TRIM # 0007028
Date Rec'd August 4, 2011
File # 24002-208-002
Canada-Newfoundland & Labrador Offshore Petroleum Board

ExxonMobil Canada Ltd.
Suite 701, 215 Water Street
St. John's, NL A1C 6C9
Tel: (709) 652-6444
Fax: (709) 652-6429

ExxonMobil

L-HE-CNO-110804-02

August 4, 2011

Mr. Jeffrey M. Bugden, P. Eng.
Manager, Regulatory Coordination and Benefits
Canada-Newfoundland and Labrador Offshore Petroleum Board
Suite 500, 140 Water Street
St. John's, NL
A1C 6H6

Dear Mr. Bugden:

Subject: Response to C-NLOPB's Completeness Review of the Hebron Development Plan

With reference to your letter dated May 31, 2011, ExxonMobil Canada Properties (EMCP), operator of the Hebron Project, is pleased to provide its response to each of the comments arising from the C-NLOPB's "completeness review" of the Hebron Development Plan. In the interest of clarity, EMCP has updated Chapters 2, 5 & 6 of the Development Plan; a copy of these updated Chapters, which form part of the Operator's overall response to the C-NLOPB's completeness review, is also enclosed.

EMCP's response makes reference to submission of additional Development Plan Part II documents. These documents are being submitted to the C-NLOPB under separate cover letter.

As indicated in our previous discussions, we would be pleased to arrange, if necessary, further technical discussions with the Board's staff during the course of their completeness review. In this regard, we plan to follow-up with you in a week or so.

Yours truly,

James E. O'Reilly

James E. O'Reilly,
Environment and Regulatory Manager

Enclosures

Operations and Safety

1. The number of personnel on board (POB) is given as 230-234. A detailed justification for selecting the POB should be submitted. Experience from certain past projects indicated that the initial selection of POB was not adequate.

Hebron Response #1

Hebron POB was discussed in detail with C-NLOPB during a meeting on October 14, 2010. At that time ExxonMobil reviewed its processes to establish a safe and efficient Platform POB. This process includes ExxonMobil best practice application, use of internal benchmarking tools and lessons learned from both our local and extensive global offshore operations. Since our last meeting with the C-NLOPB we have continued to optimize our design and improve overall safety and efficiency of the platform. The POB design is now 220 and we will continue to study further optimizations during FEED. This POB efficiency improvement is due to optimization and improved work processes during both base and peak activity periods. Base POB is expected to be approximately 151, with accommodation allocation to increase POB to 210 - 220 at peak periods (e.g. additional construction, casing, completions crews). Our base POB has been designed to operate and maintain the specific equipment on board the installation. The specific number of operators and technicians has been determined using our global benchmarking tools and best practices. These processes are designed to ensure the platform integrity and safety requirements are executed in a timely manner. Reliability is also a strong focus of our POB design, since a steady and reliable operation is a safe operation. It is important to highlight that operations and drilling will be at the base POB of approximately 151 for two thirds of a typical well program, therefore allowing significant available living quarters for unplanned maintenance work to be completed. As previously discussed with the C-NLOPB, we will be seeking approval of a regulatory query to increase personnel above the design POB (210-220) during initial start-up and commissioning activities, as well as periodic shutdowns.

It should be noted that it is our understanding that some FPSO operations in the area do not have the 50-60 POB flexibility between base and peak operations being designed into the Hebron installation. At Hebron sufficient reserve is also built into the peak operating number to allow flexibility for unplanned activity during all simultaneous operations, thus ensuring adequacy.

We offer a follow up discussion on this subject to further outline the detail that we have carried out to ensure the Hebron Platform will be operated and maintained in a safe, reliable and efficient manner.

2. The development plan is based on conceptual engineering studies and a number of FEED studies that are ongoing. The list of studies that are ongoing should be submitted along with a schedule of when they will be completed.

In addition, it is indicated that a number of studies will be required to progress detailed design and construction. The list of such potential studies should be submitted along with a tentative schedule for completion.

Hebron Response #2

This comment goes beyond the scope of the Accord Act requirements and is not part of the C-NLOPB guidance documentation. The application is complete without a listing of these studies.

The regulatory process provides for the Certifying Authority to validate the design and compliance with the Installation Regulations.

3. Section 7.1.1 indicates that the open-hole gravel pack completions may exceed current technical limits. The process to ensure that the use of new technology or extending current technology is safe should be submitted.

Hebron Response #3

The open-hole gravel techniques proposed by the Operator do not deviate from the established safety protocols already in existence for current open-hole techniques used by the industry. The Operator has completed trial testing of the proposed open hole techniques which are now considered 'base technology'.

4. a. Section 8.1.3 indicates that 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. After FEED studies are completed, it is indicated that the list of codes and standards will be updated. A commitment to submit these codes and standards should be made.

Hebron Response #4a

We confirm that a list of codes and standards will be provided at the end of FEED.

b. It is also indicated that the most recent edition of applicable codes will be used. In case of conflict between Global Practices and accepted industry practice, normally the most stringent requirements will take priority**.** A commitment to submit any requirements from Global Practices that are more stringent than the codes and standards referenced in the application should be made.

Hebron Response #4b

This comment goes beyond the scope of the Accord Act requirements and is not part of the C-NLOPB guidance documentation. It is not feasible or advantageous for the project to conduct the requested review of hundreds of ExxonMobil GPs. Any deviations from the GPs are captured through a robust Specification Deviation Process and deviations from the regulations are captured through the Regulatory Query Process.

c. Finally, since codes and standards are revised from time to time, a commitment to submit a description of the process for considering revisions to codes and standards should be made.

Hebron Response #4c

We confirm that the latest revision of codes and standards will be considered as is standard practice of any engineering organization. The EPC Contractors have developed regulatory compliance procedures which effectively describes how periodic changes to codes and standards are identified, considered and implemented. These procedures are also part of the documentation review by the Certifying Authority.

5. Figure 1.7-4 indicates that the OLS includes a vertical riser. In the past, there were challenges with wear on the flexible lines used for an OLS with a vertical riser. A discussion of how the applicant has considered these challenges and how it intends to reduce the risk of wear to the flexible lines should be submitted.

Hebron Response #5

The Operator plans to minimize this historic challenge by taking advantage of both design and operational elements. For design, the project is not using a vertical lower riser that is attached to a subsea buoy at mid column height like other projects, but using a clump weight to keep the downstream end of the lower riser on the sea floor while in the idle condition. This clump weight keeps both the lower and upper riser nearer the seafloor and out of the higher magnitude wave forces. For pick up, the Operator is studying changes that can be made on the service vessel to minimize the time that the upper riser may come in contact with the seafloor, such as a stronger winch, perhaps with heave compensation, and developing procedures to lay down the riser system after loading to avoid having to reposition it later (and thus expose it to scrapping). Consideration is also being given to replacing the riser system with a more flexible and easily handled marine hose.

6. Section 9.4.4 indicates that 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 and that the suitability of tanker fleet/standby vessels will be verified during detailed design. Section 10.1.3 of the concept safety analysis (CSA) states that it is assumed that support and standby vessels and shuttle tankers will be suitably ice strengthened to permit their use in most sea ice conditions. This assumption should be reviewed at the design stage to ensure that the possibility of sea ice is considered when selecting evacuation systems. Accordingly, a discussion of ice strengthening of shuttle tankers and standby vessels should be submitted.

Hebron Response #6

While the Hebron vessel strategy has not yet been developed ice strengthening will be considered as part of the development process. Sea ice is in the scope of the EER studies that pertain to lifeboats, life rafts, survival in the sea, and the ability of support vessels to assist in evacuation efforts.

7. Sections 1.7 and 1.8 discuss alternatives to proposed project and the preferred concept. Any supporting documents in connection with this matter should be submitted.

Hebron Response #7

The Operator has no other supporting documents in connection with this matter.

8. Section 8 discusses design criteria but does not mention the need to consider multi-directional wave loading on bottom founded structures. A discussion on how the applicant intends to consider multi-directional waves should be submitted.

Hebron Response #8

For GBS Structural design, long crested extreme waves generate the highest design loads. The Operator is taking account the directionality of these waves and will design facilities accordingly during FEED.

9. The facilities are designed for 30 years. Table 1.9-1 indicates the life of the field as greater than 30 years. A discussion on the rationale for selecting a design life of 30 years when the life of the field is greater than 30 years should be submitted.

Hebron Response #9

The design life is primarily used in the selection of materials and calculating corrosion allowances for piping and vessels. Corrosion estimates are made based on assumptions about the changing chemical composition of fluids in each service over the life of the field. Compositions towards the end of field life are difficult to predict, given uncertainties in well stream compositions over time. A nominal design life of 30 years was selected as a basis for estimating corrosion allowances. Experience has shown that materials often have a longer service life than originally estimated, if the predicted corrosion conditions were not realized. Conversely, piping and vessels may need to be replaced short of their design life if corrosion rates are greater than expected. Inspection, monitoring and maintenance programs throughout the life of the facility will dictate replacement of components or extension of field life.

Decisions to extend the facility life, through refurbishment and replacement of components will be made in the future based on market conditions and economics prevailing at that time.

10. Section 8.1.3 states that 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. Additional discussion should be submitted on the following items.

    a. Probabilistic analysis
    Clarification of the probabilistic procedure should be submitted. To our understanding, distributions are assumed for the various parameters used for generating the iceberg impact loads. Often, it is assumed that larger icebergs move at slower velocities than smaller icebergs. However, observations indicate that large icebergs may move at relatively large velocities.

Hebron Response #10a

The probabilistic load calculation for iceberg impact loads is a Monte Carlo simulation procedure in which statistical distributions are used to represent the data that describe the important iceberg input parameters. These distributions are quantified by measured data for these parameters. For iceberg velocities, the data are partitioned by iceberg size, which means that all icebergs are not assumed to drift at the same speed. The iceberg design loads of interest are those at the 10-4/year probability level. At these low probability levels, the loads of interest are associated with the larger icebergs impacting at speeds that are higher than what has been observed. Typical impact speeds for the design level loads are more than twice as high as the mean drift speed that has been observed for icebergs on the Grand Banks; for example, the 10-4/year iceberg design load may result from a 3.1 million tonne iceberg drifting at the speed of 0.72 m/sec.

    b. Return period
    ISO 19906 indicates that the representative value for actions arising from extreme-level ice events shall be determined based on an annual probability of exceedance not greater than 10^{-2}. Unlike wind and waves, iceberg impact loads do not converge to a limit at an annual probability of 10^{-2}. Sometimes a lesser annual probability is used for such actions. A discussion on the selection of annual probability for iceberg loads should be submitted.

Hebron Response #10b

ISO 19906 considers two classes of environmental load events -- frequent environmental events and rare environmental events –- with specified annual probabilities of 10-2 and 10-4, respectively for design loads. Wave loads are an example of a frequent environmental event and iceberg impact loads are rare environmental events. Thus the appropriate annual probability for iceberg impact loads is 10-4/year.

    c. Crushing pressures
    The methodology used to generate iceberg impact load uses a pressure area relationship where the average pressure decreases with increase in area. However, some researchers

suggest that there is potential for increase in pressures with increase in area for small aspect ratio contact areas. A discussion justifying the use of design loads generated by the first approach should be submitted.

Hebron Response #10c

The $10^{-4/}$year local pressures used in the design of the ice wall range from 9 to 16 MPa for a contact area 0.6m or less. However, the contact area associated with a 10^{-4}/year iceberg global load is 100's of square meters. For example, the contact area associated with a 3.1 million tonne iceberg at 0.72 m/s drift speed is 338.2 m^2. In summary, high ice pressures associated with small contact areas are used for the local design of ice walls while extreme iceberg loads associated with large contact areas determine the global design iceberg load for the structure.

11. The CSA indicates that the quantified risk assessment is based on a risk model that can be refined and updated throughout the life of the project. A discussion on the criteria (trigger) for updating the CSA should be submitted.

Hebron Response #11

The Newfoundland Offshore Petroleum Installations Regulations require the Operator to maintain and update the CSA when changes in operating procedures and practices would necessitate an update. The Hebron Project will assess risk at various stages of the project design and execution as listed in the Part II document "Early Project Risk Assessment Plan", and as updated during project design and execution. The ExxonMobil Operating Integrity Management System calls for re-assessment of risk when any of the following occur:

- Change in the platform design (according to EM Management of Change (MOC) process)
- Change in operating procedures (according to EM MOC process)
- Recognition of a new hazard

The CSA will be updated should any of the above risk assessment results identify a change in assumed risk in the initial CSA.

12. Reference is made to the Drilling Regulations and the Production and Conservation Regulations in sections 7.1.10, 7.2.10 and 14.6. Reference should be to the *Newfoundland Offshore Petroleum Drilling and Production Regulations*.

Hebron Response #12

Noted. Future references will be shown as proposed.

Environmental Protection

13. The documentation associated with the Comprehensive Study Report (CSR) pursuant to the Canadian Environmental Assessment Act is intended to fulfill the requirements for an Environmental Impact Statement under the Accord review and as outlined in Chapter 5 of the *Development Plan Guidelines*. Comments on the draft CSR have been provided to the proponent and are in the process of being addressed. A number of the comments made on the CSR are also relevant to the Hebron development application. When CSR issues are resolved, the applicant should, as required, incorporate those changes into the relevant sections of the application so the CSR and the application contain the same information. Examples of common issues are the disposal of water based mud and cuttings, produced water reinjection, flaring and oil spills.

Hebron Response #13
The Proponent is satisfied that its Development Plan is aligned with the updated CSR.

14. The applicant has not mentioned, "… the quantities and composition of atmospheric emissions, including those arising from production fluid combustion and gas flaring" as outlined on page 37 of the development plan guidelines. Atmospheric emissions are dealt with in the CSR but no connection between the CSR and the development application are made.

Hebron Response #14
The CSR is intended to address the requirements of Chapter 5 – EIS of the Development Plan Guidelines. In this respect, the CSR is a part of the Development Application.

15. The applicant has not discussed control of biological growth within the facilities seawater systems in the development plan, but has considered the use of sodium hypochlorite for biological control in the CSR. The applicant should make the connection between the CSR and the development plan.

Hebron Response #15
As previously noted, this issue is covered in the CSR. The CSR is one of the components of the Hebron Project Development Application.

16. Biofouling of the facility or control of biofouling has also not been presented in the application but biofouling has been discussed in the CSR. The applicant should make the connection between the CSR and the development plan.

Hebron Response #16
Please see Response #15.

17. Section 7.1.6.3: The applicant is reminded that use and disposal of completion fluids should be in accordance with the *Offshore Waste Treatment Guidelines*, 15 December 2010.

Hebron Response #17

The applicant acknowledges the reminder and notes that the use and disposal of completion fluids will be in accordance with the referenced OWTG guidance and procedures will be described in the offshore environmental protection plan.

18. Section 9.1.1: Disposal of interface is subject to review and to the proponent's CSR.

Hebron Response #18

The comment is noted by the applicant. The crude oil storage system is designed to keep the crude oil–water interface within the storage cell and the storage displacement water will be treated according to the OWTG. All waste handling procedures will be captured in the offshore environmental protection plan that will be reviewed and approved by the C-NLOPB.

19. Section 9.1.1: The level of detail provided on the storage displacement water system is not sufficient to understand how crude will not be accidentally discharged to sea through the open system, i.e. cell over filled. It is also unclear as to what is meant by "residence time may be reduced to fit void volume in the GBS". Additional detail is required on the system and residence time.

Hebron Response #19

The crude oil storage cells will be provided with a crude oil interface level measurement system with alarms which will be interlocked with a shut off valve on the filling line at Topsides to prevent overfilling of the cells and overflow to the displacement water system. The displacement water lines from the storage cells will be routed through a manifold and connected to the tricells in the GBS, which constitute a buffer volume towards sea. Each tricell has an area of 11.6 m^2. Total area in the system is 81.2 m^2. The internal height of the tricells is 69.2 m giving a total volume of the tricells of approximately 5600 m^3. In addition, the total buffer may include the buffer in the storage cells below the high-high level corresponding to the Lower Interface level (currently at EL. 13.9 m). This buffer of 1.5 m in one cell of approximately 500 m^2 corresponds to an additional buffer volume of approximately 750 m^3. The total effective buffer volume is therefore approximately 6350 m^3. With a crude production rate of maximum 1022 m^3/h as defined in the GBS Design Basis the residence time will be approximately 5-6 hrs.

20. Section 9.1.1.6: The applicant mentions intakes but does not mention the location or design of discharges. Both the location and design of discharges are important for dispersion and to minimize other potential effects of the discharge. The applicant also does not mention the need or how biological growth in the facilities various water systems will be accomplished. More detail is required.

Hebron Response #20

The seawater intake location(s) (orientation, elevation) has been established considering produced water, drill cutting dispersion modeling and marine growth. The seawater intake location is platform south away from shale chute 2, which is located on platform west. Seawater supply shall be taken from approximately 70 m below sea level.

The design of the seawater discharge system is not finalized at present. However, the design will consider siphon flow, partially vented flow, and fully vented flow operating conditions, as well as impacts on nearby systems and facilities.

Control of biological growth will be affected by use of biocides, primarily chlorine. Use of biocides, and all other chemicals, will be subject to implementation of the Chemical Screening Process developed in accordance with the Offshore Chemical Selection Guidelines (2009), which will be submitted as part of the Environment Protection Plan.

21. Section 9.2.3.2: The applicant states gas will; be scrubbed to remove liquids, hydrocarbons and water; and, dehydrated. The applicant should describe what the scrubbing medium is and what happens to the medium after scrubbing. The applicant should also describe how gas will be dehydrated.

Hebron Response #21; Andrew Jacob provided comments.

a) Scrubbing in this context refers to dropping out of liquids from a gas stream via physical means (a vessel with internal baffles). There are no chemical mediums involved in this process.

b) The purpose of the Gas Dehydration System is to dehydrate gas to an adequate level to avoid condensation and possible corrosion or hydrates in the production casing and injection tubing. It should be noted that, as part of the ongoing FEED optimization work, dehydration is currently not part of the Hebron design. However, some studies are still pending such that dehydration may ultimately be reincorporated back into the Hebron design. Conceptually, the dehydration system would operate as follows. Gas from the HP compressor will be routed to the Dehydration Inlet Scrubber where liquid will be knocked out. The wet gas enters the Glycol Contactor at the bottom and flows upwards through the structured packing sections, where water vapor will be absorbed by the lean TEG flowing in the opposite direction. The dry gas leaves the contactor through the top and goes downstream to the Gas Lift Compressor. Rich TEG collected in the bottom section of the contactor will be sent to the Glycol Regeneration Skid for regeneration, where fuel gas will be used as a stripping gas. Water and flashed gas from the regeneration process will be sent to flare.

22. Section 9.2.3.5: Accompanying the development plan are two reports on reservoir souring: one produced for Chevron and the other for ExxonMobil Canada Properties (EMCP). The latter report was produced because the depletion strategy for the reservoir was changed. This

change appears to have altered the souring predication in that the reservoir will sour sooner and that there is little difference between the souring potential of seawater and produced water when used for water flood. One of the reasons the applicant gives for not re-injecting produced water is that, as compared to seawater injection, the souring potential was greater. Since this predication according to the souring study done for EMCP may not be valid, the applicant should review the rational for not re-injecting produced water based on souring potential.

Hebron Response #22

The applicant believes that the 2010 reservoir souring study indicates more than a "little difference" between the souring potential of SW injection and PWRI. The key data that shows the impact of reservoir souring in this study is the total H_2S production (kg/day). The magnitude and evolution of the total H_2S production as a function of water cut shown in Figures 4.1 to 4.12 is as much as 50% greater with mixed PW/SW injection than with SW injection only. The applicant has reviewed the rational for not re-injecting PW based on souring potential and believes that the greater souring potential of PW is but one of several potential risks in adopting PWRI at project start-up. As stated in the Part II document "Produced Water Management Strategy," additional data is needed to confirm that the identified risks of PWRI are manageable. The additional data required can only be obtained and analyzed after there has been sufficient water production (several years post start-up). Hebron will initially operate with marine discharge of PW at start-up. Hebron will switch to PWRI for routine operations if testing and studies (post water production) demonstrate that the risks and impacts of PWRI are understood and acceptable.

23. Section 11.3: Spill or pollution is not mentioned in the section.

Hebron Response #23

Credible emergency scenarios provided in Section 11.3 are noted as "not necessarily be limited to". Spill or pollution may be considered credible emergency scenarios and will be incorporated into emergency response plans.

24. Section 14.1.2: The proponent's environmental assessment assesses the probability of an environmental event based on historical data from the local jurisdiction and internationally. Based on these probabilities, the risk to the environment in combination with the associated event is assessed. The assessment is not specific to a facility or its design; it is based on historical performance of all drilling or production facilities. Unlike the environmental assessment, the CSA is for a specific facility and not a generic analysis of the probability of an event occurring. The applicant should reflect the probabilities and mitigations identified in the project's environmental assessment in the design of the facility. Where it is practical to reduce the probability of an event occurring further, the necessary measures to reduce the probability are to be incorporated into the design of the facility.

Hebron Response #24

A fundamental part of the Hebron Project risk assessment process is the generation, tracking, completion, and closure of actions to mitigate risk. These mitigating actions are identified during the risk assessments listed in the Part II Document Hebron Project Risk Assessment Plan by a formal, qualitative risk assessment process with management approval of risk assessment scope, purpose, action items, and completion of action items. Mitigations identified in any risk assessment are tracked and stewarded by this same process such that these mitigations are incorporated in the facility design.

25. The applicant has not established a target level of safety for risk of damage to the environment in the application or the CSA. Nor has the applicant defined "significant" or "not significant". The application does not adequately demonstrate how section 43 of the *Newfoundland Offshore Petroleum Installations Regulations* and section 4.1 of the *Development Plan Guidelines* will be achieved, for environmental risks.

Hebron Response #25

The target level of safety for risk of damage to the environment is established in the Hebron Project Comprehensive Study Report (CSR). The definition of "Significant" is discussed in Section 4.3.3 of the CSR for each VEC. The CSR has the following conclusion:

> The Project will benefit from the experience of the existing production projects offshore Newfoundland and Labrador, with respect to many key items, including reducing resource conflicts with commercial fishers, development of effective monitoring programs and effective emergency response planning.
>
> Ecological processes will not be disturbed outside natural variability, and ecosystem structure and function will not be critically affected by the Hebron Project. Most environmental effects are reversible, and of limited duration, magnitude and geographic extent. While significant adverse environmental effects have been predicted for Marine Birds, bird Species at Risk (SAR) and Sensitive or Special Areas (those located in the nearshore only) in the case of an accidental event, the likelihood of this occurring is considered very low. EMCP will have pollution prevention measures and emergency response procedures in place.
>
> The various routine components and activities associated with the proposed Project are predicted to result in not significant residual adverse environmental effects on Air Quality, Fish and Fish Habitat, Commercial Fisheries, Marine Birds, Marine Mammals and Sea Turtles, Marine SAR and Sensitive or Special Areas.

Resource Management

26. References are provided in the Geology section and the Petrophysics section. References should also be provided in the Reservoir Engineering section, Reserve Estimates section, Reservoir Exploitation section as well as the Drilling and Completions section.

Hebron Response #26

References provided in the Geology and Petrophysics sections are to published papers, journal articles, etc used in the discussions in those sections. Sections 4 – 6 (Reservoir Engineering, Reserves Estimates and Reservoir Exploitation) do not have a list of references because these sections do not refer to any published information. Additional reference materials (project proprietary) utilized in developing these sections have been provided as Part II documentation.

Geology and Geophysics

27. The application discusses trapping configuration for Hebron (3 way fault dependent trap) but not West Ben Nevis and Ben Nevis fields. Is the configuration the same in these fault blocks?

Hebron Response #27

Added the following text to Section 2.2.1 (Structural Geology):

"The West Ben Nevis and Ben Nevis Fields lie on adjacent fault blocks to the northeast **and are also three-way fault-dependent traps**."

28. Figure 2.21 shows all of the trapped hydrocarbons at Hebron. Additional maps to show the individual pools and prospects from the Figure 2.21 map should be provided to better illustrate size and distribution.

Hebron Response #28

Figure 2.2-1 split into 5 new Figures. (2.2-1 through 2.2-5)

29. On page 2-24 it is hard to distinguish between use of the Avalon Formation in the formal stratigraphic sense and the "lumped" reservoir unit which includes the Eastern Shoals Formation and the A Marker as defined on page 2-21. For example, if the base of the Avalon is a sequence boundary, is this the base of the Avalon Formation only, or the base of the whole lumped unit? Terminology needs to be strict (always referring to the "Avalon reservoir unit" where appropriate) to avoid confusion. This should be updated to ensure common terminology.

Hebron Response #29

Revised text to read:

"The Early Cretaceous Avalon Formation and "A" Marker are collectively called the Avalon Formation / Reservoir for the geologic technical evaluation and for modeling purposes."

Deleted the following sentence:

"Overall, the Avalon Formation is a coarsening upward marine shoreface sandstone that represents progradation into the Jeanne d'Arc basin."

Added following text to Section 2.2.2.1.1:

"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 ands I-45 wells."

30. Page 2-31: Shoreline trending "northeast to southwest" is the opposite of what is depicted in Fig.2.2-8. Please clarify.

Hebron Response #30

Revised text to read:

"Seismic attribute and seismic facies analyses were used to determine that the Ben Nevis shoreline trend is west-northwest to east-southeast."

31. The petrophysical criteria and log-cut offs used to define the Ben Nevis and Avalon reservoir facies, should be provided in a format similar to Table 2.2-1 page 2 -42.

Hebron Response #31

There is no accompanying Table because logs were not used to define petrofacies in either Pool 1 or Pool 3.

Added the following text to Section 2.2.2.1.3:

"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."

32. A paleogeography map for the Jeanne d’Arc formation is to be provided.

Hebron Response #32

Added new Figure to Section 2.2.2.3.10:
Figure 2.2-30: Jeanne d’Arc Formation “B” Sand Paleogeographic Map

33. The petrophysical criteria and log-cut offs used to define the Jeanne d'Arc reservoir facies should be provided in a format similar to Table 2.2-1 page 2-42.

Hebron Response #33

The following text and tables were added to Section 2.2.2.3.11:

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

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

34. A depth migrated or converted seismic volume or Petrel velocity model is required.

Hebron Response #34

Information requested provided as Part II document.
Latest average velocity model (VM10) - separate Petrel project. This velocity model is NOT available to the general public and is labeled privileged / confidential.
-- Avg_velocity_model.pet (submit as Part II)
-- Avg_velocity_model.ptd (submit as Part II)
NOTE: Our Geophysical Applications Group has prepared a short list of comments regarding the use of this Vavg model to accompany the model itself.

35. The resolution and scale of seismic sections is insufficient to determine character of interpreted horizons and surface well ties. For example, in Figure 2.4-2, log character, or the well picks, cannot be distinguished.

Hebron Response #35

Figure 2.4-2 has been deleted and text modified to read that a representative well tie is displayed in Figure 2.4-1.

36. The top and base Avalon seismic horizon interpretation in time and depth (ASCII format) should be provided.

Hebron Response #36

Given our definition of the Avalon Fm (top=base BenNevis, Base=base Amarker), these seismic horizons have already been provided in our previous submission to C-NLOPB in July, 2010.

37. The fault interpretation at the Jeanne d'Arc level in time and depth (ASCII and Petrel Format) should be provided.

Hebron Response #37

JdA fault polygon file provided as a Part II document.

38. On page 2-76, Fig. 2.4-3 the green and red lines on the map should be defined in the caption.

Hebron Response #38

(now Figure 2.4-2) The following text was added as a note in the caption:
Bold green and red lines represent fluid contacts (red=gas-oil, green=oil-water).

39. Section 2.4.3.7.3 – there appears to be an inconsistent use of the acronym "low water large tide" (LLWLT). Later in the text, reference is made to LLWT. Is this the same reference?

Hebron Response #39

The following correction has been made to the text:
Water depth at the proposed GBS location is 92.5 m LLWLT.

40. It appears that the caption for Figure 2.4-23 does not accurately depict what is in the figure. Please clarify.

Hebron Response #40

Figure 2.4-23 is now Figure 2.4-22
Revised caption:
Seismic SW-NE traverse through the Hebron I-13, West Ben Nevis B-75, Ben Nevis L-55 and Ben Nevis I-45 wells. *Caption Note: Figure illustrates shallow amplitude anomaly at approximately 850 ms at H3 horizon. Line of section is shown in Figure 2.4-23.*

Figure 2.4-24 is now Figure 2.4-23
Figure replaced with updated text, symbols and line of section to figure. Revised caption:
Relative Amplitude on H3 Horizon. *Caption Note: This figure illustrates line of section shown in Figure 2.4-22*

41. Page 2-84, Fig. 2.4-14: Provide a gas-down-to contact for the Ben Nevis Block on this map.

Hebron Response #41

Figure 2.4-14 is a depth structure map of the top of the upper Hibernia. This zone tested water as deep as - 4169 ssTVD.

42. Net pay isopach maps for Pools 1, 4H, 4B and 3 should be provided.

Hebron Response #42

Added in Section 2.5:
Figure 2.5-3: Pool 1 & 2 Isopach of Net Pay Map
Figure 2.5-7: Pool 5 Isopach of Net Pay Map
Figure 2.5-11: Pool 4 H-Sand Isopach of Net Pay Map
Figure 2.5-15: Pool 4 B Sand Isopach of Net Pay Map
Figure 2.5-19: Pool 3 Isopach of Net Pay Map

43. A net pay isoporosity map for Pool 4H is required.

Hebron Response #43

Added Isoporosity map (Figure 2.5-10).

44. Page 2-104, Fig. 2.5-6 and page 2-108, Fig. 2.5-11: Both maps have a legend labeled "Thickness", when it should be "% porosity".

Hebron Response #44a

Figures updated. Figure 2.5-11 now Figure 2.5-14

A hydrocarbon pore volume map of Pool 5 should be provided.

Hebron Response #44b

Added in Section 2.5.
Figure 2.5-8: Pool 5 Hydrocarbon Pore Volume Map

45. Copies of all maps are to be submitted to the Board in digital form (ASCII format or high resolution format) so that they can be reviewed in detail. Color scale for some isochore and HCPV maps is insufficient - for example Figure 2.5-14 has no color variation.

Hebron Response #45

Information requested provided as Part II document.

46. Tables in the Hebron Development Plan are required in a digital format other than jpeg to facilitate analysis by Board staff. MS Excel format would be acceptable.

Hebron Response #46

Information requested provided as Part II document.

47. a. The workflow for Pools 1, 2 and 3 geological models need to be described in more detail similar to the GOCAD Earth Model reports for Pools 4 and 5 that are in the Part II document. The workflow reports for Pools 1, 2 and 3 should address the following points:

- Discussion on base, low and high cases, including a detailed explanation of the methodology, parameters, and statistical populations.
- Discussion on the five rock types, including how they relate to the six lithofacies, 4 petrofacies and 6 EODs defined in Section 2.2.2.1.2
- EOD maps should be included for each zone.
- Discussion on the porosity trends for each rock type and how they were estimated.
- What is the perm/porosity transform? How was permeability modeled? (e.g. what is the algorithim? Is it the same for both fault blocks? Was the permeability co-kriged with the porosity or was it calculated using a porosity model?)
- How are the contacts captured in the model—are they transitional or distinct?

Hebron Response #47a

The applicant is preparing a summary document describing Common Scale model construction. Summary will be available August 2011.

<u>**Reservoir Engineering**</u>

47. b. Fluid Analysis for Pool 2 in the West Ben Nevis should be provided and discussed.

Hebron Response #47b

Fluids Analysis, saturation functions and SCAL work were provided and discussed as inputs into reservoir simulation studies for the Pools targeted in the initial development phase of the project (Pools 1, 3, 4 & 5 - please refer to Sections 5.1 and 6.2). Pool 2 is not included in the initial development phase and the potential development of this resource is discussed in Section 6.8.2.3 under Contingent Developments. As such, the required simulation studies inputs (fluids analysis, saturation functions and SCAL work) for Pool 2 have not been generated. This will be done as part of a reservoir study prior to making a final development decision for Pool 2. Per the concluding paragraph of Section 6.8.1, "..a revised depletion scheme (including details of any associated studies conducted) will be communicated to and discussed with the C-NLOPB."

48. Reference to the injectivity studies that are presented in the Part II document: Hebron Water Injection Study should be provided. Also, a copy should be provided of the study mentioned in the Part II document Meng et al. "Feasibility Evaluation of Sea Water Injection on Hebron" Nov 2002.

Hebron Response #48

Information requested provided as Part II documents.

49. Saturation functions and SCAL work for Pool 2 in the West Ben Nevis should be provided and discussed.

Hebron Response #49

See comments provided for 47b above.

<u>Reserve Estimates</u>

50. Economic justification for the 30 year field life presented in the production forecasts should be provided.

Hebron Response #50

The 30-year field life is based on the nominal 30-year design life of the Topsides facilities (See response to Comment #9 – see below).

30-year field life was selected for the production forecasts to portray a reasonable expected field life to represent expected production and operations. The actual end of field life will be determined in the future when either the facility life is reached or the economic limit is reached. The facility design basis is 30 years for the topsides and 50 years for the GBS but the final facility life will be dependent on actual conditions of service over the field life. The economic limit will occur when the revenue from the produced fluids falls below the cost of operations of the field and will be impacted by oil price, production rates, operating costs, taxes and royalty rates. The end of field life will trigger abandonment and decommissioning of the field, which will be done in accordance with applicable regulatory requirements.

51. In-place estimates have only been provided for oil. In-place gas estimates distinguishing between solution gas, gas-cap gas and non-associated gas for each of the pools is also to be provided.

Hebron Response #51

In-place gas volumes have been added to the associated tables in Section 5.

52. Oil reserve estimates have been presented. Gas and NGL resource estimates are also to be provided for each pool.

Hebron Response #52

Gas resource estimates will be provided as part of the response to Comment #51. Gas reserves are not applicable, as the initial phase of the development does not currently include gas sales.

53. The information that was used in Excel and @risk software should be provided for each pool. Sensitivity value ranges for each of the parameters that impact the reserve estimates should also be provided.

Hebron Response #53

Information requested provided as a Part II document. However, we do not have values for the Chevron prepared models (Pool 3, 4 and 5).

54. The reserves estimates for each alternative production scenario should be provided.

Hebron Response #54

This information is not readily available as the GBS development option was selected nearly ten years ago. However in selecting a final development concept there were many factors that were considered including reserves, field life, economics, execution certainty and local content. The GBS option was determined to be the best development concept when all of these factors were taken into consideration.

Reservoir Exploitation

55. The base case list of drilling well sequence together with the rationale should be provided. This information should be supplemented with a map showing the well location in each block or pool to illustrate the proposed drilling sequence.

Hebron Response #55

Information requested provided as Part II document.

56. The Prosper inputs/results for different tubing sizes to understand the sensitivities of sizes and well inflow is required.

Hebron Response #56

Information requested provided as Part II document.

57. A description of future well workovers in terms of type of completions and a base case estimate of their frequency should be provided.

Hebron Response #57

It is anticipated that both rig based and non-rig based workovers will be employed for the Hebron Project.

Rig workover frequency is based on the anticipated reliability of the proposed completion techniques, and/or the need to alter the producing configuration to improve resource recovery. While full details of these workovers have yet to be developed, they may include workovers to alter the tubing design, or install isolation assemblies to modify the producing profile. Workovers to sidetrack existing wellbores are anticipated to utilize slots for increased recovery opportunities when possible.

Non-rig workovers are anticipated to be more frequent in nature than rig based workovers, but with reduced scope. Gas lift valve modifications, setting of isolation systems, retrieval of isolation systems, and re-perforating are all examples of techniques that may be utilized. Frequency of operations will be dependant upon many factors. Reservoir response, wellbore reliability, and inflow performance relationships will all influence the timing and quantity of operations required. However, operations will be conducted in a timely manner to maintain wellbore integrity and maximize recovery of the Hebron asset.

58. The reservoir simulation results of the impact of production rate(s) on ultimate oil recovery are required for each pool.

Hebron Response #58

Information requested provided as Part II document.

59. Section 6.5.2: Pool 3 Base Case Depletion Plan discusses the three approaches being considered for development. The applicant has mentioned it is currently being studied. The timing of completion of this study should be discussed.

Hebron Response #59

The preliminary study of Pool 3 development options is based upon the geologic and reservoir studies included in the Development Plan. Additional studies to further define the Pool 3 design basis including cost and schedule estimates are anticipated to be complete in 2012.

60. The timing and approximate location for an appraisal well to initiate the development approach for Pool 3 should be provided.

Hebron Response #60

Per Section 6.5.2 of the Development Plan, the appraisal well option is one of three options being considered for the development of the Pool 3 resource. The Hebron Project has not yet made a decision to pursue the appraisal well option for Pool 3. If this becomes the preferred development approach, the timing and location of the appraisal well will be communicated to the C-NLOPB.

61. Production forecasts for oil, gas and water for each of the pools should be provided in MS Excel format.

Hebron Response #61

Information requested provided as Part II document.

62. The oil, gas and water production forecast for each well for each of the pools should also be provided in MS Excel format.

Hebron Response #62

Information requested provided as Part II document.

63. "Gcf" is referenced in section 6.8.2.6. Please define.

Hebron Response #63

Gcf – billion cubic feet (of gas) – updated document with definition.

64. Figures of reservoir simulation models (such as Figure 6.2-1) need to include reference points such as north direction, well locations and layer depth.

Hebron Response #64

Figures 6.2-1, 6.3-1, 6.4-1, 6.4-2 & 6.5-1 of Part I updated.

65. Additional figures of reservoir simulation model base case results for each of the Pools should be provided, such as cross sections north-to-south or east-to-west, top of reservoir unit and bottom of reservoir unit. As well, time sequence snapshots of base case should be presented at time t=0, t= 5 years, t= 10 years and t =30 years to understand sweep efficiency.

Hebron Response #65

This request is related to the technical assessment of the depletion plans proposed and is better handled during technical review phase of the submission. It is not a requirement for document completeness.

66. Maps showing the most likely areas for each of the discovered resources and potential prospects listed in the report are required.

Hebron Response #66

An assessment on the discovered resources described in Section 6.8 (Contingent Developments) has not been performed. The Operator is preparing maps similar to those shown on pages 2-17 to 2-21 (Figures 2.2-1 through 2.2-5) which depict prospective areas based on available data. Maps will be available in August 2011.

Drilling and Completion

67. The applicant states that 41 wells are necessary to fully exploit the resource for the main reservoir. A three dimensional map of the well locations shown in Figure 7.1-1a and Figure 7.2-1 should be provided.

Hebron Response #67

A three dimensional map of all wellbores is in development as part of the work plan but not currently available. Once such work has been completed, it can be forwarded as requested.

68. Section 7.1.6.2 discusses multi-function well bores; please provide more information on the types and use of these well bores in the context of the Hebron project.

Hebron Response #68

There are currently three types of multi-functional wellbores envisioned for Hebron, as referenced in sections 7.1.6.1 and section 7.1.6.2.

The first involves water injectors that are capable of supporting gas injection. This provides a redundant injection mechanism in the event primary gas injectors are unavailable. These wellbores will be designed to ensure both operating envelopes (gas injection and water injection) are supported by the final design.

The second type of multi-functional wellbore involves gas injectors that are capable of gas production. This provides the facility the ability to produce gas back from the injection zone when facility gas requirements exceed gas available from production.

The third type of multi-functional wellbore involves water injection wellbores that are capable of supporting annular cuttings re-injection. These wellbores would have non-aqueous drilling material (fluids and cuttings) injected into an approved disposal zone via the annulus of the wellbore. Water would be injected into the producing reservoir via the tubing.

69. The Development Plan references non-aqueous based drilling fluids. The type of drilling fluids being considered should be provided.

Hebron Response #69

There are currently two types of drilling fluids anticipated for Hebron; water based fluids and non-aqueous fluids. While formulations are still under development, water based fluids utilize fresh water or seawater as a base fluid, depending on hole section and interval exposed. Non-aqueous fluids would utilize industry standard fluids such as Petro Canada PureDrill IA35LV, a synthetic isoalkane commonly used in drilling mud and in current use in Eastern Canada.

Development and Operating Cost Data

70. Any quantitative economic assessments performed in respect of the alternatives described in Table 1.8-1 should be provided.

Hebron Response #70

The information is not readily available as the GBS development option was selected nearly ten years ago. However in selecting a final development concept there were many factors that were considered including reserves, field life, economics, execution certainty and local content. The GBS option was determined to be the best development concept when all of these factors were taken into consideration.

Table of Contents

List of Tables

List of Figures

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 km^2 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.

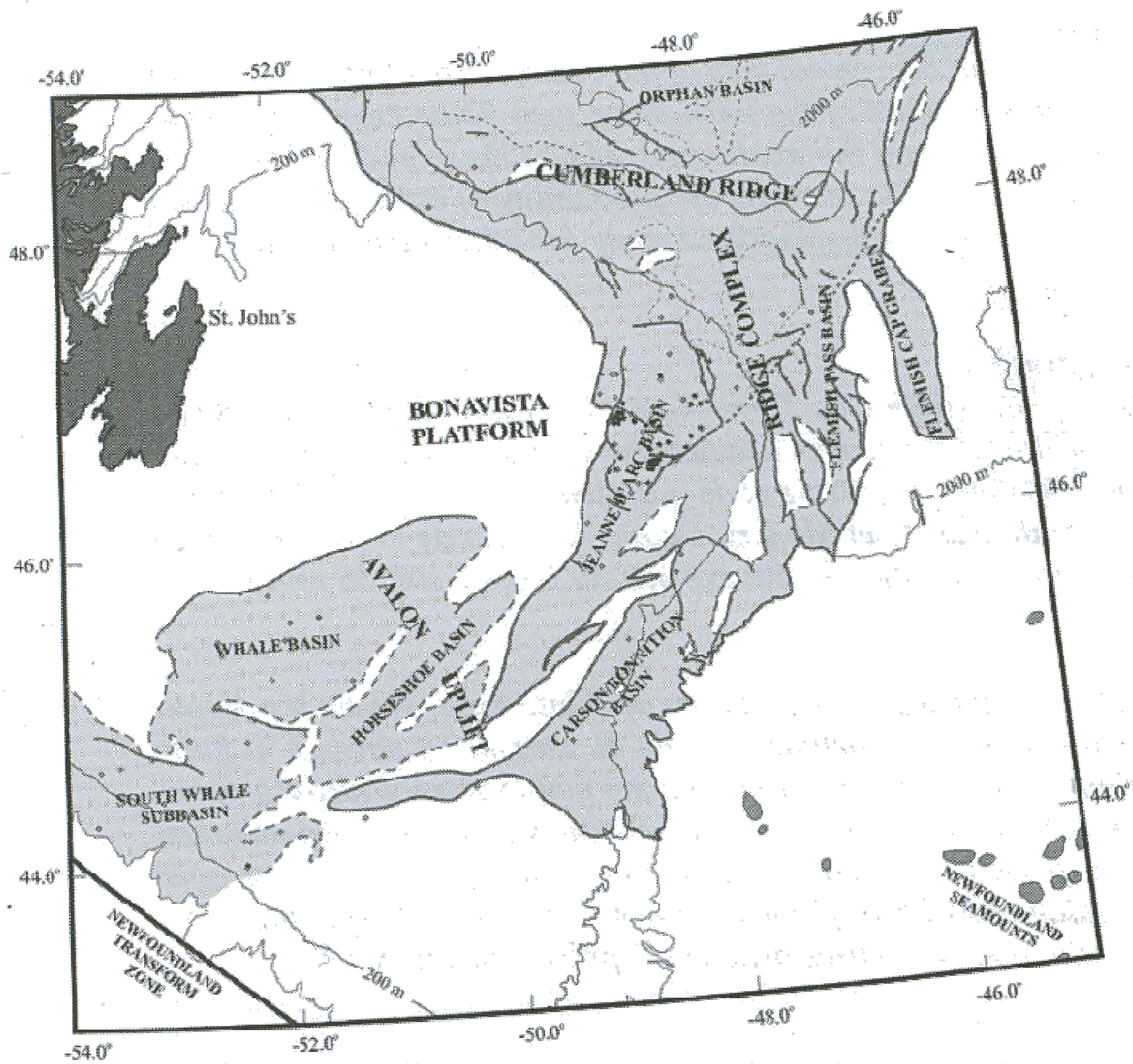


Figure 2.1-1: Mesozoic Basins on the Grand Banks of Newfoundland
(Modified from Hiscott and Pulham, 2005)

Jeanne d'Arc Basin
Generalized Tectonic Elements map

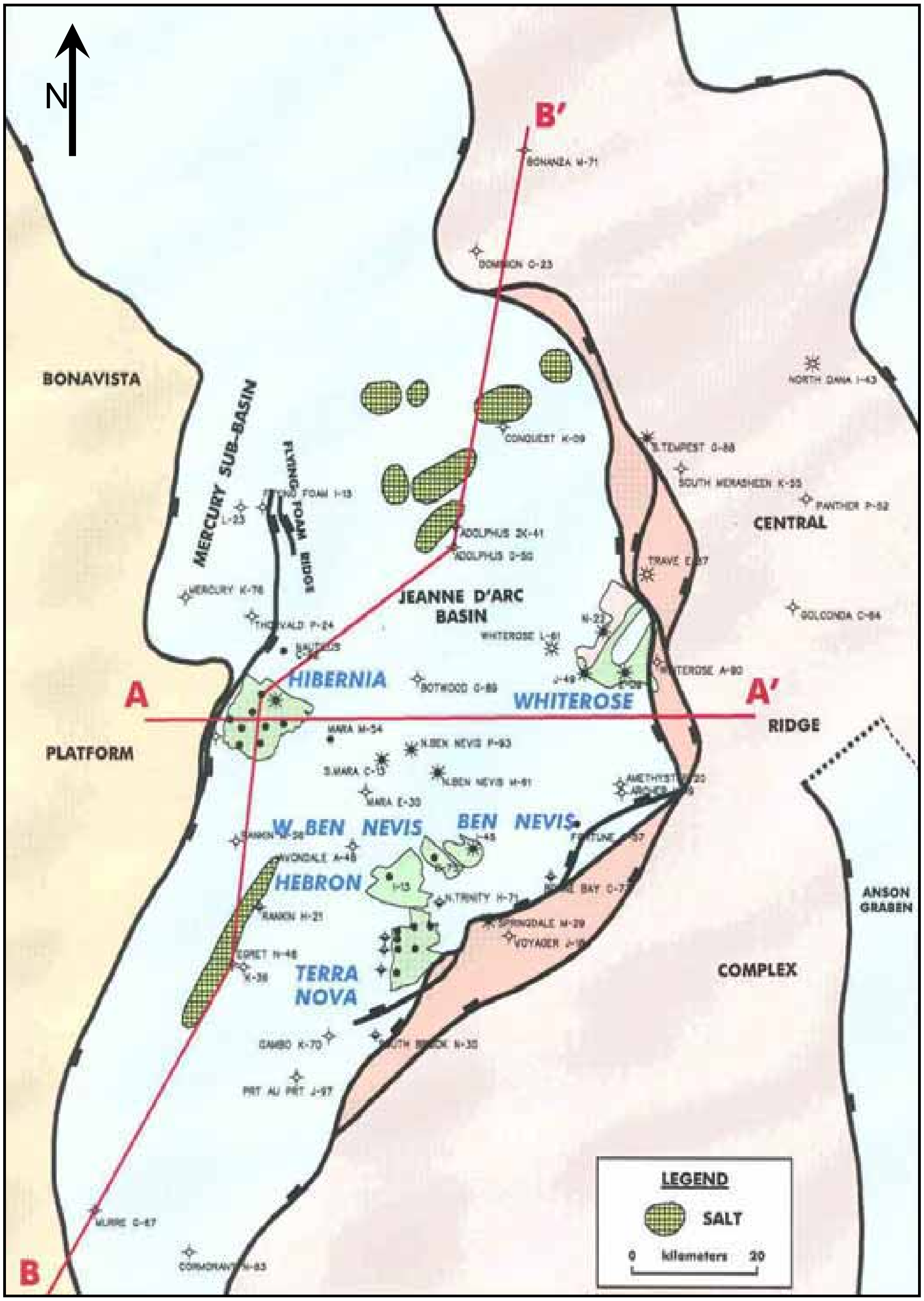


Figure 2.1-2: Main Tectonic Elements of the Jeanne d'Arc Basin
(Pink denotes basement involved fault blocks)

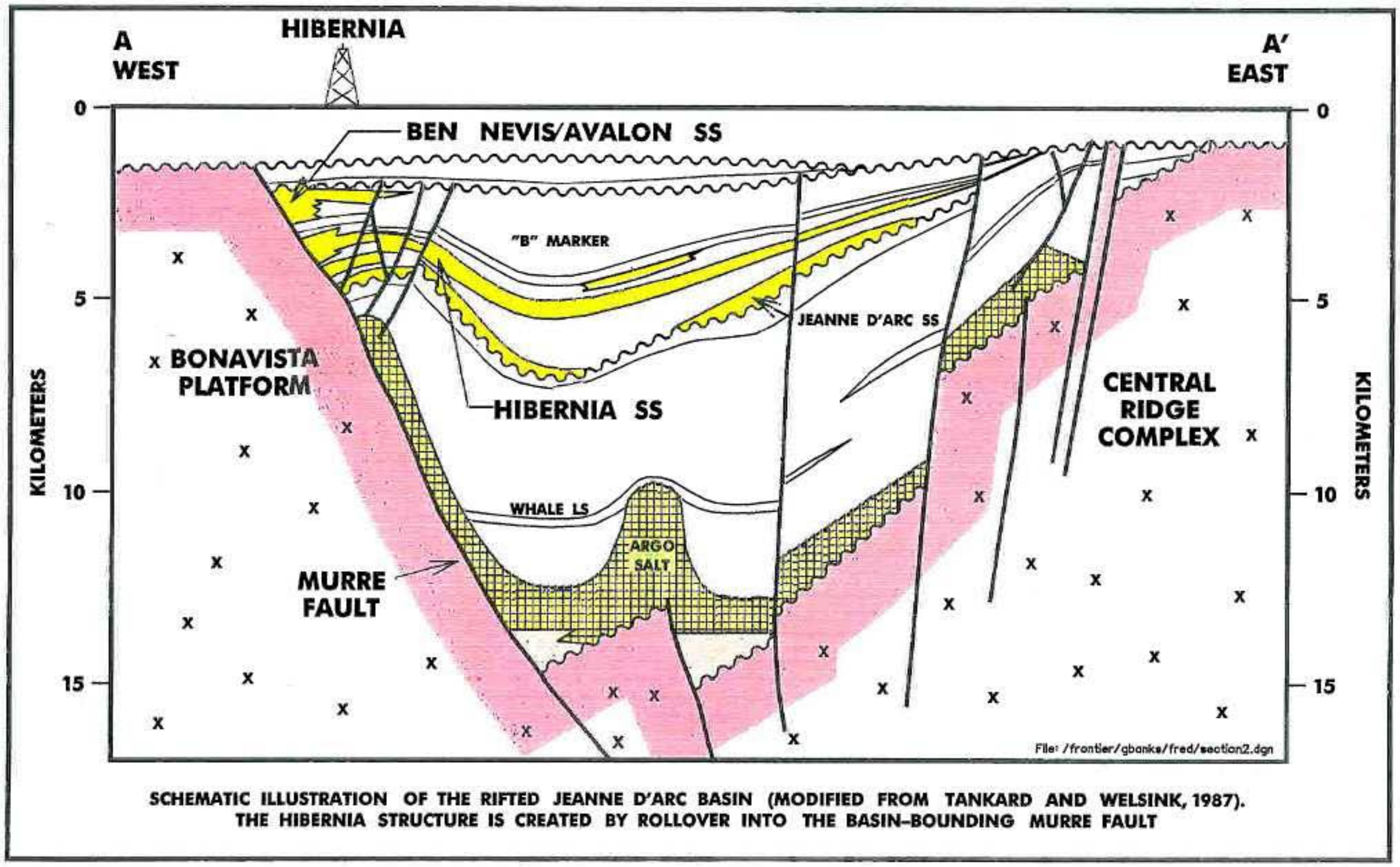
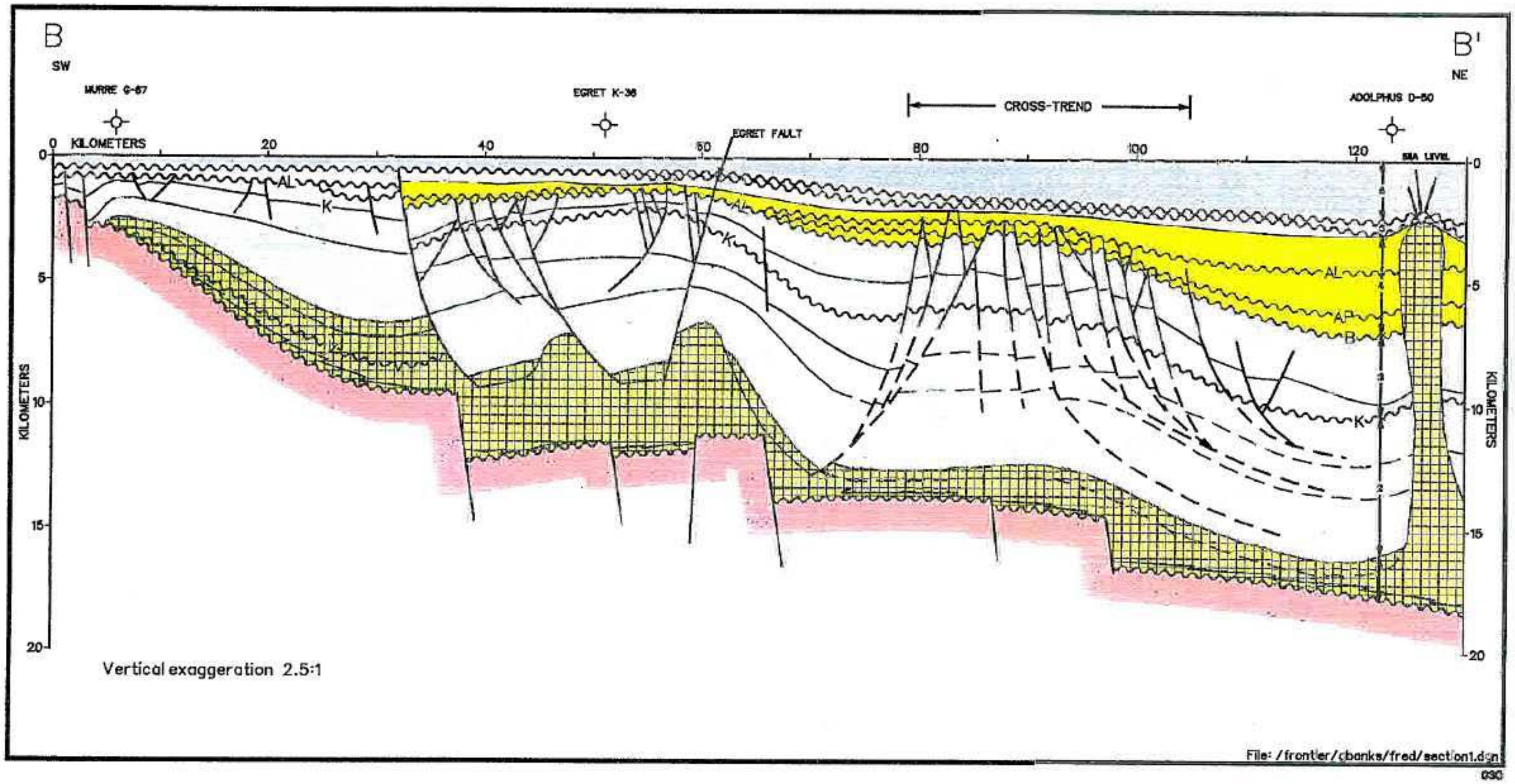


Figure 2.1-3: Cross-Section from A to A'
(Cross section is approximately 100 km long.
Sandstone is coloured yellow, salt is coloured hashed green, basement is coloured pink.)

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 DIVEDED 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.

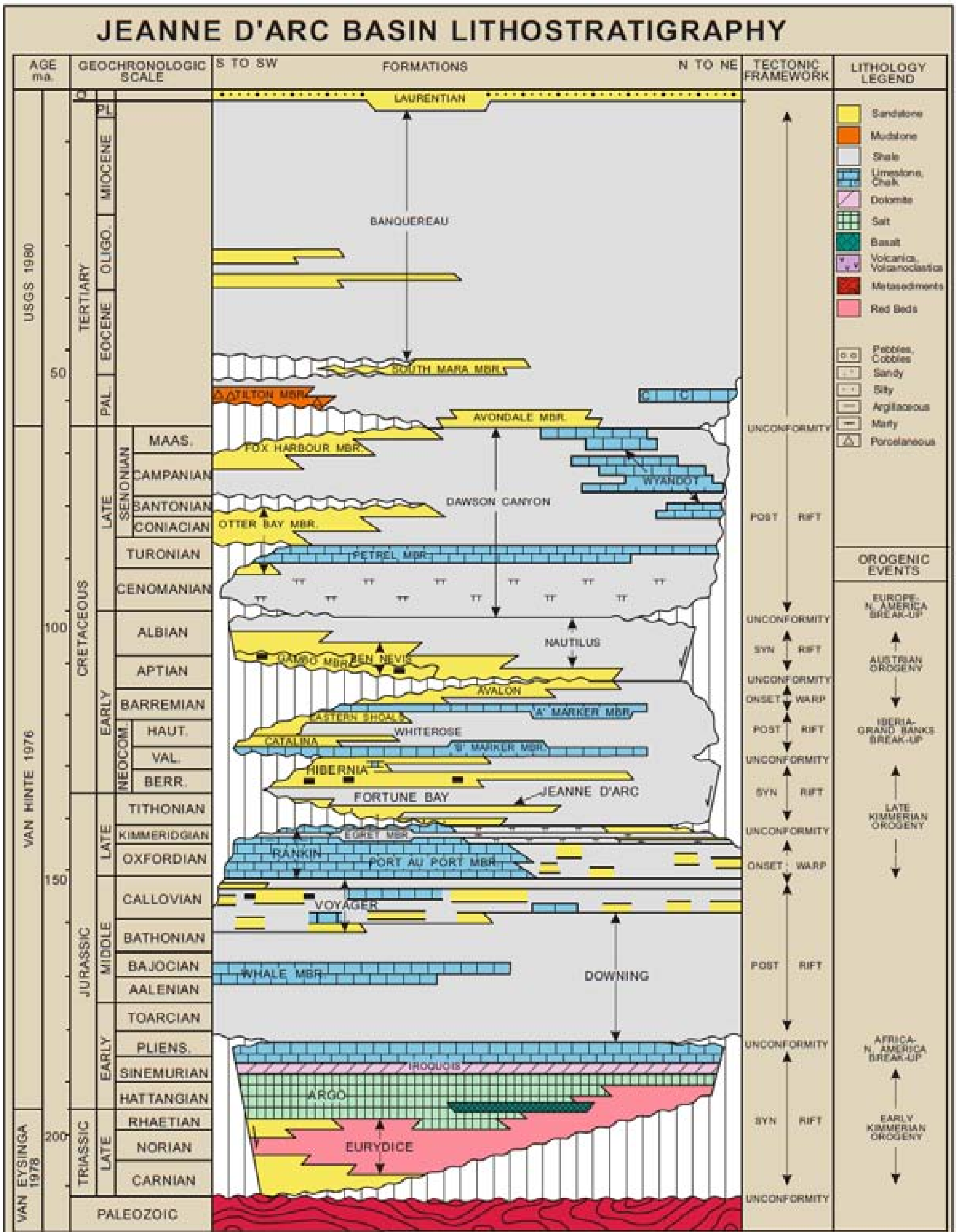
The (Berriasian to Valanginian) Hibernia Formation unconformably overlies the Fortune Bay shales in the Hebron Field. The Hibernia Formation throughout much of the Hebron Asset is composed of shoreface successions with minor fluvial and marginal marine deposits, unlike the reservoirs at the Hibernia 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.



Modified after Sinclair, 1992

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 chalks, 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.

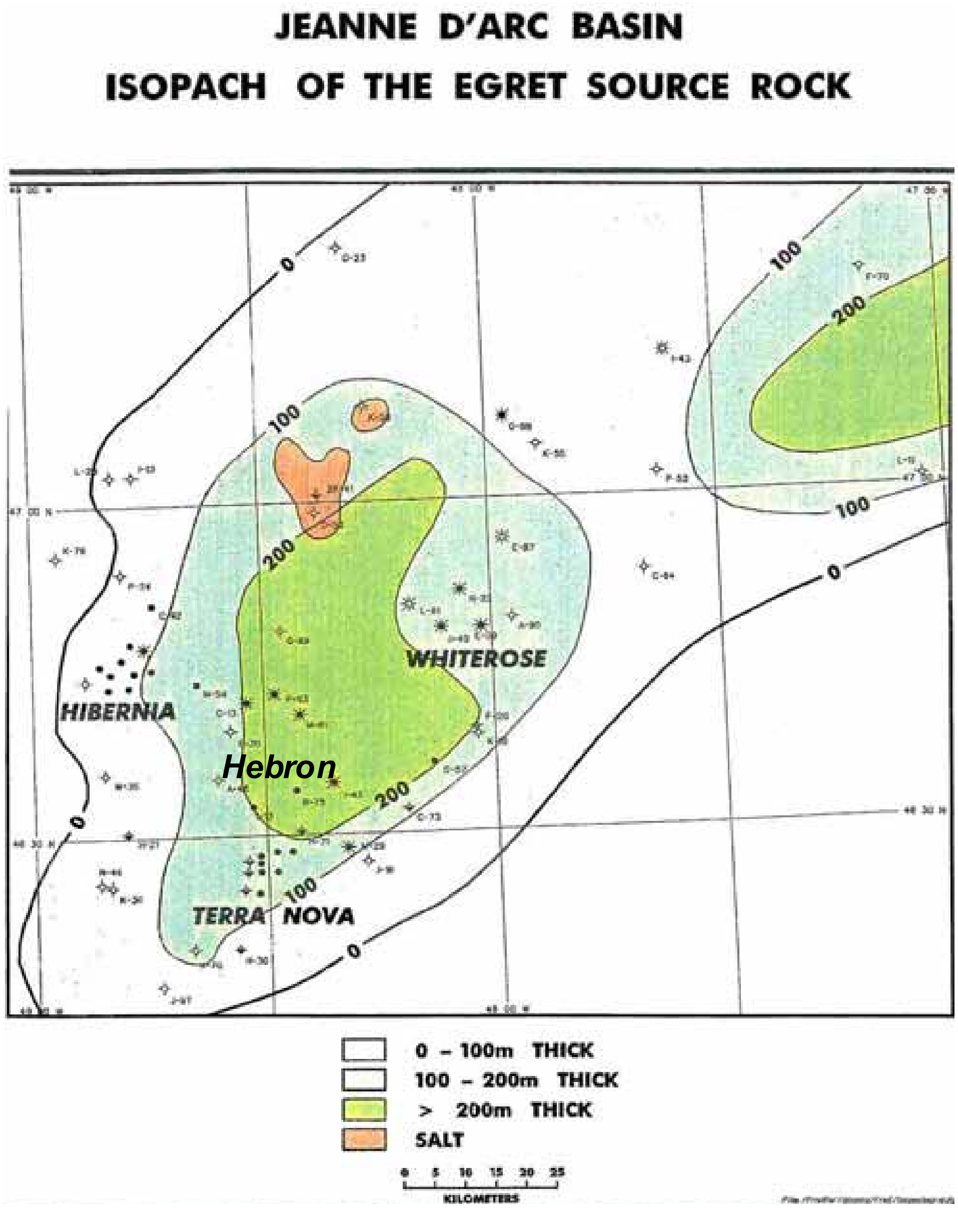


Figure 2.1-6: Isopach of the Egret Source Rock (Bowes, 1998)

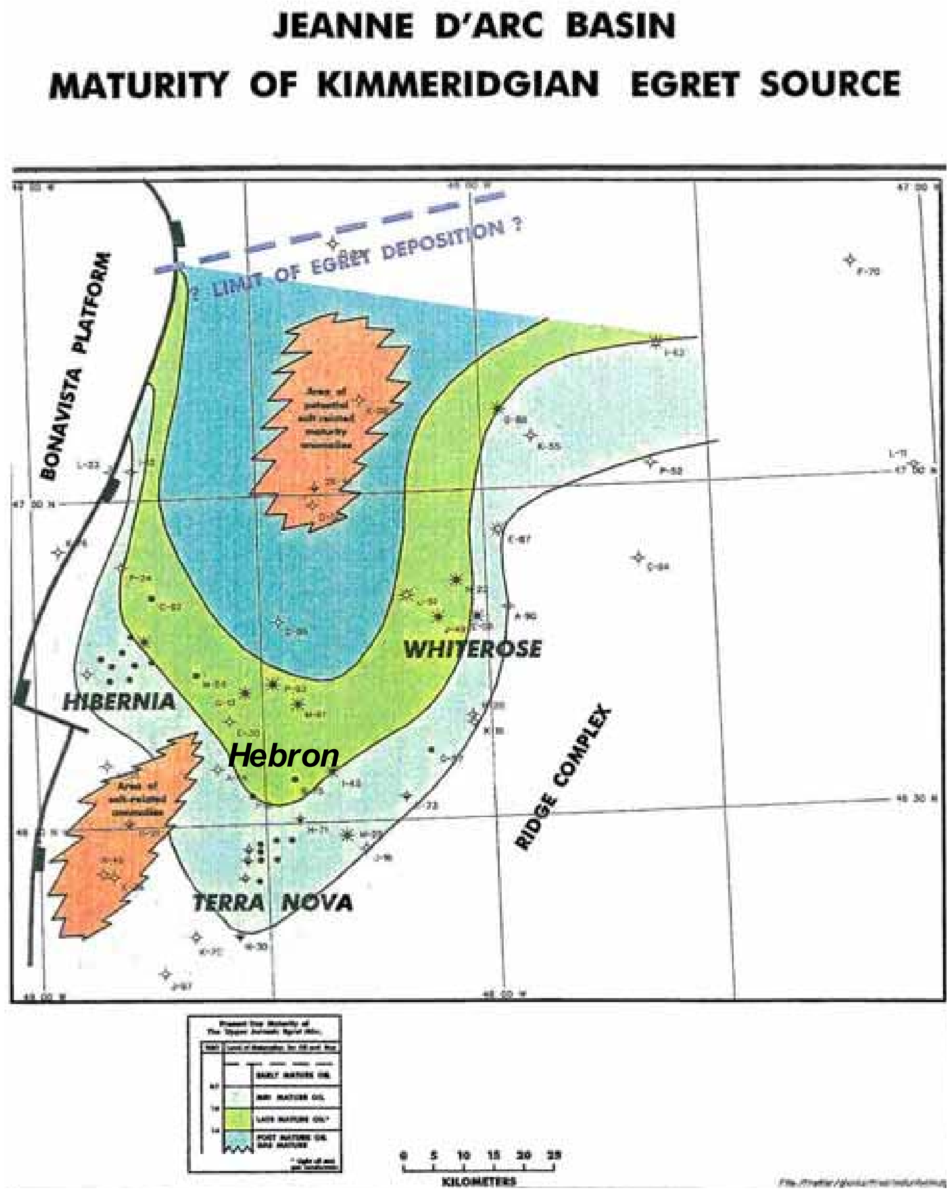


Figure 2.1-7: Maturity of Egret Source (Bowes, 1998)

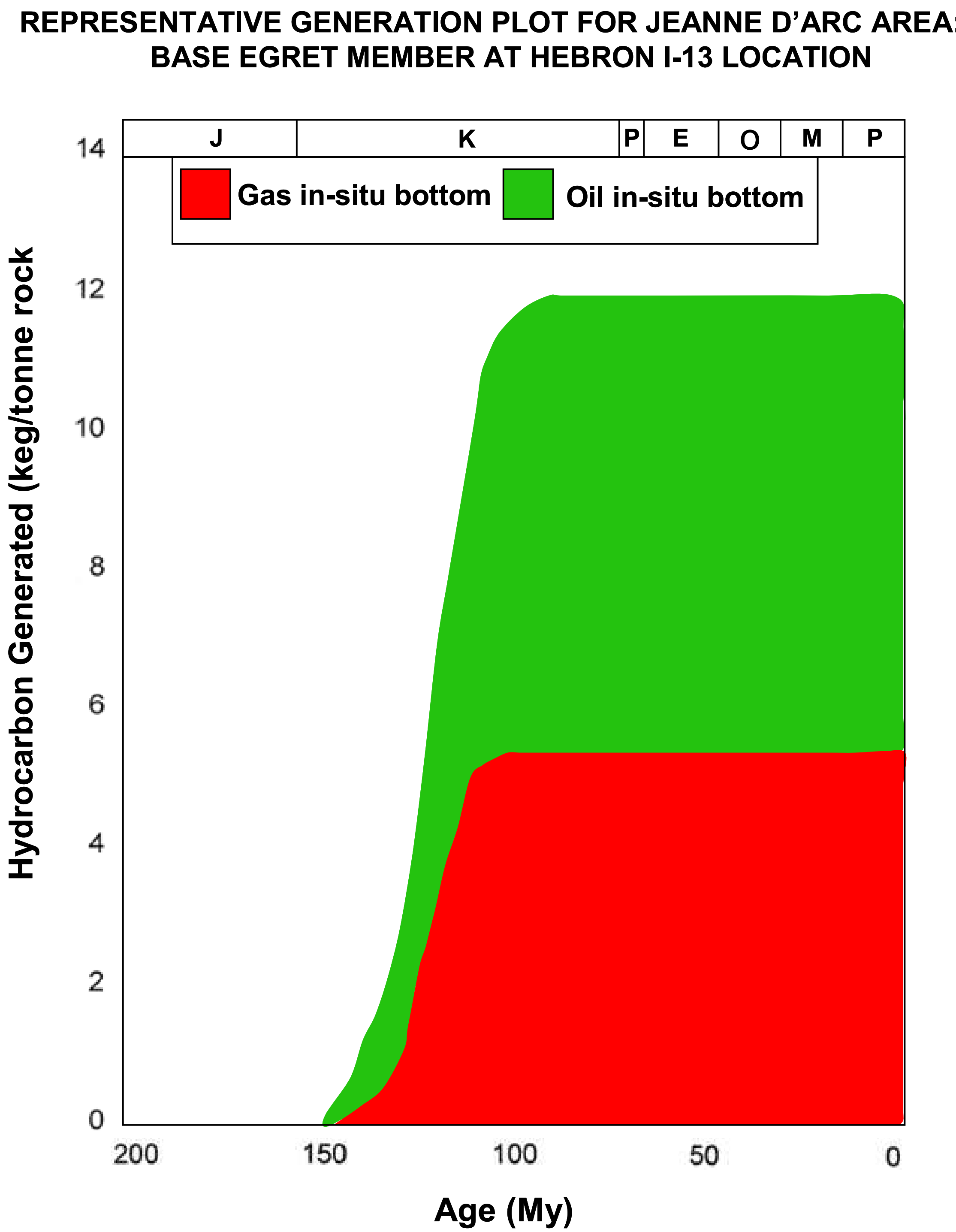


Figure 2.1-8: Hydrocarbon Generation Plot for Jeanne d'Arc (Bowes, 1998)

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.

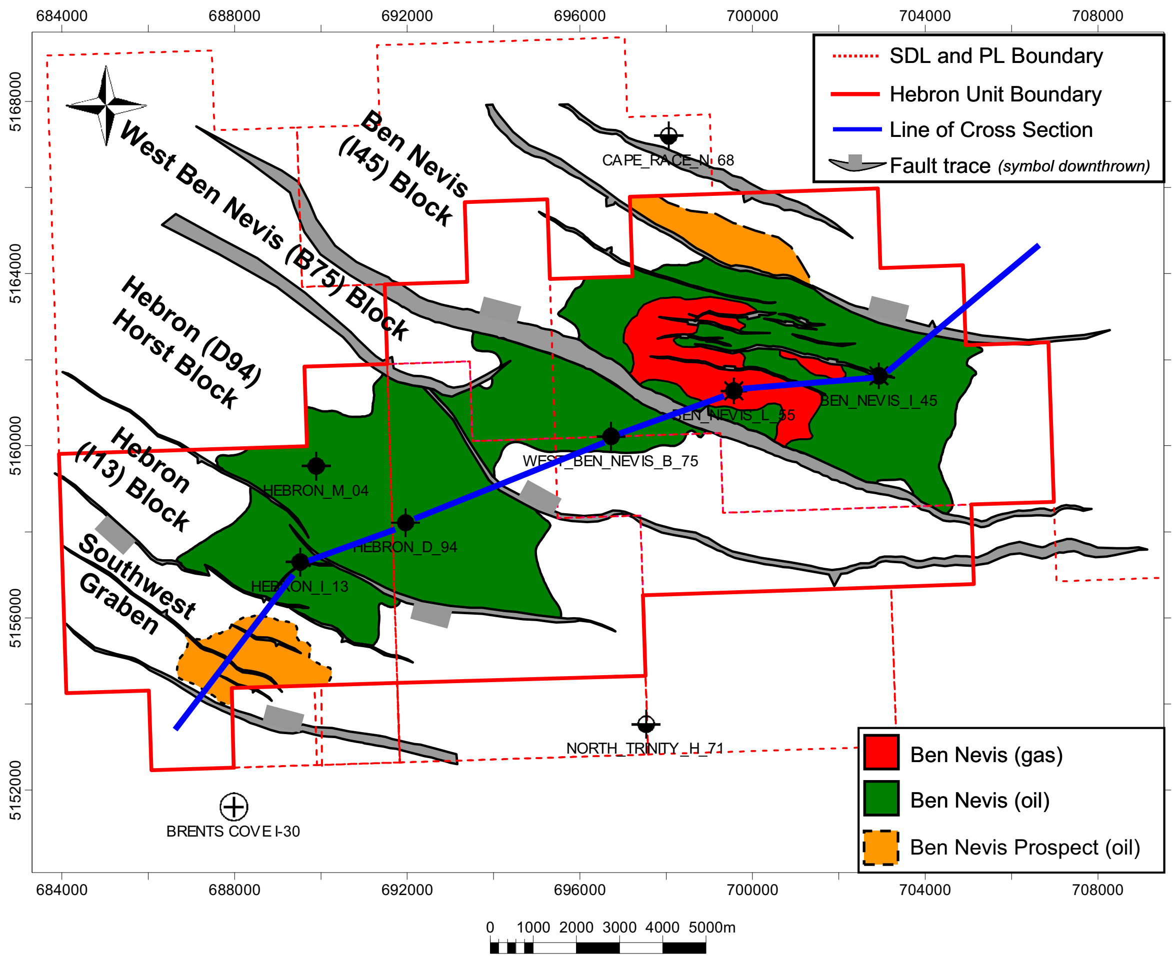


Figure 2.2-1: Schematic map of faults and trapped hydrocarbons in the Ben Nevis Formation at Hebron

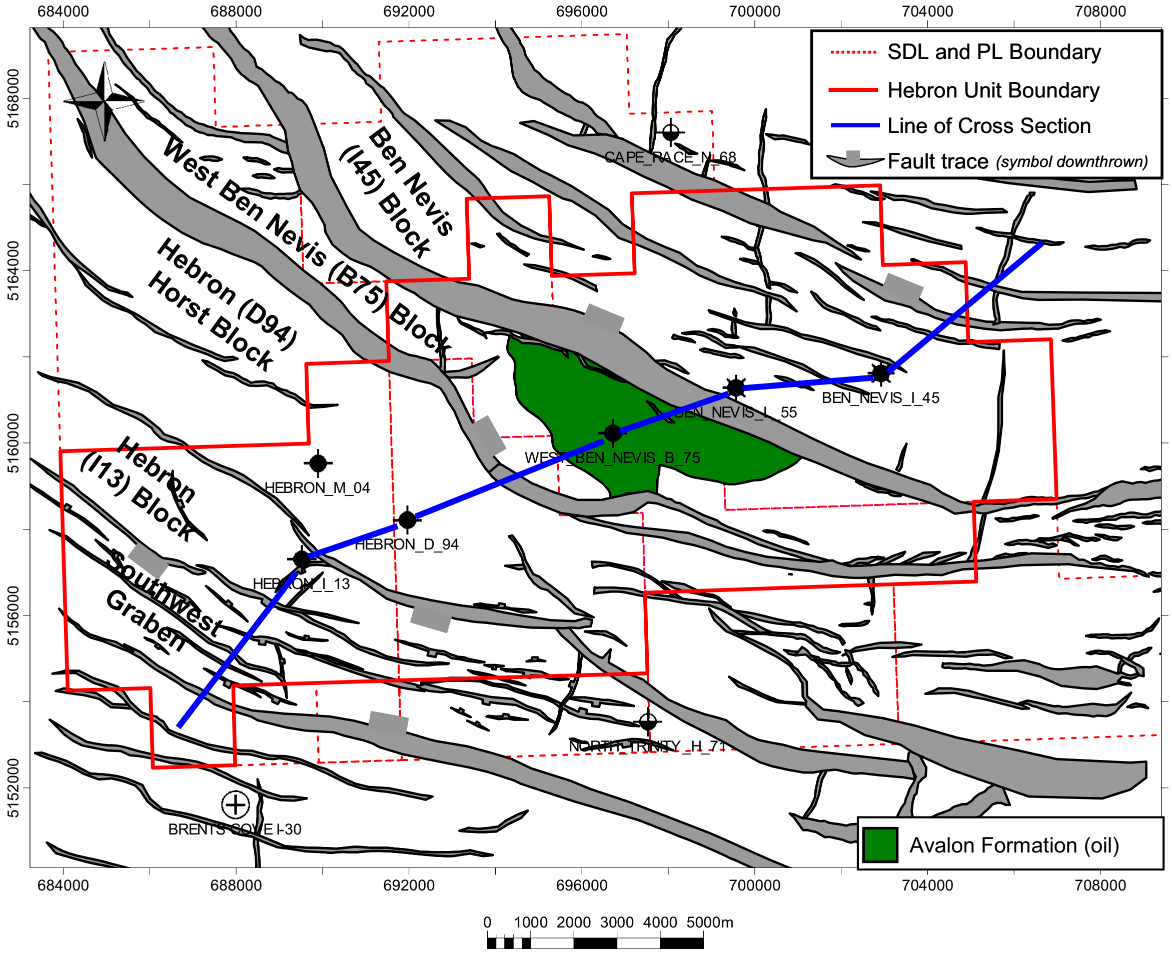


Figure 2.2-2: Schematic map of faults and trapped hydrocarbons in the Avalon Formation at Hebron

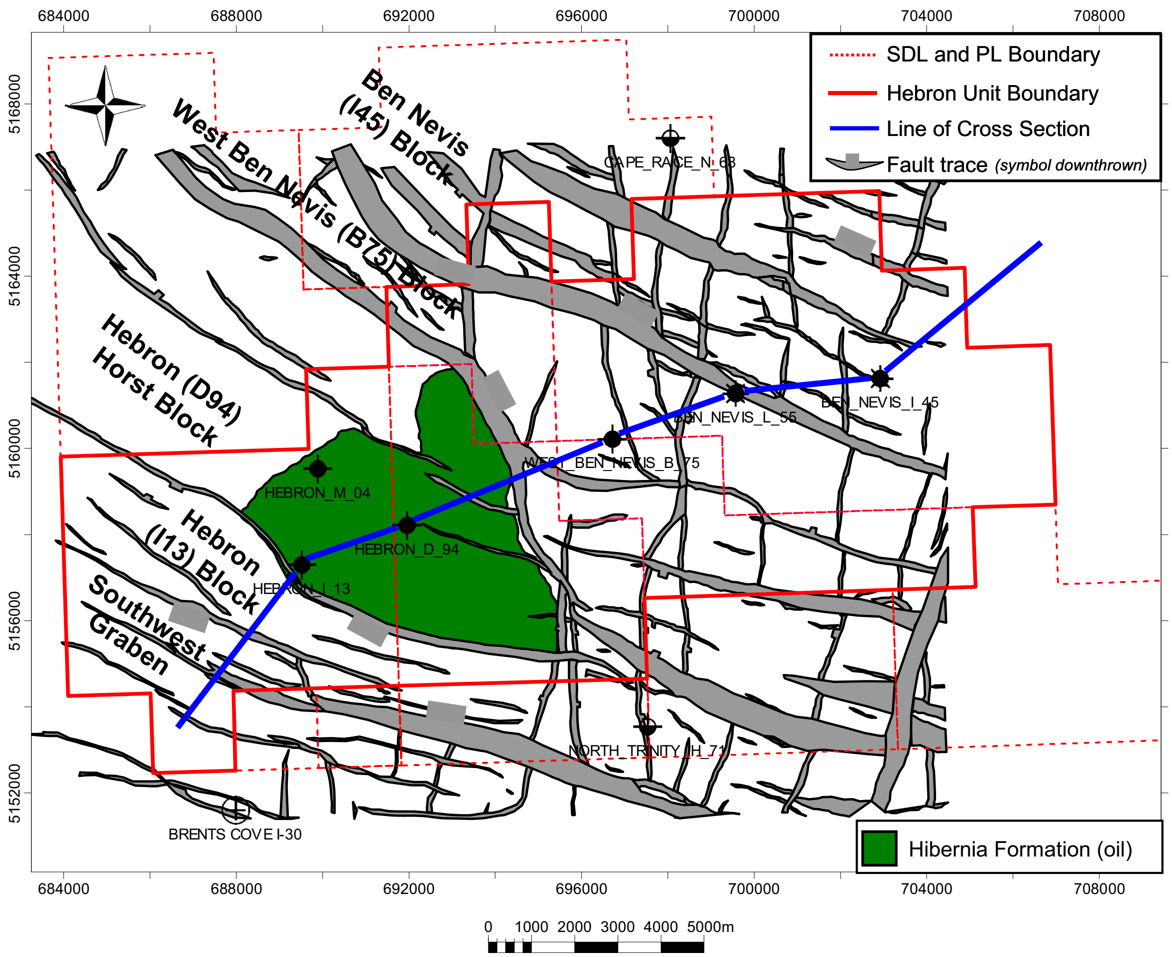


Figure 2.2-3: Schematic map of faults and trapped hydrocarbons in the Hibernia Formation at Hebron

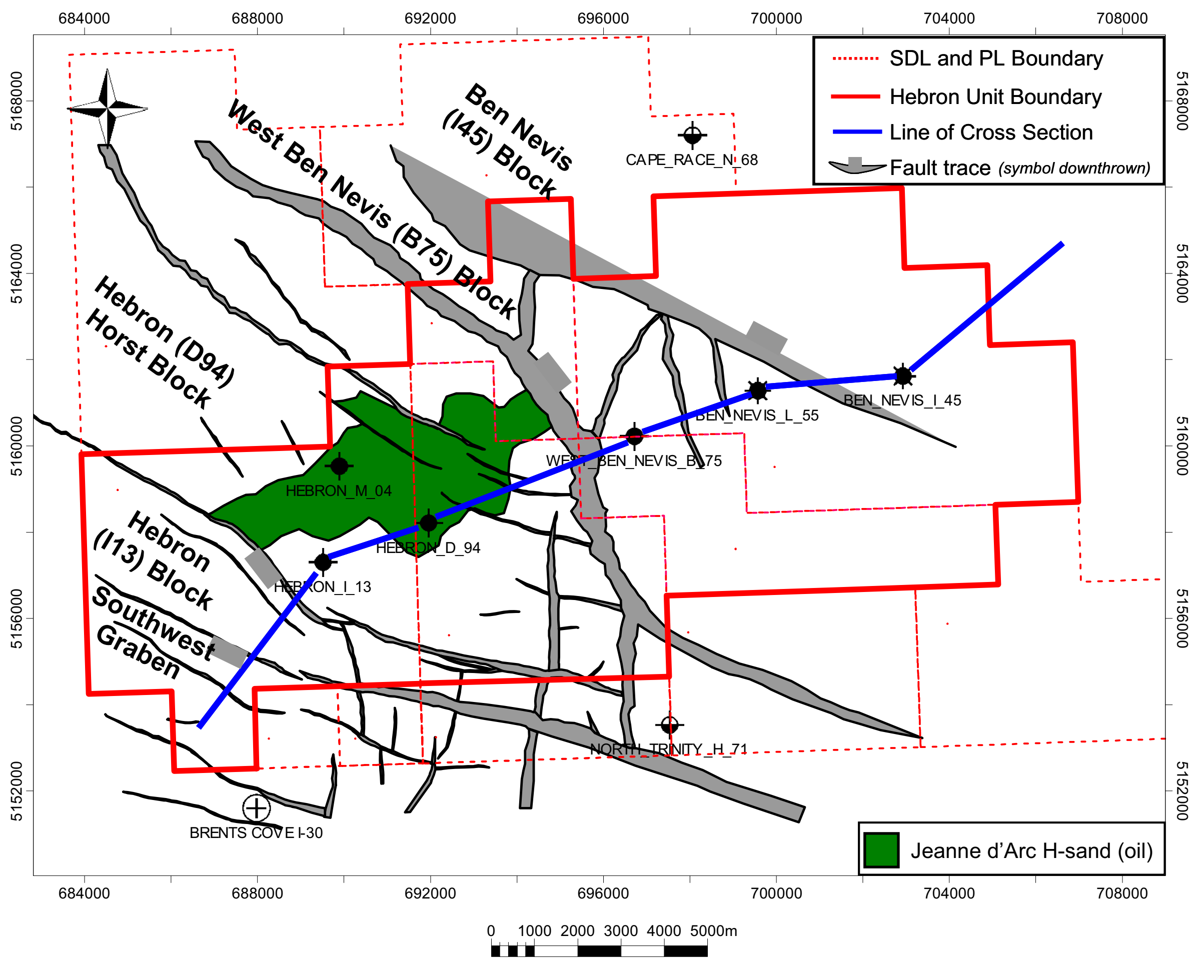


Figure 2.2-4: Schematic map of faults and trapped hydrocarbons in the Jeanne d'Arc Formation ("H" sand) at Hebron

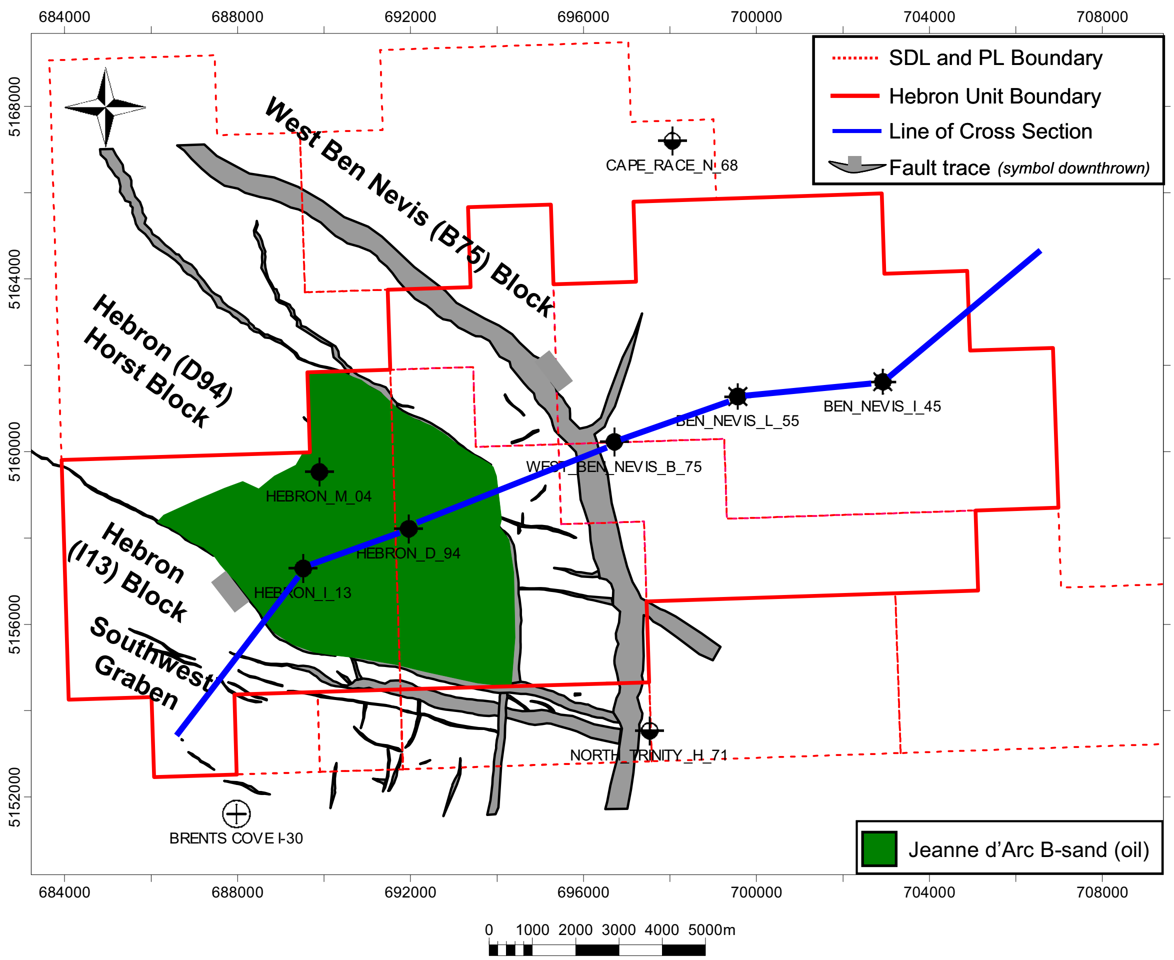


Figure 2.2-5: Schematic map of faults and trapped hydrocarbons in the Jeanne d'Arc Formation ("B" sand) at Hebron

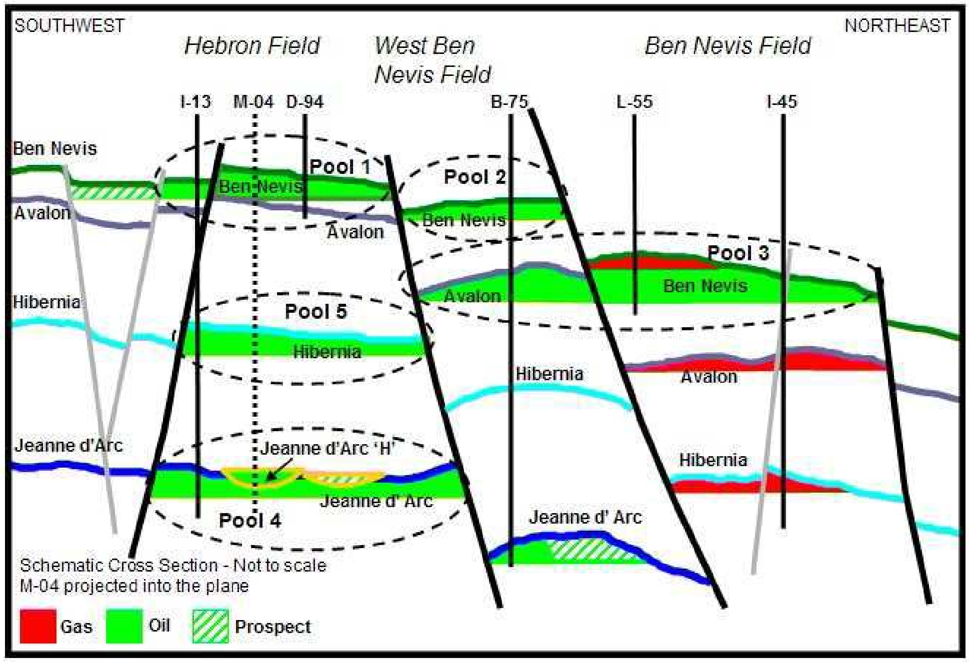


Figure 2.2-6: Schematic Cross-Section of the Hebron Asset

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.

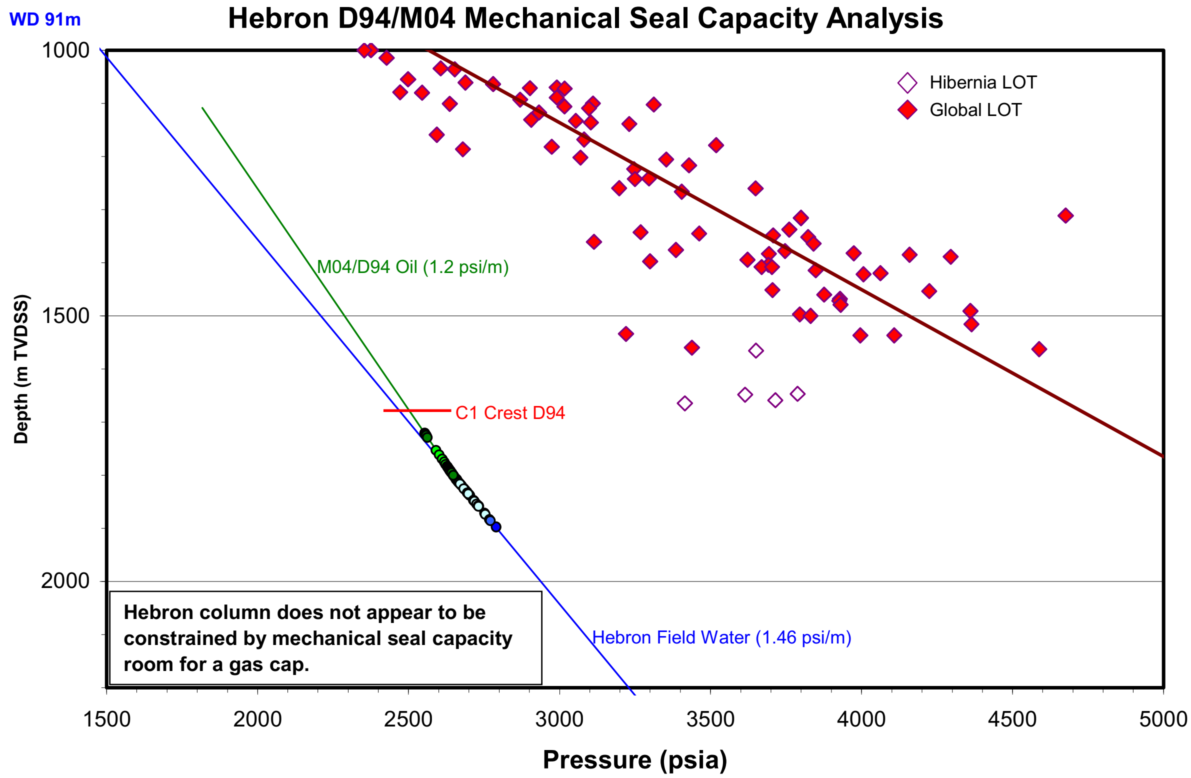


Figure 2.2-7: Mechanical Seal Capacity.
The Global Leak off trend comes from an ExxonMobil database of leakoff tests collected from around the world. The Hibernia Field LOTs are taken from the Hibernia Reservoir at Hibernia Field.

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.

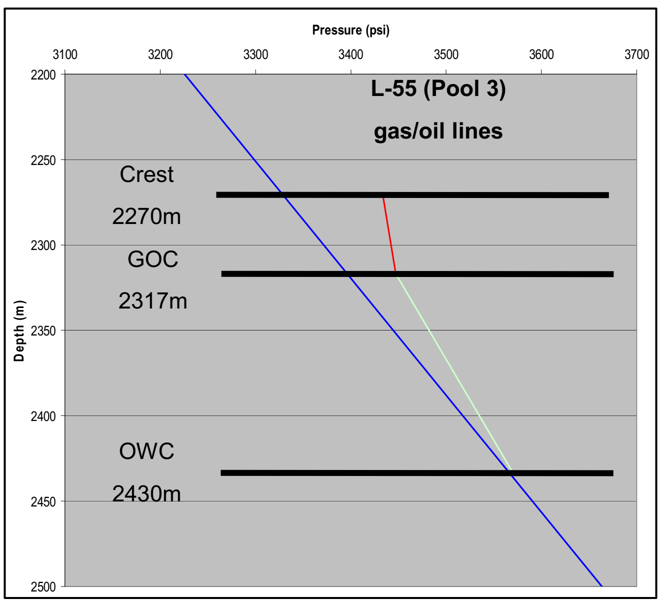


Figure 2.2-8: Pool 3 Capillary Seal

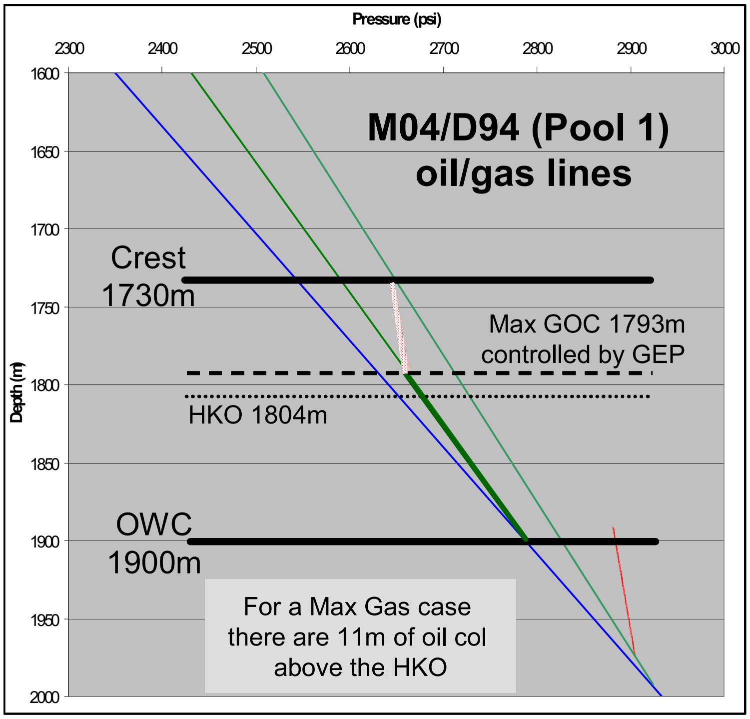


Figure 2.2-9: Pool 1 Capillary Seal

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

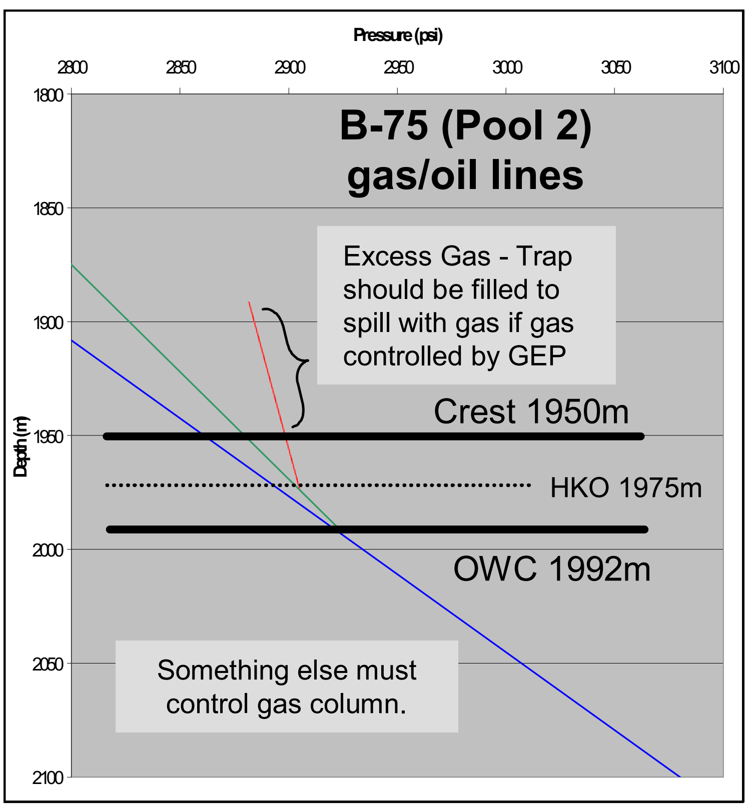


Figure 2.2-10: Pool 2 Capillary Seal

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.

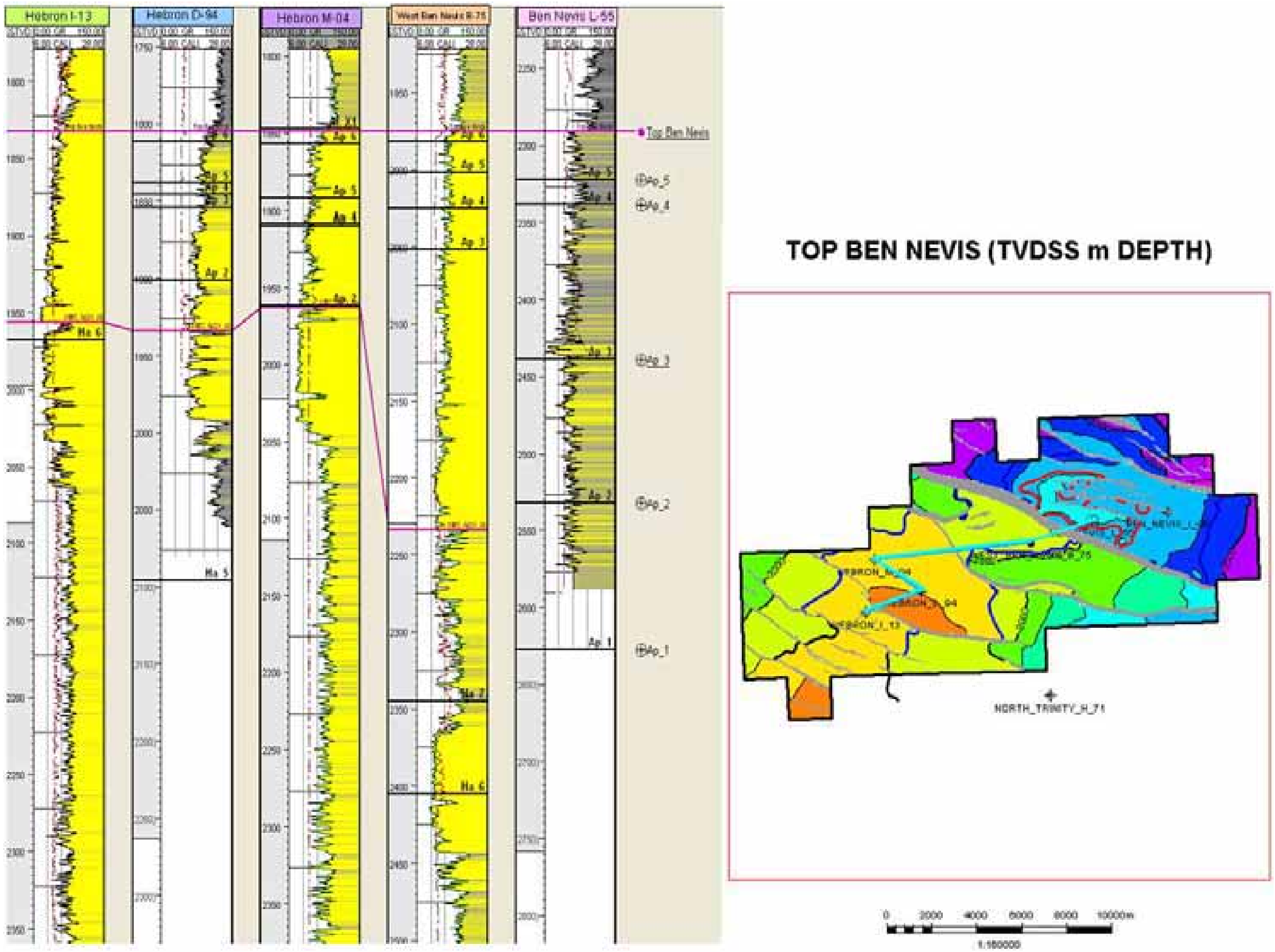


Figure 2.2-11: Ben Nevis – Avalon Biostratigraphy
Biostratigraphy markers posted on colour shaded gamma ray log. Datum is top of Ben Nevis

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 permeablilities 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.

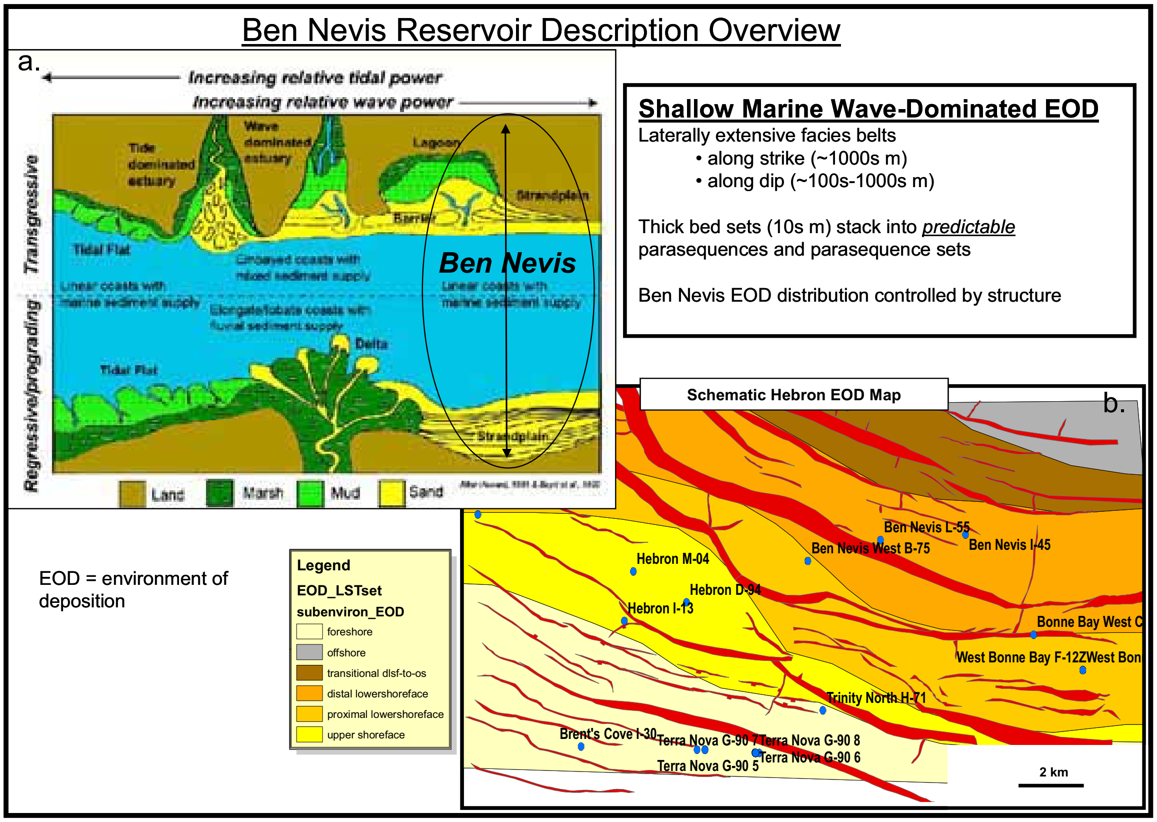


Figure 2.2-12: Ben Nevis – Avalon Depositional Environment

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.

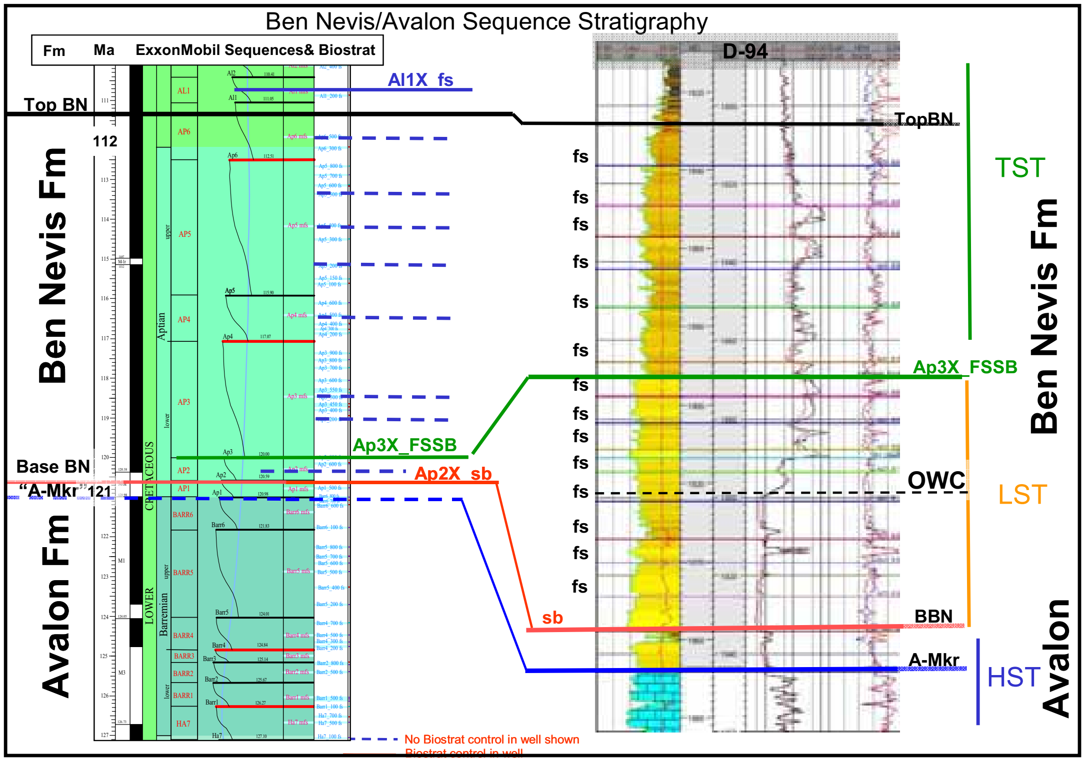


Figure 2.2-13: Ben Nevis – Avalon Sequence Stratigraphy

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).

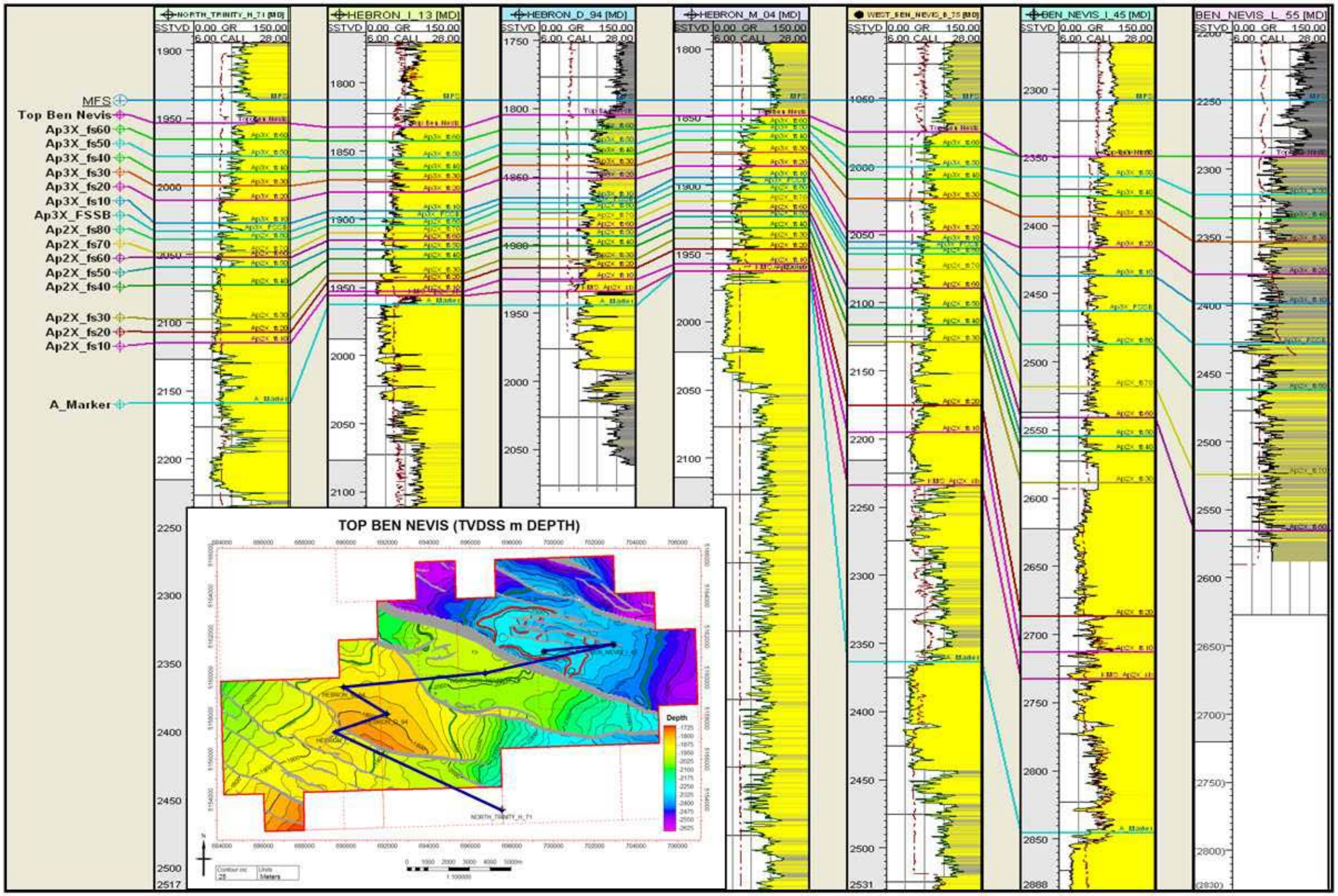


Figure 2.2-14: Ben Nevis – Avalon Well Log Correlations
Well log correlations posted on colour shaded gamma ray (GR) log. Datum is top of Ben Nevis.

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 digenetic 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.

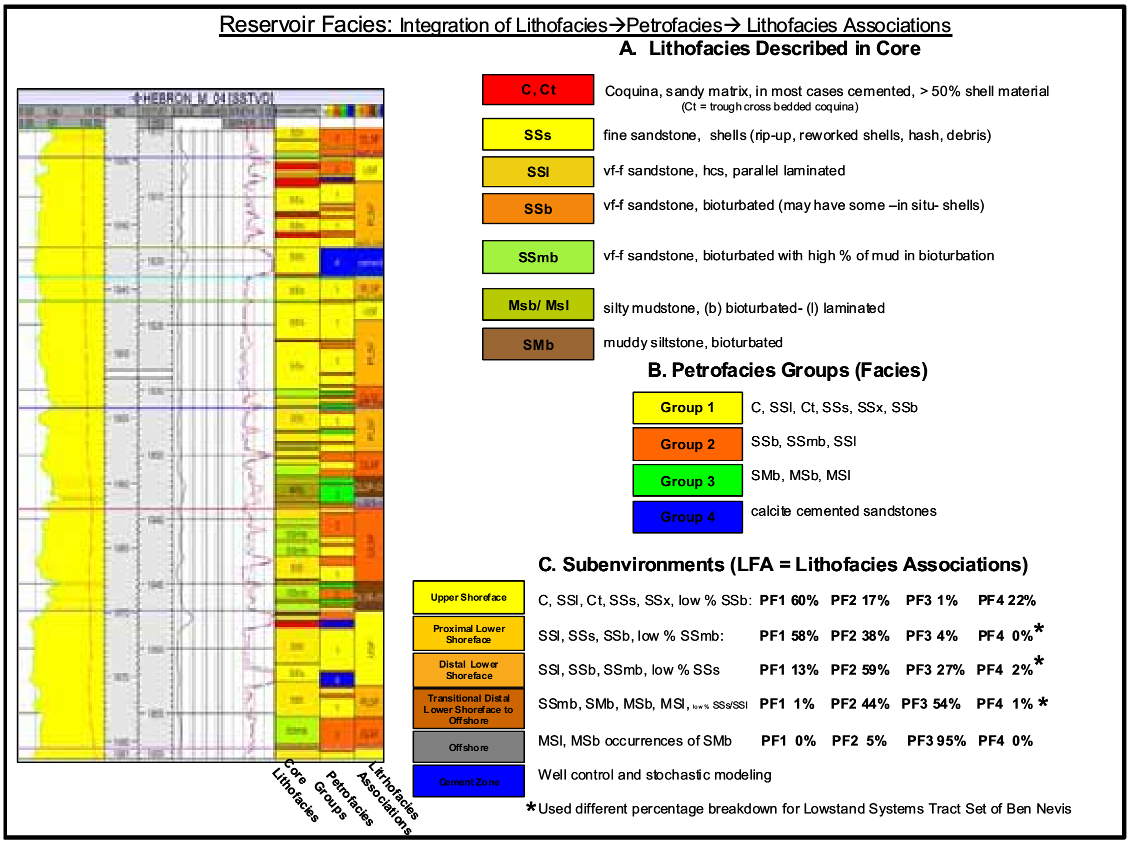


Figure 2.2-15: Ben Nevis – Avalon Reservoir Facies

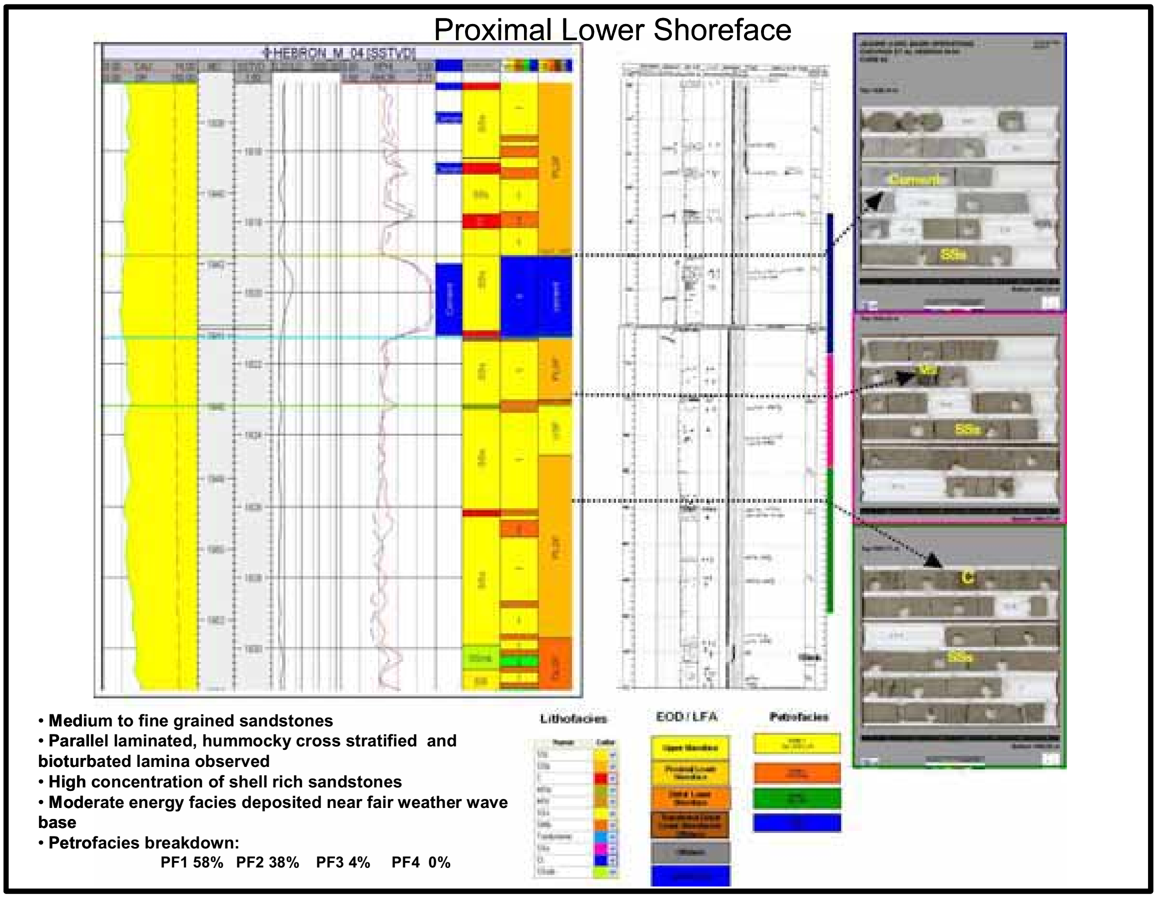


Figure 2.2-16: Ben Nevis – Avalon Proximal Lower Shoreface Facies Description

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.

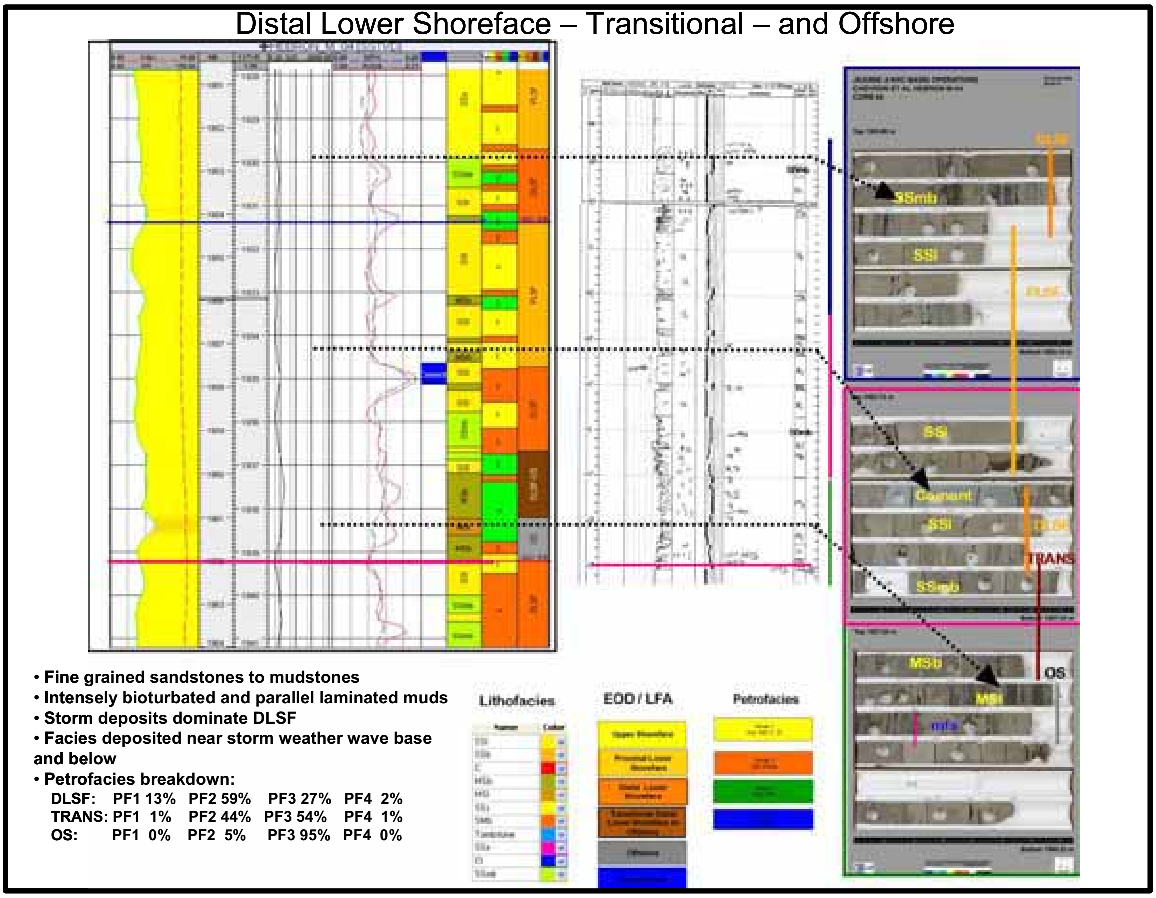


Figure 2.2-17: Ben Nevis – Avalon Lower Shoreface, Transitional, and Offshore Facies Description

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

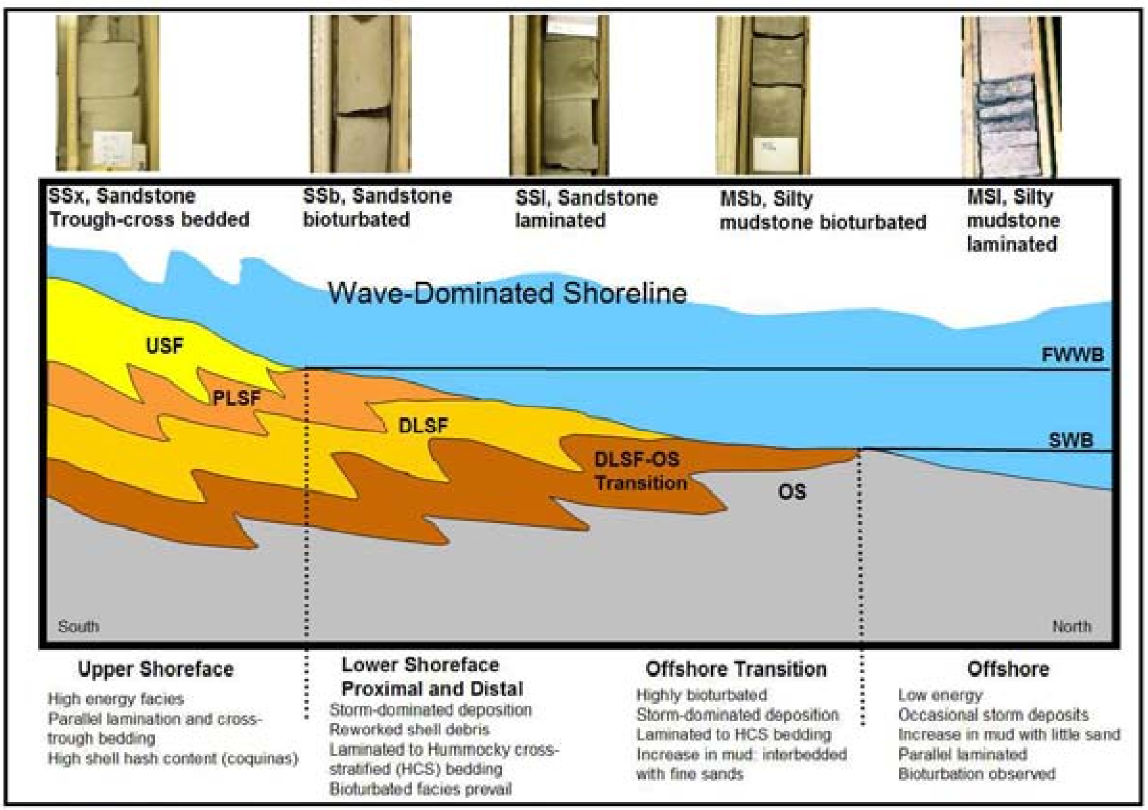
One key interval identified near the Ap2X_fs260 surface was treated as a cement horizon and is populated in the Pool 1 reservoir model with the Group 4 petrofacies. A breakdown of the petrofacies groups that define each association is provided in Figure 2.2-15. The upper shoreface (Figure 2.2-19) represents 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.

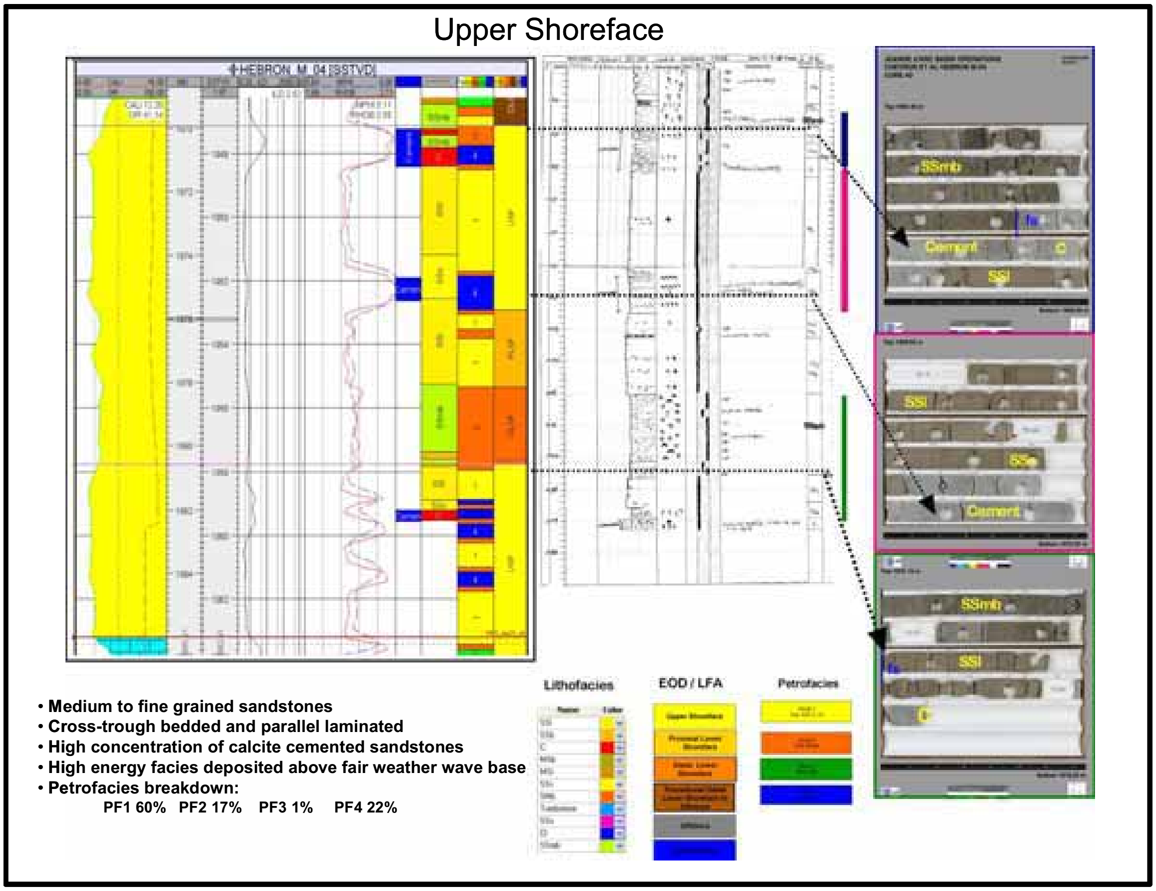


Figure 2.2-19: Ben Nevis – Avalon Upper Shoreface Facies Description

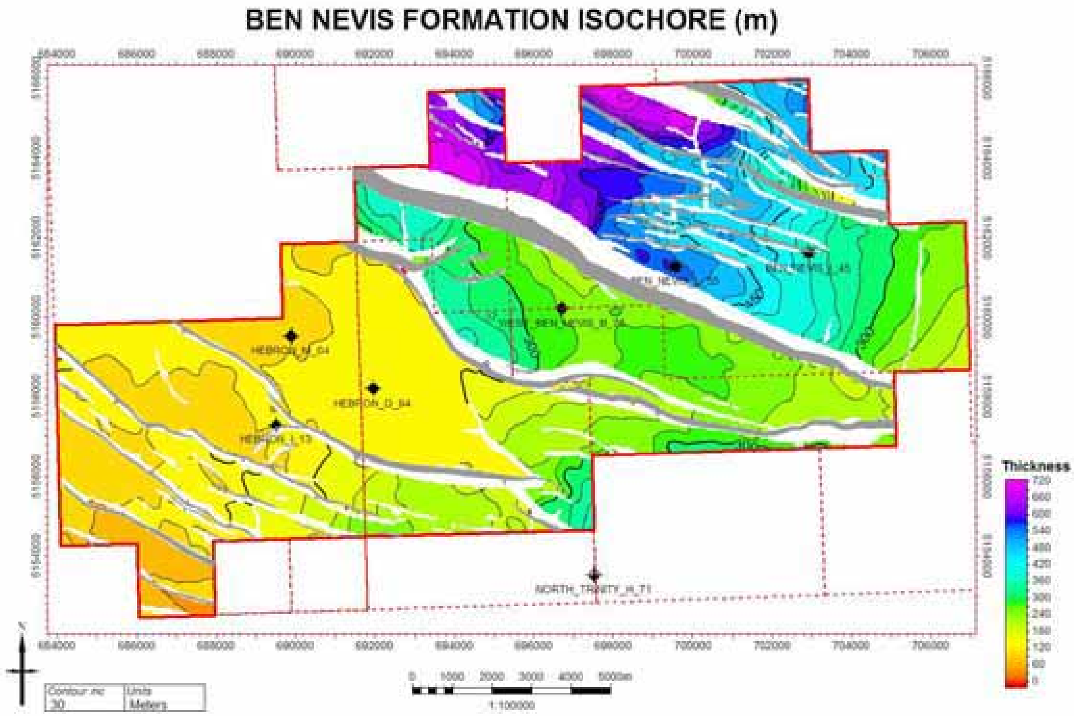


Figure 2.2-20: Ben Nevis – Avalon Isochore Map
Isochore map of the Ben Nevis Reservoir demonstrating thickening towards the northeast across the faults.

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.

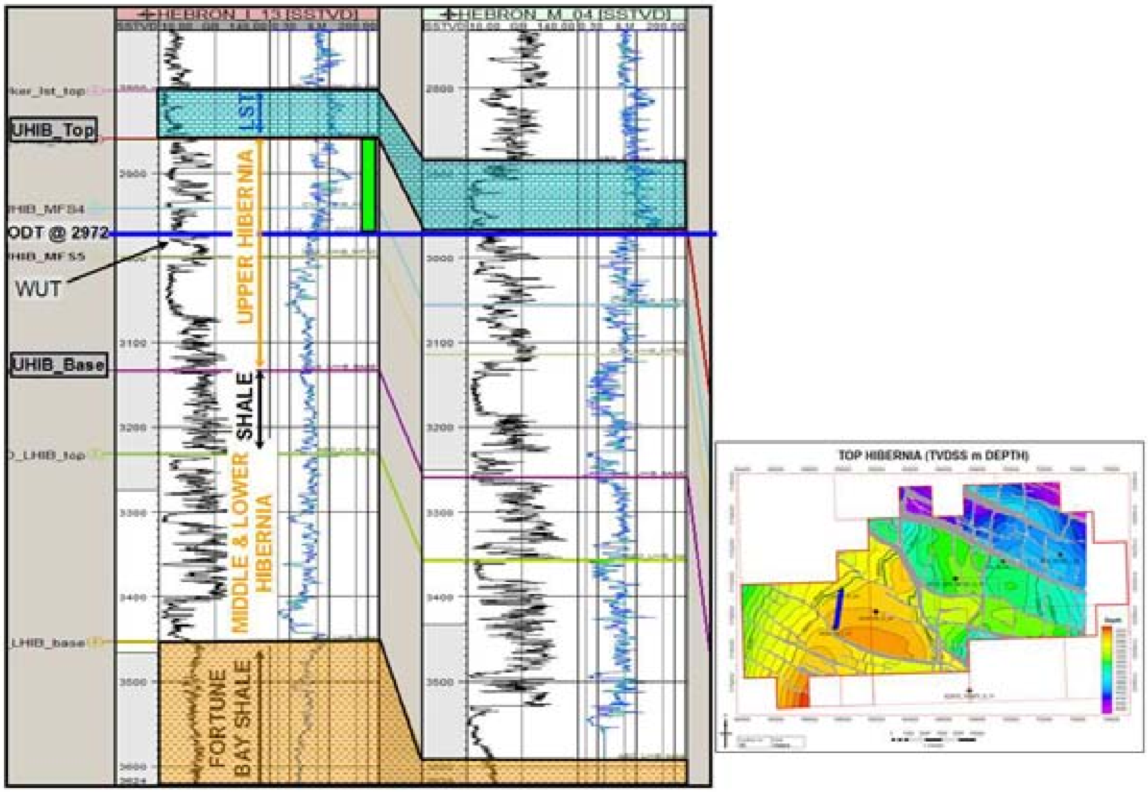


Figure 2.2-21: Hibernia Well Based Definition of Reservoir and Fluid Contacts

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.

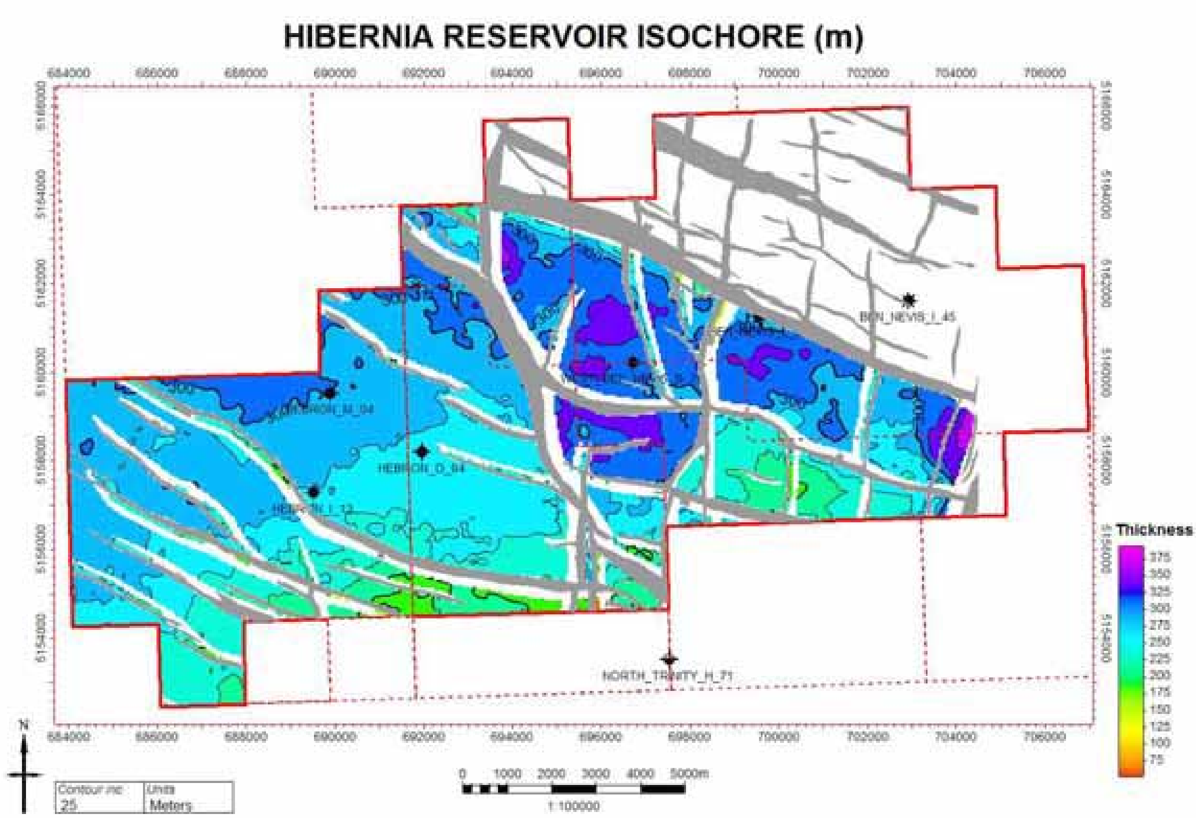


Figure 2.2-22: Hibernia Isochore Map

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).

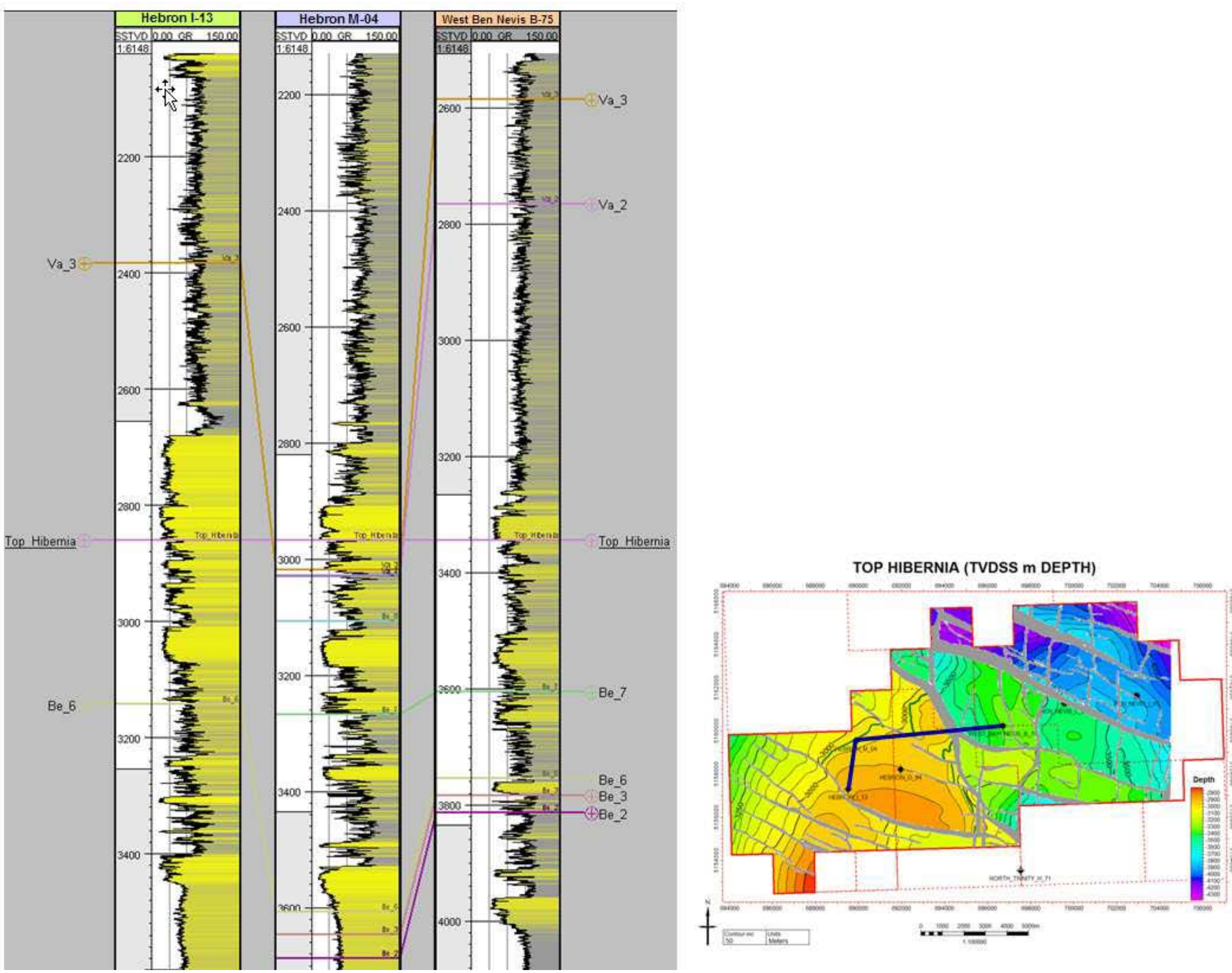


Figure 2.2-23: Hibernia Biostratigraphy

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

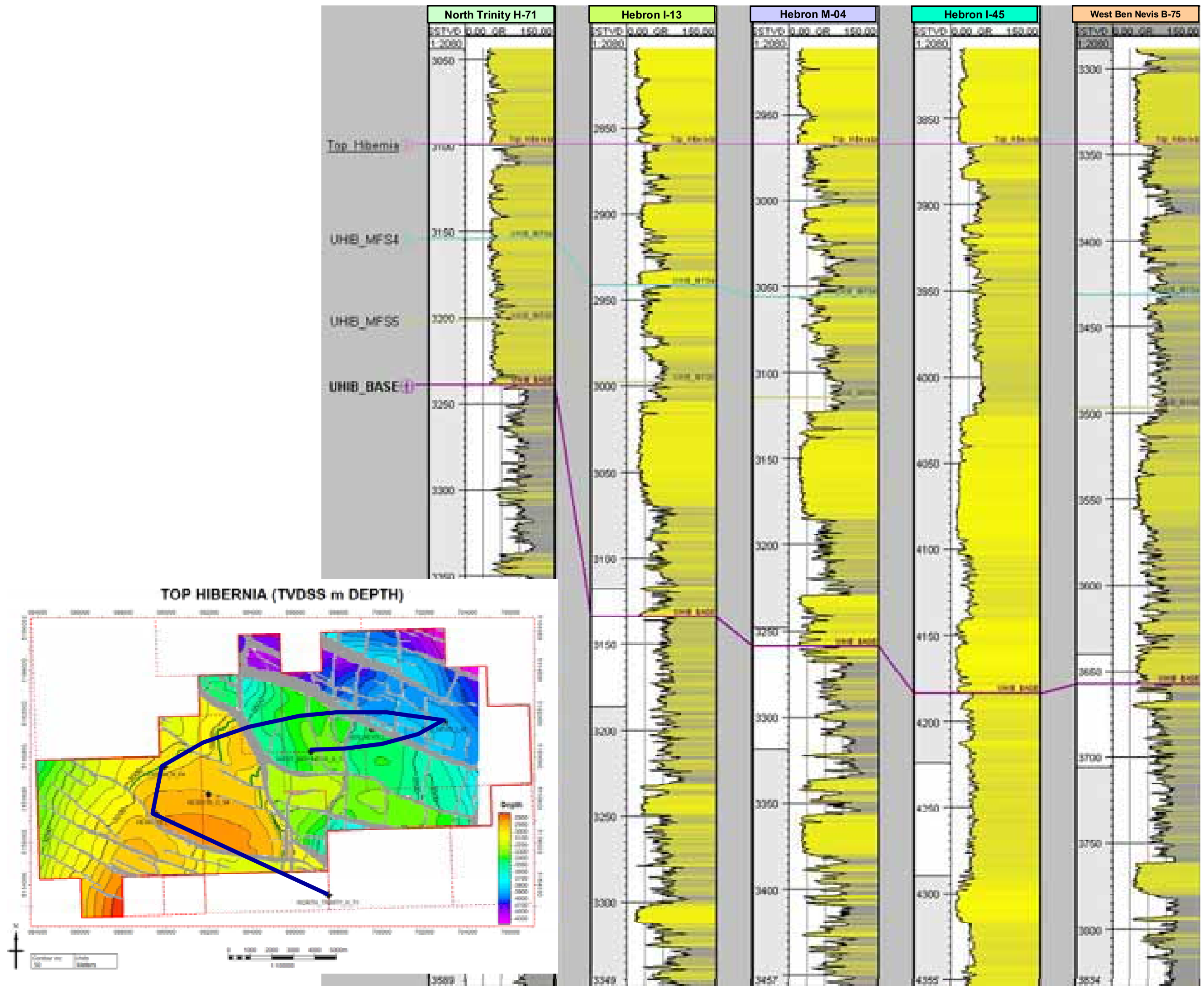


Figure 2.2-24: Hibernia Well Log Correlations

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.

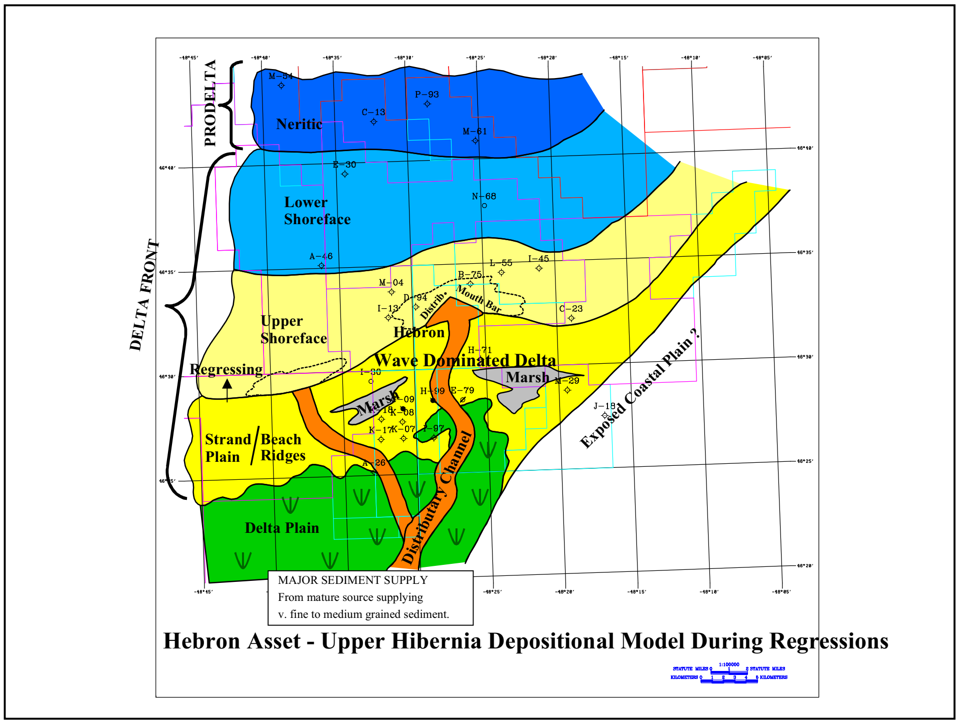


Figure 2.2-25: Hibernia Regression Paleogeographic Map

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.

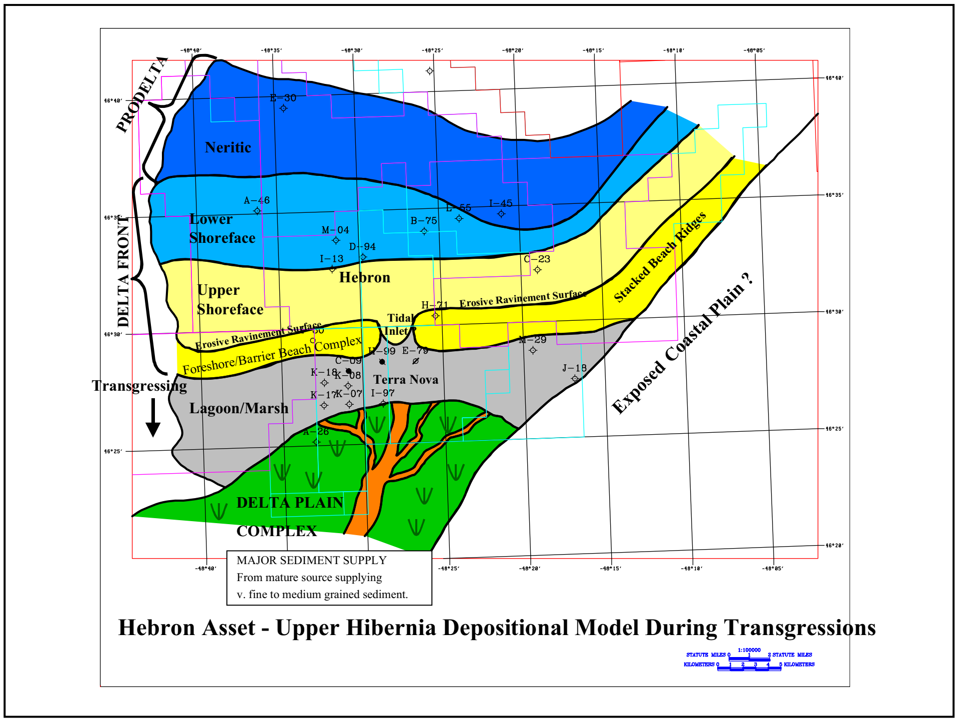


Figure 2.2-26: Hibernia Transgression Paleogeographic Map

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.

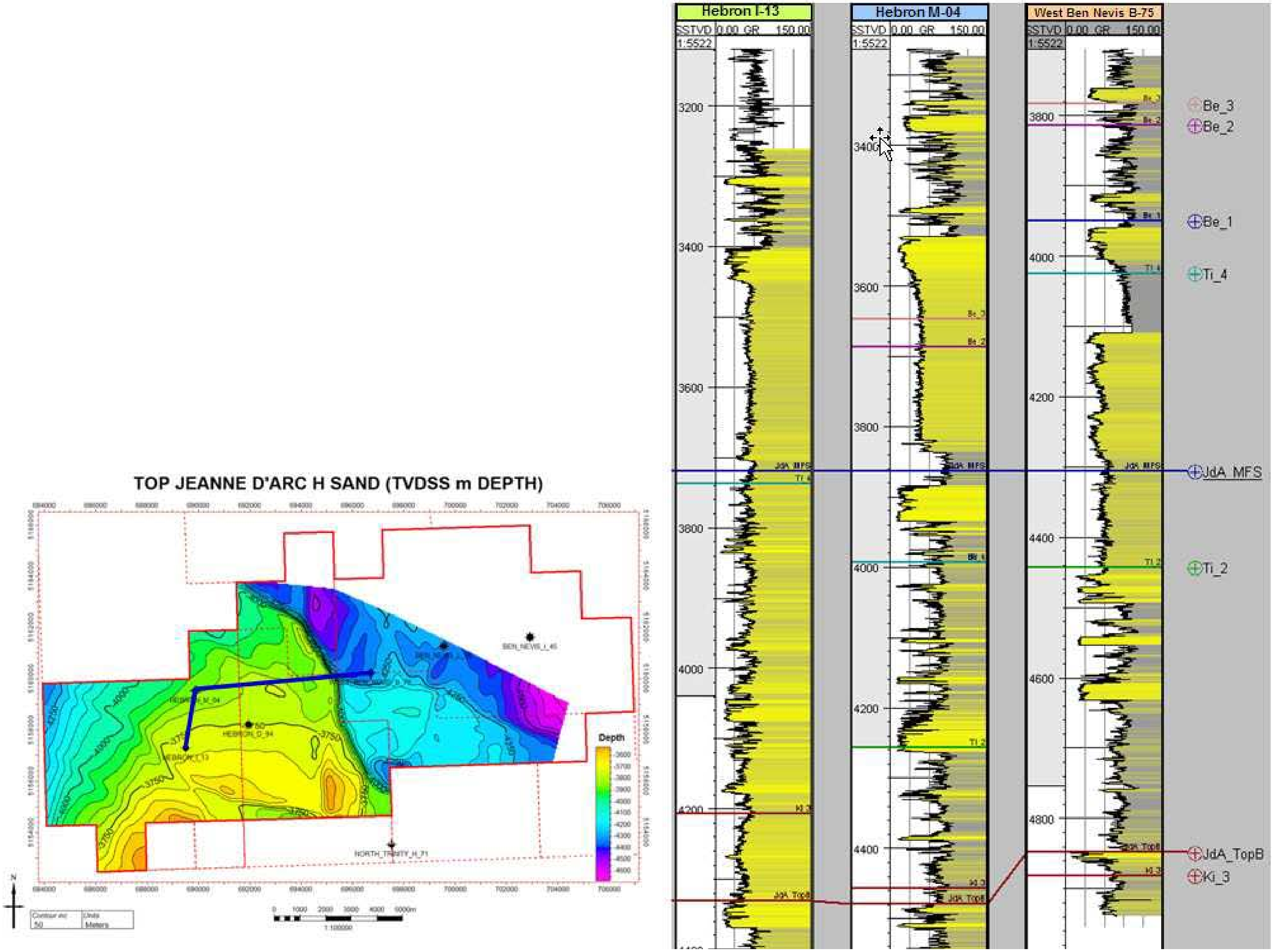


Figure 2.2-27: Jeanne d'Arc Biostratigrapy

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.

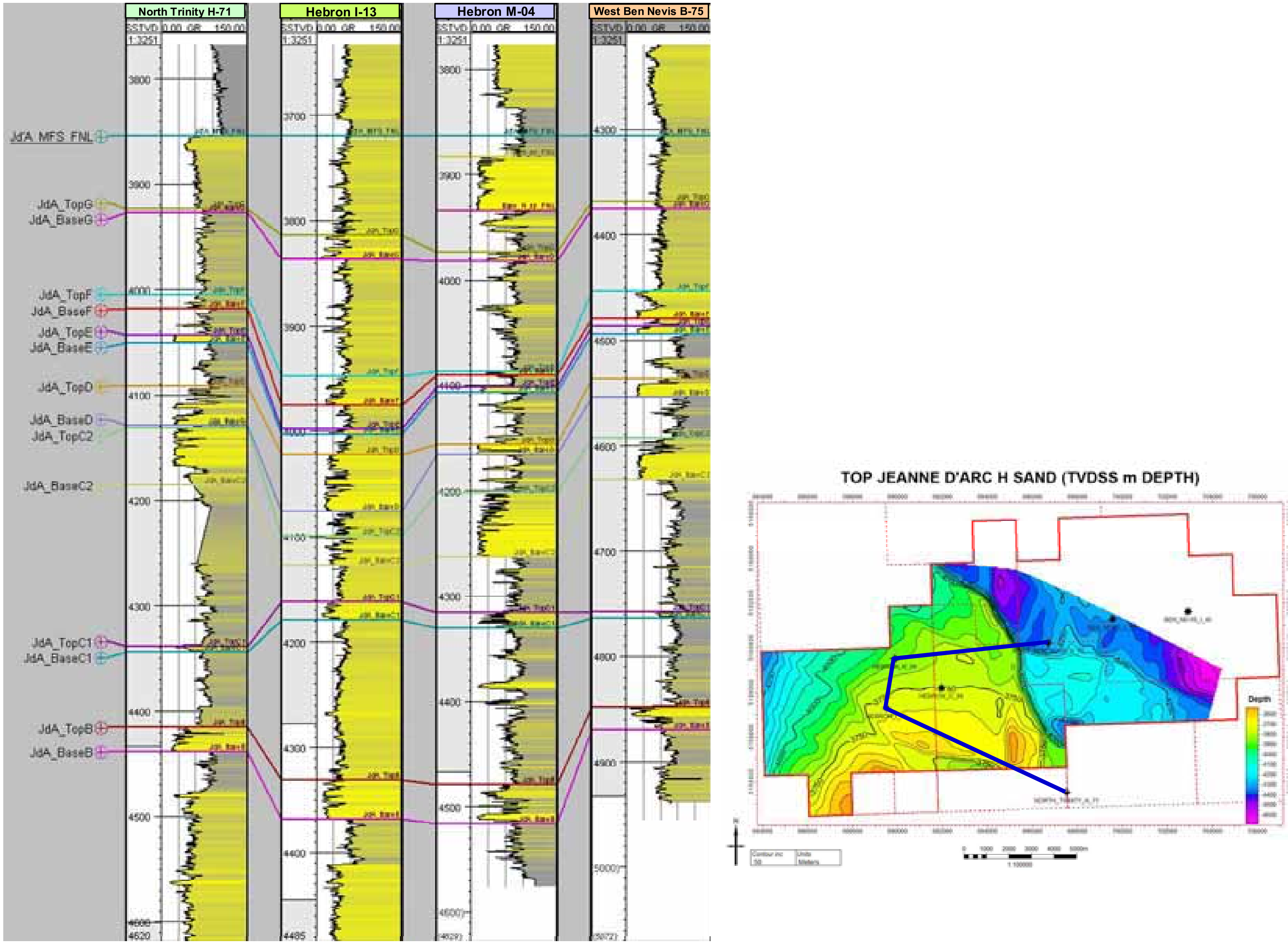


Figure 2.2-28: Jeanne d'Arc Well Cross-Section from H-71 to B-75

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.

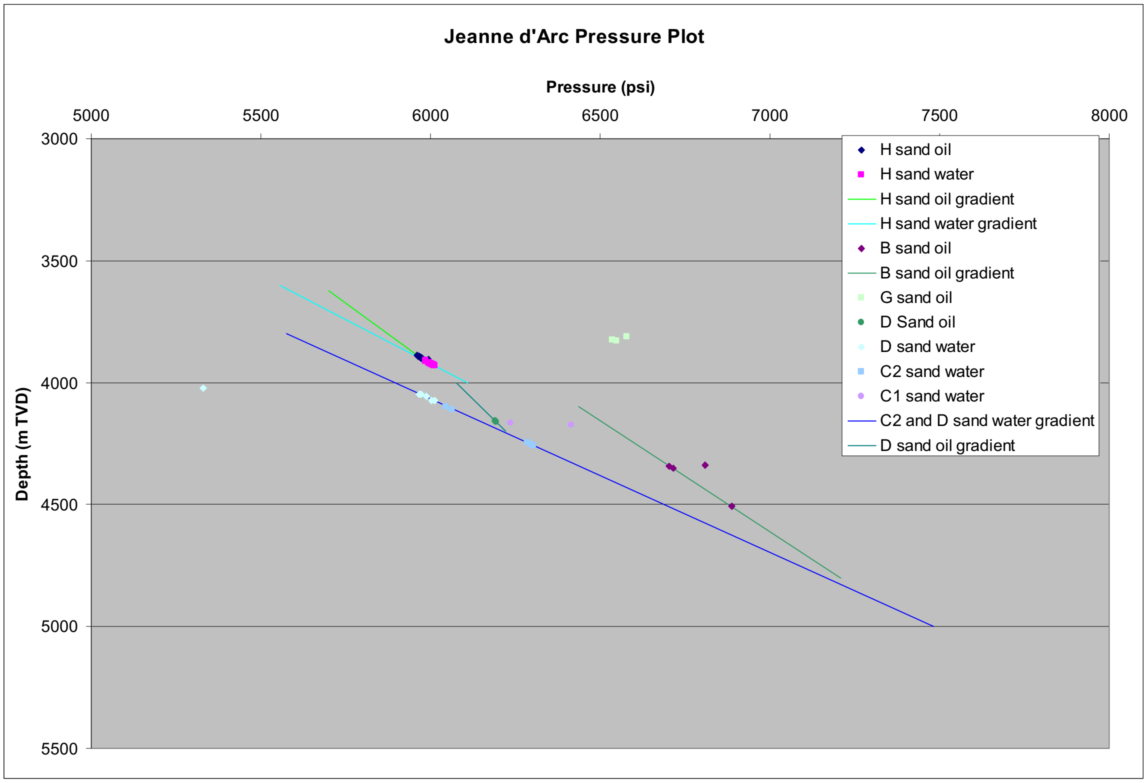


Figure 2.2-29: Jeanne d'Arc Pressure Plot
Pressure points from RFT from the M-04 and I-13 wells plotted by sand versus depth

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).

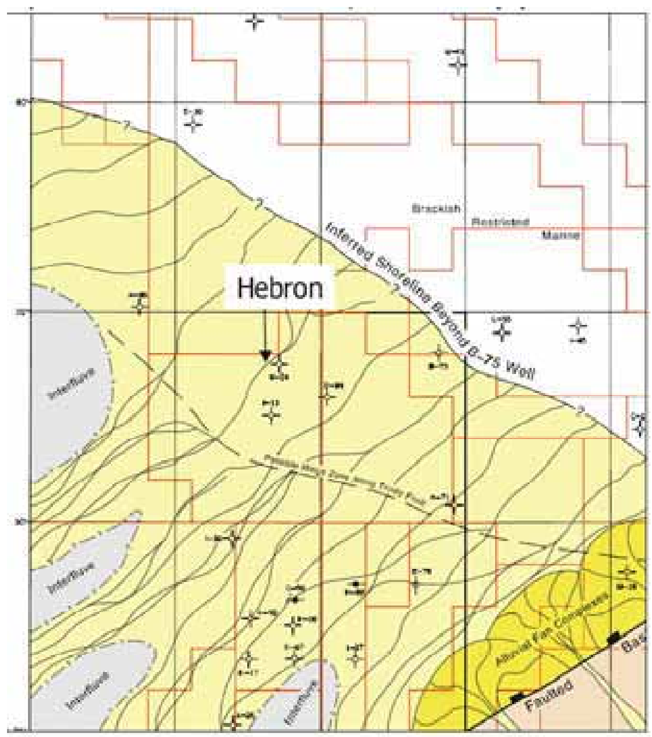


Figure 2.2-30: **Jeanne d'Arc Formation "B" Sand Paleogeographic Map**

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)
Vcalcite = volume of calcite from multimin analysis
Vclay = volume of calcite from multimin analysis

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

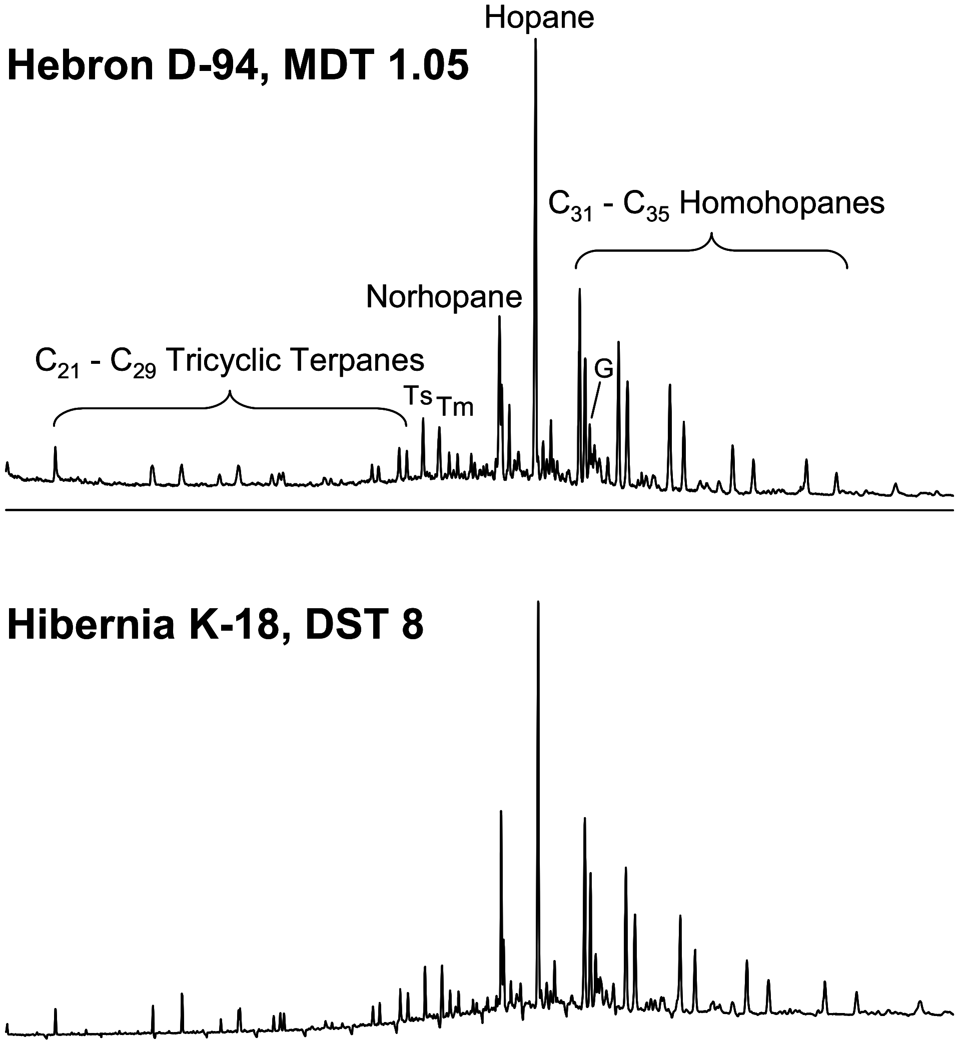
Table 2.2-3: Jeanne D'Arc Other Sands Facies

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

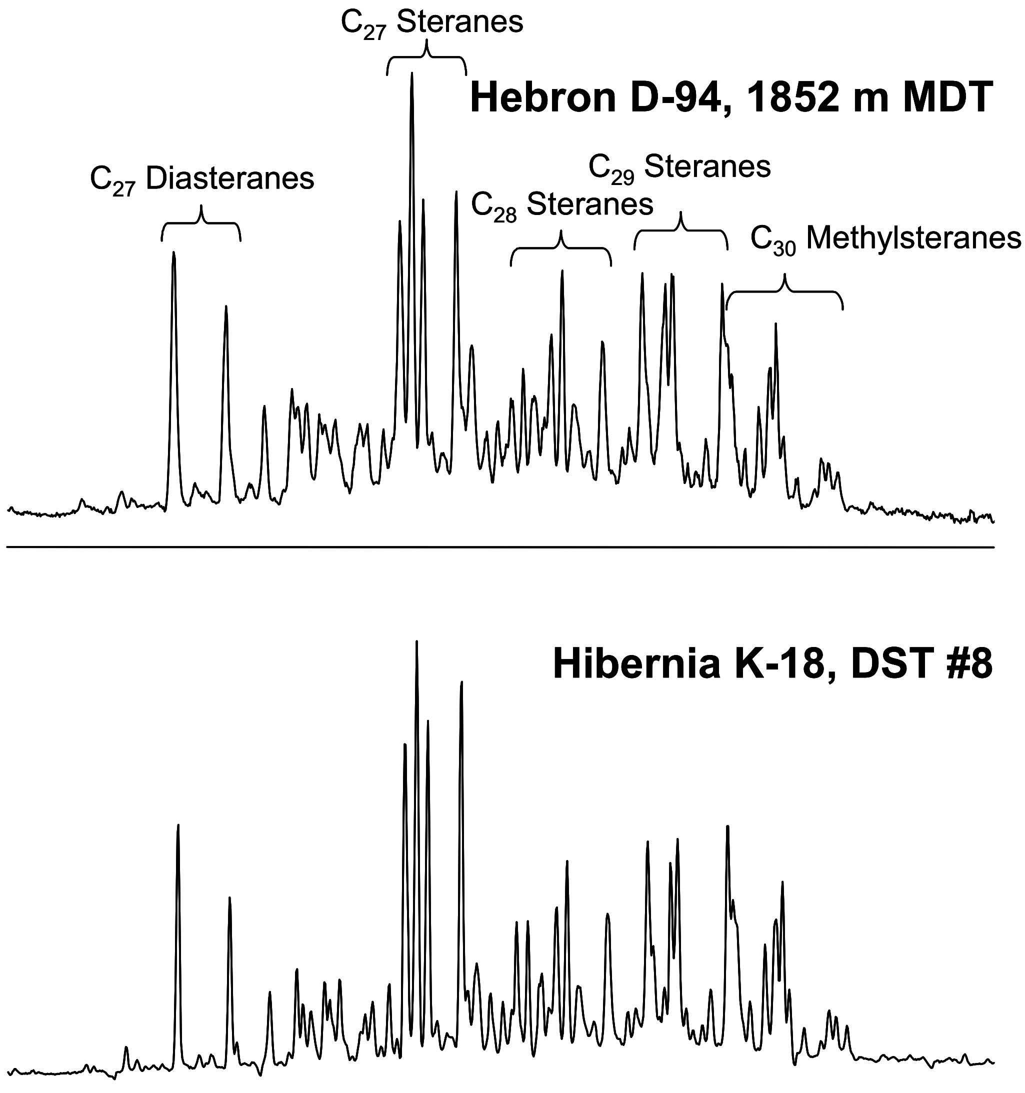
The Egret Member is the predominant source rock for the entire the Jeanne d'Arc Basin. Geochemical studies have concluded that the Egret member is the primary source rock for Hebron's hydrocarbons (Jenden, 2000). The principal cause of heavy oil occurrence is biodegradation. The closest wells that have penetrated the Egret member are in Terra Nova field and have encountered thickness ranges of 50 to100 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 tripertane 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.

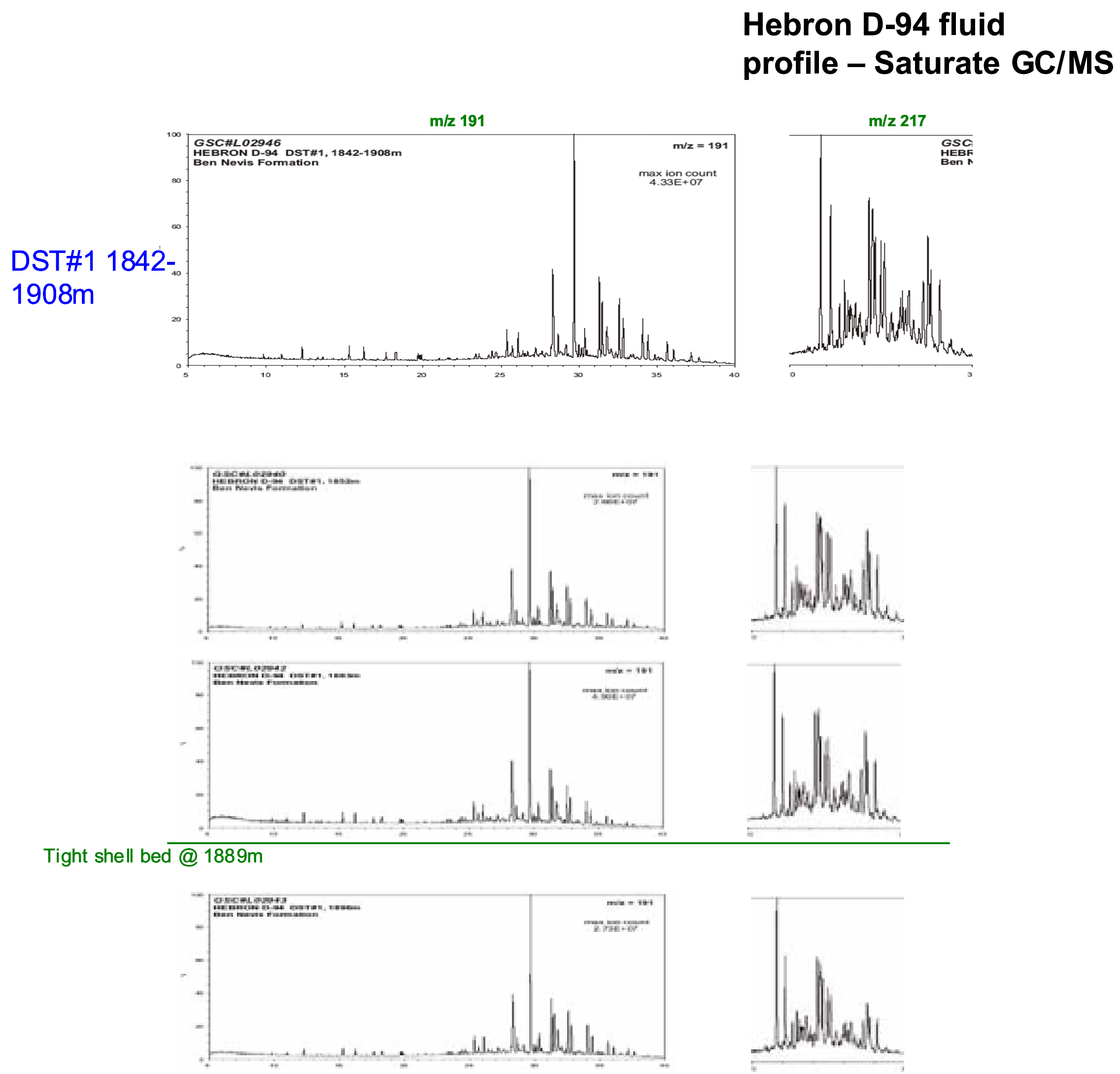


Figure 2.2-33: C3 DST Samples for Ben Nevis, Hibernia, Jeanne d'Arc – Hebron D-94 Fluid Profile – Saturate GC/MS

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.

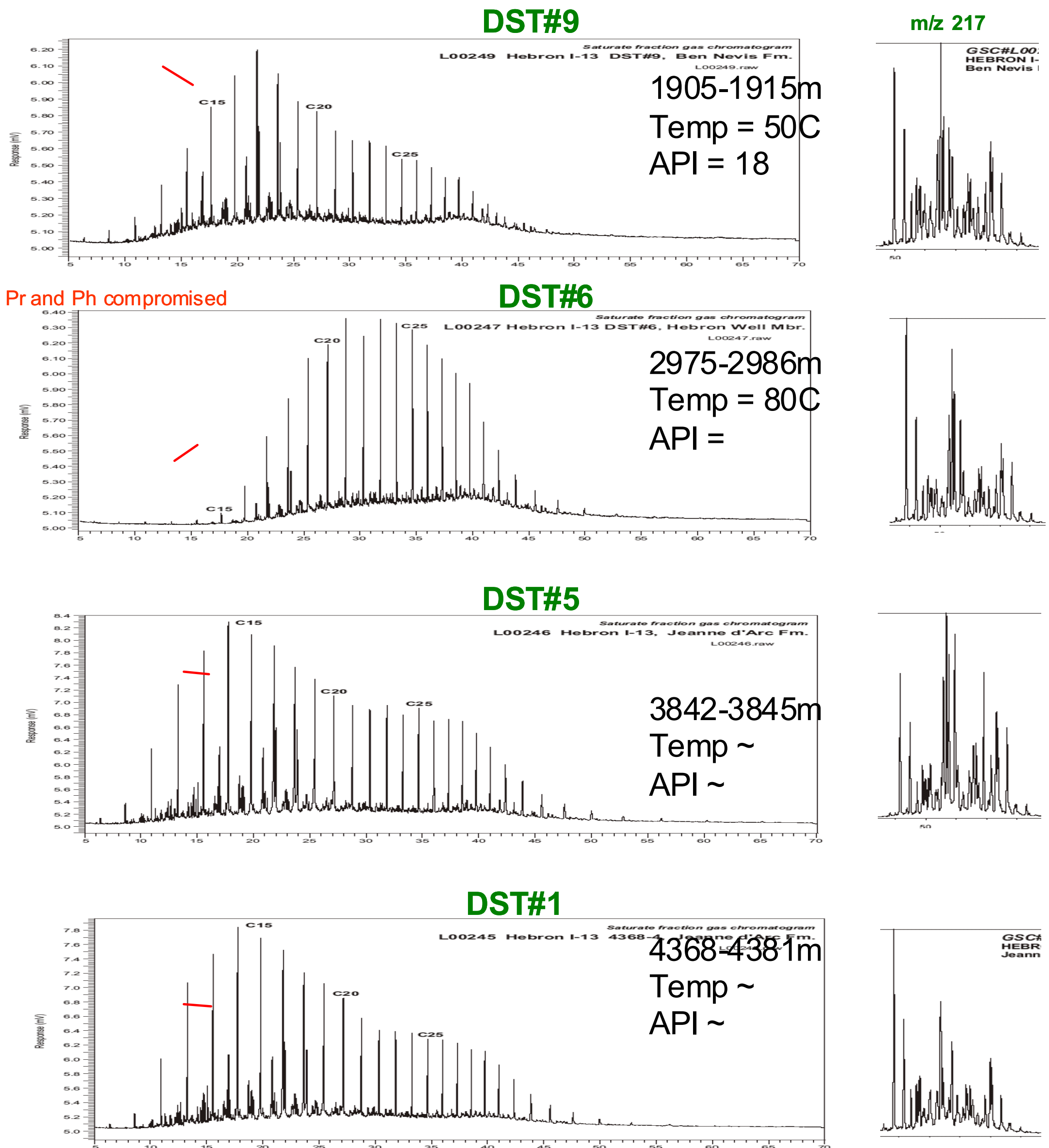


Figure 2.2-34: C4 Biodegradation of Oil in Ben Nevis
These GCs show large differences, some of which might be related to loss of light ends. GC/MS also show differences, likely due to different reservoir units.

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 km^2. 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 km^2. The Hebron 3D dataset used for interpretation covers about 800 km^2 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 Sodera 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 ± 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 ±1 m
Navigation System	Spectra Integrated Navigation System Version 2.03.10
Primary Navigation Sysem	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. SEGD 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.

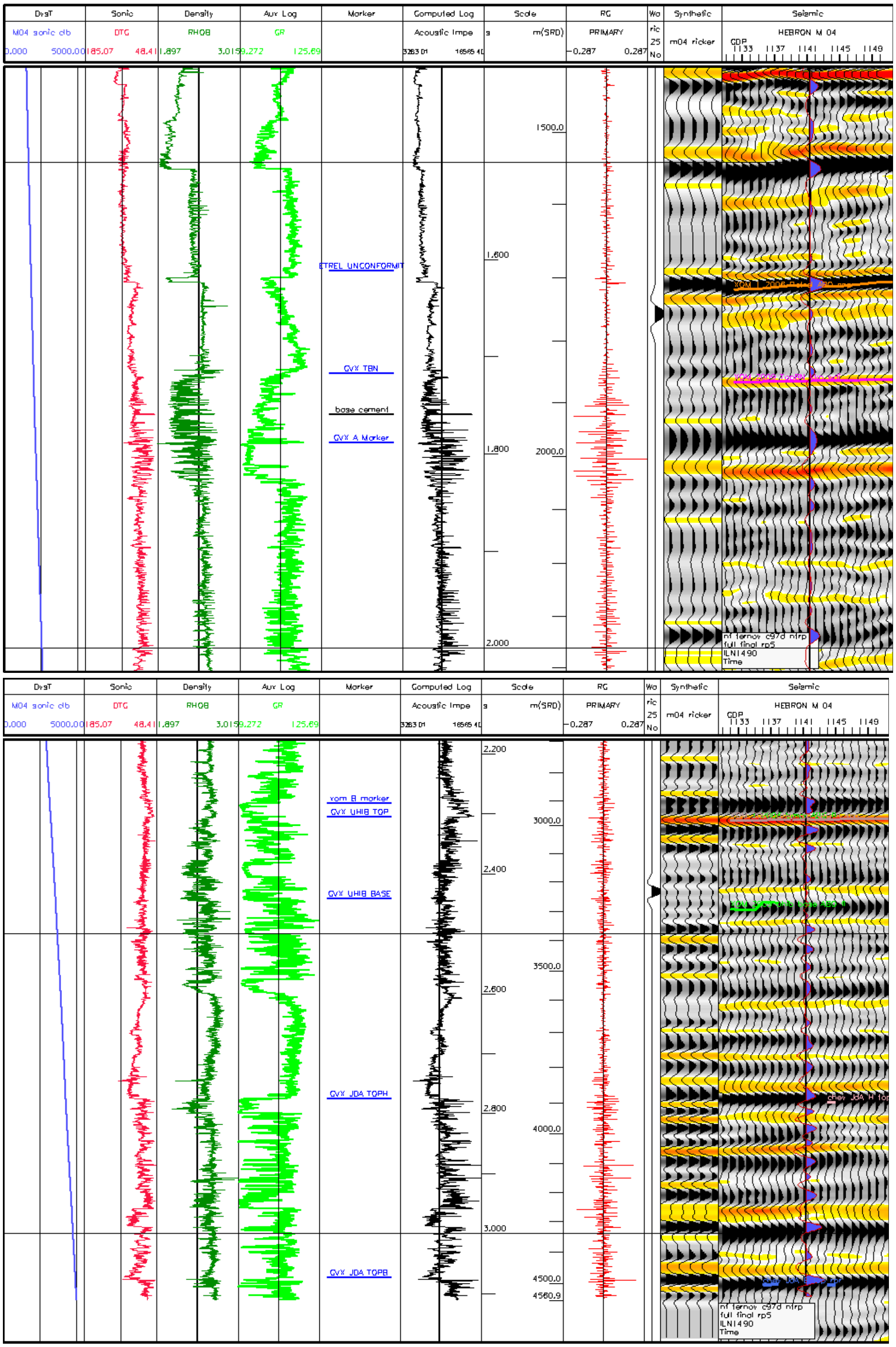


Figure 2.4-1: Representative Well Tie (M-04)

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.

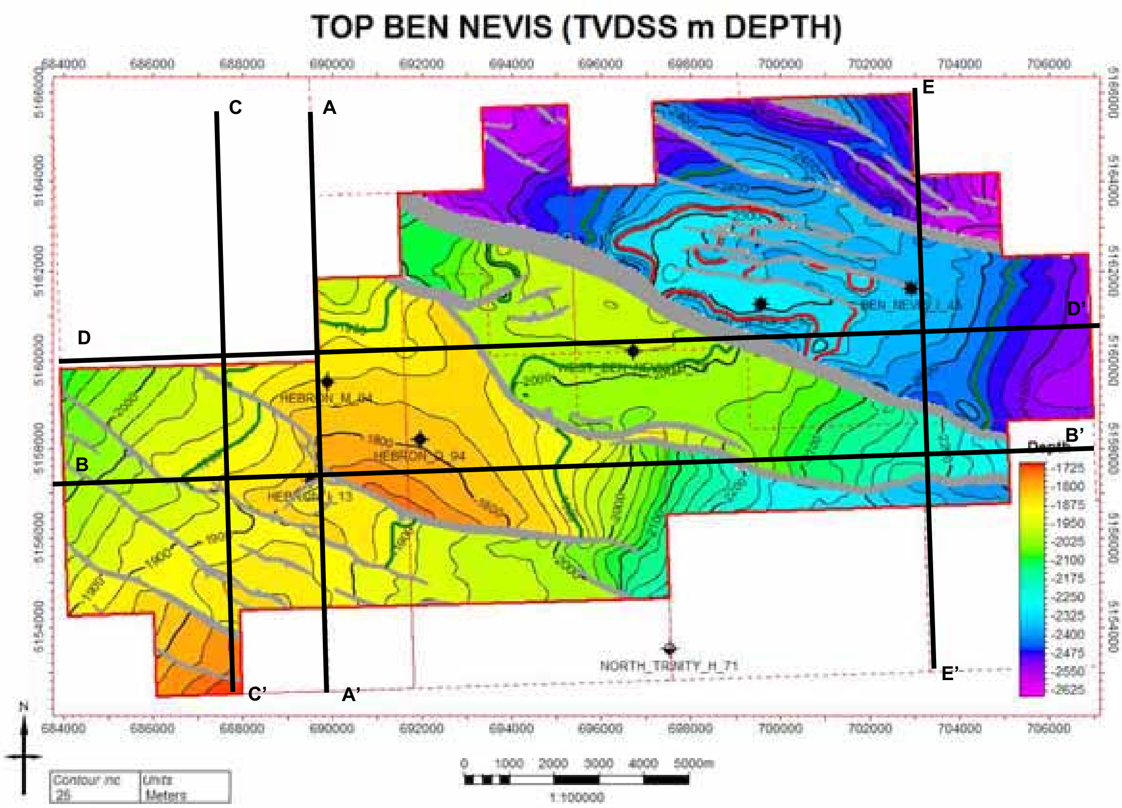


Figure 2.4-2: Seismic Section Map

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)

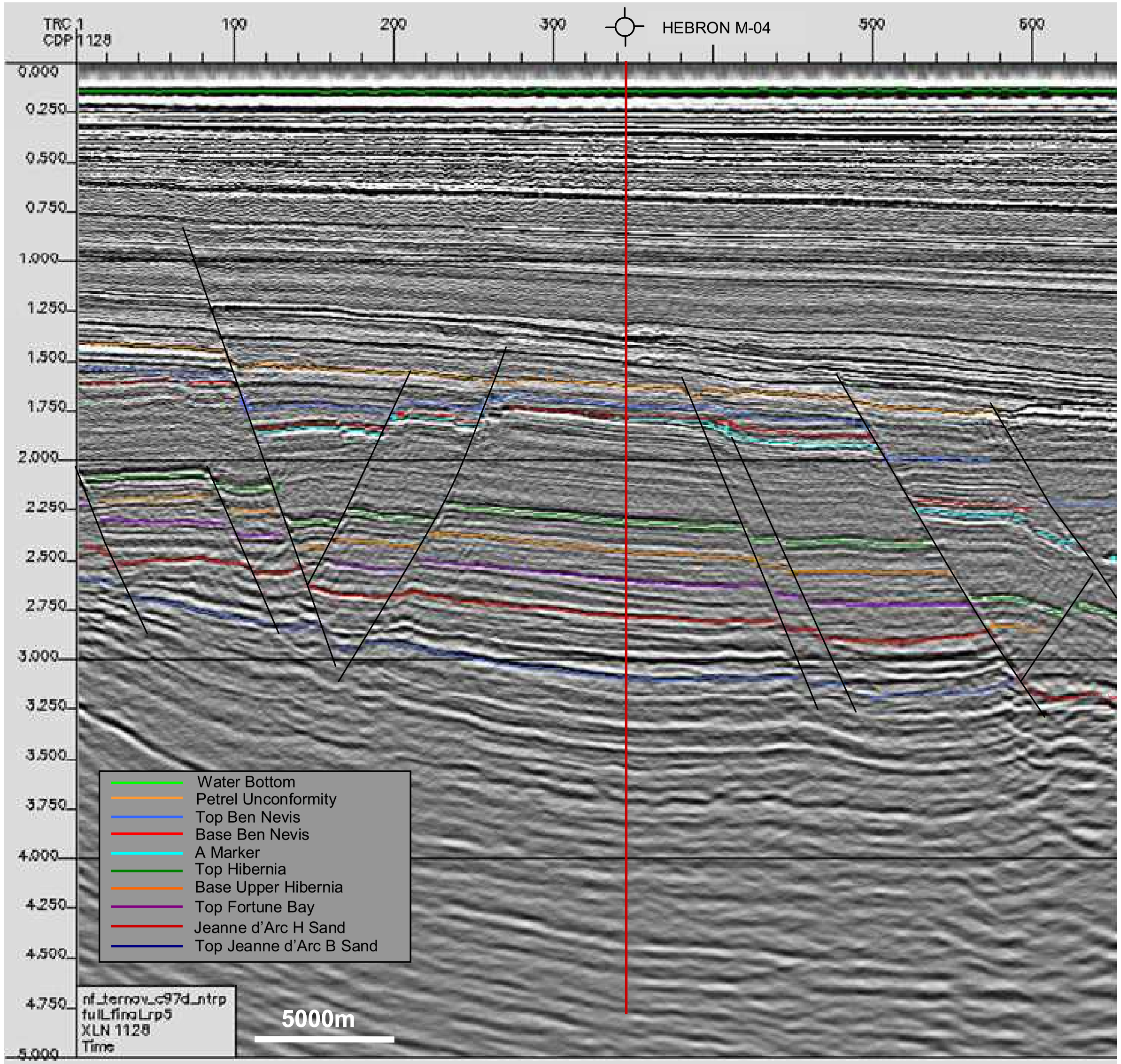


Figure 2.4-3: Seismic A-A' Section

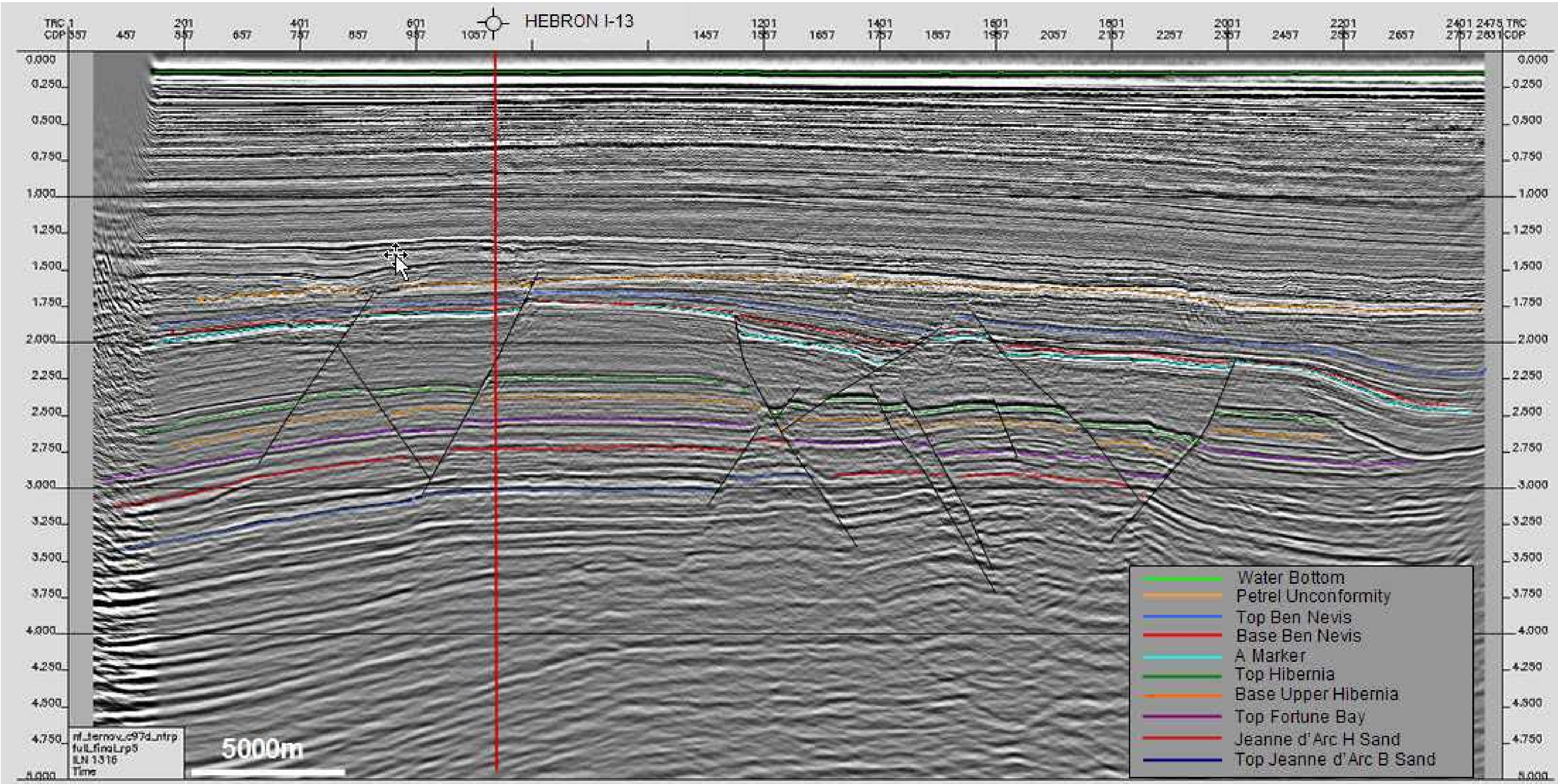


Figure 2.4-4: Seismic B-B' Section

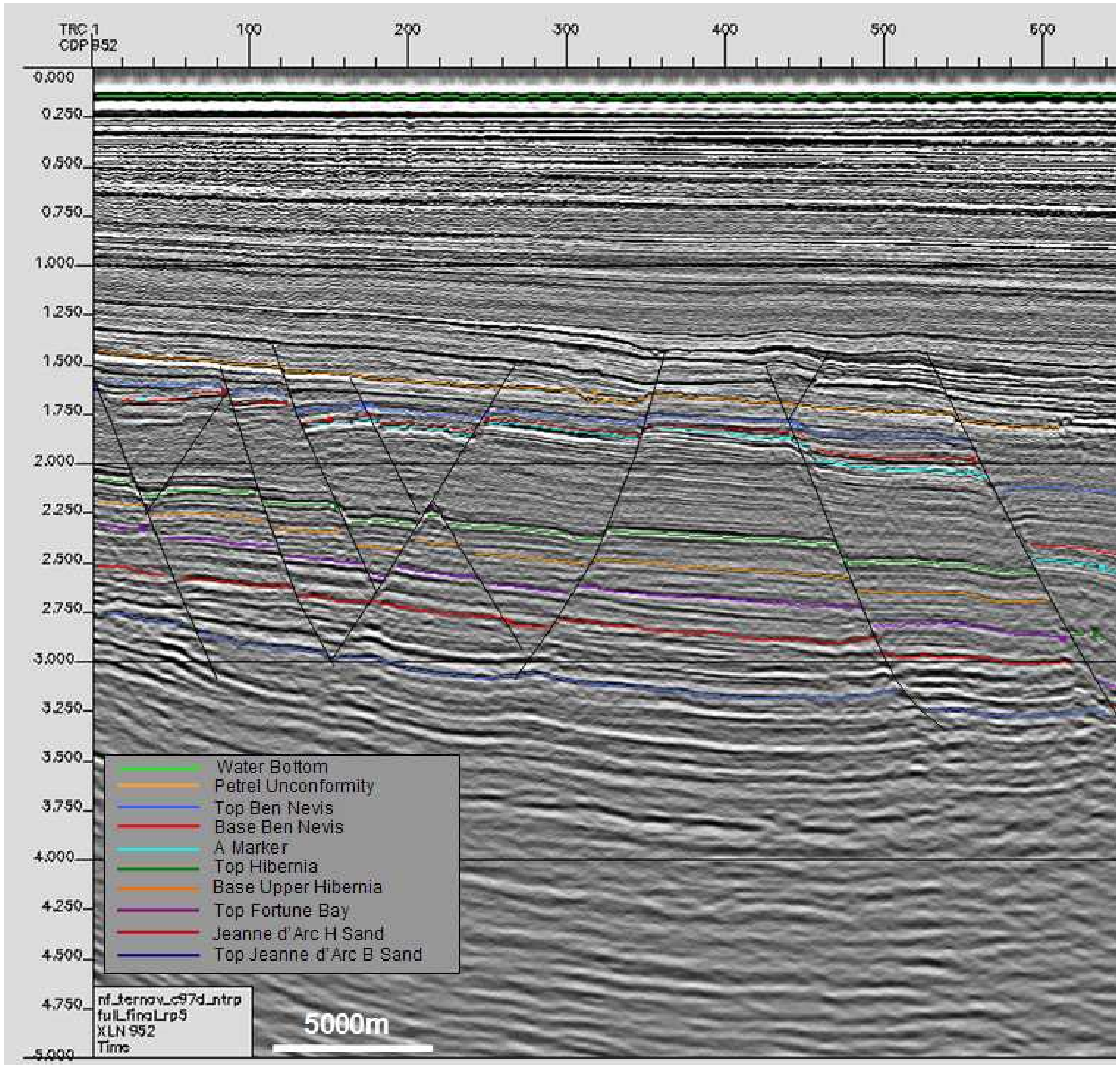


Figure 2.4-5: Seismic C-C' Section

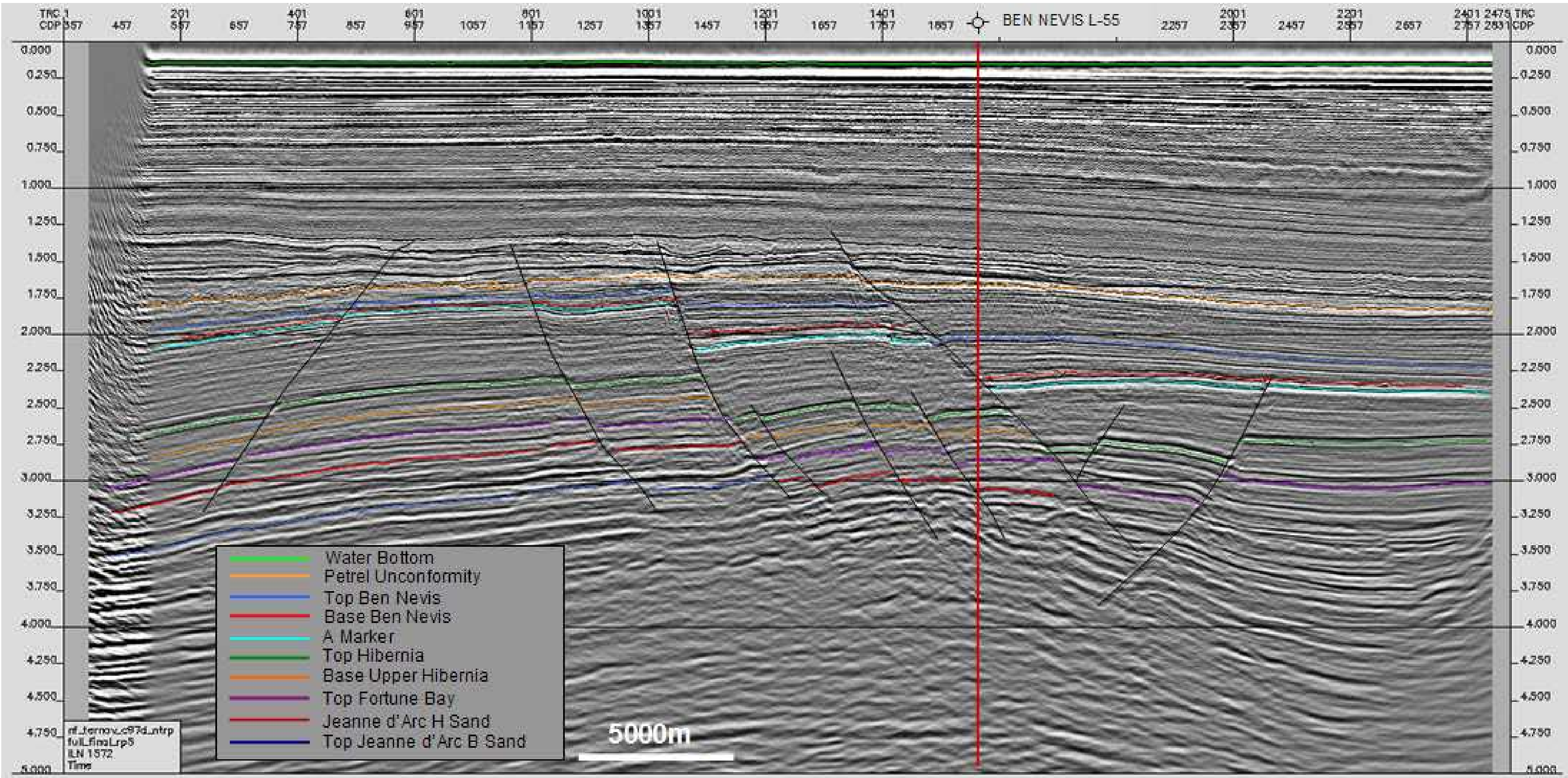


Figure 2.4-6: Seismic D-D' Section

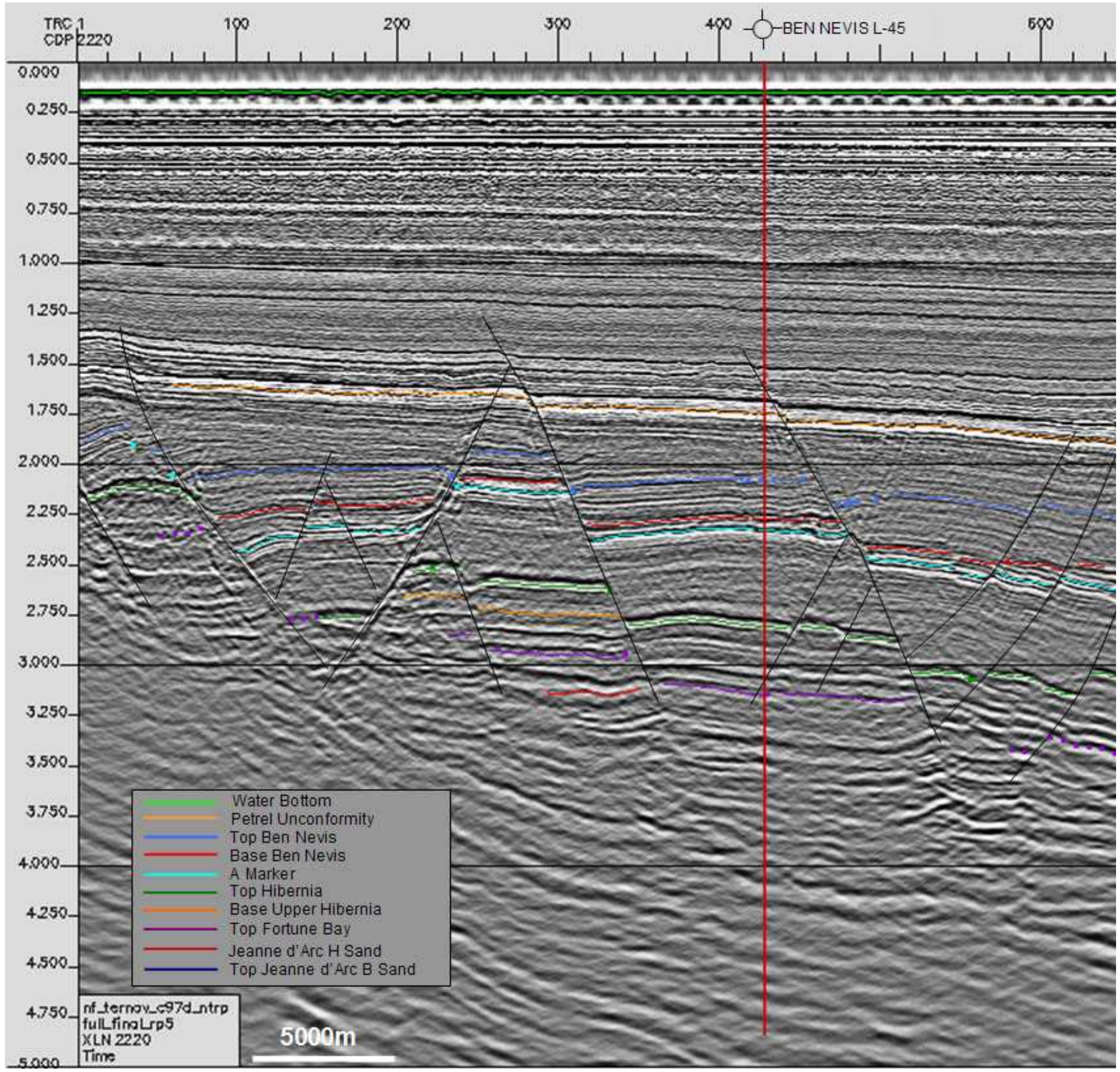


Figure 2.4-7: Seismic E-E' Section

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.

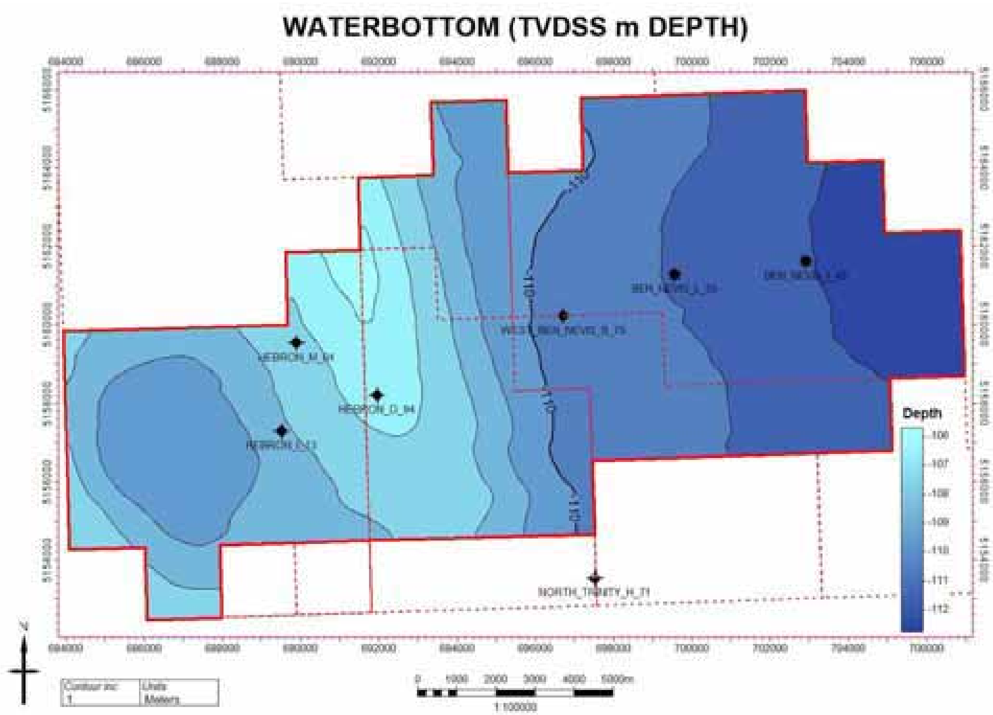


Figure 2.4-8: Water Bottom Depth Structure

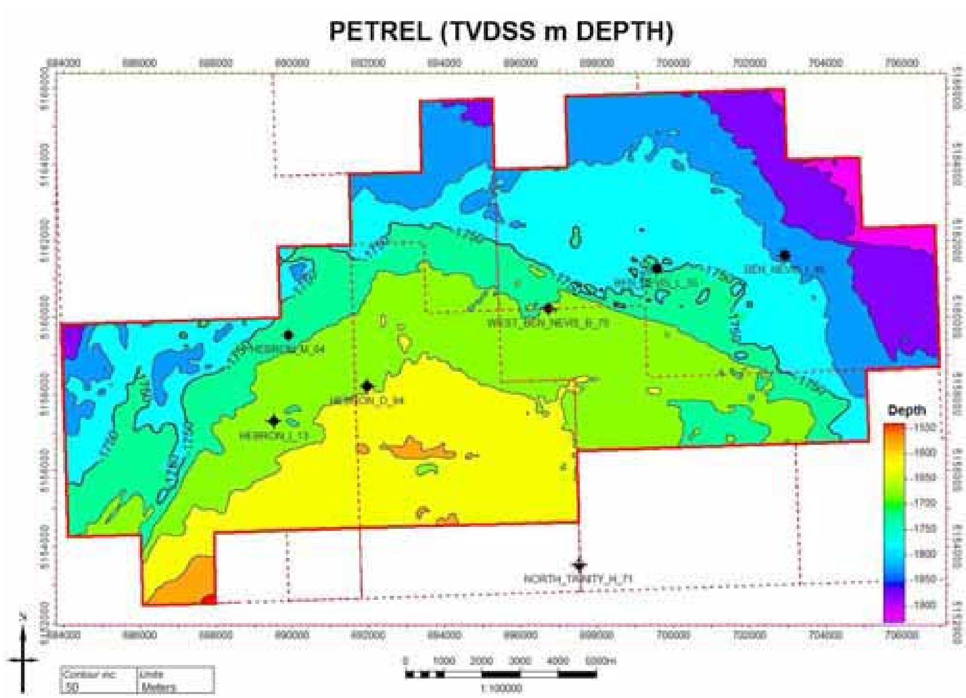


Figure 2.4-9: Petrel Depth Structure

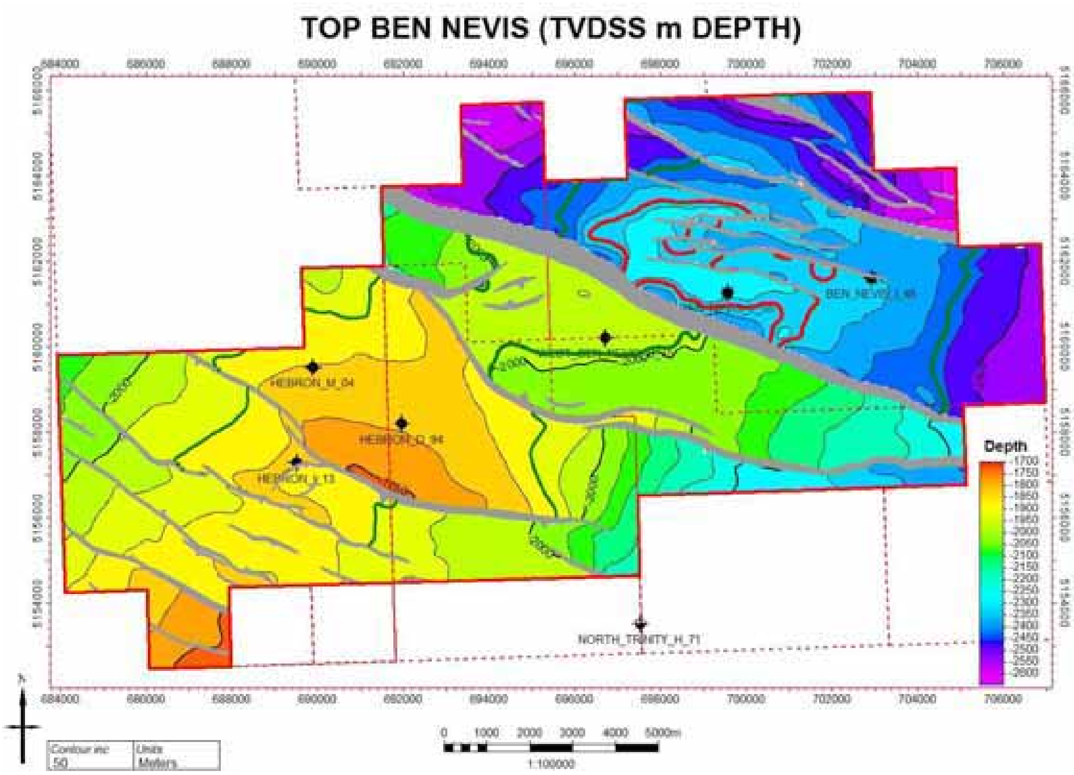


Figure 2.4-10: Top Ben Nevis Depth Structure Maps
Penetrated OWC is shown as green line and GOC is shown in red**.**

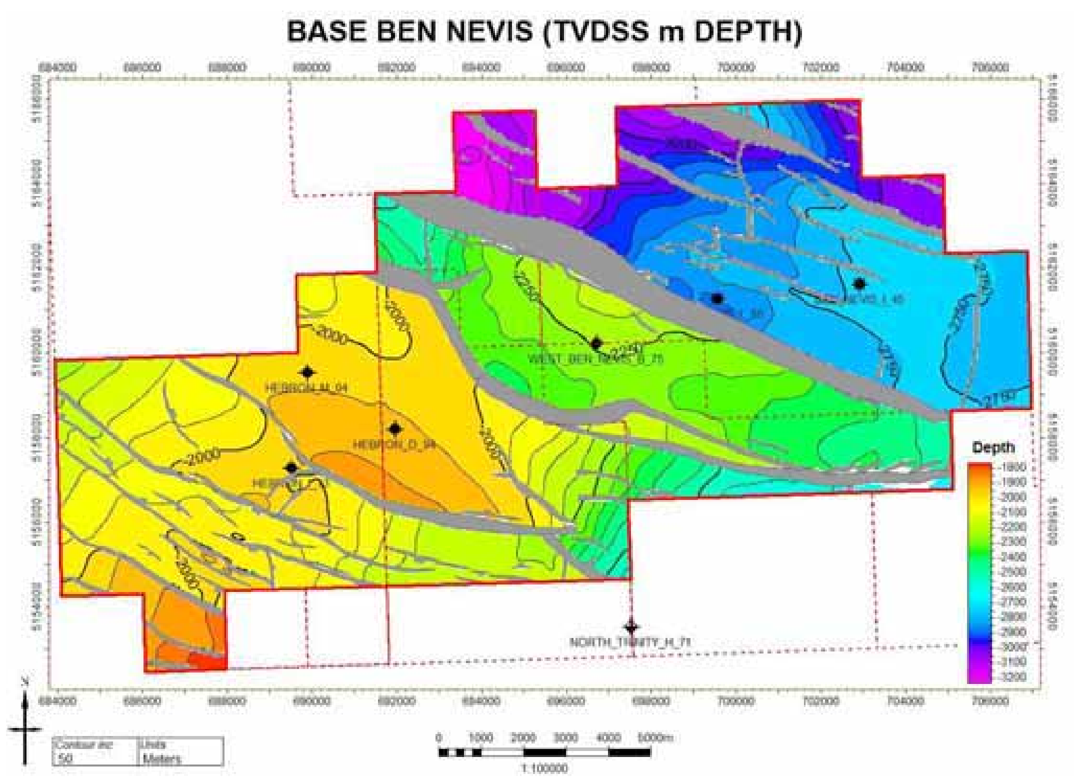


Figure 2.4-11: Base Ben Nevis Depth Structure

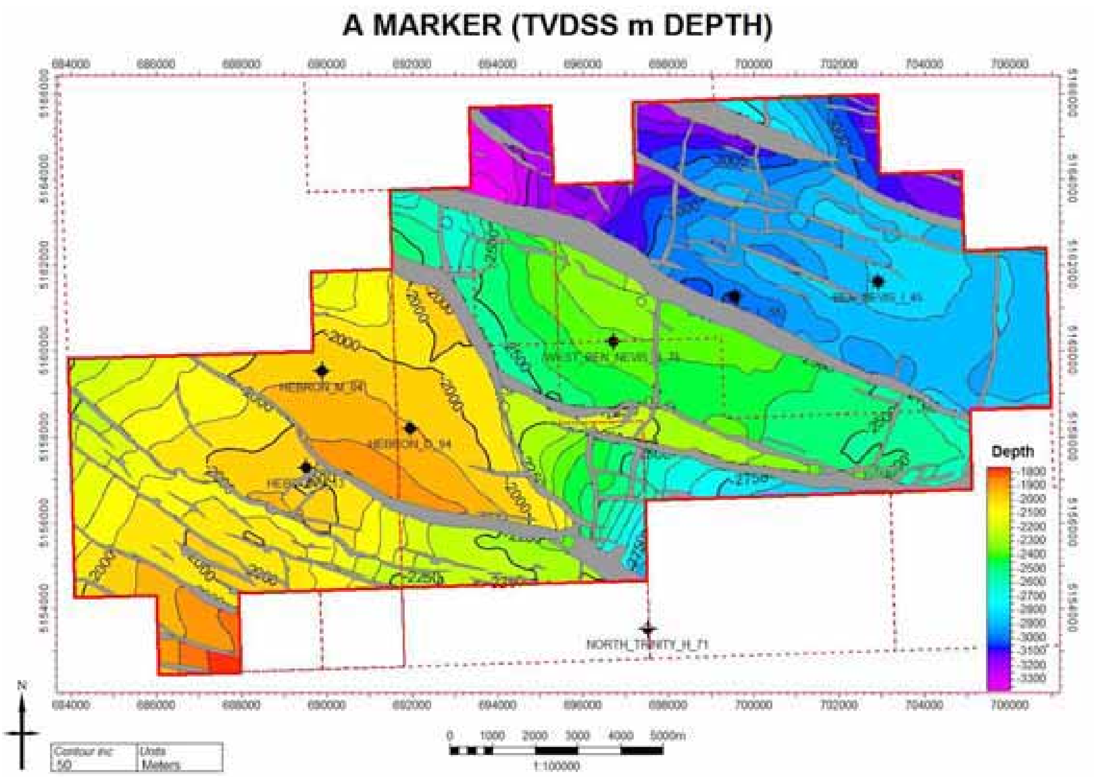


Figure 2.4-12: A Marker Depth Structure

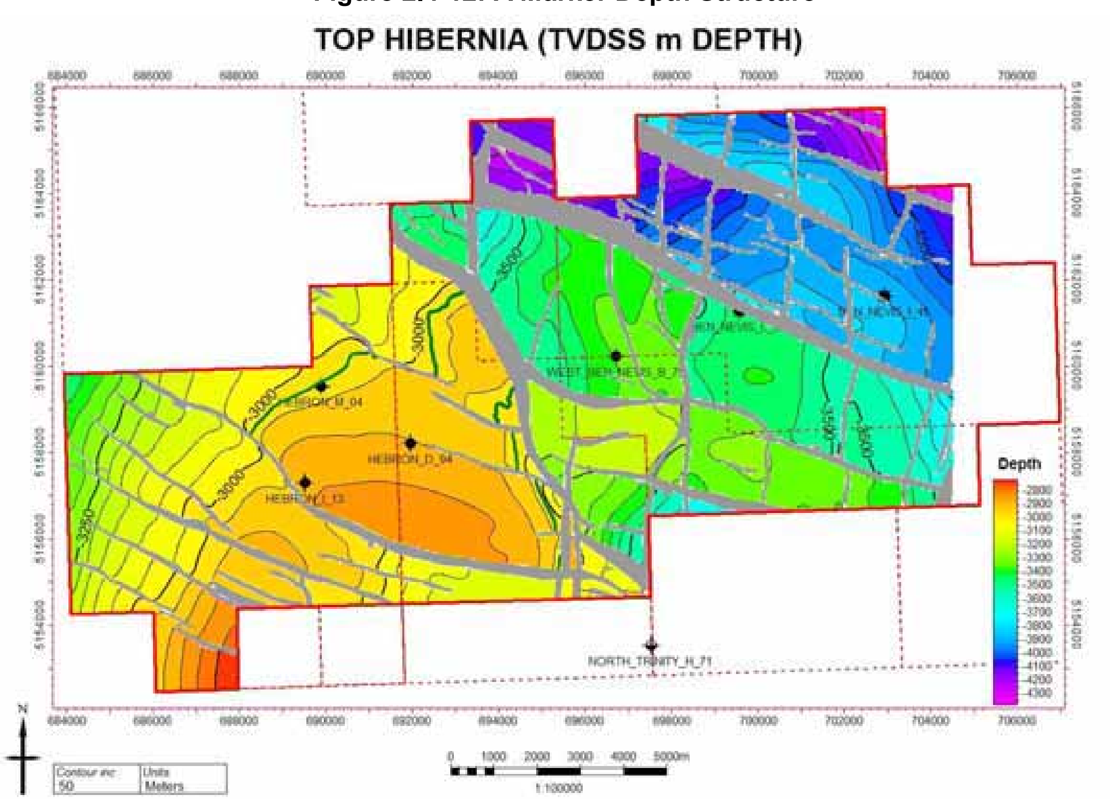


Figure 2.4-13: Top Hibernia Depth Structure
Penetrated OWC is shown as green line

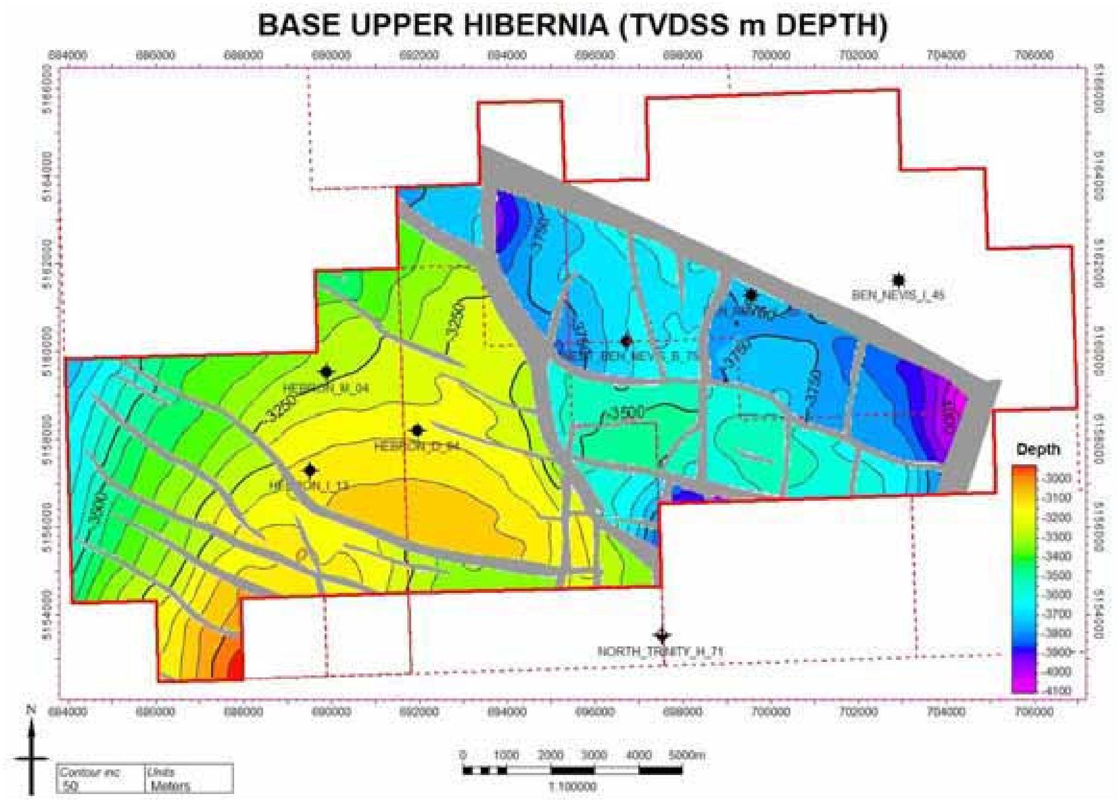


Figure 2.4-14: Base Hibernia Depth Structure

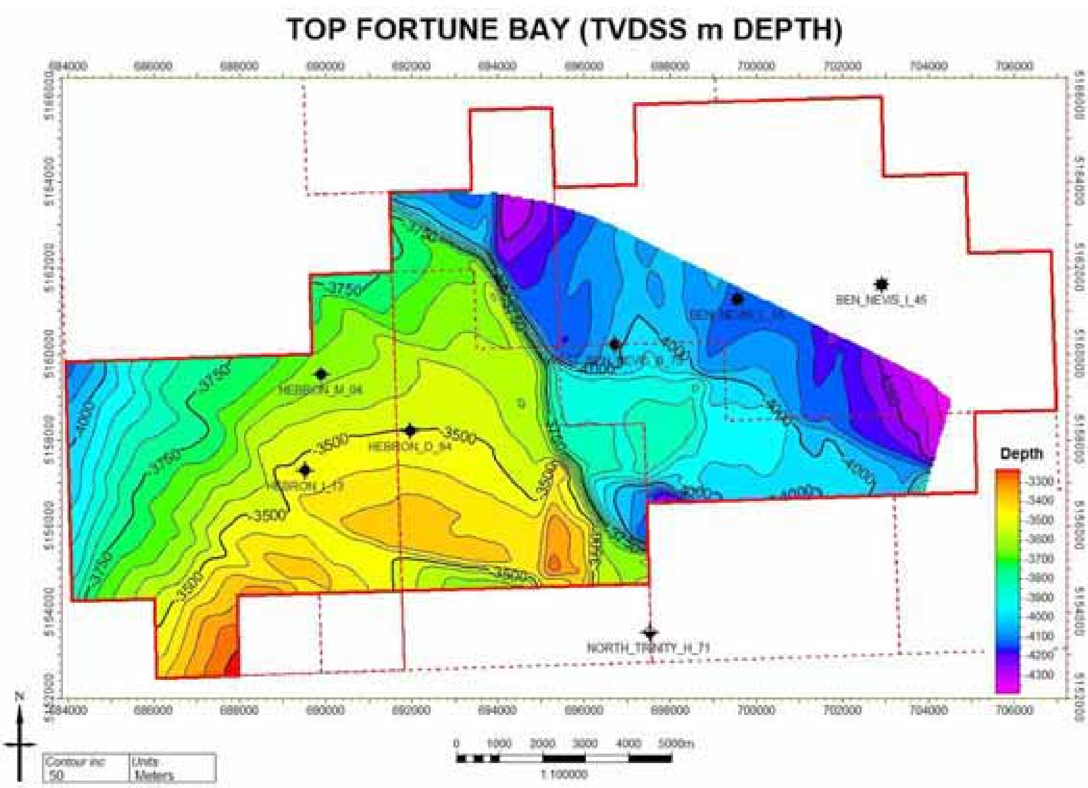


Figure 2.4-15: Top Fortune Bay Depth Structure

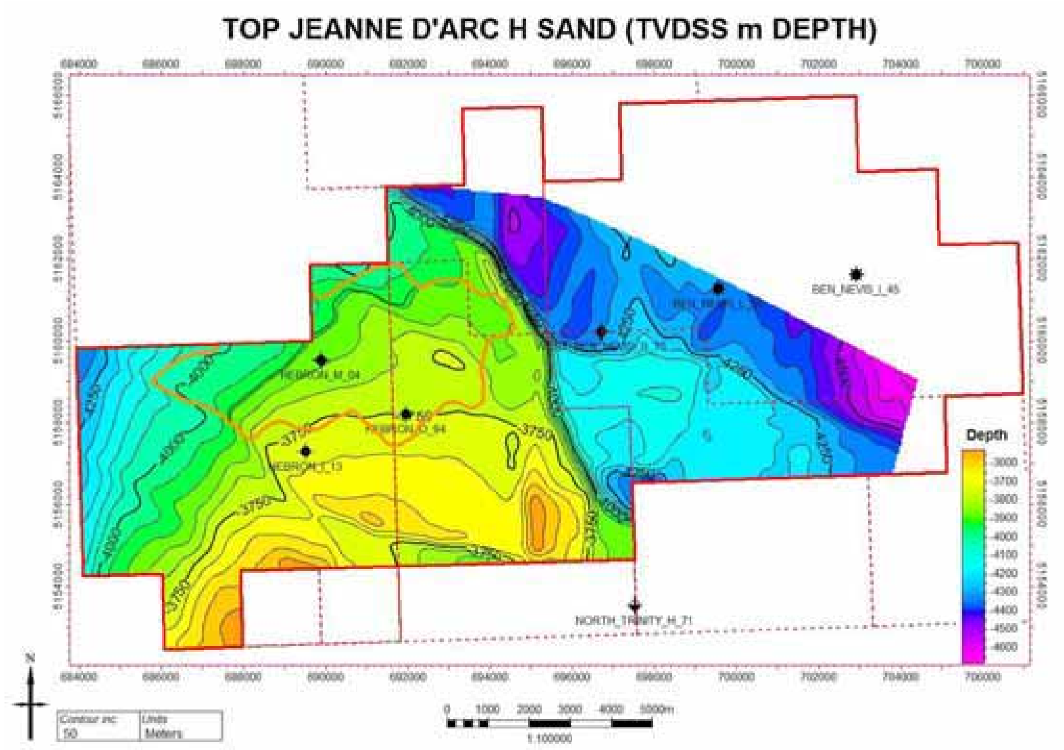


Figure 2.4-16: Top Jeanne d'Arc H Sand Depth Structure Maps

Penetrated OWC is shown as green line. The edge of the H-sand channel is shown as the orange line**.**

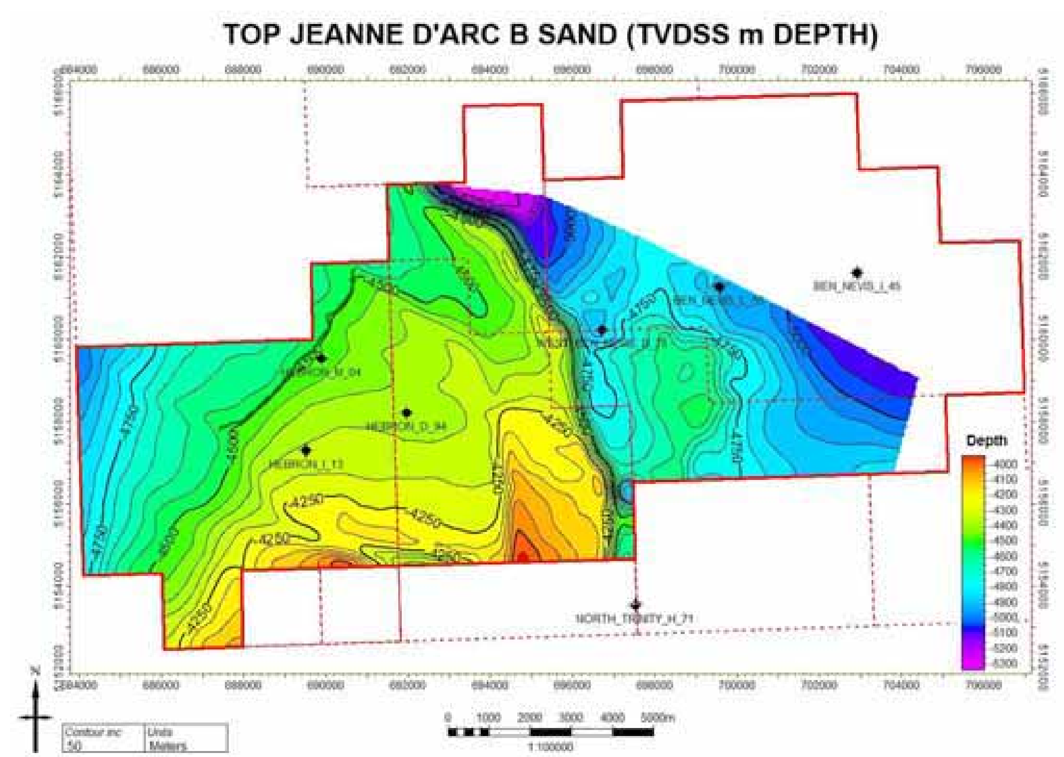


Figure 2.4-17: Top Jeanne d'Arc B Sand Depth Structure Maps

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 V0+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 V0 values for each well and layer is then calculated. The V0 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 V0 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 Huntec 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 (±0.5m) 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.

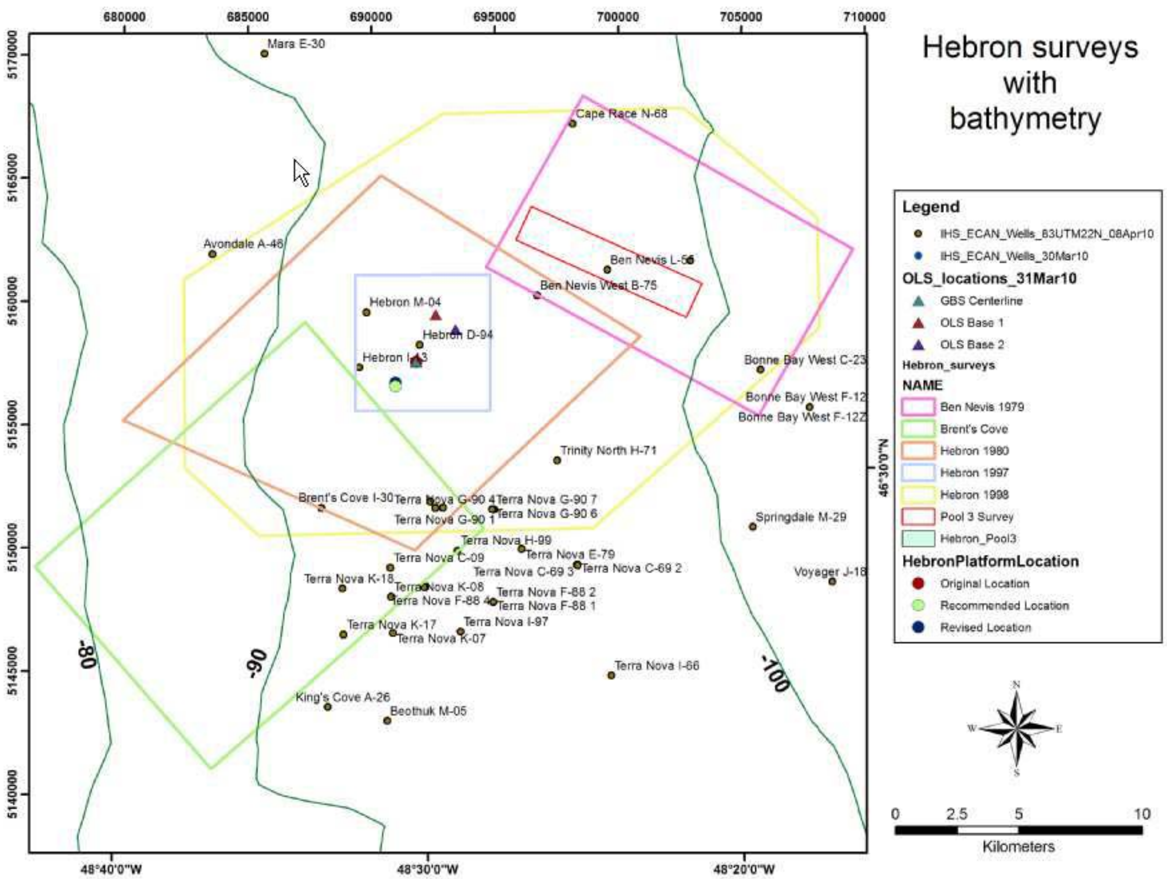


Figure 2.4-18: Hebron Project Area Survey Locations and Bathymetry

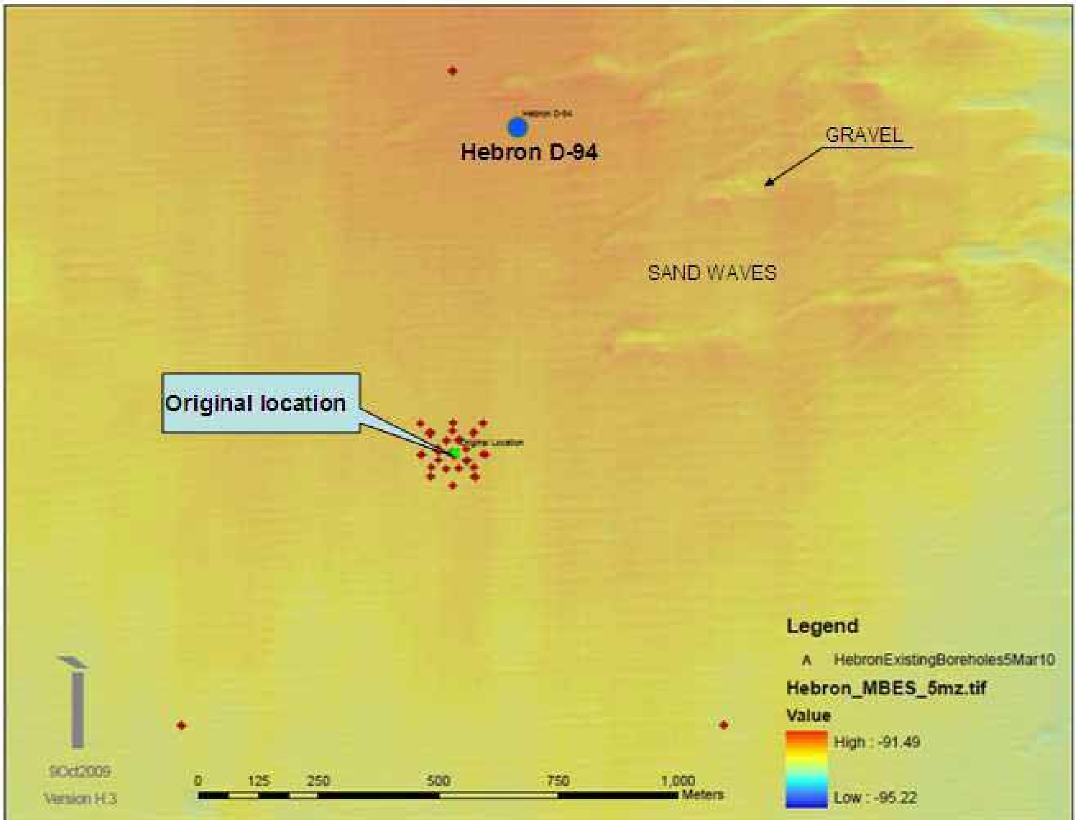


Figure 2.4-19: Multi-beam Data of Planned GBS Location (Original Location)

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.

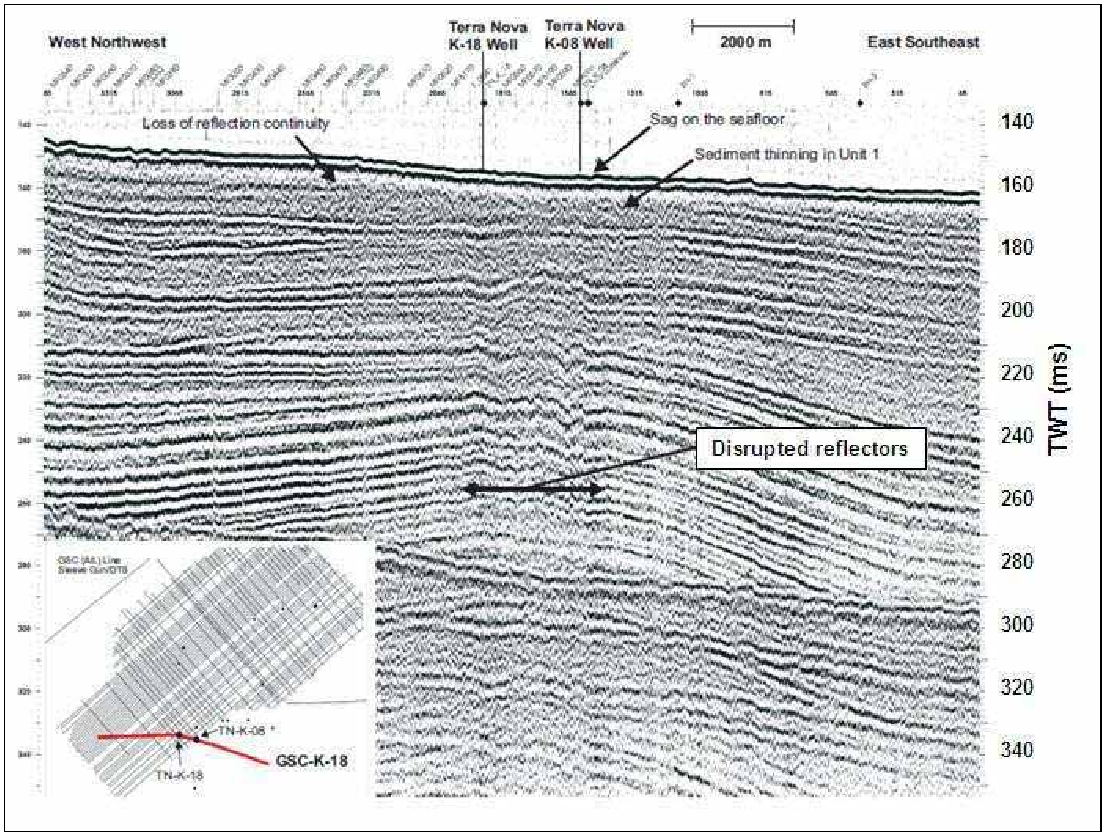


Figure 2.4-20: Airgun Profile (10 Cu. In.) through Terra Nova K-18 Anomaly

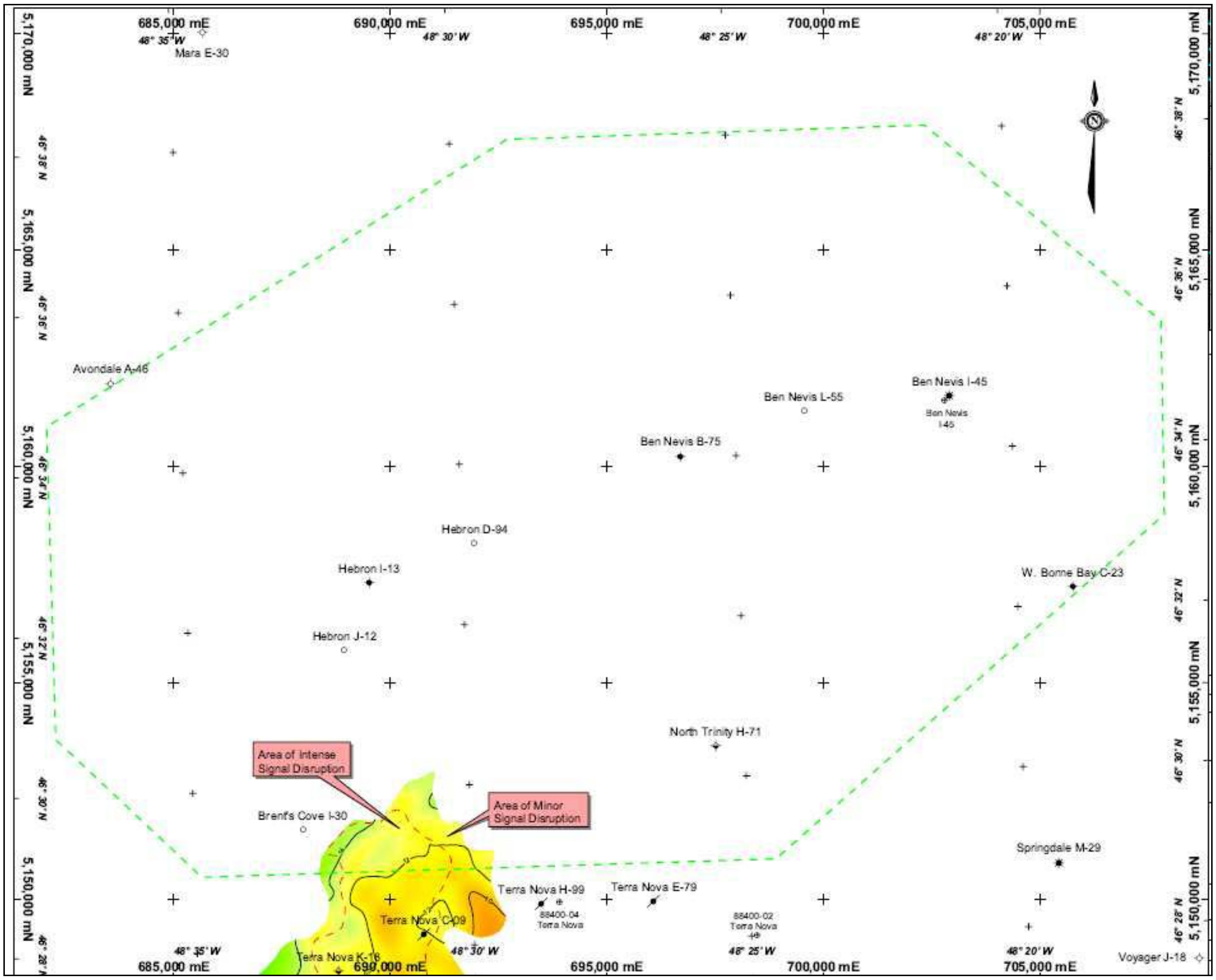


Figure 2.4-21: Lateral Extent of the Anomaly

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 Banqereau 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.

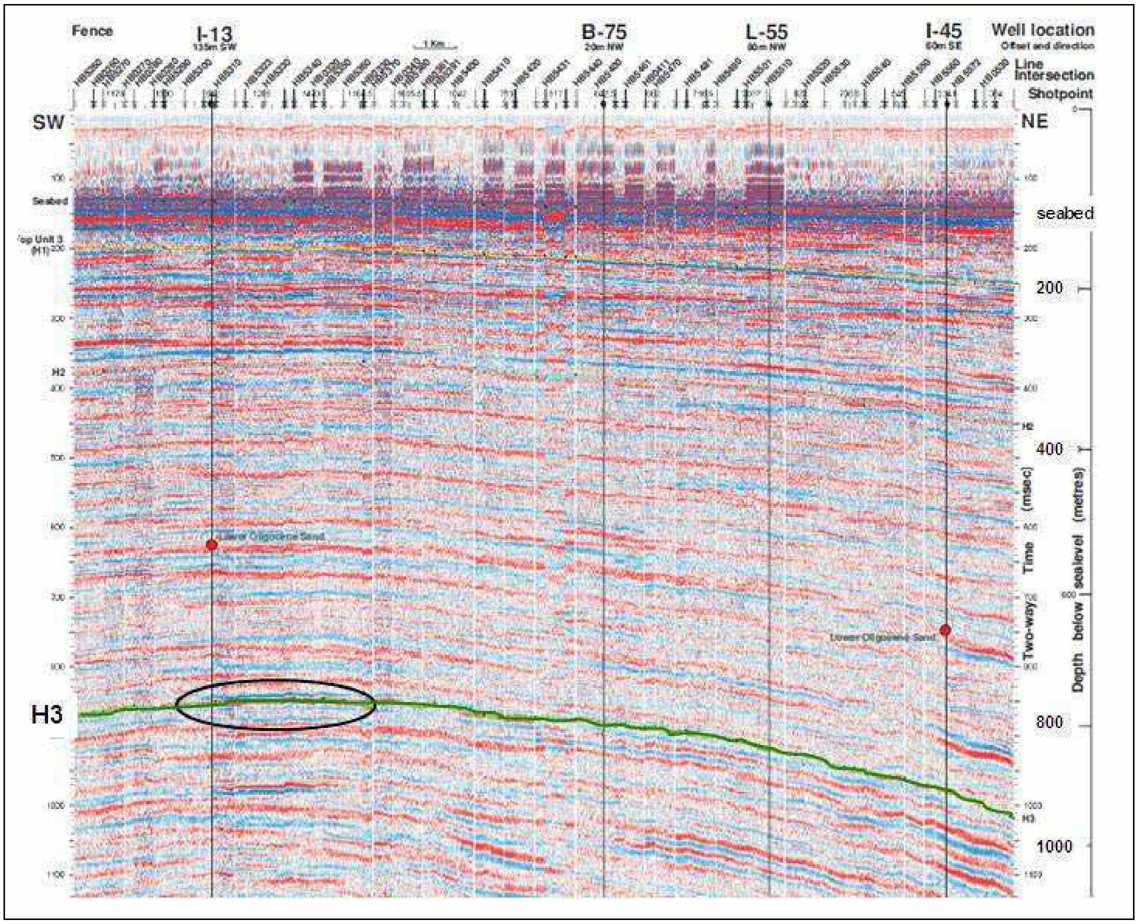


Figure 2.4-22: Seismic SW-NE traverse through the Hebron I-13, West Ben Nevis B-75, Ben Nevis L-55 and Ben Nevis I-45 wells

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

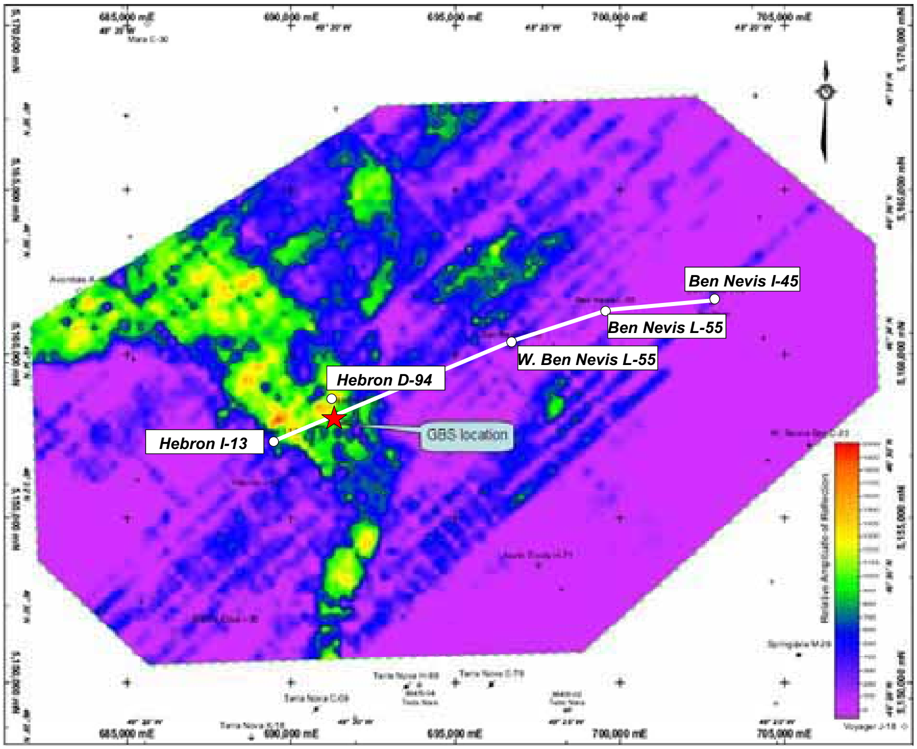


Figure 2.4-23: Relative Amplitude on H3 Horizon
This figure illustrates line of section shown in Figure 2.4-22

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.

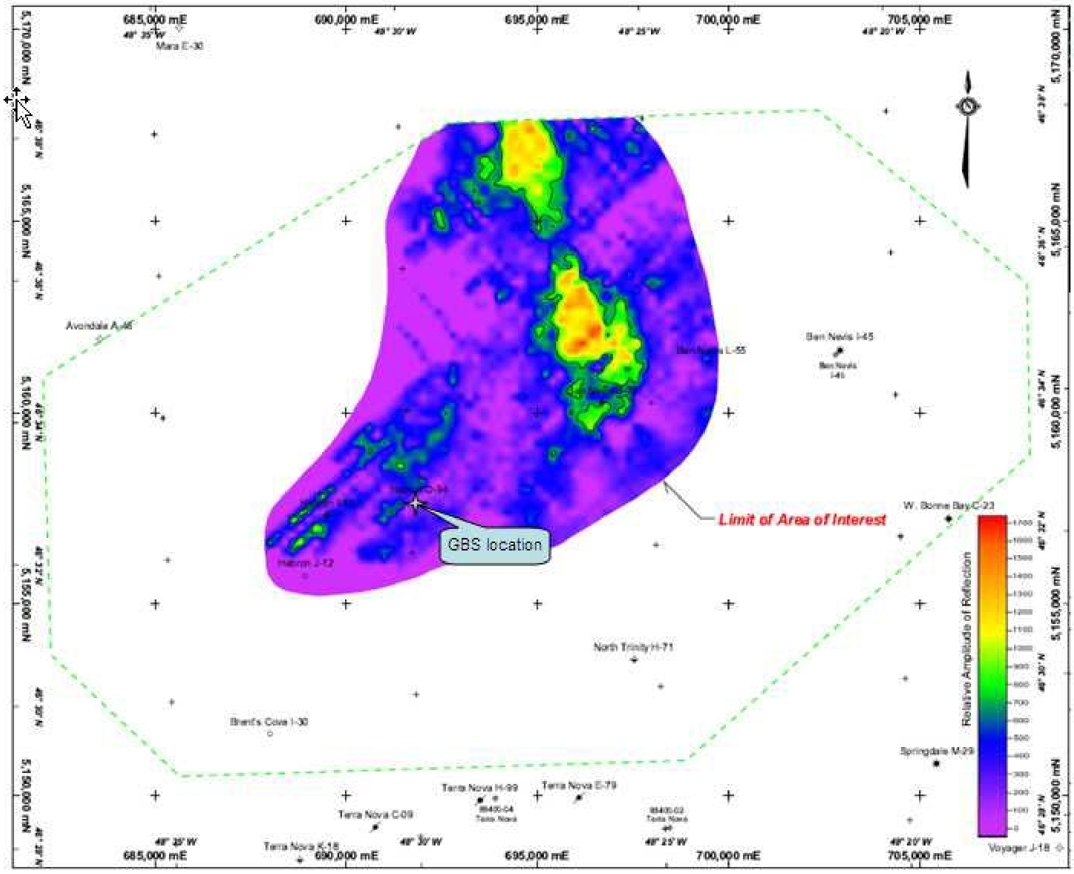


Figure 2.4-24: Relative Amplitude on Horizon within Oligocene

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.

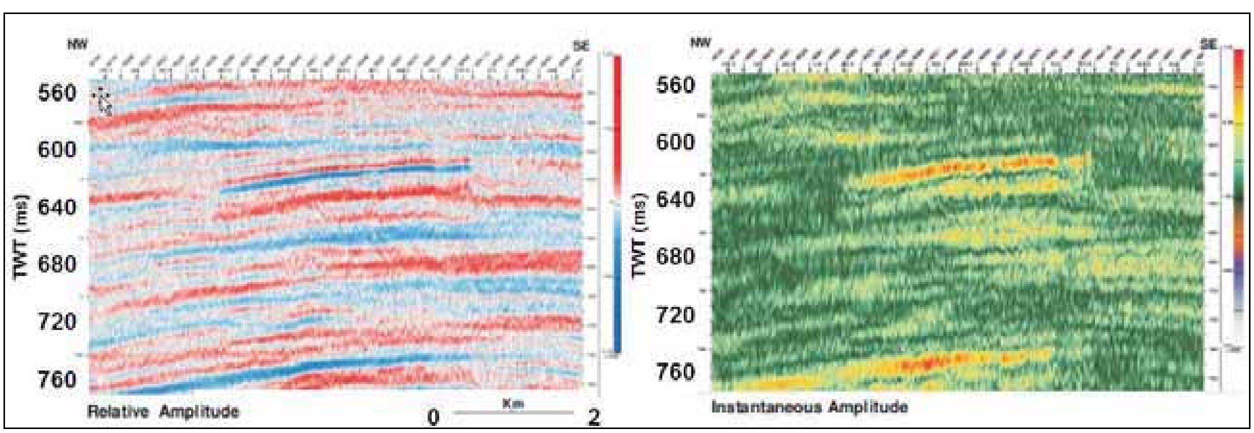


Figure 2.4-25: Seismic Attributes of the Anomaly within Oligocene

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 Huntec 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.

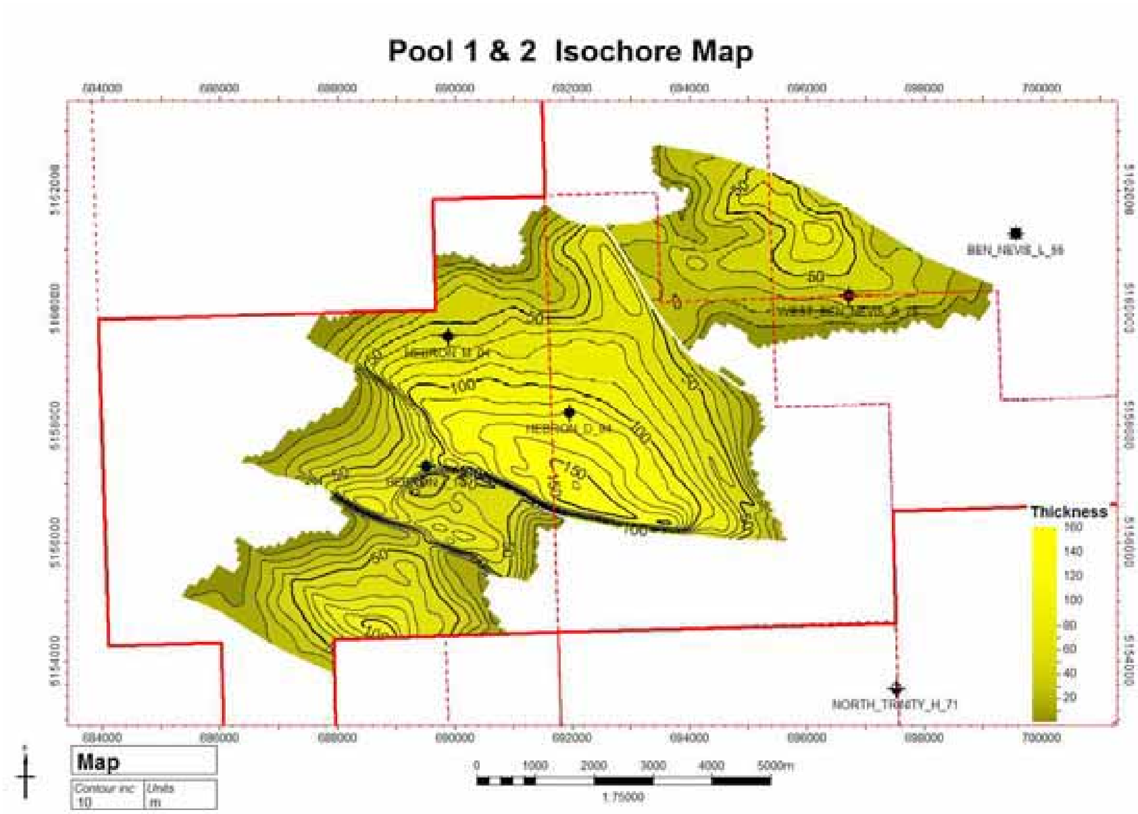


Figure 2.5-1: Pool 1 & 2 Isochore Map

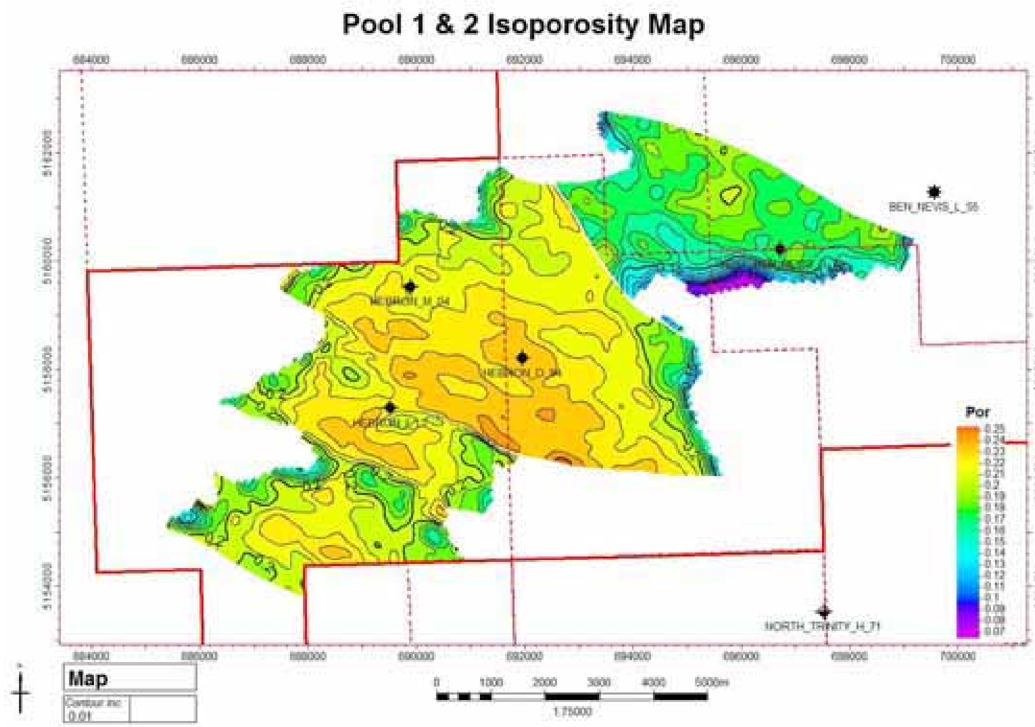


Figure 2.5-2: Pool 1 & 2 Isoporosity Map

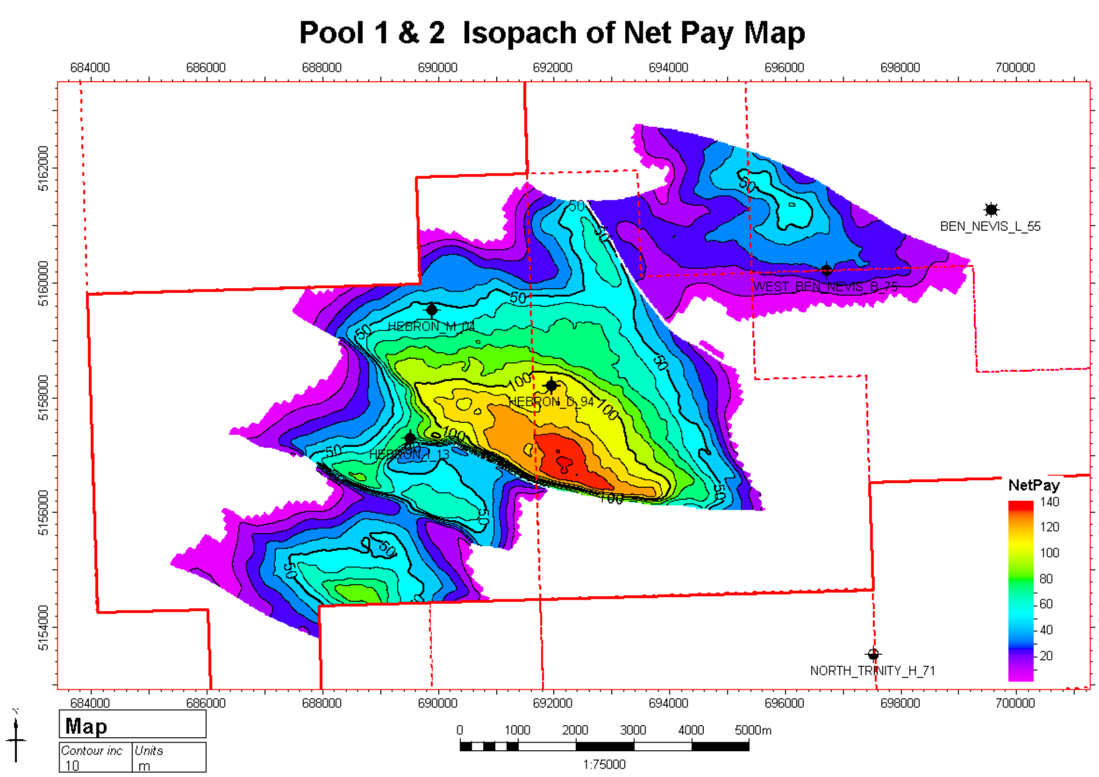


Figure 2.5-3: Pool 1 & 2 Isopach of Net Pay Map

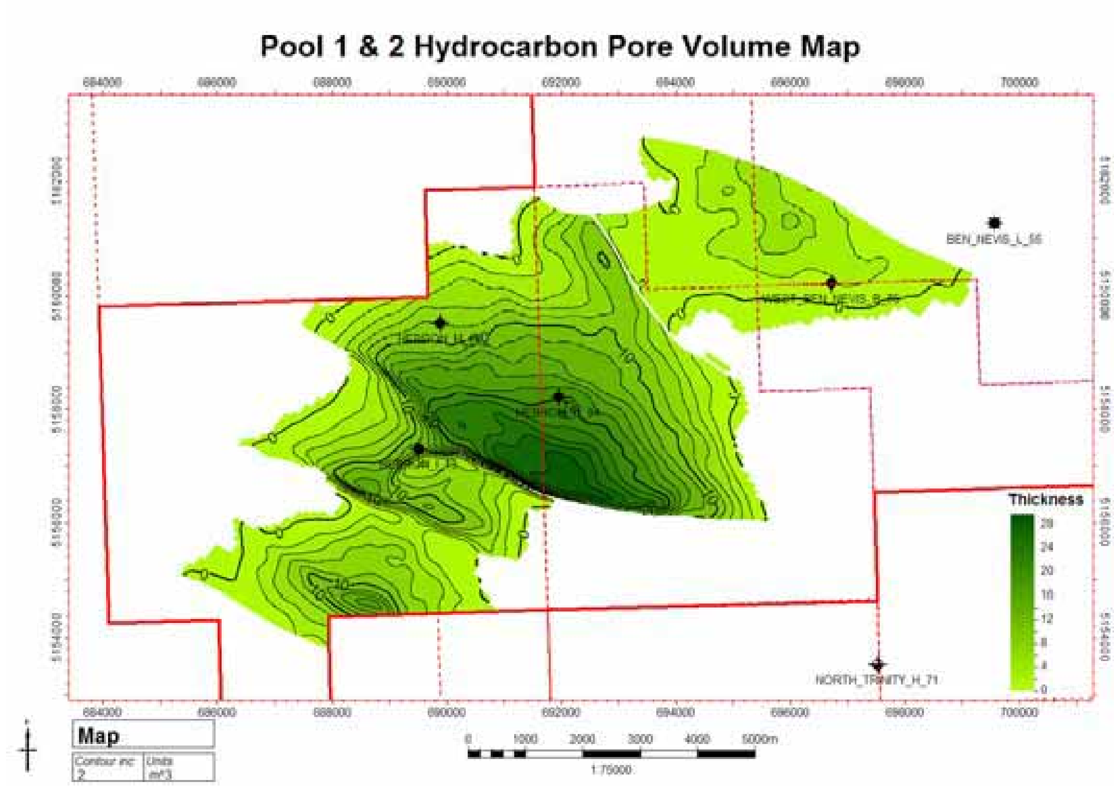


Figure 2.5-4: Pool 1 & 2 Hydrocarbon Pore Volume Map

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.

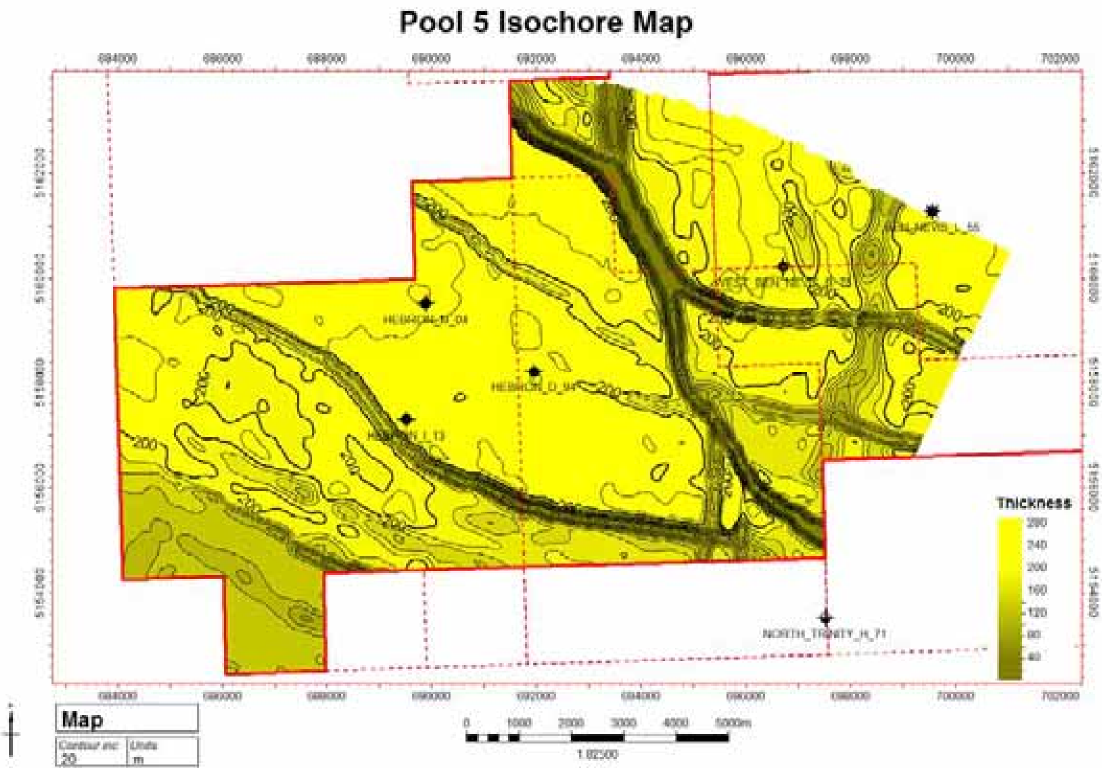


Figure 2.5-5: Pool 5 Isochore Map

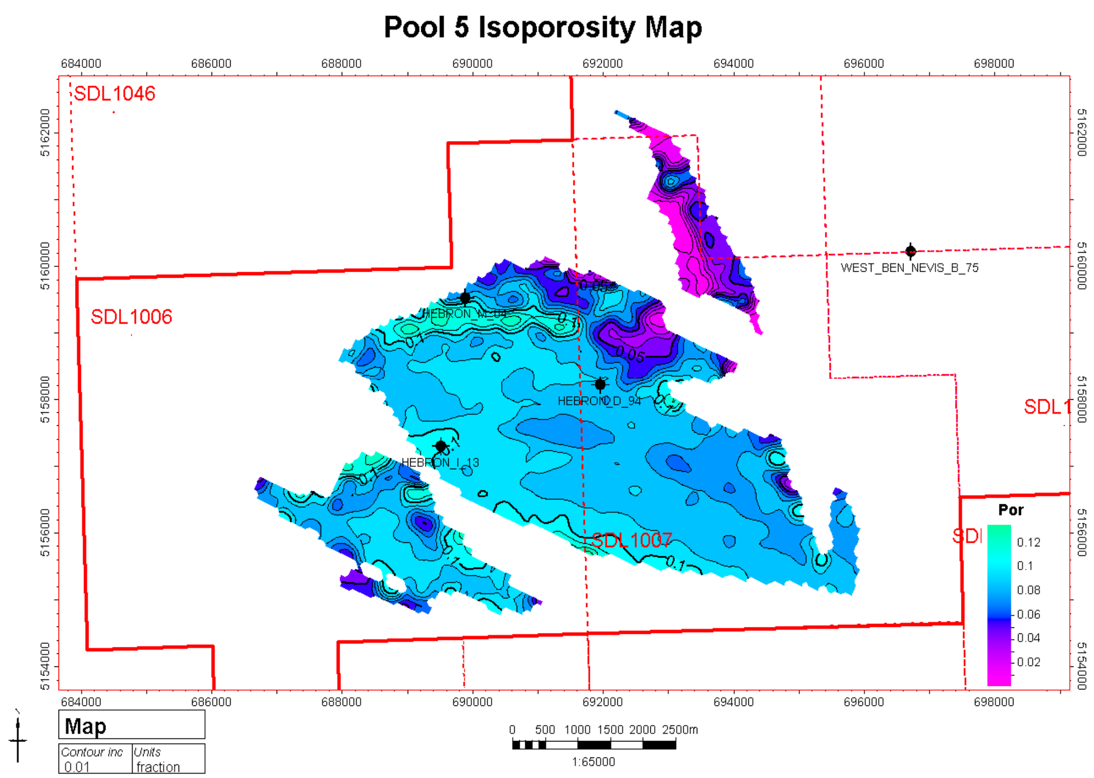


Figure 2.5-6: Pool 5 Isoporosity Map

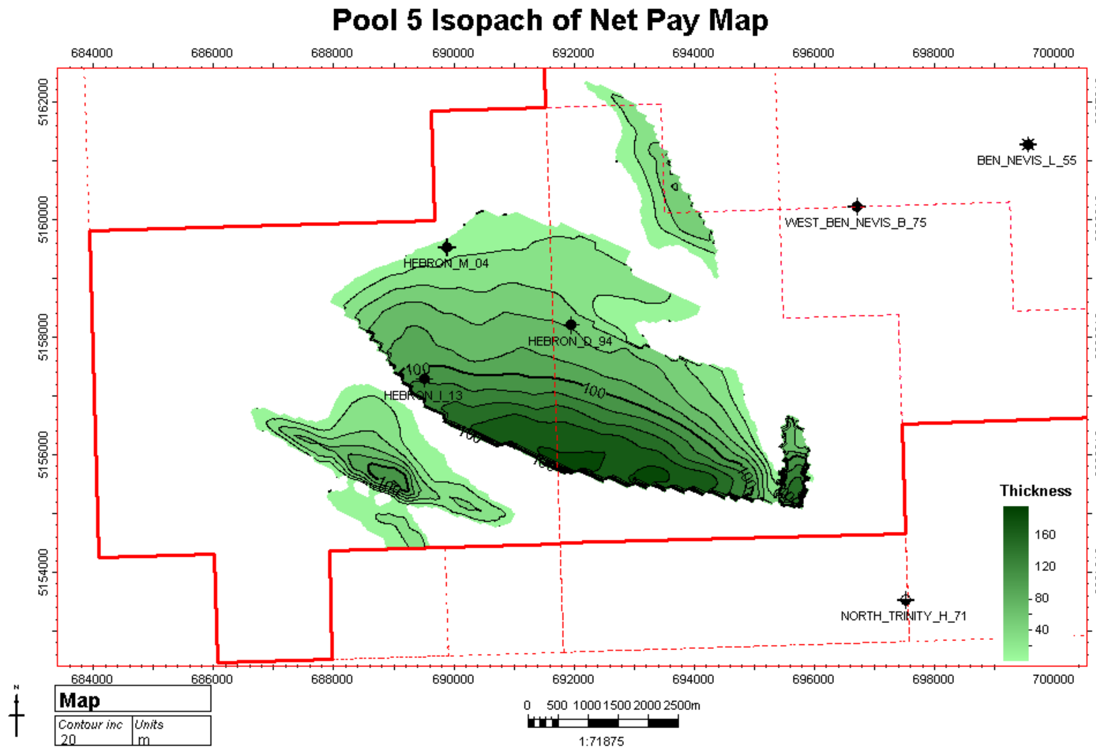


Figure 2.5-7: Pool 5 Isopach of Net Pay Map

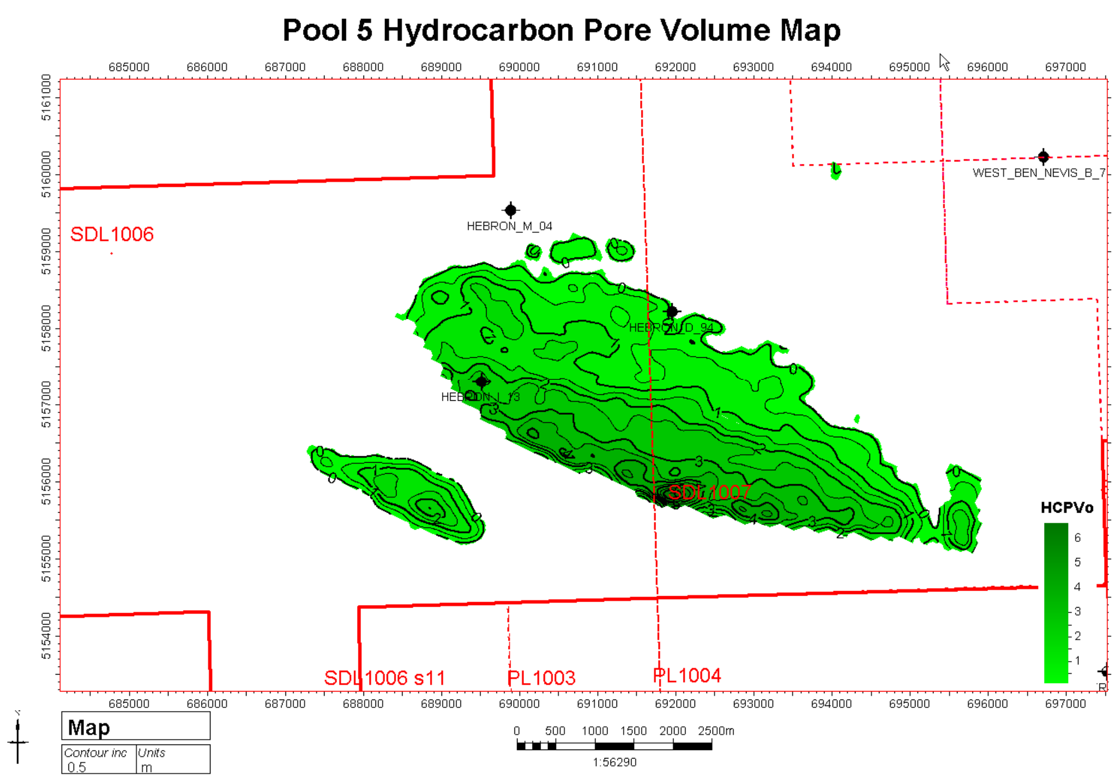


Figure 2.5-8: Pool 5 Hydrocarbon Pore Volume Map

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.

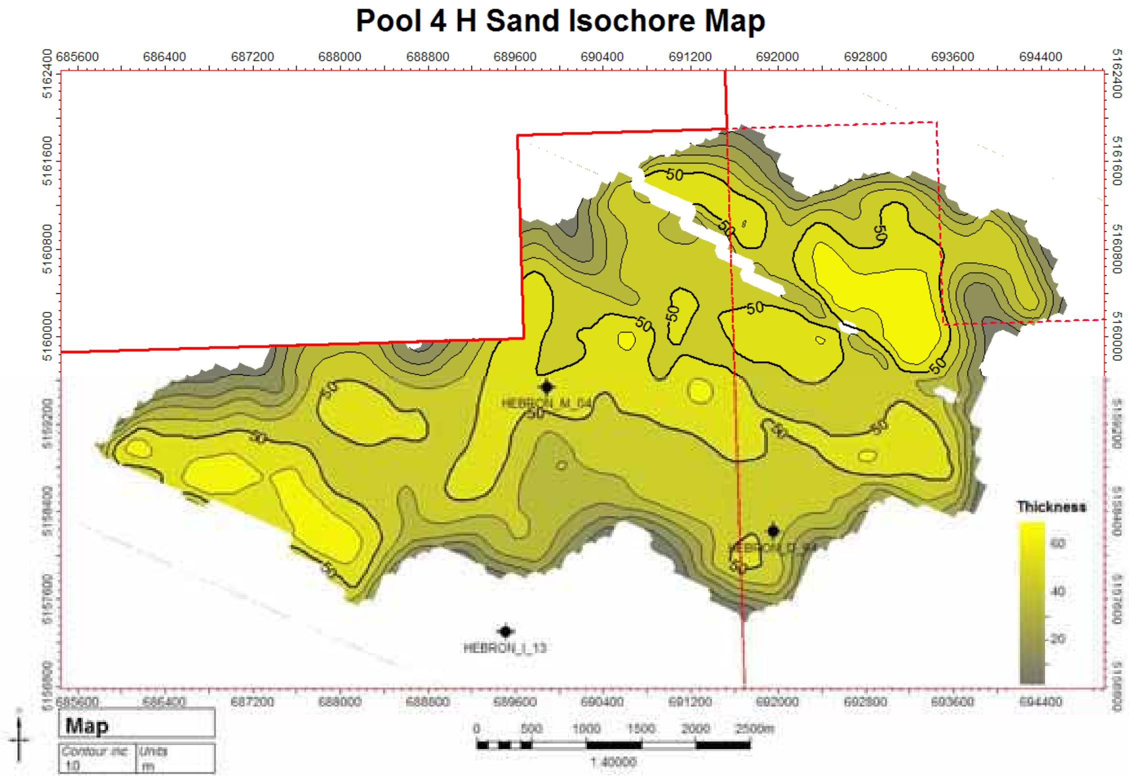


Figure 2.5-9: Pool 4 H-Sand Isochore Map

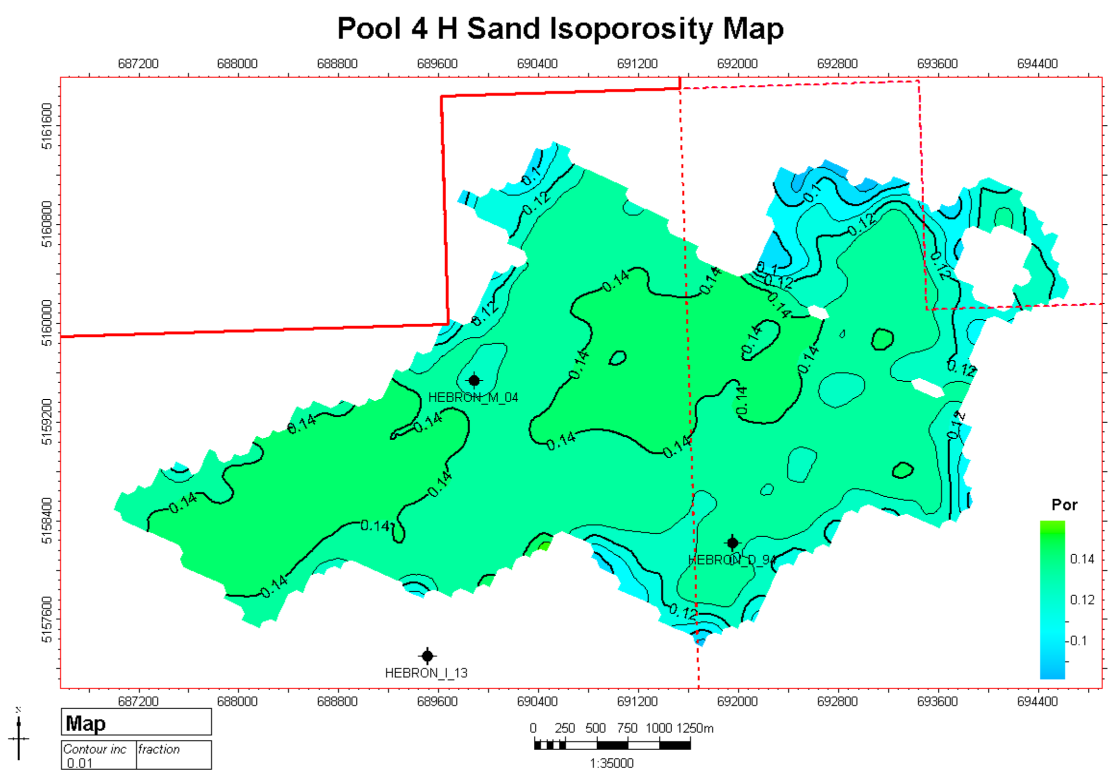


Figure 2.5-10: Pool 4 H-Sand Isoporosity Map

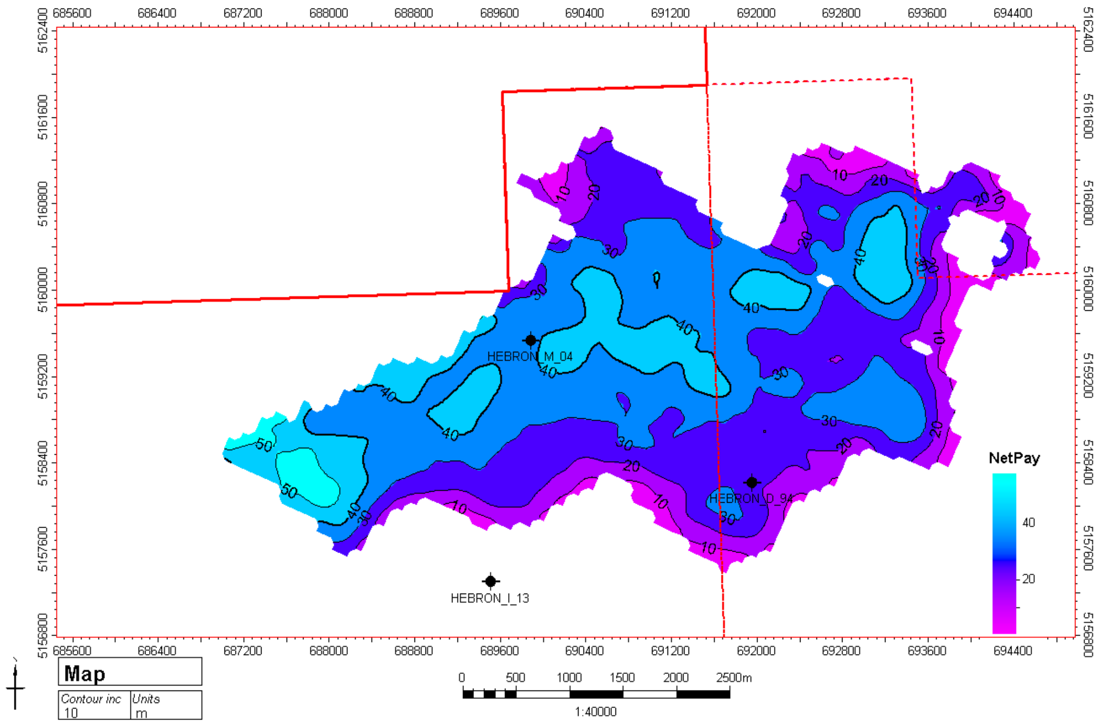


Figure 2.5-11: Pool 4 H-Sand Isopach of Net Pay Map

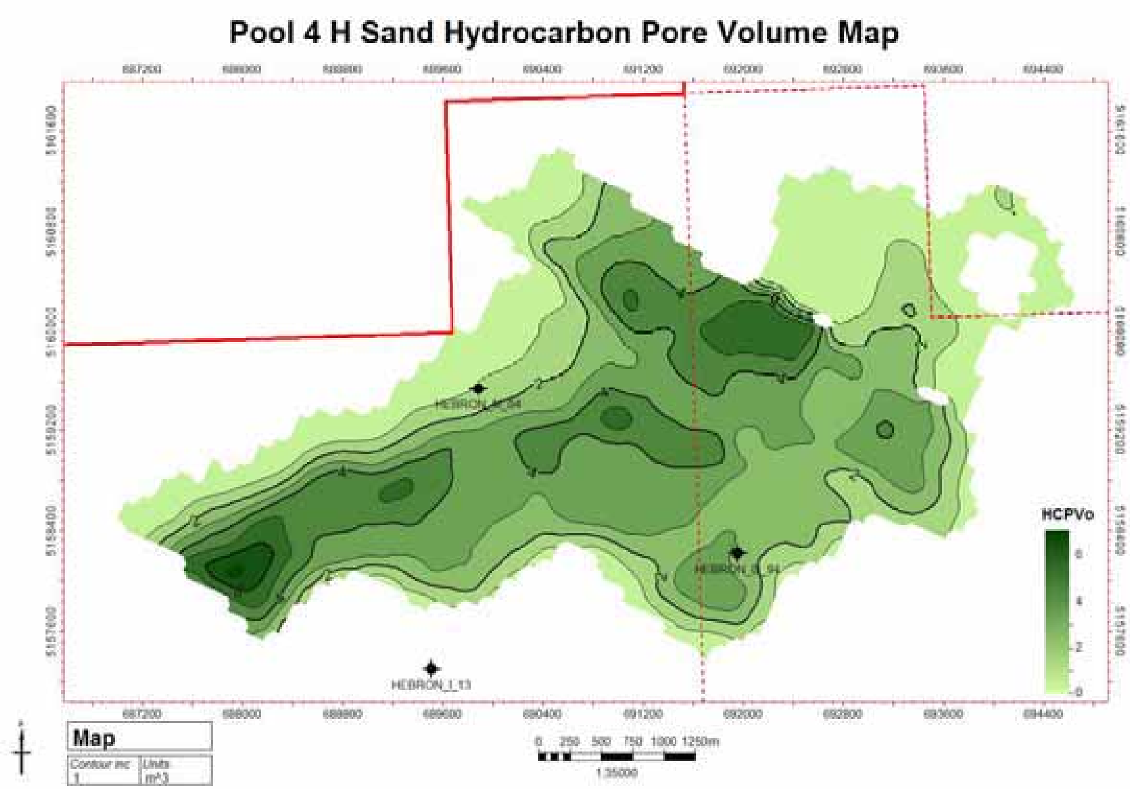


Figure 2.5-12: Pool 4 H-Sand Hydrocarbon Pore Volume Map

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.

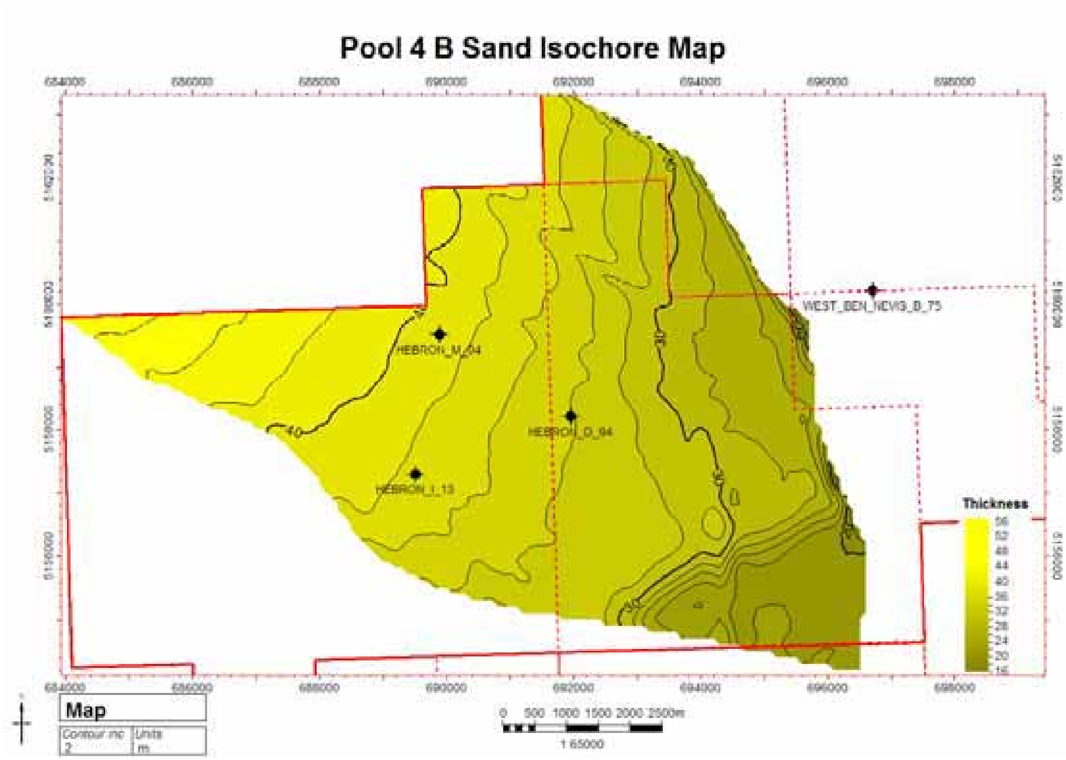


Figure 2.5-13: Pool 4 B Sand Isochore Map

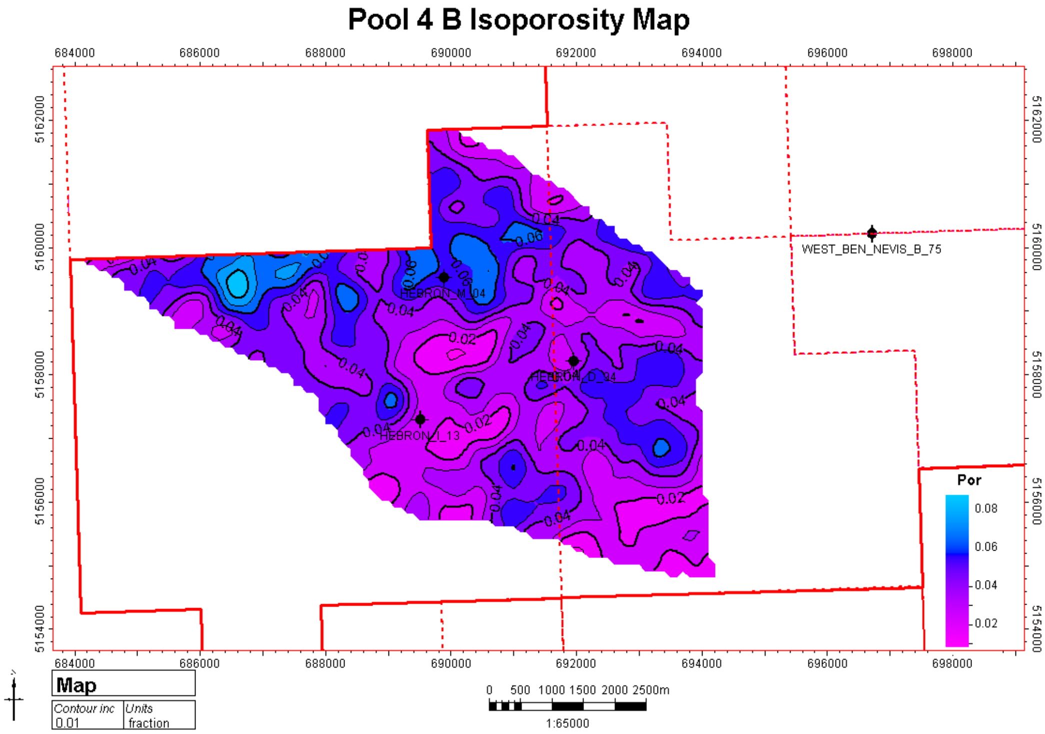


Figure 2.5-14: Pool 4 B Sand Isoporosity Map

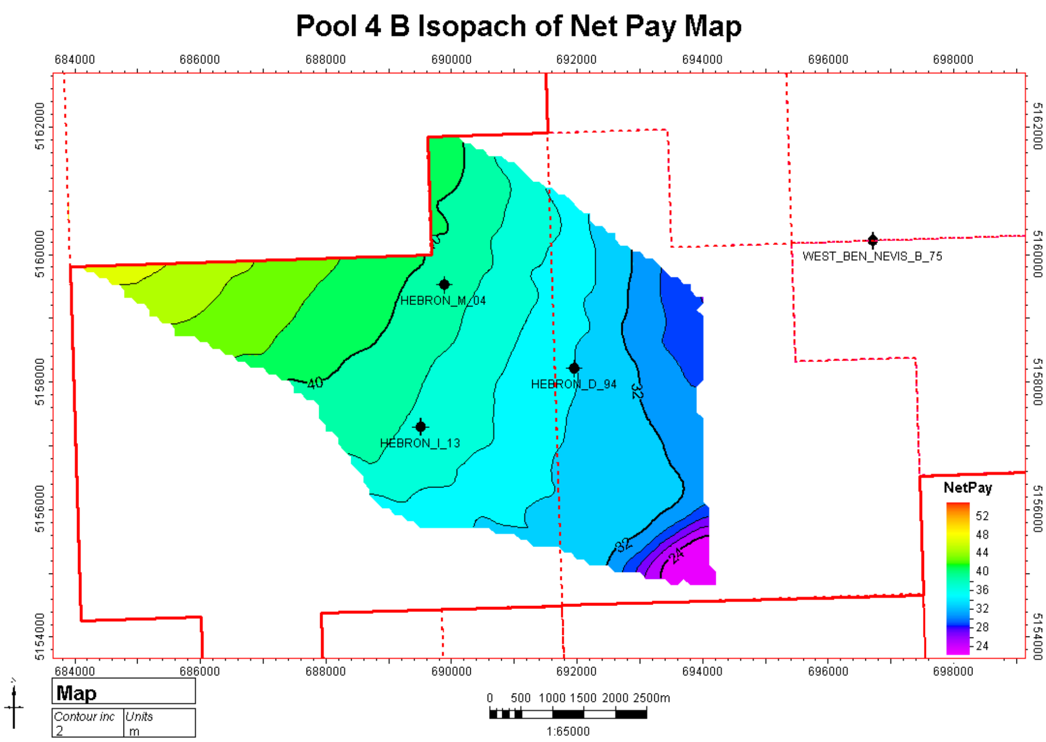


Figure 2.5-15: Pool 4 B Sand Isopach of Net Pay Map

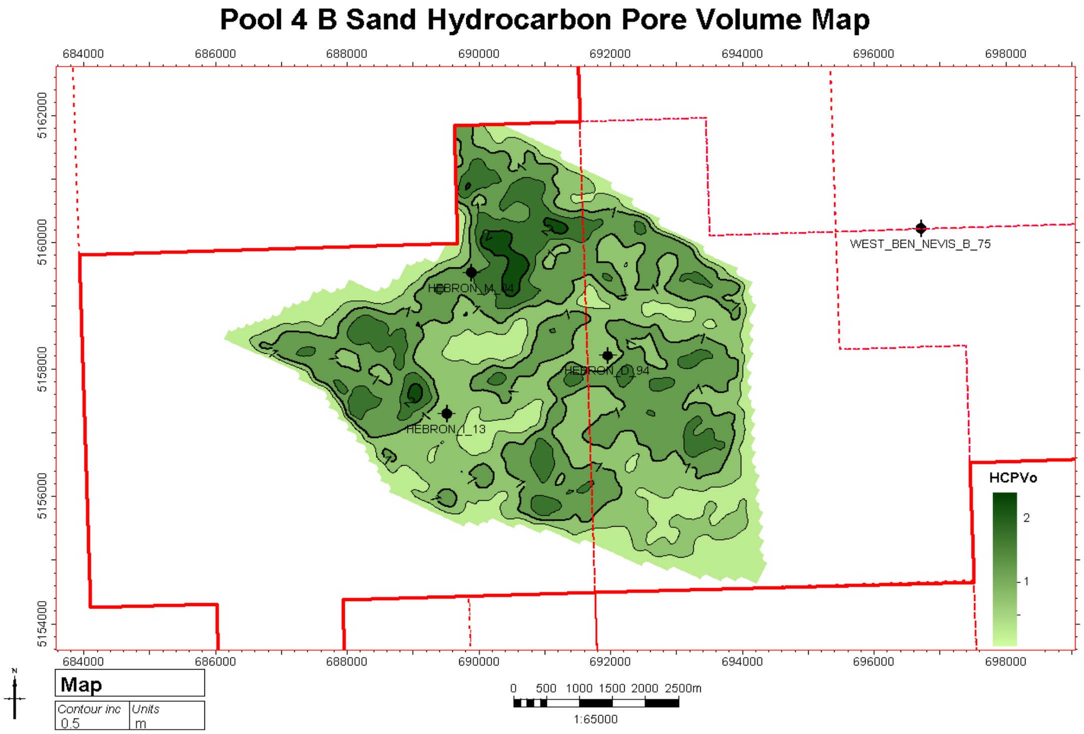


Figure 2.5-16: Pool 4 B Sand Hydrocarbon Pore Volume Map

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.

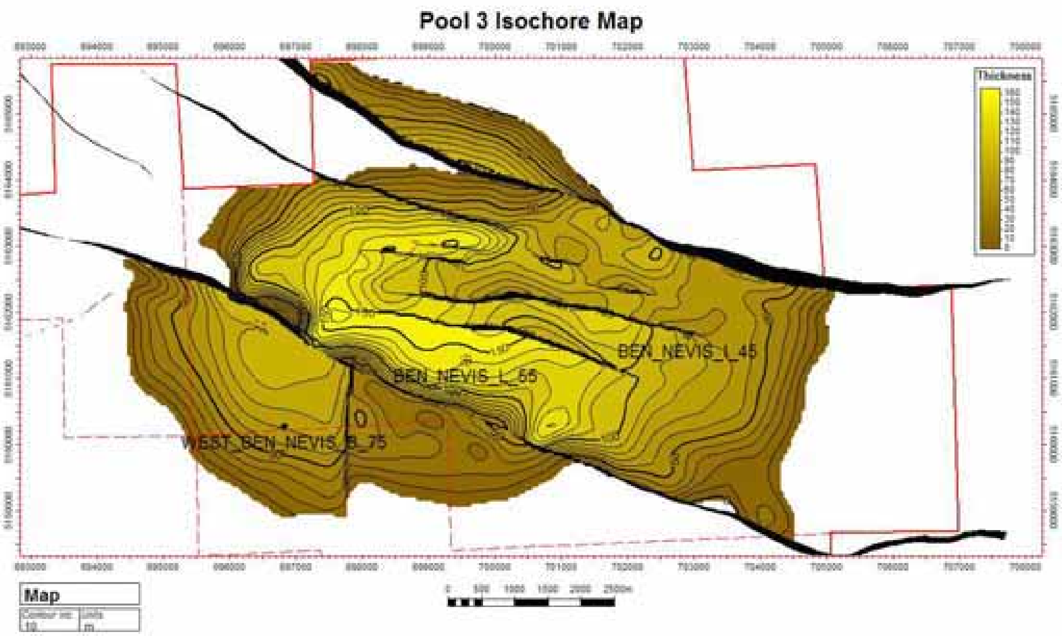


Figure 2.5-17: Pool 3 Isochore Map

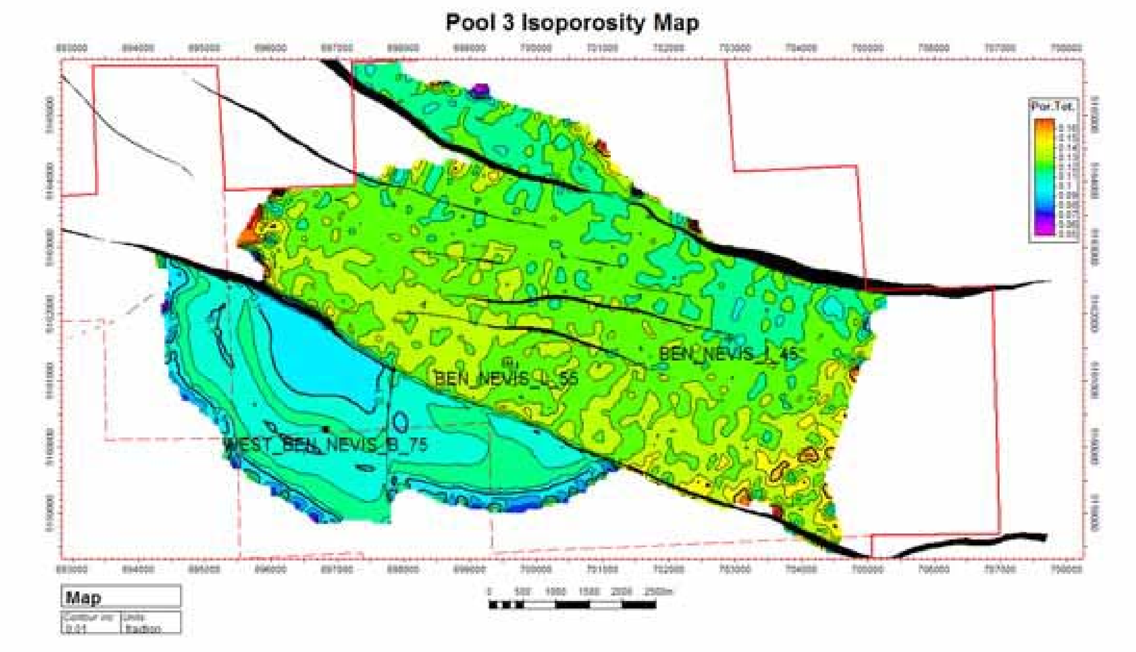


Figure 2.5-18: Pool 3 Isoporosity Map

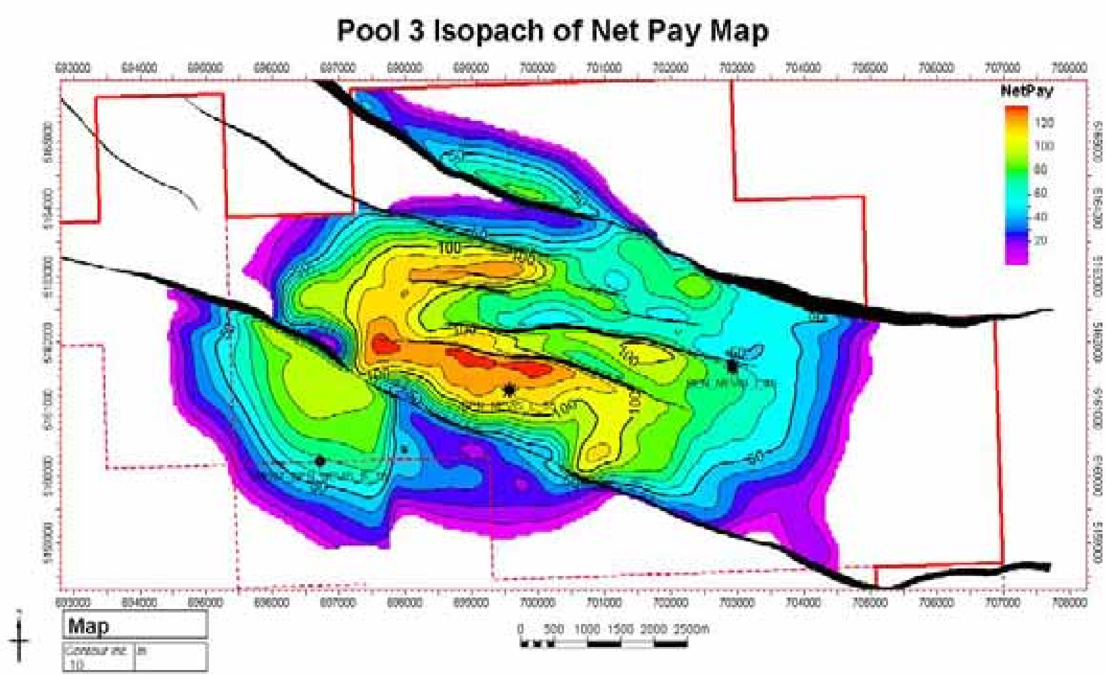


Figure 2.5-19: Pool 3 Isopach of Net Pay Map

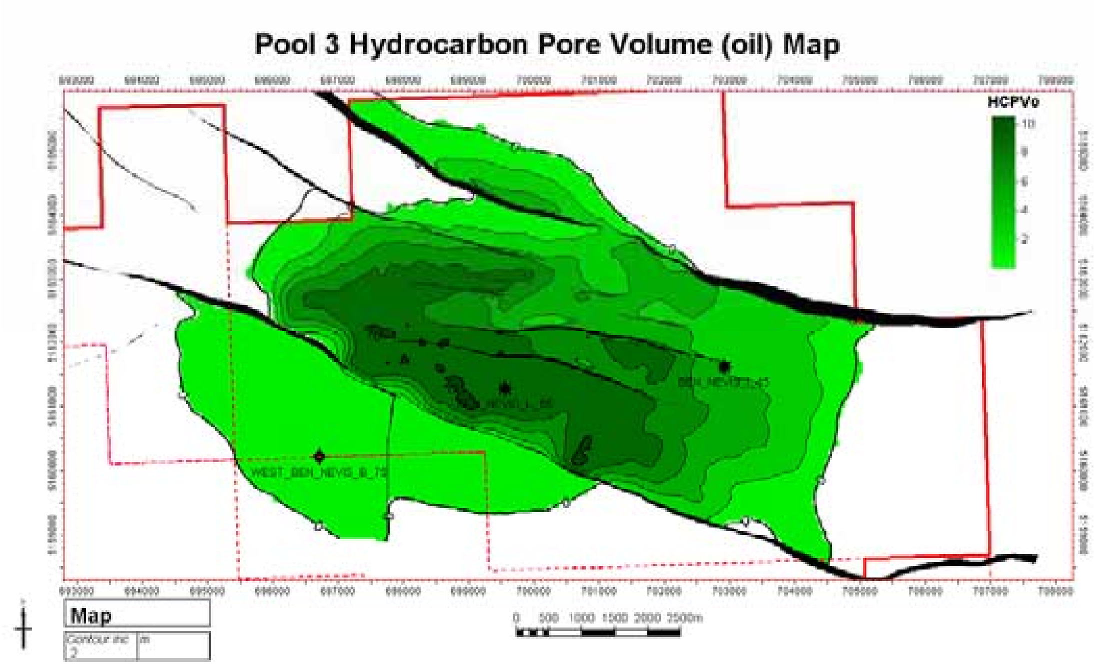


Figure 2.5-20: Pool 3 Hydrocarbon Pore Volume Map

2.6 References

Ainsworth, N.R. and L.A. Riley, 2006, Hebron-Ben Nevis Oilfields Offshore Eastern Canada; Biostratigraphy of the Ben Nevis Formation (Aptian); Wells: Ben Nevis L-55, West Ben Nevis B-75, Hebron P-94 and Hebron M-04.

Bowes, F.G. 1998. An overview of the Jeanne d'Arc Basin. Mobil Oil Canada internal report.

Desilva, N.R., 2005, Application of Petroleum System Logic to Jeanne d'Arc Basin Offshore Newfoundland *in* R. Hiscott and A. Pulham, eds., Petroleum Resources and Reservoirs of the Grand Banks, Eastern Canadian Margin: Geological Association of Canada.

Ford Biostratigraphic Services, 1998, Mobil et al. Hebron I-13, East Coast Offshore Canada, Palynostratigraphy and Zonation Jurassic Interval 4000 to 4723m TD.

Fowler, M.G., A.P. Hamblin, D. Hawkins, L.D. Stasiuk, and I. Knight, 1995, Petroleum geochemistry and hydrocarbon potential of Cambrian and Ordovician rocks of western Newfoundland: *Bull. Can. Petrol. Geol*. **43** (1995) pp. 187-213.

Fowler, M.G. and M. Obermajer, 1999. Reassessing the petroleum geochemistry of the Scotian Shelf, offshore eastern Canada—a cautionary tale for geochemists. Abstracts of the 19th International Meeting on Organic Geochemistry, September 1999, Istanbul, Turkey, pp. 469–440.

Gower, S., 1990, Hibernia Formation of the Jeanne d’Arc basin: C-NLOPB Report# GL-CNOPB-1988-05.

Haugen, E., J. Costello, L. Wilcox, E. Albrechtsons, and I. Kelly, 2007, Reservoir Management Challenges of the Terra Nova Offshore Field: Lessons Learned after 5 Years of Production: Society of Petroleum Engineers, paper number 109587.

Hiscott, Richard N., and Andrew J. Pulham. 2005. *Petroleum resources and reservoirs of the Grand Banks, eastern Canadian margin. St. John's, N.L.:* Geological Association of Canada.

Hiscott, R.N., R.C.L. Wilson, F.M. Gradstein, V. Pujalte, J. Garcia-Mondejar, R.R. Boudreau, and H.A. Wishart, 1990, Comparative Stratigraphy and Subsidence History of Mesozoic Rift Basins of North Atlantic: Comparative Stratigraphy and Subsidence History of Mesozoic Rift Basins of North Atlantic.

Jenden, P.D., 2000, Review of Hebron Geochemical Studies, Presentation to Partners 5 September 2000.

MacKay, A.H. and A.J. Tankard, 1990, Hibernia Oil Field – Canada, Jeanne d'Arc Basin, Grand Banks, Offshore Newfoundland: TR: Structural Traps III: Tectonic Fold and Fault Traps.

Magoon, L.B., T.L. Hudson, and K.E. Peters, 2005, Egret-Hibernia (!), a significant petroleum system, northern Grand Banks area, offshore eastern Canada: American Association of Petroleum Geologists Bulletin v. 89, no. 9.

Powell, T.G., 1985, Paleogeographic implications for the distribution of Upper Jurassic source beds: offshore eastern Canada. *Bull. Can. Petrol. Geol.* **33** (1985), pp. 116–119.

Richards, B., P. Vrolijk, J. Gordon, and B. Miller, 2008, Reservoir Connectivity Analysis of a Complex Combination Trap: Terra Nova Field, Jeanne d'Arc Basin, Newfoundland, Canada. Presentation to International Reservoir Compartmentalization Conference, The Geological Society, London, March 5-6.

Shimeld, J.W. and P.N. Moir, 1999 (ed 2001), Heavy Oil Accumulations in the Jeanne d'Arc Basin: A Case Study in the Hebron, Ben Nevis, and West Ben Nevis Oil Fields, Geological Survey of Canada, GSC Open File Report # D4012

Sinclair, I.K., 1988, Evolution of Mesozoic-Cenozoic Sedimentary Basins in the Grand Banks Area of Newfoundland and Comparison with Falvey's (1974) Rift Model: *Bull. Can. Petrol. Geol.* **36** (1988), no. 3.

Sinclair, I.K., MacAlpine, K.D., Sherwin, D.F., and McMillan, N.J., 1992, Part 1-Geological framework, in Petroleum resources of the Jeanne d' Arc basin and environs, Grand Banks, Newfoundland: Geological Survey of Canada, Paper 92-8, p. 1-38.

Sinclair, I.K., 1993, Tectonism: the dominant factor in mid-Cretaceous deposition in the Jeanne d'Arc Basin, Grand Banks: Marine and Petroleum Geology, v. 10, p. 530 – 549.

Sinclair, I.K., P.M. Shannon, B.P.J. Williams, S.D. Harker, and J.G. Moore, 1994, Tectonic Control on Sedimentary Evolution of three North Atlantic borderland Mesozoic basins: Basin Research, vol. 6, no. 4.

Tankard, A.J. and H. J. Welsink, 1987, Extensional tectonics and stratigraphy of Hibernia oil field, Grand Banks, Newfoundland AAPG Bulletin (October 1987), 71(10):1210-1232

Tankard, A.J., H.L. Welsink, and W.A.M. Jenkins, 1989, Structural Styles and Stratigraphy of the Jeanne d'Arc Basin, Grand Banks of Newfoundland *in* A.J. Tankard and H.R. Balkwill, eds., Extensional Tectonics and Stratigraphy of the North Atlantic Margins: American Association of Petroleum Geologists.

Van Helden Biostratigraphic Services, 1999-04, Petro-Canada et al., Hebron D-94 Jeanne d'Arc Basin, Offshore Eastern Canada Palynological Analysis of 58 Composite Ditch Cutting Samples 1535m to 2105m.

Van Wagoner, J.C., R.M. Mitchum, K.M. Campion, and V.D. Rahmanian, 1990, Siliciclastic sequence stratigraphy and well log, cores and outcrops: Tulsa, AAPG methods in exploration series, no. 7.

Veritas, 2006, Hebron 3D Antistropic Pre-Stack Time Migration (APSTM) Re-Processing Report, pp 61.

von der Dick, H., J.D. Meloche, J. Dwyer, and P. Gunther, 1989, Source-rock geochemistry and hydrocarbon generation in the Jeanne d'Arc Basin, Grand Banks, offshore eastern Canada. *J. Petrol. Geol.* **12** (1989), pp. 51–68.

Wilcox, L.B., D.E. Couturier, and M.D. Hewitt, 1995, Tectonic Controls on Upper Jurassic to Lower Cretacious Reservoir Architecture in the Jeanne d'Arc Basin, with Some Comparisons from the Porcupine and Moray Firth Basins *in* P.F. Croker and P.M. Shannon, eds., Geological Society Special Publication: London, The Geological Society, no. 93.

Williams, B.P.J., P.M. Shannon, and I.K. Sinclair, 1999, Comparative Jurassic and Cretaceous tectono-stratigraphy and reservoir development in the Jeanne d'Arc and Porcupine basins *in* A.J. Fleet and S.A.R. Boldy, eds., Petroleum Geology of Northwest Europe: Proceeding of the 5th Conference: London, The Geological Society.

Williamson, M.A., 1992, The subsidence, compaction, thermal and maturation history of the Egret Member source rock, Jeanne d'Arc Basin, offshore Newfoundland: *Bull. Can, Petrol. Geol.* **40** (1992), pp. 136–150.

Williamson, M. A., 1995, Overpressures and hydrocarbon generation in the Sable sub-basin, offshore Nova Scotia. Basin Research, 7: 21–34.

Williamson, M.A., K. DesRoches, and S. King, 1993, Overpressures and Hydrocarbon Migration in the Hibernia-Nautilus Area of the Jeanne d'Arc Basin, Offshore Newfoundland: *Bull. Can, Petrol. Geol.* **41** (1993), no. 4.

Table of Contents

List of Tables

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 Excel™ and @RISK™ 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

* $GSm^3 = 10^9$ 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**

Table of Contents

List of Tables

List of Figures

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 Mm^3d). 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, MSm³/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 Km^3d) 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, 5$^1/_2$ 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.

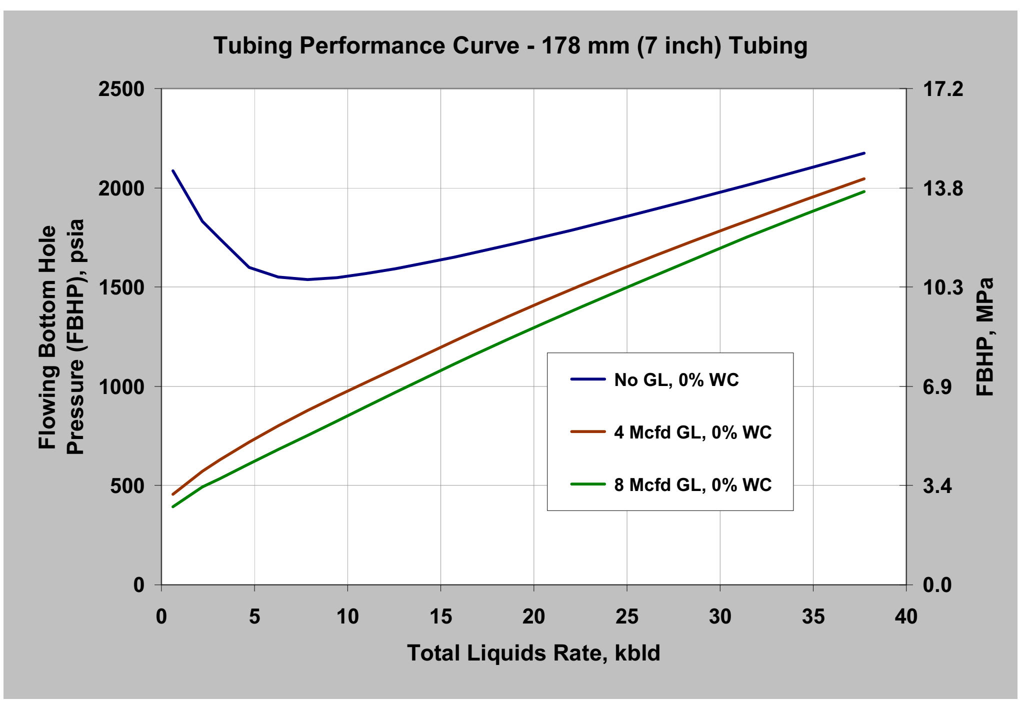


Figure 6.1-1: Example Tubing Performance Curve – 178 mm (7 inch) Tubing

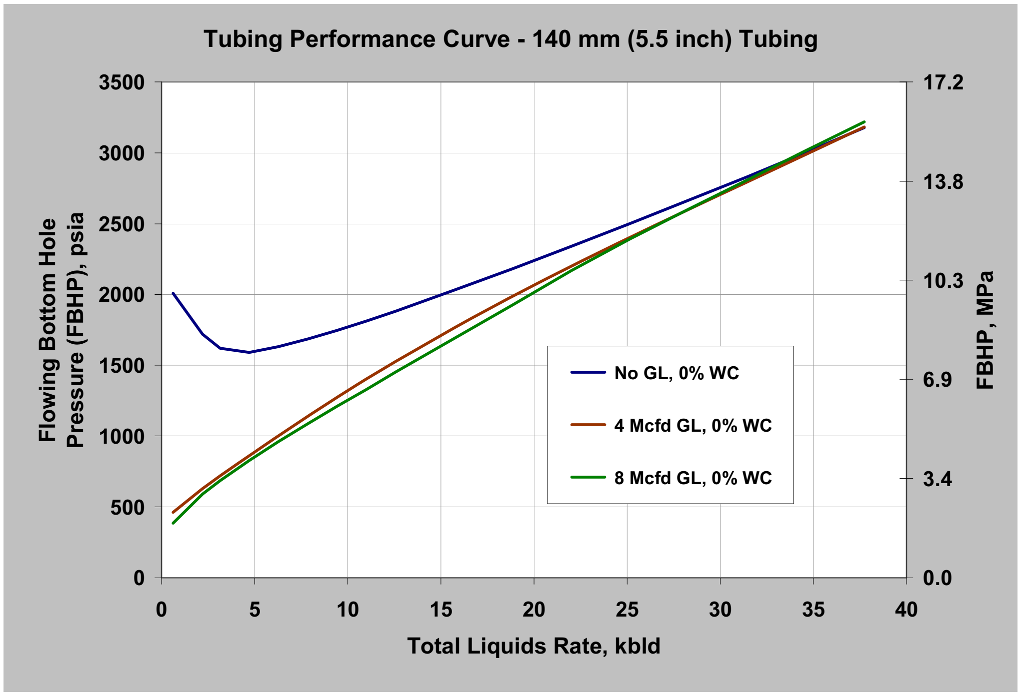


Figure 6.1-2: Example Tubing Performance Curve – 140 mm (5.5 inch) Tubing

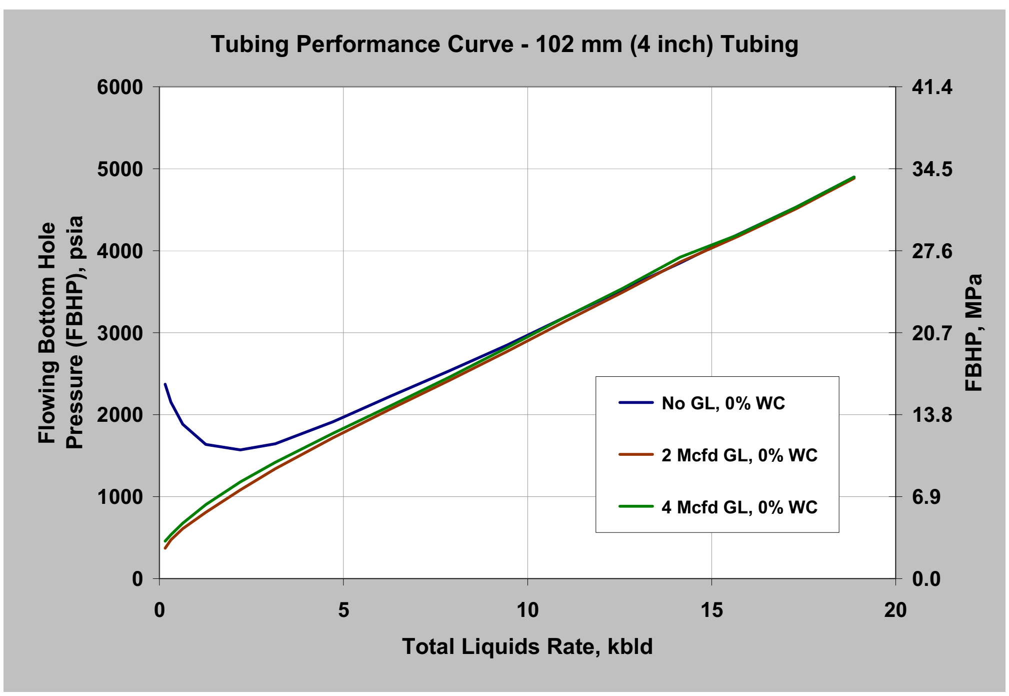


Figure 6.1-3: Example Tubing Performance Curve – 102 mm (4 inch) Tubing

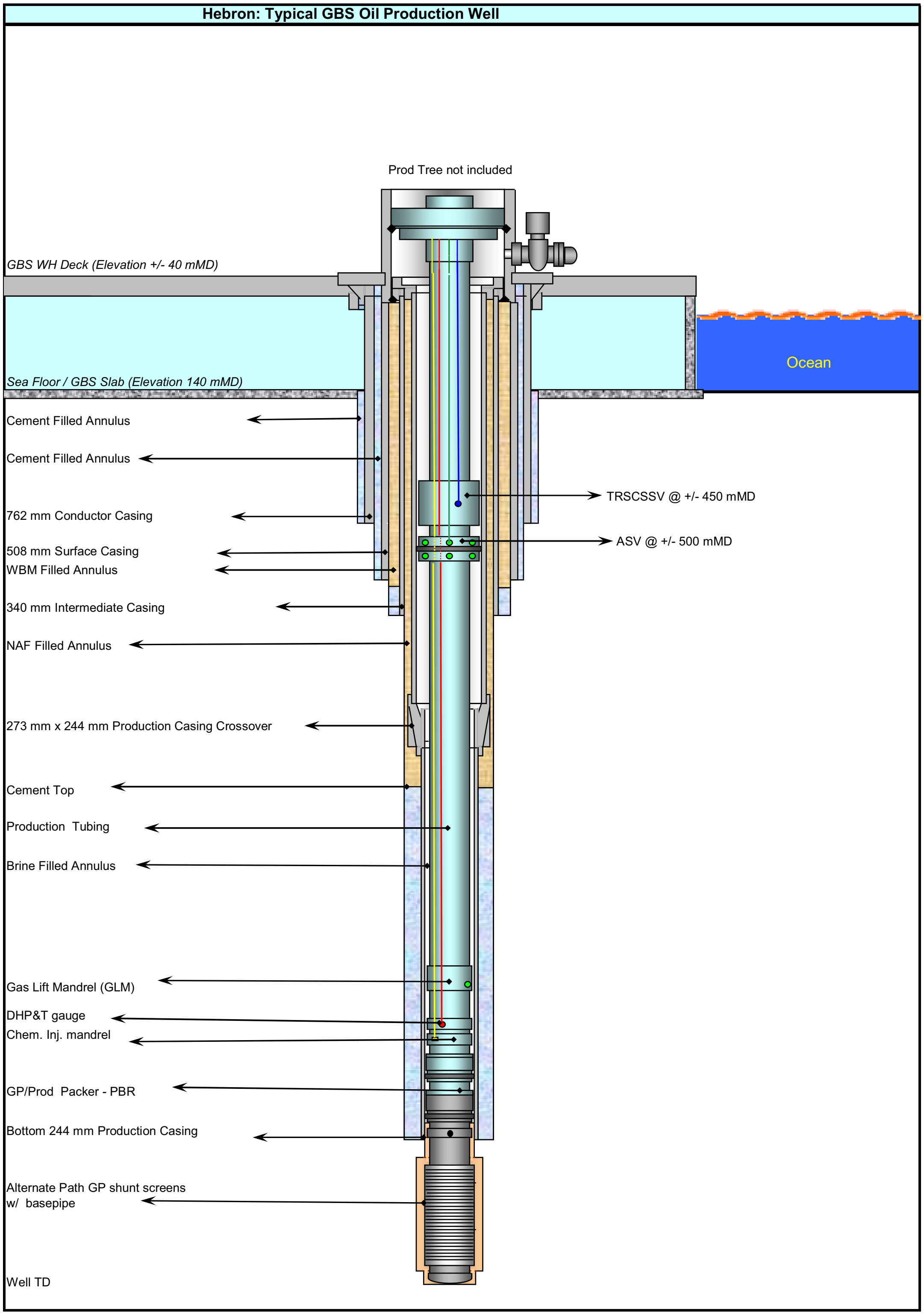


Figure 6.1-4: Schematic of a Typical Oil Production Well

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.

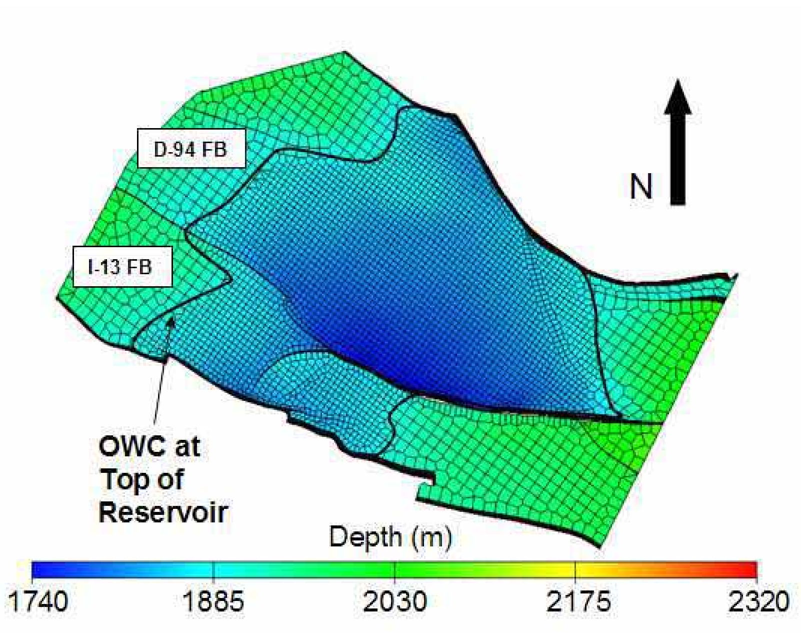


Figure 6.2-1: Hebron Ben Nevis Simulation Model Area of Interest

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 Mm^3) 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.

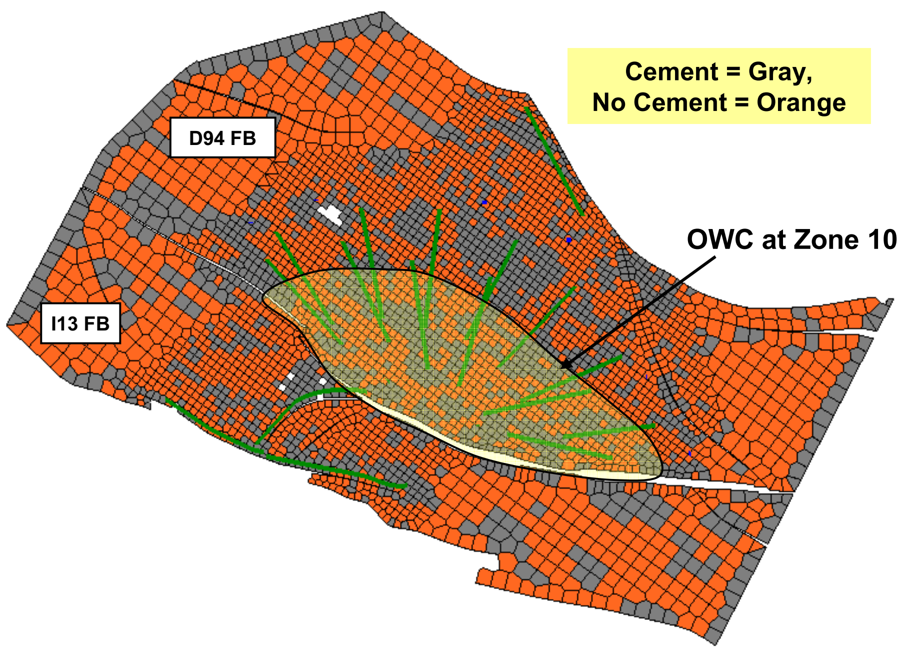


Figure 6.2-2: Cement Layer in Hebron Ben Nevis Simulation Model

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 Mm^3) 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 Mm^3) is predicted from these two fault blocks in the best estimate case with a range of 443 to 762 million barrels (70 Mm^3 to 121 Mm^3) 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 Mm^3) 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.

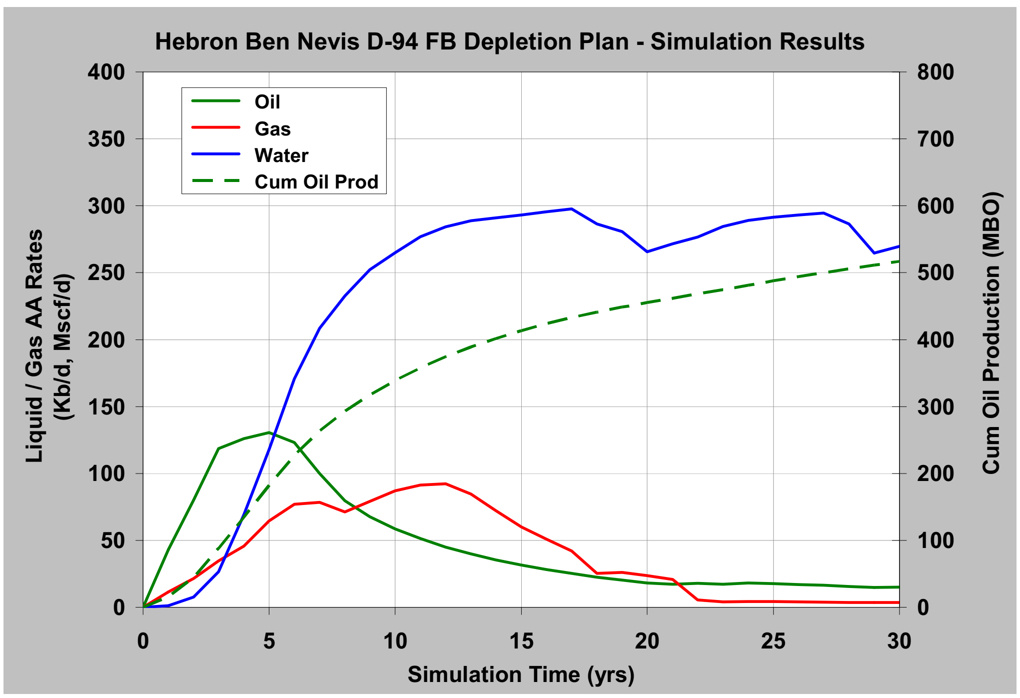


Figure 6.2-3: Hebron Ben Nevis D-94 Fault Block Base Case Depletion Plan Simulation Results

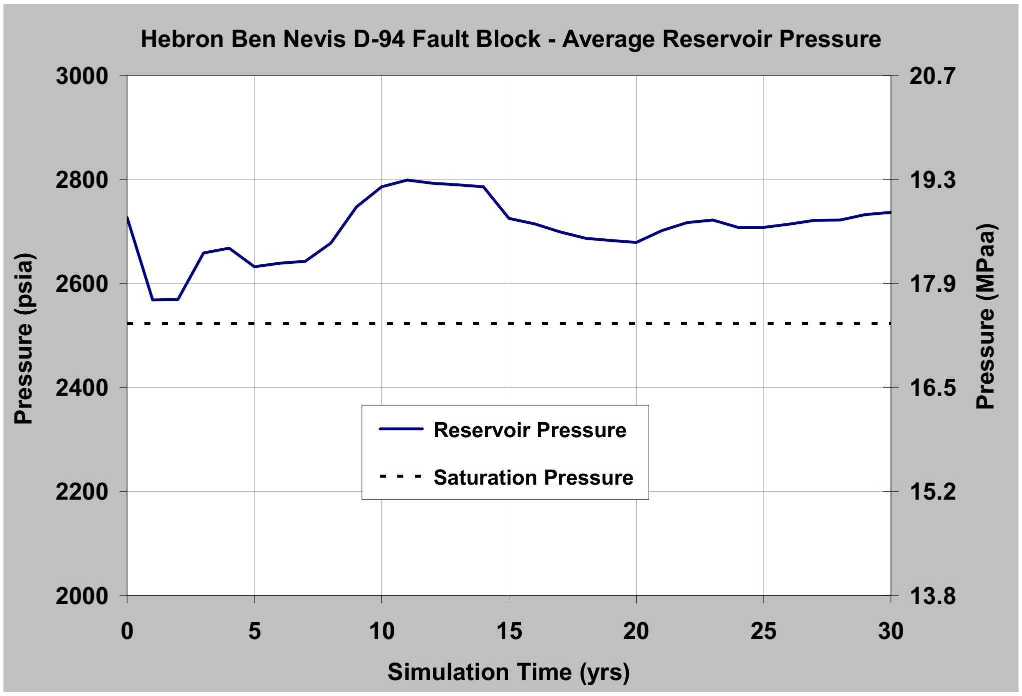


Figure 6.2-4: Hebron Ben Nevis D-94 Fault Block Average Reservoir Pressure

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 Mm^3) after 30 years (or a recovery factor of 26 percent) with a range from 38 million barrels to 80 million barrels (6 Mm^3 to 13 Mm^3) 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.

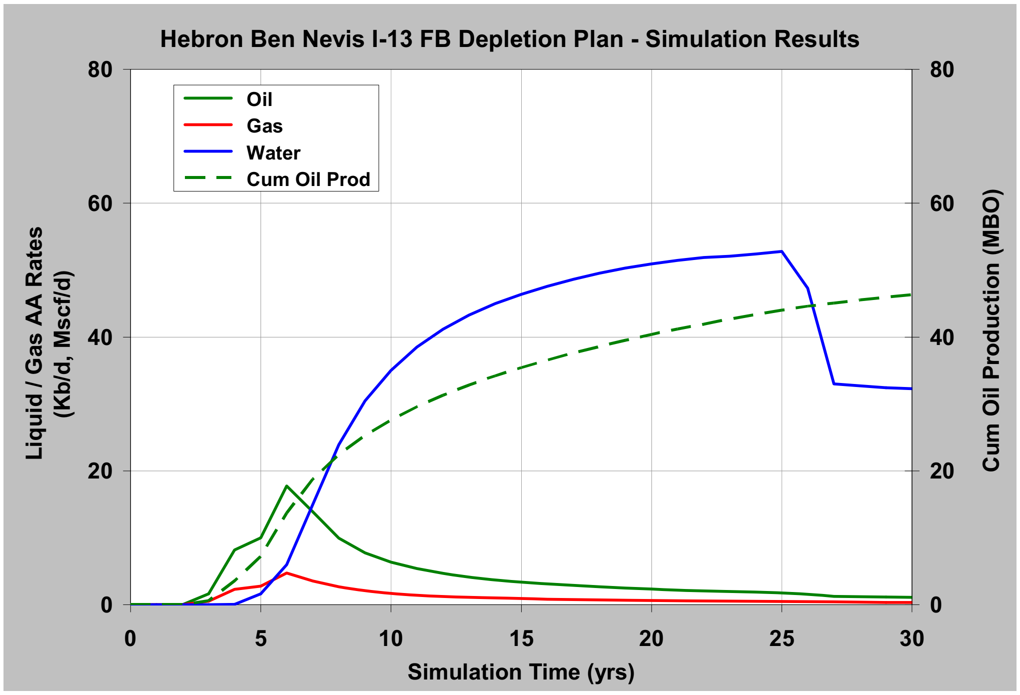


Figure 6.2-5: Hebron Ben Nevis I-13 Fault Block Base Case Depletion Plan Simulation Results

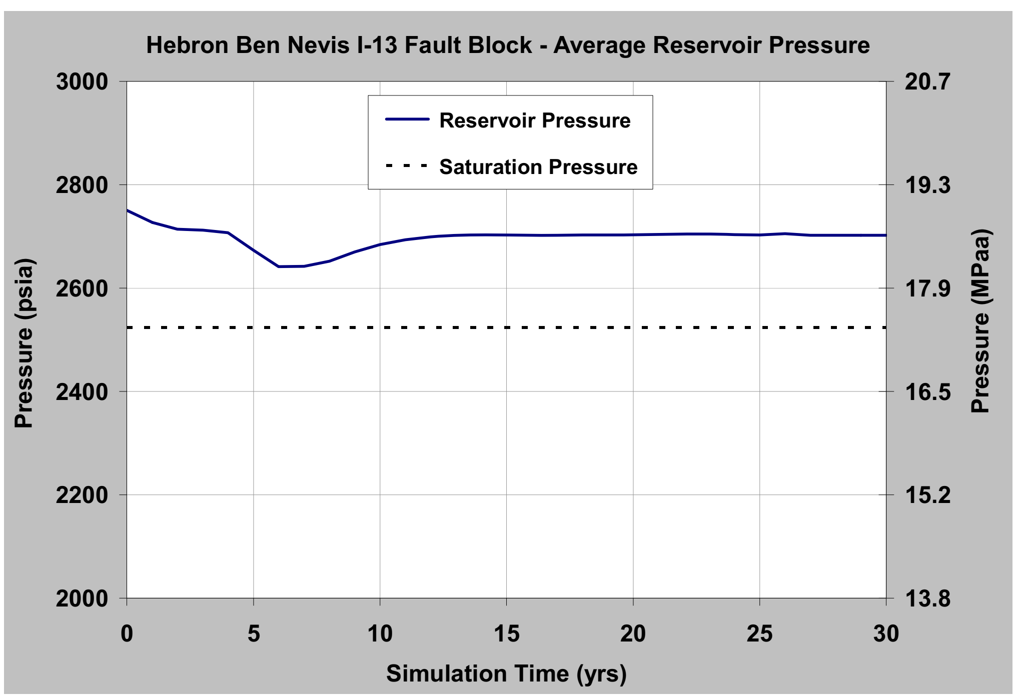


Figure 6.2-6: Hebron Ben Nevis I-13 Fault Block Average Reservoir Pressure

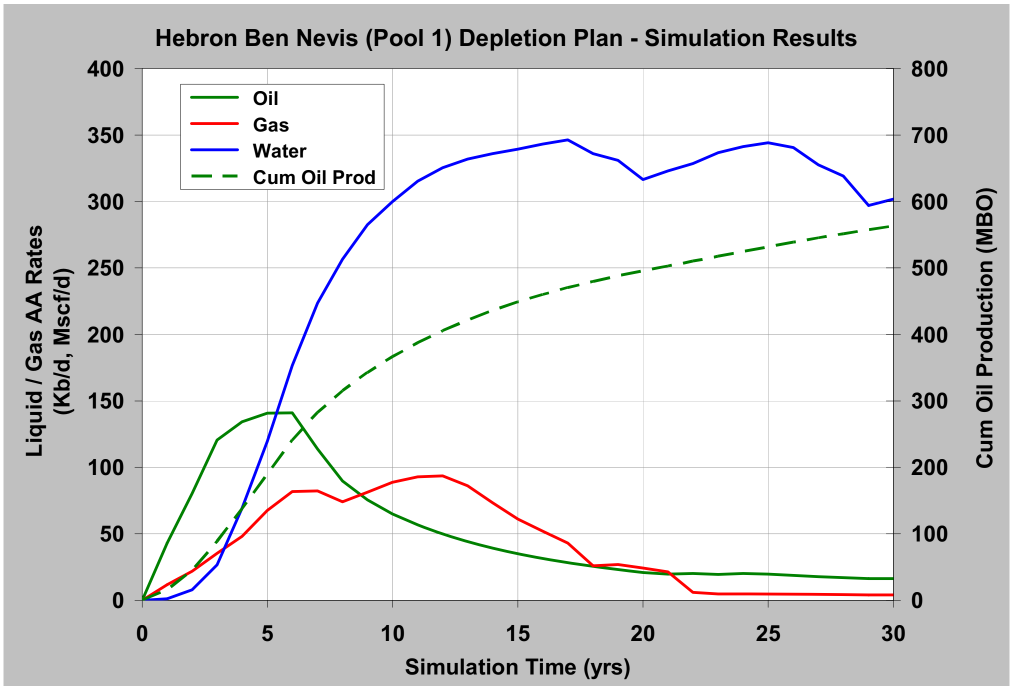


Figure 6.2-7: Hebron Ben Nevis Base Case Depletion Plan Results

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 Mm^3 recovery after thirty years).

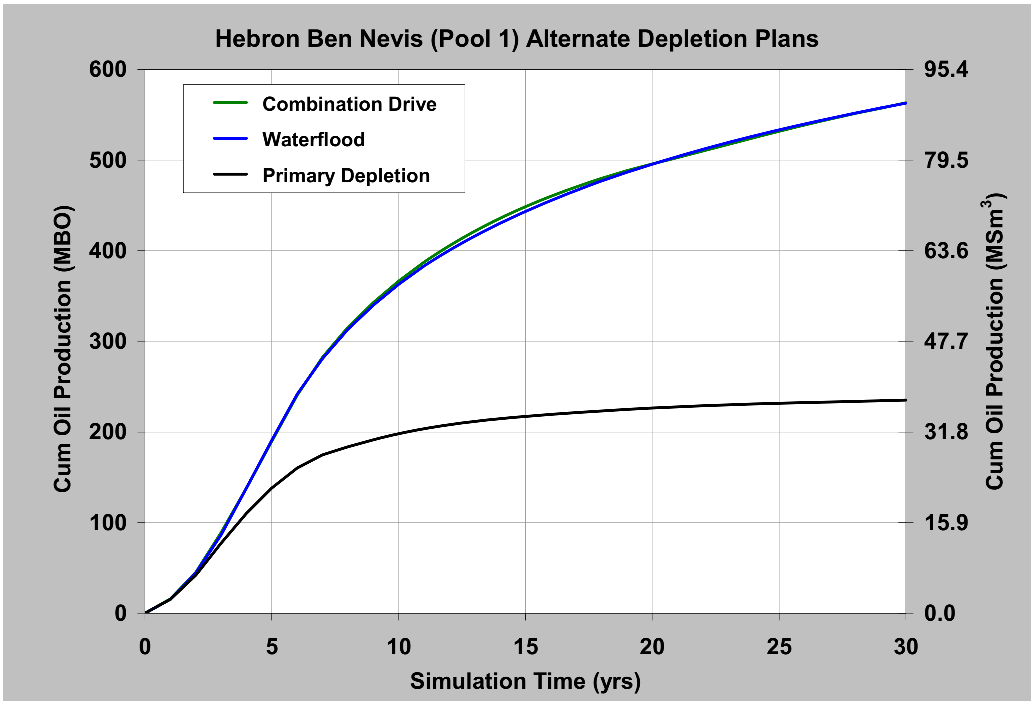


Figure 6.2-8: Hebron Ben Nevis – Alternate Depletion Plans

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.

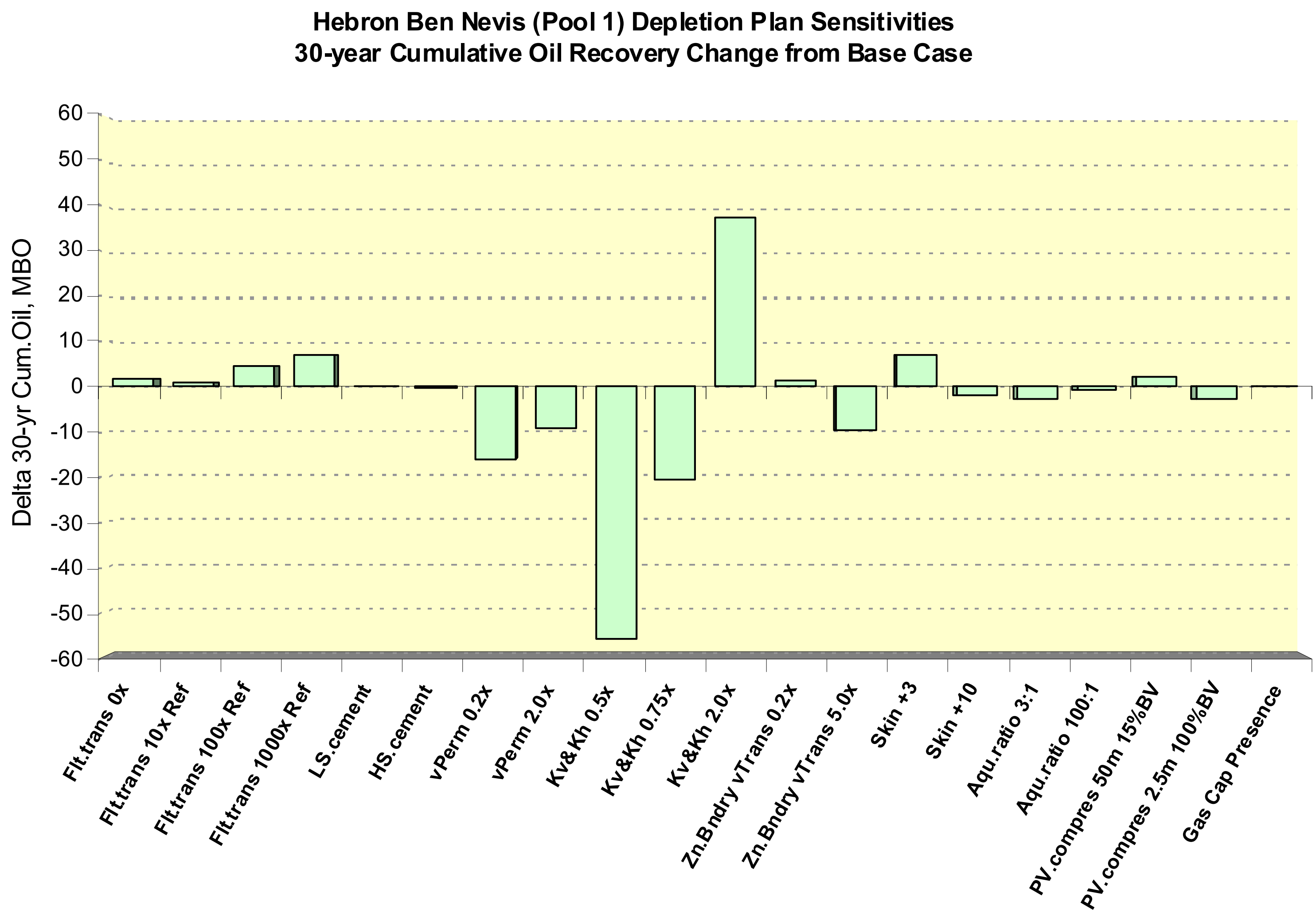


Figure 6.2-9: Hebron Ben Nevis Depletion Plan Sensitivities

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 Mm^3) 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.

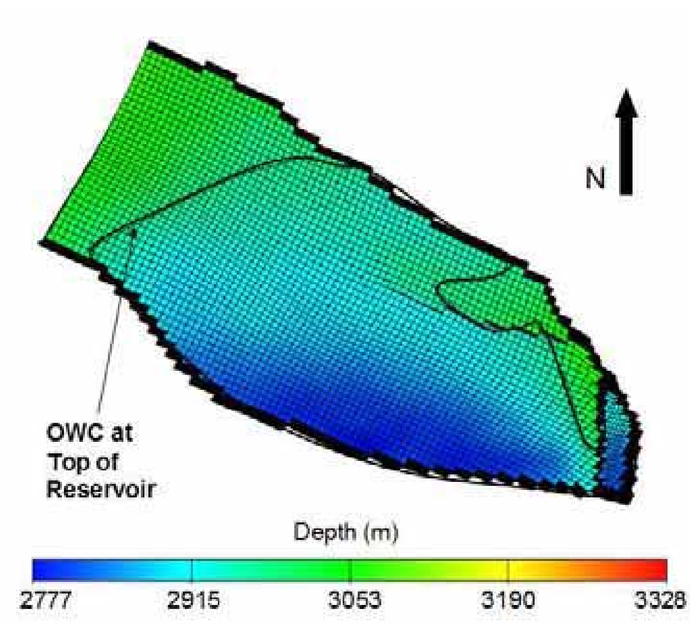


Figure 6.3-1: Hebron Hibernia Simulation Model

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 Mm^3) is predicted from the base case depletion plan (Figure 6.3-2) with a range from 6 million barrels (1 Mm^3) to 47 million barrels (7 Mm^3) 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.

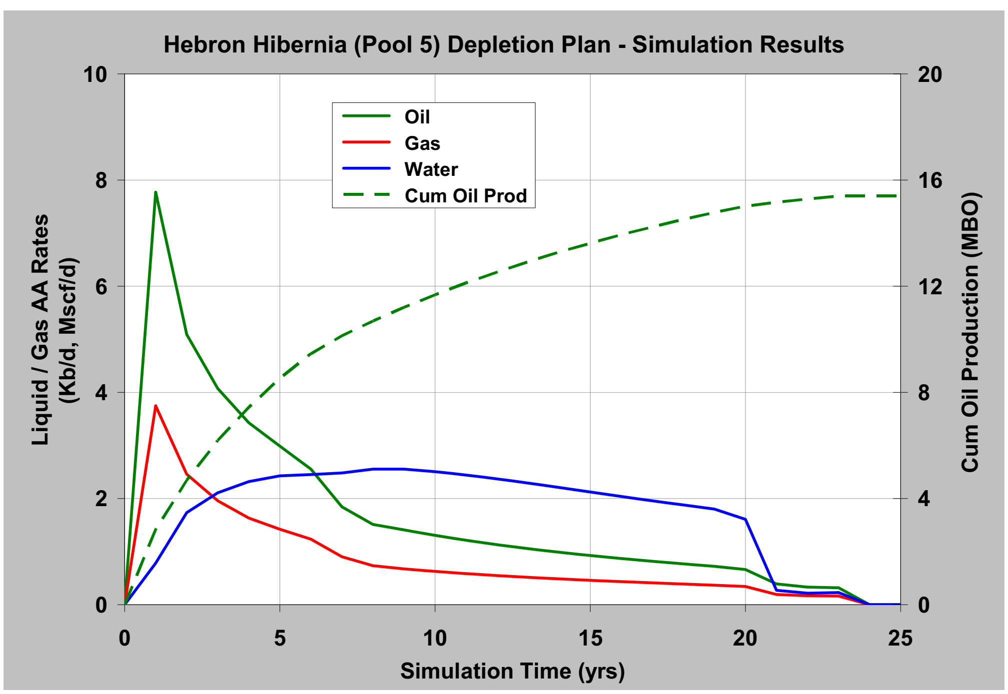


Figure 6.3-2: Hebron Hibernia Base Case Depletion Plan Simulation Results

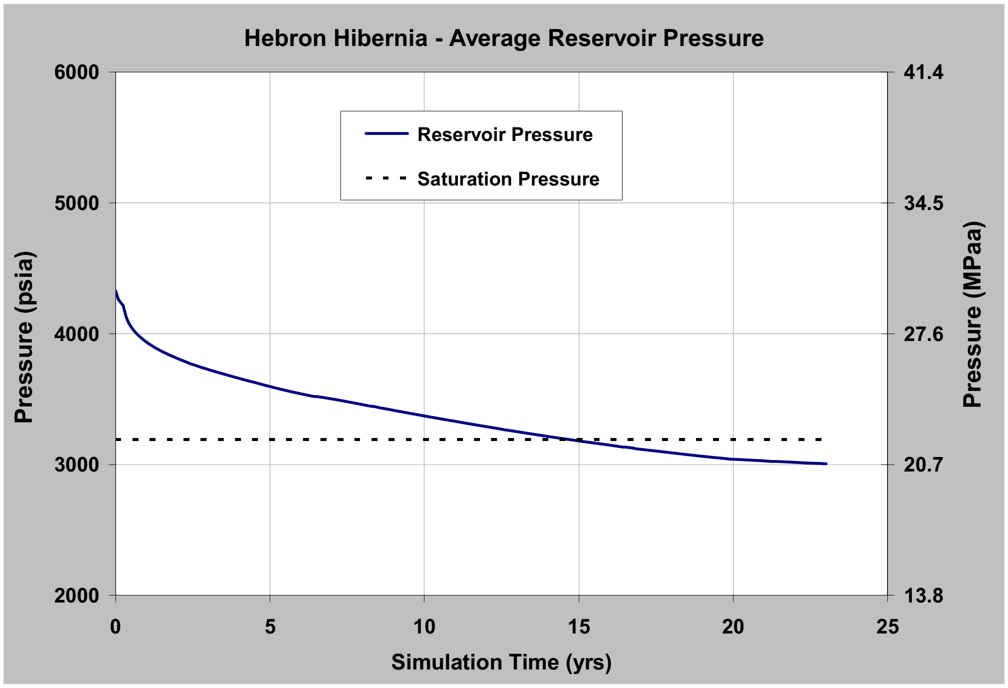


Figure 6.3-3: Hebron Hibernia Average Reservoir Pressure

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 Mm^3) compared with oil recovery of 15.4 million barrels (2.4 Mm^3) from two producers. This indicated an incremental recovery of about 5.2 million barrels (0.8 Mm^3) 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).

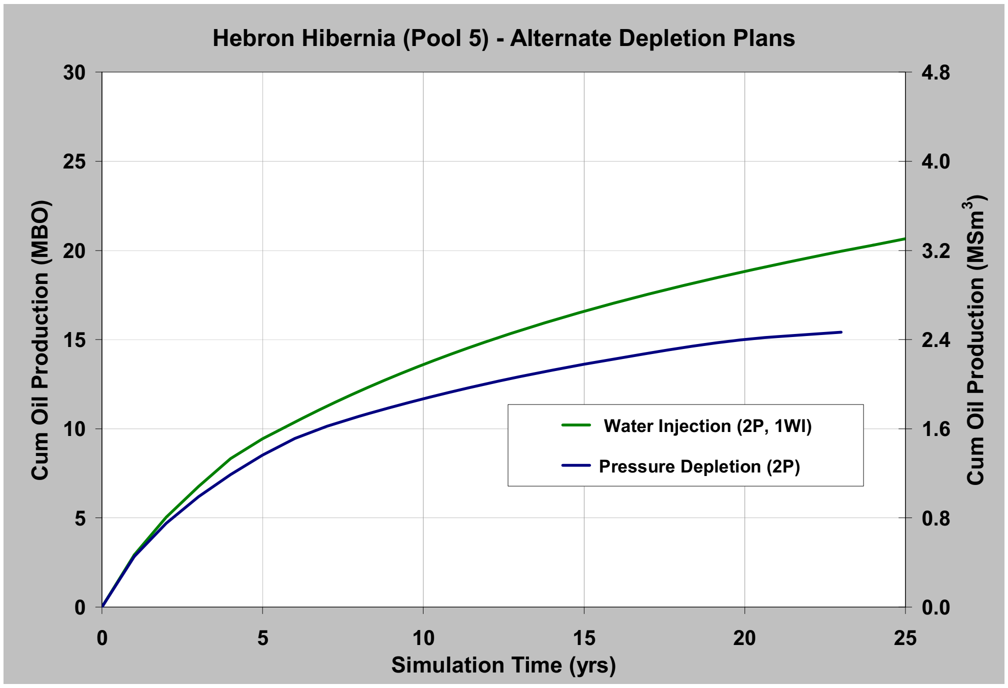


Figure 6.3-4: Hebron Hibernia – Alternate Depletion Plans

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 Mm^3) i.e. from 20.6 MB (3.3 Mm^3) in the two producer / one water injector case to 24.6 MB (3.9 Mm^3) 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.

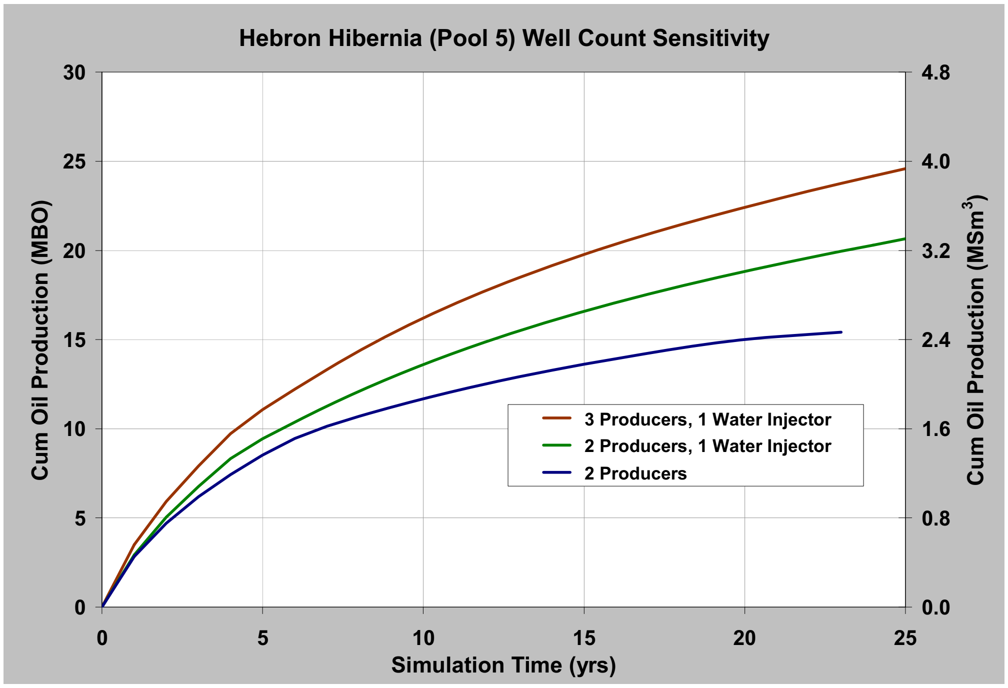


Figure 6.3-5: Hebron Hibernia – Well Count Sensitivity

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.

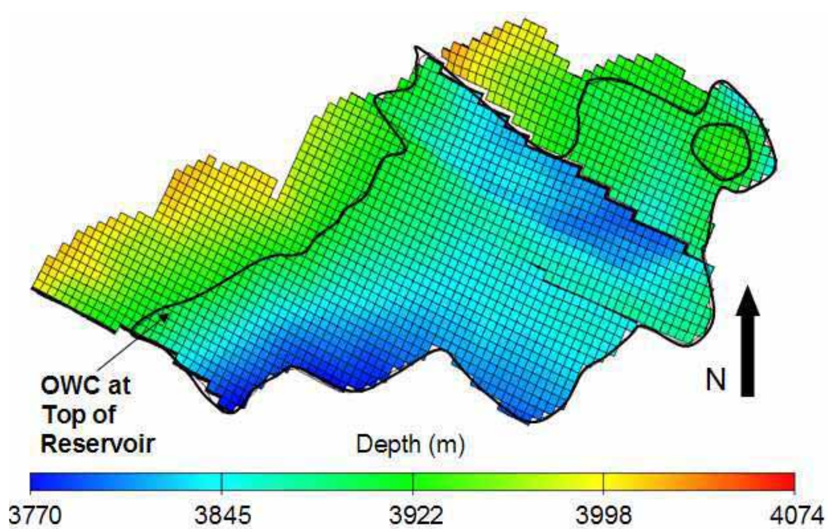


Figure 6.4-1: Hebron Jeanne d'Arc H Sand Simulation Model

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 Mm^3) or about 1.5% difference compared to the geologic model STOOIP. This volumetric difference (less than 3 MBO or 0.5 Mm^3) 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 Mm^3).

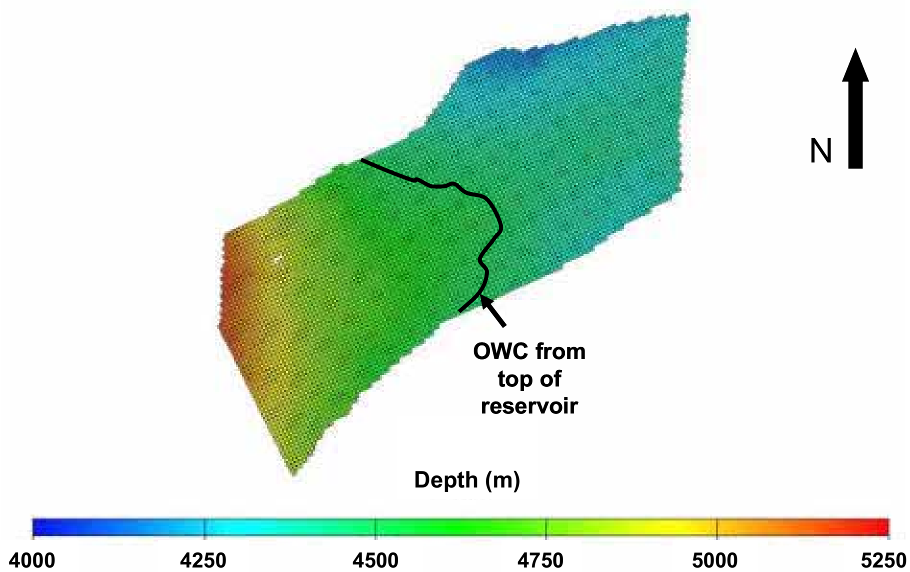


Figure 6.4-2: Hebron Jeanne d'Arc B Sand Simulation Model

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 Mm^3) after thirty years (or a recovery factor of 29 percent) with a range from 33 million barrels to 89 million barrels (5 Mm^3 to 14 Mm^3) 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.

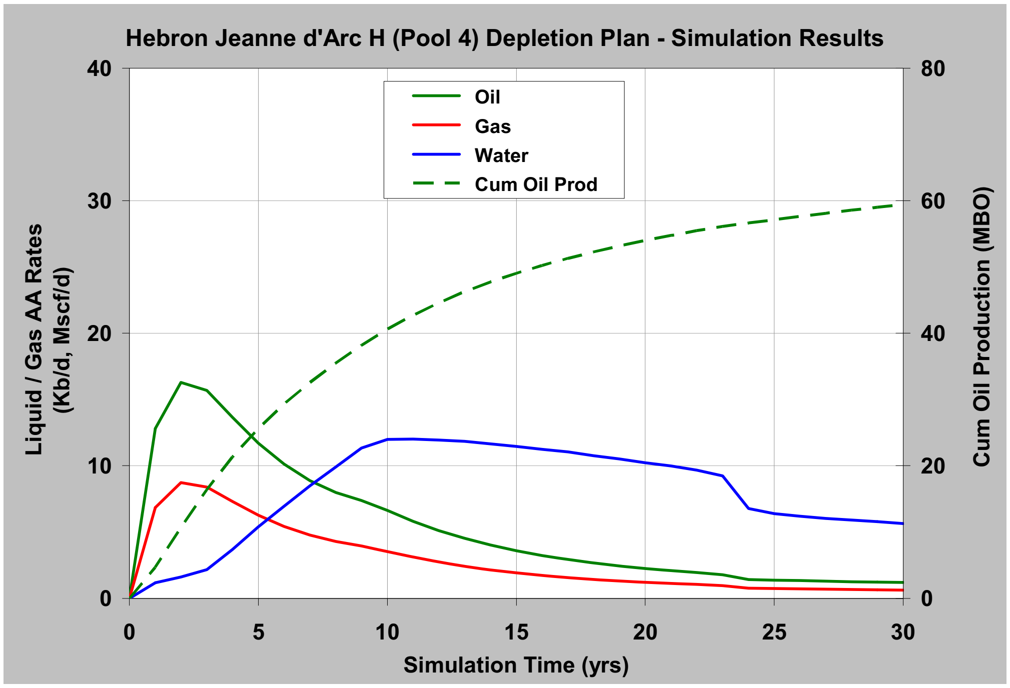


Figure 6.4-3: Hebron Jeanne d'Arc H Sand Base Case Depletion Plan Simulation Results

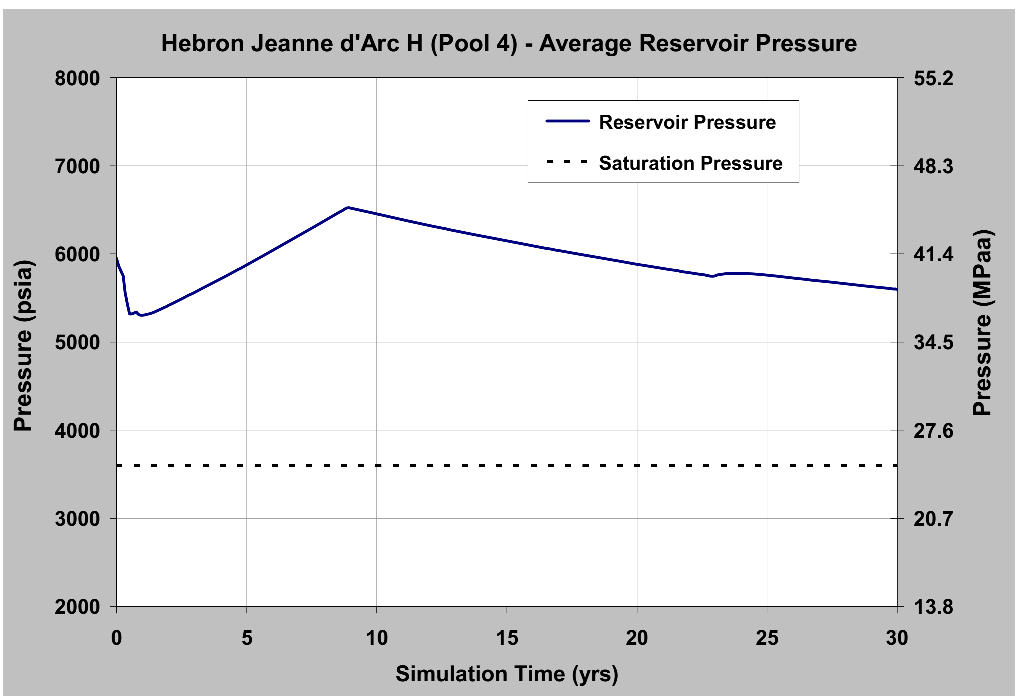


Figure 6.4-4: Hebron Jeanne d'Arc H Sand Average Reservoir Pressure

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 Mm^3) or a recovery efficiency of 24 percent in the base case scenario with a range from 11 million barrels to 60 million barrels (2 Mm^3 to 10 Mm^3) 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.

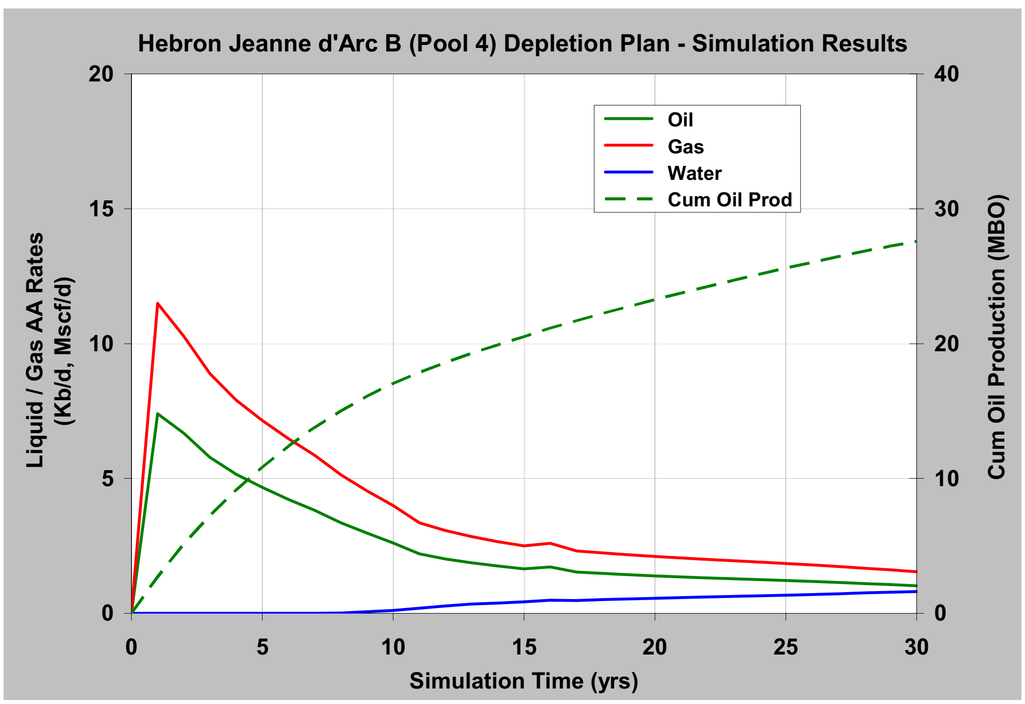


Figure 6.4-5: Hebron Jeanne d'Arc B Sand Base Case Depletion Plan Simulation Results

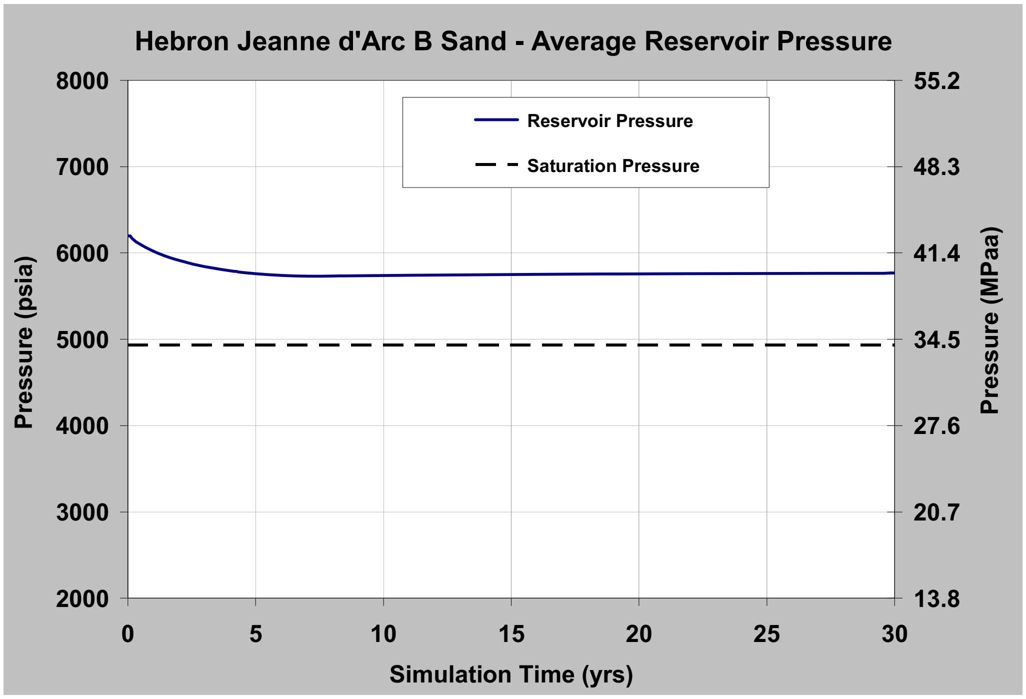


Figure 6.4-6: Hebron Jeanne d'Arc B Sand Average Reservoir Pressure

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 Mm^3) 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 m^3/day) was specified for the producers.

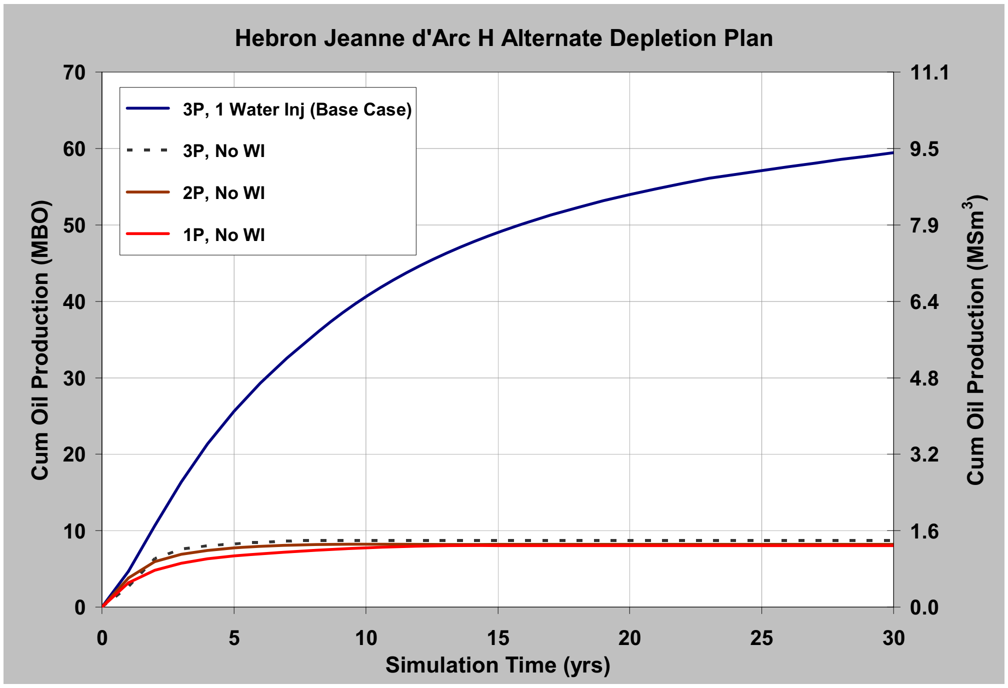


Figure 6.4-7: Hebron Jeanne d'Arc H Sand Alternate Depletion Plan – Primary Depletion

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 Mm^3) after thirty years of natural depletion compared to about 28 million barrels (4 Mm^3) in the base case depletion plan (one producer and one water injector) indicating incremental recovery of more than 7 million barrels (1 Mm^3) 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.

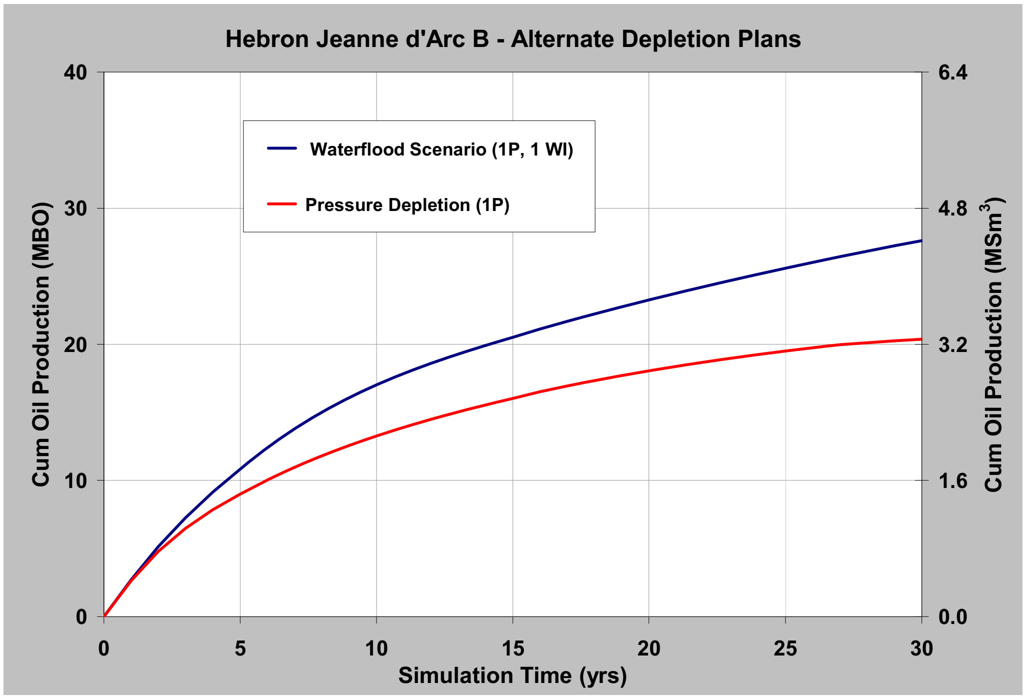


Figure 6.4-8: Hebron Jeanne d'Arc B Sand Alternate Depletion Plan – Primary Depletion

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 Mm^3) with one producer and one water injector to about 59 MBO (9 Mm^3) 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 Mm^3), can be obtained from a three-well (two producers and one water injector) depletion plan scenario depending on the placement of the two producers.

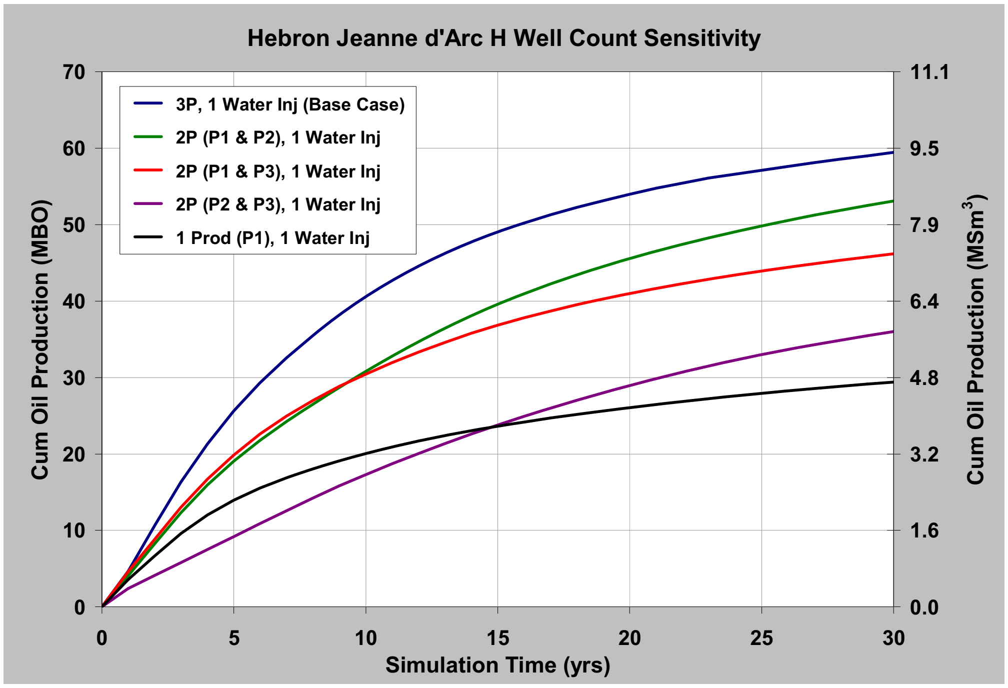


Figure 6.4-9: Hebron Jeanne d'Arc H Sand Well Count Sensitivity

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.

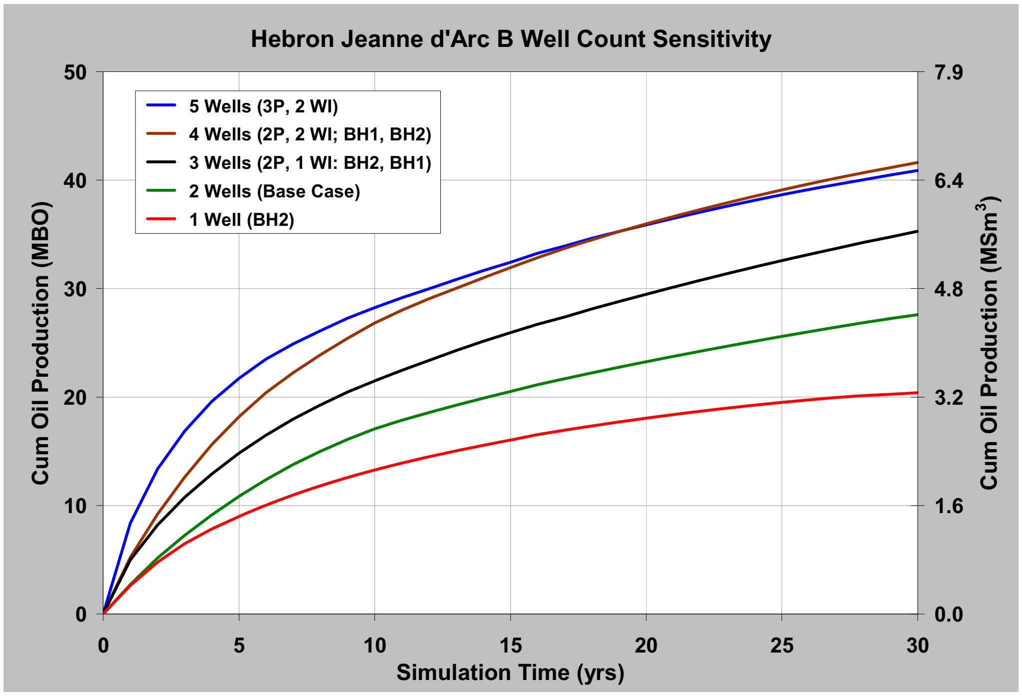


Figure 6.4-10: Hebron Jeanne d'Arc B Sand Well Count Sensitivity

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.

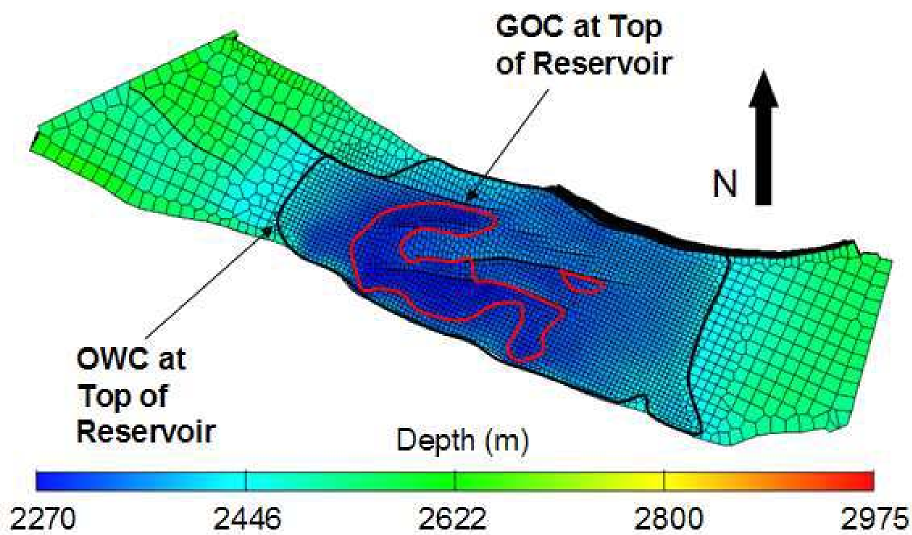


Figure 6.5-1: Ben Nevis Ben Nevis Simulation Model Area of Interest

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 Mm^3) 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 Mm^3) is predicted in the best estimate case with a range of 75 to 203 million barrels (12 Mm^3 to 32 Mm^3) 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.

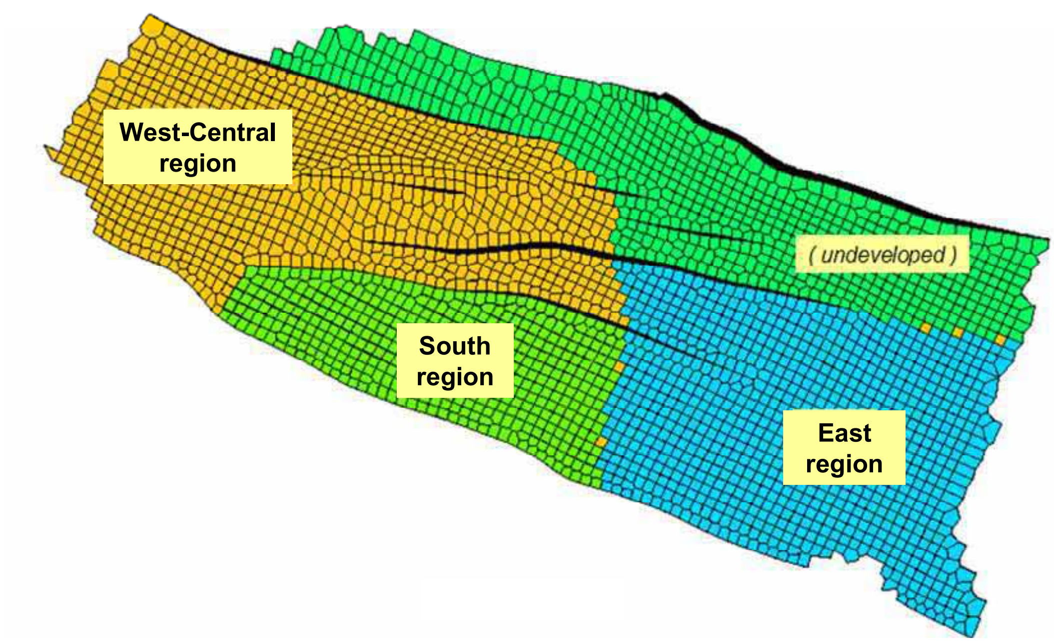


Figure 6.5-2: Ben Nevis Ben Nevis Simulation Model Pressure Tracking Regions

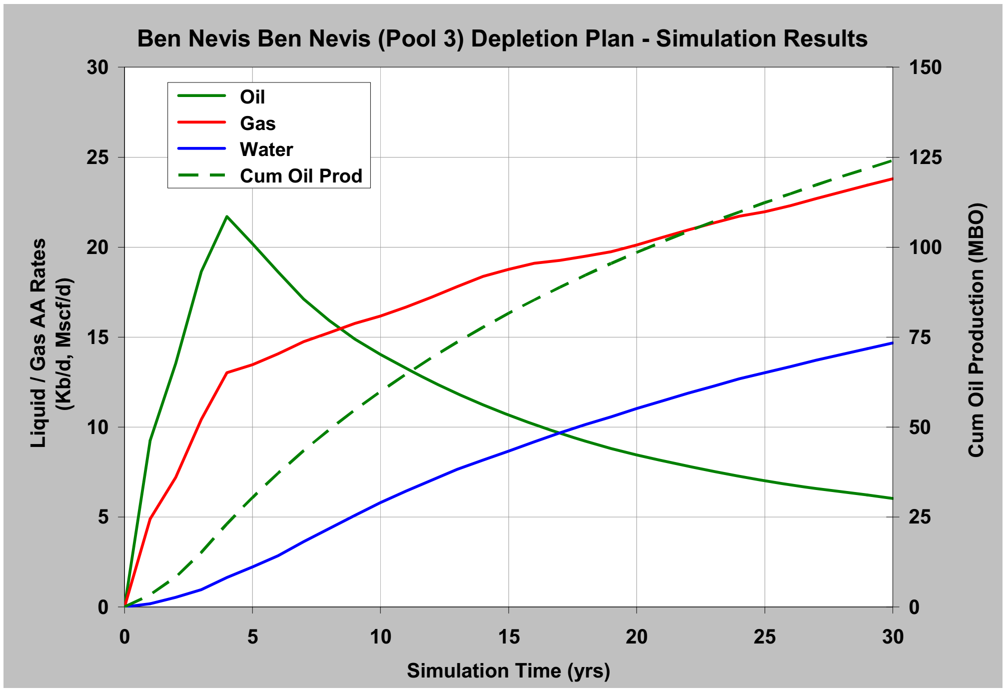


Figure 6.5-3: Ben Nevis Ben Nevis Base Case Depletion Plan Simulation Results

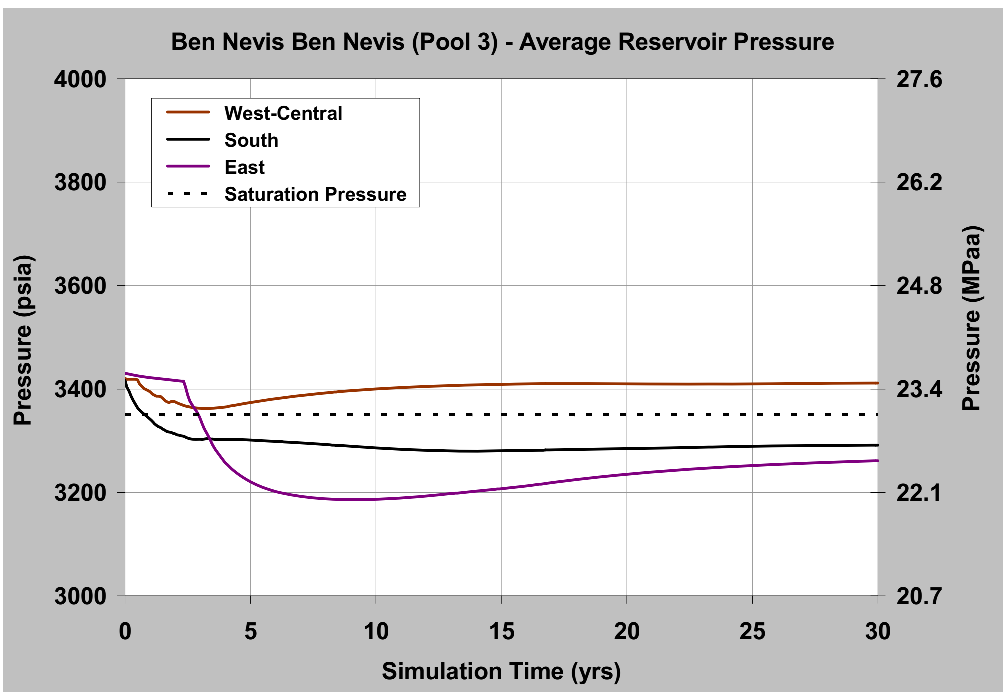


Figure 6.5-4: Ben Nevis Ben Nevis Average Reservoir Pressure

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 Mm^3) in the waterflood case and 99 MBO (16 Mm^3) in the primary depletion scenario compared to 124 MBO (20 Mm^3) in the combination drive scheme.

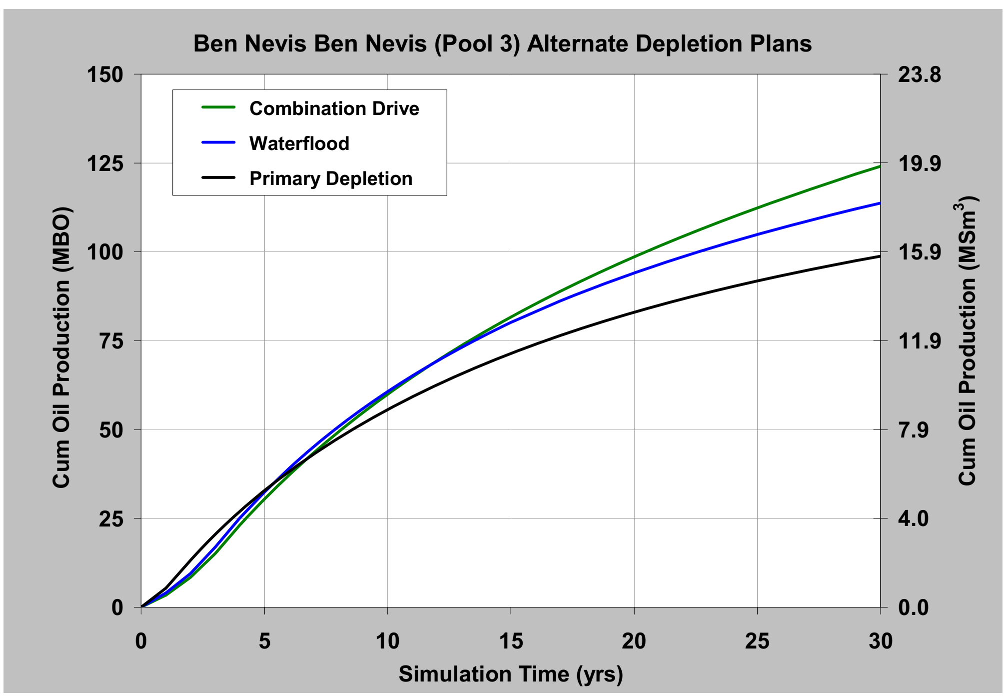


Figure 6.5-5: Ben Nevis Ben Nevis – Alternate Depletion Plans

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.

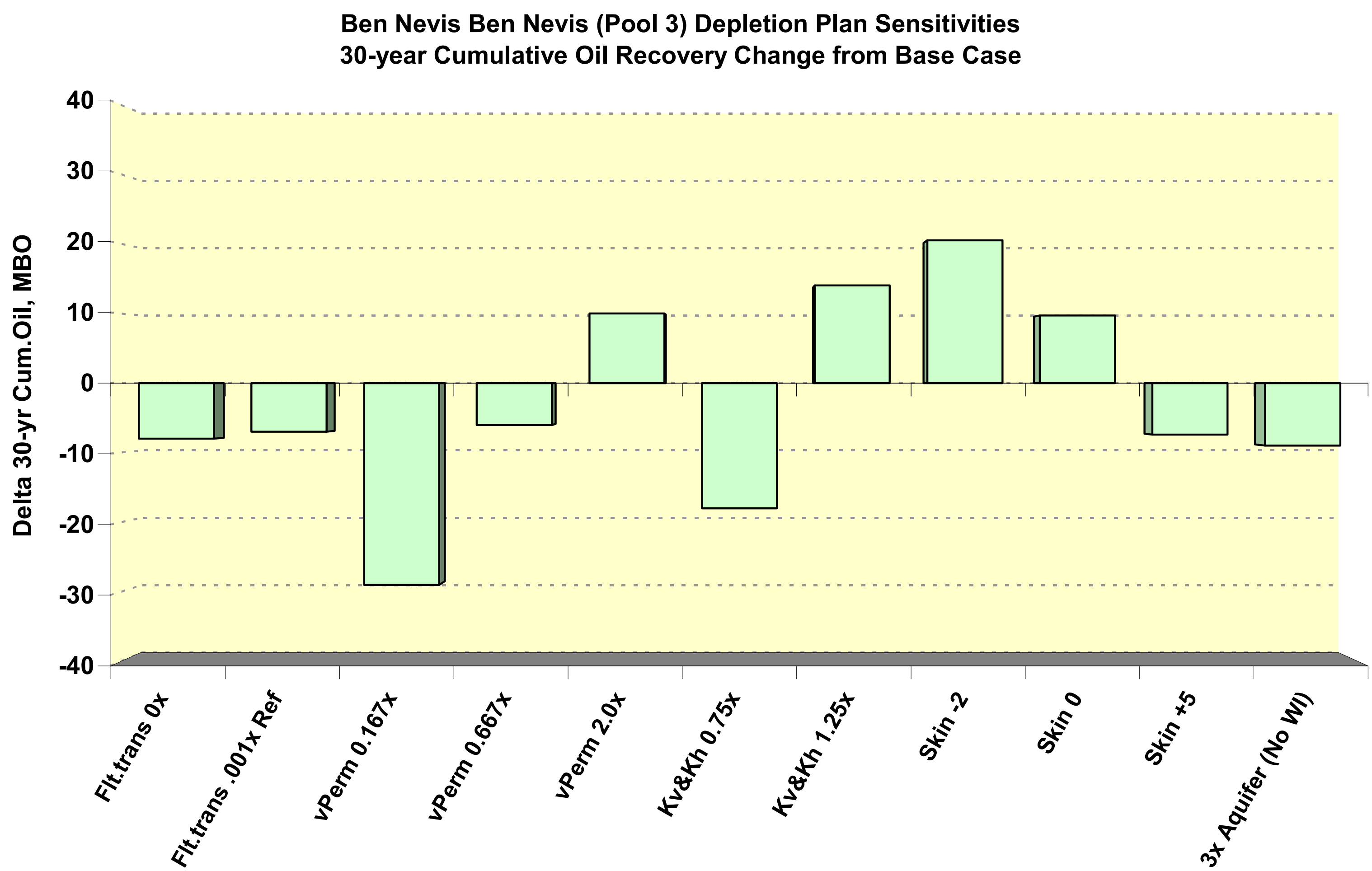


Figure 6.5-6: Ben Nevis Ben Nevis Depletion Plan Sensitivities

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.

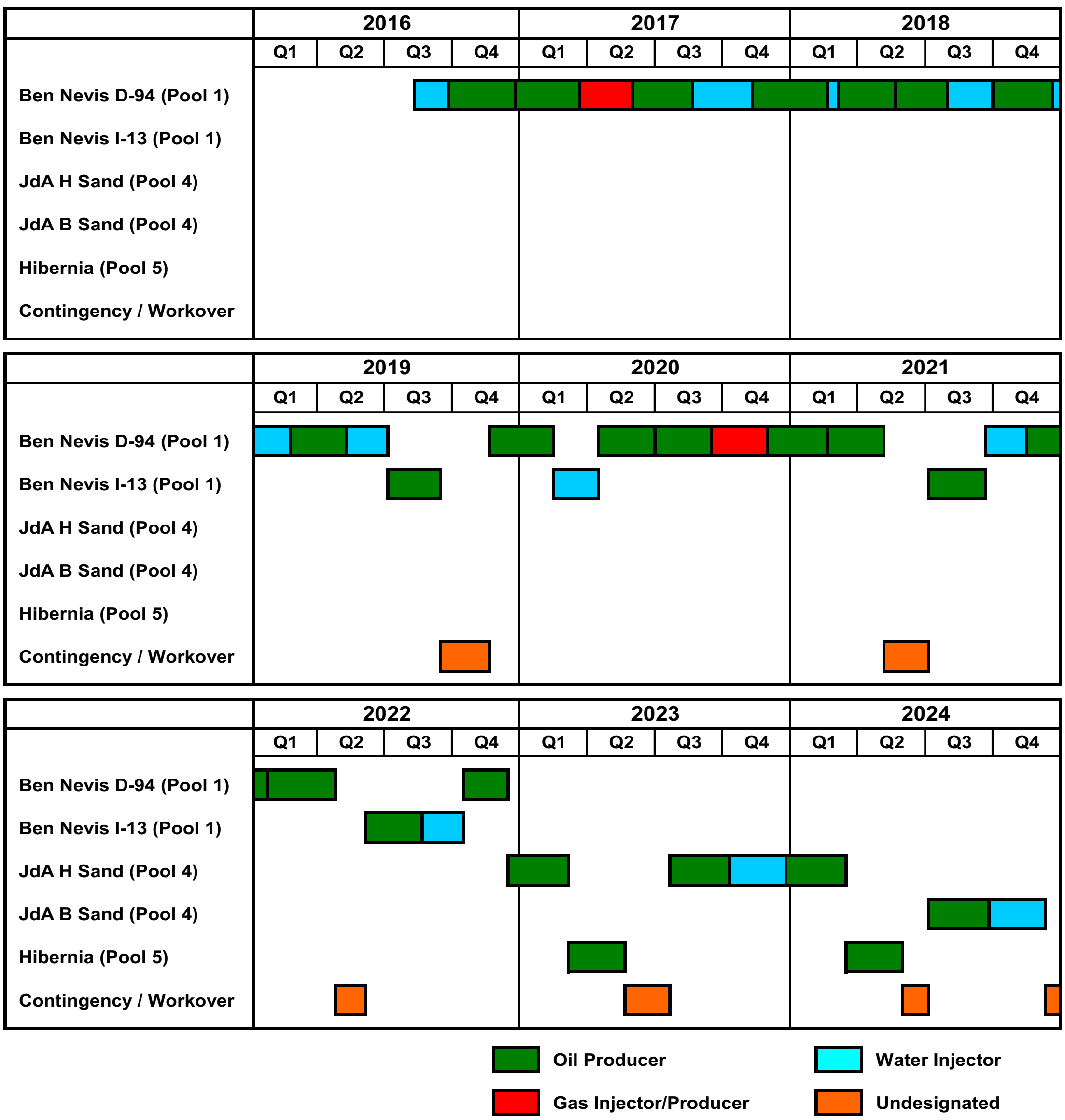


Figure 6.6-1: Drilling Schedule of GBS Platform Wells – Initial Development Phase

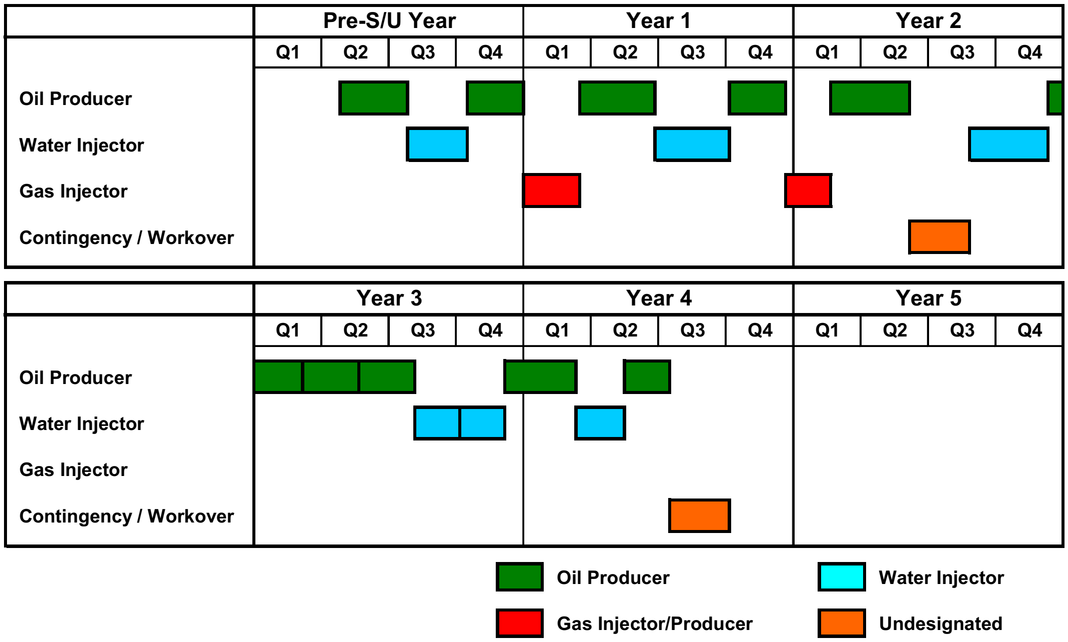


Figure 6.6-2: Drilling Schedule of Subsea (Pool 3) Wells – Full Development Scenario

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

	Metric Units		Oilfield Units	
Design Element	**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).*

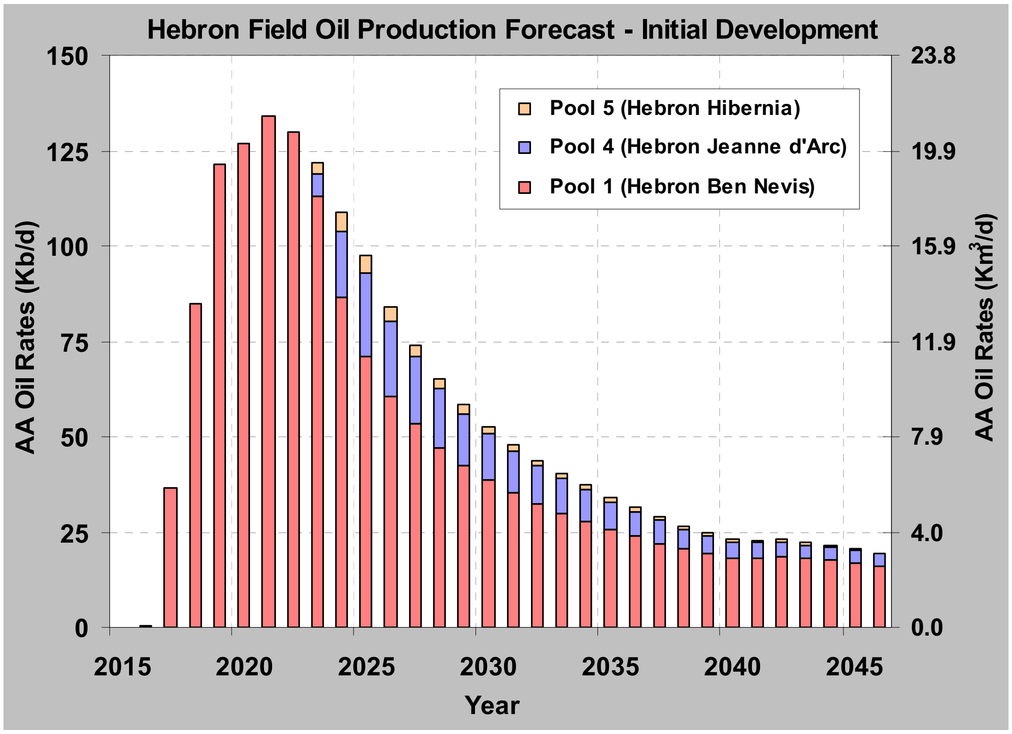


Figure 6.6-3: Hebron Field (Pools 1, 4 & 5) Oil Production Forecast

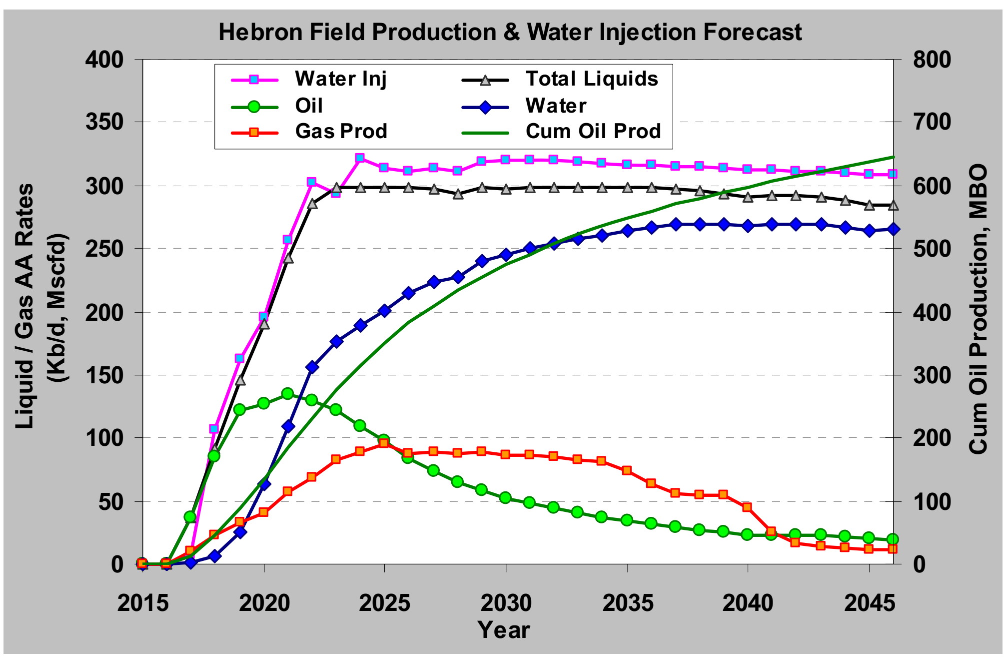


Figure 6.6-4: Hebron Field (Pools 1, 4 & 5) Production and Injection Forecast

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 / Mm^3)	**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**

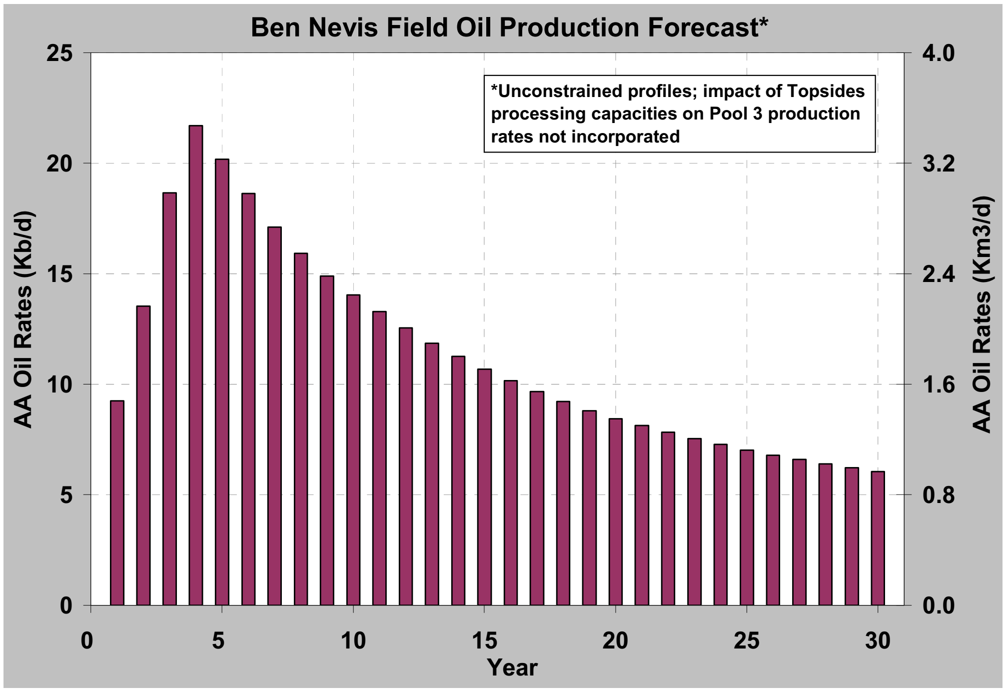


Figure 6.6-5: Ben Nevis Field (Pool 3) Oil Production Forecast

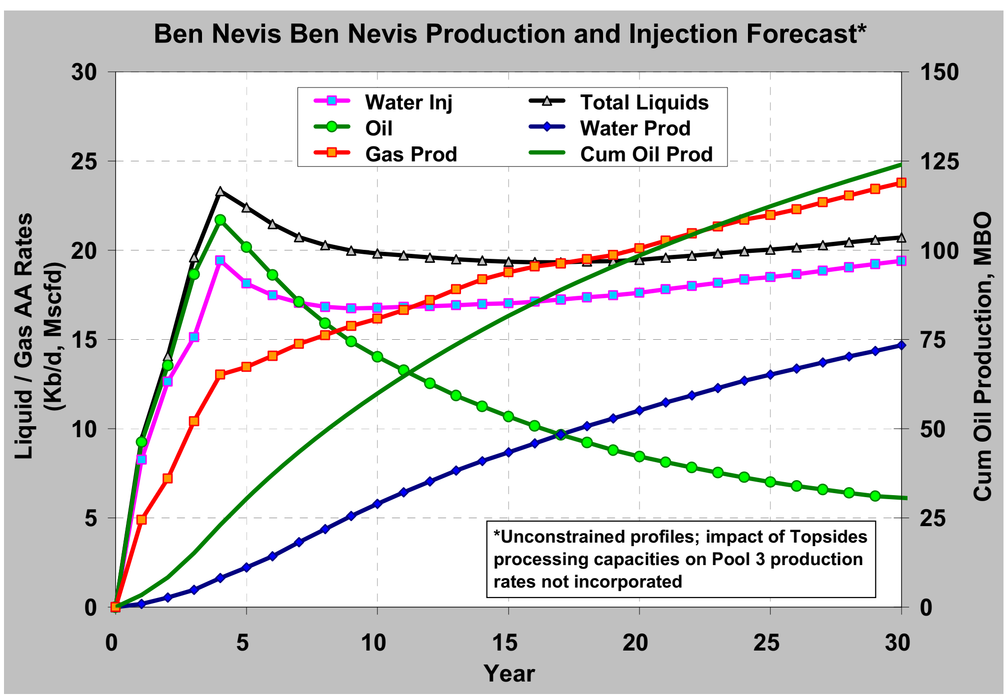


Figure 6.6-6: Ben Nevis Field (Pool 3) Production and Injection Forecast

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**

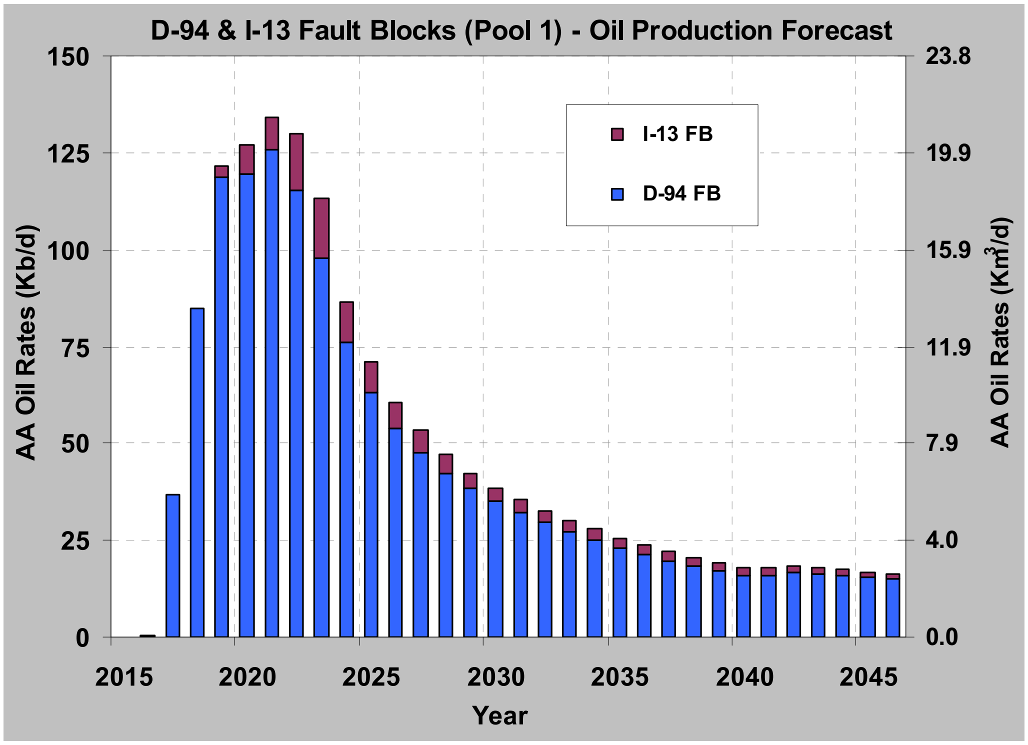


Figure 6.6-7: Oil Production Forecast: Hebron Ben Nevis D-94 and I-13 Fault Blocks

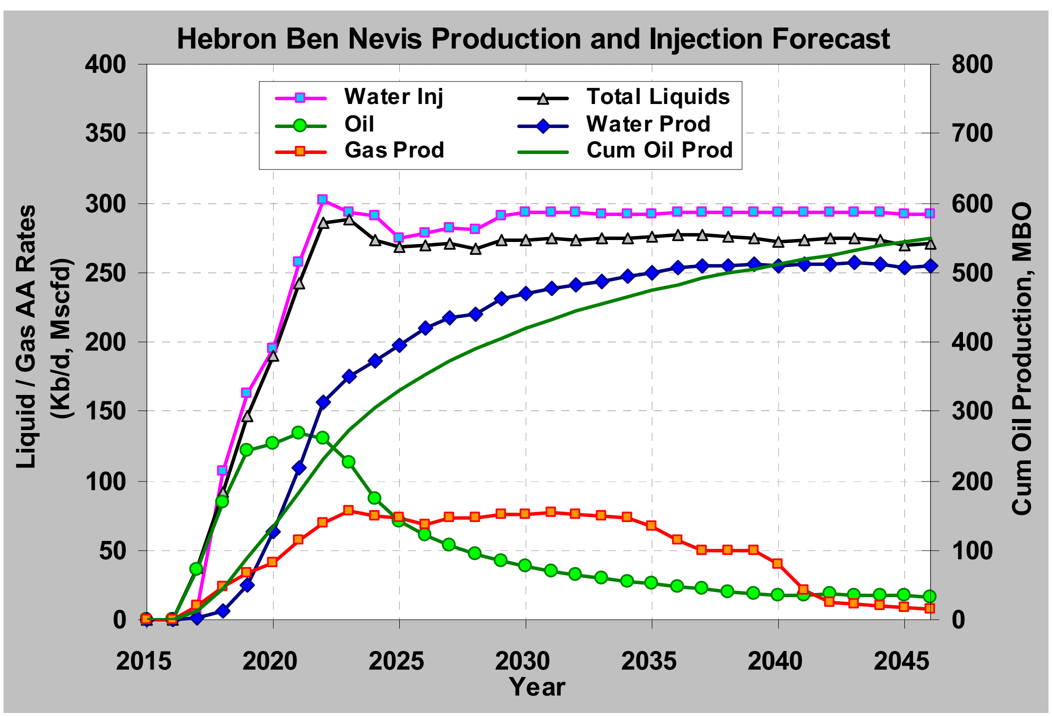


Figure 6.6-8: Hebron Ben Nevis Production and Injection Forecast

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 / Mm^3)	**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**

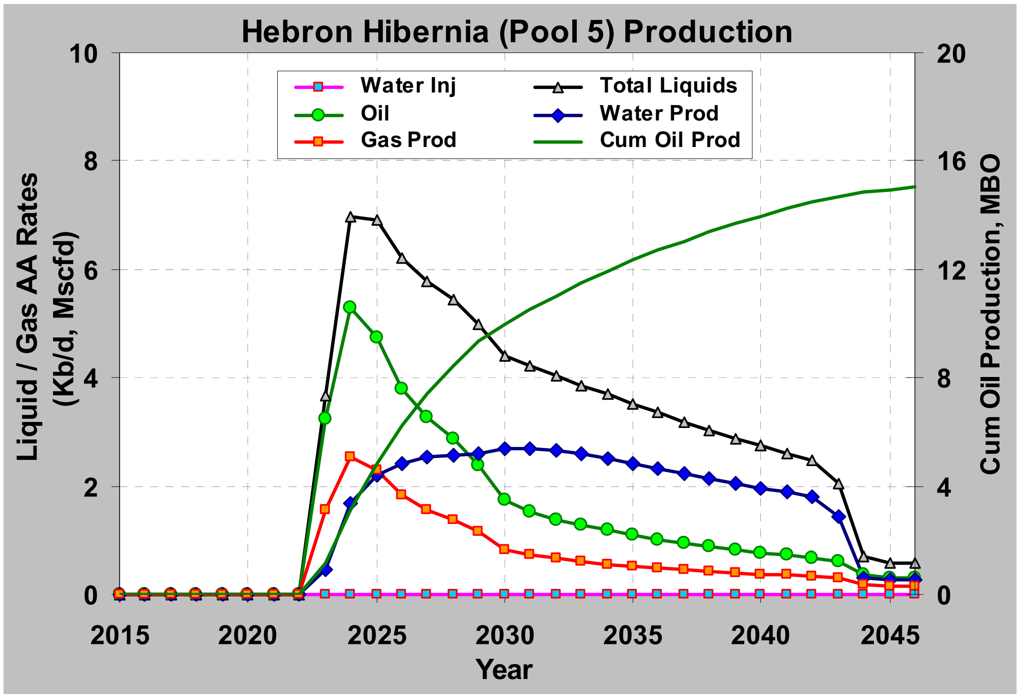


Figure 6.6-9: Hebron Hibernia Production and Injection Forecast

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**

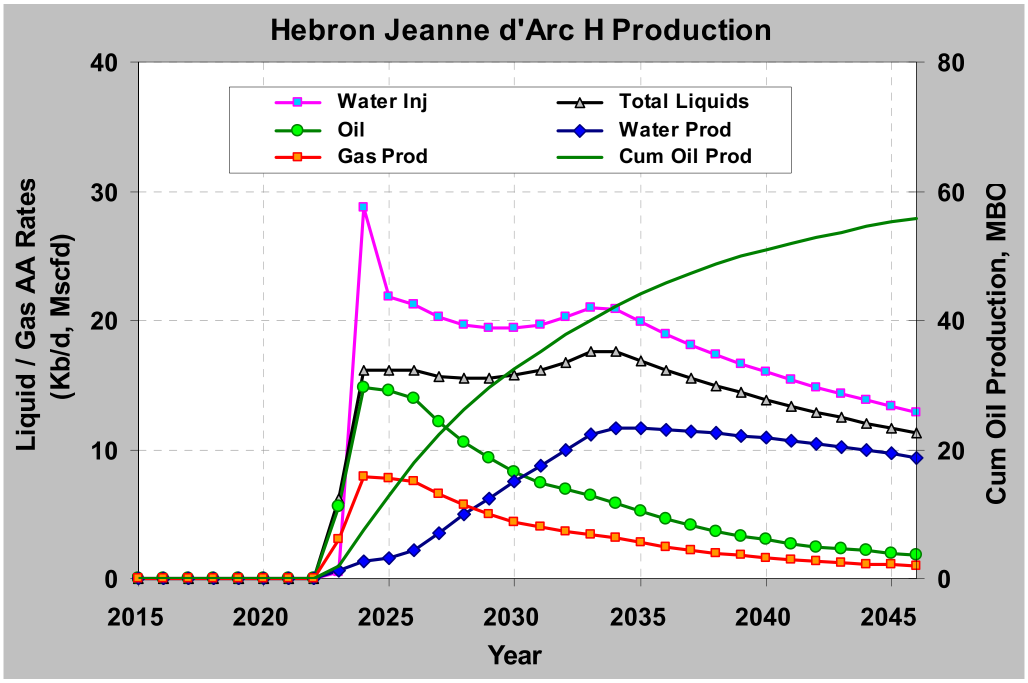


Figure 6.6-10: Hebron Jeanne d'Arc H Sand Production and Injection Forecast

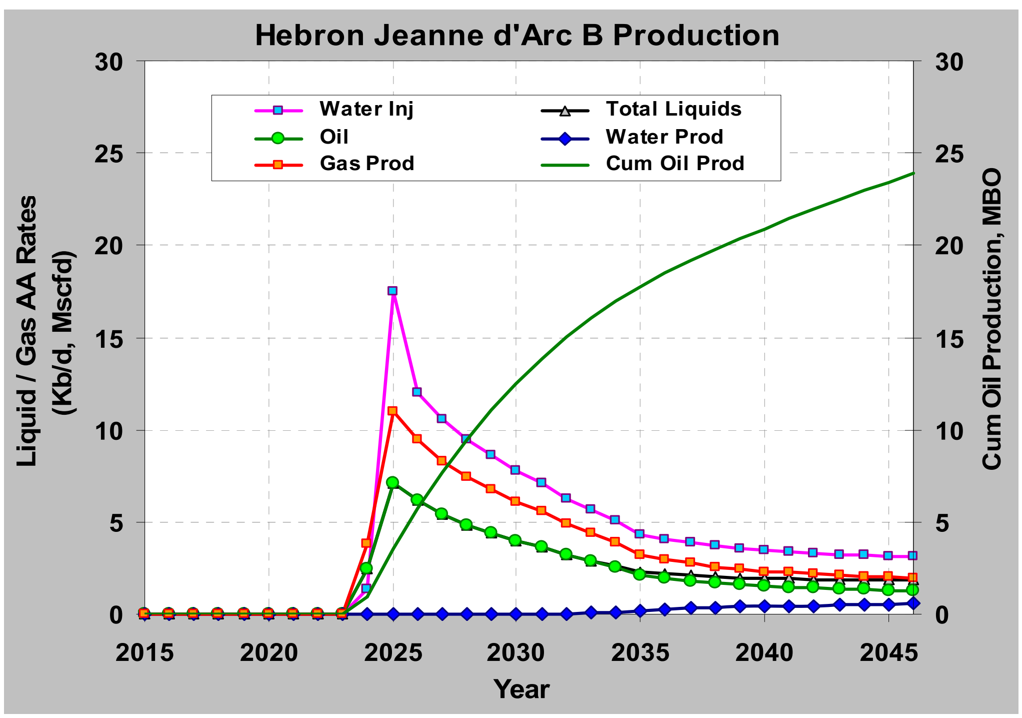


Figure 6.6-11: Hebron Jeanne d'Arc B Sand Production and Injection Forecast

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.

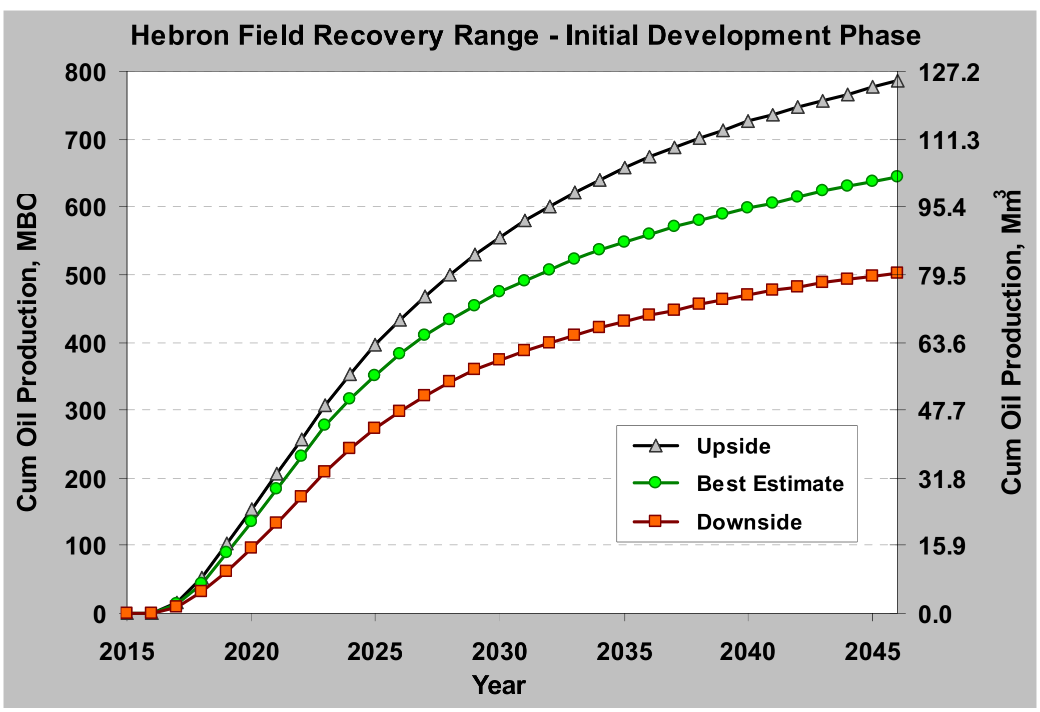


Figure 6.6-12: Hebron Field Initial Development Phase Recovery Range - Cumulative Oil Production Forecast

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 / Mm^3)	**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**

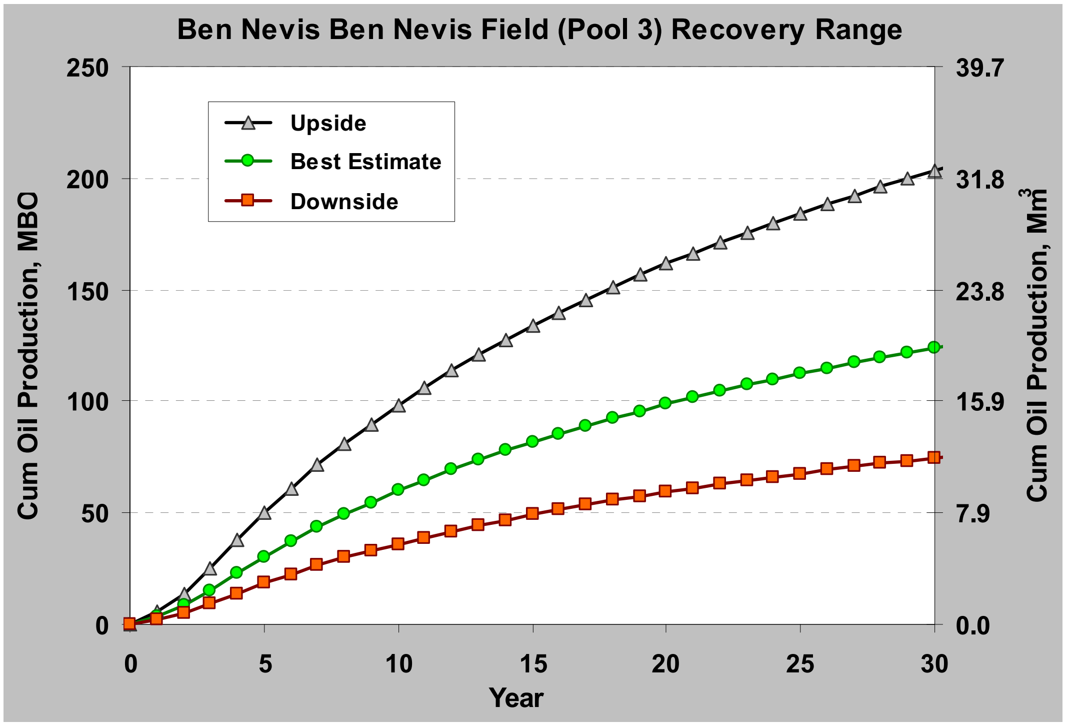


Figure 6.6-13: Ben Nevis Field Recovery Range - Cumulative Oil Production Forecast

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 / Mm^3)	**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 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 slow 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.
2	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 Msm^3) to 57 MBO (9 Msm^3).

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 Msm^3) to 11 MBO (2 Msm^3).

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 Msm^3) to 44 MBO (7 Msm^3).

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 Msm^3) to 8 MBO (1 Msm^3).

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 Msm^3) to 83 MBO (13 Msm^3).

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 Gsm^3) to 60 Gcf (2 Gsm^3).

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 Msm^3) to 19 MBO (3 Msm^3).

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 Msm^3) to 208 MBO (33 Msm^3).

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 Msm^3) to 37 MBO (6 Msm^3).

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 Msm^3) to 189 MBO (30 Msm^3).

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 Msm^3) to 44 MBO (7 Msm^3).

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 Gsm^3) to (3.5 Gsm^3)].

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 Gsm^3) to 85 Gcf (2.4 Gsm^3). 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 Msm^3) to 2 MB (0.3 Msm^3).

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 Gsm^3) to 148 Gcf (4 Gsm^3).

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 Gsm^3) to 102 Gcf (3 Gsm^3).

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 Msm^3) to 13 MB (2 Msm^3). 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 Msm^3) to 173 MBO (27 Msm^3). 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 unrisked preliminary estimates of recoverable oil range from 8 MBO (1 Msm^3) to 55 MBO (9 Msm^3).

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 Msm^3) to 333 MBO (53 Msm^3). 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 Msm^3) to 101 MBO (16 Msm^3). 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 (CO_2) at a pressure somewhere near original reservoir pressure, but is likely to be immiscible with nitrogen (N_2), 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 CO_2 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.