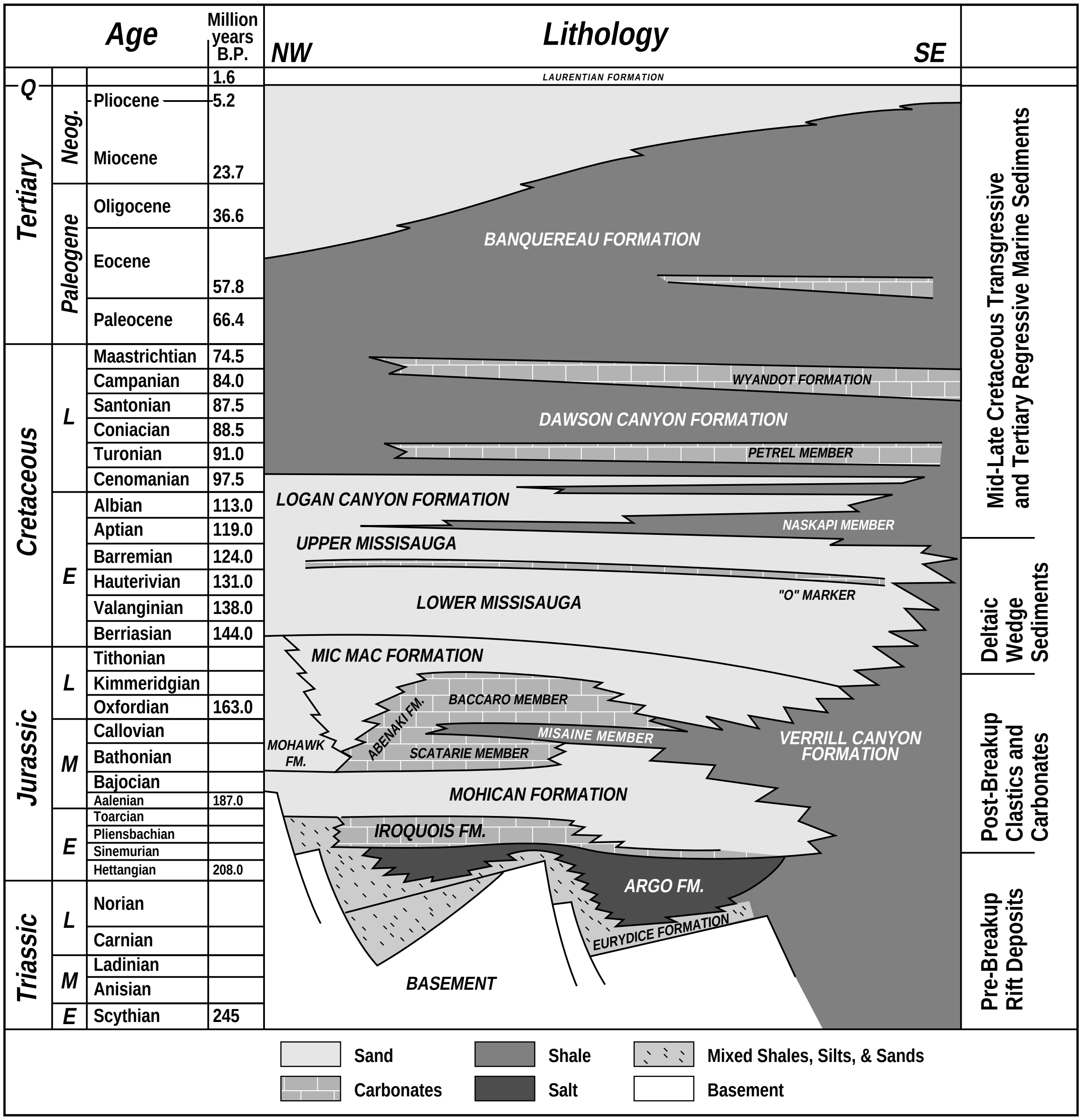


Modified from DPA Part 2 Ref# 2.1.1.5.

Figure 2.1.1.2: Tectonic Elements of the Scotian Basin

2.1.2 Regional Stratigraphy

The stratigraphy of the Scotian Shelf consists of two parts: a basement of complexly structured Cambro-Ordovician metasediments and Devonian granites, and a cover of Mesozoic-Cenozoic sediments. **Figure 2.1.2.1** illustrates the generalized stratigraphy of the Scotian Shelf.



Modified from DPA Part 2 Ref# 2.1.1.1.

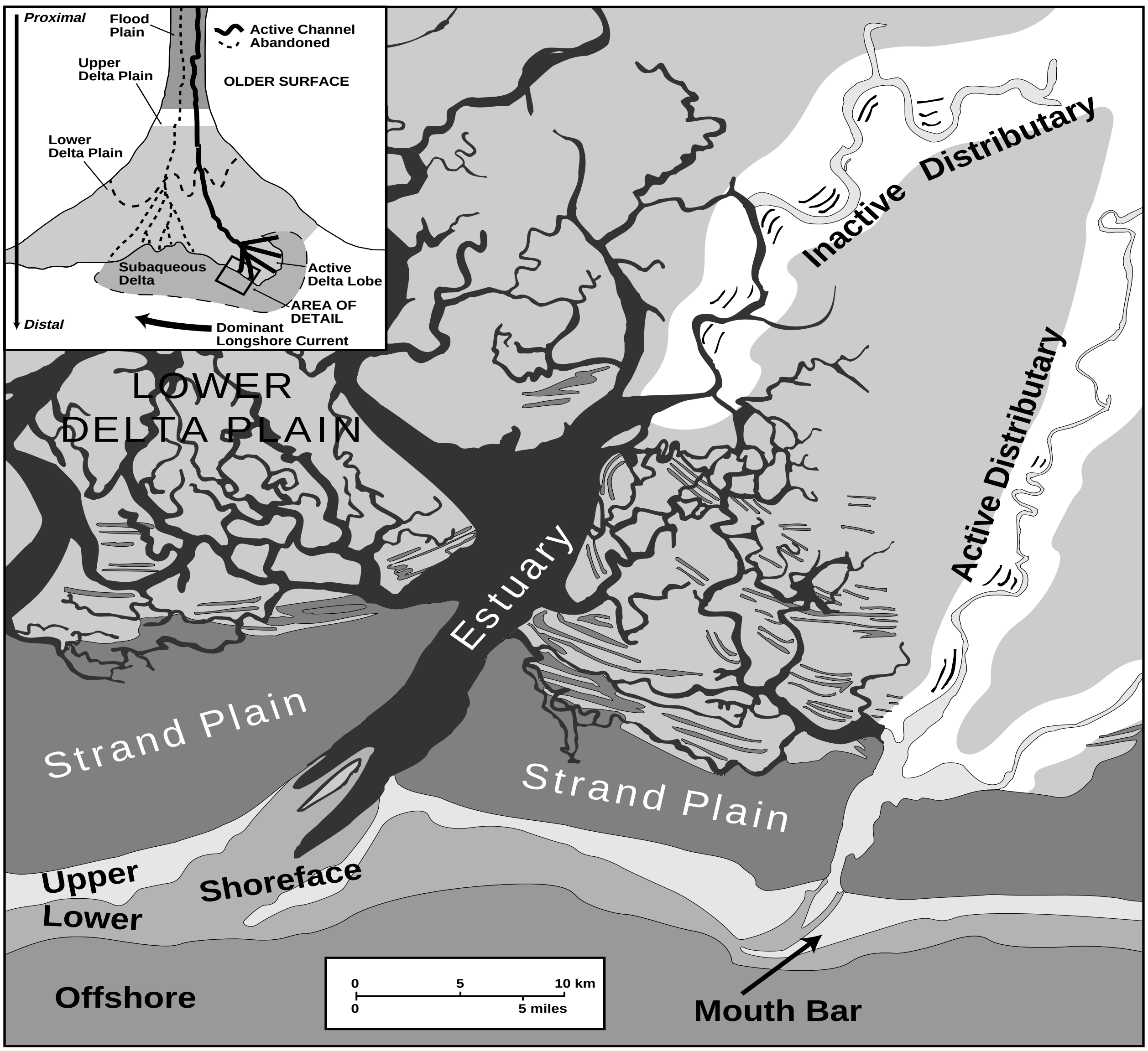
Figure 2.1.2.1: Generalized Stratigraphy of the Scotian Shelf

During the Late Triassic-Early Jurassic rifting phase, grabens and half grabens formed by basement faulting were initially filled with synrift continental clastics (Eurydice Formation). Subsequent deposition of evaporites (Argo Formation) and dolomites (Iroquois Formation) record the gradual change from non-marine to marine conditions associated with the opening of the North Atlantic.

With marine transgression and the onset of open marine conditions, a major carbonate bank, the Abenaki Formation, developed at the Jurassic shelf edge. This marked a distinct break in slope. There was an abrupt change from shallow water marine shelf environments in the north and west to deepwater environments to the south and east. Deep water marine shales, in the lower Verrill Canyon Formation, were deposited seaward of the shelf edge carbonate bank. Shallow shelf calcareous sands, shales and carbonate muds (Mic Mac Formation) were deposited landward of the shelf edge. In the Sable Subbasin, local rapid structural downwarping combined with clastic influx precluded the development of the carbonate bank. A small Mic Mac delta system developed in this area.

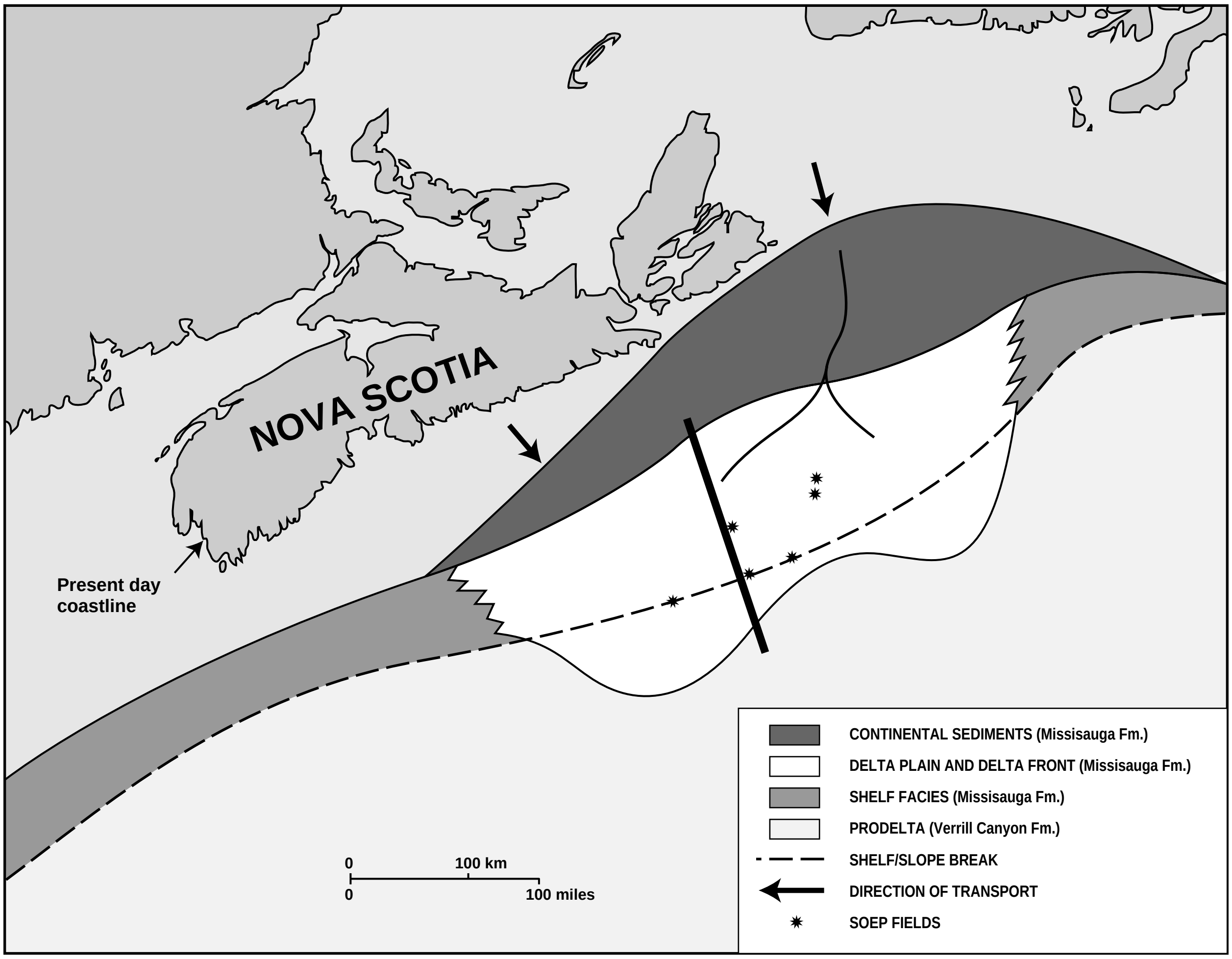
There was continued outpouring of clastic sediments during the Late Jurassic-Early Cretaceous. This was fed by a major continental drainage system and formed the Sable Delta complex (**D.P.A. Part 2, Ref. 2.1.2.2**). The Sable Subbasin was rapidly filled with sand rich delta front and delta plain sediments (Missisauga Formation) and prodelta shales (Verrill Canyon Formation). **Figure 2.1.2.2** illustrates the various depositional components of a typical, modern delta system; deposits of the sand rich shoreface and strand plain environments form the best quality reservoirs. **Figure 2.1.2.3** is a paleogeographic map showing the distribution of the Sable Delta complex, the sandstones of which form the reservoirs in the Project fields. This deltaic sequence was subsequently transgressed and capped by a thick marine shale unit (Naskapi Shale).

Modified from DPA Part 2 Ref. 2.1.1.6.



Modified from DPA Part 2 Ref# 2.1.5.1.

Figure 2.1.2.2 : Depositional Components of a Delta System



Modified from DPA Part 2 Ref# 2.1.1.1.

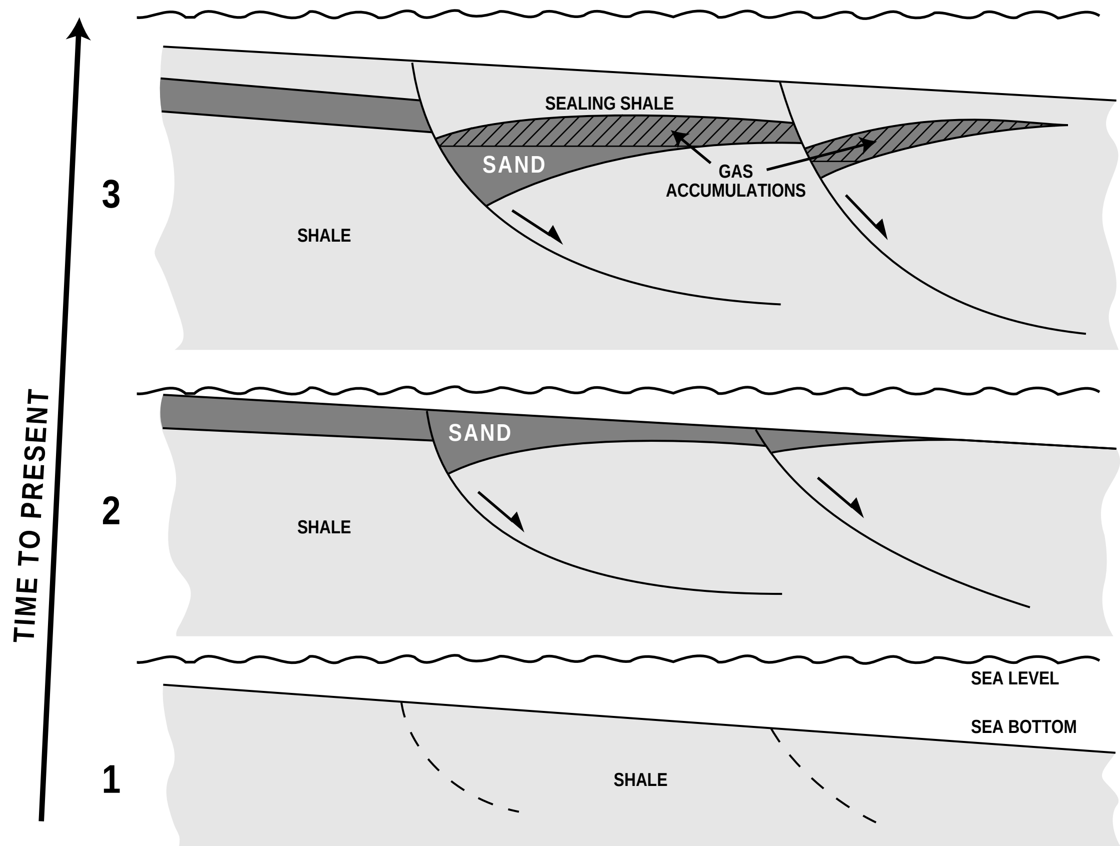
Figure 2.1.2.3: Paleogeographic Map of Sable Island Delta complex (Early Cretaceous Time). Line of Section in Figure 2.1.3.1(b) is indicated.

Late-stage passive margin development during the remainder of Early Cretaceous time was marked by a series of landward backstepping, shallow marine progradational lobes (Logan Canyon Formation) which interfinger with distal equivalent marine shales.

During the final stages of passive margin development, Late Cretaceous marine transgression deposited the Petrel limestone. This was followed by deep water deposition of Dawson Canyon Formation shales, Wyandot Formation chalky limestone, and Tertiary clastics of the Banquereau Formation. A more thorough description of the stratigraphy of the Scotian Basin is found in Part Two (**DPA - Part 2, Ref. # 2.1.1.1 through 2.1.1.5, 2.1.2.1 and 2.1.2.2**).

2.1.3 Source and Trapping of Hydrocarbons

The Verrill Canyon shales, depositionally distal marine equivalents of the deltaic Mic Mac and Missisauga Formations, are considered the most likely source of gas and condensate in the Sable Subbasin (**DPA - Part 2, Ref. # 2.1.3.1**). They are described as lipid-poor, gas-prone, low-total organic content (TOC), type III (terrestrial) source rocks (**DPA - Part 2, Ref. # 2.1.3.2 through 2.1.3.4**). Growth faults were active during and after deposition of the Mic Mac and Missisauga formations; anticlines associated with growth faulting formed traps for migrating hydrocarbons. All the **Sable Offshore Energy Project** fields occur in such growth fault related structures. **Figure 2.1.3.1(a)** illustrates the mechanism of growth fault development. **Figure 2.1.3.1(b)** illustrates the presence of growth faults in a north/south seismic line across the Sable Subbasin, and shows a strong relationship between hydrocarbon accumulations and growth fault-related anticlines.



Time 1: Represents shale deposition distal (in front of) deltaic sand, prior to development of growth faults. Future growth fault locations shown by dashed lines. Note listric (curved) nature of fault lines.

Time 2: Sandy deltaic deposits have advanced into the area. Loading by these sediments (coupled with gravity induced extension) results in the development of listric growth faults. Movement along these faults causes sand deposition to be concentrated in the space created in the downthrown block immediately adjacent to the faults. Movement on the listric faults also causes rotation of the downthrown block, resulting in the formation of 'roll-over' anticlines.

Time 3: Delta-switching and/or rise in sea level causes sand deposition to be replaced by shale deposition. These pro-delta shales act as seals, and trap gas migrating into reservoir quality sandstones in the roll-over anticlines beneath.

Figure 2.1.3.1(a) Sequential Development of Growth Faults

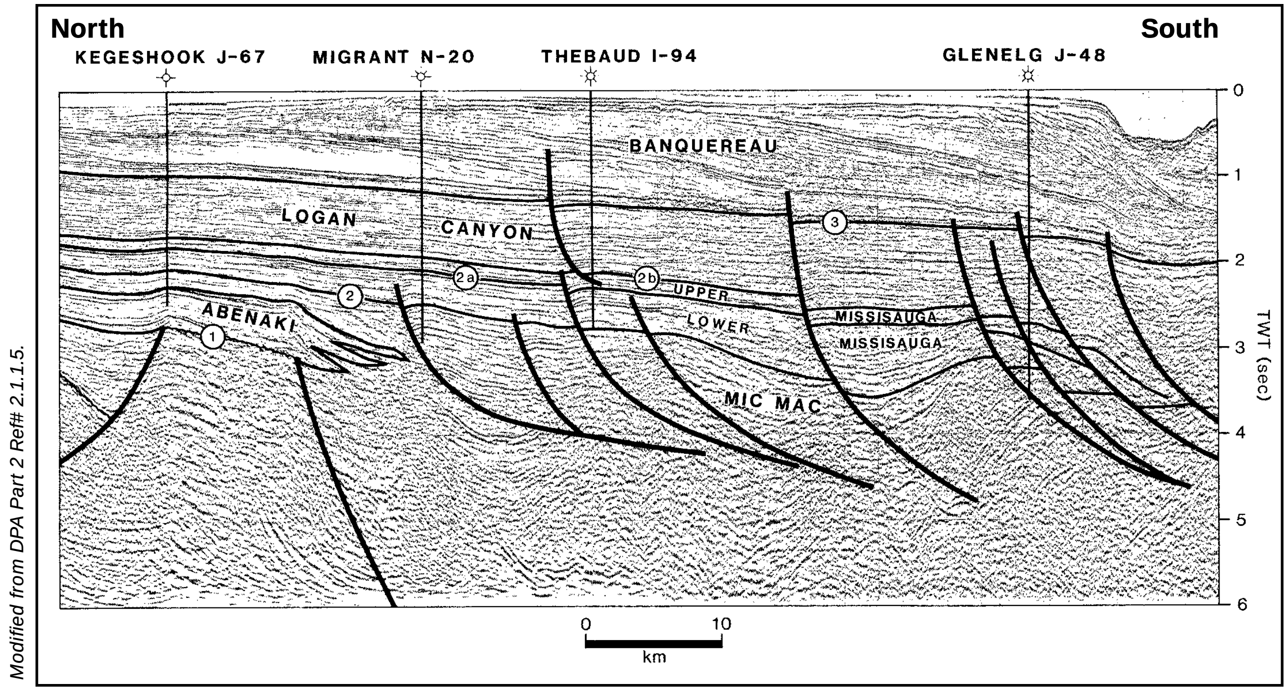


Figure 2.1.3.1(b) North-South Seismic Line Showing Growth Faults in the Sable Subbasin. Note that many growth fault-related anticlines contain hydrocarbons. Circled numbers refer to seismic events discussed at length in DPA Part 2, Ref. # 2.1.1.5. Line of Section is shown in Figure 2.1.2.3.

Gas accumulations in the Sable Subbasin occur in both hydropressured and overpressured reservoirs. Overpressured reservoirs have a subsurface pore-fluid pressure greater than that of normal hydrostatic pressure. The North Triumph, Glenelg and Alma fields are hydropressured. The shallower reservoirs of the Thebaud, Venture and South Venture fields are also hydropressured, while the deeper reservoirs in these fields are overpressured. Recent basin modeling studies **(DPA - Part 2 Ref.. #2.1.3.3)** have assumed that overpressure in the Sable Subbasin is caused primarily by compaction disequilibrium and gas generation.

2.1.4 Reservoir Stratigraphy

Sable Offshore Energy Project gas reservoirs all occur stratigraphically within the Late Jurassic to Early Cretaceous Mic Mac and Missisauga formations. They consist of deltaic and shallow marine sands deposited within the Sable Delta complex. This delta complex was sourced from the north and prograded southward through time. The maximum southward extent was at the very top of the Missisauga Formation immediately below the capping Naskapi Shale. Over the course of approximately 50 million years, the active portion of the Sable Delta complex advanced and retreated repeatedly in a general north-south direction as a result of fluctuations in sediment supply and relative sea level. Its deposits have a maximum thickness of 2500 metres in the Venture/Thebaud area, and consist of stacked, successive, coarsening-upward deltaic depositional cycles.

Gas is trapped only where there is a favourable combination of structure and seal lithology (shales). The sand/shale ratio is optimal for trapping gas toward the seaward margin of the delta complex, where there is significant interfingering of deltaic sandstones with pro-delta/marine shales. The southward progradation of the Sable Delta complex through time, and the associated upward increase in sand/shale ratio, account for the stratigraphic variation in reservoir levels in the **Sable Offshore Energy Project** fields. The more northern fields (Thebaud, Venture and South Venture) contain gas reserves in sandstones which are marginal to the delta complex; these occur stratigraphically in the Mic Mac and lower Missisauga Formation. The later arrival of deltaic sandstones at the more southern Project fields (North Triumph, Glenelg and Alma) provided favourable gas trapping conditions at the very top of the Missisauga Formation. **Figure 2.1.4.1** is a diagrammatic north-south cross-section of the Missisauga Formation showing the relative stratigraphic position of reserves in the Project fields.

The stratigraphy of the reservoir interval in the Venture, South Venture and Thebaud fields is broadly correlative. The North Triumph, Glenelg and Alma reservoirs are also broadly correlative, but are considerably younger than, and do not correlate with, the northern fields. Syndepositional growth faulting localized individual sand body distribution; this complicates high order correlation between fields located in different growth fault blocks. As a result, a unified sand nomenclature for the Project fields is not possible, and each field has its own internal sand nomenclature.

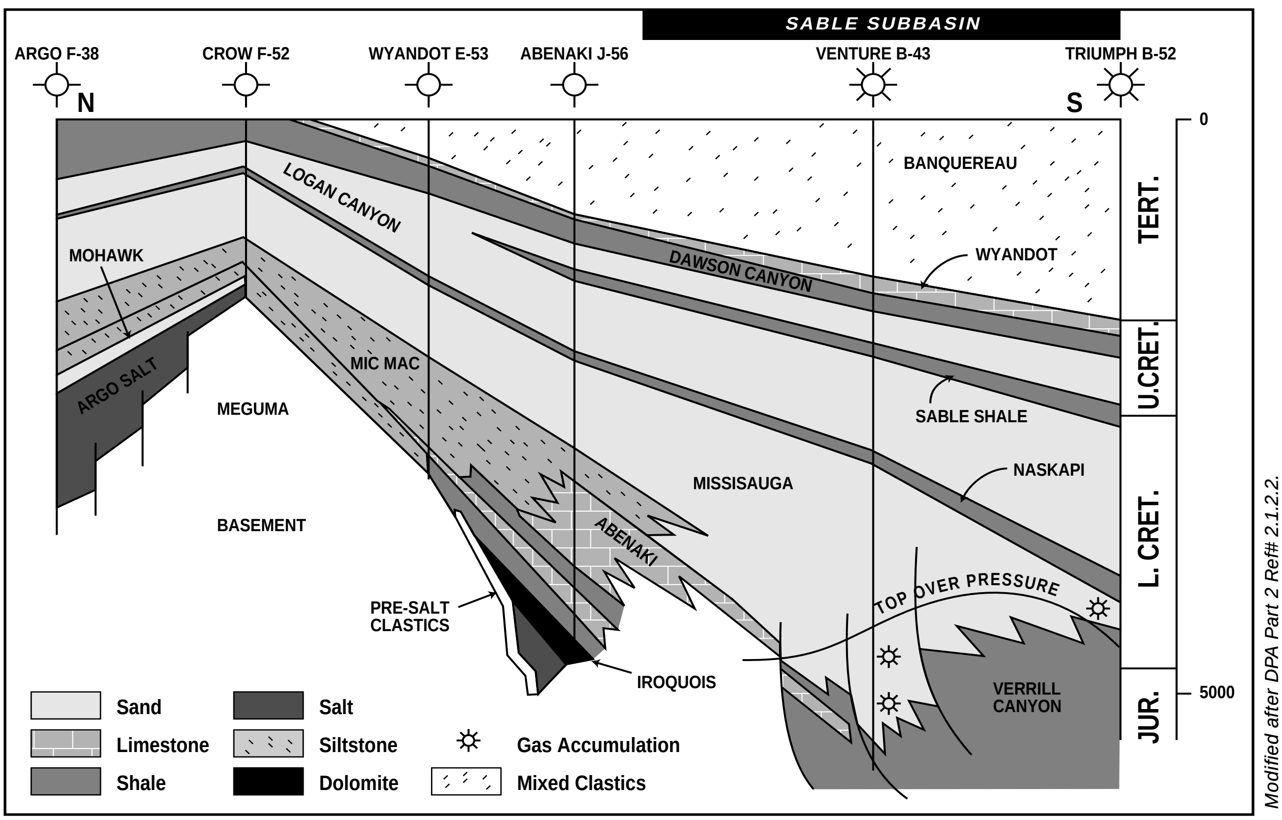


Figure 2.1.4.1 Diagrammatic North-South Cross-section of Missisauga Formation Showing Relative Stratigraphic Position of Gas Reserves in Project Fields.

2.1.5 Reservoir Sedimentology

Delta progradational shale to sand cycles 10 to 50 metres thick comprise the fundamental reservoir flow layers. **Figure 2.1.5.1** is a stratigraphic log from West Venture N-91 illustrating typical stacking of shale to sandstone coarsening-up cycles. This stacking resulted from repeated delta progradation and lobe switching.

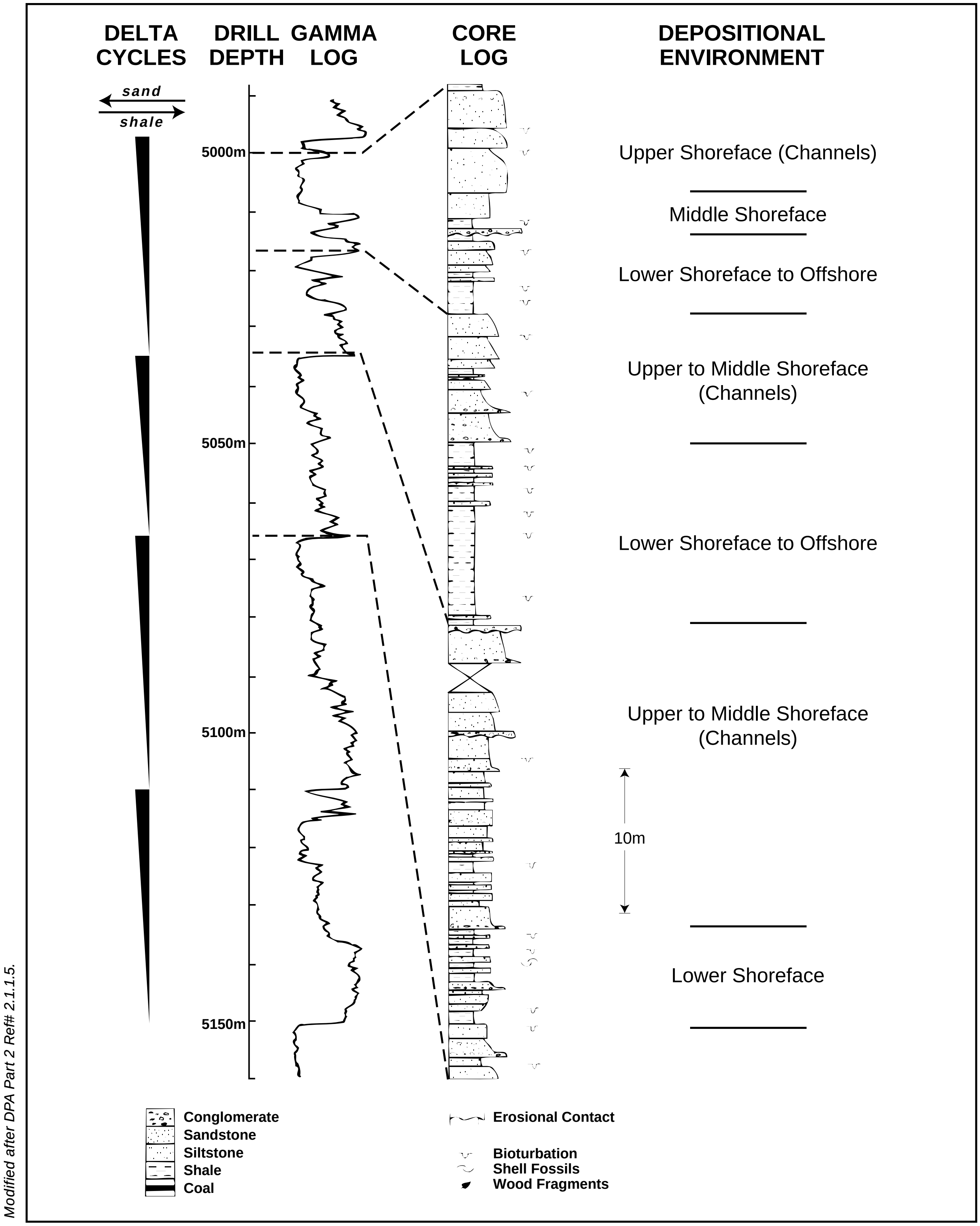


Figure 2.1.5.1: Stratigraphic Log showing stacked delta cycles.

The reservoir sands at the tops of these cycles belong to three depositional facies associations (**DPA - Part 2 Ref. # 2.1.5.1**). They are recognized based on lithology, sedimentary structures and lateral/vertical relationships. The Delta Plain Facies Association and Shelf and Strand Plain Facies Association are interpreted to have been deposited in a mixed-energy (predominantly tidal and wave dominated, but locally fluvially dominated) deltaic system. Sediments that comprise the Valley Fill Facies Association are interpreted as having been deposited within valley systems carved by distributaries into the underlying delta sediments at times of lowered relative sealevel. Sediments within these lowstand valley systems were deposited predominantly under tide-dominated estuarine conditions. **Figure 2.1.5.2** shows idealized vertical successions of the three depositional facies associations.

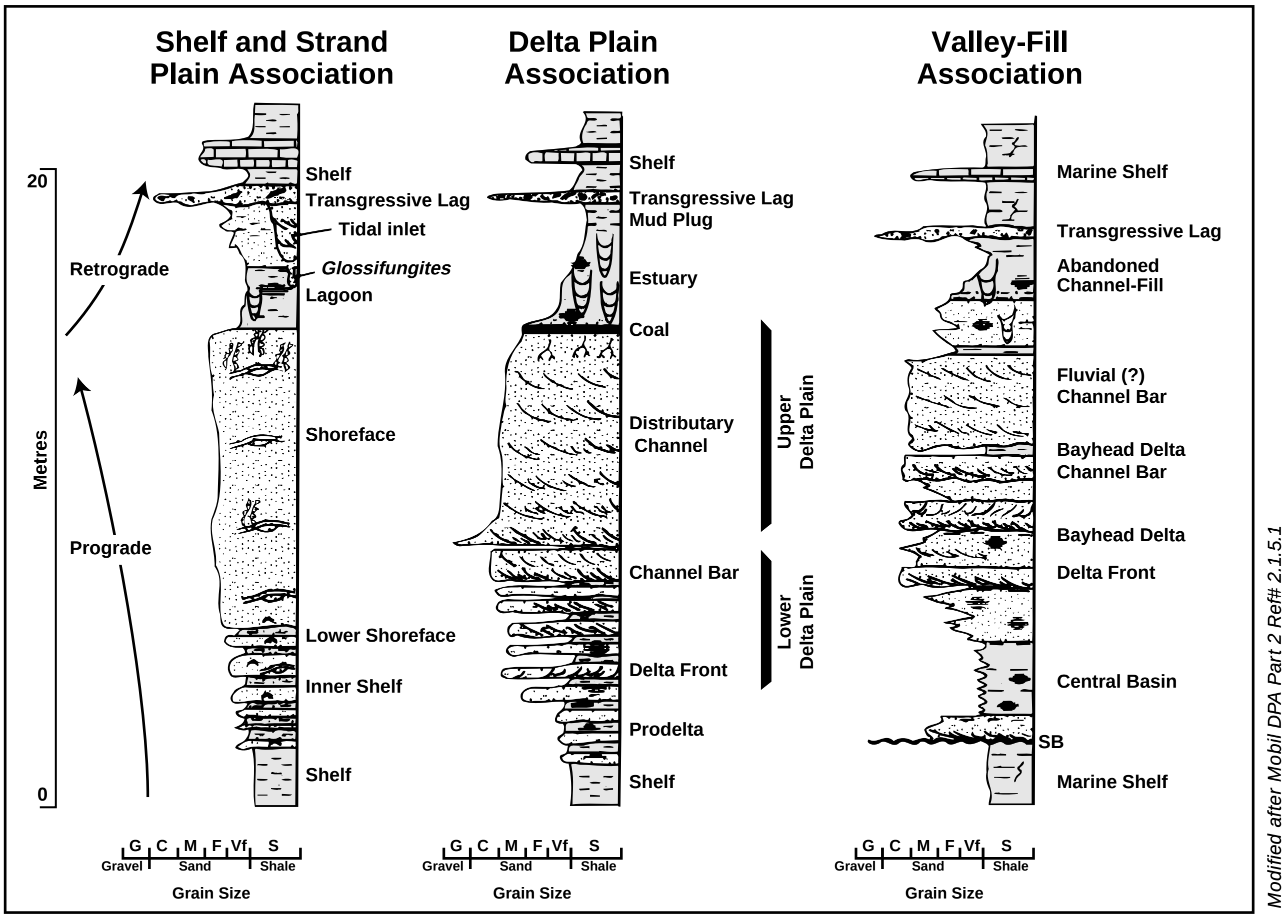


Figure 2.1.5.2: Facies Model, Sable Delta.

2.1.6 Reservoir Geophysics

Over 300,000 kilometres of 2D (two dimensional) seismic data has been acquired in the Scotian Shelf and slope since 1960; more than half of this since 1979 (**DPA - Part 2, Ref. #2.1.1.1**). The highest density of seismic data is located in the vicinity of Sable Island. Seismic acquisition geometry associated with the Project fields has been restricted to a single source and streamer configuration with limited shallow water or transition zone seismic over the western flank of the Venture structure.

Geophysical interpretations were carried out on all six fields during the mid to late 1980's. A variety of paper and workstation based approaches were used on the predominantly 2-D seismic database. Of the six fields, only Glenelg has conventional 3D (three dimensional) seismic coverage. A 1991 remapping of North Triumph incorporated a reconnaissance 3D seismic survey (focussed on the Chebucto structure) that largely covers the field.

Six regional markers; the Wyandot, Petrel, O Marker, Baccaro, Misaine and Scatarie; provide good mappable reflections throughout most of the subbasin. They have been used to define the regional setting for much of the Cretaceous and Upper Jurassic section. Numerous mappable events within the productive section of the northern fields (Venture, Thebaud and South Venture) are often limestones encased within sandstone/shale sequences or porous sands overlying tighter sandstones and shales. In the southern fields (North Triumph, Glenelg and Alma), mappable events are most often associated with the base of shale units. In both the northern and the southern fields, the mappable seismic events within the reservoir interval are often restricted areally to a single growth fault block.

Formation	Primary Seismic Reflectors	Dominant Lithology	Maximum Thickness
Sable Island		Sand and Gravel	
La Have		Clay	
Sambro		Sand	
Emerald		Silt	
Scotian Shelf		Glacial Drift	
Banquereau		Mudstone	1200 m
Wyandot	Wyandot	Chalk	230 m
Dawson Canyon	Petrel	Shale	900 m
Logan Canyon		Sandstone & Shale	250 m
		Shale	150 m
		Sandstone & Shale	600 m
Naskapi		Shale	230 m
Missisauga	"O" Marker	Sandstone	1130 m
Mic Mac		Calcareous Shale	1200 m
Verrill Canyon		Shale	>600 m
Abenaki	Baccaro	Limestone	750 m
	Misaine	Calcareous Shale	100 m
	Scatarie	Limestone	130 m
Mohawk		Sandstone & Shale	1070 m
Iroquois		Dolomite	200 m
Argo		Salt	>900 m

Modified from DPA Part 2 Ref# 2.1.1.1.

Figure 2.1.6.1: Primary Regional Seismic Reflectors, Scotian Basin

Synthetic seismograms (checkshot survey corrected), generated with all available wireline log sonic and density information from each field, were used to tie well lithology to the seismic data. The few vertical seismic profiles (VSPs) that have been acquired in the Project fields were also used to improve well data to seismic reflector ties.

The productive reservoirs in the northern fields are generally deeper than those in the southern fields and are predominantly overpressured. The overpressure does not appear to seriously degrade seismic quality and does not generate any discrete seismic events.

The velocity fields measured are generally well behaved and vary laterally in a slow and smooth manner. No significant velocity inversions are noted, although some velocity 'slowing' is observed within the overpressured section. Water depths range from surf zone on the western flank of Venture to a maximum of 90 metres over Glenelg. The water depths vary smoothly over the fields with little significant channeling. The overburden for these fields is typically flat lying with little structural disturbance.

Depth conversion of time structure maps for all six fields has been done using a vertical ray path or 'layer cake' technique. Methods applied to individual fields vary in degree of sophistication. These methods rely heavily upon well checkshot velocity information, and use some seismic stacking velocities to interpolate between, and extrapolate from, the well control where data quality permits. The resulting depth structure maps closely resemble the input time structure maps.

Reflection seismic has been used primarily to define the structural geometry of the fields, including fault plane geometry and reservoir juxtaposition. Some reservoir characterization based on amplitude mapping has been used in a limited way to guide appraisal drilling in the northern fields. The success of this technique has been restricted by the limited band width of the available seismic data.

A detailed analysis of several of the existing 2D datasets has indicated that modern 3D seismic has the potential to significantly improve the ability to map reservoir distribution and quality. Technical design work has been completed and preparation for the acquisition of 3D data, due to commence in 1996, is ongoing.

2.1.7 Reservoir Petrophysics

Full petrophysical evaluations have been completed on all six Project fields using a similar methodology. The details of the individual analyses vary according to the type and quality of the data available, and the vintage of the analysis. Listings of wireline log and core data are contained in the **CNSOPB** well history files for each well.

Reservoir sands are dominantly sublitharenites deposited as strand plain and channel sandstones. Their zonal average porosity and permeability range between eight and 20 percent, and one and 300 millidarcies (mD), respectively. The primary controls on porosity and permeability are average grain size, cementation and the presence of grain-rimming authigenic chlorite. Porosity tends to decrease with increasing depth, with the notable exception of clean overpressured reservoirs which have unusually high porosity. The occurrence of pervasive grain-coating chlorite in some overpressured reservoirs is believed to have inhibited the development of quartz cementation, preserving porosity at depth. Microporosity associated with the chlorite rims is also believed to result in locally high irreducible water saturation values. A broad range of average irreducible water saturation values, which vary from 10 to 40 percent, are calculated in the various reservoir sands of the **Sable Offshore Energy Project**.

Wherever possible, porosity was calculated from the density log measurement calibrated to stressed core porosity measurements. Porosity cutoff values between six and 10 percent were used in the determination of net porous sand thickness in the various reservoirs. These values were based on core and/or microlog indicated permeability, and correspond to permeability values between 0.1 and 1 mD to air at ambient conditions.

Water saturation values used in the estimation of gas in place were calculated using the Archie equation. Wherever possible, cementation and saturation exponent values were based on stressed core formation resistivity factor and resistivity index measurements. Formation water salinity values are high based upon the analyses of fluid recoveries from repeat formation test (RFT) and drillstem test (DST) fluid samples.

Typically, salinity increases with depth, reaching values as high as 100 to 300 thousand ppm sodium chloride. True formation resistivity was generally based on the deep induction measurement. In sands severely affected by drilling mud filtrate invasion, such as Venture, capillary pressure data was used extensively in the estimation of water saturation.

2.1.8 Gas in Place

Gas in place (GIP) estimates have been generated for all fields using both deterministic and probabilistic methods. The probabilistic estimates are considered to be the most representative, because they were generated using probability distributions for geological and petrophysical parameters that capture a range of uncertainty. Differences between the deterministic estimates and the P50 and mean values of the probabilistic estimates are due to the deterministic maps representing an unrisked gas accumulation. A description of the deterministic and probabilistic estimates for each field is outlined in the appropriate sections of this chapter.

Probabilistic gas in place determination was conducted in 1995 using Palisade @Risk™ software. This methodology permits recognition of uncertainties in the key input parameters. These parameters are: area, net pay development, porosity, water saturation, and expansion factor. Volume estimations are output as a range of possible values, with each value assigned a probability of occurring. The range of output values is dependent on the degree of uncertainty, or spread in range, of the input parameters. Future data acquisition and technical studies will be targeted to clarify these uncertainties. The results of the probabilistic analysis for the Project fields are shown in **Table 2.1.8.1**. This table expresses the gas in place estimate as the mean, or expected value, taken from the cumulative probability expectation curve. Gas in place at three other probability levels, P90, P50 and P10 are also presented. These values reflect possible gas in place volumes at different confidence levels. The total field P10, P50 and P90 gas-in-place numbers reported in Table 2.1.8.1 for SOEP fields consisting of a number of stacked pools (all but North Triumph) is an arithmetic summation of the reserves estimations at these confidence levels for each pool. For example, the P10 value shown for the Thebaud Field represents the arithmetic summation of all the P10 values for the constituent pools (see Table 2.2.1.7.1). This summation procedure was adopted for the sake of simplicity. Statistically the inference of this addition is of dependence between the stacked pools: the result is a wider range between the P10 and P90 reserves numbers for the fields than would result from a statistically independent summation. The degree of dependence between the stacked pools is not known, but likely varies in association with stratigraphic proximity, seal effectiveness, and fault juxtaposition.

Table 2.1.8.1: Probabilistic Gas In Place, E9M3

Field	P90	P50	P10	Mean
Thebaud	10.7	22.9	45.0	**26.0**
Venture	18.1	41.9	89.7	**49.2**
North Triumph	6.2	14.2	25.2	**15.2**
South Venture	3.4	10.4	20.5	**11.3**
Glenelg	7.1	12.1	17.9	**12.3**
Alma	11.5	14.9	18.7	**15.0**

2.1.9 Future Data Acquisition Strategy

During the pre-development and development phases of the Project, a data acquisition strategy will be initiated to refine current reservoir descriptions and narrow the uncertainty range associated with present gas in place estimates. This strategy includes the acquisition of 3D seismic data and the collection of wellbore data in development wells. The interpretation of these data will be used in the reservoir management of the Project fields such that recovery and value are optimized.

Future coring and logging programs will be designed to adequately evaluate development wells and clarify uncertainties unresolved by the present database. For example, core samples will be cut over selected intervals to augment the existing core database. A standard open-hole logging suite, including induction or laterolog resistivity, sonic, neutron and density tools, will be run over the reservoir section, wherever practical and safe to do so. However, formation imaging surveys and wireline formation tests may also be run, on occasion, to complement the standard open hole logging suite. Cased hole pulsed neutron logs and production logs will also be run, as required, to monitor reservoir performance.

This strategy begins with the acquisition of some 3D seismic data during the 1996 season. The interpretation of the seismic data will initiate remapping of Project fields and result in the complete integration of seismic data, most recent interpretations of existing well datasets, and current geologic models. Refinement of the map suite will continue, as stratigraphic and petrophysical relationships are further defined, based upon wireline log and core data obtained through development drilling.

2.2 Field Descriptions

This section presents a summary description of each field under the following subheadings: drilling history, reservoir description and zonation, geophysics, petrophysics, and gas in place assessments. Detailed information and the technical evaluations in support of these summaries are included in Part Two of this Development Plan Application.

The fields will be summarized in this section in the following order: Thebaud, Venture, North Triumph, South Venture, Glenelg, and Alma. **Table 2.2.1** presents a listing of basic well data for all wells drilled in the six **Sable Offshore Energy Project** fields.

Table 2.2.1: Well Data

Field	Number of Wells Drilled	Well I.D.	Year Drilled	Total Depth (metres)	Rotary Table (R.T.) to Sea Level (metres)	Water Depth (metres)
Thebaud	4	P-84	1972	4115	28.7	25.9
		I-94	1978	3962	29.9	28.0
		I-93	1985	5166	36.3	30.0
		C-74	1986	5150	41.8	31.0
Venture	5	D-23	1979	4945	31.7	20.1
		B-13	1981	5368	34.1	24.7
		B-43	1982	5872	34.1	20.4
		B-52	1983	5960	35.4	19.5
		H-22	1984	5944	38.4	22.0
North Triumph	2	G-43	1986	4504*	24.0	74.0
		B-52	1986	3960	24.0	81.0
South Venture	1	O-59	1983	6176	35.4	24.0
Glenelg	4	J-48	1983	5148	24.0	82.0
		E-58	1984	4154	24.0	79.0
	Whip	E-58a	1984	4192*	24.0	75.0
		H-38	1985	4865	24.0	88.0
		N-49	1986	4040	23.0	72.0
Alma	2	F-67	1984	5054	24.0	68.0
		K-85	1985	3602	24.0	68.0

* measured depth

2.2.1 THEBAUD FIELD

2.2.1.1 Field History

In 1972, the discovery well, P-84, encountered gas pay in several, vertically stacked, hydropressured and overpressured sandstone horizons. Three delineation wells, I-94, I-93 and C-74, were drilled in 1978, 1985 and 1986, respectively, to evaluate the structure. These delineation wells established that hydropressured gas accumulations encountered in P-84 were of limited areal extent. The first overpressured reservoir, the A Sand, was found to be entirely gas bearing in P-84 and in all three appraisal wells confirming the presence of a significant gas accumulation. The A Sand reservoir occurs at a depth of 3828 metres R.T. (Rotary Table) in the P-84 wellbore. The most recent delineation wells, I-93 and C-74, were drilled deeper into the overpressured section. The C-74 well successfully encountered several additional gas bearing overpressured sandstone horizons. The onset of overpressure in the Thebaud structure occurs at a depth of about 3800 metres. **Figure 2.2.1.1.1** is a depth structure map of the top A Sand and shows the Thebaud Field well locations.

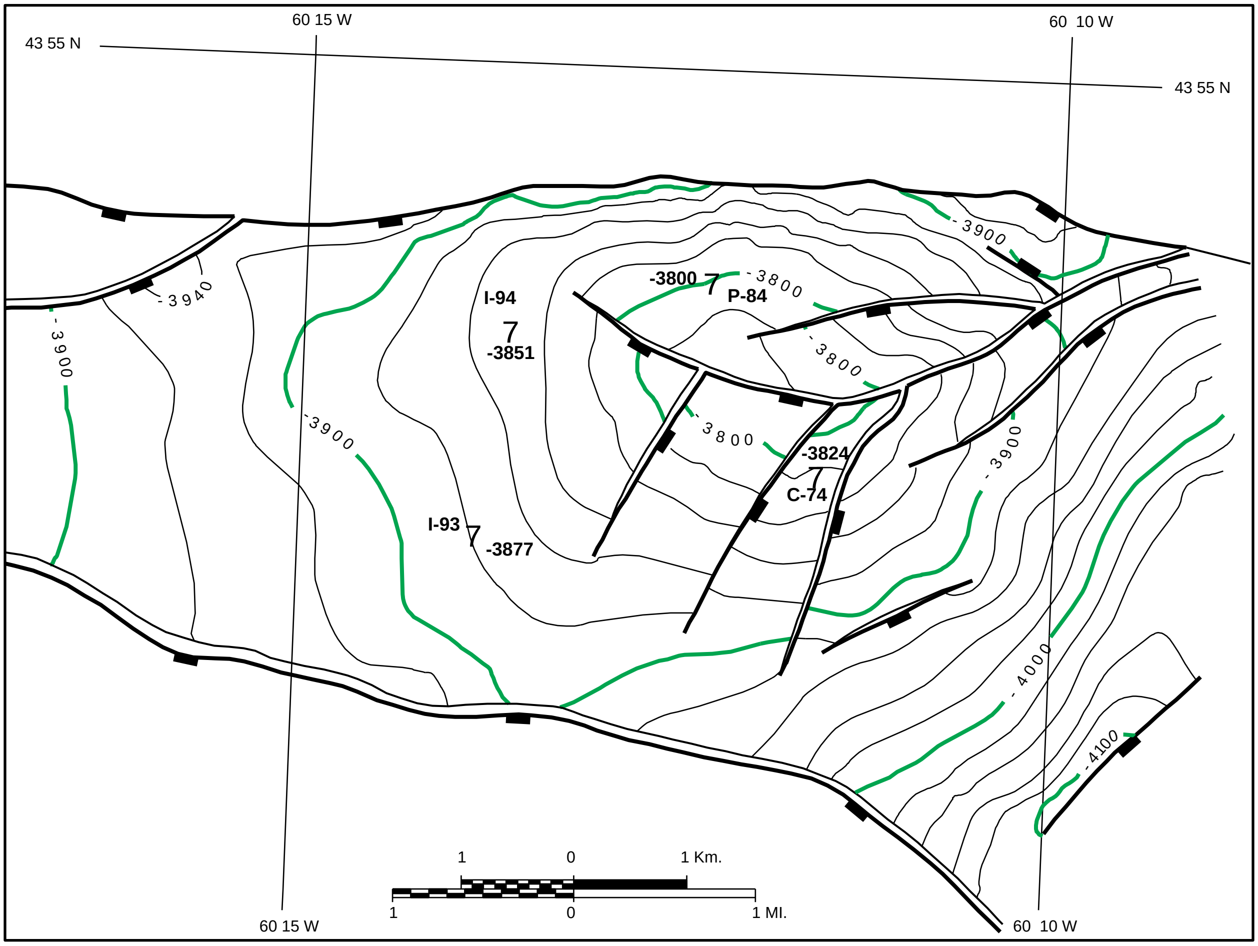


Figure 2.2.1.1.1 Thebaud Field - Top A Sand Depth Structure Map
Contour Interval: 20 Metres

2.2.1.2 Structural Configuration

The Thebaud structure is a rollover anticline on the downthrown side of a major down to the basin growth fault. At the A Sand horizon, the anticline is approximately six kilometres by five kilometres in size and encompasses an area of 31.6 square kilometres with a vertical closure of 160 metres. Gross closure at the A Sand level is established by a saddle spillpoint located on the western side of the structure. Several minor faults that occur within the structure are discontinuous at this horizon. These faults generally have displacements less than the A Sand thickness, and result in sand-to-sand juxtaposition within the structure.

2.2.1.3 Geology

The Thebaud Field is located along an east-west trend of growth fault related structures. The reservoir section in Thebaud is Late Jurassic and Early Cretaceous, Mic Mac and lower Missisauga formations. A considerable thickness of deltaic clastics is preserved within the Thebaud structure. The productive interval encountered extends from 3200 metres to 4930 metres, a gross thickness of 1730 metres.

Gas accumulations are identified within hydropressured and overpressured reservoir sandstones. They occur within a vertically stacked, alternating sequence of sandstones, shales and occasional limestones. This repetitive cyclic sedimentation is the result of episodic delta progradation that is punctuated by periods of marine incursion associated with relative sea level change. Individual delta progradations are characterized on wireline logs by 20 to 35 metre thick, coarsening, cleaning upward packages. Reservoir quality sandstones occur within the upper portion of these delta progradations. Overlying shales, associated with marine flooding surfaces, are interpreted to be areally extensive, and provide the top seal to individual gas accumulations.

Gas has been tested in four independent hydropressured reservoir horizons in the P-84 discovery well. Subsequent delineation wells were drilled structurally downdip from this location. Log analysis in I-93, the structurally lowest well, indicated all equivalent sands to be wet or tight. Log analysis in I-94 and C-74 interpreted minor gas pay thicknesses above water in these sands. Gas accumulations in the hydropressured section are of limited areal extent around the crestal P-84 well.

The A Sand is the first overpressured reservoir encountered in the Thebaud structure and has been penetrated and tested in all four wells. Wellbore net pay thickness for the A Sand horizon varies from 14 metres in the I-93 well, to 26 metres in the I-94 well. Wellbore and seismic data indicate that A Sand gross thickness decreases from north to south, away from the north bounding fault. This observation is consistent with the geologic model, where reservoir sandstones are interpreted to thicken toward the master growth fault. Gas is trapped at the A Sand level by a combination of simple rollover closure, and fault closure to the north by juxtaposition against an interpreted shale rich lithology. **Figure 2.2.1.3.1** is a net pay thickness map of the A Sand reservoir.

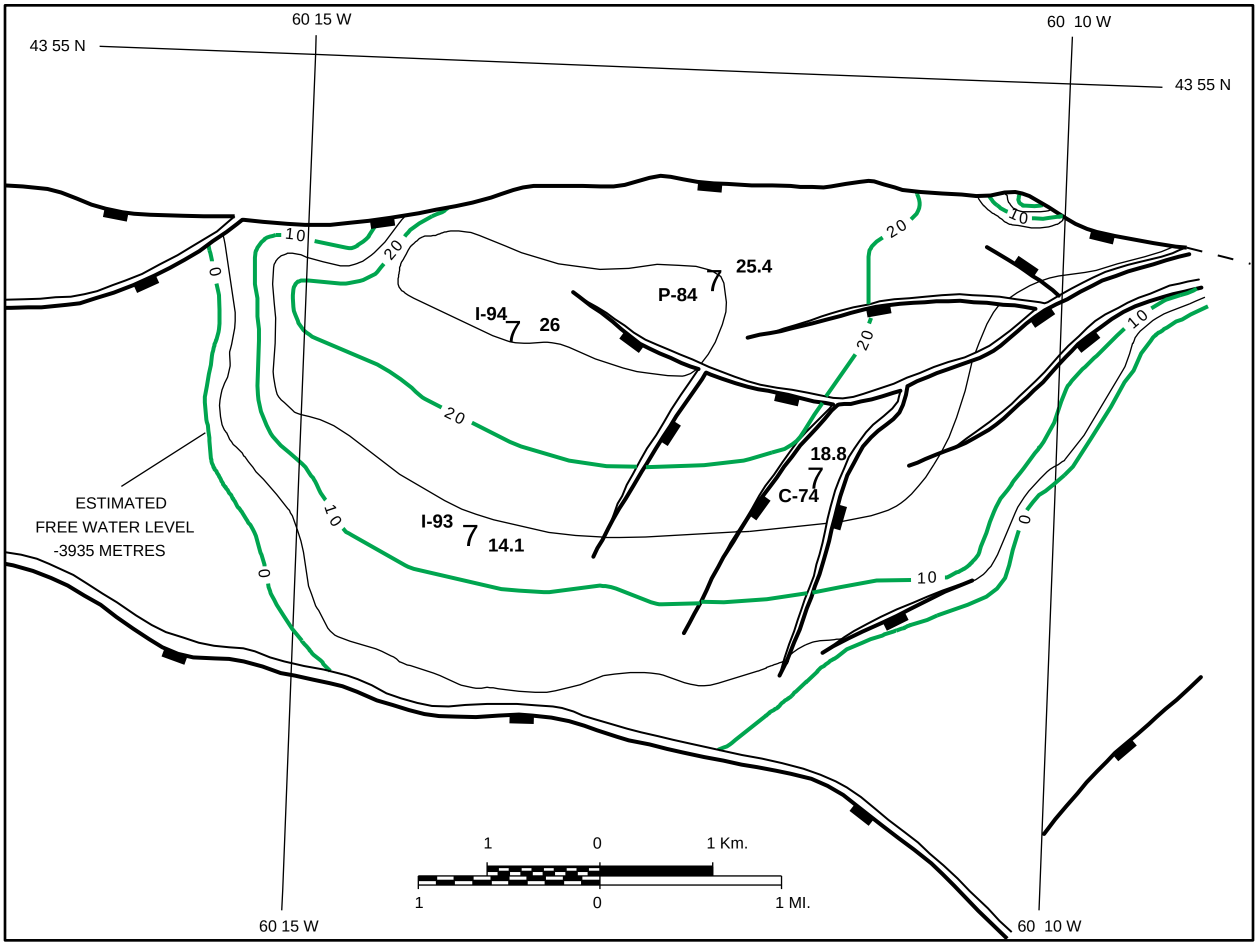


Figure 2.2.1.3.1 Thebaud Field - Sand A Net Pay Thickness Map
Contour Interval: 5 metres

The C-74 well tested high gas flowrates from a number of deeper, overpressured sandstones. Equivalent sandstones at a structurally downdip location in the I-93 well, are generally of poorer reservoir quality. Stratigraphic correlation between these two wells in the deep section, however, is problematic. The deeper overpressured section encountered in the I-93 well is characterized by a lower overall sand-to-shale ratio.

2.2.1.4 Reservoir Zonation

The stratigraphic nomenclature used for the Thebaud Field reservoir section is illustrated in **Figure 2.2.1.4.1**, a schematic cross-section incorporating the I-93 and C-74 wells. Wireline log response, core, pressure, and seismic data were used to subdivide the Thebaud reservoir section into this series of reservoir sandstone packages. Sandstone reservoirs that have flowed gas on drillstem test are depicted on the schematic cross-section. The overpressured G2 horizon was not tested, but is included due to favourable log interpretation in the C-74 well and proximity to the tested G3 Sandstone. The alpha numeric nomenclature assigned to these reservoir sandstones is unique to the Thebaud structure and is not applied to other Project fields. Uncertainty exists in the correlation of the deeper overpressured sandstone reservoirs. This is due to a general deterioration in the quality of seismic data and greater intrafield fault complexity. The deep overpressured section in I-93 has been interpreted in deterministic reservoir studies to represent a more distal fine grained delta facies. However, improved seismic data is needed to resolve the relationship between intrafield faults and reservoir stratigraphy in this deep section.

The A Sand is the largest single reservoir accumulation identified to date in the Thebaud structure. Consequently, deterministic reservoir studies conducted in the 1980's further subdivided the A Sand into four reservoir rock type layers for input to reservoir simulation models (**DPA - Part 2, Ref. 2.1.4.1**). These rock types were determined from core and log sedimentary and reservoir facies analysis. All other reservoir sandstones were mapped as single layers for purposes of gas in place estimation and reservoir simulation input.

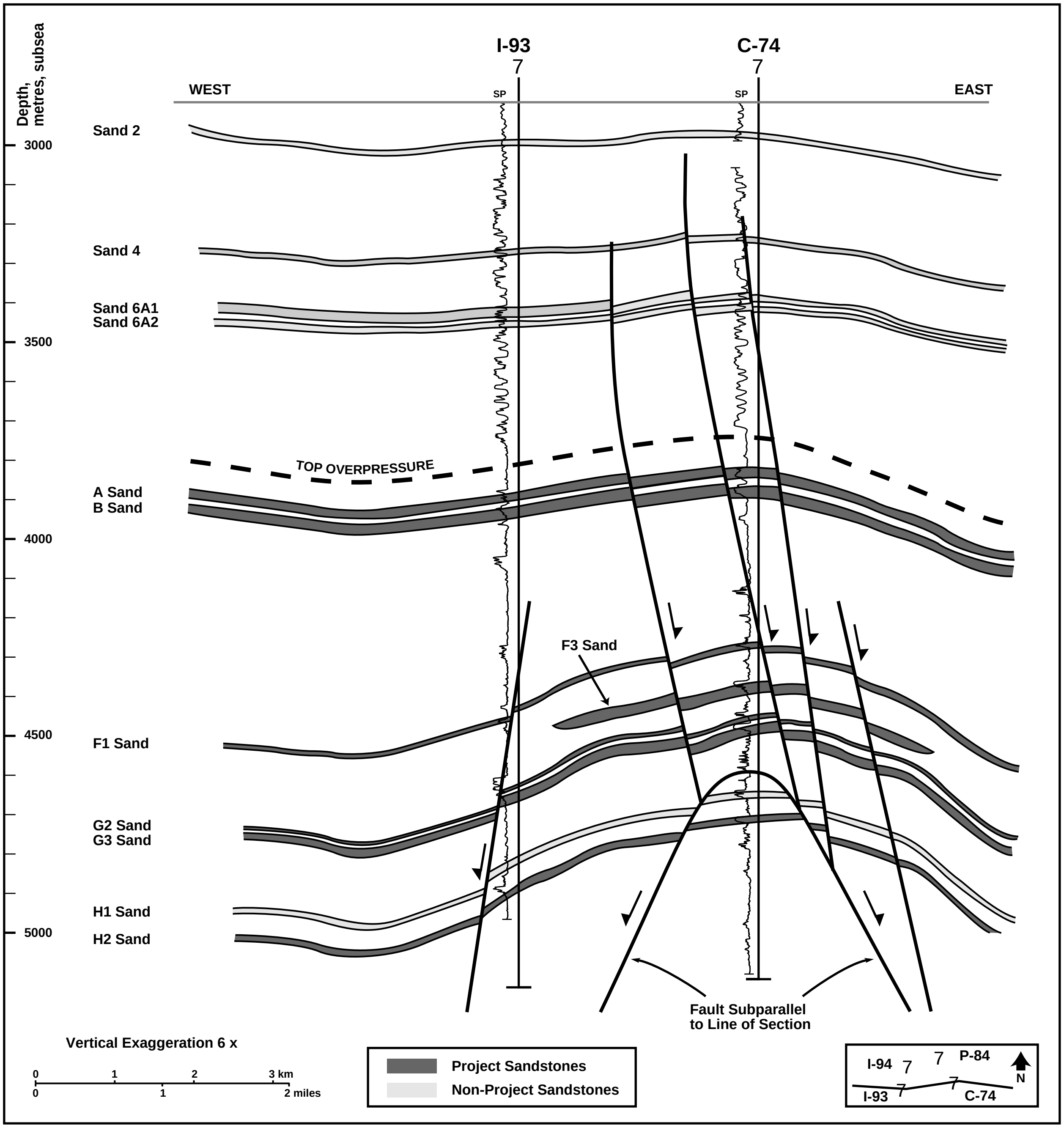


Figure 2.2.1.4.1: Thebaud Schematic Structural Cross-section

2.2.1.5 Geophysics

2.2.1.5.1 Seismic Database

Six 2D seismic datasets have been acquired over the Thebaud structure since the early 1980s. All datasets share similar characteristics. A summary of acquisition and processing details for several of these datasets is included in **Table 2.2.1.5.1.1**.

The seismic data density and quality at the main project reservoir A Sand is quite good. When incorporated with the well data, a moderately high level of confidence is generated at the A Sand level. Continuity, frequency content, and fault imagery, however, deteriorate at greater depths. This results in a considerable decrease of confidence in the deeper maps. Analysis of the seismic data indicates that significant, broadband signal is present in the seismic data at depth. The same analysis shows that overpressure has only a minor effect on sonic velocities and imaging. The poor quality of the deeper seismic is thought to be largely a function of 2D crossline dip. The acquisition parameters used, and the processing stream applied in an operationally challenging environment, have also reduced the quality of the deeper seismic. The depth structure maps used for gas in place estimates are based on the 2D seismic data grid illustrated in **Figure 2.2.1.5.1.1.**

Table 2.2.1.5.1.1: Thebaud Acquisition and Processing Summary

Data Type	Survey Name	Incorp. In Study	Acq. Date	Acq. Style	Proc. Date	Field Kms	Proc. Details	Comments
2D	8624-M003-047E	Yes	1984	Marine	1984-85	359	60 fold Decon before and after stack, FD migration	Good to very good data quality, poorer with depth, lower frequency
2D	90-1200's	No	1990	Marine	1990-91	18	60 fold Decon before and after stack, FD migration	Good to very good data quality, better fault definition and frequency
2D	91-1400's	No	1991	Marine	1991-92	81	60 fold Decon before and after stack, Kirchoff migration	Good to very good data quality, better fault definition and frequency
2D	8620-S014-006E	No	1983	Marine	1983-84	84	60 fold Desig, Decon after stack, FD migration	Generally fair to good data quality
2D	8624-M003-044E	No	1982	Marine	1982-83	8	60 fold Desig, Decon after stack, F-K migration	Generally good data quality
2D	8620-M003-033E	No	1979	Marine	1979-80	82	60 fold Decon before and after stack, FD migration	Generally fair to good data quality

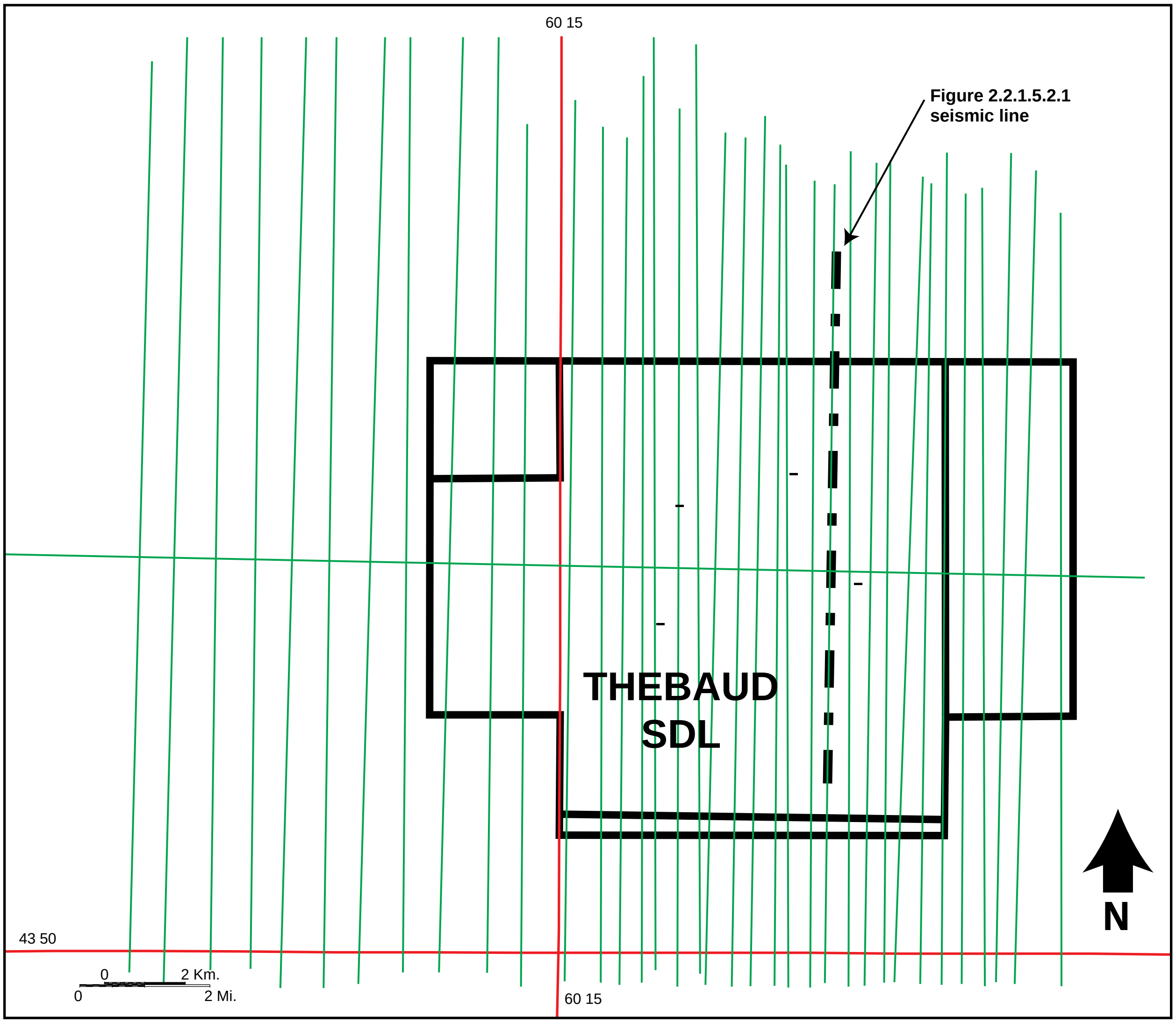


Figure 2.2.1.5.1.1: Thebaud Seismic Database Map

2.2.1.5.2 Time Interpretation

The maps used for gas in place (GIP) calculations at Thebaud are based on time and depth structure maps made in 1987. This interpretation was generated on a Landmark™ workstation using the 1984 dataset exclusively. The 1984 survey consists of 33 dip lines and one strike line for a total length of 359 line kilometres. The strike line runs 12.5 kilometres from east to west across the southern flank of the structure at the A Sand level. The dip lines have an east to west line spacing of approximately 300 metres over the crest and flanks of the structure.

Checkshot survey corrected synthetic seismograms, generated at each well by convolving a minimum phase wavelet with an acoustic impedance series derived from wireline log sonic and density information, were used to tie well lithology to the seismic data. The C-74 VSP was also used to improve the well data to seismic reflector tie.

A large number of horizons were interpreted on the workstation. The O Limestone Marker, 5A Sand, B Sand, F1 Sand and G2 Sand horizons were taken to final mapped form and used as the basis for the depth structure maps. **Table 2.2.1.5.2.1** lists the horizon markers at each of the four Thebaud wells.

Table 2.2.1.5.2.1: Thebaud Horizon Markers

	P-84		I-94		I-93		C-74	
MAP HORIZON	Depth (M, ss)	TWT (sec)	Depth (M, ss)	TWT (sec)	Depth (M, ss)	TWT (sec)	Depth (M, ss)	TWT (sec)
ZONE 1	-2582.2	2118	-2602.1	2142	-2615.0	2152	-2605.2	2164
O MARKER	-2887.3	2273	-2932.5	2303	-2961.0	2329	-2945.9	2328
ZONE #5A	-3236.0	2436	-3293.0	2468	-3316.5	2494	-3289.7	2495
B SAND	-3846.8	2745	-3894.7	2765	-3913.0	2784	-3862.6	2762
F1 MARKER	NDE	NDE	NDE	NDE	-4415.2	3032	-4264.7	2967
G2 MARKER	NDE	NDE	NDE	NDE	-4600.7	3129	-4436.5	3067

NDE - Not Deep Enough

The time structure maps are included in Part Two of this document (**DPA - Part 2, Ref. # 2.2.1.5.2.1**). Geophysical modeling and amplitude work was done to aid in positioning the C-74 well at the A Sand interval. Although these techniques are restricted by the limited bandwidth and data quality of the 1984 dataset, the post-drill results compared favourably with the pre-drill estimate. A seismic line representative of the data quality and illustrating the field geometry is shown in **Figure 2.2.1.5.2.1** and is identified with a bold dashed line in **Figure 2.2.1.5.1.1.**

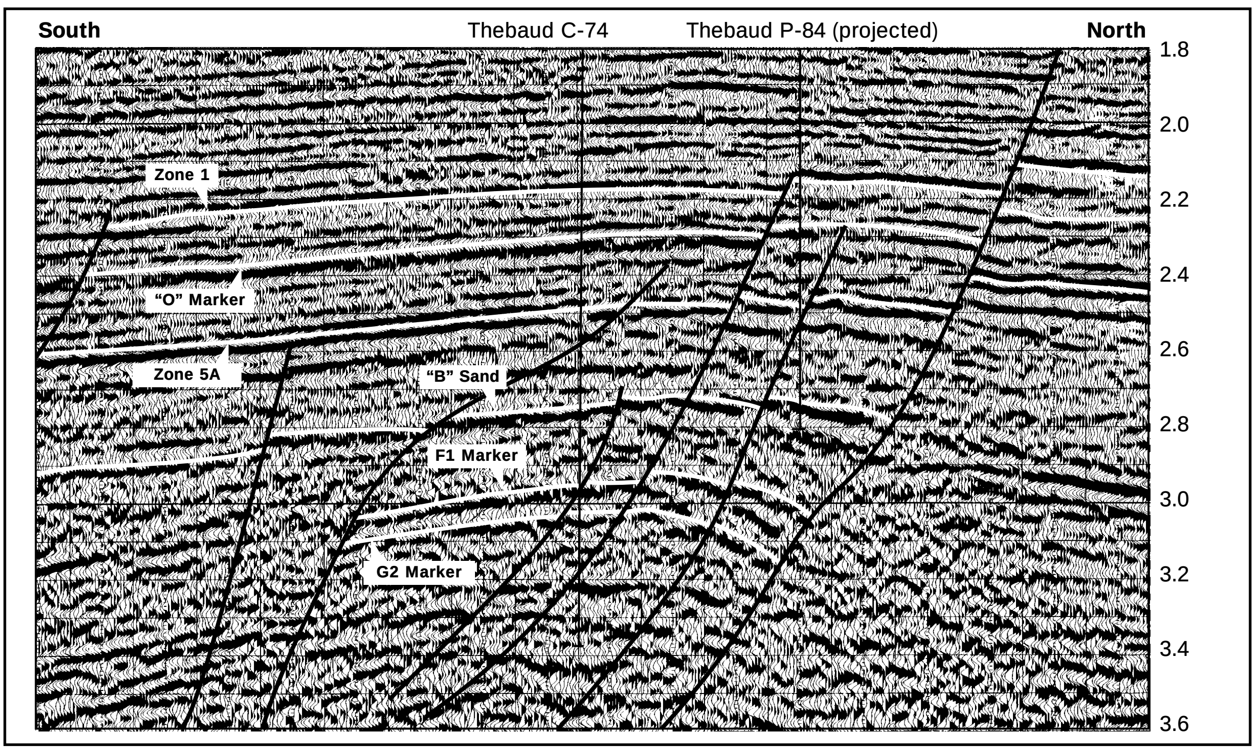


Figure 2.2.1.5.2.1: Thebaud Seismic Line

In 1990 and 1991, approximately 1400 kilometres of 2D data were acquired over the Thebaud Field and surrounding acreage. These data sets showed improvement in frequency content and resolution at the A Sand interval, and began to capture fault image energy. As with the 1984 dataset, the data deteriorated below the A Sand interval. Neither of these datasets have been used to update the current mapping suite.

2.2.1.5.3 Depth Conversion

Velocity surveys from each of the four Thebaud wells (**Table 2.2.1.5.3.1**) were used to generate average velocity values to each of the mapped horizons.

Table 2.2.1.5.3.1: Thebaud Velocity Surveys

Well	Year Acquired	Checkshot Available	Checkshot Type	VSP Available	VSP Type
Thebaud P-84	1972	Yes	Vertical	No	NA
Thebaud I-94	1978	Yes	Vertical	No	NA
Thebaud I-93	1985	Yes	Vertical	No	NA
Thebaud C-74	1986	Yes	Vertical	Yes	Vertical

These discrete values were hand contoured for each horizon following trends extracted from the 1984 2D seismic stacking velocity data. Seismic lag maps were generated for each time mapped horizon using values calculated at every well and were used to lag correct each of the time structure maps. The gridded average velocity maps and the gridded corrected time structure maps were combined to create the depth structure maps. Depth maps on intermediate horizons were generated from hand contoured wellbore thickness data. The velocity and final depth maps are included in Part Two of this document (**DPA - Part 2, Ref. # 2.2.1.5.3.1**).

2.2.1.6 Petrophysics

A detailed petrophysical evaluation of all four wells in the Thebaud Field was conducted using all available wireline log data, conventional/special core analysis data (**DPA - Part 2, Ref. # 2.2.1.6.1**), and pressure data. A detailed summary of the interpretation parameters and methodology is included in this document (**DPA - Part 2 Ref. # 2.2.1.6.2**). The results of this evaluation are illustrated in **Tables 2.2.1.6.1** to **2.2.1.6.4**.

Table 2.2.1.6.1: Thebaud P-84 Project Reservoir Parameter Summary

Sand Unit	Measured Depth Top (m)	Measured Depth Base (m)	Elevation Top (m ss)	Elevation Base (m ss)	Gross Thickness (m)	Net Pay (m)	Average Porosity (%)	Average Sw (%)	Average Permeability* (mD)
A	3828.3	3855.0	-3799.6	-3826.3	26.7	25.4	18.3	29.3	82.4
B	3875.5	3920.0	-3846.8	-3891.3	44.5	15.1	10.5	60.0	4.5
F1	NDE	-	-	-	-	-	-	-	-
F3	NDE	-	-	-	-	-	-	-	-
G2	NDE	-	-	-	-	-	-	-	-
G3	NDE	-	-	-	-	-	-	-	-
H2	NDE	-	-	-	-	-	-	-	-

NDE - Not Deep Enough

* based on core analysis porosity vs permeability transforms

Table 2.2.1.6.2: Thebaud I-94 Project Reservoir Parameter Summary

Sand Unit	Measured Depth Top (m)	Measured Depth Base (m)	Elevation Top (m ss)	Elevation Base (m ss)	Gross Thickness (m)	Net Pay (m)	Average Porosity (%)	Average Sw (%)	Average Permeability* (mD)
A	3880.7	3912.0	-3850.8	-3882.1	31.2	26.0	19.5	42.5	76.1
B	3924.6	NDE	-3894.7	NDE	22.4 (min)	0.0	-	-	-
F1	NDE	-	-	-	-	-	-	-	-
F3	NDE	-	-	-	-	-	-	-	-
G2	NDE	-	-	-	-	-	-	-	-
G3	NDE	-	-	-	-	-	-	-	-
H2	NDE	-	-	-	-	-	-	-	-

NDE - Not Deep Enough

* based on core analysis porosity vs permeability transforms

Table 2.2.1.6.3: Thebaud I-93 Project Reservoir Parameter Summary

Sand Unit	Measured Depth Top (m)	Measured Depth Base (m)	Elevation Top (m ss)	Elevation Base (m ss)	Gross Thickness (m)	Net Pay (m)	Average Porosity (%)	Average Sw (%)	Average Permeability* (mD)
A	3912.8	3932.5	-3876.5	-3896.2	19.7	14.0	16.4	51.1	44.4
B	3949.3	3981.0	-3913.0	-3944.7	31.7	0.0	-	-	-
F1	4451.5	4461.2	-4415.2	-4424.9	9.7	0.0	-	-	-
F3	-	-	-	-	-	-	-	-	-
G2	4637.0	4644.6	-4600.7	-4608.3	7.6	0.0	-	-	-
G3	4652.0	4677.3	-4615.7	-4641.0	25.3	5.9	10.9	65.0	-
H2	4915.3	4929.5	-4879.0	-4893.2	14.2	9.1	9.8	54.0	-

* based on core analysis porosity vs permeability transforms

Table 2.2.1.6.4: Thebaud C-74 Project Reservoir Parameter Summary

Sand Unit	Measured Depth Top (m)	Measured Depth Base (m)	Elevation Top (m ss)	Elevation Base (m ss)	Gross Thickness (m)	Net Pay (m)	Average Porosity (%)	Average Sw (%)	Average Permeability* (mD)
A	3865.6	3888.1	-3823.8	-3846.3	22.6	18.8	17.8	49.9	36.3
B	3904.4	3943.4	-3862.6	-3901.6	39.0	25.2	15.4	45.0	112.5
F1	4306.5	4320.2	-4264.7	-4278.4	13.7	6.1	12.8	43.0	-
F3	4405.2	4427.7	-4363.4	-4385.9	22.5	15.2	18.8	19.0	-
G2	4478.3	4486.7	-4436.5	-4444.9	8.4	7.0	16.9	27.0	-
G3	4506.0	4523.0	-4464.2	-4481.2	17.0	12.3	17.0	33.0	-
H2	4747.0	4762.0	-4705.2	-4720.2	15.0	10.3	13.3	22.0	-

* based on core analysis porosity vs permeability transforms

Zonal average porosity ranges from 10 to 23 percent. The primary controls on porosity and permeability are average grain size, cementation and the presence of grain-rimming authigenic chlorite which preserves intergranular porosity. Porosity preservation in clean sands of the overpressured section is generally associated with the pervasive occurrence of grain-coating chlorite rims which inhibited the development of pore filling quartz overgrowths. High irreducible water saturations, believed to be related to the presence of grain-rimming authigenic chlorite, are observed in some horizons.

Porosity was calculated from both density and sonic log measurements. Bulk density calibrated to stressed core porosity measurements was the preferred method. Where the density log measurements were of poor quality, due to hole washout or gas effects, sonic log porosity was used. Both density and sonic log porosity calculations were corrected for shaliness, and where necessary the sonic log was corrected for gas effect.

The Archie equation was used to determine water saturations in all the reservoirs. The cementation and saturation exponent values were based on special core analysis and log data crossplots. True formation resistivity was determined from the deep induction measurement corrected for borehole effects and invasion. Formation water resistivity was based on a formation water salinity gradient determined from drillstem test recoveries, and formation temperature gradients.

An in situ porosity cutoff value of 8 percent was generally used to define net porous sand thickness. In some sands cutoff values between 6 and 14 percent were used, based on core and microlog data. These values were all determined from core data to correspond to an air permeability value of 0.1 mD at ambient conditions. A water saturation cutoff of 70 percent was used to define net pay.

In only a few cases do existing wells intersect the gas/water contact. Therefore, free water level estimates were based on bracketing of the contacts from wireline log analysis and drillstem test results, and capillary pressure measurements.

2.2.1.7 Gas In Place

Gas in place estimates for the Thebaud Field have been generated using deterministic and probabilistic methods. The probabilistic assessment of gas in place was conducted in 1995 and is described in **DPA - Part 2, Ref. # 2.2.1.7.1**. The summation of mean values from the output expectation curves generated for the seven Project sands is 26.0 E9M3. Results of the probabilistic assessment for each of the Project sands are shown in **Table 2.2.1.7.1**.

Table 2.2.1.7.1: Thebaud Probabilistic Estimates of Gas In Place, E9M3

Reservoir Sandstone	P90	P50	P10	Mean
A	6.3	11.9	20.6	**12.8**
B	0.7	1.6	3.3	**1.8**
F1	0.3	0.9	2.2	**1.1**
F3	1.1	2.7	6.0	**3.2**
G2	0.5	1.2	2.8	**1.5**
G3	1.0	2.3	5.3	**2.9**
H2	0.8	2.3	4.8	**2.7**
Project Total	10.7	22.9	45.0	**26.0**

Deterministic reservoir maps of the Thebaud Field were generated in 1987 and 1988. Gas in place estimates for Project sands shown in **Table 2.2.1.7.2** represent the unrisked volumes which include upside. The methodology and maps used to generate the deterministic gas in place estimates are contained in Part Two of this document (**DPA - Part 2, Ref. # 2.2.1.7.2 and 2.1.4.1**).

Table 2.2.1.7.2: Thebaud Deterministic Estimates of Gas In Place, E9M3

Reservoir Sandstone	Gas in Place
A	15.6
B	2.3
F1	0.7
F3	5.4
G2	2.9
G3	5.6
H2	7.1
Total	39.6

Some minor gas accumulations have been tested in Thebaud that are currently not included in the Project. Predominantly, these are hydropressured gas accumulations with probabilistic mean gas in place estimates between 0.1 and 0.3 E9M3.

2.2.2 VENTURE FIELD

2.2.2.1 Field History

In 1979, the discovery well, D-23, was drilled on the crest of the Venture structure. Gas was encountered in multiple, stacked, hydropressured and overpressured sandstone horizons. Top overpressure occurs at about 4500 metres in the Venture structure. Four delineation wells were subsequently drilled, B-13 (1981), B-43 (1982), B-52 (1983), and H-22 (1984). **Figure 2.2.2.1.1** illustrates the location of these wells on a depth structure map on the top Sand 6 reservoir horizon.

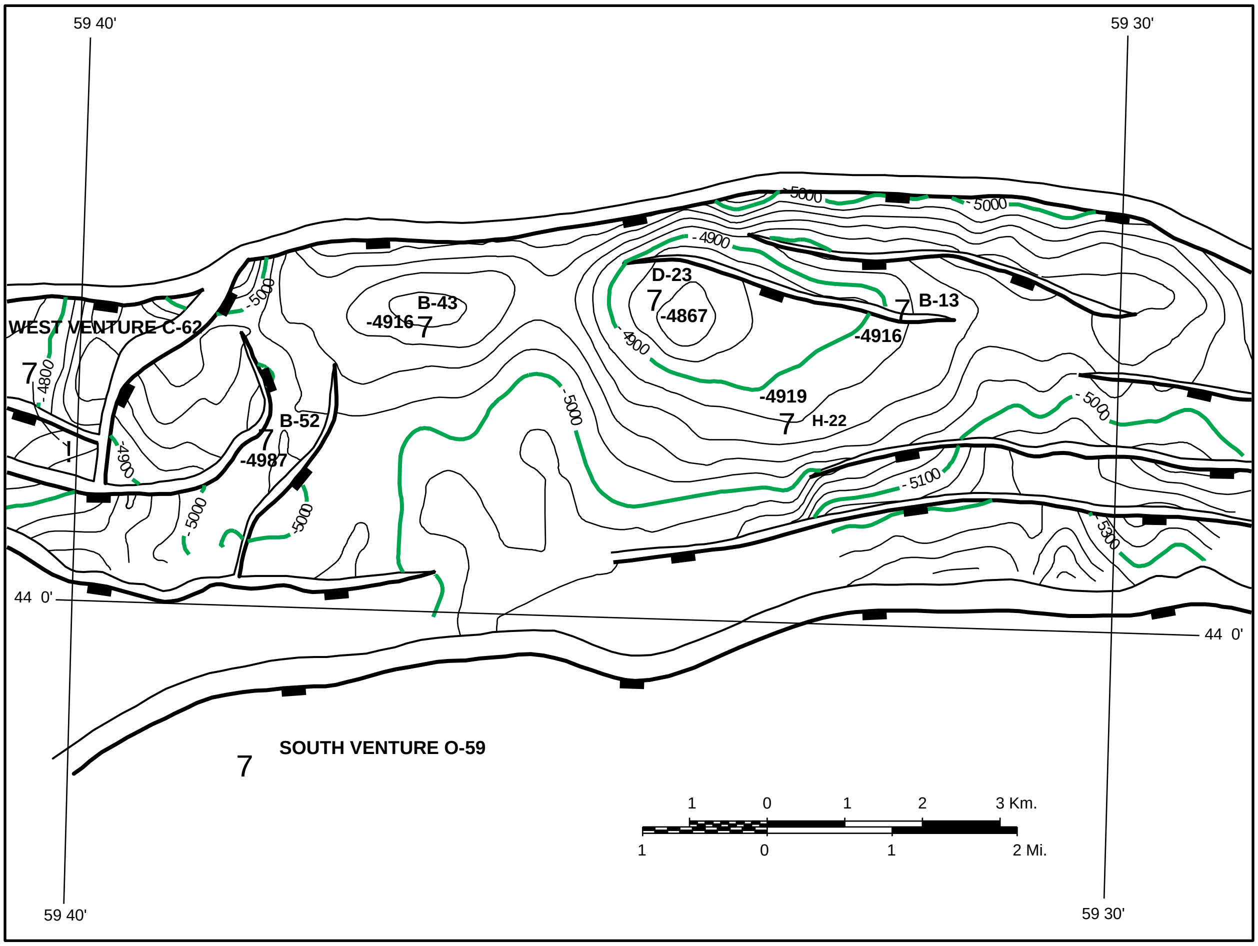


Figure 2.2.2.1.1: Venture Field - Top Sand 6 Depth Structure Map
Contour Interval: 20 metres

All four delineation wells were drilled deeper than the D-23 discovery, and encountered additional overpressured gas accumulations. The B-13, B-52, and H-22 wells, drilled structurally downdip of the discovery well, tested water in several sandstone horizons and provided control for the areal extent of these accumulations. The B-43 well drilled on a structural high west of the discovery well, flowed gas in nine sandstone reservoirs. The H-22 well encountered tighter sandstones in the deep overpressured section and provided a southerly limit to reservoir development in these horizons. Results indicate that the majority of reservoir horizons are continuous and correlatable throughout all five wells.

2.2.2.2 Structural Configuration

The Venture structure is an elongated rollover anticline situated on the downthrown side of a listric, down to the basin, east-west trending growth fault. The anticline is approximately 12 kilometres long by three kilometres wide and encompasses an area of about 30 square kilometres. The structure is characterized by the occurrence of two structural crests and an intervening saddle. The western high is located near the existing B-43 well, and the eastern high is located near the D-23 well. Some discontinuous east-west trending faults with minor offsets are mapped within the field on the eastern structural high. These faults are synthetic to the northern bounding growth fault.

2.2.2.3 Geology

The reservoir section in Venture is late Jurassic and early Cretaceous in age and is situated stratigraphically within the Mic Mac and lower Missisauga formations. As in the Thebaud Field, an impressive thickness of deltaic clastics is preserved within the Venture structure. Gas accumulations occur within a stratigraphic interval of approximately 1780 metres, from 4045 to 5825 metres R.T. in the existing wells. The principal reservoir sandstones occur within a 695 metre interval from 4406 to 5101 metres R.T. The two uppermost reservoir horizons, Sands 1 and 2, are hydropressured. The remaining reservoir sands are overpressured.

Gas is trapped in sandstones that occur within a vertically stacked, alternating sequence of sandstones, shales and limestones. This cyclic pattern of sedimentation is interpreted to represent episodic delta progradations interrupted by marine floods. Shales and limestones deposited during the major marine floods form the top seals to individual reservoir accumulations. The Venture Field reservoir section is characterized by the occurrence of several substantial limestone horizons. These limestones are encountered in all the Venture Field wells and are demonstrated by seismic to be areally extensive.

Pressure versus depth plots (**DPA - Part 2, Ref. # 2.1.2.1**) show that abrupt, ‘step like’ pressure increases take place in the overpressured section. This results in a series of overpressured zones, each more overpressured than the zone above. Certain individual pressure steps are related to the presence of limestones and calcareous sandstones. Pressure correlation between wells indicates that overpressure steps are stratigraphically controlled. Correlative sands within the overpressured zone of the five wells have similar pressures.

Figure 2.2.2.3.1 is a net pay thickness map for the Sand 6 Upper reservoir. Net pay is assigned to four wells and varies in thickness from 10.1 metres in H-22 to 14.8 metres in B-43. The B-52 well is the structurally lowest well at this horizon and is entirely water bearing. An estimated free water level at 4970 metres subsea is derived from well pressure data. Gas is trapped at the 6 Upper level predominantly by rollover closure, and a 110 metre vertical gas column is interpreted.

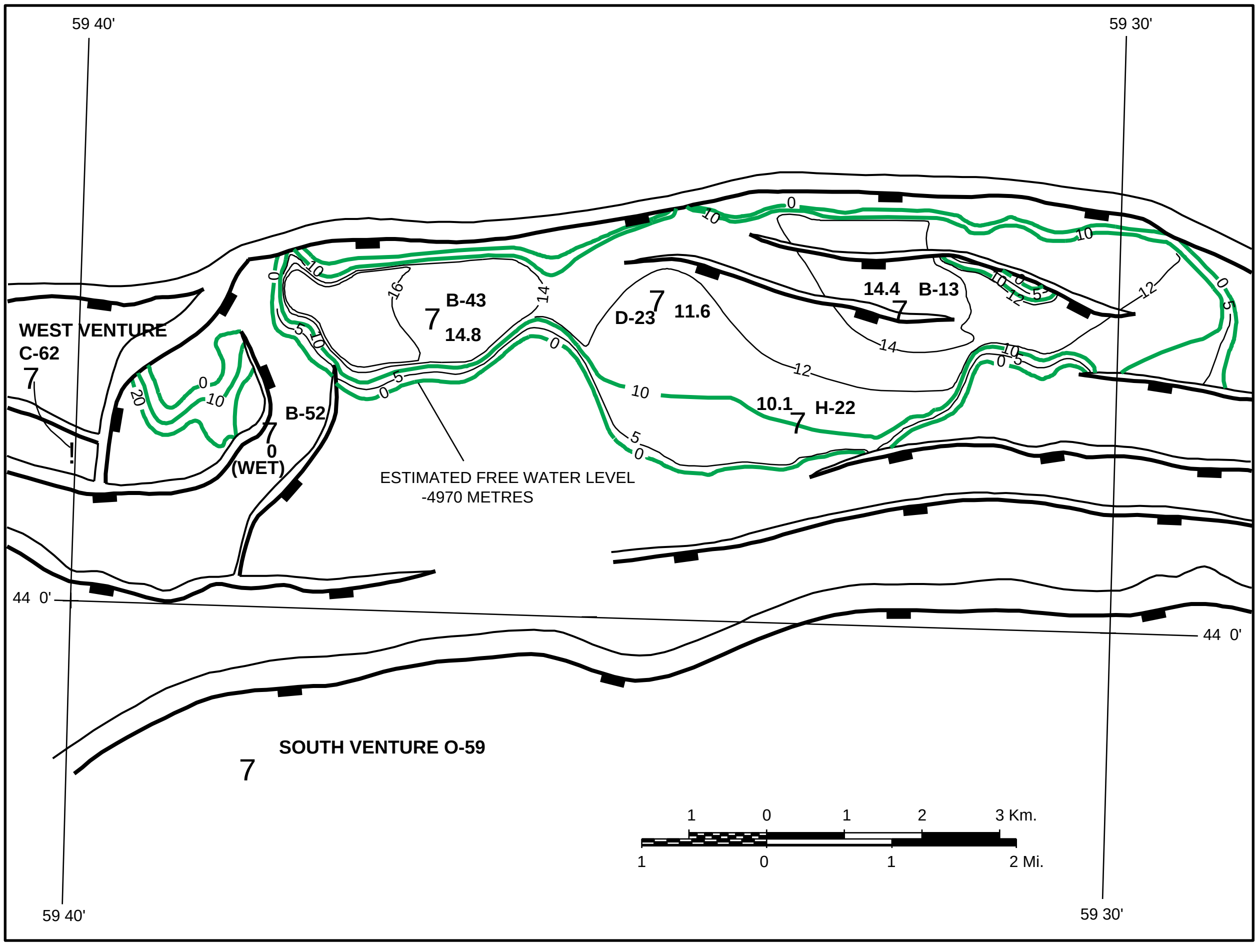


Figure 2.2.2.3.1: Venture Field - Sand 6 Upper Net Pay Thickness Map
Contour Interval: Variable, 2-10 metres

Detailed reservoir description studies of the Venture Field were conducted in 1985 and 1986 following the drilling of the H-22 well **(DPA - Part 2, Ref# 2.2.2.3.1 and 2.2.2.3.2)**. Gas accumulations were classified as major and minor sands on the basis of the size of the deterministic recoverable gas estimates. Four major sand reservoir accumulations were identified: the hydropressured Sand 2, and the overpressured Sands 3, 5, and 6 Upper. The general geological model used to construct reservoir thickness maps is of a north to south prograding delta complex. A consequent proximal to distal relationship is interpreted. Syndepositional movement on the north bounding fault is believed to influence sedimentation resulting in increased sand thickness northward toward the master fault.

2.2.2.4 Reservoir Zonation

The stratigraphic nomenclature for the reservoir section is shown in **Figure 2.2.2.4.1**, a schematic cross-section through the Venture Field. The naming convention assigned to these reservoir packages is applicable only to the Venture structure and wells drilled to the west of Venture within the same growth fault trend. There is good confidence in correlation of reservoir sandstone packages down to the 9 Limestone horizon. Confidence in correlation declines gradually with depth below this horizon due to reduced wellbore penetrations and reduced seismic data quality.

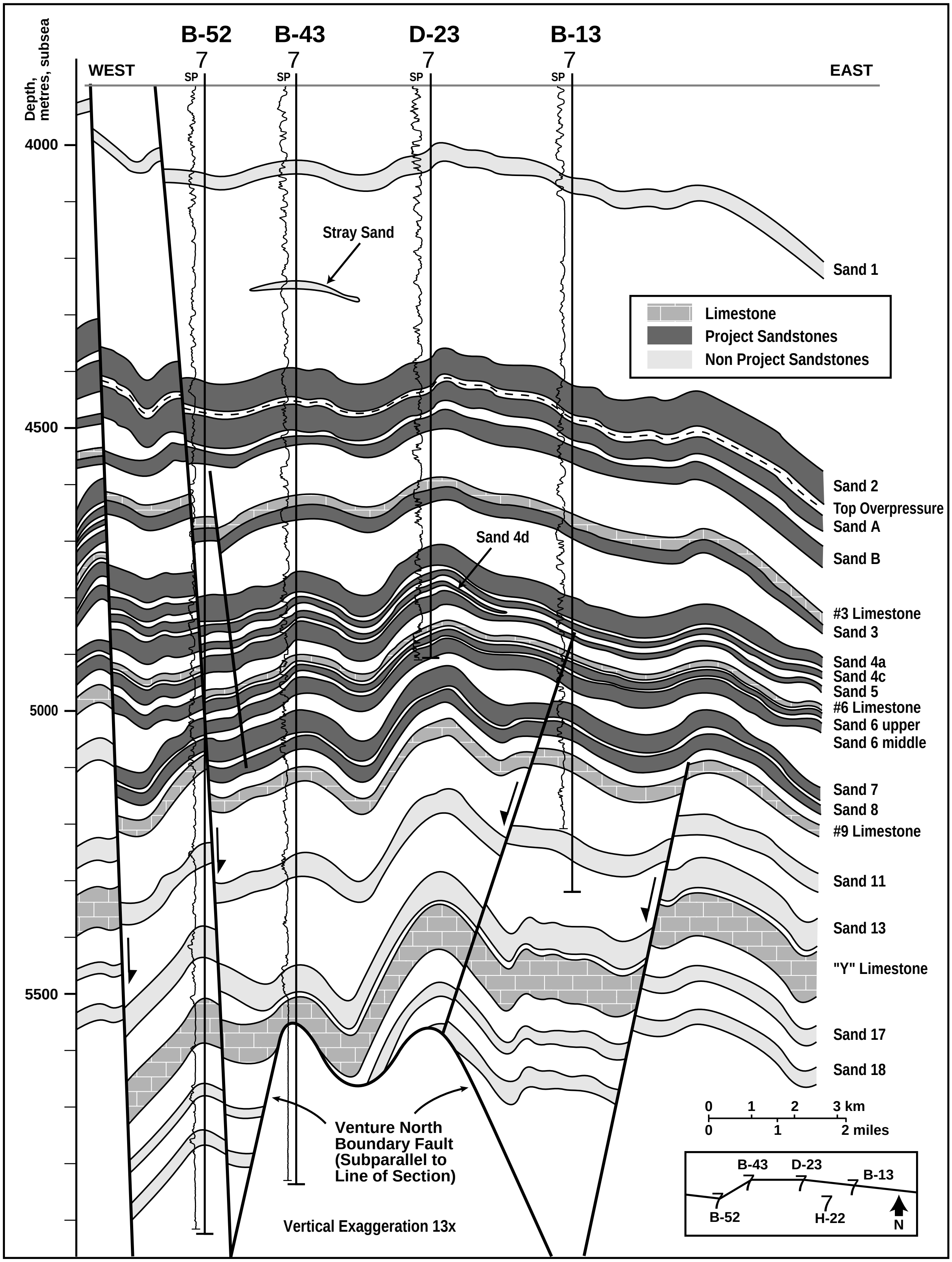


Figure 2.2.2.4.1: Venture Schematic Structural Cross-section

The deterministic reservoir studies conducted during the 1980's subdivided major sands into reservoir rock type layers for input to reservoir simulation models. The volumetrically significant minor sand reservoirs were mapped as single layers for input to simulation studies.

2.2.2.5 Geophysics

2.2.2.5.1 Seismic Database

The Venture Field is covered by many vintages of seismic data. A summary of acquisition and processing details for several of the datasets is included in **Table 2.2.2.5.1.1**. The data density and quality at the level of the major Sands (2, 3, 5, and 6) level is good to very good. Incorporated with the well data, the seismic generates a high level of confidence in the mapped intervals. Seismic continuity, frequency content and well control decreases, and mapping confidence declines slightly at depths below the 9 Limestone. The depth structure maps used for gas in place estimates are based on the 2D seismic data illustrated in **Figure 2.2.2.5.1.1.**

Table 2.2.2.5.1.1: Venture Acquisition and Processing Summary

Data Type	Survey Name	Incorp. In Study	Acq. Date	Acq. Style	Proc. Date	Field Kms	Proc. Details	Comments
2D	8624-M003-047E	Yes	1983	Marine Airgun-Digiseis Aquaflex-Digiseis	1983-84	356	60 fold Decon before and after stack, FD migration	Generally good to very good quality. Deteriorating with depth
2D	8624-M003-049E	Yes	1984	Marine Airgun-Digiseis Aquaflex-Digiseis	1984-85	121	60 fold Decon before and after stack, FD migration	Good to very good quality Deteriorating with depth
2D	8624-M003-45E	Yes	1982	Marine	1982-83	limited	60 fold DBS, DAS FK migration	Good quality data
2D	8620-S014-006E	No	1983	Marine	1983-84	42	60 fold Desig, Decon after stack, FD migration	Fair to good quality data, lower frequency
2D	8624-M003-041E	No	1981	Marine	1981-82	10	72 fold Desig, Decon after stack, FD migration	Good quality data, lower frequency
2D	8624-M003-035E	No	1980	Marine	1980-81	68	48 fold Desig, Decon after stack, FD migration	Generally good quality data, lower frequency
2D	8624-M003-033E	No	1979	Marine	1979-80	172	60 fold Decon before and after stack, FD migration	Fair to good quality, lower frequency

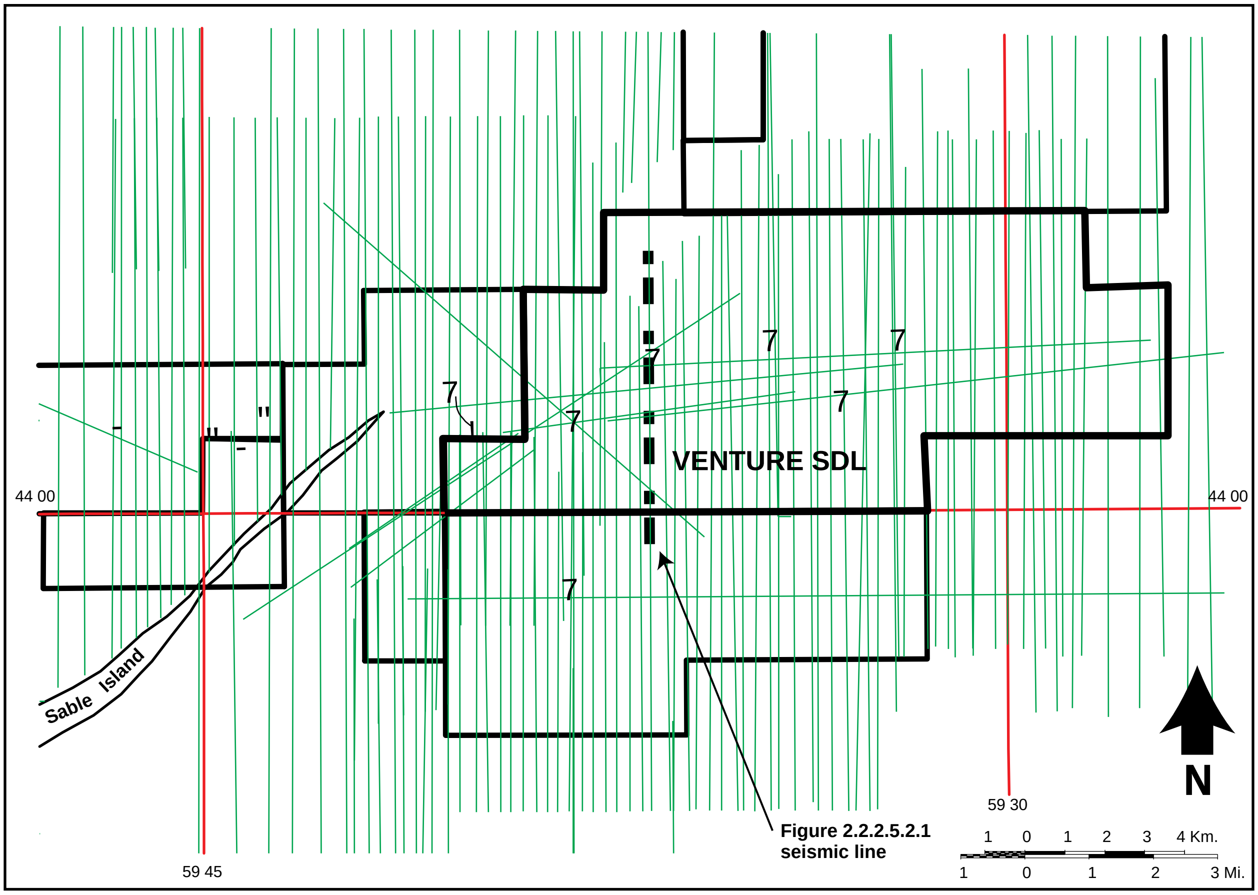


Figure 2.2.2.5.1.1: Venture Seismic Database Map

The maps used for gas in place (GIP) calculations at Venture are based on time and depth structure maps made in 1985 using the 1983 and 1984 datasets. The 1983 survey is the largest of the two and consists of 52 lines with a total of 356 line kilometres. The 1983 survey has only two strike lines over Venture. These strike lines, do however, run from west to east through the available well control. The dip lines have an east to west line spacing of approximately 300 metres over the crest and most of the flanks of the Venture structure. The extreme east and west flanks have a dip line spacing of approximately 600 metres. In the transition zone portion of this survey, data were successfully acquired via a radio telemetry, buoy-based system using airgun and aquaflex energy sources.

In 1984, a smaller combined standard marine and transition zone 2D survey was acquired to address the faulting associated with the B-52 well and to infill the flanking 600 metre dip line spacing.

2.2.2.5.2 Time Interpretation

The time and depth structure maps made in 1985 can be found in Part 2 of this submission (**DPA - Part 2, Ref. # 2.2.2.5.2.1 and 2.2.2.5.3.1**). This interpretation was generated primarily on paper sections that were hand timed, posted and contoured.

Checkshot survey corrected synthetic seismograms, generated at each well by convolving a minimum phase wavelet with an acoustic impedance series derived from wireline log sonic and density information, were used to tie well lithology to the seismic data. The B-52 VSP was also used to improve the well data to seismic reflector tie.

A number of horizons were picked and the 2 Sand, 3 Sand, 6 Limestone, 9 Limestone and Y Marker horizons were taken to final mapped form and used as the basis for the depth structure maps. The horizon markers at each of the wells are indicated in **Table 2.2.2.5.2.1**.

Table 2.2.2.5.2.1: Venture Horizon Markers

FIELD	VENTURE										OLYMPIA	
	D-23		B-43		B-13		B-52		H-22		A-12	
MAP HORIZON	Depth (M, ss)	TWT (sec)	Depth (M, ss)	TWT (sec)	Depth (M, ss)	TWT (sec)	Depth (M, ss)	TWT (sec)	Depth (M, ss)	TWT (sec)	Depth (M, ss)	TWT (sec)
#2 SANDSTONE	-4374.3	3079	-4389.2	3083	-4420.1	3110	-4415.8	NR	-4463.6	NR	-4339.0	NR
#3a Sand	-4612.0	3182	-4639.0	3195	-4680.2	3219	-4675.6	3200	-4678.3	3224	-4639.0	3042
#6 LIMESTONE	-4867.0	3303	-4916.0	3322	-4914.0	3342	-4988.0	3345	-4918.0	3329	-4959.0	NR
#9 LIMESTONE	NDE	NDE	-5100.9	3437	-5077.9	3440	-5102.6	Fault	-5063.8	3422	-4680.0	3222
" Y " LIMESTONE	NDE	NDE	NR	NR	NDE	NDE	-5506.6	3637	-5428.9	3610	-5040.0	NR

NDE - Not Deep Enough; NR - No Reflection

Several attribute projects and one principal component analysis were carried out after the Venture mapping project. The studies were based on a pseudo-3D seismic dataset generated from the 1983 2D survey. These studies supported the deterministic reservoir mapping, but results were restricted by the limited bandwidth and data quality of the seismic dataset. **Figure 2.2.2.5.2.1** is a representative seismic line illustrating data quality and structural geometry. The location of this line is shown as a bold dashed line on **Figure 2.2.2.5.1.1**.

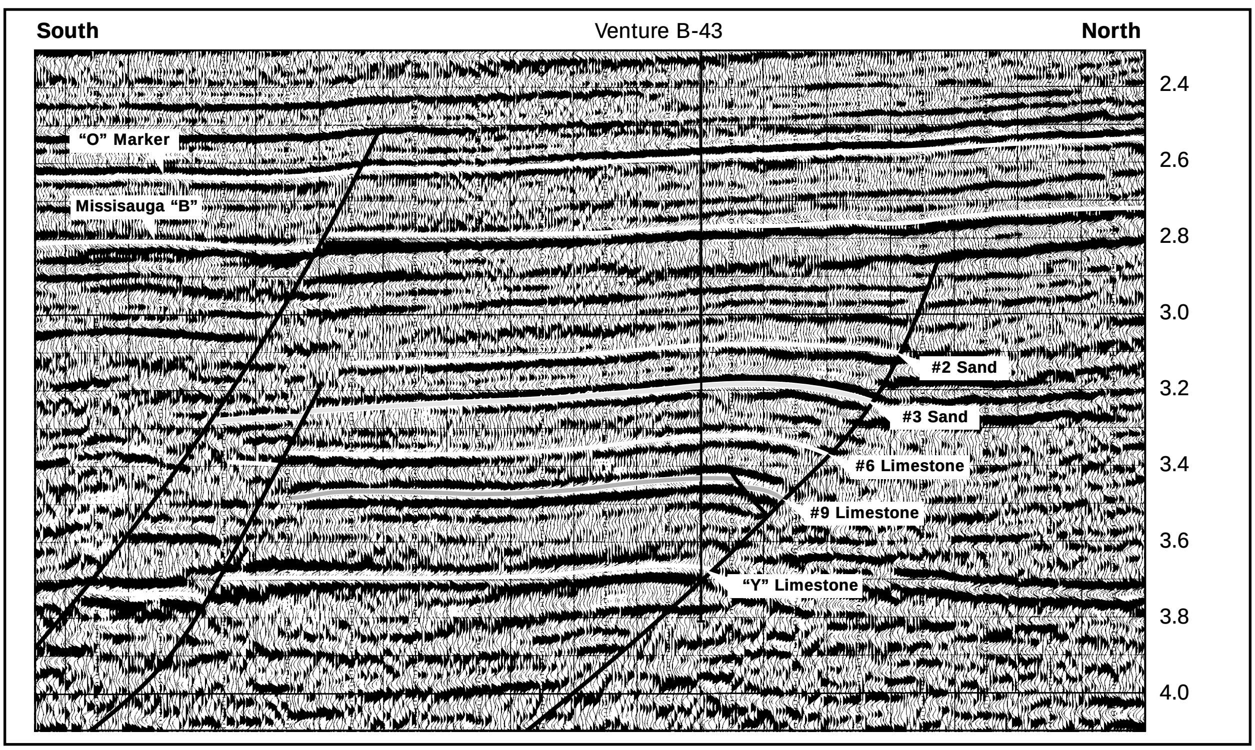


Figure 2.2.2.5.2.1 Venture Seismic Line

2.2.2.5.3 Depth Conversion

The method and details of the depth conversion technique used at Venture are documented in Part Two of this document (**DPA - Part 2, Ref. # 2.2.2.5.3.1**). The final depth conversion was completed in 1985 and incorporated the 1984 survey and adjacent well results into the time interpretation. Time structure maps for five horizons (2 Sand, 3 Sand, 6 Limestone, 9 Limestone and the Y Limestone) were digitized and gridded.

Velocity surveys from the five Venture wells, South Venture O-59 and Olympia A-12 (**Table 2.2.2.5.3.1**), were used to generate average velocity values to each of the mapped horizons.

Table 2.2.2.5.3.1: Venture Velocity Surveys

Well	Year Acquired	Checkshot Available	Checkshot Type	VSP Available	VSP Type
Venture D-23	1979	Yes	Vertical	No	NA
Venture B-13	1981	Yes	Vertical	No	NA
Venture B-43	1982	Yes	Vertical	No	NA
Venture B-52	1983	Yes	Vertical	Yes	Vertical
Venture H-22	1984	Yes	Vertical	No	NA
South Venture O-59	1983	Yes	Vertical	No	NA
West Venture C-62	1985	Yes	Deviated Well	No	NA
Olympia A-12	1983	Yes	Vertical	No	NA

The discrete points were then hand contoured for each horizon following trends present in the 1983 and 1984 2D seismic stacking velocity data. Seismic lag maps were generated for each time mapped horizon using values calculated at each well and used to time lag correct the time structure maps to the well velocity data. The gridded average velocity maps and the gridded corrected time structure maps were combined to create depth structure maps. Intermediate depth maps were generated from hand contoured wellbore thickness data.

2.2.2.6 Petrophysics

A detailed petrophysical evaluation of all five wells in the Venture Field was conducted using all available wireline log data, conventional/special core analysis data (**DPA - Part 2, Ref. # 2.2.2.6.1**), and pressure data. A detailed summary of the interpretation parameters and methodology is given in Part Two of this documents (**DPA - Part 2, Ref. # 2.2.2.6.2)**. The results of this evaluation are shown in **Tables 2.2.2.6.1 to 2.2.2.6.5**.

Table 2.2.2.6.1: Venture D-23 Project Reservoir Parameter Summary

Sand Unit	Measured Depth Top (m)	Measured Depth Base (m)	Elevation Top (m ss)	Elevation Base (m ss)	Gross Thickness (m)	Net Pay (m)	Average Porosity (%)	Average 'J' Sw (%)	Average Permeability* (mD)
2	4406.0	4452.6	-4374.3	-4420.9	46.6	15.7	11.1	34.3	2.8
A	4464.0	4497.0	-4432.3	-4465.3	33.0	0.0	-	-	-
B	4514.0	4541.0	-4482.3	-4509.3	27.0	7.3	13.7	50.0	0.6
3	4641.8	4665.0	-4610.1	-4633.3	23.2	16.3	19.9	41.4	21.3
4a&b	4747.0	4775.0	-4715.3	-4743.3	28.0	9.7	16.2	60.0	0.6
4c	4786.0	4801.0	-4759.3	-4769.3	10.0	5.8	15.1	36.7	0.6
4d	4811.0	4819.0	-4779.3	-4787.3	8.0	2.9	15.4	48.0	0.6
5	4829.2	4856.7	-4797.5	-4825.0	27.5	13.5	20.4	31.5	32.0
6u	4898.8	4912.5	-4867.1	-4880.8	13.7	11.6	21.2	31.8	65.6
6m	4916.2	4941.6	-4884.5	-4909.9	25.4	20.2	18.7	40.6	179.2
7	NDE	-	-	-	-	-	-	-	-
8	NDE	-	-	-	-	-	-	-	-

NDE - Not Deep Enough

* based on core analysis porosity vs permeability transforms

Table 2.2.2.6.2: Venture B-13 Project Reservoir Parameter Summary

Sand Unit	Measured Depth Top (m)	Measured Depth Base (m)	Elevation Top (m ss)	Elevation Base (m ss)	Gross Thickness (m)	Net Pay (m)	Average Porosity (%)	Average 'J' Sw (%)	Average Permeability* (mD)
2	4454.2	4505.4	-4420.1	-4471.3	51.2	27	14.4	39.4	62.5
A	4520.0	4552.0	-4485.9	-4517.9	32.0	9.1	13.7	60.0	0.6
B	4567.0	4602.0	-4532.9	-4567.9	35.0	9.8	14.8	62.3	1.0
3	4714.3	4738.8	-4680.2	-4704.7	24.5	6.7	19.1	76.4	38.3
4a	4833.0	4849.0	-4798.9	-4814.9	16.0	0.0	-	-	-
4c	4877.0	4891.0	-4842.9	-4856.9	14.0	10.5	14.8	55.0	26.5
4d	-	-	-	-	-	-	-	-	-
5	4897.0	4907.0	-4862.9	-4872.9	10.0	0.0	-	-	-
6u	4949.6	4964.0	-4915.5	-4929.9	14.4	14.4	18.7	39.4	47.3
6m	4969.2	4994.0	-4935.1	-4959.9	24.8	14.6	17.9	71.4	6.0
7	5017.0	5029.0	-4982.9	-4994.9	12.0	10.5	14.4	72.0	4.4
8	5057.0	5084.0	-5022.9	-5049.9	27.0	14.2	16.1	60.0	2.5

* based on core analysis porosity vs permeability transforms

Table 2.2.2.6.3: Venture B-43 Project Reservoir Parameter Summary

Sand	Measured Depth		Elevation		Gross	Net	Average	Average	Average
Unit	Top	Base	Top	Base	Thickness	Pay	Porosity	‘J’ Sw	Permeability*
	(m)	(m)	(m ss)	(m ss)	(m)	(m)	(%)	(%)	(mD)
	(m)	(m)	(m ss)	(m ss)	(m)	(m)	(%)	(%)	(mD)
2	4423.3	4474	-4389.2	-4439.9	50.7	14.7	8.6	48	0.3
A	4487.0	4534.0	-4452.9	-4499.9	47.0	5.9	13.5	53.0	0.5
B	4543.0	4567.0	-4508.9	-4532.9	24.0	3.5	15.7	49.0	1.6
3	4673.1	4697.8	-4639.0	-4663.7	24.7	21.3	23.1	45.0	210.2
4a	4788.0	4806.0	-4753.9	-4771.9	18.0	7.3	17.2	57.0	1.0
4c	4832.0	4843.0	-4797.9	-4808.9	11.0	2.6	12.9	60.0	0.3
4d	4857.0	4870.0	-4822.9	-4835.9	13.0	5.8	19.7	47.0	2.3
5	4876.3	4909.7	-4842.2	-4875.6	33.4	12.3	18.6	35.4	25.7
6u	4950.0	4964.8	-4915.9	-4930.7	14.8	14.8	20.2	37.0	79.3
6m	4976.6	5002.8	-4942.5	-4968.7	26.2	7.1	20.6	70.0	21.0
7	5028.0	5060.0	-4993.9	-5025.9	32.0	11.3	15.9	49.6	25.6
8	5077.0	5101.0	-5042.9	-5066.9	24.0	13.4	18.6	37.0	9.5

* based on core analysis porosity vs permeability transforms

Table 2.2.2.6.4: Venture B-52 Project Reservoir Parameter Summary

Sand	Measured Depth		Elevation		Gross	Net	Average	Average	Average
Unit	Top	Base	Top	Base	Thickness	Pay	Porosity	‘J’ Sw	Permeability*
	(m)	(m)	(m ss)	(m ss)	(m)	(m)	(%)	(%)	(mD)
2	4451.2	4499.6	-4415.8	-4464.2	48.4	0.0	-	-	-
A	4513.0	4568.0	-4477.6	-4532.6	55.0	0.0	-	-	-
B	4575.0	4601.0	-4539.6	-4565.6	26.0	0.0	-	-	-
3	4711.0	4734.9	-4675.6	-4699.5	23.9	12.2	19.2	79.4	13.6
4a	4836.0	4859.0	-4800.6	-4823.6	23.0	0.0	-	-	-
4c	4886.0	4901.0	-4850.6	-4865.6	15.0	0.0	-	-	-
4d	4920.0	4932.0	-4884.6	-4896.6	12.0	3.8	17.8	90.0	1.3
5	4944.3	4974.9	-4908.9	-4939.5	30.6	11.8	13.5	73.0	1.8
6u	5022.8	5047.2	-4987.4	-5011.8	24.4	0.0	-	-	-
6m	5064.1	5085.1	-5028.7	-5049.7	21.0	0.0	-	-	-
7	5113.0	5132.0	-5077.6	-5096.6	19.0	0.0	-	-	-
8	(faulted)	-	-	-	-	0.0	-	-	-

* based on core analysis porosity vs permeability transforms

Table 2.2.2.6.5: Venture H-22 Project Reservoir Parameter Summary

Sand Unit	Measured Depth Top (m)	Measured Depth Base (m)	Elevation Top (m ss)	Elevation Base (m ss)	Gross Thickness (m)	Net Pay (m)	Average Porosity (%)	Average 'J' Sw (%)	Average Permeability* (mD)
2	4502.0	4535.6	-4463.6	-4497.2	33.6	0	-	-	-
A	4546.0	4577.0	-4507.6	-4538.6	31.0	1.4	11.3	95.0	0.2
B	4594.0	4619.0	-4555.6	-4580.6	25.0	0.0	-	-	-
3	4716.7	4736.8	-4678.3	-4698.4	20.1	8.0	17.7	88.4	1.6
4a	4816.0	4833.0	-4777.6	-4794.6	17.0	1.4	11.0	95.0	0.1
4c	4861.0	4870.0	-4822.6	-4831.6	9.0	5.6	12.7	68.0	0.2
4d	4884.0	4891.0	-4845.6	-4852.6	7.0	0.0	-	-	-
5	4896.6	4920.0	-4858.2	-4881.6	23.4	0.0	-	-	-
6u	4957.5	4970.9	-4919.1	-4932.5	13.4	10.1	17.7	46.1	11.3
6m	4974.5	4998.2	-4936.1	-4959.8	23.7	6.8	17.4	90.2	1.9
7	5020.0	5033.0	-4981.6	-4994.6	13.0	12.2	17.2	52.0	19.2
8	5054.0	5079.0	-5015.6	-5040.6	25.0	6.1	18.3	58.0	1.3

* based on core analysis porosity vs permeability transforms

Zonal average porosity ranges from nine to 23 percent. The primary controls on porosity and permeability are average grain size, dissolution of unstable framework grains and the presence of early authigenic chlorite which inhibited the development of porosity occluding quartz-overgrowth cement. Water saturated microporosity associated with the grain-coating chlorite is believed responsible for the high irreducible water saturation values calculated in most overpressured gas sands.

Porosity was calculated from both density and sonic log measurements. Density porosity, calibrated to stressed core porosity measurements, was the preferred method. Where the density log measurements were of poor quality due to hole washout or gas effect, shale-corrected sonic log porosity was used.

The calculation of water saturation incorporated both wireline log data and capillary pressure data from core analysis. Although the two measurements compared favourably in most gas reservoirs, mud filtrate invasion in water bearing reservoirs was often deep enough to render the induction tools unreliable in the calculation of water saturation. Consequently, water saturation was determined primarily from capillary pressure data and the Leverett-J function equation (**DPA - Part 2, Ref. # 2.2.2.6.3**).

The Archie equation was used for wireline log water saturation calculations. Cementation and saturation exponents were determined from special core analysis measurements. True formation resistivity was determined from the deep induction measurement. Formation water resistivity was derived using a salinity gradient from DST formation water recoveries, and a formation temperature gradient determined from corrected bottom hole temperature measurements.

Net porous sand cutoff parameters were selected to correspond with a minimum permeability cutoff value of 0.1 mD to air at ambient conditions. A porosity cutoff value of 10 percent at in situ condition was generally found to be appropriate based upon drillstem tests and core analysis data. No water saturation cutoff was employed in the mapping of these reservoirs.

In only a few cases do existing wells intersect the gas/water contact. Consequently, free water levels were estimated using pressure data, and bracketing of the contacts from wireline log analysis and drillstem test results.

2.2.2.7 Gas in Place

Gas in place estimates for the Venture Field have been generated using deterministic and probabilistic methods. The probabilistic assessment of gas in place was conducted in 1995 and the methodology is described in detail in Part Two (**DPA - Part 2, Ref. # 2.2.2.7.1**). The summation of mean values from the output expectation curves generated for the 12 Project sands is 49.2 E9M3. Results of this probabilistic assessment for each of the Project sands are shown in **Table 2.2.2.7.1**.

Table 2.2.2.7.1: Venture Probabilistic Estimates of Gas In Place (E9M3)

Reservoir Sandstone	P90	P50	P10	Mean
2	2.5	6.2	12.2	**7.0**
A	0.2	0.8	2.1	**1.0**
B	0.5	1.4	3.3	**1.7**
3	2.9	5.9	11.1	**6.5**
4a	0.4	1.0	3.0	**1.4**
4c	0.5	1.4	3.7	**1.8**
4d	0.3	1.0	3.5	**1.6**
5	1.8	5.0	12.2	**6.2**
6u	4.6	9.1	16.8	**10.1**
6m	2.2	4.8	10.1	**5.6**
7	1.0	2.4	5.5	**2.9**
8	1.2	2.9	6.2	**3.4**
Project Total	18.1	41.9	89.7	**49.2**

Deterministic reservoir maps of the Venture Field were generated in 1985 and 1986. Gas in place estimates for Project sands are shown in **Table 2.2.2.7.2** and represent unrisked volumes.

Table 2.2.2.7.2: Venture Deterministic Estimates of Gas In Place (E9M3)

Reservoir Sandstone	Gas in Place
2	15.2
A	1.8
B	2.7
3	9.7
4a	2.1
4c	1.5
4d	2.2
5	10.3
6u	12.9
6m	4.3
7	3.7
8	4.7
Total	71.1

Structure maps were constructed for each reservoir sandstone based on the seismic depth maps generated at five seismic horizons. A reservoir map suite was constructed for each rock type in the four major sands and the 6 Middle Sands. The reservoir map suite consists of a structure map, a gross thickness map, a net-to-gross ratio map, an isoporosity map, and an isopermeability map. The same reservoir map suite was constructed for the following minor reservoir Sandstones; A, B, 4a, 4c, 4d, 7, 8, and the deep Sand 11 accumulation. Remaining minor gas accumulations were commonly encountered in only one well. In these cases, single well areal assignments were applied for deterministic calculation, or, as with Sand 1, a prior 1984 generation map suite was used. Individual reservoir and rock type maps are included in Part Two (**DPA - Part 2, Ref .# 2.2.2.3.1, 2.2.2.3.2, & 2.2.2.6.3**).

Some minor gas accumulations in the Venture Field are not currently included in the Project. Predominantly, these are deep overpressured sands below the 9 Limestone horizon. The larger of these accumulations, in Sands 11 and 13, have mean probabilistic gas in place estimates of 1.9 and 1.2 E9M3, respectively. These horizons are not included in the development plan because of their estimated small volumes and associated projected high drilling and production costs.

2.2.3 NORTH TRIUMPH FIELD

2.2.3.1 Field History

The North Triumph Field was discovered in 1986 (**DPA - Part 2, Ref. # 2.2.3.1.1**). The discovery well, North Triumph G-43, encountered hydropressured gas in sands at the top of the Missisauga Formation. Gas was tested at rates between 991 to 1047 E3M3/d. Follow-up drilling consists of one downdip appraisal well, North Triumph B-52. This well encountered the gas/water contact of the single gas pool comprising the field. **Figure 2.2.3.1.1** illustrates the structure at the top of the gas bearing Missisauga Formation in North Triumph.

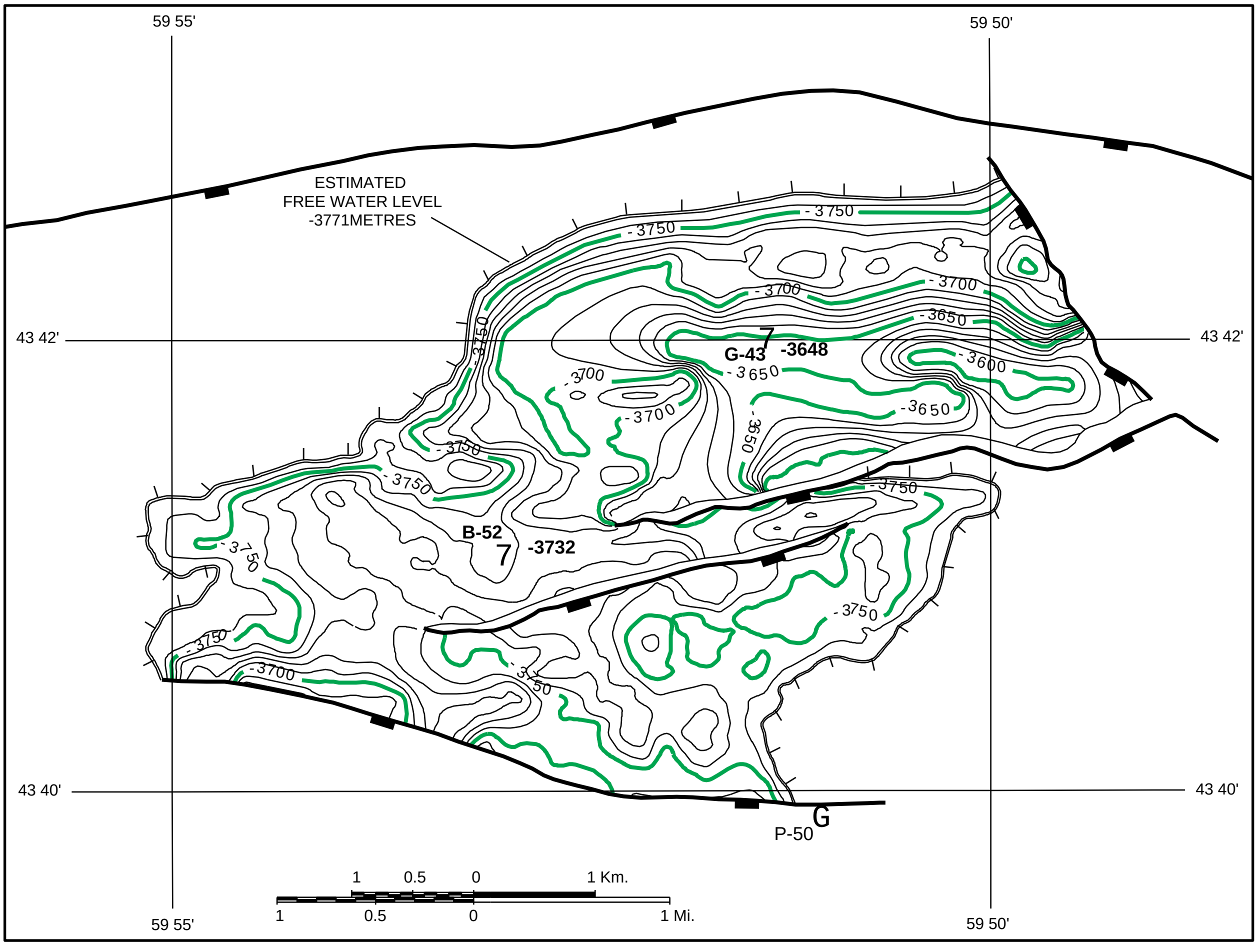


Figure 2.2.3.1.1: North Triumph - Top Missisauga Depth Structure Map
Contour Interval: 10 metres

2.2.3.2 Structural Configuration

The North Triumph structure consists of a rollover anticline bounded to the north and south by major listric growth faults. The north bounding fault downdrops to the south, and the top Missisauga level is offset by 600 to 650 metres. The southern boundary of the structure is marked by a fault system which drops the top Missisauga down to the south by as much as 1250 metres. Internally, the rollover anticline is partially dissected by two lesser en-echelon faults (**DPA - Part 2, Ref. # 2.2.3.2.1**). The field lies at a depth of 3640 metres subsea and extends over an area of 19 square kilometres.

Simple closure is provided to the north by rollover into the governing growth fault, and to the west by plunge of the anticline. Cross-fault seal is present to the east due to juxtaposition of the Upper Missisauga reservoir sands with Verrill Canyon shales. Cross-fault and/or fault-smear seal occurs across the southern bounding fault, where the Upper Missisauga reservoir sands are juxtaposed with interbedded sands and shales of the lower Logan Canyon Formation.

2.2.3.3 Geology

Hydropressured gas is trapped in a single pool within stacked sandstones in the uppermost part of the Missisauga Formation. Structural mapping indicates a gas column of 171 metres extending from the crest of the rollover anticline to the gas/water contact intercepted in the B-52 well.
The gas-bearing uppermost 100 metres of the Missisauga Formation consists of an upward coarsening and cleaning succession which is shale-dominated at its base, with an increasing sandstone content upward. This succession represents deposition from a prograding delta complex. It is composed of a number of smaller scale coarsening and cleaning upward cycles which resulted from progradation of successive individual delta lobes into the area. Log correlation of these cycles is good between the two wells, indicating stratigraphic continuity over most, if not all, of the North Triumph structure (**DPA- Part 2, Ref. # 2.2.3.3.1 through 2.2.3.3.3**). Pressure data also indicates continuity of these sandstones between the wells.

The reservoir development model implemented in the feasibility stage of this Project and used for gas in place determination at North Triumph is one of a north to south thinning wedge. This model combines the effects of a northerly source for the sands with syndepositional downward movement on the northern bounding growth fault. The latter acts to trap most of the reservoir quality sand in the northern portion of the field. According to this model, reservoir development decreases from a maximum of 45 meters adjacent to the northern bounding fault, to 38 meters at G-43, and thins linearly to 23 meters at the B-52 well. Thickness is then held constant to the southern extent of the field.

Convolution of this model with the structure map and recognized gas/water contact at -3771 m SS permits construction of a net pay map (**Figure 2.2.3.3.1**).

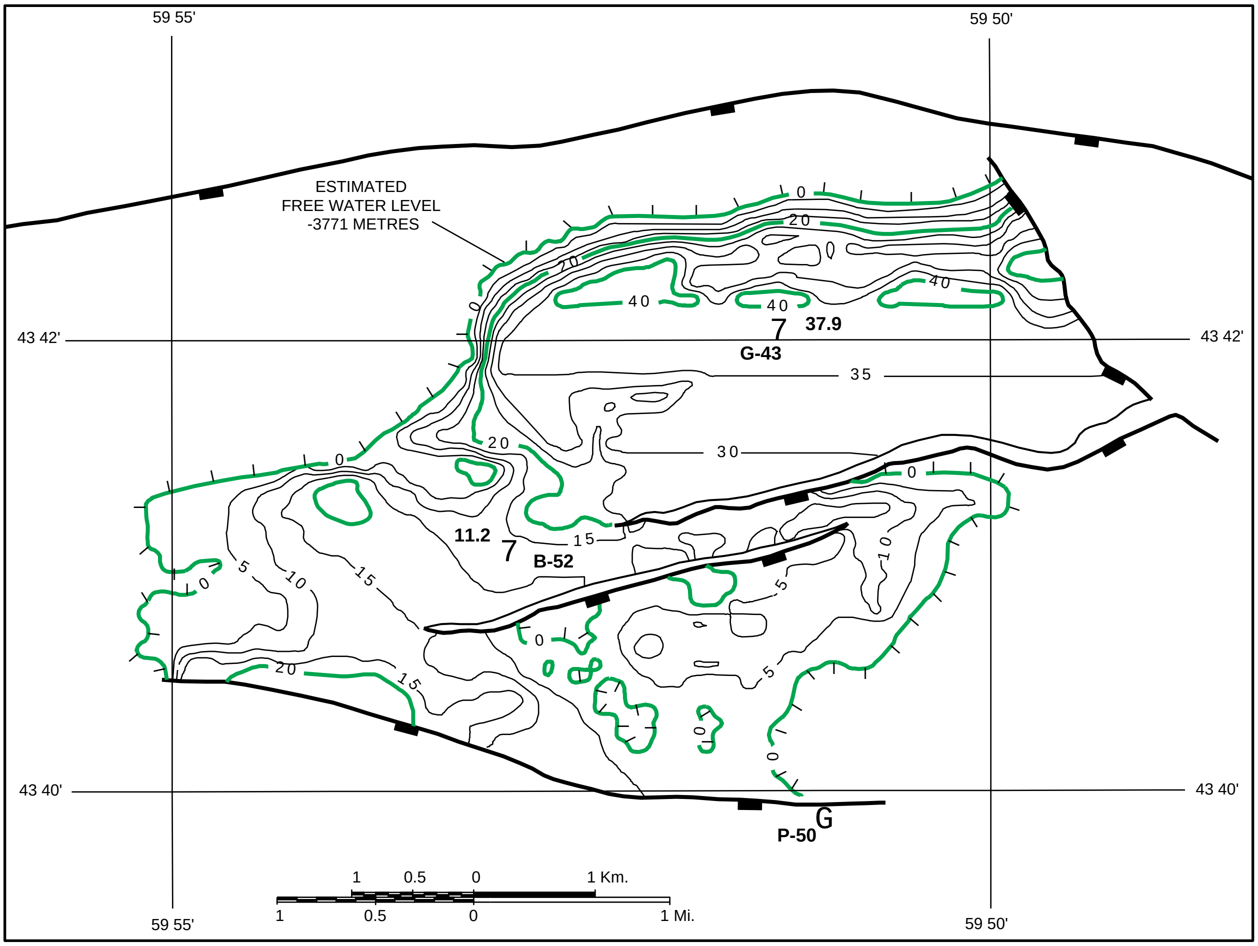


Figure 2.2.3.3.1: North Triumph - Net Pay Map
Contour interval 5 metres

2.2.3.4 Reservoir Zonation

The sands containing gas in the North Triumph Field are in pressure communication, so there has been no need to subdivide the reservoir section into different zones. The single gas pool is termed the A Pool. It lies within a 100 metre thick, coarsening-upward, shale-to-sandstone succession, which is termed the A Reservoir Zone. This is illustrated in **Figure 2.2.3.4.1**. In the initial modeling of the recoverable gas reserves, the reservoir interval has been internally subdivided into 'flow units' on the basis of petrophysical attributes and a detailed facies model (**DPA - Part 2, Ref. # 2.2.3.3.3 & 2.2.1.3.3**).

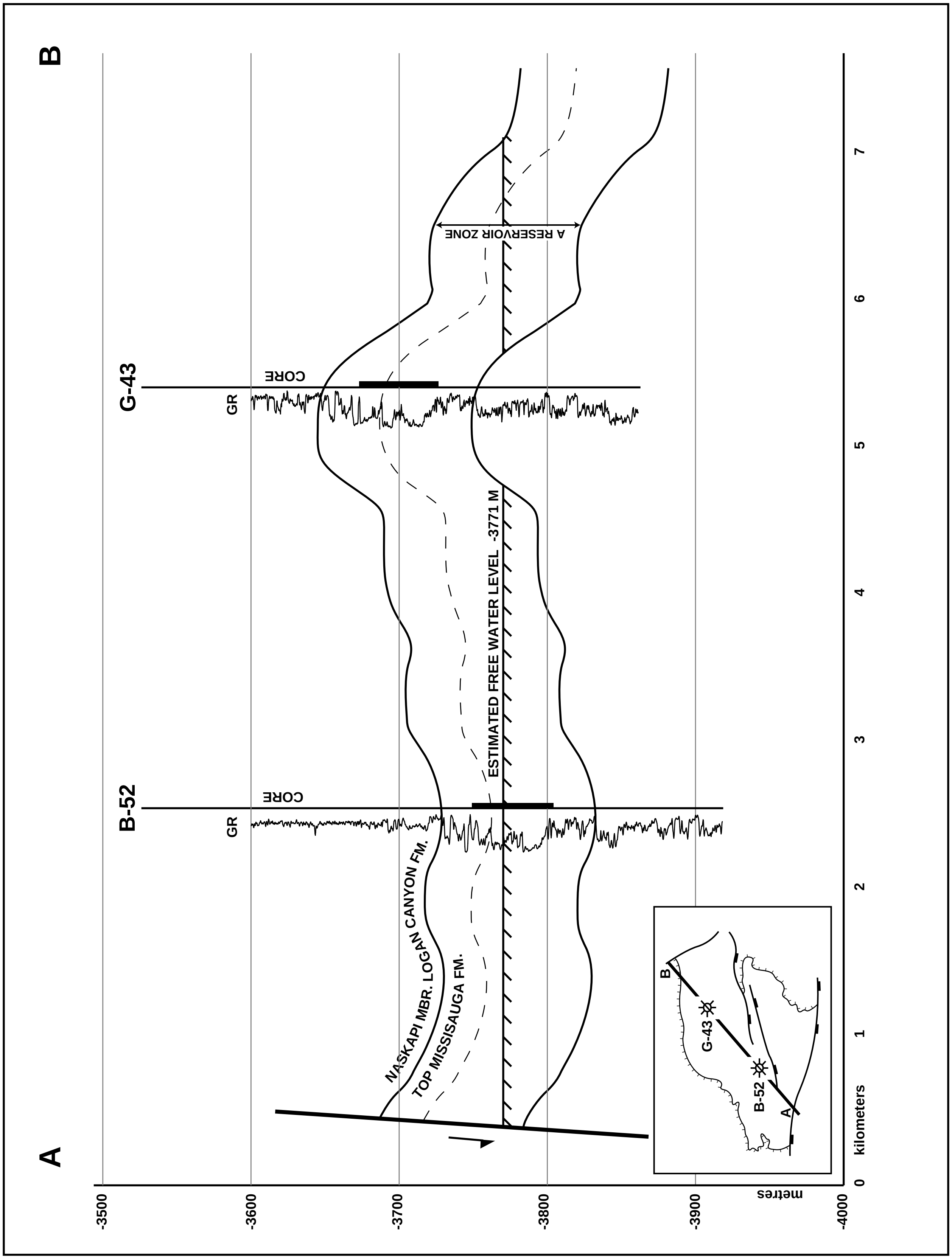


Figure 2.2.3.4.1: North Triumph Schematic Structural Cross-section

2.2.3.5 Geophysics

2.2.3.5.1 Seismic Database

The depth structure map used for gas in place estimation is based on an integration of 2D and reconnaissance 3D seismic data, as illustrated in **Figure 2.2.3.5.1.1.** The 2D data were acquired in the period from 1980 to 1982 and were processed with a standard marine runstream. These data exhibit fair data quality down to the objective Missisauga level.

The reconnaissance 3D survey which covers part of the North Triumph structure has an areal extent of 260 square kilometres. It was acquired in 1985 and purchased by Shell in 1987. It was incorporated into the interpretation in 1991. Data quality is generally better than that of the 2D data, and this results in improved fault resolution. Because the 3D survey was acquired with 100 metre in-line spacing, it required bin interpolation prior to cross-line migration. Both the 2D and reconnaissance 3D data were used to map the structural configuration of the North Triumph Field. A summary of acquisition and processing details is included in **Table 2.2.3.5.1.1.**

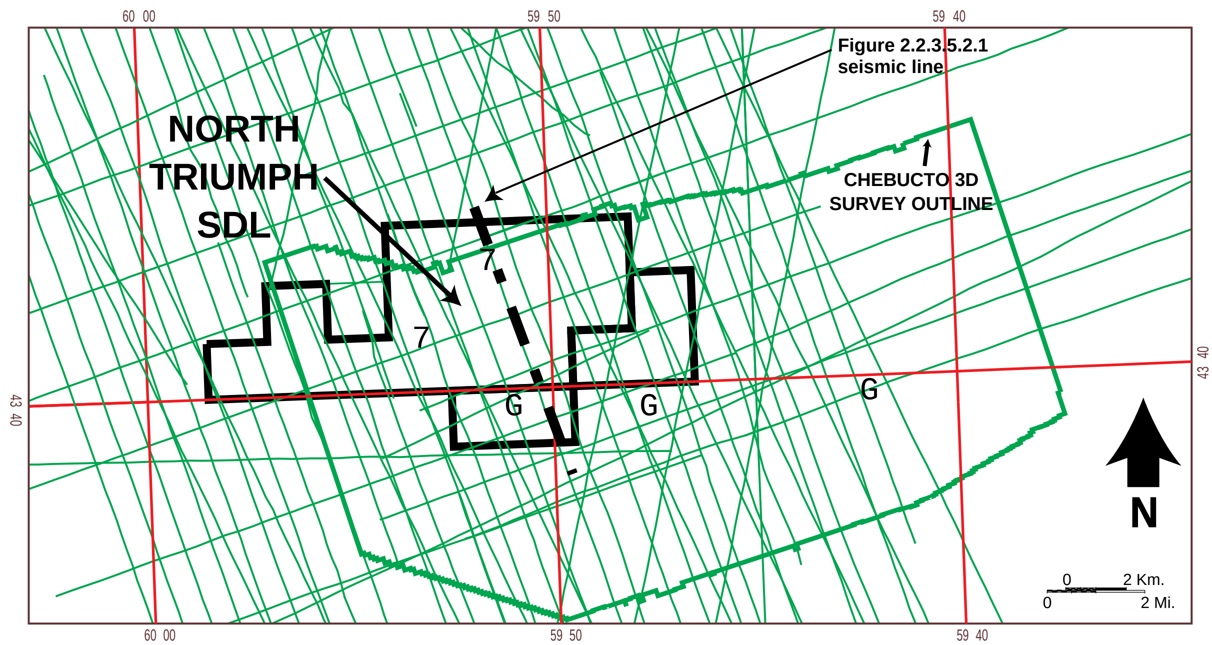


Figure 2.2.3.5.1.1: North Triumph Seismic Database Map

Table 2.2.3.5.1.1: North Triumph Acquisition and Processing Summary

Data Type	Survey Name	Incorp. In Study	Acq. Date	Acq. Style	Proc. Date	Field Kms	Proc. Details	Comments
2D	050E series	No	1987	Marine	1988	200	60 Fold, Desig, FK Migration	Generally good to very good quality data
2D	048E Series	No	1985	Marine	1985	92	54 Fold, Desig, FK Migration	Generally good quality data
3D Partial	010e Series	Yes	1985	Marine	1985	2685	64 Fold, DMO, FD Migration	Generally fair to good data quality
2D	004E Series	Yes	1983	Marine	1983	22	40 Fold Desig, FD Migration	Generally poor to fair quality
2D	033E Series	Yes	1982	Marine	1983	738	54 Fold, Desig,FD Migration	Generally poor to fair quality
2D	027E Series	Yes	1981	Marine	1981	320	60 Fold, Desig,FD Migration	Generally poor data quality
2D	023E Series	Yes	1980	Marine	1980	315	48 Fold, Desig, FD Migration	Generally poor to fair data quality
2D	020 E Series	No	1976	Marine	1976	36	24 Fold,No Mig	Generally poor to fair data quality

2.2.3.5.2 Time Interpretation

Synthetic seismic traces, based on convolving a zero phase wavelet with an acoustic impedance series derived from wireline log sonic and density information, were used to tie lithology to the seismic data.

The 3D seismic data were interpreted using a Landmark™ workstation and provide the basis for the time and depth structure maps. The 2D data were manually interpreted and provide structural control on the northern flank of the feature where there is no 3D coverage. The top Missisauga correlated from well control was picked as the main mapping horizon and was used to define the structure of the main pool (shown in **Table 2.2.3.5.2.1)**. Greater spatial resolution of the reconnaissance 3D yielded better fault imaging than the 2D dataset and indicated two small displacement faults which partially bisect the anticlinal structure. A representative seismic line is illustrated in **Figure 2.2.3.5.2.1** and is indicated by a bold dashed line on **Figure 2.2.3.5.1.1**.

Table 2.2.3.5.2.1: North Triumph Horizon Markers

FIELD	North Triumph							
	G-43				B-52			
MAP HORIZON	Depth MD (m)	Depth TVD (m)	Depth M,ss	TWT (sec)	Depth MD (m)	Depth TVD (m)	Depth M,ss	TWT (sec)
Eocene Chalk	1379	1378	-1354	1.407	1428	1428	-1404	1.437
Wyandot Chalk	1628	1627	-1603	1.609	1658	1658	-1634	1.618
Top L. Logan Can.	2316	2315	-2291	2.066	2333	2333	-2309	2.054
Naskapi	3489	3407	-3383	2.664	3407	3407	-3383	2.654
Missisauga	3778	3672	-3648	2.801	3756	3756	-3732	2.829

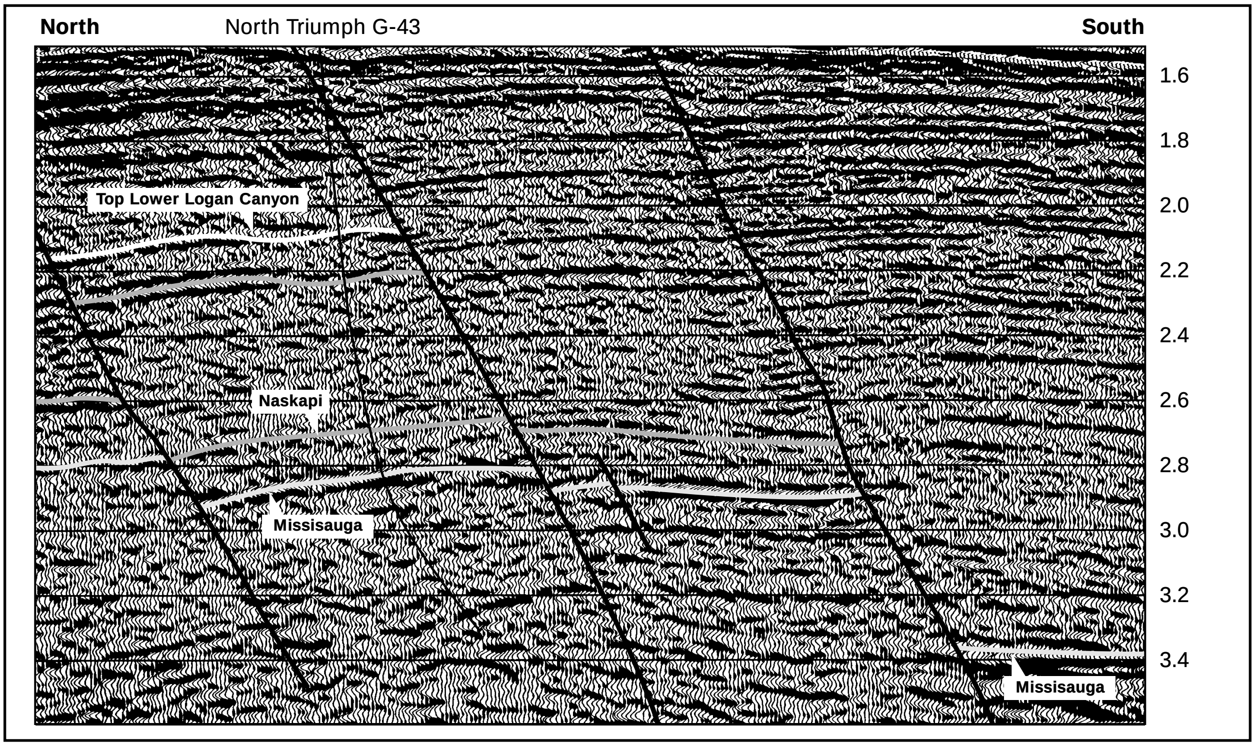


Figure 2.2.3.5.2.1: North Triumph Seismic Section

2.2.3.5.3 Depth Conversion

Time to depth conversion of the North Triumph Field is reviewed in Part Two of this document **(DPA - Part 2 Ref. # 2.2.3.5.3.1).** Depth conversions in the mid to late 1980's used a 'layer cake' methodology with a constant velocity from the seafloor to Wyandot marker. Local well control (**Table 2.2.3.5.3.1**) was used to generate time-depth functions for the Wyandot to mapped horizon interval.

Table 2.2.3.5.3.1: North Triumph Well Velocity Data

Well	Year Acquired	Checkshot Available	Checkshot Type	VSP Available	VSP Type
North Triumph G-43	1983	Yes	Vertical	No	NA
North Triumph B-52	1984	Yes	Vertical	No	NA

2.2.3.6 Petrophysics

Petrophysical evaluation of the two wells in the North Triumph Field used all available log data, extensive conventional/special core analysis data, and pressure data**.** A detailed summary of the interpretation parameters and methodology is given in Part Two of this document (**DPA - Part 2, Ref. # 2.2.3.6.1**). The results of this evaluation are in **Table 2.2.3.6.1**.

Table 2.2.3.6.1: North Triumph Reservoir Parameter Summary

North Triumph B-52 K.B. 24.0 Metres

Sand Unit	Measured Depth Top (m)	Measured Depth Base (m)	Elevation Top (m ss)	Elevation Base (m ss)	Gross Thickness (m)	Net Pay (m)	Average Porosity (%)	Average Sw (%)	Average Permeability* (mD)
A	3756.5	3858.5	-3731.9	-3834.5	102.6	11.2	18.0	36.0	60.0

North Triumph G-43 (deviated well) K.B. 24.0 Metres

Sand Unit	Measured Depth Top (m)	Measured Depth Base (m)	Elevation Top (m ss)	Elevation Base (m ss)	Gross Thickness (m)	Net Pay (m**)	Average Porosity (%)	Average Sw (%)	Average Permeability* (mD)
A	3778.0	3882.5	-3647.9	-3752.5	104.5	37.9	20.0	15.0	70-300

* Estimated from DST

** metres along hole

Pressure and test data from the two wells indicate that the North Triumph Field features a single pool of hydropressured gas. This is reservoired in the uppermost sandstones of the Missisauga Formation. These data are in agreement with a gas/water contact encountered in the more down-dip well, B-52, at 3771 metres subsea. The crest of the North Triumph structure is mapped at 3600 metres subsea, giving a total gas column of 171 metres. Net pay varies between the two wells due to changes in structural position and minor variation in reservoir development. The G-43 well contains 38 metres of net pay. The structurally lower B-52 well contains 11 metres. Net porous sand thickness was determined based on a permeability cutoff of 0.5 mD to air at ambient conditions. This was found to correspond to an in situ porosity value of 10 percent. A water saturation cutoff of 60 percent was used in the determination of net pay.

Zonal average porosity of the reservoir ranges from 19 to 20 percent. Zonal average permeabilities range from 60 to 300 mD. The primary control on porosity and permeability is average grain size. Porosity was calculated from density calibrated to stressed core porosity measurements. Zonal average water saturation of the reservoir ranges from 17 to 38 percent.

Water saturation for values used in the estimation of gas in place was calculated using the Archie equation. Cementation and saturation exponent values were based on special core analysis. Formation water resistivity was derived from RFT and DST fluid sample analysis, and a formation temperature gradient determined from bottom hole temperature measurements. Irreducible water saturations, as calculated from logs, range from six to 10 percent.

2.2.3.7 Gas in Place

The ranges of uncertainty of the parameters utilized in the probabilistic assessment of gas in place are detailed in Part Two (**DPA - Part 2, Ref. # 2.2.3.7.3)**. The results for the North Triumph Field are presented in **Table 2.2.3.7.1**.

Deterministic gas in place estimates, performed in 1990 and 1991, utilized average reservoir porosity and water saturation values determined from well petrophysics, an average net pay value as determined from the net pay map, and what was then considered the 'most likely' structure map for the area of the pool. The methodology of this deterministic gas in place estimation is presented in detail in Part Two (**DPA - Part 2, Refs #2.2.3.7.1 and 2.2.3.7.2**). The result is presented in **Table 2.2.3.7.2**. The deterministic volume is similar to the P50 and Mean values obtained from the probabilistic method.

Table 2.2.3.7.1: North Triumph Probabilistic Estimate of Gas In Place

Reservoir Sandstone	P90	P50	P10	Mean (E9M3)
Project Total	6.2	14.2	25.2	**15.2**

Table 2.2.3.7.2: North Triumph Deterministic Estimate of Gas In Place

Reservoir Sandstone	Gas in Place (E9M3)
A	15.8

2.2.4 SOUTH VENTURE FIELD

2.2.4.1 Field History

In 1983, the discovery well South Venture O-59 was drilled to a total depth of 6176 metres. Multiple, vertically stacked hydropressured and overpressured sandstone gas accumulations were encountered, testing at flowrates up to 509 E3M3/d. Hydropressured reservoir horizons occur from 3926 to 4266 metres in the O-59 well. Overpressured gas accumulations occur between 4746 and 5054 metres. **Figure 2.2.4.1.1** illustrates the South Venture Sand 2 depth structure map.

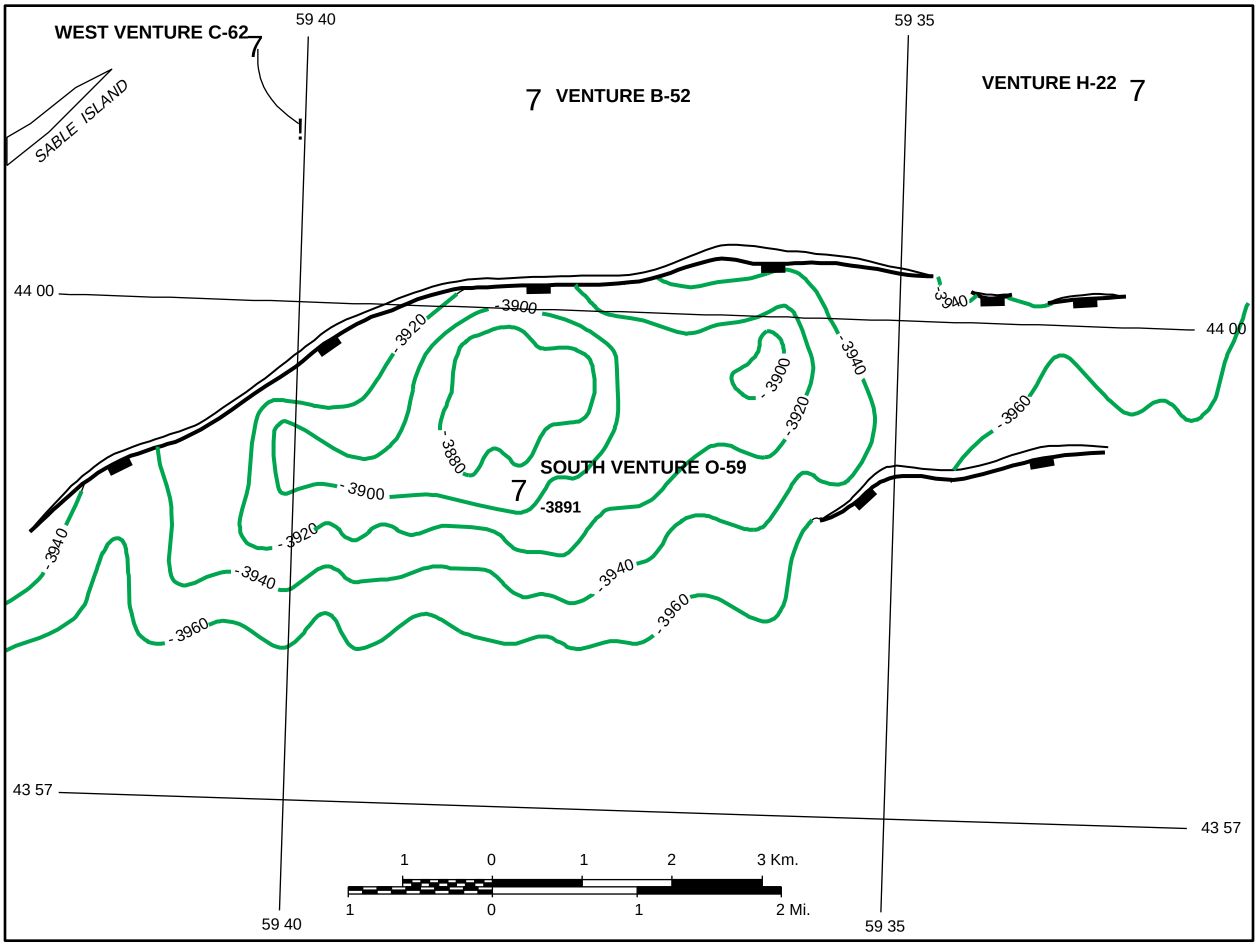


Figure 2.2.4.1.1: South Venture Field - Top Sand 2 Structure Map
Contour Interval: 20 Metres

2.2.4.2 Structural Configuration

The South Venture structure is a low relief rollover anticline situated on the downthrown side of a major east-west trending growth fault. At the top Sand 2 hydropressured horizon, the structure is approximately eight kilometres by three kilometres, encompassing an area of 23 square kilometres, with 70 metres of vertical closure. Gross closure is established by structural saddle spillpoints to the east and west of the South Venture structure.

2.2.4.3 Geology

The South Venture reservoir section consists of interbedded shales, siltstones, sandstones, and occasional limestones or highly calcareous sandstones. As in the Venture Field, this cyclic sedimentation is interpreted to be the result of delta progradations of Late Jurassic and Early Cretaceous age, the deposits of which are assigned to the Mic Mac and Lower Missisauga formations.

Hydropressured gas was tested in five independent reservoir horizons. **Figure 2.2.4.3.1** is a net pay map of one of these horizons, the Sand 2 reservoir. Net pay in the O-59 well at this horizon is 14.5 metres. The free water level elevation estimate of 3936 metres subsea is based on an assumed 80 percent fillup volume. Gas is inferred to be trapped by a combination of rollover closure and fault closure **(DPA - Part 2 Ref. # 2.2.4.3.1).**

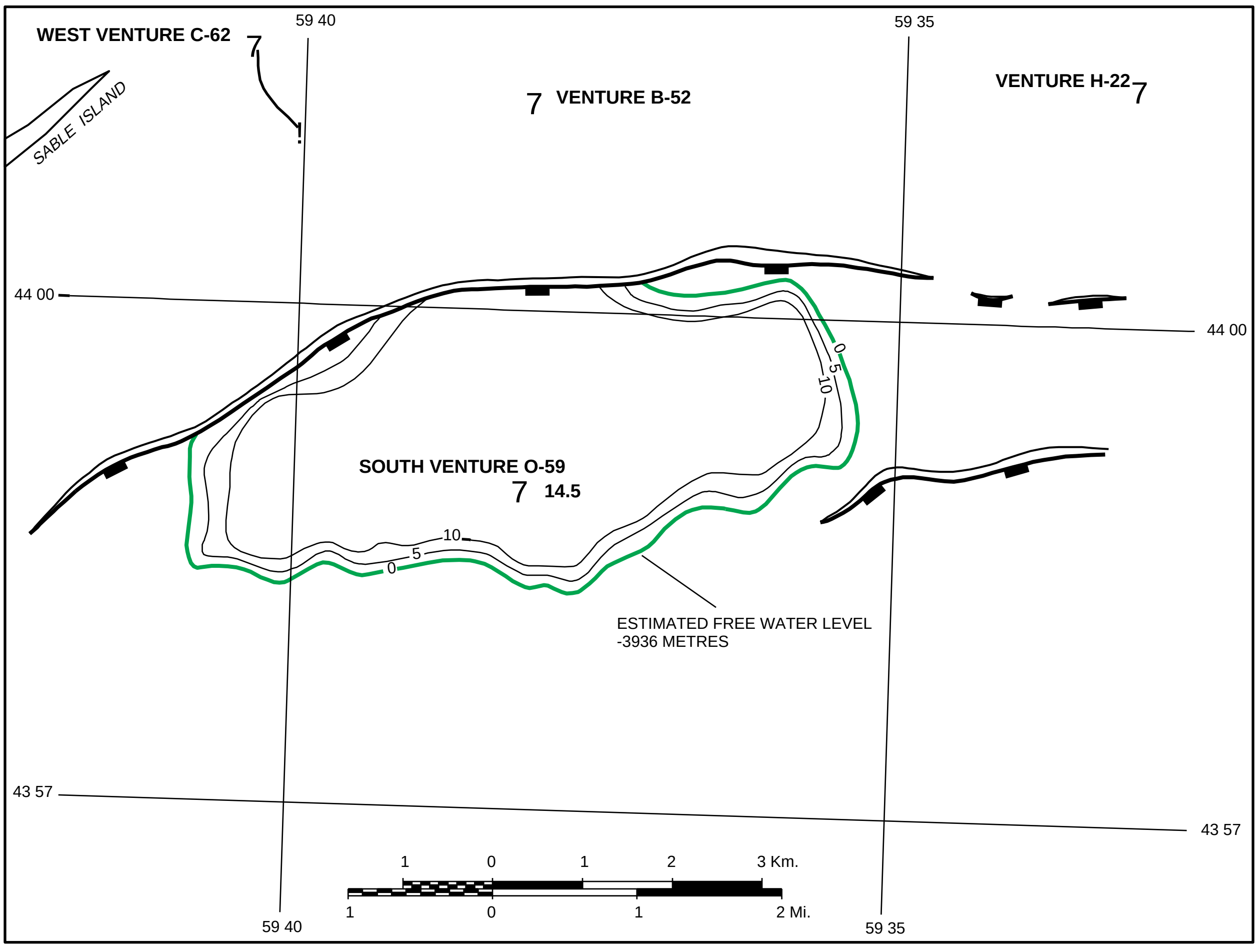


Figure 2.2.4.3.1 South Venture Field - Sand 2 Net Pay Thickness Map
Contour Interval: 5 metres

Two overpressured sandstone horizons, sands 7 and 8, tested gas in the 0-59 well. These horizons have low porosity as demonstrated by wireline logs, and exhibited significant pressure drawdown during drillstem testing. These deep overpressured accumulations are not currently included in the Project. There were no cores taken in the O-59 well, and attempts to recover Repeat Formation Test (RFT) data were unsuccessful, largely due to tool seating problems.

2.2.4.4 Reservoir Zonation

Using O-59 wireline log response, and correlations to the Venture Field wells, the hydropressure section was subdivided into sandstone packages, and numbered from zero to six. Reservoir sandstones in the South Venture hydropressure section are younger than the Venture Field reservoirs. Based on these correlations to Venture and continuous seismic reflectors within the South Venture structure, sandstone continuity in the hydropressured section is anticipated to be favourable. The reservoir nomenclature for South Venture is shown in **Figure 2.2.4.4.1**.

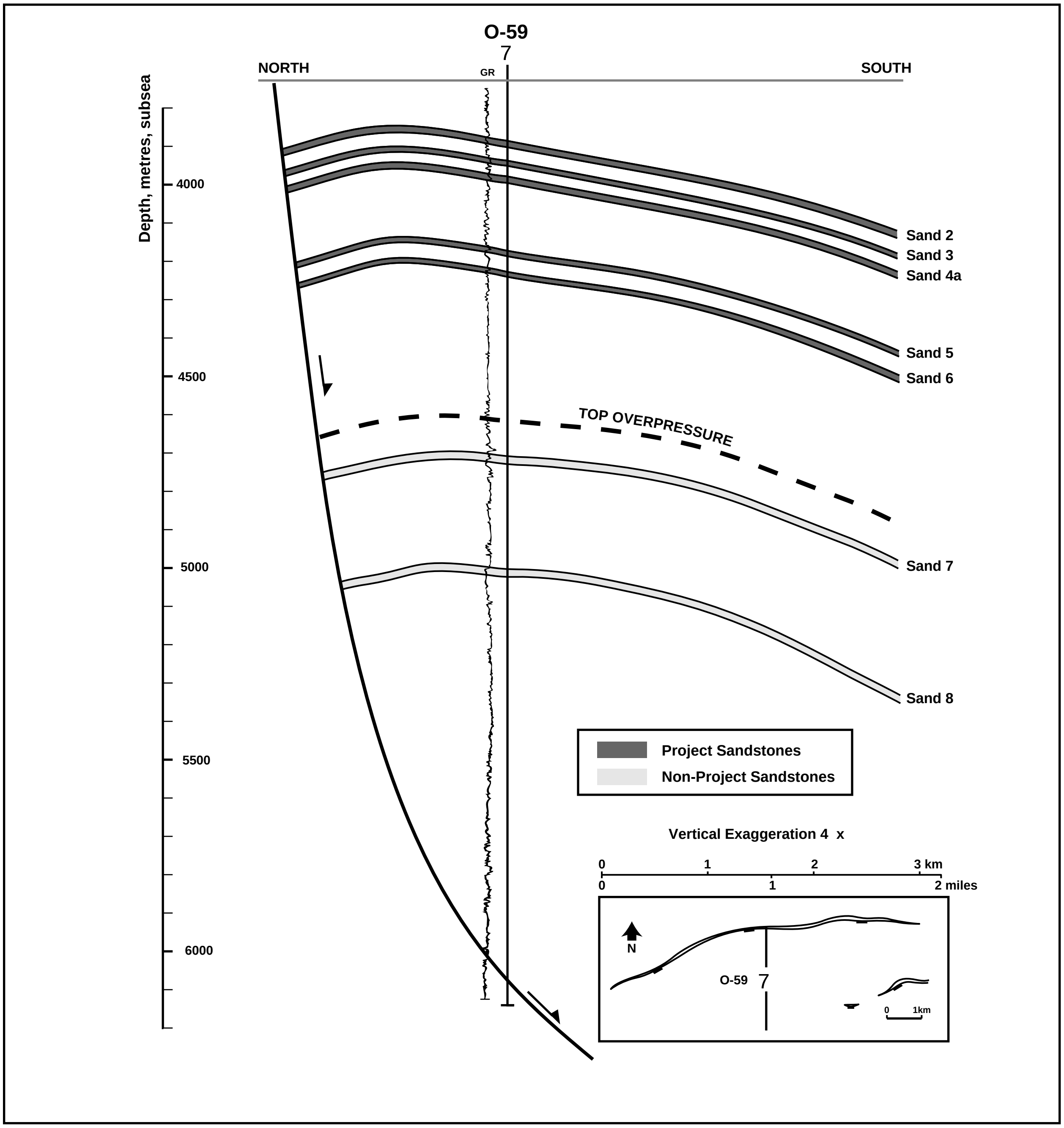


Figure 2.2.4.4.1: South Venture Schematic Structural Cross-section

2.2.4.5 Geophysics

2.2.4.5.1 Seismic Database

The South Venture Field is covered by essentially the same vintages of seismic data as the Venture Field. A summary of acquisition and processing details for several of these datasets is included in **Table 2.2.4.5.1.1**. The data density and quality at the normal pressured level sands is good to very good. There is only one strike line. The synthetic seismogram from the O-59 ties very well with the seismic at both mapped horizons. In the overpressured section, frequency content and horizon continuity has decreased but mapping confidence remains quite high. The depth structure maps used for gas in place estimates are based on the 2D seismic data illustrated in **Figure 2.2.4.5.1.1.**

Table 2.2.4.5.1.1: South Venture Acquisition and Processing Summary

Data Type	Survey Name	Incorp. In Study	Acq. Date	Acq. Style	Proc. Date	Field Kms	Proc. Details	Comments
2D	8624-M003-047E	Yes	1983	Marine	1983-84	356	60 fold Decon before and after stack, FD migration	Generally good to very good quality. Deteriorating with depth
2D	8620-5014-006R	No	1983	Marine	1983-84	31	60 fold Desig, Decon after stack FD migration	Fair to good quality
2D	8624-M003-041E	No	1981	Marine	1981-82	2	72 fold Desig, Decon after stack, FD migration	Good quality data, lower frequency
2D	8624-M003-035E	No	1980	Marine	1980-81	80	48 fold Desig, Decon after stack, FD migration	Generally good quality data, lower frequency
2D	8624-M003-033E	No	1979	Marine	1979-80	72	60 fold DBS, Decon after stack, FD migration	Fair to good quality

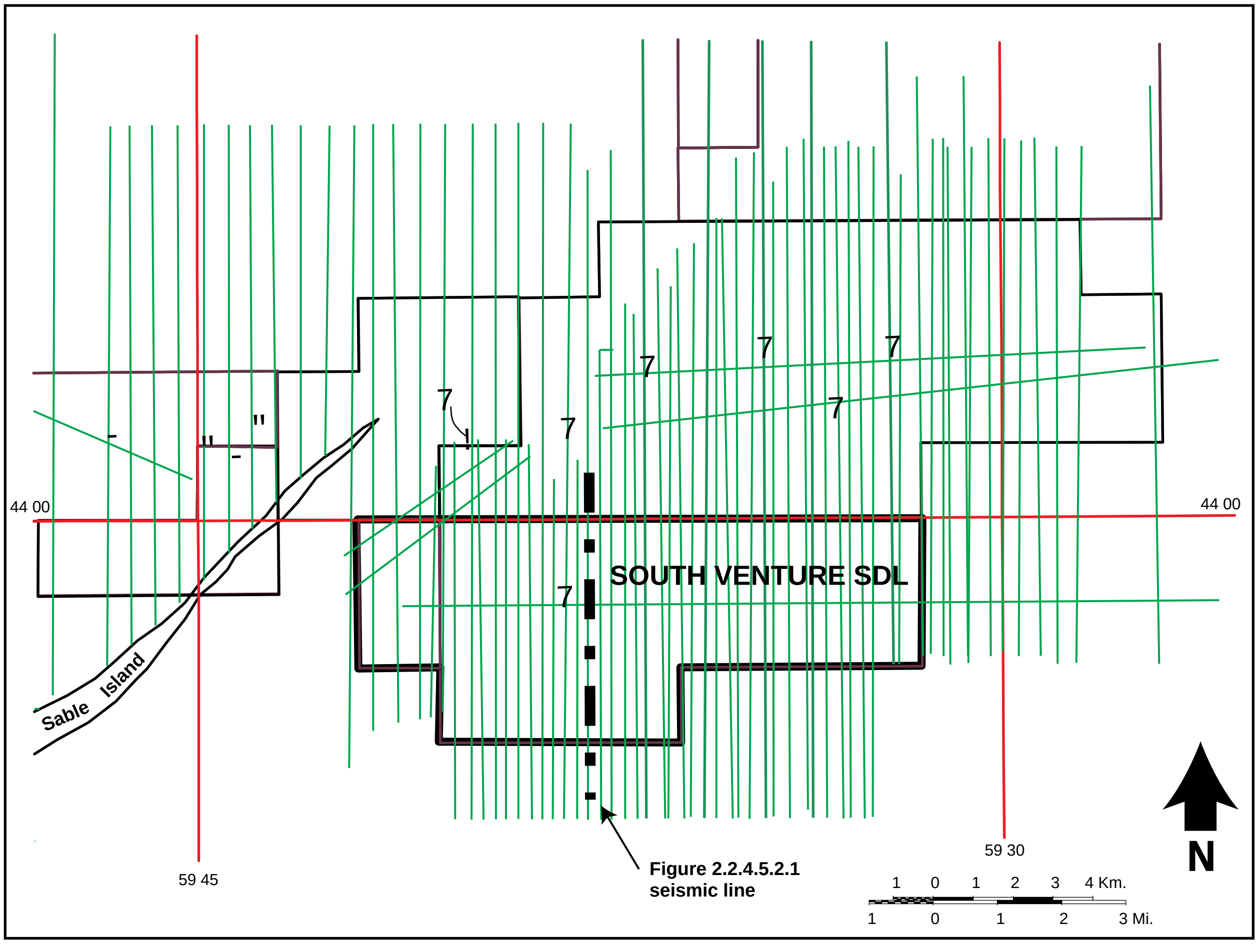


Figure 2.2.4.5.1.1: South Venture Seismic Database Map

2.2.4.5.2 Time Interpretation

The maps used for the gas in place calculations at South Venture are based on time and depth structure maps made from the 1983 data. The entire 1983 survey consists of 52 lines for a total length of 356 line kilometres. There is only one strike line in the survey that crosses the South Venture Field. This line runs from east to west, just south of the crest of the structure in the hydropressured section and through the O-59 well. The dip lines have an east to west line spacing of approximately 300 metres over the crest and flanks of the structure. A seismic line representative of the data quality and illustrating the field geometry is included as **Figure 2.2.4.5.2.1** and its location is shown as a bold dashed line in **Figure 2.2.4.5.1.1**.

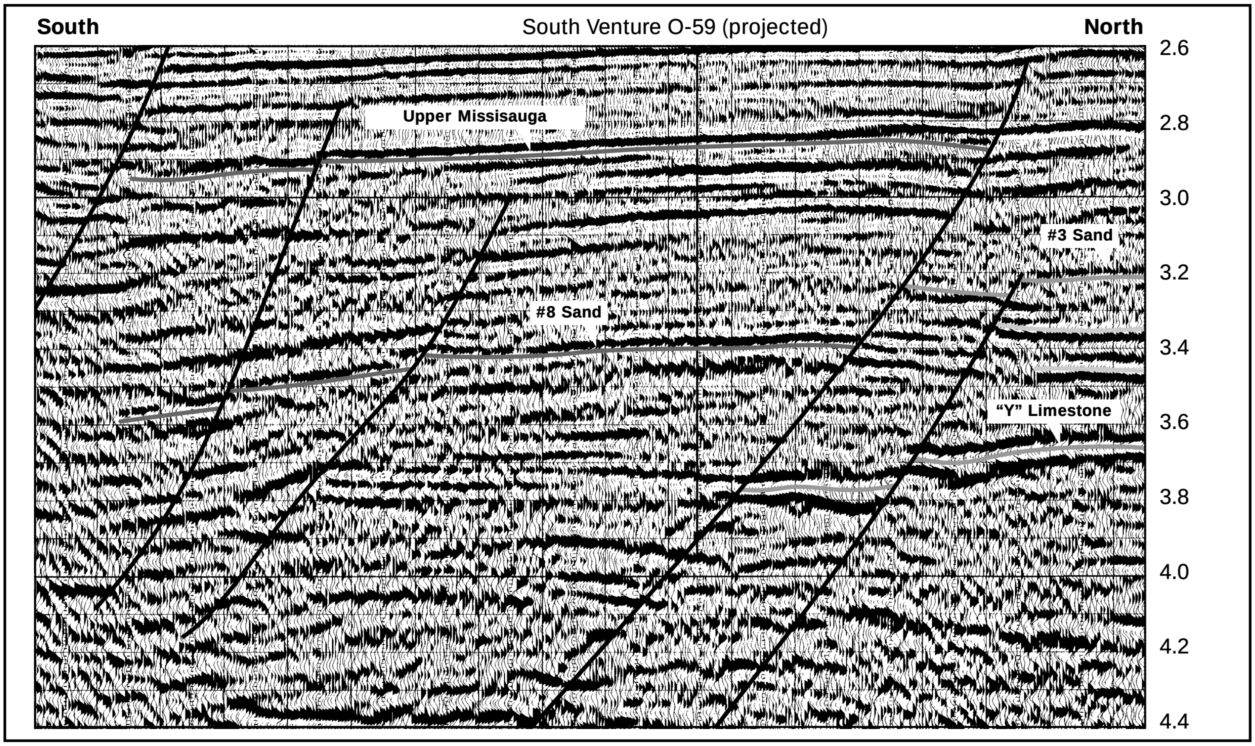


Figure 2.2.4.5.2.1: South Venture Seismic Line

The South Venture interpretation was generated on paper sections that were hand timed, posted and contoured. A checkshot survey corrected synthetic seismogram, generated at the O-59 well by convolving a minimum phase wavelet with an acoustic impedance series derived from the wireline log sonic and density information, was used to tie well lithology to the seismic data.

Two horizons were mapped in the hydrocarbon bearing portion of the field; one in the hydropressured section and one in the overpressured section. The Upper Missisauga Event corresponds to the top of the South Venture Sand 2 and was used to generate maps for Sands 2, 3, 4, 5 and 6. The second time event mapped, corresponds to the top of overpressured South Venture Sand 8 at O-59. The mapping horizons are illustrated in **Table 2.2.4.5.2.1.** Detailed maps are included in Part Two **(DPA - Part 2, Ref. # 2.2.4.5.2.1)**.

Table 2.2.4.5.2.1: South Venture Mapping Horizons

FIELD	SOUTH VENTURE 0-59	
MAP HORIZON	**Depth (M, ss)**	**TWT (sec)**
UPPER MISSISAUGA	-3890.6	2867
#8 SAND	-4999.0	3400

2.2.4.5.3 Depth Conversion

The depth conversion at South Venture used the same technique and velocity database as that described in Venture **Section 2.2.2.5.3**. Time structure maps for two horizons; the Upper Missisauga (Top of Sand 2), and the Top of Sand 8, were digitized and gridded. Intermediate depth maps were generated from the interval thickness encountered in the O-59 well (**DPA - Part 2, Ref. # 2.2.4.5.3.1**). The velocity surveys for South Venture are illustrated in **Table 2.2.4.5.3.1** .

Table 2.2.4.5.3.1: South Venture Velocity Surveys

Well	Year Acquired	Checkshot Available	Checkshot Type	VSP Available	VSP Type
South Venture O-59	1982	Yes	Vertical	No	NA
Venture D-23	1979	Yes	Vertical	No	NA
Venture B-13	1981	Yes	Vertical	No	NA
Venture B-43	1982	Yes	Vertical	No	NA
Venture B-52	1983	Yes	Vertical	Yes	Vertical
Venture H-22	1984	Yes	Vertical	No	NA
West Venture C-62	1985	Yes	Deviated Well	No	NA
Olympia A-12	1983	Yes	Vertical	No	NA

The South Venture structure has been penetrated by only one well. Stacking velocity data from the 1983 dataset was used in the same manner as at Venture, to supplement and constrain the applied velocity field. This is a reasonable approach at Venture given the well velocity data's areal distribution, but greater opportunity for error exists in the South Venture depth conversion, due to the limited well control.

2.2.4.6: Petrophysics

A detailed petrophysical evaluation of the multiple reservoir sands, hydropressured and overpressured, has been conducted on the South Venture O-59 well. The interpretation methodology and parameters are included in Part Two of this document **(DPA - Part 2, Ref. # 2.2.4.3.1)**. The results of this evaluation are illustrated in **Table 2.2.4.6.1**.

Table 2.2.4.6.1: South Venture Reservoir Parameter Summary

Sand Unit	Measured Depth		Elevation		Gross Thickness (m)	Net Pay (m)	Average Porosity (%)	Average Sw (%)	Average Permeability* (mD)
	Top (m)	Base (m)	Top (m ss)	Base (m ss)					
2	3926.0	3960.0	-3890.6	-3924.6	34.0	14.5	14.7	47.2	-
3	3977.0	3992.0	-3941.6	-3956.6	15.0	4.3	13.4	21.1	-
4a	4016.0	4034.0	-3980.6	-3998.6	18.0	5.8	13.3	30.7	-
5	4201.0	4217.0	-4165.6	-4181.6	16.0	2.3	14.0	39.0	-
6	4255.0	4266.0	-4219.6	-4230.6	11.0	4.9	14.0	24.0	-

* not calculated

The methodologies used in the analysis of the O-59 well relied heavily on those established for similar reservoirs of the Venture Field. This was necessary because no cores were cut in the O-59 well, and all sands encountered in the well, are interpreted to be either gas bearing or tight. Due to the lack of core data, water sands, and formation water samples in South Venture, petrophysical parameters derived in similar reservoirs of the Venture Field supported the interpretation.

Zonal average porosity ranges from seven to 15 percent in the O-59 well. Porosity was calculated from the raw density measurement using matrix density values determined from crossplots and lithologic descriptions. Water saturation for values used in the estimation of gas in place was calculated using the Archie equation. Cementation and saturation exponents correspond to those used in similar reservoirs of the Venture Field. True formation resistivity was determined from the deep induction measurement. In the absence of formation water samples, formation water resistivity was estimated from Venture Field data and log data.

The calculation of net porous sand thickness was found to be quite sensitive to the porosity cutoff value. In general, a porosity cutoff value of 10 percent was used. Lower porosity cutoff values of six to seven percent were applied in low porosity overpressured sands which had favourable gas flowrates on drillstem tests. The water saturation cutoff value used was 70 percent.

2.2.4.7 Gas In Place

Gas in place estimates for the South Venture Field have been generated using deterministic and probabilistic methods. The probabilistic assessment of gas in place was conducted in 1995 (**DPA - Part 2, Ref. # 22.2.4.7.1**). The summation of mean values from the output expectation curves generated for the five hydropressured Project sands is 11.3 E9M3. Results of this probabilistic assessment for the each of the Project sands are shown in **Table 2.2.4.7.1**.

Table 2.2.4.7.1: South Venture Probabilistic Estimates of Gas In Place, E9M3

Reservoir Sandstone	P90	P50	P10	Mean
2	1.4	4.8	7.9	**4.8**
3	0.5	1.5	3.1	**1.6**
4a	0.6	1.6	3.7	**1.9**
5	0.3	0.8	2.0	**1.0**
6	0.6	1.7	3.8	**2.0**
Project Total	3.4	10.4	20.5	**11.3**

A deterministic assessment of gas in place was generated in 1985. The methodology used to generate the maps and gas in place estimates is described in Part Two of this document (**DPA - Part 2 Ref. # 2.2.4.7.2**). Deterministic gas in place estimates for Project sands are shown in **Table 2.2.4.7.2** and represent unrisked volumes.

Table 2.2.4.7.2: South Venture Deterministic Estimates of Gas In Place, E9M3

Reservoir Sandstone	Gas in Place
2	4.4
3	2.2
4a	2.6
5	1.0
6	2.6
Total	12.8

2.2.5 GLENELG FIELD

2.2.5.1 Field History

The Glenelg Field was discovered in 1983 (**DPA - Part 2, Ref. # 2.2.5.1.1 through 2.2.5.1.3**). The discovery well, Glenelg J-48, encountered stacked, hydropressured, gas pay in a number of separate pools in the lower Logan Canyon Formation and throughout the Missisauga Formation. During drillstem testing, gas flowed at rates of up to 849 E3M3/d. Three subsequent wells, one of which was whipped, were drilled to delineate the accumulation. **Figure 2.2.5.1.1** illustrates the top B pool structure (near top Missisauga level) at Glenelg.

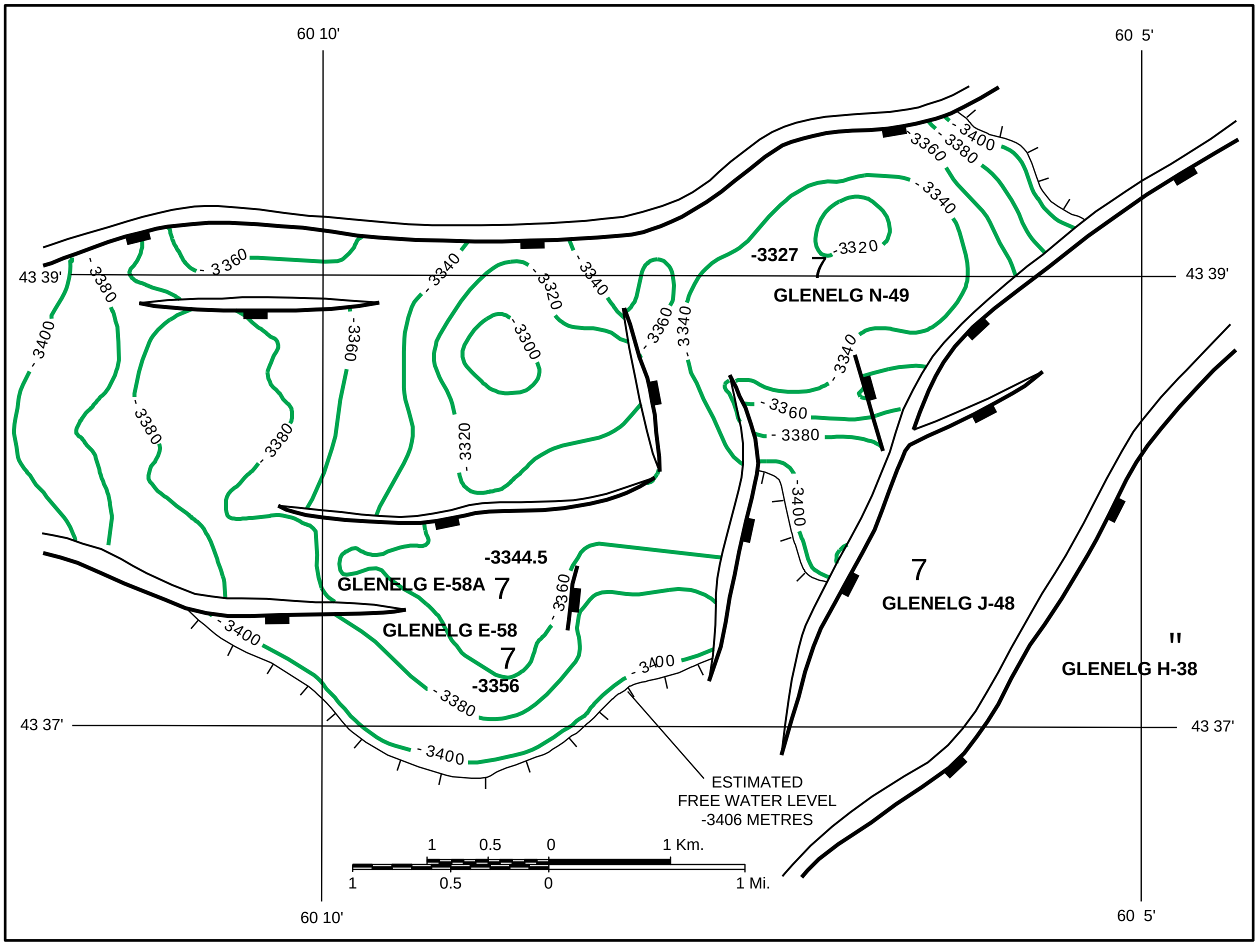


Figure 2.2.5.1.1: Glenelg - Top Missisauga (Top B Pool) Depth Structure Map
Contour Interval: 20 metres

2.2.5.2 Structural Configuration

The Glenelg feature is a large rollover anticlinal structure bounded to the north and southeast by major listric normal faults, and to the northeast, south and west by dip closure. Internally, the rollover anticline is partially dissected by a number of lesser normal faults, some of which exhibit significant throws. The field is at an average depth of 3470 metres subsea and covers an area of some 25 square kilometres.

2.2.5.3 Geology

The Glenelg area is located toward the southernmost extension of sands of the Sable Delta complex. Approximately 550 metres of Missisauga Formation is present there. The Missisauga Formation contains a lower sand/shale ratio than in more northern wells. It exhibits significant thicknesses of shale-dominated section between the interbedded sandstones and shales more typical of the Missisauga Formation.

The lower 300 metres of the Missisauga Formation at Glenelg is composed of coarsely interlayered sandstone and shale. Sandstone intervals approximately 50 metres thick, dominated by sharp-based sandy channel fill successions, are interbedded with shaley intervals of similar thickness. The channel sands exhibit variable development across the Glenelg structure. The upper 250 metres of the Missisauga Formation is composed of stacked coarsening-upward cycles of shale to sandstone, deposited by successive delta-lobe progradations into the area. These cycles are correlatable across the Glenelg structure. The individual sands capping these cycles exhibit north-south variation in thickness and log character; this is associated with variation in reservoir quality (**DPA - Part 2, Ref. # 2.2.5.1.1, 2.2.5.1.3 & 2.2.5.3.1**).

Hydropressured gas has been encountered in a number of separate pools within the Logan Canyon and Missisauga formations. Three of the pools within the Missisauga Formation, B, C and F, are considered of sufficient size to be developed. The gas pools tend to be restricted to specific stratigraphic horizons within a single structural block. The C pool is an exception, being hydrodynamically continuous across a fault separating the N-49 and J-48 wells, with gas reservoired in different stratigraphic levels in each structural block. As a result of different reservoir qualities on either side of this fault, the C accumulation is subdivided into two substituent pools, C1 and C2. This is illustrated in **Figures 2.2.5.3.1(a), 2.2.5.3.2(b) & 2.2.5.4.1**; and presented in further detail in Part Two (**DPA - Part 2, Ref. # 2.2.5.1.1**).

The B, C1/C2 and F pools are all reservoired in sands which occur in the uppermost 250 metres of the Missisauga Formation. The distribution of the various reservoir sands in this stratigraphic interval are modelled as north to south tapering wedges. This model combines the effects of a northerly source for the sands with syndepositional downward movement on the northern bounding growth fault; the latter acts to trap most of the reservoir quality sand in the northern portion of the structure. According to this model, reservoir thickness is at a maximum adjacent to the northern bounding fault, and thins systematically southward to the southern boundaries of the field. The B and C2 pools are reservoired in the same stratigraphic interval, namely in the uppermost sands of the Missisauga Formation. The C1 and F pools are reservoired in an older stratigraphic unit (informally termed the Glenelg Sand). Consequently, these gas pools may be represented by two reservoir development models.

Convolution of the appropriate reservoir development model with structure maps and gas/water contacts for each of the pools permits construction of net pay maps. Net pay maps are then used for gas in place determination. **Figure 2.2.5.3.1(a-b)** shows the structural configuration for the Glenelg C1/C2 and F pools; **Figure 2.2.5.3.2(a-c)** are net pay maps for the Glenelg B, C1/C2, and F pools.

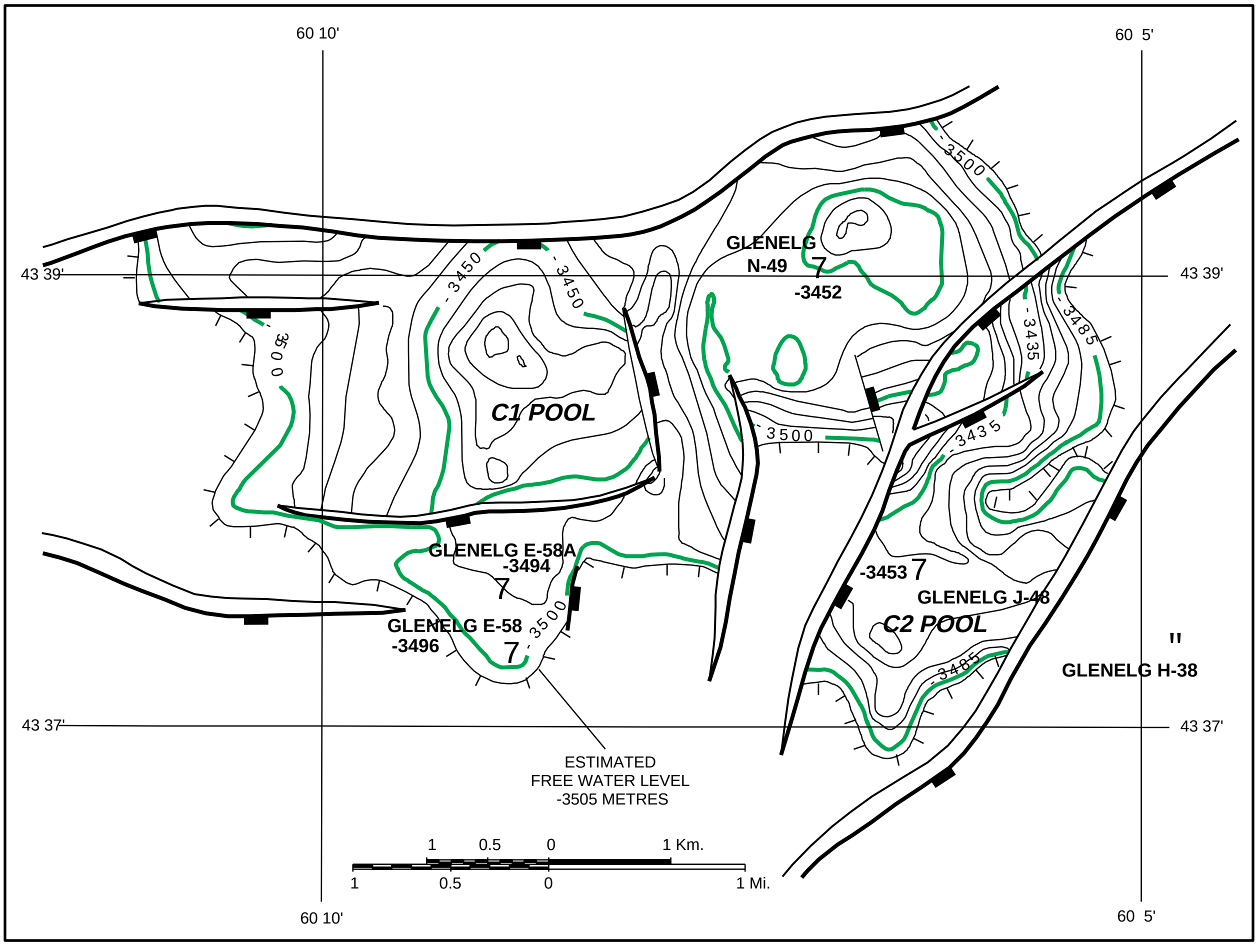


Figure 2.2.5.3.1 (a): Glenelg - C1/C2 Pools, Depth Structure Map
Contour Interval: 10 metres

Note: Change of mapping horizon between J-48 and N-49 fault blocks. Refer to text and structural cross-section (Figure 2.2.5.4.1).

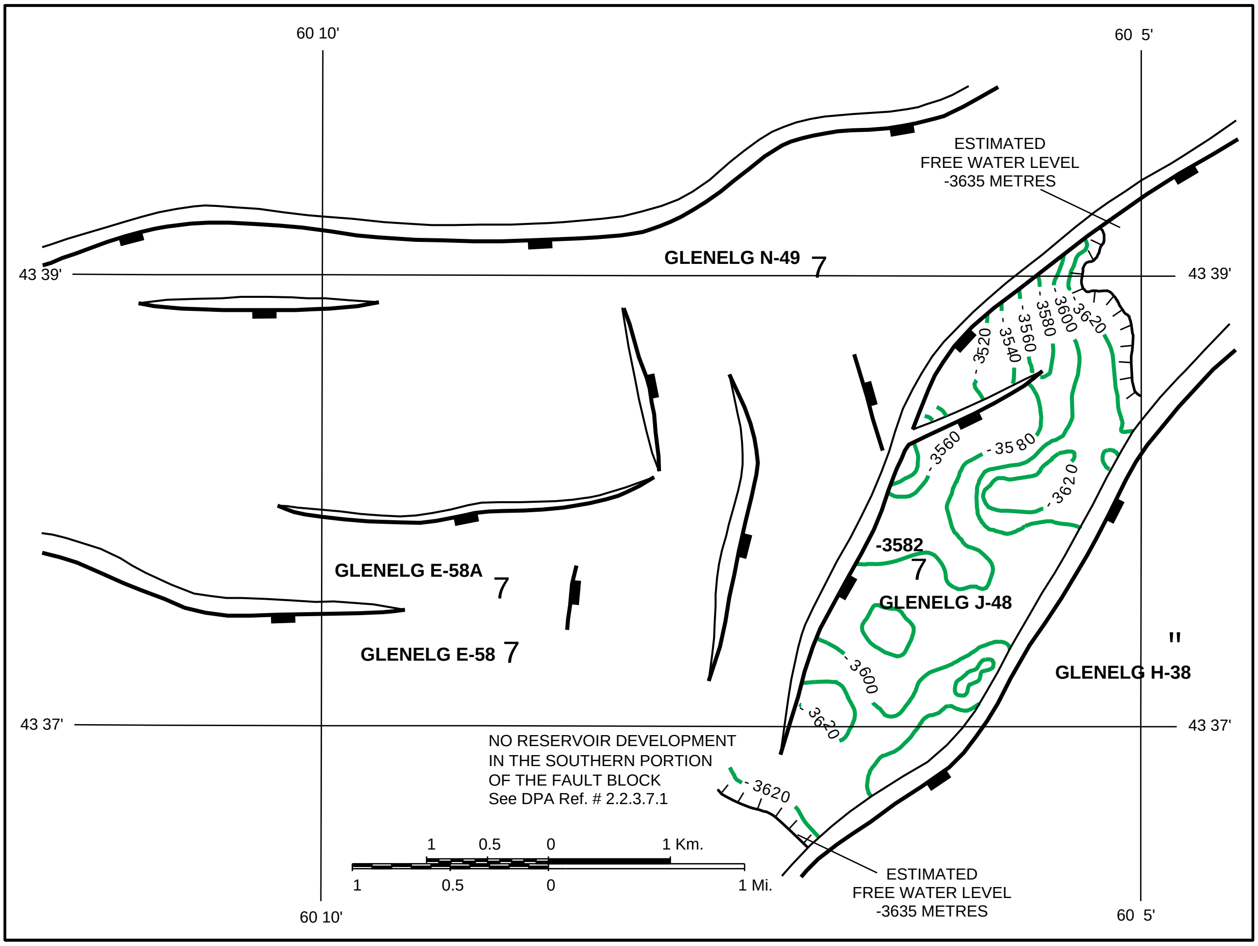


Figure 2.2.5.3.1 (b): Glenelg - F Pool, Depth Structure Map
Contour Interval: 20 metres

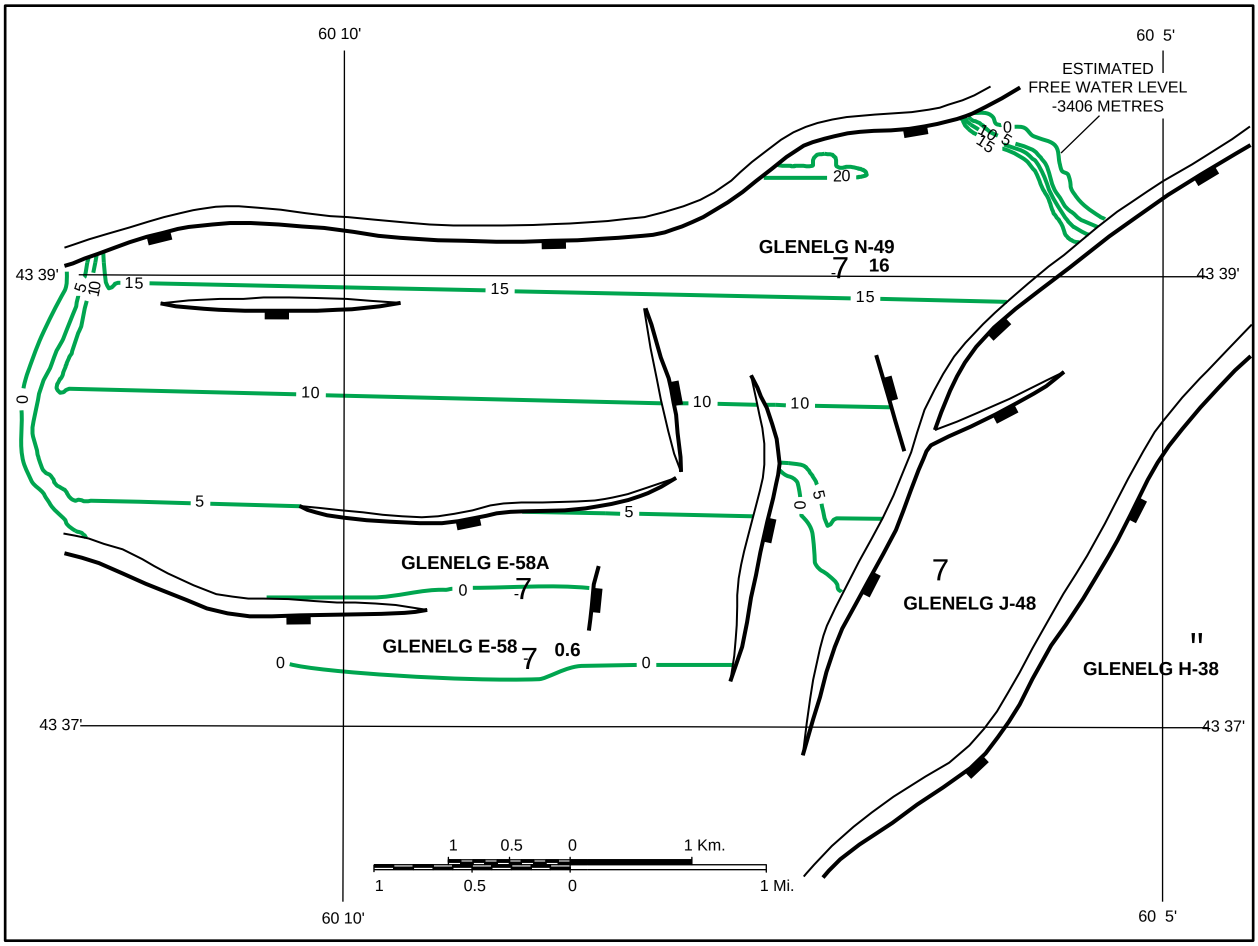


Figure 2.2.5.3.2 (a): Glenelg - B Pool, Net Pay Map
Contour Interval: 1 metre

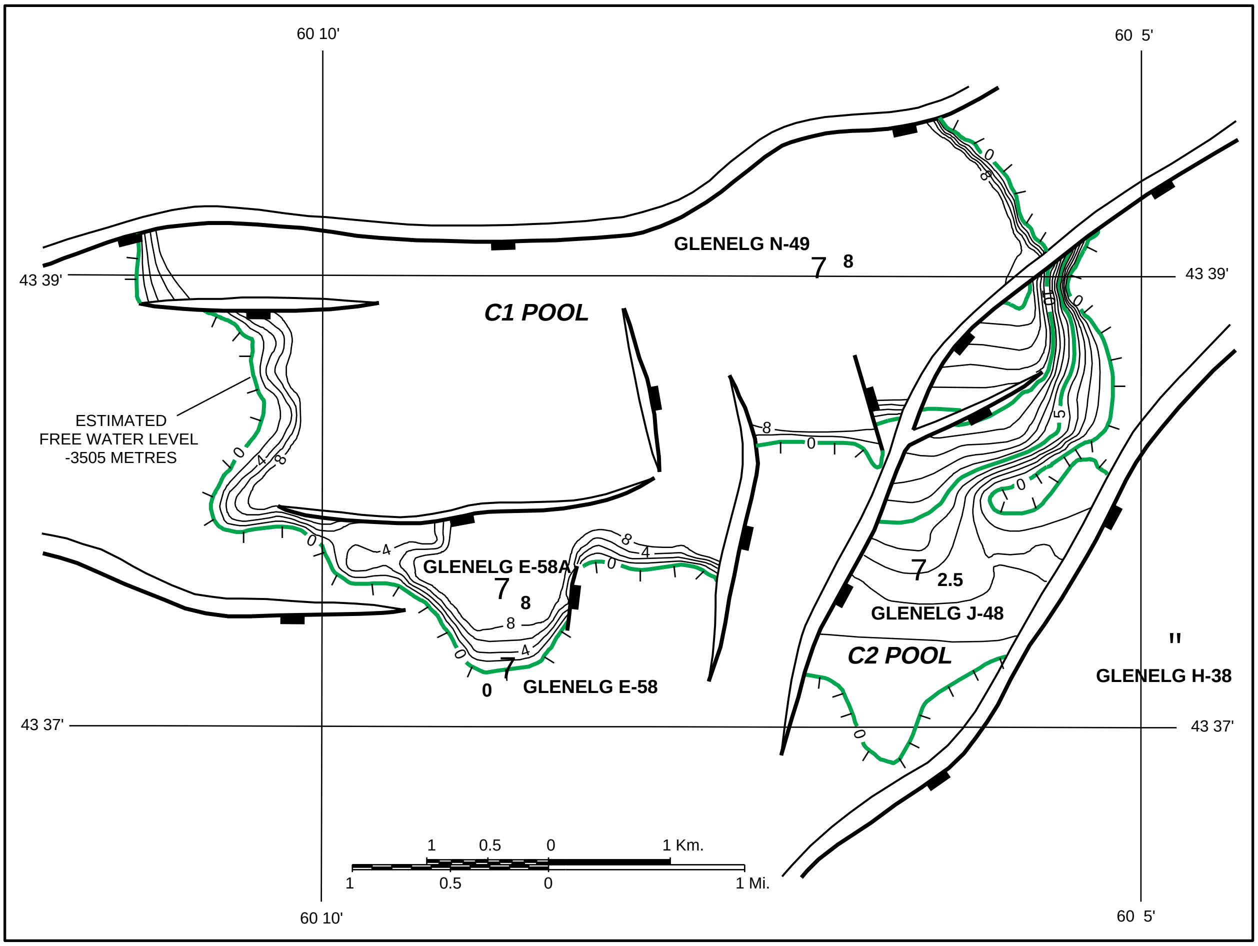


Figure 2.2.5.3.2 (b): Glenelg - C1/C2 Pool, Net Pay Map
Contour Interval: Variable, 1 - 2 Metres

Note: Change of mapping horizon between J-48 and N-49 fault blocks. Refer to text and structural cross-section (Figure 2.2.5.4.1).

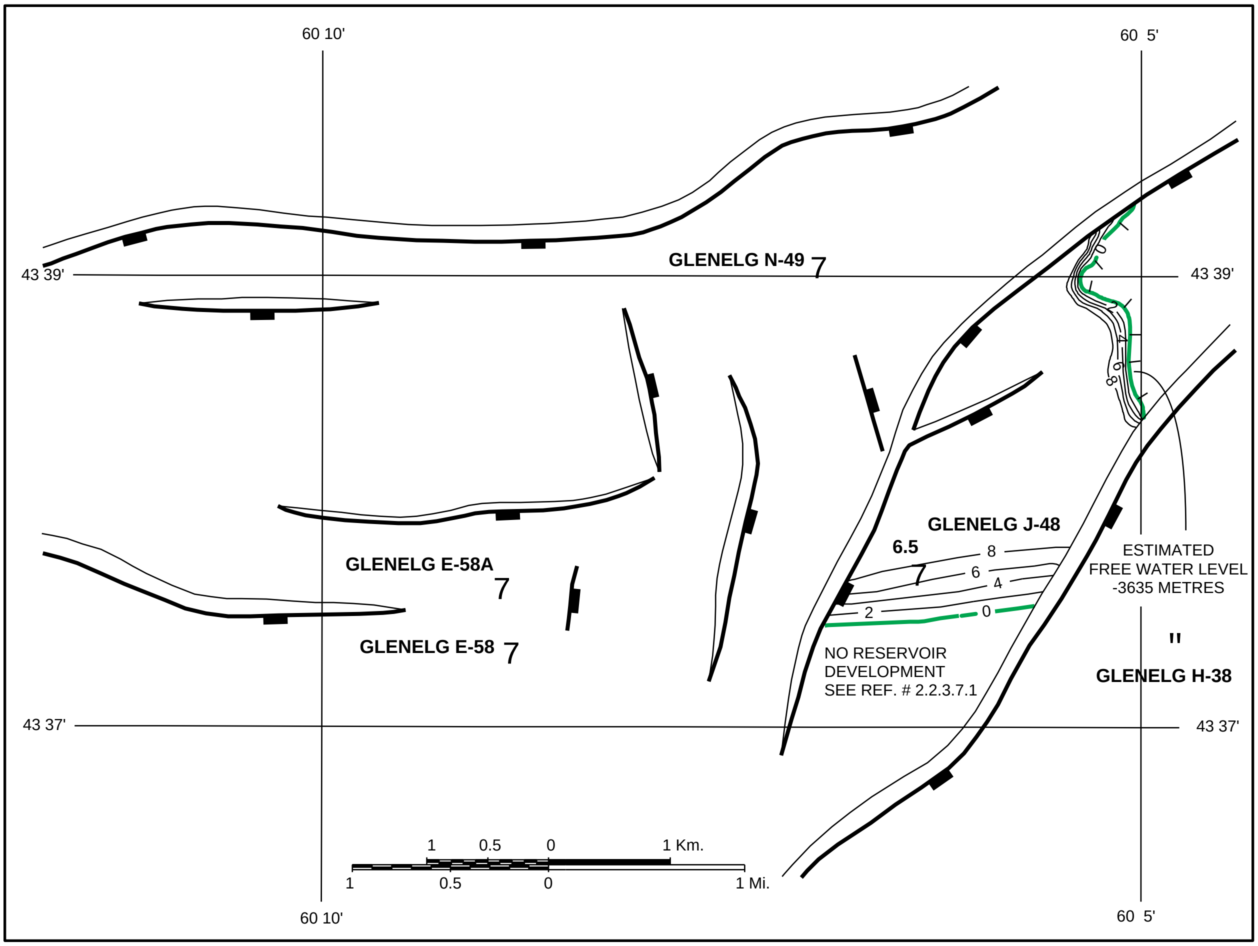


Figure 2.2.5.3.2 (c): Glenelg - F Pool, Net Pay Map
Contour Interval: 2 metres

2.2.5.4 Reservoir Zonation

The presence of hydrodynamically separate, stacked, gas accumulations in the Glenelg Field is indicated by pressure data and the intersection by the wells of several discrete gas/water contacts. This necessitates division of the reservoir interval into a number of zones. Zone boundaries are taken at the base of shale intervals believed, on the basis of pressure work, to be seals to gas migration. Each reservoir zone has, for the purpose of initial modeling of recoverable gas reserves, been treated as a single flow unit (**DPA - Part 2, Ref. # 23.1.3.5**). **Figure 2.2.5.4.1** illustrates a Glenelg schematic structural cross-section.

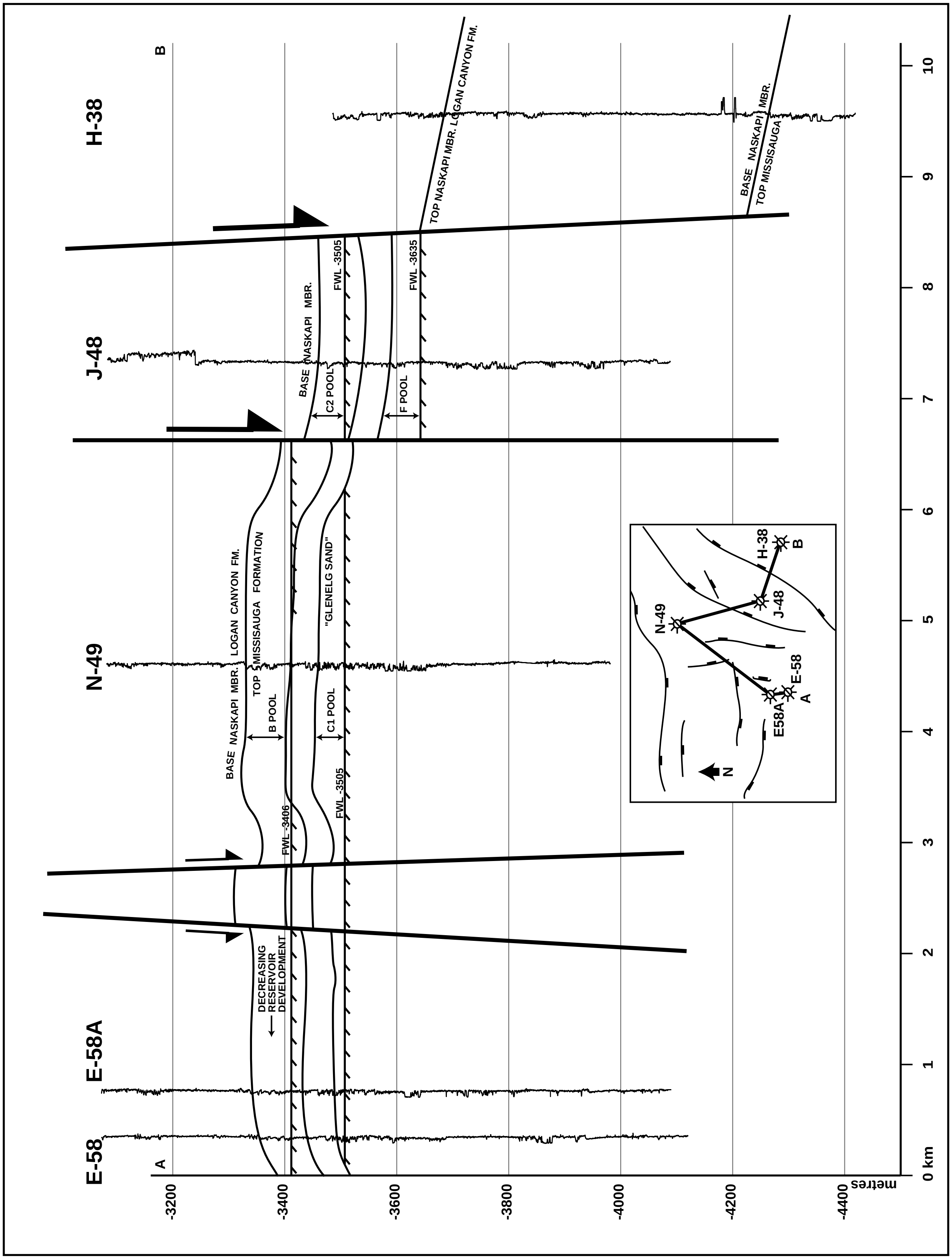


Figure 2.2.5.4.1: Glenelg Schematic Structural Cross-section

2.2.5.5: Geophysics

2.2.5.5.1: Seismic Database

The depth structure map used for gas in place estimates is based on a 3D seismic dataset covering 333 square kilometres (illustrated in **Figure 2.2.5.5.1.1**) and was acquired in 1984-1985. Acquisition and processing details are illustrated in **Table 2.2.5.5.1.1**. Seismic data quality is good down to the objective level Top Missisauga.

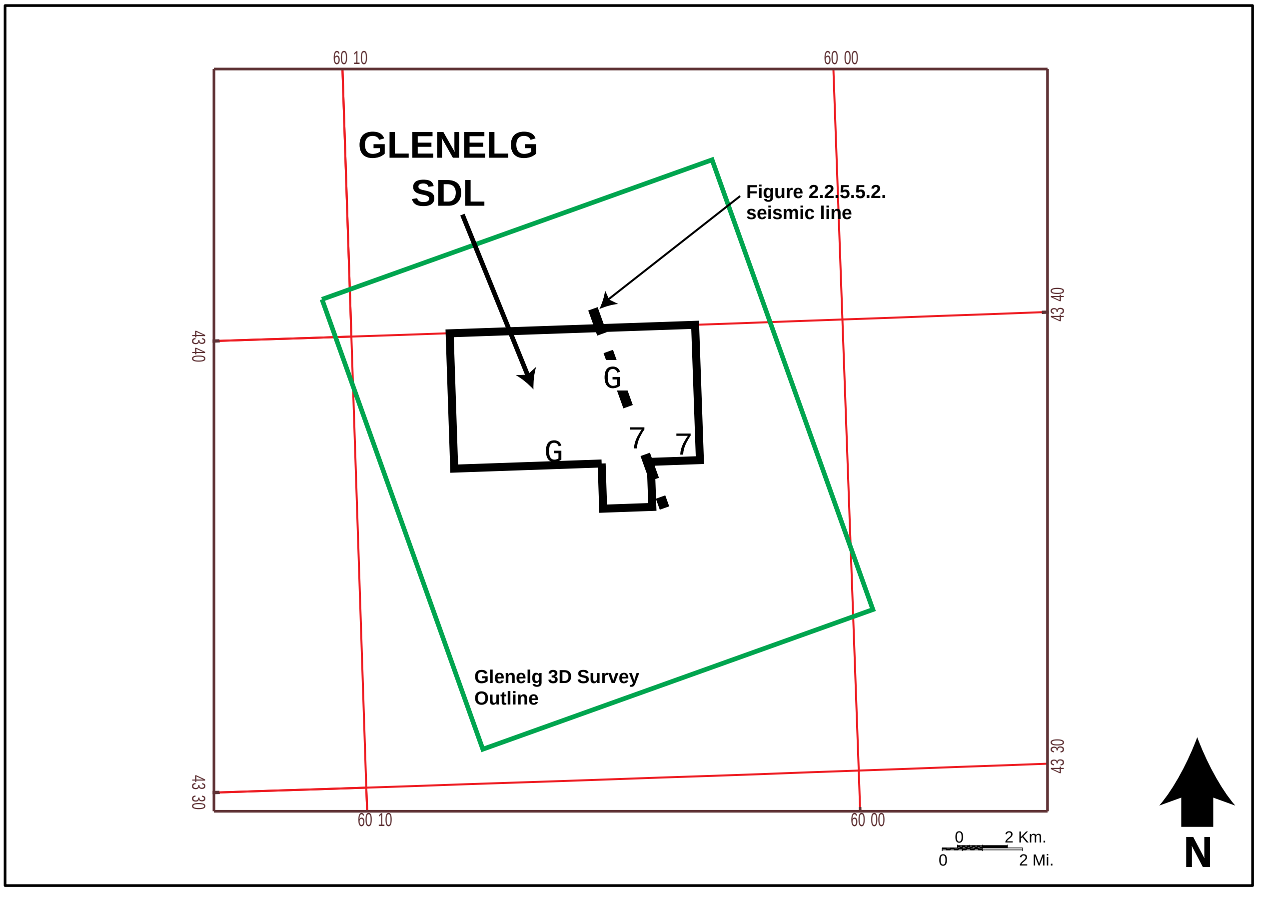


Figure 2.2.5.5.1.1: Glenelg Seismic Database Map

Table 2.2.5.5.1.1: Glenelg Acquisition and Processing Summary

Data Type	Survey Name	Incorp. In Study	Acq. Date	Acq. Style	Proc. Date	Field Kms	Proc. Details	Comments
3D	041E	Yes	1984-85	Marine	1895-86	333km2	40 Fold, Desig, FK Migration	Generally good data quality
2D	048E	No	1985	Marine	1986	201	60 Fold, Desig, FK Migration	Generally very good data quality
2D	033E	Yes	1982	Marine	1983	783	54 Fold, Desig, FD Migration	Generally poor to fair data quality
2D	027E	Yes	1981	Marine	1981	320	60 Fold, Desig, FD Migration	Generally poor data quality
2D	023E	Yes	1980	Marine	1980	315	48 Fold, Desig, FD Migration	Generally poor to fair data quality
2D	020E	No	1976	Marine	1976	108	24 Fold, No Mig	Generally poor data quality

2.2.5.5.2 Time Interpretation

Interpretation of the Glenelg 3D seismic dataset commenced in 1986 on a Landmark III™ workstation. Time structure maps for the Wyandot, Top Lower Logan Canyon, Naskapi, and Top Missisauga horizons were created, and are included in Part Two of this document (**DPA - Part 2, Ref. # 2.2.5.1.2**). The Top Missisauga Event, correlated from well control (**Table 2.2.5.5.2.1**), was selected as the main mapping horizon and used to define this large complex structure. In order to produce structure maps for the four main pools (B, C1, C2 and F), it was assumed that sands within the Missisauga Formation (eg. the Glenelg Sand) parallel the Top Missisauga marker (**DPA - Part 2, Ref. # 2.2.3.7.1**). A representative seismic line from the 3D survey is illustrated in **Figure 2.2.5.5.2.2.**

Table 2.2.5.5.2.1: Glenelg Horizon Markers

FIELD	Glenelg															
	H-38				J-48				N-49				E-58			
MAP HORIZON	Depth MD (m)	Depth TVD (m)	Depth (Mss)	TWT (sec)	Depth MD (m)	Depth TVD (m)	Depth (Mss)	TWT (sec)	Depth MD (m)	Depth TVD (m)	Depth (Mss)	TWT (sec)	Depth MD (m)	Depth TVD (m)	Depth (Mss)	TWT (sec)
Wyandot Chalk	1673	1673	-1649	1.642	1646	1646	-1622	1.612	1571	1571	-1548	1.559	1586	1586	-1562	1.574
Top L.Logan Can.	2458	2440	-2416	2.142	2302	2302	-2278	2.044	2280	2280	-2257	2.030	2247	2247	-2223	2.009
Naskapi	3702	3699	-3675	2.804	3135	3135	-3111	2.513	3056	3056	-3033	2.476	3103	3103	-3079	2.500
Missisauga	4268	4262	-4238	3.104	3491	3491	-3467	2.702	3350	3350	-3327	2.635	3380	3380	-3356	2.649
Verrill Canyon	4495	4489	-4465	3.212	3982	3982	-3958	2.940	3670	3670	-3647	2.792	3905	3905	-3881	-
Jurassic "S"	-	-		-	4760	4760	-4736	3.400	-	-		-	-	-		-
TD	4865				5148				4040					4154		

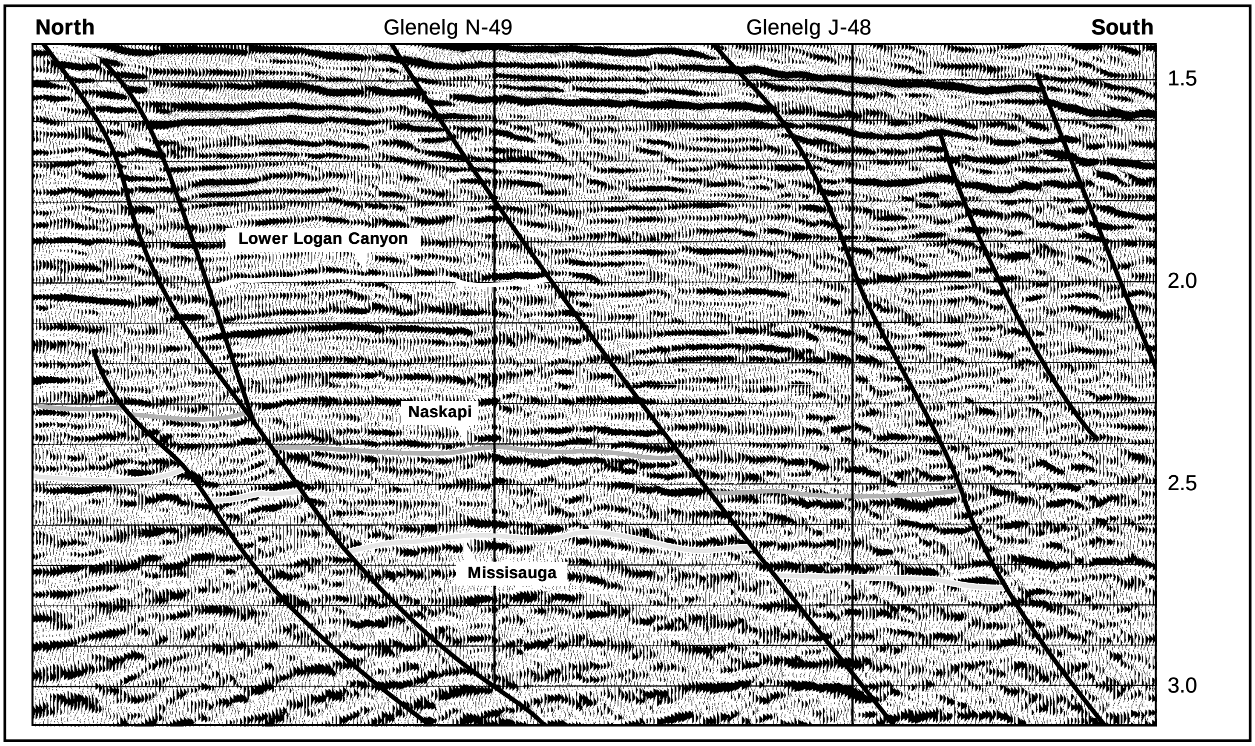


Figure 2.2.5.5.2.1: Glenelg Seismic Section

2.2.5.5.3 Depth Conversion

Utilization of time-depth functions derived from well control was found to be a more satisfactory method of depth conversion than relying on smoothed average stacking velocities. Time structure maps were generated and time-depth functions derived from the well control were used to generate depth maps (**DPA - Part 2, Ref. # 2.2.5.5.2.1**).

Table 2.2.5.5.3.1: Glenelg Well Velocity Data

Well	Year Acquired	Checkshot Available	Checkshot Type	VSP Available	VSP Type
Glenelg J-48	1983	Yes	Vertical	No	NA
Glenelg E-58	1984	Yes	Vertical	Yes	Vertical
Glenelg H-38	1985	Yes	Vertical	No	NA
Glenelg N-49	1986	Yes	Vertical	Yes	Vertical

2.2.5.6 Petrophysics

Petrophysical evaluation of the four Glenelg wells used all available log data, conventional core analysis data and pressure data. A detailed summary of the interpretation parameters and methodology is included in Part Two of this document (**DPA - Part 2, Ref. # 2.2.5.6.1**). Given the lack of special core analyses on Glenelg core, and the perceived similarities between reservoirs in the Glenelg and Alma fields, Alma special core analyses results were used for examination of the Glenelg Field. The results of this evaluation are illustrated in **Table 2.2.5.6.1**.

Tables 2.2.5.6.1: Glenelg Reservoir Parameter Summary

Glenelg E-58 K.B. 24 Metres

Sand Unit	Measured Depth		Elevation		Gross Thickness (m)	Net Pay (m)	Average Porosity (%)	Average Sw (%)	Average Permeability* (mD)
	Top (m)	Base (m)	Top (m ss)	Base (m ss)					
B	3380	3468	-3356	-3444	88	0.6	11.3	0.51	-
C1	3520	3573	-3496	-3549	53	1.6	15.2	0.56	-

Glenelg E-58A K.B. 24 Metres

Sand Unit	Measured Depth		Elevation		Gross Thickness (m)	Net Pay (m)	Average Porosity (%)	Average Sw (%)	Average Permeability* (mD)
	Top (m)	Base (m)	Top (m ss)	Base (m ss)					
B	3413	3506	-3346	-3436	91.5	-	-	-	-
C1	3566.0	3626.0	-3494.0	-3552.0	58.0	8.0	14.0	40.0	1.8

Glenelg N-49 K.B. 23 Metres

Sand Unit	Measured Depth		Elevation		Gross Thickness (m)	Net Pay (m)	Average Porosity (%)	Average Sw (%)	Average Permeability* (mD)
	Top (m)	Base (m)	Top (m ss)	Base (m ss)					
B	3350.0	3426.0	-3327.0	-3403.0	76.0	16.5	16.0	24.0	5.0
C1	3476.0	3523.0	-3453.0	-3552.0	68.0	8.0	15.0	21.6	-

Glenelg J-48 K.B. 24 Metres

Sand Unit	Measured Depth		Elevation		Gross Thickness (m)	Net Pay (m)	Average Porosity (%)	Average Sw (%)	Average Permeability* (mD)
	Top (m)	Base (m)	Top (m ss)	Base (m ss)					
C2	3477.0	3557.0	-3453.0	-3533.0	80.0	2.5	20.0	17.0	30.0
F	3606	3629	-3582	-3605	23	6.5	15.0	22.0	1.8

* Estimated from DSTs

Average porosity ranges from 14 to 18 percent in the four major gas bearing zones. The primary control on porosity is average grain size. Irreducible water saturations, as calculated from logs, range from 17 to 60 percent. Porosity was calculated from density calibrated to stressed core porosity measurements. Water saturation values used in the estimation of gas in place was calculated using the Archie equation. Cementation and saturation exponent values were based on special core analysis from the Alma Field. Formation water resistivity was derived from RFT and DST fluid sample analysis. A formation temperature gradient was determined from bottom hole temperature measurements. Net pay cutoff criteria were based on core analysis data.

Net pay thickness was determined based on a permeability cutoff of 1.0 mD to air at ambient conditions. This was found to correspond to an in situ porosity value of 10 percent and a water saturation cutoff of 70 percent.

2.2.5.7 Gas in Place

The ranges of uncertainty of the parameters utilized in the probabilistic assessment of gas in place are detailed in Part Two (**DPA - Part 2, Ref # 2.2.5.7.1**). The results for the main pools in the Glenelg Field are presented in **Table 2.2.5.7.1**.

Deterministic gas in place estimates, performed in 1990 and 1991, used average reservoir porosity and water saturation values determined from well petrophysics and average net pay values. The latter were determined from convolving the reservoir development model with what was then considered the 'most likely' structure maps for the area of the B, C1/C2, and F pools. This information is presented in detail in Part Two (**DPA - Part 2 Refs. # 2.2.3.7.1 and # 2.2.3.7.2**). The results are presented in **Table 2.2.5.7.2**. The deterministic volumes are similar to the P50 and Mean values obtained from the probabilistic method.

Table 2.2.5.7.1: Glenelg Field Probabilistic Estimates of Gas In Place

Reservoir Sandstone	P90	P50	P10	Mean (E9M3)
B	2.8	6.5	10.8	**6.7**
C1	2.9	3.9	4.9	**3.9**
C2	0.3	0.4	0.6	**0.4**
F	1.0	1.3	1.6	**1.3**
Project Total	7.1	12.1	17.8	**12.4**

Table 2.2.5.7.2: Glenelg Field Deterministic Estimates of Gas In Place

Reservoir Sandstone	Gas in Place (E9M3)
B	6.3
C1	3.9
C2	0.5
F	1.1
Project Total	11.8

2.2.6 ALMA FIELD

2.2.6.1 Field History

The Alma Field was discovered in 1984 (**DPA - Part 2, Ref. # 2.2.6.1.1**). The discovery well, Alma F-67, encountered stacked, hydropressured, gas pay in a number of separate pools in the uppermost 200 metres of the Missisauga Formation. During drillstem testing, gas flowed at rates of up to 842 E3M3/d. Follow-up drilling consists of one well, Alma K-85. This well encountered gas pay throughout the Missisauga Formation. A depth structure map for the top Missisauga Formation at Alma is shown in **Figure 2.2.6.1.1**.

Figure 2.2.6.1.1: Alma - Top Missisauga (Top A Pool), Depth Structure Map
Contour Interval: 25 metres

2.2.6.2 Structural Configuration

The Alma structure consists of a rollover anticline bound to the north and south by major listric faults. The crestal portion of the rollover anticline is divided into two highs within which each of the wells were drilled. It is complicated by a number of northeast/southwest striking normal (possibly growth) faults with minor down-to-east throws. The field lies at an average depth of 2940 metres and covers an area of some 32 square kilometres.

Separate structural maps have to be constructed for each reservoir zone because of lateral and temporal variation in growth and sedimentation along the northern bounding fault. **Figure 2.2.6.2.1(a-b)** shows the structural configuration at the tops of the B and C Sands, respectively.

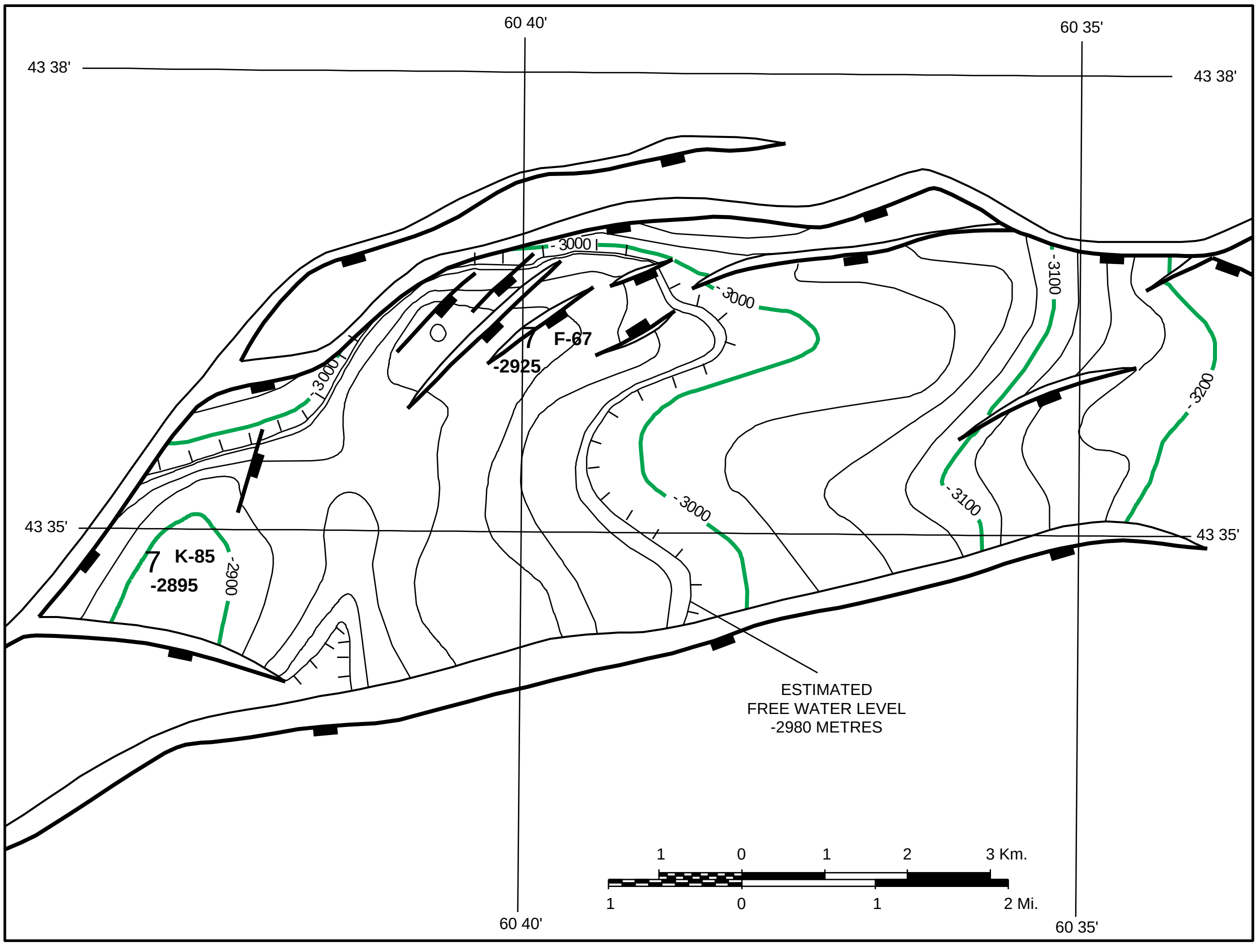


Figure 2.2.6.2.1(a): Alma - Top B Sand, Depth Structure Map
Contour Interval: 25 metres

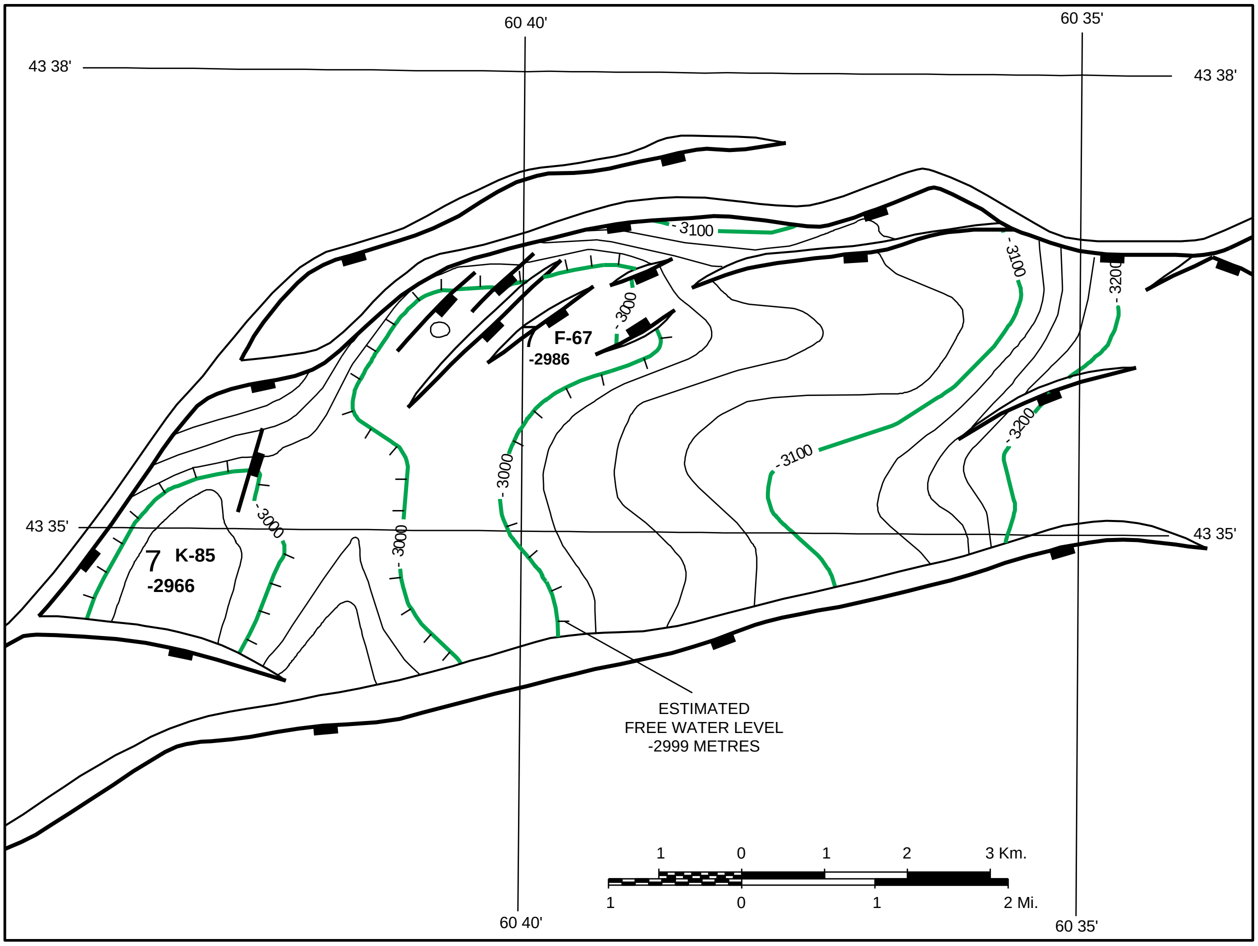


Figure 2.2.6.2.1(b): Alma - Top C Sand, Depth Structure Map
Contour Interval: 25 metres

2.2.6.3 Geology

The Alma Field is located near the southernmost extension of sands at the top of the Sable Delta complex. The sandy reservoir section (Missisauga Formation) is approximately 300 metres thick in this area.

Hydropressured gas was encountered throughout the Missisauga Formation in the K-85 well, and in the upper part of the formation in the F-67 well. Five separate pools are recognized. Three of these, A, B, and C, have significant volumes of gas.

The three main pools show simple closure to the east due to the plunge of the rollover anticline. Cross-fault seal is provided to the north by juxtaposition of the reservoir units with shales of the Verrill Canyon Formation, and to the south and west by their juxtaposition with Naskapi and lower Logan Canyon shales.

The Missisauga Formation at Alma is made up of a number of stacked coarsening-upward shale-to-sandstone deltaic cycles. Extensive coring has enabled sedimentological analysis of the reservoir section, much of which is interpreted as delta-fringe sediments. These were deposited on the shelf, several kilometres seaward of the actual shoreline, in shallow waters affected by tidal currents, as well as flood- and storm-generated flows, which carried silt and sand offshore. The uppermost sand unit in Zone A is interpreted, on the basis of sedimentary structures, as being deposited in a more tidally influenced estuarine setting (**DPA - Part 2, Ref. # 2.2.6.3.1**).

Changes in both thickness and sedimentology occur within the reservoir section between the two wells. The succession thins, and becomes less sand-rich in a southwestward direction. This is associated with a degradation in reservoir quality (see Alma: Petrophysics). The reservoir development model used for gas in place determination for the three pools at Alma is one of a north to south tapering wedge. This model combines the effects of a northerly source for the sands with syndepositional downward movement on the northern bounding growth fault; the latter acts to trap most of the reservoir quality sand in the northern portion of the structure. According to this model, reservoir thickness is at a maximum adjacent to the northern bounding fault, and thins systematically southward through the F-67 and K-85 wells, to the southern boundary of the field. Accompanying this trend in reservoir thickness is a southward decrease in grain size, and hence porosity development.

Convolution of this reservoir development model with structure maps and gas/water contacts for each of the pools permits construction of net pay maps. Net pay maps are then used for gas in place determination. **Figure 2.2.6.3.1(a-c)** illustrates the variation in net pay distribution across the Alma structure in the three main pools.

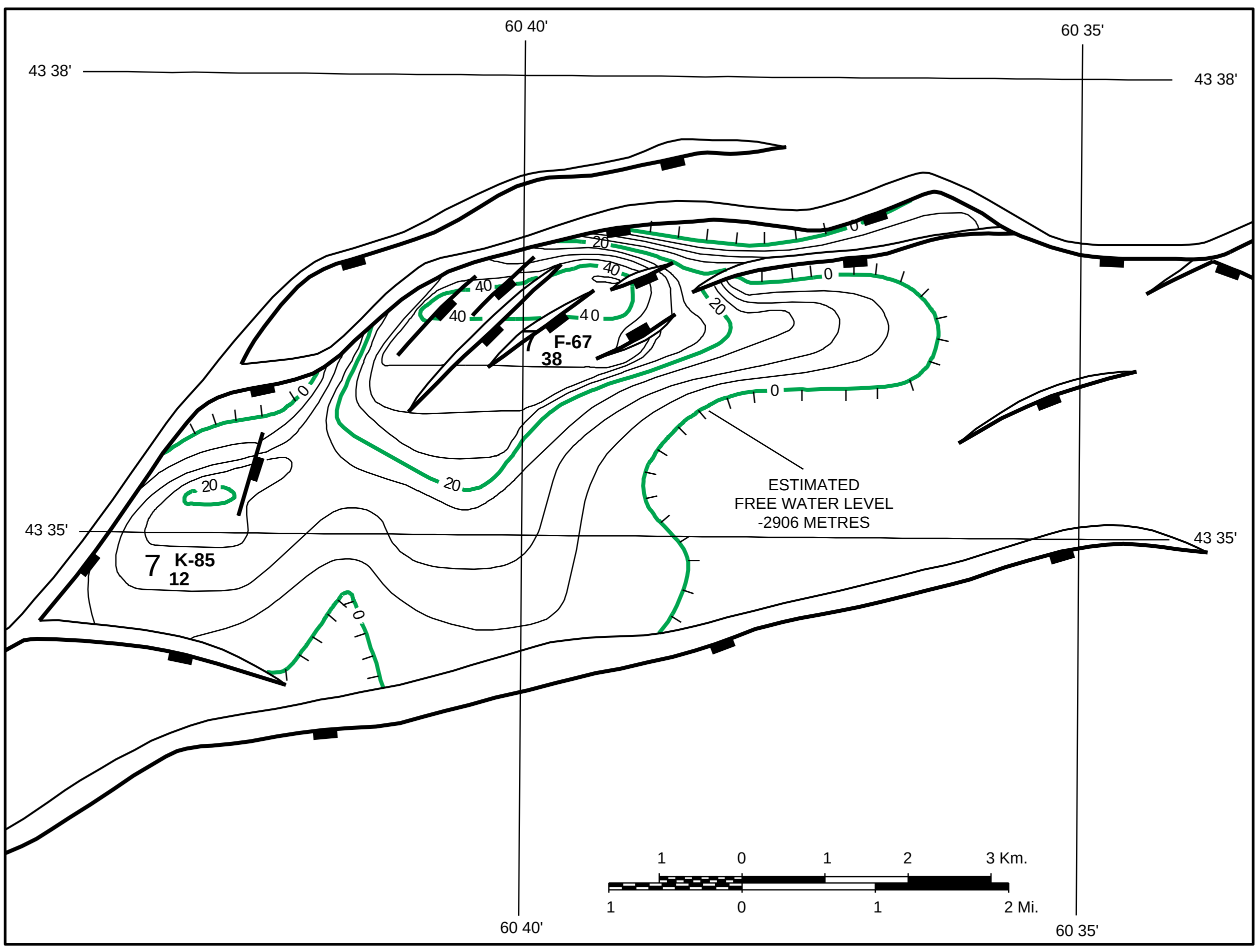


Figure 2.2.6.3.1(a): Alma - A Pool, Net Pay Map
Contour Interval: 5 metres

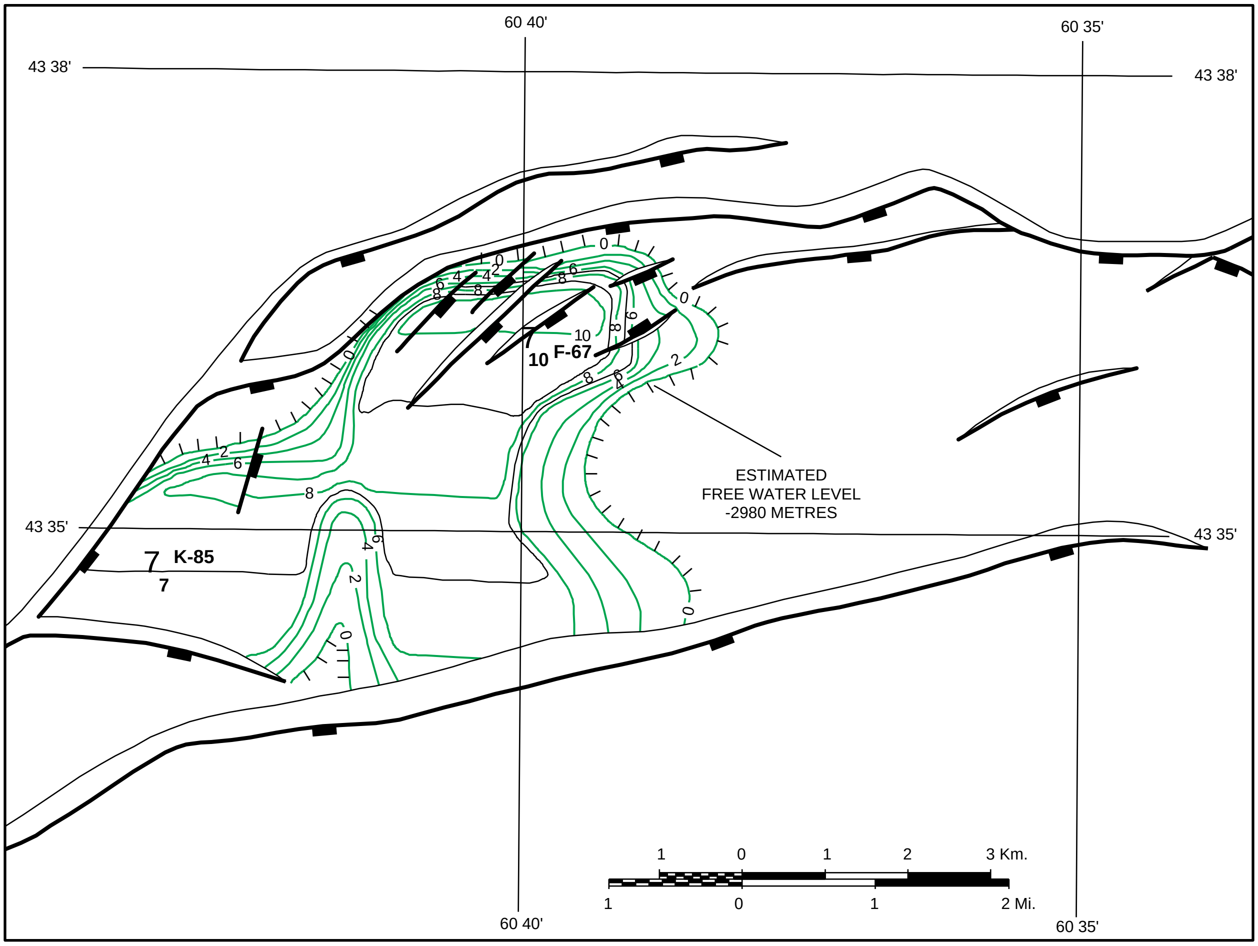


Figure 2.2.6.3.1(b): Alma - B Pool, Net Pay Map
Contour Interval: 2 metres

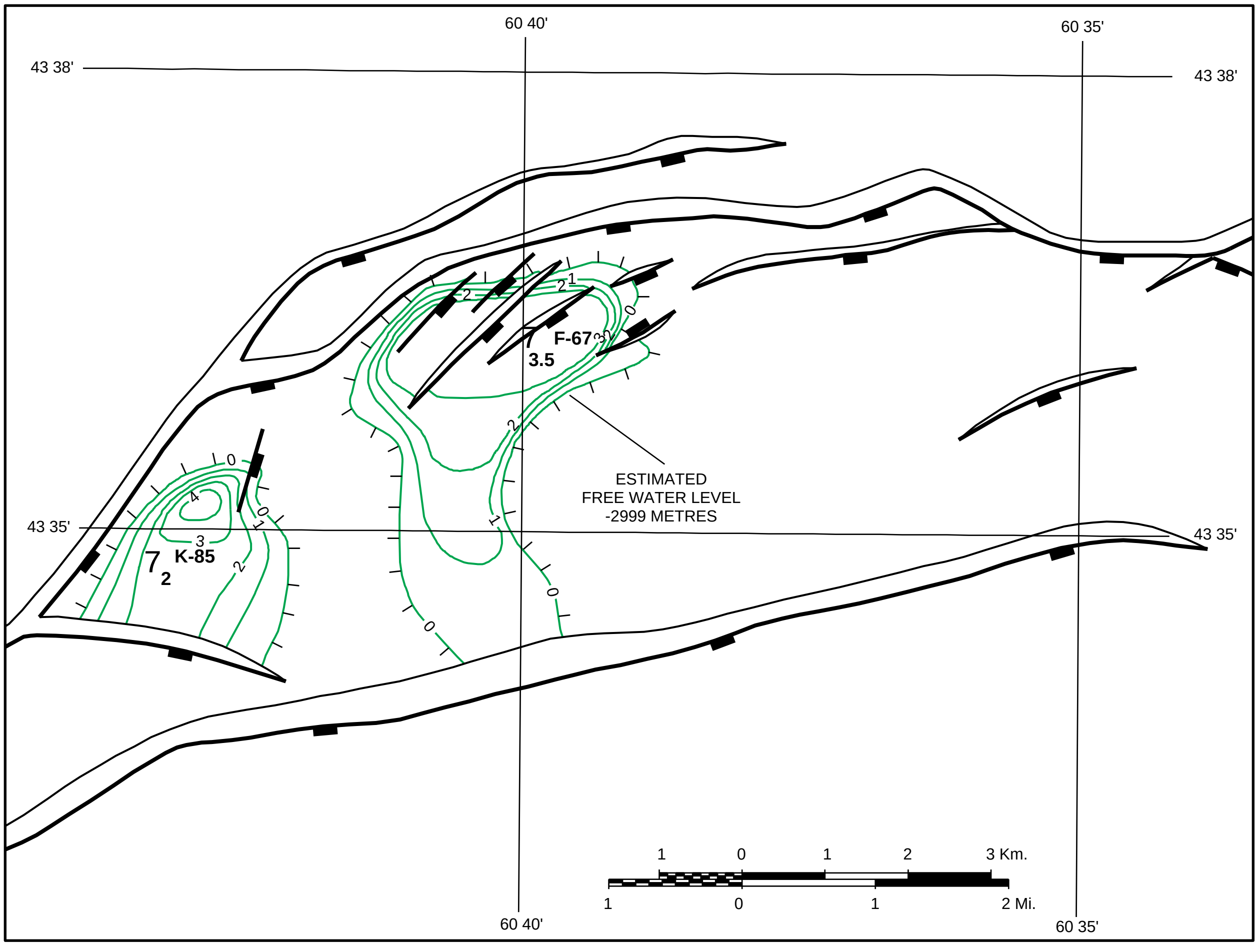


Figure 2.2.6.3.1(c): Alma - C Pool, Net Pay Map
Contour Interval: 1 metre

Log correlatability and reservoir pressure analysis indicate continuity of shales and reservoir intervals between the two wells in the upper two-thirds of the Missisauga Formation. Correlation is more problematic in the lower 75 to 100 metres of the Missisauga. This probably indicates syndepositional growth fault activity between the two wells, which has affected sand distribution patterns.

2.2.6.4 Reservoir Zonation

The Alma reservoir section is divided into five zones in order to reflect the presence of stacked, hydrodynamically separate gas accumulations (**DPA - Part 2, Ref. #2.2.6.4.1**). These separate gas pools are indicated by pressure data and the intersection by the wells of a number of discrete gas/water contacts. Their zone names correspond to the names of the associated gas pool. Zone boundaries are taken at the base of shale intervals believed, on the basis of pressure work, to be seals to gas migration. Each reservoir zone has, for the purpose of initial modeling of recoverable gas reserves, been treated as a single flow unit (**DPA - Part 2, Ref. # 2.3.1.3.6**).

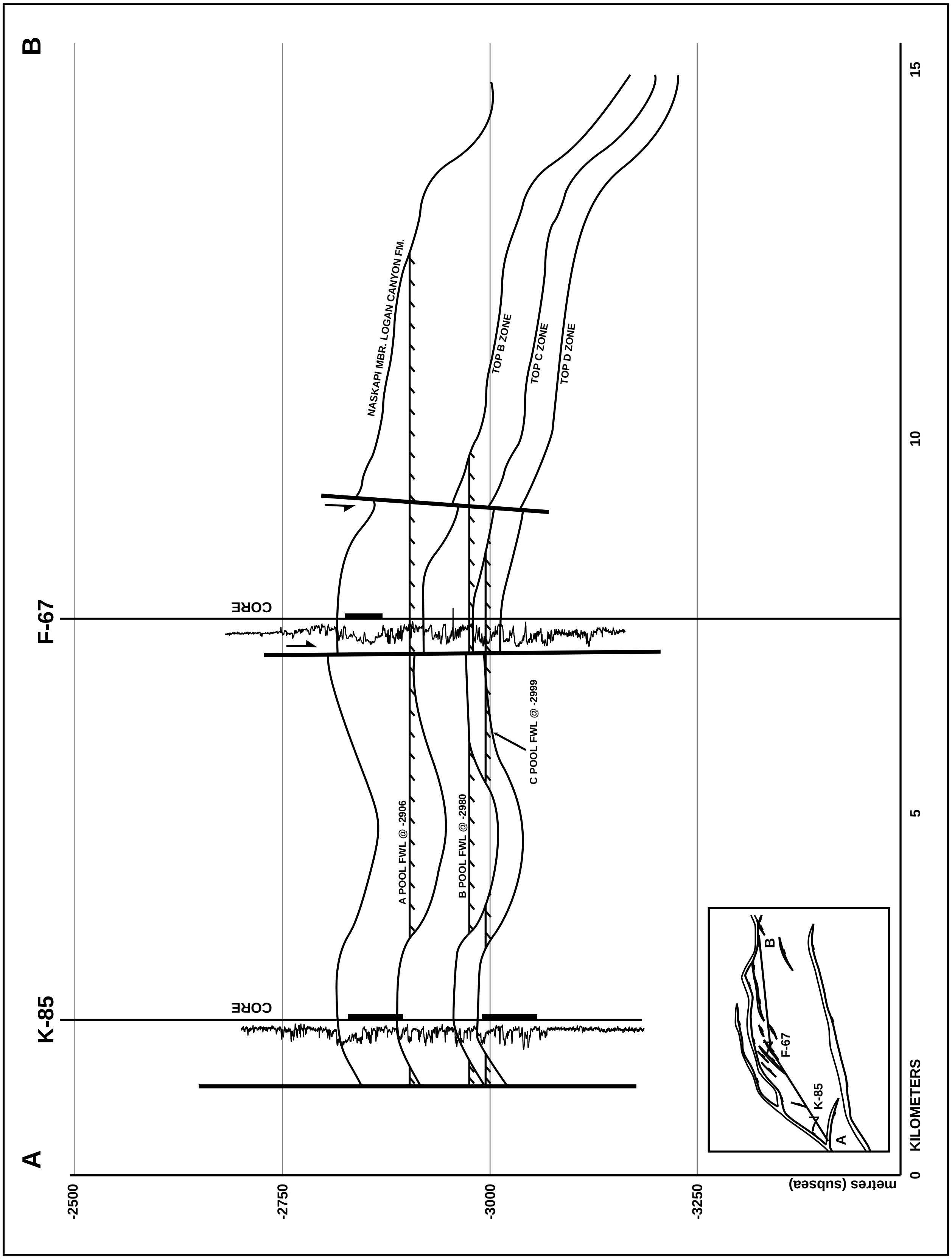


Figure 2.2.6.4.1: Alma Schematic Structural Cross-section

2.2.6.5 Geophysics

2.2.6.5.1 Seismic Database

The depth structure maps used to appraise reserves in Alma are based on a 2D seismic dataset consisting of lines acquired throughout the period 1981-1984. This is illustrated in **Figure 2.2.6.5.1.1**. Seismic data quality is generally fair to good to the objective level. A summary of acquisition and processing details is given in **Table 2.2.6.5.1.1.**

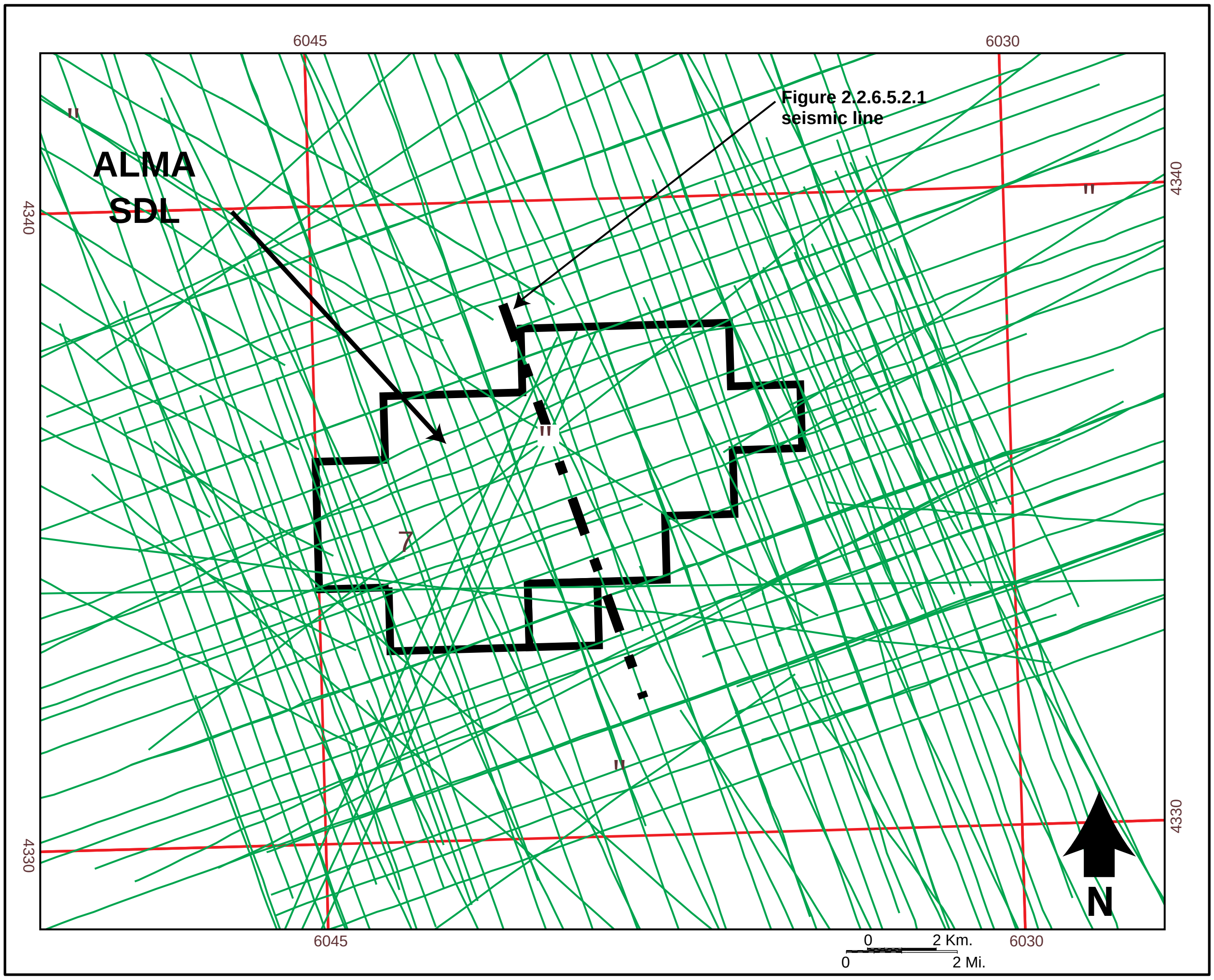


Figure 2.2.6.5.1.1: Alma Seismic Database Map

Table 2.2.6.5.1.1: Alma Acquisition and Processing Summary

Data Type	Survey Name	Incorp. In Study	Acq. Date	Acq. Style	Proc. Date	Field Kms	Proc. Details	Comments
2D	8624-s006-048E	No	1985	Marine	1985	376	60 Fold, Desig, FK Migration	Generally good quality data.
2D	8624-S006-043E	Yes	1984	Marine	1984	212	60 Fold, Desig, FD Migration	Generally fair to good data quality.
2D	8624-S006-037E	Yes	1983	Marine	1983	56	80 Fold, Desig, FK Migration	Generally fair to good data quality.
2D	8624-S006-037E	Yes	1983	Marine	1983	156	54 Fold, Desig, FD Migration	Generally fair to good data quality.
2D	8624-S006-033E	Yes	1982	Marine	1982	266	50 Fold, Desig, FD Migration	Generally good data quality.
2D	8624-S006-027E	Yes	1981	Marine	1982	571	60 Fold, Desig, FD Migration	Generally fair to good data.
2D	8624-S006-020E	No	1976	Marine	1973	19	24 Fold, No Mig	Generally poor data quality.

2.2.6.5.2 Time Interpretation

The 2D seismic data were interpreted manually and time structure maps were made for the Wyandot, Base Sable Shale, Naskapi, and Top Missisauga horizons. The Top Missisauga Event, correlated from well control (**Table 2.2.6.5.2.1**), was used as the main mapping horizon. Alma contains three main sand units which thin in a distal direction. The A Sand is assumed to be conformable to the Top Missisauga. However, the B and C Sand surfaces are not subparallel to the Top Missisauga and so new structure maps were created for these sands by summing wedges equal to the isopach thicknesses for the well tops of Sands A to B and tops A to C, respectively. This information is include in Part Two (**DPA - Part 2, Ref. # 2.2.3.7.1**).

Table 2.2.6.5.2.1: Alma Horizon Markers

FIELD	ALMA							
	F-67				K-85			
MAP HORIZON	Depth MD (m)	Depth TVD (m)	Depth (Mss)	TWT (sec)	Depth MD (m)	Depth TVD (m)	Depth (Mss)	TWT (sec)
Wyandot Chalk	1312	1312	-1288	1.317	1323	1323	-1299	1.332
Top L. Logan Can.	1878	1878	-1854	1.711	1877	1877	-1853	1.720
Naskapi	2543	2543	-2519	2.108	2523	2525	-2501	2.106
Missisauga	2843	2842	-2818	2.270	2843	2843	-2819	2.287
Verril Canyon	3107	3107	-3083	2.384	3111	3106	-3082	2.428
TD	5054				3602			

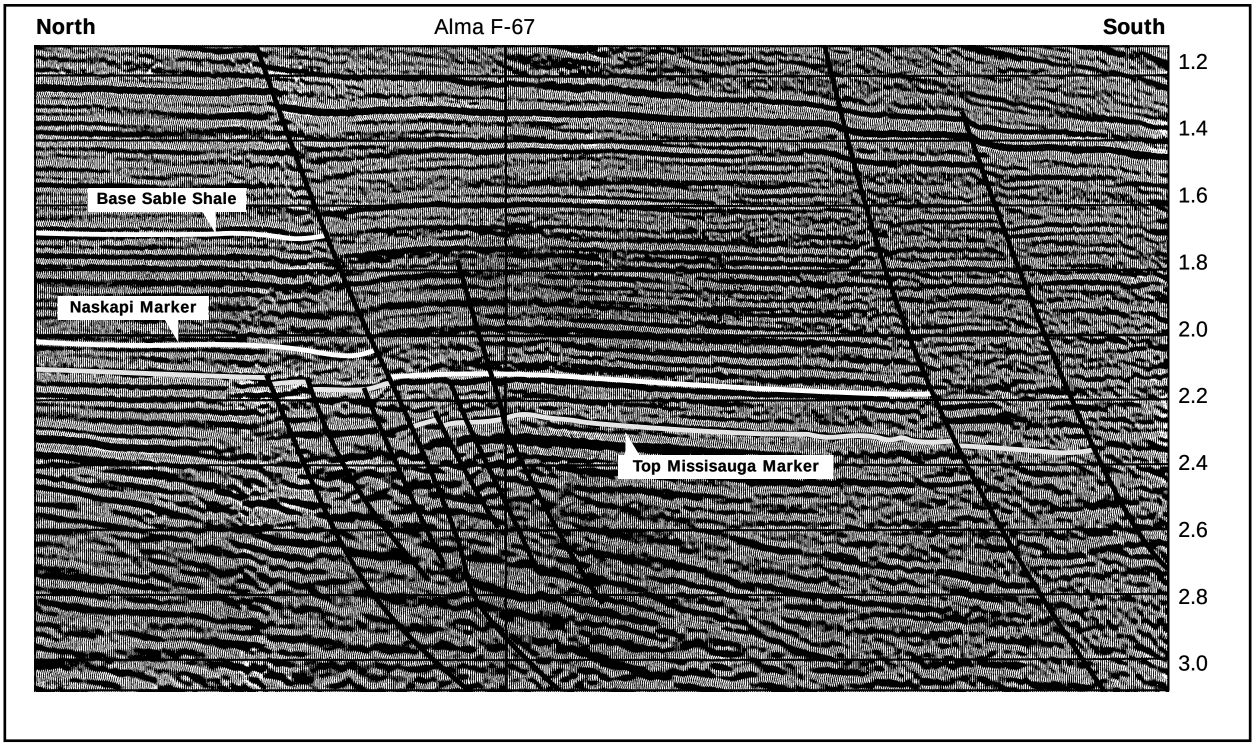


Figure 2.2.6.5.2.1: Alma Seismic Section

2.2.6.5.3 Depth Conversion

In a manner similar to the depth conversion work at Glenelg, a replacement velocity was used for the water layer; and time-depth tables, derived from the well control, were used to produce depth maps from the respective horizon time structure maps as illustrated in **Table 2.2.6.5.3.1** (**DPA - Part 2, Ref. # 2.2.6.5.3.1**).

Table 2.2.6.5.3.1: Alma Well Velocity Data

Well	Year Acquired	Checkshot Available	Checkshot Type	VSP Available	VSP Type
Alma F-67	1984	Yes	Vertical	No	NA
Alma K-85	1985	Yes	Vertical	No	NA

2.2.6.6 Petrophysics

A detailed petrophysical evaluation of the two wells in the Alma reservoir has been conducted using all available wireline log data, conventional and special core analysis data and pressure data. A detailed summary of the interpretation parameters and methodology is included in Part Two (**DPA - Part 2, Ref. # 2.2.6.6.1**). The results of this evaluation are illustrated in **Table 2.2.6.6.1**.

Table 2.2.6.6.1: Alma Reservoir Parameter Summaries

Alma F-67 K.B. 2.40 Metres

Sand Unit	Measured Depth Top (m)	Measured Depth Base (m)	Elevation Top (m ss)	Elevation Base (m ss)	Gross Thickness (m)	Net Pay (m)	Average Porosity (%)	Average Sw (%)	Average Permeability* (mD)
A	2842.0	2949.0	-2818.0	-2925.0	107.0	38.2	15.0	42.0	6-54
B	2949.0	3010.0	-2925.0	-2986.0	61.0	10.1	18.0	49.0	5-15
C	3010.0	3045.0	-2986.0	-3021.0	35.0	3.5	14.0	48.0	2

Alma K-85 K.B. 24.0 Metres

Sand Unit	Measured Depth Top (m)	Measured Depth Base (m)	Elevation Top (m ss)	Elevation Base (m ss)	Gross Thickness (m)	Net Pay (m)	Average Porosity (%)	Average Sw (%)	Average Permeability* (mD)
A	2843.0	2919.0	-2819.0	-2895.0	76.0	12.1	16.0	27.0	60
B	2919.0	2990.0	-2895.0	-2966.0	71.0	7.0	15.0	39.0	10-67
C	2990.0	3017.0	-2966.0	-2993.0	57.0	2.0	14.0	56.0	3-20

*Estimated from DSTs

The bulk of reserves in the Alma Field are contained in three separate hydropressured reservoirs, with individual gas/water contacts. Average porosity ranges from 15 to 18 percent with the primary control on porosity being average grain size. Irreducible water saturations, as calculated from logs, range from 10 to 60 percent. Porosity was calculated from density logs calibrated to stressed core porosity measurements. Water saturation values used in the estimation of gas in place were calculated using the Archie equation. Cementation and saturation exponent values were based on special core analysis stressed formation resistivity factor and resistivity index measurements. Formation water resistivity was derived from RFT and DST fluid sample analysis. A formation temperature gradient was determined from bottom hole temperature measurements. Net pay cutoff criteria were based on core analysis data. Net pay thickness was determined based on a permeability cutoff of 1.0 mD to air at ambient conditions. This was found to correspond to an in situ porosity value of 10 percent and a water saturation cutoff of 60 percent.

2.2.6.7 Gas in Place

The ranges of uncertainty of the parameters utilized in the probabilistic assessment of gas in place are detailed in Part Two (**DPA - Part 2, Ref # 2.2.5.7.1**)**.** The results for the three main pools in the Alma Field are presented in **Table 2.2.6.7.1**.

Deterministic gas in place estimates were performed in 1990 and 1991. Average reservoir porosity and water saturation values were determined from well petrophysics and average net pay values. These were determined from the net pay maps, and what was then considered the 'most likely' structure maps for the area of the three pools. The methodology of this deterministic gas in place determination is presented in detail in Part Two (**DPA - Part 2, Refs. #2.2.3.7.1 and #2.2.3.7.2**)**;** the results are presented in **Table 2.2.6.7.2**. The deterministic volumes are similar to the P50 and Mean values obtained from the probabilistic method.

Table 2.2.6.7.1: Alma Probabilistic Estimates of Gas In Place, E9M3

Reservoir Sandstone	P90	P50	P10	Mean
A	8.8	11.4	14.3	11.5
B	2.4	3.1	3.9	3.1
C	0.3	0.4	0.5	0.4
Project Total	11.5	14.9	18.7	15.0

Table 2.2.6.7.2: Alma Deterministic Estimates of Gas In Place, E9M3

Reservoir Sandstone	Gas in Place
A	11.3
B	3.4
C	0.4
Project Total	15.1

Two other pools, D and E, were encountered deeper in the K-85 well. Correlative sands in the F-67 well are wet, indicating either limited gas columns, sand pinchout, or the presence of a sealing fault between the wells. Current interpretation indicates that the reserves contained in these deeper sands in K-85 are too small to warrant inclusion in the **Sable Offshore Energy Project** development.

3.0 RESERVOIR ENGINEERING

Reservoir engineering activities continue throughout the Project. They are aimed at the generation and continual refinement of the physical descriptions of the reservoir for the optimization of economic recovery. At the early project stages prior to development, the subsurface emphasis is on the detailed seismic interpretation combined with reservoir characterization and geologic models for which cores, modern wireline logs and production test information supplements the regional geology and seismic knowledge. These reservoir geological models, developed from the integration of all the subsurface information, provide the input for numerical reservoir simulation studies.

Early simulation activity is aimed at establishing viable project development options and must be inherently flexible to allow for the integration of new data, project scope changes and advancements in new technology. Later in the life of the field, necessary adjustments are made to the reservoir simulators to history match the actual field performance. The reservoir depletion plans must be flexible enough to allow for the implementation of contingency plans should surveillance information prompt revisions to the production scheme.

The following sections describe the data used in the development of a description of the reservoir for the purpose of individual field simulations studies. The fundamental building blocks and the tools used in the development of a production forecast are described, as well as, some of the simulated alternative development options. The chapter ends with a discussion on reservoir management , from development through to operations.

3.1 Reservoir Data

3.1.1 Reservoir Mapping

More than 40 hydrocarbon bearing sands have been identified within the six Project fields. Of these sands, 32 have been identified as having sufficient volume and producibility to form the basis of the production forecast. The sands included in the development of the Project (Project Sands) consist of seven in Thebaud, 12 in Venture, one in North Triumph, five in South Venture, three in Alma and four in Glenelg. These sands have been tested, mapped and incorporated, to varying degrees, into the reservoir modelling work completed to date. The Project Sands and their associated gas in place estimates are shown in **Table 3.1.1.1**.

The shallow sands in all fields will be penetrated with wells targeted for deeper horizons. The relatively small volumes associated with these sands may be produced towards the end of the Project but have not been incorporated into the production forecast. The deeper horizons, Sands 11 and 13 in Venture, and Sands 7 and 8 in South Venture are not included in this development plan because the small volumes and associated high drilling and producing costs render them currently uneconomic. The gas volume associated with these sands is shown in the line entitled *Minor Sand Total* in **Table 3.1.1.1.** Part Two of the Development Plan (**DPA - PART 2, Ref. # 3.1.1.1**) includes a detailed discussion of the viability of the minor sand accumulations.

Table 3.1.1.1 Gas In Place Summary - Project Sands

Field	Reservoir Sandstone	P90 OGIP E9M3	P50 OGIP E9M3	P10 OGIP E9M3	Mean OGIP E9M3
Thebaud	A	6.4	11.9	20.6	12.8
	B	0.7	1.7	3.3	1.8
	F1	0.3	0.9	2.2	1.1
	F3	1.1	2.7	6.0	3.2
	G2	0.5	1.2	2.8	1.5
	G3	1.0	2.3	5.4	2.9
	H2	0.8	2.3	4.8	2.7
	Total	**10.8**	**23.0**	**45.1**	**26.0**
Venture	2	2.5	6.2	12.2	7.0
	A	0.2	0.8	2.1	1.0
	B	0.5	1.4	3.3	1.7
	3	2.9	5.8	11.1	6.6
	4a	0.4	1.0	3.0	1.4
	4c	0.5	1.4	3.7	1.9
	4d	0.3	1.0	3.5	1.6
	5	1.8	5.0	12.2	6.2
	6u	4.7	9.1	16.8	10.1
	6m	2.2	4.8	10.1	5.6
	7	1.0	2.4	5.5	2.9
	8	1.2	2.9	6.2	3.4
	Total	**18.2**	**41.8**	**89.7**	**49.4**
North Triumph	**Total**	**6.2**	**14.2**	**25.2**	**15.2**
South Venture	2	1.3	4.8	7.9	4.8
	3	0.5	1.5	3.1	1.6
	4a	0.6	1.6	3.7	1.9
	5	0.3	0.8	2.0	1.0
	6	0.6	1.7	3.8	2.0
	Total	**3.3**	**10.4**	**20.5**	**11.3**
Alma	A	8.6	11.5	14.4	11.4
	B	2.5	3.1	3.9	3.1
	C	0.4	0.3	0.4	0.5
	Total	**11.5**	**14.9**	**18.7**	**15.0**
Glenelg	B	2.8	6.4	10.8	6.7
	C1	3.0	3.9	4.9	3.9
	C2	0.3	0.5	0.5	0.5
	F	1.0	1.3	1.6	1.3
	Total	**7.1**	**12.1**	**17.8**	**12.4**
Project Total		**57.1**	**116.4**	**217.0**	**129.3**
Minor Sand Total		**1.9**	**6.7**	**18.0**	**8.9**

Note: Mean values have been summed arithmetically.
P90 = 90 % Probability of exceeding posted value.
P10 = 50 % Probability of exceeding posted value.
P10 = 10 % Probability of exceeding posted value.
OGIP = Original Gas In Place

3.1.2 Well Test Data

Data obtained from Drill Stem Tests (DST) for the Project fields have been compiled and is presented in Table 3.1.2.1. The interpretations associated with the highlighted DST's can be found in Part 2 of this submission **(DPA - Part 2, Ref. # 3.1.2.1)**.

The flowing times during cleanup and subsequent production periods varied significantly for all the DST's, ranging from 15 minutes in some of the earlier wells (Venture D-23) to 24 hours in the later wells (North Triumph G-43). The short flow and buildup periods for the earlier wells coupled with the use of mechanical gauges with low pressure sensitivities, leads to some uncertainty in the interpretations. The recent wells used electronic gauges which offered a higher degree of accuracy.

Table 3.1.2.1 Drillstem Test Summary

Well	DST No.	Sand	Top Interval (M-KB)	BHSP (MPa)	BHST (C)	Max. Gas Rate (E3m3/d)	Cond. Ratio (m3/E6m3)	Water Rate (m3/d)	Water Ratio (m3/E6m3)	Cum. Flow Time (hr)	KH (md-m)	Skin	Draw Down (MPa)	Remarks
THEBAUD														
P-84	1OH	2	2935	30	93	300	11	6.6	22	2	—	—	1	
P-84	1	D3	4027	60	126	0	0	0	0	3	—	—	16	
P-84	2	D3	4020	52	—	0	0	1	N/A	3	—	—	29	Tbg load rate
P-84	3	D3	4020	—	117	0	0	3	N/A	7	—	—	—	Tbg load rate
P-84	***4***	***A***	***3830***	—	***104***	—	—	—	—	—	—	—	—	***Misrun***
P-84	***5***	***A***	***3830***	***53***	***111***	***596***	***0***	***0***	***0***	—	—	—	***3***	
P-84	***6***	***A***	***3830***	***52***	***104***	—	—	***0***	—	—	—	—	—	
P-84	***7***	***6a2***	***3402***	***34***	***102***	***195***	***134***	***0***	***0***	***4***	—	—	—	
P-84	***8***	***6a1***	***3364***	***34***	***103***	***88***	***N/A***	—	***0***	***1***	—	—	***16***	***Misrun***
P-84	***9***	***6a1***	***3364***	—	***99***	—	—	—	—	—	—	—	—	***Misrun***
P-84	***10***	***6a1***	***3364***	***34***	—	***147***	***162***	***0***	***0***	***3***	—	—	***7***	
P-84	***11***	***4***	***3213***	***33***	***91***	***150***	***116***	***0***	***0***	***3***	—	—	***2***	
P-84	***12***	***3C***	***3139***	***31***	***85***	***0***	***TSTM***	***0***	***TSTM***	***1***	—	—	—	
I-94	***1OH***	***A***	***3769***	—	—	—	—	—	—	—	—	—	—	***Misrun***
I-94	***2***	***A***	***3769***	***52***	—	***387***	***165***	***0***	***0***	***4***	***299***	***47***	—	
I-93	1	G3	4652	90	137	0	0	0	0	4	—	—	43	No flow
I-93	2	G1	4614	87	134	0	0	0	0	4	—	—	41	No flow
I-93	3	E1	4318	—	—	—	—	—	—	—	—	—		Misrun
I-93	4	E1	4318	75	127	TSTM	0	0	0	7	—	—	62	
I-93	5	D3	4080	62	117	est. @ 0.8	0	TSTM	0	26	—	—	23	Rec. 103M ppm water
I-93	6	C	3997	54	116	TSTM	0	13	N/A	25	—	—	10	190000 ppm
I-93	***7***	***A***	***3931***	***53***	***114***	***746***	***149***	***3.0***	***4***	***44***	***526***	***37***	***12***	***Tbg load rate***
I-93	***8***	***A***	***3912***	***53***	***114***	***167***	***137***	***0***	***0***	***15***	***676***	***2.9***	***1***	
I-93	9	8	3711	38	110	0	0	0	0	18	—	—	6	54000 ppm
I-93	***10***	***6a1***	***3453***	***35***	***104***	***0***	***0***	***0***	***0***	***6***	—	—	***0.3***	***107000 ppm***
C-74	1	J1	5016	100	153	0	0	0	0	4	—	—	42	No flow
C-74	***2***	***H2***	***4748***	***89***	***131***	***1333***	***22***	***0***	***0***	***22***	***664***	***21***	***13***	
C-74	3	H1	4682	88	136	741	55	37.1	50	19	75	10	40	Tbg load rate
C-74	***4***	***GL***	***4508***	—	***142***	***872***	***57***	***15.7***	***18***	***14***	—	—	—	***Misrun-tbg load rate***
C-74	***5***	***GL***	***4508***	***84***	***143***	***1348***	***46***	***10.8***	***8***	***16***	***22***	***-1***	***12***	***Tbg load rate***
C-74	***6***	***F3***	***4405***	***83***	***141***	***1314***	***41***	***0***	***0***	***31***	***131***	***1***	***17***	
C-74	***7***	***F1***	***4311***	***80***	***129***	***184***	***47***	***0***	***0***	***8***	***2***	***-3***	***56***	
C-74	***8***	***B***	***3914***	***53***	***116***	***51***	***121***	***0.0***	***0***	***35***	***1712***	***-2***	***1***	
C-74	***9***	***A***	***3865***	***52***	***113***	***878***	***108***	***5.3***	***6***	***51***	***761***	***0***	***5***	***Tbg load rate***

Well	DST No.	Sand	Top Interval (M-KB)	BHSP (MPa)	BHST (C)	Max. Gas Rate (E3m3/d)	Cond. Ratio (m3/E6m3)	Water Rate (m3/d)	Water Ratio (m3/E6m3)	Cum. Flow Time (hr)	KH (md-m)	Skin	Draw Down (MPa)	Remarks
VENTURE														
D-23	1	6u	4899	—	—	—	—	—	—	—	—	—	—	Misrun
D-23	2	6u	4899	—	—	—	—	—	—	—	—	—	—	Misrun
D-23	3	6u	4899	—	—	—	—	—	—	—	—	—	—	Misrun
D-23	4	6u	4899	84	140	283	87	4.5	16	8	138	-2	3	4400 ppm
D-23	5	5	4829	80	135	—	—	—	—	—	—	—	—	Misrun
D-23	6	5	4829	—	—	—	—	—	—	—	—	—	—	Misrun
D-23	7	5	4829	—	—	—	—	—	—	—	—	—	—	Misrun
D-23	8	3a	4643	70	—	628	81	0	0	8	568	2	2	
D-23	9	2	4414	—	—	—	—	—	—	—	—	—	—	Misrun
D-23	9A	2	4414	—	—	—	—	—	—	—	—	—	—	Misrun
D-23	9B	2	4414	44	—	328	85	0	0	5.5	—	—	3	Poor gauge data
B-13	1	10	5168	98	142	3.7	0	192.4	52000	5	—	—	48	
B-13	2	8	5056	—	145	17	0	190.4	11200	2.5	—	—	—	No gauge data
B-13	3	6u	4949	85	140	524	5	0	0	7.5	725	-1	1	32000 ppm
B-13	4	4c	4882	82	139	128	0	246.4	1925	6	152	5	2	
B-13	5	4b	4853	80	127	0	N/A	73	N/A	7	0.003	2	26	Tbg load rate
B-13	6	B	4572	51	—	81	47	3.8	47	8	4	3.5	41	13000 ppm
B-13	7	3a	4714	—	—	—	—	—	—	—	—	—	—	Misrun
B-13	8	3a	4714	—	—	—	—	—	—	1	—	—	—	Misrun Pkr Leak *
B-13	9	A	4531	51	125	194	197	18.0	93	8	6	-3	32	4300 ppm
B-13	10	2l	4495	47	123	433	75	17.3	40	5.5	109	0	6	42000 ppm
B-13	11	2u	4478	47	126	527	116	4.7	9	6	2313	16	1	790 ppm
B-13	12	—	4418	47	123	386	120	0	0	5	—	—	2	21900 ppm
B-13	13	1l	4126	43	116	0	0	17	N/A	8	—	—	4	87000 ppm
B-13	14	1u	4107	43	118	0	0	190	N/A	1	—	—	0.1	107000 ppm
B-13	15	—	4068	43	117	0	0	350	N/A	1.5	—	—	0.06	175000 ppm
B-13	16	—	3755	38	108	0	0	300	N/A	3	—	—	0	148000 ppm
B-43	1	13	5510	107	153	0	0	16	N/A	8	—	—	47	Tbg load rate
B-43	2	13	5479	107	161	261	69	139.0	533	7	49	13	24	
B-43	3	11	5279	100	151	447	96	6.3	14	8	81	1	9	
B-43	4	8	5090	86	148	418	0	0	0	1	—	—	7	18000 ppm
B-43	5	8	5090	86	140	139	202	0	0	8	70	-1	2	19000 ppm
B-43	6	7	5036	84	137	280	78	5.3	19	6	—	—	0.4	600 ppm
B-43	7	6	4953	84	138	300	153	7.8	26	11	1017	-1	0.6	700 ppm
B-43	8	5	4883	80	132	390	330	0	0	6	664	1	1	
B-43	9	4a	4788	79	129	178	138	0	0	6	12	2	12	2100 ppm
B-43	10	3a	4680	70	127	162	71	0	0	12	639	12	2	3600 ppm
B-43	11	C	4607	—	—	—	—	—	—	—	—	—	—	misrun
B-43	12	C	4607	62	127	0.5	TSTM	0	N/A	15	—	—	—	
B-43	13	B	4543	—	125	—	—	—	—	—	—	—	—	misrun
B-43	14	B	4543	—	—	—	—	—	—	—	—	—	—	misrun
B-43	15	B	4543	—	125	0	0	0	N/A	5	—	—	—	
B-43	16	—	4251	44	119	75	94	28.7	382	13	—	—	35	
B-43	17	—	3700	39	108	TSTM	TSTM	0	N/A	8	—	—	1	
H-22	1	18	5692	114	155	0	0	0	0	8	—	—	63	No flow
H-22	2	Y	5520	110	151	0	0	0	0	7	—	—	56	No flow
H-22	3	11	5246	94	142	0	0	0	0	5	—	—	41	No flow
H-22	4	8	5056	85	140	113	0	95.0	841	5	—	—	24	187000 ppm
H-22	5	7m	5021	84	140	164	56	232.7	1419	8	50	2	4	183000 ppm
H-22	6	6m	4976	83	139	698	71	103.3	148	22	72	-1	25	189000 ppm
H-22	7	6u	4957	82	139	1081	61	42.2	39	64	67	-2	22	172000 ppm
H-22	8	4b	4837	—	—	—	—	0	—	—	—	—	—	Misrun
H-22	9	4b	4837	77	132	0	0	0	N/A	22	5	-2	21	69000 ppm
B-52	1	18	5800	—	—	13	0	1.9	143	15	—	—	—	Recorders failed

Well	DST No.	Sand	Top Interval (M-KB)	BHSP (MPa)	BHST (C)	Max. Gas Rate (E3m3/d)	Cond. Ratio (m3/E6m3)	Water Rate (m3/d)	Water Ratio (m3/E6m3)	Cum. Flow Time (hr)	KH (md-m)	Skin	Draw Down (MPa)	Remarks
VENTURE cont'd														
B-52	2	17	5725	115	161	311	3	9.0	29	13	—	—	77	44000 ppm
B-52	3	13	—	—	—	—	—	—	—	—	—	—	—	Misrun
B-52	4	13	—	—	—	—	—	—	—	—	—	—	—	Misrun
B-52	5	13	5453	108	152	0.7	0	271	N/A	7	63	-6	32	Tbg load rate
B-52	6	11	5284	99	—	1393	23	20.9	15	36	57	-3	28	16000 ppm
B-52	7	7	5126	86	142	0.8	0	231	N/A	6	494	1	4	199000 ppm
B-52	8	6m	5065	—	142	1.1	0	83	N/A	9	—	—	—	209000 ppm
B-52	9	6u	5043	84	140	2	0	851	N/A	6	399	-5	13	268000 ppm
B-52	10	6U	5031	83	—	1	0	379	N/A	5	—	—	24	231000 ppm
B-52	11	6u	5023	84	143	0.6	0	335	N/A	2	68	-3	17	246000 ppm
B-52	12	5	4963	82	142	3.3	TSTM	76	N/A	10	—	—	43	155000 ppm
B-52	13	4d	4920	81	138	44	TSTM	129	N/A	7	1	-1	49	238000 ppm
B-52	14	4a	4848	76	135	0	0	14	N/A	16	—	—	26	159000 ppm
B-52	15	3a	4711	70	133	12	TSTM	363	N/A	7	245	-4	8	257000 ppm
NORTH TRIUMPH														
G-43	1	A	3835	39	118	994	26	4.0	4	24	1061	-4	1	
G-43	2	A	3795	38	115	1045	31	6.3	6	24	1475	-5	0	
B-52	1		3810	—	118	0	0	3	N/A	2	—	—	—	186000 ppm
B-52	2	A	3795	38	119	TSTM	0	9	N/A	1	—	—	—	185000 ppm
B-52	3	A	3771	—	117	0	0	—	—	—	—	—	—	Misrun
B-52	4	A	3771	39	118	774	26	3.9	5	24	529	-7	1	
SOUTH VENTURE														
O-59	1	—	5925	—	163	—	—	—	—	—	—	—	—	Misrun
O-59	2	—	5925	—	161	0	0	0	0	1	—	—	—	No flow
O-59	3	—	5849	—	161	0	—	—	—	5	—	—	—	Misrun
O-59	4	—	5667	105	154	0	0	0	0	4	—	—	41	No flow
O-59	5	8u	5035	93	141	183	58	0	0	9	37	57	61	
O-59	6	—	4865	61	137	0	0	0	0	4	—	—	14	No flow
O-59	7	7m	4747	73	134	224	211	1.6	7	9	20	15	48	
O-59	8	—	4602	—	130	—	—	—	—	—	—	—	—	Misrun
O-59	9	—	4603	71	133	0	0	0	0	5	—	—	32	No flow
O-59	10	6	4255	44	122	379	301	6.1	16	7	501	7	2	19000 ppm
O-59	11	5	4209	43	116	391	187	5.1	13	7	62	5	15	41000 ppm
O-59	12	4a	4020	41	114	515	165	8.8	17	5	1216	25	3	9900 ppm
O-59	13	3	3985	40	112	484	198	5.8	12	6	124	-6	1	4000 ppm
O-59	14	2	3926	40	111	46	3130	14.9	323	5	420	0	2	90000 ppm
ALMA														
F-67	1	C	3026	—	—	—	—	0	—	—	—	—	—	Misrun - aborted
F-67	2	C	3026	31	104	48	0	61.3	1278	8	6	15	21	77000 ppm
F-67	3	C	3016	—	103	0	0	0	0	—	—	—	—	Aborted
F-67	4	C	3016	30	106	0	0	0	0	2	—	—	—	40000 ppm
F-67	5	B	2978	31	103	522	55	0	0	34	103	-5	14	
F-67	6	A	2911	30	101	319	77	0	0	10	1774	-2	18	
F-67	7	A	2872	30	101	846	70	0	0	39	1242	-1	2	
K-85	1	F	3073	33	102	370	6	0	0	31	—	—	21	
K-85	2	D	3020	31	100	459	76	0	0	17	—	—	16	
K-85	3		2950	31	98	595	59	0	0	31	141	3	9	
K-85	4	B	2931	30	97	272	0	0	0	9	126	9	20	
K-85	5	A	2843	30	97	855	69	0	0	30	655	3	4	
GLENELG														
J-48	1	VC	5075	97	163	0	0	11	N/A	2	—	—	44	332000 ppm
J-48	2	Miss.	3950	43	121	127	0	0	TSTM	10	—	—	24	48000 ppm
J-48	3	Miss.	3806	39	121	0	0	6	N/A	9	—	—	1	159000 ppm
J-48	4	G	3767	39	120	125	0	88.0	704	11	—	—	2	233000 ppm

Well	DST No.	Sand	Top Interval (M-KB)	BHSP (MPa)	BHST (C)	Max. Gas Rate (E3m3/d)	Cond. Ratio (m3/E6m3)	Water Rate (m3/d)	Water Ratio (m3/E6m3)	Cum. Flow Time (hr)	KH (md-m)	Skin	Draw Down (MPa)	Remarks
GLENELG cont'd														
J-48	**5**	**G**	**3746**	**39**	**120**	**801**	**18**	**0**	**—**	**10**	**—**	**—**	**8**	
J-48	6	F	3608	—	113	8	TSTM	0	TSTM	8	—	—	—	Inconclusive
J-48	***7***	***F***	***3608***	***37***	***112***	***99***	***0***	***0***	***TSTM***	***8***	***17***	***0***	***11***	
J-48	***8***	***C2***	***3491***	***36***	***110***	***594***	***56***	***19.0***	***32***	***15***	***219***	***-1***	***7***	
J-48	9	LC	3062	30	98	850	77	0	—	10	—	—	3	
E-58A	1	E	3072	37	113	663	93	0	0	31	—	—	21	
E-58A	***2***	***C1***	***3567***	***36***	***111***	***252***	***TSTM***	***0***	***0***	***12***	***309***	***-1***	***24***	
N-49	1	D	3598	37	117	596	34	0	0	8	—	—	2	
N-49	***2***	***C1***	***3476***	***36***	***109***	***871***	***26***	***0***	***0***	***24***	***404***	***-2***	***0***	
N-49	***3***	***B***	***3391***	***35***	***109***	***483***	***22***	***0***	***0***	***14***	***44***	***-1***	***13***	

* - Recovered formation water in tubing-tail fluid. Rate of cushion flow indicated inflow rate of up to 380m3/d (with leaking packer)

Highlighted well tests indicate sands that are incorporated within the present project scope

Table Notes:
- All DST's that were performed are represented
- All tests considered Misruns are indicated but are not detailed as to specific equipment failure
- Where available, all representative gauge data is presented
- KH and Skin values were determined only for the zones that produced gas
- Flow times represented are cumulative (includes clean-up and multiple flow periods)
- Water and condensate rates are based on the flow period during which they were recovered
- Water rates for non-gas producing tests are recorded in 'Remarks' column
- Water volumes recovered (rec'd) by reverse-circulating tubing on non-flowing tests are noted in remarks column as 'tbg load rates'
- Water of condensation ratios range from approximately 17 to 28 m3/E6m3 (3 - 5 bbl/MMscf)
- TSTM = Too small to measure
- All interval depths are measured depths
- VC = Verrill Canyon
- Miss. = Missisauga undifferentiated
- LC = Logan Canyon
- 4400 ppm = 4400 parts per million NaCl equivalent

The Summary, **Table 3.1.2.1**, includes the shut-in bottom hole static pressures (BHSP) and the shut-in bottom hole static temperatures (BHST) for each of the tests. These data, together with Repeat Formation Testing (RFT) data, was used to define temperature and pressure gradients for the fields.

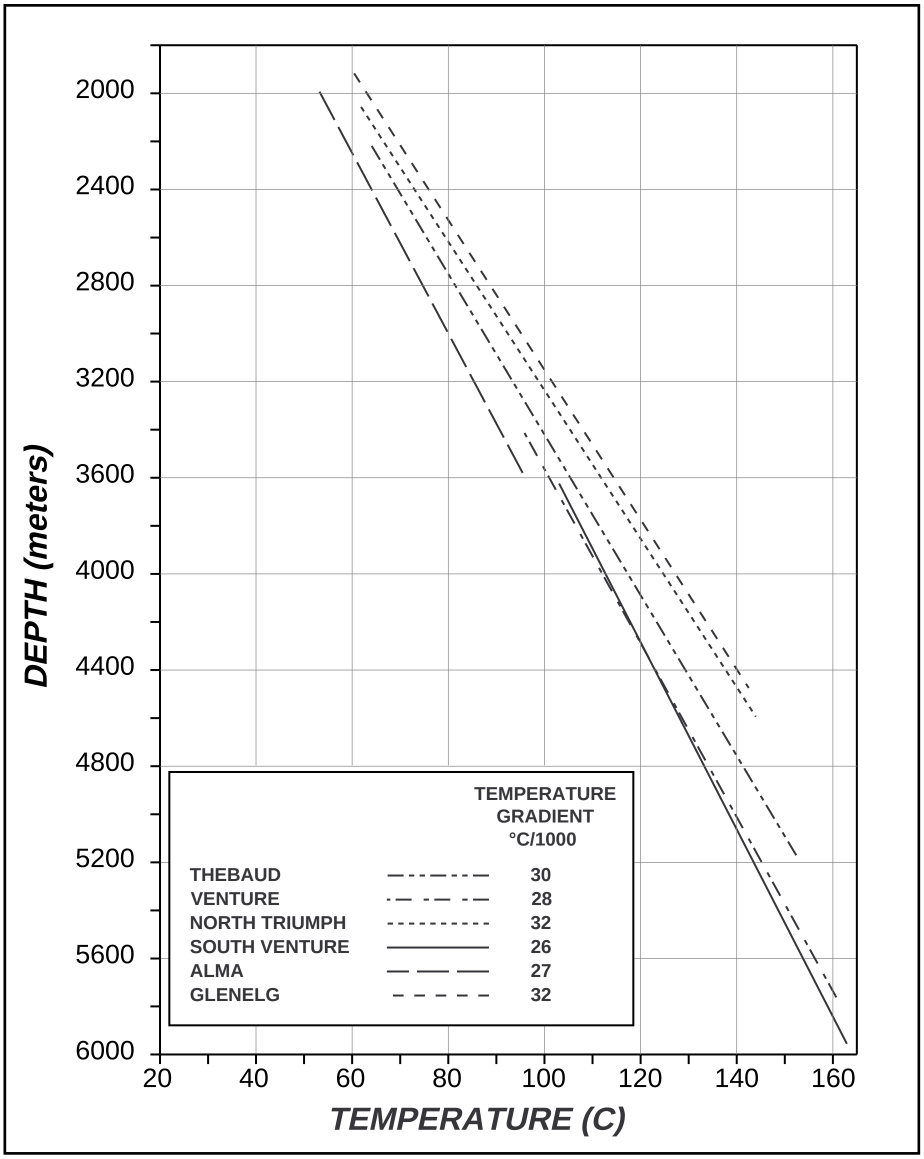


Figure 3.1.2.1 Reservoir Temperature Profile

Reservoir pressure obtained from RFT's and DST's is plotted in **Figure 3.1.2.2** for all fields. Detailed discussions of the data for each well are contained in Part Two of this document **(DPA - Part 2, Ref. # 3.1.2.2)**. Where possible, pressure depth data was used to assist in the location of the free water level for gas in place determination.

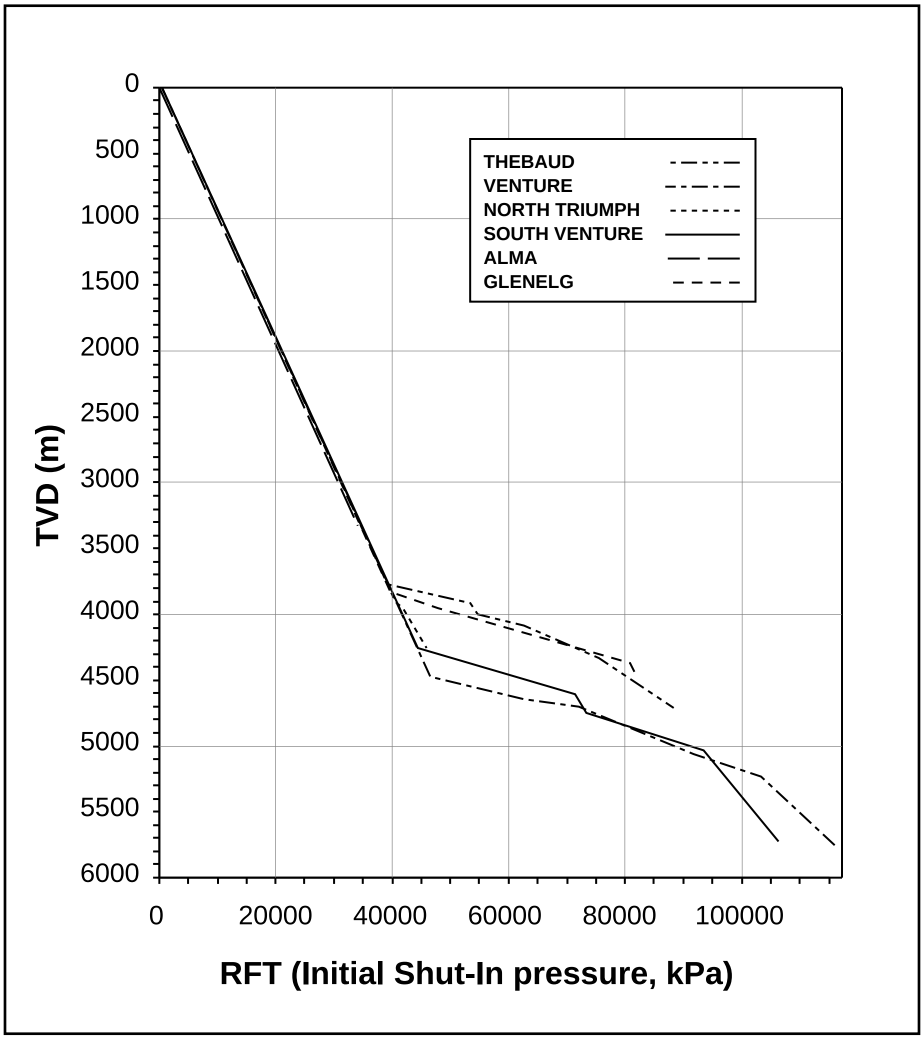


Figure 3.1.2.2 Reservoir Pressure Profile

The gas rates presented in the tables are the maximum observed rates for that test. The gas rates were generally high for all fields, with more than 1000 E3M3/d recorded for Venture (B-52 DST #6) and North Triumph (G-43 DST #2). However, drawdown pressures were, on average, only five to 10 percent of initial pressure.

Estimates of the future well performance, including consideration of various tubing configurations, have been developed from history matched models of the field DST performance. A detailed discussion regarding well deliverability and reference data tables is included in Part Two of this document **(DPA - Part 2, Ref. # 3.1.2.3)**.

The measured condensate ratios vary considerably between fields and between individual sands. In Thebaud, there is a significant difference in the A sand at 165 M3/E6M3 compared with the H and J sands at 22 and 0 M3/E6M3, respectively. For North Triumph, the condensate ratio is approximately 25 M3/E6M3, about half that of Alma and Glenelg. There is also a marked difference in the Venture sands where the condensate ranges from a low of 23 M3/E6M3 in B-52 (DST #6 - Sand 11) to a high of 330 M3/E6M3 in B-43 (DST #8 - Sand 5). There does not appear to be a correlation or specific relationship governing the variation in condensate ratio (In this context, the term condensate refers to the liquid stream from the produced fluids at the test separator temperature and pressure).

Formation water production was observed in some of the DST's, as noted in **Table 3.1.2.1**. In updip wells such as Venture D-23 and North Triumph G-43, little or no water was observed. NaCl equivalent salinity associated with these DST's was less that 5000 ppm, indicative of water of condensation. Downdip wells such as Venture B-52 and North Triumph B-52 have NaCl equivalent salinity values greater than 150000 ppm, indicative of formation water.

There is considerable variability in the permeability thickness product (kh) estimates between the pools in the fields. This data is presented in **Table 3.1.2.1**. The DST interpreted permeabilities were the main source of permeability input to the reservoir simulation models that have been constructed for the individual fields.

The wellbore skin, included in **Table 3.1.2.1**, indicates the zones are slightly enhanced with Skins of -2 to slightly damaged with Skins of +2. Certain wells, such as South Venture O-59, consistently show a significant positive Skin. This indicates zone damage, perhaps from drilling.

3.1.3 Special Core Analysis

Special core analysis has been completed for four of the six fields. **Table 3.1.3.1** presents a summary of the number of plugs taken and the type of analysis completed. All reservoir parameters have been extrapolated to reservoir conditions using the overburden relationship developed from the special core work. Water saturations calculated within the models use the capillary pressure data. In addition, trapped gas saturation and steady-state relative permeability data obtained from core analysis have been used in the reservoir modelling. In sands/fields where data was not available, analogous information from these analyses, has been used for modeling purposes and is included in Part Two of this document (**DPA - Part 2, Ref. #'s 3.1.3.1 through 3.1.3.6**).

Table 3.1.3.1 Special Core Analysis

Type of Analysis	Number of Samples Analyzed													
	Venture				Thebaud		Alma		N.Triumph		Glenelg			
	B-13	**B-43**	**B-52**	**H-22**	**I-93**	**C-74**	**F-67**	**K-85**	**B-52**	**G-43**	**N-49**	**E-58**	**H-38**	**J-48**
Porosity and Permeability Effects at Overburden Pressures	14	20	20	33	5	18	46	-	34	50	-	-	-	-
Overburden Permeability (Air) at Irreducible Water Saturation	-	10	20	30	11	19	-	-	-	-	-	-	-	-
Capillary Pressure (Air-Mercury)	14	20	10	33	-	-	29	1	36	58	-	-	-	-
Capillary Pressure (Air-Brine)	14	20	25	33	5	21	-	-	-	-	-	-	-	-
Cation Exchange Capacity	-	18	30	46	5	13	6	-	-	-	-	-	-	-
Pore Throat Size Distribution	14	20	10	33	-	-	-	-	-	-	-	-	-	-
Rock Pore Volume Compressibility	14	20	-	-	-	-	-	-	-	-	-	-	-	-
Uniaxial Compressive Strength	-	-	-	-	-	7	-	-	-	-	-	-	-	-
Triaxial Compressive Strength	-	7	-	15	-	-	-	-	-	-	-	-	-	-
Particle Size Analysis (Sieve)	-	-	-	15	-	-	-	-	-	-	-	-	-	-
Relative Permeability Study	-	-	-	6	-	6	-	-	-	-	-	-	-	-
Waterflood Displacement Trapped Gas Study	-	8	13	22	5	13	-	-	-	-	-	-	-	-
Permeability (Air) as a Function of Flow Rate	-	-	6	-	-	-	-	-	-	-	-	-	-	-
Brinell Hardness - Sand Strength	-	-	62	57	-	-	-	-	-	-	-	-	-	
Hunidy/Oven Dried Porosity	-	-	6	45	8	27	-	-	-	-	-	-	-	-
Permeability as a Function of Throughput Fluid	-	-	6	-	-	-	-	-	-	-	-	-	-	-
Formation Factor at Atmospheric and Overburden Pressure	14	20	25	33	5	21	33	-	10	11	-	-	-	-
Formation Resistivity Index at Atmospheric & Overburden Pressure 14	20	25	33	5	21	33	-	11	2	-	-	-	-	
Thin Section Studies	-	-	-	-	45	49	15	20	17	26	37	17	5	-
X-Ray Diffraction	-	-	-	-	22	21	4	4	4	4	8	3	1	-
Electron Microscope Scanning (air-brine)	-	-	-	-	25	28	4	6	4	4	8	4	1	-

3.1.4 Reservoir Fluid Properties

Surface gas samples, as well as separator liquids, were obtained during DST operations. These samples were recombined analytically at the measured producing conditions to predict the behaviour of an equivalent single phase gas at reservoir conditions. In addition, during testing of the Venture H-22 well, single phase surface samples were obtained at flowing pressures in excess of the anticipated dew point pressure.

The produced gas from the six fields in question has been determined to be sweet gas with traces of H_2S and relatively low levels of CO_2. For most of the gas samples, Venture, South Venture and Thebaud the heptane plus (C7+) hydrocarbon fractions are approximately 1.5 to 2 mole percent. The C7+ hydrocarbon fractions for Alma, Glenelg and North Triumph are considerably lower in the range of 0.5 to 0.8 mole percent. The gas compositions used in the reservoir simulations are as compiled in **Table 3.1.4.1**.

Table 3.1.4.1 Fluid Analysis Summary

Thebaud

Sand	SAND A	SAND B	F1	F3	G2	G3	H2
Technique	Dense Phase	Dense Phase	Recomb.	Dense Phase	Dense Phase	Dense Phase	Dense Phase
Well	C-74	C-74	C-74	C-74	C-74	C-74	C-74
Sample(s)	9-23	8-31	7-31/7-32	6-10	4-17	4-17	2-21
He	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N2	0.16	0.15	0.22	0.16	0.08	0.08	0.14
CO2	1.53	1.60	2.07	2.30	2.47	2.47	3.09
H2S	0.00	0.00	0.00	0.00	0.00	0.00	0.00
C1	86.01	85.22	86.67	86.94	86.94	86.94	88.20
C2	6.82	6.99	6.85	6.52	6.42	6.42	5.63
C3	2.38	2.58	2.07	1.87	1.82	1.82	1.37
iC4	0.36	0.41	0.37	0.37	0.34	0.34	0.30
nC4	0.53	0.65	0.47	0.46	0.41	0.41	0.31
iC5	0.17	0.23	0.19	0.21	0.18	0.18	0.16
nC5	0.15	0.21	0.15	0.16	0.13	0.13	0.10
C6	0.21	0.14	0.16	0.11	0.17	0.17	0.08
C7+	1.68	1.82	0.78	0.90	1.04	1.04	0.62
Total	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Pc 1	4602	4602	4631	4636	4637	4637	4667
Tc 2	695	695	677	676	677	677	664
Sg 3	0.718	0.718	0.678	0.679	0.687	0.687	0.662
Z 4	1.209	1.219	1.586	1.608	1.614	1.614	1.694
Bgi 5	324.4	323.8	363.4	383.0	383.9	383.9	392.3

1. Specific Gravity
2. Pseudo-Critical Pressure (kPa)
3. Pseudo-Critical Temperature (Deg. K)
4. Compressibility
5. Formation Volume Factor(sm3/m3)

Table 3.1.4.1 Fluid Analysis Summary continued

Venture

Sand	**SAND 2u**	**A**	**B**	**SAND 3a**	**4**	**SAND 5**	**SAND 6u**	**SAND 6m**	**SAND 7**	**SAND 8**
Technique	**Recomb.**	**Recomb.**	**Recomb.**	**Recomb.**	**Recomb.**	**Recomb.**	**Dense Phase**	**Dense Phase**	**Dense Phase**	**Dense Phase**
Well	**B-13**	**B-13**	**B-13**	**B-43**	**B-43**	**B-43**	**H-22**	**H-22**	**H-22**	**H-22**
Sample(s)	**11-2,11-10**	**9-3/9-7**	**6-3/6-8**	**10-15,10-23**	**9-6/9-8**	**8-15,8-9**	**7-14**	**6-92**	**5-18**	**4-49**
He	0.01	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00
N2	0.29	0.27	0.58	0.27	0.34	0.27	0.15	0.16	0.15	0.16
CO2	1.85	1.55	1.52	0.85	1.19	1.38	1.92	1.68	1.68	1.58
H2S	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
C1	83.25	82.10	84.98	85.46	82.20	79.11	86.37	86.80	87.85	88.11
C2	7.33	7.07	7.23	7.28	7.62	7.87	6.29	6.18	5.73	5.73
C3	3.46	3.53	2.93	2.91	3.74	4.47	2.24	2.16	1.89	1.84
iC4	0.52	0.56	0.46	0.46	0.63	0.75	0.39	0.37	0.36	0.30
nC4	0.95	1.24	0.74	0.74	1.11	1.48	0.56	0.53	0.56	0.59
iC5	0.31	0.41	0.27	0.26	0.39	0.51	0.22	0.20	0.22	0.22
nC5	0.27	0.42	0.20	0.20	0.34	0.46	0.17	0.14	0.18	0.17
C6	0.30	0.40	0.22	0.21	0.32	0.43	0.23	0.27	0.22	0.17
C7+	1.46	2.45	0.87	1.35	2.12	3.27	1.46	1.51	1.16	1.13
Total	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Pc 1	4604	4567	4611	4586	4567	4539	4617	4610	4617	4617
Tc 2	702	719	687	693	716	742	686	685	677	676
Sg 3	0.731	0.773	0.695	0.704	0.759	0.822	0.702	0.699	0.683	0.678
Z 4	1.141	1.19	1.193	1.441	1.555	1.601	1.624	1.626	1.644	1.651
Bgi 5	296.8	306.6	308.7	347.8	359.8	357.6	352.7	352.7	349.9	348.5

1. Specific Gravity
2. Pseudo-Critical Pressure (kPa)
3. Pseudo-Critical Temperature (Deg. K)
4. Compressibility
5. Formation Volume Factor(sm3/m3)

Table 3.1.4.1 Fluid Analysis Summary continued

SOUTH VENTURE

Sand	SAND 2	SAND 3	SAND 4A,4E	SAND 5	SAND 6
Technique	Recomb.	Recomb.	Recomb.	Recomb.	Recomb.
Well	O-59	O-59	O-59	O-59	O-59
Sample(s)	14-31,14-36	13-48,13-53	12-34,12-32	11-55,11-60	10-56,10-51
He	0.01	0.01	0.01	0.01	0.01
N2	0.54	0.52	0.49	0.68	0.60
CO2	1.63	1.78	1.84	1.92	1.80
H2S	0.00	0.00	0.00	0.00	0.00
C1	79.02	82.56	83.28	79.22	78.09
C2	6.01	6.61	6.57	7.10	7.94
C3	5.18	3.99	3.61	5.38	5.41
iC4	1.05	0.57	0.52	0.80	0.72
nC4	1.82	1.10	0.99	1.50	1.40
iC5	0.61	0.32	0.31	0.40	0.40
nC5	0.55	0.30	0.28	0.34	0.42
C6	0.87	0.30	0.47	0.55	0.73
C7+	2.71	1.94	1.63	2.10	2.48
Total	100.00	100.00	100.00	100.00	100.00
Pc 1	4531	4632	4593	4567	4557
Tc 2	700	681	680	704	698
Sg 3	0.83	0.75	0.74	0.79	0.81
Z 4	1.05	1.05	1.07	1.09	1.10
Bgi 5	281.4	289.6	284.5	289.1	290.1

	TRIUMPH	ALMA	GLENELG
Sand	A	A	C1
Technique	Recomb.	Recomb.	Recomb.
Well	G-43	K-85	N-49
Sample(s)	2-64,2-61	5-47,5-46	2-27,2-23
He	0	0	0
N2	0.25	0.51	0.28
CO2	2.09	1.38	2.04
H2S	0	0	0
C1	91.13	88.19	90.58
C2	3.84	4.92	4.17
C3	1.41	2.48	1.52
iC4	0.18	0.35	0.19
nC4	0.32	0.59	0.35
iC5	0.11	0.19	0.12
nC5	0.11	0.19	0.11
C6	0.12	0.26	0.14
C7+	0.44	0.94	0.5
Total	100	100	100
Pc 1	4646	4602	4644
Tc 2	654	676	656
Sg 3	0.64	0.684	0.642
Z 4	1.033	0.939	1.003
Bgi 5	284.1	241.3	271.5

1. Specific Gravity
2. Pseudo-Critical Pressure (kPa)
3. Pseudo-Critical Temperature (Deg. K)
4. Compressibility
5. Formation Volume Factor(sm3/m3)

Pressure, Volume, Temperature (PVT) analysis, including both dense phase and recombination analysis, has been conducted on all of the six fields. **Table 3.1.4.1** also summarizes the critical properties used to characterize the fluid phase behaviour.

Detailed Equation of State (EOS) analysis was completed on the Venture H-22 Sand 6U sample. The EOS suggests that Venture reservoir fluids are lean, to very lean gas-condensates, with a maximum liquid saturation under Constant Volume Depletion (CVD) of less than one volume percent at 10 MPa at a reservoir temperature of 140°C. This is unlike a typical rich gas condensate which is characterized by liquid saturations in excess of 20 to 30 percent under CVD. The H-22 sample was selected for detailed EOS analysis because it represents the most reliable PVT sample. The flow rate was stabilized and the wellhead pressures were well above the dew point pressure. The dew point pressure for the various gas samples range from a low of 18.4 MPa at Venture H-22 (DST #4) to a high of 39 MPa at Thebaud I-93 (DST #7).

Condensate recovery in the reservoir is a function of overall gas recovery, initial liquid content of the gas, and critical condensate saturation. Critical condensate saturation and relative permeability to gas at critical condensate saturation are active areas of investigation by the Proponents, their affiliates and the industry in general. The variability associated with these parameter estimates can be significant in predicting overall condensate recovery. Initial indications, using a compositional model, show condensate recovery in the range of 50 to 70 percent may be anticipated. The lean nature of the Project reservoir fluids and the low dew point pressures suggest that liquid drop-out throughout the entire reservoir occurs at pressures close to abandonment pressures. The reinjection of gas for enhanced liquids recovery is not currently viewed as an opportunity for increasing project value. A detailed discussion regarding the fluid properties associated with all sands is included in Part Two of this document **(DPA - Part 2, Ref. # 3.1.4.1)**. The study with the EOS model mentioned previously is also included in Part Two of this document **(DPA - Part 2, Ref. # 3.1.4.2)**.

3.2 Reservoir Simulation

All reservoir simulation studies for the Sable Offshore Energy Project were conducted using Pegasus/Prevue, a proprietary simulator developed by the Mobil Exploration and Production Technical Centre in Dallas. The Pegasus simulators capable of modeling full field scale non-thermal reservoir engineering processes and has a feature that allows for the integration of surface and gas contractual constraints. Prevue is an interactive preprocessor and postprocessor, designed to simplify the preparation of input simulator data and provides several tools for the display and analysis of the simulation results.

The wellbore hydraulics, or the flow characteristics for each of the wellbores within the simulators are externally modelled using a commercially available Wellbore Evaluation Model (WEM) program and mimicked within Pegasus through the use of flow tables **(DPA Part 2 ref #3.2.1)**. Similarily, when modeling the surface interactions on the reservoir performance, it is a two step approach. The surface model is first studied external to Pegasus and then the surface facility constraints are mimicked within Pegasus, using flow tables.

3.2.1 Individual Field Simulation

Multi-sand, non-compositional simulation models were developed for each of the six fields. The Sable Offshore Energy Project fields are currently at different stages of appraisal. The appraisal and follow up technical investigations conducted since discovery have primarily focused on Venture, Thebaud and North Triumph. Data on these fields include high level geological concepts, such as regional and detailed geology, stratigraphy, sedimentology and structural diagnostic data. As a result, the individual field reservoir models developed for Thebaud, Venture and North Triumph are more complex than the Glenelg, Alma and South Venture models. Refinement of all the numerical models is an ongoing process as more information becomes available. Early sources of new information include the proposed 3D seismic program and any test data obtained from the initial Project wells.

These initial field simulation studies have two primary objectives. The first objective is to investigate the key resource uncertainties related to reservoir performance. As a second objective, the models provide one of the components required for the total integration of the surface and the subsurface systems for the study of various development options.

At this stage in the project, the early individual field reservoir models provide a tool for the assessment of reserve uncertainty and the study of various depletion plans. Included in the assessment of resource uncertainty are issues such as residual gas saturation and aquifer strength. A depletion plan includes the individual field production forecast, well offtake rates, the number of wells, well location and completion details, and the overall recovery efficiency on a sand by sand basis. The early simulation input is based on the most likely reservoir characterization. Conducting resource characterization scenarios through multiple reservoir simulation sensitivity studies provides a means of acquiring further insights into possible field performance outcomes. These simulation sensitivity studies are ongoing. One example was the focused investigation of the possible reservoir fluid compositional ranges and the examination of its effect on field performance.

The results of this study are reported in **DPA Part 2, ref 3.3.2.2.** Another scenario currently under investigation involves the study of water production during production operations. The individual field models are also being used for focused technical investigations. Two such examples involve the study of commingled wellbores and the effects of wellbore geometry on performance.

3.2.2 Integrated Surface-Subsurface Simulation

The integrated surface and subsurface simulation model, referred to as Pegasus-ISF combines multiple field reservoir simulations constrained by both the surface facilities and a sales gas rate at a prescribed pressure. Early in the development of the project this model functions as a tool for assessing various development alternatives. Later in the life of the project , the tool has utility in ongoing reservoir management activities. In either application the output from the model is the Project forecast under various development plans, with full account for the system constraints, from the subsurface through to the surface and the market sales gas rate.

Figure 3.2.2.1 illustrates the network that is being modeled within Pegasus-ISF. The model assumes an onshore gas plant and a central platform at Thebaud. As stated previously, Pegasus - ISF models the surface system constraints through the use of flow tables, describing the pressure drop and rate relationships within each pipeline and the modeled surface equipment. The flow table information has been generated using a combination of commercially available and proprietary simulators. Further details are reported in **DPA Part 2, ref 3.2.1.**

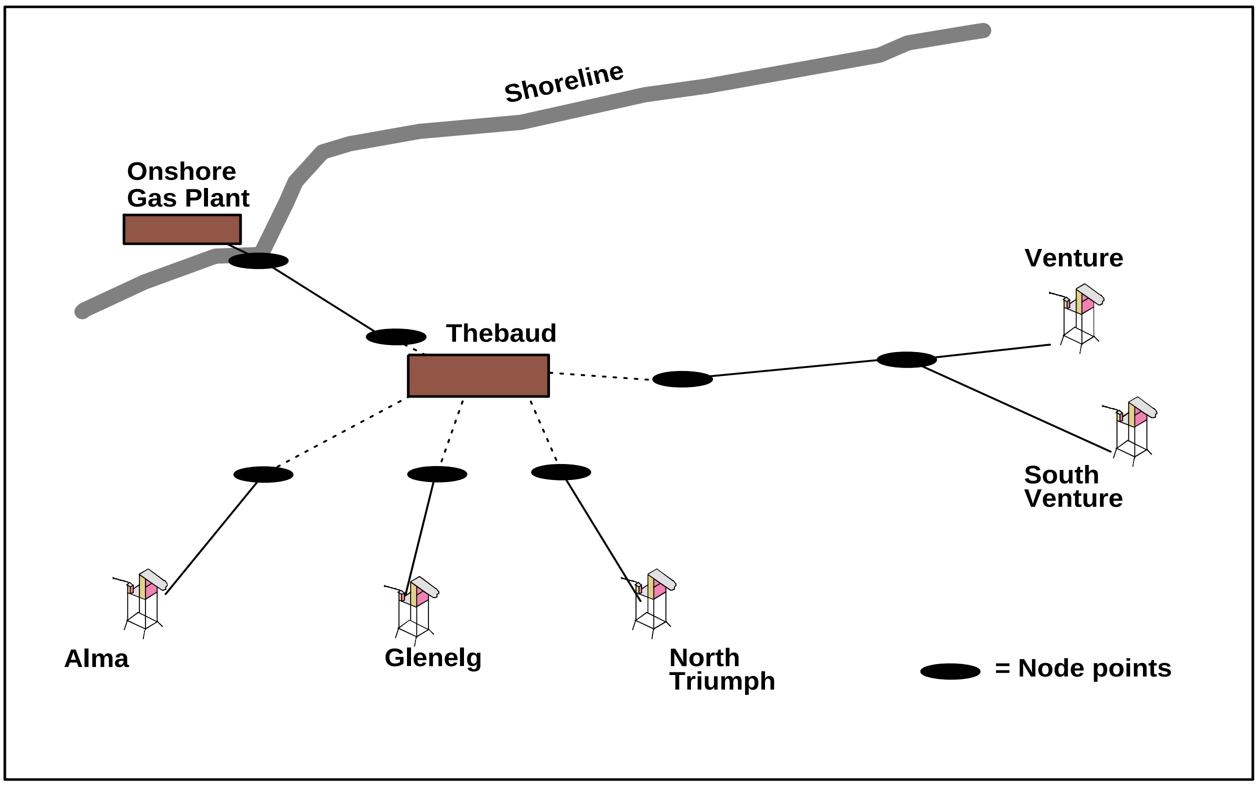


Figure 3.2.2.1 ISF Network Schematic

The node points on the diagram, represented by shaded ovals, are the data capture points for the model information. These data points provide an accounting function, capturing simulated pressures as a function of time along the pipelines and the assigned input gas/condensate ratios for the fields. The gas/condensate ratios that are captured at these points are the user supplied values on an individual reservoir basis and are consistent with non-compositional modeling assumptions.

3.3 Project Plan Development

The current Project plan has been developed through multiple iterations on the Pegasus-ISF model. The challenge is to identify field development scenarios that provide sufficient flexibility to respond to the introduction of new information, technology and/or discoveries throughout the project life.

3.3.1 Assumed Project Constraints

As a first step, the integrated model was run to develop a realistic prediction of the physical performance of the entire system for the life of the Project under a set of constraints. The constraints employed for the early predictions were a target sales gas rate of 11.3 E6M3/d for a period of no less than 15 years and an inlet pressure at the onshore gas plant of 7.2 MPa.

Within these constraints, individual models were linked with the surface network to design potential Project alternatives. The alternatives focused around field sequencing, sales gas rates and individual field platform rates. As a result of these alternative studies, the current development plan has the system constraints described in **Table 3.3.2.1.** Other than the constraints reported in this table , the central compressor, located at Thebaud has been modeled with a minimum suction pressure of 2.8 MPa.

To achieve the 15 year flat life, wells and fields were phased, while maintaining the required Project production rate. The required production rate is comprised of the sales gas rate and a deliverability excess volume, built into the design to offset the performance risk of individual wells and fields. The desired level of deliverability for Sable Offshore Energy Project is still under investigation.

Table 3.3.1.1 System Constraints

Field	Platform Design E6M3/d	Maximum Rate Limitation E6M3/d per well	Minimum Rate Limit E6M3/d per well	Condensate Gas Ratio M3/E6M3
Thebaud	6.2	1.7	0.1	148
Venture	7.1	1.7	0.1	201
North Triumph	3.7	1.7	0.3	46
South Venture	1.8	1.7	0.3	201
Alma	3.7	1.7	0.3	104
Glenelg	3.7	1.7	0.3	60

3.3.2 The Constrained Project Plan

The current plan generated under these constraints begins with production from the Thebaud, Venture and North Triumph fields, and phases in the other fields, as required, to maintain the production rate at 11.3 E6M3/d. **Figure 3.3.3.1** provides the raw gas forecast for the plan using the following field sequencing: Thebaud, Venture, North Triumph, South Venture, Alma, and Glenelg.

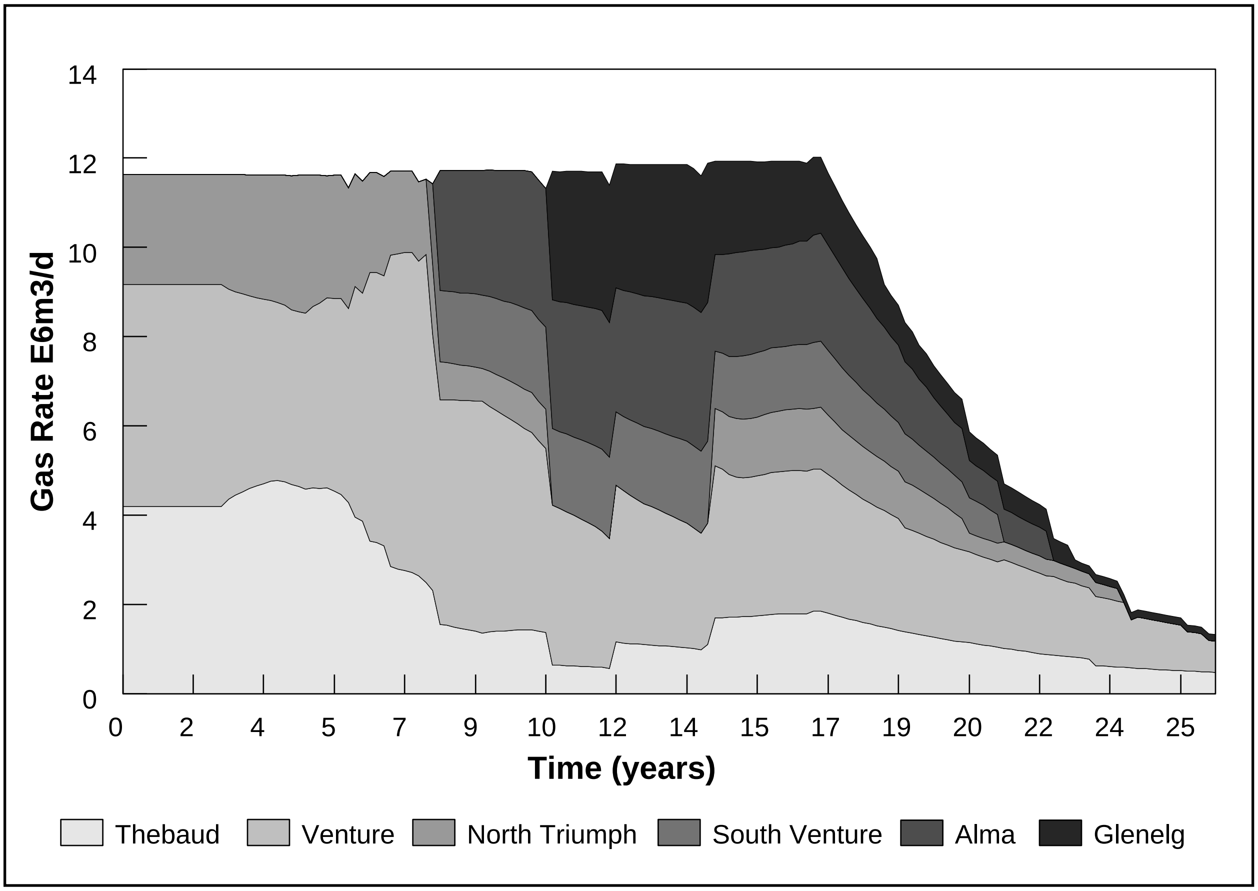


Figure 3.3.2.1 Raw Gas Production Forecast

The aquifer volumes associated with each of the models varies with the information available. In the Venture and Thebaud fields, the aquifers are considered to be limited in extent due to their overpressured nature. In the hydropressured (normally pressured) fields such as North Triumph, Alma, South Venture and Glenelg, the aquifer size is still under investigation. An objective of the reservoir management plan is to attempt to reduce the uncertainty in the size and responsiveness of the aquifers through analysis of regional geology, laboratory studies and production data.

The water production forecast associated with this Project plan is provided in **Figure 3.3.2.2**. This diagram is primarily a reflection of the Venture individual model input. The water production from a single well in the Venture field causes the production spike in years two through four. The pressures associated with these overpressured sands enables the well to lift significant volumes of water. This enhances the recovery of some of the minor sands which are commingled with this major sand.

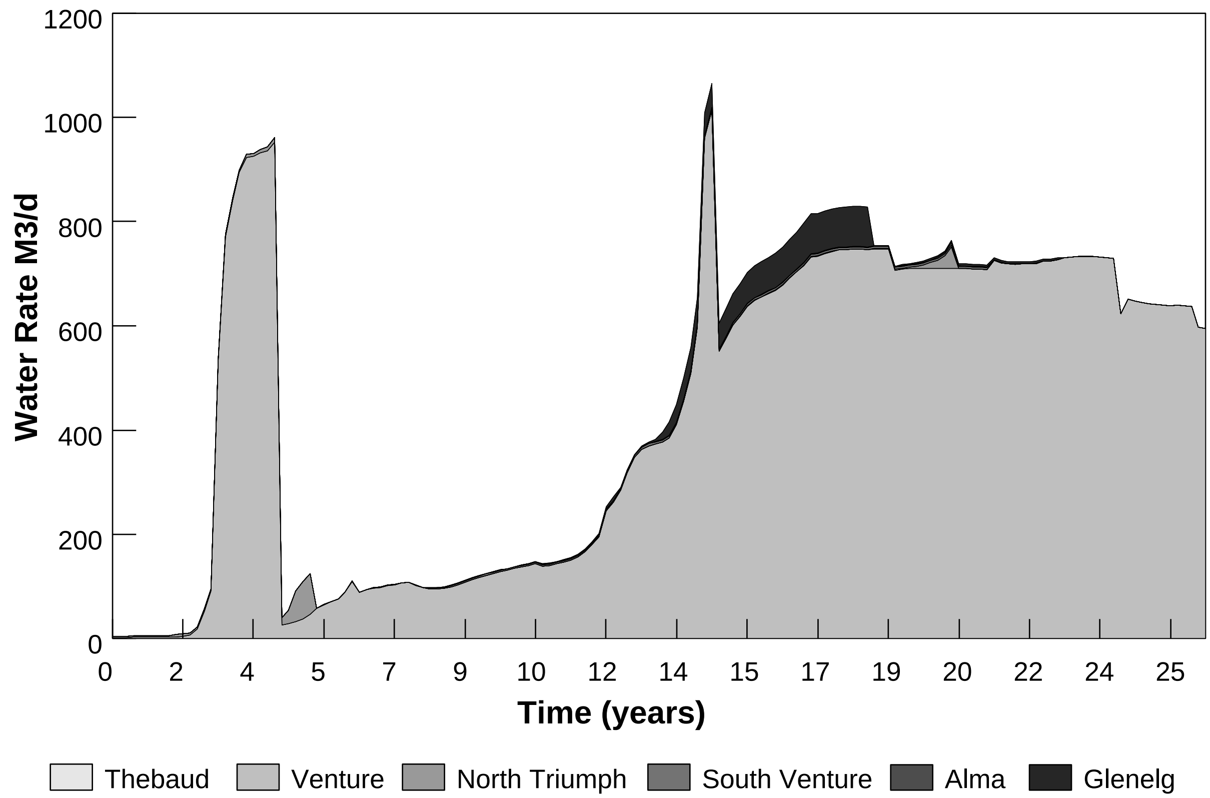


Figure 3.3.2.2 Water Production Estimate

Water production forecasts are heavily dependant on the relative permeability curves used to describe the ease with which water moves in a gas reservoir. The relative permeability curves obtained from core data were input for the Venture and Thebaud fields. This information currently does not exist for the other four fields. To accommodate this uncertainty in water production rates, the facilities design includes some flexibility to expand water handling capacity.

The total system deliverability is 50 percent higher than the required sales gas rate in the early stages of the Project, when there is a high degree of uncertainty of individual field deliverability. The system deliverability, at any point in time, is calculated as the sum of the maximum well rates, as determined from Pegasus - ISF. Total system deliverability is illustrated in **Figure 3.3.3.3**.

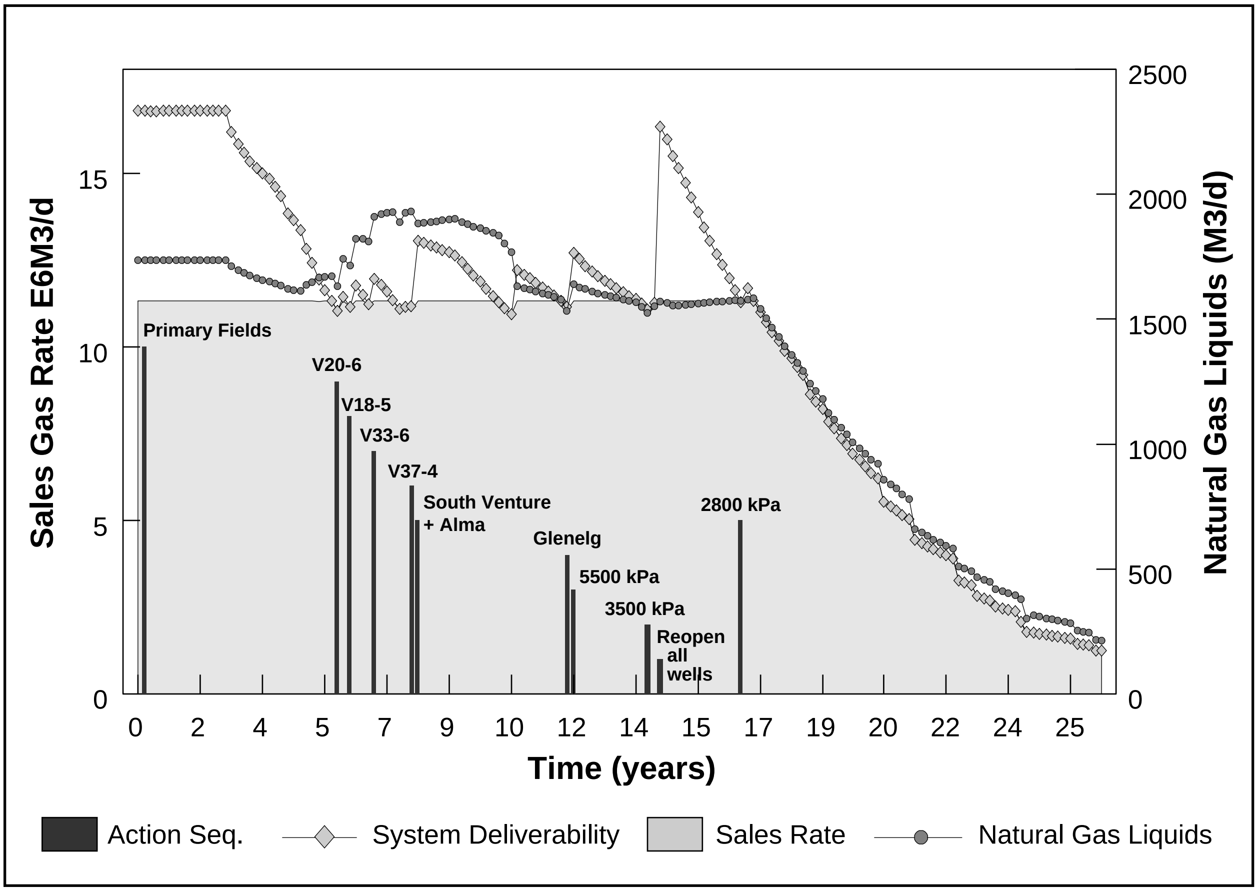


Figure 3.3.2.3 Sales Gas Forecast

The natural gas liquids rate shown on the right of **Figure 3.3.2.3** ranges from a high of 1.9 E3M3/d to a low of 1.5 E3M3/d during the sales gas flat life. This natural gas liquids forecast was based on a non-compositional simulation model with the CGR constraints as outlined in **Table 3.3.1.1**

The simulated event sequences depicted in **Figure 3.3.2.3** indicates an initial high level of activity for the start of production, with five Venture wells, four Thebaud wells and three North Triumph wells assumed to be predrilled.

In production years five through eight, the remaining four Venture wells, two wells in South Venture and five wells in Alma are added, as required, to maintain the desired level of sales gas in the simulation. The remaining five wells in Glenelg are not predicted to be required until year 10 of the project.

Following the field phasing stage of development, the first stage of compression (5.5 MPa suction pressure) is predicted to be required in year 12 of production. In years 15 and 16, the final re-staging of compression to a minimum suction pressure of 2.8 MPa completes the simulated sequence of events. The resulting average reservoir abandonment pressure ranges from a low of 7 MPa in the high deliverability, primary reservoirs to a high of 41 MPa in the lower permeability reservoirs. This simulated depletion strategy also provides for the optional recompletion of the wellbores to maintain deliverability later in the life of the field. This sequence of activities yields a plateau sales gas rate of 11.3 E6M3/d for 16 to 17 years.

The overall recovery efficiency predictions for each field are presented in **Table 3.3.2.1**.

Table 3.3.2.1 ISF - Recoverable Volumes

Field	Gas in Place E9M3	Recoverable Volume E9M3	Recovery Factor %
Thebaud	26.6	19.5	73.3
Venture	49.7	32.9	66.2
North Triumph	15.0	10.8	72.0
South Venture	9.2	7.2	77.2
Alma	15.0	11.8	78.6
Glenelg	11.9	8.1	68.1
Overall	127.4	90.2	70.9

Wells were located within the model to minimize gas trapped at the crest of the structure and for maximum areal drainage. All wells are assumed to be directionally drilled from field platforms as shown in **Figure 3.3.2.4.**

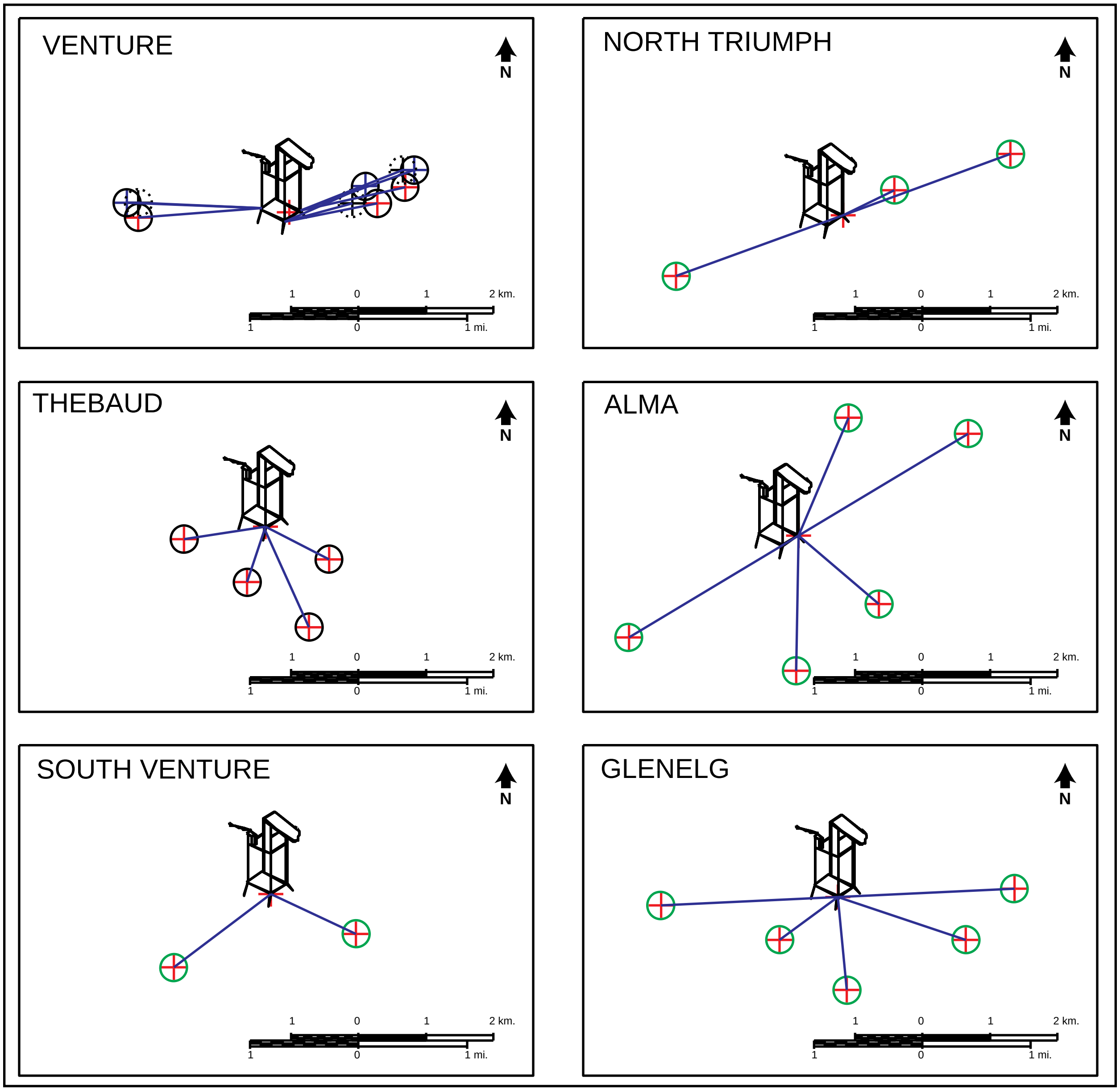


Figure 3.3.2.4 Well and Platform Location Schematic

The current simulated well completion strategy has a major sand commingled with two or three minor sands of similar pressure. The benefits of commingling are a reduction in costs and mechanical risks, while improving the recovery from the minor sands which would not be economically viable, if developed on their own. A more extensive discussion outlining the advantages, disadvantages and reasons for commingled production is included in Part Two of this document **(DPA - Part 2, Ref. # 3.3.2.1)**.

The first three wells drilled in Venture were to target the deeper horizons (Sands 6u, 6m, 7 and 8). The next three wells targeted the intermediate zones (Sands 4a, 4c, 4d and 5). The remaining three wells in the simulation were assumed to be completed in the shallowest formations of Sands 2, A, B, and 3a. **Figure 3.3.2.5** demonstrates the simulated completion strategy for the Venture Field.

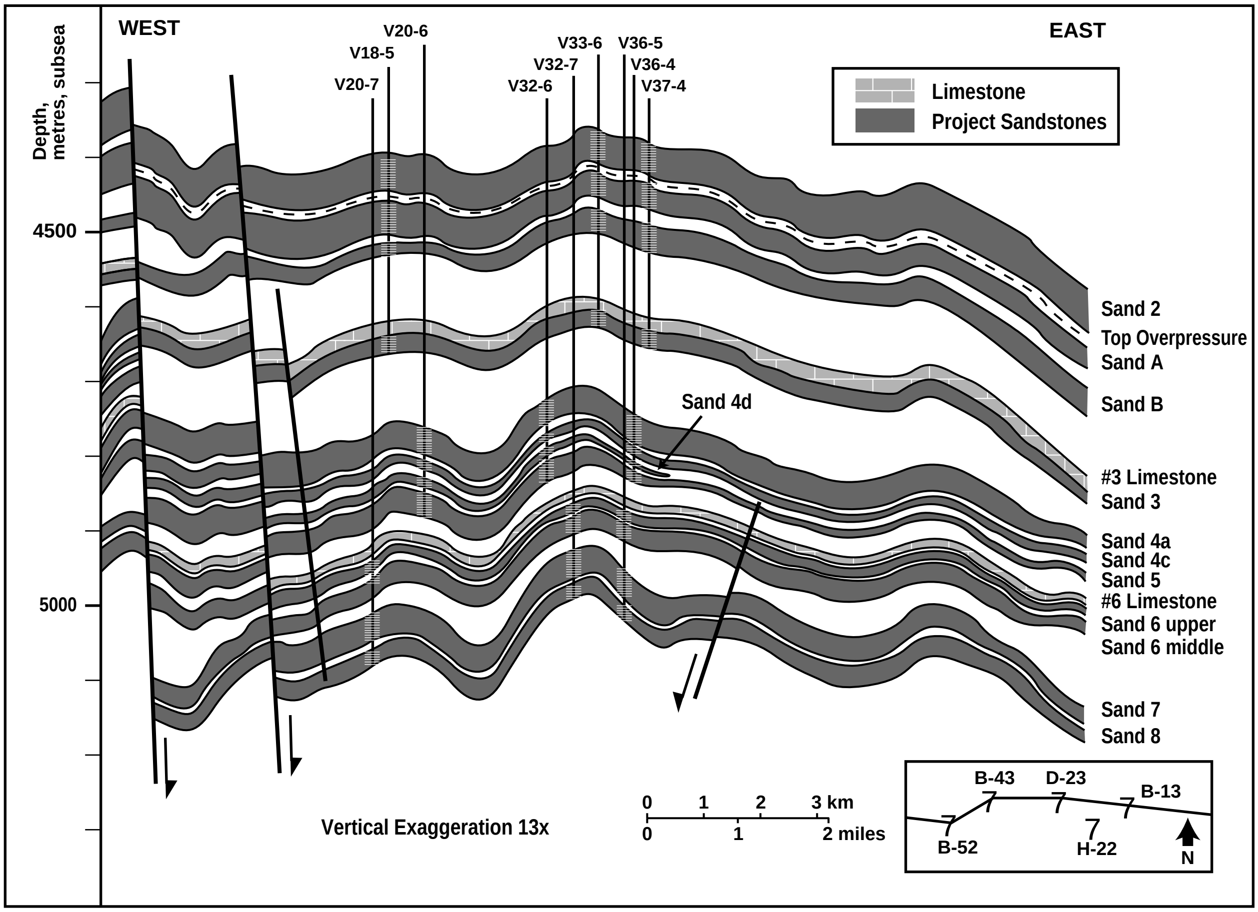


Figure 3.3.2.5 Venture Simulated Completion Strategy

Two wells in the Thebaud structure were simulated to target the deeper horizons and the remaining two wells targeted Sands A and B. This is similar to the methodology simulated in Venture. The deep wells of Thebaud were simulated to be perforated sequentially uphole, as each zone was depleted to the pressures of the upper zone. Within a relatively short time, all zones were open and producing in a commingled fashion, as shown in **Figure 3.3.2.6**.

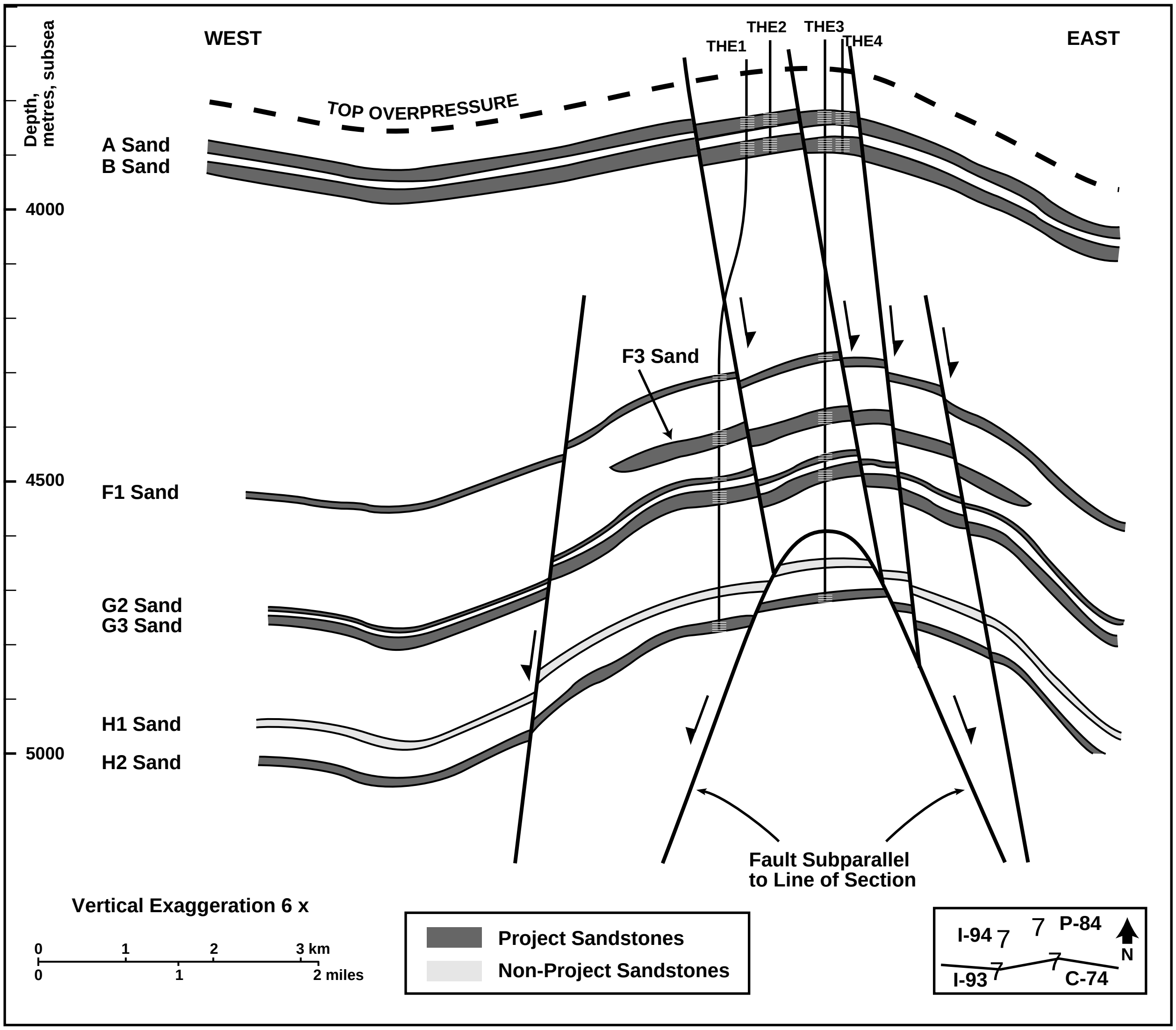


Figure 3.3.2.6 Thebaud Simulated Completion Strategy

Within the South Venture structure, the simulated two wells are targeted for the hydropressured sands, 2, 3a, 4, 5 and 6. These zones are similar in pressures and were simulated in a commingled production. This completion practice was also employed in the Alma and Glenelg simulations.

Within the simulations, all wells in Venture (shallow and intermediate horizons), North Triumph, South Venture, Alma and Glenelg were initially completed with 127 mm tubing. The two wells in Thebaud A and B sands were also simulated with 127 mm tubing. The tubing was changed to 102 mm during the simulated life of these wells. The wells in Venture and Thebaud targeted for the deeper horizons were completed with 102 mm size tubing. The optimized tubing sizes are currently under study.

To summarize, the presented simulated depletion scenario has 12 wells predrilled; five in Venture, four in Thebaud and three in North Triumph. The Venture field requires four additional wells to maintain deliverability and for adequate drainage. The remaining fields are predicted to require two wells at South Venture and five wells each for Alma and Glenelg to provide sufficient deliverability and, ultimately, drainage. The development of an optimized depletion scenario is ongoing as new data becomes available.

3.3.3 Alternative Depletion Scenarios

Several alternatives to the preferred depletion plan have been examined by the Proponents and were eliminated. In addition to these studies, there was a study commissioned by the Nova Scotia Department of Natural Resources, conducted by Indeva Energy Consultants **(DPA - Part 2, Ref. # 3.3.3.1)** which helped to screen the wide range of options for the six field development.

Two additional alternatives currently under review are discussed below:

(1) Alternative Field Sequencing

In this simulated study, field sequencing was modified. The simulation constraints were the same as those presented in **Table 3.3.1.1**. The first simulated fields on production, Venture and Thebaud are followed by North Triumph, South Venture, Alma and Glenelg prior to the onset of the compression phase. A notable feature of this study is the reduction in excess deliverability to approximately 20 percent of the sales gas rate. Compression assumptions are consistent with the case presented in the previous section which results in a similar recovery. **Figure 3.3.3.1** shows the action sequence to maintain the sales gas rate and the overall system deliverability.

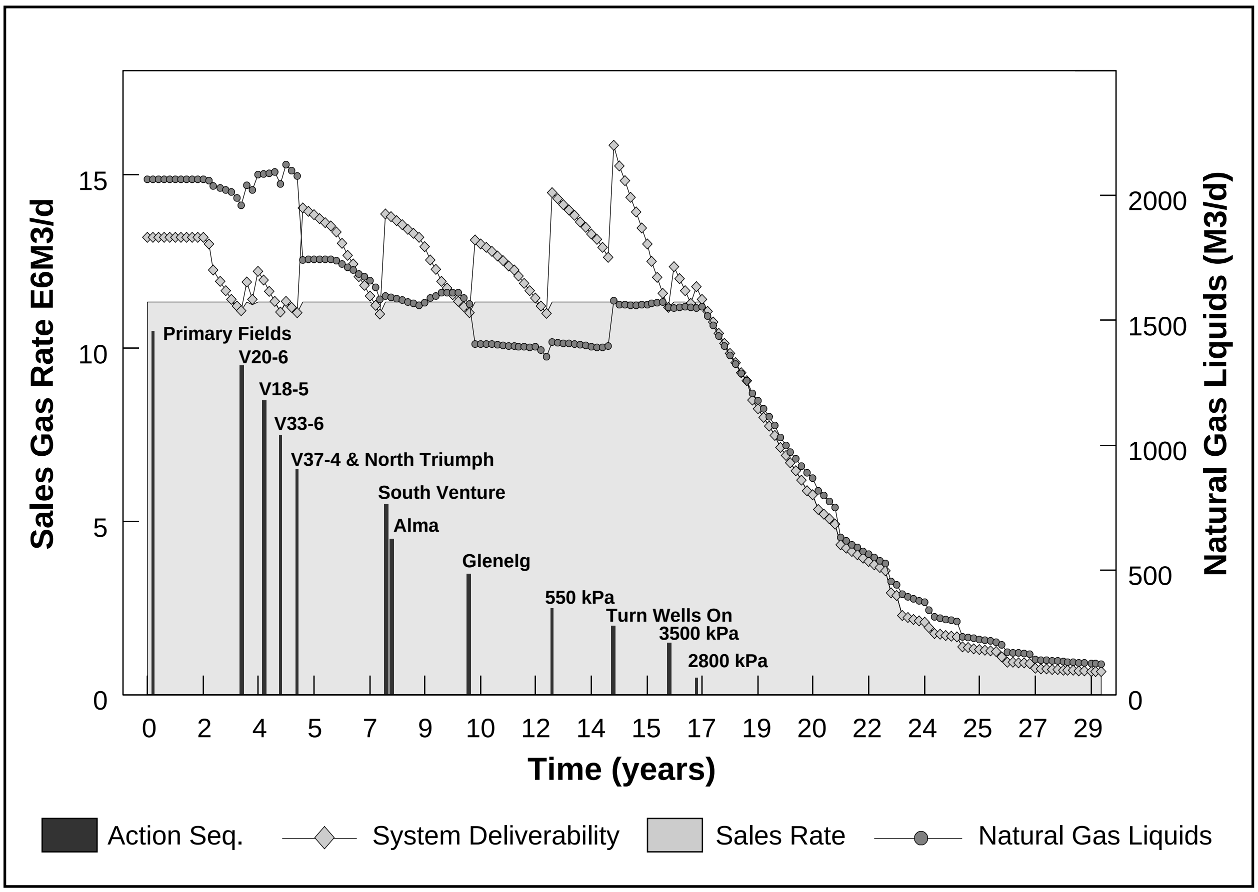


Figure 3.3.3.1 Sales Gas Forecast - Defer North Triumph Start-up

(2) Increased Sales Gas Rate

This alternative maintains the simulated field sequencing and compression assumptions outlined in **Section 3.3.2** and has an increased sales gas rate from 11.3 to 17 E6M3/d. The major impact is the reduction of the flat life from 16 years to eight years, demonstrating the dependency of the plateau life on the sales gas rate. This alternative is illustrated in **Figure 3.3.3.2**.

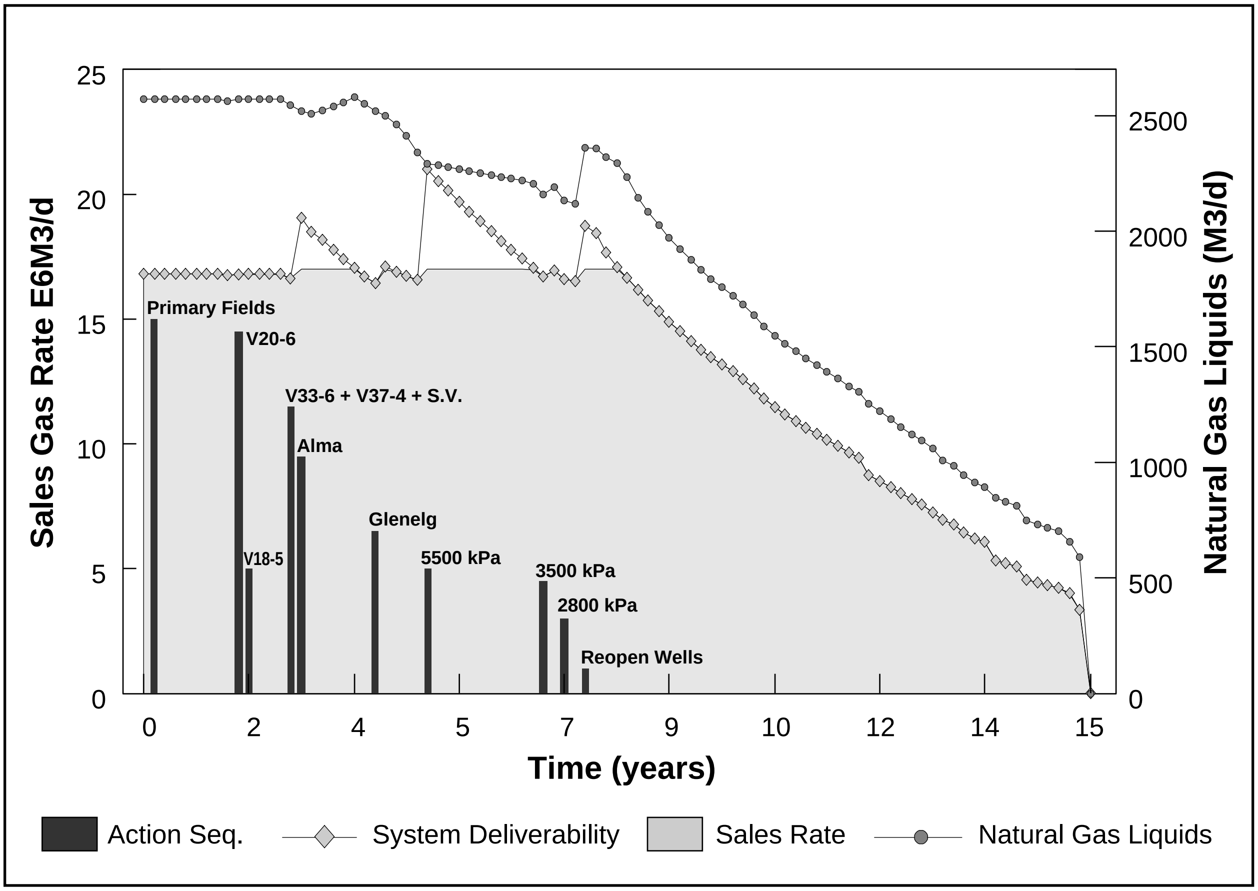


Figure 3.3.3.2 Sales Gas Forecast - Increased Gas Rate

Work to validate and screen production options is ongoing and is discussed further in Part Two of this document **(DPA - Part 2, Ref. # 3.3.3.2)** and will continue as new data becomes available.

3.4 Reserves

The recovery factors from the simulated option represented in **Section 3.3.2** have been incorporated into a probabilistic estimate of Project reserves. **Table 3.4.1** provides the recoverable reserve estimates at three different probability ranges and at the expected value for each field. A more detailed breakdown to the individual sand level is included in Part Two of this document **(DPA - Part 2, Ref. # 3.4.1)**.

Table 3.4.1 Probabilistic Reserves

Field	OGIP Ev E9M3	P90 Raw Recoverable E9M3	P50 Raw Recoverable E9M3	P10 Raw Recoverable E9M3	Mean Raw Recoverable E9M3	Mean Condensate Recoverable E6M3
Thebaud	26.0	6.4	14.4	30.3	16.9	2.4
Venture	49.4	11.9	27.1	58.6	32.2	6.2
North Triumph	15.2	4.0	9.1	17.3	10.2	0.4
South Venture	11.3	2.0	7.2	15.5	7.8	1.4
Alma	15.0	4.8	9.4	10.9	9.4	1.0
Glenelg	12.4	3.2	7.3	12.5	7.8	0.5
Total	129.3	32.3	74.5	145.1	84.3	11.9

Note: Mean values have been summed arithmetically.
P90 = 90 % Probability of exceeding posted value.
P10 = 50 % Probability of exceeding posted value.
P10 = 10 % Probability of exceeding posted value.
Ev = Expected Value or Mean Value.
OGIP = Original Gas In Place

Condensate recovery, reported in **Table 3.4.1**, was predicted using EOS, compositional and analytical models. The input data was obtained from compositional analysis and saturation pressure (dew point) measurements conducted on both **Sable Offshore Energy Project** fluid and analogous North Sea samples. **Table 3.4.1** summarizes the predicted condensate recovery at abandonment pressures for each field. The overall recovery of condensate is high and is characteristic of the lean nature (low dew point) of the reservoir fluids and the high initial reservoir pressures. Detailed discussion of the methodology and results, by sand, can be found in Part Two of this document **(DPA - Part 2, Ref. # 3.4.2).**

3.5 Reservoir Management Philosophy

Reservoir Management is a continuous process, which begins at exploration planning and is completed at the point of project abandonment. At this phase of the **Sable Offshore Energy Project** reservoir management, all existing data have been employed in a multidisciplinary approach to design a simulation tool for the generation of the development plan as presented in **Section 3.3.2.** As described in this section, the simulations at this stage vary in complexity with each field, spanning the range from simple tank type models to large scale three dimensional models.

The integral components of a reservoir management plan during the production phase include data surveillance, ongoing history matching of reservoir performance and updating of field and zonal depletion planning.

The surveillance plan is comprised of both routine and non-routine activities. The routine surveillance activities involve the collection, validation, storage and analysis of data. The type of data collected routinely may include daily production, fluid compositions, pressures and temperatures. Examples of non-routine data used for surveillance include production tests, RFT and DST tests, open and cased hole logs, as well as seismic surveys.

Other than the field surveillance plan, another key reservoir management tool is the well by well, zone by zone depletion plan. The focus of the depletion plan is for the optimization of wellbore utilization and economic recovery. For the commingled wellbores the plan could identify zonal targets and fluid contact monitoring techniques. Additional opportunities such as sidetrack or recompletion candidates could also be identified through the collection and analysis of this specific data.

It is important during the early stages of the project to recognize that most of the resource database has been obtained under static conditions and reservoir simulation provides the opportunity to predict early dynamic performance, under an initial set of assumptions. During the production phase new data will be integrated into the reservoir simulators as it becomes available. Ongoing history matching using routine well data and the more infrequent well test and possible production logging will assist in the validation of the initial reservoir performance assumptions.

One goal of the depletion plan is to identify when a focused subsurface review is required to update the field depletion plan. This identification is usually triggered when field simulations are not predicting performance within adequate target ranges. Through this non-routine reservoir recharacterization and subsequent larger simulation updating, the reservoir predictability is maintained, while honouring all the data. Such a comprehensive review would be a separate activity in addition to the ongoing depletion planning.

In summary, efficient development at **Sable Offshore Energy Project** requires a multidisciplinary reservoir management plan that will be developed in the next phase of work.

4.0 DRILLING COMPLETIONS AND WORKOVERS

4.1 Strategy

The development of drilling, completion and workover plans for the **Sable Offshore Energy Project** are guided by a desire to minimize the initial and future costs of all wells during production operations. Any technological developments that could enhance the Project, will be considered as the Front End Engineering Design (FEED) stage of the Project progresses. There may be modifications to this development plan proposal as the Front End Engineering Design (FEED) progresses. Some future options include horizontal wells (both conventional and multi-lateral), and extended reach wells. Additional studies are underway to determine the effect on formation integrity with pressure depletion. The results of this work will be shared with the **CNSOPB** when finalized.

All wells for the **Sable Offshore Energy Project** will be drilled with Cantilever Jackup rigs which have a water depth capability of up to 90 metres, and use 103 MPa Blowout Preventers (BOPs). The 100 year storm criteria establishes minimal acceptable rig design and thus limits selection. Preliminary criteria are outlined in **Section 5.6** of **Chapter 5.0: Production and Export Systems** of this document. All completion and workover operations will utilize either the rig, or equipment such as coiled tubing or wireline units, present and certified on the rig. The only exception would be skid-mounted wireline units that would be mounted on the platforms. Identical operating and certification requirements will be followed.

Contracting strategy for the Project drilling, tubular, wellhead and mudline suspension systems and services will likely be based on integrated services and enhanced supplier relationships. Synergy may be possible with contractors and suppliers already operating off the East Coast, for items such as workboats and helicopters. It would be optimal to utilize only one rig contractor for both drilling rigs, and rig contracting inquiries will be approached on a two rig basis.

Additional selection criteria for drilling contractors will be experience with high pressure offshore wells, technical ability and cost.

Specific safety issues for drilling are addressed in **Section 10.2** of **Chapter 10.0: Safety Plan** of this document. They include the development of procedures to be followed during simultaneous drilling and production.

Relief well drilling capability will be ensured in the initial phase of drilling by having two 103 MPa rigs drilling in the Sable area. During other segments of drilling, completion and workover operations, only one jackup rig may be operating in the Sable area. Agreements will be established with the Proponents to make an appropriate drilling unit immediately available for relief well drilling, if necessary. This unit would most likely be mobilized from the North Sea or the Gulf Coast, but does not preclude available units identified by the combined worldwide resources of the Proponents' affiliates. Casing, wellhead and mudline suspension equipment will be available for use, if necessary.

All manuals, drilling programs and approvals will be complete by the proposed drilling date for the Project. A tentative schedule has been developed to reference the timing and completion of the activities, and the acquisition of critical components for drilling. **Table 4.1.1** illustrates a tentative drilling development schedule.

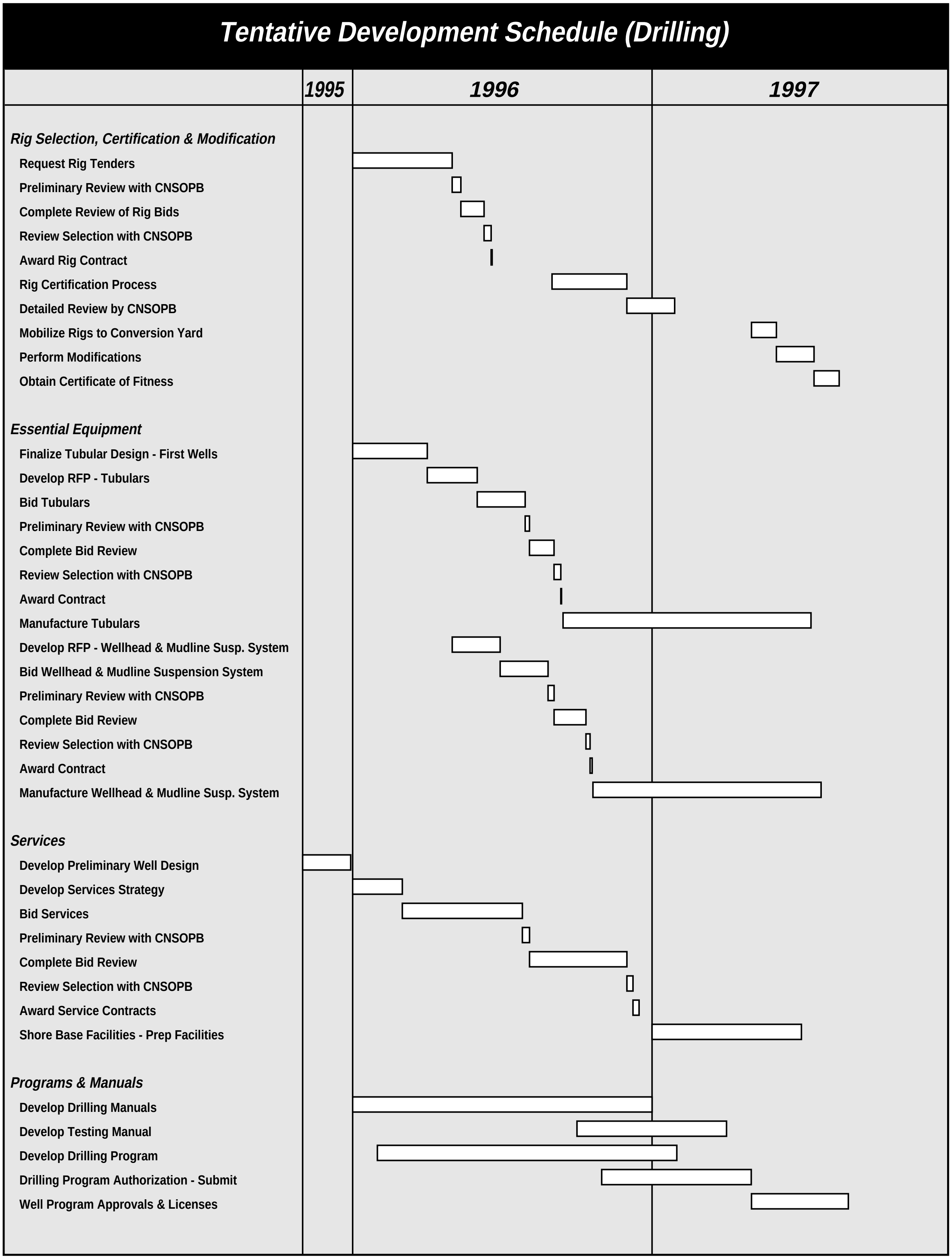


Table 4.1.1: Tentative Development Schedule (Drilling)

4.2 Projected Drilling Schedule

The target date for the start of gas produciton from the **Sable Offshore Energy Project** dictates that drilling must commence no later than September, 1997. To accomplish this goal, a number of wells will have to be completed and ready for production by that date. The number of wells required for start-up will be determined by individual well deliverability and required project deliverability.

The jackup drilling rigs will be brought in to Halifax harbour in the summer of 1997. The process for upgrades and/or inspections for **CNSOPB/CCG** Certificates of Fitness (COF) to operate in the waters off Nova Scotia will commence prior to their arrival and be completed in the Halifax harbour. There will be pre-drilling of wells using templates and mudline systems in the Venture, Thebaud and North Triumph fields. A total of five Venture wells, three North Triumph and four Thebaud wells are expected to be pre-drilled in accordance with the simulated development plan discussed in Chapter 3.

One of the rigs will begin operations after the template has been positioned on the seabed at the Venture field. This rig would require a working water depth of 30 metres, with allowance for 100 year storm criteria. It is likely that the rated water depth of the rig will be substantially greater than this requirement. The Venture jacket is planned for installation in May of 1999. A September 1997 startup of operations guarantees that up to five wells will be drilled and completed by the end of 1999. If the startup of drilling is delayed until the following April, due to rig availability or other unforeseen factors, only three wells could be completed by May of 1999 and the drilling and completion of the last two wells would be at risk for the November 1, 1999 startup. The first rig will be released once the last well at Venture is tied back.

The second jackup drilling rig will require a water depth capability of up to 90 metres. This rig will have to meet the same 100 year storm criteria as the first unit. A template will be set at Thebaud prior to drilling in September of 1997. Four wells will be drilled at Thebaud in 1997/98. The rig will then be moved to North Triumph in November and three wells will be drilled, again through a template. Once the platform is completed at Thebaud, the rig will move back to this location and tie back the wells. While this work is ongoing, the platform for North Triumph will be installed. Once the installation is complete, the rig will return to North Triumph to tie back and complete the three previously drilled wells at this location. This work is expected to end in the third quarter of 1999. Ongoing exploration and drilling activities should ensure the second rig remains in the area until the year 2004, when it will be used for the second phase of development.

In the spring of 2004, the remaining four Venture wells of the anticipated nine well program will be drilled. Once they are completed, the rig will be moved to the South Venture platform to drill two wells. In October, the rig will move to Alma to drill up to five wells. By June of 2007, these wells will be completed and the rig will be moved to the Glenelg platform to drill the remaining wells. Any additional drilling and recompletion work will commence after this period. The projected drilling schedule by year is outlined in **Table 4.2.1**.

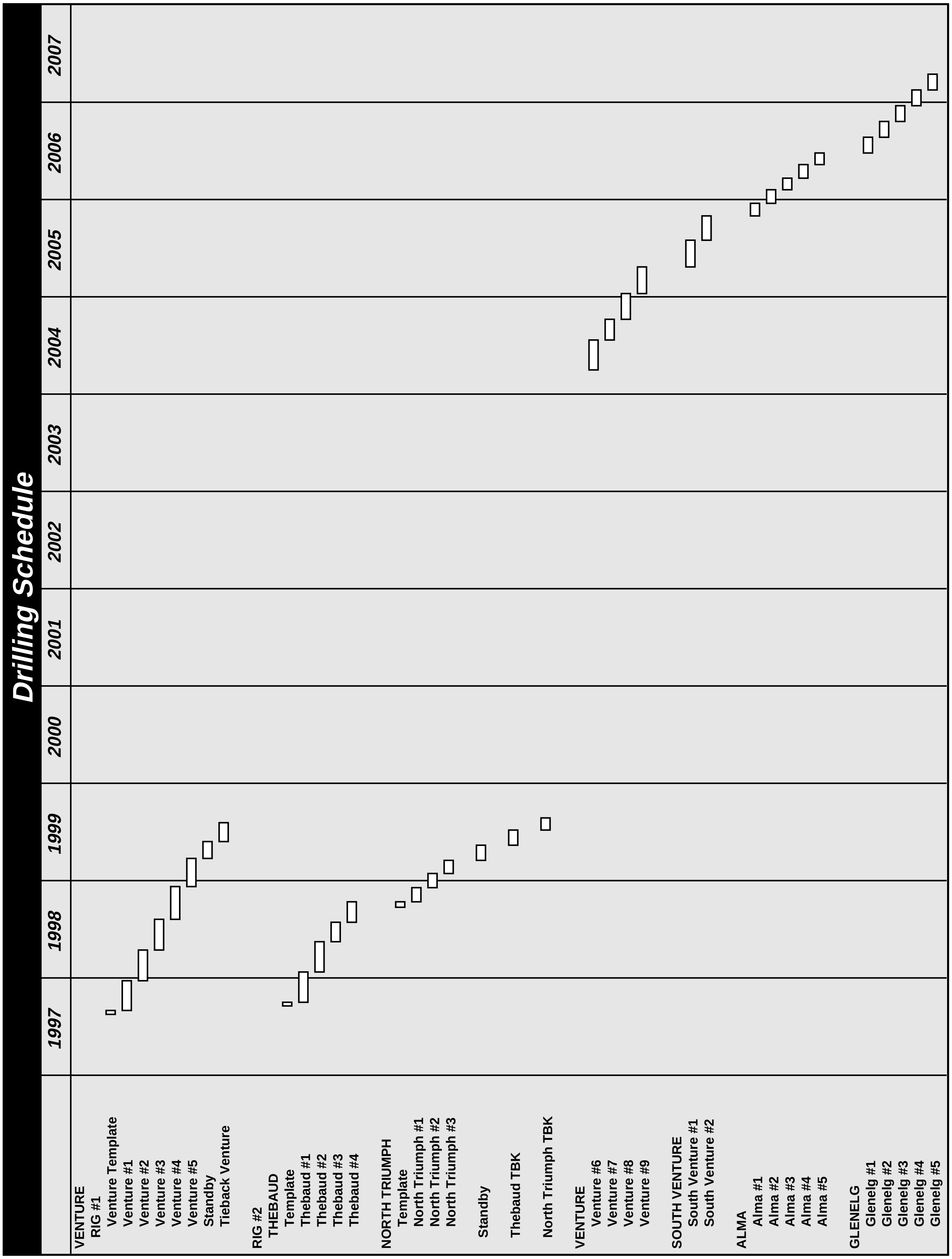


Table 4.2.1: Drilling Schedule

4.3 Equipment Selection

4.3.1 Drilling Rigs and Services

The rigs will be a minimum of a CFEM T-2005-C design, or equivalent, and have 103 MPa pressure control equipment. One rig would require a working water depth of 30 metres, in accordance with the 100 year storm criteria. It is likely that the rated water depth of that rig will be greater than required. The second jackup drilling rig will require a water depth capability of up to 90 metres. Possible modifications to the rigs selected include changes in the handling of oil based drilling fluids. These modifications will be further defined as the Project progresses.

4.3.2 Mud Handling System

All wells will have a dual water and Low Toxicity Mineral Oil (LTMO) mud system. The use of LTMO based mud provides hole stability and lubrication, which are both important for directional drilling. Conductor and surface hole will be drilled with sea water based drilling mud. The first intermediate interval will be drilled with a water based mud for holes greater than 343 millimetres (mm) in diameter. Dependent on the angle of the hole in this section, some 343 mm holes will be drilled with LTMO mud. All holes below 343 mm, will be drilled with LTMO mud. Cuttings and cleaning equipment for LTMO based drilled solids will meet or exceed **CNSOPB** regulations for oil based cuttings. Gas and water log identification may be enhanced by the use of LTMO mud in the production zone.

4.3.3 Directional Surveying

Both in-house and commercial directional survey models will be evaluated for their applicability and reliability in planning directional wells from the templates and platforms. A directional surveying manual based on North Sea experiences will be developed to address well interference, directional control, tool reliability and directional well planning and surveying procedures. The manual will also discuss areas of responsibility, precautions to avoid intersections and procedures to be followed for well paths that approach existing wellbores too closely.

4.4 Well Casing and Completion Plans

4.4.1 Casing Design

Casing designs are based on **CNSOPB** drilling regulations. Work for the casing design, using Mobil's Load Resistance Factor Design (LRFD) method, is underway at the time of filing. The LFRD method determines the actual stresses and limitations of the tubulars. This design work has the potential to reduce the overall casing and tubing costs, and provides a greater level of reliability than conventional methods. Further details are included in Part Two of this document (**DPA Part 2 - Ref. # 4.4.1.1**).

Casing points have been selected to provide sufficient kick tolerance and prevent excessive mud weights in the intermediate hole section of each well. L-80 and C-90 grades of pipe are suggested for the production casing to compliment the premium connections. Examples of completion designs for the Project wells are included in **Figure 4.4.1.1** and **Figure 4.4.1.2**.

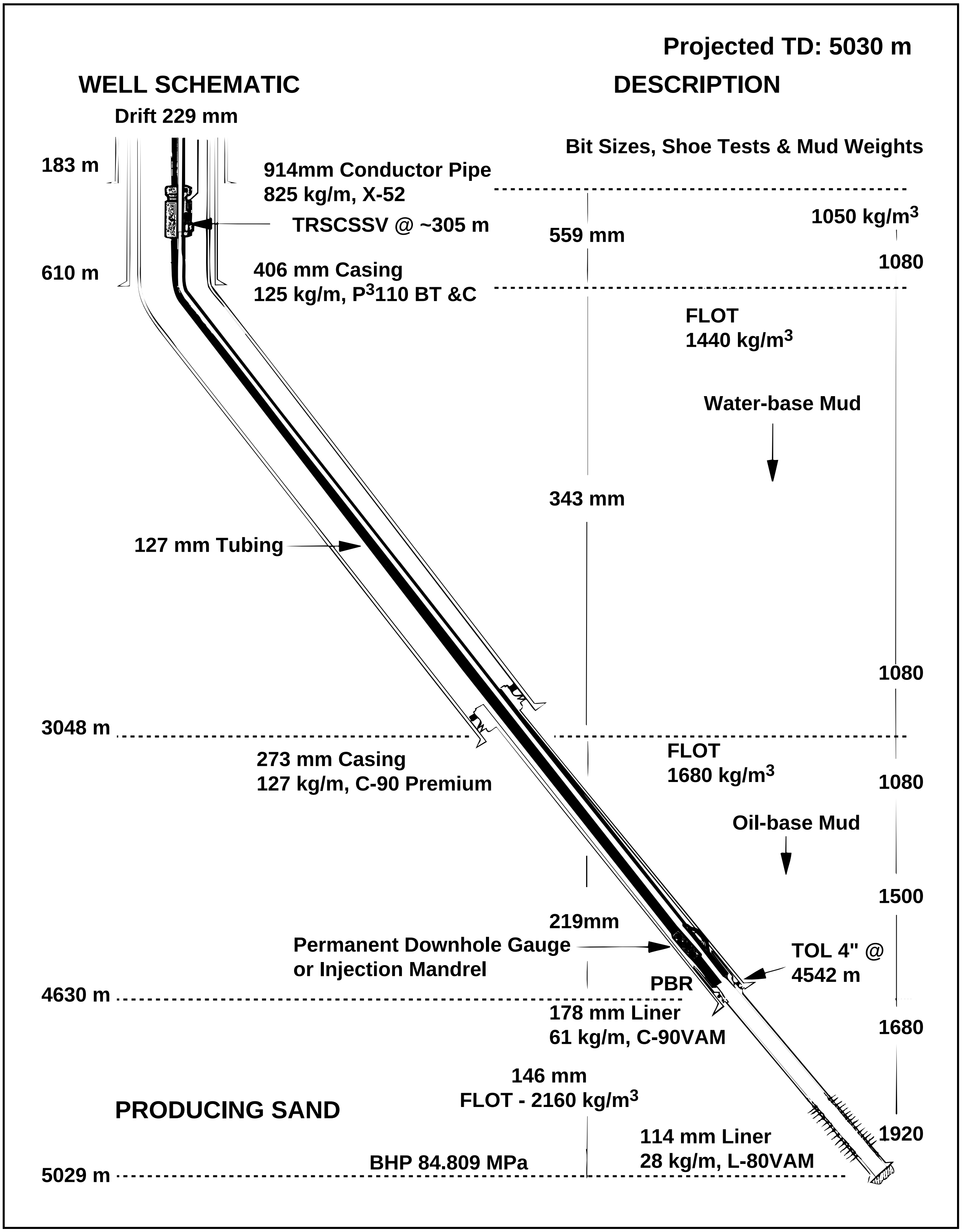


Figure 4.4.1.1: High Pressure Completion Designs

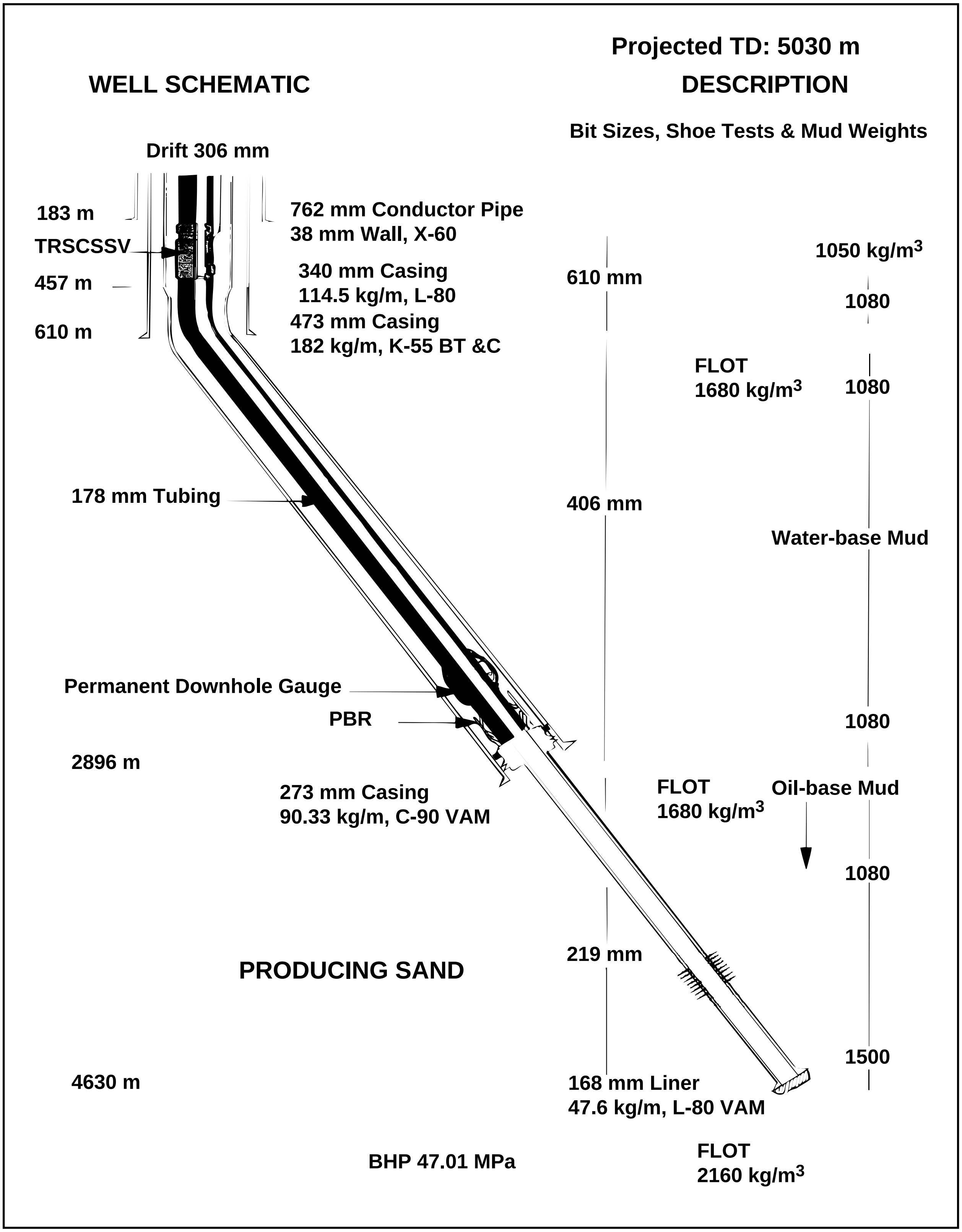


Figure 4.4.1.2: Low Pressure Completion Designs

4.4.2 Completion Design

4.4.2.1 Design Philosophy

Completion systems must be simple, reliable and economic, and meet all requirements for a high temperature, high pressure (HTHP) environment. The completions are designed on a step-monobore concept where the liner becomes part of the flow conduit presently proposed. Although the current base-case for the field simulations use 102 mm tubing, the size of tubing string will most likely be 178 millimetres (mm) for shallow and 127 mm for deep completions. In deeper sands and thus higher pressure applications, 127 mm tubing is necessary for design pressure limitations and subsurface safety valve geometries. A completion design will be used that provides the flexibility to increase the size of the tubing to a larger string without jeopardizing wellbore or equipment integrity.

Production objectives considered, but not limited to, in the design are:

- Ensure operational safety.
- Keep completions as simple as possible.
- Schedule workovers to minimize downtime.
- Maintain a surplus in deliverability to mitigate production downtime due to workovers or suspended wells.
- Minimize the number of wells for each field while maximizing recovery and effectively depleting the reserves.
- Maintain the flat-life production of the Project as long as possible, to minimize compression requirements.
- Select producing intervals to maximize individual well rates while minimizing effects of cross-flow, condensate deposition and sand production.
- Recomplete zones from bottom-up.
- Maximize drawdown on low-productivity sands.
- Allow commingling of sands.

4.4.2.2 Metallurgy

Careful consideration will be given to the materials used for tubulars, wellhead and/or downhole equipment because of exposure to corrosive fluids. Due to the presence of H_2S (albeit small) and CO_2, an alloy steel may be required for tubulars and downhole equipment, and a corrosion resistant cladding may be required for wellhead equipment.

The Proponents are undertaking a study to determine the corrosion potential of the producing environment, and to determine optimal material and operational guidelines. The results of this study will be shared with the **CNSOPB** when it is finalized.

4.4.2.3 Tubing Design

With a possible completion strategy that includes commingling to maximize productivity, maximizing the tubing size is necessary so that wellbore deliverability is not tubing constrained. The major deterrent to large wellbore size is the production casing burst limit with respect to shut-in tubing head pressure (SITHP). The tubing size is limited by the size of the Outside Diameter (OD) of the subsurface safety valve (SSSV) that will fit in the production casing. The tubing design must provide a flow conduit consistent with the inflow performance of the completed sands.
A field-by-field summary of maximum anticipated shut-in tubing head pressures, and allowable bottomhole static pressures for casing weights with the maximum setting depths for conventional casings for each field is included in Part Two of this document (**DPA - Part 2, Ref.# 4.4.2.3.1 and 4.4.2.3.2**).

The design of the tubing connections will likely incorporate the following:

- primary metal-to-metal seals
- multiple seals
- internal flush bore to prevent turbulence and corrosion
- high strength to withstand combined stresses
- minimum outside diameter
- proven reliability with make-up / break-out history, particularly with respect to the design metallurgy

Where practical, one size, weight, grade and connection will be used for each tubing / casing string. This will minimize inventory and prevent the use of improper materials. Design limits for production tubing will meet or exceed the minimum tolerances of burst, tension and collapse, as calculated for the influence of combined stress under normal operating conditions. Final selection of the tubular connection will adhere to a connection qualification program that meets industry standards.

4.4.2.4 Downhole Equipment

The use of downhole tools will be minimized to reduce workover complexity and requirements. High temperatures and pressures, coupled with the potentially corrosive environment, may reduce the performance of any equipment in the wellbore.

The current design has tubing retrievable SSSV's installed, and all wells are equipped with a Polished Bore Receptacle (PBR) system to facilitate tubing change-out. The liner hanger design incorporates a packer assembly above the slips to ensure positive pressure integrity. The selection of sealing method and elastomer type will incorporate the results of future corrosion studies.

The maximum anticipated pressure will be contained safely and effectively through the selection of appropriate wellhead and production tree equipment. Full-bore access to the tubing will allow for well-kill operations and be integrated with an operating and emergency control and shutdown system, both manual and hydraulic. Due to the operating environment, the wellhead and tree will most likely be clad in a corrosion/erosion resistant material. The tubing bonnet will be ported to allow capability to handle downhole injection and control lines, and the hydraulic valves will be capable of cutting both wireline and coiled tubing.

The present completion strategy allows for the integration and use of any anticipated downhole equipment including flow control nipples, chemical injection and mandrels for real-time pressure read-out.

4.4.2.5 Completion, Workover and Packer Fluids

Finalization of the fluid types and requirements will be dependent on the final completion design. Laboratory testing on field core samples will quantify the potential for formation damage and ensure stability with time at high temperature and pressure.

In general, all workover fluids will ensure well operations are carried out in an overbalanced condition, and that the fluid, potentially inhibited fresh or salt water for normal or depleted pressure environments, will be non-damaging to the formation. It is the intent that under normal circumstances, all environmentally sensitive fluids will be collected for disposal or re-use. The **CNSOPB** guidelines for handling and disposal of fluids as they apply to the drilling operation will be applied in these circumstances.

5.0 PRODUCTION FACILITIES

5.1 Development Plan

The present **Sable Offshore Energy Project** development plan includes the six offshore natural gas fields: Thebaud, Venture, North Triumph, South Venture, Glenelg and Alma; and extends onshore to gas processing facilities in the Country Harbour area and to liquids processing facilities in the Point Tupper area (see Figure 5.1.1). The six fields are anticipated to deliver a sales gas volume of 11.3 E6M3/d to markets in Canada and the eastern United States.

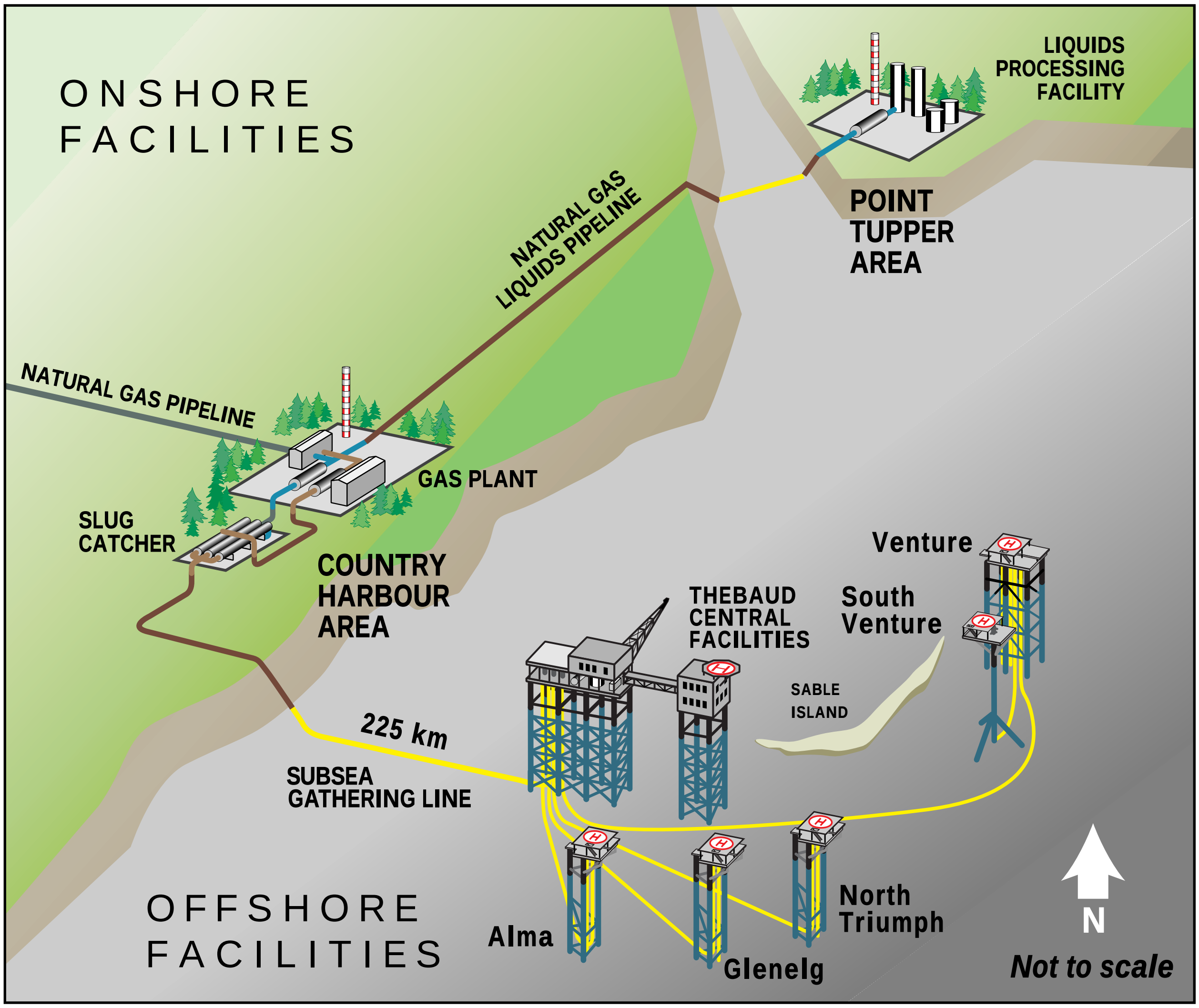


Figure 5.1.1: Production Facilities

The scope of the Production and Export Systems for the Project include:

- Offshore Facilities (production platforms and subsea pipelines)
- Onshore Facilities (gas and liquids processing facilities and liquids pipeline)

For the gas product the Project will extend to the gas plant outlet flange where processed gas will enter **The Maritimes and Northeast Pipeline**. For natural gas liquids products (Liquified Petroleum Gas and Condensate), the Project will extend to the point of loading at, or near, the Statia Terminal in Point Tupper. The project may also make use of salt caverns for gas and/or liquids storage to enhance marketing reliability. Salt cavern development would be subject to a separate development plan.

When fully developed, the **Sable Offshore Energy Project** will include up to six production platforms and an accommodation platform. The central facilities at Thebaud will be continuously manned, and include wellheads, production and processing equipment and an adjacent accommodation platform. The other fields will be developed with satellite platforms. These satellites will be normally unmanned and support wellheads and minimal processing facilities. These platforms will be equipped with emergency shelters. The satellite platforms will be tied-back to the Thebaud platform via subsea interfield flowlines. A single subsea production gathering pipeline will transport the gas from Thebaud to an onshore natural gas processing plant, with its related facilities, in the Country Harbour area. Natural gas liquids extracted from the produced gas will be fed by buried pipeline to liquid processing, storage, and shipping facilities in the Point Tupper area.

The Proponents believe that this plan is currently the most effective development plan for the resources. Their choice is based on definition engineering, environmental, economic and socio-economic (including public consultation) factors. Front End Engineering Design (FEED), the results of ongoing technical investigations and technical advances, market outlook, the acquisition and interpretation of 3D seismic, and early development drilling results will result in modifications to, and optimization of, this plan. The project development process is illustrated in **Section 1.2** of **Chapter 1.0: Project Overview** of this document.

5.1.1 Development Plan Philosophies

5.1.1.1 Facility Expansion

The design basis for the Project presented in Section 5.5 of this chapter references a raw gas design capacity for the central facilities (Thebaud Platform, Production Gathering Pipeline, Slugcatcher, Gas Plant, Liquids Pipeline, and Liquids Processing Facilities) of 12.7 E6M3/d. This rate coincides with production expectations from the current Project depletion plan in **Chapter 3.0: Reservoir Engineering**. The difference between the 12.7 E6M3/d raw gas rate and the 11.3 E6M3/d sales gas rate referred to throughout the DPA represents shrinkage from liquids production and fuel usage plus a 10% design allowance. However, there may be future expansion due to increased reserves in the base project or new discoveries in the area. An investigation of facility expansion, by up to 50 percent, to a throughput of 19 E6M3/d (raw gas inlet) has been conducted and is included in Part Two of this document (**DPA - Part 2, Ref. # 5.1.1.1.1**).

The Proponents' philosophy on facility expansion is summarized as follows:

- To prebuild expansion capacity, where it is economically justifiable.
- To provide space and weight allocations, as appropriate, in the base design to facilitate future expansion where prebuilding capacity cannot be economically justified.

5.1.1.2 Third Party Access To Facilities

The Proponents' philosophy on third party access to the facilities is as follows:

- The Proponents are prepared to permit Third Party Access to the facilities in accordance with normal regulatory practice. The Proponents believe that the appropriate terms and conditions relating to Third Party Access should reflect the appropriate allocation of cost and risk borne by the owners, particularly in the event of facilities expansions.

5.1.1.3 Measurement

The Proponents' philosophy on measurement systems is as follows:

- Measurement systems of suitable accuracy and precision will be installed consistent with the fiscal and commercial terms that are negotiated.

- Measurement systems will be installed consistent with an expectation to provide a material balance across the facilities and a basis for reservoir management.

- Measurement systems will be designed consistent with applicable regulatory requirements.

- Measurement technology will be selected consistent with Proponent goals to minimize capital and operating costs and with reference to such standards as the latest revision of the *American Petroleum Institute Manual of Petroleum Measurement Standards*.

The most common measurement systems utilized in the gas industry are orifice metering for gas and positive displacement or turbine metering for liquids. It is envisioned that meters of these types will be used at custody transfer locations such as the outlets of the onshore facilities.

New technologies continue to be developed and old technologies continue to be enhanced to improve their accuracy and precision. Multiphase flow measurement offers a significant opportunity to simplify offshore metering while providing acceptable accuracy. These **Development Alternatives** will be addressed during FEED.

5.2 Offshore Production Facilities

5.2.1 Platform Structures

The Project platforms are expected to be fixed steel jacket-type platforms. These are preferred for their lower cost, easier construction and established safe performance record. The steel jacket platform has a long history of successful operation in environments similar to the Sable Island area. Any variations in platform design resulting from FEED will not affect their environmental performance. **Figure 5.2.1.1** illustrates a typical jacket structure in the fabrication yard.

Figure 5.2.1.1: Typical Jacket Structure

Floating systems were eliminated as an alternative because they are not appropriate for use in the shallow waters and frequent severe storms of the Sable Island area. The seasonal effects of extreme storm, wind and wave conditions would make the production system susceptible to disconnect, interrupting production during the time of year when market demand for gas is highest. There are loading restrictions on floating structures, and it would be difficult to design an adequate mooring system for the shallow water depths.

Concrete structures, while not eliminated as an option, are not considered to be cost competitive. They will be investigated further in the FEED stage of Project development.

5.2.2 Well Facilities

Wellheads will be installed on the central processing platform at Thebaud and the satellite platforms. Any wells drilled prior to the installation of a platform will require the setting of a well template to serve as a conductor guide during drilling. These wells will be completed with tie-backs from the sea bottom, installed by a jackup rig once the platforms are in place. A Development Alternative would include setting of wellhead jackets prior to drilling. Wellheads suitable for the shut-in wellhead pressures of each particular field will also be installed at that time. **Chapter 4.0: Drilling, Completions and Workovers** contains further information on the wells.

5.2.3 Satellite Platform Facilities

The satellite platforms will be designed as normally unmanned, minimal processing facilities. This practice is consistent with the offshore natural gas experience of both Mobil and Shell, and their affiliates, in the North Sea and the Gulf of Mexico. A visit frequency to each of these platforms of once every one or two weeks should be attainable, if not bettered. Emergency shelters will be located at these platforms for safe refuge in emergencies and accommodation when inclement weather unexpectedly prevents helicopter access. The satellite platforms will be connected by pipeline to the central production platform at Thebaud.

Gas, condensate and water produced from the wells at the Venture, North Triumph, Glenelg and Alma fields will be separated in a three-phase group separator equipped with gas and liquid metering. The group separator will be paralleled with a test separator to facilitate individual well tests. Produced water will be treated through a hydrocyclone separator, followed by a degasser, and then discharged overboard through a caisson extending below the water surface. Gas and condensate will be recombined and sent to the central production platform at Thebaud for further processing. Monoethylene glycol (MEG) and corrosion inhibitors will be injected into the pipeline at the satellites to prevent hydrates and corrosion. A small methanol (MeOH) injection tank and pump will be provided for use on a contingency basis to deal with the infrequent formation of hydrates.

South Venture wells will be developed from a simple wellhead support structure, or possibly directionally drilled from Venture. Further measurement and treatment, other than MEG injection at the wellhead, will be done at the Venture platform.

Development Alternatives for the satellite platforms include the addition of an inlet production cooler (seawater or aerial) and the use of wet gas measurement, which would eliminate the need for a test separator. **Figure 5.2.3.1** illustrates a typical satellite platform in the UK sector of the southern North Sea.

Figure 5.2.3.1: Typical Satellite Platform

The preliminary platform site coordinates are as follows (UTM NAD27 Zone 20):

Venture	44^{o} 02.12’ N	59^{o} 34.96’W
South Venture	44^{o} 00.00’ N	59^{o} 37.00’W
North Triumph	43^{o} 41.91’ N	59^{o} 51.40’W
Alma	43^{o} 35.69’ N	60^{o} 40.92’W
Glenelg	43^{o} 39.35’ N	60^{o} 08.51’W

The platform locations are illustrated in **Figure 5.2.3.2**. Preliminary designs for satellite support facilities are outlined in the following sections.

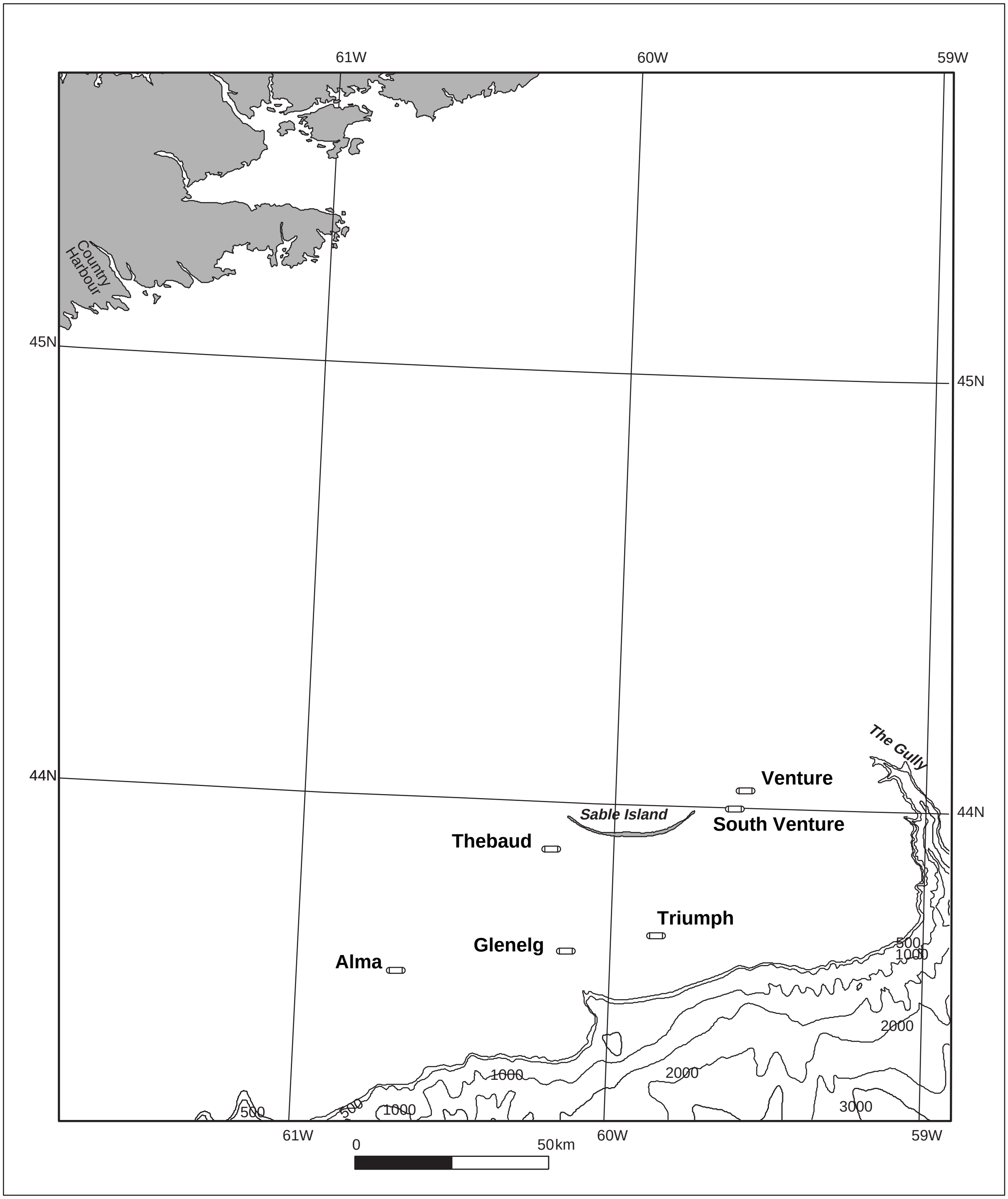


Figure 5.2.3.2: Preliminary Platform Locations

5.2.3.1 Electrical Power Generation and Distribution

Electrical power generation for each satellite platform will be provided by multiple redundant diesel generating sets. Battery back-up will be provided for essential services. Power distribution by subsea cable from Thebaud is a **Development Alternative**. However, it is currently viewed as uneconomic due to the distances involved. This option will be investigated further in the FEED stage of the project.

5.2.3.2 Service Water Supply

Service water for wash water use will either be filtered seawater or collected rainwater.

5.2.3.3 Treatment of Produced Water

Produced water will be treated using a hydrocyclone separator and a degasser to meet the draft *Guidelines for the Treatment and Disposal of Wastes from Petroleum Drilling and Production Installations on Canada's Frontier Lands*. Continuous on-line monitors will be used to ensure water quality before the water is discharged to the sea at each satellite platform. Hydrocarbon liquids separated from the water in the hydrocyclone will be pumped back in to the pipeline to the Thebaud Platform.

Hydrocyclone technology has been chosen for its design simplicity, low maintenance and proven performance. Hydrocyclone separators have no moving parts. They rely on centrifugal forces generated by a pressure drop and the difference in density between the produced water and hydrocarbons to achieve separation. The operating conditions of the Project (low viscosity, ample available pressure drop and high differential density) favour the use of this technology. Mobil has successfully used hydrocyclone separation technology in environmentally sensitive areas within the Gulf of Mexico since 1982.

A Development Alternative is the application of Corrugated Plate Interceptors or Parallel Plate Interceptors for produced water treatment. Future review in FEED will determine if this Development Alternative is acceptable.

On-line monitoring will be used to assist in compliance with applicable regulatory standards. Grab samples will be used only for calibration and testing. This protocol is similar to that accepted in offshore Australia facilities where Mobil has a working interest. At these facilities the operator has four years of successful experience in reportable monitoring of overboard water using Sigrist photometers. Recently, the Starscan monitor, licensed by Houston Photonics, has been approved by the U.S. Minerals Management Service for offshore applications. The approval was granted after examination of several successful field applications. The operator may now substitute on-line monitoring for the grab samples required at other platforms.

While current on-line monitoring technology is available and used successfully, the Proponents will consider any new developments during the FEED process. The most appropriate equipment will be selected at that time.

5.2.3.4 Closed Drain and Open Drain Effluent

Liquids coming from closed drains, caisson skimmers, and equipment drip trays will be collected and pumped to the hydrocyclone separator.

5.2.3.5 Relief and Blowdown System

Pressure relief and blowdown capability will be provided by emergency venting facilities that can be activated for either scheduled or unscheduled reasons. Scheduled activation will occur during planned tests of the system and inspection or maintenance work. Unscheduled activation will take place if there are overpressure conditions detected in the system, if there is a hazardous condition such as a fire or gas detection, or if the emergency shutdown (ESD) system is activated. Activation for any of these purposes will be infrequent.

When the system is activated, hydrocarbons will be safely directed to a cold vent at a controlled rate. The hydrocarbons will be routed through an appropriate high or low pressure knockout drum. Future FEED and safety analysis will determine if separate high and low pressure knockouts are required.

The vent will be designed so that a gas plume does not impact the helideck under worst-case wind conditions. The design will also consider maximum heat radiation conditions at the deck level to allow escape to shelter in case the gas plume ignites. Visual alarms will be provided on the helideck to warn outgoing or incoming helicopters of an impending release.

The flow capacity of the cold vent will accommodate the largest single source supplying the vent. Future safety analysis will determine the basis for the design flowrate.

5.2.3.6 Compressed Air for Instrument Use

Instrument air will be supplied from multiple electrically driven air compressors. Redundancy will be appropriate for service.

An alternative would be the use of separated and filtered produced gas for instrumentation, in which case instrument vents would be collected and directed away from the facilities. Future FEED and safety analysis will determine if this **Development Alternative** is acceptable.

5.2.3.7 Fire Protection and Safety Systems

The design basis for the fire protection and safety systems for the satellite support facilities will be developed within the Concept Safety Analysis/Evaluation (CSE) of the Project. This is outlined in **Section 10.5** of **Chapter 10.0: Safety Plan**.

Safety systems and devices will be designed to meet Project standards, the requirements of all applicable standards and codes, and local regulations. Where there is a conflict, the more stringent requirements will take priority. In all instances, however, local regulations will be met, unless exemptions are sought for alternatives that will provide an equivalent level of safety.

Relatively small unmanned platforms, with less equipment and fewer hazards, will generally require fewer protective measures. The following systems and devices are used in similar offshore developments, and are planned for this Project.

- physical barriers and/or passive fire protection to protect safe havens from the effects of fire, smoke and blast (e.g.. fireproofing, spacing, blast walls, fire walls)
- ventilation and pressurization
- shutdown, relief, and depressuring systems (including ESD)
- gas, smoke and fire detection systems in hazardous locations and at strategic locations throughout the platform
- temperature and pressure monitoring and control
- hand-portable and wheeled fire extinguishers
- high pressure and high level shut downs on process vessels
- a lifeboat capacity of 100 percent of platform capacity
- survival suits for 100 percent of platform capacity
- safe refuge/emergency quarters sized for platform capacity

For the normally unmanned satellite platforms, the provision of fire water systems (ring main distribution system, sprinkler/spray system, fixed monitor system, hose reels/hydrants, foam system) is not expected to be necessary. This will be confirmed by an evaluation of fire risks, facility value, loss of production potential and maintenance requirements.

5.2.3.8 Helicopter Deck

A helicopter deck will be situated on or above the top deck of each satellite platform. The helideck will be designed to accommodate a Sikorski 61N, or equivalent, helicopter, in accordance with *Transport Canada Recommended Practice TP4414*. The deck will be heat-traced to prevent ice buildup, and slightly cambered for drainage.

5.2.3.9 Potable Water and Sewage Systems

Water will be supplied to closed storage facilities on the satellite platforms by supply boat. The sewage system will consist of either a chemical toilet or maceration. Disposal to the sea will be in accordance with the *Guidelines for the Treatment and Disposal of Wastes from Petroleum Drilling and Production Installations on Canada's Frontier Lands.*

5.2.4 Thebaud Production and Processing Platform Facilities

The Thebaud production and processing platform will support production from the Thebaud field wells and provide central dehydration facilities for the Project. The Thebaud platform is described in detail in an initial definition engineering study in Part Two of this document (**DPA - Part 2, Ref. # 5.2.4.1**).

The preliminary location of the Thebaud Platform is 43^{o} 53.5' N, 60^{o}12'W.

Gas, condensate and water produced from the Thebaud wells will be cooled in an inlet cooler and separated in a three-phase inlet group separator equipped with gas and liquid metering. The inlet group separator will be paralleled with a test separator to facilitate individual well tests. Production from these separators will be combined with production from the satellite platform inlet separators.

There will be two three-phase inlet separators installed on the Thebaud platform for production from the satellite platforms. One will be sized to become a low pressure inlet separator for future booster compression. These separators are presently sized on the basis of projected production from the Venture and North Triumph fields. Their design and the timing of installation will be optimized during the FEED stage of the Project.

The central processing facilities at Thebaud will include triethylene glycol (TEG) gas dehydration and condensate dewatering. The combined gas stream from the inlet separators will be fed to two TEG contactor trains where the bulk of the water vapour in the gas will be removed. The TEG will be regenerated by boiling off the water absorbed from the gas and recycling the TEG to the contactors. There will also be a separate regenerator for the monoethylene glycol (MEG) produced from the satellite field inlet separators. The water vapour and trace amounts of glycol and hydrocarbons from the regenerators will be vented to the atmosphere (see **Volume 3, Environmental Impact Statement**). Condensate from the inlet separators will be combined and fed to a condensate coalescer and stripper. Dewatered condensate will be pumped into the gas stream from the TEG contactors. The recombined gas and condensate will be fed through the production gathering pipeline to the onshore gas processing facilities. Water from the coalescer and other platform sources will be fed to a water separation and treatment system and then discharged into the sea.

Expansion capability will be provided at the Thebaud platform. Sufficient space and weight allocations will be incorporated into the design of the deck and jacket to accommodate additional processing facilities. Individual pieces of equipment will be critically examined during the FEED stage to determine if this additional capacity can be installed during initial construction for low incremental cost, thereby optimizing prebuilt capacity.

When gas production begins to decline from the satellite platforms, a compression facility will be installed at Thebaud to maintain production. The compression equipment will consist of gas turbine driven centrifugal compressors. Sufficient space and weight allocations for future compression will be included in the platform design.

As in the selection of type of platform, the central processing facilities at Thebaud may be modified as the FEED stage of the Project progresses. **Development Alternatives** include a separate Thebaud wellhead platform, and dedicated inlet separation and measurement for each interfield pipeline inlet. As an **Alternative development** option to test separation, wet gas metering may be installed. Also, a **Development Alternative** with respect to future compression is the installation of a separate compression platform. **Figure 5.2.4.1** illustrates a typical central processing platform. Preliminary designs for Thebaud support facilities are outlined in the following sections.

Figure 5.2.4.1: Typical Central Processing Platform

5.2.4.1 Electrical Power Generation and Distribution

Electrical power generation will be provided by multiple sets. Redundancy will be appropriate for the service. The generators will be powered by gas turbines capable of running on natural gas or diesel. The diesel capability will be primarily for startup and commissioning duties.

5.2.4.2 Fuel Gas System

Fuel gas for onboard consumption will be supplied from dehydrated produced gas. The fuel gas system will have its own metering facilities.

5.2.4.3 Service Water Supply

Service water for process and utility systems will be filtered seawater.

5.2.4.4 Treatment of Produced Water

Produced water from the Thebaud wells and water from the condensate coalescer will be treated using a hydrocyclone separator and a degasser to meet the *Guidelines for the Treatment and Disposal of Wastes from Petroleum Drilling and Production Installations on Canada's Frontier Lands*. A continuous on-line monitor will be used to ensure water quality before the water is discharged into the sea. Hydrocarbon liquids separated in the hydrocyclone will be pumped back in to the main production stream to feed the pipeline to the onshore gas plant.

A Development Alternative is the application of Corrugated Plate Interceptors or Parallel Plate Interceptors for produced water treatment. Future review in FEED will determine if this Development Alternative is acceptable.

On-line monitoring will be used to assist in compliance with applicable regulatory standards. Grab samples will only be used for calibration and testing.

While current on-line monitoring technology is available and used successfully, the Proponents will consider any new developments during the FEED process. The most appropriate equipment will be selected at that time.

5.2.4.5 Closed Drain and Open Drain Effluent

Liquids from closed drains, caisson skimmers, and equipment drip trays will be collected and pumped to either the hydrocyclone separator or separate treatment equipment.

5.2.4.6 Relief and Blowdown System

Pressure relief and blowdown capability will be provided by emergency venting facilities that can be activated for either scheduled or unscheduled reasons. Scheduled activation will occur during planned tests of the system and inspection or maintenance work. Unscheduled activation will take place if there are overpressure conditions detected in the system, if there is a hazardous condition such as a fire or gas detection, if there is a need to depressure an interfield flowline due to a leak, or if the ESD system is activated. Activation for any of these purposes will be infrequent.

When the system is activated, hydrocarbons will be safely directed at a controlled rate to a cold vent. The hydrocarbons will be routed through an appropriate high or low pressure knockout drum. Future FEED and safety analyses will determine if separate high and low pressure knockouts and/or a flare are required. The vent will be designed so that a gas plume will not impact the helideck and living quarters in worst-case wind conditions. Maximum heat radiation conditions at the deck level will be considered to allow escape to shelter if the gas plume ignites. Visual alarms will be provided on the helideck to warn outgoing or incoming helicopters of an impending release. The flow capacity of the cold vent will be designed in accordance with future safety analysis.

5.2.4.7 Inert Gas System

The Thebaud facilities may be equipped with a supply of nitrogen to purge hazardous locations such as vessels, removing combustible vapours and making the equipment safe for entry and inspection. Prior to facility start-up, it may also be used to purge air out of vessels and piping before gas is introduced. In addition, nitrogen may be used as a blanket in glycol and other storage tanks to provide pressurization or to reduce the corrosion effects at the liquid-vapour interface. Safety analyses during the FEED stage will determine the nitrogen requirements.

5.2.4.8 Compressed Air for Instrument/Utility Use

Instrument and utility air will be supplied from multiple electrically driven air compressor sets. Redundancy will be appropriate for service.

5.2.4.9 Fire Protection and Safety Systems

The design basis for the fire protection and safety systems for the central facilities at Thebaud will be developed within the CSE for the Project outlined in **Chapter 10.0: Safety Plan**, of this document.

Safety systems and devices will be designed to meet Project standards, the requirements of all applicable standards and codes, and local regulations. Where there is a conflict, the more stringent requirements will take priority. In all instances, however, local regulations will be met, unless exemptions are sought for alternatives that will provide an acceptable level of safety.

The central facilities at Thebaud will incorporate a number of detection and suppression systems in accordance with the requirements noted above and modifications that may result from a series of hazards assessment studies planned to address these system requirements. A combination of ventilation, pressurization, fire detection, gas detection, fire systems (sprinkler, water spray, foam, gaseous and dry chemical) and manual systems (hose reel, dual agent, monitor) typically apply to normally manned platforms. The fire protection and safety systems will vary by location on the central platform.

The following systems and devices are used in similar offshore developments, and are planned for this Project:

- physical barriers and/or passive fire protection to protect safe havens from the effects of fire, smoke and blast (e.g.. fireproofing, spacing, blast walls, fire walls)
- ventilation and pressurization
- shutdown, relief and depressuring systems (including ESD)
- gas, smoke and fire detection systems in hazardous locations and at strategic locations throughout the platform
- overpressure protection
- temperature and pressure monitoring and control
- hand-portable and wheeled fire extinguishers
- high pressure and high level shut downs on vessels
- lifeboats
- survival suits
- ventilation to prevent build-up of hazardous vapours
- safe refuge locations

In support of the systems/devices listed above, the following primary systems are planned for the central facilities at Thebaud:

a) A firewater hydrant system using seawater for general deluge, water monitor and fire-fighting applications will be utilized. Firewater pumps will supply seawater to a ring main system. Associated equipment will include filters, strainers and jockey pumps. Hose reels, monitors and portable extinguishers will be situated at strategic locations around the platform.

b) An Aqueous Film-Forming Foam system (AFFF) to fight hydrocarbon-based fires will be included. The AFFF ring main will supply foam to dual-agent hose reels and fire monitors located throughout the platform.

c) An inert gas fire suppression system will be used in confined spaces such as turbine enclosures, electrical switch gear rooms and control rooms.

d) A fixed fire-extinguishment system utilizing carbon dioxide or pressure water spray for machinery, hydrocarbon liquid pump, and flammable liquid storage spaces will be used.

5.2.5 Thebaud Accommodation Facilities

The present development plan includes accommodation facilities that are connected by a steel truss bridge to the production and processing platform at Thebaud. The living quarters will accommodate up to 40 people. The Development Alternative of incorporating the accommodation facilities with the process platform will be examined during FEED. The systems that will be located on the accommodation platform are described as follows:

5.2.5.1 Living Quarters

Most of the living quarters will consist of double berth rooms. Facilities will include a recreational area, cafeteria and galley, locker area, office areas, laundry room and a medical facility.

5.2.5.2 Storage Areas

Bulk storage will be provided for safety equipment and spare parts. Separate storage will be provided for food supplies.

5.2.5.3 Helicopter Deck

A helicopter deck will be situated above the accommodation facilities at Thebaud. The helideck will be designed to accommodate a Sikorski 61N, or equivalent, helicopter in accordance with *Transport Canada Recommended Practice TP4414*. The deck will be heat-traced to prevent ice buildup and slightly cambered for drainage.

5.2.5.4 Emergency Power

Emergency power for the complex will be provided by a diesel generator set located on the accommodation platform. This unit will only be used for the living quarters and life support systems.

5.2.5.5 Potable Water System

The potable water system at Thebaud will be supplied either from watermakers with seawater desalination systems or brought from the mainland on supply boats.

5.2.5.6 Sewage Treatment System

Sewage treatment will consist primarily of maceration. The system will be designed to comply with the *Guidelines for the Treatment and Disposal of Wastes from Petroleum Drilling and Production Installations on Canada's Frontier Lands.*

5.2.5.7 Fire Protection and Safety Systems

The living quarters at Thebaud will be the primary safe haven where platform personnel can take one or more of the following actions:

- assemble during an emergency
- take refuge from fire, smoke and other hazards
- initiate emergency actions (including requirements to have secure communication)
- effect safe and orderly platform evacuation

In addition to being physically remote from hazardous areas containing hydrocarbons, the accommodations will be protected from the effects of fire, smoke and blast through the use of physical barriers and/or passive fire protection. The actual level of protection for the accommodation platform will be determined based on Project standards, codes, local regulations and a determination by hazard assessment techniques. Accommodations on a separate bridge-connected platform typically require less physical barrier protection because of the increased distance from hazards.

The following fire protection and safety systems are planned for the accommodation facilities:

- non-combustible construction
- fire rated construction (minimum one-hour duration)
- explosion overpressure protection, if required
- heating, ventilation, and air conditioning (HVAC) system capable of maintaining a positive pressure
- fire detection, smoke detection and alarm
- HVAC inlets incorporating gas detection and alarm
- platform emergency shutdown capability
- internal and external communication capabilities
- emergency lighting
- two means of egress
- alternate means of escape (lifeboats, life rafts, helideck, etc.)
- survival suits
- hand-portable and wheeled fire extinguishers
- hose reel and sprinkler fire water system

5.2.5.8 Heating, Ventilating and Air Conditioning Systems

The living quarters will have stand alone heating and air conditioning systems, separate from those on the production and processing platform.

5.2.6 Offshore Pipelines

5.2.6.1 Subsea Interfield Pipelines

Produced gas and condensate from the satellite platforms will be transported to the central processing platform at Thebaud via carbon steel pipelines. Steel lines are suitable, providing that produced formation water is removed at the satellite platforms and a corrosion inhibition program is followed. The use of MEG injection for hydrate inhibition in offshore gas pipelines is a common and proven practice. Also, the condensate content in the **Sable Offshore Energy Project** gas stream will serve as a natural inhibitor for both hydrates and corrosion. Corrosion modelling for the interfield lines indicates extremely low corrosion rates will occur if a corrosion inhibition program is followed. The potential for Stress Corrosion Cracking is considered to be insignificant due to plans for a corrosion prevention program and appropriate external protection. General corrosion and loss of wall thickness is the primary focus for corrosion prevention. Further laboratory experiments during FEED to confirm the results of the modelling will form the basis for final design. The subsea interfield pipeline corridor is shown in **Figure 5.2.6.1.1**.

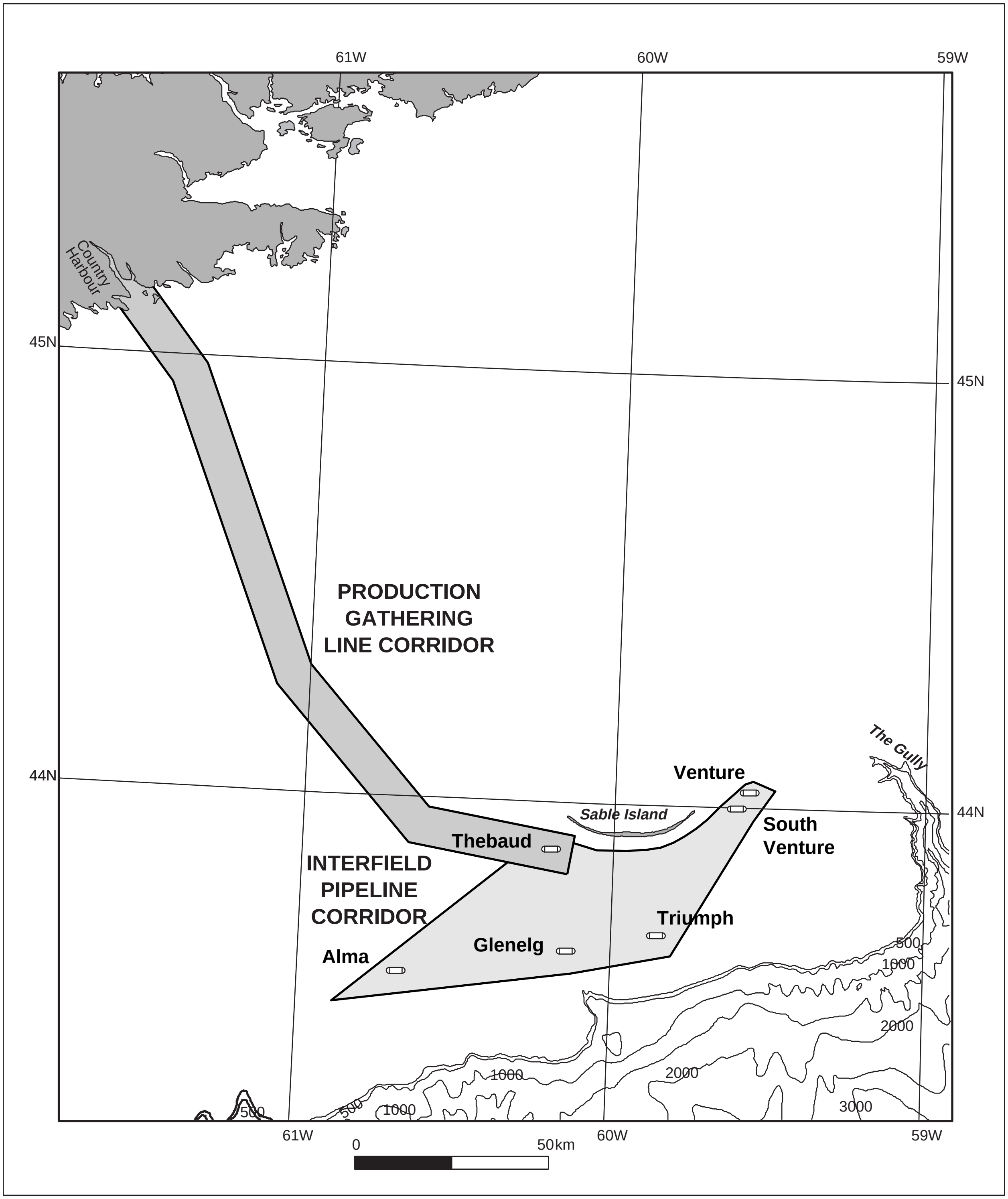


Figure 5.2.6.1.1: Pipeline Corridors

The routing of the interfield pipelines will be addressed in FEED. Route selection will be based on the optimum combination of route length, terrain variation, water depth and suitability of substrate materials.

Further data for the interfield pipeline corridor is included in Part Two of this document (**DPA - Part 2, Ref. # 5.2.6.1.1**).

The subsea interfield flowlines are presently sized as follows:

• Venture to Thebaud	54 kilometres, 457 mm OD, 12.7 mm WT
• North Triumph to Thebaud	35 kilometres, 324 mm OD, 12.7 mm WT
• South Venture to Venture	5 kilometres, 219 mm OD, 12.7 mm WT
• Glenelg to Thebaud	32 kilometres, 324 mm OD, 12.7 mm WT
• Alma to Thebaud	50 kilometres, 324 mm OD, 12.7 mm WT

These sizes and lengths are subject to change during the FEED stage.

Sizing of the interfield pipelines was determined by optimizing the trade-off between pressure drop and liquid holdup for each line. This was done to minimize slugging to the Thebaud platform and to avoid the requirements of a regular pigging program. This analysis is included in Part Two of this document (**DPA Part 2, Ref. # 5.2.6.1.2**). The pipelines will be designed to be capable of pigging, if required. Appropriate leak detection and emergency shutdown and blowdown equipment will be installed on each interfield line in accordance with applicable codes and standards.

The pipelines will be externally coated for corrosion protection and concrete coated for negative buoyancy and to provide on-bottom stability. They will be trenched, where necessary, into the seafloor. Present assumptions are that all interfield lines will be trenched and will self bury. These assumptions will be refined during FEED by the geotechnical studies referenced in Section 5.7 of this chapter.

The maximum operating pressure of the interfield lines, except the South Venture line, is expected to be 13.8 MPag, corresponding to a design pressure of 14 MPag per ANSI 900 Rating. The maximum operating pressure for South Venture is expected to be 14.1 MPag. At these design pressures, the wall thickness for all pipelines larger than 559 mm is governed by internal pressure. For smaller pipe sizes, a minimum pipe wall thickness of 12.7 mm is required, as determined by mechanical pipelay requirements. The wall thickness will be verified during FEED. Each interfield pipeline will be installed with an 88.9 mm OD line strapped to it for MEG delivery from Thebaud. Strapping an MEG line of this size to a gas pipeline is common practice in the southern North Sea.

Development Alternatives for the interfield pipelines include the use of corrosion resistant alloys rather than steel and the use of flexible pipe or insulated steel pipe for the South Venture tie-in. These alternatives will be evaluated during FEED.

5.2.6.2 Subsea Production Gathering Pipeline

The production gathering pipeline is currently sized as 609 mm OD, 15.88 mm WT for a length of 225 kilometres. The Maximum Operating Pressure (MOP) of this pipeline would be approximately 11.7 MPag, corresponding with the Project design production rate of 12.7 E6M3/d and a plant inlet pressure of 7240 KPag. The design pressure for this line would be 13.5 MPag as per *CSA Standard Z662-94* specifications. At this design pressure, the wall thickness for the pipeline will be governed by internal pressure containment requirements, plus a corrosion allowance, rather than mechanical pipelay requirements.

The production gathering pipeline sizing of 609 mm was determined by optimizing the trade-off between pressure drop and liquid holdup. The goal was to minimize slugging and avoid the requirements of a regular pigging program, while not substantially increasing future booster compressor requirements. Further information is included in Part Two of this document (**DPA - Part 2, Ref. # 5.2.6.1.2**). A regular pigging program may be required at rates below 75 percent of design capacity to maintain a manageable liquid holdup in the line. The pipeline will be designed for pigging, when required. It will be equipped with a pig sender at the Thebaud platform and a pig receiver at the onshore slugcatcher. Appropriate leak detection and emergency shutdown and blowdown equipment will be installed on the production gathering pipeline, in accordance with applicable codes and standards.

A production group line of 609 mm, when operated at maximum design pressure, is capable of carrying a maximum flowrate of about 15.9 E6M3/d. This flowrate could only be attained if considerable compression is installed earlier than planned. High backpressure would otherwise be applied to the wells. Future expansion capability equivalent to the above rate could also be achieved by preinvesting in a 660 mm OD, 17.48 mm WT pipeline, without increasing the MOP. Future expansion capability of up to 19 E6M3/d could be obtained at the same MOP by installing a 711 mm OD, 19.05 mm WT pipeline. Information to support these line sizes is included in Part Two of this document (**DPA - Part 2, Ref. # 5.2.6.1.2**). The installation of a larger diameter pipeline has implications for both slugcatcher sizing and pigging requirements, as outlined in Section 5.3.1 of this chapter, when the pipeline is operated at the Project design rate of 12.7 E6M3/d. The optimum sizing of this line will be determined during FEED.

The production gathering pipeline will be carbon steel. The potential for internal corrosion in this line is insignificant because the gas will be dehydrated at the Thebaud platform to near sales pipeline specifications and no water will condense in the pipeline. The potential for Stress Corrosion Cracking is considered to be negligible due to the lack of a corrosive environment internally and appropriate external protection. The cool operating temperature of the pipeline further reduces the potential.

The subsea production gathering pipeline corridor was selected based on the optimum combination of distance, slope and water depth and to avoid unsuitable substrate materials. Further data relative to the production gathering pipeline corridor is outlined in Part Two of this document (**DPA - Part 2, Ref. # 5.2.6.1.1**). Sensitive coastal issues such as aquaculture sites, ocean dumping sites, parks and conservation areas were also included in the evaluation. Input obtained from the fishery community during the public consultation process was particularly useful in highlighting significant fishing areas that have been avoided by the selected corridor. The subsea production gathering pipeline corridor is shown in **Figure 5.2.6.1.1**.

The pipeline will be externally coated for corrosion protection and concrete coated for negative buoyancy and to provide on-bottom stability. The line will be trenched in shallow water depths and is expected to self bury. The design criteria for burial will be refined by future geotechnical studies as described in Section 5.7 of this document. The line will be routed, where possible, to avoid extreme water depths in order to simplify lay barge requirements and avoid rock outcrops and severe slopes. The routing will be further defined in the FEED process.

5.3 Onshore Facilities

5.3.1 Scope of Facilities

The onshore facilities will include a slugcatcher and natural gas processing plant located in the Country Harbour area and a natural gas liquids processing facility in the Point Tupper area. The gas plant will produce specification sales gas and unstabilized liquids products. The unstabilized liquids will be shipped by pipeline to Point Tupper where production and loading of specification liquefied petroleum gases (propane and butane) or Liquified Petroleum Gas (LPG) mix and stabilized condensate will occur. **Figure 5.3.1.1** illustrates the process block flow for the onshore facilities.

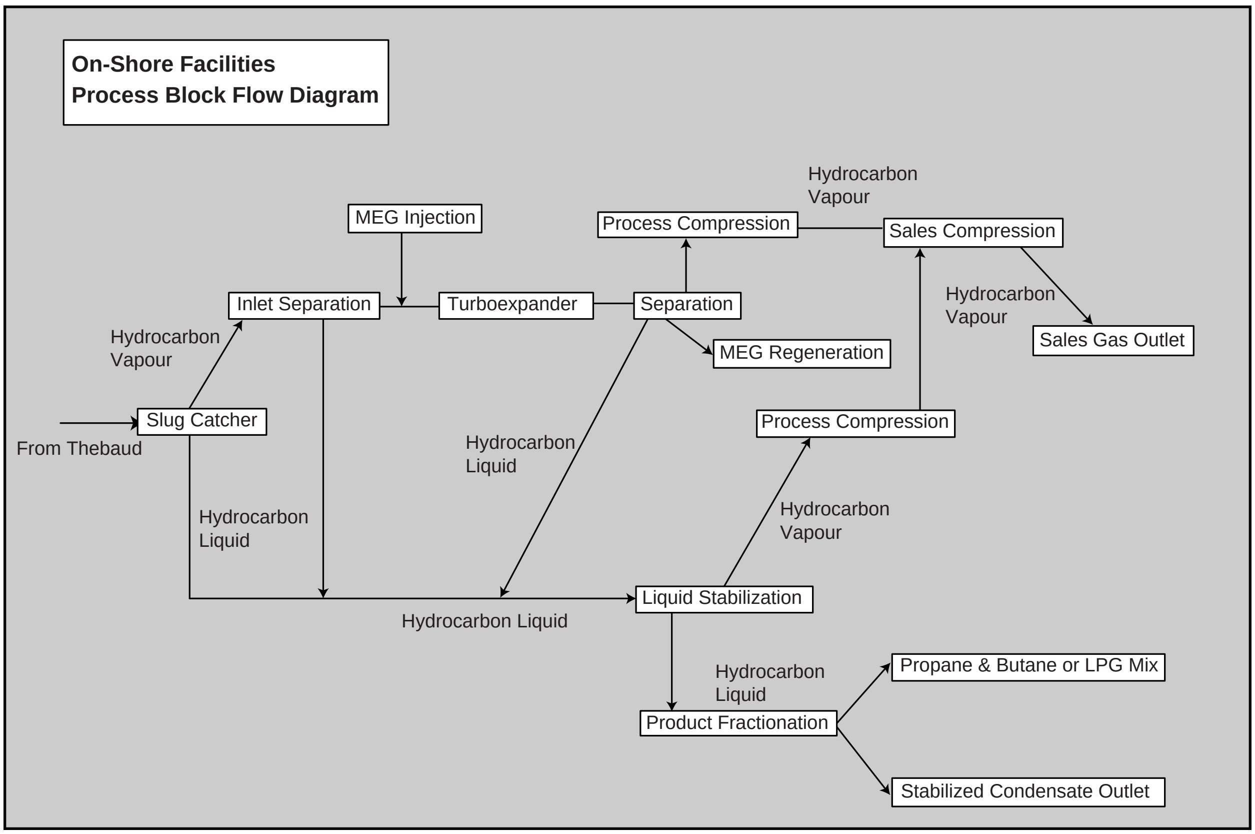


Figure 5.3.1.1: Process Block Flow Diagram

5.3.2 Slugcatcher

An inlet slugcatcher will be installed near the pipeline landfall. The slugcatcher will occupy an area of about five hectares. It will separate out hydrocarbon liquids that are reinjected into the pipeline at Thebaud or condensed from the gas as it travelled through the production gathering pipeline to shore. It will consist of a series of large diameter (up to 1220 mm OD) pipes that are up to 200 metres each in length. These pipes will be inclined downward across their length from the inlet end to the liquid outlet end. Gas will be removed through connecting piping into a header located across the top of the slugcatcher near the inlet end. Gas and liquids will be fed separately from the slugcatcher into the plant. A typical slugcatcher is illustrated in **Figure 5.3.2.1**.

SABLE OFFSHORE ENERGY PROJECT

Photo Courtesy: Taylor Forge

Figure 5.3.2.1: Typical Slugcatcher

As gas and liquids are sent to shore, temperature and pressure decrease and additional liquids condense in the production gathering pipeline. For a given flow rate the gas and liquid velocities in the pipe may be different. The liquid tends to flow along the bottom of the pipeline and typically collects in low spots or in uphill sections of the pipeline. When the flow rate in the pipeline is increased, some liquids will be swept out and an incremental flow of liquid or a liquid ‘slug’ will exit the pipeline. The slugcatcher will be designed to provide sufficient capacity to address expected changes in flow and normal operating slug sizes. This information is included in Part Two of this document (**DPA - Part 2, Ref. # 5.2.6.1.2**).

A regularly scheduled pipeline pigging program will be required when significant changes in flow are made or when the pipeline throughput decreases below a level where the normal slug size could exceed the capacity of the slugcatcher without pigging. A pipeline pig is typically either a rubber sphere or a series of rubber disks on a shaft. It has the same diameter as the pipeline and is inserted in the gas flow through the line to remove accumulated liquids. Pigging helps prevent accumulation of unmanageable liquid slugs, reduces pipeline pressure drop, and reduces the risk of corrosion which could result from any inadvertent water accumulation in the pipeline.

The diameter of the pipeline is one of the key factors in defining the volume of liquids that will accumulate in the pipeline. Although the pressure drop for a given flow rate is less in larger diameter pipelines and less compression is required, the velocity is lower and the liquid slug volume is larger. Consequently, a larger slugcatcher is required.

Based on transient flow analysis, a 609 mm OD production gathering pipeline would be optimal for the 12.7 E6M3/d Project design basis. The required slugcatcher capacity for this line size is about 2400 M3. For a 660 mm OD pipeline, the slugcatcher would need to be 50 percent larger. If a 711 mm production gathering pipeline was installed to facilitate future expansion up to 19 E6M3/d, a slugcatcher capacity of about 4800 M3 would be required to operate at the Project design flow rate of 12.7 E6M3/d. Further information is included in Part Two of this document (**DPA - Part 2, Ref. # 5.2.6.1.2**). The implementation of a regular pigging program from the outset of the Project could help reduce the slugcatcher sizing. The optimum balance of pipeline size, slugcatcher size, pigging program, and future compression requirements will be determined during FEED.

5.3.3 Country Harbour Gas Plant

A typical gas plant is illustrated in **Figure 5.3.3.1**.

Figure 5.3.3.1: Typical Gas Plant

The gas plant will be located immediately downstream of the slugcatcher. It will require approximately 20 hectares of land; 25 hectares in total including the slugcatcher **(DPA - Part 2, Ref. #5.3.3.1)**.

The plant will have an operating pressure of approximately 6900 KPag. The inlet feed, gas and liquids, will enter the plant through separate pipelines from the slugcatcher. Any liquid collecting in the gas inlet separator will be discharged into the hydrocarbon liquid flash drum.

The gas from the inlet separator will be cooled in the feed gas/residue gas heat exchanger. Any liquids formed during gas cooling will be separated in the turboexpander inlet separator. After expansion, to 5516 KPag, the resulting two-phase stream will be separated in the low temperature separator. The expander outlet gas will be used to chill the feed gas in the feed gas/residue gas exchanger. The gas will then be compressed to 5998 KPag in the expander compressor and mixed with the compressed overhead vapours from the hydrocarbon liquids flash drum. The combined stream will be further compressed to 9963 KPag in the sales gas compressors and cooled to 38^{o}C in the discharge compressor aftercooler. It will then be routed through the sales gas pipeline metering station located at the plant fence into the export pipeline.

The hydrocarbon liquid streams from the slugcatcher, the inlet separator, the turboexpander inlet separator and the low temperature separator will be sent to the hydrocarbon liquid flash drum operated at 1035 KPag. The liquids will then be transported via a 219 mm OD, 6.35 mm WT pipeline to Point Tupper for further processing. The inlet pressure to the pipeline will be 6550 KPag.

Joule-Thompson (JT) valve operation will be used as a back-up to the turboexpander process. The feed gas/residue gas exchanger will be sized to maximize the flow during JT operation. The JT operation can achieve approximately 80 percent of the plant capacity, and for this reason, only one 100 percent capacity turboexpander will be installed.

In order to prevent hydrate formation in the outlet from the turboexpander, MEG will be injected in the feed gas upstream of the feed gas/residue gas exchanger. A small MEG regeneration package is required. Water vapour and trace amounts of glycol and hydrocarbons from this system will be vented (see **Volume 3, Environmental Impact Statement**).

Expansion of the gas plant will likely be accommodated through pre-investment in larger inlet facilities and a turboexpander that is larger than the one currently specified in Part Two of this document (**DPA - Part 2, Ref. # 5.3.3.1**). This will permit the addition of a separate processing train at a later date.

The selection of a turboexpander process for the onshore gas plant is based on early definition engineering. Process alternatives, including propane refrigeration and solid bed adsorption, will be evaluated during FEED.

5.3.4 Point Tupper Liquid Facilities

The liquid handling facilities will require up to 10 hectares of land. The hydrocarbon liquids pumped from the Country Harbour area will enter the facility through the liquids feed drum at 2760 KPag and feed the deethanizer tower at 2586 KPag. The hydrocarbon liquid will be further stabilized by removing methane and ethane from the feed stream for use as facility fuel. The bottoms from the deethanizer will feed an additional fractionation tower or towers depending on whether an LPG mix or specification propane and butane is produced in conjunction with stabilized condensate. Storage and shipping facilities will include truck, rail and/or barge for the LPG's. The condensate will be shipped by tankers.

Pre-investment to accommodate future expansion will likely be limited because the liquids content of new discoveries will drive the liquid handling requirements. A "lean" gas could require little additional liquids capacity while a "rich" gas could require disproportionately more capacity. During FEED, individual pieces of equipment will be critically examined to determine if additional capacity can be installed at low incremental cost. Expansion alternatives for the liquid facilities range from utilizing lower efficiency tower trays in the base design, with later replacement by higher efficiency tower packing, to completely pre-built facilities. The 219 mm liquids pipeline from Country Harbour has sufficient capacity to handle future expansion.

Development Alternatives for the Point Tupper facilities range from a simple condensate transfer facility (LPG's deethanized and extracted at Country Harbour) to third party purchase and shipment of an unstabilized NGL stream. These alternatives will be examined in the FEED process, following market studies. The final scope for the liquid facilities will be driven by market forces.

5.3.5 Onshore Support Facilities and Services

5.3.5.1 Power

A survey will be carried out to ascertain the power available and the reliability of the available grid system in both locations. However, preliminary design calls for gas turbine driven power generation facilities to be installed at Country Harbour to make it self-sustaining. This facility will also have a diesel powered emergency generator. Diesel generator capability to power essential systems will be used only for plant startup or during major disruptions in the gas supply.

Preliminary design for the Point Tupper facilities assumes that power will be provided by the local grid. An emergency power generator capable of consuming Diesel fuel, LPG or Deethanizer overheads as a fuel will also likely be required.

5.3.5.2 Instrument Air

Instrument air for plant control functions and valve operators will be provided by multiple packaged air compressor units, with all ancillary equipment and dryers, at both locations.

5.3.5.3 Fire Protection and Safety Systems

The design basis for the fire protection and safety systems for the onshore facilities will be developed within the Concept Safety Analysis for the Project described in **Chapter 10.0: Safety Plan**, of this document.

Safety systems and devices will be designed to meet Project standards, the requirements of all applicable standards and codes, and local regulations. Where there is a conflict, the more stringent requirements will take priority. In all instances, however, local regulations will be met, unless exceptions are sought for alternatives that will provide an equivalent level of safety.

The onshore facilities will incorporate a number of detection and suppression systems in accordance with the requirements noted above and modifications that may result from a series of hazards assessment studies planned to address these system requirements. A combination of ventilation, pressurization, fire detection, gas detection, fire systems (sprinkler, water spray, foam, gaseous and dry chemical) and manual systems (hose reel, dual agent, monitor) are typically employed at manned plants.

The following systems and devices are typically used in onshore gas plant/liquid handling facilities:

- emergency shutdown and depressuring system to progressively isolate hydrocarbon inventory, and depressure and shutdown the process system
- fire and gas detection systems
- heat and smoke detection systems
- fixed fire main and hydrant system
- foam/sprinkler deluge systems
- hand-portable and wheeled fire extinguishers
- ventilation and pressurization
- an inert gas system for turbine enclosures, control rooms and electrical switch-gear room

5.3.5.4 Relief and Blowdown Systems

The relief and blowdown systems are emergency venting facilities that can be activated for scheduled and unscheduled reasons. Scheduled activation will occur during planned tests of the system, and inspection or maintenance work. Unscheduled activation will take place if there are overpressure conditions detected in the system, if there is a hazardous condition such as a fire, if there is a need to depressure a pipeline due to a leak, or if the ESD is activated. Activation for any of these purposes will be very infrequent.

Both locations will be equipped with flare systems. Both ground flare and flare stack alternatives will be investigated during the FEED process.

5.3.5.5 Water Supply

Potable water for the facilities near Country Harbour will likely be sourced from a well. The Point Tupper facility will be connected to the local municipal supply. Supply alternatives will be reviewed during the FEED process and will be consistent with all applicable codes.

5.3.5.6 Sewage Disposal

Sewage disposal for both locations will be determined during FEED and will be consistent with all applicable codes. Self-contained septic systems are the most likely alternative for both locations.

5.3.6 Onshore Natural Gas Liquids Pipeline

The natural gas liquids will be transported from the gas plant near Country Harbour to facilities near Point Tupper via a buried 219 mm OD carbon steel pipeline. The design pressure of the pipeline will be 6895 KPag. The pipeline will be constructed in accordance with *CSA Standard Z662-94*.

A detailed pipeline routing survey will be initiated following the final selection of the gas plant and liquid handling sites. On completion of the survey, a route will be selected that considers population density, environmental considerations, acidic slate potential, terrain, mining activity, quarries, forestry activities, and pipeline length. The pipeline corridor under investigation is shown in **Figure 5.3.6.1**.

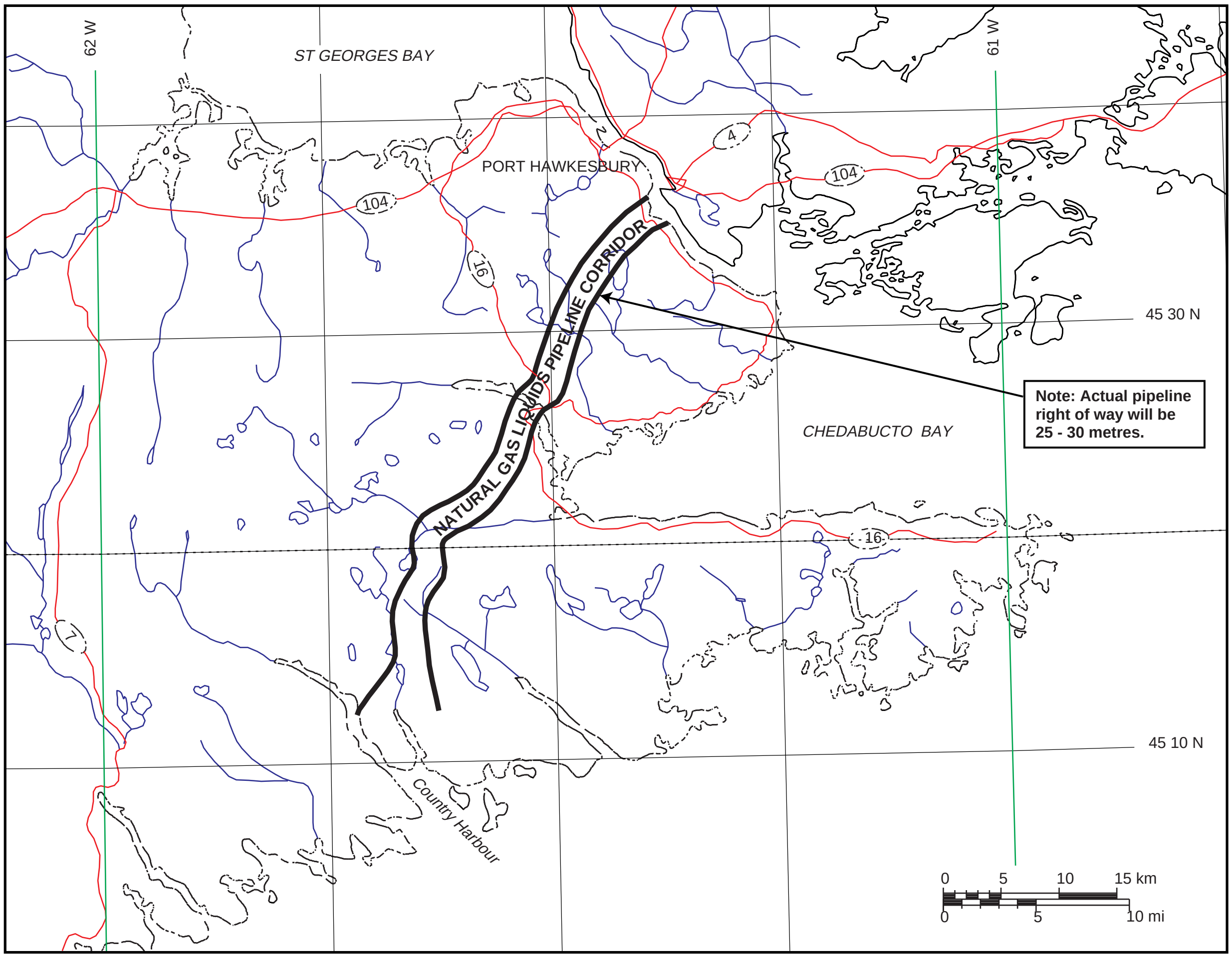


Figure 5.3.6.1: Preliminary Liquids Pipeline Corridor

The pipeline will require a major crossing of the Strait of Canso. Preliminary analysis indicates this can be achieved by either directional drilling or cut trench, as outlined in Part Two of this document (**DPA - Part 2**, **Ref.# 5.3.6.1**). The pipeline will involve several other water crossings. Depending on the facility locations and the route selected, the crossings may include Country Harbour River, Seal Harbour River, Salmon Harbour River, Clam Harbour River and Guysbourough Harbour River at Guysbourough Harbour. Determination of the appropriate method(s) for the water crossings will be completed following final route selection and FEED.

5.4 Production Operations

Detailed operating and maintenance procedures will be prepared during the detailed engineering design and construction phase of the Project. The current plans for operations and maintenance are based on previous experience of the Proponents and their affiliates in Canada, the North Sea and the Gulf of Mexico.

5.4.1 Operations Monitoring and Maintenance

The following operations monitoring and maintenance systems are envisioned:

- process monitoring and control
- fire and gas detection and protection
- rotating equipment bearing monitoring systems
- structural and foundation monitoring system
- essential services monitoring system
- compliance monitoring system
- corrosion monitoring system

5.4.2 Inspection Procedures

Regular, comprehensive visual and non-destructive testing (NDT) inspections will be an integral part of the management program. The inspection requirements for each Project component will depend on the service, manufacturers' recommendations, data obtained from monitoring systems, the operating environment and previous experience. Corrosion monitoring will include intelligent pigging, NDT testing, corrosion probes, and sample coupons.

5.4.3 Logistics

Support logistics for the offshore operation will be provided by helicopters and workboats. Workboats will meet Canada Coast Guard requirements and be suitable for the environmental conditions of the Sable Island area. An opportunity to synergize the level of logistics support may exist while drilling operations are in progress.

Initially, a daily helicopter flight will likely be required for personnel movement and satellite platform work. The schedule may be reduced as operations proceed, particularly with respect to the frequency of satellite platform visits.

Two to three workboats will be required for normal operations. One workboat will make supply trips between the shorebase and the Thebaud platform. A second workboat will be on standby at the Thebaud platform. A third workboat, or acceptable alternative, will be required when the supply workboat is unavailable to provide standby service on helicopter trips to the satellite platforms. All of these vessels will be equipped with full lifesaving and rescue capabilities in compliance with Canadian Coast Guard requirements.

5.4.4 Communications

Reliable communications systems will be installed offshore to ensure efficient operations. A combination of microwave and satellite communication systems is envisioned, but fibre optic cables are also a potential alternative.

5.4.5 Control and Monitoring Systems

The **Sable Offshore Energy Project** will have a reliable distributed control system (DCS) at both the Thebaud platform and the onshore facilities. While the satellite platforms will likely be equipped with individual programmable logic controllers (PLC's) for local control, a SCADA (Status, Control and Data Acquisition) system will also be provided to link with manned operations at Thebaud.

5.4.6 Pipeline Control/Leak Detection System

A leak detection system which meets the requirements of the *CSA Standard Z662-94 Oil and Gas Pipeline Systems* will be provided for the subsea pipeline network. The system that is currently planned will compare the mass flow in and out of pipeline segments over time. Alternatives to this system will be evaluated during FEED.

During the regular transportation of personnel between platforms, the helicopter will overfly the pipeline routes, providing an additional means of checking pipeline integrity.

5.5 Design Criteria

5.5.1 Production Facility Preliminary Design Criteria

Table 5.5.1.1 presents the preliminary design criteria for the Project facilities that are outlined in this Development Plan Application. They include: satellite platforms, interfield pipelines, Thebaud Platform, production gathering pipeline, slugcatcher, gas conditioning plant, liquids pipeline and liquids handling facility.

Table 5.5.1.1: Preliminary Production Facility Design Criteria

Equipment	MOP (kPag)	Pressure Rating	Design Range & Operating (_C)	Flowrate (E3M3/D)	Water (M3/D)	Comments
Venture Platform	13800	Ansi 900#	-20 to 120 / 110	7363	1590	
South Venture Platform	14140	Ansi 1500#	-20 to 120 / 110	1840	397	
North Triumph Platform	13200	Ansi 900#	-20 to 120 / 110	3680	397	
Glenelg Platform	13200	Ansi 900#	-20 to 120 / 110	3115	397	
Alma Platform	13200	Ansi 900#	-20 to 120 / 110	3115	397	
Thebaud Inlet	13200	Ansi 900#	-20 to 120 / 110	6230	555	
Thebaud Platform	12760	Ansi 900#	-20 to 93 / 30	12750	800	

Equipment	MOP (kPag)	Pressure Rating (kPag)	Design Range & Operating (_C)	Length (KM)	Size (mm OD/WT)	Comments
Venture Flowline	13800	14366	-20 to 120 / 100	54	457 / 12.7	Carbon Steel
South Venture Flowline	14140	29979	-20 to 120 / 100	5	219 / 12.7	Carbon Steel
North Triumph Flowline	13200	20264	-20 to 120 / 100	35	324 / 12.7	Carbon Steel
Glenelg Flowline	13200	20264	-20 to 120 / 100	32	324 / 12.7	Carbon Steel
Alma Flowline	13200	20264	-20 to 120 / 100	50	324 / 12.7	Carbon Steel
Thebaud to Shore	11725	13467	-20 to 93 / 20	225	609 / 15.88	Carbon Steel
Slugcatcher	8275	Ansi 600#	-20 to 93/0-20		1220	Carbon Steel
Plant Inlet	8275	Ansi 600#	-20 to 93/0-20			Carbon Steel
Low Temp. Process	6900	Ansi 600#	-45 to 93/ -30			Carbon Steel
Plant Gas Outlet	9930	Ansi 600#	-20 to 49 / 35			Carbon Steel
Hydrocarbon Liquids Pipeline - Pt. Tupper	6900	15108	-20 to 50 / 15	67	219 / 6.4	Carbon Steel
Liquid Fac. Inlet	2800	Ansi 300#	-20 to 93/0-20			Carbon Steel

5.5.2 Regulation, Codes, Standards and Certification

5.5.2.1 Design Philosophy

Where Nova Scotia or Canadian regulations or standards exist (i.e.: CSA) they will be met by the Project design. Where such standards do not exist, the Project design will meet accepted international standards (i.e. American Petroleum Institute(API), Deutsches Industries Normen, (DIN) British Standards (BS)). Where no specific standards exist the **Sable Offshore Energy Project** Proponents' own corporate standards will be met, following the tenets of 'good oilfield practice.'

A list of all known applicable regulations, codes and standards for engineering design and project construction is included in Part Two of this document (**DPA - Part 2, Ref. # 5.5.2.1.1**).

5.5.2.2 Certifying Authority

The *Nova Scotia Offshore Area Petroleum Production and Conservation Regulations* require that a Certifying Authority (CA) be employed by the Proponents to independently assess the compliance of the production facilities and structures with the regulations and other applicable codes and standards. The Project will be subject to a number of regulatory bodies, not all of which require a CA. However, it is anticipated that the CA scope will encompass all of the offshore facilities. The CA will assess design, methods of construction, transportation and installation, and provide material and construction inspections to ensure that the Project is designed and constructed in accordance with applicable regulations, codes and standards. 'Certificates of Fitness' will be issued by the CA when it is satisfied that the requirements outlined in the regulations and other standards have been met. The certificates will be issued prior to the application to the **CNSOPB** and other regulatory bodies, where applicable, for final approval of various elements of the Project.

The CA for the **Sable Offshore Energy Project** will be selected from the list in Schedule I of the *Nova Scotia Offshore Certificate of Fitness Regulations*. They will be selected by the Proponents through a tendering process. While effective communication between the project design team and the CA will be critical to the success of the project, the CA will be an independent third party.

5.6 Environmental Criteria

5.6.1 Preliminary Environmental Criteria

Existing data has been compiled to determine the preliminary environmental design for the Project. This data comes from two sources; The *Venture Preliminary Physical Environment Criteria* prepared by Mobil (**DPA - Part 2, Ref. # 5.6.1.1**), describes the physical environment that characterizes the Venture and Thebaud field areas, and the *Sable Gas Preliminary Environmental Study* (**DPA - Part 2, Ref. # 5.6.1.2**) commissioned by Shell includes specific environmental criteria for the North Triumph, Glenelg, and Alma field areas. The preliminary environmental design criteria for the Project is featured in **Table 5.6.1.1**.

Table 5.6.1.1: Preliminary Environmental Design Criteria

Waves and Water levels (100-year return period values)

Parameter	Venture	South Venture	Thebaud	Alma	Glenelg	North Triumph
Chart water depth (m)	20	22	30	70	80	80
Storm tide (m)	0.5	0.5	0.5	0.5	0.5	0.5
Astronomical tide (m)	1.6	1.6	1.6	1.6	1.6	1.6
Storm still water level (m)	22.1	24.1	32.1	72.1	82.1	82.1
Significant wave height (m)	14.7	13.2	12.6	12.6	12.6	12.6
Maximum wave height (m)	17.2	18.8	23.4	23.4	23.4	23.4
Period range (max waves) (s)	14-19	14-19	14-19	14-19	14-19	14-19
Maximum crest elevation (m) above storm still water	14.0	15.4	18.9	14.3	13.8	13.8

Wind (10 m above mean sea level)

Wind Parameter	100-year return period value (m/s)
1 hour mean	41.6
10 minute mean	43.7
1 minute mean	48.7
15 second gust	51.7
5 second gust	54.6
3 second gust	55.7

Current (reference d/D, ratio of depth to total depth below surface)

Reference Depth (d/D)	100-year return period current (cm/s)
0.00	230
0.10	190
0.25	162
0.50	116
0.75	109
0.90	107

The following sections outline the plans for updating and finalizing the environmental design criteria for engineering design.

5.6.2 Environmental Criteria for Engineering Design

5.6.2.1 Meteorological Conditions

The database on meteorological conditions will be updated with, and extended to include, more recent measurements and information from the area. Much, if not all, of this update will come from work summarized in the Environmental Impact Statement prepared for the Project: **Sable Offshore Energy Project**, **Environmental Impact Statement**, **Volume 3.** The design parameters that will be refined are listed below:

- Seasonal Wind Conditions
- Precipitation
- Air Temperature
- Relative Humidity
- Temperature and Salinity
- Sea Ice
- Icebergs
- Sea Spray Icing and Atmospheric Icing
- Operational Winds
- Visibility

5.6.2.2 Tides

Tide modelling for the area has been well developed. Earlier work completed on this subject is sufficient and no further development studies are planned.

5.6.2.3 Extreme Wave Conditions

Earlier studies for Venture used wave models which are now outdated, particularly for the modelling of shallow water wave mechanisms. A recent hindcast study commissioned by the Canadian government, (**DPA Part 2 - Ref. # 5.6.2.3.1**) on a limited number of storm events, used a state-of-the-art third generation wave model which predicts the shallow water wave physics properly. In recent years, a number of severe storms have occurred in this area. This has increased estimates of design level wave conditions. These storms will be included in the hindcast storm population.

A comprehensive wind and wave hindcast study will be performed for the area to produce wind and wave design criteria for the Project. This study will include a state-of-the-art shallow water wave model. It may also be necessary to perform very fine grid computer simulations of wave propagation because of the complex bathymetry in the area. The **Sable Offshore Energy Project** hindcast study will build upon the government study by adding recent storms to the government's hindcast data base. This will be completed through a cooperative exchange of information.

Present estimates of the design wave heights, which are limited by depth-induced wave breaking, are expected to be correct for the 20 to 30 metre water depth locations (Venture, South Venture, and Thebaud). In these locations the storm water depth (the combination of astronomical tide, storm surge, and water depth referenced to a tidal datum) is critical because the design wave height is directly proportional to depth. The storm surge estimates will be revised with information from the new hindcast study. The combination of the spring tidal range and the peak storm surge leads to a conservative design estimate of the deepest water depth. However, for structure design in shallow water it will be equally important to consider a low water level/high wave height condition, as has been done by Mobil in the southern North Sea gas fields. Under these conditions the water depth will be lower and the wave height will also be somewhat lower, but the nature of the shallow water waves may cause the forces exerted on the structure to be larger.

For the 70 to 80 metre water depth sites (North Triumph, Glenelg, and Alma) the wave heights will not be limited by depth-induced breaking. The water depth changes dramatically to deepwater in this area. The shallow water wave attenuation mechanisms are likely to be less effective in decreasing wave heights at these locations than they would be in areas having a more gradual change in water depth. The design criteria for these sites will be based on studies which include the most recent severe storms. This will include the "Halloween Storm" of 1991, where significant wave heights of over 17 metres were measured in deepwater off the Scotian Shelf.

5.6.2.4 Operational Wave Conditions and Normal Wave Conditions

This information will be updated with recent data gathered for the EIS for the Project, and by the results of an earlier Canadian government hindcast study (**DPA - Part 2, Ref. # 5.6.2.4.1**).

5.6.2.5 Wind Speeds

The wind speeds given in the *Venture Preliminary Environmental Criteria* are considerably higher than those found in the Canadian government-sponsored study. The 100 year return period hourly wind speeds at 10 metre elevation presented in these references were 143 and 96 kilometres per hour, respectively. This discrepancy is likely due to the joint probability approach used in the Venture work, where extreme wind and wave conditions were assumed to occur simultaneously. An 'associated' wind approach, where less severe winds occur in conjunction with the extreme wave conditions, was used in the government work. Differences of this magnitude will be resolved to establish detailed design criteria for the Project. This will be accomplished by using the wind hindcast results derived in the extreme wave hindcast study discussed above.

5.6.2.6 Currents

Existing design current values for the Project are considered too high for a number of reasons. First, they were determined by vectorially adding the extreme tidal currents, extreme background currents and wind-driven currents calculated from the extreme wind speed values. The likelihood of all these conditions occurring at the same point in time is quite small. Second, current values are independent of the wave conditions and therefore extreme currents are not necessarily the currents associated with peak wave conditions. The Proponents' experience in other parts of the world and in recent computer modelling of currents, indicates that extreme waves and extreme currents do not occur simultaneously. Third, the current speeds change significantly with depth at the same location. Using the given surface speeds will lead to an unnecessarily high design value.

To address these issues, a current model study to develop design criteria values will be performed. This will likely build on existing current modelling work done by the Bedford Institute of Oceanography in Dartmouth, Nova Scotia.

5.6.2.7 Ice and Icebergs

As with the meteorological and oceanographic information, the ice data bases need to be updated. The existing database was compiled in the late 1970s and early 1980s. Although the International Ice Patrol reports higher iceberg counts off the East Coast of Canada in the period between 1984 and 1993, the probability of occurrence of icebergs in the Project area is very low. They will not be considered as a design criteria, but will be addressed under operational contingency planning. A design criteria for sea ice will be specified.

5.6.2.8 Tsunamis

Earlier work indicated that this phenomenon will not control design. No further work is anticipated.

5.6.2.9 Marine Fouling

A study will be performed to define the design fouling levels. Data available from the existing Cohasset-Panuke operation will be analyzed and incorporated.

5.7 Geotechnical Criteria

5.7.1 Preliminary Geotechnical Criteria

Existing data has been compiled to determine the preliminary geotechnical design criteria for the Project. This data comes from two sources; The *Venture Preliminary Geotechnical Criteria* prepared by Mobil (**DPA - Part 2, Ref. # 5.7.1.1**), describes the geotechnical data that characterizes the Venture and Thebaud field areas, and the *Sable Gas Preliminary Geotechnical Study*, (**DPA - Part 2, Ref. # 5.7.1.2**), commissioned by Shell includes specific criteria for the North Triumph, Glenelg, and Alma field areas. The preliminary geo-technical design criteria for the Project is featured in **Table 5.7.1.1**.

Table 5.7.1.1: Preliminary Geotechnical Design Criteria

Sediment Transport (30-year design life)

Location	Component	Local Scour (m)	Dishpan Scour (m)	Sand Ridge Migration (m)	East Bar Migration (m)	Megaripples & Sand Waves (m)	Total Scour (m)
Venture	Legs	2.8	6.0	1.3	0.6	1.0	11.7
	Risers	1.5	6.0	1.3	0.6	1.0	10.4
	Conductors	1.5	6.0	1.3	0.6	1.0	10.4
South Venture	Legs	2.8	6.0	0.5	0.6	1.0	10.9
	Risers	1.5	6.0	0.5	0.6	1.0	9.6
	Conductors	1.5	6.0	0.5	0.6	1.0	9.6
Thebaud	Legs	2.8	6.0	1.0	-	1.0	10.8
	Risers	1.5	6.0	1.0	-	1.0	9.5
	Conductors	1.5	6.0	1.0	-	1.0	9.5

Earthquake Peak Ground Motions (all platform locations)

	Acceleration (m/s^2)	Velocity (cm/s)	Displacement (cm)
Operating Level Earthquake	0.4	2	0.6
Safety Level Earthquake (Near-field)	1.47	12	3
Safety Level Earthquake (Far-field)	1.47	20	16

The Proponents will update and finalize the geotechnical design criteria for FEED in the following ways.

5.7.2 Geotechnical Conditions and Seismicity

The geotechnical conditions on the Sable Island Bank are relatively uniform. The surficial geology of the bank top consists of Sable Island sand and gravel with occasional interbedded clays. A number of boreholes have been drilled, primarily for oil and gas exploration and also for scientific research. These boreholes are relatively uniform from location to location. All existing, publicly available data on Sable Bank surficial geology has been compiled in Part Two of this document (**DPA - Part 2, Ref. # 5.2.6.1.1**).

A localized field boring program was conducted around Venture and this data is considered to be indicative of this area. This information is included in Part Two of this document (**DPA - Part 2, Ref. # 5.7.2.1**). Information has also been obtained for the Thebaud P-84 well, which is close to the planned central platform site. The sea bottom at all planned platform sites is expected to be dense sand with excellent bearing capacity. In fact the soil borings at Venture and Thebaud consisted almost entirely of sands and gravels with the exception of a few thin clay layers below 40 metres penetration.

If site specific geotechnical data is not available for each platform site, a soil boring and analysis program will be performed prior to detailed design. Site specific data will be necessary to properly design jacket piles, and evaluate pile and conductor driveability, as well as, jacket stability (mudmat capacity). This will be done prior to driving the piles. As part of these studies, the regional seismic data will be reviewed to incorporate any advances in site seismicity characterization.

5.7.3 Bathymetry, Scour and Sediment Transport

The approximate water depth at each of the platform sites is as follows:

Field	Water depth (metres)
South Venture	20
Venture	22
Thebaud	30
North Triumph	80
Alma	70
Glenelg	80

Figure 5.7.3.1 illustrates the Sable Island area bathymetry. Detailed bathymetric surveys have been conducted across the Scotian shelf for oil and gas exploration and for scientific research. The seabed is known to be dynamic in many areas around the island with evidence of storm-current generated sand ridges, sand waves and megaripples. Conversely, some of these features could also be relict (inactive/ancient). All existing, publicly available data on Sable Bank bathymetry has been compiled in Part Two of this document (**DPA - Part 2, Ref. 5.2.6.1.1**).

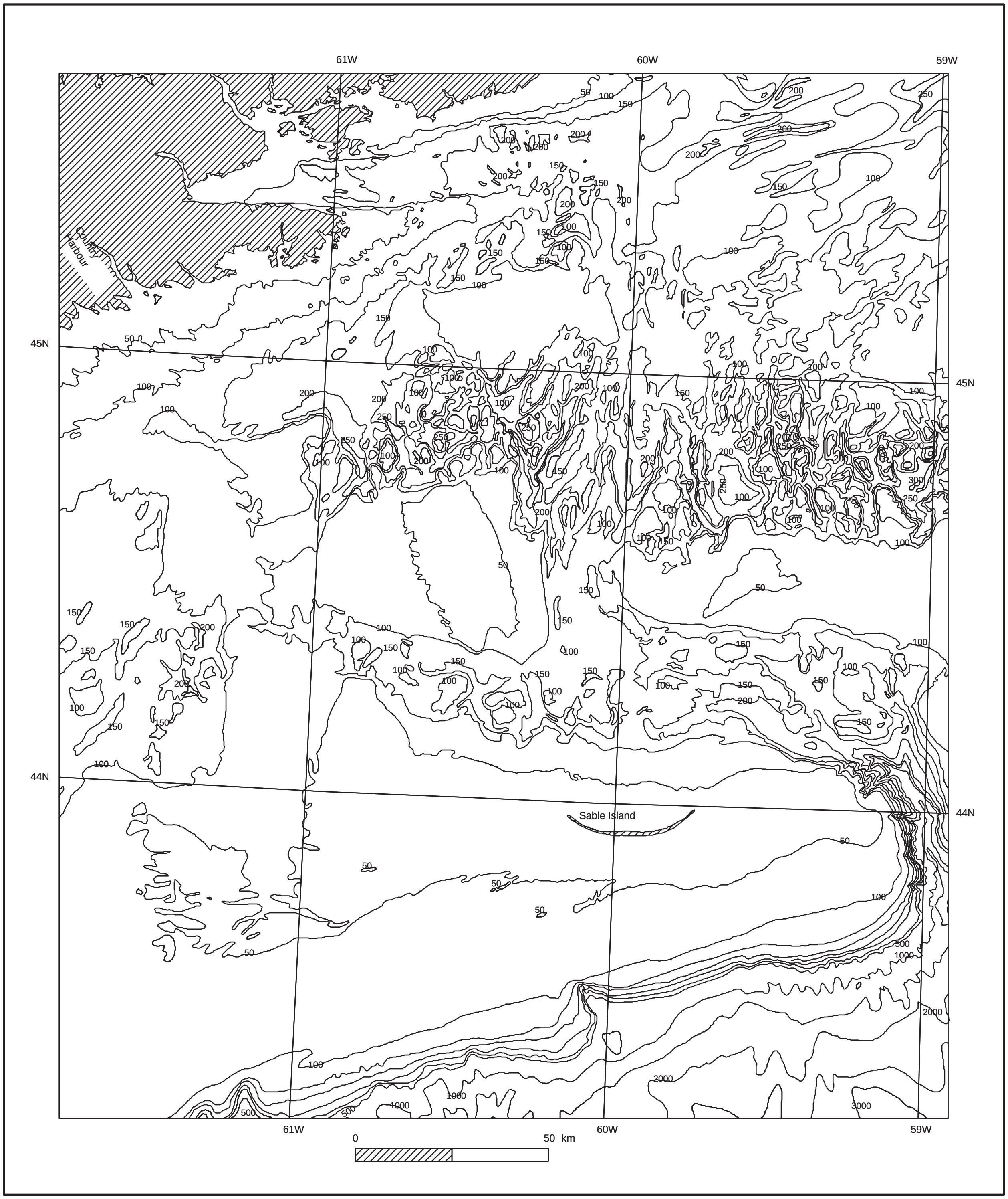


Figure 5.7.3.1: Sable Bathymetry Map

Most existing bathymetry data was obtained prior to 1985. Navigation techniques at that time were less precise than presently available. As a result, accurate rates of sand ridge and sand wave migration could not be determined. Due to advances in water depth measuring technique (Swath), and positioning technology (differential global positioning systems (DGPS)), all platform sites and the intrafield pipeline routes will be resurveyed prior to detailed final design of the pipelines. An overview of the planned survey activities in the next two years is as follows:

5.7.3.1 Baseline Swath Mapping

This survey was completed in the fall of 1995 and the results will establish an accurate swath bathymetric data set for comparative purposes with future surveys. This will accurately determine the extent of bottom feature movement over time. The Thebaud to Venture interfield pipeline corridor was the main focus of the survey. This area is characterized by numerous sand ridges, sand waves and megaripple fields. Corridors in three different water depth ranges were surveyed to determine whether feature migration diminishes with increasing water depth.

5.7.3.2 Other 1995 Swath Survey Objectives

A Country Harbour approach area of approximately three and a half by eight kilometres, located approximately 20 kilometres offshore, has been surveyed to help define a clear route through outcropping bedrock. Previous surveys indicated that a continuous channel is probable. However, the results were not definitive because of the survey technology available at the time. Swath and backscatter data will be utilized to locate an open corridor and define the best pipeline route.

The near-shore approach to Country Harbour/Issac’s Harbour has been surveyed to better define local bathymetry and to confirm the lack of rock outcrops and other hazards. Previous surveys emphasized Betty’s Cove as the preferred landfall. Other areas within the harbour approach have less coverage. This survey is expected to provide complete bathymetric detail and define rock outcrops.

The preferred pipeline route identified in the mid-1980’s has been resurveyed with Swath to improve the bathymetric data density and better identify any rough bottom areas with potential for free spans. This was completed while the survey vessel was in transit between Country Harbour, the Country Harbour approach, and the Thebaud field.

5.7.3.3 Seabed Scour Monitoring

The **Sable Offshore Energy Project** is participating in a joint research program with the Atlantic Geoscience Centre (AGC), of the Bedford Institute of Oceanography to deploy their 2D DODO (Depth of Disturbance Observatory) system near Sable Island. A 3D DODO system is also being developed during fall and winter of 1995/96. The device is a seabed frame with multiple instruments to monitor scouring of the seabed through sector scanning sonar, wave and current meters and sand suspension backscatter equipment. The equipment will be deployed in an active sand wave area near the existing Cohasset-Panuke facilities, where previous data has been gathered by AGC. Further insight into seabed dynamics, particularly during storm conditions, will be gained by this study.

5.7.3.4 Swath Re-Survey, Subbottom Data Gathering

The baseline survey areas will be resurveyed after the winter storm season (spring 1996) to assess movement of large seabed features. Sidescan sonar and subbottom profiling equipment will also be deployed to determine if the depth of the mobile sediment layer can be determined by geophysical means. Cone penetration tests (CPT's) may also be attempted to resolve this question. CPT's directly measure density state whereas geophysical profiling represents an economic means to extrapolate CPT results, providing that a reasonable correlation can be established. The depth of the mobile layer will influence pipeline burial depth requirements.

Potential for pipeline erosion will also depend on sand grain size, density state and permeability. Loose sediment may be subject to liquefaction or suspension during severe storms. Thus, geotechnical data is required to define both the sediment type and density state along the entire pipeline corridor. Accurate geotechnical data, as well as wave and current data, will be required to define the amount of weight coating required for pipeline on-bottom stability and to define the extent and depth to which the pipeline will be buried.

5.7.3.5 Swath and Subbottom Follow-up Resurveys

After reviewing the repeat Swath data, additional surveying may be required to check seabed conditions immediately following a severe storm (i.e. allowing no time for backfill or return to equilibrium), or after a second complete winter season to evaluate how seabed features change from year to year. The need for such surveys, which would be conducted during the winter of 1996/97, will be evaluated after review of the first repeat survey data. Additional surveys may also be required for reconfigured or rerouted pipelines or to better define possible platform installation impediments at their proposed locations.

5.7.4 Local and Dishpan Scour

In addition to regional sediment transport mechanisms described above, local and dishpan scour can occur about jacket structures. A study included in Part Two of this document (**DPA - Part 2, Ref. # 5.7.4.1**), concluded that sediment transport about foundation piles would be significant. Design scours of 9.1 to 11.7 metres were predicted to occur around vertical members ranging from 0.76 to 1.4 metres in diameter. This was a combination of local, dishpan, sandridge and East Bar migration, plus megaripples and sandwaves. These design values will be checked against more recent experience with the Cohasset-Panuke project structures and accounted for in platform design. Scour mitigation techniques used in the North Sea, as well as at the Cohassett-Panuke project, will also be reviewed.

5.8 Assessment of Alternative Development Plans

5.8.1 Eliminated Alternatives

Although many alternatives have been suggested, five of the most promising alternative development plans were screened for the **Sable Offshore Energy Project**, prior to the selection of this Preferred Development Plan. The **Eliminated Alternatives** are listed below:

- Electric power generation
- LNG (Liquified Natural Gas)
- LHG (Liquified Heavy Gas)
- Natural Gas conversion technologies
- Offshore Gas Plant

5.8.1.1 Electrical Power Generation

Three alternative electrical power schemes have been evaluated by the Nova Scotia Department of Natural Resources, Nova Scotia Power and TransAlta/Pan-Alberta. (**DPA - Part 2, Ref. # 5.8.1.1.1**). They used coal/natural gas or gas as fuel. The electrical power would have been delivered to, and sold in, the New England market. These proposals were based on significant growth in electrical demand in northeastern American markets but did not anticipate the level of cogeneration plant development which has occurred in the region.

Installing export power generation facilities in Nova Scotia presumes that electrical generation is more economical in Nova Scotia than in the northeastern United States. Economies of scale for plant construction in the northeastern states result in, at best, a neutral cost advantage. The cost of transmission facilities (gas or electric) are roughly the same. However, natural gas transmission has efficiencies approaching 98 percent (the 2% loss represents fuel gas used for compression) while electrical schemes are about 95 percent efficient. There are stronger business and efficiency advantages to providing gas to the marketplace and letting the local customers decide on usage. Further information is included in Part Two of this document (**DPA - Part 2, Ref. # 5.8.1.1.1**).

5.8.1.2 Liquified Natural Gas (LNG)

The manufacturing of Liquified Natural Gas (LNG) offshore, and transportation of the LNG and condensate to markets by tanker has also been studied as an alternative.

Offshore manufacturing of LNG is a complex process that would substantially increase the size of the Thebaud platform, and thus Project cost. Offshore storage and loading facilities would also be required. LNG projects generally require high production rates (over 28 E6M3/d) to support the large capital investments required. LNG makes sense if the gas is to be shipped over long distances. The comparatively short distance from the **Sable Offshore Energy Project** to the North American gas pipeline grid makes it attractive to tie into this system by pipeline, both for immediate utility and future growth. LNG is not currently competitive in the North American market except for limited peak shaving opportunities. More detail on the LNG alternative is included in Part Two of this document (**DPA - Part 2, Ref. # 5.8.1.2.1**).

5.8.1.3 Liquified Heavy Gas (LHG)

In this alternative, Liquified Heavy Gas (LHG) would be manufactured offshore and transported by custom-built tankers to markets. A propane solvent must be recycled by tanker to the field as part of this process.

Mobil investigated the application of LHG technology for the Venture Development Project. Unlike LNG, which relies on cryogenic temperatures, LHG relies on refrigeration at a higher temperature and pressure to reduce the volume of gas to be shipped. This pressure is high enough to require that the gas be shipped in a specially constructed tanker. While LHG production facilities would result in net savings through the elimination of the production gathering line, slugcatcher, gas plant, natural gas liquids pipeline and future compression; the cost of constructing LHG storage, shipping and receiving facilities would be substantially higher than the savings identified. The economies of scale of an LHG project are likely similar to LNG. LHG development has not been pursued since 1989. This study is included in Part Two (**DPA - Part 2, Ref. # 5.8.1.3.1**).

5.8.1.4 Natural Gas Conversion Alternatives

Other alternatives for conversion of gas have been investigated by Mobil and Shell, and their affiliates, for projects of similar scale elsewhere in the world. This work comes to the same conclusion about other gas conversion technologies as that drawn for LNG and LHG. This information is included in Part Two (**DPA - Part 2, Ref. # 5.8.1.4.1**).

5.8.1.5 Offshore Gas Plant Location Alternatives

In addition to the Preferred Development Plan, two alternatives to an onshore gas processing location were investigated. The two eliminated alternatives are:

- Offshore natural gas processing plant;
- Natural gas processing plant on an artificial island or Sable Island.

A brief description of each processing alternative follows.

5.8.1.5.1 Offshore Gas Plant Platform

An offshore gas plant would involve consolidating all gas processing to the central production platform at Thebaud. Sales gas and NGL's would be transported to shore in separate pipelines. The comparison of this case to the onshore base case was made on the basis of the same landfall for both. The offshore plant alternative appears, within estimating accuracy, to have essentially the same capital and operating cost profile as the onshore plant.

While the offshore plant and onshore plant were equivalent for most of the selection criteria evaluated, the following key criteria favoured the onshore plant:

- Reliability/Availability/Maintenance
- Operating Flexibility (Compositional)
- Ease of Expansion
- Safety Considerations
- Nova Scotia-Canada Benefits

An offshore plant is difficult to maintain and operate at a high level of reliability, primarily due to access restrictions. If gas composition varies considerably from the design basis, the modifications that must be made to the plant would be much more difficult and costly to undertake offshore. Similarly, space for expansion is constrained offshore. The risks associated with an offshore plant are always higher than those for an onshore plant, given the number of options for escape from an onshore plant. Finally, an onshore plant assures a significant level of Nova Scotia and Canada benefits that cannot be guaranteed with an off-shore plant. Further information is included in Part Two (**DPA - Part 2, Ref. # 5.8.1.5.1.1**).

5.8.1.5.2 Processing Plant on Artificial or Sable Island

Previous studies assessed the feasibility of constructing an artificial island in the Sable Island area for gas processing facilities. While technically feasible, environmental concerns and costs eliminate this plan as a **Development Alternative**. There have also been studies on developing an area of Sable Island itself, with the construction of a wharf and breakwater. This alternative was also eliminated because of environmental concerns related to physical disturbance of the island. Furthermore, the project principles also eliminate this alternative. This information is included in Part Two (**DPA - Part 2, Ref. # 5.8.1.5.2.1**).

5.8.2 Pipelines

A number of pipeline developments were investigated prior to the selection of the Preferred Development Plan. A list of the eliminated alternatives follows:

- The transportation of gas and condensate through a single, dense phase subsea pipeline to Nova Scotia.

- The transportation of dehydrated gas and unstabilized condensate through separate subsea pipelines to Nova Scotia.

- The transportation of dehydrated gas by subsea pipeline to a landfall at Boston, and the transportation of gas condensate by tanker to markets.

- The transportation of dehydrated gas and condensate to Nova Scotia by separate subsea pipelines.

A discussion of each of these eliminated alternatives follows below:

5.8.2.1 Single Subsea Dense Phase Pipeline

The transportation of dense rich gas involves significant compression. This must be installed at initial start-up at a considerable capital and operating cost penalty. The only capital savings occur with the elimination of the slugcatcher. This alternative has only proven attractive in the North Sea where substantial reinjection compression, and the capability to remove condensate and ship separately, already exist. This is not the case for the **Sable Offshore Energy Project**. Further information is included in Part Two of this document (**DPA - Part 2, Ref. # 5.2.6.1.2**).

5.8.2.2 Separate Subsea Gas and Unstabilized Condensate Pipelines

This alternative would require a smaller slugcatcher facility on the gas line at the landfall to separate liquids condensing from the gas stream. Slugging could occur on the unstabilized condensate line, unless it was pumped to avoid flashing. The use of two pipelines offers little technical advantage over the Preferred Development Plan, but costs considerably more (**DPA - Part 2, Ref. # 5.8.2.2.1**).

5.8.2.3 Single Subsea Sales Gas Pipeline to Boston

This alternative would have an offshore sales gas pipeline route direct to Boston. It would be dependent on an offshore gas plant and would preclude marketing of gas in Nova Scotia and New Brunswick. Offshore condensate storage and tanker loading is required. While technically feasible, and the shortest pipeline route to markets in the northeastern United States, the cost estimating accuracy for this option is not equivalent to other options. Very little is known about the prospective pipeline route, which runs just to the north of George's Bank. Transportation of condensate by tanker presents a greater environmental risk than by pipeline. The required storage and loading system would increase the offshore costs considerably, particularly when a separate LPG product is considered. While capital cost is competitive on a total project basis, the gas marketing implications of bypassing Nova Scotia, New Brunswick and Maine rule this option out. Further information is included in Part Two of this document **(DPA - Part 2, Ref. # 5.8.2.2.1**).

5.8.2.4 Separate Subsea Sales Gas and Stabilized Condensate Pipelines

This pipeline option is connected to the offshore gas plant option discussed in the previous section. At landfall, the gas line ties-in to the transmission pipeline. The condensate is routed through a buried pipeline overland to Point Tupper. This option is not required with the elimination of the offshore plant option. Further information is included in Part Two of this document (**DPA - Part 2, Ref. # 5.8.1.5.1.1**).

5.8.3 Satellite Platform Development Alternatives

The Project design philosophy for the satellite platforms is to minimize both capital and operating costs by minimizing processing at the satellites. The main challenge is to effectively deal with produced formation water.

Alternative separation technologies were considered for water treatment. These included centrifuge separators, induced gas flotation cells, caisson pipe separators and Plate Interceptors (Parallel and Corrugated). Centrifuge separators may produce marginally better effluent but require a higher level of maintenance and operator attention than is practical for unmanned operations. Induced gas flotation cells are more complex than hydrocyclone separators but produce an effluent of no better quality. They also require high levels of operator attention and maintenance. Pipe caisson separators, a simple standpipe with a hydrocarbon pump off, do not consistently achieve the same level of hydrocarbon removal as do hydrocyclone separators. Plate Interceptors, Parallel and Corrugated, have been effectively applied in the Gulf of Mexico. Potential concerns are that they are most effective with larger hydrocarbon droplet sizes, higher gravity hydrocarbons and relatively clean water. Droplet shearing associated with large pressure drop across production chokes may preclude utilization of this technology.

Development Alternatives that were considered included collection and treatment of water at the central production platform at Thebaud and treatment on-shore. Treatment at the central production platform or onshore would require very large volumes of hydrate and corrosion inhibition injection at the satellite platforms and would result in an increased pressure drop in the pipelines. The gas also cools in the pipeline and treatment at the lower temperature would be less effective. Although treatment by a single, larger hydrocyclone unit may be marginally less costly, the lower efficiency at the lower temperature offsets this advantage. Further information is provided in Part Two of this document (**DPA - Part 2, Ref. # 5.8.3.1**).

Separate gas and liquid (water/condensate) pipelines from each satellite were also reviewed. All water would be treated at the central production platform. The water treatment issues previously discussed, additional pipeline cost and serious concerns of corrosion in the gas pipeline make this alternative unattractive. The separation of hydrocarbon liquids from the gas has a detrimental effect on any corrosion inhibition program as they are expected to act as a buffer from corrosion by providing a stable film and acting as a carrying agent for corrosion inhibitors. The presence of condensed water from the cooling of the gas would still require both hydrate and corrosion inhibition in the gas line. Further information is provided in Part Two of this document (**DPA - Part 2, Ref. # 5.8.3.2**).

Hydrate inhibition using methanol or kinetic hydrate inhibitors was also reviewed. Methanol injection presented special challenges for recovering the injected volume from the gas, hydrocarbon liquids and condensed water. Vaporization and liquid hydrocarbon losses tend to be high from methanol whereas monoethylene glycol (MEG) has extremely low solubility levels in these phases. Methanol is normally the inhibitor of choice at temperatures below -40^{o}C, due to viscosity concerns for glycol, but this is of little benefit offshore. A recovery process would require installation of a refrigeration system at Thebaud and, without a suitable source of cooling, this was not found to be economical. Kinetic hydrate inhibitors, while required in less volume than MEG, are non-recoverable and therefore not currently cost competitive. The corrosion concerns outlined above remain with these alternatives. Further information is provided in Part Two of this document (**DPA - Part 2, Ref. # 5.8.3.1**).

5.8.4 Landfall Alternatives

There were three landfall and onshore facility site alternatives investigated prior to the selection of the Preferred Development Plan. Background information on these alternative sites is included in Part Two of this document (**DPA - Part 2, Ref. # 5.8.4.1**). The two eliminated alternatives are described below:

- Landfall: Country Harbour/Gas Plant: Point Tupper

- Landfall: Port Richmond/Gas Plant: Point Tupper

The alternative offshore pipeline corridors are shown in **Figure 5.8.4.1**. These alternatives were eliminated in favour of the Country Harbour landfall / Country Harbour Gas Plant / Point Tupper Liquids Processing Facilities for the following reasons:

- The pipeline route to Country Harbour is the shortest practical route from Thebaud to shore. This results in the lowest cost offshore pipeline option for the Project. The Preferred Development Plan remains the most cost effective alternative even when the cost of the liquids line to Point Tupper, and the capital credit for the use of existing infrastructure that could be accessed by a gas plant located there, are considered.

- The seabed profile and bottom conditions of the Country Harbour route also reduce the cost of the pipeline relative to the Point Tupper route.

- The cost of the Preferred Development Plan is less than the cost of an offshore pipeline to Country Harbour with a pipeline that continues overland to a plant site at Point Tupper. In this case the entire pipeline from Thebaud to Point Tupper would have to be one pipe size larger.

- The Country Harbour route avoids several offshore fishing banks and shellfishing areas. The pipeline is routed along less sensitive fisheries areas between Sable Island and the landfall than the offshore route to Point Tupper. This conclusion is based on input from fisheries groups and bathymetric mapping.

- The risk of anchors from large ships contacting the offshore pipeline is lower with the Country Harbour route. Also, the Chedabucto seismic fault line (presently inactive) along the Point Tupper offshore route will be avoided. This gives the Country Harbour route a safety advantage.

- Having the processing facilities split between Country Harbour and Point Tupper will take advantage of the local infrastructure at Point Tupper. The existing marine terminal and liquids storage capacity at Point Tupper facilitate liquid product disposition.

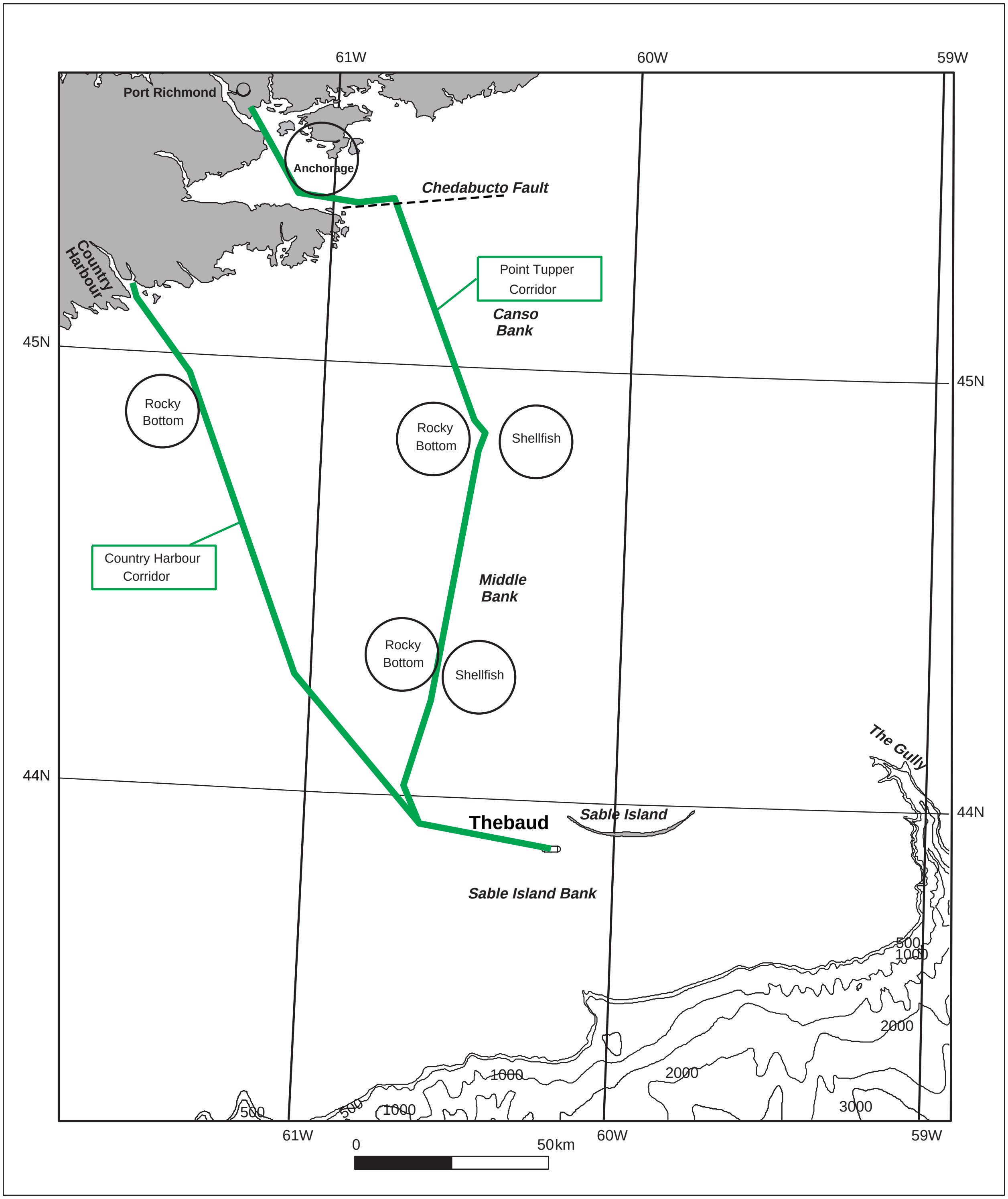


Figure 5.8.4.1: Alternative Offshore Pipeline Corridors

6.0 CONSTRUCTION AND INSTALLATION

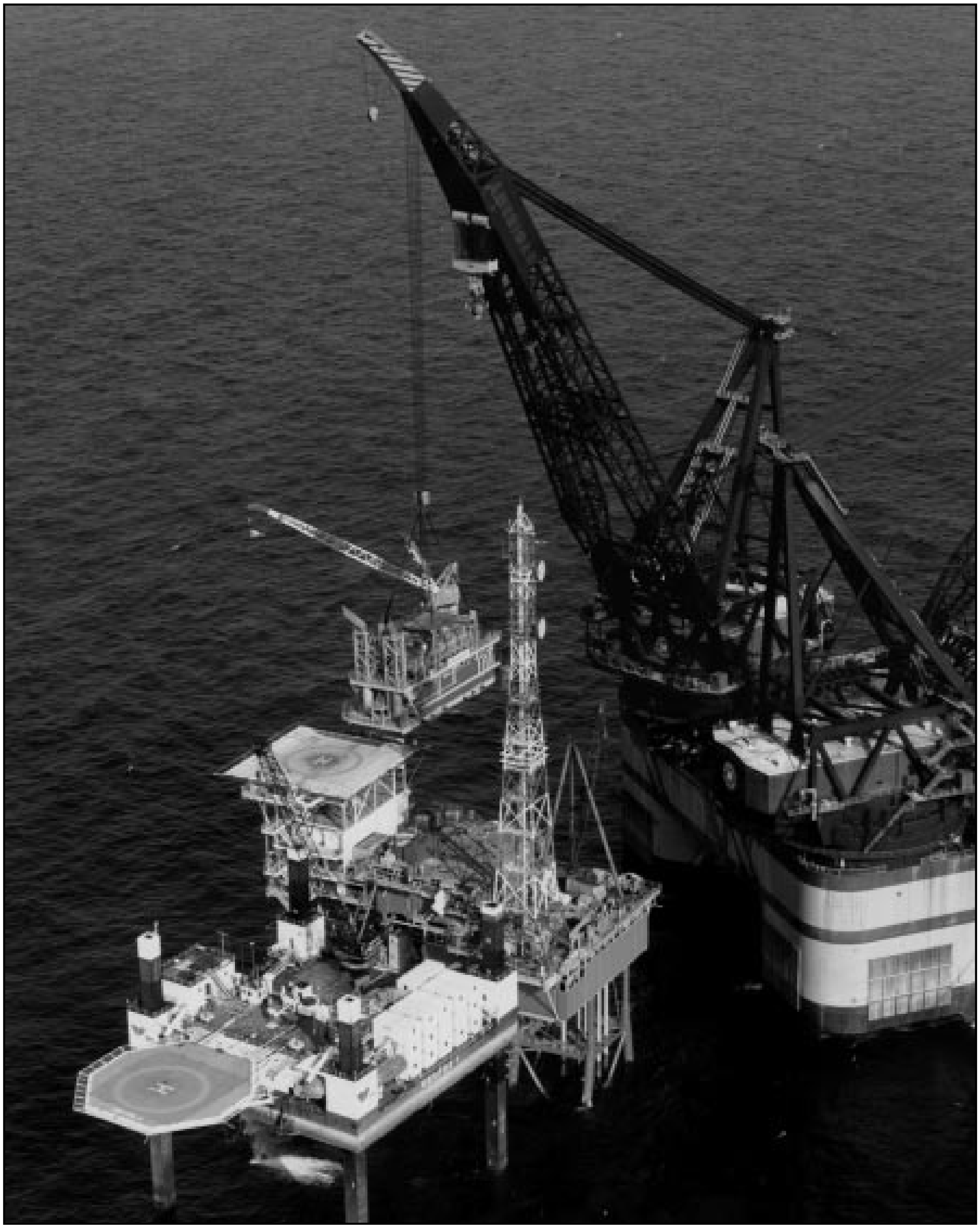


Photo Courtesy: J. Ray McDermott

Figure 6.0.1: A Heavy Lift Vessel Installing a Compressor Module At An Offshore Platform. In the foreground is a construction support jack-up.

6.1 Management Philosophy

Sable Offshore Energy Project management philosophy is based upon the belief that a successful outcome can best be achieved by harnessing the skills and experience of employees of the Project Proponents and participating contractors to create a close team with common goals. The objective is to establish a management structure and Project execution plan that will assure a quality product at low cost within an acceptable schedule. A primary activity leading up to the submission of the Development Plan Application (DPA) has been a series of dialogues between Project Proponents and prospective contractors. The Proponents have also discussed the procedures for recently contracted projects with other major operators, to take advantage of their experience in the continuously evolving contracting market. A concept of 'risk and reward' sharing between the Proponents and their contractors is being developed to identify benefits to the Project.

The Proponents of the **Sable Offshore Energy Project** recognize that a high standard of compliance with the regulatory requirements for safety and environment is inherent to any project execution and management structure plan, and will honour the benefits provisions in the *Accord Acts*. Technical excellence in design and construction, and full compliance with the appropriate regulatory and industry codes is a Project goal.

6.2 Construction Schedule

Commencement of the Front End Engineering Design (FEED) is planned to occur in 1996. The Project construction is projected to take place between July 1997 and November 1999. Construction phases are as follows:

Commencement of Front End Engineering Design (FEED)	Mid 1996
Commencement of Detailed Engineering, Fabrication and Construction	July 1997
Commissioning and Start-Up	September - October 1999
Production	01 November 1999

There is little contingency time in this schedule. In the FEED period, prior to the Development Phase decision, some 'long lead' items may require early purchase in order to preserve the schedule. The **Sable Offshore Energy Project** Proponents would be exposed to cancellation charges should the project not proceed. The commencement of FEED is not likely to be approved until Regulatory and Fiscal terms and conditions are fully defined, and reasonable certainty of approval of the DPA is assured. Completion of project construction by the end of 1999 is based upon a determination of the markets in 1997 for produced gas. The Proponents assume the requirements of the U.S. Federal Energy Regulatory Commission (FERC) for the export pipeline can be satisfied within the projected time-frame. Further refinement of the schedule will continue after construction begins.

6.3 Contracting Philosophy

The initial production phase of the current plan involves the construction of three offshore platforms, interfield pipelines, production gathering pipeline feeding the gas plant, an onshore gas plant and a natural gas liquids handling facility. The preferred contract strategy is to enter into a contract with a highly competent and experienced engineering contractor to provide engineering, project management and procurement services through the Front End Engineering Design (FEED) stage. Provisions in the contract will allow the services to continue through the Construction phase into the first few years of Production should the **Sable Offshore Energy Project** receive Proponent approval to go ahead.

Competitive selection processes or bids are scheduled to be issued for various construction and installation facilities during the latter stages of FEED. Selected bidders may be invited to participate in an 'alliance.' They will be invited to take part in an exercise to improve project engineering and execution plan, and to establish a project 'target cost.' This target cost will be one of the main factors in the Proponents' decision to go forward with the Project. An alliance, for these purposes, is an agreement by the Proponents and the contractors to share the financial risks and rewards of the Project. A sum of money, funded from potential project savings accrued by virtue of the 'alliance' approach, will be set aside and shared according to construction outcome. The agreed reward formula will also encompass quality, safety and performance. All parties will benefit from a cost underrun if the Project meets the targeted schedule; all will lose if there are delays or cost overruns. The net effect is to reward team work and encourage efficient practices.

The onshore portion of the work may be split away from the offshore portion and issued as a separate contract.

These decisions have not been made at this point in time. The Proponents will continue to define an agreed upon development plan basis and undertake further dialogues with prospective contractors. The objective is to determine the greatest benefit to the Project, in terms of both cost and schedule; and to comply with the benefit provisions of the *Accord Acts*.

A questionnaire to prospective engineering contractors has been issued, inviting them to qualify for the FEED, project management and procurement portions of the Project. Engineering contractors were selected based on recent experience with similar work, corporate strength, and their degree of interest in undertaking work on behalf of the Project in an Alliance. The questionnaire is a means of determining these qualifications; as well as other important issues such as safety and environmental record, quality control, and Nova Scotia/Canadian content. Their responses to the questionnaires are analyzed, and further discussions with contractor(s) have taken place, and a contractor is being selected. Front End Engineering Design (FEED) is planned to commence on Stage 3 approval by the Proponents. At that time, the framework for the alliance structure and compensation package will also be formulated.

All contracts for fabrication, supply and installation during construction will be offered for tender to pre-qualified contractors on the basis of free, open and international competition. The combination of quality, safety performance and management, cost and delivery, representing 'best value' is the most important criteria for contract award. Potential contractors will be made fully aware of the Project criteria and must demonstrate their compliance with the Project policies.

6.4 Project Team

An integrated team of qualified personnel from the Proponents and the selected engineering contractor will lead the development of the Project through FEED to completion. As the Project proceeds and the scope expands, the team will expand to include other engineering specialists, fabricators, construction contractors and suppliers. Executive and technical roles will be determined on a "best person for the job" basis.

The **Sable Offshore Energy Project** team will be augmented, as required, with specialists from the areas of Environmental Affairs, Loss Prevention and Operations. Input from these disciplines is required at all stages of project design and execution to ensure that our standards of Environmental, Health and Safety are maintained. The specialists will be involved in Hazard and Operability (HAZOP) reviews, Process And

Instrumentation Diagrams (P&ID) reviews, and Operational Accessibility and Maintenance studies. Team members and visiting specialists will be nominated on the basis of skill, experience and availability.

The make-up of the Construction phase team will depend upon the strategy of the Construction contract. A larger contribution of personnel by the Proponents will be required than in the FEED stage. The principles of an integrated team, and the Proponents' high standards, will remain the same.

6.5 Project Execution Plan

The Drilling and Construction stage of the Project will begin with one or two drilling rigs at the proposed platform locations. Development wells are most likely to be drilled through templates or wellhead jackets placed on the sea floor. The templates are put in place to ensure the correct spacing of the well casings where the platforms will be installed. The uncompleted wells will be temporarily suspended with casings detached above the sea floor. At the time of installation, steel jackets with casing guides, spaced to match that of the casings, will be positioned over the wells and piled to the sea floor. Should wellhead jackets be used, then the wells will be suspended by plugging downhole and at the surface, and the wellheads left in place.

While drilling is in progress, engineering design, procurement and fabrication will begin on the facilities to be installed offshore. Under the current Development Plan, the central platform to be placed at Thebaud will consist of an eight-pile steel jacket and an integrated deck, estimated, at this time, to weigh about 4500 tonnes. The Venture platform will have six piles and a deck-weight of about 2500 tonnes. A minimal facilities platform at North Triumph will have a deck weight of about 1100 tonnes. **Figure 6.5.1** illustrates an example of offshore platforms that are similar to those proposed for the satellite fields.

Figure 6.5.1: Example of Offshore Platforms

There will be competitive tenders issued on the international market for construction of the platforms and jackets. Consequently, they may be built in various locations throughout the world. The various components of the facilities may, depending on market forces, be constructed in several places as well. The Thebaud deck is the largest and most complicated unit. It will require a large, fairly sophisticated waterside yard for fabrication. There is generally more flexibility for the construction of the other units, although covered construction space is required to fabricate and outfit the integrated decks. Open yard space is suitable for jacket construction; with the requirement that sufficient crane lift and height capacity are in place to erect the jackets. **Figure 6.5.2** illustrates an example of jacket erection. **Figure 6.5.3** illustrates module deck construction while **Figure 6.5.4** illustrates a heavy lift barge installing a living quarters module.

Figure 6.5.2: Jacket Erection

Figure 6.5.3: Module Deck Construction

Upon completion, the jackets and decks are planned to be sea-fastened to ocean-going barges and towed to the Sable Island area. The barges may standby offshore or be held in a Nova Scotian port to await the arrival of a 'heavy-lift' barge. Lifts of 4500 tonnes and 2500 tonnes can be made in the shallow water depths existing at Thebaud and Venture with modern-day barges. There are no applicable water depth limitations for lifts in the other fields.

Photo Courtesy: J. Ray McDermott

Figure 6.5.4: Heavy Lift Barge Installing Living Quarters

One alternative method for installation of the offshore facilities is a ‘float over’ approach. The decks would be floated on barges over the jackets and then jacked into final position. This method will be investigated in the FEED stage, although sea conditions on the Scotian Shelf may be too severe for its use.

The decks should be virtually complete when they are installed because of the integrated deck design applied during fabrication. The final steps of installation will be to re-enter and complete the wells and to pipe the wells to the production manifolds. This will require minimal offshore labour. Minimal offshore labour is the key to a cost-effective construction program for the Project. Work done offshore is estimated to cost at least three times the work performed in onshore construction yards.

Pipe-laying work on the 609 mm OD, 225 kilometre line from the Country Harbour area to Thebaud will begin while the platforms are being installed. Interfield lines are planned to be laid at the same time. **Figure 6.5.5** illustrates a semi-submersible pipe-laying barge.

Photo Courtesy: J. Ray McDermott

Figure 6.5.5: Pipe-laying Barge

A pipe-lay barge with anchor handling boats, supply boats and barges will perform the work. The pipe material will be pre-coated on the outside for corrosion control, and concrete-weight coated for bottom stability and then stored for delivery to the barge at the appropriate time. The linepipe for the pipeline may be supplied from a large number of mills worldwide, including those in Canada. Corrosion and weight coats can be applied at or near the mills, or after delivery to the Project area. An 88.9 mm OD pipe will be "piggybacked" to the interfield lines to supply Monoethylene Glycol (MEG) to prevent hydrates from occurring in the interfield lines between the Thebaud platform and the Venture and North Triumph platforms.

The 609 mm OD pipeline will be laid on the seabed, and will be trenched in shallow water. Future studies will determine the likelihood of self burial by the pipeline, and identify places where sand movement or bottom terrain may cause instability in the line. The line may be trenched in areas of concern by one of several possible methods: mechanical trenching, ploughing, jetting or dredging. The appropriate method will be chosen to conform to bottom conditions and ecological concerns. For example, if a shellfishery is important in the area, methods that stir up a large volume of silt would be avoided.

The 'heavy lift' and 'pipe-lay' barges are special purpose, multi-million dollar vessels of which there are very few in the world. There are no Canadian operators or owners of these barges. They are primarily operated by international contractors in Europe and the United States. The vessels come fully crewed and will require little assistance beyond provision of supplies to the worksite. The high operating cost and the world-wide demand for these vessels means they work to a very tight schedule. Standby time would be very costly to the Project. Every effort will be made to ensure the most efficient use is made of barge time. The Project Proponents and the vessel operator will ensure that the appropriate clearances for working in Canadian waters are obtained from the Canadian Coast Guard.

Onshore construction of the gas plant, pipelines and natural gas liquids handling facility will proceed at the same time as construction for the offshore facilities. All facilities are scheduled to be completed during the third quarter of 1999, to allow for commissioning during September and October in preparation for first gas sales in early November of that year.

The pipeline from Thebaud will make landfall in the vicinity of Country Harbour, Nova Scotia. The pipeline will be buried in the shallow water approach and through the beach area. The landfall could be bored, if inshore conditions are suitable. The pipeline will continue inland a short distance to the gas plant and slugcatcher site.

Contractual division between onshore work and offshore work will be decided as the Development Phase of the Project progresses. The engineering, procurement and construction contract for the gas plant will be awarded through international competition. The most likely scenario for construction is that the site will be cleared and the foundations poured, with the majority of the equipment erected there. Some of the equipment will be skid mounted and some of the piping prefabricated. It is possible that the plant could be partially constructed elsewhere in several modules and be brought to the site by barge or road. This will depend on site access and the costs involved. In either case, there should be significant opportunities for local civil, mechanical, electrical and general building trades to bid for work at the site.

From the gas plant, a 67 kilometre, 219 mm OD pipeline will be trenched and buried to carry gas liquids to the Point Tupper area. As the pipeline crosses the Strait of Canso, it will either be trenched and buried, or horizontally bored (directionally drilled). This decision will depend on future engineering, geological, environmental and economic studies. An experienced inland pipeline contractor will be hired to construct this pipeline. Considerable reliance on local trades, equipment and labour is likely. **Figure 6.5.6** illustrates an onshore pipeline construction spread.

Photo Courtesy: Fluor Daniel

Figure 6.5.6: Onshore Pipeline Construction Spread

A natural gas liquids handling facility will be built at Point Tupper, Nova Scotia to stabilize the condensate and process the natural gas liquids. The condensate will then be shipped, either through the Statia Terminals, or through other facilities. The decision for shipping arrangements has not been made at the time of filing. Construction of the natural gas liquids handling facility and construction of the gas plant will most likely be under the same contract. Local construction skills are again anticipated to be needed at Point Tupper.

The total construction of Project facilities will be of modern design and incorporate well established engineering practices. Technology developed in the North Sea and the Gulf of Mexico will be applied to the offshore work, and technology developed in Western Canada will be applied to the onshore work. There are no concerns that the technological applications will cause cost or re-engineering delays.

The scenario presented here is subject to change as Front End Engineering Design (FEED) progresses and new ideas are developed. However, there are not likely to be any significant changes to the general sequence and scope of this construction scenario.

7.0 PROVISIONS FOR FACILITIES DECOMMISSIONING AND ABANDONMENT

There will be three **Sable Offshore Energy Project** facility sites which require decommissioning and abandonment once the Project is finished: the offshore facilities, the onshore gas plant and natural gas liquids pipeline, and liquids handling facilities.

Decommissioning and abandonment activities will be undertaken in accordance with the regulatory requirements applicable at the time of such activities. The following description outlines the decommissioning and abandonment activities that are currently anticipated for the Project. As there is a long period of time between construction and abandonment, industry practice, technological and regulatory requirements may change in this period. The abandonment plan will be submitted to the appropriate regulatory authorities for approval prior to abandonment.

Special consideration to the removal process will be given during the design of the facilities. Eventual abandonment of the offshore platforms and jackets is planned by cutting off the jacket legs and/or piles below the mudline and transporting the jackets and platforms to a suitable site for recovery and disposal. Due consideration will be given to any potential contaminants that could present a hazard during recovery and transportation of the facilities. Reuse of the platforms and jackets will be considered in terms of economic benefits as the time for abandonment approaches.

Wells will be abandoned according to standard industry practices, in compliance with applicable drilling regulations.

Offshore pipelines will be abandoned ‘in place’ after they are flushed internally and filled with seawater. Their ends will be capped. The lines will be surveyed, and any pipelines or parts of lines presenting an environmental or commercial hazard will be recovered and scrapped.

The onshore gas plant will be removed and the land restored to a state similar to that which existed before construction began. Onshore pipelines, where buried, will, in general, be flushed internally, capped and abandoned in place. The right-of-way will be revegetated and allowed to return by natural succession. Any above ground structures associated with onshore pipelines will be removed.

Prior to the commencement of production from the Project, the Proponents will provide evidence of financial responsibility to the regulatory authorities to address decommissioning and abandonment regulatory requirements applicable at the time of such activities.

8.0 PROJECT ECONOMICS

The **Sable Offshore Energy Project** has been analyzed using discounted cash flows together with a computer modelled risk analysis for Project costs from January 1995 forward. The results are a function of the Project specific input data, from the risk assessment and the economic assumptions.

The risk analysis combined technical and non-technical issues associated with the Project, assessed the ranges of input assumptions, quantified the outcomes and identified Project risk areas for mitigation.

Economic parameters, such as cash flows (before and after tax), rate of return, Project payout and net present value, have been used to assess the effect of various fiscal and regulatory scenarios and determine Project viability.

The range of input data and related assumptions for the economic model are included in Part Two of this Development Plan Application (**DPA - Part 2, Ref. # 8.1**). More detail on economic benefits can be found in **Volume 4, The Socio Economic Impact Statement, Section 8.2**.

9.0 LIABILITY AND COMPENSATION

9.1 Liability

Liability may be imposed upon a party that is responsible for an incident or activity that has impacted the environment while conducting offshore operations. The Accord legislation currently provides that liability may be imposed on a party for spills or debris attributable to offshore work or activity, such as the **Sable Offshore Energy Project**. In addition, fisheries legislation may impose liability for any action that must be taken to clean up spills and debris, or any adverse effects of deleterious substances on the fisheries. Shipping legislation in Canada may also provide a basis for statutory liability in connection with offshore operations. Civil liability may be imposed on a ship owner for damage and clean up measures caused by oil pollution and debris from a ship not specifically engaged in exploration, drilling, production, conservation or processing of oil or gas. Voluntary compensation plans may also apply to the Project, such as the industry compensation plan for fishermen who suffer loss or damage to their vessels and fishing equipment, in certain circumstances. Additional liabilities from statute, legislation, government policy or voluntary agreement may apply to the Project when offshore operations commence. The current liability regime, as applicable to the Project, is summarized below.

The Accord legislation provides a statutory liability regime under which a party carrying out offshore work or activity may be strictly liable, without proof of fault or negligence, up to a prescribed limit, for actual loss or damage and costs reasonably incurred in taking any action in respect of spills and debris which may be attributable to the work or activity. A limit of liability, in the amount of $30 million, has been established by regulation. In addition, the Accord legislation provides that the statutory liability regime does not suspend or limit liability or remedies, that may be available at law, by reason only that the incident gives rise to liability under the Accord legislation.

Fisheries legislation also provides potential statutory joint and several strict liability for parties that own, or have charge, management or control of deleterious substances. Liability may arise for reasonable costs incurred by government to remedy adverse effects as a result of a deposit of such substances in water frequented by fish, as well as, for loss of income of licensed fishermen to the extent that the loss can be established to have been incurred as a result of the deposit or a prohibition to fish resulting therefrom. In addition, there may be joint and several liability for such costs and loss of income imposed according to the respective degrees of fault or negligence on those who cause or contribute to the cause of the deposit. The legislation also provides that the liability provisions do not affect or suspend available civil remedies or limit the right of a party to recourse that the party may have to another that is liable under the legislation.

Shipping legislation in Canada may also provide a basis for statutory liability for incidents or activities in connection with offshore operations for the Project. The *Canada Shipping Act* provides for civil liability on the part of a ship owner for damage and clean up measures caused by oil pollution and debris that emanates from a ship not specifically engaged in exploration, drilling, production, conservation or processing of oil or gas.

In addition to compensation available by statute, voluntary compensation plans may have application and provide a further basis for compensation for loss arising from conducting offshore operations for the Project. For example, the Canadian Association of Petroleum Producers' Fishermen's Compensation Policy may provide for compensation to fishermen for damage or loss to vessels and fishing equipment caused by debris of unknown origin.

At the time offshore operations are conducted for the Project, there may be additional or other liability obligations and provisions for compensation prescribed by statute or regulation, as well as the application of government policy or voluntary agreement for any losses that arise.

9.2 Strategy

The **Sable Offshore Energy Project** strategy to address compensation, environmental degradation community concerns and financial responsibility matters for offshore operations is as follows:

9.2.1 Compensation

A fisheries compensation plan will be filed with the appropriate regulatory authorities during activities leading up to construction of facilities for the Project. Consultation with the fisheries industry is ongoing in connection with the preparation of the fisheries compensation plan. The general policy for compensation, the scope of potential claimants and the extent of claims, and the outline for the procedures to make and assess claims, as well as the consequences of making a claim will be included in the fisheries compensation plan.

9.2.2 Environmental Community Concerns

Community concerns relating to the environment, including those of the fishing and aquaculture industries, have been recorded as part of the pre-filing public consultation program. The concerns expressed are summarized in the Socio-Economic Impact Statement (SEIS) for the Project (**The Sable Offshore Energy Project, Socio-Economic Impact Statement, Volume 4**) and have been used by the Proponents as input in certain Project decisions. In addition, the Environmental Protection Plan (EPP) to be filed with the appropriate regulatory authorities will take into consideration remaining concerns that have been raised and, where appropriate, will address such concerns.

In addition to community concerns relating to the environment, the results of studies conducted on the environmental impact of the Project will form a basis for the preparation of the EPP for the Project (**DPA - Part 2, Ref. # 9.2.2.1**).

9.2.3 Financial Responsibility

As a condition for the approval of work or activities in the offshore, the Accord legislation requires evidence of financial responsibility to address the liability obligations referred to in Section 9.1, above. The *Nova Scotia Offshore Area Petroleum Drilling Regulations* also contemplate the provision of evidence of financial responsibility to meet financial liabilities that may be incurred in the conduct of an offshore drilling program.

Different forms of evidence of financial responsibility may be acceptable to satisfy the financial responsibility requirements under the Accord legislation and the *Nova Scotia Offshore Area Petroleum Drilling Regulations*, as well as for other obligations that may be applicable, such as platform abandonment. The Proponents will provide evidence of financial responsibility to address such requirements prior to commencement of the specific offshore activity in respect of which the applicable financial requirement relates. Consideration will be given to financial instruments such as a letter of credit, a financial institution guarantee or an indemnity bond, as well as to the provision of financial statements or insurance where appropriate, to address such requirements.

10.0 SAFETY PLAN

10.1 Introduction

The Safety Plan will be part of a comprehensive Environmental, Health and Safety Management (EHSM) system for the Project. This is a framework for managing and improving operations, in terms of personnel and public safety and protection of the environment. The Proponents of the **Sable Offshore Energy Project** have comprehensive EHSM systems in place. The management system and Safety Plan will be built from these foundations.

A description of Mobil's EHSM System (Operation Assurance (OA)) is on file with the **CNSOPB**. The 12 elements of OA (listed in **Section 10.4**) are similar to those found in the management systems of the other Proponents. OA will provide the basis for the policies, standards and practices of the Project. OA, while developed for Western Canadian land based operations, is based on Mobil's North Sea Environmental, Health and Safety Management System. The existing system will be modified and further developed to incorporate additional onshore and offshore experience from the Project Proponents. The Safety Plan components will be designed to address, in a comprehensive manner, onshore and offshore safety issues. Activities will be planned, organized, executed and maintained in a manner that achieves safety and protects the environment, in accordance with the various acts and regulations.

Each of the specific safety plan requirements noted in the **CNSOPB Guideline No. 3150.002 OPERATOR'S SAFETY PLAN** (**DPA - PART 2, Ref. # 210.1.1**) are contained in Operation Assurance. They will be further defined as the specific Safety Plan for this Project is developed. In addition to the general safety plan requirements for all projects, the Safety Plan will reflect the recommendations developed from the Project's Concept Safety Analysis/Evaluation (CSE). The various studies initiated from this analysis, the Preliminary Hazard Assessments (PHAs), the Hazard and Operability (HAZOP) reviews, Safety Reviews, and Safety Audits will be conducted as the engineering and procurement stages move forward.

The Safety Plan will be developed as the Project progresses. It will include an outline for the decision making process and a complete Environmental, Health and Safety Organizational Structure. The preliminary Nova Scotia organization for the **Sable Offshore Energy Project** is illustrated in **Figure 10.1.1**. As indicated in this figure, Environment, Health and Safety will report directly to the **Sable Offshore Energy Project** Operations Manager.

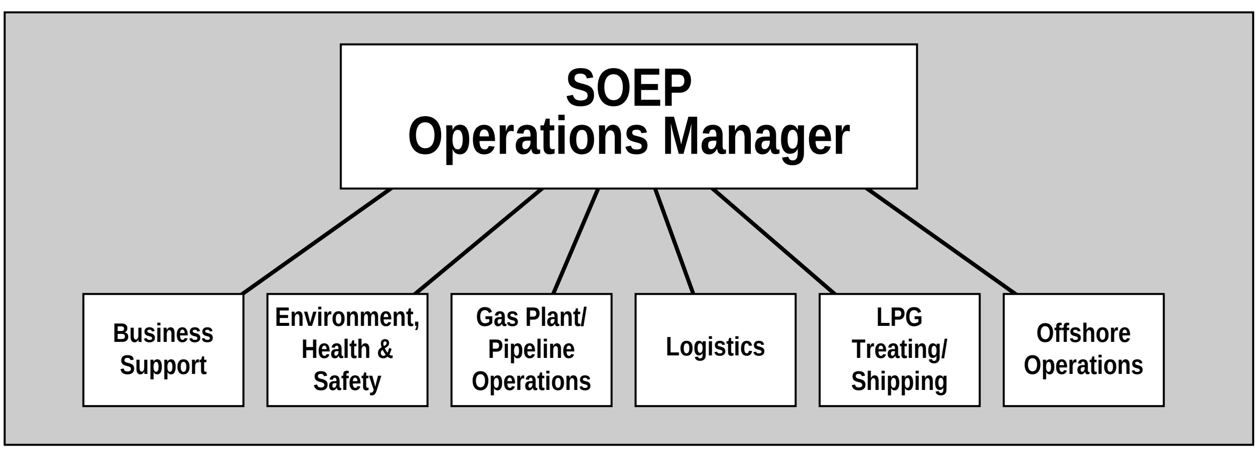


Figure 10.1.1: Preliminary Nova Scotia Organization

The development process for environmental, health and safety documentation, manuals, programs and procedures, with key activities highlighted, is illustrated in **Table 10.1.1**.

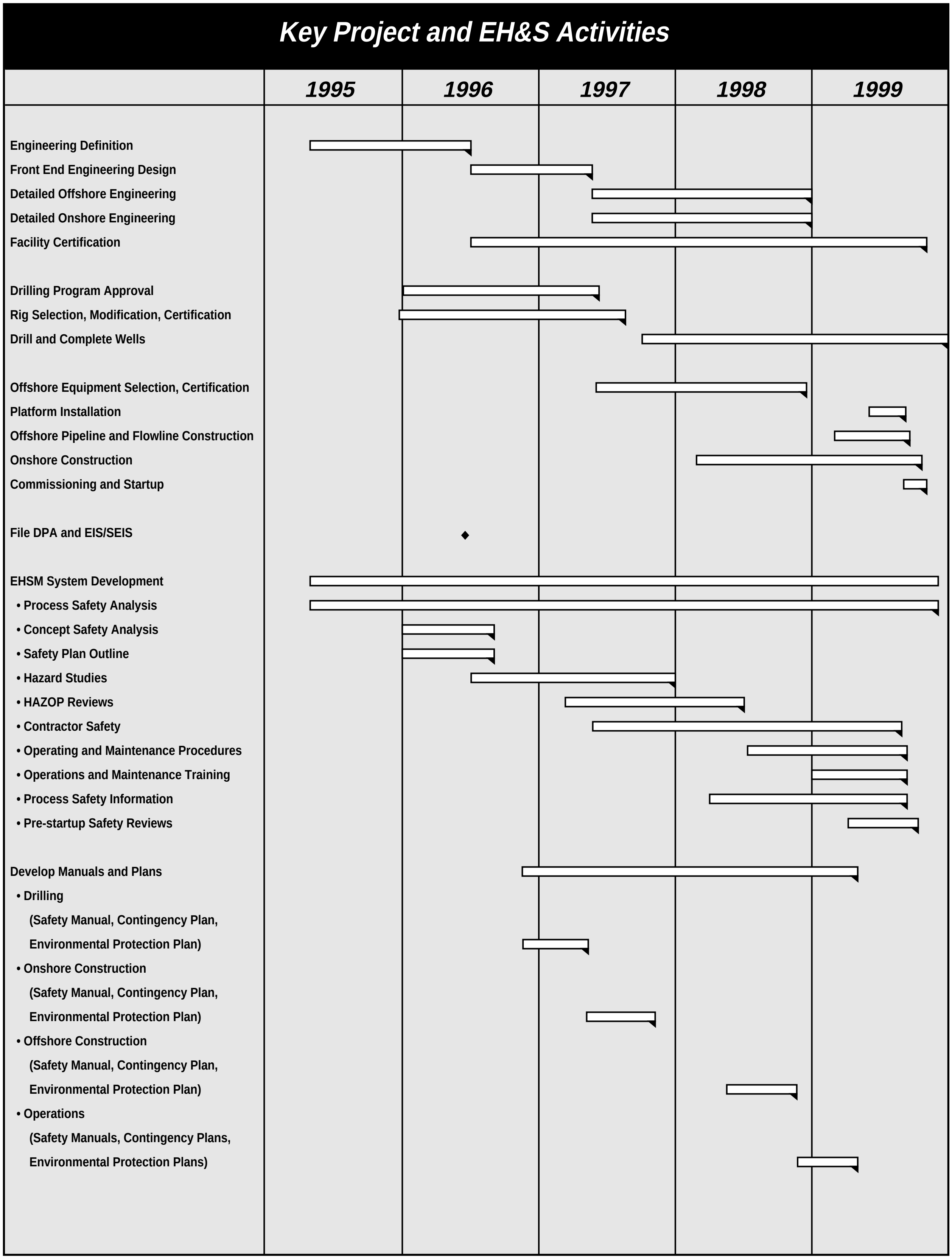


Table 10.1.1: Key Project and Environmental, Health and Safety Activities

An annotated outline of the Safety Plan and a schedule for the development of the Project's EHSM System will be provided to the regulatory authorities at the time the CSE is filed. The CSE will proceed concurrently with the Design Basis Specifications for both the offshore and onshore Front End Engineering Design (FEED), and will be filed near the beginning of FEED.

10.2 Hazard Management

Key EHSM system activities relating to hazard management are closely linked to the Project schedule (Table 10.1.1). In Engineering Definition, Front End Engineering Design (FEED) and Detailed Engineering, the **Sable Offshore Energy Project** is applying a deliberate, systematic and efficient approach to Project hazard identification, analysis and control.

Early in FEED, at the completion of Engineering Definition, the Project Concept Safety Analysis/Evaluation (CSE) will be completed. The initial step in the CSE is the definition of Target Levels of Safety to be applied throughout the life of the Project. These targets apply to the risk to life and the risk of damage to the environment from major hazards that apply to all activities associated with each phase of the life of the Project. A suitable criterion for the Target Levels of Safety will be developed based on the Proponents' experience, industry recommended practice, accepted Codes of Practice and worldwide industry experience. These targets will be reviewed over the life of the Project and modified and improved, as appropriate.

Potential and major safety and environmental hazards associated with the Project installations (platforms, pipelines, gas plant, liquids processing facility) will be assessed in the CSE, including: blowout, explosion, fire (and smoke), structural failure, collision, helicopter crash, earthquake, extreme weather, pipeline rupture, platform spills, simultaneous drilling and construction, simultaneous drilling and production. An assessment of the effects on key safety systems (evacuation systems, safe refuge systems, control systems, emergency shut-down systems), personnel, the public and the environment will be made. The likelihood of occurrence and the potential consequences of these hazardous events will be estimated and be used in the assessment. The CSE will also address contingency plans to avoid, mitigate or withstand these potential hazards.

The Concept Safety Analysis/Evaluation, prepared by recognized experts in this type of analysis, will consist of the following:

- Hazard identification
- Assessment of major hazard risk levels
- Assessment of major hazard consequences
- Assessment of prevention, control and mitigation
- Assessment of rescue and evacuation
- Assessment of Levels of Safety achievable
- Specification of updating and tracking procedures
- Recommended design improvements and studies

Based upon the results of these analyses, plans and measures will be developed for the **Sable Offshore Energy Project** to assure that the Target Levels of Safety specified for the Project will not only be met, but improved upon where practicable by embracing the principle of As Low As Reasonably Practicable (ALARP) design. A series of specific safety and environmental studies will follow the CSE. These will incorporate recommendations from the CSE and provide necessary additional analysis required for the Detailed

Engineering of the Project. These could include recommendations for additional fire risk analysis, ventilation and gas detection studies, and various quantitative risk assessments.

The studies, recommended in the CSE, will support other components of process hazard analysis conducted during the FEED and Detailed Engineering. Key environmental, health and safety components during engineering will include:

- The Hazard Management Plan at the start of FEED
- The Process Hazard Reviews of process flow and general arrangement drawings in FEED
- The Detailed Hazard Reviews (using check lists, what if analysis and HAZOPs) of process flow and instrumentation in FEED
- Final HAZOP Reviews of process flow and instrumentation in Detailed Engineering
- Environmental, Health and Safety Audits, in both FEED and Detailed Engineering

This work will support the updating of the Concept Safety Analysis and contribute to the Safety Plan for the Project.

10.3 Drilling

Environmental, Health and Safety initiatives will be designed to compliment existing OA procedures and standards, while developing specific drilling safety plan details and procedures (Table 10.1.1) for this Project.

The drilling contractor will be required to have a comprehensive safety program in place. This program must meet or better all applicable industry, government and Proponent standards. The contractor safety program will be evaluated by Loss Prevention personnel familiar with offshore drilling installations prior to acceptance of the drilling unit. The Loss Prevention personnel involve specialists from the Proponents, Project team and contractors and will ensure that sufficient training, information and equipment is made available to the workforce.

Survival equipment, emergency procedures and training are a major focus of the Safety Plan. Emergency drills, procedures for evacuation and abandonment, fire fighting, stability control, man overboard, well control and spill response will be reviewed, further developed and approved. These procedures will be further modified to align with the offshore installation when the structure is in place.

The general Drilling Safety Program from the operating company will be utilized for the Project to encompass both drilling and workover operations. This program, which forms part of the Quality Management System, will facilitate continuous improvement and safe and environmentally responsible drilling, completion and workover activities. Internal safety audits will be held at a sufficient frequency to ensure the success of the safety program.

Proven operator safety programs from the North Sea and Gulf Coast will be incorporated into the development of a Simultaneous Drilling and Production Operations Manual and a specific Drilling Operations Manual. Within the second manual, limits and procedures to deal with close proximity well bores will be defined.

Procedures will be established for the early detection and control of hazardous well conditions in the Drilling Operations Manual. These procedures include, but are not limited to, tripping speeds, flow checks, well-kill procedures and testing of casing and well control equipment. Data logging units will be used to continuously monitor all drilling parameters.

10.4 Construction

The Safety Plan for construction incorporates two elements: the protection of life and materials during the physical act of construction, and the safety features designed into the facilities.

Safety during construction is a team effort between Proponents and contractors. The roles vary however, according to the stage and location of the work. In off-site locations, for example, the Proponents monitor the work and manage safety improvements in co-operation with the contractor. The Proponents' Offshore Manager has direct responsibility for all activities that are undertaken within the Proponents' Licence.

The contractor's safety management system and safety record is part of the qualification criteria used to determine contractor suitability to participate in the Project. Contractor's safety manuals, organization and performance will be audited prior to contract award. Corrective action will be required of the contractor where necessary, prior to qualification. Compliance with Project environmental, health and safety standards, and those of the country of jurisdiction where the construction activity is taking place, will be a contractual requirement. The contract will also contain the Proponents' Environmental, Health and Safety rules which will form part of the basis for the Project's Safety Plan. The Project Manager's team will monitor performance in the construction yards and arrange audits by the Proponent's Loss Prevention Specialists.

The Proponents' Offshore Manager is responsible for the safety of all work undertaken within the Licence. A Loss Prevention organization will be in place during the construction stage of the Project. 'Work Permitting' procedures, an element of the EHSM system, will be the normal method of work authorization. These procedures will ensure that the requirements for safe work are in place. The Loss Prevention organization will be pro-active in the education of the workforce. Safety will have first priority at the work site.

Technical Safety is built into the engineering design by compliance with the appropriate regulatory requirements, the application of industry standards and active Quality Assurance/Control reviews of all aspects of the design. HAZOP reviews, Loss Prevention reviews, and Access/Maintenance reviews will be periodically held to ensure the integrity of the design. These reviews will involve the Proponents' corporate loss prevention and operations experts, as well as Project and contractor personnel.

10.5 Operations

The Proponents recognize the need for safe operations, and the hazards which are inherent in the operations of the proposed Project. The **Sable Offshore Energy Project** Safety Program is being designed to reduce risks As Low As Reasonably Practicable (ALARP). This will be accomplished through a combination of qualitative and quantitative risk assessment procedures.

Project environmental, health and safety philosophy is based upon the following beliefs:

- all environmental, health and safety incidents are preventable.
- environmental, health and safety objectives must never be sacrificed for expediency.
- environmental, health and safety objectives are an integral part of operations objectives.

The Environmental, Health and Safety program will consist of 12 key elements:

- Leadership, Responsibility and Accountability
- Personnel Training, Awareness and Motivation
- Personnel Health and Safety
- Drilling and Well Servicing Safety
- Process and Facility Safety
- Operations and Maintenance
- Management of Change
- Environmental Protection
- Emergency Preparedness
- Community Relations
- Incident Investigation, Reporting and Analysis
- Compliance Assurance and Improvement

The Proponents will require all employees and contractors for the Project to follow this Safety program.

The following safety tools will be used in the various hazard reviews/studies for this Project: Preliminary Hazard Assessments (PHAs), HAZOP reviews, and Quantitative Risk Assessment (QRA).

Preliminary Hazard Assessments are used to identify risk and consequences associated with safety hazards, such as a small or large gas leak, explosions, and fires. PHA's can be used to focus remedial work during the design stage, or to eliminate obvious hazards before construction. This tool is also invaluable for managing change and to assess existing operations.

HAZOP reviews require the availability and use of Process and Instrument Diagrams and the assistance of experienced design and operations personnel. HAZOPs are very effective in the later stages of design to identify safety issues and to provide alternative designs and operating procedures.

Quantitative Risk Assessment is a tool used to understand the relative levels of risk associated with different safety procedures and emergency equipment. It is helpful in selecting life saving equipment, determining the best locations for this equipment and predicting the optimum arrangement of safety equipment.

10.5.1 Routine Operations

Routine operations are predicated on the following principles: a well trained and experienced staff, Operations Assurance, Continuous Improvement and Risk Management. These operations include logistical support operations using helicopters and work boats, as well as routine operations and maintenance activities.

The Proponents propose the use of a training computer for both onshore and offshore operations staff to familiarize them with the equipment and procedures. It is a learning tool for plant and equipment operation used prior to actual “hands on” training and operations. Operations and maintenance personnel will also be exposed to continuous updating and review training through a computer based, self-paced program. All personnel are required to set objectives for, and complete, yearly training reviews.

Offshore operations staff will be selected on a hierarchical basis by their experience in the following areas: previous offshore gas production experience, previous land based oil and gas production experience and previous marine experience. In addition to the offshore operations training, survival training, first aid and other safety training will be required.

All new staff members will be indoctrinated in Project operations as a condition of employment. Each employee will be required to function as part of an operating team, with both individual and shared objectives based on Operation Assurance. Managers and leaders within the organization are required to demonstrate leadership by practising safe performance themselves, and to recognize this achievement in those they lead. Managers and leaders are also required to demonstrate commitment to OA.

Continuous Improvement (CI) is a powerful safety management tool. It can be used to measure safety performance, to identify causes of variation in safety performance and to develop and test solutions to these causes. This philosophy is directed at fixing the problems by eliminating the causes. The Proponents will implement a strong organizational culture which recognizes and rewards the commitment and follow-through of employees who strive to eliminate variation in safety performance on a day-by-day basis.

10.5.2 Management Of Change

The Management of Change is a key Safety Plan element supporting continuous improvement in risk management. The Proponents will develop procedures to identify, report and consider **all** changes within the operation. Initially, these procedures will be derived from current Proponent practices, onshore and offshore. This will be followed up with CI to measure the effectiveness of the process, identify variations and implement improvements in the process. This process will have a strong documentation element to allow for follow up measurements and identification of root causes of variation.

Management of Change is an element of the Environmental, Health and Safety Management (EHSM) system and will receive continuous development, assessment and improvement, as outlined in this application.

10.5.3 Well Servicing Operations

The safety program for well servicing operations will be developed in conjunction with the drilling safety program. It will include the elements of a total loss prevention and control program in conjunction with the EHSM system initiatives. The Proponents will develop a manual to describe specific elements of the program as they apply to the well servicing operation, in order to minimize all types of accidental losses. The standards established will reflect technology with a high level of safety applicable for local conditions, and will take full advantage of technical advancements in equipment, materials and operational techniques. The standards will adhere to industry and regulatory requirements. This will be reviewed by the **CNSOPB** prior to final implementation.

As with the drilling program, contractors will be required to demonstrate a comprehensive program to track all accidents, incidents and near misses. They will be required to ensure all Government and industry standards are met, as well as standards of safety training similar to those of the drilling program.

10.5.4 Emergency Preparedness

The Project Proponents have extensive experience with Emergency Preparedness. Monthly safety drills, including realistic emergency exercises, will be conducted in both the onshore and offshore facilities. In the offshore, weekly lifeboat drills, man overboard exercises and fire drills will be conducted. A major annual emergency exercise will mobilize staff to the emergency command centre. The exercise will act out evacuation, verify and improve emergency procedures, and test communication systems.

The facilities and equipment will be operated to keep risk at a minimum. Operations and management personnel will be trained and drilled to handle all identified emergencies. The Proponents will prepare Alert/Emergency Response Plans (ERPs) (**Chapter 12.0: Contingency Plans**), to outline identified emergencies, establish responsibilities and accountability for these events and lay out notification and response procedures.

An assessment of safe havens for offshore personnel and the provision of QRA for specified events will also be part of the overall emergency preparedness program.

11.0 ENVIRONMENTAL PROTECTION PLAN

11.1 Introduction

The Proponents are committed to stewardship of the environment in which they seek to operate, and will design this Project to eliminate or minimize impacts on the environment (See **Volume 3: Environmental Impact Statement**). Environmental protection, an important element of the Proponents' overall Environmental, Health and Safety Management (EHSM) system, will be managed to ensure that utilizing resources and the environment today will not impair prospects for future generations. This goal will be achieved through a balanced approach that recognizes the mutual long term dependence of a healthy environment and a healthy economy. The Proponents consider protection of the environment essential to the integrity of ecosystems, human health and the well-being of society. This will be a measure of the success of this development over its Project life of 25 years or more.

An Environmental Protection Plan (EPP) will be developed to provide detailed guidance, particularly for project personnel, on how to eliminate or minimize and mitigate adverse environmental effects from the Project. The EPP will provide a practical framework for implementation of the environmental requirements of development.

The Proponents will prepare an EPP, in a timely manner, for the management of Project-related impacts. The EPP will consolidate all the proposed environmental mitigation and monitoring procedures for construction (offshore and onshore), drilling, production, decommissioning and abandonment. The EPP will be an integral part of the overall Operational Plan and a reference document for the life of the Project. The EPP will, by necessity, reflect the activities of the Project and will be phased so that protection measures will be in place prior to each stage of activity.

Environmental performance will be the subject of yearly reviews by all personnel for the design, construction, operation, decommissioning and abandonment of this Project. Performance measures will be established. Continuous Improvement of these performance measures will be equally as important as the economic indicators which impact the operation.

The EPP, as part of the overall comprehensive EHSM system, will consist of the following elements:

- Environmental Policy
- Standards and codes of practice
- Mitigation / Operating procedures (construction, drilling, production, decommissioning and abandonment)
- Environmental education, training and orientation procedures / programs
- Chain of command (mechanisms for environmental decision-making)
- Environmental Effects Monitoring (EEM) practices and reporting
- Environmental Compliance Monitoring (ECM) practices and reporting
- Reference Laws, Regulations, Guidelines, Licenses, Permits and Approvals
- Waste Management Plan (WMP)
- Atmospheric Release Management Plan
- Effluent Release Management Plan
- Accidental Discharge Contingency Plan
- Contractual commitments, including special environmental clauses
- Environmental inspection and audit procedures

- Interaction with landowners and compensation procedures
- Interaction with the fishing industry and compensation procedures
- Special conservation plans, where appropriate (example: Sable Island)
- Environmental Management Continuous Improvement

The EPP will reflect the commitments the Proponents have made in this Development Plan Application, the Environmental Impact Statement, Socio-Economic Impact Statement, Review Panel Conditions of Approval, and other regulatory requirements for the Project. Additional detail is provided in **The Sable Offshore Energy Project Environmental Impact Statement, Volume 3, Biophysical Environment, Section 8.0 Environmental, Health and Safety Management System.**

One component of the EPP will be the Environmental Effects Monitoring (EEM) program. Effects monitoring will detect changes to the environment caused by a specific activity or development. The EEM program will provide an early warning of undesirable changes in the environment. The EEM program, where applicable, would address the following issues: Are changes being caused in the receiving environment? What is the size of the area affected? What biological components are affected? How severe are the impacts? What is the significance of the impacts? Are corrective measures necessary?

The other major monitoring component will be Environmental Compliance Monitoring (ECM). Part of this ECM is directly related to regulatory environmental surveillance and the conditions associated with licenses, permits and approvals. For example, this would include conformance with legislated spill reporting requirements. The other part of ECM is self-imposed, and is used to monitor performance standards developed for this Project by the Proponents.

There will also be a provision for specific EPPs on an ‘as needed’ basis in support of specialized activities such as future seismic work.

11.2 Construction

Each element noted above will be addressed in the EPP section on Construction. This will include offshore platforms, interfield pipelines, production gathering pipeline, onshore slugcatcher, onshore pipelines, gas plant and liquids processing facility. The EPP will be an Action Plan to guide inspectors and contractors during construction. It will contain construction specifications relevant to environmental protection, codes of practice for protecting sensitive features of the environment during construction, and mechanisms for dealing with an environmental emergency or unplanned occurrences.

Compliance with the EPP will be a mandatory element within each construction contract. The contractors’ environmental practices and specific Waste Management Plan (WMP) will be among the criteria for contract award. In terms of the offshore, the Proponents will have in place, within the Offshore License, an Offshore Manager who has responsibility for ensuring that all discharges and emissions are within statutory limits. The WMP will be based upon the elimination of accidental spills and discharge of waste into the sea. Responsible waste disposal, in consultation with the local authorities, will be the mode of operation for all aspects of construction. Specific elements of the EPP relating to construction are presented in the **Sable Offshore Energy Project Environmental Impact Statement, Volume 3, Section 8.3.3**. These will be modified as a result of the EIS review. The EPP section on Construction will be presented in final draft to the appropriate regulatory authorities at least six months prior to commencement of major physical construction activities.

11.3 Drilling, Completions and Workovers

The Proponents fully acknowledge the environmental significance of the Sable Island and the Gully areas, and will conduct operations in a way that will address all potential impacts on those environments. Policies and procedures to eliminate or minimize environmental impacts will be established. The Proponents will meet or better all applicable regulations, corporate policies and environmental obligations. A Waste Management Program for drilling and workover operations to minimize waste, to recycle, to establish waste handling procedures and ensure regulatory compliance will be established. An accurate system of monitoring areas of environmental concern will also be established.

Qualified personnel, equipment and procedures will be in place in the event of an environmental incident, in order to correct the situation as soon as possible and to limit any damage. A reporting system will be established to record any incidents, regardless of size, and to record any near miss incidents and report these as required to the appropriate authorities. This information will be used to improve procedures and reduce incidents.

11.4 Operations

Each element noted above will be addressed in the EPP section on Operations. A combination of ECM and EEM programs will be established to monitor and report on the following, as well as other possible situations as they develop over the Project life:

Examples for Offshore Platforms

Flaring/venting (durations, volumes and causes)
Spill causes and volumes, with a zero tolerance threshold (all spills no matter how small will be reported)
Waste volumes and sources including:
- Process and well treating chemicals
- Produced water treatment and disposal (oil content)
- Sewage discharges (volumes, BOD, suspended solids)

Hazardous materials inventories, use and disposal
Heat losses to the atmosphere
Noise emissions

Examples for Offshore Gathering Systems

Flow rates and pressures
Periodic external inspections
Periodic internal inspections
Hydrostatic test fluid disposal

Examples for Onshore Facilities

Gas plant emissions
Gas plant effluent
Noise emissions
Flowline route revegetation
Flowline stream crossings
Hydrostatic test fluid disposal
Gas liquids processing emissions
Gas liquids processing effluent
Storage and shipping

The details of these programs will be established at the early stages of the Project, in response to requirements associated with Project activities. Additional detail is provided in the **Sable Offshore Energy Project Environmental Impact Statement, (Volume 3, Section 8.3.3)**. The EPP section on Operations will be presented to the regulatory authorities at least six months prior to the commissioning of the facilities. It will be an ongoing Continuous Improvement (CI) guide for management, operations and maintenance personnel to minimize wastes and emissions. Management will endorse written environmental policies and procedures for operations. The underlying philosophy of the Operations Plan will be Continuous Improvement: measuring and reporting on environmental issues, identification and elimination of 'root' causes of variation, and achievement of 'excellence' in environmental operations.

11.5 Decommissioning and Abandonment

The EPP section on decommissioning and abandonment will address the elements noted above. Matters relating to decommissioning and abandonment of facilities are addressed in **Section 7.0 Decommissioning and Abandonment** of this DPA.

12.0 CONTINGENCY PLANS

12.1 Introduction

The objective of the contingency plans is to ensure the safety of Project personnel and the public, and to protect both the environment and the Proponents' investment. The Mobil Field Support Emergency Response Plan (Field ERP) is currently being used for the **Sable Offshore Energy Project**. This is to ensure effective mobilization of personnel, facilities, and resources in the event of an accident or incident related to Project work. This plan provides information on Levels of Alert, Notification Structure, key response team duties, Emergency Control Centre (ECC) support teams, emergency telephone lists, and various forms and checklists. A copy of the Field ERP is on file with the **CNSOPB** and will be filed with other regulatory authorities as required. As Project activities increase, there will be a need for other contingency plans. These will deal with the response to, and mitigation of, accidental events affecting the safety of personnel and the public or the integrity of the facilities, and the response to, and mitigation of, accidental release of hazardous substances. Existing ERPs will be reviewed and updated on an annual basis.

Emergency Response Plans (ERPs) for the **Sable Offshore Energy Project** will be developed in compliance with the Canadian Association of Petroleum Producers (CAPP) *Guidelines for the Preparation of Emergency Response Plans* and *CAN/CSA-Z731-95 Emergency Planning for Industry*. They will be a logical extension of present plans used by the Proponents in similar onshore and offshore projects.

The Offshore Alert/Emergency Response Plan (**Offshore ERP**) will be quite similar to Offshore Alert/Emergency Response Plans the Proponents had in place while drilling off Nova Scotia in the 1980's; and to the *LASMO Nova Scotia Limited Alert/Emergency Response Contingency Plan* currently on file with the **CNSOPB**. The **Offshore ERP** will address construction, operation, drilling, decommissioning and abandonment activities associated with the offshore components of the project (platforms, pipelines, vessels, aircraft).

The Onshore Alert/Emergency Response Plan (**Onshore ERP**) will be quite similar to the ERPs the Proponents have in place for their Western Canadian facilities. The **Onshore ERP** will address construction, operation, decommissioning and abandonment activities associated with the onshore components of the project (gas plant, slugcatcher, pipelines, liquids processing facility).

The process for development of the ERPs will include hazard identification and assessment, environmental sensitivities, consultation with government agencies to ensure regulatory compliance, incorporation of industry Codes of Practice and consultation with local and other emergency resources. The plans will take into account the availability of existing industry and government emergency equipment and facilities.

The Proponents' contingency plans will incorporate the appropriate government agencies and other operating companies. This will be addressed, not only in planning, but also in coordinated exercises and drills. The goal will always be to reduce the impact from an emergency situation through the rapid and appropriate response of available resources, knowledge, and experience. The Proponents plan to become a member of the Regional Environmental Emergencies Team (REET) and Point Tupper Marine Services (PTMS). The Proponents will cooperate and interact with several other cooperative bodies. These include: Department of National Defence Rescue Coordination Centre (RCC) and Search and Rescue (SAR), the East Coast Response Corporation (ECRC) and the Emergency Measures Organization (EMO).

12.2 Offshore ERP

The **Offshore ERP** will be filed with the regulatory authorities at least six months prior to the commencement of Project activities (construction, drilling, operation, decommissioning and abandonment). The following topics will be addressed in the **Offshore ERP**:

1. **Administration**
   Introduction, policy, purpose and scope
   Manual Organization
   Definitions
   Amendment sheet and distribution list

2. **Organization**
   Internal emergency organizations
   External emergency organizations

3. **Roles and Responsibilities**
   Emergency Task Force Members (offshore, onshore, administrative)
   Description of key roles and responsibilities

4. **Communications**
   Alert and Emergency Notifications (charts, lists)

5. **Emergency Response** (actions by positions, onshore and offshore, specific hazard/emergency action plans)

   Offshore Installation Emergency
   - Loss Of Well Control
   - Gas Leak
   - Fire/Explosion
   - Structural Failure/Damage
   - Offshore Flowline Failure/Damage
   - Severe Weather

   Transportation Emergency
   - Overdue/Lost (vessel, aircraft)
   - Collision Avoidance (infringement of Safety Zones)
   - Severe Weather

   Personnel Emergency
   - Serious Injury/Fatality
   - Medevac Plan
   - Man Overboard
   - Abandon Platform
   - Diving Emergency

   Security Alert/Emergency
   - Criminal Acts
   - Act of terrorism/sabotage (includes bomb threats)

Environmental Alert/Emergency
Spill Incident (formation fluids, fuels, oils, lubricants, chemicals, gas/condensate, bulk products)

6. Resources
Personnel/equipment
Contractor resources
Government and mutual aid resources
Contact lists

7. Training
Employees and contractors
Drills and emergency exercises
Continuous Improvement system

8. Appendixes
Logs
Procedures
Severe weather criteria
Communication system overview

Additional information is provided in subsequent sections on Loss of Well Control, Pipeline Breaks, Platform Incidents, Collision, Marine Incidents, Aviation Incidents, and Force Majeure.

12.3 Loss Of Well Control (Drilling & Well Servicing)

A diverter system will be used for drilling below the conductor casing on all **Sable Offshore Energy Project** wells. This policy corresponds with **CNSOPB** requirements. The system will be designed with lines that are as straight as possible and have a minimum line size of 254 mm.

Once surface casing is set, either a 34 or 69 MPa blowout preventer (BOP) will be installed prior to drilling out. Pressure test requirements will be developed to meet government and Operator standards. This will include test pressures, test times, documentation, type of test and test frequency.

At intermediate casing point, a BOP of suitable pressure rating to reach total depth will be installed. In a number of cases, this will be a 103 MPa BOP. The choke manifold system and additional well control equipment will be designed to work with the 103 MPa working pressure BOP. The BOP working pressure requirements will be determined by the maximum possible surface pressure and will meet, or better, **CNSOPB** requirements

Procedures for well control and equipment, and procedures for early kick detection, will be formalized in the **Sable Offshore Energy Project** Drilling Operations Manual. This will include, but is not limited to, shallow gas, lost circulation, kicks and underground flows. Those procedures will be referenced and extracted, as necessary, to address Loss of Well Control during drilling. Similarly, procedures relating to Well Servicing operations will be supported in the **Offshore ERP** sections relating to Loss of Well Control.

During workover and completion operations, a minimum two-barrier well control philosophy will be strictly adhered to. This will ensure redundancy for well control against all predictable occurrences. This will include combinations of kill fluid, downhole plugs, BOPs, wellhead and safety valves. Safety procedures will be developed and implemented to ensure compliance with **CNSOPB** regulations and identification of critical operations. The safety procedures will adhere to Proponents' safe operating practices guidelines.

Where possible, all contingency plans will be developed in cooperation with other operators on the East Coast to maximize response capability and reduce duplication. This approach will help minimize the negative effects of any incident. During segments of drilling, completion and workover operations, only one Project jackup rig may be operating in the Sable area. Agreements will be established with the Project Proponents to make an appropriate drilling unit immediately available for relief well drilling, if required. This unit would most likely be mobilized from the North Sea or the Gulf Coast, but does not preclude available units identified by the combined worldwide resources of the Proponents. Casing, wellhead and mudline suspension equipment will be available for use, if necessary. Experienced personnel from other operating areas will be identified for well control or relief well operations. These individuals will be mobilized immediately in the event of a major well control incident.

12.4 Gathering Line Breaks

Contingency plans for gathering line breaks will be included in the **Offshore ERP** and its supporting documentation. These will include:

- Isolation procedures for ruptured or broken flowlines; which include 'securing the area' and preventing vessels from approaching the hazard area.'
- Containment and clean up of spilled hydrocarbons, with on-site and special hired equipment.
- Repair procedures including mobilization of necessary equipment and services.
- Inspection procedures for assessing the damage, adequacy of repairs and restart of operations.
- Compensation procedures for damage caused by flowline incidents.
- Documentation procedures to report and monitor spill causes, and to meet regulatory requirements.

12.5 Platform Incidents

Contingency plans for platform incidents will be included in the **Offshore ERP** and its supporting documentation. These incidents would include: injury to personnel from operational or environmental hazards, sickness of personnel, death, structural failure from environmental or operational forces, gas leak, fire/explosion, severe weather (storm winds and/or waves, pack ice, icebergs, superstructure icing), man overboard, diving emergency, and abandon platform.

12.6 Collision

To a large extent, fixed facilities in the open sea are reliant on the skill and vigilance of mariners to avoid collision. With proper procedures and the provision of special equipment, the risk of collision can be reduced to a very low and acceptable level. The **Sable Offshore Energy Project** has commissioned work around this contingency which is contained in Part Two of this document (**DPA - Part 2, Ref. # 12.6.1**).

A 'safety zone' will be established 500 metres all around the facilities rising above the sea surface. This 'safety zone' is mandated in offshore regulations. Standby boats and other vessels of the Proponents will be instructed to warn other vessels trespassing within the zone. The Canadian Coast Guard will also be requested to prohibit vessel anchoring within 200 metres of any Project subsea flowline.

Where appropriate, the Proponents will install active and passive navigational aids, such as radar reflectors, fog horns and lights on all surface facilities. In addition, anti-collision radar will operate in the producing area. This will give early warning to the personnel on platforms and standby boats of a potential collision hazard. This will give time for the vessel concerned to be warned and diverted. If the vessel cannot be diverted, prior to collision there will be time to secure the production and/or drilling equipment, and evacuate personnel in a safe and orderly manner. Operations and emergency procedures will be prepared and practiced to handle this contingency.

The platforms are protected from damage in normal day-to-day dealings with supply boats and other vessels by guards and bumpers. The mariners on these vessels will be made familiar with the facilities to reduce the risk of accidental contact and damage.

12.7 Marine Incidents

Guidelines for the safe and effective operation of **Sable Offshore Energy Project** vessels will form the basis of a marine operations manual. It will outline Project procedures for both routine and emergency marine applications. Emergency procedures relating to marine incidents (overdue, missing, damaged, sinking, or sunk vessels) will be detailed in the **Offshore ERP**.

12.8 Aviation Incidents

Sable Offshore Energy Project facilities will be designed to minimize the number of personnel involved in the operation of the offshore manned facilities, and to also minimize the number of visits required to service the normally unmanned facilities.

Helidecks will be designed to fully meet the standards, in size and equipment, required by regulatory authorities and aviation advisors to the Project. Helicopter operating companies with experience in offshore operations and experienced pilots and ground staff will be contracted. Maintenance, safety and operations records will be audited by the aviation specialists.

The Proponents will develop Procedures in Operations (for example, flight following), and emergency manuals to cover crash landings on the facilities and in the sea (late, missing, downed, or damaged aircraft). These will involve platform personnel, standby boats, other marine vessels and aircraft. Canada Coast Guard and other government services will be included when appropriate.

Personnel using helicopter transportation will receive training on how to react in the event of a helicopter accident. Frequent users will also receive 'ditching at sea' training. Training for the use of, and the wearing of survival protection gear will be mandatory.

12.9 Force Majeure

Force Majeure is, by definition, an occurrence beyond the control of the Project. The timing and magnitude of these occurrences are never predictable. Force Majeure basically falls into two categories: Acts of Nature; such as storms and earthquakes; and Human Induced; such as war, insurrection or strikes.

All the facilities are constructed with the most recent meteorological, climatological, oceanographic and geotechnical data available to the designers. The design allows for natural occurrences that can reasonably be expected within the vicinity of the facilities. A risk management program will be developed to address financial exposure in the event of injury, death, damage or loss of the facilities from natural disasters and human acts.

The operations and emergency procedures of the Project will address most of the effects from Force Majeure. These are generally: fire, hydrocarbon spills, rescue at sea, or stoppage of work or production. All these incidents will be covered by recommended action plans, training programs and periodic drills.

12.10 Onshore ERP

The **Onshore ERP** will be filed with the regulatory authorities at least six months prior to the commencement of Project activities (construction, operations, decommissioning and abandonment). The following topics will be addressed in the **Onshore ERP**:

1. **Administration**
   Introduction, policy, purpose and scope
   Manual Organization
   Definitions
   Amendment sheet and distribution list

2. **Organization**
   Internal emergency organization
   External emergency organizations

3. **Roles and Responsibilities**
   Emergency Task Force Members (onshore, administrative)
   Description of key roles and responsibilities

4. **Communications**
   Alert/Emergency Notifications (charts, lists)
   Resident Notification/Emergency Planning Zones (EPZs)

5. **Emergency Response (actions by positions, specific hazard/emergency action plans)**
   Onshore Facility Emergency
      Gas Leak
      Fire/Explosion
      Structural Failure/Damage (gas plant, slugcatcher, natural gas liquids handling facility)
      Onshore Flowline Failure/Damage
      Evacuation (personnel and residents)

Personnel Emergency
- Serious Injury/Fatality
- Medevac Plan

Security Alert/Emergency
- Criminal Acts
- Act of terrorism/sabotage (includes bomb threats)

Environmental Alert/Emergency
- Spill Incident (fuels, oils, lubricants, chemicals, gas/condensate, bulk products)

6. Resources

Personnel/equipment
Contractor resources
Government and mutual aid resources
Contact lists

7. Training

Employees and contractors
Drills and emergency exercises
Continuous Improvement system

8. Appendixes

Logs
Procedures
Communication system overview
Maps (residence, environmental features)

Additional information on certain topics is provided in subsequent sections on Fire/Explosion, Serious Injury/Fatality, and Spills.

12.11 Fire/Explosion

The **Onshore ERP** will be address all levels of fires and explosions, including:

- small fires in a non-critical area of a facility;
- fires that can be controlled with on site personnel and equipment; and
- fires that are out of control that will cause major equipment losses, could cause a release of an explosive mixture, could cause a unconfined vapour cloud expansion (UVCE) or could cause a boiling liquid expanding vapour explosion (BLEVE).

12.12 Serious Injury/Fatality

The **Onshore ERP** will provide the Project with procedures to deal effectively with incidents involving serious injury and/or death. Such an incident could occur during a fire or explosion, or as a result of an accident during normal operations, an automobile or similar incident involving **Sable Offshore Energy Project** personnel and contractors, or from natural causes.

12.13 Spills

The **Onshore ERP** will contain specific information how the Proponents will respond to a major spill or flowline rupture. Small spills or line breaks will be treated in other procedures outlined in the Environmental Protection Plan (EPP).

DEVELOPMENT PLAN APPLICATION
PART TWO: BIBLIOGRAPHY

Mobil Oil Canada Properties, for itself and on behalf of the Proponents of the Sable Offshore Energy Project, hereby declares that certain designated material contained in Part Two of the **Sable Offshore Energy Project** Development Plan Application contains financial, commercial, scientific or technical information which:

a) is **CONFIDENTIAL** under the terms of the Access to Information Act (Canada) and is not to be released or made public except as provided in the Act;

b) is **CONFIDENTIAL** under the terms of the Freedom of Information and Protection of Privacy Act (Nova Scotia) as disclosure would affect the continued access to such information, would affect the competitive position of the Proponents and result in undue financial loss and access thereto should be refused pursuant to the Act;

c) is **PRIVILEGED** under Section 122(2) of the Canada/Nova Scotia Offshore Petroleum Resources Accord Implementation Act (Canada) and is not to be released or made public except as provided in the Act; and

d) is **PRIVILEGED** under Section 121(2) of the Canada/Nova Scotia Offshore Petroleum Resources Accord Implementation (Nova Scotia) Act and is not to be released or made public except as provided in the Act.

Any notices regarding this matter should be sent to:

Mobil Oil Canada Properties
P.O. Box 800
Calgary, Alberta
T2P 2J7

Attention: Vice President, Frontier Development

Legend

Canada-Nova Scotia Offshore Petroleum Board: **CNSOPB**
Mobil Oil Canada Properties: **Mobil**
Shell Canada Limited: **Shell**
Sable Offshore Energy Project: **SOEP**

1.0 EXECUTIVE SUMMARY

Ref.#	Report Title Source	Year	Status
1.2.5.1	Venture Development Plan Mobil	1984	

2.0 GEOLOGY, GEOPHYSICS AND PETROPHYSICS

Ref.#	Report Title Source	Year	Status
2.1.1.1	Petroleum Exploration and Development, Offshore Nova Scotia Canada. CNSOPB 83p + Enclosures	1991	
2.1.1.2	East Coast Basin Atlas Series: Scotian Shelf. Atlantic Geoscience Centre, Geological Survey of Canada	1991	
2.1.1.3	MacLean, B.C. and J.A. Wade, Seismic Markers and Stratigraphic Picks in Scotian Basin Wells. Geological Survey of Canada and East Coast Basin Atlas Series	1993	
2.1.1.4	MacLean, B.C. and J.A. Wade, Aspects of the geology of the Scotian Basin from recent seismic and well data. In: The Geology of the Southeastern Margin of Canada Geology of Canada, No. 2. Geological Survey of Canada (M. Keen and G.L. Williams Eds.). Chapter 5, pp. 190-238	1990	
2.1.1.5	Welsink, H.J., J.D. Dwyer, and R.J. Knight, Tectono-Stratigraphy of the Passive Margin Off Nova Scotia. In: Extensional Tectonics and Stratigraphy of the North Atlantic Margins. A.J. Tankard and J.R. Balkwill (Eds.) American Association of Petroleum Geologists Memoir 46, Chapter 14, pp. 215-231	1990	
2.1.1.6	Coleman, J.M., and D.B. Prior. Deltaic Environments of Deposition In: Scholle, P.A. and Spearing, D. Sandstone Depositional Environments. American Association of Petroleum Geologists Memoir 31, PP. 139-178	1982	
2.1.2.1	Drummond, K.L. Geology of Venture, a Geopressured Gas Field, Offshore Nova Scotia In: Giant Oil and Gas Fields of the Decade 1978-1988. American Association of Petroleum Geologists Memoir 54, Chapter 5, pp. 55-71	1990	

Ref.#	Report Title / Source	Year	Status
2.1.2.2	Jansa, L.F. and Wade, J.A. Paleogeography and Sedimentation in the Mesozoic and Cenozoic, Southeastern Canada. In: Yorath, C.J., Parker, E.R. and D.J. Glass (Eds.) Canada's continental margins and offshore petroleum exploration. Canadian Society of Petroleum Geologists Memoir 4, pp. 79-102	1975	
2.1.3.1	Powell, T. Petroleum Geochemistry of the Verrill Canyon Formation: a source for Scotian Shelf Hydrocarbons. Bulletin of Canadian Petroleum Geology Vol. 30, pp. 167-179	1982	
2.1.3.2	Williamson, M.A. and Smyth, C. Timing of Gas and Overpressure Generation in the Sable Sub-basin, Offshore Nova Scotia: Implications for Gas Migration Dynamics. Bulletin of Canadian Petroleum Geology, Vol. 40, No. 2, pp. 151-169	1992	
2.1.3.3	Williamson, M.A. Overpressures and Hydrocarbon Generation in the Sable Sub-basin, Offshore Nova Scotia. Basin Research Vol. 7, pp. 21-34	1995	
2.1.3.4	Williamson, M.A., and DesRoches, K. A Maturation Framework for Jurassic Sediments in the Sable Sub-basin, Offshore Nova Scotia. Bulletin of Canadian Petroleum Geology, Vol. 41, pp. 244-257	1993	
2.1.4.1	Reservoir Geology of the Overpressured Reservoirs of Thebaud / Mobil	1988	Confidential
2.1.5.1	Stratigraphic Analysis of Reservoir Geometry and Reservoir Quality, MicMac and Missisauga formations, Scotian Shelf. / Mobil	1995	Confidential
2.2.1.5.2.1	Time Structure Maps for Thebaud Field / Mobil	1995	Confidential
2.2.1.5.3.1	Velocity and Final Depth Maps for Thebaud Field / Mobil	1995	Confidential
2.2.1.6.1	Well Evaluation Data for Thebaud Wells / CNSOPB	1972-86	
2.2.1.6.2	Thebaud Field Log Analysis / Mobil	1987	Confidential
2.2.1.7.1	Probabilistic Resource Evaluation of the Thebaud Field / SOEP	1995	Confidential
2.2.1.7.2	Reserves Determination of the Thebaud Field / Mobil	1987-88	Confidential
2.2.2.3.1	Reservoir Mapping of the Major Sands in the Venture Field / Mobil	1987	Confidential

Ref.#	Report Title Source	Year	Status
2.2.2.3.2	Venture Field Minor Sands Reservoir Mapping Mobil	1986	Confidential
2.2.2.5.2.1	Time Structure Maps for Venture Field Mobil	1995	Confidential
2.2.2.5.3.1	Velocity and Final Depth Maps for Venture Field Mobil	1985	Confidential
2.2.2.6.1	Well Evaluation Data Files for Venture Wells CNSOPB	1979-84	
2.2.2.6.2	Venture Field Petrophysics Mobil	1995	Confidential
2.2.2.6.3	Venture Reservoir Management Study Mobil	1992	Confidential
2.2.2.7.1	Probabilistic Resource Evaluation of the Venture Field SOEP	1995	Confidential
2.2.3.1.1	North Triumph Significant Discovery Area Application Shell	1986	Confidential
2.2.3.2.1	Addendum for North Triumph Significant Discovery Area Husky Oil Ltd.	1986	Confidential
2.2.3.3.1	The Sedimentology and Petrology of an Upper Missisauga Reservoir, North Triumph Field Husky Oil Ltd.	1987	Confidential
2.2.3.3.2	Sedimentology and Stratigraphy of the Upper Missisauga Formation, North Triumph Field Shell	1995	Confidential
2.2.3.3.3	Stratigraphic Cross-section, Missisauga Formation, North Triumph Field Shell	1995	Confidential
2.2.3.5.3.1	A Review of Depth Structure Mapping at North Triumph Shell	1995	Confidential
2.2.3.6.1	Petrophysical Evaluation Methods for the North Triumph Field Shell	1995	Confidential
2.2.3.7.1	Sable Gas Reserves Study: Net Pay Mapping; Alma, Glenelg and North Triumph Fields Shell	1990	Confidential
2.2.3.7.2	Sable Gas Feasibility Study: Reserves Estimation in Alma, Glenelg, Thebaud, Triumph and Venture Fields, Offshore Nova Scotia Shell	1991	Confidential
2.2.3.7.3	Probabilistic Resource Evaluation of the North Triumph Field SOEP	1995	Confidential

Ref.#	Report Title / Source	Year	Status
2.2.4.3.1	South Venture Reservoir Geology Mobil	1986	Confidential
2.2.4.5.2.1	Time Structure Maps for South Venture Field Mobil	1995	Confidential
2.2.4.5.3.1	Velocity and Final Depth Maps for South Venture Field Mobil	1995	Confidential
2.2.4.7.1	Probabilistic Resource Evaluation of the South Venture Field SOEP	1995	Confidential
2.2.5.1.1	Glenelg Significant Discovery Area Application Shell	1988	Confidential
2.2.5.1.2	Glenelg Significant Discovery Area Application: Appeal Shell	1989	Confidential
2.2.5.1.3	Glenelg Field Significant Discovery Review SDL 2299A CNSOPB Internal Report	1992	Confidential
2.2.5.3.1	Sedimentology and Stratigraphy of Upper Missisauga Formation; Glenelg Field Shell	1986	Confidential
2.2.5.5.2.1	Reflection Seismic Final Interpretation Report, Sable Island Area Shell	1988	Confidential
2.2.5.6.1	Petrophysical Evaluation Methods for the Glenelg Field Shell	1995	Confidential
2.2.5.7.1	Review of Existing OGIP Probability Work for Alma and Glenelg Fields SOEP	1995	Confidential
2.2.6.1.1	Alma Significant Discovery Area Application Shell	1985	Confidential
2.2.6.3.1	Sedimentology and Stratigraphy of Upper Missisauga Formation; Alma Field Shell	1986	Confidential
2.2.6.4.1	Structural Cross-Section, Alma K85 to F-67 Shell	1995	Confidential
2.2.6.5.3.1	Time and Depth Structure Maps; Alma SOEP	1995	Confidential
2.2.6.6.1	Petrophysical Evaluation Methods for the Alma Field Shell	1995	Confidential

3.0 RESERVOIR ENGINEERING

Ref.#	Report Title Source	Year	Status
3.1.1.1	Minor Sand Accumulations within the SOEP Fields SOEP	1995	Confidential
3.1.2.1	Well Test Analyses for the SOEP Fields SOEP	1995	Confidential
3.1.2.2	RFT Data Analyses for the SOEP Fields SOEP	1995	Confidential
3.1.2.3	Well Deliverability Modelling SOEP	1995	Confidential
3.1.3.1	Discussion of the Venture Reservoir Simulation SOEP	1995	Confidential
3.1.3.2	Discussion of the Thebaud Reservoir Simulation SOEP	1995	Confidential
3.1.3.3	Memorandum on the Reservoir Simulation Aspects of North Triumph SOEP	1995	Confidential
3.1.3.4	Discussion of the South Venture Reservoir Simulation SOEP	1995	Confidential
3.1.3.5	Memorandum on the Reservoir Simulation Aspects of Glenelg SOEP	1995	Confidential
3.1.3.6	Memorandum on Reservoir Simulation Aspects of Alma SOEP	1995	Confidential
3.1.4.1	Individual Sand Fluid Composition Data SOEP	1995	Confidential
3.1.4.2	Equation of State Modelling for Venture SOEP	1995	Confidential
3.2.1	Well Evaluation Model (WEM) P.O. Moseley and Associates	1992	
3.2.1.1	Radial Compositional Modelling Study for SOEP SOEP		
3.2.2.1	Pipephase Modelling for the Integrated Surface Facilities, ISF, Simulation Studies SOEP	1995	Confidential
3.3.2.1	The Study of Commingling for Application in SOEP Fields SOEP	1995	Confidential

Ref.#	Report Title Source	Year	Status
3.3.3.1	Offshore Nova Scotia Gas Development Studies Indeva Energy Consultants	1993	
3.3.3.2	An Early Investigation of Depletion Alternatives for the Sable Offshore Energy Project SOEP	1995	Confidential
3.4.1	Probabilistic Reserve Estimates for the SOEP Fields SOEP	1995	Confidential
3.4.2	Estimating Condensate Recovery for the SOEP Fields SOEP	1995	Confidential

4.0 DRILLING, COMPLETIONS AND WORKOVERS

Ref.#	Report Title Source	Year	Status
4.4.1.1	A Discussion of Load Resistance Factor Casing Design Mobil	1995	Confidential
4.4.2.3.1	Technical Memo - Maximum Shut-in Tubing Head Pressure Calculations for Casing Design SOEP	1995	Confidential
4.4.2.3.2	Technical Memo - Casing Design Limitations for the Proposed SOEP Wells SOEP	1995	Confidential

5.0 PRODUCTION AND EXPORT SYSTEMS

Ref.#	Report Title Source	Year	Status
5.1.1.1.1	SOEP Facilities Expansion Study SOEP	1996	Confidential
5.2.4.1	SIGP Gas Plant Options Study Fluor Daniel	1995	Confidential
5.2.6.1.1	SOEP Preliminary Pipeline Corridor Data Review Seabed Exploration	1995	
5.2.6.1.2	SIGP Multiphase Flow Study Mobil	1995	Confidential
5.3.3.1	Venture Preliminary Geotechnical Survey: West Side of Country Harbour Mobil	1985	
5.3.6.1	Technical Memo - Strait of Canso Crossing SOEP	1995	
5.5.2.1.1	SOEP List of Relevant Codes, Standards and Regulations Tri Ocean	1996	
5.6.1.1	Venture Preliminary Physical Environment Criteria Mobil	1987	

Ref.#	Report Title Source	Year	Status
5.6.1.2	Sable Gas Preliminary Environmental Study MacLaren Plansearch Ltd.	1989	
5.6.2.3.1	Verifications of Wave Models for Canadian Waters Atmospheric Environment Service, MacLaren Plansearch	1995	
5.6.2.4.1	Wind - Wave Hindcast Extremes for the East Coast of Canada Canadian Climate Centre, MacLaren Plansearch	1991	
5.7.1.1	Venture Preliminary Geotechnical Criteria Jacques McClelland Geoscience Inc.	1987	
5.7.1.2	Sable Gas Preliminary Geotechnical Study Jacques McClelland Geoscience Inc.	1989	
5.7.2.1	Venture Field Soil and Foundation Investigation Jacques McClelland Geoscience Inc.	1983	
5.7.4.1	Sediment Transport Criteria Study Mobil	1986	Confidential
5.8.1.1.1	Technical Memo - SOEP Power Generation SOEP	1995	Confidential
5.8.1.2.1	Technical Memo - SOEP LNG SOEP	1995	Confidential
5.8.1.3.1	LHG at Venture - Producing Cost Estimate Mobil	1989	Confidential
5.8.1.4.1	Technical Memo - Gas Conversion Technology Mobil	1995	Confidential
5.8.1.5.1.1	Technical Memo - Offshore Gas Plant Evaluation SOEP	1995	Confidential
5.8.1.5.2.1	Technical Memo - SOEP Artificial Island SOEP	1995	Confidential
5.8.2.2.1	Technical Memo - Pipeline Alternatives SOEP	1995	Confidential
5.8.3.1	Satellite Options Study SOEP	1996	Confidential
5.8.3.2	Corrosion Study SOEP	1995	Confidential
5.8.4.1	SOEP Gas Plant Location Evaluation SOEP	1995	Confidential

8.0 DEVELOPMENT ECONOMICS

8.1 SOEP Economic Input Assumptions
SOEP 1995 Confidential

9.0 LIABILITY AND COMPENSATION

9.2.2.1 Environmental Impact Studies
SOEP 1995

10.0 SAFETY PLAN

10.1.1 CNSOPB Guideline No. 3150.002 Operator's Safety Plan
CNSOPB

12.0 CONTINGENCY PLAN

12.6.1 Collision Avoidance For Sable Offshore Energy Project Facilities
SOEP 1995

SABLE OFFSHORE ENERGY PROJECT

ADDITIONAL REFERENCE MATERIAL

Gas Plant Site Screening Data Review Neill and Gunter	1995	
Sable Gas Plant Facilities Preliminary Site Assessment and Review Neill and Gunter	1995	Confidential
MNSL Minimum Facilities Platform Study Mobil	1994	Confidential
Venture Offshore Pipeline Geophysical Survey Mobil	1984	
SIGP Technical Feasibility Study Mobil	1994	Confidential
Technical Memo - Floating Storage Mobil	1995	
Technical Memo - Produced Water Treating SOEP	1996	Confidential
Venture Environmental Impact Statement Mobil	1984	
Venture Onshore Facilities Site Selection Mobil	1985	