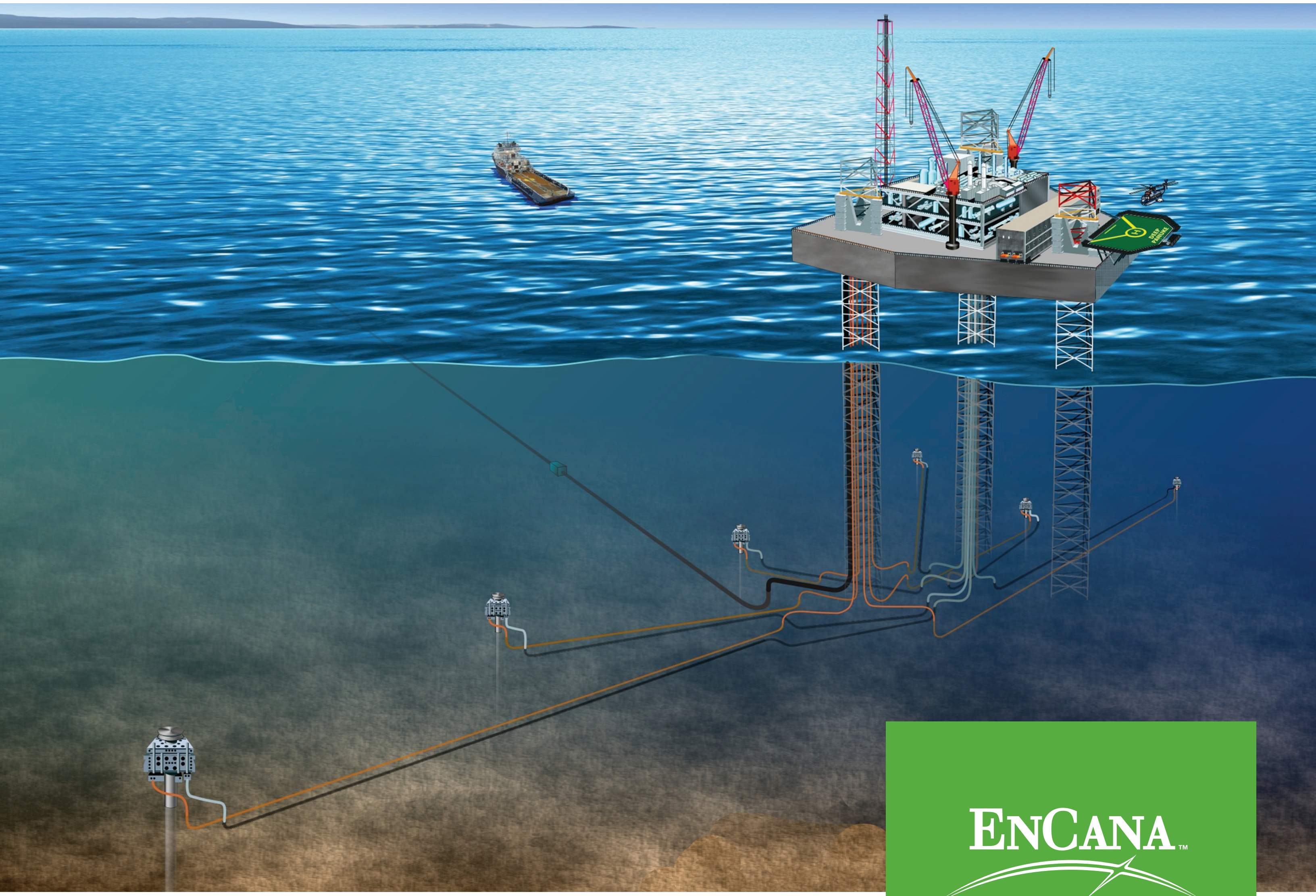
November
2006

Deep Panuke Offshore Gas Development
Development Plan



EnCana

energy for people

Volume 2

DEEP PANUKE OFFSHORE GAS DEVELOPMENT

DEVELOPMENT PLAN
VOLUME 2

Document No: DMEN-X00-RP-RE-00-0003 Rev. 01U

Prepared by:
EnCana Corporation
Suite 700, 1701 Hollis Street
Halifax, Nova Scotia
B3J 3M8

November 2006

PREFACE

This Development Plan is the second of five documents comprising a Development Plan Application (DPA) for approval of the Deep Panuke Offshore Gas Development. The documents comprising the DPA are as follows:

Volume 1 Project Summary
Volume 2 Development Plan
Volume 3 Canada-Nova Scotia Benefits Plan
Volume 4 Environmental Assessment Report
Volume 5 Socio-Economic Impact Statement

Volume 1, the Project Summary, summarizes the DPA and provides a description of the Project for a general review.

Volume 2, the Development Plan, describes the development strategy and includes details on subsurface interpretation, drilling, processing, facilities, and environmental and safety management for the Project.

Volume 3, the Canada-Nova Scotia Benefits Plan, describes the processes to promote Canada and Nova Scotia benefits associated with the Project.

Volume 4, the Environmental Assessment (EA) Report, describes the physical and biological environment in which the Project will operate, provides an assessment of the potential environmental, and socio-economic effects of the Project, and identifies mitigation measures.

Volume 5, the Socio-Economic Impact Statement (SEIS) provides a summary of the existing socio-economic conditions and a summary of the potential impacts with the project.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

INTERPRETATION

Unless the context otherwise requires,

"2-D" means two dimensional (length, width);

"3-D" means three dimensional (length, width, height);

"*Accord Act*" means the *Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act,* S.C. 1988, Chapter C-7.8 as amended;

"*Accord Acts*" means collectively, the *Accord Act* and the provincial *Accord Act*;

"ALARP" means as low as reasonably practicable;

"AVC" means annular velocity control;

"AVO" means amplitude versus offset;

"bcf" means billion cubic feet;

"BOP" means blow out preventer;

"BVW" means bulk volume water;

"CA" means Certifying Authority;

"CAPP" means Canadian Association of Petroleum Producers;

"*CEAA*' means the *Canadian Environmental Assessment Act, S.C. 1992, c. 37,* as amended;

"CDP" means common depth point;

"CNG" means compressed natural gas;

"CNOPB" means the Canada-Newfoundland Offshore Petroleum Board;

"CNSOPB" means the Canada-Nova Scotia Offshore Petroleum Board established under the *Accord Act* and the *Provincial Accord Act;*

"CO_2" means carbon dioxide;

"COF" means certificate of fitness;

"CR" means corporate responsibility;

"CRA" means corrosion resistant alloy;

"CSA" means concept safety analysis or Canadian Standards Association;

"CSP" means Construction Safety Plan;

"CSR" means a comprehensive study report contemplated by Section 21 of *CEAA;*

"Deep Panuke" and "Project" means the Deep Panuke Offshore Gas Development Project;

"D & A" means dry and abandoned (with no economic hydrocarbons found in the well);

"Development Plan Application" and "DPA" means an application filed by EnCana Corporation to the CNSOPB seeking approval for its development of the project;

"DPEMP" means Deep Panuke Emergency Management Plan;

"DST" means drill stem test;

"DSV" means diving support vessel;

"EA" means environmental assessment;

"EAV" means equivalent aquifer volume;

"ECM" means environmental compliance monitoring;

"EEM" means environmental effects monitoring;

"EEMP" means environmental effects monitoring plan;

"EHS" means environment, health and safety;

"EnCana" means EnCana Corporation, including the legacy company PanCanadian Petroleum Ltd.;

"EPP" means environmental protection plan;

"ESD" means emergency shut down;

"FEAC" means Federal Environmental Assessment Coordinator as that term is defined in CEAA;

"FEED" means front end engineering design;

"FMI" means Formation Micro-Imager™;

"Gas Show" means a small uneconomic gas flow on a drillstem test;

"GR" means gamma ray or gross revenue;

"GMI" means Geo-Mechanics International;

"GWC" means gas/water contact;

"HAZID/HAZOP" means a risk screening tool for hazard identification/hazard operations

"H_2S" means hydrogen sulphide;

"HDD" means horizontal directional drilling;

"HPRF" means high permeability reef front;

"IMT" means integrated management team;

"J" means function method – a preferred method for describing capillary pressure relationships;

"JT" means Joule-Thompson;

"JOSH" means Joint Occupational Health and Safety;

"KCl" means potassium chloride;

"km" means kilometer;

"KP" means kilometer point;

"LMR" means Lambda-Mu-Rho;

"LNG" means liquid natual gas;

"LP" means low pressure;

"LTBR" means long term Government of Canada bond rate;

"LWD" means logging while drilling;

"LWIV" means light well intervention vessels;

"m" means metre;

"MDT" means Modular Dynamic Tester™;

"Metocean" means meterological and oceanographic;

"M&NP" means Maritimes & Northeast Pipeline;

"MODU" means mobile offshore drilling unit;

"MOPU" means mobile offshore production unit;

“MR” means mid-reef;

“MWD” means measurement while drilling;

“NaCl” means sodium chloride;

“NEB” means National Energy Board;

“NEB Act” means *National Energy Board Act*;

“NN” means Neural Net technology;

“NPHI” means neutron porosity;

“NR” means net revenue royalty;

“O” means marker;

“OGIP” means original gas in place;

“P-impedance” means compressional wave impedance;

“PAV” means probabilistic aquifer volume;

“PEF” means photo-electric factor;

“PGM” means Project General Manager;

“Phi_{tot}” meanstotal porosity;

“PLT” means production logging tool;

“Mean” means the statistical mean value of a probability distribution;

“POB” means persons on board;

“ppm” means measurement in parts per million

“PSDM” means pre-stack depth migration;

“PSP” means Project Safety Plan;

“PSTM” means pre-stack time migration;

“P10” means value at the 10^{th} Percentile;

“P50” means value at the 50^{th} Percentile;

“P90” means value at the 90^{th} Percentile;

“RA” means return allowance;

"RAB" means resistivity at bit;

"RACI" means responsible-accountable-inform-communicate;

"Responsible Authority" or "RA" means responsible authority as that term is defined in *CEAA*;

"RF" means recovery factor;

"RFO" means ready for operations;

"RG III" means Rowan Gorilla III drilling rig;

"RG V" means Rowan Gorilla V drilling rig;

"RG VI" means Rowan Gorilla VI drilling rig;

"RGIP" means recoverable gas in place;

"RHOB" means bulk density;

"ROV" means remotely operated vehicle

"Rp" means compressional amplitude;

"Rs" means shear amplitude;

"S-impedance" means Shear wave impedance;

"SBM" means synthetic based mud;

"SCAL" means special core analysis;

"SCM" means subsea control module;

"SO_2" means sulphur dioxide;

"SOEP" means Sable Offshore Energy Project;

"SSIV" means subsea isolation valve;

"SSSV" means sub-surface safety valve;

"SW" means water saturation;

"Swi" means water saturation (initial);

"SWC" means side-wall core;

"tcf" means trillion cubic feet;

"TEG" means thiethylene glycol;

"Tight" means very low porosity and permeability;

"TLS" means target levels of safety;

"TQP" means training and qualifications practice;

"TS" means tight streak;

"TVD" means true vertical depth taken from the rig;

"TVDss" means true vertical depth taken from the sea level

"VL" means vuggy limestone;

"Vol_{Ds}" means volume of dolostone;

"WBM" means water based mud;

"WC" means whole core.

1 INTRODUCTION AND PROJECT OVERVIEW

1.1 Introduction

The Nova Scotia offshore has been the subject of exploration and study for the past five decades. Much of the recent interest in exploration activities in the Nova Scotia offshore is likely attributable to the development of the Sable Offshore Energy Project (the SOEP) and the Maritimes and Northeast Pipeline (M&NP) project, each of which began operations in 1999. SOEP was the first offshore natural gas development on the Scotian Shelf. M&NP provides open access natural gas transportation facilities to growing markets located in Canada and the northeastern United States.

Since 1996, when the regulatory applications for SOEP and the M&NP project were filed, there has been a total of 57 exploration, delineation, and development wells drilled in the Nova Scotia offshore.

In 1983 the Geological Survey of Canada, in the last published estimate of gas potential on the Scotian Shelf, estimated the total potential gas resources for the Scotian Shelf at 508 billion cubic metres. This equates to about 18 trillion cubic feet (tcf) while actual discovered gas on the Scotian Shelf is only 6 tcf. The undiscovered gas potential for the deepwater Scotian Shelf is estimated to be between 15 to 41 tcf, dependent on geological risk factors (Kidston *et al.* 2002).

EnCana Corporation (EnCana) is an active participant in the exploration activities in the Nova Scotia offshore. From June 1998 to January 2006, EnCana participated in 15 exploration and delineation wells, including the Deep Panuke discovery well, PP-3C.

Developments, such as SOEP and the Deep Panuke Offshore Gas Development Project (Deep Panuke Project, Project), in the Nova Scotia offshore have not only resulted in positive economic benefit for the Province of Nova Scotia, but have also allowed Nova Scotia's potential as a participant in the offshore oil and gas industry to be noticed on the world stage.

The proximity of the Nova Scotia offshore, now connected by the M&NP mainline to growing markets in Canada and the northeastern United States, creates an impetus for further developments, such as the Deep Panuke Project, offshore Nova Scotia.

While these circumstances are encouraging, it must be recognized that the Nova Scotian offshore oil and gas industry, with only one producing project at present, is in the early stages of development compared to other offshore areas around the world. The oil and gas industry is an internationally competitive industry, subject to the uncertainties and realities of the marketplace. The economics of each individual project determine when and where development takes place.

The development plan for the Deep Panuke Project is specifically described in this Volume 2 of the Development Plan Application (DPA). The Deep Panuke DPA also includes an assessment of the environmental (biophysical and socio-economic) impacts of the Project (Volume 4), a socio-economic impact statement (Volume 5) and a Canada-Nova Scotia Benefits Plan (Volume 3) describing various processes and procedures to promote Canada-Nova Scotia benefits associated with the Project. Volume 1 of this DPA is a Project Summary.

Simultaneous with the filing of this DPA, EnCana is also filing an application with the National Energy Board (NEB), pursuant to Section 52 of the *National Energy Board Act* (*NEB Act*).

EnCana filed a project description for the Deep Panuke Project on August 28, 2006 to initiate the *Federal Coordination Regulations* process under the *Canadian Environmental Assessment Act* (*CEAA*). The environmental assessment (EA) report is being filed under the *CEAA* process, the DPA process, and the NEB process.

1.2 Purpose and Scope of the Project

In 1996, EnCana became the operator of the Cohasset Project. While producing oil from the Cohasset Project, EnCana was also conducting exploration drilling in the area, which resulted in the drilling of the PP-3C discovery well in late 1998.

The PP-3C well encountered the fractured and porous Abenaki 5 formation, a portion of a larger carbonate reef structure. The PP-3C discovery well was followed by five successful delineation wells, PI-1B, H-08, M-79A, F-70, and D-41.

The six Deep Panuke wells have identified a natural gas reservoir containing recoverable sales gas estimated to be within a range of 11.0 x 10^9 m^3 [390 bcf] to 25.1 x 10^9 m^3 [892 bcf] with a Mean of 17.8 x 10^9 m^3 [632 bcf]. The Deep Panuke field centre is located approximately 176 km southeast of Goldboro, and 250 km southeast of Halifax, Nova Scotia where water depths are approximately 44 meters (m). The purpose of the Project is to maximize recovery of Deep Panuke natural gas resources in a manner that maximizes return to EnCana's shareholders at the same time as contributing to the economies of Nova Scotia and Canada through royalty and tax revenue and job and business opportunity creation.

Corollary benefits of the Project are the establishment of additional infrastructure and Project development skills to the benefit of the developing Nova Scotia gas industry. As a single project, the Deep Panuke Project does not constitute a natural gas industry in Nova Scotia; such an industry will only arise as further development projects occur. However, the Deep Panuke Project will contribute to the establishment of the skills, infrastructure and, by providing a second source of gas supply, assist in developing a sustainable natural gas industry in Nova Scotia.

1.3 Project Facilities

The Deep Panuke gas pool is located on the Scotian Shelf and encompasses natural gas located on, at the time of this filing, offshore licenses PL 2902 (Panuke), EL 2387 (Margaree), SDL 2255H (Deep Cohasset), PL 2901 (Cohasset), and EL 2360 (Lower Musquodoboit). Gas will be produced from the completion of four existing wells and one new production well feeding a central production facility sized for a peak sales gas throughput of 8.5 x 10^6 m^3/day [300 MMscfd], producing a Mean cumulative production total of 17.8 x 10^9 m^3 [632 bcf] over approximately 13 years.

Deep Panuke natural gas reservoir contains low volumes of associated gas liquids and approximately 0.18% hydrogen sulphide. The Mean volumes of condensate produced are small, approximately 163 m^3/d [1030 bpd] at a peak sales gas production of 8.5 x $10^6 m^3$/d [300 MMscfd]. Peak production will continue for a period of approximately two years, after which, production is expected to decline until production cut-off at 1.1 x $10^6 m^3$/d [40 MMscfd] sales gas.

The Project field centre is located approximately 250 km southeast of Halifax and about 47 km west of Sable Island. The Project consists of a jack-up mobile offshore production unit (MOPU) in water depths of approximately 44 m. The Project will initially include completing four previously drilled wells and drilling two new wells, one production well and one acid gas injection well. All wells will have horizontal trees and will be tied back individually to the MOPU with subsea flowlines and control umbilicals. Up to three additional subsea production wells could be drilled; such wells would be drilled after production start-up and at least one full year of production. They would also be completed with horizontal trees and tied back individually to the MOPU with subsea flowlines and control umbilicals. Figure 1.1 is the proposed field layout for the Deep Panuke Project.

The export system will consist of a single subsea pipeline delivering Deep Panuke sales product to one of two delivery points:

- Goldboro, Nova Scotia, to an interconnection with M&NP (herein referred to as the M&NP Option), or
- SOEP 660 mm [26 inch] export pipeline at a close point on the pipeline route to Goldboro (herein referred to as the SOEP Subsea Option).

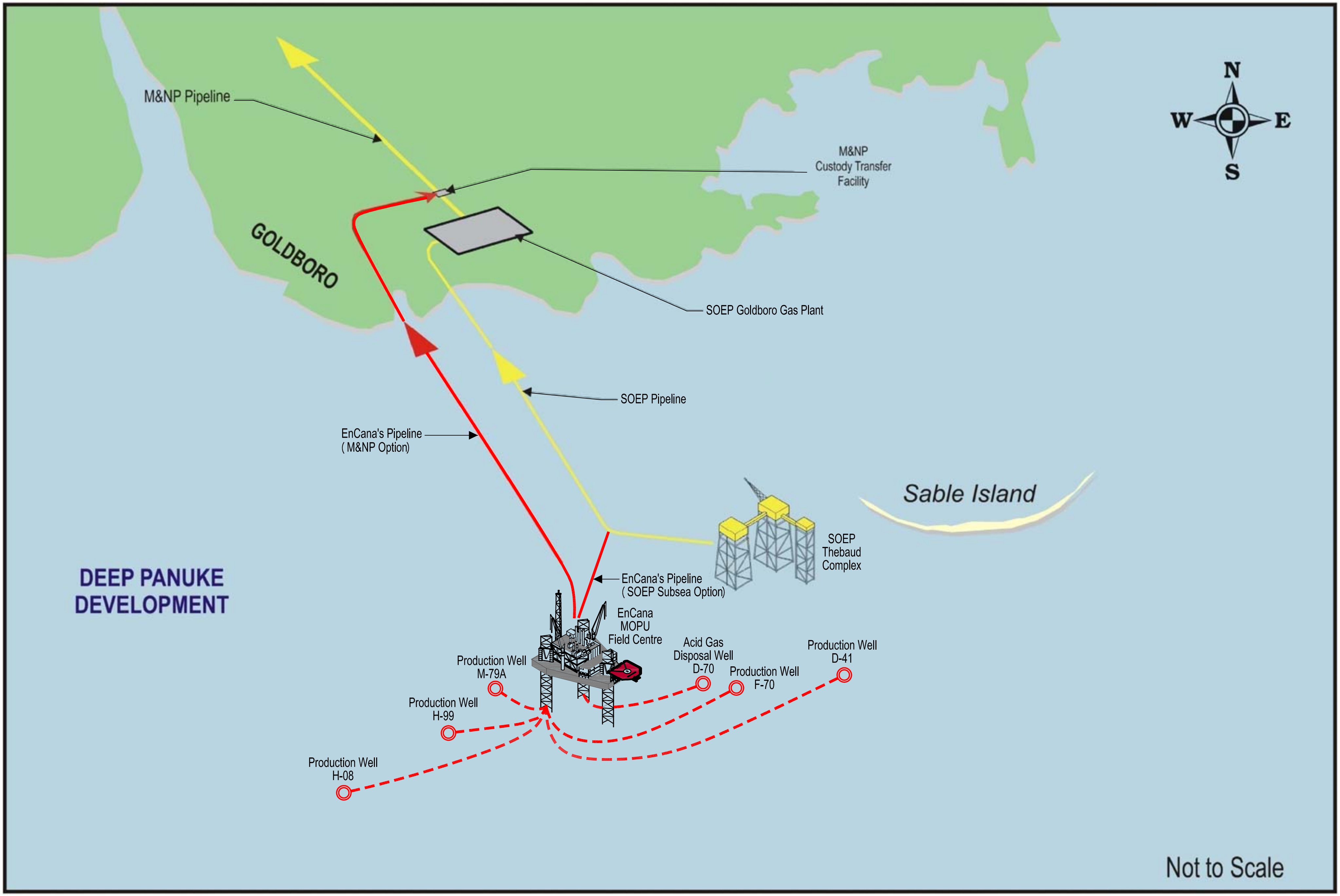


Figure 1.1 Proposed Field Layout

The export pipeline will be 176 km in length for the M&NP Option and 15 km in length for the SOEP Subsea Option.

The MOPU field centre will be designed, supplied and operated by a contractor under a lease arrangement with EnCana over the field production life. The MOPU will be constructed using a "standard" drill rig design without drilling equipment, but purpose built to accept a topsides production module. The MOPU hull will be outfitted in the optimal manner to minimize change to the standard drill rig design to allow flexibility and minimize cost if the hull was to be re-fitted as a drill rig after production shutdown of the Deep Panuke Project.

The hull will contain the standard drilling rig auxiliaries and services, including jacking systems, legs, deck, and accommodations, to provide a safe working platform to accept the topsides production module. The hull will provide accommodations for a minimum of 68 personnel on board (POB), a central control room, and non-hazardous utilities, which service the hull and can potentially be shared with the process module. Additionally, the MOPU facilities will include a helicopter deck with associated re-fuelling facilities. Some hull upgrades to the standard rig design will be required to meet the *Nova Scotia Offshore Petroleum Installations Regulations*, SOR/95-191.

The process module will be a purpose-built module containing all processing equipment needed to process Deep Panuke gas to sales specification. The main process equipment includes separation, sweetening, dehydration, dew-pointing, and inlet and export compression. In addition, condensate treatment, process utilities, produced water treatment, main power generation, and acid gas disposal equipment will also be located on the module.

For the M&NP Option, the produced condensate will be used as the primary fuel for the gas turbine drivers located on the MOPU to maximize sales gas. Drivers will be designed for tri-fuel operation, thus allowing for start-up and shutdown on diesel and operation on gas when condensate production is exhausted or not available.

For the SOEP Subsea Option, the condensate will be commingled with the export gas and routed to shore via the existing SOEP pipeline. The gas and condensate will be further processed at SOEP facilities near Goldboro and in Point Tupper, as necessary. The gas turbine drivers located on the MOPU will use fuel gas primarily with diesel for start up and shutdown only when fuel gas is not available.

A flare will be designed and welded out to the hull to provide for high and low pressure flare systems. The production unit will be installed onto the hull and commissioned atshore and then towed to the field centre to minimize offshore hook-up, commissioning and start-up.

Each well will be tied back individually to the MOPU via single flowlines connected to a wet production tree. Flowlines will be constructed of corrosion resistant alloy (CRA) materials to suit the wet, sour corrosive wellbore fluids. Flowlines will be insulated, trenched and then buried. Each wellhead will also be serviced with a dedicated umbilical to carry control functions, chemical injection lines and instrumentation signals to and from the MOPU. Umbilicals will be laid in a separate trench and buried. Subsea wellheads and production trees will be protected by a subsea protection structure.

For the M&NP Option, the pipeline carrying the sales gas to shore will be a 560 mm [22 inch] diameter carbon steel line which will be coated for weight and corrosion protection. The line will be buried for stability and physical protection over approximately 50% of the route to shore. A subsea isolation valve (SSIV) assembly will be located approximately 150 m from the MOPU. Burial will predominately be in areas where the water depth is less than 85 m. The pipeline route will follow the same corridor as the existing SOEP pipeline and come ashore near Goldboro, Nova Scotia. The onshore pipeline will be approximately 2-4 km in length with an onshore metering station before the tie in point to the M&NP pipeline.

The onshore facility for the M&NP Option will consist of the physical components necessary for interconnection of the Deep Panuke pipeline with M&NP's facility. The exact onshore facility site has not yet been determined but will be located in the Goldboro Industrial Park in Nova Scotia. The facility will include a pig launcher/receiver facility and a safety/emergency shutdown valve system. The area of the onshore facility is estimated to be 60 m x 45 m and will be enclosed by a security fence. Depending upon the final location of the metering station, an access road to the metering station may be required. The total length of the export pipeline will be 176 km for the M&NP Option.

For the SOEP option, a 510 mm [20 inch] diameter export line will be constructed to connect the Deep Panuke facilities to the existing SOEP offshore pipeline. The new pipeline will be a two phase pipeline, approximately 15 km in length and will tie into the SOEP offshore pipeline by means of a "hot tap" connection. The new export pipeline will be fitted with a SSIV assembly near the platform (similar to the M&NP Option) and will also be fitted with a manual isolation valve and subsea pig receiving facilities to allow for periodic pigging of the pipeline for inspection and maintenance.

Safety and loss management will be a major part of the Deep Panuke Project. The facilities will be designed to meet all the anticipated hazards identified through scenario based design methods and in addition, equipment and infrastructure will be designed to meet EnCana target levels of safety and environmental emission goals. Special systems will be added to reduce the risk of H_2S gas exposure to personnel.

1.4 Project Principles

Project success depends upon Project economics, the quality of output, and the efficiency of operation in a very competitive world energy market. In particular, the basic principle for the development and operation of the Deep Panuke Project is that it must be internationally competitive as it operates in a dynamic, market-driven environment.

Along with Project economics, other important principles, such as safety and environmental performance, also guide the Project's development team.

Also crucial to the success of the Project are open and ethical business practices. Open and ethical business practices include working to the highest professional standards, placing top priority on safety and quality and ensuring that staff, employees and contractors are treated in a fair and equitable manner. The Deep Panuke Project Management Principles are more particularly described in the Canada-Nova Scotia Benefits Plan (DPA Volume 3).

The principles that will guide EnCana in the development of the Deep Panuke Project are described in Table 1.1.

Table 1.1 Deep Panuke Project Principles

GUIDING PRINCIPLE

The Project operates in a dynamic, market-driven environment and must be internationally competitive.

ENVIRONMENT, HEALTH & SAFETY

The Project is fully committed to protecting the health and safety of all individuals affected by their work, as well as the environment in which they live and operate. Specifically, the Project will be guided by the following principles, which outline EnCana's Environmental, Health, and Safety (EHS) commitments under EnCana's Corporate Responsibility Policy.

- *We protect the health and safety of all individuals affected by our activities;*
- *We provide a safe and healthy working environment and expect our workforce to comply with the health and safety practices established for their protection;*
- *We safeguard the environment and contribute to the well being of the communities in which we live and operate;*
- *We maintain EnCana's commitment to clear, honest and respectful dialogue with stakeholders;*
- *We strive to make efficient use of resources, minimize our environment footprint, and conserve habitat diversity and the plant and animal populations that may be affected by our operations;*
- *We strive to reduce our emissions intensity and increase our energy efficiency;*
- *We integrate Environment, Health and Safety Best Practices, EnCana's EH&S Management System, into all parts of our business;*
- *We comply with applicable laws, regulations, and industry standards;*
- *We identify, assess and manage EH&S risks throughout our business;*
- *We ensure each employee, contractor and third-party service provider understands their EH&S responsibilities, is trained to meet them, and is monitored for compliance; and*
- *We establish EH&S objectives, regularly measure our progress, and strive to continually improve our EH&S performance.*

DEVELOPMENT PRINCIPLES

- The Project will be competitive with other investment opportunities available to EnCana.
- Our Project will serve natural gas customers on a competitive basis, on reasonable terms and conditions.

CANADA-NOVA SCOTIA BENEFITS

The Project will provide full and fair opportunity for Nova Scotians and Canadians to participate in the supply of goods and services to the Project on a "best value" basis.

- Goods and services will be procured through competitive tender.
- The bidding process will be open and fair.
- Best value is a blend of total cost, quality, technical suitability, reliability, delivery and assurance of supply, while at the same time meeting or exceeding safety and environmental standards.
- We will encourage the development of long-term industrial support for the Project in Nova Scotia and Canada through consultation and communication.

PROJECT MANAGEMENT

Safety and quality are the fundamental values that define the Project's Management Philosophy.

- The Project's management structure will operate to ensure quality and safety, while maintaining cost control and schedule requirements.
- The Project will fully comply with all appropriate regulatory standards and industry codes.

New technology will be embraced where an analysis indicates that such use is prudent and does not create undue risk for the Project.

1.5 Development Approach

This Development Plan (DPA Volume 2) has been refined based on the advice of various disciplines. Building upon the best efforts of the multi-disciplinary team assembled to develop the Deep Panuke Project, the Development Plan (DPA Volume 2) provides flexibility so as to allow the Project to respond to the challenges of an offshore development.

The Deep Panuke Project contracting strategy proposes an integrated management team (IMT) providing various levels of support and expertise to effectively manage all internal and external stakeholder interfaces with a focus on effective change management, risk mitigation, and timely delivery of the Project within established cost parameters as per Figure 1.2.

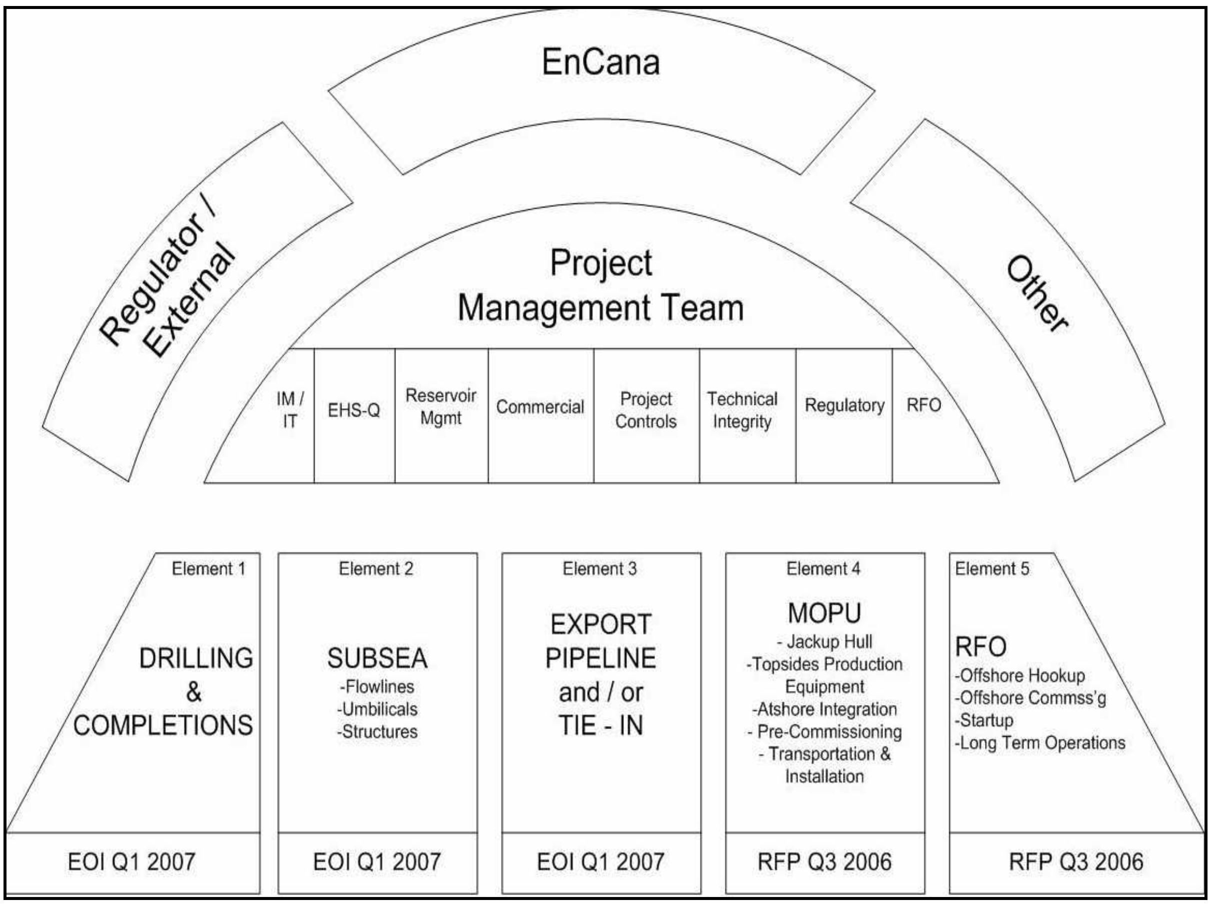


Figure 1.2 Deep Panuke Project Elements

The organization will be designed to integrate five major contract elements of the development, as follows:

1. drilling and completions;
2. subsea flowlines, umbilicals and structures;
3. export pipeline;
4. provision of a leased MOPU; and
5. ready for operations (RFO) support and long term logistics and operations.

Where possible, key personnel from within the major contractors and supplier organizations will be incorporated into the IMT to enhance communication, interface management and alignment.

EnCana will not consider full sanction to the Project until the conclusion of the bid competition phase and after regulatory approvals are received.

During the concept development and front end engineering and design (FEED) stages, several potential development alternatives were analyzed. As a result of this analysis, the production and transportation systems described in this Development Plan (DPA Volume 2) are the most technically and economically feasible means of developing the Project in a safe and environmentally responsible manner. The evaluation of development alternatives is described in Section 4 of this Development Plan (DPA Volume 2).

1.6 Project Timing

The Project's three main phases are the Development Phase, the Production Phase, and the Decommissioning Phase. The Development Phase consists of the following activities:

- definition – MOPU bid competition and regulatory application;
- engineering;
- procurement;
- well construction;
- facilities construction; and
- facilities commissioning.

The Project is currently in the MOPU bid competition and regulatory application phase.

The Production Phase will consist of gas production and processing and, as required, further drilling and well workovers.

Currently, the Development Phase is expected to continue until 2010. Following the commissioning of the Project facilities, the Project life of the Production Phase is expected to be in the range of 8 to 17.5 years with the mean case of approximately 13 years. It is important to note that the Project facilities have a design life of 25 years, with the exception of the topsides which have a design life of 20 years. With proper maintenance, Project facilities can be available to other projects including subsequent discoveries within the Panuke area.

Project timing may be adjusted to account for market conditions or other developments that may occur over the life of the Project and/or Project facilities.

Figure 1.3 provides a detailed breakdown of the Development Phase schedule for the Project.

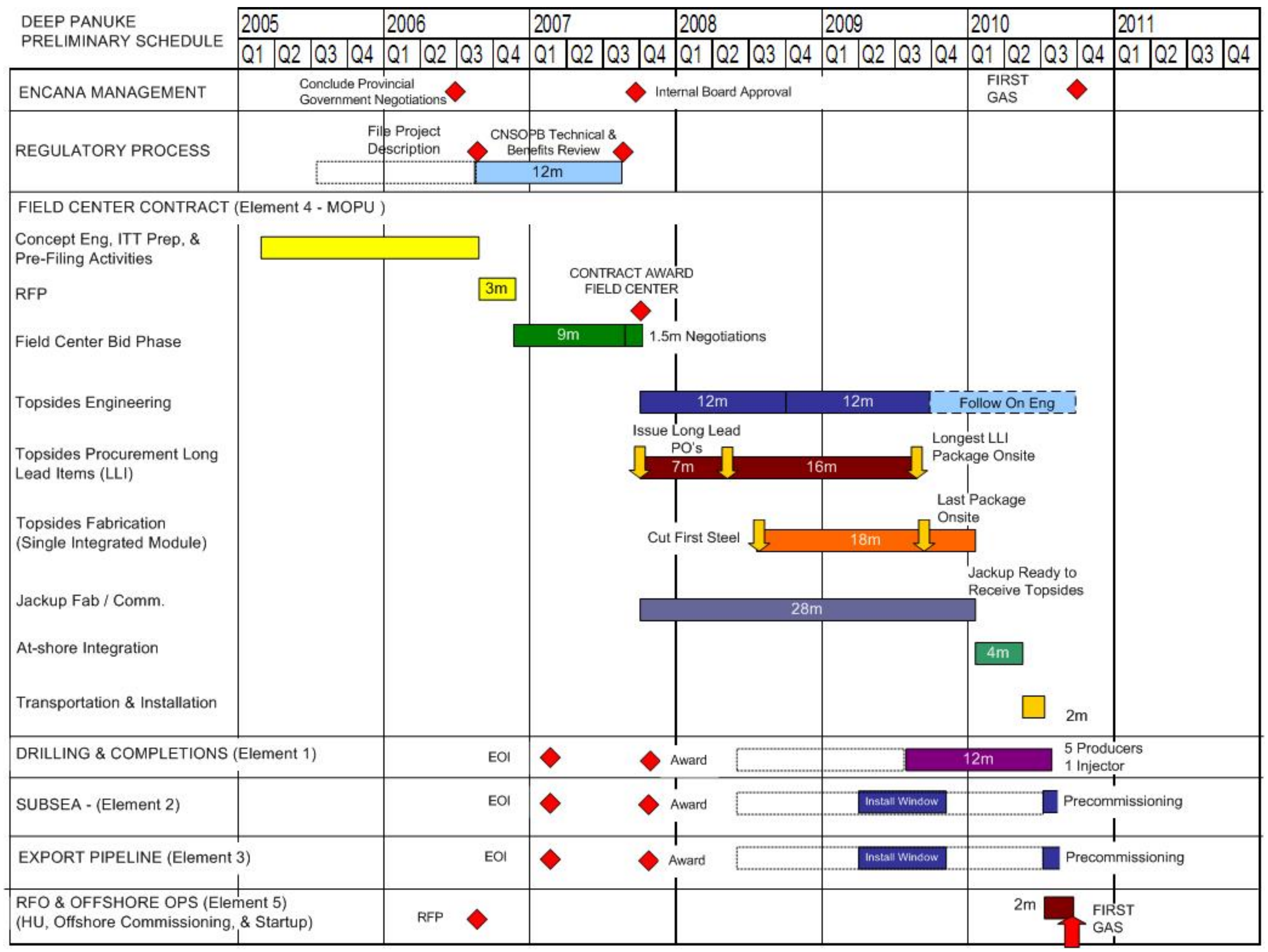


Figure 1.3 Preliminary Master Schedule

1.7 Regulatory Overview

The Deep Panuke Project involves three separate regulatory processes and requires that four major approvals be issued. The three separate regulatory processes are as follows:

- Comprehensive Study Process (CEAA Process);
- Development Plan Application (DPA) Process (CNSOPB Process); and
- National Energy Board (NEB) Process.

The CEAA Process pertains to the environmental assessment of the Project. The CNSOPB Process pertains to the offshore aspects of development, including the offshore pipeline. The NEB Process pertains to the entire transmission pipeline from interconnect with the MOPU to interconnect with downstream facilities.

The major approvals that must be obtained through the three regulatory processes listed above are as follows:

- A determination by the Federal Minister of the Environment that the Project is unlikely to have significant adverse environmental effects (outcome of CEAA Process);
- CNSOPB approval of the Benefits Plan for the Project;
- CNSOPB approval of the Development Plan for the Project; and
- NEB approval of the pipeline application for the Project.

Proposed production installations and development drilling for offshore oil and gas are subject to environmental assessment (EA) under *CEAA*. The CNSOPB and NEB have a mandate for environmental protection and are Responsible Authorities (RAs) under *CEAA*. The Canadian Environmental Assessment Agency is the Federal Environmental Assessment Coordinator (FEAC) and, together with the CNSOPB, will lead the environmental assessment process for the Project.

Application of the *Federal Coordination Regulations* process under *CEAA* requires federal departments with decision making responsibility under CEAA, (that is, RAs), or expert knowledge to declare their interest in the project. The expected RAs for this project and respective *CEAA* "triggers" include:

- CNSOPB (approval of a development plan, under Section 143(4)(a) and authorization under Section 142(1)(b) of the *Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act (*the *Accord Act)*, referred to as item 1.2 in Schedule I, Part I of the *Law List Regulations*);
- Fisheries and Oceans Canada (authorizations under Sections 32, 35 and 37 of the *Fisheries Act*, referred to as item 6 in Schedule I, Part I of the Law List Regulations);

- Environment Canada (Disposal at Sea permit under paragraph 127(1) of the *Canadian Environmental Protection Act*, referred to as item 3 in Schedule I, Part I of the Law List Regulations);
- Transport Canada (paragraph 5(1) of the *Navigable Waters Protection Act*, referred to as item 11 in Schedule I, Part I of the Law List Regulations);
- Industry Canada (paragraph 5(1)(f) of the *Radio Communication Act*, referred to as item 13 in Schedule I, Part I of the Law List Regulations); and
- National Energy Board (Certificate under Section 52 or Section 58 authorization of the *National Energy Board Act* related to the pipelines, referred to as item 7 in Schedule II of the *Law List Regulations*).

The CNSOPB requires an environmental impact statement (EIS) as a condition of its approval process. The NEB requires an EA as a condition of its approval process. Based on pre-filing consultation with the regulators, EnCana's *CEAA* EA Report (DPA Volume 4) will also form the EIS requirement of the regulatory applications with the CNSOPB and the EA of the NEB application.

In 2002, EnCana conducted an EA in the form of a comprehensive study under *CEAA*. EnCana submitted a CSR and received Ministerial approval in December 2002. In February 2003, EnCana requested a regulatory time-out to allow further evaluation of the Deep Panuke Project. In December 2003, EnCana withdrew the regulatory applications with the CNSOPB and the NEB to allow further review and refinement of the Project.

Between 2003 and 2006, EnCana re-evaluated the reservoir and facilities to determine the optimum project basis. As part of pre-filing consultation with the regulators, the FEAC and expected RAs put together a draft work plan for the Deep Panuke Project in order to guide the regulatory review process. The draft work plan indicated that the assessment would be a new comprehensive study, but that it would solely address the modifications between the Project basis of the approved 2002 CSR and the revised Project basis.

The NEB regulates international and interprovincial aspects of oil, gas and electric utility industries under the NEB Act. To determine whether a pipeline project should proceed, the Board must be satisfied that the proposed facilities are required by the present and future public convenience and necessity in the form of a Certificate Application filed by the proponent. The Environmental Assessment Report will also be included as a part of the NEB application.

The Deep Panuke Project also involves several supplemental approvals. These supplemental approvals will depend on the final Project design but may include an approval from Transport Canada related to navigable waters, for example. These supplemental approvals will be addressed as a part of regulatory compliance monitoring during the execution of the Project.

In addition, CNSOPB Work Authorizations will be required in order to install, construct and hook-up the offshore facilities. A CNSOPB work authorization will also be required for the drilling program. After a Drilling Program Authorization is issued, each well within the drilling program must also be approved through a CNSOPB's Approval to Drill a Well or Approval to Alter the Condition of a Well (for re-entries). A CNSOPB Production Operations Authorization is also required in order to start-up and operate the offshore facilities. An NEB operating permit will also be required.

2 SUBSURFACE

The Deep Panuke pool will produce natural gas from a porous and permeable carbonate reservoir located about 3500 m below the seafloor in the area of the decommissioned Cohasset Project.

Preparing the subsurface portion of the Deep Panuke Project involved careful integration of all available subsurface information to achieve the best possible understanding of the pool and to minimize uncertainty. Nevertheless, the limited number of wells drilled into the pool and the relatively complex nature of the reservoir leave remaining uncertainties. Therefore, a probabilistic approach has been employed in quantifying the volume of gas present in the pool, the volume which is recoverable and forecasting production from the pool.

To summarize the subsurface methodologies and approach applied to the pool, a simplified Subsurface Development Planning Workflow is presented in Figure 2.1. The workflow begins with the application of Basic Data from wells and seismic data to create a detailed Reservoir Description. Analyses and interpretations of pool geology, petrophysics, geophysics, fluid and pressure studies are combined into a three-dimensional computer model of the pool, termed the "Earth Model", from which many deterministic estimates of Original Gas in Place (OGIP) are calculated. Dynamic reservoir simulation was next used to ensure that the "Earth Model" is consistent with well test behavior and to predict key reservoir performance parameters (e.g. gas recovery factor) leading to estimates of the range of Recoverable Gas is Place (RGIP).

The Earth Model and the reservoir simulation model act as focal points for the subsurface reservoir description and dynamic reservoir behavior predictions. Subsequently, OGIP, Aquifer Size and Transmissibility, Recovery Factors, Life after Plateau and RGIP are key uncertainties addressed using Probabilistic Resource Modelling via Monte Carlo simulation. Based on the resource estimates, the recommended pool Development Strategy and Plan is formulated.

Many of the steps in the Subsurface Development Planning Workflow are iterative. The remainder of this section describes the final products actually used in creating the proposed Development Plan.

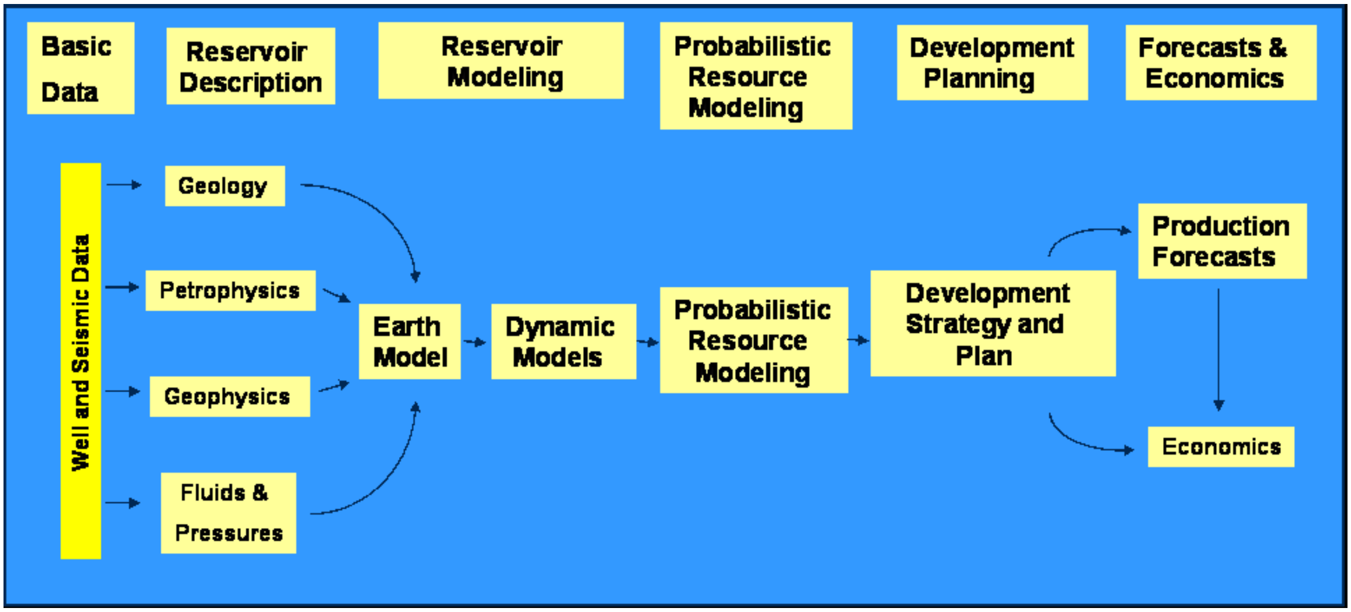


Figure 2.1: Subsurface Integrated Development Planning Workflow (Simplified)

2.1 Geology

The Deep Panuke natural gas pool occurs along the margin of the Abenaki Formation carbonate platform which formed along the East Coast of North America during the opening of the Atlantic Ocean in the Middle to Late Jurassic, approximately 170 to 128 million years ago. The reservoir is made up of porous limestone and dolomite. The natural gas pool is formed in a combined structural/stratigraphic trap, with structural closure to the northeast and southwest, and stratigraphic closure updip into tight carbonate platform interior sediments to the northwest. The carbonate platform thins and plunges to the southeast. The pool is located about 250 kilometers (km) offshore southeast of Halifax, Nova Scotia. General characteristics of the Abenaki gas play are summarized in Part 2 (DPA-Part 2, Ref # 2.1).

The general location of the pool is shown in Figure 2.2

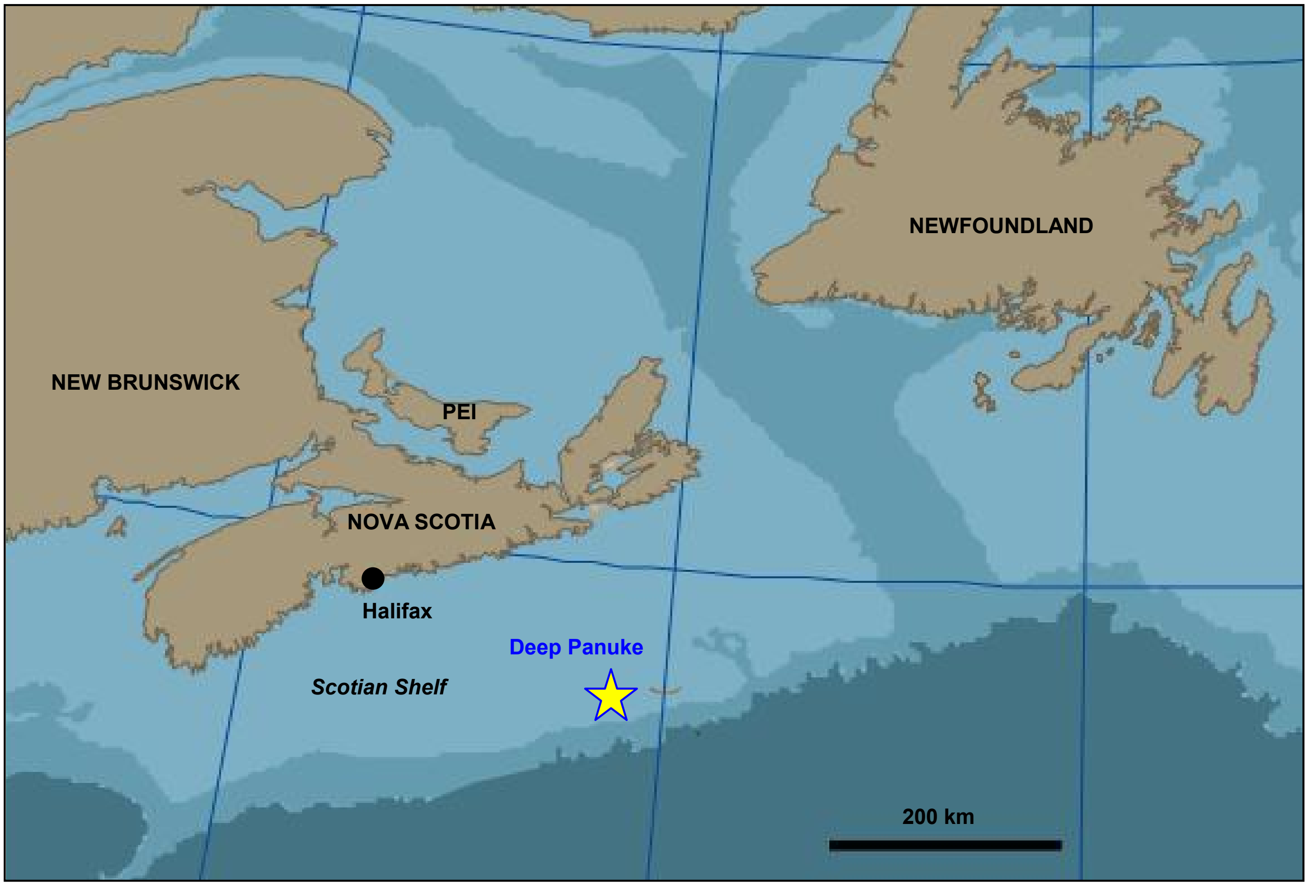


Figure 2.2: Location of the Deep Panuke Pool

2.1.1 Deep Panuke Regional Setting

The Scotian Shelf is part of the continental margin of eastern North America. The shelf extends from the Laurentian Channel in the east to the Northeast Channel in the west. The Deep Panuke gas field is located about 40 km southwest of Sable Island. The physiographic location of the Scotian Shelf is shown in Figure 2.3.

The regional geology of the Scotian Shelf has been reviewed in detail by several authors. Key references with regard to the regional geology of the Scotian Shelf are provided in Part 2 (DPA-Part 2, Ref # 2.2, 2.3, 2.4, 2.5 and 2.6).

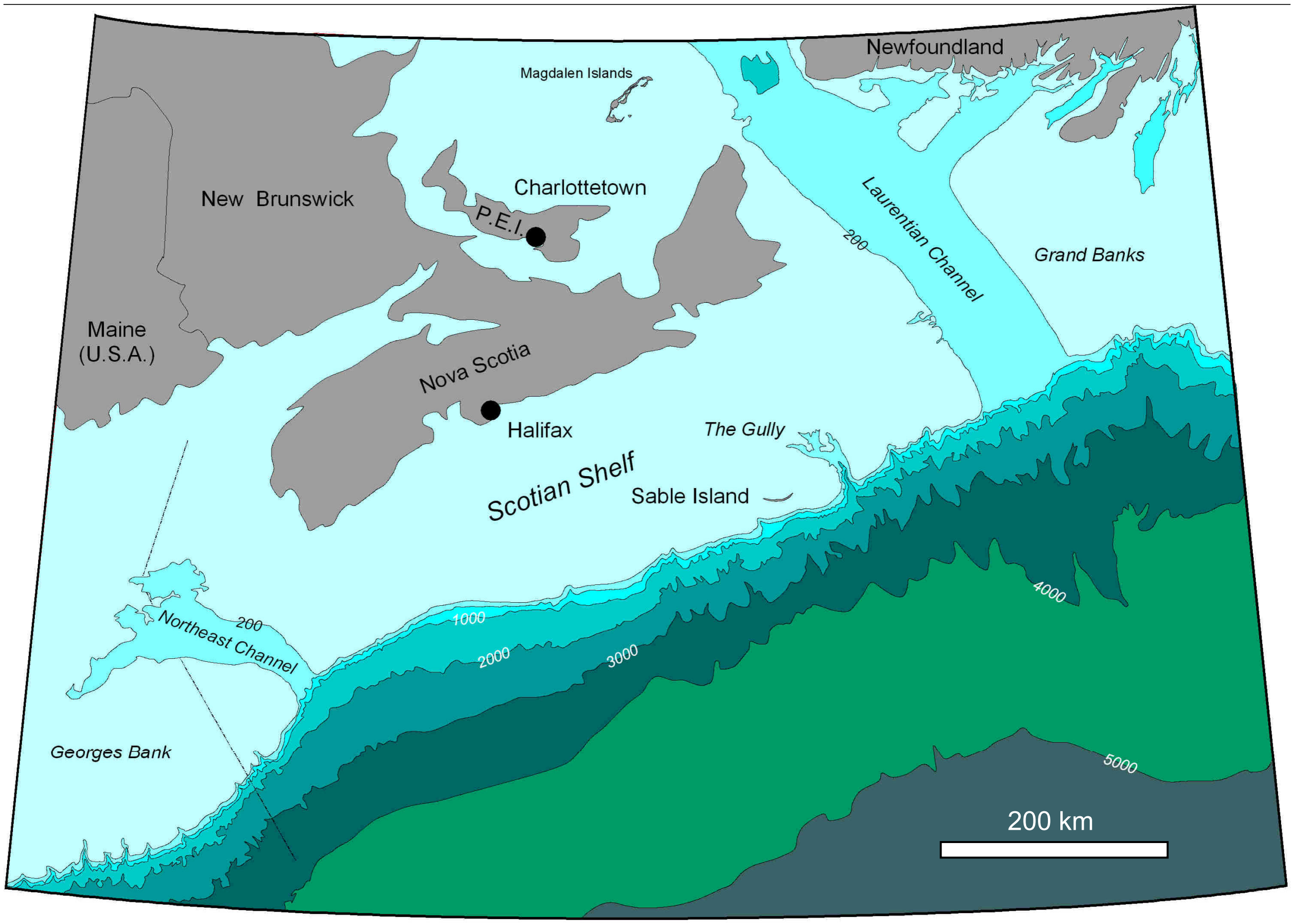


Figure 2.3: Physiography of the Scotian Shelf

2.1.1.1 Regional Structure

The Scotian Shelf is underlain by attenuated, rifted, continental basement. The basement is composed of plutonic Devonian granite and Late Precambrian to Ordovician metasediments. The Scotian Shelf began rifting in response to the separation of Africa in the late Triassic and extensional faulting was complete by the early Jurassic. This process created a network of basement ridges and basins. The Abenaki carbonate margin often overlies the outer edge of the basement ridges. The Deep Panuke gas pool overlies part of the Moheida ridge feature. The leading edge of the carbonate platform appears to have been controlled by a combination of syn-depositional listric faulting, clastic sediment influx and a break in slope produced by the underlying basement structure (DPA-Part 2, Ref # 2.2). Diagenesis may have been localized by reactivated wrench faulting along the underlying basement faults. One phase of this reactivation may have coincided with the separation of the Grand Banks and Iberia at the end of the Jurassic (DPA-Part 2, Ref # 2.3). The tectonic elements of the Scotian Shelf are illustrated in Figure 2.4.

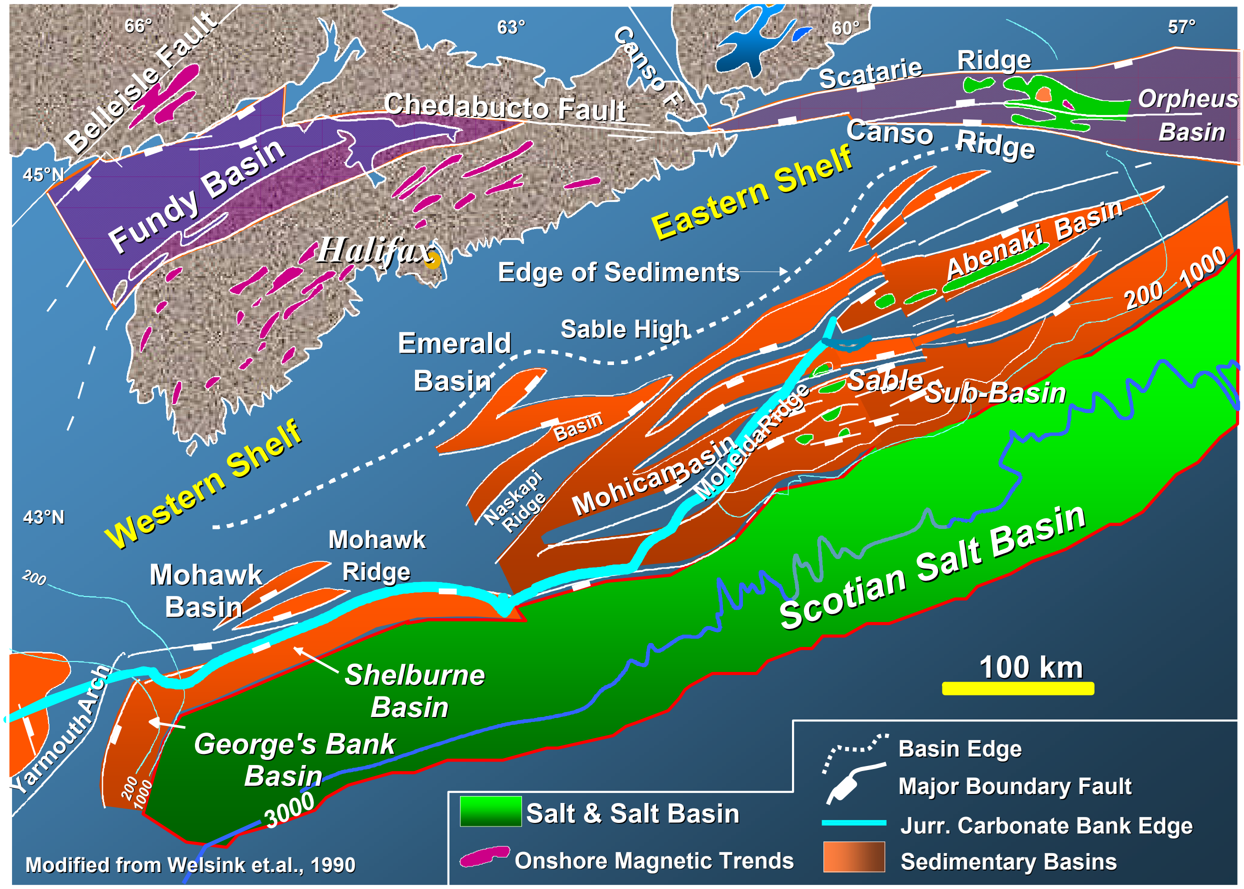


Figure 2.4: Tectonic Elements of the Scotian Shelf

2.1.1.2 Regional and Abenaki Formation Stratigraphy

The Abenaki Formation which hosts the Deep Panuke gas pool was deposited from Middle to Late Jurassic time as part of the post-rift basin fill succession, as illustrated in Figure 2.5.

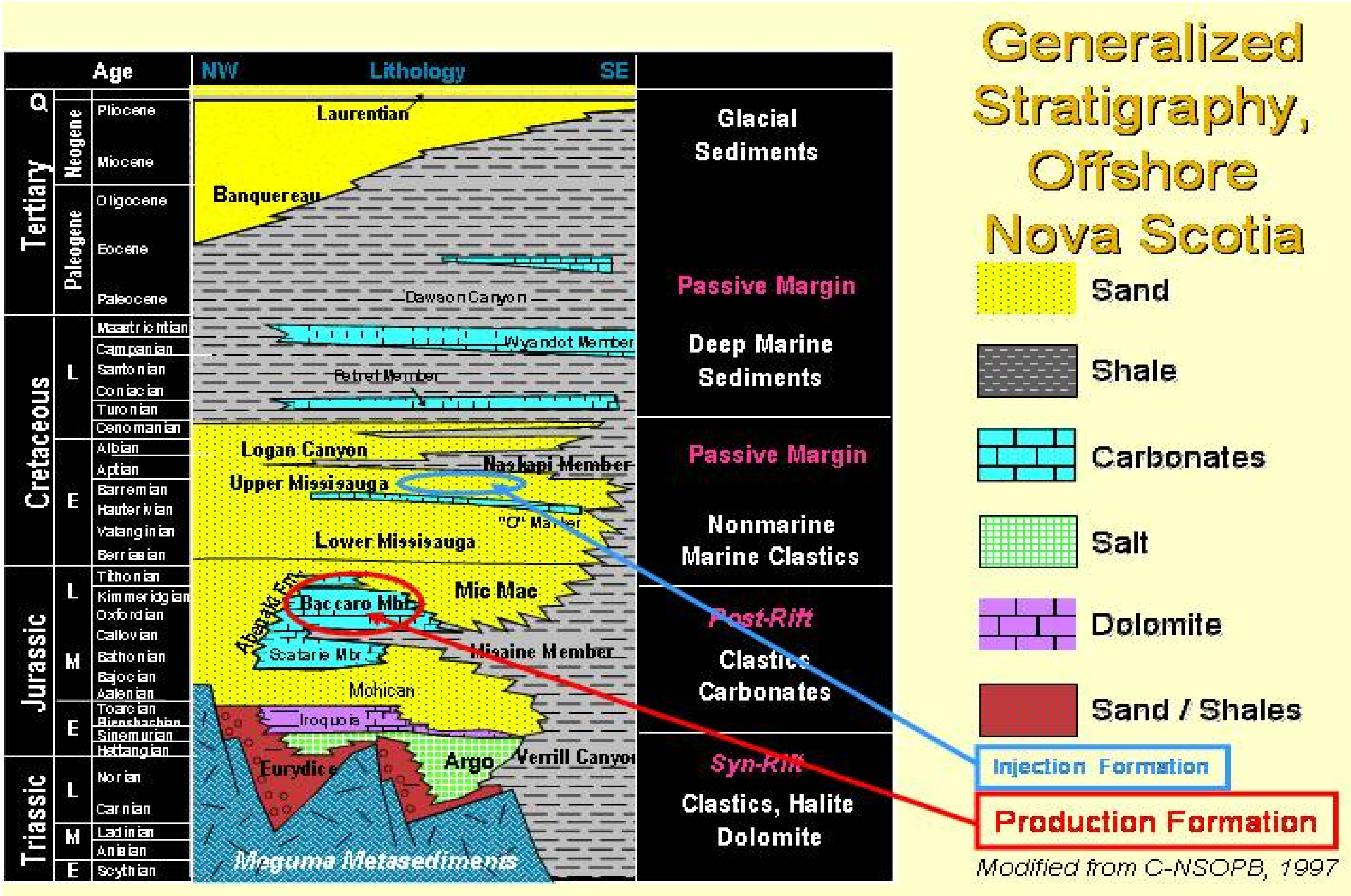


Figure 2.5: Generalized Stratigraphy, Offshore Nova Scotia

The Abenaki Formation is formally subdivided into four members. The Scatarie Member (Abenaki 1) at the base of the formation marks the onset of widespread, shallow marine carbonate deposition across the Scotian Shelf and is overlain in the Deep Panuke area by a 100 m thick succession of open marine shales of the Misaine Member. The Baccaro Member of the Abenaki Formation is an 1,100 m thick carbonate margin succession of limestones, dolomites and minor clastics. The Artimon Member caps the Abenaki Formation. Seaward of the margin carbonates, deeper marine equivalents comprise a portion of the Verrill Canyon Formation shales.

The Abenaki Formation is overlain by clastics of the lower Mississauga Formation, or Mic Mac Formation clastics at the northeast end of the carbonate platform. The DPA includes provision for the disposal of waste acid gas by injection into upper Mississauga Formation sandstones.

2.1.1.3 Baccaro Member Stratigraphy

The Abenaki Formation along the Deep Panuke platform margin is divided into seven depositional cycles based on well correlations, facies stacking patterns and seismic markers (DPA-Part 2, Ref # 2.4), as shown in Figure 2.6.

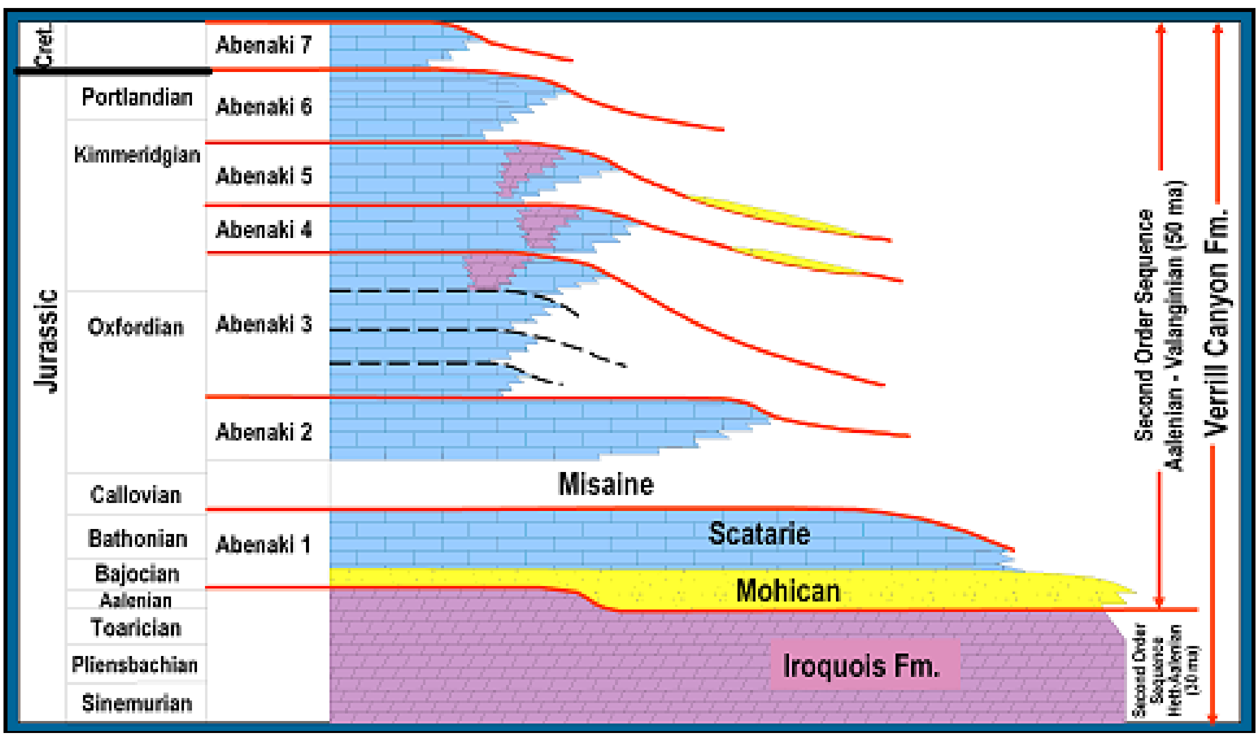


Figure 2.6: Abenaki Formation Stratigraphic Framework

The Baccaro Member of the Abenaki Formation is comprised of the depositional sequences informally referred to as Abenaki 2, 3, 4, 5, and 6, each bounded by a sequence boundary. This succession is overlain by the Artimon Member, herein referred to as Abenaki 7. The Abenaki 2 sequence overlies and is co-eval in part with Misaine Member shales. The top of the Abenaki 2 sequence is marked by a major marine flooding event which pushed the platform margin significantly landward, followed during Abenaki 3 and 4 time by a series of depositional cycles in an overall progradational sequence stacking pattern.

The Abenaki 5 sequence represents the culmination of platform development, with the Abenaki 6 and 7 cycles dominated by foreslope facies deposited during the drowning of the platform. Gas is trapped primarily in porous dolostones and limestones within the Abenaki 4 and Abenaki 5 cycles, with the potential for significant gas reserves in the Abenaki 6 (though this is currently unproven). Syn-depositional faulting appears to have occurred mainly during Abenaki 4 and 5 time. Top seal for the reservoir is non-porous limestones of the Abenaki 6 and 7 cycles. The Abenaki carbonate platform was drowned in the early Cretaceous and buried by clastics of the lower Missisauga Formation.

The carbonate margin at Deep Panuke has been sculpted by syndepositional faulting and gravitational collapse during deposition. The preserved margin area is made up of shallow-to-deeper water coral and stromatoporoid patch reefs and inter-reef and foreslope sediments while the stable carbonate shelf immediately behind it is dominated by shallow water oolitic shoals. The deeper foreslope area is dominated by coral-sponge to sponge reefs, debris flows, and thrombolitic mudstones.

2.1.2 Pool Discovery and Delineation History

The location of wells relevant to the history of the Deep Panuke pool is shown in Figure 2.7. This map excludes many shallow penetrations related to the overlying Panuke and Cohasset oil pools.

Drilling in the immediate vicinity of the Deep Panuke pool began in 1973 with the Mobil-Tetco Cohasset D-42 vertical well which was drilled to 4427 m total depth in the Misaine Member of the Abenaki Formation. This well was drilled to test for the presence of hydrocarbons within the Abenaki Formation. Limestones and minor dolomites were encountered in the Abenaki 5 but were of poor reservoir quality. Although unsuccessful in the Abenaki Formation, this first "near-miss" well is part of the spectrum of reservoir quality variations within the Deep Panuke pool. Low quality, gas-filled porosity is present, even though the gas would not flow on a drill-stem test. D-42 is therefore considered to be within the Deep Panuke gas pool, but cannot be recognized as the pool discovery well.

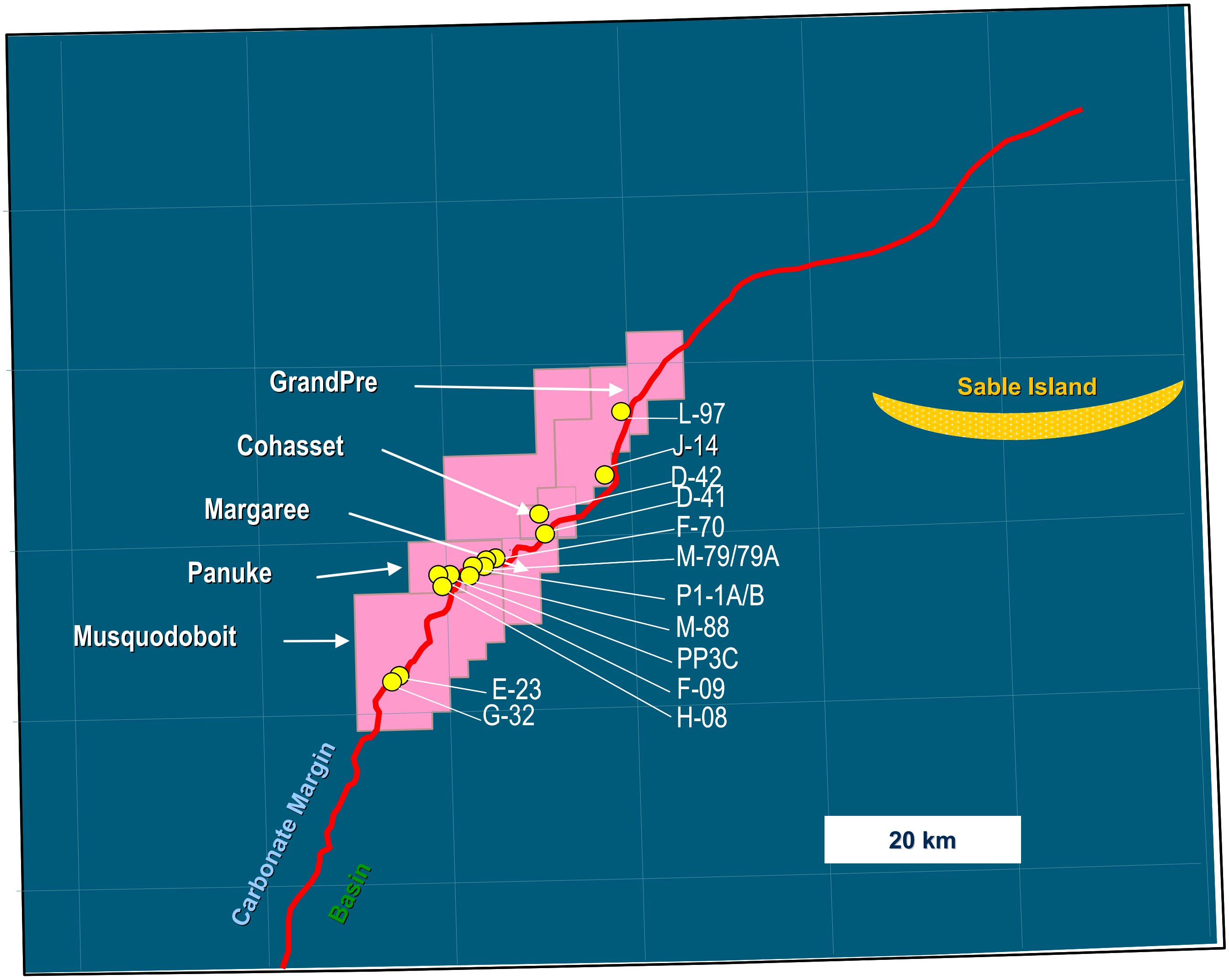


Figure 2.7: Well Location Map, Deep Panuke Area

The D-42 well found light oil up-hole in younger Mississauga and Logan Canyon Formation (Cree Member) sandstones and is the discovery well for the shallow Cohasset oil field. Subsequently, numerous development and delineation wells were drilled into and adjacent to the Cohasset oil field but none of those wells were deepened to the Abenaki Formation. The Cohasset oil field began producing oil in 1993 and achieved cumulative oil production of 4.5 million cubic meters [28.3 million barrels] of oil by December, 1999. The oil field ceased production at that time and the wells have been subsequently abandoned.

In 1978, the Mobil-Tetco PEX Cohasset L-97 vertical well was drilled along the Abenaki Fm. carbonate margin and continued drilling deeper to a total depth of 4872 m in the Iroquois Formation. A gas show was encountered in the Abenaki carbonates but the well was abandoned.

In 1986, the Shell PCI et al Panuke B-90 well was drilled to 3445 m total depth in the upper part of the Abenaki 5 zone. The primary target for this well was oil in the Mississauga and Logan Canyon Formations, following up on previous success nearby at Cohasset field, with the Abenaki Formation as a secondary target.

The B-90 well is not considered as a Deep Panuke pool delimiting well since no porous reservoir was drilled and the well penetrated only the upper part of the Abenaki 5 zone. The B-90 well discovered oil in upper Mississauga Formation sandstones (informally designated as the Panuke sandstones) and is the discovery well for the shallow Panuke oil pool. Oil production at Panuke began in 1992, achieving cumulative oil production of 2.56 million cubic meters (16.2 million barrels) of oil by December, 1999. The oil field ceased production at that time and the wells have since been abandoned.

Numerous Panuke oil production wells have been drilled into the Mississauga Formation but none penetrated to the Abenaki Formation until just 18 months before the Panuke oil pool ceased production.

EnCana involvement in the Panuke area began in 1996 when it purchased LASMO PLC's 50% working interest in the Cohasset Project. Seismic data and well control indicated that a structural high was present along the Abenaki Formation carbonate margin which also exhibited seismic amplitude anomalies indicative of porosity. On July 17, 1998, EnCana, in partnership with Nova Scotia Resources Ltd., spudded the Panuke PP-3C well from the Panuke oil production platform to test for hydrocarbons in the deeper horizon.

2.1.2.1 Deep Panuke Discovery and Delineation Drilling

The Panuke PP-3C well is the discovery well for the Deep Panuke gas pool. The pool has subsequently been delineated by other gas-bearing wells. Table 2.1 is a listing of the Deep Panuke pool wells, including the non-commercial D-42 well and F-09 wells. Five of the pool wells have been production tested at exceptional flow rates of greater than 1.4 x 10^6 m^3/d [50 MMscfd] with rates limited by the testing equipment.

Table 2.1: Listing of Deep Panuke Pool Wells				
Well Name	**Operator**	**Rig Release**	**Status**	**Flow Rate 10^6 m3/d (MMscfd/)**
Cohasset D-42	Mobil-Tetco	16-Jul-1973	D & A	Dst mud
Panuke PP3-C	EnCana	12-Apr-1999	Gas	1.6 (55)
Panuke PI-1A/B	EnCana	19-Feb-2000	Gas	1.5 (52)
Panuke H-08	EnCana	20-Aug-2000	Gas	1.6 (57)
Panuke F-09	EnCana	11-Nov-2000	D & A	0.003 (0.1)
Panuke M-79/A	EnCana	18-Dec-2000	Gas	1.8 (63)
Margaree F-70	EnCana	06-Aug-2003	Gas	1.4 (50)
MarCoh D-41	EnCana et al	23-Oct-2003	Gas	No Test

The Panuke F-09 well had a very low gas flow rate due to poor porosity and permeability and is considered a non-commercial well. The F-09 well is part of the spectrum of reservoir quality present in the Deep Panuke pool and the gas phase is continuous with other wells thereby making this well part of the pool.

While considered successful, the most recently drilled well, MarCoh D-41, was not production tested since wireline log results were deemed sufficient to prove the presence of producible hydrocarbons by comparison to previous wells.

The lateral extent of the Deep Panuke pool is restricted by four unsuccessful pool-delimiting wells, listed in Table 2.2.

Table 2.2: Listing of Deep Panuke Pool Delimiting Wells

Well Name	Operator	Rig Release	Status	Flow Rate 10^6 m3/d (MMscfd)
Cohasset L-97	Mobil-Tetco	21-Nov-1978	D & A	Gas Show
Musquodoboit E-23	EnCana	02-Sep-2001	D & A	Wet
Queensland M-88	EnCana	12-Feb-2002	D & A	No Test, Tight
Dominion J-14/A	EnCana	26-Jan-2006	D & A	No Test, Tight

2.1.2.2 Original Depletion Plan Submission (2002-2003)

Having drilled five wells into the Deep Panuke pool by the end of 2000, EnCana undertook a pool reserves evaluation and examination of various options for developing the field. The work was focused in the Panuke license where it was then thought that sufficient gas reserves could be accessed by a new fixed platform infrastructure to which existing wells could be tied-in. Further development wells could be directionally drilled as required.

A Development Plan Application (DPA) was filed with the Canada-Nova Scotia Offshore Petroleum Board (CNSOPB) in early 2002 for the development of the Deep Panuke pool. Ongoing technical studies and evaluation of the Deep Panuke pool continued as the early phases of the DPA were under regulatory review.

During this time, uncertainty was growing regarding the recoverable gas reserves accessible within the immediate Panuke license area between the Panuke H-08 and Panuke M-79 wells. Continuing subsurface technical studies indicated that the gas resources in the pool were likely to be smaller than first estimated. It was recognized, however, that the pool was likely to extend farther to the northeast along the Abenaki carbonate margin and that it was necessary to drill additional pool delineation wells to extend the known limits of the Deep Panuke pool prior to development.

2.1.2.3 Additional Pool Delineation (2003–2006)

Three wells were drilled as pool delineation step-out locations during the period from 2003 to 2006 with the ultimate objective to increase the established gas resource base for the pool. Fortunately, the Margaree F-70 and MarCoh D-41 wells both found thick dolomitized gas reservoir. No reservoir was penetrated in the vertical Dominion J-14 or sidetrack J-14A wellbores.

The drilling of these wells confirmed that commercial gas-bearing reservoir extends at least as far to the northeast as the D-41 well. Additional data collected from well logs, core and a production test in F-70 have greatly improved the understanding of the reservoir.

The principle technical learnings from this phase of pool delineation are as follows:

- gas resources in the pool exist mainly in dolomite reservoir along the carbonate margin with lesser gas volumes in adjacent vuggy limestones;
- the reservoir is fractured;
- an aquifer of uncertain size exists below the gas pool; and,
- in-place and recoverable gas volumes have been substantially revised.

Since the original filing of the Development Plan Application (DPA) in 2002, considerable capital has been spent to delineate the pool along with many person-years of additional subsurface technical study. Heavy emphasis has been placed on fully integrating all of the subsurface technical disciplines such as geology, geophysics, petrophysics and reservoir engineering, resulting in the construction of detailed reservoir models. The overall level of confidence in the understanding of the pool has increased considerably but substantial uncertainties remain. No production data is available for the pool. Such data would reduce reservoir performance uncertainties and help to better assess aquifer size and strength.

Figure 2.8 shows the currently established extent of the Deep Panuke gas pool including the position of the PP-3C discovery well and the pool delineation wells.

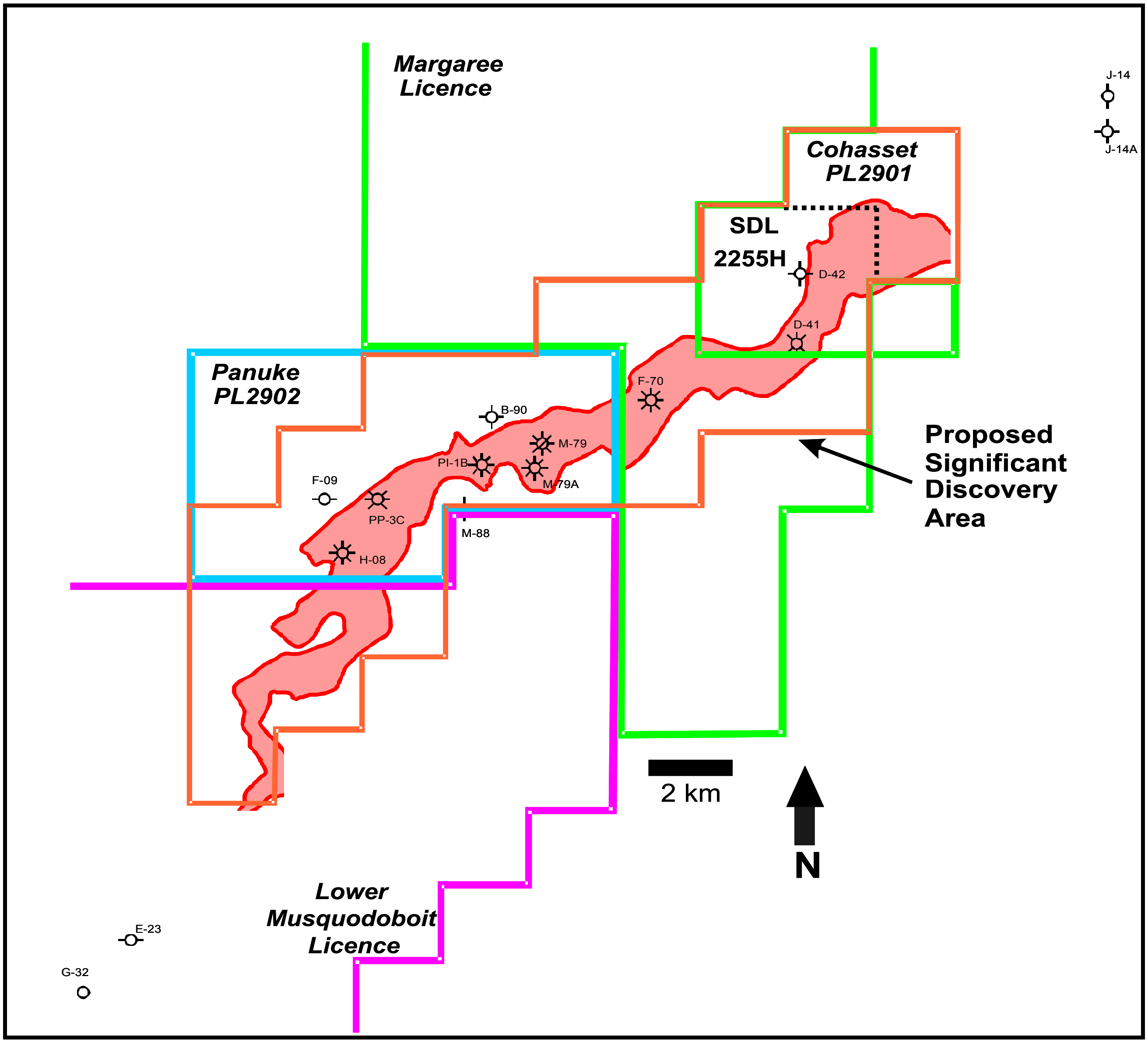


Figure 2.8: Deep Panuke Area Drilling

2.1.3 Geological Reservoir Description

The geological description of a hydrocarbon accumulation typically deals with five key elements which are all required for a hydrocarbon accumulation to exist, namely:

- source rock, which generates hydrocarbons;
- migration of hydrocarbons from the source rock;

- reservoir, with porosity and permeability, to host the hydrocarbons;
- trap, which captures the hydrocarbons; and
- seal, which prevents the hydrocarbons from migrating out of the trap.

Shales of the Verill Canyon Formation are thought to be the source rock for Deep Panuke gas, with migration of gas from the source rock into the Abenaki Formation via carrier beds within basinal deposits and / or faults and fractures within the Abenaki Formation (DPA-Part 2, Ref # 2.1) These elements will not be further discussed since they do not affect the estimation of Original Gas in Place (OGIP) in the reservoir or Recoverable Gas in Place (RGIP). The main emphasis in presenting the pool geological description has been placed on the reservoir. Description of the trap is addressed in Section 2.3, Geophysics. Tight limestones of the Abenaki 6 form the top-seal and Abenaki 4/5 tight limestones provide lateral seal landward of the gas pool.

2.1.3.1 Sedimentology

Sedimentology is the science that deals with the description, classification and interpretation of the origin of sedimentary rocks. The geological description of a reservoir begins with macroscopic observations made from basic well data such as well logs and cores along with microscopic examination of cuttings samples and thin sections cut from cores. For each individual well, observations of rock lithology (e.g. limestone or dolomite), color, grain size and type, fossil content, cements, pore types and pore size are used to describe the characteristics of the reservoir interval with vertical changes carefully noted. The initial sedimentological study work on the Abenaki Formation by Eliuk (DPA-Part 2, Ref # 2.7) provides the fundamentals upon which recent well information is still interpreted.

Based on the described set of characteristics of a particular reservoir interval, it is classified into one of a series of Facies Associations. A Facies Association includes a wide variety of very detailed, fine-scale rock depositional characteristics grouped at larger scales to more generally describe a rock-type.

Each Facies Association is assigned an origin relating to the depositional environment into which the sediments are interpreted to have initially been deposited before burial.

The following Facies Associations defined for the Abenaki Formation are applied to the Deep Panuke Pool as in Table 2.3.

Table 2.3: Listing of Facies Associations		
#	**Facies Association Name**	**Inferred Water Depth**
1	Open Marine - Deep	>200 m
2	Open Marine - Shallow	>100 m <200 m
3	Foreslope	
3a	Channel (Debris Flow or Turbidite Related)	10 m to >100 m
3b	Proximal Foreslope (Fore-reef)	10 m to 70 m
3c	Distal Foreslope (Microbial mud mounds-"5c")	70m to 100m
4	Foreslope (Deeper-water Bioherms and Biostromes)	
4a	Siliceous sponge (hexactinellid & lithistid) reef	>100 m
4b	Lithistid sponge-chaetetid-strom. 'shallow' reef,	30 m to 100 m
4c	Coral-demosp. (lithis.-strom.-chaet.) 'shallow' reef	10 m to 50 m
5	Open Marine Platform Margin	
5a	Skeletal Rich (Fore-reef rubble, reef crest etc.)	Forereef 10 - 50 m Reef crest 1 - 2 m, Backreef 1 - 5 m
5b	Coral-stromatoporoid-chaetetid-algal reef boundstone	2 m to 10 m
5c	Pelletal mudstone (to grainstone)	5 m to 10 m
5d	Oolitic grainstone shoals	1 m to 5 m
5e	Oncolitic Backreef (shallow backreef to shoal margin)	1 m to 5 m
5f	Sandstone (Bypass, lowstand sandstone)	1 m to 3 m
6	Carbonate Platform Interior (Moat)	5 m to 20 m
7	Mixed Carbonate Siliciclastic Platform Interior	3 m to 10 m
8	Coastal Deltaic Lagoonal/Continental	1 m

The next stage in the sedimentological work is to synthesize the individual well interpretations into a Depositional Model for the entire pool which serves the following purposes:

- explain lateral and vertical spatial variations observed within the pool; and
- predict the lateral and vertical distribution of particular characteristics which may be found between existing wells and in future wells.

Figure 2.9 shows the Detailed Deep Panuke Facies Model presented in a sequence stratigraphic context illustrating the spatial distribution of Facies Associations within a complete depositional sequence.

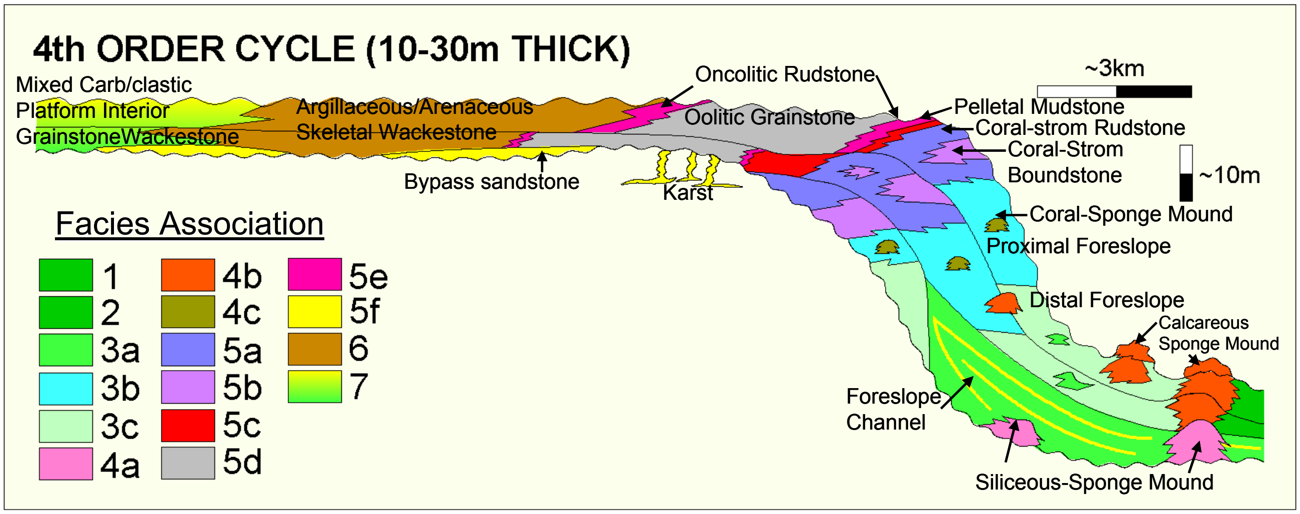


Figure 2.9: Detailed Deep Panuke Facies Model

The simplified version of the Deep Panuke Facies Model presented in Figure 2.10 still conveys the essence of the Facies Associations and depositional environments across the Abenaki carbonate margin. The Deep Panuke gas pool is assigned to the 'Reef', associated 'Foreslope (Upper)' and 'Inter-reef' environments.

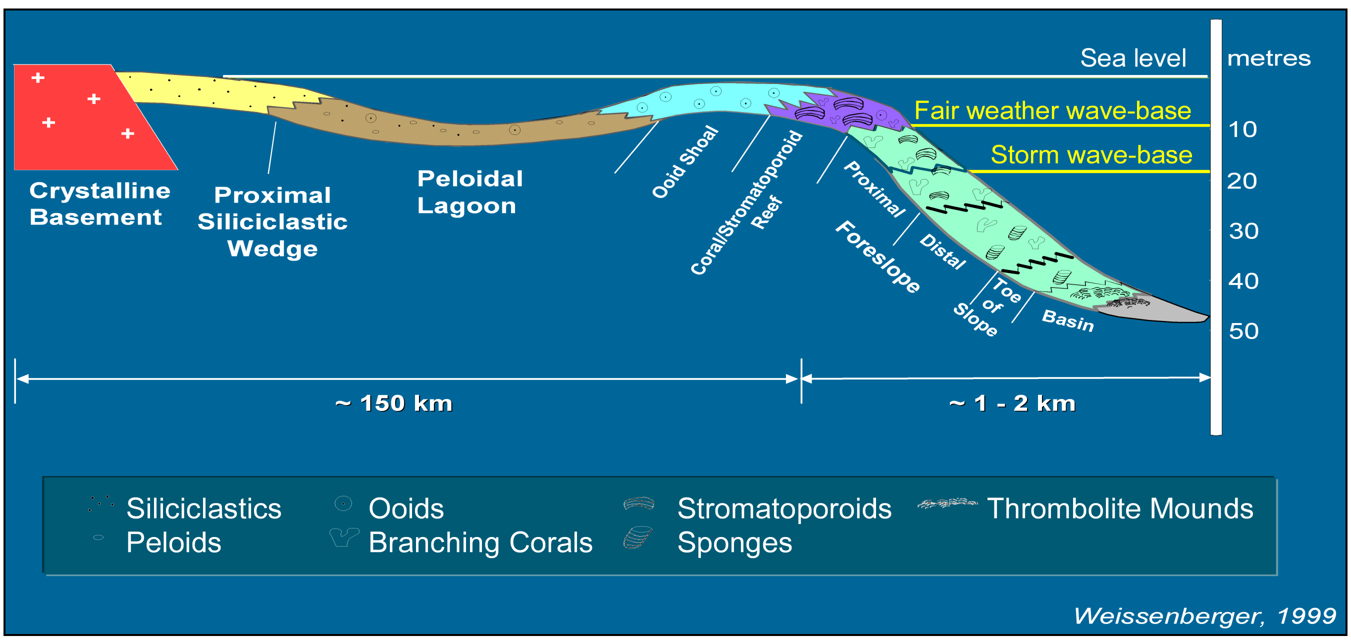


Figure 2.10: Simplified Deep Panuke Facies Model DPA-Part 2-Ref # 2.8

The principle applications of sedimentology in reservoir studies are to document the known distribution of reservoir-prone and non-reservoir facies to predict from the resultant depositional model where additional reservoir may (or may not) be found.

For the Deep Panuke pool, there are practical limitations to the utility of sedimentological analysis and depositional facies mapping. Firstly, specific depositional facies cannot be confidently predicted from seismic analysis, so the information available is largely confined to sparse well control. Secondly, much of the primary porosity has been occluded during early diagenesis, regardless of Facies Associations and depositional environments, which are therefore only weak predictors of ultimate reservoir potential.

Despite these limitations, the sedimentological analysis of the wells has shown that the reefal margin Facies Associations host the main reservoir at Deep Panuke. The more seaward Foreslope Facies Association has limited reservoir potential due to higher carbonate mud content and higher argillaceous content which make this facies less prone to subsequent dolomitization. To date, the back-reef Facies Associations, including oolitic grainstones, have not shown significant porosity development due to early cementation and lack of dolomitization away from the carbonate margin. However, the occurrence of limited porosity in oolitic grainstones in the F-09 well and up to 13% porosity in the Abenaki 4 in the E-23 well suggest that porous oolitic grainstones may yet be found by further drilling within the Deep Panuke pool.

2.1.3.2 Diagenesis

Diagenesis refers to the biological, physical and chemical changes which a sedimentary rock undergoes after its initial deposition. Of particular concern at Deep Panuke are the physical and chemical changes which the rock has undergone during dolomitization, leaching and the evolution of porosity during the history of the Abenaki Formation. The development of secondary porosity tends to over-ride depositional facies in determining the final distribution and quality of the reservoir at Deep Panuke.

Based on extensive studies of well logs, core, isotopes, and in particular, specialized thin-section petrographic observations, (DPA-Part 2 Ref # 2.9, 2.10, 2.11, 2.12) the diagenetic processes which have acted on the Abenaki Formation through time are summarized in the paragenetic sequence illustrated by Figure 2.11. The evolution of porosity in the reservoir can be simplified into the following three principle stages:

- Stage 1) Early cementation then later burial compaction resulting in decreased porosity;
- Stage 2) Burial dolomitization with increased porosity along the reef front, dissolution in the Vuggy limestone region with increased porosity; and

- Stage 3) Dolomite Leaching (dedolomitization) and late calcite cementation with likely net decrease of porosity.

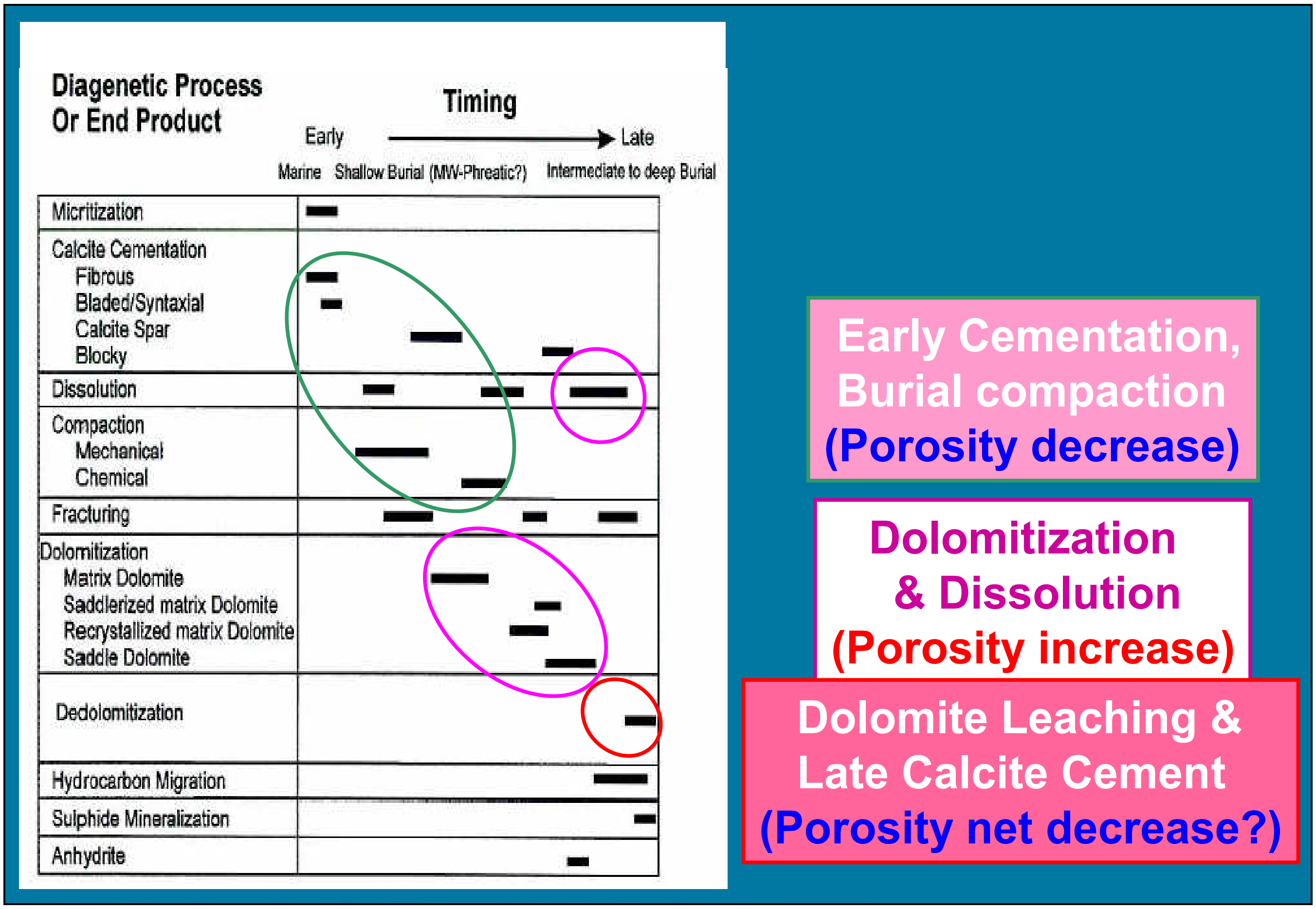


Figure 2.11: Diagenesis and Porosity Evolution

The most important observation from the petrographic work and the diagenetic history is that porosity in the pool is now dominated by secondary porosity development directly associated with dolomitization and leaching. The porosity of economic interest exists only in the dolostones and leached limestones, not in unaltered limestones. This fact must be accounted for when evaluating rock volumes composed of a mixture of dolostone and limestone as described in Sections 2.1.3.4 and 2.2.5.

To illustrate the close relationship of the dolostones to limestones in the dolomitized part of the pool, Figure 2.12 illustrates the results of petrophysical analysis of the F-70 well in the Abenaki 5 Member, along with a series of five thin section photo-micrographs showing key aspects of the rock fabrics present. The thin sections were cut from the F-70 conventional core. The selected photo-micrographs are illustrative of the partially dolomitized region of the pool (see Section 2.2.2). Many other thin sections exist in addition to those shown (DPA-Part 2 Ref # 2.10, 2.11, 2.12).

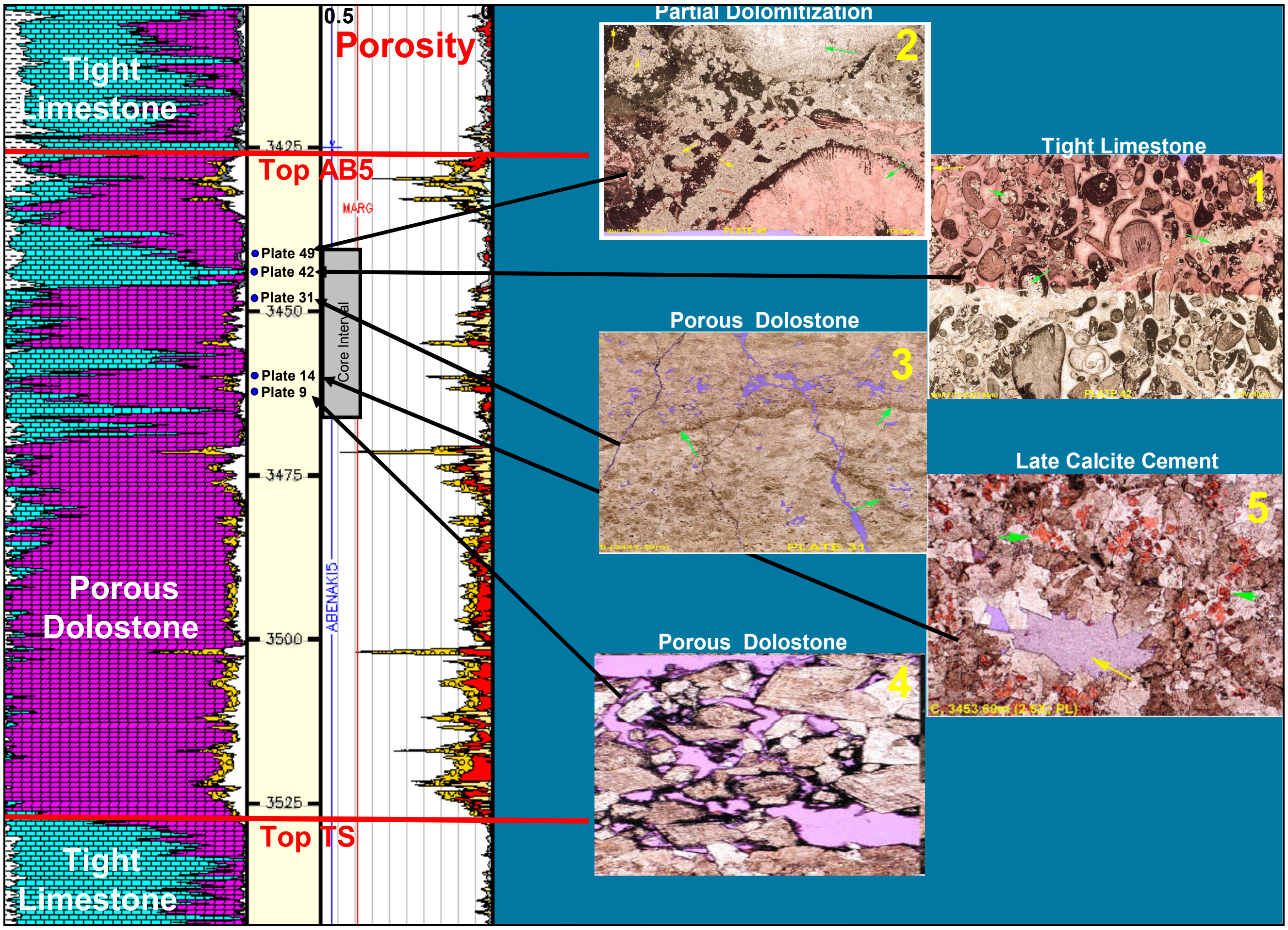


Figure 2.12: F-70 Well Abenaki 5 Rock Fabrics

On the left-hand side of the figure, Track 1 shows the proportions of dolostone (mauve) limestone (pale green), argillaceous material (pale grey), vuggy porosity (yellow) and matrix porosity (white). Above the "Tight Streak" (TS) interval of tight limestones (at the base of the Abenaki 5), the porous reservoir is composed primarily of dolostone with several interbeds of limestone present in the upper part. Obviously there is a close physical association of the dolostone and limestone interbeds.

In Track 3, the Total Porosity (Phi$_{tot}$) is further subdivided into vuggy porosity (yellow) and gas-filled matrix porosity (red), moved fluid (pale yellow), clay bound water (grey) and free water (pale blue). It should be noted that porosity occurs almost exclusively in the dolostones.

2.1.3.3 Fracturing

Initial studies of the Deep Panuke pool did not regard it as having a significant flow contribution coming from fractures. Touching vugs were thought to dominate permeability in the reservoir. Subsequently, as the dolomitized reservoir in the F-70 and D-41 wells was analyzed, it became evident that fracturing does indeed play an important role in enhancing permeability in the pool. Structural analysis now indicates that open fractures are dominantly oriented roughly sub-parallel to the carbonate margin edge hence permeability will be enhanced parallel to the margin edge. The following discussion provides an overview of the current understanding of fracturing in the pool.

Overall there does not appear to be a great deal of fracturing present in the Abenaki 5 limestones. This is consistent with the observation that limestone and vuggy rock tends not to fracture as they are more ductile and bend rather then break. In addition, fractures are short as they tend to terminate when they encounter a bedding plane, vug or a change in fabric like a coral head. The F-70 and D-41 wells encountered much more dolomite in the Abenaki 5; these wells are more fractured, especially in the non-vuggy dolomites.

It would appear that the rock recovered in the H-08 core is brecciated to some degree rather then fractured, probably caused by partial solution collapse of the high porosity zone. The H-08 well has a Resistivity At Bit$_{TM}$ (RAB) tool image of the porous interval. The RAB tool is a Logging While Drilling (LWD) tool with a much coarser resolution (pixels are about 3 cm wide by 10 cm high) than a Formation Micro-Imager^{TM} (FMI) tool. The image shows some large fractures in an overall very vuggy, high porosity area. The fractures in the H-08 well appear to have been leached open and probably were in place prior to leaching. PI-1B has an RAB tool log and does not show any fractures.

In the backreef setting in the F-09 well, there is limited fracturing of small aperture and it is restricted to single beds or small groups of beds and will not have great lateral continuity. The tested interval in F-09 contained a few thin intervals of fractures. As indicated by the acid fracture pressures required and the test results, these fractures are not open.

It was noticed in the petrographic study of thin sections from sidewall cores, predominantly from the matrix, that micro-fracturing is fairly common. This type of tiny fracture relieves the stress within the system and reduces the likelihood of large fractures. Micro-fracturing can improve the connectivity in secondary porosity rock by connecting pinpoint vugs.

Overall, there are not a lot of fractures in the Abenaki limestones or vuggy dolomite; where they have not been enhanced by leaching, they appear to be closed. Given that the majority of porosity-related events interpreted from seismic data are parallel to the carbonate margin, it appears that the extensional fracture sets are the more important control on access of diagenetic fluids into the Abenaki platform. The fractures will contribute to the connectivity of the reservoir but not to any greater degree than the vuggy nature of the high porosity zones. However, the fractures likely explain the more uniform continuity of permeability along the margin edge (interpreted from well tests) where porosity is variable and vuggy intervals discontinuous. As these are steeply dipping fractures, they may allow some aquifer access if open into the water leg.

Integrating data from the F-70 core and FMI log has added new insights into the fracture analysis (DPA-Part 2, Ref # 2.13). The F-70 well has the most complete data set available with which to characterize fracture distribution, morphology and orientations. FMI log, Stoneley wave log and core datasets are available for analysis. The core shows a common short-length, leaching-enhanced fracture set. The fractures are random, seem to be more brecciated than fractured and terminate in 10 to 20 cm against styolites or fossil fragments. Fractures seem mechanically constrained to dolomitized beds whilst limestones are generally unfractured. There are several generations of fractures. The FMI shows several fracture swarms, some with fairly high-angle dipping events. Fracturing coincides with lower porosity dolomitized grainstones i.e. denser brittle rock. The core fractures are dominantly oriented parallel to the margin edge, though the FMI log shows great variation in fracture orientation.

An example of fracture identification from the F-70 FMI log is shown in Figure 2.13. Fractures are discernable as high angle sub-vertical or sinusoidal features on an FMI log. Fracture strike and dip are calculated from this data since the FMI tool is spatially oriented. Low angle dips are discounted as fractures and are treated as bedding surfaces. Rock fabric interpretation is also done on the FMI with vugs prominent on some images such as at 3525 m TVD.

The F-70 FMI shows several fracture swarms as at 3485 m TVD, some with fairly high angle larger dipping events, such as at 3475 m TVD. Fracturing coincides with lower porosity dolomitized grainstones i.e. dense, brittle rock. The FMI log shows great variation in fracture orientation.

The production test in the Abenaki 5 flowed gas at a sustained rate of 1.5 million m^3/d (52 MMscfd) limited by production equipment. The test showed that 93% of the gas production inflow came from 10 m of reservoir thickness. This is strong evidence that relatively thin, highly fractured intervals are responsible for much of the overall permeability in the pool.

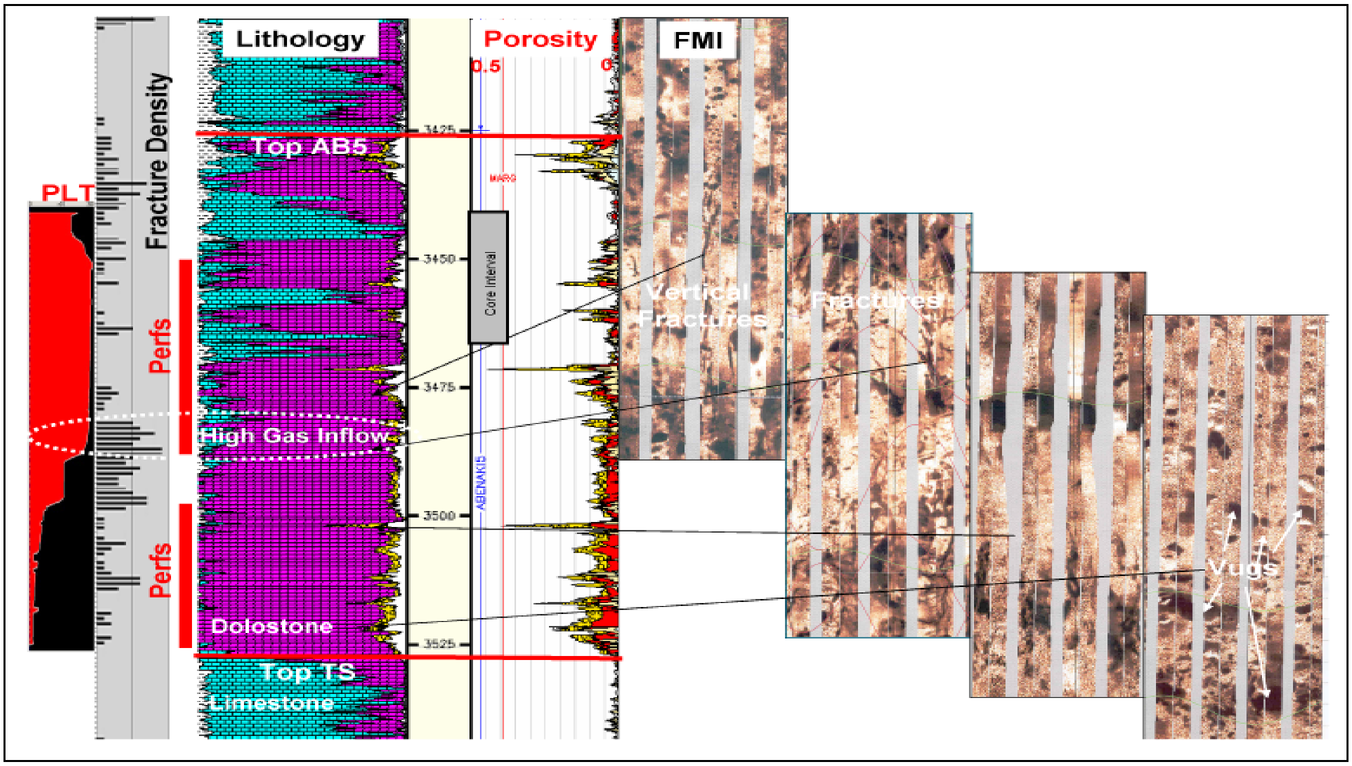


Figure 2.13: Fracture Identification in Well F-70

2.1.3.4 Lithotypes

Three rock fabrics or lithotypes have been defined in the Deep Panuke pool, one which does not contribute significantly to the gas reservoir (margin limestone) and two which do (i.e. dolostone and vuggy limestone).

Lithotype/Rock Fabric: Margin Limestone

The first Lithotype/Rock Fabric to consider is the Margin Limestone Lithotype, illustrated in Figure 2.14. It represents the rock fabric and porosity characteristics of the Abenaki Formation as a result of early cementation and subsequent burial compaction stage of reservoir development resulting in decreased porosity. This lithotype was not subjected to dolomitization or leaching.

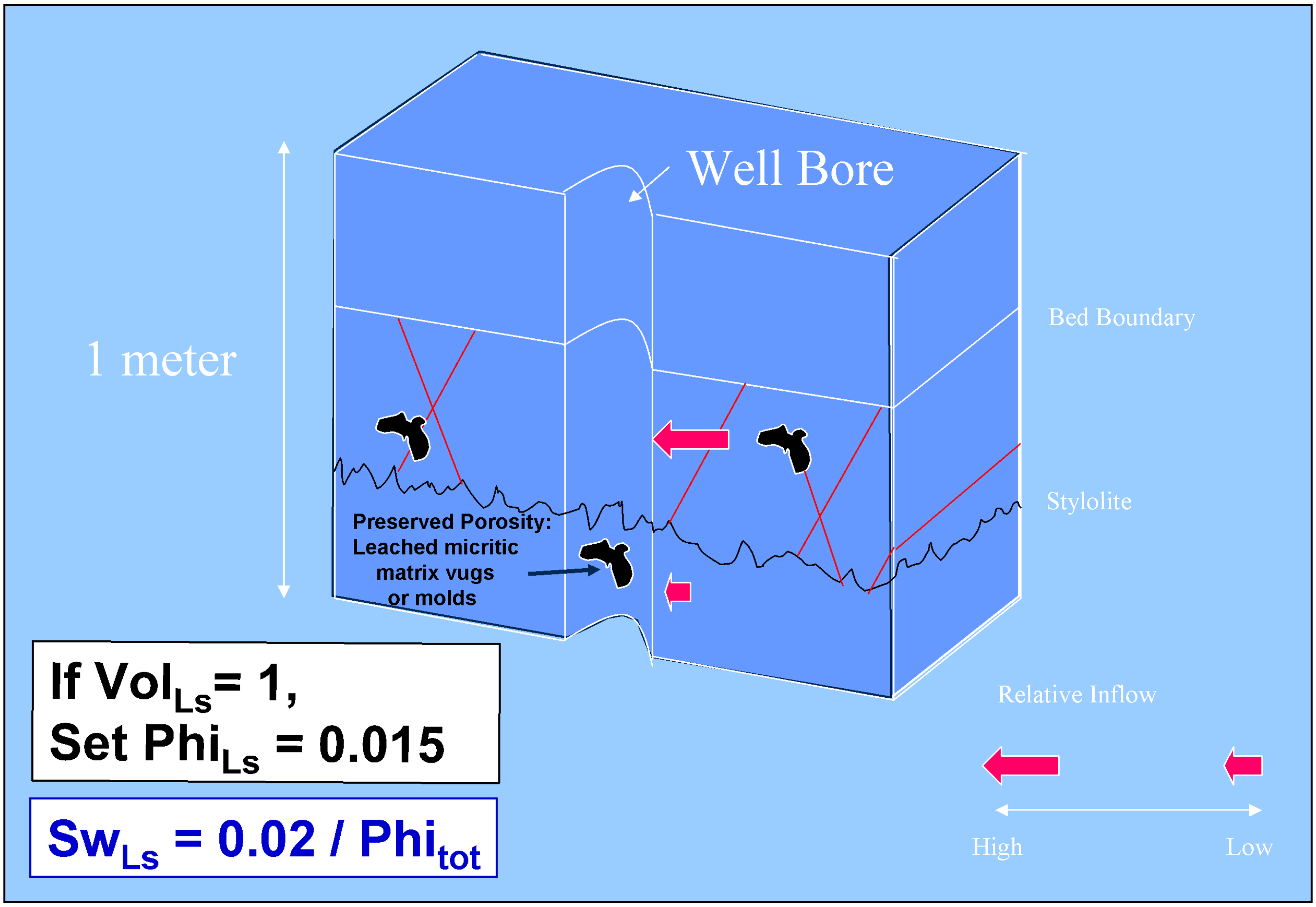


Figure 2.14: Lithotype/Rock Fabric - Margin Limestone

This Lithotype/Rock Fabric is characteristic of the Mid-Reef region of the pool (see Section 2.2.2) but also occurs in the other regions of the pool as non-reservoir "tight" limestones with minor preserved porosity, mainly as leached, micritic matrix vugs or molds.

Lithotype/Rock Fabric: Dolostone

The second Lithotype/Rock Fabric is Dolostone, as illustrated in Figure 2.15, which accounts for the majority of the reservoir rock in the pool. It is characterized by dolomite mineralogy with vuggy/moldic to inter-crystalline porosity with several stages of fracturing resulting in high permeability. This lithotype is considered to be a dual porosity reservoir. The rock matrix provides the bulk of the reservoir volume and the fracture network provides the majority of the reservoir permeability.

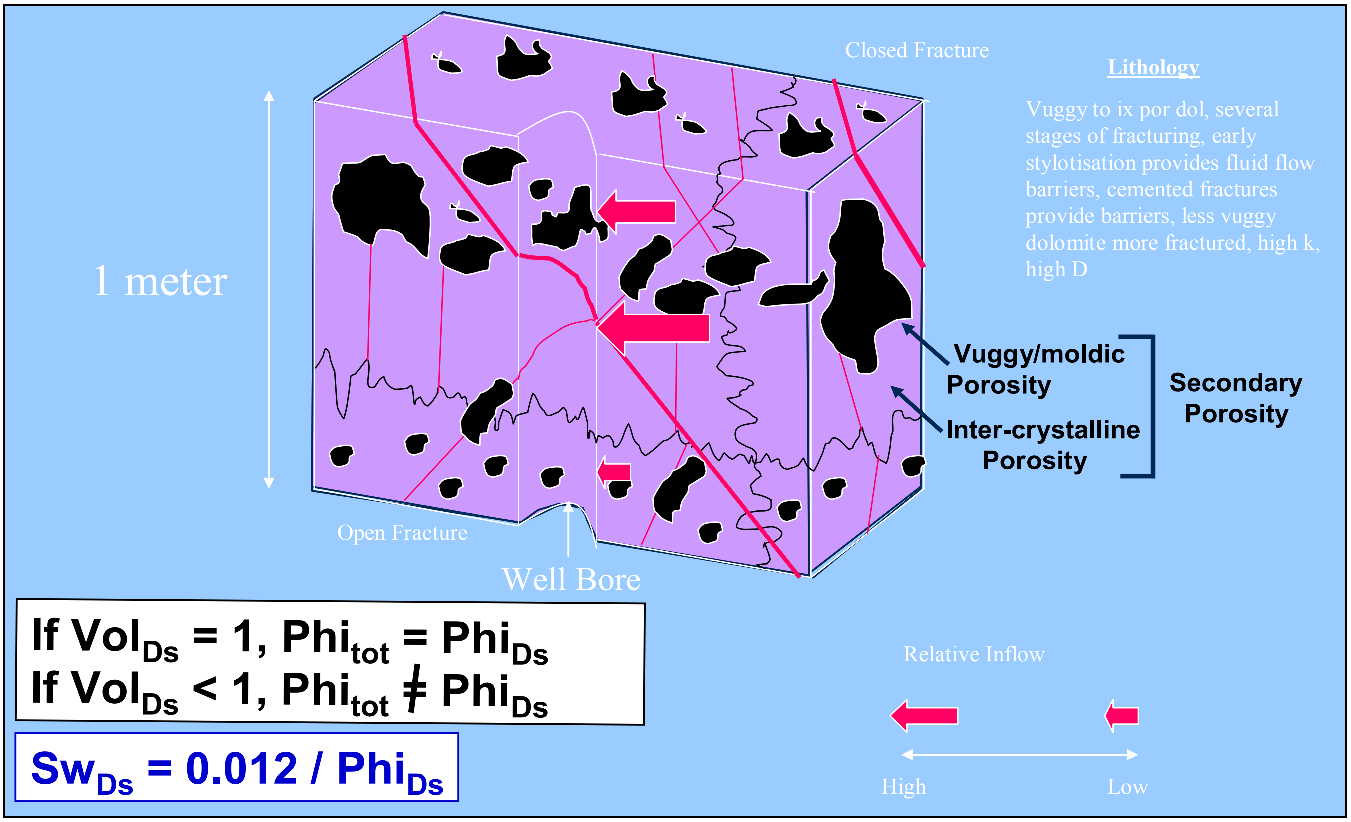


Figure 2.15: Lithotype/Rock Fabric – Dolostone

It is observed on all scales from thin section petrographic scale (DPA-Part 2 Ref # 2.10, 2.11, 2.12) to well log scale (see Section 2.2.3) that a volume of rock may be only partially dolomitized. This phenomenon is of great importance to the petrophysical description of the reservoir, reservoir characterization and the subsequent building of a reservoir model since the vast majority of the reservoir porosity exists in the dolomitized portion of the rock, not in the unaltered limestone portion.

The rock fabric and porosity occurrence in a partially dolomitized rock volume is illustrated in Figure 2.16. The interface between the dolomitized and un-dolomitized (i.e. limestone) portions of the rock volume is a chemical reaction front where the dolomitization process stopped.

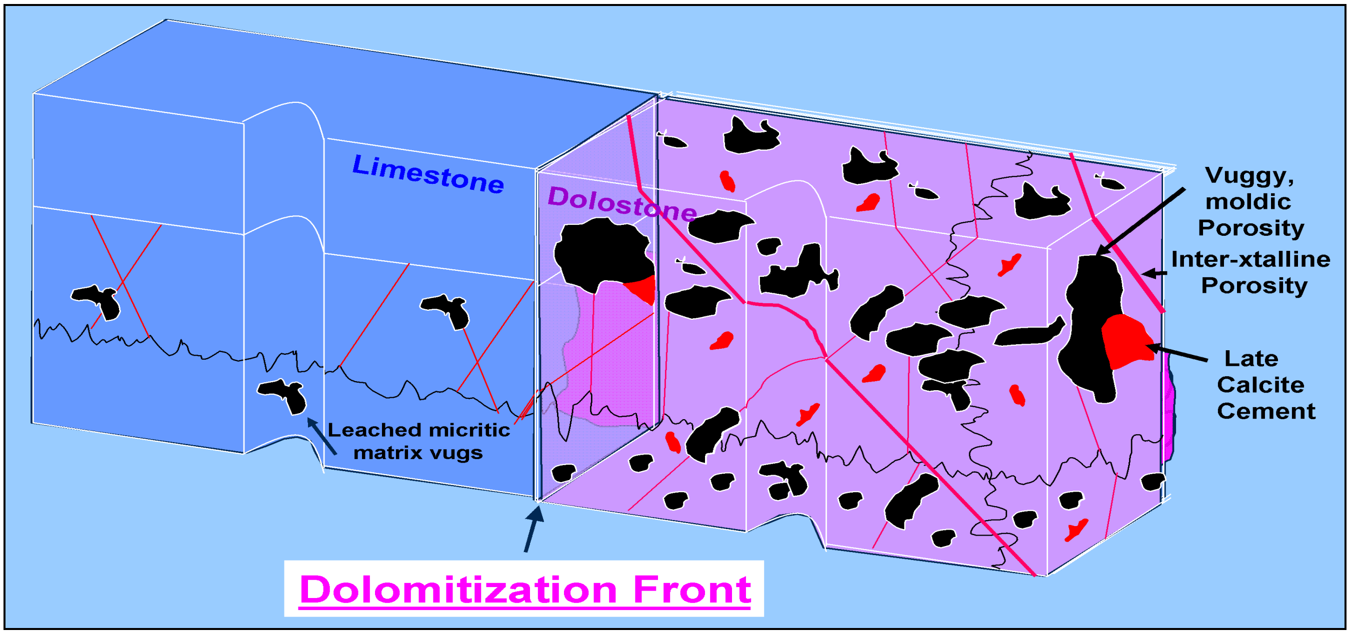


Figure 2.16: Lithotype/Rock Fabric – Partially Dolomitized

In a partially dolomitized rock volume, porosity measurements from core and well logs primarily yield total porosity (Phi_{tot}) measurements. It is important to discriminate porosity in the dolostone fraction (Phi_{Ds}) from porosity in the limestone fraction (Phi_{Ls}) since other reservoir properties such as permeability and water saturation are dependent on lithology and pore types.

Total porosity (Phi_{tot}) can be allocated to the dolostone and limestone fractions in direct proportion to the volume of each lithology present within the rock volume being analyzed. It can be stated in mathematical terms as follows:

Equation 1: $Phi_{tot} = (Vol_{Ls} \times Phi_{Ls}) + (Vol_{Ds} \times Phi_{Ds})$

Where Phi_{tot} = Total porosity in a given rock volume
Vol_{Ls} = Volume of Limestone (or calcite)
Vol_{Ds} = Volume of Dolostone (or dolomite)
Phi_{Ls} = Porosity in limestone
Phi_{Ds} = Porosity in dolostone
Note: $Vol_{Ls} + Vol_{Ds} = 1$

A key implication of this statement is that different reservoir property statistical populations/distributions may be present in each of the dolostone and limestone fractions. For example, the dolostone fraction may host a particular porosity population described by a statistical distribution unique to the dolostone lithotype. The limestone fraction may host a completely different porosity population described by a statistical distribution specific to the limestone lithotype. For the total rock volume, the Phi_{tot} porosity distribution represents a composite which may exhibit bi-modality.

Lithotype/Rock Fabric: Vuggy Limestone

The third Lithotype/Rock Fabric is Vuggy Limestone, present in the reservoir region named as such, is illustrated in Figure 2.17. Lithologically the region of the H-08 and PP-3C wells is characterized as limestones with massive vuggy porosity and some matrix porosity present along with fractures. Where diagenesis has not created Vuggy Limestone in this region, the "background" Margin Limestone Lithotype is preserved.

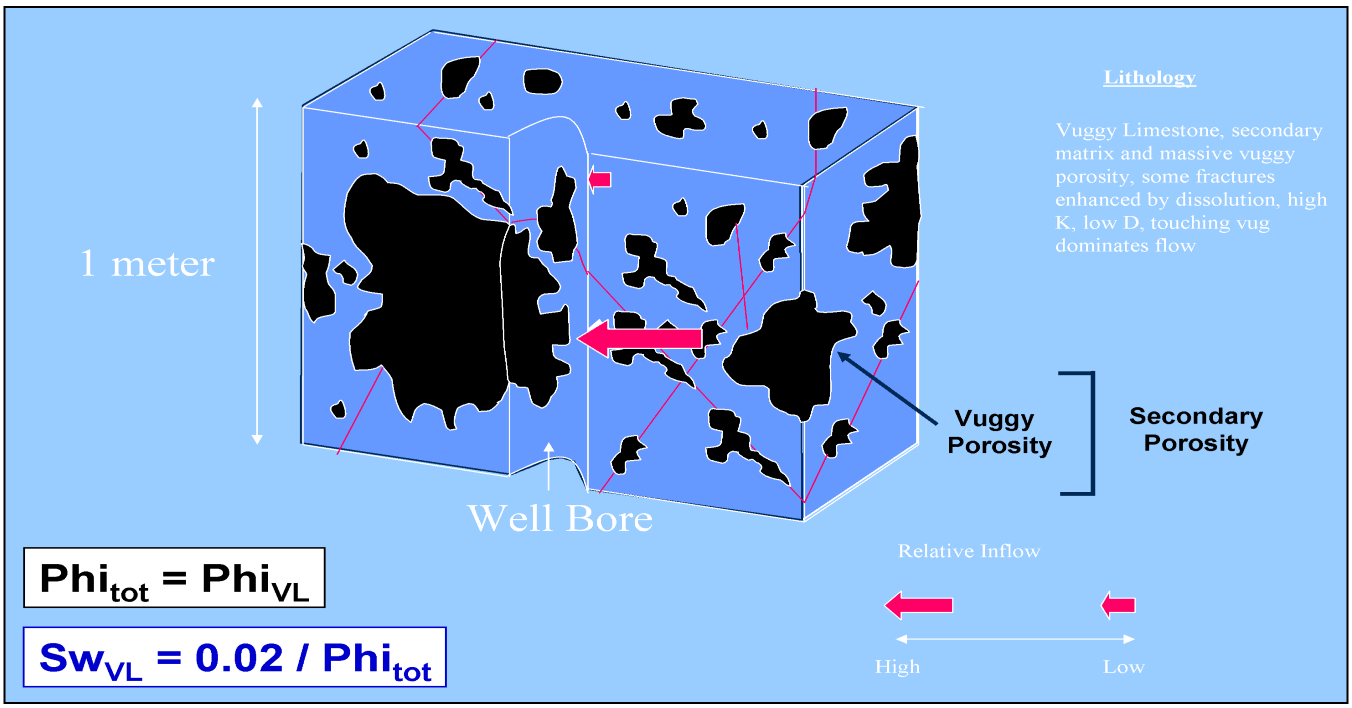


Figure 2.17: Lithotype/Rock Fabric - Vuggy Limestone

Two possible explanations exist for the occurrence of Vuggy Limestone in close (< 300m) lateral proximity to the High Permeability Reef Front (HPRF) region. The first explanation is that the creation of the Vuggy Limestone region is part of the continuum of diagenetic processes which formed the HPRF region. As magnesium was consumed in the dolomitization of the HPRF region, a diagenetic fluid presumably evolved which was capable of leaching calcite from the limestones in the adjacent area but no longer capable of dolomitizing the rock. A key implication is that the HPRF and VL regions would most likely be in reservoir continuity with each other.

The second explanation is that the fluids which leached the limestone in the Vuggy Limestone region were of a different initial chemistry and presumably different timing to those which dolomitized the HPRF region. The two regions may or may not be in reservoir continuity depending upon the areal extent to which the different diagenetic events reached.

2.1.3.5 Reservoir Stratigraphy

A simple stratigraphic zonation is used to describe the reservoir stratigraphy at Deep Panuke:

1) porous and permeable limestones and dolomites in the Abenaki 5;
2) low porosity/permeability argillaceous limestones near the base of the Abenaki 5 (“Tight Streak”); and
3) porous and permeable limestones and dolomites in the Abenaki 4.

The reservoir stratigraphy of the Deep Panuke pool is illustrated by Figure 2.18. The gas/water contact is at approximately -3504 m TVD SS and is most easily identified in the upper Abenaki 4 at the D-41 well.

The lower Abenaki 5 argillaceous limestone is correlative between wells as a consequence of its deposition as lower Foreslope facies above a major marine flooding surface (which marks the top of the Abenaki 4). It is informally termed the “Tight Streak”, although this is strictly a misnomer due to the presence of some porosity and permeability in the interval. The interval deserves recognition as being significantly different in its reservoir and fracture properties from the reservoir zones above and below it. Unfortunately, the “Tight Streak” interval cannot be directly mapped seismically due to its lack of impedance contrast with underlying and overlying rocks. It is correlated stratigraphically using well logs and between wells by isopaching up from a geophysically mapped horizon corresponding to Abenaki 4 porosity.

The lower Abenaki 6 has minor effective porosity in the wells drilled to date. Overall, it is regarded as top seal for the pool but seismic evidence indicates that there is local porosity development in the Abenaki 6 which may be tested in future drilling.

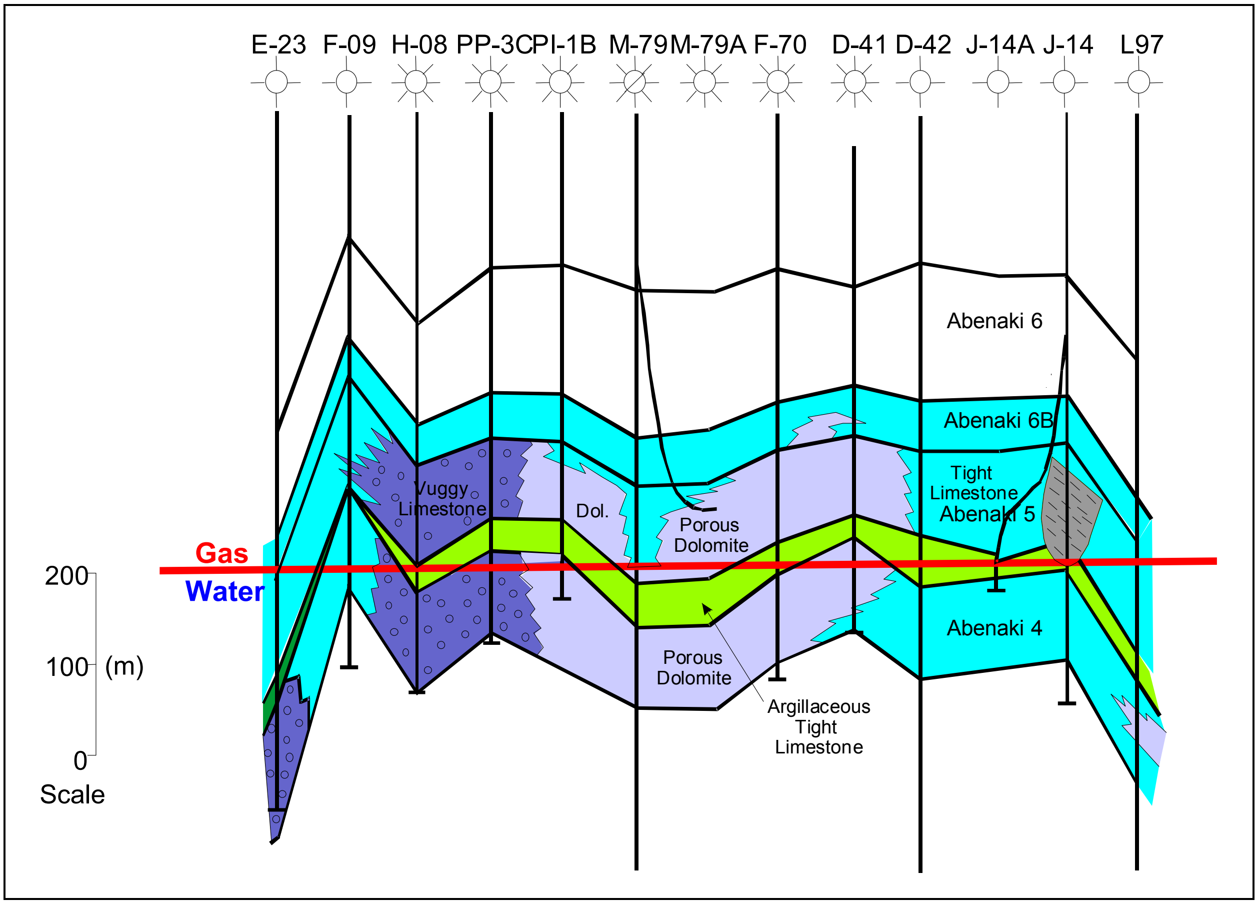


Figure 2.18: Reservoir Stratigraphy

2.2 Reservoir Characterization

2.2.1 Integrated Depositional and Facies Model

An integrated description of this complex reservoir in presented in Figure 2.19. For the sake of simplicity, this model illustrated in the figure depicts gas-bearing reservoir only in the Abenaki 5 sequence which accounts for the majority of the gas in the pool. This figure does not fully address the reservoir and gas in the Abenaki 4 sequence which has been proven in the D-41 well.

The Abenaki 5 sequence is schematically shown to form above a dipping surface at the top of the Abenaki 4 sequence. The dip can be interpreted as either structural in origin (due to syn-depositional structure), or depositional dip (reflecting pre-Abenaki 5 topography) or a combination of both. Depositional facies within the Abenaki 5 are (from deeper to shallower water deposition) Lower

Foreslope, Foreslope/Reefal Margin, Backreef Sand Flat and Oolitic grainstone Shoal, arranged in an overall progradational stacking pattern.

Post-deposition extensional faulting has removed the Abenaki 5 seaward of a major listric fault. Although not shown on the diagram, juxtaposition of Mic Mac Formation or lower Missisauga Formation is implied to the right side (hanging wall) of the fault.

Associated with the faulting is the migration of burial-diagenetic fluids up the fault plane and fractures, resulting in dolomitization of portions of the Abenaki 4 and 5. In the Abenaki 5, dolomite is shown to penetrate into the Foreslope Reefal Margin and Backreef sand flat facies wackestones and grainstones, but does not reach as far as the Oolitic Grainstone Shoal facies. From the wells, a "plume" of dolomite is known to penetrate the Abenaki 4, spreading out horizontally below the top of Abenaki 4, but is not depicted to its full extent in Figure 2.19.

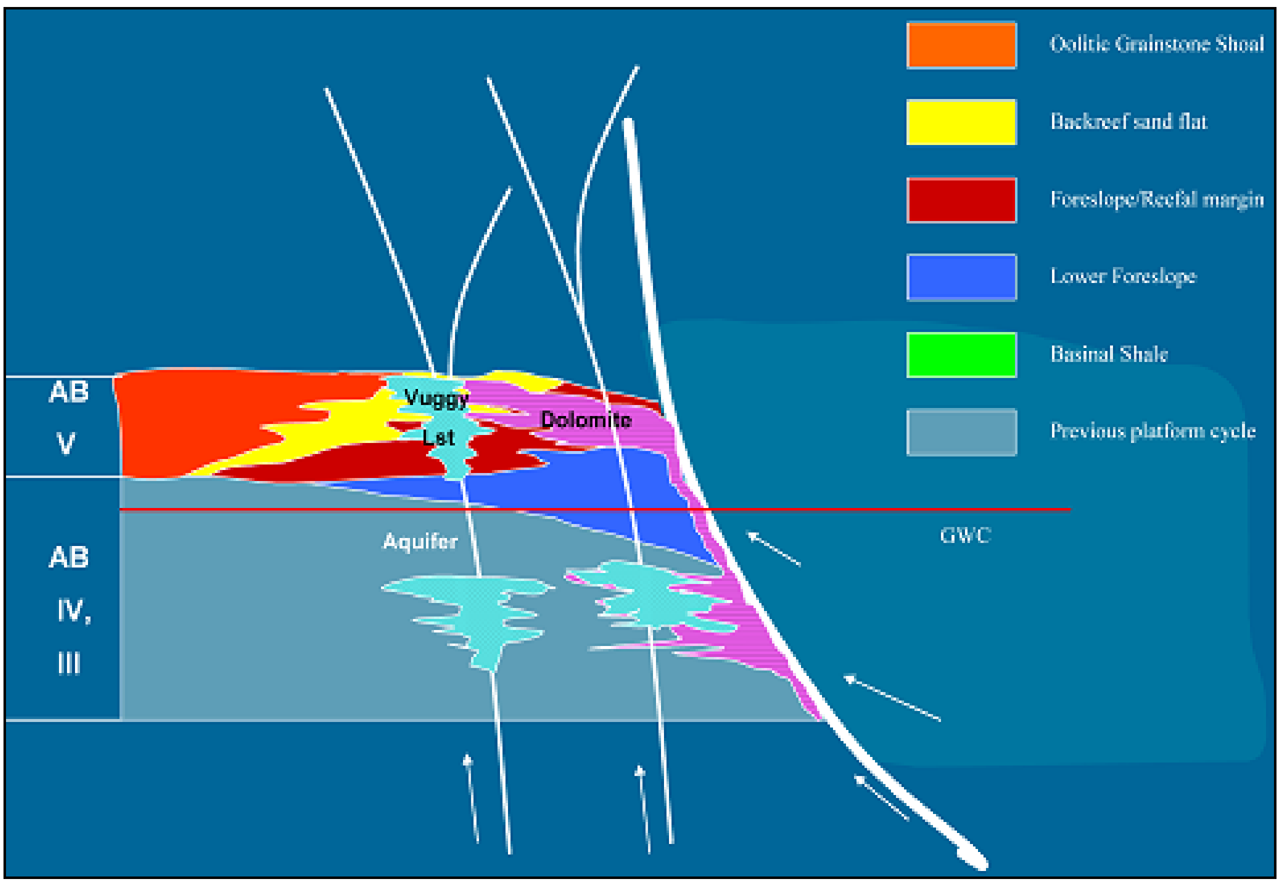


Figure 2.19: Integrated Depositional Facies and Diagenetic Model

The argillaceous Lower Foreslope limestones of the lower Abenaki 5 (aka "Tight Streak") overlie the major marine flooding surface separating the Abenaki 4 and 5 sequences. It is shown as undolomitized except in close proximity to the fault plane. This is a consequence of the argillaceous nature of these Lower Foreslope deposits, leaving them with very low post-compaction permeability thereby limiting the penetration of dolomitizing fluids into this zone.

A younger set of basement-involved wrench faults is shown to cut the Abenaki Formation more landward than the listric fault-controlled margin. Associated with the younger age of faulting is a second major diagenetic event responsible for creating the vuggy limestone regions within both the Abenaki 5 and 4. Again, diagenetic fluids are shown to be derived from basement or at least deeper formations. Extensive leaching of the limestones in some areas and de-dolomitization in other areas is implied.

Although simplified, and therefore prone to excluding important information, this model has been found to be very useful in portraying a broad series of observations about the Deep Panuke pool.

2.2.2 Reservoir Regions

The more drilled area of the Deep Panuke pool (extending from south of the H-08 well to northeast of the D-41 well) has been subdivided into a series of four Reservoir Regions, each incorporating two or more facies associations and lithotypes, with distinctive reservoir characteristics:

1) **High Permeability Reef Front (HPRF):** The region comprising the reefal margin which has been extensively dolomitized and has a high density of fractures. Secondary porosity is variable and moderate matrix permeability is enhanced by fractures. The PI-1A/B, M-79A, F-70 and D-41 wells are within the HPRF region.
2) **Mid-Reef (MR):** The low primary porosity and low permeability, lightly fractured regions of the pool immediately landward of the reef margin which has undergone limited diagenesis and secondary porosity creation. Several Mid-Reef sub-regions are present which partially separate the other regions of the pool. The M-79 vertical well and D-42 well are within the mid-reef region.
3) **Vuggy Limestone (VL):** The region in the southwest portion of the pool which is characterized by high porosity and high permeability leached limestones with a moderate density of fracturing. The H-08 and PP-3C wells are within the VL region.
4) **Shoal:** The undrilled region of the pool extending along a linear structural high present northeast of the D-42 well toward the J-14 well location. The reservoir in this portion of the pool may be either limestone or dolomite dominated; it is thought to have been deposited mainly as oolitic grainstones which are expected to exhibit high porosity and permeability.

The general characteristics of the Reservoir Regions are summarized in Table 2.4**.**

Table 2.4: Reservoir Region Characteristics

Reservoir Characteristics	**Reservoir Region**			
	High Permeability Reef Front	***Mid-Reef***	***Vuggy Limestone***	***Shoal (Undrilled)***
Principle Lithology	Dolomite	Limestone	Limestone	Limestone or Dolomite
Depositional Facies	Reef Margin	Reef Margin	Back Reef	Oolitic Grainstone
Diagenesis	Early cement, late dolomite	Early cement	Leached (Karst)	Leached (Karst) or Dolomitized
Porosity	Variable	Low (Primary)	High	High
Permeability	High	Low	High	High
Fracturing	High Density	Low Density	Moderate Density	Moderate Density

2.2.2.1 Reservoir Regions Applied to Facies and Diagenetic Model

The following Reservoir Regions are applied to the Integrated Depositional Facies and Diagenetic Model in Figures 2.20 and 2.21:

a) The High Permeability Reef Front (HPRF) region is shown extending from the seaward limit of the pool through mainly dolomitized reefal margin to backreef sand flat facies.
b) The Mid-Reef (MR) region is shown in less diagenetically-altered portions of the pool between the HPRF and VL regions.
c) The Vuggy Limestone (VL) region is shown in close association with faults, extending vertically through reefal margin and sand flat facies.
d) The Shoal region (undrilled) is shown within oolitic grainstones developed landward of the reefal margin and back reef sand flat facies.

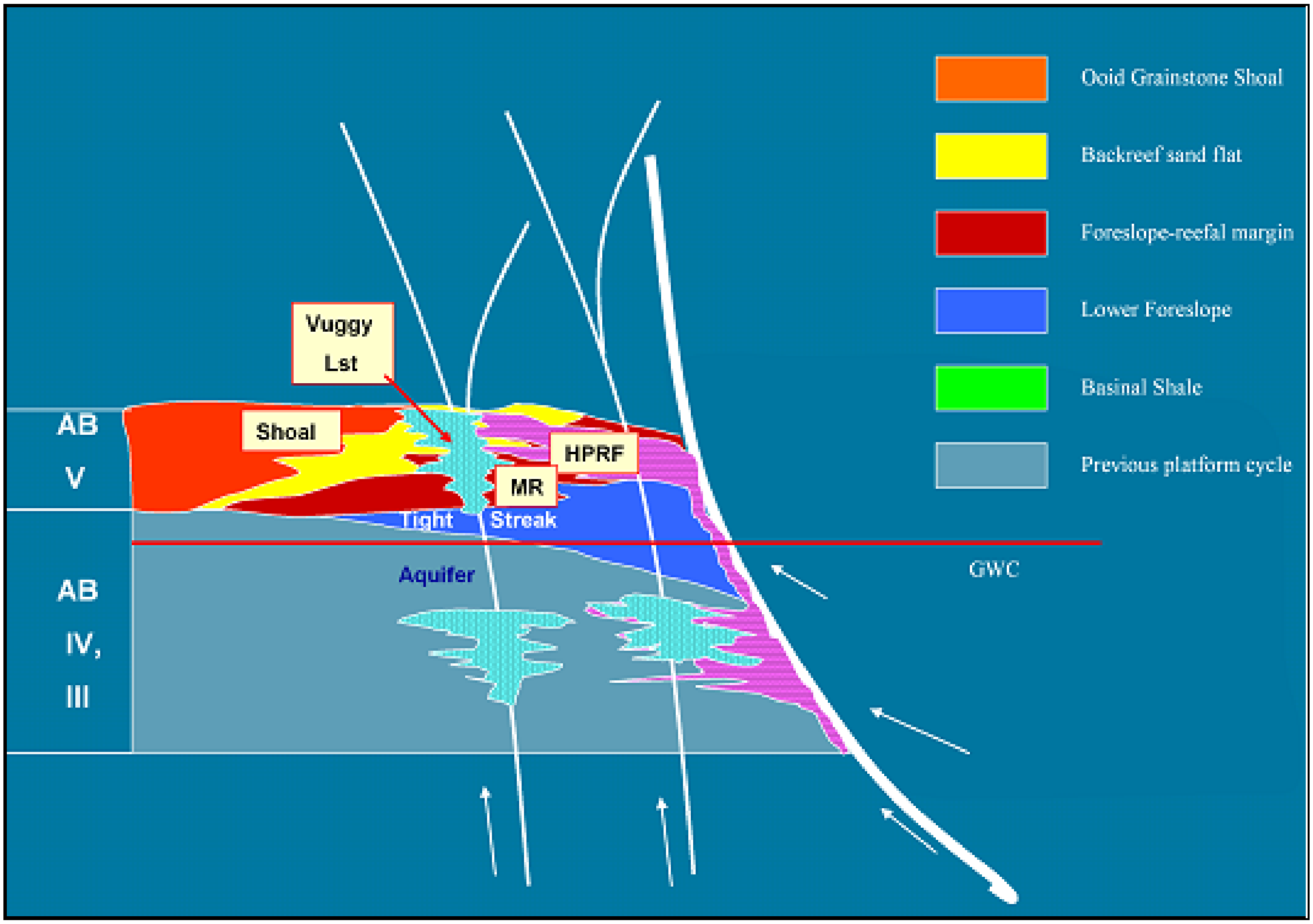


Figure 2.20: Reservoir Regions Applied to the Integrated Depositional Facies and Diagenetic Model

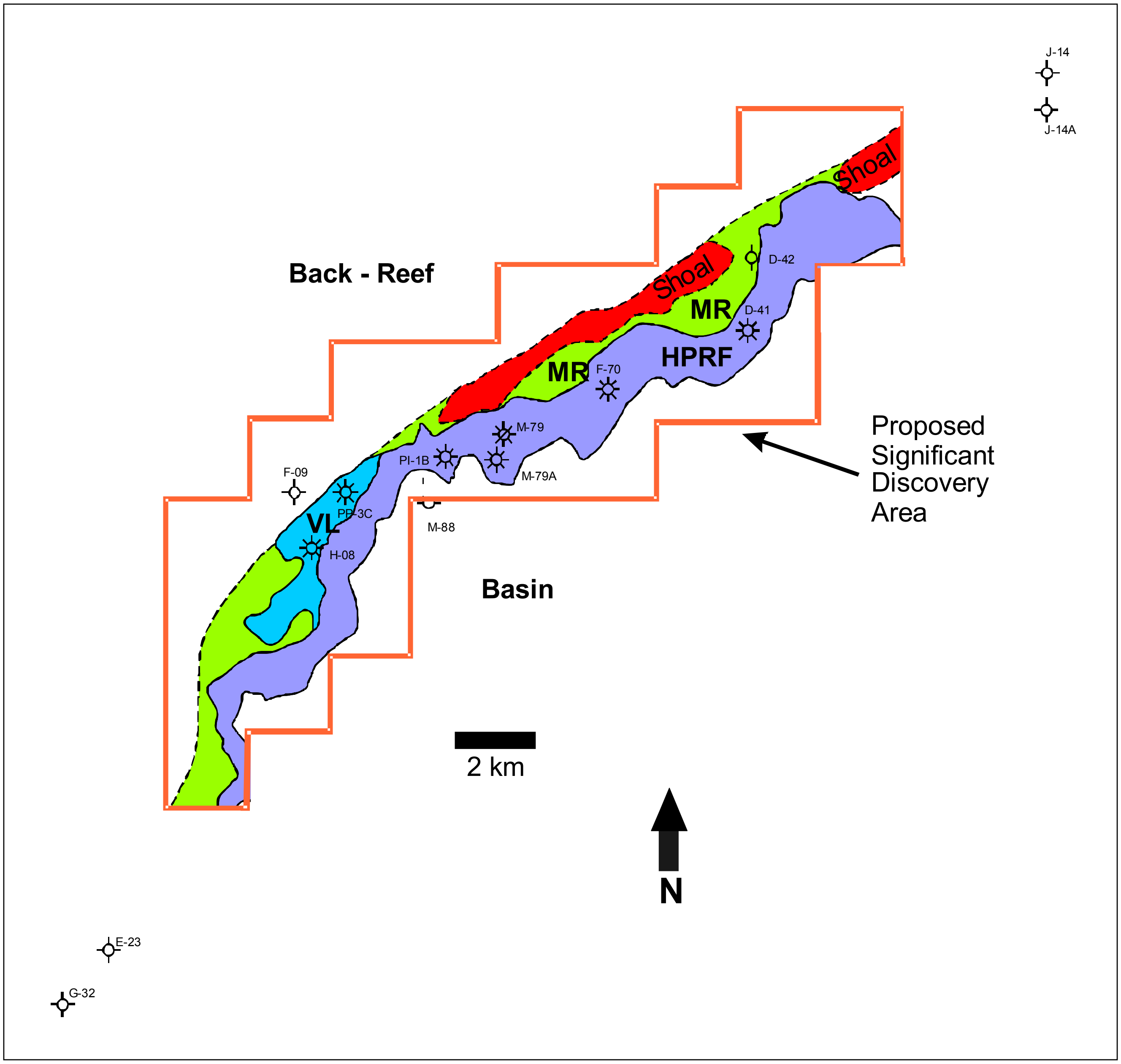


Figure 2.21: Map of Reservoir Regions

2.2.3 Petrophysical Metrics and Models

Consideration of the geology of the Jurassic Abenaki carbonates and corresponding drilling operations parameters led to the application of comprehensive LWD and wireline logging programs in Deep Panuke exploration and delineation wells. Formation evaluation program objectives achieved include the development of a robust logging program to minimize the risk to key data collection and secondly the development of a robust petrophysical model to describe the prolific gas-bearing carbonate reservoir intervals.

Within well operations limitations, the same evaluation program was run in all of the pool wells and EnCana operated pool-delimiting wells. In wells drilled later (eg. F-70, D-41, J-14) extra care was taken to maximize data collected to characterize fractured rock.

The well sketch provided in Figure 2.22 illustrates typical stratigraphy, casing program and the target Jurassic Abenaki Formation penetration by 216 mm hole section drilled with KCL water-based mud. Annular velocity control (AVC) drilling procedures were employed where indicated by fluid losses in highly vuggy carbonates.

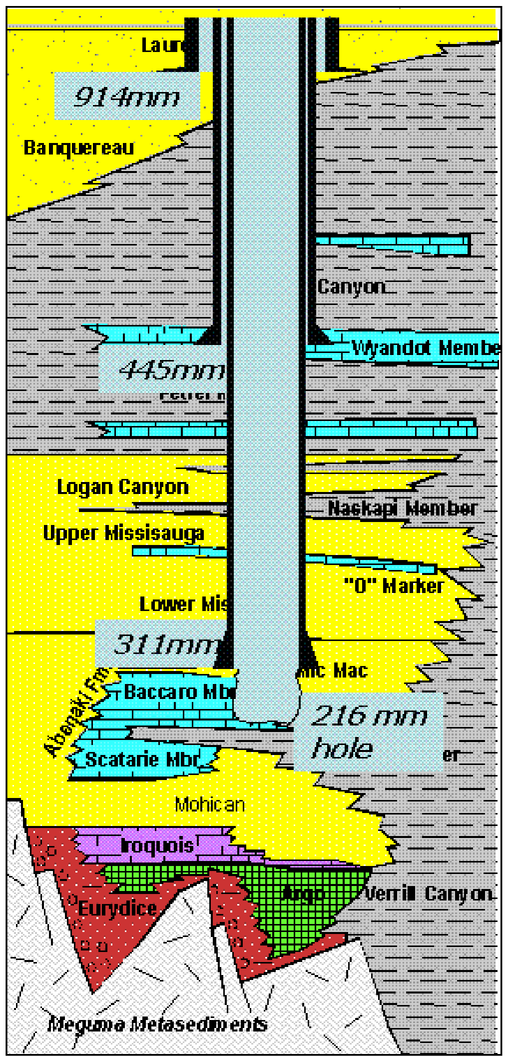


Figure 2.22: Well Sketch

The base logging program is LWD or wireline gamma ray, density, neutron, compressional and shear sonic and resistivity. On success, additional wireline electrical image logs (FMI), rotary sidewall cores, and formation tester pressures/samples (MDT) are taken.

To adequately describe the variable dolomitized/leached carbonate rock fabric in petrophysical terms, a dual porosity, complex lithology model was applied (DPA-Part 2 Ref # 2.14). It is constructed using sonic, density, photoelectric, neutron, resistivity, borehole image logs, standard core and special core data.

To maximize the robustness of the model, measurement environment differences between LWD, wireline and core data were reconciled as much as possible in the data acquisition program and model design.

2.2.3.1 Baseline Logs

Baseline logs provide metrics to describe the baseline petrophysical model structure and in some cases even provide a degree of valuable "over-constraint" to further validate the model. As illustrated in Figure 2.23, the Density / PEF / Gamma Ray logs describe lithology (carbonates), gas saturation ("crossover") and total porosity structure in the data. The resistivity logs mainly describe primary porosity and constrain water saturation model data structure. The compressional sonic log also provides primary porosity and supplemental lithology (sandstone) model data structure. Lastly, the Neutron log data serves as the other "bookend" for gas "crossover" and total porosity data structure in the model.

Log data quality issues include data scatter and bias. Much of the observed log data scatter derives from scale-dependant variance and heterogeneity of rock physical parameters as shown Figure 2.24.

Some key data bias issues addressed in the analysis include the following:

- barite in mud which systematically raises PEF;
- filtrate flushing of cavernous porosity which systematically lowers resistivity;
- KCL in mud/mud filtrate which systematically raises GR; and
- gas in the formation which systematically lowers RHOB and NPHI.

While this last point renders the nuclear "porosity" logs useless as independent measurements of formation porosity, it sets up important end-members for gas saturation determination in the petrophysical model.

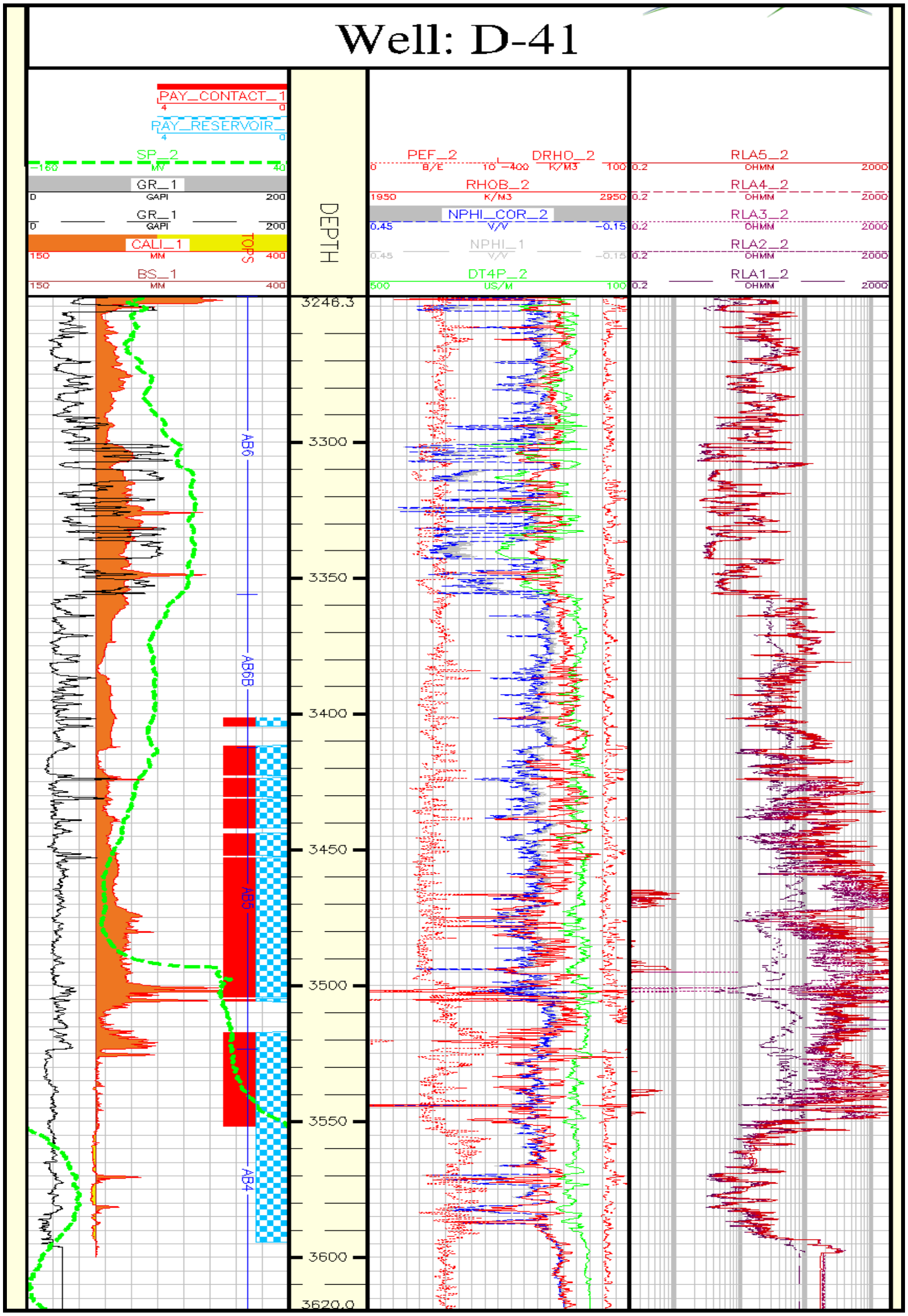


Figure 2.23: Baseline Log Dataset

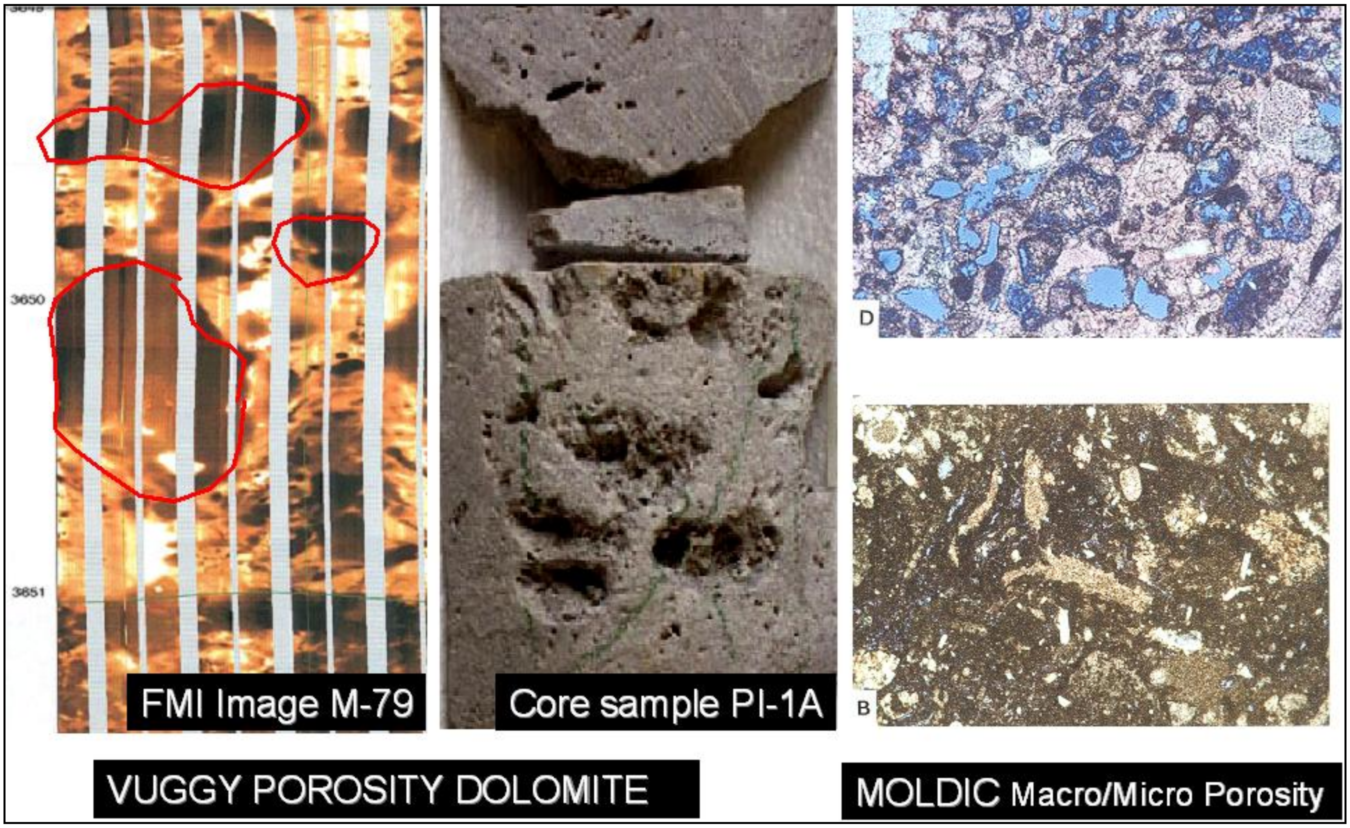


Figure 2.24: Porosity heterogeneity on several scales is illustrated in the core and log images

Special log data

The key special log data to supplement the baseline model includes Dipole Sonic Log (used for AVO, LMR Stoneley permeability), Formation Micro-imager (used for FMI-depositional environment, rock fabric texture, vugs, fractures), wireline Formation Tester (used for MDT-Pressure profile for GWC & fluid identification) and Spectral Gamma Ray (shale).

2.2.3.2 Rock and fluid samples

Sample data include conventional and rotary sidewall core (used for porosity, permeability, grain density) and fluid samples from wireline formation tester and production tests (used for fluid and gas description).

Rock and fluid sample data issues include data scatter and bias. Much of the observed rock sample data scatter derives from scale-dependant variance and heterogeneity of rock physical parameters. Because of sparse sampling and operational challenges in sampling vuggy and fractured reservoir rock, bias is introduced into the data as well.

Notwithstanding the rock heterogeneity, lithology and porosity from core plugs and full diameter core are employed to constrain and validate the petrophysical model parameters. Special core analysis (SCAL) saturation data are integrated with in-situ-derived (log) data to describe the "constant bulk volume water" (BVW) fluid saturation model for up-scaling into the 3-D earth model.

2.2.3.3 Conventional Core Analysis

The following whole core was available for analysis for Deep Panuke:

- 3m from the H-08 well (DPA-Part 2, Ref # 2.15);
- 1.5 m from the PI-1A well (DPA-Part 2, Ref # 2.16);
- 24.7 m from the F-70 well (DPA-Part 2, Ref # 2.17); and
- about 250 rotary sidewall core samples from wells PI-1A/B, F-09, M-79, F-70, D-41 and E-23.

The depositional facies and lithologies observed in the F-70 conventional core are summarized schematically in Figure 2.25. The core is predominantly dolomite except for the uppermost 6 m which are tight limestone. The vertical succession is interpreted as upward-deepening reefs developed on proximal fore-reef slope.

Although very helpful in characterizing the Abenaki 5 depositional environment and facies and in providing lithology and porosity-permeability measurements with which to calibrate well logs, the F-70 well whole core did not extend down into the better reservoir quality, higher porosity dolomites below the core in the Abenaki 5.

Only 3 m of whole core for the vuggy limestone in the H-08 well is available; side-wall core recovery is problematic in vuggy rock since vug size often exceeds the side-wall core size.

There is a systemic bias in the core sampling of the Deep Panuke reservoir whereby both the high porosity-permeability dolostone and VL lithotypes have been under-sampled. This limits the ability to effectively characterize the reservoir because the conventional and special core analysis data available comes from the low porosity samples and does not fully serve to characterize the range of porosity known to be present in the pool.

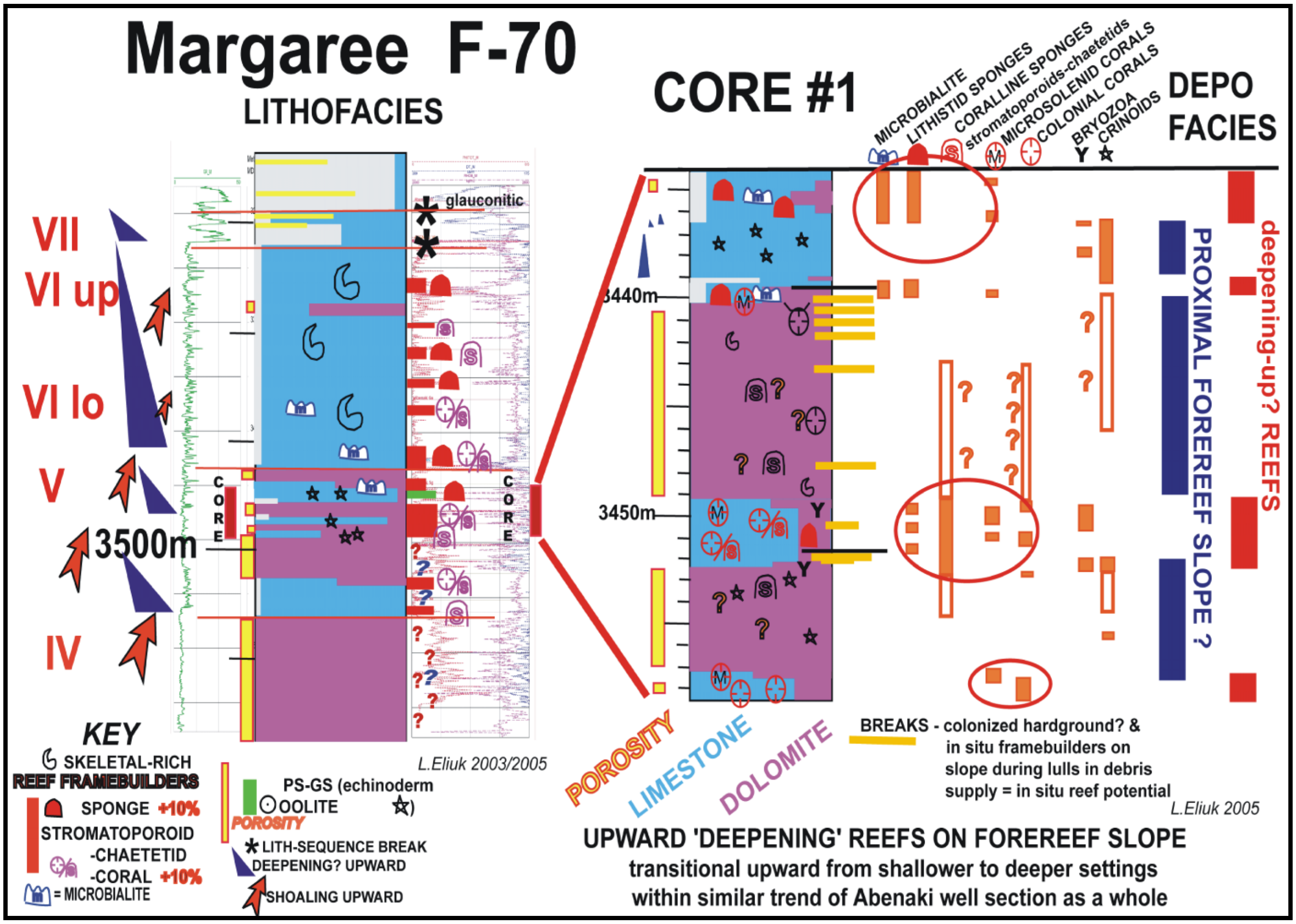


Figure 2.25: Margaree F-70 Schematic Core Description (DPA-Part 2, Ref # 2.18)

All available porosity and permeability data from conventional cores and sidewall cores in the pool are cross-plotted in Figure 2.26 with no discrimination of lithology or depositional facies. Core porosity ranges from 0 to 18 percent with the majority of the data points having less than 7 percent porosity. Permeability ranges over six orders of magnitude, from 0.01 to 10,000 milli-darcies. The core sampling bias must be considered when examining this plot since high porosity values evident from well logs (e.g. H-08) are not adequately represented in the core data.

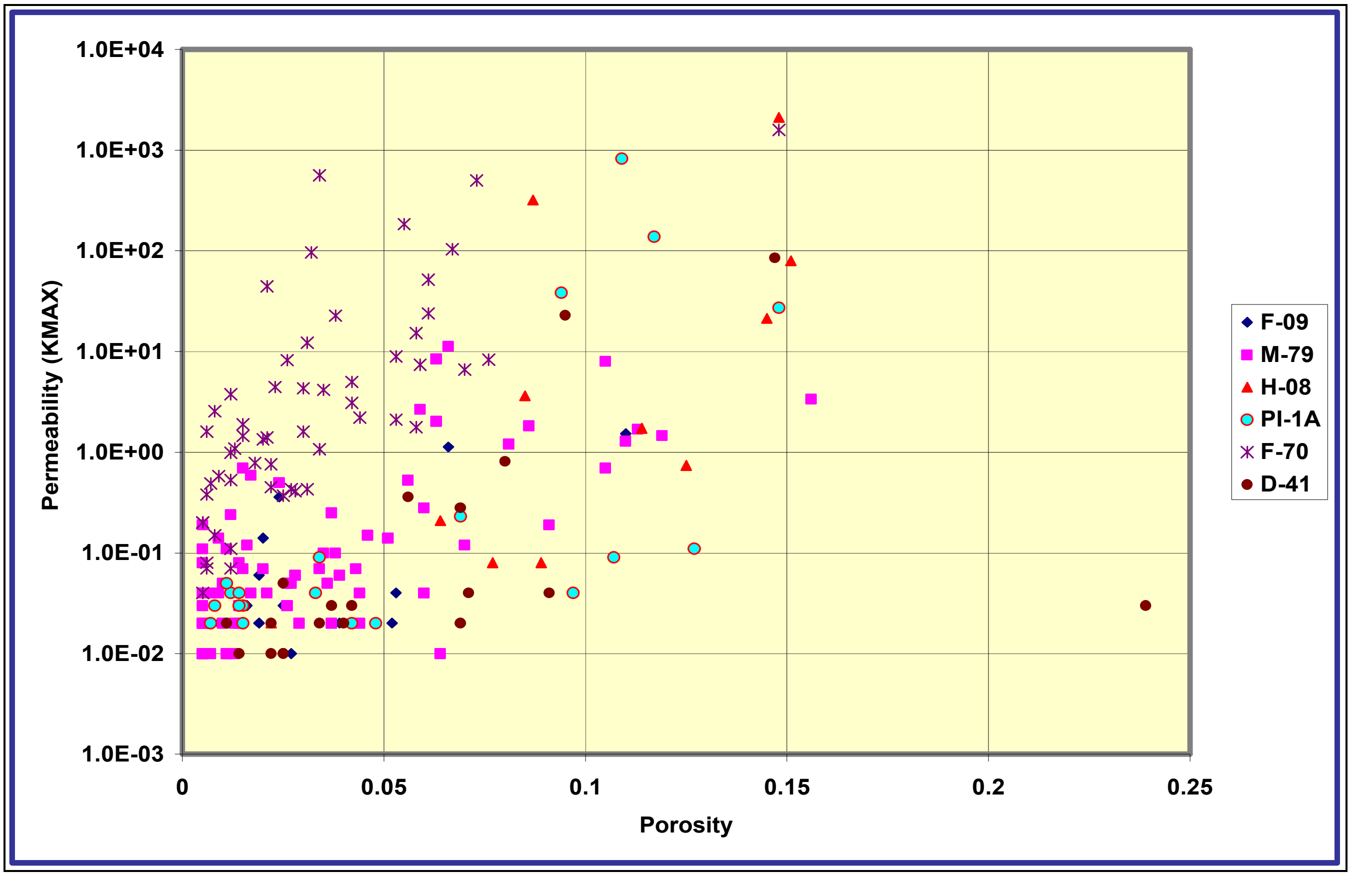


Figure 2.26: Porosity and Permeability – All Wells

No simple, obvious porosity-permeability relationship is evident in the data aside from a general increase in permeability with increasing porosity.

The porosity-permeability cross-plot from both whole and side-wall core for the dolomite lithology is presented as Figure 2.27.

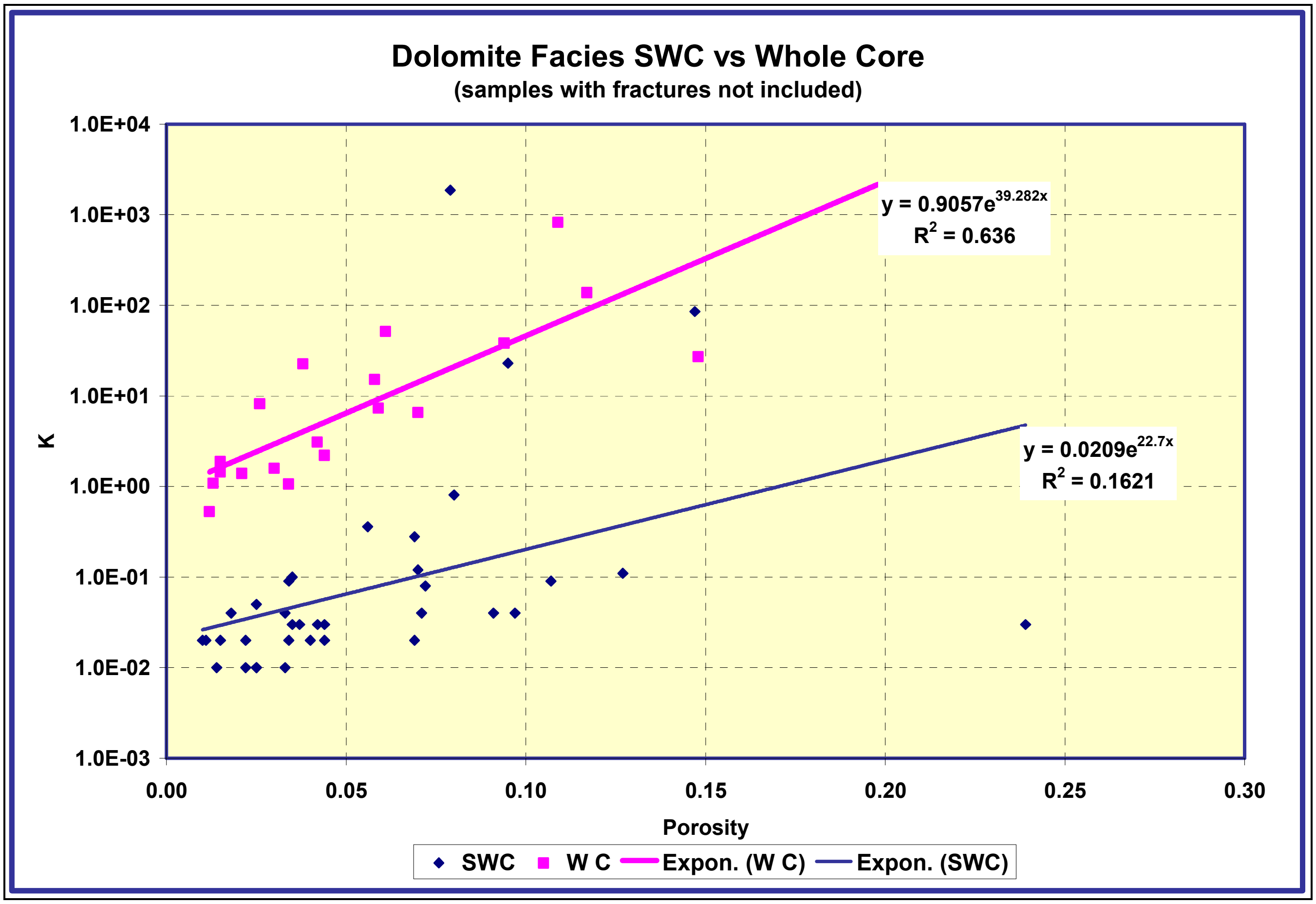


Figure 2.27: Dolomite Facies SWC vs. Whole Core

An obvious discrepancy is present in the data whereby side-wall core samples show the same range of porosity as whole core samples but most permeability values are about two orders of magnitude lower for the side-wall core samples. The side-wall core samples are too small in size to adequately represent permeability in a vuggy, fractured reservoir such as Deep Panuke. Side-wall core permeability measurements may be adequate measurements of matrix permeability but are inadequate for evaluating flow through touching vugs or fractures.

The whole core data does show a reasonable relationship between porosity and permeability, though it must be noted that most of this data comes from just the F-70 well and excludes the samples that had fractures identified in their sample description. The exponential trend line for the whole core reduced by a factor of 0.25 for overburden represents the baseline matrix permeability used for the HPRF in the reservoir models (see Section 2.4).

The porosity versus permeability plot for limestones, Figure 2.28, shows wide scatter, particularly for the whole core data for which there are relatively few data points. Maximum side-wall core porosity matches the whole core data but maximum side-wall core permeability values are much less than from whole core data. This is likely a consequence of small side-wall core sample size in vuggy limestones, as per the dolomite data. The exponential trend-line through both WC and SWC reduced by a factor of 0.5 represents the baseline permeability used for the VL in the reservoir models (see Section 2.4).

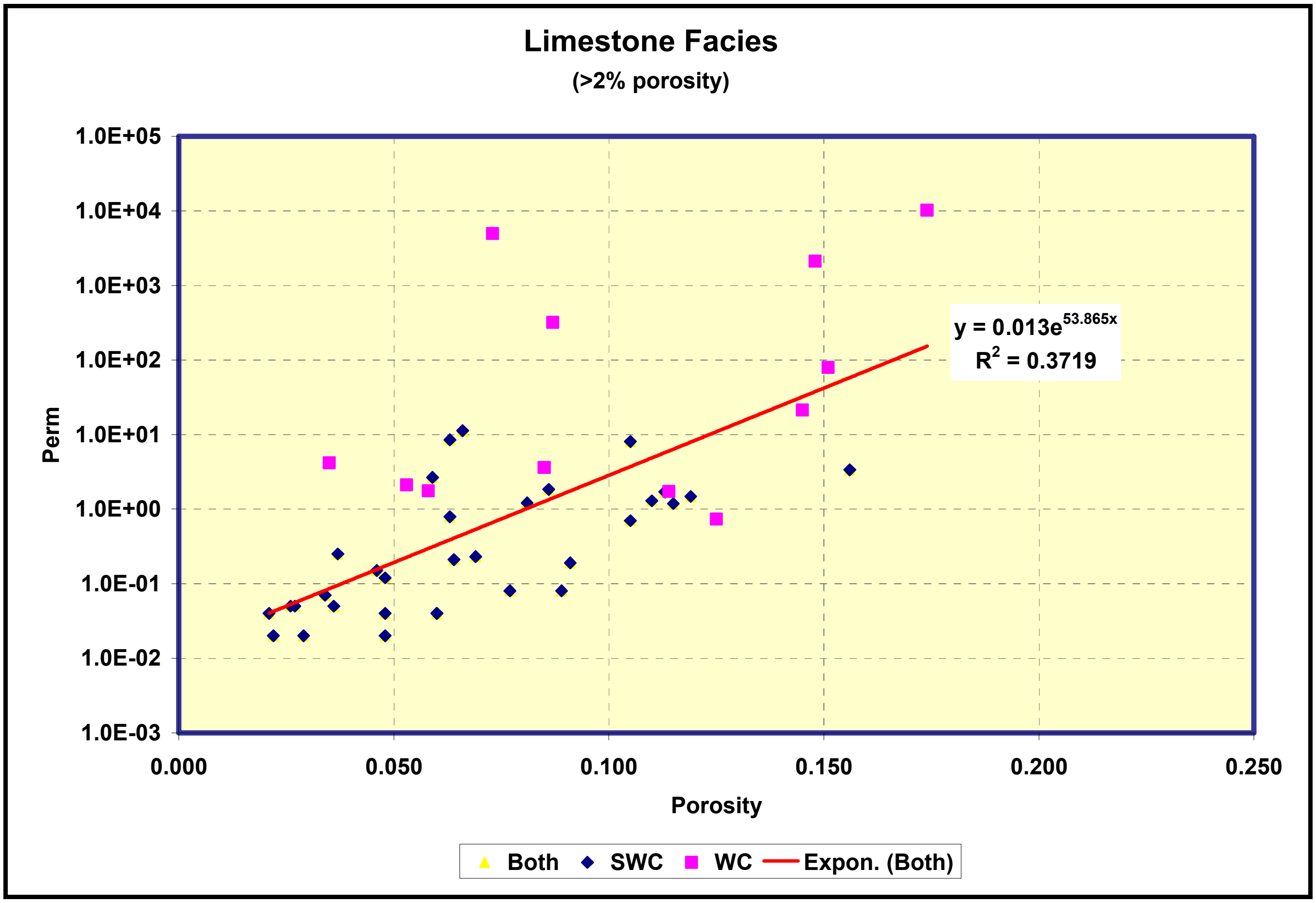


Figure 2.28: Limestone SWC vs. Whole Core

2.2.3.4 Special Core Analysis

Special core analysis (SCAL) studies have been performed on conventional core and sidewall cores from the H-08, M-79 (sidewalls only), F-09 (sidewalls only) and F-70 wells and are summarized in Table 2.5.

Table 2.5: Special Core Analysis Studies

Type of Analysis	Report Name	Reference No.	Application
Mercury Injection Capillary Pressure	Core Laboratories 2001a, Report # 52132-01-1063 Core Laboratories (2004b, Report # 52132-03-0680	2.21 2.19	See Section 2.2.3.5
Porous-Plate Air-Brine Capillary Pressure Drainage	Core Laboratories (2004b)	2.19	See Section 2.2.3.5
Capillary Pressure FF/RI	Omni Laboratories, 2004 File # S-00207	2.24	See Section 2.2.3.5
Air-Brine Capillary Pressure	Core Laboratories, 2001b, Report # 52132-01-1076), Core Laboratories, 2001c, Report # 52132-01-1105 Core Laboratories, 2004b, Report # 52132-03-0680).	2.22 2.20 2.19	See Section 2.2.3.5
Compressibility Measurements	Terra Tek, Compressibility Measurements – Deep Panuke Carbonates Report # TR04_401037, May 2004	2.23	Used in simulation for reservoir and aquifer modelling.
Gas Regain Permeability	Core Laboratories, 2001c, Well H-08, Report # 52132-01-1105	2.20	To evaluate the potential formation damage caused by the accidental leakage of seawater into the Abenaki formation and the effectiveness of using methanol to remove the excess water in the near wellbore region. Not used
Porosity and Permeability at Net Overburden Pressure	Core Laboratories, 2004b – Advanced Rock Properties Study Report # 52132-03-0680	2.19	Large variability in results. Not used directly.

2.2.3.5 Compilation of Capillary Pressure Results

The compilation of capillary pressure data for the pool, converted to wetting phase saturation fraction versus height above free water level, is displayed in Figure 2.29. The figure immediately reveals wide scatter in the data. This can be attributed to the heterogeneous nature of the reservoir which includes varying lithologies (e.g. limestone, dolomitic limestone, limy dolomite, and dolomite) and pore types (e.g. micro-porosity, intergranular, intercrystalline, and vuggy) and the different testing and analytic methods used to generate the data.

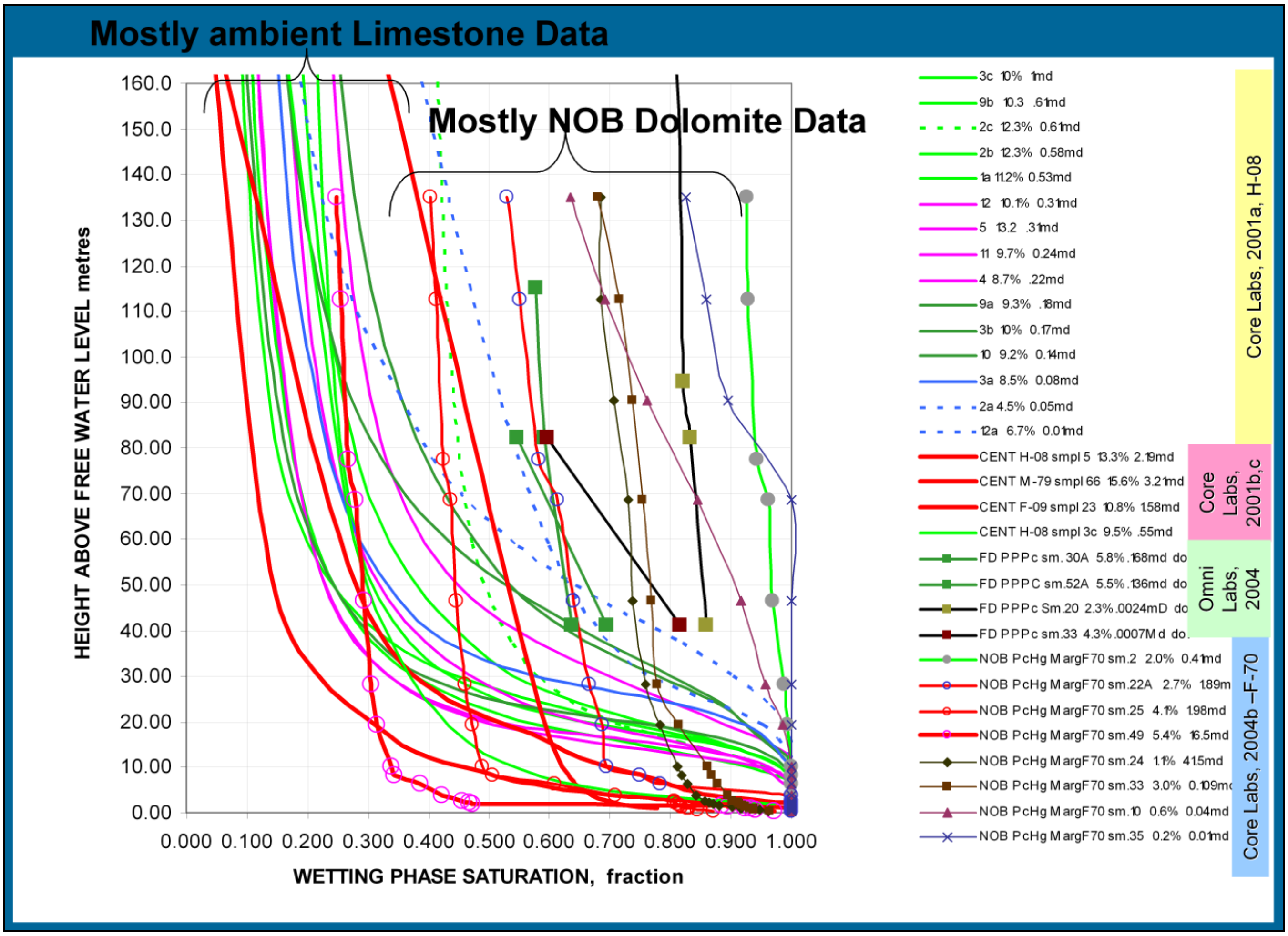


Figure 2.29: Capillary Pressure Data Compilation

A preferred method for describing capillary pressure relationships is called the "J-function" method. Despite attempts to select data sub-sets and manipulate the data for Deep Panuke, it was concluded that it was not possible to derive one or more "J-functions" from the widely scattered capillary pressure data for application across the pool. It was determined that the methodology best suited for describing and modelling water saturations at Deep Panuke above the free water level is the Bulk Volume Water (BVW) method as will be described in detail in Sections 2.2.3.7 and 2.2.3.8.

The porosity and irreducible water saturation data for the tested dolomite and limestone core plugs are plotted with lines of constant BVW in Figure 2.30. The trend-lines and relatively high correlation factors support the use of constant BVW to determine water saturations for the individual lithofacies. The trend lines for the dolomite samples yield a BVW between 1.0 to 1.5 percent. The trend line for the limestone closely approximates a BVW of 2 percent.

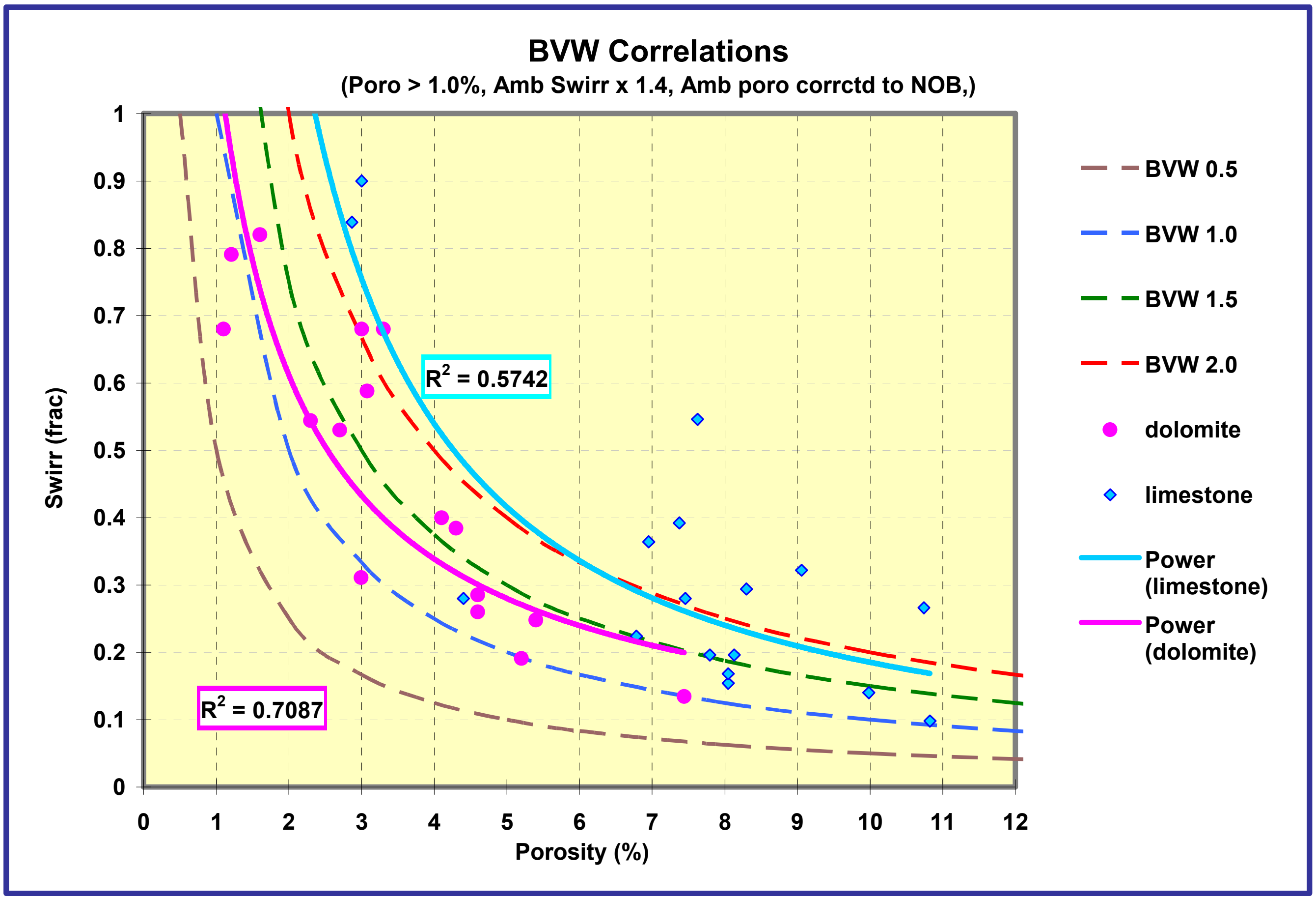


Figure 2.30: SCAL BVW Correlations

2.2.3.6 Future Data Acquisition Strategy

During the pool development phase, data acquisition plans for subsequent wells drilled will be directed toward verification of the amount and quality of reservoir rock penetrated and toward evolution of the working reservoir model to reconcile observed gas production to that point in time. These efforts aim to further reduce uncertainties in pool size and thereby to maximize resource recovery and value realized.

LWD and/or wireline recordings of sonic, density/neutron and resistivity logs will be recorded over the reservoir section where practical and safe to do so to verify well placement in the working reservoir model. On occasion, particularly where reservoir rock facies not previously encountered are drilled, supplemental data acquisition to describe formations and fluids will be carried out. The specific data acquisition plan is dependant on the reservoir facies encountered, but might include special wireline and/or LWD surveys and sample taking to verify geological structure, geological depositional environment, rock and fluids composition, formation porosity, formation pressure, fluid saturations and permeability.

Cased hole production monitoring logs will also be run as required to monitor reservoir performance.

2.2.3.7 Petrophysical Model Development

A petrophysical model to solve for lithology (mineral volumes) and porosity (fluid volumes) was developed for a baseline set of wireline logs. A conventional probabilistic solver inverts the matrix representing the set of linearized log responses by minimizing an error function to yield the desired volumes (DPA-Part 2 Ref # 2.25, 2.26, 2.27).

The number of baseline model output volumes is kept to a minimum. This enables redundancy of input logs for most well data sets. Therefore, a robust, marginally over-determined probabilistic model was realized featuring a tightly-linked analytical check on model validity. Additional special log and rock/fluid sample data provide a further independent loosely-linked analytical model check, which is reconciled in a looping integration/modelling workflow.

Figure 2.31 describes the bulk rock volume model in terms of volumes of solid and liquid components showing associations for rock framework, Archie-type (inter-grain/intercrystalline) and vuggy (dissolution) porosity.

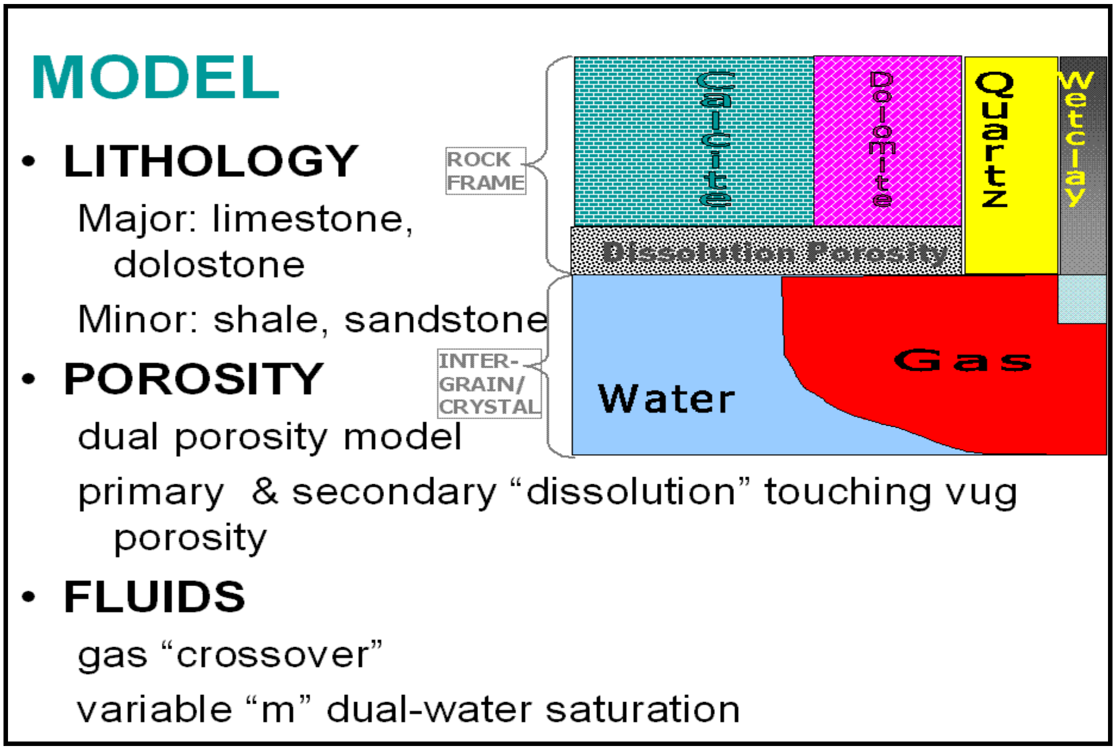


Figure 2.31: Petrophysical model minerals (4) and fluids (2) volumetric associations diagram

The difference of sonic and nuclear porosity logs response to vuggy dissolution pores in rock that otherwise exhibits an intergranular/intercrystalline pore fabric response differentiates porosity types. An Archie-type saturation relationship between porosity and resistivity (Dual-Water if shaley) applies to the "inter-grain/crystal" portion of the dual-porosity model only.

The effect of dissolution porosity, modelled here as electrically and acoustically "isolated" (DPA-Part 2, Ref # 2.28) from participating in the Archie saturation relationship and Wyllie time-average porosity relationship can be accounted for by a "variable m" behavior in a saturation relationship. The baseline petrophysical model assumes the dissolution-porosity portion of the dual porosity model is 100% gas-filled above the GWC (DPA-Part 2, Ref #2.29). The water saturation (Sw) then of the "total porosity" is a composite of these two saturation volumes. However, it is gas cross-plot "crossover" effects on nuclear porosity log data that most reliably identify gas-bearing intervals in the wells at Deep Panuke.

As would be expected in such a pore fabric, dissolution porosity effects also drive the analytical modelling of the capillary pressure (SCAL) irreducible water saturation (Swi) data. Total porosity and surface-to-volume ratio of the pore fabric are effectively uncorrelated.

Sequence stratigraphy and petrophysical core data provides control and context on model lithology and porosity end-points. Production test data ultimately provides control on fluid type and permeable zone identification.

The integrated petrophysical model applied to the wells in the pool area is illustrated in Figure 2.32.

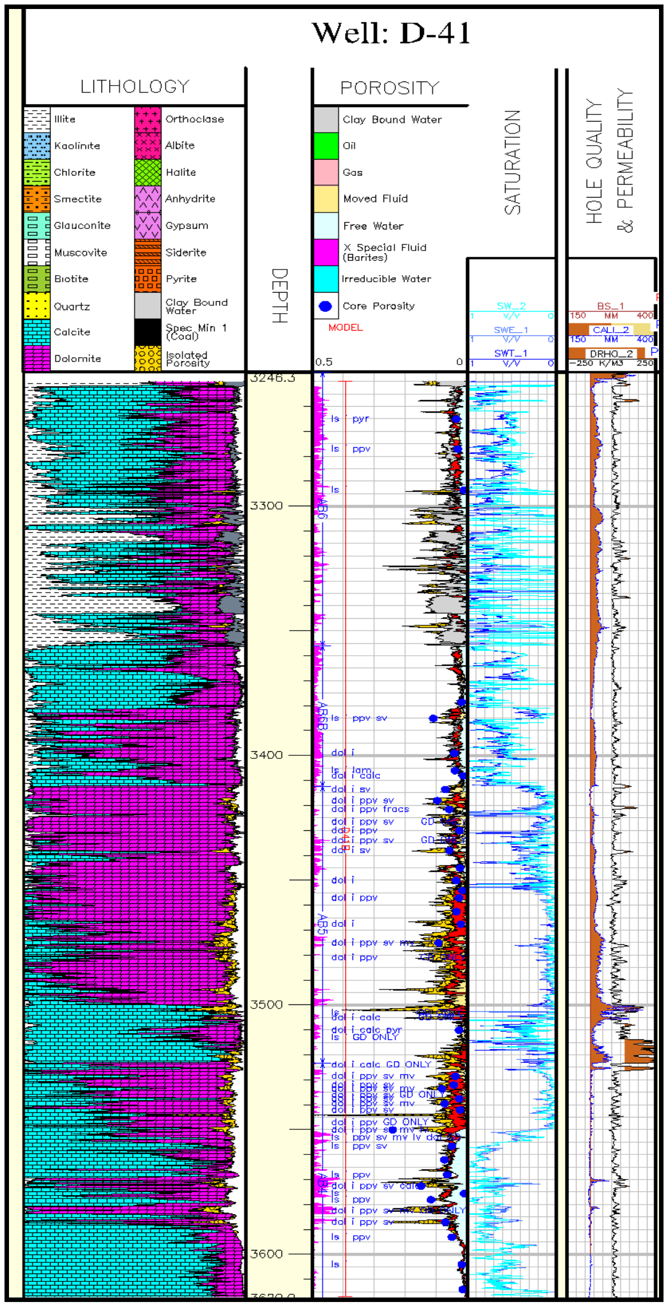


Figure 2.32: Petrophysical model results plot type-log

Across the area wells, the Abenaki gas pool reservoir rock exhibits complex dolostone and limestone lithology where rock pore fabric and corresponding petrophysical properties are dominated by a heterogeneous spatial distribution of diagenetic and dissolution porosity features. Porosities range from three to forty percent with net gas pay intervals ranging from 7 to 122 m as per Table 2.6.

To summarize the petrophysical analysis of the Deep Panuke wells, a cross-section through the wells is presented in DPA-Part 2, Ref # 2.30.

2.2.3.8 Petrophysical Summary Data

Porosity/Lithology Distribution Statistics

In the Deep Panuke pool, the majority of the reservoir porosity is found in dolostones in the HPRF region where petrophysical data exhibit a strong relationship between volume of dolostone (Vol_{Ds}) and total porosity (Phi_{tot}). This power-law relationship is illustrated in Figure 2.33, a cross-plot of the total interval data from top lower Abenaki 6 (AB6B) to base Abenaki 4 in eleven wells (VL wells H-08 and PP-3C not included). Dolomitization improves the porosity of the otherwise tight limestone by up to one order of magnitude and the highest porosities are usually vuggier (vuggy porosity fraction indicated by hotter colors).

Two lithotype end-members are described here; pure limestone and pure dolostone, each of which possess an end-member characteristic porosity distribution. Degree of dolomitization is the major control on porosity for a mixture of these end-members.

This is best illustrated on a colored frequency plot Figure 2.34 where the bimodality of the porosity distribution is evident as peaks and the degree of dolomitization as hotter colors. The Abenaki formation (AB6B, AB5, AB4) in these wells is characterized here as a mixture of the two end-member lithotypes and exhibits a corresponding bimodal porosity distribution on a frequency plot.

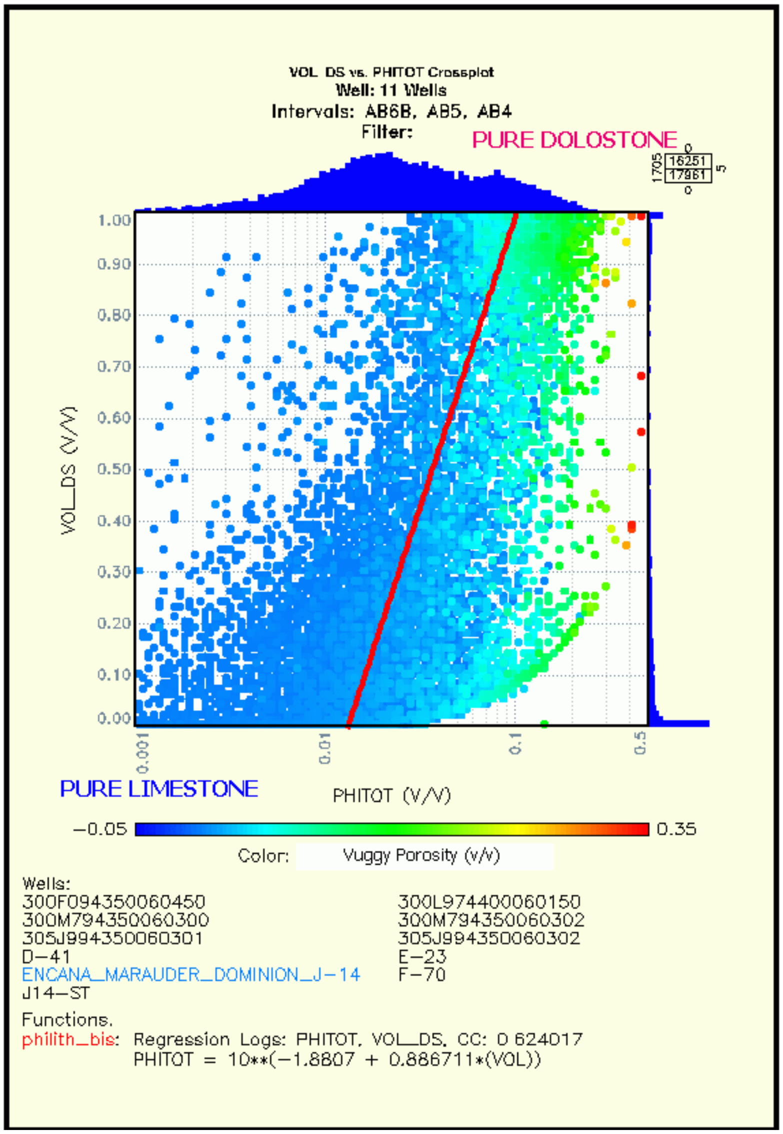


Figure 2.33: Petrophysical Relationship of VolDs to Phitot

Visual inspection of the data on this plot suggests a pure limestone mode porosity of approximately 1.5% and a pure dolostone mode porosity of approximately 10%, each approximately lognormally distributed with a range (P10-P90) of about one-half an order of magnitude.

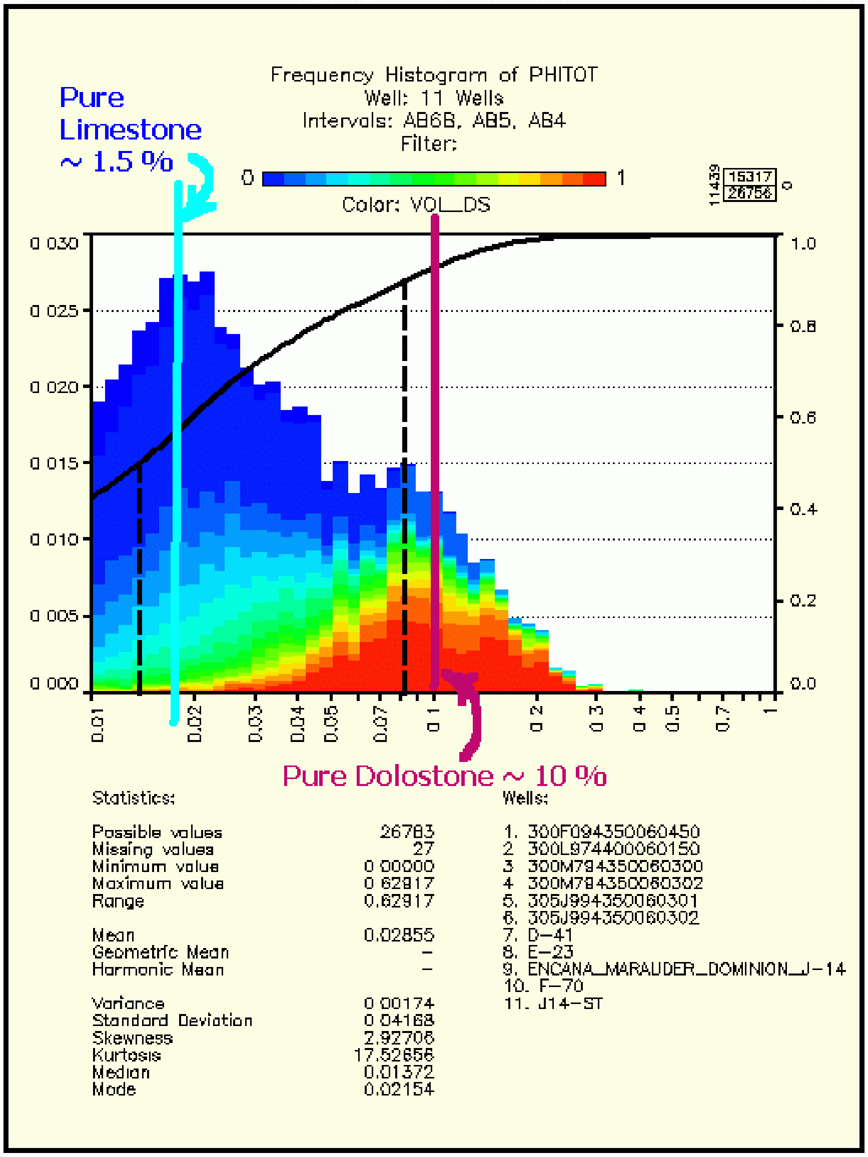


Figure 2.34: Frequency Plot of Total Porosity Distribution for Limestone and Dolostone Lithologies

Within and across several important scales of measurement (reservoir, seismic, log and core sample), the Abenaki porosity distribution is heterogeneous. Porosity, a volume ratio, is also scale-dependant. However, the power-law relationship evident in petrophysical porosity-lithology data and lognormal distributions of end-member diagenetic porosity data are consistent with fractal distributions of rock fabric and pore space.

The range of porosity values expected at seismic scales (approximately 10-25 m vertical resolution) is much less than that observed with petrophysical data derived from well logs (approximately 1 m vertical resolution) or core plug scale (approximately 2 cm vertical resolution) where observed 2 cm diameter vugs have 100% porosity.

In the HPRF region, effects of up-scaling porosity by averaging to seismic scale are illustrated in Figure 2.35. One effect is that the variance of porosities exhibited by limestone and dolostone end-member lithotype modes collapses (regresses) to the mean value for each lithotype. Mode peaks are sharpened with up-scaling to seismic scales.

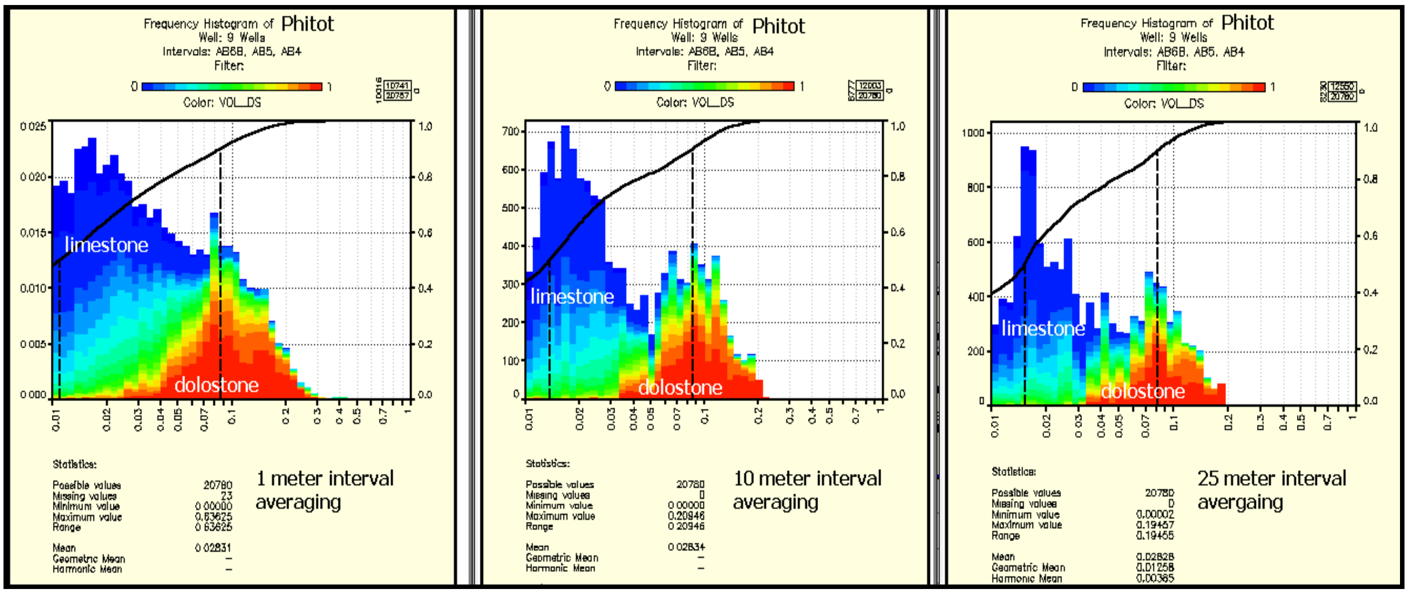


Figure 2.35: Scaling and Diagenetic (Dolomitization) controls on HPRF Porosity Distributions

In the VL region, the bimodal porosity end members are tight and vuggy limestones as shown in Figure 2.36. On smaller scales, very high porosity is seen in vuggy limestone. One meter bit drops experienced while drilling suggest 100% porosity on a 1 m scale. On seismic scales, the upper end of the vuggy porosity range is about 20-30%.

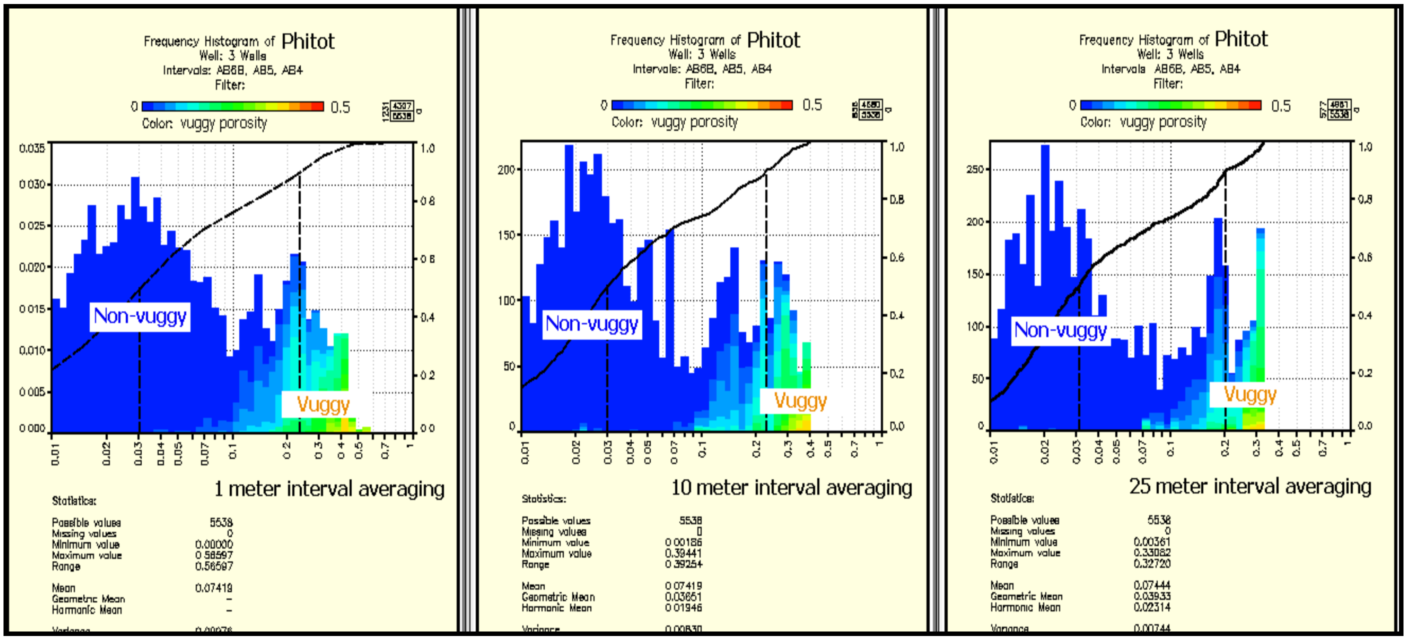


Figure 2.36: Scaling and Diagenetic (Dissolution) controls on VL Porosity Distributions

Fluid Saturation Distribution Statistics

Early in the drilling program of the Deep Panuke exploration and delineation wells, BVW, the product of total porosity and water saturation (BVW = Phi_{tot} x SW), was seen to be well-suited to characterize the distribution of gas in the Abenaki formation. Even though porosity variation is large, the BVW parameter serves to identify the location of the gas-water contact and gas-filled net porous reservoir intervals on petrophysical plots.

Figure 2.37 displays total porosity versus depth for thirteen wells in the Abenaki 4, 5, & 6 intervals. Hotter colored points represent gas-bearing porous intervals (BVW filled porosity is colored darkest blue).

Subsequently, this analytical approach led to characterizing water saturation by aligning core (see section 2.2.3.3) and in-situ (log) capillary (Swi) data by “constant BVW” also.

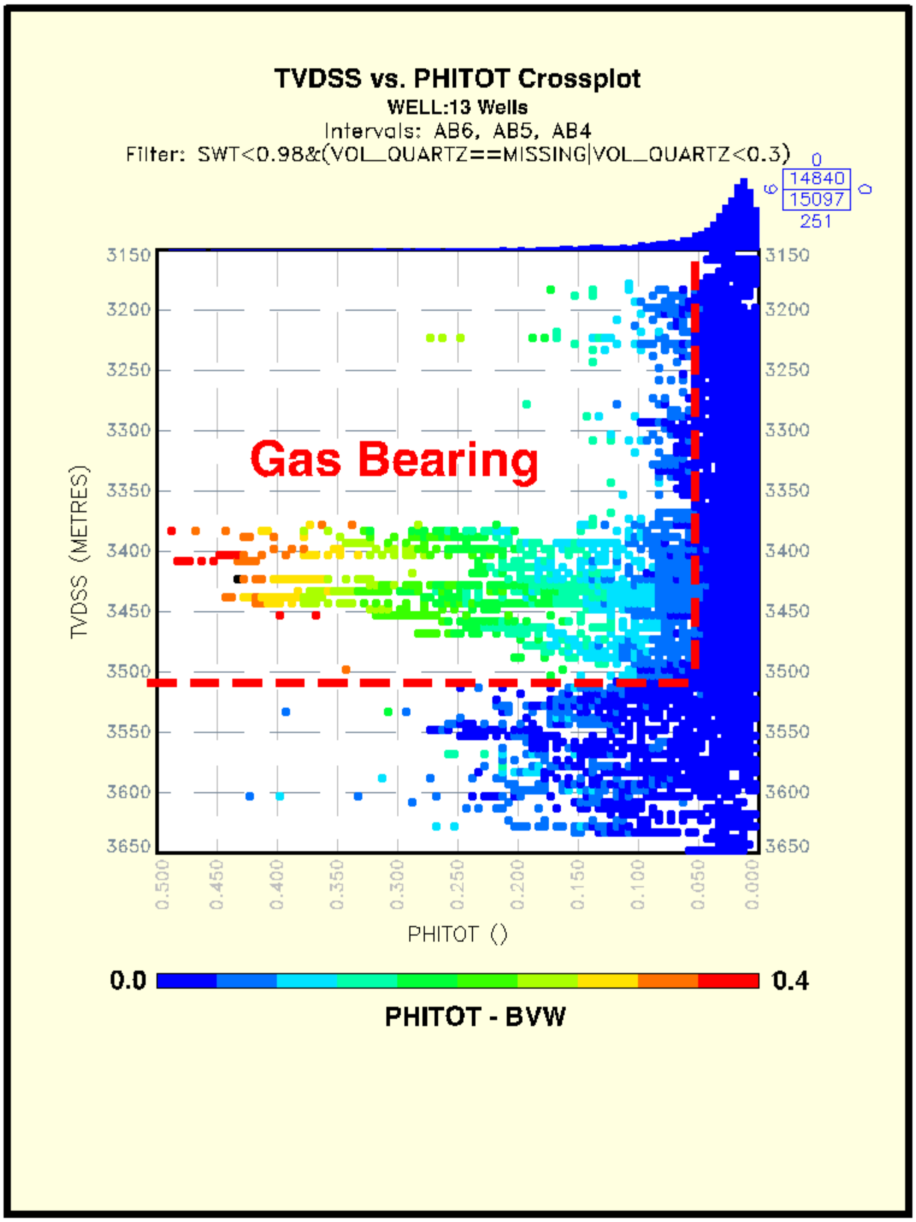


Figure 2.37: Plot of Total Porosity vs. Depth

A constant BVW analytical model is constructed on an overlay of the well-log and SCAL porosity and Swi data for all the wells and core data in Figure 2.38. Within the substantial variation of the data, exaggerated near real physical boundaries on this linear plot, the core and log analysis of Swi correspond well. The plot illustrates data structure along "constant BVW" lines (hyperbolae). SCAL data at Swi and net overburden conditions overlays the modelled log data at Swi (points plotted are greater than 80 m above the GWC) for thirteen wells in the Abenaki 4 and 5. In the Abenaki carbonates, the reservoir porosity is seen to be mainly diagenetic in origin. Diagenetic processes have decoupled any pre-existing relationship between porosity and rock fabric surface-to-volume ratio that occurs normally in variably-sorted clastic sediments.

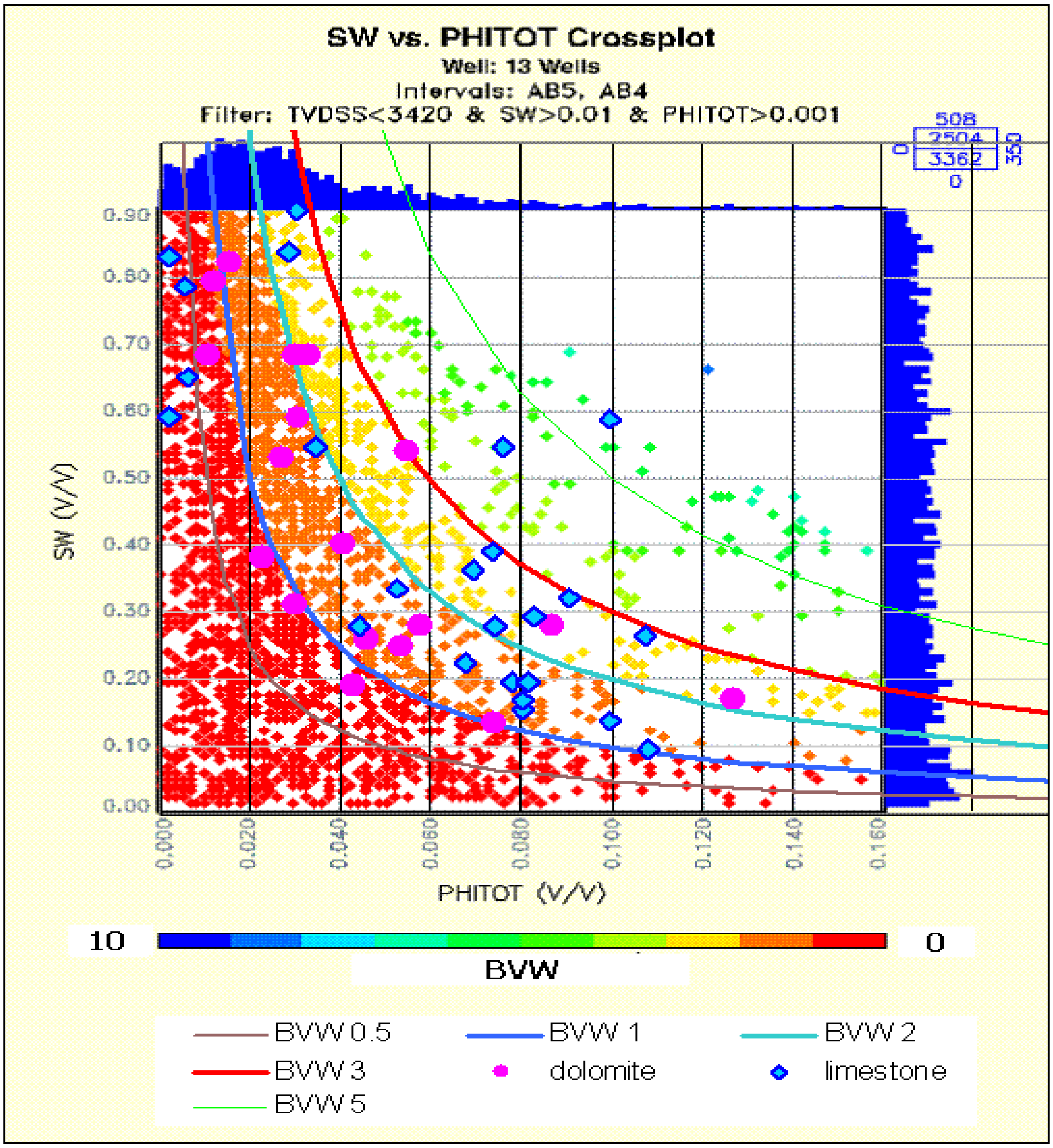


Figure 2.38: All Wells: Saturation (Swi) vs. Total Porosity

In random glass bead packs (and many clastic reservoirs) the grain-size distribution (sorting) tightly links petrophysical properties of porosity and surface-to-volume ratio (water-wet irreducible water saturation). A "J-function" analytical approach works to characterize irreducible water saturation where pore fabric surface-to-volume ratio (Swi) and pore-throat diameter (intrinsic permeability) are determined by a characteristic porosity ultimately derived from packing and sorting of grains.

A constant BVW model for irreducible water saturation determination (Swi) is better aligned with the Deep Panuke porosity system which is dominated by dissolution/secondary porosity that develops with a relatively small change in surface-to-volume ratio, a key controlling factor for BVW.

For wells in the HPRF region, a near constant BVW relationship (Phi_{tot} x SW equals approximately 1%) is illustrated in Figure 2.39 as a hyperbolic regression exhibiting a correlation coefficient of 0.63. This implies a power-law relationship for these data. As porosity is a volume ratio and Swi is strongly dependant on surface to volume ratio, this is consistent with fractal pore fabric geometry.

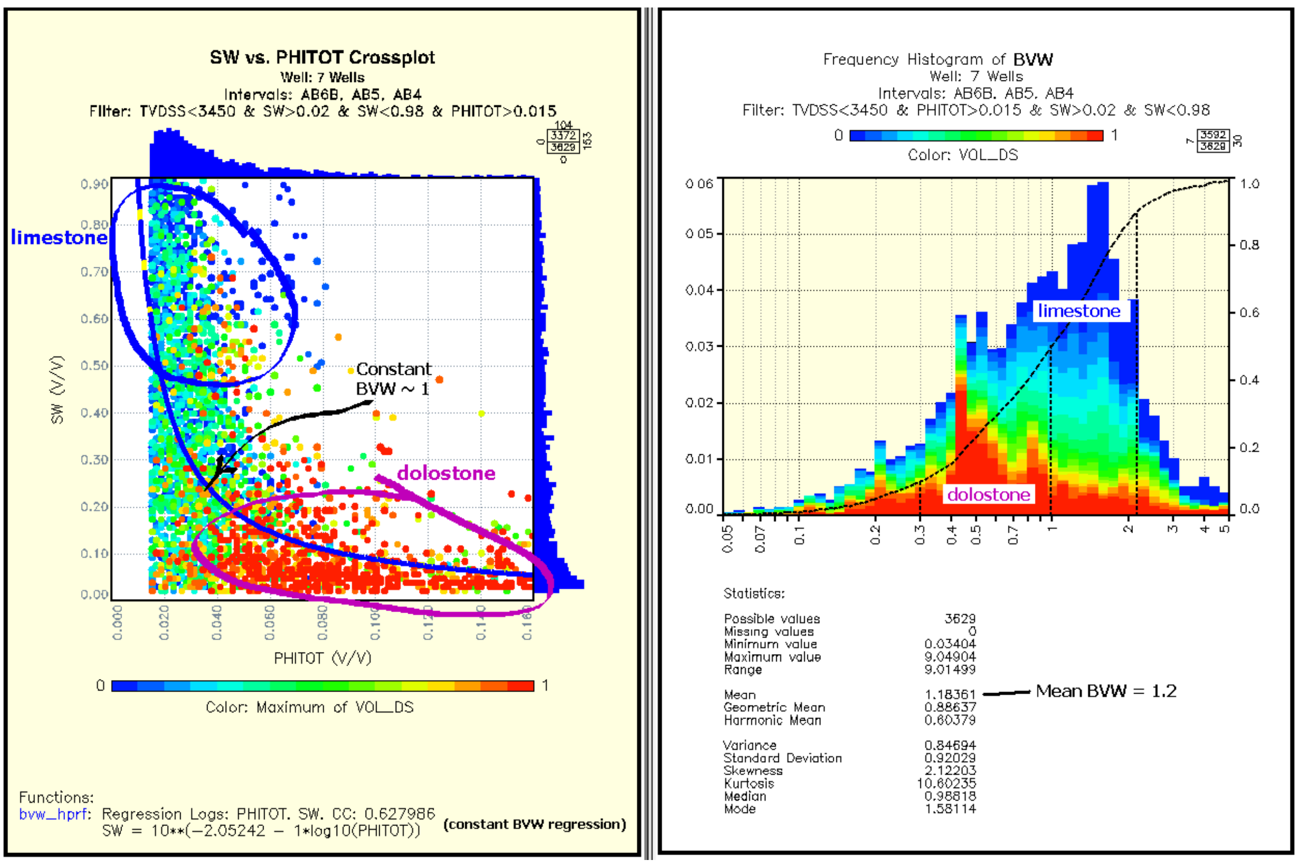


Figure 2.39: BVW and Lithology illustrated on a Saturation (Swi) vs. Porosity (Phitot) cross-plot and BVW frequency plot

Alternatively, on a log frequency plot of BVW, a somewhat skewed bimodal lognormal distribution highlights the limestone end-member mode (BVW approximately 1.4 percent) and the more widely ranging dolostone end-member (BVW approximately 1.0 percent). These parameters permit gas saturation in the upscaled 3-D earth model to be derived from neural network (NN) seismic porosity and lithology volumes trained from corresponding petrophysical well data.

2.2.3.9 Gas in Place Calculations

To determine the percentage of the rock volume (RV) occupied by gas (GV) in the HPRF region the following methodology is applied.

- A fixed "background" porosity of 1.5 % is assigned to the limestone fraction ($Vol_{Ls)}$ of the rock.
- The dolostone porosity is determined using equation 1.
- A fixed water volume (BVW) of 1.2% is assigned to the dolostone porosity.
- The GV is determined using equation 2. By using Vol_{Ds} and Phi_{Ds} in the equation the limestone portion of the rock has been eliminated.

Equation 1: $Phi_{tot} = (Vol_{Ls} \text{ x } Phi_{Ls}) + (Vol_{Ds} \text{ x } Phi_{Ds})$
Equation 2: $GV = RV^* (Vol_{Ds} * Phi_{Ds} - Vol_{Ds}*0.012)$
Equation 3: $GV = Phitot + 0.003*Vol_{Ds} - 0.015$

Phi_{tot} = Total porosity in a rock volume
Vol_{Ls} = Volume of Limestone
Vol_{Ds} = Volume of Dolostone
Phi_{Ls} = Porosity in limestone
Phi_{Ds} = Porosity in dolostone
RV = Rock Volume
GV = Gas Volume

Combining equations 1 and 2 yields Equation 3. Note that the second term in Equation 3, ($0.003*Vol_{Ds)}$, will have a small value compared to Phi_{tot}, so even if Vol_{Ds} is inaccurately estimated, it will have little adverse impact in the GV calculation. Therefore, GV is primarily a function of "$Phi_{tot} – 0.015$" where the 0.015 value is the characteristic "background" porosity in the margin limestone lithotype.

There is only one lithology (limestone) present in the VL region. The gas volume is calculated with Equation 4. A fixed water volume (BVW) of 2.0% is assigned to the limestone porosity.

Equation 4: $GV = RV^*(Phi_{tot} -.02)$

Although not used for volumetrics in this work, Table 2.6 provides a summary of the mean petrophysical properties in the gas-bearing intervals penetrated by wells. This provides an alternative view of rolling-up mean petrophysical parameters at the well locations for the intervals penetrated.

Table 2.6: Well Petrophysical Summary

Well	Interval	TVDSS TOP	TVDSS BASE	GROSS	NET	NET_TO_ GROSS	PHIX_AV	SW_AV	BVW_AV
		METER	METER	METER	METER	M/M	V/V	V/V	V/V
PP-3C	AB6B	3313.1	3362	48.9	0	0			
PP-3C	AB5	3362	3487.3	125.3	85.4	0.68	0.17	0.34	0.06
PP-3C	AB4	3487.3	3575.5	88.2	11.8	0.13	0.06	0.78	0.05
PP-3C	subtot	3313.1	3575.5	262.4	97.2	0.37	0.16	0.36	0.06
PI-1B	AB6B	3318.5	3368.7	50.2	0	0			
PI-1B	AB5	3368.7	3493.1	124.4	38.6	0.31	0.05	0.13	0.01
PI-1B	AB4	3493.1	3521	27.9	10.2	0.37	0.06	0.1	0.01
PI-1B	subtot	3318.5	3521	202.5	48.8	0.24	0.06	0.13	0.01
PI-1A	AB6B	3317.4	3369.9	52.4	0	0			
PI-1A	AB5	3369.9	3503.7	133.8	6.9	0.05	0.04	0.29	0.01
PI-1A	AB4	3503.7	3543.3	39.7	0	0			
PI-1A	subtot	3317.4	3543.3	225.9	6.9	0.03	0.04	0.29	0.01
M-79A	AB6B	3350.6	3405.4	54.8	4.3	0.08	0.04	0.43	0.02
M-79A	AB5	3405.4	3445.3	37.8	16.2	0.43	0.08	0.06	0
M-79A	subtot	3350.6	3445.3	92.5	20.6	0.22	0.07	0.1	0.01
M-79	AB6B	3365.5	3417.2	51.7	0	0			
M-79	AB5	3417.2	3572.8	155.7	13.5	0.09	0.04	0.58	0.02
M-79	AB4	3572.8	3658.1	85.2	0	0			
M-79	subtot	3365.5	3658.1	292.6	13.5	0.05	0.04	0.58	0.02
H-08	AB6B	3349.7	3394.4	44.7	6.2	0.14	0.12	0.23	0.03
H-08	AB5	3394.4	3532.1	137.7	105.8	0.77	0.23	0.23	0.05
H-08	AB4	3532.1	3644.2	112.1	0	0			
H-08	subtot	3349.7	3644.2	294.5	112	0.38	0.22	0.23	0.05
F-70	AB6B	3326.1	3378.1	52	1	0.02	0.06	0.26	0.01
F-70	AB5	3378.1	3515	136.9	75	0.55	0.09	0.06	0.01
F-70	AB4	3515	3597	82.1	0	0			
F-70	subtot	3326.1	3597	270.9	76	0.28	0.09	0.06	0.01
F-09	AB6B	3250.9	3295	44.1	0	0			
F-09	AB5	3295	3412.4	117.3	11	0.09	0.05	0.46	0.02
F-09	AB4	3412.4	3529.8	117.4	15.8	0.13	0.04	0.72	0.03
F-09	subtot	3250.9	3529.8	278.8	26.8	0.1	0.04	0.6	0.03
D-41	AB6B	3308.4	3364.7	29.4	2.5	0.09	0.03	0.61	0.02
D-41	AB5	3364.7	3475.6	110.8	91.4	0.82	0.09	0.06	0.01
D-41	AB4	3475.6	3572.2	96.6	28.2	0.29	0.09	0.07	0.01
D-41	subtot	3308.4	3572.2	236.8	122.1	0.52	0.09	0.07	0.01
All Wells	**AB6B**	**-**	**-**	**428.2**	**14**	**0.03**	**0.08**	**0.36**	**0.02**
All Wells	**AB5**	**-**	**-**	**1079.7**	**443.8**	**0.41**	**0.13**	**0.19**	**0.03**
All Wells	**AB4**	**-**	**-**	**649.2**	**86.6**	**0.13**	**0.07**	**0.3**	**0.02**
All Wells	**TOTAL**	**-**	**-**	**2156.9**	**503.3**	**0.23**	**0.12**	**0.2**	**0.03**

PHIX	>= .03 V/V	Standalone Minimum Thickness:		1 METRES	
CARB	> 0 V/V	Include Minimum Thickness:		0.25 METRES	
TVDSS	<= 3504 METRE	Maximum Separation:		0.5 METRES	

2.2.4 Hydrogeology

Regional Abenaki Formation and Deep Panuke pool pressure data was analyzed by Cox, W., 2001 (DPA-Part 2, Ref # 2.31) to determine the regional pressure regime(s) and pressure continuity within the Abenaki Formation in the pool and region. Given the data uncertainties due to drilling practices and limited quantity of data, Cox's key conclusions are that the Abenaki Formation is in a normal pressure regime and that the best interpretation is that there is one pool at Deep Panuke underlain by a regional Abenaki Formation aquifer. The pressure data for the wells analyzed are displayed in Figure 2.40.

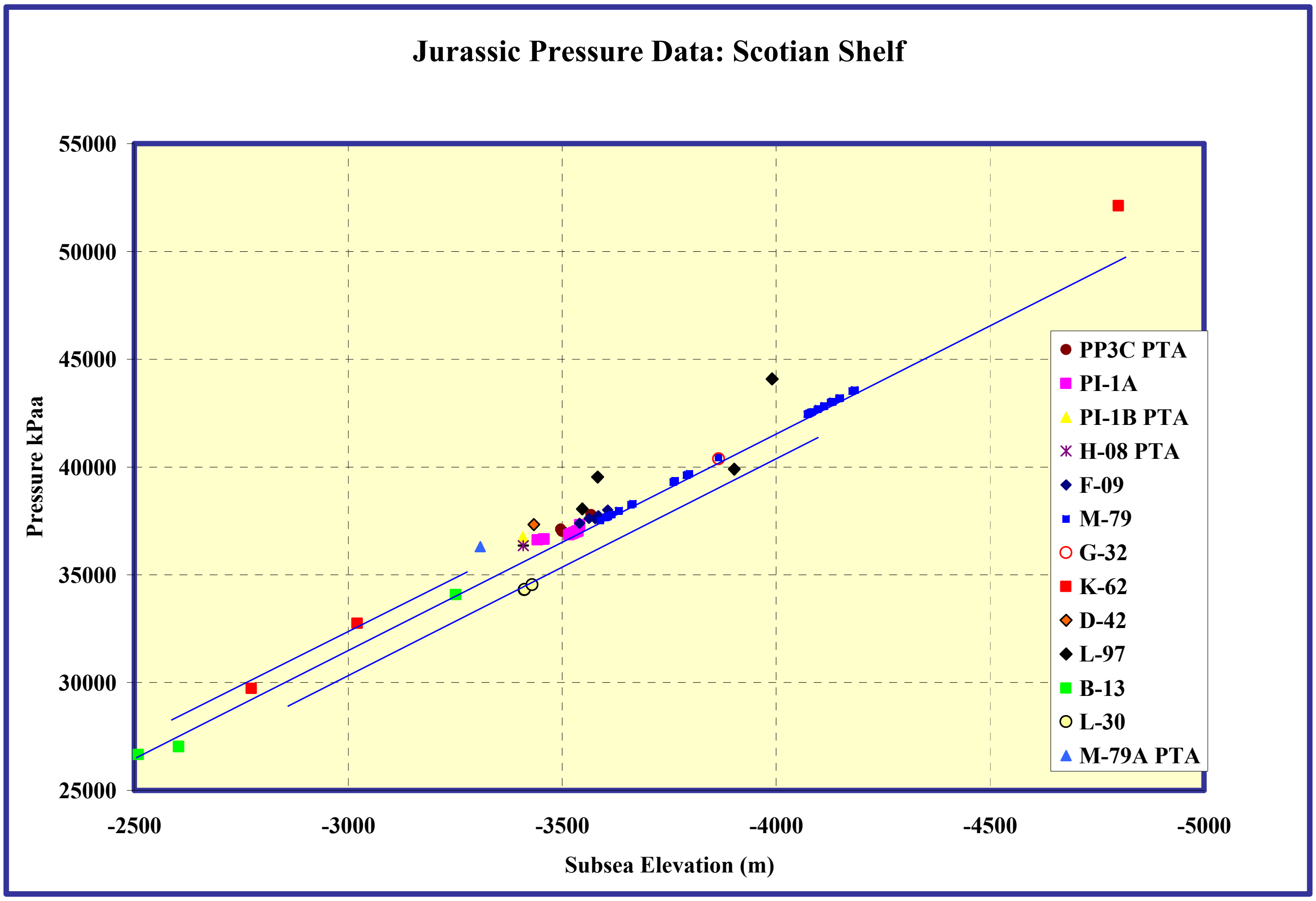


Figure 2.40: Pressure vs. Depth Cross Plot – All Deep Panuke Wells

All wells excluding the K-62, B-13 and L-30 wells are included in the general pool area. All are considered close to the trend line except for the L-97 well which encountered some marginal porosity in the Abenaki 5 and 6. The pressures for the four Drill-Stem Tests (DST) completed on that well are plotted. DST #2B had a minor gas show (flared gas) from an interval approximately 70 m below the

Deep Panuke GWC. The quality of the pressure data is considered poor and cannot be used to either confirm or dispute its connectivity with the main Deep Panuke Gas Pool.

Additional pressure data became available in 2003 following the drilling of the F-70 and D-41 wells. The new data strongly supports the conclusions of the 2001 study.

The pressure data from MDT, well tests and production logging (PLT) for wells H-08, PI-1A, PI-1B, F-70, M-79, M-79A and D-41 are displayed in Figure 2.41 and Figure 2.42.

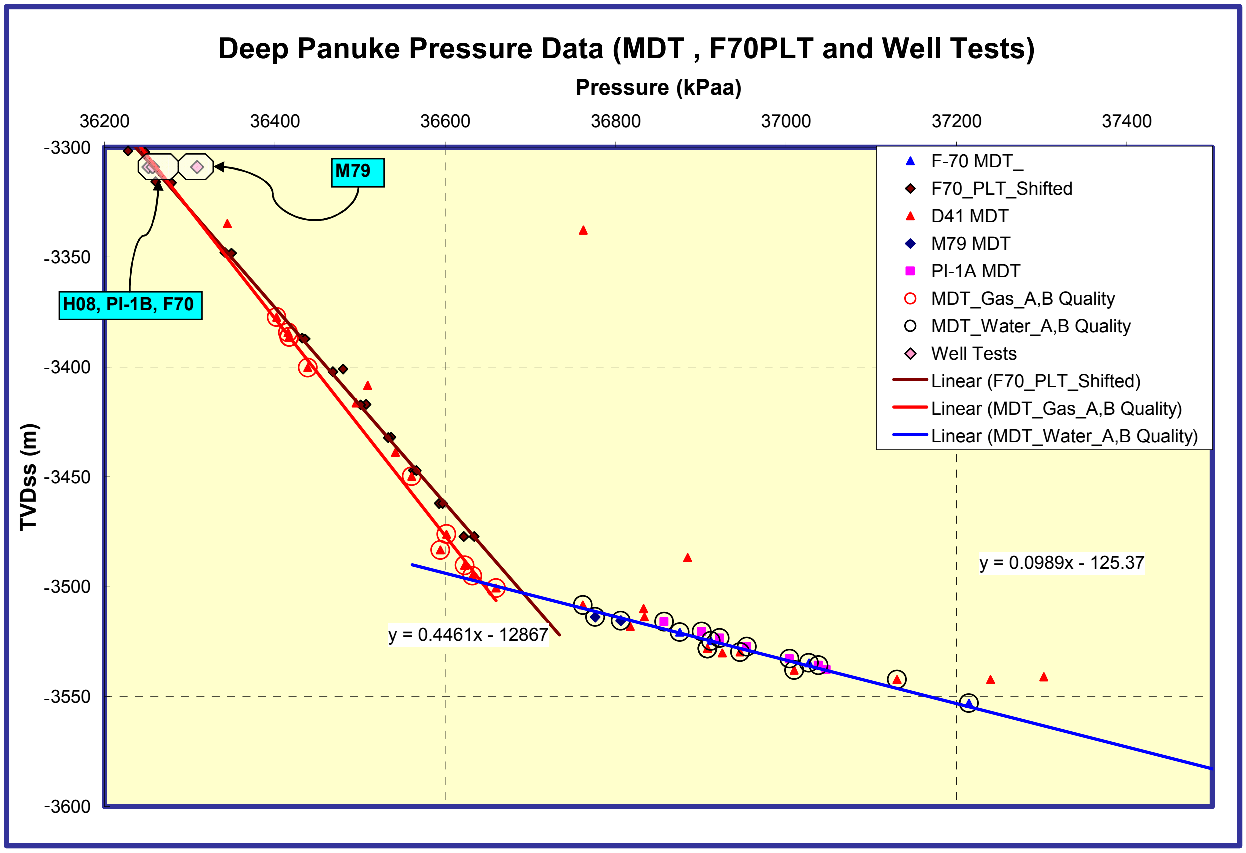


Figure 2.41: Pressure vs. Depth Cross Plot – Small Scale

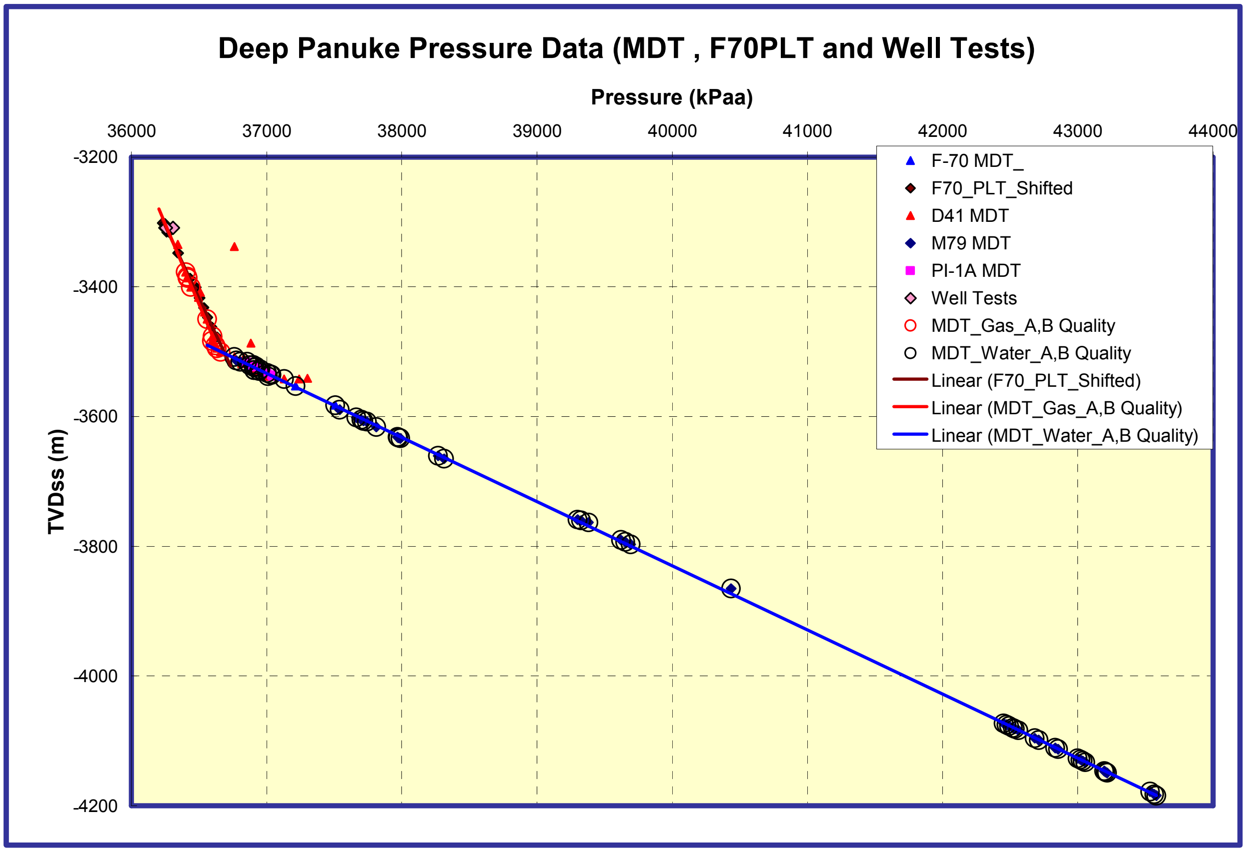


Figure 2.42: Pressure vs. Depth Cross Plot – Large Scale

The plots illustrate that the Deep Panuke pool is a normally pressured reservoir with discovery pressure of about 36.3 MPa. The Abenaki 4 and 5 fall on the same pressure gradient in the D-41 well indicating communication between the two zones, at least in geological time but not necessarily in the pool production life time-frame.

The best estimate pool GWC is at -3504 mss. The intersection of the gas gradient(s) with the water gradient shown in Figure 2.41 and Figure 2.42 are used to estimate the GWC:

- The water gradient is a best fit through the higher quality points in the water zone. The lower quality MDT points were excluded from the analysis, including points that have super-charging effects, short build-up times in low permeability rocks, and/or have mechanical measurement issues.
- Two different gas gradients were used. Following the main shut-in for the F-70 well test, a production logging tool (PLT) was used to measure the static gas gradient in the well-bore. The data quality is high resulting in an excellent gas gradient estimate. The F-70 well PLT data was shifted by 67 kpa to match the initial reservoir pressures determined during the well test. A lesser quality gas

gradient estimate is also provided in the figure by drawing a best fit line through the higher quality MDT points in the gas zone.

Well log and well test information supports the contact of -3504 mss.

- D-41: GWC identified on logs @ - 3508 m subsea elevation in the Abenaki 4;
- PI-1B: GWC identified on logs @ -3504 m subsea elevation in the Abenaki 4. PI-1B well tested both water and gas from an interval (3497.5 – 3503.5 m subsea) just above -3504 m subsea; and
- Other Wells: Low porosity at GWC depths; unable to clearly identify the contact on logs.

The measured pressures and initial reservoir pressure determined from well tests for wells PI-1B, H-08, M-79A and F-70 at a common datum depth of -3309 m subsea elevation are displayed in Figure 2.43. The data for the PP-3C well is not presented as it is considered unreliable because of the large fluid losses to the reservoir during drilling, completion and testing operations (see section 2.2.6).

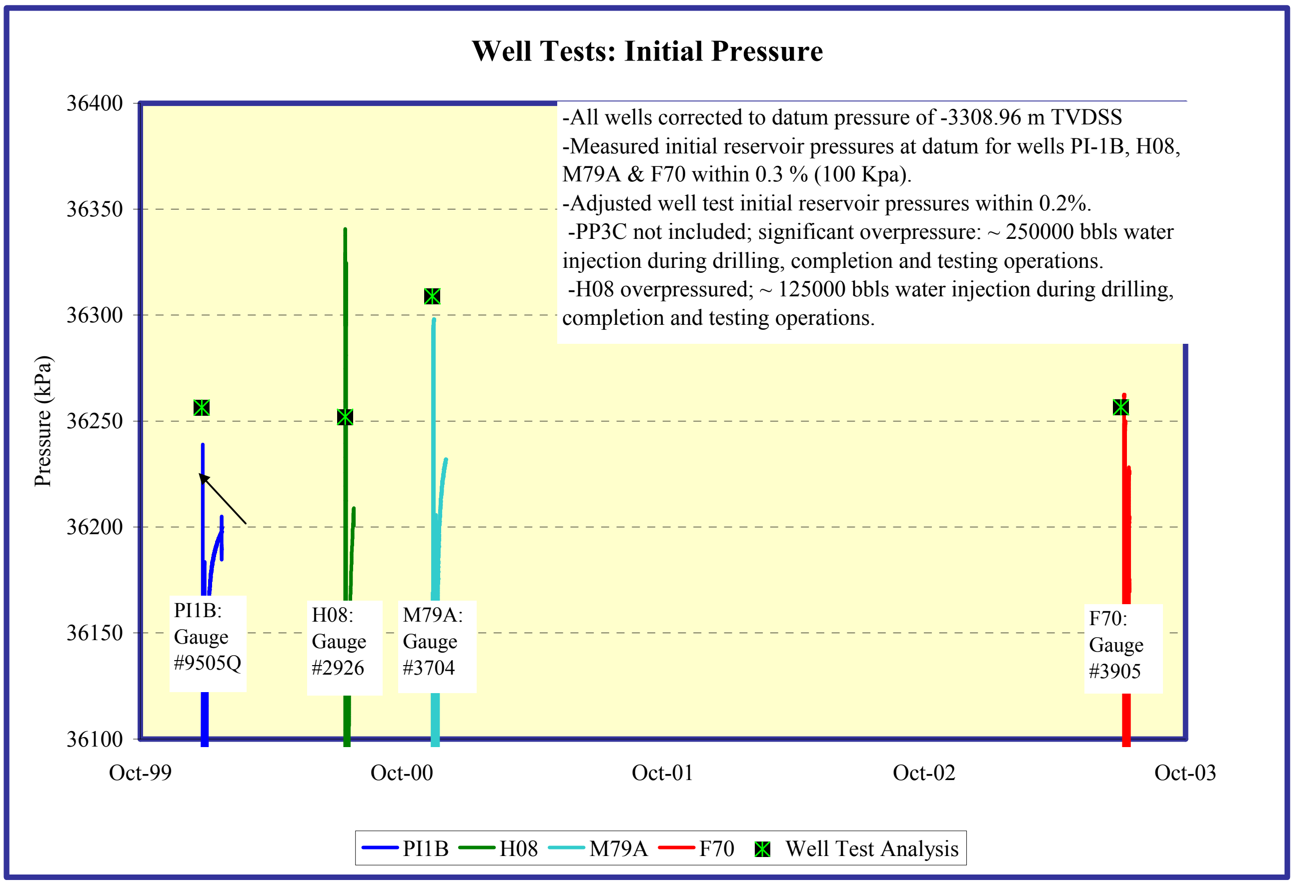


Figure 2.43: Pressure vs. Time Cross plot – All Deep Panuke Wells

The initial reservoir pressures based on well test analysis are also plotted in Figure 2.43. The pressure data was reconciled to account for changing liquid levels, sub-optimal pressure recorder placement and operational issues during drilling, completion and/or testing operations. The PI-1B, H-08 and F-70 well data are on trend: the M-79A data is approximately 50 kpa off the gas trend line.

2.2.5 Abenaki Aquifer Geologic Model

The above pressure information indicates a normally pressured aquifer in the deeper parts of the Abenaki Formation. However, the existence of a single pressure regime does not prove that there is present-day reservoir continuity, permeability and transmissibility between porous bodies within the lower Abenaki Formation which may affect the Deep Panuke gas pool. The vertical and lateral extent of the aquifer and the degree of connectivity of porous bodies within the aquifer is poorly known since only five wells have penetrated to the Misaine Member shale between the G-32 and L-97 wells (about 1 well/10 km). Lower Abenaki Formation porosity is “patchy” with no continuous porosity through all of the wells. On a regional basis, the Abenaki Formation has only limited porosity development, with the Deep Panuke area as the main exception, suggesting that the aquifer has limited lateral extent.

A geological model has been developed for the Abenaki aquifer system as displayed in Figure 2.44. The aquifer system is defined as the total pore volume in pressure continuity with the Deep Panuke gas pool; this includes water-filled pore volume, solution (dissolved) gas in the water and free gas-filled pore volume in currently undiscovered gas pools which are in pressure continuity with the aquifer.

The Misaine Member shale, underlying the Abenaki Formation is treated as a regional aquiclude, forming the base seal for the aquifer. The Abenaki 6 acts as the top seal for the Deep Panuke gas pool and also the aquifer.

Porous parts of the Abenaki 2, 3 and 4 layers are included in the aquifer system. Vertical connectivity between the deeper and shallower parts of the potential aquifer remains unproven so connectivity probabilities are assigned. Thick tight limestone sections occur in the M-79 and D-42 wells. Internal seals provide the possibility of free gas accumulations (i.e. gas pools) in the Abenaki 2 and 3, though none have been found to date.

The connection of aquifer in the Abenaki 4 to the Deep Panuke gas pool is considered to be proven given the clear GWC observed in the D-41 well. However, the Tight Streak (TS) interval in the lower Abenaki 5 may locally baffle the vertical flow of water into the gas zone but local breaches are likely to be present (i.e. fractures or faults).

Any aquifer contribution within the Abenaki 5 zone must occur down-structure from the gas pool (e.g. the E-23 well) and only along the basin margin, and hence is probably of limited extent.

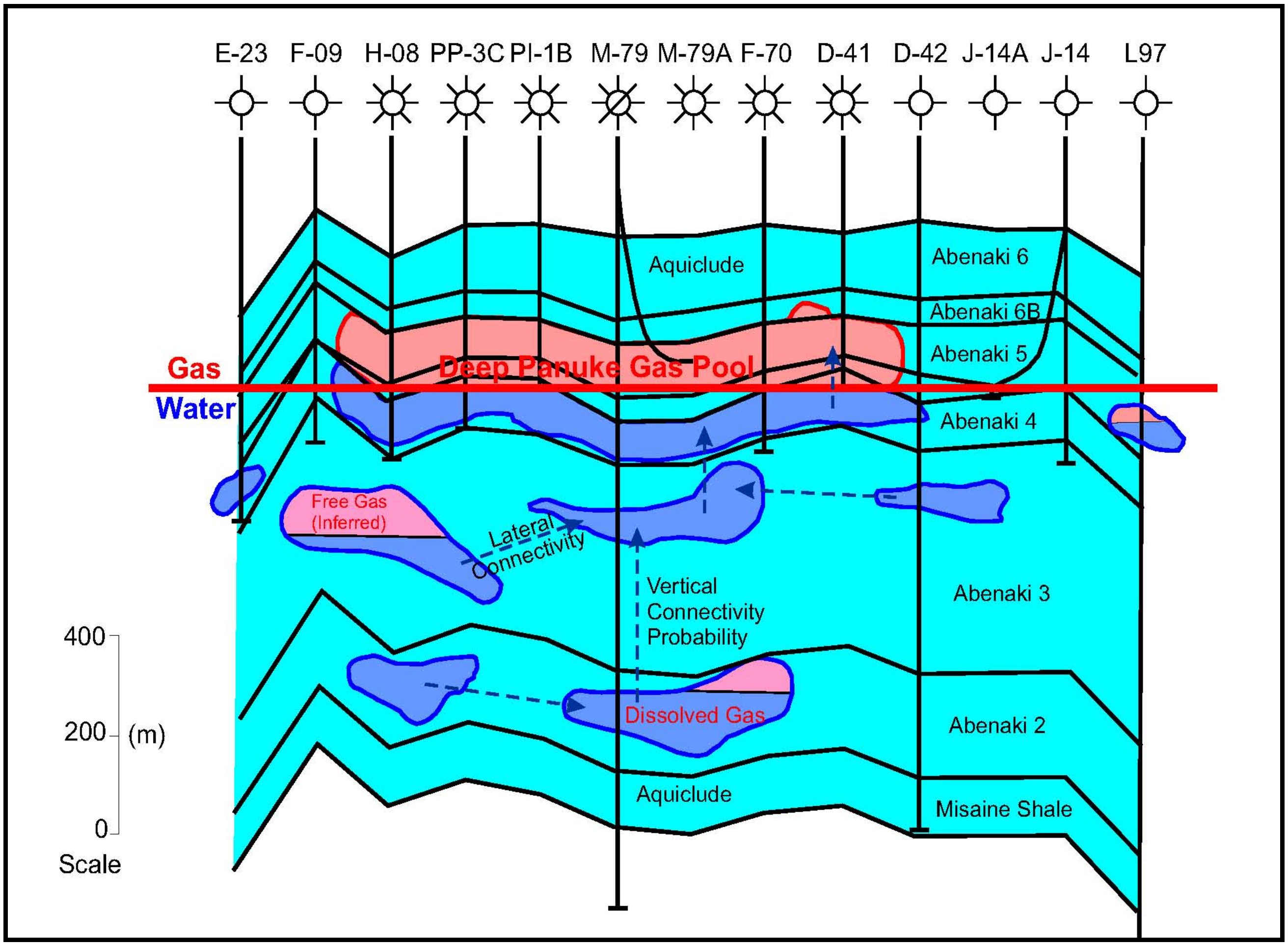


Figure 2.44: Abenaki Aquifer Model

2.2.5.1 Aquifer Size

Sufficient information is not available to directly and accurately determine by geological or geophysical mapping the total area and volume of aquifer attached to the Deep Panuke gas pool. The range of potential fluid volumes in the aquifer system has been assessed using a methodology similar to the industry standard approach to evaluating fluid volumes in an exploration drilling prospect. Statistical ranges assigned for basic reservoir parameters such as pool area, net pay, porosity and water saturation result in statistical prospect volume distributions for oil, free gas and dissolved gas using Monte Carlo simulation. The fluid volume distributions have a probability associated with each potential outcome. In addition, there is uncertainty about whether or not a prospect is viable. Therefore, a risk parameter is used to discount the potential volumes, resulting in risked, probabilistic volume calculations.

Thus, a probabilistic approach has been used to calculate aquifer volume distributions and associated probabilities of occurrence for the Deep Panuke aquifer (DPA-Part 2, Ref # 2.14). The chosen methodology is a four step process, involving the following:

- pore volume calculations for each potential aquifer layer;
- fractioning the total pore volume into free gas and water proportions whilst simultaneously calculating the volume of solution (dissolved) gas in the water;
- connectivity risking for each layer; and
- probabilistic volume calculations

All calculations were performed in an "Excel™" spreadsheet linked to the "Crystal Ball™" Monte Carlo simulator program.

The calculated range of aquifer sizes is expressed as the ratio of Probabilistic Aquifer Volume (PAV) to gas pool OGIP using the full statistical range for each parameter. Typically, an aquifer is considered to be weak if it is less than five (5) times the gas pool OGIP. A moderate aquifer is five to ten times and a strong aquifer is greater than ten times the gas pool OGIP. The smallest aquifer size results (less than 5 times) represent statistical trials with very small PAV divided by very large OGIP. Similarly, large aquifer size results (much greater than 10 times) represent trials with very large PAV divided by very small OGIP.

The Deep Panuke aquifer size calculation results fall within a broad range from two to thirty times the gas pool OGIP, reflecting the high degree of uncertainty in the connected aquifer volumes. The most likely case (Mean) is an aquifer 9.8 times the gas pool OGIP. These estimates of aquifer size are used to guide recovery factor determinations as discussed in Section 2.4.2 and Section 2.4.3.

2.2.5.2 Aquifer Connectivity to Gas Zone

The degree of connectivity between the gas zone and underlying aquifer is a key dynamic uncertainty in modelling reservoir performance at Deep Panuke. The aquifer may be connected to the gas pool by one or more of the three possible geometries illustrated in Figure 2.45:

- edge water may be connected to the gas leg to the southeast and northwest of the pool where the porous carbonate margin plunges down structure below the gas water contact. The E-23 well to the southwest suggests this may not be a significant issue in that area since the Abenaki 5 was tight, although good reservoir quality, wet porosity is present in the Abenaki 4;

- bottom water underlying the gas pool may be vertically connected via faults and fractures. Although the "Tight Streak" argillaceous limestones at the base of the Abenaki 5 appear to be depositionally continuous throughout the pool area, local fault/fracture breaches are likely to be present; and
- back-reef connection of bottom water which may move laterally around the "Tight Streak" through fractures. The F-09 well suggests this is not the case.

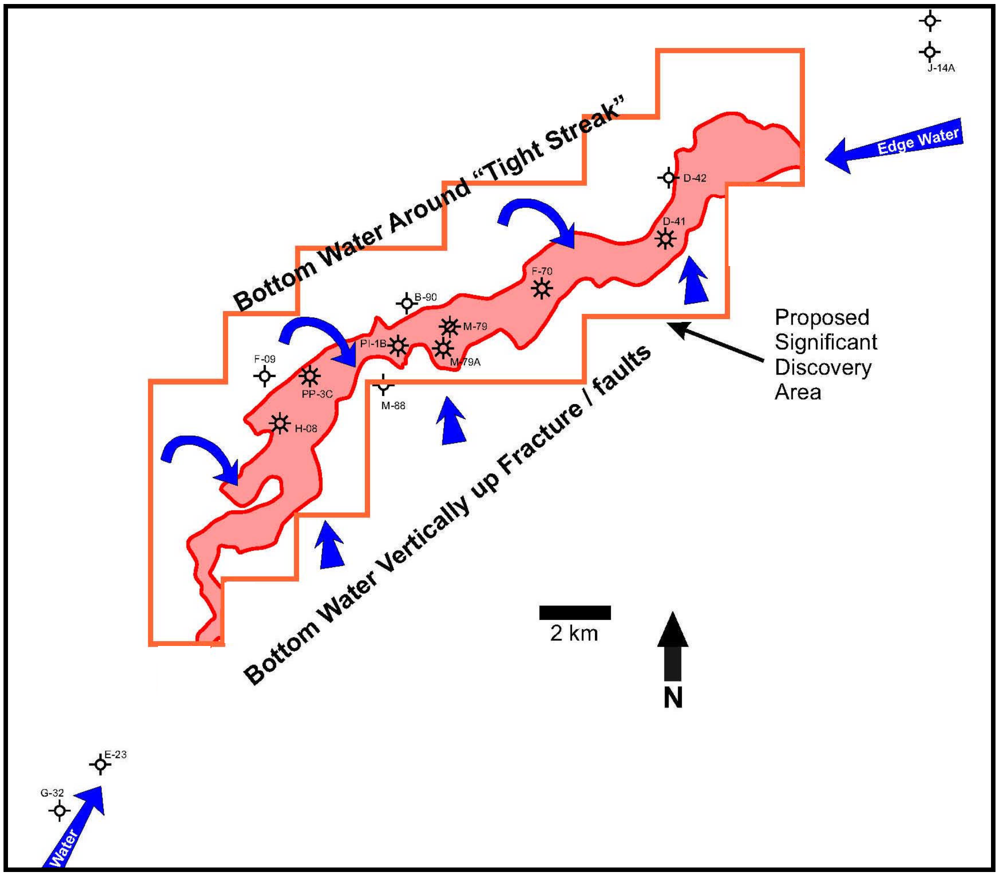


Figure 2.45: Aquifer Connectivity

Even if there is a low individual probability that any one of the three possible connection geometries is valid, the overall probability of some aquifer connection becomes significant. Given that the D-41 well has a clear GWC in a porous section, it is certain that a bottom-water aquifer connection does exist to gas within the Abenaki 4 at least locally around that well.

Given the great uncertainty regarding the degree of connectivity and since there is no further information which can be gathered at this time to reduce the uncertainty, it is necessary to allow a wide range of connectivity possibilities. This is addressed further in Section 2.4.2.

2.2.6 Well Test Analysis

Six different wells in the Deep Panuke pool have been production tested: PP-3C, PI-1B, F-09, H-08, M-79A and F-70. Five of the six wells tested at rates greater than 1.4 x 10^6 m^3/d (50 MMscfd).

The results of the well tests are summarized in Table 2.7. Individual well detailed analyses are provided in (DPA-Part 2, Ref # 2.32)

Table 2.7: Deep Panuke Well Test Key Results

Well	Region	Max Rate (MMscfd)	Pri (kpa)	Kh (md)	Total Skin	Minimum OGIP 10^9 sm3 [BCF]
PP3C	VL	60	N/A	23200	58	N/A
H08	VL	56	36252	11500	16	2.25 [80]
PI-1B	HPRF	53	36256	10600	214	11.27 [400]
M79A	HPRF	64	36308	18300	349	5.92 [210]
F70	HPRF	54	36256	24800	476	6.76 [240]
F09	Back Reef	<.1	36350	<.01	N/A	N/A

The tests have been analyzed both internally by EnCana and externally many times, with some significant differences in interpretations. The "base" results presented here are considered to be a realistic solution. They were generated using a numerical simulator within SAPHIR™. The models were derived based on our current geologic understanding of the reservoir and P50 seismic interpretation. It must be emphasized that these solutions are not unique but are representative of a reasonable geologic reservoir model.

Individual well minimum OGIP estimates were determined by reducing connected pore volumes in the base models to the point where pressure matches were lost.

For each well test, potential data problem areas caused by operations have been identified and then integrated into our interpretations. This makes the analyses more complex and introduces new uncertainties that must be accounted for when drawing conclusions, especially those conclusions based on relatively small changes in data. Typical problem areas include fluid injection during drilling, completion and testing operations, “hanging” liquid levels, rate/pressure measurement issues and sub-optimal pressure recorder placement.

While drilling through the Abenaki 5, high porosity/permeability vuggy limestone was encountered in the PP-3C and H-08 wells resulting in severe loss of circulation. To stabilize the wells and permit drilling operations to continue, Annual Velocity Control (AVC) drilling was undertaken whereby large volumes of untreated sea water were injected into the reservoir. Lost circulation material pills and diesel/gel ‘gunk’ squeezes were also attempted on PP-3C only. The end result is that approximately 7.1 x 10^3 m^3 (250,000 bbls) and 3.5 x 10^3 m^3 (125,000 bbls) of seawater was injected into the PP-3C and H-08 wells respectively to block the reservoir permeability in the near well-bore region. Significant fluid mobility changes (or permeability reductions) have been identified close to the well-bore for each well. The results of these well tests are very uncertain and must be used with extreme caution, especially for the PP-3C well because of additional operational issues that impact the results.

The flow and build-up characteristics for the three HPRF region wells PI-1B, M-79A and F-70 all exhibit similar dual porosity behavior with high pressure draw-downs, rapid build-ups, dual porosity valley on the pressure derivative plot and dual slopes on semi-log plots. This behavior is consistent with observations of the core, PLT, and FMI logs for the F-70 well and the FMI log for the D-41 well.

The F-09 well was completed and tested in a tight oolitic limestone in the back reef area; gas rates were very low and uneconomic.

Geo-mechanics International (GMI) was engaged to study the ocean tide-related pressure fluctuations observed in each well test (DPA-Part 2-Ref # 2.33). They concluded that the pressure fluctuations can be explained by ocean tide loading; an underlying aquifer is not required to explain the observed pressure variations.

2.2.7 Reservoir Fluids

2.2.7.1 Fluid Summary

The detailed description of the reservoir fluids is provided in the Reservoir Fluids Basis of Design (DPA-Part 2-Ref # 2.34). Gas from Deep Panuke is very lean (specific gravity = .62) with relatively low levels of H_2S (0.18 %) and minor amounts of CO_2 (3.44 %). No retrograde behavior is expected of the Deep Panuke gas at the reservoir temperature of 123°C. Some condensate dropout may occur in the tubular and subsurface flow-lines prior to separation and processing.

The reservoir fluid compositions for the expected range of condensate yields are provided in Table 2.8. The best estimate of condensate/gas ratio is 0.0185 m3/10^3 (3.28 bbls/Mmscf), ranging between 0.0141 m3/10^3(2.5 bbls/Mmscf) and .0254 m3/10^3 (4.5 bbls/Mmscf). The compositions were determined using data from the F-70 well test. It provided the most believable and reliable results of all well tests.

Table 2.8: Reservoir Fluid Composition

F-70 Separator Pressure : 3089 kpa Separator Temperature : 28 °C			**Condensate Yield (bbl/MMscf)**		
			Most Likely	**Low**	**High**
Component	**Separator Liquid (mole%)**	**Separator Liquid (mole%)**	**Wellstream (mole%)**	**Wellstream (mole%)**	**Wellstream (mole%)**
Hydrogen	0.0000	0.0002	0.0002	0.0002	0.0002
Helium	0.0000	0.0002	0.0002	0.0002	0.0002
Nitrogen	0.0000	0.0079	0.0079	0.0079	0.0079
CO_2	0.0090	0.0345	0.0344	0.0344	0.0344
H_2S	0.0021	0.0018	0.0018	0.0018	0.0018
Methane	0.1068	0.9105	0.9081	0.9087	0.9081
Ethane	0.0171	0.0281	0.0281	0.0281	0.0281
Propane	0.0163	0.0084	0.0084	0.0084	0.0084
i-Butane	0.0055	0.0014	0.0014	0.0014	0.0014
n-Butane	0.0136	0.0022	0.0022	0.0022	0.0022
i-Pentane	0.0100	0.0007	0.0007	0.0007	0.0007
n-Pentane	0.0123	0.0006	0.0006	0.0006	0.0006
n-Hexane	0.0232	0.0005	0.0006	0.0006	0.0006
Hexanes +	0.7841	0.0030	0.0053	0.0048	0.0053
Totals	1.0000	1.0000	1.0000	1.0000	1.0000

An internal study was conducted to determine the most likely Abenaki water composition because of the significant difference in the water samples that have been acquired (DPA-Part 2-Ref # 2.35). The best estimate composition is summarized in Table 2.9.

Table 2.9: Water Composition	
Component	**Abenaki 5 Formation Water (mg/l)**
Na^+	29163
K^+	513
Ca^{2+}	5885
Mg^{2+}	950
Ba^{2+}	8
Sr^{2+}	448
Fe^{2+}	0
Mn^{2+}	0
Cl^-	55321
HCO_3^-	731
CO_3^-	0
SO_4^{2-}	1570
Total Dissolved Solids	94589

A summary of key reservoir properties is provided in Table 2.10.

Table 2.10: Summary of Reservoir Properties	
Reservoir Fluid Parameters	**Value**
Reservoir Datum Depth	3309 mTVDss
Gas-water contact (best estimate)	3504 mTVDss
Temperature @ Datum	123 ^oC
Gas Gravity	0.62
Condensate Gas Ratio	.0185 m3/10^3 (3.28 bbl/mmscf)
Formation Volume Factor	0.004 rsm3/sm3
Initial Reservoir Pressure @ Datum	363 Barsa

The "Deep Panuke Reservoir Fluid Basis of Design" (DPA-Part 2-Ref # 2.34) provides significantly more detail on reservoir fluids, oil and gas contaminants and production chemistry.

2.2.7.2 Acid Gas

The reservoir contains both H_2S and CO_2; the best concentration estimates are 0.18% and 3.44% respectively. The acid gas concentrations are expected to increase slightly over time (to 3.62% to 4.30%)

with both H_2S and CO_2 being evolved from formation water during pool pressure depletion, as illustrated in Figure 2.46. Although the gas content in the formation water does not appear to be that high (1.2 sm3/sm3 - from the D-41 MDT samples), there is enough CO_2 and H_2S to cause the souring.

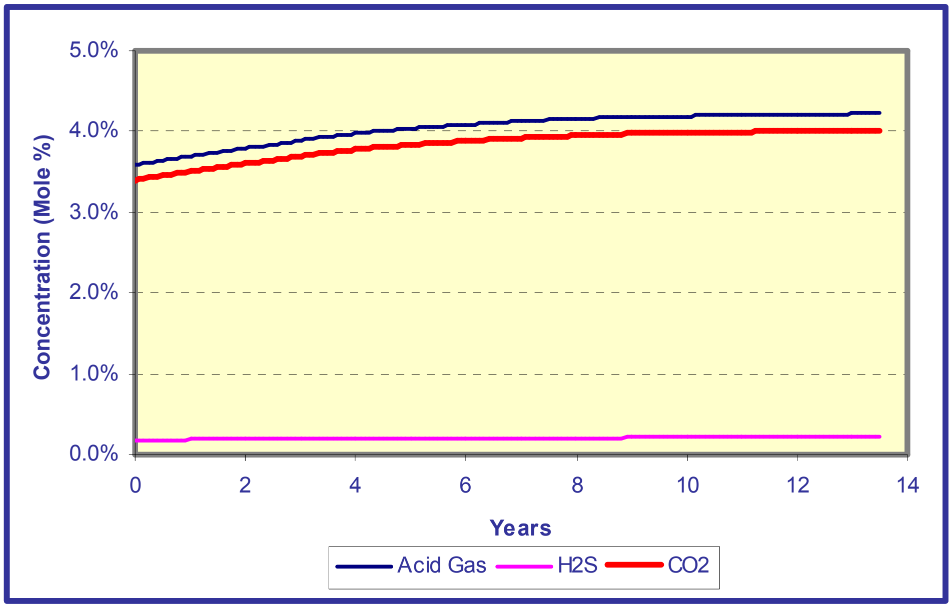


Figure 2.46: Reservoir Souring

Processing of the raw gas is required to remove the H_2S and reduce the CO_2 content to less than 3% to meet sales gas specifications. An amine sweetening system to remove the acid gas and an acid gas disposal system (compression, flow-line and injection well) is planned. Further details of the proposed acid gas disposal system are found in Sections 3 and 4.

2.2.7.3 Other Reservoir Contaminants

Mercury was detected in the gas from the F-70 and PI-1B well test in quantities usually less than 0.5 microgram/m^3. This is a low level of mercury but its presence is indicative of basement rock interactions with the reservoir fluids, supporting the deep burial diagenetic interpretations presented in Section 2.1.3.2. This level of mercury in the production stream will not be an impairment to marketing nor production or facility design.

The level of radon gas (measured in Becquerels - Bq) is about 50 Bq/m3 in the PI-1B well and 100 Bq/m3 in the F-70 well. This level of radon in the production stream will not be an impairment to gas marketing.

2.2.7.4 Subsurface Flow Assurance

Down-hole flow assurance issues are addressed in “Deep Panuke Reservoir Fluid Basis of Design” (DPA-Part 2-Ref # 2.34); this is a follow-up the detailed flow assurance study that was conducted in 2002 (DPA-Part 2-Ref # 2.36). The focus was to manage risk and minimise capital and operating expenses with the main objective of ensuring reliable gas production from Deep Panuke. The following topics were reviewed:

- wax, asphaltene, solids deposition;
- scale/salt deposition;
- hydrate potential; and
- sulphur and diamondoid deposition.

The key conclusions were as follows:

- Asphaltene content is very low and not a significant flow assurance issue.
- There are not anticipated to be any production/transportation challenges due to wax.
- Because of the uncertainty in the formation water analysis (re: section 2.2.7.1) conclusive predictions of scale formation is difficult. No major problems are anticipated. However, it will be necessary to monitor the production system closely for evidence of scale and take remedial action.
- Hydrates are not anticipated to be a significant operational concern during normal operating conditions. A down-hole chemical injection valve is not required for hydrate control. However, for well start-up conditions, provisions must be in place for methanol injection.
- Only trace concentrations of Diamondoids were found in the condensate stream and should present no production problems.
- The risk of sulphur deposition in the Deep Panuke production system is considered extremely low because of the low H_2S content in the produced gas.

2.3 Geophysics

Reflection seismology, commonly referred to as seismic, is the geophysical method of choice for subsurface reservoir mapping. The basic principle behind the seismic method is the reflection of sound waves by boundaries between different rock types within the earth. A surface source generates sound waves that penetrate the earth and then are reflected back to the surface where receivers measure the strength and travel time of the reflected waves. This data is processed and is commonly displayed vertically as a seismic wiggle trace in which the amplitude of the wiggle indicates the strength of the reflection and the vertical direction represents travel time. The display of such data collected along a line on the surface produces a two-dimensional (2-D) seismic section that is an image of the rock boundaries beneath the surface. Data collected over a grid on the surface produces a three-dimensional (3-D) volume or "cube" of traces.

The principle applications of seismic data in describing the reservoir are as follow:

- mapping the vertical and lateral extent of the pool; and
- predicting lithology and porosity between the wells.

The following sections discuss the seismic time and depth interpretations and seismic lithology and porosity predictions (DPA-Part 2, Ref # 2.14).

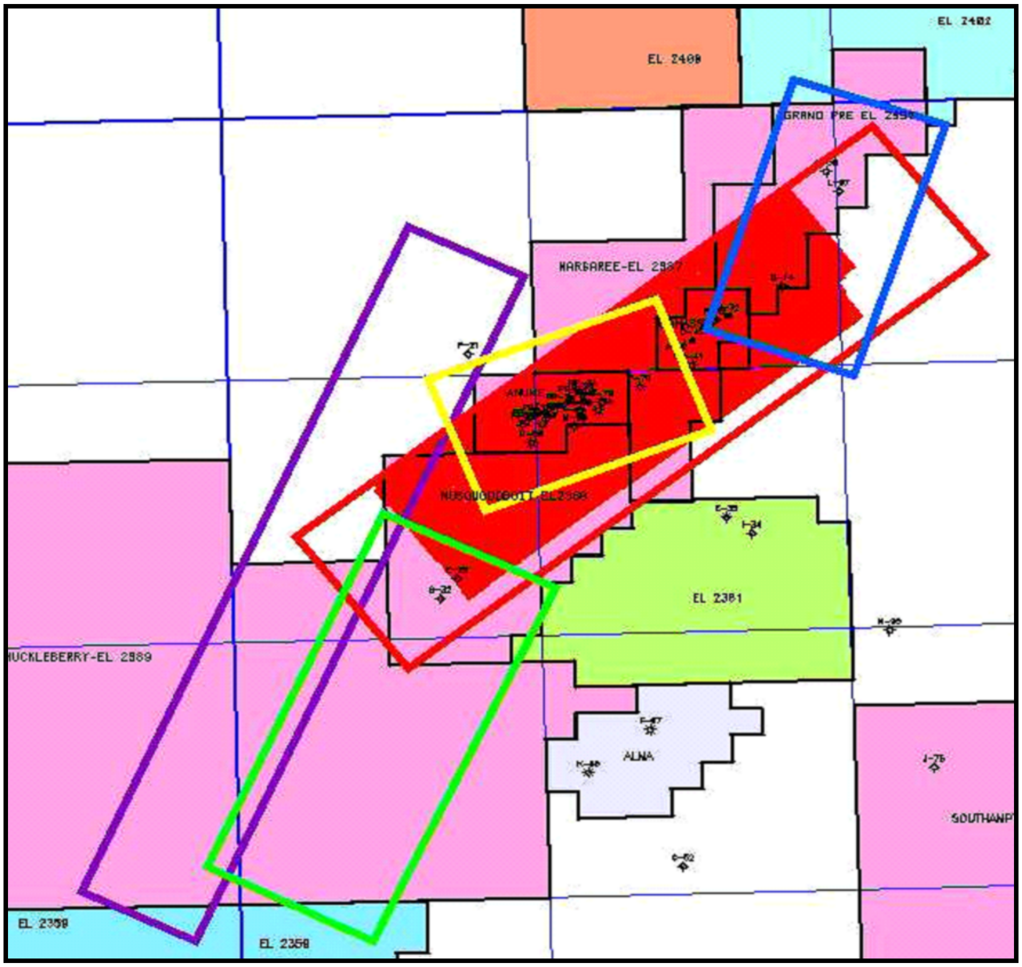
2.3.1 Seismic Database

EnCana's seismic database over the Deep Panuke pool consists of several 3D seismic datasets as shown on the map in Figure 2.47. The "Abenaki 3D" was the exclusive source for the geophysical reservoir interpretations presented below. The other 3D seismic surveys provide supplementary information but are not integral to the Deep Panuke pool mapping.

Western Geco shot the approximately 450 km^2 "Abenaki 3D" marine survey in 2002. A seismic vessel acquired the data towing a dual air-gun source array and eight receiver cables (or streamers) each 5200 m in length. Subsequent processing of the data provided a seismic reflection amplitude trace at every 12.5 m in the NE-SW direction and at every 25 m in the NW-SE direction over the survey area. Overall, the Abenaki survey is a data set of high quality.

The Abenaki 3D was processed for Pre-Stack-Time-Migration (PSTM) and Pre-Stack-Depth-Migration (PSDM). The PSDM processing was transformed from depth back into the time as the basis for the geophysical reservoir interpretation. Figure 2.47 shows the outline of the PSDM processed Abenaki 3D survey. Due to the migration aperture, the area of the PSDM processing becomes smaller than the area of the original survey.

To support the interpretation, various volumes of seismic attributes have been computed including partial offset stacks, Rp and Rs extractions, P-impedance and S-impedance, coherency volumes and LMR volumes. A full seismic reservoir characterization was only executed on the higher quality PSDM-processed Abenaki 3D. Therefore, lithology and porosity analyses were completed only for the area of the PSDM-processed Abenaki 3D survey.



Legend: Purple: Blueberry 3D,Green: Huckleberry 3D,Red:Abenaki 3D,Yellow:Panuke 3D, Blue:Grand Pre 3D

Figure 2.47: Outline of PSDM-processed Abenaki Survey (shaded in red)

2.3.2 Geophysical Reservoir Description Requirements

The following categories summarize the major seismic interpretational requirements for geophysical reservoir description of the Deep Panuke pool:

1) Reservoir Vertical Extent

- Seismic time horizon interpretation of the Top Carbonate, Top Porosity, Abenaki 5 and Abenaki 4 plus several external horizons (necessary for depth conversion beyond the reservoir zone);
- Depth conversion and well ties to create geological depth horizons; and
- Additional geological horizons (not seismically resolvable) based on seismic horizons (e.g. Abenaki 6B, Tight Streak).

2) Reservoir Lateral Extent

- HPRF Probability prediction;
- HPRF Basin Masks (minimum/best estimate/maximum cases);
- HPRF Back Reef Boundary; and
- VL region boundaries (P90/P50/P10 cases).

3) Lithology and Porosity Predictions

- Dolostone prediction (HPRF region);
- Porosity predictions -HPRF (low/mid/high cases); and
- Porosity predictions -VL (P90/P50/P10 cases).

This following discussion summarizes the methods by which these requirements were met.

2.3.3 Reservoir Vertical Extent

Seismic Time Horizons

The Abenaki 5 is the main reservoir zone with gas also present in the Abenaki 4 and lower Abenaki 6. Three seismically mappable horizons are interpreted for the reservoir zone of the pool as follows:

- Top Porosity geophysical horizon;
- Abenaki 5 geophysical horizon; and
- Abenaki 4 geophysical horizons.

These surfaces are illustrated in a seismic time cross-section view in Figure 2.48.

In addition, the top O-Marker, base O-Marker, top carbonate/Abenaki 6-7 and Abenaki 3 horizons are also picked external to the reservoir interval to be used in structural mapping and depth conversion.

Time to Depth Conversion

Seismic time horizon data is converted to the equivalent depth horizons. Time values measured from seismic cross-sections are transformed to depth in accordance with the mathematical relationship of velocity equals distance divided by time, using interval velocities measured and "tied" at the wells using synthetic seismograms (DPA-Part 2, Ref # 2.37). The end result of the depth conversion process is that each time horizon has been transformed into its equivalent depth horizon for mapping and modelling purposes.

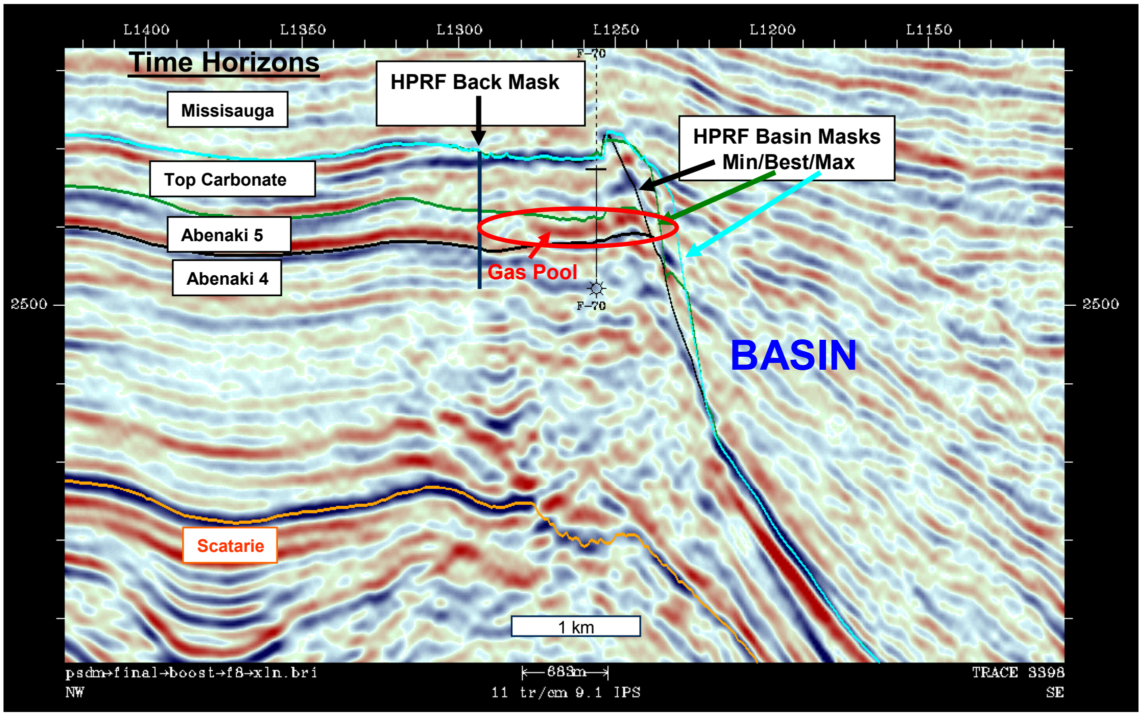


Figure 2.48: Geophysical Surfaces Cross-Section

Based on well Vertical Seismic Profile (VSP) and Check-Shot Data of wells B-90, D-42, E-23, F-70, H-08, J-14, L-97 and M-88, plus the time-depth curves derived from the sonic logs of wells D-41, G-32, F-09, M-79 and PI-1A, a generalized layered velocity field was built from surface to the Abenaki 4 horizon as shown in Figure 2.49.

The velocity field was optimized by hand-contouring each velocity layer below the top O-Marker. The objective of the hand-contouring was not to match all well data perfectly but to impart a geological pattern to the contours. The consequence is that minor mis-ties remain but a smooth velocity field is generated which has a higher probability to be representative between the wells.

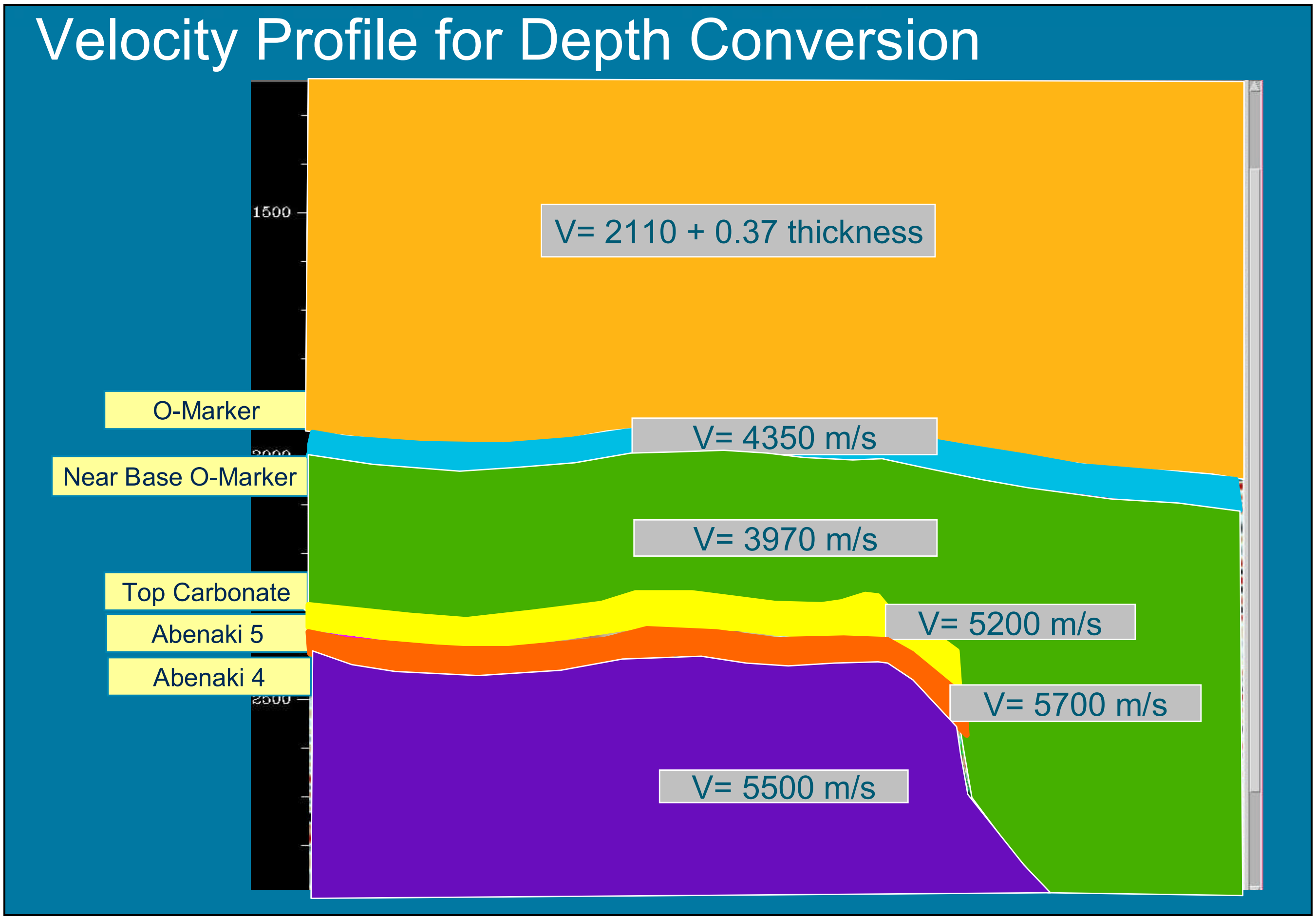


Figure 2.49: Generalized velocity model

As an example of a key time horizon, the Top Porosity horizon is created by modifying the Abenaki 5 geophysical horizon in areas of the pool where porosity appears to be present in the lower part of the Abenaki 6 in continuity with underlying Abenaki 5 porosity. Figure 2.50 shows the structural configuration of the pool in map view at the Top Porosity horizon. The map shows an overall rise in structural elevation up-dip toward the northwest. The mapped surface is cut to the south-east where the GWC intersects the Maximum Basin Mask. A north-east-southwest oriented structural high is present as a linear feature near the D-42 well with a structural low bounding it to the north-west. These are structural drape features related to an underlying basement high and adjacent basement low.

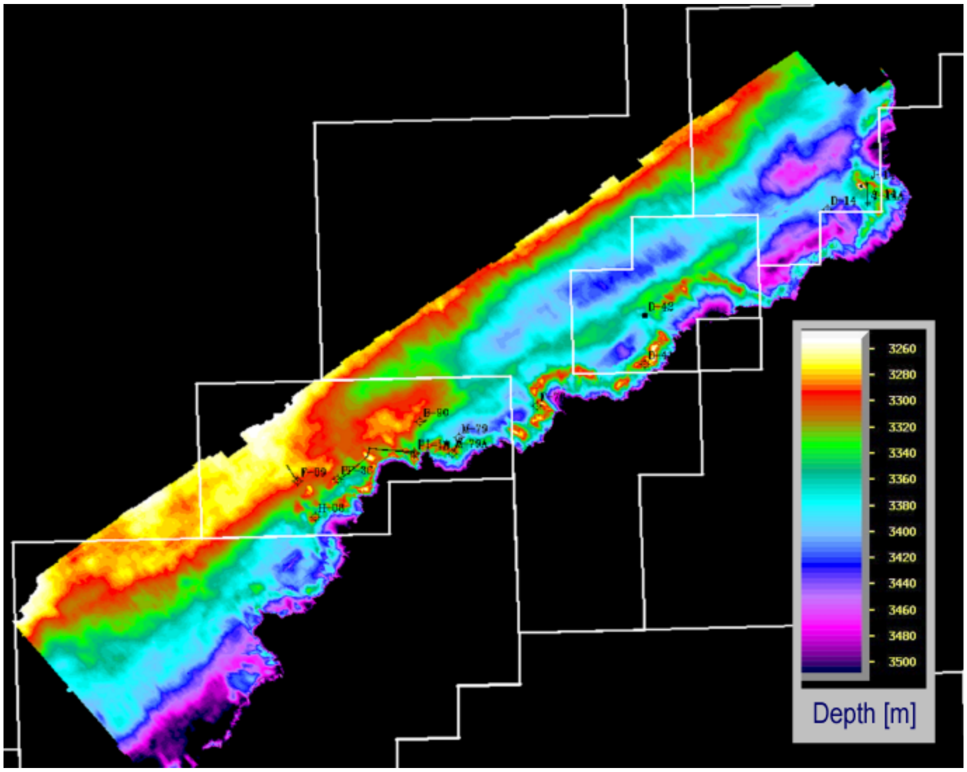


Figure 2.50: Top Porosity Map – Depth

Depth Horizons

Through the depth conversion process, depth-equivalent horizons are created for:

- Top Porosity;
- Abenaki 5 geophysical horizon; and
- Abenaki 4 geophysical horizon.

These structure maps are in included in DPA-Part 2, Ref # 2.30.

Due to phase changes laterally in the seismic data, the geophysical horizons (which conform to continuous seismic events) do not necessarily conform to geological horizons at the wells. For that reason, the geophysical horizons are adjusted where necessary to match the wells and the new surfaces re-named as geological horizons. This procedure does not involve any modification to the velocity fields used in depth conversion.

In addition, two more depth horizons are added which are not seismically mappable. The Abenaki 6B and Top TS horizons (see Section 2.1.3.5) are created by adding the appropriate isopach thickness up from the Abenaki 5 and Abenaki 4 geological horizons respectively.

The final result of the depth conversions, adjustments and addition of sub-seismic surfaces are the following horizons which are available for mapping and reservoir modelling in depth:

- Abenaki 6B horizon (top of the reservoir prone lower Abenaki 6)
- Top Porosity geological horizon
- Top Abenaki 5 geological horizon
- Top TS Interval
- Top Abenaki 4 geological horizon

A series of structure maps are included in DPA-Part 2, Ref # 2.30. The map series includes Depth Structure Maps on Abenaki 6B, Abenaki 5, Abenaki 4 and Top Porosity displayed showing the position of the Minimum, Best Estimate and Maximum Basin Masks. The Basin Masks are interpreted positions along the carbonate margin where reservoir-prone rocks terminate or change facies into their non-reservoir basinal equivalents. Uncertainty in the exact positions at which this change occurs gives rise to the need for three Basin Masks.

2.3.4 Reservoir Lateral Extent

Defining the lateral extent of the HPRF and VL regions requires that seismic interpretational uncertainties be addressed. The change from reef to basin or reef to backreef can be either abrupt or it can be transitional in some portions of the pool. Since there is local uncertainty concerning the position of the lateral changes, it is necessary to define a set of Basin Masks (minimum/best estimate/maximum cases) and a Back Mask for the HPRF region along with VL region boundaries (P90/P50/P10 cases).

The HPRF boundaries are identified first by defining the probability of HPRF occurrence throughout the pool area then integrating that prediction with independent porosity and dolostone predictions. The VL region boundaries are defined primarily from the porosity predictions but their interpretation also involved lithology predictions.

The mapped positions of the interpreted reservoir boundaries where they intersect the GWC are shown in Figure 2.51.

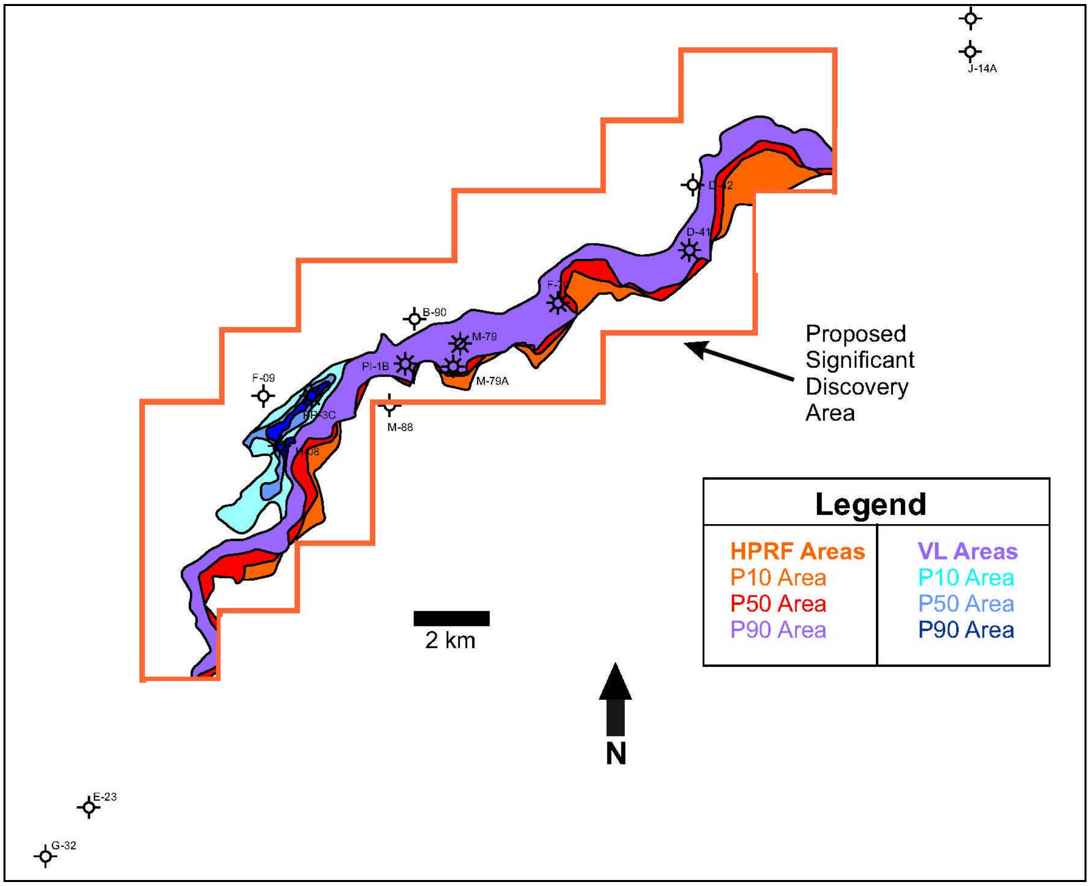


Figure 2.51: Reservoir Lateral Extent Map

HPRF Probability Prediction

An important early step in determining the lateral extent of the reservoir is to seismically separate the HPRF reservoir rocks from their non-reservoir basinal and back-reef equivalents. The resulting HPRF probability prediction cube describes the probability (in the range from 0-100 %) of HPRF existence at each position in the cube.

To create this prediction, a neural net (NN) was trained to differentiate HPRF rock (High Perm Reef Front), basinal rock (BR) and remaining rock (Rest). The first step in the supervised NN analysis is the identification of training points. These points were identified from petrophysical data, well test data (i.e., some wells indicate a significant inflow from areas around the well bore so consequently high permeability cannot be restricted to the direct well location), and deposition pattern (i.e. far beyond the reef boundary, the pattern is significantly different to allow training points for the basin to be picked).

Figure 2.52 illustrates the selected training points. Several NN architectures and many different input seismic attribute combinations were tested to identify the best NN. A simplified diagram of the NN with the selected input attributes is shown in Figure 2.53. Figure 2.54 illustrates the procedure of NN training and the generation of the lithology cube.

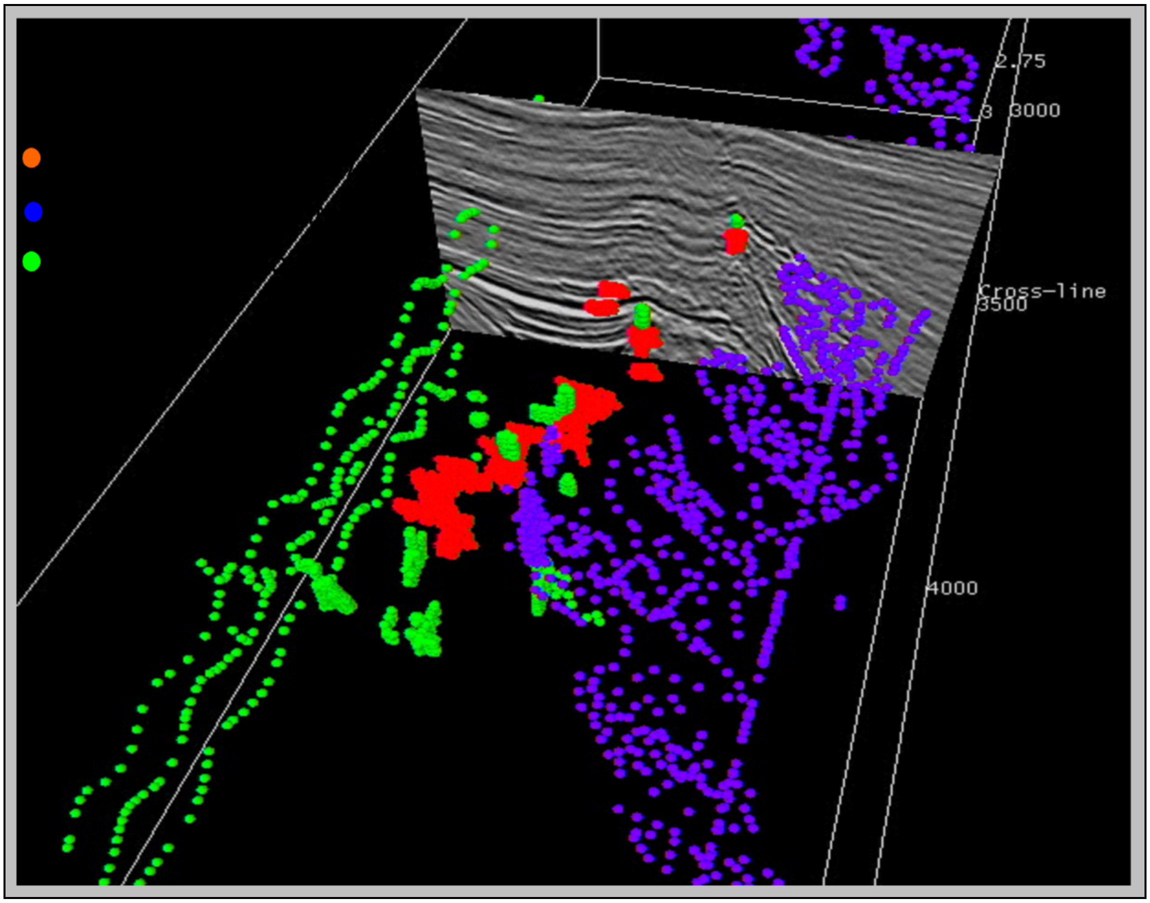


Figure 2.52: Training points for lithology interpretation BR: Purple, HPRF: Red, Rest: Green

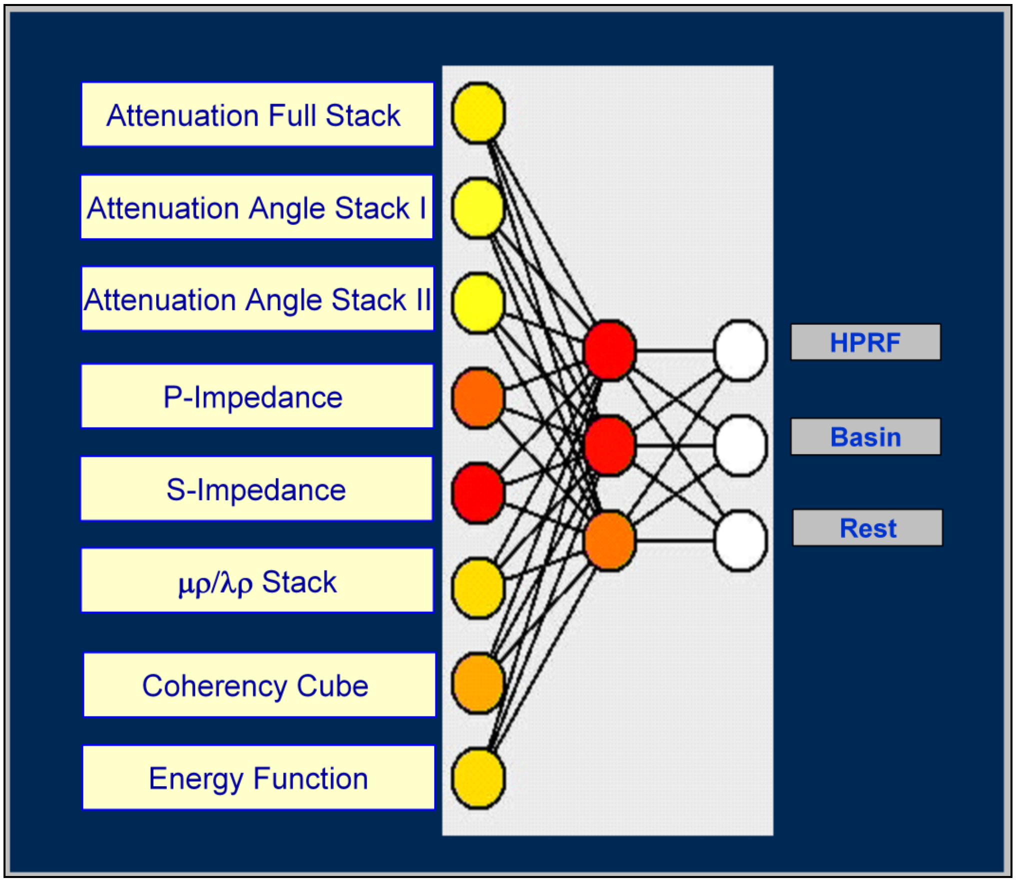


Figure 2.53: Architectures of a NN for lithology interpretation

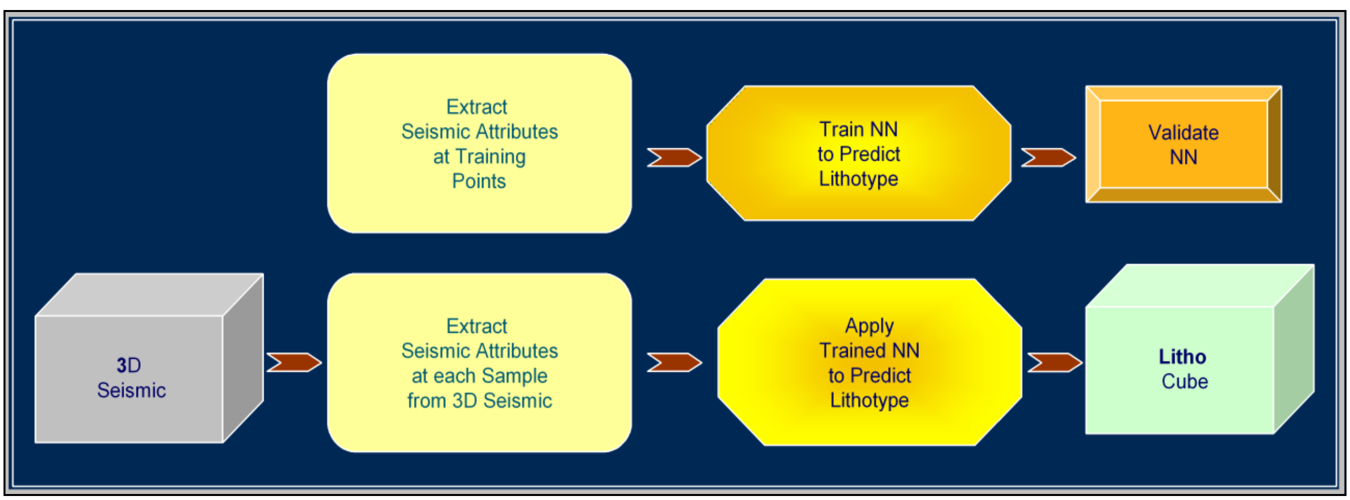


Figure 2.54: Workflow for Lithotype NN analysis

HPRF Basin Masks

Seismic interpretational uncertainty exists regarding the physical basinward limit of Abenaki carbonates. The change from reef to basin can be abrupt or it can be more transitional in some portions of the pool. Where there is uncertainty concerning the physical position of the lateral change from reservoir-prone carbonate to non-reservoir basinal deposits, it is necessary to choose a set of basin masks for minimum/best estimate/maximum cases. At locations where little uncertainty exists, the minimum and best estimate cases may coincide.

The HPRF basin masks were identified by integrating several different types of predictions, including HPRF probability, Dolostone Prediction (see section 2.3.5) and HPRF Porosity Prediction (see section 2.3.6).

A seismic cross-section display example of the HPRF Basin Masks is shown in Figure 2.48.

HPRF Back Reef Boundary

The HPRF back reef boundary is defined at the landward limit of the dolomitized HPRF region. Northwest from the HPRF back reef boundary is the VL region (where present) or the MR region. A fixed HPRF back reef boundary is used (rather than variable boundaries) to limit to a manageable number the number of deterministic OGIP cases to be evaluated (see Section 2.4.1). Uncertainty in reservoir rock volume of the pool is addressed primarily by the variable HPRF basin masks and secondarily by the variable porosity (low/mid/high cases) assigned within the HPRF region.

The HPRF back reef boundary was seismically picked while simultaneously viewing HPRF prediction cross-sections and NN porosity cross-sections, looking for the landward limit where they coincide. For simplicity, it is represented in the static reservoir model as a vertical boundary as shown in Figure 2.48.

Vuggy Limestone Region Boundaries

Variable boundaries (P90/P50/P10 cases) have been identified for the VL region as shown in Figure 2.51. The P10 limit for the VL region is defined as extending close to the seismically mappable maximum limit of porosity away from the PP-3C and H-08 wells. The eastern P10 limit of the VL region is a somewhat diffuse boundary separating it from the nearby HPRF region (which is only a few hundred meters from H-08). Using a vertical boundary between the VL and HPRF regions is a simplification necessary for mapping purposes but the diagenetic processes of dolomitization and leaching are likely to have created a much more complex three dimensional pattern. The western P10 boundary of the VL region has a rectilinear shape strongly suggesting fault control. This is consistent with the diagenetic model involving vertical migration of leaching fluids along faults.

The VL P90 area is confined to higher porosity in direct and obvious seismic continuity with the H-08 and PP-3C wells. The P50 area imposes a less rigorous standard whereby potentially lower porosity is allowed within the VL region.

The VL P90/P50/P10 boundaries are represented in the static reservoir model as a series of vertical boundaries (see Section 2.4.1).

2.3.4.1 Deep Panuke Trap

An integrated process is required to define the areal extent of the Deep Panuke pool. The depth converted structural horizons do not completely define the pool limits since Deep Panuke is a combination trap with both structural and stratigraphic elements. The overall extent of the trap and many of the trapping elements are illustrated diagrammatically in Figure 2.55.

The southwest limit of the trap occurs where the HPRF dips structurally below the pool GWC. To the southeast, the trap is limited by the intersection of the top porosity with the GWC (if porosity extends to the GWC) or by the positions along the carbonate margin where the change from Abenaki carbonates to basinal shales occurs. Locally arcuate listric faults have created several structural "scallops" along the carbonate margin. Since there is local seismic interpretational uncertainty regarding the limits of carbonate deposition, minimum/best estimate/maximum basin masks are defined.

To the northeast, the trap extends to the area where the shale body penetrated by the J-14 well extends into the structural low paralleling the reef margin to the north of the J-14 and D-42 wells.

To the northwest, the Trap Back Boundary is defined along:

1) the axis of the structural low paralleling the reef margin to the north of the J-14 and D-42 wells; and
2) the area northwest of the PI-1B, PP-3C, H-08 and F-09 wells where stratigraphic trapping occurs due to loss of porosity and fracturing away from the carbonate margin.

Within the trap area, porosity prediction results are integrated with HPRF predictions to define where the HPRF back boundary occurs at the change from the HPRF region to the MR region. This change does not conform to the trap back boundary.

Also within the trap area, porosity prediction results are integrated with VL lithology predictions to define where the P90/P50/P10 VL areas occur.

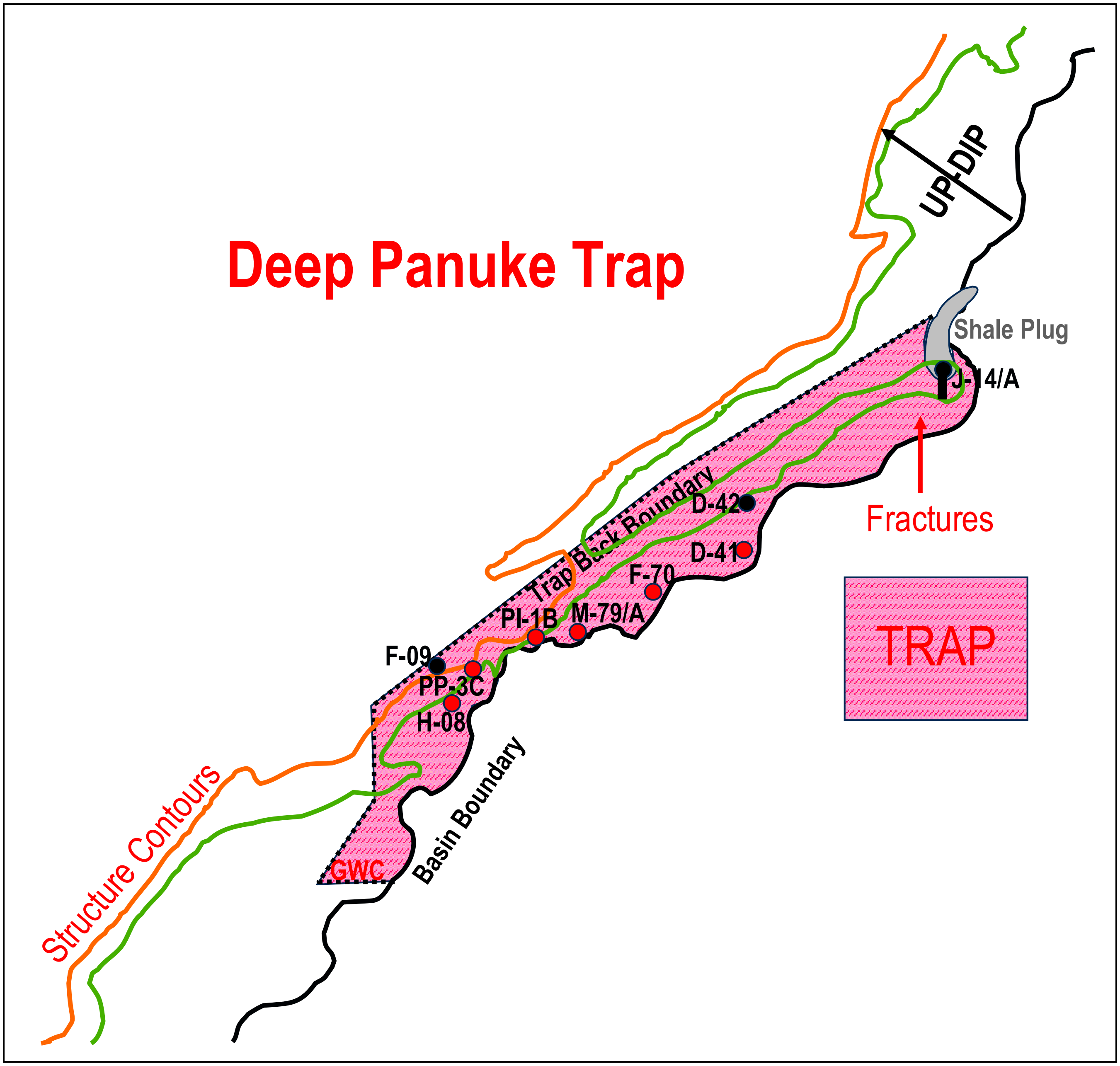


Figure 2.55: Deep Panuke Trap

2.3.5 Dolostone Prediction

The reservoir characterization methodology described in Section 2.2 for the Deep Panuke pool depends heavily on the accurate determination of two key reservoir properties in the HPRF region, namely the volume of dolostone (Vol_{Ds}) and total porosity (Phi_{tot}). These parameters are direct outputs of petrophysical analysis of the wells (Section 2.2.3) which must then be extended away from well control to all parts of the pool to construct the reservoir models for OGIP, RGIP and simulation studies.

NN technology is the method of choice for the estimation of volume of dolostone (Vol_{Ds}). The training data set for the NN consists of well log dolostone fraction and seismic attributes extracted from seismic traces at the well locations. Based on the petrophysical dolostone content up-scaled to seismic scale, a NN was trained on several seismic attributes to predict the 3-D volume percentage dolostone in the rock. The procedure is summarized in Figure 2.56.

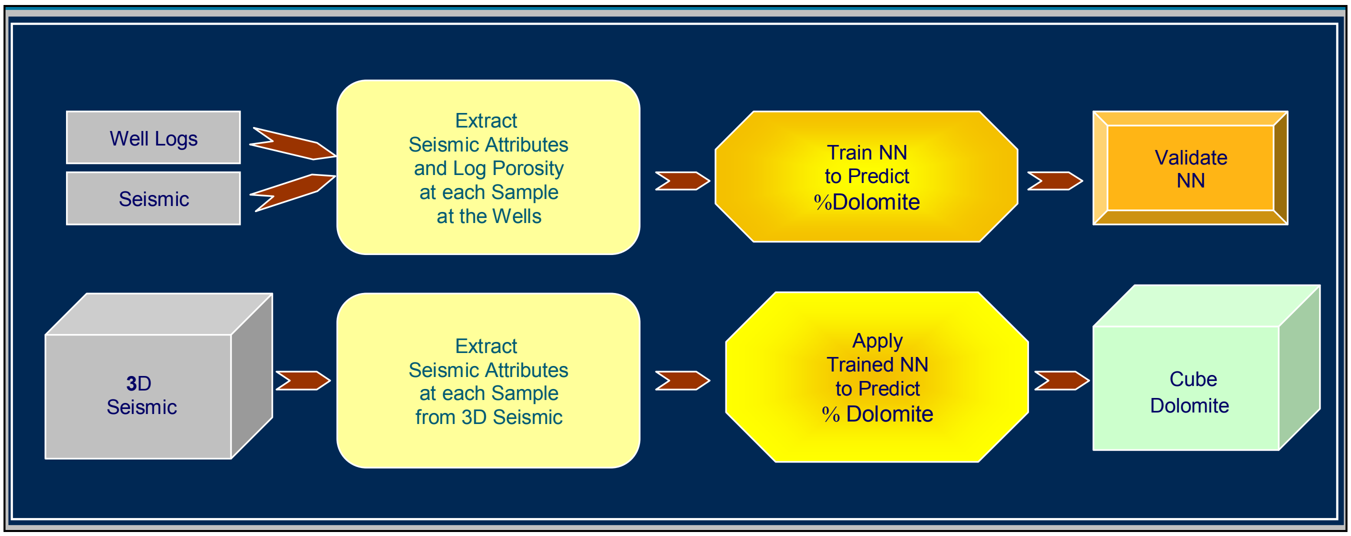


Figure 2.56: Procedure for Dolostone Estimation

After testing many different NN architectures and various input attribute combinations, the NN illustrated in Figure 2.57 was identified to deliver the best results. Criteria for this selection were:

- visual correlations at the well location with the well log dolostone content;
- consistent dolostone content around the well bores;
- high correlation co-efficient of the upscaled petrophysical dolostone content to NN predicted dolostone content immediately around the wells;
- match of the mean up-scaled petrophysical dolostone content to NN mean dolostone content;

- blind tests of wells not included in the training data set; and
- average dolostone content maps are logical.

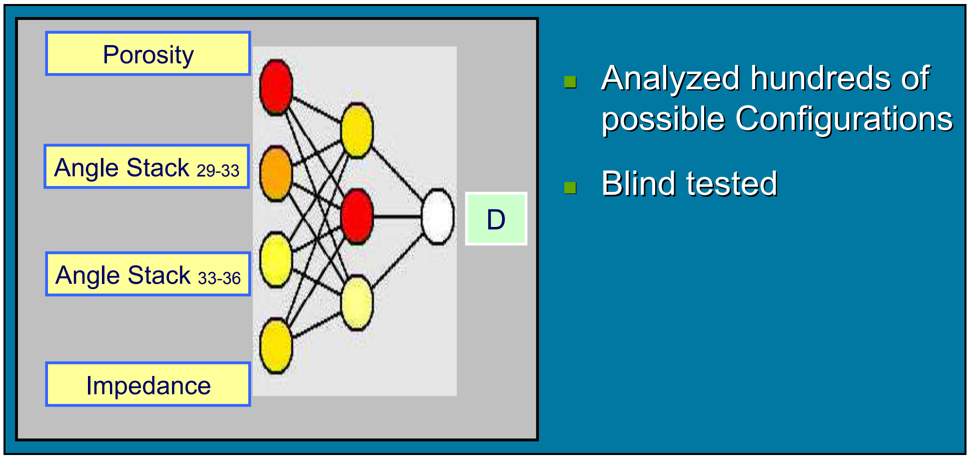


Figure 2.57: NN Architecture for Dolostone Prediction

According to these criteria, the validation procedures to determine the best-result dolostone content prediction are described in DPA Part 2, Ref # 2.14. One example of the validation is that the statistical mean dolostone content in the petrophysical input data (32.6%) is closely matched in the NN output result (31.8%). This value represents the overall mean dolostone content in the HPRF.

Average Dolostone Map –HPRF

The average volume of dolostone (Vol_{Ds}) between the top Abenaki 5 and the GWC in the HPRF region is illustrated in Figure 2.58. This map is also included in Part 2, Ref # 2.30.

The map pattern is logical, showing good continuity along the HPRF and decreasing dolostone content toward the northwest, away from the basin. Several partially connected linear trends paralleling the basin margin are likely fault related.

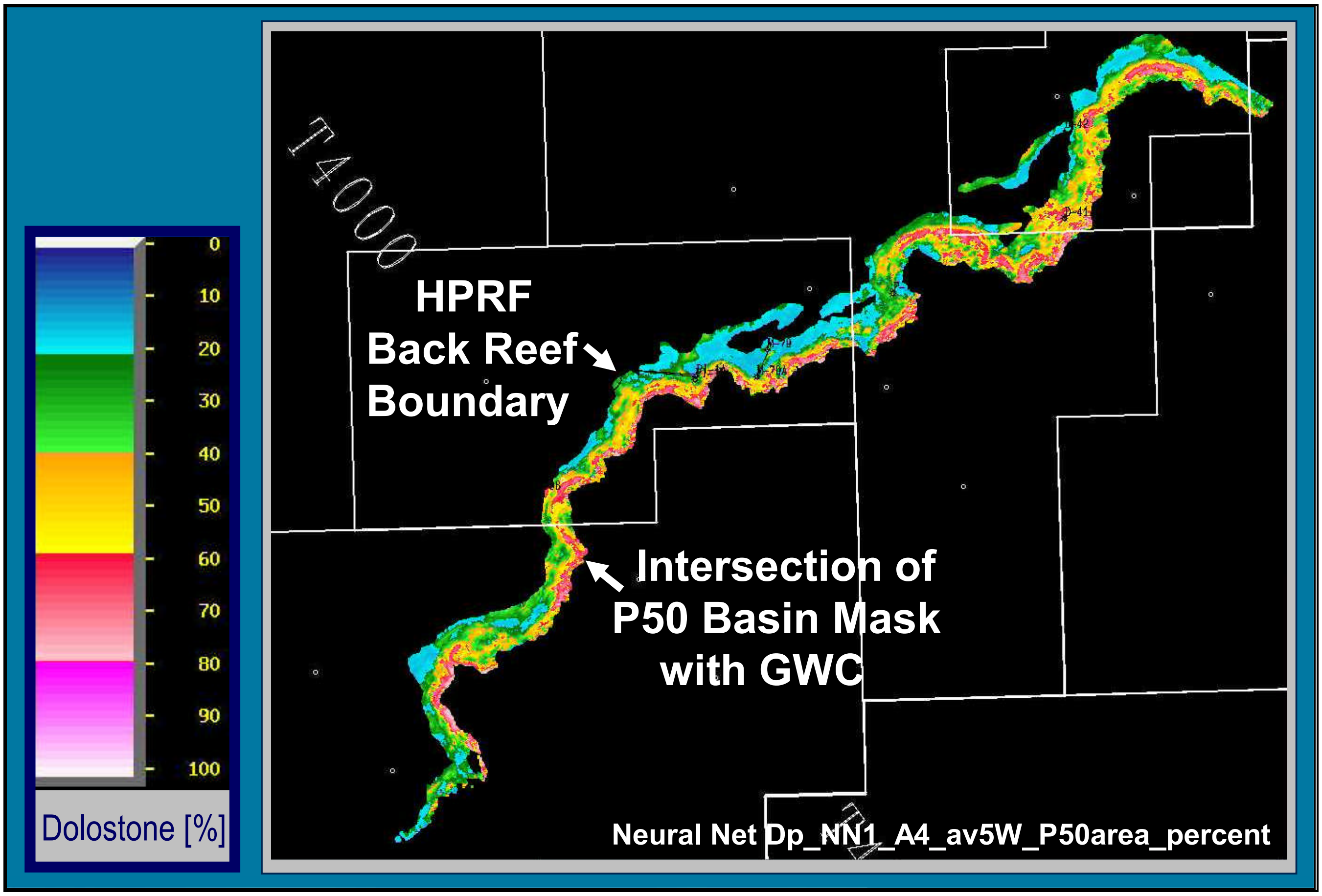


Figure 2.58: Map of Average Dolostone content within HPRF with Back Reef Boundary (Top Abenaki 5 to GWC)

2.3.6 Porosity Predictions

NN technology is the method of choice to use seismic data for the estimation of porosity away from the wells at Deep Panuke. The training data set for the porosity NN consists of petrophysical total porosity (Phi_{tot}) curves and seismic attributes extracted from seismic traces at the well locations. Based on the up-scaled well porosity data, a NN was trained on several seismic attributes to predict a 3-D volume of porosity. The procedure is summarized in Figure 2.59.

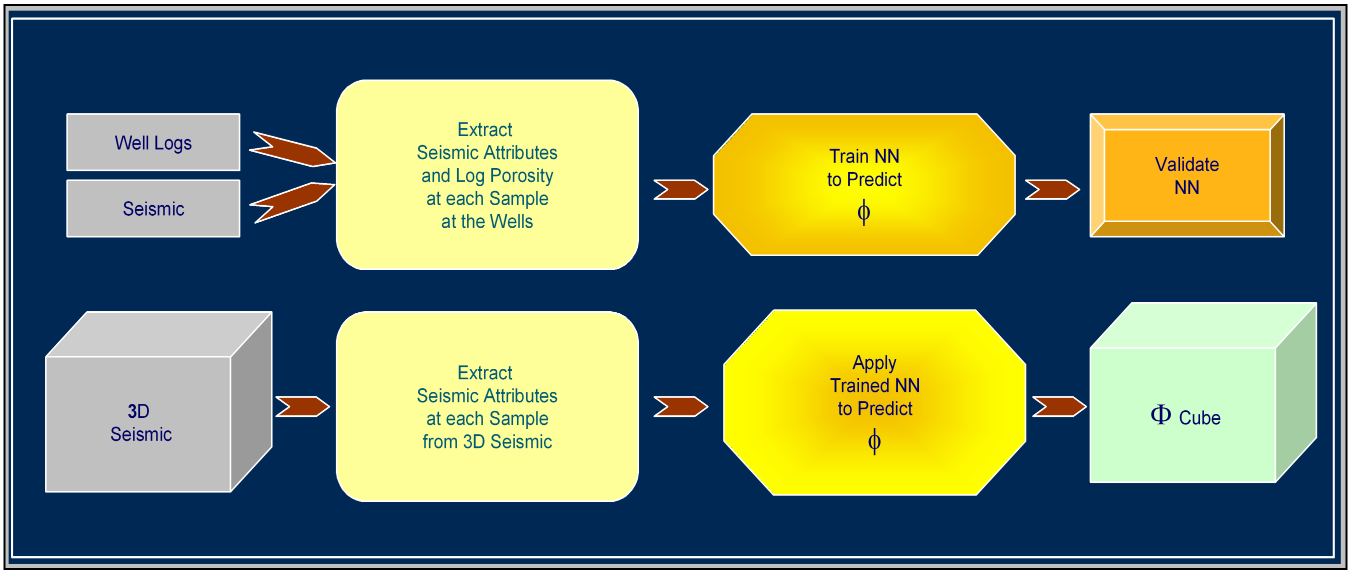


Figure 2.59: Procedure for NN porosity estimation

Acknowledging that the HPRF and VL regions represent significantly different lithologies and reservoir types, NN porosity training was done separately for each region. After testing more than one hundred different NN architectures and various input seismic attribute combinations, a set of NN were identified for the HPRF and VL regions which delivered reasonable results.

Each of the identified NN has internally consistent porosity distributions over the HPRF or VL regions. However, absolute porosity values differ for each NN result. Therefore, to determine which NNs offer the best solutions additional criteria are required.

2.3.6.1 Criteria for Porosity NN Validation

The criteria used to validate the NN porosity predictions are as follows:

1. high correlation coefficient of up-scaled petrophysical porosity to NN predicted porosity immediately around the wells;
2. match of up-scaled petrophysical mean porosity to NN mean porosity;
3. cross-section visual match of up-scaled petrophysical porosity to NN predicted porosity immediately around the wells;
4. comparison of petrophysical porosity histograms (e.g. data range, bimodality in HPRF) to NN derived porosity histograms;
5. blind tests (HPRF only) i.e. analysis of M-79A and J-14A wells which were not used in the training;
6. average porosity maps are logical;

7. porosity analogues support the range of predicted porosity; and
8. well test matches; the well tests were modelled using the new simulation models to determine modelled performance is consistent with actual well performance (Section 2.4.2.2).

Based on the above criteria, an extensive series of cross-sections, cross-plots, porosity histograms, and maps were used to validate the NN porosity predictions (DPA Part 2, Ref # 2.14).

2.3.6.2 HPRF Porosity Prediction Results

A key observation made in the petrophysical analysis of the HPRF wells (Section 2.2.3) is that total porosity (Phi_{tot}) histograms exhibit bimodality as a consequence of two underlying lithotypes in this region, namely limestone and dolostone. The bimodality represents a "background" low porosity distribution for limestones (undolomitized) and a superimposed higher porosity distribution for dolostones as a direct consequence of the deep burial dolomitization process.

The bimodal character of the well log derived porosity histograms (Figure 2.34 and Figure 2.35) has been preserved in the seismically-derived NN porosity histograms for the entire HPRF region as shown in Figure 2.60. This is an important advance in the validation of the NNs and the reservoir characterization of the pool.

The three different seismically-derived porosity NN all yield high correlation coefficients (> 0.8). When compared, the petrophysical mean porosity values closely matches the NN mean porosity values (DPA Part 2, Ref # 2.14). Each porosity distribution has an equal probability of being "correct". Therefore, all three distributions are used as input in the static reservoir modelling process to generate the range of OGIP for the HPRF.

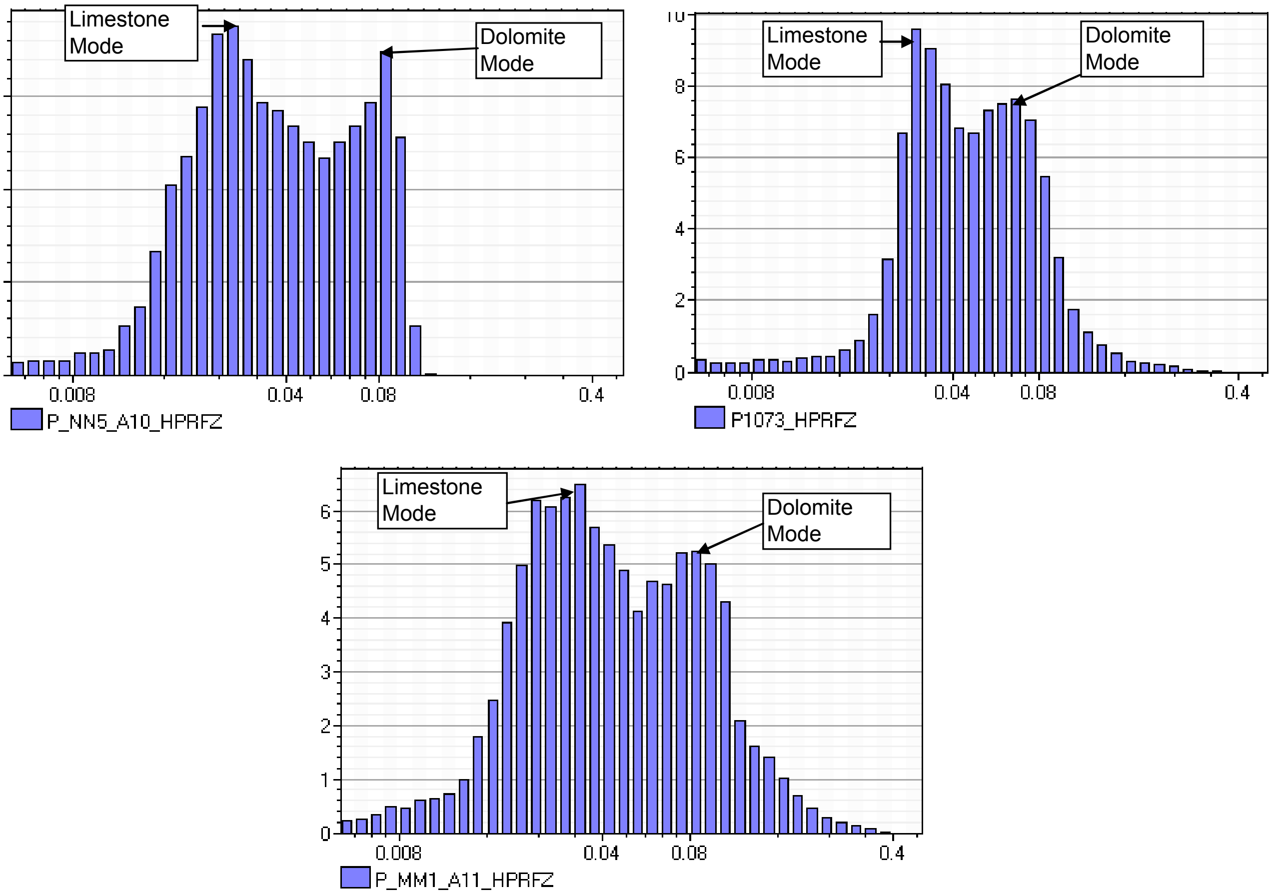


Figure 2.60: HPRF Region Porosity Histograms

The computed 3-D porosity cubes allow one to scan through the full reservoir zone to identify high porosity zones and to compute pore volumes. Furthermore, average porosity maps can be generated to gain an understanding of the general distribution of porosity within the reservoir zone. Figure 2.61 illustrates the average porosity between the top Abenaki V and the GWC within the HPRF region.

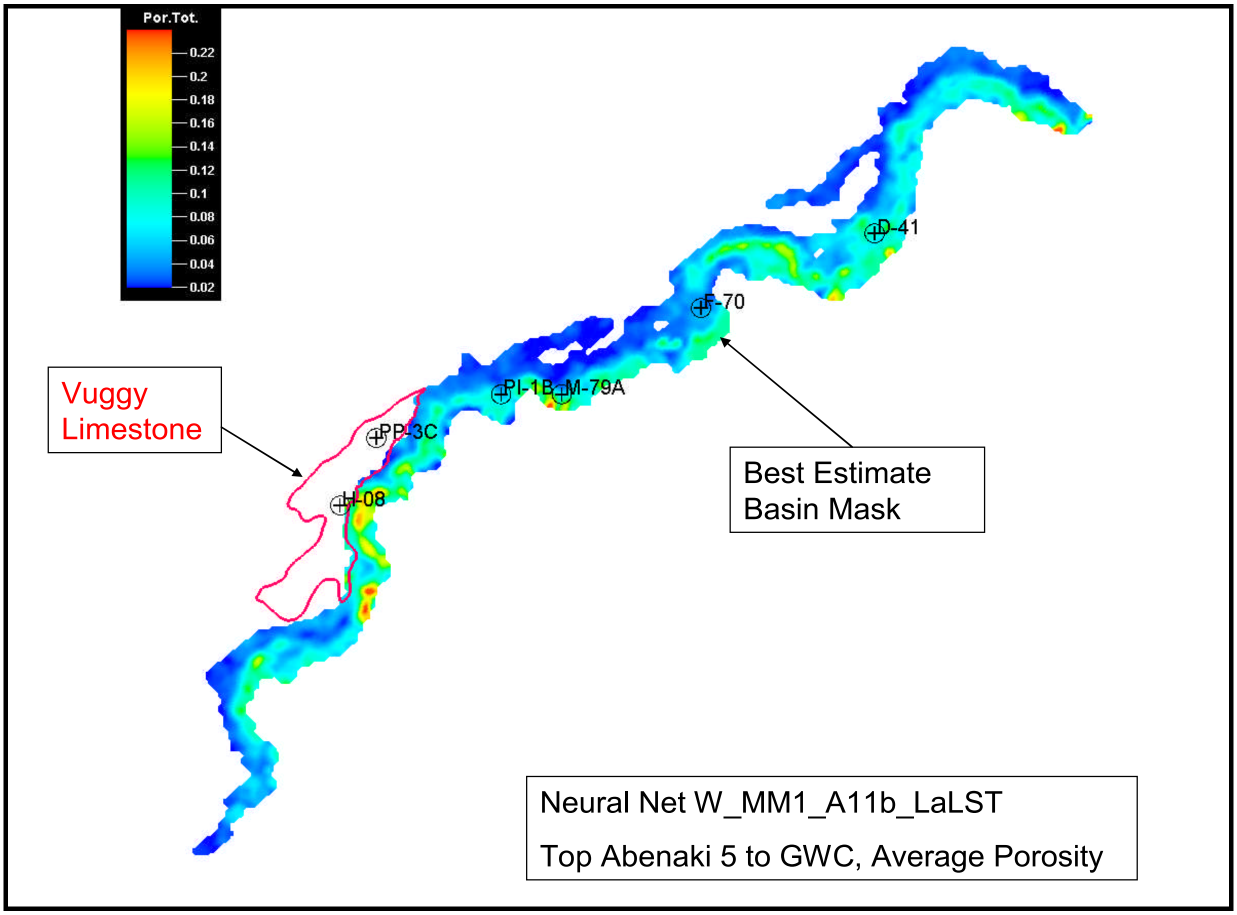


Figure 2.61: Average Porosity between Top Abenaki 5 and GWC (HPRF)

2.3.6.3 Vuggy Limestone Porosity Prediction Results

The three seismically-derived porosity NN histograms shown in Figure 2.62 were developed separately for the VL region and were validated using most of the same procedures as in the HPRF region. The porosity bimodality criteria used for the HPRF region is also preferred for the VL region (Figure 2.36) since two lithotypes are present, margin limestone and vuggy limestone. However, as is seen in Figure 2.62, the seismically-derived P50 VL porosity histogram does not exhibit a bimodal character. This NN is still acceptable since it meets the other NN validation criteria: when the relative proportions of two lithotypes in a mixed population are not optimal, bimodality may be obscured or absent.

Additional issues with the VL region porosity distributions were identified and addressed through the well test matching process as discussed in Section 2.4.2.2. The root cause of the problems may be that with only two wells drilled to date, the porosity NN training dataset may not be fully representative of the VL region. Only if additional wells are drilled into this region can this issue be further addressed.

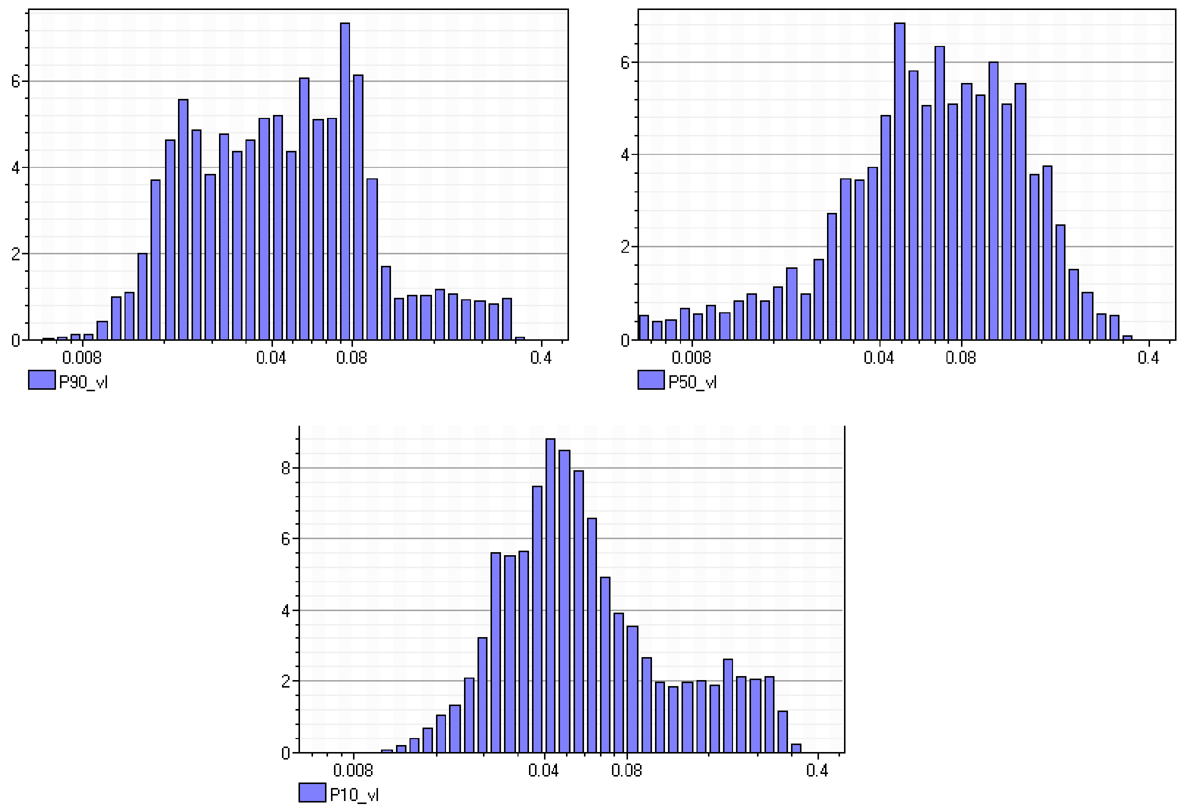


Figure 2.62: VL Region Porosity Histograms

The average porosity map for the VL shown in Figure 2.63 is based on the P10 porosity NN. The map extends to the seismically mapped P10 boundary. The eastern boundary is a somewhat arbitrary vertical boundary chosen to separate the VL region from the very nearby HPRF region which is only a few hundred meters from H-08. Using a vertical boundary is necessary for mapping purposes but the diagenetic processes of dolomitization and leaching are likely to have created a much more complex 3-D pattern.

The western boundary of the VL extends to the mappable extent of porosity and has a rectilinear shape strongly suggesting fault control. This is consistent with the diagenetic model involving vertical migration of leaching fluids along faults.

The PP-3C well was drilled into a northeast-southwest oriented high porosity (> 12%) trend which extends further toward the southwest from the well with porosity variations along the trend. The linear nature of the porosity trend suggests fault control.

The porosity distribution around the H-08 well has a more complex pattern, probably due to the proximity of the HPRF. To the southwest of H-08 there are weak porosity trends interpretable from the map, again suggesting fault control.

Such maps are simplifications which effectively collapse a three-dimensional pattern of porous reservoir and non-porous rocks into a two-dimensional representation. The patterns observed on the average porosity map shown in Figure 2.63 are logical and consistent with the diagenetic history interpreted for this region.

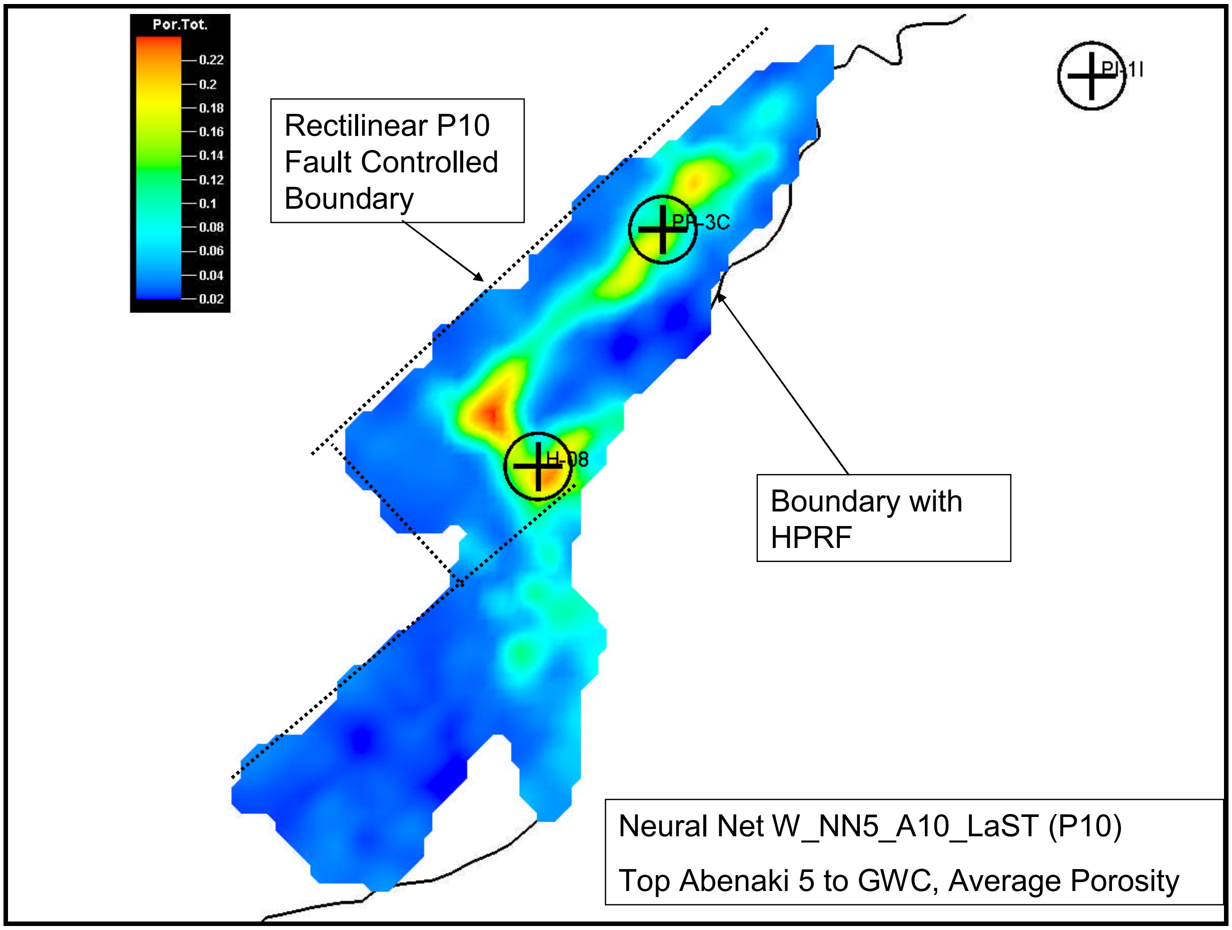


Figure 2.63: Average Porosity Map Vuggy Limestone Region with P10 Boundary

2.4 Abenaki Reservoir Models

Based on the reservoir characterization work presented in Section 2.2, a rigorous reservoir modelling process was used to generate static and dynamic 3-D “Earth Models” for Deep Panuke (DPA-Part 2, Ref # 2.14).

The key static modelling uncertainty inputs are areal extent, effective porosity and GWC which represents the uncertainty in both GWC and seismic depth conversion. The modelling effort provided a range of outcomes for OGIP. Three models which capture the range of OGIP were then selected for reservoir simulation.

The key dynamic uncertainty inputs are aquifer size, aquifer connectivity to the HPRF and connectivity within the VL. The simulation models were first history-matched to the well test results prior to running numerous cases to generate the range of gas recovery efficiencies.

2.4.1 Static Model Development

The VL and HPRF regions introduced in Section 2.2.2 comprise the proven reservoir to be developed in Deep Panuke and are the focus of our modeling work. MR region limestones are included in the earth model but are considered to be non-reservoir for simulation modeling purposes. The Shoal region has not been drilled; it is considered only as exploration potential and is not part of the static model.

There are many possible approaches by which a reservoir model can be constructed. The choice of methods is generally guided by the amount, type and quality of data available to the modelers. The Deep Panuke dataset is heavily weighted in favor of seismic data which is judged to be good quality, though with definite limitations. As discussed in Section 2.3.3, structural mapping of the reservoir is highly dependant on picking geophysical surfaces which are depth converted using wells as control points, then adjusting the geophysical surfaces to match geological surfaces at the wells. The key surfaces in the models are as follows:

- top Carbonate;
- top Abenaki 6B;
- top Abenaki 5;
- top porosity;
- top TS;
- top Abenaki 4; and

- GWC.

The mapping of reservoir lateral extent (e.g. basin masks, back-reef mask, and VL boundaries) is very dependent on geophysical methods (Section 2.3.4). For modeling purposes, the lateral extent of the HPRF has been limited by a back reef mask (constant for all cases), minimum / best estimate and maximum basin masks and varying GWC. The northeast boundary of the pool has been set to the northeast of the D-41 gas well. Further details are provided in DPA-Part 2, Ref # 2.14.

The structural elevations of the surfaces in the model are considered to be very reliable. The seismic velocity field is sufficiently well behaved that depth conversions have an accuracy of less than 15 m. The possible range in the GWC determined from petrophysical and pressure measurements is similar. Depth uncertainty in the modelling process is addressed by varying the GWC between three cases, -3496 mss (P90), -3504 mss (P50) and -3512 mss (P10). The maximum model depth was set at -3700 m subsea to include approximately 200 m of aquifer interval.

The well petrophysical data is high quality but relatively sparse in terms of the number of wells available. Only six wells are available which have penetrated good reservoir along the length of the pool. Due to the sparse well control, rather than applying poorly constrained geostatistical methods to predict porosity away from the wells, NN prediction methods are the preferred approach to mapping the distribution of porosity away from the wells as described in Section 2.3.6. The NN approach in Deep Panuke uses up-scaled petrophysical porosity estimates along with the various combinations of seismic attributes at the wells to train the network. This is then applied throughout the seismic volume to predict porosity away from the wells. An extensive series of validations are performed to verify and iteratively improve the efficacy of the method and accuracy of the porosity predictions. A similar NN approach was used to predict dolostone volumes and also fracture intensity in the HPRF.

One of the key outputs of the static modelling work is to generate the range of potential OGIP for resource calculations. For Deep Panuke the static model parameters that account for the majority of the uncertainty in OGIP are areal extent, effective porosity and GWC.

- Areal Extent: Three separate structure models were built in PETREL™ (Schlumberger's 3D visualization, mapping, modelling and simulation software) to represent the minimum, most likely and maximum basin masks for the HPRF. The VL structure is the same for all three models; P90/P50/P10 VL areas were determined based on the geophysical interpretation to represent the uncertainty in areal extent. The structure models were constructed with 50 x 50 m areal cell dimensions and 5 m cell thickness for the Abenaki gas zone. The model dimensions are 694 x 172 x

69 m cells, resulting in more than 7 million cells in the model. The HPRF and VL regions were handled separately to populate the models with reservoir parameters.

- Effective Porosity: Over 100 NN porosity scenarios were initially evaluated for the HPRF (Section 2.3.6). These were narrowed down to ten cases based on quality of the fit to petrophysical data, then further narrowed down to the three best cases by ensuring that the predicted porosity distributions are consistent with the petrophysical analysis described in Section 2.2.3. The three best NN HPRF total porosity (Phi_{tot}) distributions and their associated volume dolostone (Vol_{Ds}) distributions were input into each structure model to represent low, mid-range and high porosity cases. Effective dolomite porosity and water saturations were then determined. The process used to generate P10/P50/P90 porosity estimates for the VL was similar to the HPRF but not as rigorous. Water saturations were determined using a BVW equal to 2 percent.
- GWC: The range in GWC (see above) was used to address the depth conversion uncertainty and GWC for both the VL and HPRF regions.

Twenty Seven deterministic estimates of OGIP for both the HPRF and VL to account for the variability in areal extent, porosity and GWC were generated with the static models and based on the gas in place calculation methodology presented in Section 2.2.3.9. The results are presented in Table 2.11.

Table 2.11: OGIP Estimates –HPRF and VL

HPRF OGIP Estimates				VL OGIP Estimates			
Basin Mask	Porosity	Contact (mSS)	OGIP (10^9 sm3)	Area	Porosity	Contact (mSS)	OGIP (10^9 sm3)
minimum	A10	3496	13.2	p90	p50	3496	1.8
minimum	A10	3504	14.2	p90	p90	3496	1.9
minimum	A10	3512	15.2	p90	p50	3504	2.0
minimum	P1073	3496	15.6	p90	p90	3504	2.1
minimum	P1073	3504	17.0	p90	p50	3512	2.1
minimum	P1073	3512	18.4	p90	p90	3512	2.2
minimum	A11	3496	19.5	p50	p90	3496	2.7
best estimate	A10	3496	20.9	p50	p90	3504	2.9
minimum	A11	3504	21.0	p90	p10	3496	3.0
best estimate	A10	3504	22.4	p50	p90	3512	3.2
minimum	A11	3512	22.4	p90	p10	3504	3.2
best estimate	P1073	3496	23.0	p90	p10	3512	3.3
best estimate	A10	3512	23.9	p50	p50	3496	3.5
best estimate	P1073	3504	24.8	p10	p90	3496	3.6
maximum	A10	3496	25.3	p50	p50	3504	3.7
best estimate	P1073	3512	26.7	p10	p90	3504	4.0

Table 2.11: OGIP Estimates –HPRF and VL							
HPRF OGIP Estimates				VL OGIP Estimates			
Basin Mask	Porosity	Contact (mSS)	OGIP (10^9 sm3)	Area	Porosity	Contact (mSS)	OGIP (10^9 sm3)
maximum	A10	3504	27.3	p50	p50	3512	4.0
maximum	P1073	3496	27.7	p10	p90	3512	4.3
maximum	A10	3512	29.3	p50	p10	3496	4.5
maximum	P1073	3504	30.1	p50	p10	3504	4.8
best estimate	A11	3496	31.0	p50	p10	3512	5.0
maximum	P1073	3512	32.5	p10	p10	3496	5.9
best estimate	A11	3504	33.2	p10	p10	3504	6.3
best estimate	A11	3512	35.3	p10	p10	3512	6.6
maximum	A11	3496	36.5	p10	p50	3496	6.6
maximum	A11	3504	39.0	p10	p50	3504	7.2
maximum	A11	3512	41.8	p10	p50	3512	7.8

"Small", "Mid" and "Large" Models were initially selected for reservoir simulation to represent the low, mid and high end OGIP estimates. The well test history-matching process followed (see Section 2.4.2.2).

Modification to the fracture permeability near the wells was required to get an acceptable match for the HPRF wells F-70, PI-1B, and M79-A in all models. Additional pore volume was added close to M-79A for the small and mid-range models.

The H-08 well test was used to calibrate the VL region. The matching process did not initially yield acceptable results:

- The P90 and P50 porosity distributions did not have sufficient connected OGIP for the P90, P50 and P10 areas without major adjustments.
- The P10 porosity distribution did not have enough connected OGIP in the P90 area; the connected OGIP for the P50 and P10 areas were too large.

Three new VL scenarios were then selected for simulation. The small and mid-range models use the P10 porosity estimate with the west half of the P50 area; the large model utilizes the P10 porosity cube and the P10 area. Acceptable well test history matches were obtained. The final simulated OGIP volumes are provided in Table 2.12.

Table 2.12: Simulation Model OGIP								
		HPRF			VL			TOTAL
Simulation Model	Contact (mSS)	Basin Mask	Porosity	OGIP (10^9 sm3)	Area	Porosity	OGIP (10^9 sm3)	OGIP (10^9 sm3)
Small	3496	minimum	A11	20.0	P50	P10	2.5	22.5
Mid	3504	best estimate	P1073	26.8	P50	P10	2.9	29.8
Large	3504	best estimate	A11	33.2	P10	P10	5.8	38.9

A series of maps are included in DPA-Part 2, Ref # 2.30 which correspond to the Small, Mid and Large reservoir simulation models identified in Table 2.12. The map series includes the following:

- Average Porosity Maps -both HPRF and VL regions
- Net Pay Maps -both HPRF and VL regions
- Porosity*Thickness Maps (phi *h) -both HPRF and VL regions
- Porosity*Thickness*Gas Saturation Maps (phi*h*Sg) - both HPRF and VL regions

2.4.2 Reservoir Simulation Model Development

The three cases selected for reservoir simulation identified in Table 2.12 are referred to as Small, Mid and Large. The models focus on the HPRF and VL in the areas that have been appraised by drilling and were up-scaled to grid block sizes of approximately 100m x 100m x 10m. "ECLIPSE 100™" simulation software was used. Effective dolostone porosity, dolostone volume and fracture intensities were up-scaled. Matrix permeability was estimated on the up-scaled grid using the porosity/permeability relationships established in Section 2.2.3. The initial estimate of fracture permeability was based on well test results discussed in Section 2.2.6. A vertical to horizontal permeability ratio of 0.1 was assumed.

Approximately 200 m of aquifer thickness was modelled. A "Fetkovich Bottom Water Drive" analytical aquifer was attached to the bottom layer of the simulator to represent the remaining aquifer volumes.

As discussed in Section 2.1.3, the HPRF is considered to be a dual porosity reservoir. The rock matrix provides the bulk of the reservoir volume and the fracture network provides the majority of the reservoir permeability. To model dual porosity systems in the simulator, two cells are associated with each block in the geometric grid, representing the matrix and fracture volumes of the cell. Characteristics of the twin cells such as porosity, permeability and water saturation are independent. A matrix to fracture coupling transmissibility is constructed in ECLIPSE™ to simulate the flow between the matrix and fractures.

The model dimensions are 272 x 73 x 74 m which equates to approximately 1.5 million cells. The volumetrics of the up-scaled models are consistent with the finer grid static models.

2.4.2.1 Model Aquifer Size and Connectivity

As discussed in Section 2.2.5, the aquifer size and the degree of connectivity between the gas zone and underlying aquifer are important dynamic uncertainties in modeling reservoir performance. A "Fetkovich Bottom Water Drive" analytical aquifer was used to supplement the "modeled aquifer" (simulation model grid extends approximately 200 m below GWC) to achieve the desired aquifer size. It was concluded that the range of connectivity alternatives discussed in Section 2.2.5 can effectively be handled by varying the "Fetkovich" aquifer productivity index "J" as follows:

- The P90 "J" index is estimated to be 30. This equates to a water influx rate equivalent to the "modeled aquifer".
- The P50 "J" index is estimated to be 100. This equates to a water influx rate approximately 1.5 times that of the "modeled aquifer".
- The P90 "J" index is estimated to be 400. This equates to a water influx rate approximately 2 times that of the "modeled aquifer".

2.4.2.2 Simulator Well Test Matches

An important step in any modeling process is the history matching of the available dynamic reservoir data. As was discussed in Section 2.2.6, six well tests were conducted. Three wells, PI-1B, M-79a and F-70, tested the HPRF. The H-08 and PP-3C wells tested the VL. The F-09 well tested in the back reef area outside of the modeled area.

The major objective of the history matching process is to constrain the up-scaled geologic models with the well tests. The focus of the match is on stabilized well and reservoir performance: closely matching the early time behavior is not considered important because of scaling issues. Well operational problems as identified in Section 2.2.6 must be taken into account. The Small, Mid and Large models were all history matched.

The production rate of the wells is set at the well test rates, the model is run and the bottom-hole flowing and shut-in pressures at the wells are compared to the measured gauge data. When performing the matching, the initial changes are only made to permeability since permeability is relatively uncertain. Only when a match cannot be achieved by changing just permeability are changes to porosity also considered.

The HPRF wells, PI-1B, M-79a and F-70, all had acceptable matches with only minor adjustments to the simulation grid. The fracture permeability within 500 m of each well was increased and additional pore volume was added close to M-79A for the Small and Mid models (see Figure 2.64). The log-log plot for the actual and simulated bottom-hole pressures for well PI-1B is provided in Figure 2.65 to demonstrate the quality of the matches. Semi-log and linear comparisons were also conducted.

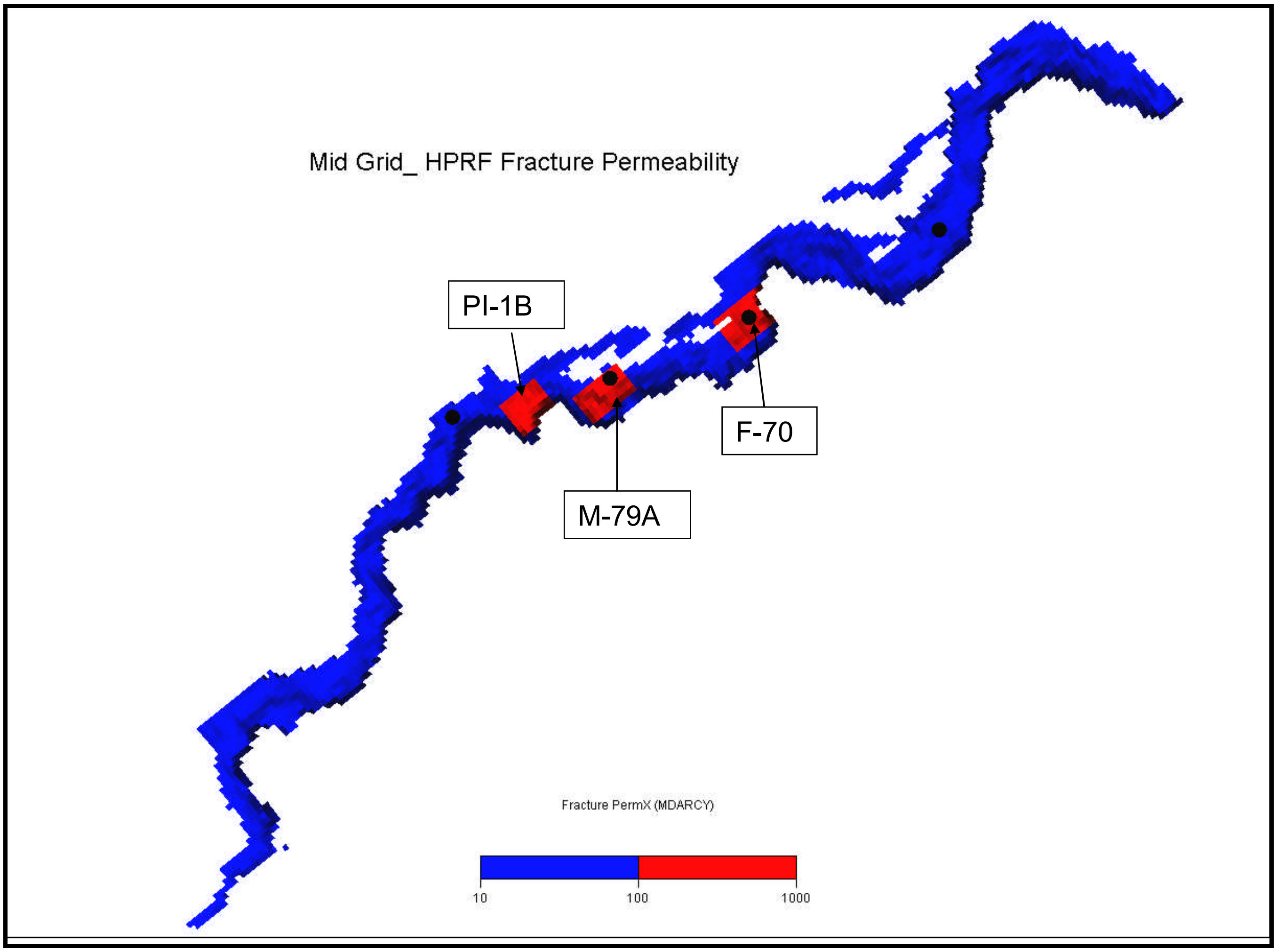


Figure 2.64: Regions for Adjusting Fracture Permeability

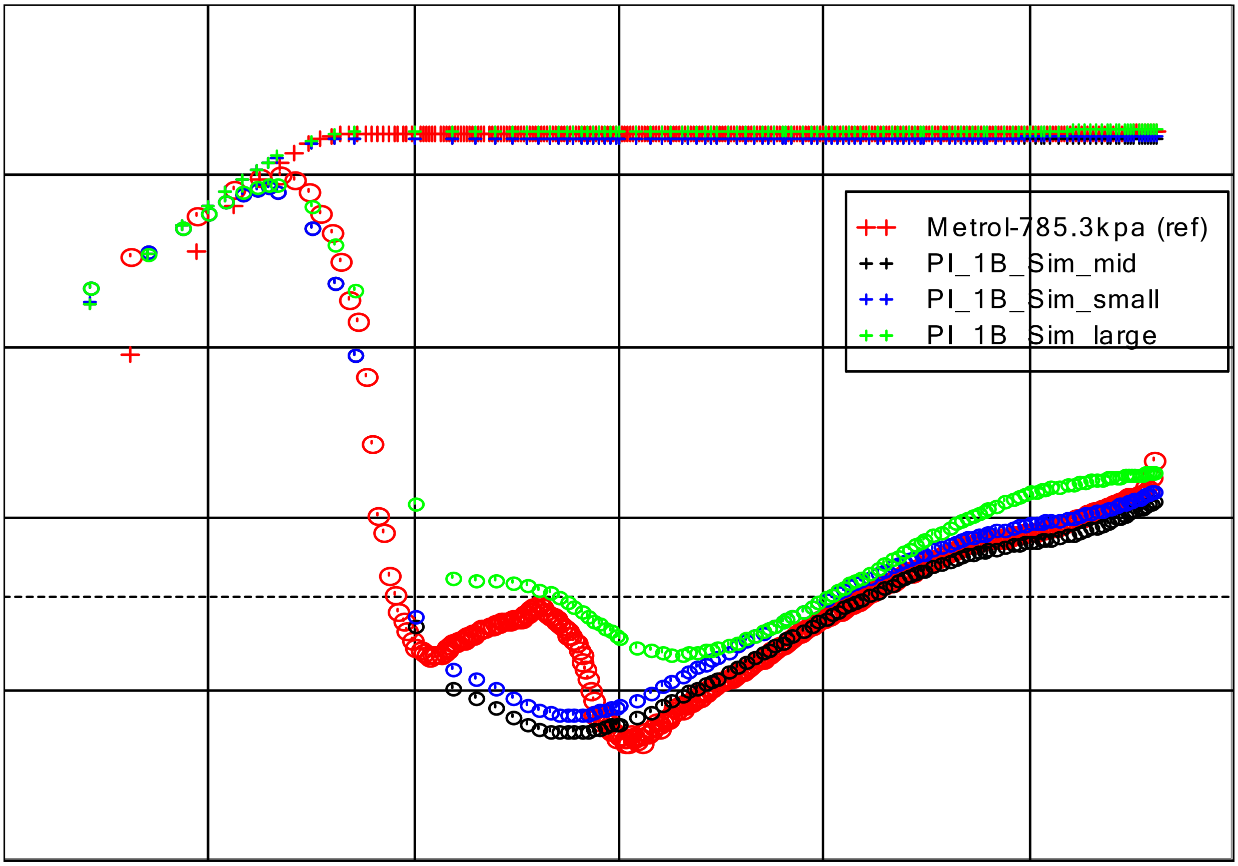


Figure 2.65: PI-1B History Match

As was discussed in Section 2.2.6 both PP-3C and H-08 experienced major operational problems during the well tests that significantly impacted the results. The PP-3C data quality was so compromised that it was not of sufficient quality to use in the well test matching process. The data for H-08 was also compromised but considered to be of adequate quality to calibrate the VL in the simulation models.

The matching process did not initially yield acceptable matches.

- The P90 and P50 porosity distributions did not have sufficient connected OGIP for the P90, P50 and P10 areas without major adjustments. This is best illustrated by looking at the average permeability for the "P90 porosity" provided in Figure 2.66. The OGIP connected to H-08 is not large enough to match the well test results.
- The P10 porosity distribution did not have enough connected OGIP in the P90 area; the connected OGIP for the P50 and P10 areas were too large.

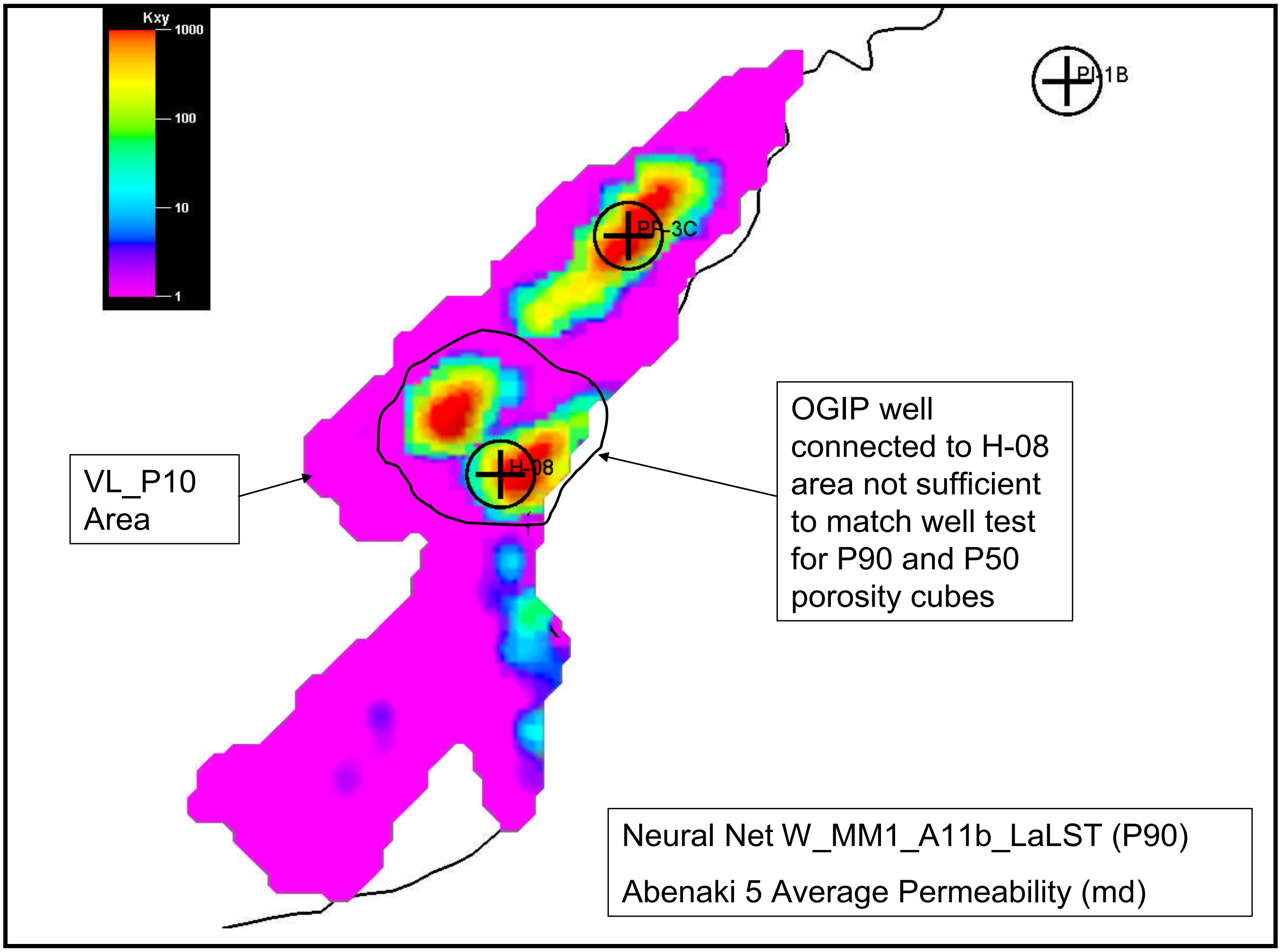


Figure 2.66: VL: "Average Permeability for P90 Porosity"

New VL models were selected using only the P10 porosity distribution to progress the simulation work and history matching. For the "Small" and "Mid" models, the P50 area was used and the eastern half of the VL was eliminated (Figure 2.67). For the "Large" model the full P10 area was used.

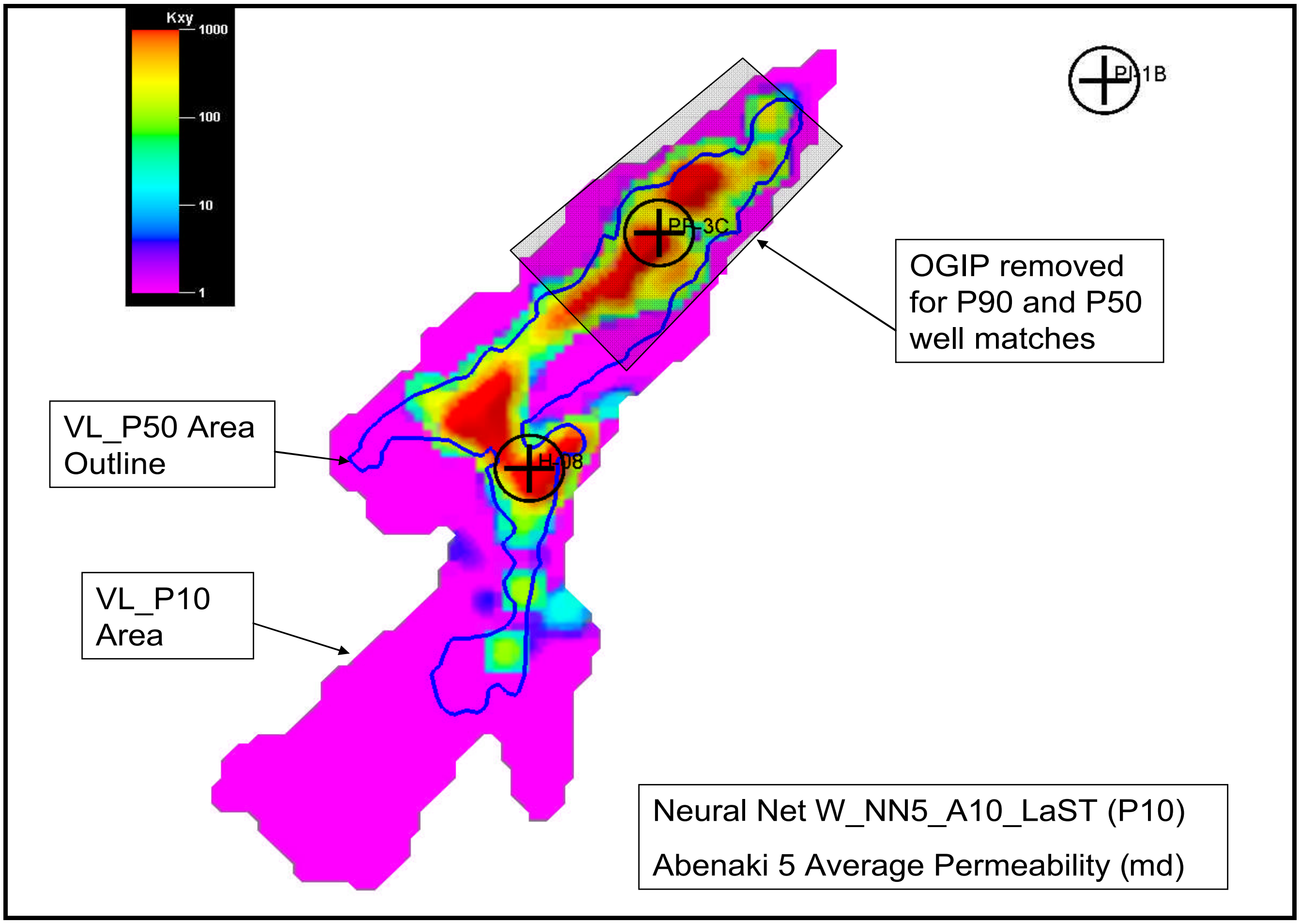


Figure 2.67: VL: "Average Permeability for P10 Porosity"

Further details on the history matching process are provided in DPA-Part 2, Ref # 2.14.

2.4.2.3 Simulation Results

Simulation results for fifty-eight cases are provided in Table 2.13 to illustrate the impact of the uncertainty in the HPRF OGIP, aquifer size and aquifer connectivity on reservoir performance. The correlation coefficients between the input and output parameters are provided in Table 2.14. Both the HPRF and VL regions were simulated. The focus of the analysis was on the HPRF and then applying the learnings to the VL.

Table 2.13: Simulation Results for the HPRF

Inputs			Outputs				
HPRF OGIP (10^9 sm3)	Aquifer Size (X_OGIP)	Aquifer Trans. (J)	HPRF RF	HPRF Plateau RF	Project Life Years)	Life After Plateau (years)	HPRF RGIP (10^9 sm3 raw)
20.0	4.7	10	0.72	0.244	11.4	9.6	14.4
20.0	9.9	10	0.712	0.244	11.2	9.3	14.2
20.0	16.6	10	0.708	0.244	11.1	9.2	14.2
26.8	4.7	10	0.751	0.263	15.0	12.4	20.2
26.8	9.9	10	0.738	0.263	14.5	11.9	19.8
26.8	16.6	10	0.734	0.263	14.2	11.7	19.7
33.2	4.7	10	0.773	0.294	16.4	12.7	25.6
33.2	9.9	10	0.769	0.294	16.3	12.6	25.5
33.2	16.6	10	0.767	0.294	16.3	12.6	25.4
20.0	4.7	40	0.702	0.243	11.6	9.7	14.0
20.0	9.9	40	0.667	0.243	10.6	8.7	13.3
20.0	16.6	40	0.636	0.243	9.7	7.8	12.7
26.8	4.7	40	0.746	0.262	15.0	12.4	20.0
26.8	9.9	40	0.694	0.262	13.3	10.7	18.6
26.8	16.6	40	0.667	0.262	12.4	9.8	17.9
33.2	4.7	40	0.757	0.287	16.8	13.1	25.1
33.2	9.9	40	0.722	0.281	15.1	11.5	23.9
33.2	16.6	40	0.702	0.281	14.2	10.6	23.3
20.0	4.7	150	0.719	0.232	11.7	10.0	14.4
20.0	9.9	150	0.666	0.232	11.2	9.4	13.3
20.0	16.6	150	0.558	0.231	8.2	6.4	11.2
26.8	4.7	150	0.744	0.262	14.9	12.4	20.0
26.8	9.9	150	0.691	0.254	13.9	11.4	18.6
26.8	16.6	150	0.613	0.254	11.3	8.8	16.5
33.2	4.7	150	0.757	0.274	16.9	13.5	25.1
33.2	9.9	150	0.689	0.26	14.9	11.6	22.8
33.2	16.6	150	0.61	0.254	12.0	8.7	20.2
20.0	4.7	350	0.718	0.231	11.8	10.1	14.4
20.0	9.9	350	0.668	0.22	11.5	9.8	13.4
20.0	16.6	350	0.525	0.22	7.6	5.9	10.5
26.8	4.7	350	0.738	0.254	14.7	12.2	19.8
26.8	9.9	350	0.688	0.145	14.0	11.6	18.5
26.8	16.6	350	0.609	0.245	11.8	9.4	16.4
33.2	4.7	350	0.774	0.267	17.5	14.1	25.7
33.2	9.9	350	0.692	0.241	15.9	12.8	22.9
33.2	16.6	350	0.578	0.234	12.0	9.0	19.2
20.0	4.7	1250	0.695	0.22	11.1	9.4	13.9
20.0	9.9	1250	0.641	0.196	10.6	9.1	12.8

Table 2.13: Simulation Results for the HPRF

Inputs			Outputs				
HPRF OGIP (10^9 sm3)	Aquifer Size (X_OGIP)	Aquifer Trans. (J)	HPRF RF	HPRF Plateau RF	Project Life Years)	Life After Plateau (years)	HPRF RGIP (10^9 sm3 raw)
20.0	16.6	1250	0.51	0.185	8.2	6.8	10.2
26.8	4.7	1250	0.722	0.245	14.4	12.0	19.4
26.8	9.9	1250	0.678	0.236	14.2	11.8	18.2
26.8	16.6	1250	0.558	0.227	10.8	8.6	15.0
33.2	4.7	1250	0.753	0.234	17.9	14.9	25.0
33.2	9.9	1250	0.662	0.207	15.5	12.8	22.0
33.2	16.6	1250	0.566	0.208	12.0	9.3	18.8
26.8	30	3000	0.433	0.201	10.2	8.2	11.6
26.8	30	1250	0.472	0.218	10.3	8.2	12.7
26.8	30	150	0.533	0.254	9.2	6.7	14.3
26.8	30	10	0.533	0.254	9.2	6.7	14.3
26.8	16.6	3000	0.504	0.211	9.2	7.2	13.5
26.8	9.9	3000	0.635	0.219	12.7	10.5	17.0
20.0	30	3000	0.403	0.15	7.2	6.1	8.1
20.0	30	1250	0.425	0.173	6.8	5.5	8.5
20.0	30	150	0.483	0.231	6.4	4.7	9.7
20.0	16.6	3000	0.494	0.173	8.4	7.1	9.9
20.0	9.9	3000	0.619	0.185	9.9	8.5	12.4
20.0	1.14	N/A	0.744	0.244	11.7	9.9	14.9
26.8	1.61	N/A	0.772	0.263	15.5	12.9	20.7
33.2	0.89	N/A	0.787	0.301	16.6	12.7	26.1

Table 2.14: Correlation Coefficient

INPUTS	OUTPUTS				
	HPRF RF	HPRF Plateau RF	Project Life Years)	Life After Plateau (years)	HPRF RGIP
HPRF OGIP	0.39	0.55	0.75	0.61	0.83
Aquifer Size (x_OGIP)	-0.80	-0.32	-0.66	-0.76	-0.53
Aquifer Transmissibility	-0.50	-0.73	-0.26	-0.22	-0.34

The simulation results indicate that the reservoir performance is highly variable with some strong correlations to OGIP, aquifer size and aquifer connectivity. They also indicate that the relationships are complex, leading to the conclusion that a statistical approach is the best methodology to predict overall ranges of reservoir performance. The strongest correlation coefficient for the HPRF_RF is with aquifer size at -0.80; however the range in recovery factor for one aquifer size is very wide (0.49 to 0 .77 for the "16.6 x OGIP" aquifer cases). Figure 2.68 illustrates this complexity; the HPRF recovery factor is plotted versus aquifer size (an exponential trend-line is also provided).

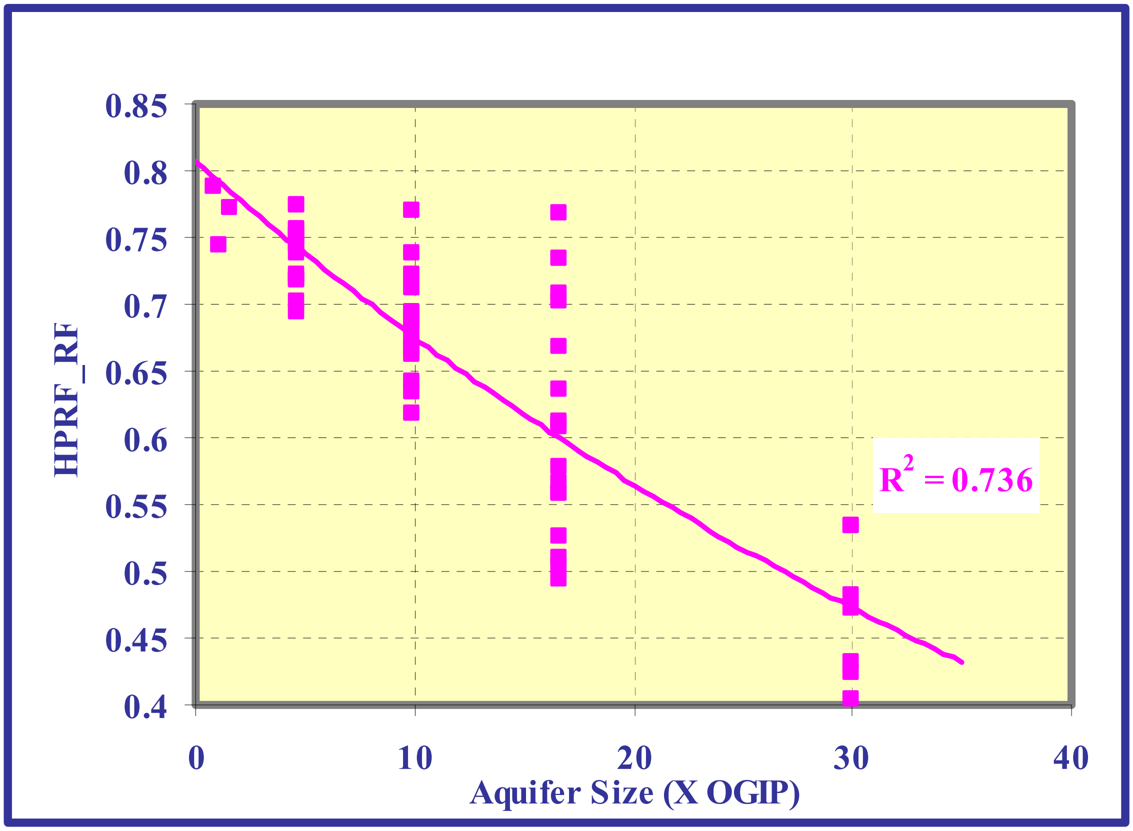


Figure 2.68: HPRF_RF vs. Aquifer Size

The key simulation outputs required for the risk modeling process are recovery factor, plateau recovery factor and life after plateau.

2.4.3 Subsurface Risk Model

A subsurface risk model was built in "Crystal Ball™" (Risk Analysis Software attached to Excel™) to integrate the output from the static and dynamic reservoir models with economic parameters, then to probabilistically generate resource estimates and production forecasts accounting for the full range of subsurface uncertainties and different depletion strategies.

2.4.3.1 Risk Model Input Parameters

Original Gas in Place (OGIP)

The OGIP distributions for the HPRF and VL regions are illustrated in Figure 2.69 and Figure 2.70. A lognormal distribution provided the best fit to the HPRF OGIP data in Table 2.12. This was then limited to a minimum OGIP of 11.27 10^9 sm3 (400 BCF) based on well test results (see Section 2.2.6) and a maximum OGIP of 36.63 10^9 sm3 (1300) BCF.

A triangular distribution was used to characterize the VL OGIP. The OGIP values for the P90 cases provided in Table 2.12 were eliminated because of the well test matching issues discussed in detail in Section 2.4.2.2.

OGIP_HPRF

Lognormal distribution with parameters:

Mean (un truncated)	26
Standard Dev.	8

Selected range is from 11.30 to 36.60

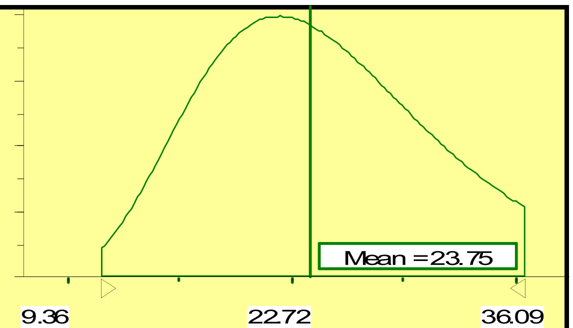


Figure 2.69: OGIP Distribution –HPRF

OGIP_VL

Triangular distribution with parameters:

Minimum	2.10
Likeliest	3.60
Maximum	9.00

Selected range is from 2.10 to 9.00

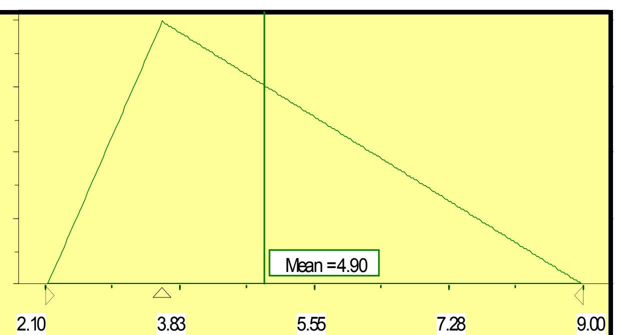


Figure 2.70: OGIP Distribution –VL

Aquifer Size and Transmissibility

The methodologies used to determine the ranges of aquifer size and transmissibility were discussed in detail in Section 2.2.7. Lognormal distributions were used as illustrated in Figure 2.71 and Figure 2.72.

AQ SIZE

Lognormal distribution with parameters:

10% - tile	4.7
90% - tile	16.6

Selected range is from 2.0 to 30.0

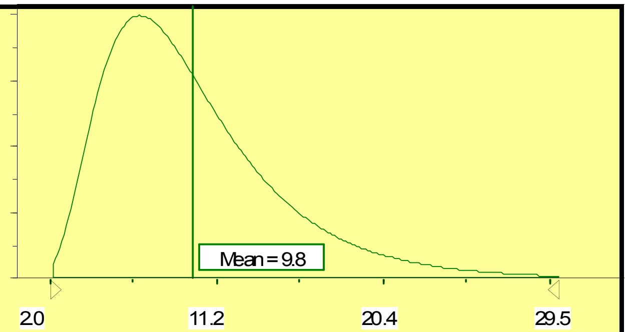


Figure 2.71: Aquifer Size Distribution

AQ Trans

Lognormal distribution with parameters:

10% - tile	29.6
90% - tile	420.0

Selected range is from 5 to 1979

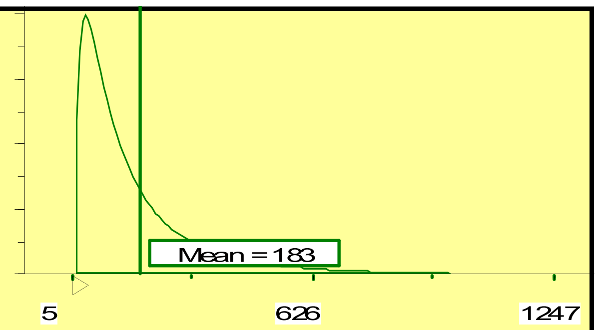


Figure 2.72: Aquifer Transmissibility

Recovery Factor – HPRF

The simulation results provided in Table 2.13 yielded a recovery factor range for the HPRF between 0.40 and 0.79. This range is considered too narrow. Additional risks have not been modelled on the downside associated with fracture heterogeneity, well completion problems and poor well performance at high water cuts: recoveries as low as 20% are possible. Some upside potential has also not been modelled; recoveries as high as 87% which corresponds to reservoir abandonment pressure of 5000 kpa are considered possible. Additional wells, well optimization activities, installation of booster compression and/or a primary depletion scenario with no water production issues would all lead to higher recovery factors.

The recovery factor distribution illustrated in Figure 2.73 was created to characterize the HPRF region based on the simulation results and to accommodate the potential upsides and downsides. It was correlated to the HPRF OGIP, aquifer size and aquifer transmissibility based on the correlation coefficients provided in Table 2.14.

The same recovery factor distribution was used for the VL region. A connectivity factor was also applied to the VL to account for the VL connectivity uncertainty identified through the well tests (see Section 2.2.6).

RF_HPRF

Extreme Value distribution with parameters:

Mode	0.720
Scale	0.085

Selected range is from 0.215 to 0.870

Correlated with:

OGIP_HPRF	0.39
AQ SIZE	-0.80
AQ TRANS	-0.50

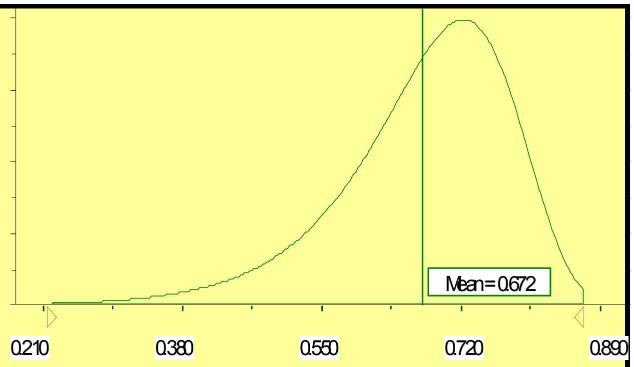


Figure 2.73: Recovery Factor – HPRF

Plateau Recovery Factor and Life after Plateau

"Plateau recovery factor" and "life after plateau" are the key factors in addition to the RGIP that are required to generate production forecasts.

The simulation results provided in Table 2.13 yield a plateau recovery factor range for the HPRF between 0.17 and 0.29. This range is considered too narrow for the same reasons as for the recovery factor. The distribution shown in Figure 2.74 was created to characterize the plateau recovery factor in the HPRF based on the simulation results and to accommodate the potential upsides and downsides and then correlated to the HPRF OGIP, aquifer size and aquifer transmissibility for risk modelling.

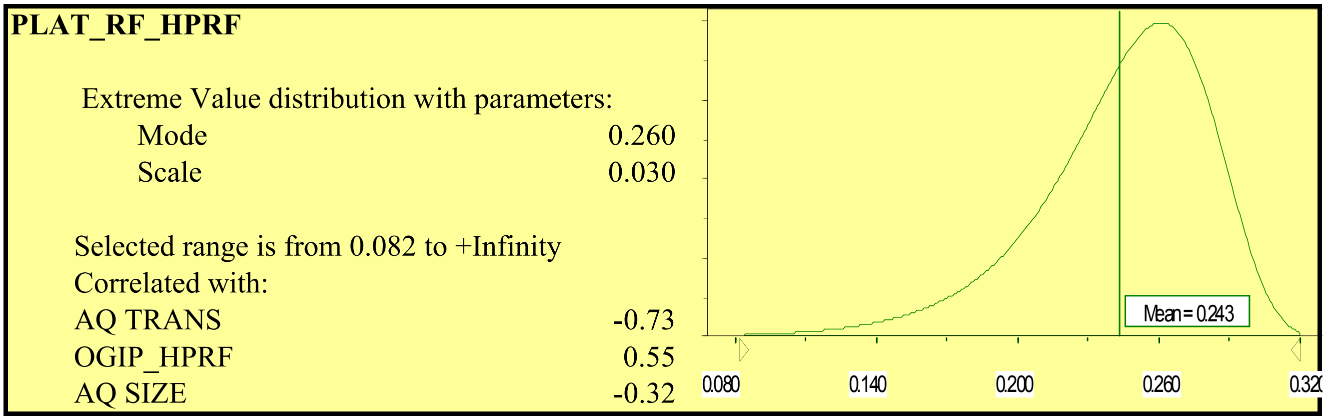


Figure 2.74: Plateau Recovery Factor – HPRF

The simulation results provided in Figure 2.75 indicate that "life after plateau" correlates very well with the HPRF RGIP. The logarithmic trend-line is used in risk modeling to generate "life after plateau".

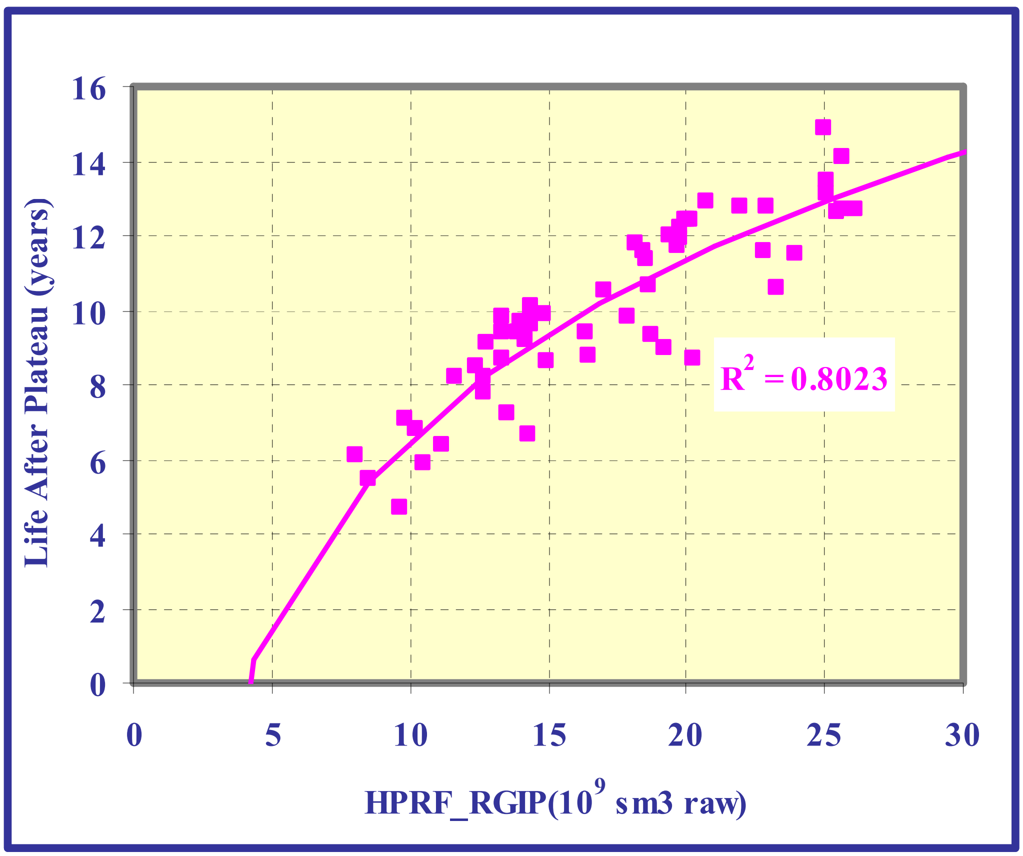


Figure 2.75: "Life after Plateau" –HPRF

Recoverable Gas in Place (RGIP)

The most important output from the model is total pool RGIP which is illustrated in Figure 2.76. The sensitivity of the total RGIP to the key technical parameters is illustrated in Figure 2.77.

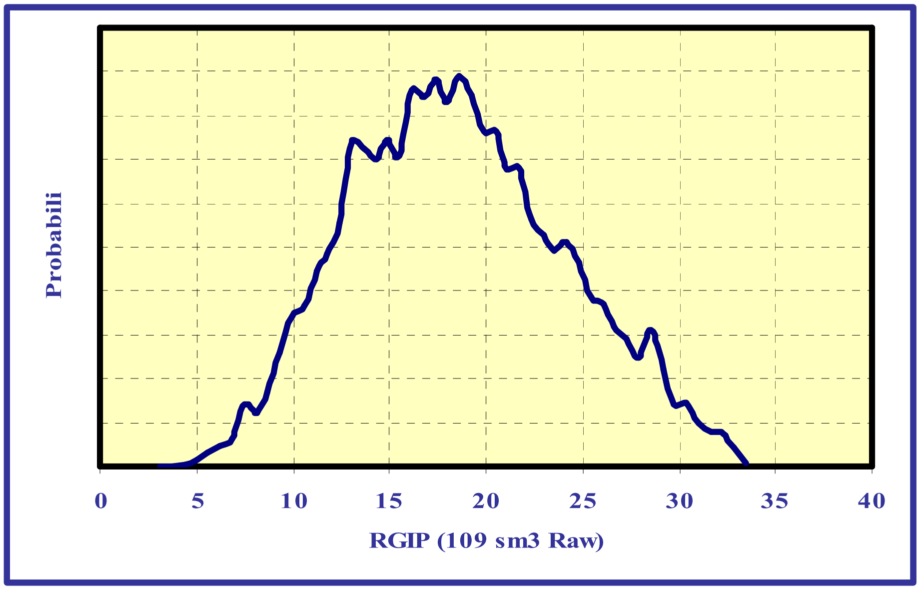


Figure 2.76: Total RGIP Distribution

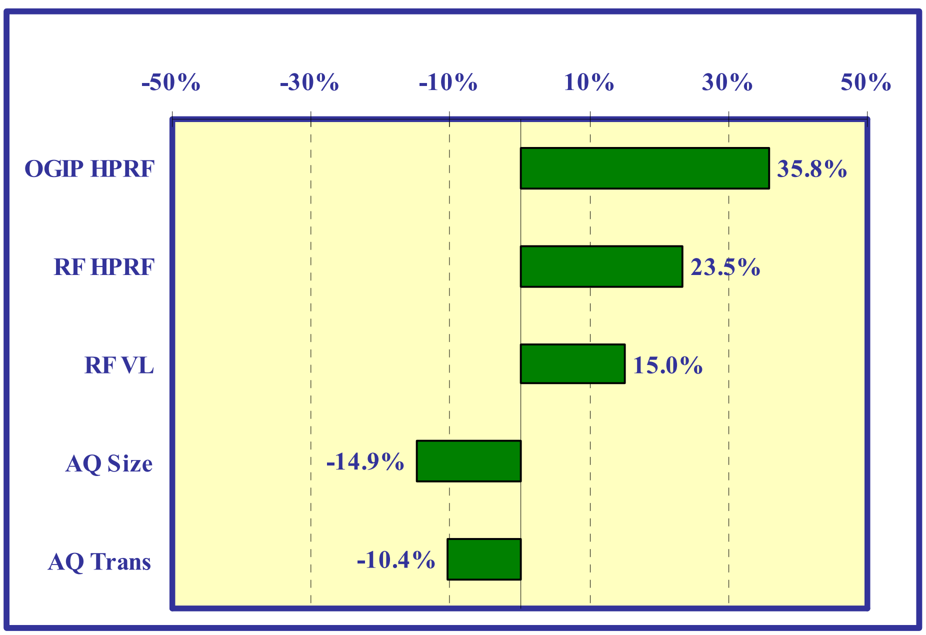


Figure 2.77: Total RGIP Sensitivity Analysis

2.5 Acid Gas Disposal

2.5.1 Introduction

Deep Panuke natural gas reserves contain approximately 0.18% hydrogen sulfide (H_2S) and 3.44% carbon dioxide (CO_2). This sour gas must be removed from the raw gas stream before it can be sent to market. The following methods of removal were considered:

- injection of waste acid gas into a stable geological formation;
- flaring of waste acid gas and discharge to atmosphere;
- high temperature conversion of waste acid gas with seawater scrubbing and marine discharge;
- offshore sulphur recovery; and
- onshore acid gas processing.

Although the injection of waste acid gas into a subsurface formation is one of the most expensive alternatives, it was chosen as the preferred method of disposing of the acid gas due to the minimal impact on the environment.

The volume of acid gas which requires disposal is a function of the total raw gas reserves in the Deep Panuke pool and the efficiency of the processes used to remove acid gas from the raw gas stream. The injected acid gas volumes range from 149 x $10^6 sm^3$ to 465 x 10^6 sm^3 (5.3 to 16.5 Bscf).

For the MN&P Option, the condensate that is produced will be the main source of fuel for the MOPU, and condensate production in excess to MOPU fuel requirements will be disposed of into the acid gas disposal well. For the SOEP Subsea Option, gas will be the main source of fuel on the MOPU, and treated condensate will be re-combined with the gas in the multiphase export pipeline (See Section 4.7.7).

Details on the proposed subsurface acid gas disposal scheme can be found in the "Acid Gas Disposal - Subsurface Summary Report" (DPA-Part 2, Ref # 2.38).

2.5.2 Acid Gas Disposal Scheme

The amine sweetening system on the Mobile Offshore Production Unit (MOPU) (See Section 4.7.3) removes H_2S and CO_2 from the raw gas stream resulting in an acid gas stream containing mainly H_2S and CO_2 (Table 2.15). The acid gas is then compressed to approximately 15100 kpa, pipelined to a disposal well and then injected down-hole into a disposal zone. The disposal zone selected for the Deep Panuke project is the Tidal-Fluvial Sandstone of the upper Missisauga Formation that occurs at a depth of approximately 2.4 km below sea level (See Section 2.5.3). These Tidal-Fluvial Sandstones are a regionally extensive water bearing aquifer. The salinity of the aquifer water is estimated to be approximately 82000 ppm; the salinity of sea water is approximately 35000 ppm.

Table 2.15: Acid Gas Injection Composition	
Pressure	150 bar
Temperature	40°C
Mole. Wt.	39.27
Hydrogen (H_2)	0.000003
Nitrogen (N_2)	0.000303
CO_2	0.695811
H_2S	0.198641
Methane (C_1)	0.030635
Ethane (C_2)	0.000969
Propane (C_3)	0.000302
iso-Butane (i-C_4)	0.000044
n-Butane (n-C_4)	0.000074
iso-Pentane (i-C_5)	0.000021
n-Pentane (n-C_5)	0.000017
Hexane (C_6)	0.000010
Heptane (C_7)	0.000009
Octane Plus (C_8^+)	0.000002
Benzene (C_6H_6)	0.000014
Toluene (C_7H_8)	0.000016
Water (H_2O)	0.073128
TOTAL	**1.000000**
Notes: 1)Composition with low volumes of stripping gas (low water rates) 2)Conditions at compressor outlet.	

Once the acid gas is injected into the disposal zone, there are a number of processes at work to ensure that it is contained within a relatively small area around the injection well as illustrated in Figure 2.78.

1. The total reservoir volume of injected acid gas is very small compared to the volume of water in the aquifer. In the aquifer, the estimated maximum area affected by acid gas is 4 km^2 compared to the aquifer area of thousands of km^2.
2. The density of the acid gas is less than water; so it will tend to rise in the aquifer due to buoyancy effects. Shales within the interbedded Panuke Sandstones and Shales (Upper Mississauga Formation) will mitigate vertical migration from the Tidal-Fluvial Sandstones upward within the Formation. The Naskapi Formation Shale, which is the top seal for the Upper Missisauga Formation will ensure containment within the Formation.
3. After the acid gas is introduced into the aquifer, a portion of the acid gas will dissolve in the aquifer water.
4. A portion of the acid gas will become trapped in the pore spaces and become immobile due to relative permeability effects.
5. Some acid gas may become temporarily trapped under inter-bedded shales.
6. The trapped gas will eventually dissolve into the aquifer water through diffusion.
7. The end product will be acid gas saturated water trapped in a deep aquifer (-2450 mss).

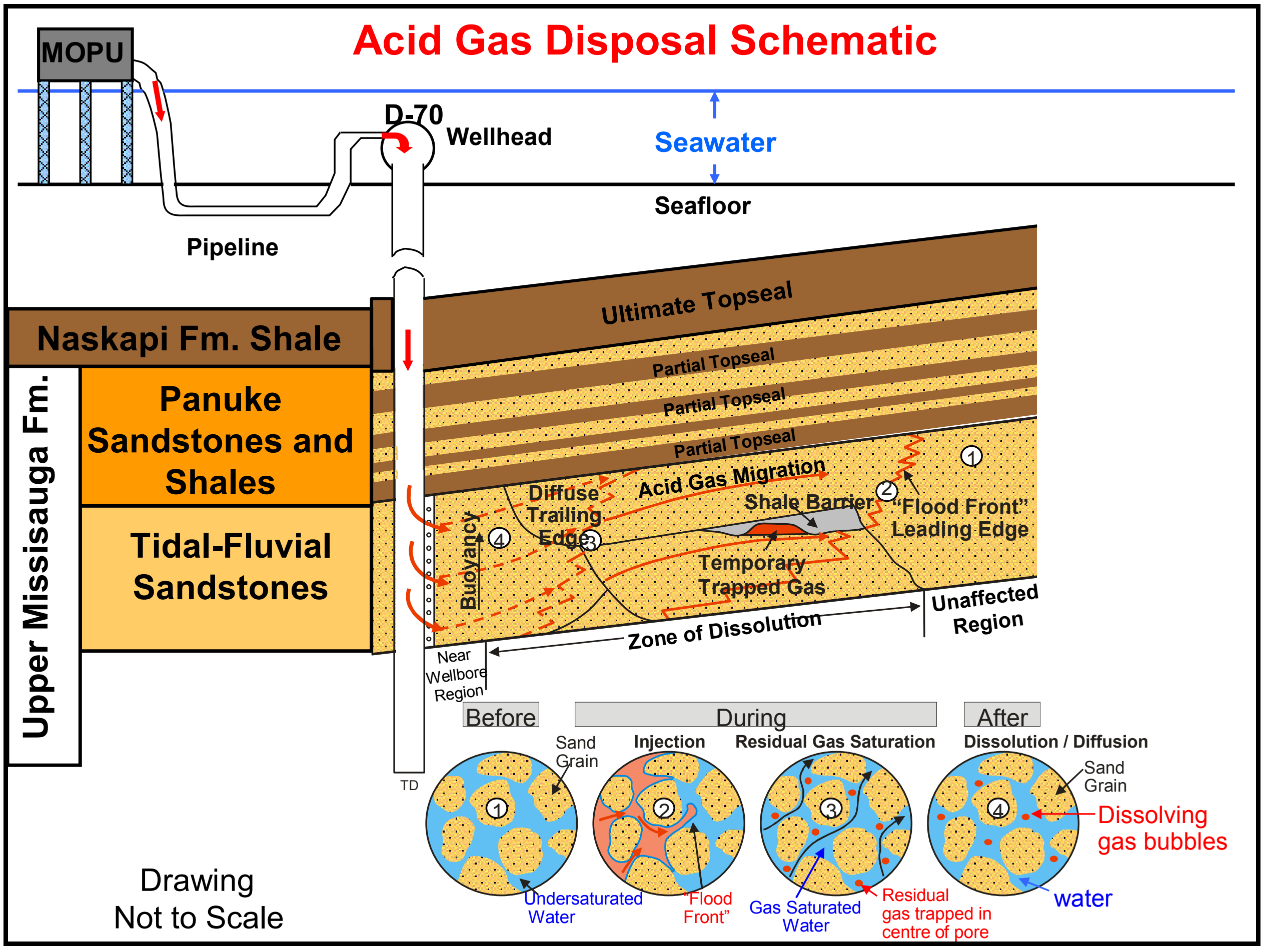


Figure 2.78: Acid Gas Disposal Schematic

2.5.3 Prospective Disposal Zones

Upon the selection of injection as the preferred disposal method, all possible zones of interest were investigated to determine the best alternative. The following zones were scrutinized:

- Dawson Canyon and Upper Logan Canyon Sands
- Cohasset and Lower Logan Canyon Sands
- Panuke "P" Sands -upper Missisauga Formation
- Tidal-Fluvial Sandstones -upper Missisauga Formation
- lower Missisauga Formation Sandstones
- Abenaki Formation

The “Tidal-Fluvial Sandstones” were identified as the best formation for the disposal of acid gas. They are very thick (greater than 40 m), located approximately 50 m below the Panuke “P” sands, regionally extensive (towards the NW for at least 100 km) and have excellent reservoir quality with porosity up to 30 % and air permeability as high as 10 darcies. The “Tidal-Fluvial Sandstones” at the preferred injection well location, D-70, are water-bearing and occur at a depth of about 2460 m below sea level. The estimated reservoir pressure and temperature are 24000 kpa and 90^{o}C respectively at this depth.

Completion of only the lower half of the “Tidal-Fluvial Sandstones” is preferred since it would provide sufficient injectivity and at the same time maximize the vertical distance to the Panuke “P” sands.

Hydrodynamic analysis of the water-bearing sandstones indicates that no statistically significant vertical pressure breaks (seals) can be identified within the base Naskapi Formation to top of O -Marker succession which includes the Panuke and “Tidal-Fluvial Sandstones”. Despite the potential regional connectivity between the Tidal-Fluvial Sandstones and Panuke “P” sands, local vertical connectivity is unlikely due to the presence of numerous thick regionally extensive shales which will act as partial topseals. The thick Naskapi Formation Shale is an effective regional top seal as proven by the existence of the Panuke oil pool beneath this topseal.

The geology of the Upper Missisauga and Naskapi Formations in structure and cross-section views is illustrated in DPA-Part 2, Ref # 2.39.

2.5.4 Potential Well Locations

Several different options were identified for locating an acid gas disposal well:

- A preliminary location was selected involving injection into the “Panuke Sandstones” updip of the now abandoned Panuke oil pool: this location would avoid any possibility of souring the remaining oil in that pool. This proposed injection well location to the northwest of the planned Deep Panuke field centre production facility was rejected by EnCana (due to its position in an up-wind direction from the field centre raising safety concerns).

- H-82 is a non-sequestered acid gas disposal well location involving injection into the “Tidal-Fluvial Sandstones” with initial updip migration and dissolution of injected gas into the aquifer over a distance of about 3 km to the northwest before the residual gas saturation becomes so low that the gas is no longer mobile. There are no consequences for future drilling under this option. This location is outside of the proposed Deep Panuke Significant Discovery Application area.

- D-70 acid gas disposal well location involves injection into the "Tidal-Fluvial Sandstones" with updip migration and dissolution of injected gas into the aquifer over a lateral distance of about 2 km before the residual gas saturation becomes so low that the gas becomes immobile. Injection is proposed down-dip from the abandoned Panuke oil pool. Prior to dissolution, the acid gas will most likely move to the west/southwest along the axis of the structure in the direction of the Panuke oil pool because of the buoyancy of the acid gas. However, it is very unlikely that the acid gas will reach the oil pool due to the limited lateral migration of the injected gas. D-70 is much closer to the Deep Panuke pool than H-82 but the potential consequences (if any) for future drilling are manageable by applying industry-standard drilling practices to future wells. This well location is within the proposed Significant Discovery Application area, downwind of the MOPU.

EnCana prefers the D-70 acid gas injection location to minimize sea-bottom infrastructure and costs whilst achieving the goals of a safe, effective, environmentally advantageous injection scheme.

2.5.5 Reservoir Model

To determine the ability of the reservoir to contain the effluent injected, a representative geocellular model was built of the Naskapi to Lower Missisauga interval. The model was built in GoCad™ using a seismic structural map of the O-marker as the basis of the grid (See Figure 2.79). The static model was constructed only to the west of the structural saddle which separates the Panuke structural high from the Cohasset Structural High. By injecting up-structure from the saddle, injected gas will not migrate into the Cohasset High.

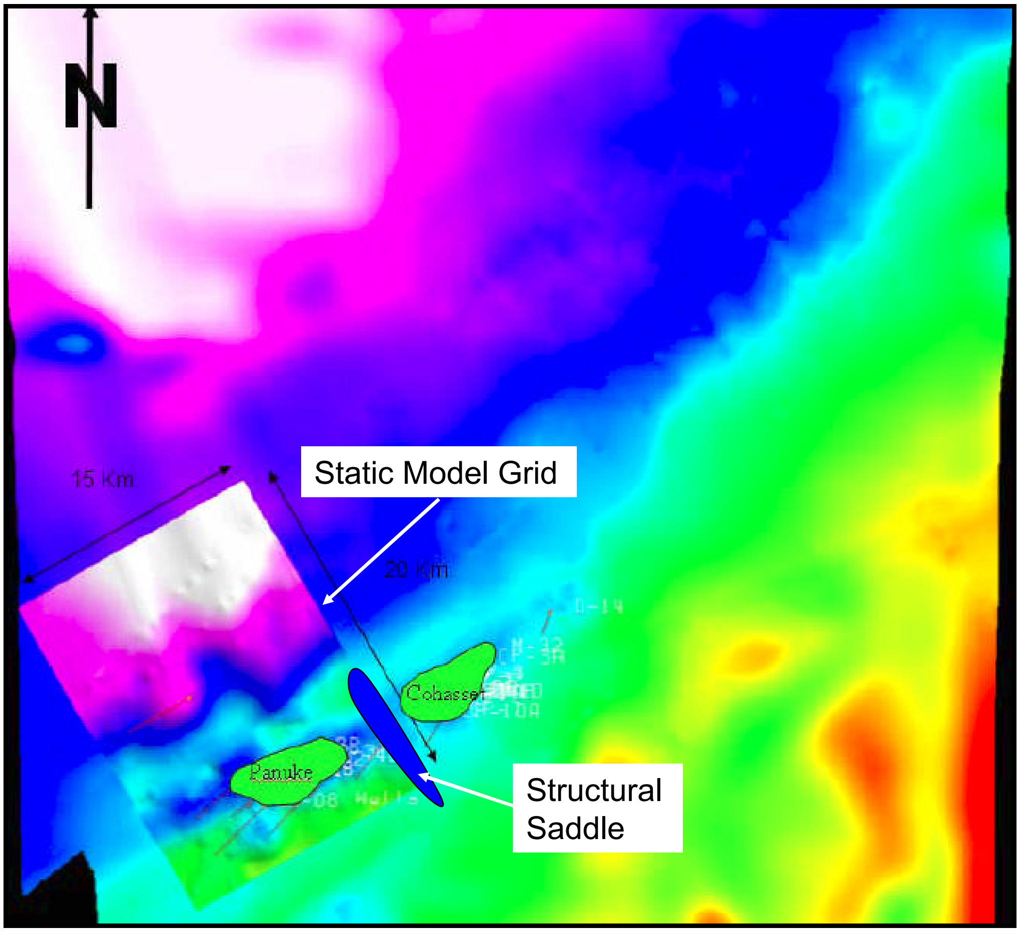


Figure 2.79: O Marker Structure

Porosity and permeability data was collected from all the shallow and deep wells in the area that had reasonable information (DPA-Part 2, Ref # 2.39). Permeability was estimated from whole and side-wall cores and well log data. Tops were picked for all wells and the O marker surface was translated and flexed to match all tops. Layers were created for the Naskapi, Panuke P0 sandstone, P2 sandstone, P3 to P5 sandstone, Upper Missisauga-Tidal/Fluvial, O-marker, and Lower Missisauga. A simulation grid (S-grid) extending 15 km by 20 km was built using the translated surfaces. Cell size was 200 m by 200 m. Cell thickness varies between 3 and 10 m.

The dynamic model was created using only the eastern half of the static model as shown in Figure 2.80. The simulation grid represents an area north and to the east of the Panuke oil field; it was created with local grid refinement about the injection location and up-scaling to the northwest.

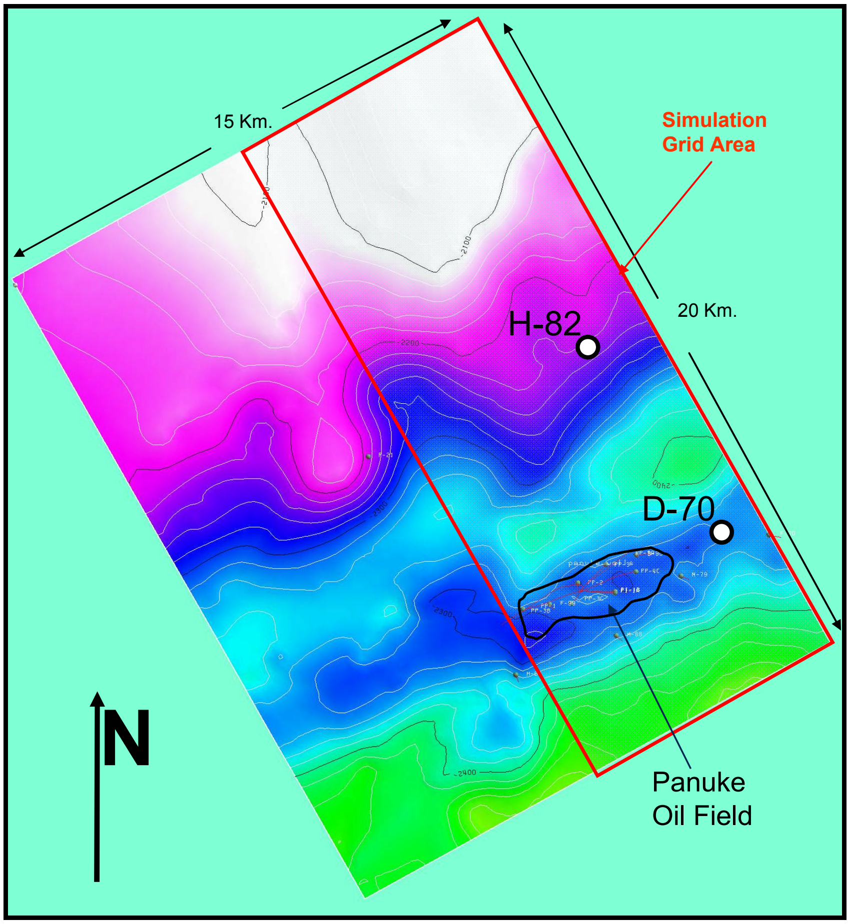


Figure 2.80: Static and Dynamic Model Area

As described in Section 2.5.3 the large lateral extent of the upper Missisauga sandstones will provide aquifer support; an analytical aquifer on the perimeter of the reservoir simulation model was created to simulate this aquifer support.

Eclipse E300™ which is a compositional simulator and allows CO_2 to be absorbed into the water phase was used. The absorption of H_2S into the water is expected to be similar to the CO_2; E300 does not handle H_2S dissolution. Diffusion of the CO_2 and H_2S was not modeled; its positive effect on the outcome was ignored.

The Mean and P10 acid gas forecasts as provided in Table 2.16 were modelled followed by a shut-in period of over 80 years to determine the extent of the migration and CO_2 dissolution for the two different well locations (H-82 and D-70) and three different completion strategies. Completions into the lower half only of the Tidal-Fluvial Sandstones, both the lower and upper half of the Tidal-Fluvial Sandstones and into the Panuke P2 sandstones only were modelled.

Year	Table 2.16: Acid Gas Forecast							
	P90		P50		P10		Mean	
	(10^3 sm3/d)	(MMscfd)	(10^3 sm3/d)	(MMscfd)	(10^3 sm3/d)	(MMscfd)	(10^3 sm3/d)	(MMscfd)
2010	60.8	2.2	60.3	2.1	60.7	2.2	60.5	2.1
2011	101.9	3.6	101.6	3.6	101.8	3.6	101.9	3.6
2012	93.4	3.3	114.9	4.1	114.7	4.1	111.0	3.9
2013	63.5	2.3	95.9	3.4	129.5	4.6	91.5	3.2
2014	46.2	1.6	77.1	2.7	132.7	4.7	79.2	2.8
2015	33.9	1.2	64.8	2.3	112.1	4.0	67.8	2.4
2016	25.6	0.9	54.8	1.9	94.5	3.4	59.4	2.1
2017	20.3	0.7	46.1	1.6	86.6	3.1	50.2	1.8
2018	18.3	0.7	40.1	1.4	73.9	2.6	43.4	1.5
2019	0.0	0.0	31.6	1.1	67.3	2.4	36.7	1.3
2020	0.0	0.0	28.7	1.0	58.2	2.1	31.2	1.1
2021	0.0	0.0	29.6	1.1	50.7	1.8	26.9	1.0
2022	0.0	0.0	26.1	0.9	44.0	1.6	26.3	0.9
2023	0.0	0.0	23.2	0.8	40.2	1.4	24.0	0.9
2024	0.0	0.0	0.0	0.0	37.6	1.3	0.0	0.0
2025	0.0	0.0	0.0	0.0	38.6	1.4	0.0	0.0
2026	0.0	0.0	0.0	0.0	36.1	1.3	0.0	0.0
2027	0.0	0.0	0.0	0.0	32.6	1.2	0.0	0.0
2028	0.0	0.0	0.0	0.0	30.3	1.1	0.0	0.0

As well, an understanding of the possible effects of any future oil production from the Panuke Oil Pool was desired. This production could create a large pressure drawdown within the Upper Missisauga formation and impact the migration of the injected effluent. Two production wells were located near the crest of the Panuke structure and placed on production at a rate of 8000 sm^3/day fluid (~50,000 bbl/day) for a five year period for a total removal of 14.6 million sm^3 (92 million bbl) of fluid. The results presented in Table 2.17 assume using D-70 injection location, P10 acid gas forecast and Panuke production commencing in 2028 after the Deep Panuke Gas Pool has been shut-in.

2.5.6 Acid Gas Simulation Results

Table 2.17 provides the results of a number of different simulation cases to illustrate the impact of the key parameters (completion zone, acid gas well location, CO_2 dissolution, Panuke Oil Pool production and reservoir permeability) on the migration patterns for the injected acid gas. Additional simulation results are provided in DPA-Part 2, Ref # 2.38. The key output parameters are “100 Year Migration Distance and Pore Volume Impacted” and “CO_2 Dissolution”.

Table 2.17: Acid Gas Injection Simulation Results

Input Parameters						Results		
Fcst	Completion Zone	CO2 Sol.	Inj. Loc.	Panuke Oil Pool Prod	Perm Adjustment	100 Year Migration Distance (km)	100 Year Migration: Pore Volume Impacted (rm3)	CO2 Dissolution (%)
Mean	Lwr 1/2 TF SS	Yes	D-70	No	None	1.2	6.48E+06	32%
Mean	Lwr 1/2 TF SS	**NO**	D-70	No	None	1.4	9.42E+06	0%
Mean	Lwr 1/2 TF SS	Yes	D-70	No	**YES**	1.2	7.25E+06	34%
Mean	Lwr 1/2 TF SS	**NO**	D-70	No	**YES**	1.4	1.16E+07	0%
Mean	Lwr 1/2 TF SS	Yes	D-70	**YES**	**YES**	1.3	7.91E+06	38%
Mean	P2	Yes	D-70	No	None	1.3	3.61E+06	13%
Mean	TF SS	Yes	D-70	No	None	1.6	4.02E+06	19%
P10	Lwr 1/2 TF SS	Yes	D-70	No	None	1.8	1.04E+07	31%
P10	TF SS	Yes	D-70	No	None	2.2	5.96E+06	19%
P10	TF SS	Yes	D-70	**YES**	None	2.2	6.69E+06	22%
P10	P2	**NO**	D-70	No	None	1.8	8.46E+06	0%
P10	P2	Yes	D-70	No	None	1.7	5.86E+06	14%
P10	P2	Yes	D-70	**YES**	None	2.0	8.40E+06	22%
Mean	TF SS	Yes	**H-82**	No	None	2.5	7.61E+06	38%
Mean	P2	Yes	**H-82**	No	None	2.3	5.75E+06	24%
P10	TF SS	Yes	**H-82**	No	None	2.8	1.18E+07	34%
P10	P2	Yes	**H-82**	No	None	2.9	8.72E+06	22%

Completion Zone: TF SS- Tidal Fluvial Sandstone, Lwr ½- Lower Half, P2 – Panuke Oil Sands
Perm Adjustment: 2X Kx, 2X Ky, 10X Kz
Panuke Oil Pool Prod: 8000 m3/d for 5 years in 2028 after shut-in of Panuke Gas Pool

Based on the results of the dynamic modelling we have concluded the following:

1. It is evident that the acid gas does not move far from the injection well(s) for all cases; approximately 2.9 km maximum after 100 years for the cases evaluated. The 100 year migration distance for the Base Case, D-70 completed in the lower half of the Tidal Fluvial Sandstones, and the mean forecast was approximately 1.2 km, the smallest for all cases modeled (see Figure 2.81). Figure 2.82 is a SW-NE sectional view of the same migration pattern. It illustrates that the majority of the acid gas is contained within the Tidal-Fluvial Sandstones.

2. The migration distance and the contacted pore volumes increased by approximately 40% and 60% respectively for the P10 forecast.
3. An increase in permeability applied to the base case resulted in larger contacted pore volumes; however the migration distances remained essentially the same.
4. Production from the Panuke Oil Pool in 2028 had a very small impact on the acid gas migration patterns for the cases with acid gas injection into the TFSS, the targeted completion zone. Panuke Oil Pool production following acid gas injection into the P2 zone in D-70 was also modelled for illustration purposes only. The migration distance and the contacted pore volumes increased by approximately 20% and 40% respectively over the case without Panuke Oil Pool production.

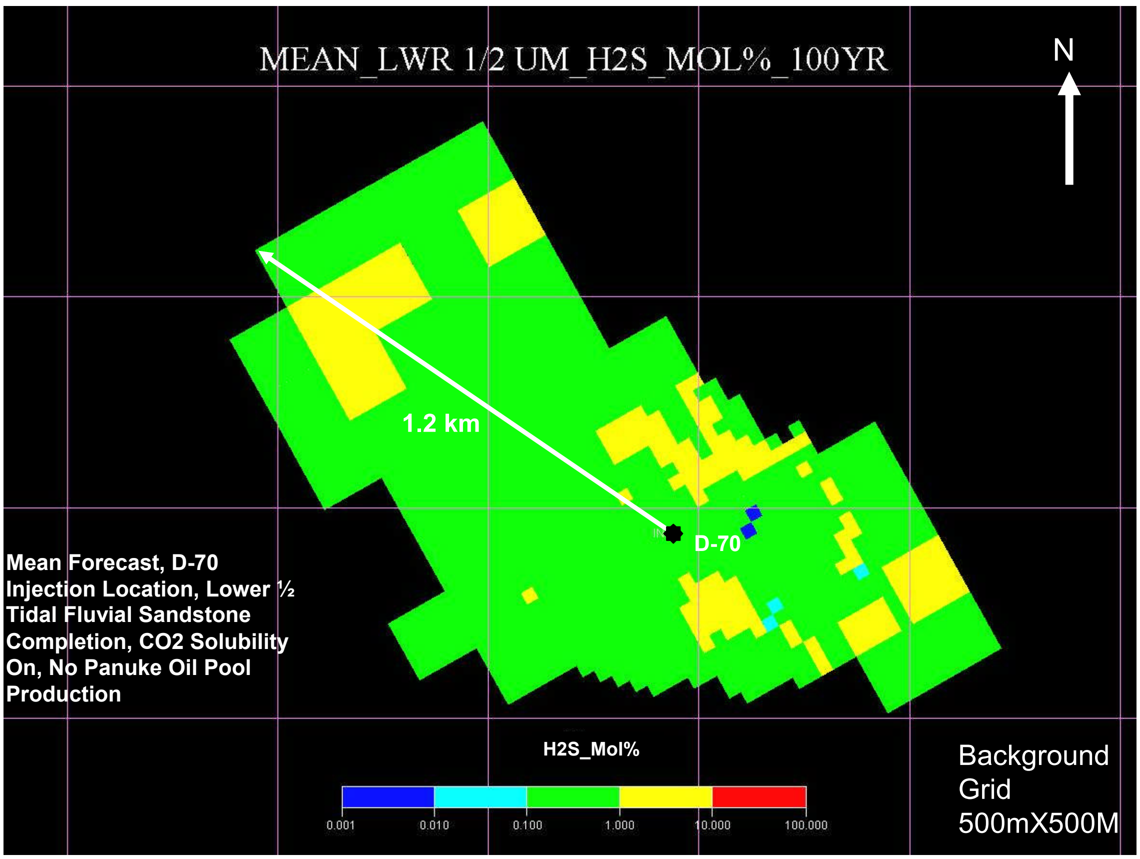


Figure 2.81: 100 Year H_2S Mol % Plan View

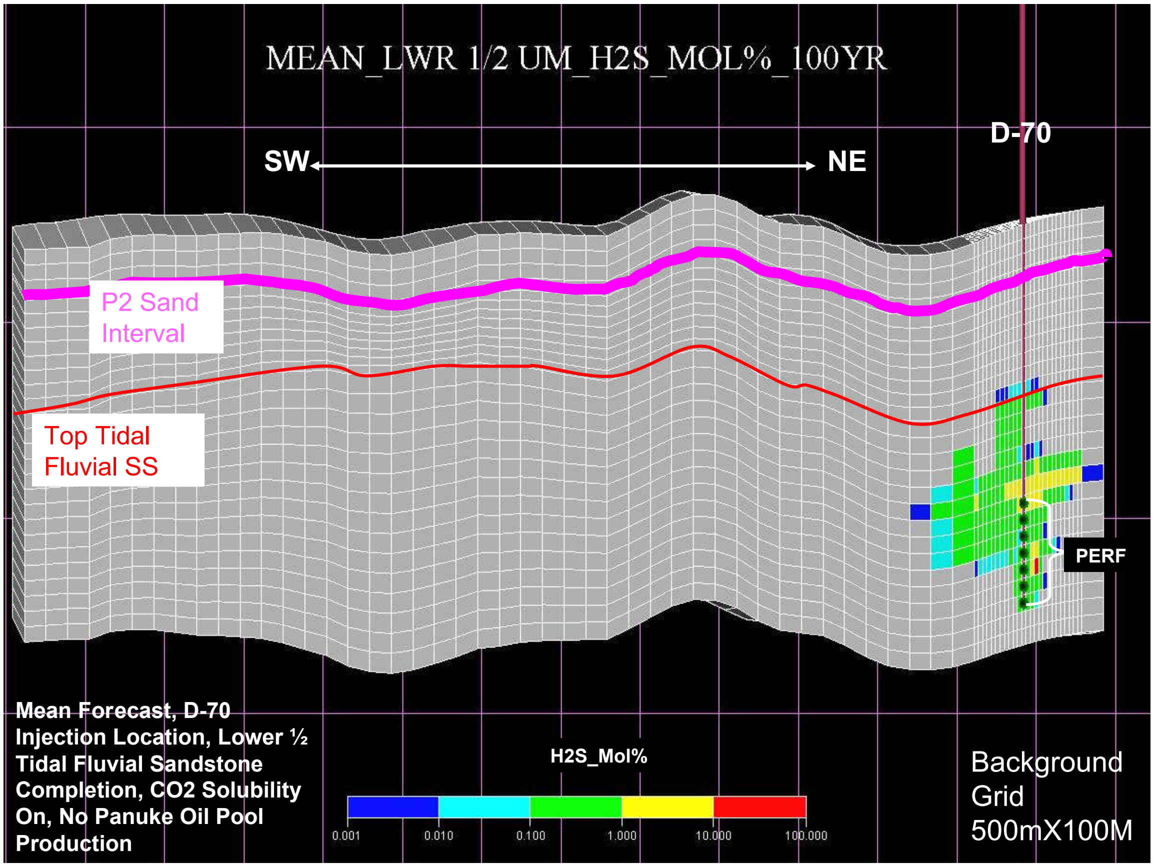


Figure 2.82: 100 Year H_2S Mol % SW-NE Section

5. The migration distance and the contacted pore volumes increased by approximately 60% and 70% respectively with the H-82 injection location. This is a direct result of the increase in buoyancy effects due to the steeper structural gradient at this location as shown in Figures 2.83 and 2.84.

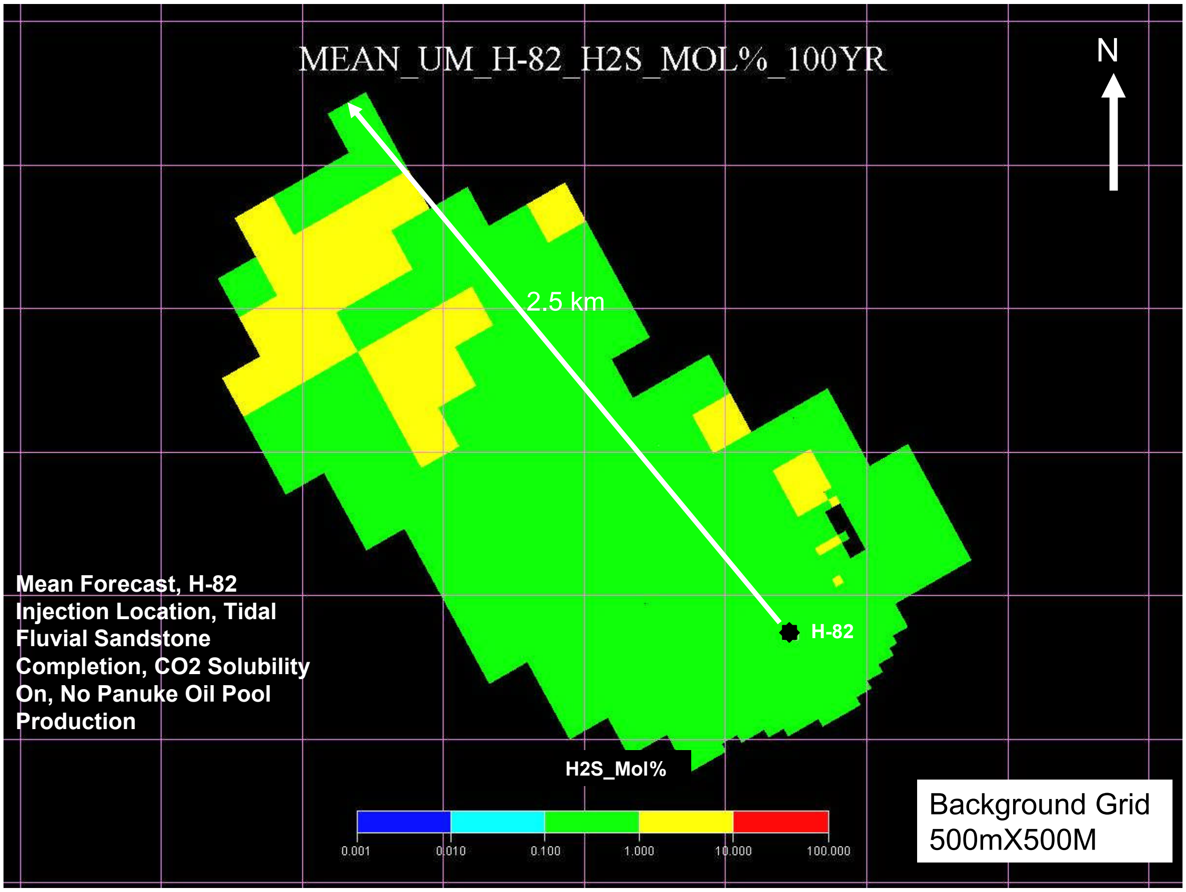


Figure 2.83: 100 Year H_2S Mol % Plan View

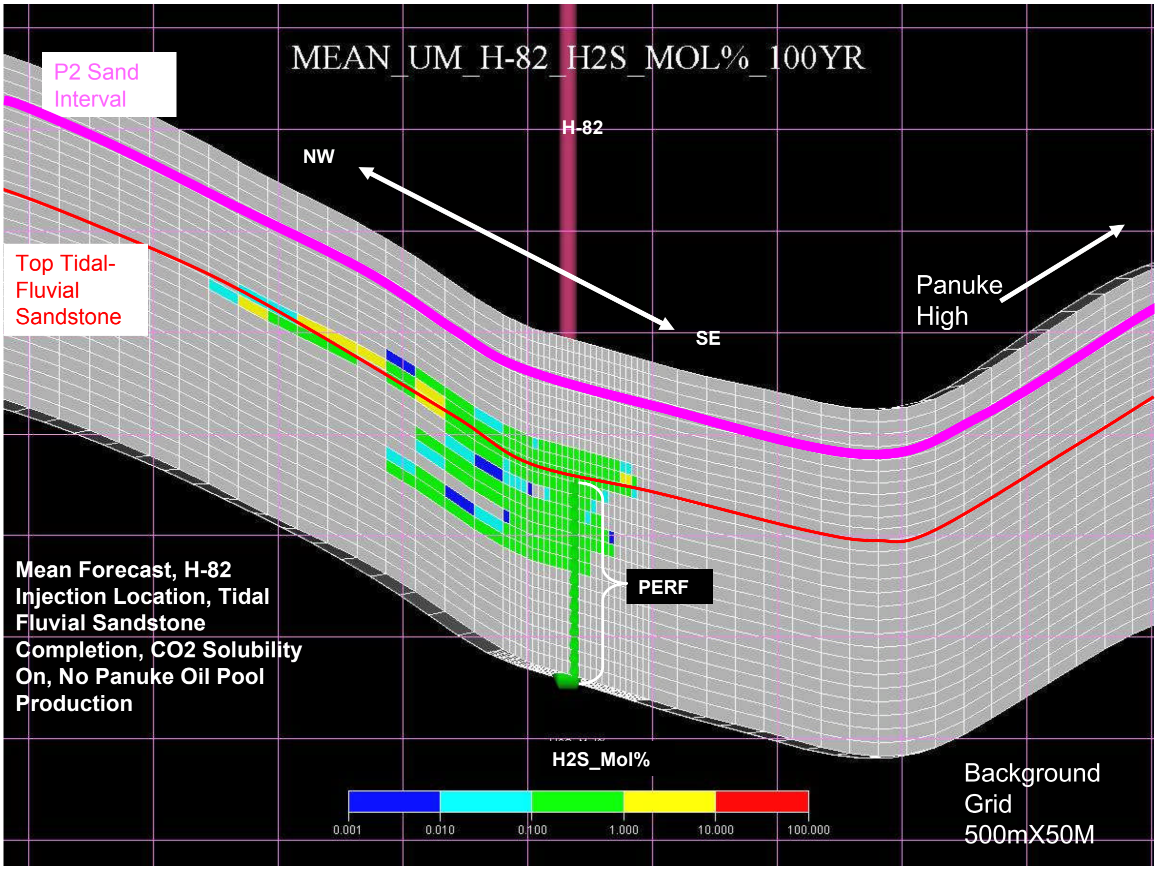


Figure 2.84: 100 Year H_2S Mol % NW-SE Section

6. The percent CO_2 dissolved is well correlated to the pore volume contacted as illustrated in Figure 2.85. H_2S dissolution was not modelled but is expected to be similar to the CO_2. All the gas would eventually dissolve in the water leaving only a water phase as diffusion and migration continues. Hence, there would be no free phase existence of any of the injected components. Initially, this water would only be slightly more acidic than the original native waters as the effluent continues to migrate. But eventually, even the slightly more acid waters would be consumed due to the rock-water reactions. The linear trend-line in Figure 2.85 illustrates that 100% dissolution would be expected with a contacted pore volume of just over 18 x 10^6 m^3. Increased reservoir permeability, connectivity between the different sand layers and/or an increase in buoyancy effects with the ability of the acid gas to move up structure (as was demonstrated with the H-82 injection location) would all lead to increased contact volumes.

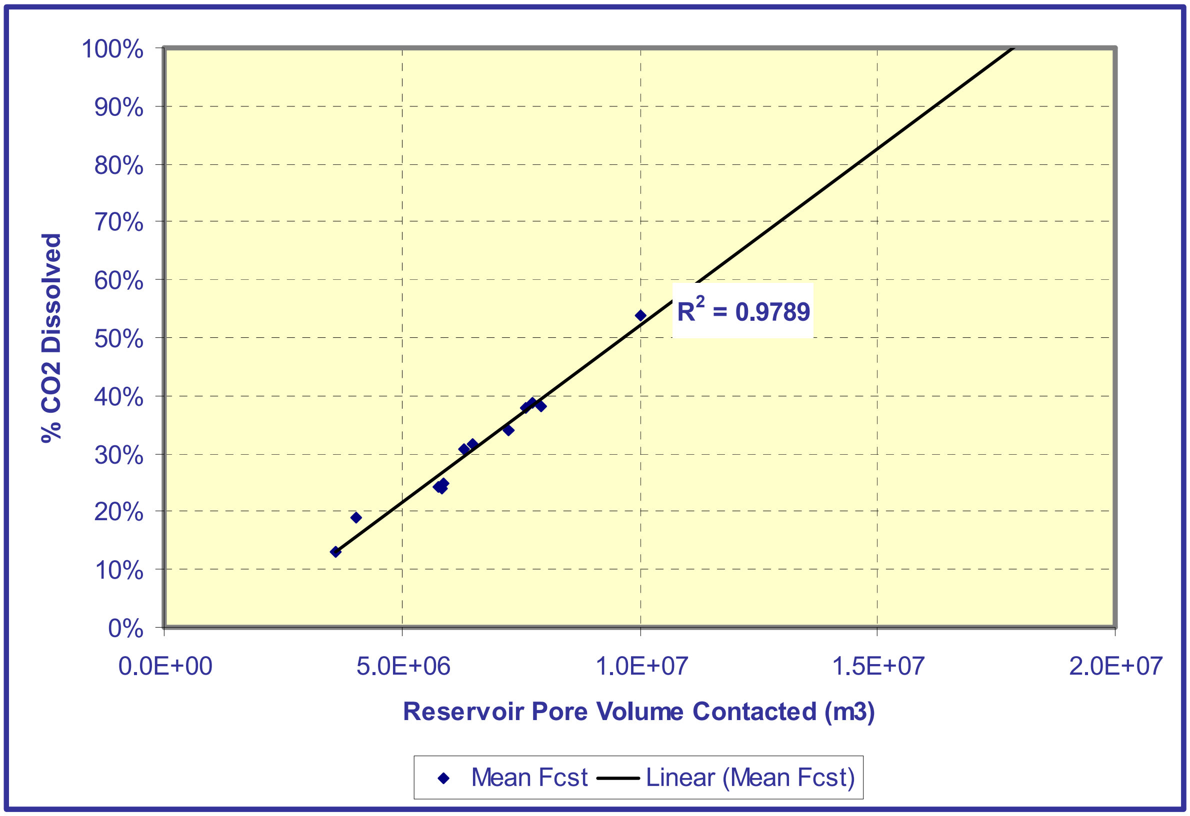


Figure 2.85: CO_2 Dissolution

2.5.7 Acid Gas Disposal Summary

Sub-surface injection into the "Tidal-Fluvial Sandstones" is the optimal scheme for acid gas disposal with no environmental consequences. The small volume of acid gas to be injected at the preferred D-70 injection well location is very likely to remain in close proximity to the well as it dissolves into the aquifer and is very unlikely to result in souring of the oil remaining in the Panuke oil pool. Industry standard drilling practices are sufficient to manage any possible consequences for future drilling in proximity to the injection well. Injection at the H-82 location would have no possibility of souring of the oil remaining in the Panuke oil pool but requires increased sea-bottom infrastructure and costs.

2.6 Reservoir Depletion Plan

2.6.1 Resource Estimates

The probabilistically generated resource estimates are summarized in Table 2.18.

Table 2.18: Resource Summary Raw Gas(metric)

RESERVOIR	GROSS OGIP (E9M3)				GROSS RGIP (E9M3)			
REGION	P90	P50	P10	MEAN	P90	P50	P10	MEAN
HPRF	16.5	23.7	32.2	24.0	9.7	16.0	23.9	16.5
VL	3.1	4.7	7.1	4.9	1.4	2.0	3.0	2.1
TOTAL	21.3	28.6	37.4	28.9	11.5	18.2	26.2	18.6

Resource Summary Raw Gas (Imperial units)

RESERVOIR	GROSS OGIP (BCF)				GROSS RGIP (BCF)			
REGION	P90	P50	P10	MEAN	P90	P50	P10	MEAN
HPRF	585	841	1143	853	345	568	849	584
VL	110	166	252	174	48	72	106	75
TOTAL	755	1016	1327	1027	407	645	931	659

2.6.2 Recommended Development Concept

2.6.2.1 Production Well Strategy

The well count required to fully develop the resources at Deep Panuke is uncertain. This is mainly due to the RGIP uncertainty caused by uncertainty in OGIP, aquifer size and aquifer connectivity.

A phased development approach is planned. The initial phase of development is to re-use the four existing wells, H-08, M-79A, F-70 and D-41 as producers and to drill an additional producer, Panuke H-99 to replace PI-1B. PI-1B will not be used because of the risks of installing a wellhead and tree on a cut casing; it has essentially been abandoned with the exception of cutting the conductor below the mudline. A new well for acid gas injection is required; the proposed location is Margaree D-70.

The second phase of development will include up to three new production wells. The identified potential locations are Panuke D-99, Panuke O-79 and MarCoh C-42. The actual number and specific locations for the new production wells will be determined post-startup based on well and reservoir performance.

For the P50 and Mean cases, it has been assumed that in two years one additional well will be required to optimize pool recovery and economics. No new wells have been assumed for the P90 case; for the P10 case three new production wells have been assumed: two additional wells are required two years after start-up and one new well four years after start-up.

All development well and the field centre locations are illustrated on Figure 2.86. All wells will be tied back to the MOPU with subsea flowlines.

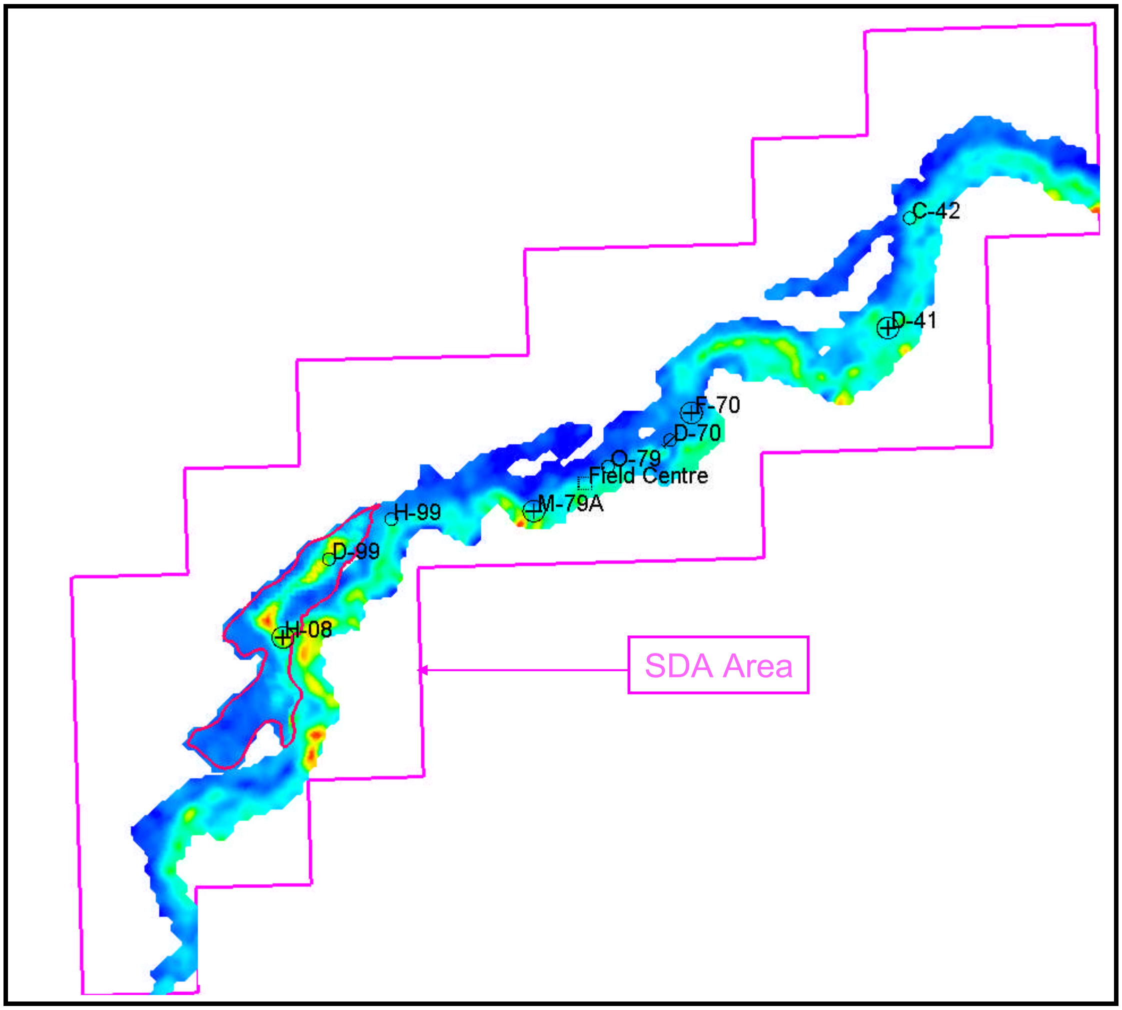


Figure 2.86: Deep Panuke Well Strategy

2.6.2.2 Production Profiles

Gas and Condensate

Field raw gas, sales gas and condensate production profiles in both metric and imperial units for the P90, P50, P10 and Mean cases have been generated in the risk model and are presented in Tables 2.19, 2.20 and 2.21. Given our current state of knowledge and the current economic environment, these profiles cover the range of probable reservoir performance and are derived from a realistic range of depletion strategies. The field raw gas and sales gas production forecasts are illustrated in Figures 2.87 and 2.88.

The same base well number (five wells) has been used for each forecast. It has been assumed that the additional wells that are planned for the P50, Mean and P10 cases are required to replace problem wells that "are not forecast in the simulator" (i.e., the forecasts do not change).

Facilities start-up is planned for October 2010 with a two-month facility ramp-up period. It was assumed that the topsides capability is 8.5 x 10^6 m3/d [300 MMscfd] sales on a calendar day basis. Well production efficiency of 95% has been assumed. The estimated raw gas shrinkage factor is estimated to be 0.9585.

Year	**Table 2.19: Raw Gas Forecast**							
	P90		**P50**		**P10**		**Mean**	
	(10^6 sm3/d)	**(MMscfd)**	**(10^6 sm3/d)**	**(MMscfd)**	**(10^6 sm3/d)**	**(MMscfd)**	**(10^6 sm3/d)**	**(MMscfd)**
2010	5.9	211	5.9	209	5.9	211	5.9	210
2011	8.8	313	8.8	312	8.8	313	8.8	313
2012	7.3	260	8.8	313	8.8	312	8.5	303
2013	4.7	166	6.7	238	8.8	313	6.4	229
2014	3.2	115	5.0	179	8.1	287	5.2	185
2015	2.3	82	4.0	142	6.3	222	4.2	149
2016	1.7	60	3.2	115	4.9	175	3.5	124
2017	1.3	47	2.6	93	4.3	151	2.9	101
2018	1.2	42	2.2	79	3.5	123	2.4	85
2019	0.0	0	1.7	61	3.0	108	2.0	70
2020	0.0	0	1.5	54	2.5	90	1.6	58
2021	0.0	0	1.5	54	2.1	76	1.4	49
2022	0.0	0	1.3	47	1.8	64	1.3	47
2023	0.0	0	1.2	41	1.6	57	1.2	42
2024	0.0	0	0.0	0	1.5	53	0.0	0
2025	0.0	0	0.0	0	1.5	53	0.0	0
2026	0.0	0	0.0	0	1.4	49	0.0	0
2027	0.0	0	0.0	0	1.2	43	0.0	0
2028	0.0	0	0.0	0	1.1	40	0.0	0
Start of Forecast	01-Oct-10		01-Oct-10		01-Oct-10		01-Oct-10	
End of Forecast	30-Jun-18		31-Aug-23		31-Mar-28		31-Dec-23	
Project Life (Years)	7.8		12.9		17.5		13.3	

Year	Table 2.20: Sales Gas Forecast							
	P90		P50		P10		Mean	
	(10^6 sm3/d)	(MMscfd)	(10^6 sm3/d)	(MMscfd)	(10^6 sm3/d)	(MMscfd)	(10^6 sm3/d)	(MMscfd)
2010	5.7	202	5.7	201	5.7	202	5.7	201
2011	8.5	300	8.4	300	8.5	300	8.5	300
2012	7.0	249	8.5	300	8.4	300	8.2	291
2013	4.5	159	6.4	228	8.4	300	6.2	219
2014	3.1	110	4.8	171	7.7	275	5.0	177
2015	2.2	79	3.8	136	6.0	213	4.0	143
2016	1.6	58	3.1	110	4.7	168	3.4	119
2017	1.3	45	2.5	90	4.1	145	2.7	97
2018	1.1	40	2.1	76	3.3	118	2.3	81
2019	0.0	0	1.6	58	2.9	103	1.9	67
2020	0.0	0	1.5	52	2.4	86	1.6	55
2021	0.0	0	1.5	52	2.1	73	1.3	47
2022	0.0	0	1.3	45	1.7	62	1.3	45
2023	0.0	0	1.1	40	1.6	55	1.1	41
2024	0.0	0	0.0	0	1.4	50	0.0	0
2025	0.0	0	0.0	0	1.4	51	0.0	0
2026	0.0	0	0.0	0	1.3	47	0.0	0
2027	0.0	0	0.0	0	1.2	41	0.0	0
2028	0.0	0	0.0	0	1.1	38	0.0	0

Year	Table 2.21: Condensate Forecast							
	P90		P50		P10		Mean	
	(m3/d)	(bpd)	(m3/d)	(bpd)	(m3/d)	(bpd)	(m3/d)	(bpd)
2010	110	692	109	687	110	691	109	689
2011	163	1028	163	1025	163	1027	163	1028
2012	135	851	163	1027	163	1025	158	995
2013	86	543	124	781	163	1025	119	750
2014	60	378	93	586	149	940	96	605
2015	43	269	74	466	116	729	78	489
2016	32	198	60	377	91	574	65	408
2017	25	154	49	306	79	496	53	332
2018	22	138	41	258	64	404	44	278
2019	0	0	32	199	56	353	36	228
2020	0	0	28	177	47	294	30	190
2021	0	0	28	179	40	249	26	161
2022	0	0	25	155	34	211	24	154
2023	0	0	22	136	30	189	22	139
2024	0	0	0	0	27	173	0	0
2025	0	0	0	0	28	174	0	0
2026	0	0	0	0	25	160	0	0
2027	0	0	0	0	22	141	0	0
2028	0	0	0	0	21	131	0	0

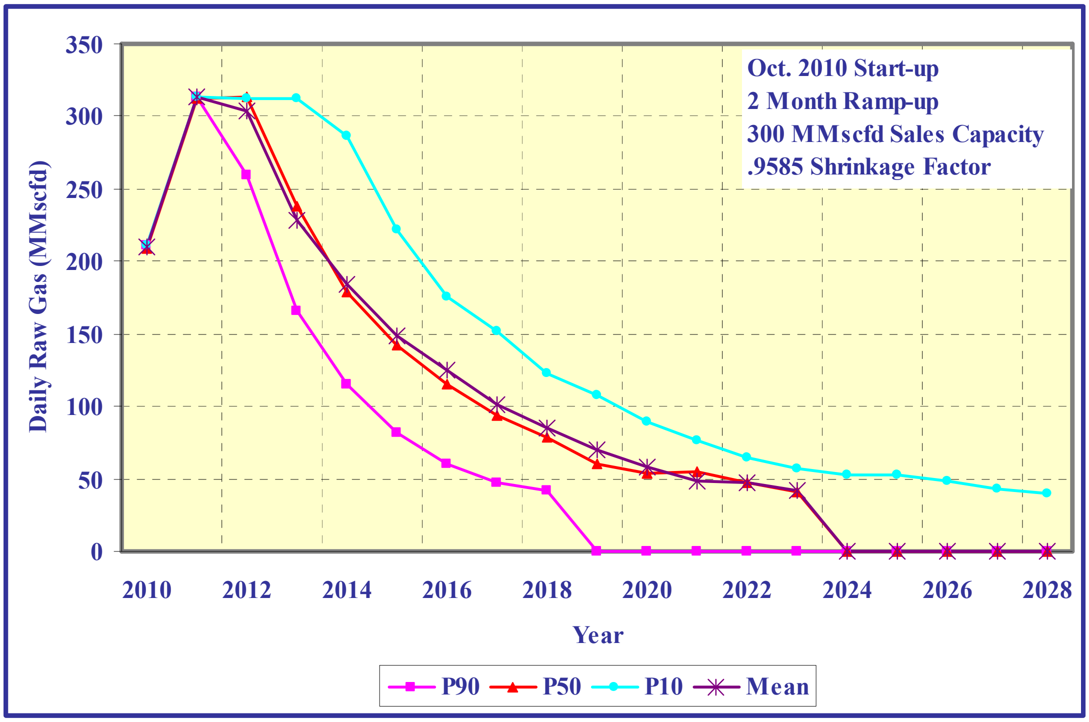


Figure 2.87: Raw Gas Forecast

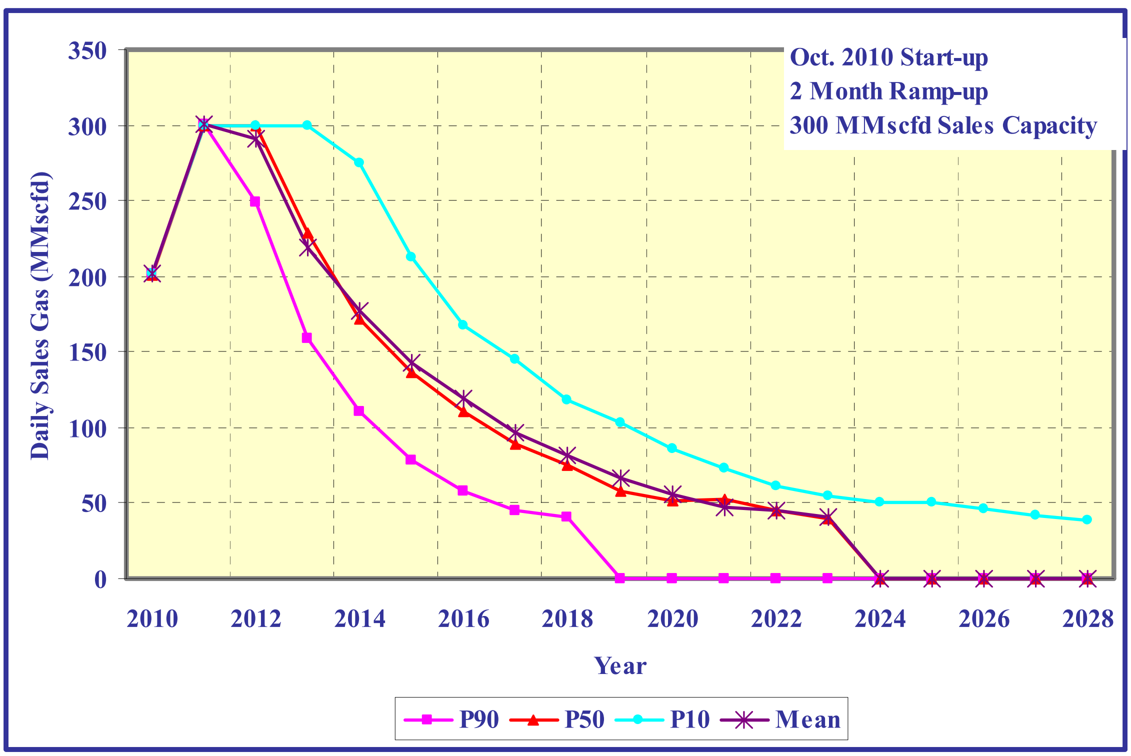


Figure 2.88: Sales Gas Forecast

The key areas of uncertainty that have the greatest impact on the forecasts are the connected OGIP, aquifer strength/connectivity and the ability of the wells/reservoir to produce large volumes of water. The reservoir surveillance plan that will be developed will focus on developing a better understanding of these issues and their relative impact on performance. However, because of the complexity of the reservoir significant uncertainty will remain throughout the productive life of the field.

Water Production

The field water production forecasts for the P90, P50, P10 and Mean cases presented in Table 2.22 are indicative of the expected water rates for high water-cut cases. For design purposes, 6400 m3/d (40,000 bwpd) is a reasonable maximum water rate for the topsides design. The water forecast is illustrated in Figure 2.89.

	Table 2.22: Daily Water Forecast							
	P90		P50		P10		Mean	
Year	(10^3 m3/d)	(mbwpd)	(10^3 m3/d)	(mbwpd)	(10^3 m3/d)	(mbwpd)	(10^3 m3/d)	(mbwpd)
2010	0.0	0	0.0	0	0.0	0	0.0	0
2011	1.7	11	0.5	3	0.5	3	0.5	3
2012	5.6	35	2.5	16	2.4	15	2.4	15
2013	6.3	40	4.4	27	5.3	33	4.0	25
2014	5.9	37	5.1	32	6.4	40	5.1	32
2015	5.1	32	5.4	34	6.4	40	5.6	35
2016	4.2	27	5.4	34	6.4	40	5.9	37
2017	3.6	22	5.1	32	6.4	40	5.6	35
2018	1.7	11	4.8	30	6.4	40	5.3	33
2019	0.0	0	4.1	26	6.4	40	4.8	30
2020	0.0	0	3.9	25	6.4	40	4.3	27
2021	0.0	0	4.2	26	6.4	40	3.9	25
2022	0.0	0	3.9	24	6.2	39	3.9	25
2023	0.0	0	2.3	15	5.8	36	3.7	24
2024	0.0	0	0.0	0	5.5	35	0.0	0
2025	0.0	0	0.0	0	5.8	36	0.0	0
2026	0.0	0	0.0	0	5.5	35	0.0	0
2027	0.0	0	0.0	0	5.0	32	0.0	0
2028	0.0	0	0.0	0	1.2	7	0.0	0

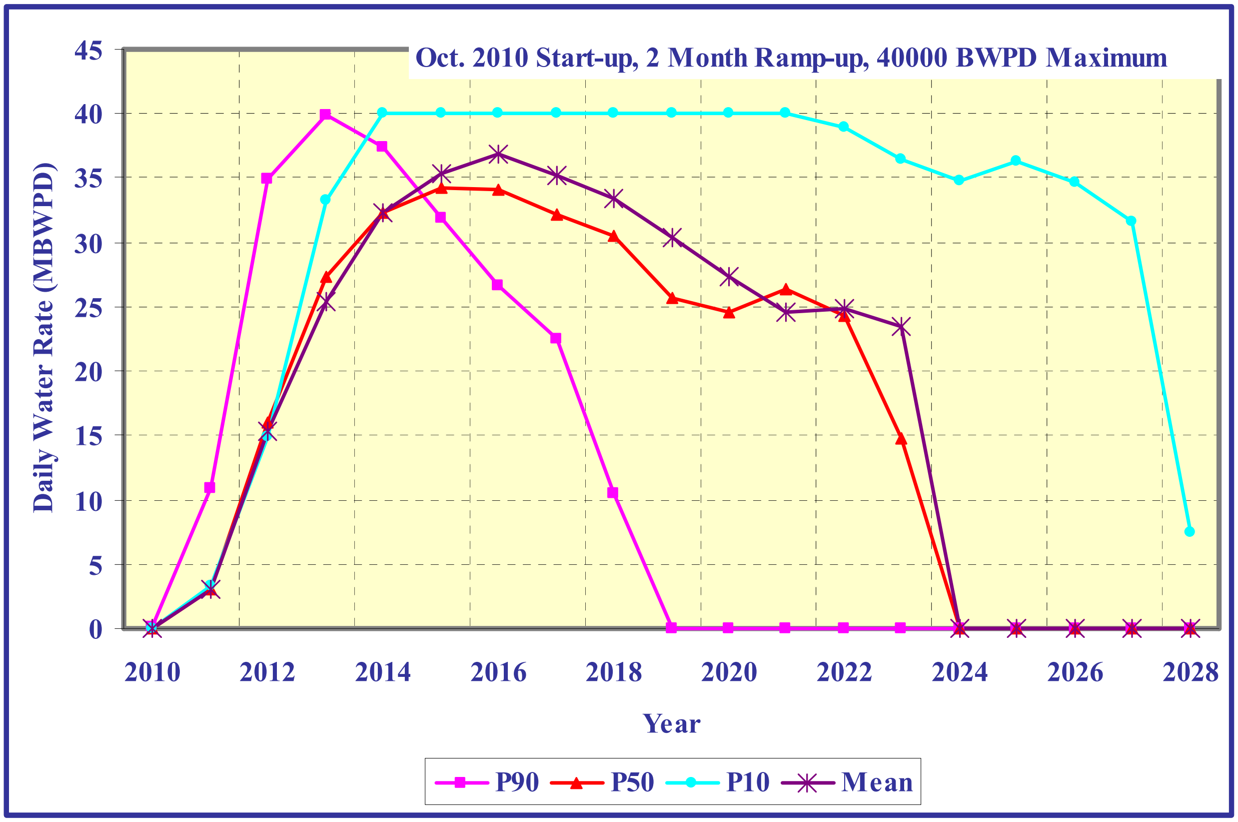


Figure 2.89: Water Forecast

Individual Well Production

Typical individual well forecasts (gas, water and flowing pressure) for the initial five wells are provided in DPA-Part 2, Ref # 2.40. These forecasts are provided to illustrate the ranges of well performance that are expected and must be used with caution when referring to a specific well. In the simulator, one well may produce at a very high water rate and another well may produce very little water. Until this reservoir is produced and water breakthrough occurs it will remain very difficult to predict a specific wells' performance.

Acid Gas Production

Acid gas forecasts were generated for the P90 /P50/ P10 /Mean cases with increasing acid gas yields to account for the souring of the raw gas stream and were provided in Table 2.16. Additional details on the proposed subsurface acid gas disposal scheme can be found in the "Acid Gas Disposal- Subsurface Summary Report" (DPA-Part 2, Ref # 2.38).

2.6.3 Subsurface Risks

Significant subsurface uncertainty does exist and will exist for the life of the Deep Panuke project. The following table highlights these uncertainties, their impact and some mitigation options.

Table 2.24: Subsurface Risks, Impacts and Mitigation

Risk	Impact and/or Uncertainty	Action Taken / Mitigation Options
Range OGIP	Significant impact on recoverable reserves and value.	Delineation and risk analysis complete Phased development.
Recovery Efficiency	Significant impact on value.	Risk analysis complete.
Aquifer Drive Potential	Significant uncertainty in the drive potential (aquifer size and connectivity). Major driver of well performance, recovery and value.	Accounted for in Risk analysis. Comprehensive reservoir surveillance plan. Phased development. Future development options to be analyzed include well counts, smaller tubing sizes and drilling a water production well.
Compartmentalization -Vuggy Limestone	Well tests indicate potential compartmentalization. Potential impacts include reduced recovery, reduction in time at plateau, extension to project life and reduced NPV.	Accounted for in risk analysis. Comprehensive reservoir surveillance plan. Phased development. Additional vuggy limestone location if reservoir performance dictates.
Fracture Heterogeneity in HPRF	High permeability fracture streaks leading to premature water breakthrough. Potential impacts include reduced recovery, reduction in time at plateau, extension to project life and reduced NPV.	Recovery factor range in risk analysis adjusted for potential outcome. Comprehensive reservoir surveillance plan. Phased development.
Well completion problems.	Completion problems leading to premature water breakthrough. Potential impacts include reduced recovery, reduction in time at plateau, extension to project life and reduced NPV.	Recovery factor range in risk analysis adjusted for potential outcome. Comprehensive reservoir surveillance plan. Phased development.

Table 2.24: Subsurface Risks, Impacts and Mitigation		
Risk	**Impact and/or Uncertainty**	**Action Taken / Mitigation Options**
Well / reservoir performance at high water rates	Uncertainty in well performance at high water rates. Potential impacts include reduced recovery, reduction in time at plateau, extension to project life and reduced NPV.	Recovery factor range in risk analysis adjusted for potential outcome. Comprehensive reservoir surveillance plan. Phased development. Future development options to be analyzed include well counts, smaller tubing sizes and drilling a water production well.
New Well Locations	Uncertainty in 3D seismic interpretation could result in a poor location and additional funds to sidetrack.	Pre-Spud sidetrack evaluations.
New Well Timing	Unable to drill and tie-in well in time to offset production decline.	To be addressed in reservoir surveillance plan.
Acid Gas Well Injection Efficiency	Potential shutdown. Environmental concerns with flaring of acid gas and excess condensate.	Approval from regulator to flare during upsets.
Well Start-up at reduced reservoir pressures.	Well ability to start-up after shutdown in low reservoir pressure and high water-cut scenarios. Impact is expensive work-overs and/ or reduced recovery.	Reservoir surveillance plan. Smaller tubing sizes and/or drilling a water production well.
Flow Assurance	Flow assurance work completed for dry trees. No major problems were identified.	Work needs to be updated with the consideration of Sub-Sea infrastructure.

2.6.4 Reservoir Management Philosophy

Reservoir management is an evergreen process, starting with the identification of a commercial development and continuing through to abandonment and reclamation. The projection of field performance and acceptable performance tolerances, the monitoring of actual performance, and the identification of contingency actions are the building blocks of a successful depletion plan.

A phased development approach at Deep Panuke is required to optimize recovery and economics because of the large range of uncertainty in reservoir performance. The initial phase of development is described in Sections 3 and 4. Future development is totally contingent on well / reservoir performance and could include drilling up to three new wells.

A Reservoir Surveillance Plan will be developed to document the data requirements, introduce the methods used to analyze the data and determine the relative impact of the uncertainty of the key risk factors on reservoir performance. The plan and resulting increased understanding of the reservoir will then be used to optimize future development plans, reservoir management strategies and overall project economics. The focus of the plan will be on analyzing the first year of production.

The data captured will include daily pressure, temperature, production numbers, and fluid compositions. Additional information will also be acquired as needed to address specific questions or uncertainties.

In addition to managing expected production volumes and rates at the field and well level, it is also critical to manage resource depletion within the total field. History-matching of production data and any additional information within the current reservoir model will aid in better understanding of resource definition within the reservoir and its subsequent depletion patterns. Model changes will occur to account for energy balances and fluid movements within the reservoir. Changes to resource and recovery factors will be reviewed with the goal of optimizing recovery of the total system.

Enhancements to the reservoir model honor the original input data while incorporating new dynamic and static data. Re-characterization of the reservoir model requires a multi-disciplinary team to incorporate this new data in an effective manner. In addition to the conventional input received from subsurface geosciences and engineering team members, contributions from wellbore, pipeline, compression and facilities team members are critical in understanding total system performance and identifying bottlenecks to the system.

This multi-disciplinary team will recommend adjustments to the Reservoir Management Plan and take remedial action where appropriate. This may include additional drilling, re-completions or infrastructure upgrading.

The development of a multi-disciplinary asset management team and management plan will be a focus of future work, prior to commencement of production.

3 WELL CONSTRUCTION

Since the discovery of the Deep Panuke gas reservoir in 1998, several delineation wells have been drilled. There are four delineation wells that have been suspended for potential future re-entry with the remaining wells abandoned. EnCana plans to re-enter the four suspended wells, drill two new wells, including one production well and one acid gas injection well, and complete all wells as subsea tiebacks. Once production is established at Deep Panuke, up to three additional production wells may be drilled. This section details the overall construction (drilling and completion) of the wells to be used for the Project.

3.1 Strategy

The development of well construction plans for the Project is guided by the requirement to minimize risk and costs associated with the drilling, completion, and future operations of all wells.

All wells for the Project will be constructed using a cantilever jack-up rig that is equipped with appropriately sized blow-out preventers (BOPs). All completion and workover operations will utilize either a large drilling rig or equipment, such as coiled tubing or wireline units, present and certified on the rig. An exception would be skid-mounted units that could be placed on light well intervention vessels (LWIV) if weather and availability permit.

Specific safety issues for well construction will be considered in the Project's Safety Plan (see Section 8). These safety issues include the development of procedures to be followed during simultaneous operations, such as drilling and production.

During some periods of well construction operations, the potential exists that only one rig may be operating in the Scotian Shelf area. Agreements will be established with the CNSOPB for a contingency plan should relief well drilling be necessary. In the event of a well control situation where the surface equipment is not sufficient to contain the well, well fluids can escape under blowout conditions. In order to regain control of such a well, it is necessary to drill a well intersecting the original wellbore, called a relief well, and use it to control the blowout well. Casing, wellhead, and mudline suspension equipment will be available for control of a blowout situation. The likelihood of a blowout is extremely unlikely and is further addressed in the EA Report (DPA Volume 4).

All manuals and drilling programs will be completed, and required approvals will be obtained prior to the proposed well construction start for the Project. The tentative schedule for the timing of the drilling and completion activities is included in Figure 1.3.

3.2 Exploration and Delineation Wells

The Deep Panuke gas reservoir was discovered in late 1998, with the original discovery well, PP-3C, drilled from the Panuke platform using the jack-up/drilling production unit, Rowan Gorilla III (RGIII). This well discovered a highly fractured, highly porous carbonate formation, which led to significant loss circulation problems during drilling. The discovery well was eventually cased, tested and then abandoned. Following this discovery, a delineation well and its sidetrack, PI-1A/B, were drilled from the Panuke platform in late 1999. The sidetrack, PI–1B, was tested in early 2000 and then suspended for potential re-use. Since that time, the PI-1B well has been abandoned with the exception of cutting the conductor below the mudline. Because PI-1B was drilled from the Panuke Platform, a mudline suspension system was not used, making it very difficult to convert to a subsea wellhead. The decision was made to abandon PI-1B due to the risk and technical challenges related to converting it to a subsea wellhead.

In May 2000, the RGIII moved to a new location and drilled the third delineation well, H-08. This vertical well found a substantial pay zone of gas and also experienced significant loss circulation problems; the well was tested and suspended. Concurrently, the Rowan Gorilla V (RGV) moved to drill M-79; this was the deepest vertical well through the Abenaki reef to date. The M-79 vertical well encountered poor porosity; the main well was plugged back and a sidetrack was initiated by milling a window near the bottom of the 245 mm casing. The sidetrack was drilled to almost horizontal, and it was cased, tested, and then suspended.

After finishing the H-08 well, the RGIII was moved to drill the Panuke F-09 well targeting prospects to the west of Deep Panuke on the back reef. The F-09 well was drilled directionally to investigate targets from the Abenaki 6 to the Scatarie formation. Intermediate logging proved the Abenaki 3 & 4 were water-saturated and so drilling was terminated at 3733.1 m true vertical depth (TVD). A drill stem test (DST) was conducted in the Abenaki 5 but proved non-commercial. The well was plugged and abandoned.

In July 2001, the RGV was again mobilized to drill Musquodoboit E-23 to the south west of the Panuke license on EL 2360. It penetrated 466 m of Jurassic limestones and lesser amounts of sandstone and shale. The prospective Abenaki 5 zone did not reveal any gas bearing intervals. Zones of vuggy porosity were found to contain water from the electric logging evaluation. The well was subsequently plugged and abandoned.

In May 2003, further delineation drilling was conducted using the RGV, to first drill Margaree F-70 on EL 2387 and then MarCoh D-41 on SDL 2255H. Both wells were drilled vertically at locations to the north-east of the discovery well. Each well encountered a substantial gas pay zone in the Abenaki. A production test was conducted on Margaree F-70 and the well was subsequently suspended. An extensive logging program was conducted on MarCoh D-41 including MDT pressure points and fluid sampling in lieu of a production test. The D-41 well was cased and suspended.

In November 2005, the Rowan Gorilla VI (RGVI) was mobilized to further delineate the Deep Panuke field to the northeast by drilling the Dominion J-14 well. The vertical well was drilled to a total depth of 3700 m TVD but did not encounter any gas bearing formations. The Dominion J-14A horizontal sidetrack was drilled due south from the J-14 well but did not encounter any gas bearing formations. Both the vertical well and sidetrack were abandoned.

Figure 3.1 shows the relative locations of the existing wells. Table 3.1 lists details of the existing wells.

The Project plans to re-enter and complete the Panuke H-08, M-79A, Margaree F-70 and MarCoh D-41 wells as part of the pool development.

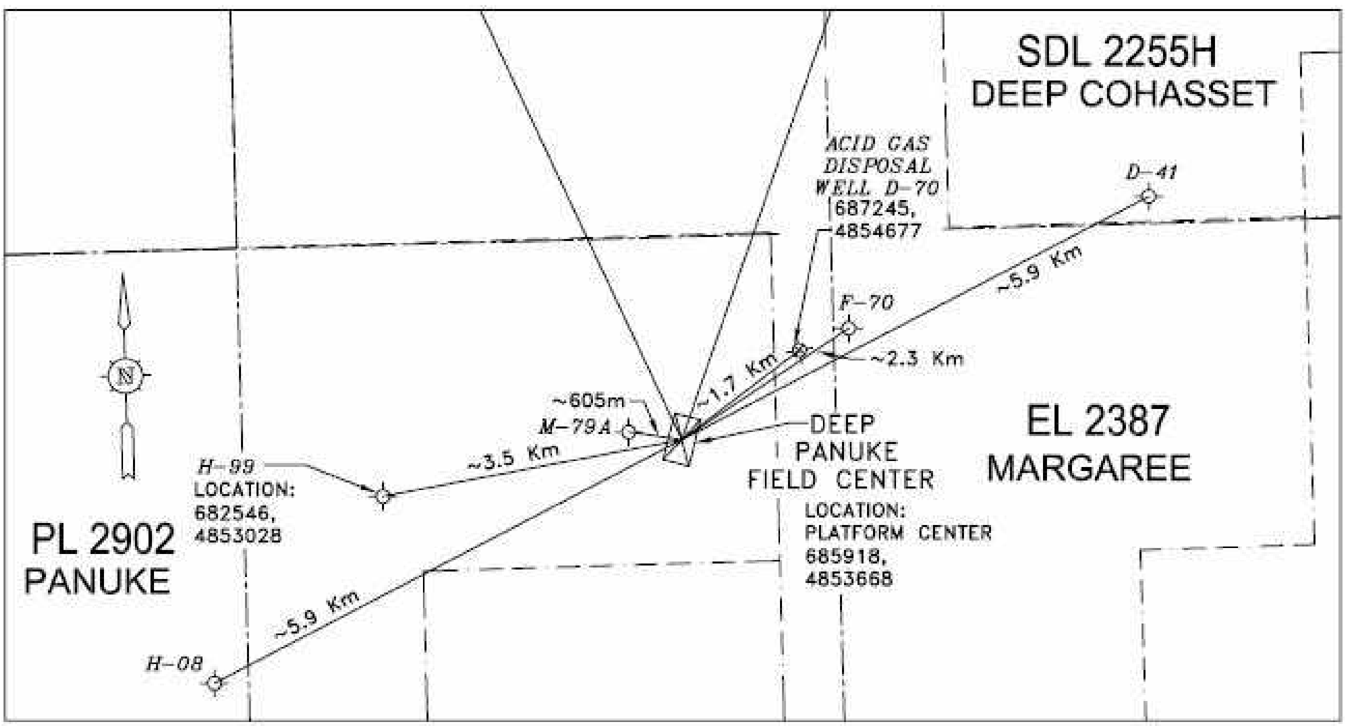


Figure 3.1 Deep Panuke Exploration and Delineation Wells

Table 3.1 Exploration and Delineation Wells - Summary Information					
Well Name	**Year Drilled**	**Status**	**Rig**	**Measured Depth[1]**	**TVD[2]**
PP-3C (Discovery Well)	1998	Abandoned	RGIII	4163 m	3643 m
Panuke PI-1A	1999	Abandoned	RGIII	4033 m	3595 m
Panuke PI-1B	2000	Abandoned[3]	RGIII	4046 m	3589 m
Panuke H-08	2000	Suspended	RGIII	3682 m	3682 m
Panuke M-79	2000	Abandoned	RGV	4598 m	4597 m
Panuke M-79A	2000	Suspended	RGV	3934 m	3492 m
Panuke F-09	2000	Abandoned	RGIII	3815 m	3654 m
Musquodoboit E-23	2001	Abandoned	RGV	3818 m	3814 m
Margaree F-70	2003	Suspended	RGV	3677 m	3676 m
MarCoh D-41	2003	Suspended	RGV	3625 m	3625 m
Dominion J-14	2005	Abandoned	RGVI	3700 m	3699 m
Dominion J-14A	2006	Abandoned	RGVI	4440 m	3568 m

[1] Measured Depth below the Rotary Table (RT)

[2] True vertical depth (TVD) below the Rotary Table (RT)

[3] PI-1B has been abandoned downhole but still requires cutting and removal of conductor pipe 3m below the mudline.

3.3 Development Drilling

EnCana's current plan is to re-enter the four suspended wells (H-08, M-79A, F-70, D-41), drill two new wells prior to start-up, including one production well and one acid gas injection well, and complete all wells as subsea tiebacks. Once production is established, up to three additional production wells may be drilled. All of these wells will be completed with subsea production trees and tied back to the MOPU with individual flowlines and control umbilicals.

3.3.1 Tentative Drilling Schedule

The current schedule is to start well construction activities in early-to-mid 2009 to enable full production to be available by the time the MOPU and pipelines are commissioned in 2010. During this time, the four existing exploration wells will be re-entered and completed, and one new production well and one acid gas injection well will also be drilled and completed. This schedule may change based on availability of existing equipment and services. Figure 1.3 provides a preliminary overall well development schedule.

3.3.2 Drilling Hazards

Extensive drilling experience within the area of the Deep Panuke pool provides an excellent understanding of the well construction hazards. The two primary areas of concern when dealing with any wells in the Abenaki reef structure are the potential for loss circulation problems and the H_2S content of Deep Panuke gas. While these operational difficulties were dealt with appropriately during the drilling of the discovery and delineation wells, they must be appropriately accounted for during any well construction activity.

Other more routine drilling hazards could include hole instability, shallow gas and differential sticking. These hazards are described in more detail as follows.

3.3.2.1 Loss Circulation

While drilling into a highly fractured/highly porous carbonate formation, it is sometimes difficult to maintain circulation. Under normal drilling circumstances, the drilling fluid is pumped into the wellbore through the drillstring and out of the drill bit and back to surface through the annulus. From the surface to the drill bit and back to surface represents one full circulation of drilling fluids. The volume of fluid entering the wellbore is equivalent to the volume of fluid coming back to surface under normal drilling conditions and any change in this would represent a well control situation. This condition was encountered during the drilling of the discovery well, PP-3C, where it was determined that the formation would only support a mud density of approximately 10 kg/m^3 more than the wellbore fluid ingress density required to keep formation fluids in place. Therefore, a wellbore that would stand full of drilling mud would begin to lose fluid as soon as circulation began due to annular pressure loss.

To overcome this problem, a drilling method called the annular velocity control (AVC) drilling technique was developed. The AVC technique employs a rotating BOP while injecting seawater down the drill string and casing annulus at a rate that is higher than the gas migration rate up the wellbore to maintain dynamic well control while drilling. Initially, the AVC technique involved the use of stripping and snubbing equipment to move the drill string (or casing) into and out of the wellbore. A modification to this procedure replaces the stripping and snubbing equipment with continuously pumping a weighted brine solution while moving the drill string (or casing) in and/or out of the wellbore.

3.3.2.2 Hydrogen Sulphide (H_2S)

H_2S was encountered during all well tests from the discovery and delineation wells, but none was detected during the drilling of any of these wells. Through proper drilling practices and the application of appropriate environment, health and safety (EHS) procedures and policies, the exposure of well construction operations to the H_2S risk will be managed safely.

3.3.2.3 Shallow Gas

A shallow gas deposit could cause uncontrollable well flow before adequate casing is set to allow use of a BOP system to divert the gas flow. Although some site surveys have indicated the possibility of shallow gas on the Panuke license, it has not been encountered in any of the wells drilled to date. Detailed site surveys of the proposed new well drilling locations will be performed to ensure shallow gas is not a risk during drilling operations.

3.3.2.4 Hole Instability

Hole instability problems result in extended drilling times and increased costs but do not pose a hazard to personnel or the environment. The Deep Panuke exploration wells were drilled using a water-based drilling fluid which provided good hole stability and inhibition to reactive shale sections when fluid density is properly controlled. This water-based fluid also provided excellent directional control while drilling carbonate section in highly deviated, near horizontal, sidetracks such as Panuke M-79A and Dominion J-14A.

The new drill production and injection wells are expected to be vertical or sidetracked similar to M-79A or J-14A. A water-based mud system will be used for all new wells with careful attention to the density and visco-elastic properties of the fluid in order to prevent any hole stability problems.

3.3.2.5 Abnormal Pressure

Abnormal pressures are not expected throughout the Abenaki Reef. Reservoir pressure in the Abenaki 5 is approximately 36.3 MPa at 3309 m TVD. This pressure has been measured directly using logging tools and through well testing and has been correlated with all of the Deep Panuke delineation wells.

3.3.2.6 Well Control

As described above in Section 3.3.2.1, well control is of primary concern due to the very tight pore pressure kick tolerances within the reservoir. The discovery well, PP-3C, experienced significant loss circulation that was eventually controlled using a seawater bullheading technique. The probability of well control incidents or uncontrolled kicks is low through the utilization of EnCana's tripping (moving pipe in or out of the wellbore), drilling, and AVC techniques.

3.3.2.7 Differential Sticking

Differential sticking across the hydrocarbon zones is possible due to lost circulation and AVC drilling. Tight control of drilling fluid properties and good operating practices will minimize this potential.

3.3.2.8 Directional Control

Direction will be closely controlled using the latest measurement-while-drilling (MWD) technologies on the additional development wells. The wellbore trajectory will also be confirmed by the application of two independent measurement sources. Likewise, locating existing wells is not a concern due to accurate records and tight directional control techniques used during the previous drilling of these wells.

3.3.3 Drilling Details

This section presents the well design based on experience from existing Deep Panuke discovery and delineation wells. The well design will evolve over the life of the Project and the field to take advantage of equipment development, new techniques, and drilling experience. The detailed design specifications will be submitted with the Drilling Program prior to the "spud" of each well in accordance with CNSOPB Regulations. "Spudding" a well is generally considered the first moment the drill bit touches the seabed or ground level in the case of a land well.

3.3.3.1 Casing and Hole Sizes

The normal drilling program for all Deep Panuke wells involves conventional hole and casing/pipe sizes. All casing designs are based on *Nova Scotia Offshore Area Petroleum Drilling Regulations*. Additional information on casing design and drilling program is contained in the Part Two (DPA-Part 2, Ref. # 3.1)

For the new production and injection wells drilled, the conductor pipe (first string of pipe) will be set approximately 100 m below the seafloor by first drilling a 914 mm hole and then cementing a 762 mm conductor pipe. This is the same method that has been used on the existing suspended delineation wells. This section will be drilled primarily with seawater and viscosifiers to aid in ensuring cuttings removal from the wellbore. These cuttings are deposited at the seabed and approximately equivalent to the volume of the hole drilled.

The conductor pipes will serve as the primary weather barrier to take environmental loading and protect the inner strings of casing (length of pipe) while drilling the well. The conductors also take the surface loading implied by the other strings of casing that are returned to the mudline suspension system. Once the drilling has been completed, the conductors will be removed and the well will be converted to a subsea wellhead. With the production tree installed, a high pressure riser will be required to tieback to the surface BOP stack. The high pressure riser will be designed to withstand the environmental loads as well as all internal design loads.

All production and injection wells will set the surface casing into the Wyandot member (refer to Figure 2.5) at approximately 950 m true vertical depth from sea surface (TVDss) in the general direction that the bottom of the well will be located. The existing suspended delineation wells have drilled a 445 mm hole and set 340 mm surface casing approximately 50 m into the Wyandot with cement back to the seabed. The BOP stack is then installed on top of the surface casing prior to drilling the intermediate hole section.

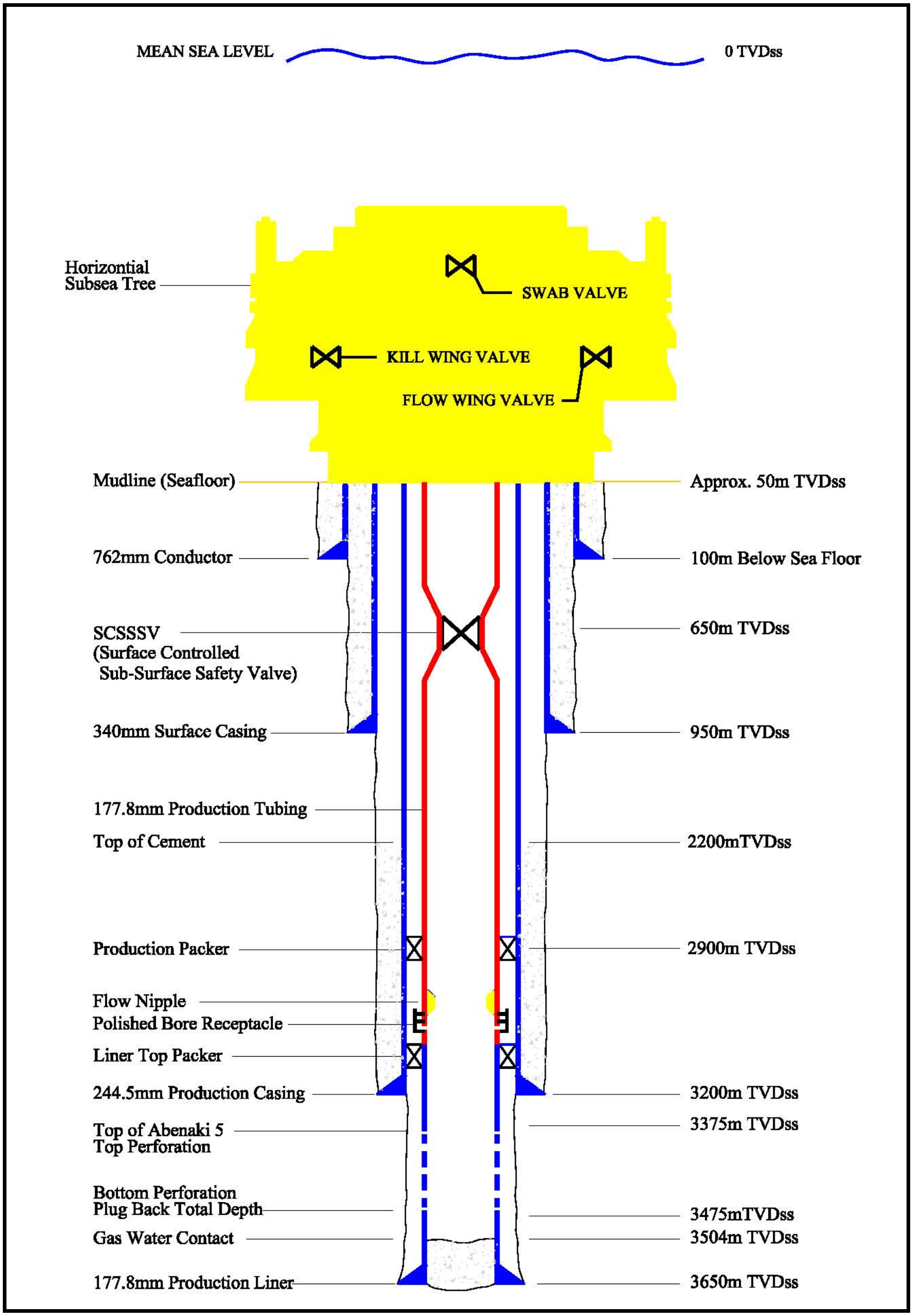


Figure 3.2 Typical Production Well Schematic

For the re-activation wells, a 311 mm intermediate hole section has been drilled just into the top of the limestone at approximately 3200 m TVDss. A 244.5 mm intermediate casing string has been set 20m into the Abenaki 7/6 formation and cemented back just above any potential hydrocarbon bearing sands (~2300m).

A rotating BOP and an injection spool will be installed with the surface BOP stack in preparation for AVC drilling techniques and the main hole section will be drilled through the productive interval of the carbonate reef. For the re-entry wells, the reservoir section has been drilled to a total depth of circa 3650m TVDss which is about 150m past the gas/water contact (GWC) at 3504m TVDss. On many of the delineation wells, this GWC was not clearly evident while drilling the section as the formation was not porous at this depth; however, it was clearly identified while drilling the MarCoh D-41 well. On each of the wells to be re-used for production, a 177.8 mm liner (string of pipe) has been installed across the reservoir section and cemented back to the previous casing shoe.

The new production well(s) will be similarly constructed to the existing suspended delineation wells. Prior to drilling the reservoir section and with the well secured, the surface wellhead and conductor will be removed and the well will be converted to a subsea wellhead. The production tree will be installed with the high pressure riser connected back to the surface BOP stack. For the new producing well(s), the reservoir section may be left open, with no liner in place, in order to maximize the flow potential of the well.

For re-entry of the existing wells, a 762 mm "trash cap" will first be removed from the conductor stub 3m above the seafloor. A "trash cap" is a cylindrical device closed on one end that fits over the conductor to keep out sea life or falling debris. Once the trash cap has been removed, a running and retrieving tool is used to back off the temporary abandonment caps from the 340 mm and then 244.5 mm mudline suspension thread profiles. Each of the wells then has a 100m thick cement plug set at approximately 2900 m in the 244.5 mm casing that has to be drilled out.

For H-08, there are two mechanical bridge plugs set below the cement plug that must also be retrieved prior to gaining access to the 177.8 mm liner section. For M-79A, there is one mechanical bridge plug set inside the 244.5 mm casing and one inside the 177.8 mm liner that will be pulled. Also, each of these two wells has a production packer and 114.3 mm tailpipe installed with plug and prong profile nipples installed. The tailpipes have two plugs and prongs that must be pulled before opening the well to flow. Pulling the plugs and prongs will be done only after the new completion has been installed and the well is ready for production clean-up operations. The Margaree F-70 well has a 100 m cement plug set just below the 177.8 mm liner top which will be drilled out. Margaree F-70 and MarCoh D-41 each have a sealed permanent packer installed in the 177.8 mm liner that will either be drilled out or cut and pulled. For F-70, once the packer is pulled, the well is open to the perforations below that were put in the liner during production testing. On MarCoh D-41, the well was not tested and therefore it should be secure after pulling the 177.8 mm packer. Due to size restrictions on the subsurface safety valve, the abandonment packer will have to be pulled prior to running the completions on these two wells.

The production wells will all be completed with a downhole packer (plus other ancillary downhole equipment), production tubing, surface controlled subsurface safety valve, a tubing hanger, and a subsea production tree. Once all hydrostatic tests and function tests are performed, the production wells will be opened for clean-up flow on the drilling rig. This will remove any water or debris from the wellbore prior to handover for production operations on the MOPU. See Figure 3.2 for details on the production wells.

The injection well will be drilled using similar processes and procedures as with the production wells. Once the surface casing is set in the Wyandot formation, the main well bore will be drilled vertically to the injection zone in the Upper Mississauga formation located at approximately 2400m TVDss. See Figure 3.3 for details on the injection well. Similar to the production well, the completion for the injection well will consist of tubing, downhole packer, subsurface safety valve, tubing hanger and injection tree.

This injection well for acid gas and condensate (if necessary) will be drilled into a porous and permeable zone in the Upper Mississauga Formation; the targeted injection zone is the Tidal-Fluvial Sandstone. The impermeable Naskapi shales located directly above the Upper Mississauga Formation will prevent any migration of injected acid gas or condensate. The Upper Mississauga Formation will be capable of containing the entire acid gas and surplus condensate volumes that will be produced over the life of the Project. Migration of injection fluids to other formations and/or to the surface is considered extremely unlikely. The possibility of acid gas injection souring the Panuke oil zone is also considered to be extremely unlikely. The injection zone in the Upper Mississauga is expected to have 14% porosity and 400 mD permeability.

3.3.3.2 Drilling Fluid Program

Water-based muds (WBM) will be used in development drilling. These muds are used to protect and clean the drill hole, for overbalancing formation pressures, and for bringing cuttings to the surface. The selection of the drilling fluid is based on factors such as the hole angle, the formation types drilled (mudstone, sandstone, clays, etc.), and the time of exposure.

WBM is a suspension of solids and dissolved material in a carrier base fluid of water. WBM tends to be used for wells that are normally pressured or do not encounter difficult geology. Based on the experience gained while drilling the Deep Panuke delineation wells, it was determined that only WBM will be used for any new development drilling activities. This fluid has proven to be successful even when drilling highly deviated wellbores such as the M-79A sidetrack.

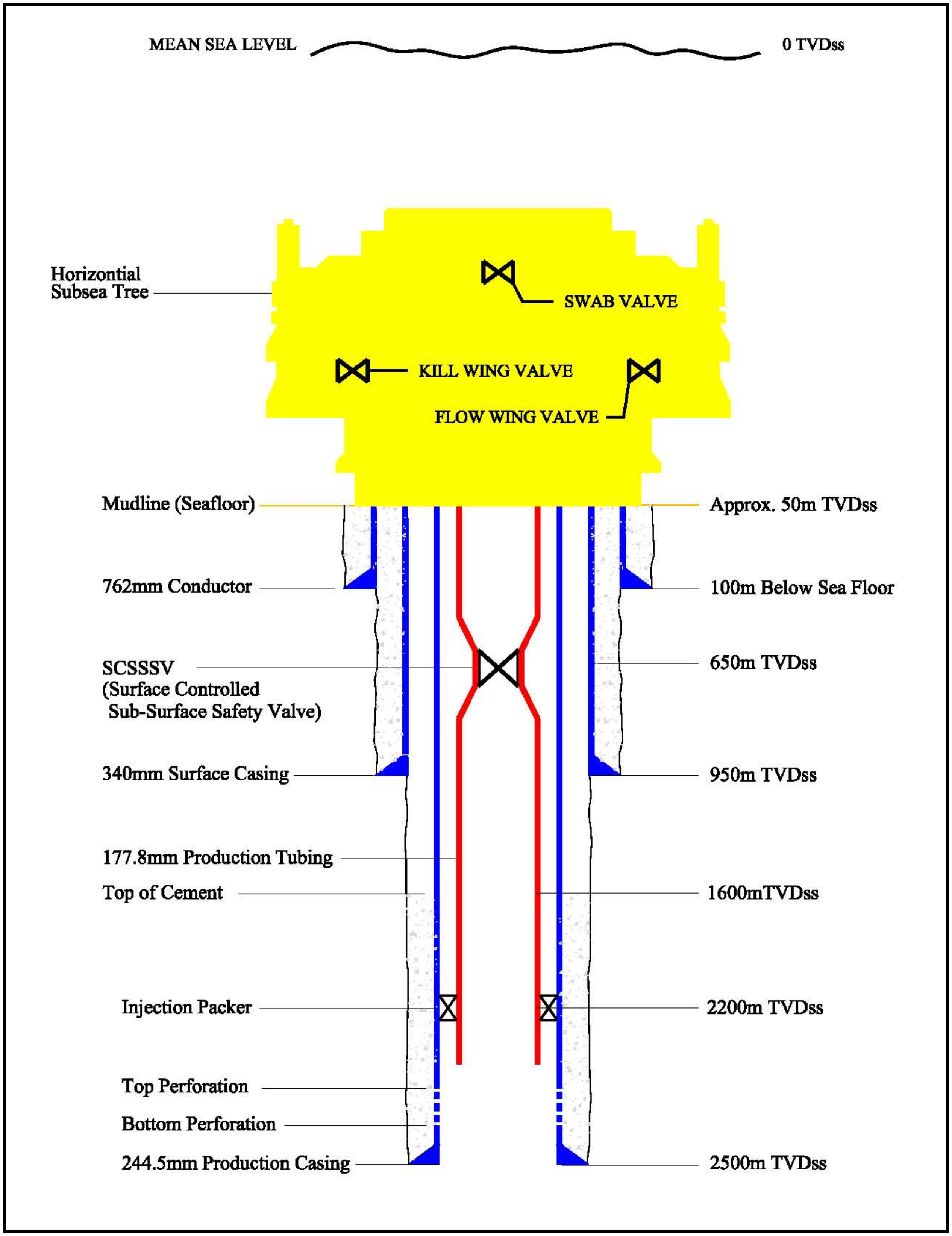


Figure 3.3 Typical Injection Well Schematic

For each well there are three hole sections below the 762 mm conductor, each of which has different mud-type requirements. These three sections are: (1) surface hole section (from seabed, ± 100m below the sea floor (BSF), to the Wyandot formation, ± 950m TVD); (2) intermediate hole section (from the Wyandot formation to the top of Abenaki formation at ± 3200m TVD); and (3) the main hole section (from the top of the Abenaki formation to the production zone, ± 3400 m TVD).

WBM will be used to drill the surface hole for several reasons. The surface hole section drills very quickly, so oil-based mud would not increase the rate of penetration. Most importantly, the potential for surface (seafloor) break-through of the drilling fluid while drilling this hole section is fairly significant. From an environmental and economic perspective, this break-through would be undesirable if oil-based muds were used. The WBM for this hole section will be a one to one ratio of pre-hydrated bentonite (gel) to seawater.

For the intermediate section, WBM will be used. The drilling fluid for the intermediate hole will be selected based primarily on pressure regime, formation types drilled, and time of exposure. The selection of drilling fluid will be as per the delineation wells, which consisted of a 3% glycol and 8% potassium-chloride (KCl) mixture, which provides adequate shale inhibition, good lubricity for the drill bit and relatively good gauge hole.

Finally, for the main hole section, WBM will also be used in case AVC drilling with total mud losses is required. This will be the same drilling fluid from the intermediate section; however, the glycol and KCl properties will not be maintained in the event total loss circulation is encountered. In the event total losses are encountered, the AVC drilling technique, which uses seawater, will be used to complete drilling the section. When moving the drill pipe in or out of the hole under AVC conditions, a densified brine (NaCl) mixture will be used throughout the length of the trip. Once the drill string is out of the hole, the well can again be controlled by pumping seawater at a continuous rate.

For the wells to be re-entered and completed, some drilling is required to remove cement plugs. This will be done using a viscosified brine solution and therefore drilling mud will not be required. For running the completions, a completion fluid will be required which is described in more detail in section 3.4.6.

During drilling, the mud is circulated down the drillpipe from the drilling unit to the bottom of the wellbore and returned to the drilling unit in the annular space (between drill pipe and open hole/casing) carrying the cuttings from the well. Each hole section of a wellbore requires different fluid properties for the mud. Thus after each hole section, the mud is modified or changed out. WBM that is no longer required will be disposed of overboard, along with WBM cuttings in accordance with the *Offshore Waste Treatment Guidelines* (NEB et al. 2002).

Through the life of the field, workovers will be required in the wellbores. These workovers will require various pieces of equipment to be sent offshore to perform downhole work. Completions brines may be used during these processes. These brines would be composed of water and a salt formulation kept in suspension using a viscosifier (polymer).

3.3.3.3 Cementing Program

The cementing program is expected to be similar to that used for the exploratory and delineation wells. The conductor will be cemented from shoe to seabed. The surface, intermediate and production casing will be cemented high enough to prevent future casing instability and to isolate permeable zones. To ensure a leak-off path for trapped-fluid expansion during production, intermediate and production casings may not be cemented into the previous casing shoe. If a liner is used in the new drill production wells, it will likely be left as an uncemented completion. External casing packers and stage tools may be used in high loss circulation situations to isolate the highly porous zones. If the liner is not cemented in place, proper metallurgy and liner top packers will ensure containment of the reservoir fluids to ensure a safe production wellbore. See Part Two for existing well casing and cementing details (DPA-Part 2, Ref. # 3.2).

3.3.3.4 Well Control System

The selection of the BOP configuration will be part of the rig evaluation process. Typically, a 346 mm, 103 MPa (or 69 MPa) BOP equipped with four rams and an annular preventer will be installed on a 508 mm wellhead and used for the remainder of the well. In addition, an injection spool and rotational BOP will be installed for the sections drilled using the AVC method.

3.3.4 Directional Drilling

High hole angles (up to horizontal) may be used in the pay zone if increased productivity can be realized. Kick-off elevation and well profiles will be customized for each new well. High hole angles may also be used to minimize the possibility of encountering low quality reservoir rock since longer intervals of the reservoir will be exposed.

Mud pulse telemetry directional tools will be used for directional control. The survey intervals and the type of surveying system used will be sufficient to assure entry into the target, while avoiding collision with adjacent wells, and providing adequate wellbore positioning information to reliably target a relief well. The wellbore trajectory will be confirmed by using two independent sources of MWD tools and correlating the data from each tool.

3.4 Well Completions

3.4.1 Design Philosophy

For the Project, EnCana will use completion systems that are simple and reliable and meet all requirements for the corrosive environment in which they will be placed. The completions will be designed with minimal need for intervention as one of the key drivers. Preliminary design indicates that a 177.8 mm tubing string will be required for the production wells. The injection well will likely use a 88.9 mm string. Due to size limitations with the existing delineation well construction, a smaller diameter subsurface safety valve will be required if a 177.8 mm tubing string is used. Figures 3.2 and 3.3 provide schematic examples of the production well and injection well.

Some of the production and injection objectives considered in the completion design are as follows:

- to ensure operational safety;
- to keep completions as simple as possible;
- to minimize the number of wells while maximizing recovery and effectively depleting the reserves;
- to ensure that downtime is minimized, including workovers;
- to maintain a surplus in deliverability to mitigate production downtime due to workovers or suspended wells;
- to maintain the plateau production of the Project as long as possible; and
- to reduce or eliminate one-off well designs to reduce the number of spares required.

The completions will ensure operational safety by providing an effective barrier and seal to the reservoir while at the same time providing a conduit for delivering well fluids to the subsea flowline. The design incorporates a surface controlled sub-surface safety valve (SSSV) that can effectively isolate the flow stream downhole in the event of an emergency or extended shut-down period. The tubing string, downhole completion equipment, and subsea production tree will be selected with materials suitable to the corrosive environment of well fluids over the life of the Project. The completions will be kept as simple as possible to reduce the potential of downhole equipment failures that could require a workover during the life of the Project.

A rigorous engineering analysis will be performed to select the optimum tubing size, which will minimize the number of wells required to produce the field while at the same time maximize plateau production rates. This analysis will include liquid loading issues that might develop near the end of the Project's economic life. Liquid loading occurs when the velocity of the flow stream is not sufficient to carry the liquid out of the wellbore. If the liquid builds up to significant levels, it would render the well insufficient to flow gas to surface. The velocity of the flow stream can be greatly affected by the size of the tubing string used. Generally, a smaller tubing string will yield higher flow velocities for the same wellhead pressure.

The tubing may be sized such that peak production can be achieved from as little as three to four wells, which will allow some redundancy in the system. In the event of losing a well prematurely, some time would be required to mobilize a drilling rig before a workover could be completed. Redundancy in the production capacity of the wells would ensure peak or maximum production rates until the workover was completed.

3.4.2 Tubing Design

The tubing size will be maximized so that wellbore deliverability is not minimized by tubing constraints. Tubing size is limited by the outside diameter of the SSSV that will fit in the production casing. The tubing design must provide a flow conduit consistent with the inflow performance of the completed reservoir for the life of the field. The injection well will also be designed so that the tubing string does not provide pressure constraints.

A monobore completion technique is an alternative to conventional completions. This style has production casing set near the top of the zone and uses a liner with a tie back packer to case the zone. Tubulars, downhole equipment, and trees are sized so that all equipment has a similar internal diameter. The Deep Panuke production wells will be "quasi-monobore" completions in that the subsurface safety valve will have a smaller inside diameter if a 177.8 mm tubing string is used due to the size constraints inside the 244.5 mm casing.

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; and
- 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 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 expected operating conditions. Final selection of the tubular connection will adhere to a connection qualification program that meets industry standards. The design will also incorporate any reduction in strength of materials due to temperature considerations under flowing and static well conditions.

3.4.3 Metallurgy

Careful consideration will be given to the materials used for tubulars, wellhead and downhole equipment because of exposure to corrosive fluids. Due to the presence of H_2S, CO_2, and chlorides, high alloy steel or corrosion resistant alloy (CRA) material may be required for tubulars and downhole equipment, and a corrosion resistant cladding may be required for subsea production tree equipment. Both production and injection wells will require detailed attention to the type of materials used for all components. EnCana has undertaken a study to determine the corrosion potential of the producing environment, and to determine suitable material and operational guidelines.

3.4.4 Downhole Equipment

The use of downhole completion tools will be minimized to reduce workover potential and wellbore complexity. The corrosive environment may reduce the performance of any equipment in the wellbore.

The current design has tubing-retrievable SSSVs installed and all wells are equipped with a polished bore receptacle 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 all seals and elastomers will incorporate the results of the corrosion study.

The maximum anticipated wellhead pressure will be contained safely and effectively through the selection of appropriate wellhead and production/injection 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. Operating control and the emergency shut-down (ESD) system will be achieved through an electro-hydraulic umbilical from the MOPU to the subsea production tree. There will be a similar control panel from the drilling rig during completion and workover operations. Due to the operating environment, the wellhead and tree will most likely be clad in a corrosion/erosion resistant material. The tubing hanger will be ported to allow capability to handle the downhole gauge cable, SSSV control lines, and chemical injection. Depending upon anticipated workover scenarios, the hydraulic valves in the production trees may be capable of cutting both wireline and coiled tubing.

The present completion strategy allows for the integration and use of typical downhole equipment including flow control nipples and mandrels for real-time pressure and temperature read-out gauges.

3.4.5 Completion, Workover & Packer Fluid

Separate completion fluids will be used for the following three phases of completions operations:

- cleaning out the well;
- providing an annular packer fluid; and
- perforating (when required) pre-flow.

Well clean-out will follow the installation of the production liner. The fluid used to clean the wellbore will be water based. Viscous pills of polymer gelled fluid may be used at total depth to sweep the hole clean.

Packer fluid will likely be saltwater based (brine), corrosion inhibited, and oxygen and hydrogen scavenged. The packer fluid will be weighted such that in the event of a tubing leak deep in the well, the fluid will overbalance the formation pressure and kill the well.

Three alternatives are available for a perforating/pre-flow fluid: non-damaging brine, a nitrogen cushion or an oil-based fluid. The fluid of choice will depend upon the well and the final reservoir requirements. All of these fluids will be flowed back to the processing or testing system during startup or cleanup.

3.4.6 Annular Barriers

There will be two annular barriers between the formation and the seafloor. The first barrier is the packer in the well, separating the formation from the annulus. The second barrier is the tubing hanger and annular kill wing valve on the subsea tree.

3.4.7 Production/Injection Trees

The production and injection trees will be located on the seafloor and will consist of a standard horizontal configuration. The reactivation wells have all been drilled with a surface wellhead and mudline suspension system. These wells will be converted to subsea wellheads through the mudline suspension system to provide a platform to mount and seal the subsea production trees.

The maximum expected pressure at surface is approximately 37 MPa for all wells due to pressure testing requirements on abandonment. Therefore, standard 34.5 MPa subsea tree equipment will be not be sufficient and it may be necessary to have 45 MPa equipment or more standard 69 MPa.

During workovers, control of the wellhead equipment from the MOPU will be locked out to avoid accidental operation of equipment when the workover unit is connected to the wellhead.

Valve function on the subsea trees will be controlled by an electro-hydraulic umbilical tied back to the MOPU during production and to the drilling rig during completion and workovers. This system will be integrated with the MOPU ESD system during production operations. The subsea tree design will also incorporate an interface for remotely operated vehicle (ROV) intervention in the unlikely event of a topside control system failure.

3.4.8 Perforating

Perforating the production casing or liner allows formation fluids to flow into the wellbore (or injected fluids to access the reservoir). If perforating is required, the three alternatives available for perforating are :

- wireline-conveyed perforating;
- tubing-conveyed perforating using coiled tubing or drillpipe; or
- tubing-conveyed perforating on tail pipe below the packer.

The appropriate method of perforating for each individual well will be chosen based on its merits for the particular operation.

3.5 Well Interventions

EnCana's well workover philosophy for the Project is to maximize resource recovery from the Deep Panuke reservoir on an economically viable basis. The viability of workovers will take into account the amount of resource likely to be recovered together with the availability, proximity, and cost of MODU required to complete the workover, either major or minor.

3.5.1 Major Workovers

Major workovers are those that require a mobile drilling unit to accomplish the required tasks. Few major workovers are anticipated through the life of the field due to the reservoir type, the completion style and the use of quality components throughout.

Typical major intervention activities include:

- replacing tubing;
- replacing tubing-retrievable SSSVs and control lines;
- drilling up/replacing packer;
- sidetracking to improve reservoir productivity; and

- replacing a subsea production tree or valve.

3.5.2 Minor Workovers

Minor workovers could encompass both wireline and coiled tubing operations for both production and injection wells. Coiled tubing or wireline intervention could also require a jack-up rig or specialized light well intervention vessels, equipment and operating procedures.

Typical minor workover activities include:

- installing or removing plugs and prongs;
- running or retrieving downhole pressure recorders;
- production logging;
- formation logging;
- perforating;
- circulating fill or debris from wellbore;
- jetting scale or paraffin from tubing interior;
- acid stimulations;
- setting packers or bridge plugs; and
- cement squeezes.

4 PRODUCTION AND TRANSPORTATION SYSTEMS

4.1 Introduction

The Deep Panuke reservoir contains lean sour gas. Full processing of the gas including H_2S removal will be carried out offshore using a MOPU which will provide all the necessary production equipment. Subsea producing wells will be connected to the MOPU via individual subsea tiebacks. The Deep Panuke Project currently includes two options for the export of the sales product: either by constructing a new 176 km, 560 mm [22 inch] diameter stand alone export pipeline to shore near Goldboro, N.S. (M&NP Option); or to interconnect with the existing SOEP pipeline and downstream facilities at Goldboro via a 510 mm [20 inch] diameter subsea pipeline, approximately 15 km, and subsea tie-in (hot tap) at a close point on the SOEP pipeline route (SOEP Subsea Option). The gas will be conveyed to market via the M&NP pipeline. See Figure 4.1 for the proposed field rendering.

This section outlines the technical summary of the production and transportation systems as well as discusses options and alternatives that were considered for the development.

4.2 Design Criteria

4.2.1 Philosophy

EnCana is committed to protecting the health and safety of all individuals as well as the environment in which it operates. Therefore, the design of the Project facilities is based on high standards for personnel safety, environment, and resource conservation. EnCana will employ a systematic approach in identifying and addressing potential hazards, and defining design criteria and appropriate control and recovery measures.

Applicable standard industry practices will be adopted for the Project. Safety reviews will be held periodically throughout all phases of the Project, including during detailed design, construction, commissioning, and decommissioning. All Project installations will be designed, constructed, installed and commissioned in accordance with a quality assurance program that will meet the requirements specified in the CNSOPB regulations.

EnCana also intends that the quality assurance for the Deep Panuke Project will meet the requirements of ISO 9000 program. Quality plans and procedures will be developed and quality control, through auditing and surveillance, will ensure that the appropriate levels of quality assurance will be present throughout the Project and that all requirements will be met.

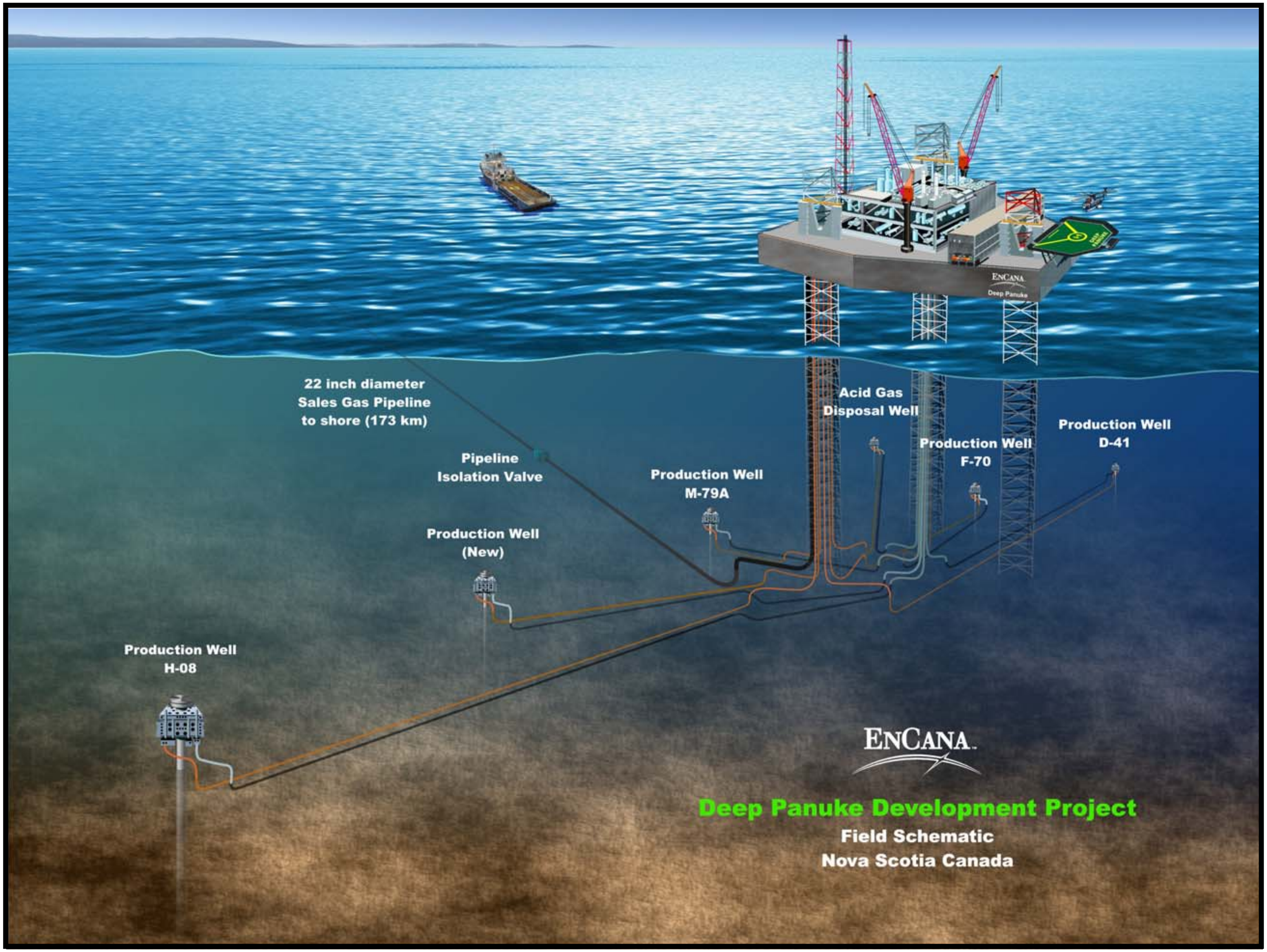


Figure 4.1 Proposed Field Layout

The final design will achieve fit for purpose facilities using proven technology and equipment with low life cycle costs.

4.2.2 Regulations and Certifying Authority

The Project facilities will comply with all applicable regulatory requirements. Regulations and guidelines that will be used for both the offshore and onshore portions of the Project include, but are not limited to, the following:

- *Nova Scotia Offshore Area Petroleum Production and Conservation Regulations*;
- *Nova Scotia Offshore Certificate of Fitness Regulations*;
- *Nova Scotia Offshore Petroleum Installations Regulations*;
- *Nova Scotia Offshore Petroleum Occupational Health and Safety Requirements*;
- *Nova Scotia Offshore Petroleum Drilling Regulations*;
- *Nova Scotia Offshore Area Petroleum Diving Regulations*;
- *Canada-Nova Scotia Oil and Gas Spills and Debris Liability Regulations;*
- *NEB Onshore Pipeline Regulations*;
- *NEB Pipeline Crossing Regulations Part I & Part II*;
- *NEB Power Line Crossing Regulations*;
- *Canada Shipping Act* (and related guidelines);
- *Fisheries Act* (and related guidelines);
- *Offshore Waste Treatment Guidelines*;
- *Offshore Chemical Selection Guidelines*;
- *Physical Environmental Guidelines*; and
- *Guidelines on Operator's Safety Plans*.

EnCana will adhere to applicable regulations or other international standards as deemed acceptable to the Certifying Authority (CA) and the CNSOPB.

To fulfill the requirements of the *Accord Act*, an independent third party known as a CA is required to confirm, through design appraisal and works survey, that all Project facilities and structures have been designed, constructed, transported and installed in accordance with the *Nova Scotia Offshore Certificate of Fitness Regulations*. This confirmation is provided in the form of a Certificate of Fitness (COF) issued by the CA. The COF must be issued by the CA prior to the installation of any offshore facility.

In order to support the CA's function and demonstrate compliance with regulatory requirements, the Project will implement a certification process. The certification process addresses the following certification requirements:

1. CA design appraisal of preliminary & detailed engineering;
2. procurement design appraisal, works survey & documentation review by CA;
3. pressure system component certification;
4. structural welding certification;
5. lifting appliance certification;
6. container certification;
7. material certification;
8. Transportation of Dangerous Goods cylinder certification;
9. electrical product certification;
10. Marine Warranty certification; and
11. inspection operator certification.

The CA Scope of Work was approved and in place for the Deep Panuke Project at the time of Project time-out in 2003. The scope of work is essentially unchanged since 2003.

4.2.3 Codes and Standards

Various codes and industry standards from the following organizations will typically be used for the Deep Panuke Project:

- American Petroleum Institute;
- American Society of Mechanical Engineers;
- National Fire Protection Association;
- National Association of Corrosion Engineers;
- Canadian Standards Association;
- Institute of Electrical and Electronic Engineers;
- International Standards Organisation;
- International Electrotechnical Commission;
- Transport Canada;
- International Maritime Organisation;
- Canadian Council of Ministers of Environment; and
- Det Norske Veritas.

4.3 Environmental Criteria

Meteorological and oceanographic (Metocean) design criteria will be developed for the Deep Panuke Project in accordance with the *Nova Scotia Offshore Petroleum Installation Regulations*. These criteria will be created from hindcast studies of environmental data from the Scotian Shelf and Sable Island areas and on data accumulated over the nine year life of the Cohasset Project. The design criteria will take into account parameters, such as winds, waves, currents, air and sea temperatures and ice conditions and will convert extreme conditions into 1, 10 and 100-year outlooks for design purposes. Wave and current criteria have also been developed for representative locations along the export pipeline route for design purposes.

The preliminary environment design criteria for the export pipeline to be constructed from the MOPU to shore (M&NP Option) is listed in Table 4.1. For the pipeline of the SOEP Subsea Option, the values from KP157 – MOPU data are applicable.

Table 4.1 Preliminary Environmental Design Criteria – Export Pipeline

Return period (years)		Sites along pipeline route	KP[1] 2-8.5	KP[1] 12.5-17.5	KP[1] 37.5-47	KP [1] 61-80	KP[1] 105-125	K[1]P 125-157	KP[1] 157-MOPU
		Depth (m)	30	50	145	100	60	30	45
Waves	1	**Hmax[2] (m)**	9.8	10.7	12.2	12.8	13.6	13.4	16.3
		Tp[3] (s)	11.3	11.4	11.5	11.6	11.8	11.9	12.2
	10	**Hmax [2] (m)**	13.5	14.6	16.4	17.1	17.7	17.8	20.0
		Tp[3] (s)	13.3	13.1	13.7	13.5	13.6	13.5	14.3
	100	**Hmax[2] (m)**	17.1	18.5	20.7	21.5	21.8	22.6	23.7
		Tp[3] (s)	15.4	14.9	15.9	15.5	15.3	15.1	16.3
Currents	1	**Uc[4] (m/s)**	0.84	0.76	0.64	0.68	0.76	0.84	0.81
	10	**Uc[4] (m/s)**	1.04	0.95	0.80	0.85	0.95	1.04	1.00
	100	**Uc[4] (m/s)**	1.24	1.12	0.95	1.00	1.12	1.24	1.19

Notes:
1. Kilometre point from shoreline noted *KP*
2. Maximum wave height noted *Hmax*
3. Associated Peak Period noted *Tp*
4. Estimated bottom current (non-wave component) noted *Uc*

A summary of the 1, 10 and 100-year return preliminary environmental design criteria for the Deep Panuke MOPU and flowlines/umbilicals is listed in Table 4.2. These criteria will be refined in the course of detailed engineering design.

Table 4.2 Preliminary Environmental Design Data - Deep Panuke MOPU and Flowlines/Umbilicals

Parameter	1 year	10 year	100 year
Winds			
1 hour wind speed at 10m MSL[1] (m/s)	27.1	35.8	41.6
3 second gust at 10m MSL (m/s)	36.3	48.0	55.7
Waves			
Significant wave height (H_s) (m)	8.8	10.8	12.7
Maximum wave height (H_{max}) (m)	16.3	20.0	23.7
Peak period associated with H_s (sec)	12.2	14.3	16.3
Currents			
Surface (m/s)	1.47	1.84	2.19
Mid-depth (m/s)	1.24	1.54	1.82
Bottom (m/s)	0.81	1.00	1.19
Water Levels			
MOPU Design water depth (m LAT[3])			44
Maximum astronomical tide (m)	1.6	1.6	1.6
Storm surge above MSL (m)	0.3	0.5	0.7
Tsunami water level above MSL[2] (m)			0.5
Air and Water Temperatures			
Minimum air temperature (^{0}C)	-13.7	-16.8	-20.0
Maximum air Temperature (^{0}C)	23.3	26.4	29.4
Minimum sea surface temperature (^{0}C)			-1.1
Maximum sea surface temperature (^{0}C)			24.6
CSA Toughness (^{0}C)	-13.7		
Marine Biofouling			
+2m LAT to –25m LAT (mm)			125
-25m LAT to mud line (mm)			60

Notes: [1] MSL refers to Mean Sea Level
[2] It should be noted that the likelihood of a tsunami is low and thus its effect is not included in the calculation of extreme water level.
[3] LAT refers to Lowest Astronomical Tide

4.3.1 Operating Limits

Initial operating limits for offshore equipment were developed and verified during the Cohasset Project. These limits will be reviewed and adapted for the Deep Panuke Project in conjunction with the MOPU contractor during detailed design.

4.3.2 Marine Growth

Marine growth criteria (100-year) have been developed for the Project. The criteria identified for the Project build upon earlier Cohasset Project studies and take into account data accumulated at site between

1993 and 2000. The compressed thickness criteria for marine growth for the MOPU legs is 125 mm (from +2m LAT to –25m LAT) and 60 mm (from –25m LAT to the mud line).

EnCana will monitor biofouling of the MOPU legs during annual underwater ROV inspection surveys. Marine growth will be removed using the ROV by scraping or hydrojetting if the equivalent marine growth thickness exceeds the design threshold. Typically, a natural reduction of biofouling levels is observed during winter months.

4.4 Geotechnical Criteria

4.4.1 Preliminary Geotechnical Data – Deep Panuke Site

EnCana has obtained geotechnical data for the Deep Panuke site from the Cohasset Project, the Deep Panuke Project, and for each of the Panuke delineation wells that have been drilled. Table 4.3 gives a typical description of the soil stratum per depth drilled.

Table 4.3 Preliminary Soil Profile for Deep Panuke Site

Stratum	Description (Depth in m)	Core Resistance (Mpa)	Density (kN/m^3)	Water Content (%)	Relative Density (%)	Undrained Shear Strength (kPa)	Friction Angle (deg.)	Effective Cohesion (kPa)	Over consol. ratio
I	Dense to very dense Fine to medium SAND (19.5)	30	20.0	22	70-100	-	45-41	-	>10 (>4)
II	Very stiff CLAY (24.1)	3	20.0	25	-	200	24	20	(4.0)
III	Dense SAND with gravel (27.0)	25-70	21.0	15	85-100	0	40-42	-	(3.8)
IV	Hard CLAY (29.5)	6	21.0	15	-	340	24	30	(3.8)
V	Very dense fine SAND (32.3)	70	20.0	21	95-100	-	41	-	(3.7)

This geotechnical data will be used for the initial design of the MOPU, as well as the subsea flowlines and associated umbilicals/wellhead protection structures. Additional geotechnical surveys will be performed to obtain more site specific geotechnical design data as required by the MOPU contractor.

4.4.2 Geotechnical and Geophysical Survey – Export Pipeline

4.4.2.1 M&NP Option

The export pipeline will transport market-ready gas from the process facilities on the MOPU to the onshore connection with the existing M&NP main transmission pipeline near Goldboro, Nova Scotia. The total length of the offshore pipeline is approximately 173 km and the onshore pipeline is approximately 3 km.

Geophysical and geotechnical surveys of the proposed pipeline corridor were conducted in September and October 2001 and in May 2002. The pipeline corridor surveys were comprised of three elements: (1) a shore-based topographic survey of the landing site; (2) a nearshore geophysical survey near Goldboro; and (3) an offshore geophysical survey near Goldboro to the Deep Panuke site.

The initial route surveyed between September and October 2001 followed a base case defined centreline with additional data on four to six wing lines offset at 150 m intervals from the centreline. In May 2002, additional survey work was conducted to define potential optional routes, which were identified in several areas from the earlier phase of the study.

Table 4.4 provides a summary of the geophysical data acquired along the export pipeline route to shore. The kilometre point (KP) range refers to the distance in kilometers along the pipeline route from the landing site in Goldboro at KP-0. The data provided documentation of the sediment types, rock formations and seabed geology along the pipeline route.

Table 4.4 Summary of Geophysical Data		
KP Range (km)	**Geophysical Zone**	**Description**
0.0 – 0.9	Shore Approach near Goldboro	Surficial sediments predominantly gravels and boulders with minor sands and silts.
0.9 – 9.4	Country Harbour Basin	Silty sand and silts coarsening to sands toward harbour entrance.
9.4 – 12.0	Country Harbour Sill	Bedrock with a mantle of glacial till, surficial sediments and gravels.
12.0 – 34.4	Inner Shelf Outcrop	Numerous linear outcrops of Meguma Group sedimentary bedrock, surrounded by stratified glaciomarine sands and silts overlying glacial till. SOEP pipeline transits an ancient riverbed system.
34.4 – 43.0	Inner Shelf Platform	Thick glacial and glaciomarine sediments. Seabed consisting of gravels, cobbles and boulders with some silty sands. Relict ice scours are present.
43.0 – 49.9	Inner Shelf Basin	Broad depression host to stratified silts, sands and silty clays. Seabed consisting of sandy silt and silty sands.
49.9 – 57.4	Country Harbour Moraine	Part of Scotian Shelf End Moraine complex with a thick till ridge. Seabed consisting of gravel, cobbles and boulders.
57.4 – 92.4	Middle Shelf Proglacial Deposits	Surficial sediments are sands, silts and gravels with occasional boulders overlying soft to stiff sandy clay. Relict ice scours present.
92.4 – 102.4	Bank Margin Deposits	Slope deposits of coarse sand and interbedded sand and clay. Till lobes and ridges are present with surficial sands, gravel, cobbles and boulders. Slopes of 12° are present on the margins.
102.4 – 132.4	Outer Shelf Sand Sheet	Continuous thin sand deposit with superimposed megaripples and sand waves that overlay cross-stratified, potentially gravelly sands.
132.4 – 139.4	Coarse Grained Outer Shelf Deposits	Medium to coarse grained sands with localized cobbles and boulders near KP 132 (KP 131). Sand ridges and waves are present with coarser sand and gravels exposed in the trough.
139.4 – 154.4	Low Relief Sand Ridges	Gravelly sand with crest heights less than1m aligned in a predominant east–west direction.
154.4 – MOPU	High Relief Sand Ridges	Fine to medium grained sand with coarser sand (perhaps gravel) exposed in the trough.

Table 4.5 summarizes the seabed sediments and physical properties found at various locations along the export pipeline route to shore. These findings will be applied to the engineering design in the evaluation of trenching methods, assessment of potential pipeline spanning, and in the detailed selection of route options.

Table 4.5 Surficial Seabed Characteristics			
Section Number [1]	**Section KP Range (km)**	**Subsection KP Range (km)**	**Description**
NA [2]	NA [2]	0 – 0.3	Gravel-boulder lag with thin discontinuous sandy silt veneer overlying glacial till. Boulders are observed from the shoreline to KP 0.3.
		0.3 – 0.5	Veneer of sandy silt overlying glacial till
		0.5 – 0.7	Sand and gravel overlying glacial till
		0.7 – 0.9	Silty sand with gravels, cobbles and boulders
		0.9 – 1.65	Thin layer of silty sand on clayey silt overlaying glacial till
		1.65 – 3.0	Very soft to soft organic silt
I	3 – 30	3 – 10	Loose silty sand overlying very soft organic silt
		10 – 15	Extensive bedrock outcrops with surficial soil of thin sand or clean gravel with cobbles.
		15 – 30	Loose silty sand overlying very soft organic silt. Numerous cobbles and boulders with a thin veneer of sand. Bedrock outcrop observed at KP 18, 20, 21 23 and 28, however, the degree of bedrock continuity is not known due to point source data sampling.
II	30 – 50	–	Loose to compact silty sand to sandy silt with organics overlying very soft lean clay with occasional gravel and organic streaks. Interbedded silty sand and clay overlying soft clay observed between KP 34 to KP 37. Dense silty sand observed at KP 49.
III	50 – 102	50 – 54	Thin veneer of compact to dense sand, with occasional clay pockets, overlying firm to stiff lean clay. Numerous boulders and cobbles were observed.
		54 – 96.2	Thin veneer of compact to dense sand, with occasional clay pockets, overlying firm to stiff lean clay.
		96.2 – 102	Channelised area containing interbedded sand and clay overlying soft clay. An adjacent ridge till between KP 98.4 and KP 100.4 was observed but not sampled.
IV	102 – MOPU	–	Compact to very dense poorly graded sand with gravel

Notes: 1. Section classification.
2. Nearshore geotechnical characterization based on site description, grab sample and sub-bottom profiler data.

In the subsequent survey in May 2002, three areas were evaluated for potential route alternatives that included:

- KP 0 to KP 5 – shore approach optimization including potential horizontal directional drill option;
- KP 22 to KP 28 – bedrock outcrop and potential crossing of the existing SOEP pipeline; and
- KP 135 to MOPU – platform approach optimization due to mega-ripples or sandwaves on seabed topography.

The additional data collected in these surveys has advanced design considerations in these areas. Presently, consideration is being given to horizontal directional drilling (HDD) of the nearshore pipeline to avoid trenching the first kilometre of the pipeline. A geotechnical investigation must be performed during detailed design to evaluate the soil conditions, which will help to determine the technical feasibility of the HDD option.

4.4.2.2 SOEP Subsea Option

The proposed offshore pipeline route for the SOEP Subsea Option extends 15 km taking a direct path from the MOPU to the existing SOEP gas pipeline. The export pipeline will transport both export gas and condensate commingled from the process facilities to the existing SOEP pipeline.

Geophysical and geotechnical surveys of the proposed pipeline corridor will likely be performed if this option is selected.

4.5 Production Installation and Topsides Facilities

The primary infrastructure for the Project is the central offshore processing facility, known as the MOPU. The MOPU will be located in a central location to accept production from the surrounding subsea producing wells. The final location of the MOPU or the "field centre" will be determined during detailed design; however, the present tentative location is positioned at coordinates of Northing 4853668 and Easting 685918 (ZONE 20 NAD 83).

The reservoir fluids are sour and contain formation water and condensate as well as natural gas. The MOPU will include all the required processing equipment for separation and processing to allow product to be shipped to market. Product will be shipped via one of two alternative pipeline arrangements; directly to shore (M&NP Option) or to a subsea hot tap to the existing SOEP pipeline (SOEP Subsea Option). The sales gas production capacity is 8.5×10^6 m^3/d [300 MMscfd], with a turn down to 1.1×10^6 m^3/d [40 MMscfd] to allow for reduced production as the field declines over time. The facility will not be designed for expansion of production capacity; however, it will have the capability to connect up to eight subsea production wells at one time.

The offshore processing required for both pipeline options is nearly identical; however, there are minor variances for each alternative. One of the key differences is that the SOEP Subsea Option allows for the condensate to be recovered and processed onshore by SOEP, whereas in the M&NP Option, the condensate will be used as the primary source of fuel. Process requirements are discussed in Section 4.7. Pipeline options are discussed in Section 4.9.

The MOPU will also provide all necessary utility systems to support the process and non-process functions as well as craneage, accommodations, helideck, and a central control room. The MOPU will allow for a minimum continuous POB complement of 68 persons to sustain year round production. The normal steady state POB complement is expected to be approximately 30 persons; however, it could also be larger should the design be a standard MODU accommodations design to allow for easier conversion back to MODU operations in the future.

The MOPU will likely comprise a newly built unit. The MOPU has the following two main components:

- a floating hull structure with jack-up legs, which provides a "dry" deck and ancillaries to support the processing equipment; and
- a topsides production facility which contains all the necessary production and processing equipment necessary to produce the field.

There is no drilling provision provided on the structure and all drilling will be done by MODUs. The MOPU will be built in two main sections (the hull and the topsides), integrated atshore, and then towed to field where it will self-install by jacking up on location. Final hook-up to the subsea production flowlines and the export pipeline will be done offshore before the reservoir is brought on stream.

The MOPU will be a leased facility, with a lease arrangement to accommodate the Deep Panuke Project. When the production at Deep Panuke is complete, it will be disconnected, jacked down, and demobilized. It could be refitted/reused at a new location for another project or refitted as a drilling unit.

The MOPU concept was selected because of the inherent flexibility to match the predicted production life, ease of decommissioning, and the economic advantages of leasing this type of structure. Other alternatives were studied and these are discussed in Section 4.11.

4.6 Subsea Systems

The Project's development wells will be subsea wells comprised of:

- four re-entry wells (H-08, M-79A, F-70 and D-41);
- one new drill production well (H-99);
- one new drill acid gas injection well (D-70); and
- up to three additional new wells if required.

The Project's subsea system will include all equipment from the wellhead to the connection of the flowlines at the riser on the MOPU, including the riser section. This will be comprised of the following components:

- horizontal production trees;
- protection structures;
- flowlines;
- umbilicals; and
- control systems.

4.6.1 Subsea Production Tree

Subsea well completions will be designed with two barriers against well flow under all conditions.

The standard wellhead system will likely be based on a 346 mm wellhead housing with a 69 MPa pressure rating. Horizontal trees are to be used and will likely be rated for approximately 45.0 MPa minimum. Metal-to-metal seals will likely be used for all seals with potential for exposure to well fluids.

The production trees, with connections for production and service lines, will be optimized for productivity and ease of access for downhole interventions. Production trees will be designed to allow chemical injection into the production stream both downstream of the upper master valve and below the tree in the wellbore. Hydraulically actuated subsea choke valves will be installed at each tree for flow control during start-up and shut down. Figure 4.2 provides an example of a mudline conversion subsea production tree.

4.6.2 Wellhead Protection Structure

The subsea wells will be protected by dedicated protection structures against dropped objects, dragging anchors, and fishing gear. The protection structure is to be designed to allow adequate access to the wells for all planned diver and ROV intervention tasks. These protection structures will be designed to be trawlable even though they will likely be located within the facilities safety zone.

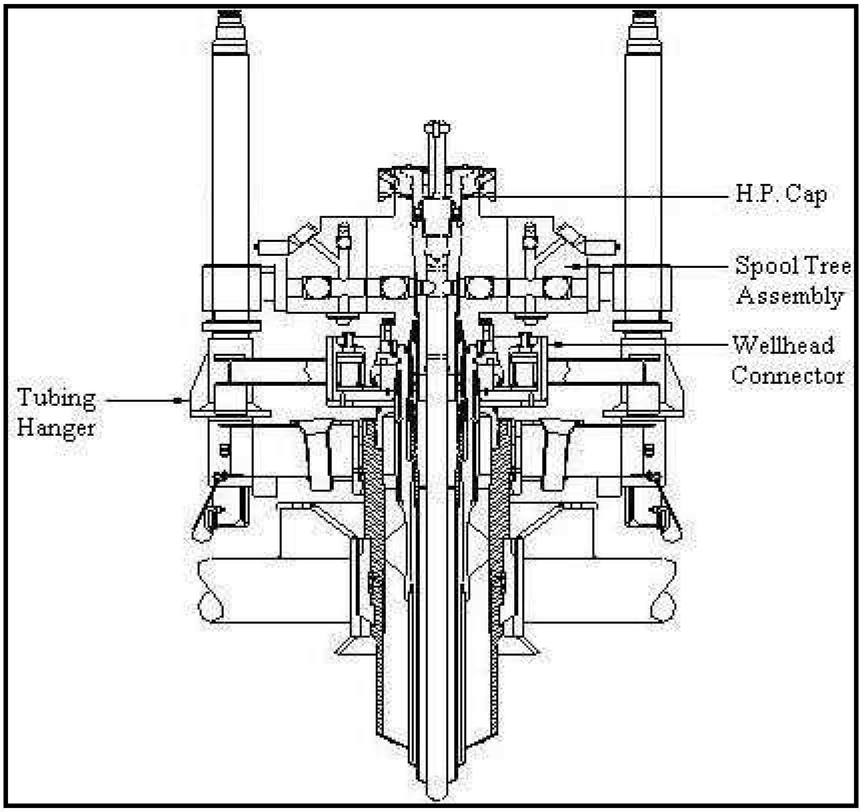


Figure 4.2 Spool Subsea Trees

4.6.3 Flowlines

Each production well will be tied back to the MOPU platform with its own dedicated infield subsea flowline. The initial production flowlines are expected to be 200 mm [8 inches] in diameter and range from 1 to 6 km in length. The acid gas injection flowline is expected to be 75 mm [3 inches] in diameter and approximately 1.7 km in length. Flowlines would be of either rigid steel or flexible construction and installed by either S-lay or reel-lay methods respectively. The rigid steel production flowlines will likely have a CRA inner liner material due to the corrosive nature of the production fluids and the rigid steel injection flowline will likely be carbon steel material.

The flowlines will be trenched their entire length. Final flowline lengths, diameters, construction, and material type will be confirmed during detailed design.

4.6.4 Umbilicals

Subsea umbilicals are required for each of the production wells and the acid gas injection well. Each well will have its own dedicated umbilical controlled from the MOPU; it will be laid beside the well flowline and will be trenched and buried along its entire length.

The structural integrity of the umbilical will be designed such that it can withstand the installation loads without tensile or crushing damage to the internal components. The umbilicals will be pulled through J-tubes located on the MOPU.

4.6.4.1 Production Well Umbilical

The services to be provided within the production well control/chemical injection umbilical will include the following:

- high pressure (HP) hydraulic conduit;
- low pressure (LP) hydraulic conduit;
- spare HP/LP hydraulic conduit;
- methanol injection;
- chemical injection;
- spare chemical injection;
- electrical power quad cable;
- communications power quad cable; and
- spare communication/power quad cable.

4.6.4.2 Injection Well Umbilical

The services to be provided within the injection well control umbilical will include the following:

- HP hydraulic conduit;
- LP hydraulic conduit;
- spare HP/LP hydraulic conduit;
- electrical power quad cable;
- communications power quad cable;
- spare communication/power quad cable; and
- chemical injection.

4.6.5 Subsea Control System

The control system for the subsea wells will be configured as a multiplexed, open loop type system with tree-mounted subsea control modules. The system will be capable of controlling, monitoring, and supplying chemicals to the subsea wells. The subsea well control system will comprise the tree mounted subsea control module (SCM) and the associated topsides equipment.

The subsea control system will provide redundant power, signal, HP hydraulic, and LP hydraulic supplies to the tree-mounted SCM. The hydraulic control fluid used will be a water-based biodegradable type since this fluid will be vented to the sea via the SCM during valve functioning. The SCM is to be designed so that it may be retrieved by ROV.

The subsea control system topsides equipment will include, but not be limited to, a subsea control unit, operator work station, hydraulic power unit, electrical power unit, and topsides umbilical termination unit.

4.7 Production Facilities

Production facilities on the MOPU will be designed and operated to optimize production while maintaining environmental protection and high safety standards. The production facilities will be staffed on a 24-hour basis. Facilities maintenance and inspection requirements will be managed through a maintenance management system that will incorporate proactive and predictive methods as well as intelligent condition monitoring techniques.

Production facilities will consist of equipment for separation, metering, amine sweetening, acid gas injection, dehydration, hydrocarbon dewpoint control (M&NP Option only), produced water treatment and disposal, condensate treatment, condensate injection (M&NP Option only), feed gas and export gas compression, and utilities. A simplified process flow diagram is presented in Figure 4.3.

For the M&NP Option, all production and treatment facilities are located offshore. For the SOEP Subsea Option, production and treatment facilities are primarily located offshore but the export gas and hydrocarbon liquids will be routed via the SOEP 660 mm [26 inch] pipeline to the existing SOEP facilities near Goldboro. The hydrocarbon liquids will be transported from Goldboro to the SOEP fractionation plant at Point Tupper via the dedicated SOEP 200 mm [8 inch] pipeline.

For the M&NP Option, the export gas will be "on specification" sales gas meeting the hydrocarbon dewpoint and water content requirements for the M&NP pipeline. As a result, there is no onshore treatment required. The sales gas will be routed to shore near Goldboro in a new 560 mm [22-inch] pipeline with a connection into the existing M&NP pipeline. Onshore facilities are related to metering/ quality measurement and isolation valve requirements only. The liquids will be treated offshore and used as fuel. Currently, it is estimated that there will be no surplus condensate produced beyond fuel usage; however, in the event that condensate must be injected because of maintenance and unexpected outages, it will be commingled with the acid gas and re-injected for disposal.

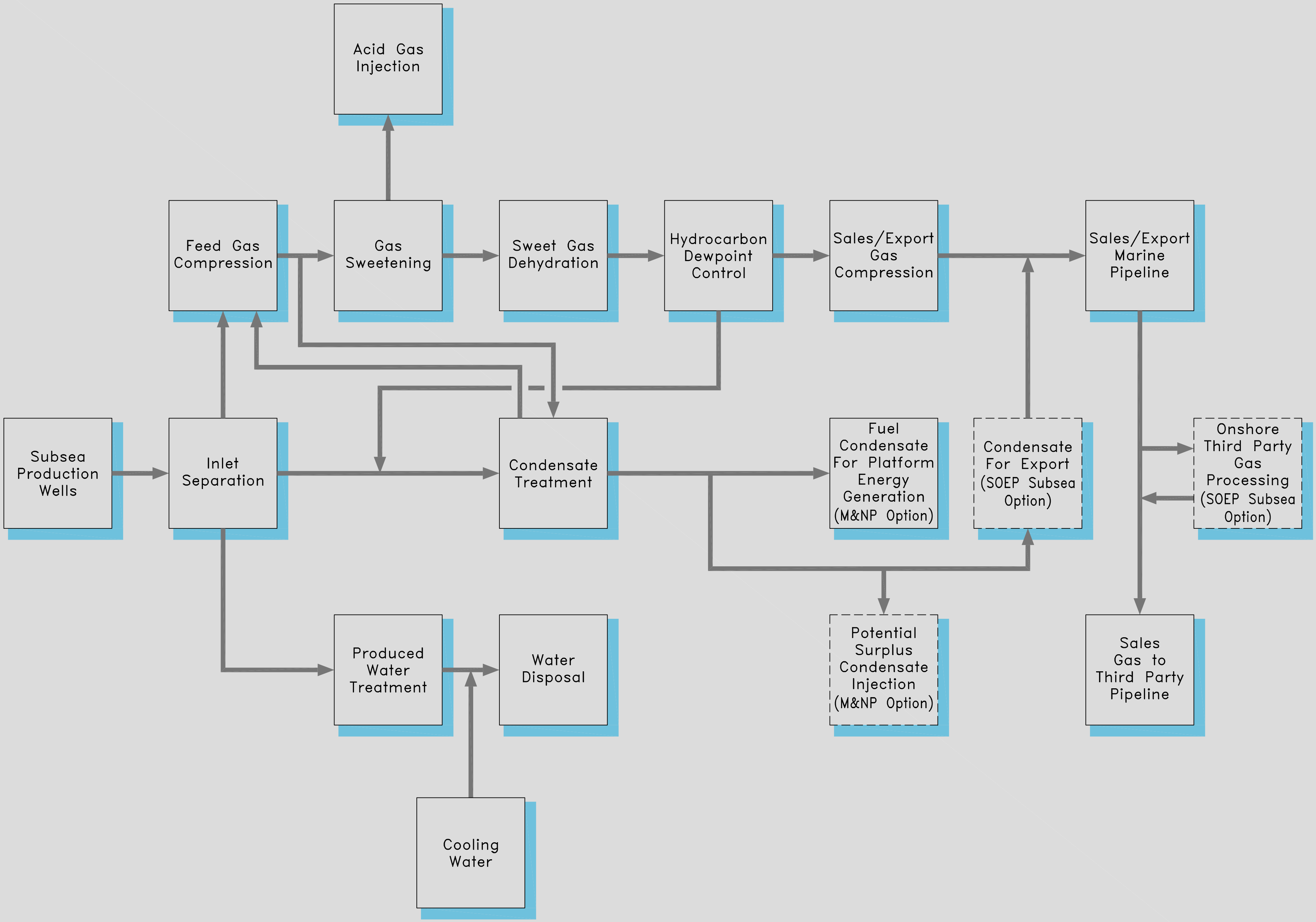


Figure 4.3 Simplified Process Flow Diagram

For the SOEP Subsea Option, the export gas and condensate will be commingled and routed, via the SOEP 660 mm [26-inch] pipeline and routed to the existing SOEP Goldboro gas plant. The gas and liquids will be separated and the gas further processed into sales gas by SOEP and shipped via the existing M&NP pipeline to market. The liquids will be routed to the SOEP Point Tupper liquids plant for processing and sale.

4.7.1 Separation

The well fluids will be processed through the production or test separator for separation of the gas, condensate, and water.

4.7.2 Metering

The Deep Panuke production facilities will adhere to the Canada-Newfoundland/Canada-Nova Scotia Offshore Petroleum Board (CNOPB/CNSOPB) *Measurement Guidelines in the Newfoundland and Labrador and Nova Scotia Offshore Areas,* October 2003.

The individual wells will have facilities to be routed to a test separator for metering of all three phases while the facility is in production. The fluids leaving the facility, namely, export/sales gas, flared gas, condensate, acid gas, and produced water, will be metered. The fluids consumed internally on the facility, namely gas and condensate for fuel, gas for continuous purging, and make up water to gas sweetening, will be metered. The buy-back gas from the export pipeline will be metered.

All metering will be designed, operated, and tested in accordance with the applicable regulations and/or guidelines. The records of such design, operation, and testing will be forwarded to the applicable authorities per the applicable regulations and/or guidelines.

A detailed study will be carried out during the design phase to ensure that all intended meters will adhere to the applicable regulations and/or guidelines and the study deliverables will be forwarded to the CNSOPB Chief Conservation Officer for approval of all systems.

4.7.3 Amine Sweetening

The amine sweetening system is designed to remove the H_2S and a portion of the CO_2 contained in the raw gas. The removal of the H_2S and CO_2 from raw gas results in a waste acid gas stream predominantly containing H_2S and CO_2. The H_2S content of the raw gas during the life of the Project will vary. The amine sweetening system is designed to operate safely over the expected variation of H_2S content in the raw gas.

The Deep Panuke gas contains approximately 1,800 ppm (0.18%) H_2S and up to 3.5 mole % CO_2. The amine sweetening unit is designed to be fed with gas that contains up to 2,500 ppm of H_2S and up to 3.5 mole % CO_2 to provide some operational design flexibility. The facility metallurgical design will be for 3,000 ppm of H_2S and 4.0 mole % CO_2 to provide some metallurgical design flexibility. The sales gas specification requires the H_2S content to be a maximum of 6 mg/m^3 (approximately 4 ppm) and 3.0 mole % CO_2. The current design basis unit outlet is for an H_2S level of 2 ppm and CO_2 at 2.8 mole %. Although the M&NP Option is the only option producing sales gas, the same production specification requirements will be met for the SOEP Subsea Option as the SOEP facilities require a sweet feedstock.

The amine-sweetening unit is based on physical absorption using a solvent to absorb the impurities (H_2S and CO_2). The solvent is then regenerated via heating to release the absorbed impurities. The process is cyclic, in which the amine is continuously circulated through the absorber/contactor to pick up the impurities, then routed to a regenerator to release the impurities.

The amine solvent used in the sweetening unit will be methyldiethanolamine (MDEA), which will improve the selectivity between H_2S and CO_2 absorption. The cyclic process can result in a build up of impurities in the amine solvent over time. If the amine solvent requires a change, whether complete or partial (dilute out the impurities), it is removed from the process and shipped to shore for reclaiming (manufacturer to clean and recycle). Production will be halted when a complete change-out of amine solvent is required. The change-out of the amine solvent will be subject to the Environmental Protection Plan (EPP).

4.7.4 Acid Gas Handling

Acid gas from the amine regenerator will be compressed to approximately 15,100 kPa using a multistage compressor. Water condensing between the compression stages is recycled back to the processing facilities. The compressed acid gas will be injected into the selected subsurface reservoir (see Section 2.5). Table 4.6 describes the design flow and composition for the acid gas injection system.

The Project does have the capability to flare acid gas. The capability to flare the acid gas stream is required to provide operational flexibility in times of maintenance and/or operational issues.

4.7.5 Dehydration

Sweet gas from the amine-sweetening unit contains water that must be removed prior to hydrocarbon dewpoint adjustment (M&NP Option) or prior to export (both options). The gas dehydration unit is a liquid desiccant process utilizing a solvent to absorb the water. The solvent, triethylene glycol (TEG), is then regenerated via heating to release the absorbed water. The process is cyclic in which the TEG is continuously circulated through the absorber/contactor to pick up the water then routed to a regenerator to release the water.

Spent TEG has no measurable H_2S and will be disposed at an approved facility.

Table 4.6 Acid Gas Injection System – Composition and Flow

Description	Design Data
Mass Flow (kg/h)	8100
STD Gas Flow (m^3/hr)	5325
Molar Flow (kgmole/hr)	230
Pressure (kPa)	150
Temperature (C)	56
Component Mole %	
CO_2	63.2
H_2S	18.5
CH_4	17.0
$C2^+$	1.1
H_2O	0.24
Note: The flow represents the total feed to the acid gas management system including acid gas from the amine system and H_2S removed from the condensate fuel for the Mean Production Profile.	

4.7.6 Hydrocarbon Dewpoint Control

For the M&NP Option, the dehydrated gas from the TEG system is cooled via the Joule-Thompson (JT) effect by dropping the pressure of the gas. A portion of the gas stream condenses (condensate), which is then separated. This step will be done offshore as it is necessary to satisfy pipeline gas specification requirements.

For the SOEP Subsea Option, the export gas routed to the SOEP 660 mm [26 inch] pipeline does not need to meet sales gas specification requirements. For these cases, hydrocarbon dewpoint control operations will be done via the Goldboro gas plant existing facilities.

4.7.7 Condensate Treatment for Fuel

Recovered condensate will be treated via stabilization to remove light ends and H_2S. The light ends and H_2S thus released will be recycled back to the raw gas stream for processing.

For the M&NP Option, condensate is used on the MOPU as the primary source of fuel. Operation of the condensate stabilizer will be such as to remove all H_2S in order to minimize air emissions and to produce a fuel meeting the turbine driver requirements. Given that the amount of condensate is a function of raw gas rate thus declining over the life of the Project, it will be supplemented with natural gas as necessary to maintain adequate fuel levels.

For the SOEP Subsea Option, all recovered condensate will be routed to the shore based SOEP facilities for separation, processing, and sale.

Condensate production is based on the production profile for the Project. The production profile has been calculated for a range of reservoir gas compositions. The intent is that the platform will be designed for the entire possible range. Over the range, the facility will produce less condensate than that required for fuel for the M&NP Option; thus it is expected that no surplus condensate will exist. Table 2.21 presents the condensate production profiles that have been generated in the risk model for the P90, P50, P10 and Mean cases (see Section 2.6.2.2).

The MOPU will have some minimal storage for condensate. This storage will be approximately 55 m^3 and represents approximately five hours of consumption at full rate. The intention of this storage is to cover periodic production upsets with enough time to allow for short term troubleshooting and/or swinging fuel from condensate to either fuel gas or diesel for load levelling to ensure maximum condensate usage. The storage tank will be a pressure vessel that is pressured with inert gas with excess pressure routed to the flare.

For the M&NP Option, it is estimated that there will be no surplus condensate produced beyond fuel usage; however, the ability to inject condensate down-hole with the acid gas stream provides operational flexibility in times of maintenance and/or operational issues. The probability of the acid gas injection well malfunctioning and becoming inoperable is very low. If possible, any maintenance work for the well would be scheduled during planned shutdowns. If the injection well becomes unavailable at any time, additional condensate can be consumed through the operation of "spare" fired turbine equipment.

There is no capability to flare the condensate stream on the MOPU.

4.7.8 Produced Water Treatment and Disposal

Water produced with raw gas and separated during the initial stages of processing is called produced water or formation water. This water contains residual hydrocarbons and other contaminants that must be removed to acceptable levels prior to ocean discharge.

The design basis for produced water composition is provided in Table 2.9 (see Section 2.2.7.1). Table 2.22 indicates the design basis for produced water production profile (see Section 2.6.2.2).

Treated produced water will be discharged overboard according to the *Offshore Waste Treatment Guidelines* (NEB *et al.* 2002). The following is a brief description of the treatment process.

Water from the inlet separator, test separator, condensate stabilizer surge drum, and stabilizer feed filter coalescers is commingled and routed directly into the produced water feed drum. Water from other LP vessels is typically routed to the closed drains header, which is routed to the LP flare drum. Liquids from the LP and HP flare drums are routed to either the inlet or test separators.

The function of the water feed drum is to hold produced water until sufficient volume is available to route to the hydrocyclones. The small amount of gas from this drum is routed to the acid gas injection compressor. At the start of the field life, the produced water rates are anticipated to be very low, such that batch processing in the hydrocyclones is likely. As the water rates increase, the flow will be continuous.

The hydrocyclones will remove all but trace amounts of liquid hydrocarbons. The hydrocyclones' oil outlet is routed to the closed drains. The water is continuously routed to cartridge-style produced water polishers to further reduce trace amounts of liquid hydrocarbons.

The water is then heated in the produced water stripper feed preheater prior to entering the produced water stripper. The amount of heat will be adjusted to aid in the H_2S removal capabilities of the stripper tower. The produced water stripper tower is a packed counter current gas/liquid stripping column in which sweet fuel gas flows upwards counter current to the water to remove H_2S. Preliminary indications suggest that H_2S will be lowered to a concentration between 1 to 2 ppm. The gas from the stripper is routed to the acid gas injection compressor. The flow to the stripper column will change dramatically over the field life. It may be necessary to provide flow via recycle or process in batches during low flow periods.

The water outlet of the stripper is then sampled for oil and H_2S and routed overboard. The waste gas from the produced water stripper will be routed to the acid gas injection compressor for injection. This will be the normal mode of operation. The plant does have the capability to divert the produced water stripper gas to the flare in the event of a malfunction of the acid gas injection well. If the produced water stripper gas were flared, it would be approximately a maximum of 980 kg/h of 19.7 MW gas containing 1.5 mole % H_2S.

Currently the design envisages platform-based laboratory facilities for verification of produced water measurements.

The produced water will be routed overboard via the discharge caisson where it will mix with approximately 2,400 m^3/hr of seawater, which is used for process cooling purposes.

4.7.9 Compression

For the M&NP Option, the sales gas will be compressed on the platform for delivery to shore. The expected sales gas discharge pressure on the platform is approximately 13,000 kPa. The Deep Panuke compressor system is comprised of three 7 MW units for a total of 21 MW of compression power. The compressors will be used for sales gas export and feed gas. The feed gas service will be to account for declining reservoir pressure. These compressors will be tri-fuel (condensate, fuel gas, and diesel).

For the SOEP Subsea Option, the export gas will be compressed on the platform for delivery to the existing SOEP 660 mm [26 inch] pipeline and subsequently routed to shore. The expected export gas discharge pressure on the platform is approximately 13,000 kPa. Like the M&NP Option, the Deep Panuke compressor system is comprised of three 7 MW units for a total of 21 MW of compression power. The compressors will be used for gas export and feed gas. The feed gas service will be to account for declining reservoir pressure. These compressors will be dual-fuel (fuel gas and diesel).

It is currently envisioned that the compressors will be piped in an arrangement that allows the compressors to be used in either feed or export service as the pressures and flow rates decline with time. Initially feed gas compression is not required until after Year 1. Thus the compressors will initially be set-up for export service. When a feed compressor is required, one compressor will be assigned to feed service. Late in the Project life as reservoir pressures and flow rates begin to decline, two compressors may be required for feed service. The final configuration will be confirmed during detailed design.

4.7.10 Utilities

4.7.10.1 Electrical Power Generation

Electrical power generation for the Deep Panuke MOPU will be provided by multiple redundant fuel turbine generating sets. For the M&NP Option, the turbines will be tri-fuel (condensate, fuel gas, and diesel). For the SOEP Subsea Option, the turbines will be dual-fuel (fuel gas and diesel). For the first production start-up, sufficient quantity of diesel will be available for power generation.

Emergency power will be provided by a diesel engine driven generator set as per CNSOPB regulations. The design requires the use of diesel fuel for emergency situations (emergency generator, firewater pumps), for certain start up scenarios (*i.e.*, when buy back gas is not available), and for certain maintenance scenarios (*i.e.*, power generators when no buy back gas is available).

The transfer of diesel from ships to the MOPU storage tanks will occur via loading hose. Bulk transfer/hose-handling procedures will be outlined in the EPP.

Battery back-up will be provided for critical emergency services.

4.7.10.2 Platform Fuel

For the M&NP Option, condensate will be used as fuel. Fuel gas will be used as supplemental fuel as condensate production declines. For the SOEP Subsea Option, fuel gas will be used as the primary fuel source.

Diesel will be used as fuel for the crane and the emergency generator. Diesel will also be used for start-up and shutdown of the compressor and power generation turbines. The MOPU will have a storage capacity of approximately 70 m^3 for diesel. The area around the diesel storage will be "bunded" or "dyked" to collect diesel fuel in the unlikely event of a leak/spill. The bunded area will be routed to the open drains system within which the hydrocarbon is recovered.

All fuel will be metered.

4.7.10.3 Heating Medium System

The processing facilities require heat input for a number of systems including amine regeneration, TEG regeneration, condensate stabilization, and produced water processing. The heating system is a "closed circuit" system in which a heating medium (essentially the same solution as per the cooling medium except it contains some stabilization additives) is pumped through waste heat recovery units (WHRUs). There are three WHRUs, one installed on each turbine exhaust of the compressors.

The heating medium, circulating through the WHRUs, extracts heat that would be destined as waste to ambient and routes it to various users.

4.7.10.4 Cooling Medium System

Cooling water for process and utility systems will be done via an indirect seawater/cooling medium system. Seawater will be pumped through a filter then a heat exchanger. The exchanger will cool a mixture of ethylene glycol and water (cooling medium). The cooling medium will then be distributed to the equipment and the plant requiring cooling. The once through seawater is returned to the ocean via the discharge caisson where it is mixed with produced water.

4.7.10.5 Deck Drainage

Deck drainage will be collected and treated according to the *Offshore Waste Treatment Guidelines* (NEB *et al.* 2002). Drainage from equipment areas will be directed through a header system to a collection tank to an oil/water separator treatment unit on the MOPU. Petroleum hydrocarbons and sludge in the oil/water separator will be transferred into containers for shipment to shore for disposal. The water from the oil/water separator will be treated using cartridge-style water polishers and tested prior to discharge to ensure compliance with the discharge criteria of 15 mg/L or less.

The deck drainage system does have overflows to permit water to be routed directly overboard in the event of a deluge event or rain water in excess of the design condition.

4.7.10.6 Relief and Blowdown System

Safety systems and devices will be designed to meet Project standards and the requirements of all applicable standards, codes, and regulations, including:

- API B31.3 – Piping,
- API 14C – Cause and Effects;
- API 520, 521 – PSV's/Rupture Discs;
- IEC 61508 – Functional Safety System;
- ANSI/ISA-84.01-1996 – Safety Instrumented Systems;
- NFPA 72E – Automatic Fire Detectors; and
- NORSOK-1-002 – Safety and Automation System.

The principal elements of the relief and blowdown system include the pressure relief devices, flare piping system, flare separator, and the flare structure. The flare design will take place during detailed design. Application of all relevant codes will be followed for the system design. The system will be designed considering emergency shutdowns, blocked discharges, fire exposure, tube rupture, control valve failure, thermal expansion and utility failures.

Scheduled activation of the relief and blowdown system will occur for planned tests and inspection or maintenance work. When the system is commissioned and activated, hydrocarbons will be safely directed to the flare system. The flare will be designed to prevent any impact on the helideck and the living quarters during worst-case weather scenarios.

4.7.10.7 Inert Gas System

The Project will include an inert gas system. Inert gas is necessary for commissioning and start-up exercises as well as ongoing operations. The main use of the inert gas is to maintain the sealing of the main compressors (from migration of hydrocarbons). The inert gas may also be used as a blanketing or purging gas to displace hydrocarbon vapours and reduce the risk of explosion and fire.

4.7.10.8 Instrument Air

Instrument air will be produced by electric driven air compressors and used in the instrumentation and controls system. The air will be dried.

4.7.10.9 Breathing Air

A breathing air system will be included in the design of the Project. Breathing air will be required for emergency purposes and for routine maintenance activities.

4.8 Operations

Operations personnel will be involved in all phases of the Deep Panuke Project, including the Development Phase. This execution strategy includes establishing a relationship with the MOPU contractor to cover the provision of services for both the ready for operations and long-term logistics and operations phases of the development. More specifically, these services would cover the following activities:

- operations input to design phase;
- establish operations organization;
- support onshore pre-commissioning;
- installation phase logistics management;
- offshore hook-up and commissioning;
- facilities start-up;
- long-term logistics management; and
- long-term production management, operation and maintenance.

While there is considerable overlap in the activities listed above, the MOPU contractor will develop a Project-specific team of experienced personnel to deliver each of these activities. In addition, the MOPU contractor will be responsible for providing the necessary equipment, facilities and services to fully support the operations group. All operations will be coordinated from a Halifax-based office.

Supply vessels and helicopters will be used to supply personnel, fuel, food, well construction equipment and other materials required to maintain production, construction, and well construction operations. Typically, helicopters will be used for regular crew changes, visits from regulatory agencies, service personnel and other visitors that need to be transported to and from the offshore facilities.

Supply vessels will be used to provide the platform operations with materials. Supply vessels will hold consumables and other equipment and materials necessary for production operations. It is anticipated that supply vessels will make periodic round trips from a dockside shorebase in Nova Scotia to the platform operation between two and four times a week during normal operations. It is anticipated that there will be approximately six trips a week during construction and heavy maintenance periods. In addition, a standby vessel is required near the platform at all times as per CNSOPB regulations. Supply vessels will also be used to support well construction operations.

Personnel will be transported to and from the offshore facilities via helicopters from the heliport located at the Halifax International Airport. During pipelay and heavy lift activities, the frequency of helicopter activity is estimated to be two to three trips per week. During hook-up and commissioning, the frequency is estimated to be seven to ten trips per week. The frequency will reduce to approximately six to ten flights per month during operations. These helicopters are used primarily to transport crew members, company personnel, and service personnel. In some cases, small equipment and parts are transported via air transportation.

For the onshore facility, periodic mechanical, electrical, instrumentation and general housekeeping maintenance will be performed. For example, valves, piping, or general lighting will require routine maintenance. Site visits will take place periodically.

4.9 Export Systems

4.9.1 Offshore Pipeline

EnCana proposes to transport sales product via a subsea pipeline from the offshore processing facility to one of two delivery points:

- Goldboro, Nova Scotia (M&NP Option) to an interconnection with M&NP; or
- SOEP 660 mm [26 inch] pipeline tie-in (SOEP Subsea Option) at a close point on the pipeline route.

The Deep Panuke export pipeline will have a sales gas capacity of 8.5 x 10^6 m^3/d [300 MMscfd] at mean environmental conditions. The proposed routes of the export pipeline will minimize its footprint by using existing pipeline corridors where practical. The pipeline details for both options are presented in Table 4.7.

Table 4.7 Export Pipeline			
	Pipeline diameter [mm (inch)]	**Pipeline length [km]**	**Pipeline phases**
M&NP Option	560 (22)	176 (including approximately 3 km onshore)	Single phase
SOEP Subsea Option	510 (20)	15	Multiphase

The subsea pipeline will be designed in accordance with the *Nova Scotia Offshore Petroleum Installations Regulations*. Steel pipe, coated with concrete to reduce buoyancy and improve on-bottom stability, will be installed on the bottom of the ocean by a pipelay vessel. Non-destructive testing will be carried out on the vessel.

It is anticipated that the pipeline will be buried in the zones where the water depth is less than 85 m for on-bottom stability reasons. For water depth greater than 85 m, the pipeline has sufficient on-bottom stability and thus will not be buried. This will also reduce span correction and reduce the potential for sediment scour to the pipeline. The pipeline will be designed to withstand impacts from conventional mobile fishing gear in accordance with the *Det Norske Veritas (DNV) Guideline No. 13, Interference Between Trawl Gear and Pipelines*, September, 1997.

The following criteria were used to determine the proposed pipeline route:

- Minimize the environmental effects, seabed disturbance, and effects to fisheries due to the installation and operation of the new pipeline;
- Minimize the pipeline route length where possible while still satisfying all other route criteria;
- Minimize the number of subsea pipeline and cable crossings. Where crossings are unavoidable, routing of the pipeline will, where possible, have a crossing angle of greater than 30°;
- Consider any known future pipelines;
- Consider concerns raised by the landowners and fishing interests;
- The pipeline route will be such that "normal" pipelay operations (pipelay vessel) are not precluded and appropriate minimum horizontal radius of curvature (to be defined during detailed design, dependent on the pipeline size and water depth) could be kept;
- Consider approaches near the MOPU field centre (which may be installed in advance of the pipeline installation) to ensure compliance with safety and layout requirements;
- The shore approach routing will be such to enable shore pull-in systems to be as simple as possible. Consideration will be given to the existing SOEP pipeline in the close confines of the harbour; and

- Within the limits of the lay corridor and SOEP pipeline proximity requirements, route selection will minimize potential pre-lay works (pre-sweeping, etc.) and post-lay rectification requirements for freespans.

The M&NP Option offshore pipeline route extends approximately 173 km and closely follows the existing SOEP pipeline. The offshore pipeline route starts at the landing site near Goldboro, approximately 50 m northwest of the existing SOEP pipeline, at KP0 (landfall point). The landfall technique is still under review and may be completed by either conventional landfall techniques or HDD from KP0 to KP1.1. The proposed route then extends southeast paralleling the SOEP pipeline, with a minimum separation from the SOEP pipeline of approximately 250 m from KP7.0 to KP23.7 to minimize the width of the corridor in the nearshore area. From KP 23.7 to KP28, the route narrows towards the existing SOEP pipeline to a minimum separation of 8 m as the pipeline passes through a narrow corridor of an ancient riverbed system.

Between approximately KP28 and KP133.5, the route follows along the eastern side of the SOEP pipeline paralleling the SOEP pipeline at a target nominal separation of 1000 m with a target minimum separation distance of 500 m.

At KP133.5, the pipeline diverts from following parallel to the SOEP line and is re-directed towards the Deep Panuke MOPU location until it reaches the MOPU at approximately KP173.

The onshore pipeline route starts at the landing site near Goldboro, approximately 50 m northwest of the existing SOEP pipeline, at KP0 (landfall point) and also represents the onshore station post, STN 0. This landing point is located within a 100m onshore pipeline corridor that has been established by the Municipality of The District of Guysborough. The pipeline corridor is located along the easterly and northerly boundary lines of the Goldboro Industrial Park from landfall to the M&NP facility. The pipeline corridor land is owned by the Municipality of the District of Guysborough. The onshore pipeline will be situated in this established 100m corridor in consultation with the Municipality of The District of Guysborough.

The proposed offshore pipeline route for the SOEP Subsea Option extends approximately 15 km from the MOPU to a close location on the existing SOEP 660 mm [26-inch] multiphase export pipeline.

The proposed offshore pipeline route is presented on Figure 4.4, 4.5 & 4.6. There will be an SSIV assembly located on the export pipeline within 150 m of the MOPU. This SSIV assembly consists of a check valve complete with a small diameter bypass containing an on/off actuated buy back gas valve. The buy back gas valve will be controlled via an umbilical from the MOPU.

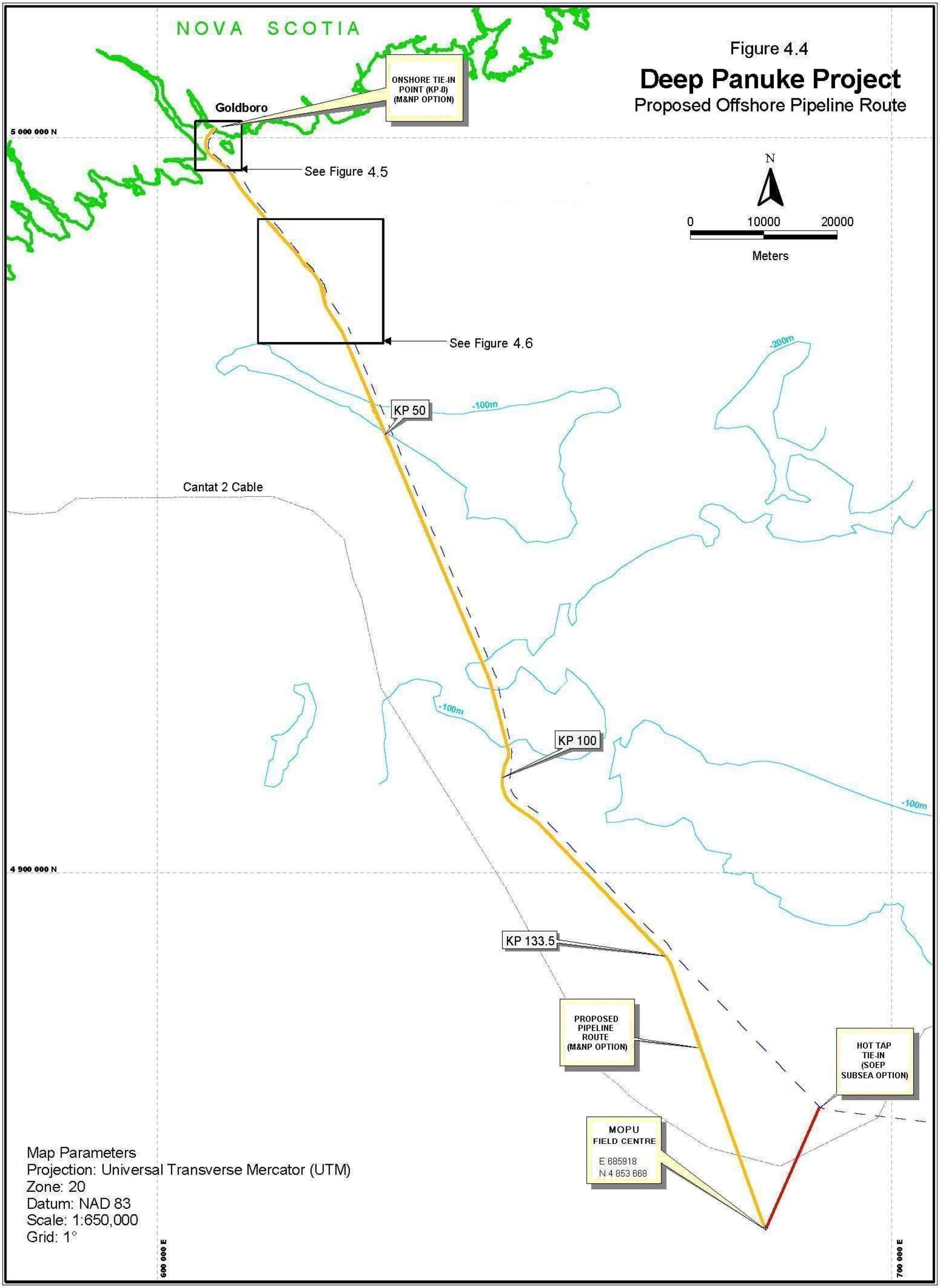


Figure 4.4
Deep Panuke Project
Proposed Offshore Pipeline Route
NOVA SCOTIA
Goldboro
ONSHORE TIE-IN POINT (KP-0) (M&NP OPTION)
5 000 000 N
See Figure 4.5
See Figure 4.6
N
0
10000
20000
Meters
-200m
-100m
KP 50
Cantat 2 Cable
-100m
KP 100
-100m
4 900 000 N
KP 133.5
PROPOSED PIPELINE ROUTE (M&NP OPTION)
HOT TAP TIE-IN (SOEP SUBSEA OPTION)
MOPU FIELD CENTRE
E 685918
N 4 853 668
Map Parameters
Projection: Universal Transverse Mercator (UTM)
Zone: 20
Datum: NAD 83
Scale: 1:650,000
Grid: 1°
600 000 E
700 000 E

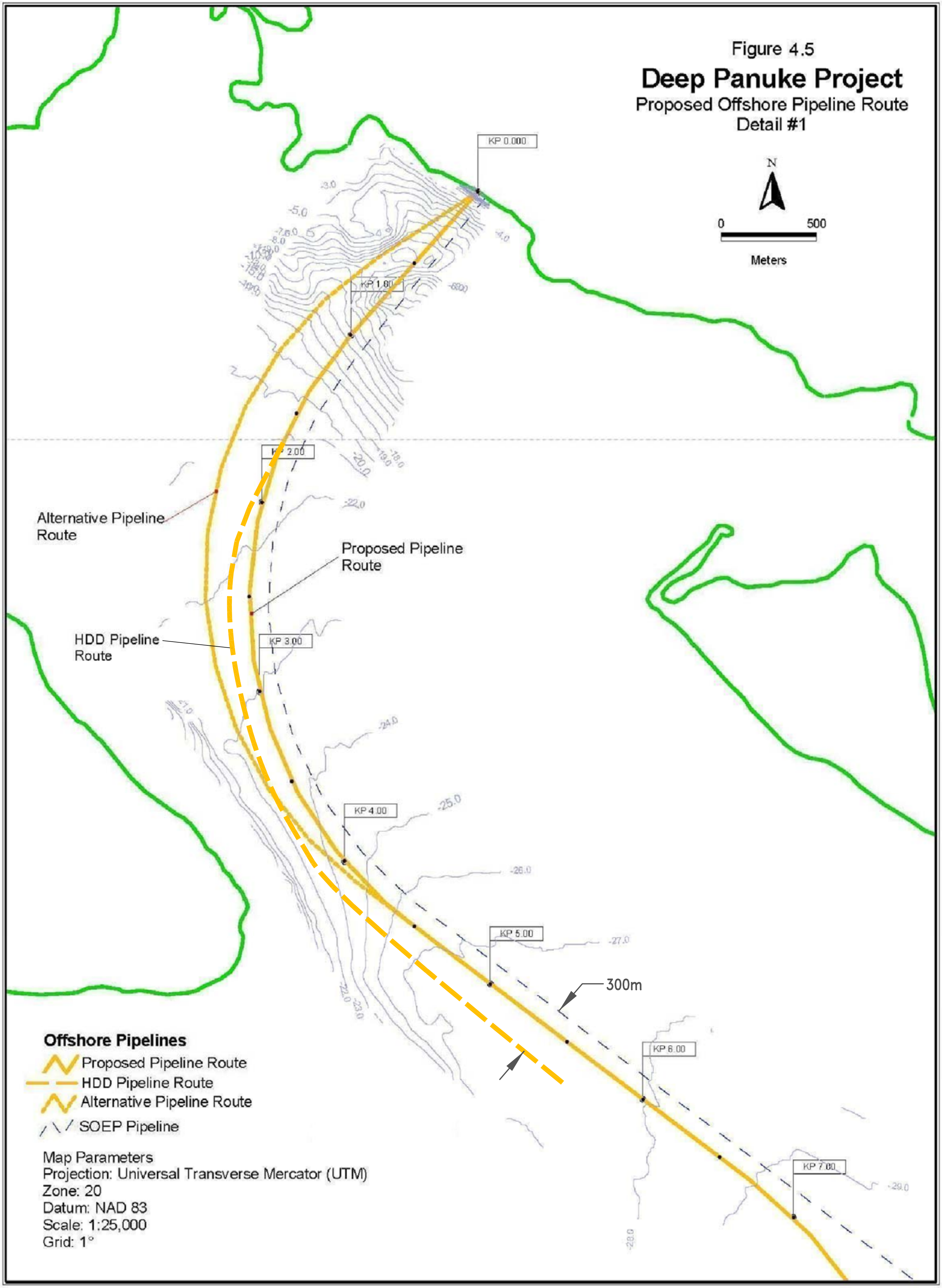


Figure 4.5
Deep Panuke Project
Proposed Offshore Pipeline Route
Detail #1
N
0
500
Meters
KP 0.000
KP 1.00
KP 2.00
KP 3.00
KP 4.00
KP 5.00
KP 6.00
KP 7.00
Alternative Pipeline Route
Proposed Pipeline Route
HDD Pipeline Route
300m
-5.0
-22.0
-24.0
-25.0
-26.0
-27.0
-29.0
Offshore Pipelines
Proposed Pipeline Route
HDD Pipeline Route
Alternative Pipeline Route
SOEP Pipeline
Map Parameters
Projection: Universal Transverse Mercator (UTM)
Zone: 20
Datum: NAD 83
Scale: 1:25,000
Grid: 1°

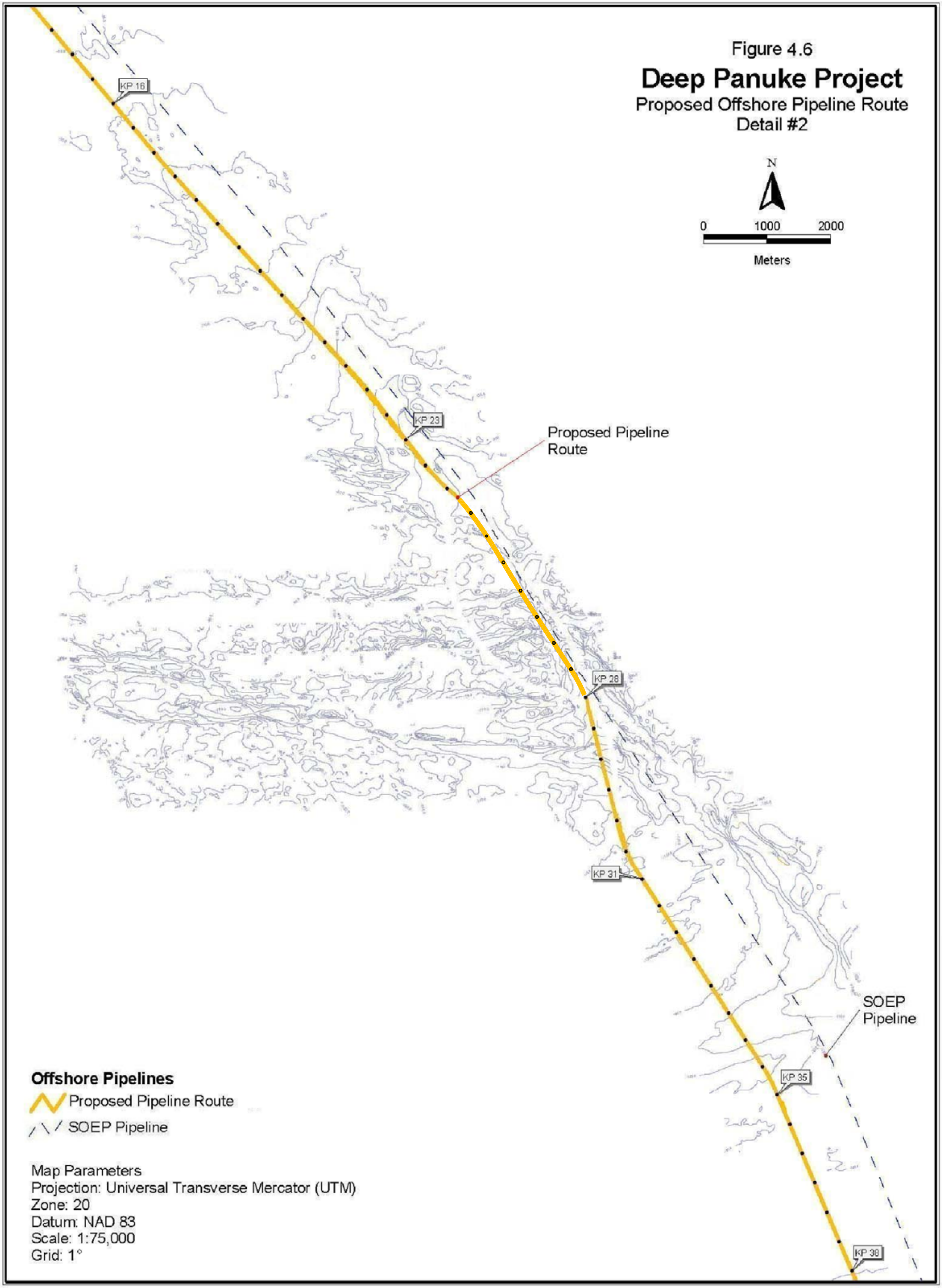


Figure 4.6
Deep Panuke Project
Proposed Offshore Pipeline Route
Detail #2
N
0
1000
2000
Meters
KP 16
KP 23
KP 28
KP 31
KP 35
KP 38
Proposed Pipeline Route
SOEP Pipeline
Offshore Pipelines
Proposed Pipeline Route
SOEP Pipeline
Map Parameters
Projection: Universal Transverse Mercator (UTM)
Zone: 20
Datum: NAD 83
Scale: 1:75,000
Grid: 1°

4.9.2 Onshore Pipeline and Facilities

Onshore facilities are required for the M&NP Option only. In this option, EnCana's onshore facility will consist of a pipeline and the physical components necessary for interconnection of EnCana's pipeline with M&NP's facility. EnCana's pipeline will tie into the M&NP transmission main at Goldboro, Nova Scotia, downstream of the SOEP gas processing plant. The onshore pipeline will be located within the pipeline corridor in the Goldboro Industrial Park, as indicated on Figure 4.7. The onshore portion of the pipeline will be approximately 2 to 4 km in length depending upon the final routing selected.

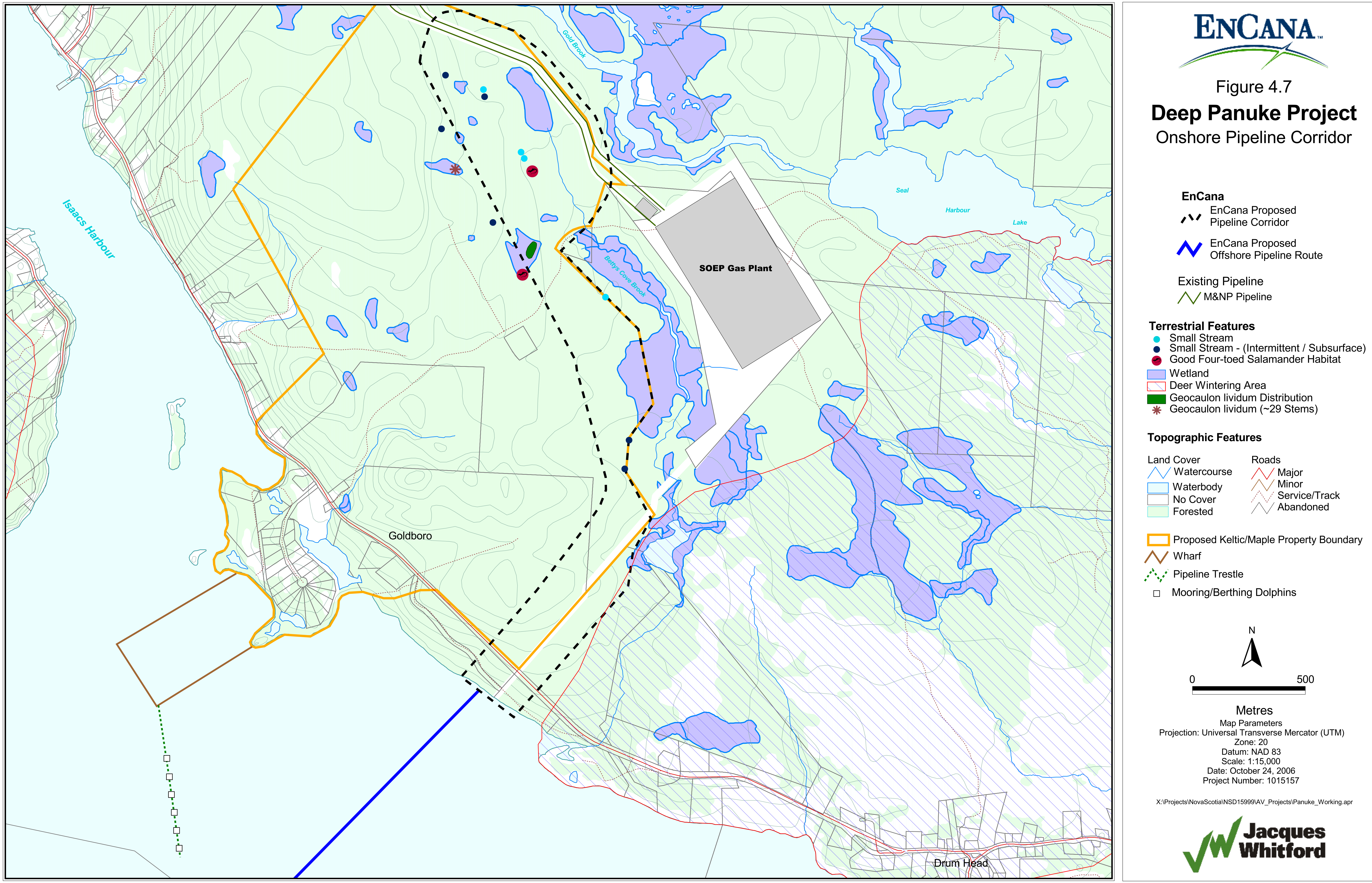
The onshore facility will include a pig launcher/receiver facility and a safety/emergency shutdown valve system. The onshore facility will interface with the M&NP owned facility which will include custody transfer meters, the final section of pipeline, and tie-in to the existing 760 mm [30 inch] M&NP pipeline. Additionally, the area of the facility is estimated to be 60 m x 45 m and will be enclosed by a security fence. A new access road to the metering station may be required. Figure 4.8 is a schematic of the onshore facility that would be required for the Deep Panuke Project.

For the SOEP Subsea Option, no new onshore facility will initially be required since the export gas and condensate will be processed by the existing SOEP onshore gas plant (Goldboro) and liquid facilities (Point Tupper).

4.10 Provisions for Decommissioning and Abandonment

The mean production life of the Project is anticipated to be approximately 13 years; however, the resource forecasts show a probable production life ranging from 8 years to 17.5 years. The actual field life will be predicted with greater certainty after production commences. The topsides will be designed for a life of 20 years and structures will be designed for a life of 25 years. The following facilities will be utilized during the life of the Project and will eventually require decommissioning and abandonment:

- the MOPU;
- subsea production and injection wells;
- the subsea facilities;
- the offshore gas export pipeline;
- the onshore gas pipeline (M&NP Option only); and
- the onshore facility (M&NP Option only).


EnCana
Figure 4.7
Deep Panuke Project
Onshore Pipeline Corridor
EnCana
EnCana Proposed Pipeline Corridor
EnCana Proposed Offshore Pipeline Route
Existing Pipeline
M&NP Pipeline
Terrestrial Features
Small Stream
Small Stream - (Intermittent / Subsurface)
Good Four-toed Salamander Habitat
Wetland
Deer Wintering Area
Geocaulon lividum Distribution
Geocaulon lividum (~29 Stems)
Topographic Features
Land Cover
Watercourse
Waterbody
No Cover
Forested
Roads
Major
Minor
Service/Track
Abandoned
Proposed Keltic/Maple Property Boundary
Wharf
Pipeline Trestle
Mooring/Berthing Dolphins
N
0
500
Metres
Map Parameters
Projection: Universal Transverse Mercator (UTM)
Zone: 20
Datum: NAD 83
Scale: 1:15,000
Date: October 24, 2006
Project Number: 1015157
X:\Projects\NovaScotia\NSD15999\AV_Projects\Panuke_Working.apr
Jacques Whitford
Isaacs Harbour
Gold Brook
Seal
Harbour
Lake
SOEP Gas Plant
Bettys Cove Brook
Goldboro
Drum Head

The decommissioning and abandonment of these facilities will be performed in accordance with the regulatory requirements applicable at the time such activities are undertaken. Potential changes in technology, regulations, and accepted industry practices over the time between initial construction and decommissioning make it difficult to commit to a specific course of action at this time. At the time of decommissioning, an action plan will be submitted to the regulatory authorities for approval prior to commencement of decommissioning and abandonment activities. Based on current regulatory requirements, a typical action plan is included below.

The requirement for eventual removal of facilities will be taken into account during detailed design. Decommissioning of the MOPU will essentially be a reverse of the installation process. The processing equipment will be systematically shutdown, flushed, and cleaned. The MOPU will then be disconnected from the subsea infrastructure, jacked down, and removed from the site. It is expected that the MOPU will be reused following decommissioning but this will be evaluated on an economic basis at the time of decommissioning.

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

Subsea equipment, such as wellhead trees and manifolds, will be purged, rendered safe, and recovered. Trenched flowlines and umbilicals will be flushed and left *in situ* below the seafloor. All other subsea facilities above the seafloor, including protection structures, will be purged and decommissioned in accordance with applicable regulations at the time.

The offshore export pipeline will be abandoned "in place" after it is flushed and filled with seawater.

With the exception of the pipeline, the onshore facility will be removed and utilized land restored in accordance with applicable regulations. Buried onshore pipeline will be flushed, capped, and abandoned in place. The onshore pipeline RoW will be re-vegetated and allowed to return to a natural state. Any above ground structures associated with the onshore pipeline will be removed.

A decommissioning plan will be developed for the Project, which will provide detailed procedures for decommissioning the onshore facility.

4.11 Assessment of Development Alternatives

4.11.1 Introduction

The development of the Deep Panuke Project has been studied since the initial discovery was made in 1998. A front end engineering design (FEED) study and other supporting studies were conducted between 1999 and 2002 leading to the filing of a DPA in March 2002. The DPA was withdrawn in 2003 pending further assessment of the reservoir and a further review of the facilities concept.

Since the withdrawal of the DPA in 2002, EnCana has investigated options and alternatives that are more economically feasible based on resource estimates which are lower than those predicted in 2002. The Project, as conceived at present, shares many similarities with the original Project concept; however, some aspects have changed.

This section describes the Project as originally conceived in 2002 and discusses the alternatives that were studied leading to the final concept selection.

4.11.2 The 2002 Deep Panuke Project

The 2002 Project basis was designed to produce a sour gas reservoir via an offshore processing concept and transport sales quality gas to market via a 610 mm [24 inch], 176 km pipeline with an onshore tie-in to the M&NP pipeline near Goldboro, NS. The producing reservoir was located in a relatively small area enabling production to be sourced from a cluster of directionally-drilled wells from a central wellhead platform. Offshore processing was to be performed on a second bridge-linked production platform. The production platform contained the main process-related utility systems. The main elements that formed the process were:

- H_2S removal;
- condensate recovery and processing as the primary source for fuel on the platform;
- gas dehydration;
- gas dewpointing;
- produced water treatment and disposal; and
- extraction and disposal of acid gas and surplus condensate.

The process plant also required inlet and export compression to maximize resource recovery and to transport sales gas through the offshore pipeline to market. The production platform was bridge-linked to a third platform which housed the central control room, non-hazardous utilities, and accommodations for offshore workers.

The 2002 Project basis was designed to process 11.3 x 10^6 m^3/d [400 MMscfd] at peak capacity with design allowances to allow peak production year round. This overall concept required significant infrastructure with a total topsides weight of approximately 13,000 tonnes to accommodate all the required facilities offshore. The topsides were to be built as three separate integrated decks and installed offshore by means of a semi-submersible crane vessel.

Key similarities in the design basis between the current Project basis and the 2002 Project basis are:

- fluid composition and properties;
- offshore gas processing;
- acid gas injection into a subsea reservoir;
- produced water treatment and ocean disposal; and
- condensate handling (for the M&NP Option only).

Compared to the 2002 Project, the current Project design basis has:

- larger reservoir area requiring subsea completions with tie-backs;
- reduced resource estimate;
- reduced peak production capacity;
- increased volume of produced water; and
- a MOPU, replacing the three fixed platforms.

4.11.3 Alternative Assessment Methodology

The following methodology was used to assess Project alternatives:

- review the alternatives and supporting work for the 2002 DPA, and determine which fundamental principles and decisions are still valid for the revised resources forecast and current concepts;
- consider concept alternatives for reduced peak production capacity (5.7 x 10^6 m^3/d and 8.5 x 10^6 m^3/d [200 MMscfd and 300 MMscfd]);
- consider a subsea tie-in to the SOEP pipeline as a product export option;
- consider platform and processing facilities which could be leased to reduce capital expenditures; and
- reassess safety/occupational health and environmental criteria in light of revised concepts.

The decision to proceed with the development basis described herein was based on evaluation of the following criteria:

- technical suitability (including operational factors, flexibility and ease of decommissioning);
- capital and operating costs, taking into consideration leased arrangements of some infrastructure;
- commercial risk;
- concept deliverability;
- safety; and
- environmental considerations.

If an alternative was deemed to be technically and economically unfeasible, further assessment of that alternative using other criteria was not considered.

As a precursor to the formal evaluation of various development alternatives against selected evaluation criteria, it is also worth noting that development alternatives which will not allow EnCana to take advantage of the infrastructure installed by M&NP were not evaluated due to economic reasons. Examples of development options which fell outside the Project's central development concept (and hence were determined not to be economically feasible) are alternatives involving landfall sites other than Goldboro, and the use of technologies requiring substantial new infrastructure such as liquefied natural gas (LNG) or compressed natural gas (CNG) technologies. The following development alternatives were evaluated:

- substructure type;
- topsides type;
- total number of platforms;
- re-use of existing platform;
- processing location;
- acid gas handling;
- produced water disposal;
- condensate handling;
- production capacity alternatives;
- field centre structure type;
- export pipeline alternatives;
- subsea tie-back alternatives; and
- acid gas injection location.

For the 2002 Project basis, consideration was given to using, in addition to WBM, oil-based muds due to the drilling conditions associated with directionally drilled wells. However, based on the experience gained while drilling the Deep Panuke delineation wells, it was determined that only WBM will be used for any new development drilling activities. Therefore, the disposal options for oil-based mud drilling cuttings described in the approved 2002 Comprehensive Study Report (CSR) are no longer applicable to the Deep Panuke Project.

4.11.3.1 Substructure Type

The environmental conditions at the field centre location are considered harsh, by offshore standards, but are well within the criteria which fit many world-wide accepted design solutions for substructures. Several types of substructures were investigated and were classed into three groups; 1) floating structures, 2) permanent bottom founded structures, and 3) mobile structures. Each option was evaluated against the evaluation criteria summarized in Table 4.8 and these are discussed in the following sections.

Floating Structures

The floating type structure evaluated was the semi-submersible type which requires a fixed mooring system with fluids being conveyed on and off the structure through a series of subsea flexible risers. This type of structure is not well suited for the relatively shallow water depth at the field centre location and has not been proven for use in harsh, shallow water applications. It would be technically challenging to provide a mooring and riser design that would meet the project environmental conditions. Also, there have been some unfavourable experiences in other projects using a semi-submersible as a gas production platform. Therefore, this concept was eliminated for technical reasons.

Bottom-Founded Structures

Two types of permanent bottom-founded structures were investigated: gravity-based and jacket structures. The gravity-based concept was deemed to be technically acceptable; however, it was rejected due to higher commercial risk imposed by limited suppliers in the world market.

Jacket-type structures piled into the sea floor are the most common solution world-wide for the environmental conditions experienced at the Project site. This concept is currently in use in Nova Scotia by SOEP. The concept has the advantage of offering the lowest cost, technically acceptable solution with acceptable commercial risk. However, the disadvantage is that fixed structures have little to no residual value at the end of a project as they are unlikely to be reused on another project. Since this option does not fit with EnCana's financing objectives for the projected life of the Deep Panuke Project, it was rejected based on commercial considerations.

Mobile Structures

Two types of mobile structures were investigated; a jack-deck structure and a jack-up type structure. Each of these configurations can be used to construct a MOPU. The MOPU concept provides a facility that is designed to self-install, produce oil or gas at a given location and then demobilize for reuse at another location. This concept is in use world-wide for fields that have marginal reserves or are expected to have a short production life. Also, contractors may offer these types of structures on a lease basis; therefore, the capital cost can be amortized over more than one project.

Both the jack-deck and the jack-up concept are quite similar, each employing a three-legged structure supporting a production topsides. The MOPU is brought to the field centre where it self elevates by jacking up on location. Risers for production fluids and export pipeline are connected to the structure for conveying produced fluids on and off the structure. At the end of the field life, the risers are disconnected from the flowlines and pipeline, legs are retracted and the platform jacked down for removal from the field. The structure can potentially be relocated and reused at another field.

The main difference between the jack-deck and the jack-up structure is in the design of the deck. The jack-deck is a custom engineered lattice-type structure designed to house the specific production equipment needed for the specific application. Because it is a lattice-type structure, it cannot float and therefore is brought to and removed from location on a barge. The jack-up type structure incorporates a floating hull so it does not require a barge for transportation. The jack-up carries a purpose-built topsides to provide the necessary production equipment. The jack-up hull design concept is used extensively for mobile offshore drilling rigs.

The jack-deck concept was investigated and deemed to be technically feasible. However, it had some distinct disadvantages when compared to the jack-up concept. First, this concept requires a custom design where the topsides are fully integrated into the supporting leg structure. Further, the legs and foundations are custom engineered for the specific application. Thus, at the end of the Project life, the chance of reuse for this type of structure at another location is greatly reduced, thus affecting the residual value of the MOPU. The majority of the cost must be amortized over one project. Also, this structure type must be transported on an installation barge. The on-site installation using a barge scheme is much more weather-dependent than using a floating hull type installation and requires a calmer sea state. This could impact the project by adding cost and time for schedule impacts due to unfavorable weather. The cost of the jack-deck is also more expensive than other solutions and leasing options were not available. As a result of the economic disadvantages compared to the jack-up solution, this option was rejected.

Two approaches for executing the jack-up concept were investigated: 1) build a new jack up-hull to a 'harsh environment' drill rig specification to accommodate a new purpose-built topsides or 2) refit/modify an existing harsh environment MODU to accommodate a new purpose built topsides.

The jack-up structure was selected as the best option for the Project; the final concept of a new build or re-fitted jack-up structure will be confirmed during the MOPU bid competition.

4.11.3.2 Topsides Type

The type of topsides for the revised Deep Panuke Project has not yet been confirmed. It will be largely dependent on the hull design of the jack-up structure. This design will be conducted by the MOPU contractor, selected through a competitive bid process, who will engineer all elements of the MOPU, including the topsides.

4.11.3.3 Total Number of Platforms

Offshore installations are generally designed to be built as the largest components possible to maximize construction, hookup and commissioning activities onshore, which greatly reduces cost. Multiple structures are used when the size of the structure exceeds lifting capabilities for heavy lift vessels or there are other specific requirements that dictate the use of multiple platforms. As per the Project design basis for the approved 2002 CSR, the preferred development alternative for number of platforms was three separate platforms for wellheads, processing, and living quarters/utilities based on concept deliverability criteria, reduced drilling and installation flexibility, as well as safety.

For the revised Project, the size of the topsides required for the revised 8.5 x 10^6 m^3/d [300 MMscfd] production capacity is well within the weight and size limitations for placement on one jack-up type structure. However, EnCana had specific concerns regarding personnel safety offshore because of the presence of H_2S in the fluids stream. A twin-platform arrangement employing a production platform and separate bridge-linked accommodations and control room platform was investigated, but was found to increase capital cost significantly.

A single platform solution was investigated on a single jack-up type structure. Target levels of safety were identified that are consistent for offshore installations within the industry. All types of hazards for the installation were identified, including fire, explosion, ship collision, helicopter crashes, and sour gas leaks. The work concluded that the Project facilities could be safely placed on one platform offshore, provided additional special measures are put in place to protect workers against the effects of a potential sour gas leak. The special measures include a combination of infrastructure, such as portable breathing air apparatus, and work procedures for personnel offshore. Thus, the Project has selected a single-platform solution to support the topsides facilities.

Table 4.8 Centre Substructure Type Alternatives

Alternative	Technical Suitability	Cost/Lease	Commercial Risk	Technically and Economically Feasible	Concept Deliverability	Safety	Environmental Impact
New build jack up	Existing proven designs are available for the Deep Panuke site conditions	Capital cost slightly higher than jackets Lease available	Low	yes	best	no specific concerns	low/negligible similar to other alternatives
Refit existing jackup	Existing harsh environment drill rigs exist, although none presently identified as available.	Capital cost higher than new build jackup Lease not available	High cost & schedule overruns to be expected	yes	poor	existing rig may require significant upgrades to meet regulations	low/negligible similar to other alternatives
Jackdeck	Relatively new concept, no proven experience in these environmental conditions Technically acceptable , with risk	Capital cost higher than new build jack up	Medium (new design could lead to overruns, potentially single source supplier)	yes	risk involved	no specific concerns	low/negligible similar to other alternatives
Jacket	Proven for Deep Panuke site conditions	Lease option not available	Low	Technically feasible Not economically feasible			
Steel Semi-Submersible Hull	Technical concerns related to riser design and mooring, adjacent to other platforms and riser design Lack of experience in shallow/harsh conditions Only one semi in use for gas production (deeper water)	Slightly higher than jacket option	Greater than jacket	no			
Concrete GBS	Gravity based system (GBS) widely used – six examples in water this shallow Inshore topsides analysis avoids large crane requirement	most expensive	single source of supply could lead to high costs	no			

4.11.3.4 Re-Use of Existing Platform

In the approved 2002 CSR, re-use of the existing Panuke platform, which was installed as part of the Cohasset Project was examined and rejected as a Project option. In any event, the Panuke jacket was removed during the decommissioning of the Cohasset Project in 2005, and therefore, re-use of the Panuke platform is no longer a valid alternative that can be assessed.

4.11.3.5 Processing Location

Onshore versus offshore processing was reviewed to determine which alternative provided the best option for the evaluation criteria noted above. Onshore versus offshore processing was assessed in 2002 with the following cases considered:

- full offshore processing;
- onshore processing with minimal offshore processing to allow transportation only; and
- split onshore/offshore processing (intermediate case).

Between 2002 and 2006, the following additional alternative was considered:

- full onshore processing via a long subsea tieback.

The alternatives are summarized in Table 4.9 and are discussed below.

Full Offshore Processing

Full offshore processing involves gas sweetening, acid gas injection, TEG dehydration, gas dewpointing, gas compression, produced water treatment and disposal, and condensate treatment/usage for platform fuel offshore. Market-ready natural gas is shipped to shore in a subsea pipeline.

Onshore Processing with Minimal Offshore Facilities

Onshore processing with minimal offshore processing was based on minimally treating the gas such that the gas and the condensate could be transported, in a common pipeline, for processing onshore. Onshore processing involves some processing offshore including dehydrating the gas and separating the water from the condensate so that the pipeline may be operated free of water. The removal of water is necessary for corrosion control and hydrate prevention. The offshore facilities for the onshore processing alternative include separation, TEG dehydration, condensate treatment, produced water handling and a multiphase export pipeline for the combined gas and condensate streams. The associated onshore facilities include a slugcatcher, separation, gas sweetening, sulphur recovery, TEG dehydration, gas compression, gas dewpointing, condensate treatment, and sour water handling. Onshore processing is more expensive than the offshore processing due to the duplication of facilities at both the offshore and onshore locations including separation, TEG dehydration, condensate treatment, compression, and sour water handling. Due to economic reasons, the onshore processing case was rejected.

Full Onshore Processing with Long Subsea Tie-Back

Another alternative for providing full onshore processing would be to use a "long subsea tie-back". This alternative involves using only the reservoir pressure to push reservoir fluids to shore via a 176 km corrosion-resistant pipeline. An offshore subsea gathering system, with a subsea manifold, collects all the fluids produced from the subsea wells and transports them to shore via a multiphase pipeline. The onshore plant provides full processing of the reservoir fluids and contains all the process equipment similar to the offshore processing alternative plus a slugcatcher, sulphur recovery plant and sour water handling equipment.

Onshore processing creates additional safety and human health risk associated with handling sour gas onshore near populated areas. The probability of a large-scale accidental release of sour gas from a processing facility, albeit remote, is a serious concern. While the oil and gas industry has proven capable of handling sour gas in populated areas, EnCana submits that the most prudent approach is to minimize risk by locating sour gas facilities away from populated areas.

While proven and effective mitigation measures exist to address safety/occupational health and environmental concerns, EnCana's preferred approach for this Project is to deal with the sour gas at source to minimize overall risk. While population density in the onshore project area is low, there would nevertheless be some added risk to the public with an onshore compared to offshore acid gas handling site. In general, there are many more environmental receptors onshore, and acidic buffering capacity is far greater in the marine environment.

After carefully considering the concept, EnCana rejected the onshore processing with subsea tie-back option as not technically feasible. There is no precedent of tiebacks of this length anywhere world-wide to date. In addition, the lack of inlet compression offshore would impact the recovery of the resource and result in a larger unrecoverable portion of the resource when compared to an offshore solution. These technical issues and reduced resource recovery contributed to the rejection of the onshore processing with subsea tie-back option.

Split Onshore/Offshore Processing (Intermediate Case)

An intermediate case for onshore processing was also reviewed. The intermediate case requires dehydration and H_2S removal offshore, transportation to shore in a dedicated multiphase pipeline, and separation, dewpointing and condensate treatment occurring at the onshore facility. Under this scenario, condensate must also be treated offshore for H_2S removal since the pipeline and the onshore facility are designed for processing sweet gas . Treating condensate offshore requires the same facilities as full offshore processing plus, additional, duplicative facilities onshore. There is no technical or economic advantage in recombining the gas and condensate for multiphase transport since duplicate facilities for condensate separation and treatment would be required onshore. Accordingly, the intermediate case was rejected based on technical and economical considerations.

EnCana's proposed solution is offshore processing. The alternate pipeline case will dictate the final configuration - full offshore processing under the M&NP Option or partial processing under the SOEP Subsea Option.

In summary, offshore processing was selected as the preferred option based on the following:

- treating and disposing of sour gas as close to source as possible and thereby reducing risk to the local population and environment near Goldboro;
- offshore injection of acid gas minimizes safety and environmental risk due to the buffering capacity of the marine environment and the few receptors in the offshore project area;
- reduced risk related to subsea pipeline integrity with the removal of both water and H_2S prior to transport to shore; and
- capital and operating costs.

Table 4.9 Processing Location Alternatives

Alternative	Technical Suitability	Cost	Commercial Risk	Technically and Economically Feasible	Concept Deliverability	Safety	Environmental Impact
Full Offshore Processing	best technical solution (H_2S and condensate removal at source to produce natural gas)	Lower cost than onshore processing	No specific concerns	Yes	Equivalent	deals with H_2S at source thereby minimizing safety risk related to pipeline transport of gas to shore	Deals with H_2S at source, thereby eliminating risks to the onshore environment. Fewer sensitive environmental receptors and greater acid buffering capacity in the offshore marine environment
Onshore Processing (with minimal offshore processing for transportation)	higher risk than offshore processing associated with pipeline integrity	Higher cost than offshore processing	Risk to Project economics should pipeline corrode and be out of service for an extended period of time increased risk to project economics due to pipeline integrity concerns	Yes	Equivalent	transports H_2S from offshore to populated area (increased safety risks)	A greater number of sensitive environmental receptors and therefore potential impacts onshore with regard to H_2S emissions Increased corrosion risk associated with transmission of H_2S in a 176 km pipeline increases risk of gas release
Onshore Processing (Long subsea tieback)	technically not feasible						
Offshore/Onshore (Intermediate Case)	duplication of some facilities onshore and onshore	Highest – must duplicate elements of processing offshore and onshore	No specific concerns	No			
Offshore/Onshore using SOEP Subsea Tie-in	Technically feasible	Yet to be determined	Yet to be determined	Yes	Marginal increased risk when compared to full offshore	Same as offshore processing	Marginal increased advantage over full processing by reduction of benthic disturbance resulting from a shorter pipeline

4.11.3.6 Acid Gas Handling

Removal of H_2S from the inlet gas stream results in a concentrated waste stream to be handled offshore. The FEED study investigated four options for handling acid gas offshore including flaring, seawater scrubbing, offshore sulphur recovery, and acid gas injection. The alternative chosen for the Project is the acid gas injection technology. A summary of the investigation is included below and summarized in Table 4.10.

Flaring acid gas consists of directing the acid gas stream to a flare system for incineration and emission to the atmosphere. Flaring is a relatively low-cost option and is widely used for this type of acid gas. There are SO_2 emissions resulting from the incineration process, which, while permissible, can impact air quality. In this case, the amount of SO_2 released is within air quality guidelines. This alternative was not ruled out but was considered less preferable than acid gas injection, where economic and operable.

The seawater scrubbing option consists of an incinerator and a scrubber. The unit accepts acid gas from the incinerator that has converted the H_2S to SO_2. The SO_2 is subsequently removed by seawater absorption in a packed column. The acid gas leaving the incinerator flows up the column contacting the seawater counter currently. The spent seawater flows by gravity to a mixing device, where it is combined with other plant discharge water (cooling water, produced water, etc.) and returned to the ocean.

Seawater scrubbing technology has been used in some onshore facilities, such as power plants, but there has very limited experience in offshore applications. Two offshore applications were identified, and both installations do not have established performance records. Further, an environmental review of this technology performed in 2002 identified that the discharge stream would likely be considered to be deleterious to marine life. Further recent investigation has found that equipment vendors are no longer offering this type of equipment. The seawater scrubbing option was rejected on the basis of being a technically unproven and unacceptable alternative.

Offshore sulphur recovery was considered as an alternative for acid gas handling. After preliminary review of the option, it was determined that it was not economically feasible due to the size of the platform required for the process and the logistics of handling the sulphur product.

Table 4.10 Acid Gas Handling Development Alternatives

Alternative	Technical Suitability	Cost	Commercial Risk	Technically and Economically Feasible	Concept Deliverability	Safety	Environmental Impact
Acid gas injection	Proven technology Used extensively in Western Canada – EnCana has existing installations	Approximately $45 MM	No significant concerns	Yes	Moderate risk – specialized equipment and additional safety concerns	Incremental risk over flaring due to handling of high pressure acid gas	Significantly reduces air emissions and marine discharges compared with other feasible options
Flaring	Proven technology Used worldwide	Approximately $1 MM* Fuel gas required to ensure efficient operation	Not applicable	Yes	Least risk	Some risk associated with handling acid gas	Highest air emissions
Seawater scrubber	Technology no longer available	Not assessed	Not applicable	No			
Offshore sulphur recovery	Offshore footprint required makes Option uneconomical	Very high	Not applicable	No			

Note: * Based on estimates prepared in 2002.

4.11.3.7 Produced Water Disposal

EnCana identified four potential alternatives for produced water disposal on the Deep Panuke Project. These alternatives were treatment and discharge overboard, injection into a dedicated well, simultaneous injection into the condensate/acid gas injection well, and injection into the annular space of an existing well. Each alternative carries different types and levels of risk to the Project (further information provided in Table 4.12). After a thorough review of the alternatives, the treatment and discharge overboard option was deemed the best technical and commercial option.

Discharge Overboard

Treatment and discharge overboard is a proven technology that is used world-wide in offshore oil and gas facilities, including offshore Nova Scotia. The treatment technology proposed for the Project will ensure that the prescribed CNSOPB limits for produced water discharge are met or improved upon.

Injection into a Dedicated Well

Water injection into a dedicated well is a proven technology on offshore oil developments and is normally done for reservoir pressure maintenance. This concept would involve the use of all equipment for the overboard disposal scheme plus the addition of a dedicated flowline, a dedicated umbilical, a new injection well, injection pumps, and filters. For this concept, the capability to discharge produced water overboard would be required to provide operational flexibility in times of maintenance and/or operational issues.

The concept, while technically feasible, is considerably more expensive than the simpler overboard disposal concept. Since the overboard disposal concept provides a proven, environmentally acceptable alternative at significantly lower cost, the dedicated injection well was rejected based on economic considerations.

Simultaneous Injection of Acid Gas and Produced Water

Simultaneous injection of produced water into the condensate/acid gas well is not commonly practiced offshore due to risks associated with phase separation. Although the design rate of 6400 m^3/d [40,000 bpd] of produced water is sufficient to dissolve 130 x 10^3 m^3/d [4.5 MMscfd] of acid gas, the rate of produced water varies between 0 and 6400 m^3/d [40,000 bpd] and cannot be predicted with certainty at this time. Therefore, this option cannot be considered as a reliable solution for produced water disposal and was rejected.

Injection of Produced Water into an Annular Space

Injection into the annular space of an existing well is not widely practiced. This concept involves injecting the produced water into an annular space between the surface and production casing strings. The concept will require injection pumps and equipment on the topsides similar to the dedicated well concept as well as a special dual completion type wellhead and production tree arrangement. This concept has the following technical challenges:

- the annular space on any of the existing production wells will not have sufficient cross-sectional area to accept up to 6400 m^3/d [40,000 bpd]. Therefore, none of the existing wells could be re-used;
- well construction to accommodate this concept for either of the two new drill wells (H-99 or D-70) will be difficult and technically challenging because a special oversized surface casing will be needed along with a custom wellhead and production tree;
- injection of the total expected quantity of produced water over the field life into a non-permeable zone, where the surface casing terminates, is questionable. This may be operational issues with this concept.

Therefore, injection into an annular space was rejected on the basis of high risk of deliverability of this concept.

Table 4.11 Produced Water Disposal Alternatives

Alternative	Technical Suitability	Cost	Commercial Risk	Technically and Economically Feasible	Concept Deliverability	Safety	Environmental Impact
Treatment and disposal overboard	Proven technology Currently used worldwide in offshore oil and gas facilities Meets published CNSOPB guidelines	Base case for capital costs Annual operating costs for environmental monitoring	No significant concerns	Yes	No significant concerns	No significant concerns	Likely no significant impact to the marine environment due to hydrodynamically active discharge location Water will be treated and disposed according to existing regulations
Injection into dedicated well	Proven technology onshore Will require duplication of overboard equipment in case well goes down	Base cost for disposal overboard plus approximately $60MM Additional operational costs for well interventions, injection chemicals, and power for pumping.	No significant concerns	Technically feasible Unattractive economically, add unnecessary cost and complexity			
Simultaneous injection with acid gas into gas injection well	Concept is not technically feasible due to varied produced water volumes	Not assessed	Not assessed	No			
Injection into an annulus	Concept has significant technical risks If corrosion problem occurs, will shut down a producer well	Additional capital cost for injection equipment, additional piping, well construction, and wellhead modifications Additional operational costs for injection chemicals	Potential risk of shut-down of production well that is being injected into (corrosion) Uncertainty with regard to a suitable injection zone	No			

4.11.3.8 Condensate Handling

The method employed for condensate handling is directly tied to the export tie-in alternatives. For the M&NP Option, three options were investigated for handling condensate. The preferred option is to use the condensate as primary fuel for the turbine drivers offshore. The rationale for this selection is described below.

For the SOEP Subsea Option, the condensate is transported to SOEP via the export pipeline and commingled with the export gas. Final condensate handling is done onshore at the SOEP gas plant at Goldboro and the fractionation plant at Point Tupper.

Handling of the condensate stream either as the primary fuel on the platform or processing at the SOEP facilities are both technically feasible. Final selection of the condensate handling alternative will be made when discussions between EnCana and ExxonMobil are concluded.

The following three options for condensate handling were evaluated for the M&NP Option:

1. the use of a dedicated pipeline to shore;
2. use of condensate as a fuel; and
3. condensate storage and shipment by tanker.

The three alternatives were identified as technically feasible with different types and levels of risk (refer to Table 4.12); however, options 1 and 3 were deemed not to be economically feasible. After reviewing the alternatives, it was determined that use of condensate handling as the primary fuel is the preferred alternative for the M&NP Option.

The maximum expected volume of condensate that will be produced with Deep Panuke gas at peak production is approximately 220 m^3/day [1400 bpd].

Use of a dedicated condensate pipeline to shore would necessitate the construction of onshore condensate handling facilities such as storage tanks which would result in substantial capital costs. The pipeline would have to be buried over its entire length (not easily accomplished over rocky areas) to meet regulatory requirements and to protect it from possible damage from mobile fishing gear. In addition, the condensate pipeline would not be protected from clam dredges unless deeply buried. The potential environmental effects associated with rupture of such a condensate pipeline would also be a concern. The quantities of condensate to be produced from the Deep Panuke field do not justify the costs associated with a dedicated condensate pipeline. Thus, a dedicated condensate pipeline to shore was deemed not economically feasible and was therefore rejected.

The use of condensate as the primary fuel on the MOPU was also considered. Using condensate as fuel eliminates the substantial capital and operating costs associated with a condensate pipeline to shore and associated onshore handling facilities. The use of condensate as fuel on the platform conserves the resource by maximizing the quantity of natural gas exported to shore and by utilizing all components of the Deep Panuke resource.

A seafloor subsea storage tank for holding a six-month volume of condensate offshore was also considered. While subsea storage tanks have been used at other offshore facilities, there is a high risk for potential seafloor scour due to the relatively shallow water at the Deep Panuke site. That would necessitate large quantities of rock protection around the tank. The prohibitive costs of such an installation resulted in this option being considered not economically feasible.

4.11.3.9 Production Capacity Alternatives

The 2002 Project basis for production capacity was 11.3 x 10^6 m^3/d [400 MMscfd]; however, alternatives for smaller facilities with peak production capacities of 8.5 x 10^6 m^3/d [300 MMscfd] and 5.7 x 10^6 m^3/d [200 MMscfd] were also considered. Concepts were initially developed for jacket-supported structures for each alternative. It was found that the platform footprint, weight, and cost reduced considerably when the production capacity was reduced from 11.3 x 10^6 m^3/d [400 MMscfd] to 8.5 x 10^6 m^3/d [300 MMscfd]. However, the reduction in topsides weight (and cost) when the production capacity was further reduced to 5.7 x 10^6 m^3/d [200 MMscfd] is marginal since the size of processing equipment does not decrease in the same proportion as production capacity. The economic modelling case at the 5.7 x 10^6 m^3/d [200 MMscfd] production rates showed that the payout period was too lengthy at this rate, severely impacting the economics. It was concluded that the 8.5 x 10^6 m^3/d [300 MMscfd] plant size is more economically feasible for the mean reservoir case and therefore was selected for the plant production capacity rating.

Table 4.12 Condensate Handling							
Alternative	**Technical Suitability**	**Cost**	**Commercial Risk**	**Technically and Economically Feasible**	**Concept Deliverability**	**Safety**	**Environmental Impact**
Dedicated pipeline to shore	Proven technology	High capital costs	No significant concerns	No			
Use of condensate as a fuel	Tri-fuel usage (gas/condensate/diesel) not widely used in offshore production, but feasible	Least expensive	No significant concerns	Yes	Specialized equipment which is not available in Canada has long lead delivery	Requires special design considerations however, technically achievable	Reduced transfers of diesel (required as a backup fuel) since a tri-fuel system will be in use
Storage and shipment by tanker	Proven technology	High capital costs	No significant concerns	No			

4.11.3.10 Export Pipeline Alternatives

There are two alternatives for the export pipeline. EnCana proposes to transport product for sale via a subsea pipeline from the offshore processing facility to one of two delivery points:

- Goldboro, Nova Scotia (M&NP Option); or
- SOEP 660 mm [26-inch] pipeline tie-in (SOEP Subsea Option).

Both export pipeline alternatives are technically feasible and routes have been chosen to minimize environmental impact. The selected alternative will be determined pending the outcome of commercial discussions between the operator of SOEP, ExxonMobil, and EnCana.

4.11.3.11 Subsea Tie-back Alternatives

The Deep Panuke reservoir areal extent has changed substantially from the 2002 Project basis of one license, PL2902, to the current Project basis covering PL2902, EL2387, SDL2255H, PL2901, and EL2360. The pool size estimate requires a minimum of five production wells for the P90 case and a maximum of eight production wells for the P10 case to effectively deplete the resource. The large extent of the pool necessitates the use of a subsea solution.

The Project plans to utilize four suspended wells from the exploration drilling program as production wells which allows for reduced capital costs and environmental interactions. One new production well will be drilled for the Project start-up. Up to three additional production wells could be drilled in future. A subsea tie-back study was carried out to determine the optimal method of tying in the wells to the field centre. It should be noted that a new acid gas injection well must also be tied back to the field centre; however, the geology in the area allows numerous options for the location of this well so this was not considered as a driver for the lay-out study.

From a layout consideration, it was determined that a tie-back of individual wells to the field centre was the best technical solution. The proposed well locations do not suit a template or manifold arrangement. The field centre location was determined by minimizing the tie-back lengths of the wells to lower capital costs and improve flow assurance.

Three alternative methods for flowline installation were considered: 1) "S-lay" barge method; 2) "reel lay" technique; and 3) flexible flowline method. The "S-lay" lay barge method involves the use of an offshore barge to weld and then lay lengths of rigid pipe on the seabed by means of a "stinger" overhanging the stern of the barge. Subsequently, the pipe is trenched using a subsea trenching or ploughing spread. The "reel lay" method involves pre-welding rigid pipe lengths together at a specialized “spool base” onshore and then reeling the entire flowline onto a large diameter reel. The reel is taken offshore on a special lay vessel where it is straightened and laid on the seabed as a continuous length. The flowline is trenched in a similar manner to the lay barge method. The “flexible” solution uses a flowline of non-rigid type. Each flowline is manufactured in one single piece at a specialized factory and coiled on a large reel and taken offshore. A special lay vessel uncoils the flowline and lays it on the sea bed. Trenching methods are similar to the other schemes. Hook-ups for all three alternatives are carried out by diver/ROV operations.

All three methods are technically acceptable with similar environmental effects and the preferred solution will be chosen following the competitive bidding process.

4.11.3.12 Acid Gas Injection Location

As indicated in Section 4.11.3.6, the option chosen for acid gas handling for the Project is the acid gas injection technology. The location chosen for the acid gas injection well is D-70. An alternative location considered for the acid gas injection well was H-82. A summary of the investigation is included below and summarized in Table 4.13.

Both acid gas well locations are technically and economically feasible. However, the distance from the MOPU to H-82 is longer than the distance to D-70 (4.8 km versus 1.7 km), which would result in an additional cost of approximately $1MM to $2 MM for the extra length of flowline and umbilical for H-82.

The possibility of acid gas injection souring the Panuke oil sands is considered to be extremely unlikely for both the D-70 and H-82 locations; the likelihood of souring is only slightly greater for the D-70 location.

The longer flowline for an acid gas injection well at H-82 results in an increased operational risk associated with a higher risk of hydrate formation in the flowline. In addition, there is also an increased safety risk in the very unlikely event of an acid gas injection flowline rupture due to the larger volumes of acid gas contained in the longer flowline to H-82.

The environmental impact from both locations would be very similar, although the H-82 location is expected to have a slightly higher environmental impact due to the following:

- longer flowline resulting in larger benthic footprint (greater area of benthic disturbance)
- larger safety zone area to include H-82 well and flowline location, resulting in higher impact on fisheries (especially quahog fishery) and other ocean users

- increased impact to air quality in the unlikely event of acid gas flowline rupture due to larger volume of acid gas contained in the longer flowline to H-82.

However, these differences are not likely to result in significant environmental effects and the assessment presented in the EA Report (DPA Volume 4) for the D-70 location is expected to be applicable to the H-82 location.

Based on the fact that both acid gas well locations are very similar in terms of technical feasibility and environmental impact, the acid gas well injection location at D-70 was selected due to lower costs and slightly lower risks associated with concept deliverability and safety.

Table 4.13 Acid Gas Injection Location Alternatives

Alternative	Technical Suitability	Cost	Commercial Risk	Technically and Economically Feasible	Concept Deliverability	Safety	Environmental Impact
D-70	Technically feasible	Base case for cost (as per Table 4.10)	Extremely low risk of souring the Panuke sands,	Yes	Least risk	Least risk	Lower impact
H-82	Technically feasible	Additional cost from base case of approximately $1-2 MM for the extra length (approx. 3.1 km) of flowline and umbilical	Risk of souring the Panuke sands extremely unlikely (slightly lower than D-70)	Yes	Increased operational risk associated with longer flowline (primarily increased risk of hydrate formation)	Increased safety risk associated with unlikely rupture of acid gas injection flowline due to larger volume of acid gas in flowline (4.8 km flowline instead of 1.7 km)	Higher impact due to longest flowline resulting in: - larger benthic footprint (greater area of benthic disturbance) - larger safety zone area and impact on fisheries (especially quahog) and other ocean users - increased impact to air quality in unlikely event of acid gas flowline rupture due to larger volume of acid gas in flowline

5 CONSTRUCTION AND INSTALLATION

5.1 Philosophy

The MOPU concept has the distinct advantage over conventional jacket and topsides construction methods of allowing the offshore installation of a mechanically complete, fully commissioned production facility without heavy lifts or extensive offshore hook-up and commissioning.

The MOPU will be constructed, commissioned, and installed using the following key philosophies:

- hull design and construction using as much of a "standard" MODU as possible. This technique of using the hull as the main support structure without drilling equipment will allow MODU designers and constructors to use as much of their standard design and fabrication practices to minimize cost and allow for potential reuse after decommissioning;
- design of topsides module(s) to be installed to the extent possible in large mechanically complete, pre-commissioned pieces. Module(s) will be designed to be installed onto the hull at an atshore integration yard, thus allowing fabricators to take advantage of installations independent of weather;
- final mechanical integration, commissioning, and testing of all systems atshore, prior to tow to field, to allow for higher utilization of labour and equipment without the expense of offshore hook-up; and
- minimal final offshore hook-up and commissioning. Offshore activities will be limited to the final hook-up of the subsea wells and equipment, offshore pipeline and startup of production.

EnCana intends to maximize onshore completion and pre-commissioning and to minimize offshore hook-up and commissioning scopes of work without compromising safety.

EnCana has committed to construction of the accommodations unit(s) and flare structure in Nova Scotia. The construction and installation philosophy will address additional design, construction, commissioning and transportation requirements to ship and integrate these components with the remainder of the MOPU.

5.2 Schedule

5.2.1 Development Phase

The schedule for the development phase of the project is set out in Figure 1.3. The revised concept definition for the Deep Panuke Project was completed through 2005 and the first half of 2006. The project is currently in the tendering stage for the bid competition phase for the MOPU. The initial phase of detailed design will be conducted as a competition with an expected duration of nine months.

Following completion of the regulatory process and at the conclusion of the bid competition phase, EnCana will make a decision regarding full project sanction.

Assuming sanction and after contract awards, the Project will then engage in detailed engineering and procurement. Subsequent onshore fabrication at existing facilities will occur prior to installation offshore.

Hull and topsides fabrication is scheduled to commence late third quarter 2008, with the MOPU hull and topsides ready for atshore integration first quarter 2010.

It is anticipated that the export pipeline and flowlines will be constructed in either 2009 or 2010. The tie-ins to the MOPU and to either the M&NP facilities or to the SOEP pipeline will be completed after the MOPU and the export pipeline installation is complete.

Hook-up and offshore commissioning activities will commence in the third quarter of 2010 once the MOPU has been transported to its field location. First gas is anticipated to be produced in the fall of 2010.

5.2.2 Production Operations Phase

The operations phase of the Project is forecast to begin in late 2010, and is estimated to last approximately 13 years in the Mean case with production from the field continuing through late 2023. The P90 case for the project has a life of approximately 8 years, and the P10 forecast indicates a Project life of approximately 17.5 years.

5.3 MOPU Facilities

The hull portion of the MOPU is expected to utilize the basic design premise of an existing MODU jackup with the minimum number of changes required to accept the topsides production facilities. Some modifications are expected for additional safety and control systems, which must be integrated platform wide and other specific modifications, including appurtenances, risers and umbilicals, which interface with the sea and seabed below. However, the intent will also be to minimize the deviations from the standard MODU design so that re-conversion of the unit back to a drilling unit can be readily accommodated in the future, if desired.

The hull design will be structurally capable of withstanding the environmental design conditions for offshore Nova Scotia on a year-round basis; these MODUs are generally referred to as “harsh environment jack-up rigs”.

The production topsides will house all the production equipment and will be located on the hull maindeck in the areas where the drilling package is normally located. The hull will be designed to carry the larger live loads of the drilling activities in this area of the hull; therefore, locating the topsides in this area is ideal from a structural perspective. The topsides will be constructed in modular format. The expected weight of the production facilities is 6000 tonnes and a single module is preferred from a construction and commissioning perspective. However, multiple modules can also be utilized should this be a better fit for the selected hull. Final arrangement will be determined during detailed design. The modules will be designed to be installed onto the hull structure and will be supported by the main girders/bulkheads within the hull.

The construction philosophy for the topsides will in general be based on a single (or several) module(s). The single module will most likely be a pancake-build, which involves completing the various levels of the topsides, stacking one level on top of the other placing equipment into location during the operation. The decks will be constructed from pre-fabricated plate girders, rolled sections and pre-rolled long length tubulars. The intent is to maximize opportunities for equipment installation and the subsequent erection of pipework, cable trays and support steel prior to deck stacking operations.

The accommodations unit(s) will be designed to be constructed in Nova Scotia and therefore may have a design and build plan, which will allow for transportation to the integration site and integration of the unit with the remainder of the MOPU, if required. Special considerations will include design of interface systems for power and utilities as well as loadout and lifting. The accommodations unit will be designed for a minimum continuous POB complement of 68 persons and steady state POB of approximately 30 persons; however, a higher POB design basis may be considered if the MOPU contractor chooses to use a MODU accommodations design to allow for easier conversion back to MODU operations in the future. Final accommodations size and layout will be determined during detailed design.

The flare structure will also be designed to be constructed in Nova Scotia and therefore must also accommodate the loadout, transport, and installation considerations similar to the accommodations unit(s). The flare structure is expected to be a tubular lattice-type structure and may be vertical or a boom type configuration. It will be in the order of 70 m above the topsides production facilities top most deck and will house the HP and LP flare lines and flare tips.

The topsides module(s) and the MOPU hull may be fabricated at separate locations and then brought to a common yard where they will be integrated. The topsides will be installed onto the MOPU hull and the remaining construction work will then be completed. It is crucial to the effectiveness of the offshore phase that all the construction and commissioning work is as complete as possible prior to the MOPU sail away for installation.

The key drivers during the construction and installation phase will be as follows:

- ensure design deliverables arrive on site when required;
- ensure equipment arrives on site when required in a complete tested and commissioned state; and
- ensure bulk materials are available on site when required.

The philosophy adopted for the fit-out of all disciplines will be to maximize the amount of work which can be completed in advance of deck stacking and structural completion while work-faces are open, reducing congestion, increasing safety and allowing milestone dates to be realized. Once deck stacking is complete, coordination of fit-out activities will be of major importance to ensure that access is given to allow tasks to be completed in the correct sequence. A fit-out driven program allows early completion of testing activities, which in turn, helps to define priorities. Area completions are considered as important as system completions and attention is given to the efficient management of areas and area releases to allow commissioning activities to proceed.

Once testing activities commence, additional consideration will be given to access to work areas and personnel safety; weekend and nightshift working will be utilized as required.

5.4 Mechanical Completion

Mechanical completion will denote the conclusion of all construction work, inspection and static testing prior to dynamic testing and livening-up with power and fluids. Mechanical completion will, at a minimum, include the following:

- locating, installing, connecting and testing all 'tagged' equipment;
- installing, completing non-destructive testing, pressure testing, flushing, drying and reinstating all piping systems;
- completing all chemical cleaning;
- completing all oil flushing;
- installing and testing all electrical systems;
- installing and testing all instrumentation systems; and
- completing all leak testing.

To facilitate handover from the construction team to the commissioning team, each of the systems will be sub-divided and allocated to a sub-system. Each sub-system will relate to a specific element or group of elements that are to be commissioned. As each sub-system is certified as mechanically complete, responsibility for the particular sub-system will be transferred to the commissioning team. No further construction work will be allowed, and a permit to work system will then be enforced.

5.5 Commissioning

The objective of the commissioning phase is to safely and economically bring utilities, production and export systems into service and to achieve a handover of these systems to producing operations while demonstrating their performance within the specified design criteria.

The following principles will be adopted as part of the overall commissioning strategy:

- early involvement of commissioning personnel to assist in the detail design and planning phases;
- maximization of commissioning at the vendor's work-site through factory acceptance tests and system integration tests;
- planning of fabrication and commissioning activities so that overlap, as far as practical, can be achieved to facilitate the commissioning process;
- maximizing onshore pre-commissioning and commissioning of systems;
- accessing vendor expertise by including the vendor representatives on the commissioning team;
- utilizing operations maintenance and operations personnel in the commissioning team; and
- operating commissioning workpacks to ensure the safe and controlled handover to producing operations, via the project completions system.

Commissioning representation will be established at the commencement of the design phase so as to define commissioning package limits, advise designers, review the developing design with a view to effective commissioning, and prepare commissioning procedures.

As the construction phase gets underway, the commissioning team will proceed to preparation of plans and schedules, identification of requirements for materials, spares and consumables, establishing contracts for logistics and support services, and attendance at factory acceptance tests on major equipment.

Finally, members of the commissioning team will be assigned to construction sites to familiarize themselves with the plant and undertake pre-commissioning activities.

5.6 Loadout

Transportation of the topsides module(s) from the fabrication site to the quay for loadout onto a barge will typically be accomplished by means of self-propelled trailers installed under each component to suit the final barge grillage support arrangements. Construction supports will be arranged to provide the same trailer space as the barge grillage supports. Alternatively, the topsides module(s) will be loaded onto the barge by skidding. It is anticipated that specialised loadout contractors will be used to execute the loadout operations.

The contractor will engineer and install the loadout and ballasting requirements for the floating barge and operate ballasting systems during the loadout.

Immediately after the topsides module(s) have been transferred to their final position on the barge, the trailers and all loadout correction ballast will be removed, the module(s) sea fastening installed and the barges prepared for towing.

5.7 MOPU Transport and Installation

Installation activities include the transportation and installation of the completed MOPU.

During the early stages of the detailed design phase of the Project, it will be important to ensure that the MOPU is designed to be transportable by the most economical means. Accordingly, until the MOPU fabrication yard is known, it will be essential to maintain design flexibility.

The actual installation of the MOPU at the offshore location is the same as the installation of a typical jack-up drilling rig. That is, the MOPU jacking system will be activated to raise the hull above the sea level to its final design elevation.

Installation will be in accordance with installation manuals, which will provide full details of the sequence and content of each operation. The Project's EPP will be integrated with the development of the installation manuals. The following summarizes the installation activity for the MOPU:

- tow the MOPU to the offshore site;
- jack the MOPU legs down to the seafloor;
- jack the hull out of the water to the pre-loading elevation;
- perform pre-loading operations and jack the hull to the final design elevation; and
- installation of scour protection material (if required).

5.8 Export Pipeline Installation

The following sections describe the typical installation methods that will be used for the export pipeline. It should be noted that landfall, nearshore, directional drilling and pipeline pull-in sections are not applicable for the SOEP Subsea Option.

5.8.1 Landfall Preparation

Well in advance of the pipelay vessel's arrival on site, the landfall will be prepared to receive the export pipeline. The landfall will consist of a conventional open cut trench construction.

The landfall area will be graded in preparation for the pipeline and pull-in winch and reels. It is anticipated that due to the soil conditions at the site, some blasting may be required but, if required, will be conducted in the "dry" only. Blasting requirements will be defined during the detailed design phase after the geotechnical survey has been performed.

It is anticipated that the pull-in arrangement will consist of a single linear winch tied back to either a temporary pile or block anchor. Final operational details for the pull-in procedure will be confirmed once a pipeline contractor has been selected, and a detailed site and soil inspection has been performed.

Once the pipeline has been pulled in, the trench will be mechanically backfilled to ensure cover depth and protection. The remaining landfall site will be returned to conditions similar to original conditions.

5.8.2 Nearshore Pre-Lay

Prior to the arrival of the pipelay vessel, the export pipeline route for a distance approximately 1 km from the shoreline will be pre-trenched. Floating equipment will be used that is capable of digging glacial till. Additional localized drilling and blasting may be required close to the shoreline. Upon completion of the pipeline pull-in operation, this section will be mechanically backfilled. Fisheries interests will be notified well in advance of pipelay operations using the "Notice to Mariners" and by direct contact with key fisheries representatives.

5.8.3 Directional Drilling

As an option to trenching in the nearshore area, directional drilling is considered another potential method for bringing the pipeline ashore. This method would require drilling an oversized hole from the shore to an offshore tie in point approximately 1 km offshore (KP1). To install this section of the pipeline, the pipeline would be pulled from the pipelaying barge at KP1, through the drilled hole, to the onshore drill site. The onshore component of the pipeline from this point to the tie in with the M&NP pipeline would be installed in the conventional manner.

An analysis of the directional drilling option will compare technical feasibility, potential environmental effects, and costs of this method against those of seabed trenching and backfilling for the nearshore installation.

The use of directional drilling as a nearshore installation alternative is currently under review and evaluation. This decision will be made in conjunction with the pipeline contractor in either late 2007 or early 2008.

5.8.4 Pre-Lay and As-Laid Surveys

An independent survey vessel with a full workclass remotely operated vehicle (ROV) will be mobilized to undertake surveys and provide export pipeline installation assistance. Just prior to the mobilization of the pipeline installation spread(s), the survey vessel will be mobilized and will conduct a pre-lay survey of the pipeline routes.

During the installation, the survey vessel will perform pre-lay and as-laid surveys and will provide installation assistance and touchdown monitoring during critical operations. Such operations are anticipated to be required when laying through boulder fields and bedrock outcropping as well as during pipeline crossings.

Upon completion of the pipeline laydown, the survey vessel will complete the as-laid survey. The as-laid survey will also provide a visual survey of the pipeline.

5.8.5 Pipeline Pull-in

Prior to the arrival of the pipelay vessel, the pull-in cable will be pre-installed in the pipeline trench and buoyed off at a convenient point offshore.

Once the pipelay vessel is on location, the pull-in cable will be recovered by one of the supporting anchor handling vessels and will be transferred to the pipelay vessel. Once the pipelay vessel has recovered the cable, it will be connected to the export pipeline pull-in head.

The lay-vessel will arrive on site with a ‘string’ of pipe on the firing line with the pipeline lay-down head at the top of the lay-vessel ramp. The linear winch will pull the pipeline onto the beach as the lay-barge simultaneously welds further sections of pipe onto the string. This process is continuous until the pipeline end has reached the designated point. The winch will then retain tension on the pipeline pull-in head while the pipelay vessel ‘lays away’ from the shore pull location. The winch will retain tension on the head until sufficient pipe has been laid on the seabed to provide enough ‘hold back’ tension to allow the pull-in cable to be released.

5.8.6 Pipelay

The installation method will be to 'S-Lay' the export pipeline from a conventional pipelay vessel. Figure 5.1 illustrates a gas pipeline being installed, with the stinger in the water and the pipe being fed from the underside of the vessel. The actual vessel to be used cannot be determined at this time and may be either a conventional pipelay vessel, which is controlled by the use of anchors, or a dynamically positioned vessel, which is controlled by the use of thrusters located at the bow and stern. If an anchored vessel is used, the anchors will typically weigh 25 tonnes and will be positioned using an anchor-handling vessel. The function of the anchor-handling vessels is to transport the anchor from the lay-vessel to the designated anchor point. The lay-vessel transfers the anchor to the vessel using a davit crane. Once on station, the anchor-handling vessel lowers the anchor to the seabed using a winch. Each anchor location will cover an area on the seafloor of approximately 4 m wide by 4 m long with a chain section cable running from the anchor to the barge. Typically, 12 such anchors are used. The reverse procedure is adopted when the anchor is recovered.

There are a very limited number of pipelay vessels capable of installing the subsea pipeline. The final selection of the pipelay vessel will be based on technical capability, availability, and cost.

Figure 5.1 Typical Pipelaying Vessel – Castoro SEI

For the export pipeline, the nominated vessel will set up at-the-beach pull location approximately 1 km from landfall and the pipeline will be pulled onto the beach as described previously. Once the export pipeline has been pulled-in, the vessel will 'lay away' and continue along the pipeline route. With respect to regions of complex lay, such as through the rocky outcrop, the dedicated survey vessel will assist with laying operation. The survey vessel will perform touchdown monitoring using an ROV and will check the route ahead of the pipelay vessel.

While laying pipe in close proximity to the SOEP pipeline, an exclusion zone will be set up to eliminate the risk of damage. In addition, if the pipelay vessel uses anchors (as opposed to dynamic positioning), where the anchor cables cross the SOEP pipeline and there is potential for the cable to reach the pipeline, a buoy will be placed on the anchor cable. In the unlikely event the anchor cable breaks, the buoy will prevent the cable from falling onto or damaging the SOEP pipeline. Details of the final anchor handling program will be determined with the selected pipeline contractor.

The pipeline will be sealed with a temporary 'head' at the end of the pipe and laid down adjacent to the MOPU field centre location.

5.8.7 Pipeline Stabilization

In order to stabilize the pipeline on the seabed, concrete weight coating will have been applied prior to delivery of the pipe to the pipelay vessel. It is anticipated that the pipeline will be buried in the zones where the water depth is less than 85 m for on-bottom stability reasons. For water depths greater than 85 m, the pipeline has sufficient on-bottom stability and thus will not be buried. This will be performed using sub-sea trenching equipment, which will trench the pipeline and so that after the soil has backfilled, there will be approximately 1 m of cover.

There are two main methods that may be used to form the trench for pipeline burial. The first option is to use a towed plough. In this method the plough is deployed from a host vessel and lowered over the pipeline. The pipeline is raised into the chassis of the plough and the ploughshares are closed below the pipeline. As the plough moves forward, under control of the host vessel, it forms a V-shaped trench into which the pipeline is lowered. The second option is to use a self propelled subsea digging tool. This type of machine is positioned over the pipeline and moves forward. Hydraulic digging arms are used to form the trench underneath the pipeline. Alternatively, strong jets of water may be used to fluidize the loose material under the pipeline, to ensure that the pipe is lowered as far as possible into the V-shaped trench. For either option, backfill of soil from the sides of the trench will cover the pipeline.

In the rock outcrop area, where trenching may not be possible, the option to stabilize the export pipeline with rock will be investigated during detailed design. Additionally, span rectification using rock may be performed in any locations where high stress in the pipeline would otherwise occur due to excessive undulations in the seabed. The source of such rock will likely be onshore from an existing rock quarry, such as that in Mulgrave, Nova Scotia.

5.8.8 Pipeline and Flowlines Commissioning

The export pipeline for both M&NP and SOEP Subsea Options and the production and injection flowlines will be hydrostatically tested. It is necessary to treat the seawater introduced into the pipeline and flowlines with corrosion inhibitors and biocides to protect the interior pipe surface if the time between the installation of the pipeline/flowline and its commissioning into service exceeds the timeframe allowed for leaving untreated seawater in the pipeline. Leaving untreated seawater in the pipeline for more than one month can establish conditions which permit corrosion to occur at a later stage in the life of the pipeline. The introduction of treatment chemicals is a safety measure for the prevention of corrosion over the life span of the pipeline.

For the M&NP Option, the pipeline will be installed cleaned, gauged, flooded, and hydrotested. The pipeline spool between the pipeline and MOPU will be installed and the pipeline will be leak tested, dewatered, dried and nitrogen packed. The hydrostatic test fluid will be discharged at the MOPU location.

For the SOEP Subsea Option, the pipeline will be installed cleaned, gauged, flooded, and hydrotested. The pipeline spool between the pipeline and MOPU will be installed and the pipeline will be leak tested, dewatered, dried and nitrogen packed from the MOPU location. The hydrostatic test fluid will be discharged at the SOEP subsea tie-in location.

The flowlines will be installed cleaned, gauged, flooded and hydrotested. The flowline spool between each flowline and the MOPU will be installed and the flowline leak tested. For the flowlines, it is unknown at this time whether the hydrostatic test fluid will be discharged at the MOPU or at the individual wellhead locations. This will be determined during detailed design.

All the water introduced into the line will be thoroughly filtered to 50 microns. During filling, cleaning, gauging and hydrostatic testing, chemical inhibition package(s) will be continuously injected into the seawater. The chemical inhibition package may include: dye to aid in the detection of leaks; a biocide to control marine organisms and sulphate reducing bacteria; a corrosion inhibitor; and a dissolved oxygen scavenger to minimize corrosion on the interior of the pipeline. During the filling cycle, some spillage of this water may occur at the pig receiving station offshore. This occurs when excess hydrostatic water is required to push the pig into the pig receiver at the end of the pipeline.

The chemicals to be used in this application will be selected from a list of chemicals approved for use in Canada and approved for offshore discharge through the *Offshore Chemical Selection Guidelines* (NEB et al. 1999). Since the installation program for the pipeline and flowlines is still under development and a supplier has not yet been selected, the definitive treatment chemicals cannot be specified.

A study, consisting of two components, will be undertaken to confirm predicted effects of the selected chemicals discharged into the environment. A toxicity bioassay program (first study component), will be undertaken prior to discharging these compounds. The bioassay will employ samples of the proposed chemical diluted in seawater to emulate the mixtures of chemicals and concentrations proposed for the hydrostatic test program. The results will be applied in a plume dispersion model (second study component) to confirm that there will be minimal effect to the marine environment around the platform. Prior to undertaking this study, the parameters and scope of the bioassay study will be discussed with Environment Canada and Fisheries and Oceans Canada.

The onshore section of the export pipeline will also require hydrostatic testing, which may be conducted concurrently with the offshore section of the pipeline as discussed above, using the same seawater source and treatment chemicals.

Should the schedule of the onshore section of the pipeline installation be changed, then a separate hydrostatic test may be required. Under this circumstance, the hydrostatic test water could be left in the onshore pipeline until the offshore testing is completed and the hydrostatic test water discharged with the offshore hydrostatic test water.

5.9 Subsea Installation

The subsea infrastructure required to be installed includes the following:

- flowlines;
- umbilicals;
- SSIV assembly;
- hot tap (SOEP Subsea Option); and
- subsea protection structures.

The flowlines and umbilicals will require trenching for on-bottom stability, protection and potentially for insulation purposes. The trenching methods have been discussed in Section 5.8.7. Pipeline and flowline commissioning has been discussed in Section 5.8.8.

5.9.1 Flowlines

The following three options are being considered for the in-field flowlines:

- rigid flowlines laid from a pipelay barge
- flexible flowlines
- reeled rigid flowlines

The variability in the execution of the three options lies primarily in the laying method of the in-field flowlines.

The rigid flowlines laid from a pipelay barge option will be an “S-lay” installation from a conventional pipelay vessel. This installation method is the same method used for the export pipeline as discussed in Section 5.8.6, which involves the transportation of short pipeline sections to the pipelay barge where they are welded together and placed onto the seafloor.

The flexible flowline option is based upon the flowlines being manufactured onshore and loaded onto installation reels, which will be transported by cargo vessel to the installation vessel. Alternatively, the installation vessel would load and transport the flowlines from the manufacturing facility to the Deep Panuke field location. The installation vessel will anchor the flexible flowline end with a clump weight and then lay the flowline along a pre-surveyed corridor to the well location. Each flowline will be laid in turn, until all the flexible flowlines are installed.

The reeled rigid flowline option is based upon the short pipeline sections being transported to an onshore spool base location where they will be welded together into a continuous section and inspected. The installation (i.e. reel) vessel will be mobilized to the spool base where the flowlines will be ‘reeled’ onto the vessel’s reel or carousel. The vessel will transport the flowlines to the Deep Panuke field location where the flowlines will be ‘reeled’ from the vessel and placed on the seafloor.

5.9.2 Umbilicals

The subsea umbilicals will be manufactured and loaded onto installation reels which will be transported by cargo vessel from the manufacturing facility to the installation vessel mobilization port.

The installation vessel will load the umbilical reels and sail to the Deep Panuke field location. The vessel will likely set up adjacent to the MOPU where a pre-installed J-tube messenger wire will be passed to the lay vessel and the umbilical will be subsequently pulled into the MOPU J-tube prior to lay away to either the wellhead or the SSIV where it will be temporarily abandoned for later tie-in by a diving support vessel (DSV). Each umbilical will be laid in turn until all the umbilicals are installed.

5.9.3 SSIV Assembly

There will be a SSIV assembly located on the export pipeline within 150 m of the MOPU. This SSIV assembly consists of a check valve complete with a small diameter bypass containing an on/off actuated buy back gas valve. The buy back gas valve will be controlled via an umbilical from the MOPU.

5.9.4 Hot Tap (SOEP Subsea Option)

For the SOEP Subsea Option, sales product is transferred from the Deep Panuke MOPU via a 15 km, 510 mm [20 inch] export pipeline to the existing SOEP 660 mm [26 inch] pipeline. The connection to the SOEP pipeline will be by a subsea tie-in, referred to as a "hot tap". The hot tap process involves the connection of a tee (i.e., branch nipple) and an isolation valve onto the existing pipeline through which a "coupon" can be cut out of the existing pipeline while the pipeline is still operational. The branch nipple connection can either be attached by welding or installing a mechanical clamp.

"Welded" hot tap activities can be described as follows:

- expose buried pipeline section by airlifting sediments;
- remove weight and corrosion coating;
- install and commission welding habitat;
- inspect pipeline;
- weld branch nipple onto pipeline;
- install reinforcement sleeve;
- install branch nipple flange;
- install isolation valve;
- remove habitat;
- install "hot tap" machine;
- perform "hot tap";
- remove "hot tap" machine; and
- install "hot tap" protection structure.

"Mechanical" hot tap activities can be described as follows:

- expose buried pipeline section by airlifting sediments;
- remove weight and corrosion coating;
- inspect pipeline;
- install mechanical clamp;
- install "hot tap" machine;

- perform “hot tap”;
- remove “hot tap” machine; and
- install “hot tap” protection structure.

The “hot tap” structure is connected via a spool piece to a Deep Panuke tie-in structure which houses the equipment that will be required at the end of the Deep Panuke export pipeline. This equipment includes a manual isolation valve, a check valve and provision for a temporary subsea pig receiver. A protection structure will be placed around each of the SOEP pipeline hot tap equipment and the Deep Panuke pipeline tie-in equipment.

5.9.5 Protection Structures

The protection structures for the wellheads, hot tap/tie-in and the SSIV assembly will be fabricated onshore and transported by cargo vessel or barge to the installation vessel. The installation vessel will lift the structures into their appropriate position and they will be attached to the seabed most likely by piling.

5.10 Hook-up and Final Commissioning

It is intended that the MOPU will be commissioned as fully as possible onshore. The scope of the offshore hook-up phase will likely be limited to the final tie-in of the following items:

- installation of final subsea hook-up spools between the MOPU and the flowlines;
- installation of final hook-up spool between the MOPU and the export pipeline;
- installation of the jumper spools between the MOPU legs and the topsides for flowlines and export pipeline;
- pull-in and final connection of the subsea umbilicals;
- installation of miscellaneous equipment and materials; and
- final commissioning activities.

The priorities for the hook-up phase will be to ensure that the platforms provide a safe working and living environment, to establish that life support systems are fully operational, to commission all utility and process systems, and to introduce the first hydrocarbons to the process facilities.

6 DEVELOPMENT ECONOMICS

Project economics for the Deep Panuke Offshore Gas Development have been analyzed using discounted cash flow models under various scenarios. The economic and financial models were developed using forecast production data, cost inputs, and other economic assumptions regarding pricing, royalties, and taxation. Details regarding the development of the cost inputs and economic assumptions are contained in Part Two (DPA – Part 2, Ref. # 6.1).

Production profiles and cost estimates contained in this section are based on estimates compiled from engineering studies and reservoir interpretation work carried out by EnCana staff, engineering contractors and other external consultants. The estimates shown will continue to be refined and revised through additional engineering, reservoir analysis, and as information becomes available from inquiries to potential suppliers and contractors.

The input data is used to generate cash flow models including economic indicators and metrics used to assess the economic viability of the Project and to compare and rank the Project against other investment opportunities on a consistent basis. Examples of core economic metrics used in evaluating the Project include net present value, internal rate of return, profit investment ratio and supply cost. Cash flows are calculated on both before and after tax basis.

6.1 Production Profiles

Field raw gas production profiles for the P90, P50, P10 and Mean cases have been generated in a subsurface risk model and are presented in Table 6.1 Given our current state of knowledge and the current economic environment, these profiles cover the range of probable reservoir performance and are derived from a realistic range of depletion strategies.

Facilities start-up in late 2010 and a two-month facility ramp-up period was used in the forecast. It was assumed that the topsides throughput capability is 8.5 x 10^6 m^3/d [300 MMscfd] sales on a calendar day basis. Well production efficiency of 95% has been assumed. The estimated raw gas shrinkage factor is estimated to be 0.9585.

Table 6.1 contains the sales gas production forecasts. Recoverable sales gas is estimated to be within a range of 11.0 x 10^9 m^3 [390 bcf] to 25.1 x 10^9 m^3 [892 bcf] with a Mean of 17.8 x 10^9 m^3 [632 bcf]. The Mean profile shows a production life of approximately 13 years, starting in late 2010, with final production occurring in 2023.

Table 6.1 Sales Gas Forecast								
Year	**P90**		**P50**		**P10**		**Mean**	
	(10^6 sm3/d)	**(MMscfd)**	**(10^6 sm3/d)**	**(MMscfd)**	**(10^6 sm3/d)**	**(MMscfd)**	**(10^6 sm3/d)**	**(MMscfd)**
2010	5.7	202	5.7	201	5.7	202	5.7	201
2011	8.5	300	8.4	300	8.5	300	8.5	300
2012	7.0	249	8.5	300	8.4	300	8.2	291
2013	4.5	159	6.4	228	8.4	300	6.2	219
2014	3.1	110	4.8	171	7.7	275	5.0	177
2015	2.2	79	3.8	136	6.0	213	4.0	143
2016	1.6	58	3.1	110	4.7	168	3.4	119
2017	1.3	45	2.5	90	4.1	145	2.7	97
2018	1.1	40	2.1	76	3.3	118	2.3	81
2019	0.0	0	1.6	58	2.9	103	1.9	67
2020	0.0	0	1.5	52	2.4	86	1.6	55
2021	0.0	0	1.5	52	2.1	73	1.3	47
2022	0.0	0	1.3	45	1.7	62	1.3	45
2023	0.0	0	1.1	40	1.6	55	1.1	41
2024	0.0	0	0.0	0	1.4	50	0.0	0
2025	0.0	0	0.0	0	1.4	51	0.0	0
2026	0.0	0	0.0	0	1.3	47	0.0	0
2027	0.0	0	0.0	0	1.2	41	0.0	0
2028	0.0	0	0.0	0	1.1	38	0.0	0

Further gas supply information can be found in Section 2, Subsurface, of the Development Plan (DPA Volume 2). Section 2 provides a detailed, integrated review of the Deep Panuke pool reservoir characterization, including geological, petrophysical, geophysical and reservoir engineering aspects. The reservoir depletion plan, including resource estimates, production forecasts, development concepts and subsurface risks is also provided within the context of EnCana's Reservoir Management Philosophy.

6.2 Pre-Development Expenditure

Total Pre-Development expenditure for the Deep Panuke Development was approximately $430 million (Canadian) from 1998 to the end of the third quarter of 2006. This figure includes cost for the successful Panuke PP3-C discovery well, five successful delineation wells, two unsuccessful wells, project management, engineering, studies, geophysical acquisition and interpretation, and subsurface evaluation.

6.3 Forecast Expenditures

Forecast expenditures shown for the Project are estimated in 2006 Canadian dollars. The forecast is estimated to be accurate at a +/-25% level at this stage of project definition, and will become more accurate as further engineering design, procurement and contracting activities, and commercial and leasing alternatives are developed.

6.3.1 Development Phase Expenditures

Estimates for the development phase include costs incurred by EnCana, as operator of the Project, from the fourth quarter 2006 to first gas production, scheduled to occur in the fourth quarter of 2010.

The costs shown in Table 6.2 are for the M&NP option, and exclude any costs associated with the MOPU, which will be included as operating costs payable during the production life of the Project.

The SOEP Subsea Option would see a reduction in the cost of the export pipeline during the Development Phase. However, there would be an increase in operating costs for tariffs charged as a result of using the SOEP pipeline. At this time, these costs are not defined.

Table 6.2 Development Phase Expenditures	**C$ Millions 2006**
EnCana Project Management & Engineering	115
Subsea	135
Export Pipeline	200
Drilling and Completions	160
Subtotal:	610
Contingency	90
Total Cost to First Gas	**700**

6.3.2 Production Operations Phase Expenditures

During the producing life of the field, the expenditures will be required for production operations, logistics, onshore support, well interventions, ongoing capital improvements, as well as for the field centre lease and operations services contract. There is significant variability in the potential operations cost forecast for Deep Panuke, primarily because of the impact of the field centre lease, which will constitute the single largest component of operating costs. The annual field centre lease cost will depend on the actual cost of the MOPU, lease terms, duration of amortization, and other factors.

Annual operating costs, including the field centre (MOPU) lease, are estimated at $150 million per year, +/-25%.

As well, depending on the performance of the reservoir, up to three additional production wells could be drilled after production startup. The Mean and P50 production profiles shown in Table 6.1 require one additional well drilled after startup, while the P10 production profile requires three additional wells. The estimated cost of drilling, completing, and tying back the future subsea production wells is approximately $120 million for one well in the P50 and Mean cases and $260 million for three wells in the P10 case.

6.4 Corporate Income Tax Rates

The federal corporate income tax rate for 2006 is 24.12%, including surtax, reducing to 19% by 2012 per measures included in the 2006 federal budget.

The Nova Scotia provincial corporate income tax rate is 16%.

6.5 Crown Royalty

Crown Royalties with respect to the Deep Panuke Project will be calculated in accordance with the *Offshore Petroleum Royalty Regulations* for Nova Scotia, with certain amendments as agreed to between EnCana and the Province of Nova Scotia.

The Nova Scotia Offshore Petroleum Royalty Regime is based on increasing royalty rates as project profitability increases. The payout thresholds are calculated at the point where project revenues first reach or exceed the sum of allowed predevelopment costs (exploration & predevelopment), capital costs, operating costs, crown royalties paid plus the appropriate return allowance.

For the Deep Panuke Project, the royalty rates are as follows:

- GROSS REVENUE ROYALTY

  Tier 1: 2% of Gross Revenue (GR), until simple payout + a return allowance (RA) based on 5% + the Long Term Government of Canada Bond Rate (10 year) (LTBR), then;

  Tier 2: 5% GR until simple payout + RA based on 12.5% + LTBR, then;

- NET REVENUE ROYALTY

  Tier 3: 20% Net Revenue Royalty (NR) until simple payout + RA based on 25% + LTBR, then;

  Tier 4: 32.5% NR

For the Tier 3 and Tier 4 Net Revenue royalty, the royalty payable is the greater of the Net Revenue Royalty shown or 5% of Gross Revenue.

7 LIABILITY AND COMPENSATION

7.1 Introduction

Throughout the course of the Project, events could potentially occur which result in adverse environmental effects or loss or damage to others.

EnCana's strategy is focused on managing such potential events by following a well devised EPP, which prevents or mitigates such events. In the event, however, that EnCana's activities cause adverse environmental effects or cause others to suffer loss or damage, EnCana will address its liability through compliance with legislated compensation schemes or guidelines.

7.2 Environmental Protection

EnCana will prepare an EPP to address potential interactions with Aboriginals, local communities and stakeholders, including those involved in the fishing industry. The concerns of such communities and stakeholders were canvassed during the preparation of the EA Report (DPA Volume 4). The EPP, which will be filed with the appropriate authorities, will address those issues raised during the preparation of the EA Report (DPA Volume 4) as having potential adverse environmental effects. The EPP will address all phases of the Project, including drilling, construction, installation, operation, decommissioning and abandonment. The EPP will also provide contingency measures to control and mitigate potential adverse environmental effects.

7.3 Legislative and Regulatory Requirements

The *Accord Act* requires applicants for work or activity authorization in the offshore area to provide proof of financial responsibility to the CNSOPB in a form and in an amount satisfactory to the Board. EnCana acknowledges those requirements and will fully comply with them.

The *Fisheries Act* imposes strict liability upon those responsible for deleterious substances. In addition, the *Canada Shipping Act* makes ship owners civilly liable for damage and cleanup caused by oil pollution and debris from ships not engaged in exploration, drilling or production of oil or gas.

7.4 Voluntary Compensation

With respect to compensation for loss or damage to fishing or aquaculture gear or vessels, EnCana will adopt the CNSOPB *Compensation Guidelines Respecting Damages Related to Offshore Petroleum Activity* (March 2002).

Where loss or damage to vessels and fishing equipment is caused by debris of unknown origin, the non-attributable fisheries compensation plan of the Canadian Association of Petroleum Producers (CAPP), of which EnCana is a member, may provide compensation.

8 SAFETY PLAN

8.1 Introduction

The implementation of EnCana's Environment, Health and Safety (EHS) management system involves the development and implementation of Safety Plans that will ensure efficient and safe activities during all phases of the Project, from concept development through to construction, operations and abandonment. Safety Plans will conform to the expectations and requirements of EnCana's Corporate Responsibility Policy, company-wide EHS Best Practices Management System, Deep Panuke EHS Management System, and CNSOPB Operator Safety Plan Guidelines 3150.002. The EnCana EHS policies and management systems are described in Section 8.2.

A Project Safety Plan (PSP) will be developed initially, that will cover activities during the design and construction phases, through to the "ready-for-operations" stage of the Project. A Construction Safety Plan (CSP) will be developed as a subset of the PSP, prior to the commencement of construction activities. At that point, the PSP will be succeeded by an "Operations Safety Plan" that will be developed in conjunction with the MOPU Contractor. An Abandonment and Decommissioning Safety Plan will be developed later in the Project's lifecycle to ensure that the facilities are decommissioned in a safe and environmentally-sound manner. Safety Plans will be supported by the environmental management and contingency plans discussed in Sections 9 and 10 respectively.

Major contractors (production, marine, drilling, aviation and diving) will be required to have and implement formal EHS management systems that address site/operations-specific risks, while conforming to EnCana's overall requirements. Where significant gaps are identified between EnCana's and Contractor's systems, they will be addressed through a bridging process to ensure that health and safety expectations are properly communicated and understood and the implementation of EHS management systems and programs is coordinated. EHS and quality assurance requirements will be outlined for equipment and material suppliers where these are procured directly by EnCana.

This section provides information on the following:

- Project Safety Plan;
- Concept Safety Analysis;
- Operations Safety Plan; and
- Abandonment and Decommissioning Safety Plan.

8.2 Project Safety Plan

The PSP will specify the resources and measures needed to plan, schedule, control and monitor implementation of the day to day safety-critical work activities. It will incorporate risk prevention and mitigation measures identified in formal risk assessment and safety engineering studies undertaken during the design phase. Major contractors will be required to develop Safety Plans for their installations and operations and those plans will be incorporated by reference in the Project Safety Plan. EnCana will suggest a standard for the content and format of such Safety Plans, to ensure uniformity as well as to optimize the interfacing between the various plans.

This section discusses the PSP in the context of EnCana's EHS management system expectations and requirements defined by the following documents:

- Corporate Responsibility Policy;
- EHS Statement of Principles;
- Environment, Health, and Safety Best Practices Management System; and
- Deep Panuke EHS Management System Guidance Manual.

A brief description of these documents is provided below.

8.2.1 Corporate Responsibility Policy Statement

EnCana's Corporate Responsibility (CR) Policy defines its commitment to EHS and provides the foundation for its management. The CR policy builds on the base of EnCana's Constitution, translating Shared Principles and values into actionable commitments in eight key performance areas, including EHS. The CR policy commits all employees to conducting EnCana business ethically, legally, and in a manner that is fiscally, environmentally, and socially responsible. It provides the overarching values and policy framework for EHS performance. EnCana's Corporate Responsibility Policy is stated below:

> *EnCana believes our reputation is critical to the creation of long-term value for our shareholders. We also recognize that success on the bottom line is reinforced by our behavior beyond the bottom line. Protecting and enhancing our reputation and social license to operate is a significant element of sustained financial success and requires us to define and commit to Corporate Responsibility as an organization-wide standard.*

In alignment with the values and principles embodied in EnCana's Constitution, this Corporate Responsibility Policy commits us to conducting our business ethically, legally, and in a manner that is fiscally, environmentally, and socially responsible, while delivering sustainable value and strong financial performance. It illustrates our Constitution in action and demonstrates its impact on decision-making. EnCana aspires to be a leader in Corporate Responsibility and will implement changes as required to reflect leading Corporate Responsibility practices.

This policy applies to any activity undertaken by or on behalf of EnCana, anywhere in the world, associated with the finding, production, transmission, and storage of our products, including decommissioning of facilities, marketing, and other business and administrative functions.

The CR Policy is built around eight pillars of commitment that reflect existing and emerging benchmarks of corporate responsibility as follows:

1. leadership commitment;
2. sustainable value creation;
3. governance and business practice;
4. human rights;
5. labour practices;
6. environment, health and safety;
7. stakeholder engagement; and
8. socio-economic and community development.

8.2.2 Environment, Health & Safety – Statement of Principles

EnCana's "EHS Statement of Principles" comprises eleven principles that guide the implementation of corporate policy commitments to achieve high EHS performance and is part of the accountability of all employees. The EHS Principles are stated below:

We protect the health and safety of all individuals affected by our activities;

We provide a safe and healthy working environment and expect our workforce to comply with the health and safety practices established for their protection;

We safeguard the environment and contribute to the well being of the communities in which we live and operate;

We maintain EnCana's commitment to clear, honest and respectful dialogue with stakeholders;

We strive to make efficient use of resources, minimize our environment footprint, and conserve habitat diversity and the plant and animal populations that may be affected by our operations;

We strive to reduce our emissions intensity and increase our energy efficiency;

We integrate Environment, Health and Safety Best Practices, EnCana's EH&S Management System, into all parts of our business;

We comply with applicable laws, regulations, and industry standards;

We identify, assess and manage EH&S risks throughout our business;

We ensure each employee, contractor and third-party service provider understands their EH&S responsibilities, is trained to meet them, and is monitored for compliance; and

We establish EH&S objectives, regularly measure our progress, and strive to continually improve our EH&S performance.

8.2.3 Environment, Health and Safety Best Practice Management System

The EnCana EHS Best Practice Management System is a corporate-wide standard for systematically achieving a desired level of EHS performance and serves as the overall framework for safety and environmental management. Specifically, it provides for a structured approach to be taken with respect to the identification, evaluation and management of hazardous conditions or practices that could potentially harm people or result in environmental damage. It comprises a set of ten inter-linked elements which address important business practices that enable the company to achieve its intentions outlined in the CR policy and EHS Statement of Principles. The EHS management system elements are stated below:

1. leadership;
2. managing risk;
3. emergency preparedness and response;

4. assuring competency;
5. conducting our business responsibly;
6. ensuring contractor and supplier performance;
7. managing incidents;
8. documentation management;
9. reporting EHS performance; and
10. evaluating system effectiveness.

8.2.4 Deep Panuke EHS Management System Guidance Manual

The Deep Panuke EHS Management System Guidance Manual will provide guidance to the Project team, including contractors, in implementing the requirements of the corporate-wide EHS Best Practices Management System. It will reflect East Coast offshore-specific requirements, including the regulations, guidelines and practices issued by CNSOPB and CAPP Atlantic Canada.

The manual will address or incorporate the following aspects of safety management:

- EHS organization structure with defined responsibilities and accountabilities;
- EHS performance objectives and their measurement, and the recognition of good performance;
- regulatory compliance monitoring and reporting;
- requirements for contractor safety and environmental programs and provisions to bridge between EnCana and the contractor where significant differences exist in policies or practices;
- safe work practices, systems and programs for preventing accidents, injuries or illnesses in the performance of work;
- environmental practices and programs for operations that have the potential to cause environmental harm;
- safety training standards to ensure that personnel are aware of hazards, applicable safe work practices, and emergency procedures;
- medical and occupational health management to ensure employee health and wellbeing;
- joint management of occupational health and safety under the auspices of a Joint Occupational Health and Safety Committee (JOHS) that provides a forum for management and non-management personnel to work together in identifying and resolving health, safety and environment issues;
- incident management system for the reporting, investigation and follow-up of injury-causing accidents, property damage incidents, environmental incidents and near misses;

- requirements for periodic safety meetings with contractors to ensure that contractors are aware of hazards and incidents at the worksite and sanction the resources necessary for implementation of corrective actions;
- on-hire safety and environmental surveys to ensure that contracted installations, vessels, aircraft and facilities provide an acceptable level of protection for personnel and property, and meet regulatory requirements;
- major accident hazard reviews and formal risk assessments to ensure that hazards are controlled to as low as reasonably practicable (ALARP) levels;
- safety and environmental audits of operations controlled by EnCana and/or contractors to verify compliance with plans, procedures, system specifications and/or contract requirements;
- periodic safety and environmental inspections to verify that site conditions conform to EnCana and regulatory requirements;
- identification and control of hazardous substances and the safe isolation of energized equipment during repair or maintenance activities;
- emergency response planning, exercises and drills; and
- requirements for recording and retention of EHS-related documentation.

EnCana will use the Deep Panuke EHS Management System as a means of documenting and demonstrating compliance with required hazard prevention, control and mitigation measures, and regulatory requirements. The Project Safety Plan, when finalized, will reflect the structure and requirements of this document.

8.3 Organization and Responsibilities

The responsibility and accountability for implementation of the Project Safety Plan will rest with the Project General Manager (PGM). A responsible-accountable-inform-communicate (RACI) chart will be developed outlining specific responsibilities for the Project Team and will be appended to the PSP. Dedicated safety, environmental and regulatory professionals will advise and coordinate the implementation of the PSP.

The Project EHS and quality assurance organization chart is shown in Figure 8.1.

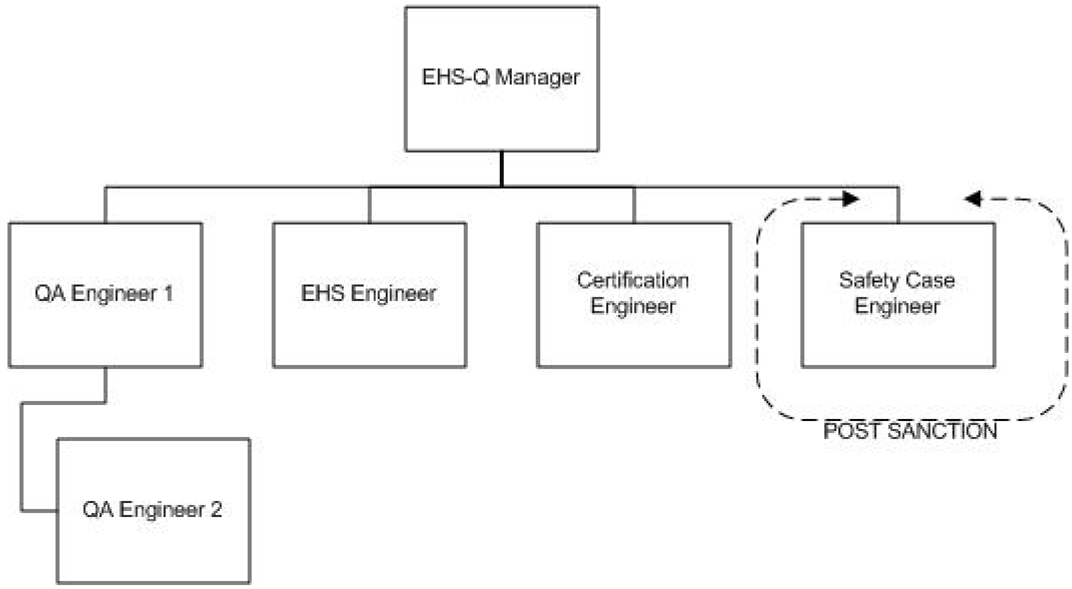


Figure 8.1 Project EHSQ Organization Chart

8.4 Documentation Management

A formal document management system will be established for the Project. The system will assure compliance with regulatory requirements, and meet Project Quality Control and EnCana's own internal requirements.

8.5 Training and Competence Assurance

Developing the Project team's competence, including contractors' competence, will be one of the priorities in managing workplace hazards. EnCana will implement a comprehensive training program for its Project team to comply with the CAPP East Coast Offshore Training and Qualifications Practice (CAPP TQP) and internally-defined training requirements. Project contractors will be required to meet the training and competency requirements of the CAPP TQP and any other requirements imposed by EnCana. The TQP will be adopted as the standard for training throughout the Project lifecycle.

Prior to assignment, the Project team will undergo a safety induction to familiarize with EnCana's health and safety policies, procedures and on-the-job hazards and controls. Competency requirements will be specified to ensure that individuals assigned to the Project have the required knowledge and skill sets.

8.6 Audit and Management Reviews

As required by EnCana's EHS Best Practices Management System, regular audits will be conducted throughout the lifecycle of the Project. Examples of these audits include the following:

- Project safety reviews;
- contractor facilities audits; and
- EHS management system audits.

8.7 Joint Occupational Health and Safety Committee

A JOHS committee complying in structure and mandate with Nova Scotia legislative requirements is in place at the Project Office in Halifax. The JOHS Committee is responsible for:

- identification of hazards and effective safety systems to respond to the hazards;
- auditing of compliance with health and safety requirements in the workplace;
- disposition of matters with respect to workplace health and safety and resolution of refusal to work complaints for dangerous work;
- participation in inspections, inquiries and investigations concerning health and safety;
- providing input on the selection of personnel protective equipment;
- advising on health and safety policies and program and making recommendations for their improvement;
- maintaining records and minutes of meetings, and
- other duties prescribed by the *NS Occupational Health and Safety Act*.

Additional JOHS committees will be established at Project worksites to promote worker participation in day to day safety activities and programs. EnCana will support its JOHS Committee with training/orientation and the resources required for its effective functioning.

At the business unit level, a Senior Management Committee meets on a regular basis to review the implementation of the EHS management system and EHS performance results. Contractors will be actively engaged in EHS management through periodic meetings.

All information and initiatives resulting from management reviews, audits and meetings will cascade down to all levels of the organization through a formal communication procedure.

8.8 Hazard and Risk Management

A Hazard and Effects Management Process (HEMP) or equivalent risk assessment methodologies will be implemented for the identification, assessment, control and mitigation of hazards throughout the Project life.

8.8.1 Concept Safety Analysis

This section discusses the Concept Safety Analysis (CSA) in the context of EnCana's risk management philosophy.

The Concept Safety Analysis will be the key starting point for risk management for the Project. It addresses the identification of the major accident events (MAE) associated with the facility, taking into account the basic design concepts, layout and intended operations within each phase of the life of the facilities. Further, it includes a determination of the frequency of occurrence and potential consequences of the identified MAE and details the safety measures designed to protect personnel and the environment from such accidents. The CSA will present the results of these assessments and compare them to the target levels of safety (TLS) established for the Project.

The CSA implementation plan will include hazard analyses, risk evaluation and safety studies that will be conducted during the MOPU bid competition phase. This approach involves the use of engineering judgement and qualitative and quantitative risk analyses. The CSA will determine the required focus, level of detail, and complexity of future safety studies. Prior to the start of the decommissioning and abandonment phase, a risk assessment and other required studies will be conducted to verify and validate the assumptions made during the design phase.

8.8.2 Hazard and Risk Assessment - Design

The Deep Panuke design philosophy is to provide a purpose-built facility, which ensures high standards of safety, environmental protection, quality, reliability, constructability, operability, and maintainability. EnCana will employ a systematic approach to identifying and addressing potential hazards, and defining appropriate control and recovery measures.

8.8.3 Target Levels of Safety

A fundamental objective of the offshore facilities design is the selection of design targets to protect the safety of personnel and the environment. These TLS will be used in the design to:

1. provide personnel with a safe work environment and the ability to effectively evacuate in an emergency; and
2. reduce the risks to personnel and the environment to ALARP.

In deriving the TLS for the Project, major accident and occupational hazard databases will be identified and referenced. Examples of major accidents and occupational events are listed below:

- fire and explosion;
- loss of containment;
- dropped objects;
- collisions at sea;
- helicopter crash;
- loss of structural integrity;
- extreme environmental conditions;
- major occupational hazards, (e.g. H_2S, heat radiation);
- loss of well or process control;
- natural seismic activity; and
- simultaneous drilling/production/construction operations.

The TLS will be based on the experience of Atlantic Canada and North Sea offshore petroleum Operators, and guidelines published by the U.K. Health & Safety Executive and NORSOK standards published by Standards Norway. They consist of risk-based criteria and impairment-based criteria. Seven TLS have been identified for the Project, as follows:

Risk-based Criteria

1. TLS 1: Individual Risk Criteria
2. TLS 2: Group Risk Criteria
3. TLS 3: Environmental Risk

Impairment-based Criteria:

4. TLS 4: MOPU Primary Structure
5. TLS 5: Temporary Refuge Impairment Frequency
6. TLS 6: Escape Routes
7. TLS 7: Evacuation Systems

The Basis of Design for the field centre, subsea facilities, and product export arrangements will incorporate the findings and recommendations identified through the CSA, and demonstrate the ability to meet TLS established by EnCana.

8.8.4 Hazard Register

Hazards and their associated risks controls will be recorded and tracked via a Hazard Register, which will be updated when new scenarios, control measures or design changes occur. The Hazard Register will feed into the Project Safety Plan and will be communicated to engineering teams. It will include hazards and risks identified by major contractors for their respective installations and/or operations.

8.8.5 Hazard and Risk Assessment – Construction

As the construction phase represents its own hazards, a CSP will be established and implemented as a subset of the PSP in conjunction with the major contractors. The CSP will specifically focus on contractor safety management, including the following:

- planning;
- pre-qualification and selection;
- pre-mobilization audits;
- pre-execution audits; and
- monitoring audits.

As previously noted, EnCana will require its contractors to implement a formal environmental, health and safety program. Bridging documents will be prepared to properly interface and manage areas where significant differences are found between the Contractor's and EnCana's EHS policies and practices. As a minimum, the contractor EHS program will address the requirements outlined in the CNSOPB "Operators Safety Plan Guidelines 3150-002". These requirements include, but are not limited to the following:

- an EHS organization;
- an EHS training and competency assurance program;
- EHS standards and procedures (e.g. ‘permit to work’ systems, job hazard analyses);
- methods and procedures for hazards and effects management;
- emergency response management;
- facility and equipment management;
- EHS inspections and audits; and
- incident/accident reporting, investigation and analysis.

During the construction phase, procedures will be in place to ensure the following:

- design validation and reviews;
- multi-disciplinary reviews;
- change control & validation;
- document control; and
- personnel induction, competence assurance and hand-over.

A Project management organization and appropriate resources will be assigned to ensure proper implementation of the CSP and EHS management system. Dedicated EHS staff will be assigned for monitoring contractor performance and implementation of safety procedures during the construction phase, such as work permit systems, job hazard analyses, and safe work practices. Any design changes that may be imposed by construction methods will be identified through quality assurance and risk management reviews and carefully evaluated to ensure the integrity of the hazards and effects management process.

Engineering assumptions and options that are agreed upon and translated into final design and construction will also be translated into ‘issued for use’ operations and maintenance manuals at the operations phase.

A system of EHS key performance indicators will be established to monitor safety and environmental performance and compliance with objectives.

8.9 Operations Safety Plan

The PSP will be succeeded by an Operations Safety Plan that documents all the hazards and effects associated with the facility and the corresponding control measures. These control measures will be translated into operations procedures, maintenance procedures, and emergency response systems.

Management of hazards during the operational phase will focus on procedural and administrative aspects. Hazard management techniques such as an effective permit to work system, job hazard analysis, EHS performance monitoring system, and contingency planning, will be implemented to address operations-specific hazards.

Production operations manuals, drilling operations manuals, and other manuals required for safe operations will be developed for routine activities. Formal maintenance management systems will be established to ensure safe and environmentally-sound operations of the production facilities.

Where operations involve simultaneous drilling, diving, or construction activities, procedures will be developed jointly with the contractors involved to ensure that these activities are conducted in a safe and coordinated manner. In these cases, the major contractors involved will be required to have or develop site-specific Safety Plans (e.g. Drilling Safety Plan, Diving Safety Plan), that meet EnCana's requirements.

8.10 Security Plan

Security threats and incidents will be managed under the Deep Panuke Emergency Management Plan. An Offshore Facility Security Plan conforming to API RP 70 *Security for Offshore Oil and Gas Operations* will be developed and implemented for the MOPU and drilling rigs. EnCana will ensure that Transport Canada-approved Security Plans complying with the Marine Transportation Security Regulations are developed and implemented at contracted or subcontracted vessels and the supply base. For foreign-flagged or contracted vessels, the requirements of the International Ship and Port Facility Security Code (ISPS Code) and SOLAS Amendments 2002 will be met to the extent applicable for operation in Canadian waters.

8.11 Abandonment and Decommissioning Safety Plan

At the end of the Project lifecycle, an Abandonment and Decommissioning Safety Plan will be developed that conforms to regulatory requirements applicable at the time of such activities.

9 ENVIRONMENTAL PROTECTION

Environmental protection is fundamental to EnCana's operations and forms an integral part of its EHS management system. EnCana is committed to the implementation of international best practices for environmental management systems. This section outlines EnCana's commitment to EHS management, with an emphasis on environmental management for the Deep Panuke Project.

9.1 Environmental Management Framework

EnCana's environmental management framework, shown in Figure 9.1, shows Project-specific plans as an integral part of EnCana's corporate responsibility (CR) policy framework. These plans will be developed and revised as the Project moves through the phases of design, construction, installation, production, and decommissioning. Inherent in the environmental management system is the provision for continual improvement, and adaptability to allow the system to respond to environmental challenges so that predicted and actual effects are managed effectively.

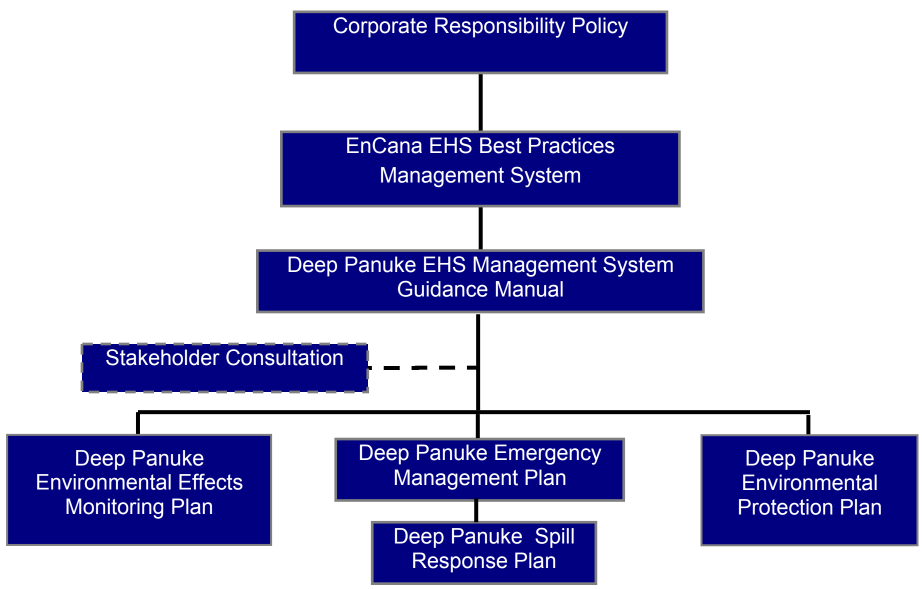


Figure 9.1 Deep Panuke Environmental Management Framework

9.1.1 Corporate Responsibility Policy

EnCana's CR Policy is outlined in Section 8.2.1. Under this Policy, EnCana is committed to the following:

- safeguarding the environment and operating in a manner consistent with recognized global industry standards in EHS;
- striving to make efficient use of resources, to minimize its environmental footprint, and to conserve habitat diversity and the plant and animal populations that may be affected by its operations; and
- striving to reduce its emissions intensity and increase its energy efficiency.

9.1.2 EHS Best Practices Management System

The EnCana EHS Best Practices Management System is a corporate-wide safety and environmental management system designed to guide all levels of employees, contractors and sub-contractors in achieving the desired level of EHS performance. The ten elements (outlined in section 8.2.3) that make up the best practices focus on areas that are applicable to all operating entities within EnCana. By following the programs, practices and procedures stemming from the best practices, EnCana meets its required accountabilities and, in turn, demonstrate sound EHS performance to its stakeholders.

Environmental management expectations and requirements are outlined for each of the ten elements and include the following:

- setting of environmental goals and performance objectives, and measurement and communication of performance;
- environmental risk assessment;
- emergency response planning and preparedness;
- training and competency to ensure that employees are aware of and trained on the environmental responsibilities associated with their job activities;
- practices to ensure environmentally-sound performance throughout the lifecycle of the asset;
- compliance with permits, regulations and legal requirements;
- evaluation and selection of third party goods and services for conformance with environmental standards and requirements;
- reporting, investigation and follow-up of environmental incidents; and
- system audit to identify opportunities for continuous improvement.

9.1.3 Deep Panuke EHS Management System Guidance Manual

The Deep Panuke EHS Management System Guidance Manual provides guidance to the Project team, including contractors, in implementing the expectations and requirements of the corporate EHS management system. Please refer to Section 8.2.4 for more details. The environmental component will provide an umbrella for environmental protection planning, environmental monitoring, and stakeholder consultations. It will provide a framework to document, evaluate and communicate Project environmental performance.

As shown in Figure 9.1, the following environmental management plans will be developed as a part of the Deep Panuke Project:

- Deep Panuke Emergency Management Plan (DPEMP);
- Deep Panuke Spill Response Plan;
- Deep Panuke Environmental Effects Monitoring Plan (EEMP); and
- Deep Panuke Environmental Protection Plan (EPP).

Details of the above-mentioned plans will be finalized once the Project design is complete. The plans will be developed in consultation with the applicable regulatory agencies to ensure that their concerns are addressed in the planning process. Full versions of these plans will be provided to the regulators for review prior to Project start-up.

9.2 Stakeholder Consultation

Inherent in the EnCana's EHS management system is the provision for stakeholder consultation, especially in relation to environmental issues. Stakeholders for the Deep Panuke Project include regulatory agencies, the fishing industry, non-government organizations, and the general public. With respect to environmental management, effective consultation is crucial for issues such as environmental assessment, environmental effects monitoring (EEM), environmental protection, emergency response, and compensation.

The objectives of the consultation program for the Deep Panuke Project are as follows:

- provide information to the public and interested stakeholders about the proposed Project in a timely fashion;
- provide opportunities for the public to have input into the Project to identify issues and concerns;
- provide early and adequate notice of these opportunities for involvement and input;
- seek advice from the scientific community to enhance environmental management; and

- develop relationships with stakeholders and Aboriginal groups, that can lead, where appropriate, to mutually beneficial relationships throughout the life of the Project, and also contribute to communications around other EnCana activities.

Section 5 and Appendices H and I of the EA Report (DPA Volume 4) describe the Project's public consultation program during various stages of the Project development.

9.3 Deep Panuke Emergency Management Plan

The Deep Panuke Emergency Management Plan described in Section 10.2 will contain specific provisions for the notification, assessment and response to environmental incidents. The Deep Panuke Spill Response Plan described in Section 9.4 will be a subset of the emergency management plan.

9.4 Deep Panuke Spill Response Plan

The Deep Panuke Spill Response Plan will be a subset of the emergency management plan described in 9.3. The anticipated table of contents is shown in Table 9.1. The purpose of this plan is to respond to spills that may result during offshore activities related to the development of the Deep Panuke Project. The plan will include planning considerations, response, and spill environmental effects monitoring. EnCana will make arrangements with third-party contractors for onshore spill response and clean-up.

9.5 Deep Panuke Environmental Effects Monitoring Plan

As part of its commitment to adaptive ecosystem management, EnCana will implement an environmental effects monitoring plan for the lifecycle of the Project. The EEMP will take into account the following:

- environmental effects predictions in the approved 2002 CSR and the 2006 EA Report and the resulting CSR;
- findings of the EEM program;
- mitigation measures for various effects, and

Table 9.1 Deep Panuke Spill Response Plan Table of Contents (Anticipated)

- issues that may arise regarding environmental sustainability. The issues to be addressed by EnCana include but are not limited to:
  - development of follow-up program principles;
  - refining the EEMP with updated information on marine birds;
  - management of spills and effects on marine birds;
  - influence of lighting and flaring on birds;
  - the development of a program to monitor project effects on the roseate terns;
  - development of a program to discourage all-terrain vehicle traffic on the pipeline row;
  - verification of the absence of species of special concern;
  - verification of the impacts of drilling muds and cuttings;
  - applicability of the national pollutant release inventory;
  - verification of the impacts of produced water discharges; and
  - consideration of resident organisms in the vicinity of the project and contaminant transport.

Specific programs to address these issues will be developed in consultation with the regulatory authorities having jurisdiction in such matters. It is anticipated that this planning process will be managed by the CNSOPB. The anticipated table of contents for the Deep Panuke EEMP is shown in Table 9.2.

9.6 Deep Panuke Environmental Protection Plan

EnCana will implement environmental protection measures, which will be documented in an EPP, to mitigate potential environmental effects from its activities. The EPP for EnCana's Deep Panuke Project will be developed during the detailed engineering phase of the Project in consultation with regulators and key stakeholders. It will be developed to ensure the implementation of EnCana's environmental commitments. The EPP will be updated as required over the life of the Project and will be consistent with the requirements of the CNSOPB's regulations and guidelines.

The EPP will include environmental protection procedures for general activities common to all phases in the Project lifecycle. The EPP will cover the various Project phases/activities/procedures to provide clear and specific instruction and guidance to employees and contractors during these short term, but critical, phases of Project development. The EPP will cover practices (referred to as plans in the approved 2002 CSR) such as spill response, waste and chemical management; activities associated with onshore and offshore construction and decommissioning and compensation for fishing and aquaculture vessel and gear damage. Corporate environmental Codes of Practice will also be included in the EPP. The strategy and overall approach to spill response will be dealt with in the DPEMP.

Table 9.2 Deep Panuke Environmental Effects Monitoring Plan Table of Contents (Anticipated)

1.0 PREFACE
- 1.1 Purpose
- 1.2 Scope
- 1.3 Organization
- 1.4 Maintenance

2.0 RESPONSIBILITIES AND TRAINING
- 2.1 Roles and Responsibilities
- 2.2 Training Requirements

3.0 PROJECT ACTIVITIES
- 3.1 Construction
  - 3.1.1 Pipeline (onshore, nearshore and offshore)
  - 3.1.2 Drilling
  - 3.1.3 MOPU Installation
- 3.2 Operations
  - 3.2.1 Produced Water
  - 3.2.2 Air Emissions
  - 3.2.3 Noise/Lights
  - 3.2.4 Spills
  - 3.2.5 Vessel & Helicopter Operations
  - 3.2.6 Pipeline
- 3.3 Decommissioning
- 3.4 Special Areas

4.0 EEM METHODS
- 4.1 Decision Criteria for Selection of Methods
- 4.2 Overview of Methods

5.0 CONSULTATION
- 5.1 Workshop Overview and Proceedings
- 5.2 Appropriate Stakeholder and Regulatory Authorities

6.0 IMPLEMENTATION
- 6.1 Timeline
- 6.2 Costs
- 6.3 Logistics

7.0 DOCUMENTATION & COMMUNICATIONS

8.0 REGIONAL EEM MECHANISM

9.0 KEY CONTACT LIST

9.6.1 Objectives

The EPP will be developed to provide detailed guidance for the Project team, including contractors, on methods of eliminating or minimizing and mitigating adverse environmental effects from the Project. Specific objectives will be to:

- ensure that EnCana's commitments to minimize environmental effects are met;
- document environmental concerns, applicable legislative requirements and appropriate protection measures;
- provide clear and specific guidance to employees and contractors regarding procedures for protecting the environment and minimizing environmental effect;
- provide a field-usable, reference document for personnel when planning and/or conducting specific activities;
- provide for appropriate training of employees/contractors;
- communicate changes in procedures through the specified revision process; and
- provide procedures for monitoring compliance with applicable regulations.

9.6.2 Scope

This document is applicable to all EnCana Deep Panuke operations, both offshore and onshore. All EnCana and third party personnel working on the Deep Panuke Project will be required to adhere to the requirements of the EPP. The EPP will be reviewed at least annually during the life of the Project to ensure its effectiveness.

9.6.3 Integration with Deep Panuke EHS Management System

The EPP will be a practical document containing environmental protection requirements and will serve as an important tool in staff orientation and training, and an integral component of environmental inspection under EnCana's Deep Panuke EHS Management System.

Environmental performance will be reviewed throughout the life of the Project. The EPP will reflect the commitments that EnCana has made in the EA Report and other DPA documentation, regulatory conditions of approval, and other regulatory requirements of the Project, and will be a critical tool in understanding and evaluating these commitments.

9.6.4 EPP Requirements

An important aspect of the EPP is Environmental Compliance Monitoring (ECM), which ensures compliance with all regulatory requirements and self-imposed environmental commitments. EnCana will use ECM to monitor performance standards developed for the Project. ECM will primarily involve monitoring for conformance with the discharge limits identified in the *Offshore Waste Treatment Guidelines* (NEB *et al.* 2002) and targets set by EnCana.

ECM procedures will be clearly defined in the EPP including sampling protocols, responsibilities, training requirements, and reporting. The EPP will address routine and abnormal conditions and emergencies that can reasonably be anticipated. Specifically, the CNSOPB's *Nova Scotia Offshore Area Petroleum Production and Conservation Regulations* stipulate the development of a program to monitor the environmental effects of routine operations from a production installation, and identification of the measures adopted to mitigate these effects. Compliance monitoring programs ensure that the composition of operational discharges is in accordance with the limits specified in the EPP.

The EPP will also affirm EnCana's adoption of the CNSOPB's *Compensation Guidelines Respecting Damages Related to Offshore Petroleum Activity* (March 2002).

The EPP will also include EnCana's Codes of Practice for Sable Island, the Gully MPA and Country Island. The intent is to provide requirements for the development and implementation of the Deep Panuke Project so that sensitive and valued local environmental components are protected. All EnCana personnel and its contractors must comply with these Codes. For further detail on these Codes, refer to Appendix G of the EA Report (DPA Volume 4).

Contractors' environmental protection measures for particular scopes of work such as those related to construction and installation activities, will comply with the EPP.

9.6.5 Responsibilities

To ensure the successful implementation of environmental protection procedures, the EPP will include a clear description of the roles and responsibilities of all personnel having environmental responsibilities. This description will provide clear direction related to accountability, lines of communication and reporting relationships.

The anticipated table of contents for the Deep Panuke EPP is shown in Table 9.3.

Table 9.3 Deep Panuke Environmental Protection Plan Table of Contents (Anticipated)

10 CONTINGENCY PLANNING

10.1 Introduction

The primary objective of contingency planning is to ensure the safety of Project personnel and the public and to protect the environment. Other important objectives are the protection from loss of the financial investment, investigation of the incident, and restoration of business continuity in the aftermath of an emergency.

Specifically, EnCana's principles to effectively manage incidents are as follows:

- protect human life, (workers, responders, public);
- effectively rescue and treat casualties;
- minimize environmental impacts;
- minimize damage to company, public and private property;
- effectively use the combined resources of EnCana, mutual aid partners, the government and other external services;
- provide factual information to news media and other stakeholders on a timely basis;
- preserve records and evidence for use in post incident investigations; and
- protect shareholder value.

The Deep Panuke Emergency Management Plan (DPEMP) will replace Alert/Emergency Response Contingency Plan (AERCP), which has been used for the Cohasset Project and EnCana's other East Coast offshore activities. The DPEMP will provide emergency response command and control functions for both onshore and offshore emergency situations and will cover foreseeable emergencies during all phases of the Deep Panuke Project. The DPEMP will take into account hazard identification and assessment, environmental considerations, consultation with government agencies, incorporation of industry best practice, and use of external support resources.

As a requirement of the EnCana EHS Best Practices Management System, the DPEMP will align with the corporate standard for emergency response plans with respect to the incident command structure and incident classification terminology. It will also conform to the CAPP "Guidelines for the Preparation of Emergency Response Plans", Canadian Standards Association (CSA) standard CAN/CSA-Z731 "Emergency Planning for Industry", and the Joint Rescue Coordination Centre (JRCC) "Search and Rescue Protocol for the Oil and Gas Industry".

The DPEMP will tie in three levels of operations: field, business unit, and corporate office, to ensure effective forward planning, communications and an effective overall response strategy. A copy of the

DPEMP will be filed with the CNSOPB and other relevant regulatory agencies prior to commencing operations.

The DPEMP will define the call-out procedures for the EnCana Incident Command Team, support resources, liaison with government agencies, communications with the corporate organization, media response, and communication with next of kin and relatives.

The MOPU and support vessels will have site-specific emergency response plans complying with regulatory requirements. These plans will ensure the effective mobilization of personnel, facilities, and onsite resources in the event of an on-site accident or incident. They will provide information on the incident type and severity, notification and mustering protocol, incident command team structure and key duties, response and evacuation procedures, communication protocol, and supporting forms and checklists.

Procedures will be developed to bridge the DPEMP and contractors' emergency response plans, when necessary, to ensure a coordinated response during an emergency.

EnCana's emergency preparedness process also involves all aspects of planning, training, exercising, response, and quality assurance. The DPEMP may be amended, as required, as the project progresses through the construction, drilling, operation, decommissioning, and abandonment phases of its lifecycle.

Figure 10.1 identifies the key components of EnCana's Emergency Preparedness.

10.2 Deep Panuke Emergency Management Plan

The DPEMP will outline the measures to effectively prepare for and respond to foreseeable emergency situations involving operations, equipment and products. The DPEMP will cover the following three broad areas of emergency management responsibility:

- provision of logistical, consultative advice and support to the field Incident Commander. Incident Commander is an incident command system terminology for the "person in charge" of on-scene response, for example, the Offshore Installation Manager, Vessel Master, or Helicopter Pilot;
- assessment of short and long term risks and impact of the emergency, and co-ordination of regulatory liaison, media communications and relative response; and
- appropriate notification of and communication with the EnCana Crisis Management Team.

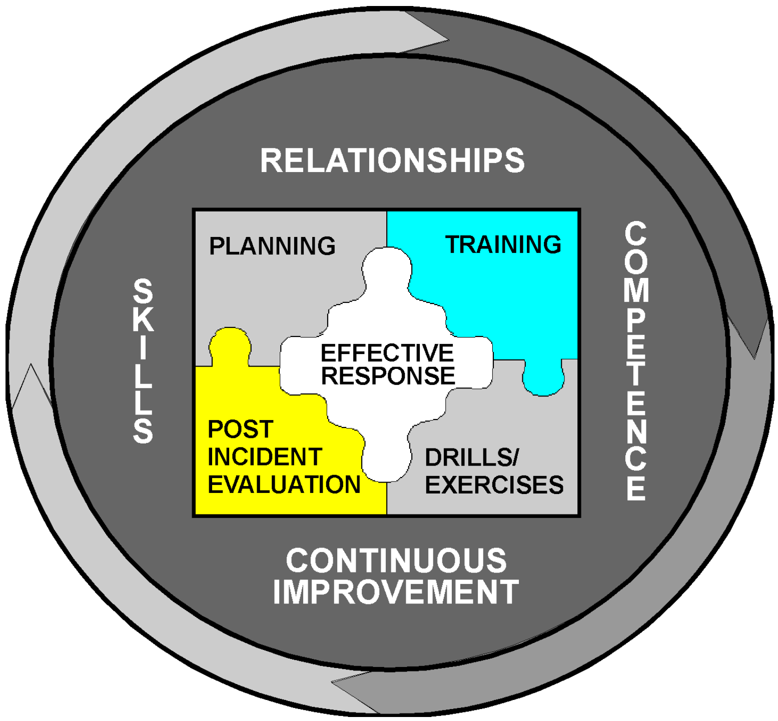


Figure 10.1 EnCana's Emergency Preparedness

The DPEMP will address or include the following:

- plan administration;
- incident command organization, roles and responsibilities;
- notification and communication protocol;
- emergency response actions based on incident severity classification;
- risk assessment criteria for developing incident action plans;
- emergency response procedures for serious injury/death, including medical evacuation, loss of well or process control, fire/explosion, overdue/lost craft, collision avoidance, diving emergency, spill incident, severe weather, and security incident/threat of criminal activity;
- JRCC liaison;
- support resources;
- media, next-of-kin and relative response procedures;
- business restoration/resumption planning;
- training requirements;

- supporting documentation including manuals, forms, checklists and information appendices, and
- auditing and continuous evaluation.

Additional information on specific emergencies that could occur during offshore activities is outlined as follows.

10.2.1 Loss of Well Control (Drilling & Well Servicing)

All plans and equipment necessary for the establishment and maintenance of well control will be completed and provided for offshore drilling operations, in compliance with CNSOPB requirements.

Procedures and equipment for well control, and early kick detection are covered by the "EnCana Well Control Procedures Manual" and the "EnCana Drilling Policies and Guidelines Manual" which will be updated for the Deep Panuke Project. This will include, but is not limited to, shallow gas, lost circulation, kicks and underground flows.

During workover and completion operations, a minimum two-barrier well control philosophy will be strictly adhered to. This ensures redundancy for well control against all predictable occurrences. This will include combinations of kill fluid, downhole plugs, blowout preventers, and wellhead safety valves.

The MOPU contractor's safety procedures for loss of process control will be reviewed to ensure compliance with CNSOPB regulations and the Deep Panuke project's safety design philosophy.

10.2.2 Subsea Pipeline Loss of Containment

Contingency procedures for loss of containment of the subsea pipeline will be included in the MOPU operations procedures manuals and supporting documentation. The mitigation measures will include the following:

- isolation procedures for ruptured flowlines (including closing SSSV), which include securing the area and notifying vessels in the vicinity;
- containment and clean up of spilled hydrocarbons using on-site and/or specialized third-party sourced equipment;
- repair procedures including mobilization of necessary equipment and services;
- inspection procedures for assessing the damage, adequacy of repairs and restart of operations;
- compensation considerations for damage to third party caused by pipeline incidents; and
- documentation to report and monitor spills, and to meet regulatory requirements.

10.2.3 Platform Incidents

Contingency procedures for incidents on the MOPU will be included in the MOPU Emergency Response Plan and its supporting documentation as noted previously. These incidents include injury/illness/death to personnel from operational or environmental hazards, structural failure resulting from environmental or operational forces, loss of containment, hydrogen sulfide release, fire/explosion, severe weather (storm winds and/or waves, ice accretion/impact), man overboard, manned diving emergency, and abandon platform.

10.2.4 Collision

To a large extent, fixed installations in the open sea rely on the skill and vigilance of mariners to avoid collision. Vessels approaching the installation must be detected and the potential threat to the installation assessed as early as possible. This is in order to initiate timely action and to advise the approaching vessel of the situation.

The collision hazard will be addressed by establishing a Safety Zone rising above the sea surface around the MOPU and potentially the subsea facilities, augmented by EnCana's existing collision-avoidance procedures. The Safety Zone, MOPU, infield flowlines, umbilicals, subsea equipment, hot tap location (SOEP Option) and export pipeline, including point of landfall (for M&NP Option) will be identified in nautical charts published by the Canadian Hydrographic Service and in the Notice to Mariners issued by the Canadian Coast Guard.

The premise for establishing the Safety Zone will be based on a risk assessment, regulatory requirements, fisheries considerations, and EnCana East Coast Collision Avoidance procedures. The procedures provide for the establishment of a "Collision Zone" 500 yards (~500m) around the installations and a "Near Miss" zone, having as its inner boundary the perimeter of the Collision Zone (500 m) and its outer boundary at 2.0 nautical miles from the installation. In addition, contacts with vessels with an estimated closest point of approach of between 2 and 5 nautical miles will be tracked and reported to the installation if radio contact cannot be established.

A dedicated 24-hour standby vessel will monitor potential incursions near and into the Safety Zone and will make the necessary interventions if required.

Active and passive navigational aids, such as radar transponders, fog horns, and lights, will be installed on the MOPU and other surface facilities. In addition, anti-collision radar will be operated on the MOPU and standby vessel. This will provide early warning of a potential collision hazard to personnel on the MOPU and offshore support vessels, and allow for the straying vessel to be warned and diverted. If the vessel cannot be diverted prior to collision, the production and/or drilling installations will be secured and personnel evacuated promptly. The operations and emergency procedures will address this kind of contingency.

10.2.5 Marine Incidents

Guidelines for the safe operation of vessels chartered by EnCana are addressed by the "EnCana Standby/Supply Vessels Operating Manual". Vessels chartered by EnCana will be certified by Transport Canada, insured, and will meet applicable regulatory requirements with respect to safe manning, emergency response equipment, plans and procedures, and crew emergency response training. EnCana will review the marine procedures manuals of chartered vessels and inconsistencies identified through this review will be addressed by way of bridging documents. A vessel tracking procedure will be implemented to stay updated on the vessel's position and mode of operations round the clock. If vessels are sub-contracted by contractors, the safety procedures to be followed will be bridged to EnCana's requirements.

10.2.6 Aviation Incidents

Project facilities will be designed to minimize the number of personnel involved in the operation of the offshore manned facilities to reduce the transportation risk to workers. EnCana will use Transport Canada-licensed helicopter contractors with eastern Canadian offshore flying experience, experienced pilots and ground staff. Installation helidecks will be designed to ensure that they comply with Transport Canada (Aviation Safety) regulations and the helicopter contractor's standards. Flight-following procedures will be implemented to track helicopter movements. A standby vessel will stay in close proximity to the MOPU during helicopter arrivals and departures. Pre-acceptance and routine audits of the helicopter contractor's maintenance, safety and operational documentation will be performed by EnCana.

A bridging document will be prepared to ensure that the MOPU helideck safety procedures are bridged with that of the aviation contractor. Alternatively, EnCana may elect to adopt the helicopter contractor's practices and procedures. Periodic exercises simulating crash landings on the facilities will be conducted and these exercises may involve personnel on the platform, standby and supply boats, other marine vessels and the helicopter contractor. The JRCC and government agencies, such as the CNSOPB and Transport Canada will be requested to participate in these exercises, when appropriate and available.

Personnel using helicopter transportation will receive training on how to react in the event of a helicopter accident, including escape and egress underwater. The use of helicopter survival suits and emergency breathing apparatus will be made a compulsory requirement for all passengers.

10.2.7 Fire / Explosion

The Deep Panuke Emergency Management Plan will address all levels of fires and explosions including the following:

- 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 and have the potential to cause major equipment loss, release of an explosive mixture, unconfined vapor cloud expansion or boiling liquid expanding vapor explosion.

For onshore fire incidents, site specific procedures will be developed to deal with the situation and to protect nearby residential or commercial premises and the general public.

10.2.8 Hydrogen Sulphide (H_2S) Release

A H_2S Contingency Plan conforming to API RP 55 'Recommended Practices for Oil and Gas Producing and Gas Processing Plant Operations Involving Hydrogen Sulfide' will be developed for the MOPU. The purpose of this plan is to ensure that the consequences of an escape of hydrogen sulphide are known, and that the preventive and mitigative actions are documented. Contracted drilling rigs will be required to have and implement H_2S contingency plans conforming to API RP 49 'Recommended Practice for Drilling and Well Servicing Operations Involving Hydrogen Sulfide'.

The H_2S Contingency Plan will be communicated to the Project team, including contractors, and regular drills and exercises will be conducted to ensure a high state of alert and response preparedness. The plan will include information on potential hydrogen sulphide release sources on the installation, detection and alarm systems, and control measures to be taken in the event of a release. A positively-pressurized temporary refuge will be established on the MOPU and a breathing air system will be installed on board.

In-field flowlines containing H_2S will be identified in nautical charts and may be included within the Project Safety Zone. Offshore support vessels will be equipped with H_2S detectors and respiratory protective equipment. H_2S training will be mandatory for all personnel traveling to or working in the field once operations commence.

10.2.9 Spills

The DPEMP will contain specific information on how EnCana will respond to spills or pipeline loss of containment and will be supplemented by the Deep Panuke Spill Response Plan and EPP. Please refer to Section 9 for details.

10.3 Accountability

A key component of the DPEMP is the accountability of personnel and their roles within the emergency response management system. These accountabilities are at all levels of the organization and specify various actions prior to, during, and after a response.

Senior management is accountable for endorsing the DPEMP and will ensure that the necessary resources are allocated to support its implementation. Field supervisors are expected to ensure that the system is properly implemented at the worksite and that an appropriate response is carried out. Each employee's responsibility is to ensure that they report emergencies immediately and conduct the on-site emergency response in compliance with their experience and training.

10.4 Training

All training records will be maintained throughout the Project team member's tenure with EnCana. Emergency response training requirements stipulated in the CAPP East Coast Offshore Training and Qualifications Practice will be followed for the duration of the Project. EnCana will support the Project team, including contractors, in achieving the highest levels of competency with regard to emergency response preparedness.

10.5 Drills and Exercises

10.5.1 Purpose of Exercising

Conducting emergency exercises allows EnCana to validate and improve response capability without actually going through real-life incidents. While meeting the needs and requirements of external parties, the internal benefits of exercising include the following:

- enhances emergency response capability;
- improves co-ordination and proficiency of tasks;
- identifies areas in need of program improvements;
- identifies resource requirements in terms of staffing, equipment, logistics or procedures;

- validates existing plans and procedures; and
- meets regulatory requirements.

10.5.2 Philosophy of Exercising

EnCana's overall philosophy to emergency response exercising is based upon the following principles:

1. **Validate vs. Test** – A test tends to imply a pass/fail relationship or the possibility of performing poorly. EnCana conducts exercises in order to identify areas for improvement, rather than to indicate a failure to perform.

2. **Training** - EnCana's second principle of emergency response exercising is that it should always provide positive learning opportunities and enable participants to demonstrate the use of skills and knowledge. Successful exercises and simulations maximize learning opportunities by developing an action plan to capitalize on the lessons learned and areas for improvement. This leads to a cycle of continuous improvement that extends beyond the participants or the individual business unit.

3. **Mix of Exercise Activities** - Utilizing a mix of exercise activities ensures an adequate level of capability is maintained, while ensuring the program is cost-effective. Exercise activities range from single function drill or table top discussion, to a complex full-scale exercise involving internal and external personnel.

4. **Exercise Scheduling** - Exercising should be scheduled and part of the overall emergency preparedness process.

11 REFERENCES

Kidston, A.G., D.E. Brown, B. Altheim, and B.M. Smith. 2002. *Overview of Hydrocarbon Potential of the Deep-Water Scotian Slope.*

National Energy Board (NEB), Canada-Newfoundland Offshore Petroleum Board (CNOPB) and Canada-Nova Scotia Offshore Petroleum Board (CNSOPB). 1999. *Guidelines Respecting the Selection of Chemicals Intended to be used in Conjunction with Offshore Drilling and Production Activities on Frontier Lands.*

National Energy Board (NEB), Canada-Newfoundland Offshore Petroleum Board (CNOPB) and Canada-Nova Scotia Offshore Petroleum Board (CNSOPB). 2002. *Offshore Waste Treatment Guidelines*. NEB, Calgary, AB.

DEVELOPMENT PLAN
PART 2: BIBLIOGRAPHY

EnCana Corporation hereby declares that certain designated material contained in Part 2 of the Deep Panuke Natural Gas Project Development Plan 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 expect 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 Proponent 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 (Canada) Act* 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:

EnCana Corporation
Deep Panuke Project
Suite 700, Founders Square
1701 Hollis Street
Halifax, NS
B3J 3M8

Attention: Donna Morykot, Regulatory Lead

Ref #	Reference Source	Year	Status
2.	**SUBSURFACE**		
2.1	Kidston, A.G., Brown, D.E., Smith, B. and Altheim, B., *The Upper Jurassic Abenaki Formation, Offshore Nova Scotia: A Seismic and Geologic Perspective*. Canada-Nova Scotia Offshore Petroleum Board, Halifax, Nova Scotia, 168 p.	2005	
2.2	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	*1990*	
2.3	Ziegler, P.A. *Evolution of the North Atlantic - An Overview,* In: *Extensional Tectonics and Stratigraphy off the North Atlantic Margins*, A.J. Tankard and J.R. Balkwill (Eds.) American Association of Petroleum Geologists, Memoir 46	1990	
2.4	Jansa L.F. and J.A. Wade. *Paleogeography and Sedimentation in the Mesozoic and Cenozoic, Southeastern Canada.* In: *Offshore Geology of Eastern Canada,* W.J.M. van der Linden and J.A. Wade (Eds.), Geological Survey of Canada, Paper 74-30	1975	
2.5	Given, M.M. *Mesozoic and Cenozoic Geology of Offshore Nova Scotia*, Bulletin of Canadian Petroleum Geology, Vol. 25, No.1	1977	
2.6	Withjack, M.O., P.E. Olsen, and R.W. Schlische. *Tectonic Evolution of the Fundy Rift Basin, Canada: Evidence of and Shortening During Passive Margin Development, Tectonics*, Vol. 14, No. 2	1995	

Ref #	Reference Source	Year	Status
2.7	Eliuk, L.S. *The Abenaki Formation, Nova Scotia Shelf, Canada - A Depositional and Diagenetic Model for a Mesozoic Carbonate Platform*, Bulletin of Canadian Petroleum Geology, Vol. 26, No. 4	1978	
2.8	Weissenberger, J., Harland, N., Hogg, J. and Syhlonyk, G., Sequence Stratigraphy of Mesozoic Carbonates, Scotian Shelf, Canada. In: GeoCanada 2000 Convention (CSPG-GAC etc.) CD disk Paper No. 1262.	2000	
2.9	Al-Aasm, Ihsan, *Petrography, Stable Isotopes, Sr Isotopes and Fluid Inclusion Analysis of the Jurassic Abenaki Formation,* EnCana Internal Report.	2003	Confidential
2.10	Dravis, J.J., *Petrographic evaluation of samples from the Abenaki Formation, offshore Nova Scotia (wells G-32, L-97, P-23, G-13, P-15, I-100, K-62 and PP-3C),* EnCana Internal Report.	1999	Confidential
2.11	Dravis, J.J. *Diagenesis and Porosity Evolution of Abenaki Carbonates, Panuke Field, Offshore Nova Scotia: Implications for Controls on Reservoir Quality*, EnCana Internal Report	2001	Confidential
2.12	Dravis, J.J., *Diagenesis and Porosity Evolution of Abenaki Carbonates, Panuke Field, Offshore Nova Scotia: Well F-70*, EnCana Internal Report.	2003	Confidential
2.13	Gillen, K., *Fracture Study, EnCana Murphy Margaree F-70 Core, Offshore Nova Scotia, Canada*, EnCana Internal Report.	2003	Confidential
2.14	Skrypnek, T., Corbett, N., Tonn, R. and Uswak, G., *Reservoir Modelling and Gas Resources, Deep Panuke Pool,* EnCana Internal Report.	2006	Confidential

Ref #	Reference Source	Year	Status
2.15	Core Laboratories Canada Ltd., *PCP Panuke H-08, Routine Core Analysis, Report #52143-00-9084*.	2000a	
2.16	Core Laboratories Canada Ltd., *PanCanadian NSRL Panuke PI-1A, Routine Core Analysis, Report #52144-99-8018.*	2000b	
2.17	Core Laboratories Canada Ltd., *EnCana et al Margaree F-70, Routine Core Analysis, Report # 52132-03-0271.*	2004a	
2.18	Eliuk, L., *Margaree F-70 Detailed Cuttings and Core Description, EnCana Internal Report*	2005	Confidential
2.19	Core Laboratories Canada Ltd., *Advanced Rock Properties Study for EnCana Corporation EnCana Margaree F-70, Report # 52132-03-0680.*	2004b	
2.20	Core Laboratories Canada Ltd., *Advanced Rock Properties Study for PanCanadian Resources PCP Panuke H-08, Report # 52132-01-1105 – Gas Regain Permeability.*	*2001c*	
2.21	Core Laboratories Canada Ltd., *Advanced Rock Properties Study for PanCanadian Resources PCP Panuke H-08, Report # 52132-01-1063 - Mercury Injection Capillary Pressure.*	2001a	
2.22	Core Laboratories Canada Ltd., *Advanced Rock Properties Study for PanCanadian Resources Panuke H-08, M-79, F-09, Report # 52132-01-1076- Air-Brine Centrifuge Capillary Pressure Testing*	2001b	

Ref #	Reference Source	Year	Status
2.23	Terra Tek, *Compressibility Measurements Deep Panuke Carbonates Report #TRD4-401037*	2004	
2.24	Omni Laboratories Inc., *Pc/FF/RI Deep Panuke (F-70-four samples), File # S-00207*, EnCana Internal Report.	2004	
2.25	Peeters, M. and Visser, R., *A Comparison of Petrophysical Evaluation Packages: LOGIC, FLAME, ELAN, OPTIMA, and ULTRA*, The Log Analyst, v. 32, no. 4, p. 350-357.	1991	
2.26	Paradigm Geophysical Limited, *Geolog Multimin Reference Guide*, PTGL 0022.008.	1999	
2.27	Paradigm Geophysical Limited, *Geolog Reference Guide,* PTGL 0020.008.	1999	
2.28	Watfa, M. and Nurmi, R., *Calculation of Saturation, Secondary Porosity and Producibility in Complex Middle East Carbonate Reservoirs*, Transactions of the SPWLA 28th Annual Logging Symposium .	1987	
2.29	Lucia, F.J. 1995, *Rock-Fabric/Petrophysical Classification of Carbonate Pore Space for Reservoir Characterization*, American Association of Petroleum Geologists, Bulletin, Vol. 79, No 9.	1995	
2.30	*Deep Panuke Well Petrophysical Cross-Section and Reservoir Map Series*, EnCana Internal Report	2006	
2.31	Cox, W., *Deep Panuke and Regional Abenaki* Confidential Hydrodynamic Evaluation, EnCana Internal Report	2001	Confidential

Ref #	Reference Source	Year	Status
2.32	*Well Test Summary Report, Deep Panuke*, EnCana Internal Report	2006	Confidential
2.33	Shultze, K., Brudy, M. and Moos, D., GMI, *Ocean Tide Loading for the Deep Panuke Gas Reservoir Offshore Eastern Canada,* EnCana Internal Report, 26p.	2005	Confidential
2.34	*Reservoir Fluids Basis of Design,* ECB-SU-BOD-00001-000, EnCana Internal Report	2004	Confidential
2.35	*Abenaki Formation Water Composition Report*, DP20-1D-0014, EnCana Internal Report	2004	Confidential
2.36	*Flow Assurance Deep Panuke Production Wells,* DP20-1D-0008, EnCana Internal Report	2002	Confidential
2.37	*Deep Panuke Synthetic Seismograms ,* EnCana Internal Report	2006	
2.38	*Acid Gas Disposal- Subsurface Summary Report*, ECB-SU-BOD-00001-000, EnCana Internal Report	2006	Confidential
2.39	*Acid Gas Disposal – Petrophysical Cross Section and Structure Maps (Upper Mississauga and Naskapi Formation)*, EnCana Internal Report	2006	
2.40	*Deep Panuke Simulation Individual Well Forecasts*, EnCana Internal Report	2006	Confidential
3.	**WELL CONSTRUCTION**		
3.1	*Preliminary Casing and Tubing Design,* EnCana Internal Report	2001	Confidential
3.2	*Existing Deep Panuke Casing and Cement Details*, EnCana Report	2001	Confidential

Ref #	Reference Source	Year	Status
6.	**DEVELOPMENT ECONOMICS**		
6.1	*Deep Panuke Development Economics 2006: Input Assumptions*, EnCana Internal Report	2001	Confidential