

Hebron

HEBRON PROJECT

Development Plan

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ExxonMobil



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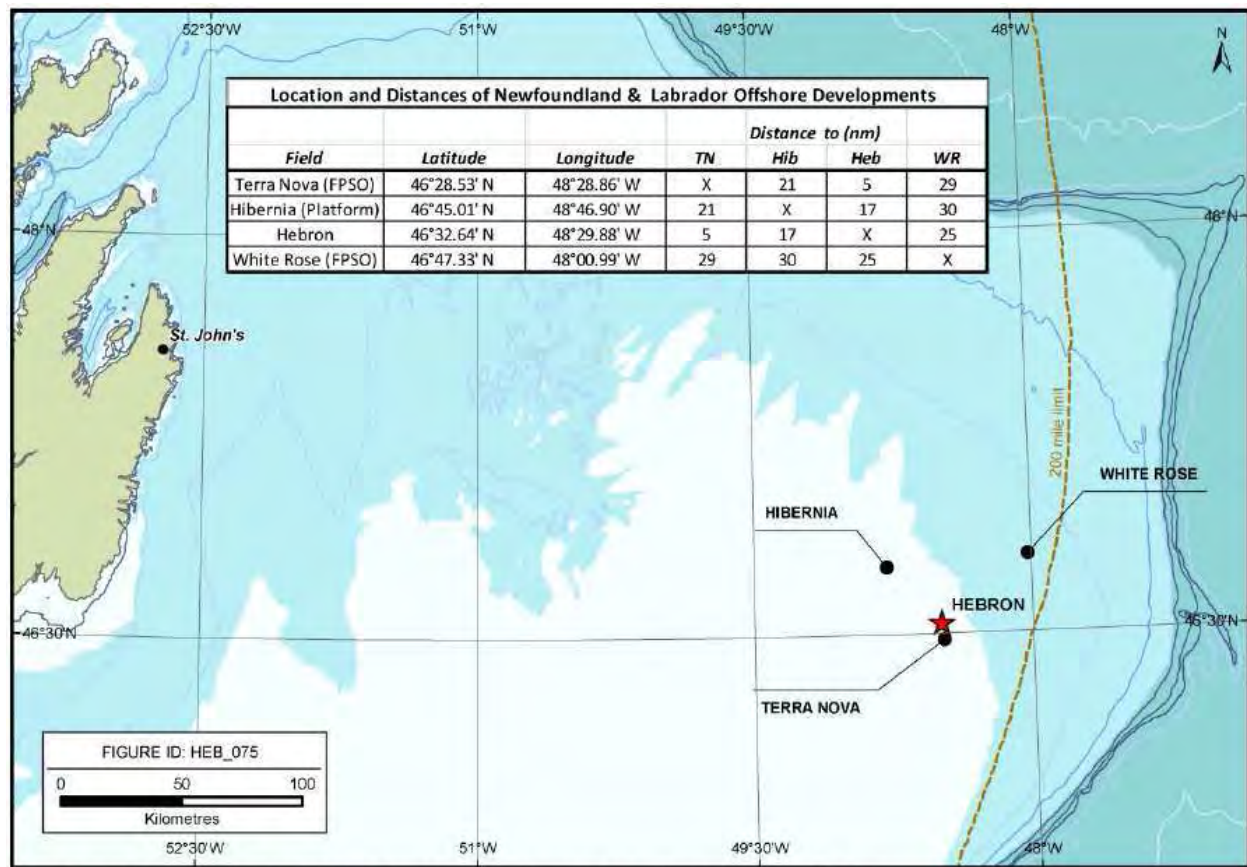
1 OVERVIEW

ExxonMobil Canada Properties (EMCP), as Operator, on behalf of the Hebron Project proponents, ExxonMobil Canada Properties, Chevron Canada Limited, Petro-Canada Hebron Partnership through its managing partner Suncor Energy Inc., Statoil Canada Ltd. and Nalcor Energy – Oil and Gas Inc., is leading the development of the Hebron Project offshore Newfoundland and Labrador. The Hebron Project will be the fourth stand-alone development project on the Grand Banks and, considering the two tie-back projects to the Hibernia and White Rose facilities, the sixth offshore petroleum project. The Hebron Project includes offshore surveys, engineering, procurement, fabrication, construction, installation, commissioning, development drilling, production, operations and maintenance and decommissioning of an offshore oil / gas production system and associated facilities.

1.1 Hebron Project Area

The Hebron Project Area is located in the Jeanne d'Arc Basin (centred at approximately 46°32.64344 min. N; 48°29.88379 min. W), 340 km offshore of St. John's, Newfoundland and Labrador, approximately 9 km north of Terra Nova, 32 km southeast of Hibernia, and 46 km southwest of White Rose (Figure 1.1-1). The water depth ranges from 88 to 102 m.

The Hebron Asset currently contains three discovered fields (the Hebron Field; the West Ben Nevis Field and the Ben Nevis Field) and incorporates four Significant Discovery Licences (SDLs) (SDL 1006, SDL 1007, SDL 1009 and SDL 1010) (Figure 1.1-2). These four SDLs contain the most likely extent of the oil for the delineated pools within the Hebron Asset. The Hebron Asset could be expanded if additional studies, seismic surveys, or exploration and/or delineation drilling proves that economically recoverable oil pool accumulations extend beyond the currently envisioned boundaries of the Hebron Asset.



Note: The distances in the inset table above are in nautical miles (1 nm = 1.85 km)

Figure 1.1-1: Hebron Project Location

1.3 Project Need and Justification

The Hebron Project will be a major contributor to the economic development of Newfoundland and Labrador, as well as to Canada. The Hebron Project will be Newfoundland and Labrador's fourth offshore oilfield development project. As such, it will build on and contribute to the multi-phase offshore petroleum industry in the province. In particular, the Project will provide substantial benefit through diversity programs, employment and training opportunities, business opportunities for the local service and supply community, and research and development opportunities, further expanding the province's industrial capabilities.

The Hebron Project's contribution to a sustainable economic development within the province is described in detail in the Socio-economic Impact Statement and the Canada-Newfoundland and Labrador Benefits Plan for the Project. In 2008, the Project Proponents and the province signed a Benefits Agreement. Through this Agreement, the Hebron Project has made significant commitments to the people and government of the province for engineering work, diversity programs, education and training, research and development, and construction and fabrication in the province.

The Project has committed to providing significant person-hours of work in Newfoundland and Labrador during the six-year design, fabrication and construction phase, including local project management, front-end engineering and design (FEED), detailed design and construction of the Gravity Base Structure (GBS), with additional employment during construction of Topsides modules.

During the operations phase there will be employment opportunities in areas such as logistics, engineering and technical support, drilling and production, marine support vessels (helicopters, supply vessels, tankers), catering, and similar onshore support. These opportunities during construction and operations will further develop the capabilities of Newfoundland and Labrador companies and individuals working on the project, and thereby enable local companies and individuals to develop capabilities to compete internationally on future opportunities.

Throughout its operations, the project will also contribute substantial revenues to the provincial government through corporate taxes and royalty payments. If approved, the Hebron Project will extend the life of the offshore oil and gas industry in Newfoundland and Labrador. It represents an important next step in the development of a sustainable offshore oil and gas industry in Newfoundland and Labrador.

1.4 The Hebron Asset

1.4.1 History

Oil was initially discovered in the Hebron Project Area in the Ben Nevis I-45 well in 1980. Test results showed uneconomic rates of oil in the Ben Nevis reservoir, and gas / condensate in the A Marker and Lower Hibernia reservoirs. The initial I-45 discovery was followed by two phases of delineation drilling. In the first phase of delineation drilling, the Hebron I-13 well was drilled in 1981 to evaluate the potential of the 'Hebron horst' fault block. The well was drilled to assess the structurally highest point of the fault block at the Hibernia and Jeanne d'Arc reservoirs, and tested oil in these reservoirs. The well also penetrated the Ben Nevis reservoir in the downthrown fault block to the south, and tested oil. The West Ben Nevis B-75 well was drilled in 1985 to evaluate the fault block between the I-45 and I-13 wells. This well tested oil in the Ben Nevis, A Marker, and Jeanne d'Arc reservoirs. The North Trinity H-71 was also drilled in 1985 to assess these reservoirs, but found no significant amounts of hydrocarbon. The hydrocarbon that was discovered in this first round of drilling was deemed uneconomic, for the time, due to either the poor oil quality or the poor reservoir quality.

A second phase of delineation drilling began in 1996 to test if there was an economic upside to the Hebron Project Area. The D-94 well was drilled to test the Ben Nevis reservoir on the 'Hebron horst' fault block in early 1999. The well encountered over 1 Billion barrels Stock Tank Original Oil In Place (STOOIP) and better reservoir and oil quality than observed in the I-13 well. The D-94 well encountered the same oil water contact as identified in the I-13 well, indicating that the I-13 fault block was in communication over geologic time with the D-94 fault block. The Ben Nevis L-55 well was drilled in 1999 to evaluate the potential for higher structure and better reservoir quality in the Ben Nevis reservoir of the Ben Nevis fault block. The well encountered higher structure than the I-45 well and a gas cap to the pool. The Hebron M-04 well was drilled in 2000 to investigate a seismic incised valley-fill feature at the top of the Jeanne d'Arc horizon (H sand), and to extend and gather data on the existing Ben Nevis, Hibernia, and Jeanne d'Arc reservoirs. The well tested oil in the Ben Nevis and Jeanne d'Arc H sand. The second phase of delineation drilling added significant recoverable resources to the Hebron Project Area and helped to resolve subsurface uncertainty.

1.4.2 Hebron Asset

The Hebron Asset is composed of four reservoir intervals organized into several normal fault-bounded fault blocks. The central horst block is the Hebron field, and the down-dropped fault blocks to the north-east are the West Ben Nevis and Ben Nevis fields. The down-dropped fault block to the

south-west forms the Southwest Graben (Figure 1.4-1). The four stratigraphic units are the Late Jurassic Jeanne d'Arc formation, the Early Cretaceous Hibernia formation, the Early Cretaceous Avalon formation and Early Cretaceous Ben Nevis formation.

The four vertically stacked reservoirs and multiple fault blocks contribute to the complexity of the multiple hydrocarbon columns with different contacts at the Hebron Asset. To simplify communication, the Hebron Asset is currently divided into five major pools (although other hydrocarbon-bearing pools beyond these exist). The pools, shown in Figure 1.4-1, are defined in Table 1.4-1.

Table 1.4-1: Hebron Asset Hydrocarbon Pools

Field	Reservoir	Wells	Pool Identifier
Hebron Field	Ben Nevis Reservoir	Including the fault block penetrated by the D-94 and M-04 wells and the fault block penetrated by the I-13 well	Pool 1
Hebron Field	Hibernia Reservoir	Defined by the I-13 and M-04 wells	Pool 5
Hebron Field	Jeanne d'Arc Reservoir, including the isolated B, D, G, and H hydrocarbon-bearing sands	Defined by the I-13 and M-04 wells	Pool 4
West Ben Nevis Field	Ben Nevis Reservoir	Penetrated by the B-75 well	Pool 2
West Ben Nevis Field	Avalon Reservoir	Defined by the B-75 well	Pool 3
West Ben Nevis Field	Jeanne d'Arc Reservoir	Penetrated by the B-75 well	unassigned
Ben Nevis Field	Ben Nevis Reservoir	Defined by the L-55 and I-45 wells	Pool 3
Ben Nevis Field	Avalon and Hibernia Reservoirs	Penetrated by the I-45 well	unassigned

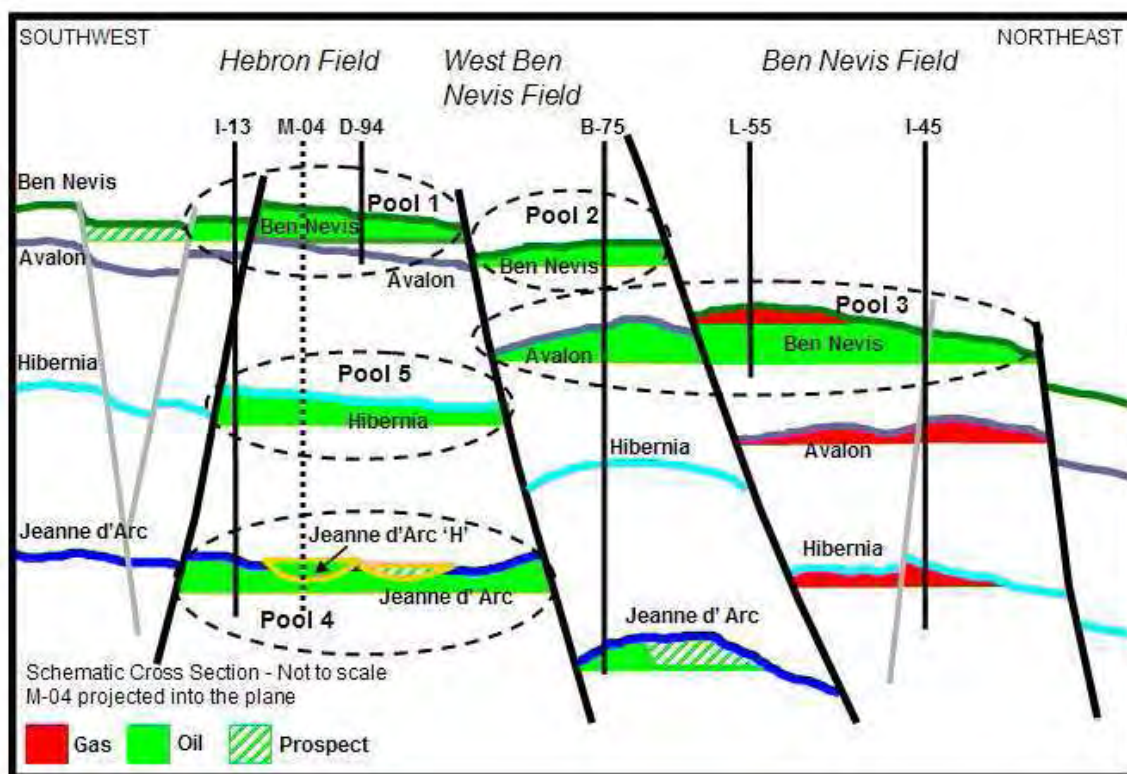


Figure 1.4-1: Schematic Cross-section across the Hebron Project Area

The Ben Nevis Reservoir within the Hebron Field (Pool 1) is the core of the Hebron Project, and is anticipated to produce approximately 80 percent of the Hebron Project's crude oil. However, the 20°API crude in this reservoir presents production challenges, as the viscosity can be 10 to 20 times higher than that of water.

The Jeanne d'Arc and Hibernia Reservoirs within the Hebron Field (Pools 4 and 5) and the Ben Nevis Reservoir of the West Ben Nevis and Ben Nevis Fields (Pools 2 and 3) are also significant resources within the Hebron Asset. Relative to the Hebron Ben Nevis Reservoir, the Jeanne d'Arc and Hibernia Reservoirs have higher oil quality but decreased reservoir quality consistent with deeper burial and cementation. The Jeanne d'Arc Formation has lower reservoir quality than the Jeanne d'Arc Formation of the Terra Nova Field, just as the Hibernia Formation at Hebron has lower reservoir quality than the Hibernia Formation of the Hibernia Field.

A depletion strategy for each of the reservoirs in the Hebron Project Area is discussed in Section 6. The depletion strategy balances economic value, risk mitigation and overall development flexibility to allow the reservoirs to be effectively managed over the life of the field. All reservoirs within the Hebron Asset are being evaluated with respect to risked production performance.

The initial development phase focuses on developing crude oil resources from the Ben Nevis, Hibernia and Jeanne d'Arc H and B Reservoirs within the Hebron Field. The Hebron Proponents have also assessed the Ben Nevis Reservoir within the Ben Nevis Field to an extent necessary to present a development plan for C-NLOPB review and approval.

Therefore, this Development Plan describes the plans to implement a platform development of the Hebron Field resources as well as a potential subsea tie-back development of the Ben Nevis Field resources.

Three concept options are currently being considered for the development of the Ben Nevis Reservoir within the Ben Nevis Field namely drilling of appraisal well(s) (Option 1), implementation of a production pilot (Option 2) or a subsea development (Option 3). The merits of each option are discussed in Section 6.5. Success with either Option 1 or 2 could lead to a development similar to Option 3.

Forecasted cumulative oil recovery from these resources after 30 years of producing life ranges from 105 Mm³ (660 MBO) to 168 Mm³ (1055 MBO).

There are also ongoing evaluations to consider development of additional resources in the Hebron Project Area, depending on the results of further drilling, production performance of the initial drill wells, studies, possible delineation wells, additional seismic data or some combination of these. In anticipation of potential expansion development, the GBS will be designed to include 52 well slots. To maximize resource development, slots may later be reclaimed for re-use. Expansion development could also occur from subsea tie-back from drill centres. The platform will have space available for future installation of production facilities and J-tubes and / or risers to allow for such future expansion.

The formation gas produced in association with oil production will be used principally to meet the fuel requirements for the production and drilling facilities. During periods when the volume of produced formation gas exceeds operational requirements, the surplus gas will be injected into one of the Hebron area reservoirs for storage and / or pressure maintenance purposes. Later in field life, the gas production rate is expected to decrease in conjunction with a natural decline in oil production. If the level of gas production falls below the volumes required for platform operations, the gas previously stored may need to be withdrawn in order to provide fuel for platform operations. In addition, other reservoirs in the Hebron Project Area, such as the gap cap of the Ben Nevis Reservoir in the Ben Nevis Field (Pool 3), will be considered as potential gas sources. The gas management plan takes into account a number of considerations, including:

- ◆ Use of associated gas in applying artificial lift to oil producing wells
- ◆ Fuel requirements are expected to vary with time
- ◆ Down-time gas flaring (not continuous)

- ◆ Prospective subsurface location(s) for storing any temporary surplus of produced gas
- ◆ Potential need to withdraw gas that has previously been stored in order to provide fuel for platform operations
- ◆ Potential for using gas in any enhanced oil recovery method in the Hebron Project Area, should such a method be deemed technically and commercially viable
- ◆ Potential for future commercial gas production

1.5 Scope of the Project

The Hebron Project includes a combination of works and activities, onshore and offshore, necessary for the construction and operation of an offshore oil production system and associated facilities to allow the exploitation of the hydrocarbon resource accumulation.

1.5.1 Project Components

Over the life of the project activities will likely include:

- ◆ Construction of topside modules at a variety of fabrication locations and delivery to the Nalcor Energy - Bull Arm Fabrication facility in Bull Arm, Trinity Bay for integration
- ◆ Construction of a GBS and mating of topside modules with the GBS at the Nalcor Energy - Bull Arm Fabrication facility in Bull Arm, Trinity Bay
- ◆ Tow-out of platform to its offshore location
- ◆ Offshore site and clearance surveys, including geophysical, geological, geotechnical, and environmental (including iceberg surveys)
- ◆ Installation of the platform at its offshore location (may include site preparation activities such as clearance dredging, seafloor levelling, underbase grouting, offshore solid ballasting, and placement of rock scour protection on the seafloor)
- ◆ Platform hook-up and commissioning
- ◆ Operation, maintenance, modifications, decommissioning of the platform petroleum production facility
- ◆ Drilling operations from the platform, including well testing, well completions and workovers, wellsite / geohazard surveys
- ◆ Operation of one or more mobile offshore drilling units (MODUs) for subsea developments

- ◆ Construction, installation, maintenance, abandonment / decommissioning of one or more excavated drill centres and associated equipment for subsea developments; may include the disposal of dredged material at one or more offshore locations
- ◆ Construction (including trenching, excavation, covering and/or spoil deposition), installation, maintenance, protection, and abandonment / decommissioning of subsea flowlines, umbilicals and associated equipment (inclusive of water, gas and oil flowlines) tied back to the Hebron Platform
- ◆ Installation of additional production facilities on the Hebron Platform
- ◆ Construction, installation, operation, maintenance of an offshore loading system (OLS) (may include dredging activities, pile driving, installation and insulation of riser and OLS (rock dumping, concrete mattress pads, etc.)
- ◆ Tankering operations
- ◆ Supporting activities, including platform supply operations, helicopters, standby vessels, diving programs, remotely operated vehicle (ROV) surveys and operation of support craft associated with the above activities
- ◆ Seismic programs and other geotechnical and/or geophysical activities

1.5.2 Potential Expansion Activities

- ◆ Seismic programs and other geotechnical and/or geophysical activities
- ◆ Installation of additional production facilities on the Hebron Platform
- ◆ Operation of one or more MODUs
- ◆ Construction, installation, maintenance, abandonment / decommissioning of excavated drill centres and associated equipment within the Hebron Asset; may include the disposal of dredged material at one or more offshore locations
- ◆ Construction (including trenching, excavation, covering and/or spoil deposition), installation, maintenance, protection, and abandonment / decommissioning of subsea flowlines, umbilicals and associated equipment (inclusive of water, gas and oil flowlines) tied back to the Hebron Platform
- ◆ Supporting activities, including diving programs, ROV surveys and operation of support craft associated with the above activities

1.6 Overview of Approach to Project Management

EMCP will be the Operator of the Hebron Project. The Operator's authority, role, responsibility and reporting requirements are outlined in the Hebron,

Ben Nevis and West Ben Nevis Unitization and Joint Operating Agreement (JOA). A management committee will establish overall Proponents' requirements and annual budgets. EMCP will review, on a regular basis, the development status with the Proponents who will provide advice and guidance per the JOA. EMCP will manage and direct all aspects of the development within the authority and approval parameters of the JOA.

The Hebron Project will use ExxonMobil's proven project management system that is utilized worldwide. The system has been developed with sound project management processes designed to ensure successful execution of major capital project developments. The structured activities included in the process are designed to assure that projects are conducted in a safe and environmentally responsible manner, deliver assets of appropriate quality, meet cost and schedule expectations, and achieve commercial success.

Hebron's project management approach will encompass:

- ◆ Commercial Development Business Planning
- ◆ Evaluation and Selection of Development Alternatives
- ◆ Final Scope Definition, Detailed Design of Selected Facility Development, Construction, Installation, and Operational Plan Development
- ◆ Execution of Fabrication, Construction, Installation, Hook Up, and Commissioning of Facilities
- ◆ Start-up and Operation of Facilities

The Hebron Project Team will employ a contracting philosophy to award work, in accordance with the Hebron Project Benefits Plan, to contractors whose experience and capability will minimize risk to project success, thereby optimizing execution certainty.

It should be noted that submission of this Development Plan is based on completion of our conceptual engineering studies, which were carried out to demonstrate the feasibility of the proposals contained in the application. As engineering studies progress, these concepts will be refined and revised.

1.7 Alternatives to the Proposed Project

1.7.1 Project Alternatives Evaluation and Screening Criteria

An extensive process was undertaken to review the alternative development concepts for the Hebron Project.

Economic analysis considering ranges for variety of input parameters including, but not limited to, facility costs, production profiles, and oil prices was used to assist the concept selection process.

Assessments were made regarding the robustness of various concepts under a particular scenario. In each case, the ability to mitigate a downside risk or take advantage of an upside opportunity was considered. Among the scenarios considered were:

- ◆ Downside reservoir performance
- ◆ Operability challenges
- ◆ Cost and schedule challenges
- ◆ Upside reservoir performance

A number of other decision criteria were considered for the Hebron Project, including:

- ◆ Safety and environmental performance
- ◆ Regulatory compliance
- ◆ Benefits to Canada / Newfoundland and Labrador
- ◆ Economic metrics (e.g., net present value, rate of return, profit to investment ratio)
- ◆ Mitigation of downside reservoir risk (including the use of phasing)
- ◆ Operability risk (e.g., wet vs. dry wellheads, artificial lift options, sand control vs. stand alone screens)
- ◆ Cost and schedule risk
- ◆ Technology application risk for the environment (e.g., disconnectable turret)
- ◆ Ability to capture upside potential
- ◆ Operating costs
- ◆ Capital exposure

The Hebron Project Team screened each development concept using criteria listed in Table 1.7-1 to narrow the options to four project alternatives, each of which is discussed in detail below.

Table 1.7-1: Selection Criteria for Alternatives Screening

Criteria		Level 1	Level 2	Level 3
Evaluation Criteria	Technically feasible / practical	Comparative		
	Compliance with applicable regulatory requirements and Proponent's safety, health and environmental standards		Comparative	Comparative – some quantitative analysis
	Value creation (net present value, rate of return)		Deterministic	Fully risked
	Option value (opportunity for reservoir risk mitigation and upside value capture)		Comparative	Quantitative
	Canada-Newfoundland and Labrador Benefits	Comparative	Comparative	Quantitative
	Project schedule to first oil	Comparative	Comparative	Quantitative
Risks	Concept technology maturity and risk	Comparative	Comparative	Quantitative
	Reservoir uncertainty	Comparative	Comparative	Quantitative
	Capital exposure		Comparative	Quantitative
Inputs	Capex and Opex estimates		Class 1 (±50%)	Class 2 (±30%)
	System availability (uptime)	Comparative	Comparative	Quantitative
	Production profiles		Deterministic	Case specific
	Fiscal parameters		Deterministic	Quantitative

1.7.2 Alternative Means of Offshore Development

The selection of the preferred concept for development of the Hebron Project included consideration of environmental effects, safety, capital and operating cost, reliability, energy efficiency, constructability and schedule for construction. Four potential concepts were considered in detail:

- ◆ Subsea wells tied back to Hibernia Platform
- ◆ Floating Production, Storage and Offloading (FPSO) facility in combination with subsea wellheads (wet tree), manifolds, pipelines and risers
- ◆ FPSO in combination with wellhead gravity base structure (WHGBS)
- ◆ GBS (with or without pre-drill alternative)

1.7.2.1 Tie-back to Hibernia

In this concept (Figure 1.7-1), subsea wells would be drilled by a MODU over the life of the Hebron Project. Subsea equipment, including metering facilities, would be installed in two excavated drill centres, one for the Ben

Nevis horizon wells and another for the Hibernia and Jeanne d'Arc wells. The produced fluids would be delivered to the Hibernia Platform (31.5 km to the north) from the excavated drill centres by two insulated, subsea, multi-phase, production lines using multiphase pumps (MPPs).

The production lines would have round-trip pigging capability. The power for the MPPs would be supplied by two independent power cables from the Hibernia Platform. Two umbilicals would control the subsea wells and isolation valves. Gas lift would be delivered from the Hibernia Platform to the subsea wells. Injection water would be supplied from the Hibernia Platform via a water injection line. All the flow lines, power cables and umbilicals would be installed in trenches to protect them from iceberg scour. Modifications to the separation, compression, power generation and water injection systems on the Hibernia Platform would be required.

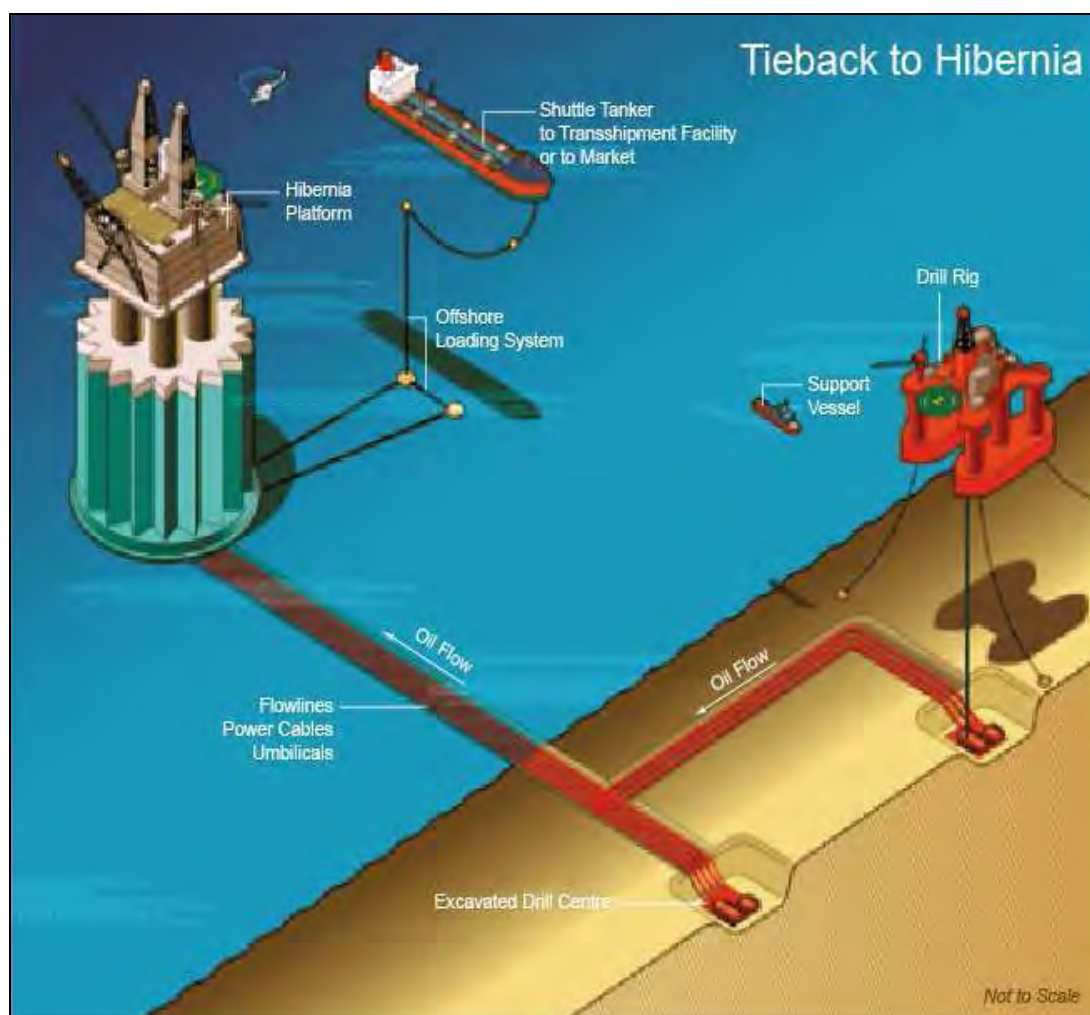


Figure 1.7-1: Tie-back to Hibernia

1.7.2.2 FPSO with Subsea Wellheads

A FPSO with subsea satellite wells concept would entail subsea wells being drilled using a MODU (Figure 1.7-2). Subsea wells would be located in excavated drill centres to protect them from iceberg scour. Production fluids would be transferred to a FPSO via flowlines and flexible risers. The FPSO would be double-hulled and double-bottomed, with appropriate storage capacity for crude oil, thrusters (for heading control), and would house the oil treatment, gas compression, gas lift, water injection and utility equipment, including power generation. It would also include quarters to house operations and maintenance personnel. The FPSO would stay on station by means of an internal, disconnectable turret anchored to the sea floor. In the event of an encroaching iceberg or dense pack ice, the FPSO would be able to disconnect and depart from the field. Stabilized crude oil would be stored in the FPSO prior to tandem loading onto tankers for shipment to market or to the Newfoundland Transshipment Terminal.

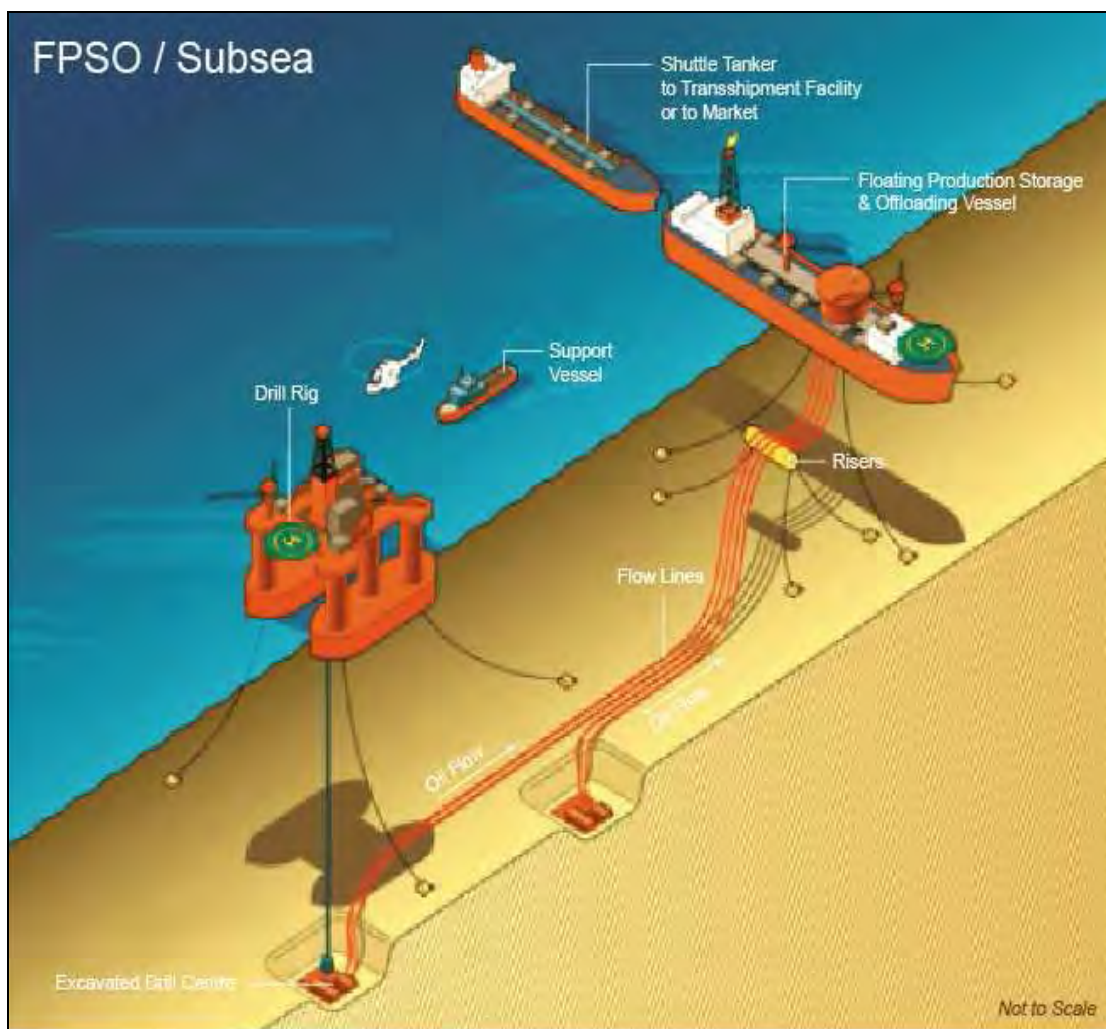


Figure 1.7-2: Floating Production, Storage and Offloading Facility and Subsea Infrastructure

1.7.2.3 FPSO with WHGBS

This concept requires wells to be drilled from a concrete mono-tower WHGBS using a MODU in a tender assist mode (Figure 1.7-3). All wells (producers and injectors) would be drilled from the WHGBS. The WHGBS would be constructed and installed approximately two years prior to FPSO completion to enable pre-drilling and, hence, improved production ramp-up.

The WHGBS would be configured with minimal topsides processing functionality to reduce the numbers of personnel on the structure. WHGBS process equipment would be limited to manifolding and well testing via multiphase meters. Utility systems, notably those involving rotating equipment, would be limited. Trenched pipelines, with riser base manifolding, would be used to tie the WHGBS to the FPSO. Injection water, gas lift and power to the WHGBS would be supplied by the FPSO. Oil export would be undertaken with tankers loading in tandem off the stern of the FPSO.



Figure 1.7-3: Floating Production, Storage and Offloading Facility with Wellhead Gravity Base Structure

1.7.2.4 Gravity Base Structure

The stand-alone GBS production facilities concept is similar to Hibernia and includes a concrete GBS with associated topsides (Figure 1.7-4). The GBS and topsides would be constructed separately and then mated at an inshore site prior to towing and installing the platform at the Hebron site.

All wells (producers and injectors) would be drilled by the platform rig. Treated oil would be stored in the platform prior to custody transfer metering and subsequent shipment. An OLS, complete with a looped pipeline and two separate loading points, would be installed to offload the oil onto tankers for transport.

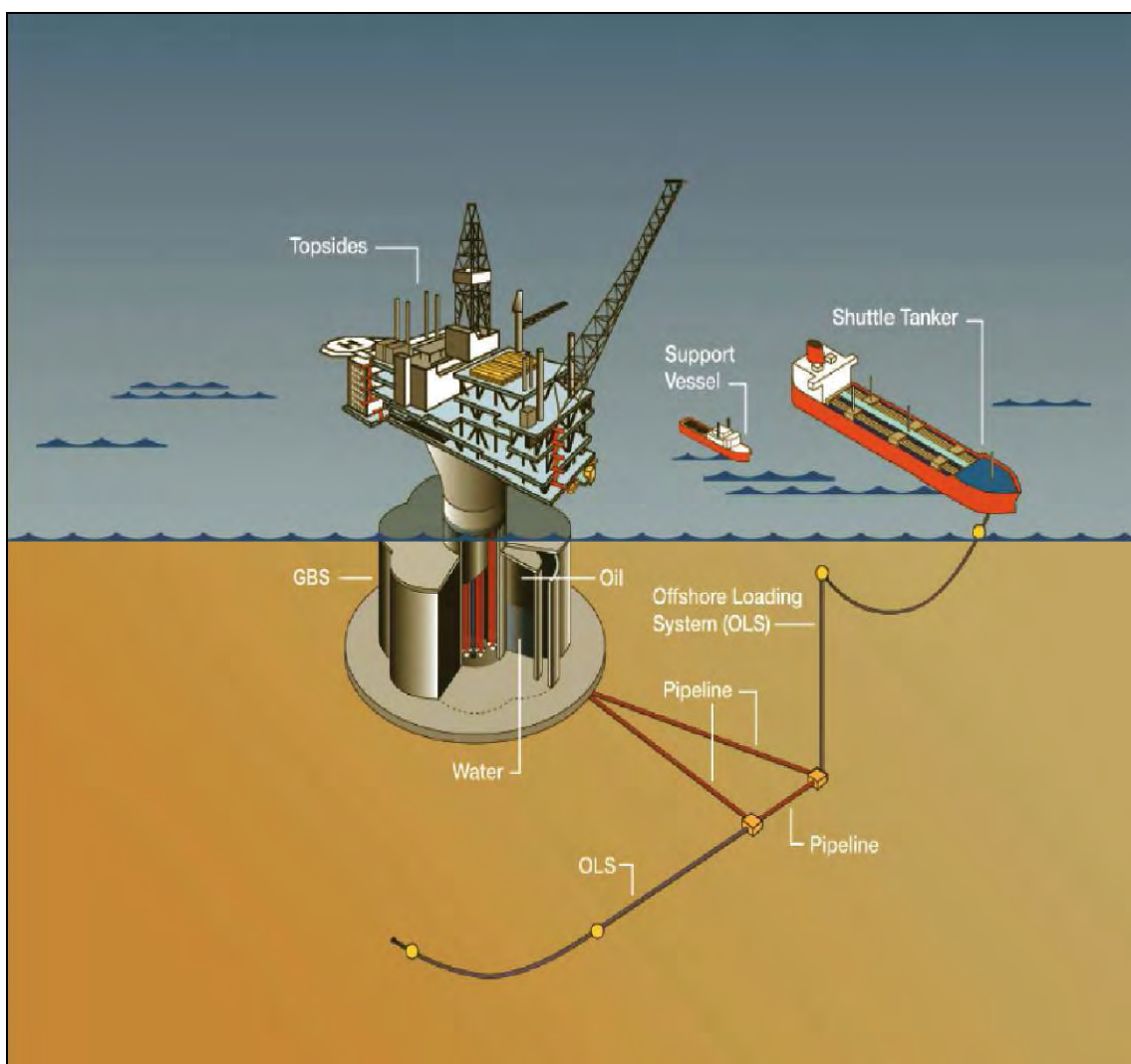


Figure 1.7-4: Stand-alone Gravity Base Structure Preliminary Development Layout

Pre-Drill Alternative

Within the stand-alone GBS option, consideration has been given to a pre-drill alternative, where some wells would be drilled prior to the arrival of the platform, through a pre-drill template.

With the pre-drill alternative, a MODU would be used to drill and partially complete the pre-start-up wells prior to the installation of the platform. However, an excavated drill centre would not be constructed for the pre-drill option; the platform cannot be installed over an excavated drill centre. Rather, the well heads would remain, unprotected, above the sea floor until the platform was installed over the wellhead. Drill cuttings, both water-based and non-aqueous fluid (NAF) based, would be processed and discharged overboard in accordance with the C-NLOPB guidelines.

Once the pre-drill has been completed, the platform is installed by floating the platform structure over the template, and lowering the platform to the seafloor. The pre-drilled wells would be connected to the platform topsides and then completed from the platform. The remaining wells would then be drilled by the platform rig in parallel with operations.

1.8 Preferred Concept

The Project Proponents evaluated the alternative modes of development, including development drilling options, and determined that the preferred concept is to develop the Hebron Asset using a stand-alone concrete GBS (no pre-drill option) and topsides, and an OLS. It provides greater technical and economic certainty and there is greater environmental benefit than with the other options. A few of the key decision criteria are discussed in the following paragraphs.

Most of the crude oil in the Hebron Asset horizons is “heavy” and may therefore pose flow assurance challenges. To mitigate these flow assurance issues and enable easier wellbore access for remedial work the use of above-water wellheads (dry trees) is preferred for the Hebron development. A dry tree design would be used in this context for any concept where the valves at the top of the well (tree) are located above sea level, as is the case for the GBS concept. Conversely, wet trees refer to designs where the valves are located below sea level, as is the case with the FPSO / Subsea option. Dry tree technology can reduce well drilling and maintenance costs, and hence, improve the lifecycle economics of a heavy oil project such as Hebron.

Dry trees also provide an environmental benefit during drilling over wet trees. The GBS concepts include an injection well for the disposal of cuttings and NAF-based mud. Water-based mud will be discharged within GBS shaft, or overboard in accordance with applicable guidelines. In the other concepts with wet trees or pre-drilling, disposal of cuttings is either overboard into the sea or back to a landfill onshore.

The GBS no pre-drilling alternative was chosen relative to the pre-drill option based on:

- ◆ Concept refinement work has concluded that the pre-drilling plan is not viable for technical, operational and economic reasons
- ◆ The resultant concept has the highest execution confidence and the least economic and operational risk; this may enhance opportunities for an early start-up benefiting all stakeholders

The items listed above far outweigh the potential oil production acceleration benefit that pre-drilling can offer. From technical, execution, economic and environmental perspectives, the no pre-drill alternative provides significant advantages over the pre-drill concept.

The evaluation of the Hebron Project development options considered is summarized in Table 1.8-1.

Table 1.8-1: Summary of Analysis of Alternate Means of Carrying Out the Project Showing Determination of Risk

Alternative Considered	Technical Feasibility	Economic Feasibility	Environmental Effects
Tie-back to Hibernia	High-red	High-red	Medium-yellow
FPSO	Low-green	High-red	Medium-yellow
FPSO with WHGBS	Low-green	High-red	Low-green
Stand-alone GBS (with pre-drill)	High-red	High-red	Medium-yellow
Stand-alone GBS (no pre-drill)	Low-green	Low-green	Low-green
<i>Note:</i> High-red; Medium-yellow; Low-green			

Neither FEED nor detailed design for the Topsides and GBS have been completed. However, the main criteria upon which the detailed design will be based are provided in Section 1.9.

1.9 Hebron Project Concept and Design

1.9.1 Hebron Project Facilities Concept

The GBS for the Hebron Project will be a post-tensioned reinforced concrete structure designed to withstand impacts from sea ice and icebergs, and the meteorological and oceanographic conditions at the Hebron Project Area. It will accommodate up to 52 well slots and be outfitted with J-tubes and / or risers for tie-ins to outlying subsea developments.

The GBS will be designed to store approximately 190,000 m³ (1.2 Mbbbl) of crude oil in multiple separate storage compartments. It will have a single main shaft supporting the topsides and will encompass all wells to be drilled from the platform. The GBS will be designed for an in-service life of 50 or more years. The Topsides facilities will include the following modules:

- ◆ Drilling Support Module (DSM)
- ◆ Derrick Equipment Set (DES)
- ◆ Flare boom
- ◆ Utilities and Processing Module (UPM)
- ◆ Living Quarters, including helideck and lifeboat stations

A schematic of a typical GBS and Topsides layout are provided in Figures 1.9-1 and 1.9-2, respectively.

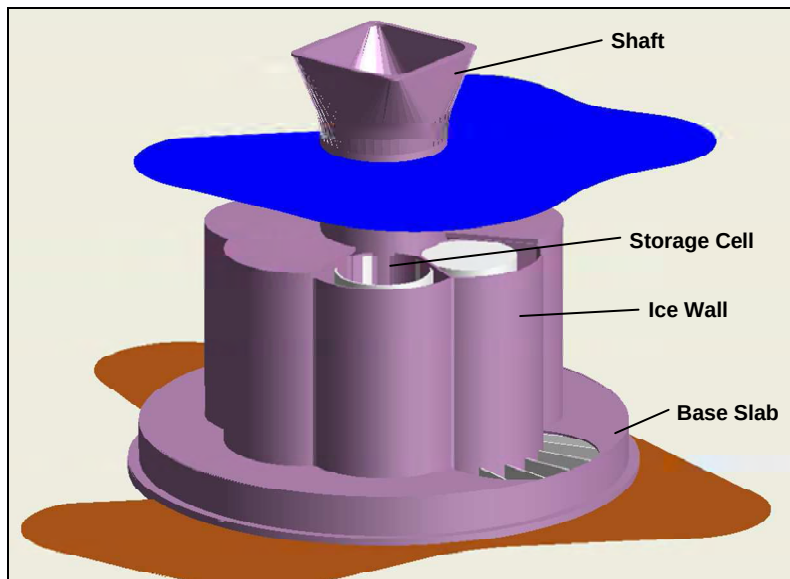


Figure 1.9-1: Schematic of Gravity Base Structure

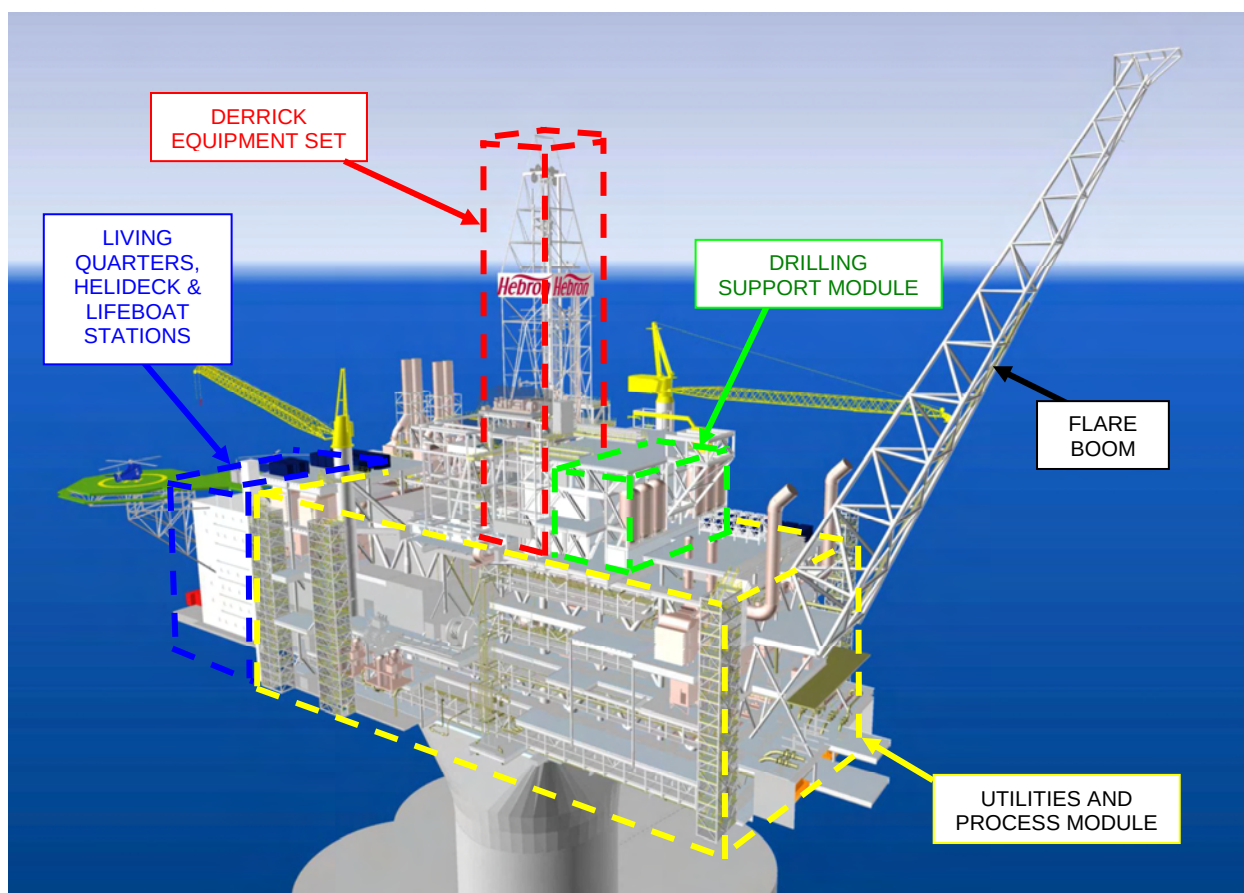


Figure 1.9-2: Schematic of Topsides

Production facilities will have the capacity to handle the requirements of drilling and production of crude oil, storage and export, gas management, water injection, and the management of produced water, for a production life of 30 or more years. Topsides facilities will be designed for a nominal design life of 30 years. Surveillance and maintenance programs will be implemented throughout the operation of the facility and the production life may be extended through refurbishment or replacement of select components as required.

The Hebron Project will include an OLS to offload crude oil onto tankers for transfer to the Newfoundland Transshipment Terminal or directly to market. The currently planned OLS system, as shown in Figure 1.7-4, consists of two main offshore pipelines running from the GBS to separate riser bases (Pipe Line End Manifolds, PLEMs) with an interconnecting offshore pipeline connecting the two PLEMs. The notional offloading rate of the system is 8,000 m³/hr (50,300 bbl/hr).

The closed loop arrangement is planned to allow round-trip intelligent pigging and flushing operations through the pipelines and PLEMs if an iceberg threatens the loading facilities.

During loading, the riser will be connected to the dynamically-positioned, bow-loading shuttle tanker.

1.9.2 Hebron Project Design Criteria

An overview of the Hebron GBS and Topsides design criteria is provided in the following paragraphs. More details are provided in Section 8. The following design criteria are based on current estimated project requirements. However, during FEED and detailed design and engineering, some of these elements may be modified. The following description provides for ranges in design criteria to allow for any modifications to project design.

The Hebron production facilities will have the capacity to handle the predicted life-of-field production stream for 30 plus years. Based on the current initial development phase, it is expected the facility will be designed to accommodate an estimated production rate of 23,900 m³/day of oil (150 kbd). It is anticipated that, with de-bottlenecking and production optimization post-start-up, that the total capacity of the facility could potentially be raised to 28,600 m³/day (180 kbd). The produced water system will be designed to process up to 55,000 m³/day (350 kbd) of produced water and inject up to 74,000 m³/day (470 kbd) of water. Gas handling of up to 8,500 km³/day (300 MSCFD) will be required to accommodate gas re-injection and artificial lift gas.

An overview of the design basis for the Hebron Project is provided in Table 1.9-1. These design rates may change as the reservoir depletion strategy and initial development phase are finalized.

Table 1.9-1: Hebron Project Attributes

Project Component	Attribute
Platform Location	46°32.64344 min N; 48°29.88379 mi n. W
Life of Field	Greater than 30 years
Well Slots	Up to 52
Measured Well Depths	2,300 to 6,500 m measured depth
Topsides Design Basis Summary	
Preliminary Topsides Weight	30,000 to 44,000 tonnes
Crude Oil Production	23,900 to 28,600 m ³ /d (approximately 150 to 180 kbd)

Project Component	Attribute
Water Production	31,800 to 55,000 m ³ /d (approximately 200 to 350 kbd)
Water Injection	43,000 to 74,000 m ³ /d (approximately 270 to 470 kbd)
Gas Handling (includes associated gas and gas-lift gas)	6,000 to 8,500 km ³ /d (approximately 215 to 300 MSCFD)
GBS Notional Design Metrics	
Concrete GBS Structure	Reinforced concrete with post tensioning
Overall Height (seabed to top of central shaft)	Approximately 120 – 130 m (394 - 427 ft)
Foundation Diameter	122 to 133 m (400 to 436 ft)
Caisson Diameter	100 to 110 m (328 to 361 ft)
Shaft internal diameter	Approximately 33 m (108 ft)
GBS Dry Weight	300,000 to 340,000 tonnes
Solid Ballasting	50,000 to 100,000 tonnes
Concrete Volume	115,000 to 126,000 m ³ (150,300 to 164,700 cubic yards)
Reinforcing Steel	33,000 to 50,000 tonnes
Post Tensioning Steel	3,700 to 5,000 tonnes
Topsides Support during tow-out	Up to 44,500 tonnes
Base Storage	7 storage cells Approximately 190,000 m ³ (1.2 M bbl)
Life Expectancy of GBS	Approximately 50 years
Potential Field Expansion	J-tubes, risers, and unused well slots Future options may include use of additional platform drilling slots, reclamation of previously-utilized slots, and/or subsea wells connected via tie-back to the GBS
Water Quality	
Produced Water Handling (OWTG limits)	≤ 30 mg/L 30-day average; ≤60 mg/L 24-hour average
Storage Displacement water (oil content – OWTG limits)	≤ 15 mg/L
Ballast / Bilge Water	≤ 15 mg/L

Project Component	Attribute
(oil content – OWTG limits)	
Deck (open) Drainage (oil content – OWTG limits)	≤ 15 mg/L
Well Treatment Fluids	≤ 30 mg/L; strongly acidic fluids should be treated with neutralizing agent to a pH of at least 5.0 prior to discharge
Cooling Water	As approved by the Chief Conservation Officer
Desalination Brine	No discharge limit
Fire Control Systems Test Water	No discharge limit
Monoethylene Glycol	As approved by the Chief Conservation Officer
Sewage and Food Waste	Macerated to ≤ 6 mm
Water-based Drill Solids	No discharge limit
NAF-based Solids	Re-injected where possible; if not, ≤ 6.9 g/100 g on wet solids
Offshore Loading System	
OLS Location	Approximately 2 km north-northeast of platform
Transfer Rate	Up to 8,000 m ³ /h (50,312 bbls/hour)
Off-loading line length (each)	2 km (approximate) (6,560 ft)
Interconnecting off-loading line Length	1000 m (approximate) (3,280 ft)
Export vessels	Anticipated use of existing shuttle tankers

The design basis values presented in Table 1.9-1 are those listed at peak production; these are the limits expected when the facility is operating at peak production levels.

1.9.3 Gravity Base Structure Systems

The GBS will be designed to have permanent and temporary mechanical systems installed as follows:

- ◆ Up to 52 well slots and associated conductor guides and J-tubes and / or risers
- ◆ Two shale chutes
- ◆ Seven crude oil storage compartments, including associated booster pump(s) to lift the oil for offloading, and level monitoring equipment

- ◆ Seawater systems including storage displacement water, cooling water and firewater, will likely include:
 - A large-diameter caisson for return of seawater to the marine environment
 - Separate lift pumps to supply the firewater and seawater systems; firewater pumps will be segregated to ensure that no single point of failure can cause loss of firewater supply.
 - Storage displacement water from the crude oil storage compartments will pass through a buffer cell before horizontal discharge. The final temperature of the storage displacement water prior to its discharge will be approximately 30°C.
- ◆ Corrosion protection system to protect metal elements against corrosion and biological growth where seawater is present. The discharge from the hypochlorite system will be treated in accordance with the **Offshore Waste Treatment Guidelines** (OWTG) [National Energy Board (NEB) *et al.* 2002] (Note: the OWTG are currently being revised. While this development plan may refer to the 2002 OWTG, all operations will adhere to the most recent version of the guidelines).
- ◆ A separate sewage disposal line may route water from the sewage treatment unit to the marine environment. Merits of combined disposal will be addressed during detailed engineering design work. Sewage will be discharged overboard in accordance with the OWTG (NEB *et al.* 2002).
- ◆ Systems to minimize the occurrence of flammable gases and flammable or combustible liquids entering the shaft and allowance for removing any accumulations of gas
- ◆ Fire and gas detection system
- ◆ Control and monitoring systems including instrumentation to control crude oil levels, monitor corrosion systems and monitor foundation integrity
- ◆ Cooling system to ensure proper temperature maintenance of the GBS shaft over the life of the project
- ◆ Grounding / Earthing System including cables running through the GBS

1.9.4 Topsides Systems

The topsides will include all equipment required for the drilling, processing and power generation for the Hebron Project.

1.9.4.1 Drilling Facilities

Based on preliminary design work, drilling facilities on-board the GBS will consist of the following systems:

- ◆ Mechanical drilling systems, including drawworks and pipe handling
- ◆ Well control system consisting of a blow-out preventer (BOP) stack, complete with diverter assembly, hydraulic control system, kill and choke manifold, trip tank, atmospheric separator (de-gasser)
- ◆ Bulk material and storage system, including storage tanks and surge tanks for dry bulk materials
- ◆ Mud storage, mixing and high pressure system, including liquid storage tanks, mixing equipment, and mixing, transfer, pre-charge and high-pressure mud pumps
- ◆ Mud return and reconditioning system, including shaker distribution box, shale shakers, degassers, centrifuges, and associated tanks and pumps
- ◆ Onboard gravel pack equipment
- ◆ Cementing system, including a dual high-pressure pump unit, a batch mixing unit and a Liquid Additive System
- ◆ Driller's cabin containing drilling controls as well as monitoring capabilities for all drilling, pipe handling, mud handling and cement handling operations
- ◆ Cuttings re-injection system for NAF-based mud and cuttings. NAF-based mud and cuttings will be re-injected into the subsurface via a re-injection well. There will be no NAF-based cuttings treatment on the platform. The cuttings re-injection system will be designed with dual redundancy; there will be a minimum of two wells for re-injection. All water-based drill mud and cuttings will be discharged overboard, as per the OWTG (NEB *et al.* 2002). There will be two shale chutes for water-based cuttings discharge

1.9.4.2 Process Systems

The main function of the production facility will be to stabilize the produced crude by separating out the water and gas from the oil, sending the crude oil to storage, and treating and managing the separated gas and water and associated components such as sand. The following is a list of the main systems employed in the process and utilities during crude oil processing.

- ◆ Three-stage separation system
- ◆ Water injection system
- ◆ Gas compression
- ◆ Gas lift

- ◆ Gas injection
- ◆ Produced water treatment
- ◆ Vent and flare system
- ◆ Oily water treatment
- ◆ Chemical injection
- ◆ Seawater lift
- ◆ Power generation and distribution
- ◆ Fuel gas
- ◆ Process cooling
- ◆ Crude oil offloading and metering
- ◆ Potable and service water
- ◆ Fire suppression systems
- ◆ Escape, evacuation, and rescue facilities
- ◆ Jet fuel storage
- ◆ Diesel fuel storage
- ◆ Hydraulic power
- ◆ Heating, Ventilating and Air Conditioning (HVAC)

1.9.5 Subsea Production and Injection Systems

A full development option of Hebron Pool 3 is as a subsea tie-back to the Hebron GBS (Option 3). A conceptual design for the subsea production and injection system has been developed (Figure 1.9-3) and consists of the following elements:

- ◆ One or more subsea excavated drilling centres with production, water injection, and gas injection manifolds and trees, umbilical termination assemblies, subsea distribution units, control pods, jumpers and flying leads.
- ◆ Production, water injection, gas injection, gas lift, and well stimulation pipelines and / or flowlines, and control umbilicals between the GBS and the subsea drilling centers.
- ◆ Pipeline risers and / or J-tubes pre-installed in the GBS
- ◆ Additional Topsides equipment necessary to support subsea development

Subsea facilities will include all equipment necessary for the safe, efficient operation and control of subsea wells, and transportation of production and

injection fluids between the subsea wells, subsea manifolds, and GBS facilities. Specifics of the conceptual design may change as designs are finalized.

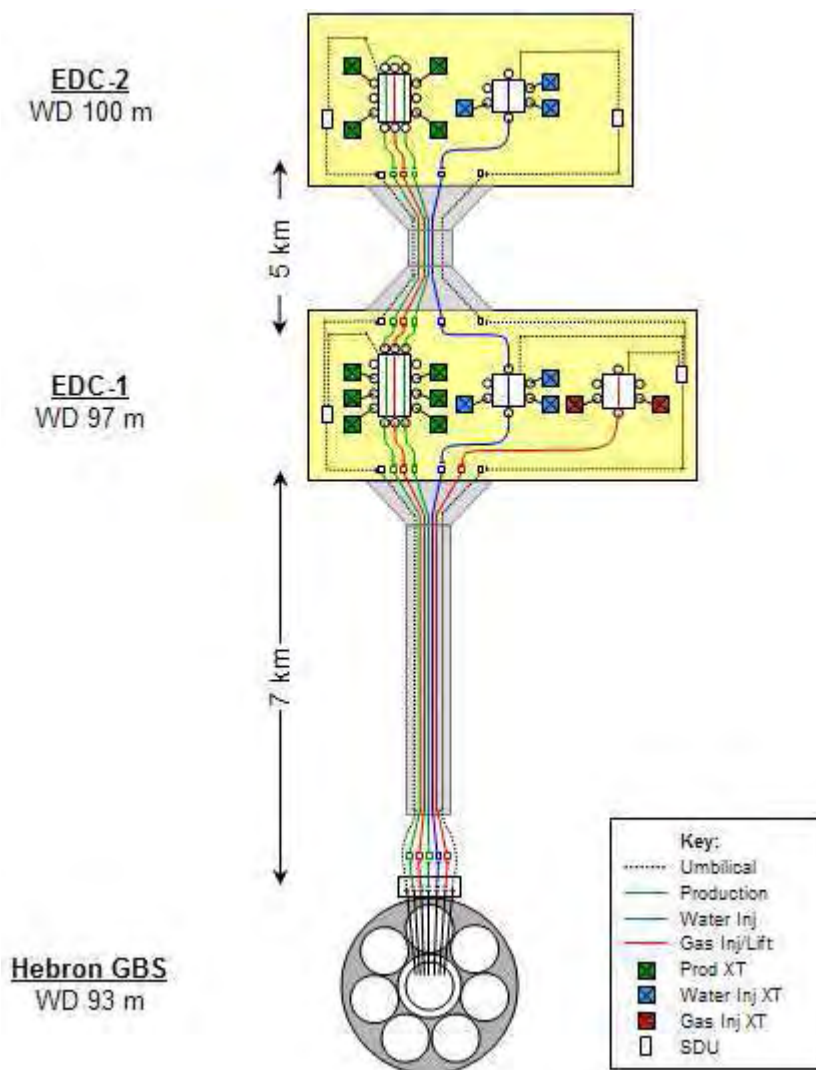
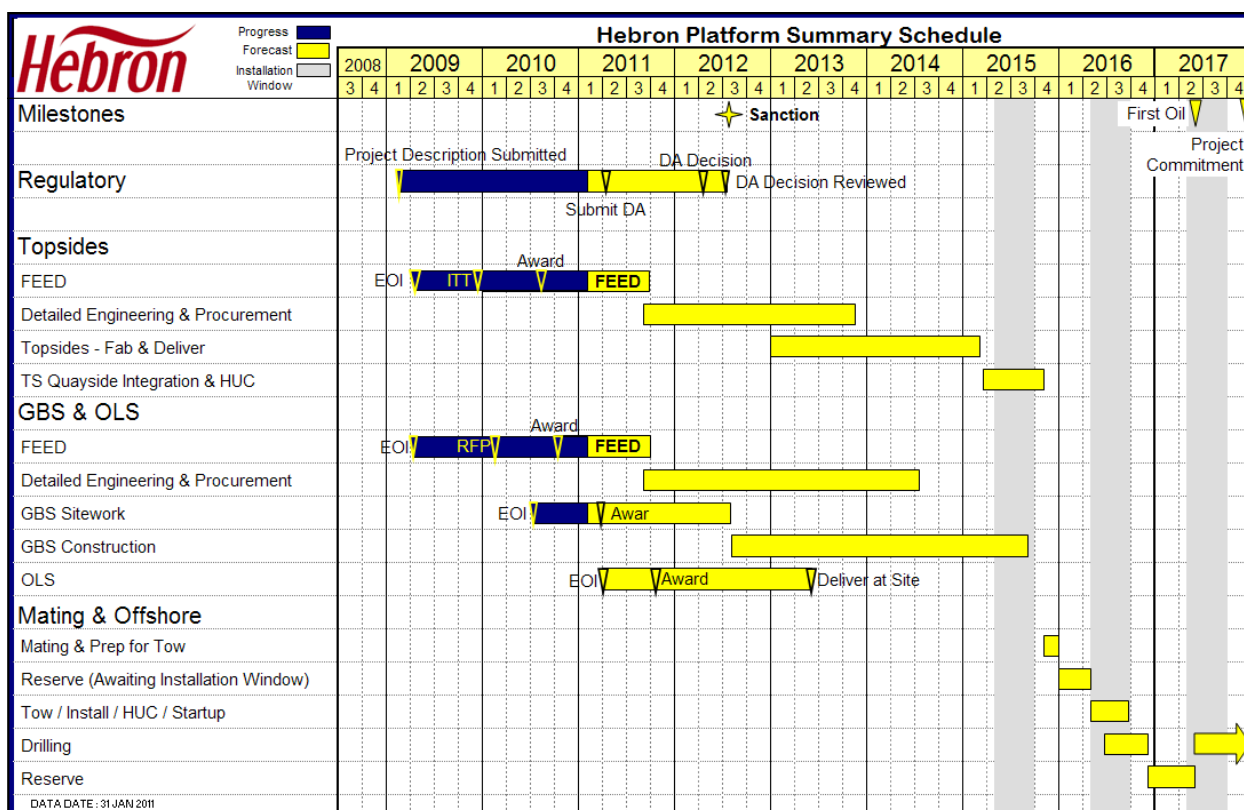


Figure 1.9-3: Pool 3 Full Development Option Subsea Concept Layout

1.10 Project Schedule

The overall project development schedule is shown in two parts as the duration and timing of the Hebron Platform Development is more mature than the schedule for the Hebron Pool 3 Development. The Hebron Platform Development schedule is illustrated in Figure 1.10-1.



Note:

* DA - Development Application includes Development Plan, Benefits Plan, EIS / SEIS and other supporting documents as determined by the C-NLOPB

Figure 1.10-1: Hebron Platform Development Schedule

A preliminary Pool 3 subsea development (Option 3) schedule is illustrated in Figure 1.10-2. Specific duration and timing of the development is under evaluation with the earliest start-up date envisioned to be concurrent with the platform first oil date.

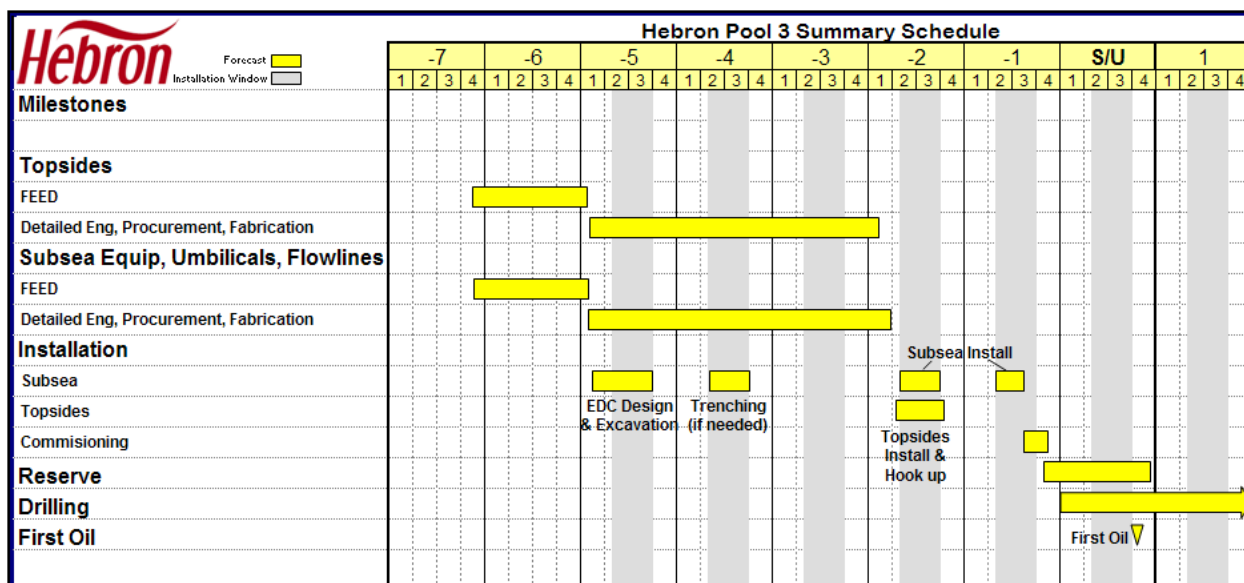


Figure 1.10-2: Hebron Pool 3 (Option 3) Development Schedule

1.11 Hebron Project: Construction and Installation

Construction of the Hebron facilities will maximize the use of existing technology and expertise. Safety, experience, quality, and commercial terms will be considered when selecting contractors.

The Hebron Project has four major construction scopes – the Topsides Integrated Deck, the GBS, the Export System / OLS, and the Pool 3 Subsea Development. The Topsides will employ a modular fabrication strategy with subsequent module integration, while the GBS will employ civil construction techniques along with installation of mechanical outfitting. After completing construction of these two scopes, they will be mated creating one integrated system. The Export System / OLS and the Pool 3 Subsea Development will be tied into the facility subsequent to platform installation at the offshore site.

The strategy for the GBS is to design the structure with thorough consideration of the construction process and input from construction planning. As the GBS will be floating for a significant portion of the construction and installation phase, the design must ensure stability of the structure at all times. Thus, the design is a function of the various construction stages.

The Bull Arm Site has been selected as the primary construction and integration site for the GBS and topsides modules. This location provides adjacent dry dock and deep water GBS construction sites as well as facilities to fabricate components and integrate the topsides modules.

When ready for mating with the GBS, the assembled Topsides will be loaded onto specialized barges and floated to the Deepwater Site using the barges in a catamaran configuration. Once the Topsides are in position over the GBS shaft, the GBS will be de-ballasted and will lift the Topsides off the barges.

After de-ballasting the GBS to ensure the necessary under keel clearance, the platform will be released from its moorings and towed to the field. The completed platform comprising the GBS and Topsides will be towed to the field (340 km offshore) and installed at site, most likely during an April to October weather window. Tow duration may be 10 to 14 days. The project plans to install the OLS during the same weather window.

Once at site the platform will be water ballasted. Once ballasted, grouting around the base of the platform may be required to increase uniformity in foundation bearing pressure and increase the platform stability *in situ*.

Once installed at the site, final hook up and commissioning activities of the Topsides and GBS facilities will be executed offshore. These include connection of the OLS to the platform.

The overall construction sequence for the Hebron Platform Development is shown in Figure 1.11-1 and described in more detail in Section 10.

Construction and installation activities for the Pool 3 Subsea Development will be generally similar to those used previously on the Grand Banks. Section 10 describes these activities in more detail.

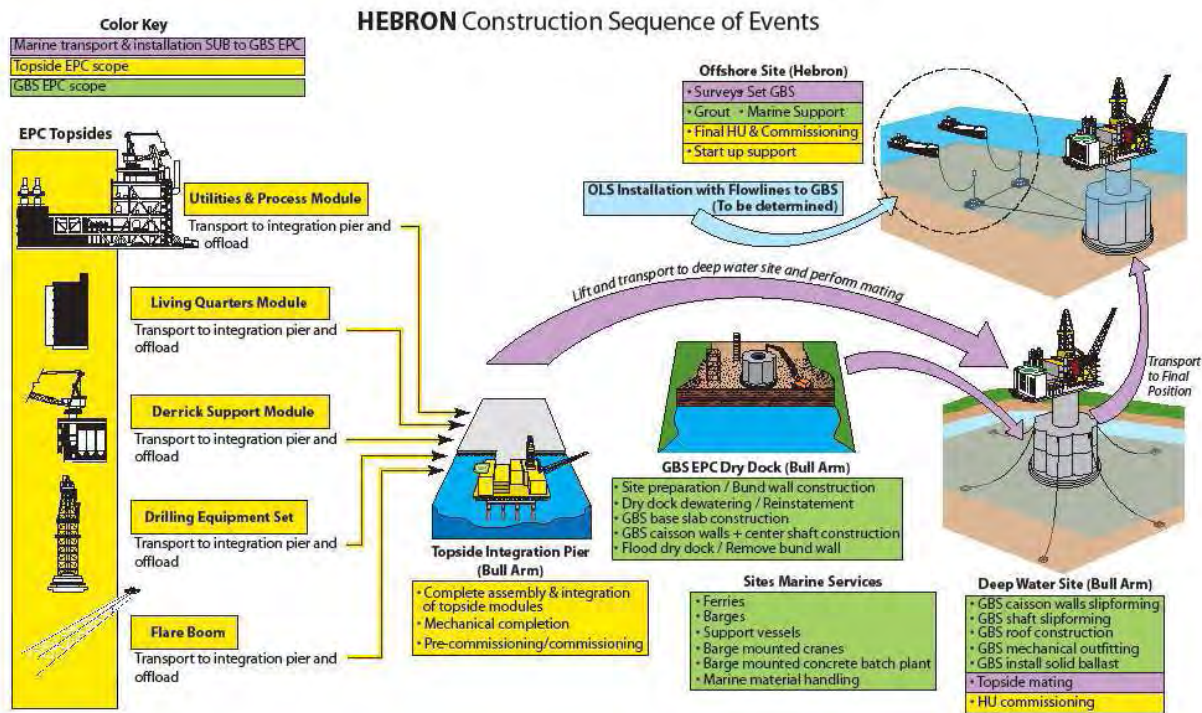


Figure 1.11-1: Hebron Construction Sequence

1.12 Hebron Project Operations

The Hebron Project operations, as described in Section 11, will be managed by EMCP as Operator, employing both Company and third-party services. The project will be managed and operational decisions will be made from offices in St. John's, Newfoundland and Labrador.

1.12.1 Operational Support

The onshore organization will include engineering, technical, SSH&E (safety, security, health and environment), logistics, financial and administrative personnel. Onshore support for docking, warehouse space, helicopter operations and product transshipment will be carried out at existing worksites in Newfoundland and Labrador. The Hebron Project will look to optimize existing operations at EMCP, through the sharing of resources and, contracted services, where feasible.

1.12.2 Logistics and Other Support

Four key areas of logistical support required during the operation and maintenance of the project are shorebase support, personnel movements, vessel support and iceberg management. Where practicable, the Operator

will consider possible synergies with existing Grand Banks operators. The project will also be supported by Oil Spill Response personnel.

Shorebase Support: Marine shorebase and warehouse facilities using existing facilities in St. John's and surrounding areas capable of providing project support activities will be used. Existing port facilities are capable of servicing multiple operations, including wharfage, office space, crane support, bulk storage, consumable (fuel, water) storage and delivery capability.

Personnel Movements: Helicopters will be the primary method to transfer personnel between St. John's and the offshore platform. Personnel may also be transferred using supply vessels, when required (*i.e.*, weather or other logistical delays). The Operator will consider and discuss possible shared services with other Grand Banks operators with a view to optimizing the fleet configurations of all operations and providing the safest and most efficient and effective service.

Vessel Support: Supply and stand-by vessels will be required to service the operational needs of the platform and drilling units in the Hebron Project Area. Supply vessels may also be required to conduct components of the environmental effects monitoring program and for oil spill response support, training and exercising. The Operator will consider and discuss possible synergies with other Grand Banks operators, where practicable, with a view to optimizing the fleet configurations of all operations and providing the safest and most efficient and effective service. As with current operations, vessels associated with the Hebron Project will operate within established shipping corridors between St. John's and the offshore project area

Ice Management

The Grand Banks Ice Management Plan has been developed by existing operators and the Hebron Project is expected to participate in this program. Reliable systems for the detection, monitoring and management of icebergs and pack ice, including towing techniques, have been developed for the Grand Banks area.

Communications

Equipment and systems will be installed to provide industry accepted high standards of communications on the Hebron Platform itself and between Hebron, the onshore office and facilities, and other offshore installations, vessels and aircraft in the vicinity of the Hebron Platform.

The communications systems will include radio, telephone, telemetry, local area computer network, and other related equipment necessary to provide the high standard of reliable communication that is required for safe and efficient operations. The systems will comply with all regulatory requirements. Back-up systems will be used to provide the maximum

continuous communications capability available in any reasonable environmental condition.

1.12.3 Shipping / Transportation

Crude oil from the Hebron Platform will be transported to the Newfoundland Transshipment Terminal or direct to market. Tankers will be in compliance with Canadian regulations and use existing international shipping lanes and established shipping lanes.

1.13 Decommissioning and Abandonment

The Operator will decommission and abandon the Hebron production facilities according to applicable regulatory requirements. The platform infrastructure will be decommissioned and the wells will be plugged and abandoned. The platform structure will be designed for removal at the end of its useful life. This is discussed further in Section 12.

1.14 Potential Expansion Development

Further development of resources is anticipated within the four Significant Discovery Licences, and / or on adjacent land that may be acquired by project proponents. These expansion developments may be produced from the platform or through tie-back using subsea systems similar to those described for the Pool 3 development.

1.15 Document Organization

This development plan is organized into the following chapters:

- ◆ Section 1 - Overview: Provides a description of the project area, identifies the project proponents, details the scope of the project, discusses and evaluates the alternatives within the project, and discusses in detail the preferred concept for the project.
- ◆ Section 2 - Geology and Geophysics: Provides a brief description of the geological settings and features of the Hebron Project Area provides an overview of regional geology and a general field description, discusses petrology and reservoir quality, discusses seismic data acquisition, seismic processing, and seismic interpretation, shallow hazards and geologic models.
- ◆ Section 3 - Petrophysics: Describes the petrophysical and analytical data of the Hebron Asset, provides an overview of petrophysical methodology, discusses the Ben Nevis Reservoir, the Hibernia Reservoir, and the Jeanne d'Arc Reservoir, to include petrophysical data, overburden corrections, core clay corrections, volumetric multi-mineral models, water

saturation models, permeability, comparison with Drill Stem Test analysis, and overall summaries.

- ◆ Section 4 - Reservoir Engineering: Presents an overview of the available reservoir engineering data and the resulting analysis / interpretations used as the basis for resource depletion planning. Topics include drill stem test results, fluid properties, reservoir pressures, temperatures and flow assurance considerations and special core analyses.
- ◆ Section 5 - Reserve Estimates: Provides an estimate of the original hydrocarbons in-place estimates and recoverable resources estimates for the resources targeted in the initial development phase of the project.
- ◆ Section 6 - Reservoir Exploitation: Describes the proposed reservoir exploitation schemes for the Hebron Asset and associated production profiles. The asset gas management strategy, preliminary reservoir management plan and contingent developments within the Hebron Project Area are also covered in this section.
- ◆ Section 7 - Development Drilling and Completions: Describes the proposed drilling program and typical completion designs for the development wells of the Hebron Project.
- ◆ Section 8 - Design Criteria: Describes the design philosophy for the production and export systems of the Hebron Project.
- ◆ Section 9 - Production and Export Systems: Provides an overview of the development of the production and export systems for the Hebron Project with a discussion on production installation, safety systems, functional requirements for a GBS, the production facility systems, and the export system (offshore loading system).
- ◆ Section 10 - Construction and Installation: Describes an overview of the construction and installation of the production and export systems for the Hebron Project.
- ◆ Section 11 - Operations and Maintenance: Describes the production and maintenance operations associated with the Hebron Project.
- ◆ Section 12 - Decommissioning and Abandonment: Describes the provisions included in the design of the Hebron Platform to facilitate its decommissioning and abandonment at the end of its production life.
- ◆ Section 13 - Development and Operating Cost Data: Provides an estimate of development and operating costs of the Hebron Project.
- ◆ Section 14 - Safety Analysis and Commitment: Provides an overview of safety integration into the design of the Hebron Platform with discussions on the concept safety analysis and target levels of safety, the risk assessment plan, quality assurance and quality control, training plans, the safety management system and the security plan.

2 GEOLOGY AND GEOPHYSICS

2.1 Overview of Regional Geology

The Hebron Project Area is located in the east central part of the Jeanne d'Arc Basin. Section 2.1.1 describes the regional setting of the Jeanne d'Arc Basin.

2.1.1 Regional Tectonic History and Structure

The Jeanne d'Arc Basin is one of several Mesozoic extensional-sag, cratonic margin basins that underlie the Grand Banks of Newfoundland (Figure 2.1-1). The basin dimensions are approximately 160 km long by approximately 50 km wide. The basin covers an area greater than 10,000 km² and comprises a Mesozoic-Cenozoic sedimentary succession 17 km thick. Presently, the basin is fault-bounded and plunges northeastward. A large basement platform, called the Bonavista Platform, borders the basin to the west and a series of basement ridges, referred to as the Central Ridge Complex, defines the eastern boundary (Figure 2.1-2). The Avalon Uplift borders the basin to the south. The Murre-Mercury fault is the major basin bounding fault on the basin's western margin (Figure 2.1-3).

The Jeanne d'Arc rift basin is wider in the north than the south and trends northeast-southwest. The basin formed as a result of prolonged extension from the Triassic to Lower Cretaceous. The Jeanne d'Arc Basin is created from meta-sedimentary and crystalline rocks of Precambrian to Early Paleozoic age Avalon basement (Tankard et al., 1989). The Avalon basement was deformed during the Caledonian and Hercynian orogenies with the creation of Pangaea.

Multiple Mesozoic rifting episodes on the Grand Banks were initiated in the Late Triassic, preceding break-up of the Pangaea supercontinent and the ancestral opening of the North Atlantic Ocean. These rifting episodes dominated the tectonic and sedimentation style of the Jeanne d'Arc Basin.

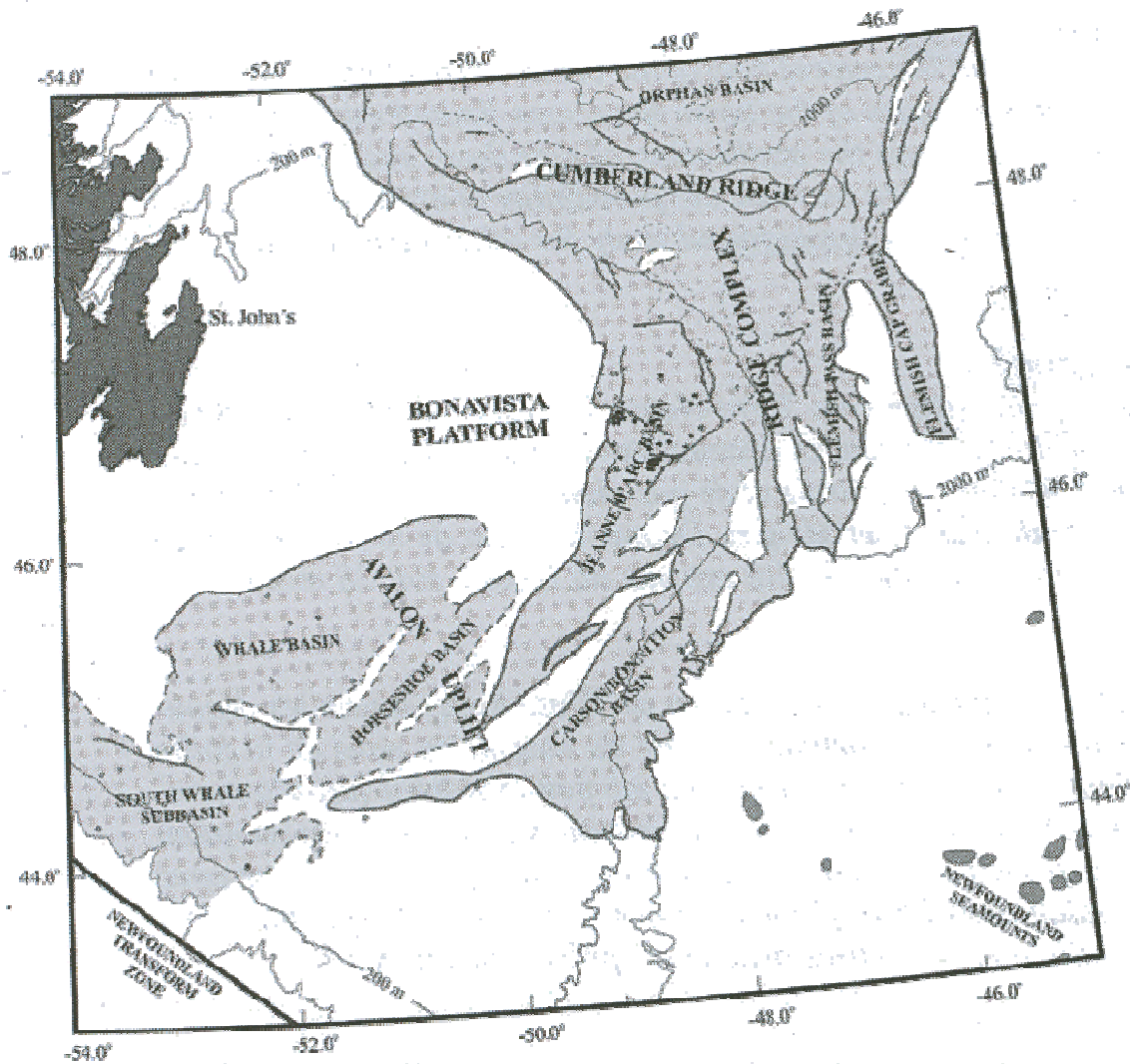


Figure 2.1-1: Mesozoic Basins on the Grand Banks of Newfoundland
(Modified from Hiscott and Pulham, 2005)

Jeanne d'Arc Basin Generalized Tectonic Elements map

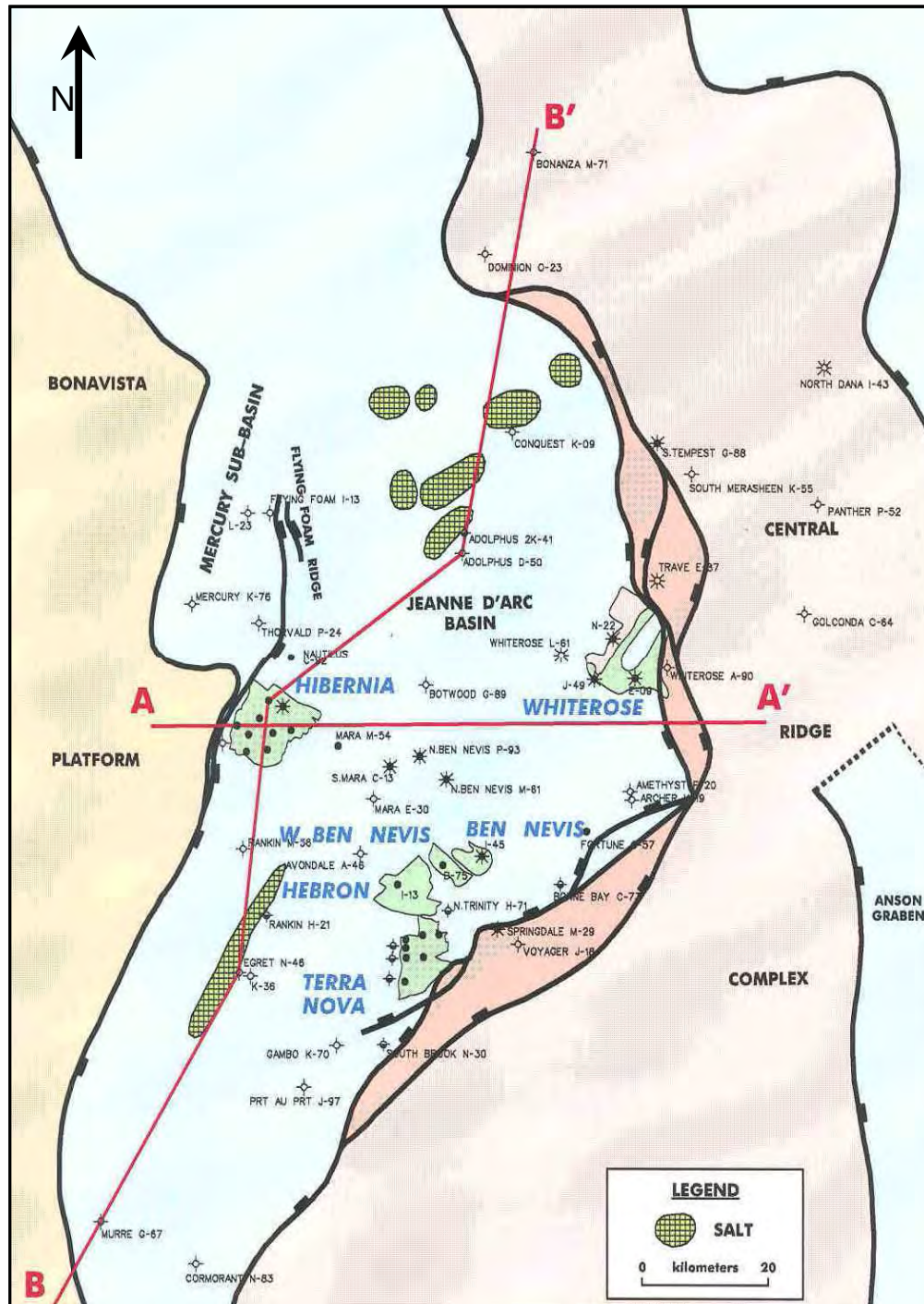


Figure 2.1-2: Main Tectonic Elements of the Jeanne d'Arc Basin
(Pink denotes basement involved fault blocks)

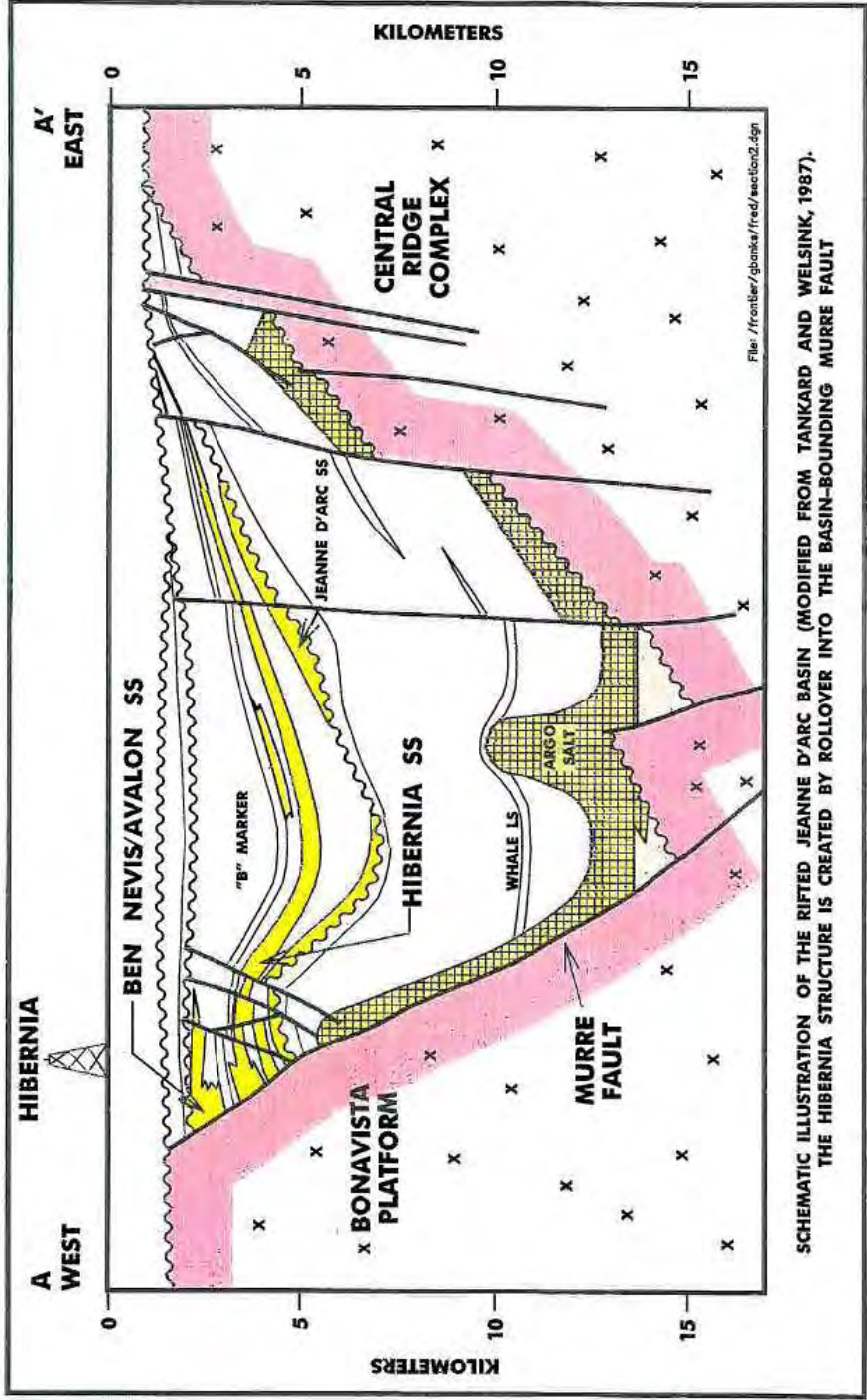
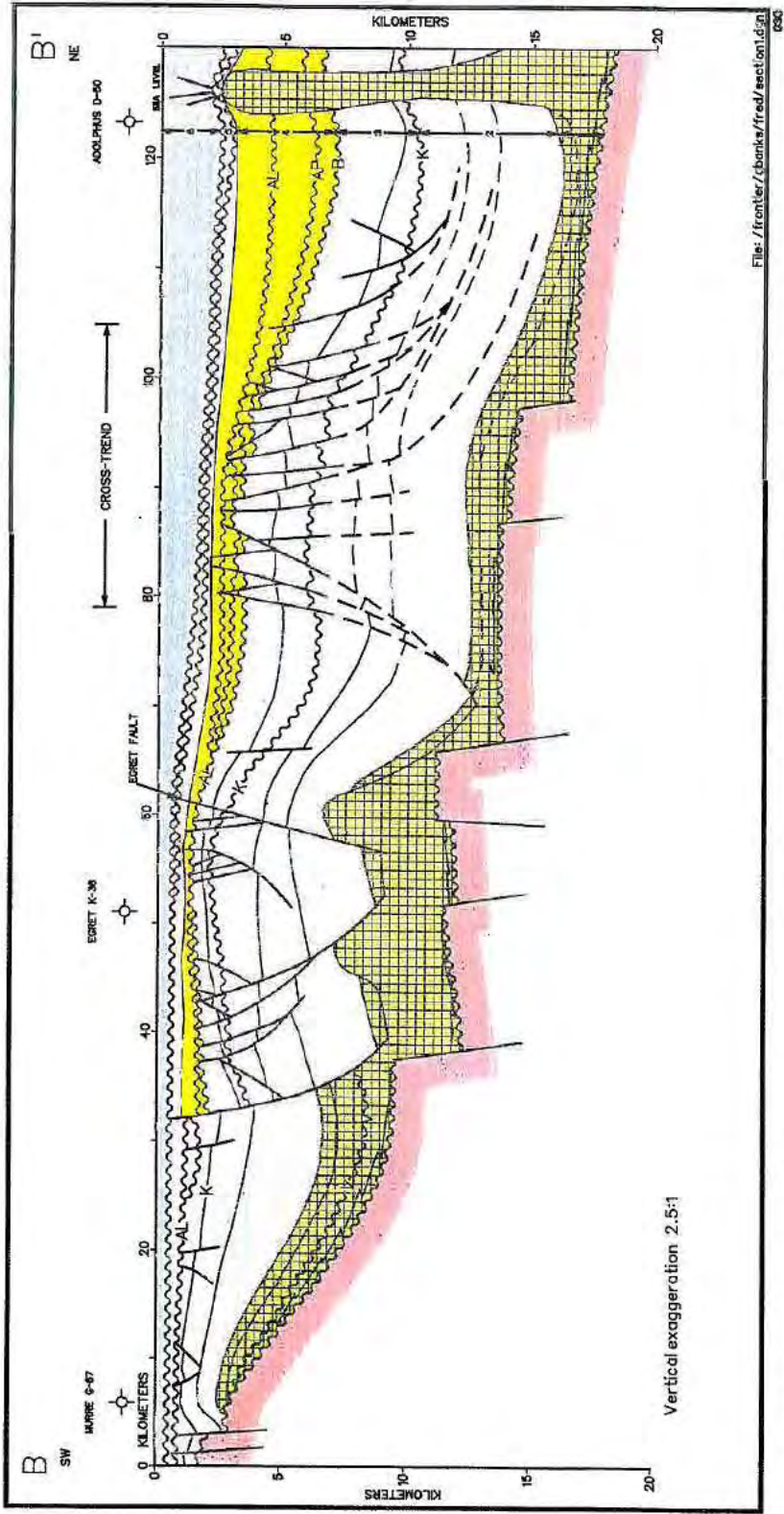


Figure 2.1-3: Cross-Section from A to A'
(Cross section is approximately 100 km long.
Sandstone is coloured yellow, salt is coloured hashed green, basement is coloured pink.)

The tectono-stratigraphic history of the Jeanne d'Arc Basin is protracted and complex and can be related to the separation of Newfoundland from Europe during the Mesozoic. Key basin-forming events include the following:

- ◆ Rifting initiated in the Late Triassic to Early Jurassic along major northeast-southwest trending basin-bounding faults and led to the development of a thick half-graben containing Triassic red beds, Early Jurassic salt, shales and limestones, and Middle Jurassic sands and shales (Figure 2.1-2).
- ◆ Lithospheric extension continued throughout the Jurassic, providing accommodation for the deposition of thick Middle and Upper Jurassic marine and fluvial successions. The Avalon Uplift in the southern Jeanne d'Arc Basin is interpreted to have created a broad regional high that may have been a controlling factor on the localized deposition of the Egret source rock and likely created the drainage area that provided the source of the fluvio-deltaic siliclastics that form many of the Upper Jurassic and Early Cretaceous reservoirs.
- ◆ Early Cretaceous (Valanginian) extension resulted in the development of the Central Ridge and several half-grabens that penetrate the Flemish Cap. This extension can be related to clockwise rotation of the Flemish Cap.
- ◆ Mid-Aptian to Late Albian extension resulted in the growth of major northwest-southeast trending ("trans-basin") normal faults in the basin (Figure 2.1-4). These faults detach at various levels within the stratigraphic succession and generally terminate beneath the Aptian unconformity, implying that extension within the basin was essentially complete by this time. These faults form local grabens, horsts, tilted blocks, reverse drag folds, and local rollovers. Many of these features constitute excellent hydrocarbon traps in the basin. The Terra Nova Anticline has been described in the Terra Nova Development Plan Application as being bound to the north by the Trinity Fault. The anticline is believed to extend to the north beyond the Trinity Fault and across the Hebron Asset.
- ◆ Regional analysis suggests that rotation of the Flemish Cap had ceased by the end of the Aptian and that from this point forward the Jeanne d'Arc Basin has formed part of an extensive passive margin. Relatively minor re-activation of major basin faults (e.g., Murre, Egret, and Spoonbill) in the Late Cretaceous and Early Tertiary has been attributed to salt tectonics and/or an additional phase of subdued extension that may have preceded the opening of the Norwegian-Greenland Sea in the Middle Eocene.



GEOLOGICAL INTERPRETATION OF NORTH-NORTHEAST SEISMIC PROFILE APPROXIMATELY ALONG THE AXIS OF THE JEANNE D'ARC BASIN.

- AL - LATE ALBIAN-CENOMANIAN
- AP - LATE APTIAN
- B - LATE BARREMIAN
- K - KIMMERIDGIAN

THE MESOZOIC-CENOZOIC STRATIGRAPHIC RECORD IS DIVIDED INTO SIX DEPOSITIONAL SEQUENCES WHICH CAN BE RELATED TO UNIQUE TECTONIC PERIODS IN THE EVOLUTION OF THE NEWFOUNDLAND MARGIN.

Figure 2.1-4: Cross-Section from B to B'

(after Bowes, 1998. Cross-section is approximately 120 km long.

Sandstone is coloured yellow, salt is coloured hashed green, basement is coloured pink.)

2.1.2 Regional Stratigraphy and Depositional Environments

Depositional megasequences in the basin can be related to distinctive regional tectonic events.

2.1.2.1 Late Triassic to Middle Jurassic Basin Fill

Late Triassic to Middle Jurassic extension created accommodation for the first megasequence in the Jeanne d'Arc basin. This megasequence includes Upper Triassic to Lower Jurassic (Carnian-Pliensbachian) continental redbeds of the Eurydice Formation, restricted-marine evaporates of the Argo Formation, and carbonates of the Iroquois Formation (Figure 2.1-5). These are overlain by marine mudstones and carbonates of the Downing Formation, shallow marine sandstones and shales of the Voyager Formation, and limestones and fine-grained clastics of the Rankin Formation. These sedimentary units have been penetrated by several wells in the southern part of the basin and can be tied to seismic data that allows for regional mapping of these intervals.

The Rankin Formation is a dominantly marine interval and consists of a heterogeneous mix of massive limestone, fine clastics, and thinly interbedded limestone, marl, and shale in the southern part of the basin, and an interval of interbedded sandstone, siltstone, shale, and occasional limestone in the northern part of the basin. The prolific source rocks of the Egret Member are found in the upper part of the Rankin Formation. The source rocks are regionally extensive and consist of thinly interbedded and laminated marls, calcareous shales, and claystones deposited in a low-energy, restricted-marine environment. The Egret Member is estimated to range in thickness from approximately 50 to 120 m, based on wells outside the field that penetrated the entire Rankin Formation.

2.1.2.2 Upper Jurassic to Early Cretaceous Basin Fill

A pronounced sequence boundary defines the base of the second megasequence in the Jeanne d'Arc Basin. The base of this unit is defined by Kimmeridgian and Tithonian fluvial to shallow marine sandstones and shales of the Jeanne d'Arc Formation. The Tithonian Fortune Bay Formation shales and silts overlies the Jeanne d'Arc Formation. These in turn were overlain by the fluvio-deltaic sands and shales of the prograding Berriasian to Valanginian Hibernia Formation.

The Kimmeridgian to Tithonian Jeanne d'Arc Formation is a coarse-grained conglomeratic fluvial braidplain deposit with associated restricted-marine shales. The Jeanne d'Arc Formation consists of a thick succession (up to 650 m) of eight depositional sequences, each composed of stacked fluvial channel sands and a shaly unit.

Offshore marine shales and siltstones of the Tithonian-aged Fortune Bay Formation overlie the Jeanne d'Arc rocks. The Fortune Bay Formation ranges from 200 m to more than 300 m in thickness across the Hebron Asset.

The (Berriasian to Valanginian) Hibernia Formation unconformably overlies the Fortune Bay shales in the Hebron Field. The Hibernia Formation throughout much of the Hebron Asset is composed of shoreface successions with minor fluvial and marginal marine deposits, unlike the reservoirs at the Hibernia Field, which are fluvial sandstones. The sediment source for the Hibernia Formation is from the south in the Avalon uplift. The Hibernia represents an overall regional regression that can be separated into an upper and lower member.

The Jeanne d'Arc basin returned to passive subsidence during deposition of the Hibernia Reservoir. The B marker limestone was deposited along with the fine-grained clastics and oolitic limestone of the Catalina Formation and the distal equivalent shales of the White Rose Formation during this passive subsidence phase. The B marker (mid-Valanginian) unconformably overlies the Hibernia Formation on the flanks of the Jeanne d'Arc Basin, but is conformable over portions of the Hebron Asset (Figure 2.1-5). The B marker consists of a 55 m to 110 m succession of oolitic limestone and minor fine to medium grained sandstone.

The Hauterivian Catalina Formation, an 80 to 130 m thick succession of nearshore marine fine-grained clastics and oolitic limestone, overlies the B marker in the southwestern portion of the asset. Elsewhere, the distally equivalent, 475 to 825 m thick marine shale of the Hauterivian to Barremian White Rose Formation represents deposition associated with the post-rift subsidence across the asset.

The Hauterivian to Barremian Eastern Shoals Formation conformably overlies the White Rose Formation. The Eastern Shoals Formation consists of a 100 m to 150 m succession of shallow-marine to marginal-marine calcareous sandstone and oolitic limestone.

The Eastern Shoals Formation is unconformably overlain by the upper Barremian to upper Aptian Avalon Formation, consisting of a 50 m to 100 m succession of coarsening-upward, very fine to fine grained sandstone with minor siltstone, limestone, and claystone. The Avalon Formation was deposited in a shallow marine setting and consists of a stacked succession of marine to marginal-marine calcareous sandstone, bioclastic limestone, and minor shale of varying thickness across the basin.

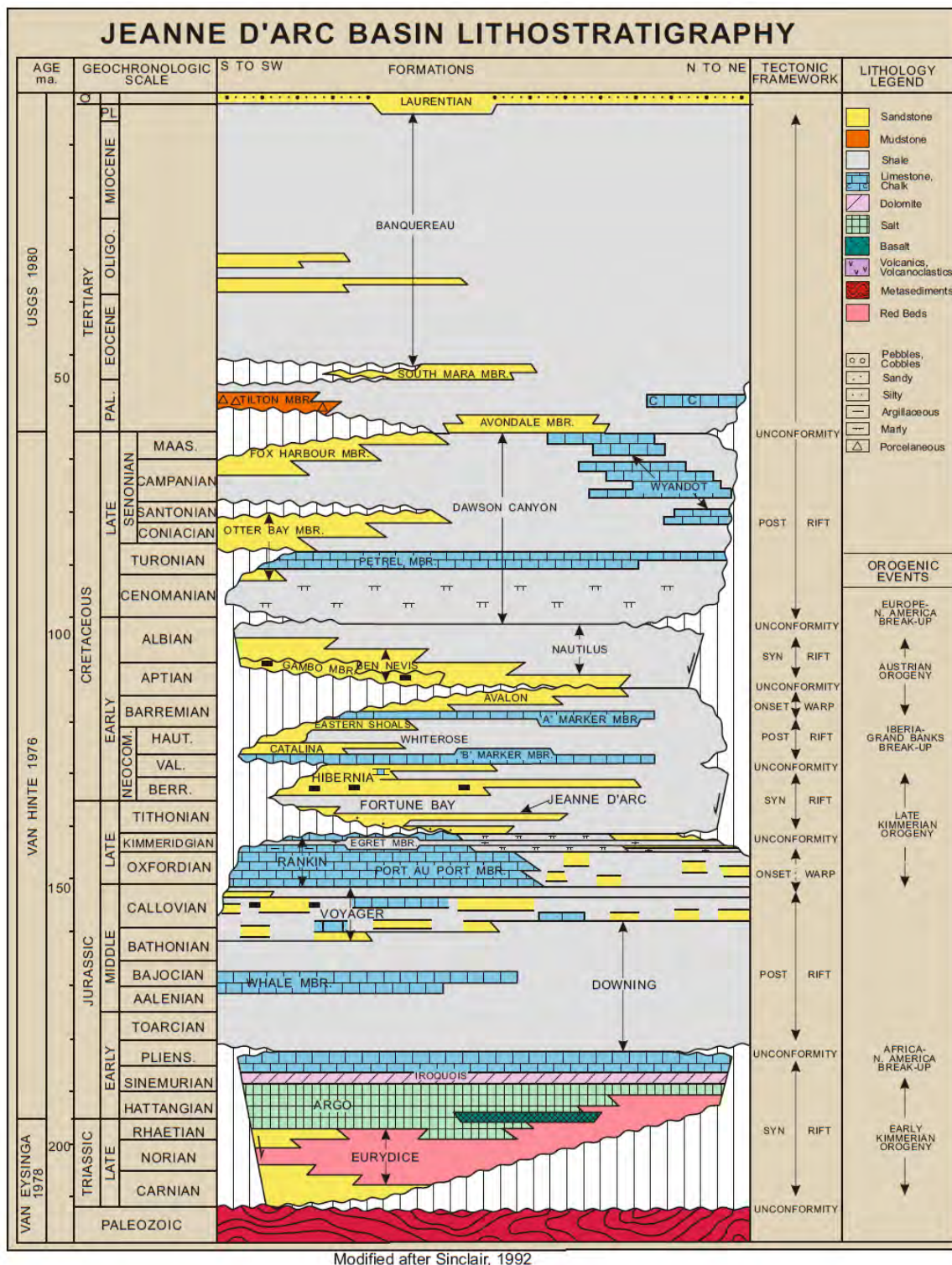


Figure 2.1-5: Basin Lithostratigraphy

2.1.2.3 Aptian – Tertiary Basin Fill

The Ben Nevis Formation (upper Aptian to Albian), unconformably overlies the Avalon Formation and consists of a 125 m to 500 m thick fining-upward succession of fine to very fine grained calcareous sandstone with interbedded thin layers of sandy limestone grading upward into glauconitic siltstone and shale. The Ben Nevis Formation consists of a succession of transgressive shoreface sandstones and was deposited in a shallow, open to restricted shelf environment.

Further transgression of the shoreline resulted in deposition of the laterally extensive offshore shales of the Nautilus Formation. Upper Albian marine shales of the Nautilus Formation conformably overlie the Ben Nevis Formation. The Nautilus Formation ranges from 70 m to 360 m in thickness across the asset.

The Nautilus Formation is unconformably overlain by the Upper Cretaceous (Cenomanian to Maastrichtian) Dawson Canyon Formation. This 200 m to 300 m post-rift sequence of dominantly marine shales also contains the thin (5 m to 45 m thick) grey to brown argillaceous limestone known as the Petrel Member. All of the Upper Cretaceous post-rift succession, ranging from Cenomanian to Maastrichtian, is assigned to the Dawson Canyon Formation. This succession consists mainly of marine shales, but also includes the deltaic members of the Otter Bay and Fox Harbour, the Turonian chalky Petrel Member, and the Coniacian to Maastrichtian chalky Wyandot Member. The marine shales and minor chinks, siliceous mudstones and rare sand-silt beds of the Banquereau Formation represent the Tertiary passive margin sequence.

A 1270 m to 1650 m thick sequence of Tertiary marine shale, minor chalk, and occasional sandstones of the Banquereau Formation represents the youngest rocks in the Hebron Asset. The South Mara Member sandstone is occasionally present at the base of the Banquereau where it overlies the Base Tertiary Unconformity.

2.1.3 Regional Geochemistry

The presence of commercial amounts of hydrocarbons in the Jeanne d'Arc Basin proves the existence of a working petroleum system. This requires the favourable coincidence of mature, organic-rich, oil-prone source rocks; reservoir facies; effective migration pathways; hydrocarbon traps.

The Kimmeridgian-aged Egret Member of the Rankin Formation is generally accepted as the major source of oils in the Jeanne d'Arc Basin (Magoon, et al., 2005). Found near the top of the Rankin Formation, it consists of marls and organic-rich, laminated shales deposited over most of the Jeanne d'Arc Basin. The organic matter is oil-prone, amorphous Type II-I kerogen. This deposit is interpreted as the result of a sea level highstand creating euxinic conditions in a deep, silled basin (Powell 1985). The Egret source rock

thickens from the basin margin (0 m) towards the basin centre (greater than 200 m) (Figure 2.1-6). Other potential source rocks occur sporadically throughout the basin but are not believed to contribute significantly to the oils analyzed to date. Among these potential source rocks are intervals within the Banquereau, Fortune Bay, Jeanne d'Arc, Lower Rankin, and the Voyager Formations (Fowler et al 1995; Von der Dick et al 1989). Currently, the Egret member is at depths greater than 10 km, which is in the gas window, but there are places in the basin that are currently within the oil window (Figure 2.1-7).

Timing of hydrocarbon generation and migration has been estimated by determining when the source rocks reached thermal maturity. For Type II kerogen such as is found in the Egret Member, oil generation is expected to begin at a 0.5 % Ro (vitrinite reflectance value), peak at 0.8 % Ro, and end at about 1.35 % Ro. Present maturation levels for the Egret Member source rocks, as well as time-temperature modeling of hydrocarbon generation (Williamson 1992), suggest that oil generation began about 100 million years ago and that peak generation was not reached until about 50 million years ago during the Early Tertiary (Figure 2.1-8). Pre-Tertiary hydrocarbon generation and expulsion were possible only in the deepest part of the basin, where the Jurassic source rocks are buried to an estimated depth of 10,000 m.

Faulting and subsidence in the Late Cretaceous and Early Tertiary (mid-Eocene) probably contributed significantly to the generation, migration, and distribution of hydrocarbons in the basin, even though this was after major extensional events. Regional source rock maturity and distribution of oils in the basin suggests a primarily vertical migration pathway from fully mature or late mature source beds, although lateral migration has most certainly occurred in the basin. The numerous listric normal faults and fractures dissecting the Mesozoic and Cenozoic sections provide excellent conduits for vertical migration during episodes of extension. In addition, direct charging of reservoir sands has been observed where reservoirs are in direct contact with the source beds such as in the case of the Jeanne d'Arc pools at Terra Nova.

Although the Jeanne d'Arc Basin oils are similar, having been derived largely from the same Egret Member source, they exhibit a wide range in maturity. In addition, variations in maturity of the oils are evidence of more than one episode of oil migration in some areas of the basin. Significant lateral migration on the South Tempest and Trave structures on the east side of the basin has been postulated because highly mature oil and condensate are trapped above marginally mature Jurassic source rocks. However, vertical migration up along a major north-south fault adjacent to the structures may have sourced these reservoirs from mature and overmature Jurassic source rocks.

In addition, hydrocarbon pools trapped in shallow reservoirs at a depth of less than 2000 m (such as Hebron, Ben Nevis, Mara, E. Rankin, and King's Cove) show heavy oil of moderate to extensive biodegradation.

JEANNE D'ARC BASIN ISOPACH OF THE EGRET SOURCE ROCK

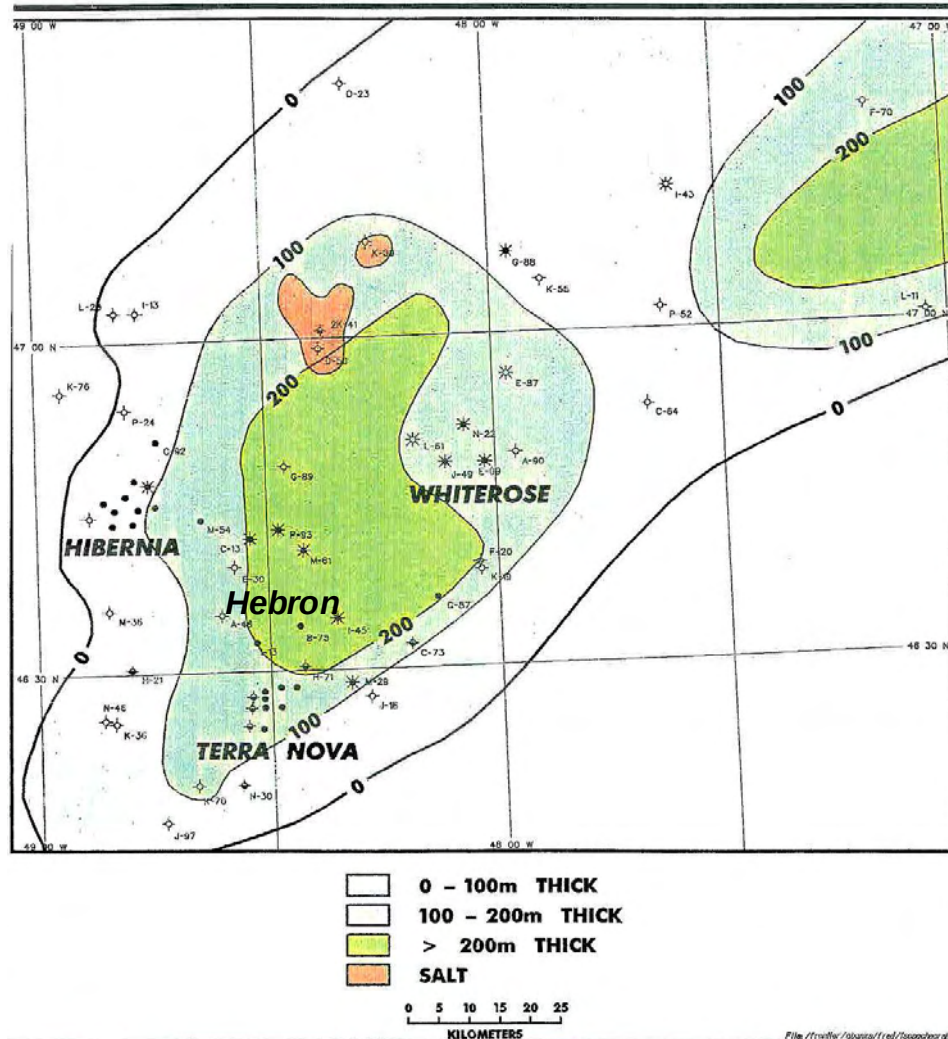


Figure 2.1-6: Isopach of the Egret Source Rock (Bowes, 1998)

JEANNE D'ARC BASIN MATURITY OF KIMMERIDGIAN EGRET SOURCE

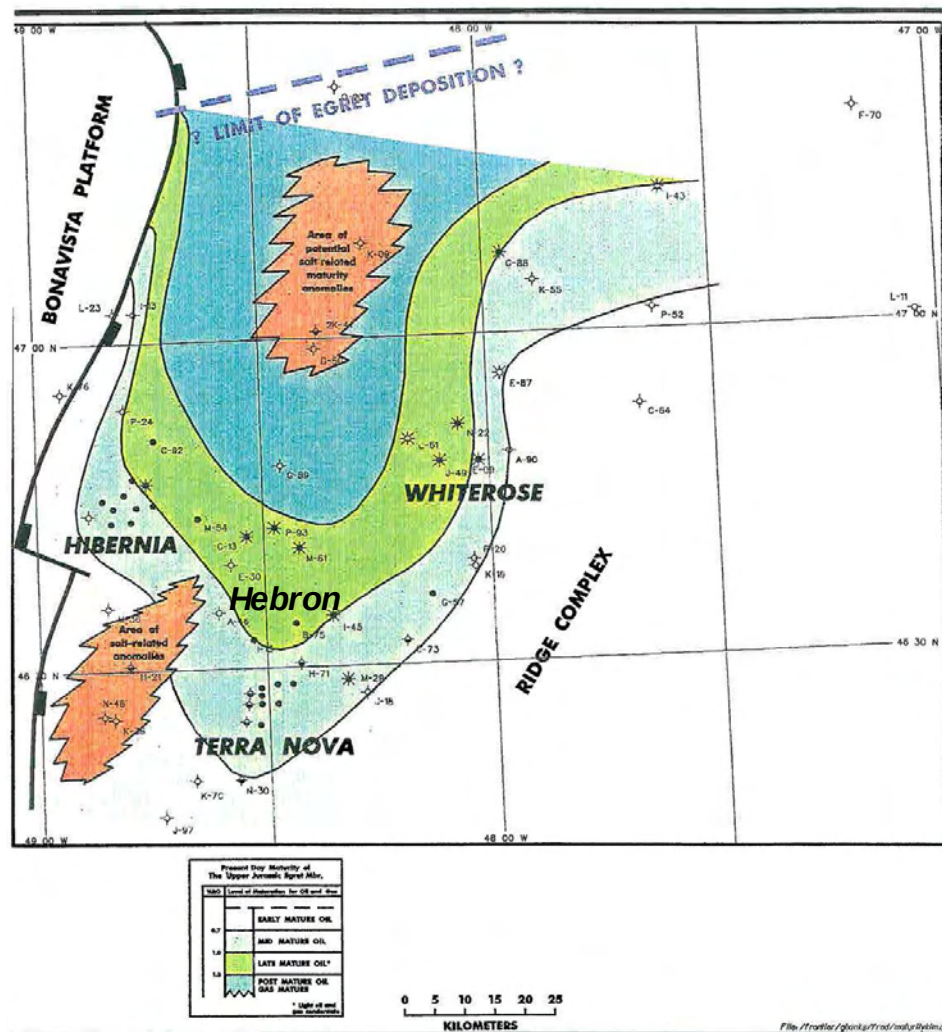


Figure 2.1-7: Maturity of Egret Source (Bowes, 1998)

**REPRESENTATIVE GENERATION PLOT FOR JEANNE D'ARC AREA:
BASE EGRET MEMBER AT HEBRON I-13 LOCATION**

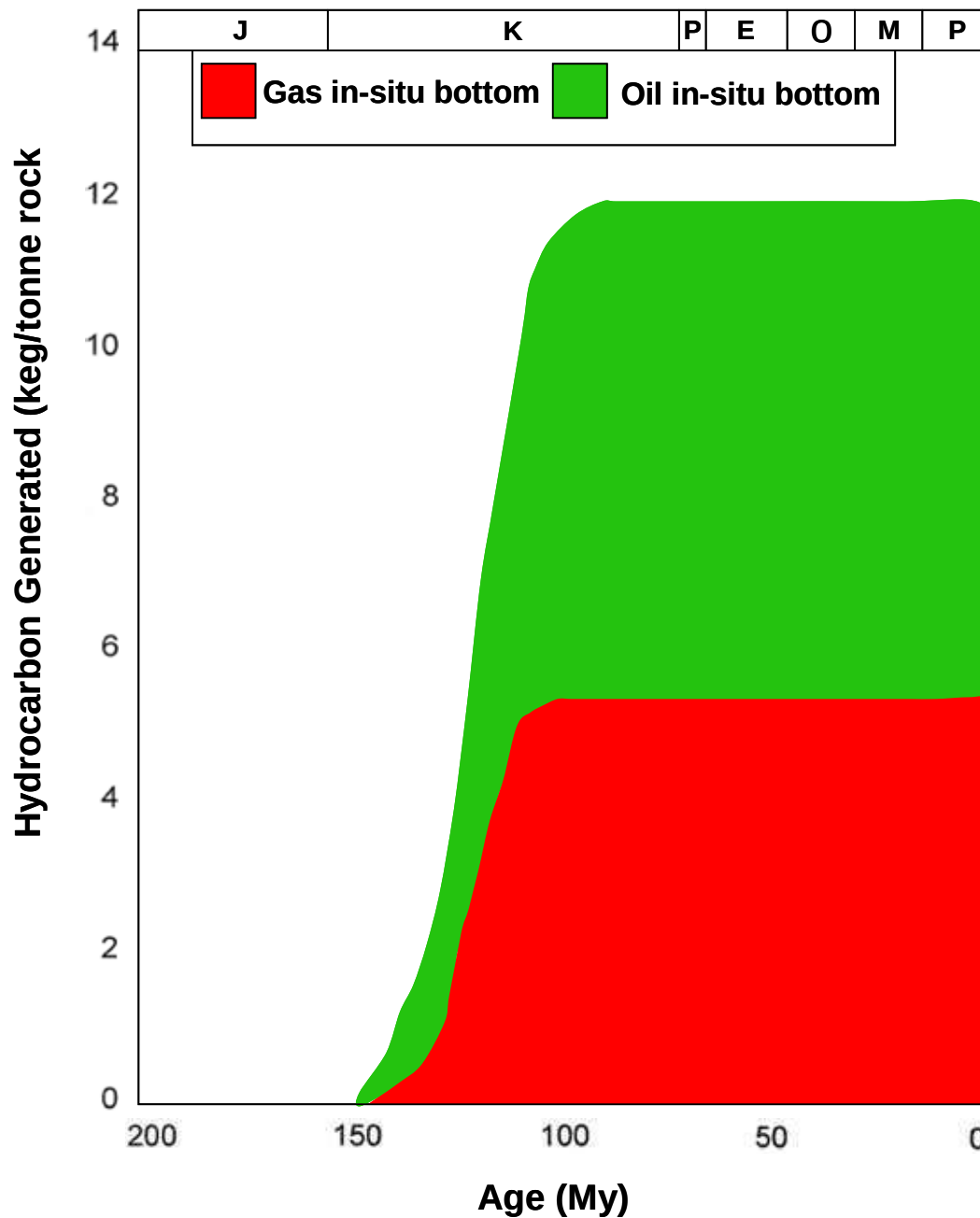


Figure 2.1-8: Hydrocarbon Generation Plot for Jeanne d'Arc
(Bowes, 1998)

2.2 General Field Description

This section describes the Hebron Project Area geology and is organized into the following subsections:

- ◆ Section 2.2.1: Structural Geology
- ◆ Section 2.2.2: Reservoir Geology
- ◆ Section 2.2.3: Hebron Project Area Geochemistry

The oldest rocks penetrated in the Hebron Asset are the Late Jurassic (Early Kimmeridgian) marine limestones, marlstones, shales, and siltstones of the Rankin Formation. The uppermost part of this succession, which ranges in age from Late Callovian to Kimmeridgian, was encountered in the basal portion of the I-13 discovery well. The Egret Member (Kimmeridgian) source rocks occur near the top of the Rankin Formation. The source rocks are regionally extensive and consist of thinly interbedded limestone, marlstone, and calcareous shale, deposited in a low-energy, restricted-marine environment.

2.2.1 Structural Geology

Structural analysis of the Jeanne d'Arc Basin is based on integration of seismic interpretation, well data, and regional understanding. Timing of structural deformation has been constrained by stratigraphic geometries and biostratigraphy.

The Hebron Field lies on a horst block with a graben to the southwest and to the northeast. The horst block is part of the north-south trending and north-plunging Terra Nova anticline and the fault-bound basin-dividing northwest-southeast "trans-basin" trend. The trapping configuration for the Ben Nevis and Hibernia Reservoirs on the horst block is fault dependent three ways. The Jeanne d'Arc Reservoir has a combination structural and stratigraphic trap configuration. The West Ben Nevis and Ben Nevis Fields lie on adjacent fault blocks to the northeast and are also three-way fault-dependent traps.

North-to-south striking normal faults were created during the second extensional event during the Late Jurassic to Early Cretaceous. The highest concentration of the north-to-south striking faults is east of the Hebron horst block. These faults mostly offset Jeanne d'Arc Reservoir but a few also offset the Hibernia Reservoir. There are several faults in the Hebron Project Area that are related to the north-south fault system. The majority of the north-south-striking faults dip between 40 and 50 degrees either to the east or west depending on the fault. The horst block has remained mostly unfaulted. Interpretation of seismic data provides evidence that growth on the north-south faults has occurred between the top of the Rankin Formation and the top of the Hibernia Formation.

The third episode of rifting in the basin took place in the mid-Aptian to late Albian, and resulted in the growth of the major northwest-southeast trending ("trans-basin") normal faults. The Hebron horst and adjacent fault blocks were delineated during this extensional event. The faults are moderately steep with most dipping between 40 and 60 degrees.

The Hebron Project Area is divided into five major fault blocks (Figures 2.2-1 through 2.2-6) from south to north:

1. Hebron Southwest Graben (undrilled)
2. Hebron I-13 fault block (I-13)
3. Hebron Horst (D-94 and M-04 wells)
4. West Ben Nevis (B-75)
5. Ben Nevis (L-55 and I-45)

There is the potential for further fault block subdivisions, based on small-scale, seismically defined faults and sub-seismic faults.

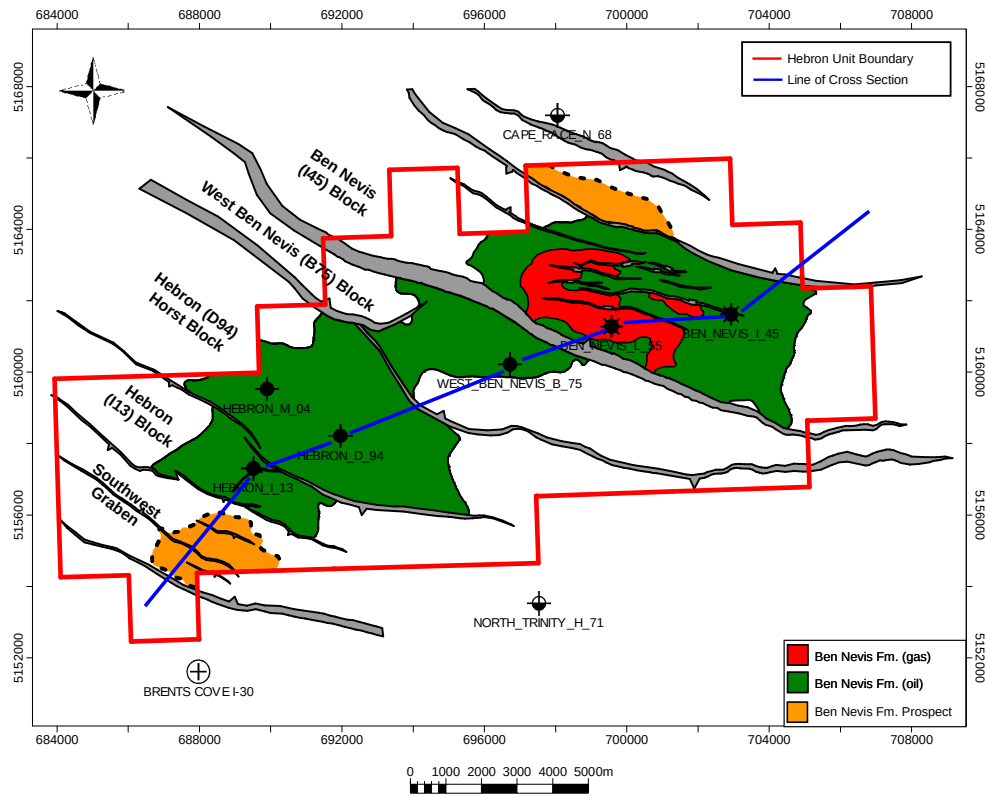


Figure 2.2-1: Schematic map of faults and trapped hydrocarbons in the Ben Nevis Formation at Hebron.

Discovered accumulations are shown in red & green; untested prospects are shown in orange. The prospect in the Southwest Graben assumes independent closure only; the North Lead assumes a common oil-water contact with Pool 3 (-2432m).

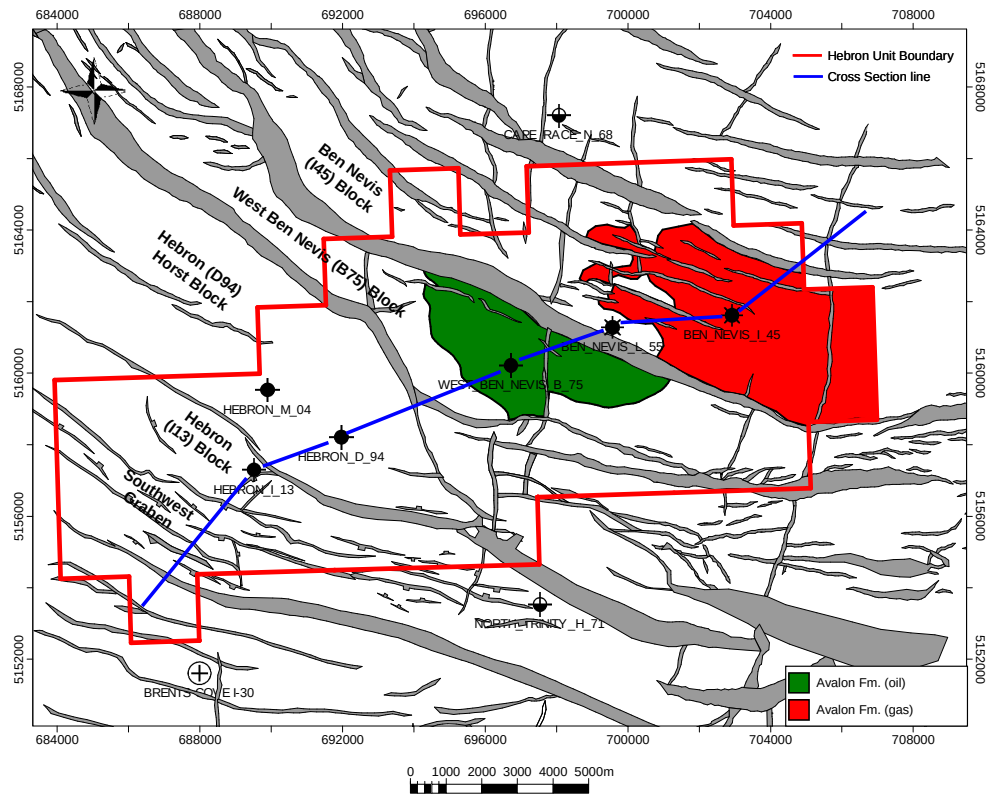


Figure 2.2-2: Schematic map of faults and trapped hydrocarbons in the Avalon Formation at Hebron.

The oil-water contact in West Ben Nevis B-75 is assumed to be -2432m, consistent with the OWC in Ben Nevis Pool 3. In Ben Nevis I-45, the limit of gas is assumed to be at -2930m based on the deepest possible gas response on well logs; no detailed assessment of this area has been conducted.

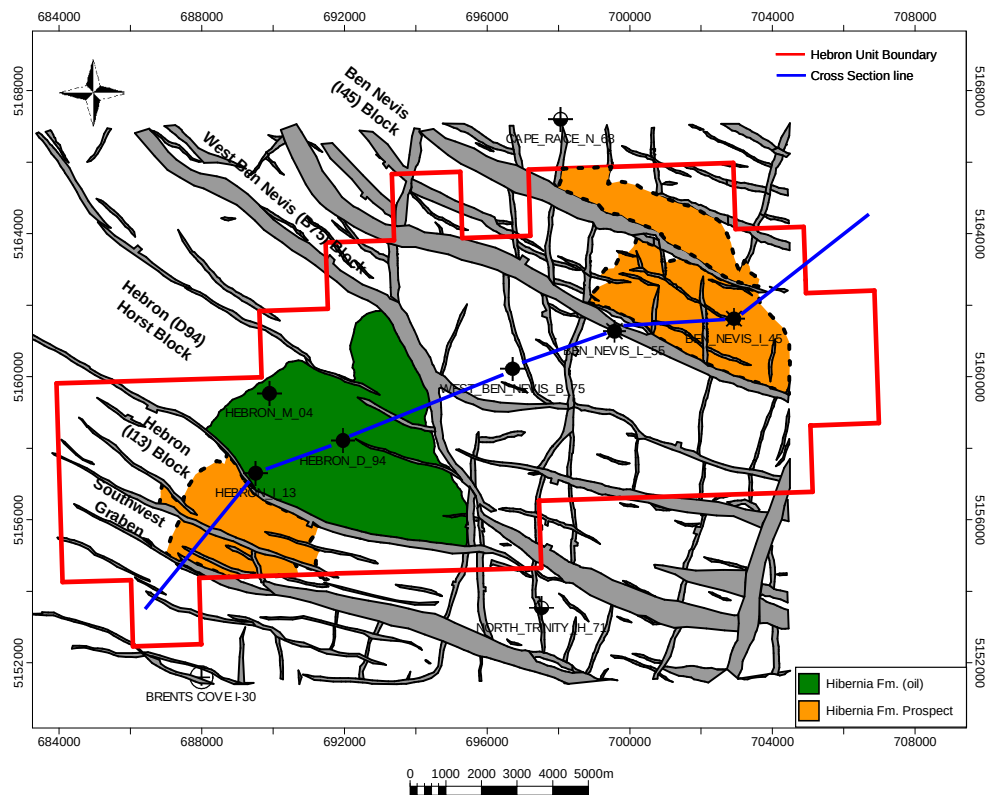


Figure 2.2-3: Schematic map of faults and trapped hydrocarbons in the Hibernia Formation at Hebron.

The oil-water contact in the Horst Block is -2897m and that contact is assumed for the southern prospect. In the Ben Nevis area, the -3950m contour on the Top Hibernia Fm has been used to outline the maximum prospective area; no detailed assessment of this area has been conducted.

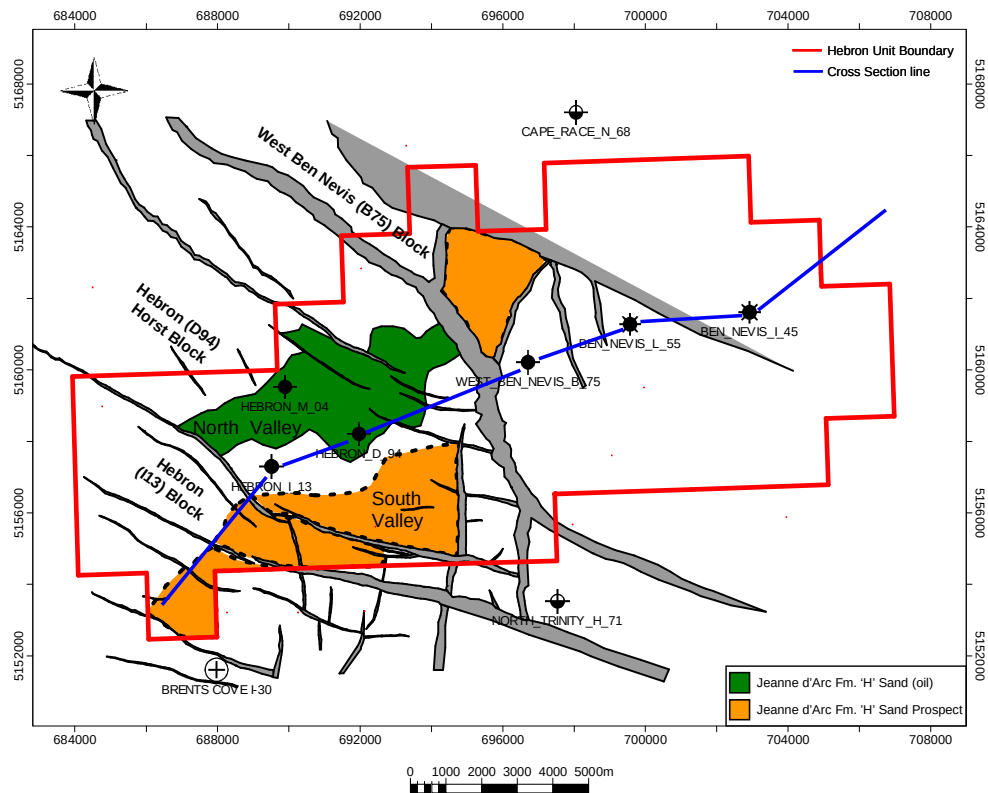


Figure 2.2-4: Schematic map of faults and trapped hydrocarbons in the Jeanne d'Arc Formation ("H" sand) at Hebron.

The oil-water contact in the North Valley in the Horst Block is at -3910m and that contact is assumed for the South Valley prospect in the Horst block and adjacent fault blocks. In the West Ben Nevis (B75) fault block, a northeast extension of the North Valley is postulated but no detailed assessment has been conducted.

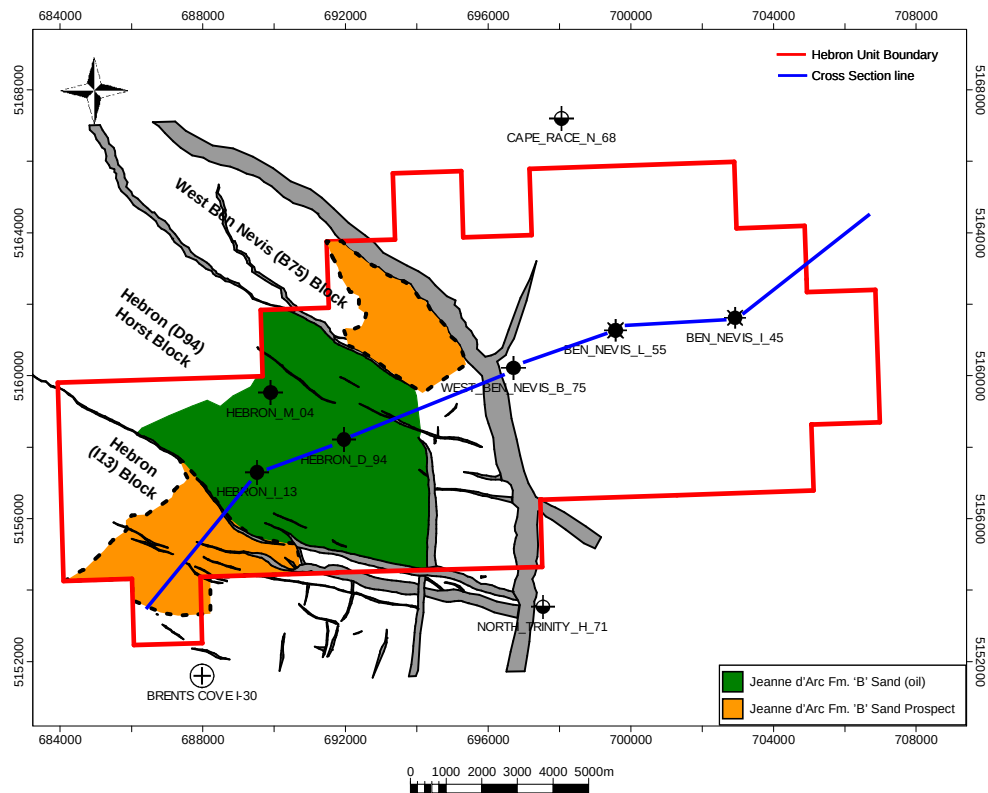


Figure 2.2-5: Schematic map of faults and trapped hydrocarbons in the Jeanne d'Arc Formation ("B" sand) at Hebron.

The oil-water contact in the North Valley in the Horst Block is at -4510m and that contact is assumed for the prospects in the Hebron I-13 and West Ben Nevis (B75) fault blocks. No detailed assessments have been conducted for these prospects.

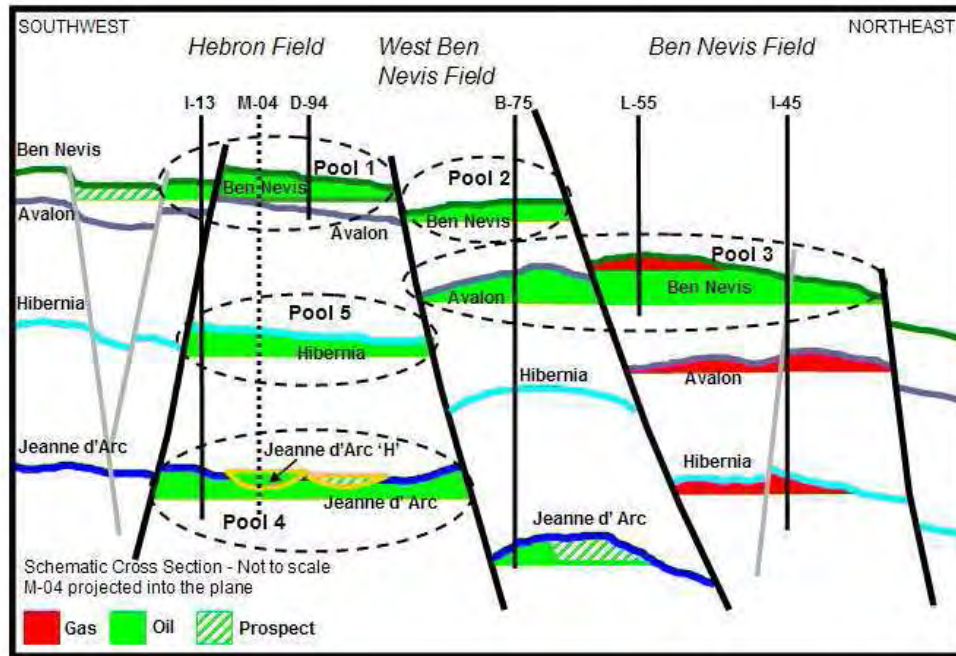


Figure 2.2-6: Schematic Cross-Section of the Hebron Asset

Fault growth within the Avalon and Ben Nevis Formations is observed on the seismic data and wells. NE-SW striking faults in the field range from less than 0.5 km to 4.5 km in length and dip predominantly to the northeast between 55 and 60 degrees. The exception to this is the Hebron Fault, which dips between 55 and 60 degrees to the southwest and created the Hebron horst fault block. The pools are in structural traps defined by the major faults that create the fault blocks, with the oil-water contacts determined by spill-points between the fault blocks. The Hebron horst, penetrated by the D-94 and M-04 wells, appears to be a large, competent fault block, with very little apparent internal faulting. The I-13 and South Graben fault blocks are down-thrown to the southwest. The West Ben Nevis and the Ben Nevis fault blocks are down-thrown to the northeast. This faulting was syn-depositional, and had a significant impact on the accommodation and thickness of the preserved reservoir section. There is significant growth in the thickness of the Ben Nevis Reservoir across these faults. However, the reservoir quality actually becomes poorer in these thicker sections because of the increase in water depth and deposition of more distal facies on the downthrown side of the fault. The Avalon, Hibernia, and Jeanne d'Arc Reservoirs were deposited prior to the onset of this third episode of rifting. These reservoirs were faulted by the Late Cretaceous rifting, but since the sands were deposited pre-rift, there is no change in thickness or reservoir quality across the faults.

The structural traps were created by end of the Cretaceous prior to peak oil generation, which is favourable for trapping hydrocarbons. There is also minimal post-Cretaceous fault activity.

2.2.1.1 Mechanical Seal

The hydrocarbon column at Hebron is not constrained by mechanical seal capacity. The Hebron Field water gradients, oil gradients, and global leakoff trend were all plotted on depth versus pressure plot (Figure 2.2-7). At the crest of the Hebron Field there is sufficient separation between the oil gradient and the leakoff trend, indicating the seal is strong enough to hold back the column at Hebron. Because the global leakoff trend has a shallower gradient than the Hebron Field water gradient, the deeper reservoirs' hydrocarbon columns will not be constrained by mechanical seal capacity either.

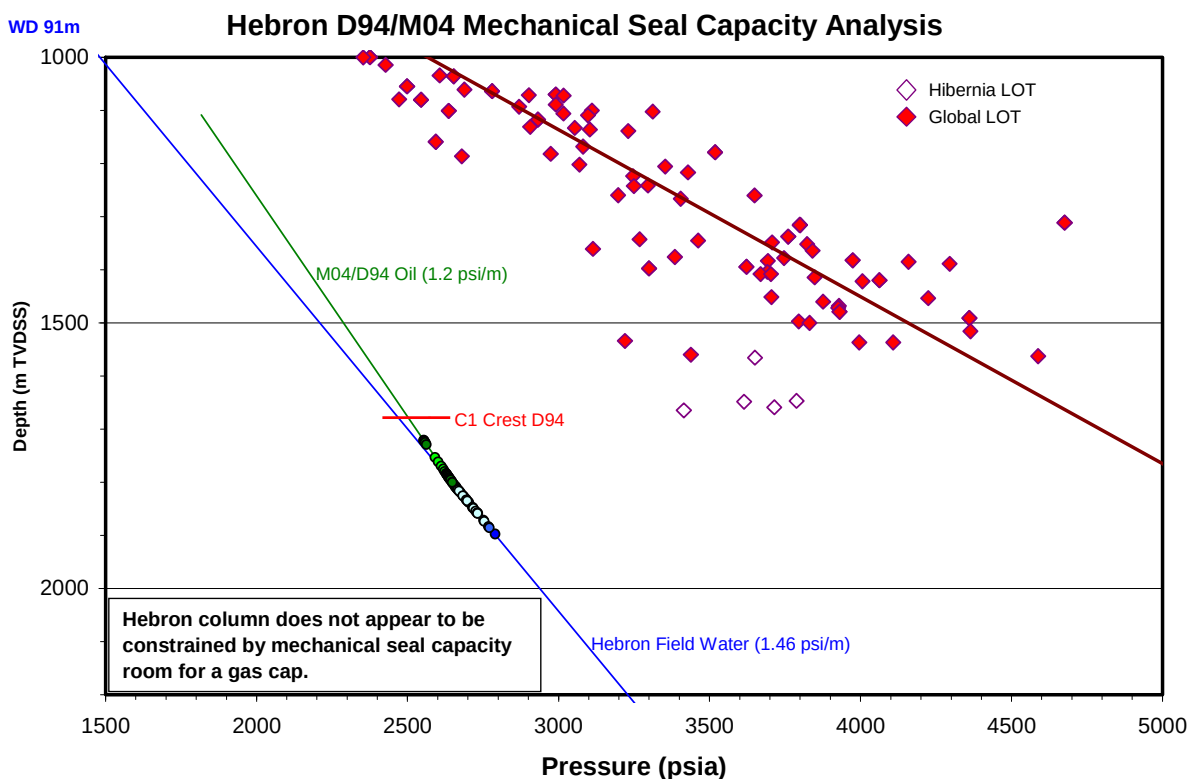


Figure 2.2-7: Mechanical Seal Capacity.

The Global Leak off trend comes from an ExxonMobil database of leakoff tests collected from around the world. The Hibernia Field LOTs are taken from the Hibernia Reservoir at Hibernia Field.

2.2.1.2 Capillary Seal

The capillary entry pressure analysis is based on the single gas penetration in the L-55 Ben Nevis Field well. At the L-55 well all the variables to calculate capillary entry pressure are known, including the gas gradient, gas-oil contact (GOC), oil gradient, oil-water contact (OWC), and the crest of the structure. With those inputs, a capillary entry pressure for the top seal can be calculated at the L-55 well. This top seal gas entry pressure (GEP) is then extrapolated

to other fault blocks. The gas gradient, oil gradient, and water gradient are posted on a depth versus pressure plot for the L-55 well (Figure 2.2-8). The L-55 well is in Pool 3. This analysis is based on the assumption that the GEP across the field is similar to what is observed in L-55 well. For Pool 1 a maximum GOC controlled solely by the GEP would be at 1793 meters True Vertical Depth (TVD) (Figure 2.2-9). This is 11 m above the high known oil (HKO) seen in the D-94 well. No gas column was observed on the logs of the two wells penetrating Pool 1. There is still uncertainty as to the presence of a gas cap in Pool 1. Based on the GEP, Pool 2 could be filled to spill with gas (Figure 2.2-10). But based on the logs, the B-75 well has HKO at 1975 TVD meters. Because the observed HKO is above the calculated gas on rock elevation, the GOC in Pool 2 is controlled by another mechanism. Two possibilities for the observed GOC in Pool 2 are lateral variable capillary entry pressure within the seal across the field or the source is gas charge limited.

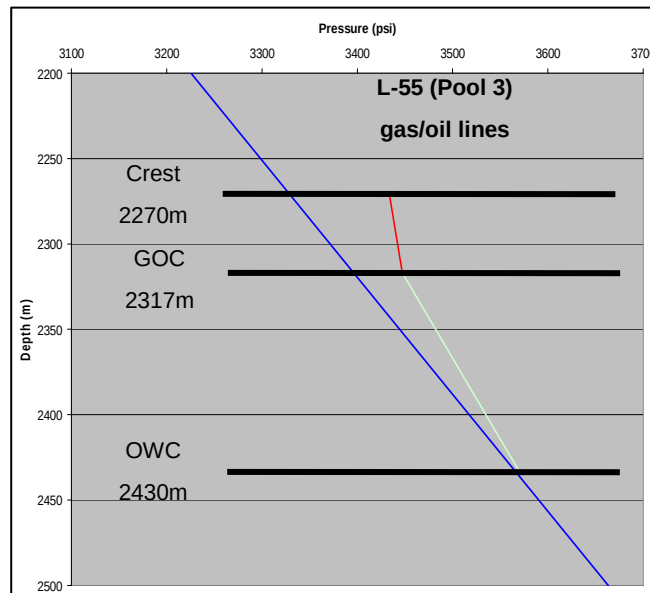


Figure 2.2-8: Pool 3 Capillary Seal

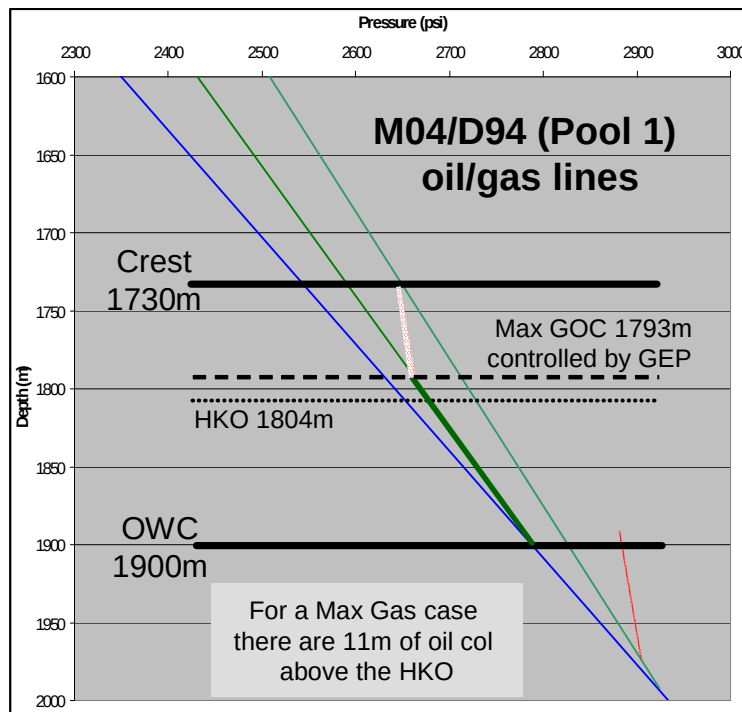


Figure 2.2-9: Pool 1 Capillary Seal

All depths in m TVDSS. Water gradient is blue, oil gradient is green, and gas gradient is red.

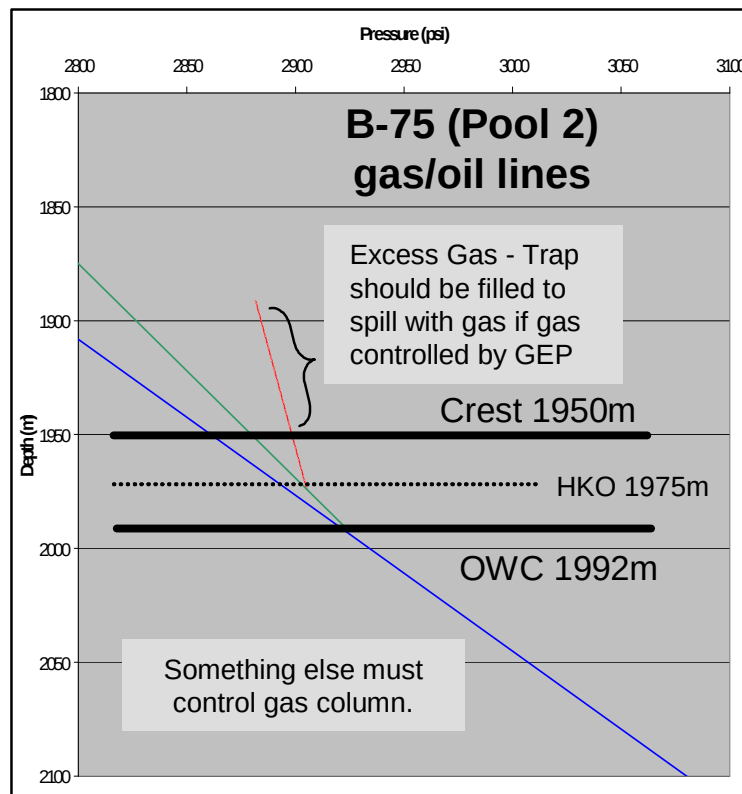


Figure 2.2-10: Pool 2 Capillary Seal

2.2.2 Reservoir Geology

The three main reservoirs for the asset are the Ben Nevis – Avalon, Upper Hibernia, and Jeanne d'Arc Formations. This section describes reservoir geology for each of the main reservoirs. The reservoir geology description will focus on the reservoir formations over the whole Hebron Asset.

2.2.2.1 Ben Nevis – Avalon Reservoir Geology

During the third extensional event there was fault movement on the basin margins and the cross fault trends during the Aptian-Albian that was synchronous with deposition of the Ben Nevis Formation. The syntectonic reservoir exhibits thickening and thinning across fault blocks and onlap on the horst fault block. The mid-Aptian to late Albian Ben Nevis Formation is a fining upward sequence representing a marine transgression. At Hebron, the Ben Nevis is a fine-grained sandstone with few shales that were deposited in a marine shoreface depositional environment. The Aptian age Avalon Formation is a coarsening upward marine shoreface sandstone that represents progradation into the Jeanne d'Arc basin. Both of these formations contain variable amounts of calcite cement. The Early Cretaceous Avalon Formation and "A" Marker are collectively called the Avalon Formation / Reservoir for the geologic technical evaluation and for modeling purposes.

The depositional environment is primarily lower to upper shoreface environment, with subtle facies changes, highly correlative, and a very high net-to-gross. On a more detailed scale, the depositional environment and stratigraphy are more complicated. The core shows many cycles of wave-dominated marine depositional events that encompass a range of facies (upper shoreface to offshore marine). Individual cycles are thin (10s of centimeters), and are interpreted to be laterally extensive (1 to 10s of kilometers).

At Hebron there are six well penetrations of the Ben Nevis Formation (I-13, M-04, D-94, B-75, L-55, I-45). Four offset wells have been used, with varying degrees, to aid the understanding of the Ben Nevis stratigraphy and environment of depositions (I-30, H-71, C-23, and N-68).

The age of the Ben Nevis Reservoir is well constrained by biostratigraphy. Five wells (I-13, M-04, D-94, B-75, and L-55) have biostratigraphy markers that delineate the age of the reservoir. There are sufficient data to constrain the age of the gross reservoir interval, but the lack of shales within the Ben Nevis makes it more difficult to define ages within the formation. Based on the sampled dinoflagellates, the age of the Ben Nevis Reservoir is Aptian to Albian (report van Helden, 1999; Ford, 1998; Ainsworth and Riley, 2006) (Figure 2.2-11). The age of the Avalon Formation is Aptian.

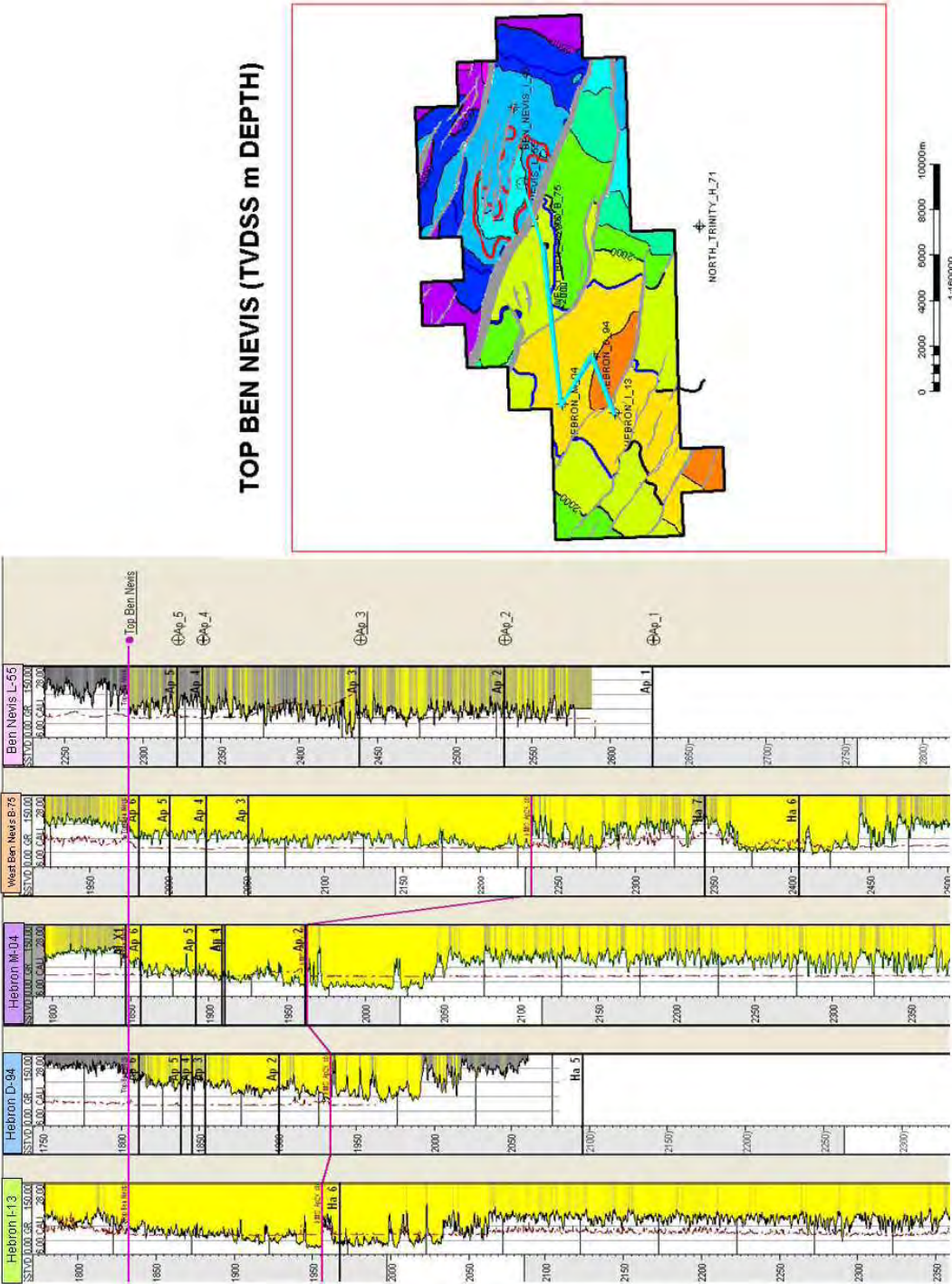


Figure 2.2-11: Ben Nevis – Avalon Biostratigraphy
Biostratigraphy markers posted on colour shaded gamma ray log. Datum is top of Ben Nevis

Ben Nevis Reservoir quality is fair to good in the Hebron Field at the Ben Nevis level (Pool 1) with average permeabilities ranging from 50 to 400 mD and average gross porosities ranging from 10 to 28 percent. In the Ben Nevis field (Pool 3) area, which is dominated by more distal facies, the reservoir quality degrades. Average permeabilities range from 0.1 to 100 mD and average gross porosities ranging from 4 to 24 percent.

2.2.2.1.1 Ben Nevis – Avalon Internal Stratigraphy

The Avalon Formation consists of a stacked succession of marine to marginal marine calcareous sandstone, bioclastic limestone, and minor shale of varying thickness across the basin. The Avalon Formation is composed of coarsening upward progradational parasequences that are topped by a flooding surface and was deposited in the High Stand System Tract (HST). In this document, the Avalon Formation is defined as the interval from the Base Ben Nevis sequence boundary to the base of the “A” marker, which tested oil in the B-75 and I-45 wells.

The overlying, syn-rift mid-Aptian to upper Albian Ben Nevis Formation consists of a succession of transgressive shoreface sandstones. The Ben Nevis Reservoir section is composed predominantly of laminated and bioturbated medium to fine grained sandstones. Minor secondary lithologies include coquinas, shell rich sandstones, mudstones, and calcite nodules. The Ben Nevis Formation is interpreted as being deposited in a transgressive shallow marine, wave-dominated shoreface environment with sediment supplied from the south and west. The sandstones were deposited around the wave base. The dominant environment of deposition on the horst block of the Hebron Field is proximal lower shoreface. The reservoir package has occasional coquinas, made of shallow marine shell debris, and rare shales. In the northeastern fault blocks, the dominant environment of deposition is distal lower shoreface to transitional environment. In these more distal facies, the very fine grained sandstones contain more mud and silt fraction than those of the Horst block. The distal facies are highly bioturbated. Figure 2.2-12 shows the depositional model for the Ben Nevis Reservoir. The facies belts are interpreted to be laterally continuous.

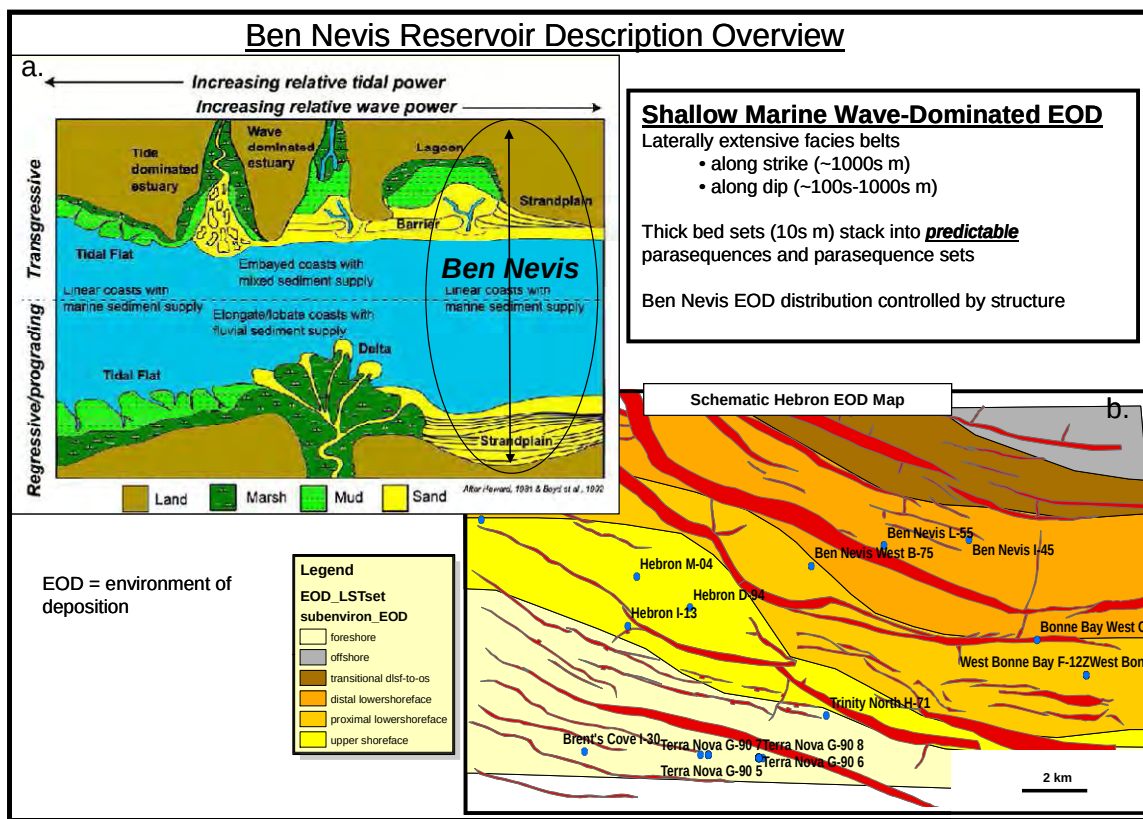


Figure 2.2-12: Ben Nevis – Avalon Depositional Environment

The top left image is a schematic paleogeographic map showing the depositional style in map view of the Ben Nevis. The bottom right image is the environment of deposition (EOD) on one of the layers from the Pool 1 geologic model.

The internal stratigraphy was defined with a combination of seismic, well-logs, lithostratigraphic, and biostratigraphic events, using a rigorous sequence stratigraphic approach. A sequence stratigraphic approach will aid in explaining and predicting facies distributions and seismic events. Figure 2.2-13 illustrates the regional stratigraphic column and the major sequence stratigraphic surfaces within the Ben Nevis – Avalon section.

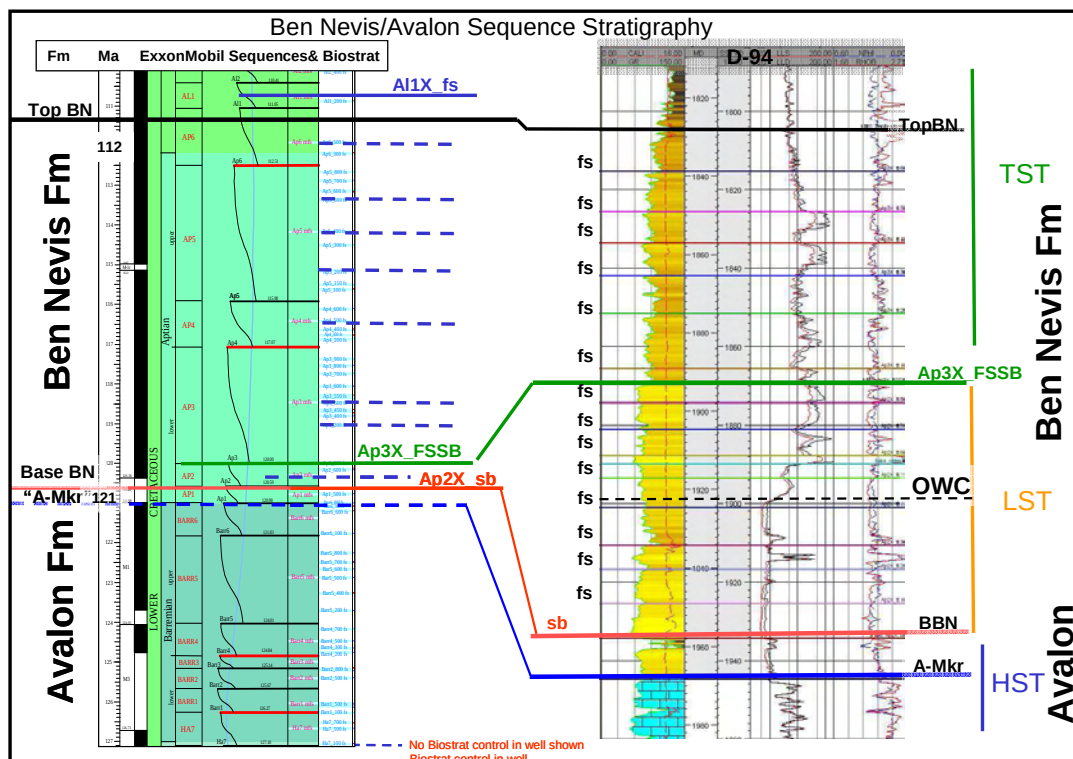


Figure 2.2-13: Ben Nevis – Avalon Sequence Stratigraphy

The left column shows time and relative sea level curve, where the right column shows gamma ray, caliper, measured depth, TVDSS, resistivity, density and porosity curves. The D-94 well is displayed.

The base of the Ben Nevis represents a third order sequence boundary. Sequence boundaries indicate basinward shift in facies and are regional, chronostratigraphic surfaces that can be identified in seismic data based on reflection terminations, internal reflection geometries, and changes in seismic facies. The sequence boundary was picked using seismic data, well log stacking patterns, log signatures, and petrophysical facies. The base Ben Nevis sequence boundary is tied to the eustatic sea level curve through use of biostratigraphic data and is assigned the European Stage Name of Ap2X_SB. The European Stage Name nomenclature allows for assignment of relative ages based on confidence of the biostratigraphic control. The biostratigraphic control within the Ben Nevis Reservoir is not robust enough to confidently assign absolute ages to the sequence boundaries and flooding surfaces. The sedimentation of the area did not provide an ideal locale for using biostratigraphic data confidently. No well developed shales are observed within the Ben Nevis Reservoir, and no maximum flooding events are observed in the core data.

The top of the Ben Nevis is a transgressive surface. The seismic character of the top Ben Nevis changes across the region in response to variations of lithology including silt beds and calcium carbonate rich beds overlaying the flooding event.

The Ben Nevis Reservoir consists of a succession of coarsening upward shoreface parasequences bound by flooding surfaces. Flooding surfaces identified on the well logs represent a shift in facies from proximal to distal, but do not have well-developed shales coincident with the flooding events. One maximum flooding event is interpreted to be present in the lower Ben Nevis section. Correlations were based on log response and stacking patterns. The internal stratigraphy is below seismic resolution on the horst fault block. The parasequences are the building blocks for sequences.

Two third-order sequences are interpreted in the Ben Nevis Reservoir. The older sequence, bound by Ap2X_sb and Ap3X_FSSB, is characterized by aggradational to progradational parasequences stacking patterns. This sequence is interpreted to be a Low Stand Systems Tract sequence. The younger sequence, bound by Ap3X_FSSB and Top Ben Nevis, is characterized by a retrogradational parasequences stacking pattern and is interpreted to be a Transgressive Systems Tract (TST) sequence. The Ap3X_FSSB is a flooding surface sequence boundary, an amalgamation of a sequence boundary and flooding surface where the lowstand systems tract is not observed to be present in the sequence. This chronostratigraphic surface was interpreted where a significant shift in well log signature to more distal prone facies occurs and a retrogradational parasequences stacking pattern dominates the stratigraphy. Overall, the Ben Nevis is fining upward and retrograding into more distal facies at the top of the reservoir.

Within the Lowstand Systems Tract (LST) sequence, nine parasequences are defined and the corresponding eight flooding surfaces can be correlated across the field. As observed in the seismic data, the lower three parasequences onlap onto the paleo-high structure of the horst fault block. Seven parasequences are interpreted to be present within the TST sequence. Six flooding events are correlated between the wells. The significant parasequences and parasequences sets that represent the internal stratigraphy of the Ben Nevis Reservoir are modeled as zones in the reservoir models of Pool 1 and Pool 3 (Figure 2.2-14).

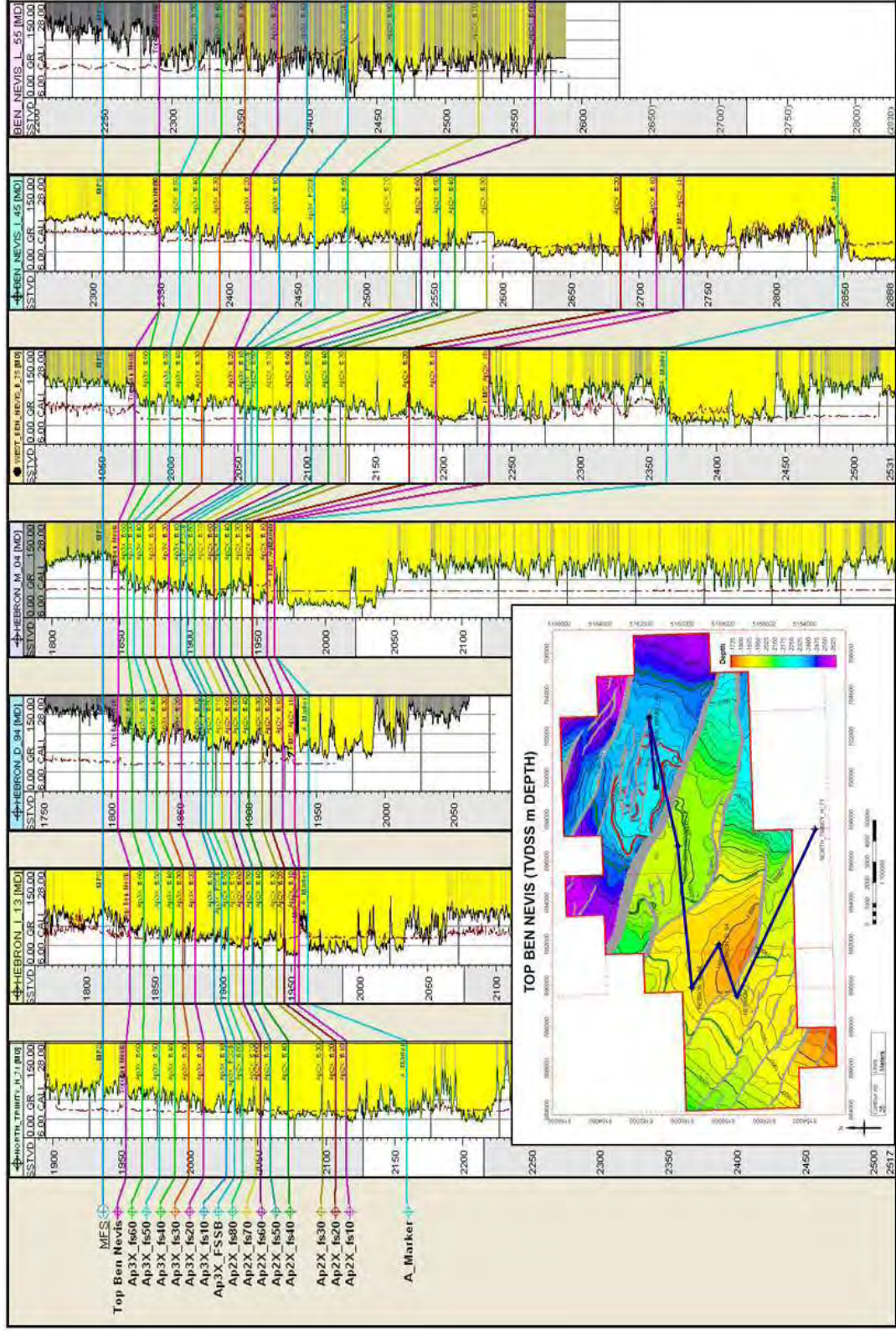


Figure 2.2-14: Ben Nevis – Avalon Well Log Correlations
Well log correlations posted on colour shaded gamma ray (GR) log. Datum is top of Ben Nevis.

Reservoir quality is degraded by diagenetic calcite cement and incorporation of mud into the sand via bioturbation. Diagenetic carbonate cements are found throughout the Ben Nevis Reservoir. Calcite cements occur in two observed forms, as follows:

- ◆ Cemented sandstone and shell beds that are frequently coincident with flooding or abandonment events
- ◆ Calcite cement nodules that have irregular margins that cross-cut bedding boundaries

Both types of calcite cementation have scales of approximately 1 cm to several meters in thickness. The distribution and lateral extent of calcite cemented sandstones are not well established in the literature. Several scenarios for predictive models are used to estimate the distribution of these diagenetic effects on the Ben Nevis Reservoir and are provided in the Pool 1 geologic model.

The Ap2X_fs60 is a significant flooding surface in the internal Ben Nevis stratigraphy in the Pool 1 area. The Ap2X_fs60 may represent an exposure surface or time of little to no deposition of sediment. Occurring at or near the Ap2X_fs60 surface is a thick (1 to 4 meter) calcite cemented, fine-grained sandstone. The cemented sandstone is observed in M-04 and D-94 wells. Continuity and thickness of the cemented sandstone is not well constrained and variations in these parameters are addressed in the reservoir modeling and uncertainty analysis of the Ben Nevis Pool 1 Model. This event is modeled in the static reservoir model and is referred to as the "cement zone". This type of significant flooding event coincident with laterally continuous cement is not observed in the Ben Nevis fault block (Pool 3) area. Therefore, a cement zone was not included into the Pool 3 model. Based upon detailed reservoir quality investigation of cements in the L-55 core samples, calcite cements are interpreted to be early diagenetic features that form small cement nodules. These nodules are represented in the Pool 3 model as discrete cells that have very low to zero percent porosity. Geometry of the shelf and shoreline orientation is the key uncertainty of the depositional model for the shoreface reservoir. However, reservoir quality distribution related to facies changes away from well control is a secondary uncertainty. It is unlikely that the cement zone is laterally continuous across the whole Hebron Field because of its multi-point source genesis it is unreasonable for all the points to coalesce in one impermeable sheet.

2.2.2.1.2 Ben Nevis – Avalon Depositional Environment and Paleogeography

The depositional environment of the Ben Nevis – Avalon Reservoir at Hebron is interpreted as being a shallow marine, wave-dominated shoreface environment. The sediment is believed to have been primarily deposited around wave base in middle and lower shoreface environments

(Figure 2.2-15). The Ben Nevis Reservoir consists of stacked, coarsening upwards parasequences (10s meters scale) comprised of predominately hummocky cross-stratified and bioturbated sandstones with a lack of shale-prone facies. The reservoir is bioturbated with a high diversity of trace fossils indicating an open-marine, shallow water environment. The lack of well developed flooding surfaces and multiple stacked lower-shoreface parasequences are indicative of a strandplain environment (Figure 2.2-16) that lack lagoonal facies or a point-source of sediment supply. The predictable stacking patterns of the coarsening upward parasequences of a strandplain shoreface result in laterally extensive facies belts that extend several kilometers in the strike direction and 100s to 1000s of meters in dip direction.

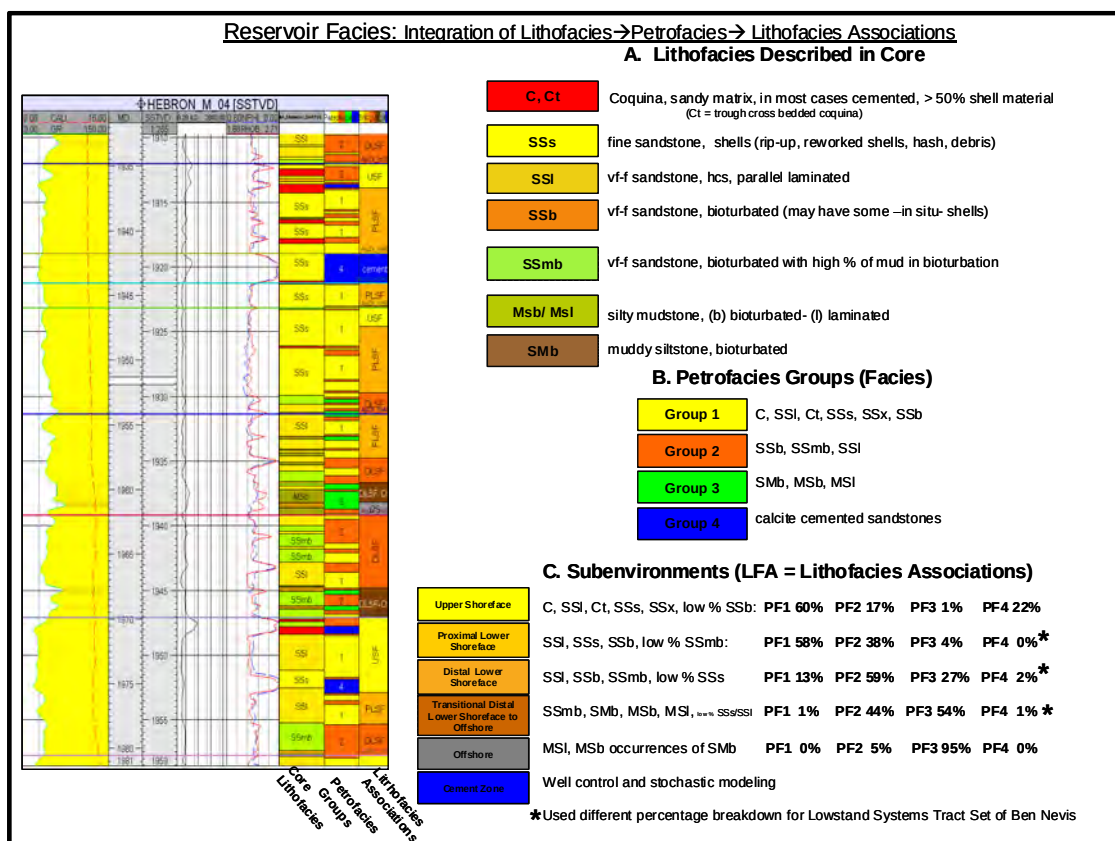


Figure 2.2-15: Ben Nevis – Avalon Reservoir Facies

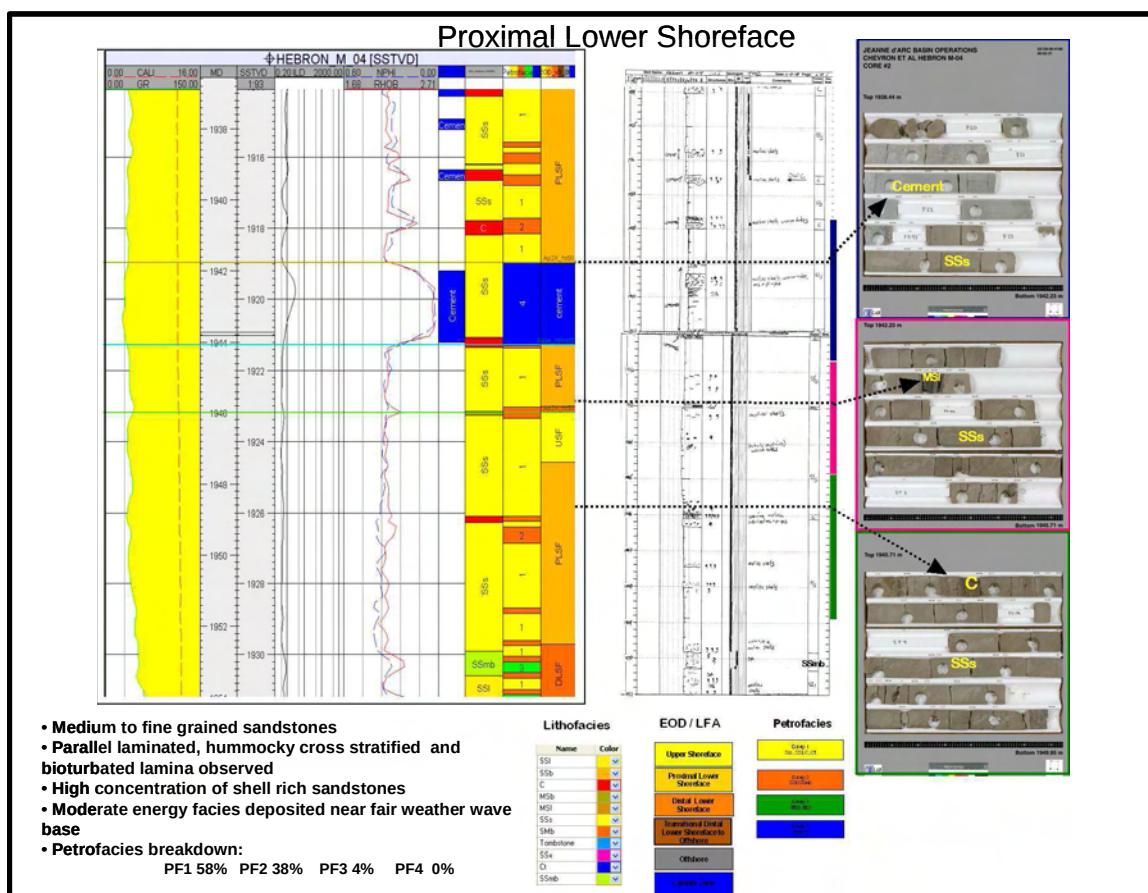


Figure 2.2-16: Ben Nevis – Avalon Proximal Lower Shoreface Facies Description

Seismic data were used to interpret a shoreline trend and proximal to distal facies variations across the Hebron Asset. Onlap and reservoir thinning on the horst fault block indicate a paleo-high was present at the time of Ben Nevis Reservoir deposition. Thickening is observed across large normal faults in the asset area indicating syndepositional timing of the fault movement. Change in water depth and accommodation across these growth faults was great enough to influence a transition into more distal facies belts (Figure 2.2-17). The facies distribution and orientation of facies belts were controlled by structural highs and accommodation changes over faults. Seismic attribute and seismic facies analyses were used to determine that the Ben Nevis shoreline trend is west-northwest to east-southeast. Uncertainty remains around the exact shoreline trend. Seismic facies were also integrated with core, petrophysical data, and regional trends to distribute facies in asset area.

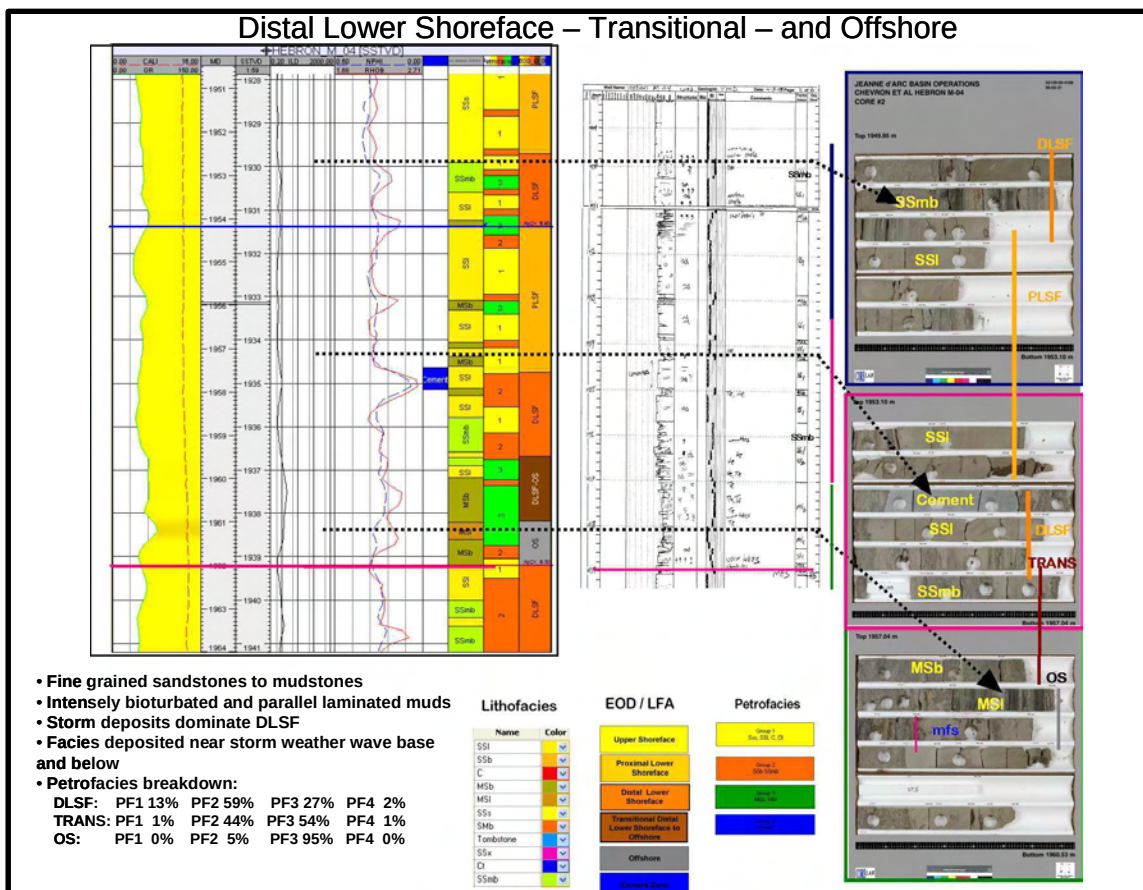


Figure 2.2-17: Ben Nevis – Avalon Lower Shoreface, Transitional, and Offshore Facies Description

The Ben Nevis Reservoir lacks significant variation of grain size (predominately fine grain upper sandstone) and has a high sand-to-shale ratio on the horst fault block wells. A higher proportion of shale and more distal facies are observed in B-75 and L-55 wells. Higher energy facies and coarser grain sizes are observed in the H-71, D-94, I-13, and M-04 wells. These observations are integrated with seismic attribute analyses, discussed previously, with a result of a northwest to southeast trend to the shoreline.

2.2.2.1.3 Ben Nevis – Avalon Reservoir Facies

Detailed core description and interpretation of the approximately 600 m of core through the Ben Nevis and Avalon intervals have been completed from wells H-71, D-94, M-04, I-13, B-75 and L-55. Lithofacies, grain size, trace fossil identification, bioturbation index, sedimentary structures, and stratigraphic surfaces were described. Interpretation of the depositional environment for each well was completed as a basis for the generation of the depositional model. The interpretation of depositional facies was based on biostratigraphic data, log data, petrophysical data, and description of the core. The Ben Nevis to A Marker section was divided into zones of similar depositional facies and petrophysical rock properties.

The Ben Nevis Reservoir section is composed predominantly of laminated and bioturbated fine to medium grained sandstones. The sandstones are predominantly sublitharenites, containing large bioclasts. Secondary lithologies include shell rich coquinas, shales, and calcite nodules. Ten different lithofacies were identified based on composition, grain size, sedimentary structures, and bioturbation. Lithofacies classification is presented in Figure 2.2-15. These lithofacies represent lamina and lamina sets of the stratal unit hierarchy which range in thickness from a few millimeters to meters. Lamina sets are defined as relatively conformable succession of fenetically related lamina bound by surfaces of erosion, non-deposition, or their correlative conformities (Van Wagoner et al, 1990). The range of lateral extent is 100s of square meters to square kilometers. Based on stratigraphic analyses, core description, and lithofacies associations, an environment of deposition (or subenvironment) was assigned to the cored intervals. The Ben Nevis interval is dominated by hummocky-cross stratification and ichnofacies (Skolithos, Arenicolites, and Cruziana) indicating open-marine, moderate energy, shelf to beach environments.

The lithofacies and environment of deposition interpretations were integrated with petrophysical log response analyses and grouped into petrofacies categories (Figure 2.2-15). High energy facies and clean(er) bioturbated sands comprise Group 1 Petrofacies. Bioturbated, laminated, and muddy bioturbated sandstones comprise Group 2 Petrofacies. Mudstones and siltstones comprise Group 3 Petrofacies. Petrofacies Group 4 represents the calcium carbonate cemented sandstones that are a secondary diagenetic overprint found throughout the reservoir. Diagenetic secondary cements at the Ben Nevis level span a range of textural features from unconsolidated sandstones to cementation associated with nodules and thin layers. These cements are generally believed to be of limited areal extent, and are typically several centimeters thick and have lateral extents of several meters. Some of the cements are associated with shell rich lamina of "lag" deposits at the base of a scour. In other cases, the coquinas are cemented and occur at the top of a coarsening/shoaling upward bedset. The shell rich sandstones and coquinas are not always cemented and cements do not always correspond to either flooding or erosive events. Where the cement can be correlated, as in the Ap2X_fs60 event in Pool 1, this was recorded and modeled in the reservoir description. The cements tend to be randomly distributed with a high concentration in the higher energy and coarse grained facies and are considered "nodules".

The stacking patterns, stratigraphic surfaces, petrofacies, core description, and environment of deposition described at the cored interval were used to define subenvironments of deposition or lithofacies associations. Five lithofacies associations were defined (Figure 2.2-15). The lithofacies associations are the building blocks for the parasequences observed in the well logs. Lithofacies associations represent beds and bed sets of the stratal unit hierarchy. Bedsets are defined as a relatively conformable succession of

beds bounded by surfaces of erosion, non-deposition, or their correlative conformities (Van Wagoner et al, 1990). Beds and bedsets range in thickness from 10s of centimeters to 10s of meters thick and can have lateral extents ranging from square kilometers to 100s of square kilometers.

The following are the lithofacies associations interpreted in the Ben Nevis Reservoir interval:

1. Upper shoreface
2. Proximal lower shoreface
3. Distal lower shoreface
4. Transitional distal lower shoreface to offshore
5. Offshore marine facies

One key interval identified near the Ap2X_fs260 surface was treated as a cement horizon and is populated in the Pool 1 reservoir model with the Group 4 petrofacies. A breakdown of the petrofacies groups that define each association is provided in Figure 2.2-15. The upper shoreface (Figure 2.2-19) represents the highest energy facies with a high concentration of coarse grained sandstones, coquinas, and trough-to-parallel laminated sandstones. Approximately 20 percent of the lithofacies association is cemented sandstones and coquinas. The cemented facies are concentrated in this subenvironment due to the high volume of calcite available in the shell hash layers of the lamina. The high energy facies also is characterized by winnowing of fine grained material, leaving shell hash and coarse grained sands behind. As the water deepens towards the more distal facies (Figures 2.2-15, 2.2-18, and 2.2-19), the sandstones become interbedded with more bioturbated and muddier facies. The lower shoreface subenvironments (proximal, distal, and transition) are dominated by hummocky-cross stratified, amalgamated lamina sets. The more distal facies have more mud in the bioturbated sandstone matrix. The entire Ben Nevis Reservoir in the Hebron Asset is dominated by distal lower shoreface environment with an abundance of proximal lower shoreface in the lower section and transitional lower shoreface to offshore in the upper Ben Nevis interval.

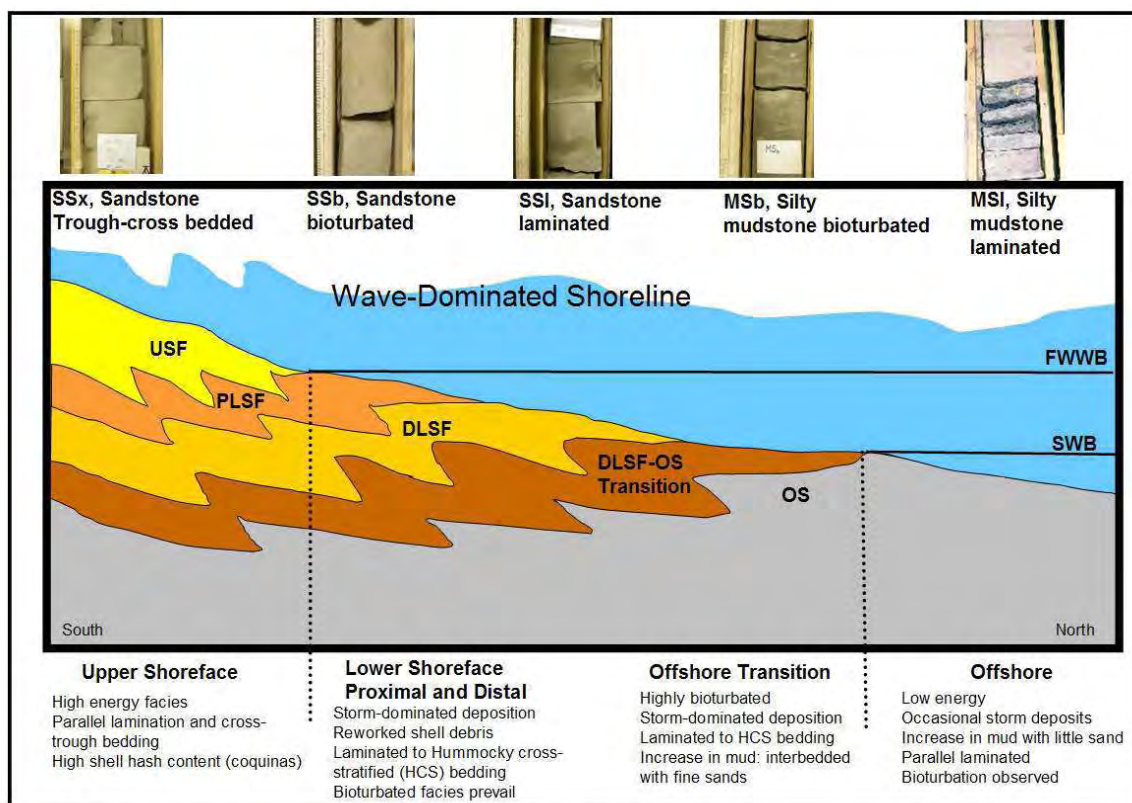
The sequence stratigraphic architecture observed in the well logs (discussed in Section 2.2.2.1.1) can be observed using available core data. The model of coarsening upward parasequences is observed at the core scale. Overall, the cored intervals indicate a deepening of water as the facies in the younger strata become dominated by muddier and more heavily bioturbated facies. Figure 2.2-19 shows examples of subenvironments described in the core. Figure 2.2-20 shows gradual thickening of the Ben Nevis Reservoir northward.

Reservoir facies were defined in the Ben Nevis Pool 1 reservoir model by tying Environments of Deposition (EOD's) deterministically at the wells. The

representative fraction of each rock type (petrofacies) in each EOD was then assigned and the distribution of rock types was modeled geostatistically using Gaussian random function simulation.

In the Pool 3 reservoir model, petrofacies were predicted by integrating core-based lithologic descriptions and log-derived total porosity and shale volume using Geolog's Facimage software. Target percentages of each petrofacies were then assigned to EOD's and populated geostatistically in the model. Cemented intervals were identified from a combination of density and microresistivity logs at the wells and populated geostatistically in the model.

Reservoir facies were not defined in the Avalon in these models.



FWWB = Fairweather wave base, SWB=storm weather wave base

Figure 2.2-18: Ben Nevis – Avalon Schematic Cross-Section

A schematic cross-section depicting the depositional model for the Ben Nevis Reservoir with representative core photos of the different facies across the top.

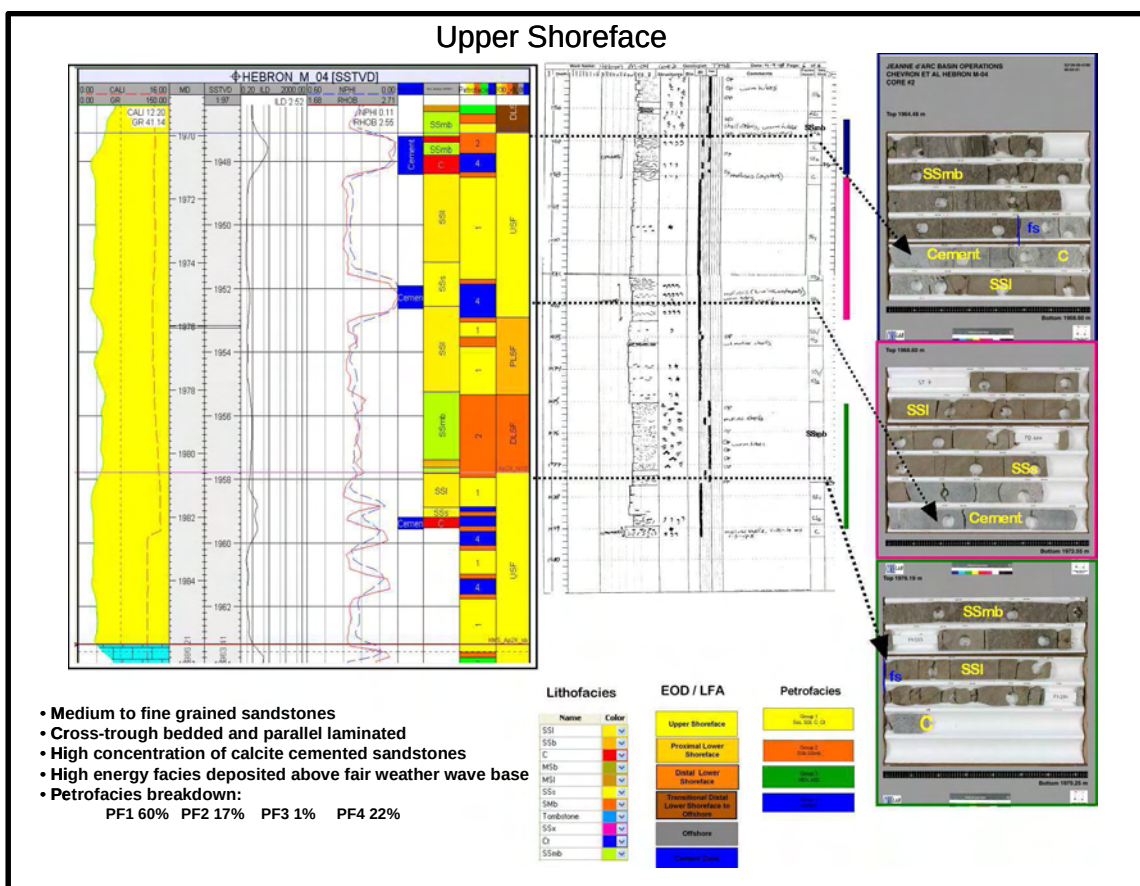


Figure 2.2-19: Ben Nevis – Avalon Upper Shoreface Facies Description

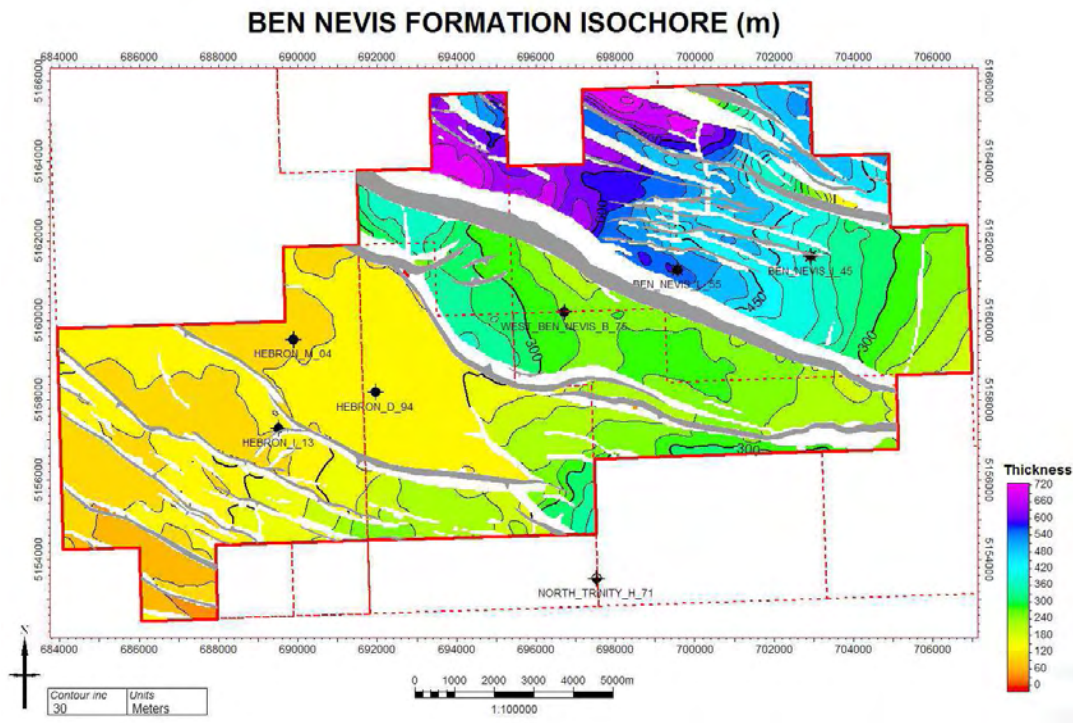


Figure 2.2-20: Ben Nevis – Avalon Isochore Map

Isochore map of the Ben Nevis Reservoir demonstrating thickening towards the northeast across the faults.

2.2.2.2 Hibernia Reservoir Geology

The Early Cretaceous (Berriasian to Valanginian) Hibernia Formation conformably overlies the Fortune Bay shales. The Hibernia Reservoir consists of interbedded sandstones and shales and has been interpreted to have been deposited in a clastic, shallow marine, wave dominated shoreface environment. It is commonly divided into an Upper and Lower member with the oil in Hebron I-13 being found in the Upper Hibernia Member (Figure 2.2-21). Stratigraphically, the Hibernia Reservoir in the Hebron Asset is the Upper Hibernia Member of the Hibernia Formation. Unlike the reservoirs at the Hibernia Field, which are braided fluvial sandstones, the Hibernia throughout much of the Hebron Asset is composed of shoreface successions with minor marginal marine deposits. Many of the sandstones are cemented with calcite carbonate. The Hibernia Formation represents an overall regional regression.

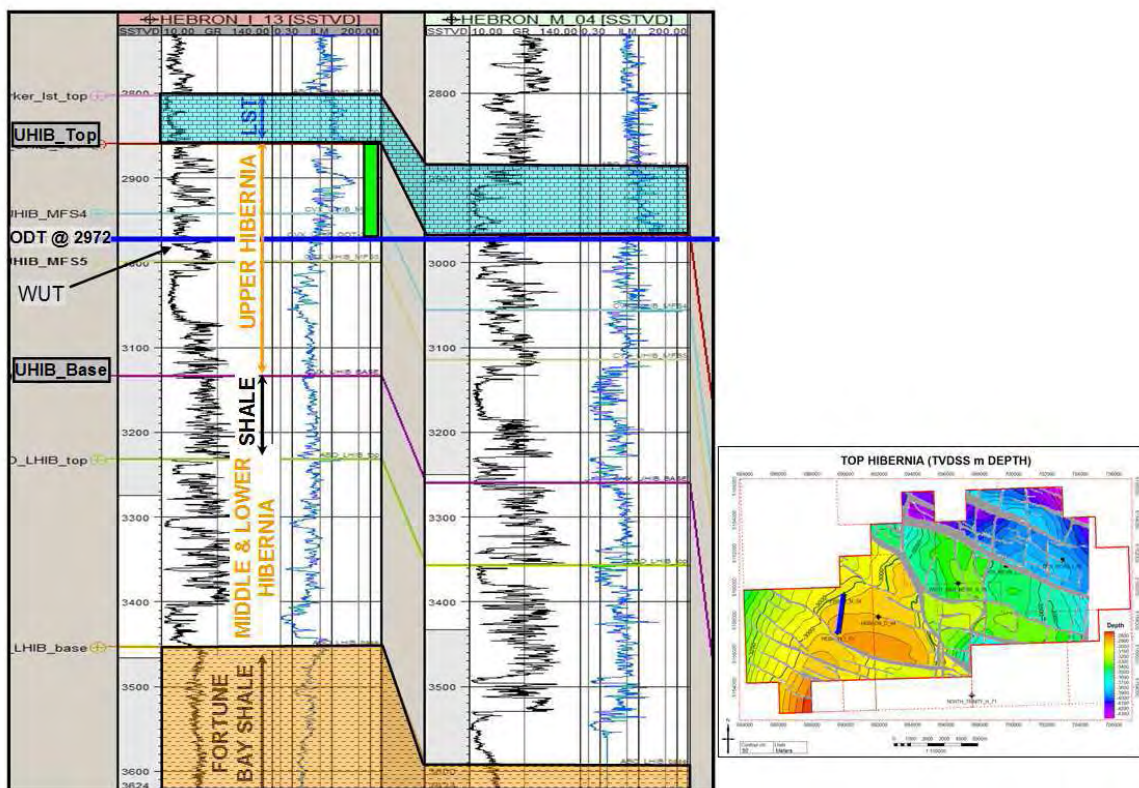


Figure 2.2-21: Hibernia Well Based Definition of Reservoir and Fluid Contacts

The Hibernia Reservoir was deposited in a wave dominated shoreline system. The lithofacies span from offshore shales to fluvial sandstones, but the majority of the preserved rocks at Hebron is deposited in the middle and lower shoreface. The shoreline for the system was predominantly oriented east-west. The Avalon uplift, south of the field, is the provenance for most of the sediment. Over the time period during which the upper Hibernia was deposited, debris was prograding into the basin filling the Jeanne d'Arc basin from the south. The Hibernia thickens from south to north over the Hebron Field, from about 200 m thick to over 300 m thick (Figure 2.2-22). This thickness trend shows the accommodation created through the second extensional event.

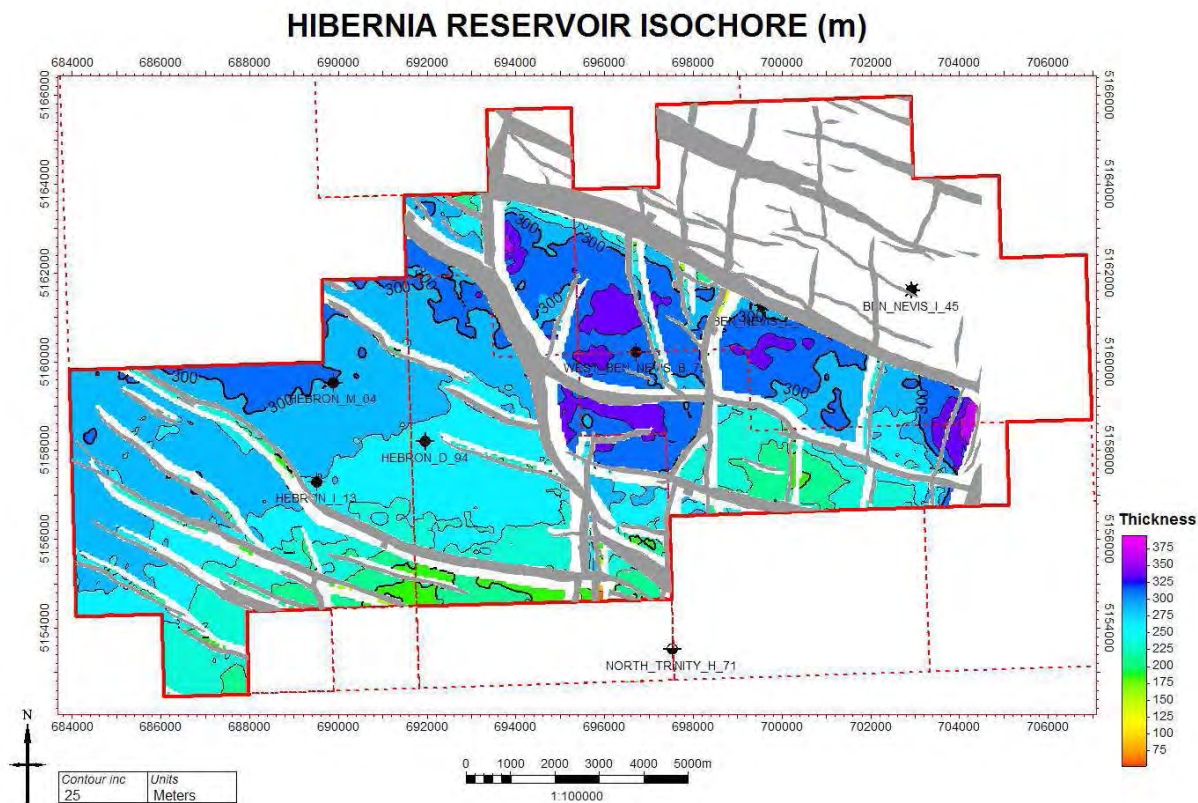


Figure 2.2-22: Hibernia Isochore Map

Isochore map of the Hibernia Reservoir demonstrating a gradual thickening to the northeast.

The age of the Hibernia Reservoir is well constrained by biostratigraphy. Three Hebron Asset wells, the I-13, M-04, and B-75, and one offset well (I-30) have biostratigraphy markers that delineate the age of the reservoir. There is sufficient data to constrain the age of the gross reservoir interval, but the data frequency is too low within the reservoir interval to provide any assistance in correlating individual sands between wells. Based on the sampled dinoflagellates the age of the Hibernia Reservoir (Upper Hibernia Formation) is Berriassian (140 Ma) to Valanginian (135 Ma) (Ford, 1998) (Figure 2.2-23).

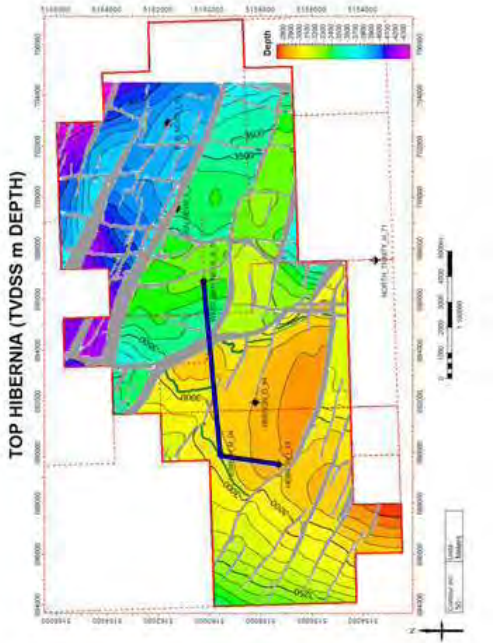
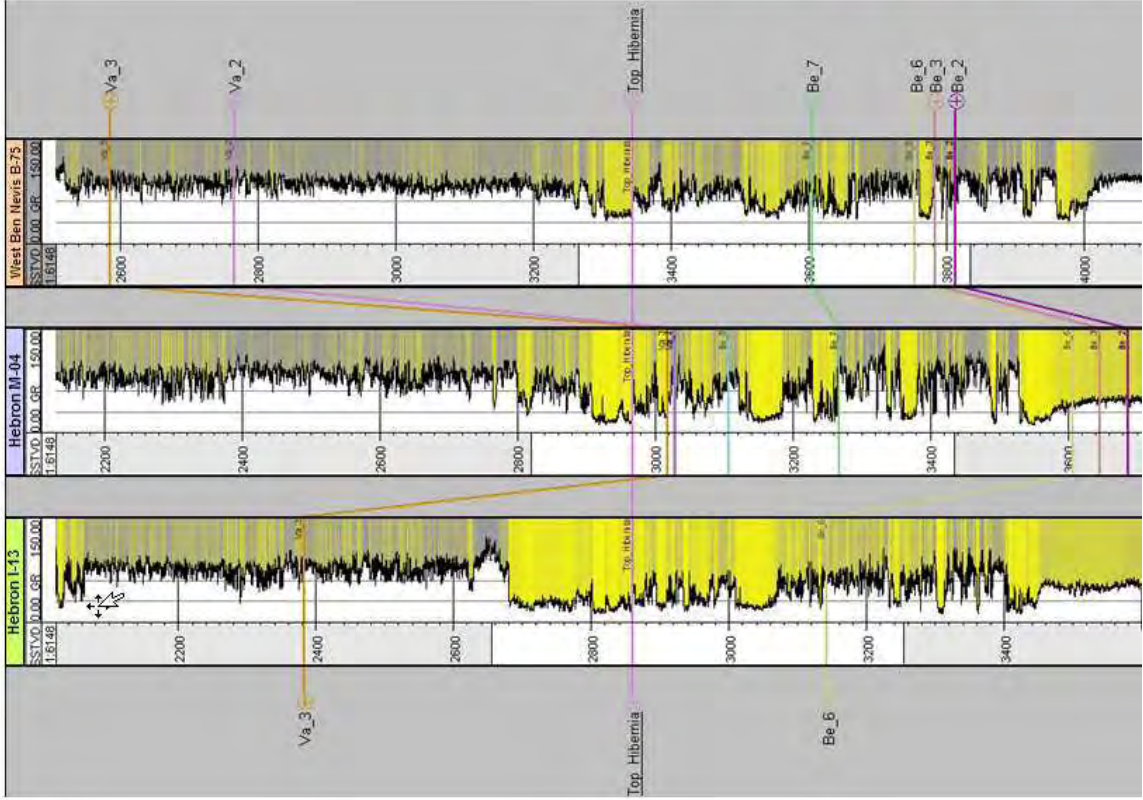


Figure 2.2-23: Hibernia Biostratigraphy

The Hibernia Reservoir is medium to fine grained sandstone and shales that have core and log porosities in the range of 13 percent to 18 percent over intervals with approximately 30 percent net-to-gross. Shales separating reservoir units may be laterally continuous and act as intra-reservoir barriers to vertical fluid movement.

The Hebron I-13 well was the only well that penetrated oil at the Hibernia Reservoir. The oil column at I-13 well is 104 m thick, but the oil column for the reservoir is about 160 m thick. In the I-13 well oil-down-to (ODT) was encountered at 2972 total vertical depth subsea (TVDSS) meters and high known water was encountered at 2978 TVDSS meters. The 6 m uncertainty in the oil-water contact is because of shale over this interval. The Hebron M-04 well did not penetrate oil and confirmed the high known water in I-13 well. The oil in Hebron I-13 well is found in the Upper Hibernia. The distinctive basal sand of the Lower Hibernia is gas-bearing in the Ben Nevis I-45 well.

2.2.2.2.1 Hibernia Internal Stratigraphy

Nine transgressive / regressive sequences (Table 2.2-1) have been interpreted within the Upper Hibernia using a sequence stratigraphic approach. Well correlation between the I-13 and M-04 wells is straightforward as the log character between these wells is very similar (Figure 2.2-24.). As a result, it is inferred that the stratigraphy across the horst block is laterally continuous. Well correlations away from the horst block are lower confidence because log character of the surrounding wells are quite different and interpreted to be of more complicated stratigraphic relationships. One well (H-71) has the fault through the reservoir interval and another (I-30) well has a fault plane at the base of the reservoir. There is an increase in thickness of the Hibernia Reservoir going from proximal to the distal in the depositional system.

Table 2.2-1: Hibernia Facies

Facies	Petrophysical Criteria	Binned Porosity Range	Binned Perm Range (md)	Depositional Environment Name
1	FZI > 78	0.31 – 0.34	1880 – 2800	Distributary channels, 1
2	32 < FZI < 78	0.26 – 0.31	262 – 1880	Distributary channels 2
3	7 < FZI < 32	0.02 – 0.17	9-262	Upper shoreface
4	FZI < 7	0 – 0.24	V. low – 9	Lower shoreface
5	Vol_Calcite > 0.05	0 – 0.24	V. Low – 170	Offshore limestone and bioclastic sand
6	KAH, 1 md Vol_Wetclay < 0.01 Vol_Calcite > 0.02	0 – 0.13	V. low – 1	Cemented sands
7	Vol_Wetclay > 0.05	0 – 0.17	V. Low – 9	Shales

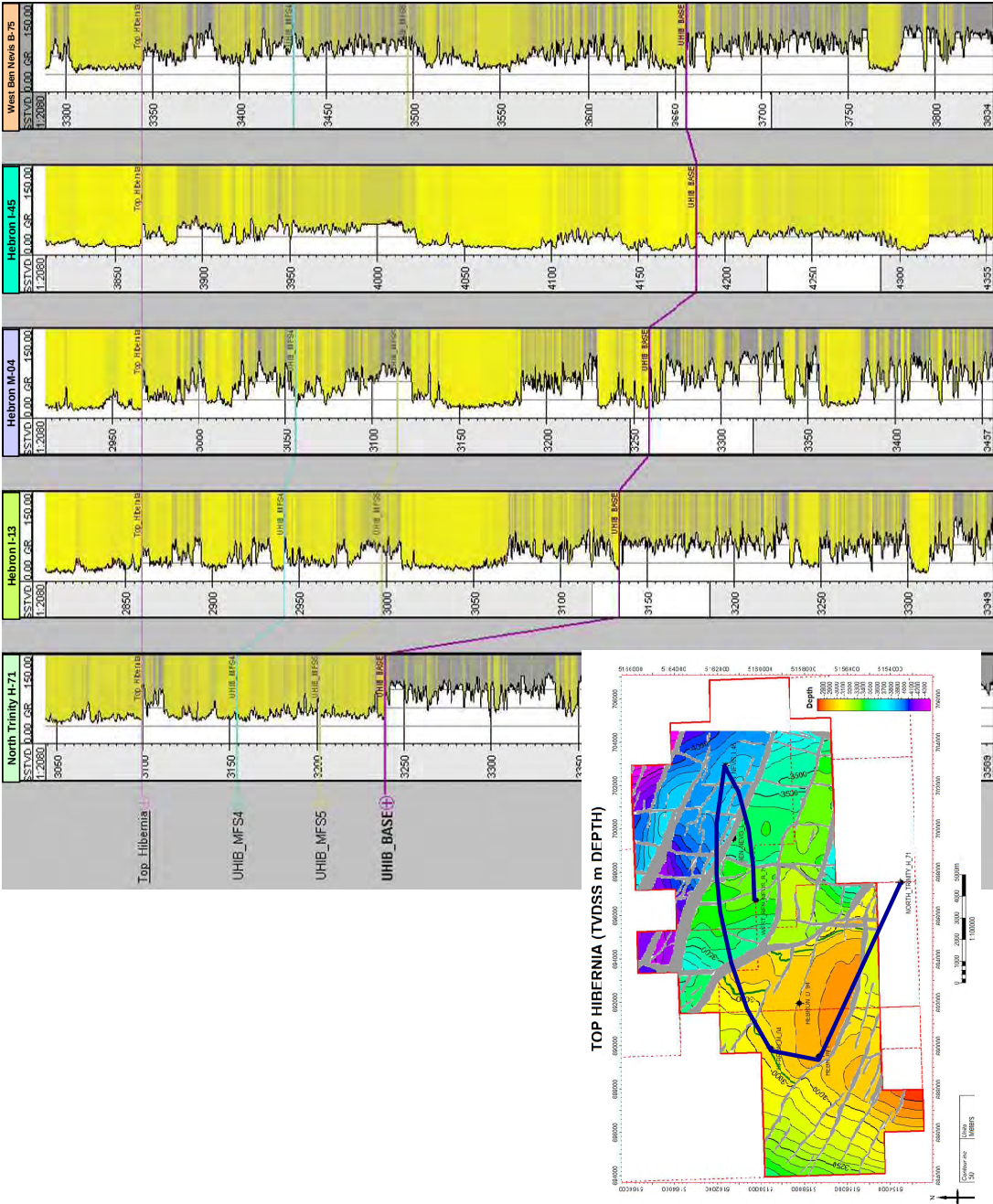


Figure 2.2-24: Hibernia Well Log Correlations

Top of the Hibernia Formation is a sequence boundary with erosion overlain by the B Marker limestone. The upper and lower Hibernia sandstones are divided vertically by thick (about 100 m) shale. The base of the upper Hibernia is a sequence boundary. The internal surfaces are flooding surfaces and sequence boundaries that bound rock of the same age. The 100 meters of core in the M-04 well provide guidance on lithofacies, depositional environment, and time significant surfaces.

The shale dividing the lower from the upper Hibernia is marine shale representing flooding of the basin. The basin of the upper Hibernia is a sequence boundary. Over the Hebron Project Area, the first sand of the upper Hibernia onlaps the sequence boundary to the south. The sand was deposited in a marginal marine environment. A marine shale overlies the first sand.

The next succession is composed of multiple parasequences going from offshore shales to middle/lower shoreface sandstones. Moving up the section, the lithofacies become more proximal. Near the top of the unit, a sequence boundary with fluvial rocks overlies the shoreface rocks. Overlying the fluvial rocks are tidal rocks and one shoreface parasequence (Figure 2.2-24).

2.2.2.2.2 Upper Hibernia Depositional Environment and Paleogeography

Overall, the upper Hibernia was deposited in a wave dominated shoreline that was prograding into the basin. Within this overall regression, there are smaller scale, shorter duration periods of transgression that are also preserved. The flooding surfaces define a turnaround from a transgression to regression. Different processes dominate during these different times, which results in different spatial patterns of depositional environments. Two paleogeographic maps were created, one reflecting depositional patterns during a regression, and one during a transgression.

Figure 2.2-25 is a map interpretation of the depositional environments of the Upper Hibernia during a period of regression (Grant, 2003). Sediment is thought to have prograded seaward in a wave-dominated delta environment (Gower, 1990). The area of major sediment supply was to the south of the Hebron Project Area. Distributary channels carried sand through the delta plain and deposited the sediment at the delta front. In this setting, extensive wave action reworks the sediment into sand-rich strand plains and beach ridges in the foreshore and upper shoreface sand deposits between sea level and fairweather wave-base. Middle to lower shoreface sands, silts, and shales are deposited between fair-weather and storm wave-base while neritic silts, shales, and limestones form below storm wave-base. Very little, if any, of the non-marine and foreshore sediments are preserved due to subsequent erosion during the transgressive phase.

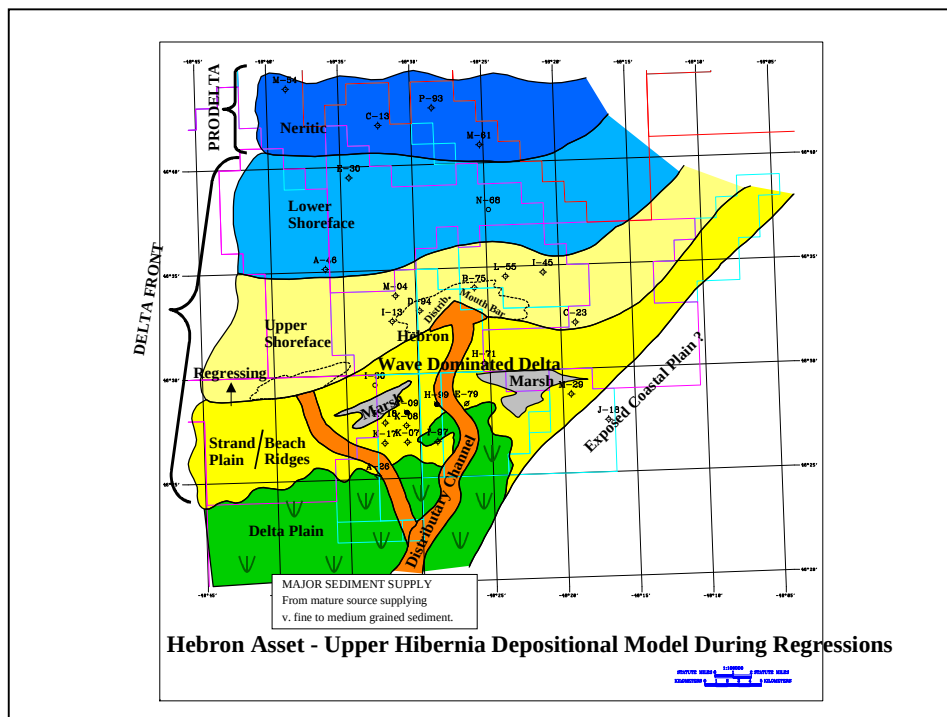


Figure 2.2-25: Hibernia Regression Paleogeographic Map

Figure 2.2-26 is a map interpretation of the depositional environments of the Upper Hibernia during a period of transgression. During the transgression the depositional environment switched from wave-dominated delta to more of a barrier beach. It is postulated that there may have been a barrier beach complex at the foreshore protecting a lagoon / marsh behind it on the landward side to the south. The delta plain, still farther south and landward, would have provided sediments into the lagoon. As the transgression progressed southwards, the erosive action on the seaward side of the barrier beach complex forms a ravinement surface, which is believed to have eroded most of the foreshore, lagoon, and delta plain deposits. These sediments were reworked and deposited in the upper and lower shoreface units that are preserved in the reservoirs today.

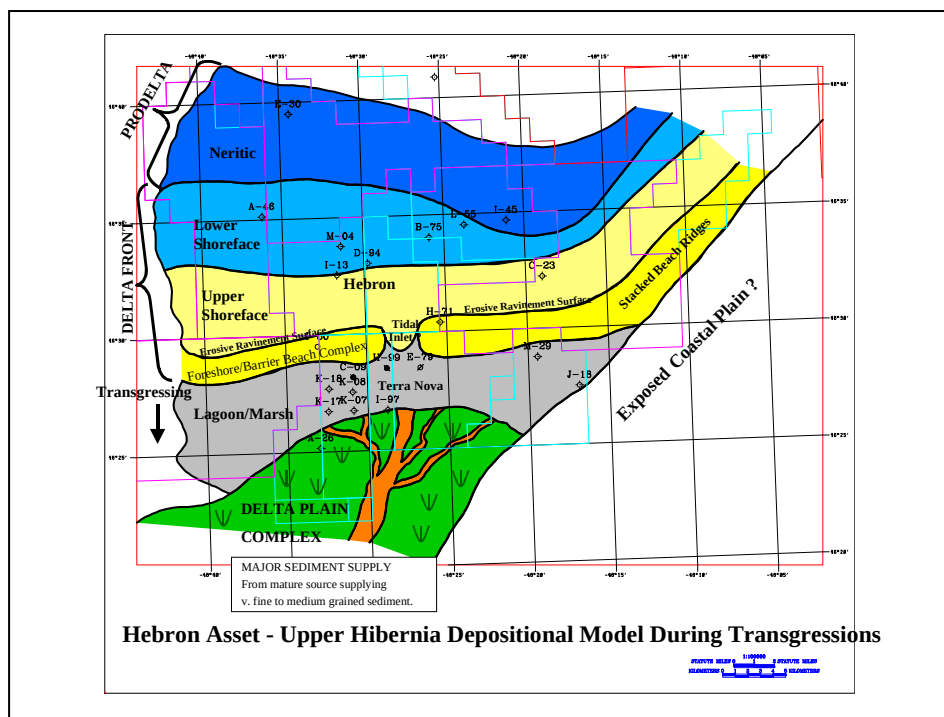


Figure 2.2-26: Hibernia Transgression Paleogeographic Map

Even though there are nine transgressive/regressive sequences correlated within the Upper Hibernia at Hebron, these are modeled as three reservoir sand packages (Figure 2.2-24). Each layer can be thought of as an upper shoreface sand unit (USF) that is sandwiched between two lower shoreface units (LSF), the uppermost unit. The upper shoreface units are likely laterally continuous over the area.

2.2.2.2.3 Upper Hibernia Reservoir Facies

Seven facies were defined to describe the Upper Hibernia Reservoir. The data used to define the facies include conventional core (M-04 and I-13), porosity, and permeability data from both core and logs. The primary control on breaking out the facies was the FZI porosity versus permeability relationship derived from core and log data, where $FZI = (PHIE/KAH)^{0.5}$ (Table 2.2-1). Along with the FZI, other selected petrophysical criteria were used (i.e., amount of calcite present). Those petrofacies bins were then assigned to depositional environments so that map shapes and patterns can be generated to populate rock properties away from the well control. These depositional environments are consistent with the paleogeographic maps of the reservoir.

2.2.2.3 Jeanne d'Arc Reservoir Geology

The Jeanne d'Arc Formation is the reservoir for Pool 4. The Jeanne d'Arc Formation was deposited during the Jurassic age and is the deepest reservoir within the Hebron Project Area. The Kimmeridgian to Tithonian Jeanne d'Arc

Formation unconformably overlies the carbonates and shales of the Rankin Formation. The Jeanne d'Arc Formation represents the beginning of a second rifting episode in the basin during the Late Jurassic. Offshore marine shales and siltstones of the Tithonian-aged Fortune Bay Formation overlie the Jeanne d'Arc Formation and is the top seal. The Fortune Bay Formation is overpressured over much of the Hebron Asset.

The Jeanne d'Arc Formation is a basinward (northward) thickening clastic wedge. The sediment provenance was from the southern high, the Avalon uplift. Reservoir sands thin and grade basinward to marine shales. The Jeanne d'Arc Reservoir consists of multiple medium to coarse-grained sandstones with minor interbedded limestones segregated vertically by shale and mudstone.

The Jeanne d'Arc Formation is also an oil-bearing reservoir at the Terra Nova Field, which is south of the Hebron Project Area. At the Terra Nova Field, the Jeanne d'Arc onlaps the Rankin Formation. Stratigraphically, Jeanne d'Arc Formation changes from south to north across the Trinity fault. At Terra Nova the reservoir has a higher net-to-gross, is coarser grained, and is more proximal in the depositional system.

The medium grained sand to conglomeratic Jeanne d'Arc Formation in the Hebron Project Area consists of a thick succession (up to 650 m) of eight depositional sequences. Each sequence is composed of stacked fluvial channel sands with a basal conglomerate fining upward to sand and topped by shale. The depositional facies range from fluvial to eustrine and possibly shoreface. The formation is Kimmeridgian to Tithonian in age, and has been subdivided into the B, C1, C2, D, E, F, G, and H Reservoirs. Oil has been encountered in the B, D, G, and H Reservoirs.

There are three well penetrations of the Jeanne d'Arc Formation (I-13, M-04, B-75) at Hebron Field. The H-71 and I-30 off lease wells also penetrate the Jeanne d'Arc Formation. From the pressure data there are multiple oil columns. The B, D, and G sands are penetrated by five wells. Only the M-04 well penetrated the H Sand. The H Sand is channelized and corresponds to a high amplitude extraction from the seismic data. The other deeper sands are more laterally continuous over the asset.

Biostratigraphy data from four wells (I-30, I-13, M-04, and B-75) constrains the Jeanne d'Arc Formation to Kimmeridgian to Tithonian in age (Figure 2.2-27). The biostratigraphy data is not at a high enough resolution for detailed log correlations, but has been used to constrain the formation age.

Porosity in the Jeanne d'Arc H Reservoir averages 14 percent with permeability in the 60 md range. Net-to-gross averages 60 percent. Porosity and permeability in the Jeanne d'Arc B Reservoir is lower than the overlying H sand (9 percent and 26 md, respectively) in sections containing approximately 40 percent net pay. The H and B sands do not appear to be in pressure communication.

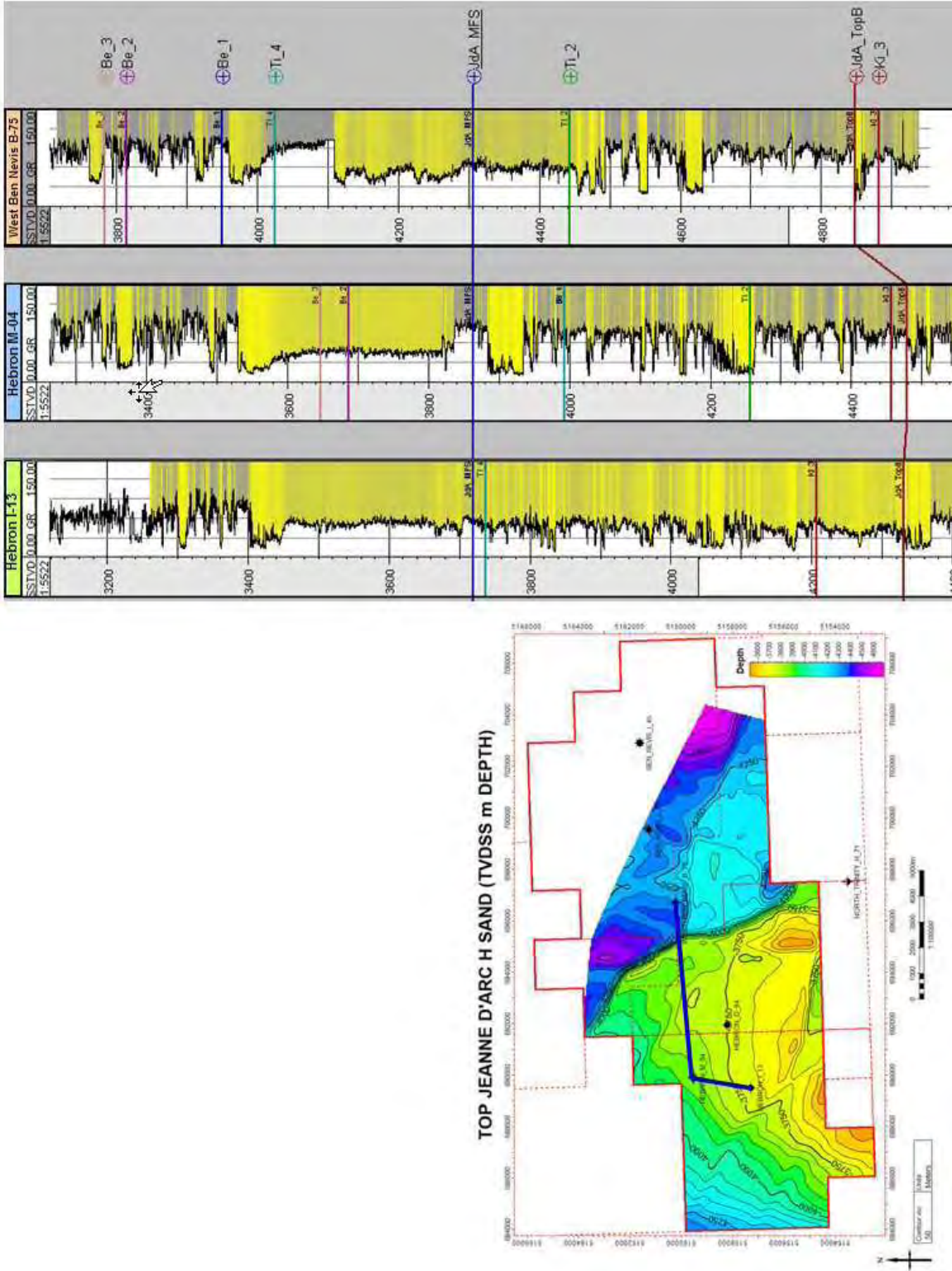


Figure 2.2-27: Jeanne d'Arc Biostratigraphy

2.2.2.3.1 Jeanne d'Arc Internal Stratigraphy

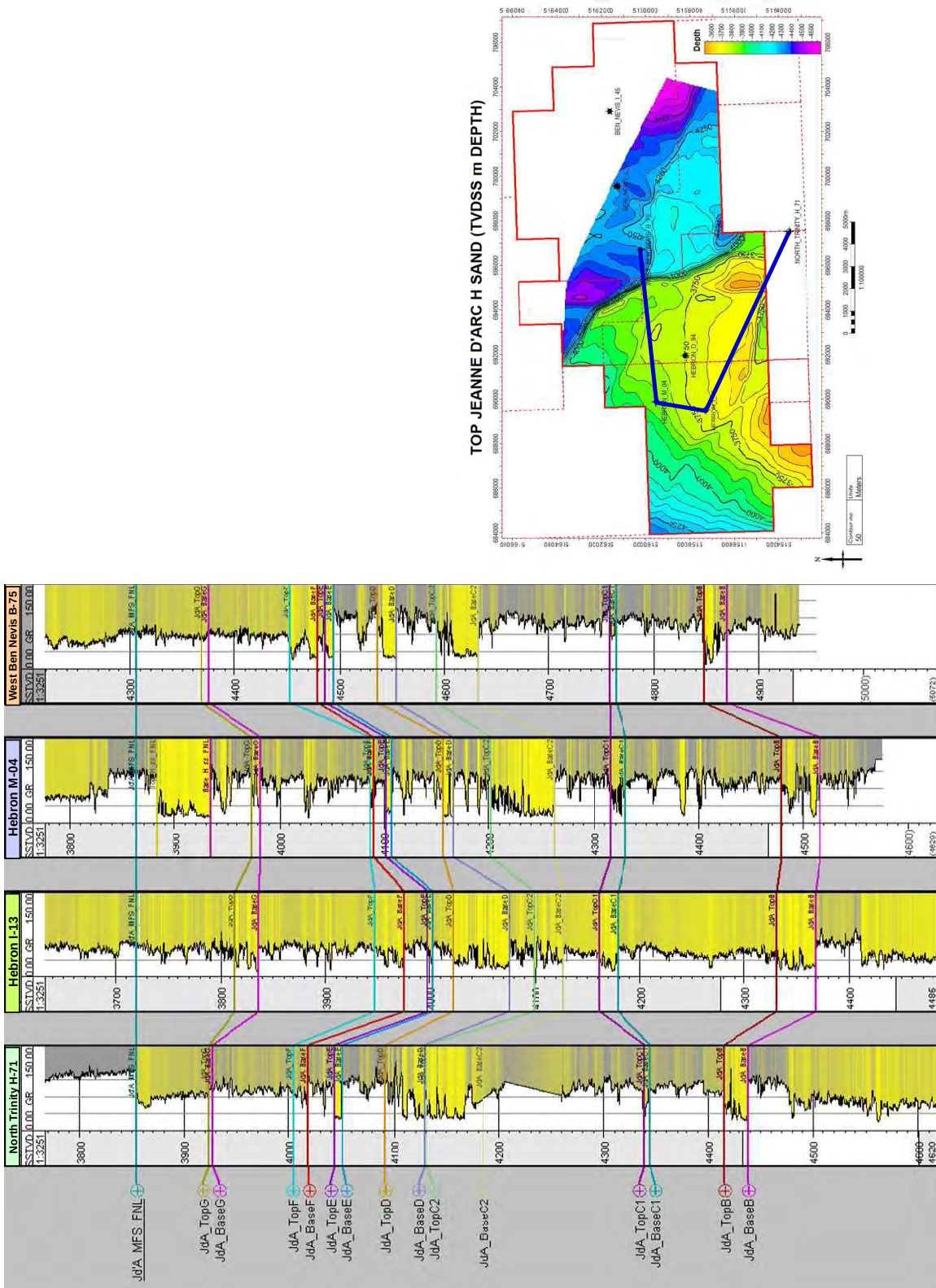
The Jeanne d'Arc Formation is bound below by an unconformity and above by a maximum flooding surface. The eight depositional sequences all have a basal sand bound below by a sequence boundary that fines up to a shale. The Jeanne d'Arc was deposited as a lowstand systems tract.

The eight depositional sequences recognized in the Jeanne d'Arc Formation in the Hebron Project Area wells are interpreted from well log and biostratigraphic data. Quantitative biostratigraphic data, diversity of species, and abundance of specimens (van Helden, 2000) suggest possible sequence boundaries near or coincident with sharp-based sands that overlie shaly, marine-looking sections observed on well logs. Many of these surfaces have been correlated from Hebron south into the Terra Nova Field where the Jeanne d'Arc sands are the main reservoirs.

The nomenclature of the internal sands was maintained from Terra Nova. The oldest Jeanne d'Arc sand is the B Sand that is interpreted as fluvial sand deposited on a braid plain. The B, D, and G Sands are more distal and tend to be of poorer quality than the adjacent reservoir system of the Terra Nova field. The youngest Jeanne d'Arc sand is the H Sand that is interpreted as an incised valley fill deposit, and is believed to be unique to the Hebron Field. The nature of the valley fill could be a combination of fluvial, estuary, or shallow marine. The F, G, and H sands are not broken out at Terra Nova, but are present at Hebron. The F to H section thickens over Hebron.

Work performed by Terra Nova Project has been leveraged to evaluate the Hebron Asset. In the Terra Nova Field, the Jeanne d'Arc Reservoir section has been subdivided into sequences alphabetically named from oldest to youngest (B1, B2, C1, C2, D1, D2, and E). It was possible to correlate the main depositional sequences from Terra Nova into Hebron. At Hebron a maximum flooding surface interpreted from logs in the F sequence was chosen as the datum for Figure 2.2-28. Good agreement was obtained with quantitative biostratigraphic data (where available) on diversity of species and abundance of specimens suggesting possible sequence boundaries where sharp-based sands were observed to overlie shaly, marine-looking sections. Given the lack of well and core control at Hebron relative to Terra Nova, it is not possible at this time to subdivide the B, C2, and D sequences to the same extent as Terra Nova.

The entire Jeanne d'Arc section is shalier and more marine in character in the Hebron Area representing a major transgression over the southern Jeanne d'Arc Basin. The F, G and H sands are represented in the Hebron Area and the H sand, and incised valley fill is hydrocarbon bearing.



2.2.2.3.2 B Sand

The B Sand is encountered in the five wells mentioned previously (I-13, M-04, B-75, I-30, H-71). The B Sand is thickest in the I-13 and M-04 Wells (37 to 32 m) and thins to about 20 m thick in the other three wells. The I-13 and M-04 wells encountered oil. Pressures indicate that communication with the B Sand between the M-04 and I-13 is possible (Figure 2.2-29). An ODT was identified in the M-04 at 4508 m TVDSS.

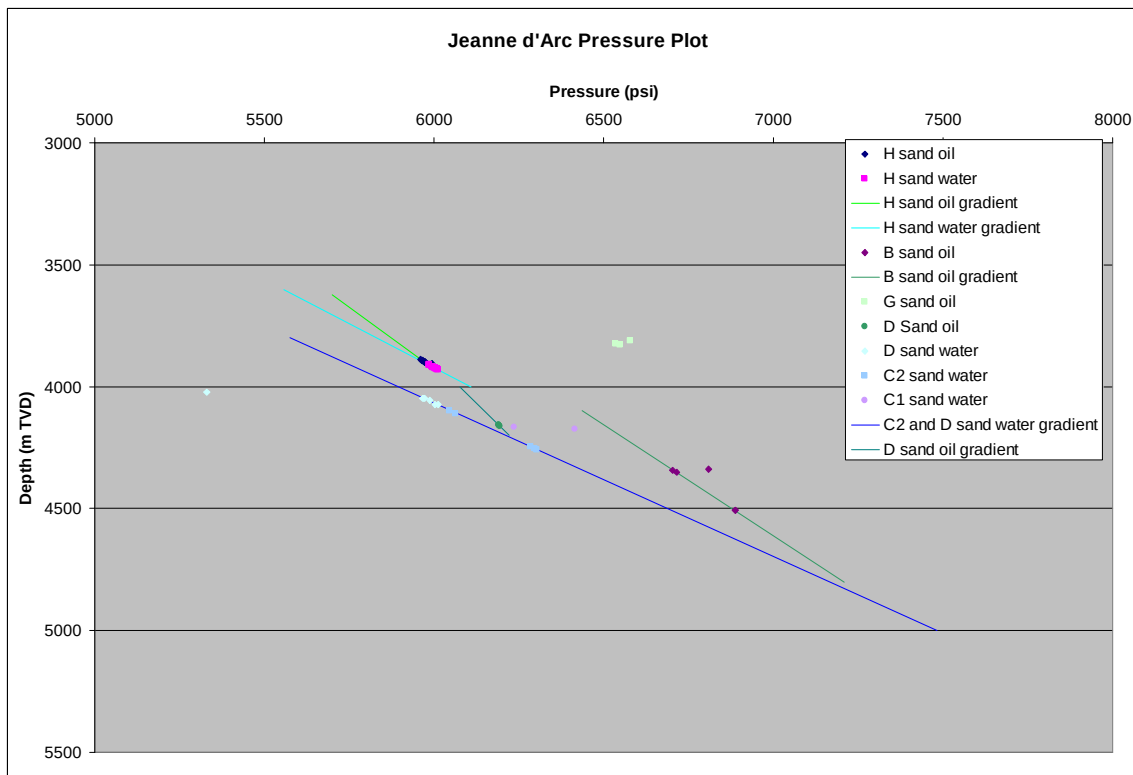


Figure 2.2-29: Jeanne d'Arc Pressure Plot

Pressure points from RFT from the M-04 and I-13 wells plotted by sand versus depth

2.2.2.3.3 C1 Sand

It is a very thin sand with a maximum well thickness of 20 m. No hydrocarbons were encountered in the C1 Sand at Hebron.

2.2.2.3.4 C2 Sand

The C2 Sand is a thick (approximately 60 m), well-developed sand at M-04, but is only half as thick at I-13. The C2 sand did not encounter any hydrocarbons.

2.2.2.3.5 D Sand

The D Sand is a fluvial system that is 30 m thick in the I-13 and 15 m thick in the M-04 well. The M-04 has an ODT 4166 m TVDSS. This sand is likely a discontinuous fluvial channel, because the I-13, which is shallower, is wet.

2.2.2.3.6 E Sand

The E Sand is a very thin, approximately 5 m, sand. No hydrocarbons were encountered in the sand at Hebron.

2.2.2.3.7 F Sand

The F Sand is present in all wells that penetrated the Jeanne d'Arc Formation. The B-75 well penetrated a thin (approximately 10 m) oil-bearing sand. Over the horst block (the I-13 and M-04 Wells), the F Sand is very thin, approximately 10 to 15 m thick.

2.2.2.3.8 G Sand

The G Sand is present in all five wells that penetrated the Jeanne d'Arc Formation. The best developed sands are in the I-13 and M-04 wells. Oil was encountered in the I-13 and M-04 Wells. At the M-04 well, the G Sand is thinner because the upper portion was removed by erosion and then the H Sand was deposited on top of the G Sand. Pressure data from the M-04 well suggests that the H and G Sands are in separate compartments. The pressure data also suggest that the G Sand in the I-13 and M-04 wells are in separate compartments as well.

2.2.2.3.9 H Sand – The North Valley

Only the M-04 well encountered the H Sand, which was approximately 75 m thick. The H Sand has an OWC of 3909 m TVDSS calculated from pressure data above and below the contact. At the I-13 well, the H Sand is shaled out with no sand present. Root Mean Squared (RMS) amplitude extractions support this lateral lithology change. From the amplitude and log data, the H Sand is interpreted as an incised valley that has two valleys, a northern valley that the M-04 well penetrated and a southern valley that is unpenetrated.

2.2.2.3.10 Jeanne d'Arc Depositional Environment and Paleogeography

There are two depositional models for the Jeanne d'Arc Reservoir at Hebron, a braid plain/delta model that is applicable for the B through G Sands and an incised valley model for the H Sand (see Figure 2.2-30).

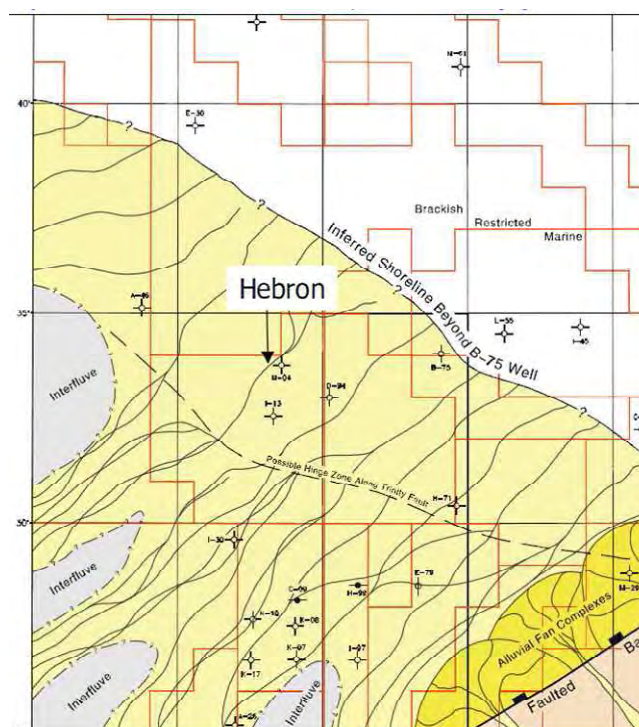


Figure 2.2-30: Jeanne d'Arc Formation "B" Sand Paleogeographic Map

These sequences are poor to moderately sand rich, have lower net-to-gross and likely poorer connectivity when compared to Terra Nova.

Cores from the B and D Sands have cross bedding, pebble lags, scour surfaces, common carbonaceous material, a distinct lack of burrowing, and fining-up grain size trends. They are interpreted as being fluvial sands, and, in this context, some of the contorted bedding observed in core may represent bank collapse features. All of the wells in the Hebron Project Area, many of which have core through the B Sand, encountered a sharp-based, fluvial sand at the base of the B sequence. Core data suggests that the B sequence braided stream deposits are widespread and extend beyond the West Ben Nevis B-75 well. The map position of the shoreline during deposition of the B Sand remains weakly constrained, but is outboard of the B-75 well.

An idealized version of the facies associations found in a complete depositional sequence starts with conglomerates at the base of the sequence overlain by aggradational braided fluvial sands, which are finally transgressed by thin marine sand and thicker marine shales. These sequences are then stacked vertically.

The Jeanne d'Arc H Sand represents incised valley fill above a sequence boundary that is oriented southeast to northwest. The valley fill was a combination of non-marine and marine depositional environments. Based on the biostratigraphy and well log evaluation, it has been interpreted that

depositional environments range from braid plain, braid delta to estuary/shoreface.

2.2.2.3.11 Jeanne d'Arc Reservoir Facies

To divide the Jeanne d'Arc H Sand Reservoir six rock types were differentiated petrophysically. The six facies scheme was developed by binning the FZI porosity versus permeability relationship. The data used for this were well logs and sidewall core interpretation of the M-04 well. The six facies are as follows:

- ◆ Braid / meander channel
- ◆ Channel / delta plain
- ◆ Delta plain / marginal marine
- ◆ Limestone and bioclastic beds
- ◆ Coal
- ◆ Shale

Reservoir facies were defined for the Jeanne d'Arc H reservoir by binning the FZI porosity versus permeability relationship described in the following table.

Table 2.2-2: Jeanne D'Arc H Sand Facies

Facies	Petrophysical Criteria	Binned Porosity Range	Binned Perm Range (md)	Depositional Environment Name
1	FZI > 28	> 12.5	> 100 md	Braid / Meander Channel
2	15 < FZI < 28	9 to 12	20 to 100 md	Channel / Delta Plain
3	10 < FZI < 15	5 to 9	5 to 20 md	Delta Plan / Marginal Marine
4	Vcalcite cutoff	< 5	< 5	Limestone and Bioclastic Beds
5	Manual input from logs	Non Reservoir		Coal
6	Vclay cutoff			Shale
where: $FZI = \sqrt{PERM / PHIE}$ <i>Vcalcite</i> = volume of calcite from multimin analysis <i>Vclay</i> = volume of calcite from multimin analysis				

Reservoir facies were defined for the other Jeanne d'Arc reservoirs using the following petrophysical cutoffs:

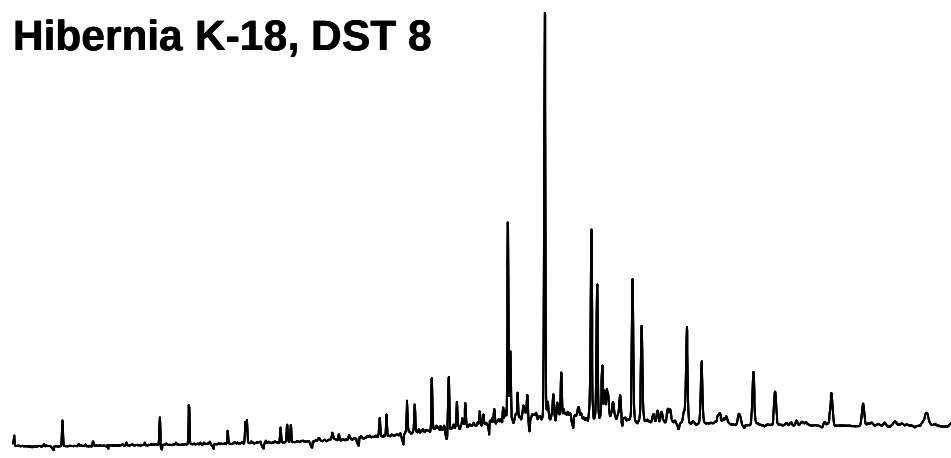
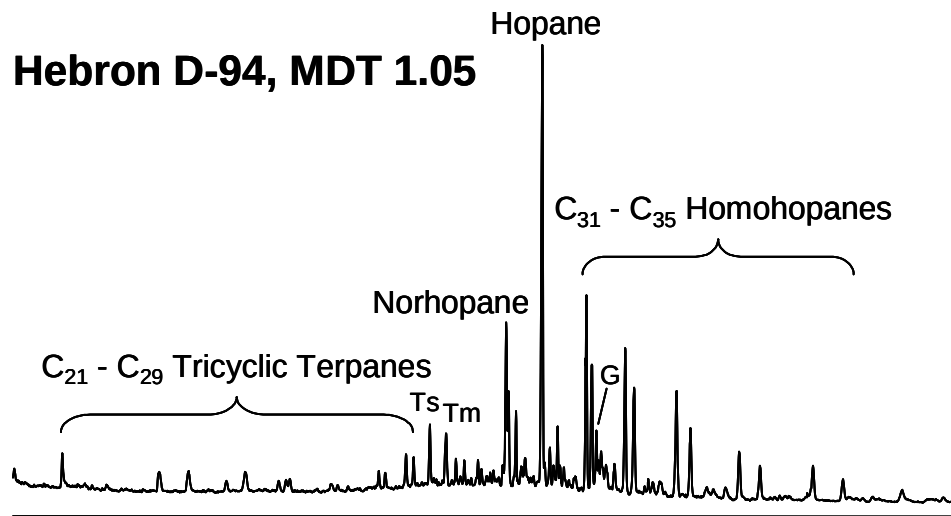
Table 2.2-3: Jeanne D'Arc Other Sands Facies

Facies	Petrophysical Criteria	Binned Porosity Range	Binned Perm Range (md)	Depositional Environment Name
1	sand > 0.4 & carb < 0.1 & kaolin < 0.15	> 12.5	> 100 md	Clean Sand
2	sand > 0.4 & range (carb, 0.1,0.4) & kaolin < 0.15	> 5	> 5	Carbonaceous Sand
3	carb > 0.4 & kaolin < 0.15	Non Reservoir		Carbonate
4	carb > 0.4 & kaolin > 0.15 & carb < 0.1			Shaly Sand
5	kaolin > 0.3 & sand < 0.4			Shale
where: sand = volume of quartz and orthoclase from multimin analysis carb = volume of calcite and dolomite from multimin analysis kaolin = volume of clay from multimin analysis				

2.2.3 Hebron Project Area Geochemistry

The Egret Member is the predominant source rock for the entire the Jeanne d'Arc Basin. Geochemical studies have concluded that the Egret member is the primary source rock for Hebron's hydrocarbons (Jenden, 2000). The principal cause of heavy oil occurrence is biodegradation. The closest wells that have penetrated the Egret member are in Terra Nova field and have encountered thickness ranges of 50 to 100 m.

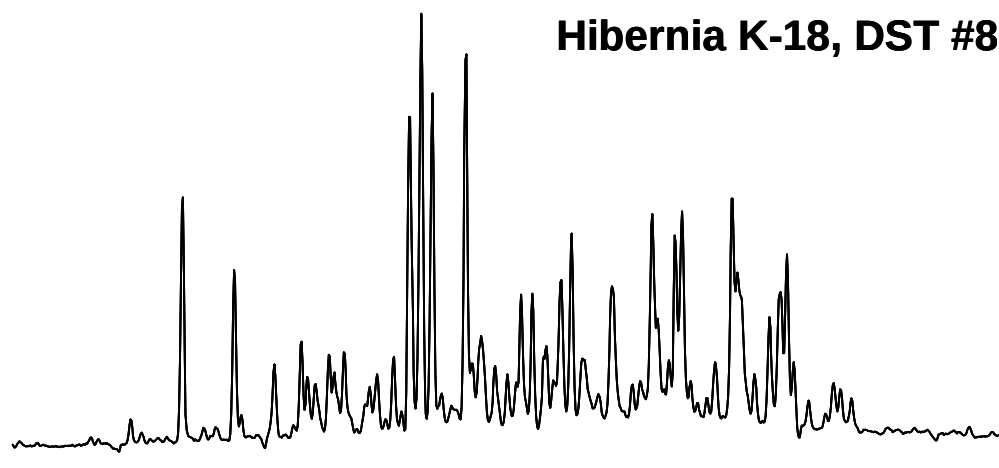
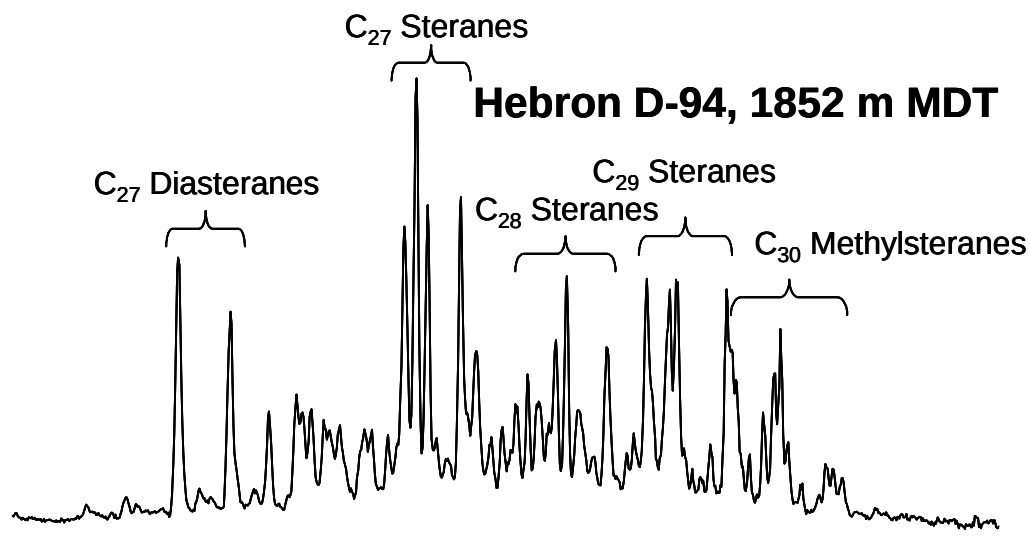
Hebron, Hibernia, and Terra Nova oils share the same Egret member source rock. The oils at Hebron and the oils at Hibernia are very similar and are likely to be sourced by the same source rock, the Egret member (Jenden, 2000). Hebron Asset oils have sterane compositions and triptertane abundances that parallel those from the Hibernia (Figure 2.2-31 and Figure 2.2-32). The fully mature, Kimmeridgian-aged, marine source rocks of the Egret Member display a nearly identical biomarker pattern to oil in the Terra Nova Field, suggesting that the Egret Member is the source rock for that field and Hebron. The Ben Nevis, Hibernia, and Jeanne d'Arc Reservoirs have the same oil geochemistry signatures because the oils share the same source rock (Figure 2.2-33).



**Hebron and Hibernia Oils Have Similar Triterpane Abundance
Patterns
(m/z 191)**

Figure 2.2-31: Terpane Significance

Compare oil samples from Hebron and Hibernia fields, which are similar.
Resulting conclusion is they share the same source rock and maturation, i.e., Egret member.



**Hebron and Hibernia Oils Have Similar Sterane Abundance Patterns
(m/z 217)**

Figure 2.2-32: Sterane Significance

Compare oil samples from Hebron and Hibernia fields, which are similar. Resulting conclusion is they share the same source rock and maturation, i.e., Egret member. Gas Chromatograph is similar and includes the same oil and shows the same signature. Therefore, it is the same oil and reservoir.

Hebron D-94 fluid profile – Saturate GC/MS

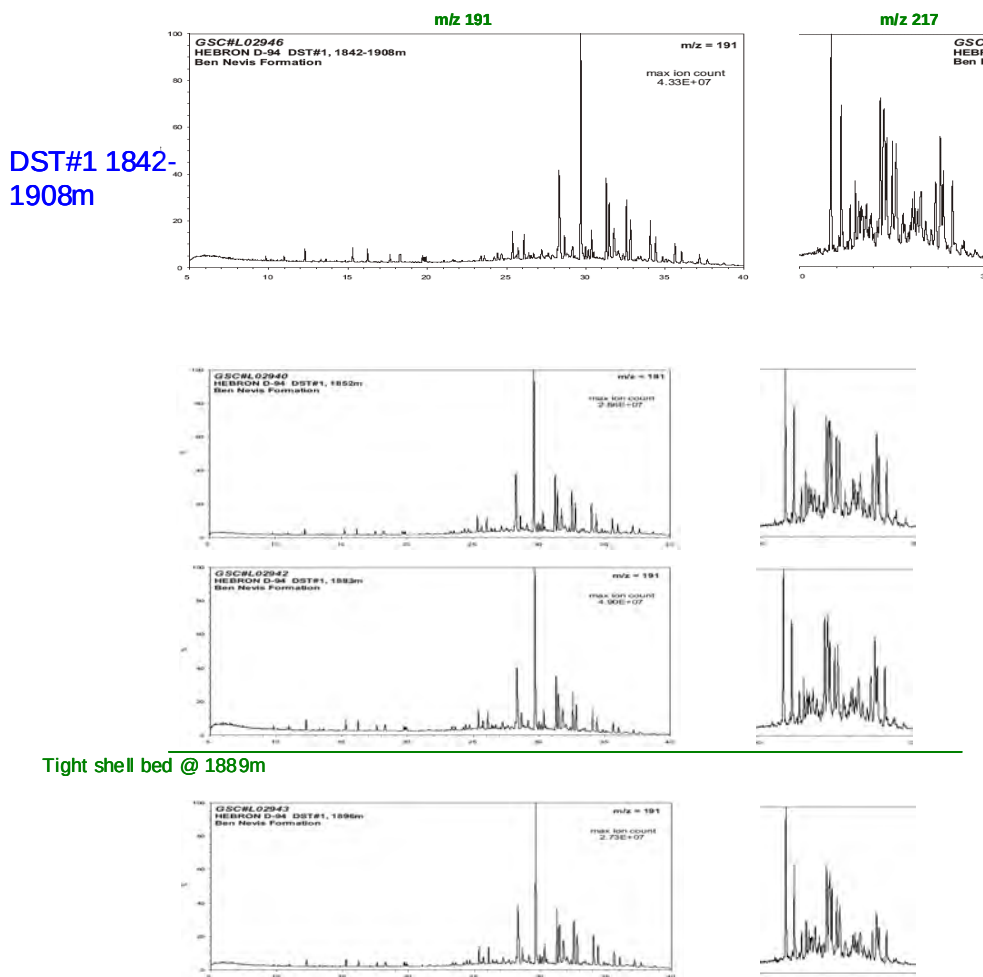


Figure 2.2-33: C3 DST Samples for Ben Nevis, Hibernia, Jeanne d'Arc – Hebron D-94 Fluid Profile – Saturate GC/MS

Geochemical data suggest that two different geological processes, maturation at the time of expulsion and subsequent biodegradation, control the physical properties of the oils in the Hebron Asset. Large maturity variations are not observed in the oils trapped in the Ben Nevis Formation (Jenden, 2000). By contrast, the quality of the oils and gas-condensates trapped in the Hibernia and Jeanne d'Arc Reservoirs (24 degrees API to >40 degrees API) is controlled by the maturity of the Egret Member source rock at the time of expulsion (Jenden, 2000).

Oil gravity variation (17 to 31 degrees API) between the Ben Nevis – Avalon pools, and within the pools, is most likely related to a complex history of biodegradation, the timing of oil migration, and the competency of fault seals. API gravity variations in these oils appear to be controlled by biodegradation of an initial oil charge and the later re-introduction of fresh oil with maturity

comparable to the initial oil charge. The oil was generated in the Jurassic Egret Formation, and prior to biodegradation would have been about 36 degrees API. Modest maturity differences are apparent amongst oils from Ben Nevis and Avalon Reservoirs within the Hebron Asset but these are not clearly related to oil gravity. However, a strong correlation exists between the degree of biodegradation as indicated by gasoline range hydrocarbons and the gravity of the Hebron D-94 modular formation dynamic tester (MDT) oil samples. Whole oil gas chromatograms of Ben Nevis L-55 Drill Stem Test (DST) #1 oil show no sign of biodegradation, a vertical gradient in API gravity of several units over a 100 m interval is apparent. Oils from Ben Nevis I-45 DSTs #10 to 13 show a similar decrease in oil gravity with increasing depth and have saturated fraction gas chromatograms suggestive of biodegradation and a recharging with fresh oil (i.e., an unresolved hump with normal alkane peaks superimposed upon it) (Figure 2.2-34). Oils from West Ben Nevis B-75 DST #6 demonstrate this saturate fraction chromatogram characteristic even more strongly (Fowler and Obermajer 2001). The recharging with fresh oil hypothesis is also supported by the observation of Shimeld, et al (1999) that fluid inclusions in grains of Ben Nevis sandstones from Hebron I-13, West Ben Nevis B-75, and North Trinity H-71 contained oil with gravity of 35 to 45 degrees API. This is much higher than gravity estimates (32.5 ± 2 degrees API) for the original unbiodegraded oil charge to the Ben Nevis Reservoir in Hebron I-13 DST #9 (Jenden, 2000). Vertical and lateral oil gravity variations within the Ben Nevis Formation in the Hebron Asset might have originated from leakage of varying amounts of high-gravity oil into the Ben Nevis Reservoirs containing variably biodegraded crudes.

Oil quality in the Hibernia and Jeanne d'Arc pools is also variable, ranging from 25 to 36 degrees API. The quality of the oils and gas condensates trapped in the Hibernia and Jeanne d'Arc Reservoirs is controlled by the maturity of the Egret Member source rock at the time of expulsion (Jenden, 2000). None of the Hibernia Reservoir oils shows any significant signs of biodegradation.

The Jeanne d'Arc H Sand oil (25 degrees API) appears to be more immature, sourced locally from the Jeanne d'Arc. The Jeanne d'Arc B, D, and G Sand oils (36 degrees API) are unbiodegraded Egret-sourced oil. The 24 degrees API oil produced from the Jeanne d'Arc H Sand Reservoir at Hebron M-04 is one of the lowest maturity oils yet analyzed. The 37.3 degrees API gravity oil produced from the Jeanne d'Arc B Sand Reservoir in Hebron I-13 DST #1 is the most mature and highest gravity oil of any Jeanne d'Arc Formation Reservoirs in the asset. Neither the Hibernia nor the Jeanne d'Arc Reservoir oils shows any significant signs of biodegradation and variations in oil quality can be explained simply in terms of variations in Egret Member source rock maturity at the time of oil expulsion.

Given the presence of Egret Member-sourced oils at numerous stratigraphic levels and of the numerous faults that cut through the Mesozoic section, vertical migration of hydrocarbons has almost certainly occurred.

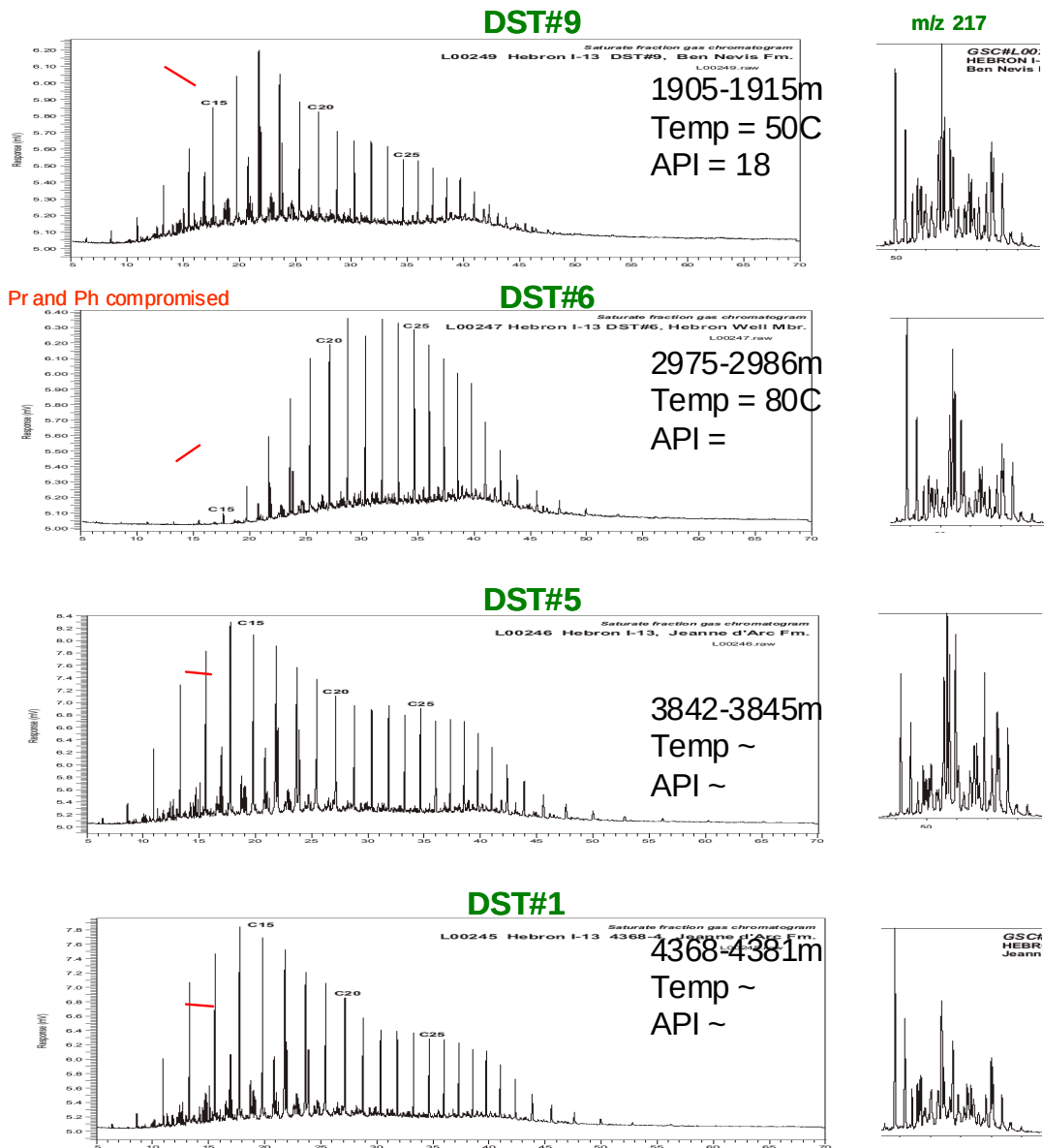


Figure 2.2-34: C4 Biodegradation of Oil in Ben Nevis

These GCs show large differences, some of which might be related to loss of light ends. GC/MS also show differences, likely due to different reservoir units.

2.3 Petrology and Reservoir Quality

Petrographic analysis was conducted on thin sections prepared from core, cuttings and sidewall cores taken from the Ben Nevis, Hibernia, and Jeanne d'Arc Formations in the Ben Nevis L-55, Hebron D-94, Hebron M-04, North Trinity H-71, Hebron I-13, and West Ben Nevis B-75 wells. The primary purpose of the analysis was to identify diagenetic mineralogy and to determine the diagenetic history of the intervals of interest. In addition, information on porosity types and controls on porosity and permeability are provided, along with indications of depositional environments where present. Generally, carbonate cementation is present in all reservoirs that most likely formed at shallow depths.

2.3.1 Ben Nevis – Avalon Petrography

Thirty-six core samples from five wells (D-94, B-75, I-13, L-55, and H-71) form the basis of petrographic analysis of the Ben Nevis Formation. The rocks in these cores are very fine to fine sand sublitharenites and siltstones with rare to abundant bioclastic debris. There also are some layers that are dominated by bioclastic debris and not siliciclastic grains. Most quartz grains show quartz overgrowths that have subsequently partially dissolved. Ferroan calcite is the major carbonate cement. Siderite may also be locally abundant, occurring predominantly as a replacement of clay minerals. In many cases, these clays infilled burrows, which show up as round siderite patches or siderite lenses or layers in thin section. Siderite also fills intragranular pore spaces of some bioclasts. Individual crystallites of siderite also occur locally disseminated through the matrix. These individual crystallites have a "wheat seed" shape.

From the petrographic examination, it is evident that the fluids causing initial cementation were likely marine in origin charged with added calcium and carbonate. Possible sources for carbonate cement include local dissolution and reprecipitation of in-situ shell material and migration of carbonate-rich fluids from underlying limestone units. The high intergranular pore volume (cement inclusive) in cemented samples indicates that cementation occurred prior to much burial compaction. Siderite preceded quartz overgrowth precipitation in some cases. Quartz overgrowth dissolution probably occurred simultaneously with carbonate cementation given that the alkaline fluids promoting carbonate precipitation will also result in dissolution of silica. Some samples show replacement of quartz overgrowths by ferroan calcite cement. Siderite was the earliest cement, but is minor except as a replacement of clay-filled burrows and in intragranular pores of bioclasts. Ferroan calcite precipitated subsequently, forming intergranular anhedral mosaics and replacing bioclasts. Dissolution of both replacive and intergranular ferroan calcite cements occurred before oil migration into the Ben Nevis.

Moldic porosity is common as is evidence of dissolution of intergranular ferroan calcite cement. There are no striking differences in the character of the cements or dissolution textures among the five cores.

2.3.2 Upper Hibernia Petrography

The Hibernia Reservoir is composed of fine to medium grained, moderately well sorted quartzarenite and sublitharenites sandstones with minor interbedded limestone and mudstone. The sandstones exhibit both bioturbation and primary laminations. Most sandstone beds are cemented with calcium carbonate cement to varying degrees. Petrographic analysis was performed on core from M-04 and I-13 wells along with cuttings from H-71 well. Pervasively cemented zones are cemented primarily by calcite that typically has a detrimental effect on porosity and permeability.

Samples with both calcite and dolomite cements often have fair to good porosity while those samples with excellent porosity have very little cement. The extensive calcite cementation may be related to the proximity of the overlying B-marker limestone or other limestone interbeds. Kaolinite is not present, and nor are authigenic clays. Variable amounts of slightly ferroan calcite and ferroan dolomite or ankerite cements are present as are minor to moderate amounts of silica cement.

2.3.3 Jeanne d'Arc Petrography

2.3.3.1 Jeanne d'Arc B Sand

Petrographic analysis was performed on core samples from M-04 I-13 H-71 wells along with one Terra Nova well, the E-79. The B Sand at Hebron consists of medium sand to conglomeratic sublitharenites. The samples are dominantly quartz, with approximately 5 percent limestone fragments, and very minor amounts of chert and shale clasts. Diagenetic mineralogy consists of ferroan calcite, ferroan dolomite or ankerite, and silica cements as well as local pore-filling kaolinite. Calcite precipitated before quartz overgrowths. The relative timing of the ankerite and silica cements is unclear. Ankerite is later than some quartz overgrowths, but some quartz overgrowths could be inherited from reworked silica cemented sandstones. In most of the pores filled by ankerite, bounding quartz grains do not have quartz overgrowths inside ankerite cement, but do have them on adjacent open pores. Most kaolinite textures indicate precipitation took place before and during quartz overgrowth development. Pressure solution along a clay parting or lamina occurred after precipitation of ankerite or ferroan dolomite cementation.

The average grain size in B Sand at H-71 well samples is considerably finer than in the Hebron M-04 B Sand core samples. Detrital composition in terms of relative amounts of quartz and rock fragments is similar, except that compacted carbonaceous debris is common in the H-71 well samples. The H-71 B Sand has undergone more intense physical and chemical compaction than the B Sand in Hebron M-04. Diagenetic mineralogy is similar, but either

ankerite and kaolinite precipitated later than calcite and silica cement, or there were two generations of precipitation of these minerals, as both occur in the rock matrix and as fracture-fill. In both M-04 and H-71 B Sand, silica cement is the dominant authigenic mineral reducing porosity and permeability.

In I-13 ferroan dolomite and ankerite pervasively cements the sand while in M-04 and H-71 silica cement is the dominant authigenic mineral reducing porosity and permeability. Ferroan dolomite or ankerite, with minor amounts of later silica cement, which forms "necks" in remnant pores between dolomite rhombs, pervasively cements the sand. The relatively undercompacted fabric of the sands indicates that ankerite precipitated prior to extensive burial compaction. Pressure solution took place after ankerite cementation.

The B Sand in Terra Nova E-79 is more similar in grain composition to the B Sand in Hebron M-04 and North Trinity H-71 than to the B Sand in Hebron I-13, but in general is better sorted and slightly finer grained than in North Trinity H-71. The sand at Terra Nova E-79 has not undergone as extensive compaction or fracturing as at North Trinity H-71.

2.3.3.2 Jeanne d'Arc C Sand

The Upper C2 Sand in Hebron cuttings is well sorted lower fine to lower medium grained sublitharenite. Petrographic analysis was performed on M-04, and H-71 cutting samples. Diagenesis consists of two main types, as follows:

1. Pervasive pore-filling ferroan dolomite or ankerite in sand with an undercompacted fabric. Most or all detrital calcite, mainly limestone rock fragments, and many unstable rock fragments are replaced by the dolomite.
2. Variably ferroan calcite, ferroan dolomite, and silica cemented sands with detrital calcite preserved, and with local early grain-rimming or scattered microcrystalline siderite.

It is not clear if the two types of diagenesis are alternating or if they represent two different intervals, one of which has caved into the deeper cuttings samples. Porosity is generally completely occluded by cements, but minor amounts of remnant reduced intergranular porosity between quartz overgrowths and/or secondary dissolution porosity are locally present.

The Hebron samples have fragments similar to slightly ferroan to zoned ferroan/non-ferroan dolomite cemented upper fine to very coarse and conglomeratic C Sands at Terra Nova. Fair to good secondary and/or reduced primary intergranular porosity is locally present in the North Trinity H-71 C Sand cuttings.

The cored C Sands at Terra Nova generally are cemented by slightly ferroan or zoned ferroan/non-ferroan dolomite with minor later quartz overgrowth development. Neither ferroan calcite nor siderite is present.

2.3.3.3 Jeanne d'Arc D Sand

The D Sand in the M-04 well consists of poorly sorted coarse sand to conglomerate in sublitharenite. Limestone rock fragments are common. Corroded remnants of both slightly ferroan calcite and ferroan dolomite or ankerite cement are present. The dolomite likely has completely replaced unstable limestone and shale rock fragments. Calcite occurs as synaxial overgrowths or radial overgrowths on limestone rock fragments. Ferroan dolomite occurs as pore-filling subhedral rhomb cement. Loosely packed aggregates of pore-filling authigenic kaolinite are scattered throughout the pore system. The rock has a relatively undercompacted fabric, probably due to the presence of early carbonate cement. Minor amounts of discontinuous quartz overgrowths are present on most quartz grains. Kaolinite precipitated before silica cement. The main diagenetic minerals in these samples are the scattered ankerite cement. The primary and diagenetic composition and texture of this sample is consistent with the upper D Sand samples in cored Terra Nova wells.

2.3.3.4 Jeanne d'Arc F Sand

The F Sand is represented by three core samples in West Ben Nevis B-75. The F Sand is the lower fine sand to upper very coarse conglomerate sublitharenite with varying amounts of limestone and some rock fragments. Neither intraformational bioclastic debris nor glauconite was identified, but a silty argillaceous burrow is present. Silica cement is extensive and minor amounts of ferroan dolomite or ankerite and ferroan calcite cements are present. Ankerite occurs outside of some quartz overgrowths, indicating that at least some of the silica cementation took place before some of the ankerite cementation. Very minor amounts of pore-filling kaolinite are locally present. Intergranular porosity is very strongly reduced by close grain packing, grain suturing, silica cement, and variably by ankerite and minor amounts of ferroan calcite in all three samples.

2.3.3.5 Jeanne d'Arc H Sand

Petrographic analysis was performed on the sidewall cores of M-04 well. The H Sand is very fine sand or gravel conglomerate sublitharenite. Primary composition consists dominantly of quartz, but limestone rock fragments are common in all samples. Individual micritic pellets and micritized oolites are assumed to be reworked from limestones rather than intraformational.

The H Sand in M-04 contains the following indicators of marine or marginal marine depositional environment:

1. Glauconite

2. Early authigenic siderite
3. Chlorite rims
4. Chloritized grains, some of which appear to have been originally biotite
5. Possible chamosite clasts
6. Delicate intraformational bioclast fragments, including rare forams and phosphatic bioclast fragments
7. Authigenic anatase

Siderite is the earliest authigenic mineral, as microcrystals clinging to quartz grain surfaces and locally as rims on detrital calcite grains. Siderite is oxidized, mostly where it occurs in open pores. Most of the siderite enclosed in ferroan calcite cement is not oxidized. Ferroan calcite bounding open pores is not obviously oxidized. The sand has a very undercompacted fabric inside the ferroan calcite cement, indicating calcite cementation took place before significant burial compaction took place. Most of the kaolinite occurs outside the ferroan calcite cement, but locally kaolinite booklets are enclosed in ferroan calcite, so the paragenetic sequence is ambiguous; there may have been more than one episode of kaolinite precipitation. Quartz overgrowth development took place after ferroan calcite precipitation and after kaolinite. The association of oxidized siderite, kaolinite, and ferroan calcite cement implies changing or fluctuating near-surface conditions. The siderite may have precipitated near surface in a marginal marine or brackish water environment. The oxidation implies surface exposure above the water table. The presence of early kaolinite may indicate flushing of original marine or brackish pore waters by meteoric waters. Kaolinite occurs in several of the other samples, and is always later than chlorite and/or siderite, and earlier than quartz overgrowths.

2.4 Geophysics

A 3D seismic survey was acquired over the Hebron Asset in 1997. The resolution and coherency of the imaging for interpretation purposes varies between good and excellent, depending on the location and depth. The decision to acquire modern geophysical surveys is currently under review and will depend upon the expected uplift in subsurface resolution (structure / stratigraphy / reservoir properties) brought about by improvements in acquisition and processing technology.

This geophysical section is organized into the following subsections:

1. Seismic Data Acquisition
2. Seismic Data Processing
3. Seismic Interpretation

2.4.1 Seismic Data Acquisition

A three-dimensional (3D) seismic survey was acquired over the Cape Race, Hebron, Ben Nevis, and Terra Nova licences from May 5 to June 29, 1997. The acquisition was performed by PGS Exploration AS using the vessel R/V Ramform Explorer.

The entire survey consists of 93 lines each spaced at 400 m with lengths varying from about 11 km to almost 29 km. A total of 2332 sail km were acquired and the survey covers an area of over 925 km². The Hebron/Ben Nevis portion of the survey consists of 28 shot lines with lengths varying from about 27 km to almost 29 km. A total of about 800 sail km were acquired specifically for Hebron/Ben Nevis, which covers about 320 km². The Hebron 3D dataset used for interpretation covers about 800 km² of the entire survey.

All of the lines were shot in an east-west orientation (88.16 degrees, North American Datum 83 [NAD-83]). A two airgun array was used with airguns separated by 50 m and a shot point interval of 25 m. A total of eight streamers, each with a cable length of 4050 m at a depth of 8 m (± 1 m), were employed. Streamer separation was 100 m. There were 162 groups with a group interval of 25 m. The natural bin size is 12.5 by 25 m. The resulting nominal fold is 4100 percent. The data are eventually processed to 25 by 25 m bins and the resulting final fold is 8200 percent.

A complete list of instrument and recording parameters used in the acquisition is given in Table 2.4-1.

The 1997 PGS survey was acquired to improve on the frequency content and spatial coverage of a GSI reconnaissance survey acquired in 1985 in the area. The 1985 GSI survey had a final interpolated line spacing of 50 m compared to the PGS survey's 25 m. The quality improvements in the new 3D recording resulted in all seismic interpretations being based on the 1997 survey.

2.4.1.1 Line Numbers

The Hebron 3D sail line (SL) numbering can be related to the Common Depth Point (CDP) bin in-line (IL) numbering by the following expression:

$$SL = IL + 978$$

Note that the SL numbers actually sailed start at 1008 and increment by 16. The outline of the final processed Hebron 3D survey has line ranges 20 to 1273 and traces 200 to 1400.

Table 2.4-1: 3D Seismic Instrumentation and Recording Parameters

Parameter	Value
Total Distance Shot	792.5 km
Source	Dual Tuned Airgun Array
Airguns	Bolt Par Model 1900L1 and Soder G-Sleeve Gun
Array	3 Parallel Sub Arrays per Source
Volume	3090 cu in.; 50.64 l
Pressure	2500 PSI; 17.237 Mpa
Operating Depth	7.5 m $\pm$ 1 m
Array Separation	50 m
Gun Controller	Syntron Gun Controller System GCS90
Average Near Group Offset	275 m
Recording System	Syntrak 480
Tape/Cartridge Decks	4 Stk IBM 3590
Tape Format	SEG-D 8036, 3 byte
Tape Polarity	A positive pressure at the hydrophone produces a negative number on tape and a downward deflection on the field tape monitor.
Number of Channels	162 per streamer 1296 for 8 streamers
Recording Length	7 s
Sample Rate	0.002 s
Gain Constant	12 dB
Recording Filters	Low Cut 3 Hz @ 6 dB/octave High Cut 218 Hz @ 484 dB/octave
Shot Line Spacing	50 m
Shotpoint Interval	25 m (50 m for each array, alternate shooting)
Group Interval	25 m
Hydrophones per Group	32
Hydrophone Interval	0.75 m
Hydrophone Type	Teledyne T2
Streamer Length	4050 m
Streamer Separation	100 m
Number of Streamers	8
Average Cable Depth	8 m $\pm$ 1 m
Navigation System	Spectra Integrated Navigation System Version 2.03.10
Primary Navigation System	Differential GPS STARFIX/Seadiff
Secondary Navigation System	Differential GPS STARFIX/WADS

2.4.2 Seismic Processing

The 1997 PGS 3D survey was processed by CGG Canada Ltd. The data processing sequence was designed to preserve relative amplitudes for possible post-processing amplitude versus offset (AVO) analysis.

2.4.2.1 Seismic Processing Sequence

The seismic processing sequence includes the following:

1. SEG-D reformat and QC (output 6.0 s at 2 ms)
2. Merge of seismic and navigational data
3. Low cut filter
4. Trace editing
5. Source and receiver adjustment to sea level
6. Spherical divergence compensation
7. Deterministic signature deconvolution
8. Spiking deconvolution (1 operator per shot, 250 ms operator length, 1% pre-whitening)
9. Predictive deconvolution (1 operator per trace, 240 ms operator length, 20 ms gap)
10. Minimum phase resample to 4 ms
11. Dynamic Equalization (2000 ms sliding window (50 percent overlap), trace by trace)
12. Velocity Analysis (every 1000 m)
13. Dynamic binning and sorting to CDP bin mode
14. Multiple attenuation (radon decomposition, F-X domain)
15. Static binning and sorting to 25 m x 25 m bins
16. Dip Move-out (3D Kirchhoff, amplitude preserved, band limited spatial interpolation)
17. Velocity analysis (every 750 m)
18. Final NMO corrections and mute
19. Stack (8200 percent)
20. Predictive deconvolution (trace to trace, 200 ms operator length, 26 ms gap)
21. 3D One pass time migration (finite difference, steep dip algorithm, 93 percent of smoothed dip move-out (DMO) velocity field)
22. Time variant filter:

- 6/10-55/65 Hz; 0-2500 ms
 - 3/7-45/55 Hz; 3000-3500 ms
 - 3/7-35/45 Hz; 4500-6000 ms
23. Dynamic Equalization
 24. 600 ms; 0-2100 ms; 50 percent overlap
 25. 1000ms; 2100-6000 ms; 50 percent overlap
 26. Phase rotation (rotation of 115 degrees to make velocity increase a peak)

The seismic data quality of the processed survey is excellent. Fault interpretations are significantly improved over the 1985 GSI data. There has also been a reduction in the uncertainty related to horizon mapping. In particular, the new data has dramatically improved the definition of the reflector at the top of the Ben Nevis Reservoir.

2.4.2.2 3D Pre-stack Time Migration

In 2000, a portion of the Hebron 3D survey was pre-stack time-migrated (PSTM) for interpretation and AVO purposes. In 2001, this process was extended to cover a larger portion of the survey. The final PSTM covers the ranges of lines 460 to 1050, and traces 200 to 1400 for the full time window.

The dip move-out corrected gathers (step 16 in processing flow above) are the input to the PSTM processing flow. The processing flow for the PSTM is as follows:

1. The DMO corrected gathers from step 16 of the original flow were read in and partially stacked on the fly into 21 common offset cubes.
2. The DMO velocities from CGG were averaged into a single function that was reduced to 95 percent of its initial value.
3. The single 95 percent function was used to do a 3D migration of each offset cube.
4. The output data were sorted back into CDP gathers and used to re-pick the stacking velocities.
5. The new stacking velocities were smoothed in preparation for the final migration.
6. The old DMO velocities were removed from the DMO corrected gathers read in at Step 1.
7. The new stacking velocities from Step 4 were applied to create the final gathers.
8. The gather data were stacked.

9. The resulting stack cube was de-migrated using the single 95 percent function used for the offsets in Step 3.
10. The data were then migrated with the smoothed velocity field from Step 5.
11. The migrated cube then went through a two-pass frequency domain (FX) deconvolution to improve coherency and the final 3D cube generated.

The gathers were then stacked and de-migrated with the single function used previously, then re-migrated with the smoothed velocity field. The output cube went through a two-pass FX deconvolution to improve the coherence and was then loaded into Schlumberger's IESX.

2.4.2.3 Reprocessing

The Hebron 3D survey was acquired and originally processed in 1997 to 98. The survey was reprocessed through a 3D anisotropic PSTM in late 2005. The re-processing was performed by the vendor CGGVeritas under supervision of co-venturers Chevron, ExxonMobil, Petro-Canada, and Norsk Hydro.

2.4.2.4 Reprocessing Objectives

The main objective for the reprocessing was improving the resolution and imaging of the data with a focus on the Hebron Field reservoir intervals and fault blocks. These reservoir targets are the Early Cretaceous Ben Nevis and Hibernia sandstones and the Upper Jurassic Jeanne d'Arc sandstones of the Hebron horst block and the West Ben Nevis and Ben Nevis fault blocks.

2.4.2.5 Technical Objectives

Key technical objectives of the reprocessing were as follows:

- ◆ Improve imaging of Hebron Field reservoir and fault blocks.
- ◆ Improve signal to noise ratio and increase bandwidth to help improve interpretation of internal event for all reservoirs.
- ◆ Focus on preserving true relative amplitudes and protecting primary signal energy to help improve the validity of seismic attributes for reservoir characterization. Reservoir characterization and modeling of all of these reservoirs currently use seismic attributes in some form to improve validity of models away from well control.
- ◆ Improve primary fidelity by attenuating multiple energy, which contributes to the uncertainty in the interpretation of all reservoirs, but particularly in the Ben Nevis Reservoirs which lie just below upper Cretaceous and lower Tertiary water bottom and peg-leg multiple generators.

2.4.2.6 Methodology

The overall strategy in the pre-processing was to perform Controlled Amplitude and Controlled Phase (CACP) processing which maintains the amplitude fidelity and zero phase characteristics required for reservoir development. To that end after the necessary and standard editing, datuming and data reduction applications a reversible gain correction was applied to equalize the data in time and offset. These data were then put through a series of cascaded noise attenuation processes to mitigate noises from the acquisition equipment and sea swell. All these processes were applied with the intent to attenuate the noise while retaining the true amplitude and phase of the data.

With most of the noise attenuated an initial acquisition footprint mitigation effort was undertaken to correct for small changes in amplitudes cause by small variations in the acquisition sources and receivers characteristics. This was then followed by cascaded deconvolution processes aimed at attenuating the short period multiples commonly found in shallow marine environments. Following the attenuation of these multiples a second effort to mitigation for variations in amplitudes cause by variations in the acquisition sources and receivers was undertaken. This was then followed by processing to mitigate the acquisition footprint between different acquisition boat passes.

Following this a series of processes to prepare the data for the imaging stage were completed. This included further residual noise attenuation as well as residual amplitude and phase corrections. The data was then equalized and regularized in preparation for the imaging step and also in an attempt to further mitigate the acquisition footprint, as well as to minimize generation of any processing footprint or artifacts. Prior to the imaging processes a significant effort was undertaken to build a geologically based sedimentary velocity model. This was initially isotropic but eventually was upgraded to anisotropic. This iterative procedure was undertaken with the guidance of well log information, which was used to refine the model until accurate.

This model was then used to process the data through the Kirchhoff pre-stack time migration. After the imaging process residual moveout corrections were estimated and applied to produce flatter gathers, which improved the quality of the final stack image. On the flattened gathers prior to the final stack process an additional application to further attenuate the multiples was applied. Finally on the stacked data additional noise attenuation was applied followed by a series of residual corrections to adjust the final amplitudes and phase of the data.

A final report which covers the described work in great detail was generated and distributed [Veritas, 2006]. A summary of the processing stream is outlined in Table 2.4-2.

Table 2.4-2: Processing Flow Overview

Processing Activity	Description
Pre-Processing	Reformat from SEG-D
	Shot and Channel Editing
	Navigation / Seismic Merge
	Gun / Cable Correction To Sea Level
	Minimum-phase Source De-signature
	Minimum-phase Anti-Aliasing Filtering
	Resample to 4 ms sample rate
	Spherical Divergence Correction
	Swell Noise Attenuation
	Direct Arrival Attenuation
	Paravane Noise Attenuation
	Residual Swell Noise Attenuation
	Common Channel De-Spiking
	1st –pass Surface-Consistent Scaling Calculation & Application
	Shot-domain Tau-P Deconvolution
	2nd –pass Surface Consistent Scaling Calculation
	Receiver –domain Tau-P Deconvolution
	Apply 2nd –pass Surface Consistent Scaling
	Sort Common-Offset Planes (41 offsets)
	Trace Interpolation and Bin Centering
	Time-varying High-cut Filtering
	Acquisition Footprint Mitigation
	Spherical Divergence T2 Removal
	Q Compensation (Phase Only)
Imaging	PSTM Anisotropic Velocity Model Building
	Kirchhoff Anisotropic Pre-Stack Time Migration
	Residual Velocity Analysis
	Normal Moveout Correction
	High-resolution Radon De-multiple
	Mute
	Stack
Post Stack Processing	Zero Phase Correction
	K-Filter
	Q Compensation (Amplitude only)
	Bandwidth Extension
	Time-varying Low-Cut Filter Noise Attenuation
	Time-varying Residual Gain Correction

2.4.3 Seismic Interpretation

The seismic interpretation includes mapping the main seismic markers and structural framework (faults). Ten key seismic horizons and over 200 faults were interpreted in all. The seismic interpretation section is organized into the following seven subsections:

- ◆ Section 2.4.3.1: Synthetic Well Ties
- ◆ Section 2.4.3.2: Seismic Markers
- ◆ Section 2.4.3.3: Seismic Fault Mapping
- ◆ Section 2.4.3.4: Seismic Sections
- ◆ Section 2.4.3.5: Depth Structure Maps
- ◆ Section 2.4.3.6: Time-to-Depth Conversions
- ◆ Section 2.4.3.7: Shallow Hazards

2.4.3.1 Synthetic Well Ties

Synthetic seismograms have been generated and used to tie the borehole logs to the 3D seismic data for all the wells, as follows, within the Hebron / Ben Nevis area:

- ◆ I-45
- ◆ I-13
- ◆ B-75
- ◆ H-71
- ◆ L-55
- ◆ I-30
- ◆ D-94
- ◆ M-04
- ◆ C-23
- ◆ N-68

These 10 wells were used in correlation of the stratigraphic units. The wells were tied to the 2006 reprocessed full-stack seismic data. The newer wells (L-55, I-30, D-94, and M-04) have better quality logs and have vertical seismic profiles (VSPs) which have been employed in the well-to-seismic ties. A zero phase, 25 Hz Ricker wavelet was used for all the synthetics. For final adjustments to tie the synthetic to the seismic, minor bulk shifts were performed, but no stretching or squeezing was done. The tool used for tying the wells to seismic is Schlumberger's Geoframe Synthetics package. A representative well tie is displayed in Figure 2.4-1.

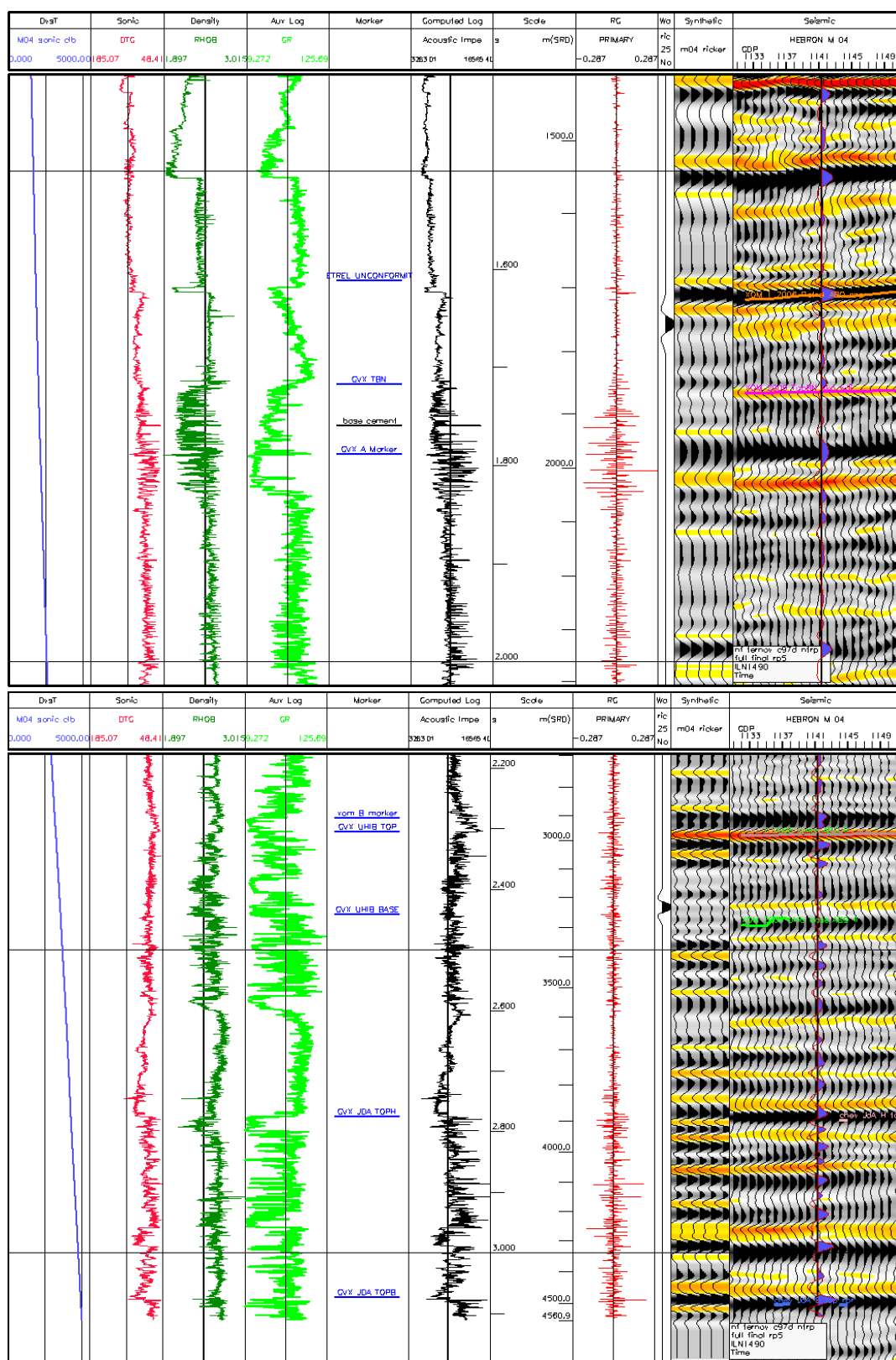


Figure 2.4-1: Representative Well Tie (M-04)

2.4.3.2 Seismic Markers

Seismic interpretation shown in this section was performed solely on the 2006 reprocessed seismic data. Key horizons and major faults were interpreted across the Hebron Asset. Minor features such as local stratigraphic horizons or small throw faults were mapped where appropriate, generally within major reservoir units. The tools used for seismic interpretation are Schlumberger's Geoframe IESX, Schlumberger's Petrel, and Paradigm's VoxelGeo applications. Most of the horizons were interpreted on the full-stack. Discontinuity volumes were used to assist the fault interpretation.

The quality of the reprocessed seismic data is generally good. The faults are generally well imaged. There are fault shadow features present below most large throw faults.

The main seismic horizons have been interpreted over the asset through the 10 wells used to correlate the stratigraphic units. The purposes for interpreting these horizons include outlining the major reservoir units, geologic model inputs, velocity model inputs, and stratigraphic correlation and understanding.

The main interpreted reflection events (from shallowest to deepest) are as follows:

- ◆ Water bottom

This reflector was needed as an input into the velocity model. The water bottom is mapped on a peak that is a high amplitude continuous reflector. This interpretation covers the whole seismic survey.

- ◆ Petrel unconformity

This reflector was provided as an input to the velocity model. The petrel unconformity is mapped on a peak that is a high to moderate amplitude continuous reflector. The horizon interpretation covers the whole seismic survey.

- ◆ Top Ben Nevis

This reflector defines the top of the Ben Nevis Reservoir. This horizon is mapped on a trough that is low to moderate amplitude semi-continuous to continuous reflector. The fining upward pattern at the top of the Ben Nevis contributes to the low acoustic impedance that makes the top of the Ben Nevis an inconsistent horizon to map.

- ◆ Base Ben Nevis

This horizon was mapped to define the base of the Ben Nevis Reservoir. This horizon is mapped on a trough that is a moderate amplitude, continuous reflector. The horizon is interpreted over the whole seismic survey.

◆ A Marker

The A Marker was mapped to further define the base of the Ben Nevis Reservoir. This horizon is mapped on a peak that is a moderate amplitude, continuous reflector. This reflector is interpreted over the whole seismic survey.

◆ Top Hibernia

The top Hibernia horizon was mapped to define the top of the Hibernia Reservoir. This horizon is mapped on a trough that is a high amplitude, continuous reflector. This interpretation covers the whole seismic survey. The limestone to sandstone transition produces large acoustic impedance, which contributes to the reflector character.

◆ Base Upper Hibernia

This reflector was mapped to define the base of the upper Hibernia, which is oil-bearing at Hebron. This horizon is mapped on a peak that is a low to moderate amplitude semi-continuous reflector. This reflector is mapped over most of the seismic survey.

◆ Top Fortune Bay

This reflector was mapped to define the base of the Hibernia Formation. This horizon is mapped on a peak that is a moderate amplitude, semi-continuous to continuous reflector. This reflector is interpreted over most of the seismic survey.

◆ Jeanne d'Arc H Sand

This horizon was mapped to define the top of the H Sand of the Jeanne d'Arc Formation. This horizon is mapped on a peak that is a low to moderate amplitude, semi-continuous to continuous reflector. This reflector is mapped over most of the seismic survey.

◆ Top Jeanne d'Arc B Sand

This horizon was mapped to define the top of the B Sand of the Jeanne d'Arc Formation. This horizon is mapped by peak that is low to moderate amplitude semi-continuous to continuous reflector. This interpretation covers most of the seismic survey.

2.4.3.3 Seismic Fault Mapping

The faults were interpreted on the 2006 reprocessed full-stack class seismic data, just as the horizons were. The tools used for seismic interpretation are Schlumberger's Geoframe IESX, Schlumberger's Petrel, and Paradigm's VoxelGeo applications. Discontinuity volumes were used to assist the fault interpretation. The discontinuity data were helpful in defining the edges of

fault segments, especially at fault relays. Over 200 faults have been picked on the 3D data.

2.4.3.4 Seismic Sections

Figure 2.4-2 is a base map showing the map location of the time seismic sections. The seismic sections are shown in Figure 2.4-3 through Figure 2.4-7 illustrate the main seismic markers.

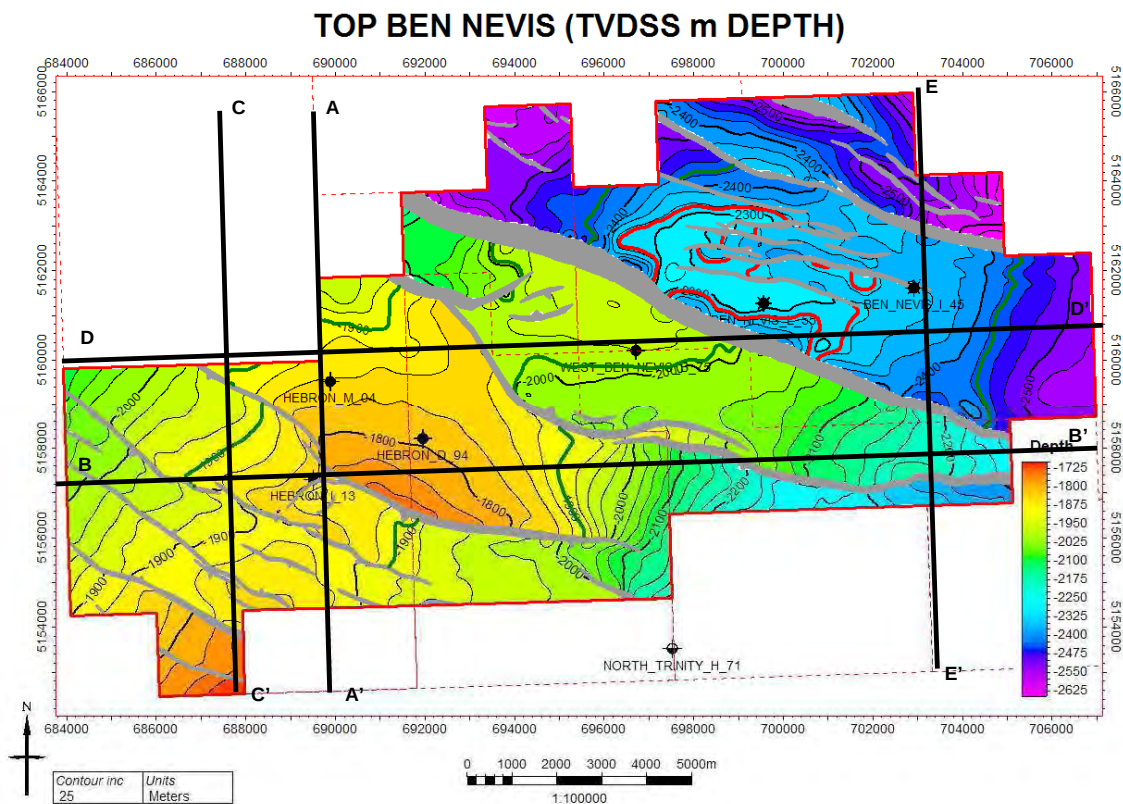


Figure 2.4-2: Seismic Section Map

Location of interpreted seismic lines are posted on depth structure map of the top Ben Nevis
Bold green and red lines represent fluid contacts (red=gas-oil, green=oil-water)

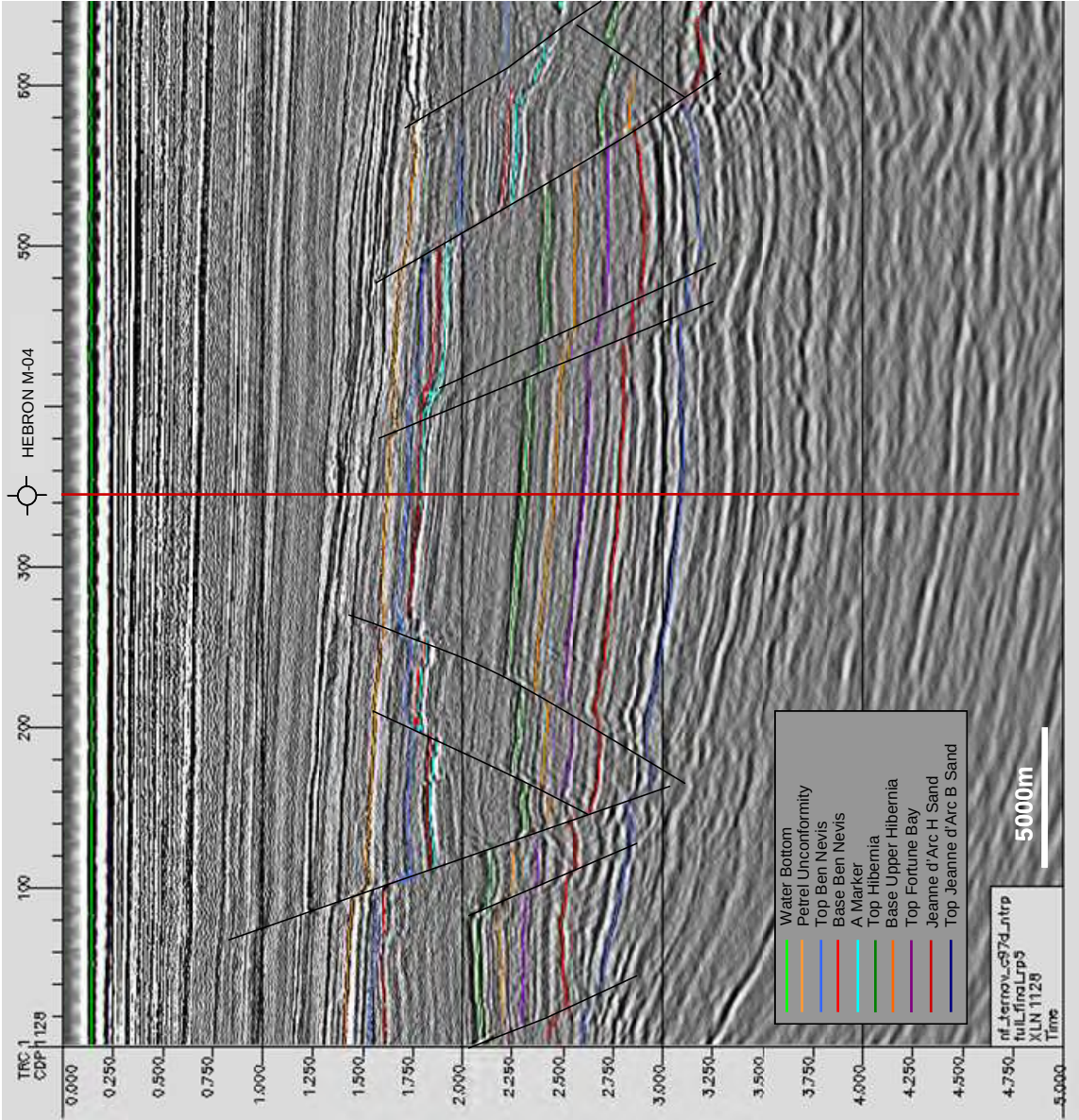


Figure 2.4-3: Seismic A-A' Section

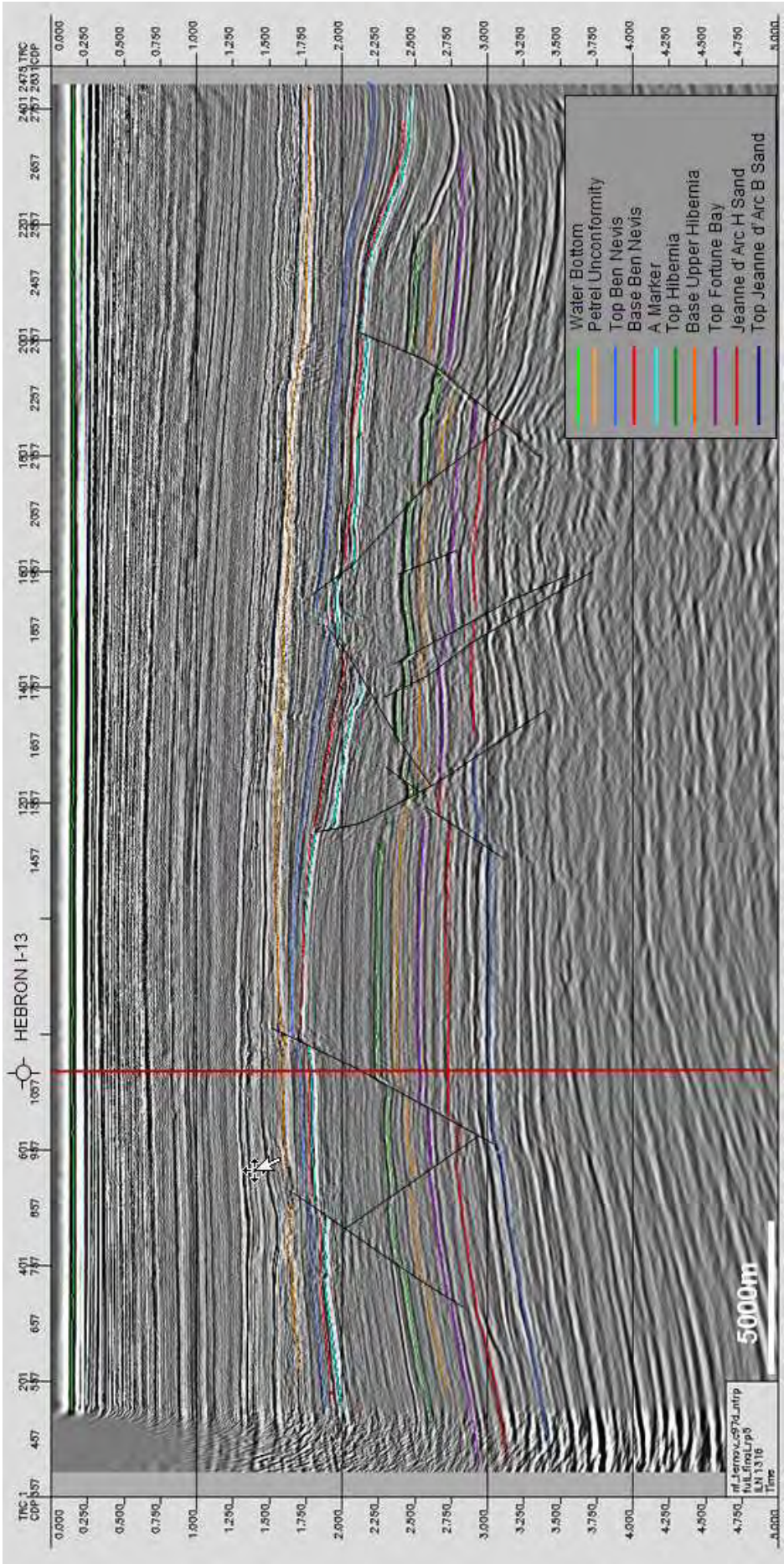


Figure 2.4-4: Seismic B-B' Section

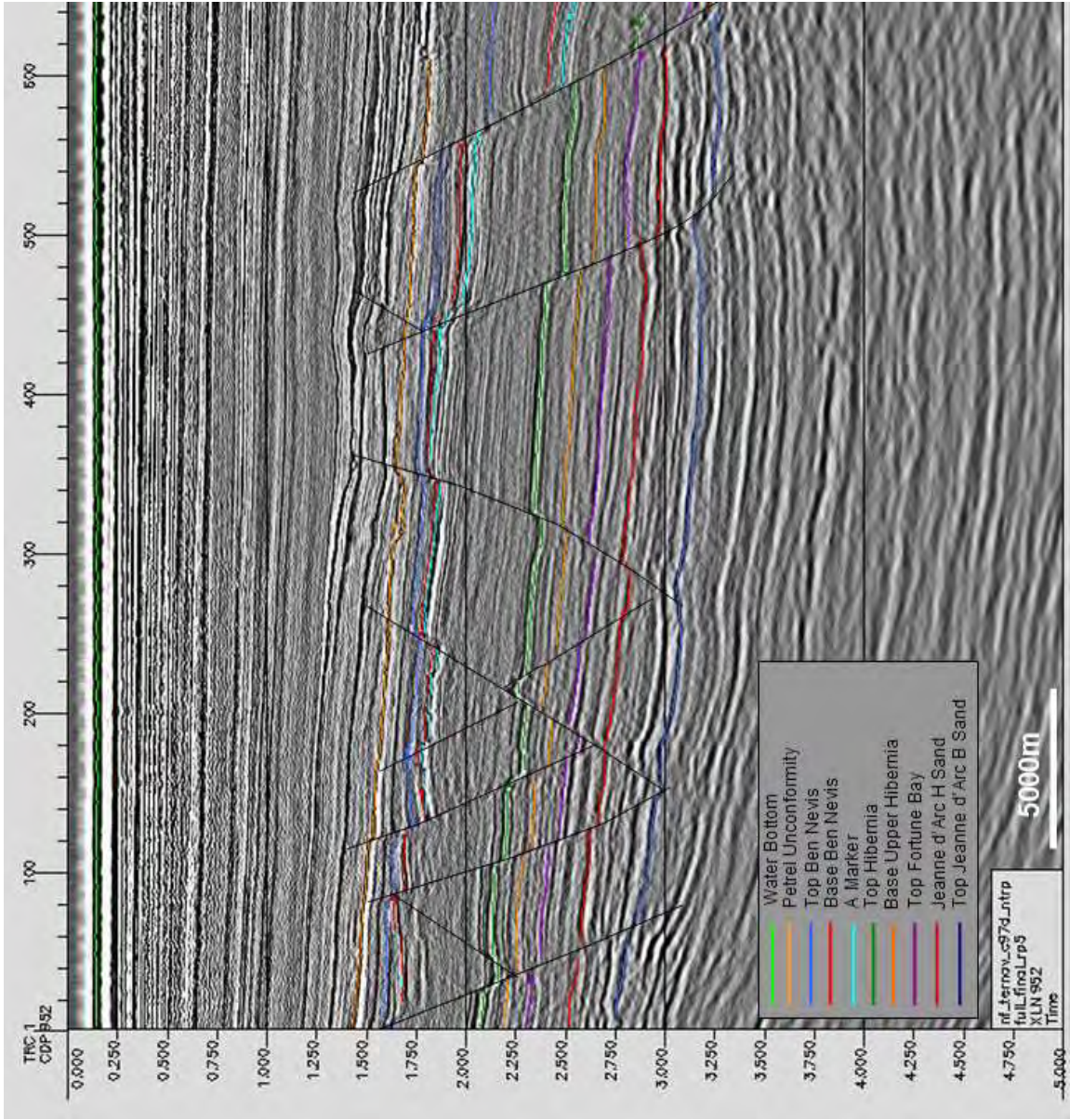


Figure 2.4-5: Seismic C-C' Section

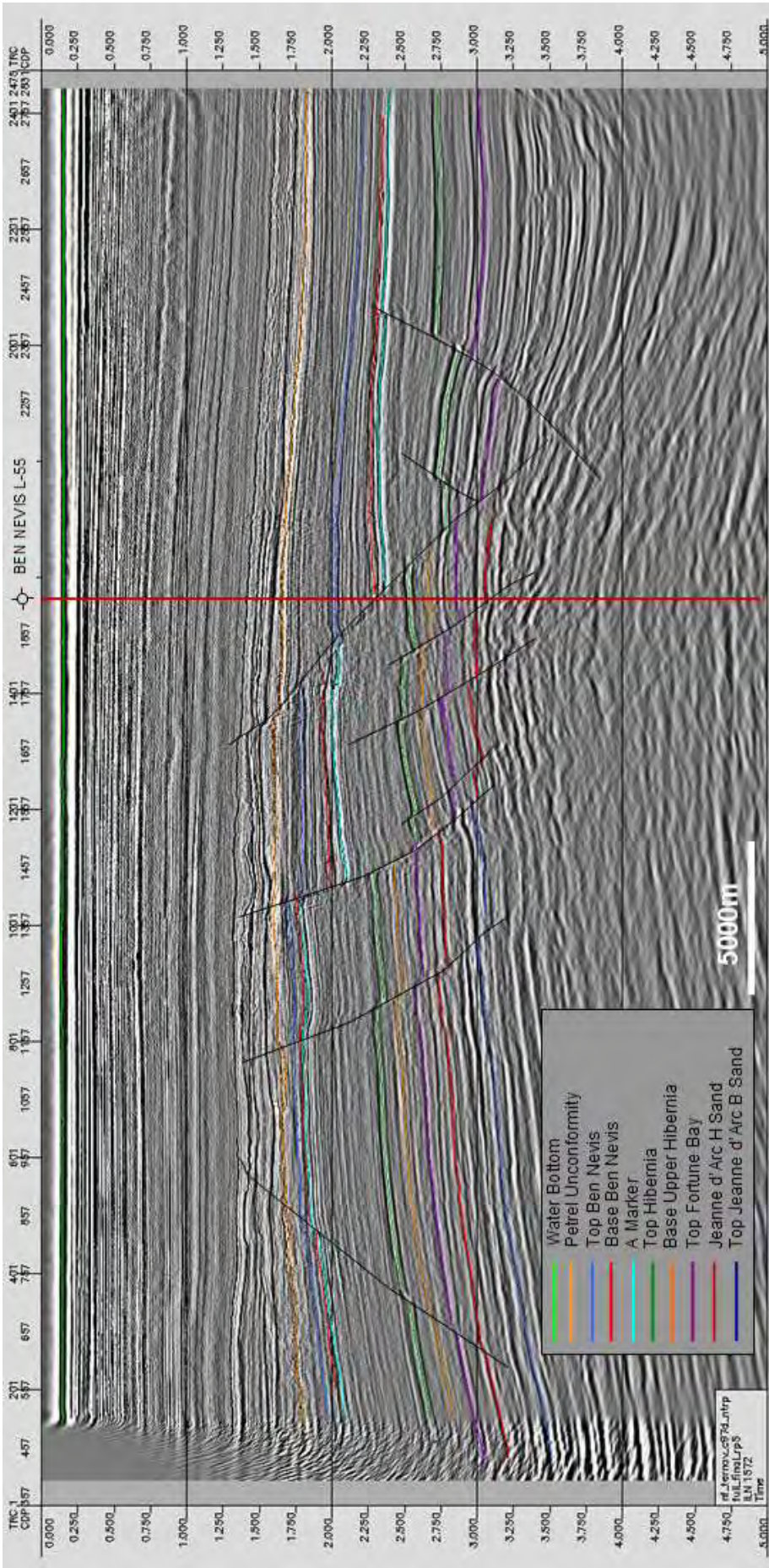


Figure 2.4-6: Seismic D-D' Section

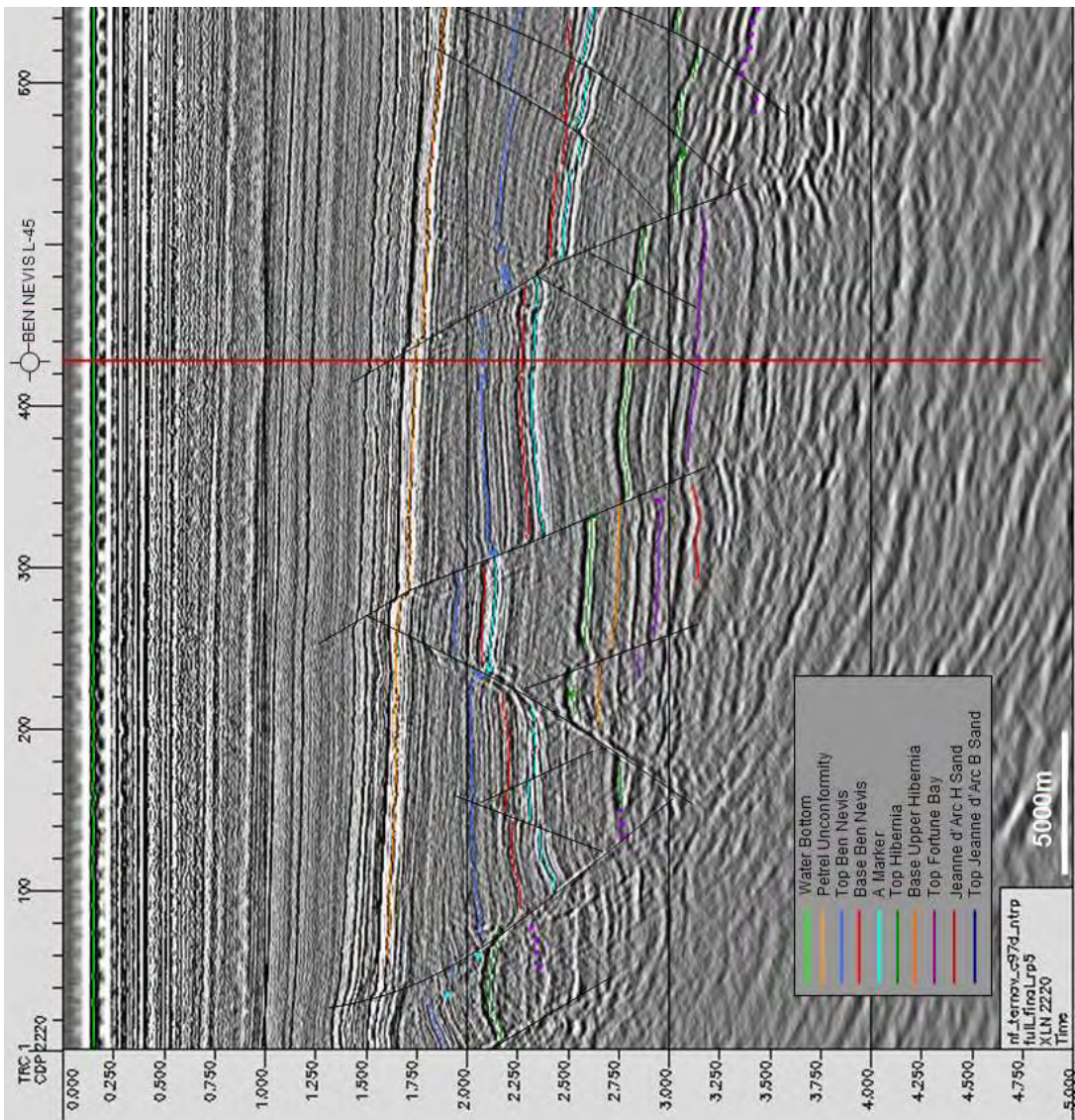


Figure 2.4-7: Seismic E-E' Section

2.4.3.5 Depth Structure Maps

Figure 2.4-8 through Figure 2.4-17 are depth structure maps for each of the seismic horizons.

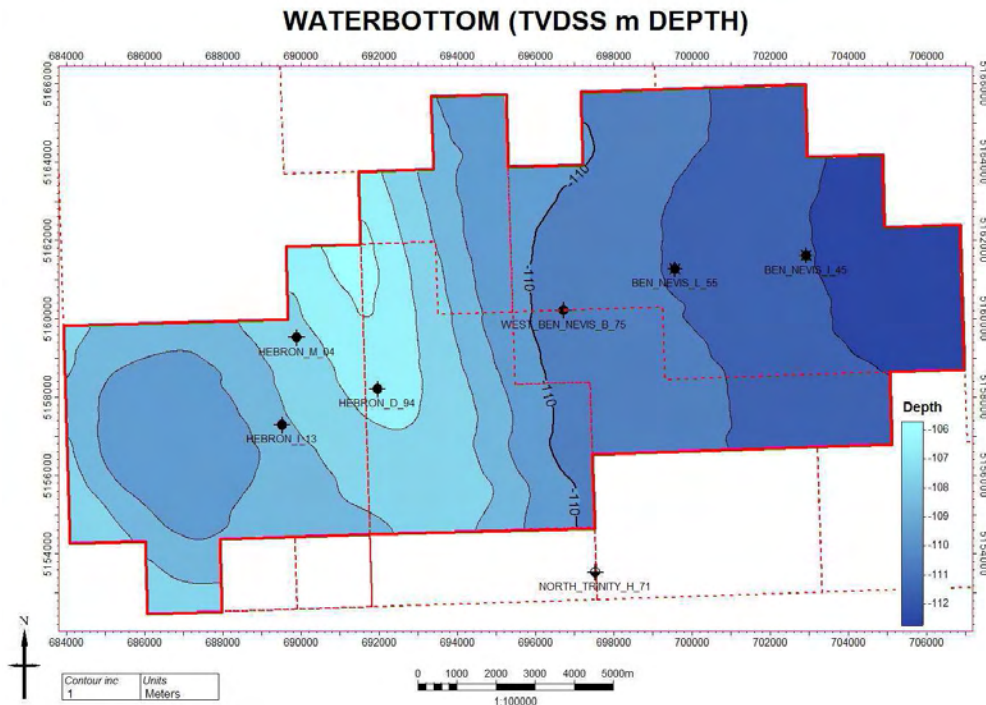


Figure 2.4-8: Water Bottom Depth Structure

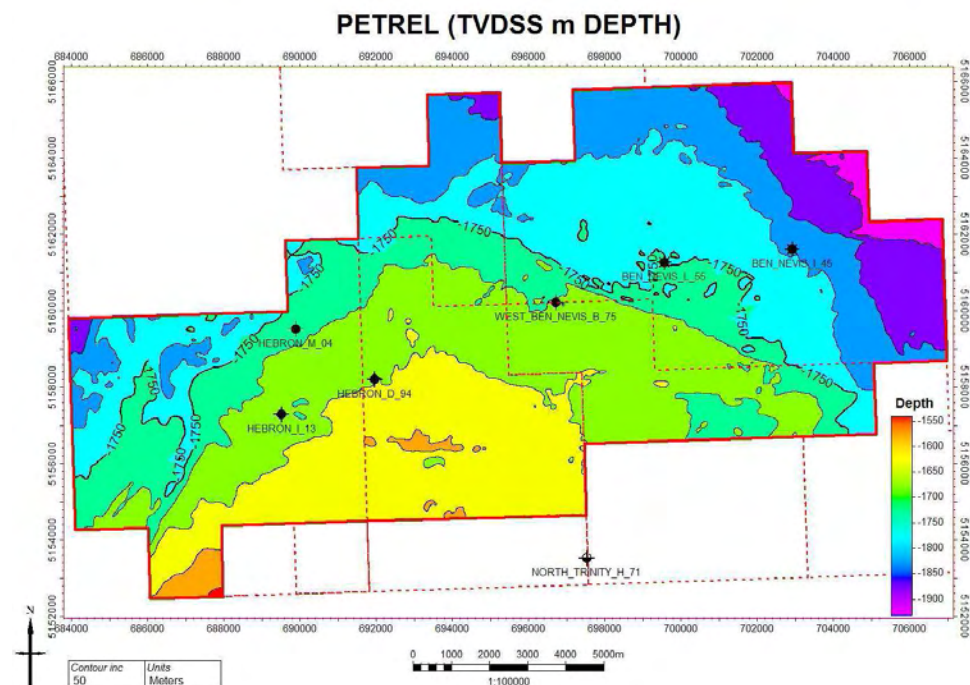


Figure 2.4-9: Petrel Depth Structure

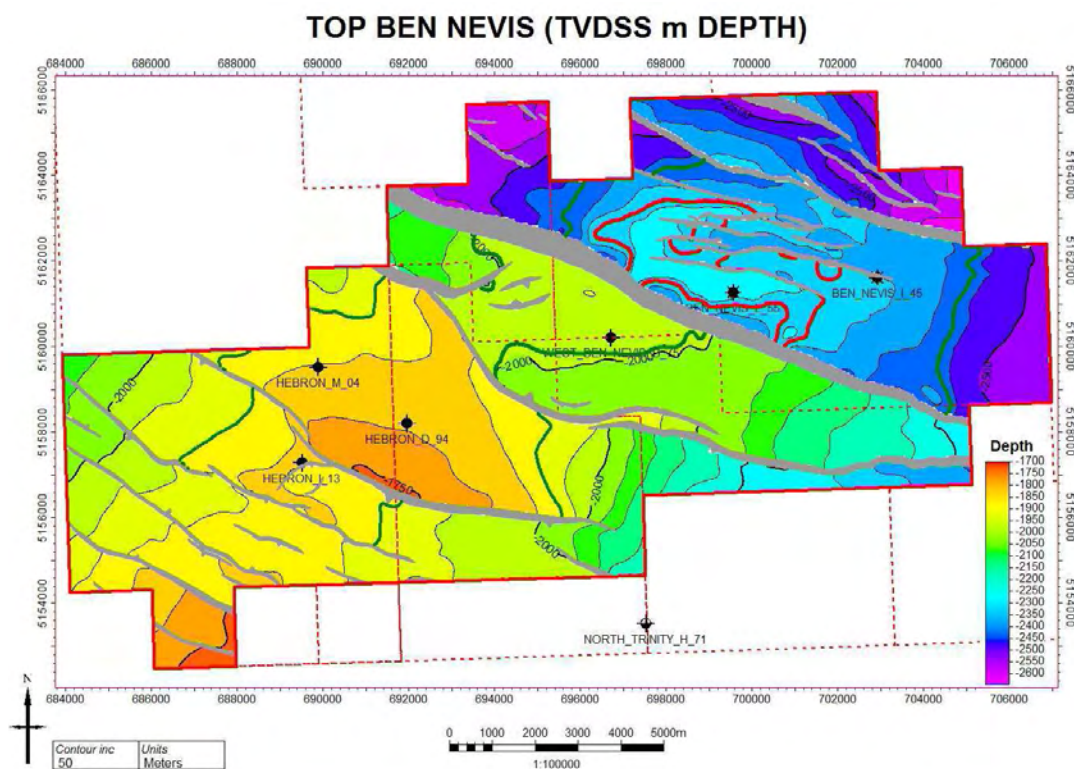


Figure 2.4-10: Top Ben Nevis Depth Structure Maps
Penetrated OWC is shown as green line and GOC is shown in red.

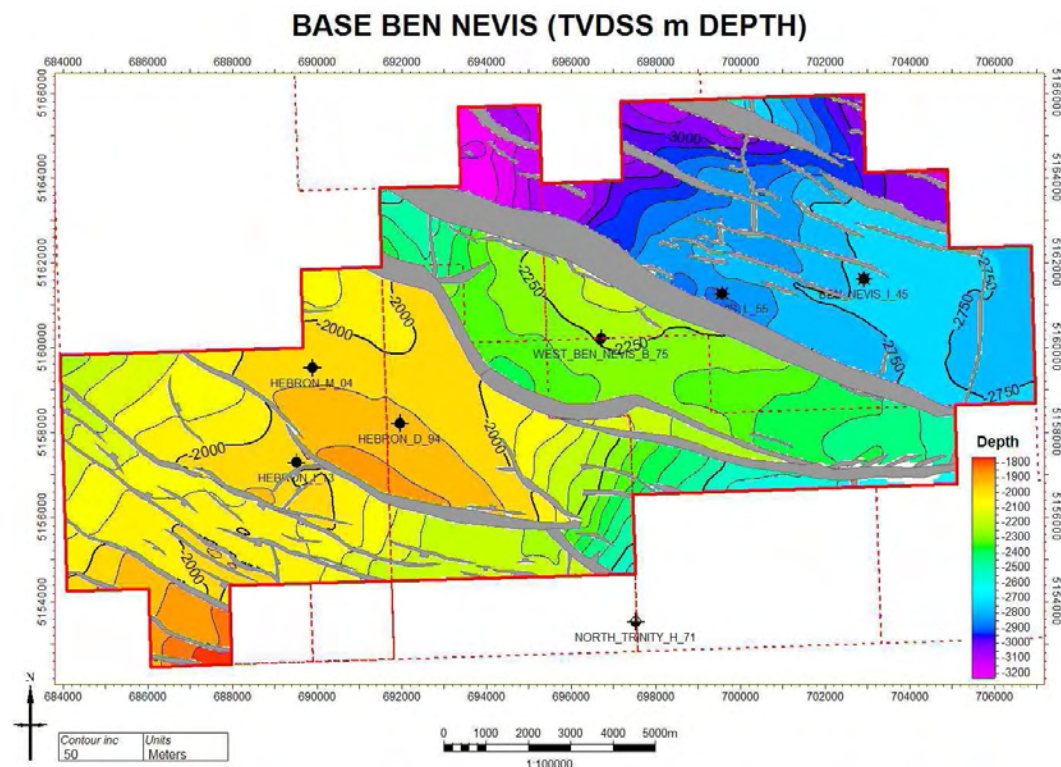


Figure 2.4-11: Base Ben Nevis Depth Structure

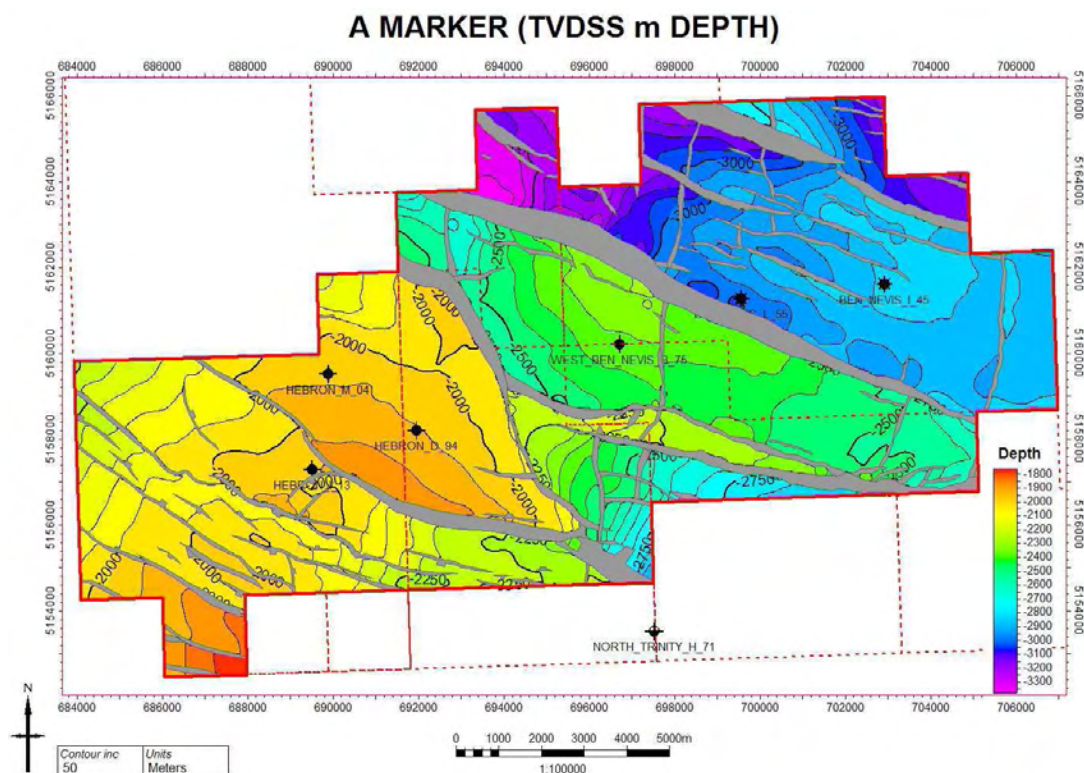


Figure 2.4-12: A Marker Depth Structure
TOP HIBERNIA (TVDSS m DEPTH)

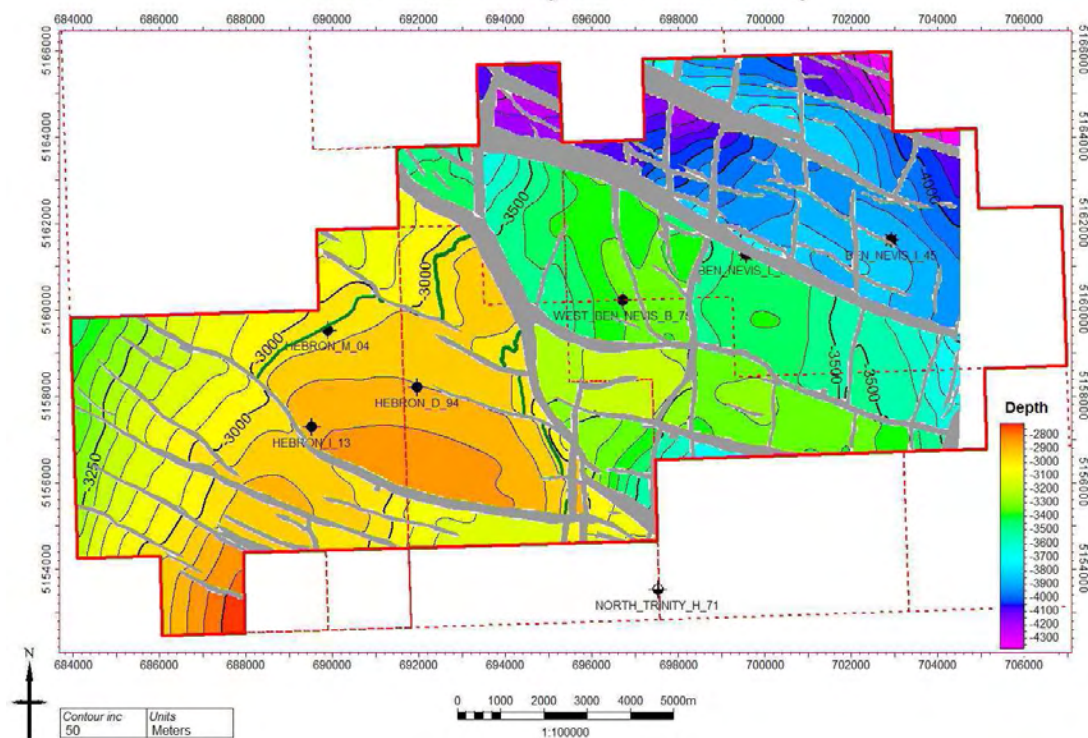


Figure 2.4-13: Top Hibernia Depth Structure
Penetrated OWC is shown as green line

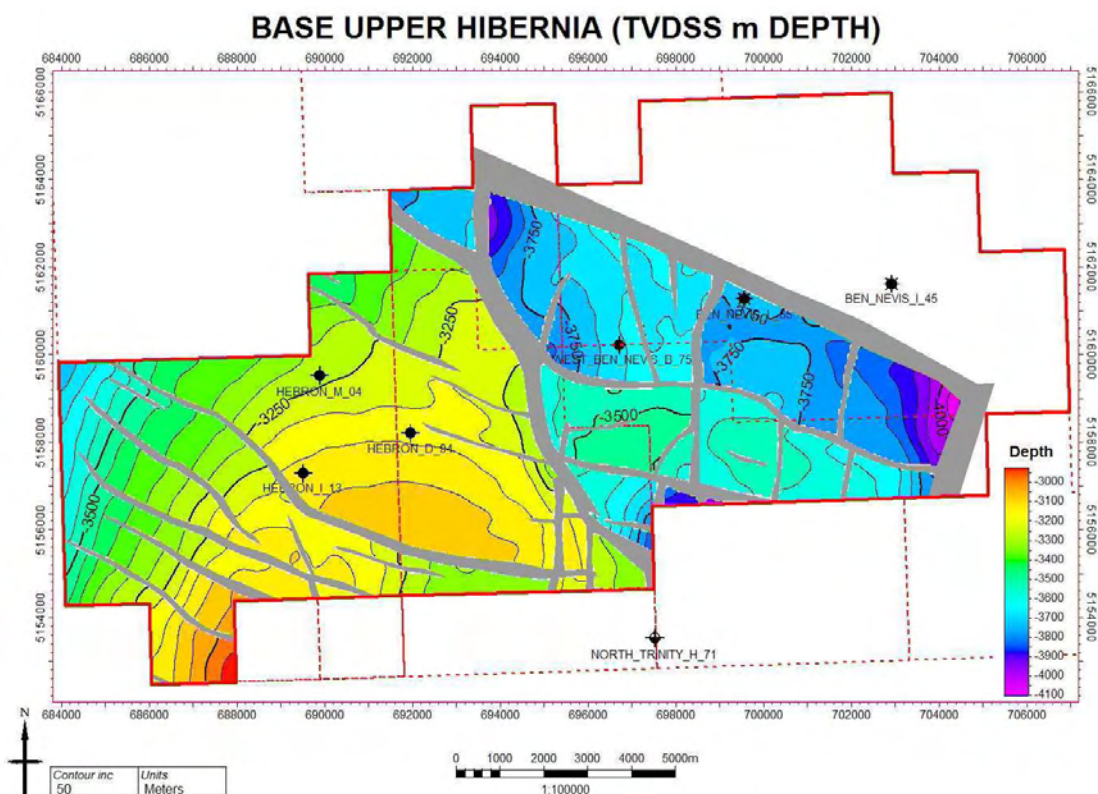


Figure 2.4-14: Base Hibernia Depth Structure

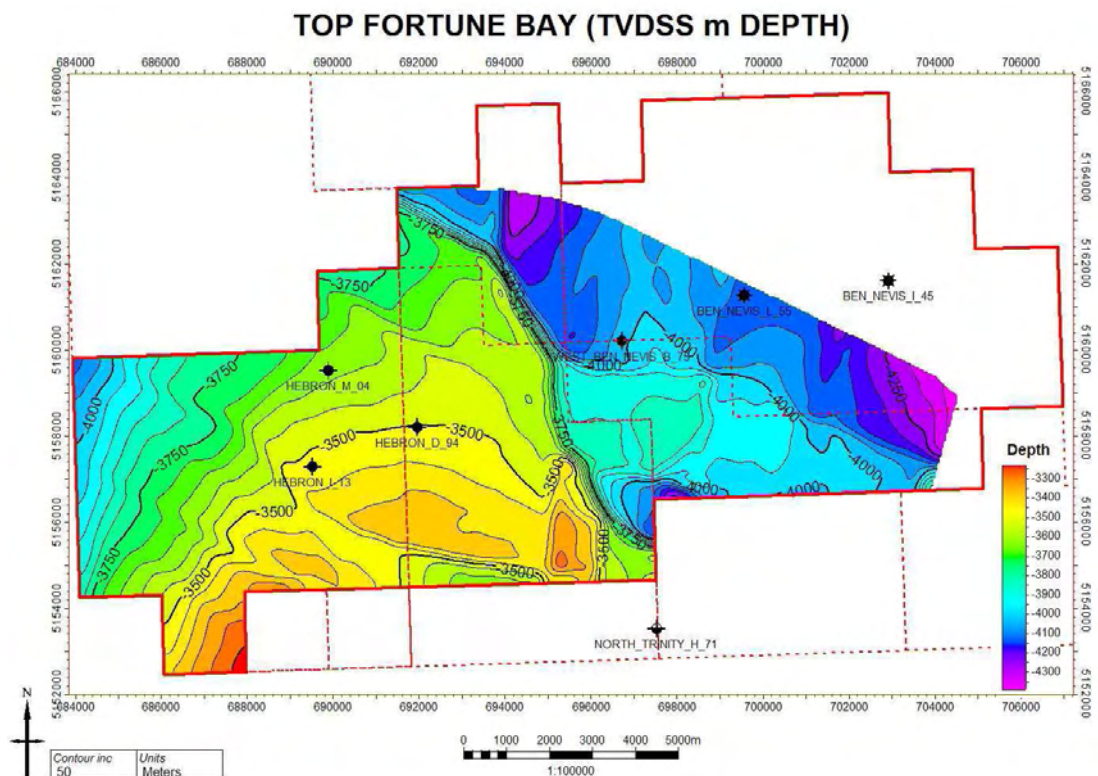


Figure 2.4-15: Top Fortune Bay Depth Structure

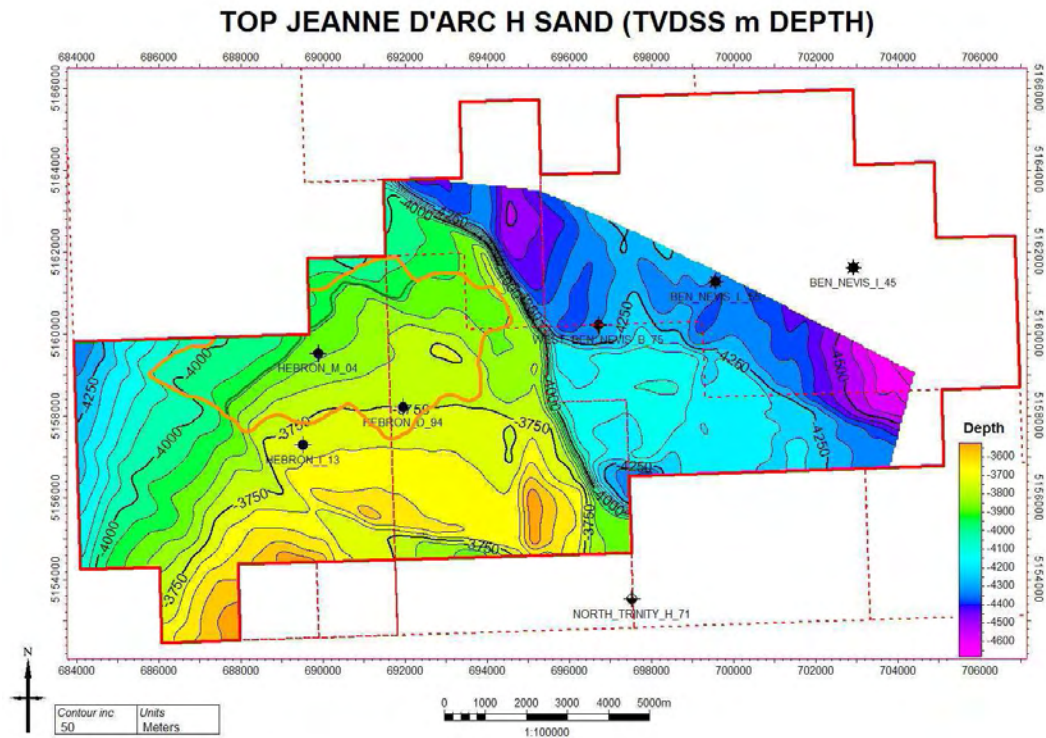


Figure 2.4-16: Top Jeanne d'Arc H Sand Depth Structure Maps
Penetrated OWC is shown as green line. The edge of the H-sand channel is shown as the orange line.

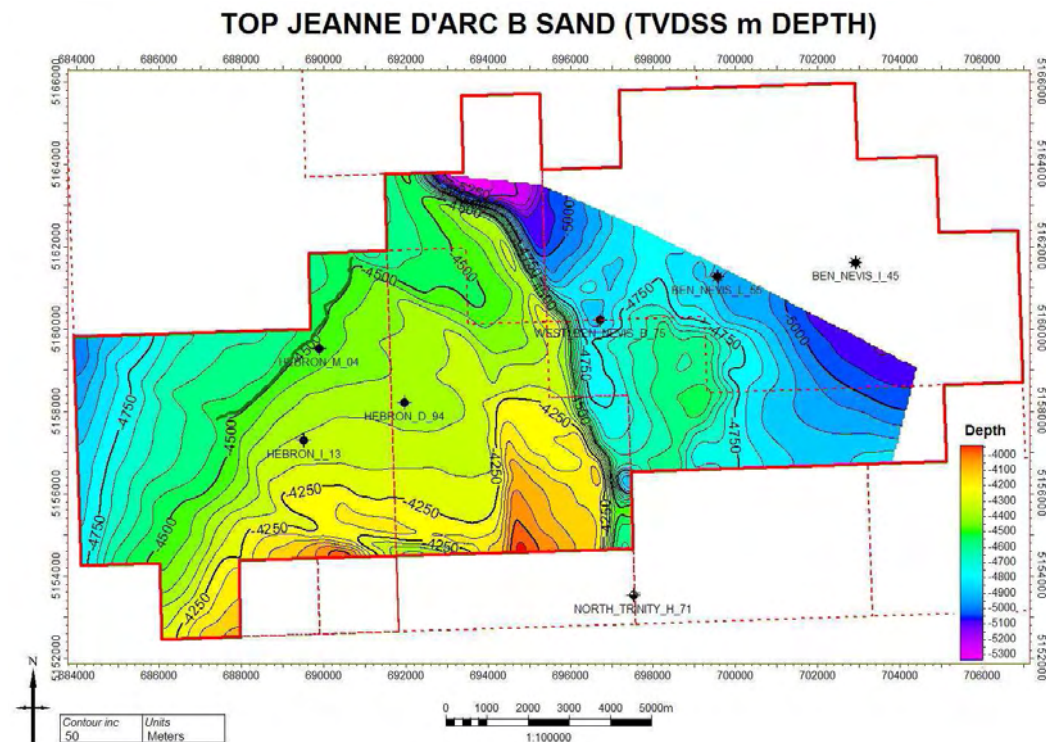


Figure 2.4-17: Top Jeanne d'Arc B Sand Depth Structure Maps
Lowest known oil is shown as the green line on the horst block.

2.4.3.6 Time-to-Depth Conversions

2.4.3.6.1 Ben Nevis

In 2009, a velocity model was created to convert interpretation objects between time and depth domains in the shallow section, above the A Marker. The data used to create this velocity model include the following:

1. 3D final stacking velocity from the Hebron 3D anisotropic PSTM reprocessing
2. Checkshots from 10 wells (L-55, D-94, I-30, G90-2, I-13, M-04, I 45, B-75, N-68 and C-23) and
3. Eight time horizons (water bottom, shallow3, base_t_unc, Top Ben Nevis, Top Hibernia, Fortune Bay, and Top Jeanne d'Arc H Sand).

The velocity model covers the same area as the seismic survey. This velocity model was created in Geodepth.

This average velocity model was built through a multi-step process that was periodically quality checked. Interval velocity maps for each of the eight time horizons were generated from the seismic stacking velocities. These interval velocity maps were calibrated to the checkshots. To do so, at each (X, Y) location, a constant interval velocity for each layer was utilized and each interval velocity map was adjusted to tie to the checkshots that penetrate that horizon. Not all of the checkshot data go through each horizon. From the calibrated interval velocity maps, an average velocity volume was created. Another constraint on the velocity model was the observed direct hydrocarbon indicator (DHI) in the Ben Nevis Reservoir. Pseudo-wells and checkshots were incorporated to conform the DHI to structure in the northwest flank of the horst block.

2.4.3.6.2 Hibernia and Jeanne d'Arc

For the deeper reservoirs, Hibernia and Jeanne d'Arc (JDA), several methods of velocity model building have been employed at Hebron, incorporating seismic stacking velocities and well checkshot/VSP velocities. The current base case velocity model is derived using all of the valid 3D velocity models built to date to derive a statistical 50th percentile (P50) most likely model. The velocity models that have been used to derive the P50 are briefly summarized below in order of creation.

The velocity models used for depth conversion of the Hibernia and Jeanne d'Arc time interpretations were constructed using the checkshot surveys from seven wells (i.e., I-45, I-13, B-75, H-71, L-55, I-30, and D-94). Due to the timing of the drilling, the M-04 well data was not available for model construction, so it was used only as a check of the models. The quality of the checkshot surveys from the 1980's (i.e., I-45, I-13, B-75, H-71) is questionable, so checkshot data for these wells were edited using the

synthetic tie with the seismic data as a constraint. The more recently acquired checkshot data tie the seismic data very well and no editing was required.

A seismic stacking velocities based velocity model was built using Chevron proprietary Velocity Toolkit. This method starts with the seismic stacking velocities and corrects these velocities to the well checkshot velocities using a single global time varying correction followed by a 3D residual error correction defined by the well residual errors. The result is a velocity model that ties the wells and retains the low frequency trends from the seismic velocity field.

The Velocity Toolkit was also used to build a linear V_0+kZ velocity model using the well checkshot data. The checkshot data are converted to interval velocity. Seven layers are defined using the following seismic mapped surfaces water bottom, Petrel, A Marker, B Marker, Fortune Bay, and Kimmeridgian. The interval velocity data for each layer are used to calculate an optimal constant k parameter for each layer. The V_0 values for each well and layer is then calculated. The V_0 values for the upper two layers (water bottom to Base Tertiary and Base Tertiary to A Marker) are interpolated by co-located cokriging to the layer isochron. The deeper layer V_0 values are interpolated by co-located cokriging with the seismic stacking velocities. A 3D residual error correction is calculated to minimize errors at the wells.

These first two velocity models were cross calibrated using the M-04 well as the unknown well. Comparisons suggest that both seismic stacking velocity and linear function methods are equally valid for the shallow horizons above the B Marker. For the deeper horizons the seismic stacking velocity model appears more robust. This may be due to the changes in overpressure within the Fortune Bay, and the difficulty modeling this with a constant k model.

In 2002, a new velocity model was generated incorporating the seismic stacking velocity data, M-04 well, and four of the closest Terra Nova wells (C-09, H-99, E-79 and M-29). The well checkshot data were edited to ensure that major seismic events (Petrel, Ben Nevis, A Marker, B Marker, Fortune Bay, and Jeanne d'Arc B Sand) tie the wells. A median validation technique was used to edit out noisy stacking velocity traces. These velocities were then corrected to the well checkshot velocity trend using a single global time varying correction followed by a 3D residual error correction defined by the well residual errors. An average velocity cube is generated from the corrected stacking velocities. Iso-velocity surfaces are generated from the average velocity cube. The edited checkshot data are then interpolated using these iso-velocity surfaces. The final 3D model ties the wells and also honors the trends in the seismic stacking velocities. The two older models were also updated to tie the newly incorporated wells. Proprietary Chevron tools were then used to generate a statistical P50 velocity model incorporating the five models to date. The weight given each model is based on the RMS residual error at the wells for each model respectively. The resulting model provides a

P50 estimate of the velocity and a variance (uncertainty) for each point in the model.

2.4.3.7 Shallow Hazards

This section includes a summary of the investigative work done for the delineation drilling program, the results seen in the field, and a discussion of the implications from the perspective of positioning the Gravity Base Structure (GBS) over the Hebron Field.

There were no significant operational problems encountered during the drilling of the Hebron delineation wells. Potential problems may be encountered during development drilling and will be addressed below and within the well design and contingency planning.

2.4.3.7.1 Surveys

A high-resolution wellsite geophysical survey was completed during the summer of 1998. The investigation was conducted by McGregor GeoScience Limited and Nortech Jacques Whitford Inc. The Hebron site survey covered a polygonal area approximately 25 km (southwest to northeast) by 17 km (northwest to southeast). Primary lines were oriented southwest to northeast with 250 m spacing. Perpendicular tie lines (northwest to southeast) were run with 500 m spacing. The coverage included magnetometer, echo-sounder, side-scan sonar, single-channel seismic, and multi-channel seismic.

A GBS and Pool 3 engineering, shallow drilling hazards, and seabed clearance geophysical survey was acquired in the summer of 2010 by Fugro Jacques GeoSurveys Inc. The survey covered a 1 km square area, centred on the GBS location. Primary line orientation - based on the geodetic grid - was 48.3156° to be consistent with the 1998 survey. Secondary (tie) lines were surveyed perpendicular to the primary lines. The Pool 3 survey covered a 7.6 km by 1.5 km area. "Analog" data acquisition comprised dual frequency ~100/500kHz side-scan sonar, multibeam echosounder, and Hunttec Boomer sub-bottom profiler. Magnetometer data were acquired to further investigate objects identified with side-scan sonar. At the GBS survey "analog" primary lines were spaced at 20 meters, with secondary (tie) lines spaced at 100 meters. The innermost 200m square area was surveyed on 10 meter x 50 meter spacing. At the Pool 3 survey "analog" primary lines were spaced at 100 meters, with secondary lines spaced at 250 meters. Multi-channel (96) 2D high-resolution (2DHR) seismic data were acquired using: 600m solid streamer towed at 2.5m (± 0.5 m) depth, 6.25m group interval, 4x40 in³ air gun array, 6.25m shot interval. The GBS 2DHR data were acquired over the entire 1km x 1km area (not including 2DHR run-in/run-out and migration aperture) centred on the planned centre point of the GBS, Line spacing for 2DHR is 40m x 100m. The Hebron Pool 3 2DHR seismic data were acquired over the entire 7.6km x 1.5 km area (not including 2DHR run-in/run-out and migration aperture) with line spacing 100 m x 250 m.

2.4.3.7.2 Geotechnical Data

The investigation was carried out at the proposed site for a production platform and three mooring piles. The site location is approximately 375 m northwest of the proposed Drill Centre 1 site investigated as part of the 2001 preliminary geotechnical investigation for Chevron.

The field program was carried out from 24 June to 9 July 2005, and consisted of a reconnaissance phase and a detailed investigation phase. The reconnaissance phase comprised nine boreholes up to 20 m depth with piezocone penetrometer testing (PCPT), five probes to 10 m depth, and a video camera survey. The detailed investigation phase consisted of ten deeper boreholes with sampling and PCPTs to depths from 25 m to 120 m and four boreholes with continuous PCPT only within the chosen GBS perimeter, as well as three surficial grab samples. In addition, two PCPT boreholes to depths of 10 m and one sampled borehole to depth of 10 m were put down at several locations to improve the data quality or quantity of the planned boreholes.

An additional supplementary geotechnical laboratory testing program was completed in 2009 on reconstituted samples of the Stratum I sands and on undisturbed samples of Stratum III clays (FJGI 2009a, b). The testing consisted of classification testing (moisture content, gradation, plasticity, and permeability), consolidation / compressibility tests, and strength testing (CAUC triaxial test, and static and cyclic direct simple shear tests).

2.4.3.7.3 Water Depth

The seabed is relatively flat over the Hebron Project Area. Water depth ranges from 86 m to 103 m Low Water Large Tide (LLWLT) across the GBS survey area and 94.9 m to 100.8 m at Pool 3 survey area. Water depth at the proposed GBS location is 92.5 m LLWLT. Some large scale but low relief (1 m or less) sand ridges are present. Average seafloor dip is 0.04 degrees towards the east-northeast, local increases in slope occur along sand wave margins (>2 degrees) and in association with iceberg pit and/or scour features. Figure 2.4-18 shows the survey locations and bathymetry. Figure 2.4-19 shows the 1998 multi-beam data.

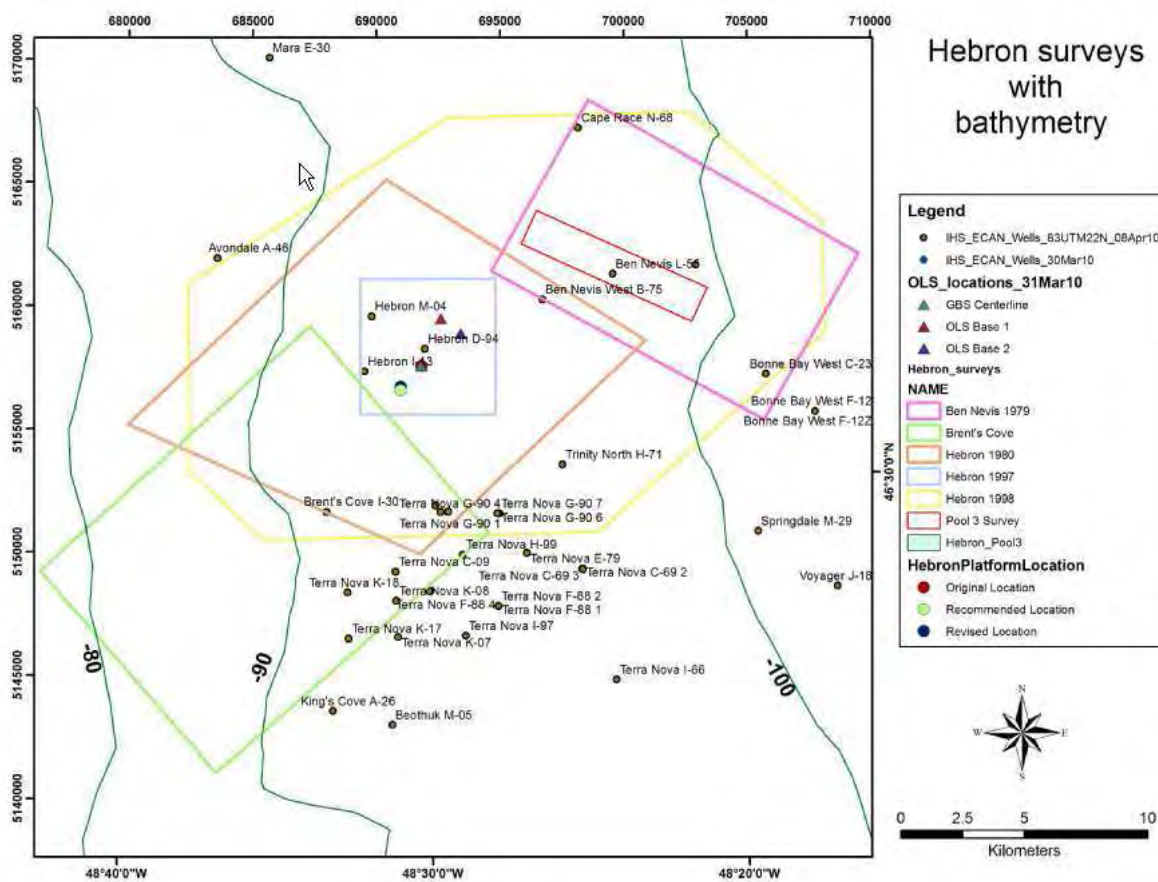


Figure 2.4-18: Hebron Project Area Survey Locations and Bathymetry

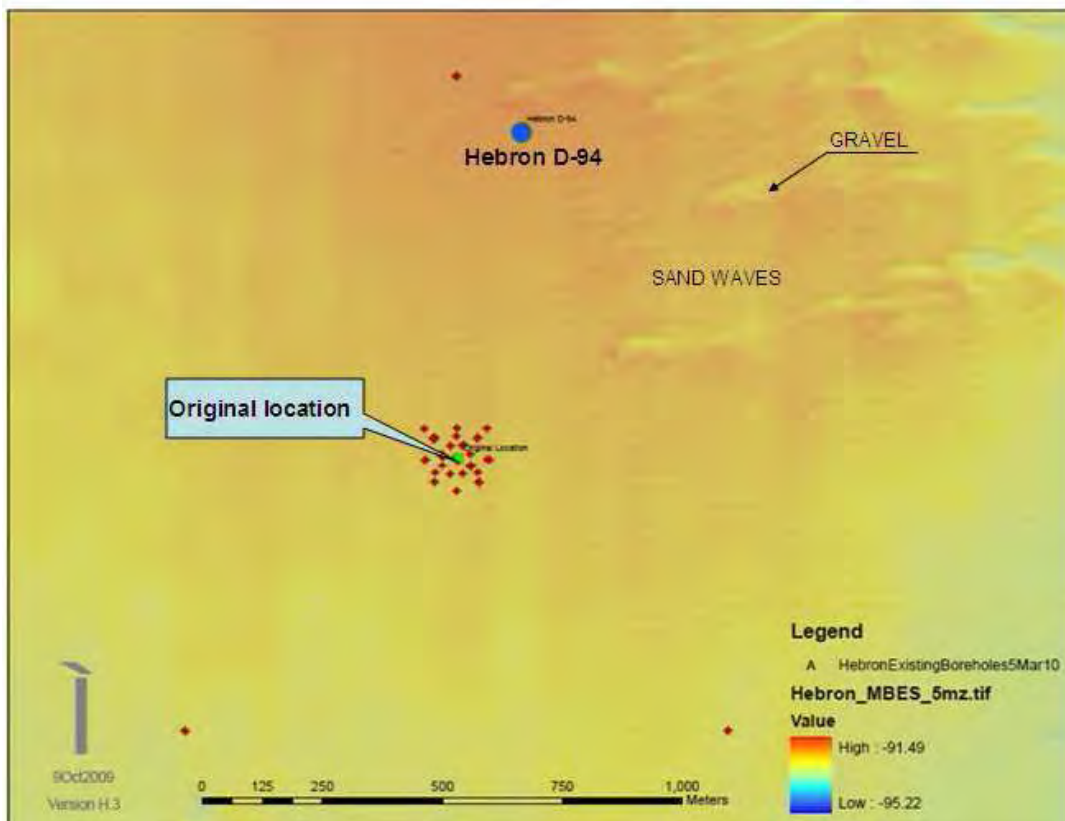


Figure 2.4-19: Multi-beam Data of Planned GBS Location (Original Location)

2.4.3.7.4 Seafloor Sediments

The seabed across the Hebron Project Area is comprised of both fine to medium sands and coarse cobbly gravels. The western half of the site is dominated by large sand ridges predominantly oriented north to south, with significant areas of gravel between. The seabed across the eastern half of the Hebron Project Area is predominantly comprised of gravel, with sand and cobbles.

- ◆ Elongate sand bodies are present, aligned in north to south bands. GBS location is situated in the middle of the north-northwest to south-southeast aligned sand ridge, within an area of featureless sand.
- ◆ Ripples are occasionally present in areas of sandy gravel. Boulders of 1 to 2 m diameter are occasionally present over the site.
- ◆ Ice scour features (< 0.5 m deep) are very common across the study area. Shallow, flat-bottomed “pock marks” are evident occasionally.
- ◆ Numerous wellheads are present within the Hebron Project survey area. These include Hebron I-13, M-04, D-94, North Trinity H-71, West Ben Nevis B-75, Ben Nevis I-45, and L-55. They will have to be considered in any future drilling and/or anchoring activities.

2.4.3.7.5 Sub-seafloor

Dense seafloor, sub-seafloor sediments and near-surface boulders potentially occurring mainly to depths <10m below sea floor may make the setting of rig anchors and future excavation of subsea drill centres difficult and potentially affect installation and alignment of structural casing, as well as drilling Rate of Penetration (ROP).

The area is free of shallow faulting to a depth of at least 1200 m.

A small-scale buried channel lies in the southeastern part of the Pool 3 site, at a depth of about 80 – 90 m BSF. There is potential for thin (<5 m) unconsolidated coarse-grained sediment fill in association with the channel feature, which may be a consideration for circulation and wellbore stability.

The presence of gas within Tertiary strata seems probable on the basis of seismic amplitude anomalies associated with phase-shift and peg-leg multiples.

A shallow seismic anomaly occurs adjacent to the southern boundary of the Hebron – Ben Nevis survey area. The anomaly is marked by signal disruption from the seafloor to the primary seafloor multiple at about 100 m depth below sea floor (Figure 2.4-20). The lateral extent of the anomaly is mapped and presented in Figure 2.4-21 as the depth from the seafloor to the top of the anomaly. The phenomena observed leads to the supposition that the shallow anomaly is caused by a gas migration from the deeper anomaly. The fact that multiple wells beyond the three exploration wells have been drilled through these anomalies without hazard or effect suggests that interstitial gas, if present, is of low concentration and / or at hydrostatic pressure, such that it does not represent an over-pressured hazard.

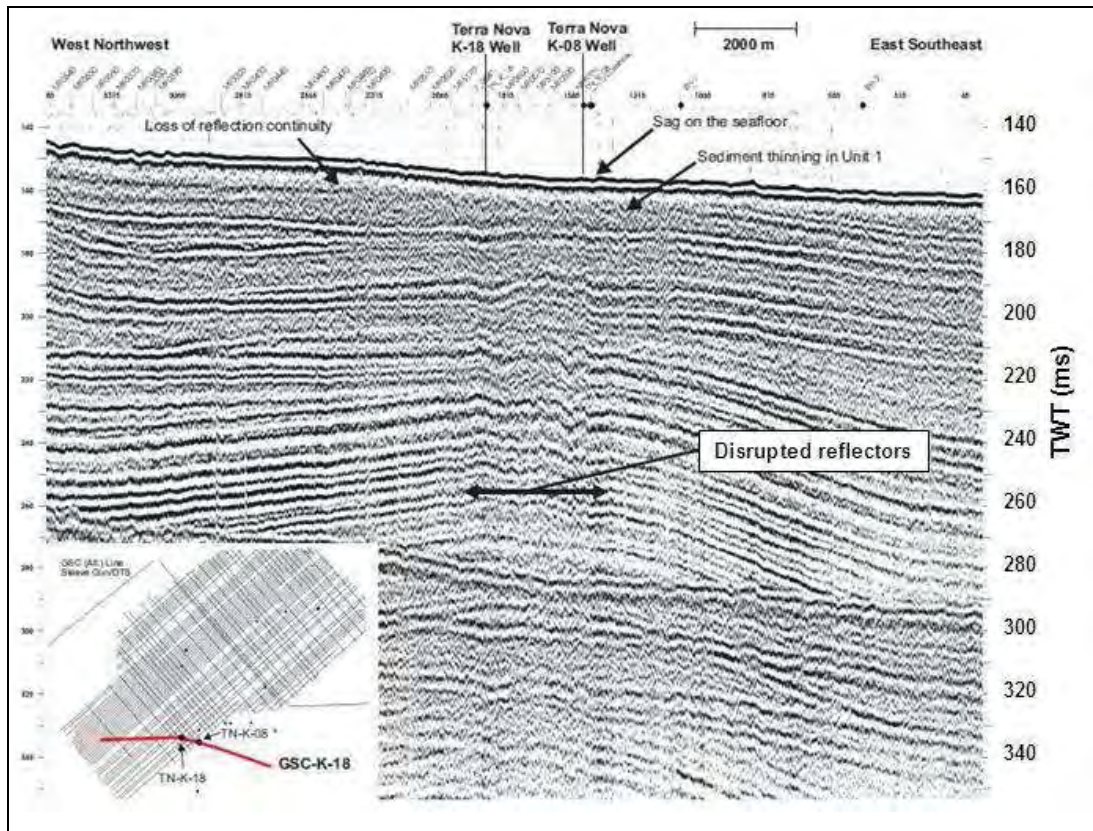


Figure 2.4-20: Airgun Profile (10 Cu. In.) through Terra Nova K-18 Anomaly

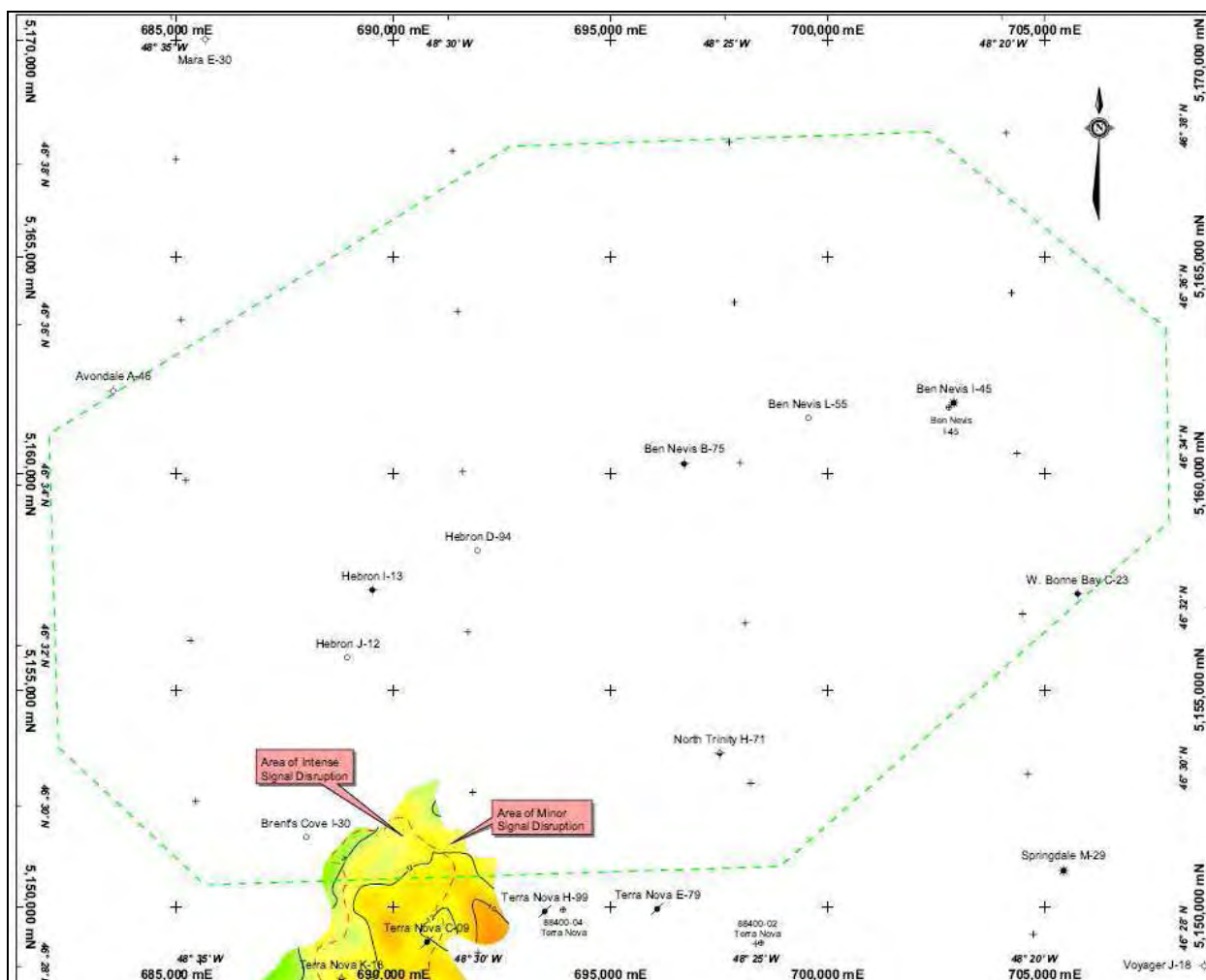


Figure 2.4-21: Lateral Extent of the Anomaly

Areas of elevated reflection amplitude occur along a reflection (H3) whose depth varies from about 780 m to 830 m (subsea). These elevated amplitudes are considered to indicate lithological changes in the Banquereau Formation, and are likely not significant quantities of gas (Figure 2.4-22 and Figure 2.4-23). The subsequent drilling of the D-94 and M-04 delineation wells did not reveal any physical evidence that the reflector was in fact shallow gas. Although there was no gas observed in the drilling of the conductor and surface hole of the M-04, D-94, and I-13 wells, the centre of the feature has not been penetrated.

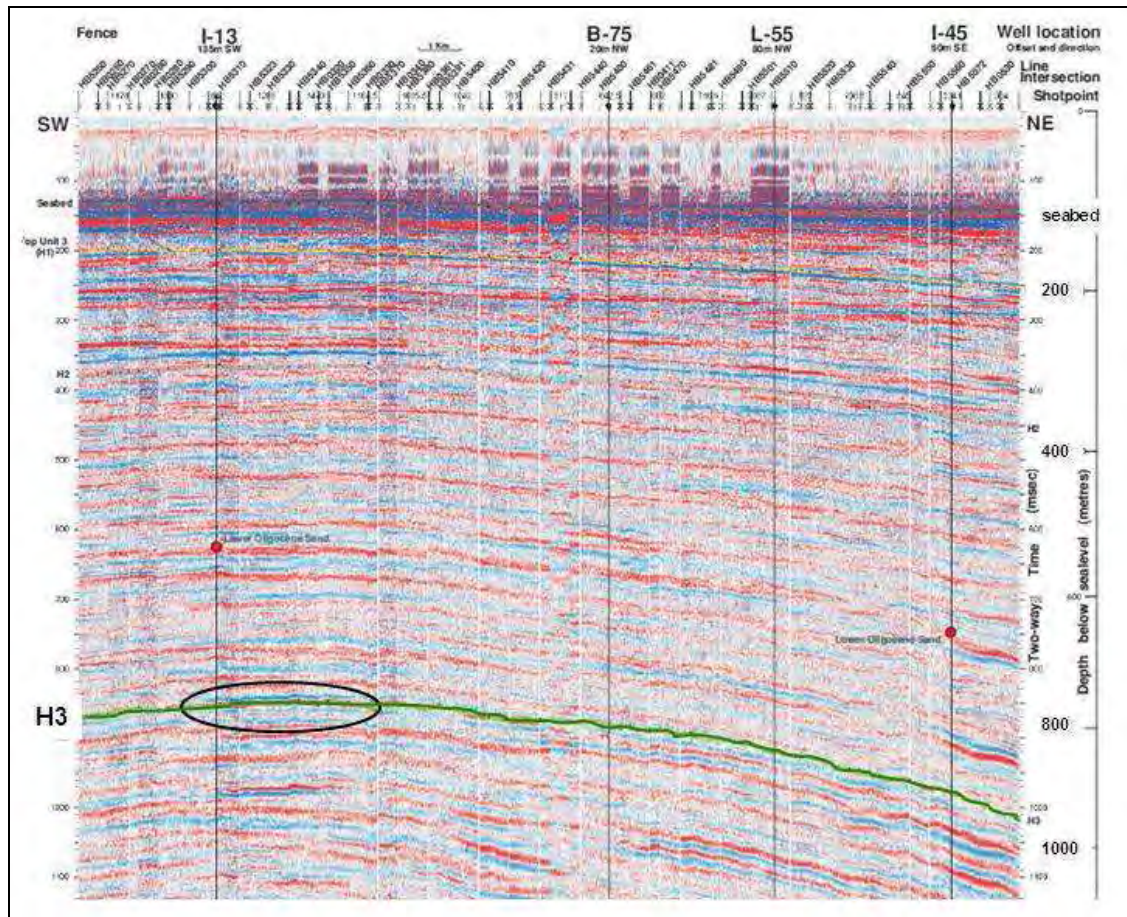


Figure 2.4-22: Seismic SW-NE traverse through the Hebron I-13, West Ben Nevis B-75, Ben Nevis L-55 and Ben Nevis I-45 wells

Figure illustrates shallow amplitude anomaly at approximately 850 ms at H3 horizon. Line of section is shown in Figure 2.4-23.

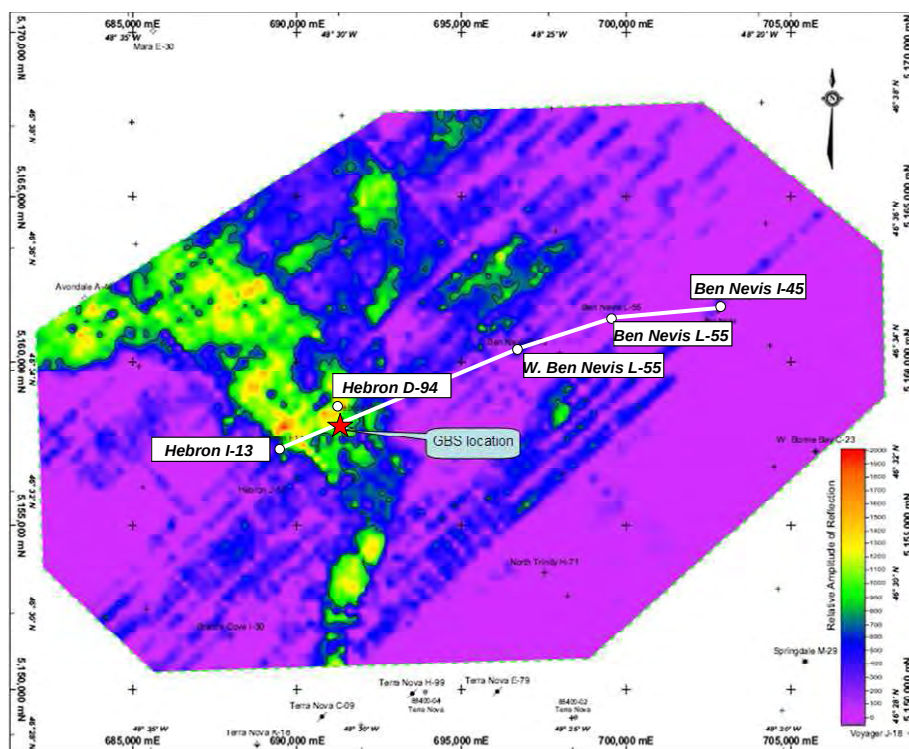


Figure 2.4-23: Relative Amplitude on H3 Horizon
This figure illustrates line of section shown in Figure 2.4-22

Anomalous amplitudes associated with Horizon H3 occur northeast of the Hebron I-13 well. Surface casing at I-13 was set at 896 m measured depth from the rig kelly bushing (MDRKB). H3 reflector is located 780 m TVD meters below sea level. No problems with shallow gas were documented.

Other anomalous amplitudes are associated with a reflector which, on the basis of data from the Hebron I-13 well, appears to lie within the Oligocene, but is younger than the Lower Oligocene Sand (i.e., 510 to 580 m below sea floor). The limit of the anomaly is defined by its mapped reflection amplitude shown in Figure 2.4-24. Figure 2.4-25 is a cross-section view of the seismic amplitude attributes of the anomaly. Characteristics of this reflector may be taken as indicators of gas charging, but most likely indicate the lithology changes.

There are no apparent shallow hazards to drilling at the proposed Hebron GBS location and Pool 3 survey area. Interpretation of sub-bottom profiler and 2DHR seismic data indicates that there are no amplitude anomalies indicative of shallow gas at the GBS location and Pool 3 within the shallow section. Normal to near-normal pore pressures are anticipated.

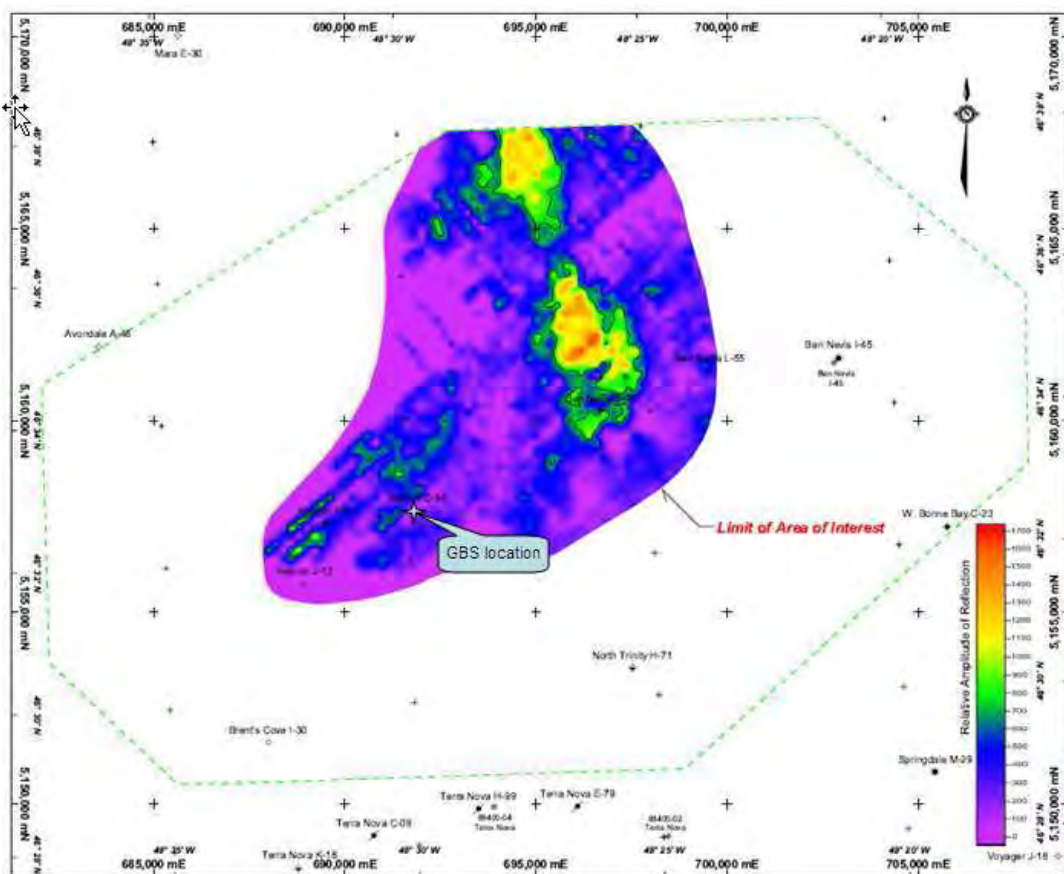


Figure 2.4-24: Relative Amplitude on Horizon within Oligocene

Depth range of elevated amplitudes within Oligocene is 510 to 580 m. Higher amplitudes are shown in red and yellow while lower amplitudes are shown in blue and purple.

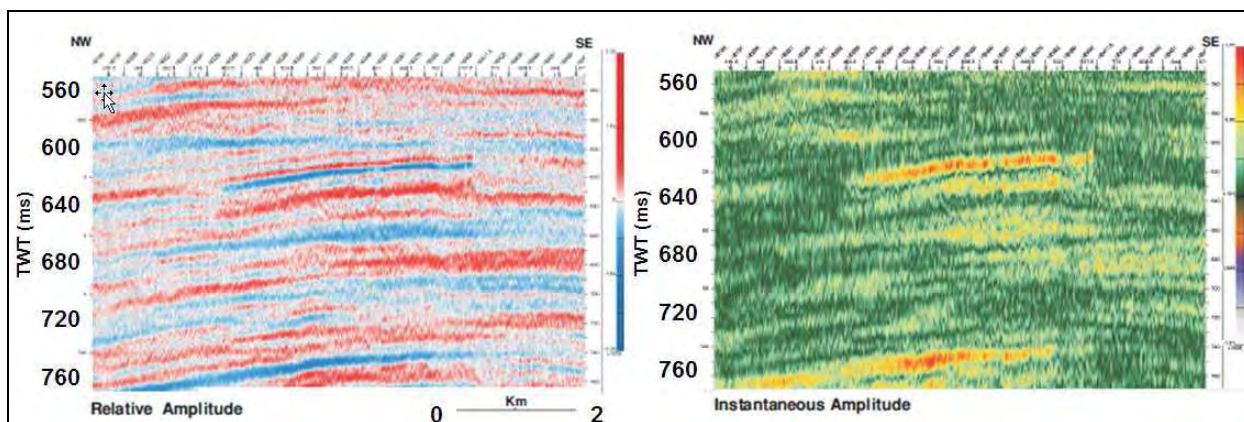


Figure 2.4-25: Seismic Attributes of the Anomaly within Oligocene

2.4.3.7.6 Future work

Results from engineering, shallow hazards, and seabed clearance geophysical surveys along the flow line corridor between the Hebron GBS location and the locations of two offshore loading systems (OLS) that was acquired in the summer of 2010 by Fugro Jacques GeoSurveys Inc will be incorporated when the work has been completed. The survey covered an area roughly 2.0 km x 2.5 km. Data acquisition comprised side-scan sonar, multibeam echosounder, and Hunttec Boomer sub-bottom profiler. Magnetometer data were acquired to further investigate objects identified with side-scan sonar. Primary lines were spaced at 75 meters, with secondary (tie) lines spaced at 500 meters.

Seabed grab samples and drop camera/video data were acquired at 250m spacing along flow line routes centre-line to provide 'ground truth' information for the geophysical interpretation and to develop friction coefficients for pipeline installation.

2.5 Geologic Models

The deterministic estimation of oil in place for the Hebron Asset was completed using 3-D geologic models that were built in the Petrel software package (Pools 1 & 2 and Pool 3) and in GoCad (Pools 4, and 5). The GoCad models were subsequently imported into Petrel in 2008. Separate geologic models were built for Pools 1 and 2 (in one model), Pool 3, Pool 5, Pool 4 H Sand, and Pool 4 B Sand. This procedure involved incorporating seismic interpretation (horizons and faults) into the structural framework of a geologic model. The structural framework is then populated with petrophysical characteristics and facies distributions.

2.5.1 Hebron Field Ben Nevis Reservoir: Pool 1 & 2 Geologic Model

The Ben Nevis Formation is the reservoir for Pool 1 & 2. This model was built to calculate in place volumes, and to simulate production from various depletion concepts. A geologic model was created of Pool 1 that contains the Southwest Graben, I-13 fault block, D-94 fault block, and West Ben Nevis fault block. The geologic model is bound vertically by the Top Ben Nevis surface and the A marker. The structural framework is composed of three seismic derived surfaces, the Top Ben Nevis, Base Ben Nevis and the A Marker. These surfaces were interpreted on the reprocessed Hebron 3-D seismic data. The Pool 1 & 2 geologic model has about 2.2 million cells that are on average 100 x 100 x 1 meters in size. Proportional layering was used on the 127 layers in the model. The OWC used in the model was 1900 m TVDSS for Pool 1 and 2000 m TVDSS for Pool 2.

The modeling workflow for distributing rock properties in Pool 1 & 2 utilizes scaling up rock properties from high-resolution brick models into coarse full field cells. This modeling strategy follows a standardized workflow developed

at ExxonMobil. Five rock types were defined by depositional environment obtained from core description and log character. Environment of deposition maps were created for each zone that tied to the wells. Porosity depth trend was defined for each rock type, and populated with ties to wells through Gaussian random function simulation. Model permeability for each rock type ties to the wells using routine core analysis data where available and porosity-permeability transform in uncored intervals. Water saturation was defined through a porosity based lambda function. The geologic model ties to the wells and there is good agreement with the D-94 DST. Figures 2.5-1, 2.5-2, 2.5-3 and 2.5-4 are maps showing outputs from the Pool 1 & 2 geologic model.

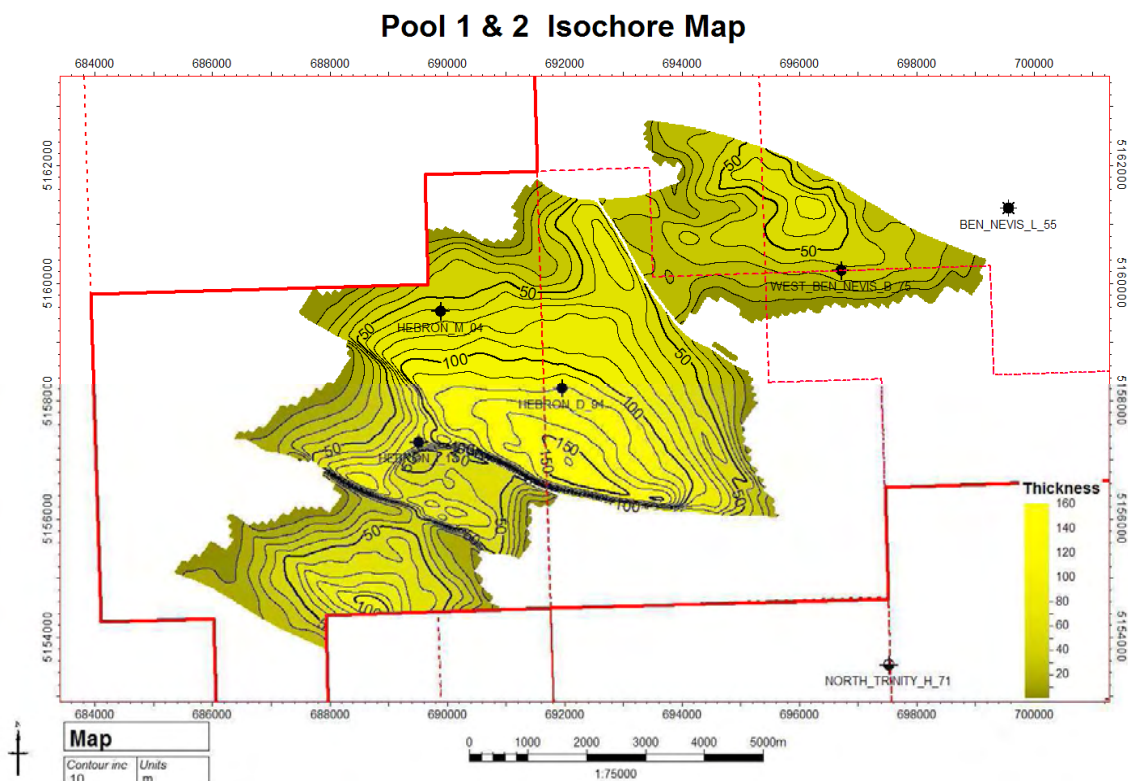


Figure 2.5-1: Pool 1 & 2 Isochore Map

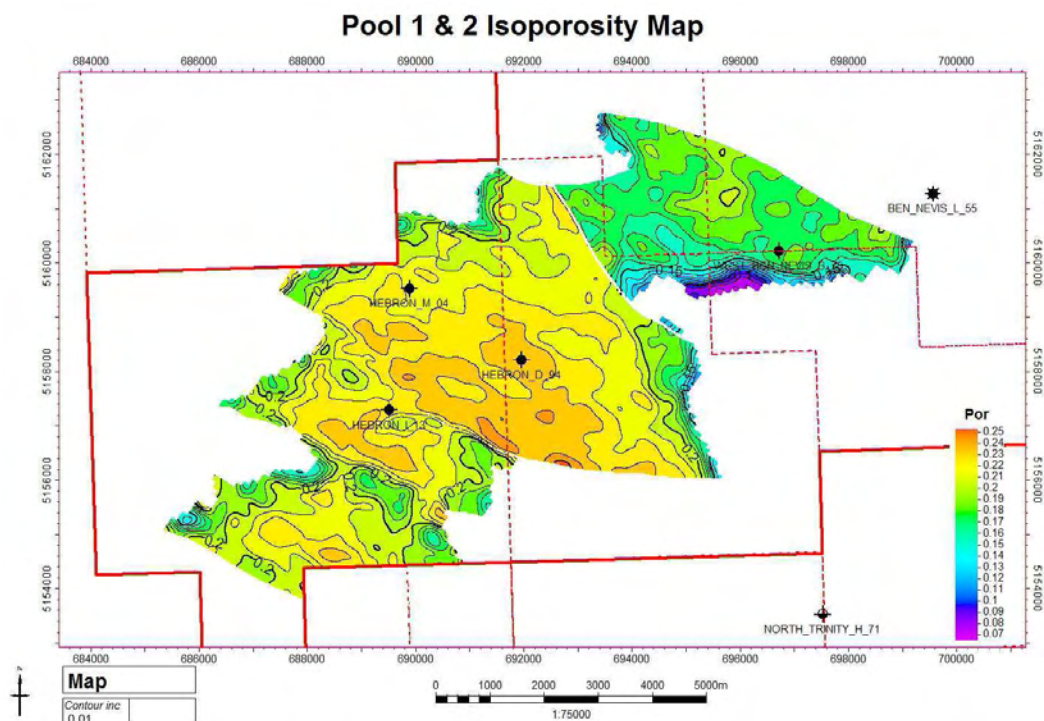


Figure 2.5-2: Pool 1 & 2 Isoporosity Map

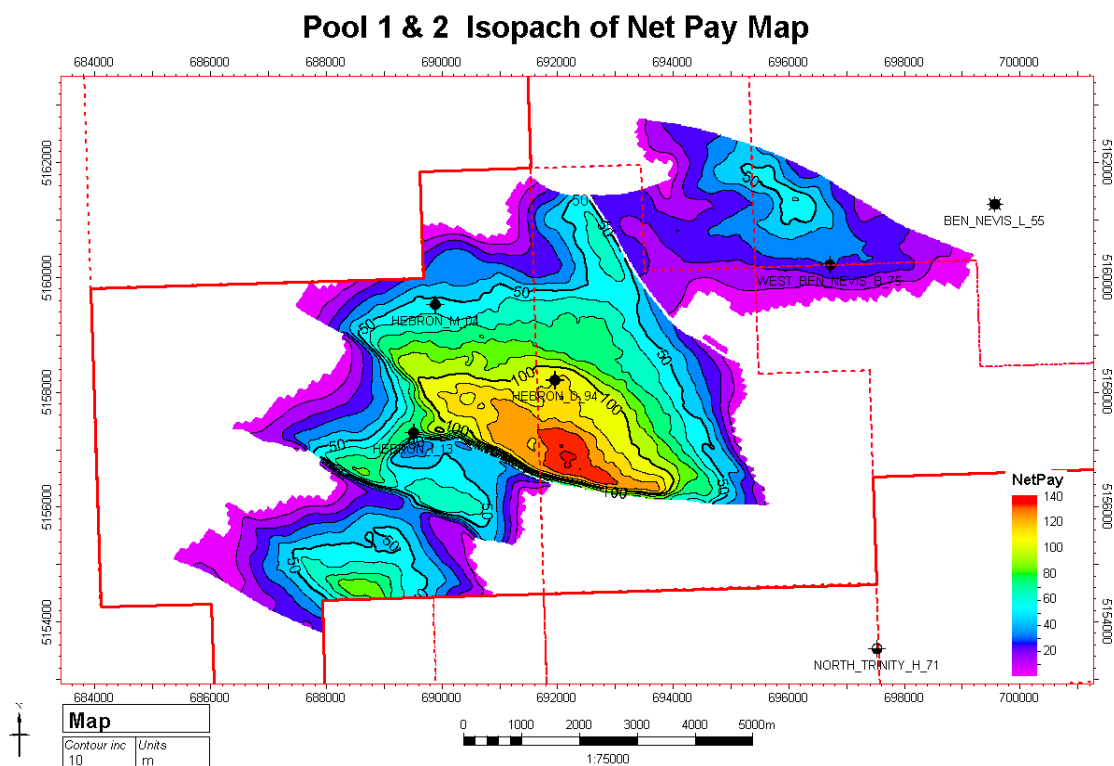


Figure 2.5-3: Pool 1 & 2 Isopach of Net Pay Map

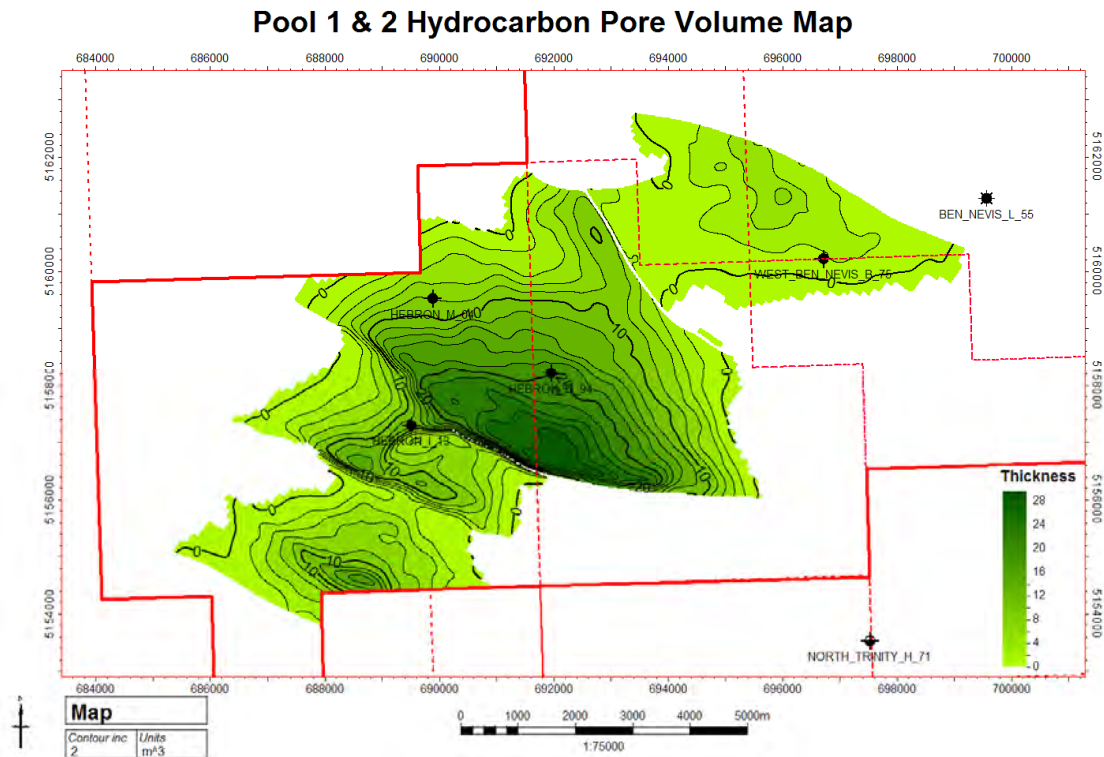


Figure 2.5-4: Pool 1 & 2 Hydrocarbon Pore Volume Map

2.5.2 Hebron Field Upper Hibernia Reservoir: Pool 5 Geologic Model

The upper Hibernia Formation is the reservoir for Pool 5. A geologic model was built for Pool 5. This model was built to calculate in place volumes, and to simulate production from various depletion concepts. The geologic model was built in GOCAD and later it was converted to Petrel. The Pool 5 geologic model has 5.45 million cells that are 100 x 100 x 1 meters in size. The geologic models that composed the 220 layers are on average 1 m thick. The water contact used in the model is 2972 m TVDSS.

The Hibernia GOCAD model was constructed from the Top and Base Hibernia seismic time horizons. Both seismic time horizons were interpreted on the original processed Hebron 3D seismic volume. The Top Hibernia horizon was converted to depth and tied to the Top Hibernia pick in the wells, I-13, M-04, B-75, H-71, I-30. The other nine surfaces were created by shifting the Top Hibernia surface to the corresponding picks in the wells.

Seven facies were defined by effective porosity and permeability ($FZI = (PHIE/KAH)^{1/2}$). GOCAD multiple point statistics and facies distribution modeling (MPS/FDM) was utilized along with training images and deposition maps to distribute the facies within the model. Effective porosity was distributed by facies using variograms and histogram per facies as inputs to a sequential Gaussian simulation (SGS). Permeability was distributed using porosity maps, variograms, and histograms per facies as inputs to SGS. There is good agreement of the geologic model to the DST. Figures 2.5-5, 2.5-6, 2.5-7 and 2.5-8 are maps showing outputs from the Pool 5 geologic model.

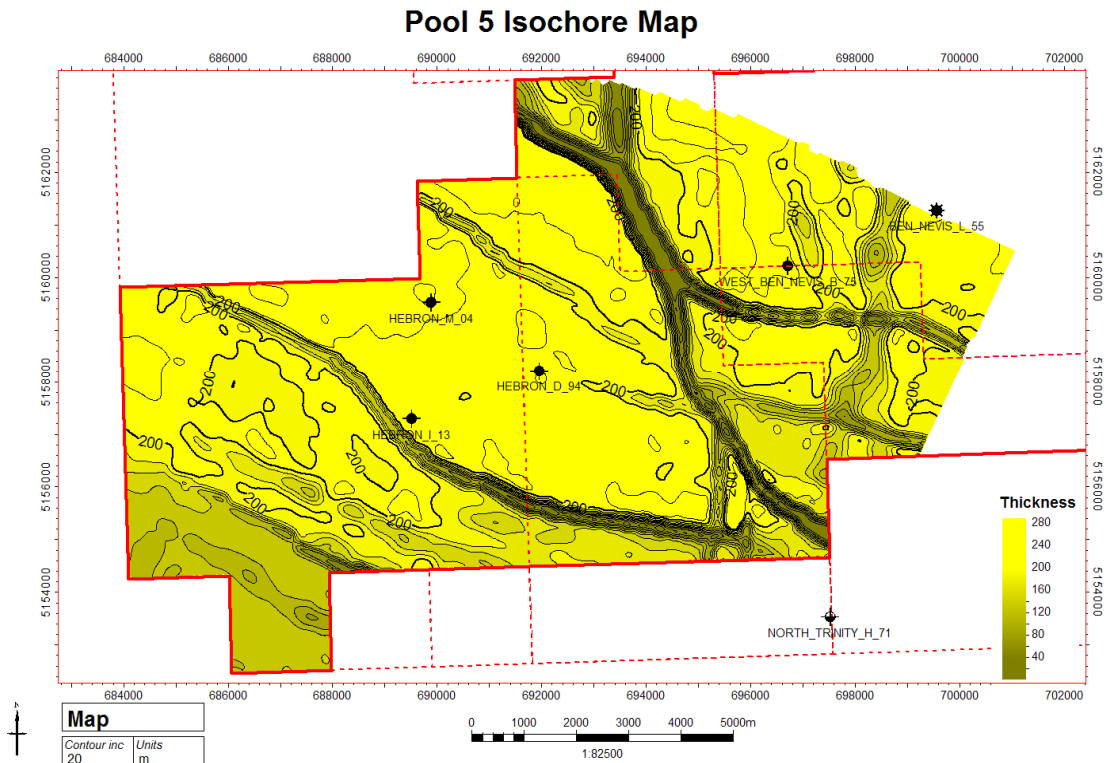


Figure 2.5-5: Pool 5 Isochore Map

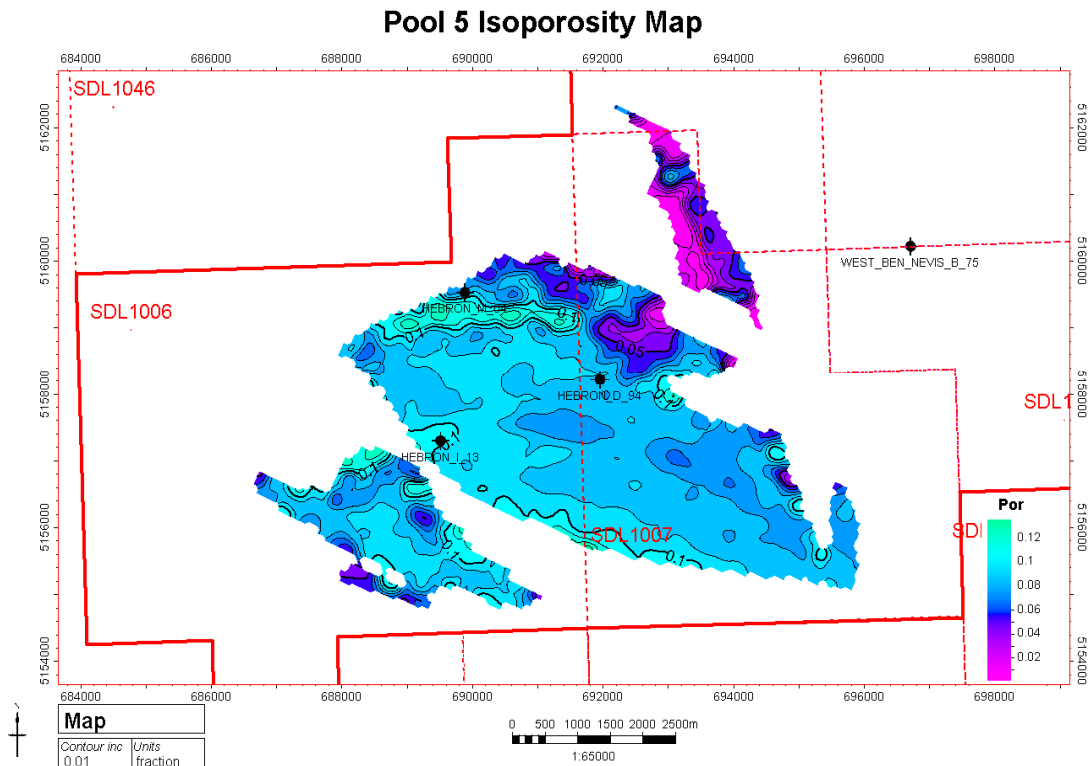


Figure 2.5-6: Pool 5 Isoporosity Map

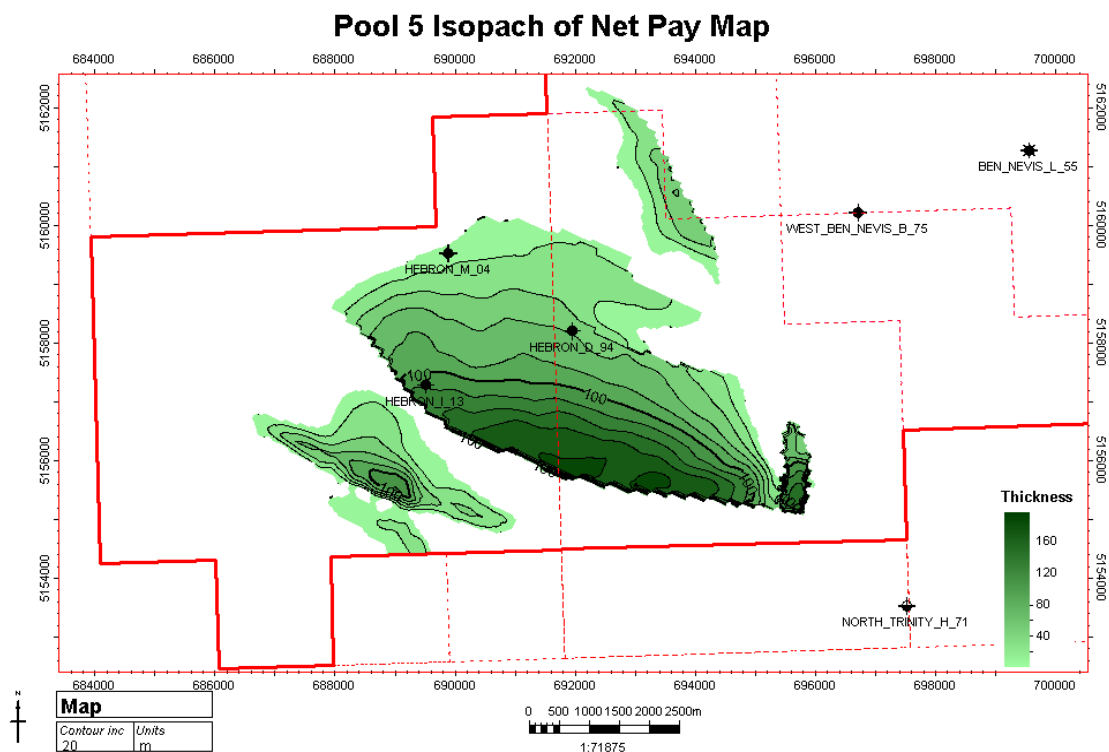


Figure 2.5-7: Pool 5 Isopach of Net Pay Map

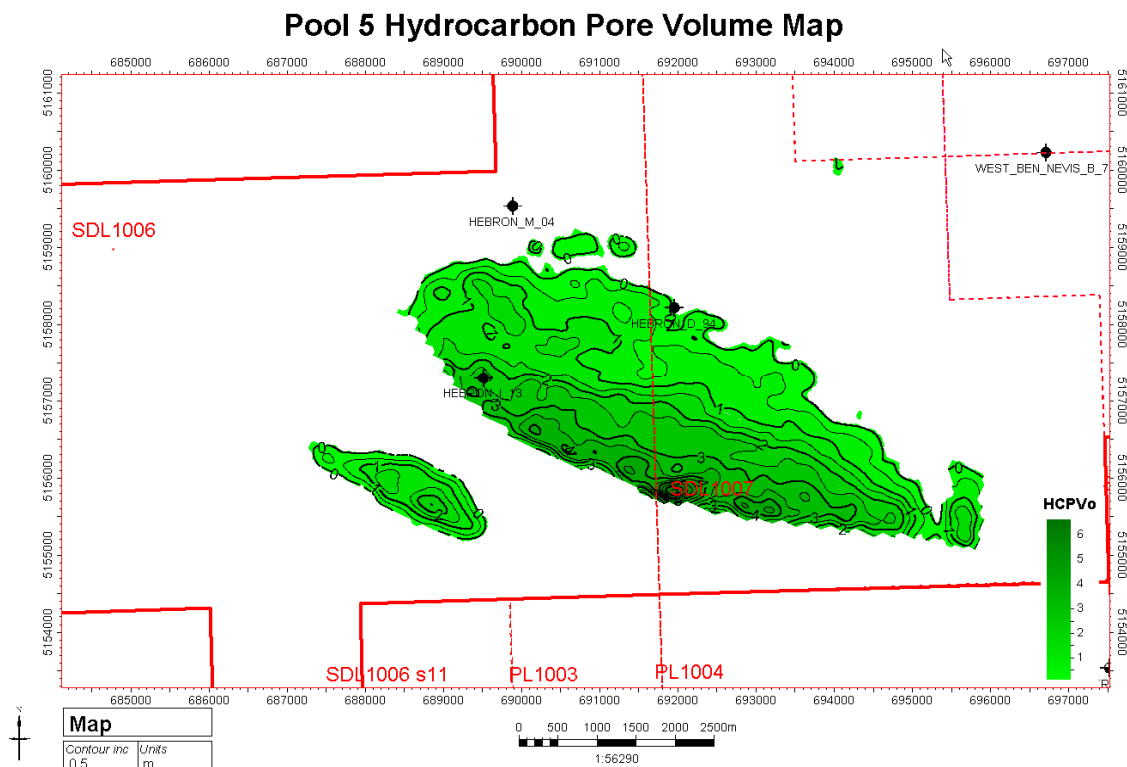


Figure 2.5-8: Pool 5 Hydrocarbon Pore Volume Map

2.5.3 Hebron Field JDA Reservoir: Pool 4 Geologic Model

The Jeanne d'Arc Formation is the reservoir for Pool 4. Pool 4 is composed of two primary oil-bearing stratigraphic units, the H and B Sands, and two minor oil-bearing sands, the D and the G sands. The geologic models of the H and B Sands were built separately in GOCAD but are in the same Petrel project. The D and the G sands are not modeled. The geologic models were built to calculate in place volumes and to simulate development concepts. The H Sand geologic model has approximately 2.5 million cells. There are 93 layers on cell thickness of approximately 1 m thick. The B Sand geologic model has approximately 1 million cells. There are 38 layers in the model, and the cells are approximately 1 m thick.

2.5.3.1 H Sand Geologic Model

The top of the H Sand GOCAD grid was created from a horizon interpreted on the original processed Hebron 3D seismic data. It is converted to depth and shifted to tie to the top H Sand in M-04. The base of the H Sand GOCAD grid was defined using a seismic attribute surface that approximated the overall shape and extent of the incised valley, shifted and flexed to match the base H Sand in M-04. The OWC used in the model is 3909 m TVDSS.

Six facies were defined by effective porosity and permeability ($FZI = (PHIE/KAH)^{1/2}$). GOCAD multiple point statistics and facies distribution modeling (MPS/FDM) was utilized along with training images and deposition maps to distribute the facies within the model. Effective porosity was distributed by facies using variograms and histogram per facies as inputs to SGS. Permeability was distributed using porosity maps, variograms, and histograms per facies as inputs to SGS with cloud transform. Figures 2.5-9, 2.5-10, 2.5-11 and 2.5-12 are maps showing outputs of the Pool 4 H Sand geologic model.

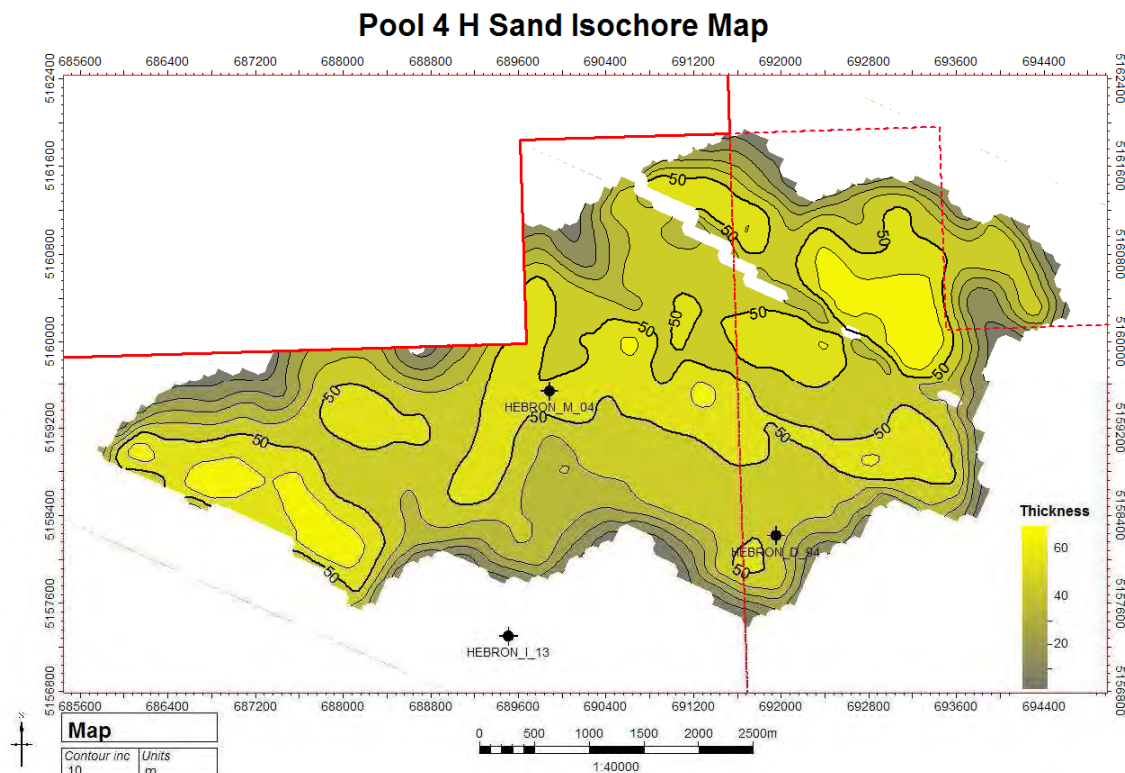


Figure 2.5-9: Pool 4 H-Sand Isochore Map

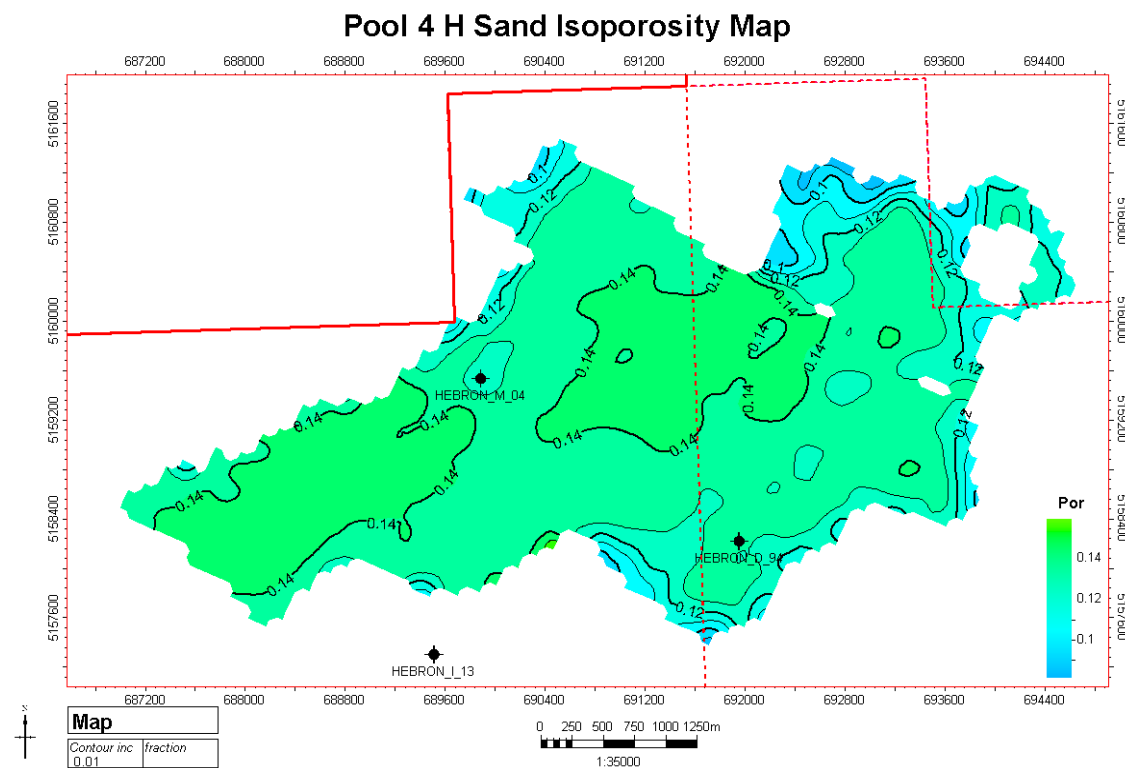


Figure 2.5-10: Pool 4 H-Sand Isoporosity Map

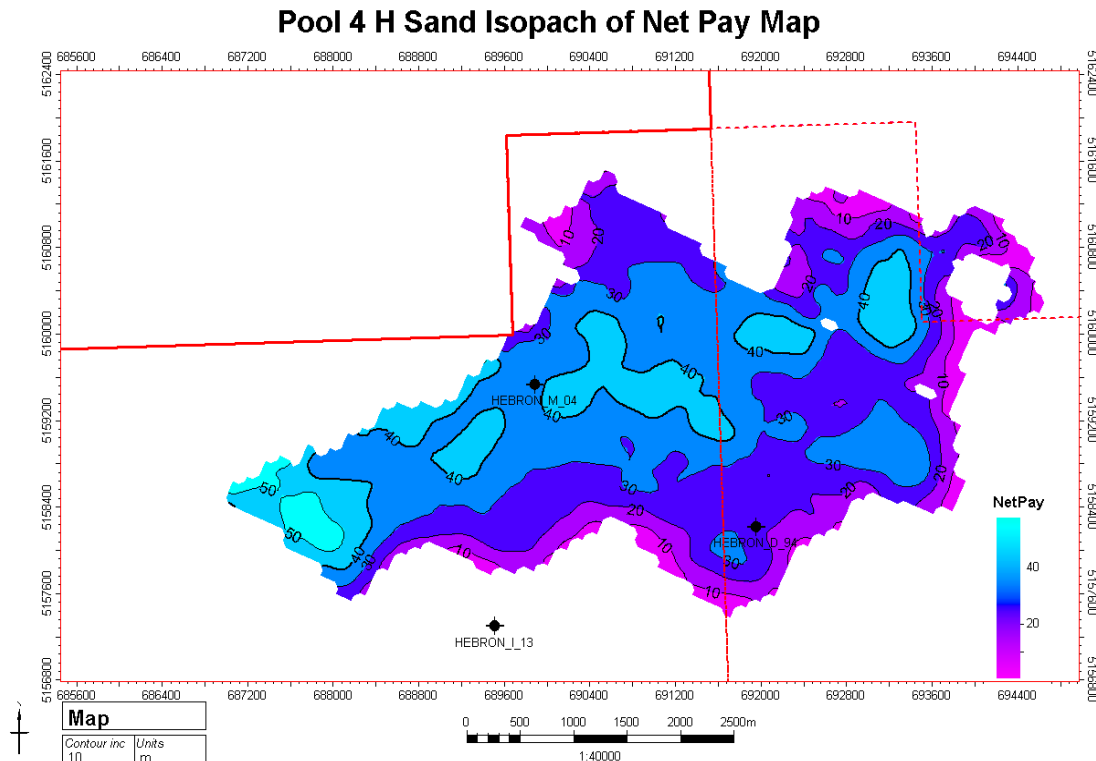


Figure 2.5-11: Pool 4 H-Sand Isopach of Net Pay Map

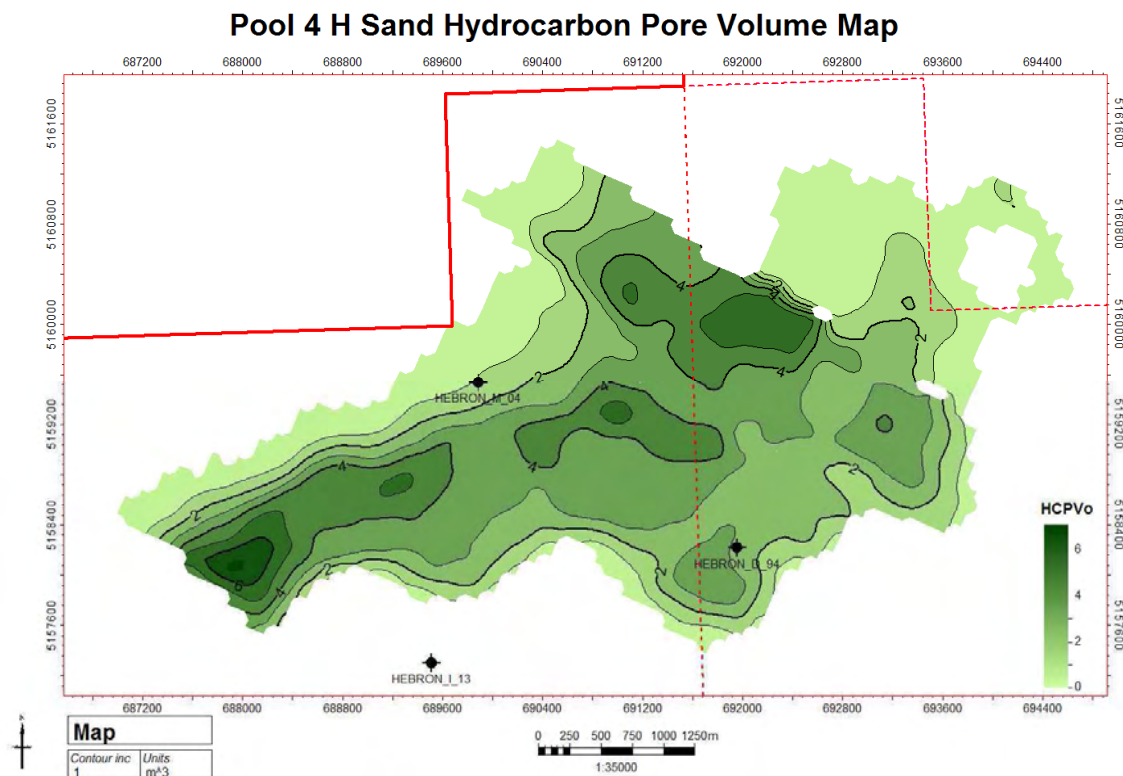


Figure 2.5-12: Pool 4 H-Sand Hydrocarbon Pore Volume Map

2.5.3.2 B Sand Geologic Model

The B Sand GOCAD model was constructed from the Top B Sand horizon interpreted on the original processed Hebron 3D seismic data corresponding to the top B Sand. The seismic horizon was converted to depth, and tied to the top B Sand in M-04, I-13, B-75, H-71, and I-30. The base of the B Sand GOCAD grid was defined by shifting the top surface to tie to the base B Sand in M-04, I-13, B-75, H-71, and I-30. The OWC used in the model was 4508 m TVDSS, which corresponds to the low known oil in the M-04 well.

Based on sand presence in the I-13, M-04, B-75, H-71, and I-30 wells non-net and net was identified and used instead of facies. To distribute porosity, a SGS was calculated using a seismic extraction of the single cycle reservoir correlated to porosity and variograms for lateral variability and well logs for vertical variability. To distribute permeability, a SGS with cloud transform is used to relate porosity to permeability with data from I-13, M-04, B-75, H-75, and I-30 wells. Figures 2.5-13, 2.5-14, 2.5-15 and 2.5-16 are maps showing the outputs from Pool 4 B sand geologic model.

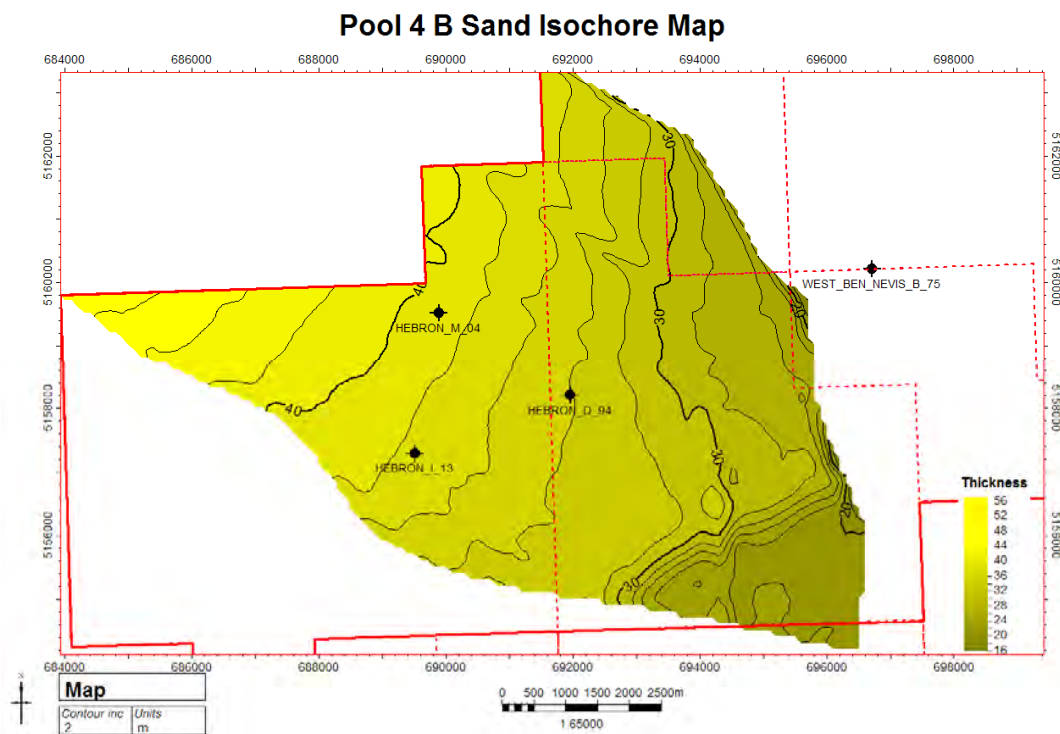


Figure 2.5-13: Pool 4 B Sand Isochore Map

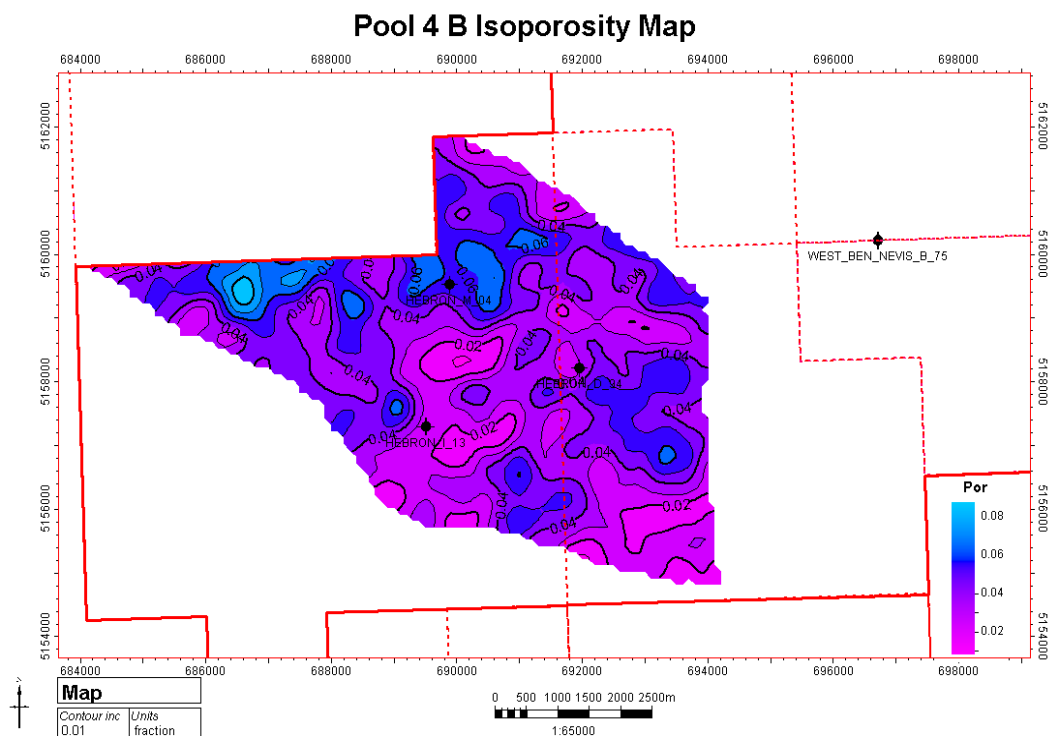


Figure 2.5-14: Pool 4 B Sand Isoporosity Map

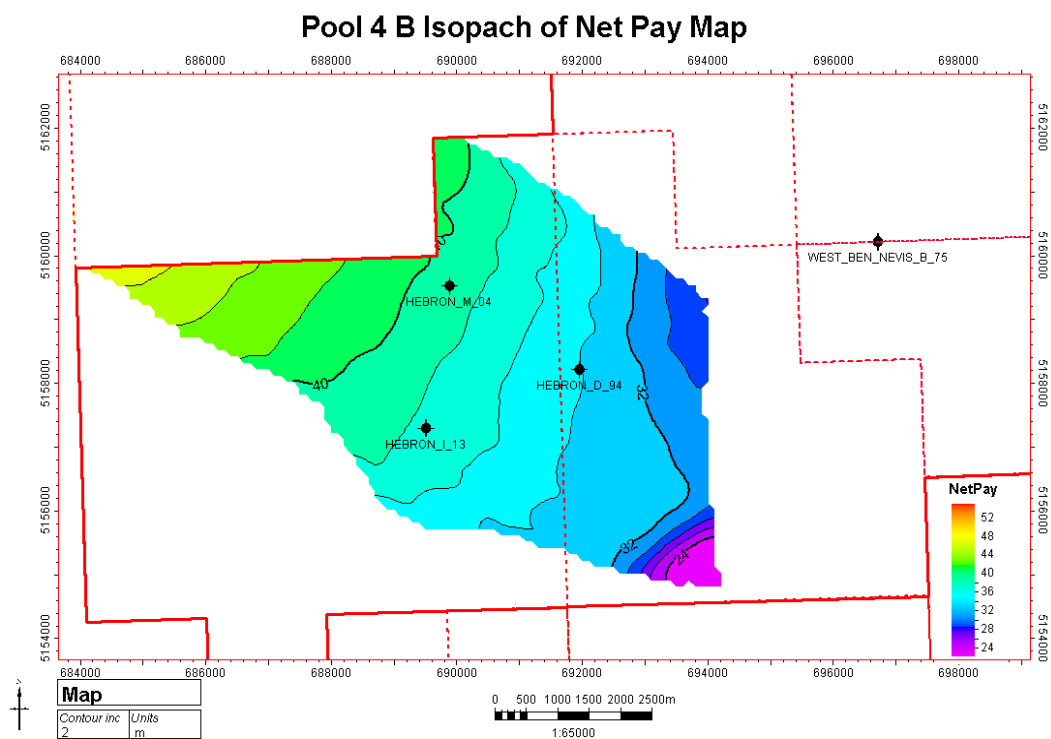


Figure 2.5-15: Pool 4 B Sand Isopach of Net Pay Map

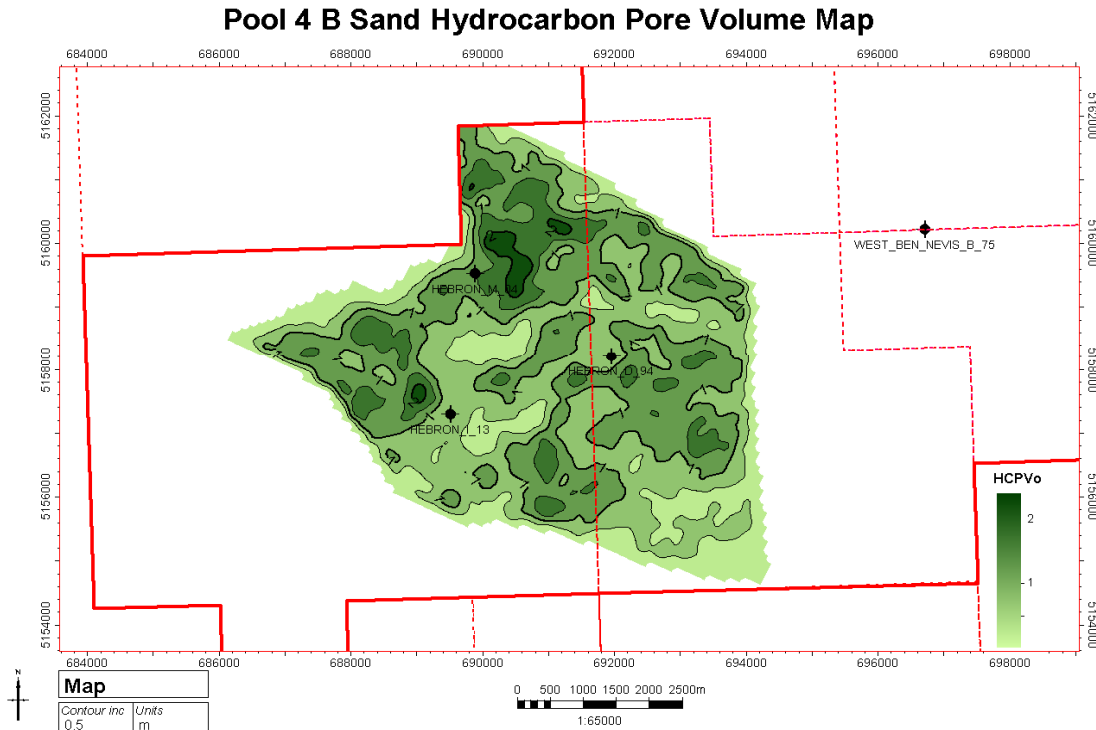


Figure 2.5-16: Pool 4 B Sand Hydrocarbon Pore Volume Map

2.5.4 Ben Nevis Field Ben Nevis Reservoir: Pool 3 Geologic Model

The Pool 3 model includes the Ben Nevis Formation in the main I-45/L-55 fault block as well as the next fault block to the NE. In addition, the model also includes part of the Avalon stratigraphy in the B-75 fault block, which is interpreted to be in fault juxtaposition with the Ben Nevis from the I-45/L-55 fault block. This model was built to calculate in place volumes, and to simulate production from various depletion concepts.

The geologic model is bound vertically by the Top Ben Nevis (Ap3X_fs60) surface and by the Ap2X_fs30 surface at the base. The model does not include the entire Ben Nevis thickness as much of the formation is in the water leg. The Avalon is bounded by seismically interpreted top and base Avalon surfaces. These surfaces were interpreted on the reprocessed Hebron 3-D seismic data. The Pool 3 geologic model has about 2.2 million active cells that are on average 100 x 100 x 1 meters in size. Proportional layering was used on the 274 layers in the Ben Nevis interval and 90 layers in the Avalon interval. The OWC used in the model was 2432m TVDSS, GOC used was 2311m TVDSS.

The modeling workflow for distributing rock properties in Pool 3 utilizes scaling up rock properties from high-resolution brick models into coarse full field cells. This modeling strategy follows a standardized workflow developed at ExxonMobil. Three rock types were defined by depositional environment obtained from core description and log character. Environment of deposition

maps were created for each zone that tied to the wells. A porosity depth trend was not used for the Pool 3 model because of the relatively limited vertical extent. Porosity was populated with ties to wells through Gaussian random function simulation. Model permeability for each rock type ties to the wells using routine core analysis data where available and porosity-permeability transform in uncored intervals. Water saturation was defined through a porosity based function relating height above free water level and bulk volume water. The geologic model ties to the wells and there is good agreement with the I-45 DST. Figures 2.5-17, 2.5-18, 2.5-19 and 2.5-20 are maps showing outputs from the Pool 3 geologic model.

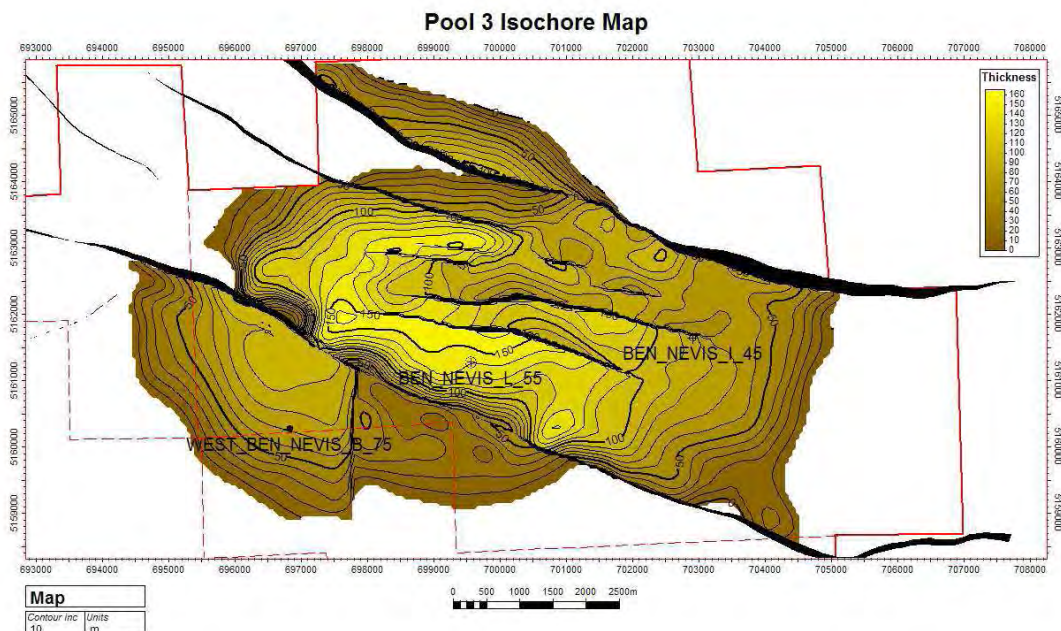


Figure 2.5-17: Pool 3 Isochore Map

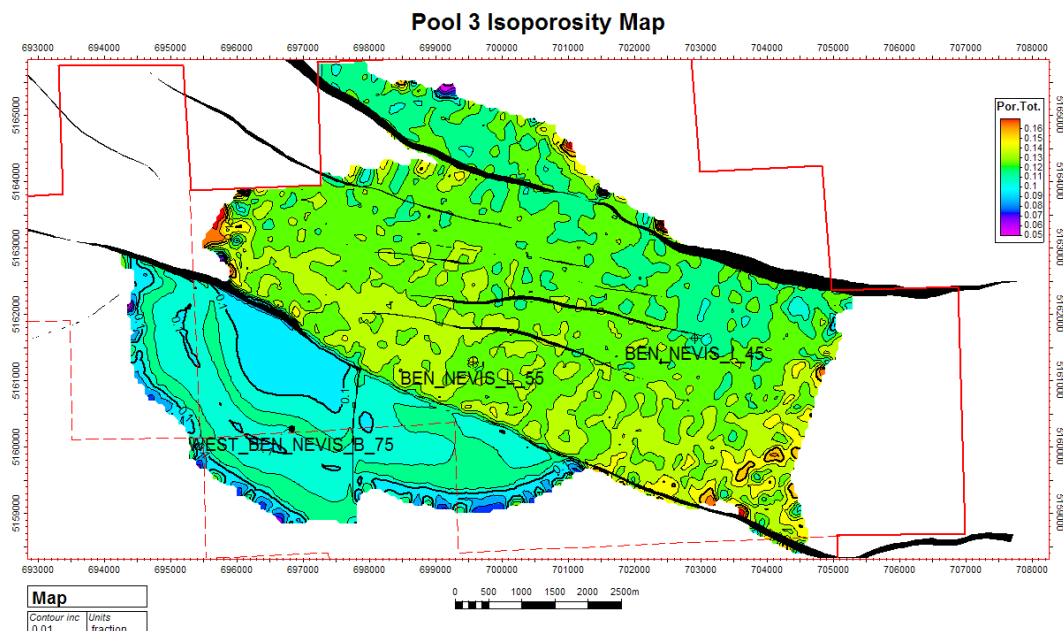


Figure 2.5-18: Pool 3 Isoporosity Map

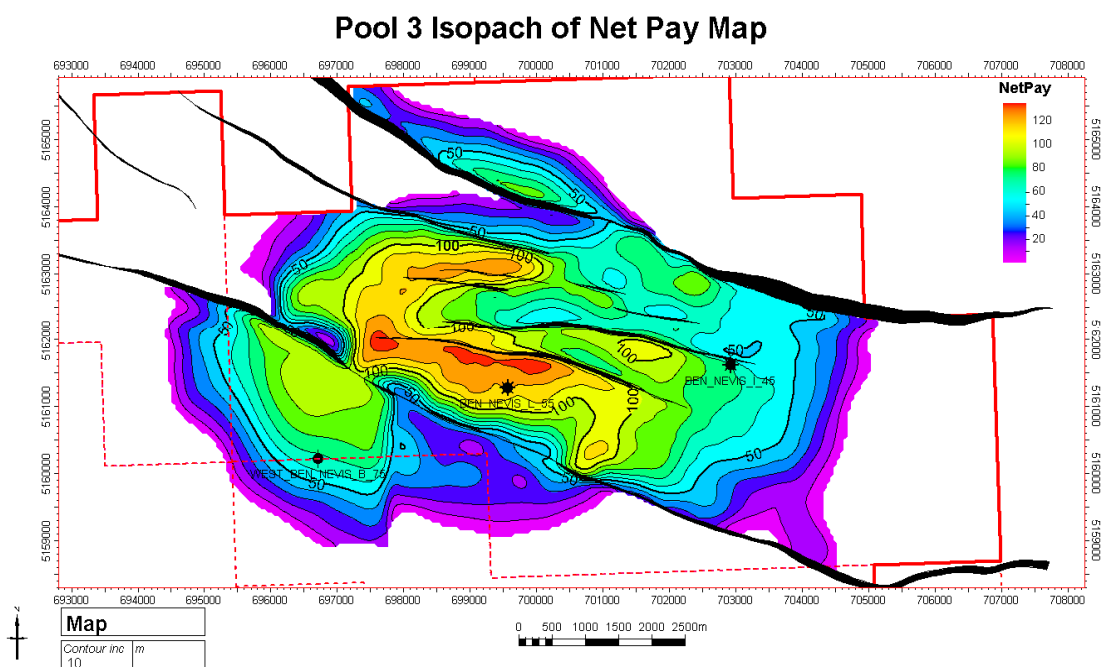


Figure 2.5-19: Pool 3 Isopach of Net Pay Map

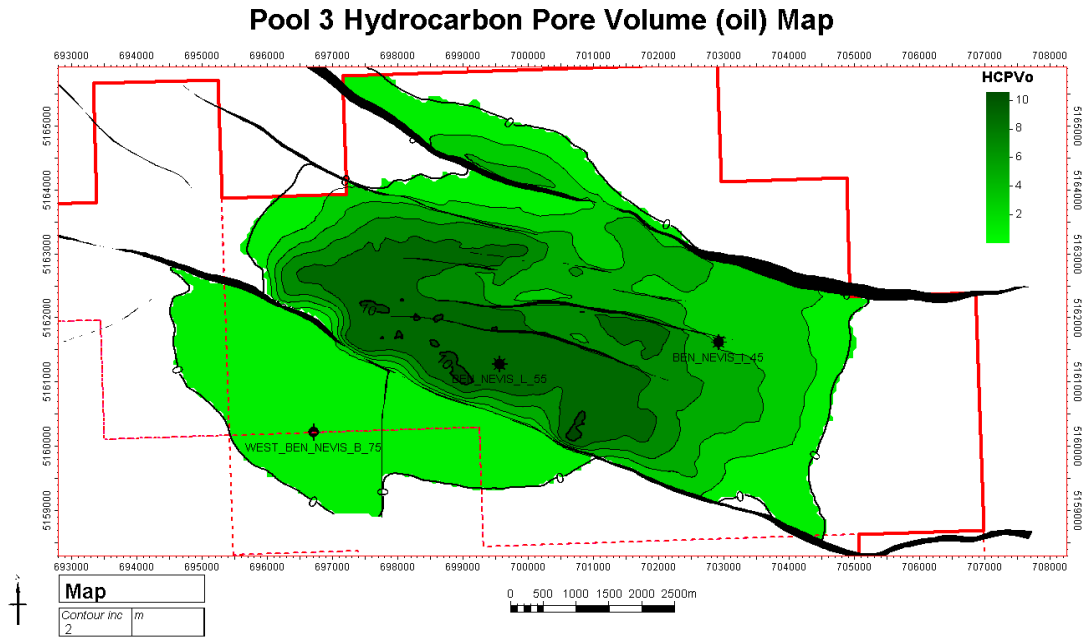


Figure 2.5-20: Pool 3 Hydrocarbon Pore Volume Map

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3 PETROPHYSICS

3.1 Petrophysics

A petrophysics study of available data was performed on the Hebron Asset to provide input to the geologic models and reservoir simulation models for the Ben Nevis, Hibernia, and Jeanne d'Arc reservoirs. Extensive data (both logs and cores) acquired in eight wells were used to calibrate multi-mineral models. Log evaluation results were validated using all core and test information. Petrophysical results are, therefore, consistent with all Hebron Asset subsurface data available. The goal of the petrophysical analysis was to determine reservoir properties (porosity, water saturation, saturation-height functions, etc.) for volumetric assessment of Pools 1, 4, and 5 and to provide support for dynamic modeling. The intention of ExxonMobil is to build upon previous work and update the inputs for modeling based on additional petrophysics studies and recommendations resulting from internal and partner reviews.

Due to very inconsistent datasets and differences between field-blocks, it was impossible to build and use one consistent model or transform for the whole Hebron Asset. Consequently, most of the models and transforms are specific to field, block, and / or formation.

Developed models were applied to process the wells and formations shown in Table 3.1-1.

Table 3.1-1: Formations and Wells Analyzed

Well	Ben Nevis	A Marker	Hibernia	Jeanne d'Arc
M-04	x	x	x	x
D-94	x	x		
I-13	x		x	x
B-75	x	x	x	x
L-55	x			
I-45	x	x	x	
H-71	x		x	x
I-30			x	x

3.1.1 Petrophysical Methodology

This study builds on previous formation evaluation work by Chevron with modifications using ExxonMobil best-practices and procedures as considered necessary. The general approach was to use all existing core data to calibrate petrophysical models and validate them using core, drill stem test (DST), and pressure results. In case of inconsistency in the validation process, petrophysical models or transforms were reviewed and modified.

When feasible, multiple method alternatives were considered (for example, permeability transforms), but only final models were reported.

Porosity was determined by multi-mineral modeling using MULTIMIN, a Paradigm / GEOLOG program similar to Schlumberger's ELAN. Analysis includes all available logs to derive internally consistent and mineral / fluid corrected porosity, water saturation, and mineral volumes. This method allows any mineral affecting logging responses to be incorporated. In the case of Ben Nevis models, introduction of orthoclase feldspar identified on X-Ray Diffraction (XRD), helped to obtain more reliable clay content.

Multi-mineral models contain three basic elements, as follows:

1. Rock volumes that affect logs. Rock volumes from core data such as thin sections and XRD analysis.
2. Logs to be used with associated uncertainty. Due to different logging vintages, two generations of models were created: Basic models use logs common in all wells and advanced models use more logs to define more minerals.
3. Logging responses connecting logs with volumes. Logging responses in multi-mineral modeling are conventionally defined by matching measured logs with logs calculated from models. This process does not guarantee correct results due to non-unique solutions. To overcome this, logging responses were defined using inverse parameter modeling. Core mineral volumes from XRD and core porosity were used as input to optimize logging responses.

The total porosity derived from Multimin was then compared to core calibrated density porosity as a further validation step.

3.2 Ben Nevis Reservoirs

The Ben Nevis formation was penetrated by seven wells in three fault blocks. Pool 1 includes wells I-13, M-04, and D-94, modern logs and core were acquired in both M-04 and D-94 wells. The adjacent Pool 2 has one penetration, B-75 with older vintage logs and core. The West Ben Nevis field (Pool 3) is characterized by two wells, I-45 and L-55. L-55 has modern log and core data. Modern well logs are considered more reliable than older vintage logs.

The log and core analysis was performed to provide inputs to the geologic model. The priority for the Ben Nevis reservoir has been Pool 1, penetrated by wells D-94, M-04, and I-13. This built upon previous work performed by Chevron, with updates based on additional log and core studies by ExxonMobil.

3.2.1 Petrophysical Data

The petrophysical study is based on both log and core data.

3.2.1.1 Log Data

Logs were acquired over a period of more than 20 years. “Old” logs, mostly Schlumberger’s 80’s vintage, consist of induction and laterolog resistivity, density, neutron, gamma ray (GR), sonic, and repeat formation tester (RFT). Resistivity bed resolution is poor, and due to water-based mud (WBM), numerous washouts affect the validity of the data.

“Modern” logs are the 90’s vintage with

- ◆ Improved resolution resistivity tools (Azimuthal Laterolog (HALS) in L-55 and D-94 or array induction tool in M-04)
- ◆ Photoelectric effect (Pef)
- ◆ Combinable magnetic resonance (CMR)
- ◆ Image logs (formation microimager (FMI) in L-55 and D-94 and / or imaging tools (OBMI, OBDT, and UBI) in M-04)
- ◆ Modular Formation Dynamics Tester (MDT)
- ◆ Elemental capture spectroscopy sonde (ECS)

Oil-based mineral mud applied in the M-04 well improved hole conditions and allowed the acquisition of a valid spectral gamma.

The log data utilized was digital log ascii standard (LAS) files of standard wireline logs, routine core analysis and nuclear magnetic resonance (NMR) logs run in M-04 and D-94. In general, log and core quality are considered very good, and can be summarized briefly as follows:

- ◆ I-13 — Drilled with water-based mud in 1981, with limited core over some of the Ben Nevis. Older vintage wireline logs were run including both Induction and Laterolog tools. The resistivity logs appear to be affected by deep invasion of water-based mud.
- ◆ D-94 — Drilled with water-based mud in 1999, with core over most of the Ben Nevis interval. Full modern wireline logs available, including Laterolog resistivity and NMR. D-94 is the most reliable well for characterizing saturation due to shallow invasion and relatively thick beds throughout the Ben Nevis.
- ◆ M-04 — Drilled with oil-based mud in 2000, with core over the uppermost and lowermost Ben Nevis. Full modern wireline logs are available, including Induction resistivity and NMR. M-04 is less reliable for characterizing saturation due to relatively thinner beds throughout the Ben Nevis.

- ◆ L-55 — Drilled with water-based mud in 1999. with core over the upper Ben Nevis. Full modern wireline logs are available, including laterolog resistivity and NMR. The gamma ray is elevated by potassium in the drilling fluid. L-55 is the most reliable well for characterizing Pool 3.
- ◆ I-45 — Drilled with water-based mud in 1980, Older vintage wireline logs were run including both Induction and Laterolog tools. The resistivity logs appear to be affected by deep invasion of water-based mud. There are log quality issues with the density and neutron curves. The well was not cored.

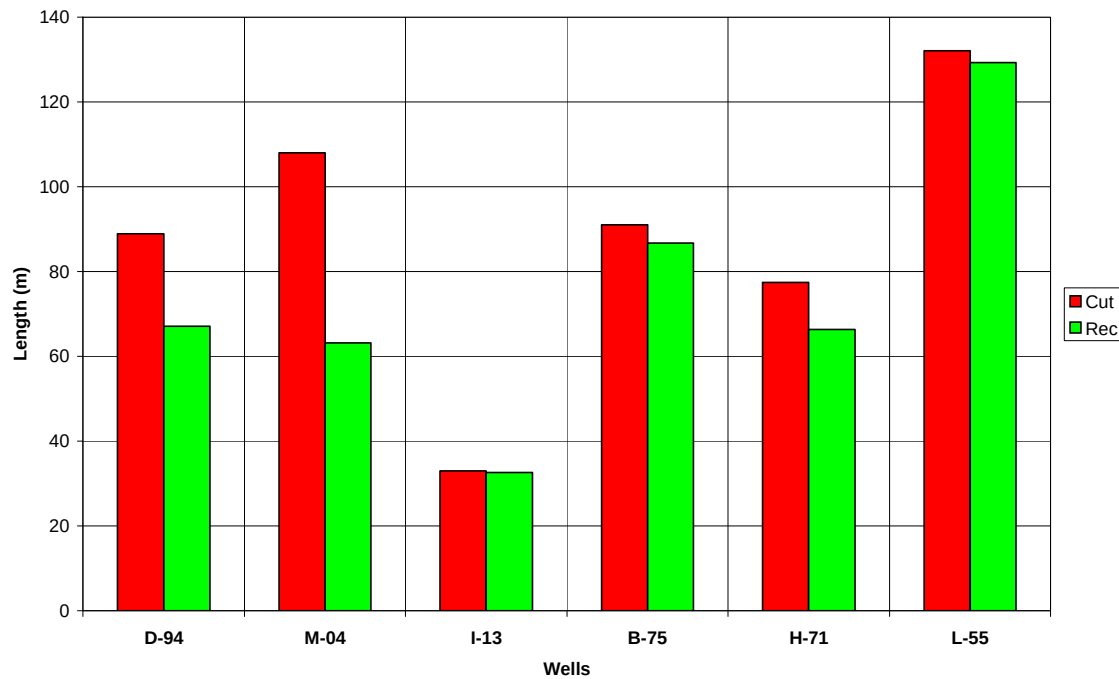
3.2.1.2 Core Data

A total of six wells were cored in the Ben Nevis Formation. 530.47 m of core was cut with a total core recovery of 445.25 m. Table 3.2-1 and Figure 3.2-1 summarize cored intervals cut and recovered and main measurements used in the petrophysical study.

Core was utilized to develop and calibrate multi-mineral models, develop permeability transforms, identify and determine facies, and develop and validate water saturation (Sw) models.

Table 3.2-1: Core Data for the Ben Nevis Formation

Interval (m)	Well	# of samples (CCA)	Xray Defraction (XRD)	Special Core Analysis (SCAL)
2004.0 – 2093.0	B-75	372	-	FF, CP
1828.8 – 1843.9				
1890.1 – 1908.0	I-13	113		-
1997.0 – 2051.9				
2088.2 – 2098.5	H-71	340	-	-
2343.0 – 2475.1	L-55	237	223	FF,RI,CP
1837.0 – 1922.2	D-94	273	97	FF,
1870.0 – 1925.0				
1927.4 – 1980.4	M-04	290* + 90 sidewalls	116	FF, RI,CP
Notes: FF = formation factor, CP = capillary pressure, RI = resistivity index CCA = Conventional Core Analysis (porosity, permeability) * Only data from core #2 was used due to poor depth correlation of the partially lost core #1.				



Total core cut – 530.47 m.

Total core recovered – 445.25 m

Figure 3.2-1: Ben Nevis Core Cut and Recovered

3.2.2 Overburden Corrections

To establish reliable overburden corrections for porosity and permeability, 91 samples were selected from the M-04 (61 samples) and L-55 (30 samples) core. Plugs for this were selected to cover the full range of facies.

Figure 3.2-2 and Figure 3.2-3 illustrate the relationships between corrected and uncorrected porosity and permeability.

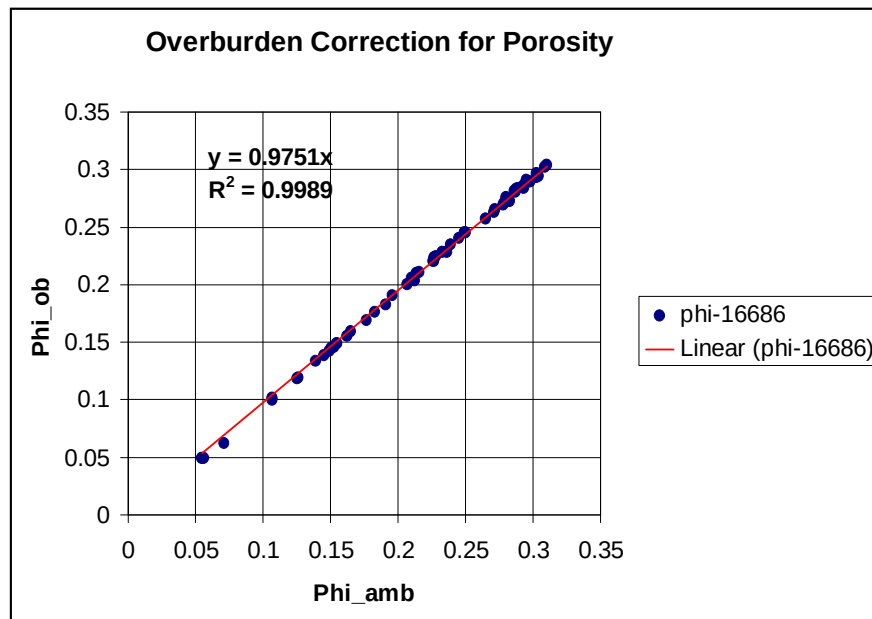


Figure 3.2-2: Ben Nevis Cross-plot of Porosity_Overburden vs Porosity_Ambient

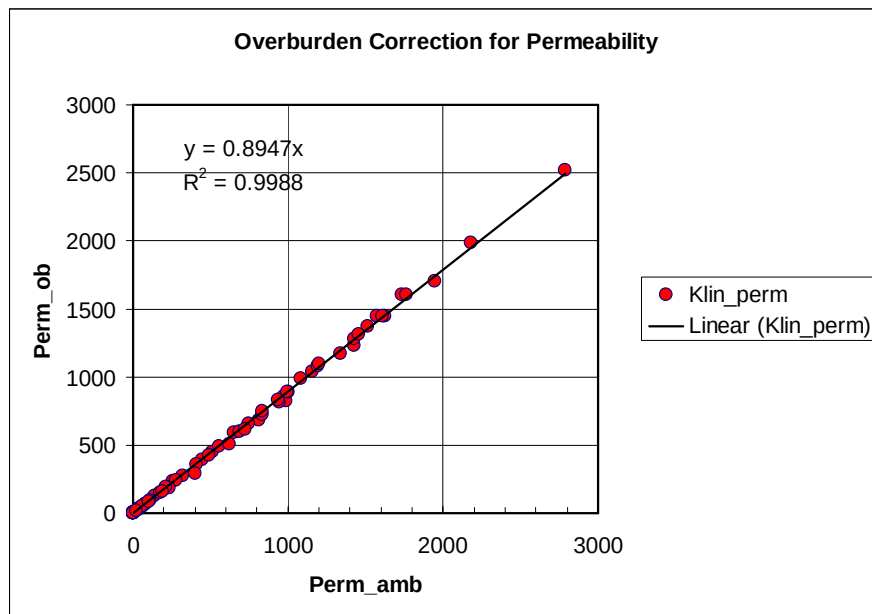


Figure 3.2-3: Ben Nevis Cross-plot of Overburden- and Ambient-corrected Core Permeability

3.2.3 Volumetric Multi-mineral Models

The Generic Field Model with a normal resolution sample rate and basic logging suite was developed and applied in the B-75, I-13, I-45, and H-71 wells. An advanced model in D-94, L-55, and M-04 included CMR and ECS.

Building the Multimin Model involved the following steps:

1. Identification of rock volumes affecting logs.
2. Acquiring XRD Data (M-04, L-55, and D-94).
3. Running inverse parameter modeling to define mineral log responses.
4. Running Multimin without core input.
5. Verifying mineral and porosity errors comparing results with core data and checking matches between measured and reconstructed logs.
6. Fine tuning the model pending verification results.

3.2.3.1 Basic Model

The Basic Model uses only logs common in all wells, and was used in I-13, B-75, I-45, and H-71 wells (Table 3.2-2).

Table 3.2-2: Main Elements of the Basic Ben Nevis Multimin Model

Minerals	Logs
Quartz	Rhob
Illite	Nphi
Calcite	GR
Orthoclase	DT
Oil	Ct (1/Rt)
Water	Cxo (1/Rxo)

Mineral end points were defined using XRD volumes and defining responses by inverse parameter modeling. Models created this way were then adjusted in each well using conventional comparison of measured and reconstructed logs.

3.2.3.2 Advanced Models

The Multi-Mineral Model was built using all available core data (XRD). An example of the input data for the M-04 well is shown in Table 3.2-3. Advanced models are created for the D-94, L-55, and M-04 Wells.

XRD analysis was completed by Corelab on every second sample. Mineral volumes from XRD together with core porosity and grain density were then used as input for inverse parameter modeling to obtain optimized log mineral end points.

Table 3.2-3: Logs and Volumes Used in the M-04 Model

Volumes	Logs
Quartz	RHOB
Illite	NPHI
Kaolinite	GR
Orthoclase	DTC
Calcite	POTA
U-Water	U
X-Water	Ct
U-Oil	Cxo
X-Oil	MPHI
U-Irrwat	MBVI
X-Irrwat	ECS_clay
	$\Sigma Vol = 1$
	$\Sigma Fluids\_X = \Sigma Fluid\_U$
Where: <i>MPHI and MBVI – porosity and bulk volume irreducible water from CMR log</i> <i>X-volumes – fluids close to the wellbore investigated by short investigation tools</i> <i>U – volumes – fluids “seen” by deep resistivity</i>	

The interpretation model included all mineral volumes that may affect logging responses.

The ECS log after Schlumberger processing yielded volumes of sand (quartz + feldspars), carbonates, and clay. The comparison of ECS and XRD results indicated that ECS tends to overestimate clay and underestimate carbonate content. After the addition of orthoclase to kaolinite and illite, the correlation with ECS dramatically improved. This correlation improvement suggests that clay from ECS also contains (at least partially) feldspars.

It was decided to put more weight on the core XRD and use ECS in a more qualitative fashion. ECS carbonate was used to trigger sand model to calcite model and ECS clay was used as a condition stating that the sum of illite, kaolinite, and orthoclase was equal to ECS_clay.

XRD analysis indicated that the predominant feldspar is orthoclase and not albite. Orthoclase is radioactive (containing potassium) and is competing with clay from the gamma ray response. Adding orthoclase in the model significantly reduced clay content.

CMR logs permitted obtaining an extra volume irreducible water saturation (Swir), which aided obtaining more accurate permeability and free water distribution.

The most critical part of the model building is defining logging responses. As mentioned above, this was done using inverse parameter modeling with mineral volumes and porosity from core as an input. More than 100 values of logging responses were defined. Multimin mineral volumes are in-between volumes from XRD and ECS.

3.2.3.3 Porosity Validation using Density Porosity

The Total porosity from Multimin was subsequently compared to core calibrated density porosity in the Ben Nevis reservoirs. As anticipated the differences between the two methods were minor.

3.2.3.4 Porosity Uncertainty

An uncertainty of calculated porosity values was assessed based on comparison with core analysis. Using 2287 core samples from six cored wells, the level-by-level differences were created subtracting core porosity from log porosity. The differential values are affected by shoulder bed effects and vertical resolution mismatch. However, the general range of uncertainty can be estimated.

Histograms of differences should have an average close to zero and standard deviation will be a measure of log estimation uncertainty assuming core data as the benchmark. Figure 3.2-4 and Figure 3.2-5 represent the error distribution of total porosity and effective porosity using all data.

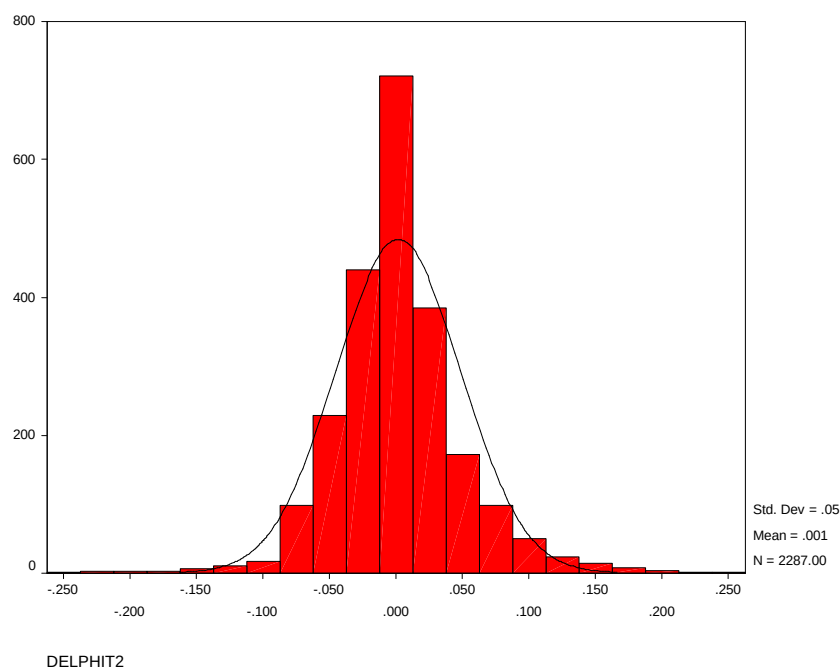


Figure 3.2-4: Total Porosity Error Distribution

Error distribution is normal with average values of -0.009 (PHIE (effective porosity) is lower than core, as expected).

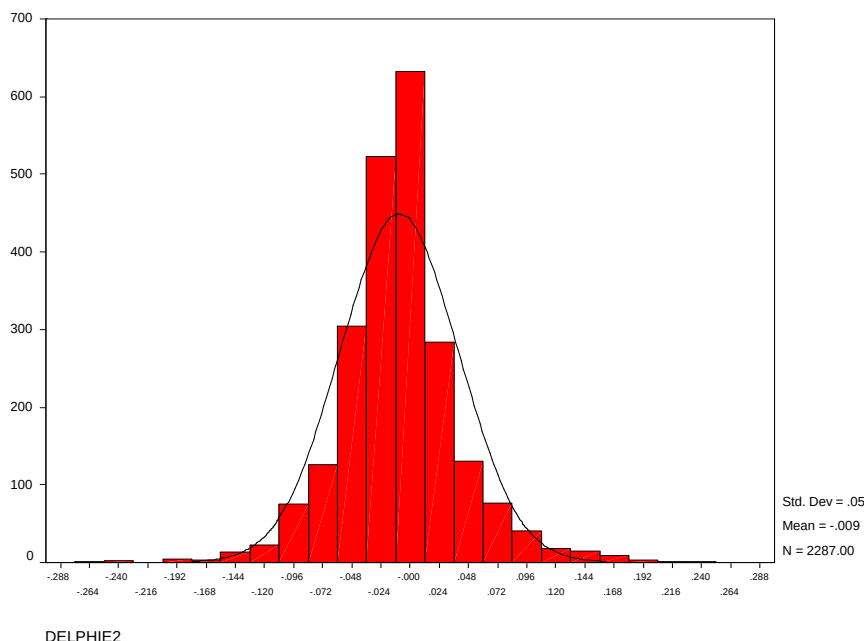


Figure 3.2-5: Effective Porosity Error Comparing with Core Data

The average error is 0.001, i.e. total porosity (PHIT) is slightly higher than core porosity. This again is expected because core porosity (if not humidity dried) still contains layers of bound water, which places core porosity between total and effective porosity.

Presented histograms, therefore, validate the log values as being free of any systematic error. Porosity prediction uncertainty of 0.05 is related to individual depth level and is affected by vertical resolution differences between core and log. An average value might be more adequate to validate log porosity. Table 3.2-4 contains values of average differences between core and log by cored wells.

Total porosity was derived from the Multimin output. Several porosity curves were compared to stress-corrected core porosity and the appropriate curve was selected for use in subsequent petrophysics calculations and static modeling. As an additional check the total porosity was compared with the CMR porosity curve (TCMR), which is regarded as a lithology independent curve. Both Multimin Total Porosity and CMR Total Porosity agree closely.

Table 3.2-4: Average Differences between Core and Log by Cored Wells

Well	Average Delta	Standard Deviation
M-04	0.008	0.04
D-94	-0.001	0.04
L-55	-0.011	0.04
I-13	-0.005	0.06
B-75	-0.002	0.04
H-71	0.012	0.06

The agreement between average porosities is excellent with differences below 1 percent (with the exception of H-71).

3.2.3.4.1 Shale Volume

Shale volume (Vsh) was provided by Chevron and deemed appropriate by ExxonMobil. Shale volume is generally very low throughout the Ben Nevis, which results in a very high net-to-gross. Non-net is usually associated with carbonate-cemented sands.

3.2.3.4.2 Lithology

The Ben Nevis lithology is generally a quartz-rich sandstone with minor feldspar and illite. Calcite occurs as cement, resulting in thin, cemented sandstone streaks and nodules throughout the Ben Nevis. Advanced logging tools and XRD data on core samples allowed Chevron to build and calibrate Multimin porosity models based on this mineralogy.

3.2.3.4.3 Formation Resistivity

Formation resistivity (Rt) was derived from an induction log, a laterolog or a combination of both as follows:

- ♦ I-13 — Drilled with water-based mud in 1981 and acquired both a laterolog and an induction log. Separation between the resistivity curves indicates deep invasion of water-based mud, probably due to a high overbalance during drilling (Figure 3.2-6). Although correction charts are available to deal with invasion, the resulting Rt curve is probably still too low in the oil interval where it is generally less than 30 ohm-m. The final Rt curve consists of an environmentally corrected deep laterolog curve above the 1900m total vertical depth subsea (TVDSS) oil-water contact (OWC) and the deep induction log below the OWC.

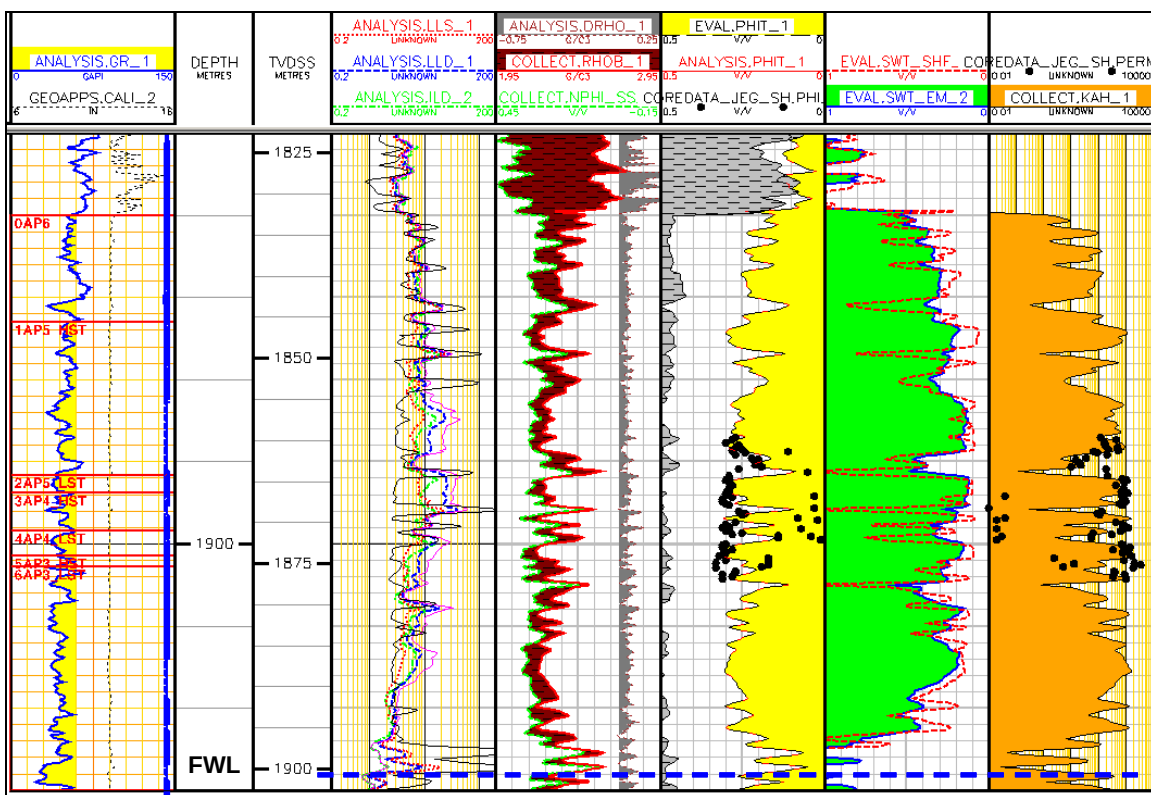


Figure 3.2-6: I-13 SHF-Swt (Red) vs. Log Swt (Green)

- ◆ D-94 — Drilled with water-based mud in 1999, and acquired a dual laterolog resistivity log. Invasion appears to be relatively shallow as the deep and shallow laterolog curves do not show significant separation (Figure 3.2-7). No invasion corrections were considered necessary as the deep laterolog curve was reading from 50 to above 100 ohm-m in many oil sands. This well is considered the most reliable well for characterizing saturation due to shallow invasion, and relatively thick beds throughout the Ben Nevis.

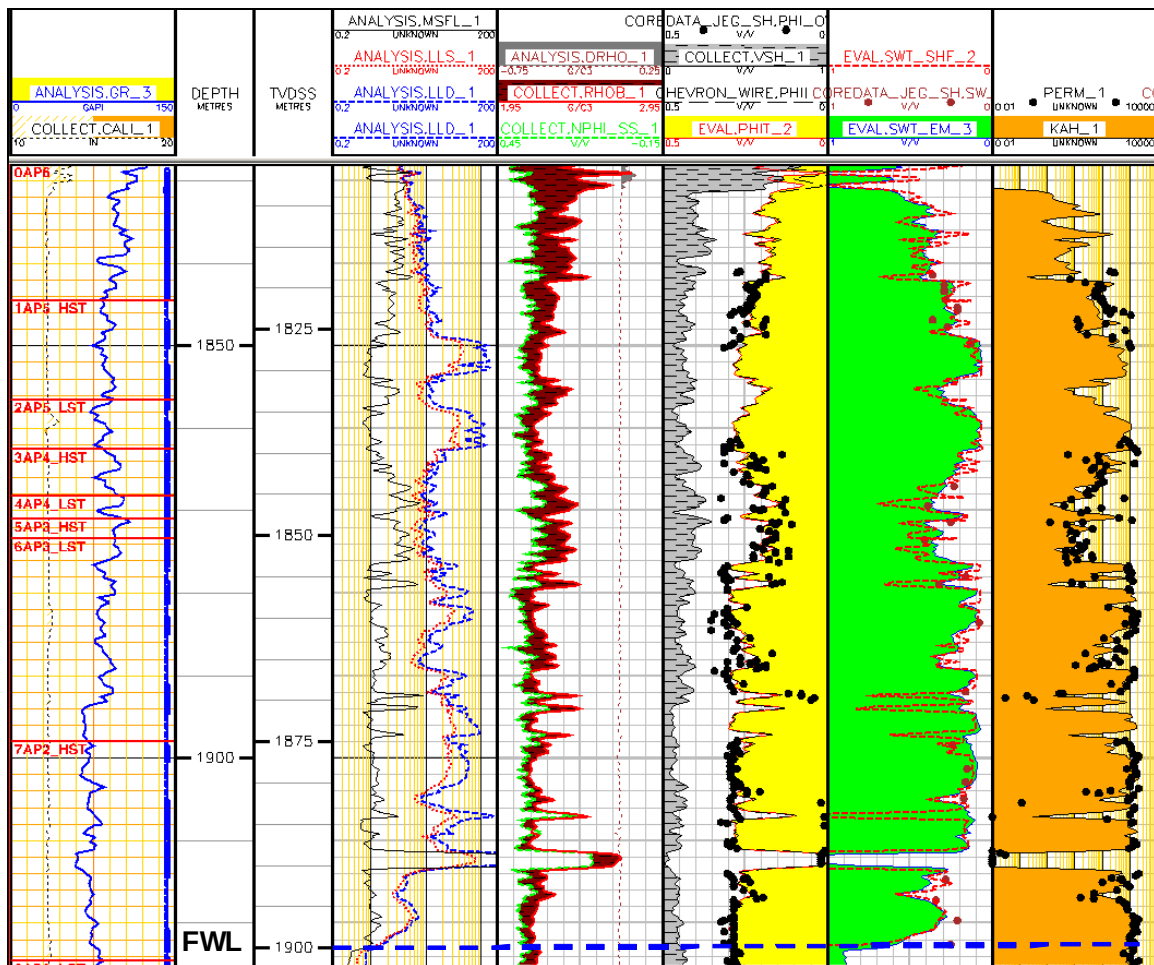


Figure 3.2-7: D-94 SHF-Swt (Red) vs. Log Swt (Green)

- ◆ M-04 — Drilled with oil-based mud in 2000, and acquired an induction resistivity log. Invasion appears to be very low; however, there seems to be significantly more bedding in the Ben Nevis compared to the other Pool 1 wells (Figure 3.2-8). The induction log has less bed resolution and is less accurate in high-resistivities than the dual laterolog.

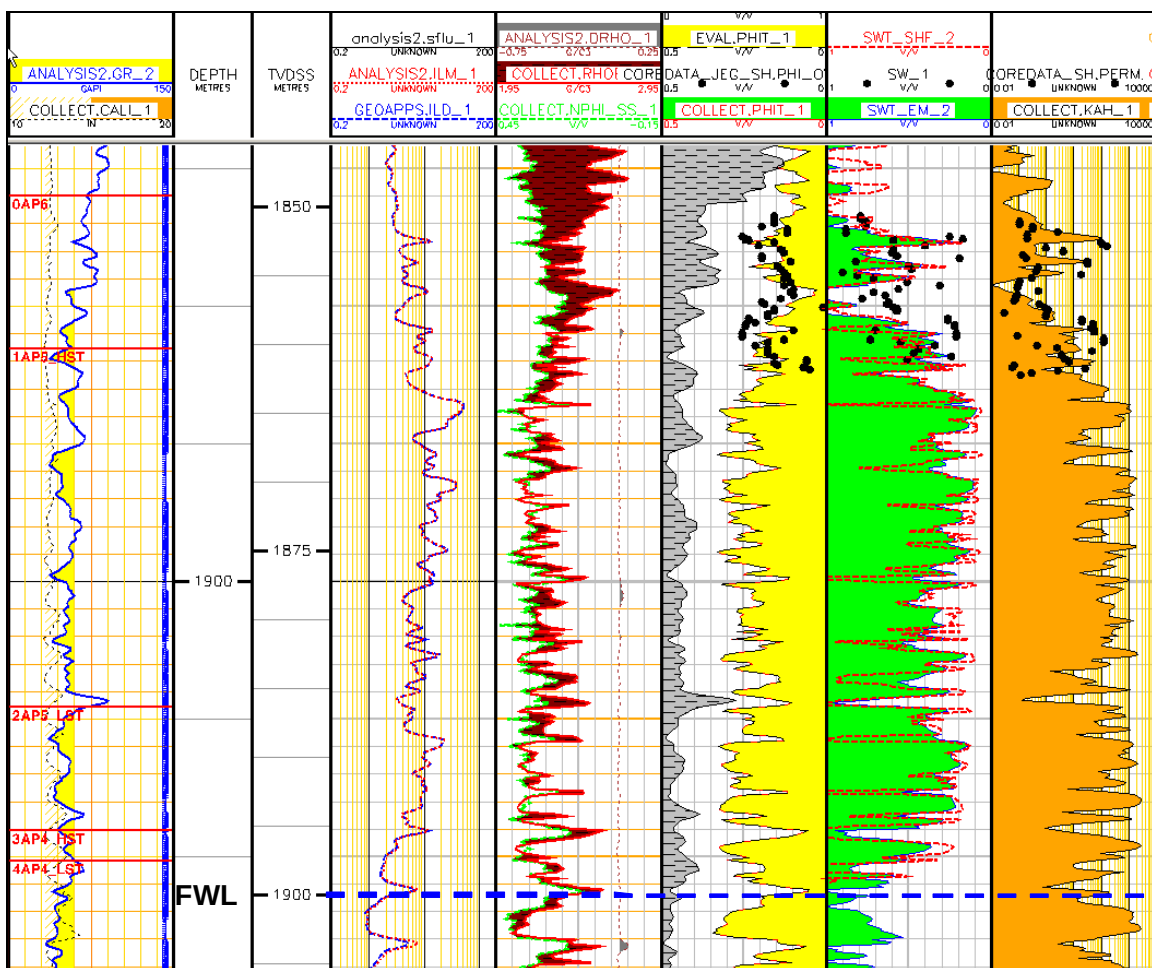


Figure 3.2-8: M-04 SHF-Swt (Red) vs. Log Swt (Green)

- ◆ L-55 — Drilled with a water-based mud in 1999, with core over the upper Ben Nevis. Full modern logs are available, including laterolog resistivity and NMR. The gamma ray is elevated by potassium in the drilling fluid. L-55 is the most reliable well for characterizing Pool 3.

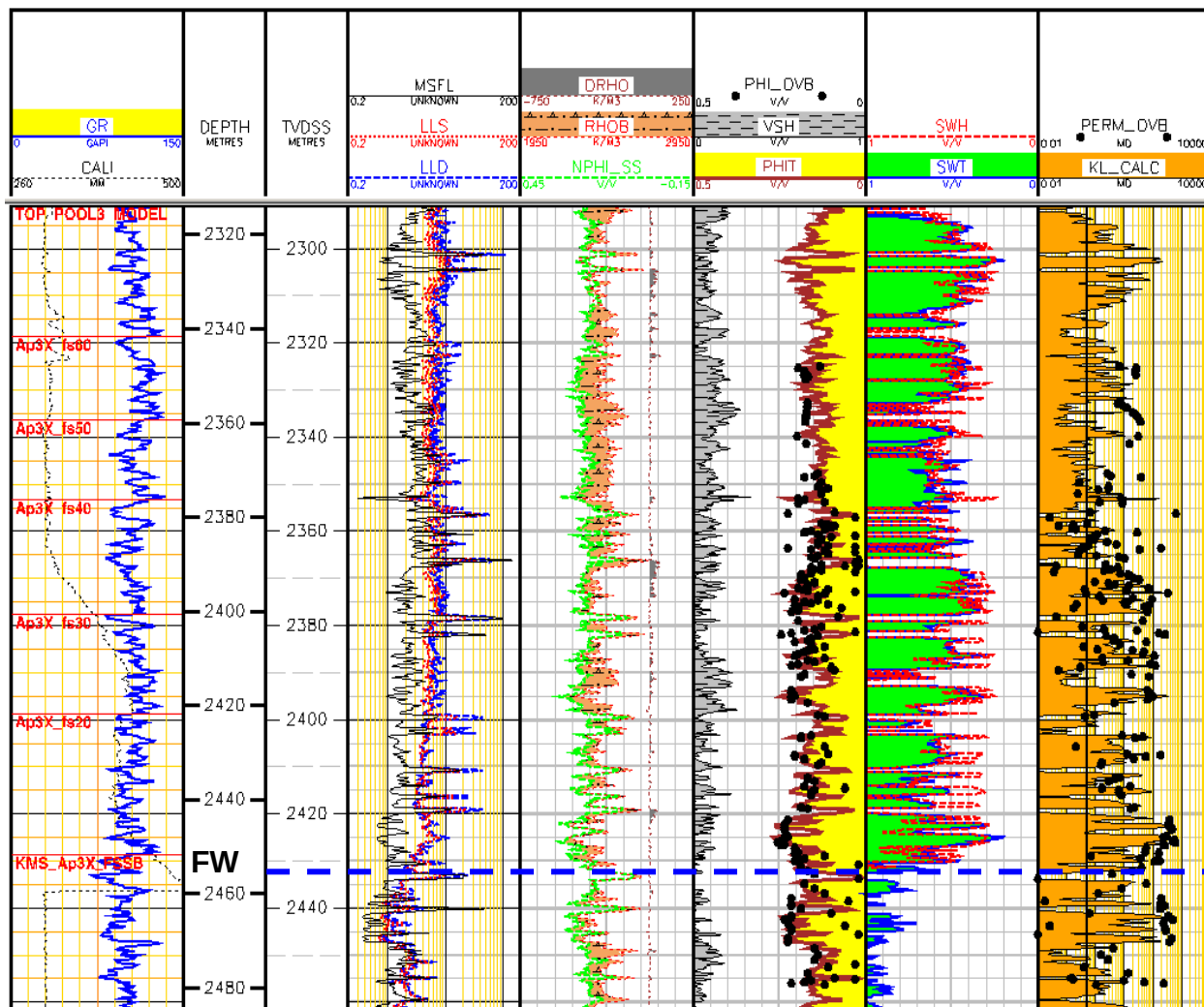


Figure 3.2-9: L-55 SHF-Swt (Red) vs. Log Swt (Green)

- ◆ I-45 — Drilled with water-based mud in 1980, Older vintage wireline logs were run including both Induction and Laterolog tools. The resistivity logs appear to be affected by deep invasion of water-based mud. There are log quality issues with the density and neutron curves. The well was not cored.

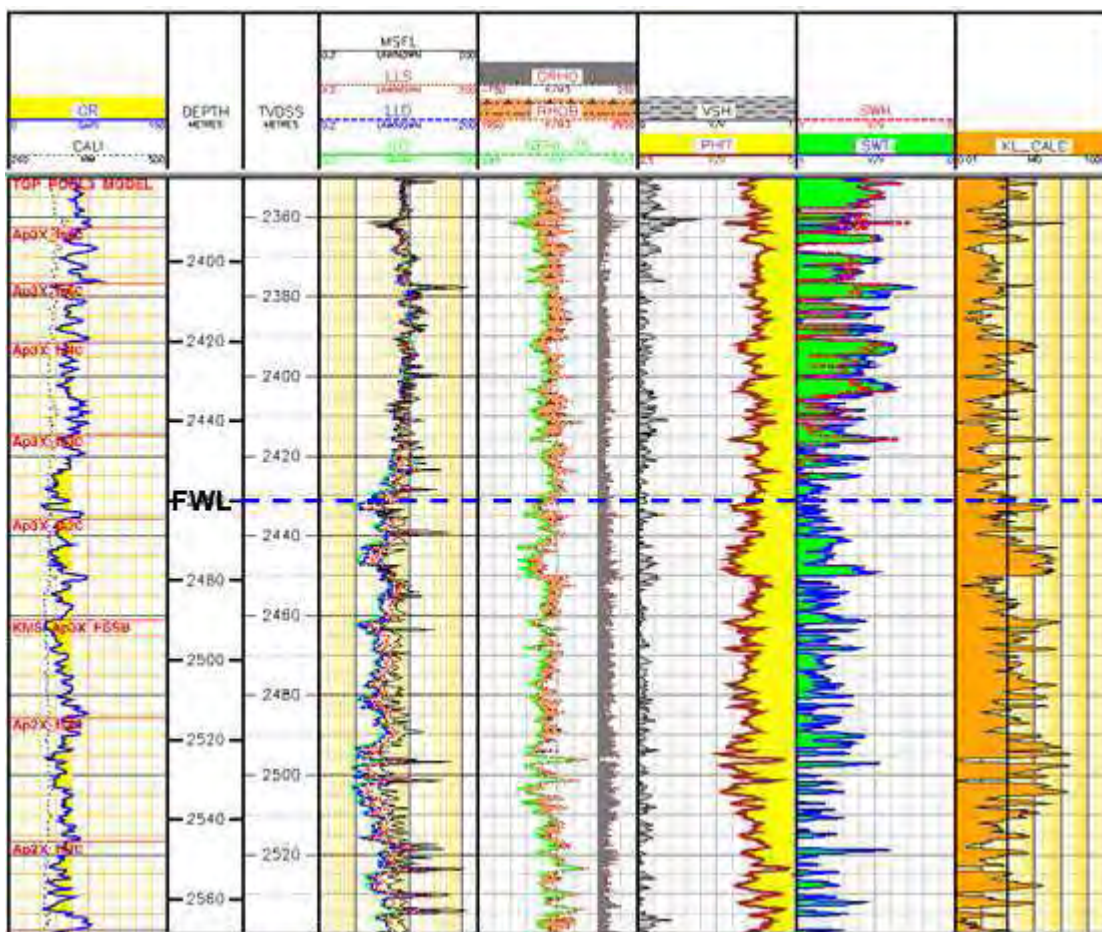


Figure 3.2-10: I-45 SHF-Swt (Red) vs. Log Swt (Green)

3.2.4 Water Saturation Model

Total water saturation was determined using the Archie equation. The use of this equation assumes that all conductivity is due to the fluids in the pore space and that no excess conductivity is contributed from the matrix grains. This assumption is valid when formations are relatively clean (i.e., lack clay or semi-conductive minerals) and sufficiently thick that log resistivity response is not suppressed. Moreover, the presence of saline formation water further validates this assumption since any excess conductivity from mineral grains will be negligible in comparison. The Archie water saturation equation is shown below:

$$S_{WT}^n = \left(\frac{a * R_w}{m * R_t} \right)$$

From this equation, the parameters required for determining water saturation are formation water resistivity (R_w), true formation resistivity (R_t), total porosity (Φ), tortuosity exponent (m), saturation exponent (n), and tortuosity factor (a). Both total porosity (Φ) and true formation resistivity (R_t) can be determined from wireline logs leaving three unknowns remaining. Formation water

resistivity was determined from Pickett plots when possible and compared with water samples from wireline formation tests. The remaining parameters were determined from special core analysis or analog data.

Evaluation of I-13 and M-04 induction logs in water saturated intervals below the Ben Nevis OWC indicates an apparent R_{wa} of 0.055 ohm-m at formation temperature and a tortuosity exponent (m) of 1.85. In D-94, the Dual Laterolog indicated an apparent R_{wa} of 0.060 ohm-m at formation temperature and a tortuosity exponent (m) of 1.85. A water resistivity of 0.055 ohm-m is equivalent to approximately 60,000 NaC_{leq} at the Ben Nevis formation temperature of approximately 70 °C. This salinity is consistent with uncontaminated water recovered from a wireline formation test sample in M-04 of 60,000 ppm NaC_{leq}.

Although some of the Special Core Analysis (SCAL) results in the Pool 1 wells indicate that a variable porosity exponent (m) may be appropriate, a fixed value of 1.85 was finally selected as it is consistent with Pickett Plot analysis in the wells. A variable saturation-exponent (n) trend is possible but is less clear from the SCAL. Based on the n values observed in Pool 1 well, a constant of 1.95 was used in Archie saturation calculations.

The Archie water saturation results can be summarized briefly as follows:

- ◆ I-13 — Analysis indicates an oil column from the top of the Ben Nevis to a free water level (FWL) at 1900 m TVDSS. Water-saturations may be slightly high in some intervals within the oil column due to the limitations of the environmentally corrected R_t curve where WBM invasion is deep. A transition zone seems to be well defined in the lowermost part of the oil column. There does not appear to be a residual-oil zone beneath the FWL as interpreted saturations are close to 100 percent.
- ◆ D-94 — Analysis indicates an oil column from the top of the Ben Nevis to a FWL at 1900 m TVDSS (Figure 3.2-7). Log saturations in this well are considered the most reliable in Pool 1. In the very best quality sands, water-saturations of 5 to 10 percent are observed. A transition zone is well defined in the lowermost part of the oil column. Immediately beneath the FWL, there may be a residual oil zone with water saturations around 10 to 15 percent. The Dual Laterolog is less accurate at low resistivities so there is an increased uncertainty with calculations and interpretations below the FWL in this well. Beneath this depth, water saturations are interpreted to be close to 100 percent.
- ◆ M-04 — Analysis indicates an oil column from the top of the Ben Nevis to a FWL at 1900 m TVDSS. Water-saturations may be slightly high in some intervals due to the bed resolution and the resistivity limitations of the Deep Induction tool. A transition zone is well defined in the lowermost part of the oil column. Immediately beneath the FWL there appears to be a residual oil zone with water saturations around 20 percent. This extends

to approximately 1916 m TVDSS. Beneath this depth, water saturations are interpreted to be close to 100 percent.

In Pool 3 a formation water resistivity (R_w) of 0.05 ohm-m at formation temperature was used in the analysis. This is equivalent to 60,000 ppm TDS and is consistent with Pool 1. A variable tortuosity exponent (m) was determined from the SCAL data in L-55 and B-75 wells where $m = 2.1861 + (PHIT * -1.7471)$. Although there is some evidence of a trend between porosity and saturation exponent (n) in the L-55 core data a saturation exponent (n) of 2 was considered to be more representative of the gross rock properties.

The Archie water saturation results can be summarized briefly as follows:

- ◆ L55 — Analysis indicates an oil column from the top of the Ben Nevis to a FWL at 2432 m TVDSS. Immediately beneath the FWL there appears to be a residual oil zone with water saturations of approximately 80 percent.
- ◆ I-45 — Analysis indicates an oil column from the top of the Ben Nevis to a FWL at 2432 m TVDSS. There is greater uncertainty in the calculated water saturations than in I-45 because of possible water based mud invasion and tool issues. A transition zone is well defined in the lowermost part of the oil column. Beneath the FWL there appears to be a residual oil zone with water saturations around 80 percent

3.2.4.1 Capillary-Pressure Data

Very little core capillary-pressure data is available from the Ben Nevis Pool 1 reservoirs. The air-brine capillary-pressure data that is available does not appear to be fully representative of the Ben Nevis reservoir in terms of porosity-permeability characteristics (Figure 3.2-9). Although some mercury-injection data is also available, there are some issues regarding the validity of the measurements. In conclusion, the capillary-pressure curves were not used directly to derive a saturation-height function. The curves were used as a guide to the shape of the transition zone; however the saturation height function (SHF) implemented in static and dynamic models was directly based on the D-94 log-derived saturation curve.

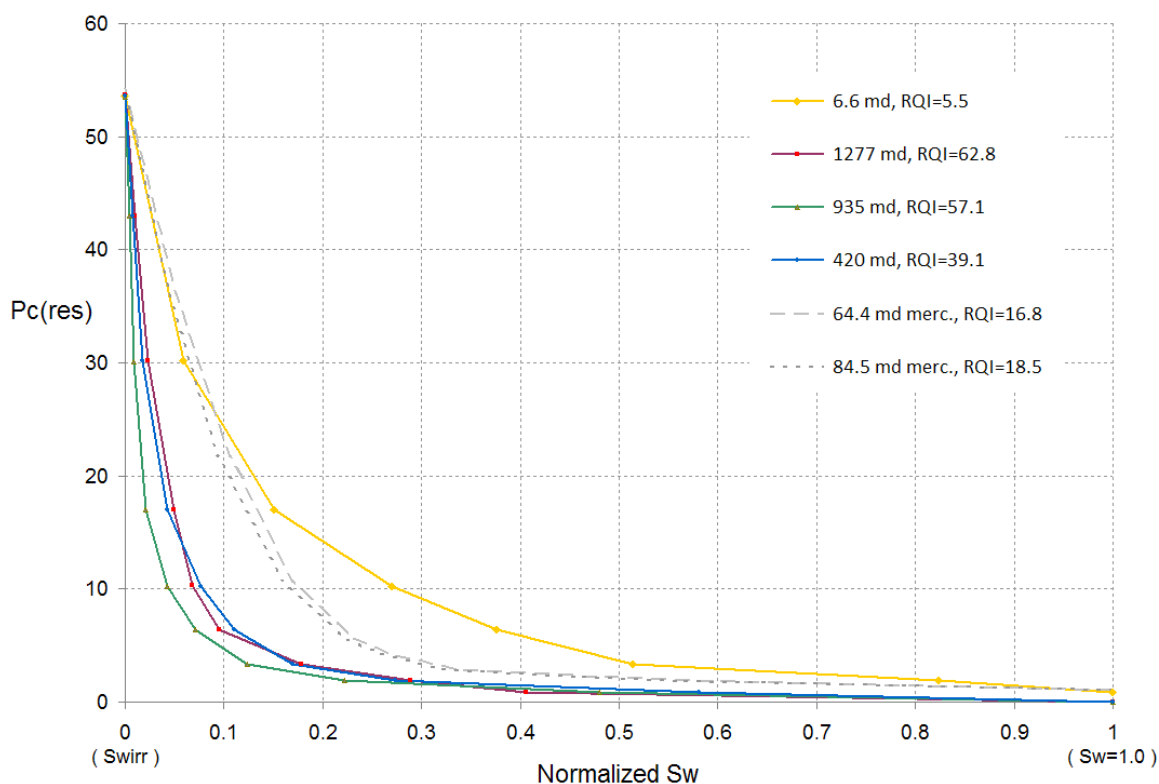


Figure 3.2-11: Capillary Pressure vs Normalized Water Saturation

Capillary Pressure (L-55)

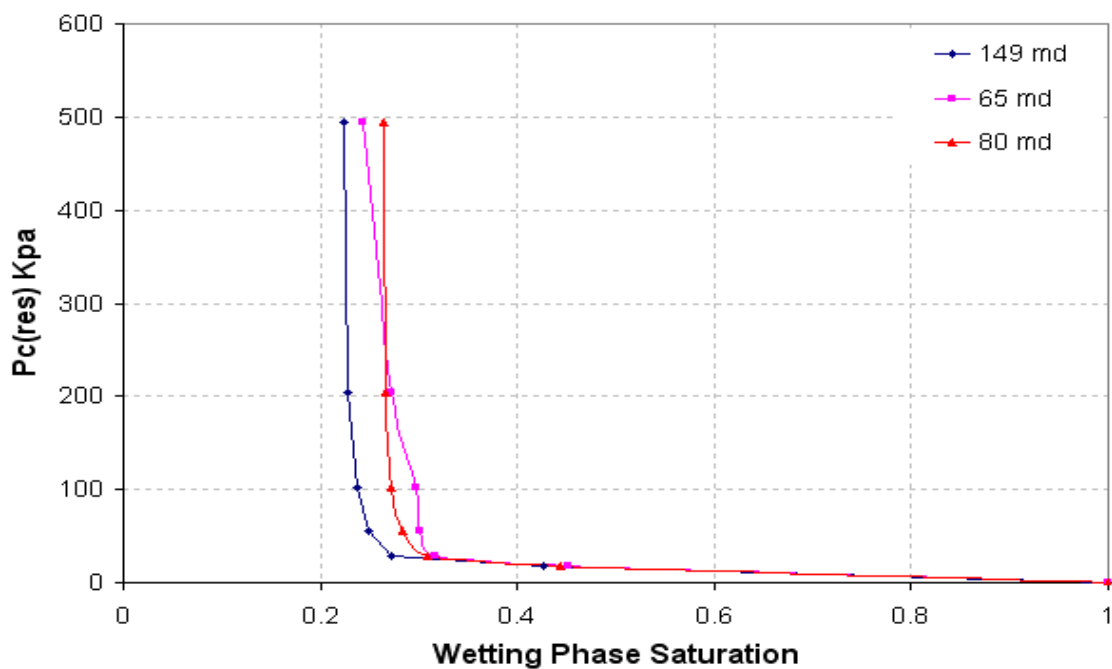


Figure 3.2-12: Pool 3 Capillary Pressure vs Water Saturation

3.2.4.2 Saturation-Height Functions (SHF) Pool 1

A lambda saturation height function was derived in D-94, as this well is considered the most reliable in Pool 1 for log-derived saturations. The SHF characterizes saturation as a function of height and porosity and takes the following form:

$$Sh = \max (0, 1 - B - [\frac{(10^{(a-b^*)})}{HAFWL}])$$

Where:	
Sh	Hydrocarbon Saturation as a fraction
Φ	Total Porosity as a fraction
HAFWL	Height Above Free Water Level in meters
a	0.7
b	3.2
λ	0.4
B	0.722 - 2.778 * Φ (Limited -0.05 to 0.5)

The SHF, although empirically derived, emulates what is expected from a series of capillary-pressure curves. The curve shape is typical of the oil-water transition zone. An increasing entry-height is observed as porosity decreases above the transition zone, and the curves become steeper as they approach irreducible water saturation (Figure 3.2-13). The SHF, as expected, provides an excellent fit to the log-derived saturations in D-94 in all levels of saturation, the very high porosity sands with low total water saturation (SWT), lower quality sands with intermediate SWT, and also in the transition zone above the FWL.

When applied to M-04, the SHF shows good agreement in all but the highest porosity zones where the Induction log is interpreted to be reading too low resistivity due to bed resolution (Figure 3.2-13). In I-13, a good agreement is observed in some intervals, although deep invasion of WBM in this well is severely decreasing the resistivity from the Dual Laterolog.

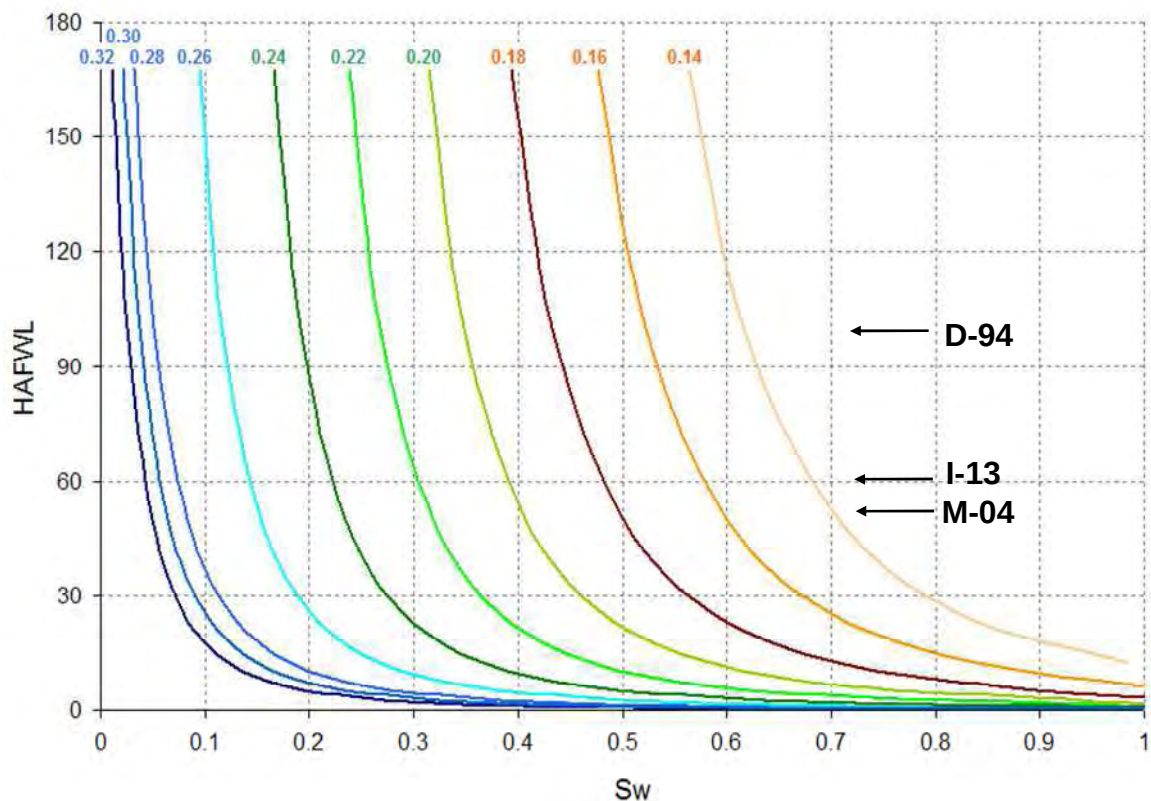


Figure 3.2-13: Lambda Saturation-Height Function

3.2.4.3 Saturation-Height Functions Pool 3

A Bulk Volume Water (BVW) saturation height function was developed for Pool 3. This function was chosen after consideration of Lamda and J functions as the BVW function resulted in the the best match to log saturations. The SHF characterizes saturation as a function of height and porosity and takes the following form:

For Permeability > 10 md:

$$Sh = (0.053 + 0.07 / HAFW^{**0.55}) / phit]$$

For Permeability < 10 md :

$$Sh = 2.72^{(-1.82 + (0.001 * PHIT * (LN(PHIT))) - (0.125 * (PHIT^{0.5})))}$$

Where:	
Sh	Hydrocarbon Saturation as a fraction
PHIT	Total Porosity as a fraction
HAFWL	Height Above Free Water Level in meters

The SHF provides an very good fit to the log-derived saturations above the FWL in both the I-45 and L-55 wells.

3.2.4.4 ExxonMobil SCAL Advisor WorldWide Database

To increase confidence in calculated saturations, the EM ScalAdvisor program was used. This program includes a database of quality-controlled core analysis measurements from reservoirs in various oil and gas fields around the world. A cross-plot of permeability versus saturation was created for clastic reservoirs using this database. When the D-94 log saturation and permeability data was compared to the ScalAdvisor data, the low water saturations (5 to 10 percent SWT) in the high-permeability sands were found to be consistent with similar permeability reservoirs (Figure 3.2-11). D-94 water saturations in lower permeability intervals were also found to be consistent with ScalAdvisor data points.

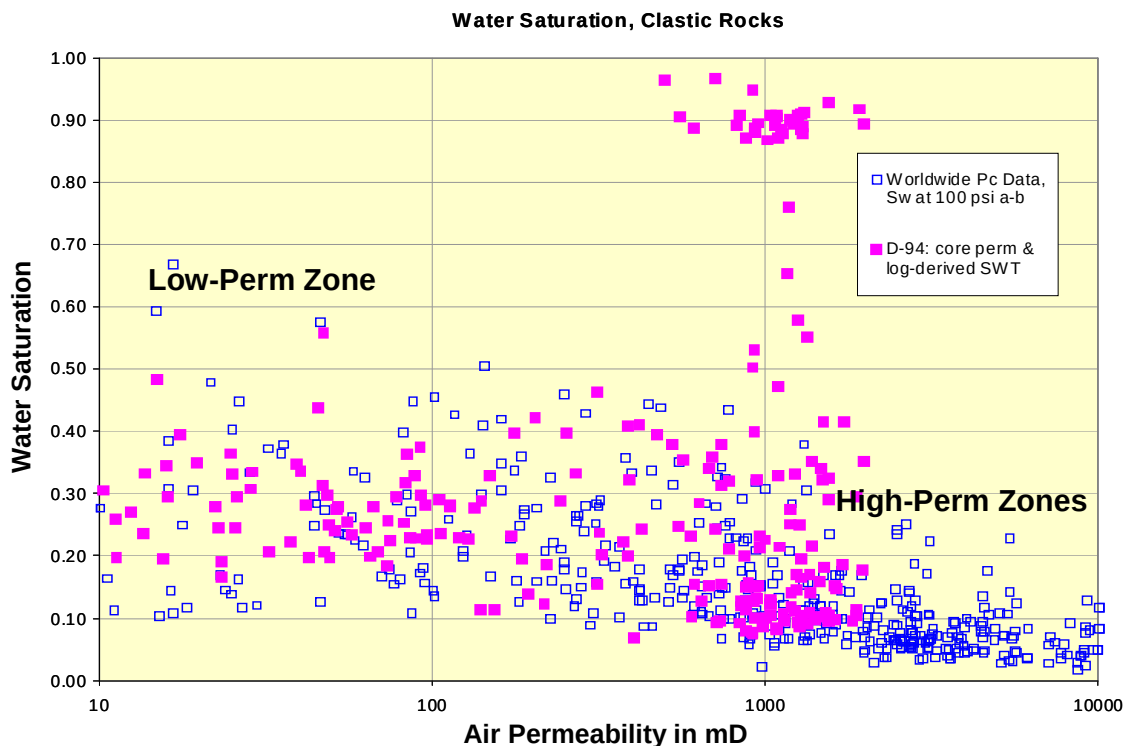


Figure 3.2-14: EM Worldwide Clastics Capillary-Pressure Database (Sw at 100 PSI)

3.2.4.5 Nuclear Magnetic Resonance (NMR)

NMR logs were run in Pool 1 wells D-94 and M-04. These logs were investigated to provide additional information in three areas as follows:

- ◆ Porosity — The NMR log provides a lithology-independent estimate of porosity that can be a reliable check of other porosity tools in water-bearing and oil-bearing reservoirs. The NMR porosity logs in the Pool 1

wells are in close agreement with core and log-derived total porosity, thus adding confidence to these calculations and their use in static and dynamic models.

- ◆ Water Saturation — The NMR log is able to sub-divide porosity into two or more components, based on a pore-size cut-off. This provides two porosity curves representing two areas of the total pore space, as follows:
 - A bound-water porosity, which consists of small pores assumed to be too small to hold any hydrocarbons;
 - A free-fluid porosity, which consists of larger pores assumed to be capable of holding hydrocarbons;
 - A simple ratio of NMR bound-water porosity to total porosity, therefore, provides an estimate of potential SWI.
 - When SWI curves were calculated from the NMR logs in D-94 and M-04, they generally show water saturations above 10 percent in the very high permeability sands (Figure 3.2-12). However, there is evidence that the relatively heavy oil in Pool 1 may cause an anomalous effect on the NMR logs. This effect causes the bound-water porosity to be too high, which would result in the SWI also being too high. An attempt at correcting the logs was made by decreasing NMR bound-water porosity in the oil intervals and recalculating SWI. When this is done it results in very low NMR SWI (5 to 10 percent), which is consistent with the log-derived and SHF saturations. Although further NMR logging and NMR core analysis is recommended, there is evidence from the Pool 1 NMR logs to support the log-derived saturations and SHF implemented in the static and dynamic models.

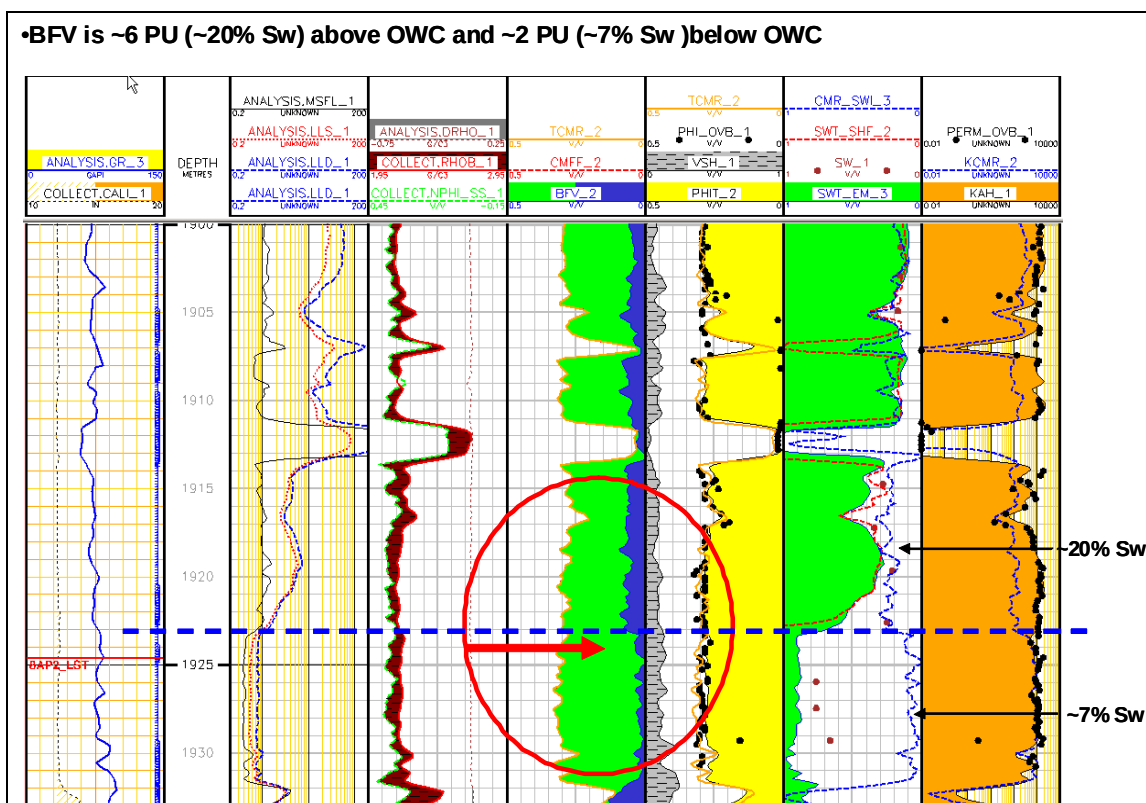


Figure 3.2-15: D-94 – NMR Porosity, Saturation, and Permeability – OWC

- ◆ Net Reservoir Sand — In the uppermost part of the Ben Nevis, there is a shaly, lower porosity interval where there is increased uncertainty in the log-derived saturations. Investigation of the NMR bound-water and free-fluid porosity curves indicates that these shaly, lower porosity sands do have potential to contain hydrocarbons. The SWI calculated from the NMR logs in shaly zones supports the log-derived saturations and SHF implemented in the static and dynamic models.

3.2.4.6 Core Fluorescence

In M-04 and L-55 core photographs taken under UV light were investigated to see if areas where the logs and SHF indicate the presence of oil actually had oil fluorescence in the core (Figure 3.2-16). Although semi-quantitative, the core photographs for the most part supported the log-derived saturations and the inclusion of these poorer reservoir zones in the static and dynamic models.

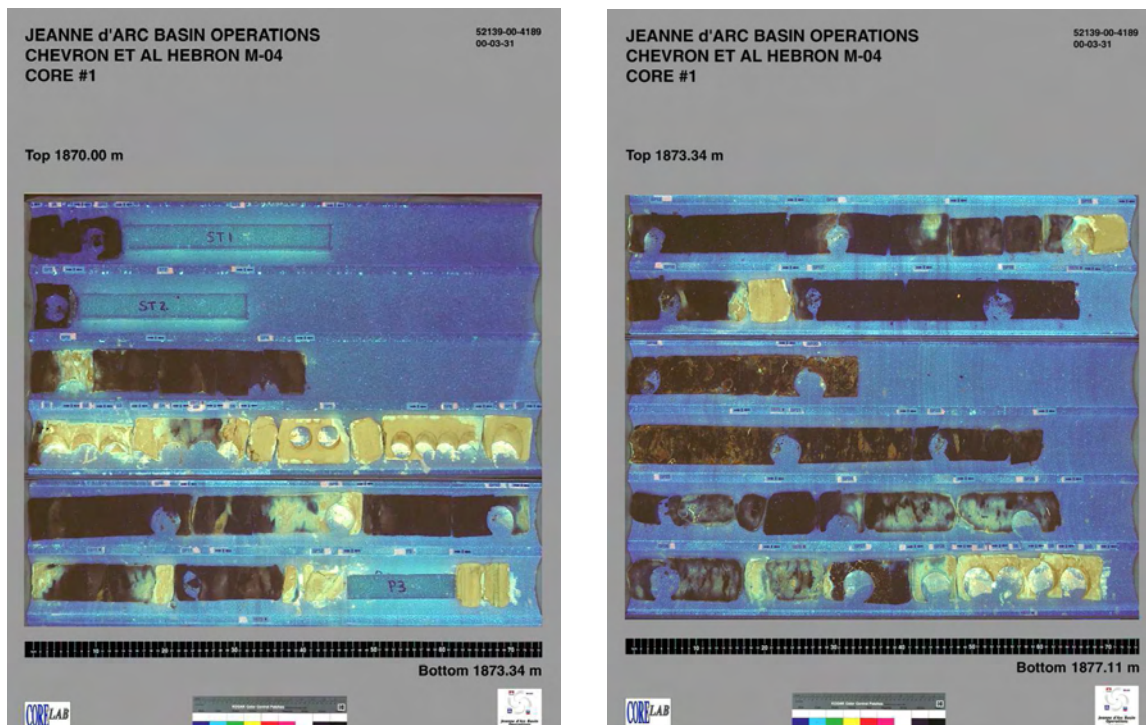


Figure 3.2-16: M-04 – Core Fluorescence – Uppermost Ben Nevis

3.2.4.7 Wireline Pressure Data

In M-04, D-94, and L-55 the uppermost shaly, lower porosity Ben Nevis sands were surveyed with wireline pressure measurements. These poorer quality zones were found to be permeable and in pressure communication with the underlying higher-quality sands (Figure 3.2-17 Pool 1, and Figure 3.2-19 Pool 3). As with the core photographs and NMR log, this was further evidence to justify inclusion of these poorer zones in the static and dynamic models.

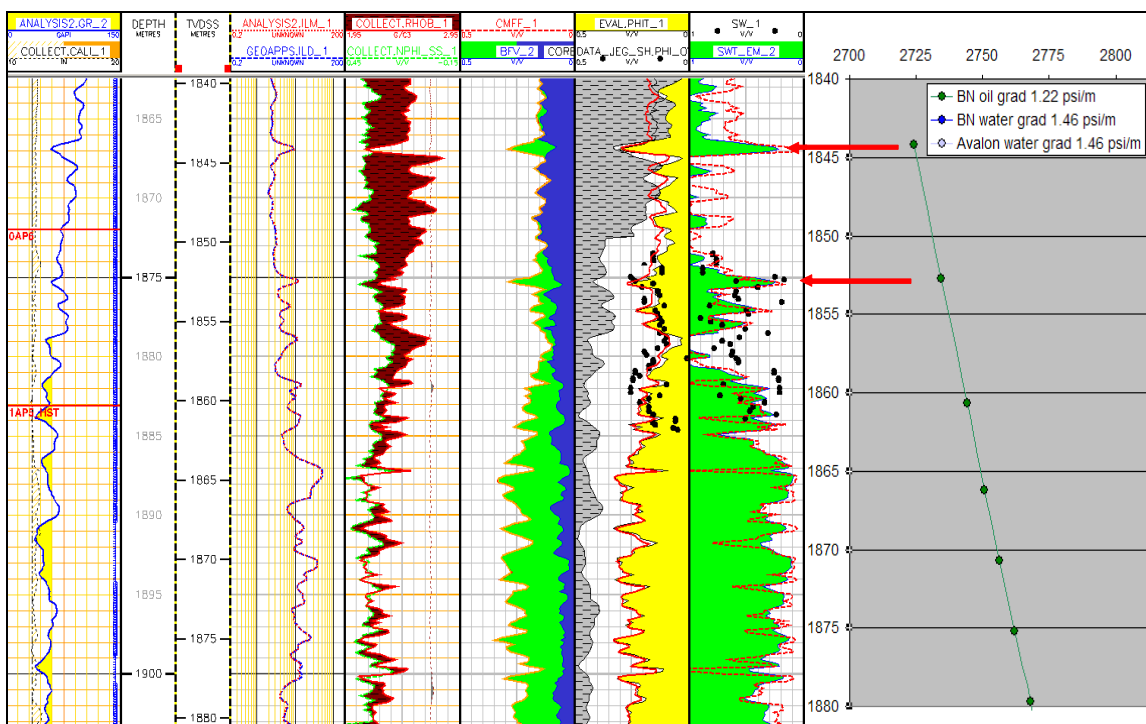


Figure 3.2-17: M-04 – NMR Analysis and Formation Pressures

3.2.4.8 Fluid Contacts

A Ben Nevis Pool 1 FWL was determined from wireline pressure measurements obtained in the Pool 1 wells (Figure 3.2-15). In the high porosity and permeability sands on Pool 1, the OWC is interpreted to, or very close to, the FWL. The I-13 well has very limited pressure data; however M-04 and D-96 have a larger and higher quality set of pressures in both the oil and the water intervals. A FWL of 1900 m TVDSS is indicated from pressure analysis. This is consistent with the resistivity log interpretation in each of the Pool 1 wells.

In Pool 3 there is insufficient pressure data in the water leg to accurately determine the FWL (Figure 3.2-19). The interpreted FWL of 2432 m TVDSS is based on interpretation of the resistivity logs in I-45 and L-55 and is consistent with oil gradient observed in the L-55 pressure data. A Gas Oil contact of 3210.5 m TVDSS has been interpreted from the L-55 pressure data.

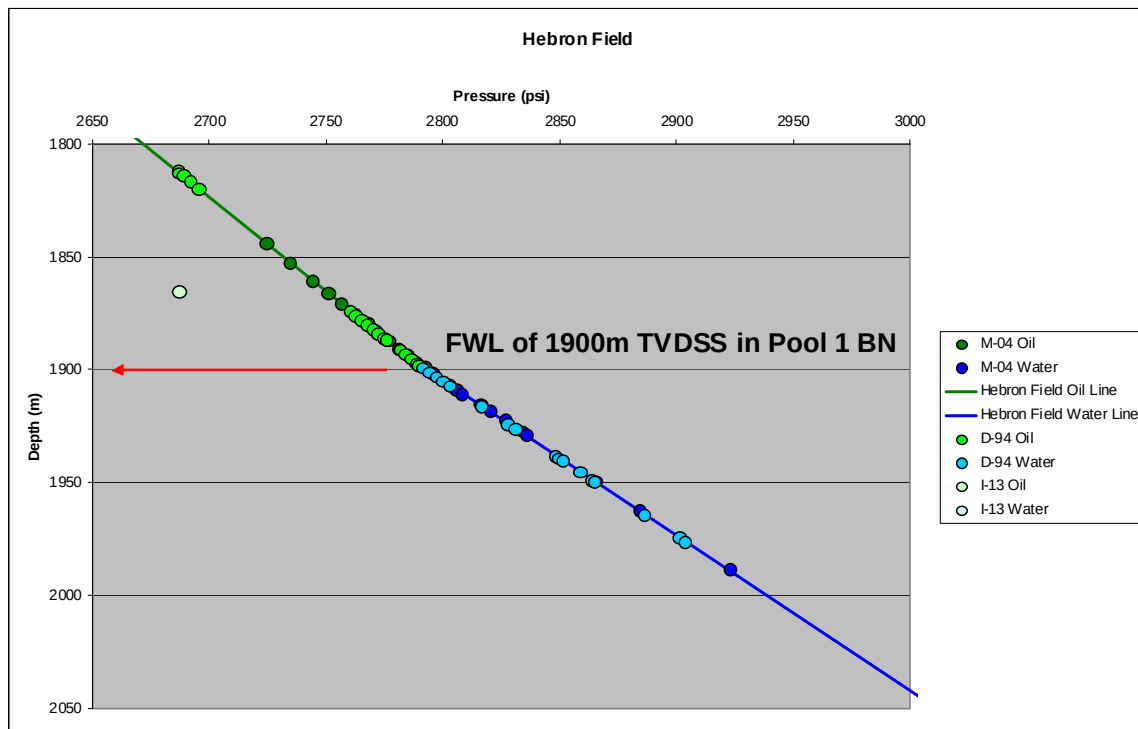


Figure 3.2-18: Formation Pressure Plot Summary

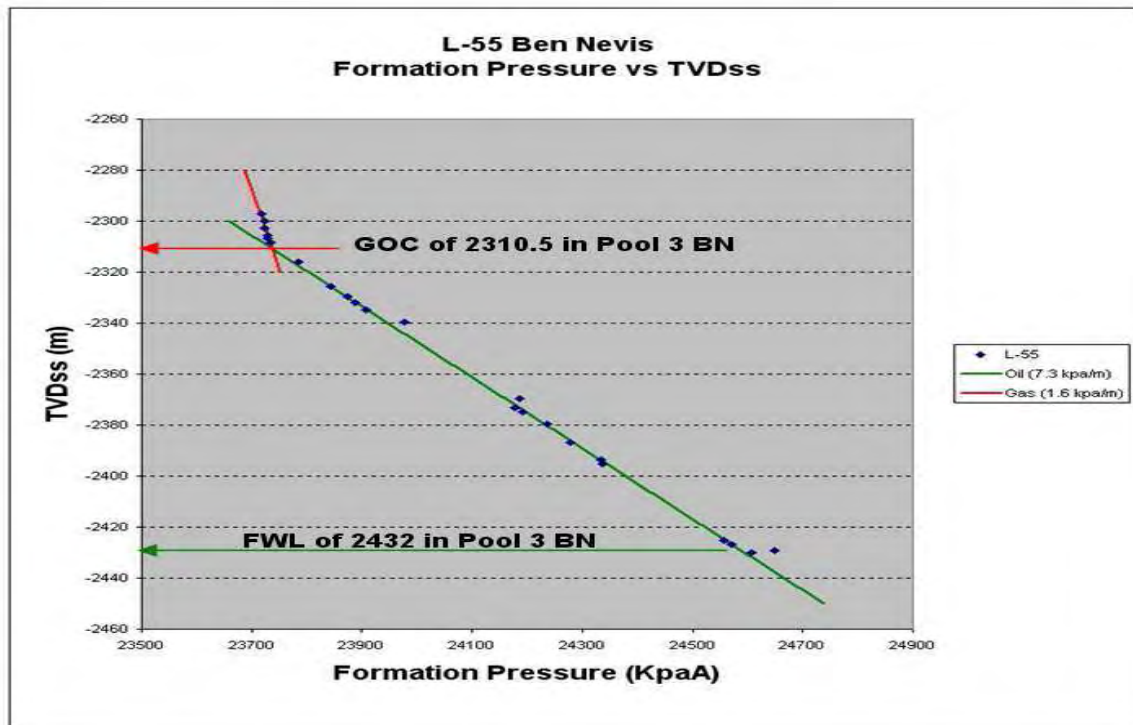


Figure 3.2-19: Pool 3 Formation Pressure Plot Summary

The water saturation profile together with MDT and RFT pressure data were used to define and validate fluid contacts within the Ben Nevis formation.

Comparison with saturation profiles obtained after using variable Archie coefficients indicates existence of residual oil below OWCs obtained from pressure. Residual oil was observed also on top of the core in M-04 and in the core from the B-75 well. Existence of paleocontacts would explain saturation profiles.

Table 3.2-5 summarizes fluid contacts from pressure gradient interpretation.

Table 3.2-5: Fluid Contacts from Pressure

Well	KB	OWC (MD)	OWC (mss)
M-04	22.8	1920.8	1898.0
D-94	22.8	1923.0	1900.2
L-55 – GOC	22.8	2333.0	2310.2
L-55 – WOC	22.8	2455.0	2432.0

The difference between M-04 and D-94 is within interpretation uncertainty. For the earth model, OWC at 1900 meters subsea (mss) was used for the Hebron Field.

3.2.4.8.1 Parameters and Equations

This section describes the parameters and equations used in formation evaluation calculations (Table 3.2-6).

Table 3.2-6: Parameters

	Model	Parameters
Shale Volume (Vsh)	As provided by Chevron and validated by ExxonMobil.	As described in Chevron documentation
Total Porosity (Φ_t)	Output from Multimin	As described in Chevron documentation
Water Saturation (SWT)	Archie Equation	$m=1.85$ $n=1.95$ $a=1$
Water Resistivity (Rw)	Pickett plot	Rw of 0.055 to 0.060 ohm-m @ 70 °C Equivalent to approx. 60,000 ppm

Table 3.2-7: Parameters Pool 3

	Model	Parameters
Shale Volume (Vsh)	As provided by Chevron and validated by ExxonMobil.	As described in Chevron documentation
Total Porosity (Φ_t)	Output from Multimin, validated by ExxonMobil (Density porosity)	As described in Chevron documentation
Water Saturation (SWT)	Archie Equation	m= variable n=2 a=1
Water Resistivity (Rw)	Pickett plot	Rw of 0.05 @ 85 °C Equivalent to approx. 60,000 ppm

Water Saturation – Archie Model

$$S_{WT} = \left(\frac{aR_w}{R_t^m} \right)^{1/n}$$

Where:	
SwT	= Total water saturation
ϕ	= Total Porosity
a	= Tortuosity factor (1.0)
m	= Tortuosity exponent
n	= Saturation exponent
Rw	= formation water resistivity (ohm-m)
Rt	= deep resistivity measurement (ohm-m)

Core Stress Corrections: Porosity Correction

$$_{in-situ} = 0.9751 * _{ambient}$$

Core Stress Corrections: Permeability Correction

$$K_{in-situ} = 0.8947 * K_{ambient}$$

3.2.5 Permeability

A flow-base-scale-averaging approach was applied to modeling permeability in the Ben Nevis reservoirs in order to capture fine-scale flow behaviour. The permeability modeling was handled in two stages:

1. By distributing core-plug scale permeabilities in fine-scale element models, and

2. Using a flow-based scale averaging approach to determine the equivalent permeability at the scale of a 100m x 100m x 1m geologic model cell.

Figures 3.2-20 and 3.2-21 show the core plug scale transforms applied in Pools 1 and 3 respectively (core plugs are larger, contoured points; small points are values distributed in a fine-scale model).

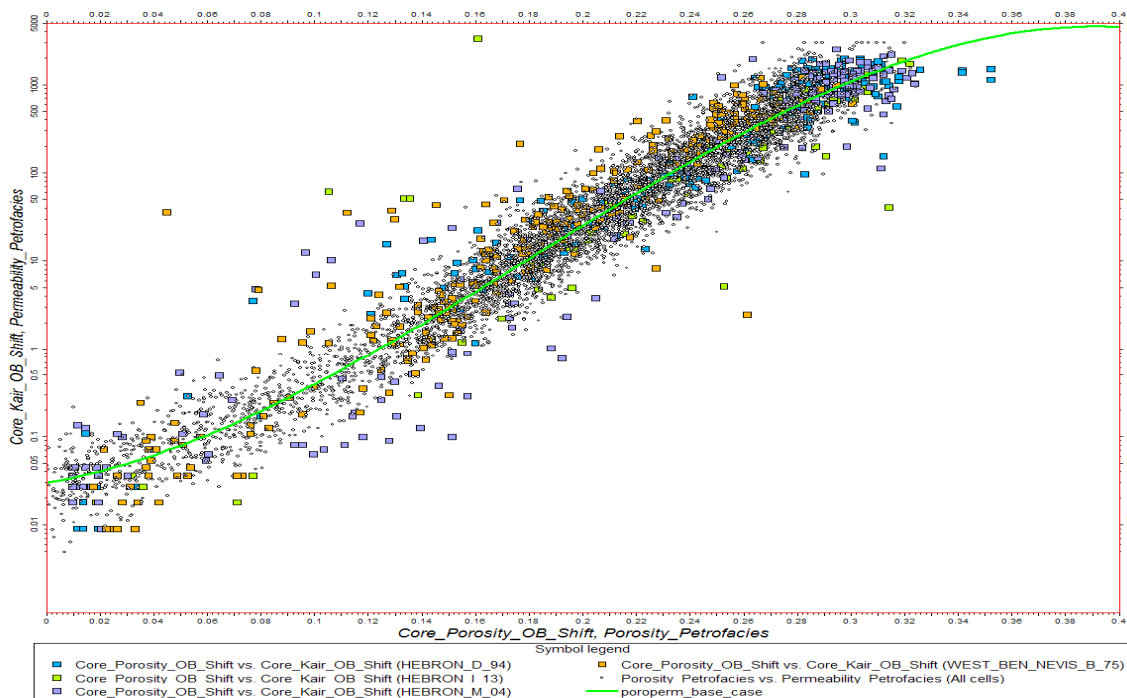


Figure 3.2-20: Pool1 OBC Core Porosity vs Permeability (Perma)

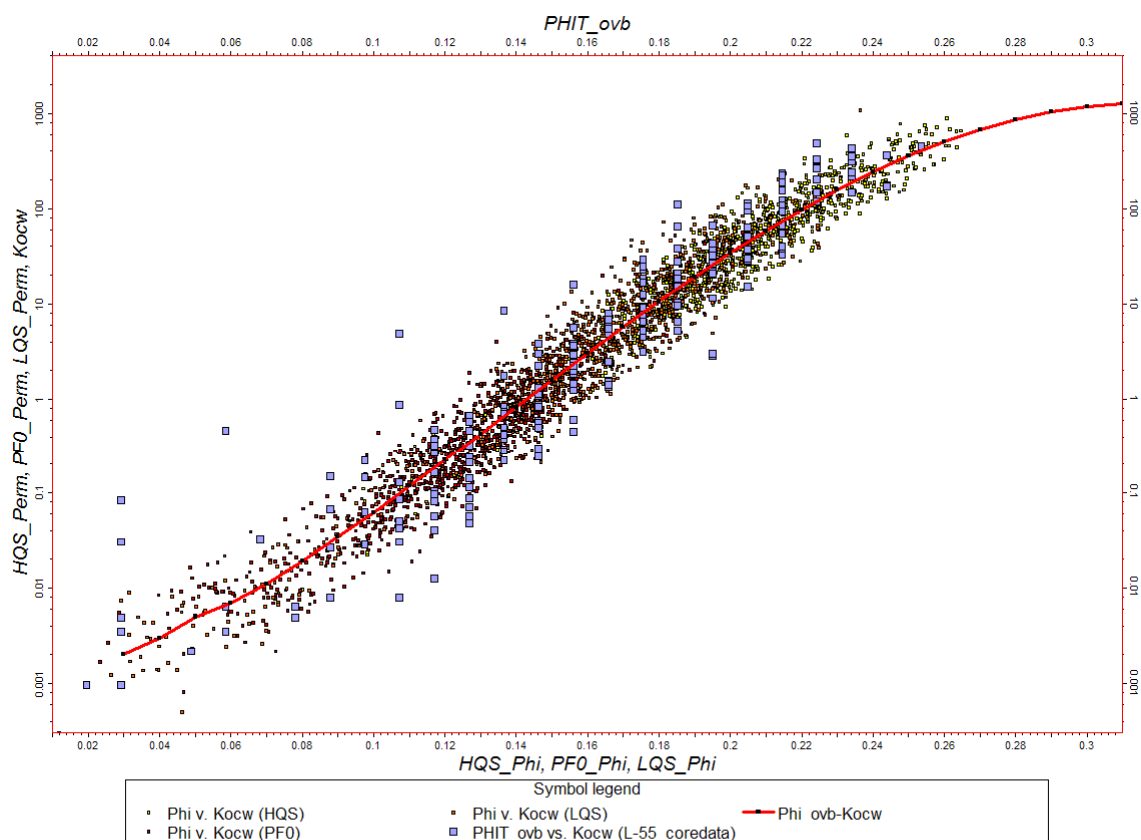


Figure 3.2-21: Pool 3 OBC Core Porosity vs Permeability (PermA)

3.2.6 Comparison with DST Analysis

Another way of validating permeability is comparison of conductivities (Kh) from logs and DST. Kh_log is permeability measured from the logs multiplied by height and Kh_DST is permeability calculated from the DST multiplied by height. Kh_log was calculated only over perforated intervals (Table 3.2-7).

Table 3.2-8: Kh Values from Log and DST Interpretation

Well	DST#	Interval (m)	Formation	Kh_log (md-m)	Kh_DST (md-m)
B-75	7	2044.0 – 2065.0	Ben Nevis	670	252
	8	2002.0 – 2015.0	Ben Nevis	266	2158
D-94	1	1842.0 – 1908.4	Ben Nevis	30094	32096
L-55	1	2347.9 – 2421.0	Ben Nevis	685	735
I-13	9	1905.5 – 1915.4	Ben Nevis	3633	22560
	10	1865.9 – 1876.0	Ben Nevis	1836	2714

The comparison is very good in wells with modern logs and good hole conditions with correction factors of 1.06 in D-94 and 1.07 in L-55. Larger differences are observed in the older wells where there is less confidence in both the log and test data.

3.2.7 Summaries

Table 3.2-9 contains petrophysical results by wells and formations. The net reservoir was defined as rock with $k > 1$ mD and $V_{clay} < 30$ percent. Net pay as reservoir rock was defined with $S_w < 55$ percent. Note that cutoffs are not applied in the reservoir models.

Table 3.2-9: Reservoir Summaries for the Ben Nevis and A Marker Formations

Well	Interval MD (m)	Net Reservoir (m)	Net Pay (m)	Avg. Phit (%) Reservoir	Avg. Phit (%) Pay	Avg. S_w (%)	NTG Res	NTG Pay
M-04	1872.5 – 1994.0	98.0	36.3	25.2	24.4	28.2	0.81	0.30
I-13	1860.0 – 1989.1	114.5	58.1	24.5	24.2	33.1	0.89	0.45
D-94	1831.4 – 1969.0	130.7	88.8	24.8	24.1	23.3	0.95	0.65
B-75 – BN	2000.0 – 2391.1	212.5	8.1	21.8	20.9	43.6	0.54	0.02
B-75 – AM	2391.1 – 2492.0	23.2	39.9	18.9	14.8	36.1	0.23	0.40
L-55 – Gas	2314.0 – 2333.5	15.4	13.9	16.7	17.1	39.2	0.79	0.71
L-55 – Oil	2333.5 – 2605.0	164.1	40.2	17.0	17.9	43.1	0.60	0.15
I-45 – BN	2376.0 – 2761.0	128.4	19.6	16.0	15.7	44.9	0.33	0.05

AM – A Marker

BN – Ben Nevis

Phit – Total porosity

Net Reservoir Definition: $K > 1$, Clay < 30 percent

Net Pay Definition: Net Reservoir with $S_w < 55$ percent

**** Average S_w – for Pay intervals only**

3.3 Hibernia Reservoir

The Hibernia formation was penetrated by four wells in the Hebron Asset (I-13, M-04, B-75, I-45) in addition to the offset well I-30; however, significant pay was identified only in the I-13 well. The log and core analysis was performed to provide inputs to geologic model of Pool 5. The Hibernia formation is the reservoir for Pool 5.

3.3.1 Petrophysical Data

3.3.1.1 Log Data

Log normalization was necessary to make consistent transfer of models built using the M-04 core data to other wells. Logging data were not consistent due to different logging vintages, different logging suites and quality (older in H-71 or I-13; Modern in I-30 or M-04), different fault blocks, and different mud systems.

Normalization was done by choosing four normalization “levels” having more consistent petrophysical properties. This 4-point normalization was performed between the M-04 and I-13 wells (Table 3.3-1). For the remaining wells, 2-point normalization was done using the B Marker as one point and overall average as a second point. The most significant normalization factors applied for all wells were related to GR. This resulted mainly from the different mud systems, especially K-based muds used in previous wells.

Table 3.3-1: Factors Used for the Four-Level Normalization of I-13 Logs

Layer/Log		GR	DT	NPHI	RHOB	RES
Level 1	M-04	21.6	198.1	0.092	2638	17.1
	I-13	32.07	200.27	0.102	2543	14.6
	Delta	-10.47	-2.17	-0.01	95	-2.5
	%	-0.48472	-0.01095	-0.1087	0.036012	-0.1462
Level 2	M-04	28.6	219.5	0.129	2496	3.2
	I-13	38.06	226.14	0.143	2464	23.7
	Delta	-9.46	-6.64	-0.014	32	-20.5
	%	-0.33077	-0.03025	-0.10853	0.012821	-6.40625
Level 3	M-04	72.15	233.3	0.128	2608	5.26
	I-13	63.8	237.4	0.147	2526	2.9
	Delta	8.35	-4.1	-0.019	82	2.36
	%	0.115731	-0.01757	-0.14844	0.031442	0.448669
Level 4	M-04	26.2	234.4	0.157	2431	1.48
	I-13	32.3	263.8	0.167	2412	1.35
	Delta	-6.1	-29.4	-0.01	19	0.13
	%	-0.23282	-0.12543	-0.06369	0.007816	0.087838
AVERAGE	M-04	41.37	223.4	0.126	2550	9.31
	I-13	44.16	227.3	0.149	2486	7.83
	Delta	-2.79	-3.9	-0.023	64	1.48
	%	-0.06744	-0.01746	-0.18254	0.025098	0.158969

For the other wells, GR normalization used factors as per Table 3.3-2.

Table 3.3-2: GR Normalization for the Hibernia

Well	GR_avg	GR_min	Norm Factor
M-04	41	12	0
B-75	64	33	-21
H-71	48	32	-21
I-30	79.8	46	-40

3.3.1.2 Core Data

A short core was cut in the I-13 well, but recovered only 18 m, and was not adequate to build a reliable field model and transform (Table 3.3-3). Extensive coring was performed in the M-04 well where 110.6 m of core were recovered in one run. Data from this core was essential to build Multimin models and permeability transforms.

Table 3.3-3: Core Data for the Hibernia Formation

Well	Interval (m)	CCA (# of samples)	XRD	SCAL
I-13	2944 – 2962	31		
M-04	2984 – 3094	498	220	

3.3.2 Overburden Correction

Overburden corrections for porosity and permeability were defined using specially selected samples from the M-04 core. The following overburden/Klinkenberg corrections were applied to core porosity and permeability:

$$Phie_{ob} = 0.9602 * Phie$$

$$Kmax_{ob} = 0.8419 * Kmax$$

3.3.3 Multimin Models

Core XRD and PKS from M-04 well was used to develop Multimin model using inverse parameter modeling.

There is an excellent agreement between log-derived mineral volumes, porosity and permeability, and corresponding core data.

Figure 3.3-1 below shows an average difference between core and log porosity below 1 percent with $Phit > cpor$ (as expected). The prediction error on depth level is 3 percent.

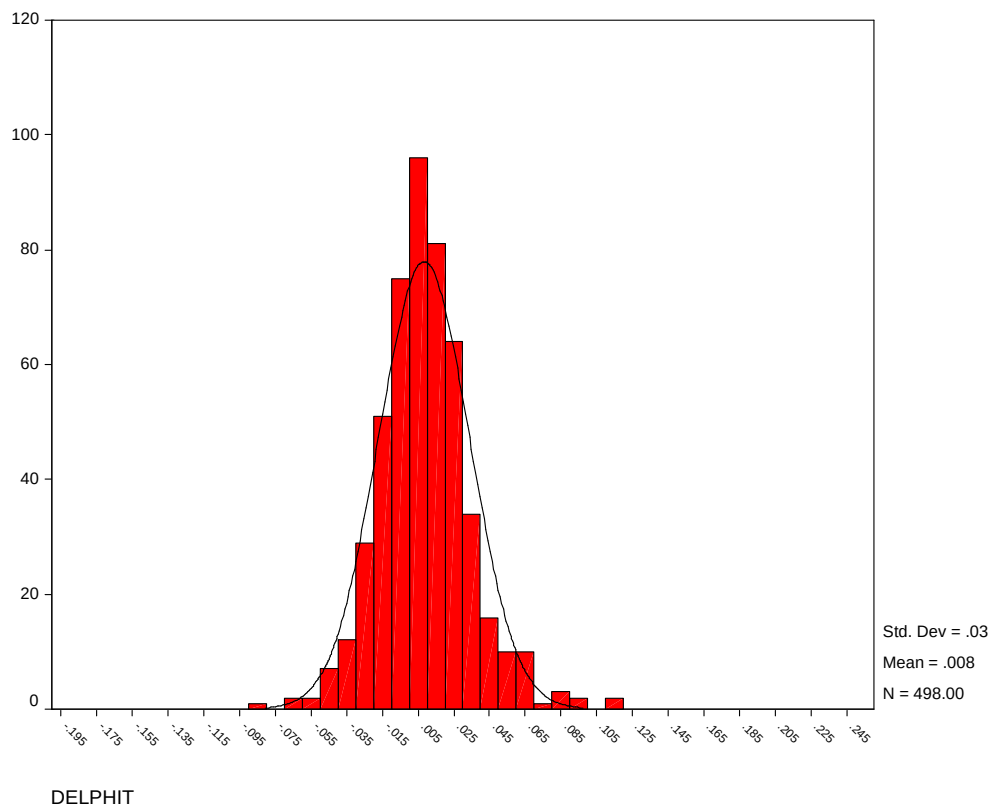


Figure 3.3-1: Porosity Error Distribution

Core Data from M-04 were used to build two models, one with modern M-04 logs and a second with a basic suite of logs existing in both M-04 and I-13. Since the simple model was built using M-04 core and logs, direct application of this model to I-13 wells required normalization of I-13 logs.

3.3.3.1 Shale Volume

Shale volume was provided by Chevron and validated by ExxonMobil. The interbedded shale and sand beds are accentuated on the Vsh curve.

3.3.4 Water Saturation

Initially Sw was derived from Multimin using the Dual Water Model with m-1.85, variable n as a function of permeability, and water salinity of 85,000 ppm.

However, Amott wettability tests in I-13 preserved samples indicated that the Hibernia reservoir is partially oil wet with wettability index to oil -0.24 (sample M1) and -0.254 (sample M6).

Since the Hibernia reservoir is partially oil wet, transforms for Sw were derived from CMR Swir data, which is independent of resistivity. Figure 3.3-2

show how these transforms were developed. These transforms were applied to the I-13 well to obtain Sw_cmr.

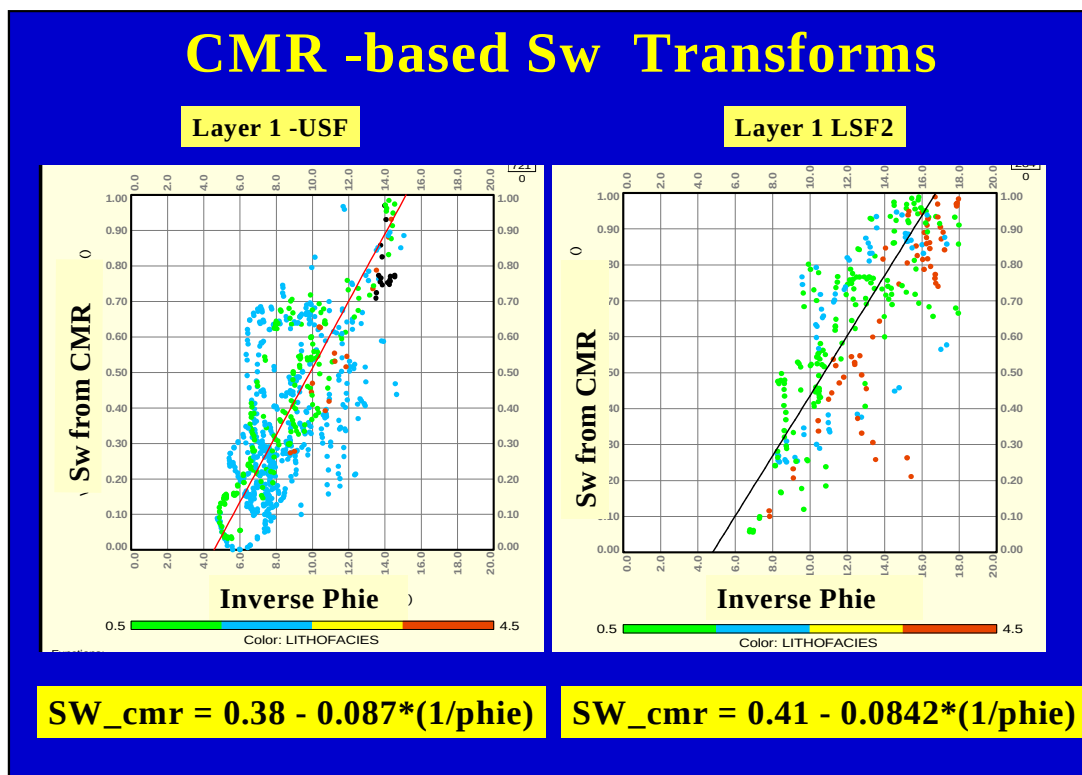


Figure 3.3-2: Cross-plots of Swir from CMR vs. 1/Phie for Layer I Upper Shoreface and Layer I Lower Shoreface in M-04

The next step was to define J functions using the Sw_cmr derived log data. The J functions (in imperial units) is defined as follows:

$$J = \frac{0.22 * P_c + \sqrt{k}}{* \cos}$$

Where:	
<i>Pc</i>	= capillary pressure in psi
<i>k</i>	= permeability from logs
<i>Φ</i>	= Phie from Multimin
<i>σ</i>	= interfacial tension assumed to be 30 dynes /cm
<i>θ</i>	= contact angle – 30 deg

Capillary pressure was calculated using the following equation:

$$P_c = \frac{h * (w - o)}{2.308}$$

<i>Where:</i>	
<i>h</i>	= height above Free Water Level (in ft)
$\rho_w - \rho_o = 0.269 \text{ g/cm}^3$	

To relate J function with Sw, the nonlinear model shown in the following equation was adopted.

$$J = \frac{1}{S_w^B}$$

This model was linearized by using the following logarithmic expression:

$$\log(J) = \log(1) - B \cdot \log(S_w)$$

Values of α and β were defined as regression coefficients between log J and log (Sw_cmr). These regression coefficients are as follows:

Upper shoreface regression coefficients

$$\alpha = .01313$$

$$B = 1.59833$$

Lower shoreface regression coefficients

$$\begin{array}{ll} J > 1 & \alpha = .02228 \\ & B = 2.346 \end{array} \quad \begin{array}{ll} J < 1 & \alpha = .03092 \\ & B = 5.061 \end{array}$$

3.3.5 Facies

Two dominant lithofacies were identified within the 10 depositional cycles of the Hibernia sands:

- ◆ Upper Shoreface
- ◆ Lower Shoreface

Within the two dominant lithofacies, five petrofacies were identifiable by logs, and were defined.

3.3.5.1 Petrofacies Definition

Petrofacies were defined using cutoffs for the mineral volumes from Multimin. Five facies were defined as shown in the following equations.

- ◆ Petrofacies

$$sand = vol\_quartz + vol\_albite + vol\_orthocl$$

$$carb = vol\_calcite + vol\_dolom$$

- ◆ Petrofacies 1 – Clean Sand

$$sand > 0.5 \ \& \ carb < 0.1 \ \& \ vol\_illite < 0.1$$

- ◆ Petrofacies 2 – Carbonaceous Sand
sand > 0.4 and carb is between 0.1 and 0.4
- ◆ Petrofacies 3 – Carbonate
carb > 0.4 and vol_illite < 0.1
- ◆ Petrofacies 4 – Shaly Sand
sand > 0.4 & vol_illite > 0.1 & carb < 0.1
- ◆ Petrofacies 5 – Shale
vol_illite > 0.3 & sand < 0.4

3.3.6 Permeability

Cross-plots of Phie and K from core indicate different PHI/K relationships existed for the previously defined Petrofacies. These differences were used to better define permeability. Transforms were derived using M-04 logs and Miniperm data. After normalization of the I-13 data to the M-04 data, these transforms were applied to I-13.

Transforms defined by Petrofacies for normalized data as follows (only logs present in both wells M-04 and I-13 were used):

- ◆ Petrofacies 1 – Clean Sand
$$Perm = 10^{**}(-0.005835 + 20.957 * phie - 1.414 * \log_{10}(gr\_norm))$$
- ◆ Petrofacies 2 – Carbonaceous Sand
$$Perm = 10^{**}(4.59 + 20.937 * phie - 6.746 * \log_{10}(gr\_norm) + 2.517 * vol\_quartz + 0.0564 * (gr\_norm) + 1.264 * vol\_calcite)$$
- ◆ Petrofacies 3 – Carbonate
$$kmax\_ms = 10^{**}(-0.641 + 18.82 * phie - 1.019 * \log_{10}(gr\_norm))$$
- ◆ Petrofacies 4 – Shaly Sand
$$kmax\_all = 10^{**}(-7.885 + 23.098 * phie - 1.263 * \log_{10}(gr\_norm) + 0.959 * vol\_quartz + 0.002708 * rhob\_norm)$$

Permeability was limited to a maximum of 3000 md

3.3.7 Summaries

Table 3.3-4 summarizes petrophysical summaries for Layers 1 to 3, which were used in this evaluation. Summaries were calculated using two reservoir cutoffs, as follows:

- ◆ Phie > 10

◆ Perm > 1 mD

The numbers in red refer to marginal pay zones in the I-13 well and B-75 wells.

Table 3.3-4: Hibernia – Petrophysical Summaries

	Cutoff	Data	M-4	I-13	B-75	H-71	I-30
Layer 1	Phi > 10%	Net Res / Pay	23.6	27.3 / 26.1	1.7	12.2	37.5
		Phi_avg	13.2	13.2 / 13.3	11.1	13.1	14.2
		Sw_avg		22.1			
	Kmax > 1	Net Res	17.6	11.3 / 11.1	0.9	9.4	26.8
		Phi_avg	13.6	15.5 / 15.6	10.5	13.7	15.3
		Sw_avg		22.0			
Layer 2	Phi > 10%	Net Res	18.4	21.9 / 11.9	0	36.8	45
		Phi_avg	14.3	14.1 / 15.0	na	14.2	16.7
		Sw_avg		40.0	Na		
	Kmax > 1	Net Res	13.2	15.2 / 8.5	0	33.8	43.1
		Phi_avg	15.4	15.2 / 16.2	na	14.5	16.9
		Sw_avg		40.9			
Layer 3	Phi > 10%	Net Res	89.5	62.3	33.6 / 2.1	30.4	45.3
		Phi_avg	17.5	16.8	11.8 / 11.7	15.0	16.1
		Sw_avg			28.1		
	Kmax > 1	Net Res	73.8	50.3	31.8 / 2.7	28.6	35.2
		Phi_avg	18.5	17.5	11.5 / 11.2	15.2	17.3
		Sw_avg			29.4		

3.4 Jeanne d'Arc Reservoir

The Jeanne d'Arc Formation was penetrated in four wells within the Hebron Asset (I-13, M-04, B-75, I-45) as well as the offset well I-30. Pool 4 includes the reservoir interval in the J d'Arc Formation penetrated by I-13 and M-04, analyses from these wells were included in the geologic model.

3.4.1 Petrophysical Data

3.4.1.1 Log Data

Only the M-04 well contained modern, good quality logs. Data from other wells are much less reliable due to log quality, borehole conditions, and missing intervals. In the B-75 well, the casing point was selected in the middle of oil-bearing F Sand, which resulted in missing data from part of this

sand. Petrophysical models were built using selected Terra Nova data to make transforms more robust.

3.4.1.2 Core Data

Core data for Jeanne d'Arc reservoir that Hebron are shown in Table 3.4-1.

Table 3.4-1: Core Data for the Jeanne d'Arc Formation

Well	Interval (m)	Conv. Core Analysis (# of samples)	XRD	SCAL
B-75	4480.9 – 4494.5	26	-	-
I-13	4075 – 4083.4			
	4393.7 – 4412	60	-	
H-71	4376 – 4394			
	4458 – 4466			
	4466 – 4472	45	-	-
M-04	4522 – 4587	65 and 53 Sidewalls		

3.4.2 Petrophysical Methodology

The Jeanne d'Arc models are not as well defined as other Hebron reservoirs due to limited and fragmental core data and poor quality logs (with the exception of M-04). Preliminary Multimin models as well as permeability transforms were based on Terra Nova data assuming similar relationships. Terra Nova data was partially used in definition of general permeability transforms. Due to poor and incomplete logging surveys, interpretation uncertainty is high.

3.4.3 Jeanne d'Arc H Sand

A model was developed for the H Sand with minerals and logs as shown in Table 3.4-2.

Table 3.4-2: Elements of the Multimin Model for the H Sand

Minerals	Logs
Quartz	RHOB
Calcite	NPHI
Illite	DT
Orthoclase	U
Bitumen	HGR
X_wat	CT
U_wat	CXO
X_oil	PHI_CM

U_oil	ECS_clay
	$\Sigma Vol=1$
	$\Sigma Fluids\_X=\Sigma Fluids\_U$

In this model, the number of logs is higher than the number of volumes to define. There is a so-called over-determined system, which assures more robust optimization. No XRD data was available, so mineral responses were defined using conventional parameters adjusted to match measured and reconstructed logs. Rw was calculated using water salinity of 85,000 ppm (i.e., the same as that for Hibernia sands). Some zones in the H Sand exhibited unusual logging responses indicating high porosity. Sidewall core description confirmed these zones as bituminous. After including bitumen in the model and CMR porosity (sensitive to movable fluid only), interpretation results were much more realistic.

3.4.4 Other Jeanne d'Arc Sands

For G to B Sands, two main models were developed the first for modern logs (M-04) and the second for old logs. Table 3.4-3 summarizes main elements of these models. Due to the lack of Pef logs in old logging suites, one mineral (orthoclase) had to be dropped from the model. That was related to the adjustment of end points for other logs (for example GR). Water saturation was calculated using water salinity of 100,000 ppm. This number is based on Rwa analysis, other fields, and Jeanne d'Arc water samples. Archie coefficients of $m = 1.8$ and $n = 2$ were used based on core analysis from the M-04 well. The Jeanne d'Arc models were designed around bad hole logic. Simple models tended to overestimate pay due to hole conditions.

Table 3.4-3: Elements of the Basic Multimin Model for Jeanne d'Arc

Minerals	Tools
Quartz	RHOB
Calcite	NPHI
Illite	DT
Orthoclase	U*
X_Oil	HGR
U_OIL	Ct
X_Wat	Cxo
U_Wat	$\Sigma Vol=1$
	$\Sigma (Fluids\_x)=\Sigma (Fluids\_u)$

Bad hole models were created for each well separately to adjust for hole and measurement conditions. Model switching logic was, therefore, more related to washouts effect than their size. Typically, density and / or neutron cutoffs together with quality log cutoffs were used. Bad hole models typically have

high porosity uncertainty as the sonic log replaces the more accurate density and neutron logs when hole conditions deteriorate.

3.4.5 Water Saturation

Sw transforms for the GOCAD model were defined in a similar way to the Hibernia reservoir using inverse porosity. The following functions were established:

$$\text{General Swe} = -0.023229 + 0.0211239 * (1/PHIE)$$

$$\text{For B Sand Swe} = -0.0339615 + 0.018225 * (1/Phie)$$

$$\text{For D Sand Swe} = -0.0917918 + 0.0296327 * (1/Phie)$$

No correlations between Swe and Phie were found in the H Sand. It is suspected that subsequent fluid exchanges altered original capillary pressure driven profiles.

3.4.6 Facies

Petrofacies were defined in a similar way to for the Hibernia reservoir using cutoffs for log-derived minerals. Below is the description of mineral cutoffs used to calculate petrofacies.

- ◆ Mineral Cutoffs

$$\text{sand} = \text{vol\_quartz} + \text{vol\_orthocl}$$

$$\text{carb} = \text{vol\_calcite} + \text{vol\_dolom}$$

- ◆ Petrofacies 1 – Clean Sand

$$\text{sand} > 0.5 \ \& \ \text{carb} < 0.1 \ \& \ \text{vol\_kaolin} < 0.15$$

- ◆ Petrofacies 2 – Carbonaceous Sand

$$\text{sand} > 0.4 \ \text{and} \ \text{carb} \ \text{is between} \ 0.1 \ \text{and} \ 0.4, \ \text{and} \ \text{vol\_kaolin} < 0.15$$

- ◆ Petrofacies 3 – Carbonate

$$\text{carb} > 0.4 \ \text{and} \ \text{vol\_kaolin} < 0.15$$

- ◆ Petrofacies 4 – Shaly Sand

$$\text{sand} > 0.4 \ \& \ \text{vol\_kaolin} < 0.15 \ \& \ \text{carb} < 0.1$$

- ◆ Petrofacies 5 – Shale

$$\text{vol\_illite} > 0.3 \ \& \ \text{sand} < 0.4$$

Petrofacies 1 and 2 corresponds to mostly reservoir facies while Petrofacies 3, 4, and 5 are predominantly non-reservoir.

3.4.7 Permeability

Preliminary pre-M-04 transforms were developed using Terra Nova core-log data. M-04 new data included sidewall cores from H and D Sands and core from the B Sand. Combining Terra Nova and M-04 data classified according to stratigraphic position and facies was used for final transforms.

3.4.7.1 Core Transforms

The slopes have been observed to be different; therefore, core-log transforms should be developed for separate groups of sands (Figure 3.4-1).

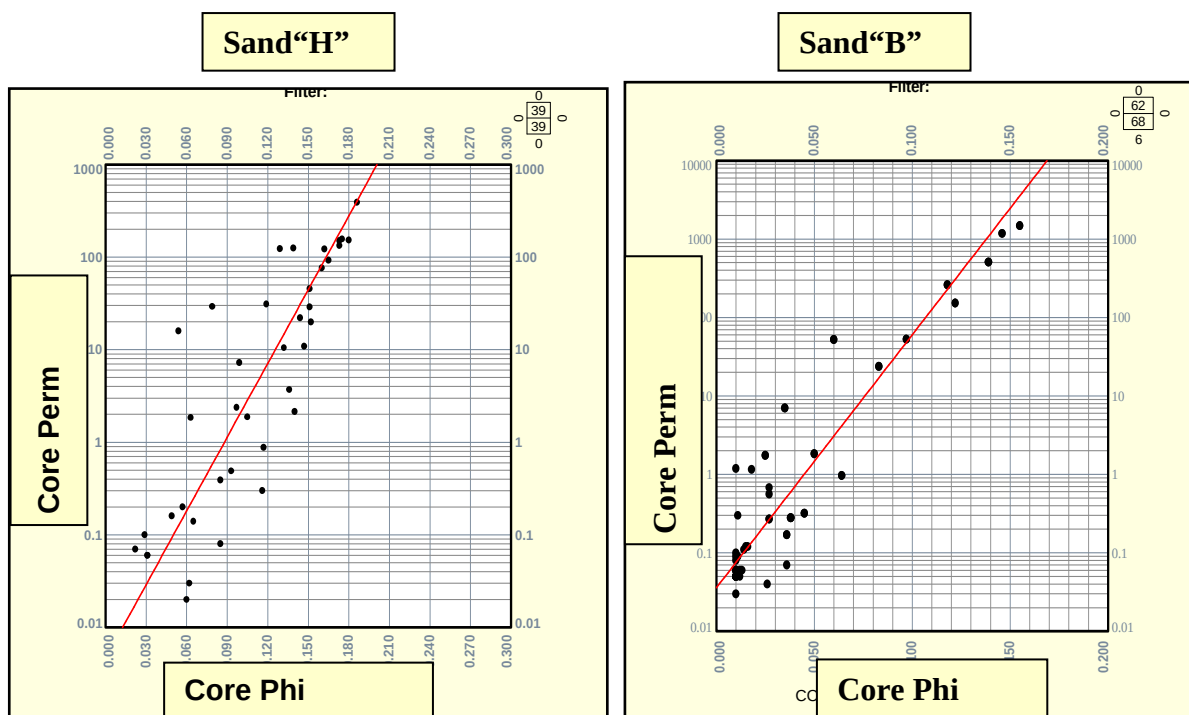


Figure 3.4-1: Phi-k Core Transforms (Ambient conditions) for H and B Sands in M-04

3.4.7.2 Multivariate Core – Log Transforms

Based on examination of core transforms, multivariate transforms were developed for the following classes:

- ◆ H Sands based on M-04 sidewall core and K-18 core (channel sands)
- ◆ Lower sands based on B and C1 Sands core from three Hebron wells, i.e., M-04, I-13, and H-71
- ◆ Intermediate Sands based on sidewall core
- ◆ Others, based on general transforms

3.4.8 Porosity Validation

The distribution of differences between log and core porosity for the B Sand interval is presented in Figure 3.4-2. The histogram includes 140 core

samples from M-04, I-13, and H-71 wells. An excellent agreement of both average values (0.1 percent) and standard deviation (2 percent) validate the accuracy of log porosity.

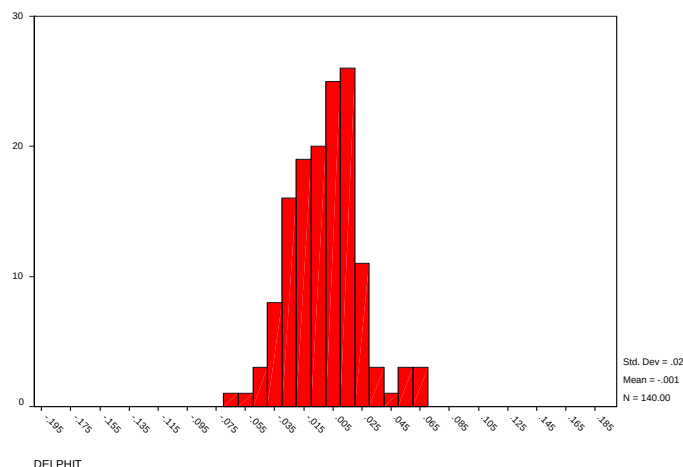


Figure 3.4-2: Porosity Error for the B Sands from Three Hebron Wells

3.4.8.1 Permeability Validation

As observed in Table 3.4-4, kh from DST is in most cases about two times higher than log-derived. A possible explanation is that inadequate vertical resolution of the logs overlooks thin, high permeability streaks. Evidence of this was identified in the miniperm data in the M-04 well (B Sand).

Table 3.4-4: Kh from Logs and DST

Well	DST #	Interval (m)	Kh (mdm)- DST	Kh (mdm)- Logs
B-75	4	4498 - 4507	504	475.8
I-13	1	4368 - 4381	776	311
	5	3842 - 3857	2040	1070
M-04	1	3906 - 3924	1210	644

3.4.9 Summaries

Examination of core Phi-K cross-plots indicates that 1 mD permeability corresponds to different values of porosity ranging from 4 percent (B Sand) to 10 percent (H Sand). For consistency, petrophysical summaries were calculated for common 1 mD cutoff.

Table 3.4-5 contains a summary of pay intervals, from log evaluation.

Table 3.4-5: Net Pay Thickness (m) Summary

Well	H Sand	G Sand	F Sand	E Sand	D Sand	C2 Sand	C1 Sand	B Sand
M-04	14.5	1.4	-	1.8	6.8	2.9	-	2.1
B-75	-	-	5.4	4.0	-	9.9	-	2.6
I-13	-	6.9	2.6	-	12.6	1.7	1.2	10.2
H-71	-	-	-	-	-	-	0.4	-
I-30	-	-	-	-	-	-	-	-

Net pay values were calculated using 1 mD cutoff for net reservoir and Sw of 45 percent for the net pay definition.

The H Sand in M-04 has an OWC at 3932 m (–3909.2 TVDSS). OWC in D Sand in I-13 is lower than previously interpreted. The new interpretation indicates a transition from 4072 m to the base of the sand at 4104 m (–4076 TVDSS).

3.5 Acronyms in Log Plots

Acronym	Definitions
BVW	Bulk Volume Water
Cali	Caliper
COREDATA_JEG_SH.PHI	Core porosity (Overburden Corrected)
DATA_JEG_SH.PERM	Core Permeability (Overburden Corrected)
DRHO	Bulk density correction
DT	Sonic Travel Time
FWL	Free Water Level
GR	Gamma Ray
ILD	Deep Resistivity (Induction)
KAH	Calculated Permeability
LLD	Deep resistivity (laterolog)
LLS	Shallow resistivity (laterolog)
NPHI	Neutron porosity
PHIT	Total porosity
RES	Resistivity
RHOB	Bulk density
SWT_EM	Archie-derived Water Saturation
SWT_SHF	Height Function-derived Water Saturation
Vsh	Volume of Shale

3.6 References

In addition to references given in Section 2.6, we utilized information contained in Chevron 2008 close out documents.

4 RESERVOIR ENGINEERING

4.1 Introduction

Reservoir engineering data and the resulting analysis and / or interpretations used as the basis for depletion planning are presented in this Section. The data was derived from a variety of sources, the most important of which were the exploration and appraisal wells drilled in the area (including the off-lease well, H-71).

This Section is divided into four main segments. Section 4.2 provides a high-level summary of the Hebron area resource and key reservoir properties including drill stem test results, fluid properties, reservoir pressures, and temperatures. Sections 4.3, 4.4, and 4.5 provide additional details specific to each of the three main stratigraphic intervals (Ben Nevis Avalon, Hibernia, and Jeanne d'Arc) that are the major hydrocarbon-bearing reservoirs across the entire Hebron Asset.

4.2 Reservoir Overview

The Hebron Asset is composed of four reservoir intervals organized into several normal fault-bounded fault blocks. The central horst block is the Hebron field, and the down-dropped fault blocks to the north-east are the West Ben Nevis and Ben Nevis fields. The down-dropped fault block to the south-west forms the Southwest Graben.

The three vertically stacked reservoirs and multiple fault blocks contribute to the complexity of the multiple hydrocarbon columns with different contacts at the Hebron Asset. To simplify communication, the Hebron Asset is currently divided into five major pools (although other hydrocarbon-bearing pools beyond these exist). The pools (See Figure 4.2-1) are defined as follows:

1. Pool 1 is defined as the Early Cretaceous Ben Nevis reservoir located in the Hebron Field (penetrated by the D-94 well) and the I-13 fault block, which is adjacent to the south and penetrated by the I-13 well.
2. Pool 2 is defined as the Early Cretaceous Ben Nevis reservoir located in the West Ben Nevis Field and penetrated by the B-75 well.
3. Pool 3 is defined as the Early Cretaceous Ben Nevis reservoir in the Ben Nevis Field and the Early Cretaceous Avalon reservoir located in the West Ben Nevis Field. Pool 3 was penetrated the B-75, L-55, and I-45 wells.
4. Pool 4 is defined as the Late Jurassic Jeanne d'Arc reservoir within the Hebron Field and penetrated by the I-13 and M-04 wells.

5. Pool 5 is defined as the Early Cretaceous Hibernia Reservoir only within the Hebron Field, penetrated by the I-13 well, and water-wet in the M-04 well.

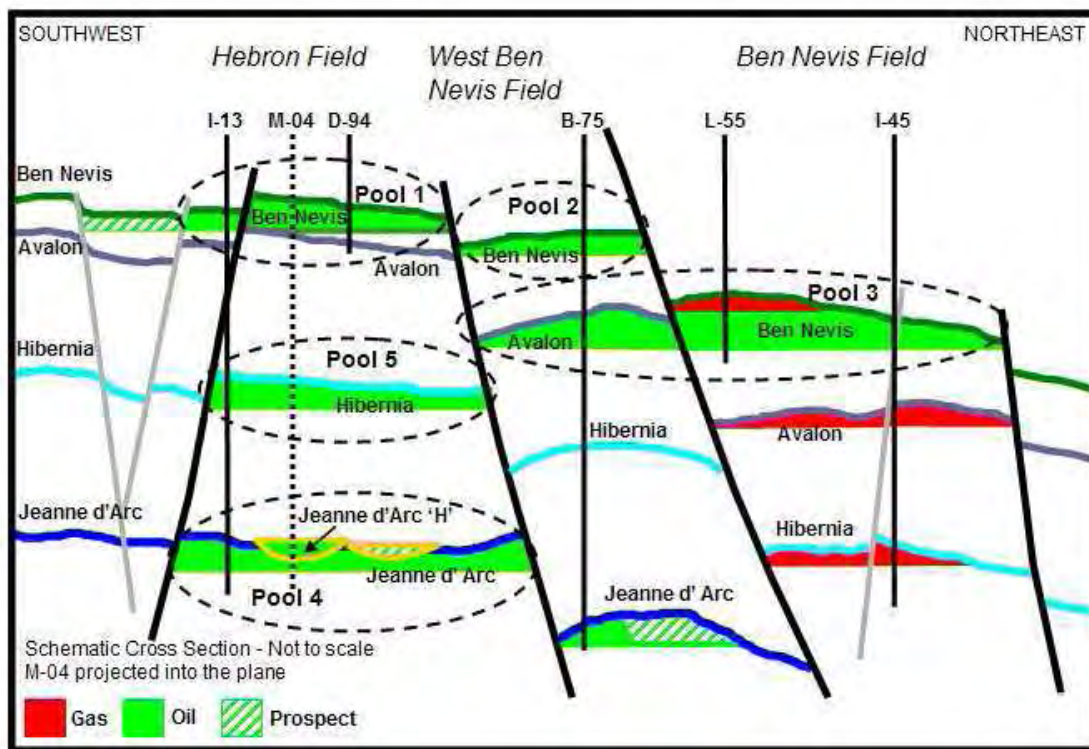


Figure 4.2-1: Schematic Cross-Section over the Crest of the Hebron Asset

4.2.1 Drill Stem Test Results

Several drill stem tests (DSTs) have been completed in the development area. The objectives of the DST programs were to evaluate reservoir performance, assess parameters applicable to reservoir studies, and obtain representative bottomhole and surface fluid samples for detailed fluids properties studies.

The most recent DSTs were conducted during the 1999 to 2000 drilling campaign of the D-94, L-55, and M-04 wells. The production tests in these wells targeted the Ben Nevis reservoir interval in the Hebron field (D-94), the Ben Nevis reservoir interval of the Ben Nevis field (L-55), and the Jeanne d'Arc Layer H pool in the Hebron field (M-04).

Most of the drill-stem tests (more than twenty) were conducted between 1980 and 1985 in the I-45, I-13, and B-75 wells. The data obtained (and the resulting interpretations) from these earlier well tests, although valuable, are not as reliable as the data from the more recent tests. Some of the issues

observed with the DSTs performed in the early wells (I-45, I-13, and B-75 wells) include the following:

1. Poor resolution or accuracy of the mechanical pressure gauges in use at the time
2. Inefficient monitoring of rate data, especially during the clean-up period
3. Poor accuracy in the flow data especially for low flow rate situations

Figure 4.2-2 provides a summary of the observed oil rates (in barrels of oil per day [BOPD]) from the drill stem tests. Detailed well test results, analyses, and interpretations are provided for the various stratigraphic intervals in Sections 4.3.1 (Ben Nevis/Avalon), 4.4.1 (Hibernia), and 4.5.1 (Jeanne d'Arc).

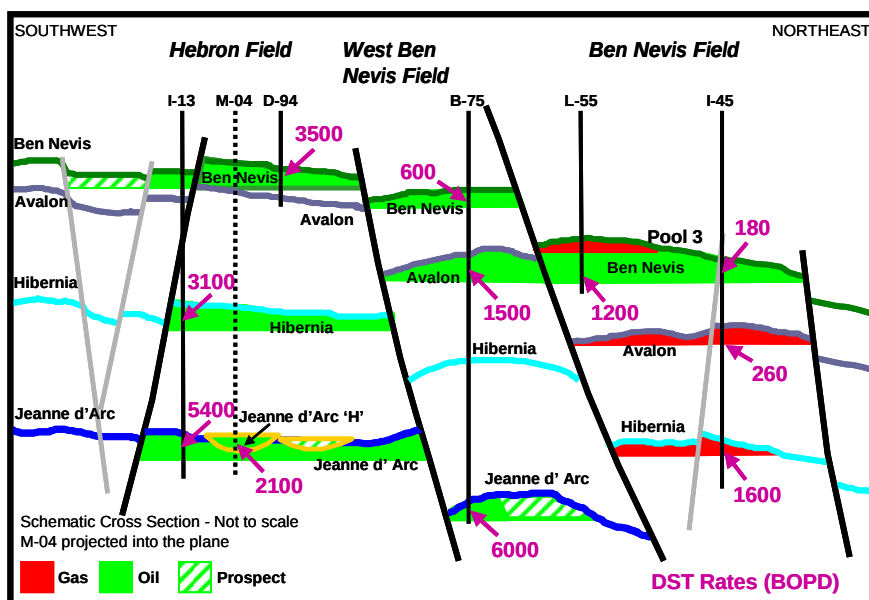


Figure 4.2-2: Drill Stem Test Overview (Rates BOPD)

4.2.2 Fluid Properties Overview

4.2.2.1 Fluid Properties Summary

Multiple bottomhole and separator fluid samples were acquired from several productive intervals of the wells drilled across the asset area and these have been used to define the fluid properties of the various reservoir intervals. Table 4.2-1 provides a high-level summary of the fluids sampling and characterization work conducted and the average fluids properties.

The available data was reviewed and compositional analyses of representative fluid samples were performed to generate data deemed to be most representative of the different reservoir intervals. Fluid properties were modeled compositionally using the Redlich-Kwong Equation of State (EOS). The EOS was tuned using pressure-volume-temperature (PVT) and

compositional data measured on the original fluids. Table 4.2-2 provides a summary of the compositional PVT data for the Hebron reservoirs.

Sections 4.3.2, 4.4.2, and 4.5.2 provide additional discussions and data on fluid properties for the various reservoir intervals.

Table 4.2-1: PVT and Oil Characterization Summary (Pools 1 - 5)

Description	Units	Hebron Field					West Ben Nevis		Ben Nevis
		Ben Nevis	Hibernia	Jeanne d'Arc Layer H	Jeanne d'Arc Layer G	Jeanne d'Arc Layer B	Ben Nevis	Avalon	Ben Nevis
		Pool 1	Pool 5	Pool 4	Pool 4	Pool 4	Pool 2	Pool 3	Pool 3
Reservoir Pressure, Pres	MPa	19.0	30.5	41.4	42.7	47.8	20.0	24.6	24.2
Reservoir Pressure, Pres	psia	2755	4423	6003	6193	6931	2900	3570	3505
Saturation Pressure, Pb	MPa	17.4	22.0	24.9	36.9	34.1	19.5	21.6	21.2
Saturation Pressure, Pb	psia	2523	3190	3611	5351	4945	2828	3130	3350
Reservoir Temperature	°C	62	86	106	116	125	70	82	82
Reservoir Temperature	°F	144	187	223	241	257	158	180	180
Average Reservoir Depth	m, TVDSS	1900	2950	3900	3975	4400	2000	2400	2400
Oil FVF, Bo @ Pres	m ³ /Sm ³ , rb/stb	1.12	1.29	1.28	1.83	1.79	1.20	1.217	1.31
Oil FVF, Bo @ Pb	m ³ /Sm ³ , rb/stb	1.13	1.30	1.30	1.91	1.87	1.20	1.218	1.31
Gas FVF, Bg @ Pb	m ³ /Sm ³	0.0053	0.0048	0.0049	0.0038	0.0042	0.0052	0.00466	0.00471
GOR, Rs	Sm ³ /Sm ³	50	100	98	277	286	72	74	98
GOR, Rs	scf/stb	281	561	550	1555	1606	404	414	550
Oil density @ Pres	kg/m ³	872	762	777	605	614	767	777	744
Oil density @ Pb	kg/m ³	869	744	760	579	587	767	775	740
Gas density @ Pb	kg/m ³	168	200	187	250	218	152	171	165
Stock Tank Oil Gravity	°API	17 - 24	29	25	36	37	31	28	31
Average Gas Gravity	(air = 1)	0.729	0.78	0.742	0.78	0.742	0.64	0.65	0.63
Water density @ ST	kg/m ³	1037	1052	1069	1069	1069	1037	1037	1037

Description	Units	Hebron Field					West Ben Nevis		Ben Nevis
		Ben Nevis	Hibernia	Jeanne d'Arc Layer H	Jeanne d'Arc Layer G	Jeanne d'Arc Layer B	Ben Nevis	Avalon	Ben Nevis
		Pool 1	Pool 5	Pool 4	Pool 4	Pool 4	Pool 2	Pool 3	Pool 3
Oil Viscosity @ Pres, Tres	cp	10.6	1.1	1.7	0.21	0.25	1.68	1.74	1.01
Oil Viscosity @ Pb, Tres	cp	10.4	1.0	1.45	0.2	0.21	1.68	1.74	0.96
Wax Appearance Temperature	[°C]	46	N/A	47	41	51	N/A	N/A	32
Pour Point	[°C]	-4	N/A	6	-27	-30	N/A	N/A	-21.3
Saturates	(wt%)	48.1	N/A	49.5	70.8	77.1	N/A	N/A	64.2
Aromatics	(wt%)	36.3	N/A	26.5	23.2	17.3	N/A	N/A	26
Resins	(wt%)	11.8	N/A	19.4	5.8	5.6	N/A	N/A	7.8
Asphaltenes	(wt%)	3.8	N/A	4.6	0.1	0.07	N/A	N/A	2

Table 4.2-2: Summary Compositional Data

Component Mole %	Hebron, Ben Nevis Well D-94	Jeanne D'Arc H, Well M-04	Ben Nevis, Ben Nevis Well L-55	Lift Gas Mole %
Nitrogen	0.01	0.24	0.05	1.61
Carbon Dioxide	0.48	1.03	0.36	1.63
Methane	37.07	46.55	45.29	83.46
Ethane	2.41	2.95	4.38	7.88
Propane	0.20	3.38	2.82	3.68
i-Butane	0.09	0.69	0.55	0.47
n-Butane	0.05	1.84	1.46	0.88
i-Pentane	0.03	0.89	0.66	0.16
n-Pentane	0.01	1.20	0.77	0.15
Hexanes	0.50	1.99	1.36	0.05
Heptanes	0.04	1.70	3.05	0.01
Octanes Plus	59.11	37.54	39.25	0.02
Total	100.00	100.00	100.00	100.00
C7+ MW	384.8	310.8	264.7	N/A
C7+ Density (g/cc)	N/A	0.91	0.89	N/A
Hydrogen Sulphide (ppm)	0.0	0.0	0.0	

4.2.2.2 Formation Water Analysis

All formation water samples acquired to date had some level of contamination that makes assessment of formation water composition difficult. The results of the analyses of some water samples collected from the M-04 well are provided in Table 4.2-3.

Table 4.2-3: Results of Formation Water Analysis

	Units	M-04 Well, Ben Nevis Sample # 2.09	M-04 Well, Hibernia Sample # 1.07
Sodium, Na	mg/l	21789	32297
Potassium, K	mg/l	255	317
Calcium, Ca	mg/l	1541	1990
Magnesium, Mg	mg/l	413	283
Strontium, Sr	mg/l	234	303
Barium, Ba	mg/l	22.30	3.62
Iron, Fe	mg/l	11.20	4.13
Manganese, Mn	mg/l	0.127	0.496
Lithium, Li	mg/l	3.39	5.65
Aluminum, Al	mg/l	0.062	0.420
Silicon, Si	mg/l	59.8	102.0
Boron, B	mg/l	92.7	186.3
Iodine, I	mg/l	122.4	276.8
Phosphorus, P	mg/l	8.0	17.5
Zinc, Zn	mg/l	0.053	1.231
Chloride, Cl	mg/l	34925	48528
Sulphate, SO ₄	mg/l	0	99
Bromide, Br	mg/l	101	134
Alkalinity	mg/l	570	560
Total organic acid	mg/l	1.05	138.15
pH @ 25°C	-	7.71	7.66
TDS	mg/l	60273	85632
Density @ 25°C	g/cc	1.0370	1.0525

4.2.3 Reservoir Pressures and Temperatures

4.2.3.1 Pressures and Pressure-Depth Plot

Average reservoir pressures for the various reservoir intervals are provided in Table 4.2-1. Pressure data gathered from wireline and DST operations are plotted in Figure 4.2-3. High-level observations from the plot show that the Hebron field reservoirs (data from the M-04, D-94, and I-13 wells) are generally normally pressured although some minor over-pressuring exists in some of the Jeanne d'Arc reservoirs in the M-04 and I-13 wells. Over-pressuring becomes more evident in the West Ben Nevis field (minor in the Ben Nevis formation and more significant in the Jeanne d'Arc Formation) and in the Hibernia formation of the Ben Nevis field.

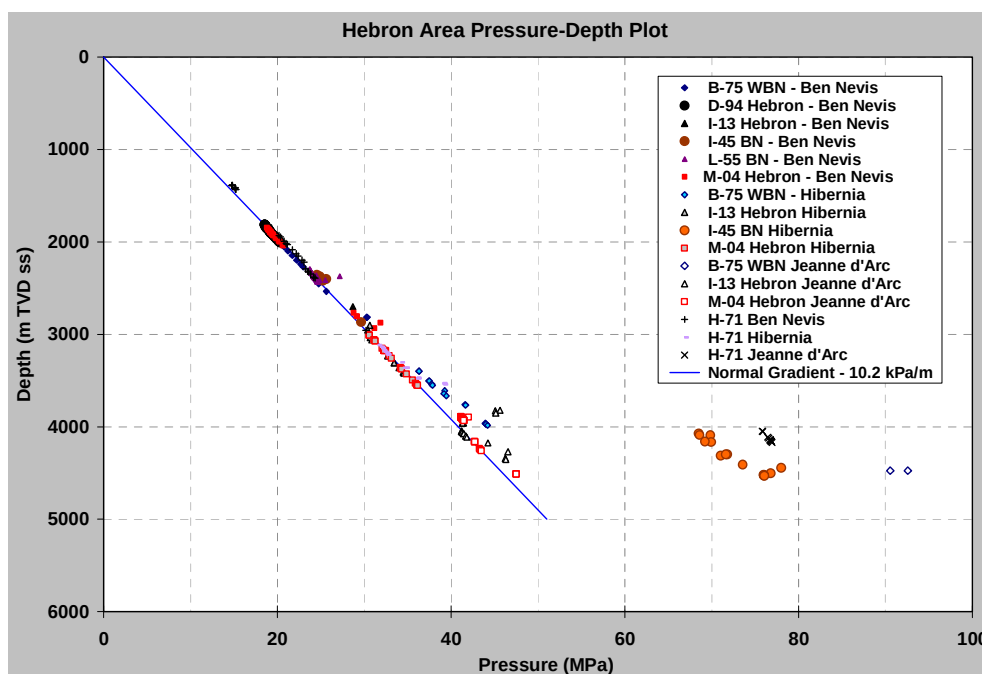


Figure 4.2-3: Hebron Asset Area Pressure Depth Plot

4.2.3.2 Reservoir Temperatures

Reservoir temperature information was gathered during the drilling and production testing operations of the Hebron area wells. The average temperatures of the different reservoir intervals are provided in Table 4.2-1. Figure 4.2-4 plots the temperature data gathered during the DST operations of the Hebron area wells. The observed temperature gradient of 2.92°C/100 m lies within the expected range of the regional geothermal gradients. The gradient was computed by constraining the curve fit to the observed sea-floor temperature of 1°C.

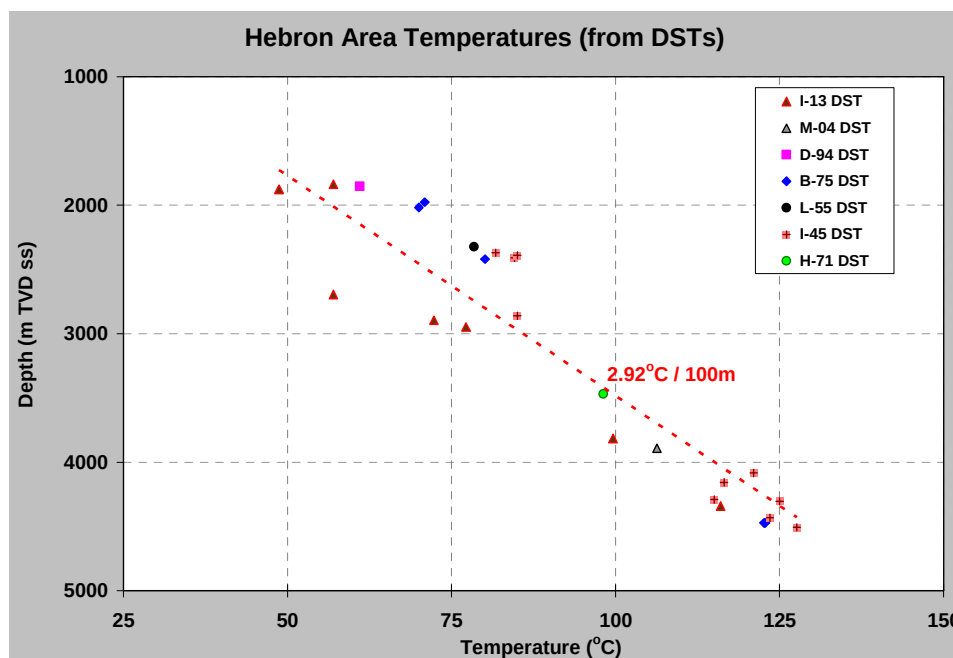


Figure 4.2-4: Hebron Area Temperatures

A regional temperature study has also been conducted for the Jeanne d'Arc basin. The study used information from other reservoirs in the basin sourced from the Geologic Survey of Canada Atlantic Basin database along with the temperature data gathered during the drilling and well testing operations of the Hebron area wells (with extrapolations where possible).

The main conclusions of the study are as follows:

1. The static bottomhole temperature of an interval within the Hebron Asset can be approximated using the following equations:

Hebron and West Ben Nevis Fields

$$Temp [^{\circ}C]_{\text{Shallower than 2000 m; transition begins at 1800 m}} = Depth [mSS] \times 0.0349 - 1.7$$

$$Temp [^{\circ}C]_{\text{Deeper than 2000 m}} = Depth [mSS] \times 0.0232 + 19.0$$

Ben Nevis Field

$$Temp [^{\circ}C]_{\text{shallower than 2500 m}} = Depth [mSS] \times 0.0349 - 1.7$$

$$Temp [^{\circ}C]_{\text{deeper than 2500 m}} = Depth [mSS] \times 0.0232 + 19.0$$

2. The regional geo-thermal gradient can best be represented by the following equations:

$$Temp [^{\circ}C]_{\text{(for <3000m)}} = Depth [mSS] \times 0.031 - 2.0$$

$$Temp [^{\circ}C]_{\text{(for >3000 m)}} = Depth [mSS] \times 0.02366 + 17.1$$

4.2.4 Reservoir Flow Assurance Considerations

Due to the cold ambient temperatures and the composition of the produced crude, various flow assurance issues are being considered in the Project design. This section deals with the potential flow assurance issues that may occur from the reservoir to the dry tree or the wet tree in a subsea tie-back development scenario for Pool 3.

4.2.4.1 Hydrates and Ice

Ambient temperature conditions in the Hebron area are sufficiently cold that hydrate and / or ice could form. The minimum sea water temperature (MSWT) is -1.7°C . During normal operations, the dry trees, wet trees and wellbores will be sufficiently warm such that they are not in the hydrate formation region. During transient operation, hydrate inhibitors will be used to prevent hydrate formation. In the event that hydrates and / or ice blockage develops, chemicals can be applied to melt the hydrates or ice.

4.2.4.2 Wax Management

The wax appearance temperatures (WAT) were measured using the Cross Polarized Microscopy (CPM) technique. As can be seen from Table 4.2-1, wax deposition in the wellbores of the platform wells is not expected during normal operations. However, the potential for Pool 3 flowline wax deposition exists and wax inhibitor will be injected subsea if deemed necessary. The WAT for the Hebron reservoirs is between 32°C and 51°C , although no measurements were obtained in the Hibernia interval as there is no representative fluid sample for Hibernia.

4.2.4.3 Asphaltenes and Napthenates

Preliminary laboratory analysis performed on fluid samples from the Hebron Ben Nevis (Pool 1) and Hebron Jeanne d'Arc (Pool 4) indicate that asphaltene precipitation is not expected in most of the wells. There is the potential for some asphaltene precipitation in the wells completed in the Jeanne d'Arc reservoir interval and so these wells may require downhole injection of asphaltene inhibitor at the completions. Laboratory analysis was also performed on fluid samples from the Ben Nevis reservoir of the Ben Nevis field (Pool 3). The results indicated the potential for some asphaltene precipitation. The capability to inject asphaltene inhibitor at the wellheads will be provided for all other wells.

For the other pools where there were no representative samples available (Pool 2 – West Ben Nevis, Pool 3 – West Ben Nevis Avalon, and Pool 5 – Hebron Hibernia) for laboratory analysis, the De Boer's Screening Method was used to evaluate the potential for asphaltene precipitation. The results

indicated that asphaltene precipitation was unlikely due to the low degree of under-saturation.

4.2.4.4 Scale Management

The potential exists for calcium carbonate scale precipitation and deposition. To control this, scale inhibition will be provided for the wells. Acid washes may be used as a secondary form of mitigation for calcium carbonate scales. Additionally, barium sulphate scales, which stabilize an emulsion, may form due to sea water injection. These will be mitigated through scale inhibitor squeeze treatments on producing wells as they cannot be mitigated with acid washes.

4.2.4.5 Corrosion Management

The potential for corrosion exists throughout the entire production system as CO₂ and water will be present in the produced fluids. Corrosion-resistant alloy production tubing and flowlines will be selected to mitigate expected corrosion or downhole / wellhead corrosion inhibitor injection will be used in combination with carbon steel. Hydrogen sulphide is not initially present in the reservoir, but field experience shows that injection of seawater (and hence sulphate ions) into the reservoir can result in generation of H₂S from sulphate-reducing bacteria (SRB) activity. An evaluation of the potential for reservoir souring due to SRB activity is currently underway and the results of the evaluation will be used to finalize the H₂S design basis for the facility.

4.2.4.6 Emulsions Management (Downhole)

Emulsions are expected to form over a wide range of water cuts. The viscosity of the produced fluid can increase significantly if an emulsion is formed. All wells will have the capability for demulsifier injection either downhole or at the wellhead.

4.3 Ben Nevis Reservoir

4.3.1 Ben Nevis Avalon Drill Stem Tests Results

All the wells drilled in the Hebron area encountered the Ben Nevis / Avalon formation. DST operations were carried out in this stratigraphic interval for all wells except the M-04 well. The results and interpretations from these tests are summarized in Table 4.3-1.

A variation in oil properties across the fields is noticeable from the data. Furthermore, a vertical variation in oil gravity was also observed in the I-13 well, which had multiple DSTs with hydrocarbon recovery.

There is some question regarding the validity of the data obtained from the fluid samples collected during DST #9 and #10 in the I-13 well (and to some

extent in the B-75 DST #7). Hence the results of the data interpretation and the analysis for these zones may be suspect. For instance, high negative skin factors were observed in the I-13 Ben Nevis DST #9 and #10, which is different from other tests in this or other stratigraphic intervals.

A large amount of gas production was observed during DST #9 in the I-45 well. Given the relatively small volume of oil recovered and its high gravity (48°API), a gas condensate study was conducted for the fluids recovered from the test. The results are discussed in Section 4.3.2. Four DSTs (DST #10 – 13) were conducted in the Ben Nevis reservoir (Ben Nevis field) encountered by the I-45 well. Fluid recovery volumes from these tests were generally low suggesting poor reservoir quality. DSTs #12 and #13 recovered mainly water which has been attributed to the filtrate/water cushion and is not representative of formation water.

Table 4.3-1: Ben Nevis Avalon DST Results Summary

Well	DST #	Field	Formation	Interval (mRT)	Fluid Type	Test Flow Rate (m3/d)	Oil Gravity	Pay (m)	Est. kh (m*md)	Est. Perm	Skin Factor	Radius of Investigation (m)	Boundaries Encountered (Yes or No)	Productivity Index (m3/d/kPa)	
														As Tested	Undamaged
I-13	9	Hebron	Ben Nevis	1905.5 – 1915.4	Oil	117	18.3	10	22560	2256	-2.1	84	Yes	0.0430	0.0321
I-13	10	Hebron	Ben Nevis	1865.9 – 1876.0	Oil	162	21.2	10	2714	271	-3.7	170	No	0.0160	0.0088
D-94	1	Hebron	Ben Nevis	1842 – 1908.4	Oil	571	20.1	66	32096	486	1.2	250	No	0.1329	0.1523
B-75	6	W. Ben Nevis	Avalon	2445 – 2465	Oil	236	22.8	20	1562	78	2.7	250	No	0.0443	0.0590
B-75	7	W. Ben Nevis	Ben Nevis	2044 – 2065	Water	218	N/A	21	252	12	-0.7	–	No	0.0437	0.0400
B-75	8	W. Ben Nevis	Ben Nevis	2002 – 2015	Oil	100	28.1	13	2158	166	18.8	195	Yes	0.0190	0.0623
L-55	1	Ben Nevis	Ben Nevis	2347.9 – 2421	Oil	183	31.4	73	734	10	7.1	146	No	0.0140	0.0247
I-45	9	Ben Nevis	Avalon	2890.5 – 2894.0	Gas condensate	140,000 Gas 41.5 Oil	48.1	3.5	455	130	25.0	110	Uncertain (poor data)	31.4	65.9
I-45	10	Ben Nevis	Ben Nevis	2440.5 – 2445.5	Oil	16	25	5	123.5	25	7.6	18	No	0.0013	0.0024
I-45	11	Ben Nevis	Ben Nevis	2420 – 2432	Oil	29	27.6	13	65	5	8.0	25	No	0.0014	0.0028
I-45	12	Ben Nevis	Ben Nevis	2398 – 2401	Water	10	N/A	3	24	8	9.4	550	No	0.0022	0.0047

4.3.2 Ben Nevis Fluid Properties

Fluid samples were collected from the wells that penetrated the Ben Nevis Avalon formation. Table 4.3-2 provides a summary of the properties of these samples. In the D-94 well, several samples captured from the same intervals were analyzed by different laboratories and slightly different results were reported (e.g., Modular Formation Dynamics Tester (MDT) samples 1.01, 1.05, and 1.06 taken from the same approximate depth of 1829 m total vertical depth subsea (TVDSS), and MDT samples 1.04, 1.09, and 1.63 taken from a depth of 1860 m TVDSS).

There is some uncertainty regarding the accuracy of the results of the PVT studies performed on the oil samples taken during DST #9 and #10 in the I-13 well. The PVT studies were carried out at a temperature of 46°C while actual temperature recordings taken during the DSTs were 49°C and 58°C for DST #9 and #10 respectively. Log data from the I-13 well indicated reservoir temperature of about 59°C. Using the log data value of 59°C, oil viscosity correlations were used to estimate the impact of temperature on viscosity and the correlation-corrected viscosity values are reported in Table 4.3-2. Furthermore, reservoir fluid compositions and geochemical analysis of these two samples indicate that they are different oils with different degrees of biodegradation. Based on the analysis and a comparison with the characteristics of the other samples taken in the Hebron Ben Nevis formation, the oil sample in DST #10 is considered to be more representative of the Ben Nevis whereas the oil from DST #9 is significantly more biodegraded. These factors may help explain the abnormally high viscosity (27 cp) reported for DST #9 in Table 4.3.2 below.

A gas condensate study was conducted on the samples recovered from DST #9 in the I-45 well. Samples of the separator liquid and gas were recombined to the separator gas-liquid ratio of 7015 m³/m³. The retrograde dew point of the recombined sample was determined to be 30.5 MPa at the reservoir temperature of 95°C. Since this value is higher than the reservoir pressure (29.4 MPa), it is possible that a two-phase system exists at reservoir conditions or the recombined sample is not representative of the reservoir fluid. The recovered fluid sample had an oil gravity of about 48°API.

The results of the fluids analysis performed on the samples taken from DST#10 and 11 in the I-45 well are considered to be of low quality because the well was flowed below the bubble-point pressure during both tests and also because of the low fluid recovery volumes.

Table 4.3-2: Ben Nevis Fluid Properties

Well	DST or Sample #	Field	Formation	Interval/ Depth (mTVDSS)	Res Pres (MPa)	Res Temp (°C)	Sat. Pres (MPa)	Oil Visc @ Psat (cp)	Oil Gravity °API	Oil FVF1 (m3/Sm3)	GOR1 (m3/m3)
D-94	1.01 MDT	Hebron	Ben Nevis	1829	18.6	54	18.4	9.6	21.3	1.114	54
D-94	1.05 MDT	Hebron	Ben Nevis	1829	18.7	60	17.9	6.1	22.6	1.122	47
D-94	1.06 MDT	Hebron	Ben Nevis	1829	18.7	60	17.6	6.1	22.5	1.114	52
D-94	1.61 PT	Hebron	Ben Nevis	1852	19.1	61	17.1	9.3	19.4	1.127	49
D-94	1.61 PT	Hebron	Ben Nevis	1852	19.1	60	16.7	11.1	20.1	1.107	50
D-94	1.04 MDT	Hebron	Ben Nevis	1860	18.9	56	19.1	10.9	21.6	1.111	53
D-94	1.09 MDT	Hebron	Ben Nevis	1860	18.9	62	17.7	7.2	22.0	1.167	49
D-94	1.09 MDT	Hebron	Ben Nevis	1860	18.9	62	17.6	8.5	20.8	1.126	50
D-94	1.63 MDT	Hebron	Ben Nevis	1860	19.0	63	17.3	12.4	20.1	1.123	46
D-94	1.03 MDT	Hebron	Ben Nevis	1873	19.0	56	17.5	10.0	20.3	1.139	63
D-94	1.11 MDT	Hebron	Ben Nevis	1873	19.0	62	17.8	7.9	20.3	1.128	46
D-94	1.03 MDT	Hebron	Ben Nevis	1873	19.0	56	17.5	10.0	19.8	1.139	63
D-94	1.65 PT	Hebron	Ben Nevis	1885	19.1	63	17.5	7.7	21.3	1.126	51
D-94	1.14 MDT	Hebron	Ben Nevis	1887	19.1	57	17.8	10.9	18.8	1.156	69
D-94	1.14 MDT	Hebron	Ben Nevis	1888	19.1	63	14.8	10.5	20.2	1.104	44
D-94	1.14 MDT	Hebron	Ben Nevis	1888	19.1	57	17.8	10.9	18.8	1.156	69
D-94	1.20 MDT	Hebron	Ben Nevis	1892	18.2	63	17.8	9.9	20.7	1.120	46
D-94	1.02 MDT	Hebron	Ben Nevis	1898	19.3	57	18.8	15.4	17.2	1.147	66
D-94	1.08 MDT	Hebron	Ben Nevis	1898	19.2	63	17.0	11.7	19.2	1.122	45
M-04	MDT	Hebron	Ben Nevis	1870	19.0	63	16.8	9.4	21.2	1.134	48
M-04	MDT	Hebron	Ben Nevis	1890	19.2	63	16.8	12.7	19.4	1.145	53
I-13	DST #10	Hebron	Ben Nevis	1839 – 1849	18.8	59	10.9	14.0	21.2	1.075	36
I-13	DST #9	Hebron	Ben Nevis	1878 – 1888	19.4	59	14.1	27.0	18.3	1.077	37
B-75	DST #8	W. Ben Nevis	Ben Nevis	1977 – 1990	20.0	69	19.3	2.3	31.0	1.200	71
B-75	DST #6	W. Ben Nevis	Avalon	2393 – 2405	24.9	84	18.7	1.2	29.7	1.261	79
I-45	DST #11	Ben Nevis	Ben Nevis	2393 – 2405	24.9	84	18.7	1.2	29.7	1.261	79
I-45	DST #10	Ben Nevis	Ben Nevis	2413 – 2418	25.2	84	10.6	2.3	26.5	1.204	44
I-45	DST #9	Ben Nevis	Avalon	2863 – 2867	29.4	95	30.5	Gas Condensate??			
L-55	1.65 PT	Ben Nevis	Ben Nevis	2317	24.2	82	21.2	1.0	29.6	1.280	98
L-55	1.63 PT	Ben Nevis	Ben Nevis	2322	23.4	82	20.1	3.1	31.5	NR	108
L-55	1.05 MDT	Ben Nevis	Ben Nevis	2373	24.2	82	19.1	3.0	31.4	NR	68
L-55	1.03 MDT	Ben Nevis	Ben Nevis	2425	24.6	85	22.9	NR	27.3	NR	90
Notes:											
1. From single-stage flash											

4.3.2.1 Hebron Ben Nevis (Pool 1) Fluids Analysis

Numerous reservoir oil samples were obtained from the D-94 well using an open-hole formation tester (MDT tool). The well was drilled with water-based mud and so there were no oil-based mud contamination issues with these samples. In addition to these samples, several cased-hole, single-phase bottomhole samples were also obtained. Two reservoir oil samples were

collected in the M-04 well. This well was drilled with an oil-based mud; hence these samples have some level of contamination from the base oil in the drilling mud. The data from all these samples are provided in Table 4.3-2 (above). An analysis of the PVT studies performed on these samples (from the D-94 and M-04 wells drilled into the Hebron Ben Nevis) provided the following conclusions:

1. The PVT data indicates a variation in oil gravity and reservoir oil viscosity with depth.
2. A curve fit of the oil gravity data yields a variation in the oil column from 24 degrees API at the top of structure to 17 degrees API at the oil-water contact (OWC) (1900 m TVDSS). This is shown in Figure 4.3-1.
3. An analysis of the measured viscosity data yields a variation in oil viscosity at bubble point pressure from 4 cp at the top of structure to 14 cp at the OWC. Figure 4.3-2 shows the live oil viscosity data at bubble point pressure and reservoir temperature as a function of depth. The data indicates some level of uncertainty. However, there is a trend of increasing reservoir oil viscosity with depth, which is consistent with the variation of oil gravity with depth.

Based on the analysis, a set of four bottomhole samples from the D-94 well (MDT samples 1.06, 1.08, and 1.09, and PT sample 1.62 respectively) that covered the range of observed oil gravity were selected for use in detailed fluid properties characterization. These samples were adjudged to be self-consistent and of generally good quality. EOS models were developed to match the measured PVT data of these four bottomhole samples. These EOS models were used to generate multiple tables of saturated oil properties that capture the variation of oil properties with depth for use in reservoir simulation studies. The data was used in the simulation model by defining six reservoir regions based on depth.

The oil PVT data inputs into the simulation modeling are shown in graphical form in Figure 4.3-3, Figure 4.3-4, and Figure 4.3-5.

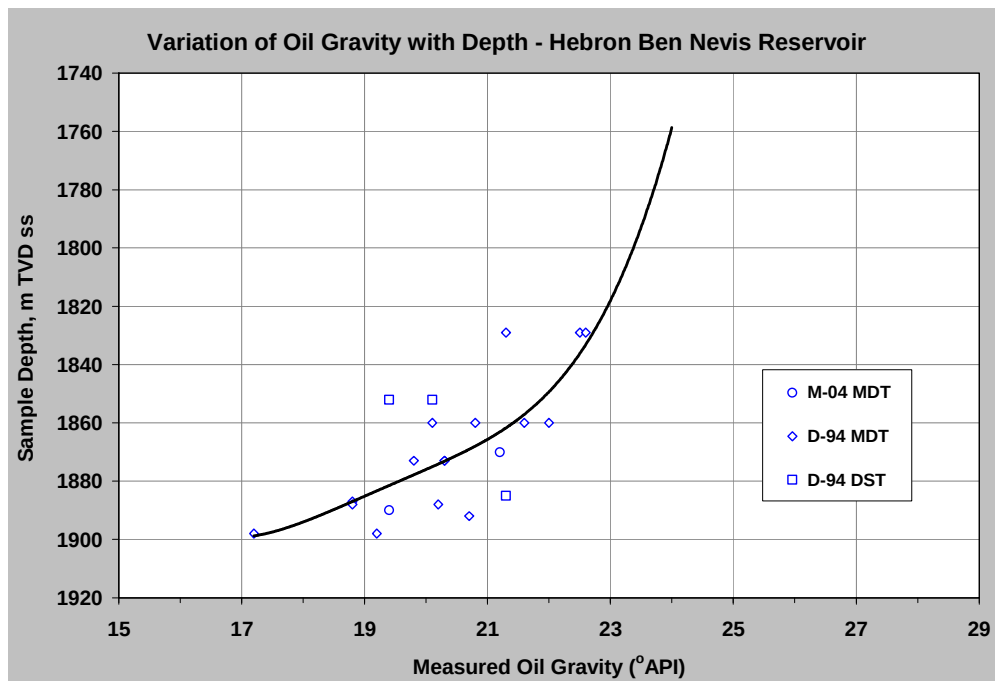


Figure 4.3-1: Hebron Ben Nevis - Oil Gravity Variation with Depth

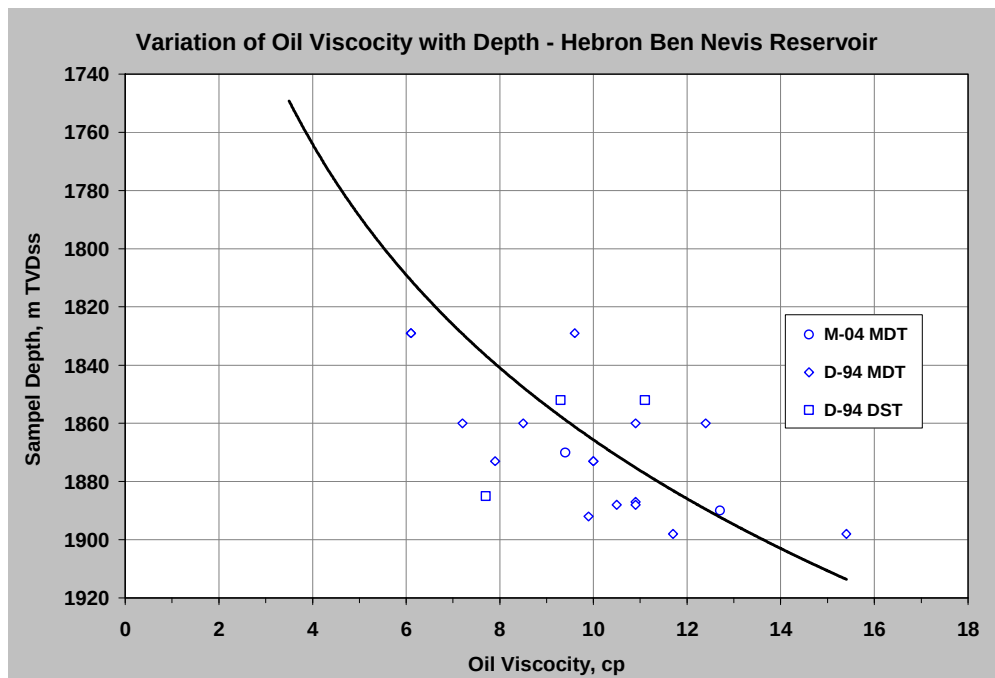


Figure 4.3-2: Hebron Ben Nevis - Oil Viscosity Variation with Depth

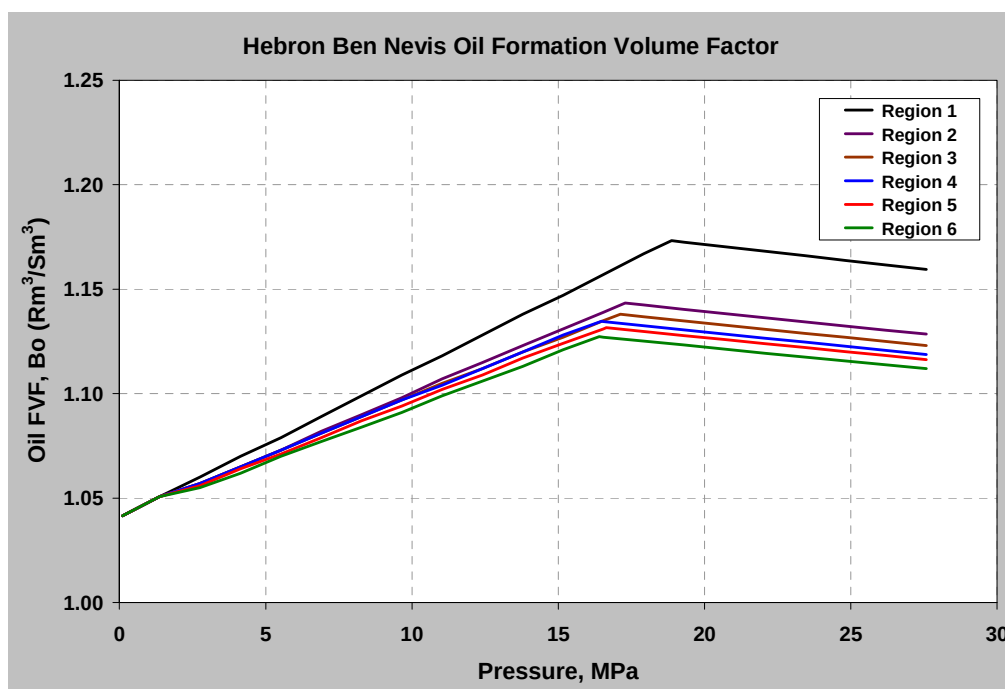


Figure 4.3-3: Hebron Ben Nevis – Oil Formation Volume Factor

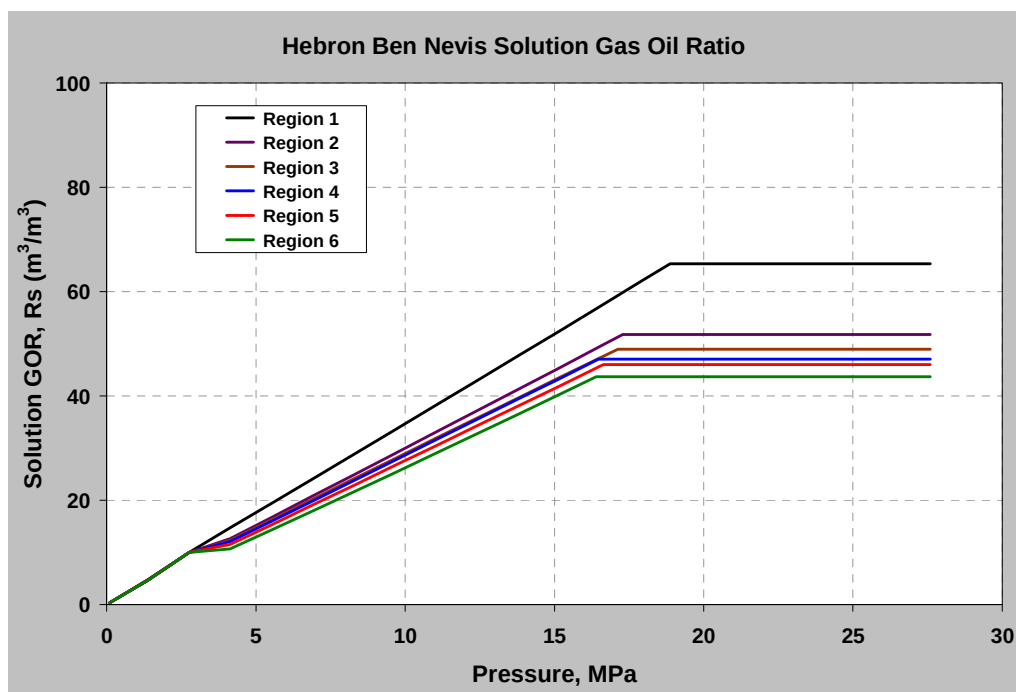


Figure 4.3-4: Hebron Ben Nevis – Solution Gas-Oil Ratio

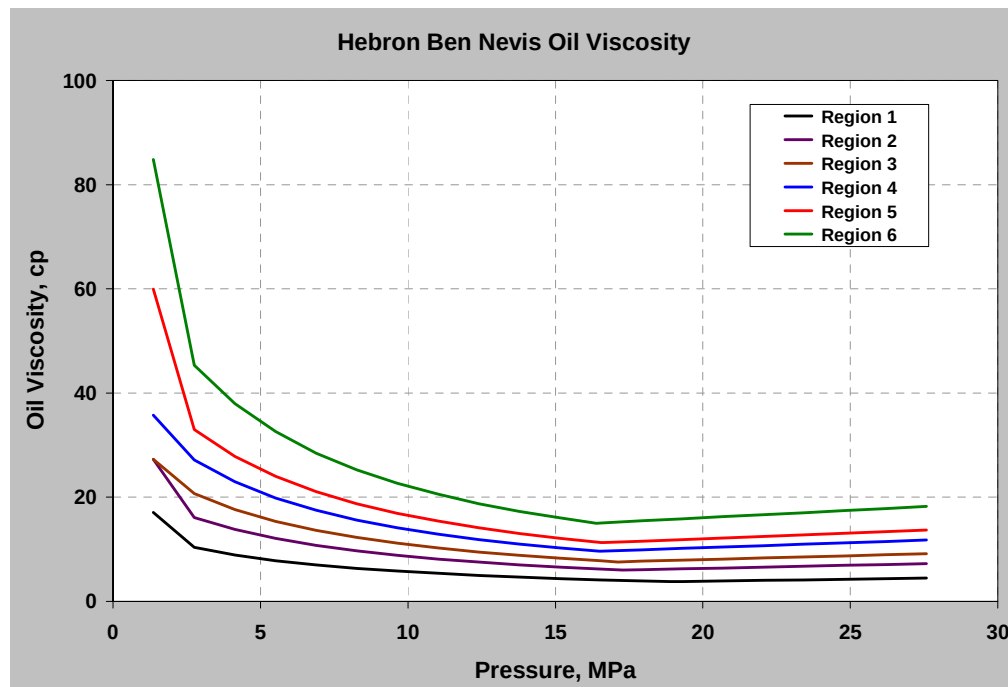


Figure 4.3-5: Hebron Ben Nevis – Oil Viscosity

4.3.2.2 Ben Nevis Ben Nevis (Pool 3) Fluids Analysis

PVT analysis was conducted on a single bottomhole sample taken from the L-55 well. Laboratory measurements included differential liberation, constant composition expansion, compositional analysis, and a separator test. The resulting data was used to calibrate an equation-of-state fluid characterization to each type of measurement, and simulation inputs were subsequently generated using this calibrated EOS characterization (Figures 4.3-6 through 4.3-10).

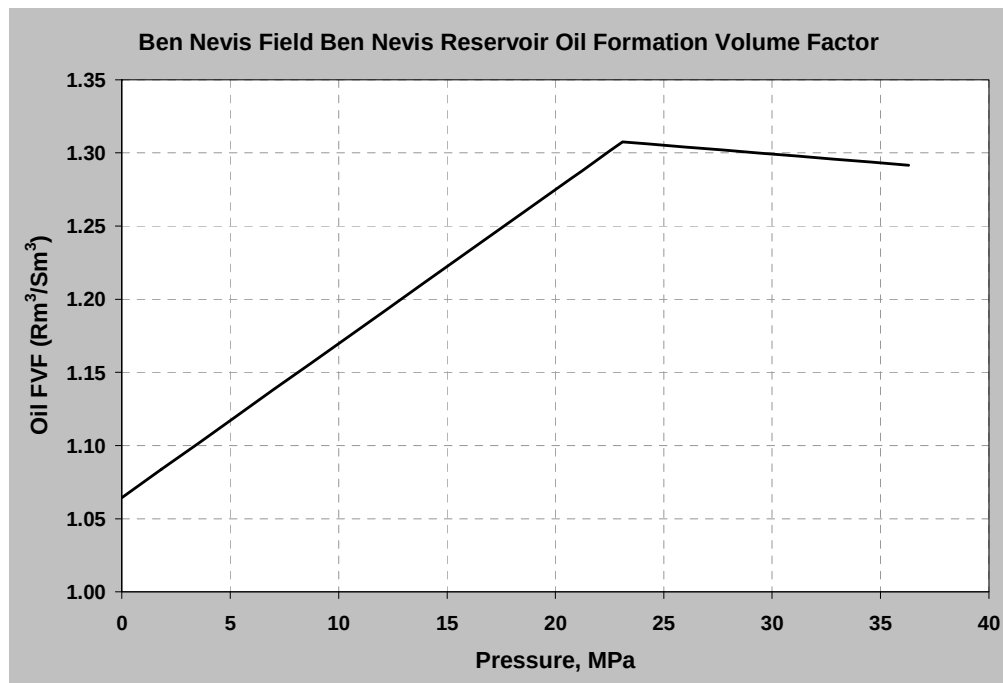


Figure 4.3-6: Ben Nevis Ben Nevis – Oil Formation Volume Factor

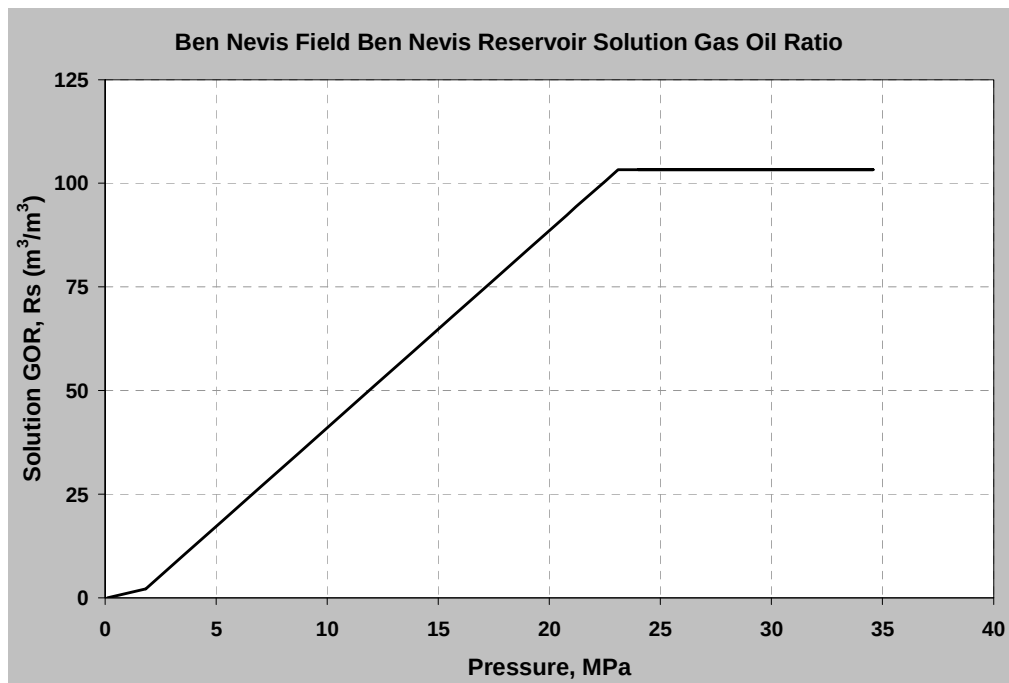


Figure 4.3-7: Ben Nevis Ben Nevis – Solution Gas-Oil Ratio

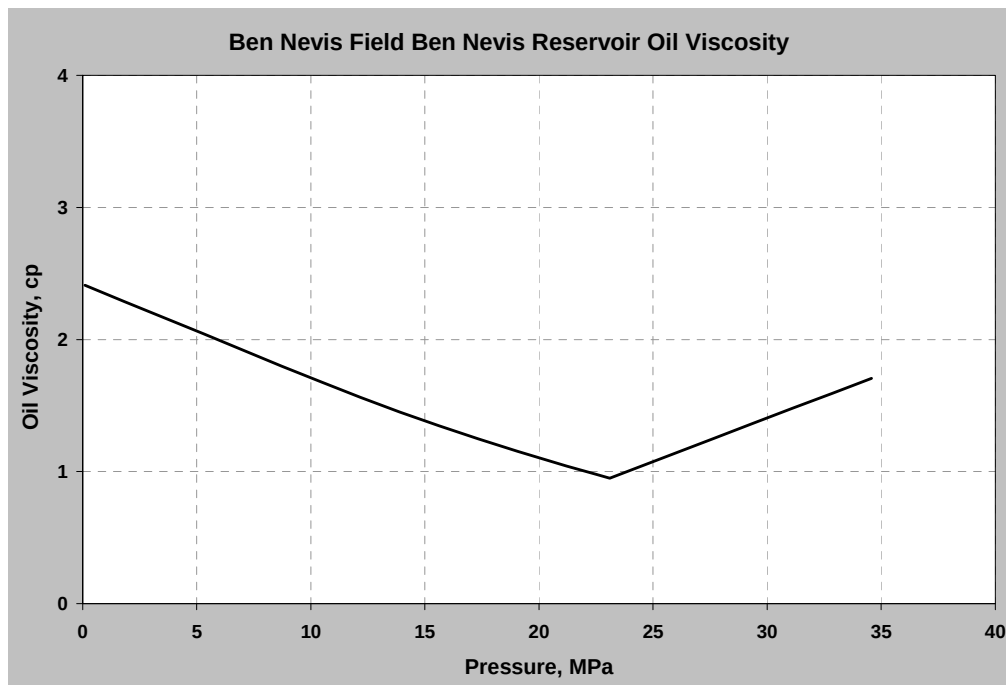


Figure 4.3-8: Ben Nevis Ben Nevis – Oil Viscosity

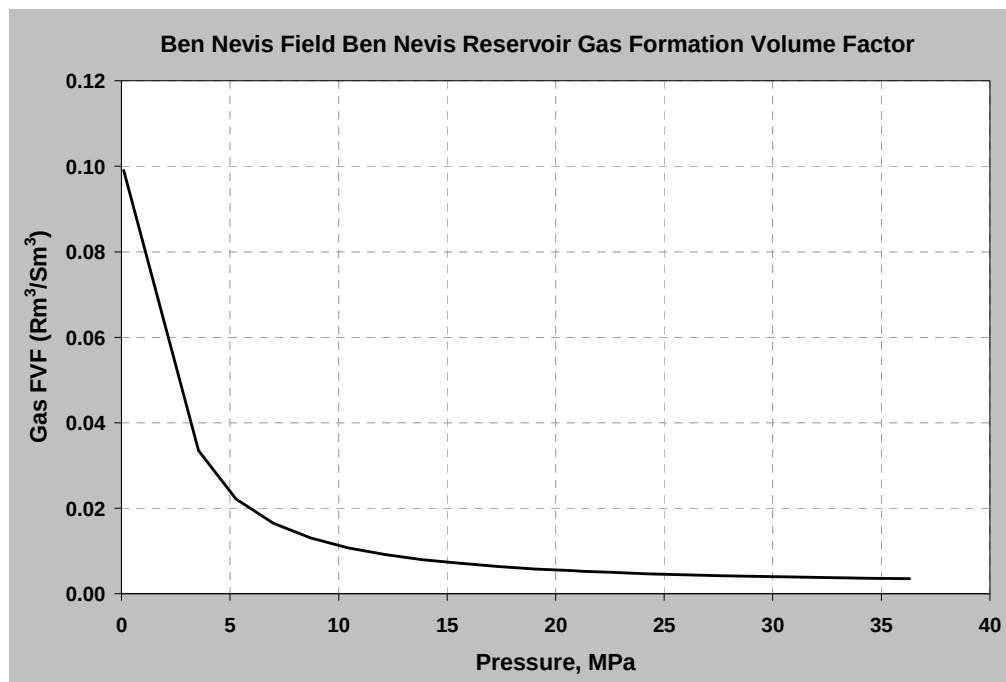


Figure 4.3-9: Ben Nevis Ben Nevis – Gas Formation Volume Factor

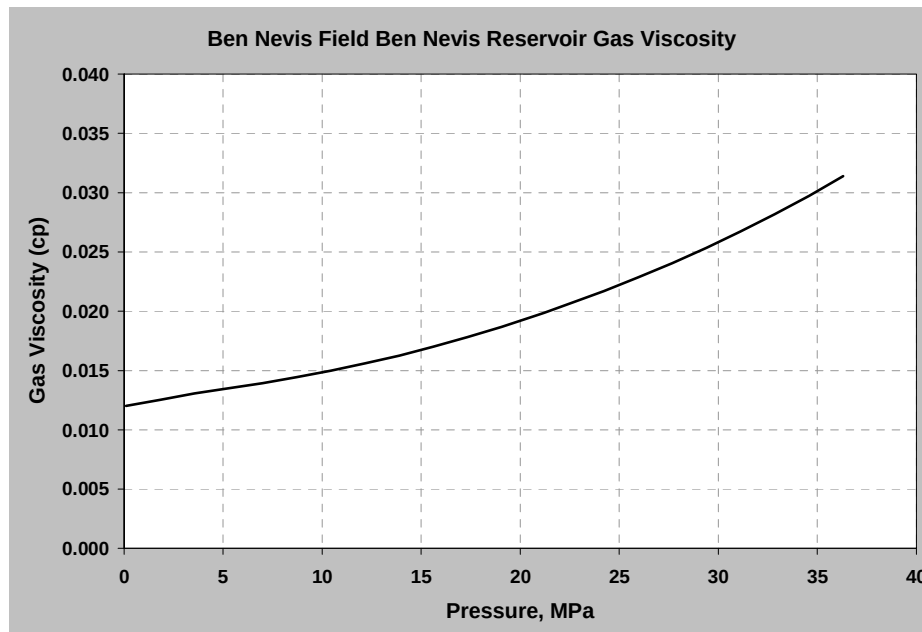


Figure 4.3-10: Ben Nevis Ben Nevis – Gas Viscosity

4.3.3 Ben Nevis Reservoir Pressures and Temperatures

4.3.3.1 Ben Nevis Pressures and Pressure-Depth Plot

Reservoir pressure measurements taken from the Ben Nevis Avalon formation in all the wells are plotted against depth in Figure 4.3-11. Overall, the Ben Nevis formation seems to be normally pressured in all the fields (Hebron, West Ben Nevis and Ben Nevis).

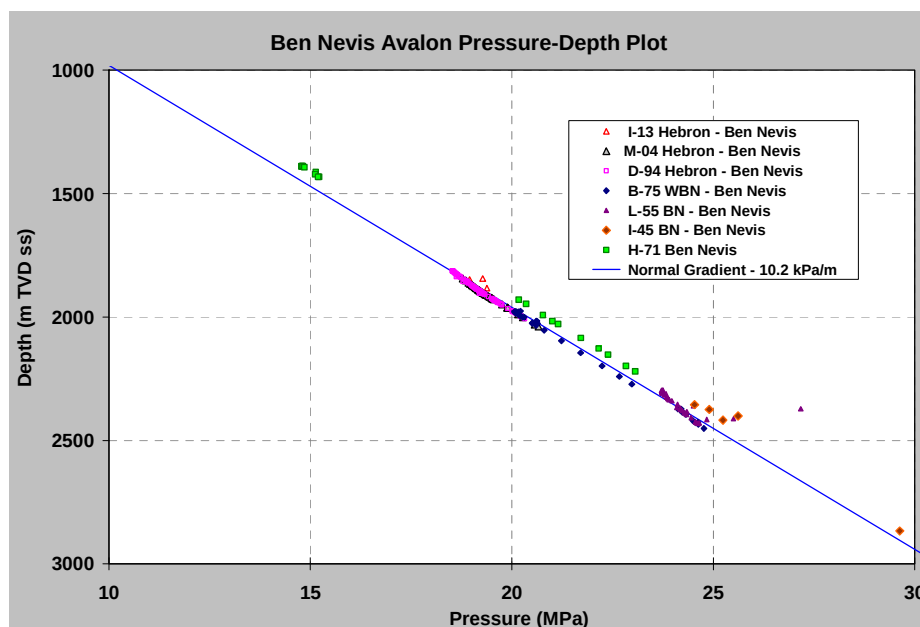


Figure 4.3-11: Ben Nevis Avalon Pressure-Depth Plot

4.3.3.1.1 Hebron Ben Nevis (Pool 1) Pressures & Pressure-Depth Plot

The Ben Nevis dataset within the Hebron field was further analyzed to determine the pressure gradients of the fluids and confirm the contacts seen or inferred from the well logs. The oil-water contacts in the M-04 and D-94 wells were determined to be at 1898 m and 1900 m TVDSS. The difference in contacts is within interpretation uncertainty. The gradients are summarized in Table 4.3-3. Figure 4.3-12 plots the pressure data from the I-13 (DST data only), M-04, and D-94 wells in the Ben Nevis formation of the Hebron field.

Table 4.3-3: Hebron Ben Nevis Fluid Gradients from MDT Data

Field	Well	Oil-water Contact, mTVDSS	Oil Gradient, kPa/m	Water Gradient, kPa/m
Hebron	M-04	1898	8.47	10.08
	D-94	1900	8.33	10.00

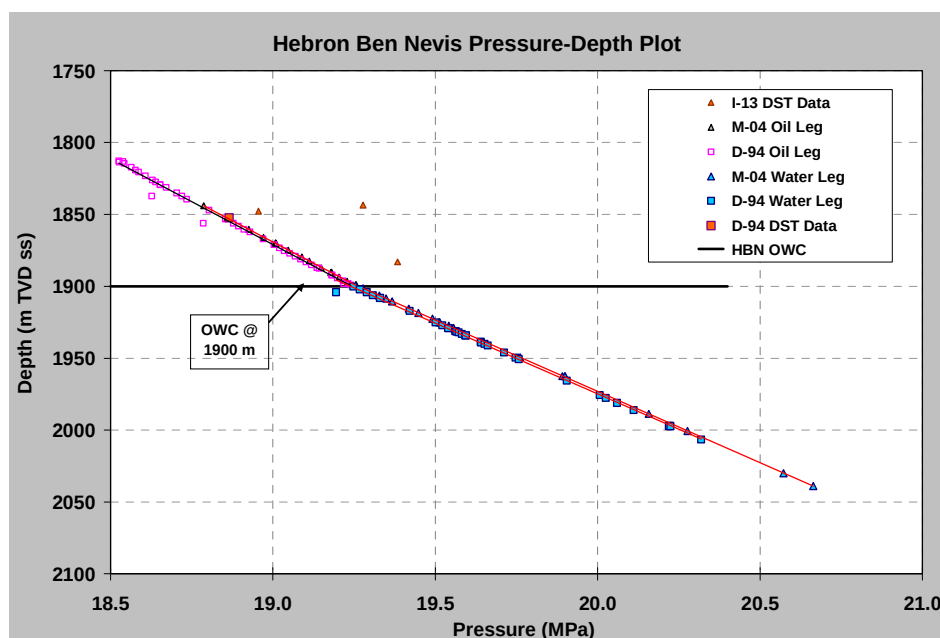


Figure 4.3-12: Hebron Ben Nevis Pressure Depth Plot

4.3.3.1.2 Ben Nevis Ben Nevis (Pool 3) Pressures & Pressure-Depth Plot

Figure 4.3-13 is a plot of the reservoir pressures versus depth within the Ben Nevis formation of the Ben Nevis field. A repeat formation tester (RFT) program to capture pressure data was not performed in the Ben Nevis interval of the I-45 well. The gas-oil contact inferred from the MDT data from the L-55 well is 2310 m which is close to the well-log interpreted gas-oil contact of 2311 m. The oil-water contact was interpreted from the I-45 and L-55 well logs. Pressures measured during the I-45 DSTs are shown in Figure 4.3-13 but were not included in the gradients calculation due to their poor data quality as discussed in Sections 4.3.1 and 4.3.2 above. The gradients are summarized in Table 4.3-4.

Table 4.3-4: Ben Nevis Ben Nevis Fluid Gradients from L-55 MDT Data

Field	Well	Gas-oil Contact, mTVDss	Oil-water Contact, mTVDss	Gas Gradient, kPa/m	Oil Gradient kPa/m
Ben Nevis	L-55	2311	2432	1.60	7.31

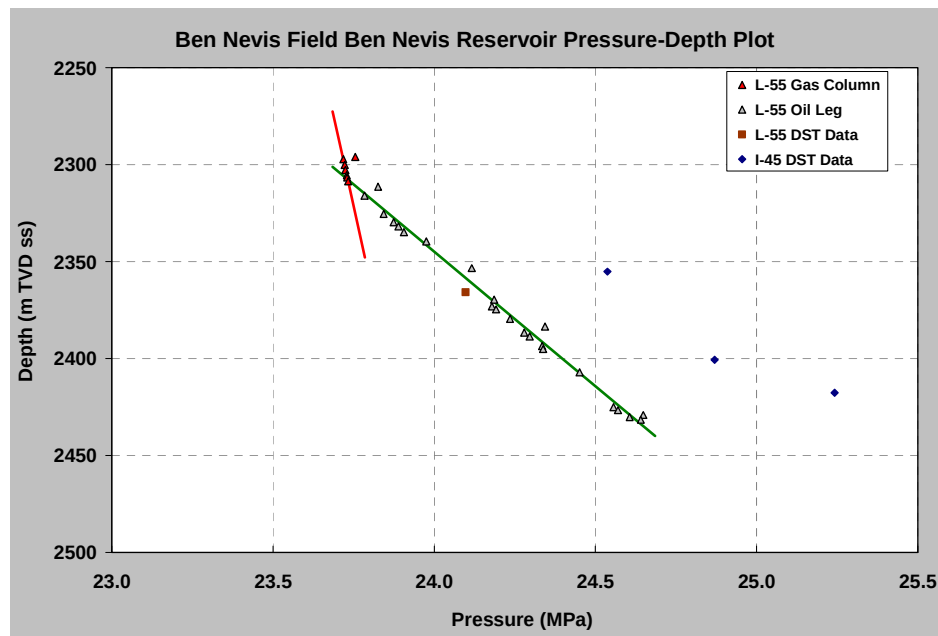


Figure 4.3-13: Ben Nevis Ben Nevis Pressure Depth Plot

4.3.3.2 Ben Nevis Reservoir Temperatures

Reservoir temperatures for the Ben Nevis Avalon formation are plotted in Figure 4.3-14. Although the individual points show considerable scatter, the observed temperature gradient of 3.37°C/100 m lies within the expected range of the regional geothermal gradients and also agrees with the generalized expression developed for the Hebron Asset.

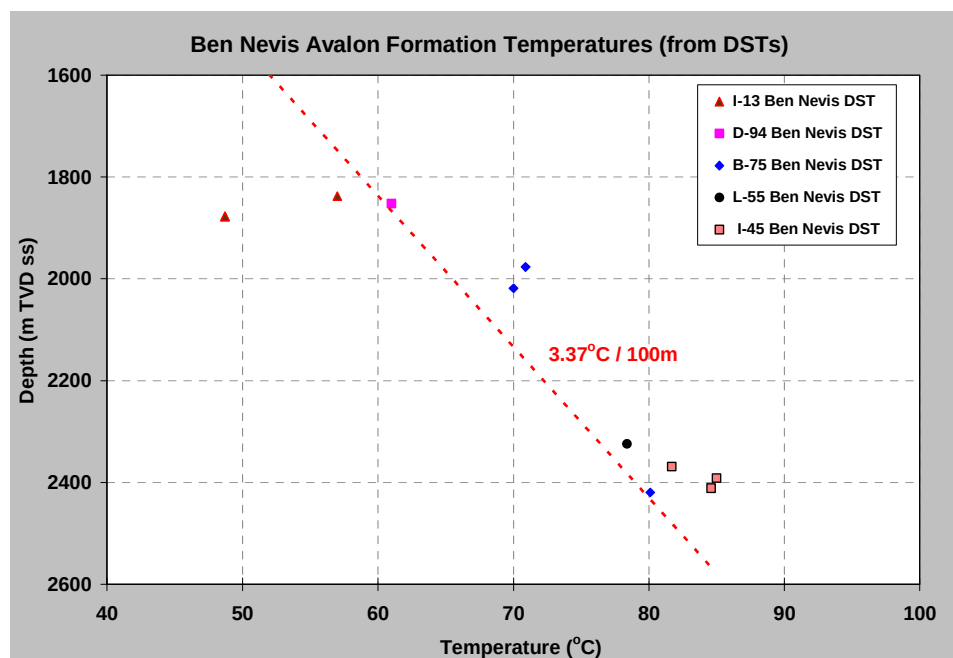


Figure 4.3-14: Ben Nevis Avalon Temperatures

4.3.4 Ben Nevis Special Core Analysis

4.3.4.1 Overview and Data Quality

Laboratory special core analysis (SCAL) tests were conducted on cores obtained from the Hebron area wells D-94, I-13, and L-55. SCAL data is available for the Ben Nevis reservoir interval in the Hebron and Ben Nevis fields (from the D-94, I-13, and L-55 wells).

A SCAL study was performed in 1982 on Core 2 from the I-13 well corresponding to the upper reservoir section of the Hebron Ben Nevis reservoir. The results indicated water wet reservoir rock for two of the three plugs tested; the third plug, taken from the upper part of the Ben Nevis reservoir was interpreted as exhibiting mixed wet characteristics. Based on a recent review of the study, there is some concern about the reliability of the results obtained from the 1982 study mainly due to questionable core handling and some potentially problematic experimental procedures employed during the study. For instance, while the wettability state of the core was unknown during the study, it was treated either as an un-invaded core or as having been cut with a bland, water-based mud as there was no wettability restoration performed on the core samples. The wettability tests were also conducted at ambient temperature using an iso-paraffinic solvent as the oil phase instead of being conducted at reservoir conditions with live crude oil. Apart from the questionable wettability, some experimental artifacts caused by the unsteady state method used in the measurements were observed. At low to intermediate values of water saturation (S_w), viscous

instabilities (and other dispersive mechanisms) dominate the displacement at and immediately after water breakthrough thereby invalidating the relative permeability measurements taken over this range.

High-quality SCAL data were obtained for the lower sections of the Hebron Ben Nevis formation using preserved core cut with a bland, water-based mud from the D-94 well. The results indicate the rock is weakly water-wet as manifested by the United State Bureau of Mines (USBM) wettability tests and the overall character of the water-oil imbibition relative permeability curves. Support for the use of these D-94 SCAL data in the generation of saturation functions for simulation of flow in Pool 1 is strengthened because one potentially major uncertainty (the wettability state of the samples used in the tests) has been removed.

In 2002, several types of SCAL measurements were performed on core samples taken from the L-55 well drilled into the Ben Nevis reservoir of the Ben Nevis field. Laboratory measurements included wettability, water-oil and gas-oil capillary pressure, water-oil and gas-oil relative permeability by core flooding, and mercury injection capillary pressure. Various types of fluids were employed during these measurements including formation water, nitrogen, air, laboratory oil (Isopar L), live crude oil, and degassed crude oil.

4.3.4.2 Hebron Ben Nevis (Pool 1) Saturation Functions

Relative permeability and capillary pressure relationships have been interpreted for characterizing the initial distribution of hydrocarbons and water-oil or gas-oil displacement behaviour in the Ben Nevis reservoir of Hebron field.

A multi-parameter saturation-versus-height function was developed for use in predicting the distribution of initial hydrocarbon saturation in the static model, as described previously in Section 3.2.4.2. This function is continuous over the full range of values for both porosity and height above free water level (HAFWL). In order to achieve a similar distribution of initial hydrocarbons in the dynamic simulation model, this function was subsequently discretized into ten bins, with each bin representing a range of irreducible S_w (S_{wir}) values. Figure 4.3-15 presents the discretized saturation-versus-height curves, which were then translated into drainage capillary pressure curves (using the density difference between oil and water) for use in establishing initial S_w in the dynamic model via gravity-capillary equilibrium. Each bin generally represented a S_{wir} range of 6 saturation units, as indicated by the red triangles in the figure. For each bin, the curve shown in the graph corresponds to a S_{wir} value at the midpoint of the indicated range. The porosity value that associates with the midpoint S_{wir} is shown in the legend of this graph.

Three distinct sets of normalized water-oil relative permeability relationships are utilized in the dynamic model, with each set being associated with a range of $Swir$ values. The curve shapes were derived starting from the three waterflood experiments conducted in core samples taken from the D-94 well, with subsequent adjustments by subject-matter experts due to the unusually favourable displacement behaviour measured during the core waterfloods. Although these expert-adjusted relationships have been adopted as the most suitable inputs for current forecasts of displacement efficiency, a possibility exists that alternate interpretations of the laboratory SCAL measurements may be offered at a future date. Any such interpretations will be evaluated based upon technical merit and multi-company expert engineering judgment.

The three sets of water-oil relative permeability relationships generally reflect the anticipated behaviour of high, medium and low ranges of reservoir quality. The high-quality set is assigned to simulation cells with $Swir$ values less than 0.18; the medium-quality set is assigned to simulation cells with $Swir$ values ranging from 0.18 to 0.36; and the low-quality set is assigned to simulation cells with $Swir$ values greater than 0.36. Graphs of these relationships as functions of normalized Sw are shown in Figures 4.3-16, 4.3-17 and 4.3-128

Endpoint scaling is applied to the water-oil displacement relationships in each cell of the simulation model, to honor the cell-specific irreducible water and residual oil saturations.

Residual oil saturation to displacement by water (S_{orw}) is assigned as 20% of pore volume, based upon imbibition capillary pressure measurements in four core plugs taken from the D-94 well. Although there was some variability in the measured values for S_{orw} , no reliable method has been identified for relating this variability to any physical characteristic of the core samples.

Two sets of normalized gas-oil relative permeability relationships are utilized in the dynamic model, each set being associated with a range of reservoir quality as described above. The curve shapes reflect the two gasflood experiments conducted in high-quality and medium-quality core samples taken from the D-94 well. Because no laboratory gasflood experiment was performed in low-quality core material, the curve shapes from the gasflood in medium-quality core material was utilized for low-quality regions in the dynamic model. Graphs of the gas-oil relative permeability relationships as functions of normalized gas saturation are shown in Figures 4.3-19 and 4.3-20.

Endpoint scaling is applied to the gas-oil displacement relationships in each cell of the simulation model, to honor the cell-specific critical gas and irreducible liquid (at residual oil) saturations.

Residual oil saturation to displacement by gas (S_{org}) is assigned as 15% of pore volume, based upon centrifuge gas displacement measurements in four core plugs taken from the D-94 well. Critical gas saturation was presumed to be 3% of pore volume in every cell since no laboratory measurements of this relative permeability endpoint are available.

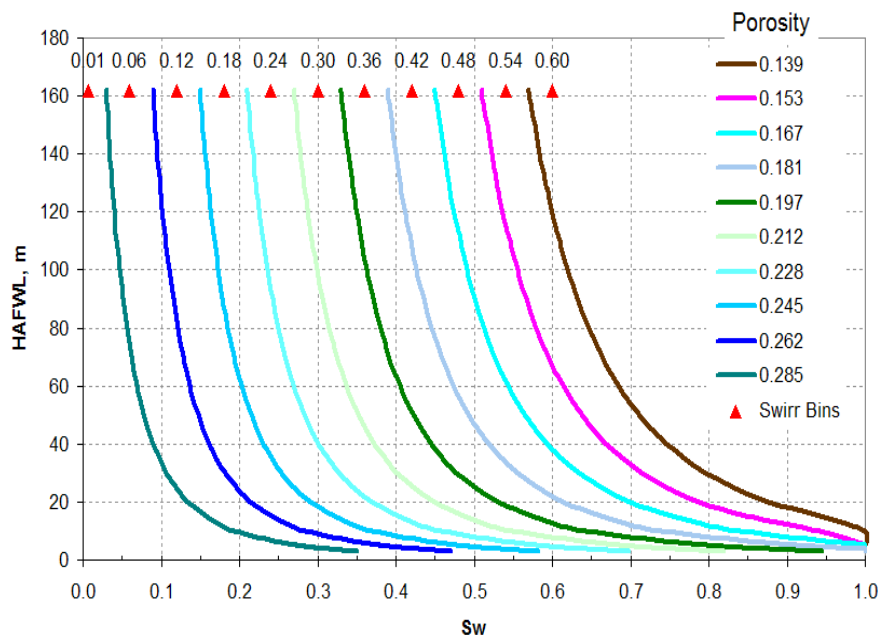


Figure 4.3-15: Hebron Ben Nevis (HBN) Saturation versus Height Curves

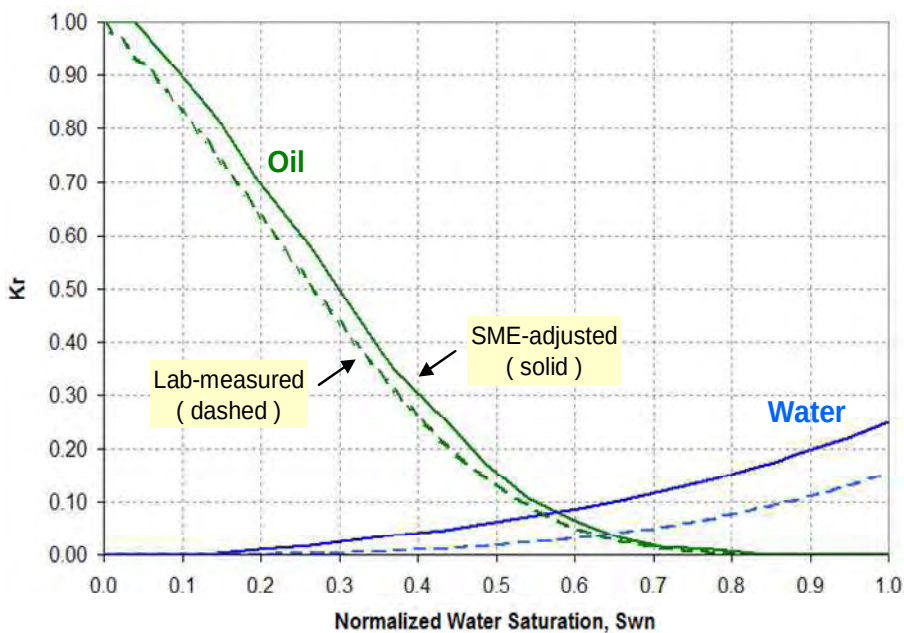


Figure 4.3-16: HBN Normalized Water-Oil Relative Permeability Curves - High Reservoir Quality

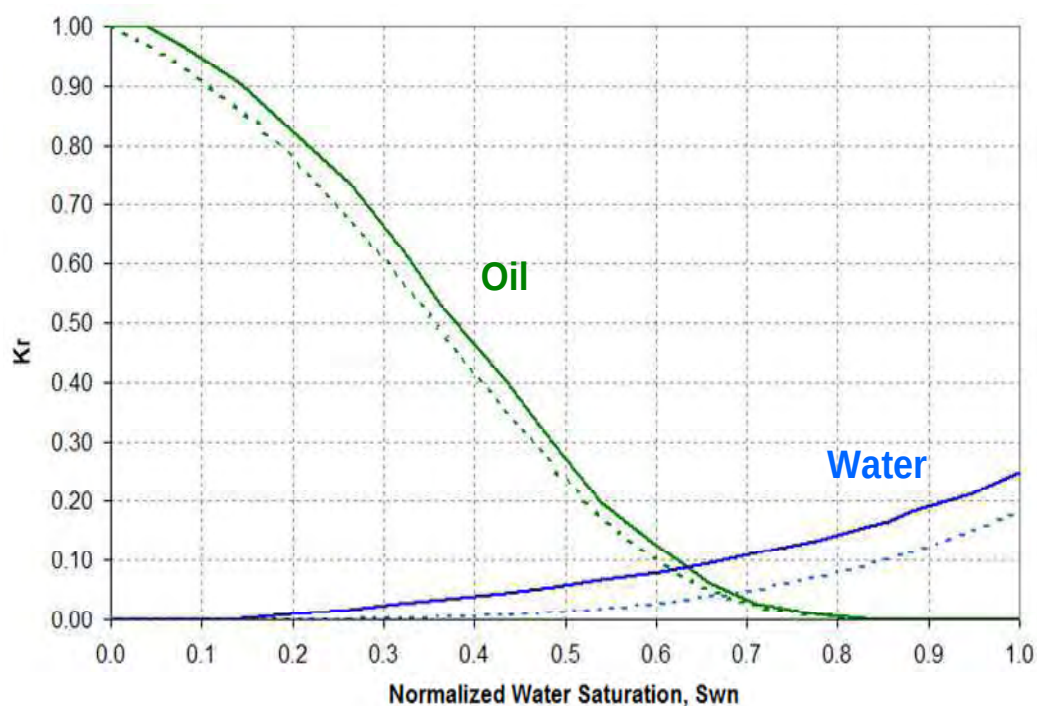


Figure 4.3-17: HBN Normalized Water-Oil Relative Permeability Curves - Medium Reservoir Quality

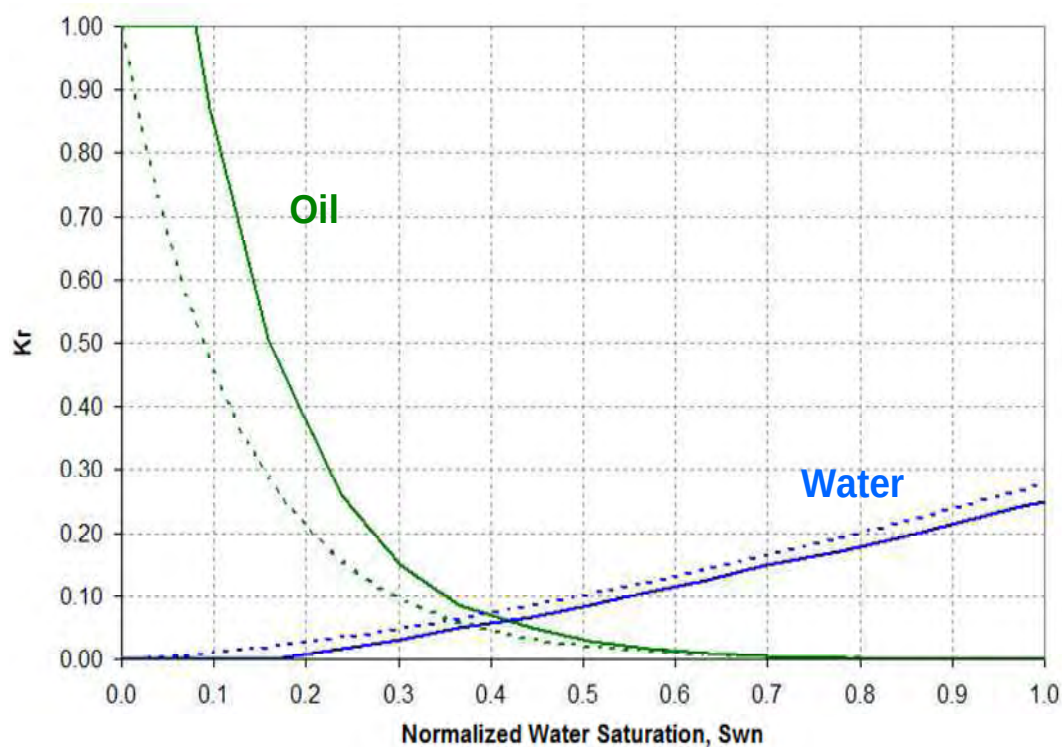


Figure 4.3-18: HBN Normalized Water-Oil Relative Permeability Curves - Low Reservoir Quality

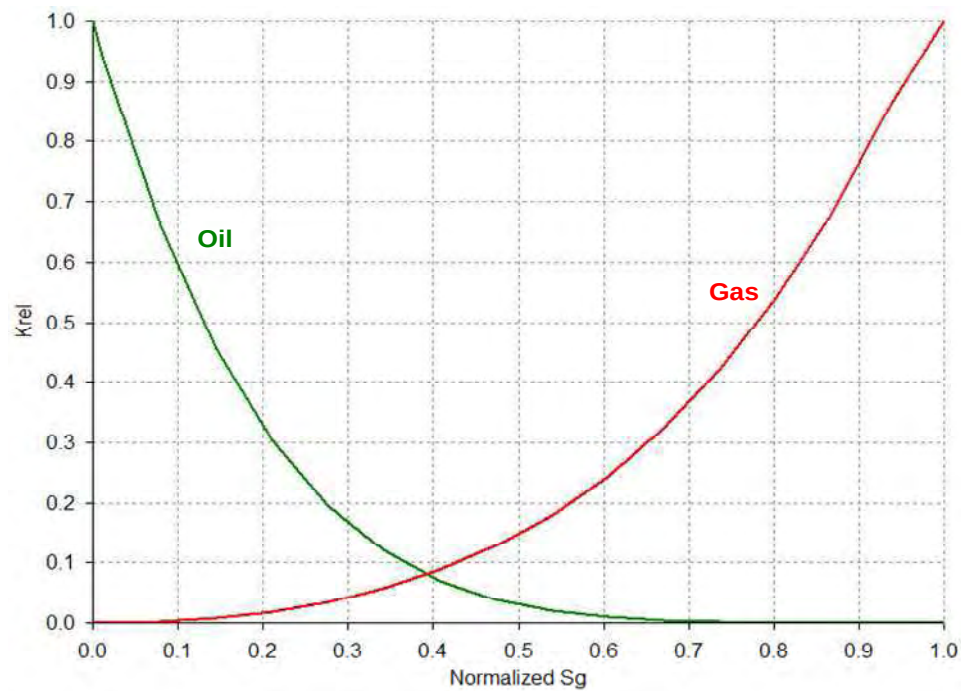


Figure 4.3-19: HBN Normalized Gas-Oil Relative Permeability Curves - High Reservoir Quality

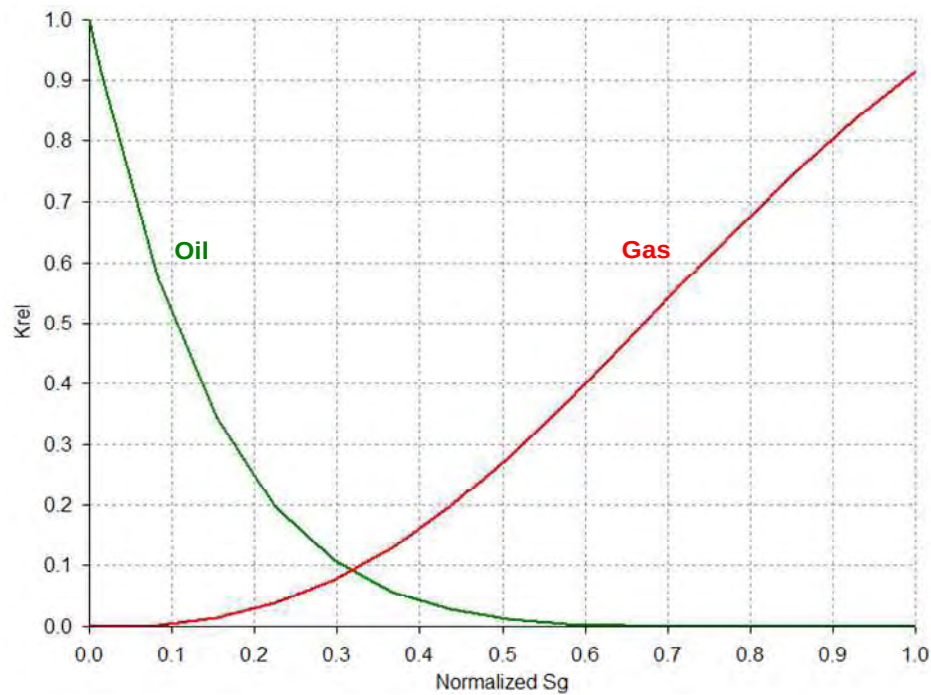


Figure 4.3-20: HBN Normalized Gas-Oil Relative Permeability Curves - Medium & Low Reservoir Quality

4.3.4.3 Ben Nevis Ben Nevis (Pool 3) Saturation Functions

Relative permeability and capillary pressure relationships have been interpreted for characterizing the initial distribution of hydrocarbons and water-oil or gas-oil displacement behaviour in the Ben Nevis reservoir of Ben Nevis field.

Multi-parameter, porosity-dependent S_w -versus-height functions were developed for predicting the distribution of initial hydrocarbon saturation in the static model, as described previously in Section 3.2.4.3. Two separate functions were recommended for characterizing regions of the reservoir exhibiting 10 md or less permeability ('LQS' region) and greater than 10 md permeability ('HQS' region). The functions are continuous over the full range of values for both porosity and HAFWL. Although these S_w -versus-height functions were derived principally from well-log resistivity measurements, they are corroborated by SCAL measurements of drainage capillary pressure in core samples from well L-55.

In order to achieve a similar distribution of initial hydrocarbons in the dynamic simulation model, these functions were each discretized into several bins, with an individual bin representing S_{wir} values. Figure 4.3-21 presents the resulting suites of drainage capillary pressure curves (inferred using the density difference between oil and water) that were used in establishing initial S_w in the dynamic model via gravity-capillary equilibrium for the Ben Nevis reservoir of the Ben Nevis field (BNBN). Each bin in the HQS suite represents a S_{wir} range of 4.5 saturation units, and each bin in the LQS suite represents a S_{wir} range of 7 saturation units. For each bin, the curve shown in the graph corresponds to a S_{wir} value at the midpoint of the range.

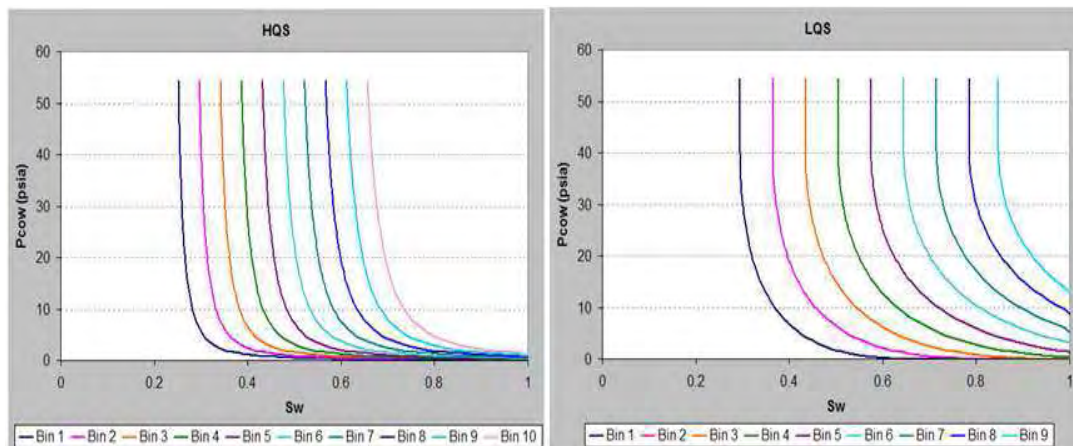


Figure 4.3-21: BNBN Drainage Water-Oil Capillary Pressures Used in Dynamic Modeling

In characterizing gas saturation above the gas-oil contact, SCAL measurements of gas-oil drainage P_c in three L-55 core samples were correlated and a single parametric P_{cgo} relationship was derived. This

relationship was used to construct gas-oil curve families for the HQS and LQS regions as shown in Figure 4.3-22.

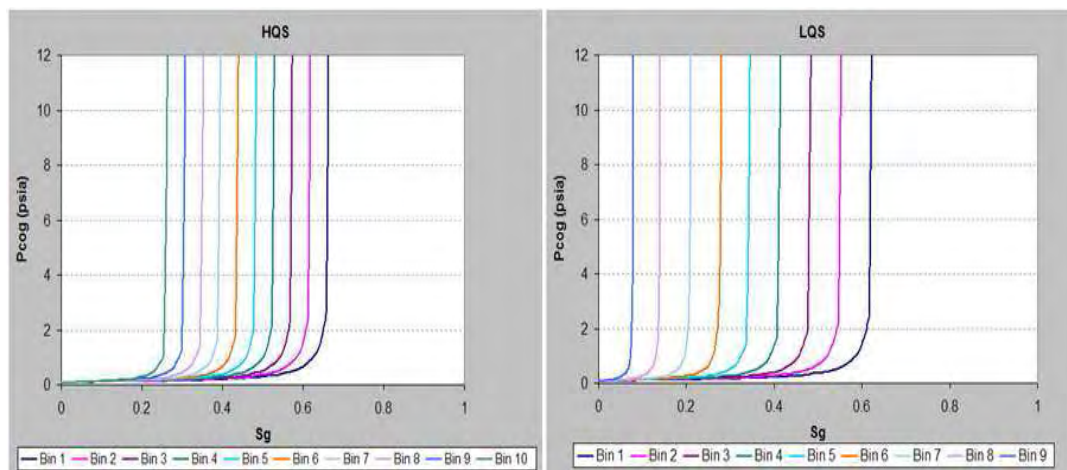


Figure 4.3-22: BNBN Drainage Gas-Oil Capillary Pressures Used in Dynamic Modeling

Water-oil relative permeabilities during imbibition displacement are characterized by five SCAL measurements performed on core samples described by ResLab as 'lower shoreface' samples. Additional water-oil displacement tests were conducted on samples described by ResLab as 'middle shoreface', but the absolute permeabilities of these samples were so unusually high (in an overall context of this resource) that they are deemed to be representative of only a negligible portion of this reservoir. Consequently, these middle-shoreface measurements were not utilized in deriving displacement relationships for dynamic flow simulation.

Water-oil displacement experiments on lower-shoreface core material included one steady-state waterflood on a composite core, one unsteady-state waterflood on a composite core, and three centrifuge displacements on single core plugs. Data collected during these experiments were combined and then correlated to derive the normalized relative permeability relationships shown in Figure 4.3-23. Endpoint scaling was subsequently utilized to construct a relative permeability table for each Swir bin (described above) in the HQS and LQS regions. Endpoint scaling within each bin was also invoked during flow simulation.

Sorw was evaluated based upon imbibition Pc measurements on three lower-shoreface core plugs. Measured Sorw values ranged from 0.13 to 0.24 in these samples, with no discernable relationship to either absolute permeability or Swir. Accordingly, a uniform Sorw value of 0.20 was assigned for flow simulation except for reservoir nodes in the two highest-Swir bins of the LQS region. In these bins, judgment-based Sorw values of 0.15 and 0.1 were assigned to reflect the likelihood of lower Sorw in regions where Swir is uncommonly high.

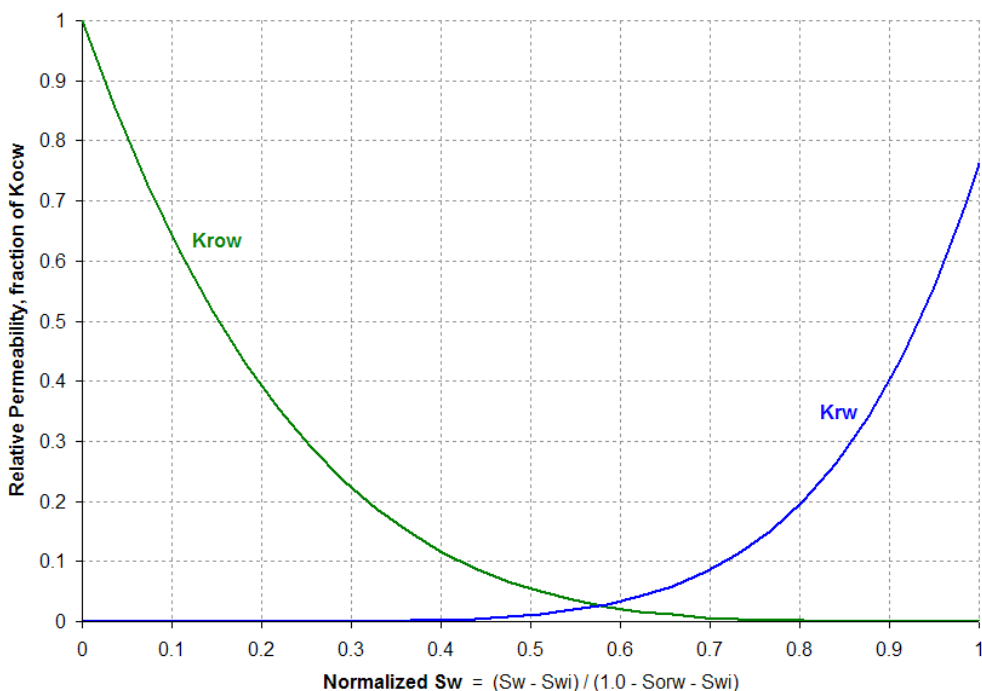


Figure 4.3-23: BNBN Normalized Imbibition Water-Oil Relative Permeabilities

Drainage gas-oil displacement experiments were all performed on lower-shoreface core material and included two composite-core unsteady-state gasfloods in the presence of irreducible water saturation, and three centrifuge displacements on individual core plugs. Data collected during these experiments were combined and then correlated to derive the normalized relative permeability relationships shown in Figure 4.3-24. Endpoint scaling was subsequently utilized to construct a relative permeability table for each S_{wir} bin (described above) in the HQS and LQS regions. Endpoint scaling within each bin was also invoked during flow simulation.

S_{org} was evaluated based upon drainage P_{cog} measurements on three lower-shoreface core plugs. Measured S_{org} values ranged from 0.06 to 0.10 in these samples, with no discernable relationship to permeability. Accordingly, a uniform S_{org} value of 0.0733 was assigned for flow simulation except in reservoir nodes where initial oil saturation was less than 0.22. In these reservoir nodes, engineering judgment was applied in setting S_{org} equal to one-third of initial S_o . Judgment was also employed in setting critical gas saturation to 0.025 for use in endpoint scaling of displacement curves.

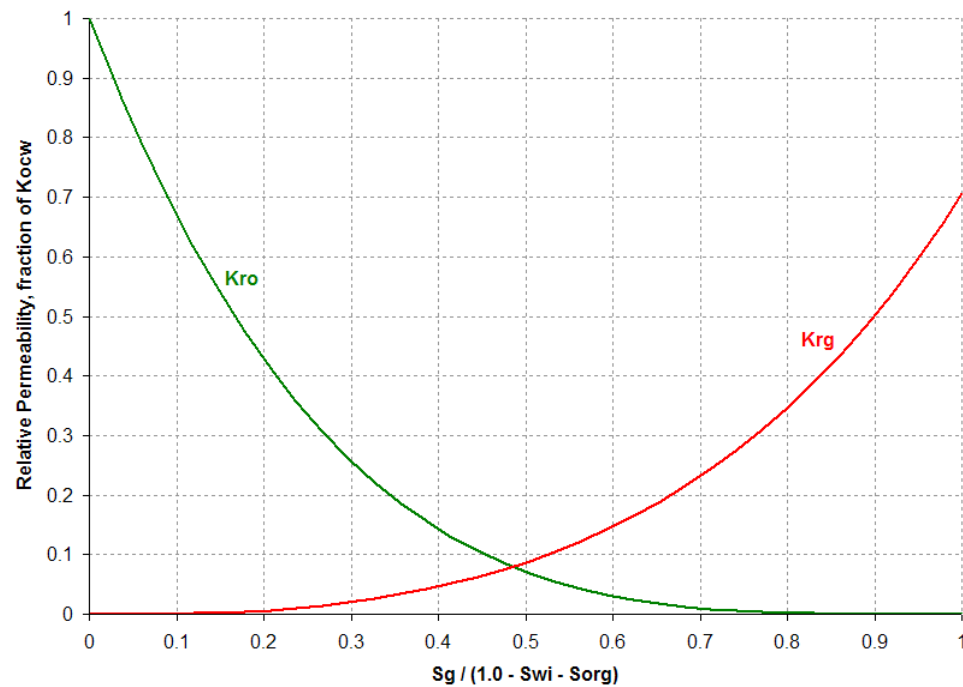


Figure 4.3-24: BNBN Normalized Drainage Gas-Oil Relative Permeabilities

4.4 Hibernia Reservoir

4.4.1 Hibernia Drill Stem Tests Results

Drill stem tests in the Hibernia formation were performed in the I-45 and I-13 wells. The tests results and interpretations are summarized in Table 4.4-1. Several tests primarily produced water that either had significant cushion or filtrate presence and so were regarded as being non-representative of the formation water. DST #3 in the I-45 well recovered a small amount of oil (4.3 m^3) and was not analyzed due to fluids injection prior to build-up.

Table 4.4-1: Hibernia DST Results Summary

Well	DST #	Field	Formation	Interval (mRT)	Fluid Type	Test Flow Rate (m3/d)	Oil Gravity	Pay (m)	Est kh (m*md)	Est Perm (md)	Skin Factor	Radius of Investigation (m)	Boundaries Encountered (Yes or No)	Productivity Index (m3d/kPa)	
														As Tested	Undamaged
I-13	6	Hebron	Up Hibernia L2	2975 – 2986	Oil	34	29.1	10	300	30	23	75	No	0.0036	0.0138
I-13	7	Hebron	Up Hibernia L1	2923 – 2940	Oil	350	28.8	17.6	3854.4	219	15.7	290	Uncertain	0.0546	0.1586
I-45	1	Ben Nevis	Hibernia HL	4535 – 4550	Oil	253.8	39	16	800	50	52	N/A	Uncertain (poor data)	45.1343	153.4006
I-45	2	Ben Nevis	Hibernia HL	4462 – 4465, 4468 – 4477	Water	No Flow	N/A	5	0.05	0.01	—	<2	None, Too tight	–	1.63E-05
I-45	5	Ben Nevis	Hibernia H1	4333.5 – 4340	Water	9.5	N/A	6.5	3	0.5	14	42	No	0.0003	0.0007
I-45	6	Ben Nevis	Hibernia H1	4320.4 – 4327.4	Water	4.8	N/A	7	0.77	0.11	4.7	25	No	0.0001	0.0002
I-45	7	Ben Nevis	Up Hibernia L3	4185 – 4197	Water	36	N/A	12	10.56	0.88	11.9	N/A	No	0.0013	0.0033
I-45	8	Ben Nevis	Up Hibernia L3	4112 – 4119	Water	80.6	N/A	7	6.3	0.9	1	57	No	0.0017	0.0020
H-71	1		Hibernia	3492 – 3502	Water	277	N/A	10	2700	270	20	310	Yes	0.1812	0.6210

Typical boundary conditions used in the I-45 drill stem tests in the Hibernia formation failed to show any boundary effects due to the limited radius of investigation resulting from the low permeability. In some cases, a reduction in the derivative was observed indicating either pressure support or increasing permeability thickness (kh) away from the wellbore. In the majority of these cases, the effect is probably a direct result of the inaccuracy or poor resolution of the mechanical pressure gauges.

4.4.2 Hibernia Fluid Properties

The Hibernia formation was encountered in the I-13, M-04, H-71, B-75, and I-45 wells. Hydrocarbons were encountered in the Hebron and the Ben Nevis fields (the I-45 well encountered gas). Drill stem tests were conducted in the I-13, H-71, and I-45 wells in this interval. Of these tests, only the DSTs conducted in the I-13 well provided oil samples; the remaining tests yielded water (Table 4.4-1 (above) summarizes the DST results in the Hibernia formation). A full PVT analysis was conducted on an oil sample from DST #7 in the I-13 well and the results are summarized in Table 4.4-2.

Table 4.4-2: Hebron Hibernia Fluid Properties

Well	DST or Sample #	Field	Formation	Interval/ Depth (m TVDSS)	Res Pressure (MPa)	Res Temp (°C)	Sat. Pressure (MPa)	Oil Visc @ Psat (cp)	Oil Gravity °API	Oil FVF1 (rm3/ Sm3)	GOR 1 (m3/ m3)
I-13	7	Hebron	Hibernia	2896 – 2913	30.4	72	17.7	1.4	30.5	1.234	81
Note: 1.From single-stage flash											

4.4.2.1 Hebron Hibernia (Pool 5) Fluid Analysis

The PROSPER® software program was used to fit PVT correlations to the measured lab data. The data was also adjusted to correct the reference temperature used in the PVT studies (72°C) to the actual reservoir temperature of 86°C. The resulting simulation inputs are plotted in Figure 4.4-1, Figure 4.4-2, and Figure 4.4-3.

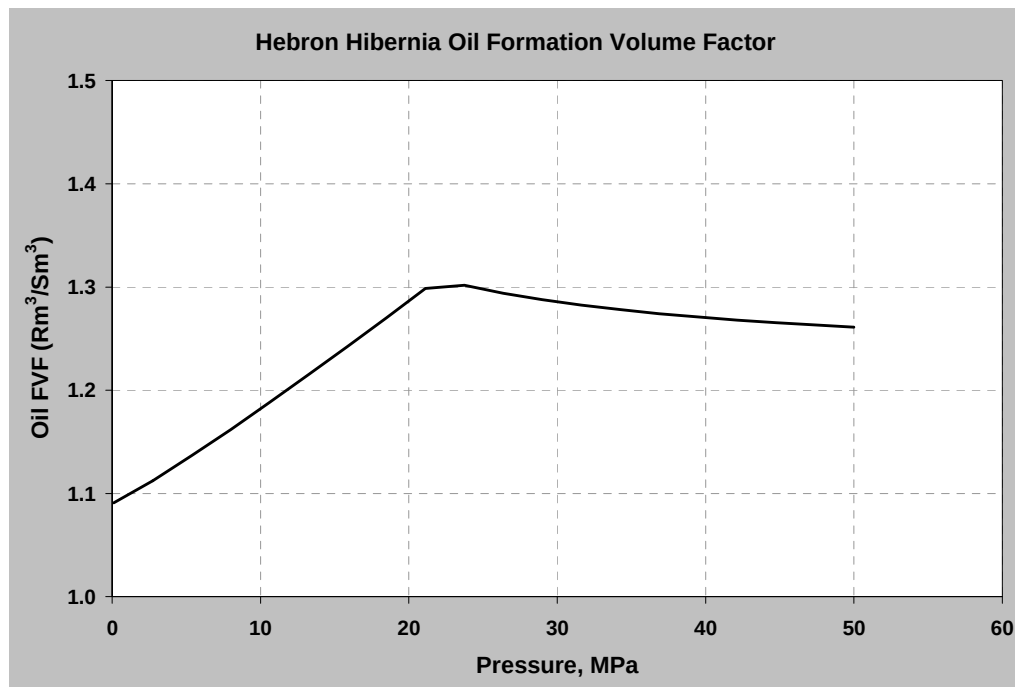


Figure 4.4-1: Hebron Hibernia – Oil Formation Volume Factor

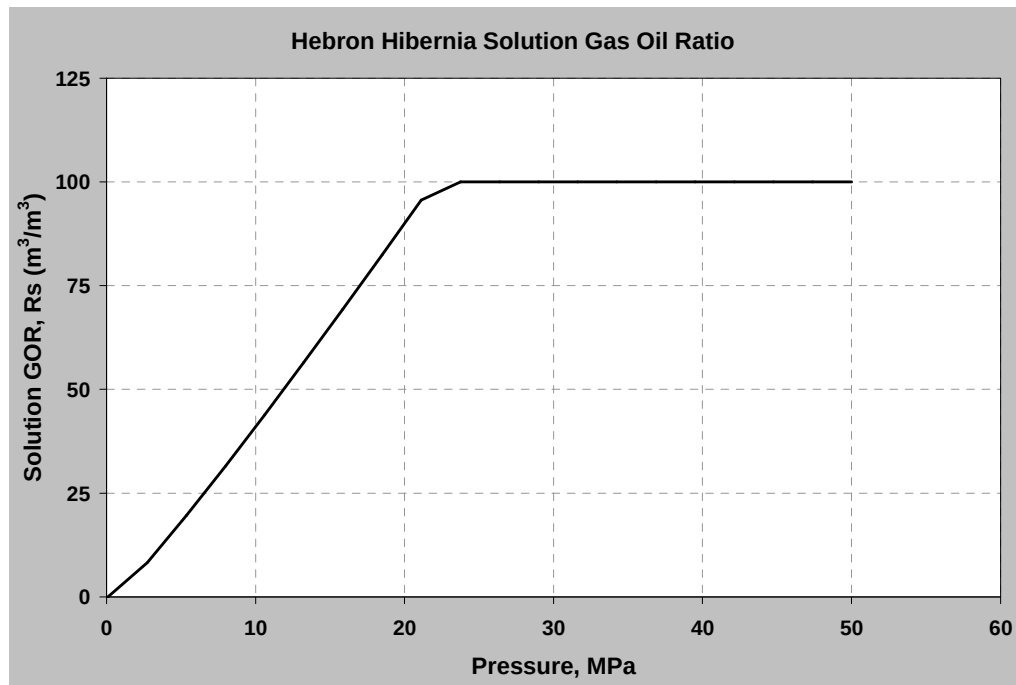


Figure 4.4-2: Hebron Hibernia – Solution Gas-Oil Ratio

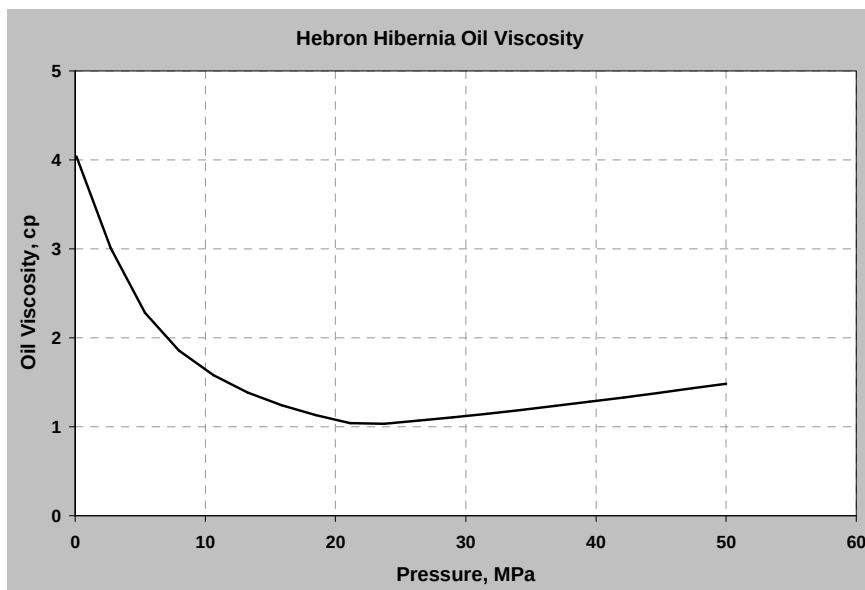


Figure 4.4-3: Hebron Hibernia – Oil Viscosity

4.4.3 Hibernia Reservoir Pressures and Temperatures

4.4.3.1 Hibernia Pressures and Pressure Depth Plot

Reservoir pressure measurements taken from the Hibernia formation in all the wells are plotted against depth in Figure 4.4-4. The plot shows that the Hibernia reservoir is normally pressured in the Hebron field (I-13 and M-04 wells), slightly over-pressured in the West Ben Nevis field (B-75), and significantly over-pressured in the Ben Nevis field (I-45 well).

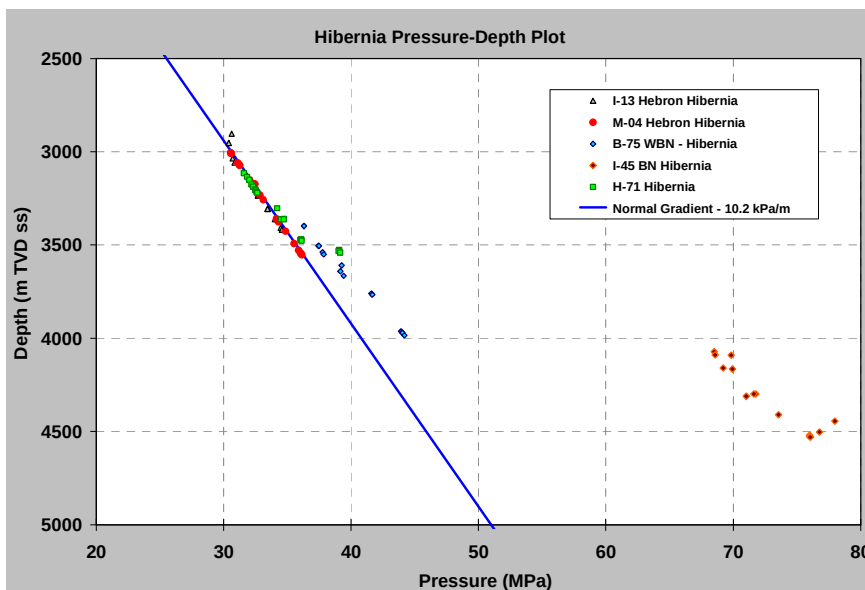


Figure 4.4-4: Pressure Depth Plot – Hibernia

Hibernia pressure data in the Hebron field was further analyzed (Figure 4.4-5). The M-04 well was wet within the Hibernia formation and so pressure data was only obtained in the water leg. The pressure data available from the I-13 RFT was confined entirely to the water leg. Due to the lack of pressure data in the oil column, it was impossible to confirm the oil-water contacts determined from the well logs. Water gradients of 10.17 kPa/m and 10.25 kPa/m were calculated for the M-04 and I-13 wells and a composite water gradient value of about 10.20 kPa/m was calculated from all the available data points.

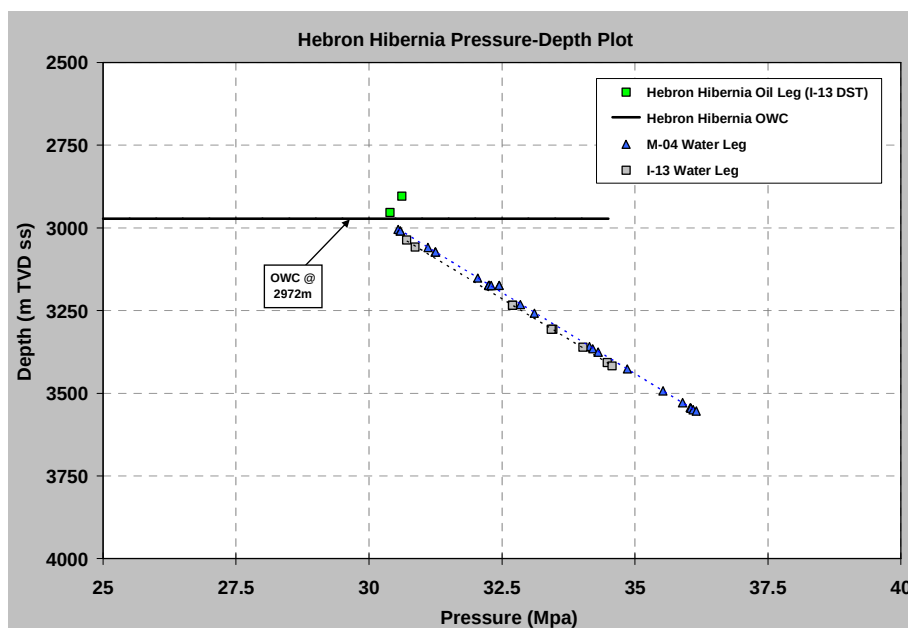


Figure 4.4-5: Hebron Hibernia Pressure-Depth Plot

4.4.3.2 Hibernia Reservoir Temperatures

Figure 4.4-6 plots the temperature data obtained from the DSTs conducted in the Hibernia formation. Based on a linear curve-fit of the data (using the seafloor temperature of 1°C as an anchor point, a temperature gradient of 2.84°C/100 m is calculated. The curve fit is also in agreement with the generalized temperature expressions developed for the Hebron Asset.

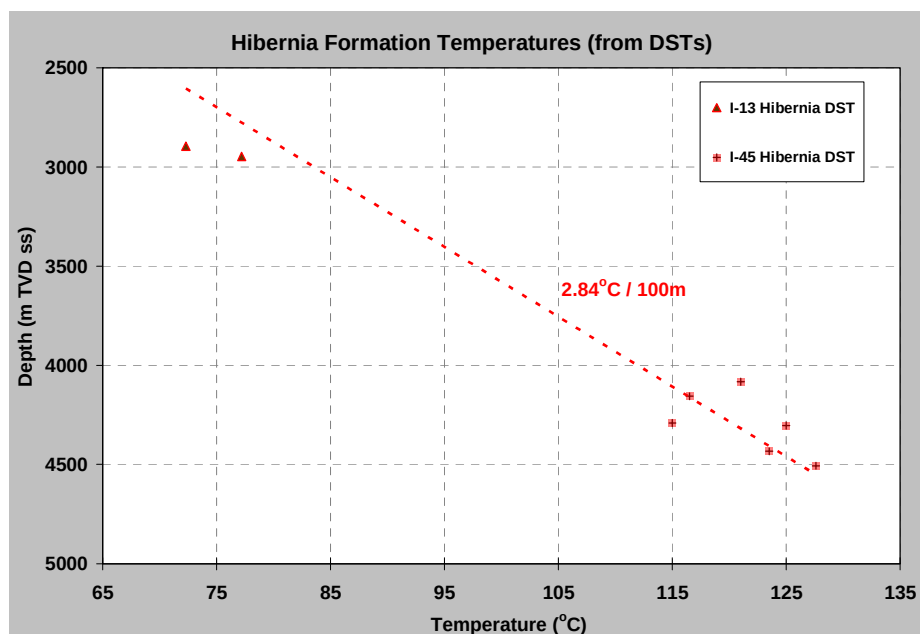


Figure 4.4-6: Hibernia Temperatures

4.4.4 Hibernia Special Core Analysis

4.4.4.1 Overview and Data Quality

Reliable SCAL data is currently not available for the Hibernia formation. The data used in developing the saturation functions were primarily from I-13 well measurements. Overall, three sets of saturation functions were developed to represent three categories of rock quality (<10 md, 10 to 100 md, and > 100 md). The relative permeability curves were generated using Corey-type equations with the end points (irreducible water and residual oil saturations) estimated from the available data. The water relative permeability end-points for these curves were chosen from a correlation of K_{rw} against permeability and obtained from the very limited core data set (Figure 4.4-7).

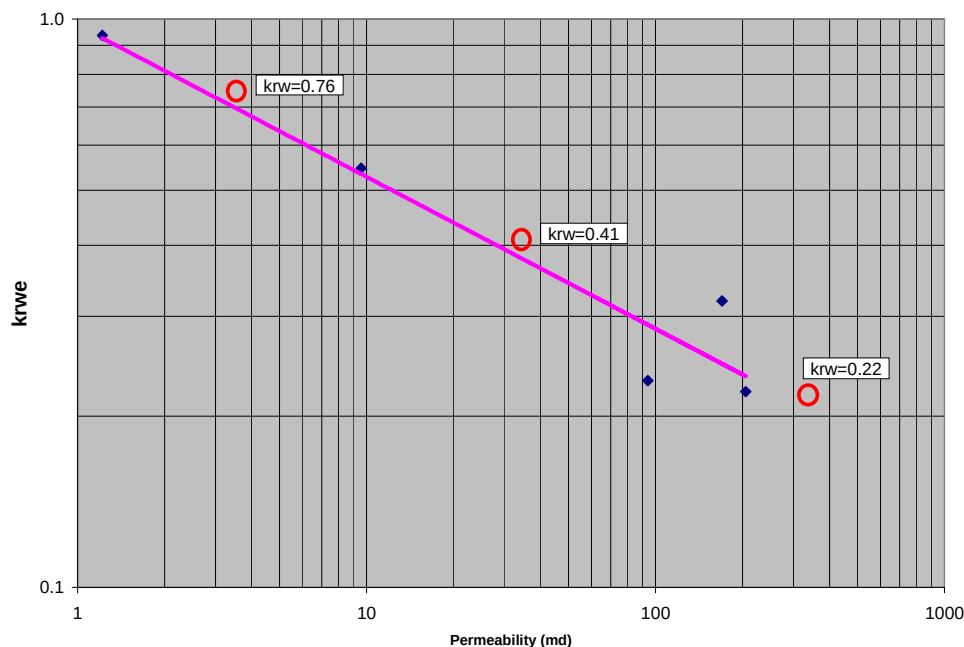


Figure 4.4-7: K_{rw} End-Point Correlation

Five relative permeability tests (two of which are from the Upper B marker reservoir above the main zone of interest) provided residual oil saturation data for the Hibernia reservoir. A limited set of capillary pressure data is available from I-13 core measurements. Five air-brine centrifuge measurements and nine mercury injection measurements were converted to oil-brine conditions and used to develop capillary pressure input.

4.4.4.2 Hebron Hibernia (Pool 5) Saturation Functions

Figure 4.4-8, Figure 4.4-9, and Figure 4.4-10 show the final sets of relative permeability and capillary pressures curves used as input into the reservoir simulation model. The curves are binned over the following permeability ranges:

1. < 10 md (Figure 4.4-8)
2. 10 to 100 md (Figure 4.4-9)
3. 100+ md (Figure 4.4-10)

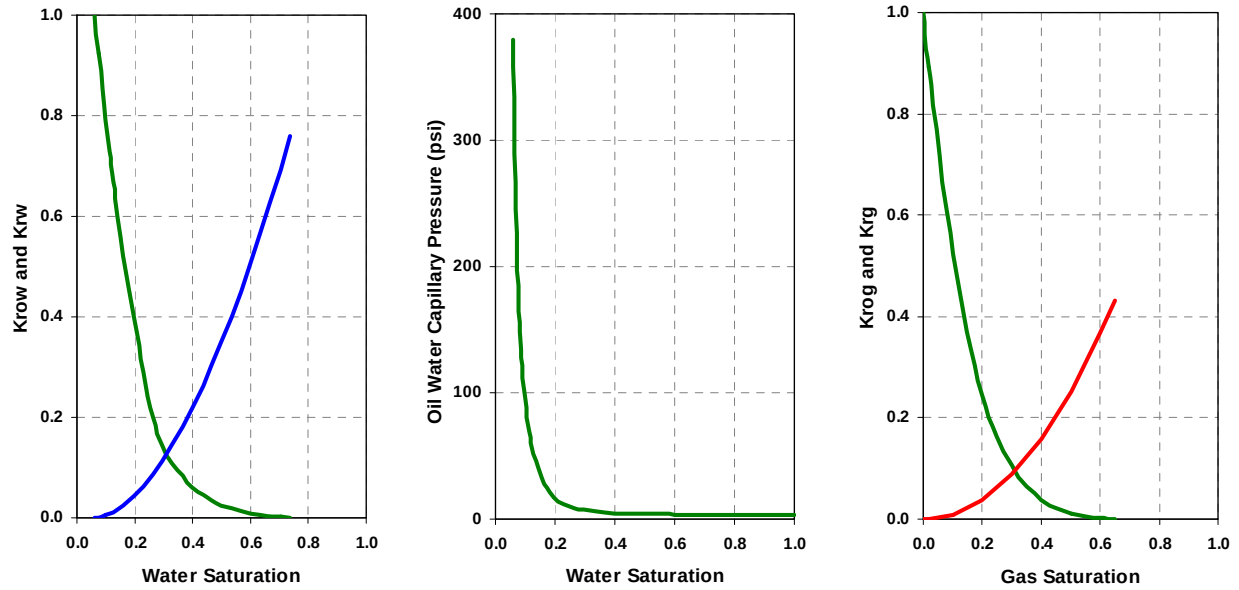


Figure 4.4-8: Saturation Functions for <10 md Bin

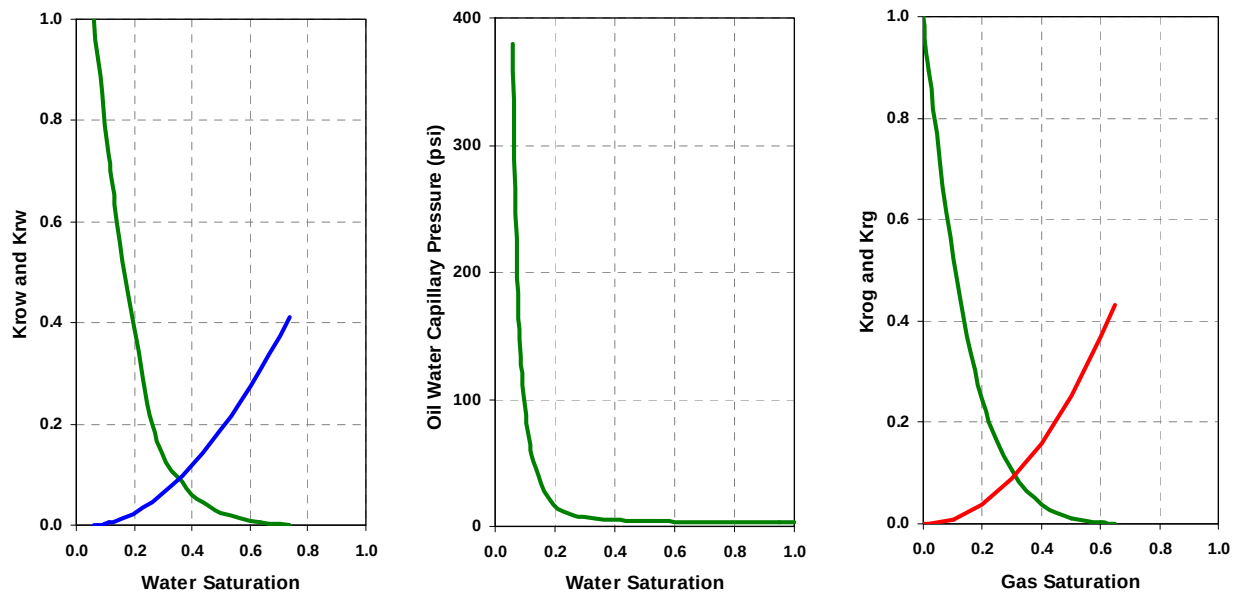


Figure 4.4-9: Saturation Functions for 10 to 100 md Bin

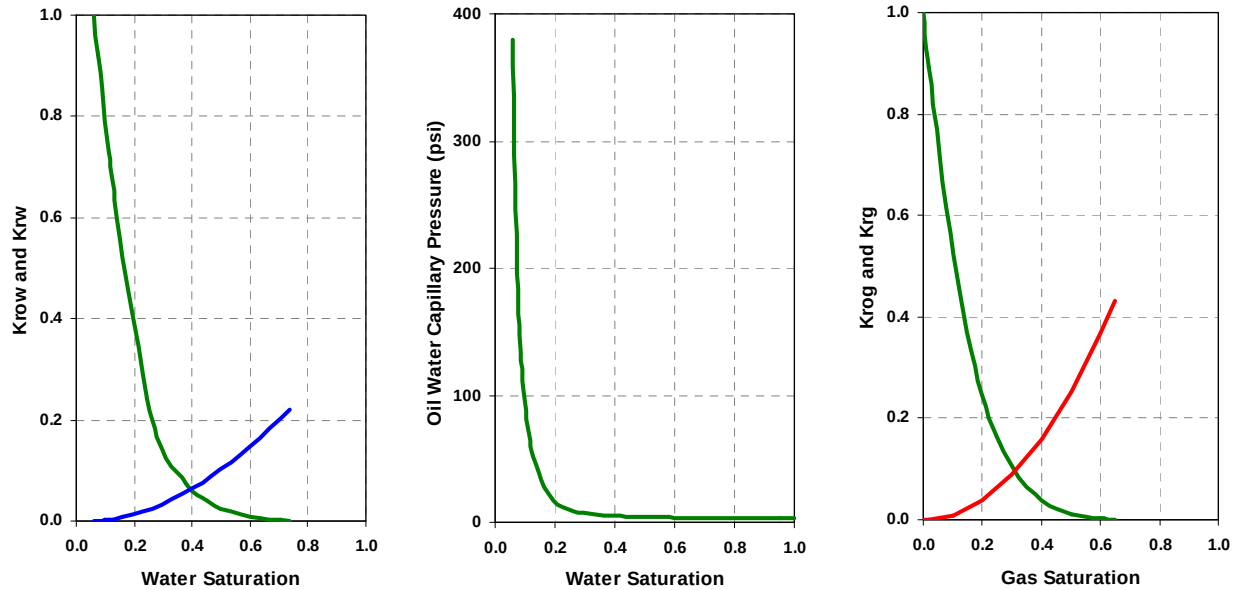


Figure 4.4-10: Saturation Functions for 100+ md Bin

4.5 Jeanne d'Arc Reservoir

4.5.1 Jeanne d'Arc Drill Stem Tests Results

The M-04, I-13, and B-75 wells were drilled into the Jeanne d'Arc formation and drill stem tests were conducted within this interval in these wells. Table 4.5-1 summarizes the results and analysis of the tests.

Table 4.5-1: Jeanne d'Arc DST Results Summary

Well	DST #	Field	Formation	Interval (mRT)	Fluid Type	Max Oil Flow Rate (m3/d)	Oil Gravity (oAPI)	Pay (m)	Est kh (m*md)	Skin Factor	Radius of Investigation (m)	Boundaries Encountered (Yes or No)	Productivity Index (m3/d/kPa)	
													As Tested	Undamaged
I-13	1	Hebron	JdA B	4368 – 4381	Oil	592	36.1	13	776	20	310	Yes	0.0494	0.1693
I-13	5	Hebron	JdA G	3842 – 3857	Oil	857	31.4	15	2040	12.4	420	Not Likely	0.0619	0.1552
M-04	1	Hebron	JdA H	3906 – 3924	Oil	340	25.4	18	1223	2.35	310	Yes	0.0260	0.0334
B-75	4	W. Ben Nevis	JdA F	4498 – 4507	Oil	896	32.2	9	504	8	—	Yes	0.0341	0.0672
B-75	5	W. Ben Nevis	JdA F	4498 – 4507	Oil	430	32.2	9	504	2.5	540	Yes	0.0515	0.0672

4.5.2 Jeanne d’Arc Fluid Properties

A summary of the PVT analysis performed on fluid samples collected from the Jeanne d’Arc formation is provided in Table 4.5-2.

Table 4.5-2: Jeanne d’Arc Formation Fluid Properties Summary

Well	DST or Sample #	Field	Formation	Interval/ Depth (m TVDSS)	Res Pres (MPa)	Res Temp (°C)	Sat. Pressure (MPa)	Oil Visc @ Psat (cp)	Oil Gravity °API	Oil FVF (rm3/Sm3)	GOR1 (m3/m3)
I-13	5	Hebron	JdA G Sand	3815 – 3830	45.8	99	22.2	1.0	31.7	1.260	103
I-13	1	Hebron	JdA B Sand	4340 – 4354	47.5	117	30.0	0.2	39.8	1.550	198
M-04	0907-EA	Hebron	JdA H Sand	3842	41.1	106	24.9	0.2	25.6	1.300	98
M-04	3421-MA	Hebron	JdA D Sand	4183	42.7	116	37.0	0.2	37.8	1.849	276
M-04	3385-MA	Hebron	JdA B Sand	4533	47.5	125	35.0	0.2	38.0	1.802	261
B-75	5	W. Ben Nevis	JdA F Sand	4473 – 4482	91.4	121	29.0	0.5	37.0	1.414	178
<i>Notes:</i>											
1.From single-stage flash											

4.5.2.1 Hebron Jeanne d’Arc (Pool 4) Fluid Analysis

The PROSPER® software program was used to fit PVT correlations to the measured lab data. The data was also adjusted to correct the reference temperature used in the PVT studies of the I-13 DST #5 (99°C) to the actual reservoir temperature of 106°C. The resulting data set (oil formation volume factor [FVF], solution gas-oil ratio and oil viscosity as functions of pressures) are plotted in Figure 4.5-1, Figure 4.5-2, and Figure 4.5-3.

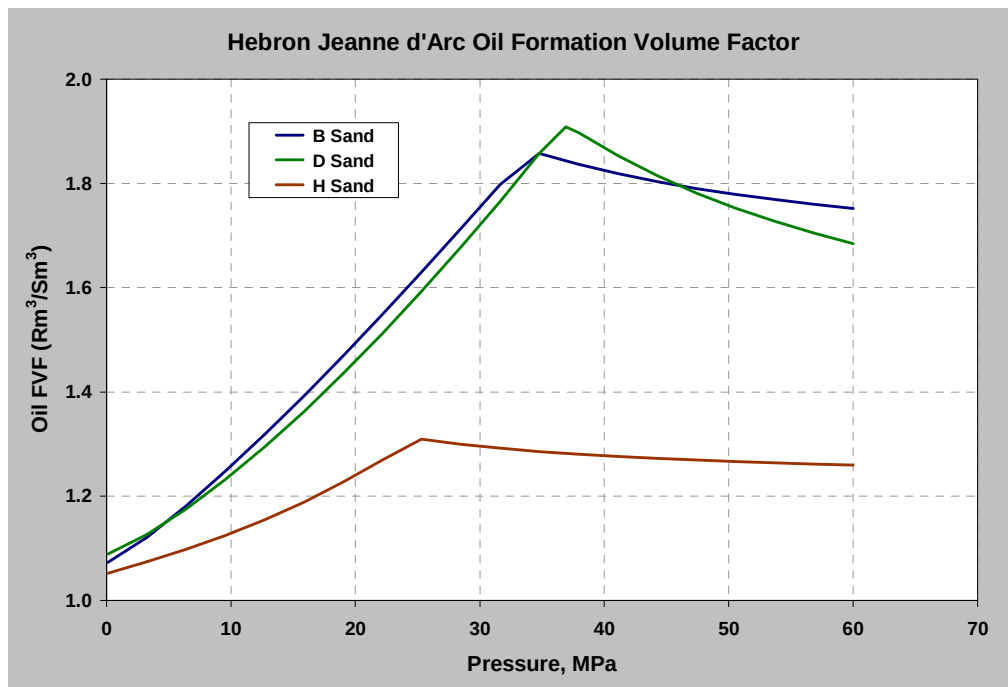


Figure 4.5-1: Hebron Jeanne d'Arc Oil Formation Volume Factor

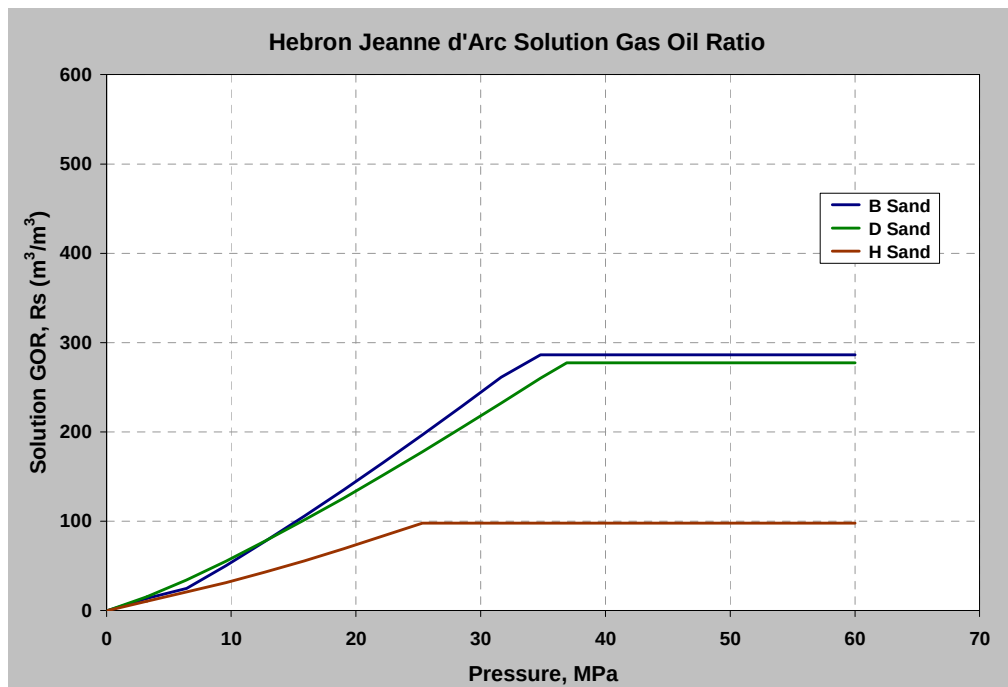


Figure 4.5-2: Hebron Jeanne d'Arc Solution Gas-Oil Ratio

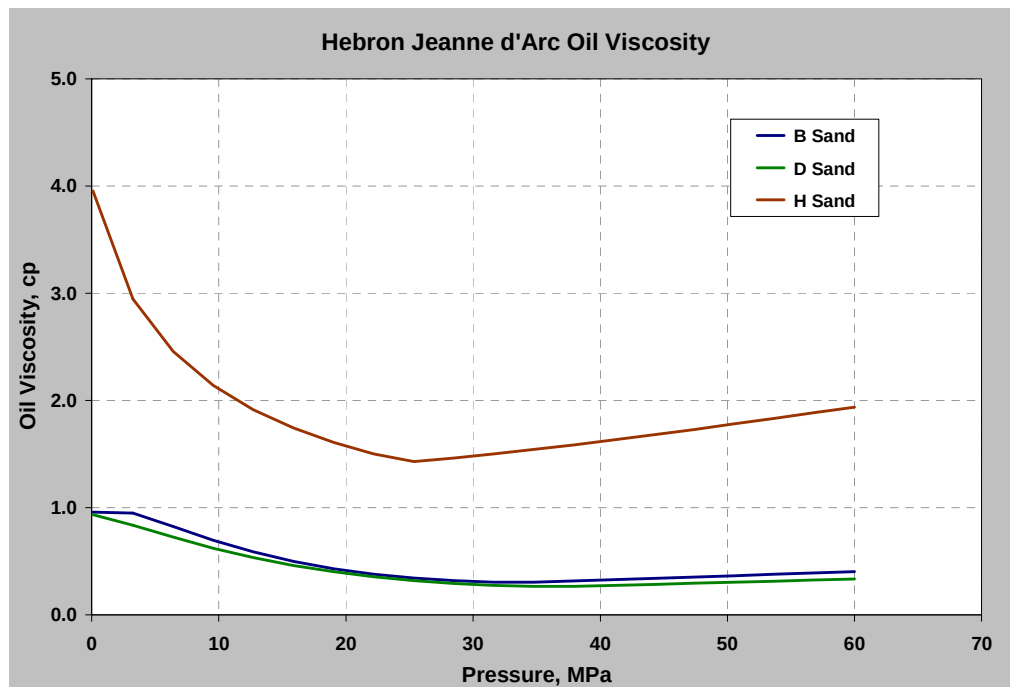


Figure 4.5-3: Hebron Jeanne d'Arc Oil Viscosity

4.5.3 Jeanne d'Arc Reservoir Pressures and Temperatures

4.5.3.1 Jeanne d'Arc Pressures and Pressure-Depth Plot

Pressure measurements recorded for the Jeanne d'Arc formation are plotted against depth in Figure 4.5-4. The plot shows that the Jeanne d'Arc formation is normally to slightly over-pressured in the Hebron field (I-13 and M-04 wells) and over-pressured in the West Ben Nevis field (B-75 well) and Trinity Fault block (H-71 well).

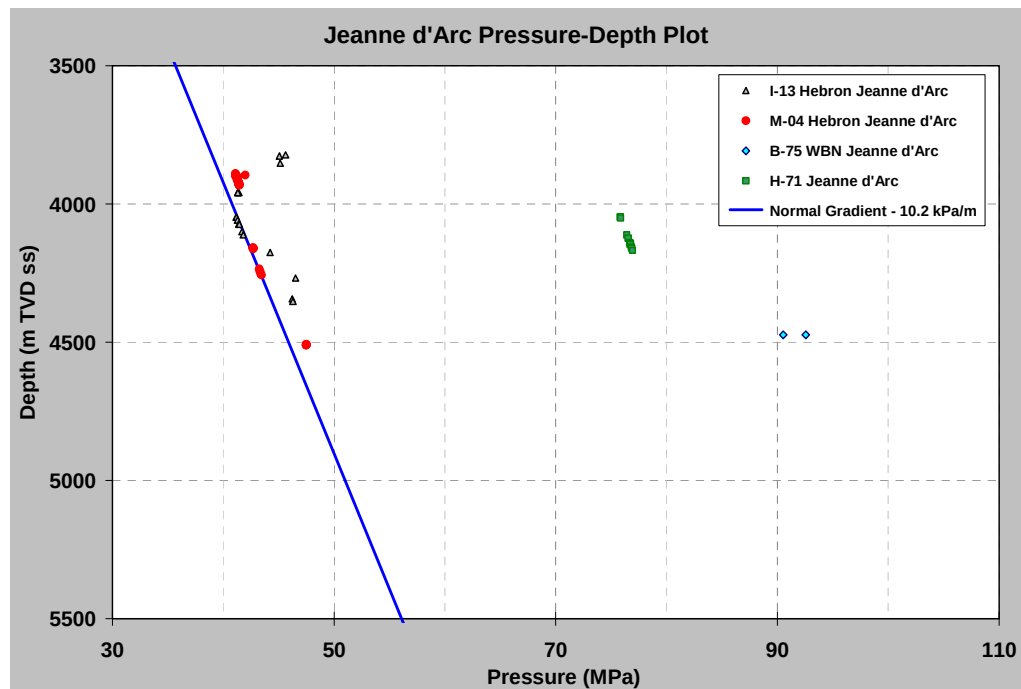


Figure 4.5-4: Jeanne d'Arc Pressure Depth Plot

Further analysis of the Jeanne d'Arc pressure data within the Hebron field (Figure 4.5-5) indicates that the different sand layers (H, G, D, C and B) are unlikely to be in pressure communication.

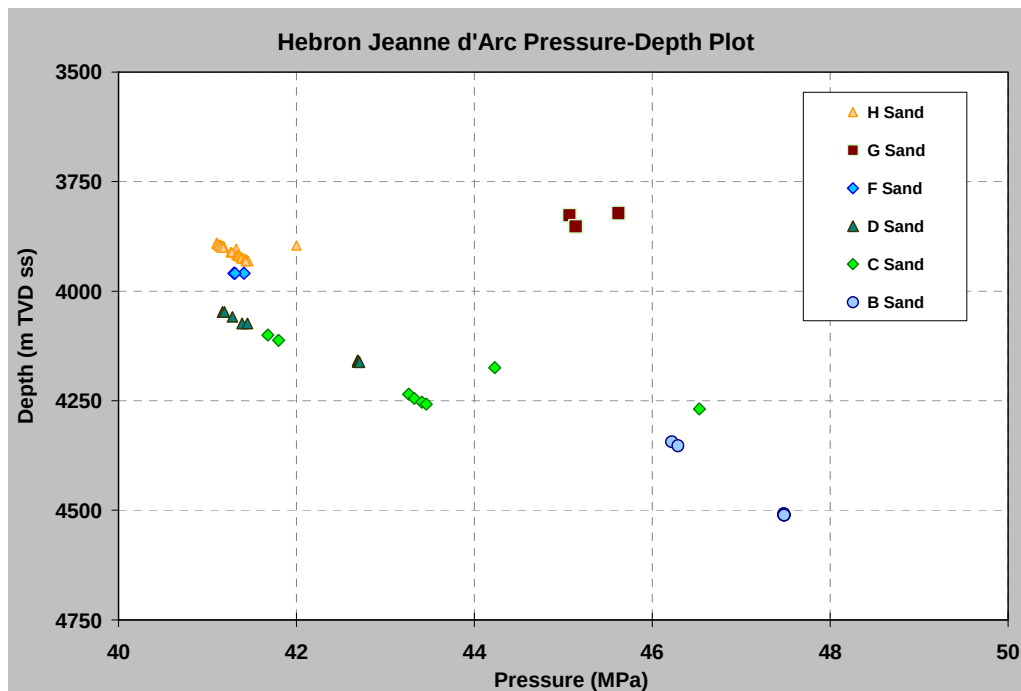


Figure 4.5-5: Hebron Jeanne d'Arc Pressure Depth Plot

4.5.3.2 Jeanne d'Arc Reservoir Temperatures

Reservoir temperatures for the Jeanne d'Arc formation are plotted in Figure 4.5-6. A limited number of data points (i.e., five data points, two of which are temperatures taken at the same depth [B-75 DSTs]) are available. The calculated temperature gradient is $2.74^{\circ}\text{C}/100\text{ m}$.

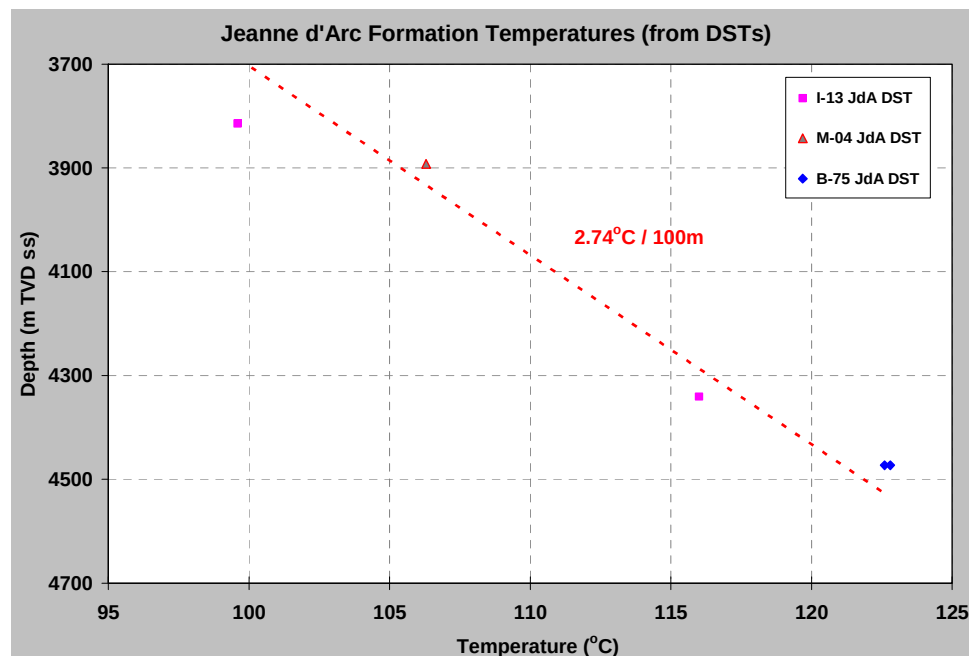


Figure 4.5-6: Jeanne d'Arc Temperatures

4.5.4 Jeanne d'Arc Special Core Analysis

4.5.4.1 Overview and Data Quality

Reliable SCAL data have not yet been obtained for the Jeanne d'Arc reservoir. Some early core data from the I-13 well are available, but the SCAL data from the tests are considered unreliable (Section 4.3.3.1 provides a detailed discussion on the issues with the I-13 SCAL data). Three relative permeability measurements are available from the I-13 SCAL data for the Jeanne d'Arc interval and these indicate residual oil saturation estimates of approximately 0.22, 0.33, and 0.35, respectively. These values are considered pessimistic as the core plugs were not flooded to residual saturation. They were however used as guides in selecting the residual oil saturation values.

4.5.4.2 Hebron Jeanne d'Arc (Pool 4) Saturation Functions

Corey type-equations were used to define the relative permeability inputs for the Jeanne d'Arc reservoir studies. Intermediate-wettability Corey exponents have been used to characterize the water-oil displacement behaviour. This

assumed behaviour is consistent with analogue data from other reservoirs producing from the Jeanne d'Arc formation in the region. Capillary pressure measurements from the I-13 well in the Jeanne d'Arc interval were analyzed and power law relationships were used to bracket the measured capillary pressure data from which a best-fit capillary pressure curve was developed. The final data input into the simulation model is shown in Figure 4.5-7.

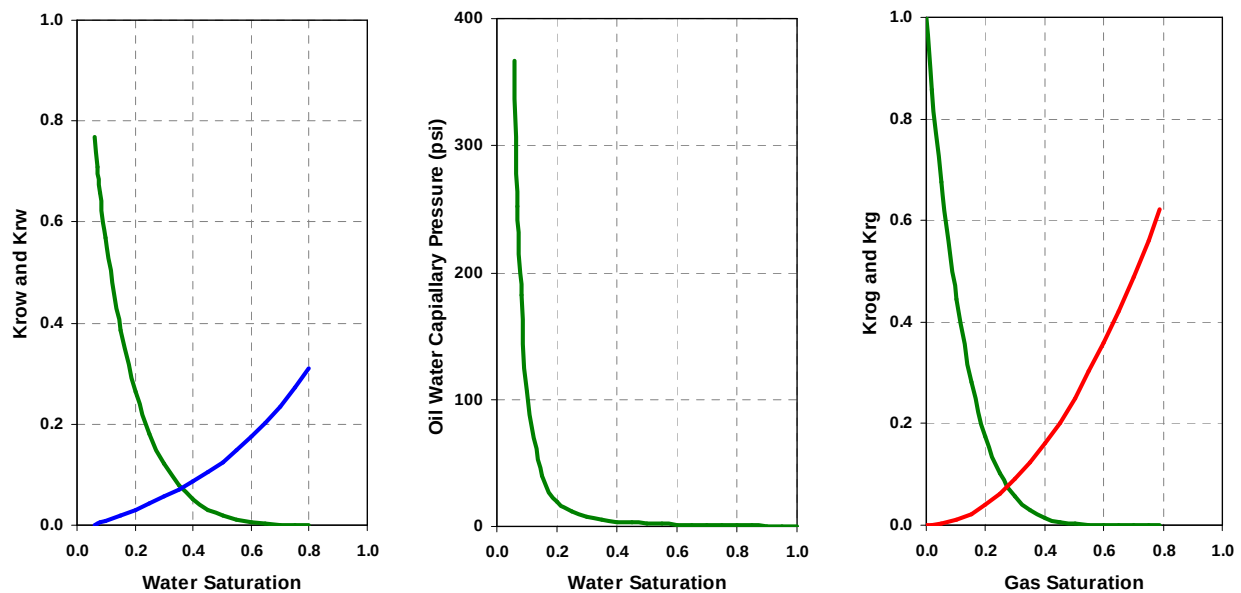


Figure 4.5-7: Hebron Jeanne d'Arc Saturation Functions

5 RESERVE ESTIMATES

5.1 Introduction

This section presents the range of hydrocarbon-in-place and recoverable resource estimates for the resources targeted in the initial development phase of the project. In-place and recovery estimates for the remaining resources are provided in Section 6.8 – Contingent Developments.

5.1.1 Original Hydrocarbon In-Place Estimates

Original hydrocarbon in-place best estimate volumes and their associated uncertainty ranges were calculated using both deterministic geologic / earth modeling and stochastic analyses.

The stochastic analysis employed the Monte Carlo method of uncertainty modeling. Each variable in the equation used to determine in-place volumes was assigned a distribution based on interpretation of well and seismic data. The distributions reflect the range of uncertainty for each variable used. The shapes of the different input distributions ranged from uniform to triangular, depending on the variable. For Pools 1 and 3, the @Risk ® software program was used to run multiple realizations of the hydrocarbon in-place volumes and produce an output distribution. Pools 4 and 5 utilized Experimental Design model-based uncertainty analysis, followed by Monte Carlo sampling in Crystal Ball ® software, thus yielding multiple realizations of the hydrocarbon in-place volumes and associated distribution.

For all the pools, the best estimate models were used for the best estimate volumes. The best estimate assessment is determined from the subsurface description represented by the base case reservoir models (static and dynamic). The models are built using available subsurface data, derivatives and / or interpretations of the data (e.g. seismic interpretation, structural framework, petrophysics, facies distribution, core analysis, pressure-volume-temperature analysis, etc). In situations where the required data is unavailable, insufficient or deemed to be of poor quality, the collective experience and judgment of the subsurface technical team is utilized to determine suitable inputs. The result of this process is a favoured deterministic reference case. The upside and downside values were computed probabilistically both for the individual pools and the total resource. The total hydrocarbon in-place volumes for the initial development phase are shown in Table 5.6-1.

5.1.2 Recoverable Resources Estimates

The ranges of recoverable resources were generated by flow simulation modeling of different scenarios. In the assessment, the starting point for each resource was the base case reservoir description, the simulation model inputs described in Section 4, and the base case depletion plans selected for each

of the pools as described in Section 6. Sensitivities to different input parameters were considered and simulated independently for each reservoir. The impact of downtime assumptions, drilling sequence, production constraints associated with the design capacity limits of the production system or economic cut-off criteria for recovery estimation were not considered in the flow simulation modeling. Section 6.6.3 presents the integrated production profiles for the best estimate case that incorporate these considerations while Section 6.6.4 presents upside and downside production scenarios of the resources included in the initial development phase of the project. The Estimated Ultimate Recovery (EUR) numbers quoted in this section are based on a 30-year assumed producing life for each developed resource.

The approach taken for the recovery uncertainty was to begin with deterministic recovery efficiency (RE) for each reservoir compartment. This deterministic RE is obtained directly from the simulation model results of the base case depletion plan. A series of stochastically determined delta recovery efficiencies that account for the uncertainties surrounding the deterministic value was then added to the base value. A spreadsheet model using ExcelTM and @RISKTM software was used to generate stochastic estimates of RE and EUR for the individual reservoir compartments. The RE input parameters were allowed to vary stochastically over their prescribed input ranges and correlation coefficients were built into the model for inter-related input parameters.

5.2 Hebron Field Ben Nevis Reservoir (Pool 1)

5.2.1 Hebron Ben Nevis Original Hydrocarbons In-Place

5.2.1.1 In-Place Parameters Considered

The results of the stochastic modeling indicate that the following parameters have the greatest impact on the overall range of in-place volumes uncertainty (listed in descending order of importance):

- ◆ Hydrocarbon Saturation
- ◆ Porosity
- ◆ Seismic Velocity Interpretation
- ◆ Oil-Water Contact (OWC) Interpretation
- ◆ Shrinkage
- ◆ Gas-Oil Contact
- ◆ Gross Interval Thickness

5.2.1.2 In-Place Volume Ranges

Table 5.2-1 shows the overall estimated in-place volumes range for the Hebron Ben Nevis reservoir, Pool 1. The total Pool 1 values for the upside and downside cases were computed via a combined stochastic evaluation of the fault blocks, and not from the summation of the stochastic evaluation of the individual fault blocks.

Table 5.2-1: Hebron Ben Nevis (Pool 1) In-Place Volumes Range

Hebron Ben Nevis Oil	Upside Volumes		Best Estimate Volumes		Downside Volumes	
	MBO	Mm ³	MBO	Mm ³	MBO	Mm ³
D-94 Fault Block	1601	255	1328	211	1077	171
I-13 Fault Block	252	40	187	30	141	22
Total Hebron Ben Nevis	1870	297	1515	241	1204	191
Total Hebron Ben Nevis Gas	Upside Volumes		Best Estimate Volumes		Downside Volumes	
	GCF	* GSm ³	GCF	GSm ³	GCF	GSm ³
Solution Gas D-94 Block	112	3.2	145	4.1	189	5.4
Solution Gas I-13 Block	10	0.3	14	0.4	22	0.6
Non-associated Gas	n/a	n/a	n/a	n/a	n/a	n/a
Gas Cap D-94 Block only	0	0	0	0	31	0.9

* GSm³ = 10⁹ cubic meters

5.2.2 Hebron Ben Nevis Recoverable Resources Sensitivity Results

5.2.2.1 Reservoir Parameters Considered

The input parameters considered in the Hebron Ben Nevis EUR sensitivity study included the following:

- ◆ Aquifer ratio
- ◆ Baffle vertical permeability
- ◆ Bulk permeability (vertical, Kv and horizontal, Kh) – concurrent increase / decrease in both horizontal and vertical permeabilities, without altering the Kv-to-Kh ratio
- ◆ Calcite cement coverage in cement-prone layer
- ◆ Fault transmissibility
- ◆ Pore Volume compressibility
- ◆ Relative permeability
- ◆ Skin

- ◆ Vertical permeability – increase / decrease in vertical permeability without altering horizontal permeability
- ◆ Viscosity
- ◆ Zone boundary transmissibility

The results of the sensitivity analysis and stochastic modeling indicate that the following dynamic input parameters (listed in descending order of importance) have the greatest impact on EUR:

- ◆ Bulk permeability (vertical, Kv and horizontal, Kh)
- ◆ Relative permeability
- ◆ Vertical permeability
- ◆ Viscosity

5.2.2.2 Recoverable Resources Range

Table 5.2-2 shows the overall EUR range for the Hebron Ben Nevis reservoir, Pool 1. The total Pool 1 values for the upside and downside cases were computed via a combined stochastic evaluation of the fault blocks, and not from the summation of the stochastic evaluation of the individual fault blocks.

Table 5.2-2: Hebron Ben Nevis (Pool 1) EUR Oil Range

	Upside EUR		Best Estimate EUR		Downside EUR	
	MBO	Mm ³	MBO	Mm ³	MBO	Mm ³
D-94 Fault Block	682	109	517	82	410	65
I-13 Fault Block	80	13	46	7	38	6
Total Hebron Ben Nevis	762	121	563	89	443	70

5.3 Hebron Field Hibernia Reservoir (Pool 5)

5.3.1 Hebron Hibernia Original Hydrocarbons In-Place

5.3.1.1 In-Place Parameters Considered

The top six uncertainties impacting in-place volumes were as follows (listed in descending order of importance):

- ◆ Porosity
- ◆ Swir
- ◆ OWC interpretation
- ◆ Facies
- ◆ Structure

◆ Permeability

5.3.1.2 In-Place Volume Ranges

Table 5.3-1 shows the overall estimated in-place volumes range for the Hebron Hibernia reservoir, Pool 5.

Table 5.3-1: Hebron Hibernia (Pool 5) In-Place Volume Range

Hebron Hibernia Oil	Upside Volumes		Best Estimate Volumes		Downside Volumes	
	MBO	Mm ³	MBO	Mm ³	MBO	Mm ³
	218	35	148	24	93	15
Hebron Hibernia Gas	Upside Volumes		Best Estimate Volumes		Downside Volumes	
	GCF	GSm ³	GCF	GSm ³	GCF	GSm ³
Solution Gas	122	3.5	85	2.4	53	1.5
Non-associated Gas	n/a	n/a	n/a	n/a	n/a	n/a
Gas Cap	n/a	n/a	n/a	n/a	n/a	n/a

5.3.2 Hebron Hibernia Recoverable Resources Sensitivity Results

5.3.2.1 Reservoir Parameters Considered

The top six uncertainties (listed in descending order of importance) impacting oil recovery were as follows:

- ◆ Facies distribution model (static model)
- ◆ Porosity
- ◆ Permeability
- ◆ Water saturation distribution
- ◆ OWC interpretation
- ◆ Structure

5.3.2.2 Recoverable Resources Range

Table 5.3-2 shows the EUR range for the Hebron Hibernia reservoir, Pool 5.

Table 5.3-2: Hebron Hibernia (Pool 5) EUR Range

	Upside EUR		Best Estimate EUR		Downside EUR	
	MBO	Mm ³	MBO	Mm ³	MBO	Mm ³
Hebron Hibernia	47	7	15	2	6	1

5.4 Hebron Field Jeanne d'Arc Reservoir (Pool 4)

5.4.1 Hebron Jeanne d'Arc Original Hydrocarbons In-Place

5.4.1.1 In-Place Parameters Considered

The top six uncertainties (listed in descending order of importance) impacting in-place volumes were as follows:

- ◆ Valley fill configuration (width and thickness)
- ◆ Facies distribution model (static model)
- ◆ Structural interpretation
- ◆ Porosity
- ◆ J-function (transition zone interpretation)
- ◆ OWC interpretation

5.4.1.2 In-Place Volume Ranges

Table 5.4-1 shows overall in-place volumes range for the Jeanne d'Arc reservoir, Pool 4.

Table 5.4-1: Hebron Jeanne d'Arc (Pool 4) In-Place Volume Range

Hebron Jeanne d'Arc Oil	Upside Volumes		Best Estimate Volumes		Downside Volumes	
	MB	Mm ³	MB	Mm ³	MB	Mm ³
H-Sand North Valley	274	44	204	32	147	23
B Sand	220	35	113	18	57	9
Total Hebron Jeanne d'Arc	464	74	317	50	243	39
Hebron Jeanne d'Arc Gas	Upside Volumes		Best Estimate Volumes		Downside Volumes	
	GCF	GSm ³	GCF	GSm ³	GCF	GSm ³
Solution Gas Pool 4 H	151	4.3	112	3.2	81	2.3
Solution Gas Pool 4 B	353	10.0	181	5.2	92	2.6
Non-associated Gas	n/a	n/a	n/a	n/a	n/a	n/a
Gas Cap	n/a	n/a	n/a	n/a	n/a	n/a
Total	504	14.3	293	8.3	173	4.9

5.4.2 Hebron Jeanne d'Arc Recoverable Resources Sensitivity Results

5.4.2.1 Reservoir Parameters Considered

The top six uncertainties (listed in descending order of importance) impacting EUR were as follows:

- ◆ Facies distribution model (static model)
- ◆ Valley fill configuration (width and thickness)
- ◆ Permeability
- ◆ J-function (transition zone interpretation)
- ◆ Structural interpretation
- ◆ Residual oil saturation

5.4.2.2 Recoverable Resources Range

Table 5.4-2 shows the EUR range for the Jeanne d'Arc reservoir, Pool 4.

Table 5.4-2: Hebron Jeanne d'Arc (Pool 4) EUR Range

	Upside EUR		Best Estimate EUR		Downside EUR	
	MBO	Mm ³	MBO	Mm ³	MBO	Mm ³
H-Sand North Valley	89	14	59	9	33	5
B Sand	60	10	28	4	11	2
Total Hebron Jeanne d'Arc	123	20	87	14	61	10

5.5 Ben Nevis Field Ben Nevis Reservoir (Pool 3)

5.5.1 Ben Nevis Ben Nevis Original Hydrocarbons In-Place

5.5.1.1 In-Place Parameters Considered

The results of the stochastic modeling indicate that the following parameters have the greatest impact on the overall range of in-place volumes uncertainty (listed in descending order of importance):

- ◆ Hydrocarbon Saturation
- ◆ Porosity
- ◆ Seismic Velocity Interpretation
- ◆ Degree of cementation
- ◆ OWC Interpretation
- ◆ Shrinkage
- ◆ Gross Interval Thickness
- ◆ Gas-Oil Contact

5.5.1.2 In-Place Volume Ranges

Table 5.5-1 shows the overall estimated in-place volumes range for the Ben Nevis Ben Nevis reservoir, Pool 3.

Table 5.5-1: Ben Nevis Field, Ben Nevis (Pool 3) In-Place Volumes Range

Ben Nevis Ben Nevis Oil	Upside Volumes		Best Estimate Volumes		Downside Volumes	
	MBO	Mm ³	MBO	Mm ³	MBO	Mm ³
	925	147	640	102	455	72
Ben Nevis Ben Nevis Gas	Upside Volumes		Best Estimate Volumes		Downside Volumes	
	GCF	GSm ³	GCF	GSm ³	GCF	GSm ³
Solution Gas	211	6.0	159	4.5	122	3.5
Non-associated Gas	n/a	n/a	n/a	n/a	n/a	n/a
Gas Cap	83	2.4	54	1.5	34	1.0
Total	294	8.3	213	6.0	156	4.4

5.5.2 Ben Nevis Ben Nevis Recoverable Resources Sensitivity Results

5.5.2.1 Reservoir Parameters Considered

The input parameters considered in the Ben Nevis Ben Nevis EUR sensitivity study included the following:

- ◆ Bulk permeability (vertical, Kv and horizontal, Kh) – concurrent increase / decrease in both horizontal and vertical permeabilities, without altering the Kv-to-Kh ratio
- ◆ Fault transmissibility
- ◆ Relative permeability
- ◆ Skin
- ◆ Vertical to horizontal permeability (Kv/Kh) ratio

The results of the sensitivity analysis and stochastic modeling indicate that bulk permeability, skin and relative permeability (listed in descending order of importance) are the dynamic parameters that have the greatest impact on EUR.

5.5.2.2 Recoverable Resources Range

Table 5.2-2 shows the overall EUR range for the Ben Nevis Ben Nevis reservoir, Pool 3. All the gas produced in conjunction with oil production will either be re-injected or used for the GBS facility operation.

Table 5.5-2: Ben Nevis Ben Nevis (Pool 3) EUR Range

	Upside EUR		Best Estimate EUR		Downside EUR	
	MBO	Mm ³	MBO	Mm ³	MBO	Mm ³
Ben Nevis Ben Nevis - Oil	203	32	124	20	75	12

5.6 Hebron Initial Development Summary

5.6.1 Total Resource In-Place Volumes

Table 5.6-1 shows the overall range of in-place volumes calculated for the resources developed in the initial project phase. The total resource values were computed via a combined stochastic evaluation of all the pools, and not from the summation of the stochastic evaluation of the individual Hebron pools.

Table 5.6-1: Hebron Initial Development In-Place Oil Volumes Range

Initial Development Phase	Upside In-Place Volumes		Best Estimate In-Place Volumes		Downside In-Place Volumes	
	MBO	Mm ³	MBO	Mm ³	MBO	Mm ³
Hebron Ben Nevis	1870	297	1515	241	1204	191
Hebron Hibernia	218	35	148	24	93	15
Hebron Jeanne d'Arc	464	74	317	50	243	39
Ben Nevis Ben Nevis	925	147	640	102	455	72
Total Hebron	3206	510	2620	417	2283	363

5.6.2 Total Recoverable Resources

Table 5.6-2 shows the overall range of EUR calculated for the resources developed in the initial project phase. The total resource values were computed via a combined stochastic evaluation of all the pools, and not from the summation of the stochastic evaluation of the individual Hebron pools.

Table 5.6-2: Hebron Initial Development EUR Oil Range

Initial Development Phase	Upside EUR		Best Estimate EUR		Downside EUR	
	MBO	Mm ³	MBO	Mm ³	MBO	Mm ³
Hebron Ben Nevis	762	121	563	90	443	70
Hebron Hibernia	47	7	15	2	6	1
Hebron Jeanne d'Arc	123	20	87	14	61	10
Ben Nevis Ben Nevis	203	32	124	20	75	12
Total Hebron	1055	168	789	126	660	105

6 RESERVOIR EXPLOITATION

6.1 Reservoir Exploitation Overview

Section 6 of the Development Plan provides a description of the reservoir exploitation schemes proposed for the resources within the Hebron Asset. The Section begins with a brief summary of the overall reservoir exploitation philosophy, the approach taken during the depletion planning process for the entire asset and high-level summaries of the resulting depletion plans for the resources included within the scope of the initial development phase of the Hebron Project. Key aspects of the depletion plan such as the asset gas management strategy and a summary of the artificial lift and field hydraulic studies are also covered as part of the overview. Subsequent sub-sections provide additional details regarding the depletion planning studies undertaken for the various reservoirs (namely the Ben Nevis, Hibernia, and Jeanne d'Arc B and H reservoirs within the Hebron Field and the Ben Nevis reservoir of the Ben Nevis Field) that are targeted in the initial development phase of the Hebron Asset. A preliminary reservoir management plan (including a preliminary data acquisition strategy) and the contingent developments within the asset are also discussed in this Section.

6.1.1 Reservoir Exploitation Philosophy

6.1.1.1 Depletion Planning Approach

The overarching objective of the resource development planning process was to maximize the economic value of recoverable hydrocarbons in the Hebron Asset. As part of this process, several reservoir exploitation schemes were evaluated with due consideration given to the specific rock and fluid properties and initial reservoir conditions of each of the stratigraphic intervals in the Hebron Asset. A noticeable variation in rock and fluid properties and varying levels of well control (exploration and appraisal drilling) currently exist over the various stratigraphic intervals in the Hebron, West Ben Nevis, and Ben Nevis fields that make up the asset, thereby leading to resource development opportunities, risks and uncertainties. Thus, a key goal in formulating the Hebron Asset depletion plan was to target the best appraised, highest-confidence resource in an initial development phase and then subsequently seek to develop the remaining resources by using the information gathered during the initial development drilling program and production performance monitoring to reduce resource risks and uncertainties.

Based on this approach, the resources located within the stratigraphic intervals of the Hebron Field and the Ben Nevis reservoir of the Ben Nevis Field were selected for exploitation in the initial development phase. Five of the seven Hebron area wells (I-13, M-04, D-94, L-55, and I-45) encountered

the hydrocarbon zones targeted for initial development and these wells penetrated stratigraphic intervals as follows:

1. Hebron Ben Nevis reservoir unit: I-13, M-04, and D-94
2. Hebron Hibernia reservoir unit: I-13 and M-04
3. Hebron Jeanne d'Arc reservoir unit: I-13 and M-04
4. Ben Nevis Ben Nevis reservoir unit: L-55 and I-45

6.1.1.2 Depletion Plan Summary

Several factors were taken into consideration in selecting the optimal depletion plan for the resources targeted in the initial development phase of the Hebron Project. Two of these include the following:

1. No gas-cap was penetrated by any of the wells drilled in the Hebron Field (I-13, M-04 and D-94). There is some uncertainty about the potential presence of a gas cap in the D-94 fault block of the Hebron Field Ben Nevis formation; however, the current best estimate is that none of the Hebron Field oil accumulations have an initial gas cap. A small gas cap (best estimate of less than 5% of total hydrocarbon pore volume) exists in the Ben Nevis reservoir of the Ben Nevis Field (Pool 3) and was penetrated by the L-55 well.
2. The low solution gas oil ratio (GOR) of the Hebron Ben Nevis reservoir (which contains more than 50 percent of the total Stock Tank Original Oil In Place (STOOIP) of the initial development) results in relatively low volumes of associated gas produced with the oil.

The net result of these two factors is that there is a limited amount of associated gas (net of operational requirements) available for re-injection into the reservoir for pressure maintenance. In some depletion plan scenarios that were considered - especially those that did not aim to store the predicted temporary surplus of produced gas in Pool 1 - the total volume of produced gas predicted was projected to be insufficient to meet the long-term operational gas-supply requirements of the production system.

Based on the above, the depletion plan options considered for the assets were focused on developing a viable plan that optimizes resource recovery with due consideration given to the overall asset-wide gas management strategy.

The overall base case depletion plan mechanisms are summarized as follows:

1. Hebron Field, Ben Nevis Formation (Pool 1):
 - a. D-94 fault block: Combination drive recovery process (pressure support provided by water injection (WI) and crestal re-injection of produced gas):

Pressure support is required to maximize oil recovery

Produced gas re-injection allows storage of temporary surplus gas that can later be back-produced to meet production operations requirements, if necessary

- b. I-13 fault block: Pressure support provided by water injection:
- 2. Hebron Field, Hibernia Formation (Pool 5): Natural pressure depletion. If adequate reservoir connectivity is evidenced by early production performance, pressure support via water injection can be considered for potential implementation to improve recovery
- 3. Hebron Field, Jeanne d'Arc Formation (Pool 4): Pressure support provided to the B and H Sands by water injection
- 4. Ben Nevis Field, Ben Nevis Formation (Pool 3): Combination drive mechanism (pressure support provided by water injection and crestal re-injection of produced gas):
- 5. West Ben Nevis Field, Ben Nevis Formation (Pool 2): Possible re-injection of gas for storage

The detailed depletion plans, alternate depletion options, and sensitivities considered for the various stratigraphic intervals are discussed in Sections 6.2.2 (Hebron Ben Nevis), 6.3.2 (Hebron Hibernia), 6.4.2 (Hebron Jeanne d'Arc), and 6.5.2 (Ben Nevis Ben Nevis) respectively. Depletion planning optimization efforts are on-going and are expected to continue until at least the time of project sanction. Any major changes to these plans, while not anticipated at this time, will be communicated in a timely manner.

6.1.2 Gas Management Strategy

The formation gas produced in association with oil production will be used principally to meet the fuel requirements for the production and drilling facilities. During periods when the volume of produced formation gas exceeds operational requirements, the surplus gas will be injected into one of the Hebron area reservoirs for storage and/or pressure maintenance purposes. Gas lift (GL) is the preferred artificial lift method and so some of the produced gas will be continuously circulated within the production system to gas-lift the production wells. (Reference Section 6.1.3.1 for a discussion on artificial lift selection). Several alternative gas storage options were evaluated and the leading options are as follows:

- 1. Gas storage in the Hebron Ben Nevis reservoir (Pool 1): In this scenario, gas will be injected into the crest of the D-94 fault block
- 2. Gas storage in the gas cap of the Ben Nevis reservoir of the Ben Nevis Field (Pool 3)
- 3. Gas storage in the Ben Nevis reservoir of the West Ben Nevis Field (Pool 2)

Depending upon the overall gas storage requirements, all of these options may be employed for asset gas management purposes. Pool 1 is the preferred subsurface compartment for storing gas, provided that the offset producing wells do not exhibit GOR trends that would imply adverse impact on oil recovery. In such a circumstance, Pool 2 would serve as a backup alternative location for storing produced gas. The current plan is to return all the gas produced from Pool 3 for re-injection back into the gas cap of Pool 3 (net of any supplemental fuel gas requirements).

Associated gas production from the initial development of Pools 1, 3, 4, and 5 is expected to be sufficient to fully satisfy requirements for gas consumed in operations (GCO) throughout field life. Long-term annual average GCO demand (sum of fuel gas and background flare volumes) is anticipated to be approximately 21 to 26 Mcfd (0.6 to 0.7 Mm³d). Under a steady state mode of operation, there will be continuous, low rate background consumption of gas attributed to flare pilot combustion and potential valve and compressor seal leakage. During early to mid field life, gas production in excess of fuel demand will be re-injected and stored for future use to the extent possible. Later in field life, if GCO demand exceeds gas production, the stored gas can be re-produced for use in operations. In addition, fuel gas could also be sourced from the gas cap of the Ben Nevis reservoir within the Ben Nevis field.

The long-term gas balance will also depend on the potential future development of Hebron area resources beyond those included in the initial development (Pools 1, 3, 4H, 4B, and 5). To provide flexibility and robustness to the gas management strategy, at least two of the proposed Pool 1 water injection wells will be capable of switching to gas injection (GI) service as a temporary alternative to the primary scheme of injecting gas at the crest of the D-94 fault block. Table 6.1-1 provides an estimate of the total gas utilization volumes. It should be noted that the GL volumes circulate within the production system.

Table 6.1-1: Gas Utilization Volumes

Year	Oilfield Units, Mcf/d					Metric Units, MSm ³ /d				
	Gas Production	Fuel Gas	Flared Gas	Gas Injection	Gas Lift	Gas Production	Fuel Gas	Flared Gas	Gas Injection	Gas Lift
2016	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2017	9.9	2.6	3.5	3.8	11.4	0.3	0.1	0.1	0.1	0.3
2018	23.1	5.5	7.3	10.3	23.8	0.7	0.2	0.2	0.3	0.7
2019	33.2	14.3	4.8	14.1	37.3	0.9	0.4	0.1	0.4	1.1
2020	45.4	15.1	7.2	23.0	57.7	1.3	0.4	0.2	0.7	1.6
2021	65.0	22.2	4.3	38.4	74.6	1.8	0.6	0.1	1.1	2.1
2022	79.5	22.7	3.9	52.9	97.2	2.3	0.6	0.1	1.5	2.8
2023	95.3	23.2	3.8	68.4	108.2	2.7	0.7	0.1	1.9	3.1
2024	102.6	24.2	3.4	75.0	106.8	2.9	0.7	0.1	2.1	3.0
2025	108.7	24.4	3.3	81.1	100.8	3.1	0.7	0.1	2.3	2.9
2026	102.3	24.8	3.9	73.6	98.4	2.9	0.7	0.1	2.1	2.8
2027	104.3	23.1	4.4	76.8	95.2	3.0	0.7	0.1	2.2	2.7
2028	103.9	23.1	4.6	76.2	94.0	2.9	0.7	0.1	2.2	2.7
2029	104.7	22.8	4.2	77.7	92.5	3.0	0.6	0.1	2.2	2.6
2030	103.3	23.0	3.7	76.5	92.0	2.9	0.7	0.1	2.2	2.6
2031	104.1	23.3	3.3	77.5	91.5	2.9	0.7	0.1	2.2	2.6
2032	102.6	23.3	3.0	76.2	92.9	2.9	0.7	0.1	2.2	2.6
2033	101.2	23.1	2.8	75.3	94.7	2.9	0.7	0.1	2.1	2.7
2034	99.7	22.9	2.6	74.2	94.4	2.8	0.6	0.1	2.1	2.7
2035	92.3	22.8	2.5	67.1	95.0	2.6	0.6	0.1	1.9	2.7
2036	82.4	22.9	2.4	57.0	95.7	2.3	0.6	0.1	1.6	2.7
2037	75.0	23.0	2.4	49.6	97.6	2.1	0.7	0.1	1.4	2.8
2038	74.2	23.0	2.4	48.8	98.4	2.1	0.7	0.1	1.4	2.8
2039	74.3	23.0	2.4	48.9	97.6	2.1	0.7	0.1	1.4	2.8
2040	65.0	23.0	2.4	39.5	98.1	1.8	0.7	0.1	1.1	2.8
2041	46.2	22.7	2.4	21.1	96.4	1.3	0.6	0.1	0.6	2.7
2042	37.7	22.7	2.4	12.6	96.0	1.1	0.6	0.1	0.4	2.7
2043	36.3	22.6	2.4	11.3	99.3	1.0	0.6	0.1	0.3	2.8
2044	35.0	22.6	2.4	10.1	99.6	1.0	0.6	0.1	0.3	2.8
2045	34.2	22.6	2.4	9.3	99.9	1.0	0.6	0.1	0.3	2.8
2046	33.7	22.5	2.4	8.8	96.9	1.0	0.6	0.1	0.2	2.7

6.1.3 Artificial Lift and Field Hydraulic Studies Summary

6.1.3.1 Artificial Lift Summary

A scoping study was performed to determine whether artificial lift would be required for oil production operations and if so, what would be the most suitable method(s) of providing artificial lift. A wide range of reservoir properties and facility design sensitivities such as reservoir pressures, productivity indices (PIs), and wellhead pressures were considered in the assessment. Based upon predictions of natural flow performance, it was concluded that artificial lift would be beneficial in maximizing oil recovery from the Hebron reservoirs.

Several artificial lift methods were considered for use and it was determined that GL and electric submersible pumps (ESPs) were the best candidates for use in the Hebron Asset.

Some of the key conclusions from the artificial lift study include the following:

1. The utilization of a GL system as the method of artificial lift will provide maximum flexibility throughout the anticipated life of the wellbores while minimizing intervention requirements
2. Wells completed with either 5.5 in. (140 mm) or 7 in. (178 mm) tubing will benefit from the application of gas lift and the gas lift designs for both tubing sizes should be able to accommodate injection rates of at least 6 Mcfd (170 Km³d) of GL gas
3. In highly productive wells that would not be susceptible to free gas intrusion, ESPs provided additional rate uplift over GL. This was especially the case with higher reservoir pressure scenarios.
4. Multiple ESP designs will be needed to efficiently produce the Hebron wells over the range of reservoir conditions expected throughout the life of the asset.
5. GL will likely outperform ESPs in early life for wells that are susceptible to free gas intrusion, which would limit the maximum ESP drawdown possible
6. Actual GL utilization rates provided to each well can be optimized for the individual reservoirs and operating conditions
7. ESPs are more susceptible to failures if solids production or scaling is encountered in the wellbore, while elevated GORs introduce operational difficulties as the pumps become more vulnerable to becoming gas-locked

Based on the foregoing, gas-lift was selected as the primary means of artificial lift for the Hebron production system. The current plan is to equip all production wells with gas-lift capability. The optimum gas lift rates for each Pool and production well are currently being evaluated.

6.1.3.2 Field Hydraulic Studies Summary

For use in reservoir simulation, hydraulics tables incorporated gas lift to account for the improvement in outflow performance. Industry-accessible PROSPER® software was used to create multi-variable lookup tables relating flowing bottomhole pressure (FBHP) to total liquid rate, water cut, lift-gas injection rate, flowing wellhead pressure (FWHP), and tubing size. The wells were binned into representative groups and prototypical well trajectories were supplied in performing the hydraulics calculations. Calculations were performed with different tubing sizes (4, 5½ and 7 inches) to provide additional flexibility to investigate the impact of implementing different tubing sizes in individual producers. GL was assumed to be available in every producing well. During reservoir simulation, each well's production was determined through a coupled solution of wellhead pressure, reservoir inflow conditions and gas-lift GI rate. Figures 6.1-1, 6.1-2 and 6.1-3 are example tubing performance curves used to predict well outflow performance in the simulation models while Figure 6.1-4 provides a schematic of a typical oil production well.

Additionally, a subsea tie-back to the Hebron Gravity Base Structure (GBS) is a potential development scenario for the Ben Nevis reservoir of the Ben Nevis field (Pool 3). In studying this scenario, industry-accessible OLGA and Pipephase software were used to analyze production and injection fluid flow respectively to determine flowline size and evaluate transient operation.

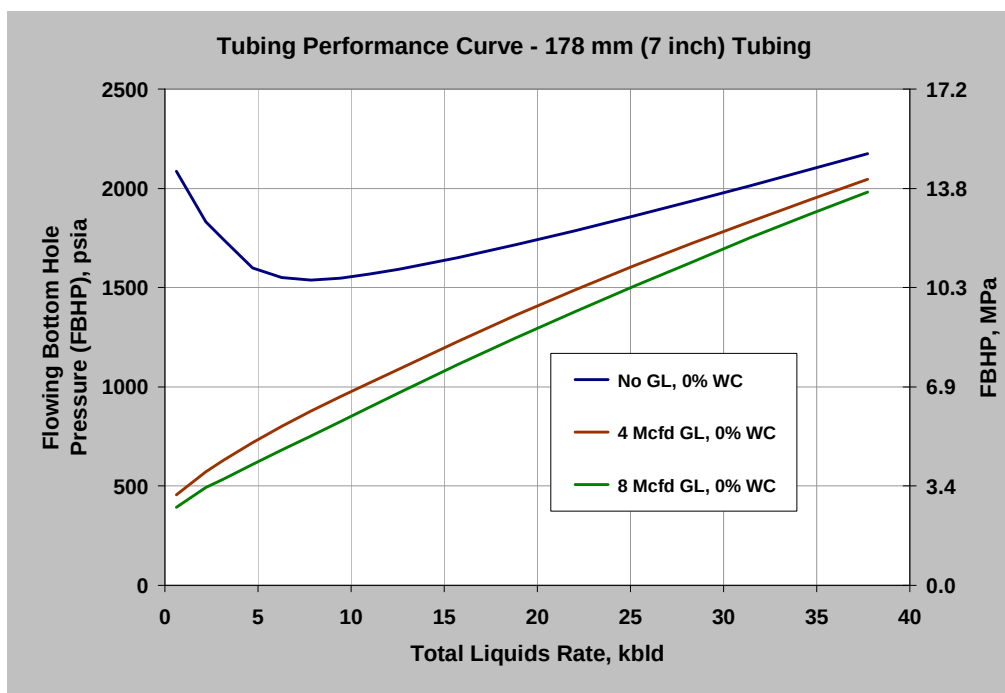


Figure 6.1-1: Example Tubing Performance Curve – 178 mm (7 inch) Tubing

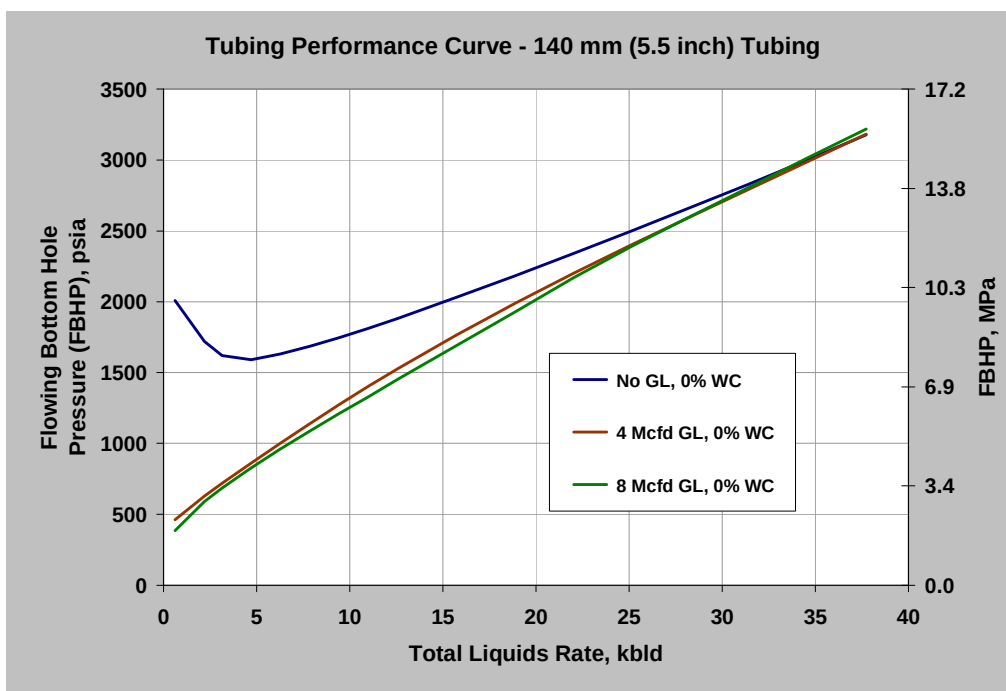


Figure 6.1-2: Example Tubing Performance Curve – 140 mm (5.5 inch) Tubing

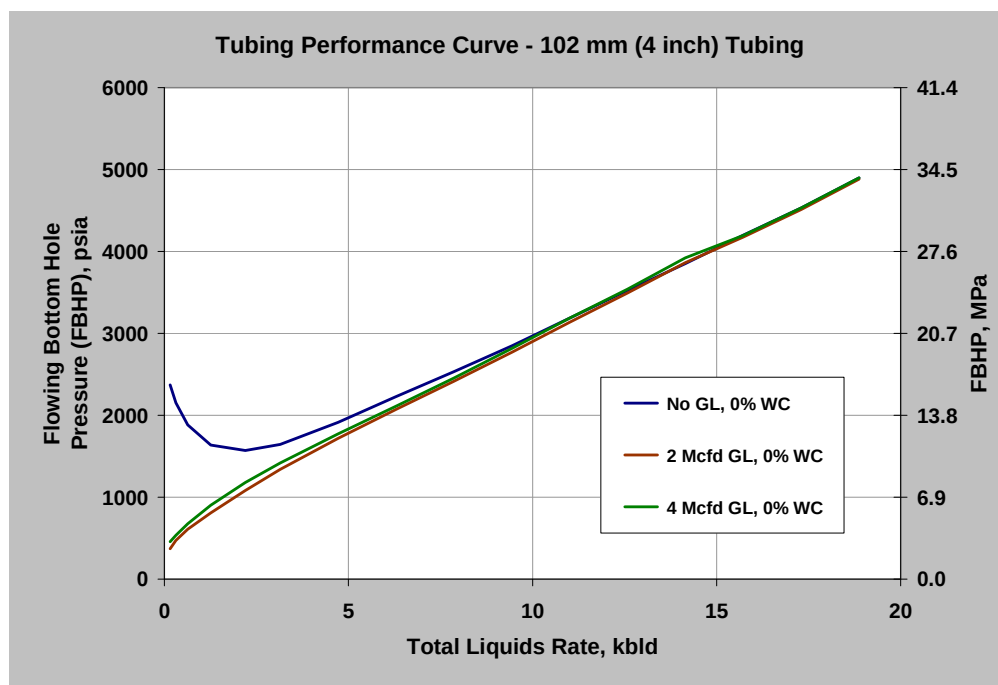


Figure 6.1-3: Example Tubing Performance Curve – 102 mm (4 inch) Tubing

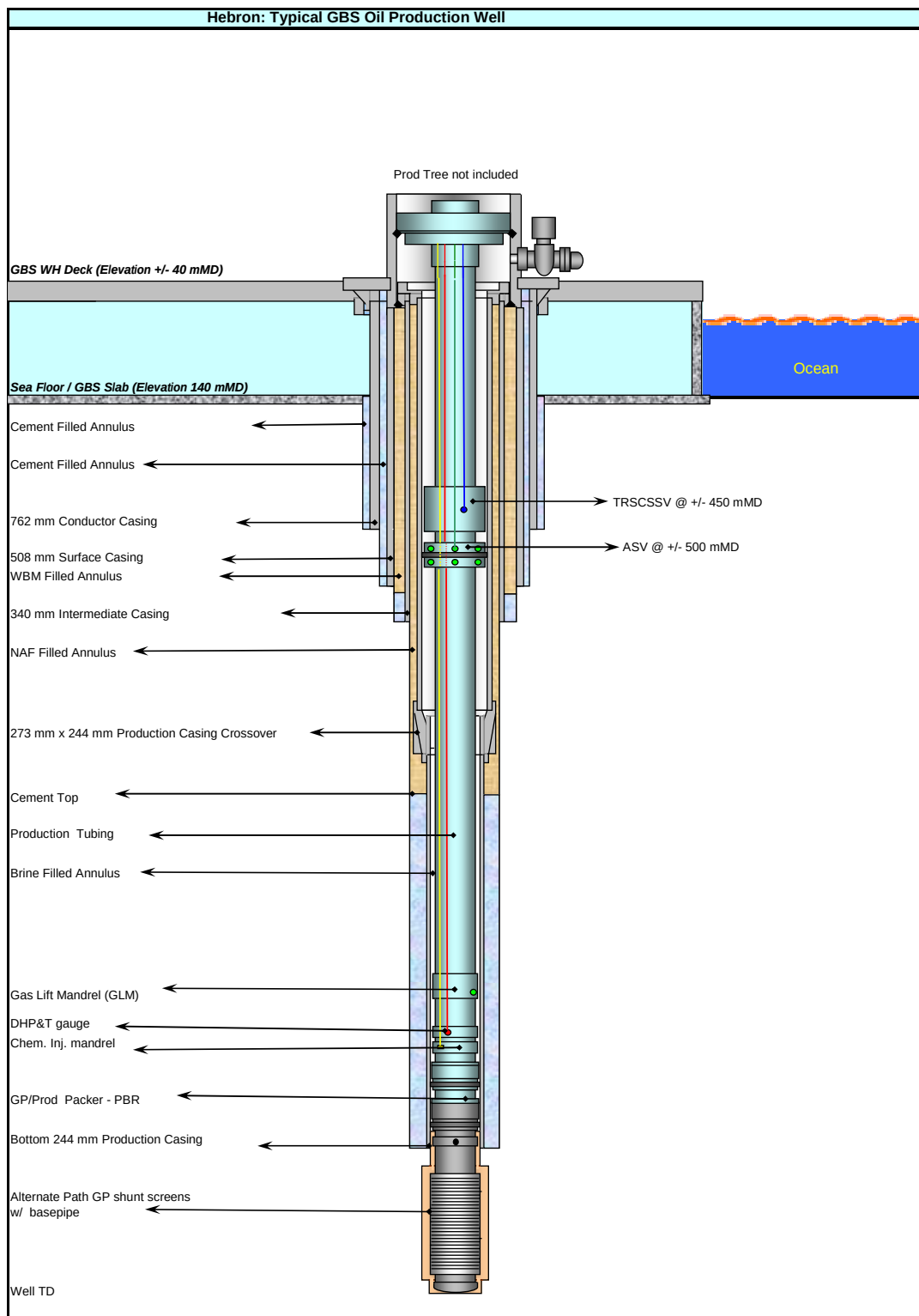


Figure 6.1-4: Schematic of a Typical Oil Production Well

6.2 Hebron Field Ben Nevis Reservoir (Pool 1) Exploitation

Section 6.2 provides a brief description of the Hebron Field Ben Nevis reservoir simulation model and a summary of the results from the simulation studies that were used in establishing the preferred depletion plan for this resource.

6.2.1 Hebron Ben Nevis (Pool 1) Simulation Model

The Hebron Ben Nevis simulation model includes the area covered by the D-94 and I-13 fault blocks of the Ben Nevis reservoir unit in the Hebron Field. These fault blocks were penetrated by the D-94 and M-04 wells (D-94 fault block) and I-13 well (I-13 fault block).

The simulation model contains 64 layers with each layer ranging from 2 to 3 meters in thickness. Simulation layers generally comprise two geologic model layers (the geologic model has 128 layers). The average areal grid size in the geologic model was 100 m by 100 m. This size was retained in the hydrocarbon-bearing region of the simulation mesh. To reduce the total cell count and improve computational efficiency of simulations, cells in the aquifer region of the dynamic model were scaled up areally to a 200 m by 200 m average cell size. The total active cell count in the Hebron Ben Nevis simulation model is about 200,000. Figure 6.2-1 provides a view of the simulation model.

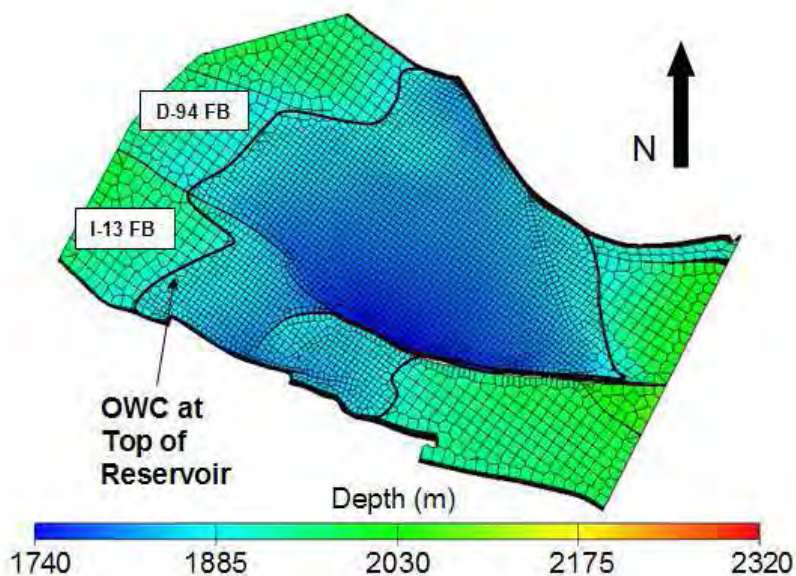


Figure 6.2-1: Hebron Ben Nevis Simulation Model Area of Interest

There is some uncertainty regarding the presence of a gas cap in the Hebron Ben Nevis Formation. The current interpretation is that no initial gas-cap is expected to be present. However, given the uncertainty, the presence of a

gas-cap and its potential impact to the depletion plan was evaluated and is documented in Section 6.2.4.

The simulation model was initialized using an assumption of gravity-capillary equilibrium conditions. Multiple pressure-volume-temperature (PVT) tables were used as input into the reservoir simulation to account for the variation in oil properties (mainly oil API gravity) observed in the Hebron Ben Nevis Formation. The STOOIP in the initialized simulation model was approximately 1470 MBO (234 Mm³) or about 3% less than the geologic model STOOIP. This discrepancy can be attributed to the fact that multiple PVT tables were used in initializing the simulation model.

A stratigraphic layer that sometimes exhibits occurrence of calcite cement bodies of uncertain areal dimensions was encountered in the D-94 and M-04 wells. Where they occur, these features are believed to act as impermeable volumes. The base case simulation model assumes an areal cement-feature coverage of approximately 50 percent, as shown in Figure 6.2-2. Sensitivity studies on varying levels of cement coverage have been performed and the results are discussed in Section 6.2.4.

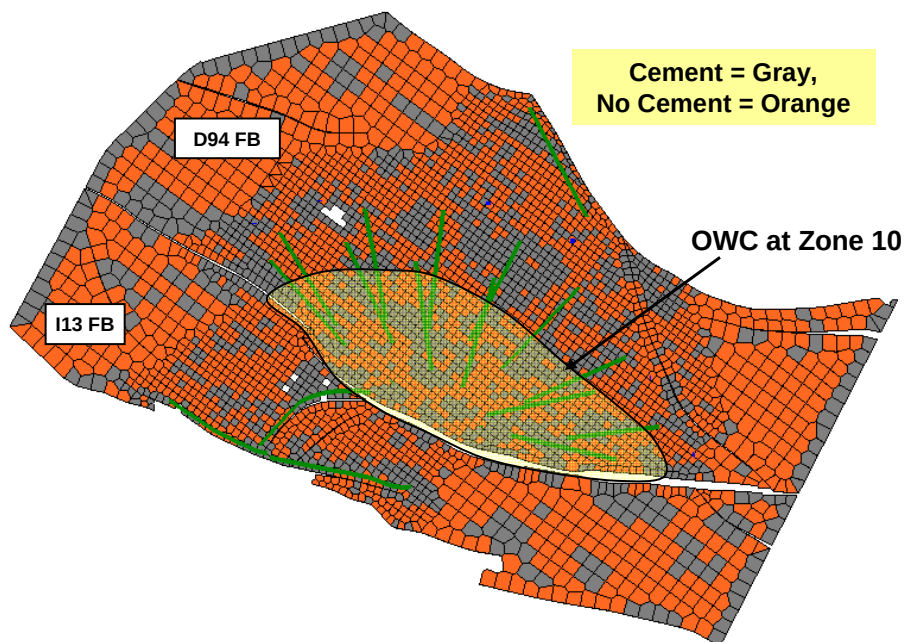


Figure 6.2-2: Cement Layer in Hebron Ben Nevis Simulation Model

For the purpose of flow simulations, cement-bearing cells are considered inactive. The potential presence of cement features has limited impact in the I-13 fault block because the cement-prone stratigraphic layer is located below the observed oil-water contact. In the D-94 fault block, about 160 million barrels (25 Mm³) STOOIP is located in stratigraphic units beneath the cement-prone stratigraphic layer.

6.2.2 Hebron Ben Nevis Base Case Depletion Plan

This section discusses the base case depletion plans for the Ben Nevis reservoir unit of the Hebron Field. This unit contains a significant portion of the total discovered resources in the greater Hebron area and as such, it forms the cornerstone of the initial development phase of the Hebron Asset. The Hebron Ben Nevis Formation comprises the I-13 and D-94 fault blocks. It is likely that the oil columns in these two fault blocks were in communication over a geologic time scale. With proper management of reservoir pressure as proposed herein, it is likely that these fault blocks will behave largely independently (with only minor predicted migration of reservoir fluids) during the productive life of Pool 1. After 30 years of production, cumulative oil recovery of about 563 million barrels (90 Mm³) is predicted from these two fault blocks in the best estimate case with a range of 443 to 762 million barrels (70 Mm³ to 121 Mm³) in the low side and high side recovery scenarios, respectively.

6.2.2.1 Base Case Depletion Plan – Hebron Ben Nevis D-94 Fault Block

The base case depletion plan includes drilling 16 producers (mostly highly deviated and / or horizontal wells) and six water injectors to exploit this resource. Gas will also be injected in the D-94 fault block to store any temporary surplus of produced gas beyond that required for production operations. Two gas injectors are planned to be drilled into the crest of the D-94 fault block. As part of the overall field gas management strategy, at least two of the water injectors in this fault block will also be equipped to switch to GI service in order to provide either backup or supplemental GI capability. Total well count and function (oil producers and water or gas injectors) may be adjusted to optimize oil recovery depending on the results of ongoing depletion plan optimization activities, learnings obtained during the development drilling program, and early production performance.

Oil-producing completion locations have been planned with primary consideration given to reservoir quality and achievement of both high well productivity and high displacement sweep efficiency. There is considerable uncertainty associated with the flow characteristics of one poorer-quality stratigraphic unit, the Ben Nevis Zone 4, which may serve as a baffle (but not likely a barrier) to vertical and horizontal fluid flow. Producers are planned to be completed in stratigraphic units above and below Zone 4, in order to facilitate good displacement sweep efficiency in shallower and deeper zones regardless of the ultimately-encountered character of Zone 4. In reaction to learnings from early production performance, placement of producers in the D-94 fault block may be adjusted either vertically or areally or both, in order to achieve maximum economic recovery of oil from this resource.

Flow simulation modeling of the base case depletion plan predicts oil recovery of 517 million barrels (82 Mm³) after thirty years (recovery factor of

40 percent based on a STOOIP of 1289 MBO) with a range from 410 million barrels to 682 million barrels (65 Mm^3 to 108 Mm^3) in the low-side and high-side recovery scenarios, respectively. These are discussed in more detail in Section 5.2.2. Figure 6.2-3 and Figure 6.2-4 show production and average reservoir pressure profiles of the base case simulation. It should be emphasized that the reservoir pressures for all the resources will be managed to maximize oil production rates and economic recovery of hydrocarbons. For instance, there may be situations it would be beneficial to either increase pressure above initial reservoir pressure or reduce pressure below initial reservoir pressure or bubble point pressure respectively.

These production profiles are forecasted by the Pool 1 simulation model and do not include any provision for downtime, nor for the effect of any production constraints associated with the design capacity limits of the Hebron production system. The combined development production profiles from the initial resource development phase with the production processing facilities design constraints and the integrated project drilling schedule assumptions are presented in Section 6.5.

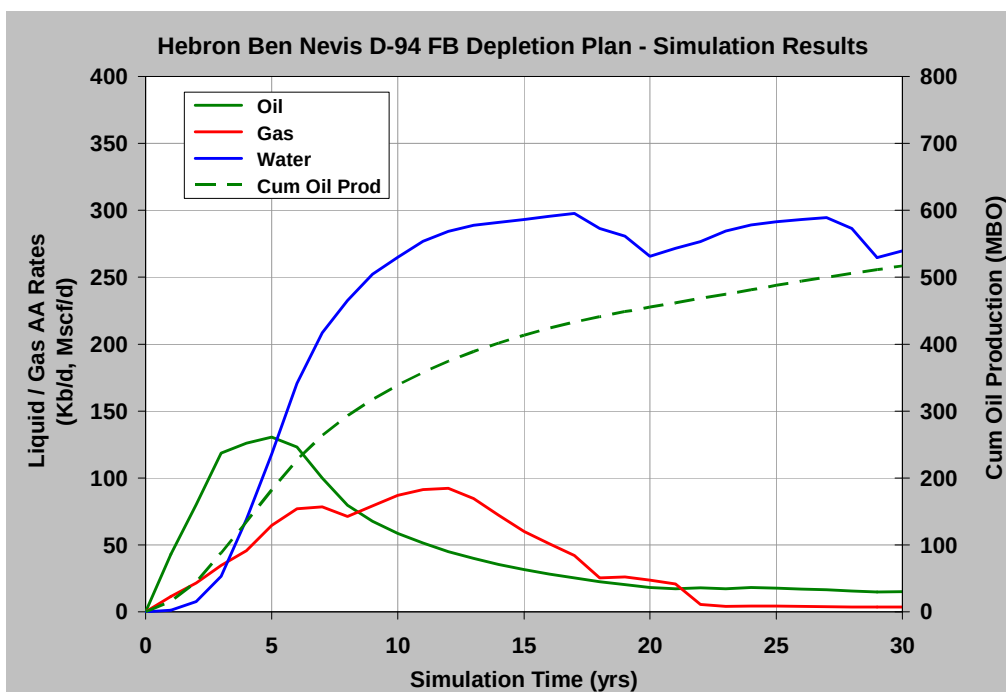


Figure 6.2-3: Hebron Ben Nevis D-94 Fault Block Base Case Depletion Plan Simulation Results

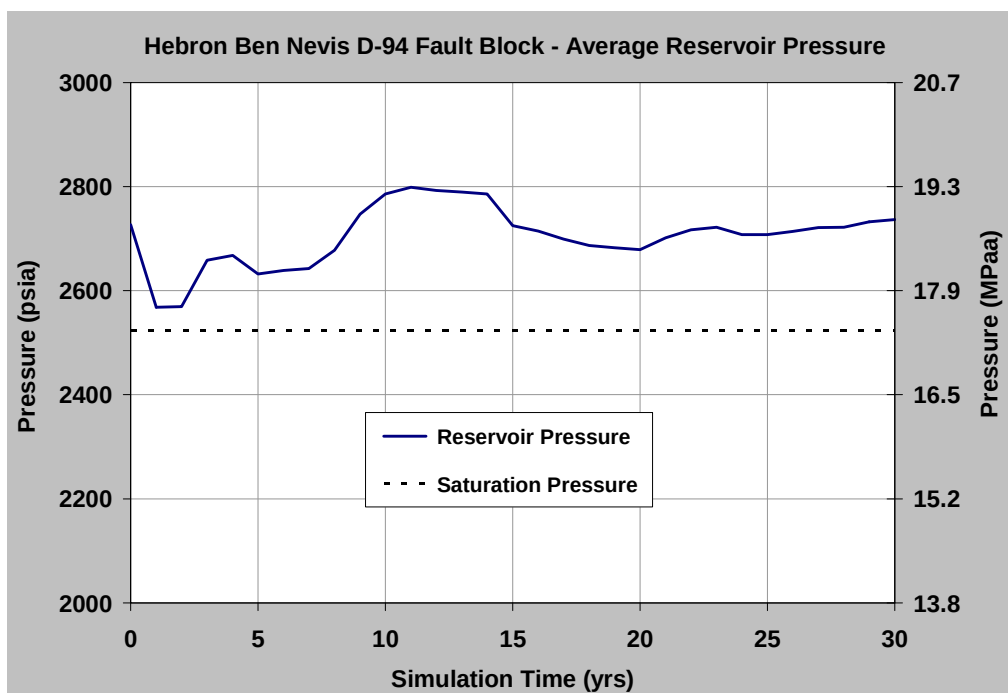


Figure 6.2-4: Hebron Ben Nevis D-94 Fault Block Average Reservoir Pressure

6.2.2.2 Base Case Depletion Plan – Hebron Ben Nevis I-13 Fault Block

The depletion plan for the I-13 fault block consists of drilling three production wells supported by two water injection wells. The best estimate case predicts oil recovery of 46 million barrels (7 Mm³) after 30 years (or a recovery factor of 26 percent) with a range from 38 million barrels to 80 million barrels (6 Mm³ to 13 Mm³) in the low-side and high-side recovery scenarios, respectively. These recoveries are forecasted by the Pool 1 reservoir simulation model and do not include any provision for downtime, nor for the effect of any production constraints associated with the design capacity limits of the Hebron production system.

Figure 6.2-5 and Figure 6.2-6 show simulation results for production profiles and average reservoir pressure, respectively. Figure 6.2-7 shows the overall Pool 1 (D-94 and I-13 fault blocks) production profiles.

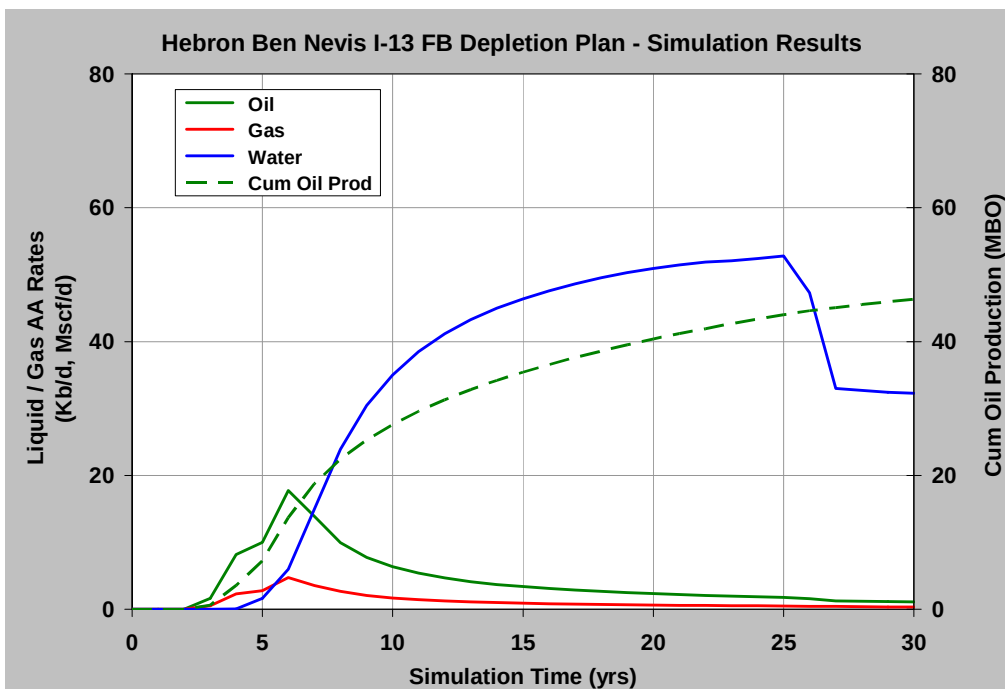


Figure 6.2-5: Hebron Ben Nevis I-13 Fault Block Base Case Depletion Plan Simulation Results

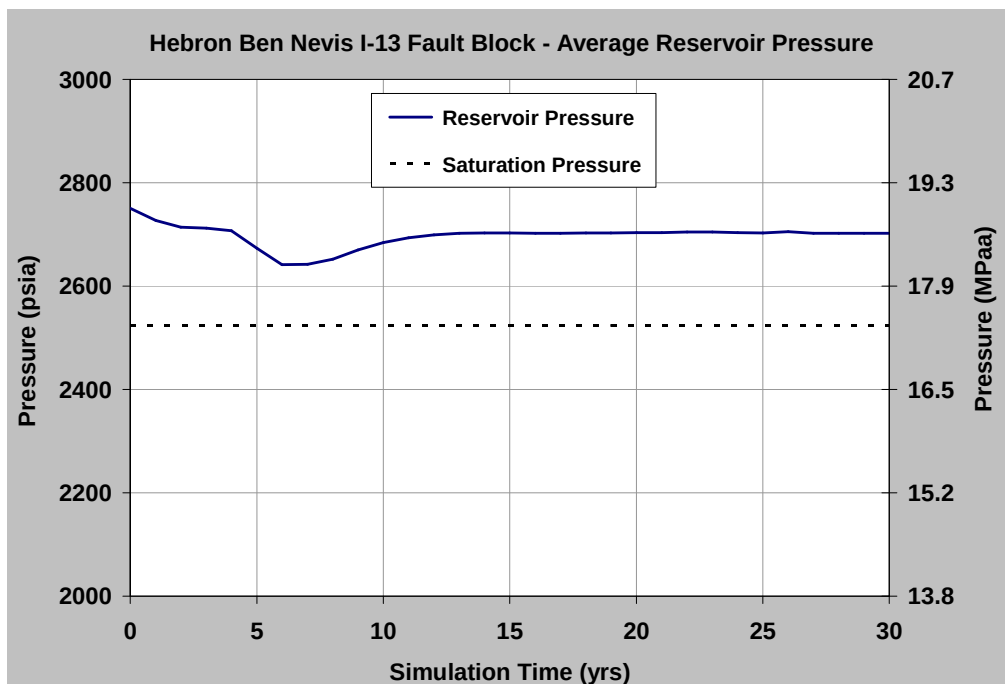


Figure 6.2-6: Hebron Ben Nevis I-13 Fault Block Average Reservoir Pressure

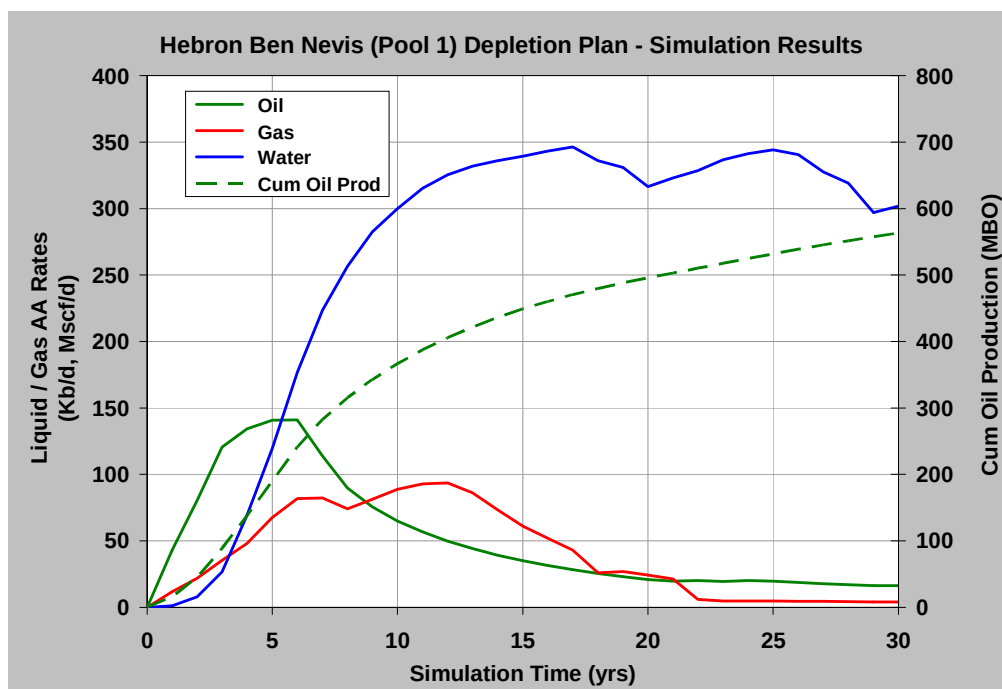


Figure 6.2-7: Hebron Ben Nevis Base Case Depletion Plan Results

6.2.3 Hebron Ben Nevis Alternate Depletion Plans

Two alternate depletion plans were considered for the Hebron Ben Nevis (Pool 1) resource:

1. Waterflood-only scheme in D-94 fault block: In this strategy, waterflood is used as the only method of providing pressure support to the D-94 fault block compared with the base case plan of a combination drive (waterflood and crestal GI) mechanism. Produced gas is stored in the Ben Nevis Formation of the West Ben Nevis Field (Pool 2).
2. Natural depletion: In this scenario, no method of pressure support is applied to either the D-94 or I-13 fault blocks

The results of these alternate depletion plan options and a comparison to the base case plan are presented in Figure 6.2-8 and indicate that cumulative oil recovery is comparable between the combination drive and pure waterflood mechanisms. The results also show a significantly lower oil recovery in the primary depletion scheme (235 MB / 37 Mm³ recovery after thirty years).

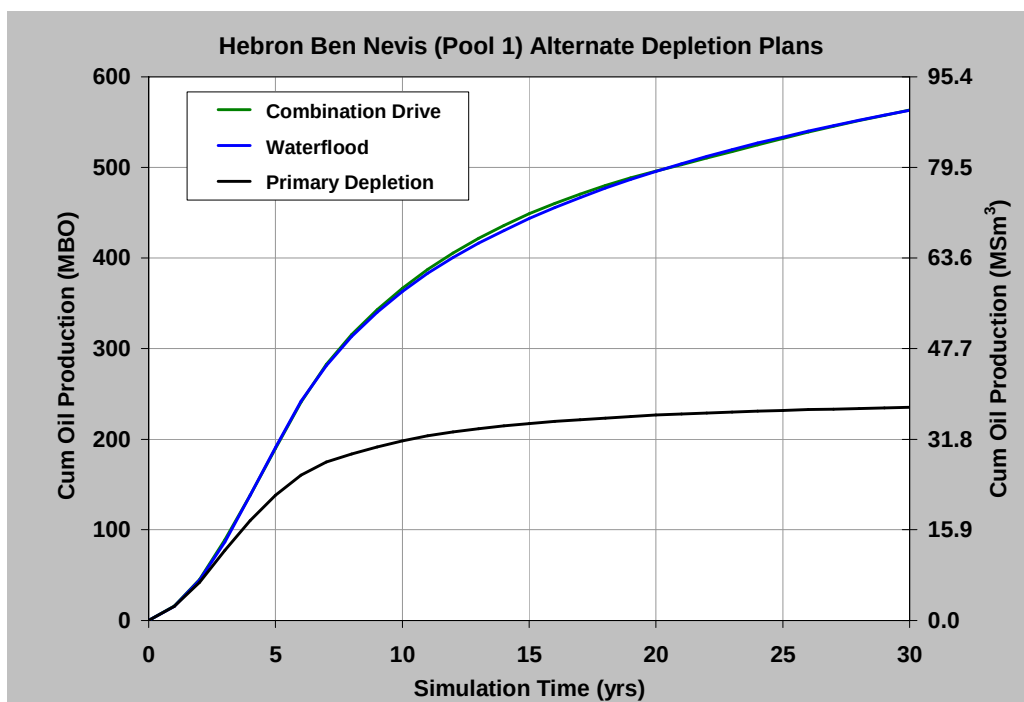


Figure 6.2-8: Hebron Ben Nevis – Alternate Depletion Plans

6.2.4 Hebron Ben Nevis Sensitivity Studies

Sensitivities to the Hebron Ben Nevis base case depletion plan described previously were performed to address uncertainties in reservoir description and well performance. These include the following:

1. Fault transmissibility multiplier: The impact of flow across the faults separating the I-13 and D-94 fault blocks on the depletion plan was tested by applying transmissibility multipliers across the faults. The multipliers ranged from 0 (no flow) to 1 (no impairment of flow between juxtaposed sections of the reservoir).
2. Cement layer coverage: The presence of a layer prone to calcite cement bodies and the associated uncertainty regarding the areal coverage of the cement was discussed in Section 6.2.1. The base case depletion plan assumed a 50 percent areal coverage. Sensitivity scenarios testing higher (90 percent) and lower (30 percent) cement coverage were evaluated.
3. Permeability: Model permeabilities were varied as follows:
 - i. Vertical permeability adjustment only (0.2x, 2x)
 - ii. Vertical and horizontal permeabilities adjusted (0.5x, 0.75x, 2x)
 - iii. Zone 4 (lower-permeability zone) vertical permeability (0.0625x)

- iv. Zone-boundary vertical transmissibility multipliers (0.2x, 2x, no-multiplier; these multipliers were applied at two specific zone boundaries that may correspond to significant flooding events)
- 4. Producing well skin (flow efficiency): The base case assumed skin factors of +8.7 for the producers. This sensitivity tested the impact of higher (+10) and lower (+3) skin factors.
- 5. Aquifer volume ratio (3:1, 100:1): The base case aquifer volume ratio is approximately 15:1
- 6. Pore volume compressibility: The base case assumed a compressibility of 10 msips. Sensitivities were tested with values of 50 msips exhibited by 15 percent of bulk reservoir volume and 2.5 msips applied to 100 percent of reservoir volume respectively.
- 7. Presence of gas cap in the D-94 fault block: A gas-oil contact occurring at 1758 m SS, the midway point between the highest known oil and the structural crest of the D-94 fault-block

The results of these sensitivities are presented as deltas to the base case depletion plan in Figure 6.2-9 and indicate that combined variations to both vertical and horizontal permeabilities had the most significant impact on recovery.

Hebron Ben Nevis (Pool 1) Depletion Plan Sensitivities
30-year Cumulative Oil Recovery Change from Base Case

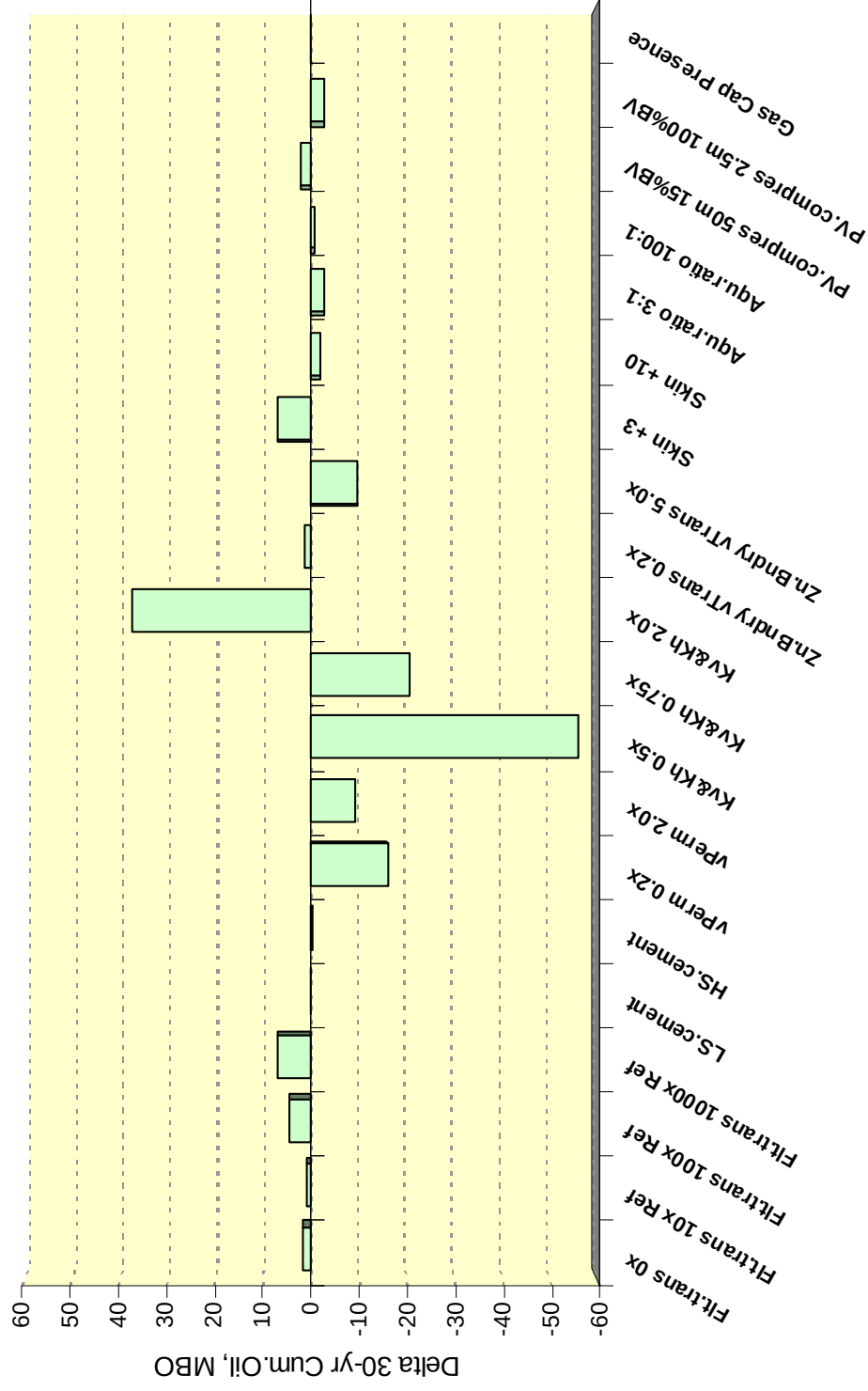


Figure 6.2-9: Hebron Ben Nevis Depletion Plan Sensitivities

6.3 Hebron Hibernia (Pool 5) Reservoir Exploitation

This Section provides a summary of the simulation studies undertaken to determine an optimal depletion plan for the Hebron Hibernia resource.

6.3.1 Hebron Hibernia Simulation Model

Initial development of the resource contained within the Hibernia formation targets the Upper Hibernia layer. This stratigraphic unit was encountered by the I-13 and the M-04 wells (the M-04 well penetrated the water leg). The Hebron Field Hibernia reservoir simulation model consists of 220 layers (full XYZ dimensions of the grid are 99 by 45 by 220) and active cell count is about 390,000 cells. A view of the simulation model is shown in Figure 6.3-1. The simulation model STOOIP is about 150 MBO (24 Mm³) or a difference of less than 1.5% compared to the geologic model STOOIP. This difference was considered immaterial and simulation studies were carried out using the volumes in the initialized Hibernia simulation model.

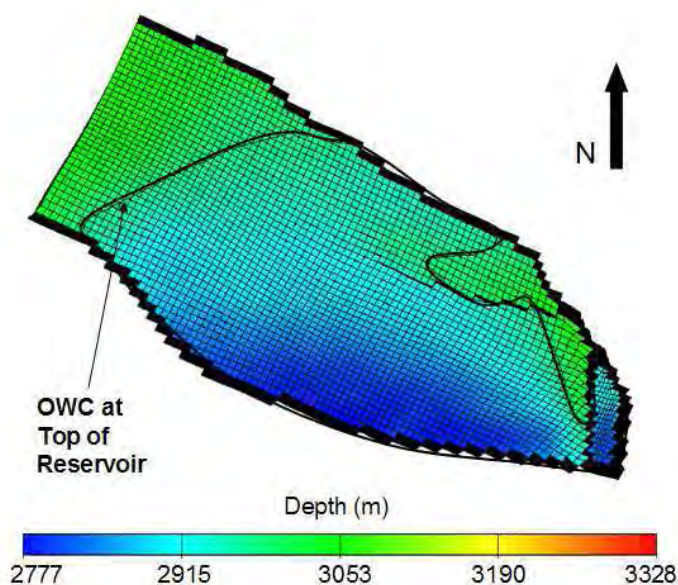


Figure 6.3-1: Hebron Hibernia Simulation Model

6.3.2 Hebron Hibernia Base Case Depletion Plan

Reservoir simulation studies were undertaken to establish the base case depletion plan for the Hebron Hibernia resource. The reservoir rock is described as being primarily comprised of inter-bedded fine to medium grained sands and shales. The key subsurface uncertainties associated with the development of this resource are related to reservoir quality and the lateral extent of cemented sands. Several sensitivity runs encompassing different recovery mechanisms (primary recovery and pressure support) and different well configurations and well counts were performed. The resulting

depletion strategy for the Hibernia asset is to drill two producers targeting the crest of the structure. If water injection can be supplied to flow units that are effectively connected to the planned producers, it would provide some uplift to oil recovery. Production information will be key to resolving the subsurface uncertainties and based on performance data, additional wells (producers and / or injectors) may potentially be drilled to maximize economic recovery from this resource.

Oil recovery of 15.4 million barrels (2.4 Mm³) is predicted from the base case depletion plan (Figure 6.3-2) with a range from 6 million barrels (1 Mm³) to 47 million barrels (7 Mm³) in the low-side and high-side recovery scenarios, respectively. Figure 6.3-3 shows a plot of the average pool reservoir pressures as a function of time. These production profiles are forecasted from the Hibernia simulation model and do not include any provision for downtime, nor for the effect of any production constraints associated with the design capacity limits of the Hebron production system. The combined development production profiles from the initial resource development phase with the production processing facilities design constraints and the integrated project drilling schedule assumptions are presented in Section 6.5.

A potential opportunity to further optimize the Hebron Hibernia depletion plan may be available from data gathered during the development drilling of the deeper Jeanne d'Arc wells if the well targets can be successfully planned to penetrate the Hebron Hibernia formation without compromising the primary objectives of the Jeanne d'Arc wells. This is discussed in further detail in Section 6.3.3 and will be considered during the detailed well planning phase.

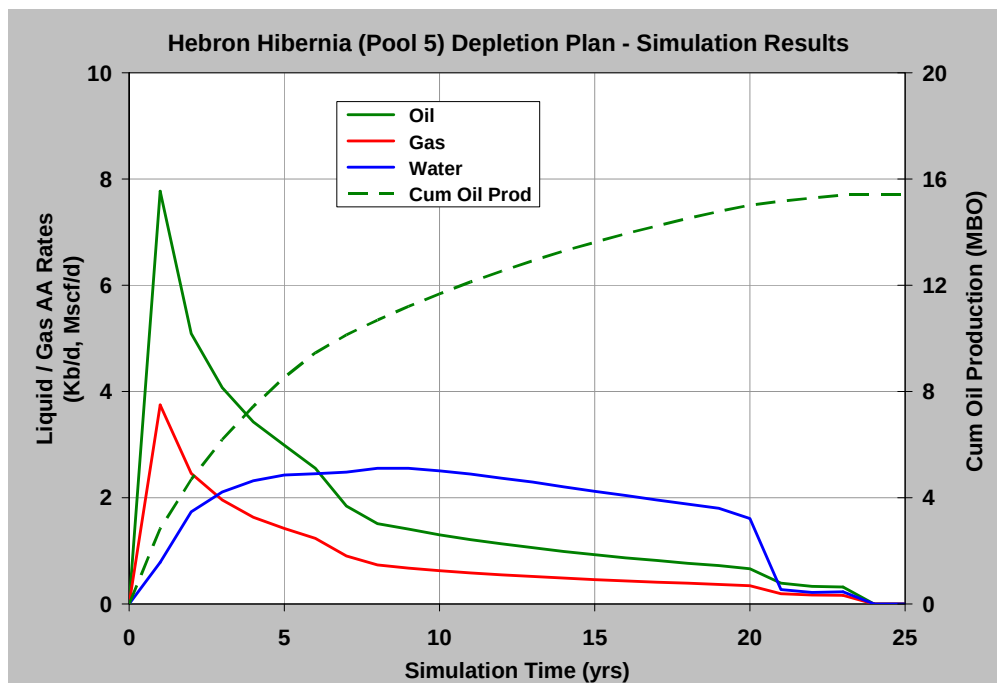


Figure 6.3-2: Hebron Hibernia Base Case Depletion Plan Simulation Results

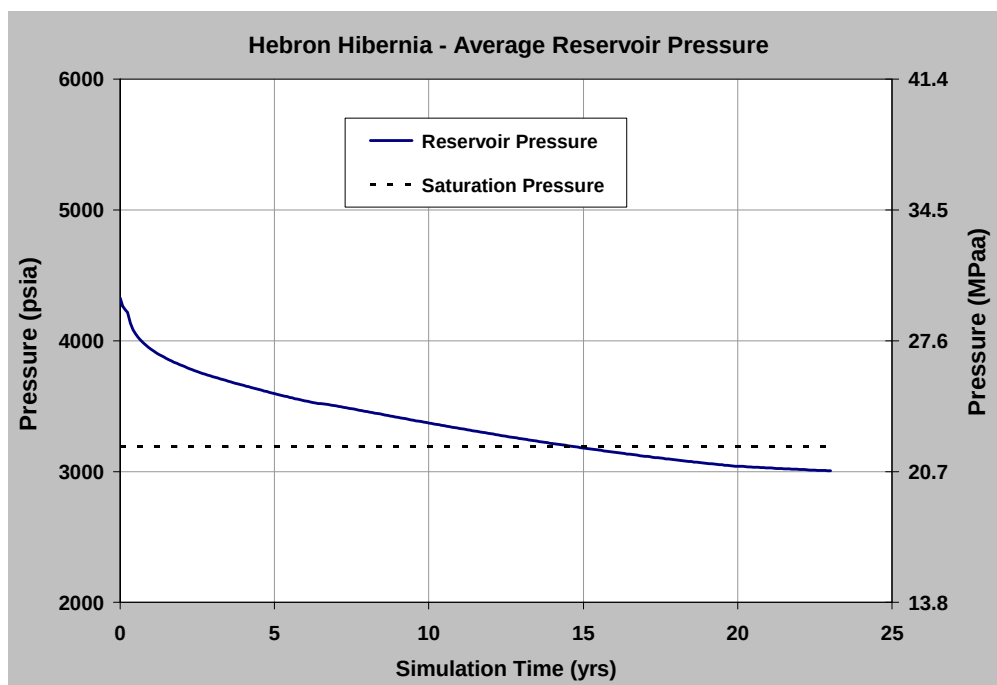


Figure 6.3-3: Hebron Hibernia Average Reservoir Pressure

6.3.3 Hebron Hibernia Alternate Depletion Plans

An alternate depletion plan with water injection to provide pressure support was considered. The results indicated that a three-well scenario comprising two producers and one water injector yielded oil recovery of 20.6 million barrels (3.3 Mm³) compared with oil recovery of 15.4 million barrels (2.4 Mm³) from two producers. This indicated an incremental recovery of about 5.2 million barrels (0.8 Mm³) from providing pressure support by water injection. Figure 6.3-4 compares the cumulative oil production profiles of the base case depletion plan and the water injection alternate plan. As discussed in Section 6.3.2, reservoir continuity is a major uncertainty associated with this resource and so effective placement of the water injection well is essential to realizing an overall economic benefit from the associated cost of drilling the injection well. Due to this consideration, the overall integrated sequence of development drilling has been designed to provide the opportunity to gather static and dynamic data from the Hibernia resource that may help resolve the uncertainty and assist in evaluating the viability of a water injection well. Specifically, the drilling schedule has been designed such that at least one well targeting the deeper Jeanne d'Arc formation is drilled after the first Hibernia producer so that pressure data can be obtained from the Hibernia formation to help understand the degree of reservoir connectivity.

The data gathered will be key in understanding the level of reservoir continuity present and will also be useful in optimizing the placement of additional wells (producers and / or water injectors).

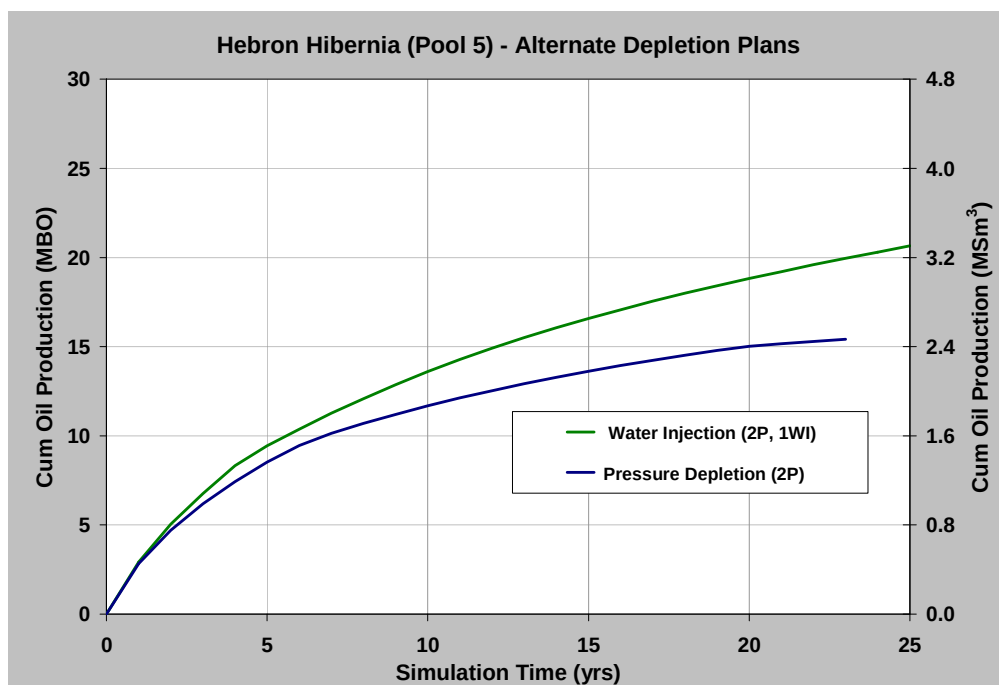


Figure 6.3-4: Hebron Hibernia – Alternate Depletion Plans

6.3.4 Hebron Hibernia Well Count Sensitivity

In addition to the alternate depletion plan scenario with two producers and one water injector, a depletion plan sensitivity case with three producers and one water injector was tested. The results of this case are compared with the base case depletion plan (two producers) and the alternate depletion plan scenario with two producers and one water injector in Figure 6.3-5.

The results indicate that adding a third producer increases oil recovery by about 4.0 MB (0.6 Mm³) i.e. from 20.6 MB (3.3 Mm³) in the two producer / one water injector case to 24.6 MB (3.9 Mm³) in the three producer / one water injector case. This uplift is predicated on the ability to effectively place the wells where connected flow units exist. The performance data gathered from the initial 2-well development plan will be utilized to further optimize the Hebron Hibernia depletion plan and to determine the number and location of additional wells to be drilled into the formation using the open slots available in the current GBS design.

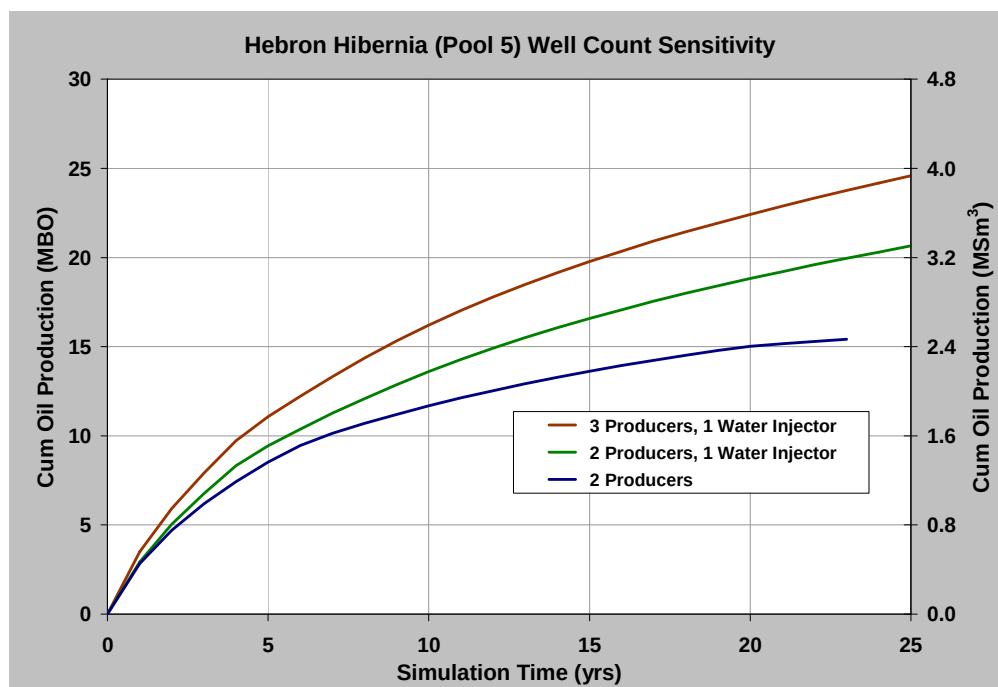


Figure 6.3-5: Hebron Hibernia – Well Count Sensitivity

6.4 Hebron Jeanne d'Arc (Pool 4) Reservoir Exploitation

The results of the depletion planning investigations undertaken for the Jeanne d'Arc H Sand North Valley and B Sand within the Hebron Field are discussed in this section.

6.4.1 Hebron Jeanne d'Arc Simulation Models

The initial development plan targets the hydrocarbon resources located in the B and H Sands of the Jeanne d'Arc formation within the Hebron Field (Pool 4). These sands were penetrated by the I-13 and M-04 wells. Two separate reservoir simulation models have been used to predict the dynamic behaviour of these reservoirs and they are described in Sections 6.4.1.1 and 6.4.1.2.

6.4.1.1 Hebron Jeanne d'Arc H Sand Simulation Model

The Jeanne d'Arc H Sand simulation model covers the area described as the North Valley and penetrated by the M-04 well. Other undrilled exploration prospects are present in the Jeanne d'Arc H Formation, namely the H Sand Main Horst (South Valley) and East Horst. These are discussed in more detail in Section 6.8.2. The simulation model consists of 92 layers (full XYZ dimensions of the simulation model are 114 by 77 by 92) and active cell count is slightly more than 86,000 cells. The XY dimension of each simulation node was set at 100 m by 100 m. There was no need for up-scaling the simulation model as it was built on a common scale with the geologic model. A view of the simulation model is shown in Figure 6.4-1.

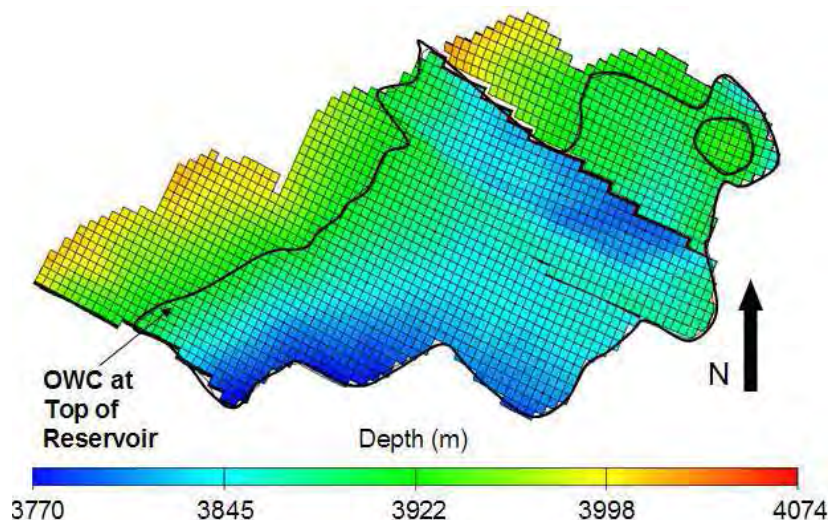


Figure 6.4-1: Hebron Jeanne d'Arc H Sand Simulation Model

The simulation model was initialized using an assumption of gravity-capillary equilibrium conditions. Oil API gravity and bubble point pressure were assumed to be constant with depth. No gas cap is predicted to exist in the Jeanne d'Arc Formation of the Hebron horst block. The STOOIP in the

initialized simulation model was approximately 207 MBO (33 Mm³) or about 1.5% difference compared to the geologic model STOOIP. This volumetric difference (less than 3 MBO or 0.5 Mm³) is considered to be negligible.

6.4.1.2 Hebron Jeanne d'Arc B Sand Simulation Model

The Jeanne d'Arc B Sand was penetrated by the I-13 and M-04 wells. The Jeanne d'Arc B reservoir is interpreted as fluvial sand deposited on a braid plain. The model built for flow simulation focused on the B Sand Main Horst and it consists of 14 layers (full XYZ dimensions of the simulation model are 114 by 94 by 14) and active cell count is slightly over 60,000 cells. The XY dimension of each simulation node was set at 100 m by 100 m. There was no need for up-scaling the simulation model as it was built on a common scale with the geologic model. A view of the simulation model is shown in Figure 6.4-2. The STOOIP in the initialized simulation model is approximately 113 MBO (18 Mm³).

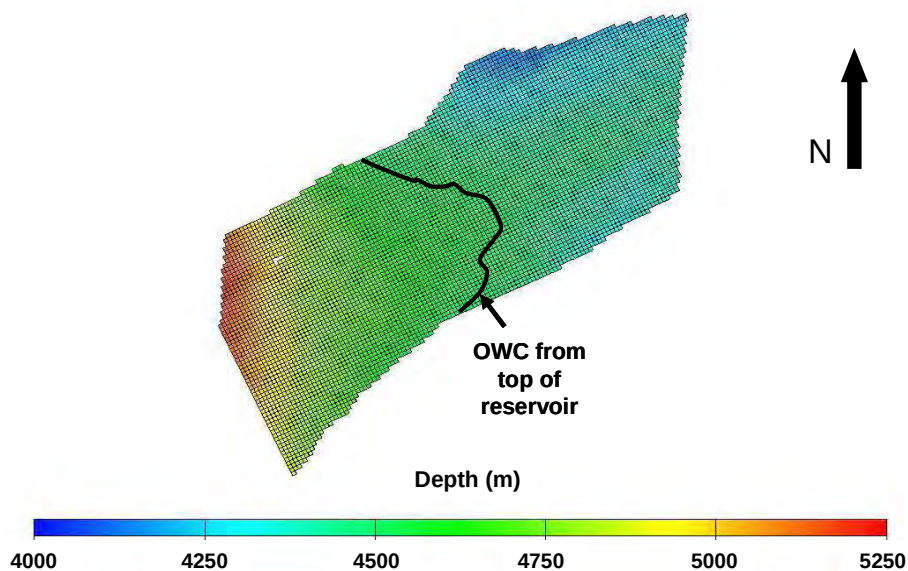


Figure 6.4-2: Hebron Jeanne d'Arc B Sand Simulation Model

6.4.2 Hebron Jeanne d'Arc Base Case Depletion Plan

6.4.2.1 Base Case Depletion Plan – H Sand North Valley, Jeanne d'Arc Formation

Numerous reservoir simulations were conducted to assess alternate depletion mechanisms, well count, and well locations to derive the depletion plan for the H Sand North Valley of the Jeanne d'Arc Formation. The base development scenario involves providing pressure support to the reservoir by means of water injection. The preliminary well count for depleting this resource consists of three producers and one water injector. The total number of wells may change due to a number of factors. These factors include, but are not limited to, the following:

1. Results of on-going activities to improve both the reservoir description and the forecasted recovery efficiency;
2. Learnings gathered during the development drilling program;
3. Early production performance from this reservoir.

The wells are currently planned to be drilled as highly deviated to horizontal wells to provide maximum wellbore contact with the reservoir to help maximize initial oil rates and oil recovery. Some of these wells may be drilled across faults for the same reason. Alternate depletion plans and depletion plan sensitivities evaluated for the Jeanne d'Arc H Sand are discussed in Section 6.4.3.1.

Overall, the base case simulation predicts oil recovery of 59 million barrels (9 Mm³) after thirty years (or a recovery factor of 29 percent) with a range from 33 million barrels to 89 million barrels (5 Mm³ to 14 Mm³) in the low-side and high-side recovery scenarios, respectively. These are discussed in more detail in Section 5.4.2.

Figure 6.4-3 shows the Jeanne d'Arc H Sand base case production profiles. The profiles shown are the unconstrained results from the Jeanne d'Arc H-sand simulation model and do not include the effects of operational downtime and facility design capacities or the position of the Jeanne d'Arc H wells in the overall integrated project drilling schedule. The Jeanne d'Arc H Sand production profiles incorporating these assumptions are presented in Section 6.5.

A profile of the average reservoir pressure as a function of time is plotted in Figure 6.4-4.

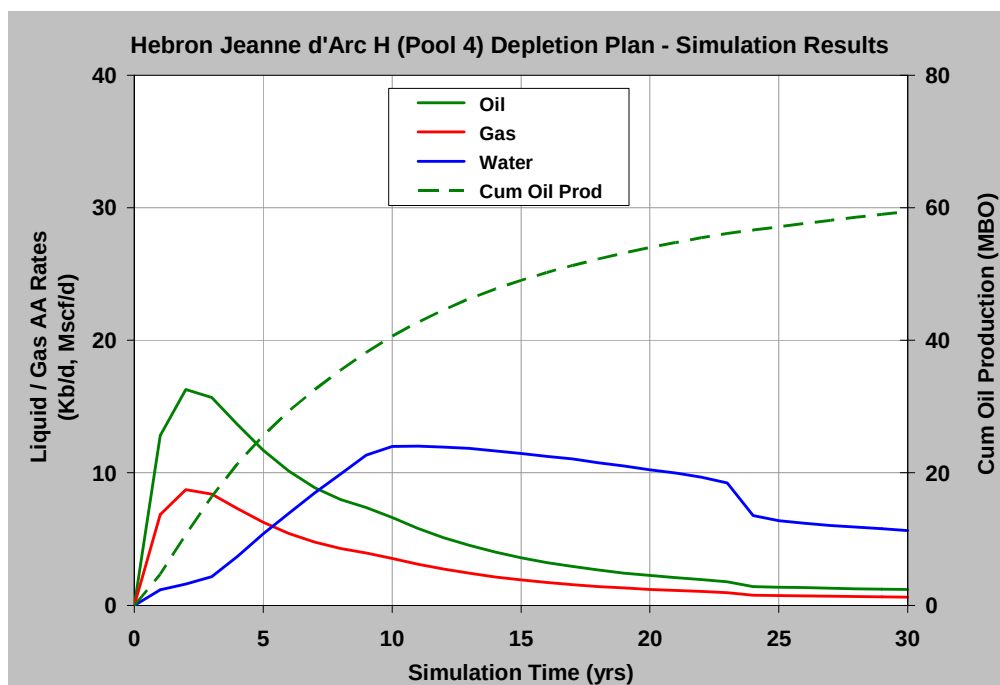


Figure 6.4-3: Hebron Jeanne d'Arc H Sand Base Case Depletion Plan Simulation Results

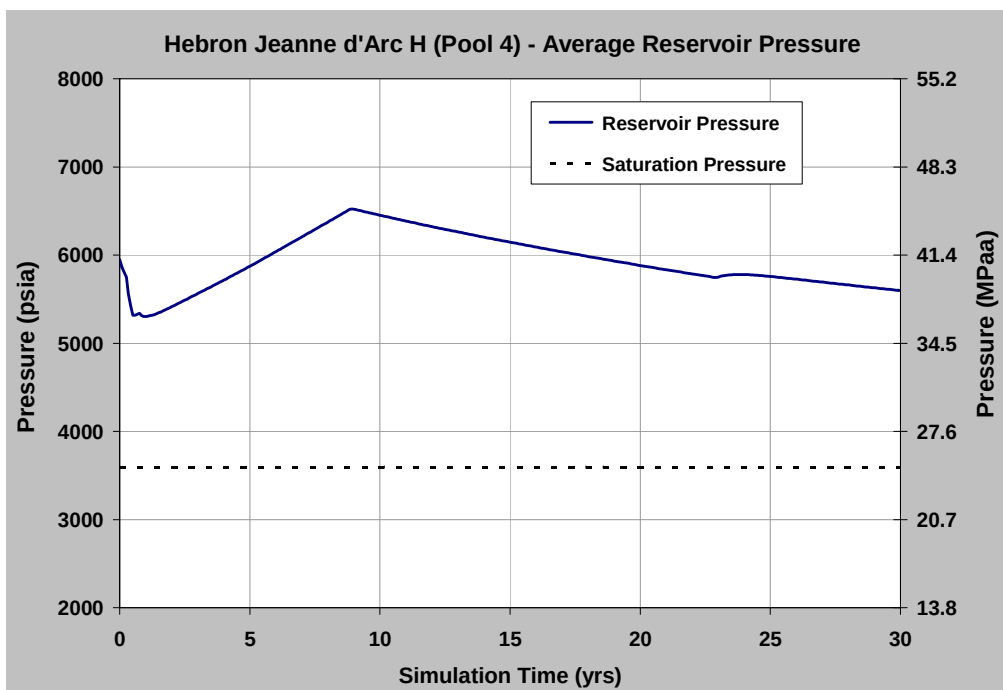


Figure 6.4-4: Hebron Jeanne d'Arc H Sand Average Reservoir Pressure

6.4.2.2 Base Case Depletion Plan – Jeanne d'Arc B Sand

The base depletion plan for this resource includes drilling one producer and water injector well pair to develop the resource. This well count has potential to change depending on results from on-going efforts to improve the reservoir description and the recovery efficiency, and / or learnings gathered during the development drilling and production phases. Oil recovery after thirty years is predicted to be 28 million barrels (4 Mm³) or a recovery efficiency of 24 percent in the base case scenario with a range from 11 million barrels to 60 million barrels (2 Mm³ to 10 Mm³) in the low-side and high-side recovery scenarios, respectively. Section 5.4.2 discusses the uncertainty range around the best estimate scenario. Figure 6.4-5 shows the simulation results from the base case depletion plan while Figure 6.4-6 shows the average pool reservoir pressures as a function of time. The profiles shown in Figure 6.4-5 do not include the impacts of facility uptime assumptions and facility design capacities or the position of the Jeanne d'Arc B wells in the overall integrated project drilling schedule. The Jeanne d'Arc B Sand production profiles incorporating these assumptions are provided in Section 6.5.

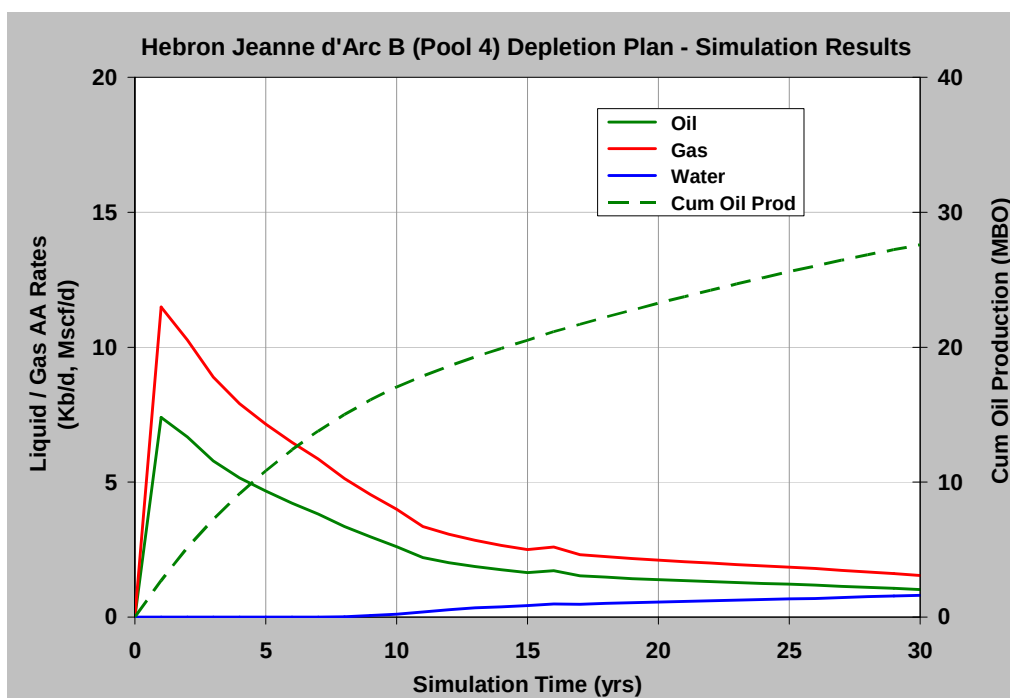


Figure 6.4-5: Hebron Jeanne d'Arc B Sand Base Case Depletion Plan Simulation Results

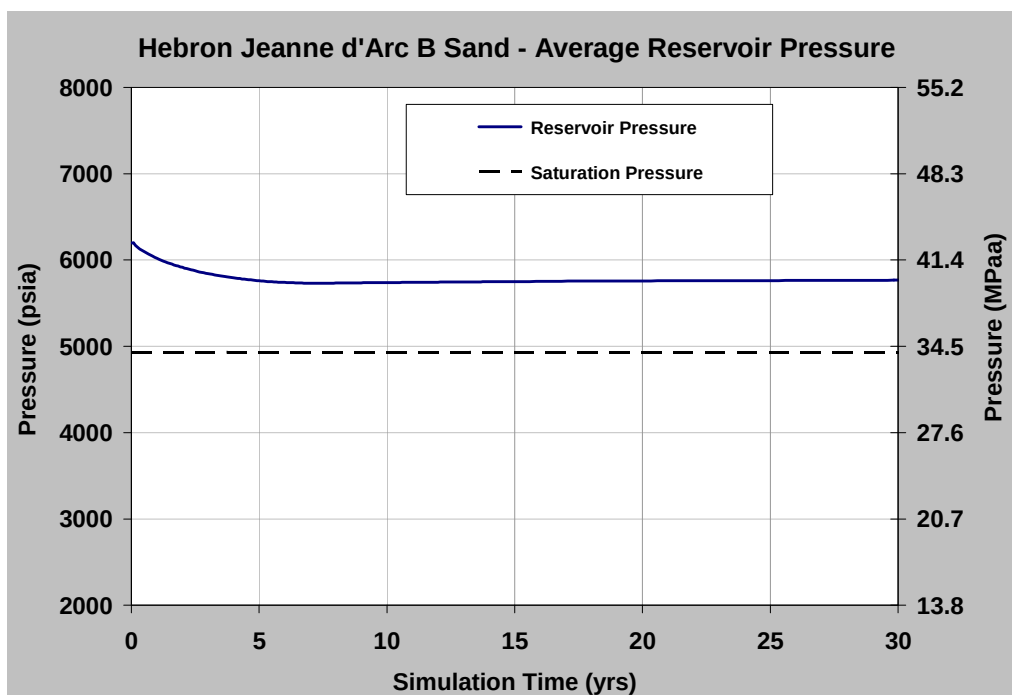


Figure 6.4-6: Hebron Jeanne d'Arc B Sand Average Reservoir Pressure

6.4.3 Hebron Jeanne d'Arc Alternate Depletion Plans

Primary depletion was the other depletion plan mechanism considered for the Jeanne d'Arc resources. GI was not considered due to the relatively higher subsurface pressure of these resources which would require added surface compression equipment, and also due to the limited hydrocarbon pore volume in the reservoir regions above the planned producers (sometimes referred to as the reservoir “attic” volume).

6.4.3.1 Primary Depletion – Hebron Jeanne d'Arc H Sand

The simulation results from implementing a primary depletion scheme in the Jeanne d'Arc H Sand predict an oil recovery of about 8 million barrels (1 Mm³) or a recovery factor of about 7 percent. The oil recovery was relatively insensitive to the number of oil producers drilled, as can be seen from Figure 6.4-7. Based on these results, it is clear that providing pressure support helps to maximize oil recovery in the Jeanne d'Arc H Sand reservoir. In these simulation runs, a minimum oil rate of 314 bbls/day (50 m³/day) was specified for the producers.

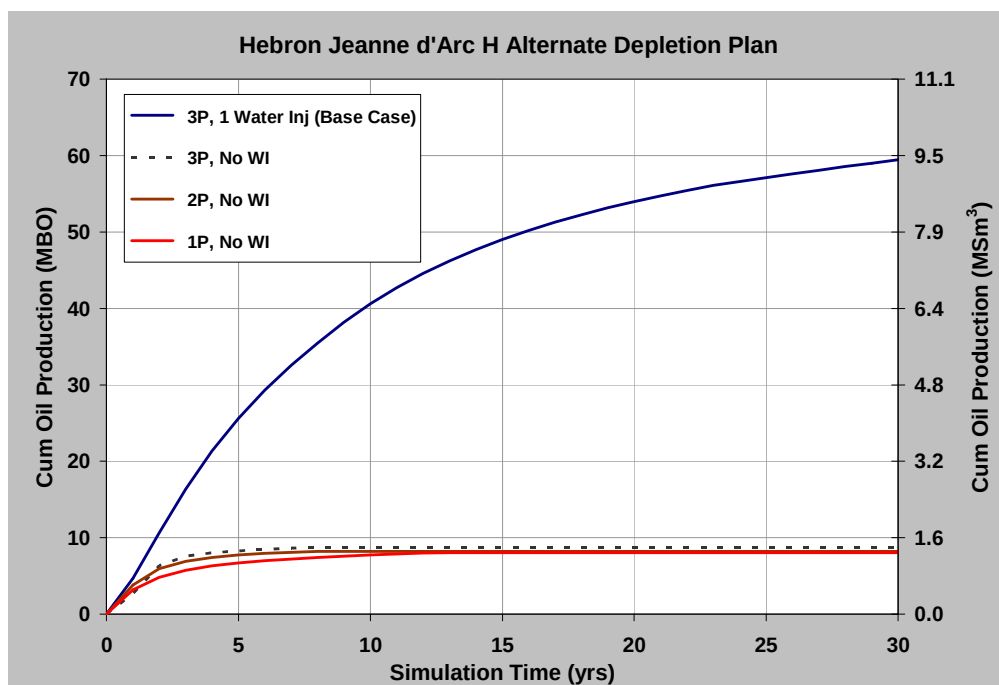


Figure 6.4-7: Hebron Jeanne d'Arc H Sand Alternate Depletion Plan – Primary Depletion

6.4.3.2 Primary Depletion in Hebron Jeanne d'Arc B Sand

Figure 6.4-8 is a graph comparing the results of a primary recovery (single producer) scheme and the base case depletion plan (one producer and one water injector). The simulations predict cumulative oil production of approximately 20 million barrels (3 Mm³) after thirty years of natural depletion compared to about 28 million barrels (4 Mm³) in the base case depletion plan (one producer and one water injector) indicating incremental recovery of more than 7 million barrels (1 Mm³) associated with providing pressure support.

During the detailed well planning phase, the possibility of drilling a single water injection well that can support both the Hibernia and Jeanne d'Arc reservoirs will be investigated to improve GBS well slot utilization and oil recovery from these reservoirs.

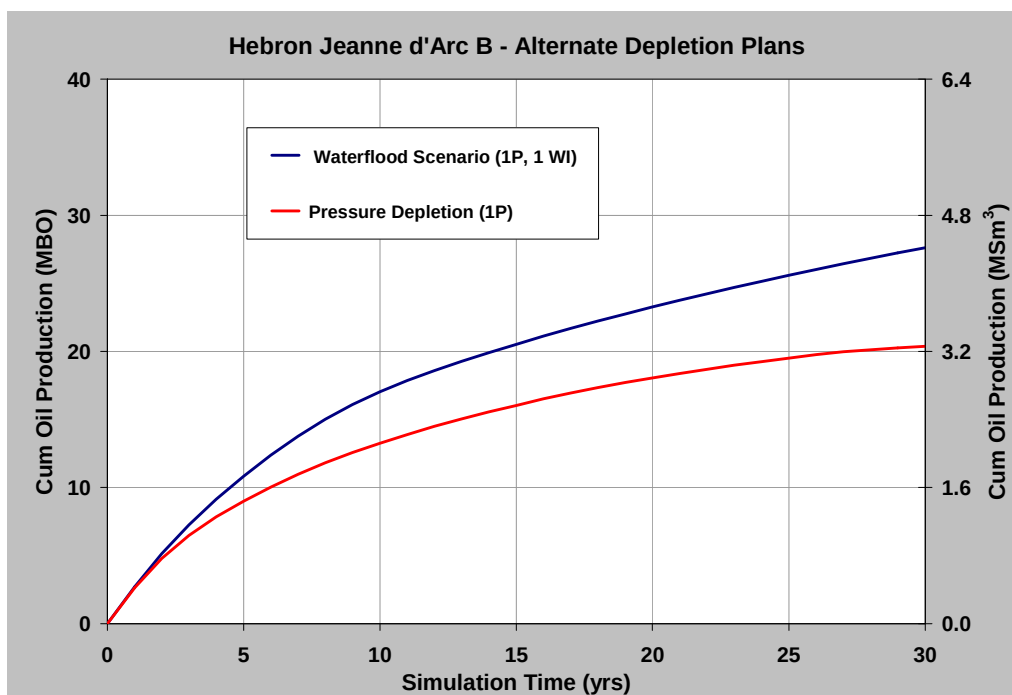


Figure 6.4-8: Hebron Jeanne d'Arc B Sand Alternate Depletion Plan – Primary Depletion

6.4.4 Hebron Jeanne d'Arc Well Count Sensitivity Study

This section summarizes the well count sensitivities evaluated for the Hebron Jeanne d'Arc H and B Sands.

6.4.4.1 Hebron Jeanne d'Arc H Sand Well Count Sensitivity

The base case depletion plan for the Jeanne d'Arc H Sand resource involves drilling three producers and one water injector. Alternate depletion plan scenarios with different producer count and configurations were investigated. (Section 6.4.3.1 presented the results of primary depletion scenarios for the Jeanne d'Arc H Sand resource). The results of the well count sensitivity studies are shown in Figure 6.4-9. Thirty-year oil recovery ranged from slightly below 30 MBO (5 Mm³) with one producer and one water injector to about 59 MBO (9 Mm³) with three producers and one water injector. As shown in Figure 6.4-9, a range of recovery - 36 to 53 MBO (6 to 8 Mm³), can be obtained from a three-well (two producers and one water injector) depletion plan scenario depending on the placement of the two producers.

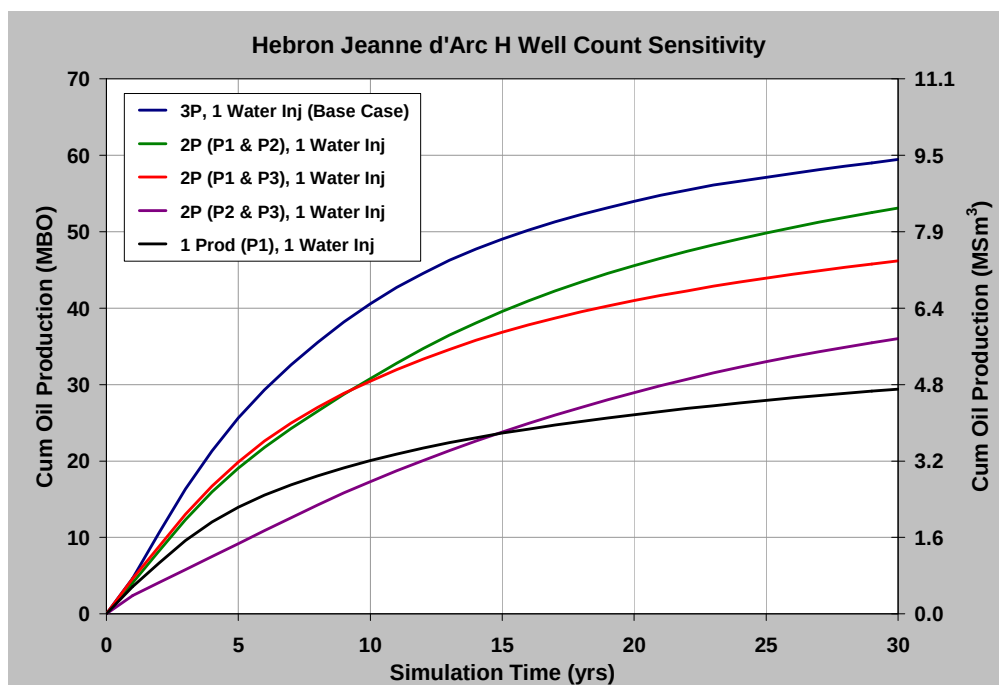


Figure 6.4-9: Hebron Jeanne d'Arc H Sand Well Count Sensitivity

6.4.4.2 Hebron Jeanne d'Arc B Sand Well Count Sensitivity

The current depletion plan for the Jeanne d'Arc B Sand resource involves drilling one producer and one water injector. Well count sensitivities studies evaluated the potential for increasing recovery by increasing the well density. In this study, high confidence in knowledge of the reservoir description was assumed and, therefore, well placement risks were not considered. The results, shown in Figure 6.4-10, indicate the potential to increase recovery from the B Sand resource with increased understanding of the subsurface description to help in selecting appropriate targets of additional wells (producers and/or injectors). On-going studies aimed at narrowing the uncertainty in reservoir description and improving recovery efficiency, information gathered during the development drilling phase, and early production performance will be key to realizing the potential recovery uplift from this resource.

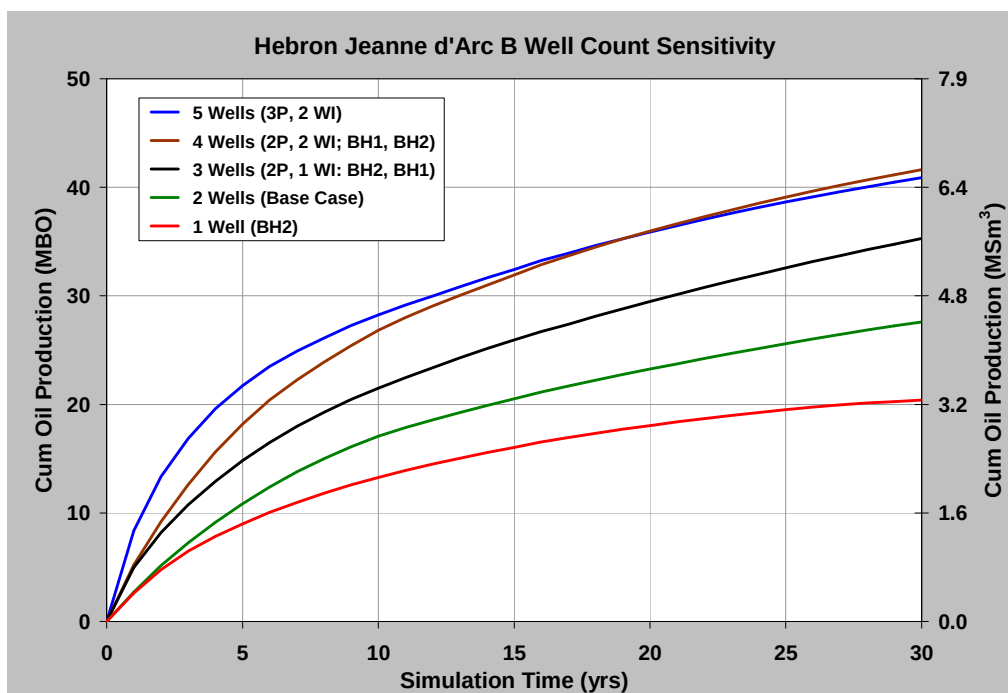


Figure 6.4-10: Hebron Jeanne d'Arc B Sand Well Count Sensitivity

6.5 Ben Nevis Field Ben Nevis Reservoir (Pool 3) Exploitation

This Section provides a summary of the dynamic reservoir simulation studies undertaken for the Ben Nevis formation within the Ben Nevis field.

6.5.1 Ben Nevis Ben Nevis (Pool 3) Simulation Model

The Ben Nevis Ben Nevis simulation model includes the stratigraphic unit penetrated by the L-55 and I-45 wells. The average cell size of the geologic model is 100 m by 100 m by 1 m. This cell size was retained in the hydrocarbon bearing region of the simulation model. Cells in the aquifer region of the simulation model were scaled up to average dimensions of 300 m by 300 m by 5 m to reduce total cell count and improve computational efficiency of simulations. The final simulation model contains 164 layers and has a total active cell count of about 480,000. Figure 6.5-1 provides a view of the simulation model.

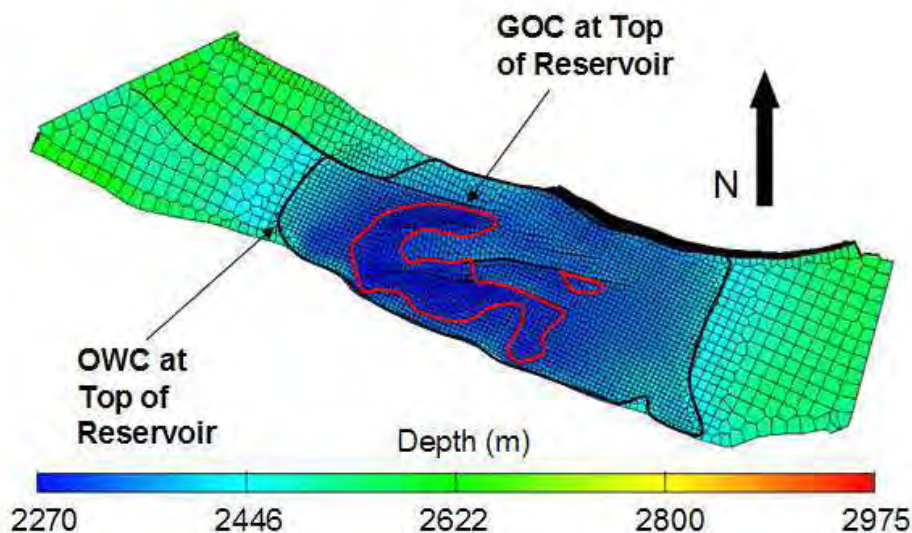


Figure 6.5-1: Ben Nevis Ben Nevis Simulation Model Area of Interest

The simulation model was initialized using an assumption of gravity-capillary equilibrium conditions. The STOOIP in the initialized simulation model was approximately 630 MBO (100 Mm³) which is about 2% less than the geologic model STOOIP.

6.5.2 Ben Nevis Ben Nevis Base Case Depletion Plan

The Ben Nevis Ben Nevis reservoir has been described as being primarily composed of distal lower shoreface deposits of sand, silt and clay along with carbonate shell fragments. Reservoir quality and continuity are the greatest uncertainties that could impact reservoir performance of this pool. Reservoir quality in Pool 3 is poorer than that of the Ben Nevis interval of Pool 1, and the extent to which the lowest-quality reservoir may contribute to oil recovery

is uncertain. Reservoir quality is controlled by the amount of depositional clay, bioturbation and carbonate cements. The presence of smaller faults, particularly in the central region of the large Ben Nevis fault block, may also disrupt hydraulic continuity within the oil leg at Pool 3. The technical uncertainties associated with the Pool 3 resource are considered to be more substantial than those of the resources described in sections 6.2, 6.3 and 6.4 and these uncertainties are expected to present significant challenges to productivity and to the efficiency of any displacement process.

It is recognized that further technical work is required to reduce the risk associated with this development. As such, three approaches are currently being considered for the development of the Pool 3 resource. These are:

Option 1: Appraisal Well(s)

One or more additional pre-development wells could be drilled to obtain greater knowledge of the depositional environment and reservoir and fluid characteristics. Such well(s) could also provide a further assessment of productivity or injectivity in regions near the associated drilling location(s). Additional study would be required to identify well location(s) that are anticipated to have the highest likelihood of providing significant learnings beyond what has been gained from the existing Pool 3 well penetrations.

Option 2: Production Pilot

Production testing may be undertaken to enhance the opportunity to maximize learnings from any new well penetrations. Testing would either be from a platform-based well or a subsea well tied back to the platform. If appropriate, some form of injection could also be incorporated to provide supplementary information about inter-well pressure communication and broader-area reservoir characteristics. Successful implementation and execution could provide a more detailed Pool 3 knowledge base and provide key information that would serve to reduce subsurface uncertainties. Any production pilot would typically be configured so that additional wells can be added over time and be capable of being expanded into a more extensive development of the resource.

Option 3: Subsea Development

A subsea development of Pool 3 resource could be undertaken with the installation of required facilities for tie-back to the Hebron GBS. Such a development might be undertaken in a phased manner, beginning with a minimal number of wells and tie-back lines that would be designed to provide similar types of dynamic performance data to those mentioned in Option 2 above. Based upon this early performance data, the scope and nature of subsequent opportunities for further development could be assessed with improved confidence.

Reservoir simulation studies were undertaken to establish a base case depletion plan. In a full-field development scenario, a combination drive mechanism (combined gas and water injection) is currently the preferred depletion strategy for this resource. This scenario involves drilling ten producers, six water injectors and two gas injectors. Total well count and function (oil producers, water injectors and / or gas injectors) may be adjusted to optimize oil recovery depending on the results of ongoing depletion plan optimization activities, information gathered should appraisal well(s) be drilled, implementation of a production pilot scheme, learnings obtained during the development drilling program, and early production performance.

After 30 years of production, cumulative oil recovery of 124 million barrels (20 Mm³) is predicted in the best estimate case with a range of 75 to 203 million barrels (12 Mm³ to 32 Mm³) in the low side and high side recovery scenarios, respectively.

For purposes of effective pressure maintenance, the reservoir simulation model was subdivided into 3 regions (East, West-Central & South) to track production and injection volumes. This is shown in Figure 6.5-2. As stated in Section 6.2.2.1, reservoir pressure will be managed to maximize oil production rates and economic recovery of hydrocarbons.

Figure 6.5-3 and Figure 6.5-4 show production and average reservoir pressure profiles of the base case simulation.

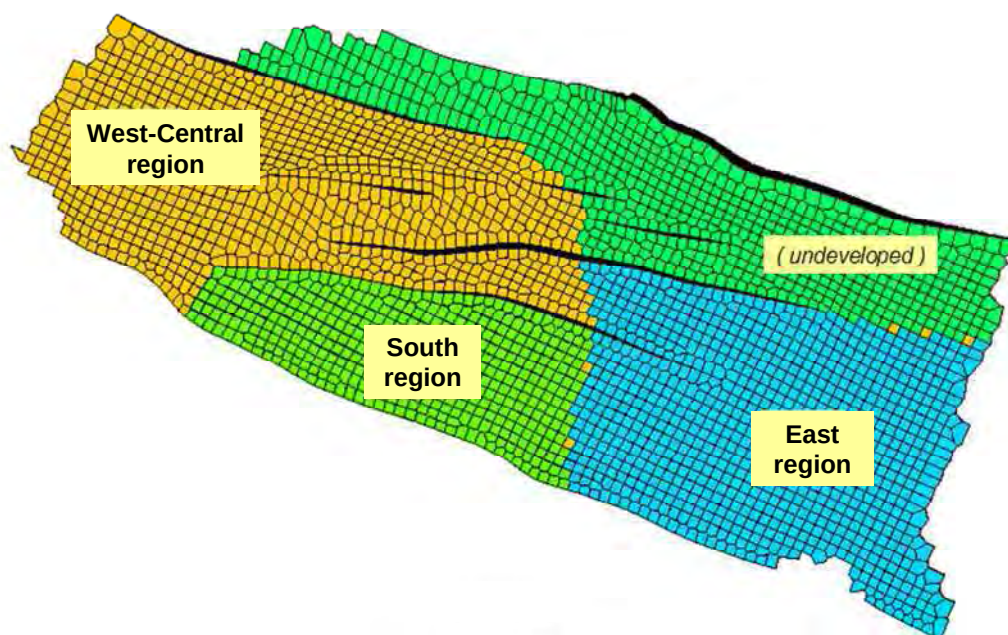


Figure 6.5-2: Ben Nevis Ben Nevis Simulation Model Pressure Tracking Regions

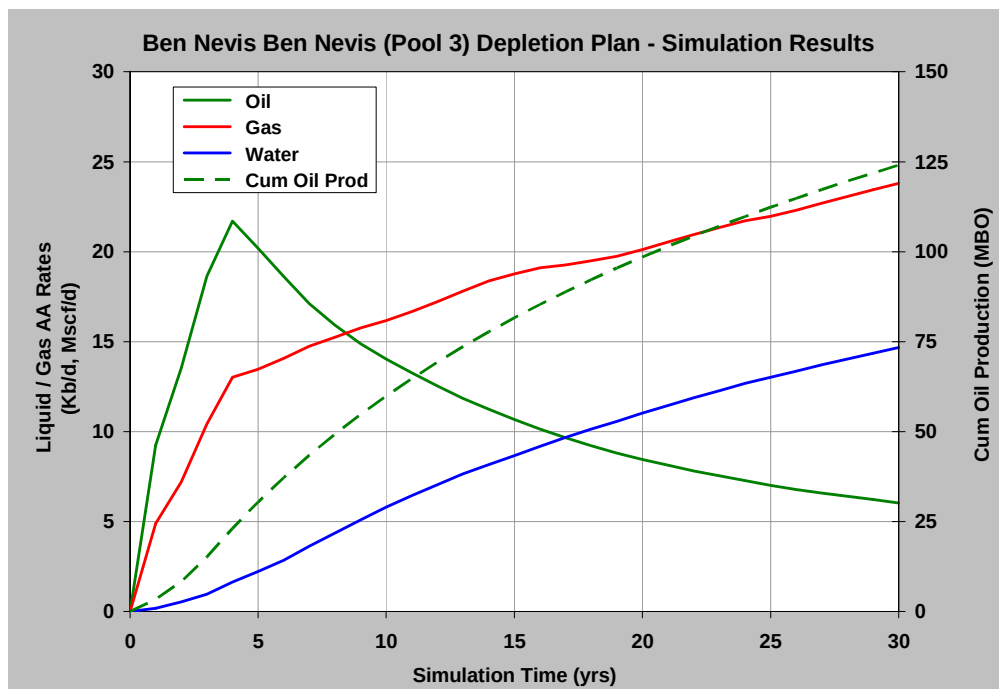


Figure 6.5-3: Ben Nevis Ben Nevis Base Case Depletion Plan Simulation Results

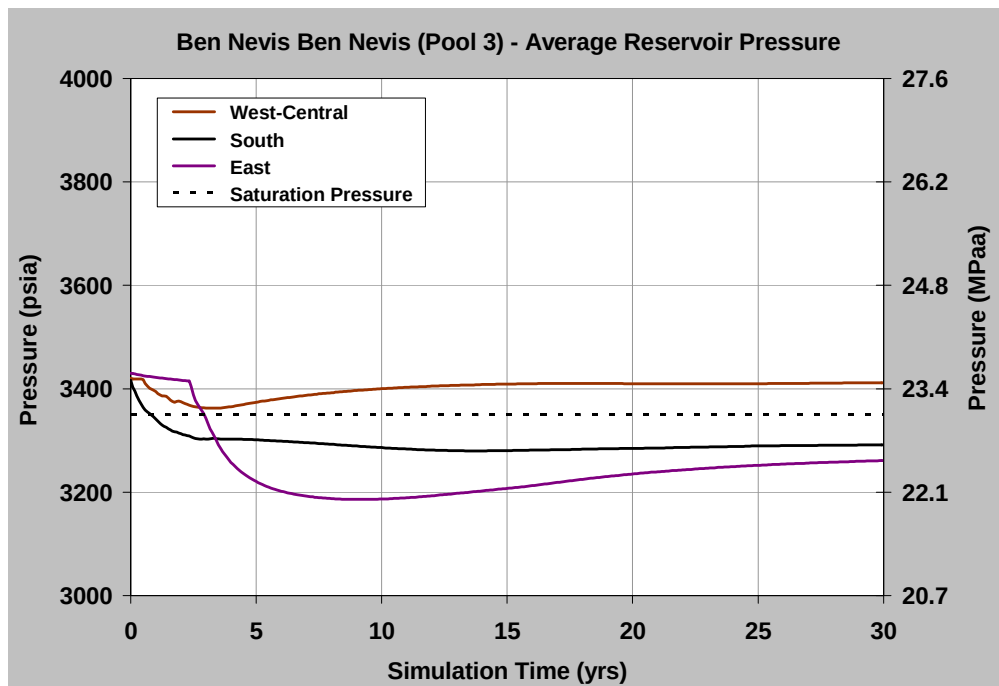


Figure 6.5-4: Ben Nevis Ben Nevis Average Reservoir Pressure

6.5.3 Ben Nevis Ben Nevis Alternate Depletion Plans

Two alternate depletion plans were considered for the Ben Nevis Ben Nevis (Pool 3) resource:

1. Waterflood-only scheme: In this strategy, waterflood is used as the only method of providing pressure support compared with the base case plan of a combination drive (waterflood and crestal gas injection) mechanism. This depletion plan scenario assumes that a viable means of storage / disposition is found for the associated gas produced in conjunction with Pool 3 oil production.
2. Primary depletion: In this scenario, no pressure support (water or gas injection) is provided.

The results of these alternate depletion plan options and a comparison to the base case plan are presented in Figure 6.5-5. Cumulative oil recovery after 30 years is predicted to be about 114 MBO (18 Mm³) in the waterflood case and 99 MBO (16 Mm³) in the primary depletion scenario compared to 124 MBO (20 Mm³) in the combination drive scheme.

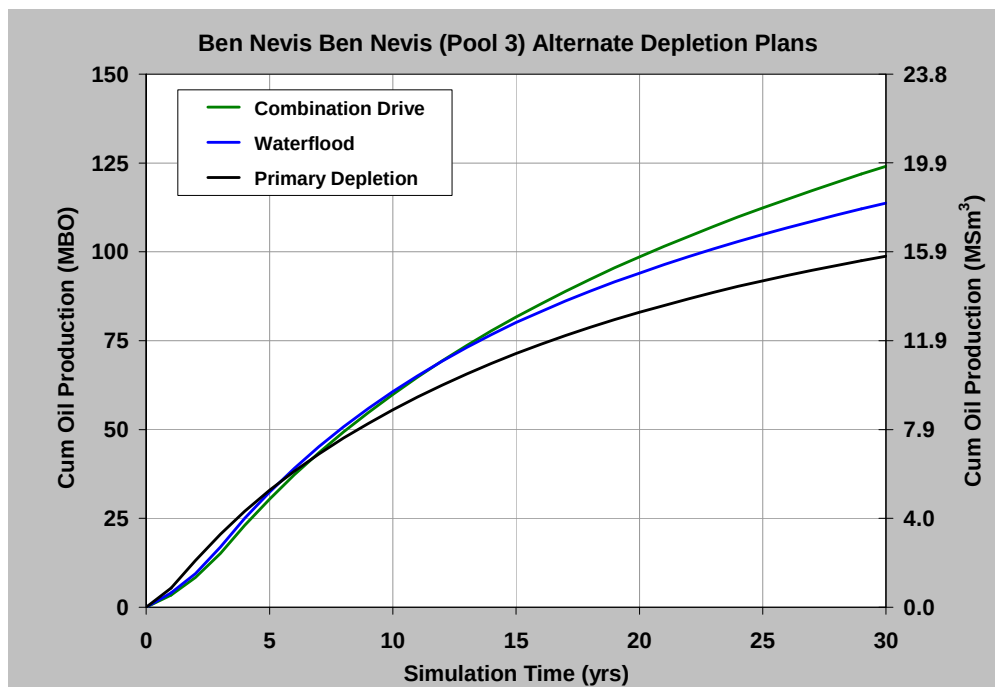


Figure 6.5-5: Ben Nevis Ben Nevis – Alternate Depletion Plans

6.5.4 Ben Nevis Ben Nevis Sensitivity Studies

Sensitivities to the Ben Nevis Ben Nevis base case depletion plan described previously were performed to address uncertainties in reservoir description and well performance. These include the following:

1. Fault transmissibility multiplier: A base model had no cross-fault transmissibility multipliers applied where there was sand-on-sand juxtaposition across faults (i.e. no flow impairment was imposed in the base case simulation). Sensitivity cases with transmissibility multipliers of 0.001 and 0 (no flow) were tested to examine the impact on flow across faults.
2. Permeability: Model permeabilities were varied as follows:
 - i. Vertical permeability adjustment only (0.167x, 0.667x, 2x)
 - ii. Vertical and horizontal permeabilities adjusted (0.75x, 1.25x)
3. Well skin (completion efficiency): A base case assumed skin values of +2.5 for all development wells. This sensitivity tested the impact of higher (+5) and lower (0 and -2 respectively) skin factors.
4. Larger aquifer volume ratio (3x): The base case aquifer volume ratio is approximately 6:1. This sensitivity tested a more substantial aquifer (aquifer volume ratio of 18:1) and assumed that no water injection wells were drilled to provide supplemental pressure support.

The results of these sensitivities are presented as deltas to the base case depletion plan in Figure 6.5-6.

**Ben Nevis Ben Nevis (Pool 3) Depletion Plan Sensitivities
30-year Cumulative Oil Recovery Change from Base Case**

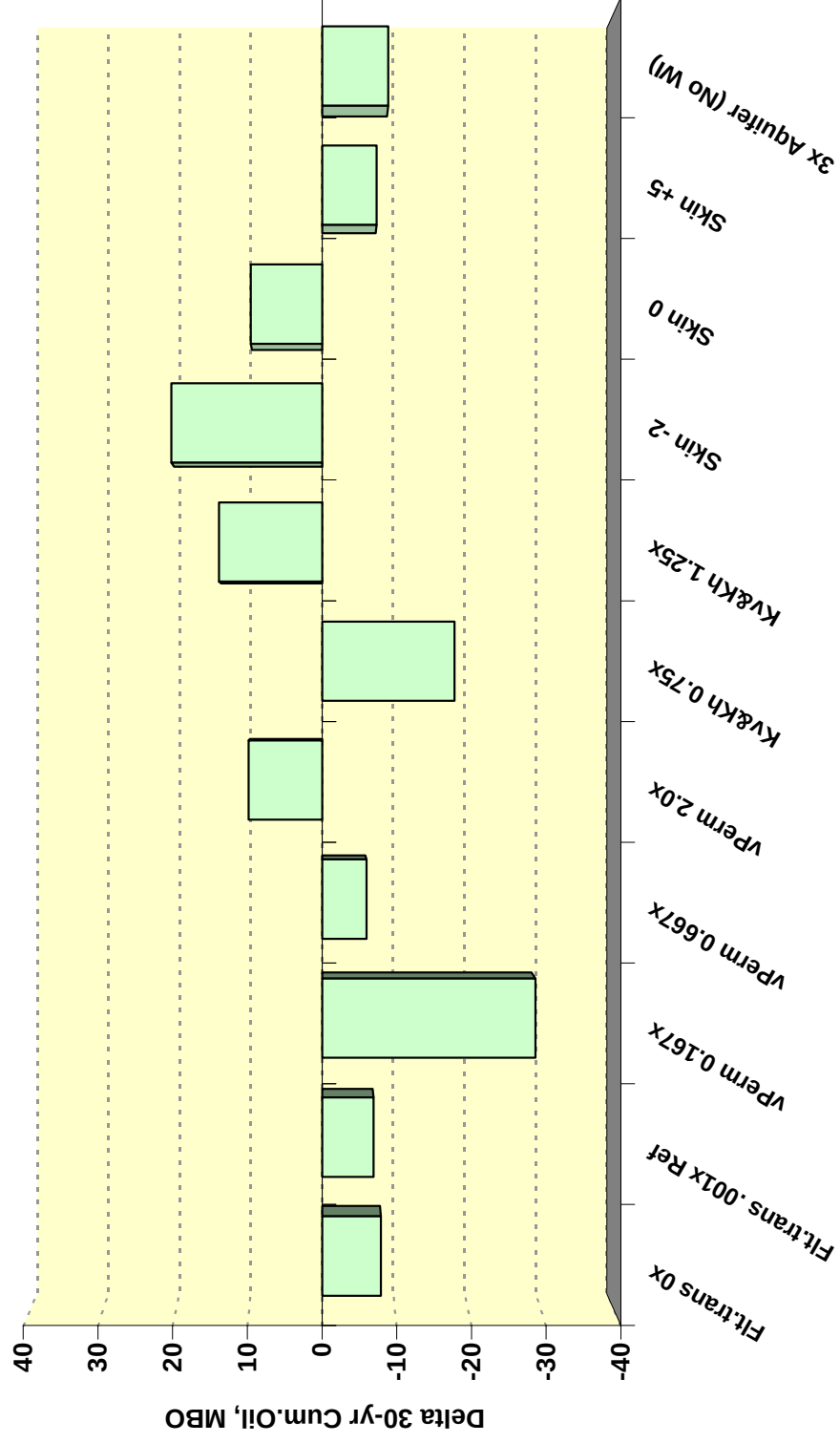


Figure 6.5-6: Ben Nevis Ben Nevis Depletion Plan Sensitivities

6.6 Hebron Asset Well Counts, Drilling Schedule, and Production Forecasts

Section 6.5 provides the anticipated well counts, drilling schedule, and associated production forecasts for the initial project development phase. The production forecasts incorporate drilling sequence, facility capacities and uptime assumptions that are discussed later in the section.

6.6.1 Well Count – Initial Development Phase

The preliminary well counts are summarized in Table 6.6-1. It should be emphasized that these well counts represent the current best estimate of the wells required to optimally deplete the resources targeted in the initial development scope of the project and are subject to change with future depletion planning optimizations resulting from on-going and future simulation studies, acquisition of new or reprocessing of existing seismic data, results of initial development drilling activities, production performance data, etc.

Table 6.6-1: Preliminary Well Count

Pool	Reservoir / Compartment	Production Wells	Injection Wells (WI/GI)
Pool 1	Hebron Ben Nevis, D-94	16	6 / 2
	Hebron Ben Nevis, I-13	3	2
	Pool 1 Totals	19	8 / 2
Pool 4	Hebron JdA, H Sand	3	1
	Hebron JdA, B Sand	1	1
	Pool 4 Totals	4	2
Pool 5	Hebron Hibernia	2	0
Pool 3	Ben Nevis Ben Nevis (subsea wells)	10	6/2
Total		35	16 / 4
Contingency / Undesignated Wells		6	

6.6.2 Preliminary Drilling Schedule – Initial Development Phase

The drilling schedule for the initial asset development phase has been designed to achieve multiple objectives including understanding and mitigation of key subsurface uncertainties and data acquisition to aid further asset depletion plan optimizations while maximizing initial oil production rates and recovery. The schedule assumes that the drilling program for Pools 1, 4 & 5 wells is executed by a single GBS rig while Pool 3 wells are drilled by a single mobile offshore drilling unit (MODU).

From the GBS drilling rig, a cuttings re-injection (CRI) well will be drilled first to support the disposal of non-aqueous fluid (NAF) based drill cuttings from the drilling program. The CRI well may later be completed for use as a water

injector into the D-94 fault block of the Hebron Ben Nevis formation. Additional discussion on the cuttings re-injection well can be found in Section 7 – Drilling and Completions.

Six contingency wells and two rig-based workover slots are also included in the drilling sequence. The planned well sequence is subject to change depending on the results from on-going depletion plan studies and the data gathered during the early phase of the development drilling program. Figure 6.6-1 shows the preliminary drilling schedule for the wells drilled from the GBS platform (for Pools 1, 4 & 5) while Figure 6.6-2 shows the tentative schedule of the drilling program of the subsea wells (for Pool 3). The Pool 3 program assumes that three wells are pre-drilled prior to production start-up.

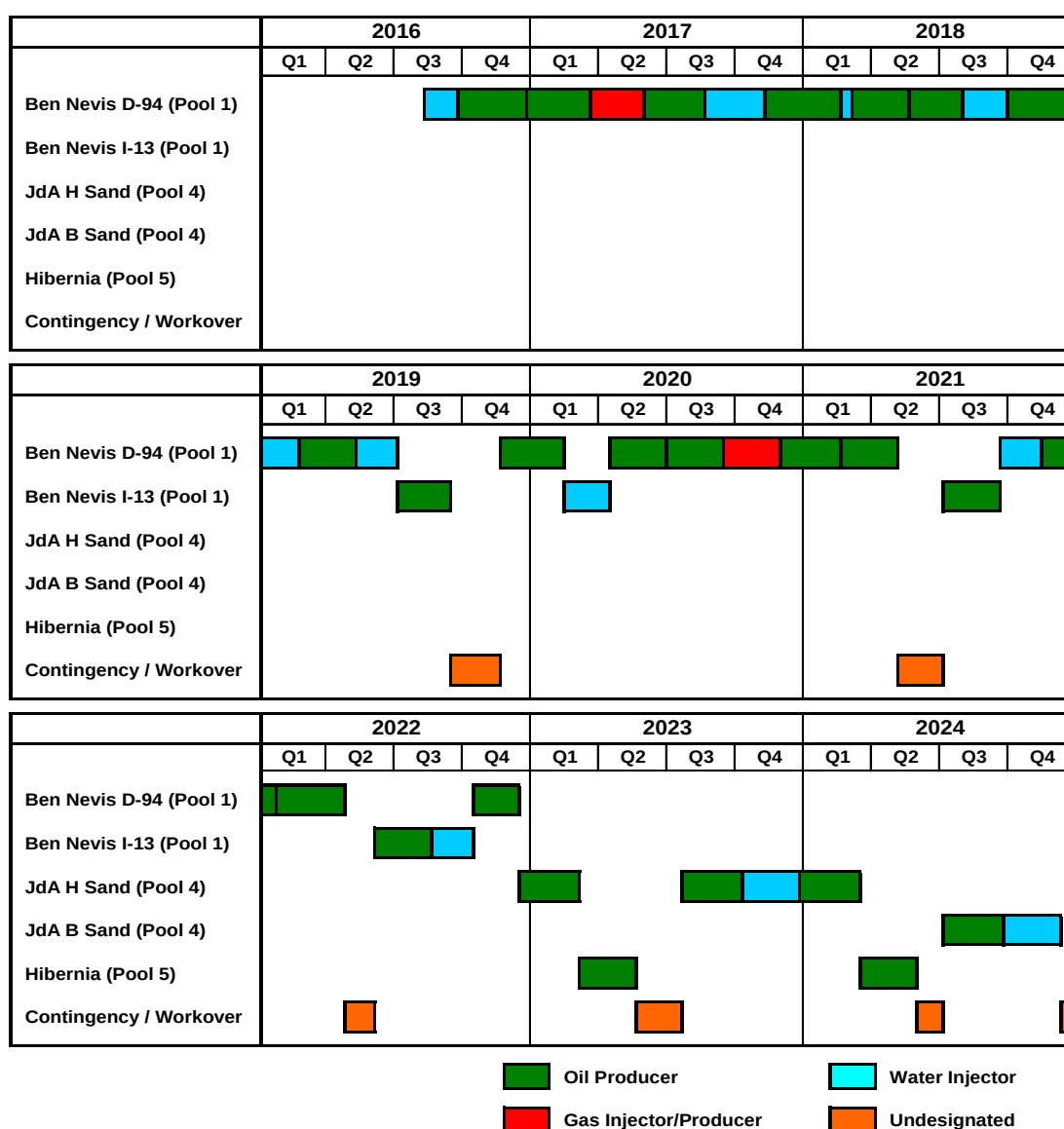


Figure 6.6-1: Drilling Schedule of GBS Platform Wells – Initial Development Phase

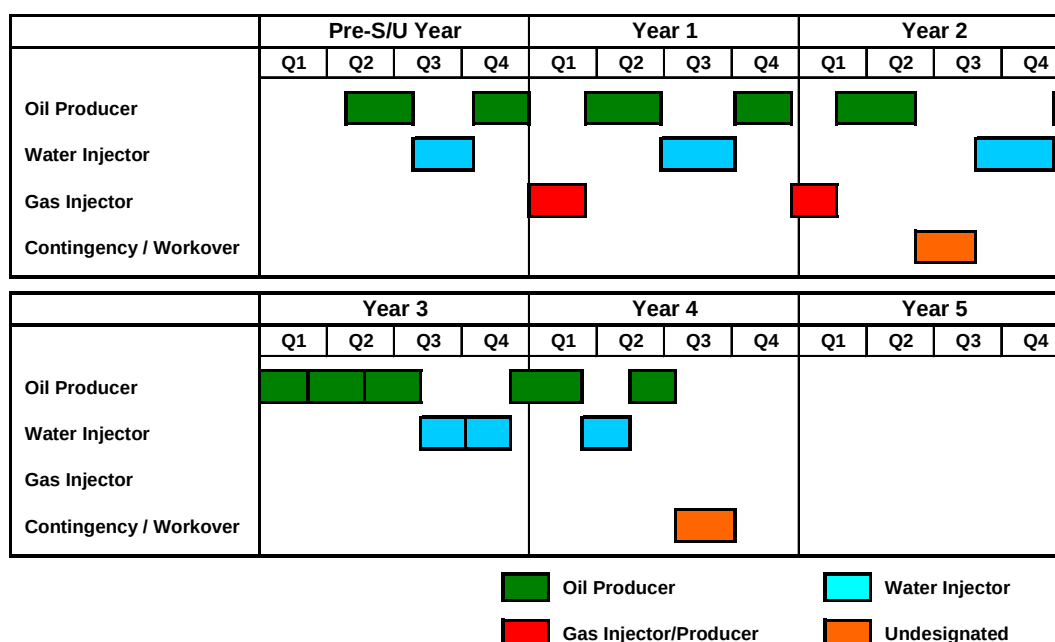


Figure 6.6-2: Drilling Schedule of Subsea (Pool 3) Wells – Full Development Scenario

6.6.3 Integrated Production Profiles (Best Estimate) – Initial Development Phase

The integrated production forecasts that follow were developed using the depletion plan assumptions, recovery estimates, well counts, and drilling schedule defined in the previous sections. These profiles are presented on an annual average basis starting from the onset of Hebron Field production and include the facility uptime assumptions. Therefore, the annual-average rates do not reflect either the maximum or minimum production rates that may occur in any given year of the forecast period. The annual average rates reflect an assumed facility downtime of 20 percent during the first year of production and 5 percent in each year thereafter. These forecasts were developed based on a target first oil date of December 2016.

The combined forecasts for the Hebron Field (Pools 1, 4 & 5) were developed using the Profile Generator tool contained in ExxonMobil's proprietary reservoir simulation software, EMPower[®]. This production forecasting tool is particularly useful in optimizing concurrent production from multiple reservoir sources. It combines the results from the simulation models of the individual pools and incorporates the overall facility design basis and uptime assumptions. The facility design basis is discussed in Section 8 and a summary of the proposed GBS design capacities used in generating the Hebron Field production profiles is provided in Table 6.6-2. The production forecasts for the Ben Nevis reservoir of the Ben Nevis Field (Pool 3) represent a full resource development scenario. As described in Section 6.5.2, there are other development approaches currently under consideration

for the Pool 3 resource (an appraisal well or a production pilot to de-risk the resource). The optimal start-up timing for Pool 3 and the sizing / scope of the topside process equipment that may be required for Pool 3 development are also currently being studied. The results of these studies along with a final development strategy would assist in understanding the impacts of the overall Topsides processing capacities on production from Pool 3. For these reasons, the Ben Nevis Field (Pool 3) production forecasts have not been combined with the Hebron Field forecasts and are presented independently.

Figure 6.6-3 through Figure 6.6-11 and Table 6.6-3 through Table 6.6-10 provide production and injection forecasts on an annual basis for the different Pools based on the project and drilling schedule assumptions in this document.

Table 6.6-2: Hebron Facility Design Capacities

Design Element	Metric Units		Oilfield Units	
	Units	Design Value	Units	Design Value
Total Oil Production	m ³ /d	23,900	Kb/d	150*
Total Water Production	m ³ /d	45,000	Kb/d	283
Total Gas Handling	Km ³ /d	6,650	Mcf/d	235
Total Water Injection Design Rate	m ³ /d	57,300	Kb/d	360
* 150 kbd represents the nominal oil rate for design of the Topsides facilities. It is anticipated that, with de-bottlenecking and production optimization post-start-up, that the total capacity of the facility could potentially be raised to 180 kbd (oil).				

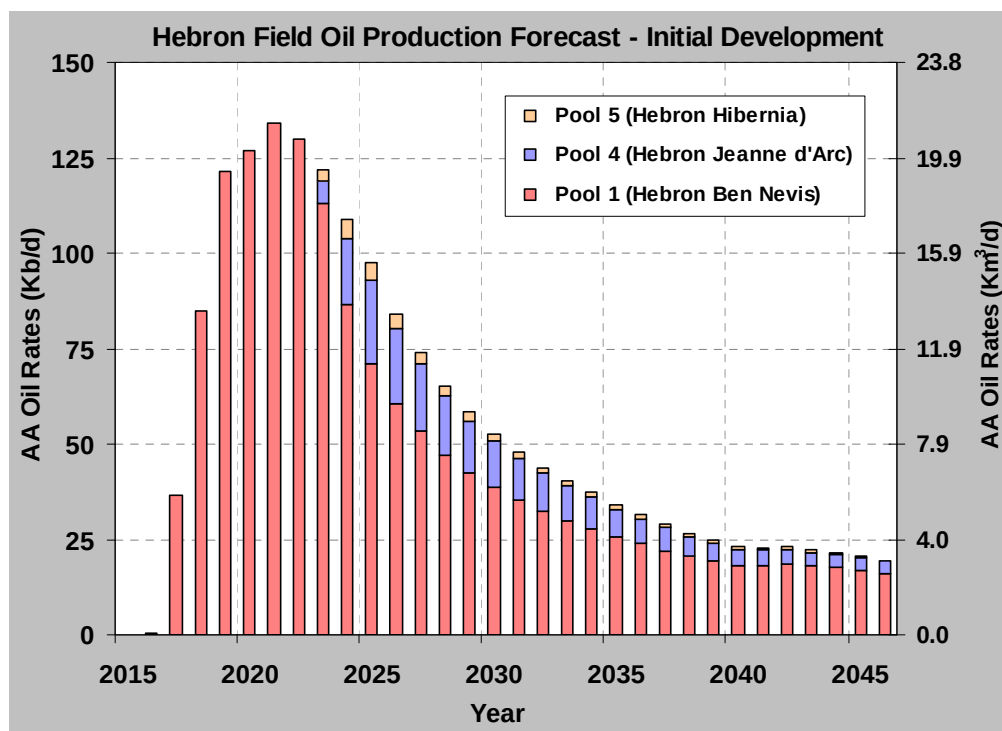


Figure 6.6-3: Hebron Field (Pools 1, 4 & 5) Oil Production Forecast

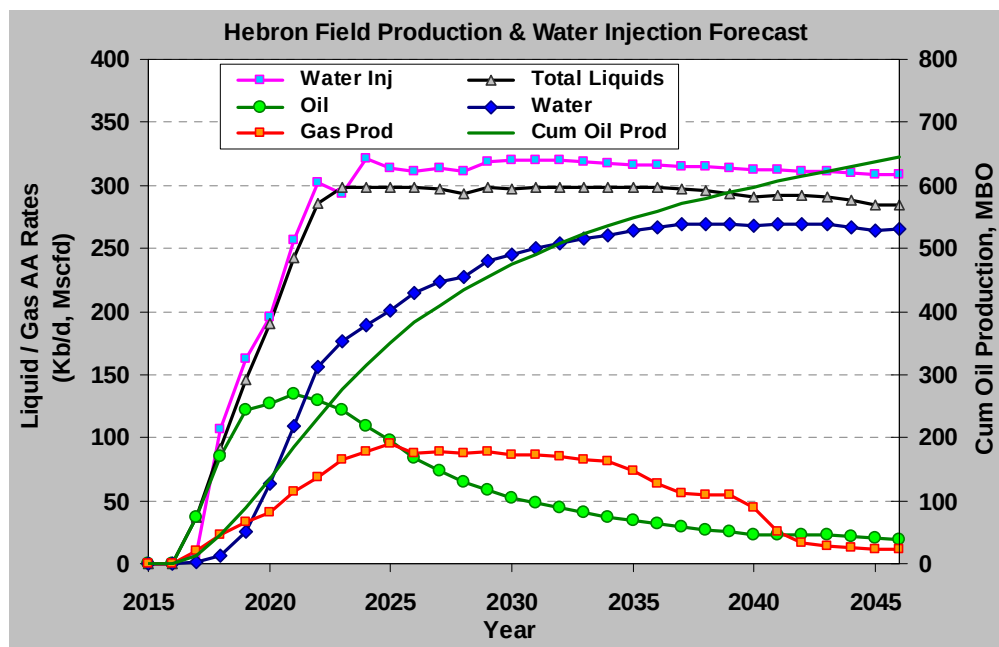


Figure 6.6-4: Hebron Field (Pools 1, 4 & 5) Production and Injection Forecast

Table 6.6-3: Hebron Field Oil Production Forecast by Calendar Year

Year	Oil Rates (Kb/d)				Oil Rates (Km ³ /d)			
	Ben Nevis	Hibernia	JdA	Total	Ben Nevis	Hibernia	JdA	Total
2016	0.5	0.0	0.0	0.5	0.1	0.0	0.0	0.1
2017	36.6	0.0	0.0	36.6	5.8	0.0	0.0	5.8
2018	84.9	0.0	0.0	84.9	13.5	0.0	0.0	13.5
2019	121.5	0.0	0.0	121.5	19.3	0.0	0.0	19.3
2020	126.9	0.0	0.0	126.9	20.2	0.0	0.0	20.2
2021	134.0	0.0	0.0	134.0	21.3	0.0	0.0	21.3
2022	129.9	0.0	0.0	129.9	20.7	0.0	0.0	20.7
2023	113.2	3.2	5.6	122.1	18.0	0.5	0.9	19.4
2024	86.4	5.3	17.3	109.0	13.7	0.8	2.7	17.3
2025	71.1	4.7	21.7	97.5	11.3	0.8	3.5	15.5
2026	60.4	3.8	20.1	84.2	9.6	0.6	3.2	13.4
2027	53.3	3.3	17.5	74.1	8.5	0.5	2.8	11.8
2028	47.0	2.9	15.4	65.3	7.5	0.5	2.4	10.4
2029	42.3	2.4	13.7	58.4	6.7	0.4	2.2	9.3
2030	38.6	1.7	12.2	52.6	6.1	0.3	1.9	8.4
2031	35.3	1.5	11.1	47.9	5.6	0.2	1.8	7.6
2032	32.4	1.4	10.1	43.9	5.2	0.2	1.6	7.0
2033	29.9	1.3	9.3	40.5	4.8	0.2	1.5	6.4
2034	27.8	1.2	8.4	37.4	4.4	0.2	1.3	5.9
2035	25.7	1.1	7.3	34.1	4.1	0.2	1.2	5.4
2036	23.8	1.0	6.5	31.3	3.8	0.2	1.0	5.0
2037	22.0	0.9	5.9	28.9	3.5	0.2	0.9	4.6
2038	20.4	0.9	5.3	26.7	3.3	0.1	0.9	4.2
2039	19.1	0.8	4.9	24.8	3.0	0.1	0.8	4.0
2040	17.9	0.8	4.5	23.2	2.8	0.1	0.7	3.7
2041	17.9	0.7	4.2	22.8	2.8	0.1	0.7	3.6
2042	18.3	0.7	3.9	22.9	2.9	0.1	0.6	3.6
2043	18.0	0.6	3.7	22.2	2.9	0.1	0.6	3.5
2044	17.5	0.4	3.5	21.4	2.8	0.1	0.6	3.4
2045	16.8	0.3	3.3	20.4	2.7	0.0	0.5	3.2
2046	16.1	0.3	3.1	19.5	2.6	0.0	0.5	3.1
Cum Oil (MB / Mm³)	550.0	15.1	79.7	644.8	87.4	2.4	12.7	102.5

Table 6.6-4: Hebron Field Production and Injection Forecast

Year	Oil Production		Gas Production		Water Production		Water Injection		Gas Injection	
	[Kb/d]	[Km ³ /d]	[Mcf/d]	[MSm ³ /d]	[Kb/d]	[Km ³ /d]	[Kb/d]	[Km ³ /d]	[Mcf/d]	[MSm ³ /d]
2016	0.5	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2017	36.6	5.8	9.9	0.3	0.7	0.1	7.1	1.1	3.8	0.1
2018	84.9	13.5	23.1	0.7	6.7	1.1	106.8	17.0	10.3	0.3
2019	121.5	19.3	33.2	0.9	24.8	3.9	163.1	25.9	14.1	0.4
2020	126.9	20.2	40.5	1.1	63.6	10.1	195.2	31.0	18.1	0.5
2021	134.0	21.3	57.8	1.6	108.8	17.3	256.8	40.8	31.2	0.9
2022	129.9	20.7	69.0	2.0	156.4	24.9	302.1	48.0	42.4	1.2
2023	122.1	19.4	82.3	2.3	176.2	28.0	293.9	46.7	55.3	1.6
2024	109.0	17.3	89.1	2.5	189.3	30.1	321.0	51.0	61.5	1.7
2025	97.5	15.5	94.7	2.7	200.8	31.9	313.9	49.9	67.0	1.9
2026	84.2	13.4	87.5	2.5	214.1	34.0	311.3	49.5	58.8	1.7
2027	74.1	11.8	89.1	2.5	223.2	35.5	313.2	49.8	61.6	1.7
2028	65.3	10.4	88.2	2.5	227.4	36.2	310.5	49.4	60.5	1.7
2029	58.4	9.3	88.5	2.5	239.7	38.1	318.6	50.7	61.5	1.7
2030	52.6	8.4	86.6	2.5	245.1	39.0	319.8	50.8	59.8	1.7
2031	47.9	7.6	86.9	2.5	250.4	39.8	320.3	50.9	60.3	1.7
2032	43.9	7.0	84.8	2.4	253.9	40.4	319.5	50.8	58.4	1.7
2033	40.5	6.4	82.8	2.3	257.8	41.0	318.8	50.7	56.9	1.6
2034	37.4	5.9	80.9	2.3	260.9	41.5	317.6	50.5	55.4	1.6
2035	34.1	5.4	73.2	2.1	264.2	42.0	316.2	50.3	48.0	1.4
2036	31.3	5.0	63.1	1.8	267.0	42.4	316.5	50.3	37.8	1.1
2037	28.9	4.6	55.5	1.6	268.8	42.7	315.3	50.1	30.1	0.9
2038	26.7	4.2	54.5	1.5	268.8	42.7	314.3	50.0	29.1	0.8
2039	24.8	4.0	54.2	1.5	268.8	42.7	313.5	49.8	28.8	0.8
2040	23.2	3.7	44.4	1.3	267.6	42.5	312.7	49.7	19.0	0.5
2041	22.8	3.6	25.2	0.7	268.9	42.7	312.1	49.6	0.1	0.0
2042	22.9	3.6	16.3	0.5	268.8	42.7	311.5	49.5	0.0	0.0
2043	22.2	3.5	14.5	0.4	268.9	42.7	311.0	49.4	0.0	0.0
2044	21.4	3.4	13.1	0.4	266.9	42.4	310.0	49.3	0.0	0.0
2045	20.4	3.2	11.9	0.3	263.7	41.9	308.5	49.1	0.0	0.0
2046	19.5	3.1	11.0	0.3	264.9	42.1	308.1	49.0	0.0	0.0
Cum Volumes	644.8	102.5	625.3	17.7	2303.7	366.3	3126.2	497.0	376.2	10.7

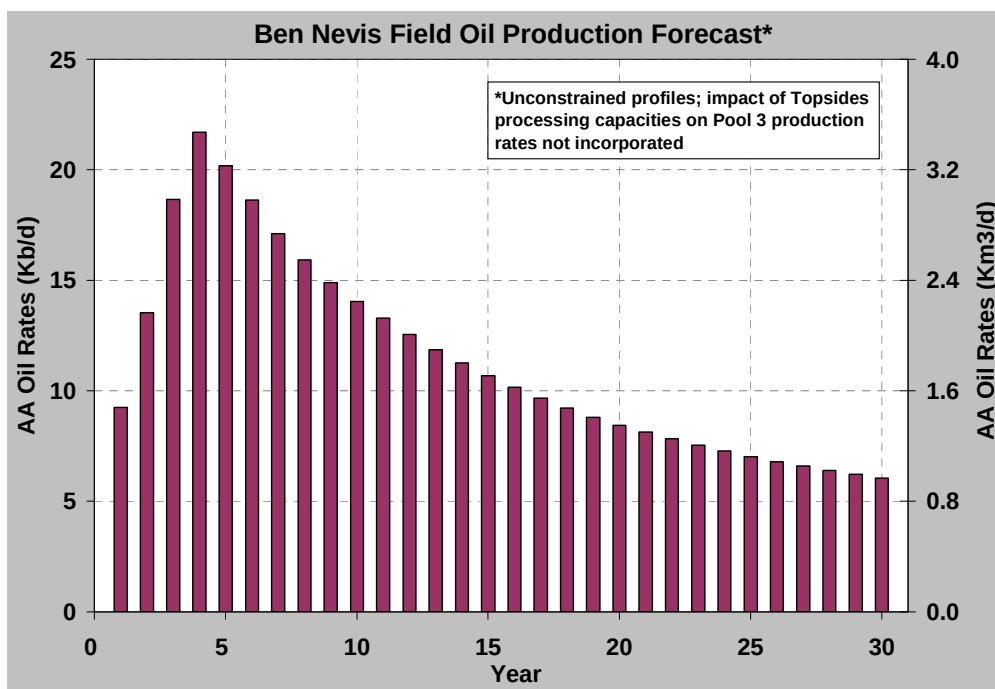


Figure 6.6-5: Ben Nevis Field (Pool 3) Oil Production Forecast

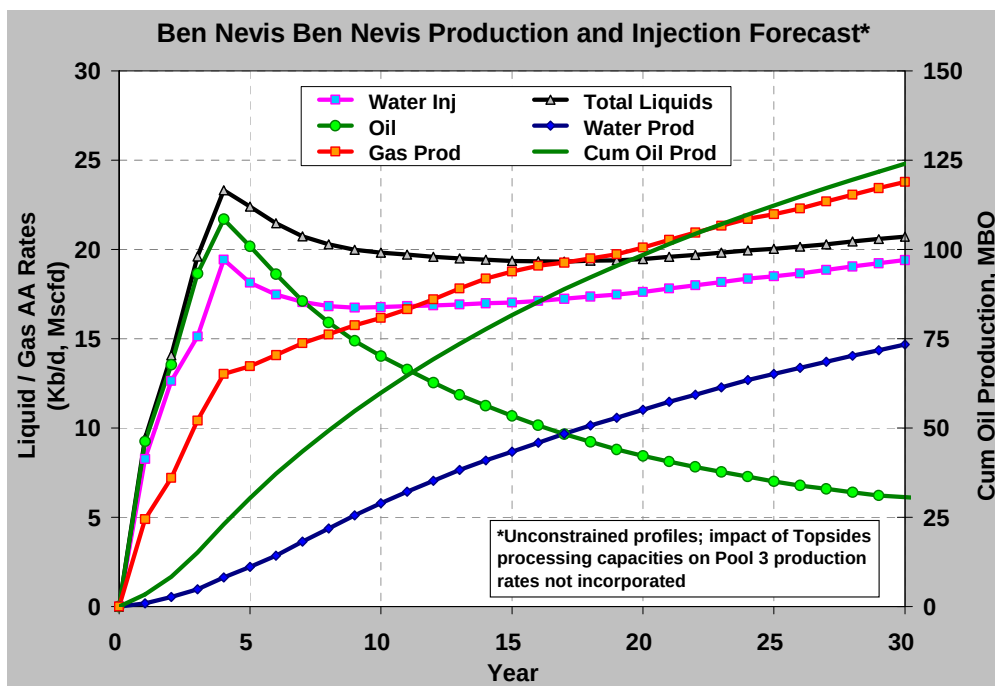


Figure 6.6-6: Ben Nevis Field (Pool 3) Production and Injection Forecast

Table 6.6-5: Ben Nevis Field (Pool 3) Production and Injection Forecast

Year	Oil Production		Gas Production		Water Production		Water Injection		Gas Injection	
	[Kb/d]	[Km ³ /d]	[Mcf/d]	[MSm ³ /d]	[Kb/d]	[Km ³ /d]	[Kb/d]	[Km ³ /d]	[Mcf/d]	[MSm ³ /d]
1	9.3	1.5	4.9	0.1	0.2	0.0	8.3	1.3	4.9	0.1
2	13.5	2.2	7.2	0.2	0.5	0.1	12.6	2.0	7.2	0.2
3	18.7	3.0	10.4	0.3	1.0	0.2	15.1	2.4	10.4	0.3
4	21.7	3.4	13.0	0.4	1.6	0.3	19.4	3.1	13.0	0.4
5	20.2	3.2	13.5	0.4	2.2	0.4	18.1	2.9	13.5	0.4
6	18.6	3.0	14.1	0.4	2.9	0.5	17.5	2.8	14.1	0.4
7	17.1	2.7	14.8	0.4	3.6	0.6	17.1	2.7	14.8	0.4
8	15.9	2.5	15.2	0.4	4.4	0.7	16.8	2.7	15.2	0.4
9	14.9	2.4	15.8	0.4	5.1	0.8	16.7	2.7	15.8	0.4
10	14.0	2.2	16.2	0.5	5.8	0.9	16.8	2.7	16.2	0.5
11	13.3	2.1	16.7	0.5	6.4	1.0	16.8	2.7	16.7	0.5
12	12.5	2.0	17.2	0.5	7.0	1.1	16.9	2.7	17.2	0.5
13	11.9	1.9	17.8	0.5	7.6	1.2	16.9	2.7	17.8	0.5
14	11.3	1.8	18.4	0.5	8.2	1.3	17.0	2.7	18.4	0.5
15	10.7	1.7	18.8	0.5	8.7	1.4	17.0	2.7	18.8	0.5
16	10.2	1.6	19.1	0.5	9.2	1.5	17.1	2.7	19.1	0.5
17	9.7	1.5	19.3	0.5	9.7	1.5	17.2	2.7	19.3	0.5
18	9.2	1.5	19.5	0.6	10.2	1.6	17.4	2.8	19.5	0.6
19	8.8	1.4	19.7	0.6	10.6	1.7	17.5	2.8	19.7	0.6
20	8.4	1.3	20.1	0.6	11.0	1.8	17.6	2.8	20.1	0.6
21	8.1	1.3	20.5	0.6	11.5	1.8	17.8	2.8	20.5	0.6
22	7.8	1.2	20.9	0.6	11.9	1.9	18.0	2.9	20.9	0.6
23	7.5	1.2	21.3	0.6	12.3	2.0	18.2	2.9	12.6	0.4
24	7.3	1.2	21.7	0.6	12.7	2.0	18.4	2.9	11.3	0.3
25	7.0	1.1	22.0	0.6	13.0	2.1	18.5	2.9	10.1	0.3
26	6.8	1.1	22.3	0.6	13.4	2.1	18.7	3.0	9.3	0.3
27	6.6	1.0	22.7	0.6	13.7	2.2	18.9	3.0	8.8	0.2
28	6.4	1.0	23.1	0.7	14.0	2.2	19.0	3.0	8.4	0.2
29	6.2	1.0	23.4	0.7	14.4	2.3	19.2	3.1	7.5	0.2
30	6.0	1.0	23.8	0.7	14.7	2.3	19.4	3.1	7.1	0.2
Cum Volumes	124.0	19.7	194.9	5.5	90.4	14.4	188.5	30.0	156.4	4.4

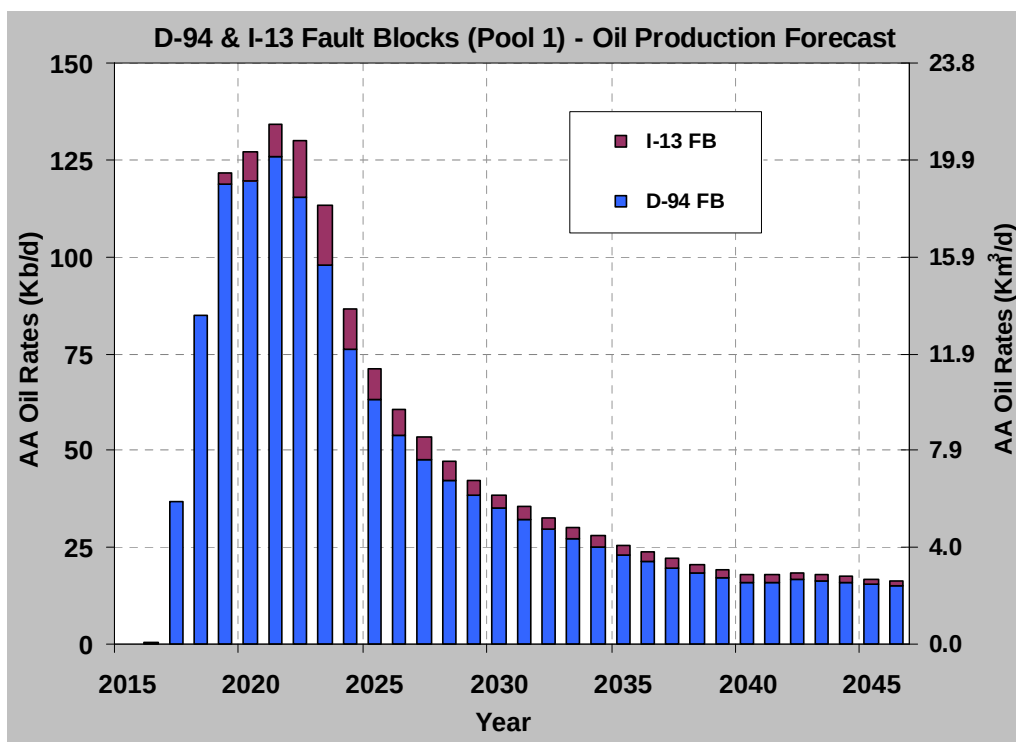


Figure 6.6-7: Oil Production Forecast: Hebron Ben Nevis D-94 and I-13 Fault Blocks

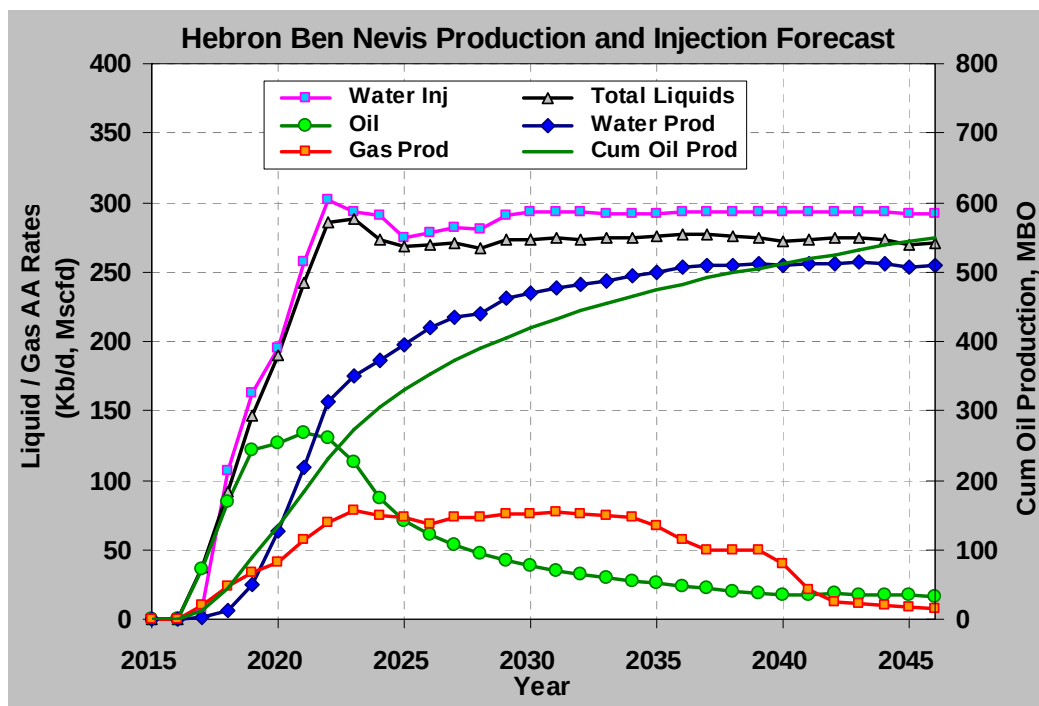


Figure 6.6-8: Hebron Ben Nevis Production and Injection Forecast

Table 6.6-6: Oil Production Forecast – D-94 and I-13 Fault Blocks

Year	Oil Rates (Kb/d)			Oil Rates (Km ³ /d)		
	D-94	I-13	Total	D-94	I-13	Total
2016	0.5	0.0	0.5	0.1	0.0	0.1
2017	36.6	0.0	36.6	5.8	0.0	5.8
2018	84.9	0.0	84.9	13.5	0.0	13.5
2019	118.7	2.8	121.5	18.9	0.4	19.3
2020	119.3	7.6	126.9	19.0	1.2	20.2
2021	125.9	8.0	134.0	20.0	1.3	21.3
2022	115.3	14.6	129.9	18.3	2.3	20.7
2023	98.0	15.3	113.2	15.6	2.4	18.0
2024	76.1	10.4	86.4	12.1	1.6	13.7
2025	63.1	8.0	71.1	10.0	1.3	11.3
2026	53.8	6.5	60.4	8.6	1.0	9.6
2027	47.8	5.5	53.3	7.6	0.9	8.5
2028	42.3	4.8	47.0	6.7	0.8	7.5
2029	38.3	4.0	42.3	6.1	0.6	6.7
2030	35.1	3.5	38.6	5.6	0.6	6.1
2031	32.2	3.1	35.3	5.1	0.5	5.6
2032	29.5	2.9	32.4	4.7	0.5	5.2
2033	27.2	2.7	29.9	4.3	0.4	4.8
2034	25.2	2.6	27.8	4.0	0.4	4.4
2035	23.2	2.5	25.7	3.7	0.4	4.1
2036	21.4	2.4	23.8	3.4	0.4	3.8
2037	19.8	2.3	22.0	3.1	0.4	3.5
2038	18.3	2.2	20.4	2.9	0.3	3.3
2039	17.1	2.1	19.1	2.7	0.3	3.0
2040	15.9	2.0	17.9	2.5	0.3	2.8
2041	16.1	1.8	17.9	2.6	0.3	2.8
2042	16.6	1.7	18.3	2.6	0.3	2.9
2043	16.3	1.6	18.0	2.6	0.3	2.9
2044	16.0	1.5	17.5	2.6	0.2	2.8
2045	15.6	1.2	16.8	2.5	0.2	2.7
2046	15.0	1.2	16.1	2.4	0.2	2.6
Cum Oil (MB / Mm³)	504.5	45.5	550.0	80.2	7.2	87.4

Table 6.6-7: Hebron Ben Nevis Production and Injection Forecast

Year	Oil Production		Gas Production		Water Production		Water Injection		Gas Injection	
	[Kb/d]	[Km ³ /d]	[Mcf/d]	[MSm ³ /d]	[Kb/d]	[Km ³ /d]	[Kb/d]	[Km ³ /d]	[Mcf/d]	[MSm ³ /d]
2016	0.5	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2017	36.6	5.8	9.9	0.3	0.7	0.1	7.1	1.1	3.8	0.1
2018	84.9	13.5	23.1	0.7	6.7	1.1	106.8	17.0	10.3	0.3
2019	121.5	19.3	33.2	0.9	24.8	3.9	163.1	25.9	14.1	0.4
2020	126.9	20.2	40.5	1.1	63.6	10.1	195.2	31.0	18.1	0.5
2021	134.0	21.3	57.8	1.6	108.8	17.3	256.8	40.8	31.2	0.9
2022	129.9	20.7	69.0	2.0	156.4	24.9	302.1	48.0	42.4	1.2
2023	113.2	18.0	77.7	2.2	175.2	27.9	293.4	46.7	55.3	1.6
2024	86.4	13.7	74.8	2.1	186.3	29.6	290.8	46.2	61.5	1.7
2025	71.1	11.3	73.6	2.1	197.0	31.3	274.5	43.6	67.0	1.9
2026	60.4	9.6	68.8	2.0	209.5	33.3	278.0	44.2	58.8	1.7
2027	53.3	8.5	72.8	2.1	217.1	34.5	282.3	44.9	61.6	1.7
2028	47.0	7.5	73.8	2.1	219.9	35.0	281.3	44.7	60.5	1.7
2029	42.3	6.7	75.7	2.1	230.9	36.7	290.6	46.2	61.5	1.7
2030	38.6	6.1	75.3	2.1	234.9	37.3	292.6	46.5	59.8	1.7
2031	35.3	5.6	76.6	2.2	238.9	38.0	293.6	46.7	60.3	1.7
2032	32.4	5.2	75.5	2.1	241.4	38.4	293.0	46.6	58.4	1.7
2033	29.9	4.8	74.4	2.1	244.1	38.8	292.3	46.5	56.9	1.6
2034	27.8	4.4	73.3	2.1	246.6	39.2	291.8	46.4	55.4	1.6
2035	25.7	4.1	66.7	1.9	250.0	39.7	292.0	46.4	48.0	1.4
2036	23.8	3.8	57.2	1.6	252.8	40.2	293.5	46.7	37.8	1.1
2037	22.0	3.5	50.1	1.4	254.8	40.5	293.4	46.6	30.1	0.9
2038	20.4	3.3	49.5	1.4	255.1	40.6	293.3	46.6	29.1	0.8
2039	19.1	3.0	49.6	1.4	255.3	40.6	293.3	46.6	28.8	0.8
2040	17.9	2.8	40.1	1.1	254.3	40.4	293.3	46.6	19.0	0.5
2041	17.9	2.8	21.2	0.6	255.9	40.7	293.3	46.6	0.1	0.0
2042	18.3	2.9	12.5	0.4	256.2	40.7	293.4	46.7	0.0	0.0
2043	18.0	2.9	10.9	0.3	256.8	40.8	293.5	46.7	0.0	0.0
2044	17.5	2.8	9.7	0.3	256.2	40.7	293.0	46.6	0.0	0.0
2045	16.8	2.7	8.7	0.2	253.2	40.3	292.1	46.4	0.0	0.0
2046	16.1	2.6	7.9	0.2	254.7	40.5	292.2	46.5	0.0	0.0
Cum Volumes	550.0	87.4	551.5	15.6	2212.7	351.8	2922.6	464.7	376.2	10.7

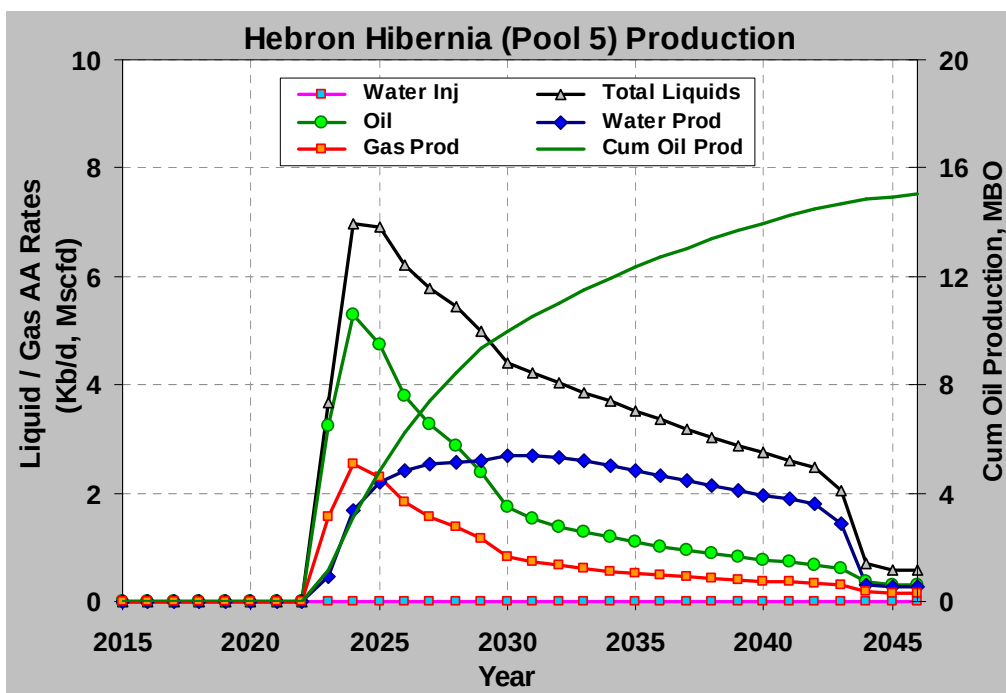


Figure 6.6-9: Hebron Hibernia Production and Injection Forecast

Table 6.6-8: Hebron Hibernia Production Forecast

Year	Oil Production		Gas Production		Water Production	
	[Kb/d]	[Km ³ /d]	[Mcf/d]	[MSm ³ /d]	[Kb/d]	[Km ³ /d]
2016	0.0	0.0	0.0	0.0	0.0	0.0
2017	0.0	0.0	0.0	0.0	0.0	0.0
2018	0.0	0.0	0.0	0.0	0.0	0.0
2019	0.0	0.0	0.0	0.0	0.0	0.0
2020	0.0	0.0	0.0	0.0	0.0	0.0
2021	0.0	0.0	0.0	0.0	0.0	0.0
2022	0.0	0.0	0.0	0.0	0.0	0.0
2023	3.2	0.5	1.6	0.0	0.4	0.1
2024	5.3	0.8	2.6	0.1	1.7	0.3
2025	4.7	0.8	2.3	0.1	2.2	0.3
2026	3.8	0.6	1.8	0.1	2.4	0.4
2027	3.3	0.5	1.6	0.0	2.5	0.4
2028	2.9	0.5	1.4	0.0	2.6	0.4
2029	2.4	0.4	1.2	0.0	2.6	0.4
2030	1.7	0.3	0.8	0.0	2.7	0.4
2031	1.5	0.2	0.7	0.0	2.7	0.4
2032	1.4	0.2	0.7	0.0	2.6	0.4
2033	1.3	0.2	0.6	0.0	2.6	0.4
2034	1.2	0.2	0.6	0.0	2.5	0.4
2035	1.1	0.2	0.5	0.0	2.4	0.4
2036	1.0	0.2	0.5	0.0	2.3	0.4
2037	0.9	0.2	0.5	0.0	2.2	0.4
2038	0.9	0.1	0.4	0.0	2.1	0.3
2039	0.8	0.1	0.4	0.0	2.1	0.3
2040	0.8	0.1	0.4	0.0	2.0	0.3
2041	0.7	0.1	0.4	0.0	1.9	0.3
2042	0.7	0.1	0.3	0.0	1.8	0.3
2043	0.6	0.1	0.3	0.0	1.4	0.2
2044	0.4	0.1	0.2	0.0	0.3	0.1
2045	0.3	0.0	0.2	0.0	0.3	0.0
2046	0.3	0.0	0.2	0.0	0.3	0.0
Cum Volumes	15.1	2.4	7.3	0.2	17.1	2.7

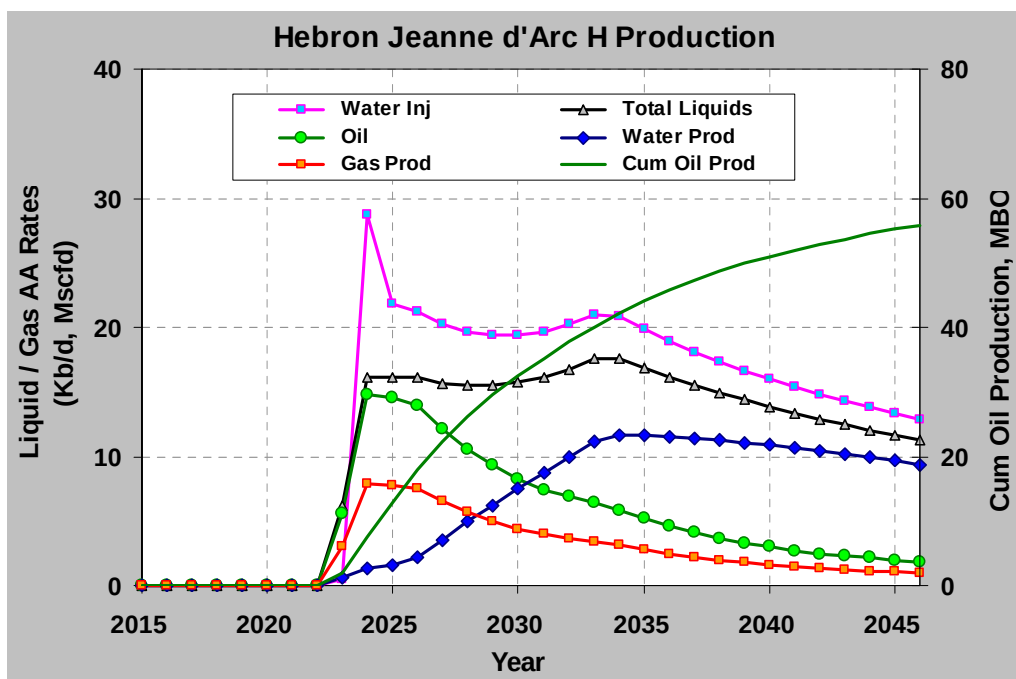


Figure 6.6-10: Hebron Jeanne d'Arc H Sand Production and Injection Forecast

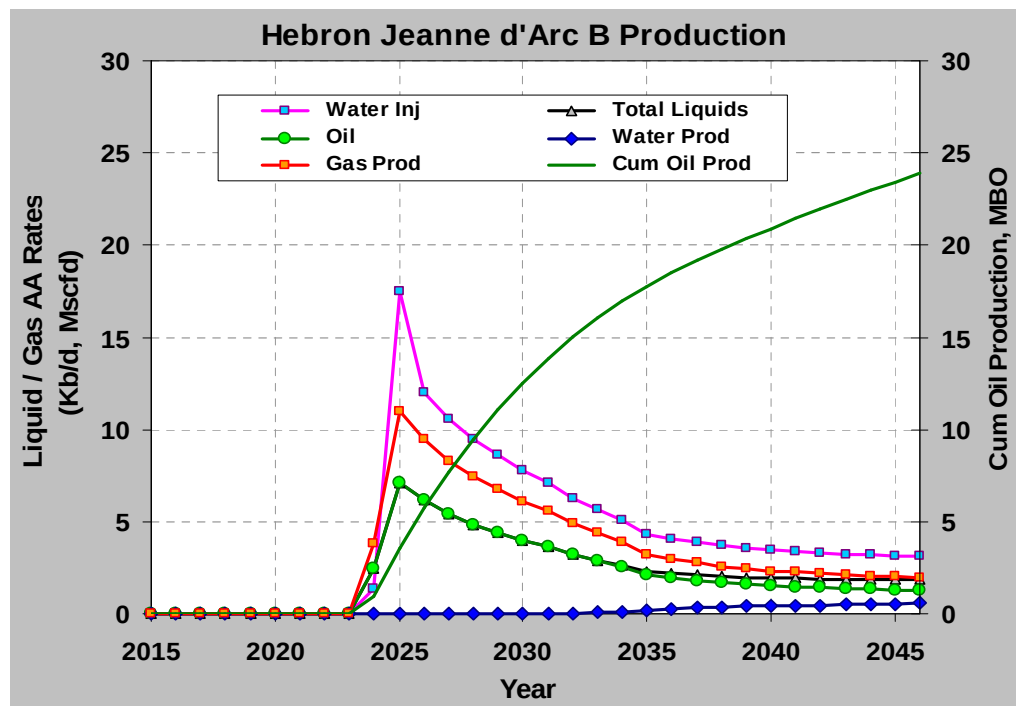


Figure 6.6-11: Hebron Jeanne d'Arc B Sand Production and Injection Forecast

Table 6.6-9: Hebron Jeanne d'Arc H Sand Production and Injection Forecast

Year	Oil Production		Gas Production		Water Production		Water Injection	
	[Kb/d]	[Km ³ /d]	[Mcf/d]	[MSm ³ /d]	[Kb/d]	[Km ³ /d]	[Kb/d]	[Km ³ /d]
2016	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2017	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2018	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2019	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2020	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2021	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2022	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2023	5.6	0.9	3.0	0.1	0.6	0.1	0.4	0.1
2024	14.8	2.3	7.9	0.2	1.4	0.2	28.8	4.6
2025	14.6	2.3	7.8	0.2	1.6	0.2	21.8	3.5
2026	13.9	2.2	7.5	0.2	2.2	0.3	21.2	3.4
2027	12.1	1.9	6.5	0.2	3.5	0.6	20.3	3.2
2028	10.5	1.7	5.6	0.2	4.9	0.8	19.7	3.1
2029	9.3	1.5	5.0	0.1	6.2	1.0	19.4	3.1
2030	8.2	1.3	4.4	0.1	7.5	1.2	19.4	3.1
2031	7.4	1.2	4.0	0.1	8.7	1.4	19.7	3.1
2032	6.9	1.1	3.7	0.1	9.9	1.6	20.2	3.2
2033	6.4	1.0	3.4	0.1	11.1	1.8	20.9	3.3
2034	5.9	0.9	3.1	0.1	11.7	1.9	20.8	3.3
2035	5.2	0.8	2.8	0.1	11.6	1.9	19.8	3.2
2036	4.6	0.7	2.5	0.1	11.6	1.8	18.9	3.0
2037	4.1	0.7	2.2	0.1	11.4	1.8	18.1	2.9
2038	3.7	0.6	2.0	0.1	11.3	1.8	17.3	2.8
2039	3.3	0.5	1.8	0.0	11.1	1.8	16.6	2.6
2040	3.0	0.5	1.6	0.0	10.9	1.7	16.0	2.5
2041	2.7	0.4	1.5	0.0	10.7	1.7	15.4	2.4
2042	2.5	0.4	1.3	0.0	10.4	1.7	14.8	2.4
2043	2.3	0.4	1.2	0.0	10.2	1.6	14.3	2.3
2044	2.1	0.3	1.1	0.0	9.9	1.6	13.8	2.2
2045	2.0	0.3	1.1	0.0	9.7	1.5	13.3	2.1
2046	1.8	0.3	1.0	0.0	9.4	1.5	12.8	2.0
Cum Volumes	55.8	8.9	29.9	0.8	72.1	11.5	154.8	24.6

Table 6.6-10: Hebron Jeanne d'Arc B Sand Production and Injection Forecast

Year	Oil Production		Gas Production		Water Production		Water Injection	
	[Kb/d]	[Km ³ /d]	[Mcf/d]	[MSm ³ /d]	[Kb/d]	[Km ³ /d]	[Kb/d]	[Km ³ /d]
2016	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2017	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2018	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2019	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2020	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2021	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2022	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2024	2.5	0.4	3.8	0.1	0.0	0.0	1.3	0.2
2025	7.1	1.1	11.0	0.3	0.0	0.0	17.5	2.8
2026	6.1	1.0	9.4	0.3	0.0	0.0	12.0	1.9
2027	5.4	0.9	8.3	0.2	0.0	0.0	10.5	1.7
2028	4.8	0.8	7.4	0.2	0.0	0.0	9.5	1.5
2029	4.4	0.7	6.7	0.2	0.0	0.0	8.6	1.4
2030	4.0	0.6	6.1	0.2	0.0	0.0	7.8	1.2
2031	3.6	0.6	5.6	0.2	0.0	0.0	7.1	1.1
2032	3.2	0.5	4.9	0.1	0.0	0.0	6.3	1.0
2033	2.9	0.5	4.4	0.1	0.1	0.0	5.6	0.9
2034	2.5	0.4	3.9	0.1	0.1	0.0	5.0	0.8
2035	2.1	0.3	3.2	0.1	0.2	0.0	4.3	0.7
2036	1.9	0.3	3.0	0.1	0.2	0.0	4.1	0.6
2037	1.8	0.3	2.8	0.1	0.3	0.0	3.9	0.6
2038	1.7	0.3	2.6	0.1	0.3	0.1	3.7	0.6
2039	1.6	0.3	2.4	0.1	0.4	0.1	3.5	0.6
2040	1.5	0.2	2.3	0.1	0.4	0.1	3.4	0.5
2041	1.5	0.2	2.2	0.1	0.4	0.1	3.4	0.5
2042	1.4	0.2	2.2	0.1	0.5	0.1	3.3	0.5
2043	1.4	0.2	2.1	0.1	0.5	0.1	3.2	0.5
2044	1.3	0.2	2.0	0.1	0.5	0.1	3.2	0.5
2045	1.3	0.2	2.0	0.1	0.5	0.1	3.1	0.5
2046	1.3	0.2	1.9	0.1	0.6	0.1	3.1	0.5
Cum Volumes	23.9	3.8	36.6	1.0	1.8	0.3	48.7	7.8

6.6.4 Upside and Downside Production Profiles – Initial Development Phase

The combined recovery range estimates for the resources included in the initial development phase of the project are presented below. It should be noted that these estimates for the Hebron Field were developed by aggregating the deterministic upside and downside simulation models of Pools 1, 4 & 5 of the Hebron Field (subject to overall facility design capacities) and should not be confused with the probabilistic assessment presented in Table 5.6-2.

For the Ben Nevis field, upside and downside estimates are based on the probabilistic assessment presented in Table 5.5-2. Deterministic upside and downside models have not yet been completed for the Ben Nevis Field. The upside and downside profiles presented for the Ben Nevis Field have been scaled in proportion to the best estimate profiles.

Figures 6.6-12 and 6.6-13 provide a graphical comparison of the cumulative oil production over time for the upside, best estimate and downside scenarios for the Hebron and Ben Nevis Fields respectively. The annual oil production rates for the Hebron Field are tabulated in Tables 6.6-11 while Tables 6.6-12 and 6.6-13 present the detailed production forecasts for the upside and downside scenarios respectively. Corresponding tables for the Ben Nevis Field are presented in Tables 6.6-14 to 6.6-16.

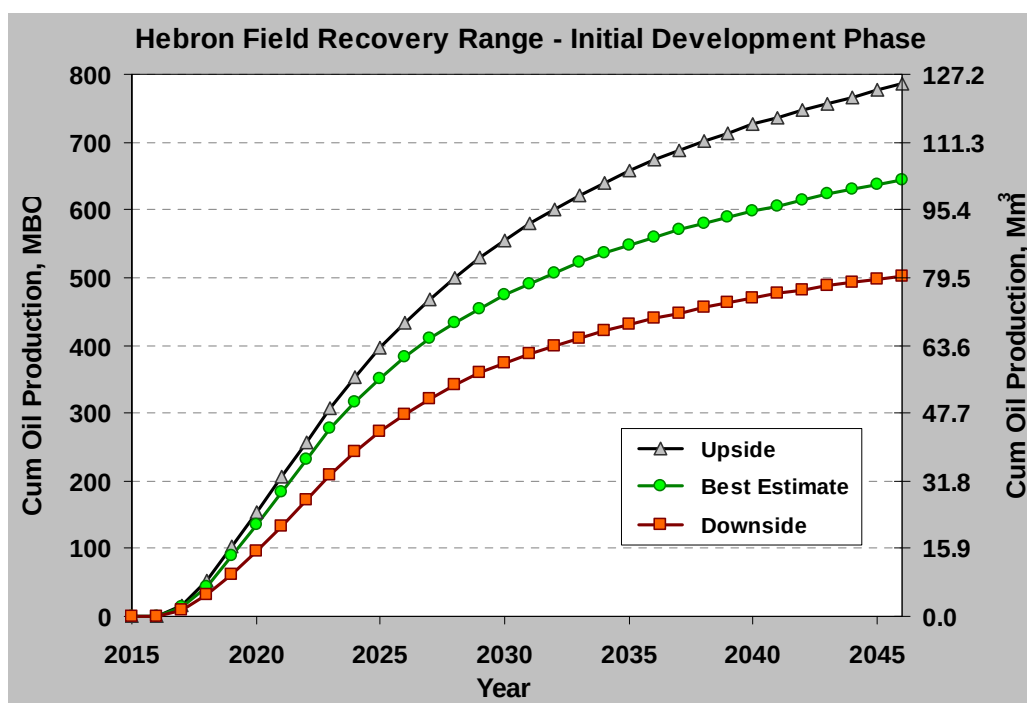


Figure 6.6-12: Hebron Field Initial Development Phase Recovery Range - Cumulative Oil Production Forecast

Table 6.6-11: Hebron Field Initial Development Phase Recovery Range - Oil Rates Forecast

Year	Oil Rates (Kb/d)			Oil Rates (Km ³ /d)		
	Downside	Best Estimate	Upside	Downside	Best Estimate	Upside
2016	0.3	0.5	0.5	0.1	0.1	0.1
2017	25.0	36.6	42.9	4.0	5.8	6.8
2018	59.7	84.9	100.6	9.5	13.5	16.0
2019	85.0	121.5	139.4	13.5	19.3	22.2
2020	93.5	126.9	138.9	14.9	20.2	22.1
2021	103.0	134.0	142.4	16.4	21.3	22.6
2022	103.1	129.9	140.6	16.4	20.7	22.4
2023	100.5	122.1	137.0	16.0	19.4	21.8
2024	92.8	109.0	124.1	14.8	17.3	19.7
2025	82.6	97.5	117.5	13.1	15.5	18.7
2026	72.0	84.2	104.8	11.4	13.4	16.7
2027	63.5	74.1	94.3	10.1	11.8	15.0
2028	55.2	65.3	86.1	8.8	10.4	13.7
2029	47.4	58.4	79.7	7.5	9.3	12.7
2030	41.2	52.6	72.2	6.6	8.4	11.5
2031	36.7	47.9	65.4	5.8	7.6	10.4
2032	33.2	43.9	60.2	5.3	7.0	9.6
2033	30.4	40.5	55.1	4.8	6.4	8.8
2034	28.0	37.4	50.7	4.4	5.9	8.1
2035	26.0	34.1	46.7	4.1	5.4	7.4
2036	24.2	31.3	43.1	3.8	5.0	6.9
2037	22.7	28.9	40.0	3.6	4.6	6.4
2038	21.3	26.7	37.4	3.4	4.2	5.9
2039	20.0	24.8	34.7	3.2	4.0	5.5
2040	18.6	23.2	32.4	3.0	3.7	5.2
2041	17.2	22.8	30.3	2.7	3.6	4.8
2042	16.1	22.9	28.6	2.6	3.6	4.6
2043	15.4	22.2	27.1	2.4	3.5	4.3
2044	14.6	21.4	25.8	2.3	3.4	4.1
2045	13.9	20.4	26.0	2.2	3.2	4.1
2046	13.4	19.5	26.1	2.1	3.1	4.1
Cum Oil (MB / Mm³)	502.8	644.8	785.5	79.9	102.5	124.9

Table 6.6-12: Hebron Field Upside Production and Injection Forecast (Initial Development Phase)

Year	Oil Production		Gas Production		Water Production		Water Injection	
	[Kb/d]	[Km ³ /d]	[Mcf/d]	[MSm ³ /d]	[Kb/d]	[Km ³ /d]	[Kb/d]	[Km ³ /d]
2016	0.5	0.1	0.1	0.0	0.0	0.0	0.0	0.0
2017	42.9	6.8	11.6	0.3	0.6	0.1	7.1	1.1
2018	100.6	16.0	27.1	0.8	9.2	1.5	106.8	17.0
2019	139.4	22.2	38.3	1.1	28.5	4.5	208.9	33.2
2020	138.9	22.1	48.1	1.4	71.3	11.3	215.8	34.3
2021	142.4	22.6	70.4	2.0	116.9	18.6	275.9	43.9
2022	140.6	22.4	84.2	2.4	155.4	24.7	312.7	49.7
2023	137.0	21.8	92.1	2.6	161.3	25.6	291.9	46.4
2024	124.1	19.7	96.2	2.7	174.2	27.7	308.3	49.0
2025	117.5	18.7	104.5	3.0	180.8	28.7	287.5	45.7
2026	104.8	16.7	92.6	2.6	191.6	30.5	284.6	45.2
2027	94.3	15.0	91.3	2.6	201.4	32.0	296.7	47.2
2028	86.1	13.7	93.2	2.6	206.3	32.8	299.9	47.7
2029	79.7	12.7	94.5	2.7	216.3	34.4	313.1	49.8
2030	72.2	11.5	91.7	2.6	225.7	35.9	323.1	51.4
2031	65.4	10.4	90.0	2.5	232.8	37.0	331.6	52.7
2032	60.2	9.6	88.2	2.5	235.6	37.5	336.4	53.5
2033	55.1	8.8	85.8	2.4	241.5	38.4	340.7	54.2
2034	50.7	8.1	87.9	2.5	247.6	39.4	343.3	54.6
2035	46.7	7.4	91.5	2.6	251.5	40.0	343.5	54.6
2036	43.1	6.9	90.3	2.6	255.0	40.5	335.1	53.3
2037	40.0	6.4	89.2	2.5	258.3	41.1	332.7	52.9
2038	37.4	5.9	89.5	2.5	260.9	41.5	332.2	52.8
2039	34.7	5.5	78.9	2.2	263.6	41.9	331.4	52.7
2040	32.4	5.2	68.4	1.9	264.4	42.0	326.8	52.0
2041	30.3	4.8	62.0	1.8	266.4	42.4	326.7	51.9
2042	28.6	4.6	58.3	1.7	268.9	42.7	327.8	52.1
2043	27.1	4.3	47.2	1.3	268.9	42.7	325.5	51.8
2044	25.8	4.1	43.0	1.2	268.9	42.7	324.0	51.5
2045	26.0	4.1	23.5	0.7	268.8	42.7	322.5	51.3
2046	26.1	4.1	21.6	0.6	268.9	42.7	322.6	51.3
Cum Volumes	785.5	124.9	785.8	22.3	2214.0	352.0	3227.0	513.0

Table 6.6-13: Hebron Field Downside Production and Injection Forecast (Initial Development Phase)

Year	Oil Production		Gas Production		Water Production		Water Injection	
	[Kb/d]	[Km ³ /d]	[Mcf/d]	[MSm ³ /d]	[Kb/d]	[Km ³ /d]	[Kb/d]	[Km ³ /d]
2016	0.3	0.1	0.1	0.0	0.0	0.0	0.0	0.0
2017	25.0	4.0	7.1	0.2	0.6	0.1	6.5	1.0
2018	59.7	9.5	17.1	0.5	4.8	0.8	86.5	13.8
2019	85.0	13.5	23.4	0.7	15.2	2.4	98.8	15.7
2020	93.5	14.9	28.2	0.8	34.5	5.5	130.9	20.8
2021	103.0	16.4	33.1	0.9	65.7	10.4	178.4	28.4
2022	103.1	16.4	32.5	0.9	102.1	16.2	215.1	34.2
2023	100.5	16.0	33.5	0.9	137.1	21.8	239.7	38.1
2024	92.8	14.8	35.3	1.0	167.5	26.6	272.9	43.4
2025	82.6	13.1	36.0	1.0	191.9	30.5	287.9	45.8
2026	72.0	11.4	33.4	0.9	213.2	33.9	299.9	47.7
2027	63.5	10.1	32.3	0.9	230.5	36.6	311.3	49.5
2028	55.2	8.8	29.4	0.8	243.1	38.6	314.3	50.0
2029	47.4	7.5	24.3	0.7	250.9	39.9	311.9	49.6
2030	41.2	6.6	19.5	0.6	257.1	40.9	309.5	49.2
2031	36.7	5.8	16.3	0.5	261.6	41.6	307.6	48.9
2032	33.2	5.3	14.1	0.4	265.1	42.1	305.7	48.6
2033	30.4	4.8	12.5	0.4	267.9	42.6	305.5	48.6
2034	28.0	4.4	11.3	0.3	268.8	42.7	304.7	48.4
2035	26.0	4.1	10.4	0.3	268.9	42.7	303.2	48.2
2036	24.2	3.8	9.6	0.3	268.8	42.7	303.4	48.2
2037	22.7	3.6	8.9	0.3	268.8	42.7	302.0	48.0
2038	21.3	3.4	8.1	0.2	268.8	42.7	302.2	48.0
2039	20.0	3.2	7.1	0.2	268.8	42.7	300.0	47.7
2040	18.6	3.0	6.1	0.2	268.9	42.7	298.6	47.5
2041	17.2	2.7	5.1	0.1	268.9	42.7	295.6	47.0
2042	16.1	2.6	4.7	0.1	268.8	42.7	292.3	46.5
2043	15.4	2.4	4.5	0.1	267.9	42.6	292.8	46.5
2044	14.6	2.3	4.2	0.1	268.9	42.7	292.1	46.4
2045	13.9	2.2	4.1	0.1	268.9	42.7	292.1	46.4
2046	13.4	2.1	3.9	0.1	268.9	42.7	293.0	46.6
Cum Volumes	502.8	79.9	188.5	5.3	2265.6	360.2	2868.9	456.1

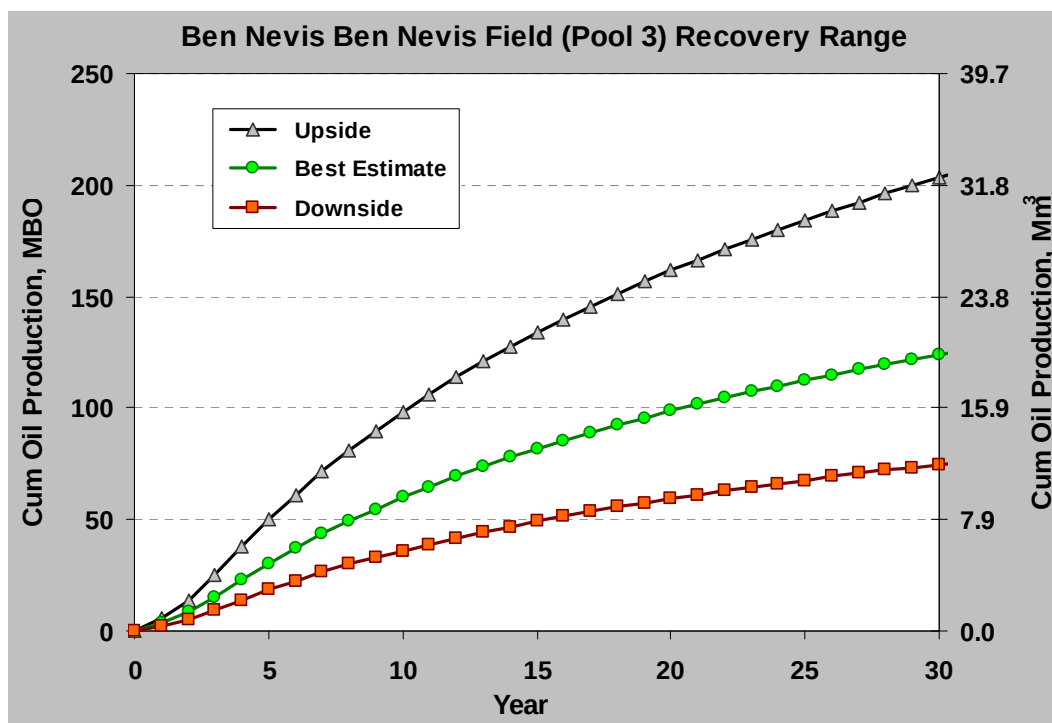


Figure 6.6-13: Ben Nevis Field Recovery Range - Cumulative Oil Production Forecast

Table 6.6-14: Ben Nevis Field Recovery Range - Oil Rates Forecast

Year	Oil Rates (Kb/d)			Oil Rates (Km ³ /d)		
	Downside	Best Estimate	Upside	Downside	Best Estimate	Upside
1	5.6	9.3	15.1	0.9	1.5	2.4
2	8.2	13.5	22.3	1.3	2.2	3.5
3	11.3	18.7	30.7	1.8	3.0	4.9
4	13.1	21.7	35.7	2.1	3.4	5.7
5	12.2	20.2	33.1	1.9	3.2	5.3
6	11.2	18.6	30.5	1.8	3.0	4.9
7	10.3	17.1	28.0	1.6	2.7	4.5
8	9.6	15.9	26.1	1.5	2.5	4.1
9	9.0	14.9	24.4	1.4	2.4	3.9
10	8.4	14.0	23.0	1.3	2.2	3.7
11	8.0	13.3	21.7	1.3	2.1	3.5
12	7.6	12.5	20.5	1.2	2.0	3.3
13	7.1	11.9	19.4	1.1	1.9	3.1
14	6.8	11.3	18.4	1.1	1.8	2.9
15	6.4	10.7	17.5	1.0	1.7	2.8
16	6.1	10.2	16.6	1.0	1.6	2.6
17	5.8	9.7	15.8	0.9	1.5	2.5
18	5.6	9.2	15.1	0.9	1.5	2.4
19	5.3	8.8	14.4	0.8	1.4	2.3
20	5.1	8.4	13.8	0.8	1.3	2.2
21	4.9	8.1	13.3	0.8	1.3	2.1
22	4.7	7.8	12.8	0.7	1.2	2.0
23	4.5	7.5	12.3	0.7	1.2	2.0
24	4.4	7.3	11.9	0.7	1.2	1.9
25	4.2	7.0	11.5	0.7	1.1	1.8
26	4.1	6.8	11.1	0.6	1.1	1.8
27	4.0	6.6	10.8	0.6	1.0	1.7
28	3.9	6.4	10.5	0.6	1.0	1.7
29	3.7	6.2	10.2	0.6	1.0	1.6
30	3.6	6.0	9.9	0.6	1.0	1.6
Cum Oil (MB / Mm³)	74.7	124.0	203.3	11.9	19.7	32.3

Table 6.6-15: Ben Nevis Field Upside Production and Injection Forecast

Year	Oil Production		Gas Production		Water Production		Water Injection	
	[Kb/d]	[Km ³ /d]	[Mcf/d]	[MSm ³ /d]	[Kb/d]	[Km ³ /d]	[Kb/d]	[Km ³ /d]
1	15.1	2.4	8.0	0.2	0.3	0.0	15.2	2.4
2	22.3	3.5	11.8	0.3	0.9	0.1	20.9	3.3
3	30.7	4.9	17.1	0.5	1.6	0.2	29.4	4.7
4	35.7	5.7	21.4	0.6	2.6	0.4	35.2	5.6
5	33.1	5.3	22.0	0.6	3.6	0.6	34.0	5.4
6	30.5	4.9	23.0	0.7	4.6	0.7	32.9	5.2
7	28.0	4.5	24.1	0.7	5.9	0.9	32.3	5.1
8	26.1	4.1	24.9	0.7	7.1	1.1	32.0	5.1
9	24.4	3.9	25.7	0.7	8.3	1.3	32.0	5.1
10	23.0	3.7	26.4	0.7	9.4	1.5	32.1	5.1
11	21.7	3.5	27.2	0.8	10.5	1.7	32.3	5.1
12	20.5	3.3	28.1	0.8	11.5	1.8	32.5	5.2
13	19.4	3.1	29.1	0.8	12.5	2.0	32.7	5.2
14	18.4	2.9	30.0	0.9	13.4	2.1	32.9	5.2
15	17.5	2.8	30.7	0.9	14.2	2.3	33.1	5.3
16	16.6	2.6	31.2	0.9	15.0	2.4	33.3	5.3
17	15.8	2.5	31.5	0.9	15.8	2.5	33.5	5.3
18	15.1	2.4	31.9	0.9	16.6	2.6	33.8	5.4
19	14.4	2.3	32.3	0.9	17.3	2.7	34.1	5.4
20	13.8	2.2	32.9	0.9	18.0	2.9	34.4	5.5
21	13.3	2.1	33.6	1.0	18.7	3.0	34.8	5.5
22	12.8	2.0	34.2	1.0	19.4	3.1	35.2	5.6
23	12.3	2.0	34.9	1.0	20.1	3.2	35.6	5.7
24	11.9	1.9	35.5	1.0	20.7	3.3	36.0	5.7
25	11.5	1.8	35.9	1.0	21.3	3.4	36.3	5.8
26	11.1	1.8	36.5	1.0	21.8	3.5	36.6	5.8
27	10.8	1.7	37.1	1.1	22.4	3.6	37.0	5.9
28	10.5	1.7	37.7	1.1	22.9	3.6	37.4	5.9
29	10.2	1.6	38.3	1.1	23.5	3.7	37.8	6.0
30	9.9	1.6	38.9	1.1	24.0	3.8	38.2	6.1
Cum Volumes	203.3	32.3	318.5	9.0	147.5	23.4	362.8	57.7

Table 6.6-16: Ben Nevis Field Downside Production and Injection Forecast

Year	Oil Production		Gas Production		Water Production		Water Injection	
	[Kb/d]	[Km ³ /d]	[Mcf/d]	[MSm ³ /d]	[Kb/d]	[Km ³ /d]	[Kb/d]	[Km ³ /d]
1	5.6	0.9	2.9	0.1	0.1	0.0	5.6	0.9
2	8.2	1.3	4.3	0.1	0.3	0.0	7.7	1.2
3	11.3	1.8	6.3	0.2	0.6	0.1	10.8	1.7
4	13.1	2.1	7.8	0.2	1.0	0.2	12.9	2.1
5	12.2	1.9	8.1	0.2	1.3	0.2	12.5	2.0
6	11.2	1.8	8.4	0.2	1.7	0.3	12.1	1.9
7	10.3	1.6	8.8	0.3	2.2	0.3	11.9	1.9
8	9.6	1.5	9.1	0.3	2.6	0.4	11.8	1.9
9	9.0	1.4	9.4	0.3	3.0	0.5	11.7	1.9
10	8.4	1.3	9.7	0.3	3.5	0.5	11.8	1.9
11	8.0	1.3	10.0	0.3	3.8	0.6	11.9	1.9
12	7.6	1.2	10.3	0.3	4.2	0.7	11.9	1.9
13	7.1	1.1	10.7	0.3	4.6	0.7	12.0	1.9
14	6.8	1.1	11.0	0.3	4.9	0.8	12.1	1.9
15	6.4	1.0	11.3	0.3	5.2	0.8	12.1	1.9
16	6.1	1.0	11.5	0.3	5.5	0.9	12.2	1.9
17	5.8	0.9	11.6	0.3	5.8	0.9	12.3	2.0
18	5.6	0.9	11.7	0.3	6.1	1.0	12.4	2.0
19	5.3	0.8	11.8	0.3	6.3	1.0	12.5	2.0
20	5.1	0.8	12.0	0.3	6.6	1.0	12.6	2.0
21	4.9	0.8	12.3	0.3	6.9	1.1	12.8	2.0
22	4.7	0.7	12.5	0.4	7.1	1.1	12.9	2.1
23	4.5	0.7	12.8	0.4	7.3	1.2	13.0	2.1
24	4.4	0.7	13.0	0.4	7.6	1.2	13.2	2.1
25	4.2	0.7	13.2	0.4	7.8	1.2	13.3	2.1
26	4.1	0.6	13.4	0.4	8.0	1.3	13.4	2.1
27	4.0	0.6	13.6	0.4	8.2	1.3	13.6	2.2
28	3.9	0.6	13.8	0.4	8.4	1.3	13.7	2.2
29	3.7	0.6	14.0	0.4	8.6	1.4	13.9	2.2
30	3.6	0.6	14.2	0.4	8.8	1.4	14.0	2.2
Cum Volumes	74.7	11.9	116.8	3.3	54.0	8.6	133.1	21.2

6.7 Reservoir Management

6.7.1 Introduction and Objective of Reservoir Management

The overriding reservoir management objective for the Hebron Asset development is to maximize the economic value of recoverable hydrocarbons. The reservoir management plan will focus on the key reservoir management assumptions, knowledge, and learnings included in the depletion plan; assessment of data collected during surveillance activities; and how the aforementioned knowledge, learnings and data will be utilized. The plan will be implemented by an integrated team of engineers, geoscientists, and production operations staff. The team's expertise, alignment, and overall understanding of the reservoir management process are key factors for the successful implementation of the reservoir management plan.

Some characteristics of an effective reservoir management plan are as follows:

1. **Flexibility:** The reservoir management plan needs to be flexible to account for uncertainties
2. **Priority Alignment:** The multidisciplinary team responsible for this development will need to agree on the priority of various activities related to the reservoir management plan
3. **Communication:** Several disciplines will be involved in managing the production operations. The purpose and objectives of the reservoir management plan, along with the key roles and responsibilities of the different disciplines should be communicated effectively across the multifunctional team whose job it is to implement it.

6.7.2 Reservoir Management Considerations

Section 6.7.2 provides a brief description of a high-level reservoir management strategy for the Hebron Asset development.

6.7.2.1 Near-Term Considerations

Key objectives / strategies during the production ramp-up / early operations period include the following:

1. **Achieving Rapid Oil Rate Build-Up:** Reflects the need to maximize oil production during the period following first oil and will be addressed via the development drilling strategy that provides a balance between maximizing production and acquiring important reservoir and fluid data
2. **Increasing Confidence in Reservoir Characterization:** Continuing to improve the static and dynamic reservoir description (e.g. structural and stratigraphic models, facies distributions, rock and fluid properties, etc.) via data collected during development drilling

3. Ensuring Efficient Utilization of Produced Gas: Encompasses all issues associated with providing gas-lift gas as well as gas consumed in operations. The objective is to utilize associated gas in the most efficient manner to benefit long-term oil recovery and fuel gas availability.

6.7.2.2 Ongoing Considerations Throughout Asset Life

Ongoing reservoir management considerations include the following:

1. Pressure Maintenance and Voidage Balancing: Monitoring water and / or GI rates in specified pools to maintain pressure at optimal levels that will maximize oil recovery
2. Flood Conformance Monitoring: Managing the evolution of water cuts and / or GORs will be key to attaining high recovery of oil
3. Connectivity and Communication: Reservoir connectivity and communication impacts effectiveness of pressure maintenance, reservoir sweep and therefore, ultimate recovery; learnings from the production performance of each reservoir unit could result in upward or downward adjustments to the well count and / or reserves
4. Compartmentalization and Fault Segmentation: Gathering data to ascertain compartmentalization will allow for dynamic adjustments to be made in the depletion plan
5. Identifying Bypassed Oil Potential: Analytical and / or reservoir simulation methods and tools (including incorporating data gathered during asset development and production phases) to assist in identifying unswept or poorly-swept regions of individual reservoirs. Effective use of these tools can potentially lead to opportunities for future exploitation of such regions.
6. Well Slot Management: Optimize slot utilization to derive maximum value from available GBS well slots. Potential activities include slot reclamation, targeting multiple production or injection zones with single wellbores, etc.

6.7.2.3 Wells and Operational Considerations

Ongoing well and facility considerations include the following:

1. Producer Well Performance: Includes attention to achieving and sustaining high completion flow efficiency and maintaining long-term effectiveness of sand control, among other considerations
2. Injector Well Performance: Includes such issues as the stratigraphic distribution of injected fluids, achieving and sustaining high completion flow efficiency, and monitoring the impact of reservoir cooling near the water injection sites

3. Potential for Operational Adjustments: Depending on actual production and injection performance of the planned facilities, potential adjustments to operating practices may need to be evaluated periodically

6.7.3 Reservoir Surveillance

Reservoir surveillance activities will be designed to optimize the asset depletion plan by addressing the reservoir management considerations discussed in Section 6.7.2. The reservoir surveillance plan will be designed with the following objectives in mind:

- ◆ Collect necessary data for optimum asset development, management, and prediction
- ◆ Allow flexibility for changes and learnings
- ◆ Obtain maximum value for associated expenditures

The following data sources are expected to provide essential information for monitoring production performance and for evaluating both global and local-area effectiveness of the planned recovery processes:

1. Permanent downhole pressure gauges in all producing wells, providing frequent data measurements
2. Periodic short-term production tests on each producing well through a test separator to provide key data regarding produced-fluid ratios
3. Periodic fluid samples obtained near the wellhead to monitor water cut, water salinity and produced oil density
4. Production logs as required to help diagnose significant and / or unanticipated changes in well performance or produced-fluid ratios
5. A baseline flow-profile log in each injection well after initial achievement of stable flow rate, with subsequent repeat logs conducted on an as-required basis following major and / or abrupt changes in injection performance
6. Occasional short-term pressure transient tests in water injection wells using wireline or coiled tubing-conveyed pressure gauges, to monitor reservoir pressure and completion flow efficiency

6.7.4 Data Acquisition and Formation Evaluation Program

An important part of the overall reservoir management strategy is the data acquisition and formation evaluation program. A tiered data acquisition scheme may be considered to meet the reservoir management goals of the Hebron Asset. Because various options and the need for certain types of evaluation arise only after wells reach total depth, flexibility must be retained to answer certain questions and address uncertainties that are manifested. Therefore, a data acquisition strategy that consists of the following three tiers

will be utilized with possible modification / adjustment to better fit actual operation and reservoir management requirements:

1. Tier 1 is considered the base case log data acquisition plan that is necessary to drill, correlate, and provide limited evaluation services for the well
2. Tier 2 is a more advanced level that includes additional measurements such as formation fluid sampling
3. Finally, Tier 3 includes all high-end data acquisition services, such as conventional coring, cased-hole logging, etc.

Table 6.7-1 outlines a typical three-tier structure for an asset evaluation program. This three-tiered structure may be revised based on drillwell information during the development drilling campaign.

Table 6.7-1: Typical Three-Tiered Asset Formation Evaluation Plan

Tier Class	Services	Uncertainty/Needs Addressed
1	Logging while drilling (LWD) in-line data acquisition that includes: • Gamma Ray, Rate of Penetration (ROP), Array Resistivity, Formation Density, Thermal Neutron Porosity, Compressional Sonic, Acoustic Caliper • Formation Pressure Tester (MDT) • Nuclear Magnetic Resonance (NMR)	Base data acquisition in order to stratigraphically locate and correlate well against offsets. Provides basic data in order to complete standard petrophysical evaluation of wellbore when drilled. Establish fluid gradients and fluid contacts in well if not directly logged in sands. NMR usually logged in combination with MDT pressure tool; provides bound fluid quantification and thin-bed identification.
	Fluid Samples (MDT)	Fluid compatibility, geochemical evaluation of fluids to establish continuity within reservoir.
	Checkshot and Velocity Survey	Limited number of wells to establish seismic velocity control in key areas of the field.
	Interference Testing	Monitor pressure variations between wells to infer degree of connectivity within reservoir.
3	Conventional Core	Provide stratigraphic and lithofacies calibration to seismic and well logs. Obtain key reservoir properties such as saturation and permeability behaviour.
	Cased-Hole Logging	Useful to production environment; assess production flow profiles, monitor changes in water and gas saturation over time, etc
	Wireline Dipole Sonic	Provides direct measurement of formation shear travel time and helps quantify acoustic anisotropy of formations
	Micro-resistivity / Acoustic Imaging Logs	Provide stratigraphic and facies calibration to core, seismic and standard well logs. Thin-bed identification.

6.8 Contingent Developments

6.8.1 Introduction

Section 6.8.1 provides an overview of the hydrocarbon resources within the Hebron Asset that are not currently included in the scope of the initial Hebron development project. Although these resources have not been included as part of the initial Hebron resource development plan, they were considered in the full asset lifecycle resource development planning and facility processing design during the facility sizing optimization studies for the production systems.

The contingent developments discussed in this section are divided into two categories as follow:

1. Discovered Resources: Resources that have been encountered and confirmed as hydrocarbon accumulations by previous drilling
2. Potential Resources: Hydrocarbon accumulations that may exist but have not yet been confirmed by well penetrations

A variety of depletion mechanisms will be considered and any one or a combination of these may be employed in the development of these resources. Some of these options include waterflood, gasflood, water-alternating-gas injection, gas cap drive, aquifer drive, and natural pressure depletion. Natural depletion, gas cap drive, or aquifer drive mechanisms may be especially applicable to the smaller resources that can not economically support a recovery process involving pressure maintenance. Depletion of such pools below the reservoir saturation pressures may also be undertaken as a way of achieving improved recovery.

The depletion plans for these resources will be matured and updated as additional information is obtained. The potential sources of information include the following:

1. Re-assessment of the resources using reprocessed or newly acquired seismic data
2. Additional well penetrations into these resources
3. Development drilling and production performance data from the initial resource development phase that provide useful analogue information

The preferred depletion mechanism will depend on the reservoir, fault block, geology, fluid properties, and fluid contacts. It should however be noted that the ultimate depletion mechanism selected will be based on maximizing the economic value of all the resources within the Hebron area for the benefit of all the stakeholders. In this regard, the final depletion mechanism selected will be based on considering the following factors among others:

1. Resource size and risk
2. Well slot availability / optimization of available well slots
3. Available facility capacity to process produced fluids and to supply any surplus produced gas at the conditions required for subsurface storage
4. Potential for well recompletions or combined production from (or injection into) multiple reservoir intervals through single wellbores
5. Efficient drilling rig utilization
6. Impact on existing / potential future production
7. The depletion plan mechanisms of other assets
8. Technology advances e.g. advances in drilling technology / capability

Should there be any material changes to the preliminary depletion plans outlined for any of the resources discussed in the subsequent sections, a revised depletion scheme (including details of any associated studies conducted) will be communicated to and discussed with the C-NLOPB.

6.8.2 Discovered Resources

6.8.2.1 Hebron Field: Jeanne d'Arc G Sand Reservoir

Oil has been proven in the Jeanne d'Arc G Sand within the Hebron Horst fault block. Pay was encountered in the G Sand by the Hebron I-13 and M-04 wells. The pressure data in the wells indicated that the pay encountered within the two wells was isolated. A preliminary estimate of STOOIP for this resource ranges from 19 MBO (3 Msm³) to 57 MBO (9 Msm³).

Reservoir thickness and quality are the principal uncertainties. Reservoir continuity also appears to be poor, as demonstrated by the pressure data in the I-13 and M-04 wells. The preliminary depletion plan for this resource is based on plugging back and re-completing the B Sand producer and injector after the B Sand resource has been depleted. On this basis, preliminary estimates of recoverable oil range from 2 MBO (0.3 Msm³) to 11 MBO (2 Msm³).

There is a potential opportunity for an additional well penetration into the G Sand during the development drilling program of the deeper Jeanne d'Arc B Sand. This will be considered during the detailed well planning phase for the B Sand wells. However, due consideration will be given to ensure that the primary targets and objectives of the B wells are not compromised. If additional data is successfully acquired by this means, it will be used in conjunction with any new seismic surveys and reprocessing to update the resource description of the G Sand and an updated depletion plan will be developed as part of this effort.

6.8.2.2 Hebron Field: Jeanne d'Arc D Sand Reservoir

The Hebron I-13 and M-04 wells encountered reservoir pay in the Jeanne d'Arc D Sand and proved an oil accumulation in this stratigraphic unit. STOOIP has been estimated to range from 8 MBO (1 Msm³) to 44 MBO (7 Msm³).

Presently, the most significant uncertainties associated with the D Sand resource are reservoir thickness, quality, and continuity.

Potential development options include recompleting the B Sand wells in this interval, the use of dual-zone producers and / or injectors to target both the D and G Sands (if feasible), or natural pressure depletion. Given the current view on the resource size, the ultimate depletion plan selected will be a balance between resource development risk and technical and commercial viability. Preliminary estimates of recoverable oil range from 0.6 MBO (0.1 Msm³) to 8 MBO (1 Msm³).

These reserve estimates are based on a notional depletion plan of re-completing the B Sand producer and water injector in this reservoir interval.

As with the G Sand, a potential opportunity to acquire additional information from well penetration(s) into the D Sand exists during the drilling operations of the deeper B Sand wells. If such data is successfully acquired, it will be used to develop an updated subsurface description. Potential new technologies that could improve the seismic resolution of the reservoir, or improve the drilling efficiency to the pool, will be also be monitored to assess the impact on the perceived value of this resource.

6.8.2.3 West Ben Nevis Field: Ben Nevis Reservoir (Pool 2)

Oil has been proven in the Ben Nevis reservoir within the West Ben Nevis fault block. Pay was encountered and tested within the West Ben Nevis B-75 well. There is also the potential for the pool to have a small gas cap. The pressure data in the well and seismic attributes suggest the possible presence of an overlying gas cap. If an initial gas cap exists, the oil leg will be fairly thin, sandwiched between the gas-oil contact and the aquifer. STOOIP has been estimated to range from 31 MBO (5 Msm³) to 83 MBO (13 Msm³).

The possibility of a gas cap and the lateral extent of the pool are the largest uncertainties. Reservoir quality is uncertain as well, and continuity may also be poor due to the presence of smaller, intra-fault block faults. The gas in-place (GIP) has been estimated to range from 11 Gcf (0.3 Gsm³) to 60 Gcf (2 Gsm³).

This reservoir is viewed as an alternate gas storage location in the event that additional (or back-up) gas storage capacity is required during the temporary period of surplus gas production from the initial Hebron development.

The leading depletion plan option for developing the oil in the Ben Nevis pool of the West Ben Nevis Field is to drill a horizontal oil producer near the crest and a downdip water injector. Currently, the economic viability of such a development is challenged. With this notional plan, preliminary estimates of recoverable oil range from 1 MBO (0.2 Msm³) to 19 MBO (3 Msm³).

Use of this resource for gas management or potential depletion will continue to be evaluated. The reservoir characterization interpretation will be updated with any re-processed seismic interpretation and/or new well data.

6.8.2.4 West Ben Nevis Field: Avalon Reservoir (Pool 3)

Oil has been proven in the Avalon reservoir within the West Ben Nevis fault block. Pay was encountered and tested within the West Ben Nevis B-75 well. STOOIP has been estimated to range from 13 MBO (2 Msm³) to 208 MBO (33 Msm³).

The large range in STOOIP is primarily due to uncertainty in structure of the top of the reservoir and ambiguous oil-water contact. Reservoir quality and continuity risks exist due to the presence of smaller, intra-fault block faults.

A preliminary view of developing this resource is to drill two wells: a horizontal oil producer near the crest of the structure and a water injector down the flank. With this depletion plan, preliminary estimates of recoverable oil range from 6 MBO (1 Msm³) to 37 MBO (6 Msm³).

The reservoir characterization interpretation will be updated with any re-processed seismic interpretation and / or any new well data.

6.8.2.5 West Ben Nevis Field: Jeanne d'Arc Reservoir

Oil has been proven in the Jeanne d'Arc reservoir within the West Ben Nevis fault block. Pay was encountered and tested within the West Ben Nevis B-75 well. Using a range of input parameters that define the key uncertainties, STOOIP has been estimated to range from 22 MBO (4 Msm³) to 189 MBO (30 Msm³).

The large range in STOOIP is primarily due to significant uncertainty in structure of the top of the reservoir, ambiguous oil-water contact, and reservoir quality and continuity due to the presence of smaller, intra-fault block faults.

The oil recovery from this resource is based on a notional depletion plan of two producers and a flank water injector. A preliminary forecast of recoverable oil ranges from 3 MBO (0.5 Msm³) to 44 MBO (7 Msm³).

The reservoir characterization interpretation will be updated with any re-processed seismic interpretation and/or any new well data.

6.8.2.6 Ben Nevis Field: Avalon Reservoir

Gas was proven in the Avalon reservoir within the Ben Nevis fault block by the I-45 well. There is also the potential that there is an oil leg to the pool that has not been penetrated yet. GIP has been estimated to range from 7 billion cubic feet (Gcf) to 124 Gcf [(0.2 Gsm³) to (3.5 Gsm³)].

The large range in GIP is primarily due to the uncertainty in gas-water contact and reservoir quality and continuity due to the presence of smaller, intra-fault block faults. Preliminary estimates of recoverable gas range from 4 Gcf (0.1 Gsm³) to 85 Gcf (2.4 Gsm³). Based on a drill stem test in the I-45 well, there is the possibility that this reservoir could be a gas-condensate reservoir. This possibility (along with the potential for an oil leg) will be considered in making a development decision for this resource. Preliminary estimates of condensate recovery volumes range from 0.1 MB (0.02 Msm³) to 2 MB (0.3 Msm³).

Currently, there is no existing gas gathering infrastructure in the immediate vicinity of the project area that can be used to market the gas resources available within the Hebron area. Development of gas infrastructure in the basin will be monitored as a potential means of monetizing the gas resources in the asset. Another potential option for utilizing this (and other available) gas resources could be as a supplemental source of gas for Hebron production operations.

6.8.2.7 Ben Nevis Field: Lower Hibernia Reservoir

Gas has been proven in the Lower Hibernia reservoir within the Ben Nevis fault block. Pay was encountered and tested in the Ben Nevis I-45 well. There is also the potential for an oil leg to exist as part of this hydrocarbon accumulation. GIP has been estimated to range from 25 Gcf (0.7 Gsm³) to 148 Gcf (4 Gsm³).

The large range in GIP is primarily due to the uncertainty in gas-water contact and reservoir quality and continuity due to the presence of smaller, intra-fault block faults. Preliminary estimates of recoverable gas range from 7 Gcf (0.2 Gsm³) to 102 Gcf (3 Gsm³).

Hydrocarbon liquids were tested in this interval (Drill Stem Test #1 of the I-45 well). A preliminary estimate of liquids recovery (from the produced gas) range from 0.9 MB (0.1 Msm³) to 13 MB (2 Msm³). It should be noted that there is uncertainty in the liquids yield due to the short duration of the test.

6.8.3 Prospects

6.8.3.1 Hebron Field: Southwest Graben Fault Block, Ben Nevis Reservoir Prospect

This prospect is located in the Ben Nevis Formation of the undrilled fault block between the Hebron Ben Nevis I-13 Fault Block and the Trinity Fault. It has been mapped using the surrounding well control and the 3D seismic data.

6.8.3.1.1 Volume Estimates

STOOIP has been estimated to range from 29 MBO (5 Msm³) to 173 MBO (27 Msm³). The gross rock volume of the trap is the largest uncertainty. The precise top of the reservoir and the oil-water contact are significant unknowns.

The unrisks preliminary estimates of recoverable oil range from 8 MBO (1 Msm³) to 55 MBO (9 Msm³).

6.8.3.1.2 Risk

The primary risk is hydrocarbon presence. It is likely that the Trinity Fault is non-sealing, with the trap for the prospect likely requiring four-way closure caused by roll-over of the structure into the fault. There is also the risk of having adequate reservoir quality within the trap.

6.8.3.1.3 Factors Leading to Future Development

The prospect will be re-evaluated after additional data is acquired by the drilling of development wells in the I-13 fault block, and this data is incorporated into the seismic interpretation. A decision will then be made on drilling a delineation well from the Hebron GBS into the prospect once the risks, oil recovery, and economics have been updated. If the delineation well is drilled and confirms hydrocarbon presence and volumes comparable to the current view of the prospect, this resource could possibly be developed with one producer and pressure-supported by one downdip water injector.

Potential new technologies that could improve the seismic resolution of the reservoir, or improve the drilling efficiency to the prospect, will be monitored to assess the impact on the perceived value of this potential resource.

6.8.3.2 Hebron Field: Jeanne d'Arc H Sand, South Valley Prospect

The South Valley prospect is located at the Jeanne d'Arc H Sand horizon in the Hebron fault block. The prospect is an undrilled seismic amplitude located south of the seismic amplitude that characterizes the Jeanne d'Arc H pool drilled by the M-04 well. It has been mapped using the surrounding well control and the 3D seismic data. In addition to the main South Valley, there is an eastern horst block, which may also contain oil.

6.8.3.2.1 Volume Estimates

The unrisked STOOIP has been estimated to range from 170 MBO (27 Msm³) to 333 MBO (53 Msm³). The gross rock volume of this stratigraphic trap is the largest uncertainty. The gross rock volume uncertainty is driven by the unknown presence and extent of the valley, and the unknown oil-water contact. The net-to-gross ratio and reservoir quality of the sands that fill the valley are also significant unknowns.

The unrisked preliminary estimates of recoverable oil range from 29 MBO (5 Msm³) to 101 MBO (16 Msm³). These preliminary estimates are based on the notional depletion plan of three producers and three water injectors.

6.8.3.2.2 Risk

The primary risk is hydrocarbon presence. There is the risk that the seismic signature may not represent the presence of reservoir. There is also risk of having adequate reservoir quality, and that there is a trap. There is the potential that the prospect is the up-dip extension of the pool discovered, or it may be a separate, isolated pool. If it is a separate pool, the prospect trap could be an up-dip stratigraphic pinchout, or structurally controlled by the faults creating the Hebron Horst.

6.8.3.2.3 Factors Leading to Future Development

The prospect will be re-evaluated after additional data is acquired by the drilling of development wells in the Jeanne d'Arc H Sand north valley and incorporated into the seismic interpretation. Potential new technologies that could improve the seismic resolution of the reservoir, or improve the drilling efficiency to the prospect, will be monitored to assess the impact on the perceived value of this potential resource. A decision will be made on drilling a delineation well into the prospect once the risks, oil recovery, and economics have been updated. If the delineation well confirms the presence of economic quantities of hydrocarbons, an updated development plan for the prospect will be drafted after the results of the delineation well have been evaluated.

6.9 Enhanced Oil Recovery Considerations

6.9.1 Introduction

A preliminary high-level screening of enhanced oil recovery (EOR) methods has been undertaken, with the objectives of framing the overall consideration of EOR possibilities and suggesting focal areas for future technical studies. Some of the noteworthy findings of the screening effort are discussed in the following paragraphs that address each Pool included in the initial Hebron development phase.

6.9.2 Hebron Field, Ben Nevis Reservoir (Pool 1)

For EOR processes involving GI, screening estimates predict that the Pool 1 oil is likely to be miscible with carbon dioxide (CO₂) at a pressure somewhere near original reservoir pressure, but is likely to be immiscible with nitrogen (N₂), separator gas and enriched hydrocarbon gas. The latter three types of gas have forecasted minimum miscibility pressures with Pool 1 oil that are far in excess of original reservoir pressure.

The net thickness and vertical connectivity of Pool 1 are estimated to be favourable for gravity-stable vertical flooding by injected gas, and unfavourable for horizontal flooding. However, the critical velocity for gravity-stable vertical flooding (whether miscible or immiscible) is estimated to be impractically low for any of the gases mentioned above. Also, prospects for a source of supply for any of these gases is believed to present a formidable challenge, including separator gas which will be utilized in large part to fuel platform operations.

Polymer flooding is viewed as a potentially viable recovery process, although average permeability in Pool 1 is believed to be significantly lower than that of the global experience to-date with reservoirs where this process has been successfully applied. In the Hebron environment, the logistics and space requirements of supplying polymer chemicals and mixing an injectable solution to the necessary specifications with quality assurance would present tremendous difficulty.

Surfactant-related chemical flooding may have potential technical merit, but this type of process has not yet been proven commercially viable on a meaningful scale. Surfactant-type flooding would experience the same types of supply and mixing hurdles as those mentioned above for polymer flooding.

Thermal methods are projected to suffer too much heat loss, and are not suggested as focal areas for future studies of EOR opportunities at Hebron.

6.9.3 Hebron Field, Hibernia Reservoir (Pool 5)

For EOR processes involving GI, screening estimates predict that the Pool 5 oil is likely to be miscible with CO₂ and enriched hydrocarbon gas at a pressure near or below original reservoir pressure. Nitrogen and separator

gas have predicted minimum miscibility pressures with Pool 5 oil that are far in excess of original reservoir pressure.

Net thickness could potentially lead to gravity-unstable behaviour during a GI process, but low vertical permeability would help to counteract this risk. Uncertainties in reservoir characterization will need to be narrowed in order to assess the merits of a gas-injection process with greater confidence. Source of supply for any prospective injection gas presents the same challenge as mentioned for Pool 1.

A surfactant chemical flood may have potential technical merit, but faces the same types of commerciality, supply and mixing hurdles as those mentioned for Pool 1. Polymer flooding and thermal EOR methods are not viewed as deserving future consideration, in view of the relatively low viscosity of the oil in Pool 5.

6.9.4 Hebron Field, Jeanne d'Arc Reservoir, H-Sand (Pool 4)

For EOR processes involving GI, screening estimates predict that the Pool 4 H-sand oil is likely to be miscible with carbon dioxide, separator gas and enriched hydrocarbon gas at a pressure near or below original reservoir pressure. Nitrogen has a predicted minimum miscibility pressure with Pool 4 H-sand oil that is far in excess of original reservoir pressure.

Net thickness could potentially lead to gravity-unstable behaviour during a gas injection process, but low vertical permeability would help to counteract this risk. Uncertainties in reservoir characterization will need to be narrowed in order to assess the merits of a gas-injection process with greater confidence. Source of supply for any prospective injection gas presents the same challenge as mentioned for Pools 1 and 5.

Polymer flooding, surfactant-related chemical flooding and thermal methods are not viewed as deserving future consideration, in view of the relatively high temperature and low viscosity of the oil in Pool 4 H-sand.

6.9.5 Hebron Field, Jeanne d'Arc Reservoir, B-Sand (Pool 4)

For EOR processes involving GI, screening estimates predict that the Pool 4 B-sand oil is likely to be miscible with carbon dioxide, separator gas and enriched hydrocarbon gas at a pressure near or below original reservoir pressure. Nitrogen has a predicted minimum miscibility pressure with Pool 4 B-sand oil that significantly exceeds original reservoir pressure.

If the current reservoir characterization is confirmed by development drilling, a GI type of EOR process may have less risk of gravity override than the other Pools discussed above. Source of supply for any prospective injection gas presents the same challenge as mentioned for Pools 1, 5 and 4 (H-sand).

Polymer flooding, surfactant-related chemical flooding and thermal methods are not viewed as deserving future consideration, in view of the relatively high temperature and low viscosity of the oil in Pool 4 B-sand.

7 DRILLING AND COMPLETIONS

7.1 Platform Development Drilling

Drilling operations for the Hebron Field Development will be conducted from a consortium-owned, contractor-operated, new build drilling rig integrated into the main topsides structure. The rig will be designed for continuous operation in the Eastern Canadian Grand Banks environment of offshore Newfoundland and Labrador. The drilling package will consist primarily of two main units, the Drilling Support Module (DSM), and the Derrick Equipment Set (DES). These units will be fully integrated into the Hebron Production Platform and will interface and share common utilities as appropriate. The rig design will allow simultaneous drilling and electricline, slickline, gravel packing, and coiled tubing intervention operations (simultaneous operations [SIMOPS]). Due to the harsh weather environment of the region, the drilling package will be designed to be environmentally independent to the greatest extent possible. Design of the drilling facilities will incorporate experiences and lessons learned from the design, construction, and operation of previously successful projects, and, specifically, drilling projects located in similar harsh weather environments (Ringhorne, Jotun, and Hibernia).

It is currently envisioned that up to 41 wellbores will be necessary to fully exploit the resource base. The Hebron drilling package is currently scheduled to contain 52 slots, which is anticipated to be sufficient to achieve optimal depletion of the reservoir. The discovery and delineation wells (I-13, H-71, B-75, D-94, M-04, L-55, and I-45) in the Hebron Asset have all been plugged and abandoned in accordance to C-NLOPB guidelines. There are no plans to re-enter these wells in the development of the Hebron Asset.

7.1.1 Preliminary Drilling and Completion Plans

The Hebron Field is divided into three pools (Hebron Ben Nevis, Hebron Hibernia, and the Hebron Jeanne D'Arc B and H sands). Excess gas generated from production operations may potentially be stored in the West Ben Nevis field. See Reference Section 6 (Reservoir Exploitation) for detailed resource discussion.

Platform wellbores will have three dimensional trajectories with long horizontal sections requiring extended reach drilling profiles. Consideration of borehole stability and torque and drag issues will be necessary. It is envisioned the completions will be open-hole gravel packs (OHGP) with some wellbores targeted as candidates for cased and perforated designs. The OHGP completions will meet and possibly exceed current technical limits. Further analysis will be required in the areas of torque and drag, and integrated hole quality to fully define the well construction design. Well locations are notional at this stage for purposes of well planning, rig design, and costing purposes. The well bottom-hole locations, the proportions of

production and injection wells, and the resultant trajectories may change as further information becomes available.

7.1.2 Cuttings Re-Injection

Non-aqueous drilling fluids (NAF) are currently envisioned in selected sections of the drilling program. The NAF-based fluid system provides performance improvement in hole stability, increased penetration rates, and reduction of drilling friction.

It is currently envisioned that a dedicated geologic formation will be identified for the disposal of NAF-based drill cuttings as well as specified waste fluids. It is currently proposed that NAF-based cuttings and waste fluids be routed to the Topsides cuttings re-injection (CRI) package located in the DSM. The cuttings/waste streams will be slurrified to an appropriate rheology for injection into the assigned CRI formation. It is anticipated that open annuli of water injection wellbores will provide the injection conduit to the assigned formation, but dedicated injection wellbores also remain an option.

CRI will assist in eliminating the need for overboard discharge of NAF-based drill cuttings. Due to the critical nature of the CRI system, redundancy of all major components (tanks, pumps, shakers) has been included in the system design. This will mitigate the need for costly rig downtime or overboard discharge in the event of system upsets.

Analysis of fracture containment, injectivity rates, and total anticipated injection volumes will be carefully considered in identifying an appropriate geological formation for the injection of cuttings' slurries and waste fluids.

7.1.3 Wellbore Hole and Casing Program

Individual wellbore targets will be assigned specific trajectories taking into account drilling parameters and close approach concerns. In general, Table 7.1-1 provides the early basis for the hole and casing program for well construction activities. Shallow casing setting depths are predicted to remain consistent across pool types (762 mm and 508 mm) while deeper casing setting depths will vary depending upon pool and target. Hole and casing sizes will be further refined during front-end engineering design (FEED).

Table 7.1-1: Preliminary Platform Well Hole Size and Casing Program

Casing Size/Type	Hole Size	Preliminary Material Specification ⁽¹⁾	Connection Specification	Est. Setting Depth RKB ⁽³⁾
762 mm Conductor	838 mm (cemented)	X-52	X-52 XLF (or similar)	± 300 m TVD ⁽⁴⁾ ± 300 m MD
508 mm Surface	660 mm	X-56	X-56 XLF (or similar)	± 500 m TVD ± 500 m MD
340 mm Intermediate	432 mm	L80	Premium Connection	±1000 m TVD 2400 – 3200 m MD
273 mm x 244 mm Production	311 mm	L80/C110	Vam Top HC (or similar premium connection)	± 1800 m TVD 3000 – 5000 m MD
OHGP Screens/Liners	216 mm/ 251 mm ⁽²⁾	L80 (inj) 13Cr L80 (prod)	Hunting SLHT (or similar premium connection)	± 1900 m TVD 3000 – 6000 m MD
140 mm/178 mm Production Tubing	Inside Production Casing	L80 (inj) 13Cr L80 (prod)	Vam Top HC (or similar premium connection)	± 1800 m TVD 3000 – 5000 m MD
Note 1) All material specifications are preliminary at this stage. Further studies will be conducted to determine final materials selection. 2) Production hole interval may be required to be opened to 251 mm to accommodate OHGP techniques. 3) RKB = Rotary Kelly Bushing (elevation reference) 4) TVD = True Vertical Depth, MD = Measured Depth				

7.1.3.1 Conductor / Surface Hole Sections

The preliminary drilling plan is based on using a combination of water-based (water polymer systems) and NAF-based drilling fluids. The water-based system will be used to drill the large diameter top-hole sections (838 mm, 660 mm, and the 432 mm hole sections). The NAF-based fluid will be used to drill the lower hole sections (311 mm and 216 mm hole sections). Final fluid designs for the drilling operations will be developed as wellbore designs are matured.

It is currently proposed that the 762 mm conductor casing will be drilled and cemented in place. An 838 mm hole will initially be drilled out of the Gravity Base Structure (GBS) base slab through which the 762 mm conductor casing will be deployed and set. The interval will be drilled with water-based fluids; cuttings from the 838 mm hole will be deposited into the GBS shaft. The

conductor casing will be designed to support the weight of the subsequent casing and tubing strings and will be cemented back to the GBS base (excess cement will also be deposited into the GBS shaft). The conductor will have a verticality limitation to prevent encroachment into adjacent wellbores, prevent sloughing of any soft soils just below the seabed or surface, and provide a conduit for mud returns to the drilling rig for the next hole section.

Surface casing (508 mm) will be set and cemented in a 660 mm hole. The interval will be drilled with water-based fluids. Drill cuttings will be returned to the surface where they will be routed overboard via one of two shale chute entry points located on the wellbay. This casing is planned to be set at approximately 500 m true vertical depth (TVD) to achieve the following:

- ◆ Isolate potential shallow gas zones
- ◆ Provide shut-in capability and kick tolerance for pressure events occurring in the next hole section
- ◆ Prevent shallow soft formations from eroding
- ◆ Anchor the blow-out preventer (BOP) stack

The final setting depth for the 508 mm casing will be evaluated on a well-by-well basis.

7.1.3.2 Intermediate Casing

Intermediate casing string (340 mm) will be set and cemented in a 432 mm hole at a depth of approximately 1000 m TVD. Drill cuttings will be returned to the surface where they will be routed overboard via the shale chute. In the event a NAF system is required, drill cuttings will be routed to the CRI system for disposal. The intermediate casing will provide shut-in capability and kick tolerance for pressure events in the next hole section and complete the trajectory build as per the directional program. The casing is set to isolate potential loss zones and as protection from broaching in the event of a well control incident. The casing will be designed to accommodate wear from drilling the 311 mm hole section. Hole size to drill pipe size ratio will be maximized for hole cleaning efficiency. The casing will be pressure tested to withstand pressure events from the next hole section and ensure adequate shoe strength to allow drilling the next hole interval.

7.1.3.3 Production Casing

Production casing will notionally consist of a tapered string (273 mm x 244 mm) and will be set and cemented in a 311 mm hole at or near the top of the reservoir completion interval. The 311 mm section will be drilled with NAF-based drilling fluids. Drill cuttings from the hole section will be routed to the platform CRI system where they will be processed for re-injection into the CRI zones.

The current plan is to set the production casing string above the top of the first productive sand. The production casing string will serve to isolate the intermediate tangent hole section during drilling of the production hole interval and provide mechanical support to the shales in the sail section of the interval. It will provide shut-in capability and kick tolerance for pressure events while drilling into the producing formations. The production casing will also serve as a pressure containing barrier in the event of a leak in the completion assembly, and to this end will be pressure tested to ensure these loads can be tolerated. The larger 273 mm section will be deployed to below the hydrate depth (± 500 m TVD) to accommodate installation of the large diameter tubing retrievable surface-controlled subsurface safety valve (TRSCSSV) (specified per the completion design).

7.1.3.4 Reservoir Section

A 216 mm hole is planned to be drilled through all of the productive reservoir zones. Where required the hole will be opened to accommodate gravel packing operations. Similar to the 311 mm hole section, the production interval will be drilled with NAF-based fluids with all cuttings re-injected. Reservoir drill-in fluids will be designed to mitigate formation damage, and will be designed based on testing to be completed during FEED.

The eventual hole size will facilitate delivery of core samples, measurement while drilling (MWD), logging while drilling (LWD), and other measurements required to effectively evaluate the Hebron reservoir. Sand control is planned in most wellbores, with internal alternate path wire wrap screens in oil producers and conventional wire wrap screens in water injectors for the lower completion assembly. The completion will provide the flexibility to manage potential sand control and zonal isolation issues. Sand control studies will be conducted to confirm detailed aspects of the required sand control system such as screen materials, screen burst or collapse strength, and wire wrap specification. A final recommendation for the Hebron sand control system will be founded upon this analysis.

7.1.4 Directional Drilling

Directional planning will be critical in delivering directional profiles that satisfy the well objectives and intersect the specified reservoir targets at the designated coordinates. Anti-collision operations outlined in existing procedures will be utilized for the drilling of the platform wellbores. The directional plans should allow management of doglegs to minimize side-forces thus reducing casing wear potential and maximizing drilling efficiency (i.e. Rate of Penetration (ROP), on-bottom drilling).

Rotary steerable devices will be the primary means of achieving the desired well path. Gyros and MWD technology will be applied as appropriate to monitor the progress of the directional plan while drilling, provide feedback,

and allow modification of the planned profile to ensure all objectives are satisfied.

Learnings from previous Eastern Canada wellbores (Hibernia and Terra Nova) related to directional responses in the region will be maximized. Directional profiles for platform-based wellbores will be assigned once final slot selection has been determined.

Preliminary wellpaths have been developed. Updates to the trajectory planning will be performed as and when reservoir targets are better defined. The preliminary spider plot in Figure 7.1-1 illustrates the potential well paths for a sample of the proposed well plans.

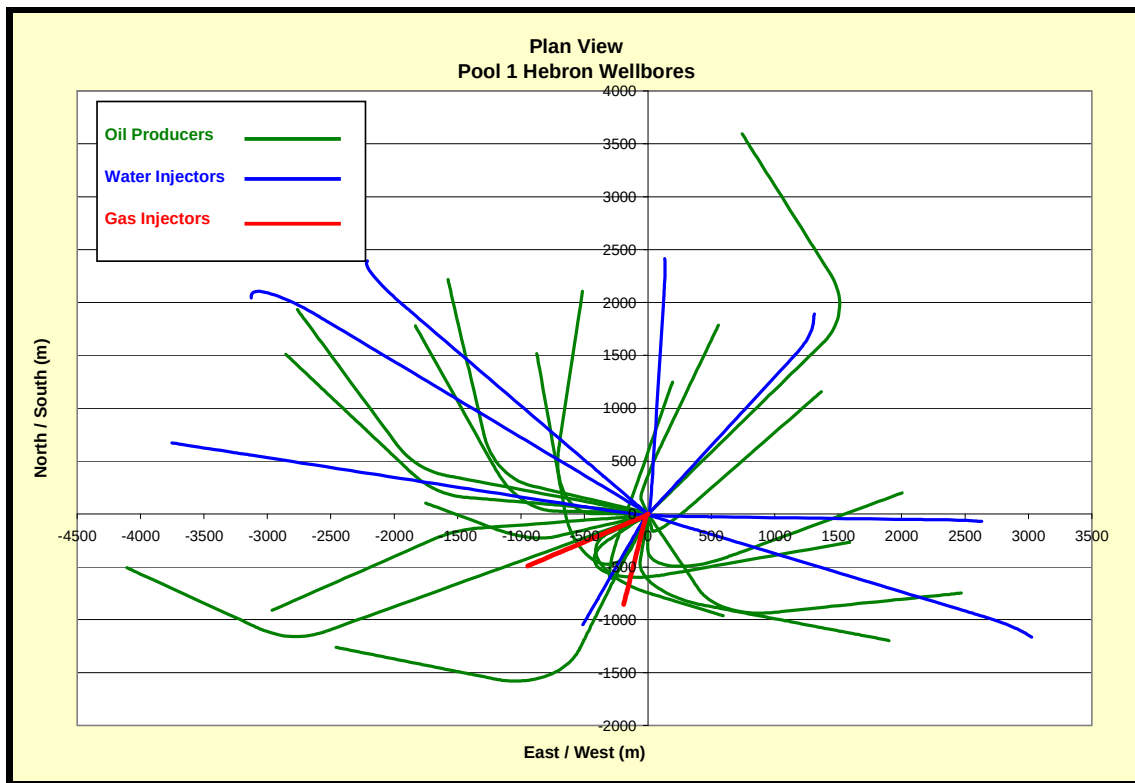


Figure 7.1-1: Preliminary Spider Plot from Platform

7.1.5 Cement

The objectives of the primary cement job can encompass all or any one of the following:

- ◆ Prevent the migration of formation fluids or gases in the wellbore annulus (zonal isolation). Zonal isolation is the most important function of the cement sheath.
- ◆ Anchor and support the casing string. The tensile strength of the cement is required to support pipe and allow drillout operations to resume. To achieve desired strength at the earliest possible time, additives will be

employed to obtain early strength development. Overall efficiencies can be realized when the waiting on cement (WOC) time is reduced via the assistance of properly designed additives.

- ◆ Protect the casing string against corrosion

Table 7.1-2 presents the preliminary cement program for the Hebron wellbores and is subject to verification during FEED. Slurry data has been taken as typical for the various well sections. Slurries are planned to be mixed with seawater or drill water (depth dependent) and liquid additives.

Annular pressure build-up (APB) in the wellbore casing will be addressed during well design and mitigated if necessary through the design of the casing cementing program. To alleviate the occurrence of APB, the cement top of the 340 mm and 244 mm casing strings will be below the previous casing shoe, or below the nearest interval that acts as a pressure-relief zone for the particular annulus. Each well will have unique design, operating, and logistics considerations that will dictate the most appropriate methods for dealing with APB. Final details of the cement design will be resolved during FEED.

Table 7.1-2: Preliminary Platform Cementing Program

Casing	Slurry Type	Planned Top (Meters MD RT) ⁽¹⁾	Thickening Time (Hours)	Target Slurry Density (kg/m ³)	Excess %	Mix Water Type
Conductor	Class "G"	GBS bottom/ seafloor	> 3.0	1900 tail	Gauge + 150%	Drill Water + Sea Water
Surface	Light Weight Class "G" Lead + Class "G" Tail	Surface	> 4.0 > 3.0	1620 lead 1900 tail	Gauge + 100% Gauge + 100%	Sea Water
Intermediate	Light Weight Class "G" Lead + Class "G" Tail	below previous shoe	> 6.0 > 4.5	1620 lead 1900 tail	Gauge + 60% Gauge + 60%	Sea Water
Production	Light Weight Class "G" Lead + C Class "G" Tail	below previous shoe	> 6.5 > 5	1670 lead 1900 tail	Gauge + 30% Gauge + 30%	Drill Water
Note 1: MD RT = Measured Depth Rotary Table elevation reference						

7.1.6 Completion Overview

Multiple pools are currently targeted for development. Each pool has unique considerations (rock strength, sand size, fluid characteristics, reservoir target, trajectory, and flow rate target) that will determine the optimal completion strategy to be deployed. To satisfy the reservoir and flow objectives of each pool, the Hebron Project envisions a variety of reservoir completion techniques that will satisfy the life of field depletion plan. These include, but are not limited to,

- ◆ Open Hole gravel packs
- ◆ Frac-packs
- ◆ Stand alone screens
- ◆ Cased and perforated liners

7.1.6.1 Completion Objectives

The final selection of pool and wellbore completion techniques will be determined as the detailed objectives for each become refined. Regardless of completion technique, common underlying objectives exist for all options to guide the design and construction of Hebron wellbores, specifically:

- ◆ Provide oil producer wellbores capable of long-term oil production at the conditions to be specified with the means to artificially lift the well as required using gas lift
- ◆ Allow for the potential of through tubing plug back of individual completed zones in the oil production wellbores
- ◆ Provide injection wellbores capable of supporting water injection and gas injection streams (separate flow streams)
- ◆ Provide for the potential of future cased hole production logging in oil producers and injectors
- ◆ Install a permanent down-hole pressure and temperature gauge in oil producers to minimize well intervention requirements for reservoir monitoring purposes
- ◆ Provide for downhole chemical injection capability to mitigate potential scaling or asphaltene deposition
- ◆ Maximize completion reliability by reducing the design complexity to the greatest extent possible using appropriate materials and equipment
- ◆ Minimize the number of active components and potential leak paths
- ◆ Allow for intervention techniques that can maintain the wellbores in a safe and functioning condition

- ◆ Proper materials selection to mitigate life of wellbore corrosion potential and ensure wellbore integrity

Modifications to the completion design will occur as and when wellbore definition is further refined. Design alternatives will be reviewed further in the FEED stage of the project. It is acknowledged that well designs will evolve and mature over the life of field as individual pools are accessed and reservoir definition is advanced. Evolutions in the well design will be communicated via the individual **Approval to Drill a Well** (ADW) process complete with supporting analysis and documentation validating design modifications.

While there are a variety of completion options available, open hole gravel packs are currently a primary candidate for Hebron Ben Nevis wellbores. The wellbore schematic below (Figure 7.1-2) represents the preliminary well design basis for this option. Water Injection and Gas Injection designs may be facilitated by stand alone screens (Figure 7.1-3 and 7.1-4). The primary components of the completion design are anticipated to be as follows:

- ◆ Production packer having a demonstrated performance envelope that exceeds all operating and pressure test loads. The packer will have a polished bore capable of providing an interface to the upper completion
- ◆ Polished bore receptacle (PBR) above the production packer to provide for movement of the tubing string over the range of load cycles expected for the wellbore. The PBR will have a means to interface and lock into the production packer
- ◆ 178 mm or 140 mm tubing string with premium connections (gas tight envelopes in oil producers, gas injectors, and water injectors)
- ◆ Permanent down-hole gauge (PDG) mandrel installed in the oil production wellbores (optional in injectors)
- ◆ Various down-hole chemical injection points for the injection of chemicals as required
- ◆ Gas lift mandrels in producers to facilitate gas lift artificial lift (type, size, quantity, and valves to be specified at a later date)
- ◆ Profiles capable of accepting isolation devices (plugs) for the purposes of wellbore isolation to accommodate future intervention requirements
- ◆ TRSCSSV set below the hydrate point
- ◆ Annular Safety Valves (ASVs) in the gas lifted producers set below the hydrate point to accommodate regulatory requirements for platform-based gas-lifted operations

Final details and specifications of completion equipment will be determined once specific well properties and objectives are established by the Reservoir,

Subsurface, and Process Engineering groups. Lessons learned from other ExxonMobil-operated wells may result in changes to the completion of the Hebron wells. During detailed design, alternate completion methods will continue to be evaluated.

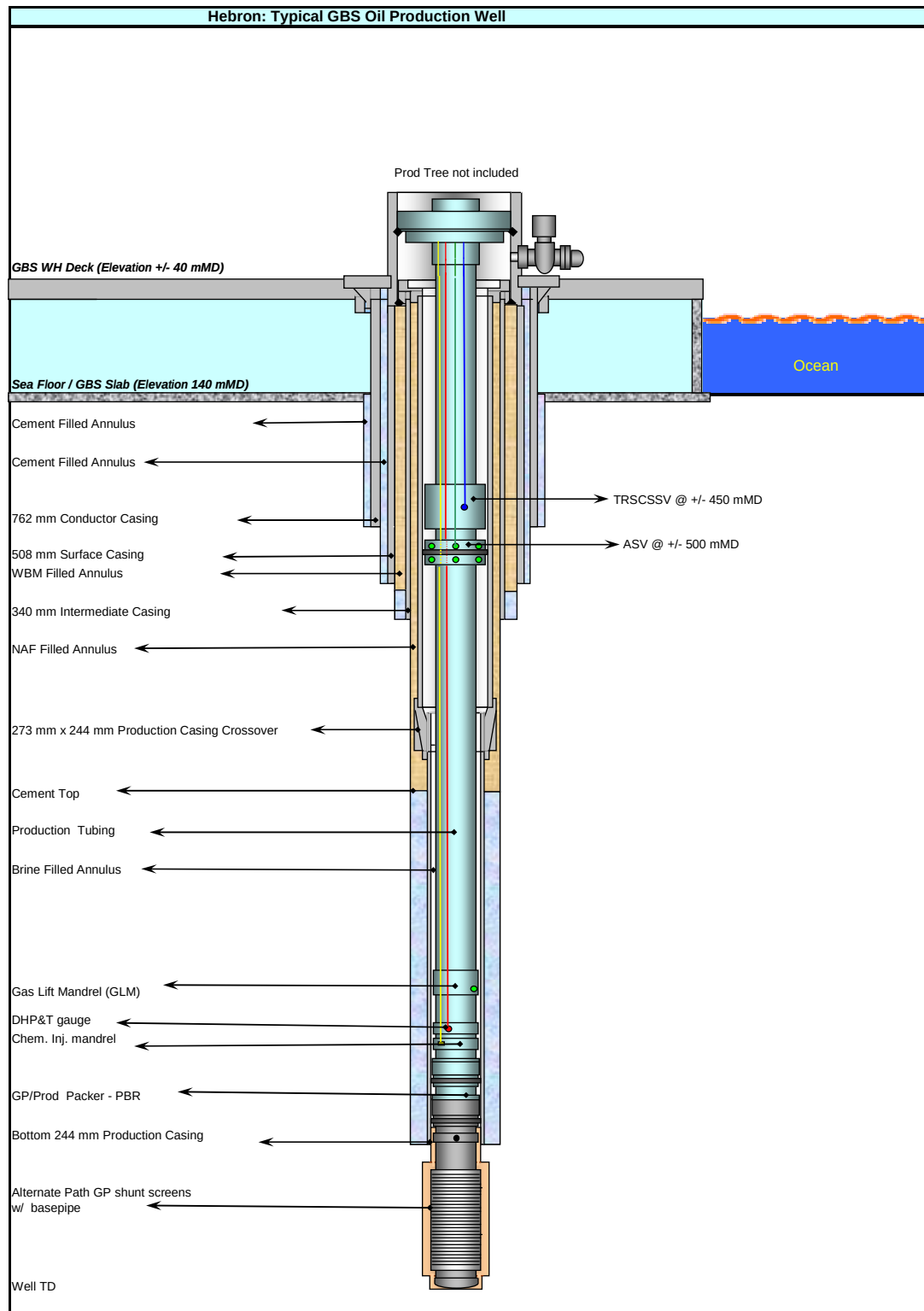


Figure 7.1-2: Typical Platform Oil Producer Schematic

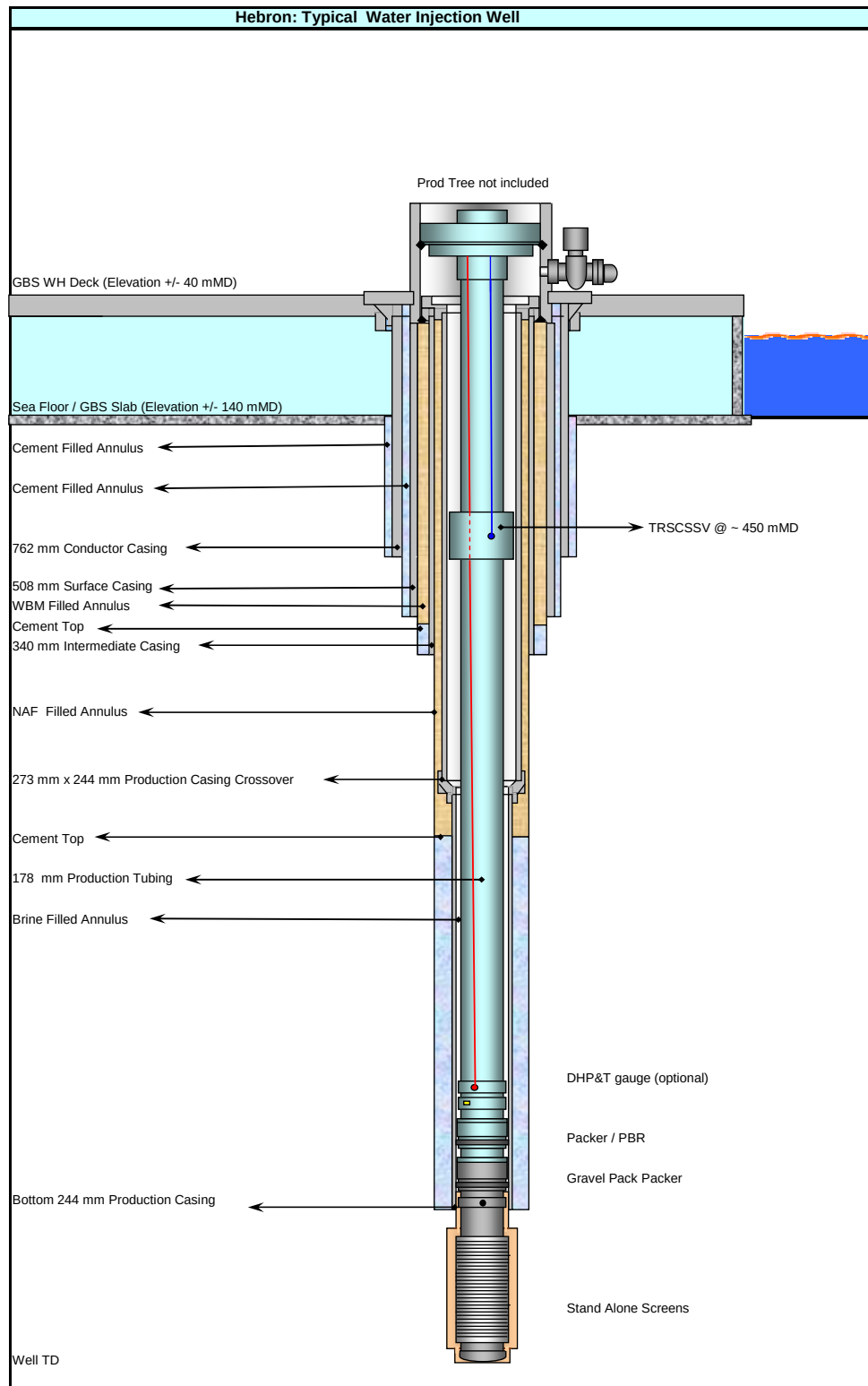


Figure 7.1-3: Typical Platform Water Injector Schematic

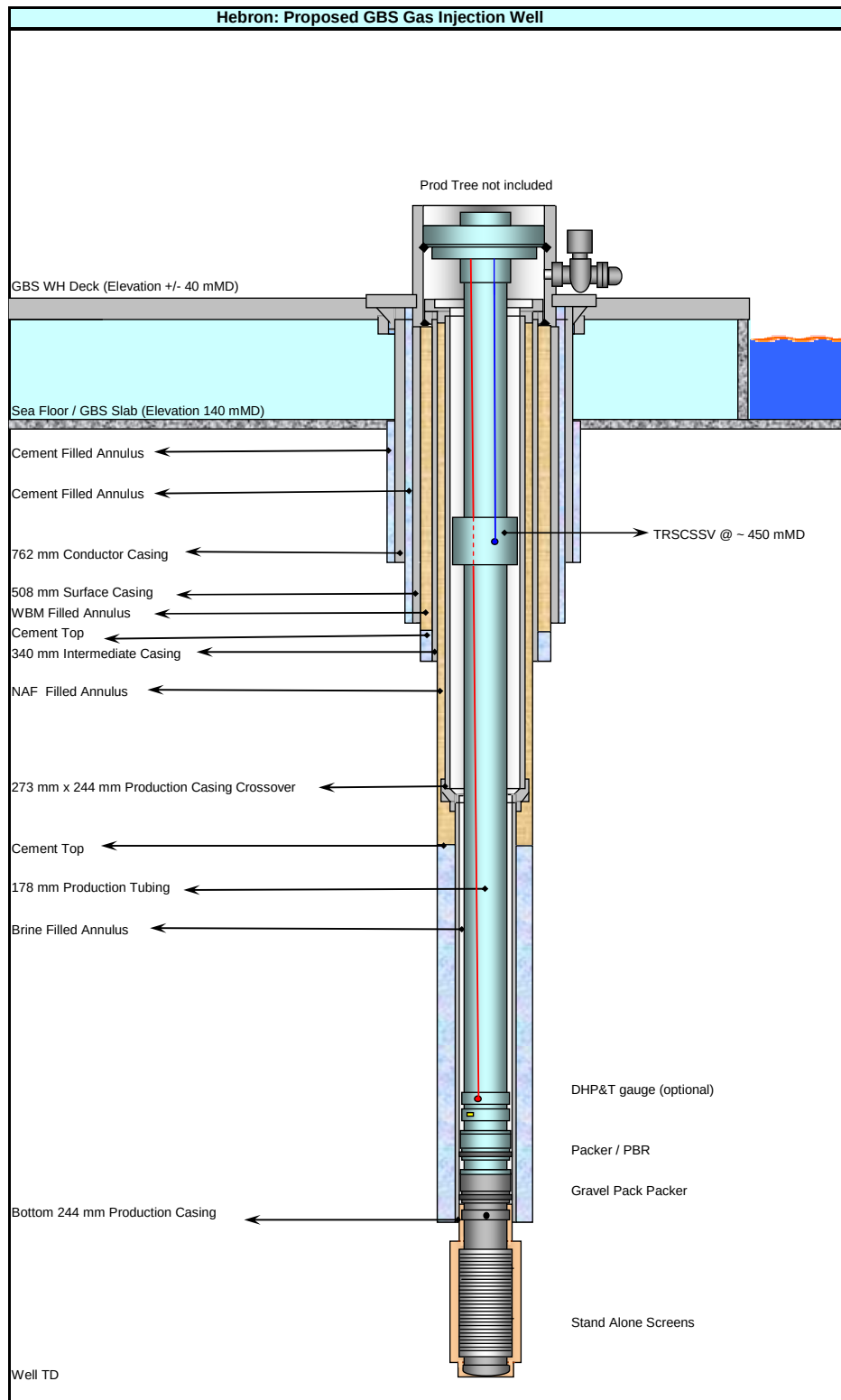


Figure 7.1-4: Typical Platform Gas Injector Schematic

7.1.6.2 Multi-Function Wellbores

A limited number of multi-functional wellbores will be required to facilitate reservoir depletion and support the gas management strategy. As discussed previously, a selected number of injectors will alternate between water injection and gas injection as a means of providing redundant gas injectors in the event the primary gas injectors are unavailable. Furthermore, dedicated gas injectors may require conversion to produce gas later in the field life if platform gas demand exceeds field wide gas production.

Specific well designs will be required to accommodate these functionalities. Material selection (metallurgy and elastomers) and equipment design will be completed once the full range of operating conditions is developed.

7.1.6.3 Completion Fluids

Completion fluids will vary depending on the operations and formations involved. In general, completion fluids may be used for wellbore cleanup, gravel pack sand placement, perforating operations, and annulus fluids (packer fluids). Packer fluids will follow local regulatory guidelines for required density, be benign in nature, and contain sufficient chemicals to mitigate wellbore corrosion over the life of the wellbore.

The details of these fluids will be determined during the FEED period and updated as improved materials or information become available during well operations. Both water based and NAF-based systems will be considered for the fluids. Completion fluids for perforating may also include the use of non-damaging brines, diesel or nitrogen blankets to provide underbalance.

Corrosion management for the Hebron wellbores will be facilitated through a combination of proper material selection, cathodic protection, chemical inhibition and, where appropriate, internal/external coating systems. The well design will facilitate the possible use of ultrasonic imaging tools or calipers for internal inspection during the operating life of the wellbore.

7.1.6.4 Wellbore Safety Systems

Completion safety systems include the use of TRSCSSVs as a means of preventing uncontrolled flow from the wellbore in the event of failure of the Xmas tree or wellhead system. Similarly, ASVs will be utilized for wellbores incorporating annular gas lift. Wireline set tubing safety valves (as contingency backup) will be evaluated during FEED where full diameter access is not required.

The Xmas tree and wellhead will form an integral part of the wellbore safety system and will be discussed in more detail in Section 7.1.10 of this document.

7.1.7 Drilling Hazards

Typical problems that may be encountered in development drilling are discussed briefly below along with mitigative techniques. The details within well specific ADW's and the Operations Authorization will supersede any statements made in this section.

7.1.7.1 Shallow Gas Hazards

ExxonMobil has shallow gas preparedness and drilling procedures incorporated into its **Standard Drilling Operations Policy** manuals. This includes incorporation of a drilling conductor, and the use of diverter assemblies in surface hole sections to manage and control the occurrence of shallow gas. Issues such as diverter line sizing, control system valve sequencing, and crew training are addressed in these manuals. This will be addressed further in the Drilling sections of the Hebron Operations Authorization Plan and integrated into each wellbore design via the individual ADW process.

7.1.7.2 Hole Stability

On high angle development wells, potentially unstable wellbore sections will be exposed whereby hole instability may become a challenge. The operator plans to employ an integrated analysis approach to determine the proper combination of fluid type and density to mitigate the onset of wellbore instability issues. Where instability does occur, the same integrated approach will be employed to assess the required fluid property changes, circulation rates, and pipe speeds (rotational and tripping) to effectively manage and remedy instability issues.

Final fluid selection will consider the needs of the overall well design and is to be determined during the FEED stage of the project. Stability studies based on the exploration and delineation wellbores, as well as offset projects in the region, will be conducted during FEED.

7.1.7.3 Formation Pressure

Neither abnormal pressures nor severe lost circulation zones have been encountered in drilling wells in those pools targeted for initial development. The primary mitigation to hazards posed by formation pressures is the proper selection of drilling fluid density and fluid type to create sufficient overbalance to counter the formation pressures expected. Where severe losses are encountered, the operator will employ several pre-established procedures to reduce and eliminate the losses to restore hydrostatic overbalance to the wellbore. Techniques range from solids manipulation of the drilling fluids and loss control formulations/pills, to squeezes and weighting agents. Required inventories of loss control materials will be available to ensure appropriate timely response to severe loss control events.

Governmental regulations and C-NLOPB guidelines, coupled with ExxonMobil Well Control Policies and industry-accepted drilling practices, will be followed to minimize the risk of well control incidents.

Drilling programs will be founded upon ExxonMobil's **Surface Blowout Prevention and Well Control Manual** for surface mounted Well Control Systems. This standard incorporates certain basic principles to effectively protect personnel and to prevent the occurrence of uncontrolled events. Specifically,

- ◆ The standard prescribes practices that will be designed so personnel and public safety are paramount, and environmental protection is provided
- ◆ Pre-planned operating procedures will be designed to rely primarily on hydrostatic pressure for well control during the time a BOP stack or production tree is not installed
- ◆ Installed surface and subsurface pressure containment equipment will be designed to confine an influx to the wellbore and to allow for controlled removal from the wellbore (either into a formation or to the surface)
- ◆ Identified components of pressure containment equipment that may be exposed to hydrogen sulphide, carbon dioxide, and other corrosive fluids will be designed to resist the harmful effects of these fluids at anticipated operating pressures and temperatures
- ◆ Pressure containment equipment will be installed, tested and operated in a manner to comply with applicable governmental regulations
- ◆ Qualified ExxonMobil field supervision will be provided to execute this standard properly

ExxonMobil's well control philosophy will entail considerations of BOP equipment specifications, ram location, as well as requirements for stack testing, the closing system, the choke manifold, trip tanks, and hydrogen sulphide (H₂S) service modifications (if required). Detailed efforts will be outlined in the Operations Authorization Application and individual well ADW applications.

7.1.7.4 Differential Sticking

Differential sticking of the drilling assemblies may occur across any permeable zones where fluid overbalance occurs i.e. hydrostatic pressure of the drilling fluid column significantly exceeds pore pressure, and is not unique to high angle wellbores. Proper well planning procedures identify permeable zones where excessive overbalances occur. The extent of the overbalance combined with assessment of the trajectory and drilling assembly quantify the risk posed by each occurrence. Control of drilling fluid properties, drilling fluid selection and good tripping procedures can reduce the risk of differential sticking. Where industry accepted techniques cannot fully abate an

unacceptable risk, alternative designs will be proposed to reduce or eliminate the overbalance situation.

7.1.8 Material Selection

Material Selection for the Hebron wellbores will be based upon analysis of the fluid streams to which the tubulars, wellheads, and Xmas trees will be exposed. Several options exist to mitigate the various forms of corrosion that may occur, including corrosion resistant alloys (CRAs), coating systems, and cathodic protection systems. Specific studies will be undertaken by the Operator to identify feasible material options for all components of the wellbore.

7.1.8.1 Reservoir Souring

Potential exists for the occurrence of hydrogen sulphide (H₂S) in the reservoir during the waterflood process. Wellbore materials will subsequently be exposed to this stream resulting in various forms of corrosion including sulphide stress cracking. The interior surfaces of production tubulars, completion accessories, and Xmas trees may be exposed during the flow of fluids from reservoir to surface. Hydrogen sulphide gas may also enter the gas lift stream, exposing the outer diameter of the production tubulars as well as the production casing, the wellhead, and the outer surface of the completion accessories.

Consideration for these occurrences will be incorporated into the material selection of the drilling and completion program, including identification of active and passive wetted surfaces as well as appropriate material mitigation measures.

Drill strings may be exposed to hydrogen sulphide during penetration of the reservoir. Surface Drilling Systems (DES and DSM), including drill strings and drilling components, will receive due consideration for the effects of hydrogen sulphide as studies are progressed and associated risks defined.

7.1.9 Well Control System

Well Control will be facilitated through the use of a Well Control system consisting of a BOP system and ancillary support systems. All Well Control systems will be in accordance with applicable regulations.

The BOP stack will include ram and annular style closing mechanisms. There is no single acceptable BOP stack arrangement, but there are operating characteristics to consider in the stack arrangement for the particular drilling program. Final selection of the BOP configuration will be a function of well design and operating characteristics of the drilling unit. Working pressure, required kick tolerances, gas hydrates, trapped gas, testing requirements, stripping and hangoff requirements, pipe shear requirements, elastomer service conditions and temperature limits all have input on the final selection of the BOP configuration.

Several auxiliary systems will be employed to support the main systems. A choke and kill manifold will serve to direct well fluids to/from the wellbore as needed to maintain an appropriate hydrostatic column. A trip tank system will be employed to assist in monitoring hole volumes into/out of the wellbore. An atmospheric ("poor-boy") mud gas separator (degasser) system will be employed in the well control system to separate entrained gas returning in the well fluids. Mud Control monitoring systems will be utilized to measure fluid volumes stored in the drilling units storage tanks (pits).

The Well Control system for the drilling package will be of dimensions and pressure rating to handle all anticipated pressures in the field. The final system design will be determined during the FEED process and presented more fully in the Operations Authorization submission. It will meet or exceed required regulatory guidelines for the wells to be drilled in the Hebron Field.

7.1.10 Wellhead and Trees

The wellhead and Xmas tree design will be in accordance with Newfoundland Offshore Petroleum Drilling and Production Regulations as well applicable industry codes. Provisions for TRSCSSV, ASV, gas lift, and chemical injection (both down-hole and at the wellhead) will be incorporated into the tree design.

The wellhead and production trees will be rated to an appropriate pressure and temperature rating to handle the anticipated shut-in and flowing conditions, in accordance with governmental regulations and C-NLOPB guidelines. The trees will incorporate remote operated (primary) and manual (secondary) master valves, a production wing valve, and a swab valve for intervention access. Production chokes outboard of the production wing valve will facilitate control of the fluid flow from the wellbores. The tree will be instrumented to permit local and remote monitoring of pressure and temperatures of the flowstream. The tubing hanger will be ported to accept the necessary control lines required for downhole monitoring, and exceed the anticipated loads imposed by the completion assembly.

The wellheads will be furnished with a connector to facilitate installation of the Xmas tree. The wellhead will be equipped with hang off points for the required casing hangers. Contingency hanger locations will be supplied within the wellhead in the event upset conditions require an additional casing system to be installed. Outlets will be provided with the wellhead to permit access to the annular spaces between casing strings. The wellhead will be instrumented to permit local and remote monitoring. A typical wellhead and surface tree assembly is shown in Figure 7.1-5.

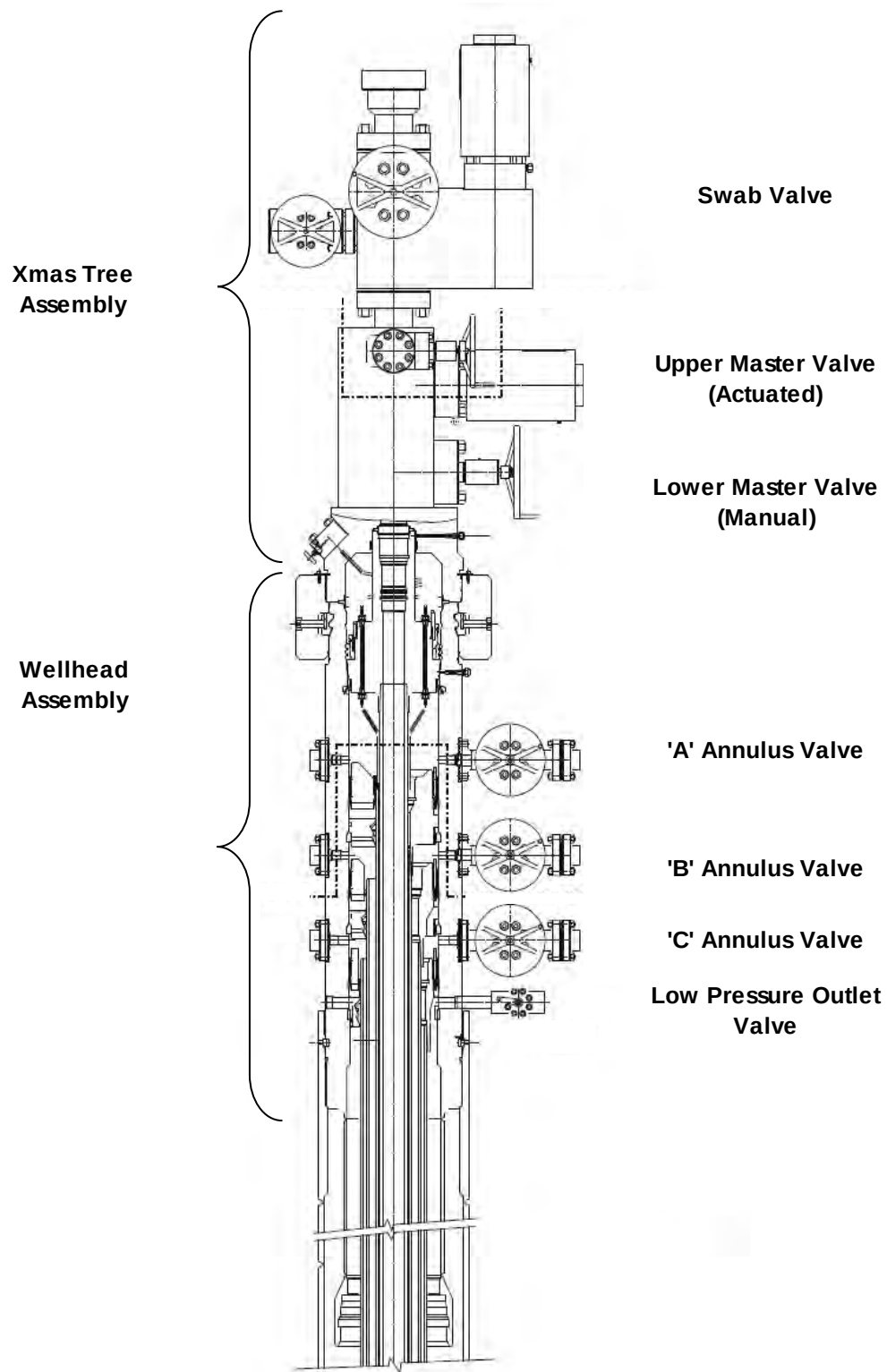


Figure 7.1-5: Typical Wellhead Surface Tree

7.2 Subsea Development Drilling

Drilling operations for the Hebron Pool 3 Development will be conducted from a mobile offshore drilling unit (MODU). The rig will be capable of continuous operation in the Eastern Canadian Grand Banks environment of offshore Newfoundland and Labrador. The wells will be drilled at subsea drill sites (Drill Centres) and tied back to the Hebron Production Platform for production processing and shipment. Due to the harsh weather environment of the region, the drilling rig will be equipped to be environmentally independent to the greatest extent possible. Drilling equipment and operations will incorporate experiences and lessons learned from the design, construction, and operation of previously successful projects, and, specifically, drilling projects located in similar harsh weather environments (Ringhorne, Jotun, and Hibernia).

It is currently envisioned that approximately 18 wellbores drilled from two drill centres will be necessary to exploit the Pool 3 resource. The discovery and delineation wells (I-13, H-71, B-75, D-94, M-04, L-55, and I-45) in the Hebron Asset have all been plugged and abandoned in accordance to C-NLOPB guidelines. There are no plans to re-enter these wells for development of the Hebron Pool 3 Asset.

7.2.1 Preliminary Drilling and Completion Plans

The Hebron Pool 3 Development consists of one pool (Ben Nevis - Ben Nevis sands). Excess gas generated from production operations (Hebron and Hebron Pool 3) may potentially be stored in this same field. See Reference Section 6 (Reservoir Exploitation) for detailed resource discussion.

The Pool 3 subsea wellbores will have three-dimensional trajectories with long horizontal sections requiring extended reach drilling profiles. Consideration of borehole stability and torque and drag issues will be necessary. It is envisioned the completions will be OHGPs with the potential for some wellbores targeted as candidates for cased and perforated designs. The OHGP completions will meet and possibly exceed current technical limits. Further analysis will be required in the areas of torque and drag, and integrated hole quality to fully define the well construction design. Well locations are notional at this stage for purposes of well planning, rig specifications, and costing purposes. The well bottom-hole locations, the number of drill centres, the proportions of production and injection wells, and the resultant trajectories may change as further information becomes available.

7.2.2 Drill Cuttings Management

NAFs are currently envisioned in selected sections of the drilling program. The NAF-based fluid system provides performance improvement in hole stability, increased penetration rates, and reduction of drilling friction.

It is currently envisioned that drill cuttings will be processed for overboard discharge in compliance with C-NLOPB Regulations.

7.2.3 Wellbore Hole and Casing Program

Individual wellbore targets will be assigned specific trajectories taking into account drilling parameters and close approach concerns. In general, Table 7.2-1 provides the early basis for the hole and casing program for well construction activities. Shallow casing setting depths are predicted to remain consistent across all wells (914 mm and 508 mm) while deeper casing setting depths will vary depending upon well and target. Hole and casing sizes will be further refined during FEED.

Table 7.2-1: Preliminary Pool 3 Hole Sizes and Casing Program

Casing Size/Type	Hole Size	Preliminary Material Specification ⁽¹⁾	Connection Specification	Est. Setting Depth RKB ⁽³⁾
914 mm Conductor	1067 mm (cemented)	X-52	X-52 XLF (or similar)	± 200 m TVD ⁽⁴⁾ ± 200 m MD
508 mm Surface	660 mm	X-56	X-56 XLF (or similar)	± 600 m TVD ± 600 m MD
340 mm Intermediate	432 mm	L80	Premium Connection	±1400 m TVD 1400 – 3200 m MD
273/244 mm Production	311 mm	L80/C110	Vam Top HC (or similar premium connection)	± 2400 m TVD 2600 – 5500 m MD
OHGP Screens/Liners	216 mm/ 251 mm ⁽²⁾	L80 (inj) 13Cr L80 (prod)	Hunting SLHT (or similar premium connection)	± 2400 m TVD 2600 – 6200 m MD
89 mm – 178 mm Production Tubing	Inside Production Casing	L80 (inj) 13Cr L80 (prod)	Vam Top HC (or similar premium connection)	± 2200 m TVD 2600 – 5400 m MD
Note 1) All material specifications are preliminary at this stage. Further studies will be conducted to determine final materials selection. 2) Production hole interval may be required to be opened to 251 mm to accommodate OHGP techniques. 3) RKB = Rotary Kelly Bushing (elevation reference) 4) TVD = True Vertical Depth, MD = Measured Depth				

7.2.3.1 Conductor / Surface Hole Sections

The preliminary drilling plan is based on using a combination of water-based (water polymer systems) and NAF-based drilling fluids. The water-based system will be used to drill the large diameter top-hole sections (1067 mm, 660 mm, and the 432 mm hole sections). The NAF-based fluid will be used to drill the lower hole sections (311 mm and 216 mm hole sections). Final fluid designs for the drilling operations will be developed as wellbore designs are matured.

It is currently proposed that the 914 mm conductor casing will be drilled and cemented in place. A 1067 mm hole will initially be drilled from the seafloor through which the 914 mm conductor casing will be deployed and set. The interval will be drilled with water-based fluids; cuttings from the 1067 mm hole will be deposited onto the seafloor. The structural / conductor casing will be

designed to support the weight of the subsequent casing and tubing strings and will be cemented back to the seafloor (excess cement will also be deposited onto the seafloor). The structural / conductor prevents sloughing of any soft soils just below the seabed or surface, and provides a conduit for mud returns to the drilling rig for the next hole section.

Surface casing (508 mm) will be set and cemented in a 660 mm hole. The interval will be drilled with water-based fluids. Drill cuttings will be returned to the sea floor where they will be transported away from the drill centre to avoid interference with the drill centre. This casing is planned to be set at approximately 600 m TVD to achieve the following:

- ◆ Isolate potential shallow gas zones
- ◆ Provide shut-in capability and kick tolerance for pressure events occurring in the next hole section
- ◆ Prevent shallow soft formations from eroding
- ◆ Support the wellhead and BOP stack assembly

The final setting depth for the 508 mm casing will be evaluated on a well-by-well basis.

7.2.3.2 Intermediate Casing

Intermediate casing string (340 mm) will be set and cemented in a 432 mm hole at a depth of approximately 1400 m TVD. Drill cuttings will be returned to the drilling rig where they will be processed for overboard discharge. In the event a NAF system is required, drill cuttings will be routed to a NAF specific processing system prior to disposal overboard. The intermediate casing will provide shut-in capability and kick tolerance for pressure events in the next hole section and complete the trajectory build as per the directional program. The casing is set to isolate potential loss zones and as protection from broaching in the event of a well control incident. The casing will be designed to accommodate wear from drilling the 311 mm hole section. Hole size to drill pipe size ratio will be maximized for hole cleaning efficiency. The casing will be pressure tested to withstand pressure events from the next hole section and ensure adequate shoe strength to allow drilling the next hole interval.

7.2.3.3 Production Casing

Production casing will notionally consist of a 273 mm x 244 mm tapered design and will be set and cemented in a 311 mm hole at or near the top of the reservoir completion interval. The 311 mm section will be drilled with NAF-based drilling fluids. Drill cuttings from the hole section will be routed to a processing system prior to disposal overboard

The current plan is to set the production casing string above the top of the first productive sand. The production casing string will serve to isolate the

intermediate tangent hole section during drilling of the production hole interval and provide mechanical support to the shales in the sail section of the interval. It will provide shut-in capability and kick tolerance for pressure events while drilling into the producing formations. The production casing will also serve as a pressure-containing barrier in the event of a leak in the completion assembly, and to this end will be pressure tested to ensure these loads can be tolerated. The casing will be designed to accommodate installation of the large diameter TRSCSSV (specified per the completion design) below the hydrate depth (± 500 m TVD).

7.2.3.4 Reservoir Section

A 216 mm hole is planned through all of the productive reservoir zones. Where required the hole will be opened to accommodate gravel packing operations. Similar to the 311 mm hole section, the production interval will be drilled with NAF-based fluids with all cuttings processed for overboard discharge. Reservoir drill-in fluids will be designed to mitigate formation damage, and will be designed based on testing to be completed during FEED.

The eventual hole size will facilitate delivery of core samples, MWD, LWD, and other measurements required to effectively evaluate the Ben Nevis reservoir. Sand control is planned in most wellbores, with internal alternate path wire-wrapped screens in oil producers and conventional wire wrap screens in water injectors for the lower completion assembly. The completion will provide the flexibility to manage potential sand control and zonal isolation issues. Sand control studies will be conducted to confirm detailed aspects of the required sand control system such as screen materials, screen burst or collapse strength, and wire wrap specification. A final recommendation for the Ben Nevis sand control system will be founded upon this analysis.

7.2.4 Directional Drilling

Directional planning will be critical in delivering directional profiles that satisfy the well objectives and intersect the specified reservoir targets at the designated coordinates. Anti-collision operations outlined in existing procedures will be utilized for the drilling of the subsea wellbores. The directional plans should allow management of doglegs to minimize side-forces thus reducing casing wear potential and maximizing drilling efficiency (i.e. ROP, on-bottom drilling).

Rotary steerable devices will be the primary means of achieving the desired well path. Gyros and MWD technology will be applied as appropriate to monitor the progress of the directional plan while drilling, provide feedback, and allow modification of the planned profile to ensure all objectives are satisfied.

Learnings from previous Eastern Canada wellbores (Hibernia and Terra Nova) related to directional responses in the region will be maximized.

Directional profiles for subsea wellbores will be assigned once the final subsea architecture/layout has been determined.

Preliminary well paths have been developed. Updates to the planned trajectories will be performed as and when reservoir targets are better defined. The preliminary spider plot in Figure 7.2-1 illustrates the potential well paths for one set of proposed well plans.

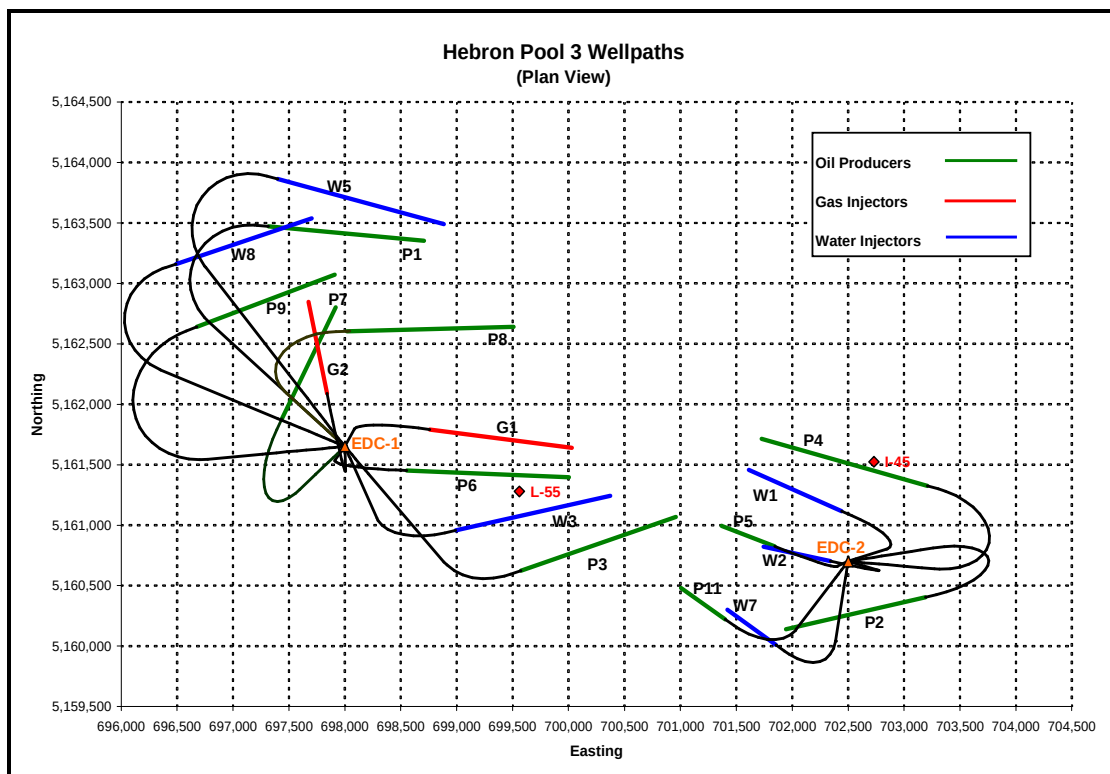


Figure 7.2-1: Preliminary Pool 3 Spider Plot

7.2.5 Cement

The objectives of primary cement jobs can encompass all or any one of the following:

- ◆ Prevent the migration of formation fluids or gases in the wellbore annulus (zonal isolation). Zonal isolation is the most important function of the cement sheath.
- ◆ Anchor and support the casing string. The tensile strength of the cement is required to support pipe and allow drillout operations to resume. To achieve desired strength at the earliest possible time, additives will be employed to obtain early strength development. Overall efficiencies can be realized when the WOC time is reduced via the assistance of properly designed additives.
- ◆ Protect the casing string against corrosion

Table 7.2-2 presents the preliminary cement program for the Hebron Pool 3 wellbores and is subject to verification during FEED. Slurry data have been taken as typical for the various well sections. Slurries are planned to be mixed with seawater or drill water (depth dependent) and liquid additives.

APB in the wellbore casing will be addressed during well design and mitigated if necessary through the design of the casing cementing program. To alleviate the occurrence of APB, the cement top of the 340 mm and 244 mm casing strings will be below the previous casing shoe, or below the nearest interval that acts as a pressure-relief zone for the particular annulus. Each well will have unique design, operating, and logistics considerations that will dictate the most appropriate methods for dealing with APB. Final details of the cement design will be resolved during FEED.

Table 7.2-2: Preliminary Pool 3 Cementing Program

Casing	Slurry Type	Planned Top (Meters MD RT) ⁽¹⁾	Thickening Time (Hours)	Target Slurry Density (kg/m ³)	Excess %	Mix Water Type
Conductor	Class "G"	Seafloor	> 3.0	1900 tail	Gauge + 150%	Drill Water + Sea Water
Surface	Light Weight Class "G" Lead + Class "G" Tail	Seafloor	> 4.0 > 3.0	1620 lead 1900 tail	Gauge + 100% Gauge + 100%	Sea Water
Intermediate	Light Weight Class "G" Lead + Class "G" Tail	below previous shoe	> 6.0 > 4.5	1620 lead 1900 tail	Gauge + 60% Gauge + 60%	Sea Water
Production	Light Weight Class "G" Lead + C Class "G" Tail	below previous shoe	> 6.5 > 5	1670 lead 1900 tail	Gauge + 30% Gauge + 30%	Drill Water
Note 1: MD RT = Measured Depth Rotary Table elevation reference						

7.2.6 Completion Overview

Pool 3 (Ben Nevis formation in the Ben Nevis field) has unique considerations (rock strength, sand size, fluid characteristics, reservoir target, trajectory, and flow rate target) that will determine the optimal completion strategy to be

deployed. To satisfy the reservoir and flow objectives, the Hebron Pool 3 Project envisions a variety of reservoir completion techniques that will satisfy the life of field depletion plan. These include, but are not limited to,

- ◆ Open Hole gravel packs
- ◆ Frac-packs
- ◆ Stand alone screens
- ◆ Cased and perforated liners

7.2.6.1 Completion Objectives

The final selection of wellbore completion techniques will be determined as the detailed objectives for Pool 3 become refined. Regardless of completion technique, common underlying objectives exist for all options to guide the design and construction of Pool 3 wellbores, specifically:

- ◆ Provide oil producer wellbores capable of long-term oil production at the conditions to be specified with the means to artificially lift the well as required using gas lift
- ◆ Allow for the potential of through tubing plug back of individual completed zones in the oil production wellbores
- ◆ Provide injection wellbores capable of supporting water injection and gas injection streams (separate flow streams)
- ◆ Provide for the potential of future cased hole production logging in oil producers and injectors
- ◆ Install a permanent down-hole pressure and temperature gauge in oil producers to minimize well intervention requirements for reservoir monitoring purposes
- ◆ Provide for downhole chemical injection capability to mitigate potential scaling or asphaltene deposition
- ◆ Maximize completion reliability by reducing the design complexity to the greatest extent possible using appropriate materials and equipment
- ◆ Minimize the number of active components and potential leak paths
- ◆ Allow for intervention techniques that can maintain the wellbores in a safe and functioning condition
- ◆ Proper materials selection to mitigate life of wellbore corrosion potential and ensure wellbore integrity

Modifications to the completion design will occur as and when wellbore definition is further refined. Design alternatives will be reviewed further in the FEED stage of the project. It is acknowledged that well designs will evolve

and mature over the life of field as reservoir definition is advanced. Evolutions in the well design will be communicated via the individual ADW process complete with supporting analysis and documentation validating design modifications.

While there are a variety of completion options available, open hole gravel packs are currently a primary candidate for the Pool 3 wellbores. The wellbore schematics illustrated in Figures 7.2-2 and 7.2-3 represents the preliminary producer and injector well design basis for this option. The primary components of the completion design are anticipated to be as follows:

- ◆ Production packer having a demonstrated performance envelope that exceeds all operating and pressure test loads. The packer will have a polished bore capable of providing an interface to the upper completion
- ◆ PBR above the production packer to provide for movement of the tubing string over the range of load cycles expected for the wellbore. The PBR will have a means to interface and lock into the production packer
- ◆ A tubing string with premium connections (gas tight envelopes in oil producers, gas injectors, and water injectors)
- ◆ PDG mandrel installed in the oil production wellbores (optional in injectors)
- ◆ Various down-hole chemical injection points for the injection of chemicals as required
- ◆ Gas lift mandrels in producers to facilitate gas lift artificial lift (type, size, quantity, and valves to be specified at a later date)
- ◆ Profiles capable of accepting isolation devices (plugs) for the purposes of wellbore isolation to accommodate future intervention requirements
- ◆ TRSCSSV set below the hydrate point

Final details and specifications of completion equipment will be determined once specific well properties and objectives are established by the Reservoir, Subsurface, and Process Engineering groups. Lessons learned from other ExxonMobil-operated wells may result in changes to the completion of the Pool 3 wells. During detailed design, alternate completion methods will continue to be evaluated.

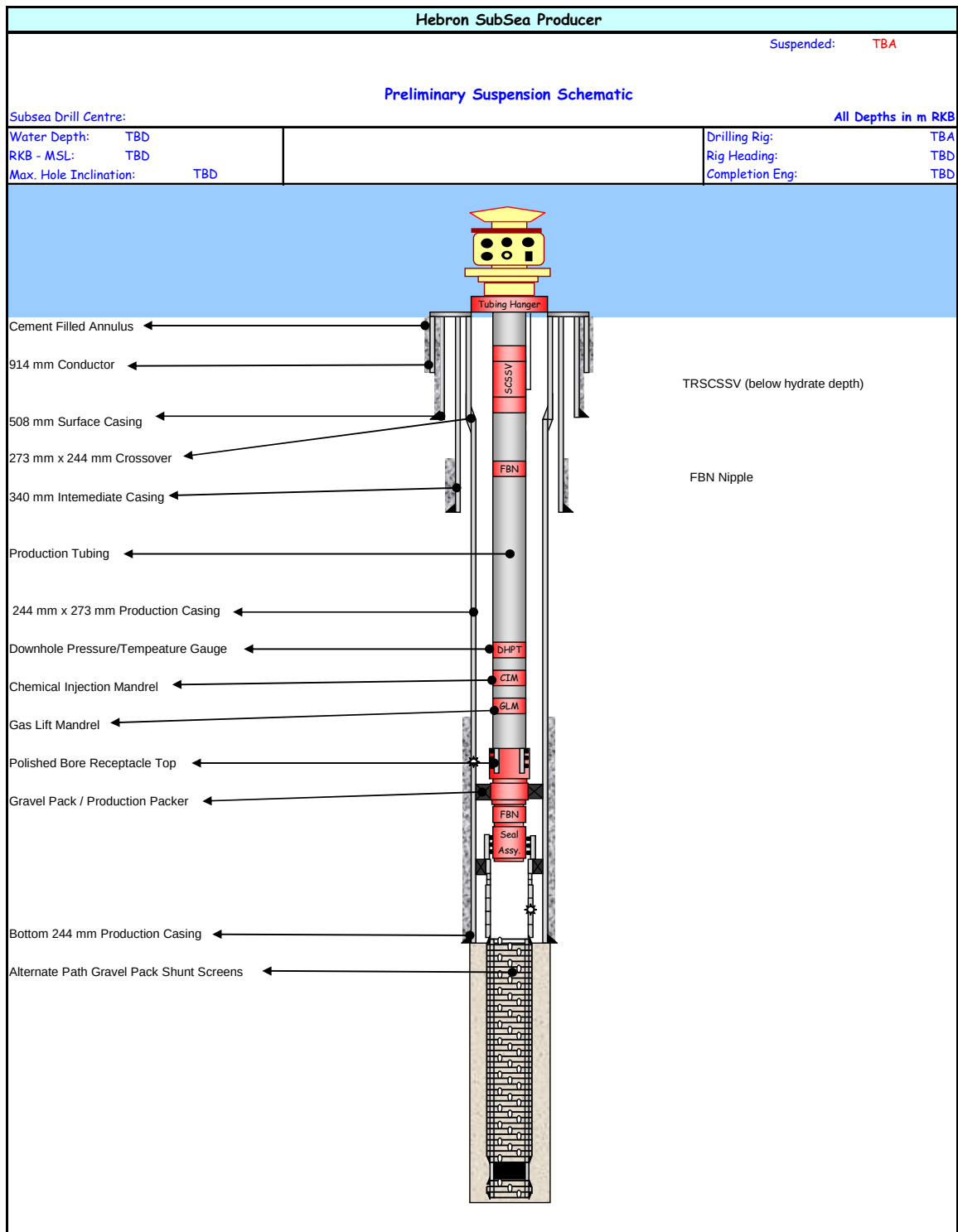


Figure 7.2-2: Typical Subsea Producer Schematic

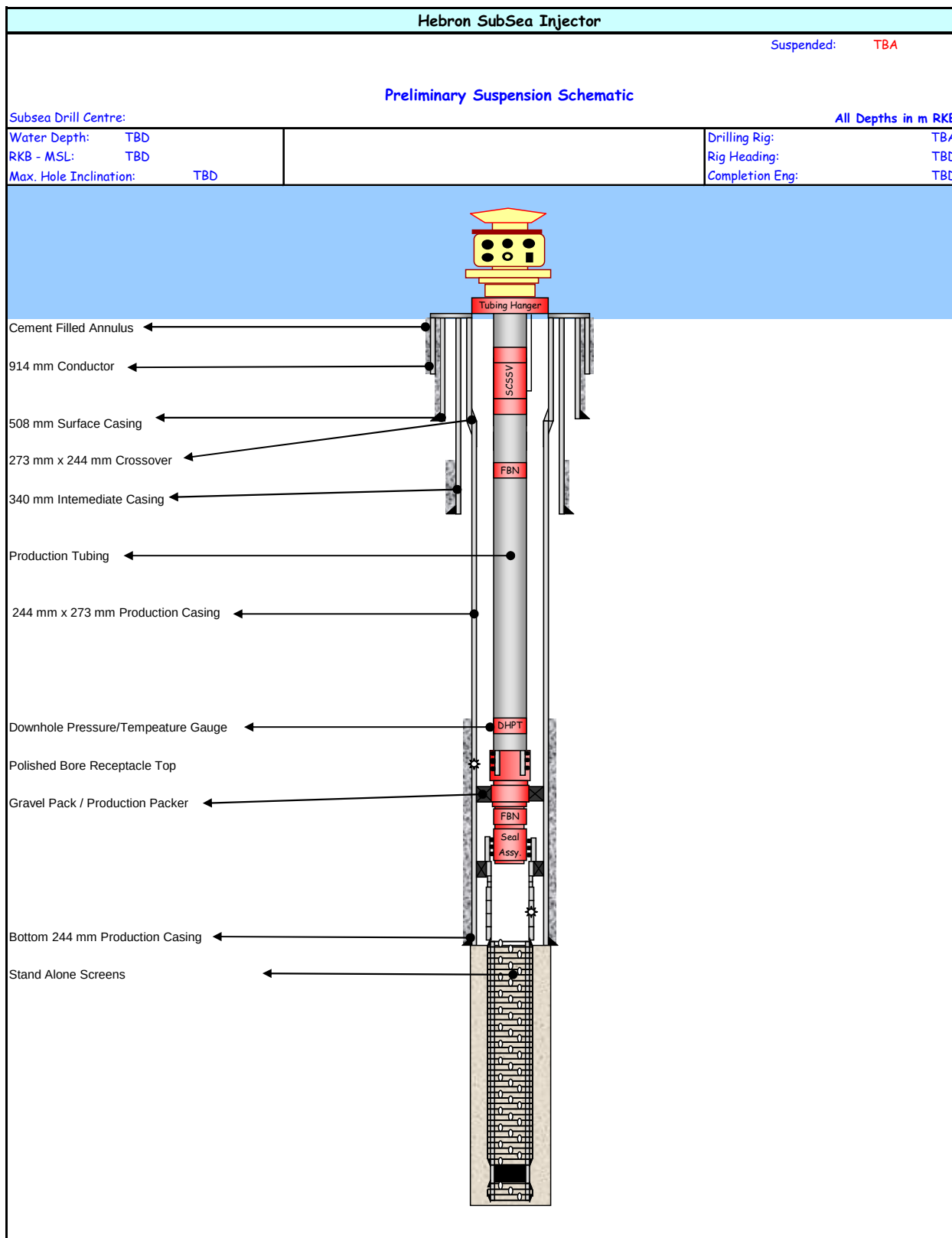


Figure 7.2-3: Typical Subsea Injector Schematic

7.2.6.2 Multi-Function Wellbores

A limited number of multi-functional wellbores may be required to facilitate reservoir depletion and support the gas management strategy. As discussed previously, a selected number of injectors may alternate between water injection and gas injection as a means of providing redundant gas injectors in the event the primary gas injectors are unavailable. Furthermore, dedicated gas injectors may be equipped to produce gas, if operations gas demand exceeds field wide gas production.

Specific well designs will be required to accommodate these functionalities. Material selection (metallurgy and elastomers) and equipment design will be completed once the full range of operating conditions is developed.

7.2.6.3 Completion Fluids

Completion fluids will vary depending on the operations and formations involved. In general, completion fluids may be used for wellbore cleanup, gravel pack sand placement, perforating operations, and annulus fluids (packer fluids). Packer fluids will follow local regulatory guidelines for required density, be benign in nature, and contain sufficient chemicals to mitigate wellbore corrosion over the life of the wellbore.

The details of these fluids will be determined during the FEED period and updated as improved materials or information become available during well operations. Both water based and NAF-based systems will be considered for the fluids. Completion fluids for perforating may also include the use of non-damaging brines, diesel or nitrogen blankets to provide under balance.

Corrosion management for the Hebron Pool 3 wellbores will be facilitated through a combination of proper material selection, cathodic protection, chemical inhibition and, where appropriate, internal/external coating systems. The well design will facilitate the possible use of ultrasonic imaging tools or calipers for internal inspection during the operating life of the wellbore.

7.2.6.4 Wellbore Safety Systems

Completion safety systems include the use of TRSCSSVs as a means of preventing uncontrolled flow from the wellbore in the event of failure of the subsea tree or wellhead system.

The subsea tree and wellhead will form an integral part of the wellbore safety system and will be discussed in more detail in Section 7.10 of this document.

7.2.7 Drilling Hazards

Typical problems that may be encountered in development drilling are discussed briefly below along with mitigation techniques. The details within well specific ADW's and the Operations Authorization will supersede any statements made in this section.

7.2.7.1 Shallow Gas Hazards

The hard gravel seafloor conditions and presence of occasional seafloor pits, scours and boulders may be considerations for semi-submersible rig anchorage.

Boulders are most probable in the upper 10 m, with low probability of isolated boulders to depths of ~120 m below seafloor (BSF). The presence of occasional seafloor and shallow subsurface boulders could potentially affect installation and alignment of structural casing, as well as drilling ROP.

A small-scale buried channel with possible thin coarse-grained sediment fill (<5 m) occurs in the southeastern part of the site at ~80-90 m BSF.

Prior drilling experience indicates potential for loss of circulation in the Oligocene Sandstone section in the surface casing interval at depths >600 m BSF.

There were no amplitude anomalies indicative of shallow gas identified within the survey site. There are no significant faults identified. Normal to near-normal pressures are anticipated in the tophole section.

ExxonMobil has shallow gas preparedness and drilling procedures incorporated into its **Standard Drilling Operations Policy** manuals. The policy includes incorporation of a drilling conductor, and discusses the use and specification of floating drilling well control systems. Issues such as equipment sizing, control system valve sequencing, and crew training are addressed in these manuals. Specific plans will be addressed further in the Drilling sections of the Hebron Pool 3 Operations Authorization Plan and integrated into each wellbore design via the individual ADW process.

7.2.7.2 Hole Stability

On high angle development wells, potentially unstable wellbore sections will be exposed whereby hole instability may become a challenge. The operator plans to employ an integrated analysis approach to determine the proper combination of fluid type and density to mitigate the onset of wellbore instability issues. Where instability does occur, the same integrated approach will be employed to assess the required fluid property changes, circulation rates, and pipe speeds (rotational and tripping) to effectively manage and remedy instability issues.

Final fluid selection will consider the needs of the overall well design and is to be determined during the FEED stage of the project. Stability studies based on the exploration and delineation wellbores, as well as offset projects in the region, will be conducted during FEED.

7.2.7.3 Formation Pressure

Neither abnormal pressures nor severe lost circulation zones have been encountered in drilling wells in those reservoirs targeted for initial

development. The primary mitigation to hazards posed by formation pressures is the proper selection of drilling fluid density and fluid type to create sufficient overbalance to counter the formation pressures expected. Where severe losses are encountered, the operator will employ several pre-established procedures to reduce and eliminate the losses to restore hydrostatic overbalance to the wellbore. Techniques range from solids manipulation of the drilling fluids and loss control formulations/pills, to squeezes and weighting agents. Required inventories of loss control materials will be available to ensure appropriate timely response to severe loss control events.

Governmental regulations and C-NLOPB guidelines, coupled with ExxonMobil Well Control Policies and industry-accepted drilling practices, will be followed to minimize the risk of well control incidents.

Drilling programs will be founded upon ExxonMobil's ***Floating Drilling Blowout Prevention and Well Control Equipment Manual*** for floating drilling Well Control Systems. This standard incorporates certain basic principles to protect personnel and to prevent the occurrence of uncontrolled events. Specifically,

- ◆ The standard prescribes practices that will be designed so personnel and public safety are paramount, and environmental protection is provided
- ◆ Preplanned operating procedures will be designed to rely primarily on hydrostatic pressure for well control during the time a BOP stack is not installed
- ◆ Installed subsea, subsurface and surface pressure containment equipment will be designed to confine an influx to the wellbore and to allow for controlled removal from the wellbore (either into a formation or to the surface)
- ◆ Identified components of pressure containment equipment that may be exposed to hydrogen sulphide, carbon dioxide, and other corrosive fluids will be designed to resist the harmful effects of these fluids at anticipated operating pressures and temperatures
- ◆ Pressure containment equipment will be installed, tested and operated in a manner to comply with applicable governmental regulations
- ◆ Qualified ExxonMobil field supervision will be provided to execute this standard properly

ExxonMobil's well control philosophy will entail considerations of BOP equipment specifications, ram location, as well as requirements for stack testing, the closing system, the choke manifold, trip tanks, and hydrogen sulphide (H₂S) service modifications (if required). Detailed efforts will be outlined in the Operations Authorization Application and individual well ADW applications.

7.2.7.4 Differential Sticking

Differential sticking of the drilling assemblies may occur across any permeable zones where fluid overbalance occurs i.e. hydrostatic pressure of the drilling fluid column significantly exceeds pore pressure, and is not unique to high angle wellbores. Proper well planning procedures identify permeable zones where excessive overbalances occur. The extent of the overbalance combined with assessment of the trajectory and drilling assembly quantify the risk posed by each occurrence. Control of drilling fluid properties, drilling fluid selection and good tripping procedures can reduce the risk of differential sticking. Where industry accepted techniques cannot fully abate an unacceptable risk, alternative designs will be proposed to reduce or eliminate the overbalance situation.

7.2.8 Material Selection

Material Selection for the Hebron Pool 3 wellbores will be based upon analysis of the fluid streams to which the tubulars, wellheads, and subsea trees will be exposed. Several options exist to mitigate the various forms of corrosion that may occur, including corrosion CRAs, coating systems, and cathodic protection systems. Specific studies will be undertaken by the Operator to identify feasible material options for all components of the wellbore.

7.2.8.1 Reservoir Souring

Potential exists for the presence of hydrogen sulphide (H_2S) in the fluids handled by the Hebron Pool 3 facilities. Wellbore materials and subsea trees will subsequently be exposed to these fluid streams resulting in the potential for various forms of corrosion including sulphide stress cracking. Hydrogen sulphide gas may also enter the gas lift stream, exposing the outer diameter of the production tubulars as well as the production casing, the wellhead, and the outer surface of the completion accessories.

Consideration for these occurrences will be incorporated into the material selection of the drilling and completion program, including identification of active and passive wetted surfaces as well as appropriate material mitigation measures.

Drill strings may be exposed to hydrogen sulphide during penetration of the reservoir. All Drilling Systems, including drill strings and drilling components, will receive due consideration for the effects of hydrogen sulphide as studies are progressed and associated risks defined.

7.2.9 Well Control System

Well control will be facilitated via a Well Control system consisting of a subsea BOP system, marine drilling riser and ancillary support systems. All Well Control systems will be in accordance with applicable regulations.

The BOP stack will include ram and annular style closing mechanisms. Subsea BOP stacks typically contain four to six ram BOPs and two annular BOPs. There is no single acceptable BOP stack arrangement, but there are operating characteristics to consider in the stack arrangement for the particular drilling program. Final selection of the BOP configuration will be a function of well design and the non-operator owned drilling rig that will be contracted to conduct drilling and completions operations. Working pressure, required kick tolerances, gas hydrates, trapped gas, testing requirements, stripping and hangoff requirements, pipe shear requirements, elastomer service conditions and temperature limits all have input on the final specification/selection of the BOP configuration.

The marine drilling riser is the conduit to attach the rig vessel to the BOP stack and wellhead on the seabed, and is used to convey drilling fluid and cuttings from the wellhead to the rig. The riser is also used to transport the BOP to and from the wellhead and serves as an attachment point for auxiliary piping (choke and kill lines) and umbilicals.

Several auxiliary systems will be employed to support the main systems. A choke and kill manifold will serve to direct well fluids to/from the wellbore as needed to maintain an appropriate hydrostatic column. A trip tank system will be employed to assist in monitoring hole volumes into/out of the wellbore. An atmospheric ("poor-boy") mud gas separator (degasser) system will be employed in the well control system to separate entrained gas returning in the well fluids. Mud Control monitoring systems will be utilized to measure fluid volumes stored in the drilling unit's storage tanks (pits).

The Well Control system for the drilling package will be of dimensions and pressure rating to handle all anticipated pressures in the field. The system employed will be supplied by the MODU contractor, and will meet or exceed required regulatory guidelines and ExxonMobil requirements for the wells to be drilled in the Hebron Pool 3.

7.2.10 Wellhead and Trees

The wellhead and subsea tree design will be in accordance with Newfoundland Offshore Petroleum Drilling and Production Regulations as well applicable industry codes. Provisions for TRSCSSV, gas lift, and chemical injection (both down-hole and at the wellhead) will be incorporated into the subsea tree design.

The wellhead and subsea trees will be rated to an appropriate pressure and temperature rating to handle the anticipated shut-in and flowing conditions, in accordance with governmental regulations and C-NLOPB guidelines. The trees will incorporate remote operated valves and production chokes (to facilitate control of the fluid flow from the wellbores) with redundant controls. The tree will be instrumented to permit remote monitoring of pressure and temperatures of the flowstream. The tubing hanger will be ported to accept

the necessary control lines required for downhole monitoring, and exceed the anticipated loads imposed by the completion assembly

The wellheads will be furnished with a connector to facilitate installation of the subsea tree. The wellhead will be equipped with hang off points for the required casing hangers. Contingency hanger locations will be supplied within the wellhead in the event upset conditions require an additional casing system to be installed.

8 DESIGN CRITERIA

8.1 Physical Environmental Criteria

The Grand Banks region has a harsh environment much like the northern North Sea. Intense storms occur frequently in winter with winds generally from the northwesterly and westerly directions. Fog restricted visibility is common, especially in the spring and summer months, when warm air masses overlie the cold ocean surface. In the Grand Banks area, there are sea ice incursions and icebergs. Superstructure icing can occur between December and March because of the wind and wave conditions, coupled with the low air temperatures. The highest waves occur from December to February.

8.1.1 Environmental Data

Existing environmental data planned for use in the preliminary design of the Hebron facilities during operation is discussed below. Referenced documents are included in the Part II documents of the Hebron Development Application.

The atmospheric and oceanic environment (climatic temperatures, waves, wind, currents and tides) of the Jeanne d'Arc Basin are described in Hebron Consolidated Metocean Criteria (CAHE-ER-JBSIT-50-220-0002).

Metocean criteria for the Bull Arm site can be found in report Hebron: Bull Arm Criteria (CAHE-ER-JBSIT-80-220-0001).

Bathymetric data at the Gravity Base Structure (GBS) location can be found in Hebron Development 2010 Geophysical Site Surveys(CAHE-FJ-GRSIT-00-000-0001). Similar data for the GBS construction site is shown in Geophysical and Bathymetric Survey Bull Arm Fabrication Site Reconnaissance Report (CAHE-FJ-GRSIT-80-000-0001).

The information shown on Tables 8.1-1 through 8.1-8, is obtained from Hebron Consolidated Metocean Criteria dated August, 2010 (CAHE-ER-JBSIT-50-220-0002).

Table 8.1-1: Air Temperature

Air Temperature (°C)													
Value	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Mean	-0.4	-1.0	-0.4	1.7	3.7	6.5	12.2	14.5	12.8	9.4	5.2	2.3	5.6
Min	-13.8	-13.5	-11.8	-8.5	-3.2	-0.8	3.6	6.9	6.2	0.6	-2.4	-6.4	-13.8
Max	10.2	10.4	10.2	11.4	13.8	14.8	19.1	20.0	19.1	16.1	14.8	11.8	20.0
Std Dev	3.3	4.1	3.4	3.3	2.8	2.7	2.8	2.3	2.5	3.2	3.6	3.3	6.1
95%LL	-5.3	-7.7	-6.6	-3.6	-0.1	2.7	7.0	10.3	8.3	3.9	0.1	-3.1	-3.7
95%UL	6.1	6.1	5.2	7.2	9.1	11.4	16.2	17.9	16.8	14.5	11.4	7.8	15.5

Table 8.1-2: Water Temperature

Depth (m)	Water Temperature (°C)				
	Value	Winter	Spring / Fall	Summer	Annual
0	mean	0.4	3.6	10.5	4.0
	min	-1.8	-0.6	4.2	-1.8
	max	4.8	11.0	15.4	15.4
10	mean	0.2	3.5	8.7	3.5
	min	-1.8	-0.6	0.1	-1.8
	max	4.8	10.8	15.4	15.4
20	mean	0.2	3.1	6.9	2.9
	min	-1.7	-0.8	-0.8	-1.7
	max	4.9	10.3	15.0	15.0
30	mean	0.1	2.5	4.1	2.0
	min	-1.7	-1.6	-1.6	-1.7
	max	4.8	10.1	12.5	12.5
40	mean	0.0	1.6	2.0	1.2
	min	-1.7	-1.6	-1.6	-1.7
	max	4.8	7.4	7.4	7.4
50	mean	-0.2	0.6	0.3	0.3
	min	-1.8	-1.7	-1.7	-1.8
	max	4.8	7.6	6.6	7.6
75	mean	-0.7	-0.6	-0.4	-0.6
	min	-1.7	-1.7	-1.7	-1.7
	max	1.0	2.8	1.9	2.8
Bottom	mean	-0.8	-0.8	-0.8	-0.8
	min	-1.7	-1.7	-1.7	-1.7
	max	1.0	2.8	1.9	2.8

Table 8.1-3: Visibility

Visibility (nm)	0.5 nm	1.0 nm	2.0 nm	5.0 nm	11.0 nm
January	9	13	18	28	55
February	14	18	22	31	54
March	12	16	21	32	56
April	23	27	31	40	61
May	30	33	36	43	57
June	31	35	39	47	67
July	55	59	62	66	78
August	30	33	36	43	58
September	12	14	17	23	39
October	9	11	14	21	41
November	14	18	21	31	49
December	11	14	18	31	58

Table 8.1-4: Ocean Tides

Parameter	Return Period		
	1-year	10-year	100-year
Astronomical Tide Range (m) [ft]	1.04 [3.41]	1.04 [3.41]	1.04 [3.41]
HAT Above LAT (m) [ft]	1.04 [3.41]	1.04 [3.41]	1.04 [3.41]
HAT above MSL (m) [ft]	0.53 [1.73]	0.53 [1.73]	0.53 [1.73]
MSL above LAT (m) [ft]	0.51 [1.67]	0.51 [1.67]	0.51 [1.67]
Storm Surge Above MSL (m) [ft]	0.50 [1.64]	0.61 [2.0]	0.73 [2.40]
Storm Surge Below MSL (m) [ft]	0.54 [1.77]	0.66 [2.16]	0.79 [2.59]
NOTES: HAT is Highest Astronomical Tide LAT is Lowest Astronomical Tide MSL is Mean Sea Level			

Table 8.1-5: Sea Water Properties

Chemical Property	Concentration (mg/L)
Na	9722
K	351
Ca	438
Mg	1167
Cl	17498
HCO ₃	128
SO ₄	1922
Physical Property	Value
Density @ 15.4 °C	1024 kg/m ³

Table 8.1-6: Extreme Waves

Return Period (yrs)	H _s (m) [ft]	T _p (s)	H _{max} (m) [ft]	TH _{max} (s)	1-hr ws _a (m/s) [knots]
95% non-exceedance	5.3 [17.4]	9.3 – 11.4	10.0 [32.8]	8.5 – 10.4	17.6 [34.2]
99% non-exceedance	7.8 [25.6]	10.7 – 13.0	14.7 [48.23]	9.7 – 11.8	21.7 [42.2]
1-year	10.5 [34.4]	12.1 – 14.8	19.7 [64.6]	11.0 – 13.5	26.2 [50.9]
5-year	12.2 [40]	13.1 – 16.0	22.9 [75.1]	11.9 – 14.6	29.0 [56.4]
10-year	12.9 [42.3]	13.5 – 16.5	24.3 [79.7]	12.3 – 15.0	30.1 [58.5]
25-year	13.7 [44.9]	13.9 – 17.0	25.8 [84.6]	12.6 – 15.5	31.4 [61]
50-year	14.3 [46.9]	14.2 – 17.4	26.9 [88.3]	12.9 – 15.8	32.4 [63]
100-year	14.8 [48.8]	14.5 – 17.7	27.8 [91.2]	13.2 – 16.1	33.2 [64.5]
Legend: H _s = significant wave height T _p = peak spectral wave period (±10% range) H _{max} = maximum individual wave height TH _{max} = period associated with H _{max} (±10% range) ws _a = Associated wind speed at 10 m height					

Table 8.1-7: Extreme Wind Speeds

Extreme Wind Speeds from MSC50 Grid Point 10834 @ 10 m elevation (m/s) [knots]			
Return Period (yrs)	1-hour	1-minute	3-Second
95% non-exceedance.	18.6 [36.2]	22.0 [42.8]	24.4 [47.4]
99% non-exceedance.	22.9 [44.5]	27.5 [53.5]	30.8 [59.9]
1-year	28.5 [55.4]	34.9 [67.8]	39.6 [77]
5-year	31.1 [60.5]	38.4 [74.6]	43.8 [85.1]
10-year	32.1 [62.4]	39.8 [77.4]	45.4 [88.3]
25-year	33.3 [64.7]	41.5 [80.7]	47.4 [92.1]
50-year	34.2 [66.5]	42.7 [83]	48.9 [95.1]
100-year	35.0 [68]	43.8 [85.1]	50.3 [97.8]

Table 8.1-8: Extreme Currents

Extreme Currents: Based on Terra Nova Current Measurements (m/s) [ft/s]			
Non-exceedence level or Return Period	Near-surface	Mid-depth	Near-bottom
50% non-exceedance	0.13 [0.43]	0.09 [0.30]	0.09 [0.30]
75% non-exceedance	0.19 [0.62]	0.13 [0.43]	0.14 [0.46]
90% non-exceedance	0.26 [0.85]	0.19 [0.62]	0.18 [0.59]
95% non-exceedance	0.32 [1.05]	0.22 [0.72]	0.21 [0.69]
99% non-exceedance	0.44 [1.44]	0.32 [1.05]	0.28 [0.92]
Maximum	0.94 [3.08]	0.74 [2.43]	0.48 [1.57]
1-yr	0.64 [2.10]	0.46 [1.51]	0.42 [1.38]
5-yr	0.84 [2.76]	0.58 [1.90]	0.51 [1.67]
10-yr	0.91 [2.98]	0.63 [2.07]	0.55 [1.80]
20-yr	0.98 [3.21]	0.67 [2.2]	0.58 [1.90]
50-yr	1.01 [3.31]	0.73 [2.39]	0.63 [2.07]
100-yr	1.16 [3.80]	0.77 [2.53]	0.66 [2.16]
200-yr	1.30 [4.26]	0.82 [2.69]	0.69 [2.26]
<i>Note: Maximum is the maximum measured value in the Terra Nova Data</i>			

8.1.1.1 Icebergs

The Hebron Project Area is located in the Grand Banks where iceberg impact and ice loading are of interest. Most of the icebergs that drift over the Grand Banks originate from the glaciers of West Greenland.

Reference is made to Updated Ice Load Design Basis for Hebron, dated Nov. 2009 (CAHE-CC-NBDES-50-220-0001). The most recent 25-year average iceberg frequency (expressed as areal density) is 0.81 for iceberg waterline lengths greater than or equal to 16 m (52.5 ft). Areal iceberg density values

for individual years during this 25 year period range from zero to 3.1. Icebergs have been sighted in the Hebron Project Area from February to August, with the greatest frequency (i.e. areal density) occurring in March to June. The mean iceberg drift speed for all icebergs in the Hebron Project Area is 0.31 m/s (1 ft/s) as shown in Table 8.1-9 below.

Table 8.1-9: Iceberg Data

Icebergs Parameters	Mean	Maximum
Frequency	0.81/degree square/yr	3.1/degree square (April)
Mass (t)	135,000	>750,000
Speed (m/s) [ft/s]	0.31 [1.0]	1.1 [3.6]

8.1.1.2 Pack Ice

Reference is made again to Updated Ice Load Design Basis for Hebron, dated Nov. 2009 (CAHE-CC-NBDES-50-220-0001). Pack ice (drifting sea ice) enters the Hebron Project Area in about one year out of four (24% of the years). This typically occurs in the February-April timeframe. When pack ice enters the area, the duration is usually one to two weeks, with about 60% of the water surface covered with ice. Recent years with pack ice in the Hebron area include 2008 and 2009. The pack ice that reaches the Hebron area is the southern edge of the ice pack and generally consists of small floes in an advanced state of deterioration. The pack ice is not a concern for platform loads; however it may interfere with iceberg management activities. Some interruption of tanker loading operations might be expected during times when pack ice is present.

Table 8.1-10: Pack Ice Characteristics

Characteristic	Mean	Std. Dev
Avg. Floe Thickness (m) [ft]	1.0 [3.3]	0.60 [2.0]
Floe Size (m) [ft]	11 [36]	3.9 [13]
Drift Speed (m/s) [ft/s]	0.27 [0.9]	0.20 [0.7]

8.1.1.3 Icing

In addition to iceberg and ice pack influences on the GBS, surface ice accumulating on structural components over the winter months is of importance. Table 8.1-11 provides expected thicknesses and densities of surface icing.

Table 8.1-11: Icing Data

Height Above Sea Level (m) [ft]	Ice Thickness and Density*			
	Sea Spray Ice		Atmospheric Ice	
	Thickness (mm) [inches]	Density (kg/m ³) [lbs/ft ³]	Thickness (mm) [inches]	Density (kg/m ³) [lbs/ft ³]
5.0 to 10.0 [16.4 to 32.8]	80 [3.2]	850 [53]	10 [0.4]	900 [56.2]
10.0 to 25.0 [32.8 to 82]	Linear Reduction from 80 to 0 [from 3.2 to 0]	Linear Reduction from 850 to 500 [from 53 to 31.2]	10 [0.4]	900 [56.2]
Above 25.0 [Above 82]	0	0	10 [0.4]	900 [56.2]
<i>Note:</i> * CAHE-CH-JBDES-50-220-0001, Metocean Design Criteria, dated Sept. 2005.				

8.1.2 Operating Limits by Environmental Factors

The Hebron Platform and Offshore Loading System (OLS) will be designed for environmental conditions defined in section 8.1.1. The limiting conditions imposed by environmental factors on the GBS, Topsides and OLS will be largely predicated upon the final design criteria adopted for the GBS and OLS that will be developed during front-end engineering and design (FEED).

Environmental factors could impose limitations on the following:

- ◆ Tanker loading
- ◆ Ice management
- ◆ Helicopter movement
- ◆ Crane operation
- ◆ Supply vessels
- ◆ Platform evacuation
- ◆ OLS maintenance and repair
- ◆ Oil spill response

8.1.3 Design Loads Methodology

The design, fabrication, installation and operation will conform to all applicable Canadian and Newfoundland and Labrador laws, regulations, codes and standards as well as ExxonMobil Engineering Practices (Global Practices) and Global Security Practices,

The design will also comply with applicable normally accepted industry practices such as American Petroleum Institute (API) recommended practices, American National Standards Institute (ANSI) / American Society of Mechanical Engineers (ASME) specifications and American Society of Civil Engineers (ASCE) specifications. The most recent edition of applicable codes will be used. In case of conflict between Company Global Practices and accepted industry practice, normally the most stringent requirements will take priority.

The effect of physical environmental loadings (wind, waves, current, ice, iceberg) on the facility will be analyzed using established recognized methods, and will be determined in accordance with the site's physical environmental criteria and governing design codes and standards.

Model testing may also be carried out to verify wave loads on the structure if determined to be necessary during FEED.

Iceberg impact loads will be calculated with a probabilistic procedure that accounts for the full range of environmental conditions that could influence iceberg loading at the Hebron location.

8.2 Functional Criteria

8.2.1 Design Flow Rate and Capacities

The process and utilities facilities will be designed to handle the forecast rates of production and injection fluids throughout the life of the field, Preliminary design rates are shown in Table 8.2-1, below.

Table 8.2-1: Design Rates

Design Element	Metric Units		Oilfield Units	
	Units	Design Value	Units	Design Value
Total Oil Production	m ³ /d	23,900	kbd	150*
Total Water Production	m ³ /d	45,000	kbd	283
Total Gas Handling	km ³ /d	6,650	MSCFD	235
Total Water Injection Design Rate	m ³ /d	57,300	kbd	360
* 150 kbd represents the nominal oil rate for design of the Topsides facilities. It is anticipated that, with de-bottlenecking and production optimization post-start-up, that the total oil production capacity of the facility could potentially be raised to 180 kbd.				

The design parameters stated above are based on the technical and economic evaluations carried out to date. As the reservoir modeling and project design progresses, the flow rates and capacities above will be further optimized. In addition, following construction and startup, an ongoing optimization program will be in place over the life of the field to capture potential incremental capacity through de-bottlenecking, increased well

performance or the tying in of additional reserves. These future optimizations combined with potential variations in oil properties may allow increased platform throughput rates at some point in time during the facility life.

The Topsides facilities will be designed to optimize system efficiency. The Hebron project team has completed a pre-FEED level reliability, availability, and maintainability simulation (RAM Study), which confirmed the selected equipment configuration should achieve a topsides reliability/uptime of approximately 95 percent. This RAM Study will be updated in FEED to assist in selection of optimal design configurations and equipment redundancy with consideration for cost/benefit analysis and evaluating operational efficiency against capital and operating cost impacts.

8.2.2 Design Life

The Hebron facilities will generally be designed for a service life of 30 years. Elements of the facilities may be designed for a service life of less than 30 years, provided this results in a reduction in life cycle costs and can be demonstrated to satisfy project risk management criteria.

The GBS design life will be 50 years to support future developments associated with the additional undesignated J-tubes and / or risers installed in the GBS shaft and to allow flexibility of decommissioning.

The design of the facilities will have the flexibility to handle subsurface uncertainty in the most cost-effective manner, without jeopardizing life of field operations, while also catering for future expansion requirements.

Materials will be selected in accordance with the requirements for their service, and environment. Consideration will be given for potential reservoir souring.

Topsides facilities will be designed for a nominal design life of 30 years. Surveillance and maintenance programs will be implemented throughout the operation of the facility and the production life may be extended through refurbishment or replacement of select components as require. Such programs would typically include measurements of corrosion, inspections and overhaul of equipment and structural inspections.

8.2.3 Well Fluids and Production Specifications

Table 8.2-2 provides well fluid compositional data for the Hebron reservoirs for use in future process modeling and heat and material balances.

Table 8.2-2: Recombined Wellstream Compositions (Mole Fractions)

Component	Hebron – Ben Nevis (Pool 1)	Hebron – Jeanne d'Arc (Pool 4)	Hebron – Hibernia (Pool 5)
Nitrogen	0.0034	0.0025	0.0025
CO ₂	0.004	0.0103	0.0103
Methane	0.38	0.4655	0.4655
Ethane	0.0228	0.0295	0.0295
Propane	0.0047	0.0338	0.0338
i-Butane	0.0025	0.0069	0.0069
n-Butane	0.0019	0.0184	0.0184
i-Pentane	0.0019	0.0089	0.0089
n-Pentane	0.0009	0.012	0.012
NBP[0]56	0.0032	0.0265	0.0265
NBP[0]103	0.0206	0.0643	0.0643
NBP[0]173	0.0599	0.0727	0.0727
NBP[0]238	0.1291	0.0712	0.0712
NBP[0]376	0.3651	0.1777	0.1777
NBP means Near Boiling Point (Degree C)			

The characterization of the pseudo components is given in Table 8.2-3.

Table 8.2-3: Characterization of the Pseudo Components

Name	NBP [C]	MW	Liq Dens [kg/m ³]	Tc [C]	Pc [bar]	Vc [m ³ /kg mole]	Acentricity
NBP[0]56	56.11	109.44	814.50	246.75	43.70	0.27	0.2059
NBP[0]103	102.50	135.12	874.28	312.60	44.21	0.30	0.2445
NBP[0]173	173.21	179.61	936.12	398.07	37.29	0.39	0.3228
NBP[0]238	237.98	228.87	974.50	467.38	31.27	0.50	0.4190
NBP[0]376	376.06	374.03	1044.45	602.61	21.84	0.78	0.6580
NBP means Near Boiling Point (Degree C)							

H₂S is not initially present in the reservoir. Field experience shows that injection of seawater (and hence sulphate ions) into the reservoir may result in generation of H₂S from the activity of sulphate-reducing bacteria (SRB). In addition, a study performed by Oil Plus Ltd. in 2005 concluded that some level of souring is likely given the reservoir conditions. Souring predictions ranged from H₂S concentrations of 29 ppm to 387 ppm in a seawater injection only case and from 155 ppm to 869 ppm in a produced water re-injection

case. The wide range of concentrations predicted for each water injection scenario is driven by uncertainty in the Volatile Fatty Acid (VFA) concentration in Pool 1 which has a suspect sample measurement with anomalously low VFA level. Further study is currently underway to reassess reservoir souring potential, facility impacts, and mitigation options. Measures will be implemented (such as chlorinating the injection water and/or adding biocides or other chemical agents) to minimize the potential for SRB growth. In addition, NACE MR01-75 compliant materials will be selected for the facilities.

8.2.4 Produced Water Characteristics

Initially the produced water will be primarily formation water; however, over time the produced water composition will change since sea water will be used to provide reservoir pressure support. The expected initial formation water composition is shown in Table 8.2-4 below.

Table 8.2-4: Formation Water Analysis

	Units	D-94 Well Ben Nevis Sample #1.15	M-04 Well, Ben Nevis Sample # 2.09	M-04 Well, Hibernia Sample # 1.07
Sodium, Na	mg/l	18600	21789	32297
Potassium, K	mg/l	14800	255	317
Calcium, Ca	mg/l	621	1541	1990
Magnesium, Mg	mg/l	365	413	283
Strontium, Sr	mg/l	212	234	303
Barium, Ba	mg/l	9.36	22.30	3.62
Iron, Fe	mg/l	5.54	11.20	4.13
Manganese, Mn	mg/l	0.0754	0.127	0.496
Lithium, Li	mg/l	2.88	3.39	5.65
Aluminum, Al	mg/l	134	0.062	0.420
Silicon, Si	mg/l	7.85	59.8	102.0
Boron, B	mg/l	12.6	92.7	186.3
Iodine, I	mg/l	<100	122.4	276.8
Phosphorus, P	mg/l	10.5	8.0	17.5
Zinc, Zn	mg/l	0.359	0.053	1.231
Chloride, Cl	mg/l	35600	34925	48528
Sulphate, SO ₄	mg/l	55	0	99
Bromide, Br	mg/l	67	101	134
Alkalinity	mg/l	381	570	560
Total organic acid	mg/l	220	1.05	138.15
pH @ 25°C	-	7.57	7.71	7.66
TDS	mg/l	66000	60273	85632

Density @ 25°C	g/cc	1.0476	1.0370	1.0525
<i>No valid sample of formation water available for Jeanne d'Arc</i>				

8.2.5 Export Crude Specification

The export crude will meet the following specifications:

- ◆ Maximum true vapour pressure (TVP) of 75.8 KPa at crude delivery / loading temperature
- ◆ Basic sediment and water (BS&W), maximum of 0.5% (volume basis)

8.3 Geotechnical Criteria

8.3.1 Seismic Hazard Potential

Reference is made to Final Report Seismic Hazard Analysis for the Hebron Site dated March 22, 2010 (CAHE-UR-BBSIT-50-220-0001). The Hebron Platform site lies within the eastern Canadian continental margin which is characterized by low to moderate levels of seismic activity, with infrequent large earthquakes. While the overall rate of seismicity in the region is low, there are zones of clustered, higher rate seismicity and historical earthquakes up to moment magnitude of $M = 7.3$ (e.g., the 1929 Grand Banks earthquake). However, there are no data indicating known seismic source faults in the vicinity of the proposed Hebron Platform; thus a seismic hazard analysis for the Hebron Platform site was completed for use in the preliminary design of the facility.

8.3.2 Soil Characteristics

Soil conditions at the Hebron Platform site have been derived based on site geotechnical investigations that are documented in reports listed below.

- ◆ CAHE-FJ-GRSIT-50-220-0001 - Final Report Volume 1 of 2, Static Laboratory Testing and engineering assessments, Geotechnical Investigation, Hebron Development dated March 31, 2006
- ◆ CAHE-FJ-GRSIT-50-220-0002 - Final Report Volume 2 of 2, Cyclic and Supplementary Static Laboratory Testing and engineering assessments, Geotechnical Investigation, Hebron Development dated March 31, 2006

In general, the site consists of dense to very dense sands overlaying over-consolidated clay, and over-consolidated clay inter-bedded with clayey and silty sands.

Boring core data from the site indicate a normally consolidated, surficial, medium dense granular stratum (sand) to a depth of 0.5 m (1.64 ft) below mudline (BML) (Layer I) grading to dense over-consolidated sand that varies in depth from 3 m to 8 m BML (Layer II). Soil Layers II and III, between 3 m (9.84 ft) and 8 m (26.25 ft) BML, consist of interlaced sand and clay.

Below this interval are continuous successions of overconsolidated, gradually changing to normally consolidated, clay and clayey sand layers, with occasional sand beds, to a depth of at least 120 m (394 ft). Drilling difficulties during the site investigation program suggest the presence of boulders and cobbles between the depths of approximately 1 m (3.28 ft) and 8.6 m (28.2 ft) BML (Layer II), which could pose an installation hazard to the GBS. A high-resolution geophysical survey that was performed during the summer of 2010 did not reveal the presence of surface boulders under the GBS footprint.

In addition to the laboratory testing reported in the documents mentioned above, advanced laboratory testing was carried out to develop static and cyclic strength, compressibility and permeability parameters for GBS foundation design. This testing is documented in reports listed below.

- ◆ CAHE-FJ-GRSIT-50-220-0003 - Laboratory Data Report, Geotechnical Properties Testing Program, Hebron Development, Grand Banks of Newfoundland, dated August 20, 2009
- ◆ CAHE-FJ-GRSIT-50-220-0004 - Evaluation of Laboratory Data, Geotechnical Properties Testing Program, Hebron Development, Grand Banks of Newfoundland, dated August 20, 2009
- ◆ CAHE-FJ-GRSIT-50-220-0007 - Supplemental Laboratory Data Report, Geotechnical Properties Testing Program Phase 3, Hebron Development, Grand Banks of Newfoundland, dated December 9, 2009

The soil and geotechnical information for Bull Arm site can be found in Bull Arm Marine Investigation, Geotechnical Report (CAHE-SA-GRSIT-84-000-0002) and Bull Arm Marine Investigation Phase 2, Geotechnical Report for the Hebron Project (CAHE-SA-GRSIT-84-000-0004).

Soil properties for Layers I through VI are given in Table 8.3-1 below.

Table 8.3-1: Soil Properties for Hebron GBS Stability Analysis

Layer	Depth (m)	Dr Relative Density (%)	Y' Submerged Unit Weight (kN/m³) [lbs/ft³]	Friction Angle (deg)	C _c Compression Index	m _v Coefficient of Volume Change (m²/MN)	C _v Coefficient of Consolidation (10 ⁻³ cm²/s)	Permeability (K _{T20} ,cm/s)
Layer Ia	0 - 0.3	60	8 [51]	30	--	--	--	3.103E-02
Layer Ib	0.3 - 0.6	75	9 [57]	35	--	--	--	1.666E-02
Layer Ic	0.6 - 1.0	90	10 [64]	40	--	--	--	9.252E-03
Layer Id	1.0 - 1.4	100	10 [64]	45	--	--	--	6.361E-03
Layer II	1.4 - 8.0	100	10 [64]	45	--	--	--	6.361E-03
Layer III	2.5 - 10	--	9 [57]	--	0.35	0.04 - 0.15	0.4-45	--
Layer IV ²	10 - 13	--	9 [57]	--	0.37	0.04 - 0.15	0.4-45	--
		75	9 [57]	35	0.15	0.04 - 0.15	0.4-45	--
Layer V	13 - 20	--	9 [57]	--	0.65	0.05 - 0.12	2-5	--
Layer VI ³	20 - 48	--	9 [57]	--	0.41	0.04 - 0.09	1-3	--
		--	9 [57]	--	0.15	0.04 - 0.09	1-3	--
		60	8 [51]	30	0.15	0.04 - 0.09	1-3	--
Notes: 1 - Below 2.5 m, the design shear strength along a potential sliding plane is a weighted average of clay and sand strengths based on percentage of GBS footprint area. 2 - For Layer IV, use a 50/50 weighted average of soil properties to approximate the interbedded nature of this layer. 3 - For Layer VI, use a 1/3rd / 1/3rd / 1/3rd weighted average of soil properties to approximate the interbedded nature of this layer.								

The shear strength of Layer III varies from 80 kPa at 3 m depth to 140 kPa at 9 m depth.

Estimated values of sea floor subsidence due to long term reservoir drainage will be evaluated separately.

8.3.3 Iceberg Scour

Reference is made to Updated Ice Load Design Basis for Hebron, dated November, 2009 (CAHE-CC-NBDES-50-220-0001). Iceberg scours and pits occur within the Hebron GBS Platform area. The mean iceberg scour depth is 0.43 m (1.41 ft), with a maximum scour depth of 3 m (9.84 ft). The mean and maximum scour width is 22.8(74.8 ft) and 118 m (387 ft), respectively. The mean scour length (which is not heavily influenced by water depth) is 645 m (2116 ft)., with a maximum observed length reaching 10.2 km (6.34 miles). The prevalent scouring direction appears to be oriented north-northeast-south-southwest. This infers a south to southwest scouring direction, consistent with the flow of the Labrador Current across the region. The design scour rate for the Hebron area has been set at 5.5×10^{-4} scours/km²/year, with a design pitting rate for the Hebron area set at 5.5×10^{-5} pits/km²/year.

8.3.4 Shallow Gas considerations

Preliminary review, of the geophysical survey completed during the summer of 2010, indicates no detection of shallow gas under the GBS footprint.

9 PRODUCTION INSTALLATION

9.1 Functional Requirements for Gravity Base Structure Mechanical Outfitting Systems

The descriptions given below are based on preliminary assessments and will be further developed during front-end engineering and design (FEED) and detailed design.

Mechanical outfitting systems for the Hebron Gravity Base Structure (GBS) categorized as permanent systems are described below:

9.1.1 Permanent Mechanical Outfittings

9.1.1.1 Crude Oil Storage

The crude oil storage system consists of storage cells, level monitoring equipment, custody transfer quality metering equipment, and dedicated booster pumps to lift the oil from the cells for delivery to the export pumps.

Functional requirements for this system include the following:

- ◆ Crude oil will be in direct contact with sea water in a wet storage system
- ◆ Approximately 190,000 cubic meters (1.2 million barrels) of working (operating) inventory based on storing 8 days production at peak stream day oil design rate
- ◆ Seven independently operable storage cells, each with an oil inlet and outlet
- ◆ No inspection or cleaning of the crude oil storage cells during the life of the field should be required
- ◆ The storage cells will be designed for a normal crude storage temperature of up to 50°C (122 °F)
- ◆ The GBS will be designed to permit a limited local effect due to temperature rise in one compartment resulting from an eight hour flow of 65°C (149 °F) crude
- ◆ The design will allow the interface layer between the oil and water to be removed from the storage cells

The exported oil volume will be measured by a fiscal meter located on the Topsides. The booster pumps will be submerged low enough in the pump caissons to have sufficient net positive suction head available for pumping oil at design rate.

Determination of working (operating) volume will, as a minimum, consider the safe operating range of level controls, dead space, volume loss to sediment

fallout from oil, and build up of the interface layer. The working volume is net of non-working heel and attic volumes.

9.1.1.2 Crude Oil Export Risers and J-Tubes

The current design includes 2 export risers and up to 12 J-tubes and / or risers. The number of J-tubes and / or risers will be further evaluated and decided during FEED.

9.1.1.3 Storage Displacement Water System

The functional requirements for the Storage Displacement Water (SDW) system include the following:

- ◆ Open to sea system (naturally pressured by seawater head)
- ◆ The SDW will be routed through a buffer cell with residence time equivalent to eight hours of production (nominal). However, the residence time may be reduced to fit void volumes available in the GBS
- ◆ Appropriate sampling of the SDW will be taken to ensure compliance with the Offshore Waste Treatment Guidelines (OWTG) (NEB et al. 2010) and the environmental compliance plan

9.1.1.4 Shaft Seawater Circulation System

A seawater circulation system will be required to maintain the temperature inside the shaft within acceptable limits. This system will be based on open natural convection requiring no mechanical equipment. As a minimum, the shaft will require convective water circulation to prevent stagnant water.

The seawater circulation system design will take into account the potential accumulation of drill cuttings at the bottom of the GBS.

9.1.1.5 Well Conductors and Conductor Guides

All conductors are routed vertically from Topsides, through the shafts, and out through the GBS base. Conductors will be guided by frames at suitable intervals as determined during FEED and detailed engineering. The requirements for the conductors are as follows:

- ◆ 52 well conductors will be required
- ◆ Well spacing will be about 2.5 m centreline to centreline in a rectangular pattern
- ◆ The conductor support system will be passive (i.e. guide frames). The support system will absorb side loading to prevent the conductors from buckling

Some conductors may be pre-installed to facilitate quick ramp-up of drilling activities. The drilling of the platform wells may result in top-hole cuttings being deposited inside the GBS shaft on top of the base slab. The design will

ensure the accumulation of cuttings does not interfere with platform wells or jeopardize the safe operation of the GBS.

9.1.1.6 Seawater Intakes and Water Discharge

There will be a number of seawater intakes which should be located far enough from wastewater discharge points and shale chute exit location to preclude accidental cross-contamination (taking into account predominant direction of currents). All seawater intakes will be equipped with fish protection devices (with grids, for example) if and as required by environmental regulations.

The seawater intake locations, orientation and elevations will be established considering produced water and drill cutting dispersion modeling and marine growth.

9.1.1.7 Fire Water Supply

A firewater supply system will provide Topsides with sufficient water for fire fighting purposes. Firewater pumps will not be subject to a single point failure. A minimum of two firewater intakes, which cannot be impaired by a single accident event, will be provided. The location, orientation and elevation of the intakes will be established with consideration of produced water, drill cutting dispersion modeling and marine growth.

To ensure maximum availability of the fire water pumps, the pumps will be located inside individual caissons. Caissons will be designed to protect the pumps from accident events in the GBS shaft. The pumps will be pulled, operated, and maintained from Topsides.

9.1.1.8 Seawater Supply

A seawater supply system will provide Topsides with water for process cooling, reservoir water injection, and other purposes.

The seawater pumps will be casing mounted with submerged pump ends. The pumps will be pulled, operated, and maintained from Topsides.

9.1.1.9 Pump Caissons

The design will allow for the following casings and piping arranged in a manner appropriate for the geometry of the GBS. The information in Table 9.1-1 is preliminary and will be updated during FEED and detailed engineering.

Table 9.1-1: Preliminary Caisson, Piping and Shale Chute Information

Item No	Qty	Service
1	7	Crude oil fill line for storage cells (one per cell)
2	7	Pump casing for oil booster pumps (one per cell)
3	4	Firewater pump caissons (minimum 4 at 50%)

Item No	Qty	Service
4	3	Pump casing for seawater supply pumps (minimum 3 at 50%)
5	1	Essential seawater lift pump caisson
6	1	Emergency seawater lift pump caisson
7	1	Produced water disposal line
8	1	Seawater return line
9	1	Sewage disposal line
10	2	Shale chute dump caisson
11	1	Displaced water sampling line
12	7	Oil cell vent lines (one per cell)
13	TBD	Seawater circulation lines (shaft annulus)
14	TBD	Biocide injection lines
15	7	Displaced water to buffer cells piping
16	3	Displacement water pump caisson
17	1	Open drain dump caisson

9.1.2 Visual Inspection and Instrumentation for Monitoring

9.1.2.1 Environmental Monitoring Systems

Environmental monitoring* systems will monitor various sea and weather conditions, as well as other meteorological data, in accordance with regulatory requirements. This information will be used to assist in the transfer of personnel, supplies, and offloading to the shuttle tanker. It will also be available to assist with emergency response to a situation threatening personnel, the environment, or the platform.

Environmental monitoring may include:

- ◆ Waterline elevation
- ◆ Wave height
- ◆ Barometric Pressure
- ◆ Wind speed / direction
- ◆ Air and sea temperatures
- ◆ Current speed and direction
- ◆ Visibility

**Note:*

Reference Document: NEB et al., Offshore Physical Environmental Guidelines, September 2008

9.1.2.2 Instrumentation (Alarm and Shutdown Systems)

The GBS instrumentation will form part of the integrated control and safety system of the platform.

Its primary function is to collect data that can be used to verify satisfactory performance of the structure after it has been installed.

Monitoring may be carried out for the following as determined during FEED:

- ◆ Settlement
- ◆ Inclination measurement
- ◆ Pore pressure measurement
- ◆ Base contact pressure measurement
- ◆ Acceleration measurement
- ◆ Temperature sensors
- ◆ Anodes
- ◆ Corrosion

9.1.3 Design Considerations for Sea Ice and Icebergs

The GBS will be designed to withstand loads from sea ice and icebergs using methodology defined in Section 8.1.3.

9.2 Topsides System Design

9.2.1 Overview

The Topsides will consist of:

- ◆ Production facilities for:
 - Separation of oil, gas and water
 - Treatment of produced water
 - Compression of gas for use in artificially lifting production from the wellbores and injection of gas for conservation
 - Injection of water to maintain reservoir pressure
- ◆ Drilling facilities to enable drilling, completion and maintenance of wells
- ◆ Utility systems including power generation and distribution

- ◆ Life support and safety systems including personnel accommodation for a normal maximum 220 personnel, integrated control and safety system, temporary safe refuge, and emergency evacuation and rescue systems

The descriptions of the systems and drilling facilities below are based on preliminary assessments and will be refined / revised during FEED and detailed design processes.

9.2.2 Production Facility Systems

The main function of the production facility will be to stabilize the produced crude by separating the water and gas from the oil. A schematic of the likely separation and compression configuration is provided in Figure 9.2-1.

A three-stage separation system is planned for separating and stabilizing the Hebron crude. Alternative processes may be reviewed as the facilities design develops. The high pressure separator will receive the fluids from the Hibernia and Jeanne d'Arc reservoirs (Pools 4 & 5), where the gas will be separated. The liquids will be mixed with the fluids from the Ben Nevis reservoir (Pool 1) prior to entering the medium pressure separator, which separates the bulk of the water and the gas. The oil then flows to the low pressure separator, where additional gas is released for vapor pressure control. From the low pressure separator the oil flows to the coalescers, where the oil will undergo its final treatment step to meet its basic sediment and water specification. To achieve effective separation between the oil and water, the fluids will be heated prior to entering the medium pressure and low pressure separators. Chemicals may also be used to aid in separation.

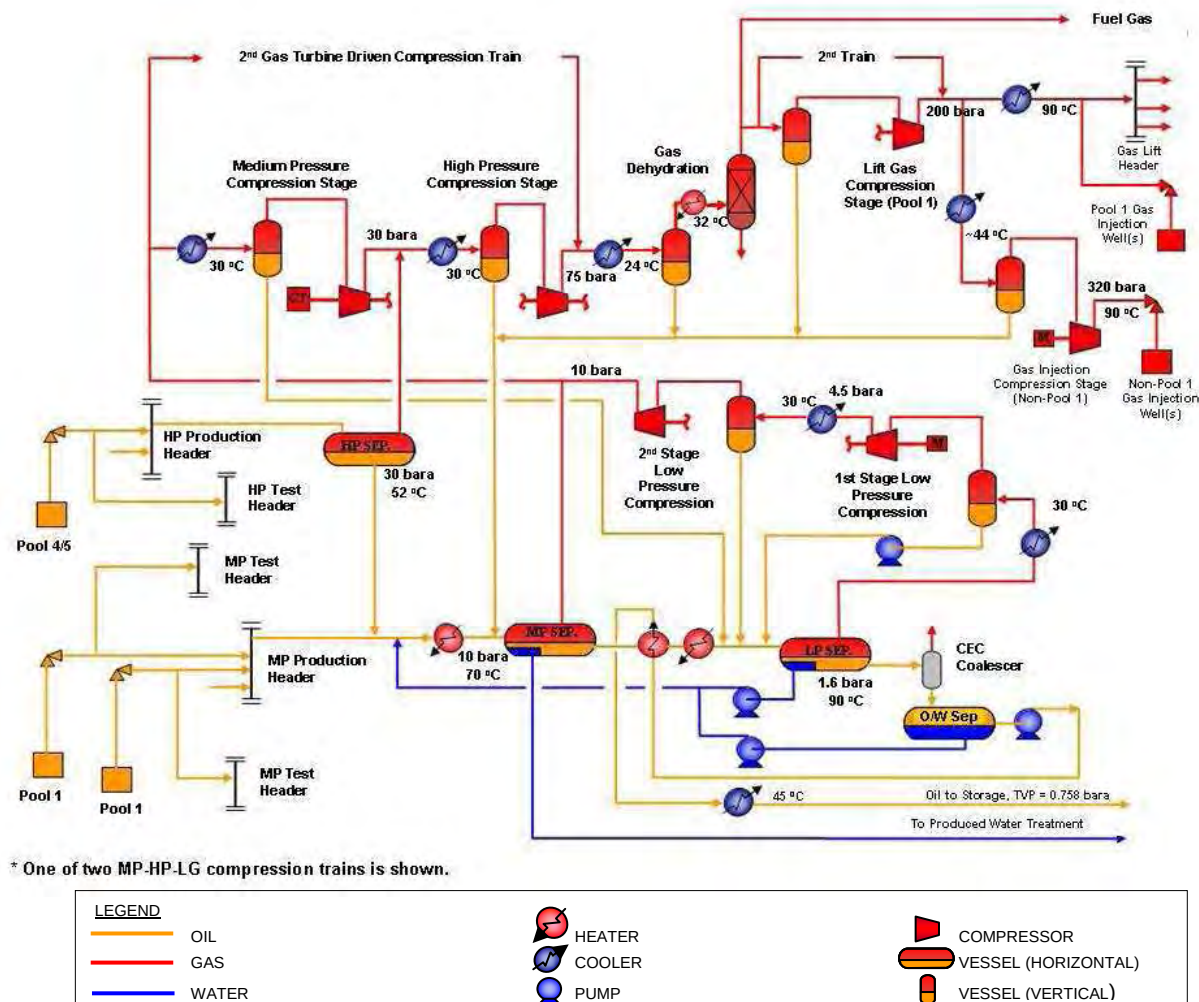


Figure 9.2-1: Separation and Compression Systems Schematic

The water from the medium pressure and low pressure separators and coalescers will be routed through additional treatment equipment to remove residual oil prior to being discharged overboard. Alternative options involving subsurface re-injection of the produced water will be studied. The gas from the high pressure, medium pressure and low pressure separators will be compressed, re-circulated for gas lift, used for fuel for platform operations or injected into a gas storage reservoir. The separation and compression system configuration will be finalized during future engineering work. High reliability equipment and operating and maintenance procedures will minimize facility downtime.

9.2.3 Production Separators and Crude Oil Treatment

The higher pressure, higher gas oil ratio (GOR) Hibernia and Jeanne d'Arc wells will first flow into a two-phase separator operating at about 30 bara (435 psi). This separator will separate gas from liquids. The liquids (oil and water)

from this high pressure separator will then flow to the medium pressure separator. The gas from the high pressure separator will join the outlet from the medium pressure compressor (~30 bara (435 psi)) and the combined stream will be compressed to about 75 bara (1088 psi).

The lower pressure, lower GOR Ben Nevis wells will be heated to about 70°C before flowing into the three phase medium pressure separator. The medium pressure separator will operate at about 10 bara (145 psi) and will separate the inlet into oil, water, and gas streams. Vessel Internal Electrostatic Coalescer (VIEC) will be included in the design for this separator to increase the separation efficiency. The gas from the medium pressure separator will join the outlet from the low pressure compressor (~10 bara (145 psi)) and the combined stream will be compressed to about 30 bara (435 psi). The water outlet of the medium pressure separator will flow to the produced water treating system before being discharged overboard or re-injected into a subsurface reservoir.

The oil from the medium pressure separator will be heated and then will flow to the low pressure separator, which will be operated at a minimum pressure of 1.6 bara (23 psi). The low pressure separator and its inlet heaters will be designed and operated to drop the pressure and add enough heat to stabilize the crude sufficiently to meet its vapor pressure specification. Water from the low pressure separator will be recycled to the medium pressure separator for heat recovery or will flow to the produced water treating system. Gas from the low pressure separator will be compressed by the low pressure compressor and then will join the gases from the medium pressure and high pressure separators in the compression train.

Oil from the low pressure separator will undergo electrostatic treatment and cooling prior to storage in the GBS storage cells and sales to tankers. Water from the Electrostatic Coalescer will be recycled to the medium pressure separator for heat recovery or will flow to the produced water treating system. Use of Compact Electrostatic Coalescer (CEC) treating technology will be included in the design.

Chemicals such as demulsifiers and defoamers may be used throughout the separation system to aid separation. Process flow, pressures, and temperatures will be further optimized and defined during the FEED and detailed design phases.

9.2.3.1 Test Separators

Two test separators are included to test wells for regulatory and surveillance purposes. These test separators may also be used for well unloading, well cleanup and well workover flowbacks. Due to the ratio of medium pressure (Ben Nevis) to higher pressure (Hibernia / Jeanne d'Arc) wells, some Ben Nevis wells will need to be tested in the "high pressure" test separator. While two test separators are currently required to meet regulatory testing

requirements, other options such as multiphase metering or modified test durations and frequencies may be pursued.

9.2.3.2 Gas Processing

The flashed gas from the low pressure separator is pre-cooled to about 30°C and scrubbed of liquid before entering the low pressure compressor. Interstage cooling to about 30°C and scrubbing is provided between the remaining compression stages - medium pressure, high pressure, gas lift, and gas injection. This interstage cooling and scrubbing removes the heat of compression as well as heavier hydrocarbons and water. Dehydration will be incorporated for fuel, lift, and injection gas streams.

Currently no additional gas processing is planned because the produced gas is predicted to have low CO₂ content and H₂S initially. However, field experience and studies performed by Oil Plus Ltd. in 2005 and 2010 show that the reservoir does have potential for souring as a result of sulphate-reducing bacteria (SRB) activity. An evaluation of future reservoir souring potential due to SRB activity is currently underway which will finalize the H₂S design basis for the facility. In addition, NACE MR01-75 compliant materials will be selected for the facilities and biocide will be injected down-hole to mitigate against souring. Facilities surveillance and maintenance programs will monitor and address H₂S impacts throughout the life of the facility. .

9.2.3.3 Compression and Gas Lift

Five stages of compression for flash gas are planned:

- ◆ Stage 1 - low pressure
- ◆ Stage 2 - medium pressure
- ◆ Stage 3 - high pressure
- ◆ Stage 4 - lift gas
- ◆ Stage 5 - injection gas

Fuel gas will be taken off downstream of the gas dehydration unit (after the third stage of compression) at about 73 bara (1,060 psi). Lift gas will be taken off after the fourth stage of compression at about 200 bara (2,900 psi). The remaining produced gas will either be injected to the gas storage reservoir at 200 bara (2,900 psi) or further compressed in an additional stage to approximately 320 bara (4,640 psi) for injection.

Compression stages 1 and 5 are relatively small electric motor-driven 1x100% compressors. Stages 2, 3, and 4 are divided into two 60% trains with each train driven by a gas turbine. All compressors are of the centrifugal type with pre-cooling and scrubbing.

Optimization of the compression and gas lift system by using different pressures, different interstage cooling temperatures, and multiple manifolds for gas lifting Pool 1 and Pools 4/5 may be studied.

9.2.3.4 Fuel Gas and Flaring Systems

During normal operations, associated gas will be cycled as gas lift gas and produced water oil flotation, consumed as fuel or re-injected. The large fuel consumers are the turbine drivers for the compressors and generators, but small amounts of fuel gas will also be used for flare pilots, as backup purge for flare system piping, and for flushing, blanketing, etc.

The vent and flare systems will be designed to manage fluids from excess pressure events as may occur during emergency or upset as well as normal material transfers, process start-up and shutdown, other operations, and maintenance. Fluids from well control or intervention excess pressure events will be managed by vent systems in the drilling areas. Fluids from process or utility system excess pressure events will be routed to vent and flare systems for safe disposal. Vent and flare systems will separate and recover liquids from the streams to be vented or flared.

Two flare systems are included. One flare system is designed to accommodate pressure relief events as from process upset or emergencies. The second flare system is designed to accommodate disposal of fluids for maintenance or operating contingencies, including clearing systems for maintenance simultaneous with a process upset.

Open, piloted flare systems will be adopted. Under mature, steady state operation there will be continuous, low rate background flaring attributed to flare pilot combustion and valve leakage. Process upset will cause larger amounts of gas to be flared until either the upset can be corrected or gas production is curtailed. It is anticipated that there will be a large volume of flaring during start-up, commissioning and initial operation prior to the gas compression system becoming available. Flaring will also occur when the low rate compressor taking suction from the low pressure separator is down for maintenance.

The primary function of the flare systems is to safely dispose of flammable gases during emergency unplanned events. To achieve this function, maximizing ignition probability, flame stability, and free movement of gas to the flare tip provides the highest level of safety. The Hebron Project evaluated pilotless flare technology and concluded that flare ignition by standard, continuous pilots without flare gas recovery is preferred.

Gas-fired continuous pilots are recommended by proven industry standards (**e.g.**, API STD 537) as providing high ignition probability and flame stability, and the Operator has significant operating and design experience with gas-fired continuous pilots. Alternative non-burning ignition devices such as the sparkers and glow bar are described in, but not recommended by industry

standards (**e.g.**, API STD 537) due to their inability to guarantee ignition and their inability to maintain a stable flame. Discontinuous ignition devices such as the ballistic pellet are not recommended by industry standards (**e.g.**, API STD 537). Use of a discontinuous ignition device with an open flare increases greenhouse gas (GHG) emissions as the GHG contribution of methane is much higher than the GHG contribution from methane combustion products (CO₂)

An open flare stack (i.e. without gas recovery) presents no obstructions to gas flow and is therefore the safest choice. Gas recovery systems require blockage (**e.g.**, valves) of the flare stack such that gas is recovered without the introduction of air, which could create a flammable atmosphere inside the flare header or gas processing facilities. This blockage introduces the possibility that, when emergency disposal of gas is required, the flare header remains blocked, with potentially severe consequences to the platform.

The emissions-reduction potential of gas recovery systems is minimal as only low-rate gas leakage may be feasibly recovered. The total quantity of low-rate gas leakage is very small compared to overall platform emissions (approximately 3 to 4 percent of total platform GHG emissions), and its recovery does not justify the potential reduction in platform safety caused by introduction of blockages in the flare header.

Systems operating at or near atmospheric pressure will be vented without burning via an atmospheric vent header that is terminated on the flare boom. Measures to reduce atmospheric emissions, including design and operating / maintenance practices to ensure high reliability of the facility will be evaluated as the design progresses.

9.2.3.5 Produced Water System

The Project Team is investigating the feasibility of injecting produced water into the reservoir for pressure maintenance. The overboard discharge of treated produced water is currently allowed by the Offshore Waste Treatment Guidelines (OWTG 2010).

ExxonMobil has completed its initial assessment of produced water re-injection (PWRI) and concluded there are unacceptable risks associated with initiating PWRI until factors associated with these risks are better known. Initial assessment indicates that PWRI into the producing formations for pressure maintenance purposes may be technically feasible, if technical risks can be reduced through further data acquisition and studies post start-up. ExxonMobil is committed to adopting PWRI once it is demonstrated that the risks and costs are manageable.

Preliminary studies identified several potential risks to adopting PWRI:

- ◆ Souring potential is up to 50% greater than with injecting sea water (SW) only due to temperature and the presence of Volatile Fatty Acids (VFAs)

- ◆ PWRI could result in greater than predicted increases in injection pressure (potentially beyond pressure limits)
- ◆ Fracture containment could be compromised with increasing use of produced water (PW)
- ◆ Scaling potential is increased when injecting PW into the formation

Confirming that these risks are manageable requires additional data that can only be obtained and analyzed post start-up and after several years of operation. For example, VFA content is highly variable across reservoirs and more produced water samples are required. Further, only a very small number of formation water samples are currently available – more are needed to draw firm conclusions.

A dedicated produced water disposal reservoir was investigated and found not to be feasible. The cumulative volume of water produced in 30 years is approximately 366 million m³ and a suitable reservoir could not be identified. In addition, over-pressuring of the disposal formation is a significant risk.

Hebron will initially operate with marine discharge of produced water at start-up. As more wells come on-line and production data and experience is gathered, further testing on rock properties and produced water/sea water/reservoir compatibility will be carried out as additional core samples and produced water become available. Hebron will switch to PWRI for routine operations, once testing and studies (post start-up) demonstrate that the risk and impacts of PWRI are understood and acceptable. When PWRI is adopted, the facility will maintain flexibility for marine discharge during unplanned events (e.g., equipment failure) or planned maintenance. In addition, it will be necessary to preserve the option to return to marine discharge if unexpected complications arise with PWRI (**e.g.**, loss of oil recovery, reservoir souring, scaling, plugging).

Facilities for PW treatment for initial operations will include the best commercially proven water treatment technology and equipment for offshore applications. Heavy oil separation challenges warrant a robust produced water treatment system that includes hydrocyclones, CFUs, and a degassing drum.

In addition, Hebron will include Vessel Internal Electrostatic Coalescer technology, which minimizes emulsion layer thickness and creates a better defined oil / water interface, helping to mitigate oil carry-under from separators to the produced water treating system.

Pre-investment has been made in the water injections system to allow for PWRI to be initiated at a later date. Design elements include:

- ◆ System designed to inject at predicted pressures required for PWRI
- ◆ Inclusion of manifolds to blend produced water with sea water make-up,

- ◆ Injection pump seals designed for the fine particles in produced water (a specialist application)
- ◆ Include space and connections for the future installation of the low pressure incremental equipment required to route produced water into the water injection system (*i.e.*, low pressure booster pumps and filters)

There is the potential for upset conditions to occur during early operation of the platform as a result of equipment turndown ratios, post-start-up equipment tuning and operational learning.

For further details, please refer to the ***Produced Water Management Strategy*** (CAHE-ED-SRZZZ-10-684-0001).

9.2.3.6 Water Injection System

Seawater that has been filtered, de-aerated and treated to control oxygen levels and bacteria will be metered and injected into the reservoir to maintain reservoir pressure and assist in oil production. A de-aeration system is included in the current design basis. The water injection system will be designed for an annual average simultaneous injection rate of about 57,300 m³/day (360 KBD) of water. A schematic of the likely water injection system is provided in Figure 9.2-2.

9.2.3.7 Chemical Injection Systems

Chemical injection requirements will be determined during the FEED phase and adjusted based on actual performance. Chemicals are generally required to enhance processing efficiency and are typical for this type of facility and fluid. These chemicals include scale inhibitors, wax inhibitors, pour point depressants, viscosity or drag reducing agents, asphaltene inhibitors, defoamers, biocides, flocculants, methanol, corrosion inhibitors, oxygen scavengers, glycols, hypochlorite, and demulsifiers. As engineering and operations input progresses, additional chemical injection requirements – beyond these typical needs – may be identified.

Following startup, adjustments based on actual production performance will be made to optimize production and chemical consumption. The chemical management system will be designed to meet the requirements of the Offshore Chemical Selection Guidelines for Drilling & Production Activities on Frontier Lands April 2009 (NEB 2009).

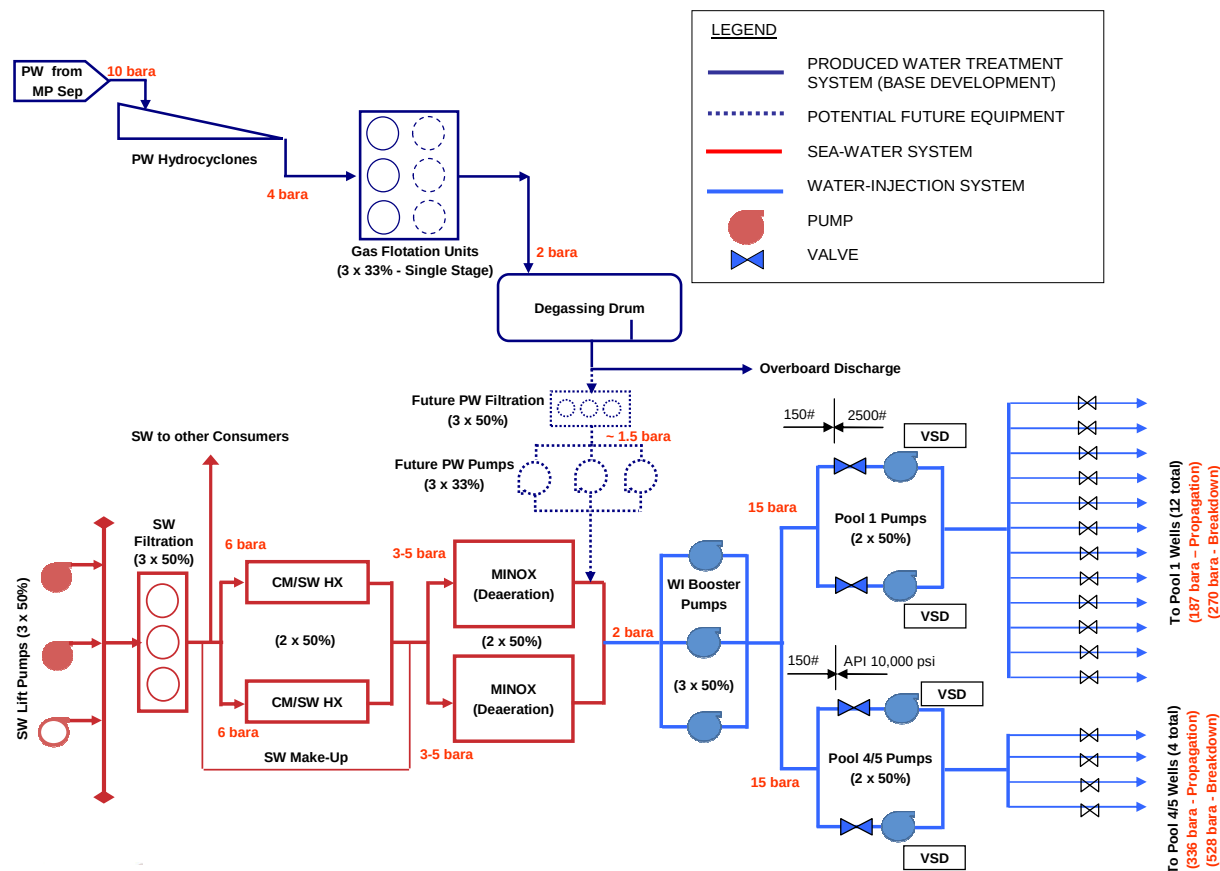


Figure 9.2-2: Water Injection System

9.2.3.8 Control System

Process control and safety functions will be implemented in an Integrated Control and Safety System (ICSS) incorporating the following subsystems:

- ◆ Process Control System (PCS) with Operator Graphics / Consoles as required for Operational requirements
- ◆ Safety Instrumented Systems (SIS) to facilitate Abandon Platform Shutdown (APS), Emergency Shutdown (ESD), Fire & Gas (F&G), Process Shutdown (PSD) and Drilling Shutdown (DSD) safety instrumented functions
- ◆ Instrument Asset Management System for archiving of process and systems diagnostic data

The process control system will perform primary process control, monitoring and data acquisition functions.

The SIS will implement safety functions utilizing logic sequencing and actuation of devices to place the platform in a safe state. These systems will

interface to the Public Address / General Alarm System (PA/GA) to provide distinct audible and visual alarm notification.

9.2.3.9 Power Generation

The current preliminary power generation system design is based upon four turbine driven main generators (at least two of which will have dual-fuel capability), each capable of producing up to approximately 30 MW for a 4x33% configuration, as well as separate emergency and essential diesel generators. The final power generation system configuration and capacity will be the subject of further engineering development studies and could change based upon updated subsurface data, artificial lift requirements and sparing / availability studies.

9.2.3.10 Fluid Measurement, Sampling and Allocation

Metering systems will be developed and selected per the C-NLOPB Measurement Guidelines (October 2003). Metering systems will be further optimized and defined during the FEED and detailed design phases. The conceptual design for measurement includes the following aspects:

- ◆ Wellhead and flowline measurement: Volumetric flow will be measured to gas injection, water injection and gas lift wells. Each well will also be equipped with down-hole pressure & temperature (P&T) measurement.
- ◆ Production metering: Each liquid and gas stream leaving the following vessels will be metered and have provision for sampling:
 - HP Separator
 - MP Separator
 - LP Separator
 - Oil/Water Separator
 - Test Separators
- ◆ Gas Metering: Gas streams will be metered and have provision for sampling, including total fuel gas, total gas injection, total lift gas and flare gas.
- ◆ Water Metering will include metering and provision for sampling of total water injection, total cutting injection and produced water overboard.
- ◆ Custody Transfer Meter will be designed in accordance with API MPMS and traceable to a NIST standard and will incorporate the following major design elements:
 - Multi-meter run design complete with stationary bi-directional prover loop
 - Flow proportional automatic sampling system with jet mixer

- Online WIO Analyzer
- Dual density meters including sampling provision for calibration
- Flow Computer and Supervisory Computer for reporting
- ◆ Facility Balance will be performed on significant flows in and out of facility. Produced fluids will be allocated back to each well using well test data
- ◆ Field Allocation may be required for future subsea opportunities:
 - Each subsea development will have appropriate meter provisions for field allocation, if required
 - MP separator crude meter piping will include space provisions for future master meter installation so it can be utilized as the field allocation meter for the Pool 1, 4, & 5 wells, if required.

9.2.3.11 Other Systems

Other systems are currently anticipated to include:

- ◆ Process Cooling – Cooling will be provided by indirect sea water / cooling medium exchange
- ◆ Potable and Service Water – A service water system will be installed to provide utility water for washdown and drilling and to produce potable water
- ◆ Jet Fuel – A jet fuel storage and pumping system will be installed to provide refueling capability for the helicopters servicing the installation
- ◆ Diesel – A diesel fuel storage and distribution system will be installed to provide fuel for the power generation during initial drilling and field production ramp-up, black start, shutdown and upset periods. It will serve a number of consumers such as drilling, fire water pump drivers and gensets, emergency and essential generators, and lifeboats
- ◆ Compressed Air – A compressed air system will be installed to provide utility air, instrument air and source air for nitrogen generation
- ◆ Inert Gas – An inert gas system (e.g. nitrogen) will be provided for flushing and inerting purposes
- ◆ Hydraulic Power – A central hydraulic storage, pumping and distribution system will be installed to provide high pressure hydraulic fluid to end users such as Topsides hydraulic valves, Xmas tree valves and wellhead valves
- ◆ Heating Medium – A heating medium system will be installed to supply hot fluid to heating, ventilating and air conditioning systems, as well as process heat exchangers. The heating medium is anticipated to be heated by waste heat recovery units on the turbines

- ◆ Drain Systems – Pressurized (closed) drain systems will be used to collect and appropriately dispose of oil, gas, and water from maintenance activities. Open-to-atmosphere (open) drain systems will be used to collect and appropriately dispose of oil and water run-off from decks to prevent it from reaching the sea.
- ◆ The closed drain system will include separation and pressure reduction equipment to separate oil, gas and water. Oil will be recycled back into the process stream. Gas will be vented, flared, or compressed for fuel. Water will be treated prior to being discharged to the sea in accordance with OWTG (NEB et al. 2010)
- ◆ The open drain system will separate oil from water before disposal overboard in accordance with OWTG (NEB et al. 2010)
- ◆ Sand Handling System - All separators including the produced water degassing drum will be equipped with a sand jetting system. Accumulated sand will be removed by jetting the vessels or by mechanical means. Disposal of sand removed from vessels will be in accordance with applicable regulations
- ◆ Solid and Food Wastes – Solid and food wastes will be handled according to all applicable regulations and guidelines. Per current regulations, food wastes will be macerated to a particle size of 6 mm or less prior to discharge to sea. Solid wastes will be compacted if practicable and transported to shore for proper handling and disposal. A trash compactor will be provided for compactable solid waste
- ◆ Sewage System – A sewage treatment system will as a minimum meet local waste disposal regulations, which currently require maceration of all domestic sewage to a particle size of 6 mm or less prior to discharge to sea. Effluent will be overboarded via the black / grey water disposal line
- ◆ Wellhead and Production Trees - The wellhead and Xmas tree design will be in accordance with Newfoundland Offshore Petroleum Drilling Regulations as well as applicable industry codes. Refer to Section 7.11 for further details

9.2.4 Safety Systems

The Operator is committed to conducting its business in a responsible and ethical manner that prioritizes the protection of the safety and health of employees, others involved in its operations, its customers and the public and that protects the environment. These commitments are documented in the safety, health, environmental, product safety and security policies of the Operator. The Operator will comply with all federal and provincial legislation.

9.2.4.1 Alarm and Shutdown Systems

Hebron Platform will have alarm and shutdown systems for the protection of personnel, the environment, and assets from fire and explosion events.

An ICSS will provide an integrated monitoring, control, protection, and safety system for the entire production facility.

SIS will be separate from the PCS and have no function related to, or affected by, the PCS. SIS shutdown logic will be separated into four categories: APS; ESD (includes F&G detection systems); PSD; and DSD.

The PCS will monitor alarms and key functions for each of the safety systems via redundant data links.

The shutdown systems will provide:

- ◆ Monitoring for abnormal process conditions
- ◆ Monitoring for fires and accumulations of flammable or potentially harmful gases
- ◆ Monitoring for abnormal drilling facilities conditions
- ◆ Automatic initiation of appropriate protective actions to isolate the source of a disturbance, to minimize sources of ignition, and to activate fire suppression systems
- ◆ Annunciation of alarms to alert personnel and identify the general location of the hazard
- ◆ Interface with facility PA/GA system for annunciation

The SIS Shutdown Systems are based on programmable electronic systems capable of satisfying the Safety Integrity Level requirements established for each SIS application.

The SIS functions will generally operate in a “fail safe” manner. Where functionality has been determined to require “energize to trip” logic, as in the case of fire detection / suppression systems, line monitoring will be implemented to detect failures that are capable of preventing the defined functionality.

Generally dedicated SIS controller(s) will be provided for shutdown groups (e.g. APS/ESD/F&G, PSD and DSD). For each system, maintenance bypass and resets will be performed from the PCS with combination keylock switches and password protection.

Boundary valves will be provided at the facility boundaries, usually on incoming and exiting pipelines at each site. These valves will be designed to close by the SIS PSD and require a manual reset after a trip.

9.2.4.2 Fire and Gas Detection System

Hebron Platform will have fire and gas detection systems for the protection of personnel, the environment, and assets from fire and explosion events.

Automatic fire detection will be installed in all areas of the installation where a fire may occur. Gas detection will be installed at locations with increased potential for release such as the wellbay, at locations with increased vulnerability to gas ingestion such as heating, ventilating and air conditioning and gas turbine intakes, and in enclosed areas. For each area the types of detectors will be selected such that the types of fire that could occur are detected at their incipient stage and spurious alarms are minimized. The installation will be raised to emergency alarm status on detection of a confirmed fire. A combination of optimum selection of detector types and voting of detectors will be used to minimize spurious alarms leading to unwarranted executive actions while still achieving reliable detection. All F&G Detection will be monitored and controlled from the Hebron Central Control Room.

Given the potential for gas souring later in field life, gas detection requirements for H₂S are under evaluation and will be incorporated as required to meet operational safety requirements.

9.2.4.3 Fire Suppression Systems

Hebron Platform will have multiple fire suppression systems:

- ◆ Water deluge systems in the Process Area supplied by the firewater ring main. Provision for automatic injection of foam will be included in the deluge systems as determined by Fire Risk Analysis.
- ◆ Individual equipment water spray systems in the Process Area supplied by the firewater ring main. Provision for automatic injection of foam will be included in the water spray systems as determined by Fire Risk Analysis.
- ◆ Operator-directed fire monitor systems at platform locations as determined by the Fire Risk Analysis. Provision for automatic injection of foam will be included in the fire monitor systems as determined by Fire Risk Analysis. Fire monitor systems are supplied by the firewater ring main.
- ◆ Live hose reels at each end of each level of the living quarters, and possibly an additional live hose reel on each level near the middle. Hose reels are supplied by the firewater ring main and are preferentially located in stairwells
- ◆ Live hose reels in the wellhead / wellbay area and other platform locations as determined by the Fire Risk Analysis. Hose reels are supplied by the firewater ring main
- ◆ Automatic sprinkler systems in the living quarters per NFPA 13. Sprinkler systems in the living quarters are supplied by fresh water with backup

from the firewater ring main. Water mist systems may be considered for this service during FEED

- ◆ Water mist systems in sensitive mechanical equipment enclosures such as gas turbines. Water mist systems are self-contained and designed for short-term use. Water mist systems are replenished with fresh water
- ◆ Inert gas systems (FM200) in switchgear rooms as determined by the Fire Risk Analysis
- ◆ Dual-agent hose reels at platform locations as determined by the Fire Risk Analysis. Dual agent hose reels are supplied by a system containing a fixed quantity of aqueous film-forming foam solution and dry chemical such as potassium bicarbonate

Firewater supply capacity is determined by the single largest credible fire scenario, taking into account hydrocarbon fluid types and inventories, platform layout, and the location of fire and blast walls. At least one spare pump is provided per C-NLOPB Installation Regulations. Firewater pumps will not be subject to single point failure. In the base design, firewater is supplied by 4, 50% capacity pumps. Firewater pump drivers will be electric, with each motor supplied by a diesel-driven generator. The diesel generators are located close to the living quarters within individual fire protected rooms and as far from process hazards as possible. The firewater pumps are submerged inside caissons in the GBS central shaft, with access from Topsides.

9.2.4.4 Safety Stations

Hebron Platform will have two Evacuation Muster Areas; one in the living quarters adjacent the lifeboats and life rafts and another at the opposite (Processing) end of the platform adjacent the lifeboats and life rafts at that end of the platform.

The Muster Area in the living quarters will be a Temporary Safe Refuge, with the means to monitor installation alarms, to communicate externally with an emergency control centre and rescue party, and to communicate internally, including use of the public address system. The living quarters is protected from platform hazards by a minimum 2-hour rated firewall, allowing time for emergency response and orderly evacuation. This firewall rating may be adjusted based on the results of studies during FEED.

The Muster Area at the Processing end of the platform will be protected from environmental and platform hazards as determined by studies during FEED. The intent of this second area is to allow personnel trapped at the Processing end of the platform by gas release, smoke, fire or explosion to muster and don environment survival suits safely, communicate with the Temporary Safe Refuge, and to evacuate in orderly fashion. This second Muster Area will not

have the same monitoring and control capabilities and may not have the same protection time as the Temporary Safe Refuge.

All of the personnel on board (POB) will be equipped with personal environment survival suits to be kept in individual living quarters rooms. The Temporary Safe Refuge and secondary Muster Area will together contain additional survival suits for a minimum of 100% of the POB and sufficient space for donning.

Hebron Platform will be equipped with a minimum of 200% POB capacity in lifeboats, 100% capacity in life rafts, and 100% capacity in lifejackets. These will be distributed between the muster areas according to the results of the Escape, Evacuation, and Rescue Analysis during FEED. Requirements of the CAPP Atlantic Canada Offshore Petroleum Industry Escape, Evacuation and Rescue Guide (2010) will be assessed during this study.

Hebron Platform will be equipped with additional lifesaving equipment as required by the Newfoundland Offshore Petroleum Installations Regulations, including lifebuoys, radio beacons, and equipment installed / stored in each lifeboat.

The effectiveness and utility of dry evacuation systems will be studied and considered for implementation if they demonstrate improved utility, reduced risk, and can be certified within the timeline of the project.

9.2.5 System Limitations

The Topsides facilities will be designed to optimize system efficiency. The Hebron project team has completed a pre-FEED level reliability, availability, and maintainability simulation (RAM Study), which confirmed the selected equipment configuration should achieve a topsides reliability/uptime of approximately 95 percent. This RAM Study will be updated in FEED to assist in selection of optimal design configurations and equipment redundancy with consideration for cost/benefit analysis and evaluating operational efficiency against capital and operating cost impacts.

The main compression (HP/MP/LG), water treatment and water injection systems include some measure of redundancy to allow production to continue at reduced rates in the event of equipment failure. Power generation will be installed in a 4x33% configuration to ensure full power is available if a single turbine fails.

9.2.6 Provisions for Future Expansion

The current Hebron design includes provisions for future subsea tie-back installations, including a potential Pool 3 development. Preliminary sizing of the J-tubes and risers is based on preliminary Pool 3 subsurface modeling and analysis. Riser sizes for the second future subsea tie-back will be selected identical to those defined for the Pool 3 subsea tie-back.

When the tie-backs are installed, the following additional equipment will be required in the wellbay area and space will be provided in the initial layout for eventual installation of the following equipment:

- ◆ Pull-in facilities for risers and umbilicals
- ◆ Umbilical termination assembly – one for each umbilical
- ◆ Hydraulic power unit(s)
- ◆ Subsea master control station – one per tie-back
- ◆ Subsea system electric power unit (panel / cabinet) – one per tie-back
- ◆ Pig launcher and receiver – one set for each tie-back flowline (these items may be located on the tie-back modules rather than in the wellbay area)

Production from the future tie-backs will be processed in existing process equipment; however, heating of the satellite flow streams, primary separation and crude washing (to remove methanol or glycol injected subsea to control hydrates), and metering may be required prior to introducing the fluids to the main separation train

Given the unknowns associated with development decisions and timing for future satellite reserves, the planning assumption is that future production equipment (pig launcher and receiver, flowline heater, separation, metering, chemical injection systems, water injection pumps, lift gas dehydration and compression, etc.) for the satellites will be installed as needed in future modules to be hung off the side of the existing Topsides. Likely attachment location(s) will be identified and allowances in the initial structural design will be made for support of these modules. Space will also be provided in the existing pipe racks, cable trays, etc. for access to and from the future modules and spare connections will be provided on the production manifolds and various utility system headers to tie in the satellite equipment.

9.3 Subsea Production and Injection System

The full development option of Hebron Pool 3 is as a subsea tie-back to the Hebron GBS. A conceptual design for the subsea production and injection system has been developed (Figure 9.3-1) and consists of the following elements:

- ◆ One or more subsea excavated drilling centres with production, water injection, and gas injection manifolds and trees, umbilical termination assemblies, subsea distribution units, control pods, jumpers and flying leads.
- ◆ Production, water injection, gas injection, gas lift, and well stimulation pipelines, complete with Pipeline End Terminations, and control umbilicals between the GBS and the subsea drilling centers.

- ◆ Pipeline risers and umbilical J-tubes pre-installed in the GBS
- ◆ Topsides equipment - master control station, topsides umbilical termination assemblies, pig launchers and receivers, hydraulic power unit, electrical power unit, and chemical injection skids.
- ◆ Flowline tie-ins between the risers and the GBS topside process facilities.

Subsea facilities will include all equipment necessary for the safe, efficient operation and control of subsea wells, and transportation of production and injection fluids between the subsea wells, subsea manifolds, and GBS facilities. Multiphase flow meters will be used to apportion produced fluids back to each well. Specifics of the conceptual design may change as designs are finalized.

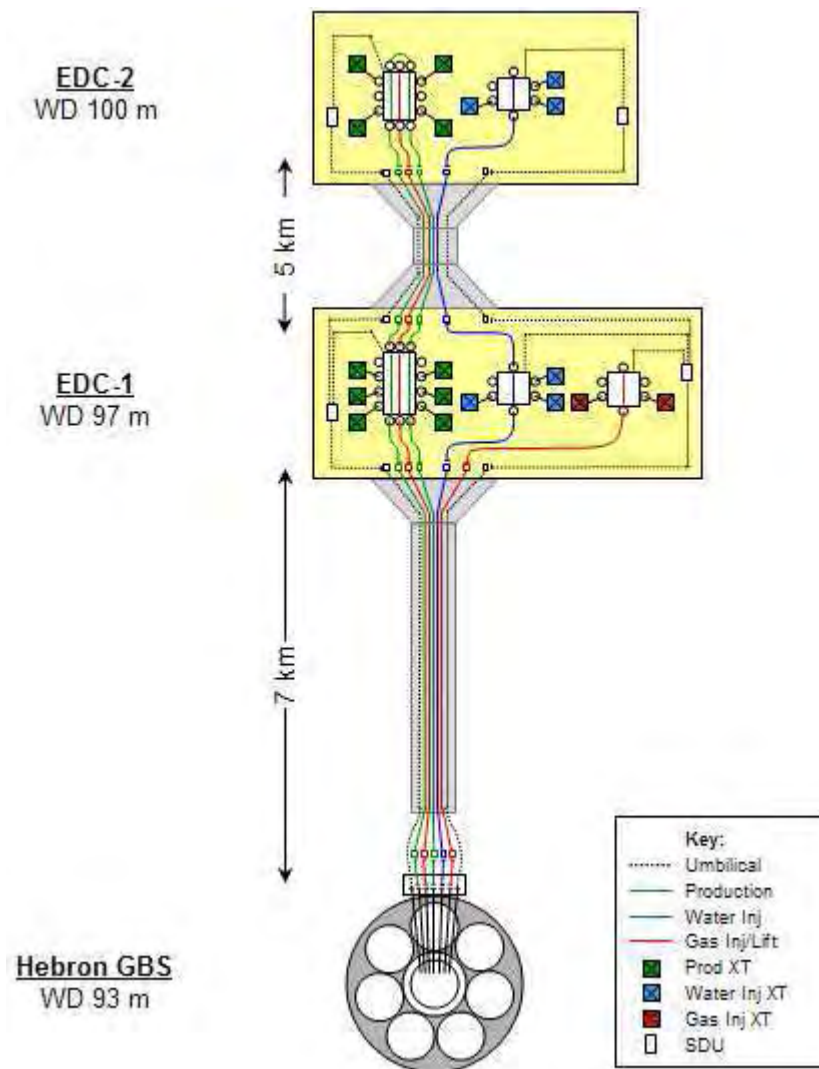


Figure 9.3-1: Pool 3 Subsea Concept Layout

9.4 Export System (Offshore Loading System)

9.4.1 Overview and Components

The Offshore Loading System (OLS) will be designed for an in-service life of 30 years. The currently planned OLS, as shown in Figure 1.7-4, consists of two main offshore pipelines running from the GBS to separate riser bases (Pipe Line End Manifolds, PLEMs) with an interconnecting offshore pipeline connecting the two PLEMs. The notional offloading rate of the system is 8,000 m³/hr (50,300 bbl/hr).

The closed loop arrangement is planned to allow round-trip intelligent pigging and flushing operations through the pipelines and PLEMs if an iceberg threatens the loading facilities.

9.4.2 Description of Offshore Pipelines and Components

9.4.2.1 Design Code

The offshore pipelines, GBS risers, and pig launchers / receivers will be designed in accordance with the latest revision of the Canadian Standards Association Z662, "Oil and Gas Pipeline Systems".

In the event additional guidance is required, beyond that provided in Z662, Offshore Standard DNV-OS-F101, "Submarine Pipeline Systems" may be utilized. However Z662 will take precedence over DNV-OS-F101 where conflict occurs.

9.4.2.2 Regulatory Requirements

The regulatory authority for the offshore pipelines is the C-NLOPB. Any and all additional requirements of the C-NLOPB will be incorporated into the pipeline design.

9.4.2.3 Offshore Pipelines Conceptual Design

The conceptual design basis for the offshore pipelines will be similar to the Hibernia OLS. i.e. a piggable system.

9.4.2.4 Offshore Pipeline Diameter

The notional outer diameter of the piggable portion of the offshore pipelines and GBS risers will be 610 mm (24-inch).

9.4.2.5 Design Pressure

Design pressure determination will consider normal pumping requirements, gelled pumping requirements if applicable, and dynamic effects including surge pressure, surge pressure protection systems, and pump shut-in pressure. Surge pressure analysis will consider inadvertent valve closure on the shuttle tanker and be based upon the loading, ESD, and breakaway characteristics of the dedicated tanker fleet.

9.4.2.6 Pipe Wall Thickness

Pipe wall thicknesses will be based on design pressure, code requirements, installation, corrosion, and robustness for the operating life.

9.4.2.7 Pipeline Length

The nominal pipeline length for each pipeline is 2 km (6,562 ft). The interconnecting pipeline between the OLS bases will be nominally 1000 m (3,281 ft). Final lengths will be determined following finalization of the OLS locations and offshore pipeline route survey.

9.4.2.8 Pipeline Pigging

The offshore pipelines will be designed for round trip pigging from and to the GBS. The system will accommodate commissioning pigs, wax scraper pigs, water-oil separation pigs and intelligent inspection pigs.

9.4.2.9 Safeguard Against Adverse Environmental Consequences

To minimize the environmental consequences of a pipeline breach, the crude oil contents of the offshore pipeline will be displaced with treated seawater in the event that iceberg interaction becomes a possibility.

9.4.2.10 Subsea Isolation Valves

Subsea valves are anticipated in the piggable sections of the offshore pipelines. However, additional analyses will be performed to confirm the need for and requirements for these subsea valves.

9.4.3 Riser Bases and Loading Risers

The PLEMs and loading riser system will consist of the following main components:

- ◆ PLEM
- ◆ Swivel
- ◆ Flexible pipe
- ◆ Riser swivel
- ◆ Coupling head
- ◆ Pick-up arrangement
- ◆ Position reference system
- ◆ Isolation Valve

The above components will be operational during the limits to be developed as per section 8.1.2.

The PLEMs will be pile anchored, which also provides anchoring of the Main Offloading Pipeline (MOP) system and the connection point for the riser system. It incorporates the pipe work for transporting crude oil from the MOP system to the Loading Riser System. Each PLEM will be equipped with vessel position reference equipment such as hydro-acoustic transponders. PLEMs will also contain the loading riser isolation valve. The isolation valve will be hydraulically operated (with manual overrides) and will be fitted with suitable hydraulic systems and remotely operated vessel / diver controls and instrumentation.

The loading riser system will allow for 360 degree shuttle tanker weathervaning and a safe operating radius from its base. Offset limits will be compatible with dynamic positioning capability and when not loading, the catenary section will rest on the sea floor.

9.4.4 Shipping and Transport

Initially the existing tanker fleet operating in the Grand Banks will likely be used to transport the Hebron crude oil to the Newfoundland Transshipment Terminal or direct to market. However, suitability of tanker fleet/standby vessels will be verified during detailed design.

9.4.5 Disposal of Transport Tankers Ballast Water

The Hebron GBS will have no facilities to handle ballast water from tankers.

Segregated ballast water loaded at the Newfoundland Transshipment Terminal is anticipated to be discharged overboard at the Hebron GBS.

Tankers coming from a port outside of the Canadian Exclusive Economic Zone will have to abide by International and Canadian ballast regulations.

9.4.6 Effects of Sea Ice and Icebergs

Please refer to Section 8.1.1

9.4.7 Features to Mitigate Oil Leaks and Spills

In situations where iceberg contact with OLS or pipeline is possible, the OLS system will be flushed with water to minimize potential oil release.

10 CONSTRUCTION AND INSTALLATION

10.1 Construction and Installation Overview

The Hebron Project has four major construction scopes – the Topsides Integrated Deck, the Gravity Base Structure (GBS), the Export System / Offshore Loading System (OLS) and the Pool 3 Subsea Development. The Topsides will employ a modular fabrication strategy with subsequent module integration, while the GBS will employ civil construction techniques along with installation of mechanical outfitting. After completing construction of these two scopes, they will be mated creating one integrated system referred to as the GBS Platform. The Export System / OLS and the Pool 3 Subsea Development will be tied into the facility subsequent to platform installation at the Hebron offshore site.

10.1.1 Integrated Topsides Deck – General Description

The Topsides Facilities consist of the following modules, varying in size:

- ◆ Integrated Utilities and Processing Module (UPM) - Area 20
- ◆ Derrick Equipment Set (DES) and Drilling Support Module (DSM) - Areas 11 & 15
- ◆ Living Quarters w/ Control Room (LQ), Helideck, Lifeboat Stations - Areas 30, 37 & 38
- ◆ Flare Boom - Area 34

The general module arrangement is depicted in Figure 10.1-1.

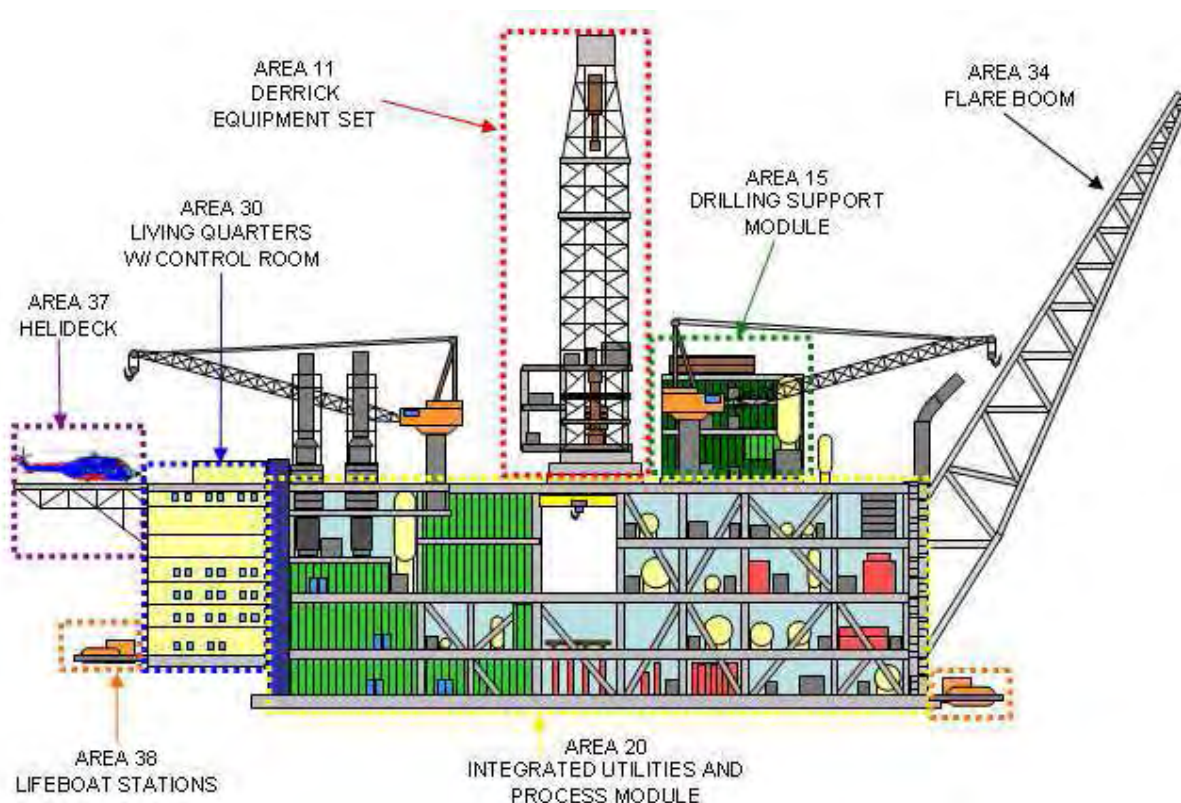


Figure 10.1-1: Topsides Module Definitions

10.1.2 GBS – General Description

The GBS is a post-tensioned reinforced concrete structure with internal cells containing ballast material. The purpose of the solid ballast is two-fold; to enhance the stability of the platform while floating and being towed to field and to increase the platform's weight and resistance to GBS base sliding once in place in the field. Mechanical outfitting systems are located in the GBS central shaft. The central shaft supports the integrated Topsides deck.

10.1.3 Export System - General Description

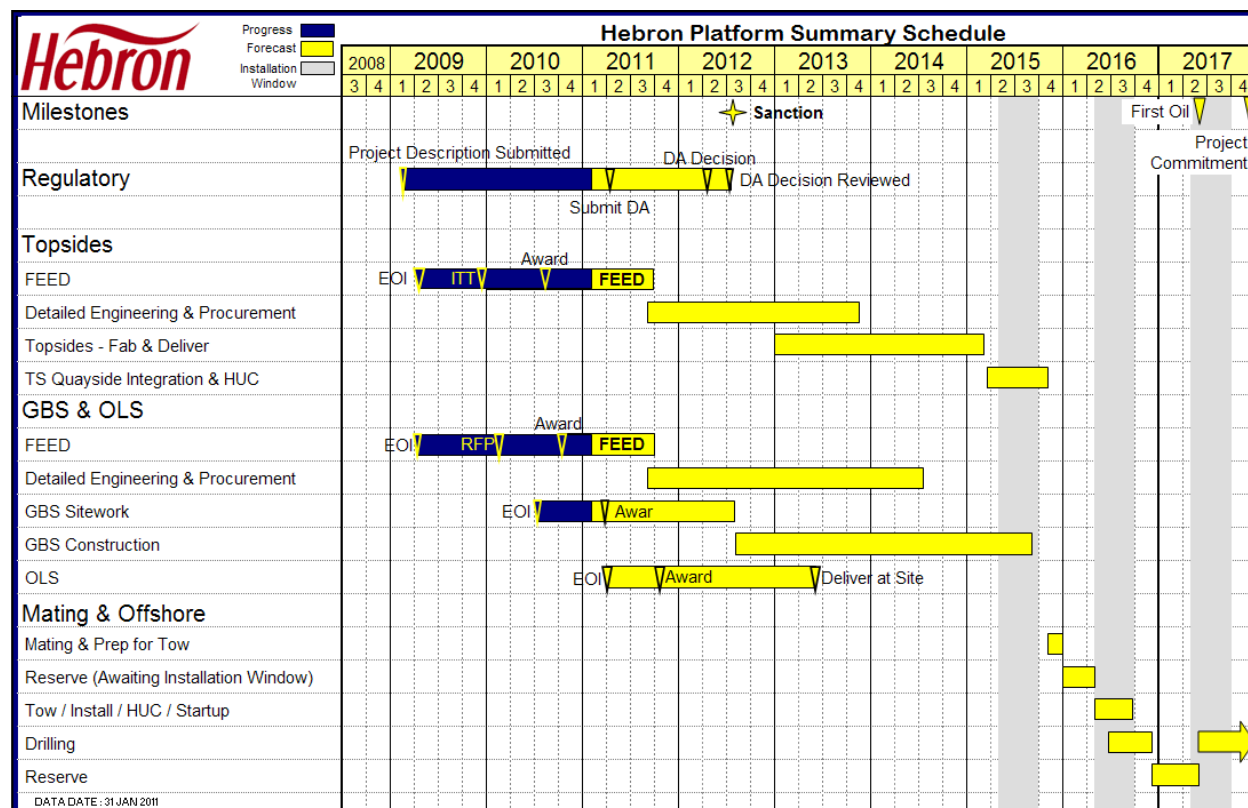
The export system to be installed for the Hebron Platform is an OLS. A general description of the OLS can be found in Section 9.3 – Export System (Offshore Loading System).

10.1.4 Pool 3 Subsea Development – General Description

A subsea development will be installed and tied back to the Hebron Platform. The development will include excavated drill centres (EDC(s)) as well as pipelines and umbilicals.

10.2 Project Schedule

The overall project development schedule is shown in two parts as the duration and timing of the Hebron Platform Development is more mature than the schedule for the Hebron Pool 3 Development. The Hebron Platform Development schedule is illustrated in Figure 10.2-1.



Notes:

* DA - Development Application includes Development Plan, Benefits Plan, EIS / SEIS and other supporting documents as determined by the C-NLOPB

Figure 10.2-1: Hebron Platform Development Schedule

A preliminary Pool 3 subsea development (Option 3) schedule is illustrated in Figure 10.2-2. Specific timing of the development is under evaluation with the earliest start-up date envisioned to be concurrent with the platform first oil date.

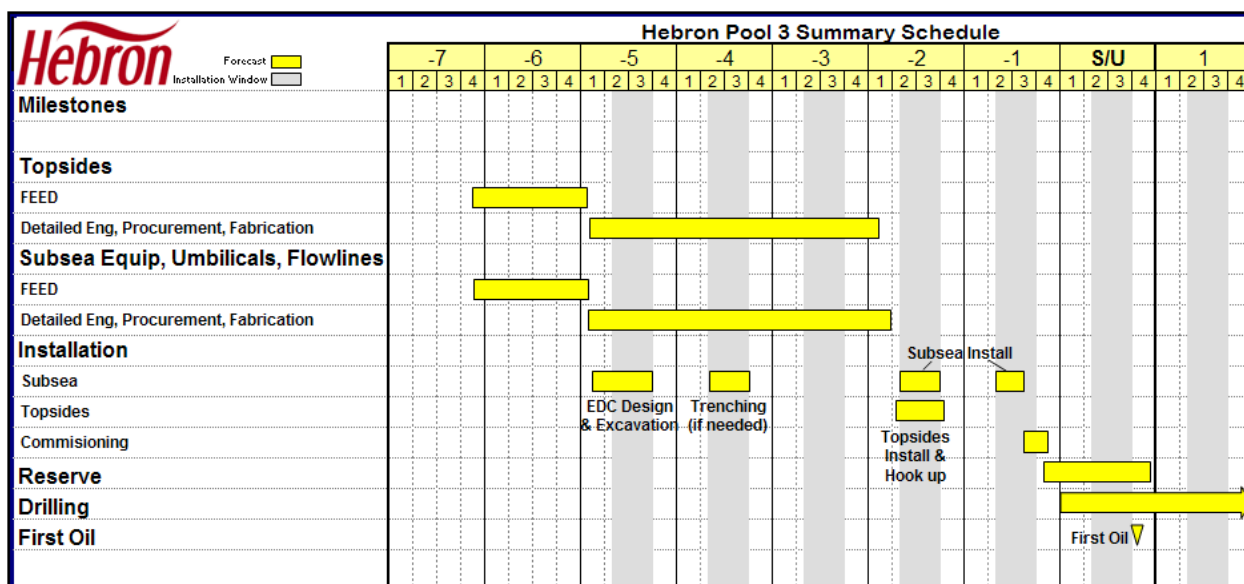


Figure 10.2-2: Hebron Pool 3 (Option 3) Development Schedule

10.3 Proposed Approach to Project Management

The Hebron Project will use ExxonMobil's proven project management system that is utilized worldwide. The system has been developed with sound project management processes designed to ensure successful execution of major capital project developments. The structured activities included in the process are designed to assure that projects are conducted in a safe and environmentally responsible manner, deliver assets of appropriate quality, meet cost and schedule expectations, and achieve commercial success.

Hebron's project management approach will encompass:

- ◆ Commercial Development Business Planning
- ◆ Evaluation and Selection of Development Alternatives
- ◆ Final Scope Definition, Detailed Design of Selected Facility Development, Construction, Installation, and Operational Plan Development
- ◆ Execution of Fabrication, Construction, Installation, Hook Up, and Commissioning of Facilities
- ◆ Start-up and Operation of Facilities

The Hebron Project Team will employ a contracting philosophy to award work, in accordance with the Hebron Project Benefits Plan, to contractors whose experience and capability will minimize risk to project success, thereby optimizing execution certainty.

It should be noted that submission of this Development Plan is based on completion of our conceptual engineering studies which were carried out to

demonstrate the feasibility of the proposals contained in the application. As engineering studies progress, these concepts will be refined and revised.

10.4 Construction and Installation Overview

Construction of the Hebron facilities will maximize the use of existing technology and expertise. Safety, experience, quality, and commercial terms will be considered when selecting contractors.

The strategy for the GBS is to design the structure with thorough consideration of the construction process and input from construction planning. As the GBS will be floating for a significant portion of the construction and installation phase, the design must ensure stability of the structure at all times. Thus, the design is a function of the various construction stages.

The Bull Arm Site has been selected as the primary construction and integration site for the GBS and Topsides modules. This location provides adjacent dry dock and deep water GBS construction sites as well as facilities to fabricate components and integrate the Topsides modules.

The overall construction sequence for the Hebron Project is shown in Figure 10.4-1.

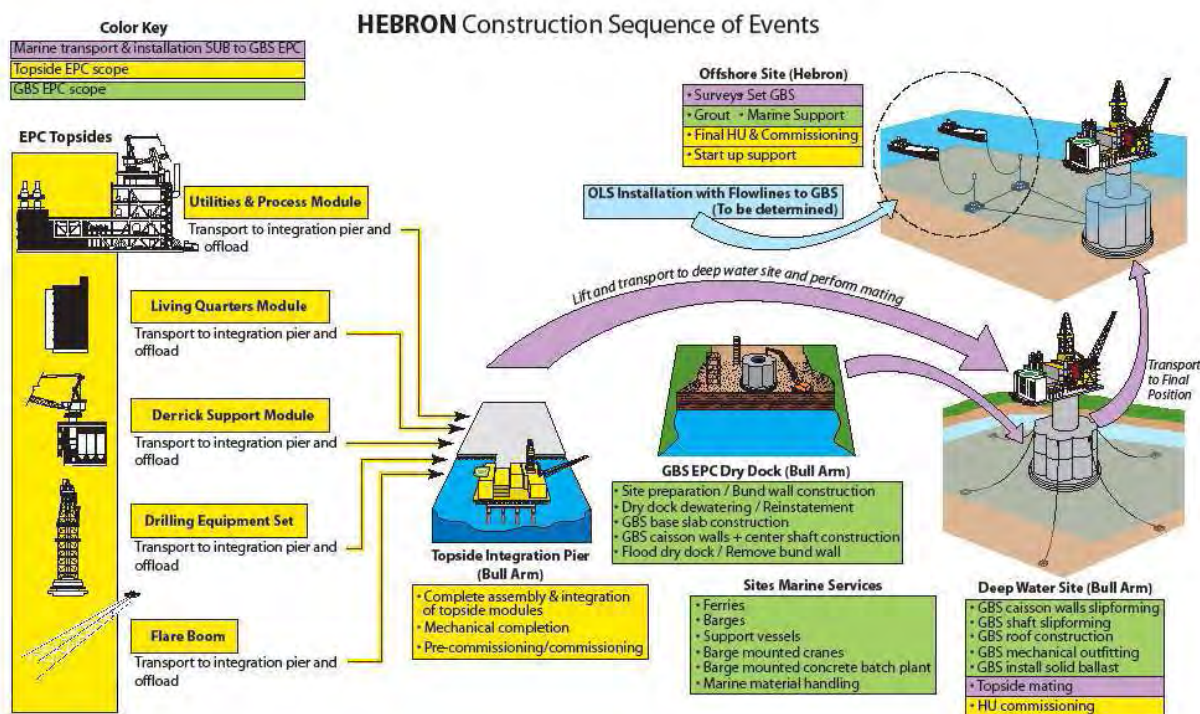


Figure 10.4-1: Hebron Construction Sequence

The development requires the construction of the following components:

- ◆ Concrete Gravity Base Structure
- ◆ Topsides Facilities
 - Utilities and Process Module
 - Derrick Equipment Set and Drilling Support Module
 - Living Quarters
 - Flare Boom, Helideck and Lifeboat Stations
- ◆ Offshore Loading System

Following construction of the major components, the sequence of events through first oil production is described below.

- ◆ Platform Integration - Project components, built at various locations including Bull Arm, will be transported to Bull Arm, Newfoundland and Labrador for integration. This may involve one transoceanic journey and several regional transports. The Topsides facilities will be integrated at the Bull Arm Topsides integration pier and mated with the GBS into an integrated platform at the Bull Arm Deep Water Site (DWS).
- ◆ Nearshore Solid Ballast Installation - The Hebron Project plans to install solid ballast, required to provide the necessary on-bottom weight to the GBS Platform, at the Bull Arm DWS prior to transport offshore.
- ◆ Nearshore Hook-Up and Commissioning - The assembled components will be tested and commissioned to the extent possible at a nearshore location.
- ◆ Offshore Installation - The completed platform comprising the GBS and Topsides will be towed to the field and installed at site, most likely during an April to October weather window. The Hebron Project plans to install the OLS during the same weather window.
- ◆ Offshore Hook-up and Commissioning - The activities to be executed offshore include connection of the OLS to the platform and final commissioning of the Topsides and GBS facilities.

10.4.1 Topsides Facilities Construction

10.4.1.1 Utilities and Process Module

While there are multiple possible UPM fabrication methods, the method selected is dependent on the fabricator's preferred construction sequence dictated largely by their site facilities and actual delivery times of equipment.

At the fabrication yard, it is envisioned that the UPM deck will be supported on skid beams during fabrication. Fabrication of deck levels, installation of

large equipment / pre-assembled units, and outfitting of the decks will require the following site features:

- ◆ Craneage capable of lifting and installing equipment and pre-fabricated assemblies
- ◆ Large automated steel fabricating equipment that is capable of handling, cutting, shaping and welding large plate widths, steel profiles and tubulars
- ◆ Generous storage areas for steel stock and plate with overhead cranes for handling
- ◆ Covered warehousing facilities, which can be dedicated to the project for receiving and storing process vessels, equipment and major subassemblies
- ◆ An adequately sized and capable workforce skilled and trained in structural welding, pipe fitting and welding, electrical and instrument installation, mechanical completion and commissioning, and load out methodologies
- ◆ A formal quality control and quality assurance program endorsed by both the yard management and the work force which complies with regulatory and industry requirements / standards
- ◆ An established procurement and expediting group
- ◆ An established engineering group capable of understanding and managing the complexities of distortion and dimensional control on a large structure and capable of managing multi discipline concurrent work activities on a large scale
- ◆ A formalized Management of Change system including scope of work, materials, cost, schedule, procurement, weight and material control procedures
- ◆ A large covered erection workshop capable of handling the significant portions of the deck
- ◆ Surface preparation and paint coatings facilities
- ◆ A quay capable of sustaining the deck weight at load out and of sufficient depth to permit access for large sea going barges, cranes, and transport vessels

10.4.1.2 Drilling Modules

Fabrication of the drilling modules may be completed multiple ways and will be determined by the drilling module fabricator(s). It is likely that the modules will be fabricated by level allowing installation of the large pieces of equipment followed by fitting out with pipe-work, electrical and instrumentation, heating, ventilating and air conditioning (HVAC) and mechanical handling, and smaller equipment components.

The construction sites will generally need to have the same features as the UPM fabrication site. Additionally, it is desirable that the yard(s) have experience in fabricating drilling derrick structures / drilling support modules.

10.4.1.3 Living Quarters

Fabrication of the LQ will be executed by a qualified fabricator with previous experience in the fabrication of accommodation modules / LQs. The contractor must be capable of executing the detailed architectural and engineering design, including that for offices, operations control room, galley / dining, sleeping accommodation, and recreational areas.

Requirements of the fabrication yard will generally be the same as for the UPM and drilling module yard. The yard must have proper dry heated storage for the architectural components. The management and work force must have specialized control and installation skills. It is most likely that the LQ will be constructed at Bull Arm as the module assembly hall is well suited for indoor fabrication of the module. Self Propelled Modular Transporters (SPMT) will be used to move the module and sub assemblies between fabrication and paint shops, and to the quay for load out.

10.4.1.4 Flare Boom, Helideck and Lifeboat Stations

The flare boom, helideck and lifeboat stations can be fabricated by established contractors with the capacity to do this work. The fabrication site(s) will require similar features as those required by the UPM fabrication site.

10.4.2 Gravity Base Structure Construction

Construction of the concrete GBS will be divided into the following areas:

- ◆ Site facilities
- ◆ Civil construction
- ◆ Mechanical outfitting
- ◆ Marine operations

10.4.2.1 Site Facilities

A site will be required for the construction of the GBS with the following minimum requirements:

- ◆ A dry dock with depth to be determined during GBS front-end engineering and design (FEED)
- ◆ A DWS with sufficient water depth for GBS construction and a clear channel with equal or greater depth for the platform to be towed to its final location
- ◆ Land based and / or floating concrete batching facilities

- ◆ Construction support facilities and equipment such as administrative offices, warehousing, cranes, covered workshops, etc.
- ◆ A construction camp with capacity to house workers critical to construction activities.

10.4.2.2 Civil Construction

Civil construction encompasses the construction of the main post-tensioned, reinforced concrete structure. Concrete slip-forming and jump-forming techniques may be employed to erect the GBS. While slip-forming techniques will be used to erect most GBS walls, jump-forming may be utilized to erect walls of lower height which do not require use of slip-forms. Construction will occur in multiple phases. The initial phase will occur in a dry dock while the second will occur in a deep water site. When moved to the deep water site, construction of the GBS will continue while the structure is floating and moored to shore. A number of support barges will be required to support the construction activities in the deep water site.

10.4.2.3 Mechanical Outfitting

The GBS will also include mechanical outfitting to be installed during construction. Mechanical outfitting includes all the piping, pumping, instrumentation and electrical systems associated with the GBS. Mechanical outfitting components will be fabricated either at various existing fabrication shops or locally at the GBS construction site.

10.4.2.4 Marine Operations

The marine operations to be conducted for GBS construction include:

- ◆ Placement and removal of the bund wall (may alternately be done from shore)
- ◆ Float out of the GBS from dry dock
- ◆ DWS construction
- ◆ Placement of inshore ballast
- ◆ Submergence testing

Details of these marine operations are described below.

10.4.2.5 Placement and Removal of Dry Dock Bund Wall

The existing Bull Arm dry dock will be prepared prior to starting construction of the GBS.

The dry dock will require a bund wall. Placement of the bund wall might be performed as a marine operation where marine vessels install and backfill against sheet piling. Alternatively, the bund wall may be constructed and removed from shore.

Removal of the bund wall after GBS float out will see the procedure largely reversed. In this case, the piling will be pulled up and the material dredged or excavated away.

10.4.2.6 Float Out of GBS from Dry Dock

The dry dock will be flooded and the GBS will begin its floating construction stage once the maximum degree of construction in the dry dock has been completed. A robust design will be pursued to minimize the affect environmental conditions may have on the float out operation. Temporary moorings will be used to maintain the GBS in place as water is pumped into the dock. When the water level has reached sufficient height, the base raft will begin to float.

An air cushion system may be utilized to force air under the skirts and force water out. This increases the buoyant force thereby adding to the amount of construction which can be completed in dry dock. The decision to employ such a system will depend on the final construction sequence.

When the water level inside and outside of the dock are equal, bund wall removal can begin. The GBS will be warped out of dock using winches, cables and mooring lines. When the GBS is clear of the dock, control will be transferred to tugs and the GBS will be towed to the DWS. The float out operation will be similar to what was conducted during Hibernia GBS construction (illustrated in Figure 10.4-2).

At the DWS the GBS will be connected to mooring chains that tie-back to shore and are rated to withstand the loads during the remainder of GBS construction.



Figure 10.4-2: Hibernia GBS Leaving Dry Dock

10.4.2.7 DWS Construction

Support and transport barges will be required at the DWS. Barges will be used for construction offices, tool cribs, support buildings, floating concrete

batching plants, and to ferry cement, aggregate, reinforcing bars, steel embedment, and mechanical outfitting to the DWS. The barges will be moored to each other and to the structure with a series of mooring points which progressively move up the GBS as it is built. Tugs will move transport barges to and from the DWS.

Ferries or large crew boats will be used to transfer personnel from shore to and from the DWS.

10.4.2.8 Placement of Solid Ballast

Once the vertical walls of the caisson are constructed, the permanent solid ballast will be installed. Ballast will be brought to the site on bulk carrier barges. The ballast will be transferred into the GBS using a series of conveyors or a pumping system. After it is installed, the material will be levelled and capped with a non-structural slab of concrete.

10.4.2.9 Submergence Testing

When GBS construction is complete a submergence test is required to confirm watertight integrity of the structure and ensure the variable ballast systems are functioning properly.

10.4.3 Construction and Installation of Export Facilities

The OLS closed loop pipelines can either be fabricated onshore and taken to the field as a submerged tow and installed on the sea floor or manufactured and installed by a pipe-lay barge. Both OLS bases are anchored to the seabed by piles to provide a stable connection for the OLS risers. Once the platform has been installed the pipelines will be tied back to the platform risers.

10.4.4 Platform Integration

The following activities are planned for integration of the Topsides prior to installation at site:

- ◆ Load out and transport of integrated UPM deck from fabrication yard and load off to integration site in Newfoundland and Labrador
- ◆ Load out, transport, and / or tow of separate modules (LQ, DES, DSM, and Flare Boom) from provincial fabrication yards to the Bull Arm site. In addition, some fabrication will probably take place at the Bull Arm facility itself. Once at the site, the modules will be lifted and integrated with the UPM at the integration pier
- ◆ Lift-off of completed Topsides and mating with the GBS

10.4.4.1 Load-Out, Transportation and Load-In of UPM

The UPM will be transported from a fabrication yard to Bull Arm, likely on the deck of a Heavy Transport Vessel (HTV). The UPM will be skidded on and

off of the vessel along beams. Design of the skid shoes and beams will be cooperatively completed by the Topsides Engineering, Procurement, and Construction (EPC), transportation and fabrication contractors. The transport arrangement of the UPM on a typical HTV is shown in Figure 10.4-3.

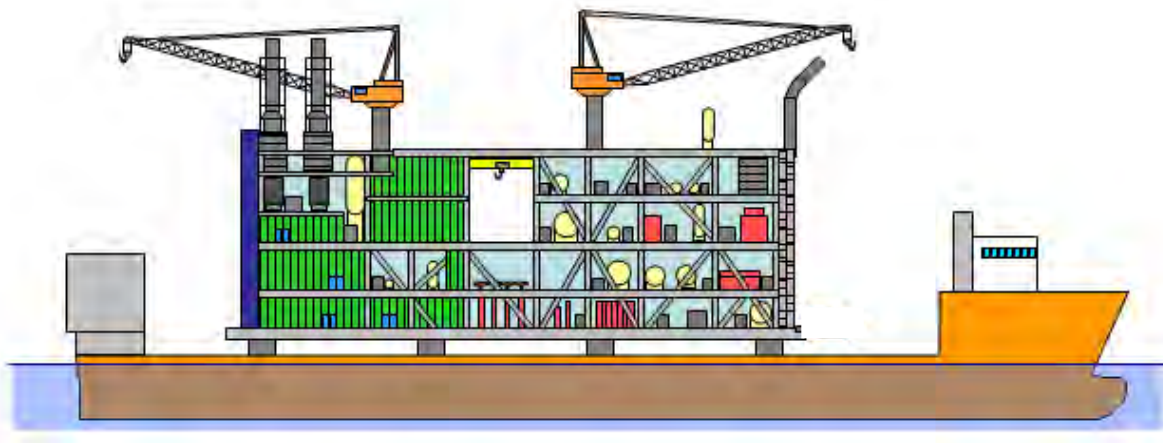


Figure 10.4-3: UPM Transport on Heavy Transport Vessel

The duration of the transport will depend on distance, meteorological conditions, and average speed over ground. Assuming the fabrication yard is located in Eastern Asia, a transit speed of 10 – 12 knots and a route around the Cape of Good Hope, the transoceanic transport will take approximately 60 days. A route around the Cape of Good Hope is likely because the combined height of the UPM and HTV will grillage and sea fastening is expected to be too high to transit through the Suez Canal.

The load-in skidding operation is illustrated in Figure 10.4-4.

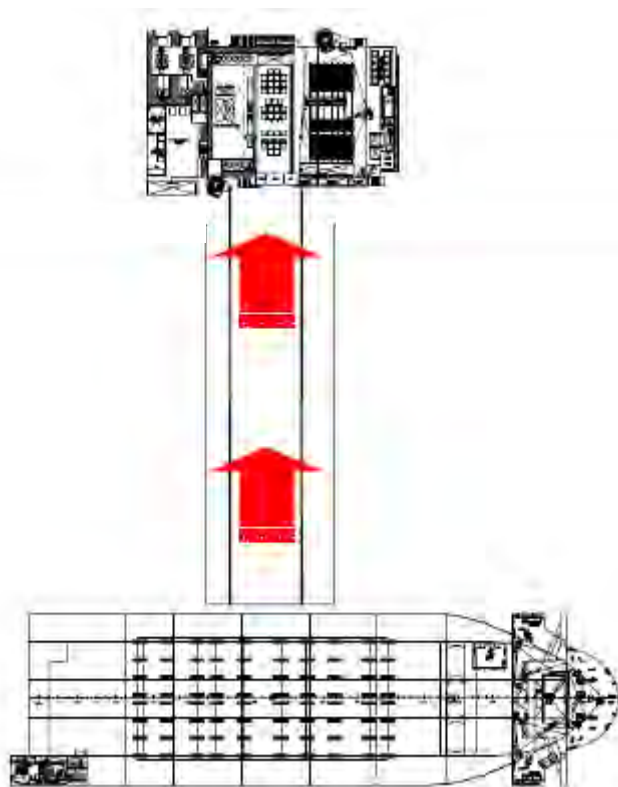


Figure 10.4-4: Longitudinal UPM Load-In onto Integration Pier Using Skid Beams

10.4.4.2 Module Integration

The UPM will be located on the Bull Arm integration pier allowing for installation of LQ, helideck, drilling modules, flare boom and lifeboat stations. This gives access for the heavy lift operations to be performed in this phase.

Two lift methods, the lifting towers method or the shear leg method, may be used in the installation of the drilling modules as described below. The lift method will be selected during detailed execution planning.

10.4.4.3 Lifting Tower Method Description

The lifting tower method is an option that may be used to install the drilling modules. In this option, the modules are transferred from a barge to a quay on trailers. At this location the lifting towers with associated equipment are erected. In addition to the towers, a pair of heavy skid beams is required for transferring the lifted modules across the UPM to their final integrated positions. The module is then raised to the appropriate elevation and skidded horizontally across the integrated deck into its final position. A typical lifting tower operation is shown in Figure 10.4-5.



Figure 10.4-5: Example of Module lifted by use of Lifting Towers

Lifting tower equipment may require sourcing and transportation from an international location for the purpose of the operation.

10.4.4.4 Floating Shear Leg Method Description

Another option for lifting the drilling modules utilizes a floating crane (illustrated in Figure 10.4-6).



Figure 10.4-6: Example of Floating Shear Leg Installing a Complete Topsides

The combined weight and size of the drilling modules coupled with the height of the lift approaches the capacity of most shear legs. The option will be further evaluated during detailed execution planning. A drawing of the DSM installation by shear leg is shown in Figure 10.4-7 and the DES in Figure 10.4-8.

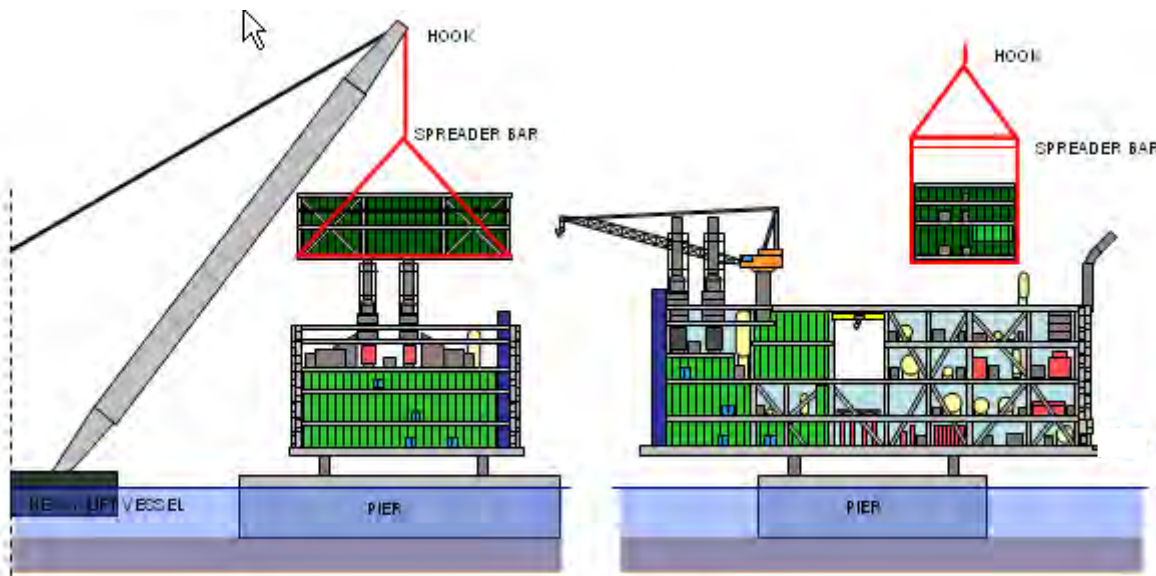


Figure 10.4-7: Lifting of the DSM (Pedestal Crane Not Shown)

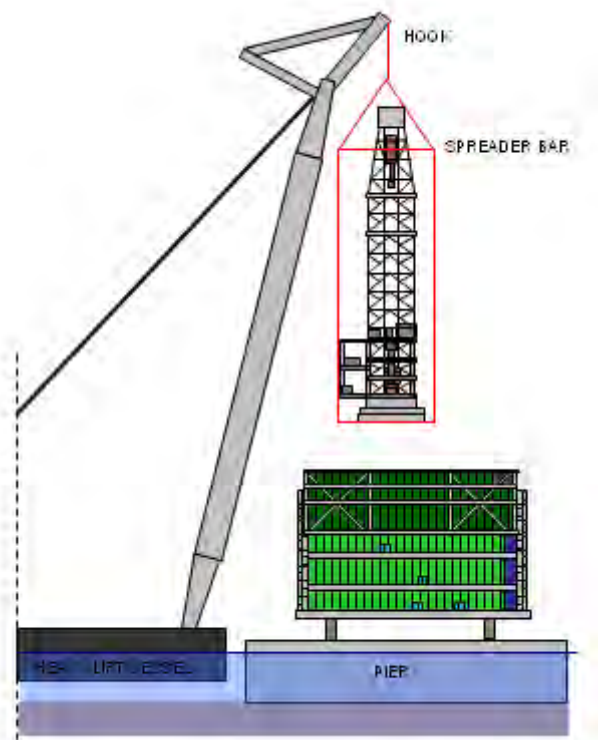


Figure 10.4-8: Lifting of DES

10.4.4.5 LQ Installation

The LQ will be positioned for integration on a barge or lifted by a floating crane. If a barge is used to integrate the LQ, final positioning of the module

will be accomplished by ballasting, SPMTs movement or supports. An illustration of using a barge to conduct the integration is provided in Figure 10.4-9. If a floating crane is used to position the LQ for integration the lift will occur similar to those previously described for the DES and DSM.

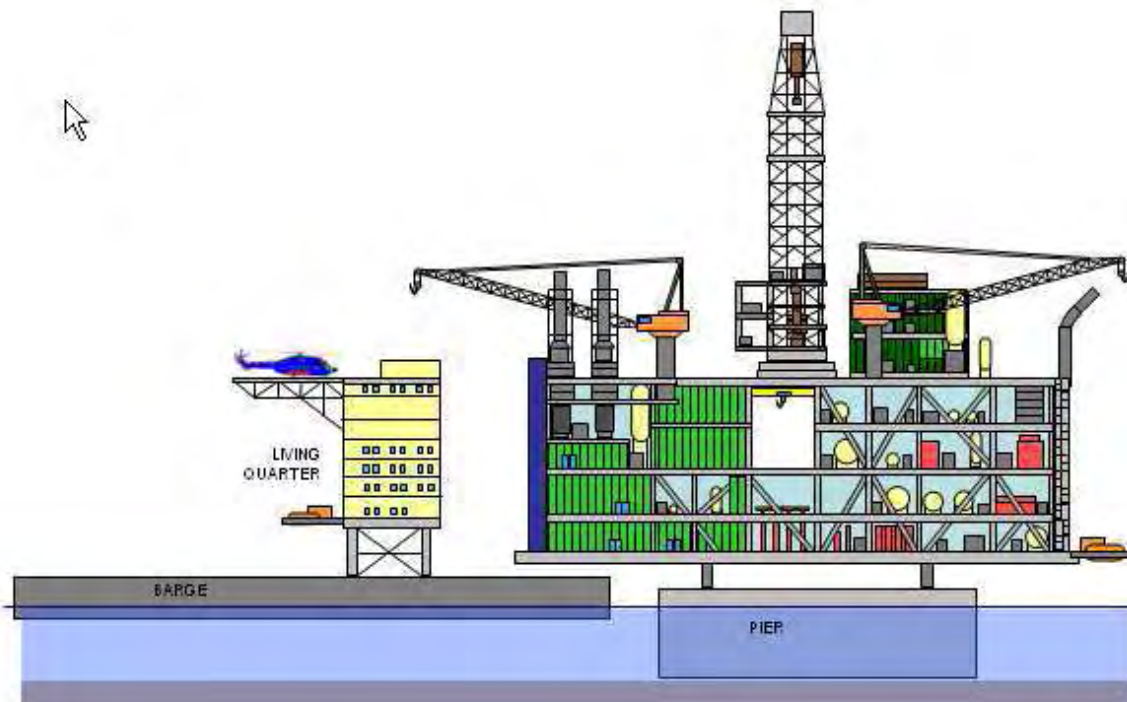


Figure 10.4-9: LQ Position on Barge prior to Installation

The helideck and lifeboat stations may be installed before or after the LQ is permanently secured to the UPM.

10.4.4.6 Flare Boom Installation

The flare boom will be transported to the integration pier on a barge lying horizontally with the rigging for the lifting operation preinstalled.

The first and last stages of the upending / installation of the flare boom are shown in Figure 10.4-10 below.

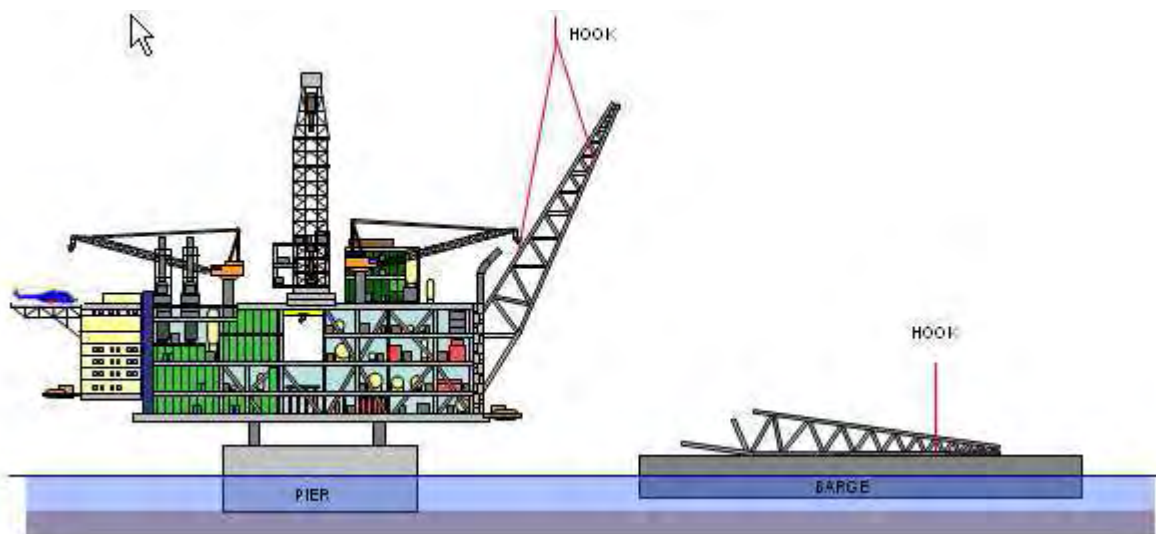


Figure 10.4-10: Flare Boom Installation

10.4.4.7 Topsides Lift-Off and Mating with GBS

During the mating of the integrated Topsides to the GBS, the GBS must support the dry weight of the Topsides while subject to the highest hydraulic loading it will experience. This operation is subject to meteorological and oceanographic (metocean) conditions and therefore will be performed at the protected Bull Arm DWS during a suitable weather window. The critical installation duration is typically one to three days. Such windows are unlikely during late fall and winter periods. Hence, this operation is not expected to start until late March or early April of any given year.

This operation begins with transferring the Topsides from the integration pier to the mating barges. The ends of the Topsides will extend sufficiently far out over the water so that barges can be floated underneath suitable load bearing points. With necessary blocking in place, the two barges will be simultaneously de-ballasted until they lift the Topsides off the pier in a catamaran configuration as seen in Figure 10.4-11. Tugs will then pull the catamaran arrangement clear of the pier.

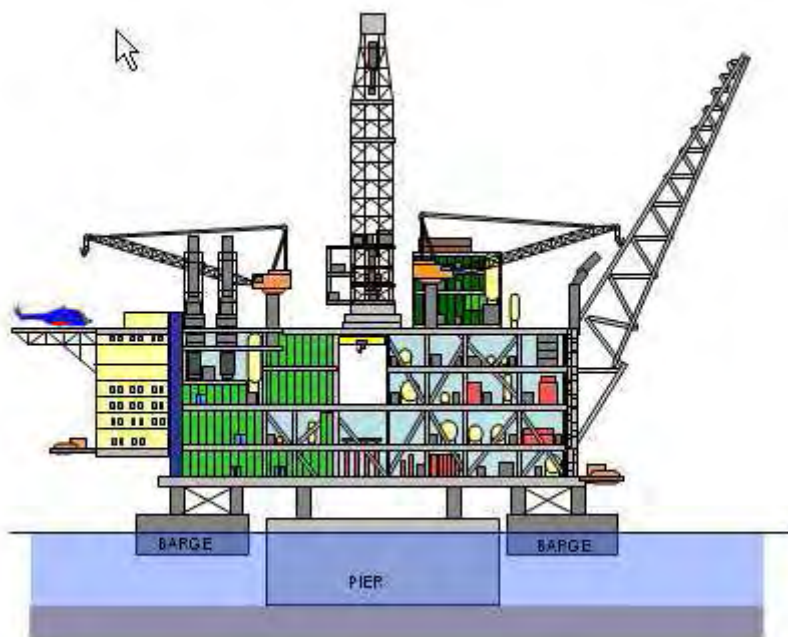


Figure 10.4-11: Topsides Lift-Off Configuration

The GBS is prepared to receive the Topsides once it has been ballasted down with the GBS centre shaft remaining above water. The Topsides catamaran arrangement is towed over the structure until the Topsides load transfer points are directly above the respective receiving points on the GBS. The GBS is slowly de-ballasted, allowing it to rise out of the water and support the load of the Topsides. After the entire load is transferred to the GBS, de-ballasting will continue to a specified draft for the mated platform. The permanent structural connection between the Topsides and GBS is then completed. Interconnection of the pumping, piping, instrumentation and electrical systems will occur over the following weeks. When interconnection of the mechanical outfitting is complete, the platform is ready for tow to the field. Figure 10.4-12 represents the platform with the Topsides mated to the GBS.

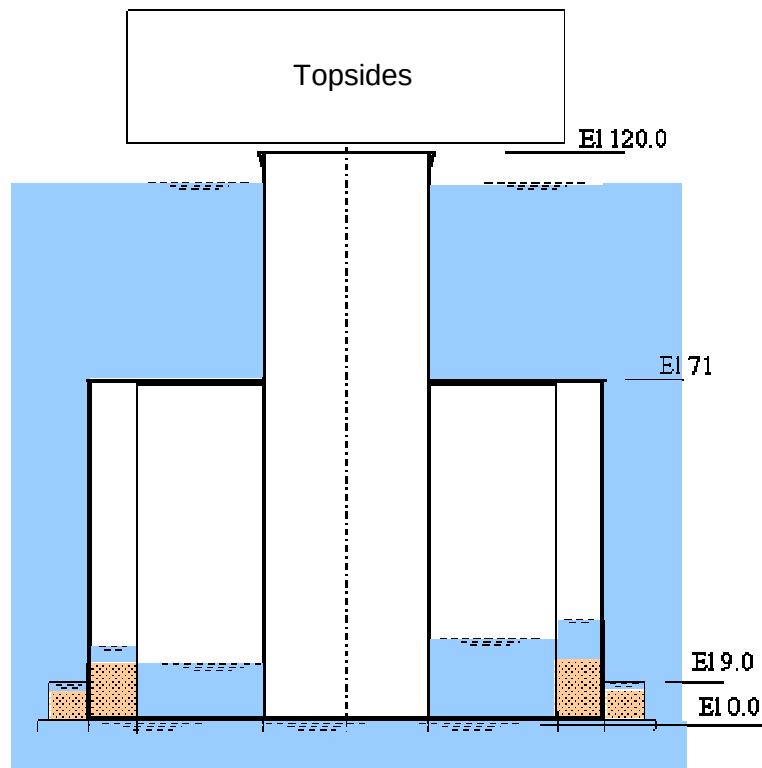


Figure 10.4-12: Topside Mated to GBS

A similar barge catamaran configuration was used during the Hibernia float over. Figure 10.4-13 depicts the sequence of activities from Topsides lift-off from the integration pier to mating the Topsides with the GBS.

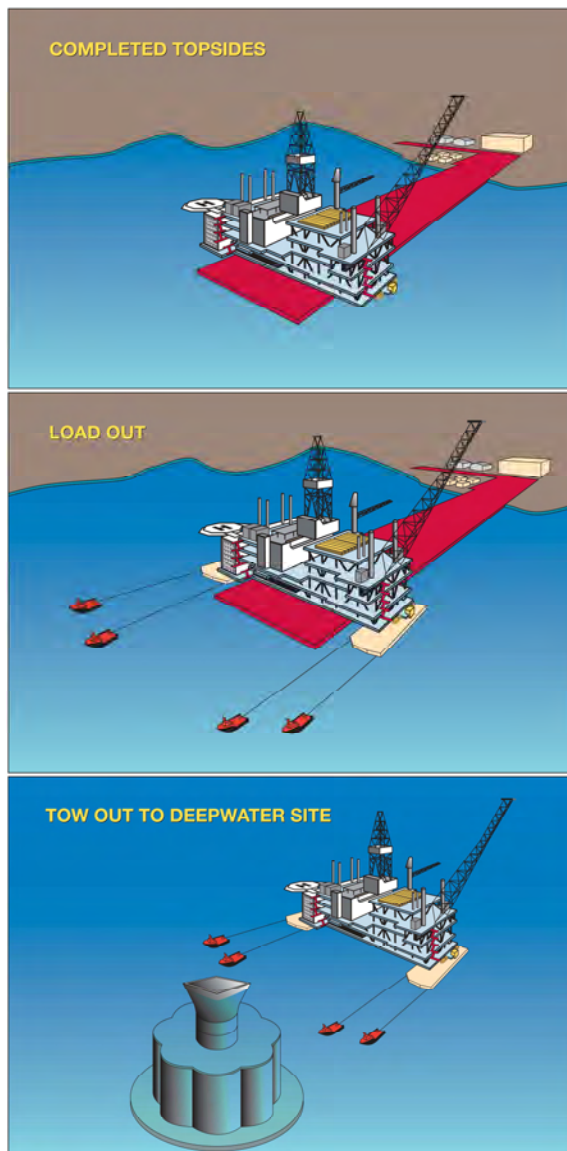


Figure 10.4-13: Topsides Float-out

10.4.5 Platform Installation

10.4.5.1 Tow Out

Approximately 10 to 14 days of tow are required to transit from the DWS to the final installation site. Additional time may be required due to unfavourable metocean conditions. As the accuracy of weather forecasts decreases significantly after about 72 hours, the tow is designed to have a series of intermediate way points where the structure can be safely held.

Six to ten ocean-going tugs will likely be used to tow out the structure. They will hook onto the structure at predetermined points around its circumference with individual lines. At least one will be at the rear of the structure in order to provide braking capability to slow the structure down as required. Sufficient

tug power will be connected to maintain control of the structure should one line break or a vessel become disabled. A similar method was used during Hibernia tow to site as shown in Figure 10.4-14.



Figure 10.4-14: Hibernia Platform Tow to Site

Upon receiving a favourable weather forecast and establishing that the tugs can control the platform, the GBS mooring chains will be released.

The platform will be towed to predetermined intermediate waypoints. At each waypoint the metocean conditions will be assessed prior to advancing to the next waypoint. Should a storm arise, the platform can be ballasted down to help stabilize the motions. The tow and the structure will be designed to handle the loads from this situation.

The tow will proceed to a point in the vicinity of the final installation and wait for a weather window to complete the final approach. When the required forecast conditions are met, the platform will be towed to final position in preparation for site installation.

10.4.5.2 Site Installation

The GBS will be ballasted with sea water to lower the platform into place while it is being controlled by the tugs or a preinstalled mooring system. The GBS skirts, if utilized, will be the first part of the platform to touch down on the seafloor. Variable ballast will be adjusted to the different cells within the GBS to ensure that the skirts penetrate evenly and the structure remains as level as possible. Once the initial natural penetration stops, the platform is in place.

The skirts will be laid out in a pattern so as to create multiple separate compartments between the seafloor and the base of the platform. The void between the seabed and the underside of the structure will be filled with

grout. The platform will be fully capable of meeting all design loads as soon as the grout reaches its design strength. The grouting operation is shown in Figure 10.4-15.

Other installation methods will be studied during FEED. An alternative method may be selected if it meets all project and regulatory requirements.

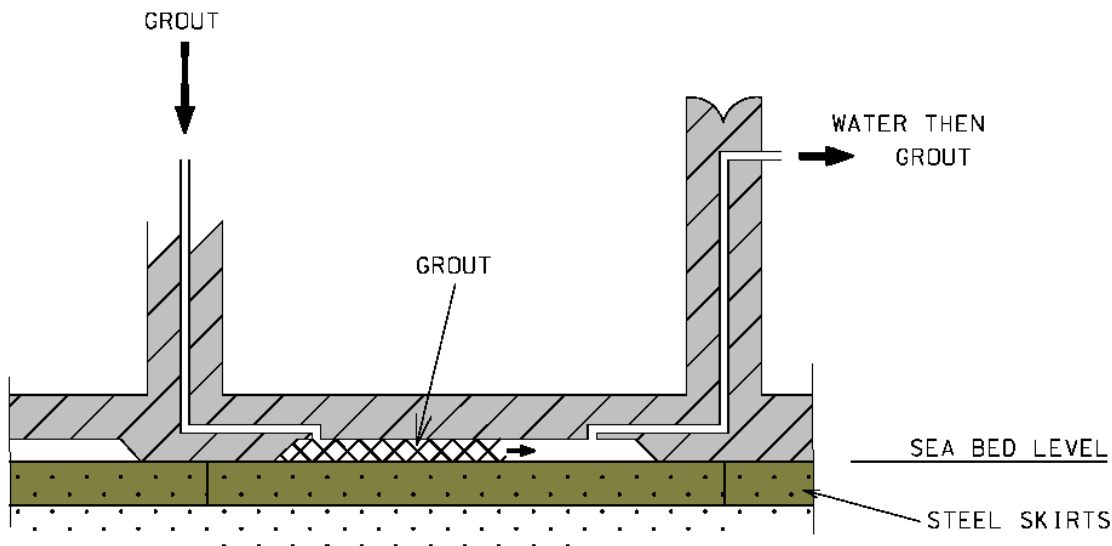


Figure 10.4-15: Grout Injection

10.4.6 Platform Completion

10.4.6.1 Module Completion

At each of the fabrication yards the Owner company representatives, operations personnel and main contractor will form an Integrated Systems Completion Team. The intent is to form a coordinated construction and commissioning plan to minimize the overall schedule. Work in the yards will include mechanical completion and commissioning activities, inclusive of chemical cleaning and flushing, loop testing, verification, testing, punch listing, preservation, adjustment and calibration.

The plan is to perform testing as early as possible for all parts of the work, based on cost / benefit / risk. This will be evaluated for all project phases, including:

- ◆ At package vendor sites and module fabrication sites
- ◆ At the integration site
- ◆ At DWS (post mating)
- ◆ At the field location

The design concept of the integrated deck, was developed such that majority of the equipment can be mechanically complete and commissioned as entire systems to the maximum extent possible prior to transport to and integration at Bull Arm. As an example the LQ and Drilling modules being mostly self contained can to a great extent be fully commissioned at their respective yards. For the remaining packages and modules, typical system completion activities are listed and planned for each of the above project phases so that the overall objective of maximizing onshore work to reduce offshore work.

Typical activities at package vendor and module fabrication sites may include:

- ◆ Complete commissioning procedures / work packs
- ◆ Hydro testing / cleaning / drying piping & vessels
- ◆ Hi-pot, meggering, polarity, terminations for electrical and instrumentation
- ◆ Non-destructive examination activities including non-destructive testing, inspection and documentation
- ◆ Valve stroking, vessel inspections
- ◆ Lube oil flushing for main rotating equipment
- ◆ Mechanical cold alignments & no-load runs
- ◆ Local loop checking
- ◆ Factory acceptance testing, vendor release notices
- ◆ Initiate punch list / Preservation Management Programs
- ◆ Commence assembly of documentation for operations such as Operation and Maintenance manuals, spares management and Turnover & Completion Packages
- ◆ Tracking, validation and certification of all tagged equipment
- ◆ Handover / turnover certificates
- ◆ Operator training
- ◆ Establish a temporaries program for power, fuel, air and water. Determine requirement and design installation, hook-up, operation and decommissioning

10.4.6.2 Topsides Integration

When all the Topsides modules have been integrated at the integration pier, hook-up of the integrated deck to the living quarters, drilling modules and ancillary structures will take place along with any further commissioning activities allowed by the schedule.

Typical activities for integration at Bull Arm may include:

- ◆ Implement permit-to-work (PTW) system for controlled work process
- ◆ Finalize loop checking
- ◆ Install temporaries and implement management program for safe operation
- ◆ Review and testing of cause and effect diagrams, emergency shutdown systems, fire and gas systems
- ◆ Conduct site integration testing of control systems
- ◆ Primary & secondary testing
- ◆ Refill lube & seal oil systems
- ◆ Final equipment alignments and runs
- ◆ Leak testing with nitrogen and helium for hydrocarbon systems integrity
- ◆ Verify protection settings with primary and secondary injection testing
- ◆ Conduct load testing, paralleling, load shedding and synchronization of power generation using load banks
- ◆ HVAC performance testing, pressurization and balancing
- ◆ Continue operator training
- ◆ Commence turnover of non-process utility systems to Operations
- ◆ Continue preservation management program, track and document
- ◆ Complete punch lists and rectify deficiencies

10.4.6.3 Hook-up and Commissioning after Mating

After mating, hook-up of the mechanical equipment in the GBS to the Topsides will be completed. Commissioning activities that can be done at this time will be undertaken with first priority assigned to making all systems necessary for life support fully operational.

Typical activities at the DWS may include:

- ◆ LQ / Central Control Room / Helideck operational
- ◆ Ballasting systems tested
- ◆ Telecoms and other communications systems functioning
- ◆ Emergency and essential generator sets and associated switchgear operational
- ◆ Navigational aids on line
- ◆ Facilities for tow master and crew commissioned

- ◆ Lifeboats installed and tested and ensure adequate coverage for personnel on board during tow
- ◆ Diesel fuel loading, storage and distribution
- ◆ Black start philosophy finalized and equipment tested and functioning
- ◆ Establish uninterruptible power supply and battery back-up
- ◆ Function test drilling facilities such as: derrick, traveling block, crown, electric drum brake, diverter, degasser, mud processing, shale shaker, data logging, wireline units and dog house
- ◆ Load on coil tubing unit and test, weight permitting
- ◆ Install a predetermined number of drilling conductors subject to weight allowance
- ◆ Complete system integrity testing with N₂/He and leave in inerted, pressurized condition for transportation to field
- ◆ Systems performance testing on systems such as: firewater, safety and detection systems, lifeboats, emergency, essential and main generator sets
- ◆ Transition to and implementation of Company PTW systems and simultaneous operations procedures

10.4.6.4 Offshore Commissioning and Start-up

After tow and installation of the completed platform, final commissioning of systems can be completed. First priority will be the start-up of utility systems and a full-scale fire water test and habitation of the living quarters. Before first oil, final emergency and production shut down and black start tests will be performed.

Typical activities at the field location may include:

- ◆ Install sea water and firewater pumps in permanent positions and re-establish performance test
- ◆ Verify all platform emergency and safety systems, fire and gas detection, alarms, Distributed Control System etc.
- ◆ Emergency and Essential generator sets online
- ◆ Diesel fuel system available
- ◆ Ensure all utilities and support systems operational to support drilling activities
- ◆ Continue established and agreed-upon simultaneous operations (SIMOPS) and work control processes
- ◆ Connection and commissioning of the main offshore pipelines of the OLS

- ◆ Start-up a main generator using load banks, energize permanent High Voltage switchgear and transformers
- ◆ Re-establish system integrity with N₂ pressure test to predetermined rating on all hydrocarbon systems
- ◆ Liquidate all punch lists, remedy remaining identified deficiencies
- ◆ Decommission temporaries
- ◆ Conduct readiness reviews, Pre Start-Up Safety Review
- ◆ Complete Turnover Completion Packages and Documentation for Operation as part of turnover process
- ◆ Provide start-up assistance to operations
- ◆ Participate and assist in performance test of facility

10.4.7 Construction and Installation of Pool 3 Subsea Systems

10.4.7.1 Excavated Drill Centres

Construction of EDC(s) will be similar to that used previously on the Grand Banks. Subject to confirmation of soil conditions by a geotechnical survey, a trailing suction hopper dredger (TSHD) will be used to excavate the EDC(s). This vessel lowers a suction pipe to within 10 m of the seabed. A heading parallel to the longest dimension of excavation is maintained, and at the start of the depression the suction head is lowered and the seabed excavated as the vessel moves forward. At the far end of the EDC the suction head is lifted. The number of passes required to excavate to any specific depth depends on the consistency of seabed material. Subsequent passes overlap to ensure layers are excavated correctly. Slopes at the edge of the depression are achieved by creating consecutive box cuts over the layer being removed. Graded feed-in ramp(s) will be constructed to allow the pipelines and umbilicals to enter and / or exit the EDC. A schematic of the EDC is illustrated in Figure 10.4-16

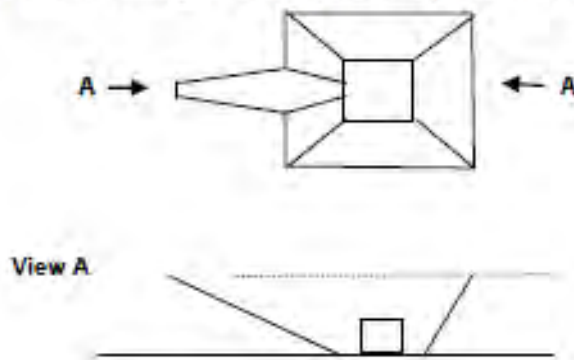


Figure 10.4-16: Aerial and Profile Views of an EDC

The EDC(s) will be excavated to a sufficient depth to ensure protection of subsea equipment; length and width are yet to be confirmed. Soil conditions are expected to include scattered hard layers with potential boulders over the excavation depth. Dredge materials will be loaded into the hopper and discharged by dumping through the bottom doors of the TSHD vessel at a specified location. Application will be made for approval of the dumping location. The approximate EDC locations in relation to the GBS are shown in Figure 10.4-17

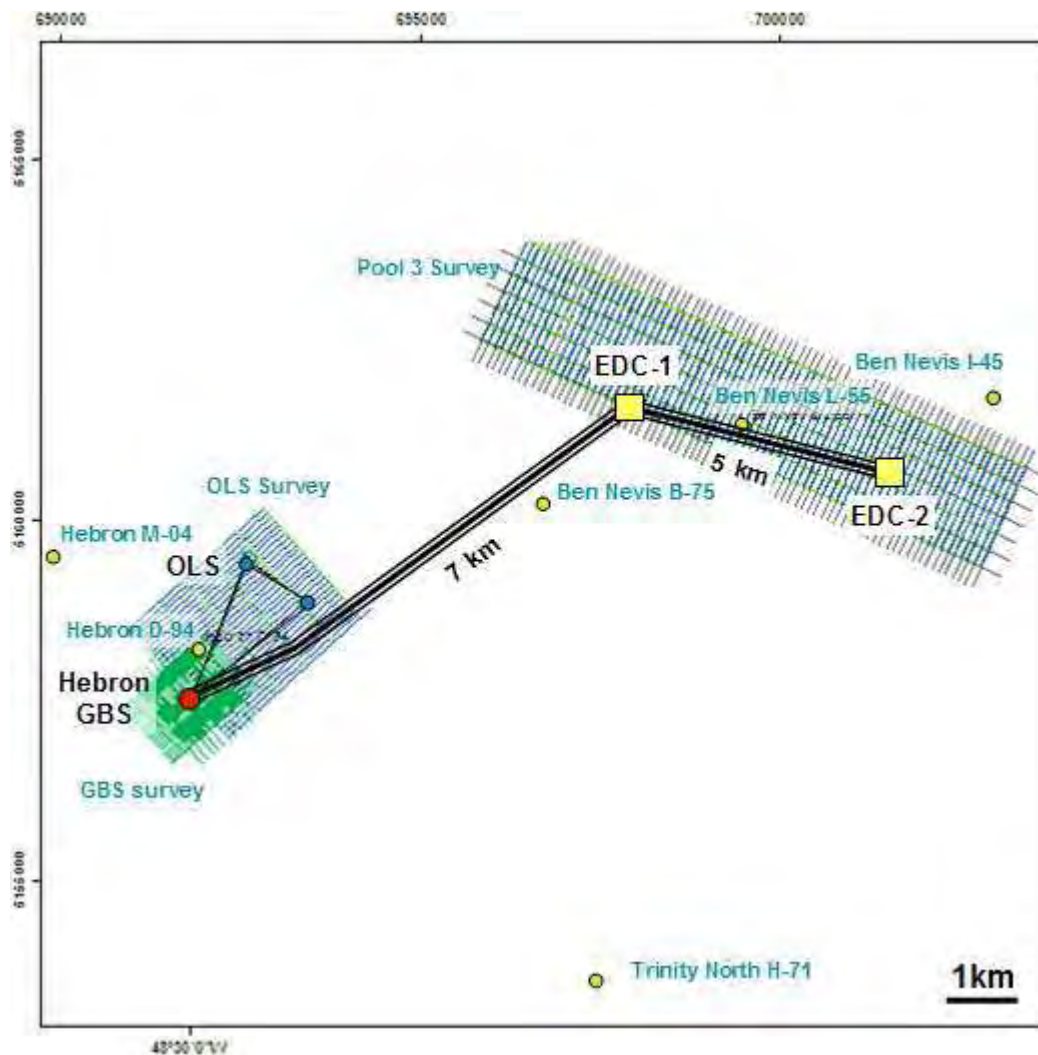


Figure 10.4-17: Proposed Pool 3 Subsea EDC Locations

10.4.7.2 Pipelines and Umbilicals

The conceptual design of the subsea tie-back includes the following pipelines between the GBS and the EDC(s): two insulated production pipelines, one water injection pipeline, one gas injection pipeline, one gas lift pipeline, and one high-pressure well stimulation pipeline. Two electro-hydraulic umbilicals will provide power, communication, and chemical injection functions to the

EDC(s), one for the subsea production facilities, and another for the subsea water / gas injection facilities. Depending on the number and location of the EDC(s), the tie-back distance will range from 7 km to 12 km.

Both ends of the pipelines and umbilicals may be equipped with weak links or break away connectors as a contingency for icebergs or other threats.

Rigid or flexible jumpers between the GBS risers and subsea pipelines will be installed by a construction vessel and connected using diverless connections. Dropped object protection for the jumpers will be also installed by a construction vessel. The pipelines, which may be rigid or flexible, will be installed by either S-lay or reel-lay vessel. The umbilicals will be installed by a construction vessel. If required, pipelines will be stabilized on the seabed using such methods as trenching (using a TSHD vessel), rock dumping (using a fall pipe vessel), or weight coating. Subsea trees will be installed by a mobile offshore drilling unit (MODU). Subsea manifolds may be installed by a construction vessel or MODU. Pipeline-to-manifold jumpers will be installed by a construction vessel using diverless connections. Well-to-manifold jumpers may be installed by either a MODU or construction vessel using diverless connections. Hydraulic / electric flying leads will be connected by remote operated vehicle (ROV). Umbilicals will be pulled in via winch through one of the GBS J-tubes.

10.4.8 Construction and Installation of Additional Topsides Module(s)

Additional topsides module(s) may be required to process hydrocarbon production from Pool 3. Techniques similar to those used in fabrication of other Hebron platform modules will be employed to fabricate these module(s).

After being fabricated the additional topsides module(s) associated with Pool 3 will be installed on the Hebron Platform at the offshore location utilizing common industry practices. A possible configuration of the additional module(s) is depicted in Figure 10.4.18. The additional module(s) would likely be installed north and/or south of the Utilities and Process Module.

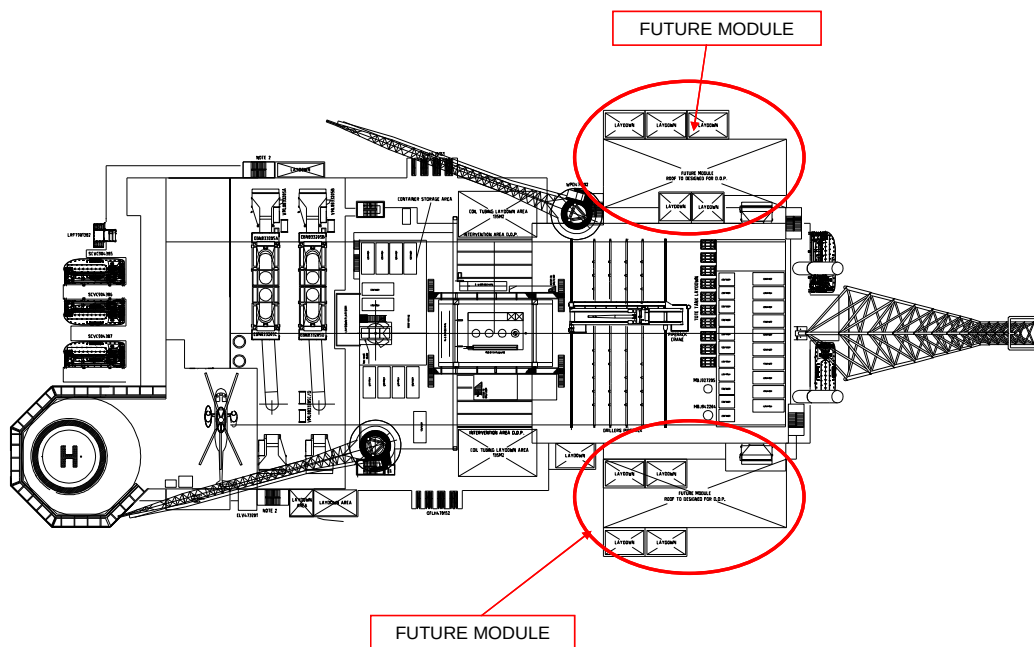


Figure 10.4-18: Additional Module(s) Configuration

Installation will likely require the use of a heavy lift offshore crane vessel to lift the module(s) in place. The module(s) will be lifted into place and secured to the platform at site as depicted in Figure 10.4-19.

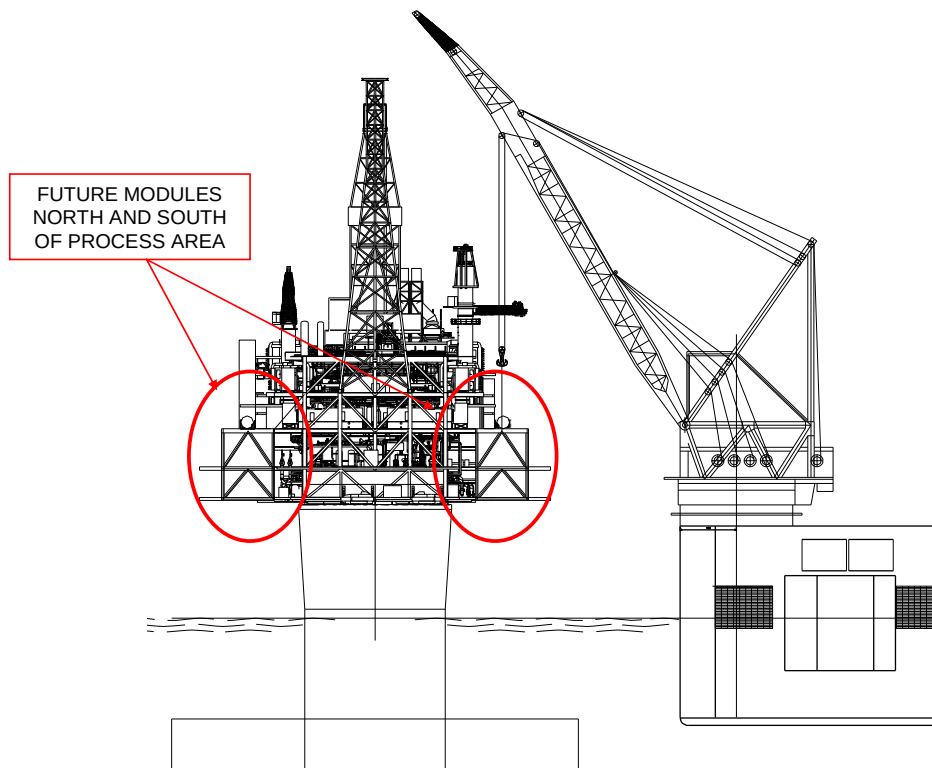


Figure 10.4-19: Heavy Lift Crane Vessel Module Installation

Specification, configuration and execution plan for the construction and installation of the module(s) will be further developed as FEED, Detailed Design, and detailed execution planning are progressed.

10.5 Special Transportation or Installation Facilities and Equipment

The following table indicates required special transportation or installation facilities and equipment.

Table 10.5-1: Special Construction Equipment

Module	Special Equipment
UPM	Skid beams / skid shoes
	Heavy lift transport
	Catamaran barges
	Strand Jacks
GBS	Temporary moorings
	Tug fleet
	Tow equipment (lines, bridles, etc.)
	Solid ballast material and bulk carrier barge
	Ballast conveyor and pumping system
Drilling Modules, LQ	Marine Installation vessel with remotely operated vessel (ROV)
	Lift towers or shear leg crane
	Transportation barge and Tugs
	Load-out system (jacking system) or SPMTs
	Various rigging and spreader bars
Helideck, Flare boom	Mobile craneage
	SPMTs or skid system
	Barge / tugs
OLS	Various rigging and spreader bars
	Pipe lay installation vessel
	Pipe line tow equipment
	Marine construction vessel with ROV
Pool 3 Subsea Development	Pipe lay installation vessel
	Suction dredging vessel
	Marine construction vessel with ROV
Pool 3 Additional Modules	Heavy lift crane vessel

10.6 Major Construction Materials and Services

The following table indicates required Major Construction Materials and Services:

Table 10.6-1: Major Construction Materials and Services

Module	Major Materials and Services
UPM	Bulk Materials – Steel, piping, valves, Pressure Safety Valves (PSVs), electrical and instrumentation
	Quality Inspection Services
	Marine Warranty Survey
	Strand Jacks
	Dimensional Control, Laser Surveys
GBS	Bulk Materials – steel, cement, sand, aggregate, piping, valves, PSVs, electrical and instrumentation, slip forms
	Quality Inspection Services
	Marine Warranty Survey
	Construction Material Lab Services
	Bathymetry & subsurface hazard survey
	Grout
Drilling Modules, LQ	Bulk Materials – steel, piping, valves, PSVs, electrical and instrumentation
	Quality Inspection Services
	Marine Warranty Survey
Helideck, Flare boom	Bulk Materials – steel, piping, valves, PSVs, electrical and instrumentation
	Marine Warranty Survey
OLS / Export system	Bulk Materials – piping, valves, electrical and instrumentation
	Marine Warranty Survey
	Pipeline Route Survey
General	Camp Services
Pool 3 Subsea Development	Bulk Materials – piping, valves, electrical and instrumentation
	Marine Warranty Survey
	Pipeline Route Survey
Pool 3 Additional Modules	Bulk Materials – Steel, piping, valves, electrical and instrumentation
	Marine Warranty Survey

10.7 Environmental Considerations of Construction and Installation

This section describes environmental considerations and associated responsibilities for the construction phases of Hebron. The Hebron Project will develop environmental monitoring and reporting programs to ensure that environmental performance requirements are incorporated into execution activities.

The Hebron Project's EPC contractors will have appropriate environmental execution capabilities within their own teams and will develop Environmental Management Plans (EMPs) specific to their scope of work. The EPC contractors' EMPs will become the basis for further development of site-specific environmental management plans and environmental documentation by the contractors (including construction wastes).

In addition to the Bull Arm Site, it is expected that all additional fabrication and construction activities will take place in existing contractor-owned facilities. Each contractor will be responsible for obtaining and maintaining permits, licences, and other regulatory and environmental requirements specific to the country and locality in which they operate. These facilities are expected to have environmental management systems in place for environmental effects such as toxic wastes, debris, effluents, and emissions.

In addition to the above, the Hebron Comprehensive Study Report (CSR), as submitted to the C-NLOPB in June 2010, addresses the environmental effects of project activities in marine waters, including in-water works at Bull Arm and offshore installation, commissioning, drilling and production operations. Mitigations identified in the CSR will be implemented for all project activities at Bull Arm and at the Hebron offshore locations, when applicable. Environmental effects monitoring programs will be developed for Bull Arm and the Hebron offshore sites.

11 OPERATIONS AND MAINTENANCE

The Hebron facility will be operated in a safe, environmentally responsible manner by implementing ExxonMobil global operating best practices, and will be compliant with all regulations, agreements, and contracts associated with the Hebron Project. The facility uptime target is 95 percent. Where appropriate, opportunities to synergize with existing Jeanne d'Arc Basin operations will be studied and leveraged for use on the Hebron Project.

Key Operation Principles:

- ◆ Meet the highest standards for safety, health and environmental compatibility, including effective implementation of Operations Integrity Management System (OIMS). OIMS provides a structured approach to meeting ExxonMobil's commitments to safety, health, and protection of the environment in a manner that protects the safety and health of employees, others involved in its operations, its customers and the public. Furthermore, it is committed to conduct business in manner that is compatible with the balanced environmental and economic needs of the communities in which it operates. This commitment requires compliance with all applicable laws and regulations, facilities that are designed and operated to high standards, and systematic identification and management of safety, health, and environmental risk.
 - OIMS is implemented at the operating level using individual management systems. Each management system is documented and defines the processes, procedures, verification and feedback mechanisms needed to satisfy specific OIMS Element requirements.
 - The success of an organization depends on everyone's commitment to continuously improving performance and meeting the expectations of the management system. To improve performance, continuous commitment and support is required from all levels in the organization as well as from every individual.
- ◆ Develop a high calibre, well trained and competent workforce through local training centres and on the job training
- ◆ Ensure all measurement for hydrocarbon streams and tankage complies with regulatory and ExxonMobil metering, measurement and analysis guidelines
- ◆ Incorporate global best operating practices to achieve a reliable, efficient and effective operation
- ◆ Maximize revenue through reliable and optimized production of gas and hydrocarbon liquids

- ◆ Adhere to ExxonMobil safety and operating principles
- ◆ Provide operational input to facility, equipment and infrastructure design and construction to ensure long term effective operations
- ◆ Ensure cost-effective operational / drilling considerations are incorporated into the design of the Hebron Platform through the Operational members of the design team
- ◆ Participate in the systems completion process and provide a dedicated start-up team to ensure effective transition from the Hebron Project Execution team to the ExxonMobil Canada Properties (EMCP) affiliate

The development of a Maintenance and Reliability (M&R) program will be stewarded by the Hebron Project Team. Technical support for program development will be provided by the Hebron Project Team, contractors, and vendors. A detailed execution plan will be developed by the Hebron Project Team during front-end engineering and design (FEED) that will address contractor and Company division of responsibilities, project staffing and organization, contracting strategy, and preliminary cost and schedule as a section of the Hebron Project operations plan. A computerized maintenance management system database will be developed consistent with established EMCP operations and maintenance practices.

The M&R process for developing the detailed maintenance plan is to use Equipment Strategies. This is a risk based process that looks at failure modes of equipment and assesses the probability and impact of a failure (safety, security, health and environment [SSH&E] / business). Using the M&R probability / consequence matrix, the risk is judged to be either acceptable, acceptable but may justify some mitigating action, or unacceptable. If the risk is not acceptable, then mitigating actions are developed to reduce the risk to an acceptable level. These mitigation actions form the basis of the maintenance program. When developing equipment strategies, EMCP maintenance practices and programs as well as Canadian regulations should be followed.

Equipment will be tagged appropriately to conform to regulatory and ExxonMobil tagging requirements for input into a computerized maintenance management system database.

The Spare Parts Inventory Development process will be employed to identify the required spares needed for start-up and commissioning. This process identifies the people, tools, procedures and instructions required to identify, procure, supply and warehouse the initial fill of spare parts.

In order to make the most effective use of Operations and Maintenance personnel and to limit the requirements for visits by Vendor or Specialist contractors, the following will be adopted:

- ◆ A detailed training plan and competency assurance process will be utilized to ensure personnel have the required skills and training to safely and effectively perform their work
- ◆ For reference, the training will consist of two major aspects:
 - Qualification and competence to hold the specific position per EMCP requirements
 - Establishment of vocational skills
 - ◆ To achieve the required efficiency within the staffing concept, a degree of multi-skilling between the disciplines will be required
 - ◆ Training is identified and actioned in advance of first oil. This training should include the use of key Operations and Maintenance personnel during the Detailed Design, Hook-Up and Commissioning Phases of the project

11.1 Organization

The Hebron organization consists of two parts - the onshore management and support groups and the offshore drilling and production operations group.

11.1.1 Onshore Organization

The onshore organization will be designed to provide the necessary support for offshore operations, during both the development and production phases. The onshore organization will include competent personnel with the necessary skills sets, and experience to provide effective support to the offshore operation, including emergency situations. It will be focused on safety, flexibility, operability, maintainability, reliability, efficiency and cost effectiveness.

The anticipated organization is shown in Figure 11.1-1

The core onshore organization is expected to be staffed with personnel in the groups shown in Table 11.1-1.

Onshore contract personnel will also be required in the following areas:

- ◆ Helicopter air and ground staff
- ◆ Dockworkers and crane operators for supply vessel operations at the shore base
- ◆ Crews for the supply and standby vessels
- ◆ Staff working for the construction, maintenance and drilling contractors

Offshore operations will be serviced by helicopter. This service will be contracted out to an appropriate aviation contractor. Helicopters will be the primary means of personnel transfer.

Offshore operations will also be serviced by marine support vessels. Each marine support vessel is expected to have a crew of approximately 10 to 12 people. A stand-by vessel will be provided within close proximity to the installation on a 24/7 basis. When not on stand-by, these vessels will provide general operational support. Supply vessels will provide routine logistical support and ice management coverage. Additional vessel support may be required during ice season. During periods of helicopter unavailability, personnel transfers may also be done by vessels.

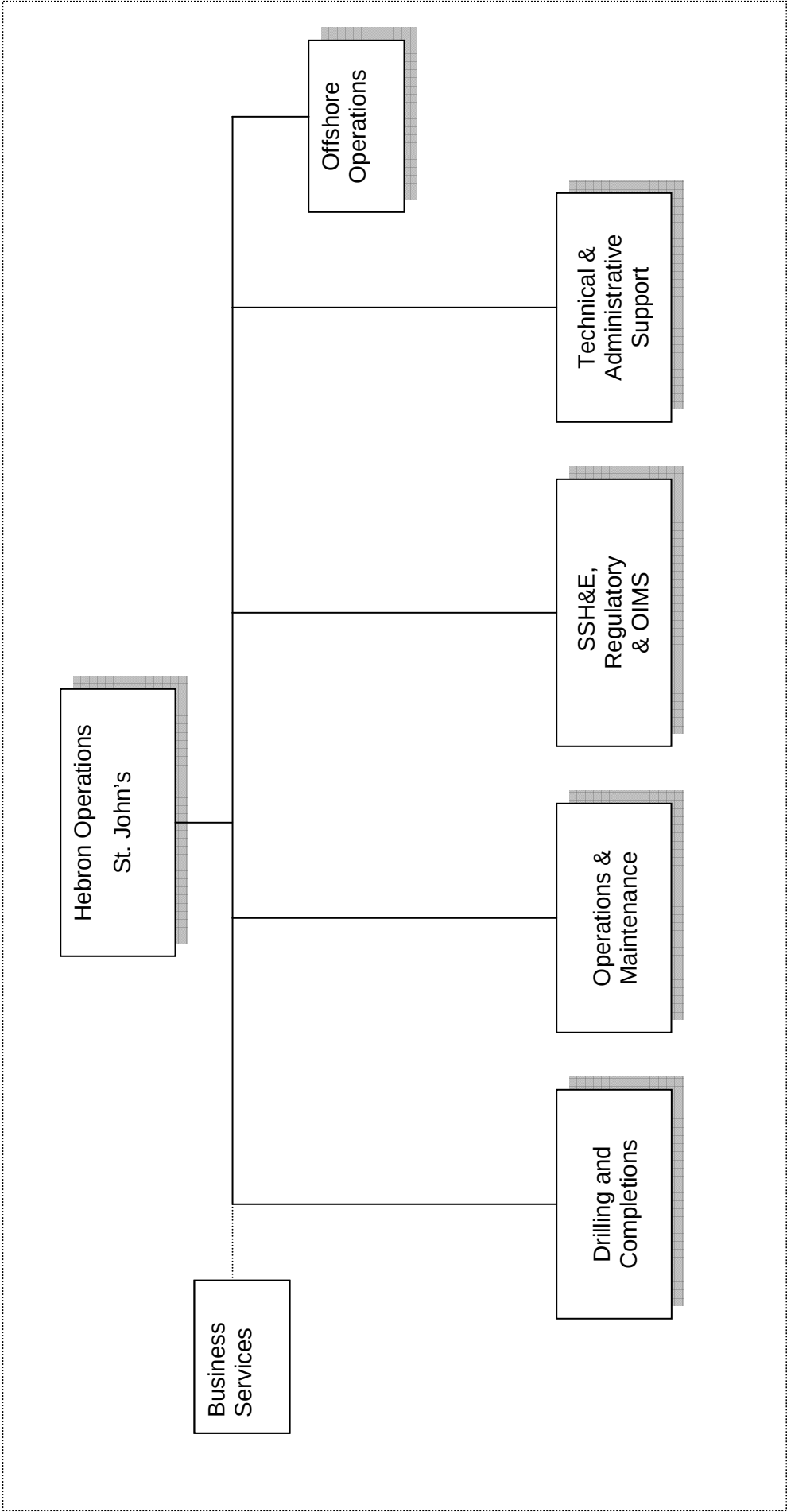


Figure 11.1-1: Onshore Organization

Table 11.1-1: Functional Breakdown of Hebron Onshore Personnel

Responsibility	Function
Management	Operations Management
Drilling and Completions	Drilling Supervision Drilling Engineering Completions Engineering
Operations & Maintenance	Central Maintenance Organization Production Engineering Subsurface Engineering Logistics / Security
Technical & Administrative Support	Facilities Engineering Programmatics Engineering Surveillance Engineering Reservoir & Geoscience - Operations Technical
Business Services	Operations Accounting Information Management Facilities - Office Procurement Medical & Occupational Health Human Resources
SSH&E, Regulatory & OIMS	Regulatory Safety Advisor OIMS / Training Coordinator Environmental Advisor

Synergies for onshore servicing and support facilities currently utilized by other area operators present an opportunity for Hebron. EMCP intends to investigate and leverage as many of these opportunities as possible.

During non-routine peak activity periods, EMCP may require additional temporary staff, sourced directly or indirectly through subcontractors.

The following describes the onshore functional groups and their support activities.

11.1.2 Operations Management

The Operations Manager will lead the onshore group and will be responsible for the entire Hebron operation, both technically and commercially. The Operations Manager will be responsible for ensuring all EMCP policies and regulatory requirements are implemented.

11.1.3 Drilling and Completions

The drilling and completions department will plan, design, implement and provide support for offshore drilling, workover, and completion activities. Activities and scheduling will be coordinated with the drilling contractor.

11.1.4 Operations & Maintenance

Onshore Operations, Maintenance and Logistics Supervision will be provided to assist the Hebron operations and maintenance program and provide logistical support for all materials, transportation, warehousing, and pipe yard management for both Operations and Drilling to achieve safe and reliable operations. This group will also provide assistance with the ice and weather surveillance efforts.

11.1.5 Technical & Administrative Support

This group will be responsible for supplying engineering, technical and administrative support to the offshore operations team in the areas of Programmatic, Surveillance, Computer and Telecommunications, Reservoir, Geoscience and Projects. It will consist of discipline engineers who will either provide the support directly or will manage the contracts for supplying the engineering and construction services.

11.1.6 Business Services

This group will be responsible for the provision of support to the Operations Team. This includes, Operations Accounting, Information Management, Public Affairs, Human Resources, Occupational Health, Facilities and Procurement.

11.1.7 SSH&E, Regulatory and OIMS

The SSH&E team ensures that SSH&E policies are developed and implemented in compliance with company standards, legislative requirements

and industry best practice. The team also provides expert advice and guidance on safety, security, health and environmental performance to the Operations Team.

In order to do this, the group will establish and maintain communication networks with other SSH&E professionals within the Company, industry experts with experience of offshore environment on Canadian East Coast and elsewhere and other external organizations. These organizations will include, but not be limited to, representatives from the fishing industry, police, Canadian Coast Guard, federal and provincial governments and environmental protection agencies.

Regulatory guidance for Hebron operations is supported by a regulatory advisor. OIMS, Emergency Preparedness & Response and Training support is provided by a dedicated co-coordinator.

11.1.8 Offshore Organization

The offshore organization will be comprised of competent personnel in all required disciplines. EMCP will utilize ExxonMobil OIMS to describe the processes and procedures by which high standards of safety, health and environmental standards, and plant efficiency and reliability will be systematically managed and continuously improved.

The anticipated organization is shown in Figure 11.1-2.

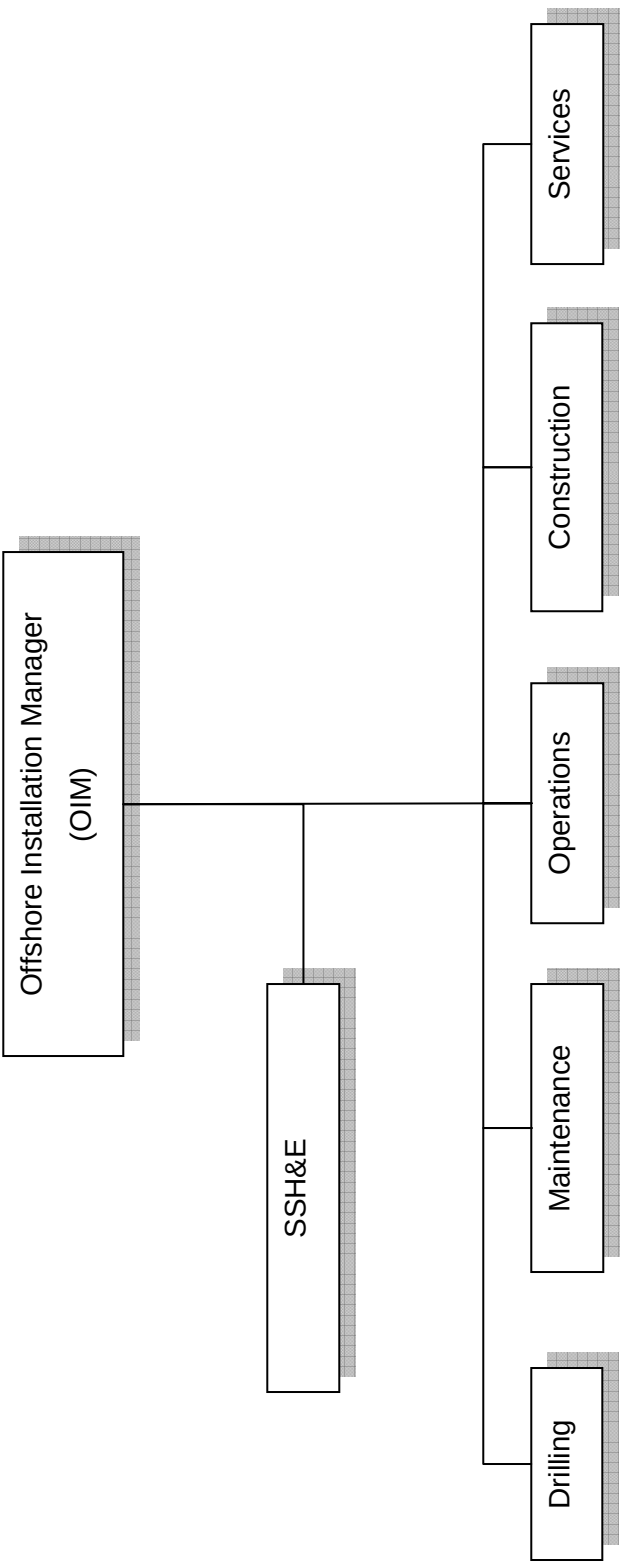


Figure 11.1-2: Offshore Organization

11.1.9 Hebron Facility

The offshore living quarters and all associated equipment and processes are expected to be built to accommodate up to 220 persons at any one time (design capacity). All rooms are designed to accommodate 2 persons per room. The likely breakdown of functional groups that will make up the Hebron staff is shown in Table 11.1-2.

Table 11.1-2: Preliminary Functional Breakdown of Hebron Offshore Personnel

Responsibility	Function
Management	Offshore Installation Manager
SSH&E	Specialist Health and Safety Registered Nurse
Operations	Supervision Control Room Operations Production Operations Lab Technicians
Maintenance	Supervision Instrument Maintenance Mechanical Maintenance Electrical Maintenance Inspection Technicians Telecommunication Maintenance
Services	Supervision Helideck Operations Deck Crew Supervision Deck Crew Operations Crane Operations Radio Operations Ice Management & Vessel Coordination Catering and Accommodations Services
Construction	Maintenance, Operations and Drilling Projects
Intervention	Workover / Intervention / Logging Support
Drilling	Drilling / Completion

There will be a need for periods of increased work activity offshore to address required construction or improvements, modifications, and / or repairs to platform equipment or systems. The work will normally be scheduled to minimize the production impact. However, operational circumstances may

dictate that personnel are mobilized on an ad-hoc basis. The workforce required to complete this activity will be dictated by the scope of the work. In order to manage the platform personnel on board, personnel already onboard will be utilized to support these activities. The design capacity to accommodate up to 220 persons for the living quarters and associated systems (water, heating / ventilating, galley, lifeboat capacity, etc) has been reviewed and determined that the existing design would be able to accommodate short duration, increases to personnel on board (POB) during commissioning, start-up and major campaign work. These incremental POB scenarios that exceed the design capacity of 220 would require special permission from C-NLOPB.

The offshore operation will be provided with ad-hoc engineering support by the Operations and Maintenance group. This support will be task specific for the identification, investigation and resolution of operational issues. Ongoing support is provided by the Technical Support group

The following describes the offshore functional groups.

11.1.9.1 Offshore Installation Management

Platform operations will be administered under the direction of an Offshore Installation Manager (OIM) who will report to EMCP Hebron Operations management based in St. John's. The OIM will be responsible for the safe and efficient execution of all platform activities, including Drilling, Well Intervention, Construction, Shipping and Ice Management.

All simultaneous operations issues and work permits will be addressed and approved locally. The OIM will be accountable for all work management offshore.

The OIM will ensure that appropriate procedures are in place and implemented for the safe, efficient operation and maintenance of the entire Hebron installation.

The OIM is the designated person in charge for emergency response.

11.1.9.2 Safety, Security, Health & Environment

As required, SSH&E personnel will provide support in the implementation of all safety, security, health and environmental policies and procedures, and development and implementation of emergency exercises and drills.

SSH&E will support Logistics in the implementation and coordination of the ice management plan. SSH&E personnel will also assist in conducting offshore safety and environmental inspections and audits, and performing accident and incident investigations.

First aid services will be provided by a qualified onboard registered nurse trained to regulatory requirements. Other operations personnel will be trained

in advanced first aid and will support the registered nurse, as required. SSH&E will assist the registered nurse in conducting first aid drills and medical escort training and implementing the company's health awareness programs.

11.1.9.3 Operations

This group will be staffed with personnel trained in control room operations, production operations, and laboratory analysis. The Hebron facility will be controlled by an integrated control system from a Central Control Room, thereby optimising the level of routine manual operation. Operations staff will be cross-trained for other tasks to the extent feasible.

Operations will be on an around-the-clock basis necessitating the requirement of two, 12-hour shifts.

11.1.9.4 Maintenance

This group will be comprised of personnel trained in mechanical, electrical, instrumentation, inspection, computer, and telecommunication maintenance. The majority will be cross-trained where appropriate and will work closely with the other to ensure safe, reliable and efficient operation of the platform systems.

The onshore EMCP Central Maintenance Organization, in coordination with the offshore teams, will plan and schedule all maintenance work activities and shutdowns.

To the extent possible, the group will coordinate with and support construction and specialist personnel to ensure efficient use of skill sets during initial builds, upgrades, repair or modifications.

11.1.9.5 Services

This group will be responsible for all other activities dedicated to the safe and efficient offshore operations including personnel and materials movement and logistics. The group will coordinate vessel movements (including supply and standby vessels and tankers), helicopter services, deck and crane operations (including scaffolders, painters and rope access personnel), radio and communications operations, catering, housekeeping, and accommodation management.

It will also be responsible for environmental monitoring, ice surveillance and coordination of the ice management plan under direction of the OIM.

11.1.10 Drilling

The Drilling Superintendent or their designee has overall responsibility for the daily drilling operations and maintenance of the drill rig and associated systems aboard Hebron Platform.

11.2 Operations and Maintenance Procedures

Operations and maintenance procedures and manuals will be developed and implemented specifically for the Hebron Platform as required by OIMS guidelines. They will comply with EMCP general operability and maintenance procedure requirements, and all regulatory requirements. These procedures and manuals will be used for training personnel to operate and maintain the platform in a safe and efficient manner.

The procedures will be finalized once vendor equipment and system documentation becomes available and will cover the following topics:

- ◆ Systems
- ◆ Equipment
- ◆ Reporting relationships and procedures
- ◆ Maintenance procedures
- ◆ Production and marine procedures
- ◆ Ice management procedures
- ◆ Health and safety procedures
- ◆ Emergency procedures
- ◆ Alert and contingency procedures
- ◆ Environmental monitoring procedures

Documents will be developed on a prioritized manner to facilitate personnel training. The basic documents will be drafted during the detailed design phase and finalized by the various user groups. Strict compliance with OIMS guidelines and regulatory requirements will be maintained.

Drilling operations and maintenance procedures and procedures for record-keeping are defined in the ExxonMobil Drilling Operations Integrity Management Manual.

11.2.1 Systems

Systems manuals will include design rationale, operability parameters, and descriptions and drawings of the primary process, ancillary systems, and associated equipment and subsystems. These manuals will be used to develop the Operator training manuals.

11.2.2 Equipment

Detailed information on each individual piece of equipment and each system and subsystem will be included in vendor data books. At a minimum, these vendor data books will contain drawings, specifications, descriptions, materials, installation guidelines, operation and maintenance guidelines, and recommendations on spare parts inventory.

11.2.3 Reporting Relationships and Procedures

Roles and responsibilities, limits of authority, lines of reporting, accountabilities in production and maintenance operations, procedures for record-keeping, the requirements for report generation and distribution and data acquisition will be set according to EMCP guidelines and applicable regulatory requirements.

Drilling operations and maintenance procedures and procedures for record-keeping are defined in the ExxonMobil Drilling Operations Integrity Management Manual.

11.2.4 Maintenance Procedures

The purpose of the maintenance procedures is to:

- ◆ ensure the safety systems will protect the staff, environment and the facility
- ◆ monitor and maintain the facility integrity to prevent uncontrolled releases of fluids or energy
- ◆ ensure the facility is reliable and available to meet production targets

Maintenance procedures manuals will be prepared for all equipment as part of the overall maintenance program. These procedures will be based on design data, recommendations by vendors, operating conditions, and the criticality of the equipment to safe operation of the facility. A risk-based process will be used to address the effect of equipment failure on personnel safety, environmental consequences, and operational efficiency and to develop mitigating actions to reduce the risk.

All monitoring, inspection, maintenance and repair, will all be addressed by the maintenance program. The maintenance program will include the installation and population of a computerized system containing detailed information on each item of equipment including criticality, maintenance history and cost, maintenance frequency and required spares.

11.2.5 Monitoring

The maintenance program will require routine monitoring of all equipment and structures. The procedures will also cover the monitoring and control of ice build-up on the various structural components of the facility.

Sensors and on-line monitoring systems will all be used, as appropriate.

11.2.6 Inspection

An Inspection program will be developed in compliance with OIMS guidelines as part of the facility integrity management process. All structural elements, piping and equipment will be included in the regularly scheduled integrity inspections. Inspection schedules will be set according to data from equipment criticality ratings, vendor recommendations and in-service feedback. Inspection techniques employed will be the recognized inspection technique most appropriate for the item under inspection.

The areas of attention will include structural, pressure containing systems, rotating equipment, lifting equipment and life saving equipment.

11.2.7 Maintenance and Repair

Preventive and predictive maintenance will be managed through the use of the computerized maintenance system. Depending on the equipment criticality, corrective maintenance (i.e. repair) will be managed on an as required basis.

11.2.8 Operations Procedures

The purpose of the operations procedures is to:

- ◆ Ensure the ExxonMobil and Regulatory standards for safety, health and environment, including effective implementation of OIMS are maintained
- ◆ Ensure all measurement for hydrocarbon streams and tankage complies with the ExxonMobil and regulatory standards
- ◆ Deliver superior reliability performance throughout the life of the facility by utilizing proven global operating and maintenance practices

The operations procedures manual outlines the procedures for safe and efficient operation of the facility throughout the production life. Detailed processes will be provided for:

- ◆ Facility start-up (initial and blackstart) and shutdown
- ◆ Routine production
- ◆ Process upset and troubleshooting guidance
- ◆ Simultaneous operations
- ◆ Operations limits
- ◆ Adverse weather conditions
- ◆ Crude storage and shipment

11.2.9 Ice Management Procedures

EMCP has an Ice Management Plan in place for its production / drilling operations on the Grand Banks and is focused on the safety of offshore personnel, the environment and the facilities. This plan will be reviewed and updated as appropriate to include the production phase of the Hebron development. The plan will include the responsibilities for ice surveillance, monitoring and reporting as well as steps necessary for avoidance of iceberg collision and ice response to evacuation plans.

The ice management procedures will draw on the cooperation of existing ice surveillance / management efforts in the area and will incorporate all available information.

Further discussion of the Ice Management Plan is included in Section 11.5.

11.2.10 Safety, Security and Health Policies and Procedures

EMCP will implement safety, security and health policies and procedures for the Hebron development that will meet or exceed all statutory requirements, ensure the safety of all personnel, provide a healthy work and living environment, and support the goal that “**Nobody Gets Hurt**”.

As part of EMCP's application for an Operations Authorization, EMCP will prepare and implement a Project Safety Plan covering all platform drilling and producing operations. The Plan will be prepared in accordance with the requirements of the **Newfoundland Offshore Petroleum Drilling and Production Regulations** and the C-NLOPB's **Other Requirements Respecting Occupational Health and Safety**.

To minimize the risk to employees of occupational injuries or illnesses, operational characteristics and conditions will be monitored. Modifications will be made to address exposure to excessive noise, heat, radiation, vibration, ventilation issues and ergonomic considerations. Programs will be developed to engage personnel and promote occupational hygiene, enhance the well-being of personnel, and prevent incidents.

Safety will be an important design criterion. Hazard and operability studies (HAZOPS) will continue to be essential activities at key stages of design. The purpose of a HAZOPS is to identify a potential hazard, assess the possible consequences and determine the most appropriate mitigating action.

Fire and gas monitoring procedures are of key importance as this system will be the primary process hazard detection system and will have a direct interface with the emergency shutdown system and active protection systems.

Safety procedures training will be provided to every employee to ensure complete awareness and understanding of these procedures. Records will be maintained on the training undertaken by each employee.

Additionally, EMCP will work with regulatory bodies to implement the requirements of the Marine Transportation Security Regulations administered by Transport Canada and the C-NLOPB's Other Requirements Respecting Offshore Security. Pursuant to these requirements, EMCP will undertake a Facility Security Assessment and prepare and implement a Facility Security Plan.

11.3 Emergency Procedures

OIMS addresses emergency preparedness and response and requires that procedures will be implemented to address credible emergency scenarios that might reasonably be expected to arise on the Hebron facilities. Detailed procedures will be available for each credible emergency scenario. Onshore and offshore emergency team responsibilities will be assigned and training provided. Regular and frequent drills will be held onboard to validate individual and team response capabilities. Teams will include, but not necessarily be limited to:

- ◆ Fire and rescue
- ◆ Medical
- ◆ Lifeboat and coxswain
- ◆ Helideck
- ◆ Well control
- ◆ Emergency command centre control
- ◆ Marine emergency

11.4 Alert and Contingency Procedures

Contingency procedures will be implemented to respond to alerts and potential emergency situations. The procedures will describe how and when a contingency measure will be initiated.

The procedures will attempt to coordinate all available information concerning the problem for analysis by the Emergency Response team and the OIM to make informed decisions.

Sufficient information will be gathered, to assist the OIM to make an informed decision to ensure personnel safety, minimal environmental impact and installation integrity. The following are examples of the kind of conditions that could trigger an alert situation:

- ◆ Loss of monitoring capability on critical systems

- ◆ Severe wind and / or sea forecast
- ◆ Icing on structure
- ◆ Possible iceberg impact
- ◆ Possible vessel impact
- ◆ Potential loss of well control
- ◆ Heavy sea ice
- ◆ Security threat

The OIM will be responsible for determining which contingency procedures are to be implemented in response to each specific alert. The OIM's decision will be based on the information at hand and the potential risks arising.

The OIM will retain control and responsibility for the facility at all times.

11.4.1 Environmental Monitoring Procedures

Environmental monitoring procedures will be developed to ensure compliance with the environmental monitoring program.

These procedures work to minimize exposure of personnel to risk, protect the environment, protect the asset, and facilitate safe and efficient operation. Key environmental factors that will be addressed will include:

- ◆ Pollution prevention
- ◆ Oceanography and Meteorology
- ◆ Chemical management
- ◆ Waste management
- ◆ Regular environmental monitoring (seabirds, whales, etc.)

11.5 Ice Management Plan

EMCP has an Ice Management Plan in place for its production / drilling operations on the Grand Banks and is focused on the safety of offshore personnel, the environment and the facilities. This plan will be reviewed and updated as appropriate to include the production phase of the Hebron development. The plan will include the responsibilities for ice surveillance, monitoring and reporting as well as steps necessary for avoidance of iceberg collision and ice response to evacuation plans.

EMCP participates in the Regional Grand Banks Ice Management Program. This is a joint effort by all the operators on the Grand Banks, and provides for:

- ◆ Coordination of ice and iceberg detection, monitoring and trajectory projection
- ◆ Coordinated management of response actions to icebergs transiting the areas

The Hebron ice management and avoidance plan will include:

- ◆ Aerial, vessel and installation-based ice surveillance
- ◆ Ice data reporting, collation, quality control and presentation systems
- ◆ Local tactical ice forecasting ability, where available
- ◆ Ice definition methods and capabilities
- ◆ Methods and facilities for iceberg detection
- ◆ Capabilities and limitations of the ice management plan and their implications for safety analysis and design considerations (details in engineering system)
- ◆ Updates to evacuation plans when ice is present at the installation, as evacuation means for open water may differ from ice season

The iceberg season for the Grand Banks runs from March through June with sea ice being present from February through April. Icing on the structure is common from November through April and is primarily due to freezing precipitation or sea spray accompanied by cold temperatures and strong winds. While falling ice is a known hazard on the platform, it does not unduly restrict operations. The greater potential impact is on helicopter and support vessel activities.

11.6 Efficiency of Hebron

The Hebron Platform is being designed for an overall facility availability target of 95 percent. This is consistent with experience on similar operating facilities in the Jeanne d'Arc Basin.

The facility availability target includes wells, offshore loading system (OLS), topsides facilities but specifically excludes reservoir performance.

A reliability, availability, and maintainability analysis for the Hebron installation will be performed by the Hebron Project Team during FEED and detailed engineering, in compliance with ExxonMobil guidelines regarding operability, maintainability and reliability of the installation. This will ensure that the final design is capable of delivering the agreed upon facility availability documented in the Project Design Basis.

The availability may be impacted by factors such as equipment reliability, environmental factors and equipment redundancy. The criteria for equipment

and system redundancy and availability, scheduled maintenance, and unscheduled shutdowns and breakdowns will also directly impact upon operational efficiency.

The primary drivers for facility outages will be scheduled maintenance, determined by the equipment strategies developed under the M&R process and local regulatory requirements. These may be changed based on a risk-based program.

All well service activities including well testing, logging, zone isolations, etc. will be coordinated with Operations and will be controlled by the platform's Work Management System. Since the Hebron wells will be gravel packed, any desire to re-complete or the occurrence of down-hole failure of a completion will require well intervention with the rig (work-over).

11.6.1 Limiting Conditions on the Structure and Facilities

The Hebron Platform and OLS will be designed for environmental conditions outlined in the environmental criteria. The limiting conditions imposed by environmental factors on operations, structure and associated systems will be established during FEED once the final design criteria has been adopted for the Hebron facility.

11.7 Logistics

EMCP intends to leverage all cooperative possibilities regarding the use of shared services and facilities to support offshore operations.

The Operations Logistics Plan will include operations requirements for marine offshore support vessels (OSV). OSVs will be procured with long-term charters and operate routinely between the offshore Hebron Platform and the shore base located in St. John's. Contracted marine vessels will comply with Canadian vessel standards, regulations, and flagging requirements. Contract sharing opportunities for marine vessels with other operators in the region are to be considered when developing longer term contracts.

11.7.1 Marine Base, Warehousing, and Storage Yard

The onshore base will require sufficient materials handling equipment (cranes, forklifts, winches etc.) to support loading / offloading operations. It must also be capable of handling the bulk materials, mud, cement, fuel, and water for multiple vessels concurrently.

ExxonMobil and EMCP Procurement will evaluate the requirements for an adequate warehouse / site storage facility providing indoor and outdoor space for Operations and Drilling long lead equipment, spares, and materials. It is anticipated that existing or leased facilities will be available and utilized. Timing will accommodate delivery of long lead equipment prior to production start-up. Final facility requirements and design, material stocking, and

equipment sparing plans will be developed in the execution plan (FEED), recognizing the Hebron Project location and logistical constraints and ensuring that critical equipment, materials, and supplies are available to support project activities.

11.7.2 Support Vessels

The number, range and configuration of the support vessel fleet will be determined after completion of the design of the offshore facilities. Vessels will be required for two primary purposes:

- ◆ Continuously available support services on location, in accordance with regulatory requirements
- ◆ Transportation between the marine base and offshore facilities

Support services on location will cover:

- ◆ Iceberg surveillance, towing, and deflection
- ◆ Environmental monitoring
- ◆ Oil spill response
- ◆ Shuttle tanker mooring assistance
- ◆ Standby service
 - Person overboard
 - On-scene command
 - Search and rescue
 - Firefighting
 - Emergency evacuation
 - Helicopter close standby

Supply vessels will convey materials, consumables and equipment to and from the offshore facilities. The supply vessels also provide the ability to crew change during periods of reduced visibility or unavailability of regular helicopter service.

All personnel staffing the support vessels will be fully trained in emergency duties. Routinely scheduled emergency drills and exercises will be scheduled to test and develop competencies.

11.7.3 Material Procurement and Movement

EMCP will maintain optimal spares inventory necessary to avoid loss of production or service from essential safety and emergency equipment. All

equipment components will have an associated equipment strategy that identifies spares requirements according to criticality ratings. The criticality assessment will determine where the spares should be located.

During operations, it is assumed that critical Hebron spares and materials will be stored on the Hebron onboard warehouse facilities since access to St. John's from the offshore Hebron Platform will be frequently restricted due to weather conditions and / or seasonal routing. Onshore warehousing will continue to be required throughout the life of the project.

Fresh food and water will be provided on a regularly scheduled basis.

11.7.4 Personnel Movements

Personnel movements between St. John's and the platform will normally be carried out by helicopter. The required helicopter usage will be to convey 220 drilling, production and support personnel that will be offshore at any one time. Personnel transport may be by seagoing vessels during extended periods of no-fly weather or as required by ExxonMobil or the C-NLOPB.

EMCP intends to investigate the potential benefits of cooperation with other operators in this regard. EMCP currently participates with other operators in the provision of first response search and rescue helicopter capacity for the Grand Banks region.

11.7.5 Diving Requirements

Dedicated areas for on-platform diving spread will not be required. If diving operations are required, a diving support vessel will be utilized. Diving activities, while preferably scheduled during the summer period, will take place when the condition warrants. Remotely operated vehicle (ROV) spreads may be mobilized to the support vessels for subsea inspections and other subsurface activity as required.

EMCP intends that diver intervention will be used infrequently and only for specific underwater operations that cannot be carried out by ROV. Diving contract services, when required, will be with a competent and experienced diving company. The company will be required to assign qualified and competent personnel to direct and control the diving operations which will be monitored by the EMCP diving representative

EMCP and the diving company will jointly develop and implement the diving procedures manual. The manual will comply with all statutory diving and safety regulations and best industry practices and meet OIMS work management guidelines.

11.8 Communications

Equipment and systems will be installed on and offshore to provide industry accepted high standards of communications on the Hebron Platform itself and between Hebron, the onshore office and facilities, and other offshore installations, vessels and aircraft in the vicinity of the Hebron Platform.

The communications systems will include radio, telephone, telemetry, local area computer network, and other related equipment necessary to provide the high standard of reliable communication that is required for safe and efficient operations. The systems will comply with all regulatory requirements. Back-up systems will be used to provide the maximum continuous communications capability available in any reasonable environmental condition.

The system components will be state-of-the-art, multi-channel, broad band width and will have adequate redundancy for their purpose. The actual systems will be finalized at a later date.

11.9 Contingency Plans

EMCP recognizes that prevention is the most effective way to avoid emergencies. Prior to commencement of drilling and production operations, EMCP will develop contingency plans that will serve as the guidelines for the company's response to an emergency at the Hebron Project. Contingency plans will be developed to address emergencies that will be identified in operations-specific hazard and risk analyses. The plans will outline the necessary procedures, personnel, equipment and logistics support required to respond to an emergency incident in a safe, prompt, coordinated manner. The plans will be distributed to designated personnel who will be responsible for emergency response actions. The content of the plans will contain sufficient detail to enable personnel to respond in a coordinated and effective manner.

Contingency planning for the Hebron Project will be addressed in a number of inter-related documents that each covers a specific aspect of production operations. Overviews of the individual documents that, collectively, will dictate all emergency response operations are presented in Tables 11.9-1 and 11.9-2. At this stage of the project, the plan names used in the tables are generic. The final structure and naming of each plan will be finalized during the development of the project production program.

Table 11.9-1: Overview of EMCP Offshore Contingency Plans

Plan	Description
Offshore Emergency Response Plan	A plan which describes onsite response actions at the Hebron Platform: • Provides very specific role descriptions for Hebron Platform personnel for a number of potential emergencies • Provides a link between all offshore facilities and onshore responders
Collision Avoidance Plan	A specific plan for identifying and avoiding a potential collision with a vessel approaching a rig or platform • Identifies potential collision situations involving the platform or mobile offshore drilling unit (MODU) • Describes communications with the threatening vessel • Lists actions to be taken on the Hebron Platform or MODU in the event that the threatening vessel does not respond • Developed specifically for offshore use and directly related to the Offshore Emergency Response Plan
Ice Management Plan	A plan which defines how EMCP operations personnel will manage the threat of icebergs and pack ice approaching the Hebron Field: • The plan provides a link between all ice management operations offshore and onshore • The plan describes the procedures for • Monitoring the movement of icebergs that might pose a threat to offshore activities • Determining the need for specific countermeasure operations including iceberg deflection
MedEvac Plan	A plan which describes how ill or injured workers will be transported to shore for medical care: • Assigns authority • Defines decision making processes • Describes logistics arrangements • Suggests onshore emergency team involvement
Spill response Plan Procedures	Procedures developed specifically for the first response to hydrocarbon spills originating at the Hebron Platform: • Directly related to the Offshore Emergency Response Plan and the Hebron Spill Response Plan; • Applies for both C-NLOPB and Canada Shipping Act (CSA) jurisdictions • Includes • Specific actions to be taken by Hebron Platform and support vessel personnel, and • Specific strategies for the response to anticipated hydrocarbon spill scenario situations
Standard Operating Procedures	Pre-established procedures for specific technical activities undertaken by offshore emergency action teams: • Fire • First aid • Helideck • Coxswains

Table 11.9-2: Overview of EMCP Onshore Contingency Plans

Plan	Description
Onshore Emergency Response Plan	A plan that describes actions taken onshore during an offshore emergency: • Provides general activation and support procedures for any emergency • Directs actions of shore-based personnel • Provides the link between offshore actions (coordinated by the Hebron Platform or MODU OIM) and corporate emergency teams • Integrates response actions after the emergency phase has passed • Allows for increasing onshore and corporate responsibility as the incident escalates
Oil Spill Response Plan	Procedures developed specifically for the response to hydrocarbon spills originating from the Hebron Platform: • Covers situations where EMCP is the responsible party or may be required to take a responsible action • Applies for both C-NLOPB and CSA jurisdictions • Includes • Specific actions to be taken by Hebron Platform and support vessel personnel • Management or coordination actions taken by shore-based company and contractor personnel • Specific strategies for the response to anticipated hydrocarbon spill scenario situations • The plan provides a link between all spill response operations offshore and onshore • Details procedures for Incident Command System based spill response management when the incident escalates above Tier 1 • The plan provides a link between EMCP and other operators • Directly related to the Tier 1 Spill Response Procedures, and the Onshore Emergency Response Plan
Family Support Plan	A plan to assist family members and friends of offshore personnel during an emergency situation: • Description of the operation of a family information service and a family support centre • Protocols for contacting family members in a constructive and proactive manner • Guidelines for volunteer family responders in how to deal with concerned relatives and friends
Business Continuity Plan	A plan to provide the means for EMCP to recover from a catastrophic incident in a safe and effective manner and resume normal business operations as quickly as possible • Addresses project units and staff functions conducting operations in St. John's • Describes processes and procedures linking pre-identified Points of Contact to the response protocol of the EMCP Emergency Response Guide. • Contains specific data and information compiled to address business continuity incidents.

Plan	Description
Emergency Communications Plan	A comprehensive guide to all communications with affected individuals, the public and the media during an emergency response • Description of the operation of a media response centre • News release and statement templates • Sample media questions and answers • Media information packages • Website development

11.9.1 Emergency Response Plan

The Emergency Response Plan will cover the facilities and locations operated by EMCP and its contractors. This plan will be updated as changes are made to these facilities, locations, and contractors. Training and regular validation of personnel competencies will be included in the overall training requirements discussed in Section 14.4.

Emergency situations are defined as unexpected occurrences that pose a serious threat to personnel safety, have a serious environmental impact or present the potential for significant property damage. The following are examples of possible emergency situations which will be covered by contingency planning:

- ◆ An accident which results, or could result, in loss of life or serious injury (for example, diving accidents, person overboard, scaffolding collapse, dropped object)
- ◆ Explosions or fires
- ◆ Loss of well control
- ◆ Damage to the gravity base structure
- ◆ Hydrocarbon or chemical spills
- ◆ Ship collision
- ◆ Loss of, or damage to, helicopters or fixed wing aircraft
- ◆ Loss of, or damage to, support or standby vessels
- ◆ Environmental conditions such as adverse weather, sea ice, icebergs
- ◆ Security-related incidents involving issues such as extortion, bomb threat, or acts of terrorism

The Emergency Response Plan will describe the actions taken during an emergency:

- ◆ Provides very specific role descriptions for Hebron Platform personnel for a number of potential emergencies
- ◆ Provides a link between all offshore facilities and onshore responders
- ◆ Provides general activation and support procedures for any emergency
- ◆ Directs actions of shore-based personnel
- ◆ Integrates response actions after the emergency phase has passed
- ◆ Allows for increasing onshore and corporate responsibility as the incident escalates

The Emergency Response Plan will be communicated to the various support groups, including the Coast Guard and oil spill response contractors.

11.9.2 Emergency Response Organization

The organization used by EMCP for Emergency Response is shown in Figure 11.9-1 and will be used for the drilling, development and production operations phases of the project.

The responsibilities of the onshore Emergency Response Team will include:

- ◆ Assisting the offshore Hebron emergency team by providing personnel and equipment resources as required
- ◆ Coordinating oil spill response using East Coast Response Corporation (ECRC)
- ◆ Providing family and employee communication and support
- ◆ Liaising with Coast Guard, government and regulatory authorities
- ◆ Addressing any engineering and other technical issues related to the emergency
- ◆ Providing briefings for the media
- ◆ Liaising with Corporate for assistance from world wide and functional teams
- ◆ Compliance with Corporate reporting requirements

The offshore Hebron Emergency Team will be led by the OIM and include key senior offshore personnel, including, but limited to the Production Supervisor, the SSH&E Advisor and the Registered nurse.

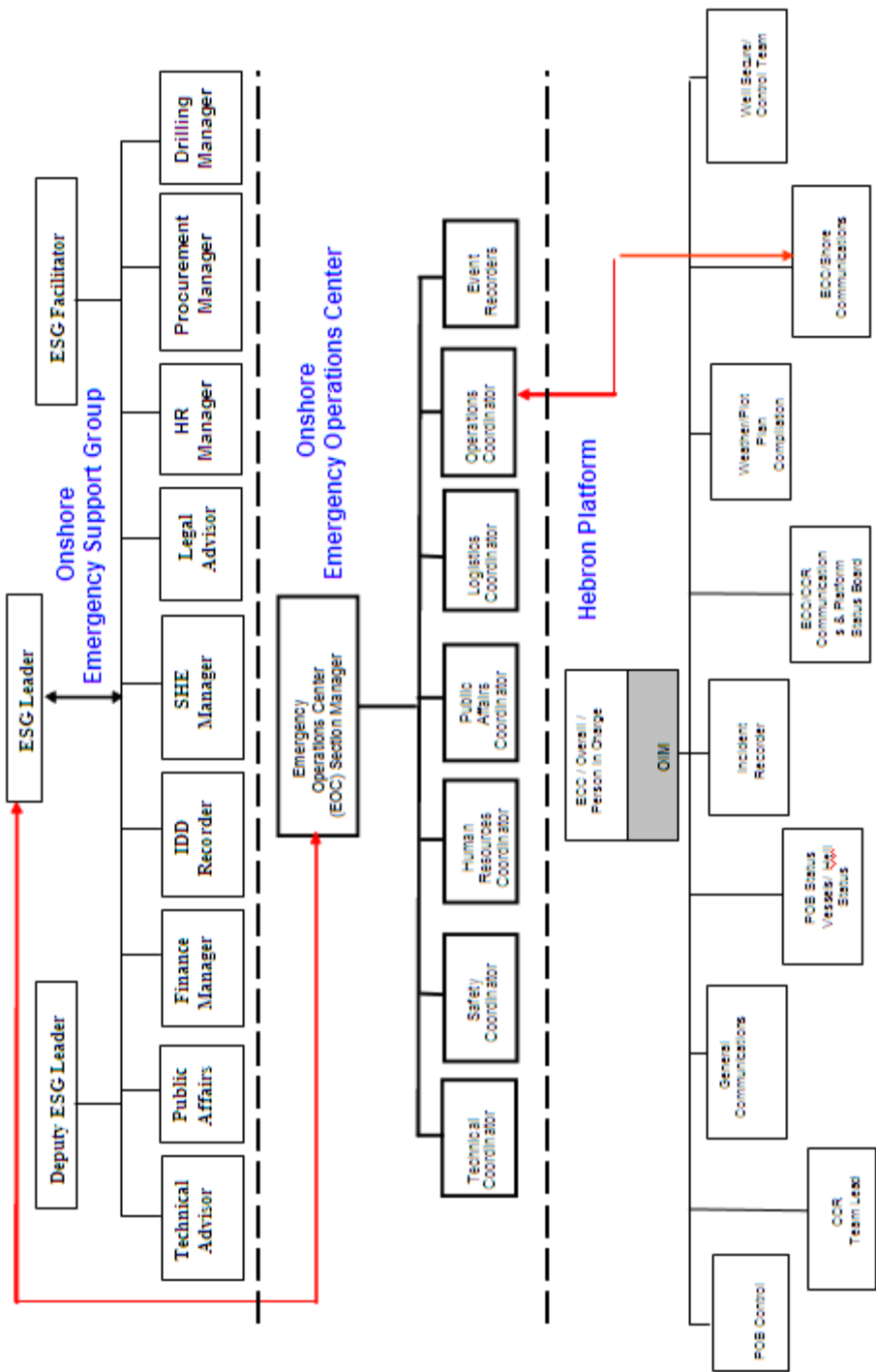


Figure 11.9-1: Emergency Response Organization

11.9.3 Training and Exercises - Emergency Response

A training matrix will identify the required scope and standard of training, the training providers and the frequency of training for each individual, on and offshore, with responsibilities under the Emergency Response Plan. Training and drills will be conducted to meet or exceed C-NLOPB / industry guidelines.

11.9.3.1 Offshore

All offshore personnel will receive emergency response plan training with frequent refresher courses.

Specialized training will be provided for offshore personnel with specific duties in emergencies including the registered nurse, members of the Fire Team and Emergency Response Team, and coxswains.

Training will also be provided by means of regularly scheduled emergency drills and exercises to validate individual and team response capabilities. These offshore exercises will be based on credible emergency scenarios and will likely include, fire and explosion, first aid, ship collision, iceberg collision, aircraft collision, person overboard, and loss of well control.

11.9.3.2 Onshore

Onshore emergency team members will receive general training in their roles and responsibilities. Familiarisation of the roles of other team members will be achieved by means of regular exercises.

The onshore Emergency Response Team will regularly conduct scheduled and planned exercises, including communications exercises, tabletop exercises and logistics exercises. In addition, the onshore Emergency Team will carry out at least one major exercise every year.

External groups such as Contractors or agencies with specific involvement or responsibilities under the plan will develop their familiarity with the plan through participation and involvement in emergency response exercises and regular communication with members of the onshore teams.

11.9.4 Response Time

EMCP will develop and test emergency procedures to minimize response time to any emergency. Weekly drills and exercises involving all personnel will be carried out to minimize time taken for entire crew to muster in the Temporary Safe Refuge (TSR) areas. These exercises will also help the Hebron Emergency Team, the Fire team and the Medical team to improve the speed and effectiveness of their response.

Personnel in all emergency response teams will be on call 24 hours per day, including the Helicopter services provider.

Key onshore personnel will be located in the St. John's area. As required, specialty skills may be called in to provide assistance with specific emergencies.

11.9.5 Response Capability Improvement Initiatives

EMCP intends to cooperate with other East Coast operators and agencies in all emergency situations through resource sharing, mutual aid and participation in joint training exercises. EMCP will seek to establish mutual aid agreements with other area operators, including the Hibernia Management and Development Company Ltd., Suncor Energy Inc., operator of the Terra Nova field and Husky Oil, operator of the White Rose field.

EMCP will work with other offshore operators to look for opportunities to apply new technologies to improve response capabilities.

11.9.6 Environmental Emergencies

A high level overview of contingency planning for environmental emergencies is included in Section 14.4 of the Hebron Comprehensive Study Report. More detailed plans for operations will be included in both the Emergency Response Plan and the Environmental Protection Plan, which also includes the plans for ice management, oil spill response and waste management.

11.9.7 Vessel Surveillance and Collision Avoidance

Vessels transiting the area of Hebron pose a potential threat to the platform and the shuttle tanker. EMCP will have vessel surveillance and collision avoidance procedures in place to protect personnel, the platform and vessels working in the vicinity.

An exclusion zone of radius 500 meters will be established around the Hebron Platform, the loading buoy and connecting flowlines and pipelines in order to provide protection to the facility. No vessel will be permitted entry without authorization from the OIM or delegated individual.

Specific personnel onboard Hebron and each standby vessel will be required to maintain radar watch at all times to monitor vessel movements in the vicinity of the platform and shuttle tanker and to identify those on possible collision course.

The approaching vessel will be alerted by radio as early as possible to take avoiding action. In the event that this is unsuccessful, the standby vessel will attempt to intercept the approaching vessel and make further efforts to attract its attention including the use of radio, lights, water cannon, foghorn and pyrotechnics.

11.10 Production Safety

EMCP believes that all accidents are avoidable and is striving to reduce accident rates to zero.

A Hebron Safety management plan will be implemented to eliminate or reduce risks to personnel, the environment, and the asset through a systematic, continuous improvement process.

The Hebron Safety Management plan will focus on preventing and minimizing accidental losses, based on the following continuous improvement process:

- ◆ Policies, organizations, roles and responsibilities
- ◆ Planning
- ◆ Implementation and operation
- ◆ Checking and corrective action
- ◆ Management review

The standby vessel is maintained in close proximity to the platform at all times. It will be fully equipped with medical facilities and triage area, emergency food provisions, and a fast rescue craft for use in retrieving personnel from the sea. Its role is to provide assistance to the platform in the event of emergency including:

- ◆ Close standby when planned over-the-side work is being carried out
- ◆ Recovery of personnel who have fallen overboard
- ◆ Close standby during helicopter take-off and landings for assistance in the event of a crash
- ◆ Watch for and alert any vessel on collision course
- ◆ Monitor exclusion zone
- ◆ Recover personnel from sea, raft or life boat in event of platform evacuation
- ◆ Respond to oil spill if directed by the OIM

The Hebron Platform will have a single TSR. Hebron living quarters will be designated as the TSR to serve as a “safe haven” where personnel can muster during emergencies. The TSR will serve as a resource base for emergency response actions and communications. The provision of at least two access routes to the TSR will provide a safe pathway from any area of the installation during the initial stages of an incident. The TSR will incorporate safe access to the platform evacuation systems (helicopters, lifeboats, life rafts, etc.) and will incorporate the following features:

- ◆ Protection from platform hazards, including smoke and gas ingress, loss of breathable atmosphere, fire, blast, and heat / temperature build-up, for the time required to complete facility evacuation
- ◆ Structural integrity for the time required to complete facility evacuation

- ◆ Alarm monitoring
- ◆ Means to control platform process and safety systems and possibly some drilling safety systems
- ◆ Reliable power supplies
- ◆ Lighting and visibility systems
- ◆ Communication systems, both external and internal
- ◆ Area for incident response and command structure
- ◆ Area for donning of survival suits, life jackets, and rescue gear
- ◆ Storage area for survival suits, life jackets, and rescue gear
- ◆ Medical facilities

A second evacuation muster area will also be located at the processing end of the platform with access to lifeboats, life rafts, and facilities for communication with the temporary refuge in the Living Quarters.

The Drilling Support Module and Derrick Equipment Set will be protected from platform events for a duration sufficient to complete drilling shutdown actions, make safe the wells, and evacuate personnel to the TSR or the second evacuation muster area.

For evacuation of small numbers of personnel such as individual medical emergency or illness, or for slowly escalating incidents, helicopter transport is the primary means of evacuation. For events in which rapid evacuation of the entire platform contingent is required, the primary means of evacuation will be lifeboats (totally enclosed motor propelled survival craft or TEMPSC). Current technology for dry evacuation directly to marine support vessels will be evaluated for capability and risk, and considered for implementation as a parallel primary evacuation means. Life rafts are provided as a secondary evacuation means. Escape directly to sea with descent assistance devices is the tertiary evacuation means.

TEMPSC capacity will be provided for a minimum of 200% of the number of personnel on board during operation. Life raft capacity will be provided for a minimum of 100% of the number of personnel on board during operation. TEMPSC and life rafts will be located at both west and east ends of the platform according to the normal distribution of personnel.

An adequate supply of lifebuoys will be provided, and distributed in such a way that at least one lifebuoy will always be visible from any point of the outside walkways on the installation. Additional escape and evacuation devices will be located on the platform as required by regulation.

Survival suits and lifejackets will be provided:

- ◆ Within the individual living quarters rooms for 100 percent of maximum personnel on board
- ◆ Adjacent or inside the TSR and secondary evacuation muster area for an additional 100 percent of the personnel on board

Every person on board will be issued with an emergency pack containing a survival suit, heat resistant gloves, a smoke hood and a flashlight. These will be kept in the individual's cabin.

12 DECOMMISSIONING AND ABANDONMENT

12.1 Abandonment

The actual need for removal of the Hebron Platform will depend on regulatory requirements and analysis conducted when the decision to abandon the field is made. In any case, before the platform is abandoned and before any decommissioning activities begin, all wells will be plugged and abandoned. All systems will be purged of hydrocarbons and other hazardous, flammable, or explosive materials. At the time of abandonment, permanent power and utilities will be unavailable.

12.2 Decommissioning

12.2.1 Gravity Base Structure

The Gravity Base Structure (GBS) will be designed to be removable at the end of field life. The procedures for platform removal / decommissioning will be developed during front-end engineering and design (FEED).

Procedures could include the following:

- ◆ Identification of appropriate regulatory bodies
- ◆ Assessment of floating the GBS by itself or together with Topsides
- ◆ Abandonment design considerations including stability, tow route survey, water de-ballasting, suction effect considerations, and various structural loads
- ◆ Decontamination and cleaning requirements
- ◆ Limiting weather criteria

All mechanical systems required for removal will be designed for GBS design life or to be easily replaced at the time of removal.

12.2.2 Offshore Loading System

The Offshore Loading System (OLS) will be designed to be removable at the end of field life. The procedures for OLS removal / decommissioning will be developed during FEED.

12.2.3 Topsides

Several methods for decommissioning the Topsides could be available at the end of the production facility's operational life. These methods are subject to the technology and / or availability of heavy lift vessels and equipment at the time of removal. A brief description of the methods is provided below.

Removal of the Topsides by lifting campaign is considered feasible and no special provisions in the initial design or construction are considered

necessary. At the time of decommissioning, several heavy lift vessels should be available to choose between. The specific lifting capacity, lifting radius, and draft of the selected vessel will influence the size, number, weight, and sequence of lifts included in the lifting campaign. Prior to lift, several of the modules may need to be temporarily secured while the structural connections to the rest of the Topsides are severed. The temporary systems will have to be easy to release once weight of the module is transferred to the crane hook during lifting. Modules will then be placed on transportation barges which will be prepared with support points and skid beams positioned appropriately for each lift. The barges will be towed to a shore location. Once arriving quayside at shore base facilities, the modules will be offloaded and demolition and recycling efforts will be undertaken to complete the decommissioning.

Float-off of the Topsides offshore may also be considered feasible although there are currently no known vessels capable of this operation. There is one known vessel under construction which is capable of removing the Hebron Topsides in one piece. It is possible that at the time of decommissioning, additional vessels could be available on the market to perform a single lift for Topsides removal. No special provisions in the initial design and construction are expected necessary as the float-off procedure will be a reversal of the inshore float-over installation of the Topsides onto the GBS. When a favourable weather forecast becomes available, the vessel will move into position and be ballasted to lift-off draft. Transfer of load will be obtained by a combination of changing vessel draft and / or use of hydraulic operating ballast arms. After completion of load transfer, the vessel will continue to de-ballast until reaching a safe float-off draft. The Topsides will be transported to onshore facility where demolition and recycling of the Topsides may be conducted to complete the decommissioning.

Pending further evaluation to determine if the GBS may be re-floated with the Topsides intact, it may be possible to tow the platform to an inshore / deepwater site for decommissioning. Here it would be moored / ballasted to a suitable draft for the Topsides removal and the installation sequence reversed. The Topsides may then either be removed by using one of the two methods above.

Each method carries unique risks by their specific nature of operation. It is expected that a detailed engineering effort for the decommissioning phase will be conducted prior to Topsides removal to detail the precise sequence of operations and to mitigate potential risks in order to safely and successfully decommission the Topsides facilities.

12.2.4 Subsea Systems

Decommissioning of any subsea development will be in accordance with common industry practices and subject to approval of the C-NLOPB.

13 DEVELOPMENT AND OPERATING COST DATA

13.1 Past Expenditures

Past expenditures associated with the Hebron Project are shown in Table 13.1-1.

These expenditures total \$538.49 million, and were incurred between 1980 and 2010. Table 13.1-1 shows the costs for each well and the engineering and project team expenditures related to the pre-development of those wells.

The well costs were incurred under the fiscal years 1980-1981 through to 2000-2001. During this period, seven wells were drilled in the Hebron-Ben Nevis field.

The pre-development engineering studies and project team costs covered the fiscal years 1997-1998 through to 2005-2006 and 2008-2010.

Table 13.1-1: Past Expenditures (1980 to 2010)

Past Expenditures (1980 - 2010)	Total
Ben Nevis I-45	29,667,505
Hebron I-13	48,205,376
Hebron D-94	34,421,746
Ben Nevis L-55	23,803,418
Hebron M-04	67,223,469
West Ben Nevis B-75	111,003,904
North Trinity H-71	58,622,900
Total Well Costs:	372,948,318
Pre-Development Engineering Studies and Project Team Costs	165,540,058
Total Costs (CAD):	538,488,376

13.2 Drilling Capital Estimate

The drilling cost estimates are based on mid-2009 price levels and include all applicable customs, duties, and sales taxes.

They are based on the following assumptions:

- ◆ Drilling and completion operations will take place as described in the Development Plan
- ◆ Drilling costs based on scoping level estimates for generic pool and well type
- ◆ Base rig rates and full rig spread rates are based on in-house data
- ◆ Estimate assumes a learning curve effect over time to reduce base activity times

- ◆ Non-production time assumed to be higher than average initially due to start-up and then decrease over time as lessons learned incorporated into project
- ◆ Supplier costs based on current East Coast cost environment
- ◆ The economic conditions prevailing world-wide in mid-2009 price levels will continue throughout the period of drilling and completion operations

13.3 Facilities Capital Estimate

13.3.1 Hebron Platform Development

The Hebron Platform Development cost estimates are based on mid-2009 price levels, and include all applicable customs, duties, and sales taxes. They are based on the following assumptions:

- ◆ The development will take place as described in this Development Plan
- ◆ There will be competition for the supply of all facilities, goods, and services on the project and contracts will be awarded in compliance with the Canada-Newfoundland Benefits Plan proposed for the project
- ◆ Current worldwide economic conditions will continue

The capital cost estimates are based on in-house cost studies and contractors' estimates. Contractors' estimates are developed from the following information:

- ◆ Preliminary facilities design
- ◆ Equipment sizes and weights
- ◆ Equipment-to-bulk-ratios and weights
- ◆ Fabrication work-hours per ton
- ◆ International wage rate surveys
- ◆ Vendor cost data
- ◆ Contractor cost data
- ◆ Fabrication and installation schedules
- ◆ Engineering and project management costs
- ◆ Marine operations costs

The capital cost estimates include costs for the following items:

- ◆ Topsides
 - Utilities and Process Module
 - Flare Boom

- Living Quarters Module
- Helideck
- Lifeboat Stations
- Drilling Rig Modules and Derrick
- Gravel Pack Module
- ◆ Gravity Base Structure (GBS)
- ◆ Offshore Loading System
- ◆ Pre-project costs
- ◆ Project management
- ◆ Contractor engineering and home office costs
- ◆ Quality assurance
- ◆ Infrastructure upgrades
- ◆ Site facility operations and Camp Costs
- ◆ Transportation and installation
- ◆ Completion and offshore hook-up
- ◆ Well drilling and completion
- ◆ Pre-startup operations

A summary of the capital estimate is presented in Table 13.4-1 for the Hebron Platform Development.

13.3.2 Pool 3 Subsea Development

For the Pool 3 Subsea Development, ranges of capital cost estimates are included for the range of development concepts described in this development plan. These costs are based on in-house cost studies. The capital cost estimates include costs for the following items:

- ◆ Topsides Process Module
 - Pig launcher and receiver
 - Three phase separator
 - Fiscal metering
 - Gas injection compressor
 - Sea water treatment and water injection pumps
 - Chemical injection and storage
 - Utilities

- ◆ Subsea Excavated Drilling Centre(s) (EDC)
 - Production manifolds and pigging loop
 - water injection manifold(s)
 - gas injection manifold(s)
 - Subsea multi-phase and single phase meters
 - Pipelines and umbilicals to tie-back to GBS
- ◆ Project management
- ◆ Contractor engineering and home office costs
- ◆ Quality assurance
- ◆ Site facility operations and camp costs
- ◆ Transportation and installation
- ◆ Completion and offshore hook-up
- ◆ Well drilling and completion
- ◆ Pre-startup operations

The range of capital costs (\$M CAD, Constant) for the Pool 3 subsea development is expected to be:

Topsides Module	\$420 to \$500 \$M CAD
Subsea EDC(s)	\$1050 to \$1750 \$M CAD
Drilling	\$1430 to \$2500 \$M CAD
Total	\$3000 to \$5000 \$M CAD

Table 13.4-2 presents the capital cost estimate for the full development of Pool 3 (Option 3).

13.4 Operating Cost Estimates

The annual operating cost estimates are based on mid-2009 price levels, and include all applicable customs, duties, and sales taxes. ExxonMobil Canada Properties (EMCP) has drawn on its extensive global operating experience and has taken into consideration the operation experience of other operators of similar facilities in order to develop the following items:

- ◆ Facility operating costs (personnel related costs, process related costs such as fuel and chemicals, communication, etc.)
- ◆ Well workovers

- ◆ Variable production
- ◆ Scheduled downtime
- ◆ Support logistics (transportation, catering, services, onshore warehouse, etc.)
- ◆ Administration (onshore support, training, etc.)

The operating costs are based on the following assumptions:

- ◆ The reservoir parameters will be as described in this Development Plan
- ◆ EMCP will operate the development in accordance with a typical co-venture agreement and will adhere to the management approach and development scenario as set out in this Development Plan
- ◆ The economic conditions prevailing world-wide in mid-2009 will continue throughout the period of operation
- ◆ Operating costs for the Pool 3 Subsea Development are expected to increase total operating expenses by 1% to 3%. This increase has not been included in the operating expense estimate since the timing of the development has yet to be determined.

A summary of the operating estimate is also presented in Table 13.4-1 for the Hebron Platform Development.

Table 13.4-1: Hebron Platform Development Capital and Operating Estimates

Year	Capital Costs (\$M CAD))					Total	Operating Costs (\$MCAD)
	Pre-Production				Drilling		
	Proj. Admin.	Topsides	GBS	OLS			
2010	68	12	13	0		93	1
2011	174	394	240	0		807	9
2012	244	704	291	12		1252	11
2013	216	698	391	36		1340	14
2014	290	643	444	107		1484	20
2015	327	409	234	69		1039	36
2016	256		175	0	82	513	65
2017					222	222	157
2018					236	236	147
2019					242	242	148
2020					242	242	174
2021					242	242	159
2022					218	218	159
2023					189	189	159
2024					215	215	179
2025							159
2026							161
2027							164
2028							187
2029							176
2030							196
2031							194
2032							210
2033							190
2034							188
2035							186
2036							202
2037							182
2038							181
2039							179
2040							197
2041							180
2042							180
2043							180
2044							187
2045							176
2046							592
TOTAL	\$ 1,575	\$ 2,861	\$ 1,788	\$ 224	\$ 1,887	\$ 8,334	\$ 5,883
Notes:							
Operating Costs exclude crude transportation costs.							
The final year Operating costs include \$430 MM for adandonment of the facility and wells.							

Table 13.4-2: Pool 3 Subsea Development Capital Estimate

Year	Capital Costs (\$M CAD, Constant)				
	Proj. Admin.	Topsides	SURF	Drilling	Total
-7	25		10		35
-6	35	80	310		425
-5	40	85	280		405
-4	40	85	180		305
-3	35	85	125		245
-2	40	80	70	15	205
-1	35	50	40	85	210
S/U				350	350
1				350	350
2				350	350
3				350	350
4				280	280
Total	250	465	1,015	1,780	3,510
Notes: Lowside estimate is -20% Highside estimate is +40%					

14 SAFETY ANALYSIS AND COMMITMENT

This section documents how the Hebron Project has integrated safety into the design of the proposed development. It includes how safety is integrated into the both the design of structures, facilities and equipment and the management systems, policies, procedures, planning processes and personnel selection, training and management that will be used during all phases of the Hebron Project.

14.1 Concept Safety Analysis and Target Levels of Safety

According to Section 43 of the Newfoundland Offshore Petroleum Installations Regulations, an operator is required to submit to the Chief Safety Officer a Concept Safety Analysis of an installation that considers all components and activities associated with each phase in the life of the production installation. The Concept Safety Analysis must include a determination of the frequency of occurrence and potential consequences of potential accidents identified, and details of safety measures designed to protect personnel and the environment from such accidents.

The report, therefore, identifies major hazards associated with the Hebron facility, taking into account the basic design concepts, layout and intended operations, and assesses the risks to personnel and the environment resulting from these hazards.

The Concept Safety Analysis, conducted by RMRI (Canada), is included in Part II of the Development Application. The following paragraphs provide a description of its contents and summarize the findings of the study.

Section 2 provides an outline description of the Hebron project and Section 3 describes the key safety design features and systems proposed for the prevention, detection and control of potential major hazards. Sections 6 to 10 present the basis of the assessment of risk to personnel due to the identified major hazards (listed in Section 5). Section 11 presents the results of the assessment, and compares them to the Target Levels of Safety set for the Project (Section 4). Section 12 details sensitivity studies that have been performed.

The Concept Safety Analysis identifies and assesses quantitatively the following Major Hazards associated with all phases of the proposed development of the Hebron Asset:

- ◆ Loss of hydrocarbon containment (resulting in fire, explosion or toxic gas release)
- ◆ Blowout (resulting in fire, explosion or toxic gas release)

- ◆ Iceberg Collision
- ◆ Ship collision
- ◆ Helicopter transportation
- ◆ Seismic activity

Dropped object events are also considered. The risk arising from such events is, however, not quantified in the Concept Safety Analysis. This is because sufficiently detailed information on lifting activities is not available at this stage and because it is assumed that appropriate procedures will be put in place to reduce this risk where possible. Dropped Object Studies will be carried out during front-end engineering and design (FEED) and / or detailed design and mitigations recommended as needed.

Occupational accidents are considered in the assessment, but the risk from such accidents is not quantified. Whilst it is clearly necessary to recognize occupational hazards, and to reduce the frequency and mitigate the consequences of such events, it is not, in general, appropriate to assess these hazards using quantitative analysis techniques. Fatal Accident Rates for occupational accidents are generally derived from historical accident data. Measures will be put in place for the monitoring, control and mitigation of occupational hazards and accidental events.

The selection of clear design goals aimed at protecting personnel and the environment is fundamental to the design of offshore facilities. With this view in mind, the Hebron Project will use design goals known as Target Levels of Safety (TLS).

For the Hebron Project, TLS are specified with regard to risk to personnel and risk to the environment.

TLS provide a benchmark against which the results of the quantitative analysis can be assessed. Tolerability of risk to personnel is generally judged based on three risk 'regions', the boundaries of which are defined by the TLS:

- ◆ An upper region (intolerable region), which defines risk levels that are unacceptable, so that further mitigation measures must be taken to make the risk tolerable
- ◆ A lower region (broadly acceptable or 'negligible' region), which defines risk levels that are generally tolerable and there is no need for consideration of further mitigation measures
- ◆ Between these upper and lower regions, an intermediate region where the risk may be tolerable but continuous efforts to reduce risk should be undertaken

14.1.1 Risk to Personnel

Risks to personnel will be measured in terms of Individual Risk Per Annum (IRPA), which is a measure that takes into account:

- ◆ The proportion of time individuals within each worker group spend in each location, based on the manning distributions
- ◆ The predicted frequency of hazardous events to which individuals are exposed in each location
- ◆ The impact of those hazardous events, in terms of predicted fatality rates

14.1.2 Environmental Risk

The design of the installation will comply with all corporate environmental policies and principles, and all applicable environmental regulations.

Environmental risks are subject to evaluation by regulatory authorities through the project registration and approval process in the Canadian Environmental Assessment Act (CEAA). These reviews include an evaluation of accidental events and operational discharges into the environment.

The TLS, in terms of risk to the environment associated with project activities, are defined qualitatively based on environmental effects analysis in the Hebron Project Comprehensive Study Report (CSR). The approach used is to identify Valued Environmental Components (VECs) (e.g., marine birds, fish and fish habitat, sensitive areas, etc.) and to evaluate the impact on such components against a number of variables, which include, for example, the frequency and size of a spill and the ability of the VEC to recover. Where potential environmental impacts to the environment are identified, mitigation measures will be implemented to reduce the potential environmental impact.

14.1.3 Impairment Criteria

In addition to the TLS outlined above, impairment criteria are specified which will be used during the design phase to distinguish between possible accident events that have the potential to escalate and affect personnel outside the immediate area of the accident and those that do not.

Provided that the impairment criteria are complied with during an accident, the accident is considered to have no potential to:

- ◆ Prevent personnel escaping from the event and mustering in the temporary safe refuge (TSR)
- ◆ Threaten the structural integrity of the installation
- ◆ Threaten the integrity of the TSR

- ◆ Threaten the integrity of the means of evacuation within the time period required to safely evacuate personnel

These impairment criteria will be developed and assessed in more detail, early in the FEED phase, in line with ExxonMobil corporate expectations, regulatory requirements and industry best practice.

14.1.4 Measures of Risk

For each of the Major Hazards listed above, the report quantifies the following measures of risk:

Theoretical Annual Loss of Life (TALL): TALL is the average number of fatalities per year on the installation. For each hazard identified, TALL is calculated as:

$$\text{TALL} = \text{Hazard Frequency (per year)} \times \text{Potential Fatalities.}$$

Individual Risk Per Annum (IRPA): IRPA is a measure of the annual risk to an individual on the installation. This is calculated as:

$$\text{IRPA} = \frac{\text{TALL}}{\text{POB}} \times \text{Exposure}$$

where “Exposure” is the proportion of the year that an individual would spend at the installation and “POB” is the number of personnel on board.

Two risk estimates are made, one for the drilling and production phase of the project (assumed to be the years up to and including 2025), and the second representative of the production only phase of the project (after 2025) when all drilling activities have ceased. This is because:

- ◆ The risk from blowouts depends on the drilling and well activities being carried out and on the number of wells in production
- ◆ The risk from process loss of containment depends on the number of wells in production

For each of the Major Hazards identified above, the risk assessed in terms of IRPA, for each phase of operation, is shown in Tables 14.1-1 and 14.1-2. Risk figures for each worker group are given in Tables 14.1.3 and 14.1.4.

The Hebron Project is currently at the concept design stage. There are, therefore, significant uncertainties in some of the risk assessment data used in this assessment, which mean that the risk values predicted are indicative only. Where uncertainties exist in the risk analysis, conservative assumptions (that is, assumptions that over-estimate the risk, rather than under-estimate the risk) are made.

Table 14.1-1: Average IRPA (Drilling and Production Phase)

Hazard	Average IRPA				Total
	Fatality Classification				
	Immediate	Escape/ Escalation	Precautionary Evacuation	TSR Impairment	
Loss of Containment (Fire/Explosion)	2.0 x 10 ⁻⁵	4.1 x 10 ⁻⁷	1.1 x 10 ⁻⁶	4.1 x 10 ⁻⁸	2. 2 x 10 ⁻⁵
Blowouts	2.4 x 10 ⁻⁶	-	4.9 x 10 ⁻⁵	1.7 x 10 ⁻⁷	5. 2 x 10 ⁻⁵
Iceberg Collision	-	-	-	3.0 x 10 ⁻⁷	3.0 x 10 ⁻⁷
Passing Vessel Collision	-	-	-	7.5 x 10 ⁻⁸	7.5 x 10 ⁻⁸
Helicopter Crash	5.0 x 10 ⁻⁵	-	-	-	5.0 x 10 ⁻⁵
Seismic Activity	-	-	3.8 x 10 ⁻⁷	7.50 x 10 ⁻⁷	1.1 x 10 ⁻⁶
TOTAL	7.2x 10 ⁻⁵	4.1 x 10 ⁻⁷	5.0 x 10 ⁻⁵	1.3 x 10 ⁻⁶	1.3 x 10 ⁻⁴

Table 14.1-2: Average IRPA (Production Only Phase)

Hazard	Average IRPA				Total
	Fatality Classification				
	Immediate	Escape/ Escalation	Precautionary Evacuation	TSR Impairment	
Loss of Containment (Fire/Explosion)	2.8 x 10 ⁻⁵	2.9 x 10 ⁻⁷	1.6 x 10 ⁻⁶	4.8 x 10 ⁻⁸	3.0 x 10 ⁻⁵
Blowouts	8.4 x 10 ⁻⁷	-	1.1 x 10 ⁻⁵	4.8 x 10 ⁻⁸	1.2 x 10 ⁻⁵
Iceberg Collision	-	-	-	3.0 x 10 ⁻⁷	3.0 x 10 ⁻⁷
Passing Vessel Collision	-	-	-	7.5 x 10 ⁻⁸	7.5 x 10 ⁻⁸
Helicopter Crash	5.0x 10 ⁻⁵	-	-	-	5.0 x 10 ⁻⁵
Seismic Activity	-	-	3.8 x 10 ⁻⁷	7.6 x 10 ⁻⁷	1.1 x 10 ⁻⁶
TOTAL	7.9 x 10 ⁻⁵	2.9 x 10 ⁻⁷	1.3 x 10 ⁻⁵	1.2 x 10 ⁻⁶	9.3 x 10 ⁻⁵

Table 14.1-3: IRPA by Worker Group (Drilling and Production Phase)

Hazard	Worker Group			
	Management / Admin / Catering	Operations & Maintenance	Drilling / Intervention	Construction
Loss of Containment (Fire / Explosion)	2.2×10^{-6}	3.5×10^{-5}	2.4×10^{-5}	4.1×10^{-5}
Blowouts	5.0×10^{-5}	5.0×10^{-5}	5.5×10^{-5}	5.0×10^{-5}
Iceberg Collision	3.0×10^{-7}	3.0×10^{-7}	3.0×10^{-7}	3.0×10^{-7}
Passing Vessel Collision	7.5×10^{-8}	7.5×10^{-8}	7.5×10^{-8}	7.5×10^{-8}
Helicopter Crash	5.0×10^{-5}	5.0×10^{-5}	5.0×10^{-5}	5.0×10^{-5}
Seismic Activity	1.1×10^{-6}	1.1×10^{-6}	1.1×10^{-6}	1.1×10^{-6}
TOTAL	1.0×10^{-4}	1.4×10^{-4}	1.3×10^{-4}	1.4×10^{-4}

Table 14.1-4: IRPA by Worker Group (Production Only Phase)

Hazard	Worker Group			
	Management / Admin / Catering	Operations & Maintenance	Drilling / Intervention	Construction
Loss of Containment (Fire / Explosion)	2.9×10^{-6}	3.8×10^{-5}	5.8×10^{-5}	4.3×10^{-5}
Blowouts	1.1×10^{-5}	1.1×10^{-5}	1.4×10^{-5}	1.1×10^{-5}
Iceberg Collision	3.0×10^{-7}	3.0×10^{-7}	3.0×10^{-7}	3.0×10^{-7}
Passing Vessel Collision	7.5×10^{-8}	7.5×10^{-8}	7.5×10^{-8}	7.5×10^{-8}
Helicopter Crash	5.0×10^{-5}	5.0×10^{-5}	5.0×10^{-5}	5.0×10^{-5}
Seismic Activity	1.1×10^{-6}	1.1×10^{-6}	1.1×10^{-6}	1.1×10^{-6}
TOTAL	6.5×10^{-5}	1.0×10^{-4}	1.2×10^{-4}	1.1×10^{-4}

From review of the tables above, the largest contributors to risk to personnel on the Hebron Platform are:

- ◆ Helicopter transportation (accounting for approximately 38% of overall platform risk during drilling and production phase, and approximately 54% in the post-drilling phase)
- ◆ Blowout events resulting in evacuation fatalities (approximately 38% of overall platform risk during drilling and production phase, and approximately 12% in the post-drilling phase)
- ◆ Process loss of containment event resulting in immediate fatalities (approximately 16% of overall platform risk during drilling and production phase, and approximately 30% in the post-drilling phase)

A review of the adequacy of potential risk reduction measures to prevent, mitigate and safeguard against these main risk contributors should be undertaken at the detailed design stage, in order to ensure that risks are adequately addressed.

The risk from blowout decreases significantly in the post-drilling phase, as the blowout risk associated with drilling activities is greater than that associated with well activities carried out on production wells. The risk from process loss of containment increases slightly in the post-drilling phase as it is dependent on the number of wells in production and it is assumed that the maximum number of wells will be in production once drilling is complete.

Comparison of the predicted risks with the Hebron TLS concludes that they are below the intolerable region and within the intermediate region

defined by the criteria. Additional risk reduction studies and activities will be undertaken during engineering to ensure that risks are adequately identified and addressed such that risk is minimized in the final design.

Risks associated with H₂S are not accounted for in these preliminary results. However, initial evaluation of these risks suggests they will be very low (if not negligible) and are likely to have little if any impact on the overall results presented in the tables above. Risks associated with production from Pool 3 are not accounted for in these preliminary results. Initial evaluation of these risks suggests the total project average IRPA during drilling and production will be no greater than 1.5×10^{-4} , and the total project average IRPA during production only will be no greater than 1.2×10^{-4} .

It is however concluded that there are no significant areas for concern that could prevent demonstration that risks have been reduced. Further studies will, however, be required at detailed design stage, to confirm or refine the assumptions that have been made in this Concept Safety Analysis and to reflect the design of the installation as it is developed by EMCP.

14.2 Risk Assessment Plan

The Risk Assessment Plan for the Hebron Project is described in the Project Risk Assessment Plan (PRAP) document (CAHE-ED-FPRSK-00-000-0001). The PRAP addresses risk assessments that are aimed specifically at the design and construction phases, including installation, commissioning, and startup. The PRAP also addresses loss prevention studies that will be done during the project to support risk assessment and hazard and operability studies HAZOPS. The early plan lists the pre-identified project-specific risk activities (both formal risk assessments and loss prevention studies) in addition to ExxonMobil template-recommended studies, workshops, philosophies, and risk assessments. The PRAP will be updated as the project progresses and the need for additional studies is discovered.

The Risk Assessment Plan is converted to the Hebron Project Risk Management Plan (PRMP) by the addition of scopes, responsibilities, and definition of the method by which action items will be documented, tracked, and closed.

14.2.1 Risk Management Overview

Risk Management includes EMCP's contractors and subcontractors planning, conducting, evaluation, and follow-up of formal risk assessments, including HAZOPS.

The risk management objectives are:

- ◆ Risks related to project execution and operations are identified by a structured approach to risk identification
- ◆ Risk assessments are planned and conducted in advance of appropriate project milestones or activities to allow timely management of risk
- ◆ Appropriate personnel are included in risk assessments to verify risks are correctly identified and assessed
- ◆ Results of risk assessments and the associated risk reduction measures are evaluated by appropriate levels of management and are documented, executed, and followed-up to completion to reduce risks to an acceptable level consistent with project objectives
- ◆ Risks and associated resolutions are documented for hand-over to Operations

14.2.1.1 Risk Management Process

EMCP and its contractors will jointly participate in risk assessments, including HAZOPS as described in the Hebron PRAP. The objectives of these assessments are to identify hazards, qualitatively assess risk levels based on consequences and probabilities, and recommend prevention and/or mitigation measures to reduce risks. Contractor(s) will be required to develop the program of risk assessments. The resulting document will be the PRMP, an extension of the PRAP with the addition of scopes, responsibilities, and definition of the method by which action items will be documented, tracked, and closed.

For team-based risk assessments, EMCP and its contractors will jointly share the facilitator, scribe, and final report. The contractors will participate in the resolution of risk assessment recommendations and will document and track recommendations until closure.

The contractors' Risk Management System and PRMP will include the following:

- ◆ PRAPs will include a schedule of risk assessments, risk reduction actions, approvals and endorsements, follow-ups, and compliance reviews to be documented. Monthly updates to the PRAP will include forecasted dates of existing and newly proposed risk assessment activities/studies as well as the activities that have been completed.
- ◆ An assessment-specific charter will be prepared for each risk assessment, which will address the following:
 - Purpose (e.g., to manage risk associated with a specified project activity through early identification of hazards, assessment of associated risk, and capture of potential preventive and mitigating actions)

- Objectives (e.g., to identify and assess significant risks to safety, health and environment, assets, schedule, and costs associated with the assessment scope; to identify plans or proposals to further evaluate or manage the risks; and to provide related documentation so management can address the identified risks)
 - Scope and/or boundaries
 - Assessment team membership (project team members and project-independent experts)
 - Risk assessment dates and location
 - Process (e.g., multidisciplinary team process that includes identification of hazards and/or issues, identification of causes and consequences related to scenarios that could lead to incidents, ranking the risk of each scenario qualitatively based on the probability and consequence of those incidents, identifying additional potential mitigation measures, and assessing the risk of each scenario with potential mitigation measures in place)
 - Agenda overview
 - Deliverables
 - Roles and responsibilities of Sponsor, Risk Coordinator, and Team Members
- ◆ Risk assessments will be conducted with adequate time prior to their related project milestones or activities to allow EMCP review and approval of the resolution of risks without schedule disruption. Risk assessments will be planned—and charters, pre-read information including procedures, and all required drawings for the activities being assessed will be issued—prior to the risk assessment taking place.
 - ◆ The membership skills of risk assessment teams to be appropriate for ensuring risks are correctly identified and assessed
 - ◆ The identification of potential risk scenarios associated with engineering, execution, and operation, including, but not limited to, risks related to safety, health, the environment, labour relations, community relations, and financial impact on EMCP
 - ◆ The identification of environmental hazards and the completion of approved risk reduction plans, incorporating as necessary control measures into the contractors' Regulatory Compliance Plans and Environmental Management Plans
 - ◆ The inclusion of human factors and health considerations in all risk assessments

- ◆ All credible risk scenarios are to be assessed for possible risk reduction by the following (in order of preference):
 - Elimination of the hazard source
 - Reduction of the likelihood or mitigation of the consequences
 - Control of the resultant impact or damage
 - Emergency response and recovery systems
- ◆ The contractors' plans for the evaluation, resolution, completion tracking, and incorporation into the design of findings or any risk reduction actions from risk / loss prevention / technical safety studies or assessments previously conducted by EMCP, including but not limited to design risk assessment and preliminary hazard and operability reviews
- ◆ The contractors' plans for conducting final HAZOPS will be based on the detailed design data (usually at a design freeze preceding construction and fabrication)

14.2.1.2 Risk Evaluation Process

The extent and complexity of proposed risk management strategies will be appropriate to the nature and magnitude of the risk.

All credible risk scenarios will be evaluated before and after any recommended risk reduction action, using ExxonMobil's Risk Matrix provided in Figure 14.2-1.

		PROBABILITY				
		A	B	C	D	E
C O N S E Q U E N C E S	I					
	II					
	III					
	IV					

PROBABILITY CATEGORY	DEFINITION
A	POSSIBILITY OF REPEATED INCIDENTS
B	POSSIBILITY OF ISOLATED INCIDENTS
C	POSSIBILITY OF OCCURRING SOMETIME
D	NOT LIKELY TO OCCUR
E	PRACTICALLY IMPOSSIBLE

Considerations				
	HEALTH / SAFETY	PUBLIC DISRUPTION	ENVIRONMENTAL IMPACT	FINANCIAL IMPACT
I	FATALITIES/ SERIOUS IMPACT ON PUBLIC	LARGE COMMUNITY	MAJOR/ EXTENDED DURATION FULL SCALE RESPONSE	MAJOR IMPACT TO CORPORATION
II	SERIOUS INJURY TO PERSONNEL/ LIMITED IMPACT TO PUBLIC	SMALL COMMUNITY	SERIOUS/ SIGNIFICANT RESOURCE COMMITMENT	SIGNIFICANT IMPACT TO CORPORATION
III	MEDICAL TREATMENT FOR PERSONNEL/ NO IMPACT TO PUBLIC	MINOR	MODERATE/ LIMITED RESPONSE OF SHORT DURATION	MODERATE IMPACT TO COMPANY
IV	MINOR IMPACT ON PERSONNEL	MINIMAL TO NONE	MINOR OR NO RESPONSE NEEDED	MINOR IMPACT TO COMPANY

Figure 14.2-1: Risk Matrix

Note:

The use of shading in the Risk Matrix is internal to ExxonMobil and indicates the requirements for endorsement by ExxonMobil management of specific hazard consequence/probability combinations.

Risk scenarios, evaluations, and proposed risk reduction actions will be approved by the contractor(s) management and then endorsed by EMCP before the risk reduction action commences.

14.2.2 Completion of Actions and Reporting

The contractor(s) will complete an action tracking report showing priority, responsibility, and timing for completion of each action. EMCP may choose to provide the tracking system or provide a specific format for the tracking system. Action tracking reports will be submitted by the contractor(s) to EMCP monthly.

At the completion of each risk assessment and its associated response actions, the results of the risk assessment and response actions will be communicated in a Closeout Report to those affected.

Compliance reviews will be undertaken to verify that formal risk assessments and follow-up actions have been implemented according to Plans.

14.2.3 Execution of Risk Assessments Required by EMCP

The contractor(s) and EMCP will participate in and/or facilitate those risk assessments required by EMCP. Typically, EMCP will provide facilitators for risk assessments and/or HAZOPS. When the facilitator is provided by the contractor, the facilitator must have as a minimum prior risk assessment and/or HAZOPS facilitation experience for the oil and gas industry (typically five years or more). The contractor will provide risk assessment and/or HAZOPS facilitator credentials for EMCP review and approval. The contractor will maintain consistency in the facilitator(s) used on the project, once approved by EMCP. EMCP may choose to provide the facilitator and reject contractor's facilitator for any reason.

The contractor will participate in risk assessments conducted by EMCP or EMCP's other contractors when these risk assessments include work activities where the contractor is involved.

14.3 Quality Assurance and Quality Control

The Hebron Project will require specific quality assurance systems across the whole Hebron development. This will be applicable to all major contractors and suppliers in the conduct of their activities associated with the Hebron Project. As well, Hebron Project will ensure that the conduct of all project tasks, and the quality of installation, are in accordance with applicable C-NLOPB offshore regulations.

Where permitted by regulation and required by the project, appropriate regulatory processes will be followed to obtain necessary approvals for regulatory deviations.

Before going into production operation, the Hebron Project will issue a Declaration of Fitness to C-NLOPB after which a Certificate of Fitness (COF) will be issued. An independent certifying agency has been selected to act as the Certifying Authority for the project. The Certifying Authority will monitor the project throughout its development and to confirm that the complete installation has been designed, constructed and installed in compliance with regulations. Pursuant to the requirements of the COF Regulations under the Atlantic Accord Acts, a scope of work for the Certifying Authority will be developed by the Certifying Authority in consultation with EMCP, and submitted to the C-NLOPB for approval. ExxonMobil has developed Global Practices which are company standards and are used to illustrate the minimum acceptable requirements for delivery of product.

EMCP will also be implementing ExxonMobil's global management Operations Integrity Management System (OIMS) to ensure compliance to company requirements.

The relationship between Hebron Project and its major contractors, particularly in the case of the installation, needs to be seamless. A key element in achieving that seamless relationship is the demonstrated compatibility of the OIMS and Global Practices with Contractor(s) management systems. This will be monitored through implementation of various surveillance programs that cover Quality, Procurement, Engineering and Construction.

The Hebron Project requires that its major contractors document how their project quality management systems will be implemented across the project. These programs will at a minimum meet ExxonMobil requirements, and where gaps are identified, contractors will be asked to rectify in order to achieve complete consistency with regard to project quality expectations.

The Hebron Project will conduct regular structured audits against the contractor's activities.

14.3.1 Certification Process

Upon satisfactory completion of the Work, Certifying Authority will issue to Company, a COF for the platform and its associated crude export loading lines and offshore loading systems attesting that facilities are "fit for purpose" for which they will be used and in compliance with the C-NLOPB Certificate of Fitness Regulations.

The COF must be in the form prescribed by the C-NLOPB such that Certifying Authority can submit a COF to the Chief Safety Officer, for authorization to commence operations.

Prior to issuing the COF the Certifying Authority will submit monthly progress reports to the Hebron Project, and where applicable, to the C-NLOPB. These reports may include items such as:

- ◆ Design Verification Reports
- ◆ Inspection and Release Notes
- ◆ Comment Response Sheets for FEED and Detailed Design of all scopes of work

Certifying Authority will also issue staged, conditional Certificates of Fitness, as necessary, to obtain approval from the C-NLOPB Chief Safety Officer of major project milestones such as:

- ◆ Living quarters occupancy
- ◆ Commencement of drilling
- ◆ Production start

Hebron Project and Engineering, Procurement, and Construction (EPC) contractors will monitor the design appraisal and certification status of documents and equipment through their document register.

The Certifying Authority is also responsible for ensuring that all industry codes and standards are being adhered to during the design, construction, transportation, installation, and operation stages.

It is also the Hebron Project's responsibility to ensure all EPC contractors and their sub-contractors adhere to regulatory codes and standards.

14.4 Training Plan

14.4.1 Onshore Organizational Structure

The onshore organization will be designed to provide the necessary support for offshore operations, during both the development and production phases. The onshore organization will include competent personnel with the necessary skills sets, and experience to provide effective support to the offshore operation, including emergency situations. It will be focused on safety, flexibility, operability, maintainability, reliability, efficiency and cost effectiveness.

The core onshore organization is expected to be staffed with personnel in the groups as previously discussed in Section 11.1.1.

Onshore contract personnel will also be required in the following areas:

- ◆ Helicopter air and ground staff
- ◆ Dockworkers and crane operators for supply vessel operations at the shore base
- ◆ Crews for the supply and standby vessels
- ◆ Staff working for the construction, maintenance and drilling contractors

14.4.2 Offshore Organizational Structure

The offshore organization will be comprised of competent personnel in all required disciplines. EMCP will utilize ExxonMobil's OIMS to describe the processes and procedures by which high standards of safety, health and environmental standards, and plant efficiency and reliability will be systematically managed and continuously improved.

The organizational structure was previously discussed in Section 11.1.8.

Platform operations will be administered under the direction of an Offshore Installation Manager (OIM) who will report to the EMCP Hebron Operations management based in St. John's. The OIM will be

responsible for the safe and efficient execution of all platform activities, including drilling, well intervention, construction, shipping and ice management.

All simultaneous operations issues and work permits will be addressed and approved locally. The OIM will be accountable for all work management offshore.

The OIM will ensure that appropriate procedures are in place and implemented for the safe, efficient operation and maintenance of the entire Hebron installation.

The OIM is the designated person in charge for emergency response.

14.4.3 Personnel Selection and Competency Verification

14.4.3.1 Required Competencies

The Production Best Practices competency assurance standard provides a process for identifying the minimum required competencies for operations and maintenance (O&M) positions and first line supervisors (FLS). Minimum required competencies are those required to protect against Operations Integrity incidents (e.g., prevent safety, health, environmental or security problems, control equipment and processes within safe limits, identify hazards, etc.).

The minimum required competencies are updated if there are changing job circumstances.

Procedure-related competencies are identified and documented in the form of an oral or written component for assessing knowledge and a practical component for assessing skills in conjunction with procedure development.

14.4.3.2 Ongoing Competency Verification

ExxonMobil Operations and Drilling's global best practices describe the process for identifying operations and drilling personnel in OIMS key positions and their required competencies.

- ◆ The verification of ongoing competency will be conducted periodically to confirm that qualifications and abilities of personnel to meet specified job requirements are being maintained
- ◆ The FLS will spend an adequate amount of time in the field coaching and assessing employees, observing and guiding operations, training, and conducting competency assurance observations. New or recently assigned employees may require more frequent evaluations and feedback.

At a minimum, all O&M personnel (and FLS, as appropriate) must re-qualify in all procedure related competencies and other non-procedure

related competencies at intervals established by the competency assurance standard, or more frequently if regulations so stipulate.

- ◆ The competency gap assessment process is also used for requalification

Third-party service providers are required to define minimum required competencies for their field-based staff and to ensure only competent, qualified personnel fill the positions. These contractor competency assurance programs are developed and administered as part of third party selection and monitoring global practices. Hebron / EMCP will monitor the compliance of all third-party competency assurance programs through regular training and development audits and reviews.

14.4.4 Personnel Training, Training Documentation and Record Keeping

Training will comply with the ExxonMobil global best practice on training personnel as well as the Atlantic Canada Offshore Petroleum Industry Standard Practice for the Training and Qualifications of Personnel (CAPP, 2008). The EMCP Operations Manager, Hebron OIMs, FLS or designated personnel will ensure that training needs are met. During the design and construction phase, the assigned New Operations Manager will steward training on behalf of the Project Manager.

The Production Best Practices competency assurance process will be utilized to ensure personnel have the required skills and training to safely and effectively perform their work.

Training will consist of two major aspects:

- ◆ Qualification and competence to hold the specific position per ExxonMobil requirements
- ◆ Establishment of vocational skills
 - To achieve the required efficiency within the staffing concept, a degree of multi-skilling between the disciplines will be required
 - At start-up, it is anticipated that the O&M staff will be a mix of experienced ExxonMobil / EMCP employees, EMCP locally hired staff, apprentices and contractors

EMCP will also conduct an apprentice trainee program to recruit, hire, and train local operating personnel. The Hebron operations phase will follow established EMCP Human Resource policies, guidelines and processes. These will be modified, as necessary, for legislative or regulatory requirements, including recruitment and diversity commitments.

At start-up and initially thereafter, experienced ExxonMobil operations staff will provide needed operations experience and will serve as

mentors to the locally hired trainees to accelerate skill development. It is anticipated that experienced staff will be displaced over time, as apprentices achieve competency.

14.4.4.1 Training Documentation and Compliance

Computer based training and other paper / spreadsheet documents are used for competency tracking, training scheduling, and tracking of re-qualification requirements.

The EMCP Operations Manager, Hebron OIMs, and FLSs or designated personnel will ensure that training records are maintained and updated to reflect training received by employees on an ongoing basis.

Training records will be maintained for all employees and will be used to assess compliance with training plans.

Training progress is reviewed annually by the employee's Supervisor. Any new training requirements are included on the employee's "roadmap" and completed per the training plan. Any documented competency gaps may be closed through training and/or developmental activities.

For those courses where testing is mandatory, designated personnel will ensure that employees are tested for knowledge and proficiency, with results recorded on file as required.

The pace of implementation for an individual's training plan includes a consideration of the following:

- ◆ business needs to ensure that the collective competency of the organization (i.e., qualifications of personnel available to meet manning criteria) is maintained
- ◆ the employee's needs
- ◆ work schedules
- ◆ vacation plans
- ◆ availability of relief
- ◆ availability of training
- ◆ priorities

The extent of initial, ongoing and refresher training provided by the Hebron Project is based on established requirements for Operations Integrity related training (i.e., safety, health, environment, and security) and an individual's competency gaps in knowledge and skills.

14.4.5 Operating and Maintenance Procedures and Practices

All necessary systems (e.g., procedures and documentation) required for the EMCP Team to operate the Hebron Asset in a safe and efficient manner will be developed and implemented prior to start-up as outlined in ExxonMobil global practices.

Operations and maintenance procedures and manuals will be developed specifically for the Hebron Platform as required by ExxonMobil OIMS operating and maintenance guidelines. They will comply with EMCP general operability and maintenance procedure requirements and all regulatory requirements. These procedures will be used for training personnel to operate and maintain the facility.

These procedures will be finalized once vendor equipment and system documentation becomes available and will cover the following topics:

- ◆ Systems
- ◆ Equipment
- ◆ Reporting relationships and procedures
- ◆ Maintenance procedures
- ◆ Production and marine procedures
- ◆ Ice management procedures
- ◆ Health and safety procedures
- ◆ Emergency procedures
- ◆ Alert and contingency procedures
- ◆ Environmental monitoring procedures
- ◆ Drilling equipment and maintenance procedures

Documents will be developed in a prioritized manner to facilitate personnel training. The basic documents will be drafted during the detailed design phase and finalised by the various user groups. Strict compliance with OIMS guidelines and regulatory requirements will be maintained.

Drilling operations and maintenance procedures and procedures for record-keeping are defined in the ExxonMobil Drilling Operations Integrity Management Manual.

14.4.6 Safety and Emergency Preparedness / Response Training

OIMS addresses emergency preparedness and response and requires that procedures will be implemented to address credible emergency scenarios that might reasonably be expected to arise on the Hebron

facilities. Detailed procedures will be available for each emergency type. Onshore and offshore emergency team responsibilities will be assigned and training provided. Regular and frequent drills will be held onboard to validate individual and team response capabilities.

Specific training will be provided for individuals and teams assigned offshore Safety and Emergency Response duties which will include, but not be limited to, fire fighting, medical response, on-scene incident command, basic survival training, helideck operations, life boat coxswain, advanced first aid, person overboard, transportation of dangerous goods and medical escort. Leadership training will be provided to those individuals assigned offshore Emergency Response duties. This training should include, but not be limited to, command and control, stress management, oil spill management and fire management.

A training matrix will identify the required scope and standard of training, the training providers and the frequency of training for each individual, onshore and offshore, with responsibilities to an emergency team.

Both the onshore and offshore Emergency Team will carry out at least one major exercise every year.

External groups such as contractors or agencies with specific involvement or responsibilities under the plan will develop their familiarity with the plan through participation and involvement in emergency response exercises and regular communication with members of the teams. Familiarization of the roles of other team members will be achieved by means of these regular exercises.

14.4.6.1 Offshore

All offshore personnel will receive emergency response plan training with frequent refresher courses.

Specialized training will be provided for offshore personnel with specific duties in emergencies including the registered nurse, members of the Fire Team and Emergency Response Team, and coxswains.

Training will also be provided by means of regularly scheduled emergency drills and exercises to validate individual and team response capabilities. These offshore exercises will be based on credible emergency scenarios and will likely include, fire and explosion, first aid, ship collision, iceberg collision, aircraft collision, person overboard, and loss of well control.

14.4.6.2 Onshore

Onshore emergency team members will receive general training in their roles and responsibilities.

The onshore Emergency Response Team will regularly conduct scheduled and planned exercises, including communications exercises, tabletop exercises and logistics exercises.

14.4.7 Training Methodologies

To provide training consistency and thoroughness, as well as to facilitate flexibility in the use of trainers, designated personnel will ensure that effective training aids such as written lesson plans, audio visual aids or computer based training will be used where possible.

The equipment contracting strategy includes plans for providing training materials as well as the equipment to facilitate the training of operations and maintenance staff. The training materials will be specific to the equipment being provided by the contractor and will be created by qualified, approved subcontractors in accordance with EMCP specifications. Where possible, an operator training simulator will be used to train operators, test control strategies and / or software configurations and aid in development. It is expected that a model based on an emulated dynamic process model for the facility will be created to suitably simulate / emulate the facility. Where practical, training will include the actual hardware being provided in the facilities.

14.4.8 Management Training and Qualifications

Management training needs for the Hebron Emergency Response Team will be identified based on regulatory requirements, EMCP emergency response guidelines and individual performance objectives.

14.5 Safety Management System and Safety Plan

The following section summarizes the Safety Management System that will be used by the Operator during all phases of the Hebron Project from engineering design and construction phases through to drilling and completions, and producing operations. ExxonMobil's Safety Management System is fully integrated into OIMS which requires project specific Safety Plans to be prepared and implemented for all stages of the project.

14.5.1 Safety Management System

EMCP believes that all accidents are avoidable and is striving to reduce accident rates to zero.

A Hebron Safety management plan will be implemented to eliminate or reduce risks to personnel, the environment, and the asset through a systematic, continuous improvement process.

The Hebron Safety Management plan will focus on preventing and minimizing accidental losses, based on the following continuous improvement process:

- ◆ Policies, organizations, roles and responsibilities
- ◆ Planning
- ◆ Implementation and operation
- ◆ Checking and corrective action
- ◆ Management review

The standby vessel is maintained in close proximity to the platform at all times. It will be fully equipped with medical facilities and triage area, emergency food provisions, and a fast rescue craft for use in retrieving personnel from the sea. Its role is to provide assistance to the platform in the event of emergency including:

- ◆ Close standby when planned over-the-side work is being carried out
- ◆ Recovery of personnel who have fallen overboard
- ◆ Close standby during helicopter take-off and landings for assistance in the event of a crash
- ◆ Watch for and alert any vessel on collision course
- ◆ Monitor safety zone
- ◆ Recover personnel from sea, raft or life boat in event of platform evacuation
- ◆ Respond to oil spill if directed by the OIM
- ◆ Tanker hook-up and emergency towing
- ◆ Ice management activities

The Hebron Platform will have a single TSR. Hebron living quarters will be designated as the TSR to serve as a “safe haven” where personnel can muster during emergencies. The TSR will serve as a resource base for emergency response actions and communications. The provision of at least two access routes to the TSR will provide a safe pathway from any area of the installation during the initial stages of an incident. The TSR will incorporate safe access to the platform evacuation systems (helicopters, lifeboats, life rafts, etc.) and will incorporate the following features:

- ◆ Protection from platform hazards, including smoke and gas ingress, loss of breathable atmosphere, fire, blast, and heat / temperature build-up, for the time required to complete facility evacuation
- ◆ Structural integrity for the time required to complete facility evacuation
- ◆ Alarm monitoring
- ◆ Means to control platform process and safety systems and possibly some drilling safety systems
- ◆ Reliable power supplies
- ◆ Lighting and visibility systems
- ◆ Communication systems, both external and internal
- ◆ Area for incident response and command structure
- ◆ Area for donning of survival suits, life jackets, and rescue gear
- ◆ Storage area for survival suits, life jackets, and rescue gear
- ◆ Medical facilities

A second evacuation muster area will also be located at the processing end of the platform with access to lifeboats, life rafts, and facilities for communication with the temporary refuge in the Living Quarters.

The Drilling Support Module and Derrick Equipment Set will be protected from platform events for a duration sufficient to complete drilling shutdown actions, make safe the wells, and evacuate personnel to the TSR or the second evacuation muster area.

For evacuation of small numbers of personnel such as individual medical emergency or illness, or for slowly escalating incidents, helicopter transport is the primary means of evacuation. For events in which rapid evacuation of the entire platform contingent is required, the primary means of evacuation will be lifeboats (totally enclosed motor propelled survival craft or TEMPSC). Current technology for dry evacuation directly to marine support vessels will be evaluated for capability and risk, and considered for implementation as a parallel primary evacuation means. Life rafts are provided as a secondary evacuation means. Escape directly to sea with descent assistance devices is the tertiary evacuation means.

TEMPSC capacity will be provided for a minimum of 200% of the number of personnel on board during operation. Life raft capacity will be provided for a minimum of 100% of the number of personnel on board during operation. TEMPSC and life rafts will be located at both west and east ends of the platform according to the normal distribution of personnel.

An adequate supply of lifebuoys will be provided, and distributed in such a way that at least one lifebuoy will always be visible from any point of the outside walkways on the installation. Additional escape and evacuation devices will be located on the platform as required by regulation.

Survival suits and lifejackets will be provided:

- ◆ Within the individual living quarters rooms for 100 percent of maximum personnel on board
- ◆ Adjacent or inside the TSR and secondary evacuation muster area for an additional 100 percent of the personnel on board

Every person on board will be issued with an emergency pack containing a survival suit, heat resistant gloves, a smoke hood and a flashlight. These will be kept in the individual's cabin.

14.5.2 Safety Plan

EMCP will implement safety, security and health policies and procedures for the Hebron development that will meet or exceed all statutory requirements, ensure the safety of all personnel, provide a healthy work and living environment, and support the goal that **"Nobody Gets Hurt"**.

As part of EMCP's application for an Operations Authorization, EMCP will prepare and implement a Project Safety Plan covering all platform drilling and producing operations. The Plan will be prepared in accordance with the requirements of the **Newfoundland Offshore Petroleum Drilling and Production Regulations** and the C-NLOPB's **Other Requirements Respecting Occupational Health and Safety**.

The Project Safety Plan will follow the approach outlined in the C-NLOPB's **Safety Plan Guidelines** and discuss the following:

- ◆ Safety management policies and procedures
- ◆ Facilities and equipment
- ◆ Operations and maintenance procedures
- ◆ Training and qualifications
- ◆ Command structure
- ◆ Contingency planning

To minimize the risk to employees of occupational injuries or illnesses, operational characteristics and conditions will be monitored. Modifications will be made to address exposure to excessive noise,

heat, radiation, vibration, ventilation issues and ergonomic considerations. Programs will be developed to engage personnel and promote occupational hygiene, enhance the well-being of personnel, and prevent incidents.

Safety will be an important design criterion. HAZOPS will continue to be essential activities at key stages of design. The purpose of a HAZOPS is to identify a potentially hazard, assess the possible consequences and determine the most appropriate mitigating action.

Fire and gas monitoring procedures are of key importance as this system will be the primary process hazard detection system and will have a direct interface with the emergency shutdown system and active protection systems.

Safety procedures training will be provided to every employee to ensure complete awareness and understanding of these procedures. Records will be maintained on the training undertaken by each employee.

14.6 Security Plan

The main objective with respect to security for all aspects of the Hebron Project is to provide security for project personnel, assets, facilities, and business information at job sites during construction and execution. Other objectives include:

- ◆ Providing employees and contractors with security safeguards, requirements, and guidelines
- ◆ Incorporating appropriate countermeasures into design and construction activities
- ◆ Protecting proprietary information from loss or unauthorized disclosure
- ◆ Full compliance to International Ship and Port Facility Security (ISPS) as per the International Maritime Organization (IMO) code for security and pursuant to subsection 51(3) of the Newfoundland Offshore Petroleum Drilling and Production Regulations.

Additionally, EMCP will work with regulatory bodies to implement the requirements of the Marine Transportation Security Regulations administered by Transport Canada and the C-NLOPB's other requirements respecting offshore security. Pursuant to these requirements, EMCP will undertake a Facility Security Assessment and prepare and implement a Facility Security Plan.

Synergies with existing EMCP security personnel and resources will be utilized. Ongoing threat assessments are being completed to understand requirements needed to meet threat escalation necessities and procedures for all project sites and travel routes. Safeguards and

security qualitative risk assessments will be conducted, along with security design and planning review procedures to enhance our knowledge of the required security parameters that must be considered.

15 ACRONYMS

Acronym	Definition	Section
2DHR	2D high-resolution	2
ADW	Approval to Drill a Well	7
AM	A Marker	3
ANSI	American National Standards Institute	8
APB	Annular pressure build-up	7
API	American Petroleum Institute	8
APS	Abandon Platform Shutdown	9
ASCE	American Society of Civil Engineers	8
ASME	American Society of Mechanical Engineers	8
ASV	Annular Safety Valve	7
AVO	Amplitude versus offset	2
BML	Below mudline	8
BN	Ben Nevis	3
BNBN	Ben Nevis reservoir of the Ben Nevis field	4
BOP	Blow-out preventer	1, 7
BOPD	Barrels of Oil Per Day	4
BS&W	Basic sediment and water	8
BSF	Below seafloor	7
BVW	Bulk Volume Water	3
CACP	Controlled Amplitude and Controlled Phase	2
CCA	Conventional Core Analysis (porosity, permeability)	3
CDP	Common Depth Point	2
CEAA	Canadian Environmental Assessment Act	14
CEC	Compact Electrostatic Coalescer	9
CMR	Combinable Magnetic Resonance	3
C-NLOPB	Canada-Newfoundland and Labrador Offshore Petroleum Board	1, 6, 7, 8, 9, 10, 11, 12, 14
COF	Certificates of Fitness	14
CP	Capillary pressure	3
CPM	Cross Polarized Microscopy	4
CRAs	Corrosion resistant alloys	7
CRI	Cuttings re-injection	6, 7
CSA	Canada Shipping Act	11
CSR	Comprehensive Study Report	10
DA	Development Application	1, 10
DES	Derrick Equipment Set	1, 7, 10
DHI	Direct Hydrocarbon Indicator	2
DMO	Dip Move-Out	2
DSD	Drilling Shutdown	9
DSM	Drilling Support Module	1, 7, 10
DST	Drill Stem Test	2, 3, 4
DWS	Deep Water Site	10
ECRC	East Coast Response Corporation	11

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Acronyms

ECS	Elemental Capture Spectroscopy Sonde	3
EDC	Excavated Drill Centre	10, 13
EIS	Environmental Impact Statement	1, 10
EMCP	ExxonMobil Canada Properties	1, 11, 13, 14
EMP	Environmental Management Plan	10
EOD	Environment of Deposition	2
EOR	Enhanced Oil Recovery	6
EOS	Equation of State	4
EPC	Engineering, Procurement, and Construction	10, 14
ESD	Emergency Shutdown	9
ESP	Electric submersible pump	6
EUR	Estimated Ultimate Recovery	5
F&G	Fire & Gas	9
FBHP	Flowing bottomhole pressure	6
FEED	Front-End Engineering and Design	1, 7, 8, 9, 10, 11, 12, 14
FF	Formation factor	3
FLS	First line supervisors	14
FMI	Formation Microimager	3
FPSO	Floating Production, Storage and Offloading	1
FVF	Formation Volume Factor	4
FWHP	Flowing wellhead pressure	6
FWL	Free water level	3
FX	Frequency domain	2
GBS	Gravity Base Structure	1, 2, 6, 7, 8, 9, 10, 12, 13
GCO	Gas consumed in operations	6
GEP	Gas Entry Pressure	2
GHG	Greenhouse Gas	9
GI	Gas injection	6
GIP	Gas in-place	6
GL	Gas Lift	6
GOC	Gas-oil contact	2
GOR	Gas oil ratio	6, 9
GR	Gamma ray	2, 3
HAFWL	Height above free water level	3, 4
HALS	Azimuthal Laterolog	3
HAT	Highest Astronomical Tide	8
HAZOPS	Hazard and operability studies	11, 14
HBN	Hebron Ben Nevis	4
HKO	High known oil	2
H _{MAX}	Maximum individual wave height	8
HP/MP/LG	Main compression (high pressure, medium pressure, lift gas)	9
HQS region	Regions of the reservoir exhibiting greater than 10 md permeability	4
Hs	Significant wave height	8
HST	High Stand System Tract	2
HTV	Heavy Transport Vessel	10
HVAC	Heating, ventilating and air conditioning	1, 10

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Acronyms

ICSS	Integrated Control and Safety System	9
IL	In-line	2
IMO	International Maritime Organization	14
IRPA	Individual Risk Per Annum	14
ISPS	International Ship and Port Facility Security	14
JDA	Jeanne d'Arc	2
JOA	Joint Operating Agreement	1
k	Permeability from logs	3
kh	Permeability thickness	4
Kh	Horizontal bulk permeability	5
Kv	Vertical bulk permeability	5
LAS	Log Ascii Standard	3
LAT	Lowest Astronomical Tide	8
LLWLT	Low Water Large Tide	2
LQ	Living Quarters w/ Control Room	10
LQS	Regions of the reservoir exhibiting 10 md or less permeability	4
LSF	Lower Shoreface Units	2
LST	Lowstand Systems Tract	2
LWD	Logging while drilling	6, 7
M&R	Maintenance and Reliability	11
MD	Measured depth	3, 7
MD RT	Measured Depth Rotary Table	7
MDRKB	Measured Depth from the Rig Kelly Bushing	2
MDT	Modular Formation Dynamics Tester	2, 3, 4, 6
MDT tool	Open-hole formation tester	4
Metoccean	Meteorological and oceanographic	8, 10
MODU	Mobile Offshore Drilling Unit	1, 6, 7, 10, 11
MOP	Main Offloading Pipeline	9
MPP	Multiphase pumps	1
MPS/FDM	Multiple Point Statistics and Facies Distribution Modeling	2
MSL	Mean Sea Level	8
Mss	Meters subsea	3
MSWT	Minimum sea water temperature	4
MWD	Measurement while drilling	7
NAF	Non-aqueous fluid	1, 6, 7
NBP	Near boiling point	8
NEB	National Energy Board	1
NMR	Nuclear Magnetic Resonance	3, 6
O&M	Operations and maintenance	14
ODT	Oil-Down-To	2
OHGP	Open-hole gravel packs	7
OIM	Offshore Installation Manager	11, 14
OIMS	Operations Integrity Management System	11, 14
OLS	Offshore Loading System	1, 2, 8, 9, 10, 11, 12
OSV	Offshore support vessels	11
OWC	Oil-water contact	2, 3, 4, 5
OWTG	Offshore Waste Treatment Guidelines	1, 9

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Acronyms

P&T	Pressure & temperature	9
P50	Statistical 50 th percentile	2
PA/GA	Public Address / General Alarm System	9
PBR	Polished bore receptacle	7
PCPT	Piezocone penetrometer testing	2
PCS	Process Control System	9
PDG	Permanent down-hole gauge	7
Pef	Photoelectric Effect	3
PHIE	Effective Porosity	3
PHIT	Total porosity	3
PI	Productivity indices	6
PLEM	Pipe Line End Manifold	1, 9
POB	Personnel on board	9, 11, 14
PRAP	Project Risk Assessment Plan	14
PRMP	Project Risk Management Plan	14
PSD	Process Shutdown	9
PSTM	Pre-stack time-migrated	2
PSV	Pressure Safety Valve	10
PTW	Permit-to-work	10
PVT	Pressure-volume-temperature	4, 5, 6
PW	Produced water	9
PWRI	Produced water re-injection	9
RAM Study	Reliability, availability, and maintainability simulation	8, 9
RE	Recovery efficiency	5
RFT	Repeat formation tester	3, 4
RI	Resistivity index	3
RKB	Rotary Kelly Bushing	7
RMS	Root Mean Squared	2
ROP	Rate of Penetration	2, 6, 7
ROV	Remotely operated vehicle / vessels	1, 10, 11
Rt	Formation resistivity	3
Rw	Water resistivity	3
SCAL	Special Core Analysis	3, 4
SDLs	Significant Discovery Licenses	1
SDW	Storage Displacement Water	9
SEIS	Socio-Economic Impact Statement	1, 10
SGS	Sequential Gaussian Simulation	1, 2
SHF	Saturation Height Function	3
SIMOPS	Simultaneous Operations	7, 10
SIS	Safety Instrumented Systems	9
SL	Sail Line	2
Sorg	Residual Oil Saturation to Displacement by Gas	4
Sorw	Residual Oil Saturation to Displacement by Water	4
SPMT	Self Propelled Modular Transporters	10
SRB	Sulphate-reducing bacteria	4, 8, 9
SSH&E	Security, Safety, Health and Environment	1, 11
STOOIP	Stock Tank Original Oil In Place	1, 6

SW	Sea water	9
Sw	Water saturation	3, 4
SWI	Initial water saturation	3
Swir	Range of irreducible Sw	4
Swt	Total water saturation	3
TALL	Theoretical Annual Loss of Life	14
TCMR	CMR porosity curve	3
TEMPSC	Totally enclosed motor propelled survival craft	11, 14
TH _{MAX}	Period associated with H _{MAX}	8
TLS	Target Levels of Safety	14
Tp	Peak spectral wave period	8
TRSCSSV	Tubing retrievable surface-controlled subsurface safety valve	7
TSHD	Trailing suction hopper dredger	10
TSR	Temporary Safe Refuge	11, 14
TST	Transgressive Systems Tract	2
TVD	True Vertical Depth	2, 7
TVDSS	Total Vertical Depth Subsea	2, 3, 4
TVP	True vapour pressure	8
UPM	Utilities and Processing Module	1, 10
USBM	United State Bureau of Mines	4
USF	Upper Shoreface Sand Unit	2
VECs	Valued Environmental Components	14
VFA	Volatile Fatty Acid	8, 9
VIEC	Vessel Internal Electrostatic Coalescer	9
Vsh	Shale	3
VSP	Vertical Seismic Profile	2
WAT	Wax appearance temperatures	4
WBM	Water-based mud	3
WHGBS	Wellhead Gravity Base Structure	1
WI	Water Injection	6
WOC	Waiting on cement	7
WSa	Associated wind speed at 10m height	8
XRD	X-Ray Diffraction	3