WHITE ROSE OILFIELD DEVELOPMENT APPLICATION

VOLUME 2
DEVELOPMENT PLAN

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This Development Application is submitted by Husky Oil Operations Limited (as Operator) on behalf of itself and its co-venturer Petro-Canada, who are the project proponents. The Application is comprised of a Project Summary and five volumes.

- Project Summary
- Volume 1 – Canada-Newfoundland Benefits Plan
- Volume 2 – Development Plan
- Volume 3 – Environmental Impact Statement (Comprehensive Study Part One (issued in October 2000))
- Volume 4 – Socio-Economic Impact Statement (Comprehensive Study Part Two (issued in October 2000))
- Volume 5 – Safety Plan and Concept Safety Analysis

This is Volume 2 – the Development Plan. This following Part II documents have also been prepared in support of Volume 2 of the Development Application.

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1 PROJECT OVERVIEW

This document is the Development Plan for the White Rose oilfield, an energy project off the East Coast of Newfoundland, Canada. It is part of the overall Development Application (DA) for the White Rose oilfield.

1.1 Purpose Rationale and Scope of the Project

The White Rose Significant Discovery Area is located approximately 350 km east of the Island of Newfoundland on the eastern edge of the Jeanne d'Arc Basin (Figure 1.1-1). The Jeanne d'Arc sedimentary basin is recognized as the principal oil-producing basin off the East Coast of North America. Husky Oil Operations Limited (Husky Oil) and its co-venturer Petro-Canada propose to develop a significant oil discovery in the White Rose area. Husky Oil and Petro-Canada believe that this project will meet international market demands for oil and generate considerable economic benefits for the economies of Newfoundland and Labrador and Canada, as well as provide a reasonable financial return for Husky Oil and Petro-Canada. The development will increase employment opportunities for people of the province and will contribute to the growth in petroleum industry infrastructure and business opportunities arising from the increased demand for goods and services. This will ultimately attract new investment to the province, contributing to the sustained growth of the provincial and Canadian economies. From Husky Oil's perspective, the proposed development will also satisfy its goal to acquire, find and develop substantial oil reserves. This will have a major impact on the company's overall growth and be in keeping with its mission statement: "to maximize returns to its shareholders in a socially responsible way." Husky Oil has undertaken detailed engineering and economic analyses of the White Rose oilfield project in order to determine that it is viable technically, economically and environmentally.

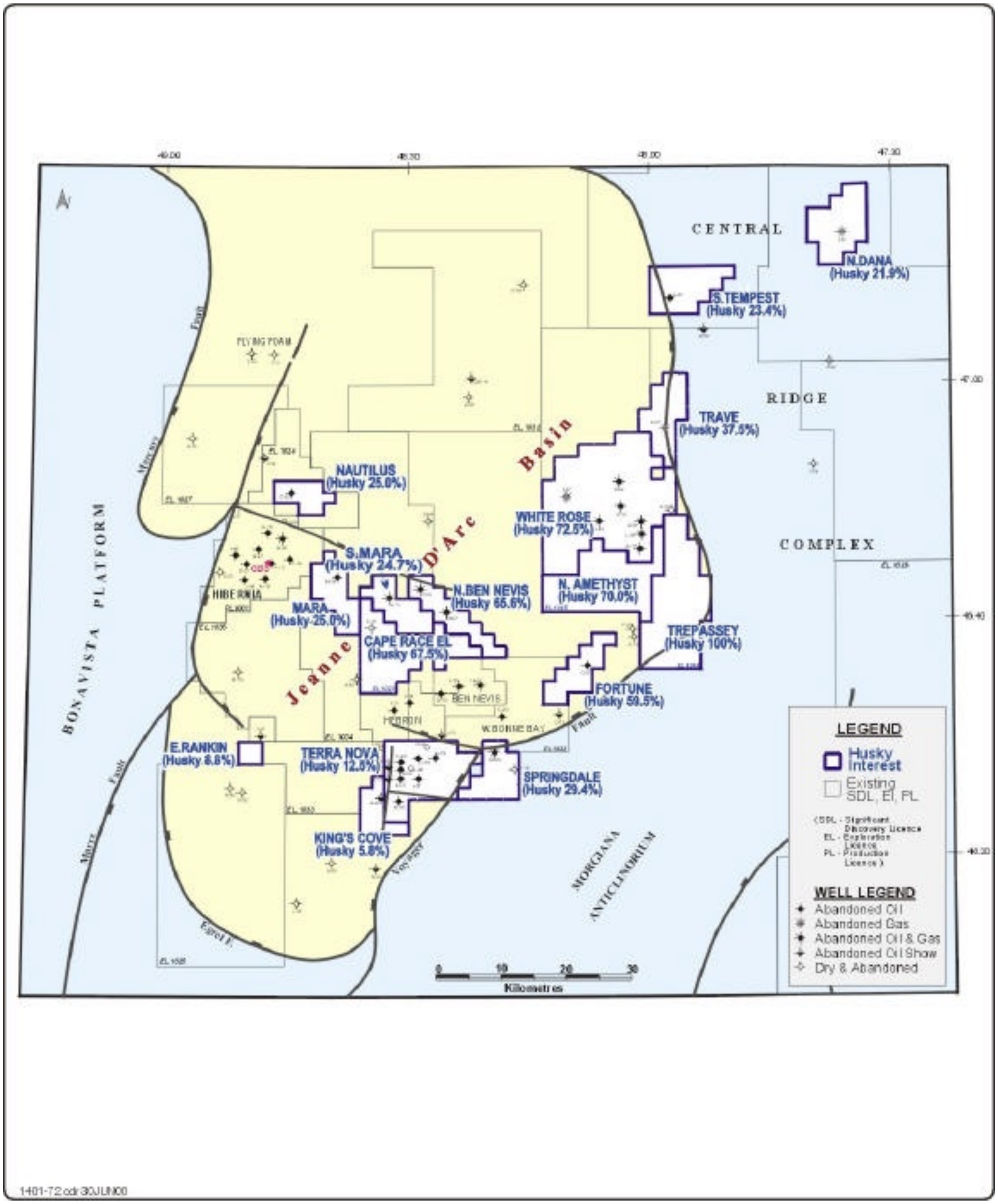
Husky Oil is one of the leading operators and interest holders in the Canadian East Coast offshore oil industry. Husky Oil's land holdings (Significant Discovery Areas and Licenses) in the Jeanne d'Arc Basin are indicated in Figure 1.1-2. The current land holdings are the result of significant investment, an extensive exploration program initiated in 1982, and a series of inter-company and land sale acquisitions over the past 18 years. Husky Oil holds an approximate 32 percent net working interest in the Significant Discovery Licence areas in the Jeanne d'Arc Basin. It is a significant business area for Husky Oil and a key to the company's continued growth.

Petro-Canada is the operator of the Terra Nova oilfield and also holds substantial interests in the Newfoundland offshore region.

Figure 1.1–1 White Rose Field Location Map

Figure 1.1-1

Figure 1.1–2 Current Husky Land Holdings and Working Interests in the Jeanne d'Arc Basin



Husky Oil's current understanding is that the White Rose Significant Discovery Area consists of both oil and gas fields or pools, including the South Avalon Pool, the North Avalon Pool, and the West Avalon Pool. The main oil reservoirs discovered at White Rose are in Avalon Formation sandstones. These Avalon sandstones were deposited during the early Cretaceous as shoreface sands along a north-south trending shoreline roughly paralleling the eastern margin of the Jeanne d'Arc Basin (refer to Figure 2.1-5). The South Avalon Pool covers approximately 40 km^2, and contains an estimated 36 x $10^6 m^3$ (million cubic metres) of recoverable oil. Current estimates of potential recoverable oil reserves from the North and West Avalon pools are in the range of 10 to 20 x $10^6 m^3$. If additional evaluation determines that economically recoverable reserves exist in the North and West pools, Husky Oil intends to ultimately tie these pools into the White Rose oilfield development infrastructure, thus extending the production plateau. Potential reserves, steps planned to obtain additional needed information and factors leading to future development of these ancillary oil pools are outlined in Section 6.7.

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

In November 1999, Husky Oil initiated a concept selection study (KSLO 2000) to identify the potential alternatives for developing the White Rose oilfield. The eight production concepts analyzed were:

- steel ship-shaped floating, production, storage, offloading (FPSO) facility;
- concrete FPSO facility;
- steel floating, production, drilling, storage, offloading (FPDSO) facility;
- concrete gravity base structure (GBS);
- steel semi-submersible facility with and without integral storage;
- concrete semi-submersible facility;
- disconnectable concrete tension leg platform (TLP); and
- concrete barrier wall with floating production unit (FPU).

A two-stage screening process was used to evaluate these concepts.

The first stage involved qualitative screening whereby options that were either undeveloped or clearly failed to satisfy primary technical criteria were identified. The outcome from this assessment was the elimination of the disconnectable concrete TLP, concrete barrier wall with FPU and the steel FPDSO. These concepts were not carried forward because they either did not meet Husky Oil's technical requirements or were prototypes with no operating history in harsh environment offshore locations.

The second stage screening process used a number of economic indicators to assess the five remaining options carried forward for detailed evaluation. These economic indicators included Net Present Value (NPV), Rate of Return (ROR), and Present Value Profitability Index (PVPI).

The remaining five options (steel FPSO facility, concrete FPSO facility, steel semi-submersible facility with and without integrated storage, concrete semi-submersible facility and concrete GBS) were further analyzed with respect to construction time, capital costs, concept maturity, concept deliverability and risk considerations.

The steel FPSO is the most economically viable way to develop the White Rose Field. A steel FPSO has a total development cost (that is, capital expenditure (Capex) plus operating expenditure (Opex)), of $3,246 million, the concrete FPSO has a total development cost of $3,366 million, the steel semi-submersible a total development cost of $3,435 million, the concrete semi-submersible a total cost of $3,516 and the concrete GBS has a total development cost of $3,793. The steel FPSO has the lowest total development cost of $3,246 million.

With respect to development time frame, the steel FPSO and the steel semi-submersible are equivalent in reaching First Oil in 36 months, while a concrete semi-submersible and concrete FPSO are equivalent at 42 months to First Oil. A concrete GBS reaches First Oil in 57 months (see Section 9.1.3 for more details on construction time periods). White Rose is considerably smaller than either Hibernia or Terra Nova in terms of recoverable reserves and therefore, an early First Oil date is important in maintaining the financial viability of the White Rose project.

There are currently no concrete FPSOs in existence and only one concrete semi-submersible (the Troll B). In addition, this existing concrete semi-submersible is not disconnectable and would require further development. Therefore, development of this new concept would subject the project to additional risk.

The concrete GBS, in addition to the higher costs and later First Oil date, also is more difficult to decommission and abandon.

The only two development concepts that were shown to be technically and economically feasible were the steel semi-submersible and a steel FPSO. Given that the development, operations, decommissioning and accidental events for both an FPSO and a semi-submersible are similar with respect to their interaction with the environment, the effects of both alternatives on the environment would be similar. Therefore, as the steel FPSO was determined through the rigorous concept selection process to be the preferred option, the environmental effects of the preferred option have been assessed in detail in the Environmental Impact Statement (EIS) (Comprehensive Study Part One).

A steel FPSO provides the optimum solution for White Rose and has a number of advantages:

- considerable flexibility for different production and storage levels;
- demonstrable competitiveness for harsh environment fields with 20 units installed, or in construction, in the last eight years;
- flexibility to tie-in future fields;
- easily and economically abandoned at the end of field life; and
- the best economic indicators.

Initial development plans for the South Avalon Pool will likely require up to 10 to 14 production wells. To maximize oil production, reservoir pressure will be maintained by injecting water into an additional six to eight strategically placed wells. Produced gas will be conserved by re-injecting into the field.

Current planning anticipates that up to four to six production wells, one to three water injection wells and one gas injection well will be drilled and tied in for First Oil production. As currently foreseen, drilling would continue over a two to four-year period after First Oil until the reservoir is fully developed. Ongoing reservoir management may require further production optimization wells in the pool over the life of the project.

As the floating production facility will not have drilling capability, wells will be drilled and completed using one or more semi-submersible drilling units. Wells are presently expected to be tied into subsea manifolds with flowlines and connected to the floating production facility through flexible marine risers.

It is anticipated that gas lift will be the artificial lift method used to optimize oil production later in the life of the field. Provisions for gas lift equipment will be included in the initial completion design of the wells.

Production design conditions are summarized in Table 1.1-1.

Table 1.1-1 Production Design Conditions

Production Parameter	Design Criteria
Maximum Shut-In Wellhead Pressure (kPa)	28,000
Flowing Wellhead Pressure (kPa)	4,000 – 10,000
Flowing Wellhead Temperature (°C)	60 – 95
Peak Oil Production (m^3/d)	12,000 – 18,000
Peak Produced Water (m^3/d)	15,000 – 30,000
Peak Produced Gas (10^6 m^3/d)	3 – 7

A typical subsea solution for floating production facilities consists of templates, manifolds, flowlines, umbilicals and risers. Projects on the Grand Banks also include some form of iceberg scour protection for their subsea installations. For the White Rose oilfield development, the main method of iceberg scour protection will be glory holes, with the possibility of implementing other solutions at strategic locations to optimize field layout. At present, a field layout has not been finalized. However, it is anticipated that three or four drill centres located in glory holes will be required to access the oil reserves in the White Rose Oil Pools. The final determination on the number of drill centres and fluid handling requirements at each drill centre will be made during the front end engineering and design (FEED) stage.

A tentative position of the development wells and drill centres is indicated in Figure 1.1-3.

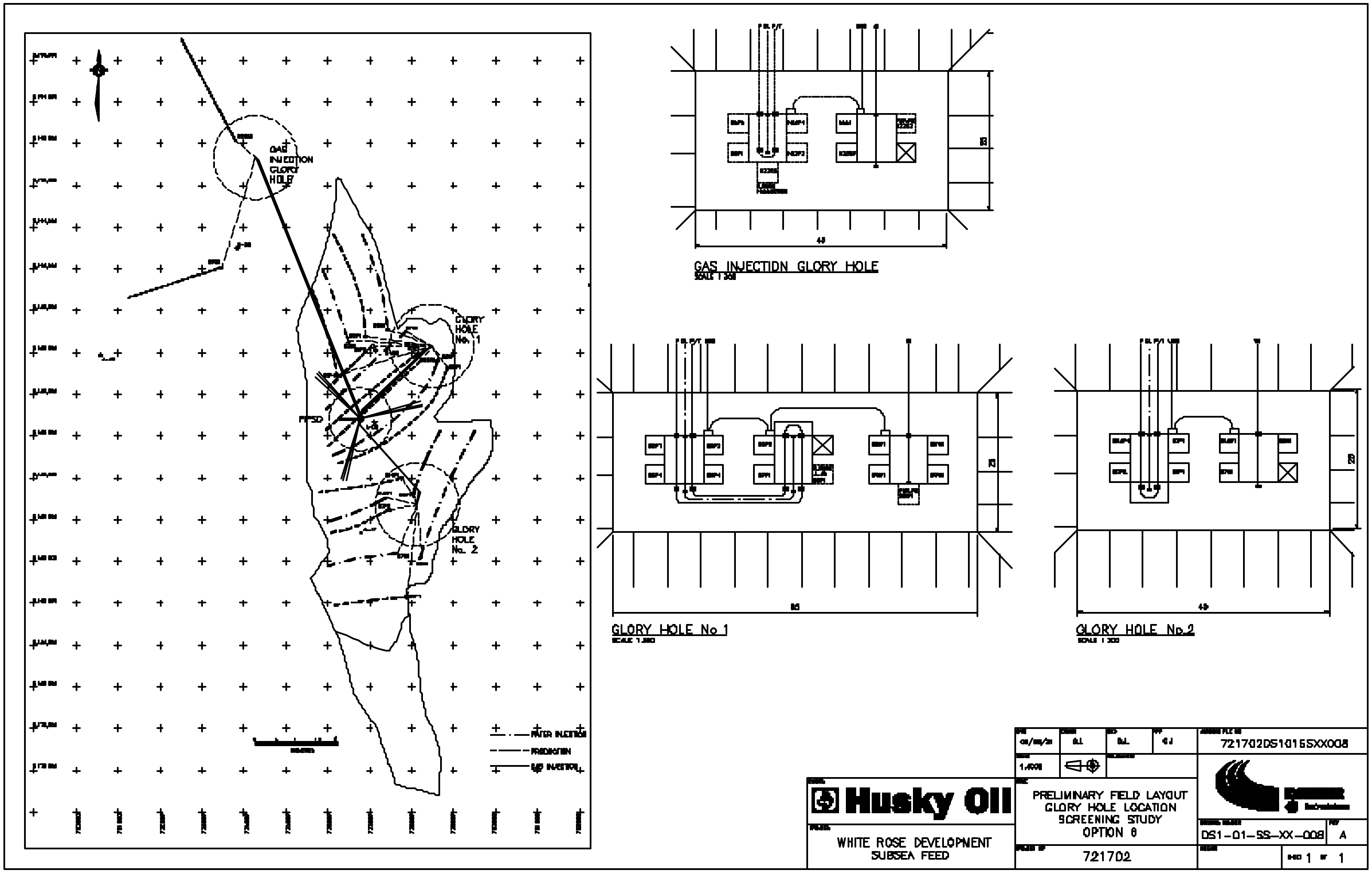
The water depth at the southern part of the White Rose area ranges from 115 to 130 m, with a seabed slope of approximately 0.05 m over 100 m (Nortech Jacques Whitford 1997). Both sea ice and icebergs occur on the Grand Banks, with iceberg severity off Newfoundland largely determined by regional sea ice conditions (Marko et al. 1994 in Petro-Canada 1996). Icing and iceberg data relevant to the White Rose area are provided in Table 1.1-2 and discussed in detail in Section 2.5 of the EIS (Comprehensive Study Part One).

Table 1.1-2 Icing and Iceberg Criteria

Theoretical Superstructure Icing Accumulation on 5 cm Cylinder	**10-Year Return**	**100-Year Return**
Glaze and Rime Icing (mm)	72	169
Spray Icing (mm)	316	514
Icebergs Sightings	**Mean**	**Maximum**
One Degree Grid	67	268
Mass (t)	220,000	--
Speed (km/h)	0.77	9.8
Sea Ice Occurrence	**Mean Cover**	**Average Number of Weeks**
Within 25 km	54 to 57 % coverage	2.3 to 2.6

Reliable systems for the detection, monitoring and management of icebergs, including towing techniques, have been developed. Husky Oil has an existing ice management plan and procedures, which involve cooperation with the other operators on the Grand Banks, including Hibernia and Terra Nova. This will give operations personnel sufficient early warning of any need to disconnect the floating production facility or drilling units from their moorings and risers. This would provide an orderly and controlled move off location, in the event that an unmanageable iceberg that presents a hazard approaches too close to the facilities. In addition, Husky and Petro-Canada are involved in ice management research and development (R&D) activities through a Centre for Cold Ocean Resources Engineering (C-CORE)-led Integrated Ice Management Initiative.

Figure 1.1–3 Typical Subsea Installation for a Two Centre Scenario



1.2 Brief History of the Field from Discovery To Date

White Rose is one of four Significant Discovery Areas operated by Husky Oil in the Newfoundland offshore area. The first three wells drilled on the White Rose Significant Discovery Area, White Rose N-22, J-49 and L-61, were drilled between 1984 and 1986. Results of these wells were encouraging, as oil and gas were encountered in all wells. Based on these results, the White Rose E-09 well was drilled in 1987-1988. This well was drilled into a separate structural culmination on the southern flank of the complex. It was the first well drilled in the South Avalon Oil Pool and encountered over 90 m of net oil pay, indicating the potential for commercial development.

In 1999, two additional delineation wells were drilled into the South Avalon Oil Pool, White Rose L-08 and A-17. These wells provided valuable data on the extent and quality of the reservoir encountered by the E-09 well.

A third well, White Rose N-30, was also drilled in 1999. It was drilled into the northern part of White Rose, downdip from the N-22 well. Results from this well helped to define the extent of the hydrocarbon pool first encountered by the N-22 well. The H-20 well was drilled in the second quarter of 2000 to delineate the northern extent of the South Avalon pool. The four wells drilled into the South Avalon pool, together with detailed interpretation of 3-D seismic data, have established reserves of approximately 36 x $10^6 m^3$ of recoverable oil for the field. The results of the first three South Avalon wells drilled are summarized in Table 1.2-1. Analysis of the H-20 well results is currently ongoing.

Table 1.2-1 Summary of South Avalon Wells

	Well E-09	Well L-08	Well A-17
Latitude:	46º 48' 26.24"N[1]	46º 47'30.987''N[1]	46º 46' 08.110''N[1]
		46º47'30.644'N[2]	46º46'07.767"N[2]
Longitude:	48º 01' 22.65"W[1]	48º 01'24.131"W[1]	48º 01'45.067''W[1]
		48º 01'20.172"W[2]	48º 01'41.111''W[2]
Water Depth:	124 m	122.7 m	119.5 m
Top Avalon			
mSS	2,807	2,879	2,855
mBRT	2,832	2,904	2,880
Base Avalon			
mSS	3,121	3,072	3,057
mBRT	3,146	3,097	3,082
T.D. mBRT	3,970	3,130	3,200
Oil Pay (m)			
Gross	117	119	114
Net	94	107	92
Status:	P&S oil and gas well	P&S oil and gas well	P&S oil and gas well

Source: Husky Oil White Rose "Basis for Design"

Notes:
1. NAD 27
2. NAD 83

mSS - Metres Subsea
mBRT - Metres below rotary table
P&S - Plugged and Suspended

Data Sources: E-09 End of Well Report, Husky/Bow Valley, June, 1988
L-08 and A-17 End of Well Reports, Husky Oil Operations, September, 1999.

1.3 Partners and Their Respective Interests

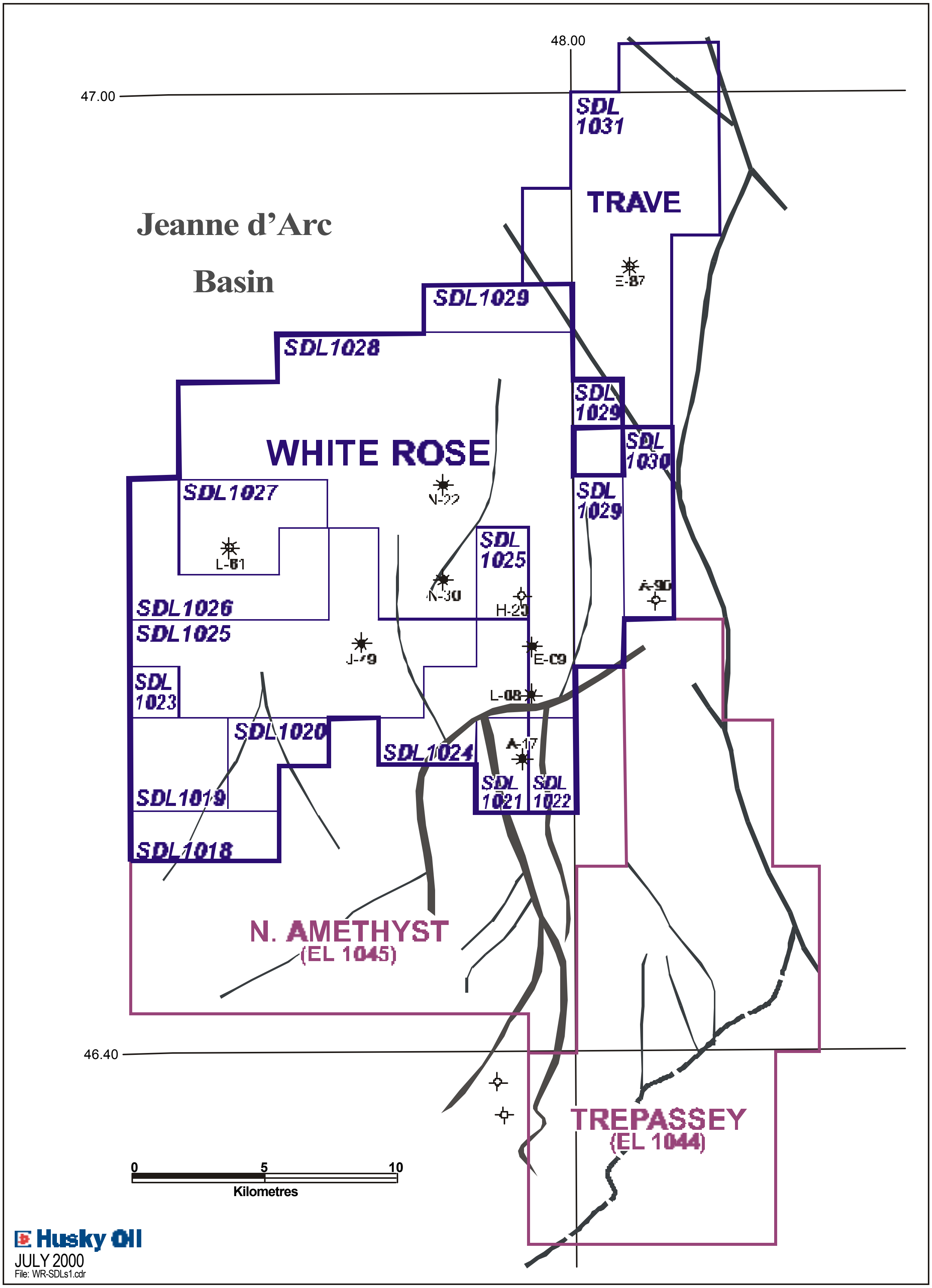
Husky Oil is developing the White Rose oilfield with its co-venturer Petro-Canada. The average interests of the co-venture parties in the White Rose Significant Discovery Area are:

- Husky Oil 77.1 percent
- Petro-Canada 22.9 percent

1.4 Land and Contracts

Husky Oil and partner Petro-Canada hold title to the White Rose discovery through 13 Significant Discovery Licenses or SDLs (SDLs 1018 to 1030 inclusive). The SDLs are outlined in Figure 1.4-1.

Figure 1.4–1 White Rose SDLs



The Working Interest split in the SDLs is defined in Table 1.4-1.

Table 1.4-1 Working Interest Split In White Rose SDLs

SDL	Husky Oil	Petro-Canada
1018 - 1020	100%	0%
1021 - 1022	72.5%	27.5%
1023	100%	0%
1024 – 1028	72.5%	27.5%
1029 - 1030	100%	0%

A portion of the "Terrace Block" within the South Avalon Pool may extend outside of the SDLs on to Exploration License 1045. Working Interest split on Exploration License 1045 is defined below:

Table 1.4-2 Working Interest Split On E.L. 1045

E.L.	Husky Oil	Petro-Canada
1045	70%	30%

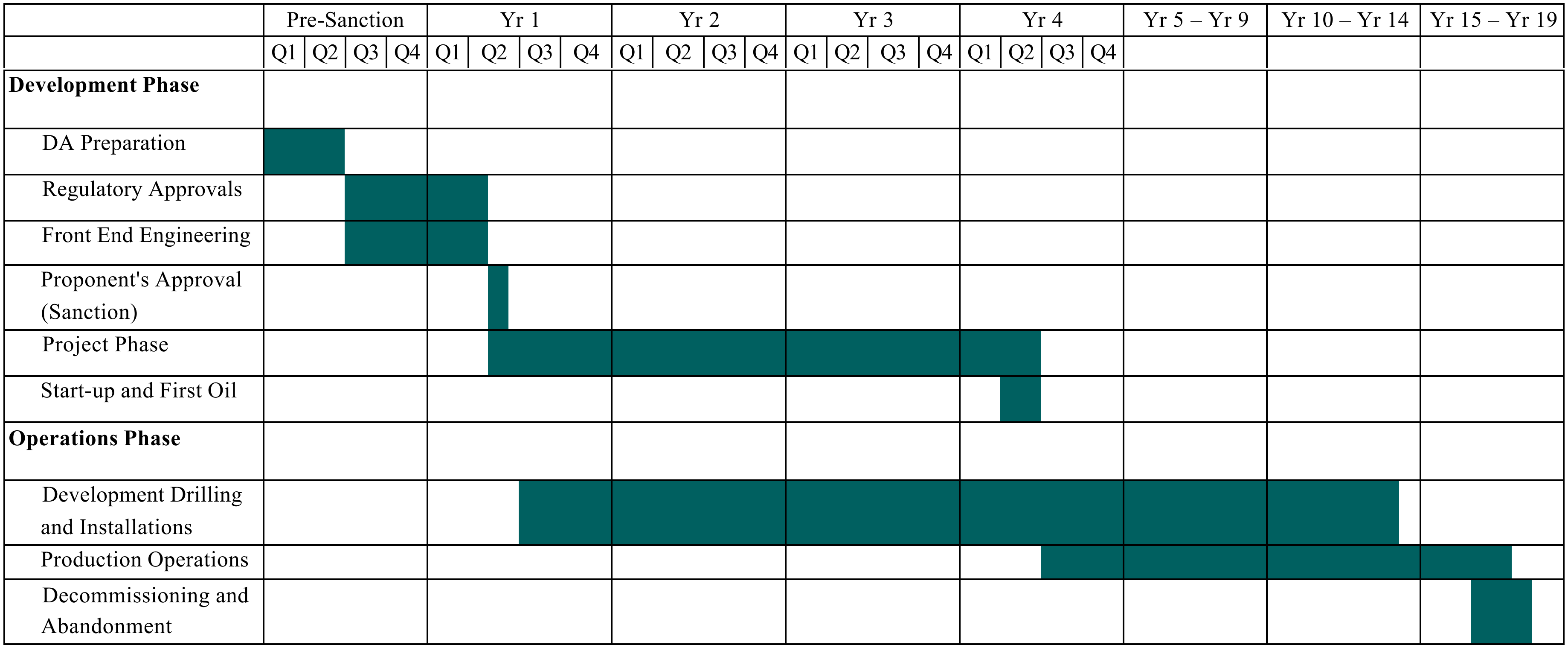
The White Rose Joint Operating Agreement, executed on July 1, 1997 currently governs operations on the White Rose project. This agreement is valid until Project Sanction. Development and production operations will be governed by a development agreement that is currently being negotiated between Husky Oil and Petro-Canada.

Pooling agreements should not be a significant issue due to the uniform Working Interest over the portions of the field containing the majority of the reserves.

1.5 Schedule

A project development overview schedule is provided in Figure 1.5-1. Key events and decision points for the design and procurements stages of all major elements of the project are provided later in this Volume in Figure 10.2-1.

Figure 1.5–1 Project Development Overview Schedule



1.6 Project Management

The operation of the White Rose oilfield will be managed by Husky Oil as operator of the field, employing both company resources, seconded personnel from Petro-Canada, and third-party services in an integrated team approach (refer to Figure 1.6-1 for a project development overview organizational chart). The on-shore organization will typically consist of approximately 45 to 50 personnel reporting to operations management. This group will include engineering, technical, loss control, logistics, financial and administrative personnel. An existing marine base and warehouse facility will be used to handle supply vessel and material movements.

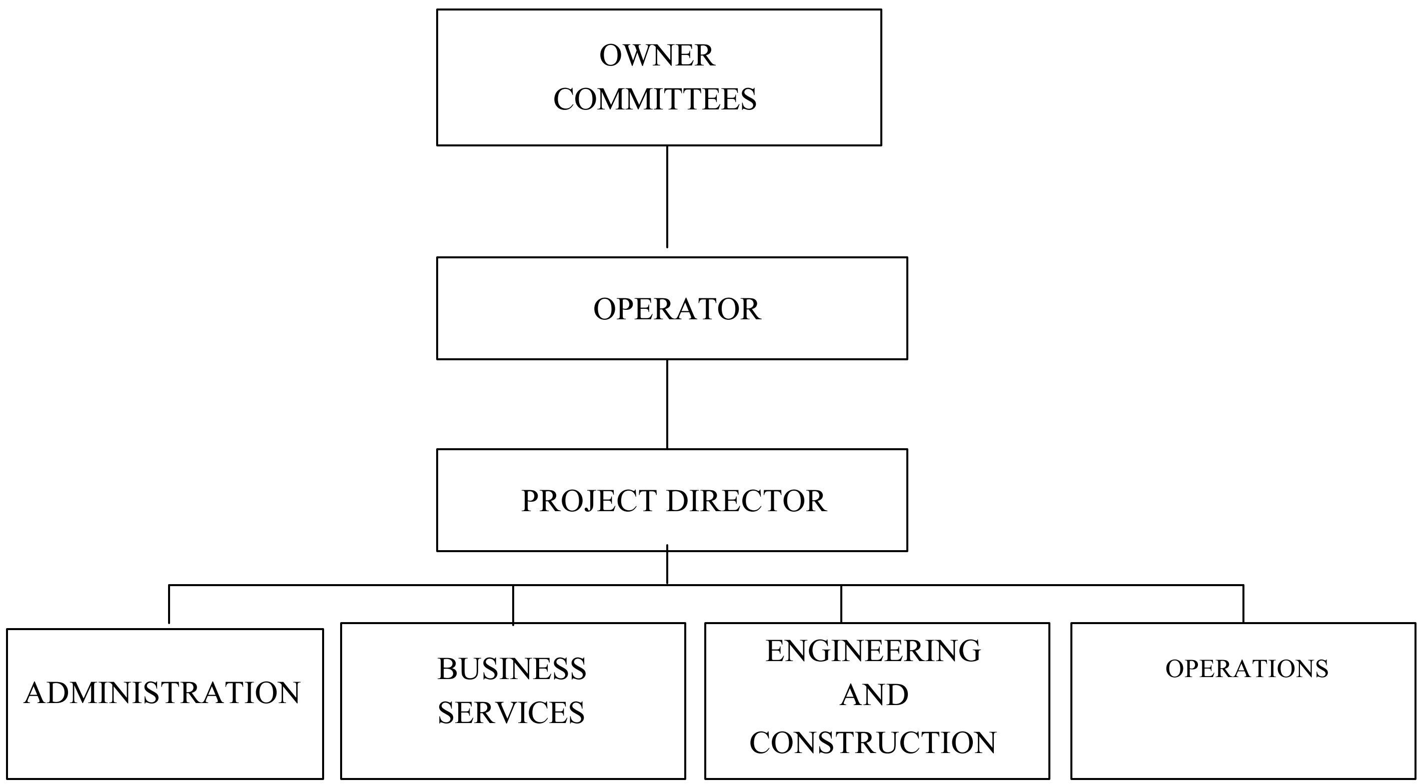
Husky Oil will operate the White Rose oilfield on behalf of itself and Petro-Canada from the Husky Oil office in St. John's, where the Operations Manager will be located. The Offshore Installation Manager (OIM) on the FPSO will be responsible for managing the FPSO and for coordinating all activities on the FPSO and all associated activities within the field. The OIM will report to the Operations Manager. Each mobile offshore drilling unit (MODU) operating in the field will be managed and controlled by an Installation Manager, who will also report to the Operations Manager. The OIM on the FPSO will, however, take responsibility for routine coordination of all concurrent offshore operations.

The offshore production organization will typically consist of approximately 90 to 100 personnel, half of whom will be on the FPSO, with the other half on rotational shore leave. The offshore group will include management, production and maintenance technicians, as well as marine, logistics, loss control and medical personnel. The OIM on the FPSO will have prime responsibility for coordinating all field activities, including emergency response, simultaneous production operations, tanker loading and drilling operations.

Drilling and workover operations will be conducted in the field using a MODU. The offshore complement on a MODU typically consists of approximately 70 to 100 personnel during drilling operations. Each MODU will have a designated manager responsible for offshore operations on that facility.

At the end of the production life of the White Rose field, Husky Oil will decommission and abandon the site according to C-NOPB requirements and *Newfoundland Offshore Petroleum Production and Conservation Regulations* and any other applicable laws. Floating production facilities will be removed from the field. Subsea infrastructure will be removed or abandoned and the wells will be plugged and abandoned.

Figure 1.6-1 Project Development Overview Organizational Structure



1.7 Issues Scoping and Stakeholder Consultation

Husky Oil has conducted an extensive issues scoping and stakeholder information/consultation program in preparing the DA for the White Rose oilfield development. This program met the requirements of the *Canadian Environmental Assessment Act*, C-NOPB Development Application Guidelines (1988) and the (*Atlantic Accord Acts*). A detailed report of the issues scoping and stakeholder consultation program is provided in the Part II Document to this DA, titled White Rose Oilfield Development Public Consultation Report (JWEL 2000). The program involved:

- reviewing relevant legislation and guidelines;
- reviewing the scoping document issued by C-NOPB, Department of Fisheries and Oceans (DFO), Environment Canada (EC) and Industry Canada (IC);
- reviewing documents prepared for the Terra Nova and Hibernia oilfield development;
- reviewing issues raised during the Terra Nova Development environmental assessment review process;
- consulting community, business, women's and non-governmental organizations, and the general public (key informant workshops, open houses and meetings/presentations);
- holding meetings with government departments and agencies;
- conducting media briefings and preparing press releases;
- tracking articles/stories from media sources;
- distributing project information (two mail distributions);
- establishing a project information telephone number (724-7244 and 1-877-724-7244);
- setting up a project-specific web site (www.huskywhiterose.com);
- documenting issues and concerns, and following up when necessary; and
- using professional judgement based on the particular characteristics of the White Rose oilfield development.

The main message heard throughout the scoping/consultation program was that the majority of participants were supportive of the development and interested in seeing it proceed. There was also a strong interest in ensuring that the project proceed in an environmentally, socially and economically responsible manner.

A number of general items that apply to all aspects of the project were noted throughout the consultation program. They are:

- learn from the Hibernia and Terra Nova experience;
- ensure ongoing, two-way communication with stakeholders;
- ensure project information is accurate, timely and appropriate; and
- do not raise false expectations in relation to benefits from the project.

Items raised throughout the scoping/consultation program have been incorporated in project planning and are reflected in the DA. A comprehensive list of items heard from the stakeholders throughout the scoping/consultation program is provided in the White Rose Oilfield Development Public Consultation Report (JWEL 2000). Items specific to each component of the DA are highlighted in the relevant DA documents. Specific comments about the project description and development plan are listed in Table 1.7-1, with the locations noted as to where they are addressed in this document.

Table 1.7-1 Comments about Project Design and Development

Comments	Where Addressed
Concept selection process, selected production alternative and rationale for selection.	Chapters 9, 14
Plans and timing for developing both the oil and gas at White Rose.	Section 6.7
Project infrastructure and activities, including activity before the actual start of the development.	Chapters 10, 11
Project-related traffic, including vessel types, volumes, routings and schedules.	Section 11.5.2
Oil Storage alternatives both onshore and offshore.	Section 9.4

2 GEOLOGY AND GEOPHYSICS

This section summarizes the regional geology of the Jeanne d'Arc Basin and discusses the geology and geophysics of the White Rose Field. Section 2.1 deals with the regional geology, including the tectonic history, stratigraphy, structure and geochemistry, and then more specifically, the geology of the White Rose Field. Section 2.2 includes data obtained from seismic studies and the geophysical interpretation of the White Rose Field and Section 2.3 describes the reservoir maps generated from core and log data and reservoir modelling. The reservoir maps are provided in Appendix 2.A.

The section is organized as follows:

- Geology;
- Geophysics; and
- Reservoir Maps.

2.1 Geology

This subsection describes the regional geology of the Jeanne d'Arc Basin and the geology specific to the White Rose Field.

2.1.1 Regional Setting

The White Rose Field is located on the eastern margin of the Jeanne d'Arc Basin, 350 km east-southeast of St. John's and 50 km from both the Terra Nova and Hibernia fields (Figure 1.1-1). This section describes the regional setting of the Jeanne d'Arc Basin and is organized into the following:

- Regional Tectonic History;
- Regional Stratigraphy and Depositional Environments;
- Regional Structure; and
- Regional Geochemistry.

2.1.1.1 Regional Tectonic History

The Grand Banks rifted area is limited by the Bonavista Platform to the west, the Cumberland Belt-Flemish Cap (CBFC) Paleozoic lineament to the north, the continent-ocean boundary (COB) to the east, and the Newfoundland Transform Fault Zone (NTFZ) to the south (Figure 2.1-1). The western rift shoulder, the Bonavista Platform, is a submerged and peneplained sector of the Appalachian Orogen, partially covered by thin Upper Paleozoic, Mesozoic, and Cenozoic strata and situated landward from the Murre Fault. The Murre Fault is a regional basin-bounding, crustal penetrative fault dipping oceanward, which was crucial to the formation of basins on the Grand Banks. The NTFZ is a major ocean transform fault that was active during the separation of North America from Africa/Iberia.

A series of interconnected sedimentary basins, including the Jeanne d'Arc, were formed on the Grand Banks of Newfoundland as a result of Early Mesozoic break-up of the Pangea continental mass and birth of the Atlantic (Figure 2.1-1). The network of basins (South Whale, Whale, Horseshoe, Carson, Flemish Pass and Jeanne d'Arc), adjacent sub-basins (Flemish Cap, Anson Graben, Salar) smaller troughs and cuvettes, have had a common evolution, though differences in their structure and stratigraphy exist. They are separated by elongate basement ridges bounded by faults that are linked at depth to the Murre detachment fault.

Three major Mesozoic rifting episodes affected the Grand Banks:

1) *Tethys phase* (Late Triassic-Early Jurassic). During this rifting episode the main basins were formed as half-grabens in the downthrown side of a major crustal detachment. The failed rift was followed by Atlantic opening south of the Grand Banks, on the Scotian margin.

2) *North Atlantic phase* (Late Jurassic-Early Cretaceous). Previously formed basins and new sedimentary troughs were affected by north-south trending faulting. The Jeanne d'Arc basin was reactivated along the Egret Fault, that forms its current southern boundary, and along the Voyager Fault, with the Central Ridge area emerging as a regional high. The southern Grand Banks area, known as the Avalon Uplift, which includes a series of rift basins, was uplifted and eroded. The Atlantic Ocean was opened south of the NTFZ. The Egret source rock was deposited during the thermal sag interlude within the Kimmeridgian.

3) *Labrador phase* (Mid to Late Cretaceous). During this episode numerous northwest-southeast trending faults severely fragmented the basins and intervening ridges. In the Jeanne d'Arc Basin, the Trans Basin Fault Zone (TBFZ) was formed. Also, several imbricates of the Voyager Fault created terraces along the basin's eastern margin. The Avalon Formation sandstone reservoir was deposited on the eastern flank of the White Rose structural high. The Atlantic Ocean opened, separating the Grand Banks from Iberia and the British Isles.

Figure 2.1–1 Grand Banks of Newfoundland – Distribution of Mesozoic Basins

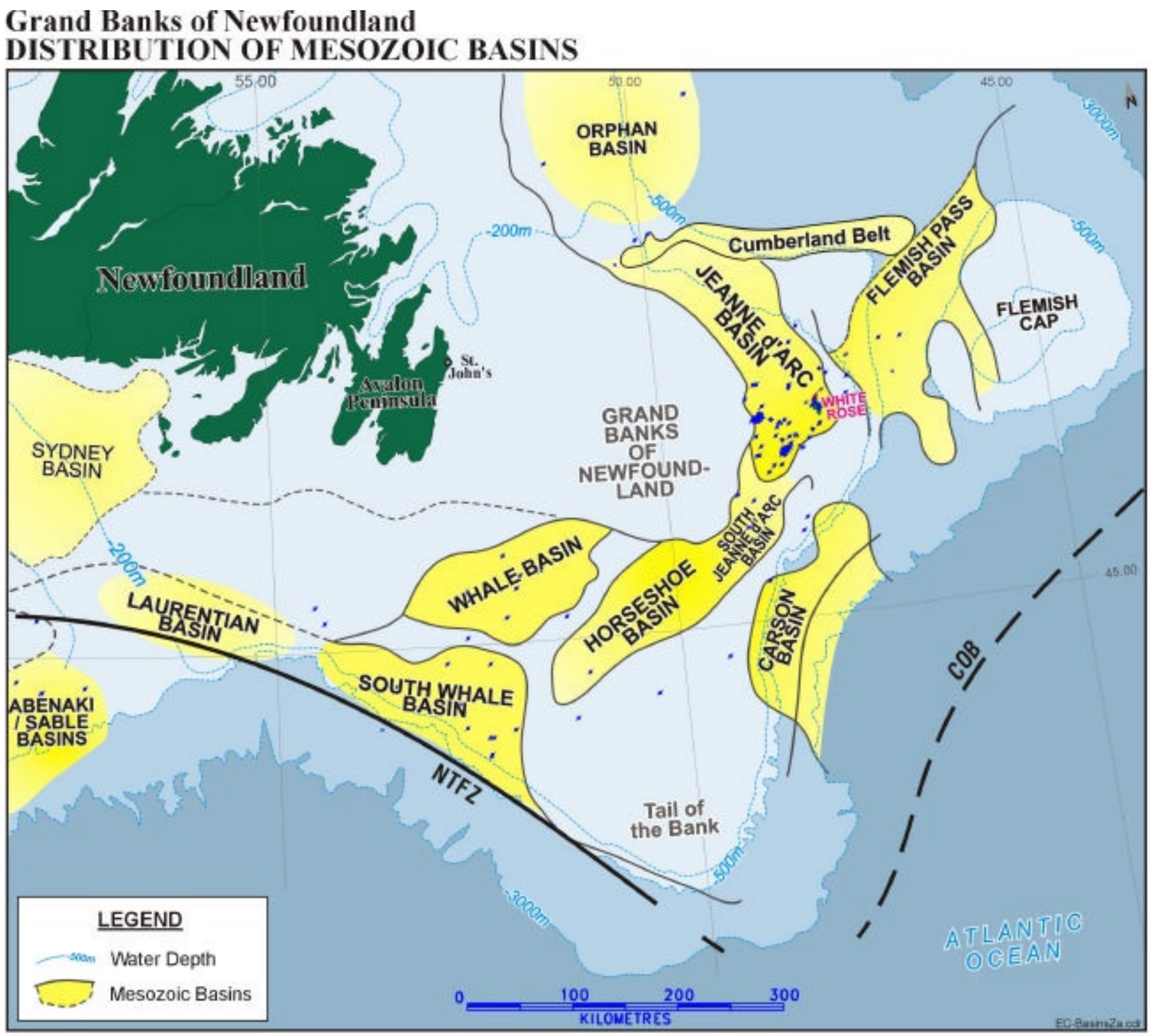


Figure 2.1-1

Each of the described rifting episodes had associated tectonic subsidence and was followed by post-rift thermal subsidence. The Tethys failed rift episode was the most important and defined the configuration and size of the basins. It was followed by a passive margin phase while the subsequent rifting episodes rejuvenated existing basins and opened new depositional areas.

Extensional and minor trans-tensional tectonic movements, accompanied by salt movement and several erosional interludes, have shaped the basin sedimentary fill. The basin infill can be divided into:

1. *Extensional stage sedimentary sequences* (Late Triassic-Early Cretaceous). These are strongly compartmentalized by normal fault systems and contains numerous structures;

2. *Thermal subsidence stage sedimentary sequences* (Late Albian to Present). These are usually tectonically undisturbed (that is, no extension) but contain depositional and erosional features.

Alongside extensional tectonics, halokinesis and halotectonics played an important role in basin evolution and structure. Prominent salt-cored structures are presently found throughout the Grand Banks. Salt features are interpreted to underlie the Hibernia, Terra Nova and White Rose fields.

2.1.1.2 Regional Stratigraphy and Depositional Environments

High resolution biostratigraphy, sequence stratigraphy, and workstation-based three-dimensional (3-D) seismic stratigraphy have been fully integrated into a tectono-stratigraphic framework (Figure 2.1-2) to develop an understanding of the stratigraphy of the Jeanne d'Arc Basin. This has been essential for the definition of unconformities, their relationship to tectonics and subsequent reservoir development. It is particularly true for the Avalon and Ben Nevis Formations within the basin and how their tectono-stratigraphic definition is carried into the White Rose area.

Principal Reservoirs

Beginning in the mid-Kimmeridgian, several cycles of coarse-grained clastics were deposited throughout the Late Jurassic and Early Cretaceous. These are the primary hydrocarbon reservoirs in the basin. The Kimmeridgian Jeanne d'Arc Formation sandstones unconformably overlie the source and are the reservoirs at Terra Nova. The Berriasian-Valanginian Hibernia Formation sandstone is the primary reservoir at the Hibernia Field. The Aptian Avalon Formation sandstones contain the reserves at White Rose and North Ben Nevis. The Albian Ben Nevis Formation are the sandstone reservoirs at Hebron, West Ben Nevis and Ben Nevis.

Figure 2.1–2 Stratigraphy of the Jeanne d'Arc Basin

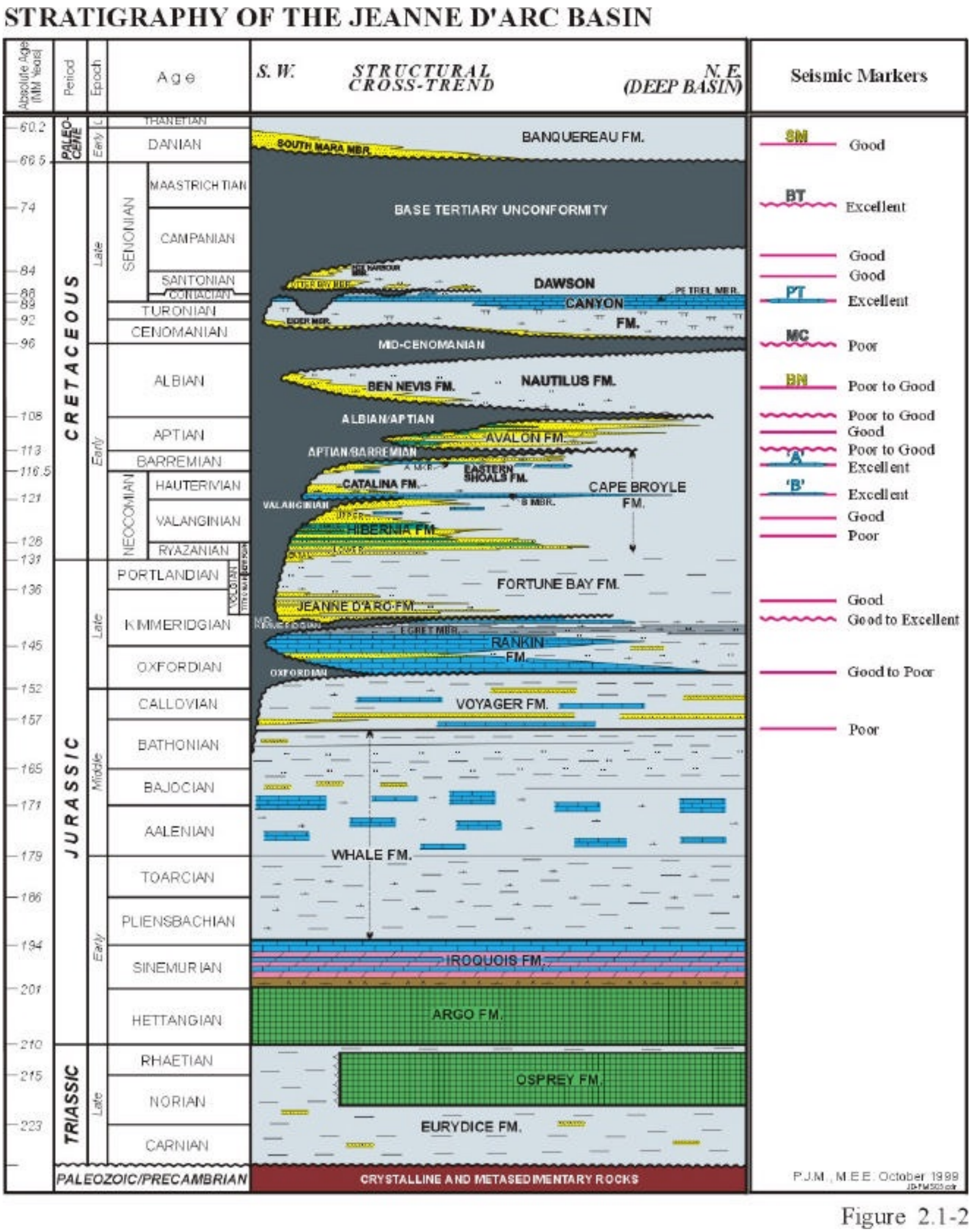


Figure 2.1-2

Triassic-Mid. Jurassic Mega-Sequence: The Early Mesozoic break-up of Pangea was a complex process which resulted in the formation of a several fault-bounded Mesozoic rift basins, one of which was the Jeanne d'Arc. Sedimentation was initiated during the Late Triassic when a classic rift sequence developed over the Grand Banks. The sequence commenced with deposition of continental red beds of the Eurydice Formation, followed by restricted marine evaporite facies of the Argo Formation. The overlying Lower Jurassic Iroquois Formation, consisting of interbedded carbonates and evaporites, indicates a transition to a more open marine environment which continued with the deposition of the Middle Jurassic Whale Formation shales and carbonates. The overlying Voyager Formation consists of interbedded limestone, shale and sandstone, the latter exhibiting poor to fair porosity, and may have generated minor amounts of the oil in the Jeanne d'Arc Basin.

Oxfordian-Mid. Kimmeridgian Mega-Sequence: The Upper Jurassic Rankin Formation is composed of marls, oolitic limestones, shales and carbonate-cemented sandstones, some with minor porosity. The carbonates create important seismic reflectors throughout the Jeanne d'Arc, even at considerable depth. Most importantly, the major source rock, the Egret Member, is found near the top of the formation. It consists of marls and organic rich laminated shales deposited in a silled basin during this highstand event. Uplift and renewed rifting of the Grand Banks during the Late Jurassic is indicated by the angular mid-Kimmeridgian Unconformity, with subsequent deposition of coarse clastics of the Jeanne d'Arc Formation sandstones.

Mid. Kimmeridgian-Valanginian Sequence: Beginning at the mid-Kimmeridgian and continuing into the Early Cretaceous, sandstones were transported into the basin from the southwest. This entry point was structurally controlled, bounded in the west by the Murre Fault and to the east by the Voyager Fault. Tectonic uplift and the associated lowstand event formed multiple incised valleys into the underlying north-northeast dipping Rankin Formation, south and southwest of the Terra Nova field.

The Jeanne d'Arc Formation sandstones are the primary reservoir at Terra Nova, forming laterally continuous braidplain to marine sandstones. They have also tested oil throughout the southwest part of the basin at Hebron, West Ben Nevis, Hibernia and King's Cove. Away from the depositional trend, and where they are more deeply buried at Hibernia, reservoir quality deteriorates. The overlying Fortune Bay shales and siltstones form hydrocarbon seals and indicate a major transgression. This highstand cycle reached a maximum near the end of the Jurassic, and is followed by increasing silt content towards the top of the Fortune Bay. Shallowing water and increasing coarse clastic content culminated in the deposition of the regressive Lower Cretaceous Hibernia Formation sandstones.

The Hibernia Formation can be subdivided into a lower and upper section, separated by a middle shale unit. The Lower Hibernia sandstones are widely distributed, beginning with a basal upward-coarsening, prograding sandstone, overlain by fluvial and shallow marine bars and channels. The Upper Hibernia sandstones are present in the shallower southwest part, and on the flanks of the Jeanne d'Arc Basin. Siltstones, minor sandstones and shales extend into the central basin as a more marine deposit. Hibernia

Formation reservoir quality is excellent at Hibernia, decreases at Hebron, and has low permeabilities at White Rose. At White Rose, the Upper Hibernia Formation is restricted to the south, towards Archer K-19, while the Lower Hibernia is present as a more distal facies, with much lower net to gross ratios than elsewhere in the basin. North of White Rose, at Trave E-87, the depositional limit of the sandstone has nearly been reached.

Hauterivian-Upper Barremian Sequence: Near the end of Hibernia Formation deposition in the Late Valanginian, minor uplift occurred, resulting in erosion and non-deposition in the southern Jeanne d'Arc and on the flanks of the basin. A subsequent marine transgression allowed the deposition of a widespread oolitic limestone, the B Marker. This unit is regionally correlatable on logs and creates an excellent seismic marker. In the southern and western part of the basin, this was followed by the deposition of the Catalina Formation, an interbedded calcareous limestone/sandstone, which forms a minor reservoir at the Hibernia Field. Elsewhere, the Cape Broyle Formation siltstones and shales were deposited, as a major transgression advanced over the entire basin, culminating in maximum flooding in the Late Hauterivian. Deposition of Hauterivian aged coarse clastics is restricted to the basin flanks. These clastics mark the onset of the Eastern Shoals Formation, a time transgressive, shallowing-upward sandstone/limestone unit with minor porous intervals. Development of shallow marine limestones, which are locally correlateable within this unit, was common during the Early Barremian, and are locally referred to as the A Marker, A sandstone or A limestone.

Subsidence and faulting continued on the basin margins in the Jeanne d'Arc Basin during the Early Cretaceous. Based on isochron and well isopach data, minor east-west extension had ended by the Late Hauterivian. In the Late Barremian major tectonism was renewed. The shallowing-upward Eastern Shoals Formation culminates in non-marine to brackish sediments over most of the Jeanne d'Arc Basin, although shallow marine sandstones and shales are more prevalent in the White Rose area. Much of the younger Barremian aged sections has been eroded because of continued uplift during the Early Aptian in the southern White Rose area.

Aptian-Upper Albian/mid-Cenomanian Sequence: The Eastern Shoals Formation is unconformably overlain by the Avalon Formation of Aptian age, which consists of stacked aggradational shoreface sandstone units, culminating in an upward-fining shaly siltstone. Typically, the Avalon sandstones are cleaner and finer grained in the White rose area, compared to the Avalon found in the central and western Jeanne d'Arc Basin. The Avalon Formation on the eastern flank of the basin unconformably overlies considerably older Lower Cretaceous section. In the Archer K-19 well, Upper Hibernia sandstones subcrop beneath the Avalon, removing the Barremian-Hauterivian section compared to other White Rose wells. As indicated by the White Rose A-90 well, erosion appears to have removed most of the Neocomian sandy section south and east of Archer K-19 and White Rose E-09. This huge volume of clastic sediment was subsequently re-deposited as the Avalon Formation at White Rose.

Tectonic activity in the basin centre culminated towards the end of the Aptian or early Albian when the uplifted TBFZ collapsed during a final episode of northeast-southwest extension, allowing deposition of the Albian aged Ben Nevis Formation in the resulting subsiding grabens, as found at Ben Nevis I-45. This formation was deposited during Albian transgression, filling accommodation space resulting from ongoing tectonic extension, initially as coarse clastic deposits, grading to lower shoreface and inner shelf silty sandstones as water depths increased. The formation shales out in a northerly and westerly direction as indicated by Albian deposition in North Ben Nevis and in the White Rose area. These overlying siltstones and calcareous shales are the Nautilus Formation and provide a regional seal.

Late Albian-Tertiary: The final thermal subsidence stage of the Jeanne d'Arc Basin has been ongoing since the end of the Lower Cretaceous, although a period of uplift allowed deposition of the Cenomanian shallow marine Eider Formation north of the North Ben Nevis field. For the most part, siltstones and shales of the Nautilus Formation filled topographic relief, followed by the marls and shales of the Dawson Canyon Formation, which blanketed the entire basin. Reactivation of a few fault blocks has occurred in some instances, such as at Mara M-54, where uplift and subsequent erosion has left a very thin Albian section underlying a Coniacian clastic wedge. A number of westerly-sourced clastic wedges, either submarine fans or fan deltas, are found on the western flank of the Jeanne d'Arc Basin in the uppermost Cretaceous and Tertiary. These are the Otter Bay, Fox Harbour and South Mara members, respectively. The South Mara is more widespread, extending to the western flank of White Rose, on the eastern side of the basin.

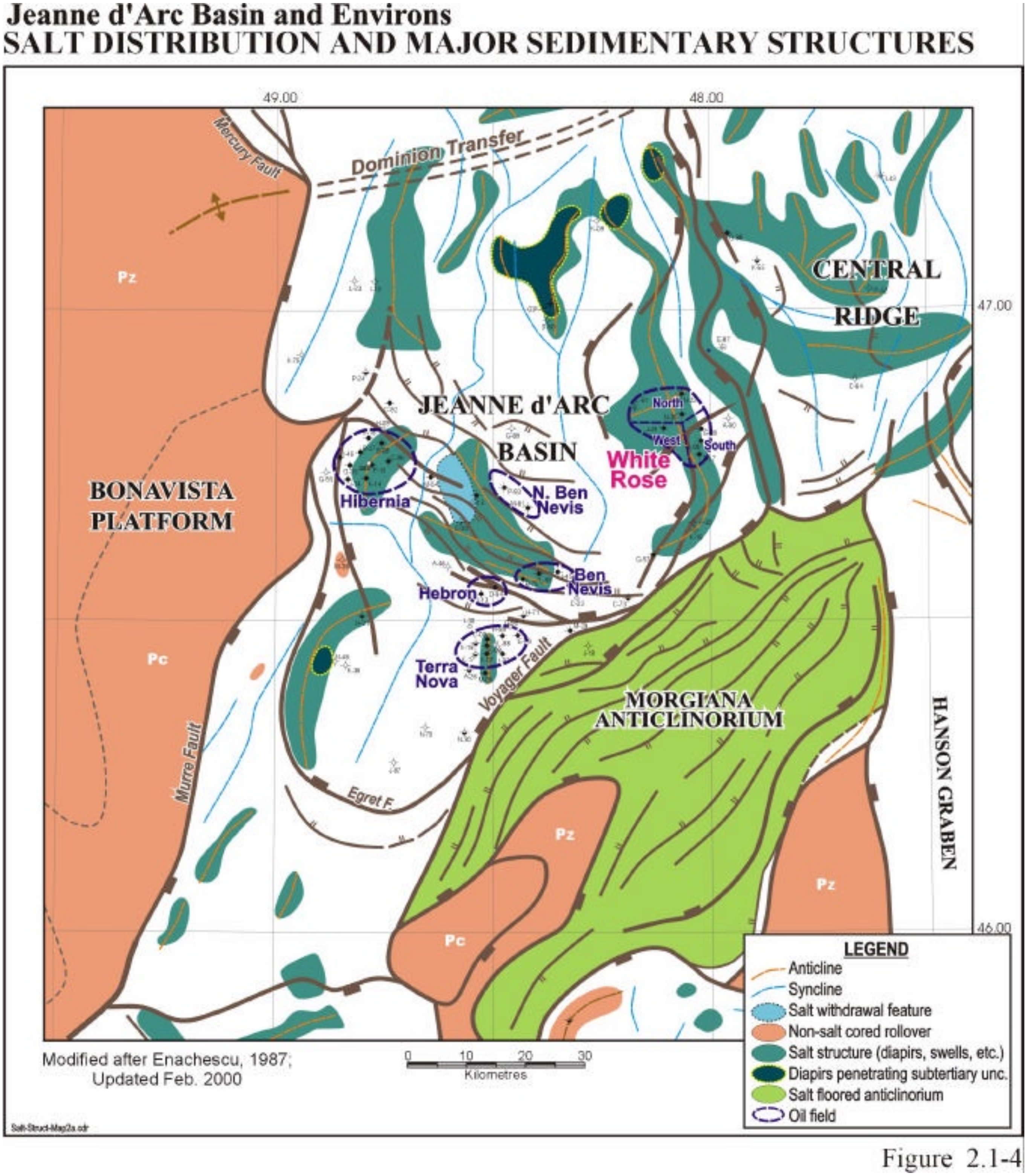
2.1.1.3 Regional Structure

The structural interpretation of the Jeanne d'Arc Basin is based on in-house and published regional seismic interpretations performed on widespread seismic horizons such as Base Tertiary, Petrel, A Marker, B Marker, Top Rankin/Kimmeridgian Unconformity, inferred Top Salt and inferred Acoustic Basement. These horizons were correlated to geological events intersected in some 40 wells drilled in the basin. Timing of structural and tectonic events was completed by using biostratigraphic analysis, isopach maps and palinspastic reconstructions.

The Jeanne d'Arc Basin is a fault-bounded Late Jurassic-Early Cretaceous reactivated sector of a larger Late Triassic-Early Jurassic depositional area on the Grand Banks. The basin forms an elongate trough trending north-northwest south-southeast, encompassing an area of roughly 10,500 km^2, bounded by the Murre Fault to the west, the CBFC lineament to the north, the Voyager fault zone to the east and the Egret Fault to the south (Figure 2.1-1). The basin tapers and shallows to the south. Over 20 km of Upper Triassic to Cenozoic sedimentary infill is present in its depocentre situated north of the TBFZ. Virtually all significant hydrocarbon discoveries in the Grand Banks are confined to the Jeanne d'Arc Basin (Figures 2.1-3 and 2.1-4).

Figure 2.1–3 Jeanne d'Arc Basin and Environs – Major Structural Elements

Figure 2.1–4 Jeanne d'Arc Basin and Environs – Salt Distribution and Major Sedimentary Structures



Late Triassic to Early Jurassic extension created the Jeanne d'Arc Basin as a half-graben on the downthrown side of a major basin forming detachment fault, known as the Murre-Mercury Fault. This extensional fault system, its associated antithetic and synthetic faults and its conjugated shear faults, compartmentalize the basin into numerous fault blocks. Major boundary faults, such as Murre, Voyager and Egret, are separated by relay ramps that accommodated diminishing extension on one fault and increasing slip on the other fault. During this rifting stage the major internal architecture of the Jeanne d'Arc Basin was established. The Upper Triassic-Lower Jurassic salt (Osprey and Argo formations) deposited in the incipient rift basin now underlies most of the basin, and forms salt pillows, diapirs and ridges (Figure 2.1-4). Salt induced structural and stratigraphic features are likely responsible for the formation of the White Rose structural complex. Thermal sag followed the initial rifting phase.

Jeanne d'Arc Basin extension continued during the Late Jurassic to Early Cretaceous phase of rifting characterized by a dominant east-west direction of extension. Basin growth occurred on the bounding faults, Murre and Voyager, and at its southern extremity marked by the Egret fault. Uplift, non-deposition and erosion affected a broad region in the southern Grand Banks, including portions of the Jeanne d'Arc Basin. Developing as a separate block in the footwall of the Voyager Fault, the Central Ridge started to emerge as a prominent and permanent regional high. Numerous north-south faults formed, especially on the Central Ridge and in the eastern portion of the basin where the White Rose field is located. Salt diapirs and salt cored ridges were formed, influencing sedimentation and local fault patterns.

In the Early Cretaceous, unconformities that developed during the Late Barremian to Early Albian mark the approximate end of the second rift phase in the Jeanne d'Arc Basin and the beginning of separation between the Grand Banks and Europe. Successive sag, rifting and then, ocean opening took place during this period. During the Aptian to Albian, northeast-southwest extension and block reorganization took place in the centre and along the margins of the Jeanne d'Arc Basin.

In the central part of the basin, towards the end of the Aptian, the TBFZ collapsed during major northeast-southwest extension, allowing deposition of Albian aged clastics (Ben Nevis Formation) into the subsiding grabens and low fault blocks. Clastics were deposited in a northerly direction reaching the western part of the White Rose Complex, but they exhibit poor reservoir properties. In the White Rose area, towards the end of the Barremian, important salt movement occurred, particularly under the North Amethyst structure, Trepassey Depression and on the White Rose salt dome area (Figure 2.1-5). Concurrently, significant erosion of older pre-Barremian clastics and sediment redeposition took place during the Aptian in these areas.

Figure 2.1–5   White Rose Complex – Regional Composite Marker Time Structure

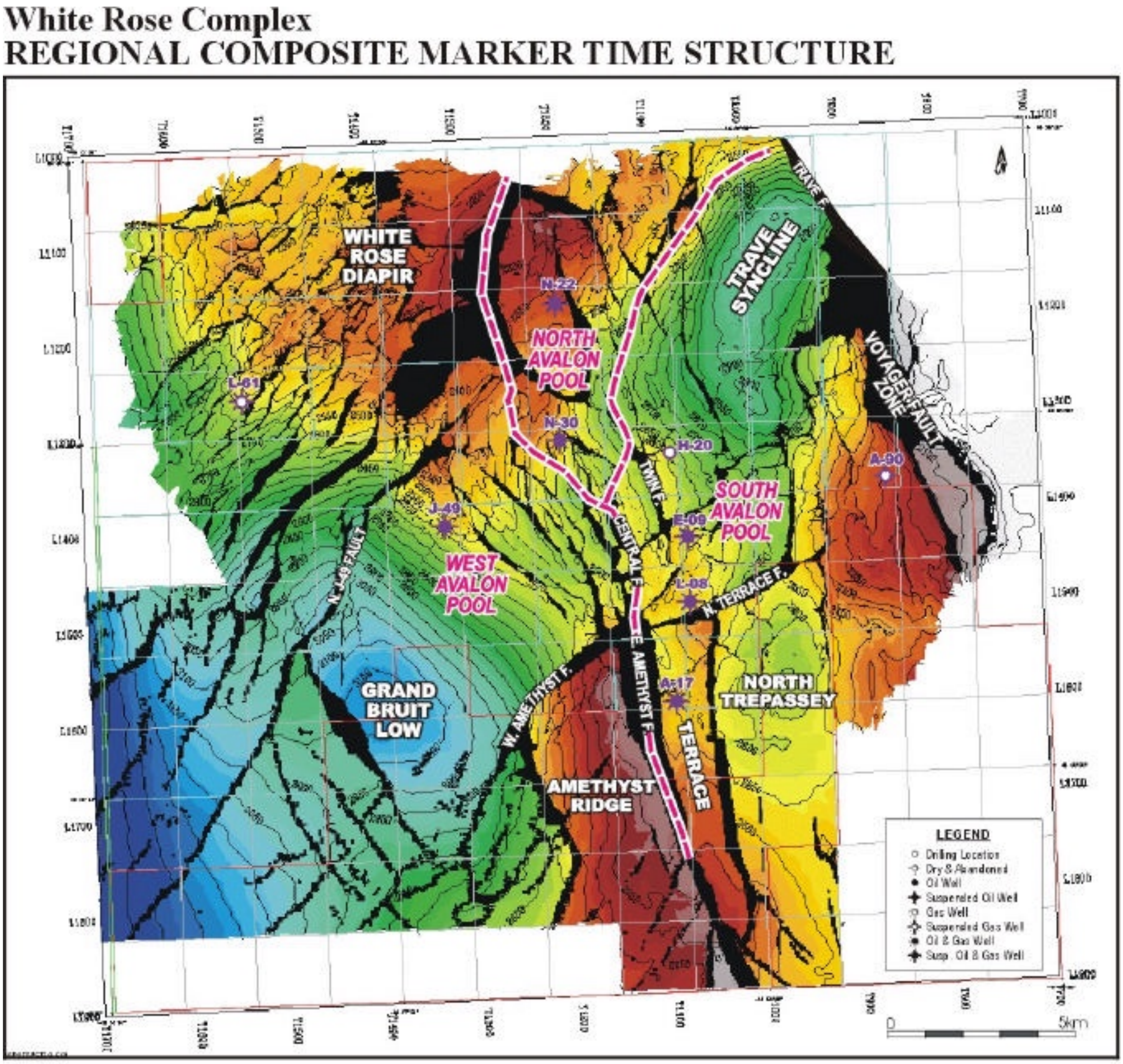


Figure 2.1-5

There is some uncertainty as to the age of the last rifting episode in the basin. In the White Rose/ Amethyst area, the post-Avalon unconformity of late Albian age, may mark the cessation of extensional events. However, small block readjustments took place up to Paleocene time.

The Base Tertiary unconformity configuration reflects tilting of the basin and thickening of post-rift sediments toward the north. Late salt movements and compaction rejuvenated a few larger faults. These faults (for example, Amethyst Fault) penetrate the unconformity and terminate in lower Tertiary sediments forming tectonic lineaments and sedimentary features, but no major structural closures.

2.1.1.4 Regional Geochemistry

The Jeanne d'Arc Basin is unique amongst East Coast basins in that it is a proven oil province containing large oil and gas fields. The rich oil-prone Kimmeridgian Egret Member source rock (Figure 2.1-6), the principal proven source (Fowler and McAlpine 1994), is similar in age and quality to the prolific Upper Jurassic Kimmeridge Clay Formation of the North Sea. The Egret Member is widespread in the Jeanne d'Arc Basin, and has been penetrated in three White Rose area wells: White Rose A-90, Archer K-19 and Trave E-87. Three additional potential source intervals occur sporadically throughout the basin, within the Jeanne d'Arc Formation, Lower Rankin Formation and Voyager Formation, but are not believed to be substantial hydrocarbon generators (Fowler and Brooks 1990).

The Egret Member is found near the top of the Rankin Formation, and consists of marls and organic-rich laminated shales (up to 8 percent total organic carbon (TOC)). These shales were deposited during highstand cycles, allowing the concentration of organic rich debris in deep silled basins (Powell 1985). The unconformable contacts bounding the Rankin Formation likely indicate tectonic formation of the paleotopography necessary for a stratified water column, and the concentration and preservation of organic material. The Egret Member was deposited over a large area, likely in a series of interconnected basins, but has since been largely eroded to the south of the Jeanne d'Arc Basin in the Horseshoe and Whale Basins.

The present day maturity pattern of the Egret was likely well established by the Late Cretaceous, due to rapid subsidence and high sedimentation rates during the Early Cretaceous. The maturity modelling work of Williamson (1992) indicates that the Egret began to generate oil in the deepest, central, Jeanne d'Arc Basin area at this time, with the mature/non-mature boundary moving progressively towards the basin's margins during the Tertiary. With the onset of maturity, hydrocarbon migration would have begun, with evidence for both vertical and lateral migration in the basin.

Current maturity values, as modelled, indicate that the source rocks are overmature in the central Jeanne d'Arc, generating only gas (Figure 2.1-6). Early mature source rocks are still present on the eastern and southern flanks of the basin, and have been penetrated at Terra Nova and White Rose (Fowler and Snowden 1989).

Figure 2.1–6 Jeanne d'Arc Basin – Egret Source Rock Maturity Map

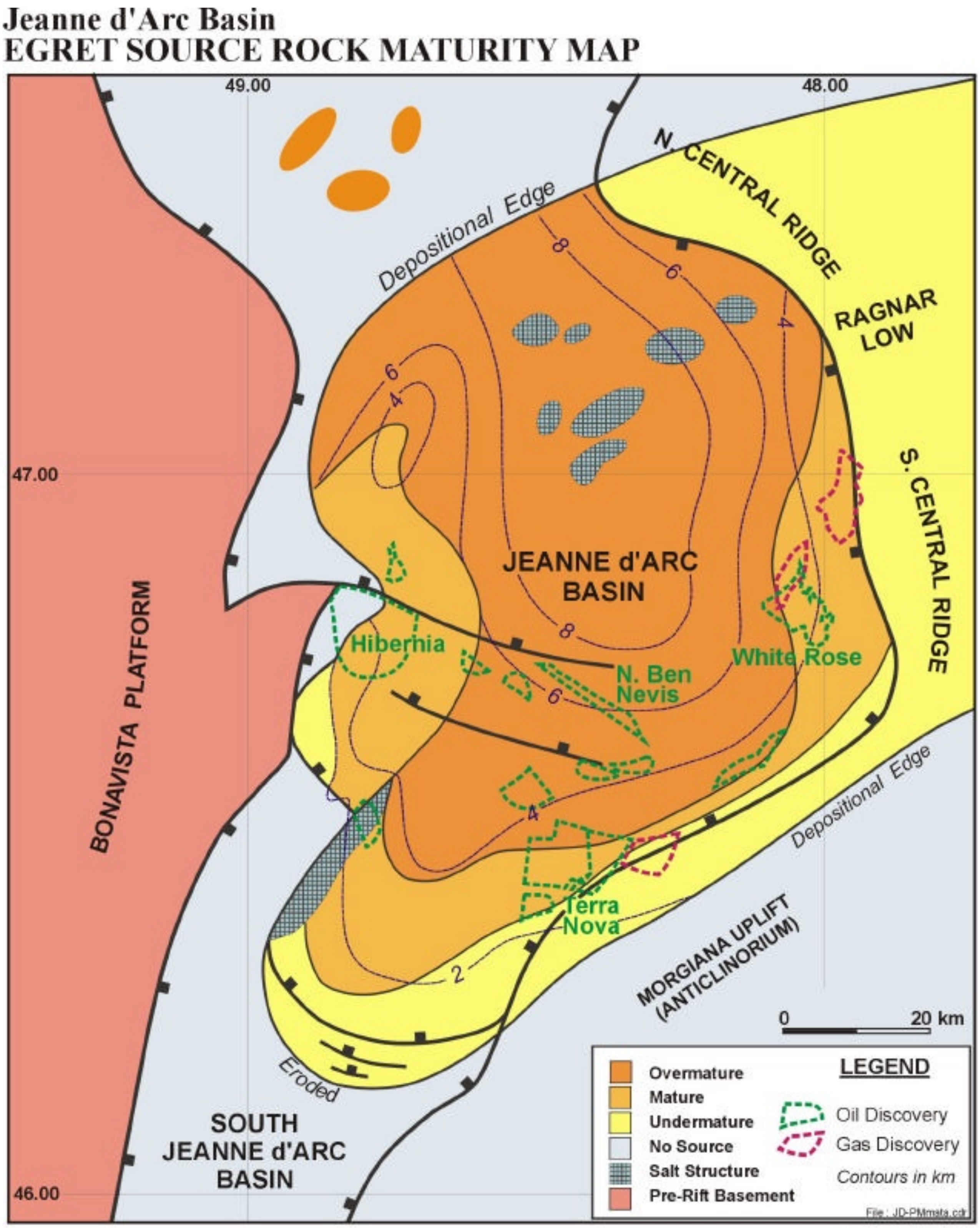


Figure 2.1-6

2.1.2 White Rose Field General

The White Rose Field is a highly faulted complex of rotated fault blocks, cored by salt at depth. White Rose is bounded to the north and west by basinward-dipping flanks of the White Rose salt dome. The eastern margin of the structure abuts against the basin-bounding Voyager Fault, while the southern boundary of the field encompasses the White Rose Terrace. The Terrace is bounded by major faults at its western, eastern, and probably, southern limits (Figure 2.1-5).

The principal reservoir is the Aptian Avalon Formation, which consists of fine to very fine grained quartzose sandstones deposited in a shallow marine to shoreface setting. As of April 2000, the field had been delineated by nine wells. Pressure measurements and fluid contracts indicates that the Avalon reservoir is divided into three separate pools. The West Avalon Pool has been penetrated by one well, J-49. The North Avalon Pool has been penetrated by two wells, N-22 and N-30. The most significant pool, South Avalon, has 350 m of sandstone with over 100 m of net oil pay. Four wells have penetrated the Avalon Formation in this most southerly pool. They are White Rose E-09, L-08, A-17 and H-20. The A-90 well did not penetrate the reservoir section, but helps define the eastern extent of the field. The L-61 well tested gas from the Paleocene South Mara Member sandstone, however the Avalon Formation was not well developed and tested a small amount of water and gas. The Hibernia Formation sandstones have tested small amounts of oil and gas from overpressured lower quality shaly sandstones in N-22 and E-09. Oil was also recovered from a Jurassic overpressured zone at the base of E-09 (Tempest Sandstone?). Analysis of the results of the H-20 well drilled in 2000 are currently ongoing.

This section is organized into the following:

- White Rose Stratigraphy;
- White Rose Structural Geology;
- White Rose Geochemistry; and
- Description of Reservoir Stratigraphy and Facies Interpretation.

2.1.2.1 White Rose Stratigraphy

The stratigraphic section penetrated by the wells drilled in the White Rose region contains Tertiary to Upper Jurassic rocks (Figures 2.1-7 and 2.1-8). Of the formations penetrated, the South Mara, Avalon, Eastern Shoals and Hibernia sections have reservoir quality sandstones. The following paragraphs review the stratigraphy of the Late Jurassic to Tertiary as seen in the White Rose region, beginning with the oldest formation penetrated. The Aptian Avalon Formation, the most economically significant formation will be discussed in more detail in the Stratigraphy and Depositional Environments subsection. The formations penetrated and fluids sampled in the White Rose Field and area are outlined in Table 2.1-1a and 2.1-1b.

Figure 2.1–7 Stratigraphy of White Rose Field

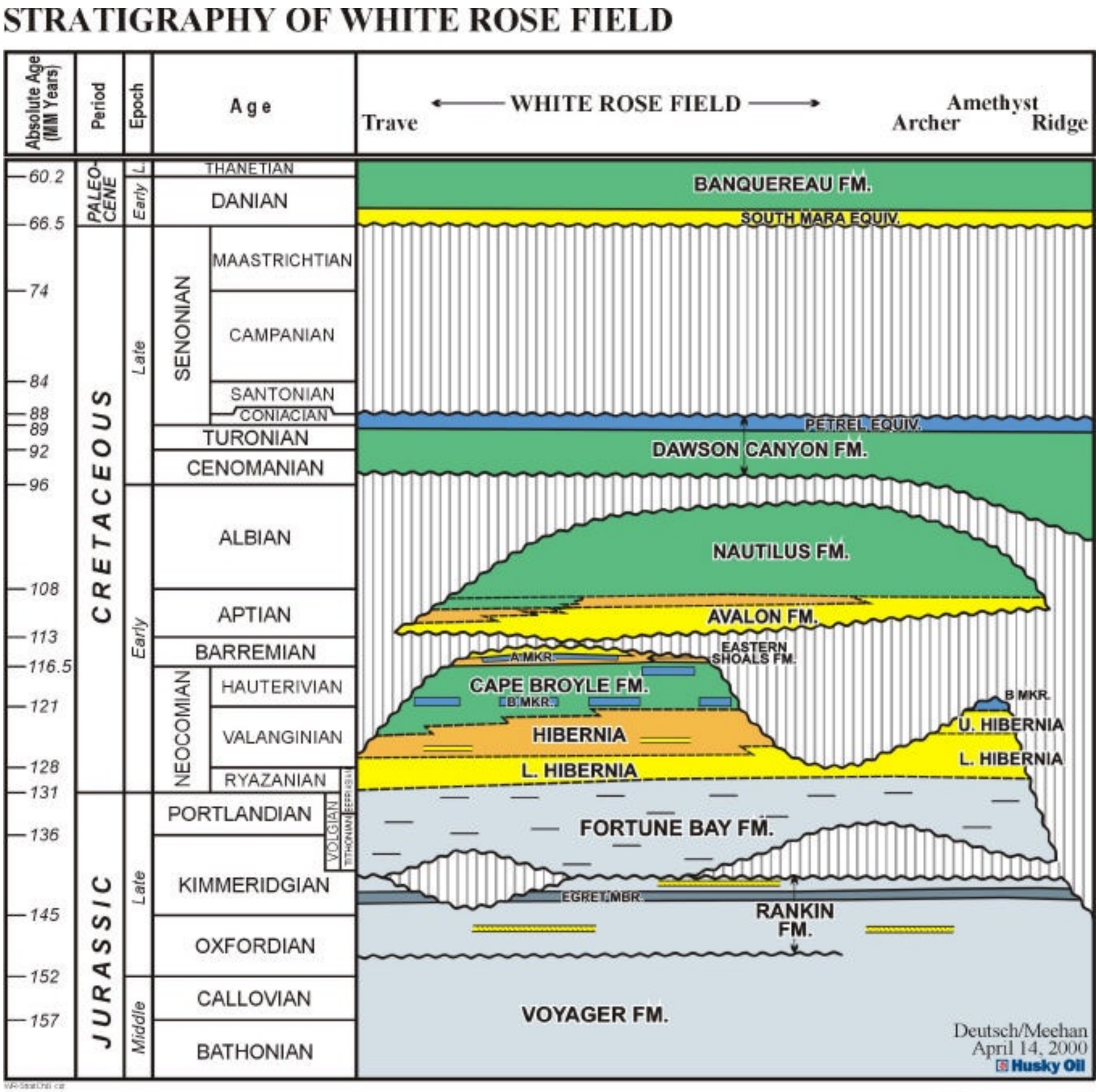


Figure 2.1-7

Figure 2.1–8 White Rose Area – Paleocene to Late Jurassic Stratigraphic Cross Section

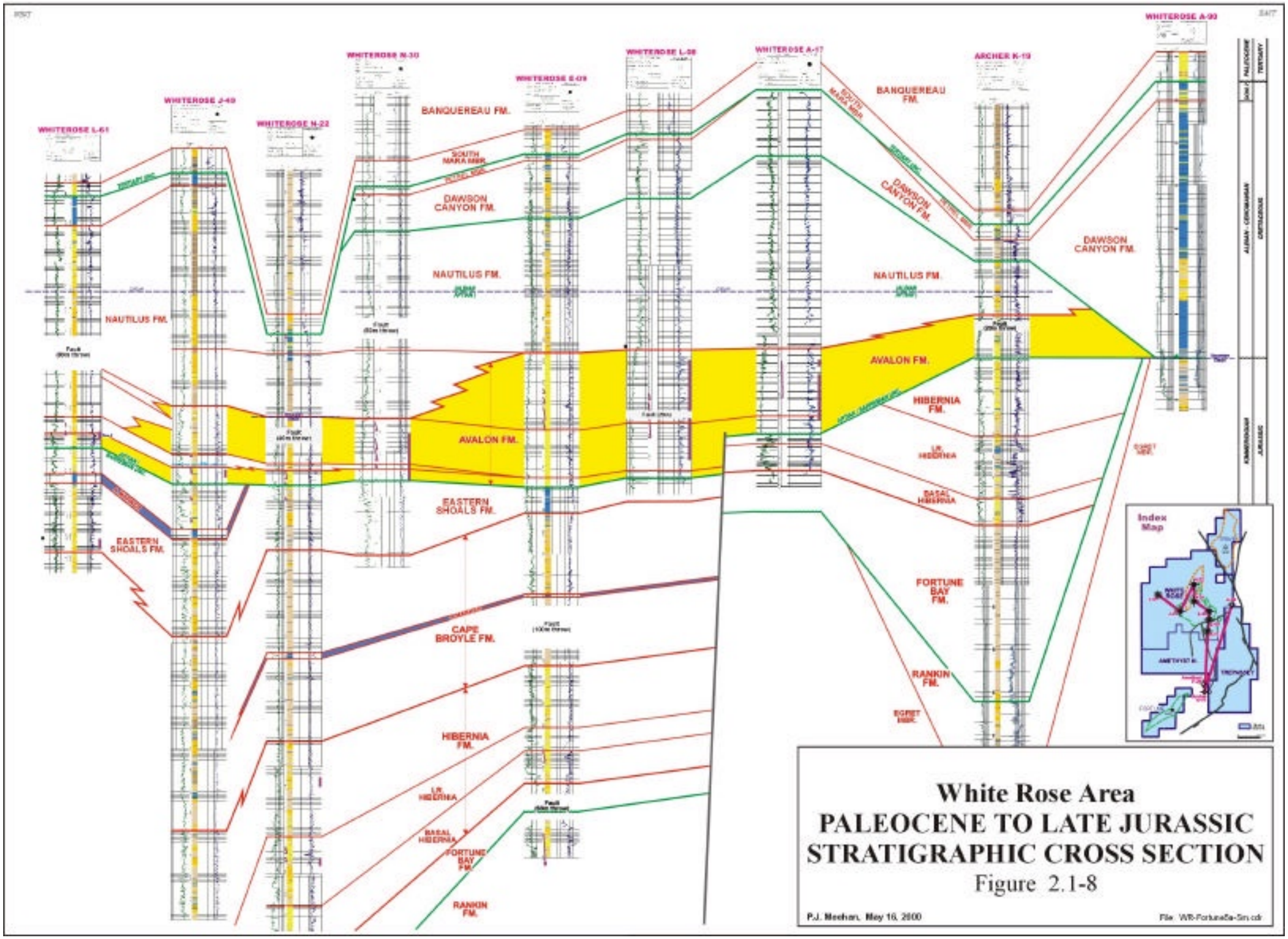


Table 2.1-1 Formation Tops and Fluids Sampled (MDT and DST)

FORMATION TOPS AND FLUIDS SAMPLED (MDT & DST)

Period		Formation	Member	N-30 White Rose	Fluids S.	N-22 White Rose	Fluids S.	J-49 White Rose	Fluids S.	L-61 White Rose	Fluids S.	E-87 Trave	Fluids S.
Paleocene		Banquereau		in casing		in casing		in casing		in casing		in casing	
Paleocene			South Mara Equiv	2357		2332		2347-2405		2506	G&C		
		Base Tertiary Unc		2419		2378		2405		2536		2139	
Cretaceous	Campanian - Cenomanian	Dawson Canyon		2419		2378		2405		2536		2139	
Cretaceous			Wyandot			2378-2387	G	2407-2438		2536-2605			
Cretaceous	Turonian		Petrel Equiv.	2419		2415		2405-2435		2536		Eroded	
Cretaceous	Cenomanian	Cenoman/Albian Unc		2523		2440		2612		2747		Eroded	
Cretaceous	Albian	Nautilus		2523		Eroded		2612		2747		Eroded	
Cretaceous	Albian	Ben Nevis				2579		2956		2986			
	Albian - Aptian Boundary			2660		Eroded		2684		2760	G	Eroded	
Cretaceous	Aptian	Avalon		2730	G	2440	G&C	2780	SG&O			Eroded	
Cretaceous	Aptian/Barremian	Base Avalon Unc		3064		2695		3131		3042		Eroded	
Cretaceous	Barremian - Neocomian	Cape Broyle										Eroded	
Cretaceous	Hauterivian - Barremian	Eastern Shoals		3064	O	2695	G&C	3131	G&C	3042	G	Eroded	
Cretaceous	Barremian		A-Mker	Eroded		Eroded		3237-3259		3101-3125		Eroded	
	Barremian - Valanginian	Cape Broyle											
Cretaceous	Hauterivian		B-Mker	NDE		3090-3105		3766		NDE		Eroded	
Cretaceous	Valanginian	Upper Hibernia		NDE		3292		3940		NDE		2139	G&C
Cretaceous	Valanginian - Ryazanian	Lower Hibernia		NDE		3460	SG&O	4177		NDE		2317	
Jurassic	Portlandian - Kimmeridgian	Fortune Bay		NDE		3772		4449		NDE		2538	
Jurassic	Mid Kimmeridgian	Tithonian Unc		NDE		3983		NDE		NDE		3200	
Jurassic	Kimmeridgian - Oxfordian	Rankin		NDE		3983		NDE		NDE		3200	
Jurassic	Kimmeridgian		Tempest	NDE				NDE		NDE		3200	
Jurassic			Egret	NDE		3983-4000		NDE		NDE		??	
			L. Tempest	NDE				NDE		NDE			
			L. Source	NDE				NDE		NDE			
Jurassic	Oxfordian - Callovian	Voyager		NDE		4283		NDE		NDE			
		TD		3290		4627.8		4561.4		3340.3		3985.6	

Table 2.1-1a

Period		Formation	Member	F-20 Amethyst	Fluids S.	K-19 Archer	Fluids S.	A-17 White Rose	Fluids S.	L-08 White Rose	Fluids S.	E-09 White Rose	Fluids S.	A-90 White Rose	Fluids S.
Paleocene		Banquereau		in casing		in casing		in casing		in casing		in casing		in casing	
Paleocene			South Mara Equiv	1957		1895		2217		2260		2309-2365		2189-2258	
		Base Tertiary Unc		1971		1929		2278		2316		2367		2258	
Cretaceous	Campanian - Cenomanian	Dawson Canyon		1971		1929		2278		2316		2367		2258	
Cretaceous	Turonian		Petrel Equiv	1971-2005		1929-1965		2278		2317		2367		2329-2669	
Cretaceous	Cenomanian	Cenoman/Albian Unc		2059		2016		2435		2466		2515		2771	
Cretaceous	Albian	Nautilius		2059		2016		2435		2466		2515		Eroded	
	Albian - Aptian Boundary					2085		2750		2680		2687		Eroded	
Cretaceous	Aptian	Avalon		2175		2140		2883	G/SG/O/W	2817	G/SG/O/W	2832	G/SG/O/C	Eroded	
Cretaceous	Aptian/Barremian	Base Avalon Unc		2270		2218		3082		3096		3135		Eroded	
Cretaceous	Hauterivian - Barremian	Eastern Shoals		Eroded		Eroded		Eroded		3096		3135		Eroded	
Cretaceous	Barremian		A-Mker	Eroded		Eroded		Eroded		NDE		Eroded		Eroded	
	Barremian - Valanginian	Cape Broyle				Eroded		Eroded		NDE		3205			
Cretaceous	Hauterivian		B-Mker	2270		Eroded		Eroded		NDE		3393-3400		2771	
Cretaceous	Valanginian	Upper Hibernia		2306		2218		Eroded		NDE		3460	SG&O	Eroded	
Cretaceous	Valanginian - Ryazanian	Lower Hibernia		2609		2403	F	3082		NDE		3730	SG&O	Eroded	
Jurassic	Portlandian - Kimmeridgian	Fortune Bay		2827		2609		3168		NDE		F/O 3734		Eroded	
Jurassic	Mid Kimmeridgian	Tithonian Unc.		3084		2892		NDE		NDE				Eroded	
Jurassic	Kimmeridgian - Oxfordian	Rankin		3084		2892		NDE		NDE		3759		2882	
Jurassic	Kimmeridgian		Tempest					NDE		NDE		3801-3882		??	
Jurassic			Egret			3278-3602		NDE		NDE		3910		2882-2963	
			L. Tempest			3640-3825		NDE		NDE					
			L. Source			3942		NDE		NDE					
Jurassic	Oxfordian - Callovian	Voyager				??		NDE		NDE					
		TD		3304.6		4299.3		3200		3130		3970		3025.2	

LEGEND		
	G Free Gas	C Liquids
	SG Solution Gas	F Filtrate
	O Oil	W Water

Table 2.1-1b

The oldest rocks penetrated in the White Rose region are from the Voyager Formation in the White Rose N-22 well. The Upper to Middle Jurassic Voyager Formation is Bathonian to Oxfordian in age. Although the full section was not penetrated, it is composed primarily of grey, dolomitic to calcareous shales and siltstones.

Unconformably overlying the Voyager Formation is the Rankin Formation containing the Egret Member source rock and the Tempest Member sandstones. The Rankin Formation is Oxfordian to Kimmeridgian in age, and consists of a mixture of shales and siltstones with minor limestones and sandstones. The Egret member, the main source rock for the hydrocarbons in the White Rose area, has been penetrated in the A-90 well and consists of organic rich grey calcareous shales and marls. Although a similar aged section was penetrated towards the base of the White Rose N-22 and E-09 wells, the Egret Member was not encountered. Oil bearing, overpressured sandstones, probably the Tempest Member were penetrated in the E-09 well.

The Jeanne d'Arc Formation has shaled out in the White Rose area, and its stratigraphic equivalent in the Fortune Bay Formation is organic rich and is found in the Archer K-19 and Trave E-87 wells. The Kimmeridgian to Portlandian aged Fortune Bay Formation has been penetrated in White Rose N-22 and J-49 and at the bottom of the A-17 well where it unconformably overlies the Rankin Formation. The Fortune Bay Formation is comprised predominantly of grey, silty marine shales deposited as part of a major transgression in the Late Jurassic.

The oldest Cretaceous aged rocks encountered in the White Rose area form part of the Ryazanian to Valanginian age Hibernia Formation. The Hibernia Formation has been penetrated in the White Rose A-17, E-09, N-22 and J-49 wells. The Hibernia sandstones form a regressive succession which can be separated into an upper and lower member, with a distinctive basal unit. The upper Hibernia Member is not well developed in the White Rose area and consists of poor quality siltstones and shales with only minor sandstones. The upper Hibernia decreases in quality and thickness to the north through the field.

The lower Hibernia Member has been penetrated in the E-09 and N-22 wells where thin shaly marine sandstones contained small amounts of oil. The lower Hibernia Member consists of fine to medium grained, light grey/brown and slightly silty sandstones. It was deposited primarily as a prograding shoreface succession as part of an overall regional regressive package. The shoreface succession contains minor fluvial and marginal marine deposits. The gross sandstone thickness varies from 272 m in White Rose J-49 where it is poorly developed, to only 86 m in the A-17 well where it has been largely eroded.

Hibernia Formation deposition is followed by a regional transgressive package of marine shales. The Neocomian to Barremian Cape Broyle Formation in the White Rose area is dominated by marine shales with minor siltstones. The B Marker, a shelly limestone which is regionally correlative through much of the Jeanne d'Arc Basin, is thin and poorly developed at White Rose. Although present in White Rose N-22 and E-09, no correlative limestone interval is observed in J-49, probably because of a deeper depositional environment. It is eroded in the Archer K-19, White Rose A-17 and the Trave E-87 wells. No reservoir quality rocks or hydrocarbon shows have been seen in the Cape Broyle Formation in the White Rose area.

The Hauterivian to Barremian Eastern Shoals Formation unconformably underlies the Avalon Formation throughout much of the White Rose Field. The White Rose E-09, L-08, N-30, N-22, L-61 and J-49 wells all penetrate the Eastern Shoals directly below the Avalon Formation. In the E-09 and L-08 wells the Eastern Shoals is largely eroded, leaving only a 60 m thick limestone, while in the N-30, N-22 and J-49 wells, it is comprised of interbedded shale, siltstone and sandstone. The A Marker, a shelly limestone within the Eastern Shoals Formation, is preserved in the J-49 and L-61 wells. The Eastern Shoals Formation has been eroded in the White Rose A-17 and A-90, and the Trave E-87 wells.

The Aptian aged Avalon Formation is the primary reservoir in the White Rose Field. The Avalon Formation will be covered in significant detail in following subsections. In general, the Avalon is a marginal marine, shoreface succession through much of the field. The Avalon is dominated by very fine to fine grained sandstones, siltstones and shales, and ranges from 0 to 400 m in thickness. The main sandstone accumulations occur in the southeastern portion of the field with the E-09, L-08 and A-17 wells (South Avalon Pool) exhibiting thicknesses of up to 350 m of sandstone. The Avalon Formation is absent in the White Rose A-90 and Trave E-87 wells.

The Nautilus Formation is primarily Albian in age and is present in all the wells in White Rose, although not to the north in the Trave E-87 well. The Nautilus Formation conformably overlies the Avalon Formation, and is laterally equivalent where the Avalon Formation shales out. It represents a regional transgressive event, reaching up to 350 m in the A-17 well. The Nautilus Formation is comprised of grey siltstones and shales with very minor sandstones. No reservoir quality rocks are present in the Nautilius Formation in the White Rose Field.

Unconformably overlying the Nautilius Formation is the Cenomanian to Coniacian aged Dawson Canyon Formation which consists primarily of marls and calcareous shales. The Dawson Canyon Formation ranges in thickness from 100 to 500 m in the White Rose Field. The Petrel Member is present at the top of the Dawson Canyon Formation in the White Rose area, except where eroded in the vicinity of the A-17 well. It consists of a thin light grey to brown argillaceous limestone.

The Banquereau Formation in the White Rose Field is composed of Tertiary clastics deposited during thermal subsidence. The Banquereau Formation is a thick shale succession (up to 2500 m) with coarser clastics at the base. The South Mara Member sandstone is occasionally present at the base of the Banquereau, directly overlying the Base Tertiary Unconformity. More often a sandy siltstone is present.

A sandstone from this zone tested gas and condensate in the White Rose L-61 well. In L-61, the South Mara Member is a 30 m section of brown, glauconitic silty fine to very fine grained sandstones The basal net porous sandstone is 5 m thick.

2.1.2.2 White Rose Structural Geology

Three episodes of rifting affected the White Rose area. During the first rifting phase, thick Osprey/Argo salt beds were deposited. This salt was tectonically mobilized during the second rifting stage forming elongated salt walls parallel with the emerging Central Ridge. The Central Ridge was formed in the footwall of the Voyager Fault Zone. Major north-south and northeast-southwest faults dissect the sediments deposited above the northerly plunging salt wall, including the source rocks. The third rifting stage had a pronounced influence on the area as the salt ridge was divided by salt withdrawal into a major ridge (Amethyst) and a northerly circular diapir (White Rose). A fault fan, creating numerous rotated fault blocks occupies the saddle zone between these salt features. In the southeastern White Rose area, imbricates of the Voyager Fault created low blocks and terraces where the Avalon Formation was deposited, and high blocks that were subjected to erosion. Toward the end of the extensional stage, two major salt withdrawal synclines in the area, Trave and Grand Bruit, were formed. The crestal areas of both Amethyst Ridge and White Rose Diapir were elevated by salt and repeatedly subjected to erosion. The existence of Avalon Formation in these areas is difficult to prove by seismic correlation alone. With the exception of the Amethyst Ridge and the northern diapir, only minor salt movements occurred during latest Cretaceous and Early Tertiary in the White Rose area.

As no extensional stage seismic marker is continuous over the entire White Rose area to allow consistent structural time mapping, a complex depositional (in the west)/erosional (in the east) surface at the base of the Avalon Formation was interpreted for structural and tectonic characterization of the field. The seismic interpretation was completed on every line, cross-line and selected dip lines using a Composite Regional Marker (Figure 2.1-5) that varies from A Marker in the west, to Base Avalon and Base Reservoir in the central area. The mid-Kimmeridgian Unconformity to Base Tertiary Unconformity markers were mapped in the eastern portion of the White Rose area.

Time structure on the Composite Seismic Marker shows the main structural elements of the White Rose area (Figure 2.1-5).

a. *high areas:* the Amethyst Ridge in the south, the White Rose Diapir in the north, and the rotated blocks adjacent to Voyager Fault Zone;

b. *low areas:* the Trave Syncline in the northeast and the Grand Bruit Low representing the southeastern tip of the basin depocenter;

c. *intermediate elevated areas:* the Terrace (A-17) block, the L-08 and E-09 blocks, the central blocks elongated in a north-south direction and the North Trepassey Depression and the numerous blocks on the fringe of the White Rose diapir;

d. *complexly faulted area:* the collapse zone and northwest-southeast trending fault fan north of Amethyst ridge; the intensely faulted southwestern flank of the White Rose diapir dissected by numerous northeast-southwest trending faults; the collapse zone on the western side of the White Rose diapir and the collapse zone east of the N-22 well.

The White Rose area abuts the Voyager Fault, a very complex zone of fault imbrication and ramping, bordering the Central Ridge. The Amethyst salt cored ridge and White Rose Diapir once formed a continuous salt cored high in front of the Voyager Fault Zone. Between these two structural features, salt withdrawal, initiated during Aptian and culminating in the Albian, caused a central collapse zone now occupied by a westerly dipping extensional fault fan. In some areas, the Cretaceous structural elevation relationships have been reversed due to post-Aptian salt movement. Thus, the seismically mapped Avalon Formation abnormally thickens toward the north and west, having the thickest interval in the rotated blocks, just east of the Central Fault.

Three intersecting fault systems oriented northeast-southwest, north-northwest south-southwest and north-south, compartmentalize the area. As indicated by reservoir pressure data, a few major faults (for example, West Amethyst, Central, Twin faults) together with a low structural trend oriented north-northeast south-southwest segment the area into three pools (Figure 2.1-5):

1. The South Avalon Pool (E-09, L-08, A-17 and environs);

2. The West Avalon Pool (J-49 field and environs) and

3. The North Avalon Pool (N-30, N-22 and environs).

Structurally, the White Rose pools reside in a complexly faulted area located on the hangingwall of the Voyager Fault Zone and are situated above the deep-seated Amethyst salt ridge and White Rose diapir (Figure 2.1-4 and 2.1-5). These three pools are associated with the White Rose Complex and are outlined in four schematic structural cross-sections, generated from seismic data across the field (Figures 2.1-9 and 2.1-10).

Figure 2.1–9 White Rose Area – Structural Cross Sections C-C' and D-D'

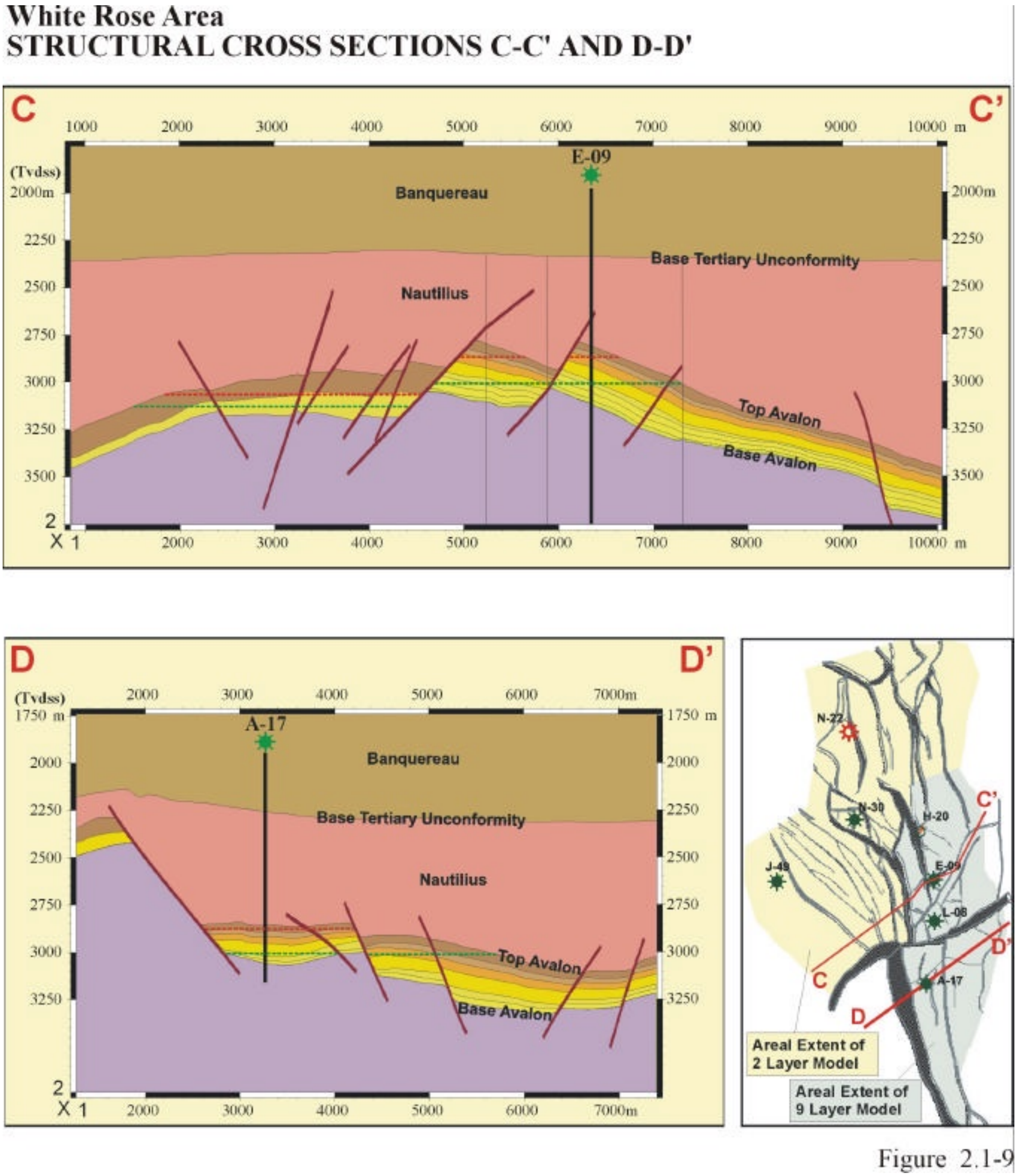


Figure 2.1–10 White Rose Area – Structural Cross Sections A-A’ and B-B’

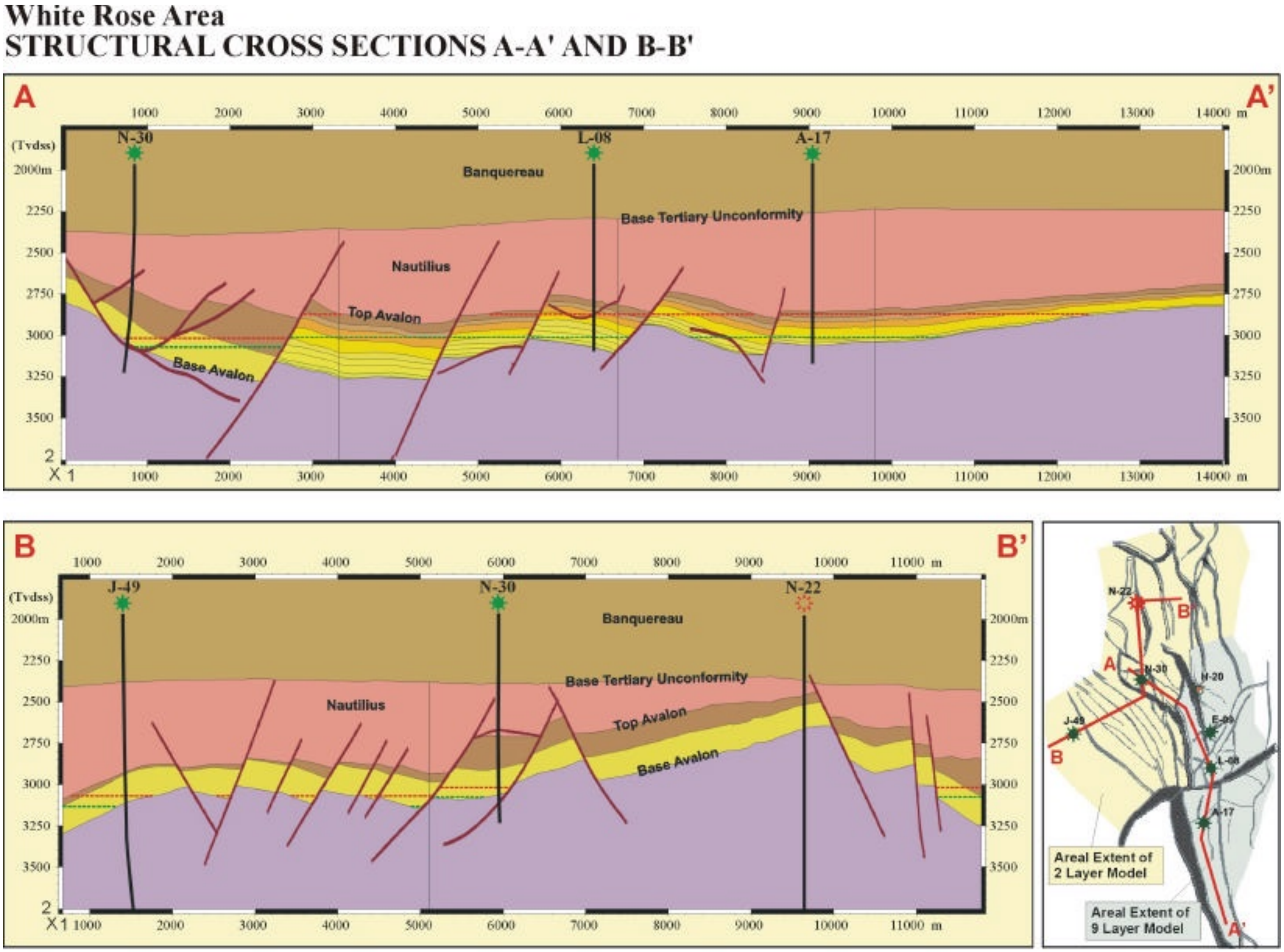


Figure 2.1-10

South Avalon Pool

The South Avalon Pool occupies an area of approximately 18 km², located east of the Amethyst Ridge and Central Fault and includes the E-09, L-08, A-17 wells (Figures 2.1-5, 2.1-9 and 2.1-10 Section A-A'). The pool is geologically complicated; the trap is structural, but may have a significant stratigraphic component. The trap is a collection of three- and four-way fault closed blocks and possible stratigraphic components toward the south and east. This pool is limited by the East Amethyst, Central and Twin faults to the west, and by structural dip toward the north and east. At the southernmost tip of the Terrace, the Avalon reservoir either thins out, onlapping the mid-Kimmeridgian unconformity or is faulted down to the north. Poor seismic data in this area precludes a definite understanding of the southern boundary.

With the exception of the Terrace, the larger blocks are tilted eastward and bounded by westerly dipping faults. Structural dip outside the Terrace varies from 7° to 12° east. The reservoir is cut by major and secondary non-sealing faults of variable throw oriented northeast-southwest. Major faults, such as the Amethyst Fault and Central Fault have a vertical throw of 500 m and 300 m and dips of 45° east and 28° west, respectively. The sandstone reservoir is in communication across the North Terrace and North E-09 faults, as shown by minimal change of fluid contact levels in the delineation wells (Section 2.2, Figure 2.2-15). Minor faults (throw less than 30 m) were carefully mapped or extracted from derivative maps in order to assess the structural complexity within the pay zone.

Most of the faults offset both Top and Base of the Avalon Formation and continue at depth beyond the mid-Kimmeridgian unconformity. Several secondary faults affect only the top or the base of the reservoir. All minor faults having vertical throws as low as 30 to 20 m, are seismically mapped (Figure 2.1-5), while smaller ones are identified as trends on the gradient maps and coherency displays (refer to Section 2.2).

No clear flat events are observed on the seismic data that might be associated with fluid contacts, although AVO modelling indicates flat spots should exist. The lack of flat events may be due to high background noise and severe demultiple routines applied to the data.

West Avalon Pool

The West Avalon Pool, which includes the J-49 well, encompasses a 16-km² area and is confined between the West Amethyst, Central and North J-49 faults and the crestal erosional edge. Structurally, the West Avalon Pool occupies the central collapse area between the northern plunge of the Amethyst Ridge and the southern part of the White Rose Diapir (Figure 2.1-5). The trap is structural and the reservoir consists of a thinner sequence of Avalon Formation than the sequence drilled in the South Avalon Pool (Figures 2.1-9 Section C – C' and 2.1-10 Section B – B'). Elongated faults of variable throw, dissect the area into many thin blocks, oriented northwest-southeast. The Base of Avalon in this area does not coincide with the mapped A Marker since erosional incision here is not as significant. Two highly complex areas that are poorly imaged by seismic data are located in the downthrown side of the Central Fault separating the South and West Avalon Pools and just north of the Amethyst Ridge. A central low trend lies between the area adjacent to the J-49 well and the area immediately north of the Amethyst Ridge.

In general, the easternmost faults have larger throws. The highest part of the pool is the northern portion where Avalon beds are gently dipping toward the southeast. However, dense north-south faults affect this part of the pool. The eastern blocks dip toward the southeast at about 8 to 10°. The block-bounding faults dip towards southwest at 30 to 38°. The western part of the pool represents the portion of the underlying Amethyst salt ridge that is unaffected by crestal collapse. It plunges, initially at 8°, and then steeper, at 14° toward the Grand Bruit Syncline. Conjugate, northeast-southwest, small faults of 20 to 30 m are mapped around the J-49 location (Figure 2.1-5).

North Avalon Pool

The North Avalon Pool includes the N-22 and N-30 wells and occupies an area of about 10 km². It is bounded by the Central Fault, White Rose Diapir erosional edge, Trave Fault and southeastern end of the Trave Syncline (Figure 2.1-5). The North Avalon Pool is located on the southeastern flank of the White Rose Diapir. The area is dissected by numerous faults trending mainly north-northwest south-southeast and north-northeast south-southwest. Two major faults bound the N-22 block. The first fault dips to the west at 40° and the second fault to the east at approximately 50° (Section 2.2, Figure 2.2-12). The structural dip on this block is 7° southeast. Two other major faults, the Central and Twin faults, bound the N-30 blocks. Another important fault forms a rotated block on the western flank of the Trave syncline. This fault dips to the northwest at approximately 20°.

The trap is structural for the area tested by the N-22 and N-30, but a stratigraphic component may exist toward the northwest, where the Avalon sandstone may be absent due to truncation or onlap. As the area is generally higher than the rest of the White Rose Complex, the Avalon Formation appears to thin over the top of the White Rose Diapir and is completely missing on its crest (Figure 2.1-5 and Section 2.2, Figure 2.2-12).

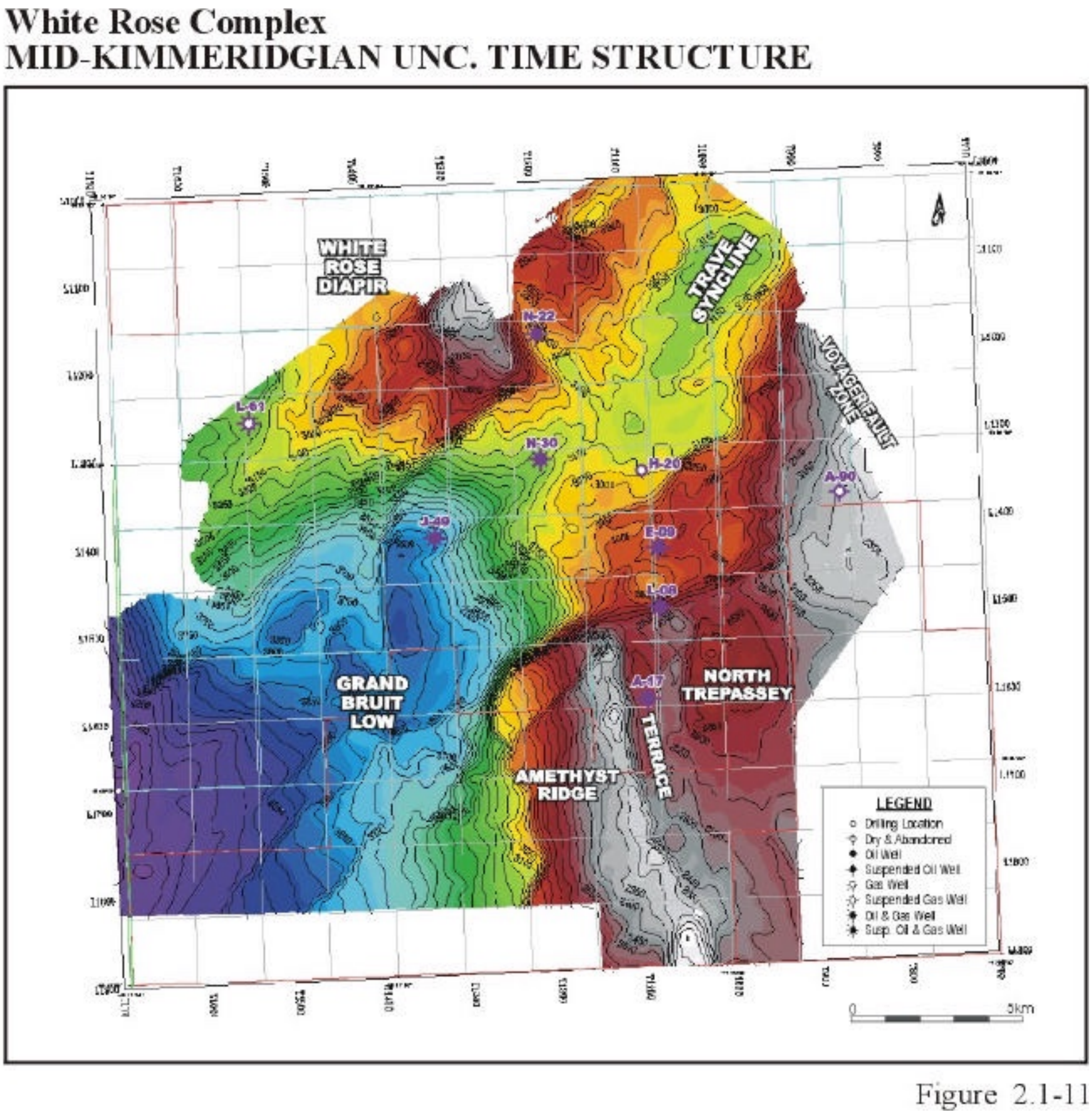
The northwestern part of the White Rose Complex is cut by a series of radial faults oriented northeast-southwest and by minor intersecting faults, part of a swarm parallel to the crestal zone. Numerous small fault blocks are formed and occupy this side of the White Rose Diapir. One of these blocks was tested by the L-61 well. The crestal zone of the White Rose Diapir trends approximately north-south. An intensively faulted high block marks the higher part of the deep-seated salt diapir. Mapping the base Avalon marker in this area is difficult as the crest is dissected by several faults having opposing dips.

Structure of the mid-Kimmeridgian Unconformity. The mid-Kimmeridgian unconformity corresponds to the Top of the Rankin Formation, which includes the Egret Member oil source rock and correlates to a strong amplitude reflector at Archer K-19, White Rose N-22 and A-90 and immediately below the White Rose A-17 well (Figure 2.1-11). This mid-Kimmeridgian unconformity is situated immediately under the reservoir on the Terrace and North Trepassey areas, is faulted down to 800 m in the central area and abruptly rises on the eastern side where it lies under Albian shaly carbonates (Nautilus Formation). The Egret source rock, if preserved, is also high in a local horst located west of the N-22. The structural lows, Grand Bruit, Trave and South Badger form veritable hydrocarbon kitchens and are extensively faulted at the Rankin marker level. These 30 - 40° dipping faults form excellent migration conduits.

Over the greater White Rose area the source rock is structurally bounded by major faults, coinciding to the three distinct pools and their hydrodynamic systems (South, North and West Avalon Pools, respectively) (Figure 2.1-5 and Section 4.5, Figures 4.5-1 and 4.5-2 Pressure Profiles in Reservoir Engineering).

In conclusion, three separate structural areas have been delineated within the White Rose Complex corresponding to three distinct oil accumulations: South Avalon Pool, West Avalon Pool and North Avalon Pool. They were identified in the White Rose area, by drilling a series of exploration and delineation wells and by interpreting structural and tectonic maps of two seismic horizons: 1. The Composite Marker map (Figure 2.1-5) and 2. mid-Kimmeridgian Unconformity map (Figure 2.1-11). These pools have a complicated structural trapping mechanism and a stratigraphic component toward the southern and northern part of the White Rose Complex.

Figure 2.1–11 White Rose Complex – Mid-Kimmerindgian Unc. Time Structure



2.1.2.3 White Rose Geochemistry

The Kimmeridgian Egret member source rock is the principal proven source (Fowler and McAlpine, 1994) in the Jeanne d'Arc Basin, and has been penetrated in three White Rose area wells. They are White Rose A-90, Archer K-19 and Trave E-87. The Geological Survey of Canada has published Rock-Eval data for these wells (Fowler and McAlpine 1994), where it appears the source maturity is marginal to early mature (Table 2.1-2). However, the interbedded nature, and subsequent variable lithologic and geochemical character, suggests that the Egret Member may be generating exploitable oil, even when the overall average maturity value appears marginally mature to immature (Bateman 1995). TOC values, on average for the three wells, range from 2.9 to 3.1 percent. The Egret Member is 170 m thick in Archer K-19. The 138 m Egret Member penetrated in White Rose A-90 and 74 m interval in Trave E-87 likely understate the true thickness, as both have unconformable upper contacts with overlying sediments.

Table 2.1-2 Rock-Evaluation Results for White Rose Area Wells

Well	Top (m)	Base (m)	No. of Samples	TOC range (%)	TOC avg (%)	HI range	HI av.	T max range (ºC)	T max av. (ºC)	Sample problems
JEANNE D'ARC FORMATION SOURCE ROCK INTERVAL										
Archer K-19	3,020	3,040	3	2.59 – 3.79	3.06	277 – 328	308	424 – 426	425	
Trave E-87	2,720	2,840	9	1.27 – 3.12	2.56	137 – 731	381	419 – 429	423	
EGRET MEMBER										
Archer K-19	3,290	3,440	14	2.13 – 6.62	2.92	210 – 519	273	424-436	429	
Trave E-87	3,050	3,120	8	2.35 – 4.24	3.05	680 – 810	746	426 - 431	428	
White Rose A-90	2,890	2,960	8	2.33 – 3.3	2.88	450 – 604	545	441 – 450	445	Light oil-based mud
LOWER RANKIN FORMATION SOURCE ROCK INTERVAL										
Archer K-19	3,570	3,620	5	2.84 – 3.57	3.33	285 – 387	333	424 – 427	426	

Other potential source horizons are present in the White Rose area (Table 2.1-2). Archer K-19 and Trave E-87 both penetrated a minor potential source in Jeanne d'Arc Formation equivalent shales and a lower Rankin Formation interval with some source potential was also penetrated in the Archer K-19 well. Regional Jeanne d'Arc Basin geochemical studies indicate only a minor hydrocarbon charge contribution from these horizons. In the White Rose area, Rock-Eval data show these horizons are generally thinner and immature where penetrated.

Although no mid-Kimmeridgian unconformity map has yet been generated for the entire White Rose area, seismic indicates the surface plunges rapidly to the west, from the White Rose A-90 well, across several mega-faults, towards the J-49 well. The underlying Egret member is increasingly mature as burial depth increases. Similarly, increasing maturity is indicated north of White Rose N-22, west of Trave E-87 and west of Archer K-19. As anticipated by the Egret depth trends, Snowden (1999) Husky

Consultant Report, in a White Rose reservoir compartmentalization study, found the biomarker ratios for White Rose J-49, N-22 and L-61 oils higher maturity than those from the South Avalon Pool. He also looked at the geochemical properties of all available White Rose oils and condensates and suggested that the two geochemical signatures are from the same Egret source, but likely from two different kitchen areas; one of which charged J-49.

The extensive faulting present in the White Rose area can be used to argue that vertical charging of the reservoirs was the dominant migration mechanism, in addition to the fact that at least three separate pools are present within the Avalon Formation reservoir. Alternatively, lateral migration can be postulated because of the thick, widespread Avalon sandstone. Lateral migration helps to explain the large gas cap over the prominent North Avalon Pool, since an overmature source is laterally accessible to the northwest. Lateral migration is also evident in the Trave E-78 well. The gas/condensate reservoir fluid, indicative of highly mature source rock conditions, could not have migrated vertically from the marginally mature Egret Member penetrated in the well. Although there is evidence to support both vertical and lateral migration, deciphering this complex history will await the acquisition and integration of additional data as more wells are drilled.

2.1.2.4 Description of Reservoir Stratigraphy and Facies Interpretation

The Avalon Formation (Aptian) has been modelled using three principal reservoir layers in the South Avalon Pool and two principal reservoir layers in the West Avalon and North Avalon Pools.

Petrographic, petrophysical, sedimentological, dipmeter/FMI, production test and seismic data were used to define the stratigraphic framework and develop a depositional model for the White Rose Field.

The section includes:

- main reservoir and non-reservoir lithofacies and facies;
- general facies associations;
- paleogeography;
- reservoir modelling facies;
- local tectonic features and influence on the reservoir; and
- geometry and stacking pattern of the reservoir layers and facies.

Main Reservoir and Non-Reservoir Lithofacies and Facies

Two main lithofacies; sandstone and siltstone/sandstone, were identified from an analysis of 467 m of core recovered from five wells in the field. The two lithofacies were further subdivided into reservoir and non-reservoir facies, as outlined in the table below (Table 2.1-3). A description and interpretation of the individual facies is provided in the following subsection.

Table 2.1-3 Description of Reservoir and Non-Reservoir Lithofacies and Facies Described in Core Within the White Rose Avalon Reservoir

Lithofacies	Facies*	
Siltstone/Sandstone[1]	(2)	interbedded siltstone and fine sandstone[1]
Sandstone	(3)	ioturbated fine to very fine silty sandstone
	(4)	aminated very fine sandstone
	(5)	hell Beds/Concretions[1]
	(10)	Bioclastic sandstone

* (after Plint 1999a; 1999b; 1999c)
[1] Dominantly non-reservoir

For a detailed analysis and description of the facies, refer to three reports: Husky et al. White Rose L-08, A-17 and N-30, Preliminary Core Description and Revised Stratigraphy for the White Rose area (Plint 1999a; 199b; 1999c). Facies 2, 3, 4, 5 and 10 described in these reports are the facies encountered in core in the White Rose Field.

Facies 2 - Interbedded Siltstone and Fine Sandstone. This facies is intergradational with bioturbated mudstone. The facies consists of cm scale, sharp-based beds of very fine to fine-grained sandstone, interbedded with and grading abruptly into cm to dm scale beds of bioturbated silty mudstone. Sandstone beds range from undisturbed, fine parallel lamination, or low-angle inclined lamination, to massive. The basal part of the sandstone beds commonly contains a layer of bioclasts. The silty/muddy portion of each bed is highly bioturbated. Small concretions are occasionally present and trace fossils are abundant.

Facies 2 is interpreted as storm deposits on a low-energy muddy shelf in water depths of 20 to 50 m, based on the trace fossil assemblage and the lack of evidence for fair-weather reworking of the deposits. This facies is best developed in core 1 of the Avalon Formation in White Rose L-61 and L-08.

Facies 3 - Bioturbated fine to very fine silty sandstone. This facies forms units typically 0.1 to 3 m, to a maximum of 9 m thick, consisting of very fine-grained, slightly to moderately silty sandstone. The facies is pervasively bioturbated, with only faint vestiges of primary lamination, consisting of dark micaceous mudstone preserved. Abundant trace fossils, in addition to common serpulid worm tubes and associated oyster and clam shells, are present. Wood fragments are common.

Facies 3 is interpreted to represent a shallow inner shelf environment, in water depths of 20 to 40 m, which for a period of time experienced a relatively low supply of sediment. This permitted a complete biological reworking of the sediment. The facies occurs interbedded with laminated very fine sandstone of Facies 4, invariably lying gradationally above it forming 'laminated to scrambled' beds typically 10 to 30 cm thick. Facies 3 also forms much thicker homogeneous units from 1 to 9 m without the laminated sandstones. Facies 3 possibly represents a more nearshore equivalent of Facies 2.

The facies constitutes a very small portion (less than 5 percent) of the total reservoir in the South Avalon Pool but may include as much as 50 percent of the gross reservoir facies in the West and North Avalon Pools.

Facies 4 - Laminated very fine sandstone. This facies consists of very fine grained (very fine upper) clean, well sorted sandstone ranging in thickness from about 20 cm to 1 m thick, deposited in less than 20 m of water. Individual beds, up to 4 m in thickness, have been observed and may represent single depositional units. However, amalgamated beds, separated by subtle erosion surfaces, are common. The sandstones generally show a fine, mm to cm scale parallel to low-angle (typically < 10º), planer to gently curved lamination. Occasionally the beds are massive. The laminated sandstones are interbedded with bioturbated silty sandstone of Facies 3 and shell beds of Facies 5. Burrows are neither significantly large or abundant.

Facies 4 is interpreted to represent deposition in a shoreface setting during intense storms when plane bed, swaley bedforms or massive beds developed. Recognition of beach/foreshore deposits in this unit is difficult because of the uniform and very fine grain size of the sand. Individual laminated sandstone units may represent a single or possibly amalgamated storm event. The absence of mud laminae in Facies 4 suggests that deposition took place in an environment in which all traces of mud, deposited during fair weather, was removed by storms. Facies 4 is genetically related to the shell beds discussed below.

The laminated very fine sandstone facies make up approximately 90 percent of the reservoir in White Rose A-17 and L-08 and one-half of the total cored reservoir interval in White Rose N-30.

Facies 5 - Shell Beds/Concretions. This facies consists principally of serpulid worm tubes and various species of bivalves, including several species of oysters. Rare brachiopod, belemnite guards and rare echinoderm plates are also present. Shell debris is generally dispersed through a matrix of very fine sand but is occasionally clast-supported. The facies ranges in thickness from one shell thick (that is, < 5 mm) but is typically 5 to 30 cm thick and is generally cemented with calcite.

Concretions, which represent the most significant diagenetic facies encountered in the White Rose core, are invariably associated with shell beds. In most cases, concretions appear to have nucleated on shell beds. The concretions range in thickness from a few centimetres to a maximum of 2.8 m. Calcite cement commonly extends several decimetres above and below the shell beds, sometimes resulting in several shell beds being incorporated into one large concretion. It is postulated that much of the cement in the concretions was provided by the dissolution of aragonite shells dispersed throughout the cored interval. Concretions have sharp boundaries with uncemented sandstone and are easily recognizable on the FMI log. Many show converging upper and lower boundaries and are interpreted as highly lenticular rather than laterally-continuous cemented intervals.

The shell beds of Facies 5 are interpreted as a basal lag and are overlain by the genetically related laminated to massive shoreface sandstones of Facies 4. Each package is interpreted to represent a major storm event.

Shell beds make up approximately 8 percent of the cored interval in White Rose L-08 and A-17 but less than 2 percent of the cored interval in N-30. Concretionary zones constitute approximately 15 percent of the cored interval in White Rose A-17, L-08 and N-30.

Facies 10 - Bioclastic Sandstone. This facies consists of medium- to very coarse-grained shell hash that includes numerous coarser bioclasts and other pebbles, set in a matrix of very fine-grained quartzose sandstone. Bioclasts include oysters, belemite guards, serpulid worm tubes and the coral Thamnasteria. The facies is crudely stratified at an angle of about 20º to massive. Burrows are common.

The bioclastic sandstone facies is interpreted as a transgressive deposit that accumulated on the Eastern Shoals Formation by marine erosion associated with the basal Avalon transgression. The facies constitutes a very minor part of the N-30 core but is significant in that it is the only example of basal Avalon Formation cored in the White Rose Field.

General Facies Associations

There is no clear organization of vertical facies within the White Rose core. However, the repetitive erosive-based, laminated sandstone, sometimes marked by a shell lag, grading up into bioturbated silty sandstone indicates a genetic relationship between Facies 3, 4 and 5. These facies are interpreted as classic examples of laminated to scrambled storm beds. The rising phase of the storm is represented by an eroded surface, cutting into the laminated or bioturbated sandstone of the underlying unit. The waning phase of the storm is represented, first by a lag of bioclasts (shells/shell bed-Facies 5) or mud pebbles eroded from the sea floor, overlain by several decimetres of laminated, very fine sandstone (Facies 4) deposited by high velocity currents generated by storm waves. The bulk of the lamination is horizontal, indicating that upper-plane bed conditions prevailed at most times. The upper bioturbated part (Facies 3) of many beds represents a protracted period which records the recolonization of the sea floor by burrowing organisms and epifauna which progressively destratified the upper portion of the storm bed. Mud was probably introduced into the sediments as faecal pellets and from background settling of suspended material. The sharp-based storm beds of Facies 2 may represent a slightly more distal equivalent of Facies 3, deposited where silt was slightly better able to accumulate. Finally Facies 10, dominantly of biogenic origin, accumulated on a rocky sea floor cut into the Eastern Shoals Formation above the basal Avalon unconformity as a transgressive deposit and forms the base of the reservoir sequence.

Paleogeography

During the time of deposition of the main sandstone package of the Avalon Formation, a period of relative stillstand or aggradation occurred where subsidence rates kept up with depositional rates. The thick sandstone sequences seen in the E-09, L-08 and A-17 wells suggest continuous deposition in a lower to middle shoreface environment with no significant breaks indicated. The inferred paleogeography during this time is illustrated in Figure 2.1-12. The shoreline appears to have trended in a south southwest to north north-east orientation with the more distal, offshore deposits to the northwest of this trend. The sources for the sediment would have been predominantly to the southeast, where erosion of the Central Ridge was taking place. Sediments sourced to the shoreline were then distributed by currents moving northward along the shoreline. The sequences within the J-49, N-30 and N-22 wells confirm this orientation with more distal deposits of bioturbated mudstones and siltstones and much thinner sandstone sections. No wells have been drilled to the southeast of the shoreline trend, and no sediments deposited above the middle shoreface have been encountered to date.

Reservoir Modelling Facies

The Aptian aged Avalon Formation is the main reservoir in the White Rose Field. The Avalon Formation consists of sandstones, siltstones and shales with calcite concretions which have developed from available bioclastic material. The Avalon is an aggradational fining upwards succession comprised of shoreface sands. In all wells in the field, the higher quality and percentage of sandstone occurs at or near the base of the Avalon, with the amount and quality of sandstone decreasing upwards. The thickest section of sandstone occurs in the vicinity of the South Avalon Pool with up to 320 m of gross sandstone encountered in the E-09 well. The south to north trending sandstone accumulation appears to have been deposited as stacked shoreface deposits transgressed and overlain by marine mud and silts near the end of Aptian time. To the northeast of this trend, the J-49, N-30 and N-22 wells have a much thinner interval where sandstone is present, with more shale and siltstone both above the sandstone and interbedded with them. This illustrates the more distal nature and lower energy deposition of this area.

The Avalon was divided into four main reservoir facies, Reservoir Sandstone, Siltstone and Tight Sandstone, Shale, and Calcite Concretions. The sandstone facies are used in the construction of the geological model for simulation purposes and are based on petrophysical facies. The divisions between different reservoir and non-reservoir units have been identified on the basis of porosity and permeability cutoffs, defined by thick cored intervals which have been calibrated to petrophysical data.

1) Reservoir Sandstone

The main reservoir facies of the Avalon is a light brown very fine to fine grained, well sorted, quartz-rich compositionally and texturally mature sandstone (predominantly Facies 4 as described by Plint (1999a; 1999b; 1999c).

Figure 2.1–12 White Rose Area – Paleography Late Aptian Time

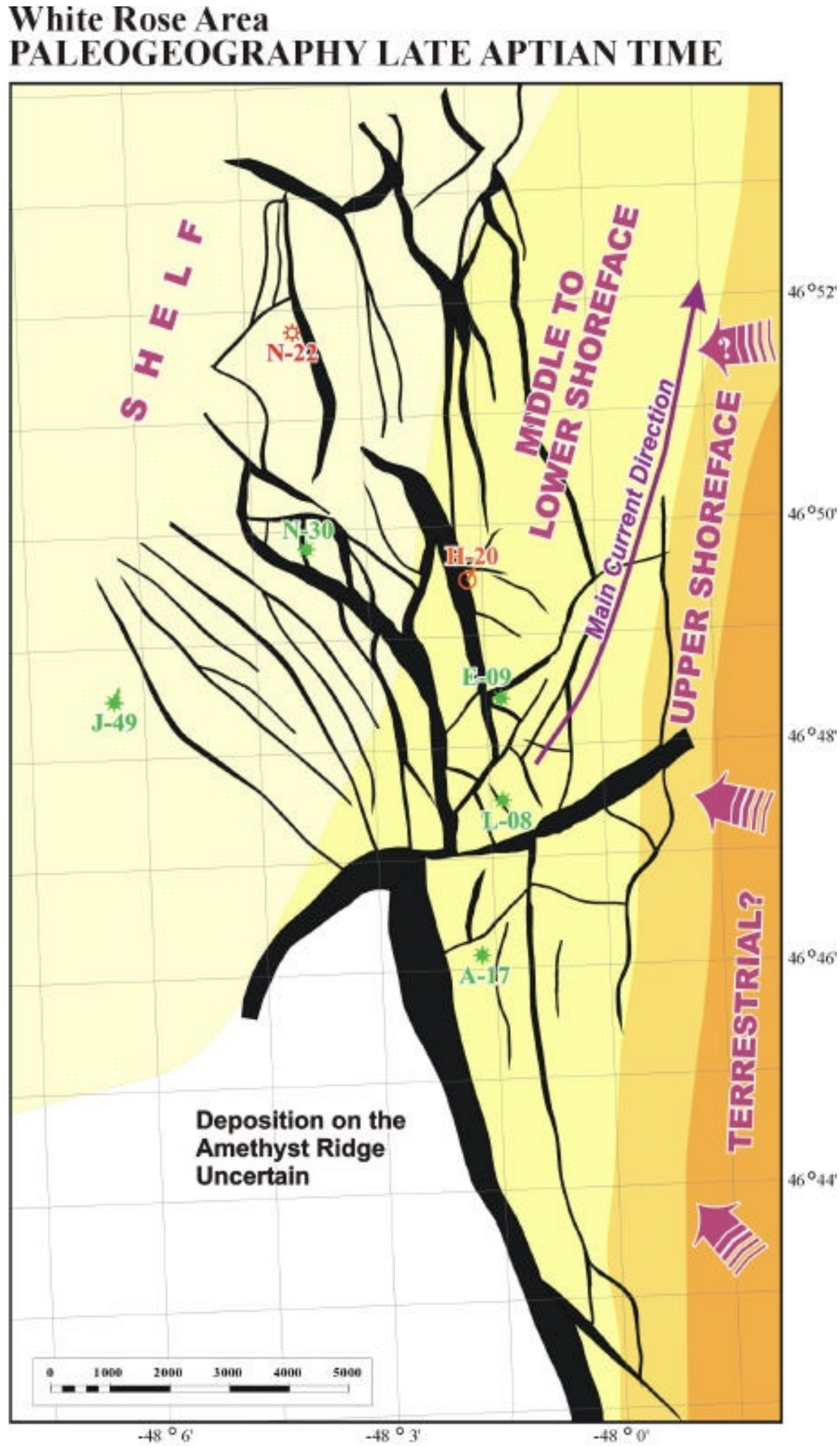


Figure 2.1-12

Most of the sandstones were deposited as middle to upper shoreface sandstones, which were subsequently reworked as storm deposits in a lower to middle shoreface setting. These storm deposits are represented as sharp based, fining upward successions which can be as thin as 1 cm or as thick as 1 m. These successions are better seen on the FMI log (Figure 2.1-13 and FMI interpretation reports L-08 and A-17 (Deutsch 1999)) than in the core due to the very fine-grained nature of the rock and the lack of significant heterogeneity or contrast in the core. The fining upward nature translates to permeability trends which were confirmed by the minipermeameter work done on the A-17 core. Permeability trends identified from the minipermeameter data in the A-17 core are shown in Figure 2.1-14.

The reservoir sandstones exhibit porosities ranging from 10 to 22 percent, averaging approximately 16 percent, and permeabilities in the 10 to 300 milliDarcies (mD) range, averaging between 70 and 100 mD in the oil section of the South Avalon Pool. A well-defined porosity/permeability relationship can be illustrated by core and petrophysical data (Figures 2.1-15 to 2.1-17). For the purposes of this report, the reservoir quality sandstones have been restricted to those having more than 10 percent porosity. The most recent porosity and permeability from core indicates that an 8 percent cutoff for pay can be used (Sections 3.2 and 3.5). This would result in slightly higher net pays.

Two principal reservoir facies have been identified. Sandstones having more than 15 percent porosity are the main flow units in the reservoir, with an average permeability of greater than 100 mD. Sandstones with porosities between 10 and 15 percent have permeabilities averaging in the 10 to 50 mD range. Any sandstones with less than 10 percent porosity are effectively non-reservoir. The porosity of the sandstones remain very similar from well to well, with the changes reflecting net-to-gross differences only.

2) Siltstone and Tight Sandstone Facies

Siltstones occur mostly near the top of the Avalon. These are identified as facies 2 by Plint (1999a; 1999b; 1999c). As the sandstones in the Avalon are very fine grained, the differentiation between the sandstones and siltstones is gradational. For the purposes of reservoir modelling, the siltstone petrophysical facies includes all of the very fine-grained rock as well as fine-grained rock whose porosity is occluded by calcite to less than 10 percent porosity. The siltstones occur mainly near the top of the Avalon and represent more distal equivalents to the sandstone facies. As a result the amount of siltstone increases towards the northwest.

Some siltstones occur near the top of the fining upwards storm deposit cycles, within the sandstone units. The siltstones become the main constituent of the storm deposit cycles, when found near the top of the sandstone.

Figure 2.1–13 Well Defined Bedding in the L-08 Well

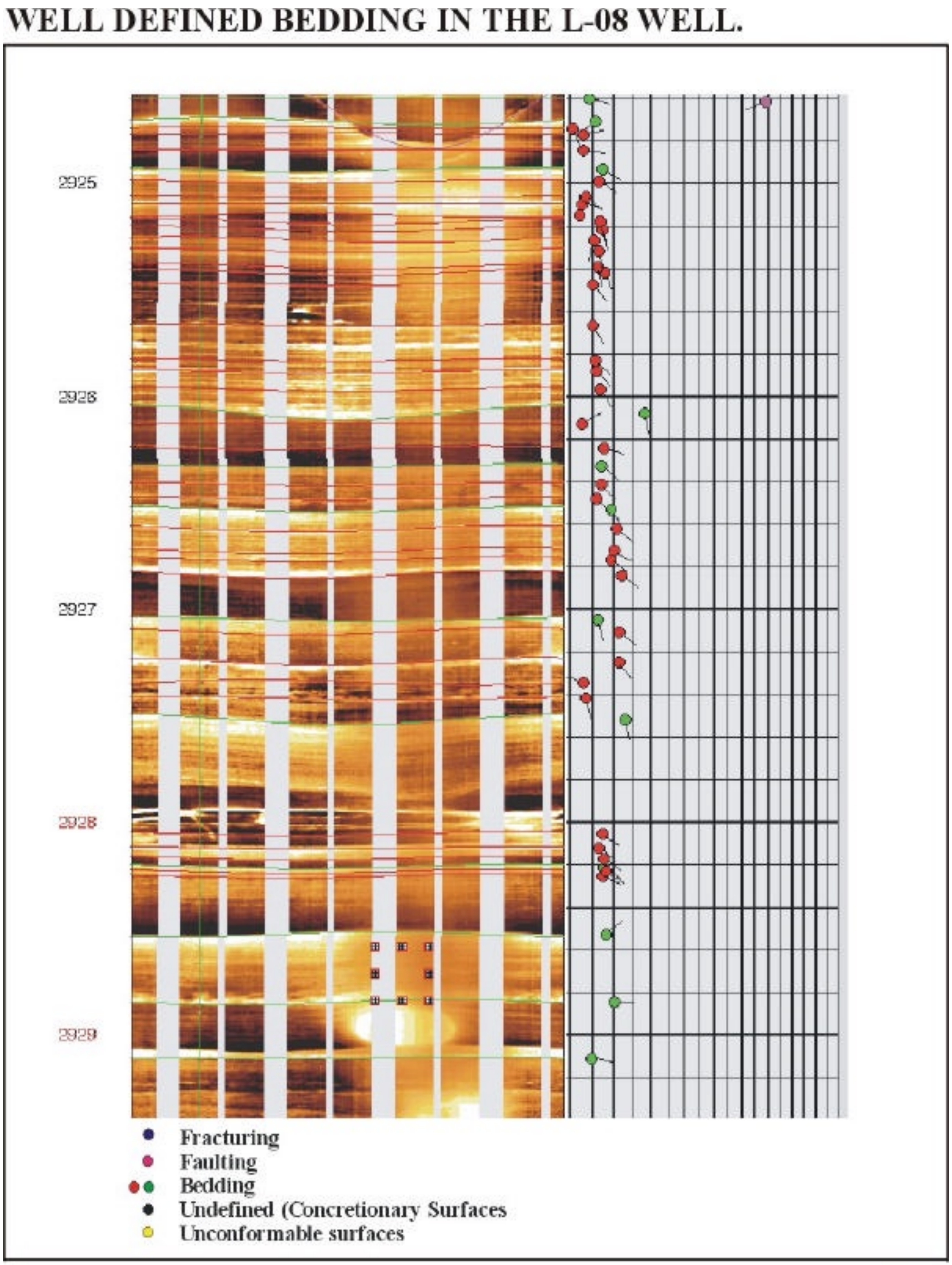


Figure 2.1-13

Figure 2.1–14 Minipermeameter Data From Husky et al White Rose A-17

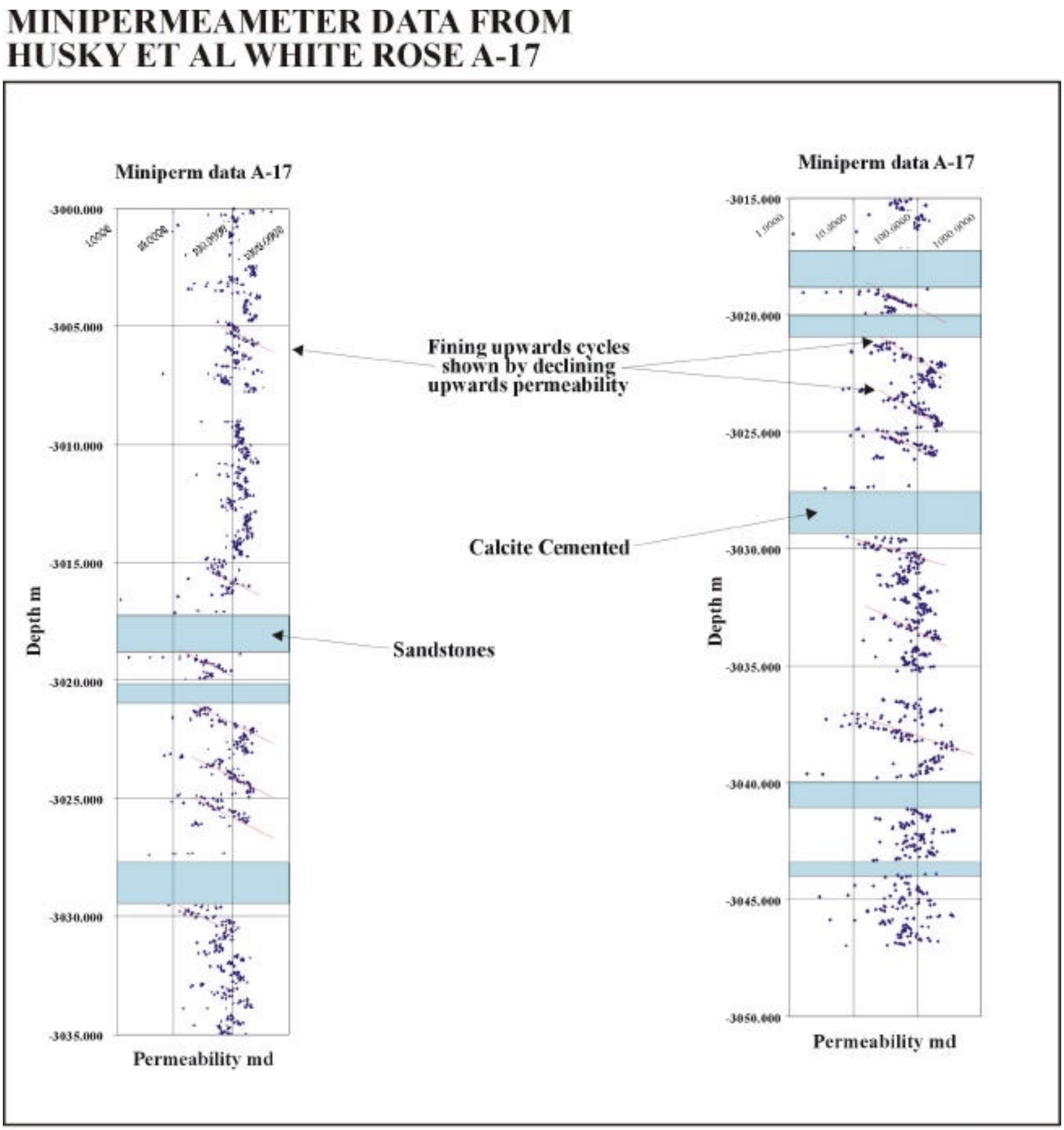


Figure 2.1-14

Figure 2.1–15 Porosity vs. Permeability Husky et al White Rose A-17

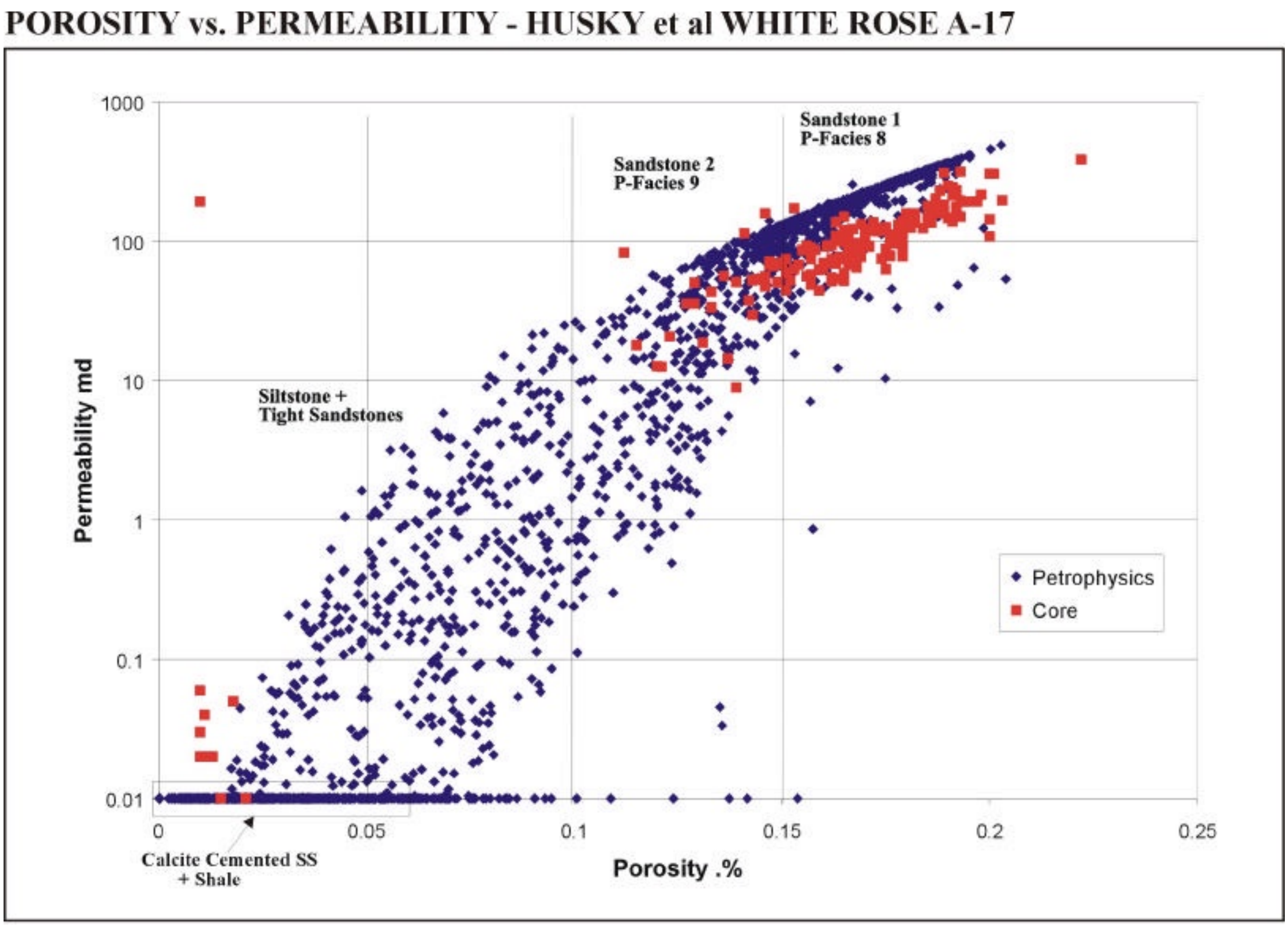


Figure 2.1-15

Figure 2.1–16 Porosity vs. Permeability Husky et al White Rose L-08

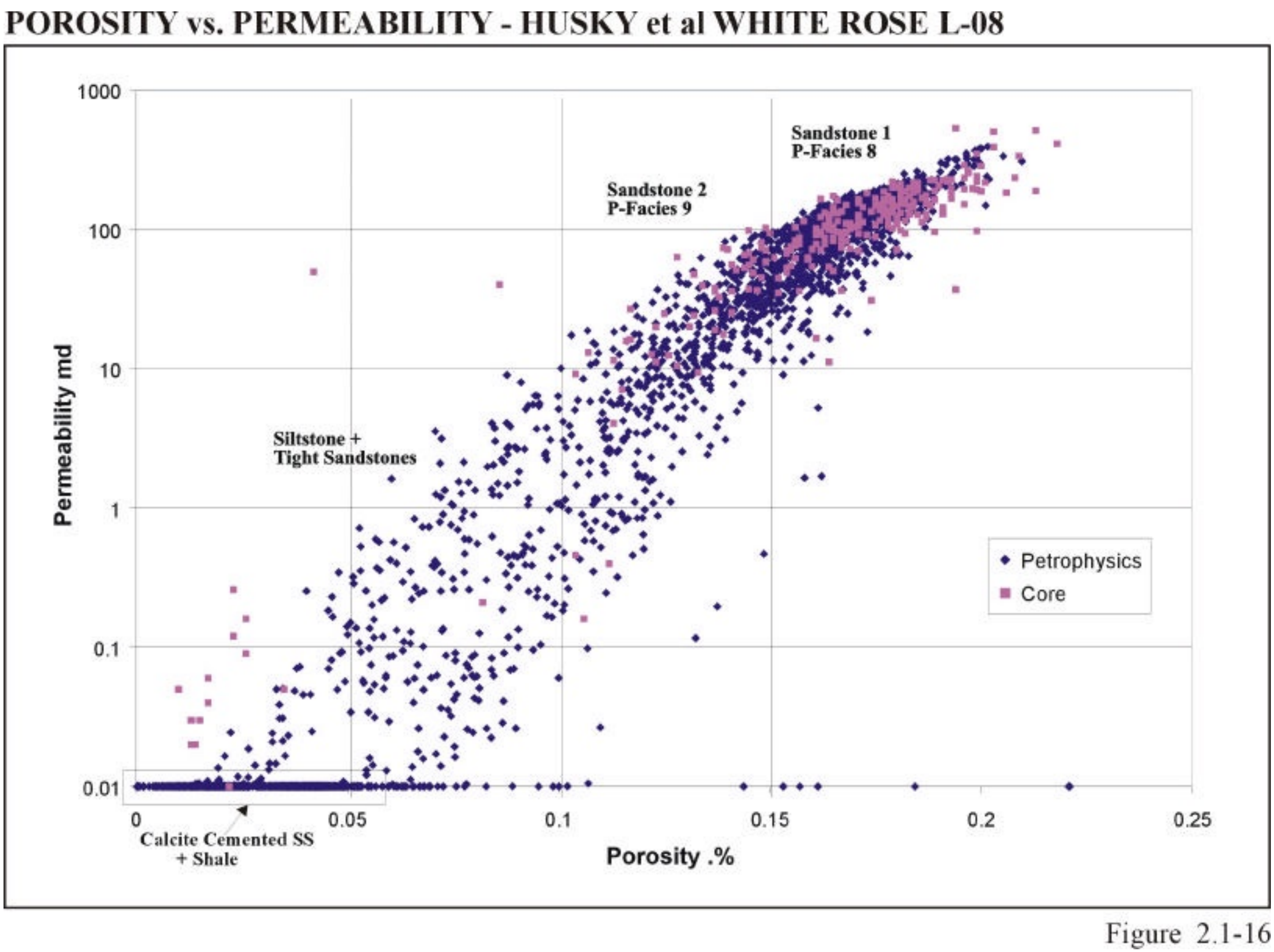


Figure 2.1–17 Porosity vs. Permeability Crossplot White Rose Field

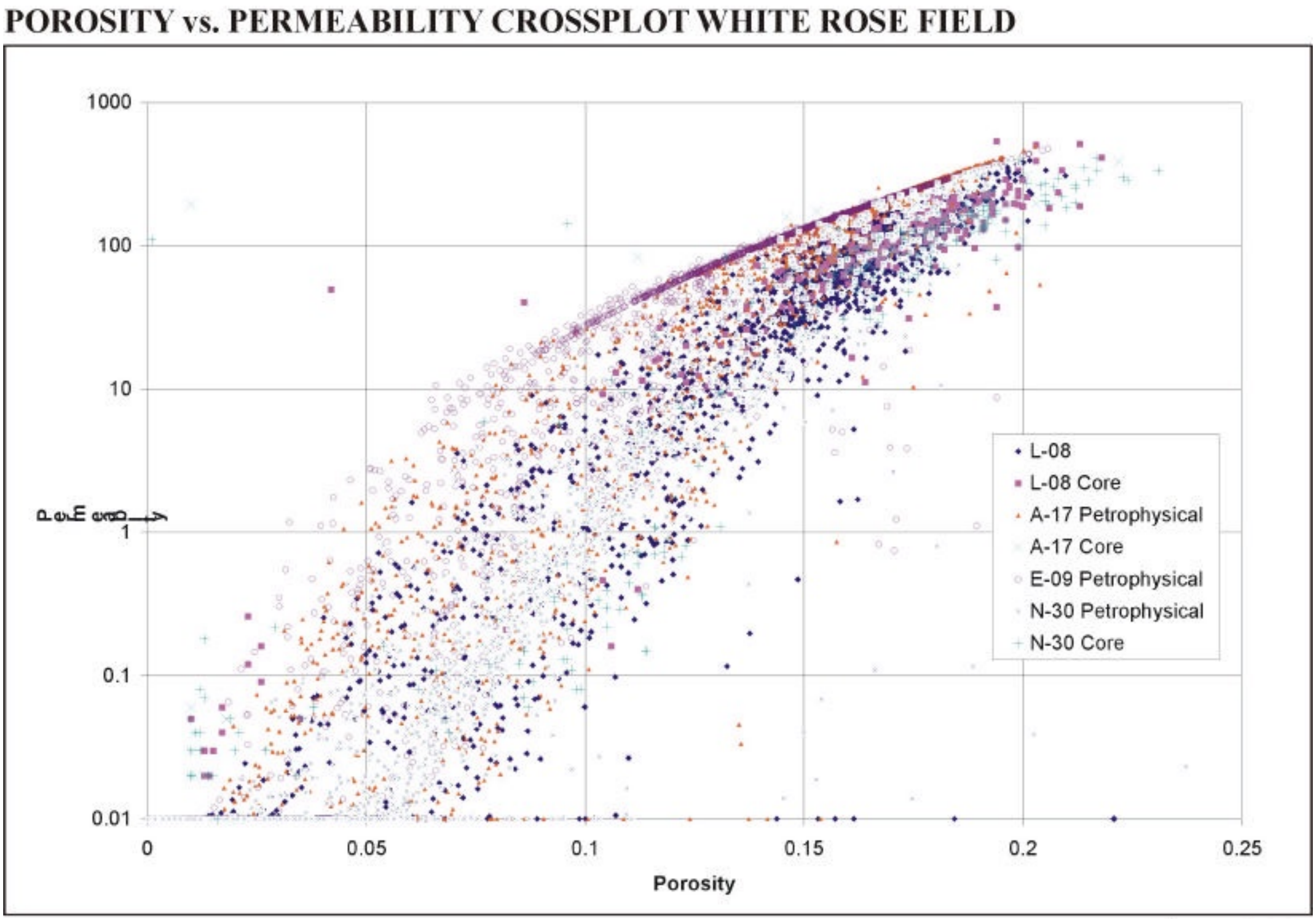


Figure 2.1-17

3) Calcite Concretions

Throughout the reservoir sandstones, calcite concretions take up approximately 8 percent of the reservoir volume. The calcite concretions are typically related to shell hash horizons. The shells have provided both the nucleation sites and some of the calcite which was dissolved and mobilized, providing material from which the nodules grew. Petrographic work suggests that the nodules occurred quite early in the diagenetic history of the Avalon (see the following section).

Interpretations from the core and FMI strongly indicate that these nodules should not extend very far in a lateral extent (Figure 2.1-18). Plint (1999a; 1999b; 1999c) notes that while the nodules are present throughout the core, they appear to be concentrated in discrete zones.

The nodularity of the concretionary horizons is evident in more than 90 percent of the concretions seen in the core or on the FMI. Since the concretions are related to thin (less than 5 cm) shell hash horizons, the concretionary horizons are likely not continuous over a large area, because of the topography of the shoreline during deposition. In addition, as the shell horizons are dissolved and re-precipitated as nodules, the formation of the concretions concentrate the thin calcite into thicker, less continuous, lenses. Plint (1999a; 1999b; 1999c) postulates that the nodules would range from 5 cm to 2 m in thickness and 20 cm to 3 m in width.

4) Shale Facies

In the South Avalon Pool, the shale component does not play a large role, as all of the shale is confined to the top 30 or 40 m of the sandstone package. The shale represents the material deposited during the transgressive event which pushed the shoreline back, southeastward of the White Rose area. Only on the fringes of the pool are there significant reserves within the shaley zone. On a pool wide basis, 8 percent of the original oil in place (OOIP) is within this shaley zone. Reservoir simulation suggests that only a small portion of this resource will be produced.

Shale plays a larger role in the North and West Avalon Pools. In these pools, shales are present in larger amounts. The shale section at the top of the Avalon is thicker, and more shale is interbedded with the reservoir facies. This represents the more distal nature of these deposits. The presence of shales within the reservoir section will have more effect on the production of hydrocarbons from the reservoir, as well as potentially having more of an effect on fault sealing.

Figure 2.1–18 Calcite Concretion in the L-08 Well

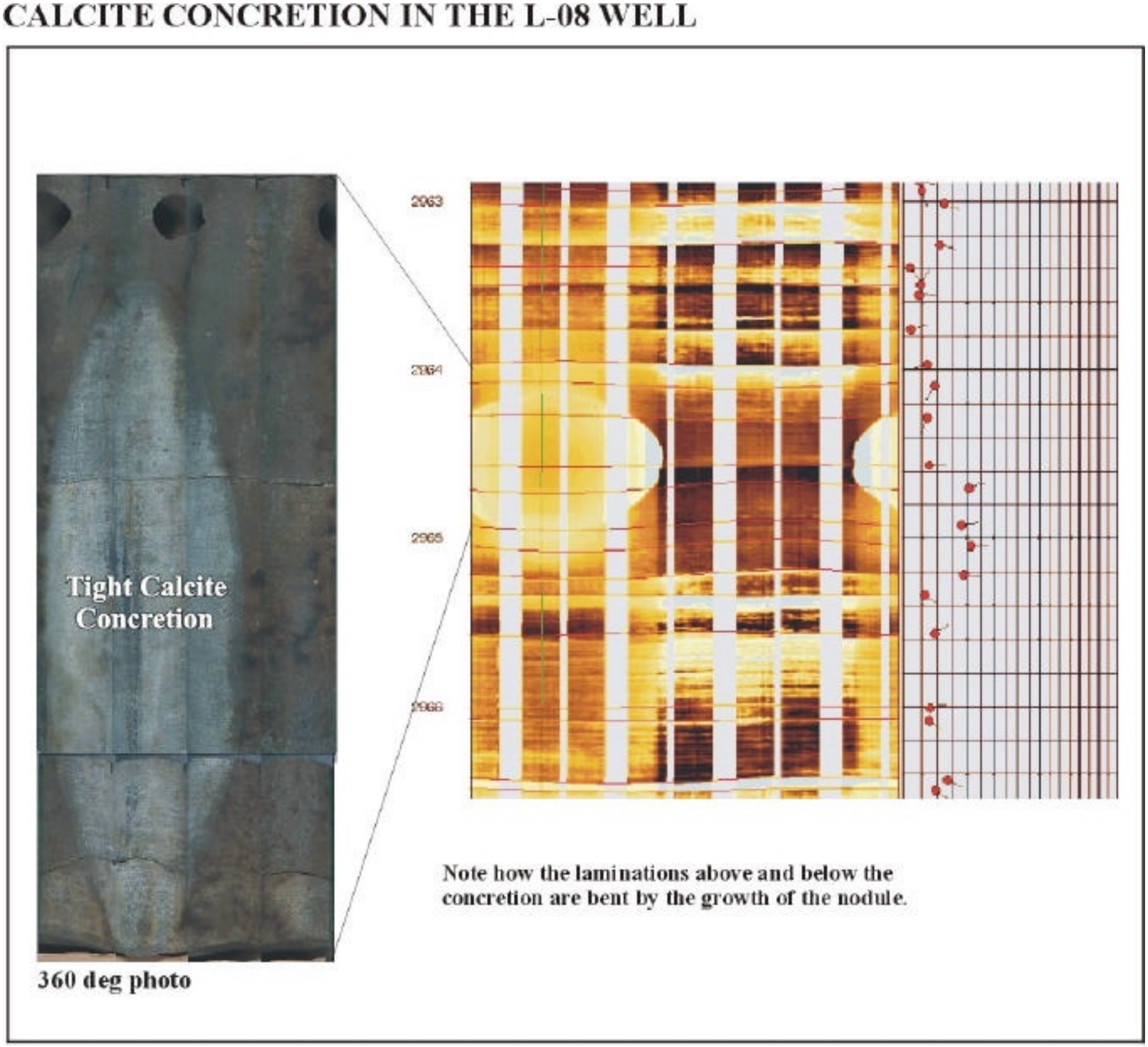


Figure 2.1-18

Local Tectonic Features and influence on the Reservoir

The complicated structural history of the White Rose area has left imprints on the reservoir. The FMI log was used for the determination of bedding attitudes and the presence of faulting and fracturing within the reservoir section. Only one significant fault within the reservoir section has been penetrated in the South Avalon Pool. The fault is seen at 2,958 metres below rotary table (mbrt) in the L-08 well, with associated fractures confined mainly to the hangingwall section. How the fault appears in both the core and the FMI log is illustrated in Figure 2.1-19. Affects on the reservoir and future production are uncertain, yet with the limited amount of faulting and fracturing seen in the wellbores, significant affects on performance seem unlikely. As noted in Figure 2.1-19, the L-08 fault is filled with calcite as are all of the associated fractures. The fault would form a semi-vertical barrier dipping at 80° to the wellbore. The reservoir engineering section will discuss the affects of this fault on the tests conducted in the well.

Geometry and Stacking Pattern of the Reservoir Layers and Facies

The three-dimensional reservoir modelling completed for use in the reservoir simulations illustrates the current thinking on depositional trends of the Avalon sands through the White Rose region. The model consisted of three main layers in the immediate South Avalon Pool vicinity, and two layers through the West and North Avalon Pools. The basal layer contains the sandstone layers which are present in the E-09 and L-08 wells, in addition to the J-49, N-30 and N-22 wells, but onlaps the Aptian. Unconformity down dip of the A-17 well. The second layer from the base contains the main reservoir sandstone, which is represented in all wells in the South Avalon Pool. The third and uppermost layer represents the low net to gross sandy siltstone and shale package at the top of the Avalon in the E-09, A-17 and L-08 wells. This layer is quite poor reservoir, and very quickly becomes completely non-reservoir to the northwest of the E-09 well.

Within the geological model for the South Avalon Pool, nine layers (Figure 2.1-20) were used to help delineate the shaling out transition along the northwestern edge of the pool. Using nine layers allowed this transition to be modelled more accurately. After the basic modelling was completed, these nine layers were compressed into the three layers mentioned above for mapping purposes. The Avalon Full Field two layer model is less detailed compared to the South Avalon Pool reservoir models. The basal layers of the two and three layer models are essentially the same, with the top layer in the three layer model representing the poorer reservoir quality section as correlated through the South White Rose region (Figure 2.1-21).

Figure 2.1–19 L-08 Fault Zone

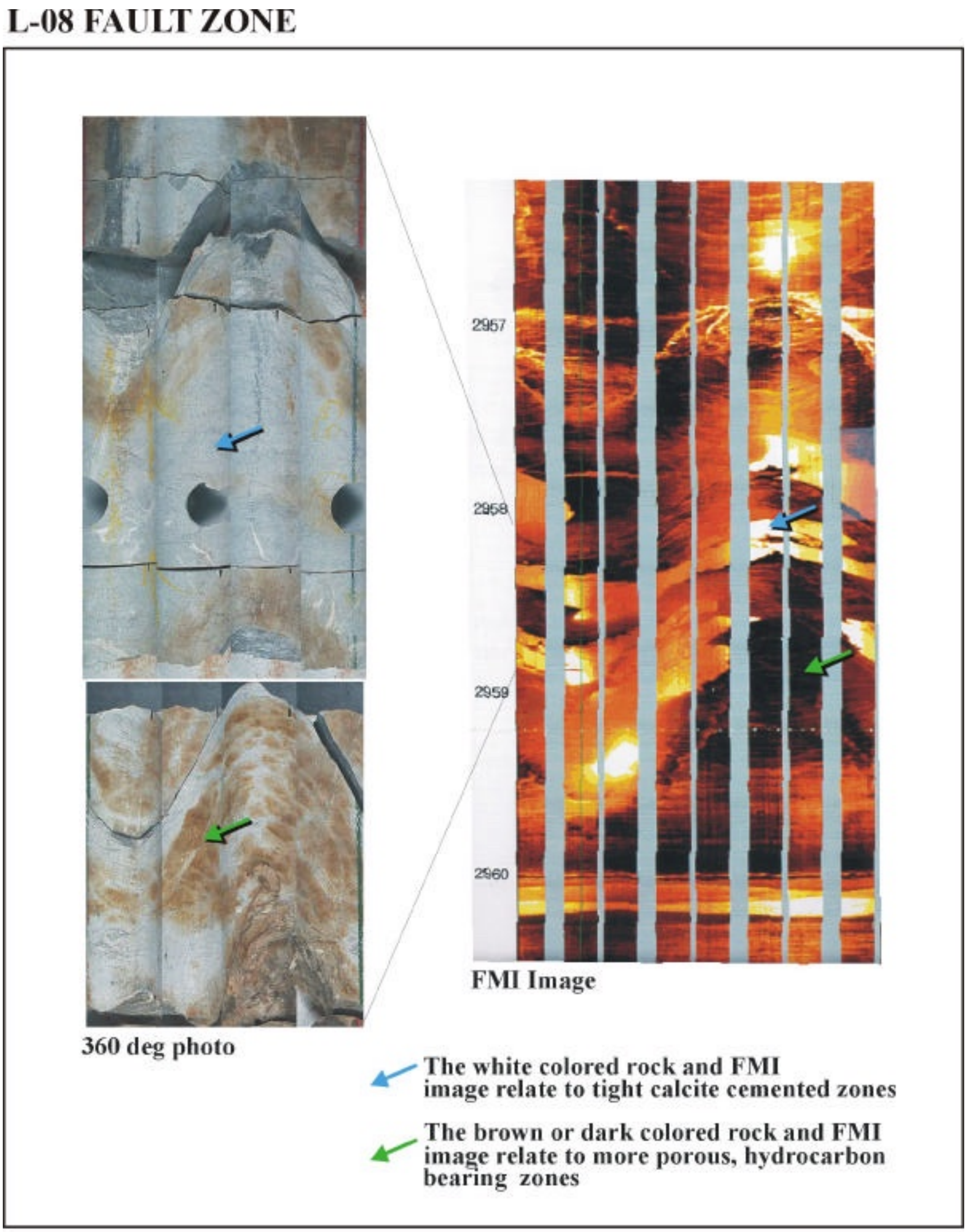


Figure 2.1-19

Figure 2.1–20 South Avalon Pool 9 Layer Model

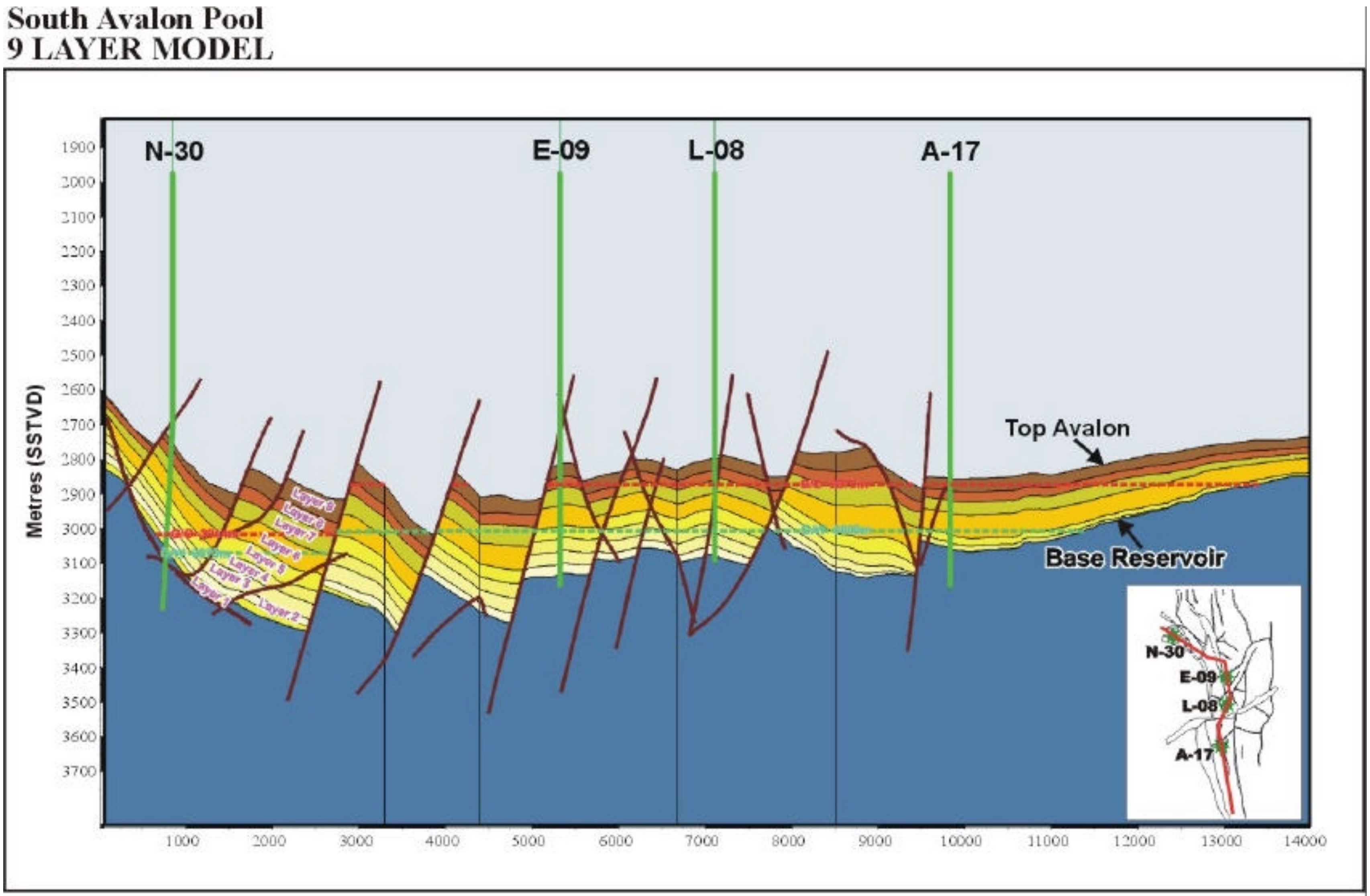
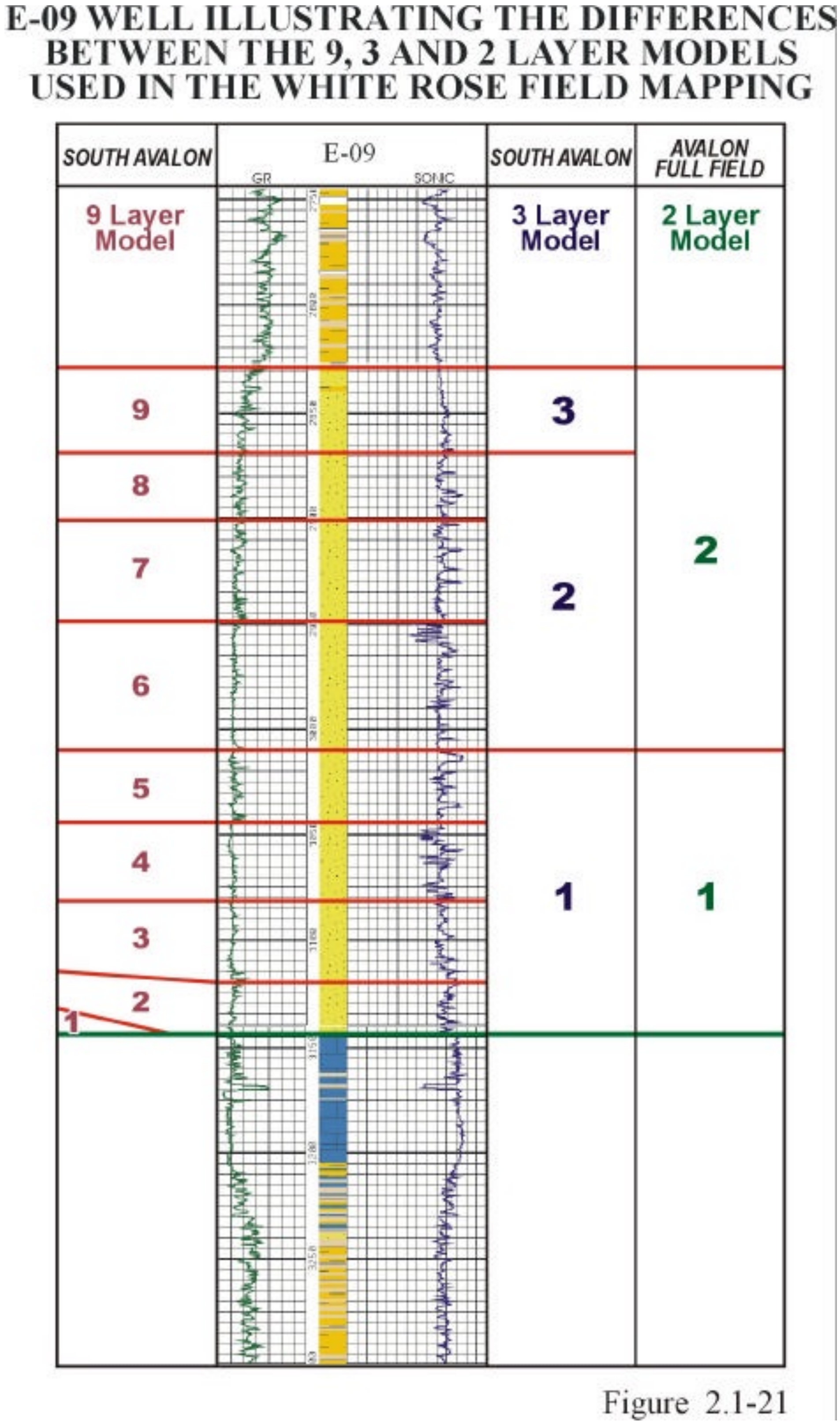


Figure 2.1-20

Figure 2.1–21 E-09 Well Illustrating the Difference Between the 9, 3 and 2 Layer White Rose Reservoir Models



Trend maps were used to constrain the model to a south-southwest to north-northeast trending shoreline through the South Avalon Pool (Deutsch and Hallstrom 2000). The shoreline may continue to the northeast of N-22. The J-49, N-22 and N-30 region was seaward of this shoreline and consists of more distal deposits represented by shales and siltstones. The region to the east of this trend represents a more proximal sand source area. The Avalon Full Field cross section (Figure 2.1-22) illustrates how the reservoir sandstone packages shale out towards the northwest. Note that the increase in shale works from the top of the Avalon down, with the main sandstones remaining at the base of the Formation.

2.1.3 Petrology and Reservoir Quality of the Avalon Formation

This subsection describes the petrology, diagenesis and reservoir quality of the White Rose Avalon Formation. Petrographic data includes an analysis of thin sections prepared primarily from core (or sidewall cores when core was unavailable) from seven wells in the White Rose area. These wells include White Rose L-61, N-22, J-49, E-09, L-08, A-17 and N-30. Detailed petrographic descriptions are found in reports by (Core Laboratories 2000; Haverslew 2000).

Interpretation of the Avalon Formation core indicates that the depositional environment was a marginal marine shoreface setting with frequent storm deposits. Numerous calcite concretions varying in dimensions are present, as layers of stratabound concretions or as scattered concretions. The geometry of the calcite concretions is controlled by the original amount and distribution of biogenic carbonate within the sandstones.

2.1.3.1 Primary Composition And Texture

The mineralogy of the reservoir sands is predominantly 85 to 99 percent quartz and lesser amounts of carbonate grains, bioclastic debris, feldspar, and trace amounts of pyrite, heavy minerals, and dolomite. The reservoir sandstones have subangular to well rounded grain boundaries. Grain size is predominantly very fine with some fine-grained sands. The detrital quartz grains exhibit sub-angular to rounded grain boundaries and moderate to high sphericities with moderate to well sorting. The sandstones are classified as sublitharenite to quartz arenite. A comparison of QFR diagrams (Figures 2.1-23 and 2.1-24) from L-08 and A-17 shows a similar rock classification.

Figure 2.1–22 Avalon Full Field Cross Section, Facies Model, Feb. 00 Geological Model

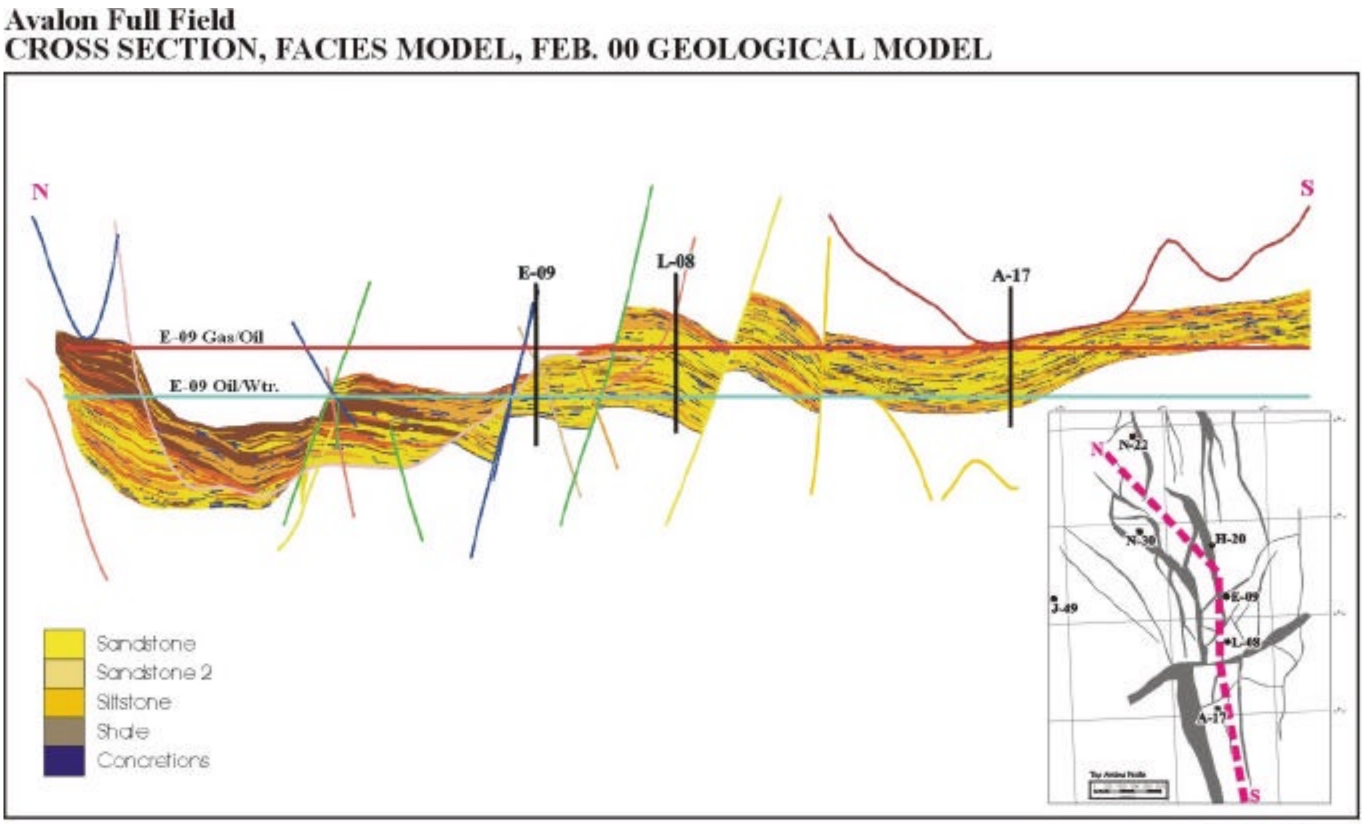


Figure 2.1-22

Figure 2.1–23 QFR Diagram – L-08 Well

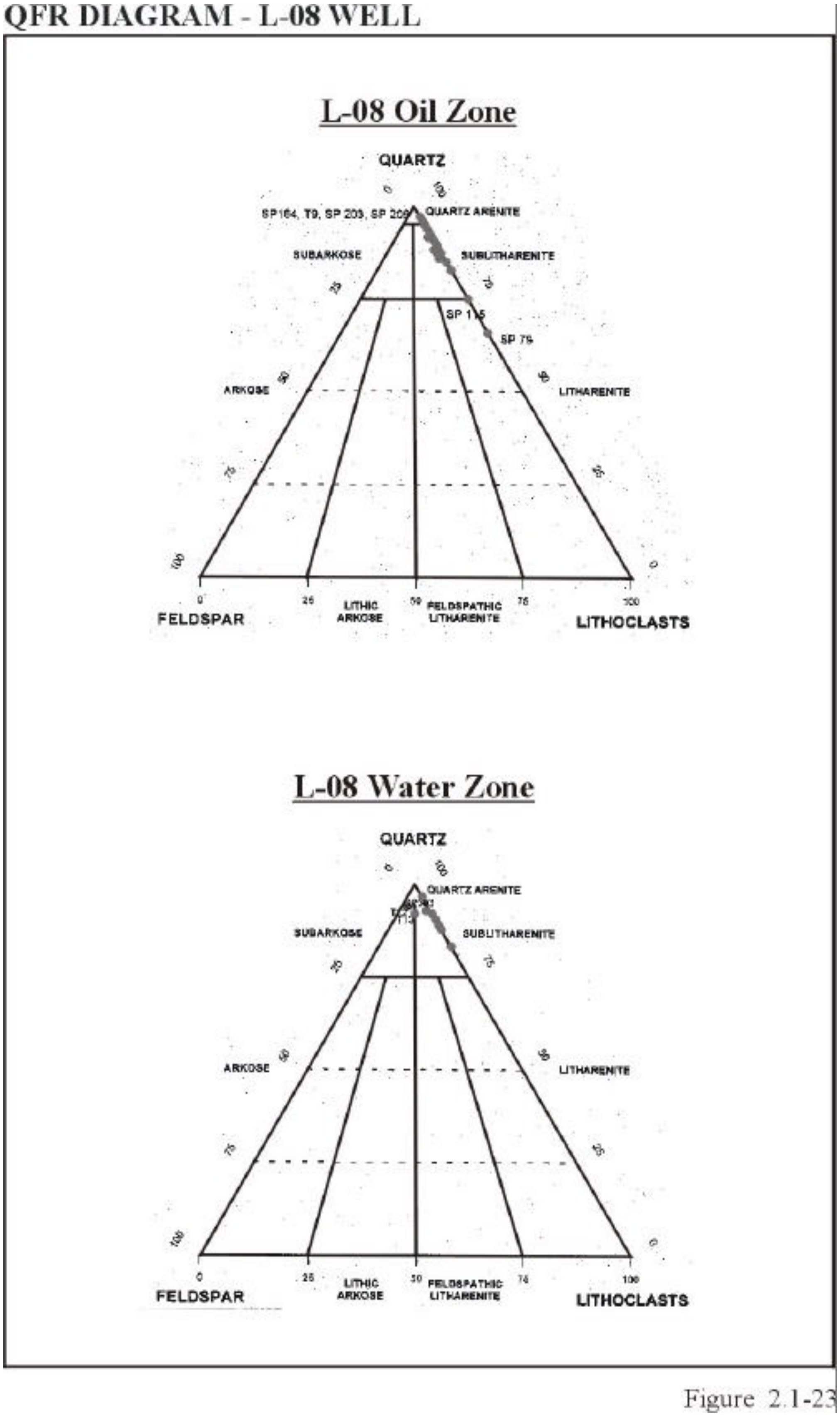


Figure 2.1–24 QFR Diagram – A-17 Well

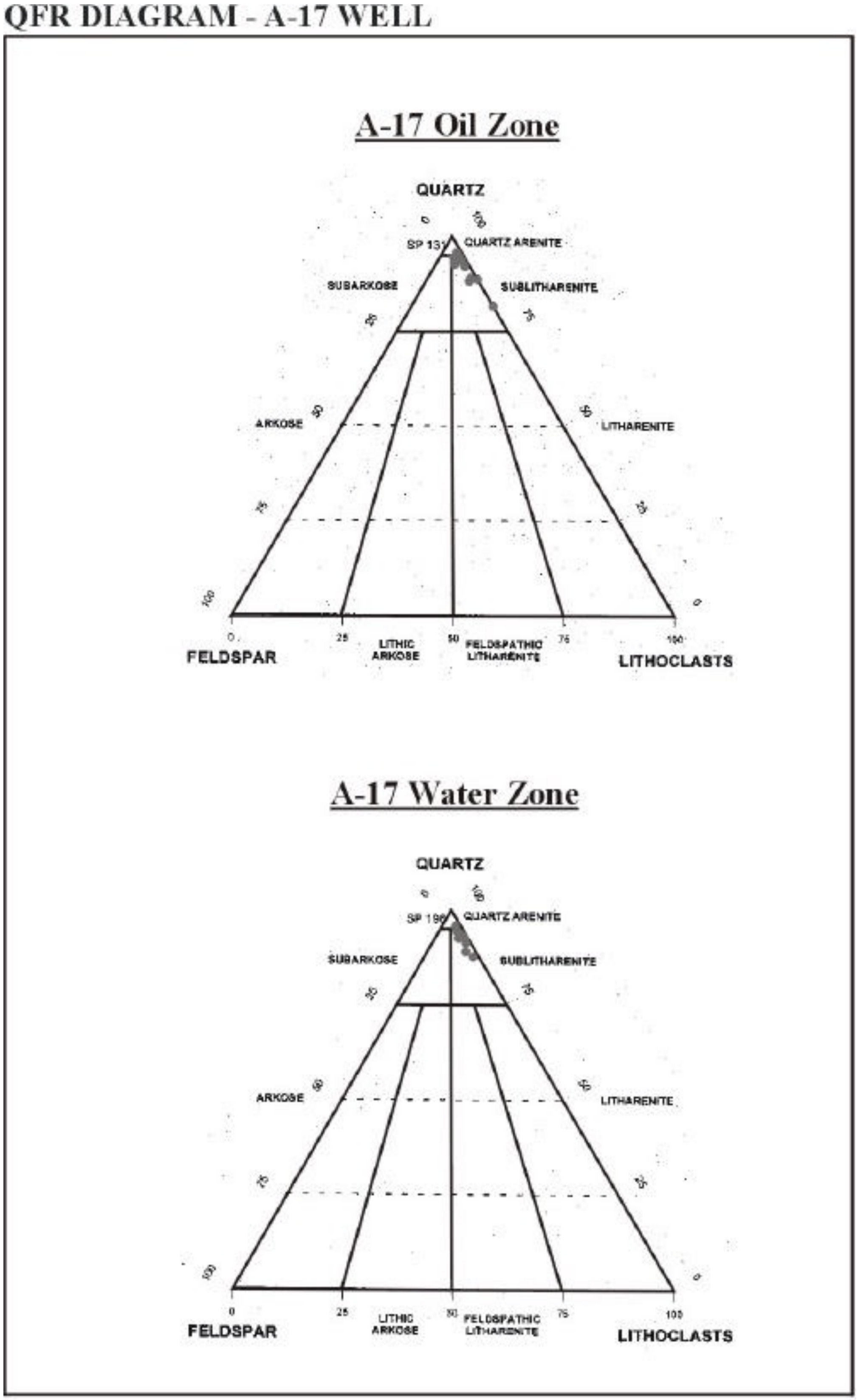


Figure 2.1-24

Monocrystalline quartz is the dominant framework grain, with lesser amounts of rock fragments and feldspar. Variable amounts of bioclastic debris, ranging from abraded fragments to relatively intact shell clasts, are present. Fragments consisting originally of calcite generally remain as non-ferroan calcite, however, bioclast fragments, or parts of shell fragments of less stable original composition, (usually aragonite), have been partially to completely replaced by ferroan calcite. All White Rose wells have similar dominant framework grains, but N-30, N-22, J-49 and L-61 are compositionally less mature, containing more feldspar, rock fragments and accessory minerals.

Accessory minerals include glauconite, heavy minerals, and detrital chlorite. Interstitial detrital clays are generally absent, but argillaceous burrows or clay partings are present. Authigenic minerals present are siderite, calcite, silica and ferroan dolomite, dolomite, pyrite, and clays.

2.1.3.2 Diagenesis

Textural relationships evident in the Avalon Formation sandstones indicate several phases of precipitation and dissolution. Reservoir properties are affected due to cement precipitation, compaction, replacement of grains, and dissolution of primary or diagenetic rock components. In many cases, such as the concretionary horizons, only one or two of the diagenetic processes have affected the reservoir.

There are three main types of compositionally different calcite cements (Table 2.1-4). These include iron free calcite, early ferroan calcite and late ferroan calcite. Early ferroan calcite cement, the most common cement occurs as pervasive pore filling mosaic or poikilotopic cement, as scattered pore fill often surrounding detrital calcite grains, as individual microcrystals and as partial to complete replacement of detrital calcite shells (rim cement). The iron free calcite is the earliest calcite cement, forming overgrowths on fossil fragments and as poikilotopic cement. Early ferroan calcite replaces iron free calcite and may also be due to the dissolution of biogenic carbonate (fossil fragments). Grain margin corrosion by late ferroan calcite completely fills the intergranular pore space. Late ferroan calcite appears to contain a higher percentage of iron than earlier formed ferroan calcite.

Table 2.1-4 Cements Occurring in the Avalon Formation, Composition and Texture

Cements – Composition	Texture
Iron Free Calcite	Grains or crystals
Early Ferroan Calcite	Rim (forms on rims of shells)
Early Ferroan Calcite	Mosaic
Early Ferroan Calcite	Poikilotopic (concretions)
Silica Cement	Overgrowths on quartz grains and crystal shards in fault
Dolomite	Grains or crystals
Late Ferroan Calcite	Microcrystals

Early ferroan calcite can be classified in three main textural fabrics, rim, mosaic and poikilotopic. Rim ferroan calcite forms on the rims of the bioclastic debris, while poikilotopic ferroan calcite is a blocky cement which completely occludes the pore space between the quartz grains. Mosaic cement refers to elongate crystals rimming or filling voids. Late ferroan calcite occurs texturally as pore filling poikilotopic microcrystals. This late ferroan calcite occurs only in the water zone.

Concretions consist of quartz grains, minor iron free calcite, ferroan calcite, and bioclastic debris (shells). Concretion formation occurs in all three zones (water, oil and gas) simultaneously. Early poikilotopic ferroan calcite cement fills the pore space creating the concretions. Ferroan poikilotopic cement phase occurs before early quartz overgrowths indicated by the absence of quartz overgrowths in the cemented sandstones. A ferroan calcite also occurs as pervasive pore filling mosaic cement, rim cement and partially replaces bioclasts in the concretionary horizons. The degree of replacement of bioclasts by ferroan calcite is controlled by the original composition of the fragment (for example, aragonite).

Minor to moderate quartz overgrowth development has taken place on quartz grains where little to no calcite cement is present. Silica fines are also present in a fault zone in L-08. A number of fractures are evident in thin section and core, some are filled with quartz crystals, bitumen, barite, clays (kaolinite, etc.) or with carbonate cementation.

Siderite occurs as microcrystals scattered throughout the pore system, and as a replacement of detrital clays in argillaceous burrows, clay partings and partially filling shell cavities. Pyrite occurs in trace to minor amounts, and is present as coatings on fossils (after early carbonate dissolution), and burrows.

Feldspars observed exhibit partial alteration and replacement by carbonates and clays, and dissolution of some grains. The gas zone in the South Avalon Pool contains more siltstone and clays than the oil or water zones. Where clays are present as coatings around grains or as matrix, the grains are protected from calcite replacement. Minor heavy minerals (zircons, garnet) sometimes occur and may be attributed to concentration by wave action along a coastline.

Paragenetic sequence for the Avalon Formation

Framework grains of quartz, bioclastic debris, with trace amounts of feldspar, siderite, and heavy minerals.

- early iron free calcite;
- early Ferroan calcite;
- quartz overgrowths;
- siderite, pyrite;
- hydrocarbon emplacement; and
- late ferroan calcite.

The original framework of the Avalon Formation consisted of quartz, bioclastic debris and trace amounts of feldspar (in South White Rose wells) siderite and heavy minerals. Early iron free calcite occurred and some was replaced by early ferroan calcite. The early ferroan calcite cement occurred next in the paragenetic sequence in different textural forms as discussed above. The ferroan poikilotopic cement phase occurred before quartz overgrowths as evidenced by the absence of quartz overgrowths in the cemented sandstones. The presence of pyrite and siderite can be explained as both late and early in the paragenetic sequence. Early as crystals and late as fillings in burrows and along shell linings. Late ferroan cement appears to be present only in the water zone, which can be explained by the fact that oil migration may have occurred just prior to this later diagenetic cement.

Reservoir Quality

The Avalon Formation is characterized by low to medium permeabilities because of the very fine-grained nature of the reservoir, and the degree of pore throat size reduction due to physical compaction and quartz overgrowths.

Porosity in the Avalon Formation is mainly primary intergranular with minor secondary moldic porosity resulting from dissolution of shells and other grains. In reservoir intervals where carbonate cement is abundant, porosity is very low due to cement plugging the pores. The presence of early carbonate cement prevents closer grain packing in response to increasing overburden. In cemented samples, shells show very little to no evidence of flattening due to compaction: whereas in uncemented samples shells may exhibit some deformation and flattening as a result of overburden pressure. Where a few quartz grains are closely packed together, silica cement reduces pore space, however in general silica cement only moderately reduces porosity.

There are several minerals in the Avalon Formation that have the potential to cause production problems, when they occur as fine grained rock constituents. Introducing acid into this carbonate bearing formation will introduce problems such as the formation of iron precipitates. Carbonate types are mainly calcite, ferroan calcite, and aragonite with minor siderite and dolomite. Clays in the upper portion of the reservoir may also cause problems in terms of fines migration. These clays include illite, kaolinite and chlorite (XRD/SEM analysis).

The pore system is generally clean. There is little to no authigenic clays, or other fines (with the exception of the upper portion of the reservoir) that could cause significant fines migration problems during production, or cause completion problems. The sandstones are competent and not friable, therefore sand production should not be a problem.

2.1.4 Reservoir Description: Secondary Hydrocarbon Bearing Reservoirs

A reservoir description of the secondary hydrocarbon bearing reservoirs, encountered in the White Rose Field, is outlined below. Refer to Formation Tops and Fluids Sampled (Table 2.1-1a and 2.1-1b), the stratigraphy of the White Rose area (Figure 2.1-7) and the Paleocene to Late Jurassic Stratigraphic cross section of the White Rose area (Figure 2.1-8).

The Rankin Formation was penetrated at the base of the White Rose E-09 well. This Kimmeridgian aged section consists of a mixture of shales and siltstones with interbedded sandstones, likely the Tempest Member. Drilling problems related to overpressure in this section did not allow a complete evaluation of this unit. An open hole test of the bottom 187 m of the well produced small amounts of gassy oil and water. Reservoir quality is very questionable, as no cores were taken. Both overpressure and fractures within this fault bounded zone likely contributed to enhancing fluid flow during the test.

The Hibernia Formation has been penetrated in the A-17, E-09, N-22 and J-49 wells. The Formation can be divided into Upper, Lower and Basal members. The Upper Hibernia is not well developed in the White Rose area. The Formation consists primarily of marine siltstones and shales, as it is far from the main southwest entry point into the basin. An 18-m core cut in N-22 is composed of poor quality siltstones and calcareous marine shales. Coarser clastics appear towards the base of the unit, where slightly porous, fine-very fine grained, argillaceous sandstones are found. The Lower Hibernia has been penetrated in the E-09, N-22, A-17 and J-49 wells. Two cores cut in N-22 recovered 15 m of siltstone, shale and minor amounts of fine-grained sandstone. Minor fractures, filled with calcite, are present, but reservoir quality is poor. The zone subsequently tested 60 m^3 oil. The lowermost Hibernia package, the Basal Hibernia, appears slightly better developed and tested 78 m^3 oil in E-09. This unit was deposited primarily as a prograding shoreface succession as part of an overall regional regressive Hibernia package. The shoreface succession contains minor fluvial and marginal marine deposits. The same basal unit, found 4.5 km further south in the A-17 well, is better developed and has good porosity described from cuttings. Although not cored, secondary enhancement of the reservoir unit immediately beneath the base Avalon Unconformity, at this location, may explain the better reservoir character. Hibernia Formation sandstone content decreases northwards, and shale content increases, until very thinly bedded, gas charged argillaceous sandstones are all that remain at Trave E-87.

The Eastern Shoals Formation has been penetrated in White Rose L-61, J-49, N-22 and N-30. In E-09 and L-08, a tight basal carbonate was encountered, indicating little prospectivity under the South Avalon Pool. In White Rose L-61, 13.5 m of Eastern Shoals core recovered thinly bedded sandstones, siltstones and shales. A drill stem test from the Eastern Shoals Formation produced 0.065 $10^6 m^3$ gas, 24 m^3 oil with 14 percent water from a thin sandstone in White Rose J-49, indicating a separate pressure system from the overlying West Avalon Pool. The Eastern Shoals Formation test (0.04 $10^6 m^3$ gas) and RFT pressure points in White Rose N-22 indicated the thin sandstones were in communication with the overlying North Avalon Pool. Similarly, formation pressures in the untested upper part of the N-30

Eastern Shoals Formation were in communication, although sandstone quality and thickness were significantly lower.

There were two hydrocarbon shows within the Upper Cretaceous section of the White Rose Field. Minor gas was recovered from a 5 m sandy limestone, immediately below the base Tertiary in White Rose N-22 (Table 2.1-1a). Biostratigraphic studies identified this section as Albian (Jenkins, Husky Oil Consultant Reports 1997; 2000). A similar, low permeable chalky zone in N-30 had 5 m of oil pay, but is identified as Cenomanian/Turonian. Secondary enhancement of these zones below the Base Tertiary way account for the porosity.

The Paleocene South Mara Member, a basal transgressive shallow marine sandstone, tested gas and condensate in the White Rose L-61 well. The South Mara Member, found at the base of the Banquereau Formation, is the thick succession of Tertiary clastics deposited during thermal subsidence. In L-61, the South Mara is a fining-upwards 30-m section of brown, glauconitic silty fine to very fine-grained sandstone. The lowermost 5 m of fine to medium grained sandstone is porous, averaging 23.5 percent porosity. Although the overlying silty shale package can be correlated throughout the field, porous sandstone appears restricted to the northwest flank of the N-22 structure, and south at Amethyst F-20.

2.2 Geophysics

This Section describes the seismic data and geophysical mapping specific to the White Rose Field.

2.2.1 Seismic Data Acquisition

The White Rose Complex is covered by three seismic surveys that were completed for different purposes, in different years and with different field geometrical configurations. However, the main seismic survey used to interpret the White Rose Field, decipher the structural and tectonic framework, correlate stratigraphy and locate delineation and development wells is the White Rose PGS 97 three-dimensional survey (Figure 2.2-1).

The PGS 97 3-D survey was shot during June-July 1997 and covers an hexagonal-shaped area of 311 km², that comprises most of the known White Rose hydrocarbon accumulations. The seismic ship *R.V. Ramform Explorer*, operated by PGS Exploration AS, conducted the 3-D geophysical survey on behalf of Husky and its partners. A total of 13,328.4 line km of seismic reflection profiles were collected in 40 variable length swaths, recorded in an east-west direction. The most extended lines are 25 km long while the shortest are 14 km long (Boyd Exploration Consultants Ltd. 1997).

Figure 2.2–1   White Rose Complex 3-D Surveys

WHITE ROSE COMPLEX 3-D SURVEYS

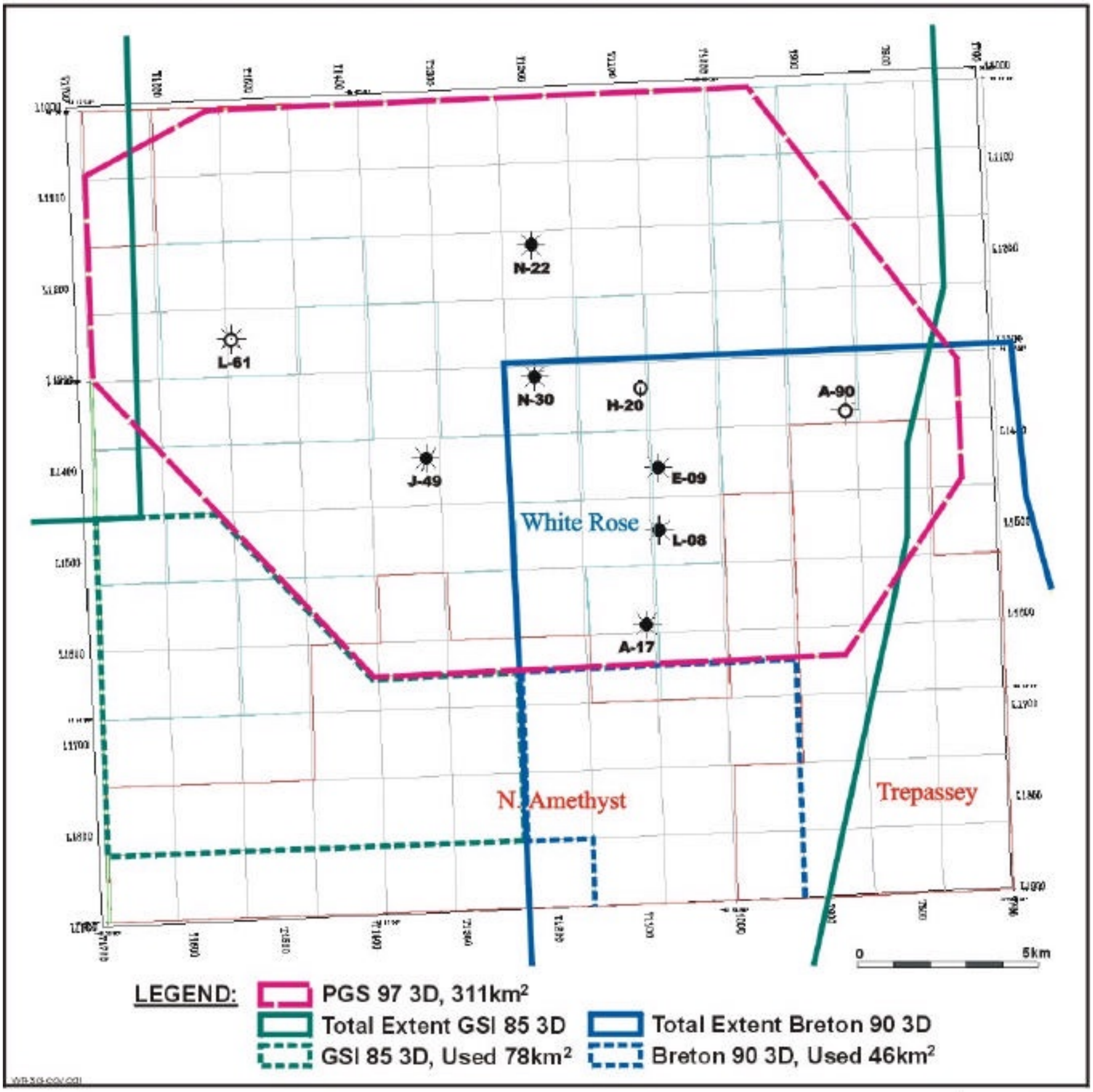


Figure 2.2-1

The PGS 97 data were acquired with a dual source/eight streamer configuration. Streamer length was 4,025 m and separation between streamers was 100 m, resulting in a 4,025 m by 700 m acquisition footprint. A number of 8 × 162 channels were recorded with a 2 ms sampling rate and 7 s recording length. The two/three air gun arrays were distanced at 50 m and fired in a flip-flop manner every 25 m. The resulting line spacing is 25 m and data is 40-fold. The signature of the tuned air gun array was excellent and stable throughout the program. Accurate Wide Area Differential Global Positioning System (DGPS) primary positioning was used throughout, in combination with land-based STARFIX positioning (better than 2-m accuracy). A complete list of acquisition parameters is given in Table 2.2-1.

Table 2.2-1 Instrumentation and Recording Parameters, PGS 1997 Survey

Parameter	Value
Total distance shot	13,328.4 km
Source	Dual tuned airgun array
Airguns	Bolt Par model 1900Ll and Sodera G-Sleeve gun
Array	3 parallel sub array per source
Volume	3,090 cu min.; 55.79 L
Pressure	2,500 psi ; 17.125 MPa
Operating depth	9 ±1.5 m
Array separation	50 m
Gun controller	Syntron Gun Controller System GCS90
Average near group offset	275 m
Recording system	Syntrak 480, more than 2,000 channels
Tape/Cartridge decks	4 Stk IBM 3590 (NTP)
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/1,296 for eight streamers
Recording length	7 s
Sample rate	0.002 s
Gain constant	12 dB
Recording filters	Low cut 3 Hz @ 64 dB/octave High cut 206 Hz @ 276 dB/octave
Shot line spacing	50 m
Shotpoint interval	50 m for each array (25m for alternate shots)
Group interval	25 m
Hydrophones per group	32
Hydrophone interval	.75 m
Hydrophone type	Teledyne T2
Streamer length	4,050 m
Streamer separation	100 m
Number of streamers	8
Average cable depth	9 ±1.5 m
Navigation system	Concept, Spectra Integrated Navigation System Version 2.03.10
Primary navigation system	Differential GPS STARFIX/Seadiff
Secondary navigation system	Differential GPS STARFIX/WADS

The Breton 3-D survey purchased by Husky et al, in 1999 was used for seismic interpretation over a 46-km² area located in the southeastern portion of the White Rose Complex. This survey was a group shoot acquired by Esso et al. in 1990 with the *M.V. Geco Searcher* and was initially used as work commitment for an Exploration License awarded to Esso, Chevron, Shell and Talisman. The Breton survey was acquired with dual streamer/dual source configuration. Streamer length was 2,800 m, streamer separation was 150 m, source separation was 75 m and the shot interval alternating was 18.75 m. This field layout resulted in a line spacing of 37.5 m and trace spacing of 12.5 m.

Husky purchased the GSI 85 seismic survey for regional interpretation of the eastern Jeanne d'Arc Basin and early delineation of the White Rose Complex. This was an exploration 3-D survey (reconnaissance 3-D) acquired with single source/single streamer configuration and a 200 m line spacing. The cable had 120 hydrophone groups and its length was 3,024 m, resulting in 60-fold data. There is a total overlap between the GSI Reconnaissance 3-D and the PGS 97 3-D survey and partial overlap with the Breton survey. Due to its poorer quality, the GSI survey was used only for interpretation of a small 78-km² area situated outside the newest surveys. More information regarding the acquisition parameters of the GSI 85 program resides with the C-NOPB office in St. John's.

2.2.2 Seismic Data Processing

Three different seismic surveys cover the White Rose area: 1) PGS 1997; 2) Breton 1990 and 3) GSI 1985 (Figure 2.2-1). The three surveys were merged after DMO and migrated as a single volume (Breton, White Rose and Recon, Final Report on Seismic Processing, Husky Oil Consultant Report, 2000). The seismic interpretation of the White Rose Complex was performed mainly on the PGS 1997 3-D survey that covers most of the significant discovery area. The survey was processed initially by Kelman in 1997 and used for locating the three delineation wells White Rose L-08, A-17 and N-30, drilled in 1999. Seismic mapping for this report was done using a reprocessed 3-D post-stack migrated volume completed during 1999 by CGG in Calgary. Outlined below are the steps and parameters used for this processing sequence.

Seismic Processing Sequence:

3-D one pass migration stack processing parameters

- Reformat from SEGD:
  - 7 s/2 ms output
- Trace editing
- Source-receiver adjustment to sea level
- Merging of seismic and navigational data
- Spherical divergence compensation
- Conversion of source signature (far field) to its minimum phase equivalent

- Spiking deconvolution:
- One operator per shot and cable operator length: 250 ms prewhitening: 1.0 percent
- Predictive deconvolution:
  - One operator per trace
  - Operator length: 240 ms
  - Gap: 20 ms
  - Prewhitening: 1.0 percent
- Dynamic equalization
- Minimum phase resampling to 4 ms
- Velocity analysis: every 1000m
- Dynamic binning and sorting
- Multiple attenuation (water multiples)
  - Radon decomposition (fx domain)
- Static binning and sorting:
  - 12.5 x 25 m bin
- Harmonization of offset classes
- 3-D Kirchoff dip moveout:
  - Preserved amplitude
  - Spatial band limited interpolation
- Multiple removal by 2nd order deconvolution (remul) in tau-p domain
- Velocity analysis: every 500m
- Final NMO corrections and mutes
- Residual multiple attenuation
  - F-k domain filtering
- Stack 4100 percent
- two-dimensional (2-D) and 3-D peg legs attenuation (splat)
  - Specified peg legs attenuation in f-x domain
- F-x random noise attenuation
- F-x interpolation (x-line 12.5 m x 12.5 m)
- 3-D one pass migration:
  - F-x domain steep-dip algorithm
- Time variant filter:
  - 6/10-55/65 Hz; 0- 2,500 ms
  - 3/7-45/55 Hz; 3,000- 3,500 ms
  - 3/7-35/45 Hz; 4,500- 7,000 ms
- Dynamic equalization
- SEGY copy every traces
- Phase rotated

The southeastern part of the White Rose Complex seismic interpretation was performed on the Breton 1990 3-D survey shot by Western Geophysical and reprocessed for Husky et al. by CGG in 1999. Reprocessing included the same processing flow as the one used for the PGS 1997 survey and the sequence is listed above. For the southwestern part of the White Rose Complex interpretation, the GSI 1985 Exploration survey was used. The survey was shot at 200-m line interval, interpolated at a 25-m line interval and reprocessed in 1999 by CGG using a similar routine.

2.2.3 Seismic Interpretation

2.2.3.1 Synthetic Ties

The main seismic markers were correlated to the White Rose wells with a good fit between the vertical seismic profiles (VSP) and synthetics generated from sonic and density logs. The correlations study is included in the White Rose VSP Synthetic Correlations Report, Husky Oil Internal Report, 2000. Examples of the individual well synthetics and the VSP-Synthetic-Seismic correlations are provided in Figures 2.2-2 and 2.2-3.

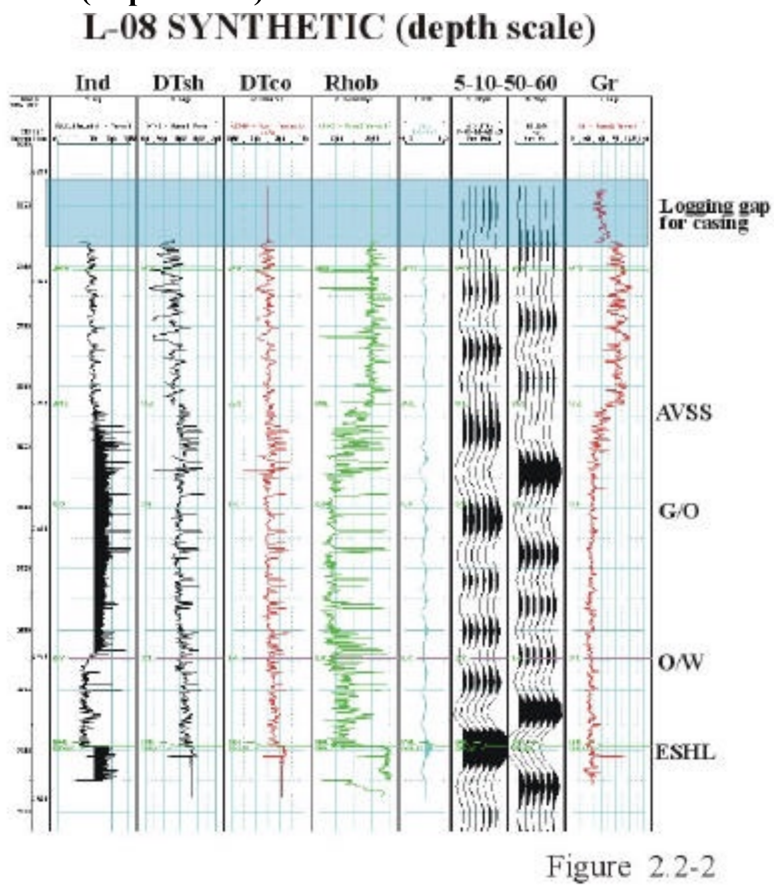
VSPs exist for six of the eight White Rose wells, with the VSPs prior to 1999 being of poorer data quality than the 1999 VSPs. The wells with deviation in the well path, N-30, J-49, and E-09, have poor ties to the synthetic and seismic below the deviation.

2.2.3.2 Seismic Markers

Seven wells provided correlation points with the stratigraphy over the White Rose Complex. The ties between the synthetic seismograms, corridor stack VSPs and marine seismic data are generally good. Most data correlation problems occur due to the low impedance contrast between the Avalon sandstone reservoir and surrounding rocks and complexity of faulting. Mapping the top and the bottom of the Avalon Formation is generally a challenge (White Rose PGS 97 3-D Interpretation Report, Husky Oil Internal Report, 2000).

Data quality vary from excellent in the southwest, to good in central regions and to poor on the Terrace, central collapsed graben and the northern part of the survey. The Avalon reservoir has overall poor reflectivity and different seismic characteristics exist in different areas of the White Rose Complex. The reservoir section is generally transparent but several existing internal reflections are locally mappable. Faults are generally well imaged. Complications are brought by the existence in the area of a number of keystone faults and local contamination of data by remnant multiples and converted waves reflectors.

Figure 2.2–2 L-08 Synthetic (Depth Scale)



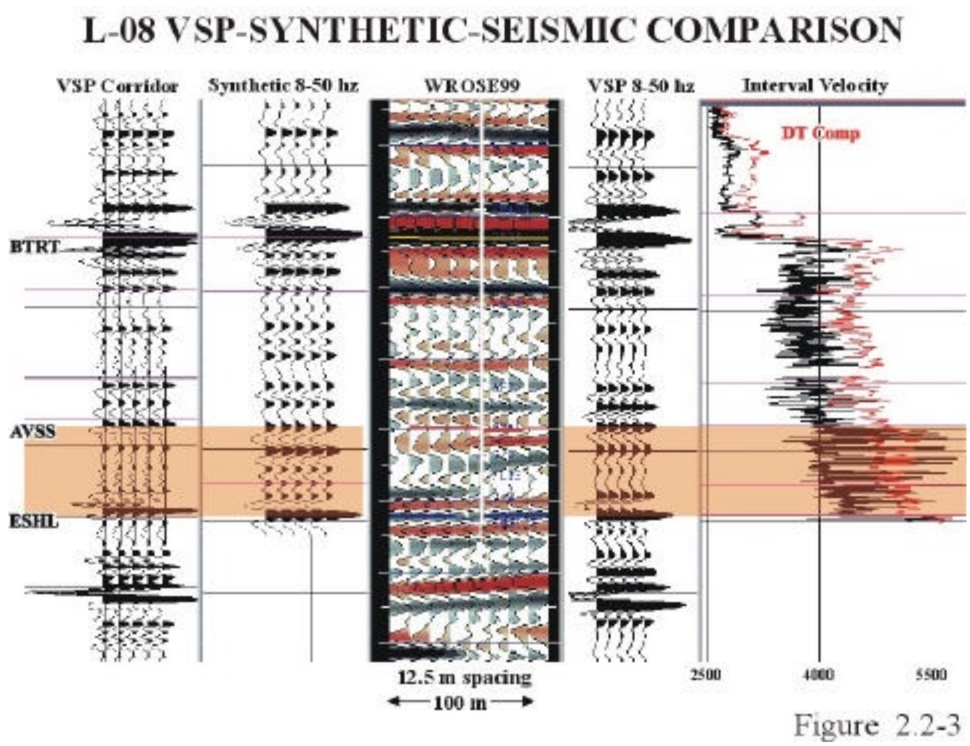


Figure 2.2–3 L-08 VSP-Synthetic-Seismic Comparison

Seismic interpretation was performed on all available lines and crosslines (25 m by 25 m line grid) and confirmed with arbitrary lines, animation files, time slices and continuity slices. The interpretation was completed using a Sun operating system and Landmark Seisworks 3.5 software release. Three displays on screen or hardcopy: 1) seismic line or time slice; 2) time-structure map; and 3) trend continuity maps were used to interactively interpret in difficult mapping areas and tectonic complexity.

Three seismic markers were correlated and mapped over the entire area: the Base Tertiary Unconformity (Figure 2.2-4), the Composite Marker (Section 2.1 Figures 2.1-5, and Figure 2.2-5) and the mid-Kimmeridgian Unconformity (Figure 2.2-6). The Top Avalon Formation was mapped only in the eastern side of the White Rose Complex, where the seismic marker was accurately tied to the wells (Figure 2.2-7). The only continuous, widespread reflectors are located within the Thermal Subsidence Sequence and include the Base Tertiary Unconformity, Polygonal Fault Marker, mid-Eocene Unconformity and younger reflectors. Reflectors older than Tertiary are of variable quality, due to intensive faulting and have no continuity over the entire area, illustrating geological complexity.

Seven interpreted, migrated seismic sections are included, to illustrate the main structural elements and tie the wells in the field. Their locations are shown on the seismic sections index map (Figure 2.2-8). The arbitrary seismic lines, well ties and corresponding figure numbers are summarized in Table 2.2-2.

Table 2.2-2 Seismic Lines, Tying Wells and Corresponding Figure Number

Seismic Line	Tying Wells	Figure Number
A – A’	A-17	Figure 2.2-9
B – B’	E-09	Figure 2.2-10
C – C’	J-49, N-30	Figure 2.2-11
D – D’	L-61, N-22	Figure 2.2-12
E – E’	L-61, N-30, H-20, A-90	Figure 2.2-13
F – F’	J-49	Figure 2.2-14
G – G’	A-17, L-08, E-09, H-20	Figure 2.2-15

The Base Tertiary Unconformity is generally a consistent, strong amplitude reflector caused by a high positive impedance contrast between the Mesozoic and overlying Tertiary layers. The Base Tertiary is defined as a maximum value of a peak on seismic displays. The quality of the reflector deteriorates in areas affected by faulting or channel incision where, an amplitude decrease is observed and the marker may change polarity.

The mid-Cenomanian Unconformity is a medium amplitude peak mimicking the Base Tertiary marker in places. This marker could not be regionally mapped (Figure 2.2-10) as it is unreliable in areas of structural complexity and is strongly affected by peg leg multiples.

The Top Avalon Formation reflector is a low amplitude peak mappable only in the eastern part of the White Rose survey. The marker is affected by multiples and has a rugose aspect. In highly faulted areas, the marker is low quality and very hard to follow (Figures 2.2-9 to 2.2-15).

Figure 2.2–4 White Rose Complex – Base Tertiary Unconformity Time Structure

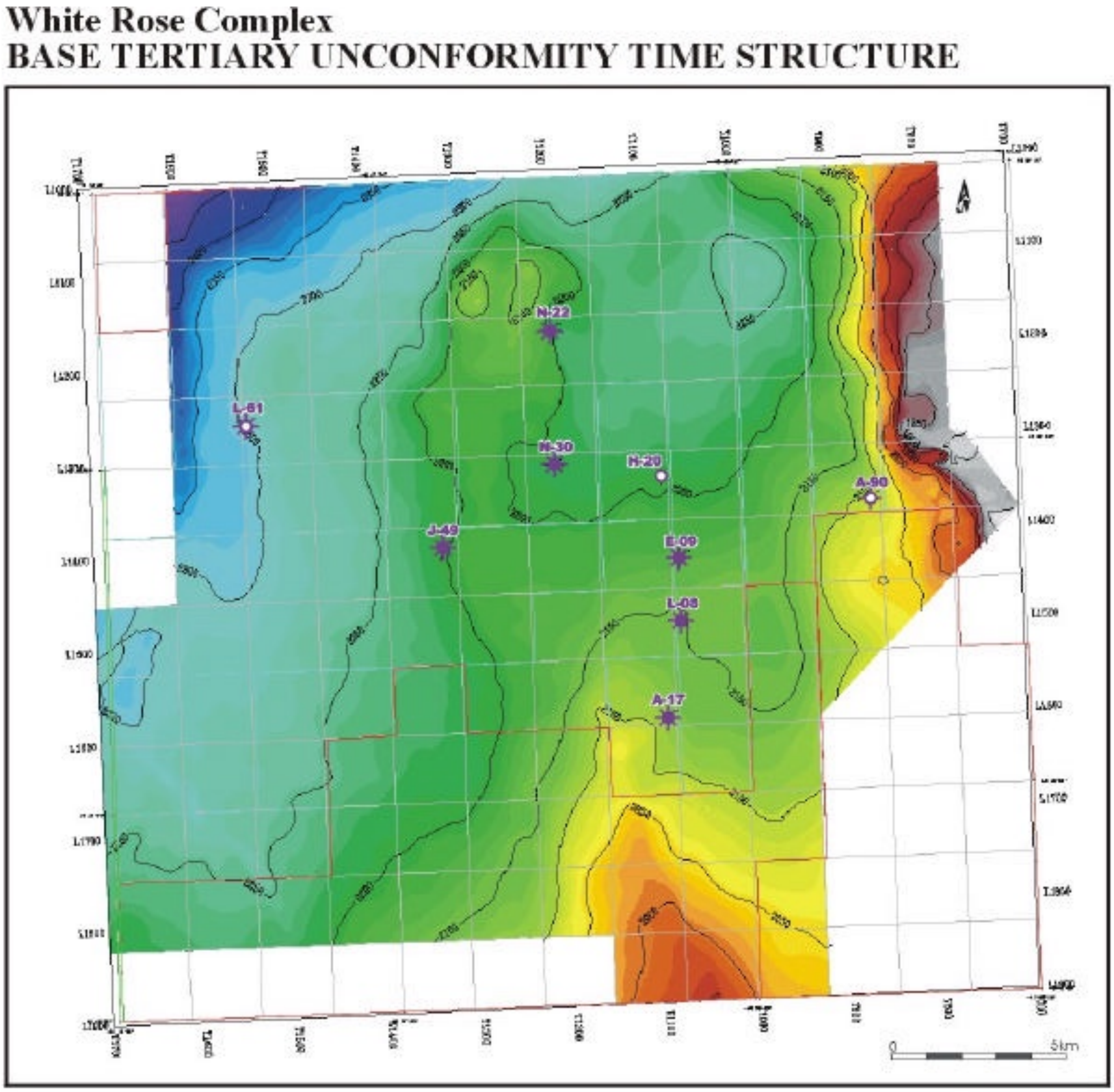


Figure 2.2-4

Figure 2.2–5 White Rose Complex – Regional Composite Marker Time Structure

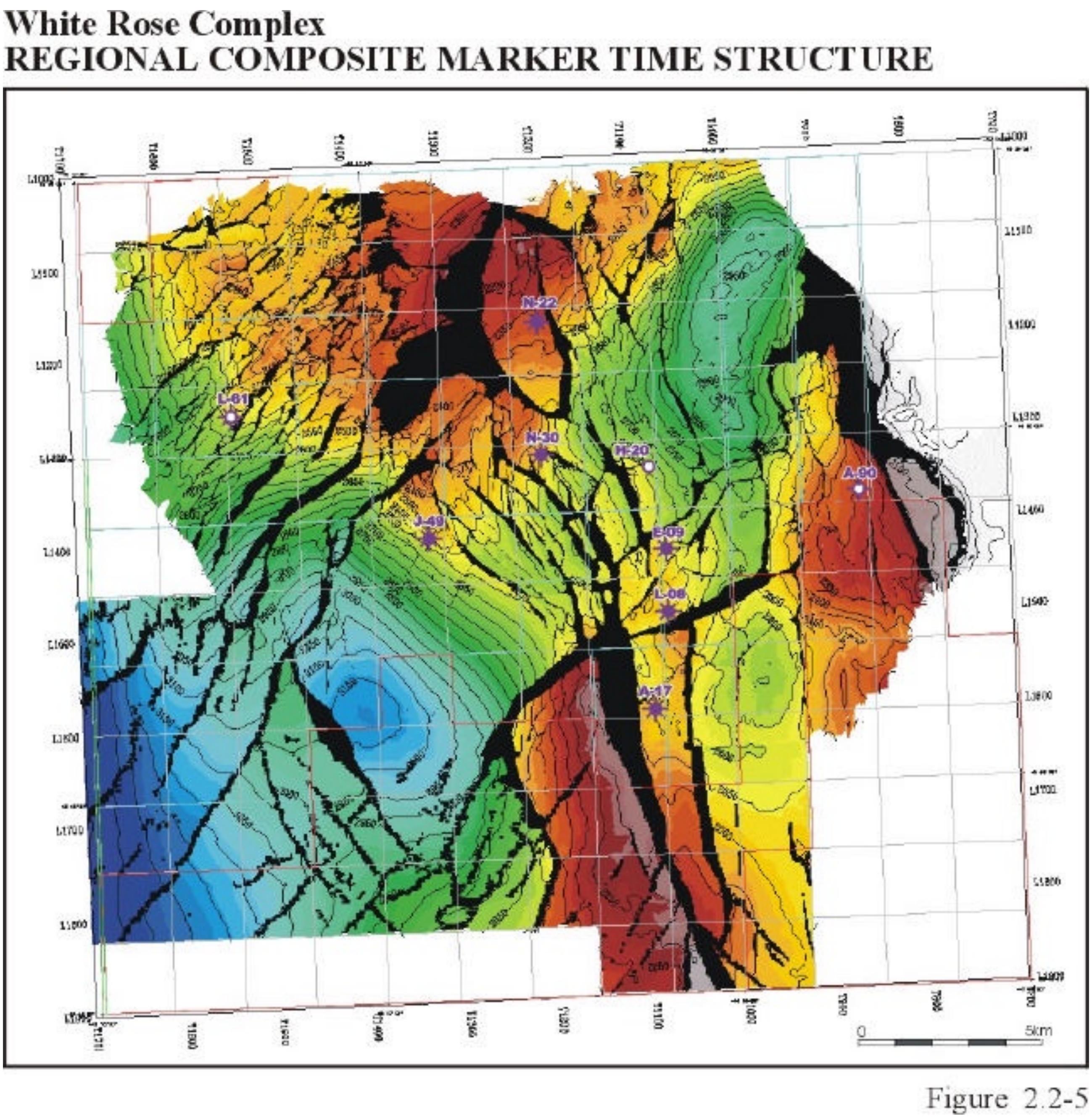


Figure 2.2–6 White Rose Complex – Mid-Kimmeridgian Unc. Time Structure

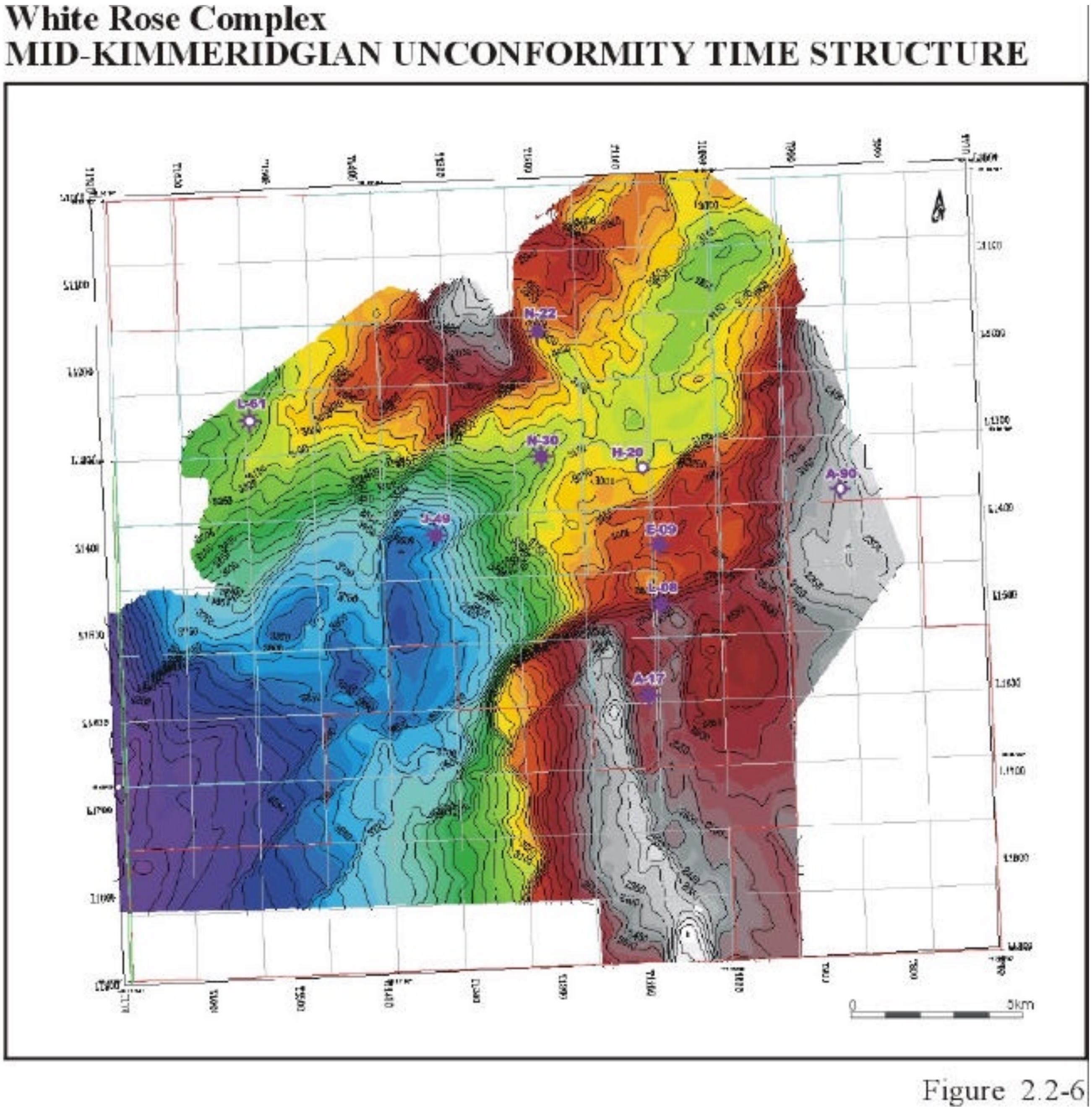


Figure 2.2–7 South Avalon Pool – Top Avalon Formation Time Structure

South Avalon Pool
TOP AVALON FORMATION TIME STRUCTURE
(Eastern part of PGS 97 survey)

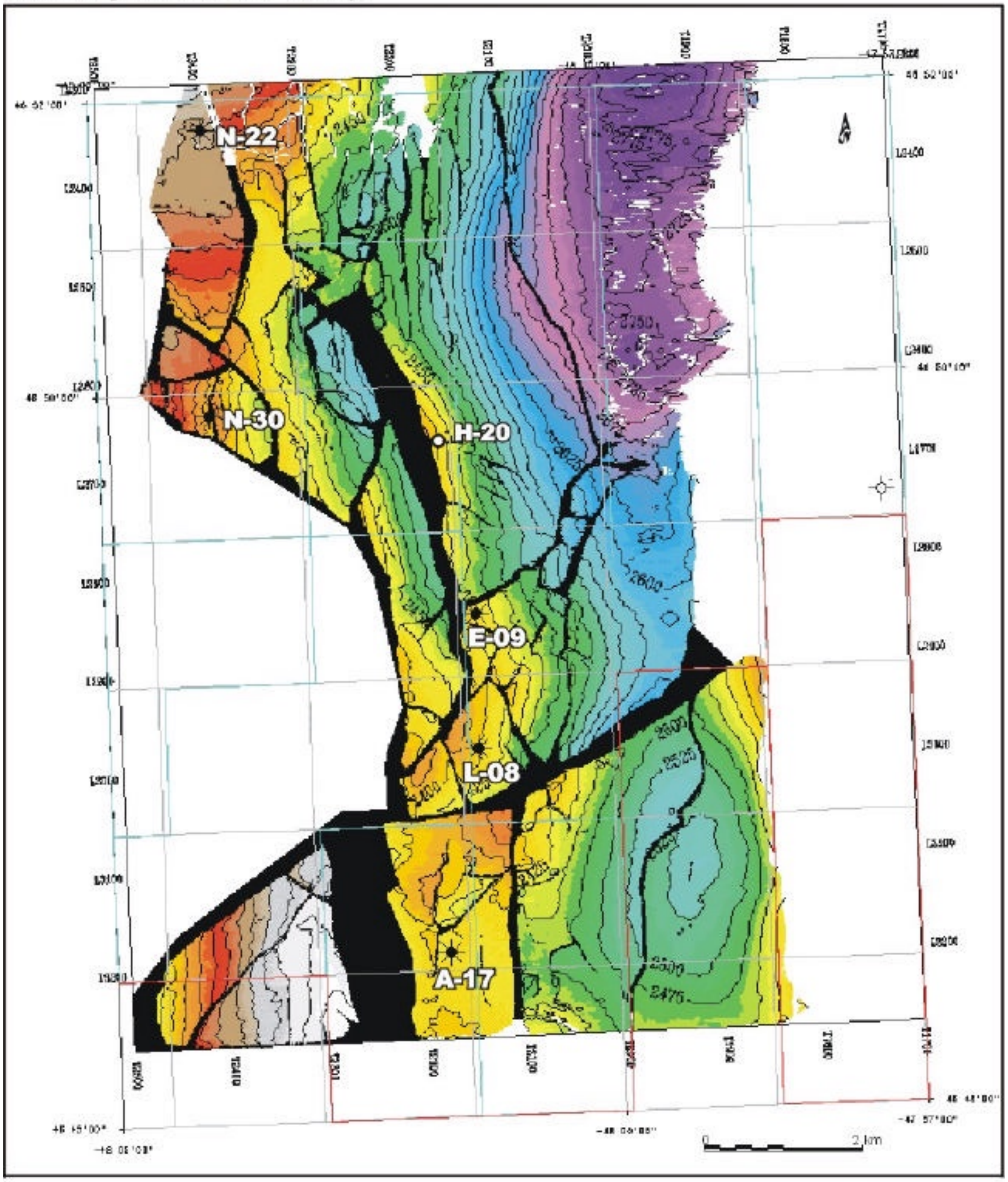


Figure 2.2-7

Figure 2.2–8 Seismic Sections – Index Map

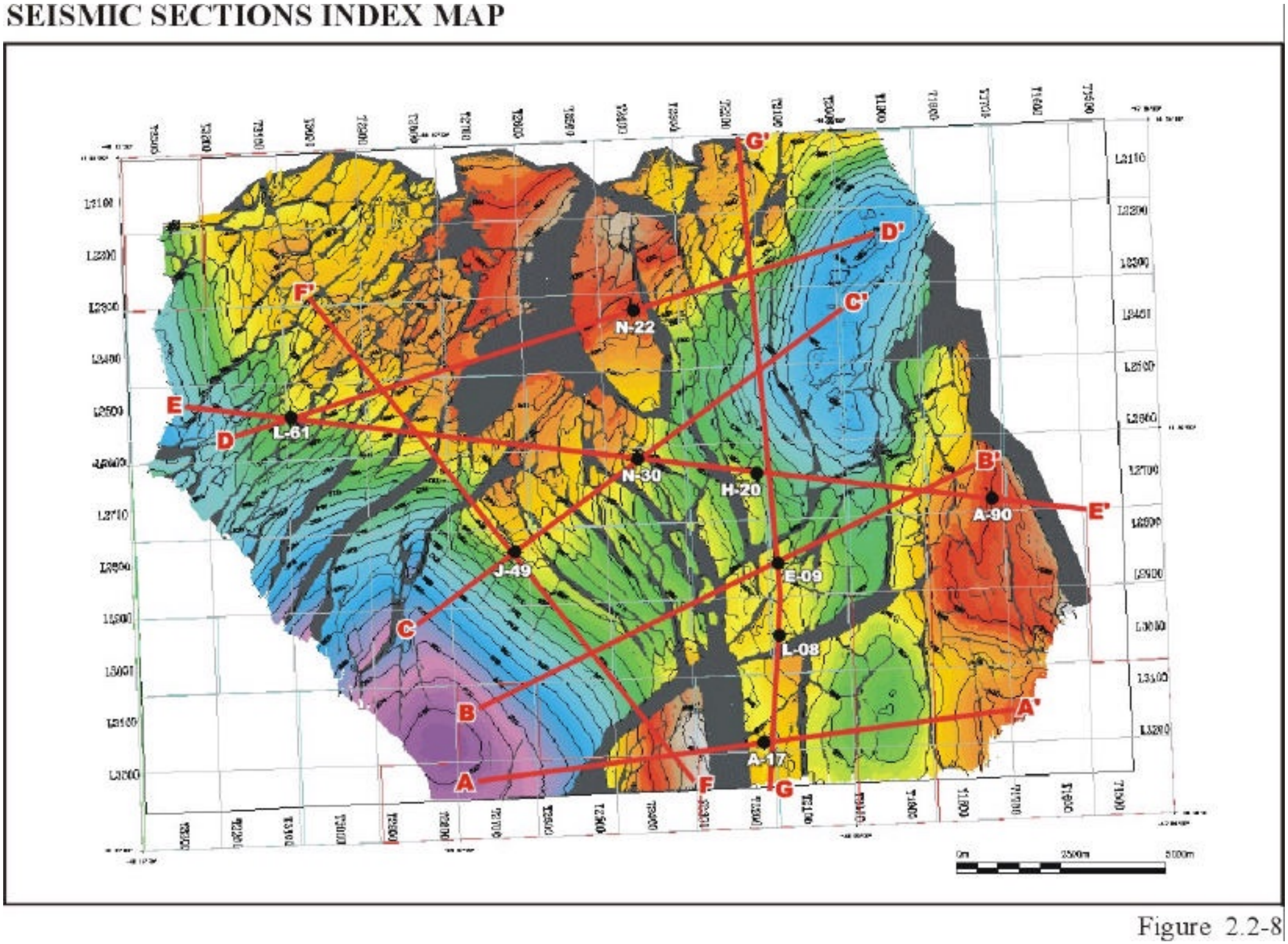


Figure 2.2-8

Figure 2.2–9 Interpreted Seismic Section Through Amethyst Ridge and A-17

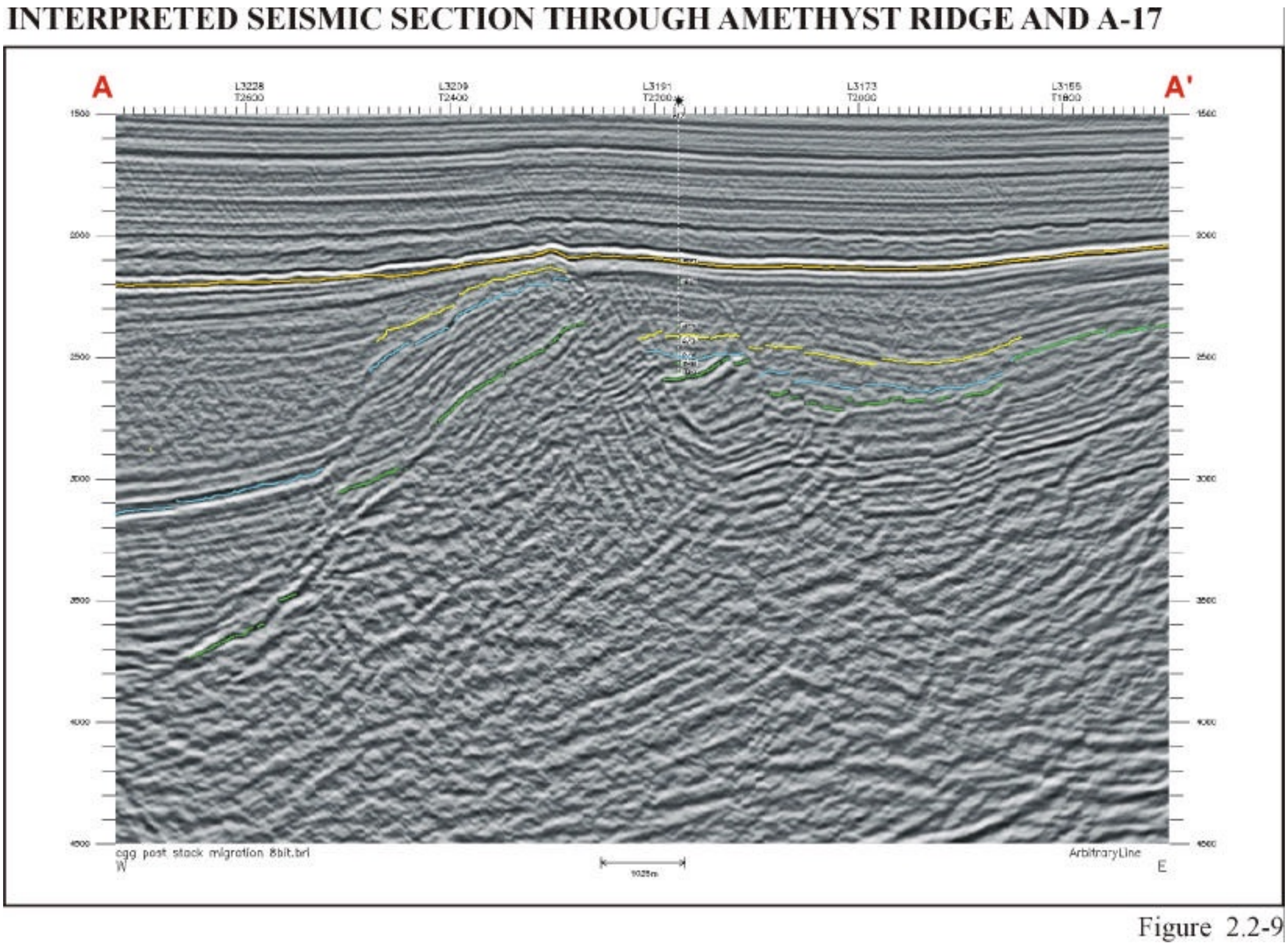


Figure 2.2–10 Interpreted Seismic Section Through E-09 in Dip Direction

INTERPRETED SEISMIC SECTION THROUGH E-09 IN DIP DIRECTION

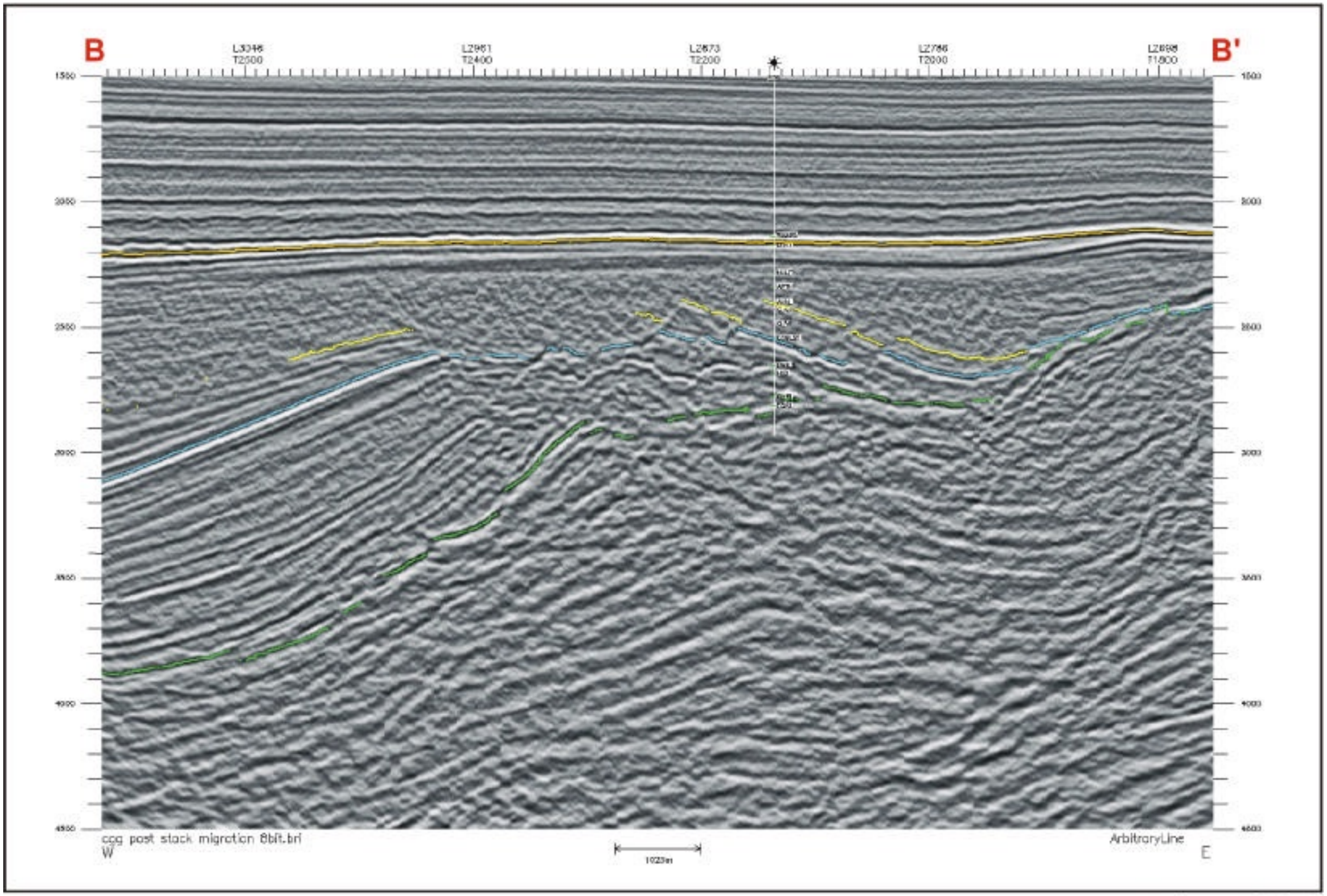


Figure 2.2-10

Figure 2.2–11 Interpreted Seismic Section Through J-49 and N-30

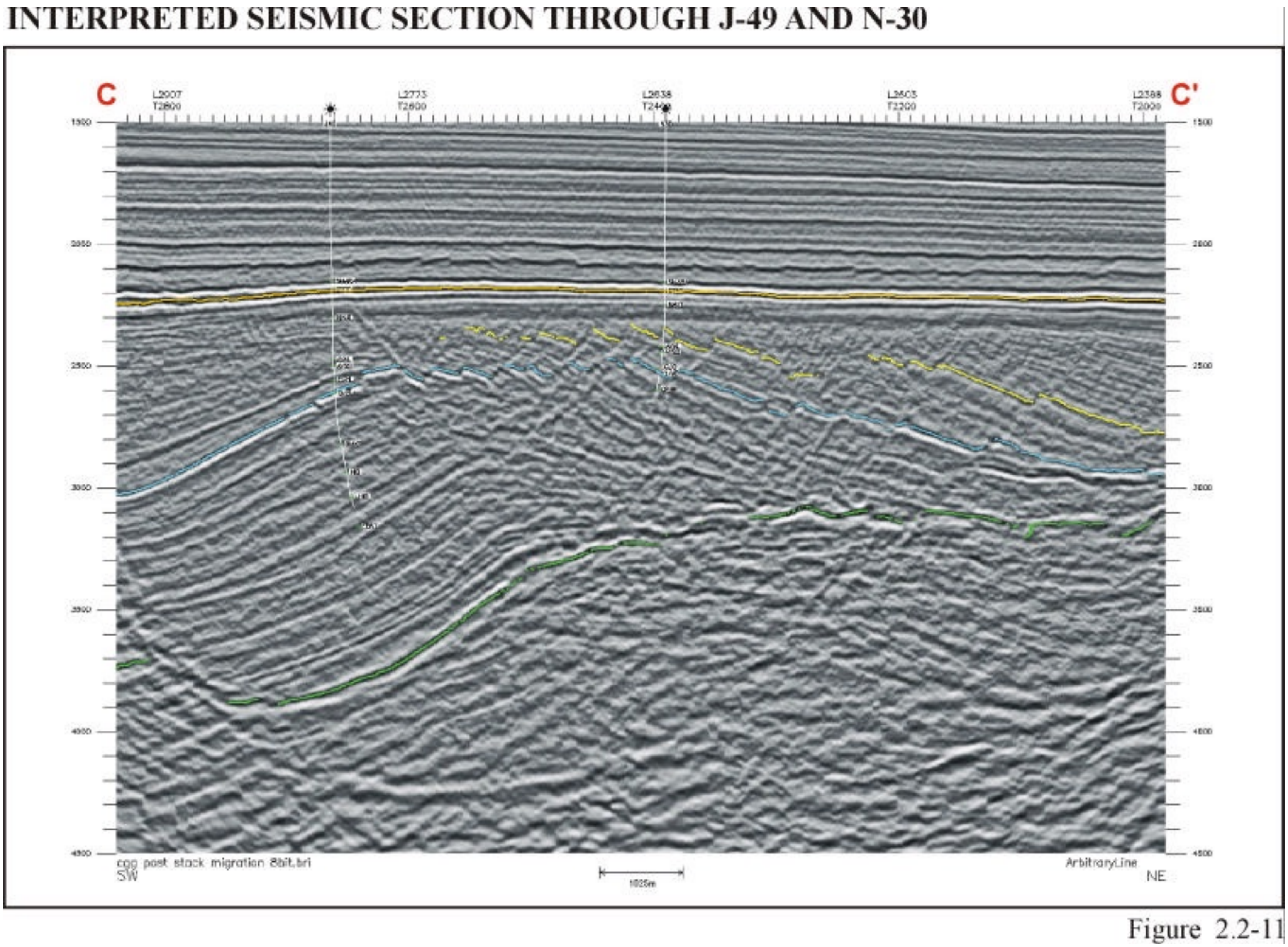


Figure 2.2–12 Interpreted Seismic Section Through L-61 and N-22

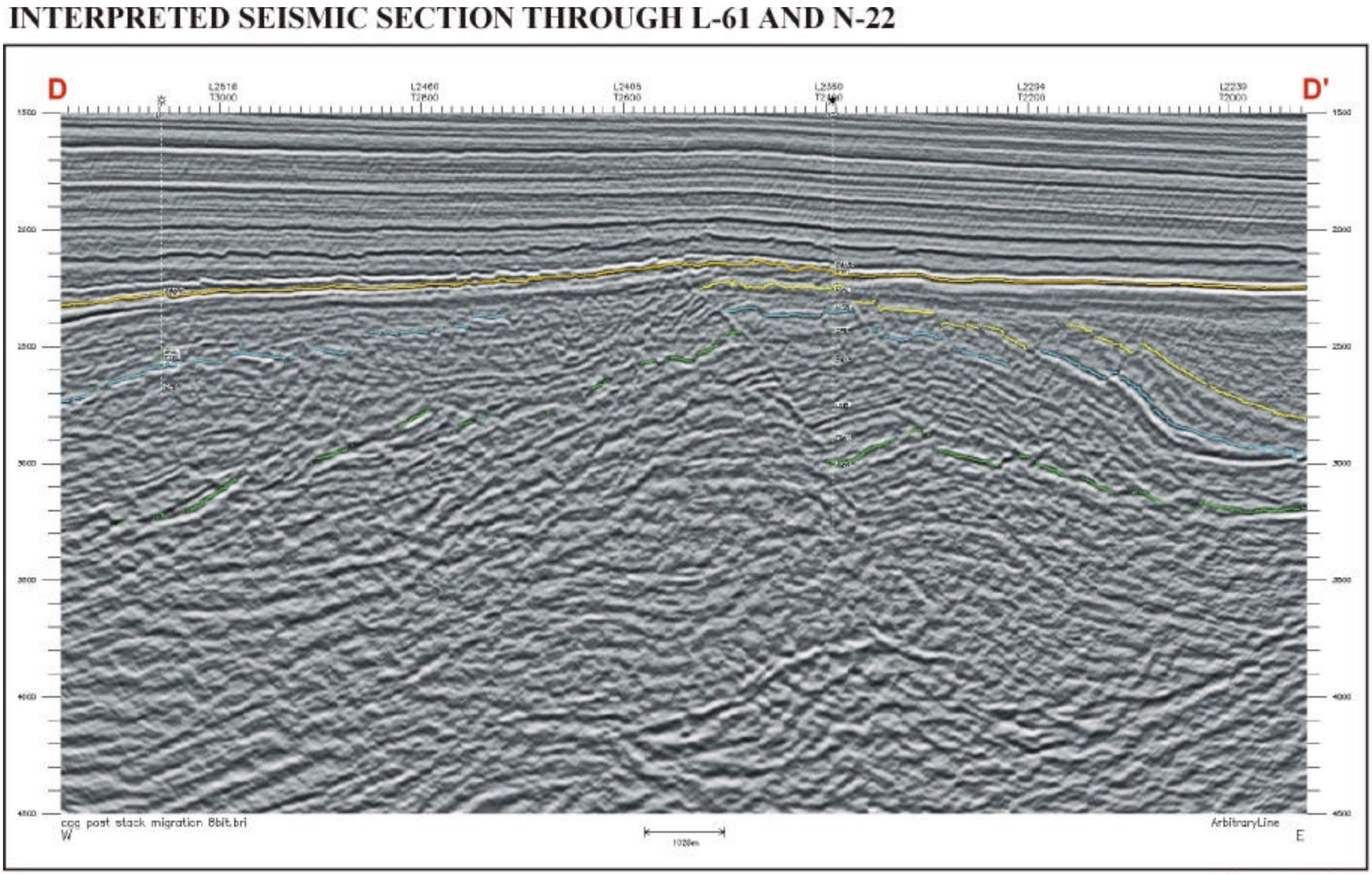


Figure 2.2-12

Figure 2.2–13 Interpreted Seismic Section Through L-61, N-30, H-20 and A-90

INTERPRETED SEISMIC SECTION THROUGH L-61, N-30, H-20 AND A-90

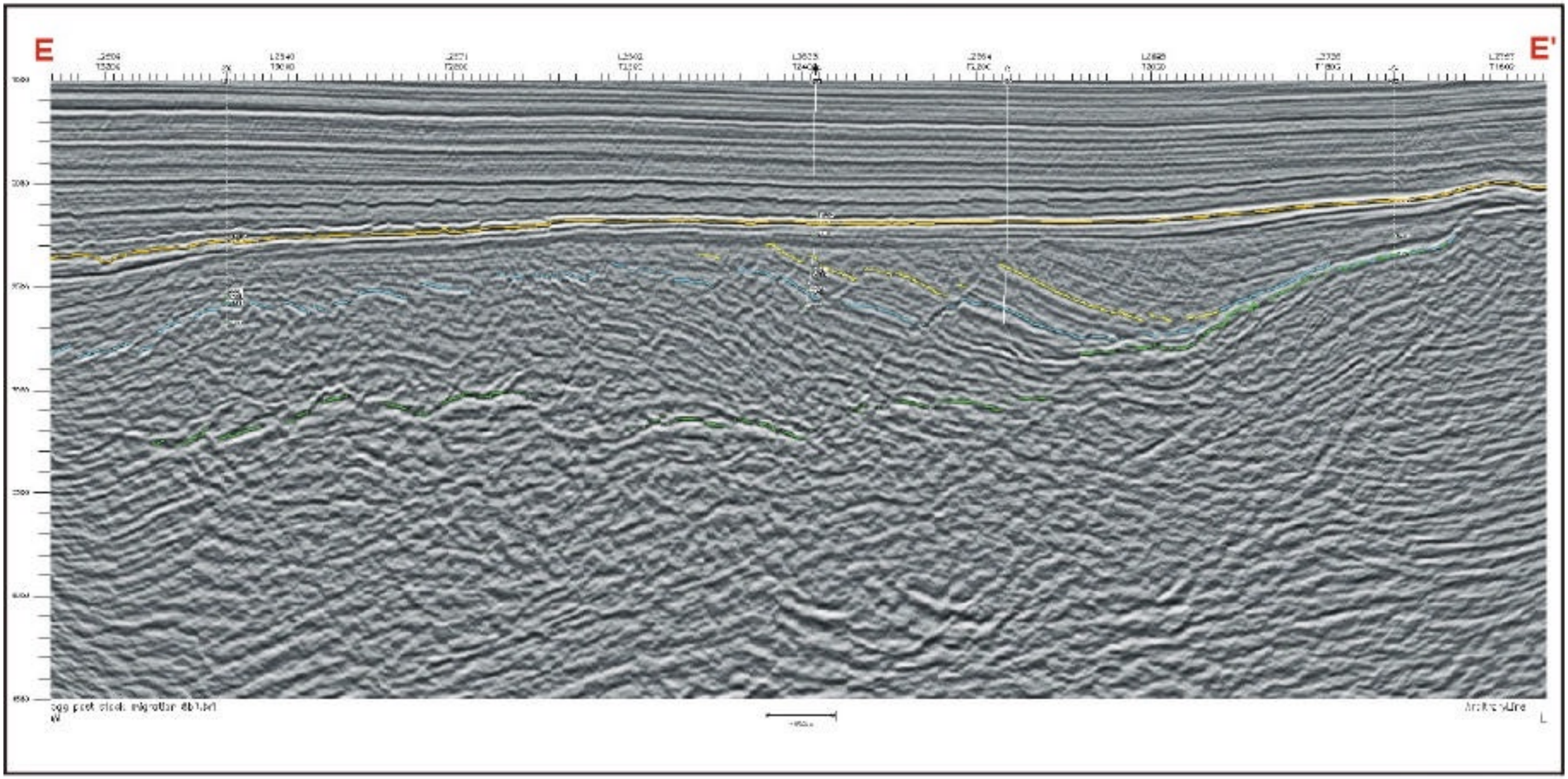


Figure 2.2-13

Figure 2.2–14 Interpreted Seismic Section Through Amethyst Ridge and J-49

INTERPRETED SEISMIC SECTION THROUGH AMETHYST RIDGE AND J-49

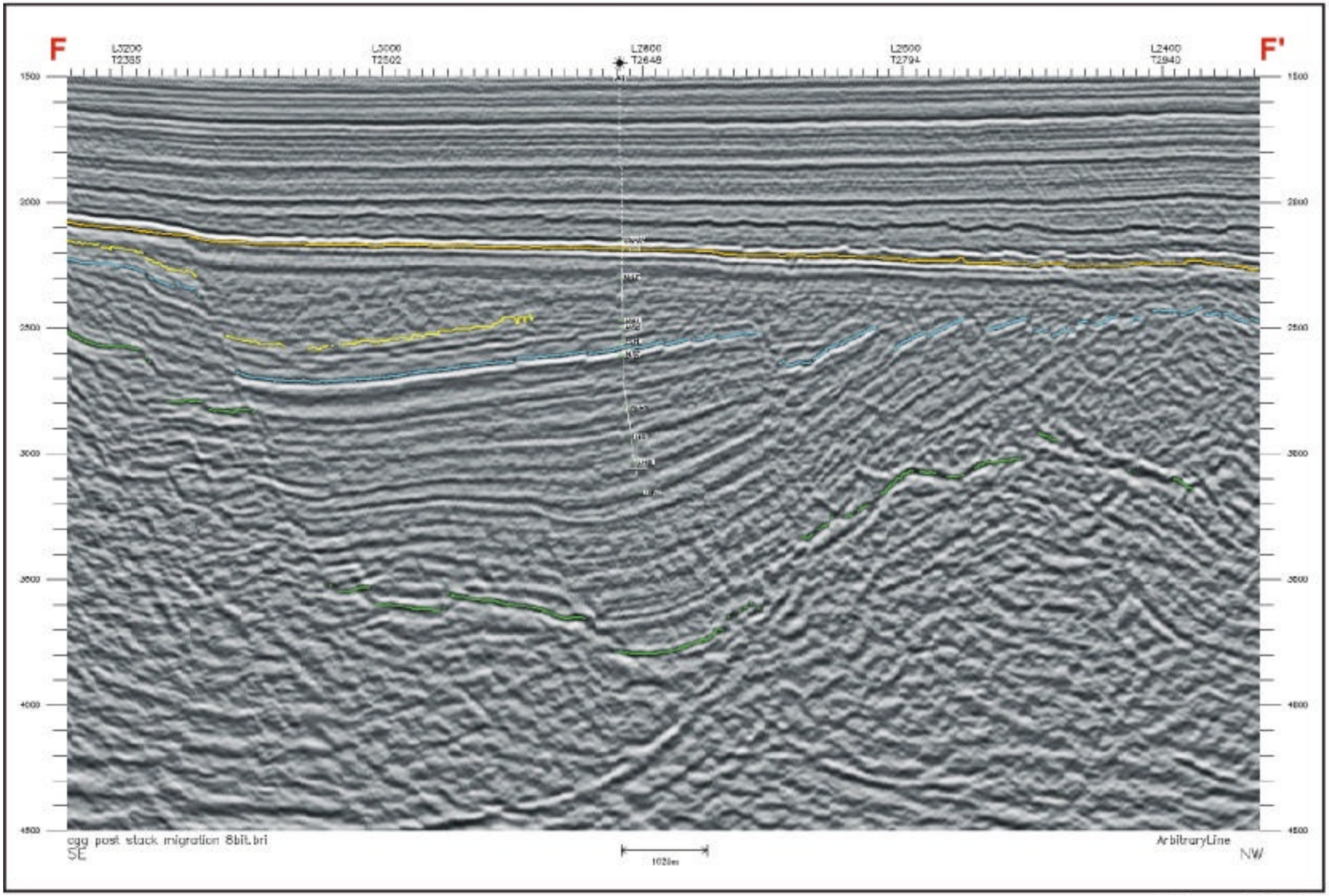
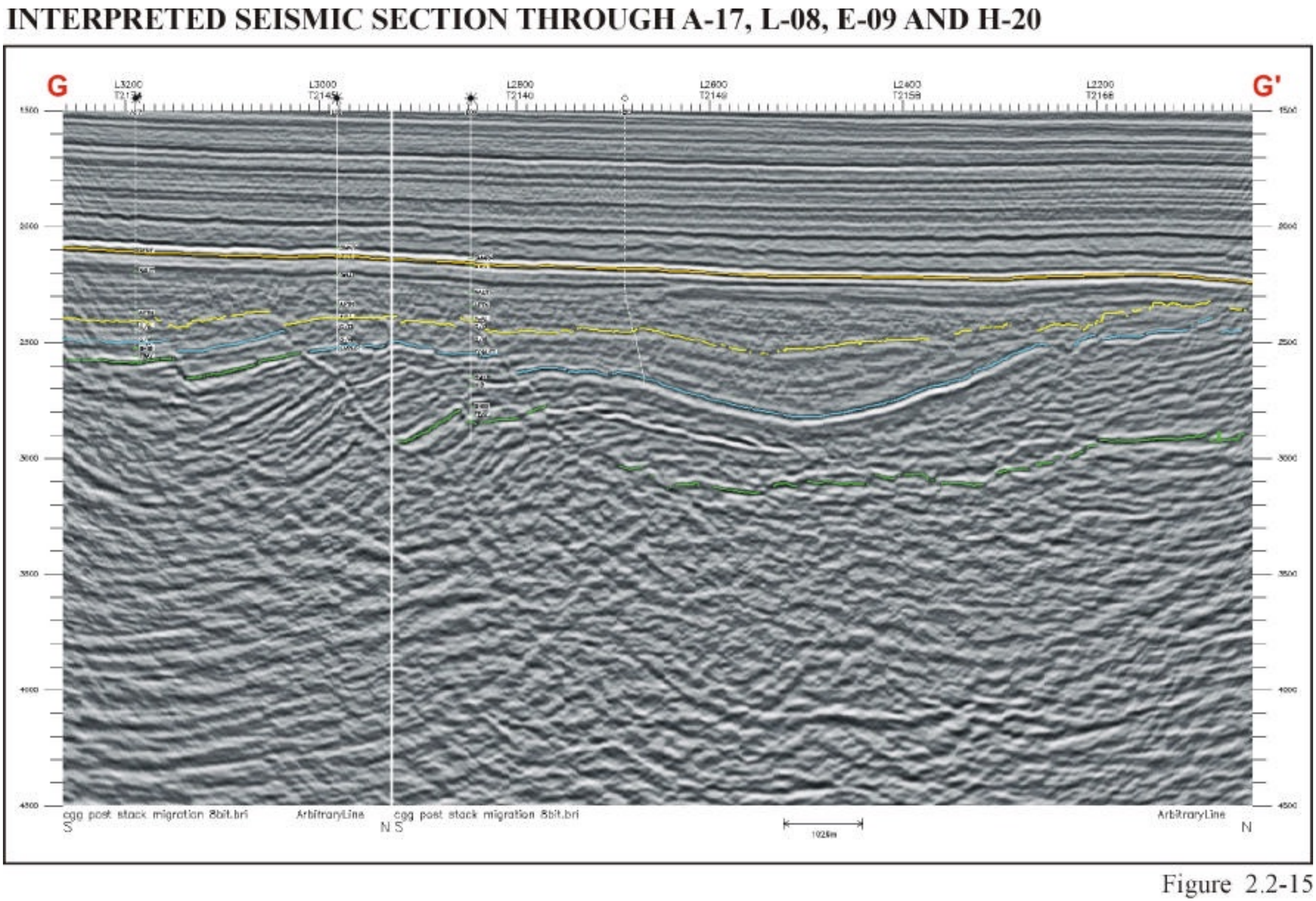


Figure 2.2-14

Figure 2.2–15 Interpreted Seismic Section Through A-17, L-08, E-09 and H-20



The Base of Avalon Formation is a highly variable marker and represents the interface between the Avalon and different age lithostratigraphic members. A composite marker represents the Base of Avalon over the eastern part of the survey (Figures 2.2-9 to 2.2-15).

The Composite Marker is a seismically complex event that was regionally mapped to describe the structural framework of the White Rose Complex. No extensional stage seismic marker is continuous over the entire White Rose area to allow consistent structural time mapping. Instead, a complex depositional (in the west)/erosional (in the east) seismic horizon was interpreted. This marker corresponds to the A Marker in the west and Base Avalon Reservoir in the central area. The mid-Kimmeridgian Unconformity and Base Tertiary Unconformity markers were mapped in the eastern portion of the White Rose area (Figure 2.2-5 and Figures 2.2-9 to 2.2-15). The marker is in general a medium to high reflectivity peak, but it may change to low amplitude or even change polarity as it truncates layers of different age and composition.

The A Marker gives a strong amplitude peak/trough/peak seismic event that can be easily followed in the western and central parts of the survey but deteriorates drastically on the flank of the White Rose Diapir. The A Marker ties perfectly at the first strong peak. The marker disappears on the crest of the White Rose Diapir and east of the West Amethyst-Central Fault lineament, where it has been eroded (Figures 2.2-9 to 2.2-15).

The B Marker is a local seismic peak of variable amplitude. Over the western part of the White Rose Complex, the B Marker is an unusually weak seismic reflector. The reflector is hardly recognizable in the central collapse area between J-49 and N-30 wells and becomes the typical strong amplitude marker in the E-09/L-08 block (Figures 2.2-9 to 2.2-15).

The mid-Kimmeridgian Unconformity (equivalent to Top of the Rankin Formation) is an overall strong amplitude peak over the entire PGS survey, but has less character in the Breton survey. As it is intensely affected by faults and influenced by intersecting faults at shallower levels, the marker may be difficult to follow in places. These seismic imaging problems are overcome by mapping local dip lines and correlating multiple loops.

The Top of Salt is hard to image at depth under highly tectonized overburden and can be only phantomed under the Amethyst Ridge and White Rose Diapir. Seismic basement is not imaged in the survey area. However, high velocity, non-prospective, indurated sedimentary sequences are recorded in the A-90 block, under the Central Ridge and White Rose Diapir sections of the survey.

2.2.3.3 Structural Maps

The following time-structure maps have been generated (Figures 2.2-4 to 2.2-7):

- Base Tertiary Unconformity time-structure;
- Top Avalon Formation time-structure (eastern part of the PGS 97 survey);
- Composite Marker time-structure; and
- Mid-Kimmeridgian Unconformity (Top of Rankin Formation) time-structure.

Using a depth conversion method simply describe below, the following depth structural maps have been created (Figures 2.2-16 to 2.2-19):

- Base Tertiary Unconformity depth-structure;
- Top Avalon Formation depth-structure (eastern part of the PGS 97 survey);
- Composite Marker depth-structure; and
- Mid-Kimmeridgian Unconformity depth-structure.

2.2.3.4 Isopach Maps

Using the same depth conversion algorithm, the following isopach maps were created (Figures 2.2-20 to 2.2-22):

- Composite Marker to Base Tertiary Unconformity;
- Avalon Formation (eastern part of the PGS 97 survey); and
- Mid-Kimmeridgian Unconformity to Composite Marker.

To illustrate fault complexity and correlate with a time structural interpretation, a Peneplain Continuity map of the Composite Marker was constructed (Figure 2.2-23).

2.2.3.5 Time-to-Depth Conversion

The White Rose regional depth conversion used a series of average velocity fields for the Base Tertiary Unconformity, the regional Composite Marker and the mid-Kimmeridgian Unconformity (Figures 2.2-16, 2.2-18 and 2.2-19). The Top Avalon surface was depth converted using the Composite Marker and the well control within the South Avalon Pool. (Figure 2.2-17 and 2.2-21). A total of 12 wells were correlated with the geophysical interpretation with additional detail analysis over the South Avalon Pool using the older check shot surveys at E-09 and the three VSP acquired in 1999 (L-08, A-17 and N-30).

Figure 2.2–16 White Rose Complex – Base Tertiary Unconformity Depth Structure

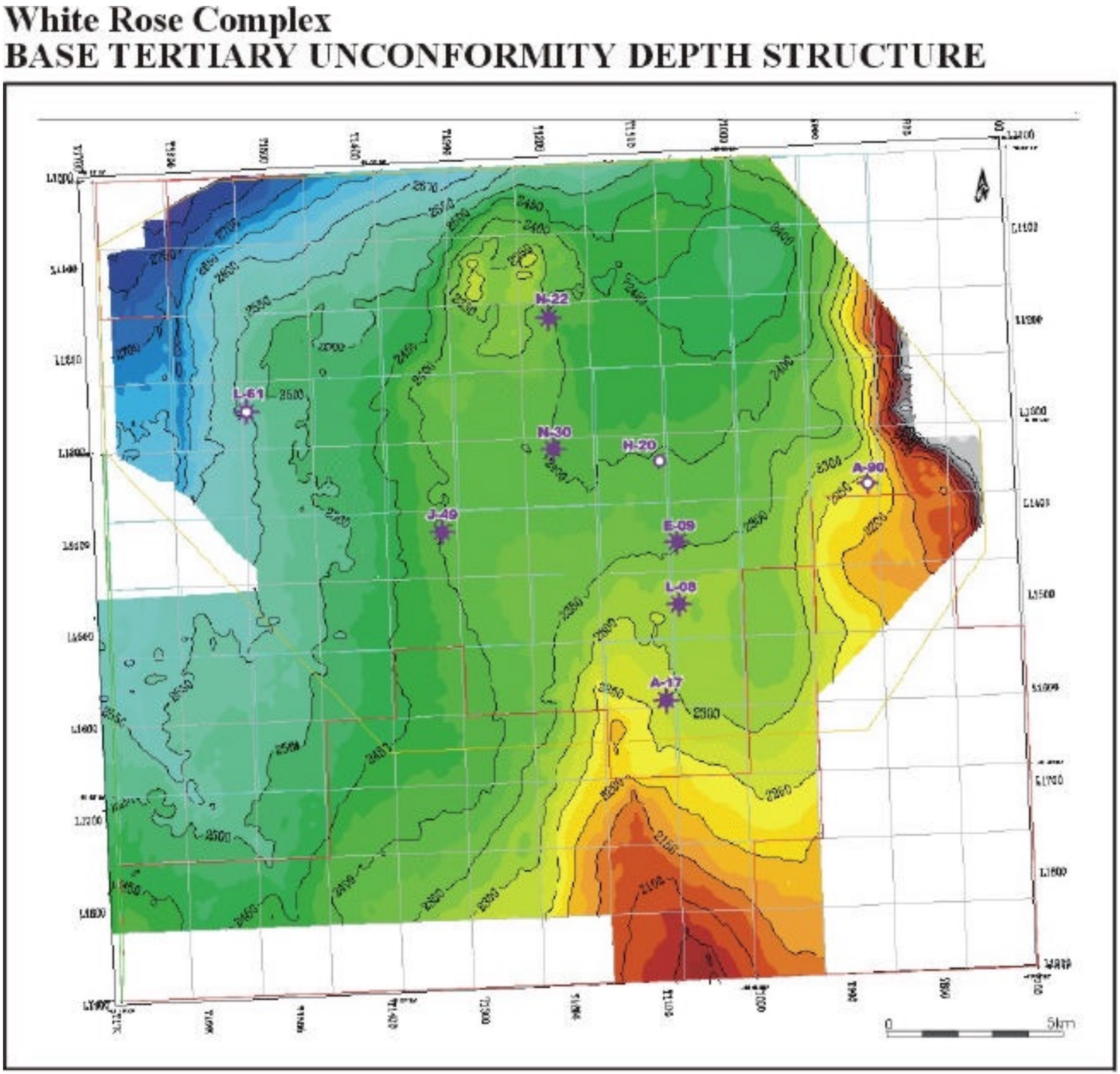


Figure 2.2-16

Figure 2.2–17 South Avalon Pool Top Avalon Formation Depth Structure

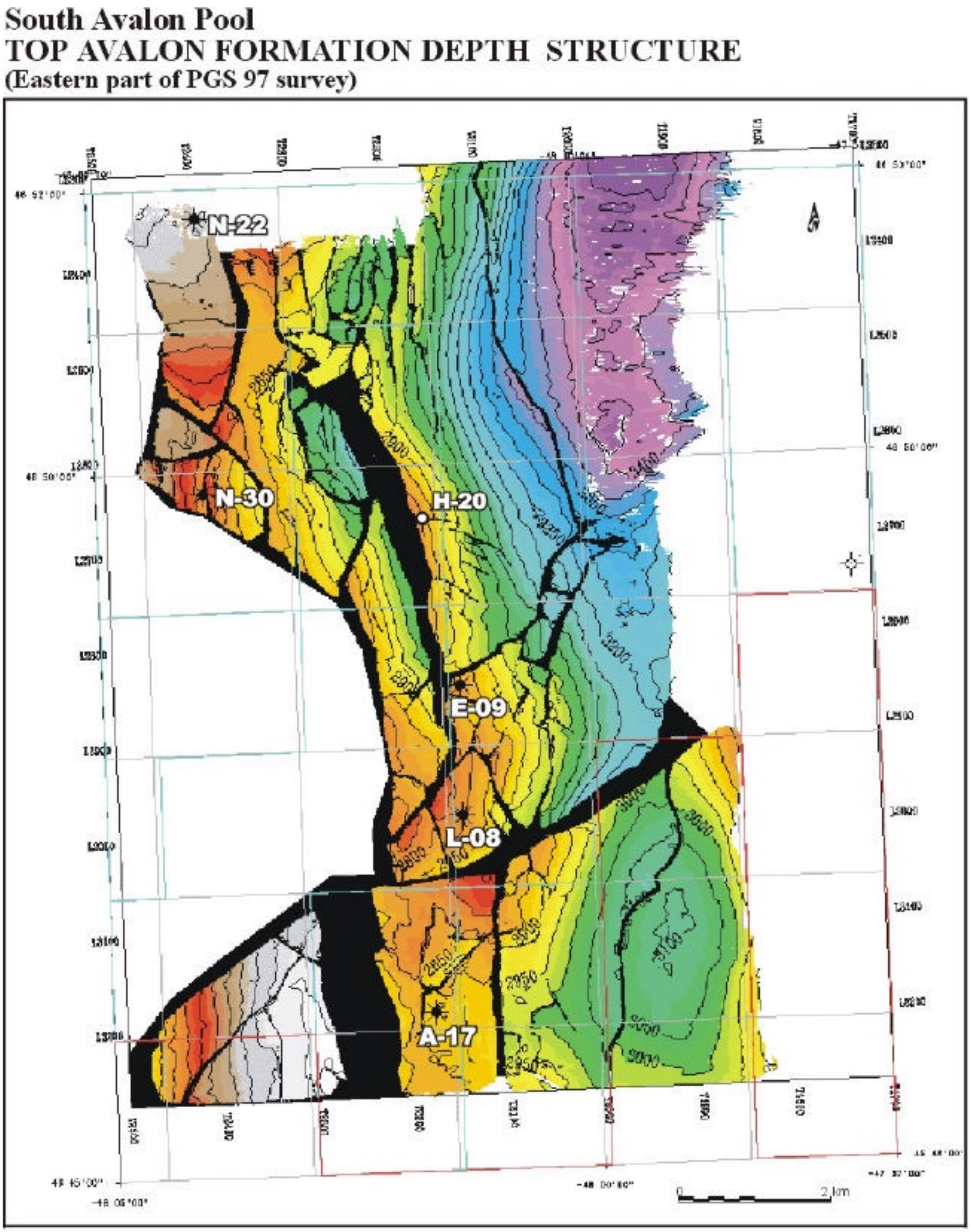


Figure 2.2-17

Figure 2.2–18 White Rose Complex Composite Marker Depth Structure

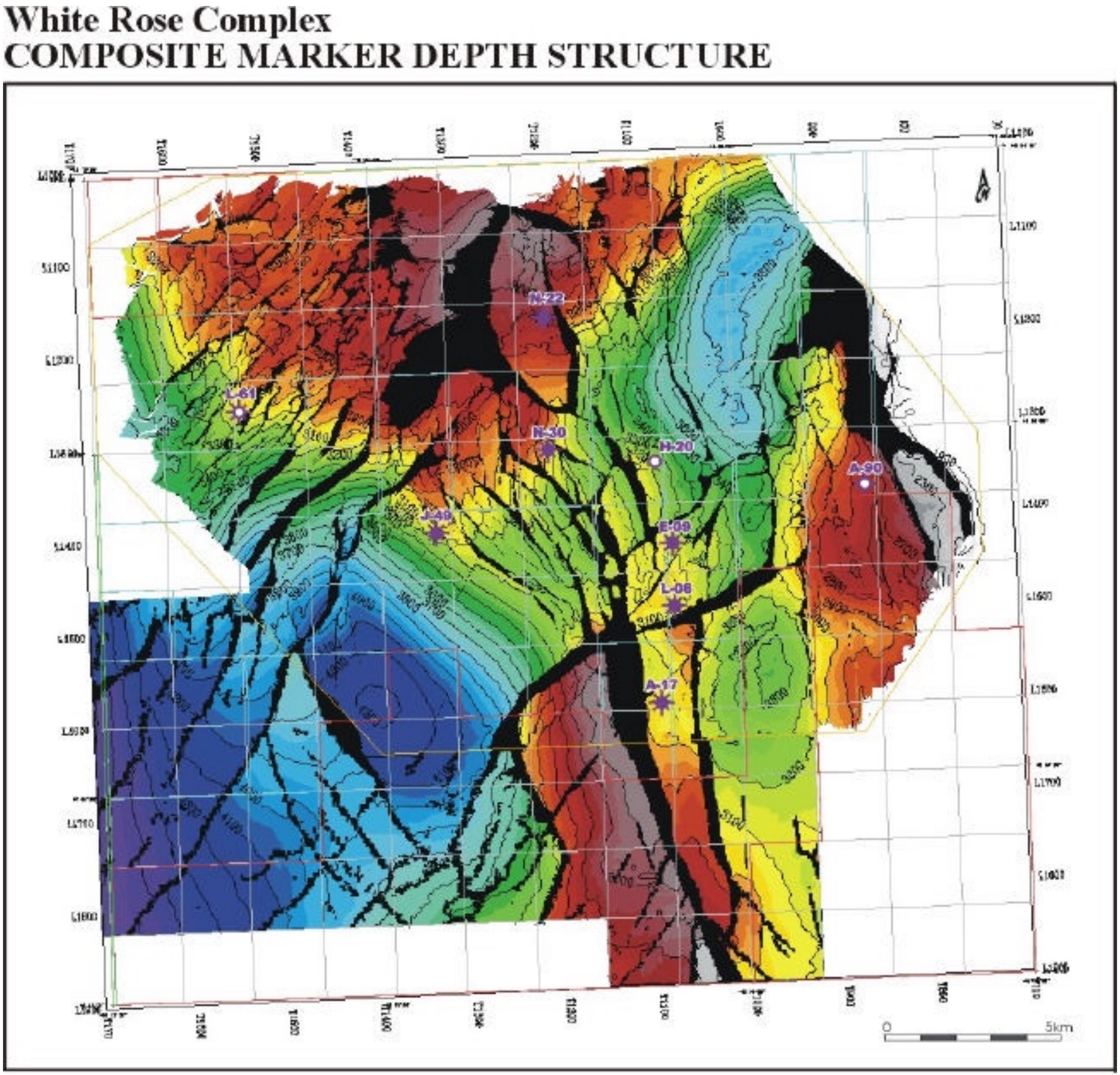


Figure 2.2-18

Figure 2.2–19 White Rose Complex Mid-Kimmeridgian Unconformity Depth Structure

White Rose Complex
MID-KIMMERIDGIAN UNCONFORMITY DEPTH STRUCTURE

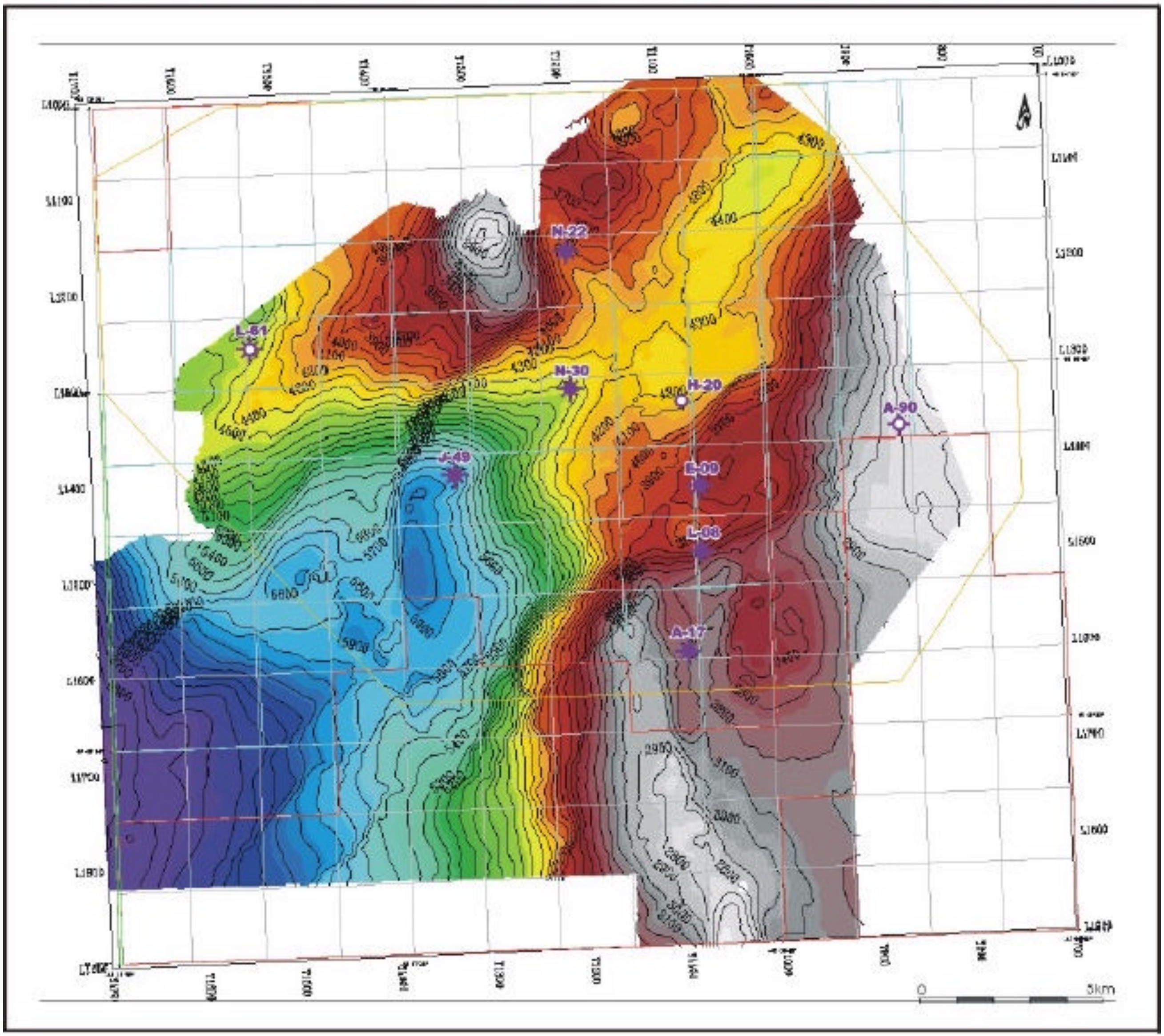


Figure 2.2-19

Figure 2.2–20 White Rose Complex Composite Marker to Base Tertiary Unconformity Isopach

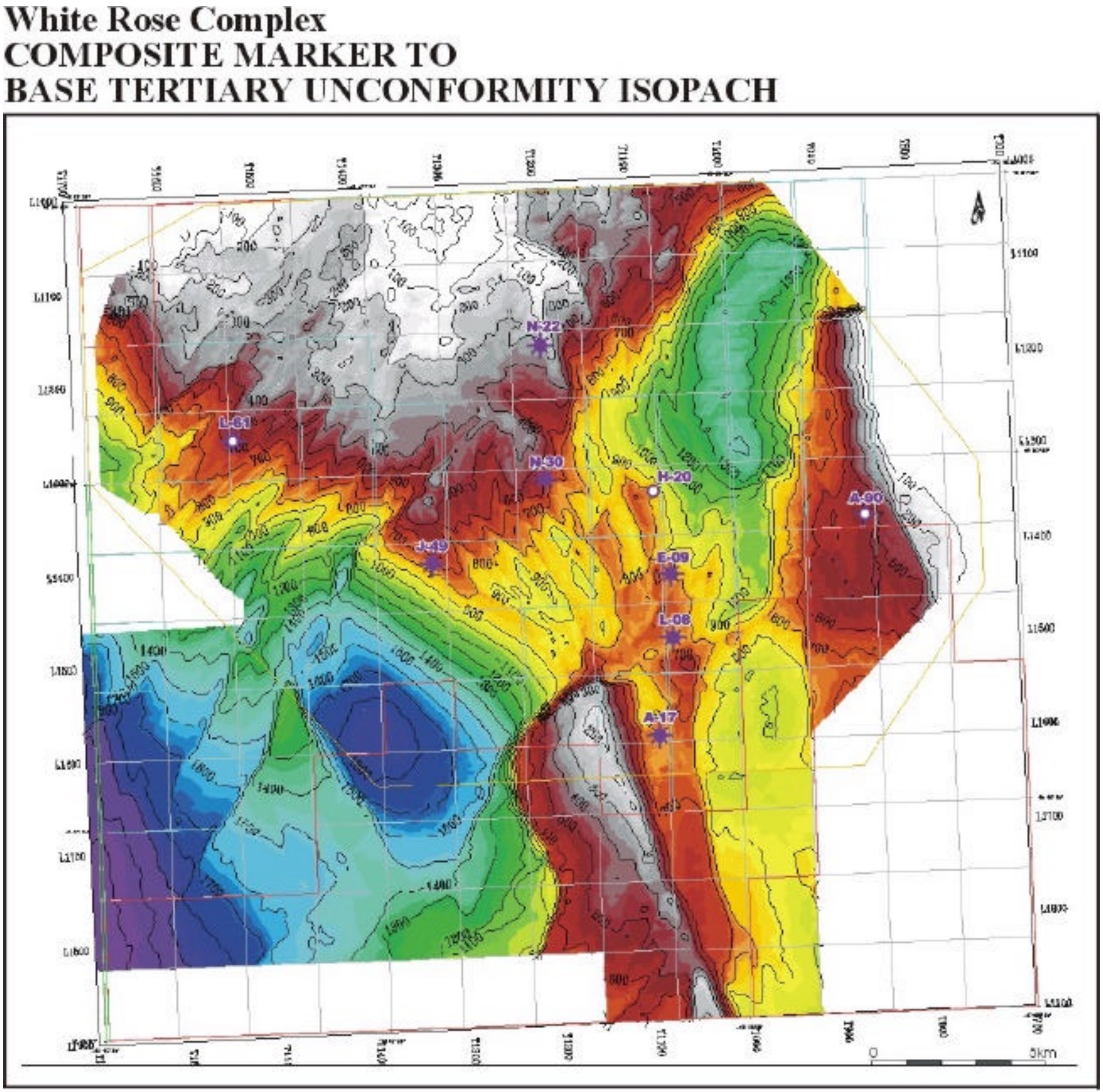


Figure 2.2-20

Figure 2.2–21 South Avalon Pool Avalon Formation Isopach

South Avalon Pool
AVALON FORMATION ISOPACH
(Eastern part of PGS 97 survey)

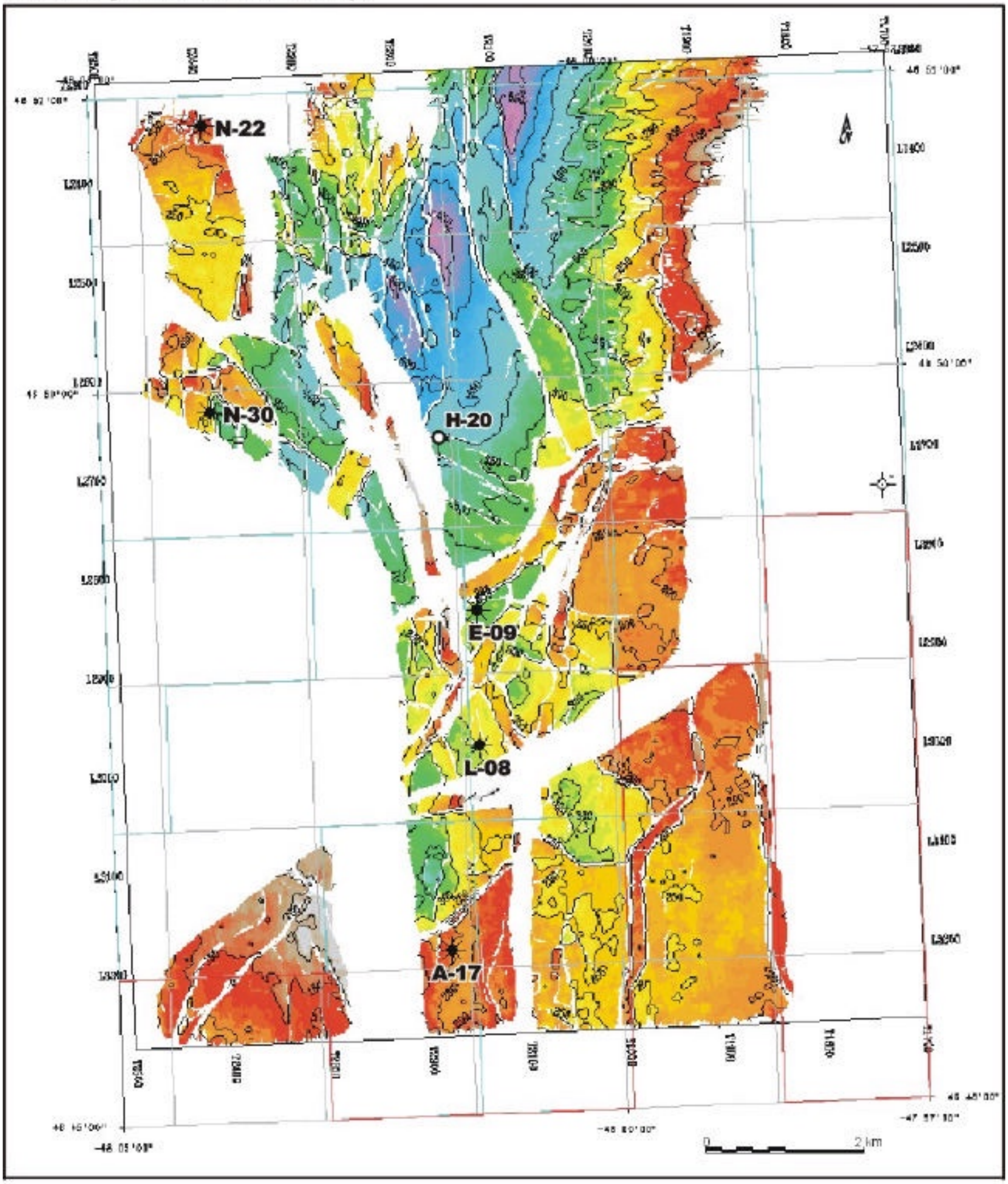


Figure 2.2-21

Figure 2.2–22 White Rose Complex Mid-Kimmeridgian Unconformity to Composite Marker Isopach

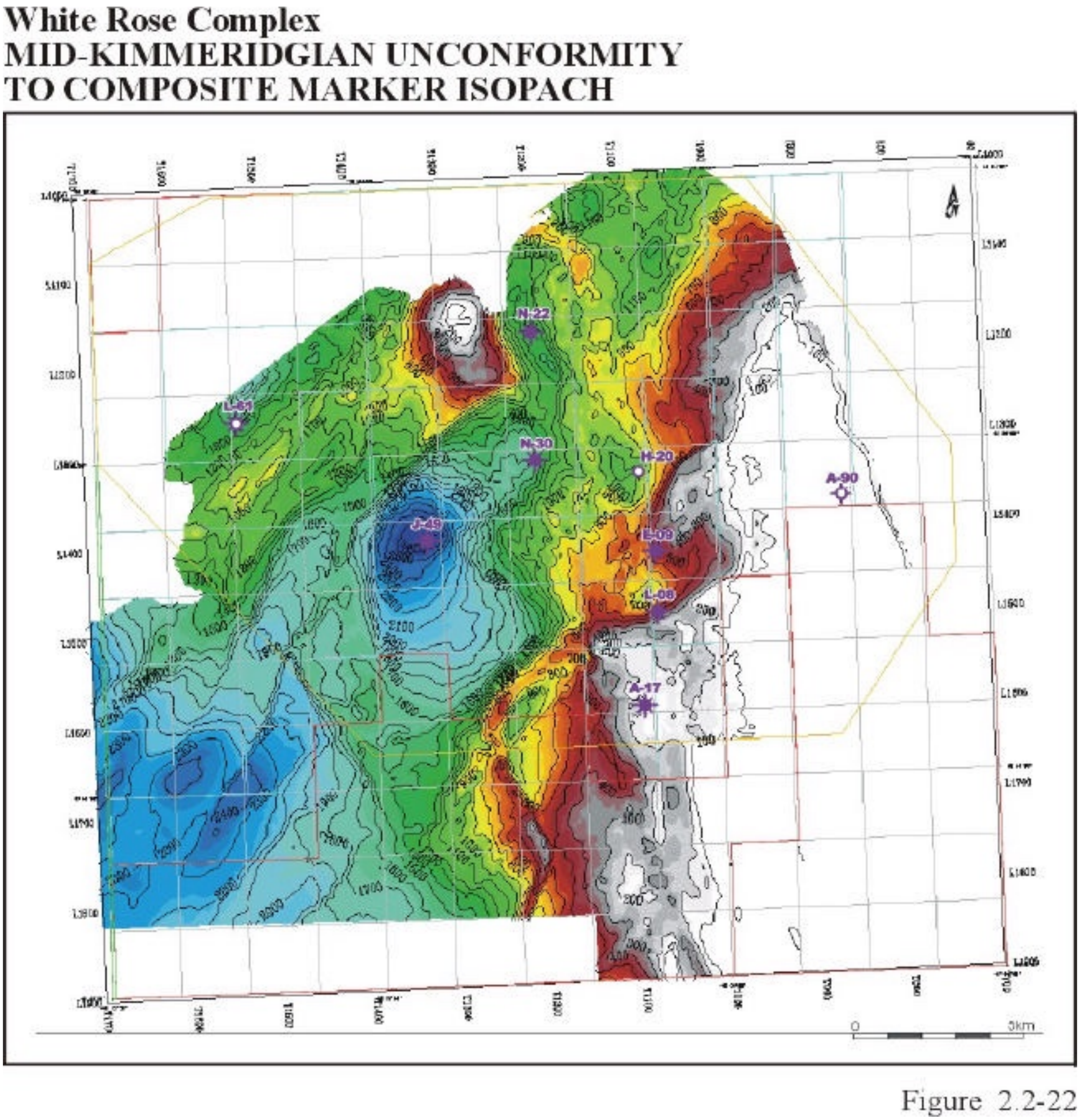
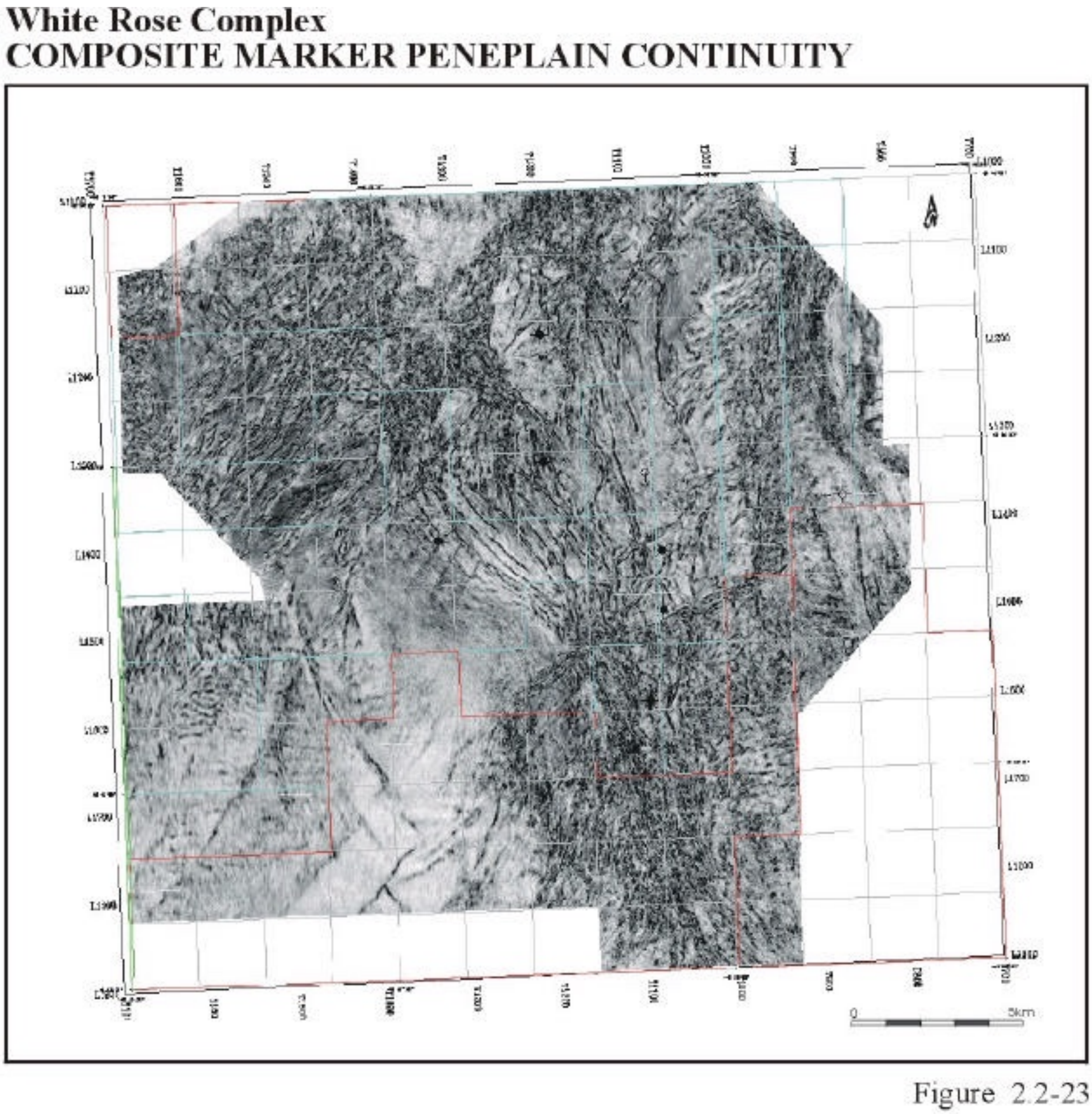


Figure 2.2–23 White Rose Complex Composite Marker Peneplain Continuity



The depth conversion for the Base Tertiary Unconformity corresponded to a linear relationship for the Tertiary sediments (Figure 2.2-16). The depth conversion for the Composite Marker reflected an Upper Cretaceous interval velocity of approximately 4,000 m/s (Figure 2.2-20). The deeper mid-Kimmeridgian Unconformity corresponded to a three-layered model with a Lower Cretaceous and Upper Jurassic interval velocity of 4,500 m/s (Figure 2.2-22). The final step in creating the depth surfaces was matching the geological tops with the geophysical horizons and distributing any residual mistie around the wells.

2.2.3.6 Shallow Hazards

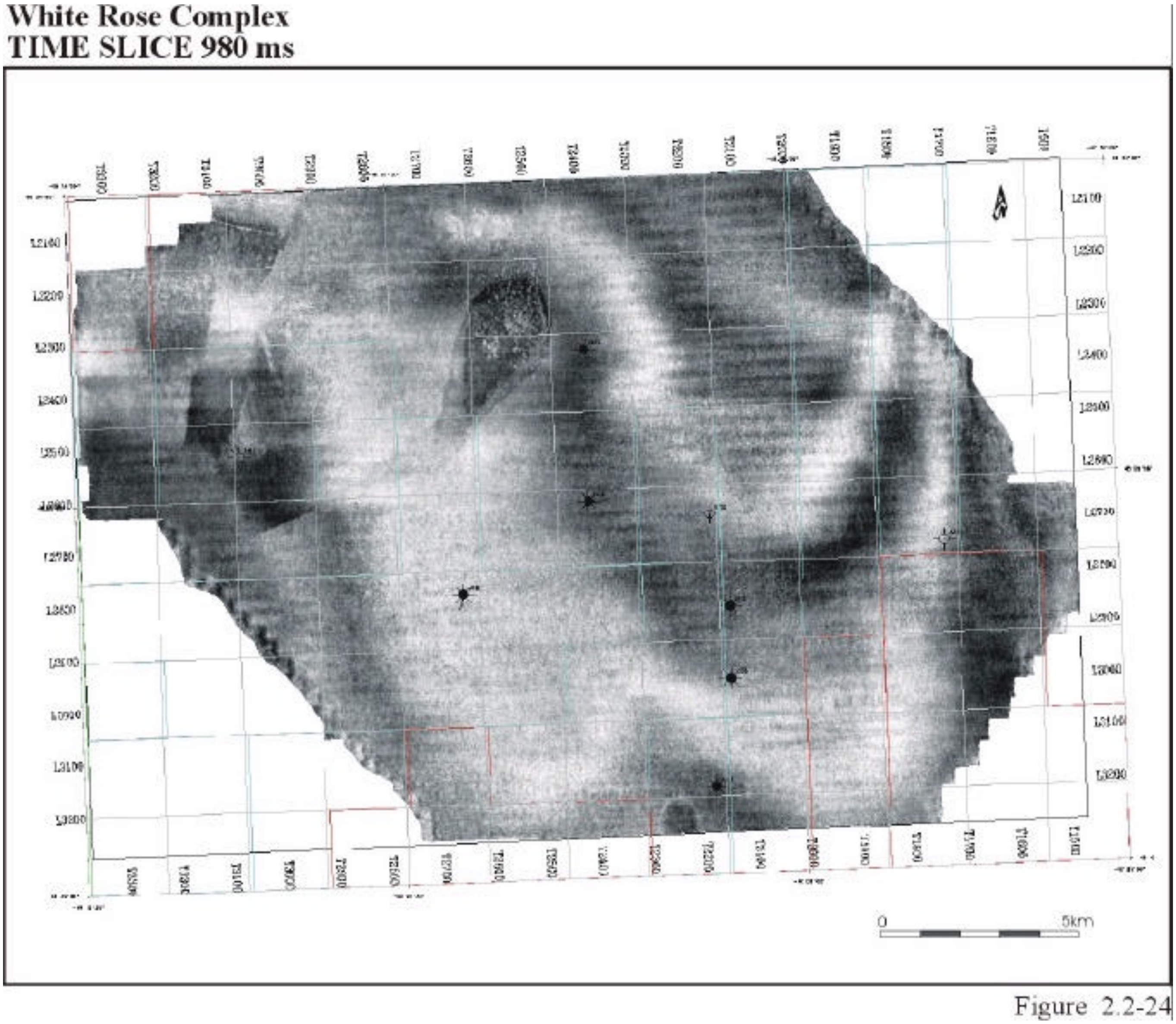
No significant shallow drilling hazards have been encountered over the White Rose Field during the drilling of eight exploratory and delineation wells. Hazards such as high-amplitude, shallow events were not identified during the inspection, studying and reporting on various 2-D and 3-D high-resolution geophysical data vintages. The only concern raised by the 1997 shallow 3-D reprocessed data is the presence of a gas chimney centred on the crest of the White Rose Diapir and that extends in a small area toward southwest (Figure 2.2-24). No delineation or development drilling is planned at this time on or near this area affected by gas contamination of low porosity sediments.

The White Rose Complex has been thoroughly studied concerning shallow drilling hazards and in particular the presence of shallow gas anomalies. The type of hazard studies includes high-resolution 2-D "sparker" seismic surveys, reprocessed exploration 3-D seismic for higher resolution and exploration 3-D seismic in different processing variants (Table 2.2-3). Interpretation of high-resolution seismic data was used for the planning of all the wells drilled in the White Rose Field. Side scan sonar has been acquired for well site planning to identify seabed features such as iceberg scours and gravel prone areas.

Table 2.2-3 Summary of Shallow Hazard Surveys in the White Rose Area

2-D Sparker Survey	Year	Recorder	Source	Gp Int	Shot Int	Rec Len	Filter	Process
Trave/White Rose C-NOPB #8626-M3-2E	1979	T1 24 CH DFS III	EG&G 9 tip sparker	16.6 m	16.6 m	2 sec @ 1 ms	27-248 Hz	GSI
Archer Flank C-NOPB #8626-M3-14E	1982	T1 24 CH DFS IV	EG&G 9 tip sparker	16.6 m	16.6 m	2 sec @ 1 ms	27-248 Hz	Seiscon United
White Rose Flank C-NOPB #8626-M3-9E	1981	T1 24 CH DFS III	EG&G 9 tip sparker	16.6 m	16.6 m	2 sec @ 1 ms	27-248 Hz	GSI
White Rose 2000	2000	ARAM24 48 CH	3 x 40 cu in air gun	12.5 m	12.5 m	2 sec @ 1 ms	27-248 Hz	Scott Pickford

Figure 2.2–24 White Rose Complex Time Slice 980 ms



2.3 Reservoir Maps

This section describes the suite of reservoir maps and how they were generated for the White Rose Field.

2.3.1 Mapping

A series of 60 maps are included as part of this document. These maps were generated from data either imported into or created within RMS, a 3-D mapping software package. The series of maps are those requested in the development application guidelines. The following discusses the processes used to generate these maps.

Two set of maps have been prepared, one which encompasses the entire White Rose Field, and a set which includes only the South Avalon Pool. The main reason for this is that the South Avalon Pool model consists of nine original layers, while the Avalon Full Field model consists of two.

The structure maps prepared for this report were created in two different ways. The main surfaces, Top and Base Avalon, are depth converted geophysically mapped horizons over most of the White Rose Field. In areas where the Avalon Formation could not be mapped seismically, the Top Avalon Formation Depth Structure map was created by adding an isopach to the Base Avalon Formation Depth Structure map. The internal surfaces were built within RMS, based on trend isopachs built to constrain the layering model. In total, there are three structure maps presented for the Avalon Full Field model and four for the South Avalon Pool.

The gross isopach maps were created by taking the structure maps and calculating the gross thickness between the different surfaces. There are three gross isopach maps for the Avalon Full Field area and four for the South Avalon Pool.

Net sand isopachs were created using the gross isopachs and applying reservoir cutoffs which calculated the amount of reservoir quality sandstone in each layer. The cutoffs used were 10 percent porosity and 30 percent volume clay. There are three net sandstone isopachs for the Avalon Full Field and four for the South Avalon Pool.

Net oil pay maps were created by taking the net sandstone maps and calculating the volume of net sandstone within the oil column. For the Avalon Full Field model, the J-49, N-22 and E-09 contacts were used. As with the net sandstone maps, there are three maps for the Avalon Full Field model and four for the South Avalon Pool. The net gas pay maps were created in the same manner calculating the volume of net sandstone within the different gas columns in the field.

Isoporosity maps were created by taking the three-dimensional model of porosity and collapsing it to a two-dimensional map, by averaging each pillar of data within the three dimensional model. The resulting average porosities were then contoured on a two dimensional map. There are three isoporosity maps for the full field model and four for the South Avalon Pool.

Hydrocarbon pore volume maps were created for both oil and gas. These were created by combining the three dimensional volumes of porosity, water saturation, and net sand to give a hydrocarbon pore volume which could be contoured in two dimensions. There are six oil and gas hydrocarbon pore volume maps for the full field and seven of maps for the South Avalon Pool. A list of reservoir maps is provided in Table 2.3-1; the maps are provided in Appendix 2A.

Table 2.3-1 White Rose Field Reservoir Maps

List of Figures for Avalon Full Field		**List of Figures for South Avalon Pool**	
Figure 2.3-1	Top Avalon Structure	Figure 2.3-25	Top Avalon Structure
Figure 2.3-2	Top Layer 1 Structure	Figure 2.3-26	Top Layer 1 Structure
Figure 2.3-3	Base Avalon Structure	Figure 2.3-27	Top Layer 2 Structure
Figure 2.3-4	Avalon Gross Isopach	Figure 2.3-28	Base Avalon Structure
Figure 2.3-5	Layer 1 Gross Isopach	Figure 2.3-29	Avalon Gross Isopach
Figure 2.3-6	Layer 2 Gross Isopach	Figure 2.3-30	Layer 1 Gross Isopach
Figure 2.3-7	Avalon Net Sand	Figure 2.3-31	Layer 2 Gross Isopach
Figure 2.3-8	Layer 1 Net Sand	Figure 2.3-32	Layer 3 Gross Isopach
Figure 2.3-9	Layer 2 Net Sand	Figure 2.3-33	Avalon Net Sand
Figure 2.3-10	Avalon Net Oil Pay	Figure 2.3-34	Layer 1 Net Sand
Figure 2.3-11	Layer 1 Net Oil Pay	Figure 2.3-35	Layer 2 Net Sand
Figure 2.3-12	Layer 2 Net Oil Pay	Figure 2.3-36	Layer 3 Net Sand
Figure 2.3-13	Avalon Net Gas Pay	Figure 2.3-37	Avalon Net Oil Pay
Figure 2.3-14	Layer 1 Net Gas Pay	Figure 2.3-38	Layer 1 Net Oil Pay
Figure 2.3-15	Layer 2 Net Gas Pay	Figure 2.3-39	Layer 2 Net Oil Pay
Figure 2.3-16	Avalon Isoporosity	Figure 2.3-40	Layer 3 Net Oil Pay
Figure 2.3-17	Layer 1 Isoporosity	Figure 2.3-41	Avalon Net Gas Pay
Figure 2.3-18	Layer 2 Isoporosity	Figure 2.3-42	Layer 2 Net Gas Pay
Figure 2.3-19	Avalon Oil HCPV	Figure 2.3-43	Layer 3 Net Gas Pay
Figure 2.3-20	Layer 1 Oil HCPV	Figure 2.3-44	Avalon Isoporosity
Figure 2.3-21	Layer 2 Oil HCPV	Figure 2.3-45	Layer 1 Isoporosity
Figure 2.3-22	Avalon Gas HCPV	Figure 2.3-46	Layer 2 Isoporosity
Figure 2.3-23	Layer 1 Gas HCPV	Figure 2.3-47	Layer 3 Isoporosity
Figure 2.3-24	Layer 2 Gas HCPV	Figure 2.3-48	Avalon Oil HCPV
		Figure 2.3-49	Layer 1 Oil HCPV
		Figure 2.3-50	Layer 2 Oil HCPV
		Figure 2.3-51	Layer 3 Oil HCPV
		Figure 2.3-52	Avalon Gas HCPV
		Figure 2.3-53	Layer 2 Gas HCPV
		Figure 2.3-54	Layer 3 Gas HCPV

3 PETROPHYSICS

This section documents the extensive logging and coring programs conducted in the White Rose wells, and provides an overview of the subsequent interpretation and integration of this database. For a comprehensive analysis of the White Rose petrophysical data, refer to the White Rose E-09, L-08, A-17, N-22, N-30, L-61, and J-49 Petrophysical Reports, Husky Oil Internal Reports, March – May 2000. Data from the H-20 well drilled in 2000 are currently being analyzed.

3.1 Logging Programs

Drilling in the field was done in two stages; five wells were drilled from 1984 to 1988, and three wells were drilled in 1999. White Rose A-90 did not encounter any reservoir section and was not analyzed. The typical logging program of the wells drilled in 1999 consisted of the following logs:

- Resistivity;
- Acoustic;
- Magnetic Resonance;
- Radioactive;
- Formation Micro Imager;
- Formation Tester; and
- Seismic Velocity.

The typical logging program of the wells drilled from 1984 to 1988, consisted of the following logs:

- Resistivity;
- Acoustic;
- Radioactive;
- Dipmeter;
- Formation Tester;
- Sidewall Cores; and
- Seismic Velocity.

Although similar logging programs were used in both stages, the 1999 log data quality is better quality and more complete because of equipment upgrades and borehole environment. Both induction and laterolog resistivity logs were sometimes run on the same well. Drilling muds were water-based, except for E-09, which used an oil-based mud. Production logs were run on the A-17 and N-30 wells.

3.2 Calibration of Log Data to Core Data

Five of the seven wells have core cut in the Avalon reservoir section. N-22 has core in the Hibernia section. An extensive core analysis program was undertaken to calibrate the log response and petrophysical parameters to core measurements. Core data were depth shifted to correlate with the log-measured responses.

Overburden corrections were applied to core porosity data to simulate *insitu* reservoir conditions. The well log response of downhole porosity devices (neutron, density, magnetic resonance, and sonic data) was then calibrated to the corrected core porosities. The mineralogy indicated from core was used to build the lithological models used in the ELANPlus analysis.

Special core analysis provided data on the overburden correction to be applied to porosity. Standard core analysis may incorporate systematic errors in porosity because these values are measured at low pressure (for example, 2,750 kPa), which lead to an over-estimation of porosity. At surface conditions pore volumes tend to expand with the decrease in confining pressure. Additional core analysis was undertaken to correct core porosity data and simulate *insitu* reservoir conditions. These data are summarized in Table 3.2-1.

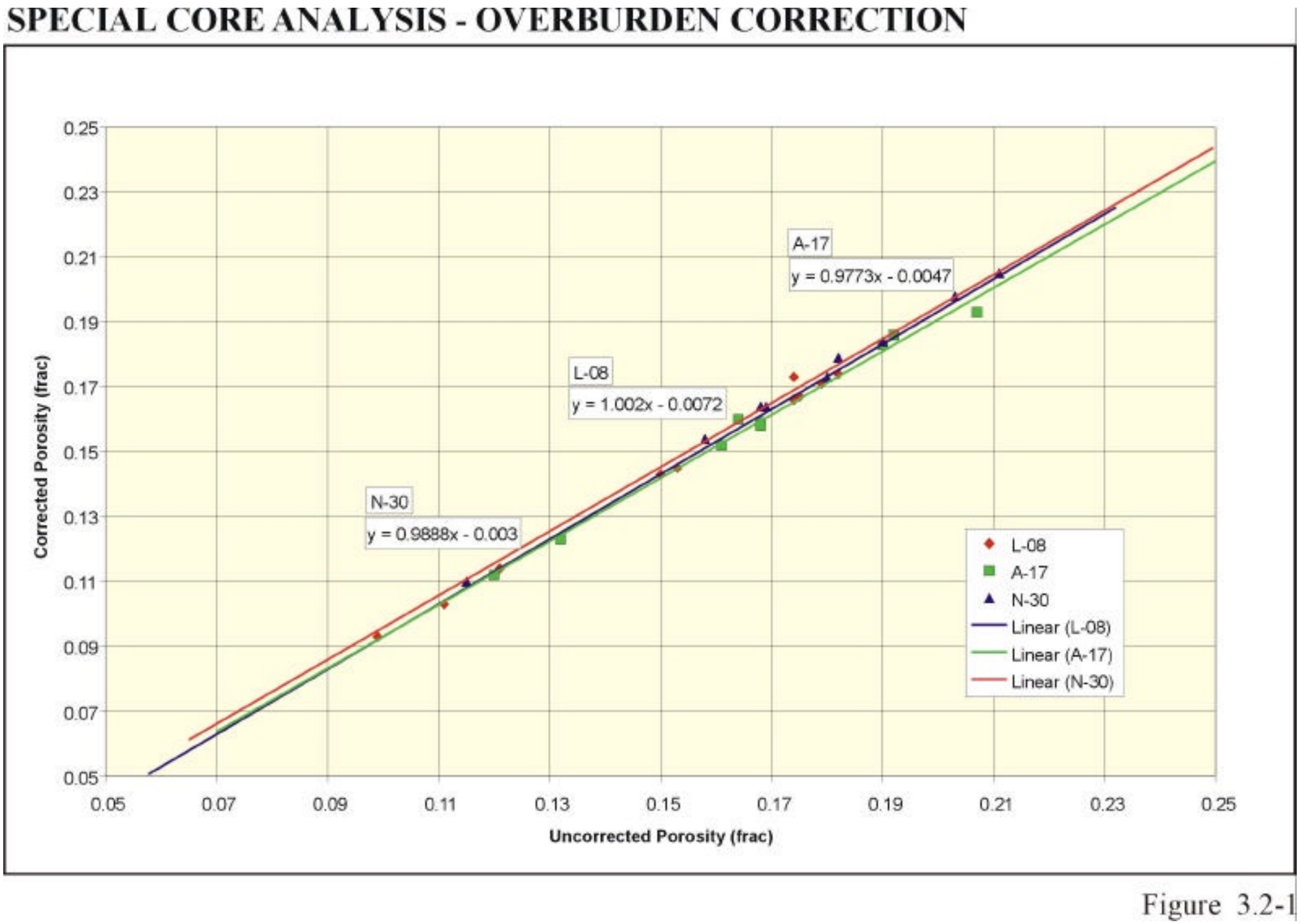
Table 3.2-1 Overburden Corrected Porosity from Special Core Analysis

Well	Phi_{corr}/ Phi_{uncorr}	Overburden Corrected Porosity	Fit Coefficient (R^2)
N-30	0.971	0.9888 x(UNCOR_PHI) - 0.003	0.9982
L-08	0.952	1.002 x (UNCOR_PHI) - 0.0072	0.9950
A-17	0.948	0.9773 x(UNCOR_PHI) - 0.0047	0.9902
All	0.957	0.9981 x(UNCOR_PHI) - 0.0065	0.9929
Note: UNCOR_PHI is core porosity measured at 2,750 kPa.			

Core porosity at low pressure versus core porosity at simulated overburden pressures is shown in Figure 3.2-1. This graph compares porosities determined at 2,750 kPa versus 35,280 kPa for the gas zones, 37,610 kPa for the oil zones, and 39,710 kPa for the water zones.

Special core analyses (SCAL) were undertaken to determine the electrical properties of the formation. Critical parameters in the calculation of water saturation from the log data are dual water equation constants ‘a’, ‘m’ and ‘n’. These should be derived from the electrical measurements on cores and from the log response of water-saturated intervals.

Figure 3.2–1 Special Core Analysis – Overburden Correction



Assuming a = 1, the following values (Table 3.2-2) for the cementation exponent ‘m’ were derived from the core data for the Avalon sand.

Table 3.2-2 Cementation Exponents from Special Core Analysis

Well	Average ‘m’	Cementation Exponent ‘m’ Equation	Fit Coefficient (R^2)
N-30	1.834	-1.7925 x (NOB_PHI) + 2.1394	0.5551
L-08	1.785	-1.1959 x (NOB_PHI) + 1.9583	0.5997
A-17	1.724	-0.9681 x (NOB_PHI) + 1.8889	0.4921
All	1.785	-1.0259 x (NOB_PHI) + 1.9534	0.2096
Note: NOB_PHI is net overburden corrected core porosity.			

Although core was cut in the Avalon Formation of J-49 and L-61, no SCAL measurements were performed on the core.

The ‘m’ relationships for the different wells is illustrated in Figure 3.2-2. The trend indicated in the figure suggests that ‘m’ increases as well position varies south to north. In the petrophysical analysis of each well, the well ‘m’ equation was used to generate a variable ‘m’ for use in the water saturation equation. The input porosity was the log-derived effective porosity (PIGN). For wells that do not have ‘m’ data from core, the data from the closest offset were used. Hence, for E-09, the ‘m’ relationship for L-08 was used, and for J-49 and N-22, the ‘m’ relationship for N-30 was used. For L-61, the field average relationship was used.

The saturation exponent ‘n’ cannot be determined from the log data. Therefore, electrical measurements of partially oil-saturated cores were performed and the results are provided in Table 3.2-3.

Table 3.2-3 Saturation Exponents from Special Core Analysis

Well	Average ‘n’	Saturation Exponent ‘n’ Equation	Fit Coefficient (R^2)
N-30	1.960	5.2726 x (NOB_PHI) + 1.0844	0.8213
L-08	1.860	7.8982 x (NOB_PHI) + 0.6378	0.6663
A-17	1.910	3.4613 x (NOB_PHI) + 1.2763	0.7079
All	1.897	5.9785 x (NOB_PHI) + 0.9297	0.6949
Note: NOB_PHI is net overburden corrected core porosity.			

Figure 3.2–2 Special Core Analysis – Cemetation Exponent – ‘m’

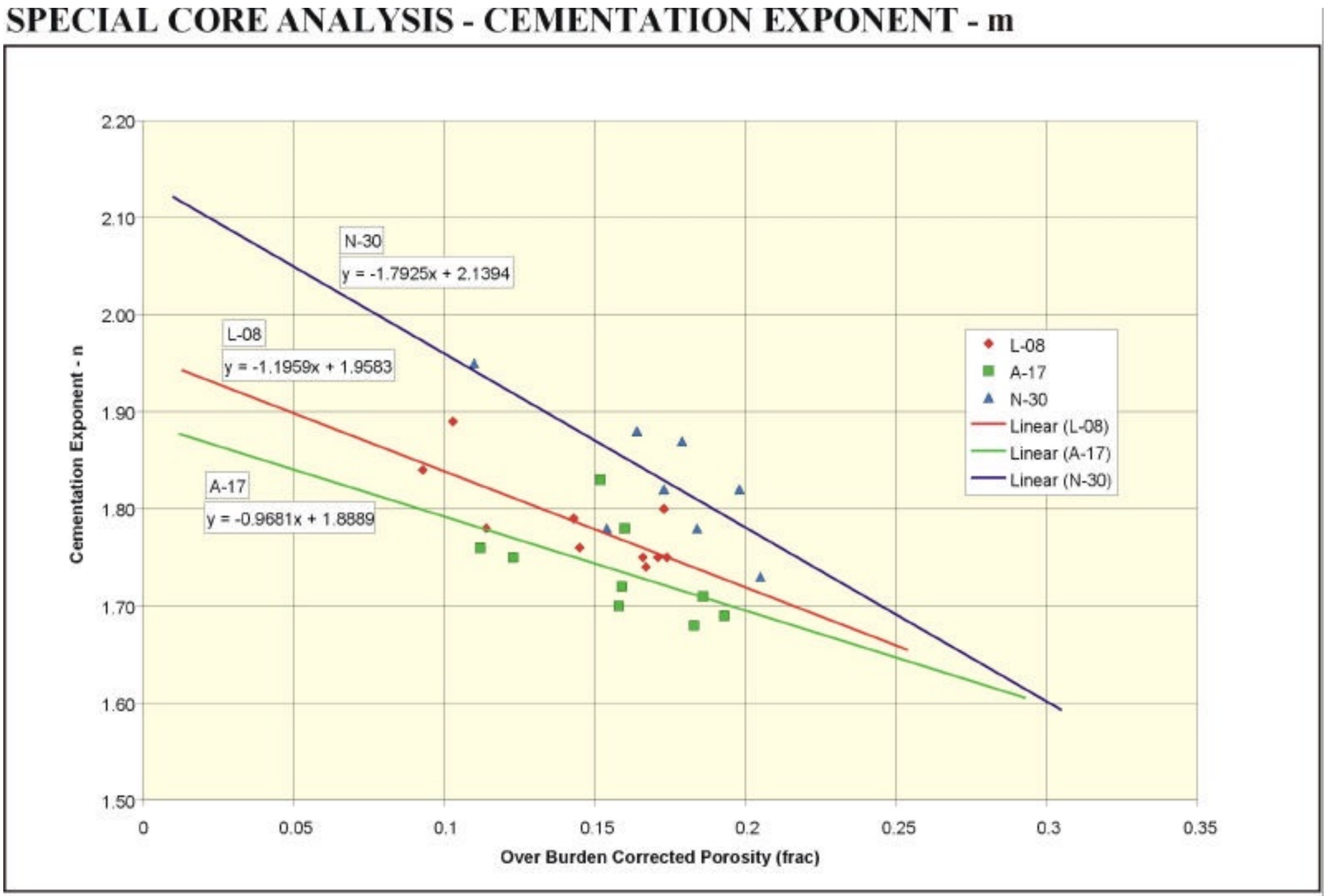


Figure 3.2-2

The 'n' relationships for the different wells is illustrated in Figure 3.2-3. The data in the figure suggest variations in the 'n' relationships. In the petrophysical analysis of each well, the well 'n' equation was used to generate a variable 'n' for use in the water saturation equation. The input porosity was the log derived effective porosity. For wells that do not have 'n' data from core, the data from the closest offset was used. Hence, for E-09, the 'n' relationship for L-08 was used, and for J-49 and N-22, the 'n' relationship for N-30 was used. For L-61, the field average relationship was used.

Another critical constant in the water saturation calculation is the formation water resistivity (Rw).

The Rw was determined using the modular dynamic tester water samples gathered in the Avalon Formation water zone at 3,047 and 3,094.5 mKB in White Rose L-08. The samples were obtained using the optical fluid analyzer and resistivity measurements to minimize the mud filtrate contamination.

A Tritium tracer, added to the mud system, was used to determine the amount of mud filtrate contamination in each sample. Each sample was corrected for mud filtrate contamination.

The values obtained for each sample are indicated in Table 3.2-4. At 25°C, the resistivities varied from a low of 0.212 to a high of 0.565 ohm-m. Sample #208 was used because this sample indicated the lowest pH above 7, and from tritium analysis, had the least amount of mud filtrate contamination.

Table 3.2-4 MDT Water Sample Analyses from L-08

Sample #	Sample Depth (m)	Sample Tritium Conc (pCi/ml)	Mud Tritium Conc (pCi/ml)	Sample Tritium Contam (%)	Contam Sample Rw@25 (ohm-m)	Contam Sample Conc (ppm)	Sample pH	Mud Salinity (ppm)	Corrected Formation Salinity PPM (ppm)	Corrected Formation Resistivity Rw @ 25 (ohm-m)
199	3,047	10,874	42,345	25.7	0.135	47,100	8	133,267	17,327	0.339
311	3,047	10,294	42,345	24.3	0.156	39,960	8	133,267	9,992	0.565
315	3,047	9,722	42,345	23.0	0.144	43,746	8	133,267	17,068	0.344
208	3,094.5	2,853	38,058	7.5	0.171	36,000	7.7	133,267	28,118	0.218
233	3,094.5	2,870	38,058	7.5	0.167	36,972	7.8	133,267	29,118	0.212
248	3,094.5	2,970	38,058	7.8	0.173	35,500	7.9	133,267	27,225	0.224

The Rw used for the Avalon field study was 0.218 @ 25°C, 0.082 @ FT of 100°C, which is 28,118 NaCl equivalent.

Figure 3.2–3 Special Core Analysis – Saturation Exponent – ‘n’

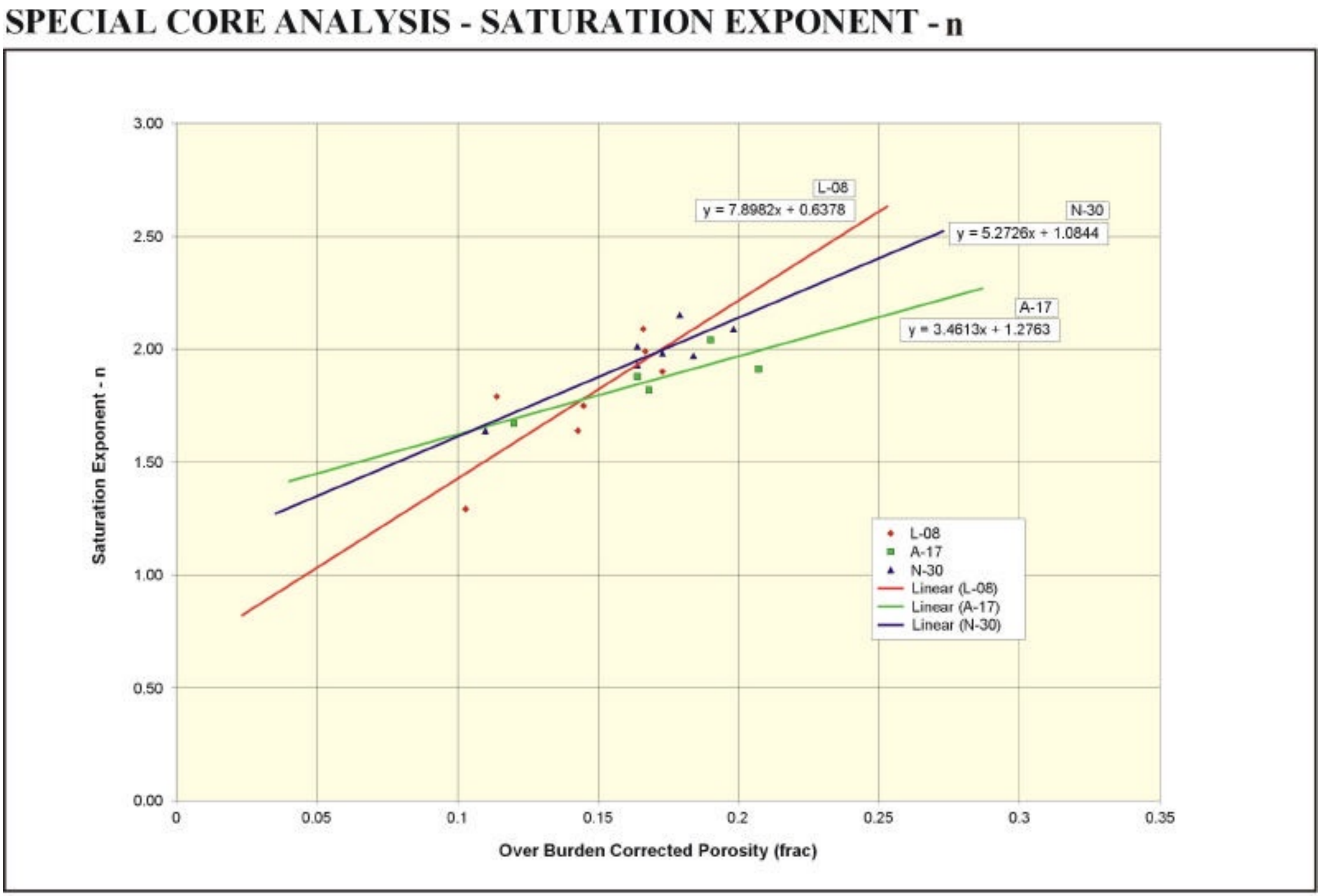


Figure 3.2-3

The water analysis of sample #208 before a mud filtrate correction is provided in Table 3.2-5.

Table 3.2-5 MDT L-08 Water Analyses of Sample #208

Cations				Anions			
Ion	**Weight (mg/L)**	**Mass Fraction**	**Mole Equivalent (mole/L)**	**Ion**	**Weight (mg/L)**	**Mass Fraction**	**Mole Equivalent (mole/L)**
Na	15,860	0.3265	689.91	Cl	25,500	0.5679	778.32
K	250	0.0517	64.26	Br	53	0.0011	0.66
Ca	757	0.0156	37.76	I	58.2	0.0012	0.45
Mg	102	0.0021	8.38	HCO_3	1,068	0.022	17.51
Ba	3.01	0.0001	0.04	SO_4	390	0.008	8.11
Sr	122	0.0025	2.78	CO_3	0	0	0
Fe	2.63	0.0001	0.14	OH	0	0	0
Ba	56.4	0.0012	15.64	H_2S	NIL		
Mn	0.25	0	0.01				

The porosity-permeability relationships of core data were studied to establish cutoff parameters for net pay calculation. A combined plot of permeability versus porosity for the cored wells in the White Rose Field is provided in Figure 3.2-4. Based on a 2-mD *insitu* air permeability cutoff, a corresponding porosity cutoff of 8 percent was derived.

Figure 3.2–4 Core Porosity Versus Core Permeability to Air

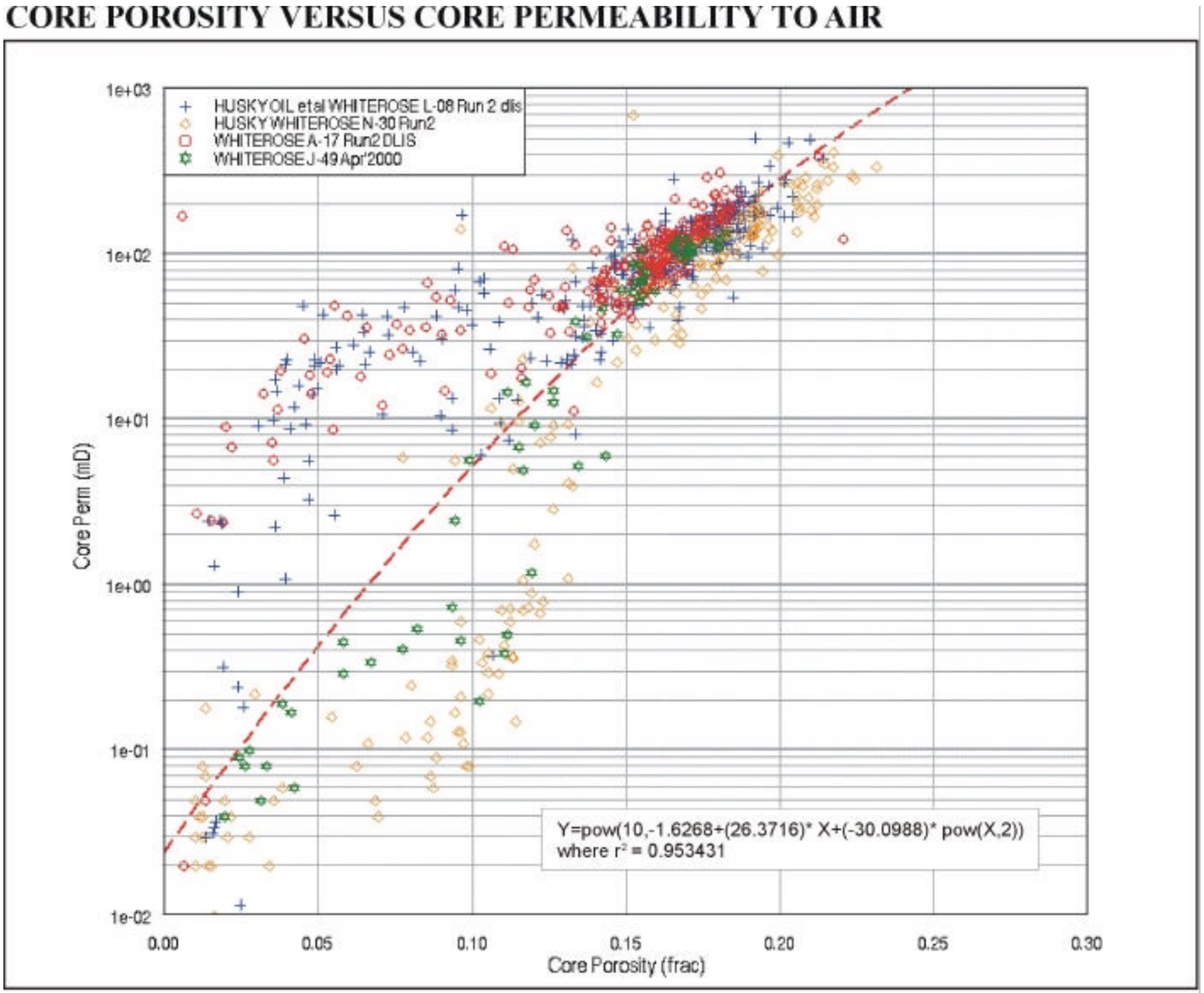


Figure 3.2-4

3.3 Petrophysical Methodology

All wells in White Rose were evaluated using ELANPlus, a volumetric computer analysis program marketed by Schlumberger Geoquest. This program determines the petrophysical parameters by solving simultaneous equations, which relate reservoir volumes to tool response equations. It solves the complex interpretation problems associated with mixed lithologies, special minerals, dual porosity systems, and varying clay and fluid types.

Reservoir models are constructed using different matrix and fluid constituents and each model uses different log inputs to create the simultaneous equations used to solve for the unknown reservoir volumes. The parameters used in the equations are selected with the help of quality control plots, curve reconstructions to validate models, and outside inputs from core pressure and water analysis. The models are combined using probabilistic algorithms and volumes are combined to give effective porosity, volume of shale, apparent grain densities, log derived permeability, and water saturations.

The following petrophysical methods were employed in analyzing the wells.

3.3.1 Volume of Shale

The volume of clay was used in determining effective porosity and reservoir quality. In each analysis, the clay volume is determined from the clay parameters for gamma ray, sonic travel time, formation density, neutron porosity, volumetric cross section, shallow and deep resistivity log data, and other reservoir parameters. Log crossplots and histograms, together with core data, were used in determining these parameters. The average clay volume in the net pay sections of each well is listed in Table 3.3-1.

Table 3.3-1 Clay Volume in Net Pay Section by Well

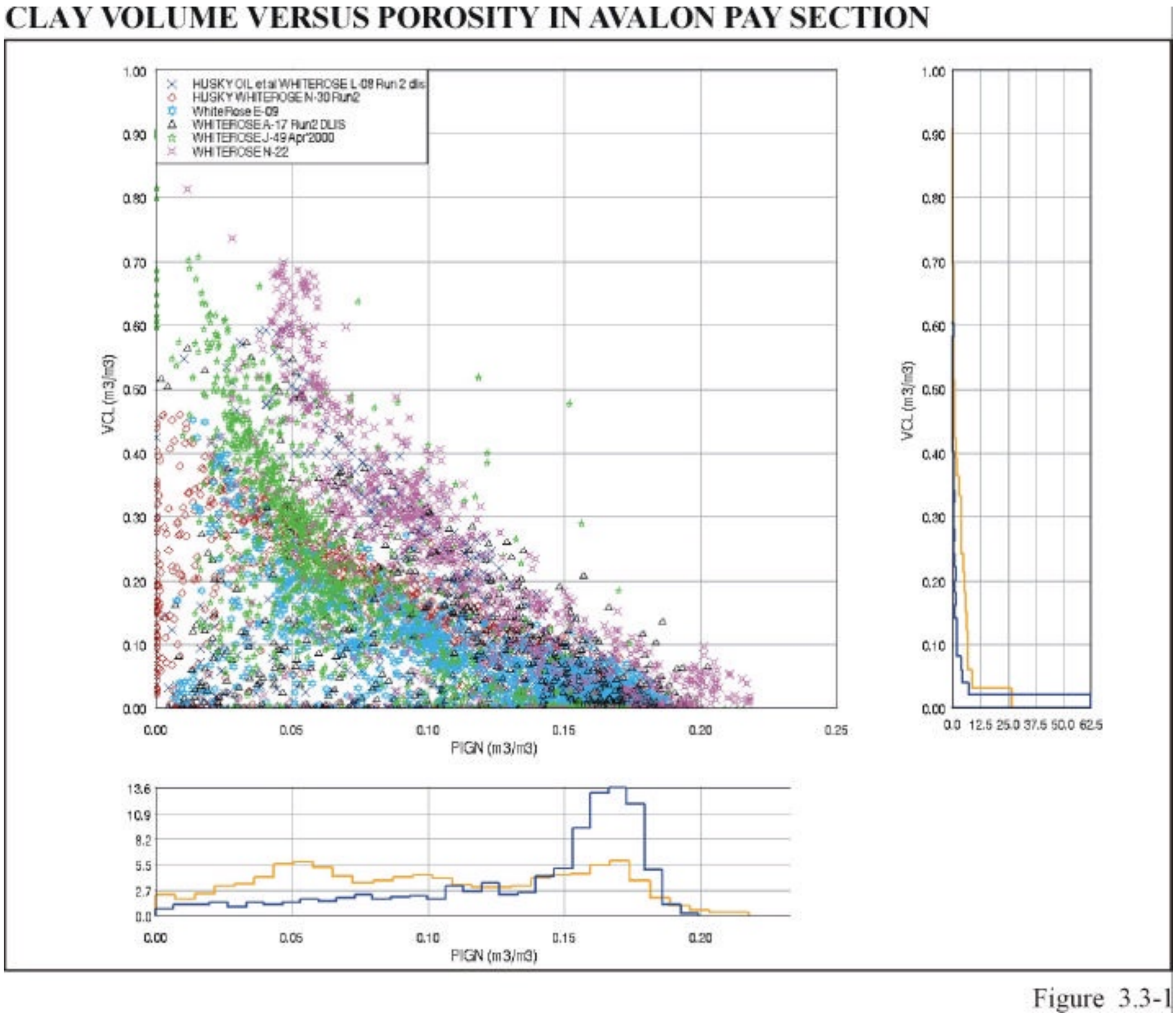
Well	Formation	Net Pay HPT h (m)	Pay Avg Vol Clay %
L-61	S. Mara Member	3.66	17
L-61	Avalon	2.44	16
L-61	Eastern Shoals	7.01	19
N-22	Wyandot (gas)	5.79	18
N-22	Avalon (gas)	35.51	9
N-22	Cape Broyle (gas)	0.61	3
N-22	Hibernia (oil)	36.73	6
J-49	Avalon Gas	6.71	10
J-49	Avalon Oil	24.99	1
J-49	Eastern Shoals Oil	6.25	3
N-30	Avalon Gas	56.54	10
N-30	Avalon Oil	12.29	1
N-30	Eastern Shoals Oil	10.05	7
E-09	Avalon Gas	28.17	9
E-09	Avalon Oil	105.54	4
E-09	Hibernia Lwr1	21.18	2
E-09	Hibernia Lwr2	8.08	9
L-08	Avalon Gas	51.49	7
L-08	Avalon Oil	108.47	1
A-17	Avalon Gas**	8.69	7
A-17	Avalon Oil	92.54	1
Note: **Major portion behind intermediate casing not evaluated. Portion of gas zone in open hole contaminated with cement.			

The clay volume in the Avalon net pay section by well, where the target well is L-08, is displayed in Figure 3.3-1.

3.3.2 Shale Cutoff

To discriminate between reservoir and non-reservoir rock each sample point had to meet a shale cutoff. The volume of shale had to be equal to or less than 30 percent of the total reservoir volume.

Figure 3.3–1 Clay Volume Versus Porosity in Avalon Pay Section



3.3.3 Effective Porosity

A consistent method was followed in determining effective porosity using ELANPlus. For wells with core in the Avalon Formation, the overburden-corrected core porosity was used to calibrate the ELANPlus derived porosity. The input parameters were modified such that core and log porosity matched. Grain density information from core was used for lithological identification and log parameter selection. It was also used to confirm the log analysis derived apparent matrix densities.

On the three wells drilled in 1999, porosity, derived independently from magnetic resonance, was used to confirm the ELANPlus derived porosities. In addition, the formation micro images on these wells were used to better describe the calcite stringers and nodules noted in the Avalon reservoir.

For wells without core, magnetic resonance or resistivity images, parameters were selected using offsetting wells drilled in 1999. For example, E-09 parameters were modified to closely match those on L-08, N-22 parameters were modified to closely match those in N-30, and J-49 parameters were modified to closely match those in N-30. More information detailing how effective porosity was determined along with a listing of the log parameter inputs used, can be found in the Appendices of the White Rose E-09, L-08, A-17, N-22, N-30, J-49, L-61 Petrophysical Reports, Husky Oil Internal Reports, March – May 2000.

3.3.4 Porosity Cutoff

To discriminate between reservoir and non-reservoir, each sample point had to meet a porosity cutoff. The effective porosity had to be equal to or greater than 8 percent of the total reservoir volume. This cutoff was determined using core porosity and permeability data.

A plot of core porosity versus core permeability for J-49, N-30, L-08, and A-17 in provided in Figure 3.2-4. The second order equation representing the line of best fit was found to be:

$$Y = 10^{-1.6268 + 26.3716\,x - 30.0988\,x^2}$$

The porosity-permeability relationship indicated a conventional 2-mD air permeability corresponding to an approximate porosity of 8 percent, hence the justification for the porosity cutoff. More information detailing how the porosity cutoff was determined along with complete summaries and listings is provided in White Rose E-09, L-08, A-17, N-22, N-30, J-49, L-61 Petrophysical Reports, Husky Oil Internal Reports, March – May 2000. For sensitivity purposes, each well report includes summaries and listings using a 10 percent porosity cutoff.

3.3.5 Water Saturation

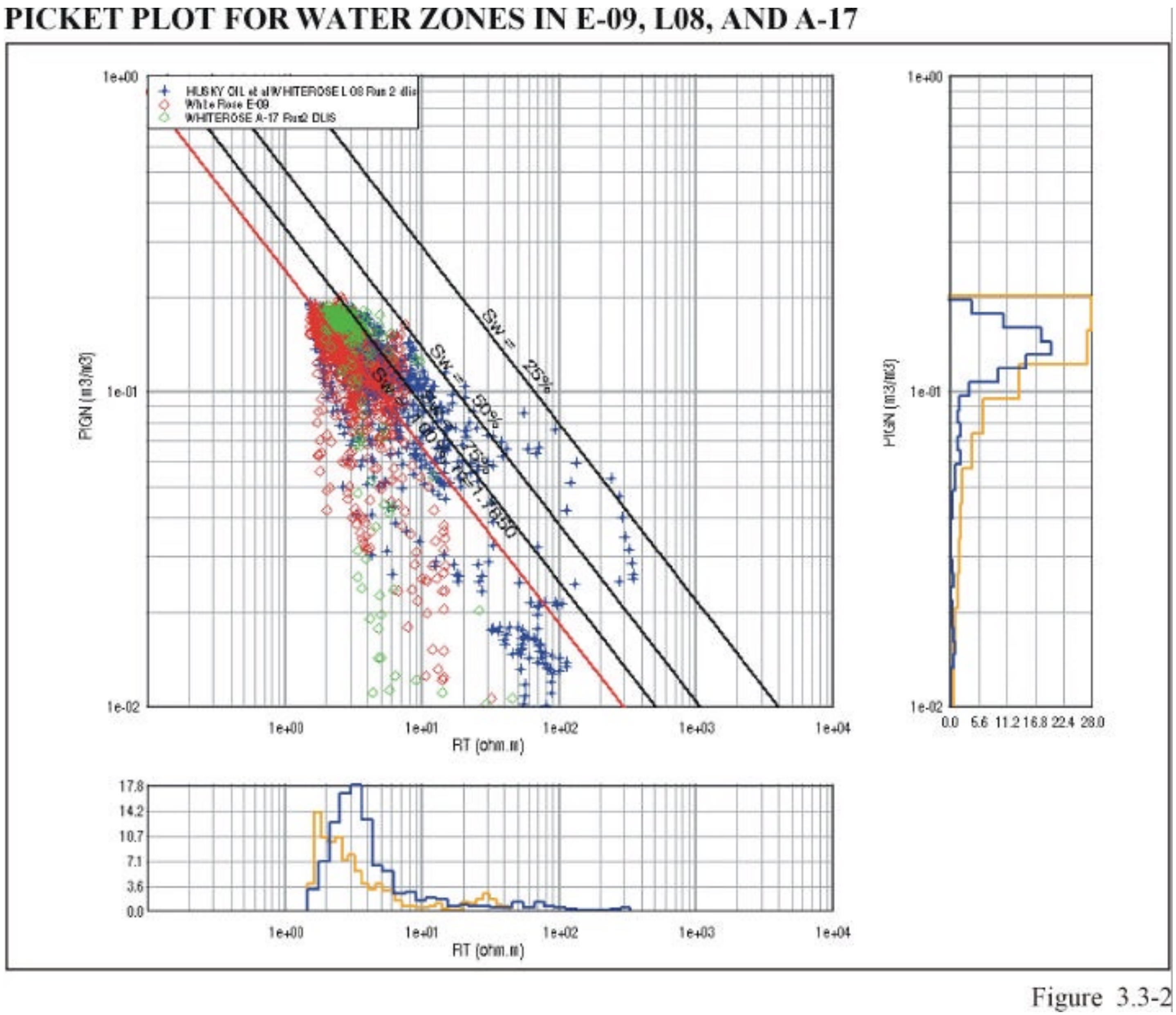
Water saturations were determined using the dual water equations of ELANPlus. In most cases, because of the generally low clay content in the reservoir rocks, the dual water relationships for flushed and undisturbed zones reduces to the simple Archie relationship for water saturations.

The core SCAL data for L-08, A-17, and N-30 were used in determining water saturation. In particular, the 'm' and 'n' values were determined from the individual well SCAL data for the respective well.

For wells without core, the 'a', 'm', and 'n' parameters were selected using offsetting wells drilled in 1999. For example, E-09 parameters matched those in L-08, N-22 parameters matched those in N-30, and J-49 parameters matched those in N-30. For L-61, the field average values were used.

A Pickett plot of the wet sandstones in the White Rose E-09, L-08, and A- 17 wells using average 'm' and 'n' (from the above tables), with a water resistivity of 0.08 Ω at formation temperature, is illustrated in Figure 3.3-2. Although the results are acceptable, they are not as good as those using the variable 'm' and 'n', as can be noted by the water saturation values in the water zones as depicted on the formation evaluation plots for the individual wells. These plots can be found the in the White Rose Appendices of the E-09, L-08, A-17 Petrophysical Reports, Husky Oil Internal Reports, March-May 2000.

Figure 3.3–2 Picket Plot for Water Zones in E-09, L-08 and A-17



The fluid contacts noted in each well, as determined from log and pressure analysis, are noted in Table 3.3-2.

Table 3.3-2 Fluid Contacts

Well	Formation	Contact	Log Depth (m TVD)	Subsea Depth (m SS TVD)
L-61	Avalon	Water		
	Avalon	Top of Transition	2,986.0	-2,963.1
	Avalon	Bottom of Transition	3,007.0	-2,984.1
N-22	Hibernia	Oil - Water	3,631.3	-3,603.6
J-49	Avalon	Gas - Oil	3,092.6	-3,069.7
	Avalon	Oil – Water	3,154.0	-3,131.1
N-30	Avalon	Gas - Oil	3,039.2	-3,014.2
E-09	Avalon	Gas - Oil	2,894.8	-2,871.8
	Avalon	Water		
	Avalon	Top of Transition	3,013.0	-2,990.0
	Avalon	Bottom of Transition	3,032.5	-3,009.5
L-08	Avalon	Gas - Oil	2,897.0	-2,872.0
	Avalon	Water		
	Avalon	Top of Transition	3,014.0	-2,989.0
	Avalon	Bottom of Transition	3,034.5	-3,009.5
A-17	Avalon	Gas - Oil	2,899.7	-2,874.7
	Avalon	Water		
	Avalon	Top of Transition	3,010.0	-2,985.0
	Avalon	Bottom of Transition	3,024.5	-2,999.5

3.3.5.1 Water Saturation Cutoff

The water saturation cutoff discriminates between hydrocarbon bearing (pay) intervals and wet intervals. Intervals that have greater than 50 percent water saturation were assumed to be wet or non-productive.

3.3.5.2 Resistivity Tools and Corrections

The true formation resistivity was determined from the deep laterolog for wells drilled with a water-based mud, or an induction log in wells with oil-based drilling fluid. The laterolog provided the preferred resistivity in wells drilled with conductive drilling fluids.

The resistivity logs were corrected for invasion effects, which were applied using the GeoFrame environmental correction program ‘PrePlus’.

3.4 Core Data (Cored Intervals, Core Recovery)

A total of 517.3 m of core was cut in the seven White Rose wells, with 508.7 m recovered, and 452.8 m analyzed.

The totals of core cut, core recovery, intervals analyzed and number of routine core analysis performed for each well are illustrated in Figure 3.4-1. Non-analyzed intervals are calcite nodules/stringers or shales.

The core diameter is 88.5 mm for N-30, L-08, A-17, and 126.5 mm for N-22, L-61, and J-49. Routine core analysis was performed primarily on plug samples in J-49 and L-61, and on both full diameter and plug samples in N-30, L-08 and A-17.

The following routine core measurements were performed:

- Permeability to air (mD)
  - $K_{h\text{-}max}$, $K_{h\text{-}90°}$, K_{vert}, for full diameter samples (N-30, L-08, A-17);
  - $K_{h\text{-}max}$ only for plug samples (L-61, N-22, J-49, N-30, L-08, A-17);
  - $K_{h\text{-}max}$, K_{vert}, for some plug samples (N-30, L-08, A-17);
- Porosity (%) for all samples (L-61, N-22, J-49, N-30, L-08, A-17);
- Water saturation (%) for all samples (L-61, N-22, J-49, N-30, L-08, A-17);
- Corrected water saturation (%) for plug and full diameter samples (N-30, L-08, A-17); and
- Grain density (kg/m^3) for all samples (L-61, N-22, J-49, N-30, L-08, A-17).

A summary of special core analysis tests is provided in Table 3.4-1.

Table 3.4-1 Special Core Analysis Test Summary

Test Name	Number of Tests		
	Well N-30	**Well L-08**	**Well A-17**
Overburden Correction for Porosity	9	10	9
Cementation Factor Exponent	9	10	9
Saturation Exponent	9	7	6
Overburden Formation Resistivity	9	10	9
Overburden Formation Resistivity Index	9	7	6
Air-Brine First Drainage Centrifuge Capillary Press	9	7	6
Acoustic Velocity (Compressional and Shear)	4	5	5
Triaxial Compressive Strength	4	-	3

Figure 3.4–1 White Rose Cores (All Formations)

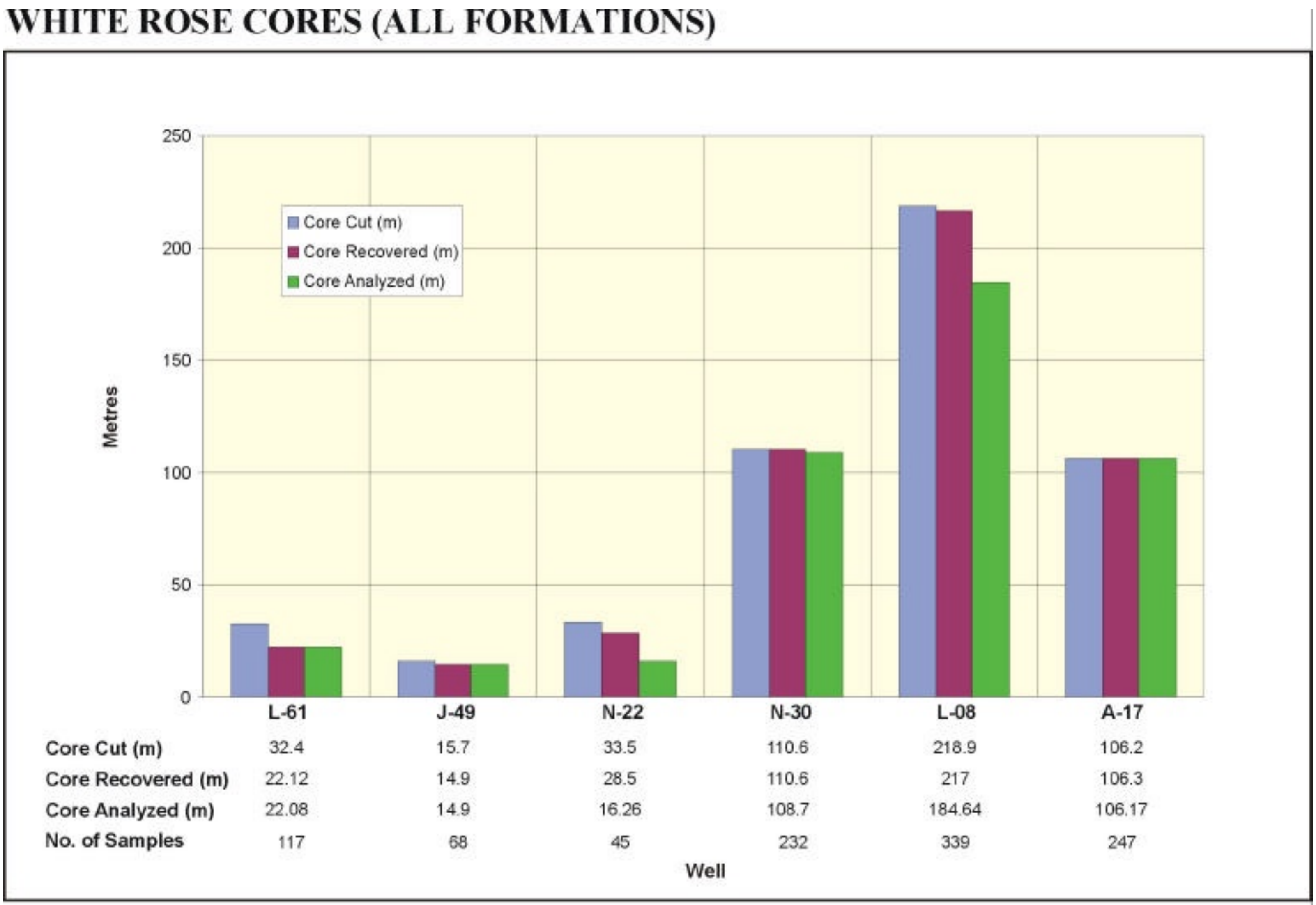


Figure 3.4-1

3.5 Petrophysical Summary

The summary in Table 3.5-1 contains petrophysical parameters determined from core, pressure, and log analysis. It summarizes the petrophysical parameters for all production tested intervals, and includes the S. Mara Member, Wyandot, the Avalon, Cape Broyle, Eastern Shoals, and Hibernia formations. The parameters were determined using a porosity cutoff of 8 percent, a water saturation cutoff of 50 percent, and a volume of shale cutoff of 30 percent.

The thicknesses for the gross, net reservoir, and net pays for the Avalon in all wells are displayed in Figure 3.5-1. The gas zone thicknesses for the A-17 well are correct for the 8.5" hole section only.

The distributions of net pay for porosity and water saturation in the Avalon section by well are displayed in Figures 3.5-2 and 3.5-3. Both the gas and the oil zones are represented.

The net pay unit thicknesses for each well for the Avalon oil and gas intervals is displayed in Figure 3.5-4. The unit thickness is defined as:

Unit Thickness = (h) x (Net Pay Avg Porosity) x (1-Net Pay Avg Water Saturation)

Table 3.5-1 White Rose Petrophysical Parameters

Well	Formation	Gross Thickness h (m)	Net Reservoir h (m)	Net Pay HPT h (m)	Pay Avg Phi %	Pay Avg Sw %	Pay Avg Perm mD
L-61	S. Mara Member Gas	30.0	4.11	3.66	22	15	29
	Avalon Gas	55.0	6.25	2.44	11	43	2
	Eastern Shoals Oil	230.9	13.41	9.45	11	41	2
N-22	Wyandot Gas	9	7.62	5.79	19	30	-
	Avalon Gas	124	65.23	35.51	16	19	29
	Eastern Shoals Gas	53.85	8.23	0.61	15	49	49
	Hibernia Oil	288	84.28	36.73	12	29	19
J-49	Avalon Gas	136.6	16.46	6.71	14	33	14
	Avalon Oil	38.25	32.12	24.99	14	23	41
	Eastern Shoals Oil	98.85	20.27	6.25	12	33	9
N-30	Avalon Gas	127.29	60.7	56.54	13	26	15
	Avalon Oil	15.2	12.29	12.29	13	18	27
	Eastern Shoals Oil	49.79	10.49	10.05	14	31	16
E-09	Avalon Gas	66.8	29.39	28.17	11	24	9
	Avalon Oil	118.1	108.28	105.54	15	19	45
	Avalon Transition	19.35	14.99	7.92	15	36	64
	Avalon Water	112	96.72	-	-	-	-
	Hibernia Lwr1 Oil	107	47.85	21.18	12	27	33
	Hibernia Lwr2 Oil	90	20.27	8.08	13	37	15
L-08	Avalon Gas	82.5	55.6	51.49	14	18	18
	Avalon Oil	116.85	108.47	108.47	16	16	82
	Avalon Transition	19.85	18.17	6.62	14	35	43
	Avalon Water	62.85	55.81	-	-	-	-
A-17	Avalon Gas**	19.20**	11.13**	8.69	12**	29**	2*
	Avalon Oil	110.13	92.85	92.54	16	21	75
	Avalon Transition	14.85	11.34	7.43	18	36	206
	Avalon Water	57.85	46.84	-	-	-	-
Note:	**Major portion behind intermediate casing and not evaluated. Portion of gas zone in open hole contaminated with cement.						

Figure 3.5–1 Thicknesses - Avalon

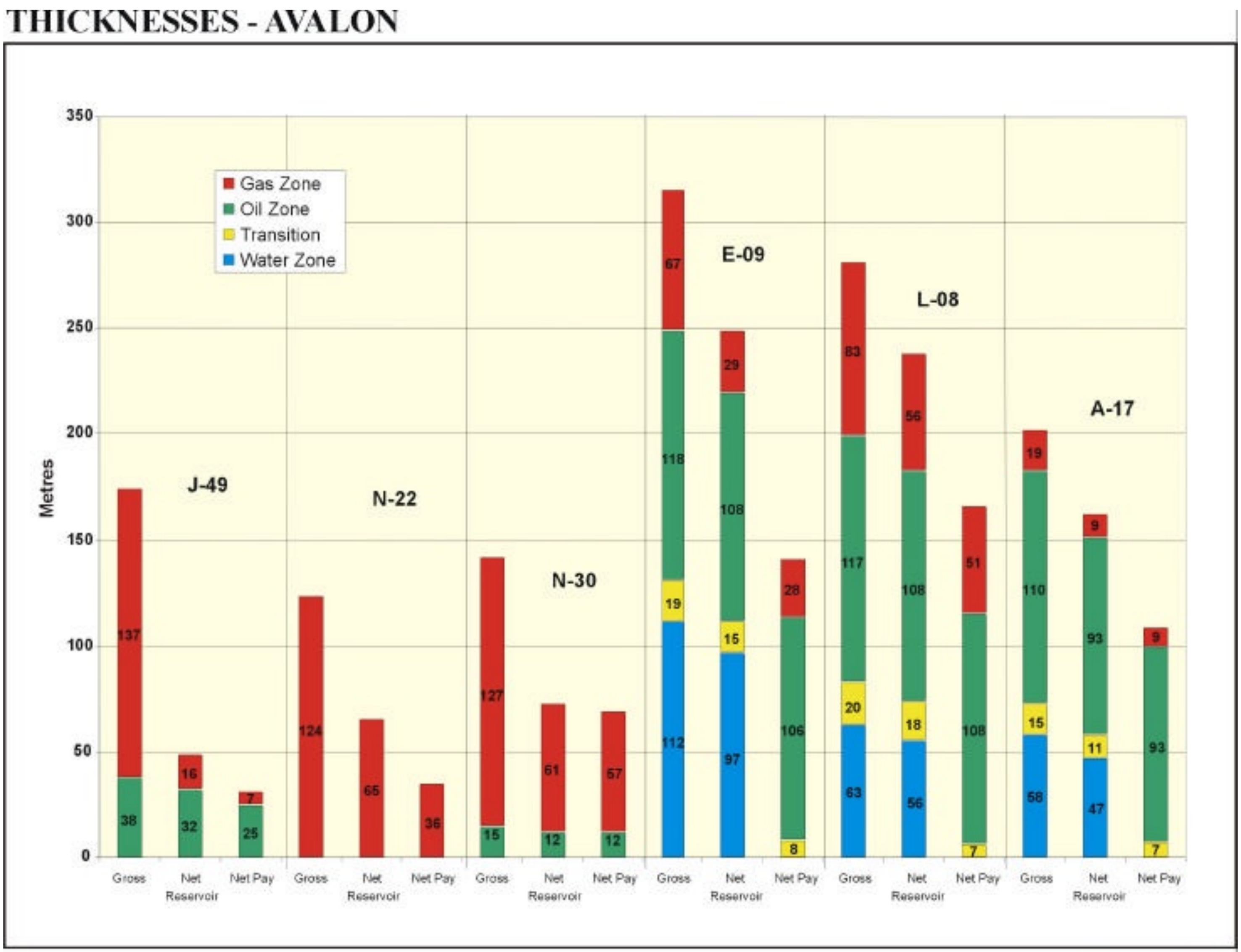


Figure 3.5-1

Figure 3.5–2 Net Pay Porosity Distribution – Avalon

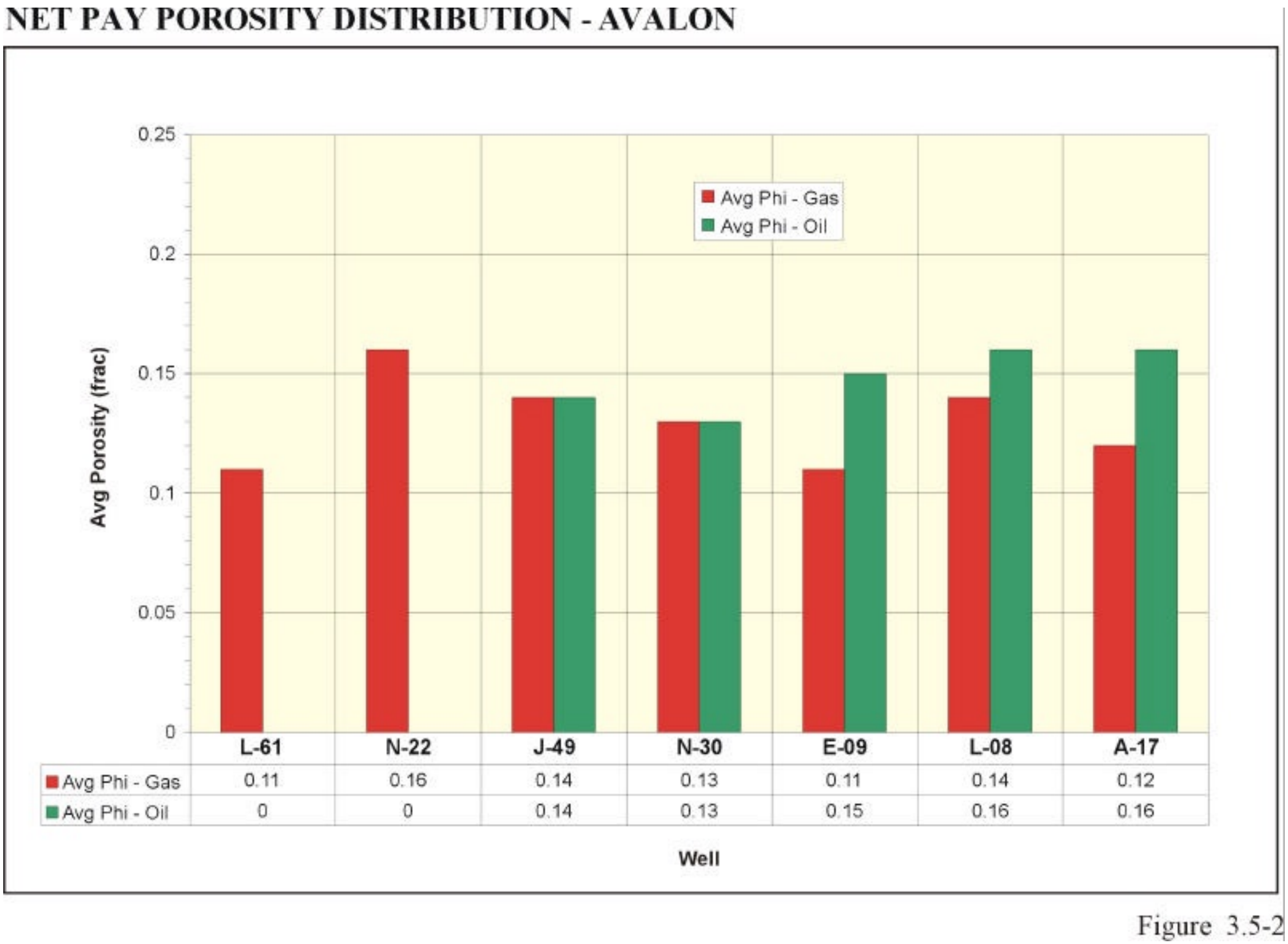
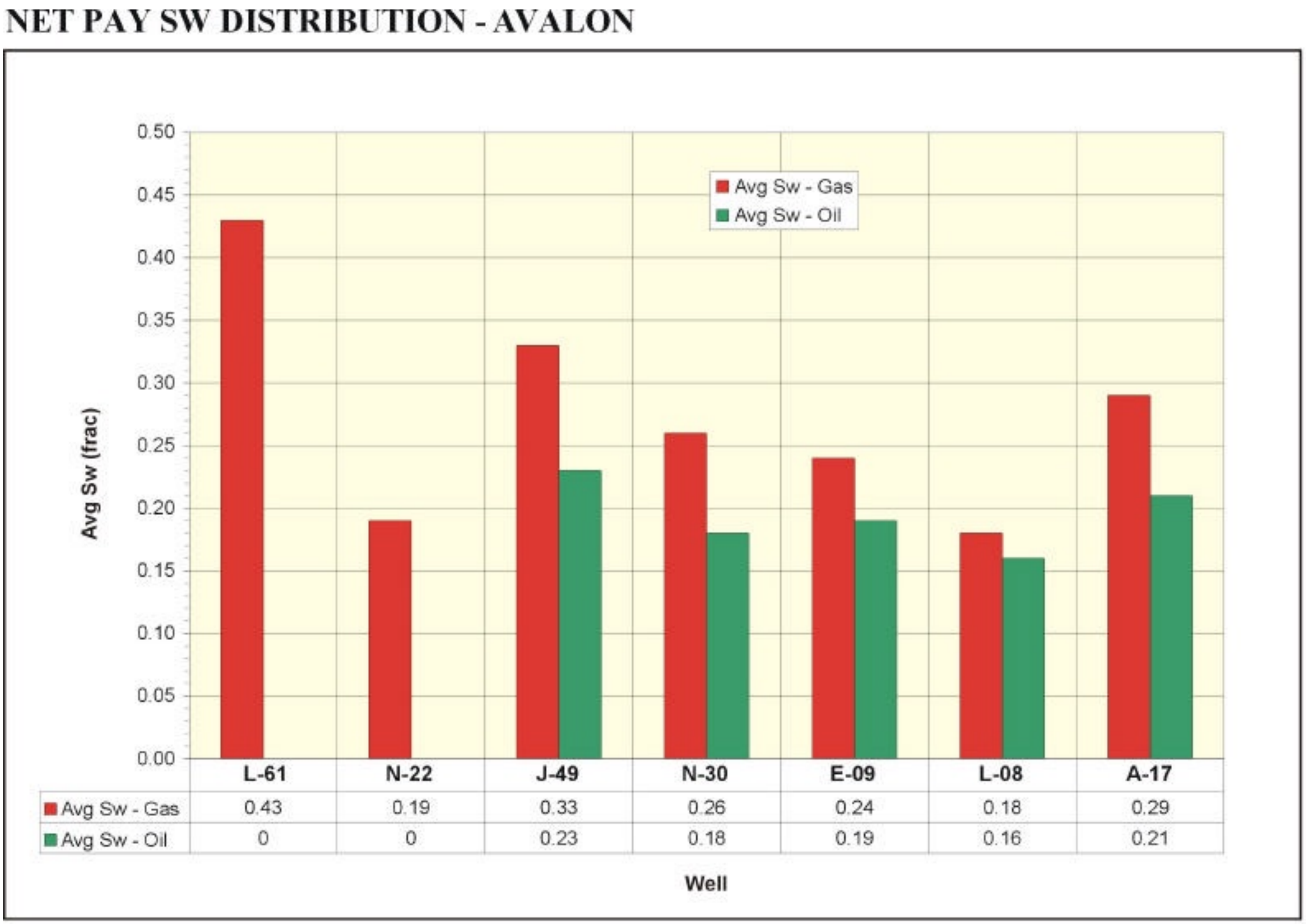


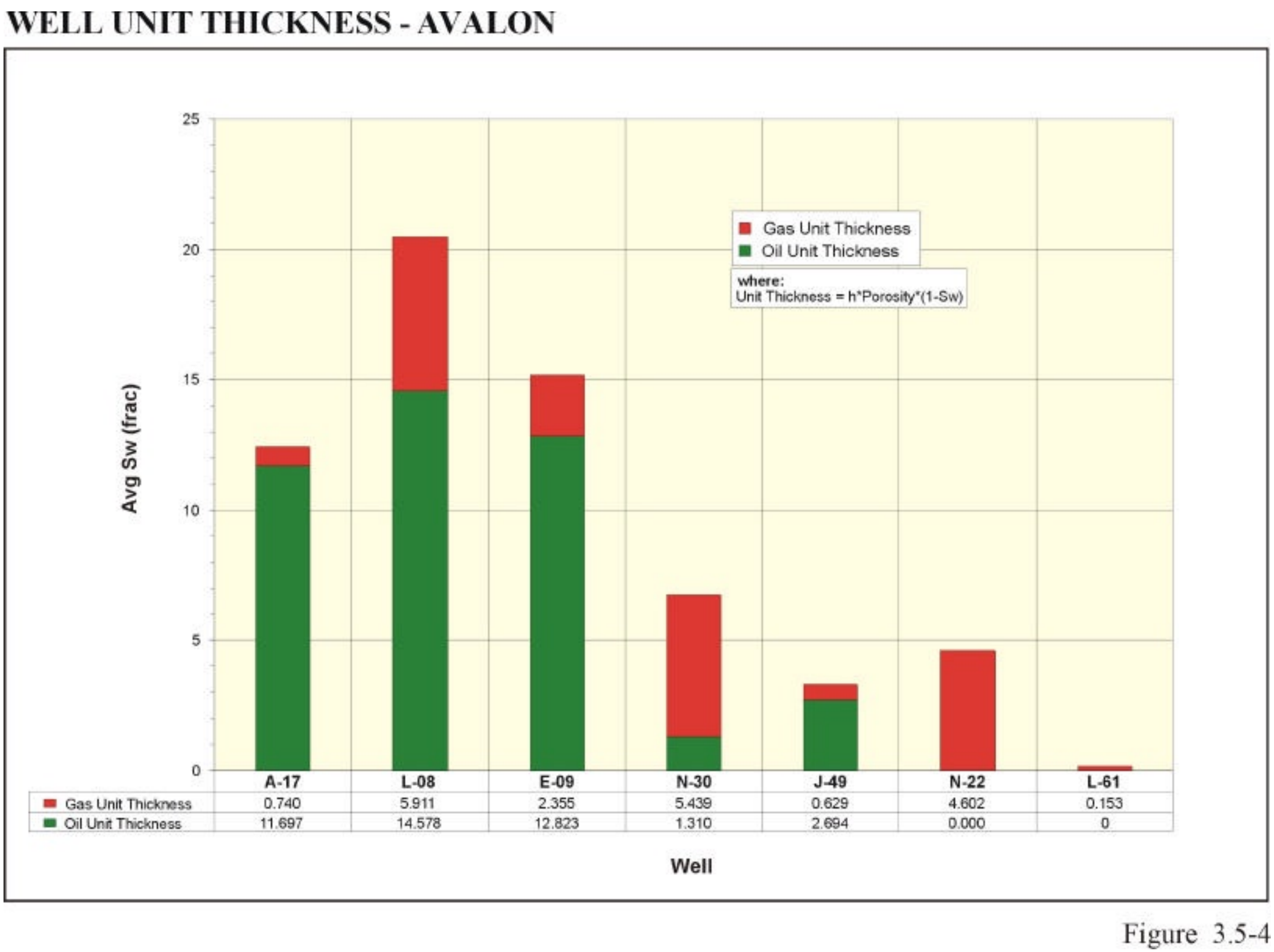
Figure 3.5–3 Net Pay SW Distribution – Avalon



	L-61	N-22	J-49	N-30	E-09	L-08	A-17
Avg Sw - Gas	0.43	0.19	0.33	0.26	0.24	0.18	0.29
Avg Sw - Oil	0	0	0.23	0.18	0.19	0.16	0.21

Figure 3.5-3

Figure 3.5–4 Well Unit Thickness – Avalon



4 RESERVOIR ENGINEERING

This chapter summarizes the reservoir engineering data and analysis used in the development of the Depletion Plan for the White Rose Field. The data were derived from seismic and geological studies, conventional core, special core, fluid and well test analysis, and the results of reservoir simulation studies.

As described in Chapter 2, the White Rose Field has three major Avalon Formation Pools, the South Avalon Pool, the North Avalon Pool and the West Avalon Pool. All three pools have oil accumulations overlain by a gas cap and underlain by a water leg. Gas-oil contacts have been drilled in all three pools. Oil-water contacts have only been drilled in the West and South Avalon pools. The water-oil contact in the North pool is inferred from extrapolation of the oil leg gradient to a common water gradient for the field. The Avalon pools are characterized as having massive, relatively homogeneous, highly faulted sands with relatively low permeability. The locations of each of the Avalon pools are shown in Figure 4-1. Representative data for the Avalon pools are summarized in Table 4-1.

There are also secondary hydrocarbon accumulations in the White Rose Field. They are South Mara Formation gas, Eastern Shoals Formation oil and Hibernia Formation oil. The locations of the secondary pools are shown in Figure 4-2. A minor oil accumulation was tested in the Jurassic sandstone in the E-09 well and a minor gas accumulation was tested in the Nautilus sandstone in the N-22 well.

Extensive data have been acquired from the eight wells drilled in the White Rose Field to date. Rock and fluid characteristics were derived from analysis of well logs, core and fluid samples. It should be noted that data from the most recently drilled H-20 well have not been included and special core and fluid studies are still under way for the wells drilled in 1999. Field rock and fluid property assessments will be updated to reflect this new information, as it becomes available over the next several months.

Figure 4-1 White Rose Complex Avalon Pools

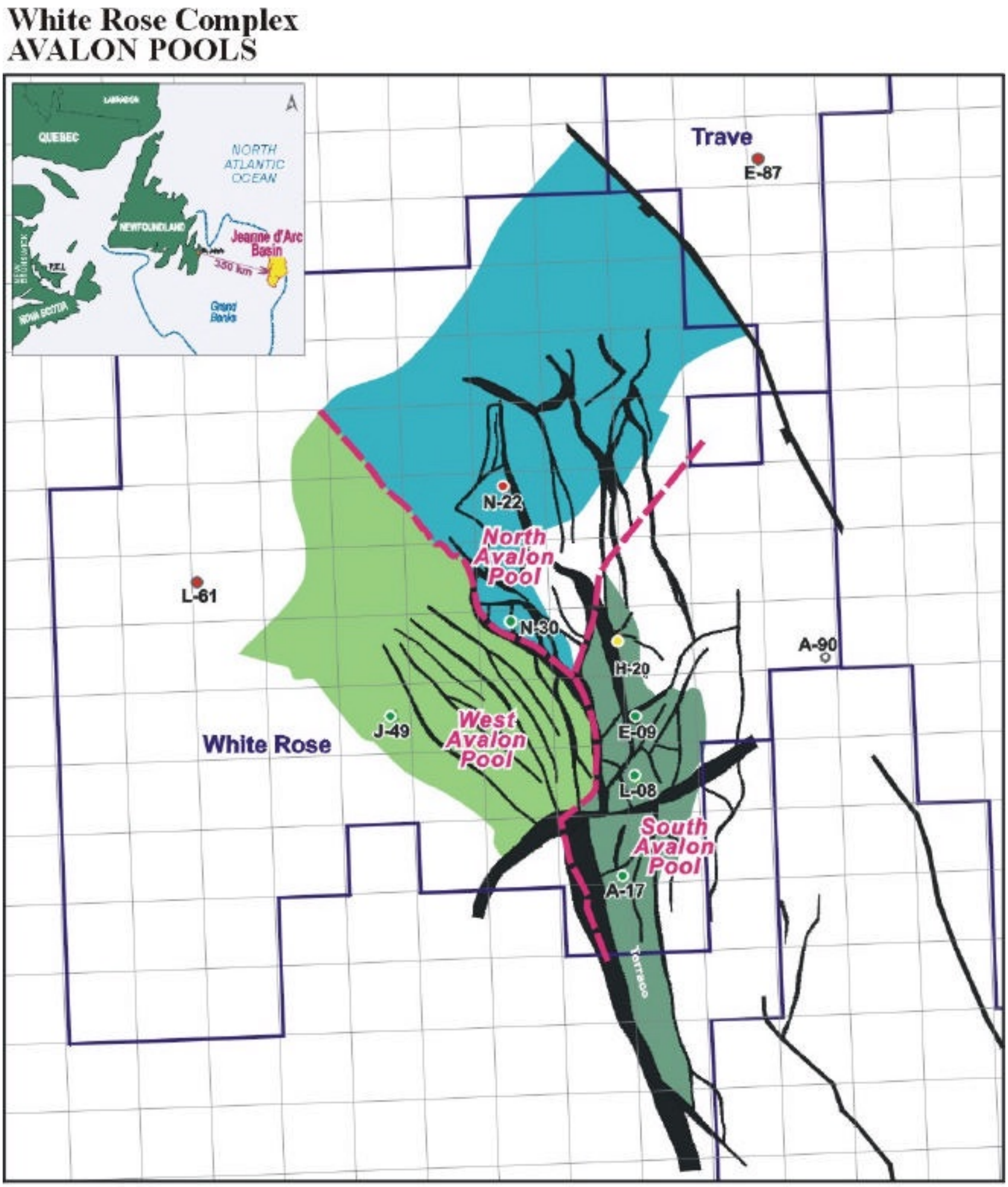


Figure 4-1

Table 4-1 White Rose Avalon Pool Summaries

Pool	South Avalon	North Avalon	West Avalon
Type of Reservoir	Structural	Structural	Structural
Age	Aptian	Aptian	Aptian
Depth to Crest (mSS)	2,650	2,350	2,500
Gas-oil Contact (mSS)	2,872	3,014	3,064
Oil-water Contact (mSS)	3,009	3,073	3,127
Temperature (°C)	106	106	106
Pressure at Gas Oil Contact (MPaa)	29.4	30.7	31.3
OIL LEG			
Original Oil in Place ($10^6 m^3$)	124	29	39
Recoverable Oil ($10^6 m^3$)	36.0	6.7	8.9
Reservoir Drive Type	Waterflood	To be determined	To be determined
Oil Pay Area (m^2)	18×10^6	10×10^6	16×10^6
Gross Thickness Average (m)	117	56	59
Gross Thickness Range (m)	0-137	0-59	0-63
Net to Gross Ratio Average (%)	68	44	49
Net to Gross Ratio Range (%)	43-76	32-67	33-61
Porosity Average (%)	15.7	15.0	14.7
Porosity Range (%)	0-21	0-20	0-20
Oil Saturation Average (%)	77	75	75
Oil Saturation Range (%)	0-88	0-75	0-75
Permeability Average (mD)	127	95	87
Permeability Range (mD)	0-600	0-600	0-600
GAS CAP			
Original Gas Cap in Place ($10^9 m^3$)	14	50	34
Gas Pay Area (m^2)	12×10^6	35×10^6	23×10^6
Gross Thickness Average (m)	81	177	122
Gross Thickness Range (m)	0-222	0-664	0-564
Net to Gross Ratio Average (%)	63	32	38
Net to Gross Ratio Range (%)	14-69	17-61	19-47
Porosity Average (%)	15.1	14.6	14.6
Porosity Range (%)	0-21	0-20	0-20
Gas Saturation Average (%)	78	78	78
Gas Saturation Range (%)	n/a	n/a	n/a
Permeability Average (mD)	110	83	83
Permeability Range (mD)	0-600	0-600	0-600

* Note: All averages are for net sands only, all ranges are for gross sands.

Figure 4-2 White Rose Secondary Pools

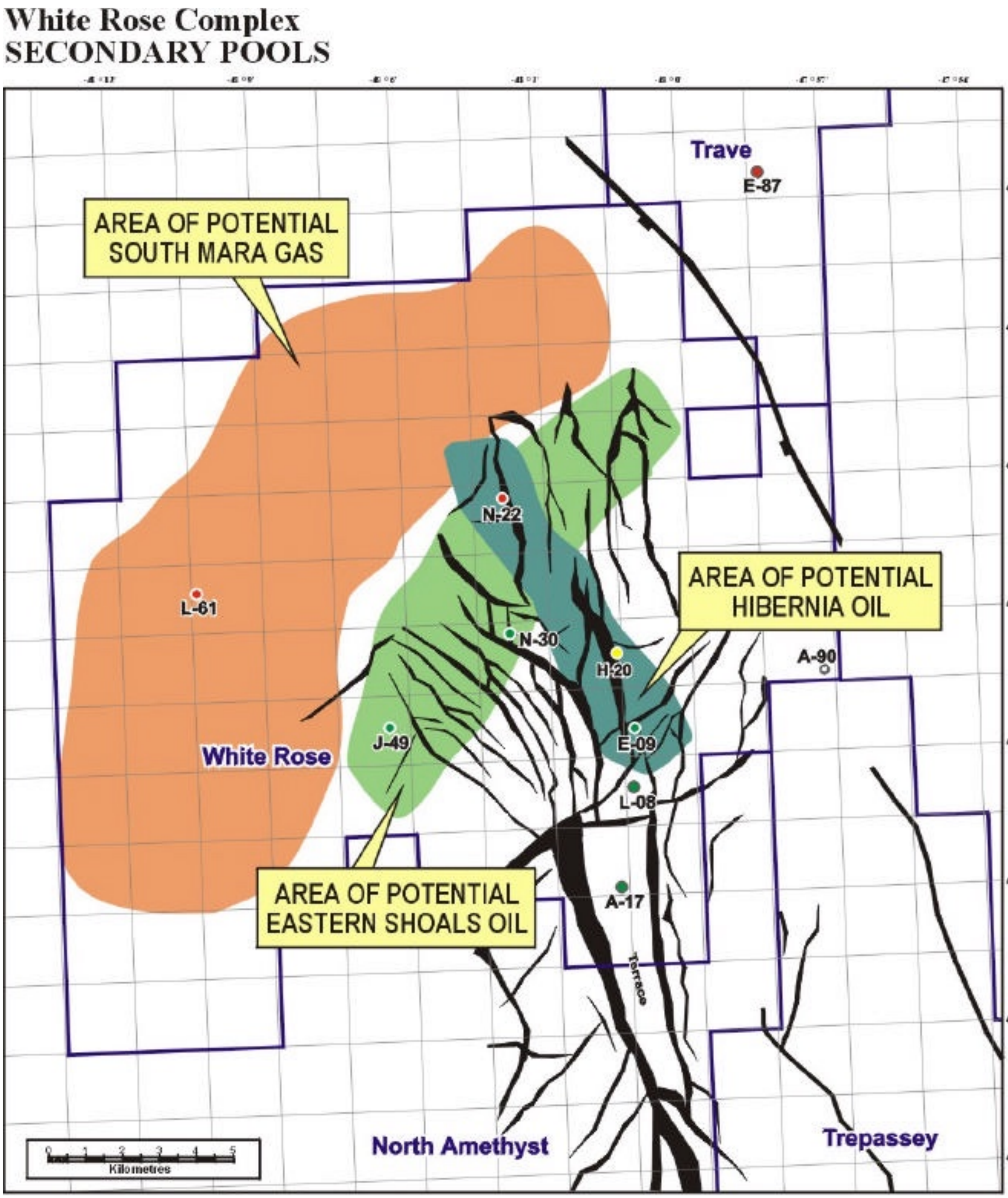


Figure 4-2

4.1 Rock Properties

Rock properties were determined from core data, well logs and production test data. Correlation of core porosity and permeability data to log porosity data is addressed in Chapter 3.

4.1.1 Avalon Formation

White Rose Avalon Formation core porosity versus core permeability is shown in Figure 3.2-4. An 8 percent porosity value with a corresponding permeability of 2 mD was used as a net pay cut off. Net pay porosities range from 8 to 23 percent, with corresponding permeabilities running from 2 to 600 mD. Average net pay porosity and permeability based on volume weighted averages from the geological model are summarized by pool in Table 4.1-1.

Table 4.1-1 Avalon Pools Average Porosity and Permeability

Pool	Average Net Oil Pay Porosity (%)	Average Net Oil pay Permeability (mD)	Average Net Gas Pay Porosity (%)	Average Net Gas pay Permeability (mD)
South Pool	16	127	15	110
North Pool	15	95	15	83
West Pool	15	87	15	83

Several drill stem tests have been carried out on the wells drilled in the White Rose Field. The permeabilities determined from the 10 analyzable oil tests and six gas tests performed in the Avalon Formation are summarized in Table 4.1-2. The range of test interval permeabilities for each of the pools is also summarized in Table 4.1-2.

Table 4.1-2 Range of Test Permeabilities for Each Pool

Pool	Oil Test Permeability (mD)	Gas Test Permeability (mD)
South Pool	7 to 110 (8 Tests)	No tests
North Pool	No tests	17 to 142 (4 tests)
West Pool	32.3 to 94 (2 tests)	<1 to 32 (2 tests)

4.1.2 Secondary Pools

The log porosity and calculated log permeabilities and the test determined permeabilities for the secondary formations encountered in the White Rose wells are summarized in Table 4.1-3.

Table 4.1-3 Comparison of Log and Test Values for Secondary Pools

Pool	Average Net Pay Porosity (%)	Average Net pay Permeability (mD)	Test Perm (mD)
South Mara Gas (L-61)	22	29	647
Eastern Shoals Oil (L-61, N-30)	11 to 14	2 to 16	Not tested
Eastern Shoals (Cape Broyle)Gas (J-49, N-22)	15	49	43
Hibernia Oil (N-22, E-09)	12 to 13	15 to 33	5.3 to 1.2 (2 tests)
Jurassic Oil (E-09)	~10	Not calculated	1
Wynandot Gas (N-22)	19	Not calculated	<<1

4.2 Fluid Properties

This section contains descriptions of the Avalon fluid samples collected during the evaluation of all White Rose wells. This includes compositional analysis of selected surface and bottomhole gas, oil and water samples, and pressure, volume, temperature (PVT) details of selected reservoir fluid samples. All available data were reviewed and critiqued to select the fluid characteristics that best represent the White Rose gas (solution or injected, gas cap and fuel), oil (as a reservoir fluid and residual for sales), and formation water. Data from the gas, oil and water deemed to be the most representative were then used in the reservoir simulations of the South Avalon Pool and the North Avalon Pool.

A summary of the Avalon oil PVT studies performed to date is provided in Table 4.2-1 and a summary of the Avalon gas PVT studies performed to date is provided in Table 4.2-2.

Table 4.2-1 Saturation Pressure and Differential Liberation Gas-Oil Ratio (GOR) Data for Avalon Oil Zone DSTs

Well	DST # and if appropriate Sample #	Type of Sample	Recombination Technique	Saturation Pressure (kPa)	Reservoir Pressure at the Gas/Oil Contact (MPa)	GOR (m^3/m^3)
A-17	1, sample #03-15	Wireline	N/A	29,165	29.4	137.51
A-17	1, sample #43-02	Wireline	N/A	29,151	29.4	135.86
L-08	2, sample #286-02	Wireline	N/A	30,130	29.4	140.04
L-08	2, sample #s 283-06 and H285	Recombined surface samples	Saturation pressure	28,972	29.4	133.65
E-09	3	Recombined surface samples	Producing GOR	26,614	29.4	133.41
E-09	4	Recombined surface samples	Producing GOR	24,152	29.4	129.66
E-09	5	Recombined surface samples	Producing GOR	24,097	29.4	134.35
E-09	6	Recombined surface samples	Producing GOR	28,227	29.4	148.64
E-09	7A	Recombined surface samples	Saturation Pressure	29,234	29.4	160.52
J-49	6	Recombined surface samples	Producing GOR	25,731	31.3	115.75
J-49	7	Recombined surface samples	Saturation Pressure	31,268	31.3	154.21

Table 4.2-2 Dewpoint Pressure and Differential Liberation GOR Data for Avalon Gas Zone DSTs

Well	DST # and if appropriate Sample #	Type of Sample	Recombination Technique	Dewpoint Pressure (kPa)	Maximum MDT Reservoir Pressure in the Gas Cap (MPa)	GLR (m^3/m^3)
N-22	4	Recombined surface samples	Producing GLR	28,972	29.9	4,331.4
N-22	5	Recombined surface samples	Producing GLR	28,751	29.9	5,251.6

4.2.1 South Avalon Pool Pressure, Volume, Temperature

For the purposes of White Rose Field development planning, the simulation of the South Avalon hydrocarbon accumulation used the PVT analysis from the A-17 well, sample 03-15. This sample had a bubble point pressure of 29.2 MPa that was very close to the expected bubble point of 29.4 MPa, the pressure at the pool's gas-oil contact. Separator flash tests were conducted on sample 43-02. The differential liberation data were corrected using the separator flash results. The oil and gas PVT data used in the simulator are provided in Tables 4.2-3 and 4.2-4. These data are also illustrated in Figures 4.2-1 to 4.2-4.

The reservoir fluid characteristics used in the calculation of OOIP and original gas in place (OGIP) are:

- an oil formation volume factor of 1.37 reservoir m^3 per stock tank m^3;
- a solution gas gas-oil ratio (GOR) of 122 m^3 of gas at standard conditions per m^3 of stock tank oil; and
- a gas formation volume factor of 0.0046 reservoir m^3 per m^3 at standard conditions.

Average compositions for the South Avalon Pool reservoir oil, stock tank oil, gas cap gas, solution gas and fuel gas used in current evaluations are provided in Table 4.2-5. Additional gas properties are provided in Table 4.2-6.

4.2.2 North Avalon Pool Pressure, Volume, Temperature

The only oil samples taken in the North Avalon area are Eastern Shoals MDT samples from N-30. Although it appears that the Eastern Shoals may be in communication with the Avalon, the highest saturation pressures measured were significantly lower than the pressure at the Avalon gas-oil contact. For North Avalon evaluations, the South Avalon Pool oil PVT data were adjusted to match the expected bubble point pressure of 30.65 MPa seen at the gas-oil contact in the N-30 well.

None of the gas samples appear to have had dew points that coincide with the reservoir pressure of 30.65 MPa at the gas-oil contact seen in the N-30 well. The fluids used for the N-22 fluid studies were surface samples of gas and condensate that were recombined to the measured gas-condensate ratio. Gas compositions from two PVT studies done on recombined separator samples from the N-22 well were adjusted to match constant composition expansion tests, and the retrograde liquid curve. The resulting PVT descriptions for both samples were very similar.

The oil and gas PVT properties being used in the North Avalon Pool simulation work are shown in Figures 4.2-5 to 4.2-8.

Table 4.2-3 South Avalon Pool Oil PVT Data

Pressure (Bara)	Solution GOR (sm^3/sm^3)	Oil Fm. Vol. Factor (m^3/sm^3)	Oil Viscosity (cp)
35.95	122.33	1.360	0.800
31.06	122.33	1.366	0.709
29.40	122.33	1.370	0.677
24.23	99.14	1.307	0.788
20.79	83.47	1.271	0.888
17.34	68.63	1.235	0.993
13.89	54.91	1.202	1.110
10.44	40.70	1.169	1.293
7.00	26.39	1.136	1.459
3.55	12.07	1.101	1.772
1.82	5.80	1.084	1.963
0.96	1.73	1.069	2.130
0.10	0	1.029	2.741

Table 4.2-4 South Avalon Pool Gas PVT Data

Pressure (MPaa)	Gas Fm. Vol. Factor (m^3/sm^3)	Gas Viscosity (cp)
35.00	0.0048	0.0250
29.40	0.0049	0.02300
24.23	0.0051	0.02093
20.79	0.0059	0.01947
17.34	0.0070	0.01816
13.89	0.0087	0.01694
10.44	0.0116	0.01585
7.00	0.0177	0.01492
3.55	0.0359	0.01398
1.82	0.0712	0.01332
0.96	0.1376	0.01269
0.10	1.4816	0.01080

Figure 4.2–1 South Avalon Pool Oil Formation Volume Factor

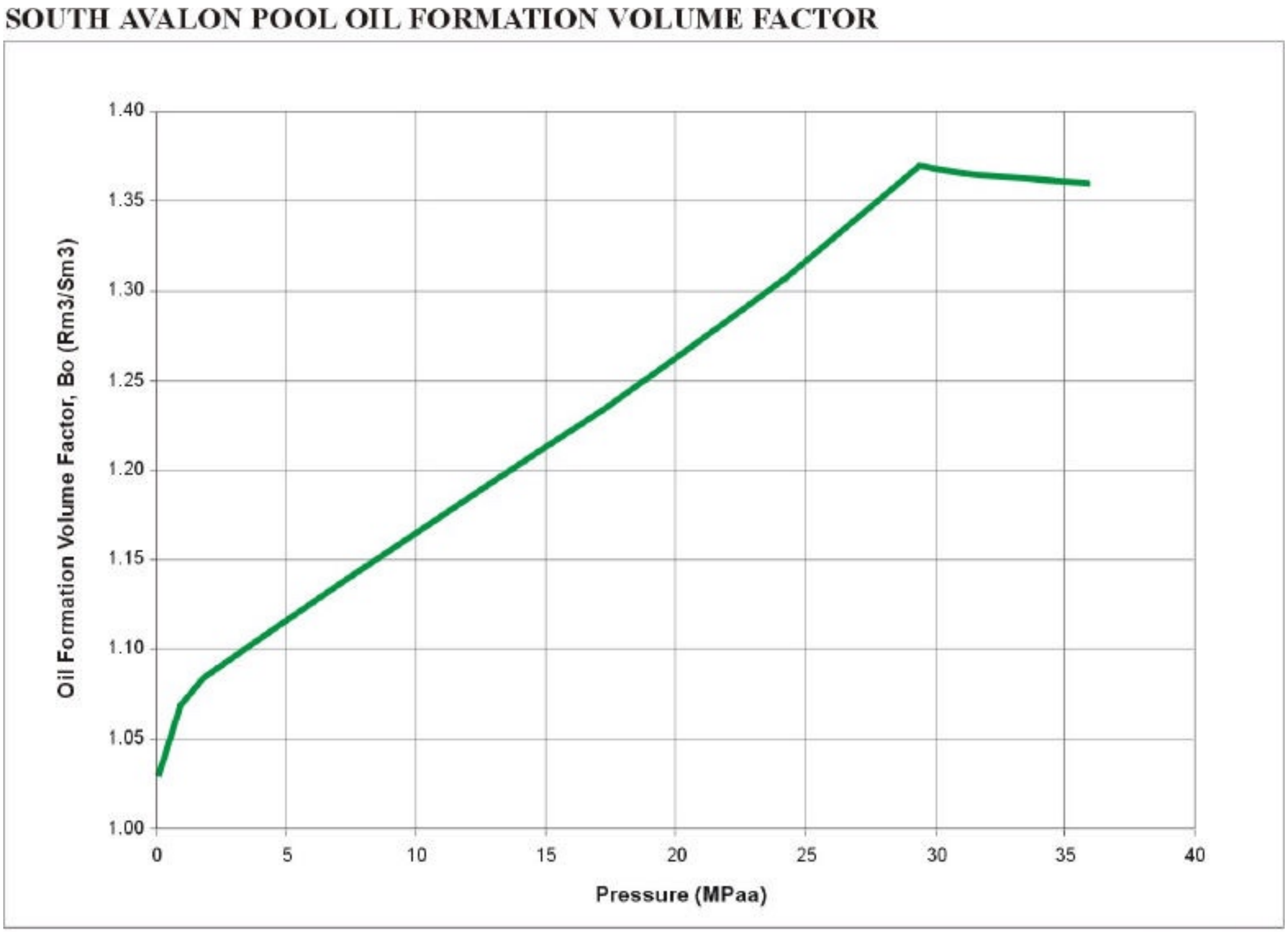


Figure 4.2-1

Figure 4.2–2 South Avalon Pool Solution Gas Oil Ratio

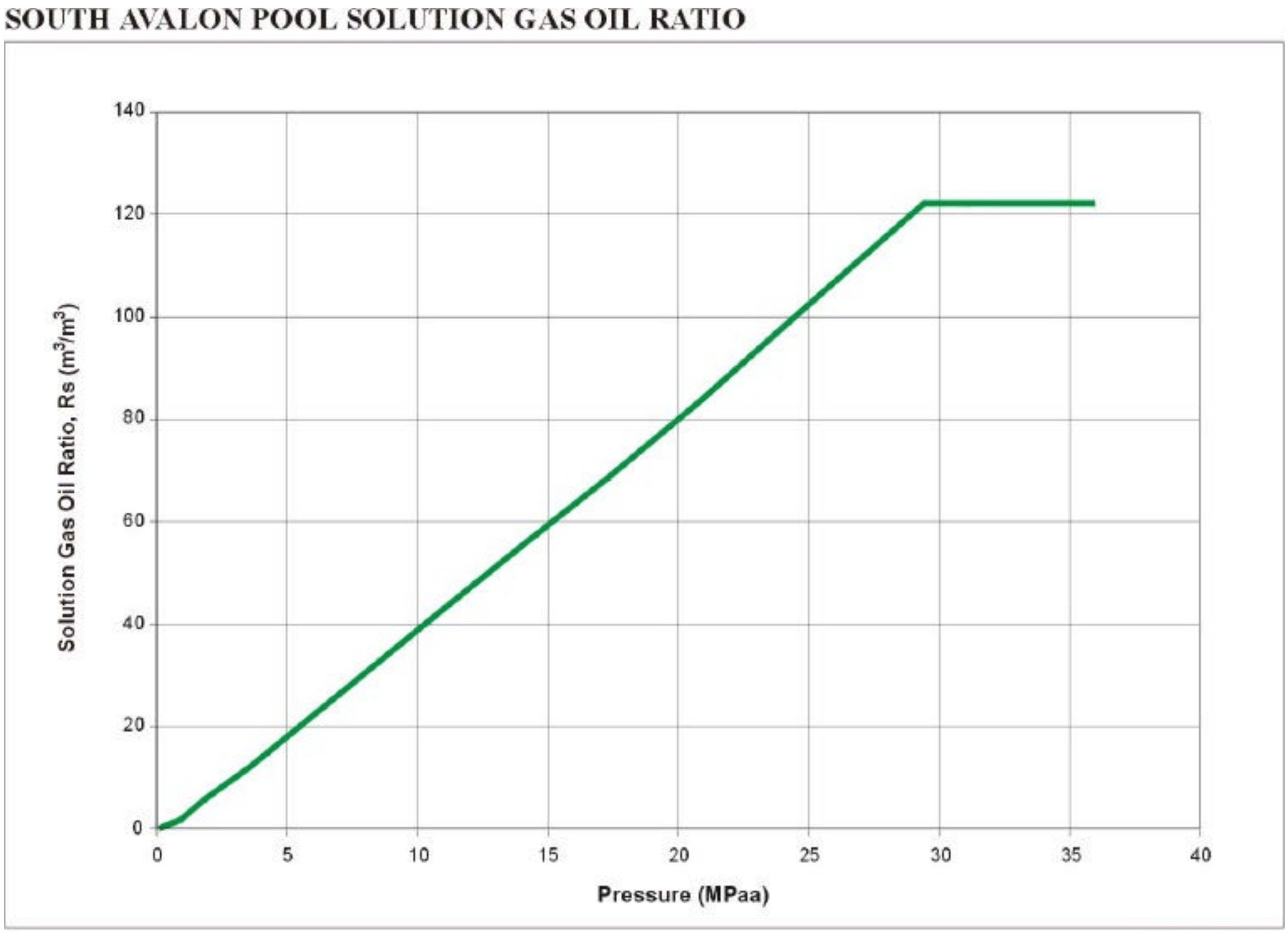


Figure 4.2-2

Figure 4.2–3 South Avalon Pool Oil Viscosity

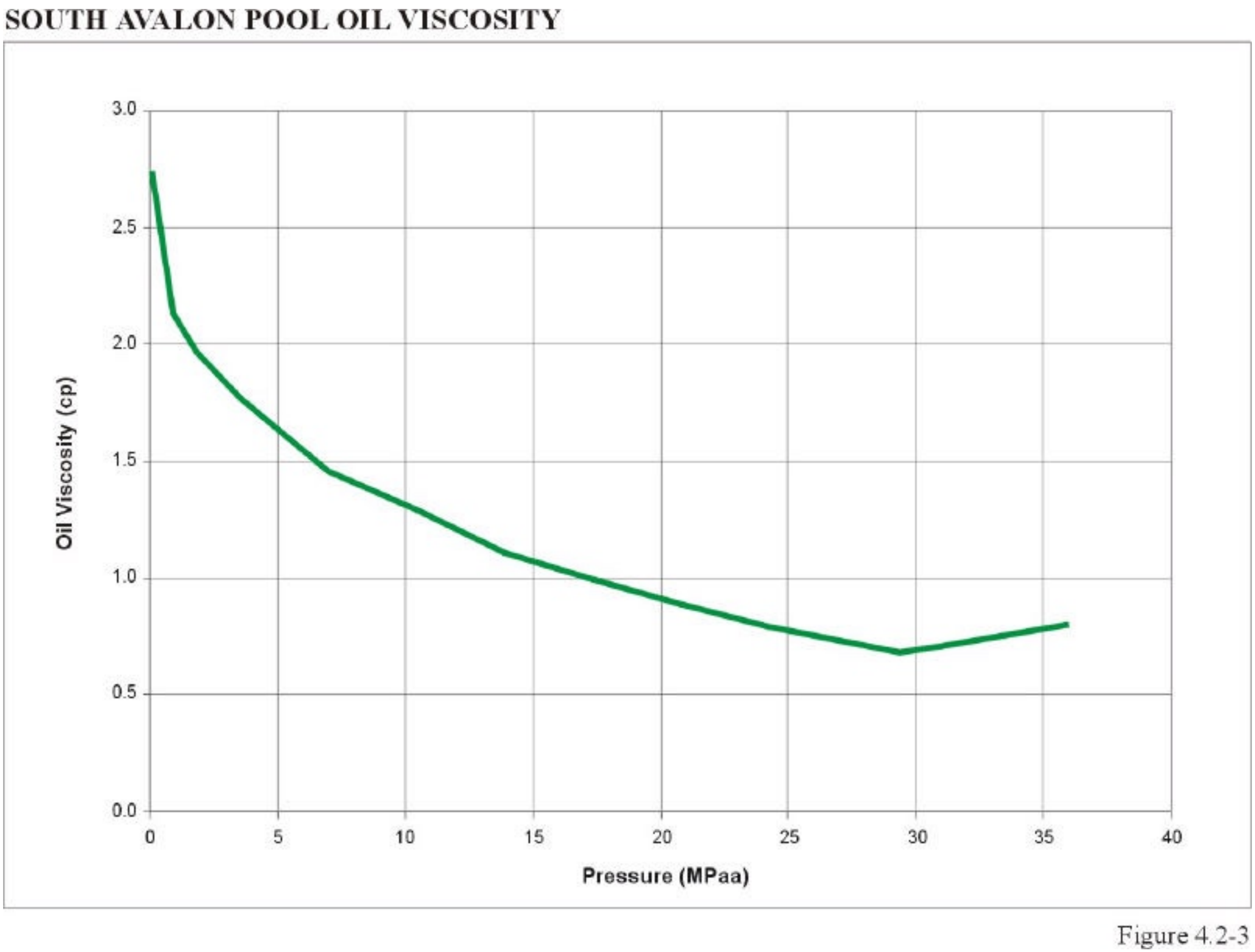


Figure 4.2–4 South Avalon Pool Gas Formation Volume Factor and Viscosity

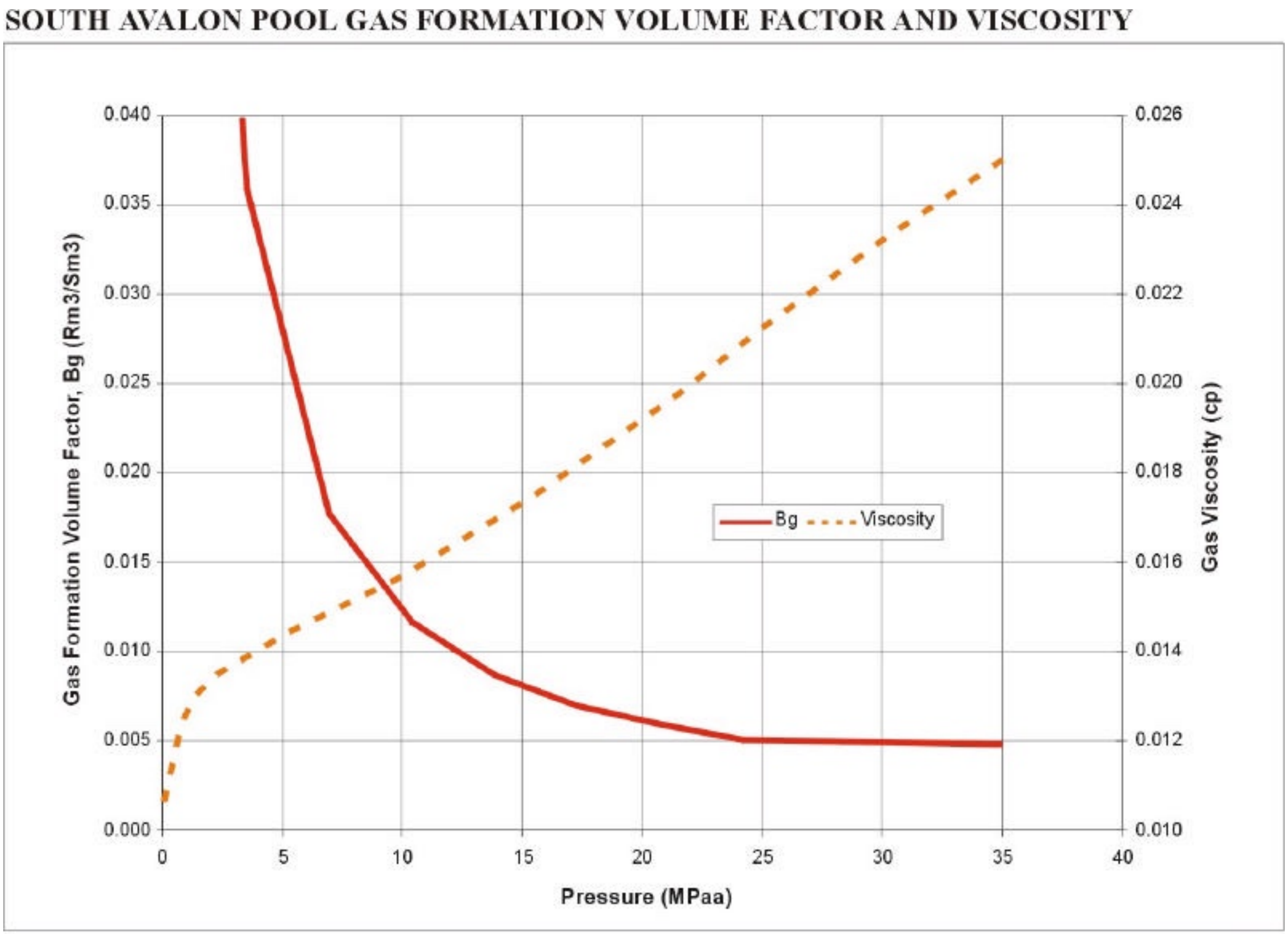


Figure 4.2-4

Table 4.2-5 Average Oil and Gas Compositions South Avalon Pool

Component	Reservoir Oil (mol %)	Stock Tank Oil (mol %)	Gas Cap Gas (mol %)	Solution Gas (mol %)	Fuel Gas (mol %)
N_2	1.12	0.00	1.19	0.90	1.01
CO_2	1.00	0.00	1.48	1.72	1.67
H_2S	--	0.00	0.00	0.00	0.00
Methane	47.02	0.00	87.73	81.58	86.66
Ethane	4.02	0.00	4.45	6.77	5.96
Propane	2.77	0.43	2.46	4.06	2.69
i-Butane	0.51	0.29	0.39	0.58	0.30
n-Butane	2.15	0.24	0.99	2.12	1.00
i-Pentane	0.84	1.38	0.29	0.57	0.21
n-Pentane	1.15	1.78	0.41	0.63	0.22
Hexane+	39.42	93.88	0.61	1.07	0.28
Total	100.00	100.00	100.00	100.00	100.00

Table 4.2-6 South Avalon Pool Gas Gravity and Pseudocritical Properties

Parameter	Gas Cap Gas	Solution Gas	Fuel Gas
Specific Gravity (air = 1.0)	0.6669	0.7345	0.6629
Pseudocritical Temperature (°K)	206.54	220.78	208.6
Pseudocritical Pressure (kPa)	4,571.33	4,602.44	4,618.46
LGR ($m^3/10^3m^3$)	218	369	187

Figure 4.2–5 North Avalon Pool Formation Volume Factor

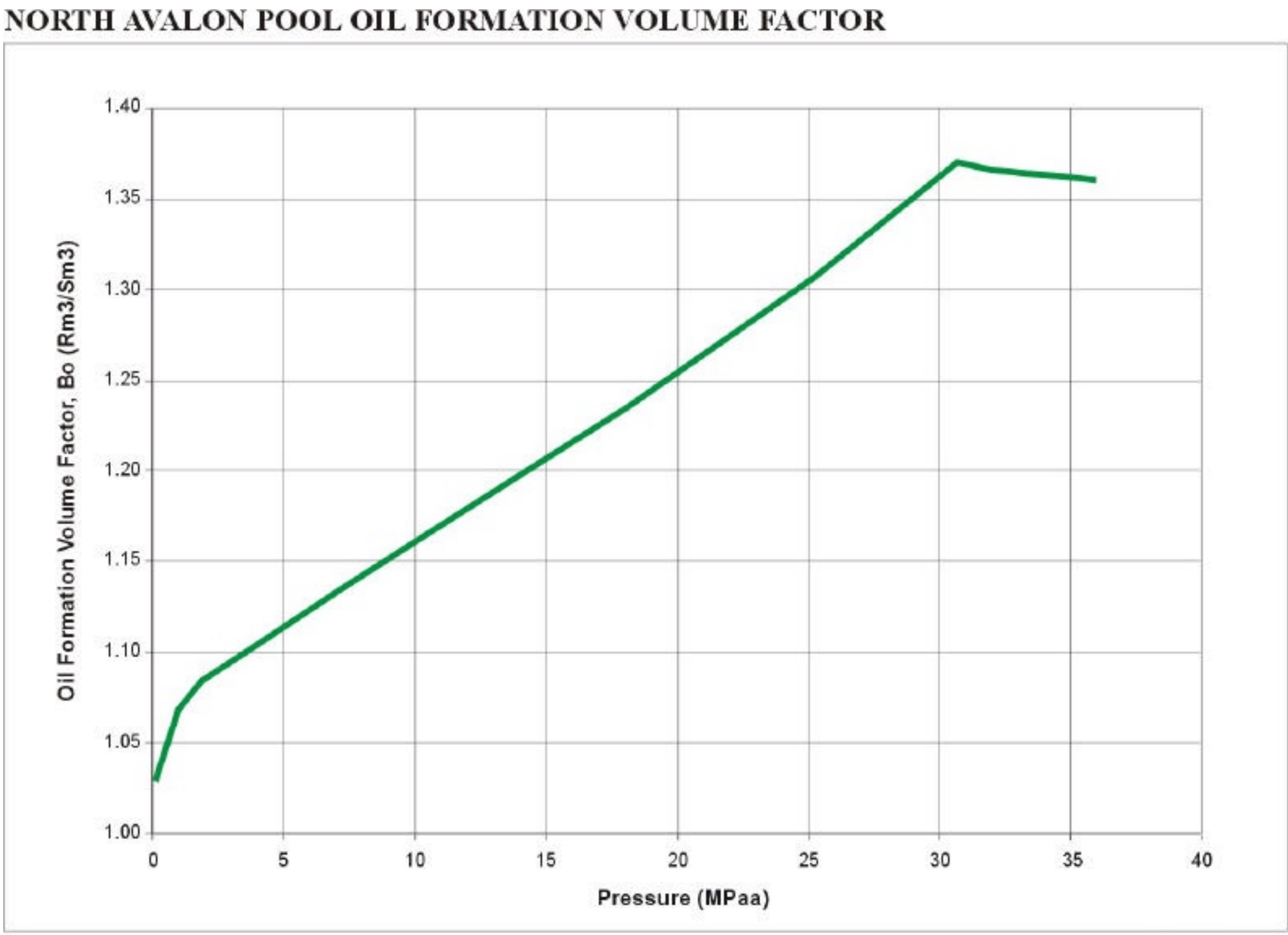


Figure 4.2-5

Figure 4.2–6 North Avalon Pool Solution Gas Oil Ratio

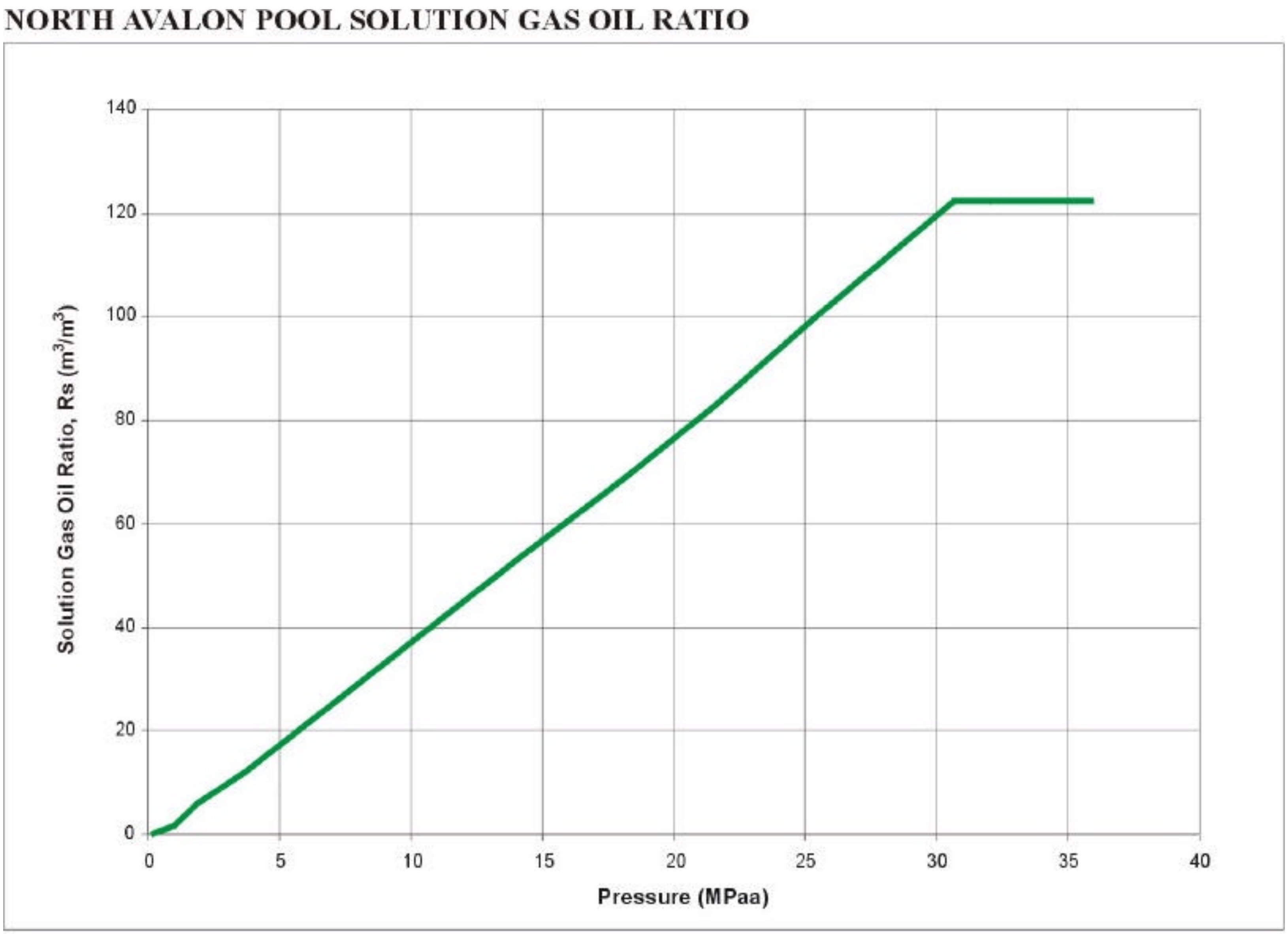


Figure 4.2-6

Figure 4.2–7 North Avalon Pool Oil Viscosity

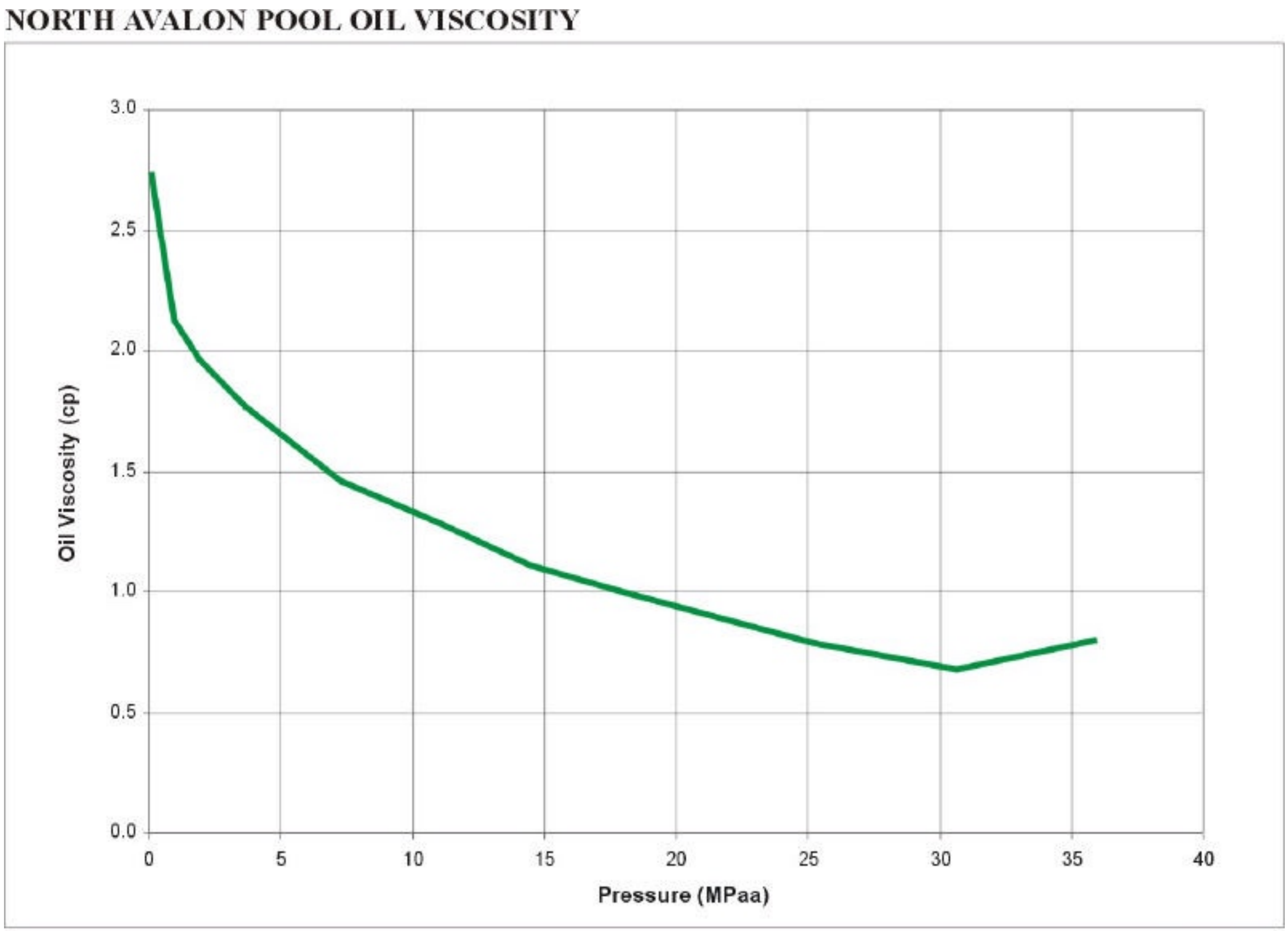


Figure 4.2-7

Figure 4.2–8 North Avalon Pool Gas Formation Volume Factor and Viscosity

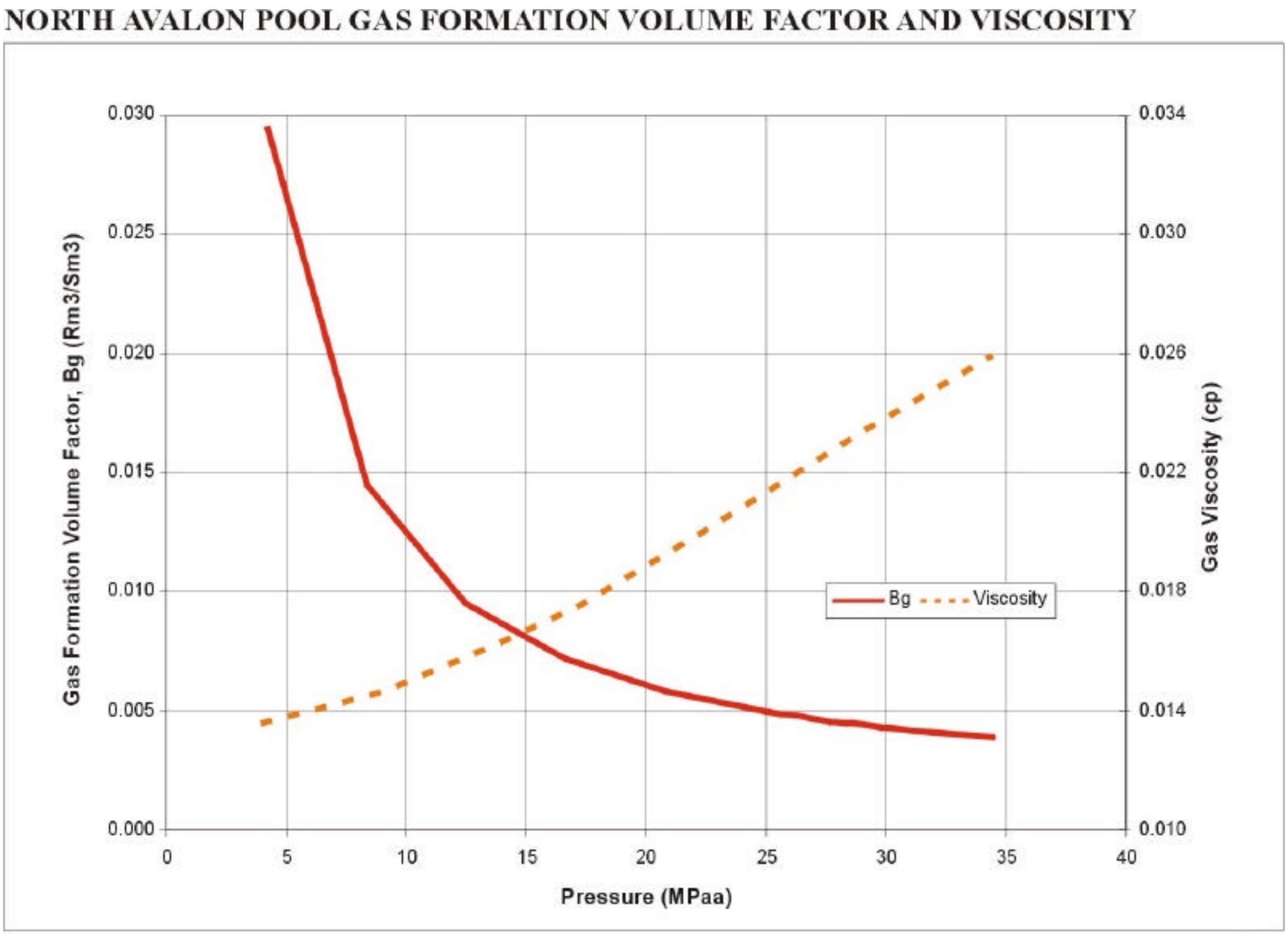


Figure 4.2-8

The reservoir fluid characteristics used in the calculation of OOIP and OGIP includes:

- an oil formation volume factor of 1.37 reservoir m^3 per stock tank m^3;
- a solution gas GOR of 122 m^3 of gas at standard conditions per m^3 of stock tank oil; and
- a gas formation volume factor of 0.0046 reservoir m^3 per m^3 at standard conditions.

4.2.3 West Avalon Pool Pressure, Volume, Temperature

The oil and gas phase fluid properties in the West White Rose hydrocarbon accumulation are provided for use in the calculation of this area's OOIP and OGIP. The fluid characteristics include:

- an oil formation volume factor of 1.41 reservoir m^3 per stock tank m^3;
- a solution gas GOR of 146 m^3 of gas at standard conditions per m^3 of stock tank oil; and
- a gas formation volume factor of 0.0037 reservoir m^3 per m^3 at standard conditions.

These reservoir characteristics are based on the fluids collected from the J-49 well, during DST #7.

4.2.4 Summary of Avalon Pressure, Volume, Temperature

The basic fluid properties used in OOIP and OGIP calculations for the three Avalon pools are summarized in Table 4.2-7.

Table 4.2-7 Basis Fluid Properties Used in OOIP and OGIP Calculations

Pool	Bo (m^3/m^3)	GOR (m^3/m^3)	Gas Cap (Bg m^3/m^3)
South	1.37	122	0.0046
North	1.37	122	0.0046
West	1.41	146	0.0037

4.2.5 Water

All formation water samples acquired to date had some level of contamination that makes assessment of formation water composition difficult. Sample #208 obtained during MDT operations at L-08 was used as a representative sample. The sample showed the least amount of contamination (approximately 7 percent) based on tritium tracer analysis. The tracer concentration data were used to generate a corrected compositional analysis. This analysis also gave the best match for petrophysical water saturation determinations. The composition used for the evaluations is given in Section 3.2 (Table 3.2-5).

4.3 Special Core Analysis

Several special core analysis studies have been completed or are in progress for the wells drilled in 1999.

4.3.1 Avalon Relative Permeability and Capillary Pressure Correlations

The relative permeability data used for the current evaluation were obtained from experiments conducted on core plugs obtained from L-08 well. The plugs were restored to an irreducible water saturation of 19 percent, corresponding to a point in the middle of the oil column based on the capillary pressure measurements made in a number of core plugs. An average water saturation close to this value was confirmed by the measurements conducted on the preserved core samples from the A-17 well. The water-oil and gas-oil relative permeability curves used in the simulation are shown in Figures 4.3-1 and 4.3-2. Currently, full size core floods are being conducted in a gravity stable manner to confirm small diameter core plug stack measurements.

The water-oil capillary pressure curve from L-08 SCAL studies was adjusted so that the approximately 20 m of transition zone seen on the well logs would be obtained at the water-oil contact in the simulation model. The gas-oil capillary pressure was assumed to be zero. The water-oil capillary pressure used in studies is plotted in Figure 4.3-3.

Figure 4.3–1 White Rose Water Oil Relative Permeability From L-08 Stack-2

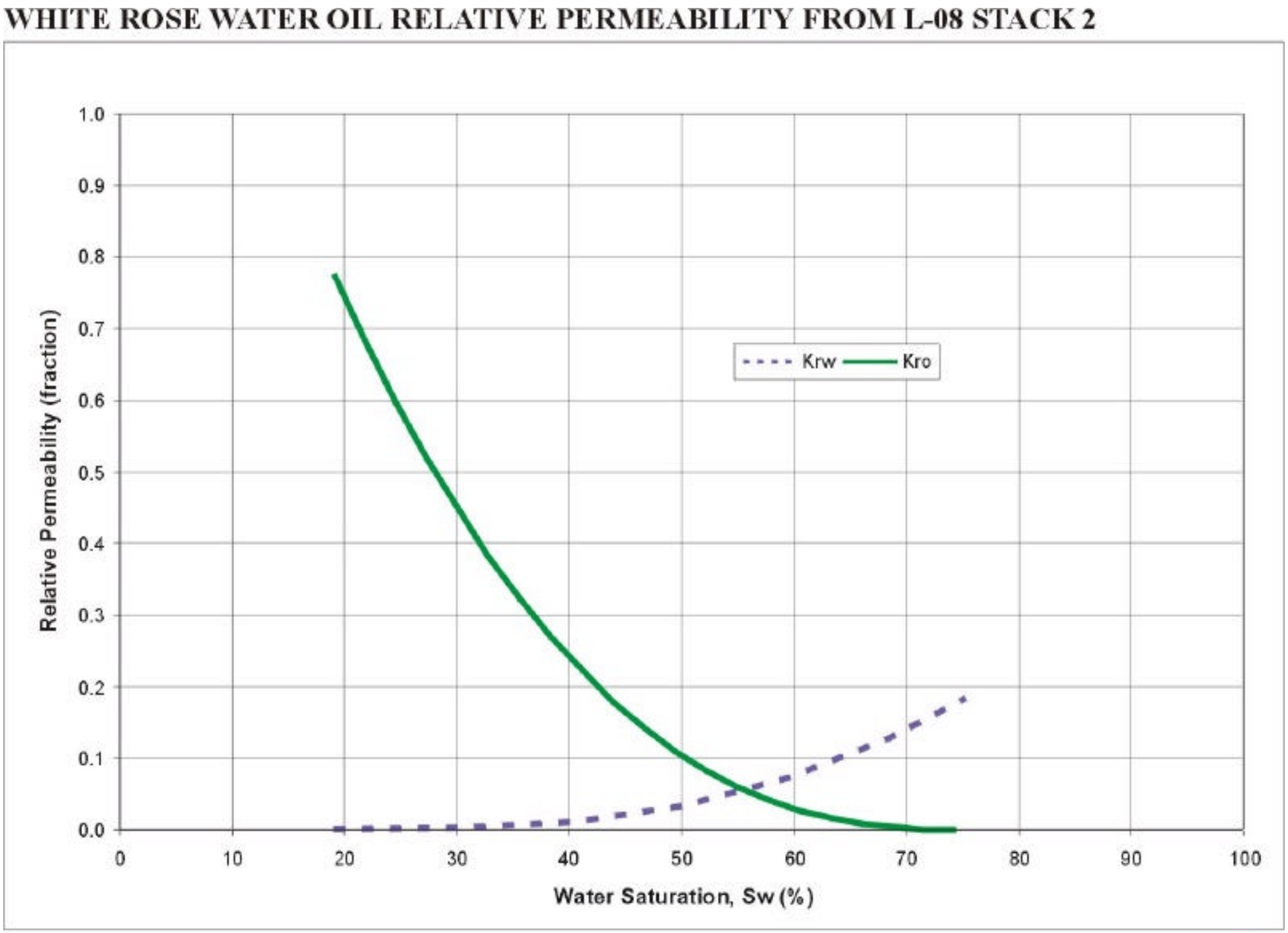


Figure 4.3-1

Figure 4.3–2 White Rose Gas-Oil Relative Permeability From L-08 Stack-2

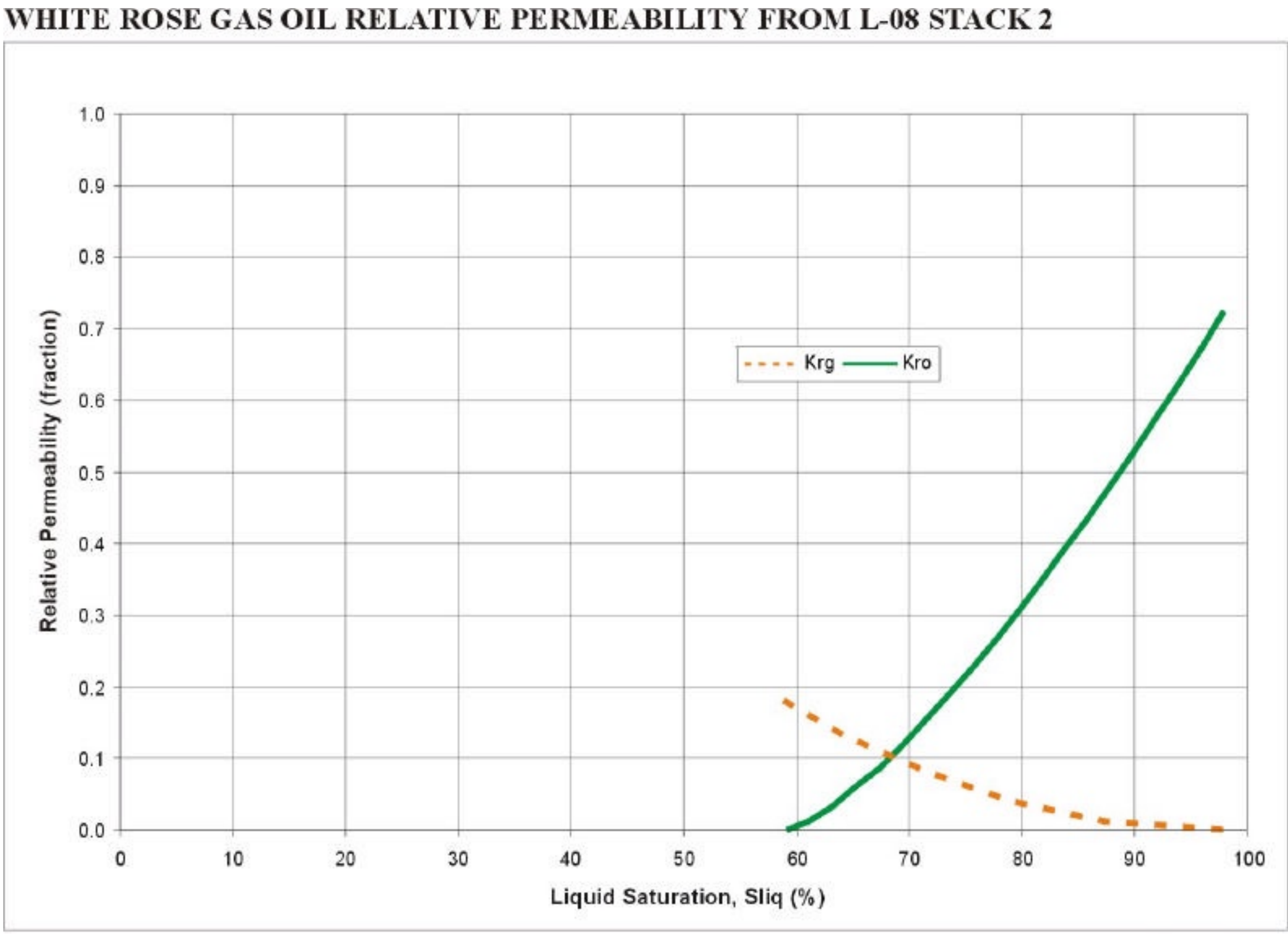


Figure 4.3-2

Figure 4.3–3 White Rose Capillary Pressure Curve Used in Simulations

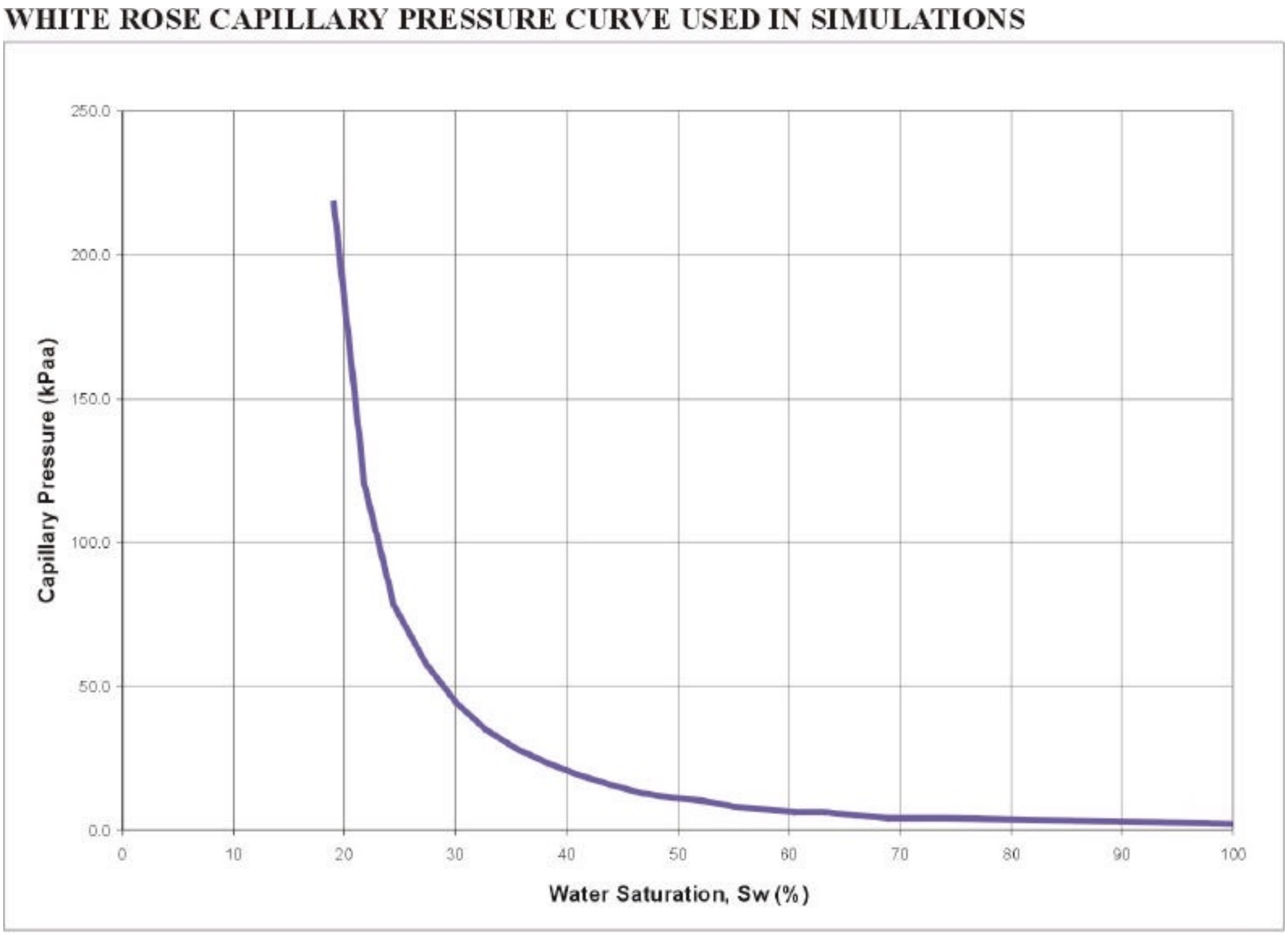


Figure 4.3-3

4.4 Well Productivity

This section summarizes the results of the various production tests carried out on the White Rose wells drilled to date.

A total of 25 drill stem tests have been run in the White Rose Field. A detailed listing of well test results and interpretations is given in Tables 4.4-1 to 4.4-3.

In addition to the DSTs, MDT interference tests have also been run to assess vertical communication in the formation and Production Logging Tests/Multi-Layer Tests (PLT/MLT) have been run to evaluate inflow performance.

4.4.1 Productivity and Skin Damage Assessment

Productivity indices from oil tests, and deliverability constants from gas tests have been calculated for each well and are given in Table 4.4-1.

Total production rates from the combined tested intervals varied from 395 to 886 m^3/d. All the tests indicated significant skin damages ranging from approximately +1 to greater than +15. If the damage zone in these wells could be removed or bypassed, then production rates could significantly increase, as is illustrated by the undamaged productivity indices provided in Table 4.4-1.

The base case depletion plan calls for horizontal wells to improve both well productivities and clarity recoveries from the field. Horizontal well lengths are expected to be in the order of 1,500 to 2,000 m. Studies, currently in progress, indicate that horizontal well productivities could be more than twice those of a vertical well, depending on the length of the horizontal section and reservoir quality. On this basis, the average initial oil well capability in South Avalon Pool should be in the order of 3,600 m^3/d of oil at a 20 percent drawdown.

4.4.2 Vertical Communication Tests - Calcite Cemented Zones

In addition to standard DSTs, vertical interference tests were run on the E-09 and L-08 wells in order to examine the impact of calcite cemented sections on vertical communication within the reservoir.

Preliminary test analysis of L-08 DST #2 indicate that major calcite cemented zones could either extend for 64 to 84 m before vertical communication is seen around the cemented zone or have effective vertical permeabilities of less than 0.5 mD.

Table 4.4-1 White Rose Oil DST Summary

Location	DST #	Formation	Interval (mRT)	Fluid Type	Maximum Oil Flow Rate (m3/d)	Oil Gravity (API)	Net Pay (m)	Estimated kh (m*mD)	Estimated Oil Permeability (mD)	Skin Factor	Maximum Radius of Investigation (m)	Boundaries Encountered (yes or no)	Productivity Index	
													As Tested (m^3/d/kPa)	Undamaged (m^3/d/kPa)
J-49	6	Avalon	3124-3131	Oil	224	30.9	7.9	255	32.3	5.7	164	NO	0.0133	0.0246
J-49	7	Avalon	3093.5-3106	Oil	171	32.8	11.4	1071.6	94	50	517	NO	0.0137	0.3095
E-09	3	Avalon	2958-2986 2991-3009	Oil	830	30.5	44.7	2208.18	49.4	4.6	195	YES	0.1162	0.1841
E-09	4	Avalon	2935.7-2945-7	Oil	230	31.6	10	900	90	11.2	275	YES	0.0224	0.0391
E-09	5	Avalon	2915.5-2923.5	Oil	68	30.7	8	56.8	7.1	0.42	101	YES	0.0056	0.0059
E-09	6	Avalon	2958-2986 2991-3009 2935.7-2945.7 2915.5-2923.5	Oil	642	30.7	63	3465	55	6.3	188	YES	0.0956	0.1301
E-09	7A	Avalon	2903.6-2986 2990.6-3009	Oil	717	30.7	101	3131	31	5.8	273	YES	0.1463	0.2493
A-17	1	Avalon	2912-2930 2935-2947 2950-2953 2956-2998	Oil	886	30	87	7938.4	91.25	12.47	334	YES	0.2218	0.4917
L-08	1	Avalon	2942-3001.5	Oil	370	31.2	56.4	5076	90	7	251	YES	0.1525	0.2245
L-08	2	Avalon	2920-2932	Oil	306	31.2	13	1430	110	13	328	YES	0.0308	0.0536
N-22	1	Lower Hibernia	3565-3572	Oil	57	32.2	7	56	9	14.4	84	NO	0.0031	0.0138
N-22	2	Lower Hibernia	3542-3554	Oil	87	32	12	63.6	5.3	14.6	124	NO	0.0032	0.0104
E-09	2	Basal Hibernia	3661-3684	Oil	78	38.3	9	10.8	1.2	2.1	56	NO	0.0022	0.0028
E-09	1A	Jurassic	3792.6-3970	Oil	46	32.8	12.5	12.5	1	1	40	NO	0.0014	0.0016

Table 4.4-2 White Rose Gas DST Summary

Location	DST #	Formation	Interval (mRT)	Fluid Type	Maximum Gas Flow Rate (e3m3/d)	Gas Gravity	Net Pay (m)	Estimated kh (m*mD)	Estimated Gas Permeability (mD)	Skin Factor	Maximum Radius of Investigation (m)	Boundaries Encountered (yes or no)	Deliverability	
													Constant C ($e^3m^3/d/kPa^2$)	Exponent n
N-22	3	Avalon	2725-2727	Gas	40	0.664	2	33.2	16.6	102	116	NO	5.79E-08	1.0
N-22	4	Avalon	2689-2695	Gas	101	0.665	6	117.6	19.6	82.2	179	NO	4.24E-03	0.5
N-22	5	Avalon	2663-2680	Gas	602	0.653	17	2414	142	8.9	394	NO	9.19E-02	0.5
J-49	8	Avalon	3063-3067	Gas	178	0.634	1.8	57	31.6	12.7	213	NO	6.69E-03	0.5
L-61	2	Avalon	2986.5-2991.5	Gas	3.3	0.625	2.2	0.07	0.03	-3.4	5	NO	2.87E-09	1.0
N-30	1	Avalon	2924.9-2943.7 2963.3-2984.6 2988.9-3014.2 3027.4-3033.7	Gas	825	0.67	54.3	1710.5	31.5	4.75	352	YES	8.58E-02	0.5
N-22	6	Wyandot Chalk	2380-2389	Gas	0.5	0.632	6	0.09	0.0147	8.8		NO	7.46E-10	1.0
L-61	3	South Mara	2527.5-2534	Gas	685	0.65	5.2	3593	691	12.7	647	NO	1.06E-01	0.5
J-49	2	Eastern Shoals	3212-3218.5	Gas	67	0.64	1.2	51	42.5	37	240	YES	1.16E-07	1.0

Table 4.4-3 White Rose Water DST Summary

Location	DST #	Formation	Interval (mRT)	Fluid Type	Maximum Water Flow Rate (m^3/d)	Water Salinity (ppm Cl)	Net Pay (m)	Estimated kh (m*mD)	Estimated Water Permeability (mD)	Skin Factor	Maximum Radius of Investigation (m)	Boundaries Encountered (yes or no)
J-49	4	Eastern Shoals	3161.5-3168	Mud Filtrate	4.4		3.3	19	5.8	20.2	120	NO
L-61	1	Avalon Sandstone	3006-3014.5	Water	54.2	22200	2.5	23	9.2	0.2	193.8528	NO

4.4.3 Vertical Communication Tests – Vertical Sand Permeability

Several MDT vertical interference tests were conducted which examined vertical communication at the 0.7 to 3.1 m scale. The results in turn were compared to kv/kh ratios measured from core to ensure that upscaling routines from log scale to reservoir simulation scale were appropriate.

The vertical to horizontal permeability (kv\kh) ratios determined from the MDT interference tests indicate decreasing kv/kh ratios as the interval increases. The average core plug scale kv/kh ratios are approximately 0.74. The MDT results have an average kv/kh ratio of 0.37 for a 0.7-m interval, 0.19 for a 2.4-m interval and 0.06 for 3.1-m interval (Schlumberger 2000 (l08 MDT Report); 2000 (A-17 MDT Report); 2000 (L-08 MDT V17 Report); 2000 (A-17 MDT V17 Report).

4.4.4 Production Logging And Multi-Layer Testing

PLT/MLT were performed on the A-17 and N-30 wells. These tests were done to assess the productivity contributions and horizontal permeabilities from the various sand intervals in the wells without incurring the large costs associated with running multiple DSTs. The tests were successful and provided reasonable matches between permeability height estimates determined from core logs and flow with those determined from contributions measured by PLT/MLT for the various test intervals in the wells. The results support the use of PLT in future wells for performance determinations (SPE paper 63080, Coskuner et al.). Permeability height estimates calculated from log and core correlations are compared with those determined by PLT/MLT in Figure 4.4-1. Also shown on the figure is the comparison for total permeability heights determined from other DST results in the field.

Figure 4.4–1 White Rose Avalon Formation – Flow Capacities From Tests and Logs

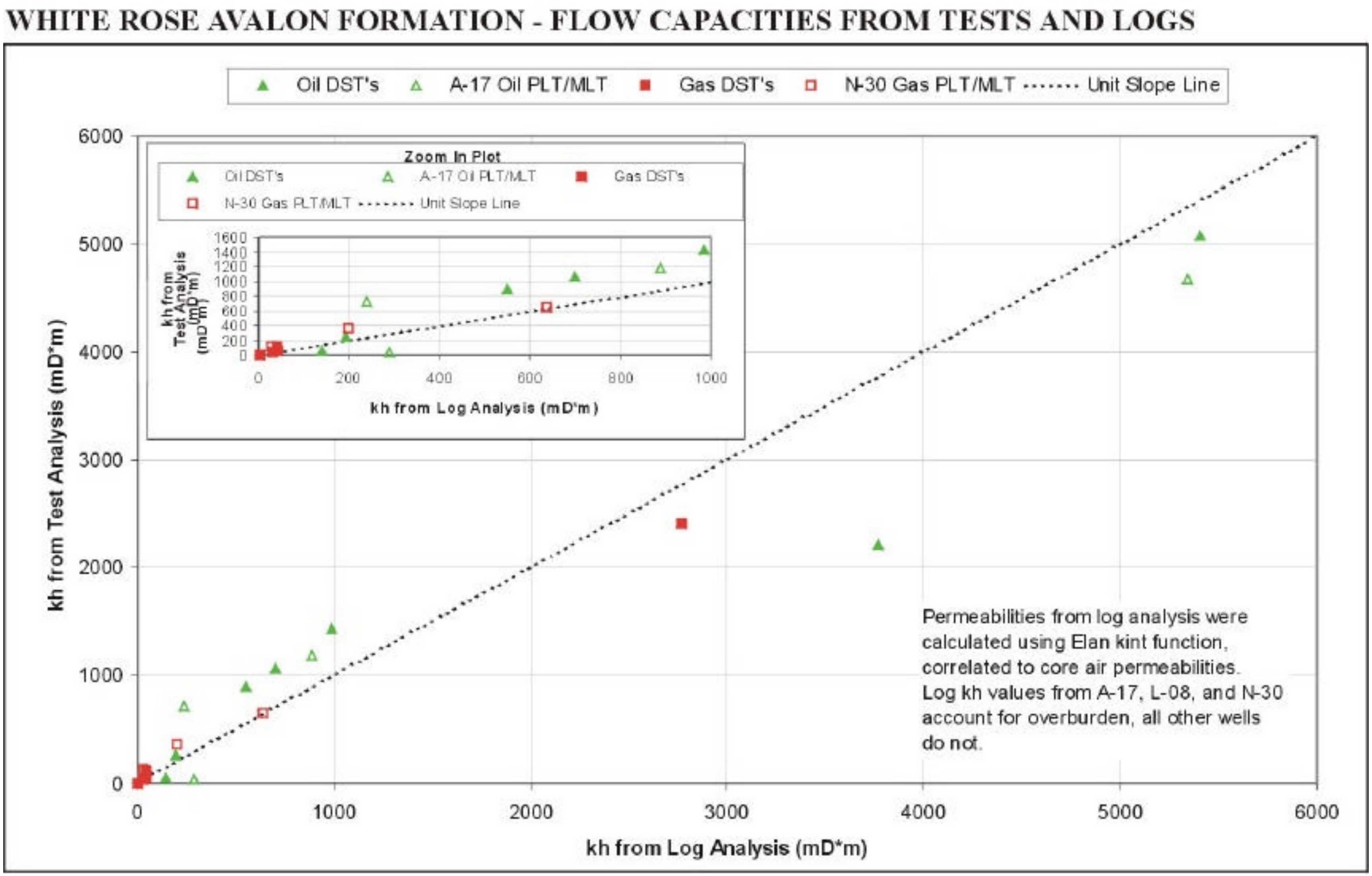


Figure 4.4-1

4.5 Reservoir Pressure and Temperature Gradients

Several pressure measurements have been taken through wireline and DST operations associated with the White Rose exploration and delineation wells drilled to date. A summary plot of the pressures taken versus depth for all formations is provided in Figure 4.5-1.

4.5.1 Reservoir Pressure Versus Depth and Fluid Contacts

Reservoir pressures from MDT and DST measurements are plotted versus depth on Figure 4.5-2. This information was used to determine pressure gradients and confirm contacts seen on logs or extrapolate contacts where they were not observed in the wells. Each of the Avalon pools have distinct pressure profiles with different gas-oil and oil-water contacts but with reasonably similar water gradients.

Gas-oil and oil-water contacts for each of the pools are summarized in Table 4.5-1.

Table 4.5-1 Avalon Pool Contacts

Pool	Gas-Oil Contact (mSS)	Oil-Water Contact (mSS)
South Avalon	2,872	3,009
North Avalon	3,014	3,073
West Avalon	3,064	3,127

Pressure versus depth relationships were also used to verify fluid density and PVT data measured from samples obtained during MDT and DST operations.

There is a good match between gradients determined from pressure data and those determined from densities measured from samples. Comparison of gradients determined from pressure plots with those determined from sample density information is provided in Table 4.5-2.

Pressures at gas-oil interfaces were also used to check PVT sample quality by comparing oil sample bubble points to the contact pressures as described in Section 4.2.

Figure 4.5–1 White Rose Pressure Profiles – All Formations (Includes Wireline and DST Data)

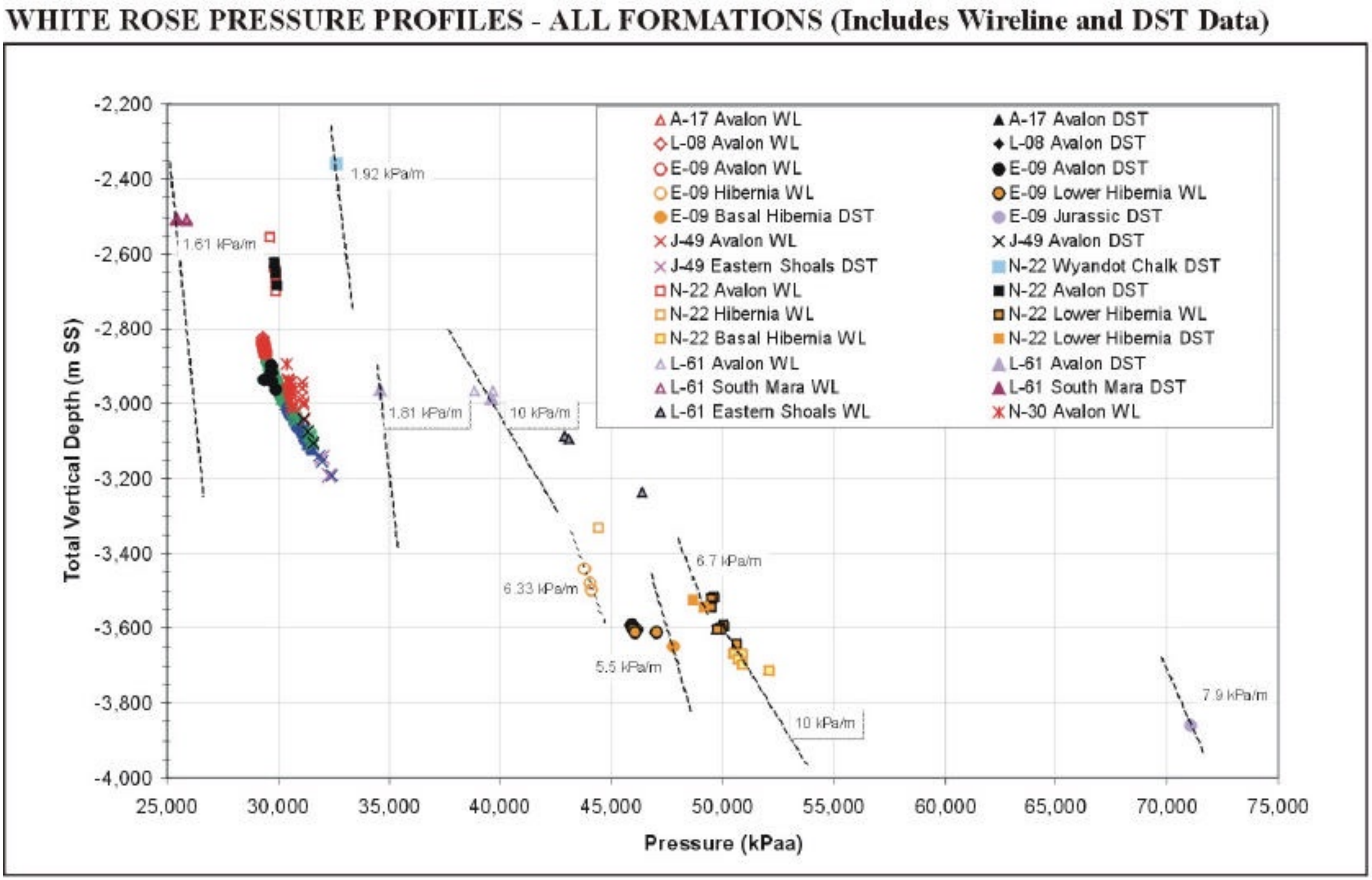


Figure 4.5-1

Figure 4.5–2 White Rose Pressure Profiles – Avalon and Eastern Shoals Formations

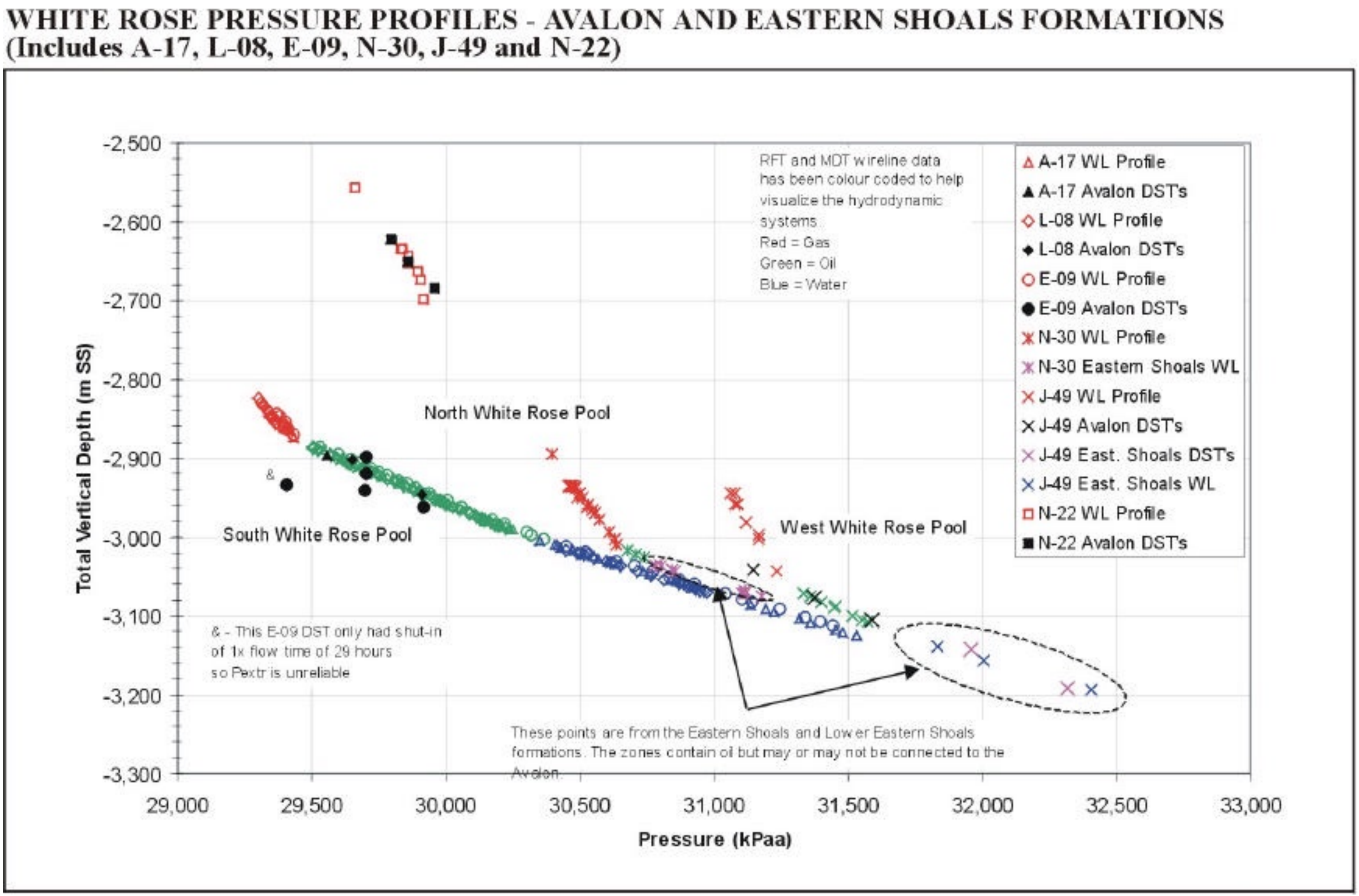


Figure 4.5-2

Table 4.5-2 Summary of Fluid Gradients by MDT

Pool	Source	Reservoir Gas Gradient (kPa/m)	Reservoir Oil Gradient (kPa/m)	Reservoir Water Gradient (kPa/m)	PVT Analysis Reservoir Oil Gradient (kPa/m)
South White Rose	A-17	2.53	6.96	9.71	7.07
	L-08	2.11	6.98	9.65	7.06
	E-09	2.28	7.09	9.81	6.85
	Average	2.31	7.01	9.72	6.99
	Pool Plot		7.04	9.88	
North White Rose	N-30	2.26	6.70		
	N-22	1.99			
	Average	2.13	6.70		
	Pool Plot	2.17	6.70		
West White Rose	J-49	1.78	6.77	10.49*	6.77
* The apparent water gradient at J-49 is from the Eastern Shoals and may not be representative due to limited data points and possible lack of communication with the Avalon.					

4.5.2 Temperature Gradients

Temperature gradients for White Rose Avalon pools have been generated using DST gauge data and are plotted in Figure 4.5-3. The temperature gradient in the Avalon formation is 2.8 C°/100 m, which falls within the expected range using standard geothermal gradients. Data points from the E-09 and N-30 tests which lie above the trend from the other wells may be due to temperature gauge calibration errors. E-09 RFT temperature information indicates a temperature gradient that is more consistent with the DST temperature information seen in the other wells.

Figure 4.5–3 White Rose Avalon Temperature Gradients

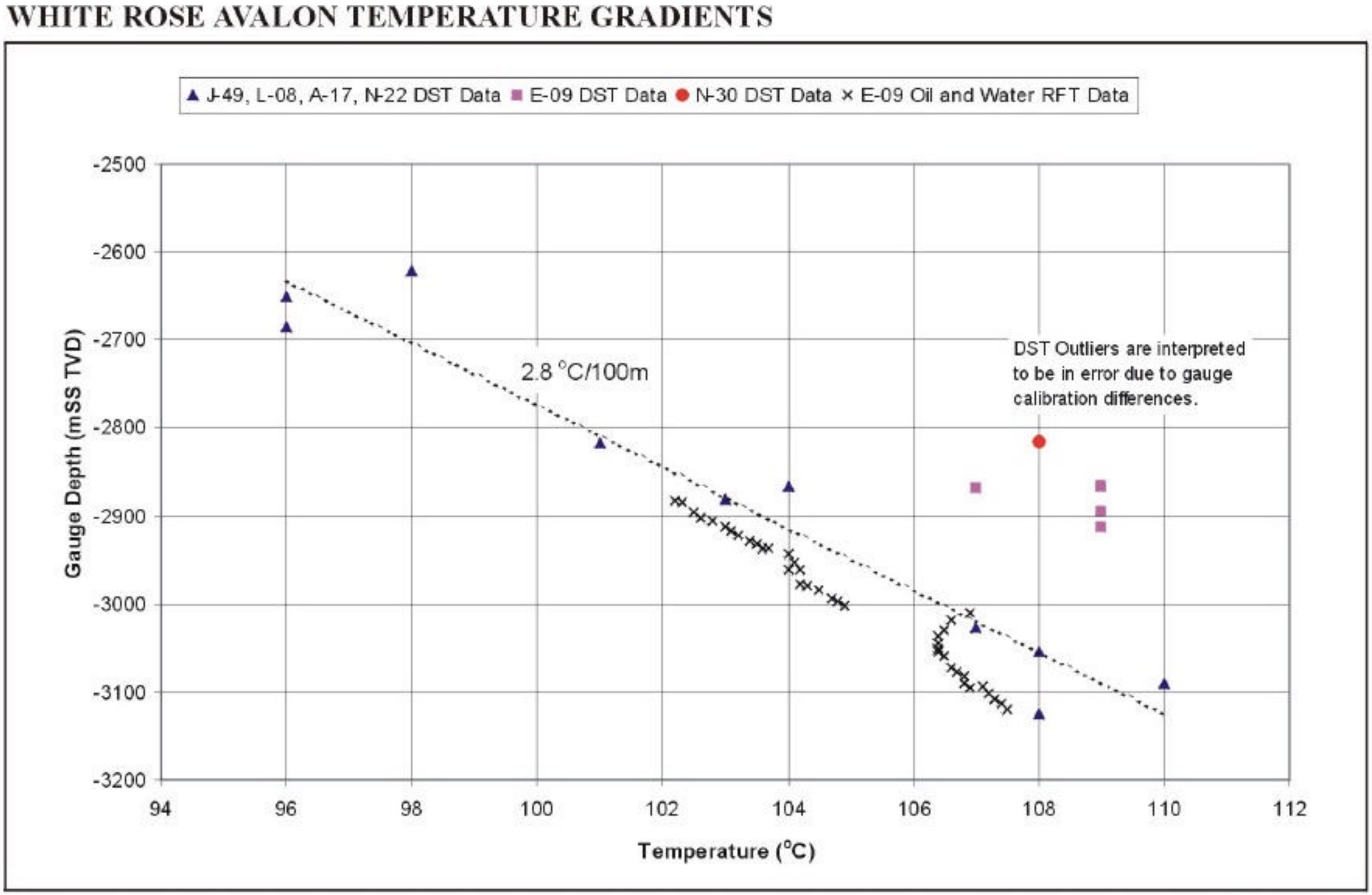


Figure 4.5-3

5 ORIGINAL HYDROCARBONS IN PLACE

The deterministic estimation of oil in place for the White Rose Field was completed using 3-D geological modelling in the "RMS" software package. This procedure involves bringing structural surfaces in from the geophysical package (Landmark), building a detailed fault model, and then modelling both facies distributions and the distribution of petrophysical parameters within the facies model (Deutsch and Hallstrom 2000). Two final models were created; a detailed model of the South Avalon Pool and a more general model which included the South pool as well as the West Avalon Pool and the North Avalon Pool. The two models are similar, with the South Avalon model being more detailed. The extents of the three pools mapped in the White Rose Field are illustrated in Figure 5-1.

Of the input parameters to the OOIP calculation, only the formation volume factor (FVF) was fixed. All of the remaining input came from the 3-D geological model. The net to gross ratio was inherent in the model by the presence of reservoir versus non-reservoir rocks. This was determined from the facies model which reflects current thinking with respect to the distribution of sandstones, siltstones, shales and calcite nodules throughout the Avalon.

These calculations do not take into account the results of the White Rose H-20 well drilled in the summer of 2000, as the models were built prior to the drilling of this well. The geological models will be updated prior to commencement of development drilling and will incorporate the results of the H-20 well. Preliminary estimates indicate that South Avalon OOIP volumes will be reduced in the order of 5 percent once the results of the H-20 well have been incorporated in the geological models.

Figure 5-1 White Rose Complex – Avalon Pools

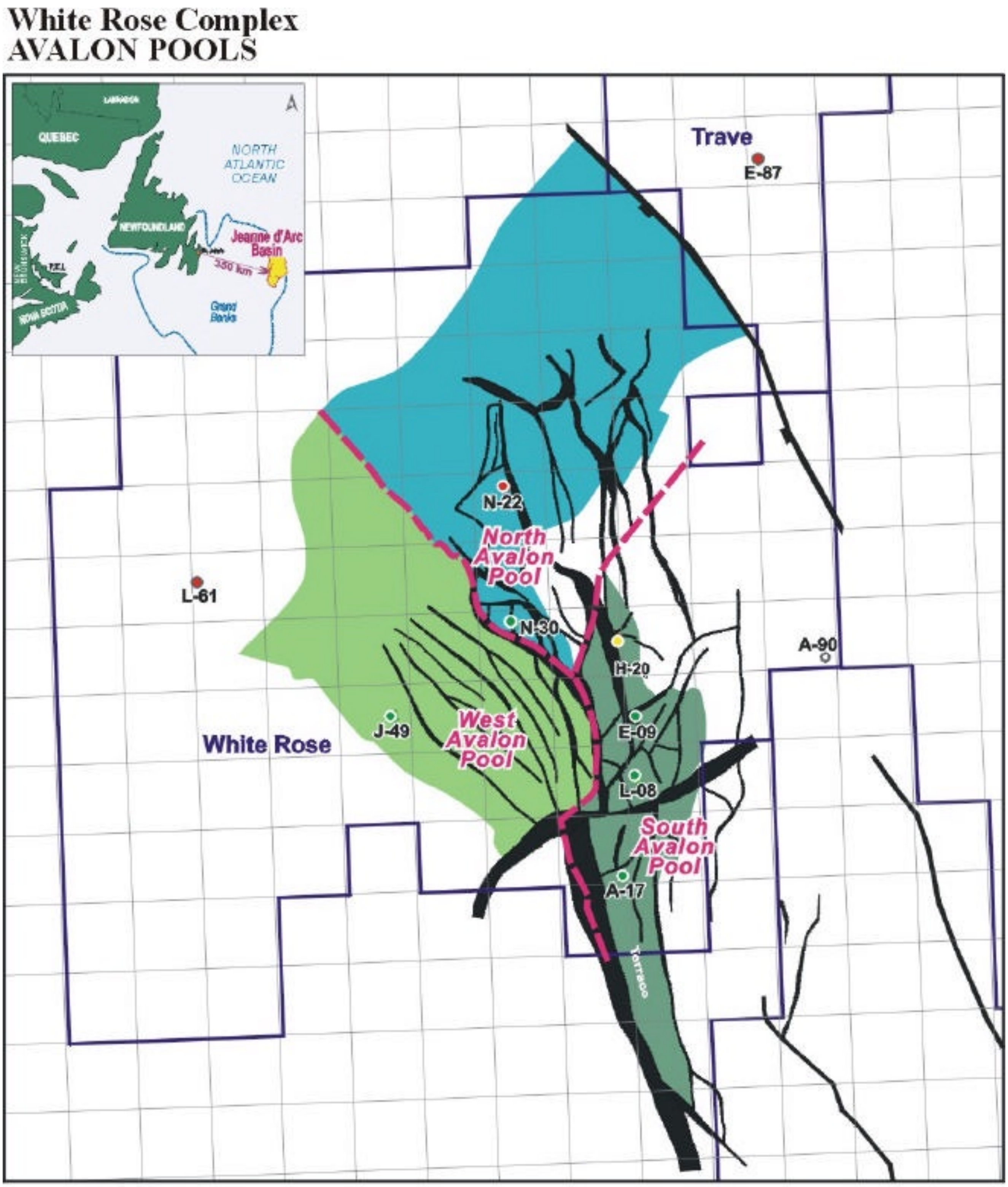


Figure 5-1

5.1 South Avalon Pool

5.1.1 Deterministic Oil in Place, South Avalon Pool

The oil in the South Avalon Pool is spread over approximately 18 km^2 (Figure 5-1), with a gross oil column of 120 m and a 15 to 20 m oil-water transition zone. The gas-oil contact used was 2,872 mSS TVD, the top of the oil-water transition zone 2,989 mSS TVD and the base of the transition zone 3,009 mSS TVD. The water saturation model used for the deterministic oil in place had 100 percent at the base of the transition, 22 percent at the top of the transition zone and 12 percent at the gas-oil contact.

In the South Avalon Pool, estimations of oil in place were calculated on a block by block basis (Table 5.1-1). The total OOIP was calculated as 124.8 $10^6 m^3$. As illustrated by the net oil pay map for the Avalon Formation (Figure 5.1-1), much of the oil is confirmed by the E-09, L-08 and A-17 wells. The only blocks which have not been directly tested by wells are blocks 2, 4, 5, and 6 (Figure 5.1-2). As noted previously, the results of the H-20 well were not entered into these calculations as the well results are currently being analyzed. The results of the H-20 well would potentially lead to the reduction of oil in place in block 2 and, to a lesser extent, block 5. However, as the maps indicate, these two blocks are quite small, and the overall effect on oil in place will be a reduction of the OOIP for the South Avalon Pool of approximately 5 percent (5 to 10 $10^6 m^3$).

5.1.2 Deterministic Gas Cap Gas in Place, South Avalon Pool

The deterministic gas cap gas in place was calculated in the same manner as the oil in place. Most of the gas cap mapped resides on the southern part of the terrace block, south of the A-17 well (Figure 5.1-3). Seismic data suggest that a fault may break the terrace block into more than one segment, with the possibility of separation across the boundary. In addition to this, there is a risk that the sandstone package seen in the A-17 well thins dramatically across this boundary. This risk has been accounted for in the probabilistic resource calculations shown in the next section. The gas formation volume factor used for these calculations is 0.0046.

In total, there are 13.49 $10^9 m^3$ (billion cubic metres) of gas in place in the South Avalon Pool gas cap. Aside from the large gas cap at the southern end of the terrace block, smaller gas caps are present in the fault block to the north of the A-17 well, and around the L-08 well. The gas in place for the individual blocks and the entire South Avalon Pool is illustrated in Table 5.1-1 and Figure 5.1-2.

Table 5.1-1 Resource Calculations for South Avalon Pool

Block	OOIP ($10^6 m^3$)		OGIP ($10^9 m^3$)	
	Deterministic	**Probabilistic P50**	**Deterministic**	**Probabilistic P50**
Block 1	8.9	10.7	0.28	0.34
Block 2	8.7	7.6	0.13	0.11
Block 3	21.8	23.0	1.88	1.78
Block 4	10.7	10.7	0.58	0.51
Block 5	6.0	5.9	0.11	0.10
Block 6	12.1	11.8	0.26	0.21
Block 7	56.1	59.0	10.25	8.72
Block 13	0.5	-	0	-
Total	**124.8**		**13.49**	
Poolwide Analysis (P50)		**127**		**12.0**

Figure 5.1–1 Avalon Full Field, Net Oil Pay

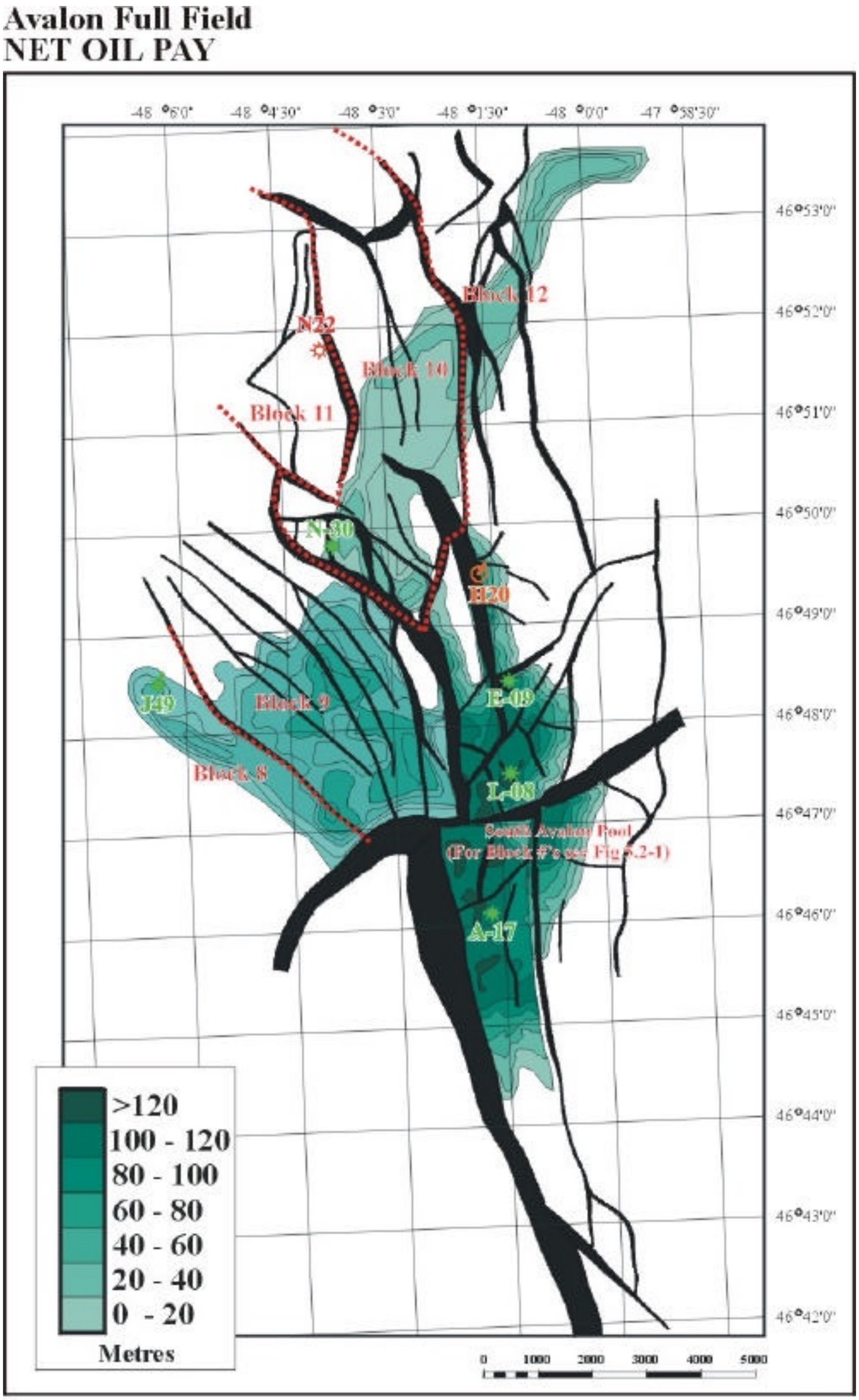


Figure 5.1-1

Figure 5.1–2 South Avalon Pool In Place Deterministic Resources

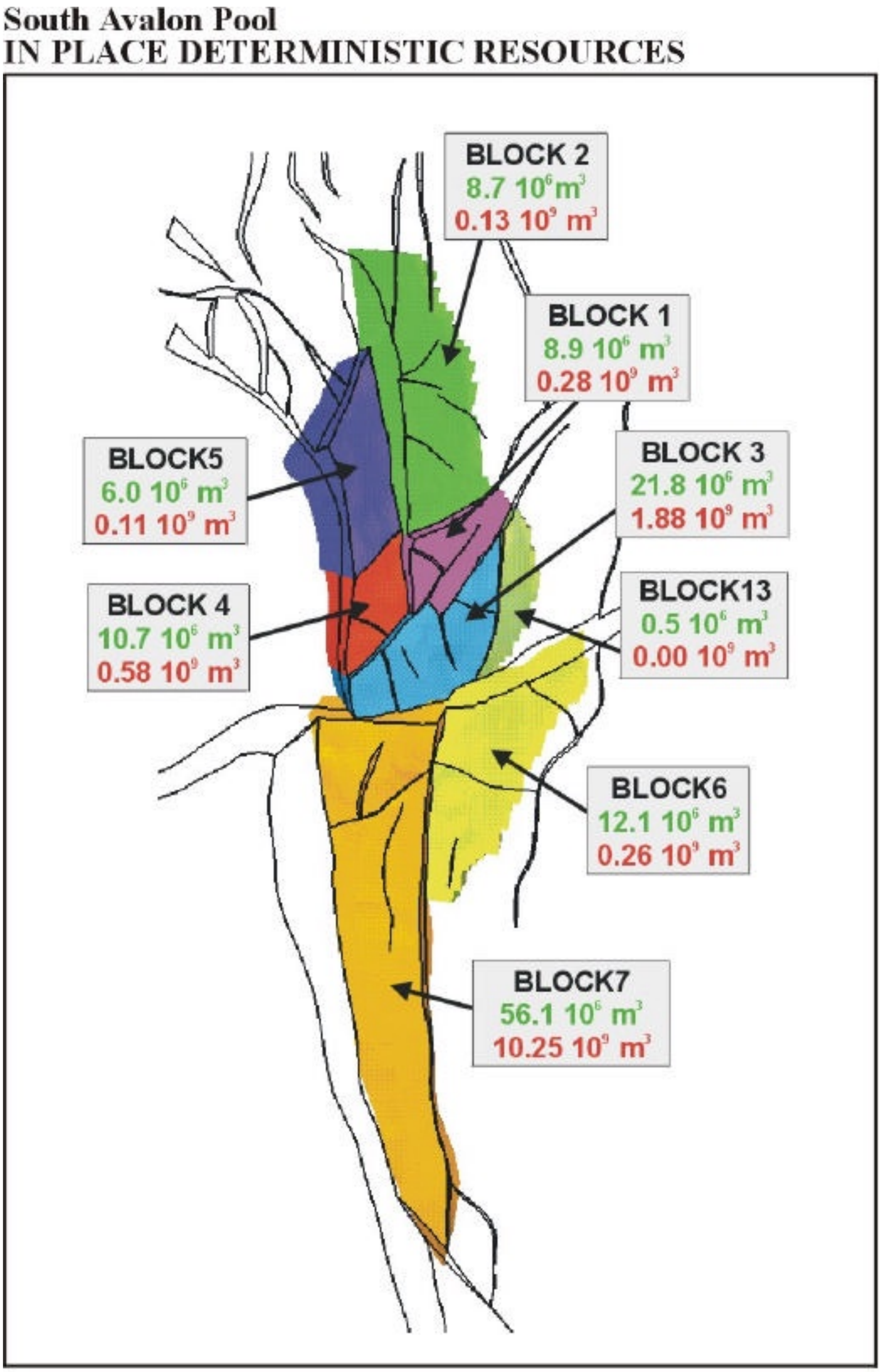
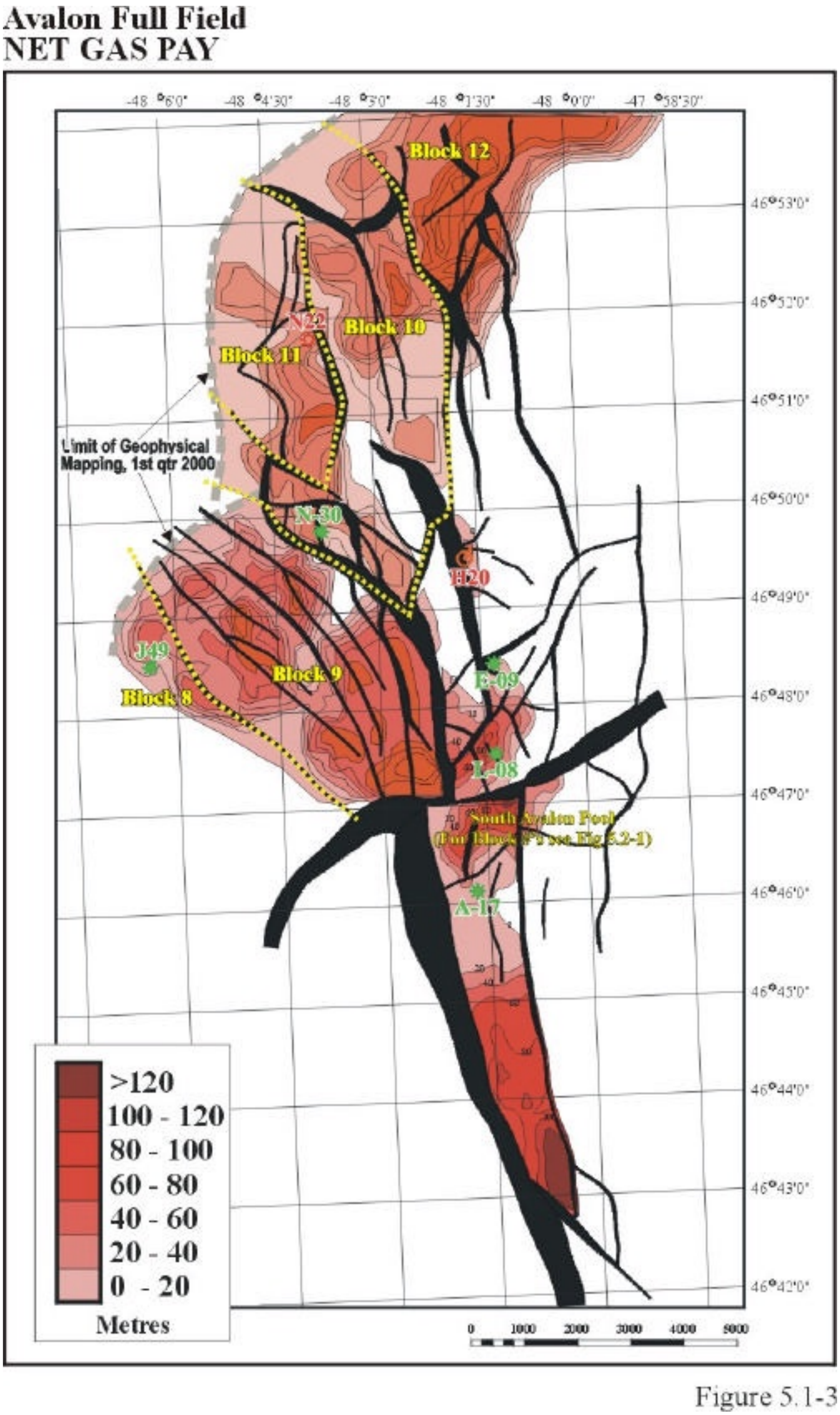


Figure 5.1-2

Figure 5.1–3 Avalon Full Field, Net Gas Pay



5.1.3 Probabilistic Oil in Place, South Avalon Pool

The probabilistic estimates of oil and gas in place have been made using the Monte Carlo method of uncertainty modelling. Each variable in the equation used to determine in place volumes were given distributions based on well and seismic data and their interpretations. The distributions reflect the range and uncertainty of each variable used. Some variables such as the FVF do not have large ranges, while other variables such as the porosity or rock volume often have larger ranges. The shapes of the different input distributions ranged from log-normal to triangular to general, depending on the variable. The program "@Risk" was used to run multiple realizations of the oil or gas in place and produce an output distribution (Deutsch, Meehan and Hallstrom 2000).

For the South Avalon Pool, block by block probabilistic resource calculations were done to properly illustrate the distributions of each input parameter on a block by block basis. The output from the block by block analysis was used to calculate the pool wide distribution. A second case, where pool average or cumulative distributions were used, was completed to check the validity of the calculations.

Using the output of the block by block analysis, it was calculated that the 50 percent probability (P50) oil in place volume is 127 $10^6 m^3$. The block by block deterministic and probabilistic total oil in place for the South Avalon Pool is compared in Table 5.1-1 and the probabilistic distributions for the OOIP of the South Avalon Pool are shown in Figure 5.1-4.

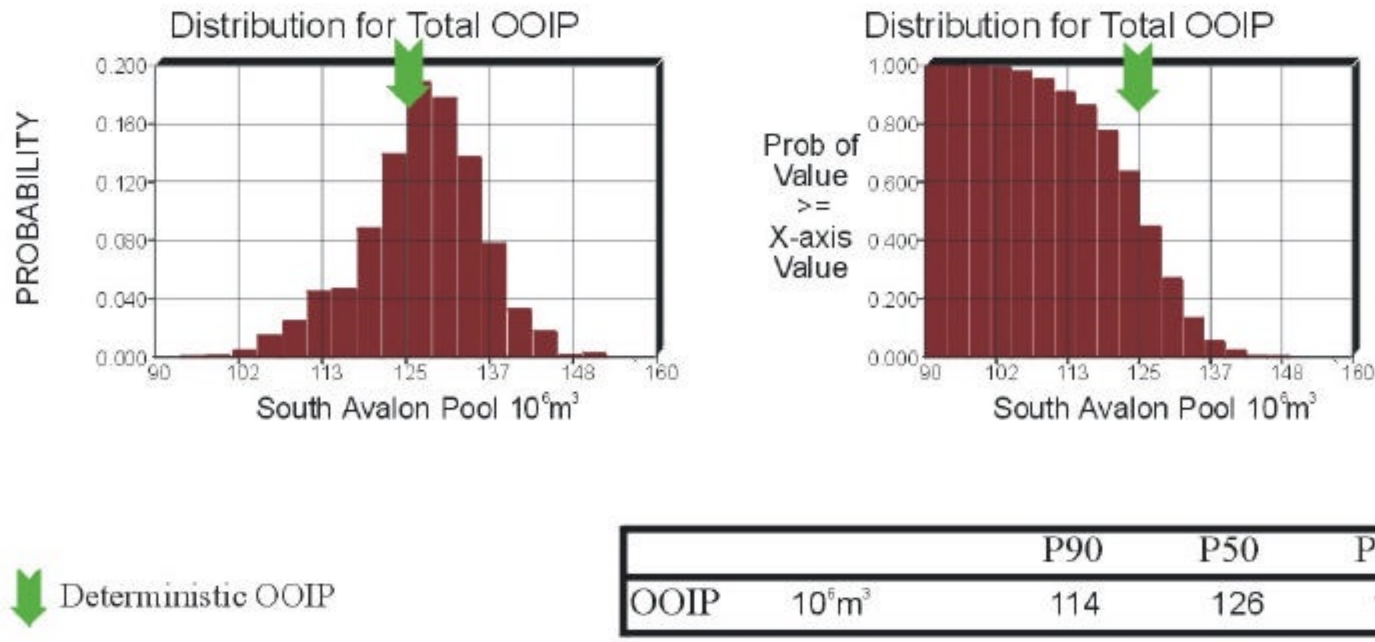
5.1.4 Probabilistic Gas Cap Gas in Place, South Avalon Pool

The same approach used to calculate the probabilistic oil in place was used for the gas cap gas estimates. The probabilistic gas in place for the South Avalon Pool takes into account the risk associated with the southern part of the Terrace block mentioned earlier. Therefore, the range and uncertainty of the rock volume is addressed in the calculation.

For the gas calculations, a water saturation of 22 percent was used throughout the gas cap. This water saturation is higher than the 12 percent used at the top of the oil column. This is due to the lower net to gross which reflects the higher clay content and finer grain size which would lead to a higher irreducible water saturation. The gas formation volume factor used for these calculations is 0.0046.

Figure 5.1–4 South Avalon Pool Original Oil in Place

SOUTH AVALON POOL, ORIGINAL OIL IN PLACE



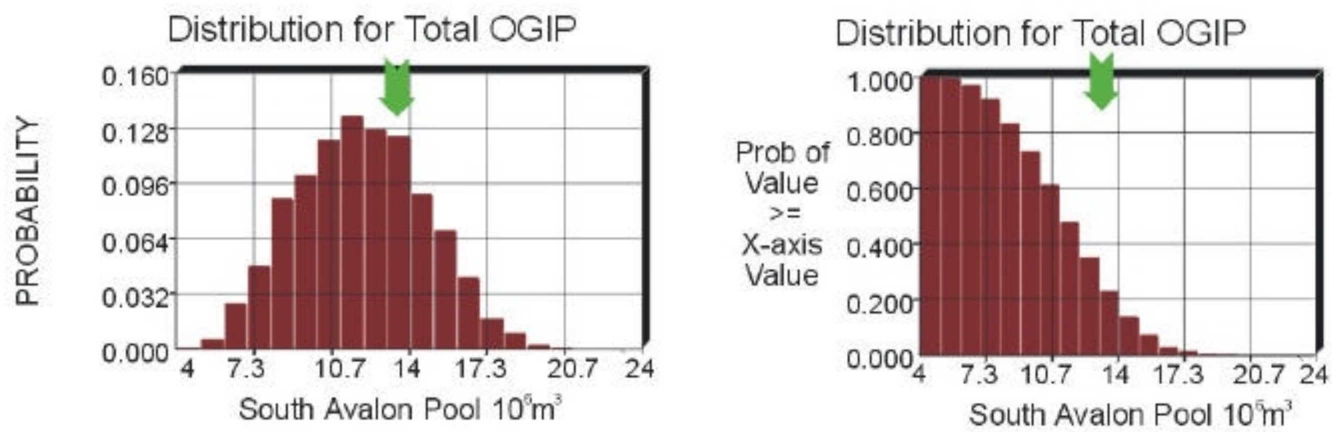
		P90	P50	P10
OOIP	$10^6 m^3$	114	126	138

Figure 5.1-4

The P50 original gas cap gas in place number for the South Avalon Pool is 12 10^9m³. This is less than the deterministic resource range for the same area. This difference is mainly due to the potential of having a much smaller gas cap associated with the A-17 Terrace block. Another reason for the lower gas volumes in the probabilistic model is the range of net to gross values used in the calculations. The probabilistic method allows the full range of net to gross values to be used in the equation, which in this case, lowers the reserve estimates. In addition to this, the risk of reservoir quality sandstone occurring lower in the Avalon than predicted in the deterministic model also contributes to the lower gas volumes by decreasing the gross rock volume in the gas cap. Given that the gas cap is typically a thin veneer over the oil leg (Figure 5.1-3), the gas volumes are very sensitive to slight changes in the top surface of reservoir. All of the wells in the White Rose Field indicate that reservoir sandstone is lost from the top downwards. The block by block and field wide totals for gas in place are summarized in Table 5.1-1. The probabilistic distributions for the gas cap OGIP of the South Avalon Pool are shown in Figure 5.1-5.

Figure 5.1–5 South Avalon Pool Total Gas Cap Original Gas in Place

SOUTH AVALON POOL, TOTAL GAS CAP ORIGINAL GAS IN PLACE



Deterministic GIP

		P90	P50	P10
OGIP	10^6m^3	8,230	11,800	15,470

Figure 5.1-5

5.2 West Avalon Pool

5.2.1 Deterministic Oil and Gas in Place, West Avalon Pool

The bounds of the West Avalon Pool are illustrated in Figure 5-1. The geological model used for the calculation of deterministic oil and gas in place was based on geophysical mapping from 1998. The geological model was a simplified two-layer, full field model populated throughout the mapped White Rose area. The validity of the simplified model was checked by comparing it to the more detailed South Avalon model.

The West Avalon Pool differs from the South Avalon Pool in that the oil leg is thinner, with the reserves spread out over a larger area. The assumption used for the deterministic calculations was that J-49 contacts prevail throughout blocks 8 and 9 of the West Avalon Pool. The chance of having either N-30 or E-09 contacts are addressed in the probabilistic calculations. Therefore, the gas-oil contact was set at 3,064 mSS TVD and the oil-water contact was set at 3,127 mSS TVD.

The remaining procedure to calculate the deterministic oil in place was the same as used in the South Avalon Pool. The FVF was set at 1.41. The oil in place for block 8 was calculated at 8.8 $10^6 m^3$. Block 9 contains 30.0 $10^6 m^3$ of oil in place, giving the West Avalon pool a total of 38.8 $10^6 m^3$ of OOIP.

The procedure used to calculate the gas cap gas in place is the same as for the South Avalon Pool. The assumption made was that the gas-oil contact is the same throughout as in the J-49 well and is set at 3,064 mSS TVD. The gas formation volume factor used for these calculations is 0.0037.

The gas cap gas in place in block 8 is calculated to be 4.14 $10^9 m^3$. Block 9 is estimated to contain 29.92 $10^9 m^3$ of gas in place, giving the West Avalon Pool a total of 34.06 $10^9 m^3$ of OGIP.

5.2.2 Probabilistic Oil and Gas in Place, West Avalon Pool

The probabilistic oil and gas in place for the West Avalon Pool is discussed in more detail in Deutsch, Meehan and Hallstrom (2000). The process used was very similar to that used in the South Avalon Pool.

The oil FVF was given a distribution from 1.35 to 1.42, with the calculated P50 FVF being 1.40. The porosity distribution for the J-49 and N-22 pools differ slightly from the South Avalon Pool, due to the higher amounts of finer grained, tighter sandstones and siltstones. The change is not significant, since the net to gross ratio applied removes much of the tighter material from the calculation.

Rock volume distributions include sensitivities on hydrocarbon contacts within the pool. Three possible scenarios exist in the East J-49 area, which is situated in a triangular fashion between J-49, N-30 and E-09. Each of these wells has a separate set of hydrocarbon contacts. The oil in place calculates to a P50 of 37 $10^6 m^3$ in the entire West Avalon Pool.

Due to the preliminary nature of the geological model, no water saturation distributions were input, and a constant water saturation of 22 percent was used in the gas calculations. The gas formation volume factor used for these calculations is 0.0037.

The P50 original gas in place was calculated to be 30 $10^9 m^3$ for the entire West Avalon Pool.

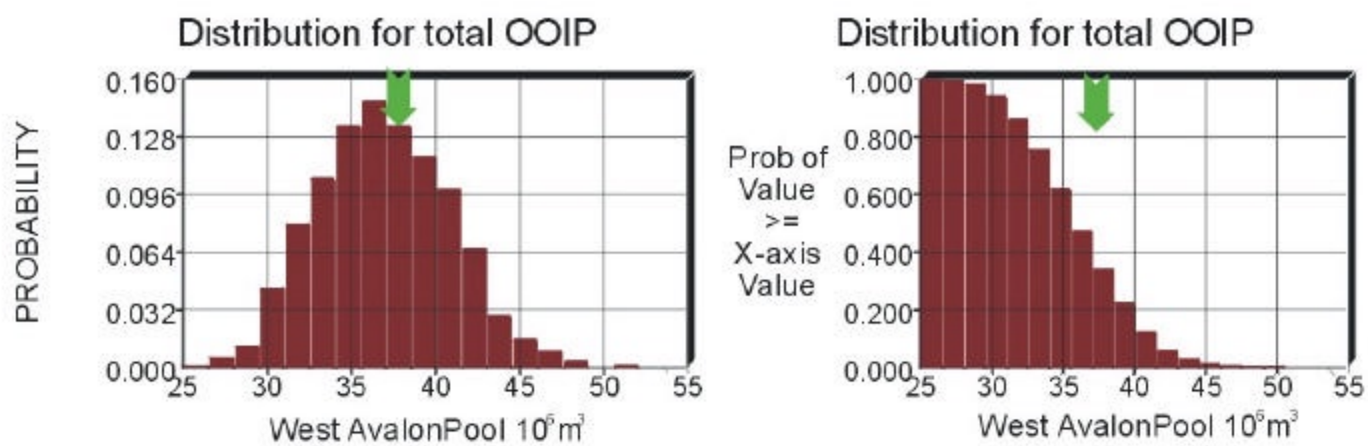
The deterministic and probabilistic P50 volumes for the two blocks, as well as the total pool, is compared in Table 5.2-1. The probabilistic distributions of OOIP and gas cap OGIP for the West Avalon Pool are shown in Figures 5.2-1 and 5.2-2, respectively.

Table 5.2-1 Resource Calculations for West Avalon Pool

Block	OOIP ($10^6 m^3$)		OGIP ($10^9 m^3$)	
	Deterministic	**Probabilistic P50**	**Deterministic**	**Probabilistic P50**
Block 8	8.8	8.9	4.14	3.24
Block 9	30.0	29.0	29.92	26.36
Total	**38.8**		**34.06**	
Poolwide Analysis (P50)		**37**		**30**

Figure 5.2–1 West Avalon Pool Total Original Oil in Place

WEST AVALON POOL, TOTAL ORIGINAL OIL IN PLACE



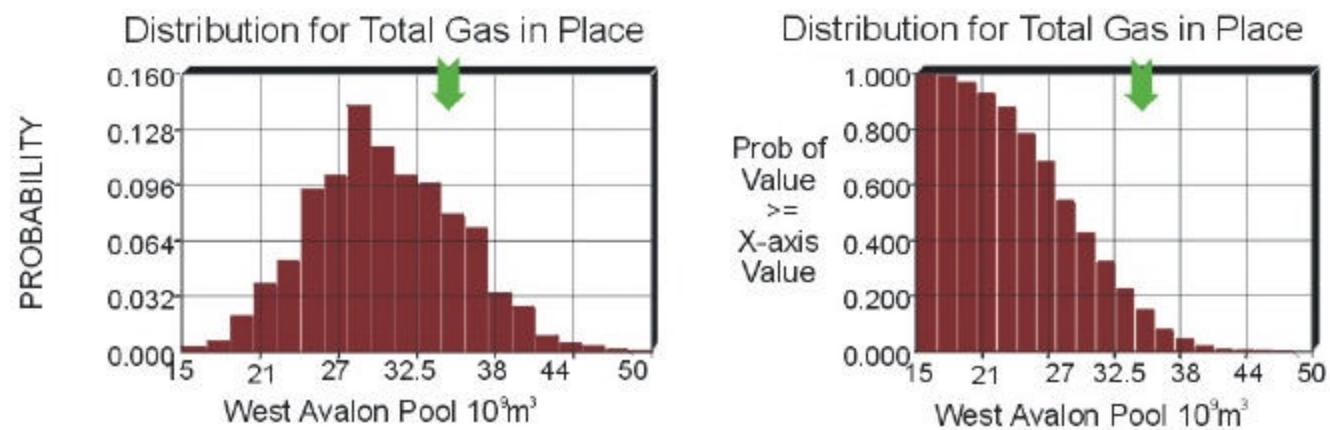
Deterministic OOIP

		P90	P50	P10
OOIP	10^6m^3	32.1	37	42

Figure 5.2-1

Figure 5.2–2 West Avalon Pool Gas Cap Original Gas in Place

WEST AVALON POOL, GAS CAP ORIGINAL GAS IN PLACE



Deterministic GIP

		P90	P50	P10
OGIP	10^9m^3	23	30	37

Figure 5.2-2

5.3 North Avalon Pool

5.3.1 Deterministic Oil and Gas in Place, North Avalon Pool

The bounds of the North Avalon pool are illustrated in Figure 5-1. The oil leg associated with the North Avalon Pool runs mainly southwest to northeast as a thin rim of the gas cap updip to the north. The procedure to calculate the deterministic oil in place was the same as used in the South Avalon Pool. The FVF was set at 1.37. It was assumed that the contacts throughout the pool were the same as determined from the N-22 and N-30 wells. The gas-oil contact is placed at 3,014 mSS TVD and the oil-water contact at 3,073 mSS TVD.

The deterministic oil in place for the North Avalon Pool was calculated as approximately 28.9 $10^6 m^3$. The North Avalon Pool has been separated into three blocks (Figure 5-1). Block 11 is entirely above the gas-oil contact. The oil is equally distributed between blocks 10 and 12.

The North Avalon Pool has a gas cap column of up to 550 m, and stretches over 10 km in length and 2 to 3 km in width. The reservoir quality may vary over this region, but in the geological model, the quality remains equivalent to the N-22 and N-30 wells. Some thinning of the reservoir occurs up structure (north) until seismic quality deteriorates, and the mapping for this model ends (see Figure 5.1-2). As with the West Avalon Pool, the water saturation was set at 22 percent. The gas FVF used for these calculations is 0.0046.

The gas cap gas in place for the North Avalon Pool is calculated to be 50.21 $10^9 m^3$. The block by block and total pool gas cap gas resources are summarized in Table 5.3-1.

Table 5.3-1 Resource Calculations for North Avalon Pool

Block	OOIP ($10^6 m^3$)		OGIP ($10^9 m^3$)	
	Deterministic	Probabilistic P50	Deterministic	Probabilistic P50
Block 10	15.0	14.5	20.22	17.44
Block 11	0.0	0.0	10.00	10.48
Block 12	13.9	14.5	19.99	18.55
Total	**28.9**		**50.21**	
Poolwide Analysis (P50)		**29**		**47**

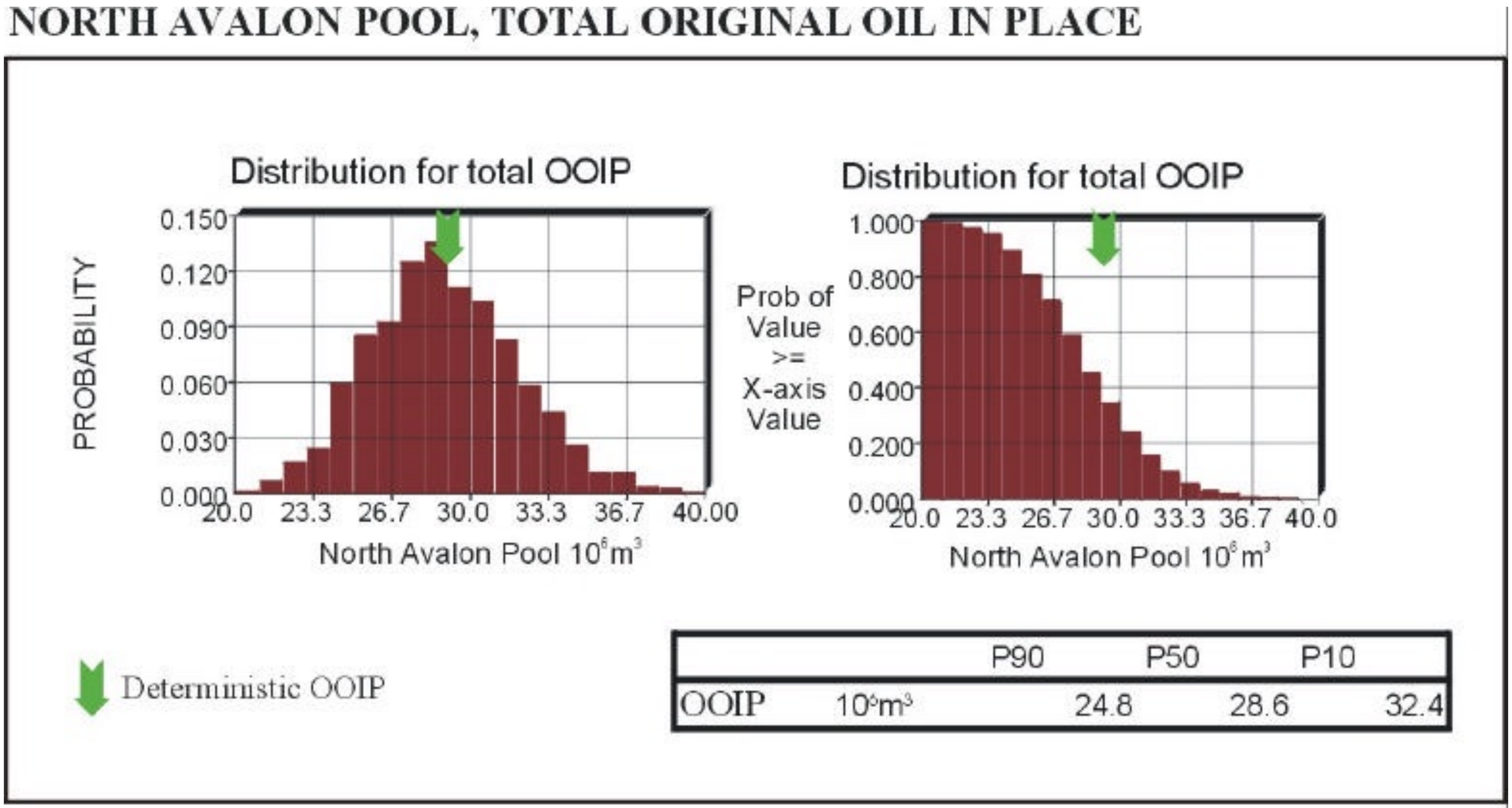
5.3.2 Probabilistic Oil and Gas in Place, North Avalon Pool

The probabilistic oil and gas in place for the North Avalon Pool were calculated in the same manner used for the West Avalon Pool. For the oil calculations, distributions of net to gross were given which reflect the potential change in rock quality away from the N-22 and N-30 wells. The base case is that the reservoir quality remains the same throughout much of the North Avalon Pool, with some deterioration to the northwest on the White Rose Diapir.

The porosity distributions used are the same for the entire pool, and represent variations seen in the two wells in the pool. The P50 porosity in the net sandstones is approximately 14.8 percent. The water saturation distribution has a P50 of 24.5 percent. The FVF distribution was the same as used in all pools in the White Rose Field. The P50 oil in place for the North Avalon Pool calculates out as 28.6 $10^6 m^3$.

For the gas cap gas in place calculations, the parameters used were the same as in the West Avalon Pool calculations, with the exception of the FVF, which is maintained at 0.0046 in the North Avalon Pool. The P50 gas cap gas in place for the North Avalon Pool calculates out to 47 $10^9 m^3$. The probabilistic P50 oil and gas in place for the North Avalon Pool are summarized in Table 5.3-1. The probabilistic distributions for oil and gas cap gas in the North Avalon Pool are illustrated in Figures 5.3-1 and 5.3-2, respectively.

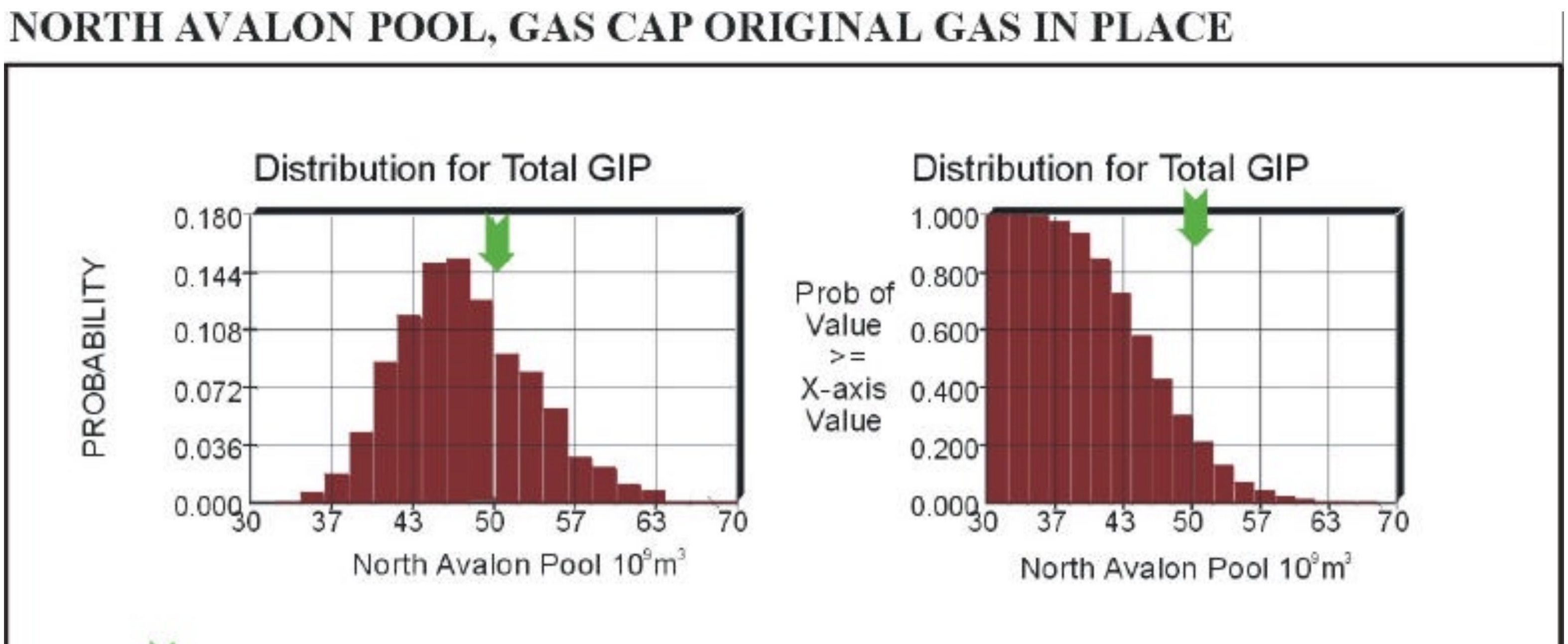
Figure 5.3–1 North Avalon Pool Total Original Oil in Place



		P90	P50	P10
OOIP	$10^6 m^3$	24.8	28.6	32.4

Figure 5.3-1

Figure 5.3–2 North Avalon Pool Gas Cap Original Gas in Place



		P90	P50	P10
OGIP	$10^9 m^3$	41	47	54

Figure 5.3-2

5.4 Avalon Summary

As the preceding sections have illustrated, the major portion of the oil in place for the White Rose Field resides in the South Avalon Pool. The main gas resources reside in the West Avalon and North Avalon Pools. The deterministic and probabilistic OOIP and gas cap OGIP volumes for each pool and the full White Rose Avalon Field are compared in Table 5.4-1. The deterministic in place volumes for all the White Rose Avalon blocks are shown in Figure 5.4-1. Refer to Deutsch, Meehan and Hallstrom (2000) for more details on the OOIP and OGIP calculations.

Table 5.4-1 Avalon Full Field and Individual Pool Estimates of Original Oil in Place and Original Gas in Place

Pool	OOIP				OGIP			
	Deterministic ($10^6 m^3$)	Probabilistic ($10^6 m^3$)			Deterministic ($10^9 m^3$)	Probabilistic ($10^9 m^3$)		
		P90	P50	P10		P90	P50	P10
South Avalon	124.8	114	127	138	13.49	8	12	15
West Avalon	38.8	32	37	42	34.06	23	30	37
North Avalon	28.9	25	29	32	50.21	41	47	54
Full Field	192.5				97.76			

Figure 5.4–1 Avalon Full Field Oil and Gas in Place

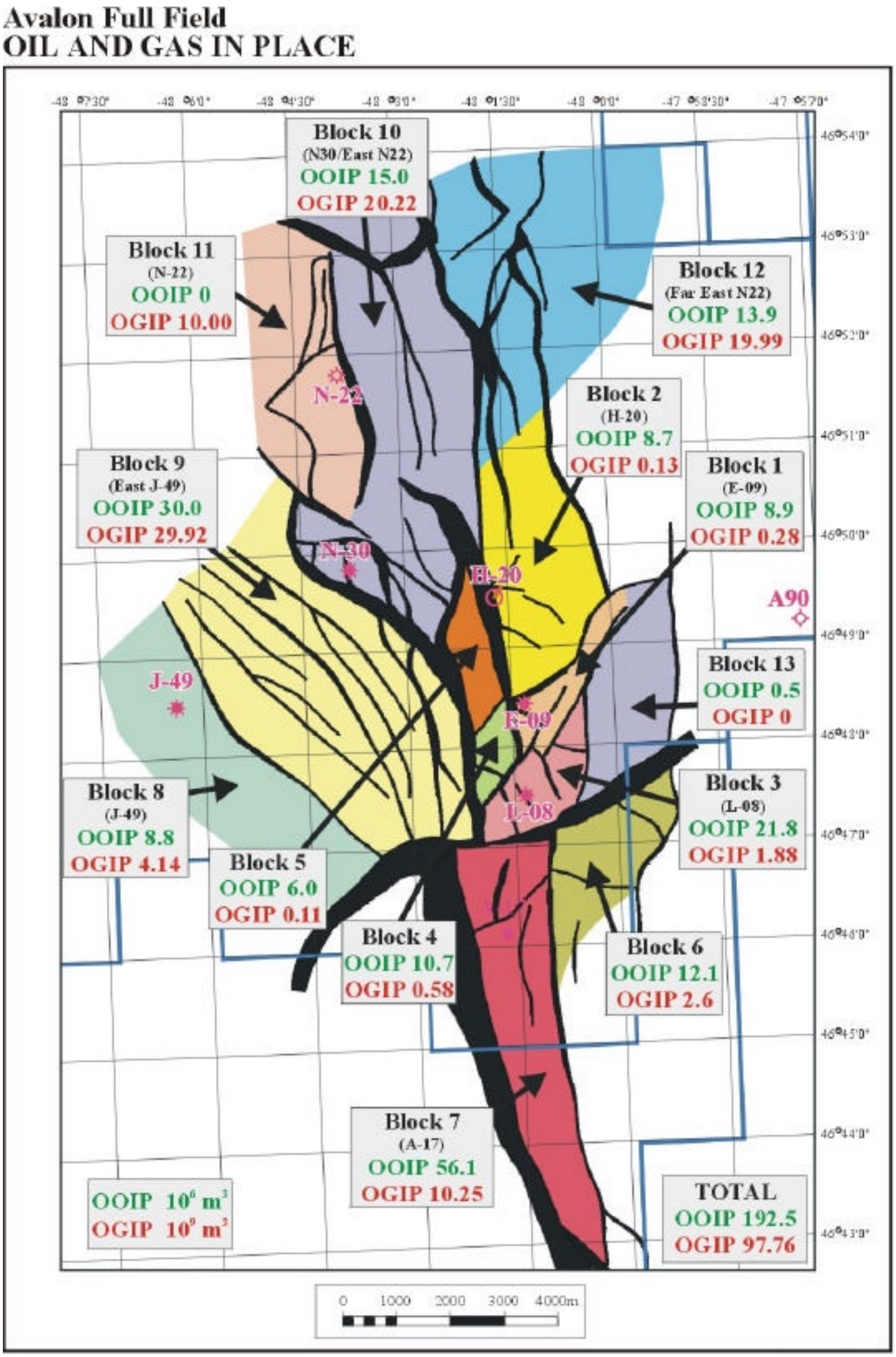


Figure 5.4-1

5.5 Secondary Zones

The secondary zones, which have tested hydrocarbons in the White Rose Field, include the Hibernia, Eastern Shoals and the South Mara Formations. None of these zones appear to have the reserve base to make them economic. The areas of potential for each of the three secondary zones are shown in Figure 5.5-1.

5.5.1 Hibernia Formation

Resource estimates for the Hibernia Formation were determined for the area between and around the White Rose E-09 and N-22 wells, which were the only wells to encounter Hibernia pay. Both the N-22 and E-09 wells have tested the Hibernia. White Rose E-09 well encountered 14.8 m of pay, with an average porosity of 14.8 percent and water saturation of 31.2 percent. The maximum rate tested from the E-09 well was 80 m^3/d. The N-22 well encountered 12 m of net pay, with an average porosity of 13.6 percent and water saturations of 22.7 percent. The maximum rate tested from the N-22 well was 87 m^3/d.

No field-wide mapping has been completed on the Hibernia due to the inconsistent nature of the Hibernia markers and sandstone content. It is estimated that there are approximately 20 km^2 of potential closure in and around the E-09 and N-22 wells. Assuming a FVF of 1.4, the resources associated with this closure would range from 8 to 24 $10^6 m^3$ of oil in place. The range is mainly due to the uncertainty of how far the pool may extend, and the quality of the sandstones.

5.5.2 Eastern Shoals Formation

Hydrocarbons have been tested from the Eastern Shoals Formation in the N-22, J-49 and N-30 wells. The N-22 well tested 40 $10^3 m^3/d$ from a zone consisting of thinly interbedded sandstone, siltstone and shales. The N-30 well contained oil-bearing sandstones similar to those in the N-22 well. In N-30, no production tests were performed, however, an MDT pass was completed that showed the upper Eastern Shoals contained oil on the same gradient as the Avalon Formation oil. The MDT also showed oil in a lower section of the Eastern Shoals being in an apparently different pressure system. The J-49 well tested gas and condensate with a fairly high (14 percent) water cut.

Overall extent and quality of the Eastern Shoals is in question. The reservoir tested to date is thin and of variable quality, resulting in relatively small volumes of hydrocarbons. The most likely extent of the Eastern Shoals is a band of sandstones along the southern edge of the White Rose Diapir. The estimated area of potential closure would be in the order of 20 to 30 km^2. The oil in place using these areas, and the average values from the three wells (4 m net pay, 13 percent porosity, 39 percent water saturation, and a FVF of 1.4) would give between 6 and 9 $10^6 m^3$ oil in place. As with the Hibernia, these ranges are due mainly to uncertainty in pool extension and quality of sandstones.

Figure 5.5–1 White Rose Complex Secondary Pools

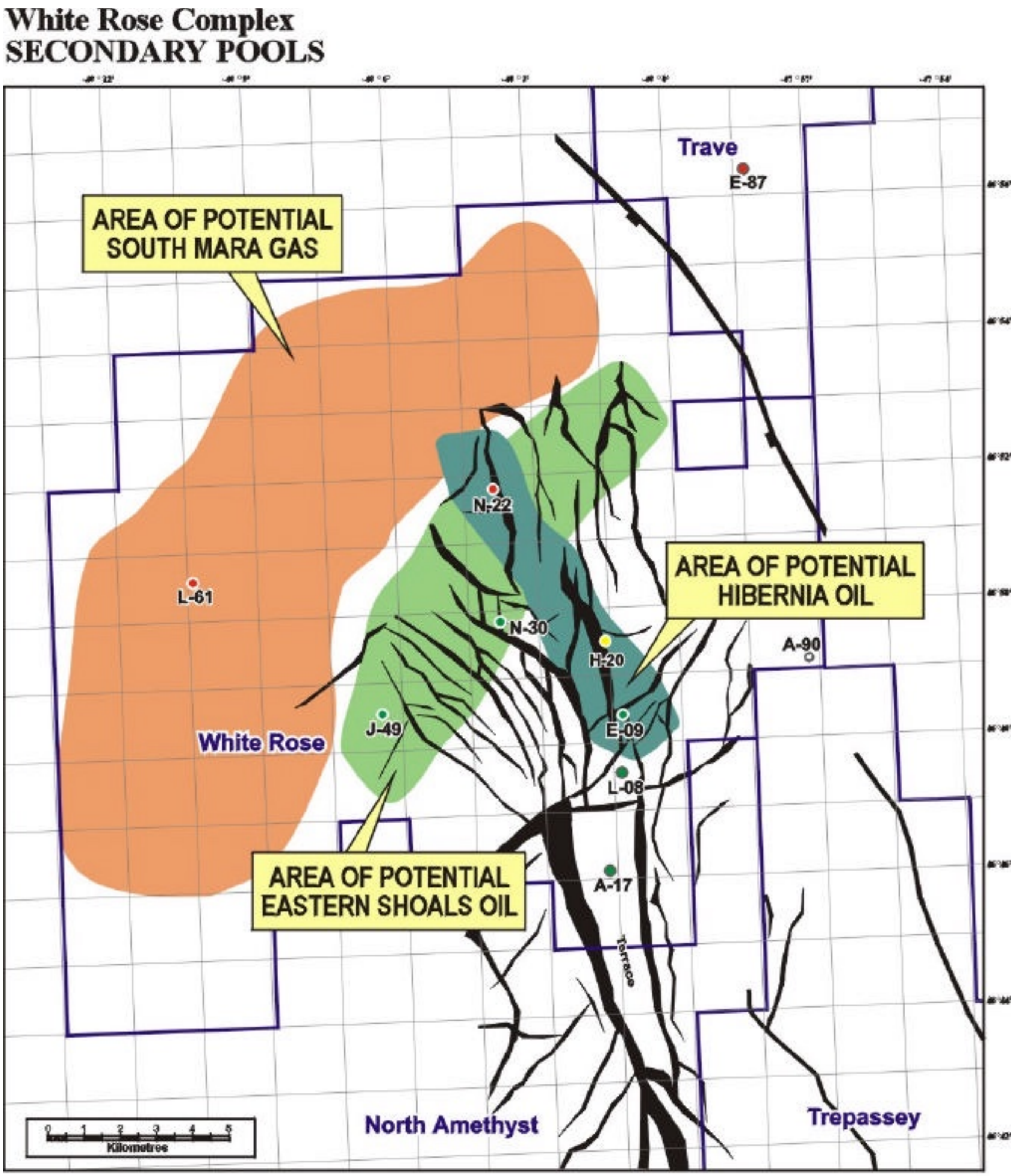


Figure 5.5-1

5.5.3 South Mara Member, Banquereau Formation

Only the White Rose L-61 well contains hydrocarbon reservoir in the South Mara Member. This well tested at a rate of 3.1 $10^6 m^3$ of gas and 70 m^3 of condensate per day from a thin sandstone. Since only the L-61 well penetrated South Mara sandstone pay, the area included in resource determinations for the South Mara is confined to the northwest part of the White Rose Field, on the northwest flank of the White Rose Diapir. This is defined in the "Application for a Significant Discovery Area White Rose Structure", submitted in March of 1987.

This area of potential resources in the South Mara Member extends over approximately 100 km^2. The net pay in the L-61 well is 3.7 m, with an average porosity of 22 percent and a water saturation of 15 percent. Other parameters assumed were a Z of 0.95, a temperature of 92°C, and a pressure of 26,000 kPa. The reserves associated with the South Mara in the L-61 area are in the range of 9 to 20 $10^9 m^3$, assuming some reservoir thickening down the flank.

5.5.4 Other Zones

Two other zones have tested minor amounts of hydrocarbons. A Jurassic sandstone (Tempest) in the White Rose E-09 well tested 10 $10^3 m^3$/d of gas. In the N-22 well, a Nautilus sandstone tested minor (0.5 $10^3 m^3$/d estimated) amounts of gas. Neither of these zones are mappable and no resource estimates have been made.

6 RESERVOIR EXPLOITATION

This chapter is a description of the reservoir studies used to develop the White Rose reservoir depletion scheme. It describes the development strategy recommended for the South Avalon Pool. Recoverable reserve ranges associated with the base case depletion scheme are presented. Deferred developments that have been assessed are also reviewed.

6.1 Reservoir Simulation Models

6.1.1 South Avalon Model

An Eclipse 100, 3-D, three-phase reservoir model was developed for the South Avalon Pool to evaluate depletion options for the pool. Non-orthogonal grids were used so that fault planes could be more accurately modelled. A view of the numerical grid used in the model is shown in Figure 6.1-1.

The model consists of approximately 80,000 grid cells whose dimensions are approximately 100 x 100 x 4 m. Grid sizing was determined by running smaller sector models to determine the optimum grid size. The simulation grid was created in RMS and was populated with porosity and permeability values by up-scaling the fine grid RMS geological model used for hydrocarbon volume assessments as described in Chapter 5. The RMS model had more than 4 million cells (Deutsch and Hallstrom March 2000). The porosity distribution in the Eclipse reservoir model is shown in Figure 6.1-2. The PVT data discussed in Section 4.2, and the SCAL data discussed in Section 4.3, were used in the model. The model was initialized with a reservoir pressure of 29.4 MPa at the gas-oil contact, located at 2,872 mSS, and an oil-water contact located at 3,009 mSS. Contacts are discussed in Section 4.5. OOIP in the model was 126.8 $10^6 m^3$, which is very close to 126.4 $10^6 m^3$ in the RMS fine grid geological model. The initial fluid distributions in the model are illustrated in Figure 6.1-3. For reference case reservoir performance determinations, all faults were assumed to be sealing.

For base case runs, the south end of the Terrace block has not been included as there is an east-west fault that is believed to be sealing and will provide hydraulic isolation of the south end of the Terrace. The OOIP south of the fault is approximately 10.8 10^6 m^3.

Figure 6.1–1 South Avalon Pool Reservoir Simulation Grid

South Avalon Pool
RESERVOIR SIMULATION GRID

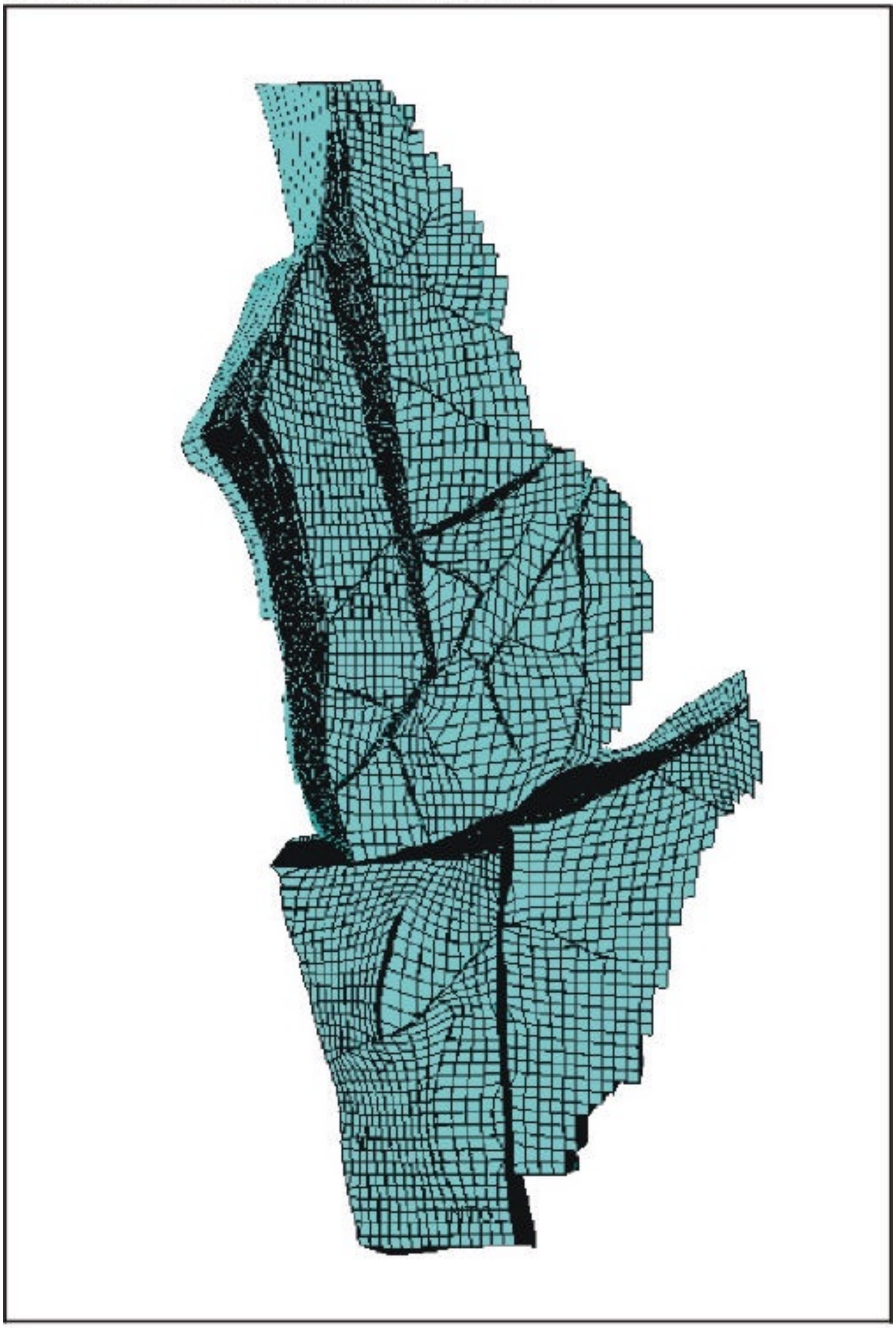


Figure 6.1-1

Figure 6.1–2 South Avalon Pool Reservoir Simulation Porosity Distribution

South Avalon Pool
RESERVOIR SIMULATION POROSITY DISTRIBUTION

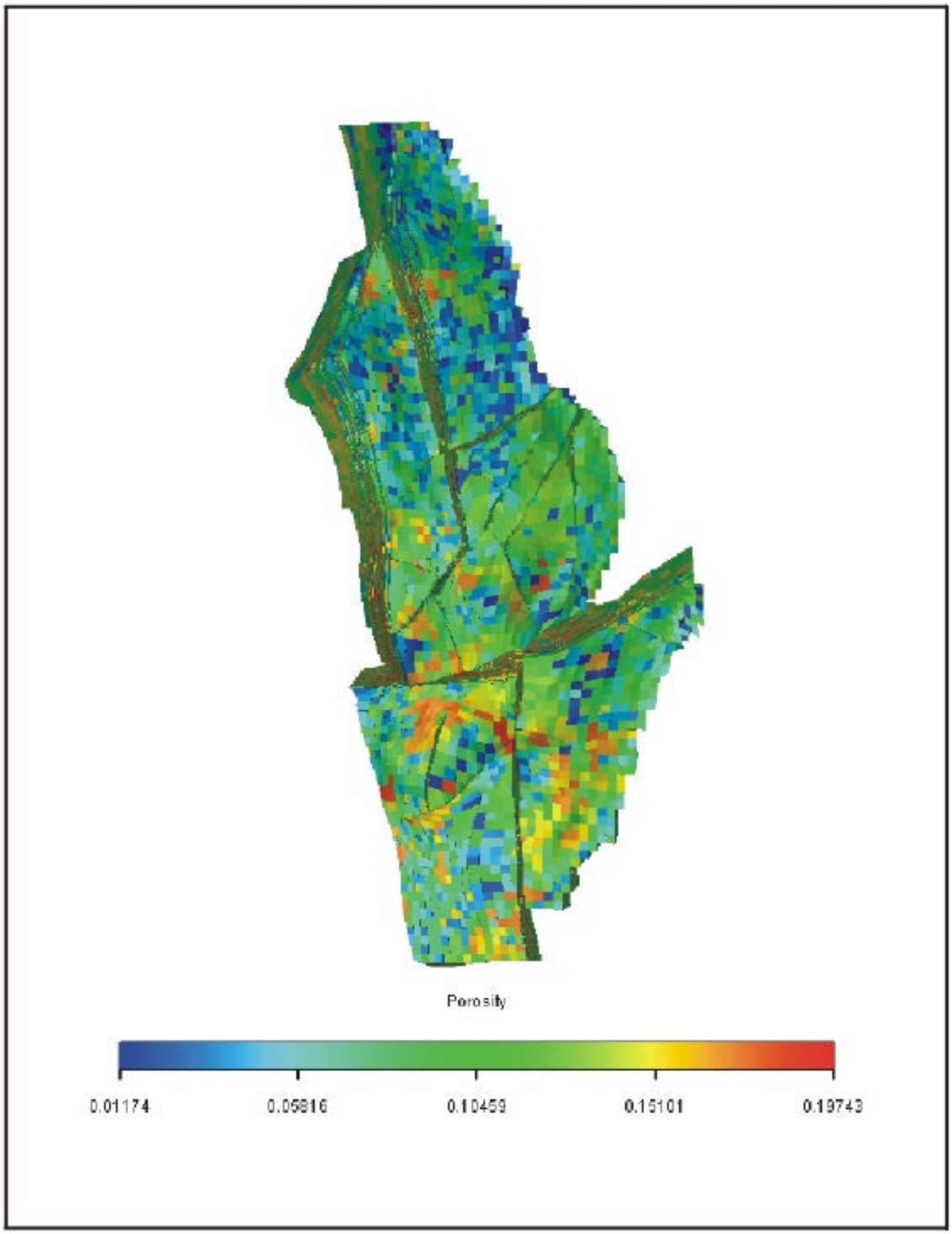


Figure 6.1-2

Figure 6.1–3 South Avalon Pool Reservoir Simulation Initial Fluid Distribution

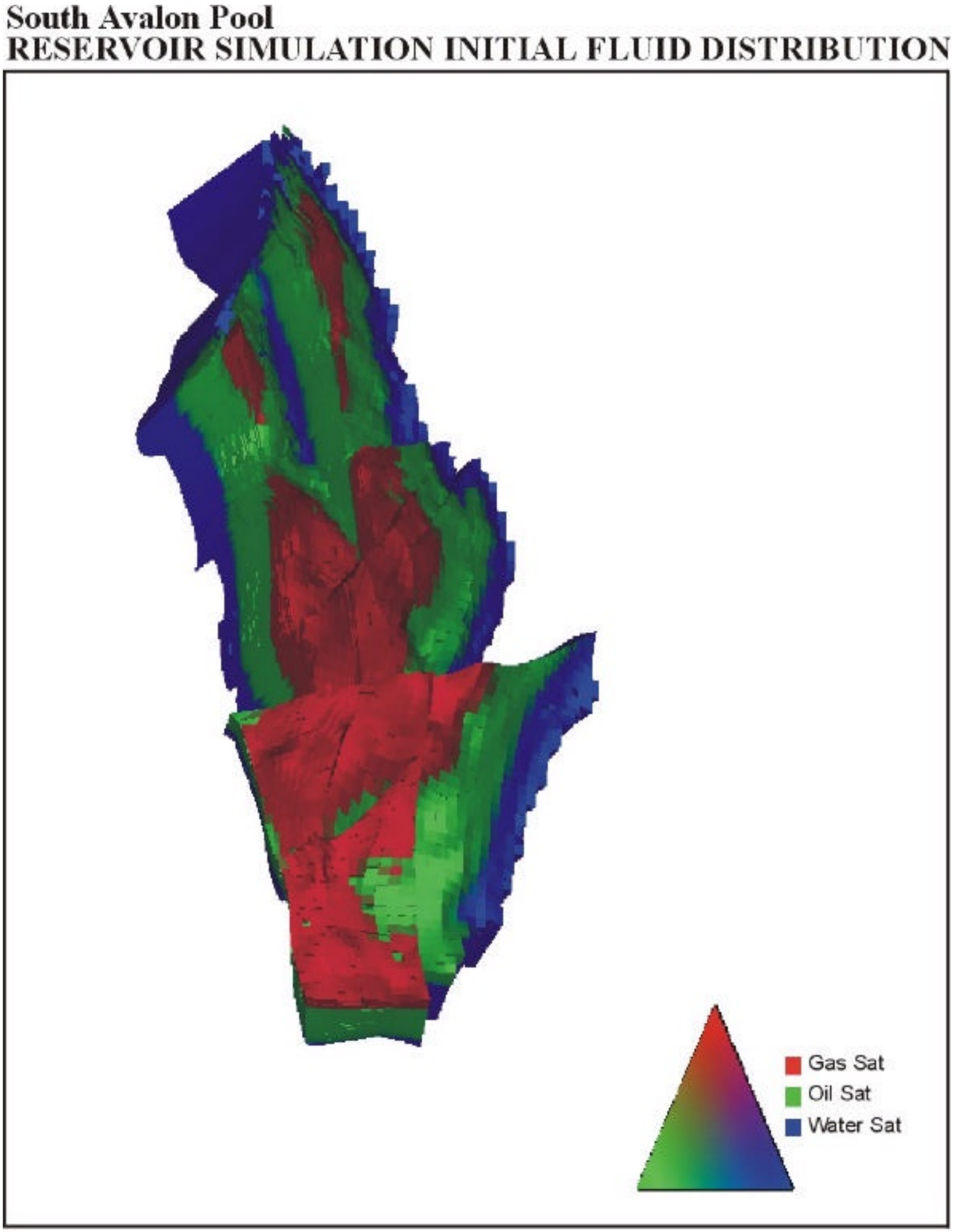


Figure 6.1-3

6.2 South Avalon Pool Reservoir Simulation

Three basic reservoir simulation models have been created for the South Avalon pool as additional data have been acquired from the drilling of delineation wells and interpretation of that data has progressed. These models have been used to assess various reservoir depletion options and sensitivity of those options to both controlable development considerations and reservoir uncertainty.

The three models discussed in this section are:

- South Avalon Pool Pre-H-20 Model (March 2000);
- South Avalon Pool Post-H20 Model (August 2000); and
- South Avalon Pool Preliminary Model (November 1999).

6.2.1 South Avalon Pool Pre-H20 Model (March 2000)

A waterflood scheme was used for the reference case development. Several model runs were made to determine the horizontal well locations that would result in optimum recoveries from the model. A total of 10 production wells and seven water injection wells were required to optimize reservoir performance in the model. Horizontal water injection wells were placed 50 m below the oil-water contact to ensure dispersion of the injection water. Horizontal oil producers were placed to maximize recoveries while maximizing the time to water and gas break through and minimize the potential for gas coning.

Facility capacity was set at 15,900 m^3/d and forecasts were run for 25 years or until the total oil production rate dropped below 100 m^3/d.

For the production wells, bottomhole pressure was set at 22 MPa to reflect expected well draw down capabilities. The maximum oil rate was set at 3000 m^3/d, with a total maximum liquid rate of 4,000 m^3/d. The minimum oil production rate was set at 50 m^3/d and a skin factor of +5 was used.

For the water injection wells, a maximum bottomhole pressure of 60 MPa was set (maximum reached was 50 MPa). Injection well maximum injection volumes were restricted to 9,000 m^3/d per well. A skin factor of +5 was also used for the injection wells.

The optimized well lay out determined from the model is shown in Figure 6.2-1. The base case production and injection rates, and cumulative production and injection curves are shown in Figures 6.2-2 and 6.2-3, respectively. It was assumed that all wells had been drilled and were available for use starting from day one, and that oil production rates were maintained at the design capacity for as long as possible.

The recovery for the South Avalon Pool after 15 years was approximately 39 percent. On a fault block by block basis, recoveries varied from 29 to 50 percent after 15 years.

Figure 6.2–1 South Avalon Pool Pre H-20 Optimized Well Layout

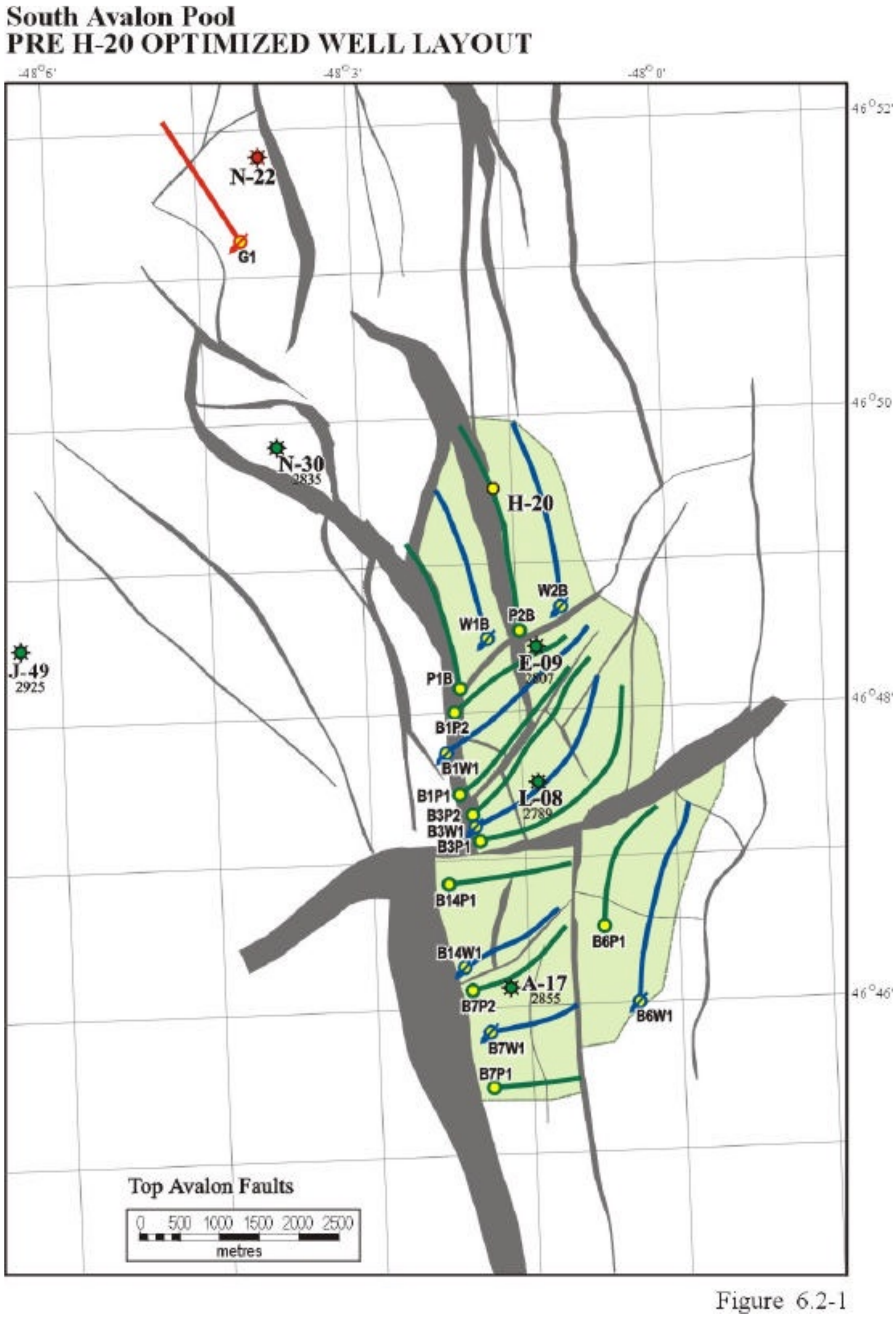


Figure 6.2-1

Figure 6.2–2 South Avalon Pool Pre H-20 Simulation Production Rate Forecasts

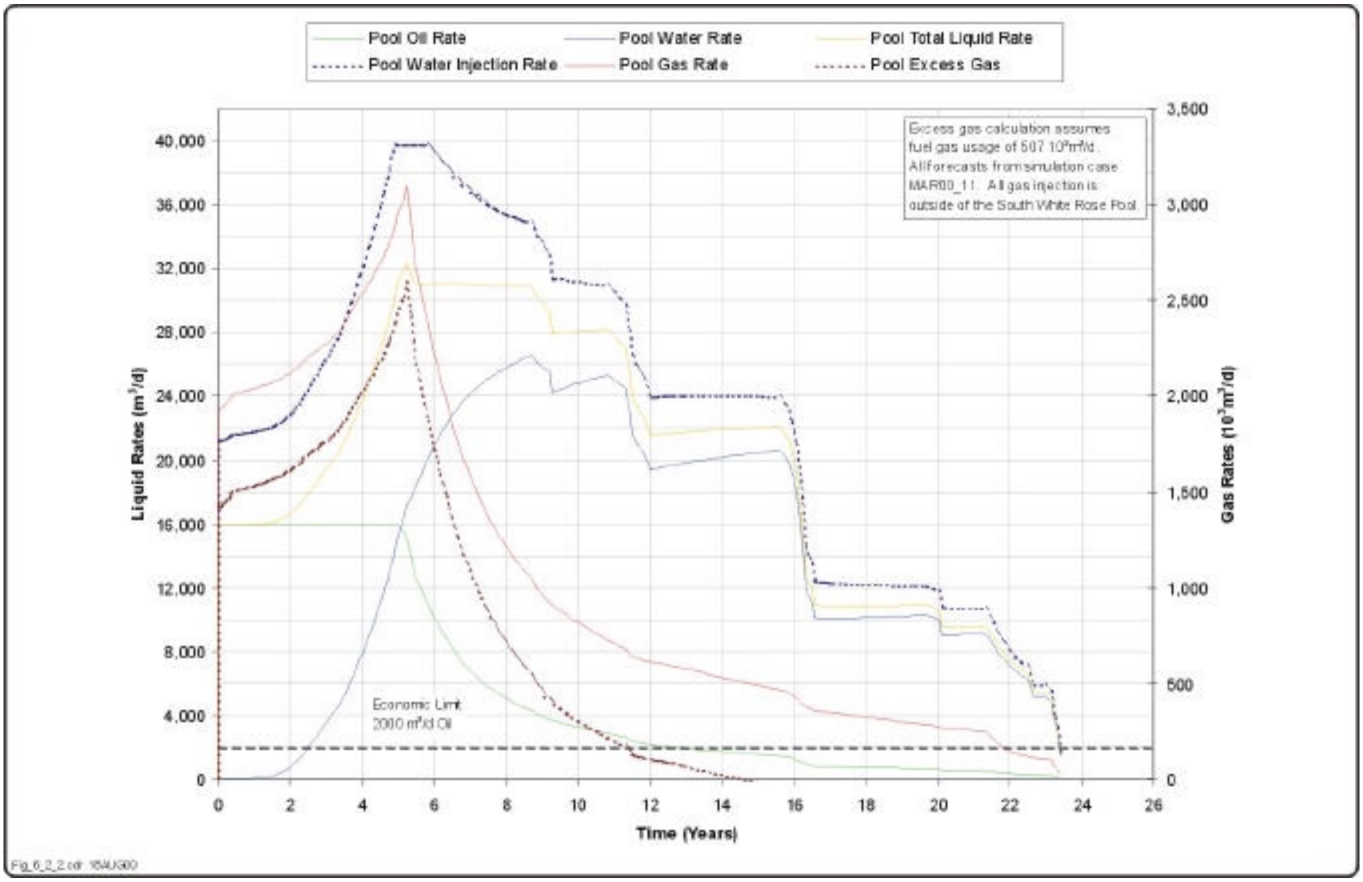
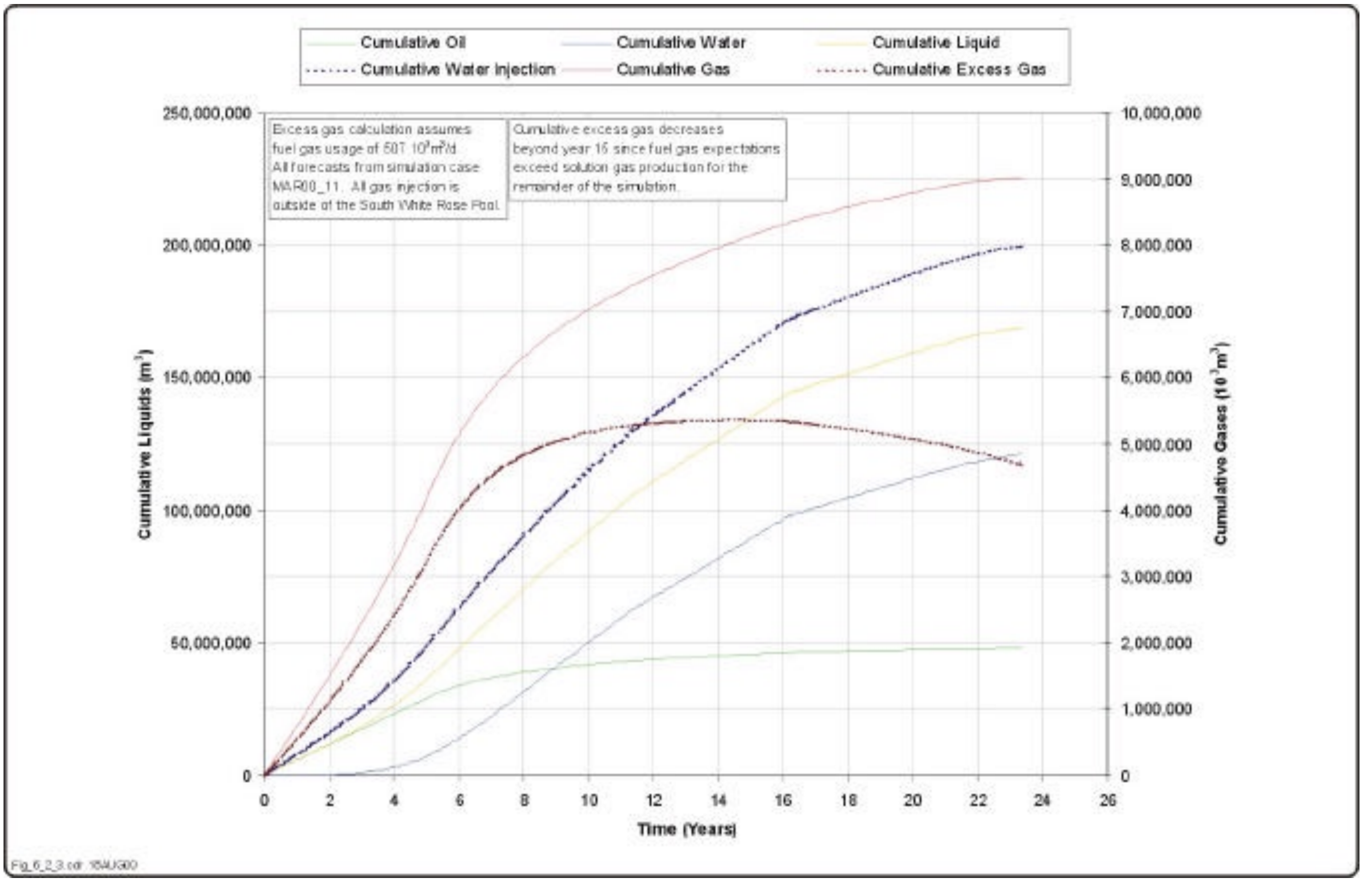


Figure 6.2–3 South Avalon Pool Pre H-20 Cumulative Production Forecast



A fundamental assumption, for the waterflood development case, is that excess produced gas is conserved by reinjecting it into another pool in the White Rose Field. Current plans are to drill the first gas injector in the North Avalon Pool in the N-22 area. After some reservoir response is seen, a decision will be made as to the number, timing and location for additional gas injectors, if required. Areas for potential future gas injector locations include the additional wells in the North Avalon Pool, the West Avalon Pool, the south end of the Terrace block in the South Avalon Pool.

6.2.2 South Avalon Pool Post-H-20 Model (August 2000)

The South Avalon Pool model created prior to the H-20 well being drilled (Section 6.2.1) included development of two fault blocks (blocks 2 and 5) north of the E-09 well. The H-20 well results indicate that no net to gross ratios in these blocks should be reduced, resulting in producable volumes that may not be economic to develop. As a result, the Pre H-20 model was updated to exclude development of those two blocks. The two injectors and two producers associated with these blocks were removed from the model. The development well layout without these wells is shown in Figure 6.2-4. Due to sealing faults in the model, there is no depletion of the OOIP in these two blocks.

Facility and well production and injection criteria were kept the same as in the Pre H-20 model (Section 6.2.1).

The forecasts of rates and cumulative production for the Pre- and Post-H-20 simulations are compared in Figures 6-2-5 and 6.2-6, respectively. The impact of eliminating the two fault blocks was to reduce the oil plateau from approximately five years to slightly over four years. Peak total fluid, produced water and gas volumes are reduced by approximately 10 to 15 percent (CoKuner, August 15, 2000). Recoverable oil is reduced from 45.7 to 41.5 10^6m^3 within 15 years, but recovery factor for the developed area increased from 39.0 to 40.8 percent during the same 15-year period. This increase is due to the fact that, in the previous model, blocks 2 and 5 had lower recovery factors than the rest of the pool and therefore reduced overall recovery factors.

6.2.3 Preliminary South Avalon Model (November 1999)

Some of the reservoir simulation sensitivity work discussed in this application is based on work done using a preliminary reservoir simulation model developed in November 1999. This model was based on an RMS model created using preliminary interpretations of the three wells drilled in 1999. The current models are supported by a more detailed geological model and includes additional faults. The preliminary model included the south end of the Terrace that is now isolated by faulting. This model also used reinjection of the produced gas into the Terrace block, in addition to waterflooding for pressure maintenance as the base case. Despite the differences in the models, some of the sensitivity work is still directionally valid. The grid used in the previous model is shown in Figure 6.2-7.

Figure 6.2–4 South Avalon Pool Post H-20 Well Layout

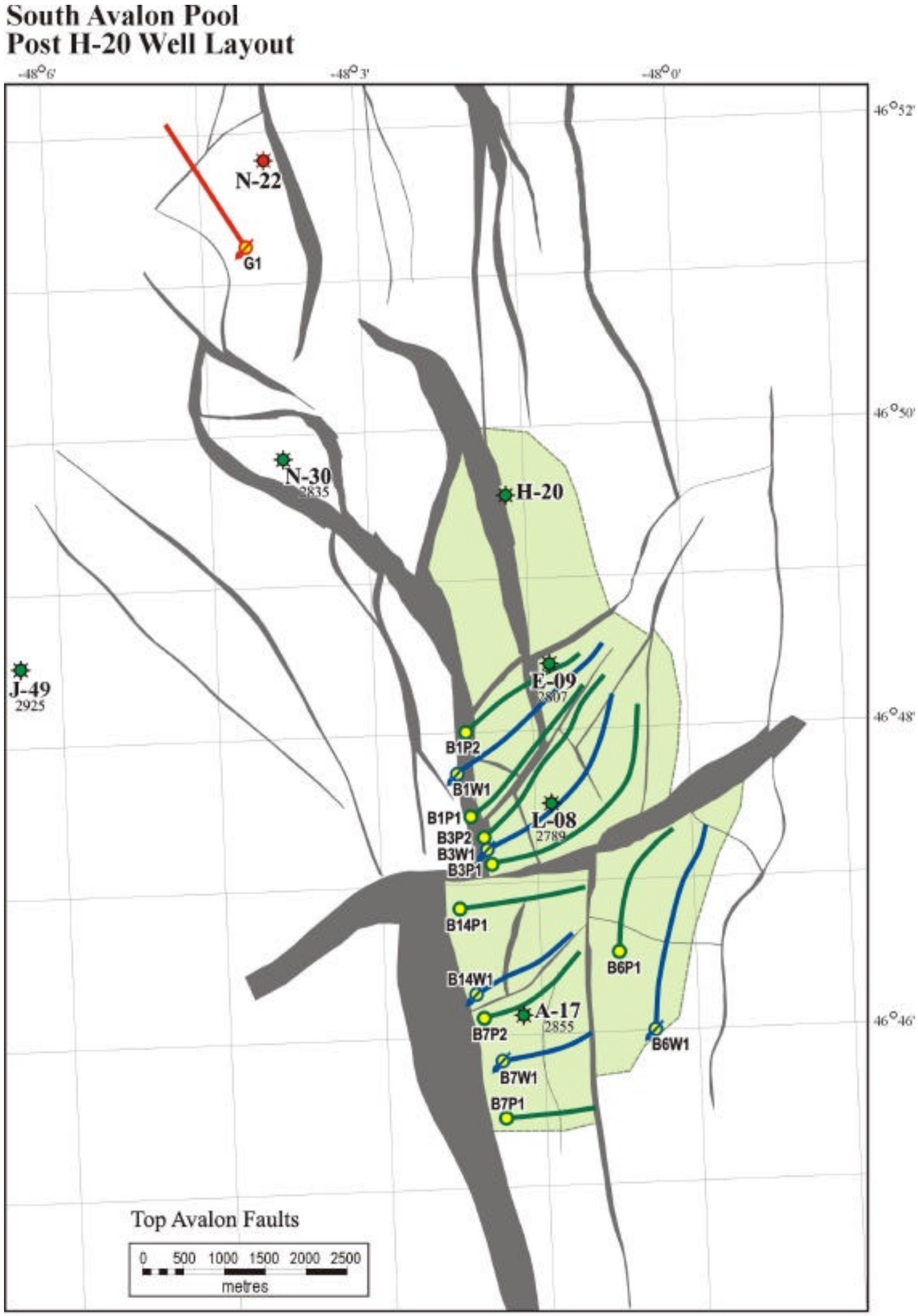


Figure 6.2-4

Figure 6.2–5 South Avalon Pool Pre H-20 and Post H-20 Comparison

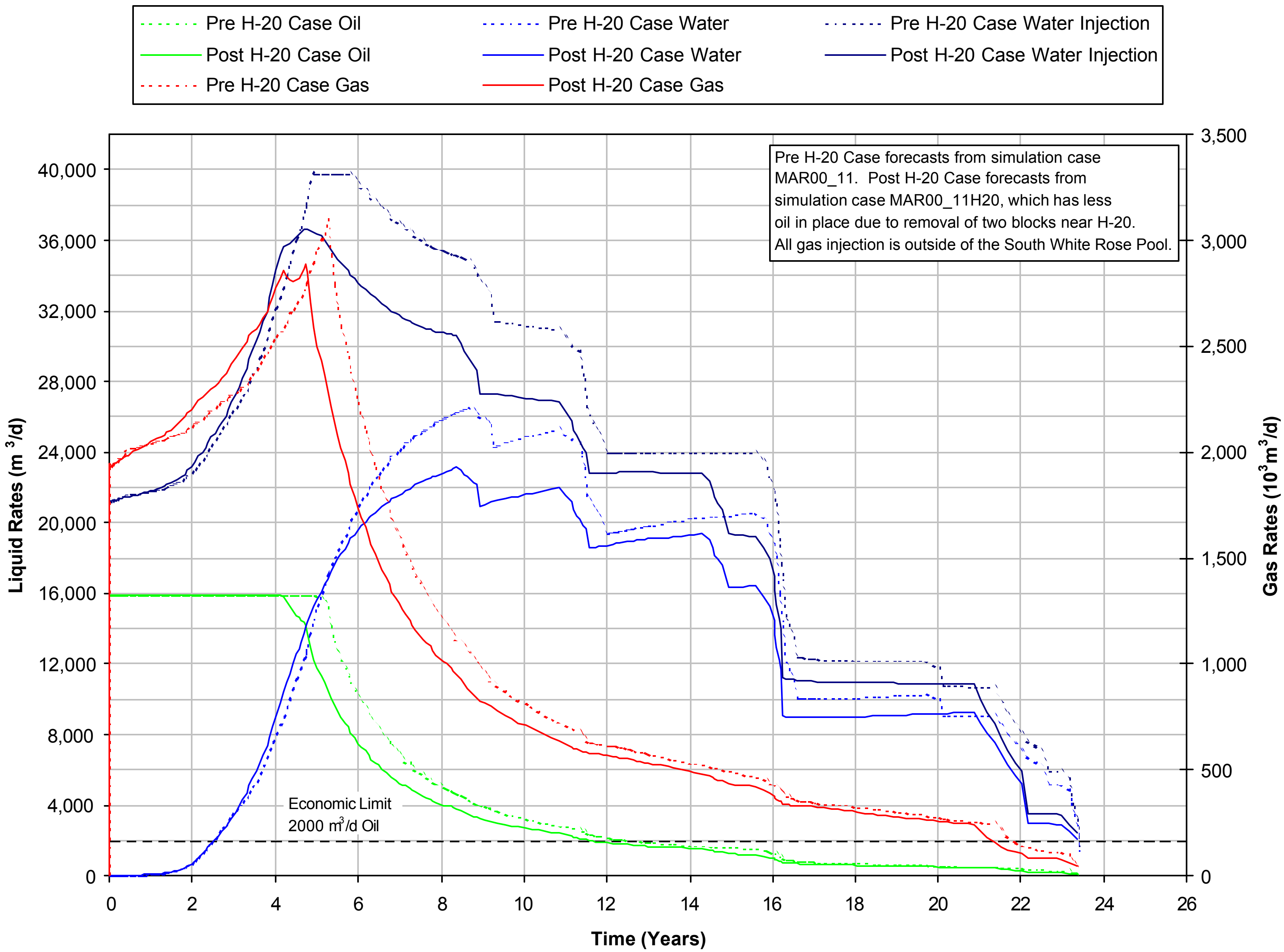


Figure 6.2–6 South Avalon Pool Pre H-20 and Post H-20 Comparison

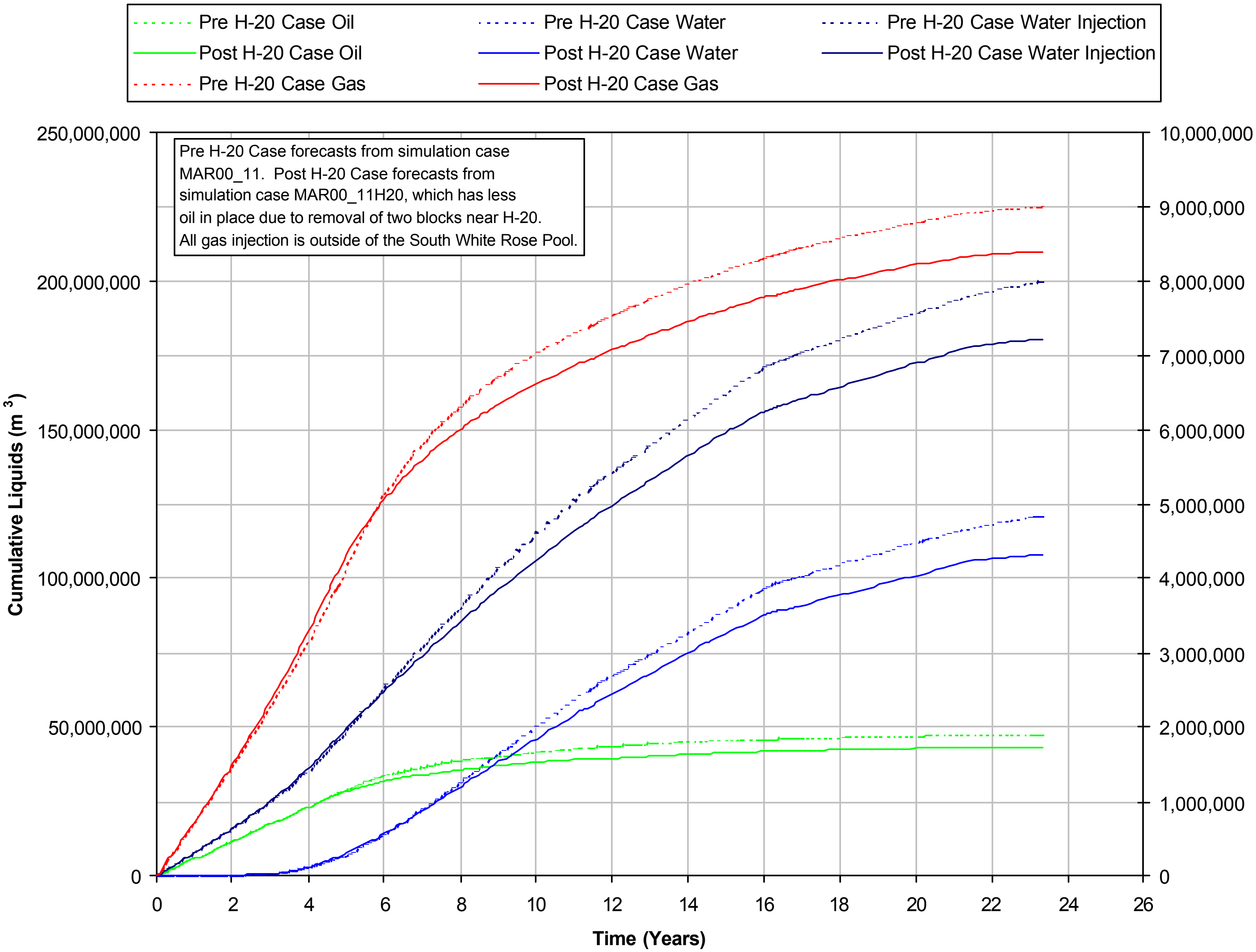
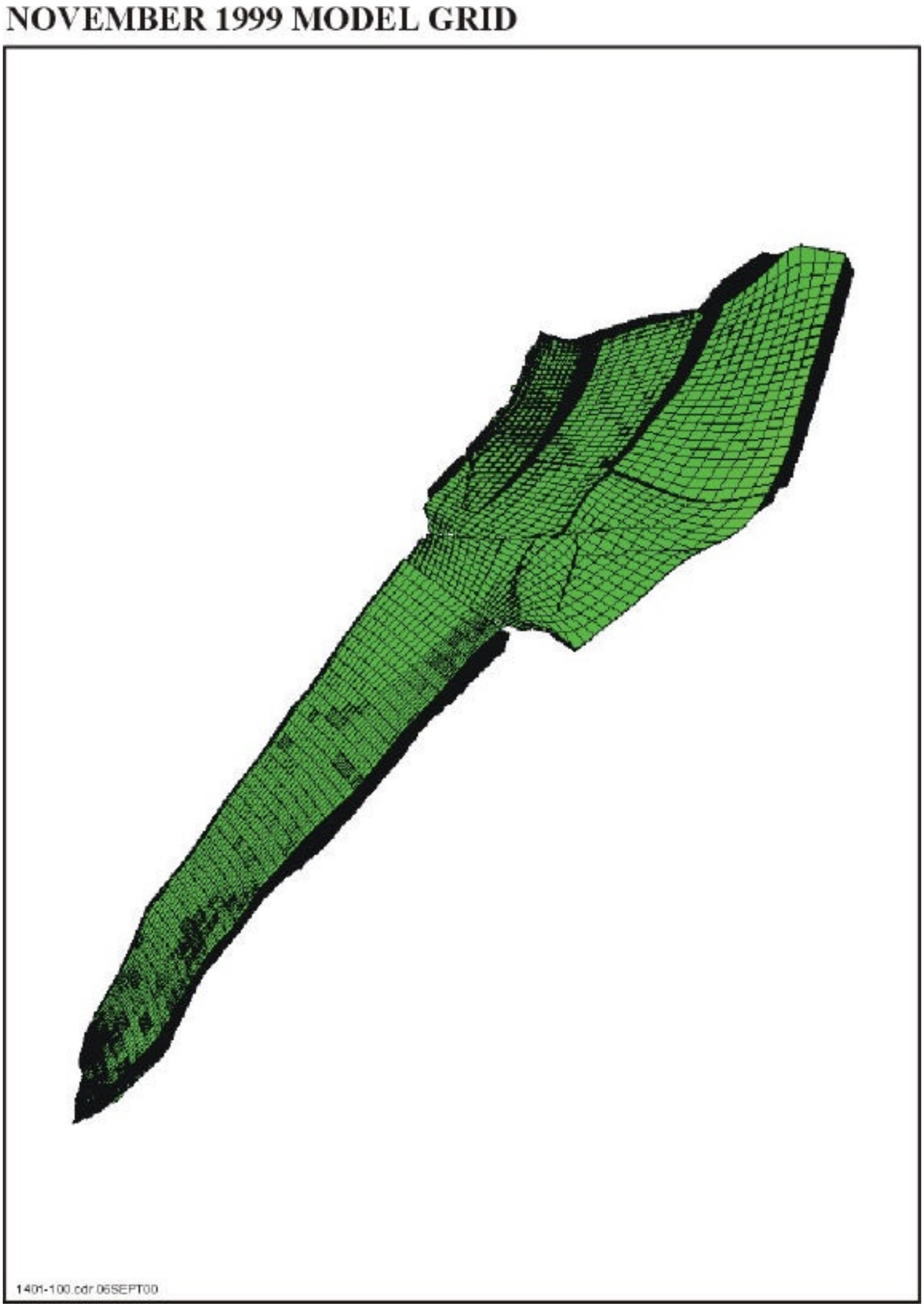


Figure 6.2–7 November 99 Model Grid



6.3 Alternative Development Options

Three other development options were evaluated for the South Avalon Pool. These were:

1) reinjection of all excess produced gas (net of fuel requirements) into the Terrace block portion of the field;
2) reinjection of excess produced gas (net of fuel requirements) into all fault blocks (except blocks 2 and 5); and
3) reinjection of only a produced gas cap gas (approximately 40 percent of total produced gas) to maintain original gas-oil contact.

These cases were run prior to the drilling of the H-20 well, so they include development of northern portion of the pool. A comparison of the production forecasts for the various cases and the pre-H-20 reference case is provided in Figure 6.3-1, and a comparison of 15-year recovery factors as well as gas and water handling requirements are provided in Table 6.3-1.

Table 6.3-1 Comparison of Alternative Development Options

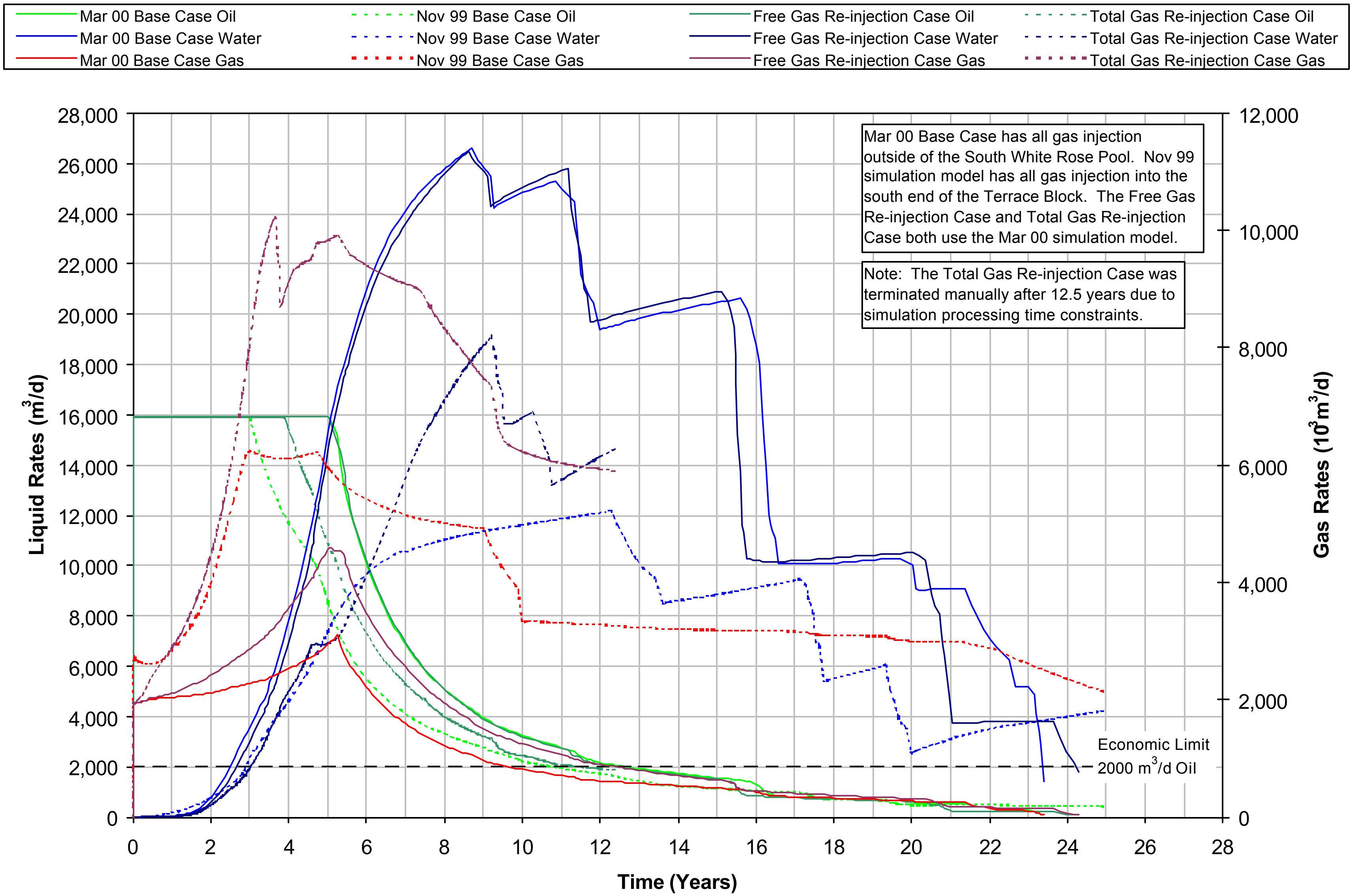
Case	Recovery Factor (% after 15 years)	Max Gas Rate ($10^6 m^3$)	Max Water Rate ($10^3 m^3$)
Pre-H-20 Reference Case–waterflood only	39	3.1	27
Post-H-20 Case	41	2.8	23
Reinjection of gas into the Terrace Block (Nov 99 model)	36	6.4 (compression capacity limited)	12
Reinjection of gas throughout the field (Pre-H-20 model)	34	10.1 (unconstrained)	19
Partial reinjection of gas throughout the field (Pre-H-20 model)	39	4.6	27

The water injection base case maximizes recoveries and minimizes gas handling requirements. Water handling and total fluid requirements are larger in the base case. However, it is expected that there would be design simplification and net cost benefits compared with cases which involve handling significantly higher gas volumes.

In cases where all produced gas is reinjected into producing oil blocks, recoveries are reduced significantly. For the partial reinjection cases, recoveries are not impacted significantly but additional gas injection wells would be required, as there would be gas injection both within and outside the pool. The cost of these additional wells would reduce project economics significantly.

In addition, for all reinjection cases, reinjection of gas into the pool increases gas handling requirements due to earlier and larger breakthrough volumes. The increased gas production rates would increase gas compression requirements which could reduce project economics.

Figure 6.3–1 Comparison of Production Forecasts for Alternative Development Options



6.4 Base Case Development Sensitivities

Two types of sensitivities were evaluated with the reservoir simulation models. The first are controllable parameters dealing with facility and well constraints. The second are uncontrollable parameters associated with uncertainties in reservoir quality and performance. These sensitivities were evaluated using the November 1999 and Pre-H-20 models and include development of the two northern fault blocks but are still directionally valid for a development without those blocks.

6.4.1 Controllable Sensitivities

Sensitivities, using the November 1999 model, were run to examine the impact of facility oil handling capacities, gas handling capacities, bottomhole producing pressure constraints and horizontal versus vertical or highly deviated wells will have on field production performance and oil recoveries.

6.4.1.1 Maximum Facility Oil Handling Capacity

Oil handling capacities of 15,900, 11,900 and 7,900 m^3/d were evaluated to see if reduced maximum oil rates would increase field recoveries as a result of having less aggressive depletion in the early years.

Reducing oil handling capacities had no noticeable effect on field recoveries during the first 15 years of production or on ultimate recoveries. The biggest impact of limiting oil handling capacities to less than 15,900 m^3/d was to extend the plateau period of the field and to slightly reduce gas handling requirements.

A comparison of the oil, gas and water production forecasts for each case is provided in Figure 6.4-1.

6.4.1.2 Maximum Gas handling Capacity for Gas Re-injection Cases

For gas reinjection cases, gas handling requirements become very large if not restricted. Gas handling capacities of 3.5, 4.2 and 5.0 $10^6 m^3$/d were evaluated using the November 1999 model to see the impact of restricting gas production rates on field production performance.

Reducing gas handling capacities did not significantly impact 25-year recoveries but would reduce 15-year recoveries by up to 10 percent. The biggest impact is to reduce the oil plateau period of the field by a year or more and to extend the field life by six years, if gas handling was restricted to 3.5 10^6 m^3/d.

Oil, gas and water production rates and cumulative oil production versus time for each case are shown in Figure 6.4-2 and 6.4-3, respectively.

Figure 6.4–1 Comparison of Production Forecasts for Different Oil Handling Capacities

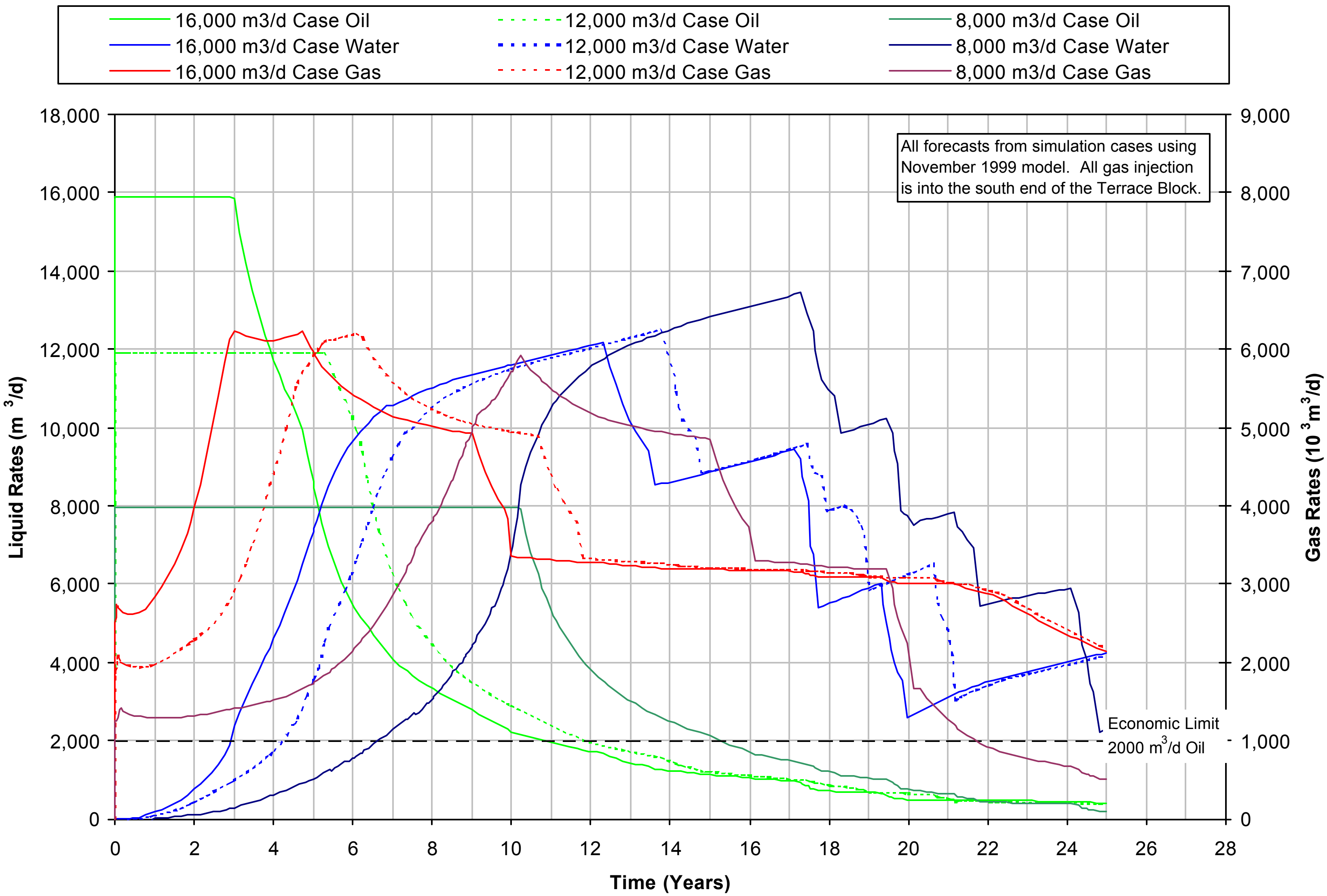


Figure 6.4–2 Comparison of Production Forecasts for Different Gas Handling Capacities

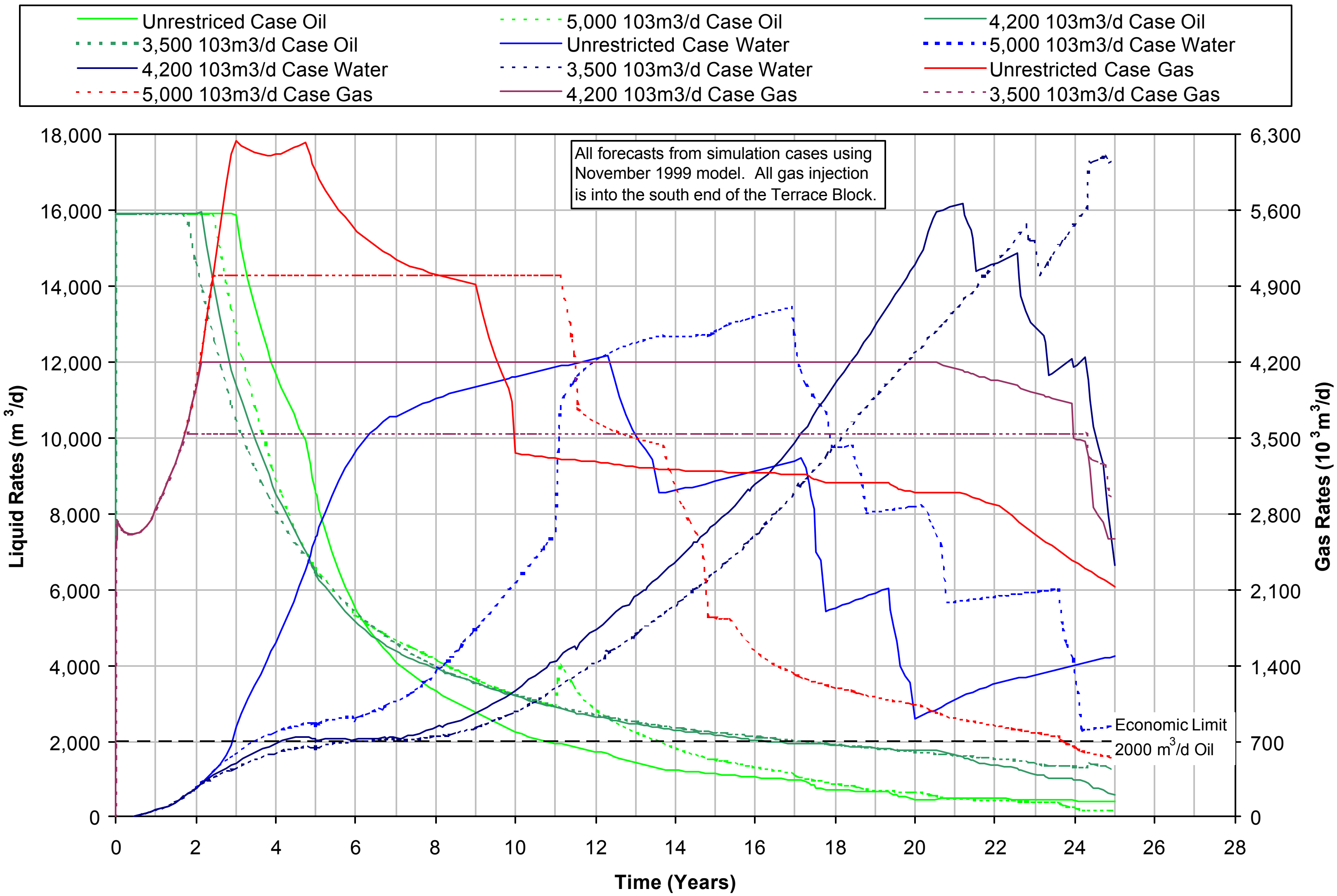
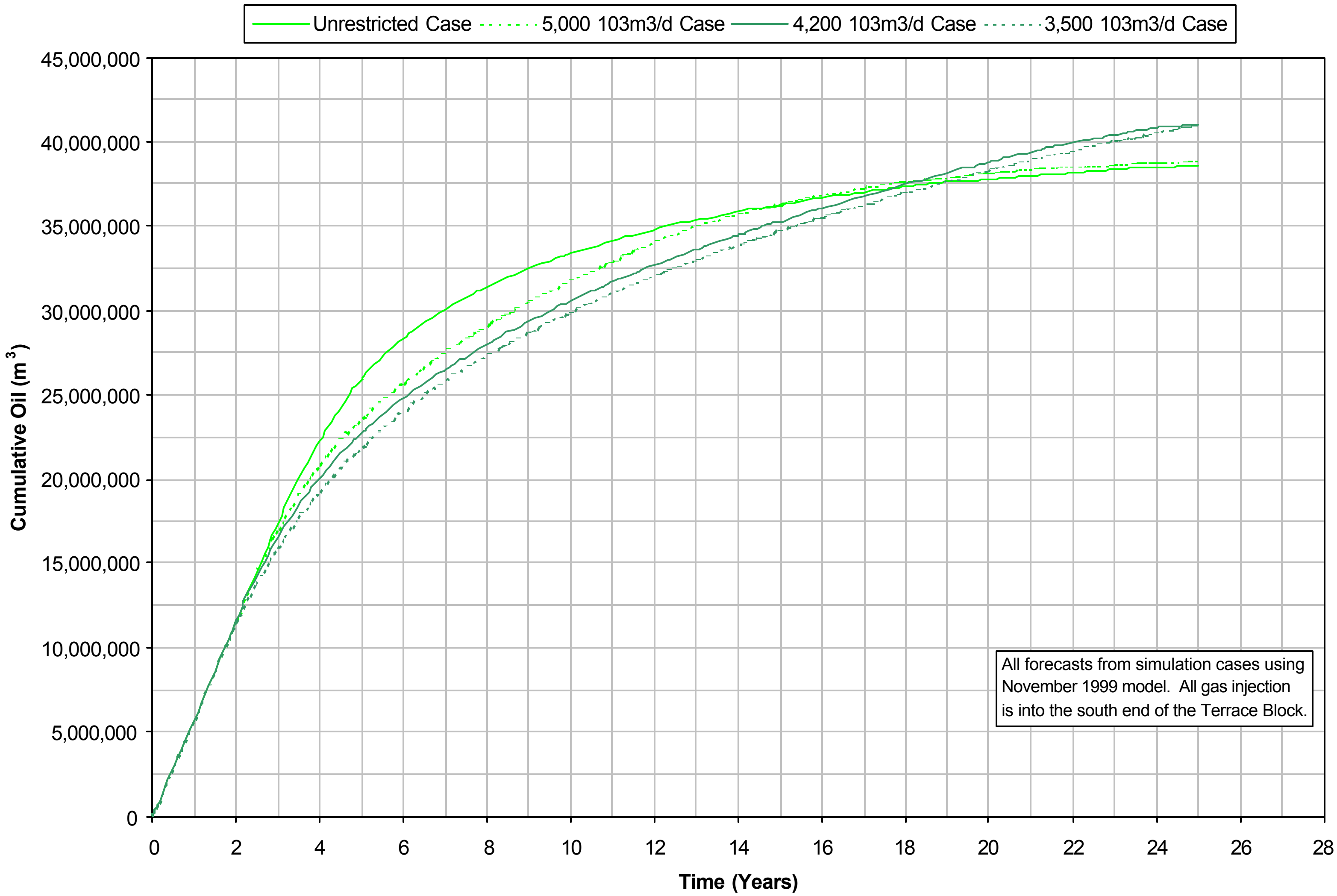


Figure 6.4–3 Comparison of Cumulative Oil Production Forecasts for Different Gas Handling Capa cities



6.4.1.3 Bottomhole Pressure Constraints

In the current model, the minimum bottomhole pressure for oil producers is set at 22 MPa. This constraint has been set based on wellbore modelling work that indicates that this may be the maximum draw down that can be achieved. Sensitivity cases were run using the November 99 model, where the bottom hole pressure constraints of 15 and 20 MPa were evaluated. The results of the two cases are shown in Figure 6.4-4. Going to lower bottomhole producing pressures does not appear to have a detrimental impact on recoveries and may have the benefit of extending the plateau period. Gas production and therefore gas handling requirements may increase at higher draw downs.

6.4.1.4 Use of Vertical or Highly Deviated Wells Versus Horizontal Wells

A sector model of the A-17 block was used to evaluate the performance of vertical or deviated wells as production wells. The advantage of vertical or deviated wells is that they would cross any vertical permeability barriers that may hinder waterflood performance.

The model showed that any deviations of greater than 4° from horizontal could significantly reduce field recoveries by allowing early gas or water breakthrough. This confirms the need for horizontal producers (WST, White Rose Well Design Simulation Study). Further assessment of the use of deviated wells will be carried out as more reservoir information becomes available.

6.4.2 Reservoir Uncertainty Sensitivities

Several model sensitivities were run to examine the impact of various reservoir uncertainties.

6.4.2.1 Reduced Vertical Permeabilities

In the base case RMS geological model, a kv\kh of 0.3 was used for the 2-m layers. A sensitivity was run to evaluate the impact of decreasing the kv\kh to 0.1 to reflect some of the lower kv\kh ratios seen in MDT interference testing (Section 4.4.3).

The major impacts of decreasing the kv\kh ratio were to delay water and gas breakthrough times and improve overall recoveries by approximately 10 percent. In particular, water production rates were reduced significantly. Cumulative oil, gas and water production differences are illustrated in Figure 6.4-5.

Figure 6.4–4 Impact of Bottomhole Pressure Constraints on Production Profiles

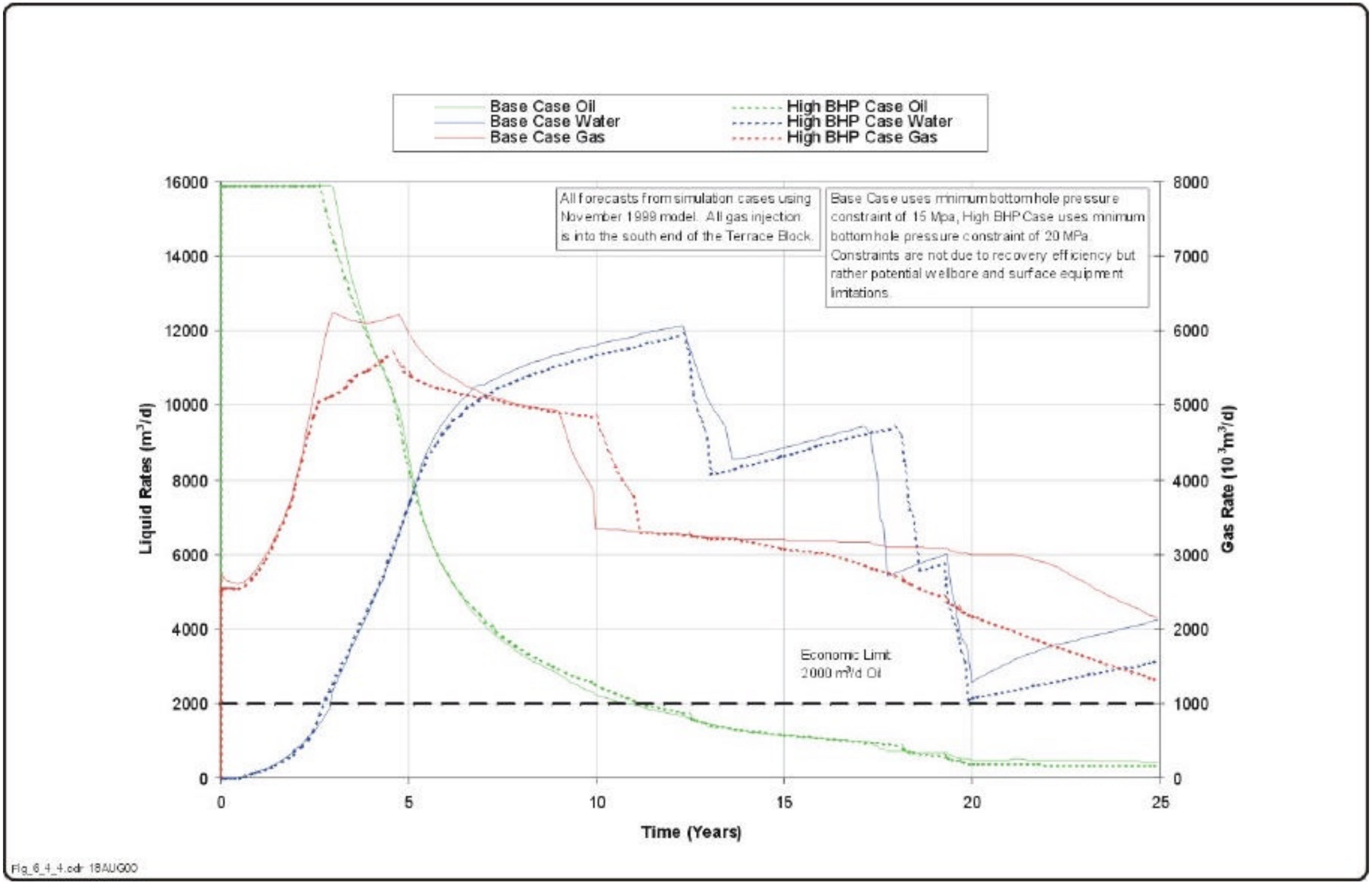
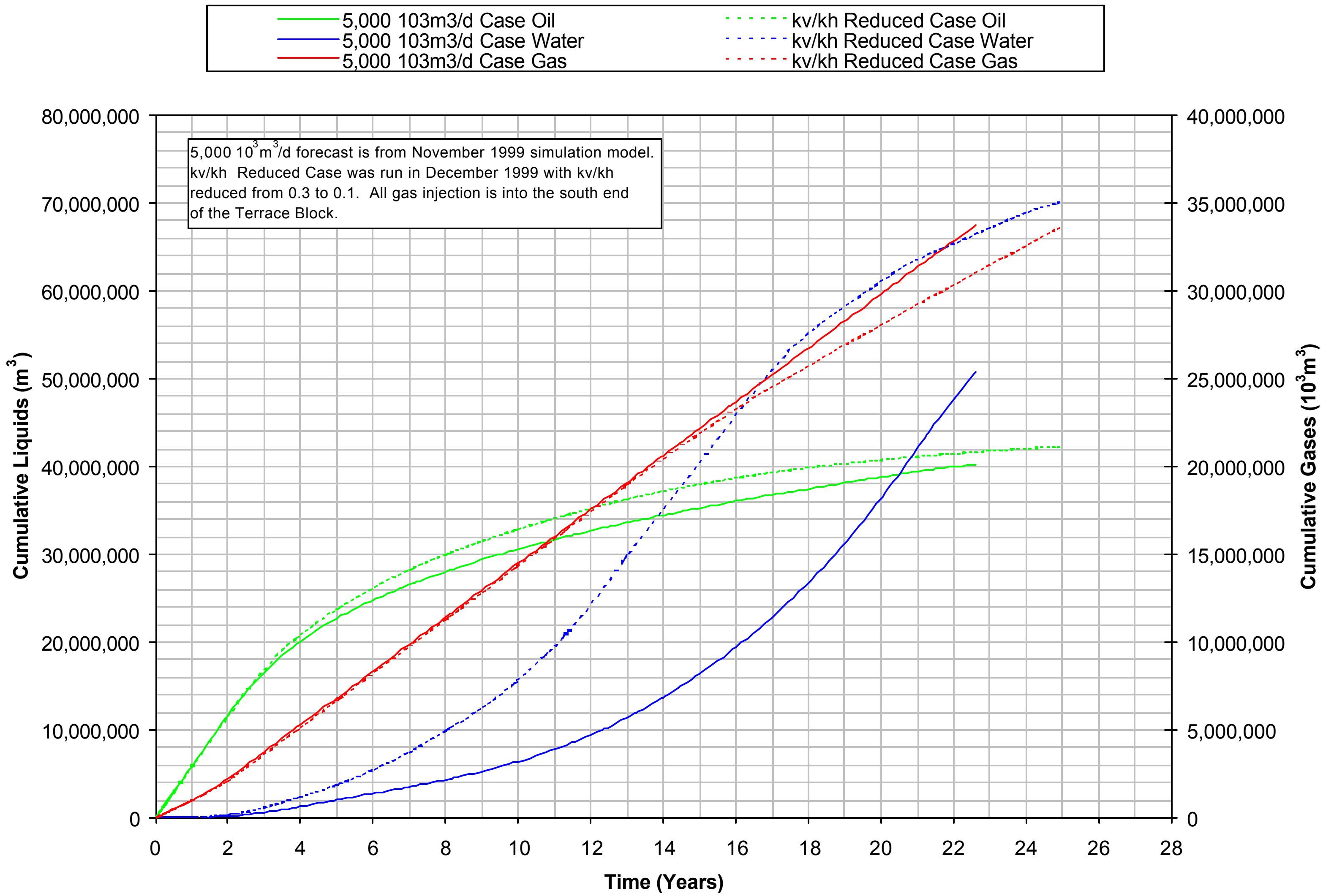


Figure 6.4–5 Impact of Reduced kv/kh Rations on Cumulative Production



6.4.2.2 Permeability Barriers

Sensitivities were run to evaluate the impact of impermeable layering, which would be equivalent to having calcite cemented beds that are parallel to the depositional trends and are laterally extensive. Cases for one, two and three impermeable layers were run. The most significant impact was to reduce the effectiveness of the waterflood, with oil decline starting earlier and recoveries being significantly reduced. The impact on the recovery factor is shown in Table 6.4-1. A case was also run with no support from water injection and recoveries were reduced by 46 percent.

Table 6.4-1 Impact of Permeability Barriers on Recovery

Case	% Reduction in Recovery Factor	Recovery Factor %
Base Case (November 99)	0	36.5
One permeability barrier	8	33.6
Two permeability barriers	33	24.5
Three permeability barriers	38	22.6
No water flood support	46	19.7

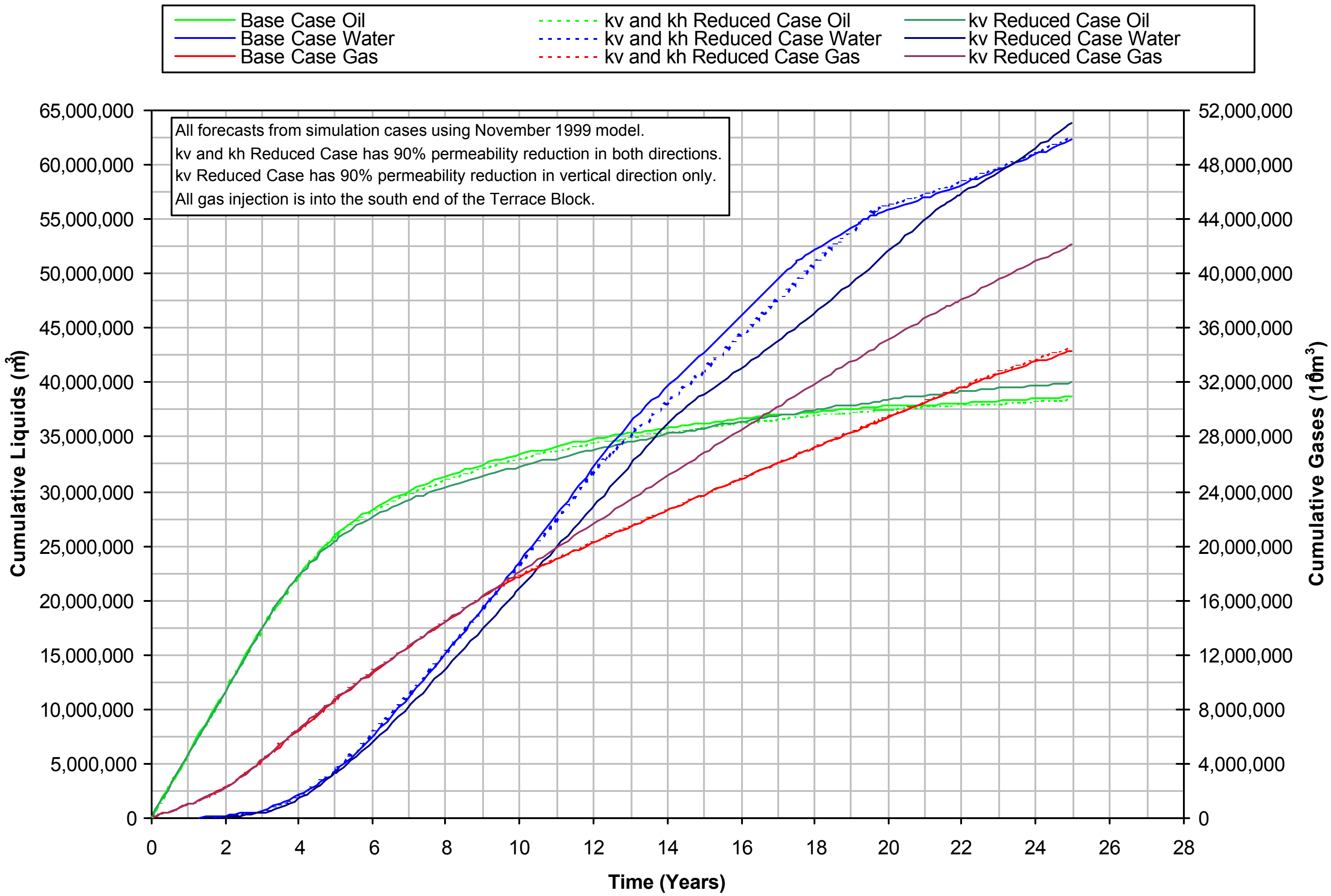
6.4.2.3 Reduced Permeability in the Water Leg

Permeability appears to be reduced below the oil-water contact and is possibly related to additional diagenesis in the water leg. Two sensitivities were run, one with a 90 percent reduction in both horizontal and vertical permeabilities and one with a reduction in vertical permeabilities only. There was almost no effect on the recoveries for these cases other than to give slightly improved recoveries. However, in the case where there was a global reduction in the water leg permeability, there was an impact on production forecasts because water injectivity was reduced. The reduction in injectivity led to slightly reduced oil rates in the initial years, which was made up later in the field life. The impact of reduced permeability in the water leg on cumulative production forecasts is illustrated in Figure 6.4-6.

6.4.2.4 Non-Sealing Faults

The current base case simulation assumes that all faults included in the simulation model are sealing. Cases were run to assess the impact of having non-sealing or partially sealing faults, which would allow communication between fault blocks.

Figure 6.4–6 Impact of Reduced Permeability in the Water Leg on Cumulative Production



The model indicated a minor improvement in recoveries of approximatley 3 percent, with no appreciable differences between the non-sealing and partially sealing cases. The reason for the improvement was that the production wells can drain slightly larger volumes unencumbered by the faults, with the plateau period being slightly extended. The biggest impact was on gas production rates that increased by approximately 10 percent. The oil, gas and water production forecasts for the three cases are shown in Figure 6.4-7.

6.4.2.5 Sub-seismic Faults

The impact of sub-seismic sealing faults was evaluated with the current simulation model. A series of geostatistical sub-seismic fault plane realizations were generated based on mapped fault statistics for fault lengths, direction and maximum throw within the reservoir model, each applying different methodologies for extrapolation of fault statistics into the sub-seismic range. The fault planes were then imported into the Eclipse model, treated as sealing boundaries and the models rerun to study the impact on recoveries.

With a fractal model of fault trends, recovery factors could be reduced by up to 6 percent. However, if an exponential model of fault trends is used, recovery factors could be reduced by as much as 30 percent. The impact of sealing sub-seismic faults on production profiles is shown in Figure 6.4-8.

The results of sub-seismic faulting evaluations are very preliminary and additional work is required to confirm results.

6.4.2.6 Faults Acting as Flow Conduits

Most faults seen in core to date appear to be cemented and non-conducting. However, there is the potential for faults or fault damage zones to have open faults or fractures and act as conduits for water from the water leg and or gas from the gas cap. If this were the case, there would be the potential for oil to be bypassed and recoveries reduced. To evaluate this factor, vertical permeability was increased by a factor of 10,000 in the grid cells on one side of the faults that were crossed by a well in the L-08 Block and a well in the E-09 Block. The impact on recoveries versus time for two wells evaluated is shown in Figure 6.4-9. If faults act as conduits, the model indicated that recoveries from the wells could be reduced by more than 20 percent. As conducting fault dimensions would be several magnitudes smaller than a cell in the model, the actual impact of conducting faults would be much more severe, with breakthrough happening very quickly. Additional evaluation of faults and fault zone characterization will be carried out.

Figure 6.4–7 Comparison of Sealing, Non-sealing and Partially Sealing Fault Cases

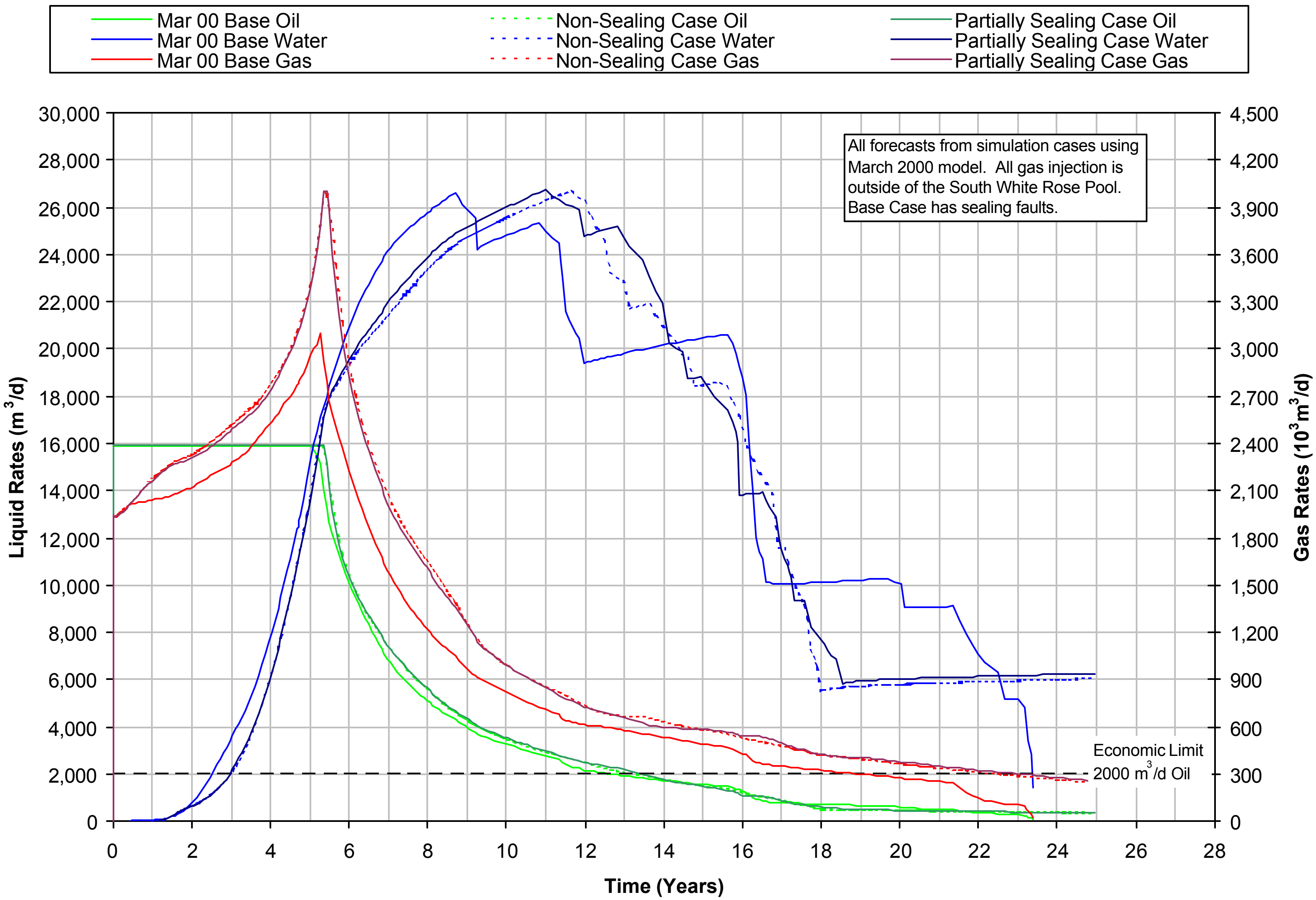


Figure 6.4–8 Impact of Sub-Seismic Faults on Cumulative Oil Production Profiles

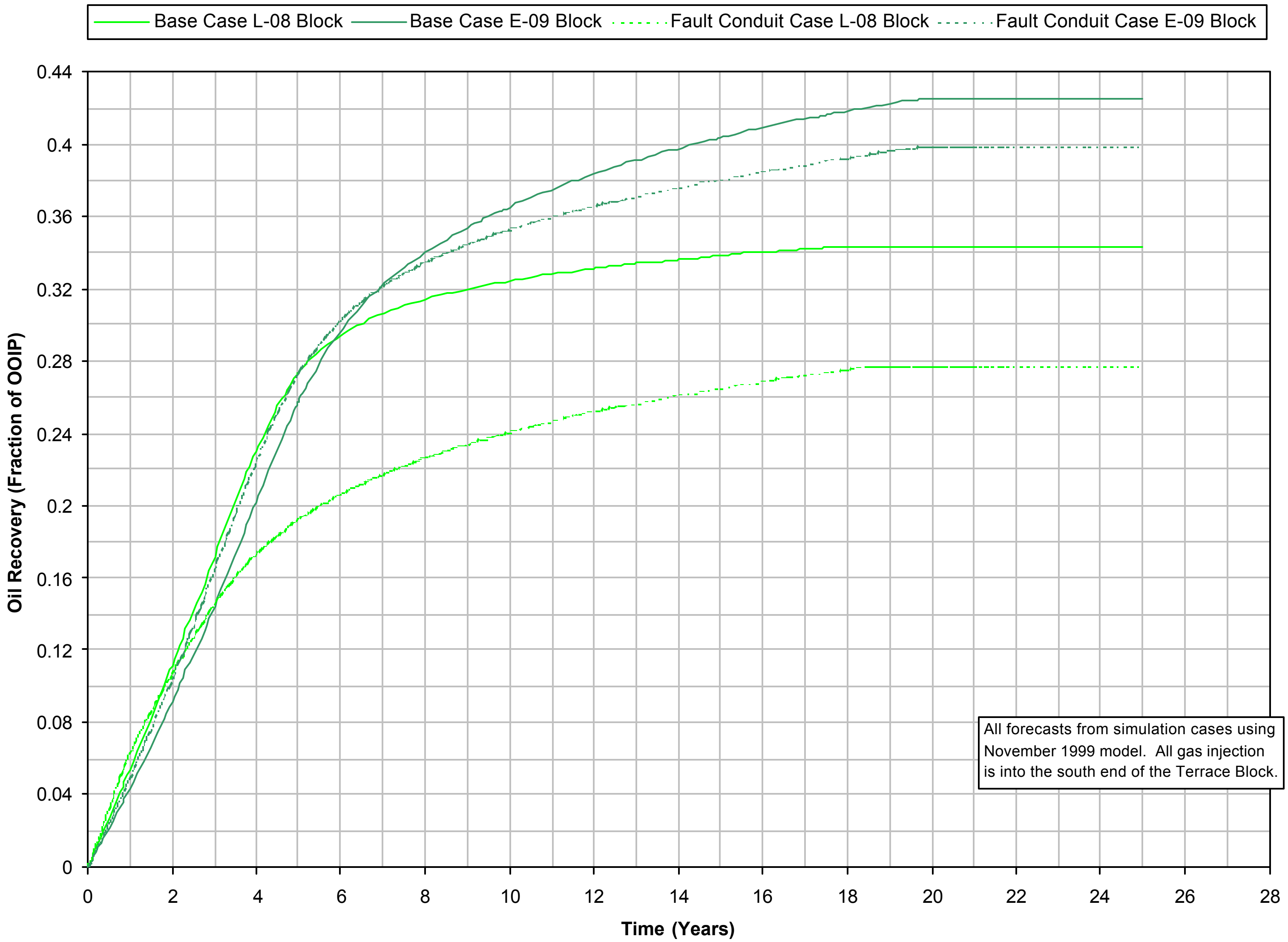
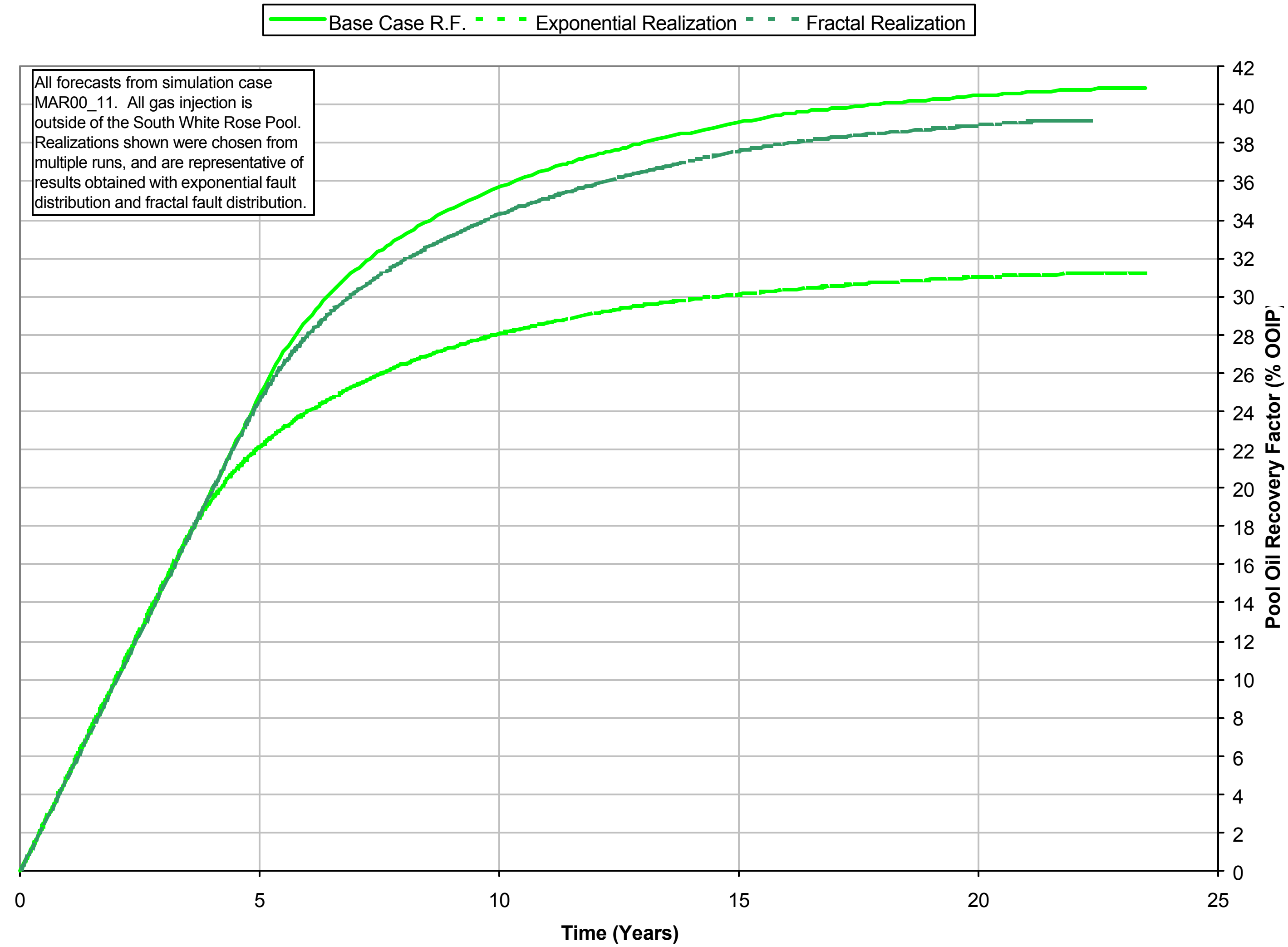


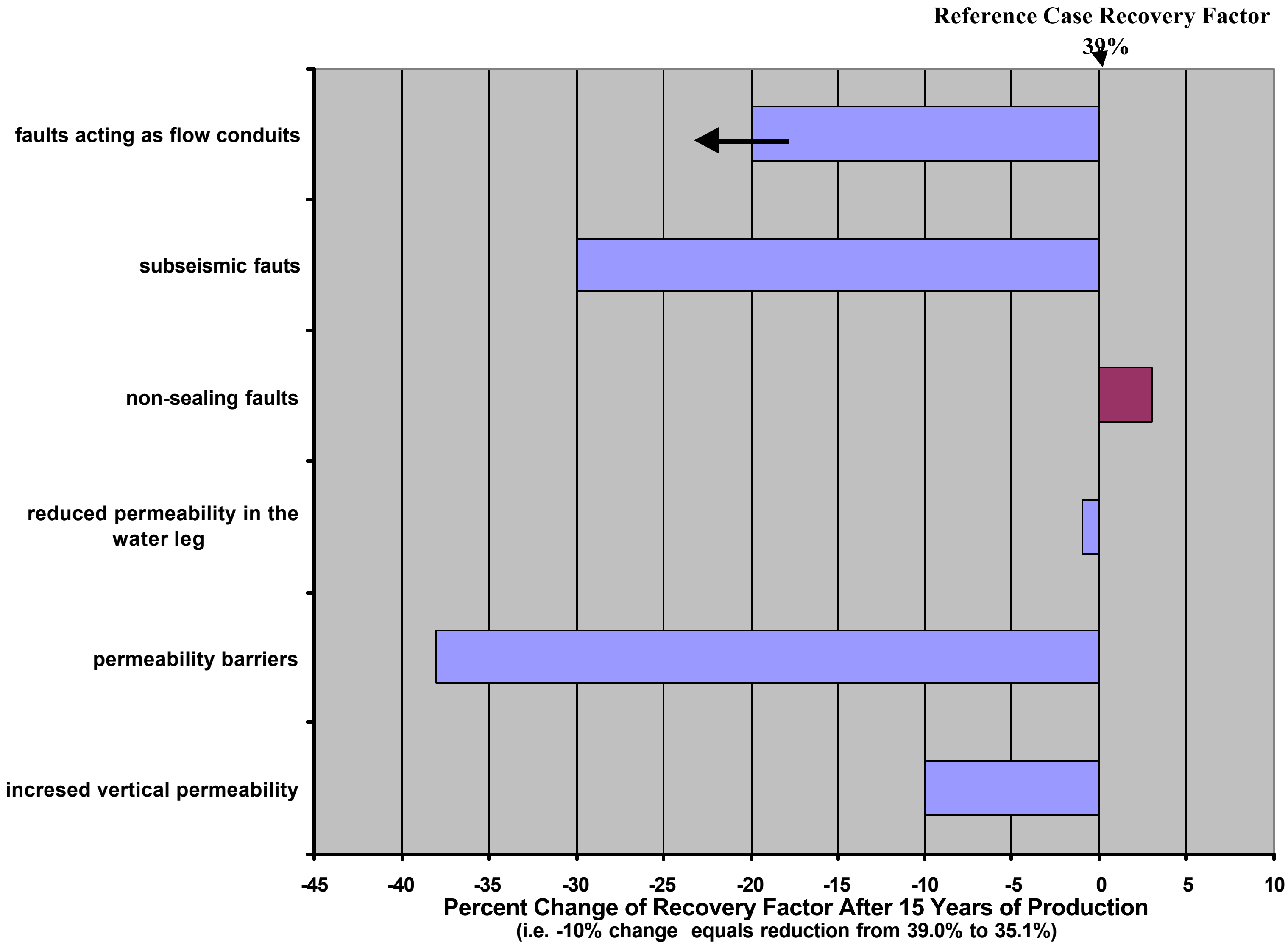
Figure 6.4–9 Impact on Recovery Factors of Faults Acting as Conduits



6.4.2.7 Summary

The impact the above sensitivities had on the Pre-H-20 reference case recovery factor is summarized in Figure 6.4-10. As can be seen, most of the sensitivities had a negative impact on recoveries. (Note: a 10 percent reduction means a recovery factor reduction from the reference case recovery factor of 39.0 percent to a recovery factor of 35.1 percent.).

Figure 6.4–10 Summary of Simulation Sensitivities



6.5 Recovery Factors and Reserves

Probabilistic recovery factor ranges and reserve ranges have been developed for the White Rose Avalon Pools.

6.5.1 Pre-H-20 Avalon Oil Recovery Factor and Reserve Ranges

The probabilistic reserves estimate is the product of the probabilistic OOIP, as contained in Chapter 5, and the Probabilistic Recovery Factor (PRF). The PRF captures the range of variances in reservoir and fluid characteristics which do not affect the volumetric calculations, but do affect the depletion strategy.

The starting point of the PRF range is the 15-year recovery factor of 39 percent from the Pre-H-20 reference case reservoir simulation.

Recovery factors for the West Avalon Pool and the North Avalon Pool were selected based on the reservoir performance observed in fault blocks in the South Avalon Pool that reflect the expected reservoir quality in the respective pools. Reference case recovery factors for the West Avalon Pool and the North Avalon Pool were set at 30 and 29 percent, respectively. These recovery factors were based on recoveries seen in Block 5 and Block 2 of the South Avalon simulation model.

Once the reference case recovery factors were established, ranges of recovery factor multipliers were developed for key recovery factor components. The key recovery factor components for which multiplier ranges were developed were:

- displacement efficiency influenced by
  - oil-water relative permeability data, and
  - gas-liquid relative permeability data;
- vertical sweep efficiency influenced by
  - k_v/k_h ratio,
  - vertical layering, and
  - reservoir diagenesis in the water leg; and
- areal sweep efficiency influenced by
  - fault seal analysis, and
  - the existence of sealing sub-seismic faults.

The ranges were developed based on the reservoir simulation sensitivity work described in Section 6.4. The multiplier ranges established for each recovery factor component are provided in Table 6.5-1.

Table 6.5-1 Recovery Factor Parameter Multiplier Ranges

Parameter	Parameter Multiplier Range		
	P90	Most likely	P10
Displacement Efficiency	0.74	1.00	1.09
Areal Sweep Efficiency	0.81	1.00	1.03
Vertical Sweep Efficiency	0.82	1.00	1.05

The reference case recovery factors for each of the pools were then statistically multiplied by the parameter recovery factor multipliers using a Monte Carlo simulation package. The resulting probabilistic recovery factor ranges for each of the pools are given in Table 6.5-2.

Table 6.5-2 Avalon Oil Recovery Factor Ranges

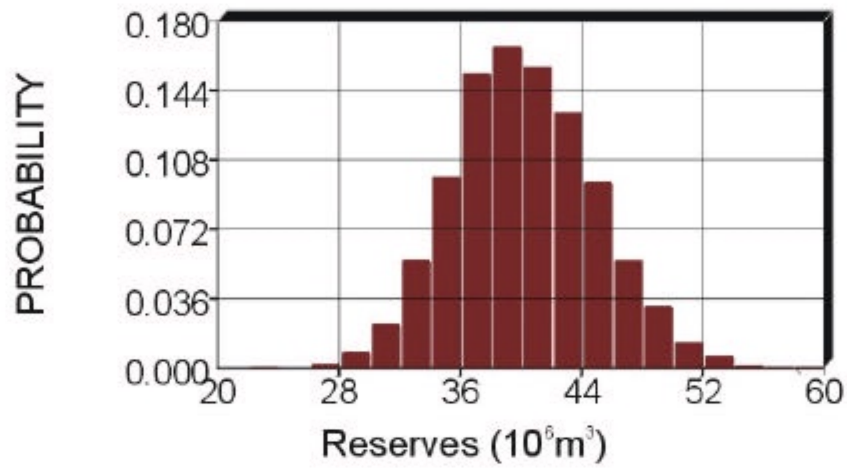
Pool	Recovery Factor Range			
	Reference Case (%)	P90 (%)	P50 (%)	P10 (%)
South Avalon Pool	39	23.9	31.4	39.3
North Avalon Pool	29	17.8	23.4	29.6
West Avalon Pool	30	18.3	24.3	30.5

The probabilistic recovery ranges shown in the previous section were then statistically multiplied by the OOIP ranges show in Chapter 5 for each of the Avalon pools. The OOIP and recoverable reserve ranges for each pool are summarized in Table 6.5-3 and the probabilistic reserve distributions for each of the pools are illustrated in Figures 6.5-1 to 6.5-3.

Table 6.5-3 Pre H-20 Avalon Oil OOIP and Reserve Ranges

Pool	P90 ($10^6 m^3$)	P50 ($10^6 m^3$)	P10 ($10^6 m^3$)
South Avalon			
OOIP	114.4	126.8	138.2
Reserves	34.2	36.2	46.4
North Avalon			
OOIP	24.8	28.6	32.4
Reserves	5.4	6.7	8.3
West Avalon			
OOIP	32.1	37.0	42.1
Reserves	7.0	8.9	11.1

Figure 6.5–1 South Avalon Pool Probabilistic Oil Reserves Distribution



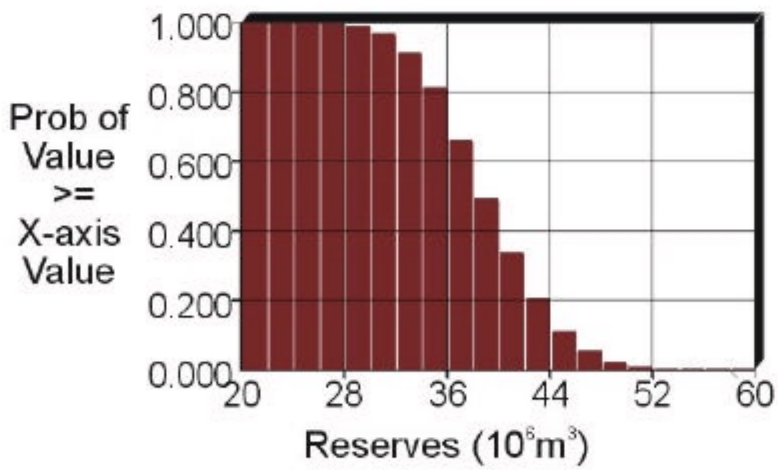


Figure 6.5–2 North Avalon Pool Probabilistic Oil Reserves Distribution

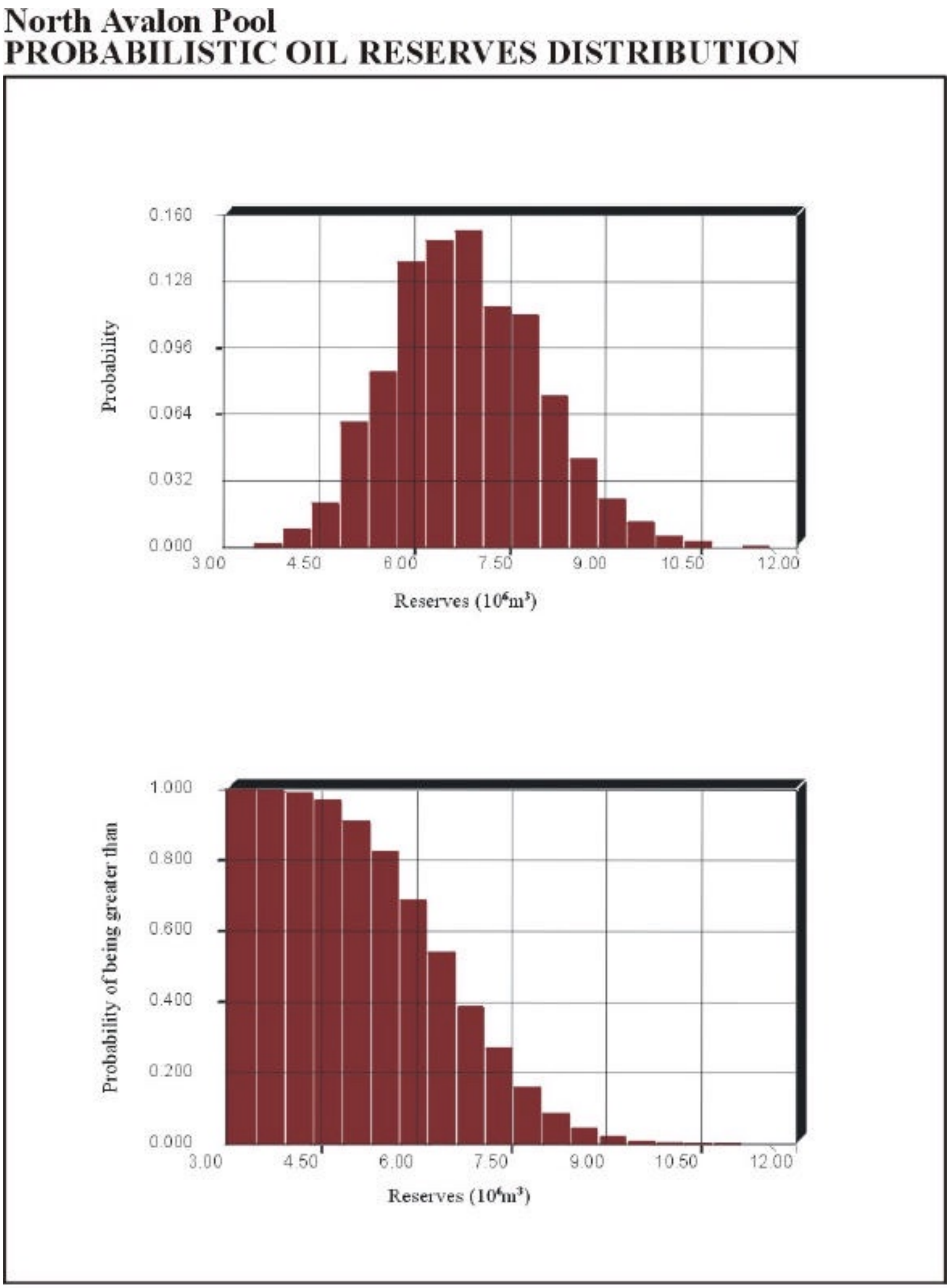


Figure 6.5-2

Figure 6.5–3 West Avalon Pool Probabilistic Oil Reserves Distribution

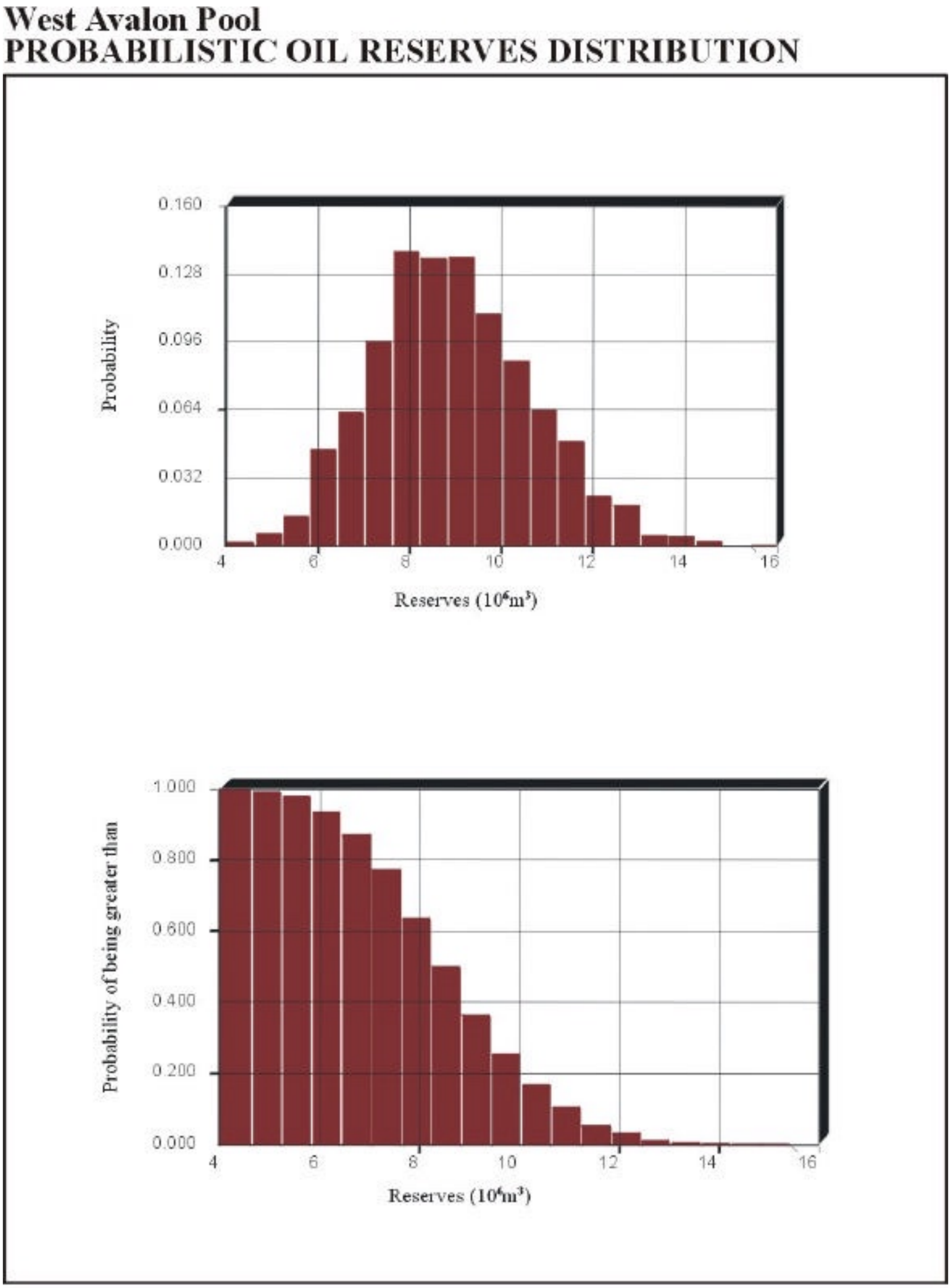


Figure 6.5-3

6.5.2 South Avalon Pool Post-H-20 Reserve Estimates

The comparison of the pre- and-post-H-20 simulation evaluations indicates that if the fault blocks to the north of E-09 are completely isolated from the rest of the South Avalon Pool and are not included in the development, then oil recoveries will be reduced by approximately 9.5 percent (Section 6.2.2). This should be a maximum reduction, as there is some net pay in the H-20 well and there is still the potential for future development of this area. Therefore, P50 recoverable oil for the South Avalon Pool should be approximately 36 $10^6 m^3$. P50 reserves were determined from the pre-H-20 evaluations.

6.6 South Avalon Base Case Development

Preliminary results of the H-20 well indicate that producible volumes in the two blocks north of the E-09 well in the South Avalon Pool (blocks 2 and 5) may be too small to economically produce. Therefore, the Base Case Development for the South Avalon Pool excludes drilling of these two blocks.

Development of these fault blocks will be re-evaluated based on the results of development drilling and initial production performance of the pool.

6.6.1 Development Drilling Schedule

Several of the development wells will be pre-drilled prior to production start-up. The proposed strategy is to pre-drill sufficient wells prior to First Oil to have the capability of producing at facility design rates. In addition, there will be pre-drilled water injection wells to provide appropriate initial pressure support and a pre-drilled gas injection well so that gas conservation can commence as soon as injection facilities are operable.

In general, water injectors will be drilled first to capture as much information about the fault block as possible before the producers are drilled. Some of the water injectors may have pilot holes drilled to the base Avalon to confirm contacts and mapping. Injection well trajectories and locations will not be as critical as those of production wells. Also, wells drilled in the same block will be spaced out as much as practicable in order to allow time to better design the trajectory of the subsequent wells.

The second gas injection well will not be drilled until after First Oil so that reservoir pressure response data from the initial gas injection well can be obtained. This information will assist in finalizing the second gas injection well.

To meet these objectives, up to 10 wells will be required prior to First Oil.

A preliminary drilling schedule for the base case well layout is provided in Table 6.6-1. This schedule may be adjusted based on further studies carried out prior to and after the start of production. Preliminary well locations are shown on Figure 6.2-4.

Table 6.6-1 Preliminary South Avalon Development Drilling Schedule

No.	Well Name	Comments
1	B14W1	Information to locate Block 14 producer (w/pilot)
2	B7W1	Information to locate Block 7 producer
3	Gas #1	Time used to locate Block 7 and 14 producers
4	B7P1	No. 1 producer
5	B3W1	Information to locate Block 3 producer
6	B14P1	No. 2 producer
7	B7P2	No. 3 producer
8	B3P2	No. 4 producer
9	B3P1	No. 5 producer – "First Oil"
10	B1W1	Information to locate Block 1 producers (w/pilot)
11	Gas #2	Second gas injector
12	B1P2	No. 6 producer
13	B6W1	Information to locate Block 6 producer
14	B1P1	No. 7 producer
15	B6P1	No. 8 producer

6.6.2 Base Case Production Forecasts

The Eclipse model forecasts do not account for base case (P50) recoveries being less than recoveries in the model, the drilling sequence, or overall operating efficiency expectations. In order to generate a base case production forecast that accounts for these constraints, the reservoir performance versus cumulative production curves from the post-H-20 simulation evaluation were made dimensionless and then used to generate production and injection forecasts. An operating efficiency of 92 percent and recoverable reserves of 36.2 $10^6 m^3$ were used to generate the Base Case Production Forecast. The 36.2 $10^6 m^3$ volume is based on the 9.5 percent decrease in recoveries predicted by the post-H-20 evaluations.

The dimensionless reservoir performance curves used are shown in Figure 6.6-1 and the base case production and injection forecasts for the South Avalon Pool are shown in Figure 6.6-2 and Table 6.6-2.

Figure 6.6–1 Dimensionless Production Data

Cum Oil	Oil Prod Rate m³/d	Cumulative Water	Cumulative Excess Gas
0.000	15900	0.000	0.000
0.132	15900	0.000	0.006
0.275	15900	0.001	0.029
0.408	15900	0.009	0.074
0.474	15900	0.017	0.108
0.540	15900	0.029	0.151
0.604	15389	0.048	0.205
0.659	13297	0.072	0.269
0.736	9281	0.132	0.376
0.791	6110	0.207	0.465
0.829	4490	0.281	0.530
0.856	3581	0.350	0.581
0.882	2896	0.427	0.631
0.903	2463	0.500	0.672
0.920	2045	0.565	0.711
0.934	1788	0.627	0.749
0.948	1603	0.691	0.786
0.961	1368	0.761	0.826
0.970	1123	0.810	0.854
0.976	736	0.845	0.885
0.982	647	0.875	0.912
0.987	598	0.905	0.936
0.991	556	0.935	0.959
0.996	514	0.965	0.980
0.998	343	0.988	0.991
1.000	148	1.000	1.000

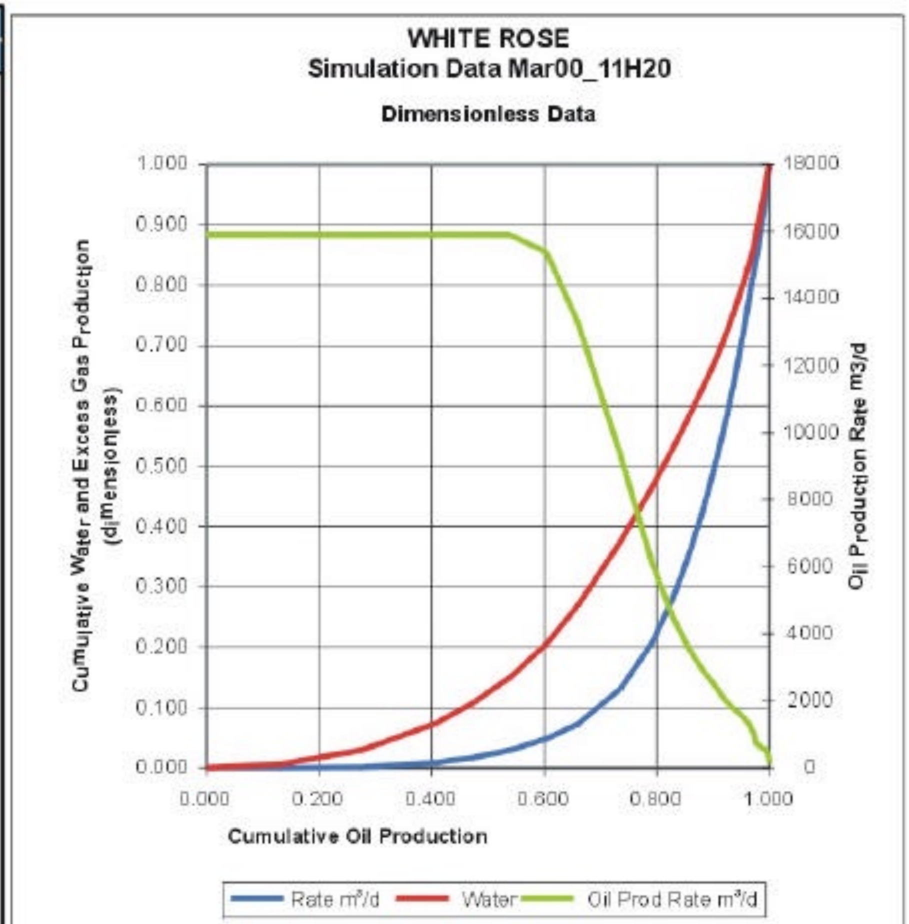


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Figure 6.6–2 South Avalon Pool Production Forecast

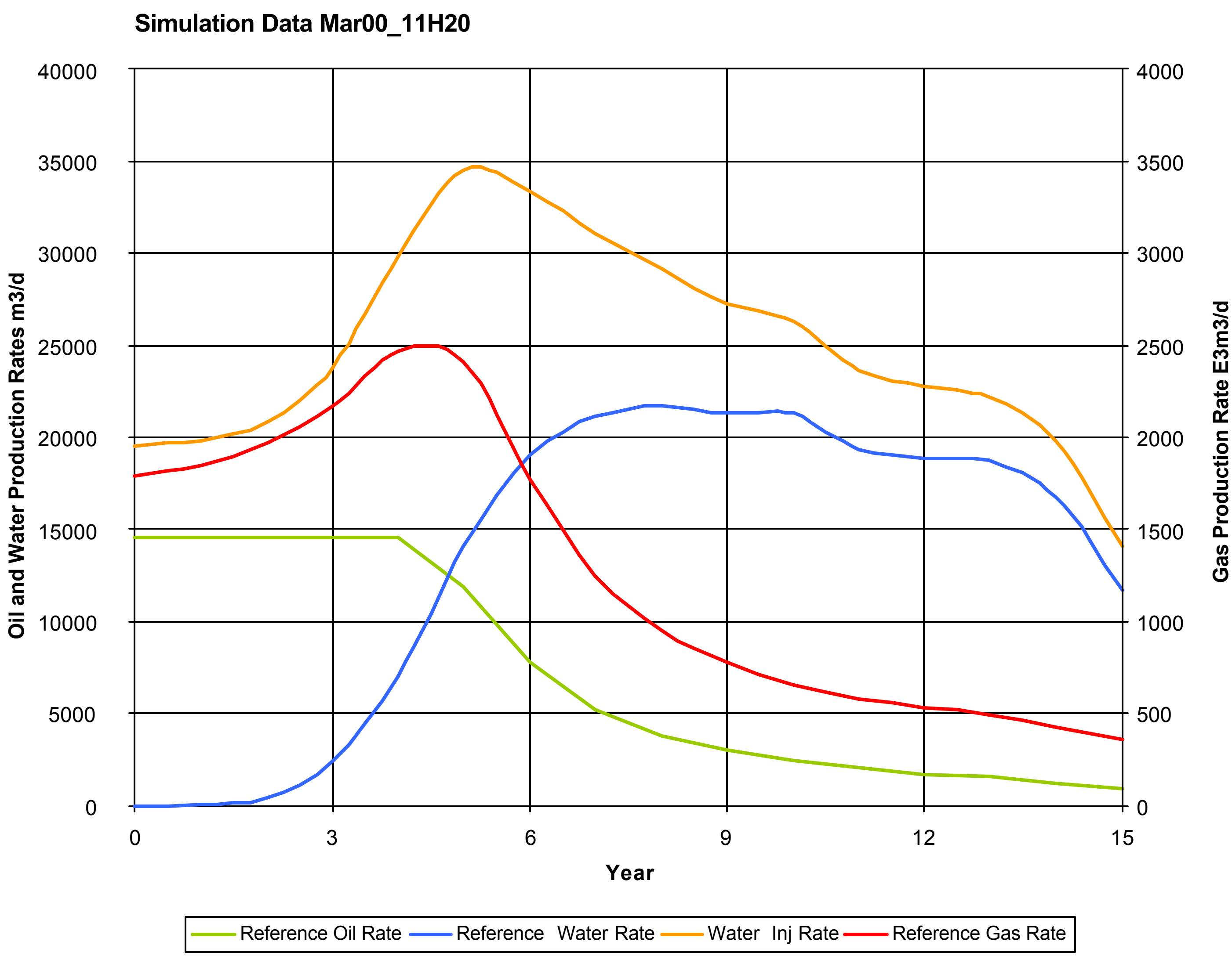


Table 6.6-2 South Avalon Pool Production Forecast

Production Forecast SI Units

Year	Oil Rate m3/d	Cum Oil E3m3	Cum Water E3m3	Water Rate m3/d	Cum Ex Gas E6m3	Excess Gas Rate E3m3/d	Total Gas Rate E3m3/d	Cum Total Gas E6m3	Water Inj Rate m3/d
1	14628	5339	16	44	21	57	1846	674	19870
2	14628	10678	169	420	87	183	1972	1393	20840
3	14628	16018	1048	2406	227	382	2171	2186	23780
4	14628	21357	3622	7053	476	683	2472	3088	29870
5	11824	25673	8780	14132	826	958	2404	3965	34510
6	7739	28497	15730	19039	1124	818	1764	4609	33290
7	5152	30378	23444	21135	1350	618	1248	5065	30980
8	3771	31754	31368	21711	1527	486	947	5411	29070
9	2969	32838	39134	21275	1676	408	771	5692	27190
10	2447	33731	46907	21298	1805	354	653	5931	26260
11	1991	34457	53968	19346	1927	332	576	6141	23600
12	1718	35085	60864	18892	2045	323	534	6336	22740
13	1492	35629	67681	18675	2156	305	487	6513	22120
14	1225	36076	73769	16680	2257	276	426	6669	19640
15	848	36386	77967	11502	2348	249	353	6798	13830

6.7 Deferred Developments

Three deferred developments will be considered, as the results of South Avalon development drilling, production and injection are evaluated. Those deferred developments are:

- development of the North Avalon oil;
- development of the West Avalon oil; and
- development of White Rose gas resources.

6.7.1 North Avalon Oil

The North Avalon Pool is comprised of several fault blocks. The pool has a large gas cap, with an associated oil leg on the southern down dip rim of the pool. In place volumes for the gas cap range from 41 to 54 10^9m^3, while the oil in place ranges from 24.8 to 32.4 10^9m^3, as discussed in Chapter 5.

As discussed in previous sections, excess produced gas from the South Avalon Pool will be injected into the North Avalon Pool for gas conservation purposes. Initial geophysical mapping indicates that the majority of the gas cap may be isolated from the oil leg by faults. This will minimize any potential influence that injection of gas into the gas cap may have on the oil leg.

The project is in the process of evaluating seismic data that were acquired in 1999 over the northern end of the White Rose Field. These data will be merged with existing seismic data and both the updated seismic interpretation and the results of the H-20 well will be incorporated into the White Rose geological model.

A reservoir model was developed for the pool. The model was used for a preliminary assessment of gas from the South Avalon Pool into the North Avalon Pool. Two injection wells were included in the model. The injection profiles for each well are shown in Figure 6.7-1, and the simulation grid with reservoir pressure distribution after 15 years of injection is shown in Figure 6.7-2.

The first gas injection well will be drilled in the N-22 area prior to the start of oil production, allowing gas injection in the north to commence as soon as injection facilities are operable. Monitoring of gas injection volumes and resulting reservoir pressure changes will be used in material balance calculations to determine the reservoir volumes in communication within the pool. The project should be able to determine whether or not there is a significant portion of reservoir volumes in communication within the pool over the first few months of project operations. In particular, it should be possible to determine if the major faults mapped near the well are sealing or not.

Figure 6.7–1 North Avalon Gas Injection Profiles

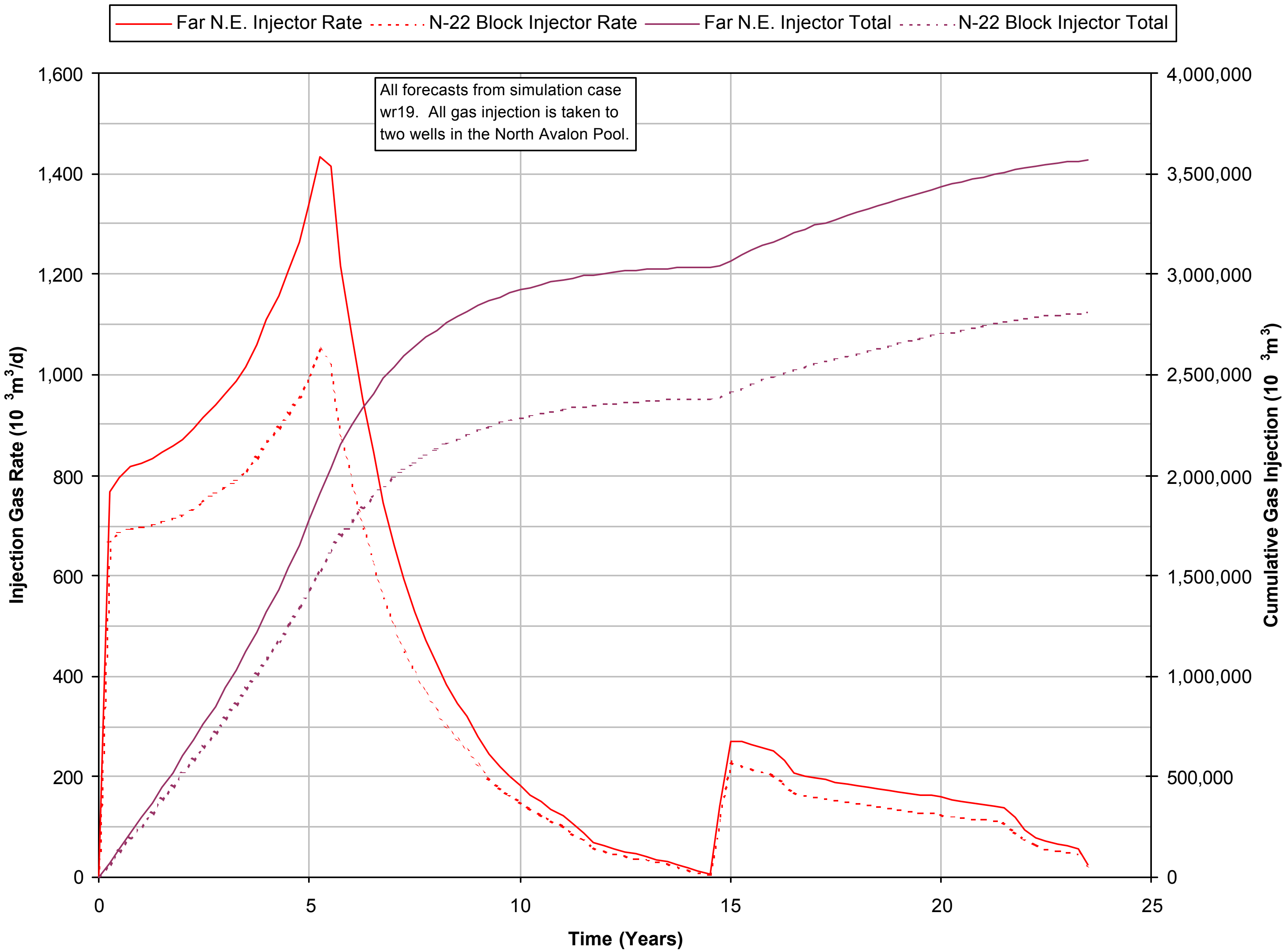
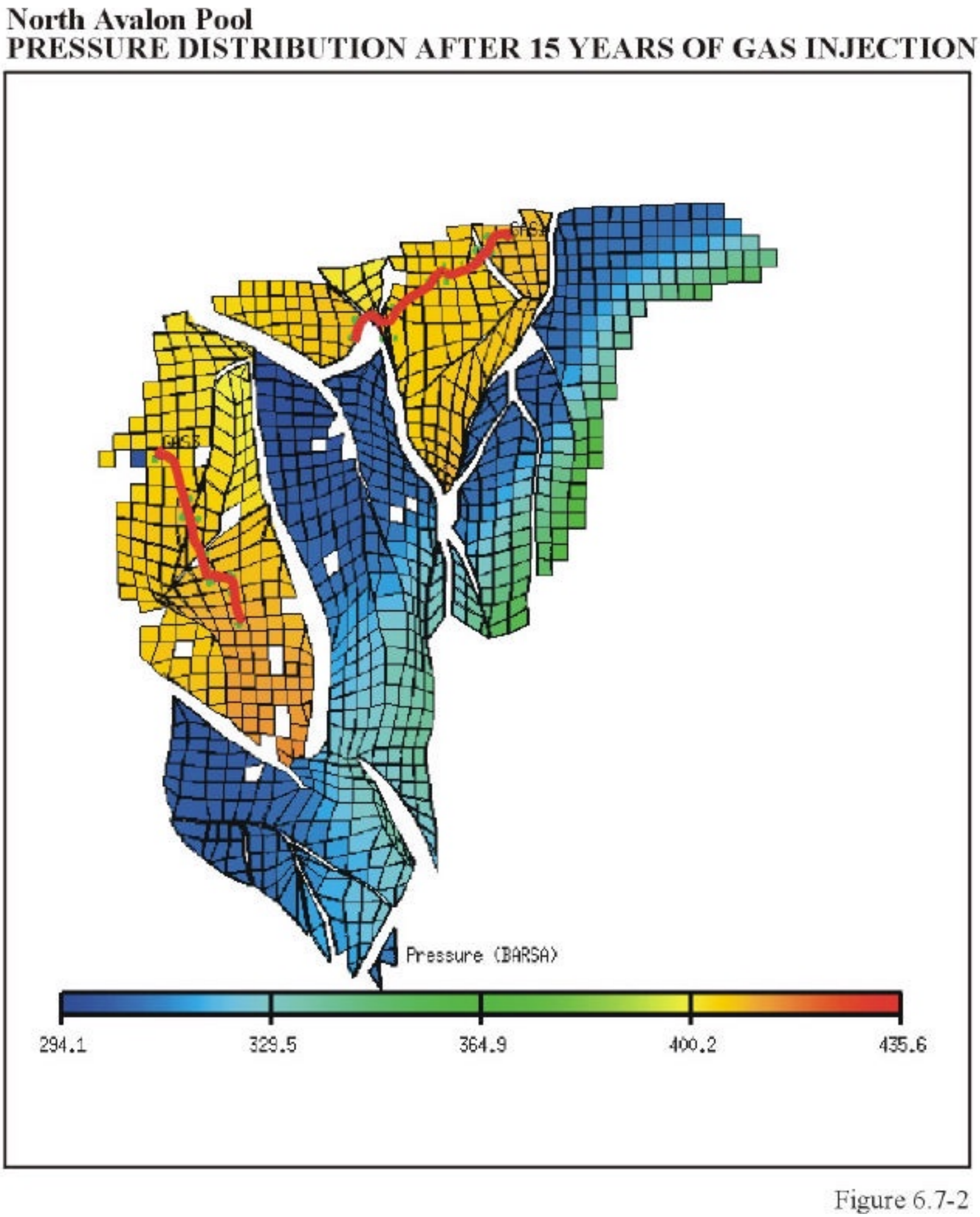


Figure 6.7–2 North Avalon Pressure Distribution After 15 Years of Gas Injection



These data, along with the data obtained from initial development drilling, will be used to update the models to assist in confirming the need for and placement of a second gas injector in the pool, and to re-evaluate options for producing oil from the oil leg in this area.

It is expected that the reservoir will be of generally poorer quality than the South Avalon Pool and, as a result, recovery factors for this area will also be lower. Preliminary assessments (Section 6.5) indicate that recovery factors could be in the order of 18 to 30 percent, with reserves ranging from 5.4 to 8.3 $10^6 m^3$. It is expected that two to three production wells would be required to recover the oil in this area if reasonable production rates could be achieved.

Ideally, oil production wells in this pool would be drilled prior to the South Avalon coming off its plateau production levels. This would allow the FPSO to continue to be used at capacity levels for a longer period of time and help extend the economic life of the South Avalon Pool, thereby increasing recoveries from that pool. Initial wells for oil production may be drilled with pilot holes to confirm reservoir quality and contacts. The pilot hole would then be plugged back and a horizontal sidetrack drilled for production.

Decisions on the viability and timing of drilling wells for oil production from the North Avalon Pool will likely not be made until after initial reservoir response to gas injection has been evaluated.

6.7.2 West Avalon Oil

The West Avalon Pool lies to the west of the South Avalon and North Avalon Pools and is currently modelled as a saddle, with gas caps at the northern and southern ends of the pool underlain by oil and water legs. It is highly faulted, with several fault blocks that may or may not be in communication. The only well drilled in this pool is the marginal J-49 well on the western-most edge of the pool. The pool is expected to be of poorer reservoir quality than the South Avalon Pool. In place volumes for the gas cap and oil leg range from 23 to 37 $10^9 m^3$ and 32 to 42 $10^6 m^3$, respectively.

The project will be updating its current geophysical and geological models for this area over the next several months. Once this work is complete, a reservoir simulation model will be built to evaluate development options for this pool, and to select potential locations for future drilling to prove up this area of the field. The models will be updated as new information is obtained from the drilling and production of the South Avalon Pool.

The West Avalon Pool is expected to have poorer quality reservoir than the South Avalon Pool, with an expected recovery factor ranging from 18 to 31 percent. The southeastern end of the pool has the best potential for economic oil production, as it is closer to the South Avalon core area and most likely to have better reservoir quality, although faulting may be more severe. This area has yet to be drilled to determine reservoir quality and fluid contacts. Current estimates of recoverable oil volumes in this portion of the pool would be between 7.0 and 11.1 $10^6 m^3$.

Two to four horizontal oil production wells and associated injection wells may be required, if reasonable production rates could be realized. These wells could be drilled from the glory holes put in place for the South Avalon Pool development. Flexibility will be incorporated into the subsea systems to allow for the potential future development of this area of the West Avalon Pool.

A decision to proceed with the drilling of the southeastern portion of the West Avalon Pool will be dependent on the results of drilling and production from the South Avalon Pool and the expected availability of the FPSO production capacity.

The western and northern portions of the West Avalon Pool are likely to be of poorer quality than the rest of the White Rose Field. Any decision to pursue development of the potential oil in this area will be dependent on the results of drilling and production in both the North Avalon Pool and the southeastern portion of the West Avalon Pool.

As with the North Avalon Pool, oil production wells for this area would ideally be drilled just prior to the South Avalon Pool coming off plateau. This would allow the FPSO to continue to produce at capacity levels for a longer period of time and extend the economic life of the White Rose pools already on production.

6.7.3 White Rose Gas Resource Development

In order for oil recoveries to be maximized in the White Rose Field, reservoir pressures must be maintained and smearing of the oil leg into the gas cap should be avoided. As a result, depletion of the gas resource should not commence until exploitation of the oil resource is well advanced.

Drilling and depletion of the oil legs, along with gas conservation monitoring, will provide valuable information as to the reservoir quality and compartmentalization in the gas cap areas. During the oil production phase, all gas, other than that used for fuel gas, will be conserved in the North Avalon gas cap.

A breakdown of gas volumes that could be potentially available for sale after the oil-only production phase is provided in Table 6.7-1. The estimates assume that, on average, approximately 40 percent of the gas produced during the oil-only production phase is required for fuel gas and that the remainder is reinjected into the gas cap for production during blowdown of the gas cap. The recovery factor for the gas is estimated at 70 percent.

Table 6.7-1 P50 Estimates of White Rose Gas Volumes

Pool	Solution Gas Injected After Fuel ($10^9 m^3$)	Gas Cap Gas In Place Volumes ($10^9 m^3$)	Total ($10^9 m^3$)	Recoverable Assuming 70% RF ($10^9 m^3$)
South White Rose	2.4	11.8	14.2	9.9
North White Rose	0.5	46.3	46.8	32.8
West White Rose	0.7	29.6	30.3	21.2
South Mara	N/A	10.6	10.6	7.4
Total	3.6	98.3	101.9	71.3

Gas development would likely require in the order of 10 additional wells, with associated glory holes and subsea systems. From a facilities perspective, it may be possible to upgrade the FPSO to handle the additional gas volumes, but this would likely require it to be brought into harbour for modification.

Full field geological and reservoir simulations models will be developed for the entire White Rose Significant Discovery Area, including the gas cap areas. The models will be updated as additional information is obtained from development drilling and field production. These models will be used to assess the technical viability and appropriate timing for gas production in the White Rose Field for sales. Commercial and business considerations related to gas development are discussed in Section 1.2.3 of the Project Summary.

6.8 Reservoir Management

Reservoir simulation is being used to evaluate and optimize proposed development scenarios. Development well locations will be drilled based on this information, with updates as required due to new data obtained during development drilling. Once sufficient production history exists, the simulation model will be updated periodically to match field history and improve prediction of future performance.

Management of the White Rose Field is discussed in specific categories below, but several general issues govern the objectives:

- Water injection should occur below the formation fracture pressure to optimize sweep efficiency.

- Pool areas that are not in communication over production time should be identified and steps taken to optimize recoveries where possible.
- Thief intervals or breakthrough points in horizontal wells should be identified and means of correction evaluated when necessary to optimize sweep efficiency.

Proper data collection programs will be designed and implemented to meet reservoir management objectives.

6.8.1 Well Tests

Well tests are one tool that can be used to diagnose problems or provide information about individual wells or the pool as a whole. Production tests and pressure build-up tests are two common tests which may be used in the future to monitor the reservoir:

- **Production tests:** Development wells will each be subject to an initial flow test as per regulations. Additional tests will be done over time to help allocate group production back to individual wells for better voidage balancing, and identify gas or water breakthrough. Increased testing frequency can be used on trouble wells when necessary.
- **Pressure build-up/falloff tests:** The wells must be shut-in to perform these tests, which is a disadvantage, however, they can help determine flow capacity and average reservoir pressure (see Section 6.8.2 below for more details).

6.8.2 Pressure Surveys

Pool pressures are critical in evaluating reserves and monitoring voidage replacement performance. Build-up pressure surveys will be conducted at least once per year, however, it is not expected that every well will be surveyed on an annual basis. Wells would be selected to incorporate planned or unplanned shutdowns where possible. Enough surveys would be completed to obtain a representative picture of the reservoir pressure.

6.8.3 Fluid Sampling

Surface fluid samples of oil, gas, and water will be collected from each development well during the initial production from the well. It is expected that surface samples will be collected from production wells each year during production testing. Additional samples will be collected as necessary to aid in troubleshooting operations.

Injection water will be sampled at least semi-annually to monitor composition and the amount of dissolved solids. Additional samples will be collected as necessary to aid in troubleshooting operations.

6.8.4 Coring

Coring will be designed in conjunction with logging, testing, and drilling operations to obtain required information about the Avalon Formation. It is expected that some of the development wells will be cored, however, as they will be horizontal wells, the entire wellbore will not be cored. Coring of zones other than the expected productive formation is not planned for at this time.

6.8.4.1 Open Hole Logs

Open hole logging programs for the development wells will be designed in conjunction with coring, testing, and drilling operations to obtain required information about the Avalon Formation. A typical logging program could include some of the following tools:

- dual induction or dual lateralogs;
- compensated neutron and density;
- gamma ray – sonic;
- dipmeter – borehole imaging; and
- wireline pressure testing/fluid sampling.

If logging while drilling is used in the horizontal sections, this data would be taken into account when designing any open hole log program.

6.8.4.2 Cased Hole Logs

Cased hole logs are another tool which can be used to obtain well information and troubleshoot problems. As with any tool, the purpose for running these logs needs to be understood and carefully reviewed to ensure that the data obtained are representative, accurate, and can be used in the decision making process. New technology should be included in the review before selecting an appropriate tool. Two common cased hole logs which could be considered are:

- cement bond logs, which could be used in vertical cased hole sections. This log can provide an evaluation of isolation between zones; and
- production logs, which have been used quite successfully in vertical wellbores to determine contributing intervals and identify water or gas breakthrough.

6.8.5 Performance Monitoring

There are several variables which can be monitored during a waterflood to provide information on how the flood is progressing. Pool pressures, water cuts, gas-oil ratios, production rates, and injection pressures will be used to update simulation models. The models allow evaluation of various scenarios over the reservoir life to select infill well locations, design recompletions, and manage voidage replacement with the goal of optimizing recoveries.

The following list identifies a few methods or tools that will be considered when creating a performance monitoring program for the South Avalon Pool:

- Permanent downhole pressure gauges should allow determination of reservoir pressures.
- Monitoring of injection pressures and rates can help determine when injection well workovers or conformance treatments may be required.
- Tracer studies can be used to track water movement within the reservoir, and may be useful if premature water breakthrough occurs.
- Production logging data from production and injection wells could help manage voidage replacement.

6.8.6 Production Optimization

Production optimization is a broad topic with connections to reservoir, wellbore, subsea, and surface facility issues. During development planning, well completion techniques, wellbore hydraulics, and subsea and surface facilities will be optimized considering field production and injection conditions over the life of the field. Some general comments regarding production optimization of South White Rose follow:

- Water injection will occur to replace production volumes and maintain reservoir pressures. The target voidage replacement ratio is 1.0.
- Conformance treatments on injectors or producers may be required due to premature water or gas breakthrough. Work will be evaluated on a case by case basis to determine if sweep efficiencies can be improved.
- Increasing watercuts over time will cause a requirement for artificial lift in order for production volumes to be maintained. The wells will initially be completed with gas lift capabilities.

6.9 Future Studies

Initial studies have focused on the South Avalon Pool, the cornerstone on which the White Rose Field development is being built. These studies were aimed at characterizing the reservoir properties from structural, depositional, reservoir flow and in place fluids perspectives. This has allowed the project to develop both geological and reservoir flow simulation models that form the basis for the South Avalon Pool development strategy and provide the underpinning for the Development Plan submission.

There are number of studies planned for the pre-production through to reservoir development and depletion phases. During the period between the submission of the DA and the start of pre-production drilling, the following activities (studies) will be carried out.

1. Incorporation of the H-20 well results into the geophysical, geological and reservoir engineering models. This will include updating of:
    - seismic marker picks;
    - depth conversion models;
    - geological trend maps and models;
    - updating of field PVT assessments; and
    - updating of reservoir simulation models.
2. Updated geophysical mapping of the entire field, including incorporation of GECO spec survey data acquired in 1999.
3. Evaluation of seismic data for potential attribute indicators of reservoir quality.
4. Updated geological model of the entire field, both deterministic and geostatistical assessments.
5. Updated reservoir simulation model for each pool, including finer grid sector models to assess various development options in more detail.
6. Evaluation of depletion strategies for each pool.
7. Fault characterization evaluations to assess fault zone properties and potential ranges of sub-seismic faults and the impacts on reservoir development and depletion.
8. Additional fluid studies to provide additional information on the potential for both vertical and aerial compartmentalization of the field.
9. Additional rock characterization studies to better define depositional environments and diagenesis processes and impacts on reservoir fluid flow.
10. Well bore stability studies for input to drilling and completion design evaluations.
11. Formation damage study to identify damage mechanisms.
12. Drilling and completion fluids study to help minimize formation damage.
13. Water compatibility study for scaling analysis of produced water/injected water.
14. Production chemistry studies for analysis of production fluids process conditions.

Each study will include recommendations on how to capture and apply data from development drilling and field depletion performance. These data will be used to improve the understanding of factors affecting performance and identify improvement opportunities.

7 DEVELOPMENT DRILLING AND COMPLETIONS

The White Rose oilfield was discovered in 1988 with the drilling of the E-09 well. Since that time, four additional delineation wells were drilled into the White Rose structure. They are L-08, A-17, N-30, and H-20. The first three of these wells were suspended. H-20 was abandoned. However, since they did not include options for iceberg protection, at present there are no plans for them to be used in the development of the White Rose oilfield.

7.1 Development Drilling

The project base case currently identifies the need for 15 wells, however, there is potential for up to 25 wells required to develop the South Avalon reservoir, of which 10 to 14 will be producing wells, six to eight will be water injection wells, and two to three will be gas injection wells.

Initially, up to 10 wells will be drilled before field production will commence. Plans call for the wells to be drilled in clusters or through templates located in glory holes. Semi-submersible MODUs will be used to drill and complete these wells before the arrival of the FPSO. The remainder will be drilled in parallel with production operations to meet the depletion plan objectives.

7.1.1 Tentative Drilling Schedule

The current plan is to start drilling 24 months prior to First Oil. Subject to ongoing petroleum engineering studies, it is anticipated that up to 10 producing and injection wells will have been drilled and completed before the arrival of the FPSO. Details on the drilling sequence are provided in Table 7.1-1.

Water injection wells, which are the deepest, are drilled first to capture as much information about the block as possible before the producers are drilled. Their trajectory/location is not as critical as would be the case for production wells.

7.1.2 Drilling Hazards

There were no significant operational problems encountered during the drilling of the White Rose delineation wells. However, typical potential problems that may be encountered during development drilling, and which will be addressed within the well design and contingency planning, are discussed below.

Table 7.1-1 Drilling Sequence Details

No.	Well Name	Comments
1	B14W1	Information to locate Block 14 producer (w/pilot)
2	B7W1	Information to locate Block 7 producer
3	Gas #1	Time used to locate Block 7 and 14 producers
4	B7P1	No. 1 producer
5	B3W1	Information to locate Block 3 producer
6	B14P1	No. 2 producer
7	B7P2	No. 3 producer
8	B3P2	No. 4 producer
9	B3P1	No. 5 producer – "First Oil"
10	B1W1	Information to locate Block 1 producers (w/pilot)
11	Gas #2	Second gas injector
12	B1P2	No. 6 producer
13	B6W1	Information to locate Block 6 producer
14	B1P1	No. 7 producer
15	B6P1	No. 8 producer

7.1.2.1 Shallow Gas

Although there has been no occurrence of shallow gas in any of the wells drilled so far in the White Rose field, indications of gas chimneys and seismic anomalies have been identified on some site surveys in the field. A shallow gas accumulation could cause uncontrolled well flow if encountered prior to setting the surface casing and installing the blow out preventer (BOP) stack. The only concern raised by the 1997 shallow 3-D reprocessed data is the presence of a gas chimney centred on the crest of the White Rose Diapir that extends in a small area toward southwest. No delineation or development drilling is planned at this time on or near this area affected by gas contamination of low porosity sediments.

Husky Oil has shallow gas preparedness and drilling procedures in its East Coast drilling policy document. The policy includes drilling riserless prior to running the stack and conducting winch-off drills prior to spudding. This policy will be reviewed for development drilling, addressing issues such as the cuttings conveyance system.

7.1.2.2 Hole Instability

Borehole shear failures occur in planes that contain the minimum and maximum principal stresses (that is, perpendicular to the intermediate stress). The different types of borehole failures that occur in isotropic and anisotropic rock can manifest as a result of mud weight and *insitu* stresses. The failure mode shifts as the intermediate stress shifts between the axial, tangential, and radial directions.

On high angle development wells, the shales will be exposed to drilling for longer periods of time and hole instability could be accentuated. Hole cleaning issues could become significant if hole instability increases.

Hole instability on White Rose is currently not considered a high drilling risk. To date, the only indications of potential stability problems occurred in the 311-mm hole section, with hole fill seen towards the total depth (TD) of the section. This phenomenon could be an indicator of a stressed formation and could have a more pronounced impact if the section was inclined.

The mud type and properties, the casing seat selection and any pilot hole design would all be impacted by the presence and mitigation of hole instability problems.

Proposals have been requested for a study into well bore stability at White Rose. The initial part of the study was to determine, using data obtained to date, the potential for instability in the White Rose formations and, if required, to provide recommendations on any additional data that could be collected in the 2000 Delineation Drilling Program.

7.1.2.3 Formation Pressure

Neither abnormal pressure nor lost circulation have been apparent in the White Rose wells. Pore pressures in the Avalon sands are between 29 and 30 MPa, depending on depth. The sands have a normal pressure gradient of 10.1 kPa/m.

7.1.2.4 Well Control

Industry-accepted drilling practices will be followed in order to minimize the risk of well control incidents or kicks. This includes such activities as continuous monitoring of drilling mud weight while drilling, hole monitoring, carefully designed casing programs and frequent BOP tests.

7.1.2.5 Differential Sticking

Differential sticking across any permeable zones may occur in high-angle wells. Tight control of drilling fluid properties, the use of synthetic-based fluid, and good tripping practices will be applied so as to minimize this problem.

7.1.3 Basis of Well Design

This section presents the basis of well design for the White Rose development wells. The basis of design takes into account experience from previous wells and the functional requirements for the development wells. Well design will evolve over the pre-production project phases, and subsequently over the life of the field, in order to take advantage of equipment development, new techniques and drilling experience.

7.1.3.1 Casing and Hole Sizes

The casing geometry will dictate the conduit size and setting depths. Once the casing has been set the flexibility of the operations are limited. The areas considered in developing the basis of casing design were:

- Completion Design: The tubing size, completion components, metallurgical requirements, and the tree configuration all impact on the casing design.

- Well Trajectory: The shape of the well bore will influence casing wear and connection types.

- Casing Seat: The two main critical casing seats are the surface casing and production casing points. The surface casing seat determines the available kick tolerance for the remainder of the well. Under the current design case, the 900-m TVD BRT depth provides enough kick tolerance to reach the well TD. The production casing seat selection could be critical for gas shut-off if the casing point is within the reservoir section. This will be further influenced by the vertical depth control and any pilot hole requirements.

- Contingency: The requirement to carry a casing string contingency will impact the casing design. Issues which influence this design feature are the minimum acceptable hole size through the reservoir, areas of identified drilling risks, pilot hole requirements, batch drilling and the need to have flexibility in the directional profile, formation evaluation, drilling performance, long lead times, and material stocks.

Wells will have an average horizontal departure of 4,000 m and a horizontal section through the reservoir of between 2,000 to 2,500 m. Well profiles have a preliminary maximum design build rate of 3°/30 m.

A 914-mm conductor hole will be drilled to approximately 250 m below the rotary table on the drilling rig and a 762-mm conductor casing will be run and cemented to seafloor. A 406-mm hole is then planned to approximately 800 to 900-m below rotary table. The 340-mm surface casing will be cemented to the sea floor.

The 311-mm main hole will then be drilled to either the top of the Avalon Formation or possibly to some deeper depth in high-angle or horizontal wells. The production casing will be set at this point. The depth in high-angle wells will depend upon sealing off the gas cap in the reservoir.

The upper section of the 244-mm production casing may have to be increased in diameter to accommodate the surface controlled subsurface safety valve (SCSSV).

A 216-mm hole will be drilled to TD and either a 178 or 140 mm liner will be run (cemented or uncemented). The well may also be completed open hole. Additional well completion details are discussed in Section 7.2, including an illustration of the well casing profiles for a 140 mm tubing string.

Drilling Fluid Program

The mechanism of formation damage in the reservoir will be one of the main drivers of the drilling and completion fluid design.

The drilling fluids used will be optimized to reduce fluid loss, to control rheology, and maintain hole stability. The drilling fluid program will be similar to that used on the past delineation wells. Seawater with prehydrated gel muds or polymer muds are planned for the top intervals of the well to the surface casing setting depth.

A water or synthetic-based system will be used for the intermediate hole, depending on the well profile. The intention would be to use water-based mud (WBM) systems in this hole section as long as the well bore stability and drag are acceptable. Synthetic-based muds (SBMs) are the most reliable method of managing hole stability and they also provide lubricity to lower drilling string torque and drag.

One of the objectives of the ongoing core and fluids studies is to identify the most likely damage mechanism(s) for the Avalon Formation. Once the mechanism(s) has been isolated, mud formulations will be tested to ensure that the fluid selected has minimal damaging characteristics or that any damage can be easily cleaned up and treated.

The mud system will also have to be tested and evaluated on the other design aspects. There will be a need to balance the fluid design against all the well design requirements.

Cementing Program

The cementing program will be similar to that used on past delineation wells. Conductor and surface casings will be cemented to the seafloor. The production casing will be cemented high enough to prevent future casing instability and to isolate permeable zones. To ensure a leak-off path for trapped fluid expansion during production, production casing will not be cemented into the previous shoe.

Well Control System

The selection of the BOP equipment will be part of the MODU bid evaluation. Typically, a 476-mm, 69 to 103 MPa BOP equipped with four rams (including shear rams) and an annular preventer will be installed on a 476-mm wellhead run with the surface casing, and used for the remainder of the well. The BOP system typically has capacity to exceed the known pressure in the White Rose field by a factor of two. This approach is taken to be able to address any unexpected pressure which could occur.

7.1.3.2 Wellhead Design

The selection of a subsea wellhead system is still ongoing. The choice of either template or clustered wells is not finalized. Subsea well protection for template and cluster wells will be by dredged glory holes. On satellite wells, drilled glory holes and caisson systems are being considered.

Directional Drilling

Plans call for drilling in clusters of approximately six wells. Wells will have an average horizontal departure of 4,000 m and a horizontal section through the reservoir of between 2,000 to 2,500 m. Well profiles have a preliminary maximum design build rate of 3°/30 m. Horizontal wells are being considered in the pay zone to provide increased productivity. Kick-off elevation and well profiles will be customized for each well.

On the main hole of the directional wells, mud pulse telemetry directional tools will be used. The survey intervals and the type of surveying system used will be sufficient to assure accurate entry into the target and avoid collision with adjacent wells, and will provide adequate wellbore positioning information to reliably target a relief well, if required.

7.2 Well Completions

The White Rose development well completions will be designed to maximize well productivity while maintaining necessary standards of risk and well integrity.

7.2.1 Production Wells

Current reservoir depletion studies indicate that horizontal wells will provide the best exploitation alternative for White Rose. It is anticipated that up to 15 to 25 new drill production and injection wells, located in up to four drill centres, will be required for the White Rose oilfield development. The suspended discovery well E-09 and 1999 delineation wells A-17, L-08, N-30 and H-20 are not being considered for completion as production or injection wells at this time.

7.2.1.1 Completion Configuration and Tubing Size

Tubing size requirements are a function of a well's production or injection capacity. Considerations of the well requirements over the life of the field can determine whether monobore or conventional completions are best used. Conventional completions have production casing (liner) across the zone of interest with a production packer and smaller internal diameter (ID) tubing to surface. A conventional completion which may be applied in oil wells that require only 140 mm tubing with a 178 mm liner is illustrated in Figure 7.2-1.

Monobore completions have tubulars, downhole equipment and tree components with a similar ID to allow full wellbore access to larger diameter wellbore equipment. The production casing is landed above the formation of interest with a tie back liner over the completed zone as shown in Figure 7.2-2. This type of completion may be employed where a 178-mm flow path is required to facilitate higher production or injection rates where friction pressure loss from high velocity fluids is a concern.

7.2.1.2 Wellbore Isolation Measures

SCSSVs will be used to prevent flow of formation fluids to surface in the event of a wellhead failure. The White Rose development wells will have tubing-retrievable SCSSVs, which are an integral part of the completion tubing string and allow for larger diameter tool access into the bottom of the wellbore. The tubing-retrievable SCSSVs will also be designed to permit the insertion of wireline-retrievable insert SCSSVs to provide a means of maintaining isolation barriers without pulling the tubing string.

Figure 7.2–1   140 mm Conventional Production Well Completion

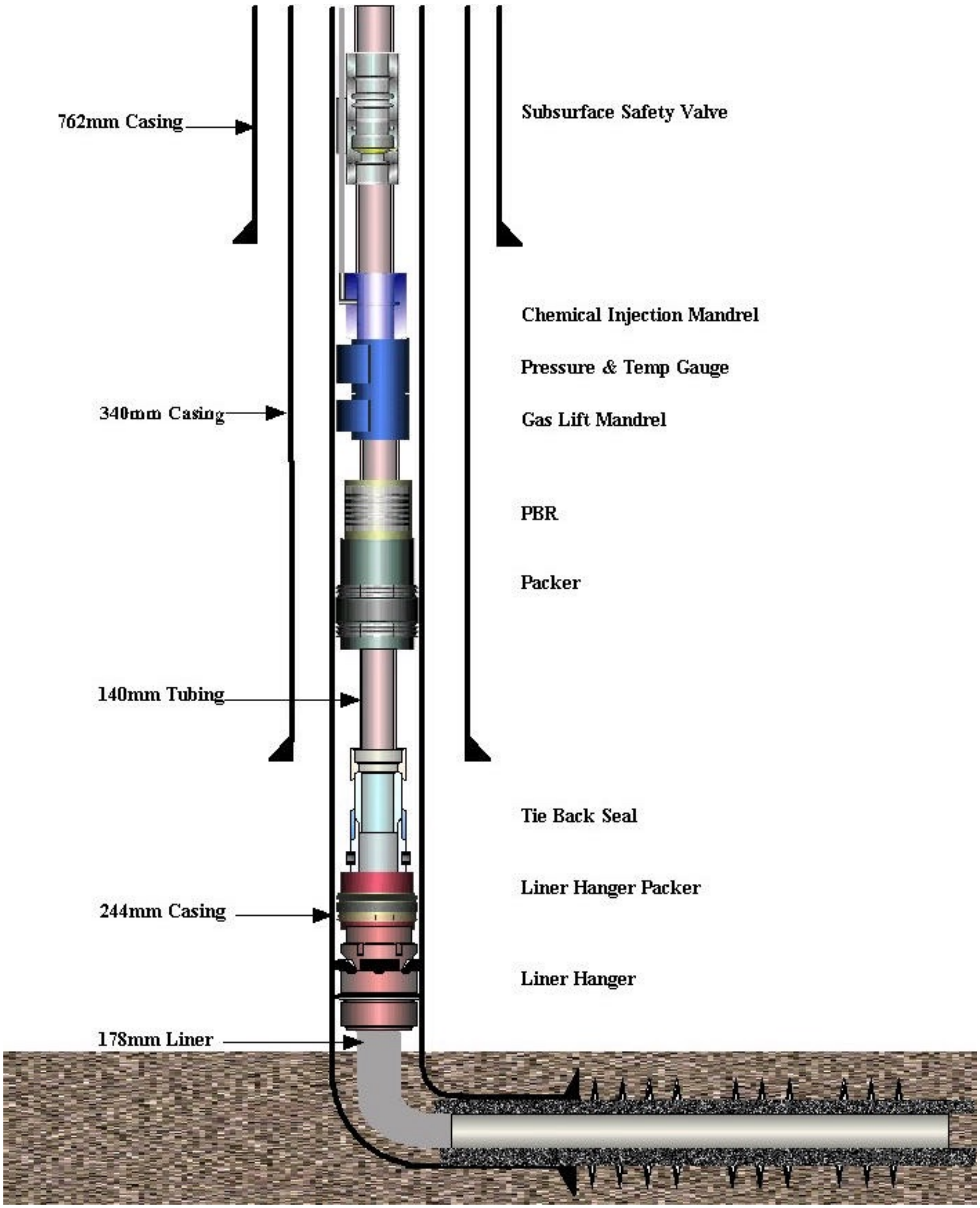
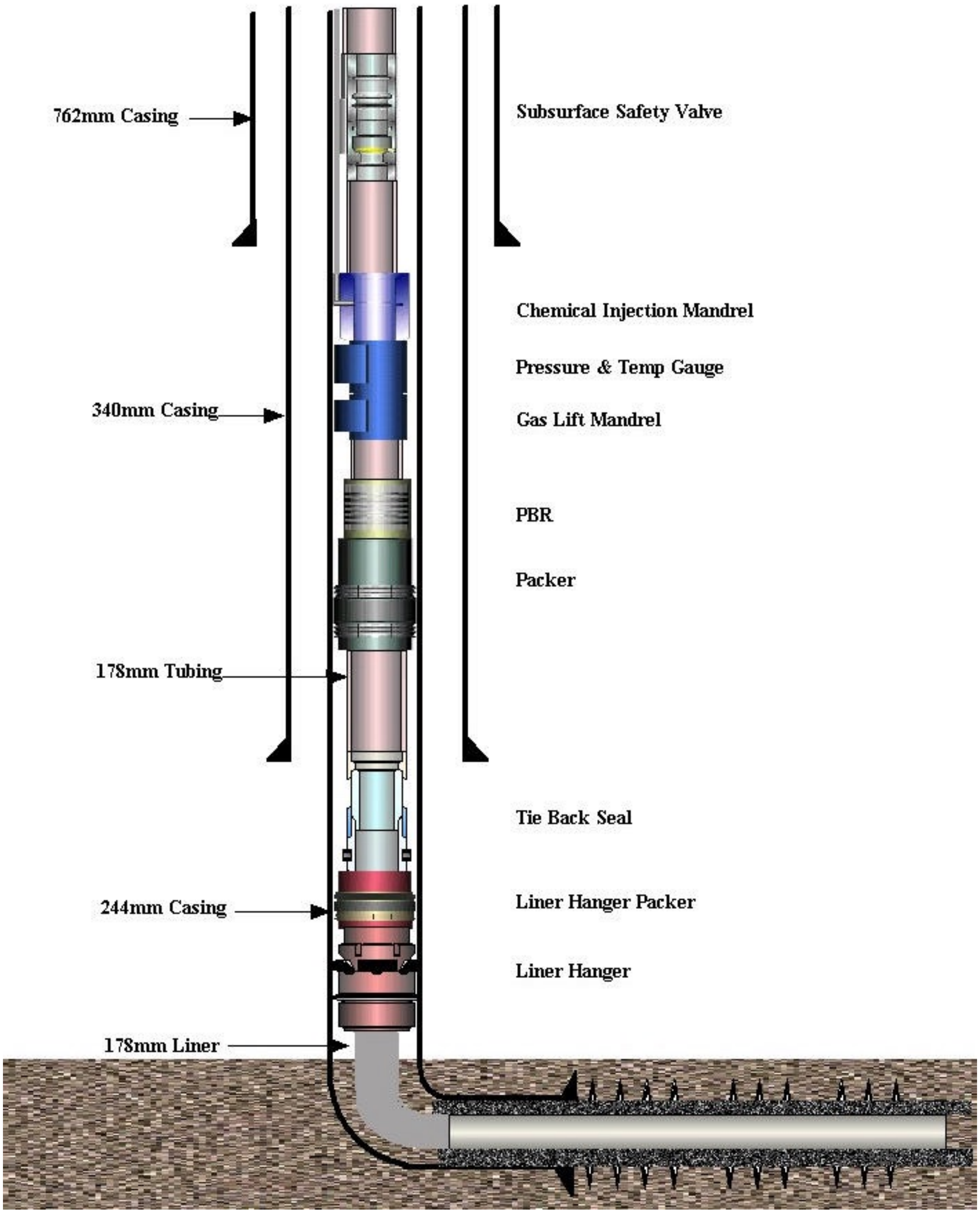


Figure 7.2–2   178 mm Monobore Production Well Completion



Completions will be designed to have two independent annular barriers between the formation and the seafloor. The well tubulars, SCSSVs and production packer located just above the completed zone is the primary annular barrier system separating the formation from the annulus. The hydraulically operated annular master valve on the subsea tree functions as the second annular barrier by automatically closing if there is a loss of control line hydraulic pressure to the valve.

7.2.1.3 Well Production Performance

Well performance modelling based on the reservoir properties of the discovery and delineation wells has been conducted for both flowing and artificial lift (gas lift) scenarios. The flowing well model suggests that initial oil rates of between 2,800 and 4,200 m^3/d are possible from horizontal production development wells completed with 140-mm tubing. A well with average reservoir properties should flow at 3,600 m^3/d oil prior to water or gas breakthrough. The flowing well performance at various water cuts with the two inflow performance lines illustrating the range of productivity expected is shown in Figure 7.2-3 for a 2,000 m horizontal production well.

7.2.1.4 Artificial Lift

Water associated with White Rose oil production is expected to increase over the project life of the development. The flow modelling referred to above indicates that oil wells will require artificial lift when water cut exceeds 40 percent. Gas lift will be a readily available means of artificial lift, with gas compression facilities required for the reinjection of produced gas. Gas lift also has the advantage over other means of artificial lift due to its high reliability and efficiency. This is critical for subsea wells where reliability and efficiency are important for effective operation. To avoid the high cost of working over wells later in their producing life, gas lift side pocket mandrels will be included in the initial completion design for oil wells. This ability to control flow from the initial completion will enable greater flexibility in reservoir depletion management. The effect of gas lift on a well producing at 80 percent water cut is illustrated in Figure 7.2-4. As shown in Figure 7.2-4, high water cut wells with superior reservoir properties are still capable of up to 2,500 m^3/d liquid (500 m^3/d oil) at an injection gas rate of 400 $10^3 m^3/day$.

Figure 7.2–3 Flowing Well Performance Curve – 2,000 m Horizontal Well, 140 mm Tubing

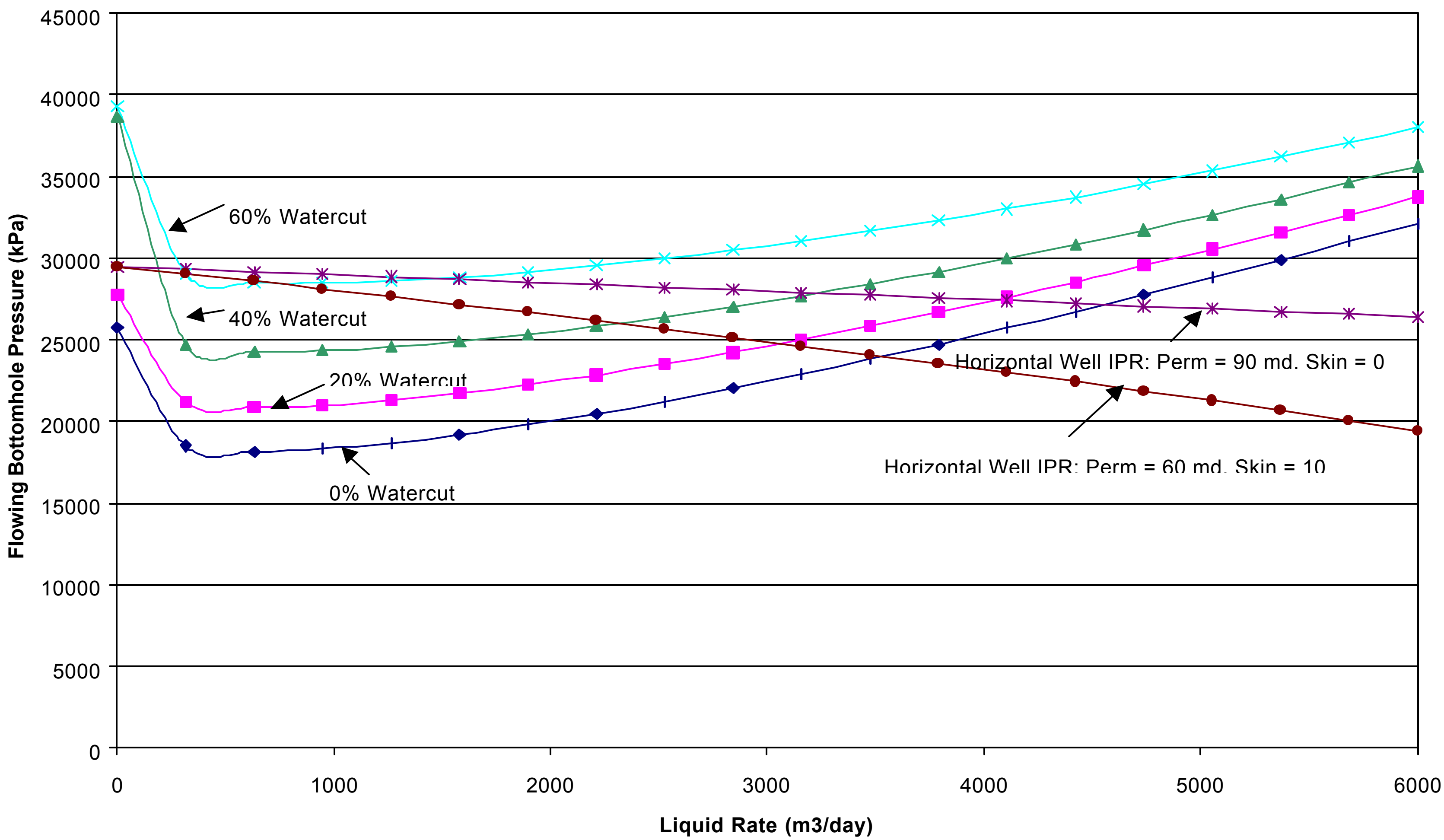
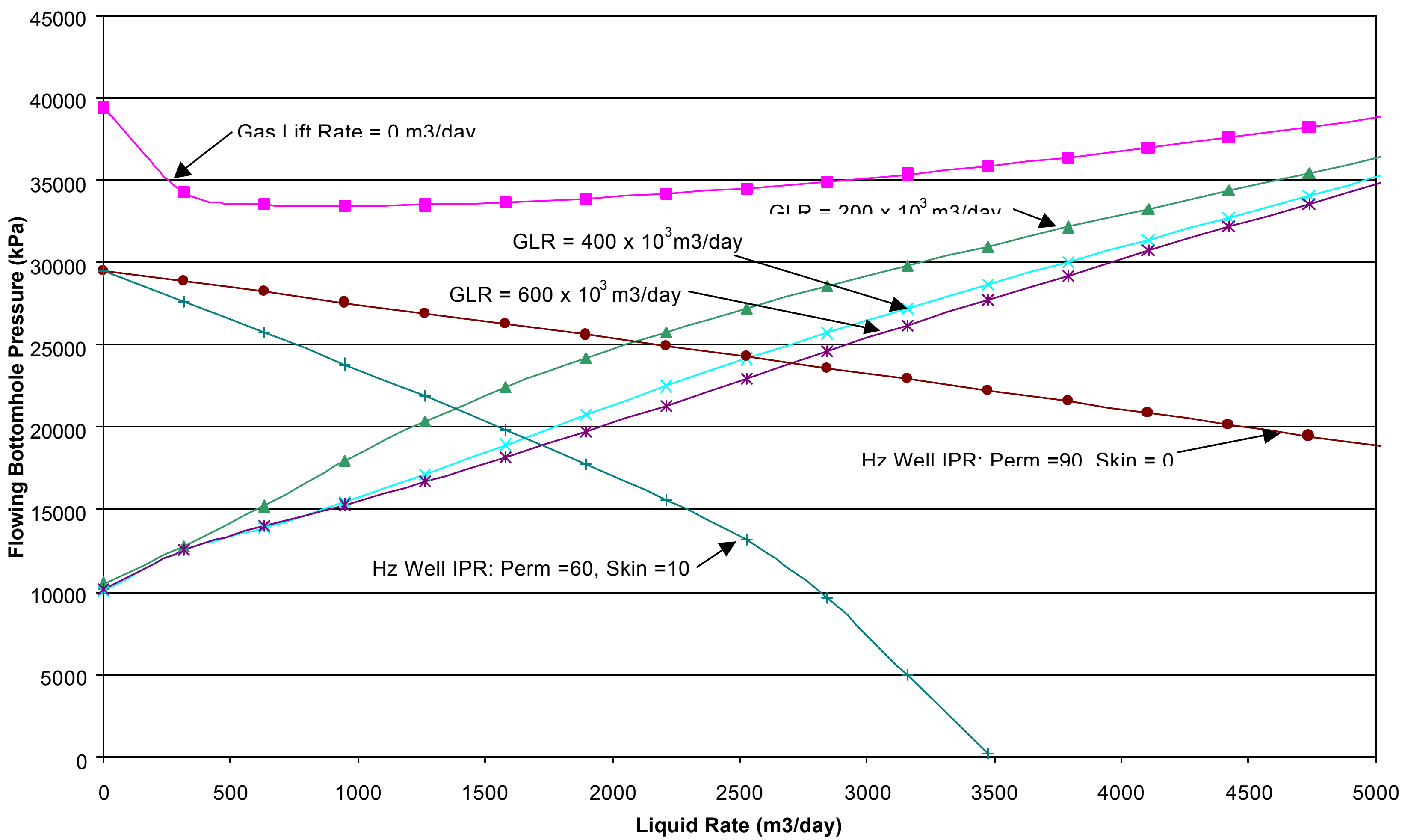


Figure 7.2–4 Gas Lift Well Performance 140 mm, 80% Water Cut, 2,000 m Horizontal Well



7.2.1.5 Completion Program

Prior to the start of production, all wells in a given glory hole will likely be batch completed after being drilled and temporarily suspended. White Rose development wells prior to First Oil will be batch completed to take advantage of operational efficiencies. A simplified summary of the operations involved in a typical completion is outlined below for a 140-mm monobore completion. At the end of batch drilling operations, the wells will be left with appropriate barriers in place.

1. Inspect wellhead and retrieve external debris cover.
2. Run in drilling BOP and riser. Connect to subsea tree.
3. Pressure test BOP and subsea tree.
4. Pull wellhead plug and bridge plug.
5. Clean out to liner top. Clean out to bottom of liner.
6. Run casing scrapers over 244-mm casing and 140-mm liner.
7. Circulate well to clear brine to remove drilling fluid and cement cuttings.
8. Run permanent production packer on work string.
9. Circulate annulus to packer fluid prior to setting packer hydraulically.
10. Run in 140-mm tubing, complete with packer seal assembly, expansion assembly, gas lift side-pocket mandrels, permanent downhole gauges, tubing-retrievable SCSSVs and control line.
11. Stab into polish bore receptacle and land tubing hanger.
12. Pressure test packer and SCSSV.
13. Perforate with coil tubing-conveyed guns.
14. Flow well for a short clean up and snub out guns.
15. Clean up and test well.
16. Displace drilling riser to water.
17. Remove drilling BOP and riser.
18. Install debris cover.

7.2.1.6 Tubing Materials and Accessories

White Rose reservoir fluids sampled to date have indicated CO_2 levels of between 1 and 2 mole percent and H_2S levels of up to 12 ppm. National Association of Corrosion Engineers (NACE) requirements for using materials that are resistant to erosion and corrosion will form the basis for production equipment specifications. Tubulars will be designed with consideration of life of field conditions.

7.2.1.7 Production Trees

Production trees will be located in open glory holes for iceberg scour protection. Installation will be through the moonpool of the drilling and completion MODU. As with all subsea facilities, production trees will be selected to provide diverless installation, operation, inspection and maintenance. The trees will be either vertical or horizontal types capable of installation on the 476 mm wellheads. The subsea tree schematics in Figures 7.2-5 and 7.2-6 illustrate the tree valve and equipment components for a typical production well. Vertical subsea trees have valves located in line vertically over the production or injection bores (Figure 7.2-5). Horizontal trees have tubing hanger plugs as vertical barriers and the master valves are located on the side outlets (Figure 7.2-6).

Provisions for gas lift and chemical injection complete with remotely operated barrier valves will be incorporated into the tree design. The production trees will also have a data cable path for the permanent downhole gauges. Subsea tree controls will also enable lock out from the FPSO during workover operations to prevent accidental operation of equipment when the workover vessel is connected to the wellhead.

The production subsea tree equipment will be rated to at least 34.5 MPa based on a maximum expected pressure at surface of 23.1 MPa. The maximum surface pressure was calculated from the original reservoir pressure with gas filled tubing.

7.2.1.8 Perforating

Alternatives of open hole, slotted liner or cemented liner completions are being studied to determine the method most suitable for the White Rose development. Where a cemented production liner is used the selection of a perforating system will be based on criteria that will deliver the optimal productivity within acceptable risk levels.

The most likely perforating system will be tubing conveyed perforating (TCP) type, deployed on either coiled tubing or a work string. The coiled tubing system enables perforating underbalanced and snubbing the guns without killing the well. The work string system allows longer intervals to be perforated in one operation but may require killing the well prior to removal of the guns. Perforating interval selection will be designed to minimize the potential for water and gas coning.

Figure 7.2–5 Vertical Subsea Tree

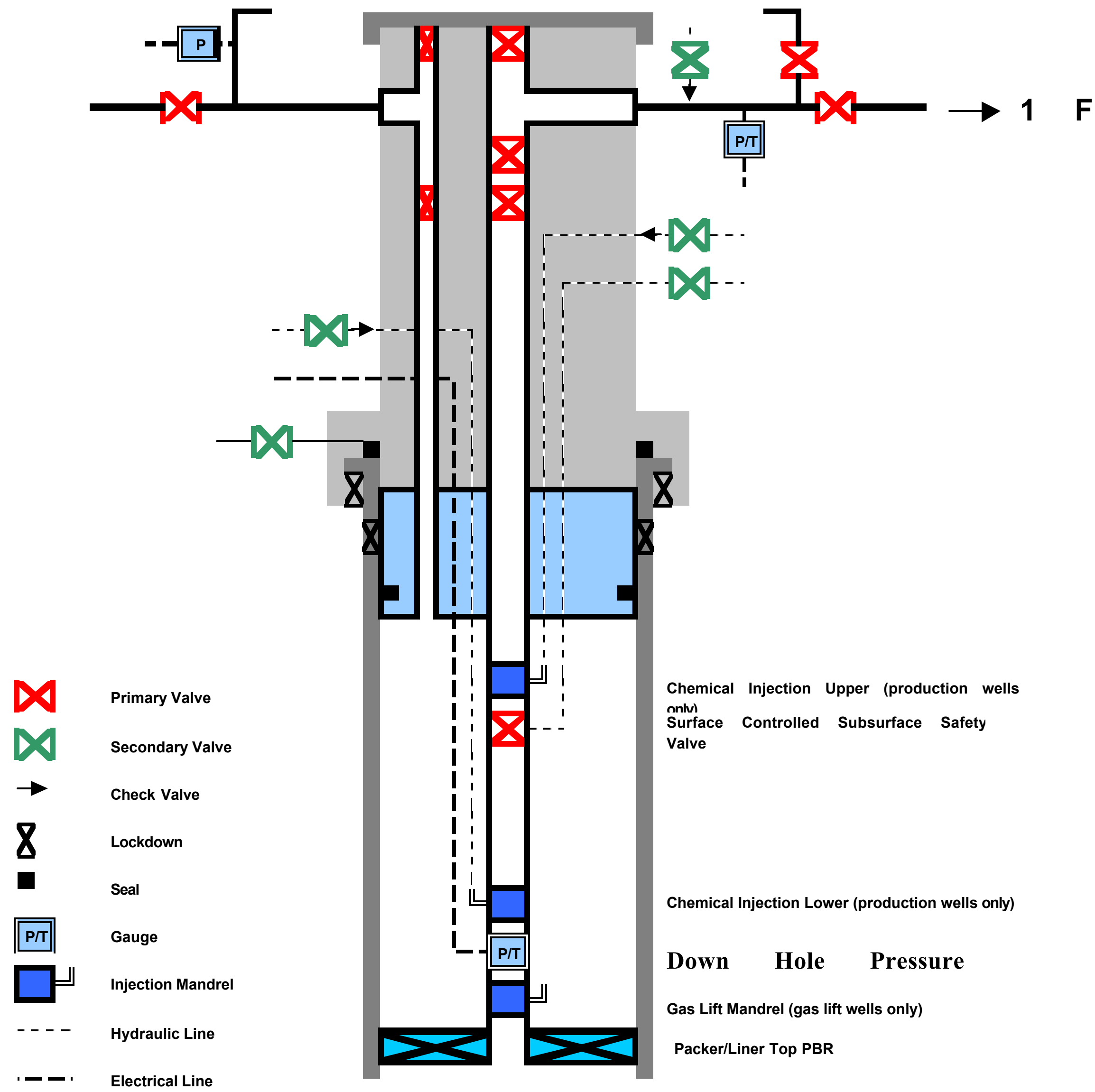
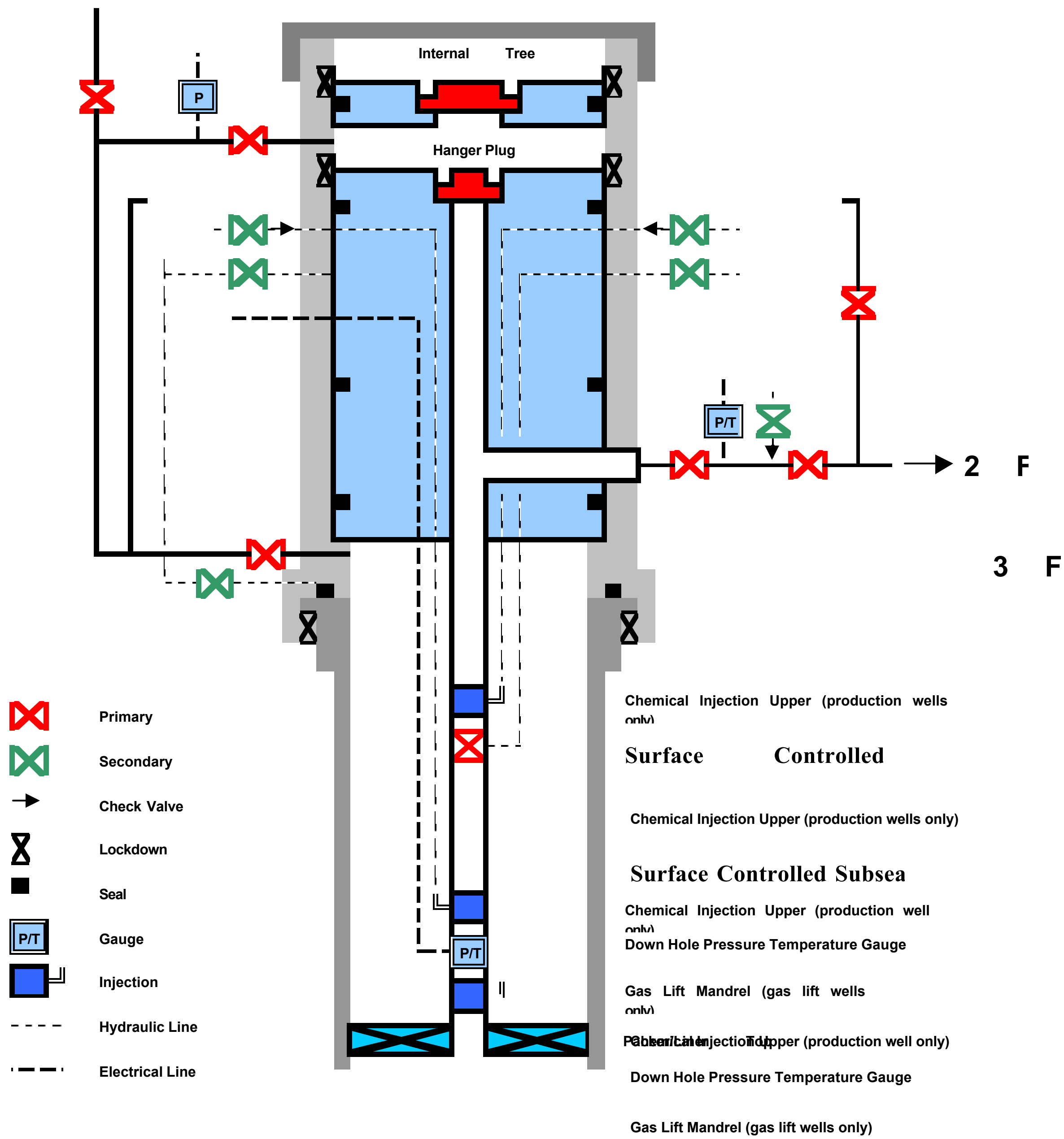


Figure 7.2–6 Horizontal Subsea Tree



7.2.1.9 Packers and Accessories

To ensure the completions can adequately accommodate all thermal and load forces, permanent hydraulically set production packers will be run. The production packers use polished bore receptacles and seal assemblies to control pipe stress and facilitate workovers. Any monobore completions can also have hydraulically set liner top packers.

7.2.1.10 Completion Fluids

Separate completion fluids will be used for cleaning out the well after drilling, providing a benign environment in the packer annulus and for perforation operations. The well is cleaned out at the start of completion operations to ensure clean casing surfaces for packer seals and to remove any debris which could impair production equipment operations. This fluid will be seawater-based and facilitates circulating up cement cuttings and contamination remaining after the liner cement job. Viscous polymer gelled fluid pills may be required to sweep the hole clean to total depth, especially over the horizontal sections.

Corrosion-inhibited and oxygen-scavenged fluid is circulated into the annulus between the completion tubing and production casing above the production packer to prevent corrosion of the completion equipment.

The perforating fluid provides a predetermined measure of hydrostatic head which controls the initial direction of flow after perforating. Work is ongoing to determine whether an overbalanced or underbalanced perforating system will be used for White Rose development wells. If an underbalanced system is used where flow is into the wellbore, then either a nitrogen cushion or an oil-based fluid will be used. An overbalance system will likely employ a clean brine fluid. The perforating fluid will also be designed to prevent any adverse fluid interaction with the formation.

7.2.1.11 Sand Control

Current reservoir rock material strengths data indicate that sand production should not be a problem. However, any well completion programs will be designed to mitigate sand production.

7.2.2 Injection Wells

7.2.2.1 Well Designs

Current water injection well design is for continuous injection of 2,000 to 6,000 m^3/day of seawater per well, with a maximum of up to 9,000 m^3/day. To ensure adequate capacity, it is likely the water injection wells will be horizontal, with 178-mm monobore completion or 140-mm conventional completion. As mentioned previously, gas injection wells are required to facilitate conservation and possibly aid reservoir pressure maintenance. The gas injection wells will be designed for continuous injection of 1,000 to 3,000 10^3m^3/d gas per well, with a maximum of up to 4,000 10^3m^3/day gas.

Water injection and gas injection well performance plots for typical development conditions are illustrated in Figures 7.2-7 and 7.2-8.

7.2.2.2 Injection Christmas Trees

For project equipment synergy and to simplify completions and workovers, injection trees will likely be similar in specifications and design to the production trees. Gas injection trees may be required to be rated to 69 MPa.

7.2.2.3 Tubing and Connections

Studies are ongoing to determine appropriate materials and connection type for injection well tubing. Efforts will be made to design injection fluid processing such that downhole equipment can be as standard as possible. The tubulars will be designed with consideration of life of field conditions.

7.2.2.4 Wellbore Isolation Measures

SCSSVs on injection wells will be similar in design and specification as production wells SCSSVs.

7.2.2.5 Liners and Packers

Injection packers serve to isolate the annulus from injection fluids and pressures. White Rose injection packers will be permanent design with polished bore receptacles to provide for thermal movement of the tubing. As an added precaution, corrosion resistant material will be used on exposed surfaces of the injection packers.

Figure 7.2–7 Inflow vs Outflow for 2,000 m Horizontal Gas Injection Well

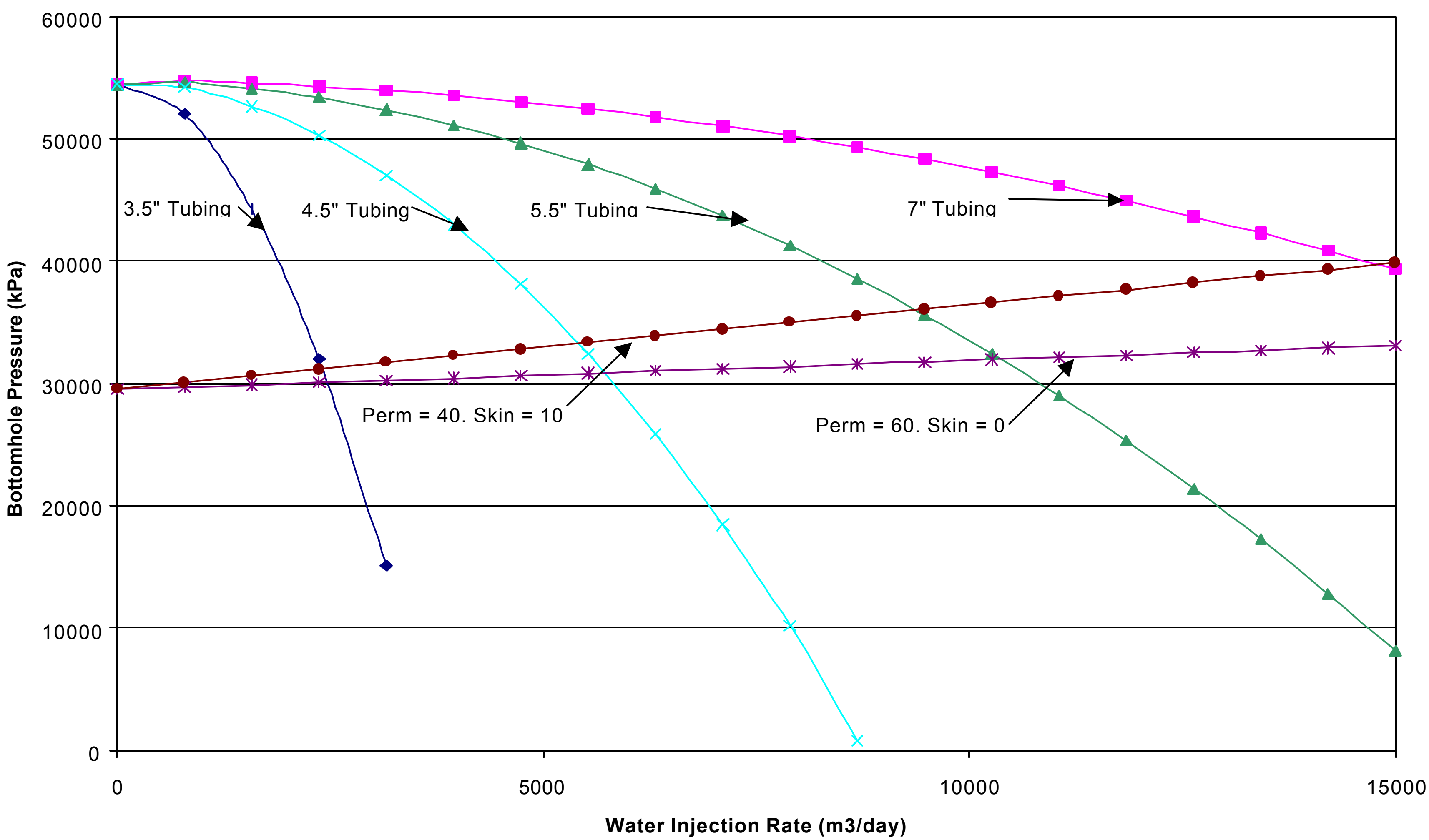
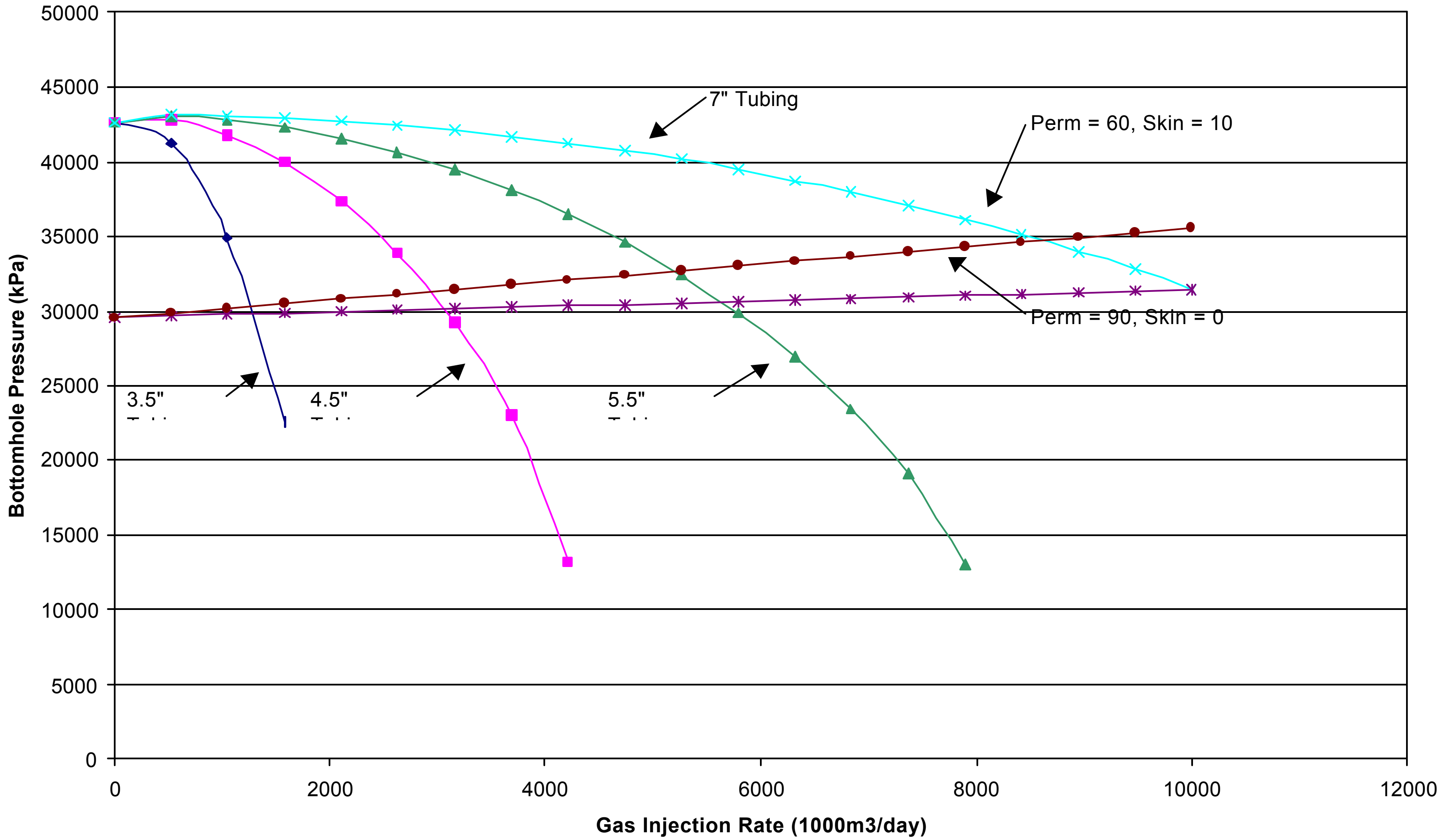


Figure 7.2–8 Inflow vs Outflow for 500 m Horizontal Gas Injection Well



7.2.2.6 Completion Fluids

Unless perforating design differs from the producing wells, the completion fluids will be the same for the injection wells.

7.3 Well Interventions

7.3.1 Major Workovers

Operations that involve replacing or removing items such as subsea trees, control lines, tubing, SCSSVs, and packers are considered major workovers. These types of workovers require mobilization of a semi-submersible drilling rig with a riser and BOP system for removal of the completion equipment. It is an objective of the completion design to reduce the number of major workovers during life of field conditions for the well.

7.2.2 Minor Workovers

Wireline and coiled tubing operations are considered to be minor workovers. However, because the wells are subsea, operations require mobilizing either a workover vessel or a semi-submersible drilling unit.

Statistics on subsea developments suggest that approximately one minor workover per well will be required every four to seven years. Operations such as installing or removing plugs, gas lift valves, chemical injection valves and downhole gauges are considered to be minor workovers, as are other interventions that do not require removal of the completion string.

8 DESIGN PHILOSOPHY AND CRITERIA

8.1 Design Philosophy

The following are the key objectives/philosophies of the project to ensure that the value of the asset is maximized, consistent with the wider business objectives of Husky Oil and Petro-Canada:

- life-cycle considerations will be taken into account during decision-making;
- integrity of the Project (in terms of safety of personnel, environment and property, and business interruption) is crucial. The project will employ risk management and value engineering principles. Refer to Volume 5, Preliminary Safety Plan and Concept Safety Analysis;
- equipment will be selected on the basis of proven history;
- availability targets will be developed for each system;
- safety is of prime concern and the Project will endeavour to provide a safe, healthy, and comfortable working environment through the design and operation of the facilities for all personnel. Formal safety assessments and the reporting of safety performance will be undertaken throughout the duration of the project pursuant to the Safety Plan;
- the environment will be protected in compliance with all pertinent laws and regulations, the Operator's Environmental Policy and the site-specific Environmental Management System (see Comprehensive Study Part One – EIS). The Project will be required to demonstrate that objectives are being met through regular performance review and supplemented by periodic auditing; and
- as deemed practical, the design will ensure that construction, testing, integration and pre-commissioning are performed at the quayside with offshore activities limited to FPSO tie-in and final commissioning.

This design philosophy will be implemented through the technical project management approach described in Section 10.1.1.

8.2 Regulations, Codes And Standards

A Newfoundland Offshore Certificate of Fitness will be obtained for White Rose production and drilling facilities. The installations will conform to the requirements of current Canadian federal and provincial regulations, including but not limited to:

- *Newfoundland Offshore Certificate of Fitness Regulations*;
- *Newfoundland Offshore Petroleum Production and Conservation Regulations*;
- *Newfoundland Offshore Petroleum Installation Regulations*;
- *Petroleum Occupational Health & Safety Regulations – Newfoundland*;
- *Newfoundland Offshore Petroleum Drilling Regulations*;
- *Newfoundland Offshore Area Petroleum Diving Regulations*;

- *Canada Shipping Act*;
- *Canada-Newfoundland Offshore Petroleum Board Offshore Waste Treatment Guidelines*;
- *Newfoundland Offshore Area Guidelines for Drilling Equipment*: and
- any and all other applicable laws.

Engineering and design practices will be common across the Project and all designs will conform to Canadian Standards, or approved equivalent International Standards, and relevant Codes and Standards listed in the above documents. Generally accepted international standards, such as American National Standards Institute (ANSI)/American Society of Mechanical Engineers (ASME) specifications and American Petroleum Insititue (API) recommended practices, will be applied as appropriate. The most recent edition of applicable codes will be used.

The production vessel, mooring, propulsion and marine systems will require classification by a certifying authority yet to be selected, but which will be chosen from amongst:

- American Bureau of Shipping;
- Bureau Veritas;
- Det Norske Veritas (DNV); or
- Lloyd's Register of Shipping.

The vessel will be Canadian-flagged.

8.2.1 Codes and Standards for the Floating Production, Storage and Offloading Facility/Mobile Offshore Drilling Units

The design of the FPSO will be based upon relevant codes and standards of internationally recognized agencies such as the following:

- API;
- ASME;
- Canadian Standards Association;
- International Standards Association;
- International Electrotechnical Commission;
- International Maritime Organization (IMO);
- NACE;
- National Fire Protection Association; and
- Transport Canada.

A list of some of the potentially relevant codes and standards applicable to the FPSO and/or MODU is provided in Appendix 8.A.

8.2.2 Codes and Standards for Subsea Facilities

The design of the subsea facilities will be based upon relevant codes and standards of internationally recognized agencies such as the following:

- API;
- Canadian Standards Association; and
- DNV.

A list of some of the potentially relevant codes and standards applicable to the subsea facilities is provided in Appendix 8.A.

8.2.3 Codes and Standards for Shuttle Tankers

The design of the shuttle tankers will be based upon current relevant codes and standards of internationally recognized agencies such as the following:

- American Bureau of Shipping;
- Transport Canada;
- Institute of Electrical and Electronic Engineers; or
- IMO.

A list of some of the potentially relevant codes and standards applicable to shuttle tankers is provided in Appendix 8.A.

8.3 Environmental Criteria

Refer to the EIS (Comprehensive Study Part One) for an in-depth examination of the White Rose environment.

The Grand Banks region has a harsh environment much like the northern North Sea. Intense storms occur frequently in winter with winds generally from the northwesterly and westerly directions. Restricted visibility due to fog is common, especially in the spring and summer months, when warm air masses overlie the cold ocean surface. The information presented in this section presents the best data currently available.

There are sea ice incursions and icebergs in the Grand Banks area. Superstructure icing can occur between December and March because of the temperature, wind and wave conditions.

The seabed is composed of dense sands, cobbles and boulders overlying alternating silty clay and fine sand beds to a depth of 40 m.

8.3.1 Data

This section provides details of environmental data that are planned to be used in the design of the White Rose facilities. The final figures used for design will be reviewed with C-NOPB and Transport Canada and the certifying authority.

The physical environment (wind, waves, currents) of the Jeanne d'Arc Basin is described in Tables 8.3-1 and 8.3-2.

Table 8.3-1 Extremes at White Rose Location - All Months and Years Combined

Return Period (years)	Wave (m)			Wind (m/s)				
	Significant wave height	Maximum wave height	Associated spectral peak period	1-h mean	10-min mean	1-min mean	15-s mean	3-s mean
1	10.5	19.7	13.5	23.6	25.0	28.8	31.2	33.7
10	12.7	23.8	14.9	27.7	29.4	33.8	36.6	39.6
25	13.5	25.2	15.4	28.8	30.5	35.1	38.0	41.2
50	14.1	26.3	15.8	29.7	31.5	36.2	39.2	42.5
100	14.7	27.4	16.1	30.5	32.3	37.2	40.3	43.6

Table 8.3-2 Currents at White Rose

Well Site	Period	Max. Speed (cm/sec)	Mean Velocity (cm/sec)	Direction
Near Surface				
White Rose N-30	Aug – Oct, 1999	89.9	5.0	Southeast
White Rose A-17	Jun – Aug, 1999	28.6	8.4	Northeast
White Rose L-08	Mar – Jun, 1999	45.7	2.7	Northwest
White Rose E-09	May – July, 1988	45.2	7.5	Southeast
White Rose J-49	Aug – Nov, 1985	61.7	4.9	South
White Rose L-61	Dec – Feb, 1985	36.0	6.4	Northeast
White Rose N-22	Jul – Oct, 1984	82.0	19.0	Southwest
Trave E-87	Nov – Jan, 1984	55.0	8.1	South
Trave E-87	Feb – Mar, 1984	40.0	11.1	Southeast
Mid-Depth				
White Rose N-30	Aug – Oct, 1999	40.8	10.6	Northeast
White Rose L-08	Mar – Jun, 1999	29.4	3.8	South
White Rose A-90	Jul – Aug, 1988	24.7	3.4	Southeast
White Rose E-09	May - July, 1988	39.0	5.9	Southeast
White Rose E-09	Jan – Feb 1988	35.0	3.5	Southeast
Whites Rose E-09	Sept – Oct, 1987	32.6	9.0	Southwest
White Rose J-49	Aug – Nov, 1985	43.7	2.6	Southeast
White Rose N-22	Jul – Nov, 1984	31.0	1.8	Southeast
Trave E-87	Feb – Mar, 1983	31.0	7.5	South
Trave E-87	Nov – Jan, 1983	46.0	5.0	Southeast
Near Bottom				
White Rose L-08	Mar – Jun, 1999	27.6	2.8	Southeast
White Rose A-90	Jul – Aug, 1988	25.2	2.3	Southeast
White Rose E-09	May- Jul, 1988	32.6	3.7	Southwest
White Rose E-09	Jan – Feb, 1988	34.5	3.7	Southeast
White Rose J-49	Aug – Nov, 1985	50.6	2.0	Southeast
Trave E-87	Nov – Jan, 1983	39.0	6.6	Southeast
Trave E-87	Feb – Mar, 1983	32.0	5.9	Southeast

The design ambient conditions, and icing and iceberg data for the White Rose location are summarized in Tables 8.3-3 and 8.3-4, respectively.

The seawater characteristics in the White Rose area are presented in Table 8.3-5.

White Rose is located at the extreme southern perimeter of a marginal ice zone. In the ice season (February to July), the area is subject to variable sea ice cover consisting of multi-year pack ice drifting south from the Labrador Sea, together with generally smaller first-year floes formed locally.

Icebergs originating from glaciers in Greenland and Ellesmere Island drift south through the White Rose area with the Labrador Current. Icebergs classified as “large” (up to 4,500,000 t) have been observed in the area.

Table 8.3-3 Design Ambient Conditions

Parameter	Value	
	Max	**Min**
Air Temperature (°C)	26.5	-17.3
Water Temperature (Surface) (°C)	15.4	-1.7
Water Temperature (20 m depth) (°C)	14.3	-1.7
Water Temperature (50 m depth) (°C)	5.6	-1.7
	April – Aug	Sept. – March
Flying Visibility <1 km / Ceiling < 100 m	26.4 – 55.1 %	10.2 – 22.9 %

Table 8.3-4 Icing and Iceberg Data

Theoretical Superstructure Icing Accumulation on 5 cm Cylinder	10-Year Return	100-Year Return
Glaze and Rime Icing (mm)	72	169
Spray Icing (mm)	316	514
Icebergs Sightings	**Mean**	**Maximum**
One Degree Grid	67	268
Mass (t)	220,000	--
Speed (km/h)	0.77	9.8
Sea Ice Occurrence	**Mean Cover**	**Average Number of Weeks**
Within 25 km	54 to 57 % coverage	2.3 to 2.6
Source: Husky Oil "Basis for Design"		

Table 8.3-5 Seawater Properties

Chemical Component	Quantity
Density at 15.4 °C	1,024 kg/m³
Na	9,772 mg/L
K	351 mg/L
Ca	438 mg/L
Mg	1,167 mg/L
Cl	17,498 mg/L
HCO_3	128 mg/L
SO_4	1,922 mg/L

Iceberg scours up to 1.5 m deep have been measured on the seafloor in the White Rose area. In order to avoid contact with scouring icebergs, subsea wellheads and templates must be placed in an open glory hole, with the top of the equipment a minimum of from 2 to 3 m below the mudline.

The FPSO will disconnect from its mooring on the approach of an unmanageable iceberg of mass greater than 100,000 t. The hull and moorings will be designed to withstand impact with icebergs up to this weight.

With respect to marine growth, allowance will be made in the design for occurrence of this on the vessel hull, mooring lines and risers. It will be based on the following information in Table 8.3-6.

Table 8.3-6 Marine Growth Thickness

Elevation Above Mean Sea Level	Marine Growth Thickness (mm)
Above + 2.5m	To be determined.
+2.5m to - 1.5m	50
-1.5m to - 7.5m	150
-7.5m to - 14.5m	100
Below - 14.5m	50

8.3.2 Operational Limits

The FPSO design targets will be established for the following operational capabilities:

- continuous production;
- station-keeping;
- operation in sea ice; and
- normal planned disconnection.

Following vendor selection and receipt of equipment/system documentation, the operating manuals will be written to define the limits for operation imposed by equipment and environmental considerations. These will deal with such factors as:

- maximum deck loads (for stability of the FPSO);
- environmental conditions for helicopter operation;
- tanker mooring and loading; and
- other production activities.

Limiting environmental conditions will be specified as guidelines in the operating manuals.

8.3.3 Physical Environmental Loadings

The effect of physical environmental loadings (wind, waves, current, ice) on the facility will be analyzed using established recognized methods, and will be based upon relevant codes and standards, technical literature, research reports and society rules. Model testing will also be carried out. Consideration will be given to load combinations and simultaneous occurrences of environmental conditions.

The design will take into account the physical environmental data presented in Tables 8.3-1 to 8.3-6 inclusive.

8.3.4 Production System Response

Applicable analytical methods and model tests will be used to assess the motion characteristics and station-keeping ability of the FPSO in various states of draft. Recognized methods will be used to carry out structural and fatigue analyses. Stability analyses will also be carried out on the facility for both an intact and a damaged state.

The production response will also be evaluated with respect to the resulting motion characteristics and station-keeping of the FPSO.

8.4 Functional Criteria

The White Rose Field will be developed using subsea completions tied back to a mono-hull type FPSO unit, moored in approximately 125 m of water, with the crude oil transported to market by shuttle tankers. Accommodation, production separation, water injection, gas lift, gas re-injection, and crude export facilities will be provided on the FPSO.

The White Rose Field is expected to produce a medium-weight crude at approximately 30° API, with a relatively high pour point and wax content. The wellstream fluid will be stabilized to produce an on-specification crude for export through an offloading hose to a shuttle tanker. Produced gas will be used as fuel and for gas lift, with excess gas being injected into the Avalon formation. Produced water will be treated to comply with offshore waste treatment guidelines, prior to discharge overboard.

The subsea facilities will include up to 25 wells. There will be up to 10 to 14 producers, with the rest being water injectors for waterflood operations or gas injectors for gas conservation. The wells will be distributed between up to four drill centres. The current base case optimum design for the South Avalon Pool calls for eight production wells, five water injection wells and two gas injectors spread within three glory holes. Production and injection fluids will be manifolded at the seabed and transported via flowlines and flexible risers to the FPSO. Up to 10 wells will be drilled prior to First Oil and will include at least one gas injector and sufficient water injectors to meet initial water injection requirements. The majority of the wells are planned to be horizontal wells. Subsea wellheads will be located in glory holes to protect them from iceberg scour. Equipment within the glory hole will be designed such that the top is a minimum of 2 to 3 m below the mudline.

The subsea system will be designed to minimize any environmental consequences from equipment failure or damage. As far as is practical, the location and layout of subsea equipment will provide ease of access for inspection, testing, repair, replacement or removal. In the event of a forecast possible ice scour, the vulnerable subsea facilities will be shut in and flushed to minimize any possible spills. Flowlines may be trenched to reduce the risk from scouring icebergs. This would provide enhanced on-bottom stability as well as improved thermodynamic characteristics. These systems are discussed in Chapter 9.

Emergency shutdown valves will be provided. These will ensure the safety of personnel and minimize environmental effects in the event of accidental damage to the production facilities.

8.4.1 Design Flow Rates and Capacities

8.4.1.1 Floating Production, Storage and Offloading Facility Design Parameters

The preliminary design flow rates and capabilities for the FPSO are shown in Table 8.4-1. The design throughput of up to 18,000 m^3/d is based on the technical and economic evaluations carried out to date. An ongoing optimization program will be in place over the life of the field, to capture potential incremental capacity up to 20,000 to 22,000 m^3/d through debottlenecking, increased well performance or the tying in of additional reserves from the North Avalon and West Avalon Pools and other potential secondary pools.

Table 8.4-1 Preliminary Design Requirements for the White Rose FPSO

System	Capacity
Oil Production Rate	12,000 to 18,000 m^3/d
Water Production Rate	15,000 to 30,000 m^3/d
Total Fluids Production Rate	30,000 to 35,000 m^3/d
Gas Production Rate	3 to 7 $10^6 m^3/d$
Gas Injection Rate	3 to 7 $10^6 m^3/d$
Field Gas Lift Rate	1 to 3 $10^6 m^3/d$
Water Injection Rate	40,000 m^3/d
Oil Storage	110 to 135 $10^3 m^3$

8.4.1.2 Well Design Parameters

Horizontal production wells will be used, with pressure maintenance provided by horizontal or highly deviated water injection wells throughout the reservoir. Excess produced gas will most likely be injected into North Avalon or West Avalon Pools. The well design parameters of production wells, water injection wells and gas injection wells are shown in Table 8.4-2.

Table 8.4-2 Preliminary Well Design Requirements

Parameter	Units	Capacity
Production Wells		
Maximum Oil Production Rate	m^3/d	2,800-4,200
Maximum Liquid Production Rate	m^3/d	2,000-4,000
Maximum Water Cut Percent	%	90-95
Minimum Bottom Hole Pressure	kPa	22,000
Nominal Wellhead Flowing Pressure	kPa	4,000-10,000
Flowing Wellhead Temperature	ºC	60-95
Shut-in Wellhead Pressure	kPa	24,000
Shut-in Wellhead Temperature	ºC	0-100
Maximum Gas Lift Pressure	kPa	
Maximum Gas Lift Rate per Well	$10^3/d$	200-300
Water Injection Wells		
Maximum Water Injection Rate	m^3/d	9,000
Maximum Wellhead Injection Pressure	kPa	21,000-28,000
Wellhead Injection Temperature	ºC	10-20
Shut-in Wellhead Pressure	kPa	0-5000
Shut-in Wellhead Temperature	ºC	0-20
Gas Injection Wells		
Maximum Gas Injection Rate	m^3/d	$1\text{-}3 \times 10^6$
Maximum Wellhead Injection Pressure	kPa	21,000-38,000
Wellhead Injection Temperature	ºC	30-60
Shut-in Wellhead Pressure	kPa	28,000
Shut-in Wellhead Temperature	ºC	0-60

8.4.2 Design Life

The White Rose facilities will be designed for a service life of 20 years.

Elements of the facilities may be designed for a service life of less than 20 years, provided this results in a reduction in life cycle costs and can be demonstrated to satisfy project risk management criteria.

Target fatigue lives for the turret and vessel will follow Lloyd’s rules or equivalent, while topside and subsea equipment will be in accordance with needs as specified in this section and the requirements of API, Lloyds and Canadian Standards Association guidelines and practices or equivalents.

The design of the White Rose facilities will have the flexibility to handle subsurface uncertainty in the most cost-effective manner, without jeopardizing life of field operations, while also catering for future expansion requirements.

Materials will be selected in accordance with the requirements for their service, environment, temperature and compatibility with interface materials.

8.4.3 Well Fluids and Product Specification

8.4.3.1 Produced Oil Characteristics

Typical Avalon oil characteristics are discussed in Section 4.2 and are provided in Table 8.4-3.

Table 8.4-3 Typical Avalon Oil Characteristics

Characteristic	Value
Component	
N_2	0.54 (mol %)
CO_2	1.04 (mol %)
H_2S	0.00 (mol %)
Methane	48.83 (mol %)
Ethane	4.20 (mol %)
Propane	2.88 (mol %)
i-Butane	0.52 (mol %)
n-Butane	2.13 (mol %)
i-Pentane	0.88 (mol %)
n-Pentane	1.11 (mol %)
Hexane+	37.87 (mol %)
Total	100.00 (mol %)
Pour Point	< 12 °C
Wax appearance temperature	45 °C
Wax Content	8.0% by weight

CO_2 is present in the well stream fluids in the range of 1 to 2 mol % and will create some corrosion concerns when water is produced. Suitable materials to resist CO_2 corrosion will therefore be specified.

Although no significant sulphur compounds have been detected in the well stream fluids, experience suggests that the introduction of seawater injection tends to produce small levels of H_2S in the reservoir. Suitable materials will be specified to meet NACE requirements for sour service as appropriate.

8.4.3.2 Export Crude Characteristics

Well fluids will be processed to produced stabilized crude oil with the characteristics and specifications shown in Table 8.4-4.

Table 8.4-4 Export Crude Characteristics and Specifications

Item	Data*
Stabilized crude specific gravity range @ 15ºC	0.87
Stabilized crude API gravity	30
RVP, Vapour pressure at 50ºC (kPa)	76
BS&W (% vol. Basis)	0.5
Kinematic Viscosity at 40ºC (cst)	11.6
Sulphur (weight %)	0.5
* Data based on E-09, L-08 and A-17 Crude Assays	

8.4.3.3 Produced Water Characteristics

Significant water production is not expected during the early life of the field. Any water produced initially will be primarily formation water. Formation water characterization is discussed in Section 3.2; a typical expected composition is shown in Table 8.4-5.

Table 8.4-5 Typical Formation Water Composition

Ion	Concentration (mg/L)
Na	15,860
K	250
Ca	757
Mg	102
Ba	3.01
Sr	122
Fe	2.63
B	56.4
Mn	0.25
Cl	25,550
Br	53
I	58.2
HCO_3	1,068
SO_4	390

All produced water will be treated and disposed of directly overboard and will meet the requirements of the 1996 Offshore Waste Treatment Guidelines (NEB, C-NOPB and C-NSOPB 1996).

Carbonate scaling is expected to occur in the producing wells as a result of the presence of carbon dioxide/bicarbonate ions in the reservoir fluids. Barium/strontium sulphate scaling may also be a problem in the producers after water breakthrough as a result of formation water/injection water incompatibility. Additional work is planned to better define the design basis for scaling.

8.4.3.4 Sand Production

South Avalon development is expected to exhibit sand-free production prior to water breakthrough, but following water breakthrough, experience shows that these types of formations may exhibit tendency to produce sand. Studies are ongoing to assess the formation sand production tendency.

Consideration will be given to the installation of sand detection upstream of test and first stage separators. Consideration will also be given to building in flexibility for all production and test piping to have sand detection installed any time during the field life. In addition, the design of the facilities will address the provision for on-line removal of excess sand.

The subsea production system design will also take into consideration the results of the studies on potential sand production.

8.4.3.5 Other Well Design Considerations

The likelihood of asphaltine deposition at either flowing or shut-in conditions is still being addressed. If this proves likely, remedial measures will be designed.

The same also applies to the possible formation of hydrates during both flowing and shut-in conditions.

8.4.3.6 Chemical Injection Requirements

The following chemicals may be required for production operations:

- methanol;
- corrosion inhibitor;
- demulsifier;
- wax inhibitor;
- scale inhibitor;
- oxygen scavenger;
- antifoam;
- biocide;
- asphaltine inhibitors;
- hypochlorite;
- polyelectrolyte; and
- hydrogen sulphide scavengers.

A final decision on the need for these chemicals will be part of the detailed design together with the quantity required. Adjustments based on actual production performance will be made. An offshore chemical management system similar to that used for other Grand Banks operations will be in place to govern the safe use of chemicals offshore.

8.5 Geotechnical Criteria

Side scan sonar images of the White Rose area indicate that the surficial geology is a thin veneer of fine to medium grained sand over a coarser substrate, consisting of sand and gravel. Occasional occurrences of gently-sloped gravel mounds in the area may correspond with old iceberg scour berms. This information, together with other geotechnical information gathered for the White Rose oilfield, is summarized in Table 8.5-1.

Table 8.5-1 Stratigraphy of Substrate in White Rose Area

Formation	Lithology	Thickness	Remarks
Adolphus Sand	Sand (fine to medium sand, relatively hard packed)	0 to 3 m	Sub-littoral deposits formed seaward of the late Wisconsian shoreline. Occurs in water depths greater than 100 m.
Grand Banks Drift	Sand and gravel (and cobbles)	2 to 10 m	This unit is composed of two facies: a normally consolidated facies deposited in basinal areas and over much of the Grand Banks, it is often interbedded or underlying the Downing Silt, and an overconsolidated facies which occurs over large areas of the Grand Banks, often underlying the normal consolidated facies. It is in unconformable contact with the underlying Banquereau Formation.
Banquereau Formation (Tertiary)	Clay with cobbles (claystone)	10 to 700 m	The unconformity is related to subaerial and glacial erosion. Seaward dipping beds are dominantly shales and mudstones.

Additional data on the soil types and characteristics are based upon a series of glory holes that were completed in the Grand Banks area for the Terra Nova development. This information is summarized in Tables 8.5-2 to 8.5-4. From the current state of geotechnical and geological knowledge of the Grand Banks, based on site-specific surveys done for the White Rose drilling program as well as published data, it is reasonable to infer that geotechnical conditions at the White Rose site will be similar to those at the Terra Nova and Hibernia site.

Table 8.5-2 Substrate Profiles and Description at Terra Nova

Substrate Stratigraphy	Profile Name and Description		
	Terra Nova Glory Holes		
	0-90 Glory Hole (BIO & Seabed Exploration, April 1996)	1998 SW Glory Hole (Seacore)	Terra Nova Project Summary
Sand	0 to 1.5 m loose sand with small stones	0 to 1.6 m[1] sand or sand and gravel and cobbles	0 to 2 m sand or sand and gravel
Clay or Hard Pan	1.5 to 2.3 m variable thickness, grey-green well-cemented, "shelly" mudstone (southwest); dark grey, stiff massive mud (north)		2 to 4 m hard pan
Sand and Gravel (and Cobbles)			4 to 5.5 m sand, gravel and cobbles/boulder; Friction Angle = 44º Cohesion = 0 kPa
Layered Clay and Sand with Cobbles/ Boulders	2.3 to 8.0 m fine grained sand with clay matrix, numerous stones (good initial strength)		5.5 to 9.5 m layered clay and sand with cobbles/boulders; Friction Angle = 42º, Cohesion = up to 28 kPa
Clay with Cobbles	8.0 to 9.0 m stiff grey/green clay		9.5 to 16.5 m clay with cobbles and boulders high to low plasticity

[1] No data below 1.6 m.

Table 8.5-3 Average Soil Properties in Terra Nova Soil Profile

Soil Type	Bulk Density (kg/m³)	Water Content (%)	Relative Density (%)	Effective Friction Angle	Average Effective Cohesion (kPa)	Undrained Shear Strength (kPa)	Other Tests	Other Tests
Sand, Sand and Gravel	1.69 - 2.28	6-35	60-100	42-46^{O}	0			
Hardpan	2.0 - 2.35	7 – 12.5		37^{O} *	36 *	1000 – 1300 **	Grain Density 2.66 g/cc	
Sand and Clay (Layers)	1.94 - 2.19	16 – 45	50 – 100+	39-46^{O} (sand) 32-40^{O} (clay)	25 – 35 (clay)	80 – 300 +	Ave. cone resistance 1.94 MPa	PI: 12-45% PL: 20-40% LL: 32-85%
Clay	1.72 - 1.96	27 - 50			35 - 40	50 - 215	Ave. cone resistance 1.99 MPa	PI: 32-60% PL: 23-40% LL: 55-90%

* = derived from direct shear test
** = derived from point load test
PL = Plastic Limit: minimum water contact limit at which soil exhibits plastic behaviour (no crumbling), less water and soil passes to a liquid state.
PI = Plasticity Index: difference between liquid limit and plastic limit, the water contact range within which the soil exhibits plastic properties.
LL = Liquid Limit: maximum water content limit at which soil exhibits plastic behaviour (does not flow), more water and soil passes to a liquid state.
Relative Density = the density of a granular material in comparison to the same soil in its densest possible state, which is RD = 100% and a soil in its loosest possible state RD = 0%.
Bulk Density = ratio total mass to total volume.

Data Reference: "Subsea Well Iceberg Protection Study", C-CORE, December 1999.

Table 8.5-4 Generalized Soil Types, Strength Parameters and Percent Occurrence

Soil Type	Strength Parameters	Percent Occurrence (based on 11.5m depth)
Sand and Gravel	$\phi' = 44^{O}$, $c' = 0$ kPa	17%
"Hardpan"	Cu = 1000 kPa $\phi'=37^{o}$, $c'= 36$ kPa (single test)	17%
Sand, Gravel and Cobbles	$\phi = 44^{O}$, $c'= 0$ kPa	12%
Layered Clay, Sand & Cobbles	$\phi' = 42^{O}$, $c' = 0$ kPa $\phi' = 37^{o}$, $c'= 28$ kPa, Cu = 150 kPa clay, ϕ'av. $=40^{o}$, $c'= 0$ kPa	33%
Clay with Cobbles/Boulders	$\phi' = 36^{o}$, $c'= 38$ kPa, Cu = 134 kPa	21%

It should be noted that drained cohesion values are uncertain.

ϕ' = friction angle.
c' = cohesion.
Cu = undrained shear strength.
CIU test = consolidated isotropic undrained triaxial compression strength.

Data Reference: "Subsea Well Iceberg Protection Study", C-CORE, December 1999.

Past interpretations of biota present in seabed photographs have suggested that the seabed is relatively stable, with relatively little sedimentary transport within the region. This is supported by recent mapping exercises within the region. These clearly display anchor marks from old drilling programs, preserved in sand after 15 to 20 years.

The White Rose area is in an area of relatively low seismic activity. The Charlie-Gibbs Fracture Zone – Dover Fault, the Newfoundland Transform Fault and the eastern edge of the continental shelf, bound the area. Past seismic events are not well documented for the offshore, particularly for earthquakes with magnitudes less than 5.

The Laurentian Channel located along the Newfoundland Fracture Zone is the most seismically active portion of the Newfoundland Continental Shelf. Most of the earthquakes occur in the Laurentian Slope Seismic Zone, and are thought to be associated with the Glooscap Fault part of the Newfoundland Fracture Zone. In 1929, a magnitude 7.2 earthquake occurred, with after-shocks as high as magnitude 6. A re-examination of the data was unable to determine if the slump that generated the 1929 tsunami was the result of an earthquake of approximately magnitude 6 or the result of a mini-slump that coalesced into a major slump. In 1951, 1954 and 1957, earthquakes with magnitudes ranging around 6 occurred in the same area.

The White Rose field is located over 650 km northeast of the Grand Banks 1929 earthquake epicentre.

The area is located on a stable cratonic block and, in common with the Hibernia and Terra Nova sites, is within the seismicity Zone 1. This is based on a scale of 0 to 5. Zone 0 is represented by the Aseismic Gulf of Mexico, while areas of severe seismic activity, such as the Gulf of Alaska are Zone 5.
Seabed equipment and anchor piling will be designed accordingly.

For water level and current speeds associated with tsunamis generated by offshore earthquakes, see Section 8.3.1 above.

9 PRODUCTION AND EXPORT SYSTEMS

This chapter presents Husky Oil's proposed approach for production and export systems for the White Rose development.

The section covers the following topics:

- production systems considered;
- steel FPSO;
- subsea facilities;
- export system; and
- system efficiency.

9.1 Production Systems Considered

Husky Oil has carried out a concept selection study to identify the potential alternatives for developing the White Rose oilfield.

All production facility concepts for the White Rose oilfield were evaluated, based on:

- economics;
- flexibility;
- feasibility;
- deliverability; and
- Canada-Newfoundland benefits.

Eight production concepts were analyzed. They were:

- steel ship-shaped FPSO facility;
- concrete FPSO facility;
- steel semi-submersible facility with and without integral storage;
- concrete semi-submersible facility;
- concrete GBS;
- disconnectable concrete TLP;
- concrete barrier wall with FPU; and
- steel FPDSO facility.

A two-stage screening process was used to evaluate the concepts.

The first stage involved qualitative screening whereby options that were either undeveloped or clearly failed to satisfy primary technical criteria were identified.

As a result of analysis at this stage, the disconnectable concrete TLP, concrete barrier wall with FPU, and steel FPDSO were not carried forward because they either did not meet Husky Oil's technical requirements or were prototypes with no operating history in harsh-environment offshore locations.

The second stage screening process used a number of economic indicators to assess the five remaining options carried forward for detailed evaluation. These comprised Net NPV, ROR and PVPI.

These remaining five options (steel FPSO facility, concrete FPSO facility, steel semi-submersible facility with and without integral storage, concrete semi-submersible facility, and concrete GBS) were further analyzed with respect to construction time, capital costs, concept maturity, concept deliverability, and risk considerations (Figures 9.1-1 and 9.1-2).

9.1.1 Preferred Production System

The concept selection study concluded that the preferred option for the White Rose oilfield development should be based on a steel FPSO facility, together with subsea wells located in glory holes, similar to that selected for the Terra Nova Development.

The FPSO concept is a floating, production, storage and offloading ship-shaped vessel. Production facilities are mounted on raised supports above the vessel deck. Reservoir fluids pass from subsea production wells, via flowlines and risers, up into the turret and then to the production facilities. Produced oil is stored in the vessel cargo tanks and periodically offloaded on to a shuttle tanker via a loading hose.

The FPSO will be ice-strengthened. It will be moored using a geo-stationary turret, which is anchored to the seabed. The turret mooring will be disconnectable so that the FPSO can move to avoid potential iceberg threat. The functional characteristics of the turret will be similar to Terra Nova. The vessel will rotate ("weather vane") around the turret to take up a position of least resistance to the weather with the bow heading into the prevailing wind and waves.

Figure 9.1–1 Construction Costs and Time for the Five Production Options

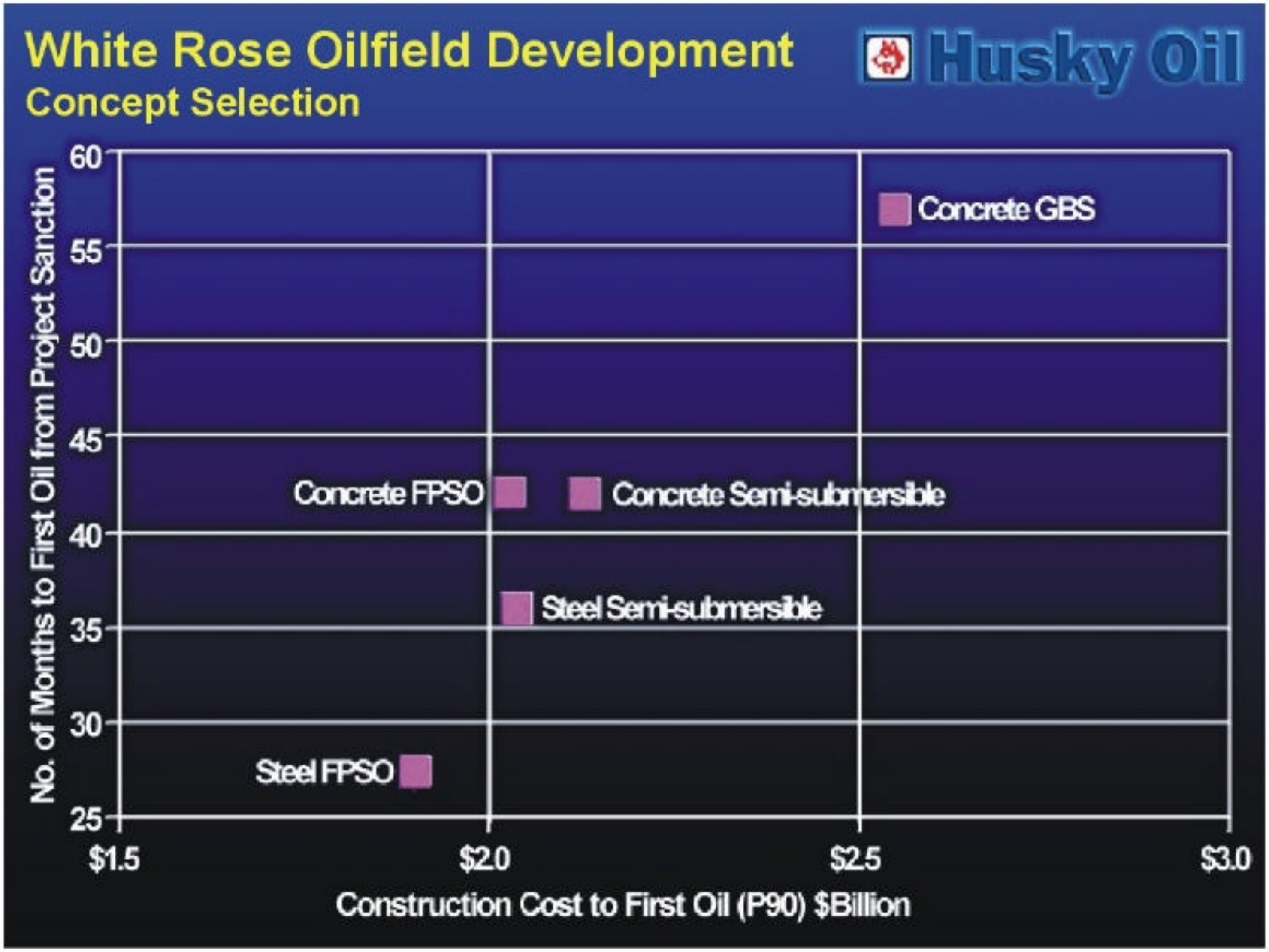


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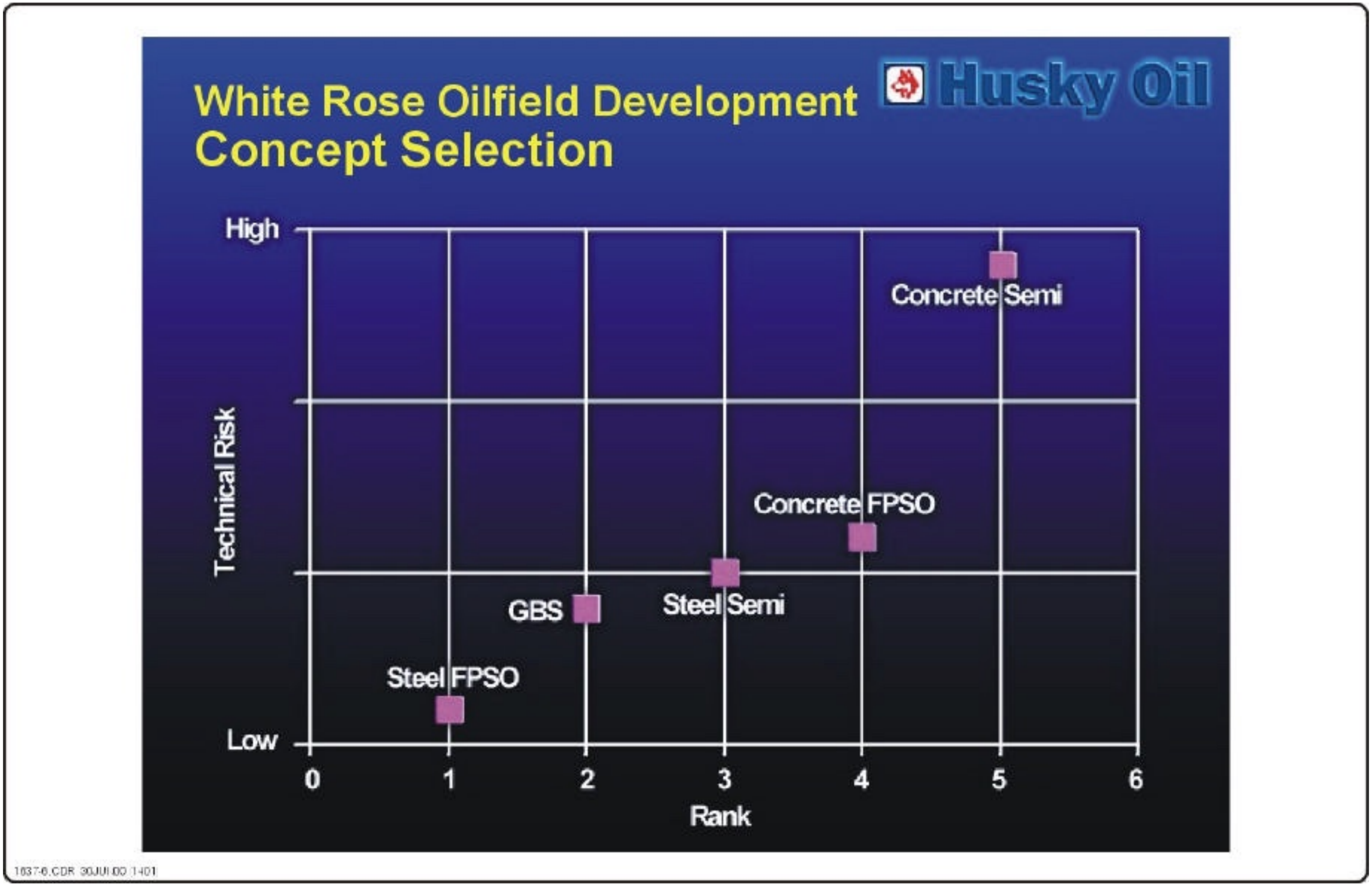
Figure 9.1–2 Relative Technical Risk for the Five Production Options



Key factors which contributed to the selection of the steel FPSO as the preferred development option included the following:

- it is the most economically feasible way to develop the White Rose oilfield, taking into account feasibility, flexibility, deliverability, economic attributes, risk and safety, and Canada-Newfoundland benefits [Refer to Table 14.4-1 in Chapter 14];
- it has commercial and technical flexibility that is well suited to a complex field such as White Rose with technical challenges and reservoir uncertainties;
- it has a proven track record in harsh environments, with 20 units installed, or in construction, in the last eight years;
- it can produce both oil and gas in sequential development;
- it has flexibility to tie in future fields;
- it offers the shortest time to First Oil, thereby enhancing economics; and
- it poses less of a challenge at decommissioning than a bottom-founded structure.

The following further attributes apply to the steel FPSO option:

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

The subsea wells will be located in glory holes dredged to a maximum of 11 m below the seafloor to provide protection to the wellheads against iceberg scour. Caisson wells will also be considered.

The FPSO will be positioned between glory holes and will receive product via flexible flowlines that deliver reservoir fluids through the turret located near the bow of the vessel. Stabilized oil will be exported to a shuttle tanker at the stern of the FPSO, via a flexible loading hose. Produced gas will be re-injected into the formation, through the turret, via dedicated flowlines.

The processing requirements will most likely be based upon a single train and will not require any unconventional facilities. The oil will be stabilized in a conventional separation train and de-watered in an electrostatic coalescer. The gas will be compressed for reinjection in a multi-stage compression train.

The subsea wells will be located in up to four glory holes strategically located in the reservoir. The wells will be drilled and completed by a conventional drilling semi-submersible, with up to eight to ten wells drilled prior to commencing production and additional wells drilled thereafter up to a total of 18 to 25.

It is anticipated that the wells will be either cluster wells or drilled through a template structure (or other appropriate subsea system). Manifold skids will be used either to co-mingle produced fluids or to distribute injection fluids. A template solution may minimize the subsea facilities envelope, hence minimizing glory hole size. Each glory hole would have two or more templates.

It is anticipated that flowlines and risers will convey the produced and injection fluids to and from the FPSO and subsea templates. An electro-hydraulic umbilical to each manifold will convey the required hydraulic fluid, chemicals, power and communication signals necessary to operate the christmas tree valves and monitor downhole and tree-mounted instrumentation.

This system was selected as top preference based on life of project cost and first equal on time to First Oil [For costs, refer to Table 14.4-1 in Chapter 14; for time to First Oil, refer to Table 9.1-1 in Section 9.1.3.]

Full descriptions of the preferred production systems are provided in Sections 9.2 to 9.4.

9.1.2 Alternative Systems

The physical characteristics of the other four alternative systems evaluated are briefly described in the following sections.

9.1.2.1 Concrete Floating Production Storage, Offloading Facility

This concept essentially comprises a concrete barge outfitted for production, storage and offloading in a similar fashion to the steel FPSO. Due to displacement considerations, its plan area is necessarily larger than the equivalent steel FPSO. It has the ability to disconnect if required by extreme conditions or icebergs.

The concrete FPSO was assessed to be inferior to the steel FPSO in respect of feasibility because there are no existing units currently in operation, thereby increasing uncertainty and risk and because the construction scale is so large, requiring extension to Bull Arm if this yard were the preferred construction facility.

A concrete FPSO is marginally more flexible than a steel FPSO because the vessel size has to be large to support its own self weight, and this size provides additional deck space.

With respect to deliverability, the concrete FPSO was considered to be inferior to the steel FPSO because of the likelihood of limited construction competition for the concrete hull and the lack of industry experience on the required scale.

This system was evaluated as second preference on life of project cost and third equal on time to First Oil. [For costs, refer to Table 14.4-2 in Chapter 14; for time to First Oil, refer to Table 9.1-1 in Section 9.1.3.]

9.1.2.2 Steel Semi-Submersible Facility With and Without Integral Storage.

The semi-submersible concept comprises a floating hull form with four surface-piercing columns connected by sub-surface pontoons. Production facilities are mounted on the semi deck. The subsea facilities are similar to the FPSO. The semi-submersible is anchored to the seabed by fixed catenary chain and wire moorings and does not "weather vane". The flexible risers are fixed to a porch(s) on the semi-submersible hull. In the event of iceberg threat, the porch(s) would be disconnected, the risers lowered and the semi moved aside using thrusters mounted on the pontoons.

A total of six semi-submersible options were evaluated; the base case option comprised a production unit with the oil offloaded to a FSU moored permanently in the field and located a short distance from the semi. Oil is exported via shuttle tanker in a similar manner to the FPSO option. The alternatives comprised:

- Alternative 1 removed the FSU but included two loading buoys and an extra shuttle tanker with one always connected; this is a so-called 'dynamic storage' arrangement;
- Alternative 2 included drilling capability as well as production facilities;
- Alternative 3 included well intervention capability as well as production facilities;
- Alternative 4 was similar to Alternative 2, but with the addition of oil storage; and
- Alternative 5 was similar to the base case but assumed the conversion of an existing drilling semi-submersible.

This option was assessed as being similar to the concrete semi-submersible in respect of flexibility but having a higher ranking in respect of feasibility and deliverability. This was largely because there is so much operational experience, with nearly 40 production units in operation world-wide.

This system was evaluated as third preference on life of project cost and second on time to First Oil. [For costs, refer to Table 14.4-3 in Chapter 14; for time to First Oil, refer to Table 9.1-1 in Section 9.1.3.]

The principal reason for selecting the steel FPSO in preference to the steel semi-submersible was forecast life-cycle cost, the steel semi-submersible cost being some $190 million more than the steel FPSO. [Refer to capital and operating cost data presented in Chapter 14.] A steel semi-submersible may become a technical and commercially viable option if the final depletion plan indicates a lower then expected production rate.

9.1.2.3 Concrete Semi-Submersible Facility With and Without Integral Storage.

This concept is similar to the steel semi-submersible concept except that the material of construction is concrete.

The same six options as described above for the steel semi-submersible were also evaluated for the concrete semi-submersible.

The only concrete semi-submersible in existence is the Troll B structure, installed in the North Sea in 1995. The semi-submersible is a production facility, without drilling or storage, with a design capacity of 27,000 m^3/d. This structure is very large compared with steel production semi-submersible counterparts, with a plan area approximately 40 percent greater, a wave area more than 200 percent greater and a displacement more than 300 percent greater. A concrete semi-submersible for White Rose would be smaller than Troll B but would still be significantly larger than a steel semi-submersible, leading to significantly higher mooring costs.

A further disadvantage of the concrete semi-submersible concept is the lack of a disconnection design. Although feasible, this would take an additional amount of design development. Another significant uncertainty is the need, or otherwise, for an independent means of propulsion in the event of disconnect. This system was evaluated as fourth preference on life of project cost and third equal on time to First Oil. [For costs, refer to Table 14.4-4 in Chapter 14; for time to First Oil, refer to Table 9.1-1 in Section 9.1.3.]

9.1.2.4 Concrete Gravity Base Structure

The GBS concept is conceptually similar to that used on the Hibernia oilfield, although reduced in complexity and design. The structure rests on the seabed and is designed to resist the forces imposed by iceberg and other environmental loads. The topside facilities include drilling equipment, as well as the process plant, with all wells drilled and maintained from the platform. Oil is stored within the base structure and offloaded via a subsea pipeline to a loading buoy located a short distance from the GBS.

The concrete GBS is jointly top ranked in respect of feasibility.

A significant challenge for the concrete GBS is considered to be deliverability where the concept is ranked lowest of the top five options.

This system was evaluated as last preference on life of project cost and last on time to First Oil. It also indicated a negative return on investment to the Owner. [For costs, refer to Table 14.4-5 in Chapter 14; for time to First Oil, refer to Table 9.1-1 in Section 9.1.3.]

The concrete GBS was ultimately discounted as an option on the following grounds:

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

9.1.3 Time to First Oil for Options Considered

The time to First Oil for each of the options considered is shown in Table 9.1-1.

Table 9.1-1 Time to First Oil for Options Considered

Option	Months to First Oil	Wells to First Oil	Ramp-up Period (months)
Steel FPSO	36	10	0
Concrete FPSO	42	10	0
Steel Semi-submersible	36	10	0
Concrete Semi-submersible	42	10	0
Concrete GBS	57	4	12

Except for the GBS, all cases assume up to 10 wells to be pre-drilled to First Oil and a production ramp-up period is not required. For the GBS, it is assumed that one well can be drilled from the GBS before the structure is operational at 48 months. It is further assumed that an additional three wells will be drilled and First Oil will occur at 57 months. It will not be until 12 months later that a total of eight wells will be available on the GBS and full production capacity is achieved. The estimated schedule for the FPSO for White Rose is 36 months from Contract Award to First Oil. This assessment is based upon experience from Terra Nova and benchmarked data for North Sea FPSOs, with due allowance for size and complexity factors. A steel semi-submersible is also tied with the steel FPSO in reaching First Oil in 36 months, while a concrete semi-submersible and concrete FPSO are tied at 42 months to First Oil. An early First Oil date is important in maintaining the financial viability of the White Rose project, which has significant less reserves than the other projects currently on the Grand Banks.

9.2 Steel Floating Production, Storage Offloading Facility

9.2.1 Vessel

9.2.1.1 Vessel Size

The FPSO hull will be approximately 200 to 300 m in length, and will support a topsides process plant. Its conceptual layout is shown in Figure 9.2-1.

9.2.1.2 Vessel Standard

The vessel will be ice-strengthened as necessary and the hull should be capable of accepting the following ice criteria:

- 100,000 t iceberg at 0.5 m/s;
- pack ice, 0.3 m thick; and
- 5/10 (50 percent) ice cover.

Vessel classification will be in accordance with Section 8.2.

The vessel will have a storage capacity commensurate with throughput, and offloading frequency. Typically this will be between 111,000 to 135,000 m^3.

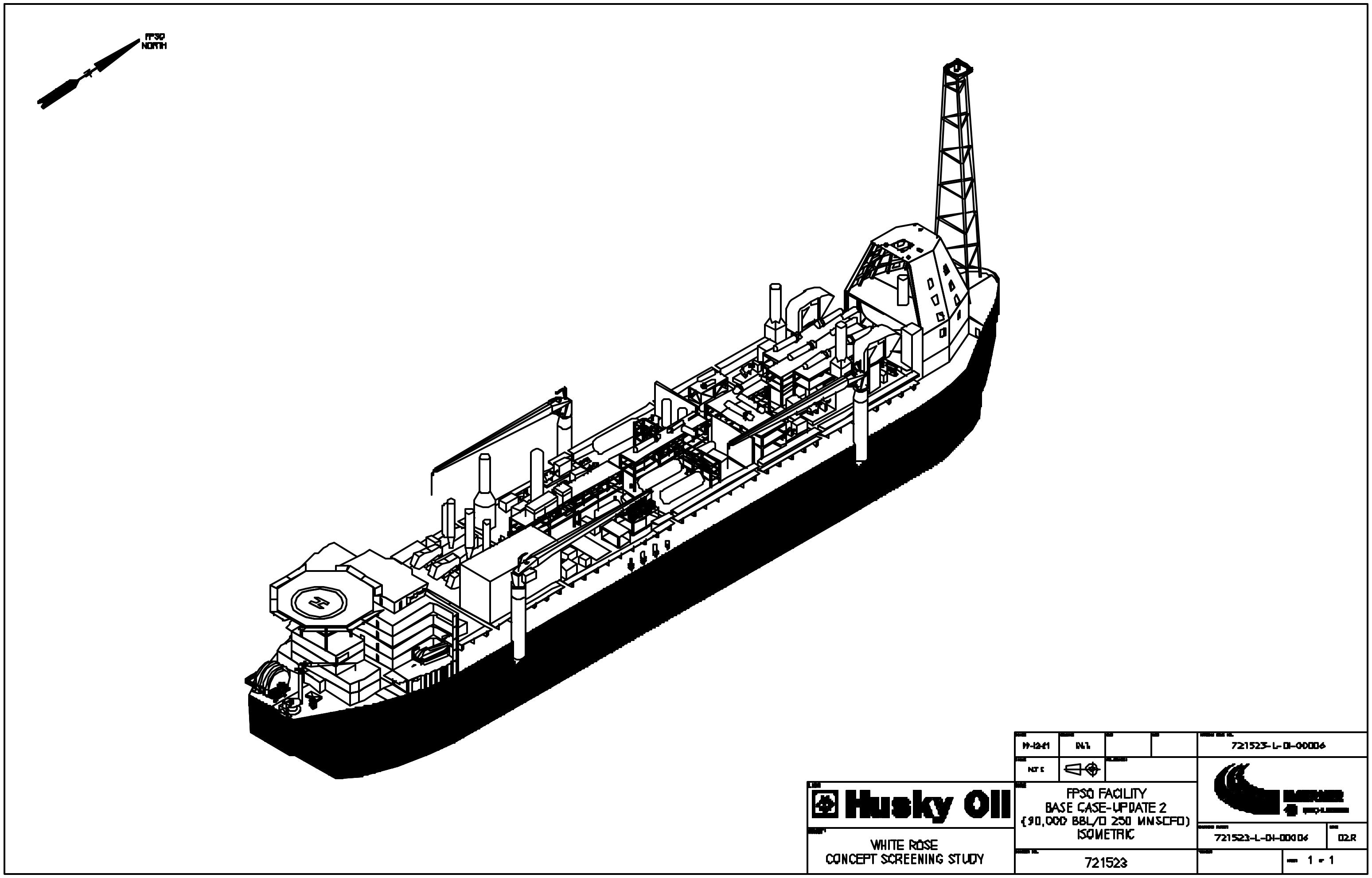
The vessel will incorporate a double hull construction and will have a segregated ballast system.

The layout of tanks will be such as to maximize storage while maintaining sufficient ballast capacity.

9.2.1.3 Structural Design Requirements

In addition to the ice-strengthening detailed above, the FPSO will be designed for the demands of Grand Banks operation and to withstand (as a minimum) the loads and motions imposed by the following:

Figure 9.2–1 FPSO Facility - Isometric



- the 100-year return period, extreme environmental conditions for the full range of FPSO operational draft, heel and trim;
- transit conditions from fabrication and assembly locations to offshore location; and
- sloshing within the tanks.

Due to the extreme environmental conditions of the Grand Banks, particular attention will be paid to hull ultimate strength and fatigue life.

9.2.1.4 General Design Requirements

The following design goals are considered the minimum requirements to obtain safe and effective vessel operation over the life of the field:

- the vessel and moorings will be designed in accordance with Lloyds Register's Guidance Notes for Structural and Mooring Aspects of Ship Type FSU and FPSO Units at a Fixed Location or equivalent;
- the main detail design features of the FPSO hull will be designed so that in-service inspection and maintenance can be undertaken;
- the hull will be designed to efficiently integrate the support requirements for the topsides facilities and all other main deck structures and equipment;
- the hull will be designed to consider possible operational impacts from supply boats. The structural response will be designed to be compatible with the safety case for the vessel;
- vessel motions will be central to the safe and efficient operation of the vessel and be such as to have no significant adverse effect on availability for production;
- vessel intact and damage stability will comply with certification authority requirements, MARPOL 1973/78 Regulation 25, and IMO Resolutions A562 & A206;
- vessel will have adequate propulsion for manoeuvring to avoid icebergs after disconnection of mooring and riser lines;
- corrosion protection will be provided for steel hull and turret for the full design life;
- the toughness and strength of the material in the hull will be compatible with the anticipated operating temperatures and stresses;
- fatigue will be fully addressed during hull design and testing;
- topsides modules/pre-assembled units (PAUs)/skids will be located at such an elevation as to avoid green water on the deck of the vessel. This will be verified by model testing. Equipment below the level of the modules/PAUs/skids will be provided with protection from the occurrence of green water; and
- full model testing program will be completed.

9.2.1.5 Marine Systems

Marine systems integrated within the hull will include the following:

- cargo handling;
- ballast;
- propulsion;
- bilge;
- hull power distribution;
- fire and gas detection;
- fire fighting for pump room, machinery spaces and accommodation;
- inert gas;
- gas freeing;
- crude oil washing system/tank cleaning;
- tank gauging;
- ballast tank gas detection;
- steam heating of cargo tanks;
- hydraulic control system for remotely actuated valves;
- diesel;
- fresh water and potable water; and
- sewage treatment.

The cargo control console, ballast controls and a monitoring/alarm system for all marine systems will be located in the FPSO Central Control Room.

In addition to the above, the cargo tanks will be fitted with a pressure monitoring system capable of detecting pressures abnormally high or low relative to atmospheric that may endanger the vessel. This system will provide both visual and audible alarms in the FPSO Central Control Room.

Some vessel utility systems have to remain active during production shutdown. The extent of hull and topsides integration will be fully addressed with respect to both shutdown philosophy and electrical isolation.

9.2.1.6 Safety Equipment

The vessel will be provided with a minimum of 200 percent capacity in persons on board in lifeboats and 200 percent capacity in life rafts. Lifeboats and life rafts will be located close to the temporary refuge and on both sides of the vessel. Additional lifeboat(s) and life rafts will be provided at other suitable locations on the vessel. All safety equipment will meet international marine requirements and Canadian regulations. A secondary muster point will be provided.

9.2.1.7 Accommodation

Accommodations will be either at the stern or at the bow of the vessel. The skids containing oil and gas will be located furthest away from the accommodations as is possible. Typical staffing levels will range from between 45 to 50 steady state crew, to between 80 to 85 with start up resources. The accommodation requirement for the FPSO will be addressed and will consider the requirements for normal operation and also offshore hook-up and commissioning and maintenance operations. Utilities, such as the galley and mess, food storage areas, change rooms and laundry, potable water and sewage treatment will be sized accordingly. Other facilities provided will include office, recreational, sick bay, and entertainment amenities.

9.2.1.8 Helicopter Operations

The FPSO will be capable of accommodating an Aerospatiale Super-Puma, EH101 or equivalent helicopter. The helideck will be designed to comply with governing legislation and for 1.5 x Super-Puma overall length (19.7 m). The helideck structure will be capable of accepting loads from the EH101 helicopter. Refuelling facilities will be installed.

9.2.1.9 Mechanical Handling

Offshore rated cranes of sufficient type and number will be provided to allow safe and efficient re-supply, operation and maintenance of the FPSO.

Arrangements will be made for the safe and easy handling of provisions to the galley storage spaces, and handling of equipment between the process and utility areas on deck and the workshop and stores areas.

9.2.2 Topside Facilities

A preliminary schematic diagram of the oil and gas process system is shown in Figure 9.2-2.

The White Rose production facilities will be designed to produce 12,000 to 18,000 m^3/day of stabilized crude oil for shuttle tanker transportation. The gas handling facilities will be designed to process 3 to 7 $10^6 m^3$/day of gas. The production facilities will handle 15,000 to 30,000 m^3/day of produced water. The facilities will handle all the oil, gas and water produced.

The topside facilities will primarily be on a horizontal plane raised above the vessel deck. It is envisaged that the topsides will be configured in modules, PAUs or skids, the number and size of which will be determined.

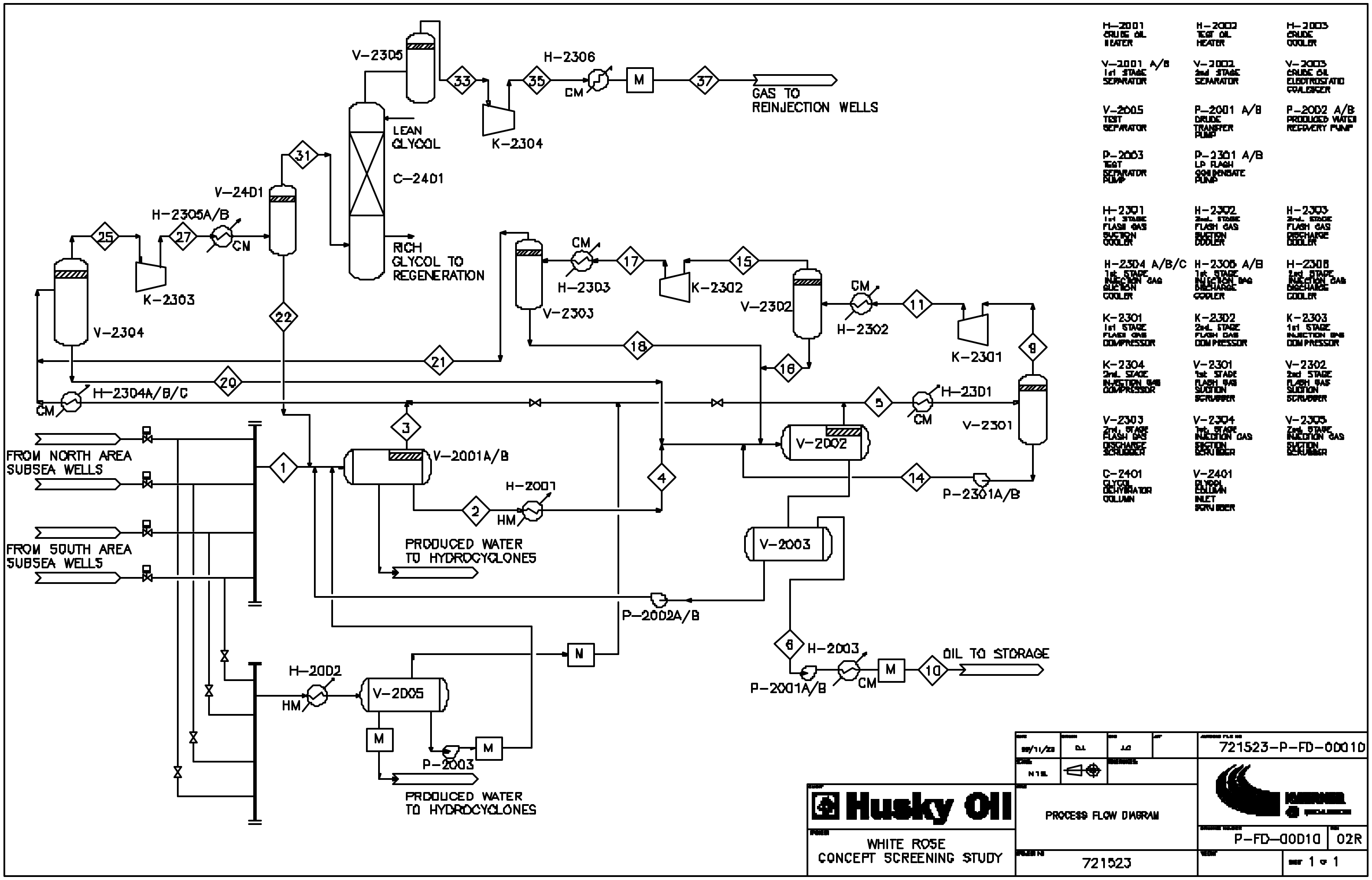
The configuration and layout of the modules/PAUs/skids will be determined giving consideration to Canadian/Newfoundland fabrication capability, safety, operability, maintainability, constructability, construction sequence, schedule, installation, hook-up and commissioning. The precommissioning and functional testing of the modules/PAUs/skids will be maximized prior to departure from the fabrication site to the at-shore hook-up and commissioning site.

The main topside facilities are expected to consist of the following:

- production from subsea wells;
- two stage oil stabilization;
- crude heating using a fired heater;
- oil dewatering using an electrostatic coalescer;
- test separation;
- produced water clean-up using hydrocyclones;
- a single train of two stage flash gas compression driven by electric motors;
- a single train of two stage gas injection compression, each stage driven by a gas turbine;
- gas dehydration by glycol contact;
- process cooling using a closed circuit cooling medium system;
- power generation using gas turbines; and
- flaring for emergencies only.

As discussed in Section 9.3, the crude oil will be stored in the FPSO tanks and offloaded to a tanker by a flexible hose. The offloading facilities will be located at the stern of the FPSO and incorporate a fiscal metering system as an integrated package. The offloading hose will be of an appropriate length, circumference and specification. Storage facilities will be provided for the hose when not in use.

Figure 9.2–2 Process Flow Diagram



Design of the storage facilities and offloading system will ensure the crude oil remains above a temperature that will avoid problems associated with wax.

9.2.2.1 Pigging

The topside facilities will include provision for launching and receiving operational pigs. The facilities will be configured so that pigs can be launched down and received from all production and production/test risers entering the turret.

9.2.2.2 Layout

The initial topsides layout is shown in Figure 9.2-3. It may also be viewed isometrically in Figure 9.2-1.

The topsides layout is to be reviewed and is subject to change during the detailed design process.

The equipment will be arranged in skids. Each process or utility subsystem will be largely self-contained within a skid so that hook-up may be minimised and to enable a maximum degree of at-shore commissioning.

It is anticipated that the layout will be based around a central piperack (sections of the piperack are fabricated on each skid) and hook-up between skids will be at the piperack only.

9.2.3 Process Utility Support Systems

The following topsides utilities systems will be required to support the process systems.

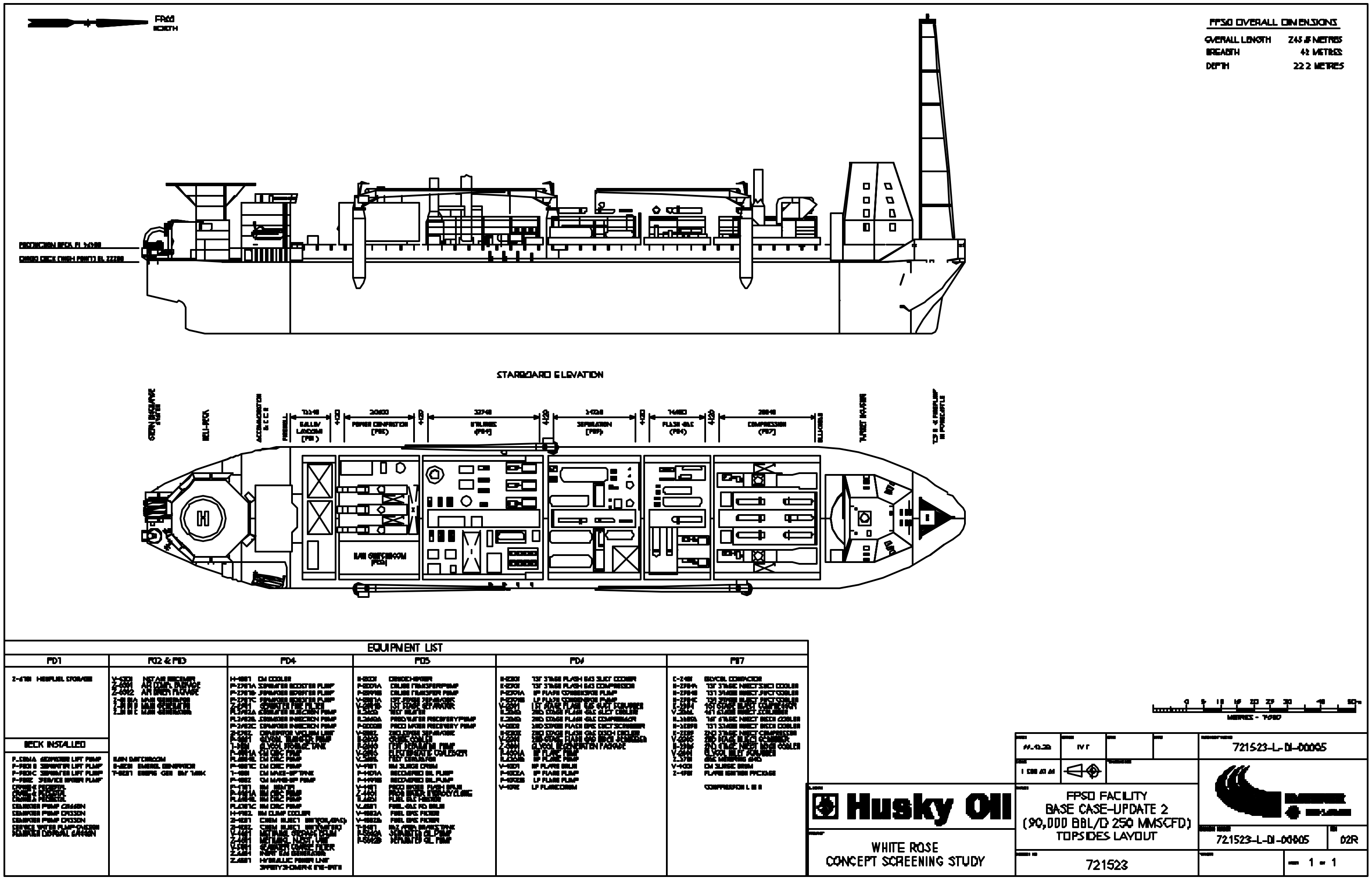
9.2.3.1 Produced Water Treatment

All produced water will be treated prior to disposal overboard. All produced water disposed of overboard will meet the requirements of the 1996 Offshore Waste Treatment Guidelines (NEB, C-NOBP and C-NSOPB 1996). This primarily requires produced water to be treated to reduce oil concentrations of dispersed oil to the following levels:

- 40 mg/L or less as averaged over a 30-day period; and
- 80 mg/L or less over any 48-hour period.

The feasibility of using produced water to meet Husky Oil's water injection requirements will be investigated during the detailed design process, as well as the feasibility of reinjecting all produced water rather than discharging overboard.

Figure 9.2–3 Topsides Layout



Water injection requirements will be met by treating and injecting seawater. Facilities for deoxygenating, filtering and preventing bacterial growth will be included in the topsides.

9.2.3.2 Cooling Medium

The cooling medium system is shown on the system utility flow diagram (Figure 9.2-4).

A cooling medium system, whereby the cooling medium is circulated in a closed loop and is itself cooled by seawater, is proposed for the present evaluations.

A tri-ethylene glycol/water solution is proposed for the cooling medium. The cooling medium will be cooled in a plate exchanger.

9.2.3.3 Heating Medium

Heating medium will be required for the crude heater and the test heater. The possible requirement for production heating to prevent wax formation in the separators will be quantified following confirmation of the wax formation temperature.

9.2.3.4 Seawater Lift

Seawater will be required for injection into the reservoir to maintain reservoir pressure and also to cool the cooling medium. The seawater system is shown on the seawater system utility flow diagram (Figure 9.2-5).

It is anticipated that seawater will be lifted by three lift pumps (two operating and one spare).

It is anticipated that the seawater will be filtered to approximately 100 micron in coarse filters and dosed with sodium hypochlorite to prevent marine growth. The hypochlorite will be generated by electrolysis of seawater.

9.2.3.5 Seawater Injection System

Initial plans are to use filtered seawater. Final filtration levels will be determined once the reservoir filtration requirements have been determined.

It is expected that the seawater will be de-aerated prior to injection to prevent corrosion in the injection wells and possibly the injection water flowline.

Figure 9.2–4 Utility Flow Diagram – Cooling Medium System

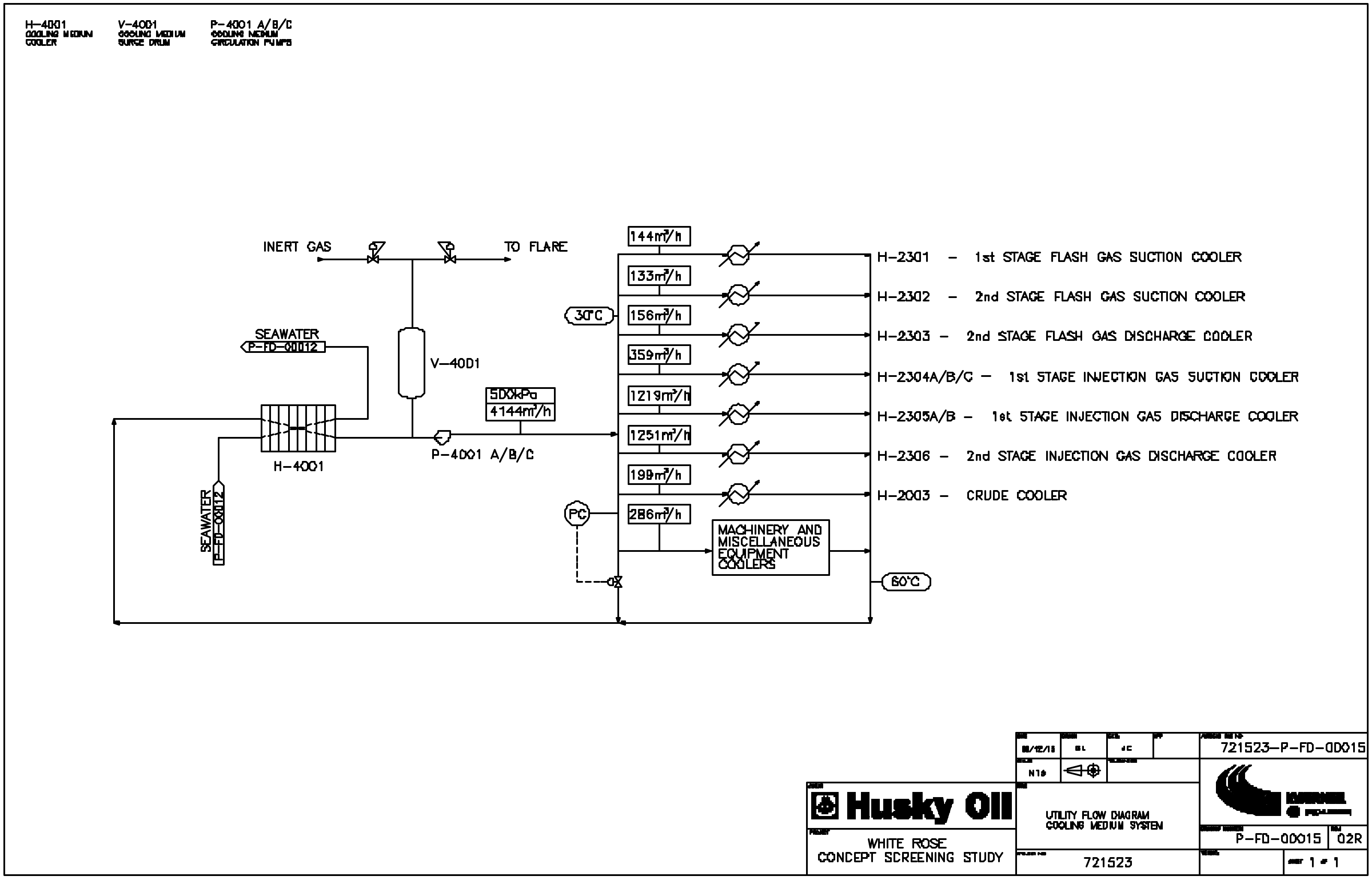
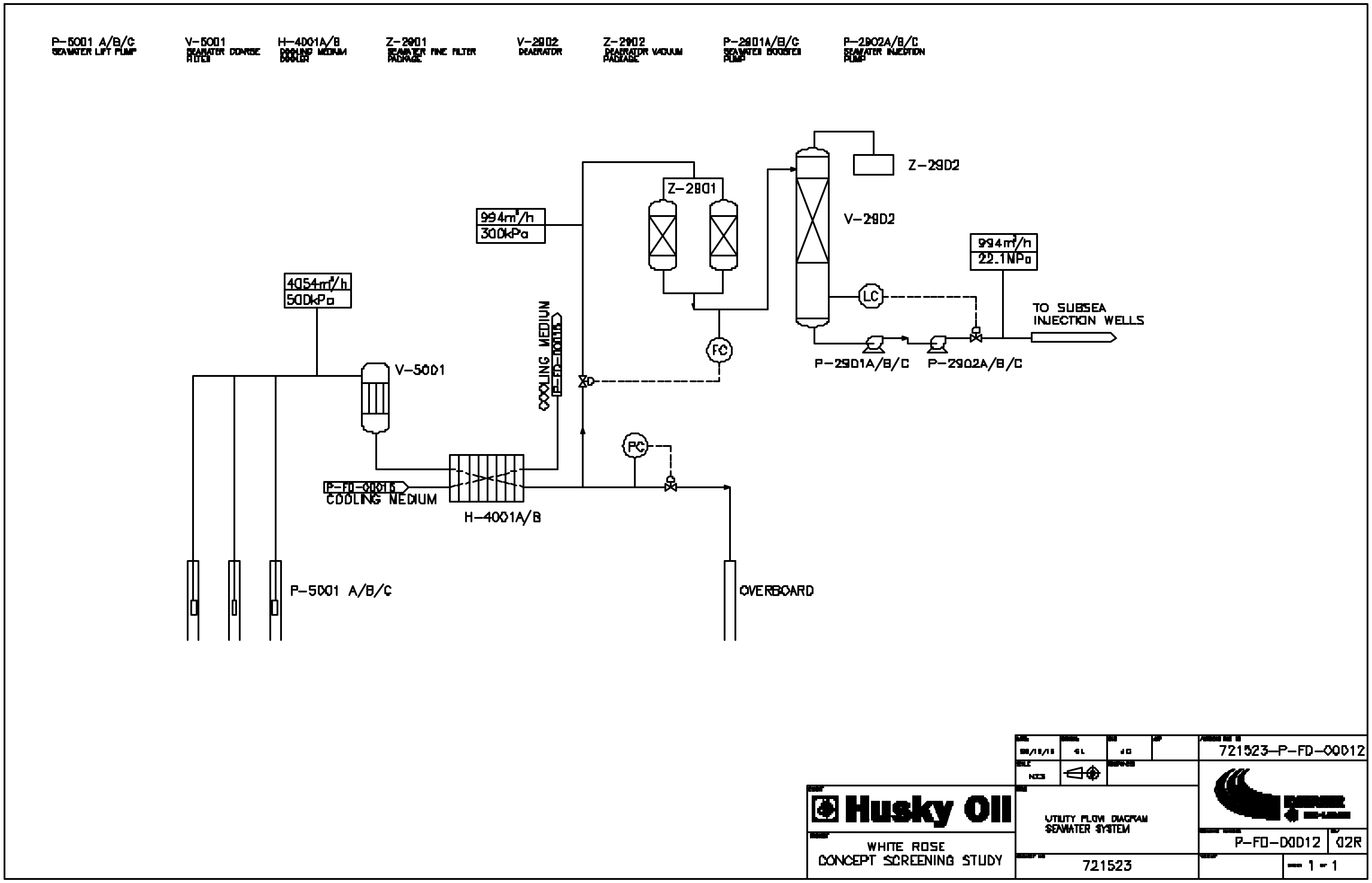


Figure 9.2–5 Utility Flow Diagram – Seawater System



The de-aeration system will be either the conventional vacuum de-aeration type or a catalytic system. This will be evaluated at a later stage in the project development.

9.2.3.6 Fuel Gas

Fuel gas will be required for the gas turbine driven injection compressor drivers (if electrical drivers not chosen), for the main power generators, inert gas system and for the heating medium fired heater and steam boilers. Small quantities are used for flushing, blanketing, flare pilots etc.

It is anticipated that fuel gas will be taken from the discharge of the first stage injection gas compressor, filtered, heated and then let down to the fuel gas system pressure (assumed to be 3,000 kPa, depending on turbine selection). The fuel gas knockout drum will act as an accumulator to allow the main generator turbines to change to diesel fuel if fuel gas pressure is lost.

9.2.3.7 Flare and Vent System

There will normally be no continuous flaring. The largest continuous flaring load is likely to be the flash gas which may be flared at start up, and which will be within the flaring consent limits if the flash gas compression system fails.

Flaring will normally only occur during non-steady state or emergency conditions. The largest relief load will be the gas injection compressor blocked discharge when 7 $10^6 m^3/d$ may have to be flared.

During design, measures will be evaluated to reduce atmospheric emissions wherever possible. The use of fuel gas and reinjection of produced gas are two of the means that will be employed. Further discussion of air emission strategies may be found in the EIS (Comprehensive Study Part One).

9.2.3.8 Drain Systems

The vessel will be provided with three separate drain systems to handle the three different types of fluid. The hazardous drainage liquids from process equipment and piping will be carried in closed drains for recycling through the second-stage separator and produced water treatment system. Water subject to contamination from hydrocarbons around equipment will be collected in open drains and conveyed to the oily water sump tank. Other routine drainage from precipitation or washdown operations will be collected in open drains and discharged overboard in accordance with 1996 Offshore Waste Treatment Guidelines (NEB, C-NOPB and C-NSOPB 1996).

9.2.3.9 Oily Water Treatment

In the case of open drains for areas around, or containing, process equipment, the liquids will be collected and piped into an oily water sump tank. Oil will be skimmed from these sumps and pumped into a reclaimed oil sump. The clear water remaining will be discharged overboard in accordance with 1996 Offshore Waste Treatment Guidelines (NEB, C-NOPB and C-NSOPB 1996). Closed drain liquids will be routed to a closed drain flash drum. Oil from the closed drain flash tank will be routed to the reclaimed oil sump. The oil accumulated in the reclaimed oil sump will be pumped to the inlet of the medium pressure production separator.

9.2.3.10 Chemical Injection

The following chemicals may be required for normal production operations:

- methanol;
- corrosion inhibitor;
- demulsifier;
- wax inhibitor;
- scale inhibitor;
- oxygen scavenger;
- antifoam;
- biocide;
- asphaltine inhibitors;
- hypochlorite;
- polyelectrolyte; and
- hydrogen sulphide scavengers.

Chemical injection requirements will be determined during the design phase and adjusted based on actual production performance.

9.2.3.11 Potable and Service Water

Potable water will be primarily supplied from supply boats. Freshwater generators will be installed for the back-up provision of potable water. Regular service water for washdown services will be seawater provided by a service water system.

9.2.3.12 Fire Water

Fire protection for the facility will be provided by a fire water system. The system will be designed such that it will incorporate appropriate back-up means of operation. A water fog system will be provided for the protection of vessel machinery spaces.

9.2.3.13 Nitrogen

A nitrogen system will be provided for flushing and inerting purposes.

9.2.3.14 Jet Fuel

Helicopter fuel storage and pumping facilities will be installed.

9.2.3.15 Diesel

To maintain operability of systems during shutdown periods, a diesel storage and distribution system will be provided for supply of fuel to the back-up power generation system.

9.2.3.16 Compressed Air

Utility air and air for instrument operation will be provided by a compressed air system.

9.2.3.17 Inert Gas

Gas blanket requirements for crude oil storage tanks will be met by installing an inert gas system.

9.2.3.18 Hydraulic Power

Hydraulic power may be provided by the installation of a central hydraulic storage, pumping and distribution system. This will provide high pressure hydraulic fluid to all points where such service is required.

9.2.3.19 De-icing

If required, de-icing of the superstructure will be accomplished by heat tracing and steaming facilities. Chemicals may be used for de-icing in certain circumstances.

9.2.4 Safety and Control Systems

Personnel safety will be paramount in the design of the facilities. This will apply to layout, construction and the provision of safety systems, which will include:

- emergency shutdown valves;
- flare and blowdown;
- hazardous drain system;
- fire and gas detection;
- active and passive fire protection; and
- personnel escape routes, temporary safe refuge and evacuation.

A safety shutdown system will be implemented for the protection of personnel, environment and equipment from accidental or aberrant operating conditions. This will isolate equipment or systems which may be detrimental to safety in the abnormal operating condition that has arisen. Several shutdown levels corresponding to various conditions are foreseen. Examples are as follows:

- Level 1: Abandon Platform Shutdown;
- Level 2: Emergency Shutdown;
- Level 3: Process Shutdown;
- Level 4: Partial Process Shutdown; and
- Level 5: Unit Shutdown.

The system will include the control and process shutdown system, the fire and gas system and the emergency shutdown system. These will operate separately, but will have common supervisory operators via an integrated, network-based system. The operator consoles will be located in the central control room, alongside other control packages.

It is anticipated that twin escape routes will be provided below the process deck. Three sides of these will be protected by walls, while the outboard side will be partially open. Temporary safe refuge areas will be provided and evacuation plans will be prepared.

In the event that an unsafe condition develops, the safety shutdown condition will be communicated by audio-visual alarms in the central control room and throughout the facility.

Safety valve actuators will be for use exclusively in safety shutdown conditions. They will not be used in routine operations. Emergency shutdown valves will be provided subsea and on the inlet manifold above the riser connectors to ensure isolation of the process facility.

Depressurization of the topside facilities and vessel systems will be done manually for all safety shutdown levels, except for Level 1 where depressurization will occur automatically.

The various areas will be classified in accordance with codes and regulations that will serve as a basis for the selection of electrical equipment and the control of ignition sources.

For further description of safety and control systems planned for the operation, refer to Volume 5 (Safety Plan and Concept Safety Assessment).

9.2.5 Power Generation

The generators will be sized to meet the electrical loads of the FPSO vessel, both for normal and emergency operation. They will be dual-fuelled, able to function on produced gas or diesel. As well, for security, there will be provision for further diesel-driven power generation for emergency.

It is anticipated that a power generation capacity of 15 MW will be required to service the electrical needs of all onboard equipment, except for the FPSO's systems and crude offloading. It is expected that the latter will be supplied by the FPSO's electrical systems.

The electrical load is assumed to be supplied by turbine driven generators.

9.3 Subsea Facilities

The subsea facilities for White Rose will include all equipment necessary for the safe and efficient operation and control of the subsea wells and transportation of production and injection fluids between the wells and the FPSO. Anticipated operations include but are not limited to:

- steady state production with and without gas lift;
- steady state water and gas injection;
- planned and emergency shutdown;
- start-up after shut down with and without gas lift;
- SCSSV leak off tests;
- hydrate, scale and wax inhibition;
- well intervention and workover;
- well treatments (for example, squeeze);
- production and gas lift choke replacement;
- subsea control module replacement;
- tie-in future facilities and possible future prospects;
- flushing and round-trip pigging;
- emergency intervention/repair activities;

- ability to flush lines in case of iceberg encroachment;
- temporary and final field abandonment; and
- controlled and emergency disconnect of the spider buoy from the FPSO.

The subsea facilities include all wellhead completion equipment, trees, manifolding, flowlines, umbilicals, risers, seabed structures, control systems and all interfaces required to control and operate the facilities and associated test, installation, inspection and maintenance equipment. Wellhead equipment, trees and manifolding structures (templates or clusters) will be located in open glory holes for iceberg protection.

In general, the subsea facilities will be designed for diverless installation, operation, inspection and maintenance, and will be based on field-proven designs wherever possible. Technology development will only be undertaken where there is a clear economic justification to do so and where the schedule allows this. New designs will be subject to comprehensive qualification testing.

The subsea facilities will be configured to allow production well testing to be performed by routing individual wells through a test flowline to the test separator on the FPSO. Whenever well testing is not ongoing, the test line will continue to be used for production to mitigate wax formation in the line. Facilities will also be provided to permit round trip pigging of the production and test lines from the FPSO.

As a minimum, metal to metal sealing will be used for all surfaces with potential for sustained exposure to well fluids.

It is anticipated that remotely operated choke valves will be included for the production, gas lift, gas injection and water injection wells. The potential requirement for back-flowing of the injection wells needs to be addressed.

The overall availability target for the subsea facilities must be compatible with the overall availability target set for the whole facility.

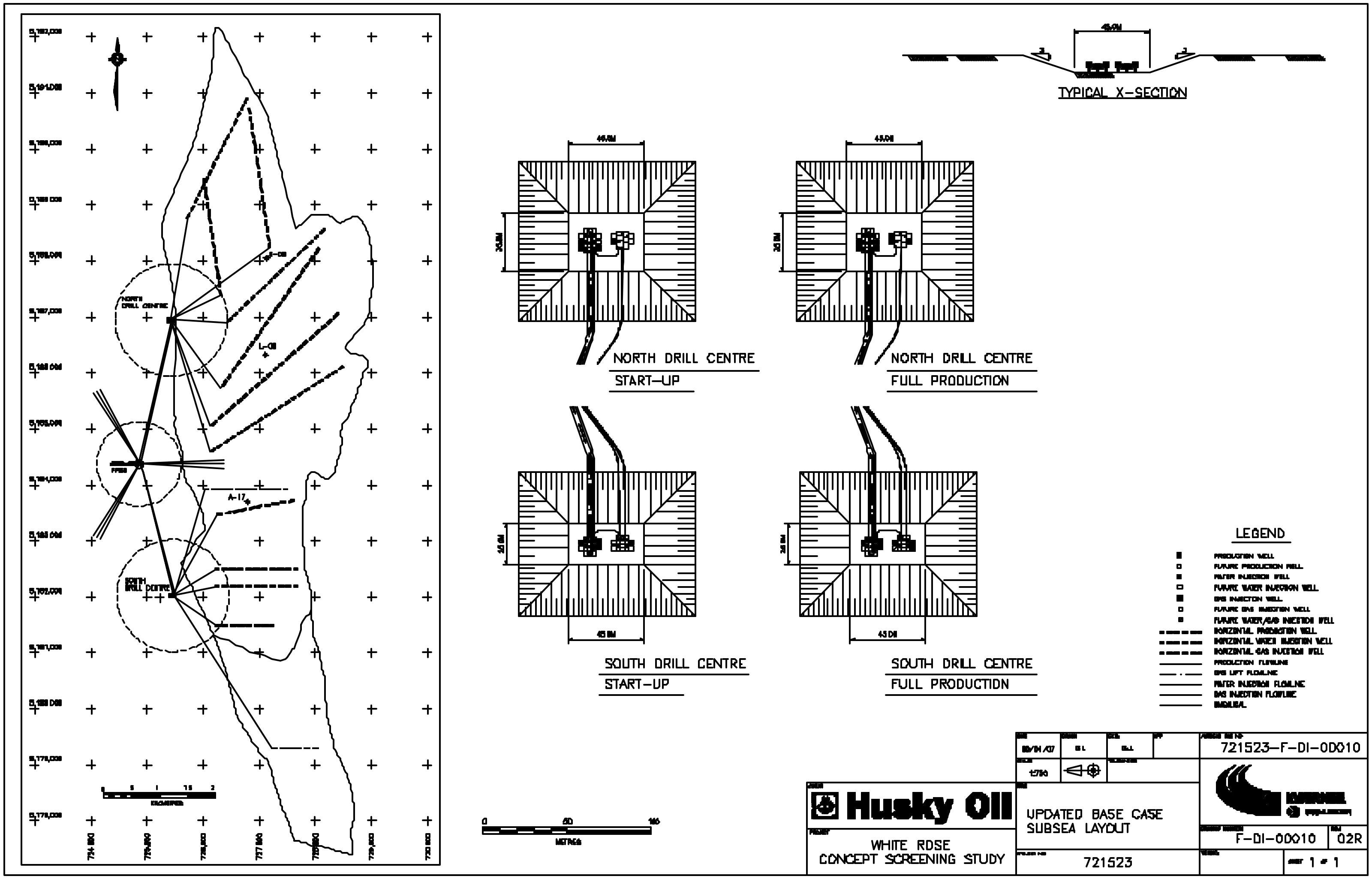
A possible layout of the subsea facilities is shown in Figure 9.3-1.

9.3.1 Manifold Systems

The subsea facilities will provide a means to co-mingle the flow from the subsea wells via a manifold. The manifold will be retrievable independently of the trees and provide sufficient flexibility to satisfy the operational requirements and also possible future expansion requirements.

Valving will be incorporated to allow for remote switching of flow between test and production headers.

Figure 9.3–1 Subsea Layout



Isolation will be incorporated into the design so that intervention on one tree or its choke valve(s) will not impede the normal operation of other wells connected to the same production/test/gas lift/injection header. In addition, where a tree connection is not used, provision will be made for installation of a pressure cap, which may remain exposed over extended periods.

Where the manifold foundation also comprises the well foundation in the form of a template, the template will be designed to be installed by the MODU in a safe manner, preferably through the moonpool.

To facilitate round trip pigging operations, a remotely actuated valve will be placed between test and production headers.

9.3.2 Chemical Injection

Provision will be incorporated in the subsea facilities and subsurface for the injection of chemicals. Isolation for ports where chemical is injected into the production stream will be in accordance with API 17D. At least one of the barriers will be a remotely operated valve. The provision for metering the injection of chemicals will be addressed.

9.3.3 Subsea Completion System

It is currently envisaged that the subsea completion system will be designed around the use of vertical or horizontal christmas trees and a 476 mm wellhead. These wellheads may be used either in a glory hole or using a caisson system.

Two types of christmas trees are required:

- production with gas lift capability; and
- injection (water and gas).

The use of common subassemblies across tree designs will be adopted.

The requirement for reverse flowing of the injection trees has yet to be addressed.

Two independent and tested barriers will be available in order to prevent discharge from the well.

The completion system will be designed to be normally deployed through a conventional rotary table and moonpool. The completion system will include an installation/workover control system.

9.3.4 Subsea Control System

The subsea control system is presently expected to be an open loop, multiplexed electro-hydraulic system. The system will feature both subsea and FPSO located equipment. The level and location of the FPSO equipment will depend on overall field facility control philosophy, topsides equipment layout and turret design.

The subsea and FPSO located control equipment will be connected via electo-hydraulic control umbilicals (see Section 9.3.5).

The control system will be designed to supply sufficient hydraulic fluid (high pressure (HP) and low pressure (LP)) to control the remotely operated valves on the manifolds and christmas trees at all drill centres. Consideration will also be given to possible future expansion requirements. In selection of a control fluid, particular attention will be given to the ambient environmental conditions discussed in Section 8.3.1. The system will also be designed to request, assimilate and transmit data from downhole, tree and manifold mounted instrumentation as required.

All subsea located equipment that is retrievable will be done by remotely operated vehicle (ROV) without the requirement for divers.

9.3.5 Subsea Control Umbilicals

The control umbilicals will be designed and manufactured to an appropriate industry standard with particular reference to API 17E.

They will convey HP and LP hydraulic fluids and chemical injection fluids and provide electrical cable paths from the FPSO to the subsea facilities. The requirement for spare cores within the umbilical is yet to be addressed.

The umbilicals will be fully compatible with the intended service duties (pressure, temperatures, control and chemical injection fluids, voltages and currents) without degradation for the design life. The umbilicals will also cater to any specific downhole or tree service operations as required.

Wherever possible, umbilicals will be a single continuous length. If this is not possible, the number of midline connections will be kept to a minimum.

The umbilicals will be comprised of static sections which will remain stable on the seabed under all operational and environmental loadings, and dynamic sections which will be designed to be compatible with the design of the dynamic risers and FPSO mooring lines.

9.3.6 Flowlines and Risers

The flowlines and risers for White Rose will be designed to an applicable industry standard (API 17J). They will provide an unobstructed flow conduit between the subsea facilities and the FPSO and will be fully compatible with the intended service duty for the entire design life. Appropriate valving will be installed subsea to control flows in both normal and emergency situations.

Design of the flowlines and risers will ensure that no maintenance is required during the design life, other than external inspection using an ROV and damage repair and operational pigging. Flowlines will be designed to be stable on the seabed and risers designed to be compatible with the mooring lines and dynamic umbilicals. In addition, the risers will not be allowed to touch the seabed or break the sea surface other than is intended by design.

9.3.7 Insulation Requirements

The subsea facilities, including flowlines, will be insulated as required to meet the minimum arrival temperature at the top of the riser. This temperature will be the optimum temperature to satisfy both wax and hydrate formation criteria. Additionally, the selected hydrate and wax prevention strategy will be taken into account in order to ensure a safe and good practice in operation of the subsea system for both regular production and well testing scenarios. Insulation will also be designed to provide a minimum reasonable period for repair and restart in the event of an unplanned shut down, to minimize gelling of the crude in the lines.

9.3.8 Subsea Tie-in and Connection Systems

Initial field installation tie-ins and connections may be by either diver or diverless methods. Any connections that are required to be broken for maintenance and repair subsequent to initial installation will be by diverless methods. The final choice of tie-in and connection method will be made with due regard to safety, economic and feasibility considerations.

9.3.9 Iceberg Protection

The White Rose oilfield is subject to scouring icebergs and the design of the subsea facilities will consider the following:

- the location of wellheads, christmas trees and manifolds in glory holes, with the top of the equipment a minimum of 2 to 3 m below the seabed level. This does not apply to components not critical to the integrity of the well;
- flowline trenching;
- rock backfilling;

- requirement for overtrawlability;
- design loads from fishing activities resulting from fishermen accidentally entering the safety zone;
- transfer of loads from icebergs to flowlines and umbilicals to ensure that well integrity is not compromised;
- design loads of snag and dropped objects; and
- flowline weak link technology.

In addition, the following inherent safety features will be built into the design of the subsea facilities:

- all subsea systems will be designed to be fail-safe (that is, all hydraulically operated isolation valves will automatically close if hydraulic power is lost); and
- any abnormal operating conditions resulting from control system damage, which endangers the safe operation of the subsea facilities, will trigger an automatic system shutdown.

9.3.10 Cathodic Protection

The subsea facilities will be protected from seawater corrosion for the life of the field by use of sacrificial anodes. Design of the protection system will be in accordance with an appropriate standard, for example DNV RP B401, but due consideration will be given to local conditions and regulatory requirements.

9.3.11 Interfaces

The following key interfaces will be addressed during the FEED phase:

- well construction:
  - MODU characteristics and operations,
  - drilling and completion activities,
  - logistics,
  - potential for carrying out installations from MODU, and
  - number of wells, glory holes and drill centres;
- FPSO mooring and turret
  - subsea layout will comply with the layout of the FPSO and mooring system,
  - dynamic riser configuration will be based on results of mooring design,
  - number and type of swivel paths; and
- topsides
  - identification of requirements for chemicals, electrical & hydraulic power, control & process interfaces,
  - integration of subsea control system with topsides control system, and
  - maximum pressures, temperatures and flow rates of production and injection fluids.

9.3.12 Oil Spill and Leak Protection

The goal in the design and operation of all subsea facilities will be to ensure that any possible iceberg impact will result in no pollution. The ice management system, described in Section 11.3, will be in operation, and continuous monitoring of iceberg locations, drifts and forecast trajectories will be maintained during the iceberg season.

Provision will be made in the design for subsea oil production lines to be shut down and flushed, and for the FPSO to be disconnected from the subsea facilities, in the event that a scouring iceberg enters the area.

Flowlines may be trenched to reduce the risk from scouring icebergs, improve the thermodynamic characteristics, or provide on-bottom stability.

9.4 Export System

9.4.1 Offloading System

It is envisaged that the offloading facilities will be located at the stern of the FPSO and incorporate a fiscal metering system as an integrated package. The offloading hose will be of an appropriate length, circumference and specification. Storage facilities will be provided for the hose when not in use.

Design of the storage facilities and offloading system will ensure the crude remains above a temperature that will avoid problems associated with wax, including an appropriate safety margin.

The offloading system and offloading rate will be designed with regard to the environmental conditions in the field, such that the availability of the facility is not compromised by weather limitations which inhibit shuttle tanker connection or cause disconnection.

The offloading system will include a mooring hawser complete with messenger line, and all equipment necessary for handling and storing of the hawser. The tension in the hawser will be monitored continually while the shuttle tanker is connected and emergency disconnect will be provided.

Telemetry and communication systems necessary for both the safe approach/mooring of the shuttle tanker and control of the offloading operation will be provided on the FPSO.

9.4.2 Shuttle Tankers

Shuttle tankers will be used for exporting White Rose crude to markets in Eastern North America, the U.S. Gulf Coast or to a transshipment facility, such as the one currently operating at Whiffen Head.

Depending on the distance to market and on the volumes of crude to be exported, one to three tankers will be required. They will be sized appropriately for the transportation requirements and will be designed according to current relevant codes and standards, with due consideration of East Coast environmental conditions. They will be bow-loading and capable of connecting to the FPSO offloading system in significant wave heights of 5 m.

9.5 System Efficiency

The White Rose facility is expected to have a system efficiency in the range of 90 to 94 percent. This is consistent with experience on similar operating facilities in the North Sea and elsewhere.

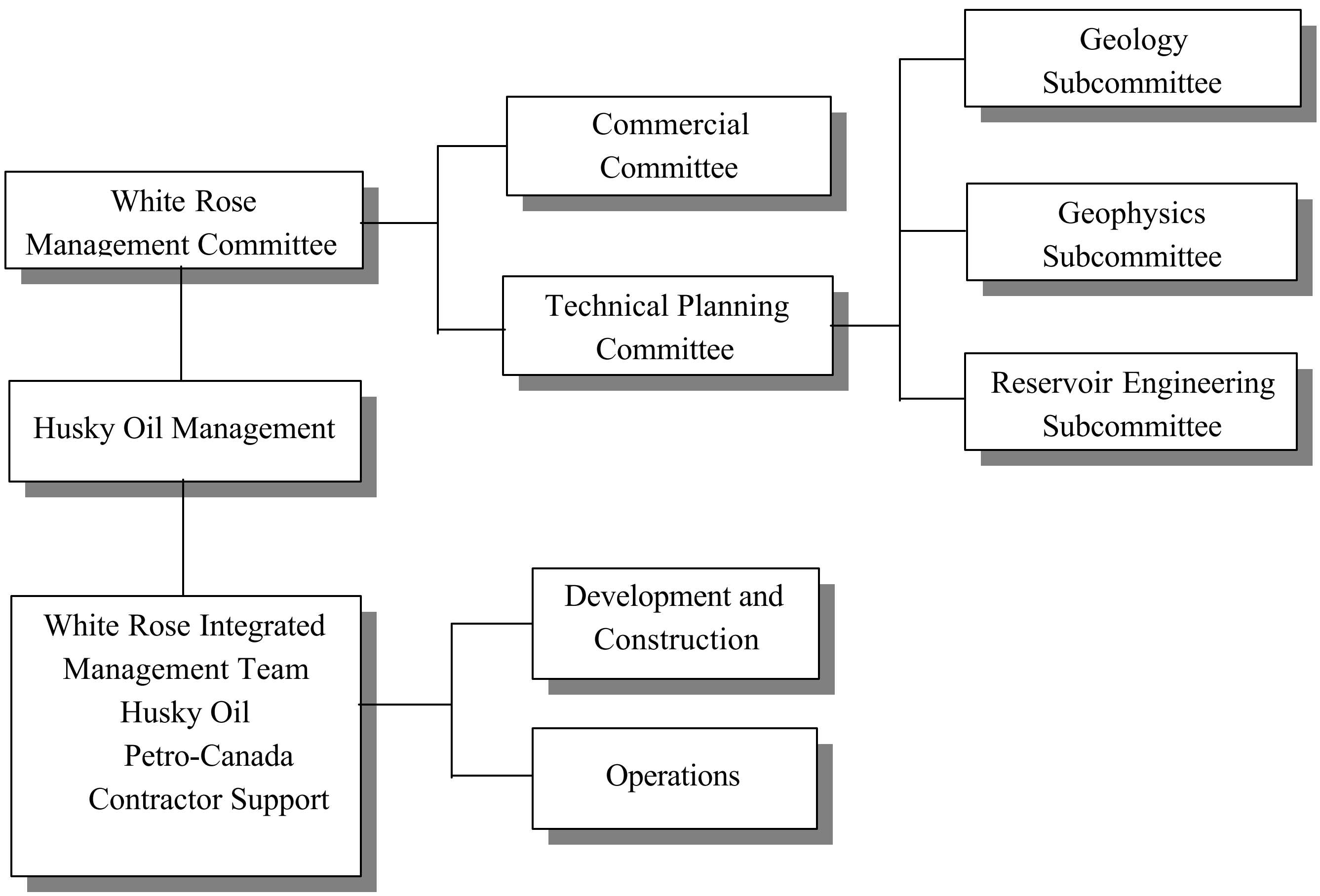
10 CONSTRUCTION AND INSTALLATION

Husky Oil has identified the East Coast as a core business area for the company. The Husky Oil project management team, located in Newfoundland and Labrador, has responsibility for development plan execution and ensuring that all operations are conducted safely, in an environmentally responsible manner, and in accordance with all corporate and regulatory policies.

10.1 Management

Husky Oil, as operator, has assembled an integrated management team comprising Husky and Petro-Canada personnel, as well as some contractor personnel. This integrated management team reports, through Husky Oil, to a top level Management Committee of project owners, established to provide for the orderly planning and supervision of all project activities (Figure 10.1-1). The Technical Planning Committee and the Commercial Committee support this committee in all its endeavours.

Figure 10.1–1 Project Team Structure



The Technical Planning Committee reports to the Management Committee on issues relating to field evaluation, development and operations, including items concerning business, technical, and health safety and environment. The Commercial Committee also reports to the Management Committee, and is responsible for reviewing and providing expert input into the negotiation and execution of major contracts, commercial agreements and owner agreements. This committee will establish a common economic evaluation system for implementation on the project.

Husky Oil and Petro-Canada each have the right to appoint one member and one alternate member to any Committee or Subcommittee. The chairperson for each committee or subcommittee is a Husky Oil appointee, based on the company's responsibility as field operator.

The integrated management team will eventually evolve into a "life-of-field" group as the project proceeds into the production stage.

To ensure technical competencies are in place for all aspects of the project, required specialized expertise will be contracted to augment the existing Husky Oil staff on an as-needed basis. The task of assembling an integrated management team for the White Rose development, incorporating managers and personnel from within the Husky Oil organization, from project co-venturer Petro-Canada, and from independent contractors, is now well under way.

The following section outlines the general requirements for the project administration on White Rose. The plan is to identify owner staff resources that may be suitable to become part of the White Rose team. This provides local continuity and increases the ability to apply the lessons learned on Terra Nova. In addition, recruitment from the local community will be an ongoing process.

10.1.1 Technical Project Management

Building corporate competence to handle the White Rose project is critical for the project's success. This includes:

- Having a General Manager who will oversee the construction planning and execution of the White Rose Development Project. This position will lead the integrated project team through the front-end engineering, contractor/partner selection, project sanction and construction phases. The responsibilities of this position include:
  - designing and delivering a complete production facility and transportation systems for offshore production, including special purpose shuttle tankers, on time and on budget;
  - coordinating development planning for additional projects in the White Rose region in order to optimize the area's resource potential;
  - integrating Husky Oil's established development and operations team with the contractors' project management teams; and

    - ensuring project compliance with Husky Oil's project engineering guidelines, administration procedures, and health, safety and environmental policies.
- Managing a core team of highly experienced specialists for the contractor selection process and then combined with contractor staff for the execution phase. During the contractor selection phase, senior, experienced personnel will be required to lead the engineering process. After contract award, the design and fabrication will be conducted by contractor staff with a defined reporting requirement that Husky Oil will review and supervise.
- Contracting to provide technical expertise that is not available in-house from Husky Oil or Petro-Canada. This approach ensures access to a large pool of readily mobilized expertise.
- Establishing clearly defined tasks for the development team, upon award of major contracts for the FPSO, the subsea package, and the glory hole excavation, to carry the project through to First Oil. This team will include technical specialists, project controls staff and contractor representatives.

10.1.2 Contracting Strategy

The White Rose Development Project is confronted with some key challenges that must be effectively addressed if a successful field development is to be achieved. These challenges include a complex reservoir, technical and operational considerations, and a harsh operating environment. Responses to these challenges will require innovative and cost-effective solutions that enhance the project's long-term economic viability.

10.1.2.1 Floating Production, Storage and Offloading Facility

Experienced contractors with proven track records of successfully managing and operating similar FPSO projects, from design through to production operations, are able to provide the necessary operational expertise and technical support required. It is possible that, by leveraging the contractor's experience and corporate resources, an aggressive project schedule may be pursued, with a potential reduction in both the commercial and technical risks.

One viable contracting strategy is to appoint a contracting company which provides an FPSO under a charter party arrangement that includes all operating and maintenance services throughout field life. Using this strategy, the selection of the contractor best qualified to provide the depth of support will be absolutely crucial to the ultimate success of the White Rose oilfield development.

Several contractors have approached Husky Oil and expressed their interest in participating in the White Rose project. In order to obtain the commercial information needed to sanction the project and facilitate achievement of the project schedule, a competitive bid process for an FPSO provider is being conducted.

Issuing a Request for Proposals to interested contractors is the starting point in the evaluation process. Proposals from contractors will be evaluated and will result in the determination of a short list of potential contractors. Furthermore, these proposals will provide a clear indication of the efficacy and feasibility of this contracting strategy. Discussions will then be conducted with the short-list contractors to determine if this strategy is viable and to ultimately identify the successful contractor.

The contracting strategy is based on leveraging the value of a contractor's established floating production facility (FPF) operating skills as the key agent throughout the life cycle of an FPF project. The focus on operations is the most critical criterion. This strategy is supported internationally by the increasing number of contracts signed with FPSO contractors with a scope of work that covers full project cycle skills.

The FPSO contract will be developed through negotiations that will address technical, commercial, and Canada-Newfoundland benefits aspects. In addition, a value engineering exercise will be carried out that challenges the existing basis for design, targeted at capturing cost reductions and performance enhancements through improvements in design while ensuring health, safety and environmental integrity. These negotiations will commence upon the initial review of the proposals. The FPSO Request for Proposal has therefore been issued with the following objectives:

- establishing the basis and criteria for comparing different proposals and contracting strategies;
- defining the scope of work for the FPSO contractor, outlining what the required deliverables are for the evaluation, and assessing the contractors proposed solutions;
- setting the stage for a value engineering process designed to capture improvements in both cost and performance over proposed target levels and existing benchmarks;
- identifying a recommended contractor, and creating a supporting document that includes a well defined technical definition of the FPSO facility, a commercial agreement with defined terms and conditions agreed to by both parties, a competitiveness assessment, and an industry benchmark analysis; and
- defining the specific Canada/Newfoundland benefits potential of the development and production activities.

Alternatives to the previously described preferred FPSO contractor strategy will also be considered. The decision on proceeding with an engineer, procure, install and construct (EPIC) fixed-price contract Request for Proposal will be reviewed following the initial review of the short-listed contractors' submissions.

10.1.2.2 Subsea

The subsea contract package will consist of all equipment from (and including) the subsea christmas trees to the riser connection on the FPF. The strategy for this component of the project will be to contract for the complete subsea system in a single contract, which will encompass everything from detailed design to installation, commissioning interfacing and the option of providing ongoing operational support. The first phase of the contract, FEED, will be conducted several months prior to sanction. The installation of subsea equipment for initial development drilling will occur in the months following sanction, with installation of flowlines and risers completed the following year.

The glory hole excavation will be dealt with as a stand-alone contract and bid competitively. In conducting a contractor capacity assessment, it was confirmed that current international projects have restricted the availability of required technology for this work. Several of the potential contractors have indicated an ability and willingness to work with Husky Oil to develop a solution, however, they have all indicated the need to plan as much lead time as is possible. To address this situation, a Request for Proposal was issued to qualified companies in June 2000. The intention is to initiate discussion and to define the process that will generate a cost-effective solution at the lowest risk profile to the owners. Contract award will be scheduled following an in-depth assessment of the contractor's proposals.

In line with the objectives for the project, the preferred solution is to conclude agreements with experienced lead contractors who will manage the supply of all subsea and glory hole services required, preferably under a single, lump sum "turnkey" contract, or, depending on commercial and interface considerations, multiple contracts.

10.2 Schedule

The schedule for the South Avalon Pool development is shown in Figure 10.2-1.

White Rose Concept Screening Study
© Kvaener - SNC Lavalin Offshore (KSLO)

****Note: YR-1 and YR-2 refers to the Pre Sanction Activities**

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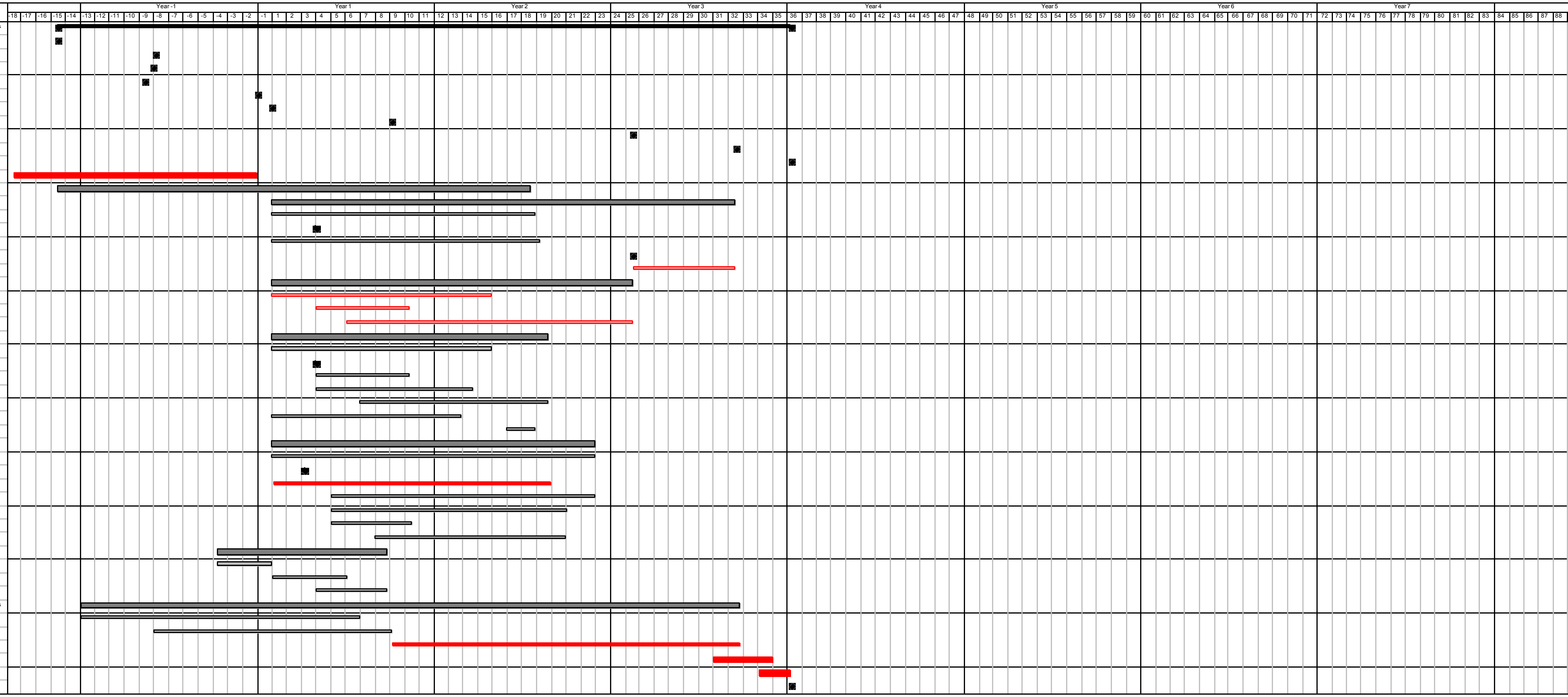
Figure 10.2 - 1

Preliminary Field Development Schedule - Level 2 - Steel FPSO

ID	Task Name	Duration
1	**Milestones**	**1517 days**
2	Start Concept Screening Study	1 day
3	Design Basis Depletion Plan Approval	1 day
4	Subsea FEED Sanction	1 day
5	Issue Draft DA	1 day
6	DA Approval	1 day
7	Project Sanction	1 day
8	Start Drilling	1 day
9	Vessel Arrives at Topsides Yard	1 day
10	FPSO Complete - Ready to Sail	1 day
11	First Oil	1 day
12	**Development Plan Application**	**504 days**
28	**Pre-Project Sanction Phase**	**979 days**
47	**Topsides**	**961 days**
48	**Engineering (Post AFC Tech. Support Excl.)**	**547 days**
50	**Start Material Procurement**	**1 day**
54	**Fabrication Topsides Modules**	**557 days**
76	Vessel Arrives Atshore Hook-up Yard	1 day
77	**Atshore Hook-up and Commissioning**	**213 days**
89	**Hull**	**748 days**
90	**Engineering (Post AFC Tech. Support Excl.)**	**457 days**
92	**Materials Procurement**	**196 days**
94	**Hull Fabrication, Outfitting and Pre-commissioning**	**593 days**
100	**Turret and Mooring System**	**573 days**
101	**Engineering (Post AFC Tech. Support Excl.)**	**457 days**
103	**Start Materials Procurement**	**1 day**
106	**Spider Buoy**	**196 days**
110	**Lower Turret**	**326 days**
114	**Swivel / Upper Turret**	**392 days**
118	**Mooring System Fabrication**	**395 days**
120	**Mooring System Installation**	**60 days**
124	**Subsea Systems**	**670 days**
125	**Engineering**	**669 days**
127	**Start Materials Procurement**	**1 day**
130	**Drilling Templates**	**572 days**
136	**Manifolds**	**548 days**
140	**Production Trees**	**489 days**
147	**Well Heads**	**168 days**
154	**Other Subsea Structures Fabrication**	**397 days**
159	**Glory Hole**	**353 days**
160	**Tender Process**	**114 days**
165	**Engineering**	**156 days**
167	**Construction**	**150 days**
173	**Drilling**	**1363 days**
174	**Engineering**	**578 days**
179	**Procurement (Rig Contract)**	**492 days**
187	**Well Construction**	**720 days**
198	**Subsea Installations**	**123 days**
205	**Offshore Hook-up and Commissioning**	**65 days**
209	First Oil	1 day



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It will be noted that the schedule implies the initiation of some project activities before the actual approval of the DA by C-NOPB. Husky Oil and Petro-Canada believe that it may be necessary to proceed on this basis to obtain the information necessary for a project sanction decision which will be evaluated subsequent to a DA decision.

Accordingly, in setting this schedule, Husky Oil and Petro-Canada adopted several objectives which they wished to reflect. These were:

- **Continuity of employment for those Newfoundland personnel involved in the engineering and fabrication aspects of the offshore oil and gas industry.** These are important aspects both for the Newfoundland economy and for project economics. Accordingly, the start of engineering will commence after the engineering on the Terra Nova project is completed. This will enable the skilled personnel then coming available from Terra Nova to become a resource pool for White Rose. The opportunities for local fabrication will follow thereafter as the engineering phase proceeds and procurement contracts are bid and awarded.
- **Early First Oil date.** This is an important financial consideration for Husky Oil and Petro-Canada, inasmuch as an early as practical First Oil date impacts on the ROR on investment for White Rose, which has fewer recoverable reserves than other fields on the Grand Banks. In this regard, the selected choice of the steel FPSO is the optimum both for time to First Oil and for capital cost.
- **Long lead items.** The target First Oil date dictates that some action on long lead items, such as work leading up to identification of contracts related to procurement of the FPSO, must be initiated in sufficient time to have the long lead items available and incorporated without jeopardizing the target First Oil date.
- **Contractor input.** Husky Oil and Petro-Canada recognize that much valuable knowledge of, and ability to contribute to, the various elements of offshore oil developments such as White Rose, rests with contractors skilled in specific areas. Husky Oil proposes to take full advantage of such experience and is already invoking such participation with respect to FPSO leasing and glory hole construction.
- **Weather windows.** The planned schedule also takes account of appropriate weather windows, particularly for the subsea installation and tie-in.

Husky Oil is currently proceeding with advancement of the White Rose development in accordance with this schedule. The Company is, however, very mindful of the necessity for C-NOPB approval of its DA, and will continuously monitor the prudence of adherence to this schedule in light of the progress of the DA through the C-NOPB approval process.

10.3 Construction

Maximum use will be made of current technology and expertise. Contractor selection will be made having regard to prior relevant experience, commercial terms, quality and safety procedures, safety performance and Canada/Newfoundland benefits.

Details of the components of the production facilities are provided in Chapter 9. They consist of:

- steel FPSO;
- topside processing facilities;
- subsea equipment; and
- offloading system.

As well, three other major activities will be necessary for the execution of the project. These are:

- **Transportation**. The various components, and sub-components, will likely be constructed in various locations. They will require transportation to an assembly site.
- **At-shore Assembly and Hookup.** This work will be carried out at the at-shore assembly site. Components from the various construction locations will be assembled, completed, tested and commissioned to the maximum extent possible.
- **Offshore Hookup and Commissioning.** The FPSO will sail from the at-shore assembly site to the White Rose production location and be tied in to the subsea system. Final commissioning will be carried out and production start-up implemented.

10.3.1 New Steel Floating Production, Storage and Offloading Facility

The FPSO will be a steel, ice-strengthened, ship-shaped vessel with a double hull. Topside facilities will be installed primarily on a horizontal plane raised above the level of the vessel deck. The vessel will be moored by a turret, which will remain geo-stationary while the vessel will be free to "weather vane" around it. A fluid swivel will convey the crude from the risers to the topside production facilities.

10.3.1.1 Construction Method

Historically, the hull and topsides have been built in separate facilities in different locations. This is expected to be the case for White Rose also.

A modular approach is normal for fabrication of the hull. The size of individual modules is dependent upon the lifting capacity available at the shipyard.

The turret is essentially a cylindrical vessel and the manufacturing and assembly practices for the turret are similar to those applicable to such vessels. Structural sections are pre-fabricated and assembled, either on the hull or separately for later lift into place.

The topside facilities are normally manufactured in modules, PAUs or skids.

The hull and turret, topside facilities and all equipment are delivered to an at-shore assembly site for hook-up, mechanical completion and testing prior to proceeding to the production site.

10.3.1.2 Construction Sites

Husky Oil has researched the interest and current capacity of all shipyards that have necessary facilities and experience in the construction of FPSOs. Eleven shipyards were identified. All are modern shipyards with sufficient dry-dock to accommodate the vessel, together with adequate lifting capacity for large modules, and fabrication capacity adjacent to the dock.

The turret is a highly specialized fabrication limited to only a handful of companies world-wide. It is a distinct component applicable only to an FPSO. It requires substantial fabrication and labour commitment, and the construction site for it will be an existing facility operated by the company selected for supply of the turret.

The at-shore assembly site must have a quay for safe moorage of the FPSO. It should preferably be capable of carrying the loads imposed by mobile crawler cranes used in hook-up. If the quay cannot support such operation, barge-mounted cranes may be used.

10.3.2 Existing Vessels

Husky Oil is examining the option of purchasing an existing vessel/hull for use as an FPSO on White Rose. Such a vessel/hull must satisfy the same criteria of operational capability and longevity as would be applicable to a new-build, as well as satisfying the class and certifying authorities.

10.3.2.1 Construction Method

The extent of work required for an existing vessel/hull to be used as an FPSO will depend on the characteristics of the candidate vessel in terms of current condition, previous use, age, and design. The work would necessarily include an assessment of the vessel's structural condition, and removal of superfluous deck structures and equipment. The scope of work could include any or all of the following:

- upgrading of structural scantlings;
- upgrading of the cathodic protection system;
- upgrading of the mooring system;
- installation of additional sea chests for the upgrading of the cooling and fire water systems;
- ice strengthening;
- upgrading of lifesaving equipment;
- upgrading of fire and gas detection and firefighting systems;
- expansion of power generation system;

- upgrading of the accommodation module; and
- installation of new or additional topside equipment.

10.3.2.2 Construction Sites

The extent and nature of modifications required would bear upon the type of facilities needed to carry out the upgrades. If no hull modifications are required, the work could possibly be accomplished at quayside, without the necessity of dry-dock facilities.

10.3.3 Subsea Facilities

The following are the types of facilities that will be included in the subsea systems:

- subsea trees;
- production and injection risers;
- riser base manifold;
- field manifolds or templates;
- flowlines; and
- control systems and umbilicals.

10.3.3.1 Construction Methods

Flexible line production and injection risers, suitable for use in the harsh environment at White Rose, will be supplied by manufacturers using their proprietary manufacturing process. The risers are supplied fully equipped and tested, and ready to install.

Subsea manifolds and flowlines will gather the production and convey it to the risers. Manifolds include headers, piping, valves, and control equipment, mounted on a base.

Subsea wells will include the following:

- wellheads;
- casing hangers;
- hydraulic connectors;
- valve assemblies;
- guide frames;
- subsea trees;
- protective structures; and
- control systems.

Many proprietary well components will comprise high quality forgings requiring heat treatment, special welding procedures and precision machining. Tree installation will require special running and testing tools.

Flowlines will be either flexible or rigid steel pipe. Flexible flowlines will be prepared by the manufacturer, ready for installation. Rigid steel pipe will be manufactured by the mill in lengths appropriate to transportation and handling constraints, and the limitations of the lay barge. Consideration will be given to the option of installing the flowlines in cased bundles. In this case, the flowline bundle will be fabricated onshore at a suitable construction site. Another option which may be examined for steel pipe is welding them into long strings onshore and winding them on to spools on a reel lay vessel for offshore installation.

10.3.3.2 Construction Sites

The construction facilities required for manifolds or templates are a yard with enclosed shop, and adequate wharfage for loading them aboard the transport vessel. The yard should preferably have facilities for testing system integration. An appropriate quality assurance quality control system will be implemented.

If rigid pipe flowlines are selected, the method of installation will dictate the characteristics required for the construction site. For the towed bundle or reel approaches, the site would require a pipe storage yard, a fabrication shop and a pipeline assembly area of from 2 to 4 km in length.

10.3.4 Marine Support Vessels

Marine support vessels will be necessary components of the project at all stages of its development and operation. These vessels will be required for:

- standby duty;
- ice management;
- oil spill response;
- cargo and consumable resupply;
- anchor handling and mooring;
- tug assistance;
- towing;
- diving;
- subsea facility inspection and maintenance; and
- minor well workovers and maintenance.

The actual composition of the fleet will be determined during the project. Husky Oil proposes to lease marine support vessels.

10.3.5 Environmental Effects of Construction

It is currently expected that all of the construction activities associated with the various items in the foregoing, including the FPSO, will take place in existing established facilities. It is therefore expected that all such facilities will be already set up to manage such environmental effects as emissions, effluent streams, or noise. Compliance with regulatory requirements will be the responsibility of the contractors or facility owners/operators of the site.

10.4 Installation

On-shore support will be rquired for installation of the FPSO and subsea facilities.

10.4.1 Floating Production, Storage and Offloading Facility

The precise location for the FPSO will be marked by underwater beacons placed by site survey, or by other appropriate methods, prior to the arrival of the FPSO. Anchors and mooring lines will also be installed at the location in advance of the arrival of the FPSO.

Following construction, sea trials, and at-shore hook-up and commissioning, the FPSO will be brought to the site and secured to the mooring system.

10.4.2 Subsea Facilities

Depending on their size, manifolds may be installed either directly through the moonpool of a semi-submersible drilling unit or from the deck of a crane vessel with sufficient lifting capacity to lower them to the seafloor, where they could be picked up and placed by a drilling unit.

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

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

Flowlines will be installed during the summer weather window.

If flexible flowlines are used, they can be spooled off a dynamically positioned lay vessel. If steel flowlines are used, they can be installed from a lay barge or a dynamically positioned reel vessel. For the towed bundle installation method, two tow vessels will be required, one for the actual forward tow and the other for the trailing end.

10.4.3 On-shore Support

The offshore installation activities will require on-shore support for warehousing and wharfage, and for helicopter landing and refuelling.

10.4.4 Environmental Effects of Installation

The following is a list of the types of installation activity that may occur offshore:

- piled seabed anchors for the FPSO;
- embedded anchors;
- riser bases and risers;
- intrafield flowlines;
- production manifolds and templates in glory holes; and
- single well ice protection systems.

These activities will occur over a fairly limited area. Their impacts will be localized and only very moderate volumes of excavation or sediment will be involved. Further information on this may be found in Chapter 4 of the EIS (Comprehensive Study Part One).

Further detailed safety and environmental issues related to the installation and commissioning work will be addressed prior to implementation of that work as part of the authorization process.

Environmental effects monitoring programs will be implemented at this stage of the project.

10.5 Drilling Services

One or more semi-submersible drilling units will be used throughout the life of the field for drilling, re-entering and completing wells. These units will be leased.

The units will be moored at each well location by onboard chain and anchor-handling equipment. Marine support vessels, with anchor-handling capability, will also be deployed.

10.6 Quality Assurance and Quality Control

Husky Oil intends to implement a specific quality assurance system, across the whole development. It will be applicable to all contractors and suppliers in the conduct of their activities associated with the project. As well, Husky Oil will ensure that the conduct of all project tasks, and the quality of installation, are in accordance with applicable Canadian and Newfoundland offshore regulations.

Before going into production operation, Husky Oil will obtain the requisite Certificates of Fitness, and Letters of Compliance. An independent certifying agency will be engaged to monitor the project throughout its development phase and to confirm that the complete installation has been designed, constructed and installed in compliance with regulations.

Husky Oil will apply its Health, Safety and Environmental (HS&E) Loss Control Management Performance Standards to the White Rose project, with the purpose of minimizing unforeseen or accidental losses during the life of the project. These standards have been developed for the Company's East Coast operations, and mirror Company standards across the country while recognizing the unique nature of the marine environment. The standards are based on the International Marine Safety Rating System are described in more detail in Section 1.5 of the Safety Plan (Volume 5, Part One).

11 OPERATIONS AND MAINTENANCE

11.1 Organization

Husky Oil will manage the production and maintenance operations of the White Rose oilfield on behalf of itself and its co-venturer Petro-Canada from the Husky Oil office in St. John's, where the Operations Manager will be located. The day to day management and control of all offshore operations will be the responsibility of the OIM, who will be located on the FPSO. The OIM will report to the Operations Manager. Each MODU operating in the field will be managed and controlled by an Installation Manager, who will also report to the Operations Manager. The OIM on the FPSO will, however, take responsibility for routine coordination of all concurrent offshore operations.

11.1.1 On-shore Organization

The on-shore organization will be structured to provide total support for all normal offshore operations, during both the development phase and the production phase. The on-shore organization will include personnel with all the requisite skills, knowledge, and experience for ensuring thoroughly competent support to the offshore operation, including emergency situations. It will be focused on flexibility, efficiency and cost effectiveness.

The preliminary intended on-shore organization is shown in Figure 11.1-1.

The permanent core of the on-shore organization is expected to comprise some 45 to 50 people, with breakdown as indicated in Table 11.1-1.

In addition, there will be further personnel onshore in the following categories:

- helicopter air and ground staff;
- dockworkers and crane operators for supply vessel operations at the shorebase; and
- crews for the supply and standby vessels.

Offshore operations will be serviced by two helicopters. It is expected that this part of the operation will require some 20 to 25 staff, including flight crews, maintenance crews, and administrative support.

Each marine support vessel is forecast to have a crew of 10 to 12 people. Up to four vessels will be needed to service routine FPSO operation plus one drilling unit. Ice season requirements will call for deployment of further support vessel strength, as will the addition of further drilling units.

Figure 11.1–1 On-shore Organization

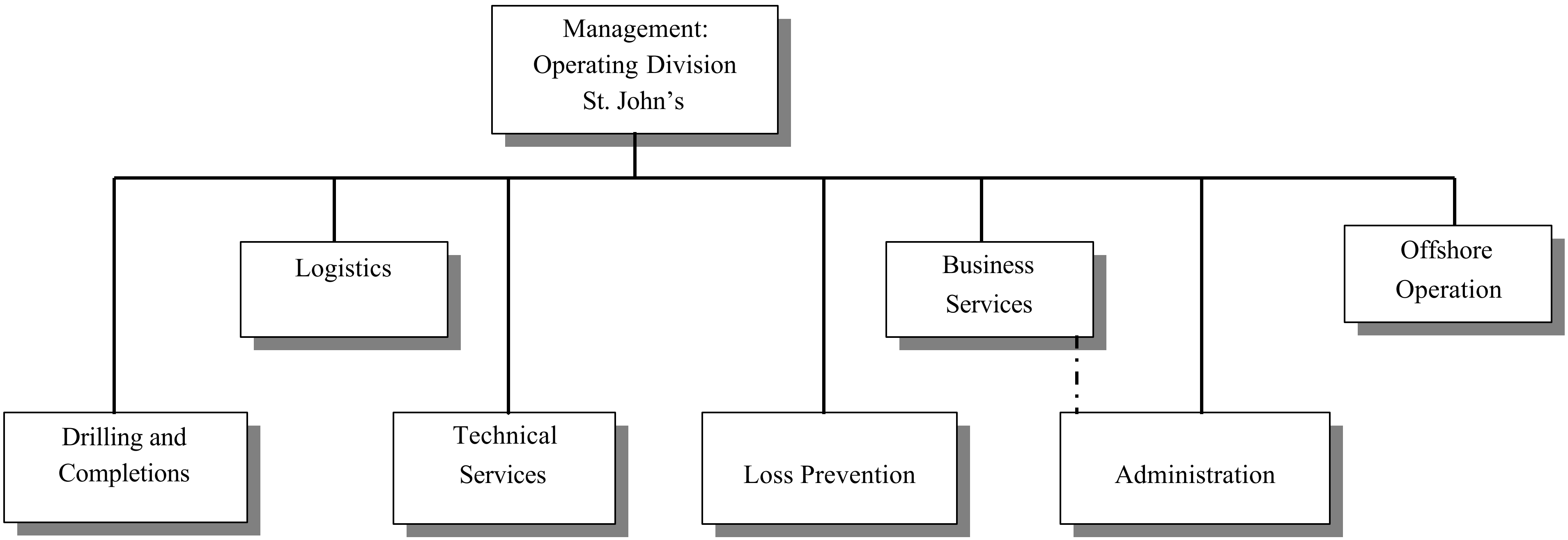


Table 11.1-1 Distribution of On-shore Personnel

Responsibility	Number of Persons	Function
Management	1	Operations Management
Drilling and Completions	3-4	Drilling Supervision Drilling Engineering Completions Engineering
Technical Services	15-16	Facilities Engineering Reservoir Engineering Geology Geophysics Petroleum Engineering Petrophysics Telecommunications Computer Services Maintenance Engineering Subsea Engineering Instrumentation and Controls
Logistics	11-12	Procurement Materials Transportation Crane Operation Radio Operation Yard Labour
Business Services	7-8	General Accounting Invoice Processing Production Accounting
Administration	5-6	Office Management Human Resources Public Relations Secretarial Services Reception Telephone
Loss Prevention	3-5	Loss Management Quality Assurance Quality Control Security
Total	45-50	

At dockside, the requirement for dock workers and crane operators is forecast at some six to eight people to handle servicing and turnaround for one supply vessel. Actual numbers will be dependent on the number of concurrent vessel servicing operations ongoing at dockside at any one time.

Husky Oil intends to examine the possibility, merits and feasibility of sharing some onshore servicing and support facilities with other operators, such as Hibernia and Terra Nova.

Husky Oil will hire additional temporary staff, either directly or via subcontractors, to cope with non-routine peak activity periods, such as shutdowns or special tasks.

The following describes the on-shore functional groups and their support activities.

11.1.1.1 Operations Management

The Operations Manager, who will be responsible for the entire operation, both technically and commercially, will lead this group. The Operations Manager will be responsible for issuing and implementing all Husky Oil policies.

11.1.1.2 Drilling and Completions

The drilling and completions department will plan and implement drilling and workover programs, and provide support during offshore drilling, workover, and well completion activities. It will be responsible for well and completion designs, and for obtaining Husky Oil, Petro-Canada and regulatory approvals. It will work with the drilling contractor to coordinate activities and scheduling.

11.1.1.3 Technical Services

This group will be responsible for supplying technical support for operations. It will provide engineering, geoscientific and maintenance services, together with document control, for:

- reservoir development planning, monitoring and management;
- engineering design;
- computer system support and development;
- telecommunication systems support; and
- technical support for production and operations.

Close liaison will be maintained with the drilling and completions group and the offshore group.

11.1.1.4 Logistics

This group will be responsible for the coordination of all logistical support to the project. This will include land and marine transportation, aviation services, and ice and weather surveillance. The warehouse, marine base, pipeyard, and 24-hour radio and communications links will be operated by this group. It will also provide coordination services to the loss management group in support of ice management operations.

The group will also be responsible for procurement activities, including expediting and inspection, as required.

11.1.1.5 Business Services and Administration

This group will be responsible for the administration of all contracts and agreements, accounting and financial reporting. Its responsibilities will include co-venture accounting, coordination of departmental budgets, financial management, hydrocarbon accounting, reporting on Canada-Newfoundland benefits, and audit management. It will also supply provide support related to employee relations, industrial relations and organizational effectiveness of internal and external committees. It is also expected that responsibility for crude movements and transportation, tanker scheduling, and administration of royalty obligations will be assigned to this group.

11.1.1.6 Loss Management

The scope of this group covers all matters related to health and safety, environment, process hazard management, risk assessment and loss prevention. The group will implement HS&E policies to encourage achievement of the optimum operating conditions with respect to health, safety and environment.

The group will establish and maintain channels of communication with appropriate external organizations required to support safe and environmentally responsible operations. These organizations will include the police, Canadian Coast Guard, and environmental protection agencies.

The group will also be responsible for ensuring that adequate and rigorous quality assurance and quality control policies and procedures are in place. The group will monitor and audit adherence to these policies and procedures.

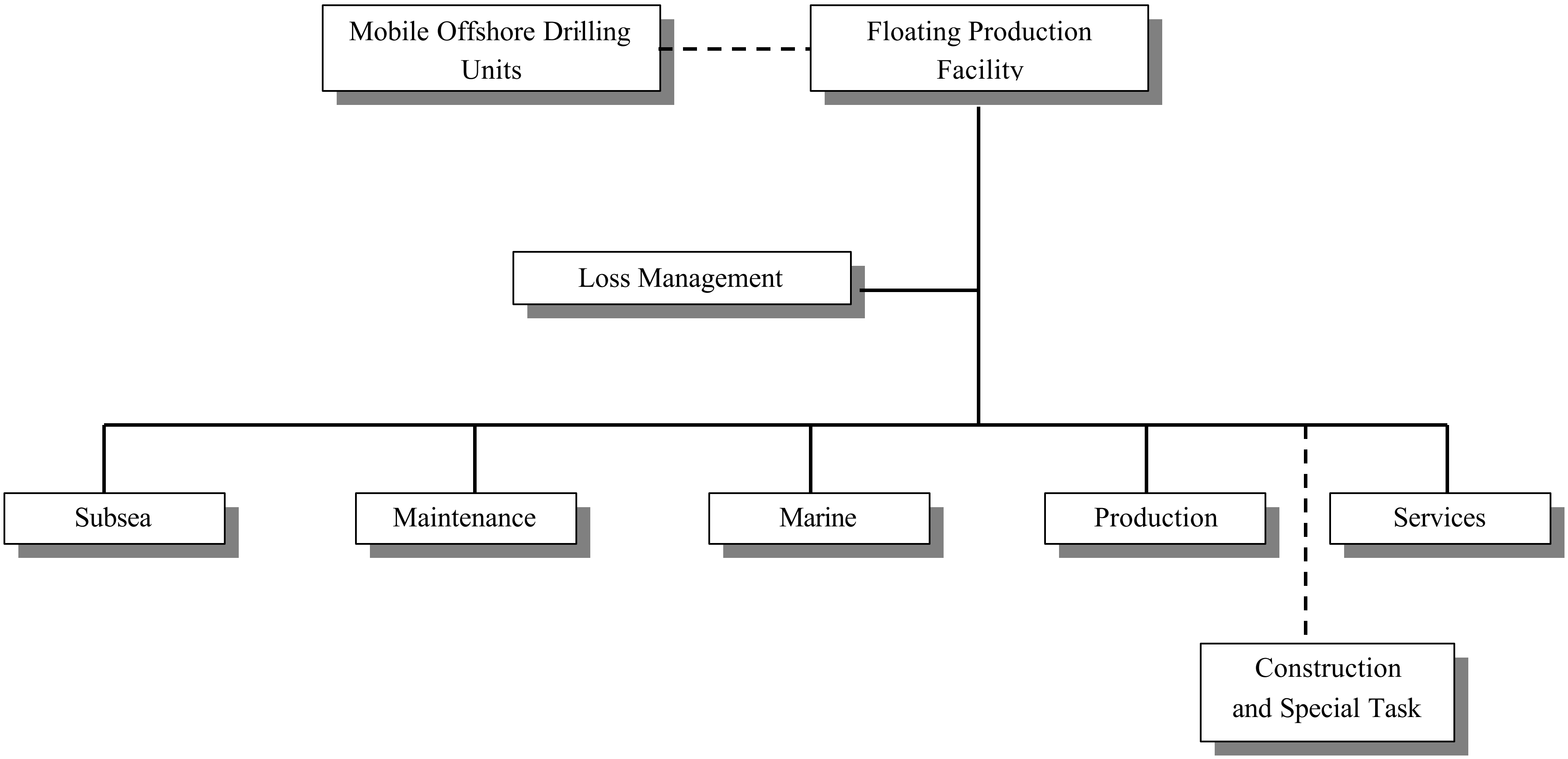
Security will also be the responsibility of this group. This will entail preparation and implementation of appropriate security procedures aimed at protection of personnel and equipment at all locations, both offshore and onshore. The group will liaise closely with the police in the implementation of this task.

11.1.2 Offshore Organization

The offshore organization will consist of skilled personnel in all disciplines required for safe, efficient, and environmentally responsible operation of all offshore facilities. The preliminary proposed organization is shown in Figure 11.1-2.

The OIM will be responsible for management of the FPSO. This will include the routine operation of the production facility and all related activities.

Figure 11.1–2 Offshore Organization



All drilling will be carried out by semi-submersible drilling units, each of which will be the responsibility of a dedicated Installation Manager onboard. The FPSO OIM will, however, have responsibility for coordination of all offshore activities. These include drilling workover, diving and ice management, in addition to the FPSO-related activities of production, storage, offloading and shipping.

The drilling semi-submersible Installation Manager will be responsible for the safe and efficient operation of that unit in accordance with the Drilling Program Authorization (DPA), Approval to Drill Well (ADW), Well Operations Authorization (WOA), or Approval for Well Operations (AWO) applicable to that well program. The semi-submersible Installation Manager will report to the Operations Manager, located on-shore in St. John's.

To ensure that all responsibilities concerning simultaneous offshore production and drilling are clearly understood, Husky Oil will prepare a manual specifically for this purpose. It will address the interfaces, particularly communications, between the FPSO and the various other units operating simultaneously offshore in both routine and emergency conditions.

A primary aim in the formulation of the offshore teams will be to foster teamwork and efficiency. This will be achieved by selection of personnel with appropriate production or marine skills and experience, coupled with cooperative positive attitudes and demonstrated competence. Multi-tasking of personnel will also be an aim, both to increase flexibility and effectiveness and to provide personnel with an enriched work environment. This cross-functional strength will be accomplished by providing regular training.

11.1.2.1 Floating Production, Storage and Offloading Facility

The crew complement for the FPSO is expected to be approximately 45 to 50 at any one time. Provision for rotation requires that this number be doubled, giving an FPSO staff strength of some 90 to 100 personnel. The likely breakdown of categories and numbers of personnel who will make up the FPSO team is shown in Table 11.1-2.

Table 11.1-2 Distribution of FPSO Offshore Personnel

Responsibility	Number of Persons	Function
Management	1	Offshore Installation Manager
Loss Management	2	Loss Prevention Advice Environment Advice Medical Services
Production	6-7	Supervision Control Room Operators Production Operations
Marine	6-7	Marine Supervisors Marine Operations
Maintenance	14-15	Supervision Instrument Maintenance Mechanical Maintenance Electrical Maintenance Telecommunication Maintenance Maintenance Scheduling
Services	16-18	Supervision Helideck Loading Deck Crew Supervision Deck Crew Operations Crane Operations Radio Operations Ice and Weather Surveillance Catering and Accommodations Services
Total	45-50	

There will be an occasional requirement for construction or other specialized personnel offshore to perform upgrades, repairs, or modifications to equipment or systems. The work to be performed by such personnel will normally be planned and scheduled for minimal impact on production. Where necessary, due to unforeseen circumstances arising offshore, they will be mobilized on an ad hoc basis. The numbers of such personnel will depend upon the scope of work to be performed. As far as possible, personnel already onboard as part of the maintenance group will be used in support of the such activities.

The offshore operation will be provided with engineering support by the technical services group. This support will be for specific tasks, or investigation and solution of process problems, and will be on an ad hoc basis.

The following describes the offshore functional groups.

Offshore Installation Management

The FPSO will be managed by the OIM. The OIM will be responsible for coordinating all activities on the FPSO, as well as other activities such as drilling, diving, workovers, and shipping, ongoing in the field. The OIM will be in command in all emergency conditions, and will be the primary communications conduit to the Operations Manager in St. John's.

The OIM will retain control and responsibility for the FPSO as long as the production system remains connected and the vessel is on station. When it becomes necessary to disconnect, the OIM will prepare the production system for disconnection and then hand over control to the senior marine officer for control of the disconnection. The senior marine officer will remain in control until the vessel has been reconnected. Control will then revert to the OIM.

Loss Management

Loss management personnel will be available for providing support to line management in the implementation of all safety and environmental policies and procedures, and development and implementation of emergency exercises and drills.

Loss management personnel will also coordinate implementation of the ice management plan in association with the services group and will also assist in conducting offshore safety and environmental inspections and audits, and performing accident and incident investigations.

First aid services will be provided by an onboard medic, who will be qualified and trained to regulatory requirements. Other operations personnel will be trained in advanced first aid and will support the medic, as required. First aid drills and medical escort training will be coordinated by the medic, who will also be responsible for implementing the company's health awareness programs.

Production

The FPSO will be a highly automated facility, controlled by an integrated control system from a Central Control Room. There will be minimal routine manual operation, and production staff will be trained for other tasks besides production, such as in marine or maintenance functions.

Production will be on a round-the-clock basis and staffing will be on a shift basis to accommodate this.

Marine

This group will be responsible for all activities related to vessel operation, including propulsion, thruster and ballasting operations, maintenance of vessel stability, monitoring of mooring loads, deck loading, and station keeping. This group will possess within its members all necessary marine qualifications and experience to meet Canadian Coast Guard and Transport Canada requirements. Such members will also liaise with, and lend assistance to, the Maintenance group to ensure optimum performance and reliability of the marine equipment and systems.

Maintenance

This group will be comprised of personnel trained in mechanical, electrical, instrumentation and communications maintenance. The majority will be trained to operate on a cross-discipline basis. They will work closely with the marine group, as indicated above, to ensure safe, reliable operation of vessel systems.

Routine maintenance operations and major shutdowns will be planned and scheduled by the group.

The group will also liaise, and participate to the highest degree possible, with construction and specialist personnel to ensure efficient use of manpower during upgrading, repair or modification tasks.

Services

This group will be responsible for all other activities necessary for an efficient offshore operation. This will include personnel dedicated to logistical, material, personnel movements, and catering. The group will coordinate other vessel movements, including those of supply and standby vessels, helicopter services, deck and crane operations, radio and communications operations, diving operations, catering, housekeeping, and accommodation management.

It will also be responsible for environmental monitoring and ice surveillance and coordination of the ice management plan under direction of the OIM.

11.1.2.2 Mobile Offshore Drilling Unit

Each drilling vessel will require some 70 to 100 drilling and support staff during drilling operations. To provide for rotation, this means a requirement of some 140 to 200 personnel per drilling unit.

11.2 Operations and Maintenance Procedures

Operations and maintenance procedures and manuals will be implemented specifically for the White Rose development. They will make provision for compliance with all regulatory requirements, and personnel will be trained to operate in accordance with the manuals and procedures.

The procedures will be finalized as requisite information becomes available (for example, systems and equipment operations and maintenance manuals after vendor selection and receipt of equipment/system documentation) and will cover the following topics:

- systems;
- equipment;
- reporting relationships and procedures;
- maintenance procedures;
- production and marine procedures;
- ice management procedures;
- health and safety procedures;
- emergency procedures;
- alert and contingency procedures; and
- environmental monitoring procedures.

Documents will be developed on a hierarchical basis to facilitate ease of use by personnel. The basic documents will be developed in the detailed design phase. They will then be augmented by the various user groups to customize them to their particular needs, all the while maintaining strict compliance with regulatory requirements.

11.2.1 Systems

Systems manuals will provide descriptions and drawings of the primary process, ancillary systems, and associated equipment and subsystems. The rationale behind the design will be presented. Operating parameters will be set out. Operator training manuals will be based upon these documents.

11.2.2 Equipment

Detailed information on each individual piece of equipment and each system and subsystem will be assembled and incorporated into data books. Such information will be drawn from vendor sources, design specifications and operational record. It will include drawings, specifications, descriptions, materials, installation guidelines, operation and maintenance guidelines, and recommendations on spare parts inventory.

11.2.3 Reporting Relationships and Procedures

Roles, limits of authority, lines of reporting and accountabilities in production operations will be set out in reporting procedures and where applicable bridging manuals. These will clearly identify reporting relationships throughout the organization as well as with external agencies.

The procedures for record-keeping will be set out in the manuals, together with requirements for report generation and distribution and data acquisition.

Operating and maintenance records will be documented as required by Husky Oil and governing regulations. Requisite reports will be produced routinely.

11.2.4 Maintenance Procedures

Maintenance procedures manuals will be prepared for all equipment. These procedures will be based on design data, recommendations by vendors, operating conditions, and the importance of the equipment to operation of the facility. This latter aspect will be based on the effect of failure of the item of equipment on personnel safety, environmental consequences, operational efficiency, and revenues.

The maintenance program will be extensively supported by computerized systems, providing detailed information on each item of equipment, including its criticality, maintenance history, and spares to be kept in inventory. The system will also be linked to an inventory control system.

The basic significant features of monitoring, inspection, and maintenance and repair, will be recognized in the program.

11.2.4.1 Monitoring

All structures and equipment will be monitored routinely as a planned part of the maintenance program. Sensors and monitoring devices will be used as part of the program. Also as part of the overall monitoring program, the integrity of the following aspects of the FPSO will be monitored, using on line monitoring systems:

- structural components;
- sub-structural components;
- equipment condition;
- corrosion rates; and
- vessel stability.

11.2.4.2 Inspection

All structural elements, piping and equipment will be inspected regularly and comprehensively to ensure their integrity. The degree of inspection will be predicated upon the item's criticality to the operation, its vulnerability and service, operating conditions, vendor recommendations, and feedback from the monitoring systems.

Inspection will be accomplished by one or more of the recognized techniques of visual inspection, non-destructive testing, operational parameter monitoring, vibration monitoring, and field and laboratory tests.

The main areas of attention will be:

- structural;
- pressure containing systems;
- rotating equipment;
- subsea systems;
- lifting equipment; and
- life saving equipment.

11.2.4.3 Maintenance and Repair

The focus of this activity is to maintain the facility in optimum condition to ensure safe and continuous production operations. Three categories of maintenance and repair are recognized:

- preventative maintenance;
- predictive maintenance; and
- breakdown maintenance.

How a particular piece of equipment is categorized depends on its criticality to safety and operations (for example, safety equipment and systems will be in the top category), and every effort will be made to avoid incurring situations where these have to receive maintenance on a breakdown basis.

The procedures will also cover the monitoring and control of ice build-up on the various structural components of the FPSO.

The maintenance and repair program will be supported by a computerized support system which will record maintenance history, maintenance costs, item availability, and breakdown frequency.

11.2.5 Production and Marine Procedures

This procedures manual will deal with the safe and efficient operation of the FPSO for all facets of production and marine-related activities. It will describe in detail how the following will be carried out or managed:

- process start-up and shutdown;
- routine production;
- operations limits;

- adverse weather conditions;
- crude storage and shipment; and
- marine activities.

11.2.6 Ice Management Procedures

Husky Oil already has an Ice Management Plan in place for its exploration operations on the Grand Banks. Husky Oil will review and update, or modify, this plan as appropriate for application to the production phase of the White Rose development.

Ice management procedures will set out clearly the steps and responsibilities for ice surveillance, monitoring and reporting. The procedures will be structured to include cooperation with other operators and government agencies in their concurrent ice surveillance and management operations on the Grand Banks. All available ice intelligence information sources will be used to ensure the well-being of the facilities offshore.

The steps necessary for avoidance of iceberg collision or excessive sea ice pressure will be detailed in the procedures. This will include how the following will be accomplished:

- disconnection of production risers;
- disconnection and flushing of loading lines; and
- repositioning of the FPSO.

Further discussion of the ice management plan will be found in Section 11.3.

11.2.7 Health and Safety Policies and Procedures

As outlined in the Preliminary Safety Plan (Volume 5, Part One) Husky Oil will implement health and safety policies and procedures for the White Rose development that will meet or exceed all statutory requirements, and ensure continued health and fitness of all employees. Operational characteristics and conditions will be monitored, and modified if required, to minimize the risk to employees of occupational injuries or illnesses and to minimize exposure to excessive noise, heat, radiation or vibration. Particular attention will be paid to providing proper adequate ventilation and to ergonomics. Programs will be developed to promote occupational hygiene, enhance the well-being of personnel, and prevent accidents.

The procedures will provide for the safe handling of hazardous materials according to the requirements of Workplace Hazardous Materials Information Systems (WHMIS). All employees will be trained to ensure complete awareness and understanding of this aspect of the procedures. The environmental management system will include a section on chemical management.

Safety will be designed into the facility via active and passive protection systems. Hazard and operability studies (HAZOPS) will be an essential work item at key stage of design. Their purpose will be to identify hazards, forecast the consequences, eliminate or ameliorate the causes, and devise options for mitigation to the maximum practical extent.

Particular emphasis will be placed on the procedures developed with respect to the fire and gas monitoring system. This system will be the main means of process hazard detection, and will have a direct interface with the emergency shutdown system and active protection systems.

Safety procedures training will be provided to every employee, and records will be maintained on the training courses provided to each employee, together with the dates on which they were provided.

11.2.8 Emergency Procedures

Procedures will be implemented to address every kind and scale of emergency that might reasonably be expected to arise on the FPSO or other offshore facilities. The procedures will detail the steps to be followed for each type of emergency, from a minor emergency situation to complete evacuation of the FPSO. Personnel both on-shore and offshore will be assigned membership in an emergency team and will be trained to perform their specified function in that team. Regular drills will be held onboard to maintain the currency of the individual and team response capability. Teams will include, but not necessarily be limited to:

- fire;
- first aid;
- lifeboat and coxswain;
- helideck;
- person overboard;
- emergency command centre control; and
- marine emergency.

11.2.9 Alert and Contingency Procedures

Standard operator's procedures will be implemented to respond to alerts and potential emergency situations. The procedures will describe how contingency measures will be initiated in the event of an imminent or possible problem condition.

The procedures will have the aim of assembling all available information concerning the problem so that it can be analyzed by the OIM, and used by the OIM to make informed decisions concerning appropriate courses of action.

The procedures will be so structured that they produce a sufficient amount of information to enable the OIM to avoid proceeding unnecessarily from an alert situation to an emergency situation. The following are examples of the kind of conditions that could trigger an alert situation:

- loss of monitoring capability on critical systems;
- severe wind forecast;
- severe sea forecast;
- heavy sea ice;
- possible iceberg impact;
- possible vessel impact;
- potential loss of well control;
- icing on superstructure; and
- system impairment conditions (loss of mooring chain).

The OIM will be responsible for determining which contingency procedures are to be implemented in response to each specific alert. The OIM's decision will be based on the information to hand and the potential risks arising.

The OIM will retain control and responsibility for the FPSO as long as the production system remains connected and the vessel is on station. When it becomes necessary to disconnect, the OIM will prepare the production system at the time of disconnection and then hand over control to the senior marine officer for control of the disconnection. The senior marine officer will remain in control until the vessel has been reconnected. Control will then revert to the OIM.

11.2.9.1 Environmental Monitoring Procedures

The environmental monitoring procedures will be developed to ensure compliance with the environmental monitoring program and are discussed further in Chapter 7 of the EIS (Comprehensive Study Part One).

The prime purpose of these procedures will be to minimize exposure of personnel to risk, protect the environment, protect the asset, and facilitate safe operation. The following are the key environmental factors that will be addressed in the procedures:

- pollution prevention;
- oceanography;
- meteorology; and
- waste management.

11.3 Ice Management Plan

As indicated earlier in Section 11.2.6, Husky Oil has an Ice Management Plan in place for its offshore exploration program. This plan will be reviewed and updated, or modified, as appropriate, for application to the production phase of the White Rose development. Such an update will draw upon the experience of other operators on the Grand Banks, together with the latest techniques and developing technologies, to produce the optimum plan for ice management for the White Rose development. It will cover both sea ice and icebergs, and will be flexible in recognition of the fact that the sea ice and iceberg conditions at the White Rose area vary considerably from year to year.

Husky Oil participates in the Regional Grand Banks Ice Management Plan. This is a joint plan of all the operators on the Grand Banks, and provides for:

- coordination of ice and iceberg detection, monitoring and trajectory projection; and
- coordinated management of response actions to icebergs transiting the areas.

The iceberg season for the Grand Banks averages 3.5 months, covering the period from March to June. Icing and iceberg frequencies and criteria are outlined in Chapter 8, as well as in the EIS (Comprehensive Study Part One).

Sea ice may be encountered from the beginning of February until the end of April. Mean sea ice concentrations have large regional variations, with the greatest concentrations being through the Avalon Channel and the Flemish Pass. Although March is the most critical month for the Grand Banks area, the ice only encroaches on this area in the most severe ice coverage years.

Icing of a structure and substructures, and above the water line on support vessels may occur from November to April if the air temperature drops below -3°C and the winds exceed 17 knots. Normally, icing is generated from sea spray although it can also be caused by freezing precipitation. Based on operational experience to date, icing does not present any restriction to operations, but it may impact helicopter and support vessel activities.

11.4 Operational Limits

The limiting conditions imposed by environmental factors on the structure and associated systems will be largely predicated upon the final design criteria adopted for the FPSO and equipment specification.

The criteria selected for equipment and system redundancy and availability, scheduled maintenance, and unscheduled shutdowns and breakdowns will also directly impact upon operational efficiency.

11.4.1 Limiting Conditions on the Structure and Facilities

Environmental factors could impose limitations on the following operations:

- station-keeping ability;
- deck loading;
- bulk storage;
- crane operation;
- helicopter movement;
- ice management; and
- crude storage and tanker loading.

11.4.2 System and Equipment Efficiency Limits

The White Rose facility is expected to have a system efficiency in the range of 90 to 94 percent. This is consistent with experience on similar operating facilities in the North Sea and elsewhere.

The efficiency may be impacted by factors such as:

- equipment failures;
- environmental factors;
- reservoir performance; and
- well performance.

11.5 Logistics

Husky Oil intends to investigate all possibilities of cooperation with other operators in the prospective use of shared services and facilities to support offshore operations. Where synergies exist, it is highly probable that cost savings on this aspect can accrue to all parties.

11.5.1 Marine Base, Warehousing, and Storage Yard

The marine base will be located in or near St. John's. The wharfage should be capable of servicing two to three supply vessels concurrently. Synergies with other East Coast operators will be investigated.

The base will require sufficient handling equipment in cranes, forklifts and winches to support the three-vessel loading/offloading operation. It must similarly also be capable of handling the bulk materials, mud, cement, fuel, and water for up to three vessels concurrently.

The warehouse and pipeyard will preferably be located at, or close to, the marine base. Non-availability of suitable land may preclude this, in which case it will be necessary to have these at a remote location, and trucking between that location and the marine base will be necessary.

11.5.2 Support Vessels

The number and range of support vessels required will be determined after the complete design of the offshore facilities. Vessels will be required for two primary purposes:

- support services on location; and
- transportation between the marine base and offshore facilities.

The support services on location will cover:

- anchor and mooring-chain handling;
- iceberg surveillance, towing and deflection;
- shuttle tanker mooring assistance;
- environmental monitoring;
- oil spill response;
- diving support;
- subsea inspection and maintenance; and
- standby service:
  - person-overboard,
  - on-scene command,
  - search and rescue, and
  - emergency evacuation.

Transportation services between the marine base and offshore facilities will require:

- cargo and bulk re-supply; and
- personnel transportation (marine).

Fleet configuration will be finalized after completion of the field depletion plan and design engineering for the FPSO. Vessels will be continuously available in the field for standby duty in accordance with regulatory requirements. Supply vessels will convey materials, consumables and equipment to and from the offshore facilities.

All personnel staffing the support vessels will be fully trained in emergency duties. There will be routinely scheduled emergency drills and exercises.

11.5.3 Material Procurement and Movement

Husky Oil will adopt a philosophy whereby a minimum spares inventory is maintained consistent with the avoidance of adverse impact on production. To this end, all equipment components will be critically assessed to ascertain maximum and minimum spares requirements. This assessment will determine where the spares should be located. This will be in accordance with the priorities assigned to them. Safety equipment and equipment critical to production will be assigned high priority and will be stored where they are easily accessed and readily available.

11.5.4 Personnel Movements

Personnel movements between St. John's and the field will normally be carried out by helicopter. It is expected that a fleet of two helicopters will be sufficient to meet the needs of conveying the 500 (250 offshore at any one time) production, drilling, and support personnel to and from St. John's and the respective offshore facilities. This is based on a scenario which includes ongoing production in conjunction with two drilling units operating concurrently.

Husky Oil intends to investigate the potential benefits of cooperation with other operators in this regard.

11.5.5 Diving Requirements

Husky Oil intends that diver intervention will only be used infrequently for certain specific underwater operations that cannot be achieved by ROVs.

Husky Oil intends to contract diving services out to a company which will have extensive demonstrated experience and competent performance in subsea production operations. That company will be required to assign a fully qualified and competent superintendent to direct and control the operation. Husky Oil will also place a diving representative onboard to monitor the diving program.

Husky Oil and the diving company will jointly implement the diving procedures manual. The manual will be structured to be compliant with all statutory diving and safety regulations.

11.6 Communications

Communications means all systems, both internal and external, that transmit voice, data, video or image information. Husky Oil will require such communications linkages between all of its facilities both on-shore and offshore on the White Rose project.

System reliability will be paramount for the safety of all offshore operation. Primary and back-up systems will be used to ensure continuous communications capability amongst all facilities in all environmental conditions.

The system components will be state-of-the-art, multi channel and will have adequate redundancy for their purpose. The actual configuration will be finalized at a later date, but is expected to based on the system currently in use by Husky Oil. In such case, the system will comprise elements as described in the following:

- FPSO and MODU/Shore Link

  Communication will be operated from a satellite earthstation in St. John's. The offshore ends of the system include a stabilized base satcom earthstation installed onboard the FPSO and MODUs, with space segment supplied by Telesat Canada's Anik E-2 satellite. The stabilized C-Band earthstation on the FPSO and the MODUs provides wide band digital services including 256 kbps of aggregate bandwidth that is subdivided into discrete voice and data channels.

  The C-Band service includes multiple platform-to-shore trunks, Group 3 digital fax service and local area network (LAN) service connectivity to the Husky Oil Operations LAN/PABX in St. John's.

  Husky Oil Operations satcom communications are down-linked through a St. John's CUF C-Band teleport. This will provide local St. John's dial-tone extended to the FPSO and the MODUs.

- Telephone System

  Telephone service on board the FPSO and MODUs, and at the Husky Oil St. John's office, will use standard services. Centrex lines from the FPSO and MODUs, and the St. John's office, will terminate in a Centrex Group at the switching centre in St. John's.

  Centrex lines will terminate on a Key Telephone System on the FPSO and MODUs. This will allow the offshore telephone lines to appear on multiple telephone sets on the FPSO and MODUs, and will allow for extension to extension calling on the FPSO or MODUs. The back-up line will terminate on the Centrex group at the Husky Oil Operations St. John's office, but will bypass the Key Telephone System on the FPSO or MODUs to provide "hot-line" protection in the event of a key system failure.

  There will be a number of direct lines which bypass the switchboard. These will be used for emergency only. They will be located throughout the office and will be activated when required.

- Local Area Network (LAN)

  The satellite communications system will include an Ethernet LAN for the Husky Oil Operations Offices in St. John's, extended to the FPSO and MODUs using a gateway over the C-Band satellite link. The LAN hubs at the St. John's office and on the FPSO and MODUs will communicate by routers at each location. The routers will address and route data between the FPSO, MODUs and shore-side devices over the link.

- Ship Radio System

  The communications system will meet the current Global Marine Distress Signalling System (GMDSS) standard and also will supply required air/ ground/air VHF radio equipment.

  The GMDSS radio station will be a complete system, including two HF/MF radios, VHF marine radios with digital selective calling, emergency position indicating beacon, and search and rescue transponder equipment for service in Ocean Area A3.

- Air/Ground/Air VHF Base Station

  One air/ground/air VHF AM base station transceiver will be installed in the radio rooms of the FPSO and MODUs. This system is used by the radio operators on the FPSO and MODUs for short-range voice communications with helicopters on arrival at, and on departure from, the FPSO or MODUs.

- Air/Ground/Air VHF Hand-held.

  Two air/ground/air VHF AM hand-held radios will be supplied for the helicopter crews on the FPSO and MODUs.

- Non-directional Beacon

  A non-directional beacon will be installed on the FPSO and MODUs. These beacons will be used by helicopter aircrews to home in on the FPSO or MODU, using radio detection finder equipment installed in the helicopters.

- VHF Radio System

  A VHF radio base station will be installed on the FPSO and the MODUs. This will also include a fleet of hand-held VHF radios. This network will be used for loading/offloading supply boats and for other local voice communications in the immediate area of the FPSO or MODU.

- Shore Base Radio Station Services

  The FPSO and MODUs will use a St. John's operations centre for marine and aeronautical coast station services. Services provided via this facility include marine vessel tracking, helicopter flight following, emergency response call-out services, and 24-hour per day monitoring of the Operator standby HF radio channel for routine and emergency response communications.

- Recording Equipment

  Offshore voice communications during an emergency will be recorded by the St. John's operations centre to assist in incident investigation following an emergency.

11.7 Contingency Plans

11.7.1 Emergency Response Plan

Husky Oil has a comprehensive detailed East Coast Operations Alert and Emergency Response Plan (AERP). Existing facilities and locations operated by Husky Oil and its contractors are currently covered by this plan. As changes are made to facilities, locations, and contractors, the plan will be continuously updated.

An emergency is defined as an unexpected occurrence either resulting in, or having the likely potential to result in, death, serious injury or illness requiring hospitalization, environmental impact posing a serious threat to on-scene personnel or wildlife, or major and significant damage to property. The following are examples of possible emergency situations which will be covered by contingency planning:

- an accident which results, or could result, in loss of life or serious injury (for example, diving accidents, person overboard);
- explosions or major fires;
- loss of well control;
- hydrocarbon or chemical spills,
- loss of, or damage to, helicopters or fixed wing aircraft;
- loss of, or damage to, support or standby vessels;
- loss or disablement of FPSO or MODU;
- loss of FPSO or MODU ballast control or stability;
- hazards posing an imminent threat to the operating area, such as heavy weather, sea ice, icebergs, or potential collision with an ocean-going vessel;
- major damage to equipment not caused by any of the above (for example, materials handling equipment failure); and
- security related incidents involving issues such as extortion, bomb threat, or acts of terrorism.

11.7.1.1 Emergency Response Organization

The organization used by Husky Oil for its 1999 and 2000 drilling programs is shown in Figure 11.7-1. A similar organization will be implemented during the drilling/FPSO operations for the development and production operations phases.

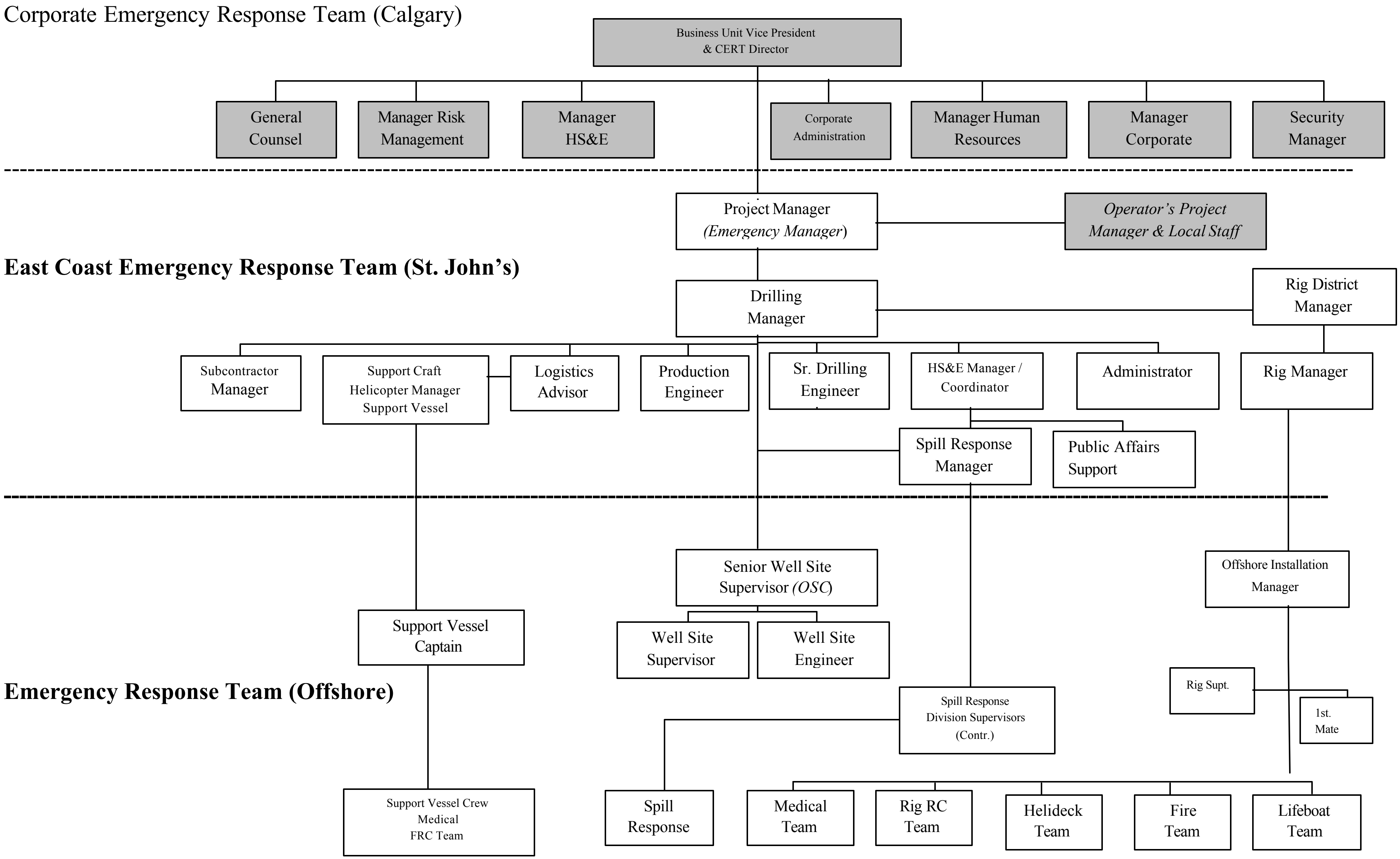
The responsibilities of the Emergency Response Team will include:

- assisting the on-scene emergency action teams by obtaining personnel and equipment resources as required;
- addressing family, public and employee communications issues;
- liaising with government and regulatory authorities;
- addressing engineering and other technical issues related to the emergency;
- addressing accounting;
- addressing insurance issues;
- addressing logistics and procurement issues; and
- addressing loss control (HS&E) issues.

Offshore emergency response teams will include:

- technical operations team;
- medical team;
- fire team;
- helideck team;
- lifeboat team;
- FPSO rescue craft team;
- MODU rescue craft team(s);
- fast rescue craft team; and
- spill response team.

Figure 11.7–1 Emergency Response Organization Chart



11.7.1.2 Training and Exercises

All personnel will receive general response plan orientation and refresher training.

Specialized emergency response training will be provided for medical teams, offshore fire teams, evacuation/lifeboat teams, rescue craft teams, support vessel fast rescue craft teams, helideck teams, and spill response teams.

Scheduled regular emergency drills will be carried out, including FPSO or MODU abandonment, fire, person overboard, loss of well control, loss of ballast control, and use of rescue and breathing apparatus.

External groups or agencies will be familiarized with the overall AERP and their specific responsibilities under the plan.

A specific AERP training matrix will identify the main training topics, personnel roles, and type of training required.

Scheduled and planned AERP exercises will be conducted regularly, including communications exercises, tabletop exercises and logistics exercises.

11.7.1.3 Response Time

Husky Oil will plan emergency response in such a way that the actual response time to any emergency will be as expeditious as it can possibly be made. Personnel in all emergency response teams will be on call 24 hours per day. Key onshore personnel will be located in the St. John's area. Specialist personnel with skills pertinent to specific emergencies will be involved, as required.

11.7.1.4 Response Capability Improvement Initiatives

Husky Oil will cooperate with other operators and agencies in all emergency situations through resource sharing and mutual aid. Husky Oil currently has established mutual aid agreements with other operators, including the Hibernia Management and Development Company Ltd. (HMDC) and Petro-Canada, operator of the Terra Nova field.

Husky Oil will also participate in joint training exercises with other operators.

11.7.1.5 Environmental Emergencies

Contingency planning for the specific case of environmental emergencies is described in Chapter 6 of the EIS (Comprehensive Study Part One).

11.7.1.6 Response Considerations

Response to all incidents will be carried out in a consolidated integrated fashion. Each person involved in emergency response will know their emergency response role thoroughly, and will be fully conversant with the roles of others with whom they will interact.

Specific considerations will apply to specific situations. Examples include:

- Personal Injury or Fatality

  Notwithstanding that every effort will be made to avoid accident or injury to personnel, such events may occur in the offshore environment. These can range from injuries of a minor nature that can be treated offshore, through serious injuries that necessitate transfer to an on-shore facility, and in the worst case, personnel fatality.

  An offshore medic trained in trauma response will be provided on the FPSO and on the MODUs. This person will have the support, when required, of other personnel trained in advanced first aid and medical escort service. The emergency medical team will complement the medic, to the extent appropriate, with the following additional personnel:

  - Level 1 first aid attendants on the FPSO and MODUs and support vessels, trained to provide first response and basic first aid,
  - Level 2 first aid attendants on the FPSO and MODUs and support vessels, trained to provide more advanced first aid to the more seriously injured as needed,
  - A shorebased designated on-call physician trained in offshore oil and gas related emergencies available for medical consultation on a 24-hour basis.

  The onboard sick bay will be supplied with all equipment and medical supplies necessary to provide immediate first aid.

- Fire or Explosion

  Passive and active protection systems will be designed into the FPSO to mitigate as much as possible the potential effects of fire or explosion.

The fire detection system, whether automatically or manually activated, will initiate response to the fire or explosion, activating water deluge, foam, or carbon dioxide protective systems.

Trained fire teams will supplement the protective systems. All personnel will receive comprehensive training in fire team duties. The teams' state of readiness will be kept at top level by regular drills. Exercises simulating major emergencies will be carried out on a regular basis. To ensure optimum ability to respond to major offshore emergencies, support vessel crews and onshore personnel will also be trained in offshore emergency response.

- Vessel Collision and Structural Impairment

If, notwithstanding all vessel avoidance procedures, there is a collision between the FPSO and another vessel, structural impairment to some degree will be likely. Production will, in such instance, be immediately suspended pending an assessment of the damage sustained to the FPSO.

The OIM will decide what action should be taken after the degree of damage is assessed. Depending on the extent of damage, this may vary from a decision to resume production, through various intermediate choices, up to a decision to evacuate the FPSO.

All FPSO personnel will carry out weekly muster and lifeboat drills, and it will be a prerequisite for all offshore personnel to be trained in basic sea survival before going offshore. A selected number of offshore personnel will be trained as lifeboat coxswains.

- Heavy Weather

Heavy weather is deemed to apply when topside facilities have to be shut down due to vessel motion.

The OIM will take appropriate precautions in advance of the arrival of heavy weather. Producing systems will also be shut down in a controlled fashion. Wells will be shut in, tankers disconnected, cranes secured, and compressors shut down. If production is expected to be shut down for an extended period of time, the flowlines may be flushed to mitigate hydrate and/or pour point problems.

The OIM will be responsible for all decisions concerning courses of action during heavy weather.

- Oil Spills

The possibility of a serious oil spill is the major environmental concern in offshore operations. The risk will be reduced to as low as reasonably practicable level through the extensive monitoring procedures on the installation.

In the unlikely event that a spill should nevertheless occur, the spill response team will take the following actions, as appropriate:

- isolate or stop the leak by closing the line, tank valves, etc.;
- place absorbent pads on deck to prevent further contamination of the water body;
- boom spill and contain, if possible;
- recover product using skimmers;
- notify as soon as possible anyone working on or using the water body, in proximity to the release;
- if necessary, the local Oil Spill Response Contractor may be contacted for advice and/or assistance;
- collect samples, if safe to do so; and
- if the spill is significant, Oil Spill Response Procedures will be initiated.

• Loss of Well Control

Loss of well control, while unlikely, is more likely to occur during work being carried out from a drilling unit. This would include such activities as drilling, well completion or well workover. Therefore, in the event of loss of well control, remedial action will be implemented by the affected drilling unit in accordance with drilling and well control procedures. If circumstances so dictate, oil spill response action will also be implemented.

• Loss of Vessels or Helicopters

All vessels and helicopters will be required to advise the on-shore flight-tracking centre and offshore facilities of their position and status on a regular basis. In the case of aircraft, reporting will be required every 15 minutes. In the event that any vessel or helicopter becomes distressed, these reports will help identify its location, and hence, improve the speed with which aid can be brought to the scene.

In the event that such aid is required, all available resources will be immediately assigned to proceed to the last estimated location of the distressed unit.

All search and rescue organizations will be immediately contacted and appropriate communication channels established. A command centre will be set up at to assist the search and rescue operation.

• Subsea Flowline or Manifold Leaks

Monitoring of subsea flowlines and manifolds will be carried out by pressure instrumentation and by visual monitoring (for example, using a ROV).

In the event that a leak is detected, action will be taken immediately to shut in the flowline or manifold affected. If necessary, oil spill contingency response will be implemented.

- Diving Emergencies

  Diving activities in the field require close coordination with all operations currently occurring on the FPSO. Ongoing diving activities will require the suspension of all over-the-side work, restriction of offloading of supply vessels, and strict monitoring of suction inlets and discharge outlets.

  In the event of a diving emergency, the field diving superintendent will coordinate the emergency response. The FPSO OIM will provide coordinated support assistance from FPSO resources on request from the diving superintendent. As well, other field resources, such as vessels and helicopters, will be assigned as appropriate to assist on the request of the diving superintendent.

11.8 Vessel Surveillance and Collision Avoidance

Husky Oil already has vessel surveillance and collision avoidance procedures in place to protect personnel and facilities in its offshore drilling operations. These are part of its AERP and will be updated as appropriate to reflect the full production operation of the field.

Ocean-going vessels transiting the area of offshore operations may pose a threat to the moored FPSO or anchored MODUs. The crews of the FPSO, each MODU and each standby vessel will be required to maintain radar watch at all times to monitor vessel traffic in proximity to the FPSO and MODUs, and to react should the possibility of collision develop. The success of any anti-collision system is dependent on early warning and fast, efficient reaction.

These will be a designated vessel exclusion zone around all project facilities (radius 500 m), a designated safety zone (radius 5 nautical miles), and cautionary zone (radius – additional 5 nautical miles) established for the operation. These zones will be communicated to mariners using established networks and are intended to facilitate communication between project vessels and ocean-going vessels.

The primary objective of the collision avoidance procedures will be to ensure that every possible effort is made to avert a collision between the approaching vessel and the FPSO or MODU, and that the approaching vessel is alerted as early as possible to take avoidance action. The FPSO, MODU, or standby vessel may attempt to attract the attention of the approaching vessel in any one or more of the following ways:

- establishing radio communication;
- shining searchlights in the direction of the approaching vessel and then towards the FPSO or MODU, whichever is threatened;
- firing suitable pyrotechnics;
- signal light of the threatened vessel, FPSO or MODU, flashing “U” (“urgency”);
- foghorn or whistle of the threatened vessel, FPSO or MODU, sounding “U”;

- using onboard equipment, such as sirens, klaxons or concussive noisemakers;
- making use of international GMDSS procedures and frequencies; and
- other means at the discretion of the OIM.

Zones will be established, centred on the FPSO or MODUs, as follows:

- **Collision Zone** is bounded by a circle of radius 500 m (0.27 nautical mile). Any approaching vessel which has a closest point of approach (CPA) within, or at the perimeter of, this zone will trigger a collision alert for the threatened FPSO or MODU; and
- **Near Miss Zone** is a circular zone having its inner boundary at the perimeter of the Collision Zone (500 m) and its outer boundary at 2.0 nautical miles from the subject FPSO or MODU. The procedures will reflect that a near miss situation has the potential to develop rapidly into a collision situation.

The degree of action initiated, when the trajectory of an approaching vessel is projected to intrude into one of the zones, will be determined by the proximity of the CPA to the threatened facility and the time for the approaching vessel to reach CPA. The actions are determined according to the following target monitoring zones:

- **First Alert Zone.** In this zone, a vessel detected approaching the threatened facility is expected to reach a CPA within the Collision or Near Miss Zone if its present course is maintained;
- **Second Alert Zone.** In this zone, an approaching vessel is expected to reach a CPA within the Collision or Near Miss Zone within 30 minutes if its present course and speed are maintained; and
- **Emergency Zone.** In this zone, an approaching vessel is expected to reach a CPA within the Collision or Near Miss Zone within 15 minutes.

The following summarizes the actions that will be taken for each of the above alert zones:

- Actions in First Alert:

  - attempt to establish radio communications with the approaching vessel;
  - inform all standby vessels, shore base and other platforms;
  - maintain constant radio and radar watch;
  - dispatch standby vessel to a position at least 2 nautical miles from the threatened FPSO or MODU on bearing of the approaching vessel;
  - suspend operations;
  - prepare lifeboats; and
  - exercise options to attract the attention of the approaching vessel.

- Actions in Second Alert:

  - advise Rescue Coordination Centre/Canadian Coast Guard and put on standby;
  - maintain contact with Candadian Coast Guard, shorebase and other platforms;
  - confirm that no personnel are below main deck and that all ballast control valves and water tight doors are closed;
  - complete suspension of operations in preparation for disconnecting;
  - continue to exercise options to attract the attention of the approaching vessel;
  - use GMDSS to issue standard marine alert with "urgency" priority;
  - sound alarm and muster non-essential personnel in lifeboats in preparation for evacuation;
  - standby vessel moves to intercept approaching vessel; and
  - standby vessel prepares fast rescue craft, rescue and medical equipment for use in evacuation of the FPSO or MODU.

- Actions in Emergency:

  - recall standby vessel to threatened facility to prepare for evacuation;
  - disconnect in sufficient time to avoid collision;
  - remaining personnel to enter lifeboats;
  - maintain contact with standby vessel;
  - remain in lifeboats while monitoring situation;
  - if the FPSO or MODU is disabled, command of the situation is passed to the standby vessel master;
  - use GMDSS to issue standard marine alert with "distress" priority;
  - maintain communications with shorebase and CCG for as long as possible; and
  - the standby vessel will continue to exercise options to attract the approaching vessel.

The marine watch or environmental observer onboard the FPSO or MODU will monitor and plot all vessels which are expected to enter a region within a 5-nautical mile (9.3 km) radius of the facility. The observer will inform the OIM of all vessels expected to enter the region within the 5-nautical mile radius.

11.9 Operations Safety

Husky Oil promotes safe operations for personnel and protection for the environment. Safe operations are paramount and will not be downgraded for reasons of expediency.

A loss management program will be implemented specific to the White Rose development. It will become an integral part of Husky Oil's corporate loss control management philosophy. This philosophy is based on elimination or reduction of risks to personnel, assets, production, and environment through continuous and systematic approach. It covers all aspects related to health and safety, environment, reliability, management of process hazards, risk assessment, and loss control.

The White Rose HS&E loss control management system will focus on preventing and minimizing accidental losses, and will be accompanied by the Health, Safety and Environmental Loss Control Management Performance Standards, addressing the following:

- leadership and administration;
- leadership training;
- planned inspections and maintenance;
- accident and incident investigation;
- emergency preparedness;
- organizational rules, policies and procedures;
- employee knowledge and skill training;
- personal protective equipment;
- health and hygiene controls and services;
- group meetings;
- environmental program; and
- other loss control issues:
  - critical operations,
  - engineering and change management,
  - personal communications,
  - personnel recruitment, and
  - purchasing and contract management.

An exclusion zone will be established around the FPSO. It will consist of two circular zones centred on the FPSO. The inner zone, the Safety Zone, will have a radius of 5 nautical miles from the FPSO. The outer zone, the Cautionary Zone, will circumscribe the Safety Zone and have a radius of 10 nautical miles (18.5 km) from the FPSO. Advice on this will be published through notices to mariners.

The FPSO and each MODU will incorporate a temporary safe refuge (TSR) to serve as a "safe haven" where personnel can muster during emergency. The TSR will serve as a resource base for emergency actions and communications. Access routes to the TSR will provide a safe path from any area of the installation during the initial stages of an incident. The TSR will be provided with the means of getting to, and using, the evacuation systems. The TSR will incorporate the following features:

- protection against smoke and gas ingress;
- protection against loss of breathable atmosphere;
- protection against heat/temperature build-up;
- reliable power supplies;
- lighting and visibility systems;
- communication systems;

- command structure; and
- facilities to handle medical and rescue emergencies.

Two safe escape routes to the TSR will be provided from all work areas to increase the likelihood that at least one route will remain accessible during any given condition.

Evacuation systems will be provided in sufficient quantity, and at strategic locations, to cater for 200 percent of the normal personnel on board. Secondary and tertiary escape systems will also be provided.

An adequate supply of lifebuoys will be provided, and distributed in such a way that at least one lifebuoy will be visible from any point of the outside walkways on the installation.

Lifejackets will be provided to accommodate as a minimum:

- 100 percent of maximum personnel on board located within the TSR; and
- a minimum of 50 percent of the maximum personnel on board located outside the TSR.

Every person on board will be issued with an emergency survival pack containing a survival suit, heat resistant gloves, and a flashlight. These will be kept in the individual's cabin. Additional survival suits to accommodate 100 percent of the personnel on board will be located in storage cabinets outside the TSR adjacent to the evacuation systems.

A standby vessel will be in place at the FPSO and at each MODU at all times. It will be equipped with hospital space, emergency food provisions, and a fast rescue craft for use in retrieving personnel.

12 SAFETY ANALYSIS

A detailed CSA (Volume 5 Part Two) has been completed for the two technically and commercially viable options that were short-listed for the White Rose oilfield development on the Grand Banks, offshore Newfoundland. These options were:

- ship-shaped FPSO facility; and
- steel semi-submersible with an attached FSU.

The risk assessment for each option has been based on established techniques of event tree modelling of the major hazards identified for each option. Event trees allow offshore-industry generic (historical) data to be employed (leak frequency, ignition probabilities, iceberg frequencies, etc.) together with estimates of likely fatality, environmental spillage and TSR impairment levels for each accident scenario, to generate a quantitative estimate of risk.

For risk to personnel, the quantitative measure of risk is expressed in terms of both the Probable Loss of Life (PLL) and average Individual Risk (IR). Major hazard environmental risk is expressed in terms of the 'frequency of oil spills in excess of 50 barrels' and TSR impairment is expressed in terms of the frequency with which the TSR can be impaired.

The PLL estimate is a statistical estimate of the average number of fatalities that might be expected per year on an installation of any given type. A PLL of 0.1 would indicate an average of 1 fatality every 10 years.

Dividing the PLL by the average number of people on board, and further dividing by two, to account for the fraction of time spent offshore, gives the IR estimate. This is a statistical estimate of the probability that any individual operative might become a fatality in any one-year period. An IR of $5x10^{-4}$ means that there is a 0.0005 probability of fatality per year on average for each operative. The Target Levels of Safety (TLS) that have been proposed for White Rose stipulate that the IR must be less than $1x10^{-3}$ per year. This criterion is a well-established acceptance criterion widely used in both the North Sea and more recently offshore Newfoundland.

The IR for the FPSO option is shown in the study to be $4.84x10^{-4}$ per year, which is well below the target of $1x10^{-3}$. The semi-submersible option is shown to have a slightly lower IR of 3.29×10^{-4} due primarily to the higher combined number of Personnel on Board (POB) with the semi-submersible and attached FSU.

In addition, the frequency with which oil spills exceed 50 barrels and the frequency with which the TSR is impaired are also assessed in this CSA for the FPSO. These have been calculated as 7.11×10^{-4} and 1.01×10^{-4} pre year, respectively, for the environmental spillage and TSR impairment, both of which meet the stipulated TLS of 1×10^{-3}.

To fully comply with the TLS, it is necessary to demonstrate that risks are as low as reasonably practicable. To achieve this, cost benefit studies must be performed at the detailed design stage to ensure that appropriate risk reduction measures are incorporated into the design.

It is concluded that no areas for concern have been identified that could prevent the risks from being shown to be alarp at the detailed design stage. Several detailed studies will be required at detailed design stage to confirm or refine some of the assumptions and approximations that have been employed in this CSA.

13 DECOMMISSIONING AND ABANDONMENT

At the end of the production life of the White Rose oilfield, Husky Oil will decommission and abandon the site according to C-NOPB requirements and *Newfoundland Offshore Petroleum Production and Conservation Regulations* and any other applicable laws. Floating production facilities will be removed from the field. Subsea infrastructure will be removed or abandoned and the wells will be plugged and abandoned. Buried flowlines will be abandoned *insitu*, after flushing.

The site will be restored to a condition that minimizes residual environmental impact and permits reinstatement of fishing in the area and unimpeded navigation through it. Nothing will be left on the seafloor to pose a threat to the fishing industry.

13.1 Approval Process

At the completion of oil production from the White Rose field, Husky Oil will seek approval to decommission the facilities and abandon the field in accordance with the requirements of the *Newfoundland Offshore Petroleum Production and Conservation Regulations.*

The approval request will include all relevant data required to demonstrate that all practical and economic extraction of oil from the field has been achieved.

13.2 Abandonment Methods

13.2.1 Production and Injection Wells

Husky Oil intends to follow the following procedure for abandonment of wells:

- install cement plugs and mechanical bridge plugs as follows:
  - at the bottom of the deepest casing string,
  - above the uppermost perforations,
  - at depths not exceeding 150 m below the mudline,
  - to seal off porous, permeable formations, and
  - to seal off formations with abnormal pressures;
- remove wellheads and cutting casings; and,
- displace hydrocarbons in production wells with a kill fluid and abandon in place.

13.2.2 Floating Production, Storage and Offloading Facility

At abandonment, the FPSO will be disconnected from the risers. The topsides equipment will be decommissioned offshore, and any residual hazardous waste arising from this will be taken to shore and treated at appropriate approved waste treatment facilities. All anchors, lines and chains will be recovered.

The ultimate disposition of the FPSO will depend upon its condition at of the end of the production life of the White Rose field, and upon the options available for further use.

13.2.3 Subsea Facilities

All equipment located in glory holes will be removed and the glory holes will be left as they are. Christmas trees and manifolds will be purged, rendered safe, and recovered.

Trenched flowlines will be flushed and left *insitu* below the seafloor.

All other subsea facilities above the seafloor, including production manifolds, riser base manifolds, loading riser manifolds, short connector flowlines, and export lines, will be purged and decommissioned in accordance with regulations prevailing at the time.

All risers and umbilicals will be decommissioned, rendered safe, and recovered.

14 DEVELOPMENT AND OPERATING COST DATA

14.1 Past Expenditures

Past expenditures on the White Rose oilfield are shown by year of occurrence in Table 14.1-1. These expenditures total $345.7 million, and were incurred between 1984 and 1999. All costs shown are in the dollar values of the year in which they occurred. The costs are shown broken down into geology and geophysics, and wells.

Table 14.1-1 Past Expenditures (1984 to 1999)

Year	Expenditures ($million as spent)		
	Geology & Geophysics	Wells (9)	Total
1984		42.1	42.1
1985		66.6	66.6
1986		39.4	39.4
1987		30.8	30.8
1988	0.4	47.3	47.7
1989		0.5	0.5
1990		0.3	0.3
1991			
1992			
1993			
1994			
1995	0.1		0.1
1996	0.2	0.1	0.3
1997	4.4	0.8	5.2
1998	0.2	3.6	3.8
1999	0	109.2	109.2
Total	**5.3**	**340.4**	**345.7**

14.2 Capital Cost Estimates

The capital cost estimates are based on 2000 constant dollars, and include all applicable customs duties and sales taxes.

They are based on the following assumptions:

- the development will take place as described in this Development Plan;
- there will be worldwide competition for the supply of all facilities, goods, and services on the project and contracts will be awarded in compliance with the Canada-Newfoundland Benefits Plan (Volume 1) proposed for the project; and
- current worldwide economic conditions will prevail.

The capital cost estimates are based on in-house cost studies and contractors' estimates. Contractors' estimates are developed from the following information:

- preliminary facilities design;
- equipment sizes and weights;
- equipment-to-bulk-ratios and weights;
- fabrication work-hours per tonne;
- international wage rate surveys;
- vendor cost data;
- contractor cost data;
- fabrication and installation schedules;
- engineering and project management costs; and
- marine operations costs.

The capital cost estimates include costs for the following items:

- production facility;
- subsea facilities;
- installation; and
- well drilling and completion.

14.3 Operating Cost Estimates

The annual operating cost estimates are based on 2000 constant dollars, and include all applicable customs duties and sales taxes. Husky Oil and Petro-Canada each have extensive operating experience, and Husky Oil has drawn upon this reservoir of experience in the preparation of these operating cost estimates. The operating cost estimates also draw upon the experience of other operators of similar facilities, and have been developed taking into account the following items:

- production facility;
- subsea and well workovers;
- variable production;
- support logistics; and
- administration.

The operating costs are based on the following assumptions:

- the reservoir parameters will be as described in this Development Plan;

- Husky Oil will operate the development in accordance with a typical co-venture agreement, and will adhere to the management approach and development scenario as set out in this Development Plan; and
- the economic conditions prevailing world-wide in January 2000 will continue throughout the period of operation.

14.4 Development Options Costs

The detailed capital and operating cost estimates on an annual basis for the five options considered are presented in Tables 14.4-1 to 14.4-5, respectively:

- new steel FPSO (Table 14.4-1);
- new concrete FPSO (Table 14.4-2);
- new steel semi-submersible (Table 14.4-3);
- new concrete semi-submersible (Table 14.4-4); and
- new concrete GBS (Table 14.4-5).

The operating costs shown do not include crude transportation costs for any of the options.

A summary of the capital costs for the five options considered is presented in Table 14.4-6.

Table 14.4-1 Capital and Operating Costs - New Steel FPSO

Year	Production		Capital Costs ($MM)							Operating Costs ($MM)
	Rate (m^3/d)	Annual ($E^3 m^3$)	Exploration Drilling	Pre-production Proj. Admin.	Pre-production Drilling	Pre-production Facilities	Pre-production SubSea	Post-Production	Total	
1				10		111			121	
2				10	115	390	82		597	
3				10	155	390	150		705	
4	14,600	4,000			41	223	82	114	460	59
5	14,600	5,340						155	155	83
6	14,600	5,340						120	120	89
7	14,600	5,340								92
8	13,000	4,780								99
9	8,700	3,160								100
10	5,600	2,060								97
11	4,100	1,480								86
12	3,100	1,150								77
13	2,600	940								71
14	2,100	760								63
15	1,800	650								57
16	1,600	570								51
17	1,300	480								49
18	1,000	350								104
19										
20										
TOTAL		36,400		$30	$311	$1,114	$314	$389	$2,158	$1,177

Notes:
Operating Costs exclude crude transportation costs
The final year Operating Costs include $41MM for abandonment of the facility and wells
The FPSO salvage value is estimated at $40MM (As spent)

Table 14.4-2 Capital and Operating Costs - New Concrete FPSO

Year	Production		Capital Costs ($MM)							Operating Costs ($MM)
	Rate (m^3/d)	Annual ($E^3 m^3$)	Exploration Drilling	Pre-production				Post-Production	Total	
				Proj. Admin.	Drilling	Facilities	SubSea			
1				10		123			133	
2				10	40	430	28		508	
3				10	155	430	98		693	
4	14,600	1,330			116	251	188	39	594	20
5	14,600	5,340						155	155	80
6	14,600	5,340						155	155	86
7	14,600	5,340						40	40	91
8	14,600	5,340								94
9	10,600	3,870								101
10	6,800	2,490								98
11	4,700	1,700								93
12	3,500	1,280								81
13	2,800	1,020								74
14	2,300	840								67
15	1,900	700								60
16	1,700	600								54
17	1,400	520								49
18	1,100	420								50
19	700	270								79
20										
TOTAL		36,400		$30	$311	$1,234	$314	$389	$2,278	$1,177

Notes:
Operating Costs exclude crude transportation costs
The final year Operating Costs include $41MM for abandonment of the facility and wells
The FPSO salvage value is estimated at $40MM (As spent)

Table 14.4-3 Capital and Operating Costs - New Steel Semi-Submersible

Year	Production		Capital Costs ($MM)							Operating Costs ($MM)
	Rate (m^3/d)	Annual ($E^3 m^3$)	Exploration Drilling	Pre-production Proj. Admin.	Pre-production Drilling	Pre-production Facilities	Pre-production SubSea	Post-Production	Total	
1				10		120			130	
2				10	115	420	93		638	
3				10	155	420	186		771	
4	14,600	4,000			41	240	93	114	488	62
5	14,600	5,340						155	155	87
6	14,600	5,340						120	120	93
7	14,600	5,340								96
8	13,000	4,780								103
9	8,700	3,160								104
10	5,600	2,060								101
11	4,100	1,480								90
12	3,100	1,150								80
13	2,600	940								74
14	2,100	760								65
15	1,800	650								59
16	1,600	570								53
17	1,300	480								51
18	1,000	350								106
19										
20										
TOTAL		36,400		$30	$311	$1,200	$372	$389	$2,302	$1,224

Notes:
Operating Costs exclude crude transportation costs
The final year Operating Costs include $41MM for abandonment of the facility and wells
The Semisubmersible salvage value is estimated at $40MM (As spent)

Table 14.4-4 Capital and Operating Costs - New Concrete Semi-Submersible

Year	Production		Capital Costs ($MM)							Operating Costs ($MM)
	Rate (m^3/d)	Annual ($E^3 m^3$)	Exploration Drilling	Pre-production				Post-Production	Total	
				Proj. Admin.	Drilling	Facilities	SubSea			
1				10		128			138	
2				10	40	448	37		535	
3				10	155	448	112		725	
4	14,600	1,330			116	257	223	39	635	21
5	14,600	5,340						155	155	84
6	14,600	5,340						155	155	90
7	14,600	5,340						40	40	95
8	14,600	5,340								98
9	10,600	3,870								105
10	6,800	2,490								102
11	4,700	1,700								97
12	3,500	1,280								84
13	2,800	1,020								77
14	2,300	840								70
15	1,900	700								62
16	1,700	600								56
17	1,400	520								51
18	1,100	420								51
19	700	270								81
20										
TOTAL		36,400		$30	$311	$1,281	$372	$389	$2,383	$1,224

Notes:
Operating Costs exclude crude transportation costs
The final year Operating Costs include $41MM for abandonment of the facility and wells
The Semisubmersible salvage value is estimated at $40MM (As spent)

Table 14.4-5 Capital and Operating Costs - New Concrete GBS

Year	Production		Capital Costs ($MM)							Operating Costs ($MM)
	Rate (m^3/d)	Annual ($E^3 m^3$)	Exploration Drilling	Pre-production				Post-Production	Total	
				Proj. Admin.	Drilling	Facilities	SubSea			
1				10		213			223	
2				10		425			435	
3				10		425			435	
4					111	641			752	
5						425	36	98	559	
6	15,300	3,760						98	98	77
7	15,300	5,570						98	98	81
8	15,300	5,570						65	65	84
9	15,300	5,570								85
10	12,700	4,630								90
11	8,400	3,050								89
12	5,500	2,000								84
13	4,000	1,450								74
14	3,100	1,130								66
15	2,500	920								60
16	2,100	750								53
17	1,800	640								48
18	1,500	560								43
19	1,300	470								43
20	900	330								194
TOTAL		36,400		$30	$111	$2,129	$36	$359	$2,665	$1,171

Notes:
Operating Costs exclude crude transportation costs
The final year Operating Costs include $150MM for abandonment of the facility and wells
No salvage value is given to the GBS

Table 14.4-6 Capital Summary Table

	Steel	Semi-Submersible		Concrete	Concrete
	FPSO	Steel	Concrete	FPSO	GBS
P50 CAPEX [Capital (2000$Can)]					
Capital to Project Sanction	**$310**	**$310**	**$310**	**$310**	**$310**
Development Capital to First Oil	**$1,769**	**$1,913**	**$1,994**	**$1,889**	**$2,306**
Drilling	$311	$311	$311	$311	$111
Total Facility	$1,114	$1,200	$1,281	$1,234	$2,129
Vessel/Turret	$462	$521	$557	$508	$1,080
Topsides/Installation/Other	$652	$679	$724	$726	$1,049
SubSea	$314	$372	$372	$314	$36
SGA	$30	$30	$30	$30	$30
Development Capital Post First Oil	**$390**	**$390**	**$390**	**$390**	**$509**
Drilling	$389	$389	$389	$389	$359
Abandonment	$41	$41	$41	$41	$150
Salvage Value	($40)	($40)	($40)	($40)	$0
Total CAPEX	**$2,469**	**$2,613**	**$2,694**	**$2,589**	**$3,125**
TOTAL OPEX	**$1,087**	**$1,132**	**$1,132**	**$1,087**	**$978**
P90 CAPEX [Capital (2000Can)]					
Capital to Project Sanction	**$310**	**$310**	**$310**	**$310**	**$310**
Development Capital to First Oil	**$1,906**	**$2,036**	**$2,137**	**$2,027**	**$2,545**
Drilling	$342	$342	$342	$342	$152
Total Facility	$1,198	$1,268	$1,369	$1,319	$2,324
Vessel/Turret	$497	$550	$595	$543	$1,179
Topsides/Installation/Other	$701	$718	$774	$776	$1,145
SubSea	$336	$396	$396	$336	$39
SGA	$30	$30	$30	$30	$30
Development Capital Post First Oil	**$564**	**$564**	**$564**	**$564**	**$595**
Drilling	$557	$557	$557	$557	$445
Abandonment	$47	$47	$47	$47	$150
Salvage Value	($40)	($40)	($40)	($40)	$0
Total CAPEX	**$2,780**	**$2,910**	**$3,011**	**$2,901**	**$3,450**
TOTAL OPEX	**$1,118**	**$1,163**	**$1,163**	**$1,118**	**$998**

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16 GLOSSARY OF ABBREVIATIONS, ACRONYMS AND DEFINITIONS

10^3. Abbreviation for thousand.

10^6. Abbreviation for million.

10^6m^3. Abbreviation for million cubic metres.

10^9. Abbreviation for billion.

10^9m^3. Abbreviation for billion cubic metres.

abandonment. The decommissioning of facilities and removal of offshore structures following exhaustion of reserves.

accretion. Growth by organic enlargement; growing of separate things into one.

ADW. Acronym for Approval to Drill Wells.

advection. The process of, or referring to the transport of one fluid mass (air, water) by the movement of another.

AERP. Acronym for Alert and Emergency Response Plan.

anomaly. A geological feature, especially in the subsurface, distinguished by geological, geophysical or geochemical means, which is different from the general surroundings and is often of potential economic value (for example, a magnetic anomaly).

ANSI. Acronym for American National Standards Institute.

anticline. A fold, generally convex upward, whose core contains the stratigraphically oldest rocks.

API. Acronym for American Petroleum Institute.

argillaceous. Applied to all rocks or substances composed of clay minerals, or having a notable proportion of clay in their composition (for example, shale, slate, etc.).

ASME. Acronym for America Society of Mechanical Engineers.

as spent. Cost at the time the dollar is spent or investment is made. Sometimes referred to a "Nominal dollar".

authigenic. Pertaining to minerals crystallized within an enclosing sediment during or after deposition, either infilling void space or replacing pre-existing rock constituents.

Avalon Formation. A particular rock deposit that formed approximately 110 million years ago in the Cretaceous period. It is the reservoir rock of the White Rose South oil pool and the principal reservoir rock of the White Rose Oilfield.

avg. Abbreviation for average.

AWO. Acronym for Approval for Well Operations.

B. Abbreviation for boron.

Ba. Abbreviation for barium.

barite. A mineral (barium sulphate); used as a weighting material for drilling because of its high specific gravity.

basement. The undifferentiated complex of rocks that underlies the sedimentary rocks of interest in an area.

bathymetry. The measurement of depths of water in oceans, seas and lakes; also the information derived from such measurements.

bbl. The abbreviation for barrel.

bedding plane. A planar or nearly planar bedding surface that visibly separates each successive layer of stratified rock (of the same or different lithology) from the preceding or following layer; an original surface of deposition. It commonly marks a change in the circumstances of deposition and may show a parting, a colour difference, or both.

bedrock. A general term for the rock, usually solid, that underlies soil or other unconsolidated, superficial material.

bergy bit. A piece of floating glacier having a sail greater than 1.5 m but less than 5 m and a water plane area greater than 20 m^2 but less than 300 m^2. Size approximates that of a small house and mass is between 120 and 5,400 t.

BHT. Acronym for bottomhole temperature.

bioclastic. Refers to rock constituents consisting of fragmental organic remains.

biodegradation. The biological conversion of organic material to inorganic nutrients.

bioturbation. The churning and stirring of a sediment by organisms.

BOP. Acronym for blowout preventer.

BOPD. Abbreviation for barrels of oil per day.

boulder. A rounded rock fragment greater than 256 mm in diameter.

BS&W. Acronym for basic sediment and water.

Br. Abbreviation for bromine.

bubble point pressure. The pressure at which the first bubbles of gas appear from the liquid phase.

Ca. Abbreviation for calcium.

calcareous. Containing calcium carbonate.

calcite. A mineral with the composition $CaCO_3$; the principal constituent of limestone; a common authigenic cement in sandstones.

CALM. Acronym for Catenary Anchor Leg Mooring.

Capex. Acronym for capital expenditure.

CAPP. Acronym for Canadian Association of Petroleum Producers.

CBFC. Acronym for Cumberlant Belt-Flemish Cap.

CCG. Acronym for Canadian Coast Guard.

C-CORE. Acronym for Centre for Cold Ocean Resources Engineering.

CCR. Acronym for central control room.

CEAA. Acronym for Canadian Environmental Assessment Act.

CERT. Acronym for Corporate Emergency Response Team.

Christmas Tree. Arrangement of valves and fittings attached to the tubing head to control flow and provide access to the tubing string.

Cl. Abbreviation for chlorine.

clast. An individual detrital constituent of a sediment.

clastic. Pertaining to a rock or sediment composed principally of individual fragments or grains, commonly derived from pre-existing rocks or minerals; also said of the texture of such a rock. The term has been used to indicate a source both within and outside the depositional basin.

clay. A mineral fragment or detrital particle of any composition (often having a crystalline fragment of a clay mineral), smaller than a very fine silt grain, having a diameter less than 4 µm.

claystone. An indurated clay having the texture and composition of shale but lacking its fine lamination or fissility.

cluster. Wells grouped together to minimize infield flowlines.

CMG. Acronym for course made good.

C-NOPB. Acronym for Canada-Newfoundland Offshore Petroleum Board.

CO_2. Abbreviation for carbon dioxide.

COB. Acronym for continent-ocean boundary.

cobble. A rounded rock fragment between 64 and 256 mm in diameter.

compaction (sediment). Reduction in bulk volume, or thickness of, or the pore space within a body of sediments in response to the increasing weight of overlying material that is continually being deposited or to the pressures resulting from earth movements within the crust. It is expressed as a decrease in porosity brought about by a tighter packing of the sediment particles.

complex. A large geological structural feature composed of several smaller structural features. In this case, the complex refers to the White Rose salt dome and adjacent collapse features, including many individual fault blocks.

condensate. Liquid hydrocarbons that are produced with natural gas and that separate from the gas as a result of decreases in temperature and pressure.

Continental Shelf. Gently sloping, shallowly submerged marginal zone of the continents extending from the shore to an abrupt increase in bottom inclination; greatest average depth less than 183 m, slope generally less than 1 to 1,000, local relief less than 18.3 m, width ranging from very narrow to more than 320 km.

Continental Slope. Continuously sloping portion of the continental margin with gradient of more than 1 to 40, beginning at the outer edge of the Continental Shelf and bounded on the outside by a rather abrupt decrease in slope where the continental rise begins at depths raging from approximately 1,400 and 3,000 m.

COPS. Acronym for Cougar Offshore Personnel System.

core. A cylindrical boring of rock from which composition and stratification may be determined.

COT. Acronym for cargo oil tank.

CPA. Acronym for closest point of approach.

Cretaceous. A period of geological time approximately 131 to 65 million years ago. Dinosaurs and other reptiles thrived in the early Cretaceous but by the end of this period, dinosaurs and many of the reptiles had become extinct.

crude oil. Unrefined petroleum.

current shear. A tangent or plane of contact where two opposing currents collide and are subsequently driven away from each other.

cuttings. Chips and small fragments of rock that are brought to the surface by the drilling mud as it circulates.

cuvette. A small depositional area, smaller than a basin or a sub-basin.

d. Abbreviation for day.

DA. Acronym for Development Application.

dB. Abbreviation for decibel.

DCS. Acronym for distributed control system.

deadweight. The maximum design weight of cargo, crew and effects for a ship (the “payload”).

dehydration. Removal of water from a hydrocarbon fluid.

delineation wells. Wells drilled after the initial exploration well to give a better understanding of the extent and performance of the reservoir**.**

deltaic. Pertaining to, or like a delta.

detrital. Particles occurring in sedimentary rocks that were derived from pre-existing igneous, sedimentary or metamorphic rocks, or other pre-existing material.

Development (White Rose Oilfield Development). "Development" refers to all phases of the project, from the decision to go ahead with construction through to abandonment of the field.

Development Application. The official title of the documentation submitted to the C-NOPB in support of an oilfield development request. The White Rose Development Application includes and Project Summary and five volumes: Canada-Newfoundland Benefits Plan (Volume 1); Development Plan (Volume 2); Environmental Impact Statement (Volume 3 - Comprehensive Study Part One); Socio-Economic Impact Statement (Volume 4 - Comprehensive Study Part Two); and Safety Plan/Concept Safety Analysis (Volume 5).

DFO. Acronym for Department of Fisheries and Oceans.

DGPS. Acronym for Differential Global Positioning System.

diagenesis. Process involving physical and chemical changes in sediment during and after consolidation; includes compaction, cementation, recrystallization, replacement and dissolution.

diapir. A dome or anticlinal fold in which the overlying rocks have been ruptured by the squeezing-out of plastic core material. Diapirs in sedimentary strata usually contain cores of salt or shale.

discovery well. An exploratory well that encounters a new and previously untapped petroleum deposit; a successful wildcat well.

DND. Acronym for Department of National Defence.

DNV. Acronym for Det Norske Veritas.

dolomite. Mineral with the chemical composition $CaMg(CO_3)_2$ occurring as cement and/or grain replacement in the sandstone.

downdip. A direction towards a lower elevation from a given point on a structure or surface.

DPA. Acronym for Drilling Program Authorization.

drill centre. Location at which a group of wells is drilled.

drilling mud. Water used as the liquid phase in water-based mud; usually denoting non-saline water.

drilling platform. An offshore structure from which a number of wells are drilled. The legs of the platform are anchored to the seabed and the platform is built on a large-diameter pipe frame.

drilling rig. A ship-shaped or semi-submersible vessel, or a jackup platform, with equipment suitable for offshore drilling.

drillstem test (DST). A short-term test of the productive capacity of a well through drillpipe.

DSV. Acronym for Diving Support Vessel.

DWT. Acronym for Dead weight tonnage.

EC. Abbreviation for Environment Canada.

ECERT. Acronym for East Coast Emergency Response Team.

EIS. Acronym for Environmental Impact Statement.

Environmental Impact Statement (EIS). A document that attempts to predict the effects of a major development might have on the human and natural environments of a given geographic area. An EIS is prepared to enable industry, government and the public to consider the environmental costs and benefits of a development project. Based on the information contained in the EIS, decisions an be made on whether to proceed with the development project.

EPIC. Acronym for engineer, procure, install and commission.

estuary. That area of a coastal embayment that is under the influence of both fresh water and seawater.

ethane. A simple hydrocarbon composed of two carbon atoms and six hydrogen atoms; a gas at atmospheric conditions.

euxinic. Pertaining to an environment of restricted circulation and stagnant or anaerobic conditions; anoxic.

exploration well. A well drilled in an attempt to find an oil- or gas-bearing formation.

facies (sedimentary). The appearance and characteristics of a rock unit reflecting the depositional environment of its origin, as distinguished from adjacent units of different origin.

fault. A fracture or fracture zone along which there has been displacement of the sides relative to each other parallel to the fracture. The displacement may be a few millimetres or many kilometres.

Fault Block Traps. A hydrocarbon trap created by differential movement along faults that fragment the reservoir into one of several structural compartments.

fault fan. Antithetic and synthetic minor faults related to a major listric fault.

Fe. Abbreviation for iron.

FEED. Acronym for front end engineering and design.

FGD. Acronym for fire and gas detection.

FGS. Acronym for fire and gas detection system.

First Oil. Milestone achieved when the first shuttle tanker has been filled with oil from the production system and the shuttle tanker disconnects from the offloading system. The entire production system is handed over to operations personnel at this point. This is the first quantity of oil to be delivered from the reservoir through the complete production and offloading system, including fiscal metering.

flare. An arrangement of piping and burners used to dispose of surplus combustible vapours (by burning).

flaring. Disposal of surplus combustible vapours by burning at the discharge of the flare tower.

flaser. Ripple cross-lamination in which mud streaks are preserved in the troughs but incompletely or not at all on the crests.

floating production system. A monohull or semi-submersible vessel with equipment suitable for producing hydrocarbons.

flowline. Pipe which conveys crude oil, water and/or gas from the well to the riser, or water or gas from the riser to the well.

foraminifer. Any protozoan belonging to the subclass Sarcodina, order Foraminifera; unicellular animals mostly of microscopic size that secrete tests, composed of calcium carbonate, or build them of cemented sedimentary grains, consisting of one to many chambers arranged in a great variety of ways. Most foraminifers are marine, but freshwater forms are known.

formation water. Water present in a water-bearing formation under natural conditions, as opposed to introduced fluids, such as drilling mud.

FPDSO. Acronym for floating production, drilling, storage and offloading facility.

FPF. Acronym for floating production facility.

FPSO. Acronym for floating production, storage and offloading facility.

FSU. Acronym for floating storage unit.

FVF. Acronym for formation volume factor.

gas lift. Gas injected into the well to reduce the hydrostatic pressure on the fluid column and hence enhance flow.

GBS. Acronym for gravity based structure.

geology. The study of the structure, origin, history and development of the Earth.

geostrophic. Pertaining to deflecting force resulting from the Earth's rotation.

glaciomarine. Marine sediments that contain glacial material.

glauconite. A green mineral, closely related to the micas and essentially a hydrous potassium iron silicate. Commonly occurs in sedimentary rocks of shallow-marine origin.

glory hole. Hole, excavated in the seabed, in which wellhead facilities are placed for protection from iceberg scour.

GMDSS. Acronym for Global Marine Distress Signalling System.

GOR. Acronym for gas-oil ratio.

GPS. Acronym for Global Positioning Systems.

graben. A fault-bounded elongate crustal block that is down-dropped relative to adjacent crustal blocks, usually resulting in a topographic low.

grain. A general term for sedimentary particles of all sizes (from clay to boulders), as used in the expressions "grain size," "fine-grained" and "coarse-grained".

gyre. Circular movement of water masses.

h. The abbreviation for hour.

H_2S. Abbreviation for hydrogen sulphide.

halokinesis. A general term for the study of the structure and mechanism of emplacement of salt domes and other salt-controlled structures.

HAZID. Acronym for Hazard Identification.

HAZOPS. Acronym for hazard and operability studies.

HCO_3. Abbreviation for formate.

HF. Acronym for high frequency radio.

HP. Abbreviation for high pressure.

HMDC. Acromyn for Hibernia Management and Development Company.

HS&E. Acronym for Health, Safety and Environment.

Husky Oil. Abbreviation for Husky Oil Operations Limited.

HVAC. Acronym for heating, ventilation and air conditioning.

hyperbenthic. Benthic or bottom organisms that spend part of their time on the water column for feeding of reproduction.

Hz. The abbreviation for hertz; unit of sound frequency equal to one cycle per second.

I. Abbreviation for iodide.

IC. Abbreviation for Industry Canada.

iceberg scour. Seafloor trench caused by the ploughing motion of an iceberg grounding on the ocean floor.

ichnology. The study of fossil tracks, trails, burrows, tubes and borings resulting from the life activities of animals, which took place on or in soft sediment.

ID. Acronym for internal diameter.

IIF. Acronym for input initiating frequency.

IMO. Acronym for International Maritime Organization.

infilling. A process of deposition by which sediment falls or is washed into depressions, cracks or holes, as the filling in of crevasses upon the melting of glacial ice.

injection water. Water pumped into the formation to maintain reservoir pressure (secondary recovery technique); offshore, injection water is filtered seawater treated with biocides, oxygen scavenger and scale inhibitor.

IR. Acronym for Individual Risk.

isopach. A line on a map drawn through points of equal thickness of a designated unit.

Jurassic. A period of geologic time from approximately 210 to 131 million years ago. Older plant groups continued to decline and newer forms continued to spread, dinosaurs were growing in size and becoming specialized for varied ways of life, and marsupial mammals and the first birds appeared.

K. Abbreviation for potassium.

kaolinite. A common clay mineral. Two-layer hydrous aluminum silicate having the general formula $Al_2(Si_2O_5)\ (OH)_4$.

kerogen. Fossilized, insoluble, organic material in sedimentary rocks (usually shales) that can be converted by distillation to petroleum products.

killing the well. Causing the flow from the well to come to a complete stop.

km. The abbreviation for kilometre.

km^2. The abbreviation for square kilometre.

kPa. Abbreviation for kiloPascal.

KSLO. Acronym for Kvaerner-SNC Lavalin Offshore.

kV. The abbreviation for kilovolts.

kv/kh ratio. Vertical to horizontal permeability ratio.

kW. The abbreviation for kilowatts.

L. The abbreviation for litre.

larva. The first immature phases of many animals after hatching of eggs and before assuming the adult form and habitat.

listric fault. A fault with a curvilinear concave-upward surface, dipping more steeply flattening with depth.

lithofacies. A subdivision of a specified stratigraphic unit distinguished on the basis of lithological features.

lithology. The physical character of a rock.

lithostratigraphy. The study of the physical make-up of strata and their organization into units based on lithological character.

logging. A systematic recording of data from the driller's log, mud log, electrical well log or radioactivity log.

Lower Cretaceous. The older strata of the Cretaceous period, which ranges from 65 million years before present to 131 million years before present.

LP. Abbreviation for low pressure.

LWD. Acronym for logging while drilling.

m. The abbreviation for a) metre or b) earthquake magnitude.

m^2 . The abbreviation for square metre.

m^3. The abbreviation for cubic metre.

manifold. Device which routes the flow from several wells into organized flow streams.

marl. Calcareous clays; consolidated primary calcareous clays.

matrix. The natural material, generally argillaceous, in which any metal, fossil, pebble, crystal, etc., is embedded; interstitial detrital argillaceous material in sandstones.

mBRT. Acronym for metres below rotary table.

mD. The abbreviation for milliDarcy.

MDT. A wireline tool normally run as part of a logging program. The tool can be used to collect pressure, temperature and fluid information from most porous intervals.

Mesozoic. An era of geologic time, from the end of the Paleozoic to the beginning of the Cenozoic, or from approximately 225 to 65 million years ago.

MFPSV. Acronym for Multifunctional Platform Support Vessel.

mg. The abbreviation for milligram.

Mg. Abbreviation for magnesium.

micropaleontology. A branch of paleontology that deals with the study of fossils too small to be observed without the aid of a microscope.

migration. In seismic processing, plotting of dipping reflections in their true spatial positions.

min. Abbreviation for minute.

mm. The abbreviation for millimetre.

Mn. Abbreviation for Manganese.

MODU. Acronym for mobile offshore drilling units.

mol. Abbreviation for molecular weight.

monohull. A ship-shaped vessel.

monophasic sample containers. Sample containers used to capture single phase samples of reservoir fluids and keep the samples in a single phase, as the sample's temperature is reduced, by elevating the samples pressure after the sample is collected.

MPa. The abbreviation for megapascal.

mSS. Abbreviation for metres subsea.

mud pulse telemetry directional tools. These tools (commonly referred to as MWD) measure and transmit to surface all the drill bit orientation information required to guide the directional drilling operations. The tool transmits the information up the drill pipe by creating coded pressure pulses in the mud column. The pulses are then decoded by surface computers, which then present the information to drilling personnel.

MW. Abbreviation for megawatt.

MWD. Acronym for measurement while drilling.

N_2. Abbreviation for nitrogen.

Na. Abbreviation for sodium.

NACE. Acronym for National Association of Corrosion Engineers.

NEB. Acronym for National Energy Board.

net oil pay. The remaining pay thickness in an oil zone after zones of low porosity, shale, and high water saturation have been discounted.

NGL. Acronym for natural gas liquids; liquid hydrocarbons produced with natural gas that separate from the gas as a result of decreases in temperature and pressure.

NPV. Acronym for net present value.

NTFZ Acronym for Newfoundland Transform Fault Zone.

OEC. Acronym for overpressure exceedence curve.

OGIP. Acronym for original gas in place.

OIM. Acronym for offshore installation manager.

oleoclasts. Bacteria that have the ability to degrade hydrocarbons.

OLS. Acronym for offshore loading system.

OOIP. Acronym for original oil in place.

oolite. Small, round, sand-sized accretionary grains of calcium carbonate.

Operations Phase. The period following First Oil until cessation of all oil production from the White Rose oilfield. Includes post-First Oil development drilling, offshore installation activities, production, operations, maintenance, well abandonment, decommissioning and removal from the White Rose oilfield of all facilities, equipment and vessels used in the production system.

Operator. When capitalized in the Development Application, refers to Husky Oil.

Opex. Acronym for operating expenditure.

ORED. Acronym for Offshore Reliability Database.

OSC. Acronym for On-Scene Commander.

overpressured. A subsurface formation that exerts an abnormally high formation pressure on a wellbore drilled into it.

Owner/Operator. When capitalized in the Development Application, refers to Husky Oil and Petro-Canada.

P50. Acronym for 50 percent probability.

P&S. Acronym for plugged and suspended.

Pa. Abbreviation for pascal.

paleo. Ancient, old.

paleogeography. The geography of ancient times or of a particular past geological epoch.

paleontology. A science dealing with the life of past geological periods as known from fossil remains.

palinspastic. Geological features that are restored as nearly as possible to their original geographic position.

palynology. A branch of science dealing with the study of pollen, spores and dinoflagellates, either living or fossil.

PAU. Acronym for pre-assembled unit.

pebbles. Smooth rounded stones ranging from 2 to 64 mm in diameter.

perforating. Piercing the casing wall and cement sheath to provide a flow path through which formation fluids may enter the wellbore. Perforating is done with shaped explosive charges.

permeability. The capacity of a rock to transmit a fluid. Degree of permeability depends upon the size and shape of the pores, the size and shape of their connections, and the extent of the latter. It is measured by the rate at which a fluid of standard viscosity can move a given distance through a given interval of time.

petroleum. Oil and natural gas.

PFD. Acronym for process flow diagrams.

pig. Device used for pumping through a pipeline to clean the walls or remove an obstruction.

PIP. Acronym for Petroleum Incentive Program.

PLL. Acronym for probable loss of life.

PLT/MLT. Acronym for Production Logging Tests/Multi-layer Tests.

plume. A trail of oil.

POB. Acronym for persons on board.

poikilotopic. Said of the fabric of an authigenic cement in a sandstone in which the constituent crystals are larger in size than detrital grains, enclose one or more detrital grains, and are in crystallographic continuity throughout more than one intergranular space.

pore pressure. The pressure of the interstitial fluids in a rock formation.

porosity. The volume of the pore space expressed as a percentage of the total volume of the rock mass.

pour point. Lowest temperature at which a substance flows under specified conditions.

ppb. Abbreviation for parts per billion.

PPE. Acronym for personal protective equipment.

ppm. Abbreviation for parts per million.

Pre-Engineering. All of the engineering work undertaken before the Project Phase to determine the preferred floating production system for White Rose. Begins with the invitation to submit alliance qualification proposals through selection of the three alliance groups, through selection of the preferred production system and alliance. Includes further definition engineering work with the preferred alliance up to the commencement of the Project Phase.

pressure gradient. The rate of pressure increase with depth.

PRF. Acronym for probabilistic recovery factory.

produced sand. Sand produced with oil and gas.

progradation (or prograding). The building forward or outward toward the sea of a shoreline or coastline (as of a beach, delta or fan) by nearshore deposition of river-borne sediments or by continuous accumulation of beach material thrown up by waves or moved by longshore drift.

Project Phase. The period beginning with regulatory approval of the Development Application and the Proponent's authorization to execute the White Rose oilfield development, up to the production and offloading of First Oil. Includes detail engineering, procurement, construction, commissioning, installation and development drilling up to First Oil. Does not include development drilling after First Oil.

PVPI. Acronym for present value profitability index.

PVT. Acronym for pressure, volume, temperature.

reflection. The return of a wave or energy incident upon a surface to its original medium. Also, in seismic prospecting, the indication on a record of such reflected energy.

regression. The retreat or contraction of the sea from land areas and the consequent evidence of such withdrawal (such as enlargement of the area of deltaic deposition). Also, any change (such as fall of sea level or uplift of land) that brings nearshore, typically shallow-water environments to areas formerly occupied by offshore, typically deep-water conditions, or that shifts the boundary between marine and non-marine deposition (or between deposition and erosion) toward the centre of a marine basin.

Regulatory Phase. The period and activities associated with the regulatory review of the Development Application. Commences with the filing of the Development Application and ends upon receipt of approval.

repeat formation tester (RFT). A logging tool capable of repeated pressure measurement or sampling in open hole (see also MDT).

replacement. The process of practically simultaneous capillary solution and deposition by which a new mineral of partly or wholly differing chemical composition may grow in the body of an old mineral or mineral aggregate.

reserves. That part of an identified resource from which a usable mineral or energy commodity can be economically and legally extracted at the time of determination.

reservoir. A subsurface, porous, permeable rock body in which oil or gas has accumulated; most reservoir rocks are limestones, dolomites, sandstones, or a combination of these.

resource. An initial volume of oil and gas that is estimated to be contained in a reservoir.

rift. An elongate structural trough bounded by normal faults formed during crustal extension.

riser base manifold. A simple structure located on the seafloor to act as a termination point for the production riser, satellite wells and transfer lines.

riser. A flowline carrying oil or gas from the seabed to the deck of a production platform or a tanker loading platform.

ROR. Acronym for rate of return.

ROV. Acronym for remotely operated vehicle.

RVP. Acronym for reid vapour pressure.

s. The abbreviation for second.

salt dome. A diapir or piercement structure with a central, nearly equidimensional salt plug, generally one to two kilometres or more in diameter, which has risen through the enclosing sediments.

sand. A detrital particle smaller than a granule and larger than a coarse silt grain, having a diameter in the range of 0.0625 to 2 mm.

sandstone. Consolidated sediment composed primarily of sand-sized grains.

SAR. Acronym for a) Search and Rescue. b) synthetic aperture radar.

SBM. Acronym for a) synthetic-based mud or b) Single Buoy Mooring.

scour. (a) Seafloor trench caused by the ploughing motion of an iceberg grounding on the ocean floor. (b) Seafloor erosion caused by strong currents, resulting in the redeployment of bottom sediments and formation of holes and channels.

SCSSV. Acronym for surface controlled sub-surface safety valve.

SDL. Acronym for Significant Discovery Licence.

sea ice. Any ice floating in the sea.

sediment. Solid material, both mineral and organic, that is being or has been transported from its site of origin by air, water or ice, and has come to rest on the earth's surface either above or below sea level.

sedimentary rock. Rocks formed by the accumulation of sediment in water or from air. The sediment may consist of rock fragments or particles, the remains of animals or plants, the product of chemical action or evaporation, or of mixtures of these materials.

SEIS. Acronym for Socio-Economic Impact Statement.

seismic. Pertaining to, characteristic of or produced by earthquakes or earth vibration.

seismicity. The phenomenon of earth movements; seismic activity.

seismotectonic. Pertaining to deformation of Earth's crust from shocks not due to volcanic action.

semi-submersible. A drilling or production vessel that has the main buoyancy chambers (pontoons) below the active wave zone to provide enhanced vessel stability.

separator. A cylindrical or spherical vessel used to separate the components in mixed streams of fluids.

sequence. A succession of geological events, processes or rocks, arranged in chronological order to show their relative position and age with respect to the geological history as a whole.

shale. Sedimentary rock consisting dominantly of clay-sized particles, an appreciable amount of which are clay minerals.

shear. A stress causing or tending to cause two adjacent parts of a solid to slide past one another in parallel to the plane of contact.

shelf break. An abrupt change in slope, marking the boundary between the Continental Shelf and the Continental Slope.

shuttle tanker. A ship with large tanks in the hull for carrying oil or water back and forth over a short route.

SI. Abbreviation for Scates Index or System Internatinale (the metric system).

siderite. A mineral, $FeCO_3$, commonly containing also magnesium and manganese.

sidescan sonar. A high frequency acoustic method used in ocean bottom mapping. The survey is completed from the side of the survey ship.

silt. A detrital particle smaller than a very fine sand grain and larger than coarse clay, ranging from 0.004 to 0.625 mm in diameter.

siltstone. Consolidated sediment consisting predominantly of silt-sized grains.

SO_4. Abbreviation for sulphate.

sorting. The degree of similarity in grain size of sedimentary particles in a sediment; a measure of the spread or range of the particle-size distribution on either side of an average.

source rock. Sedimentary rock in which organic material under pressure, heat and time was transformed into liquid or gaseous hydrocarbons (usually shale or limestone).

Spider Buoy. Disconnectable interface between the risers and the FPSO.

SPM. Acronym for Single Point Mooring.

Sr. Abbreviation for strontium.

ss [or SS]. The abbreviation for subsea.

stacked data. The sum of several seismic traces that have been corrected for moveout and statics.

stratification. Division of the water column into layers, or strata, because of differences in water density, structure or temperature.

stratigraphy. A branch of geology concerned with the form, arrangement, geographic distribution, chronological succession, composition, correlation and mutual relationships of rock strata, especially sedimentary.

stratum. A tabular or sheet-like body or layer of sedimentary rock, visually separable from other layers above and below; a bed. It has been defined as a stratigraphic unit that may be composed of a number of beds, as a layer greater than 1 cm in thickness and constituting a part of a bed, and as a general term that includes both "bed" and "lamination". The term is more frequently used in its plural form, strata.

strike. The direction or trend taken by a structural surface (for example, a bedding or fault plane) as it intersects the horizontal.

structural culmination. The highest point of a structural feature.

subaerial. Formed, existing or taking place on the land surface.

submarine canyon. Steep valley-like submarine depression crossing the continental-margin region. Common on the Continental Slope and Shelf, but some continue across the Continental Rise.

surficial. Characteristic of, pertaining to, formed on, situated at or occurring on the Earth's surface; especially, consisting of unconsolidated residual, alluvial or glacial deposits; laying on the bedrock.

2-D. Abbreviation for two-dimensional.

3-D. Abbreviation for three-dimensional.

t. The abbreviation for tonne (a metric ton).

TBFZ. Acronym for Trans-Basin Fault Zone.

TCP. Acronym for tubing conveyed perforating.

td. Abbreviation for total depth.

tectonic. Of, or relating to the deformation of the Earth's crust; the forces involved in or producing such deformation, and the resulting forms.

tectonics. A branch of geology dealing with the broad architecture of the outer part of the Earth, that is, the regional assembling of structural or deformational features, a study of their mutual relations, origin and historical evolution. It is closely related to structural geology, with which the distinctions are blurred, but tectonics generally deals with larger features.

template. Device through which a group of wells is drilled and produced.

Tertiary. A period of geologic time from approximately 65 to 2.5 million years ago. The earliest large mammals, grasses and hominids appeared during this period. It is also the period during which most of today's high mountain ranges were formed.

TIF. Acronym for test independent failure.

till. Non-sorted, non-stratified material (containing particles ranging in size from clay particles to boulders) that has been carried or deposited by a glacier.

TLP. Acronym for tension leg platform.

TLS. Acronym for target levels of safety.

topside (or topsides) facilities. The oil- and gas-producing and support equipment located on the top of an offshore structure.

TPH. Acronym for total petroleum hydrocarbons.

transgressive (or transgression). Refers to the encroachment of the sea upon the land.

transport (or transportation). A phase of sedimentation that includes the movement by natural agents (such as flowing water, ice, wind or gravity) of sediment or of any loose material, either as solid particles or in solution, from one place to another on or near the Earth's surface (for example, the drifting of sand along a seashore under the influence of currents, the creeping movement of rocks on a glacier or the conveyance of silt, clay and dissolved salts by a stream).

trap. The mechanism or feature causing hydrocarbon to be retained in a reservoir rock.

tree. (a) An arrangement of valves placed on top of a well to control flow from the well. (b) An arrangement of valves and fittings attached to the tubing head to control flow and provide access to the tubing string.

TSR. Acronym for temporary safe refuge.

turret. A low, tower-like structure capable of revolving horizontally within the hull of a ship and connected to a number of mooring lines and risers. It allows the ship to rotate with the weather while maintaining a fixed mooring system.

TVD. Acronym for true vertical depth.

umbilical. Device through which control of subsea instrumentation is maintained from the FPSO.

unconformity. The structural relationship between rock strata in contact, characterized by a lack of continuity in deposition and corresponding to a period of nondeposition, weathering or especially erosion (either subaerial or subaqueous) before the deposition of the younger beds.

UPS. Acronym for uninterruptible power supply.

VCS. Acronym for vessel control system.

VHF. Acronym for very high frequency.

viscosity. The measure of the resistance of a fluid to flow; the lower the viscosity number, the more readily the fluid will flow.

vitrinite. A coal maceral group distinguished by a middle level of reflectance higher than exinite but lower than inertinite in the same coal.

W. Abbreviation for watt.

water-based mud (WBM). A drilling mud in which the continuous phase is water. See drilling mud.

well workover. A program of work performed on an existing well; may involve re-evaluating the production formation, clearing sand from producing zones, jet lifting, replacing downhole equipment, deepening the well, acidizing or fracturing, or improving the drive mechanism.

White Rose Development. "Development" refers to all phases of the project, from the decision to go ahead with construction through to abandonment of the field.

WHMIS. Acronym for Workplace Hazardous Materials Information Systems.

wireline. A rope composed of steel wires twisted into strands that are in turn twisted around a central core of hemp or other fibre to create a rope of great strength and flexibility; used to lower and raise logging instruments and bottom line-pressure gauges.

WOA. Acronym for Well Operations Authorization.

WOR. Acronym for water-oil ratio.

workover. Intervention procedure performed on a well involving rig, wireline and/or coil tubing to improve well integrity or well performance.

yr. Abbreviation for year.

APPENDIX 2.A

Reservoir Maps

Avalon Full Field
TOP AVALON STRUCTURE

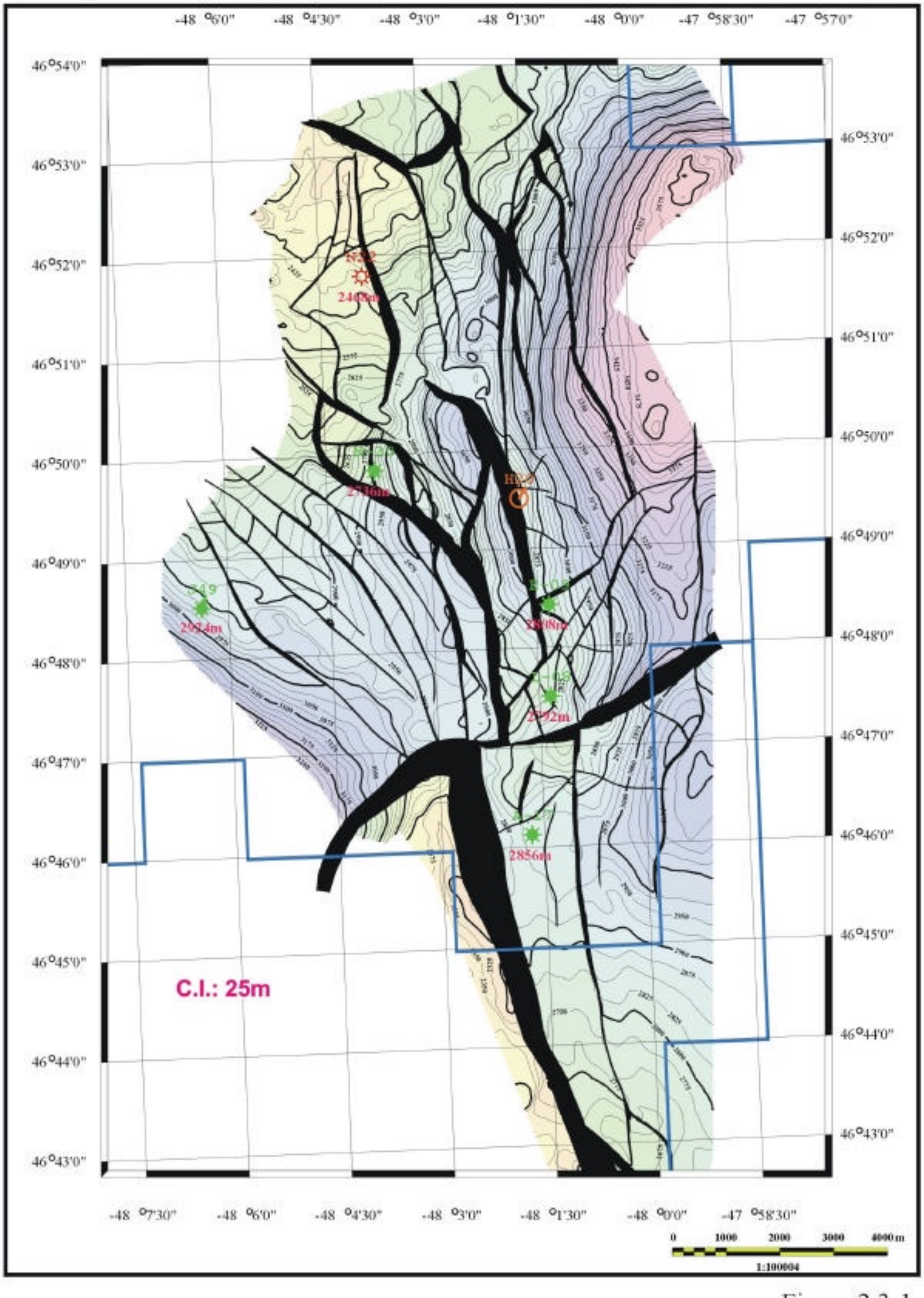

Figure 2.3-1

Avalon Full Field
TOP LAYER 1 STRUCTURE

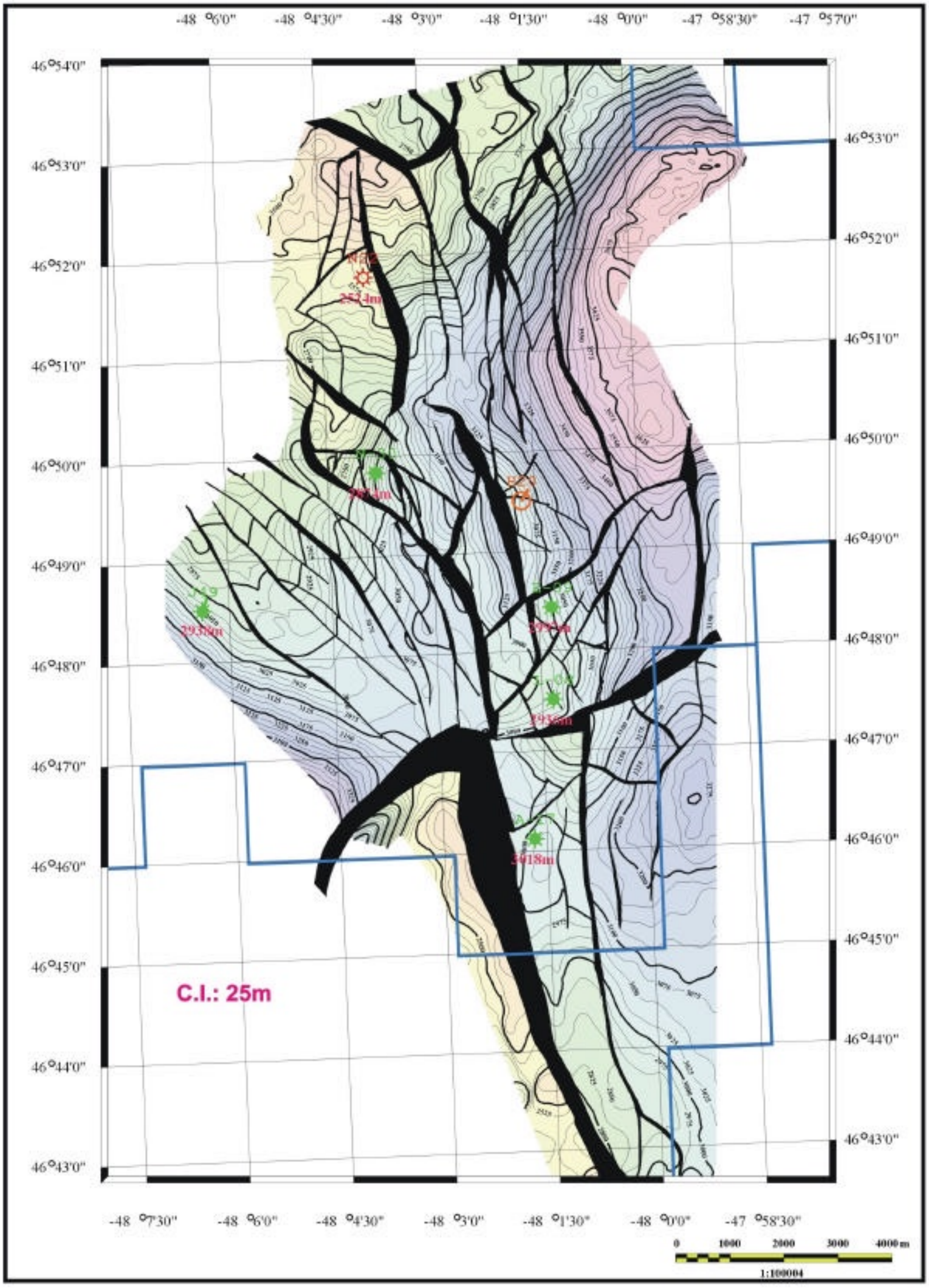

Figure 2.3-2

Avalon Full Field
BASE AVALON STRUCTURE

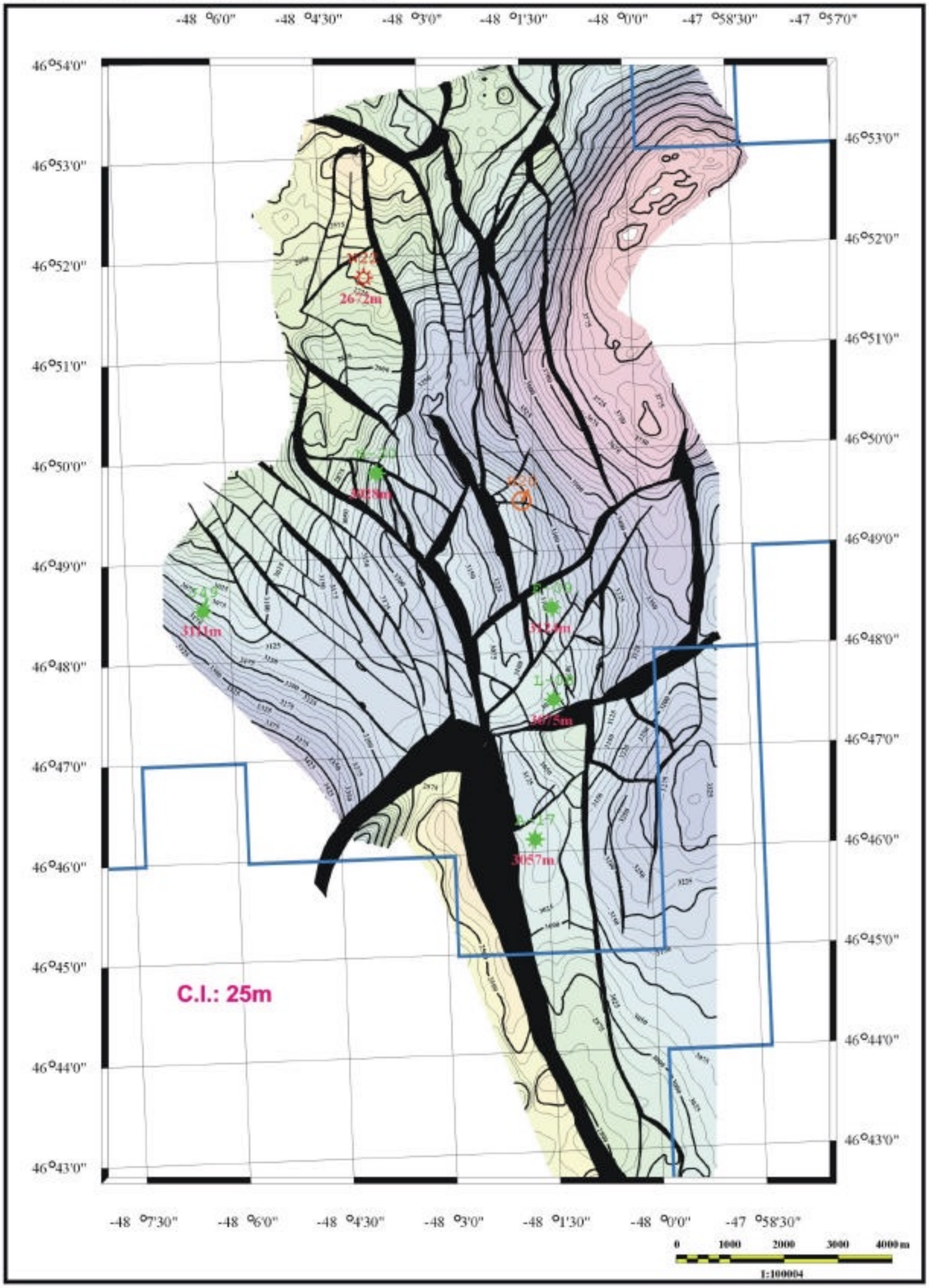

Figure 2.3-3

Avalon Full Field
AVALON GROSS ISOPACH

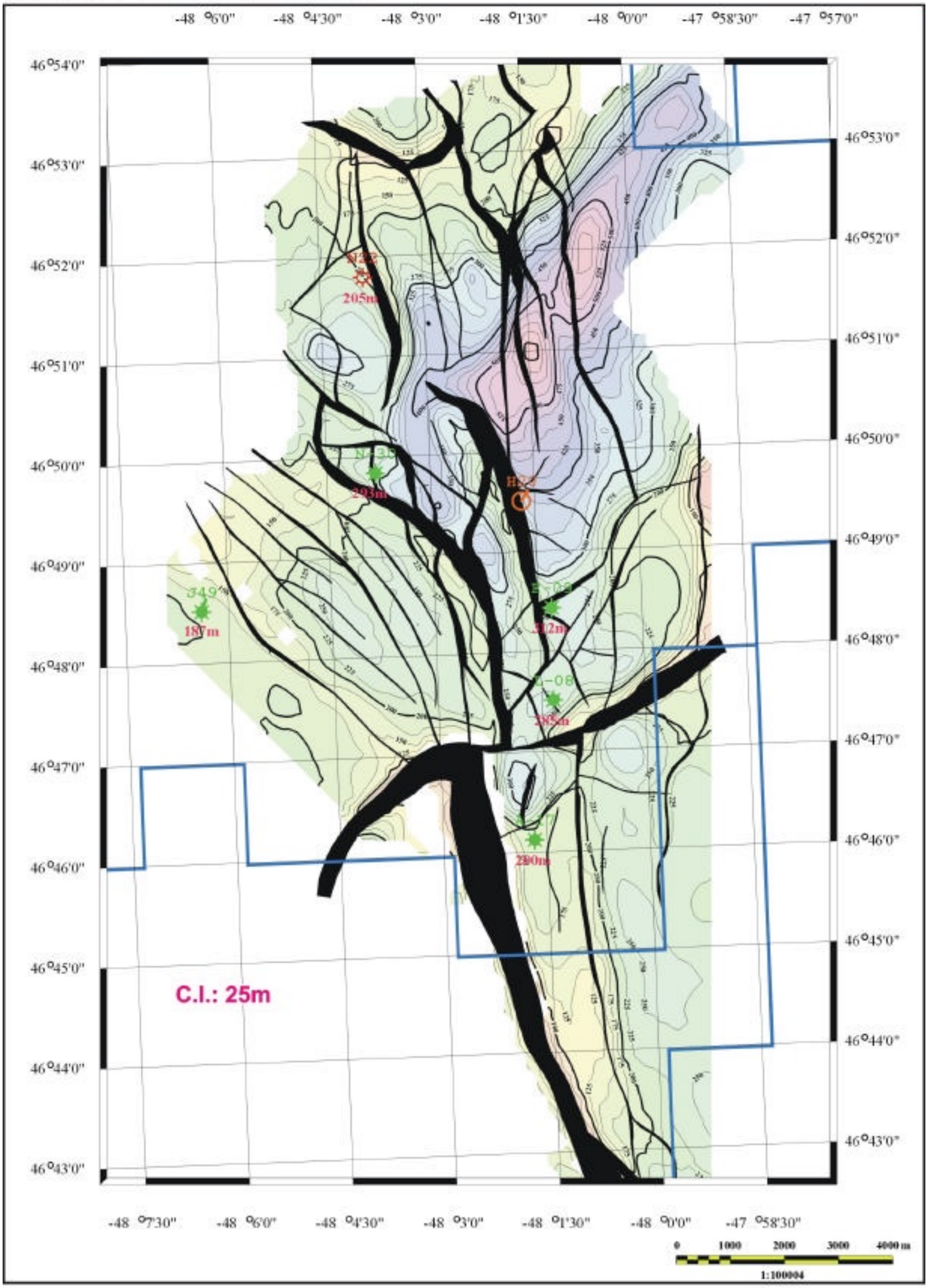

Figure 2.3-4

Avalon Full Field
LAYER 1 GROSS ISOPACH

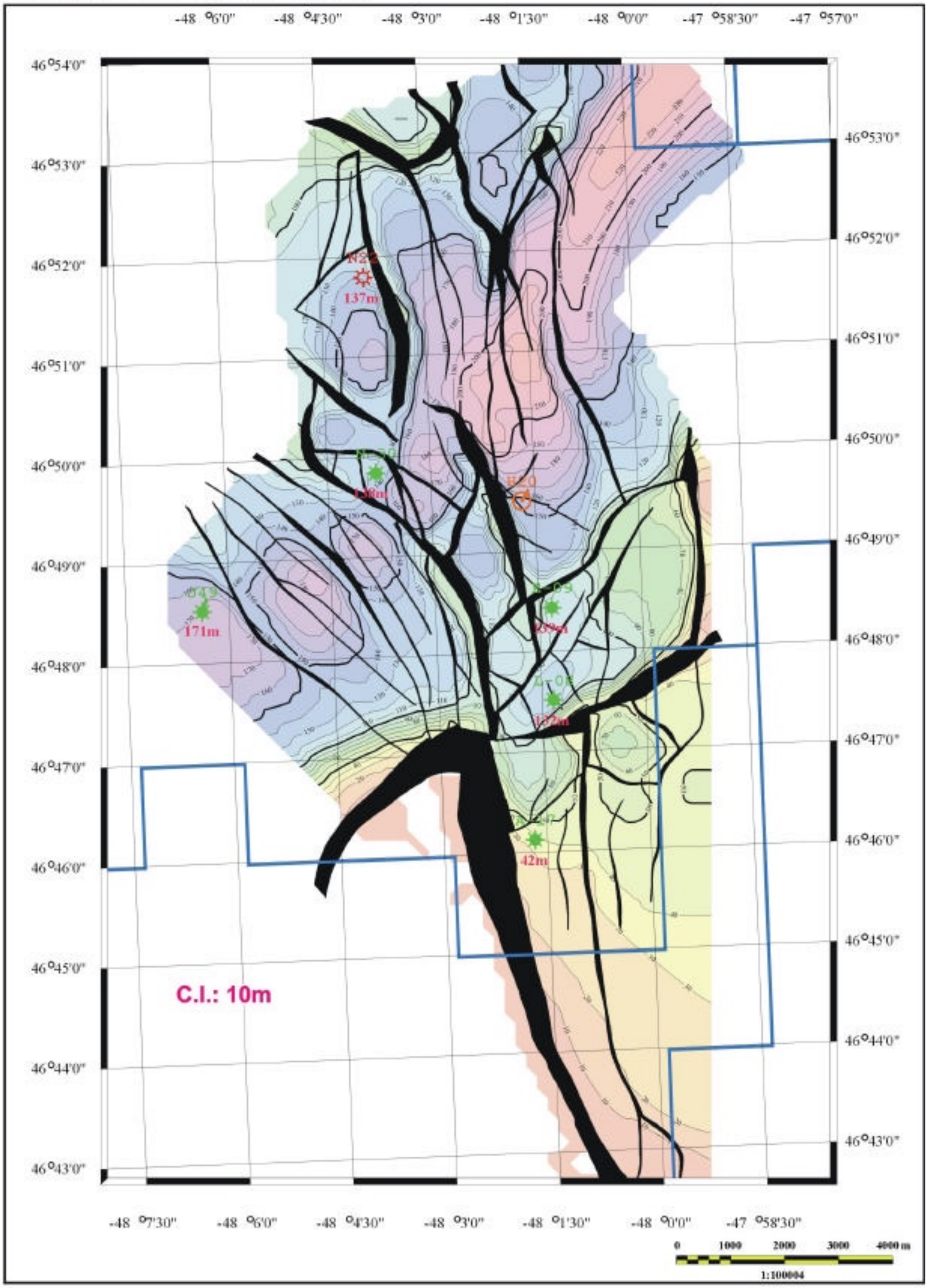

Figure 2.3-5

Avalon Full Field
LAYER 2 GROSS ISOPACH

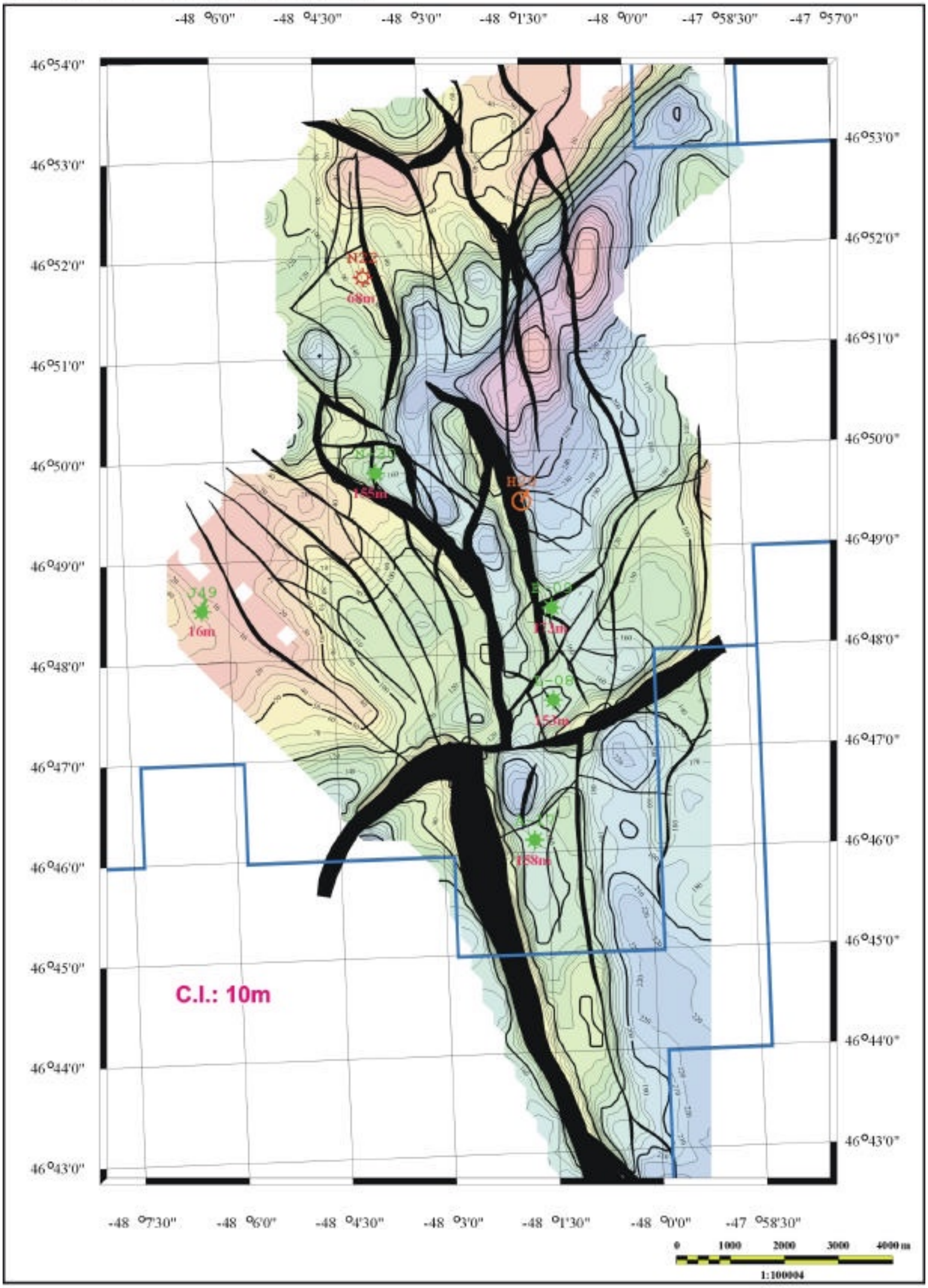

Figure 2.3-6

Avalon Full Field
AVALON NET SAND

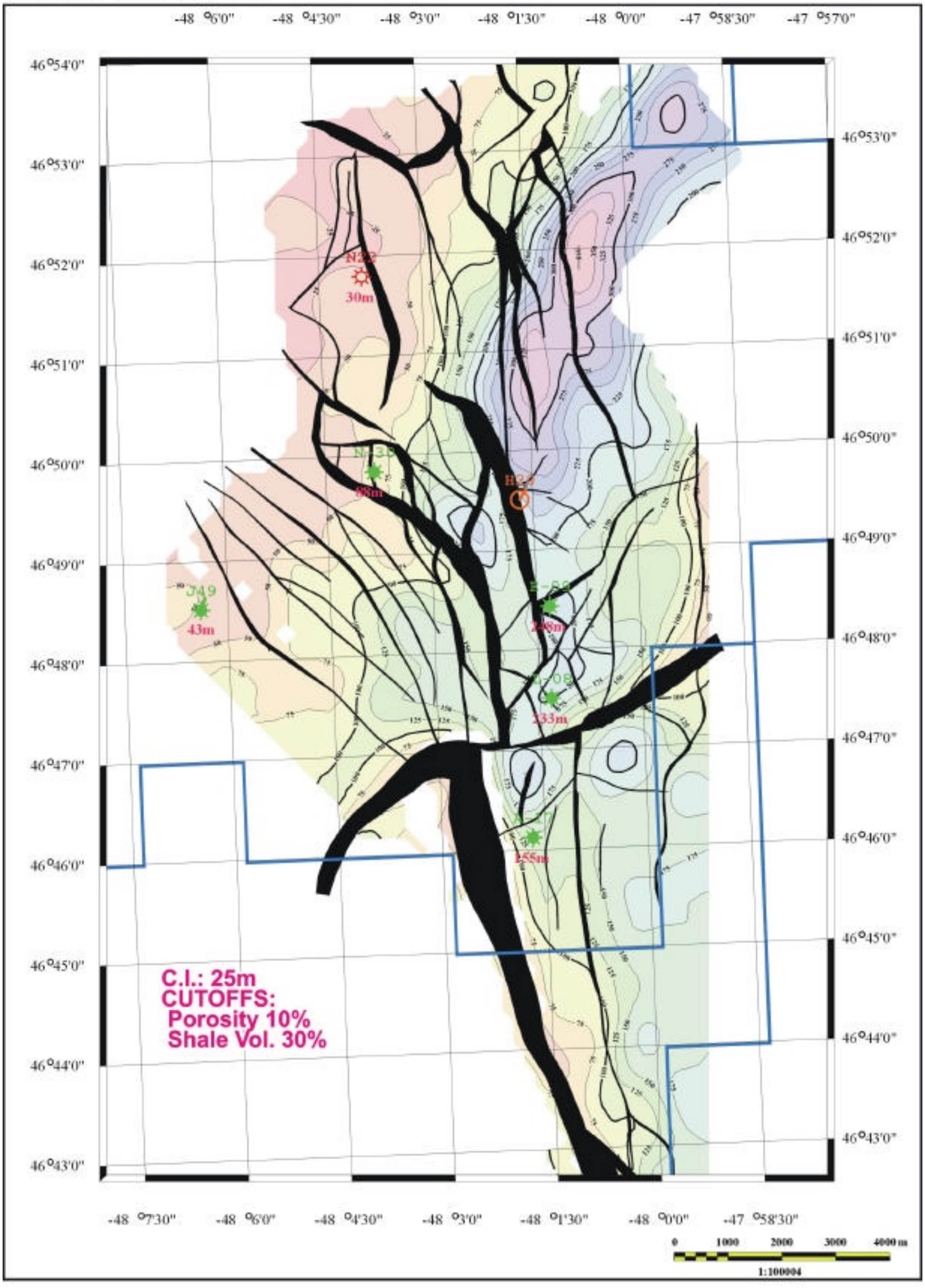

Figure 2.3-7

Avalon Full Field
LAYER 1 NET SAND

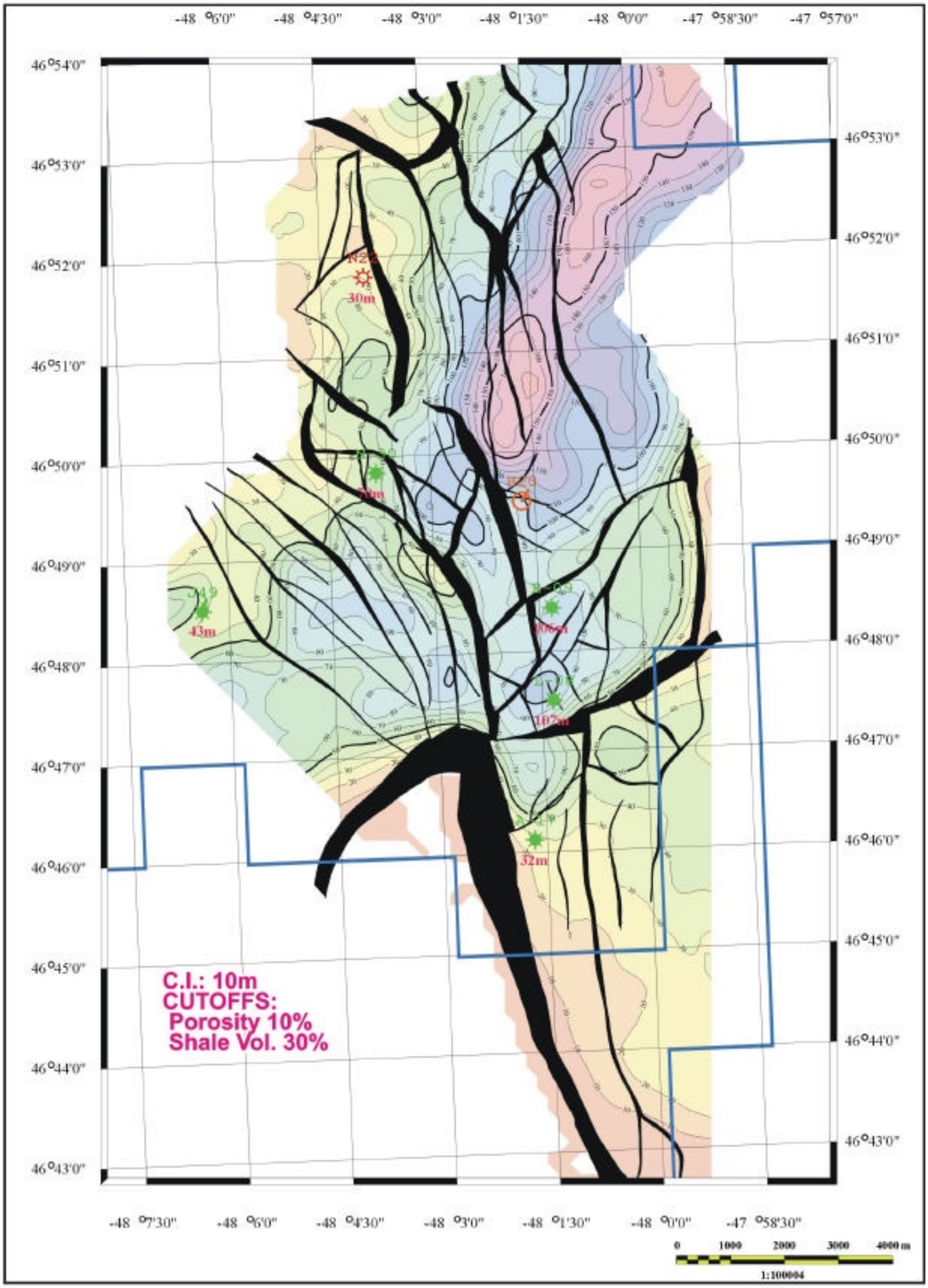

Figure 2.3-8

Avalon Full Field
LAYER 2 NET SAND

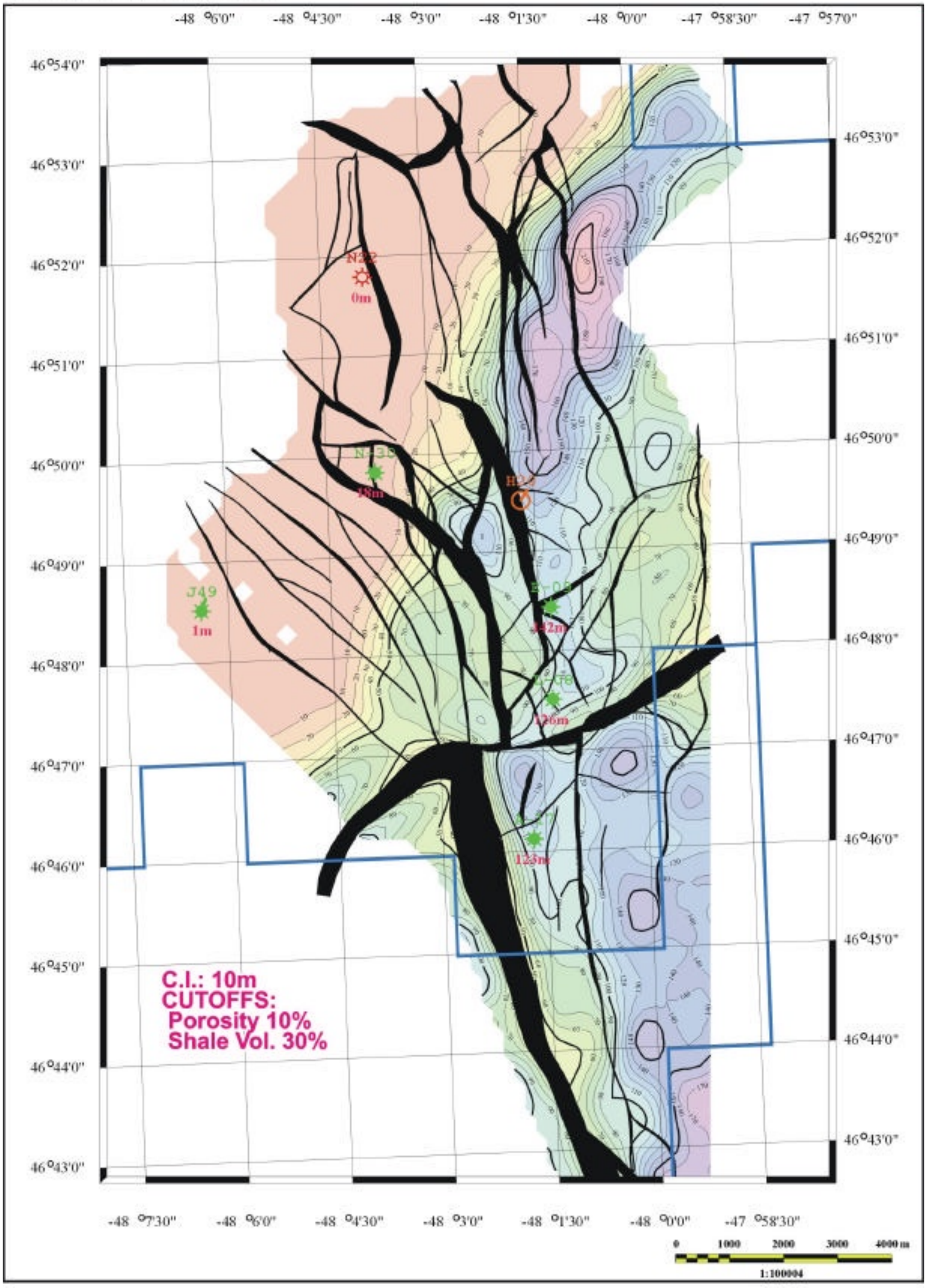

Figure 2.3-9

Avalon Full Field
AVALON NET OIL PAY

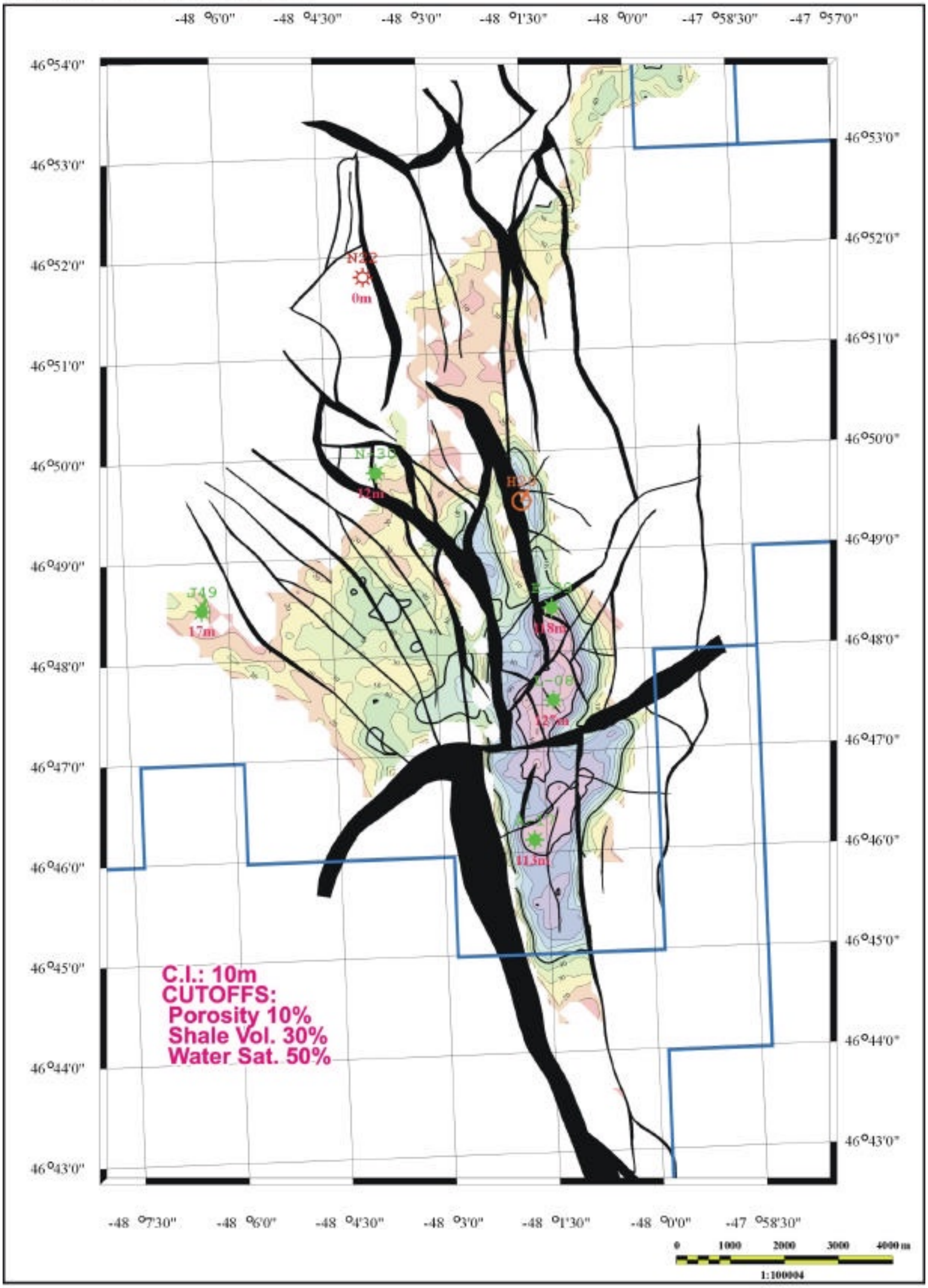

Figure 2.3-10

Avalon Full Field
LAYER 1 NET OIL PAY

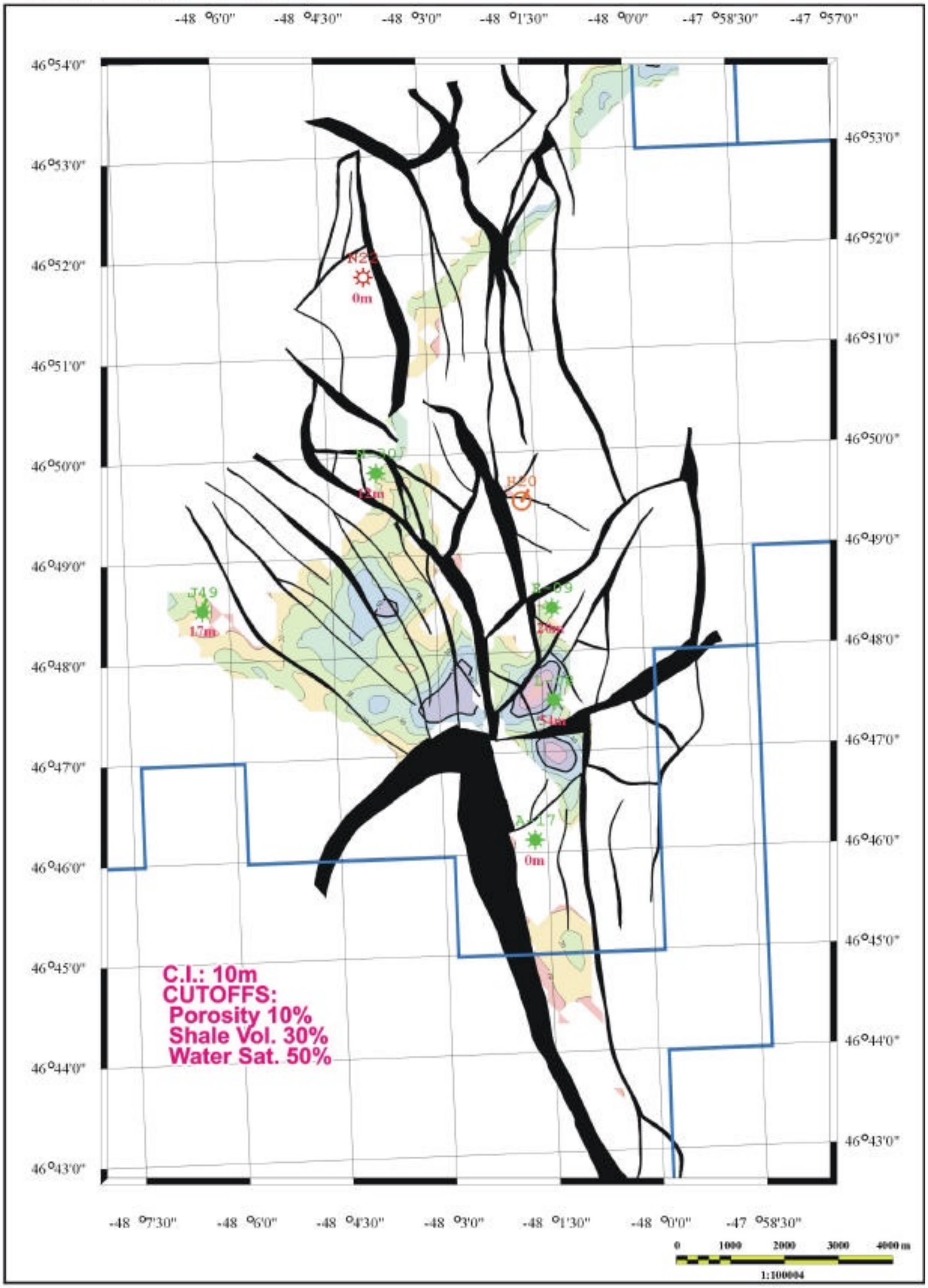

Figure 2.3-11

Avalon Full Field
LAYER 2 NET OIL PAY

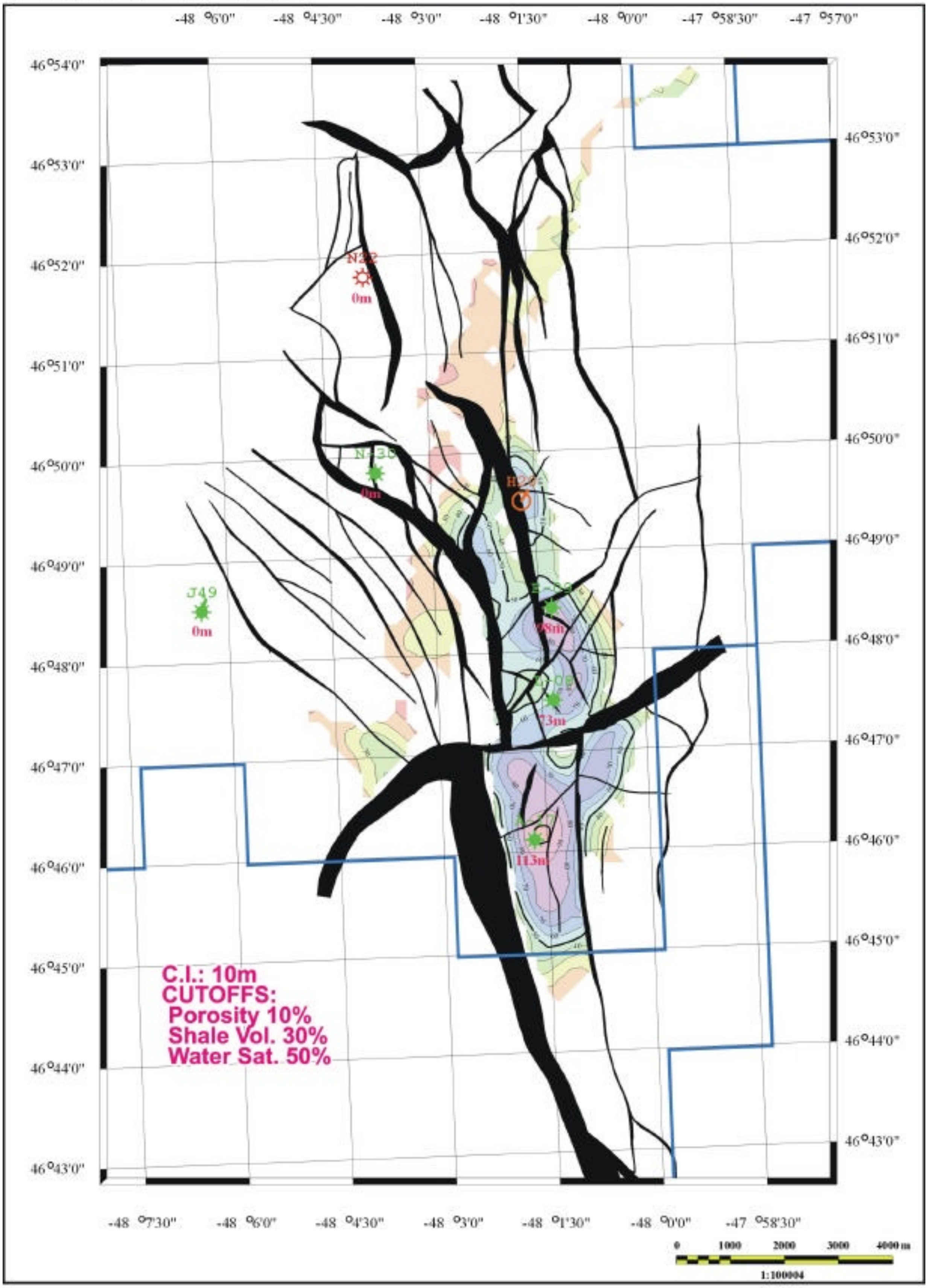

Figure 2.3-12

Avalon Full Field
AVALON NET GAS PAY

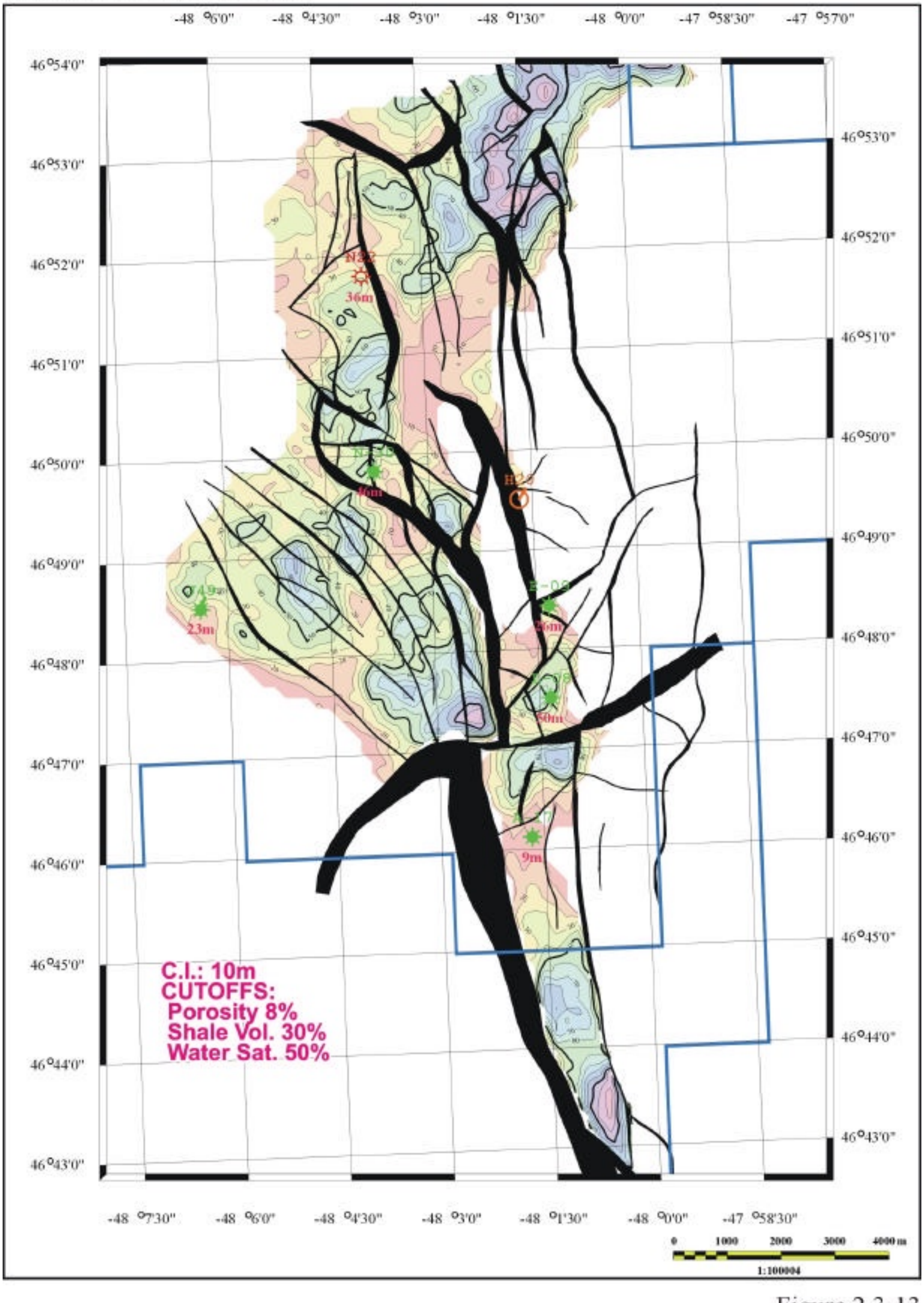

Figure 2.3-13

Avalon Full Field
LAYER 1 NET GAS PAY

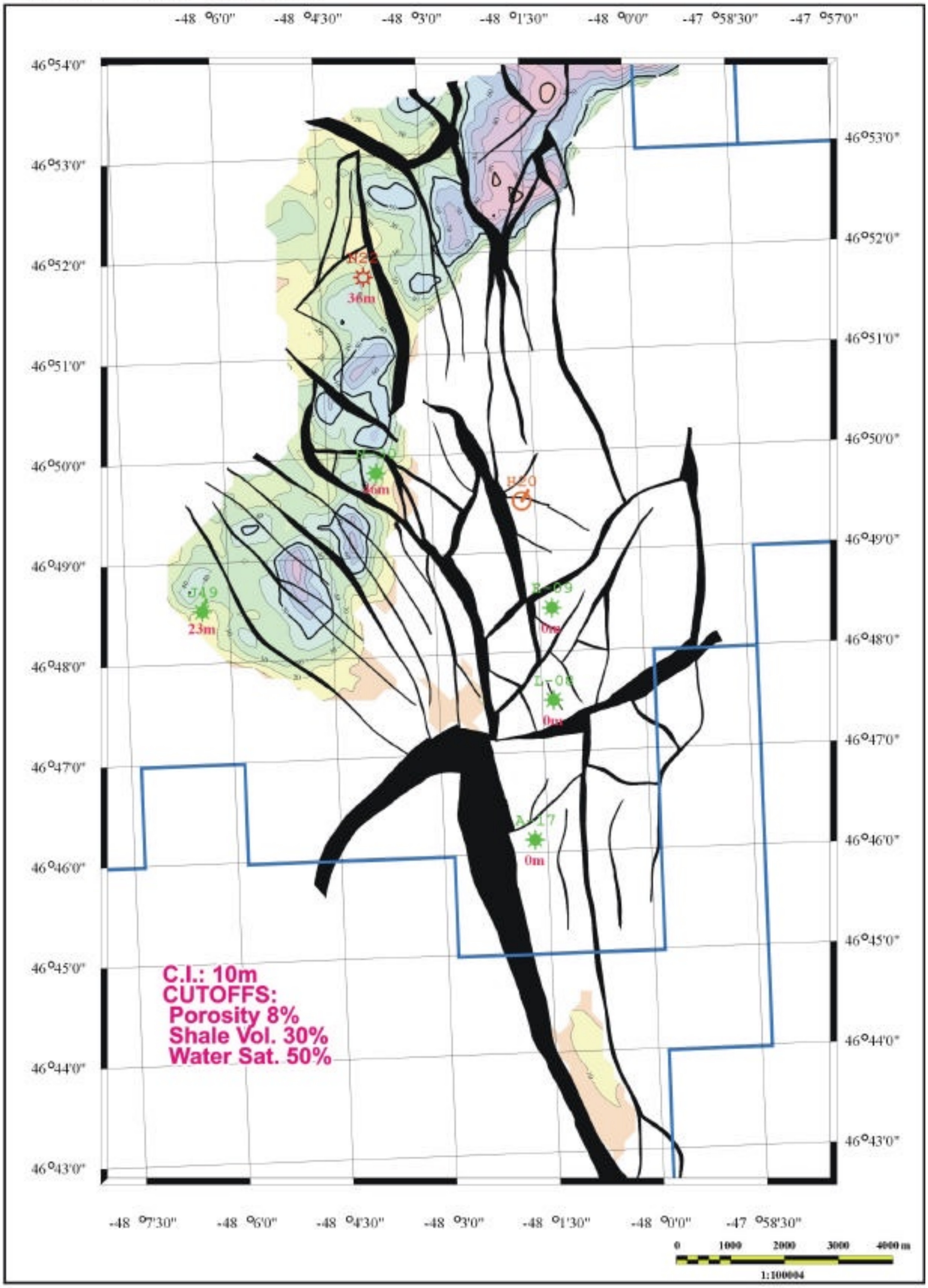

Figure 2.3-14

Avalon Full Field
LAYER 2 NET GAS PAY

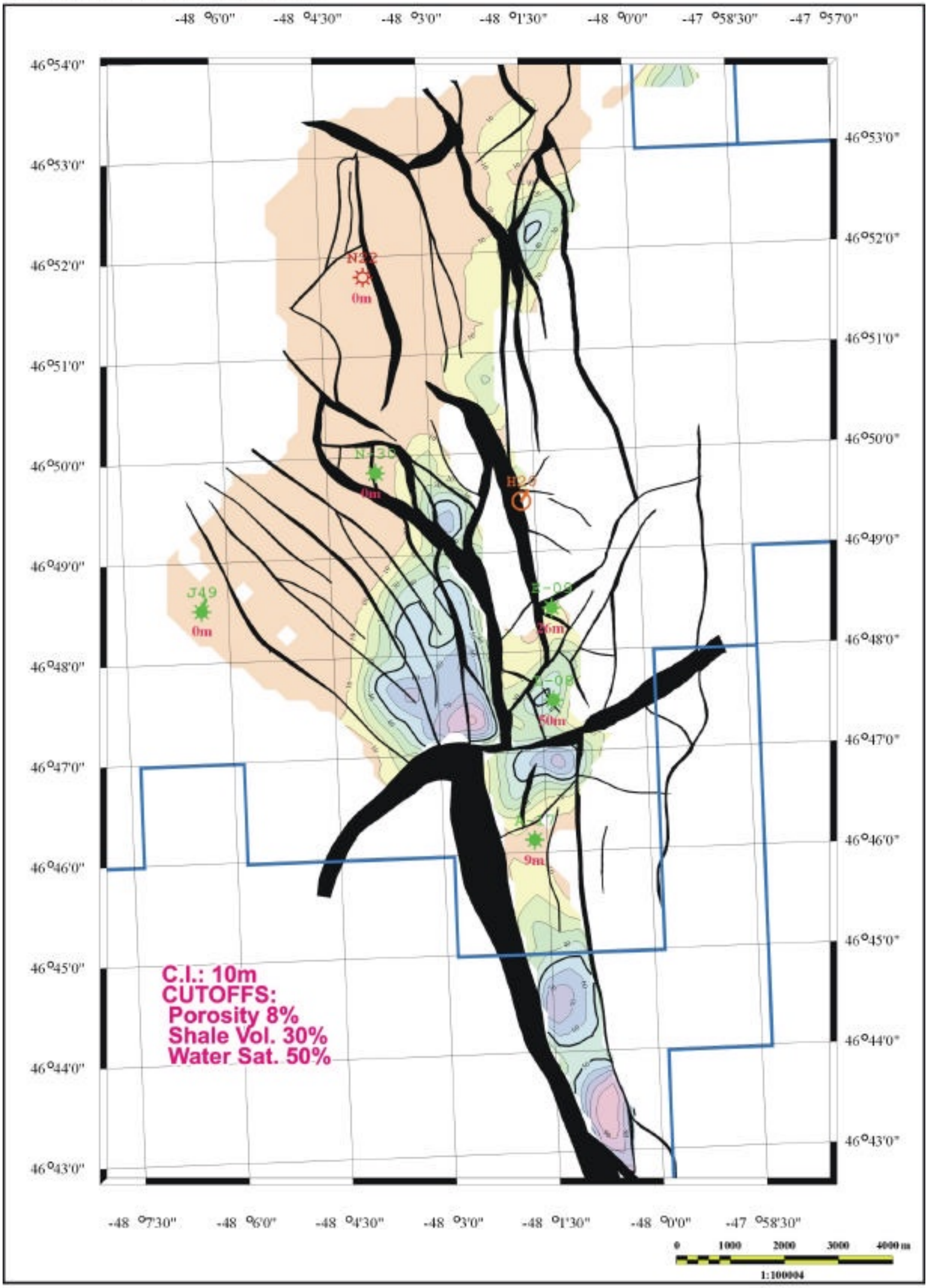

Figure 2.3-15

Avalon Full Field
AVALON ISOPOROSITY

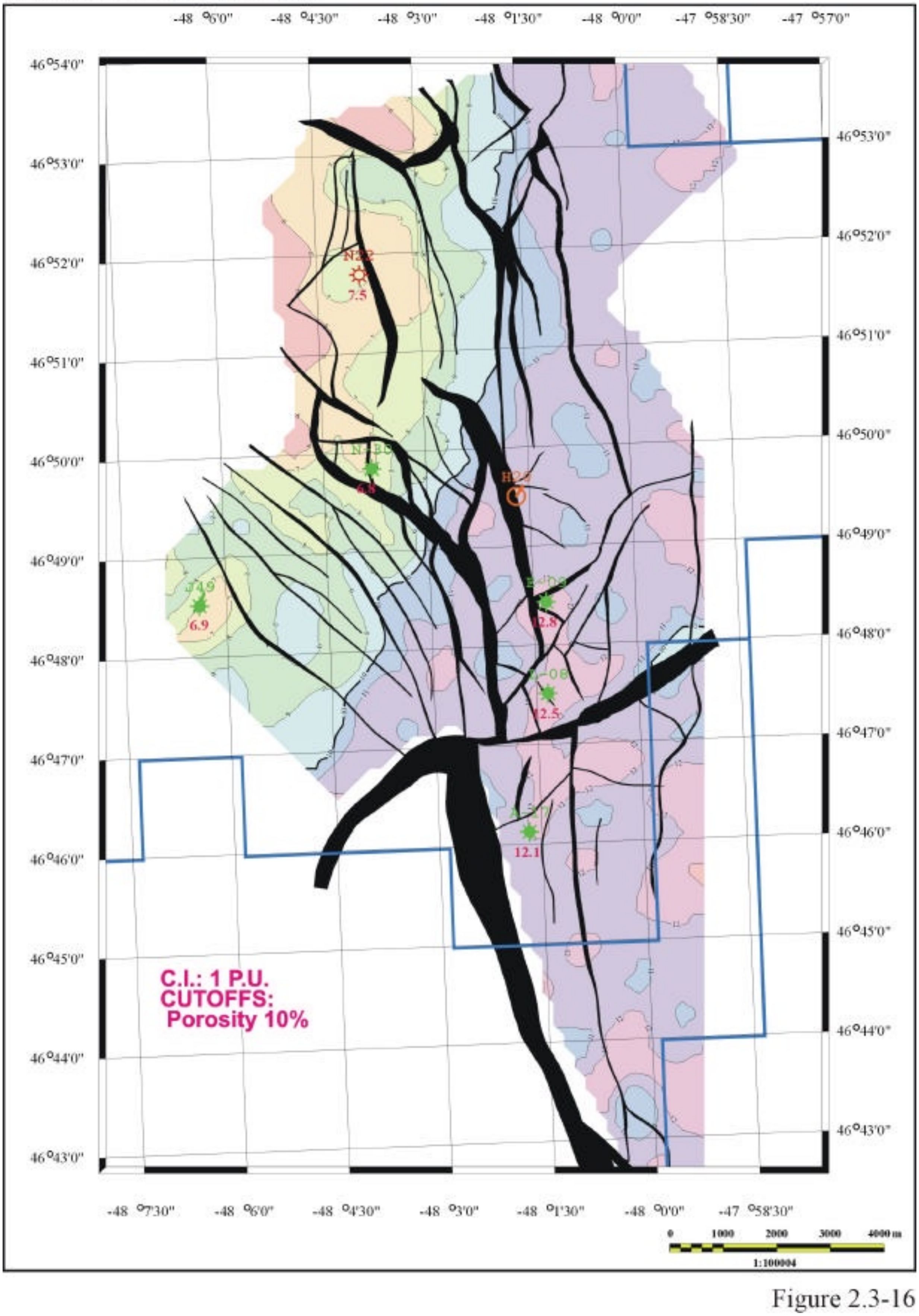

Figure 2.3-16

Avalon Full Field
LAYER 1 ISOPOROSITY

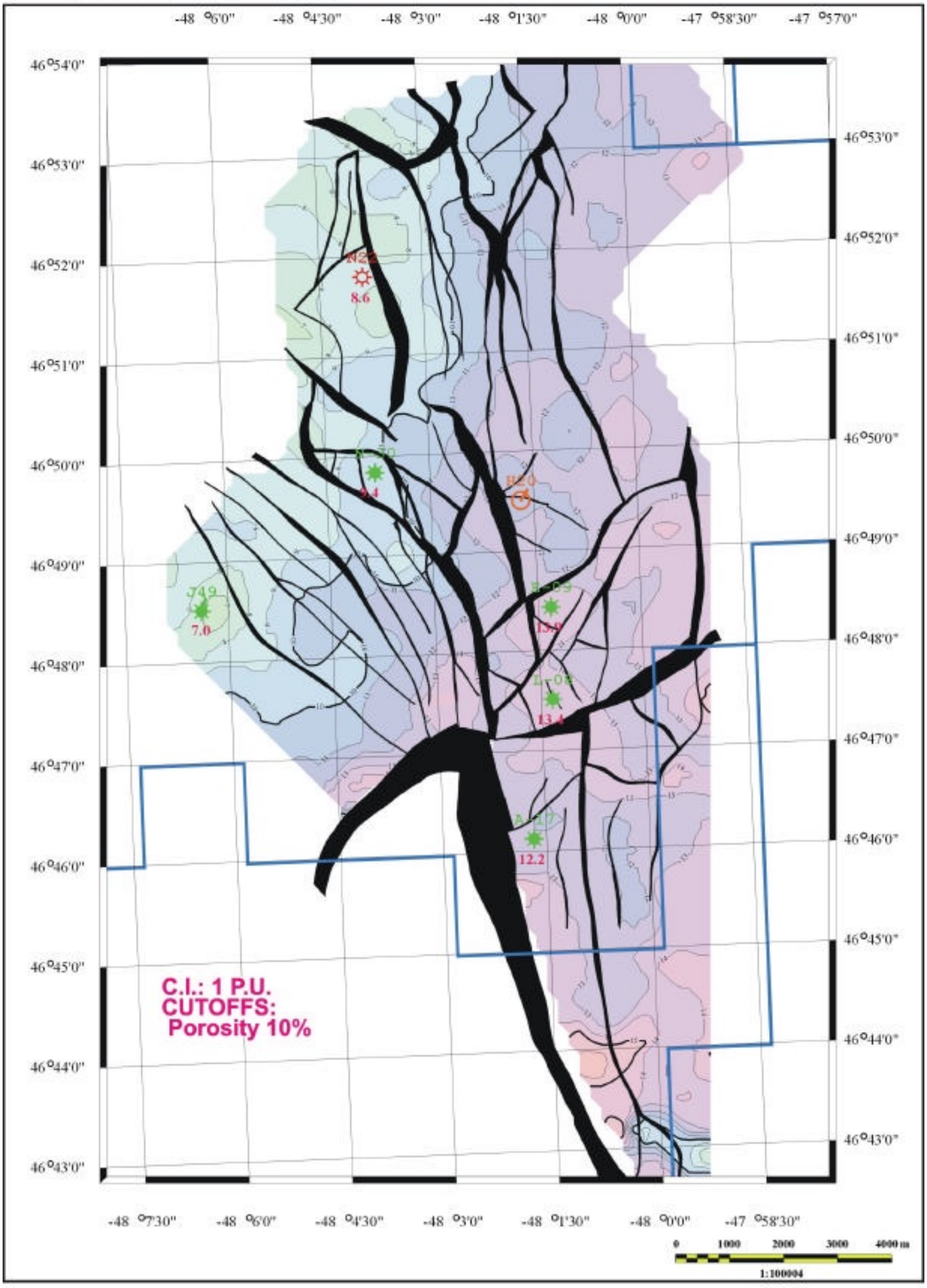

Figure 2.3-17

Avalon Full Field
LAYER 2 ISOPOROSITY

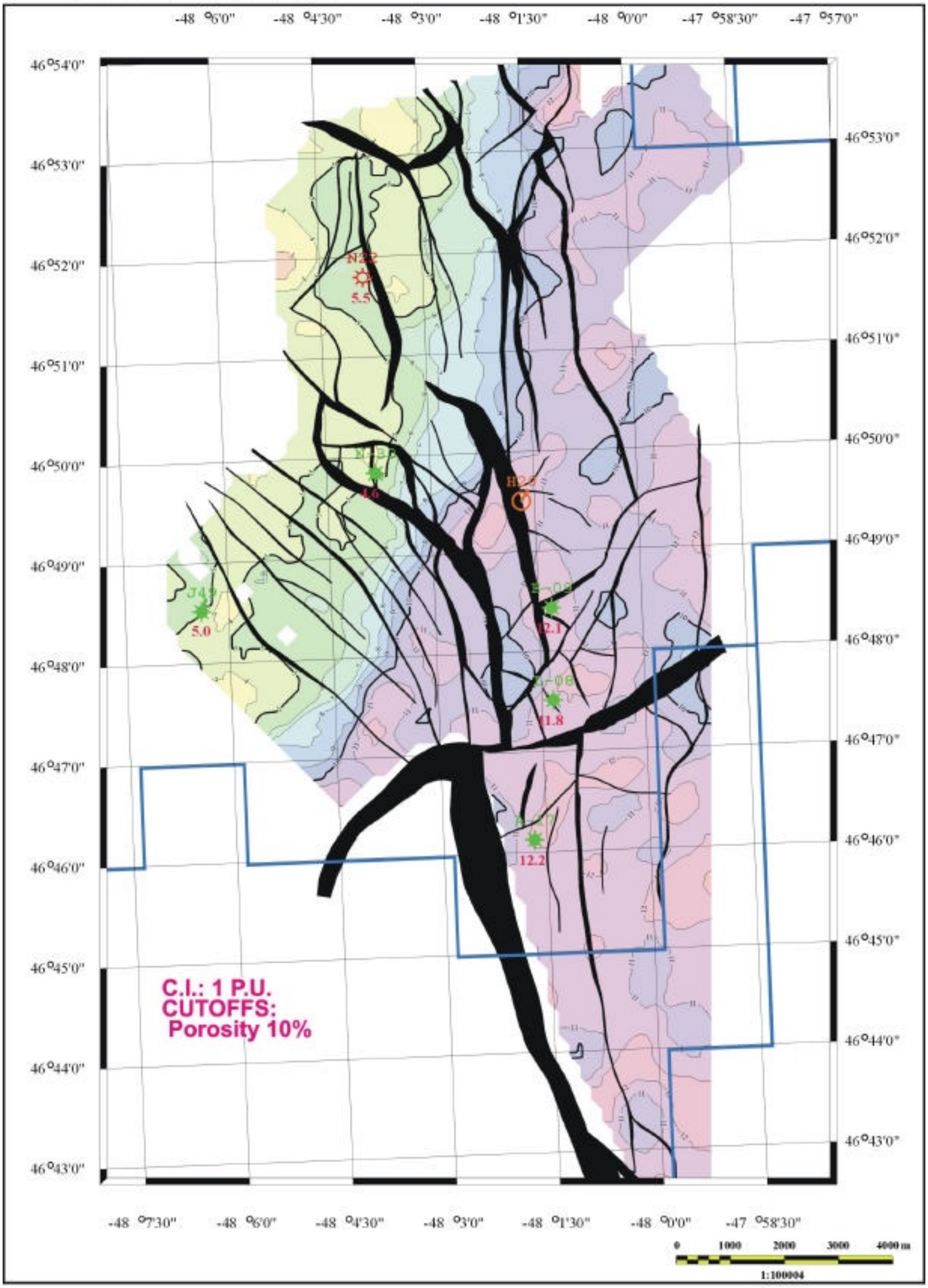

Figure 2.3-18

Avalon Full Field
AVALON OIL HCPV

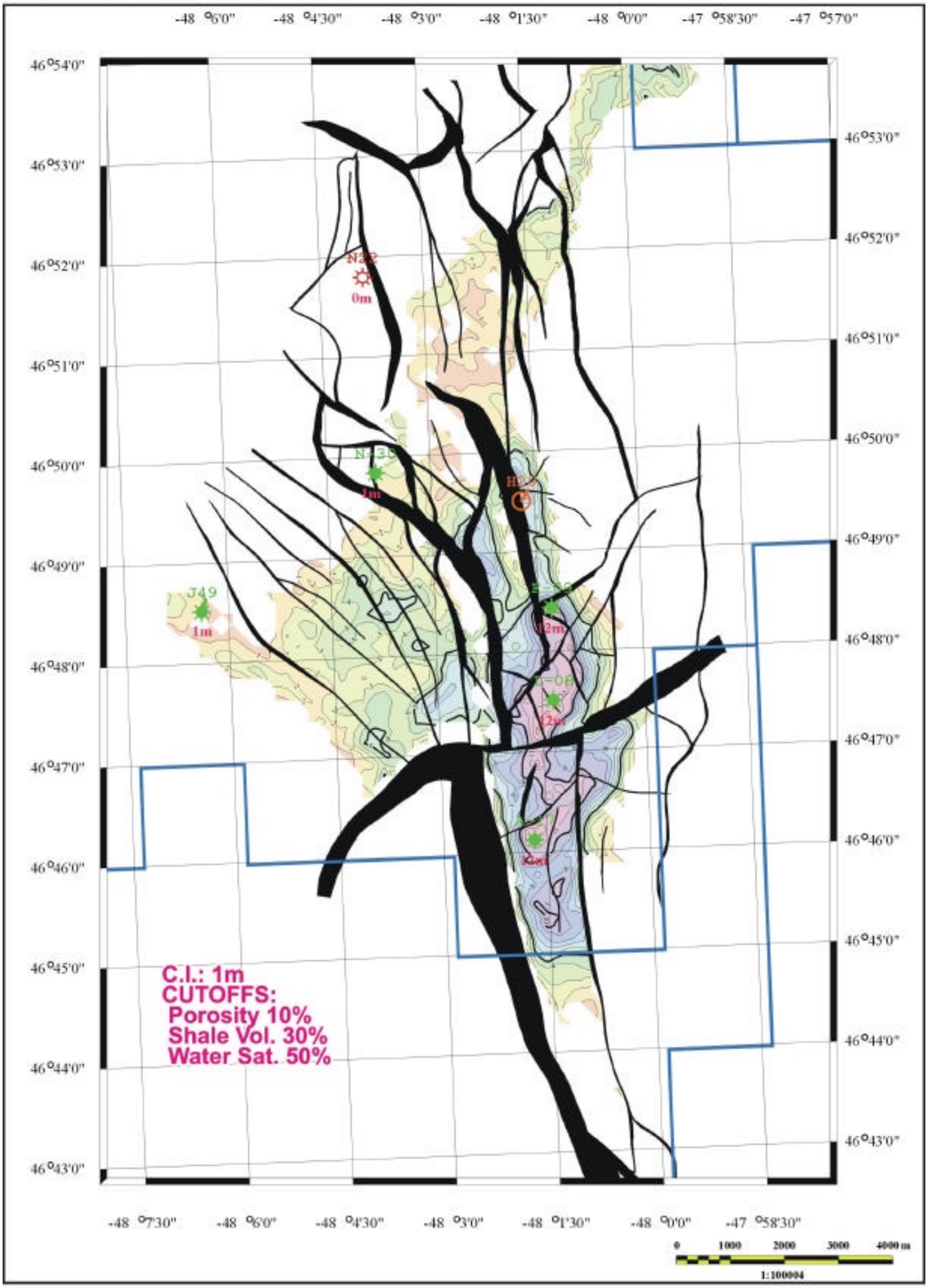

Figure 2.3-19

Avalon Full Field
LAYER 1 OIL HCPV

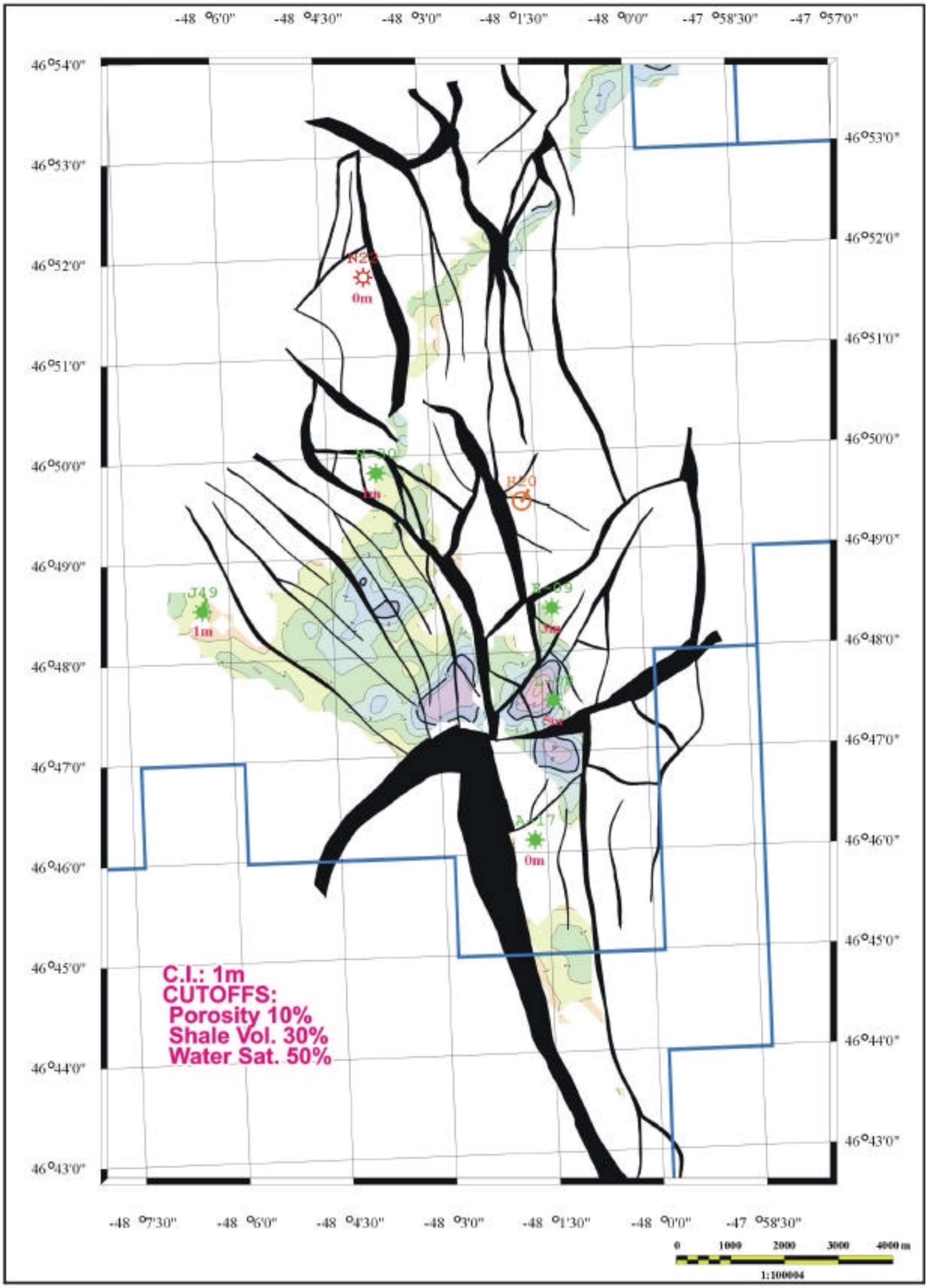

Figure 2.3-20

Avalon Full Field
LAYER 2 OIL HCPV

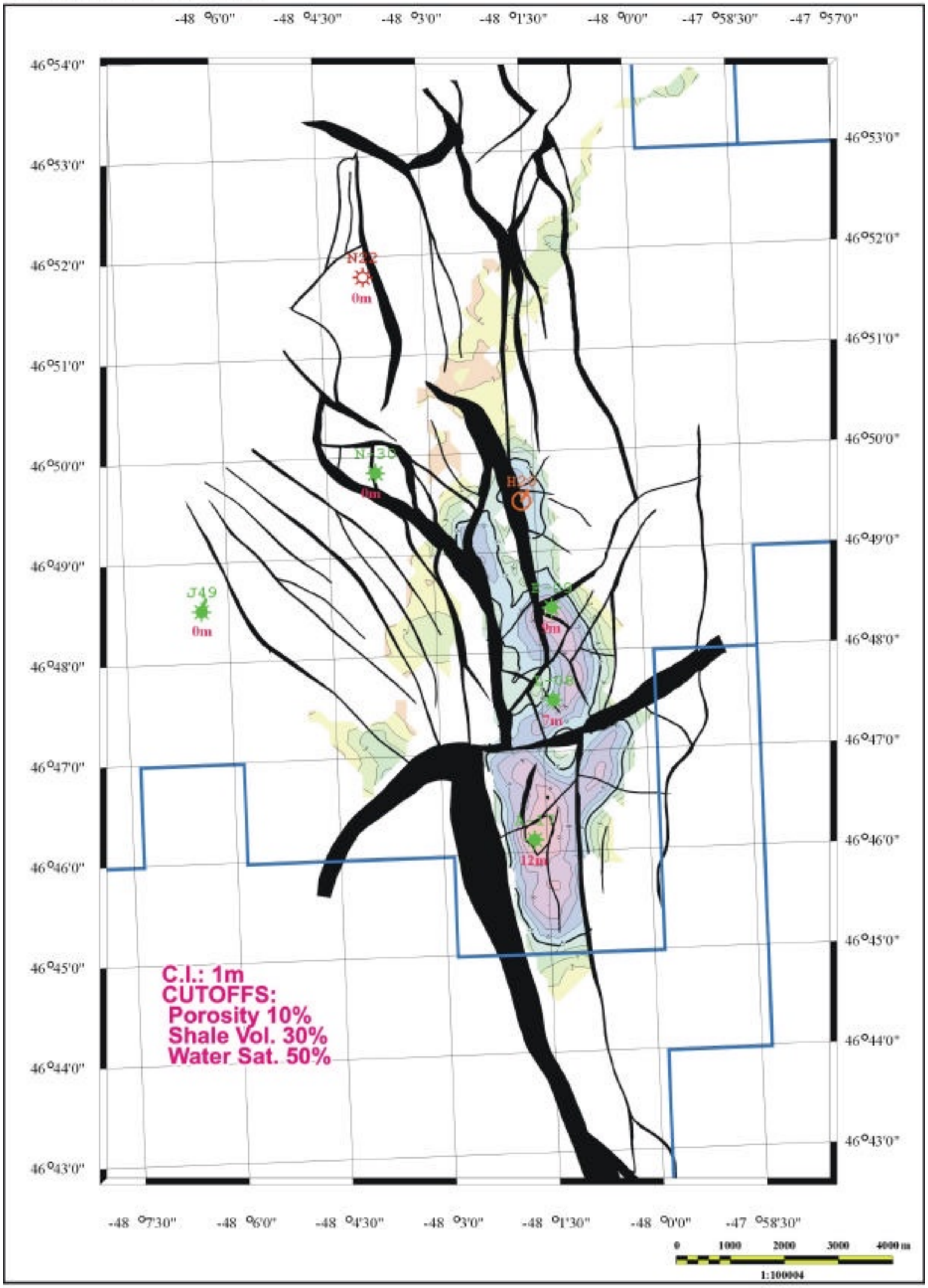

Figure 2.3-21

Avalon Full Field
AVALON GAS HCPV

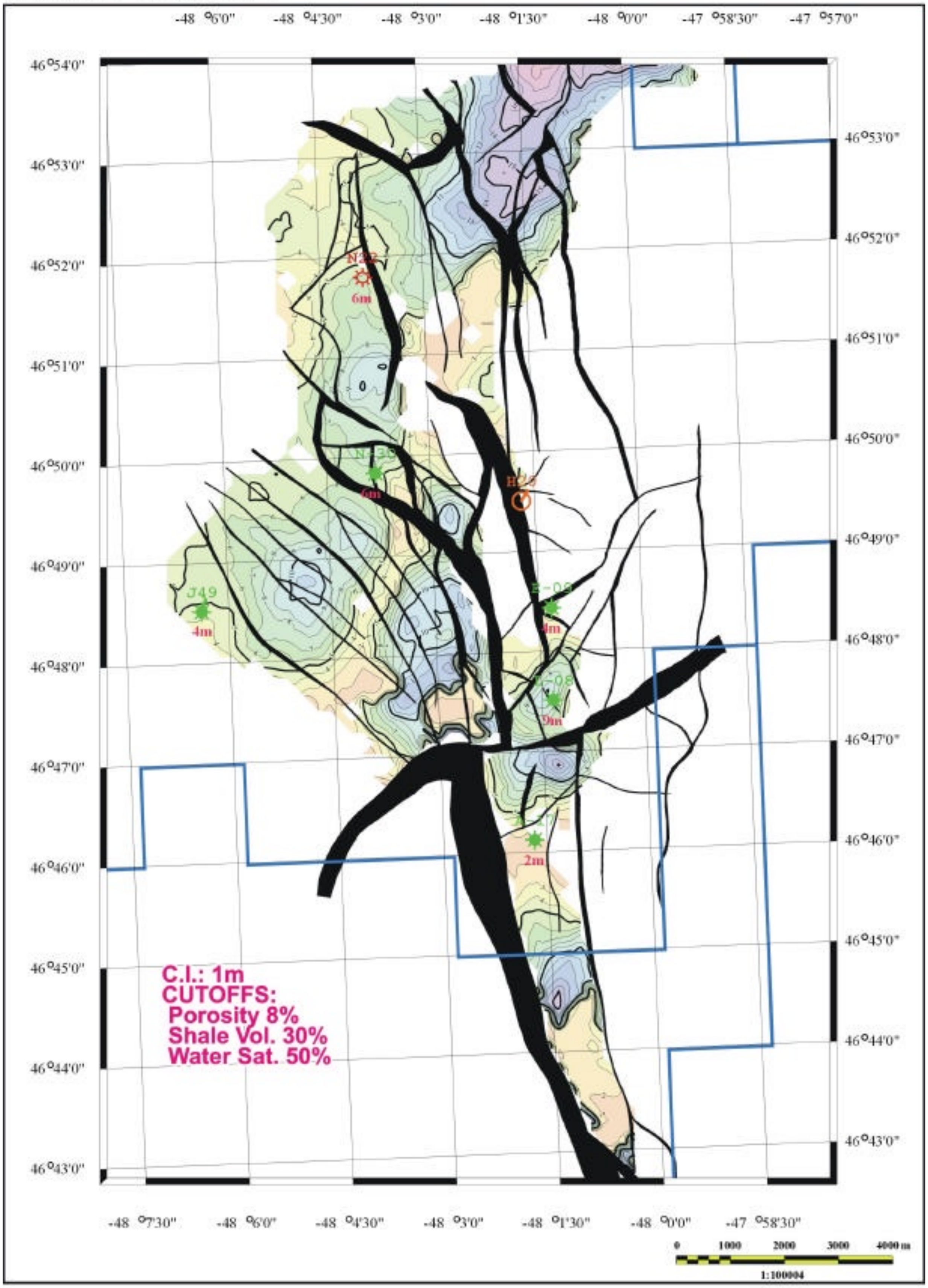

Figure 2.3-22

Avalon Full Field
LAYER 1 GAS HCPV

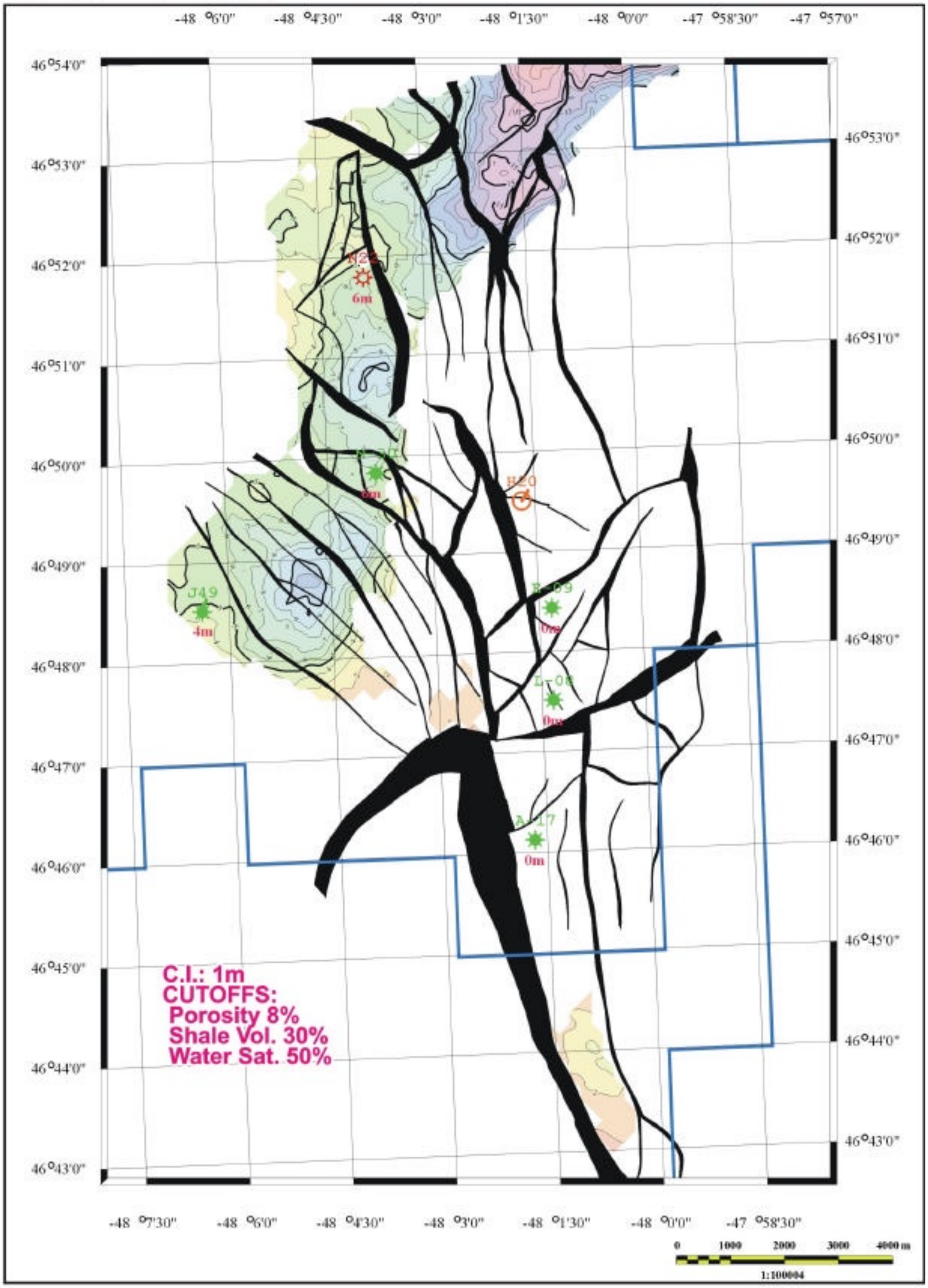

Figure 2.3-23

Avalon Full Field
LAYER 2 GAS HCPV

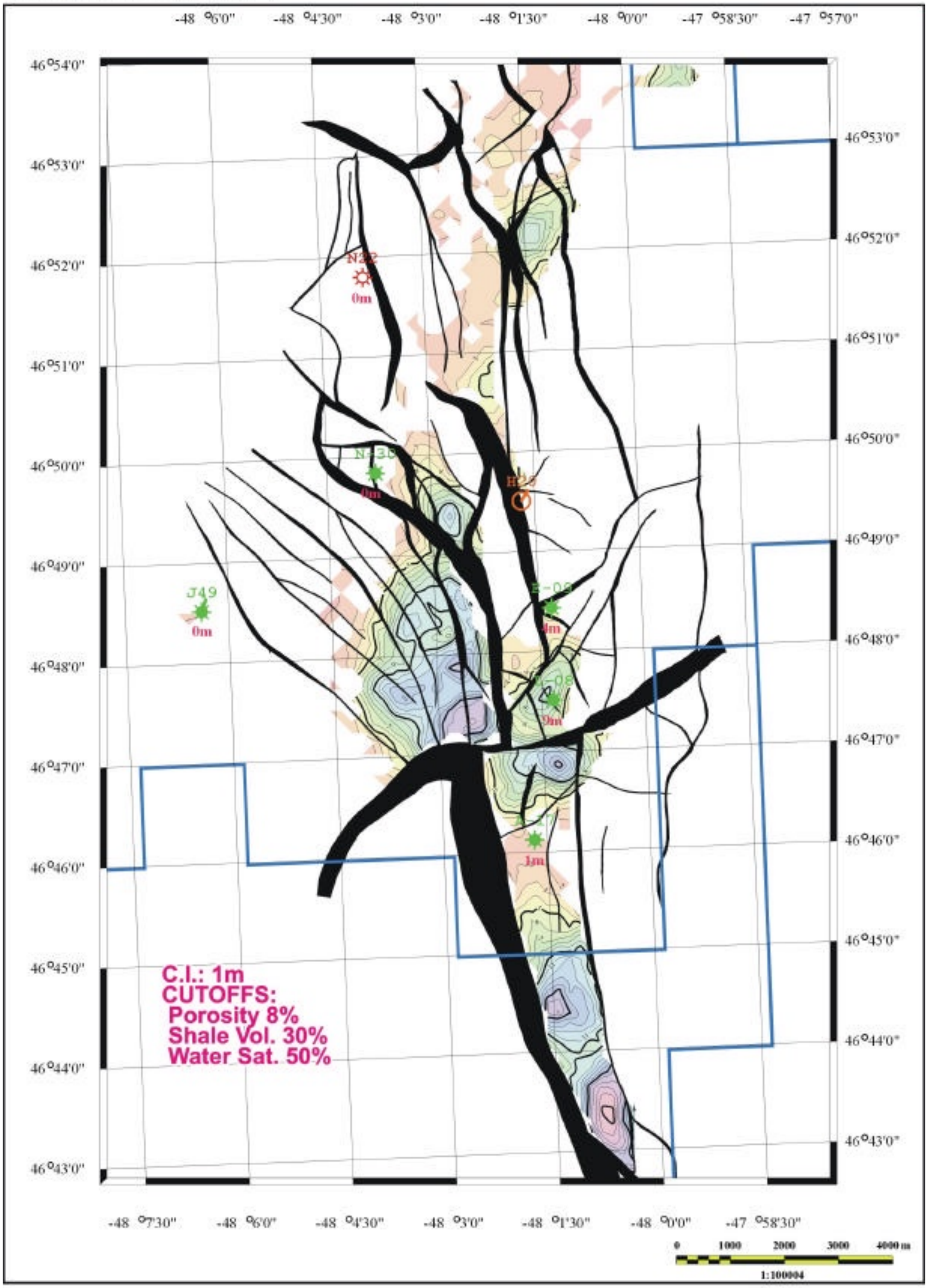

Figure 2.3-24

South Avalon Pool
TOP AVALON STRUCTURE

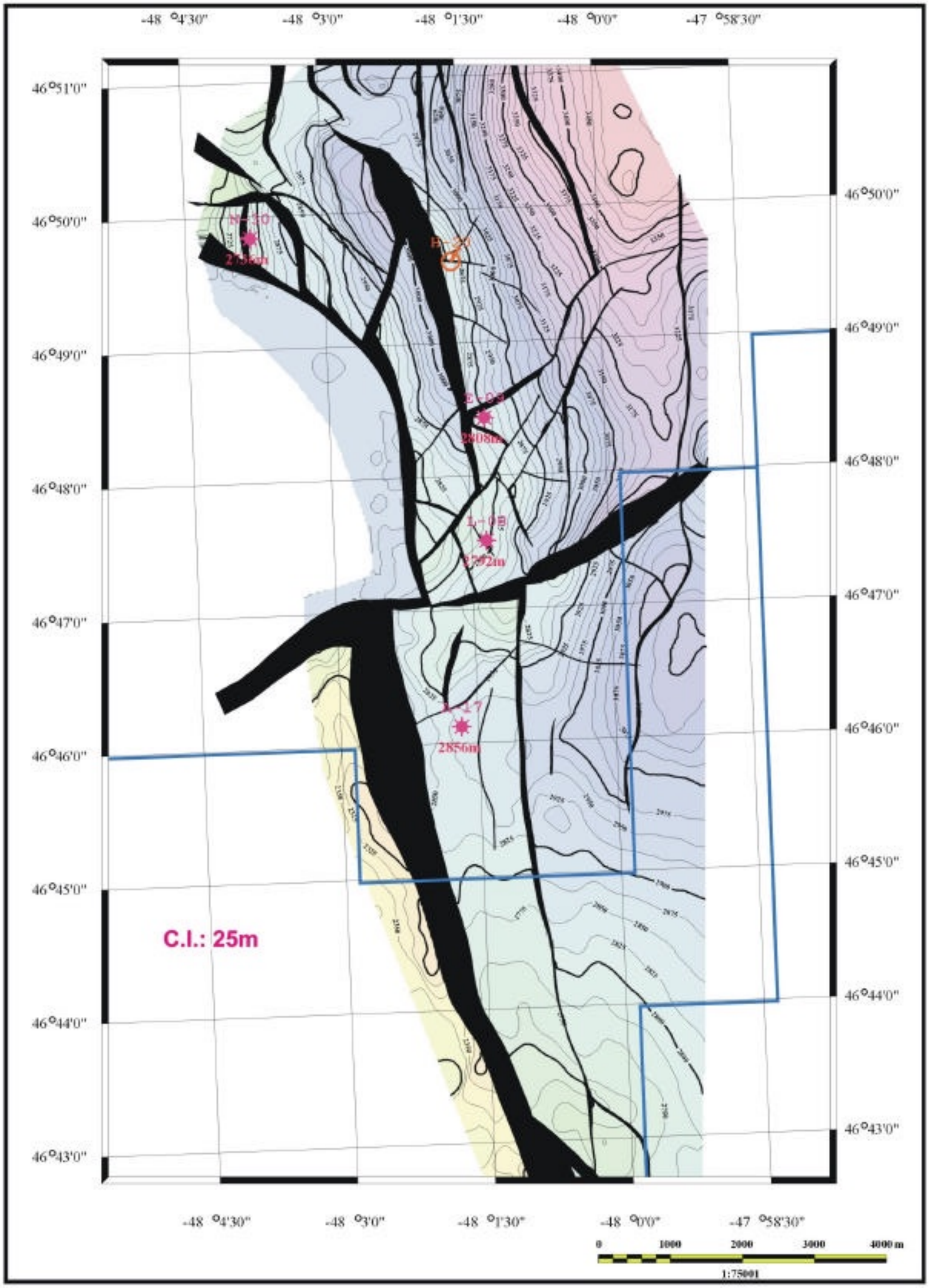

Figure 2.3-25

South Avalon Pool
TOP LAYER 1 STRUCTURE

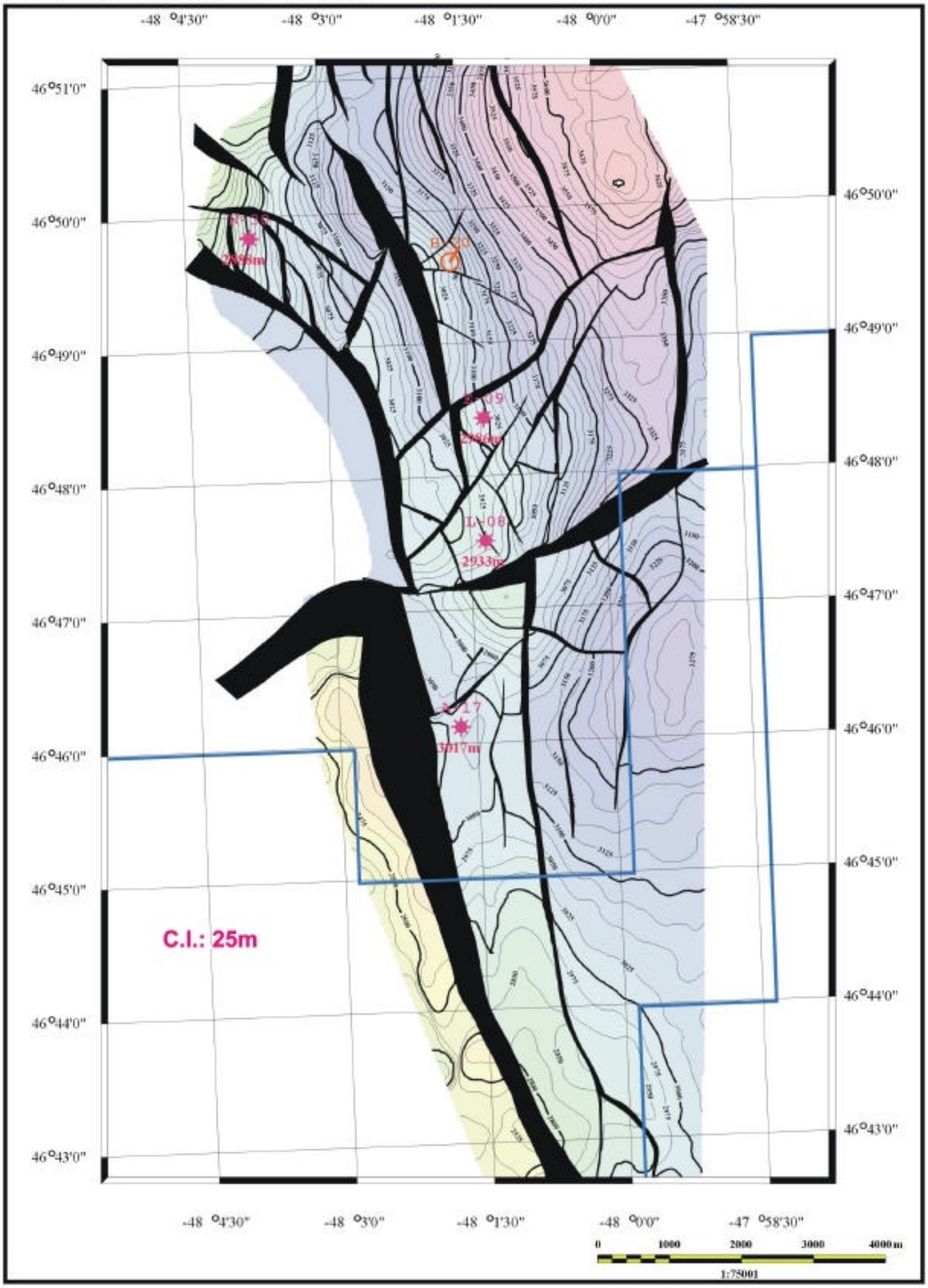

Figure 2.3-26

South Avalon Pool
TOP LAYER 2 STRUCTURE

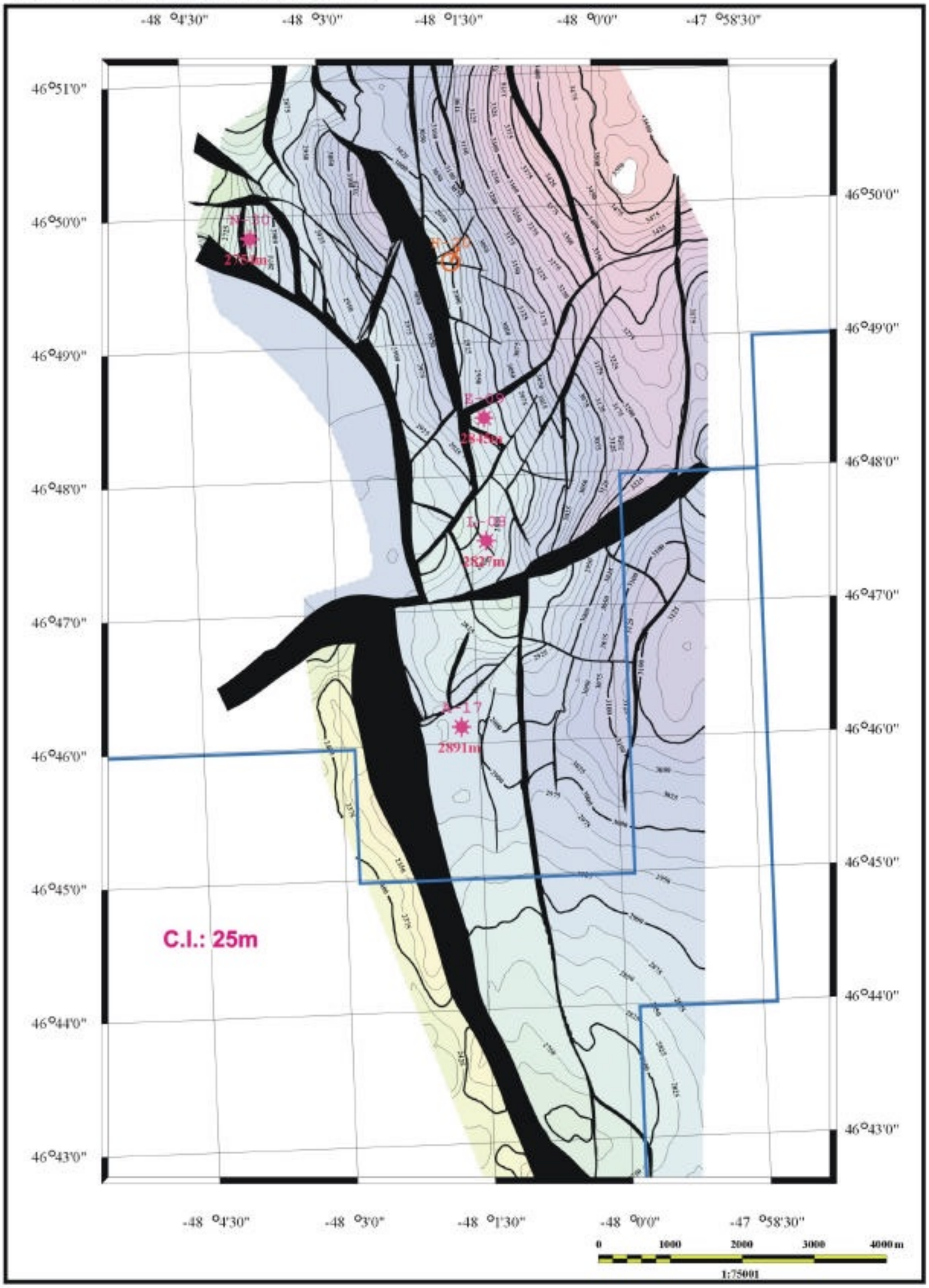

Figure 2.3-27

South Avalon Pool
BASE AVALON STRUCTURE

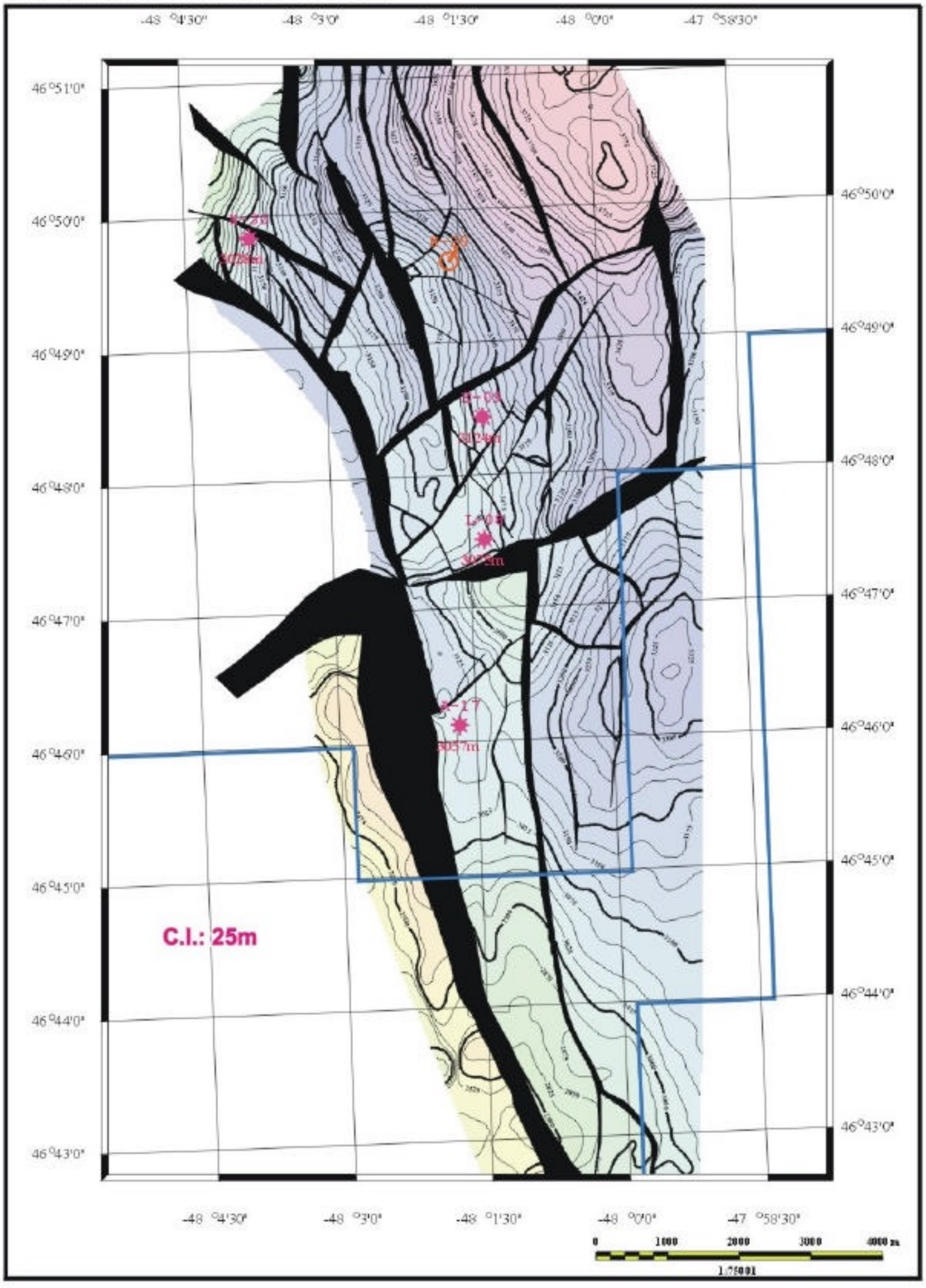

Figure 2.3-28

South Avalon Pool
AVALON GROSS ISOPACH

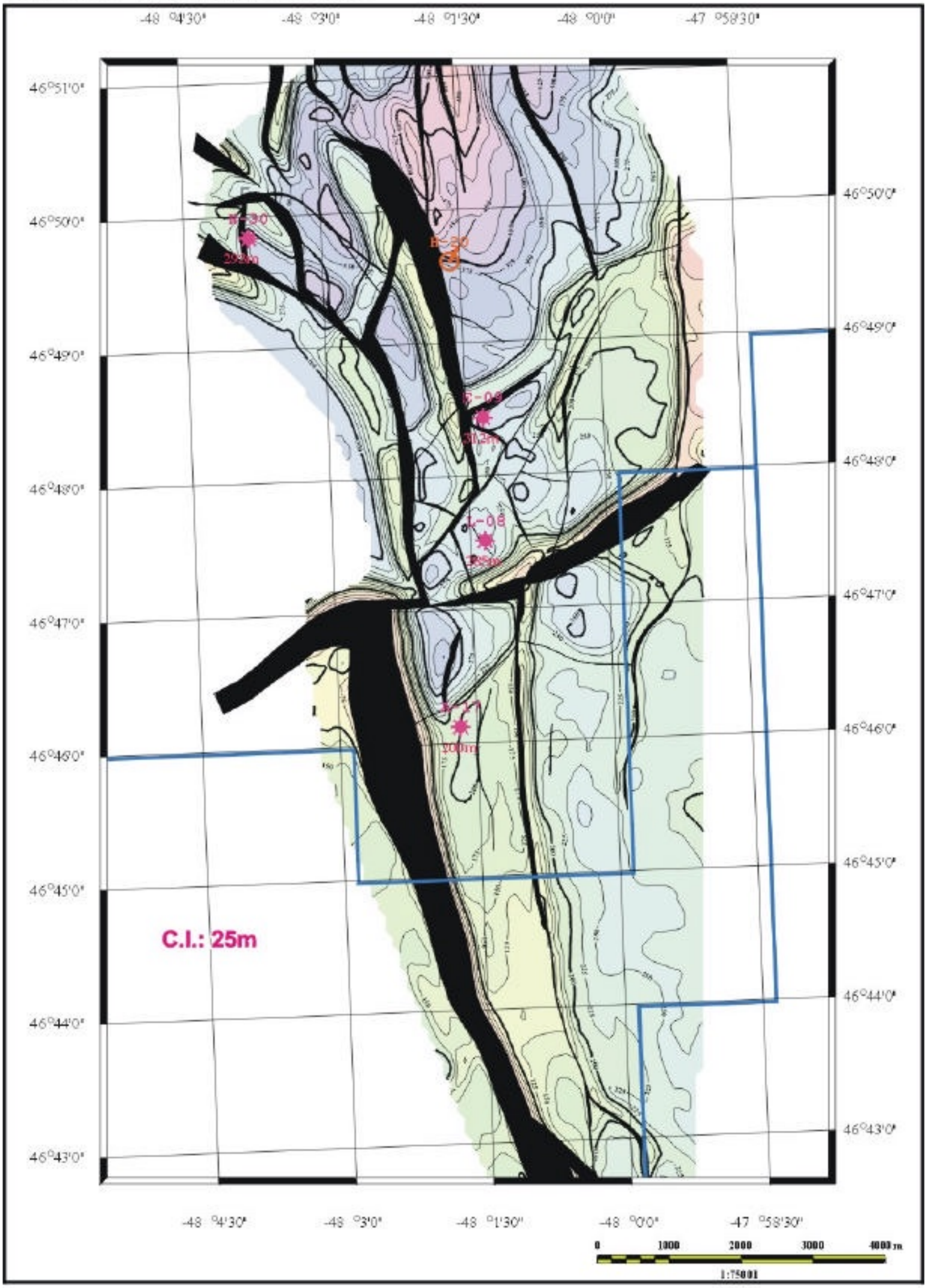

Figure 2.3-29

South Avalon Pool
LAYER 1 GROSS ISOPACH

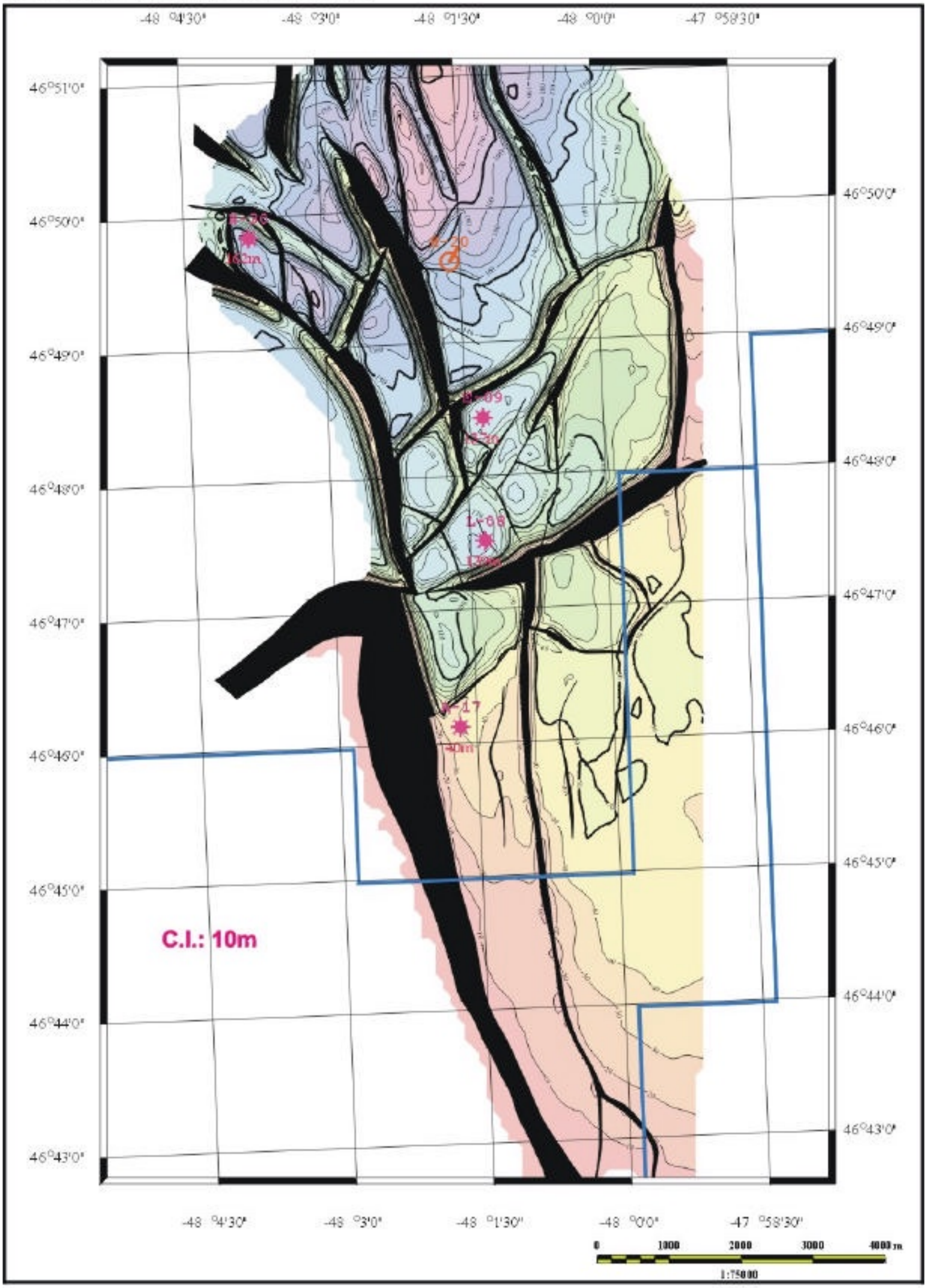

Figure 2.3-30

South Avalon Pool
LAYER 2 GROSS ISOPACH

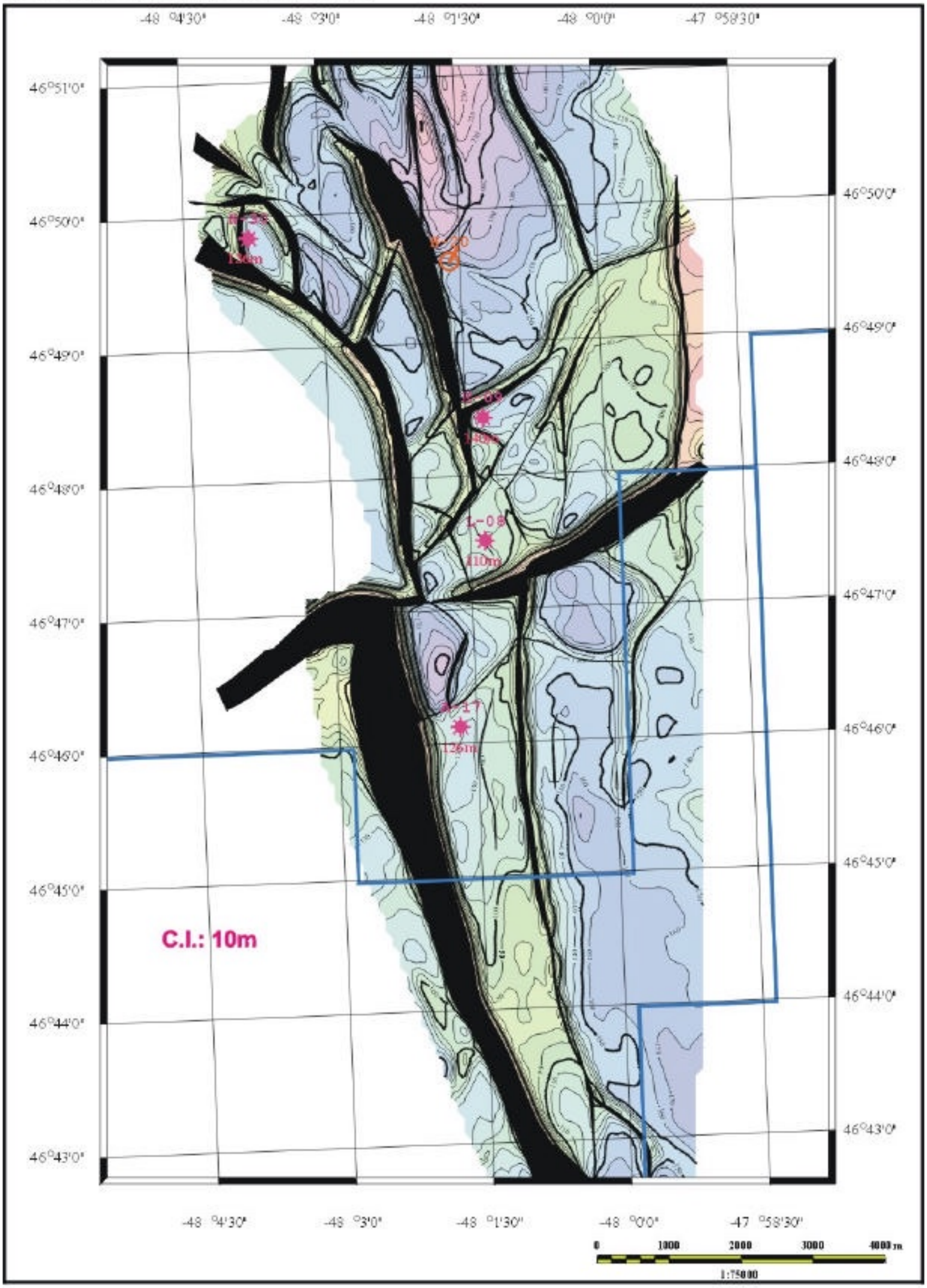

Figure 2.3-31

South Avalon Pool
LAYER 3 GROSS ISOPACH

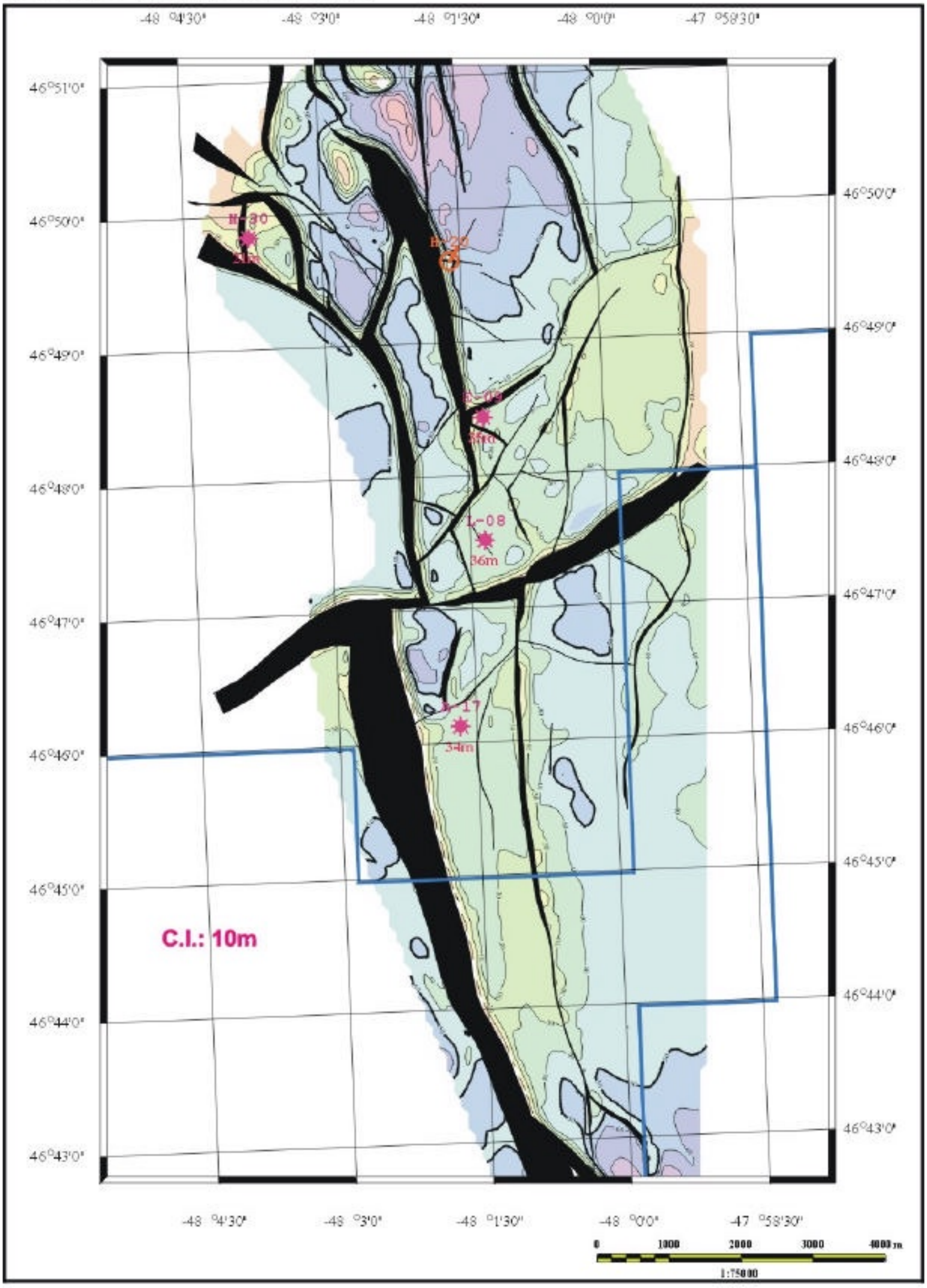

Figure 2.3-32

South Avalon Pool
AVALON NET SAND

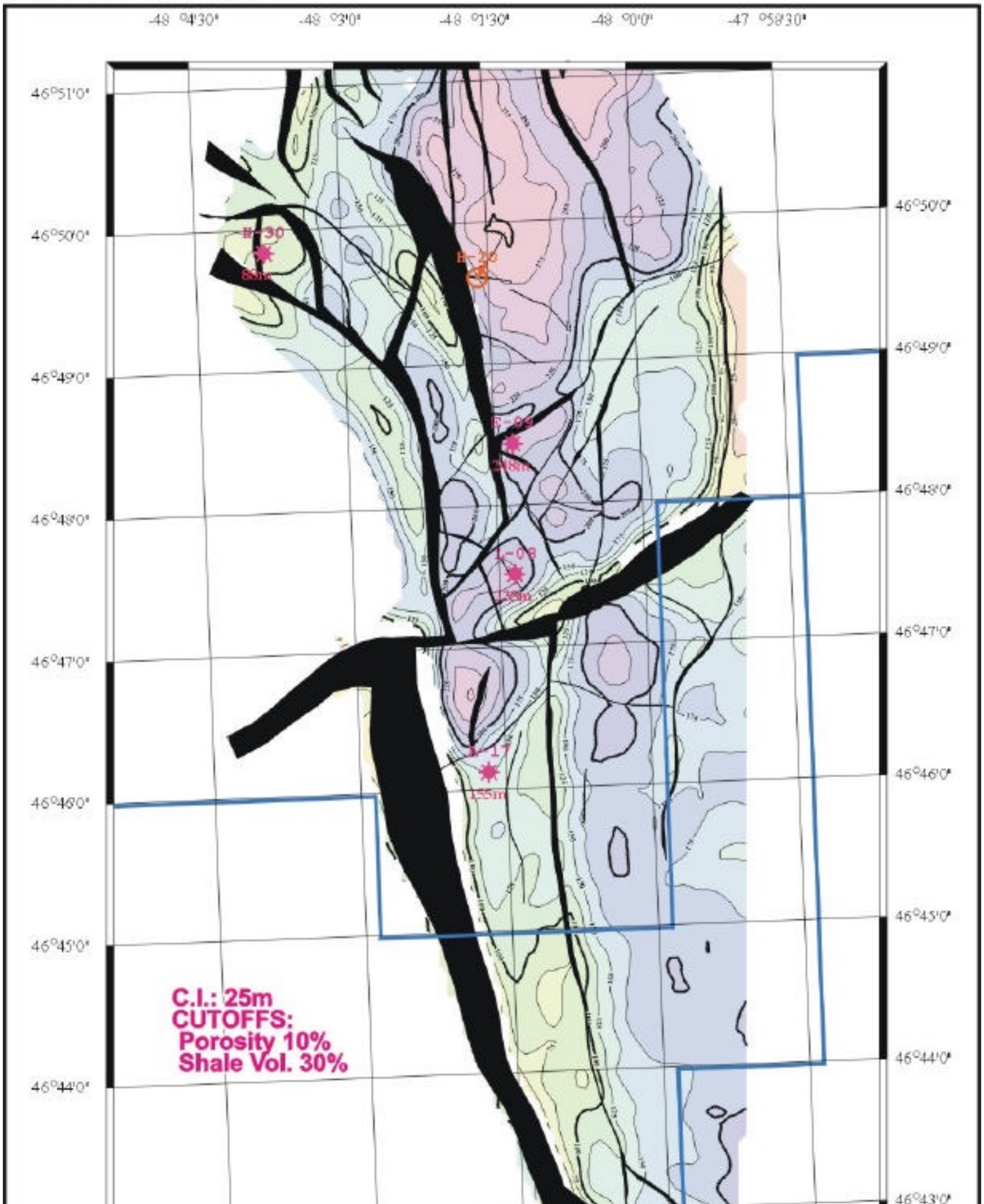

Figure 2.3-33

South Avalon Pool
LAYER 1 NET SAND

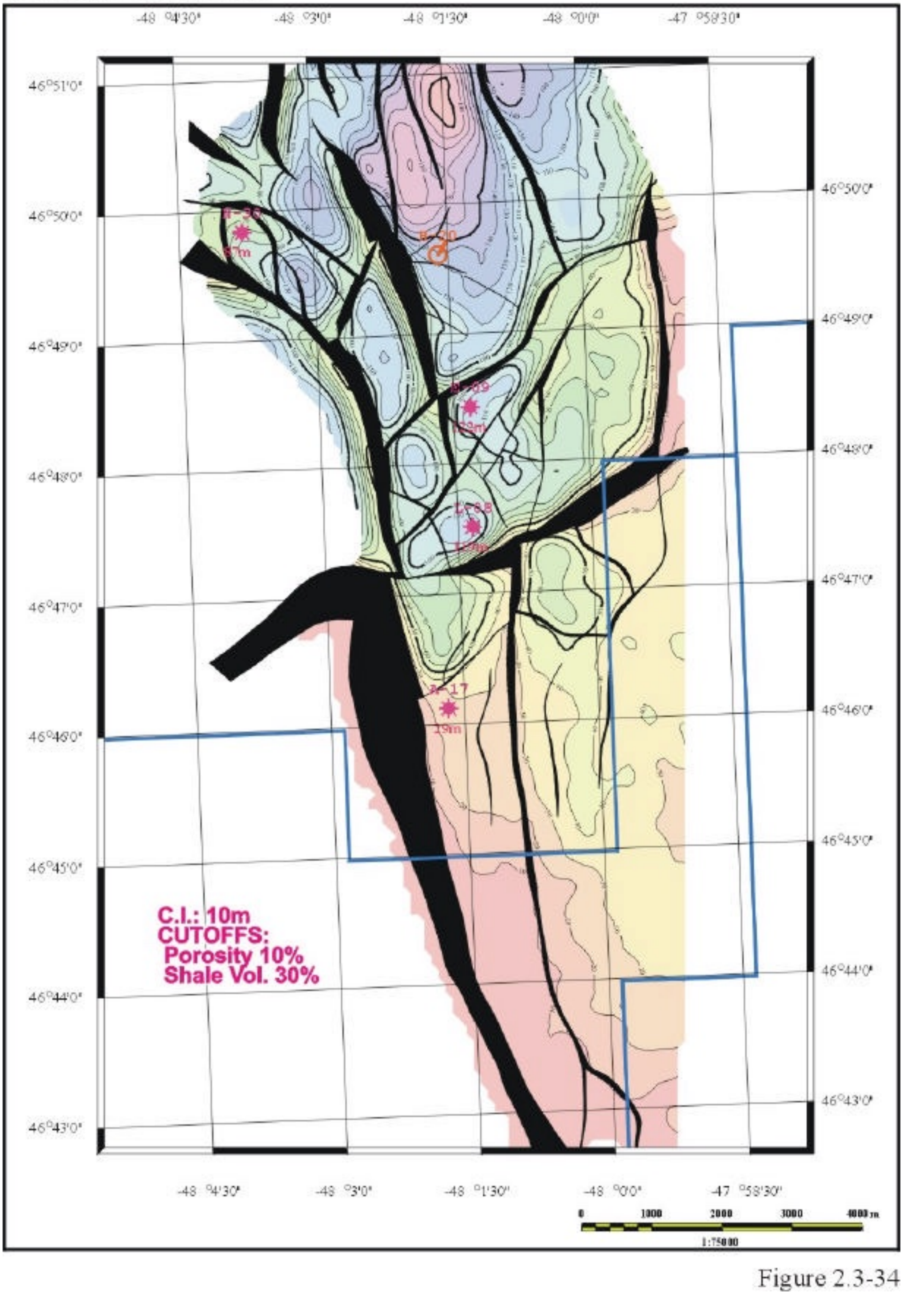

Figure 2.3-34

South Avalon Pool
LAYER 2 NET SAND

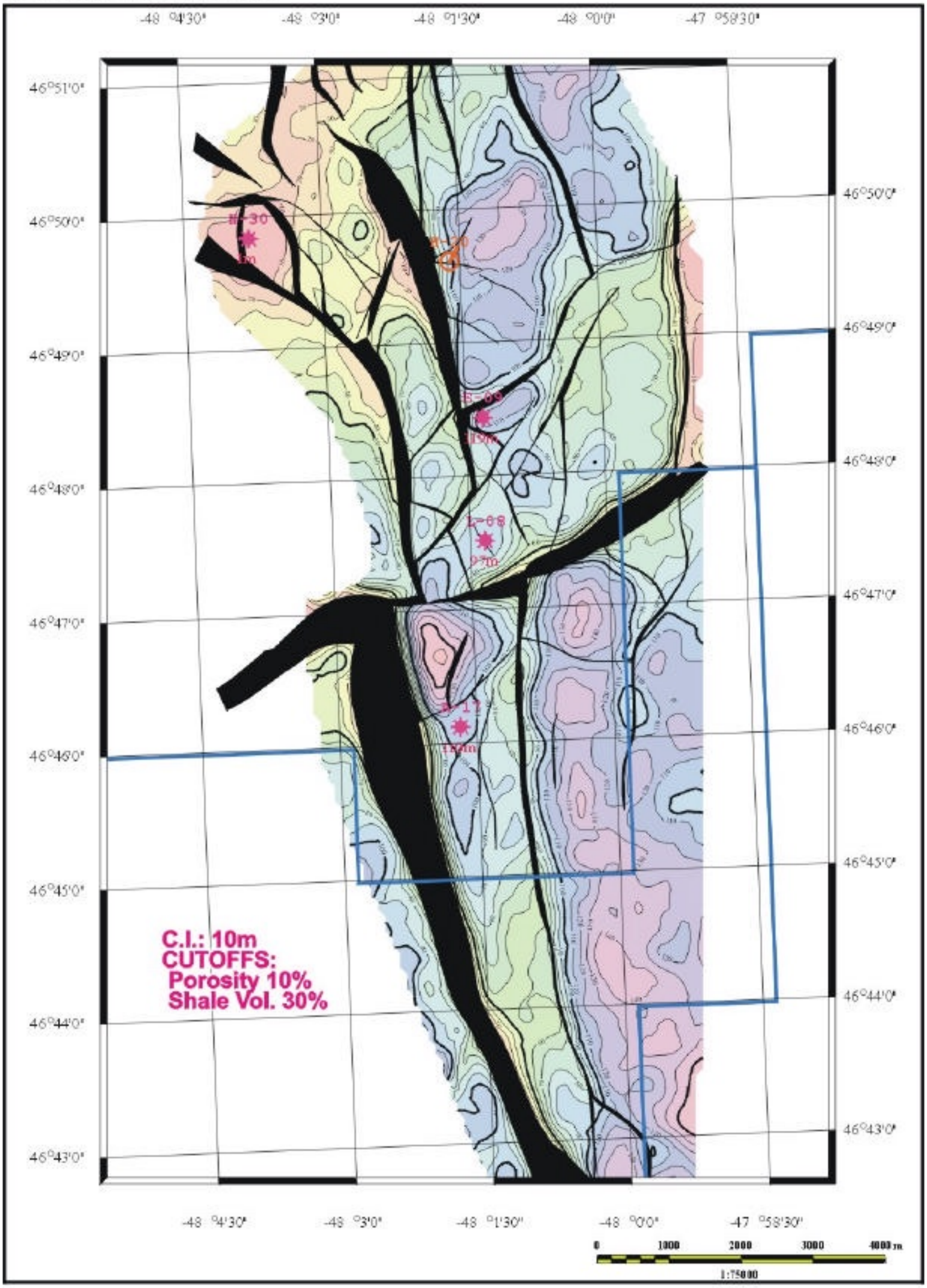

Figure 2.3-35

South Avalon Pool
LAYER 3 NET SAND

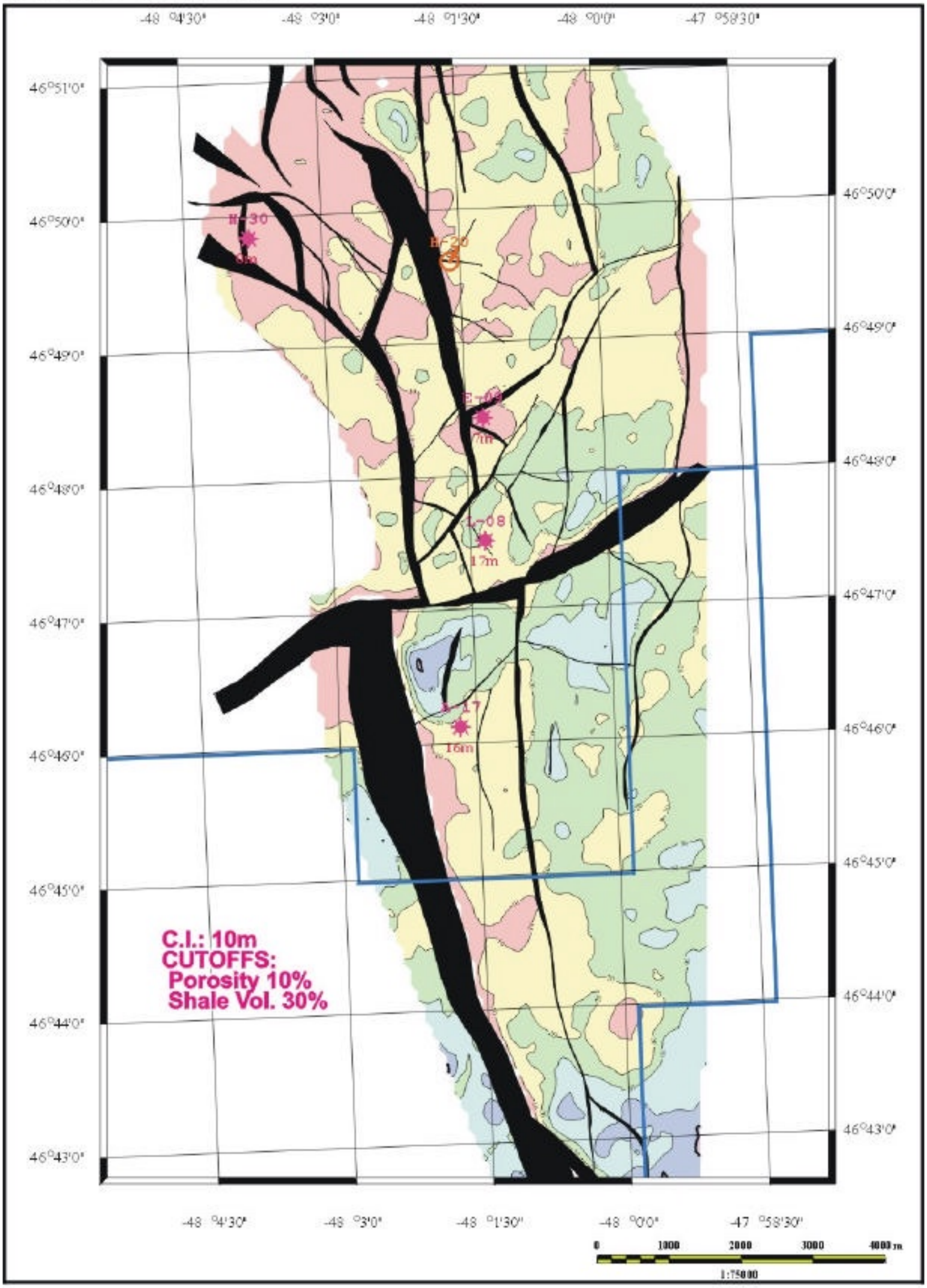

Figure 2.3-36

South Avalon Pool
AVALON NET OIL PAY

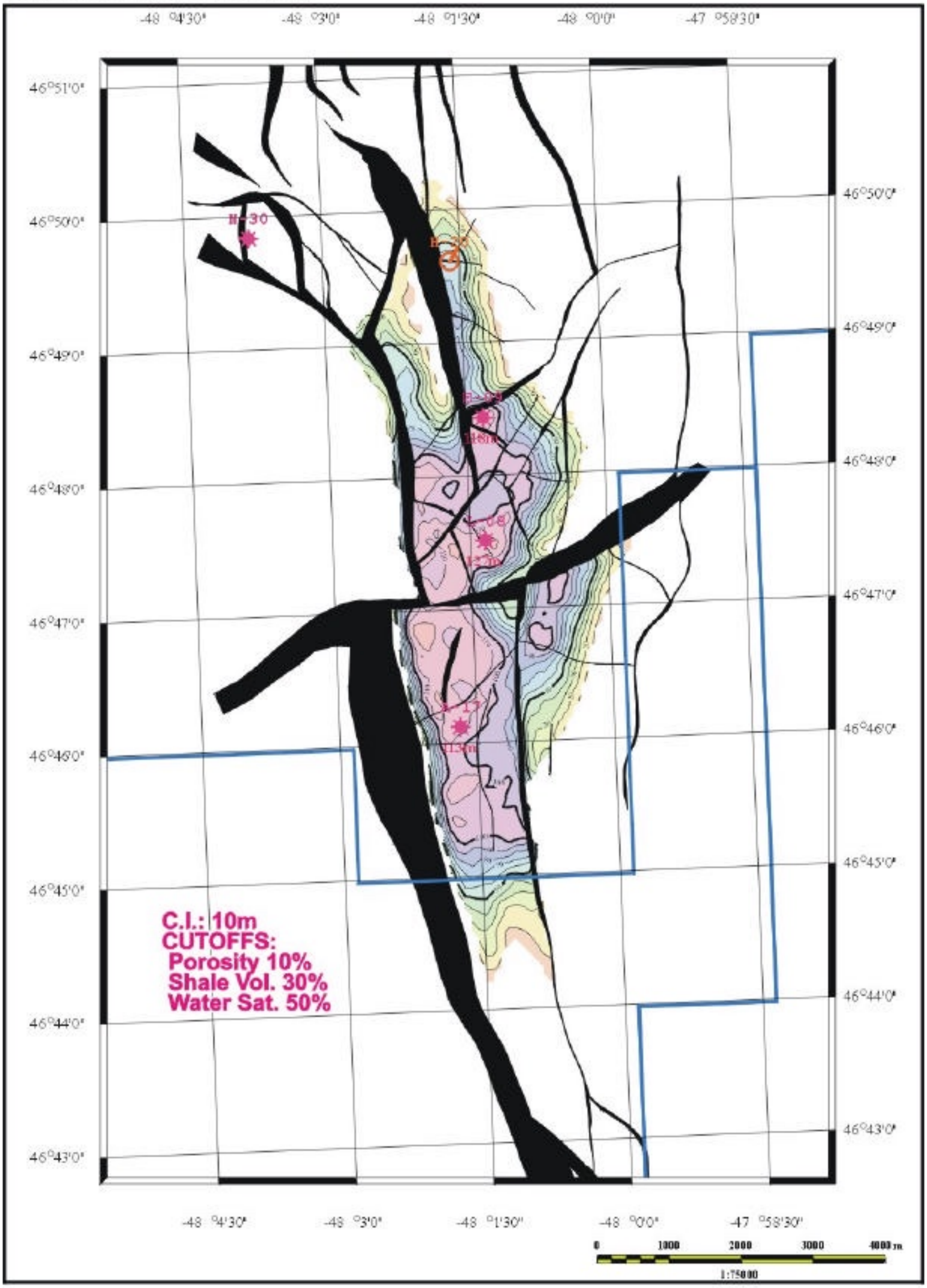

Figure 2.3-37

South Avalon Pool
LAYER 1 NET OIL PAY

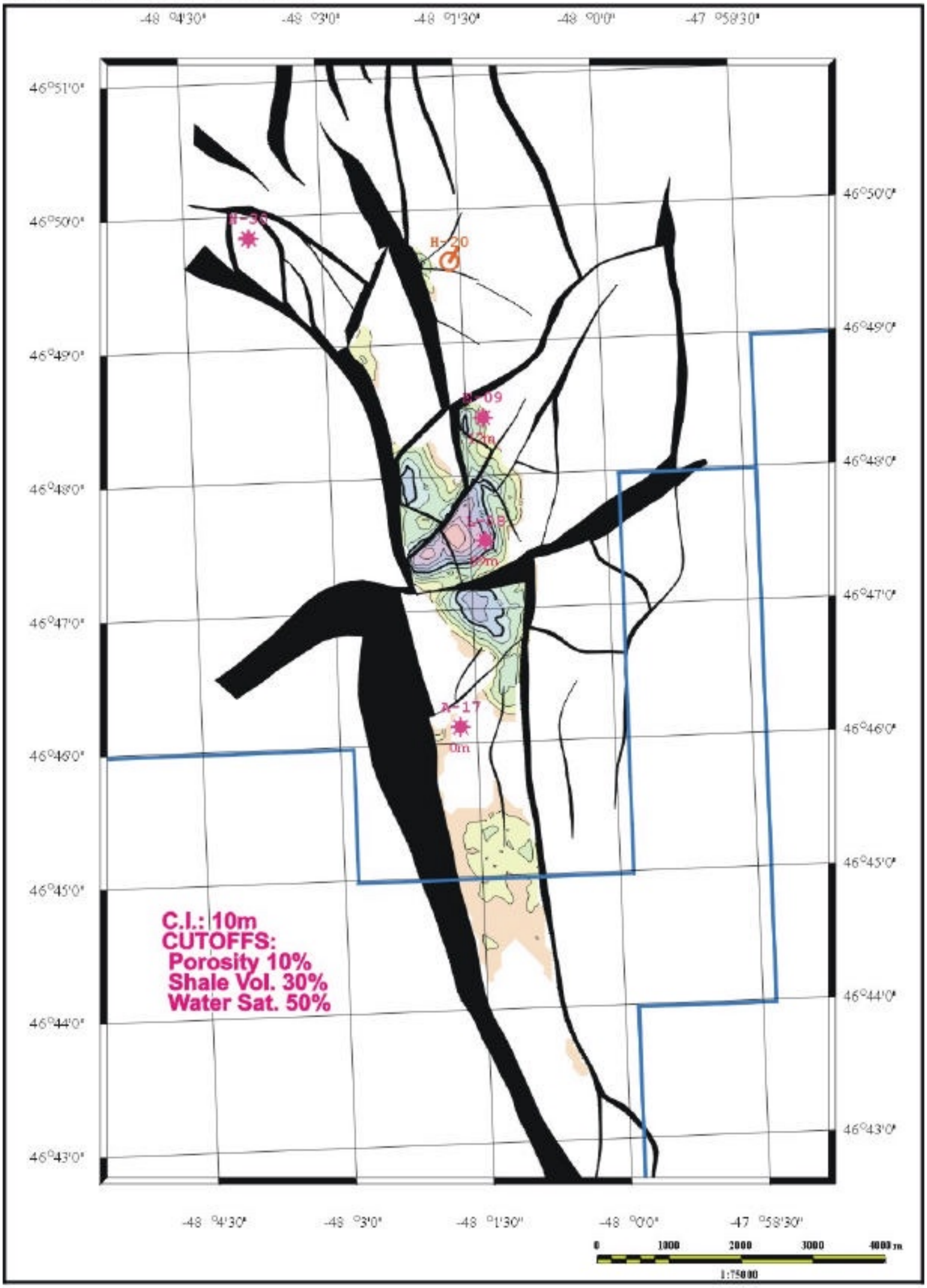

Figure 2.3-38

South Avalon Pool
LAYER 2 NET OIL PAY

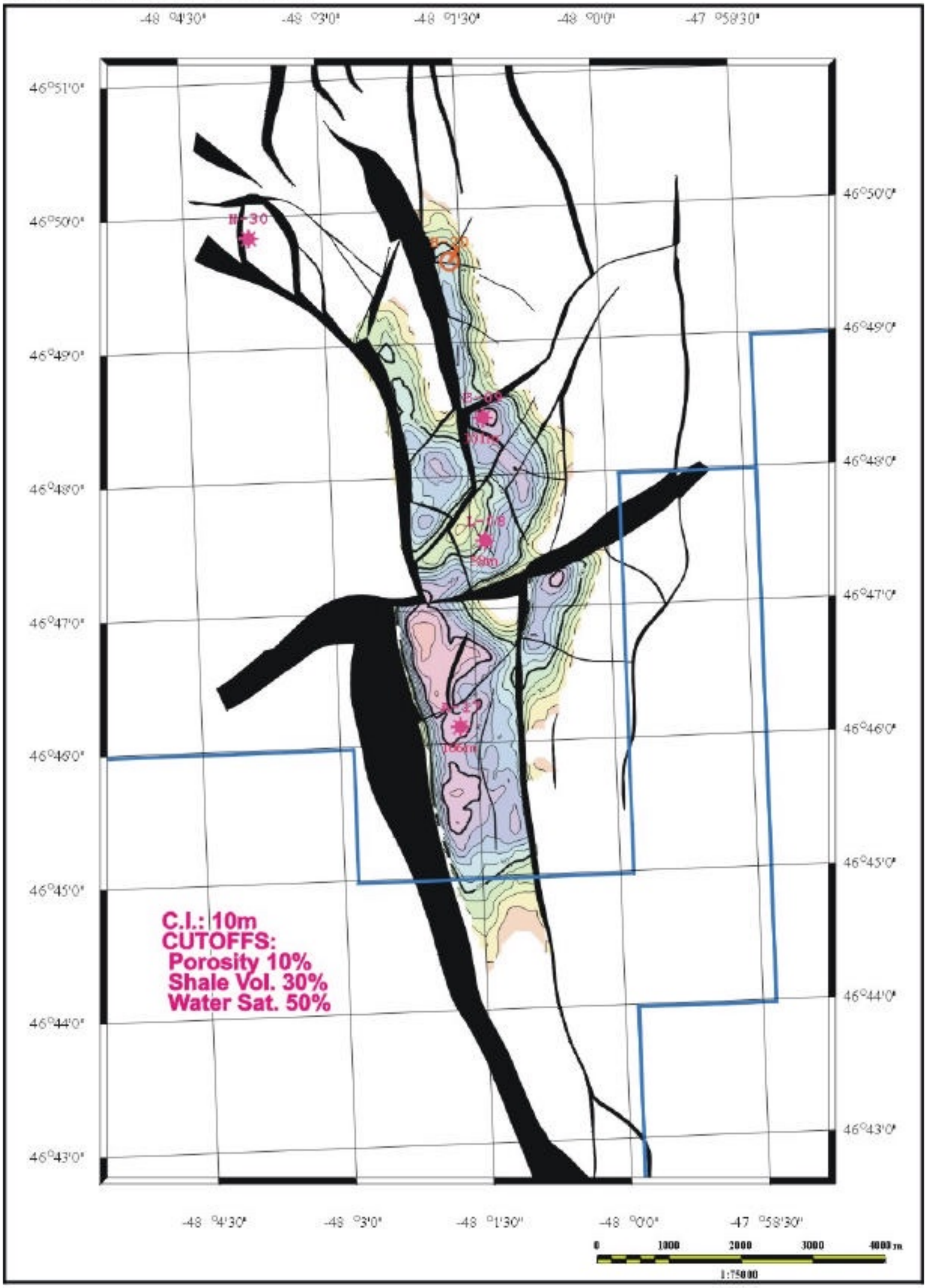

Figure 2.3-39

South Avalon Pool
LAYER 3 NET OIL PAY

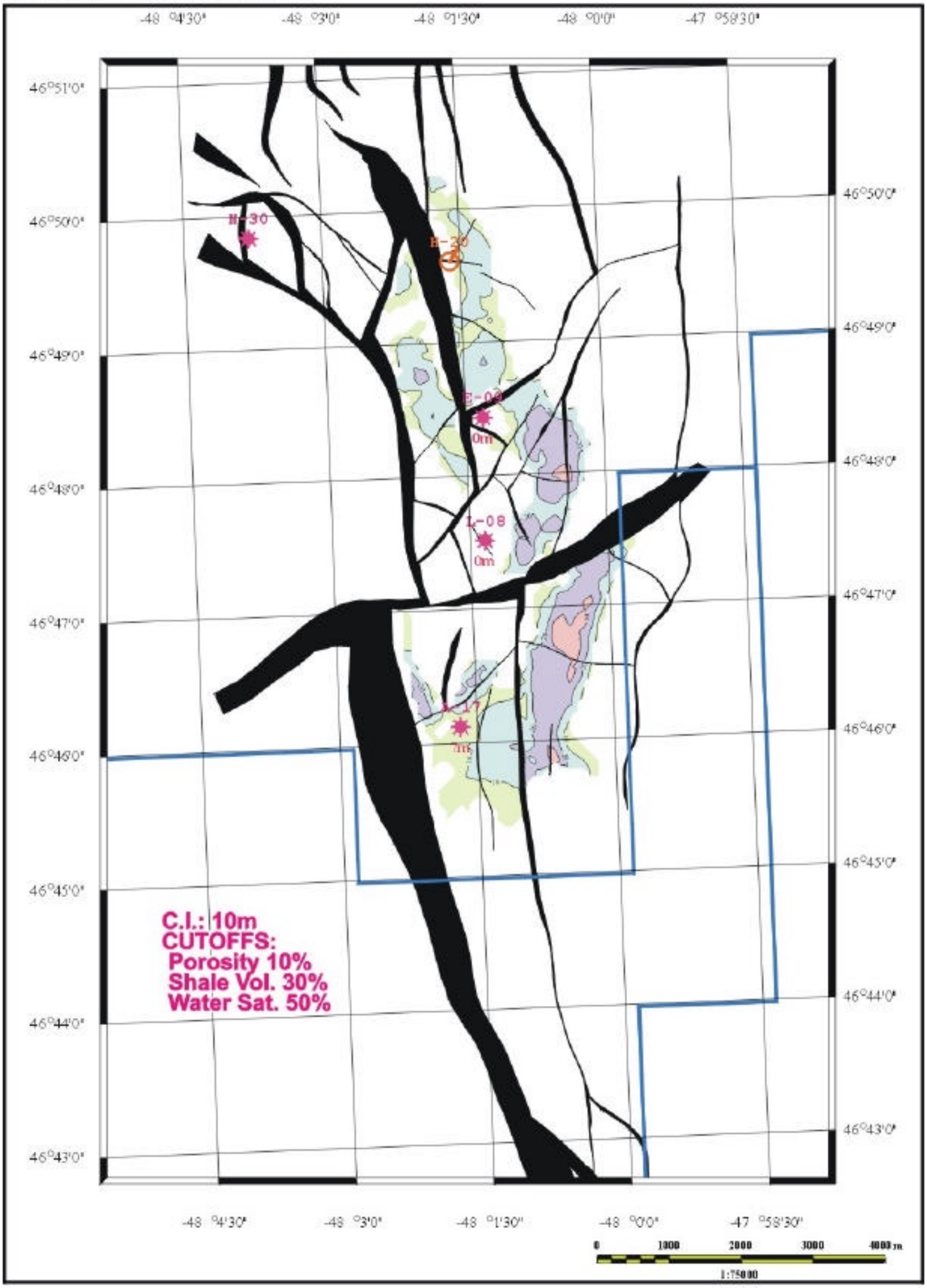

Figure 2.3-40

South Avalon Pool
AVALON NET GAS PAY

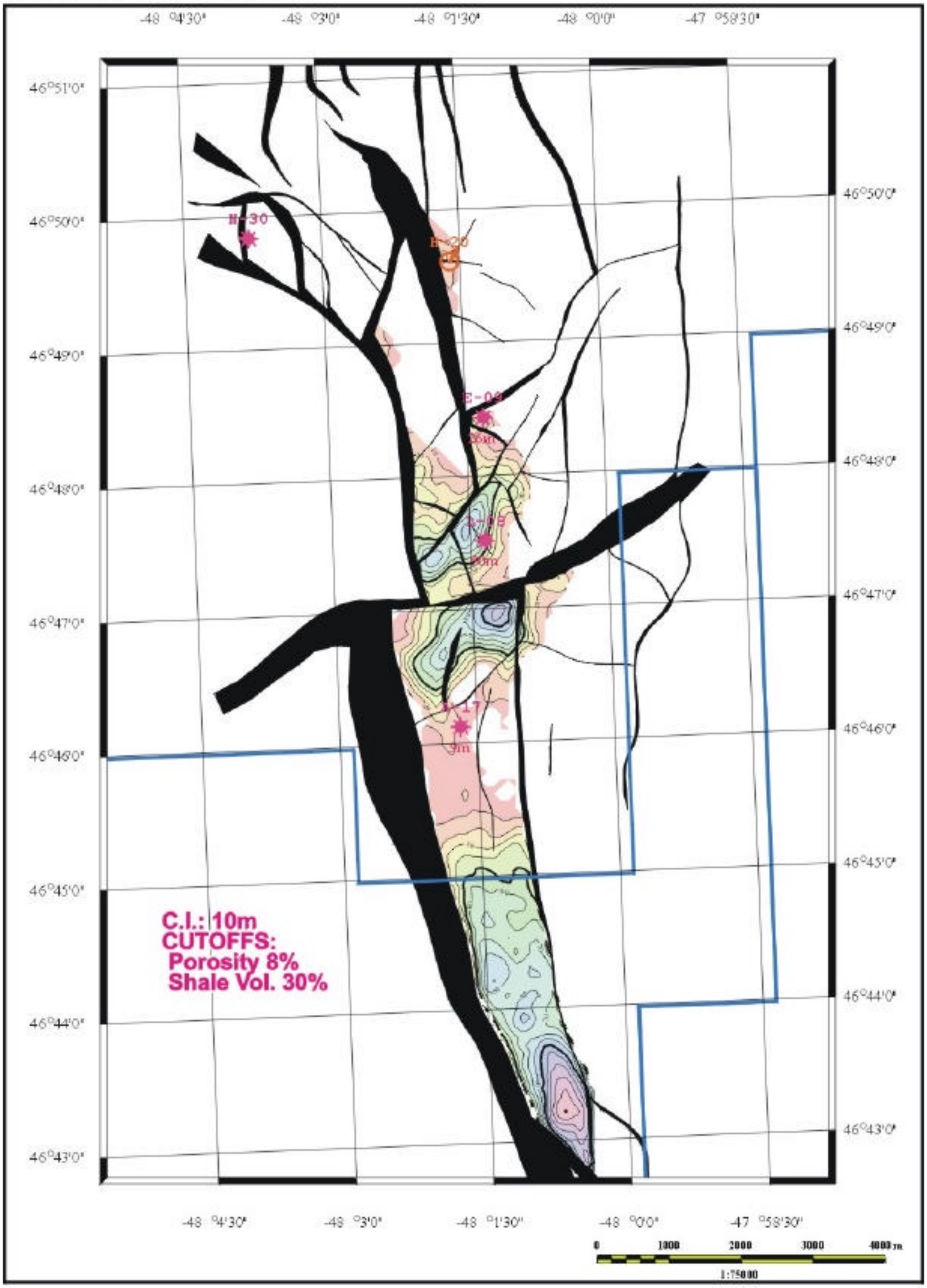

Figure 2.3-41

South Avalon Pool
LAYER 2 NET GAS PAY

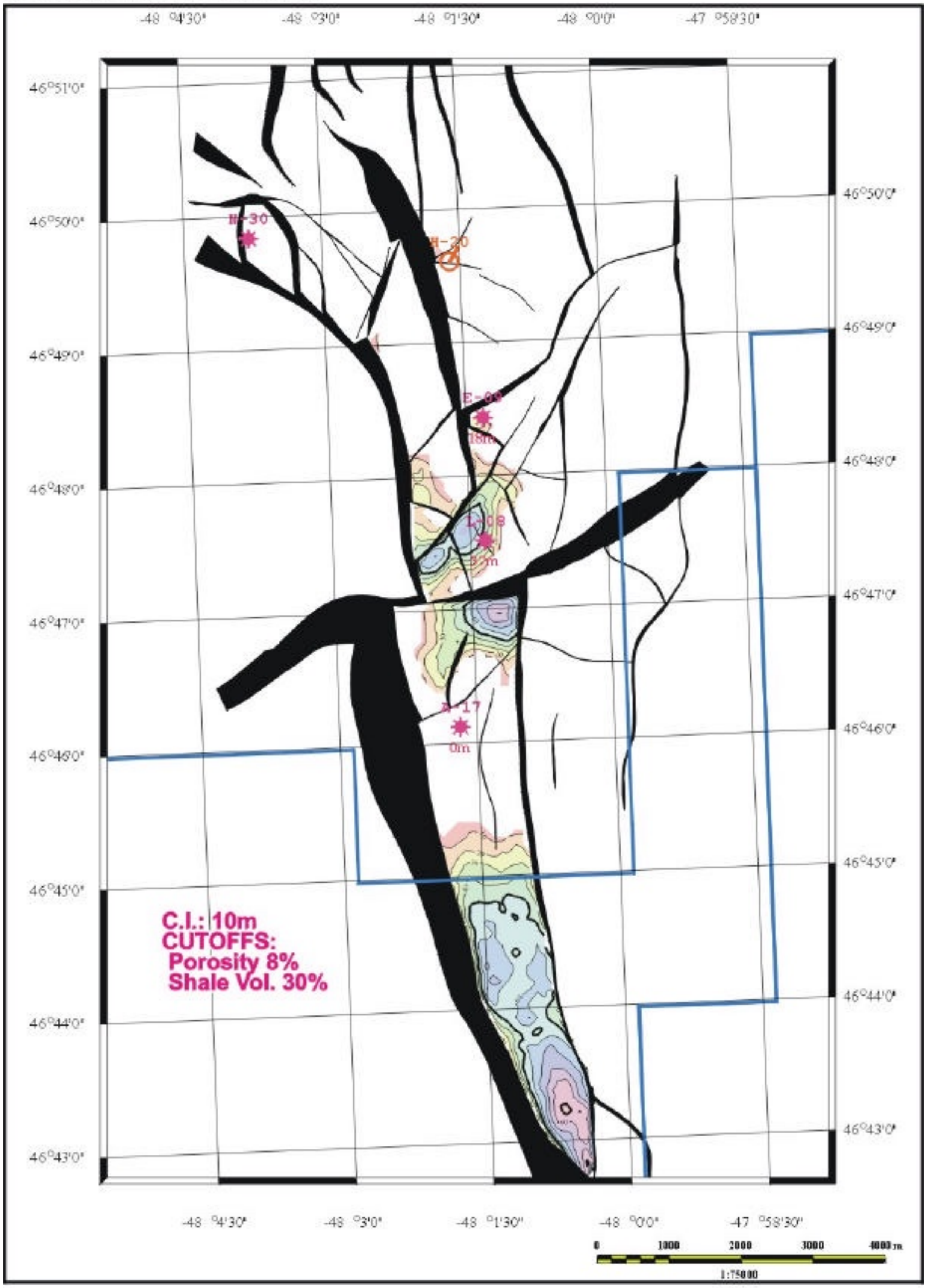

Figure 2.3-42

South Avalon Pool
LAYER 3 NET GAS PAY

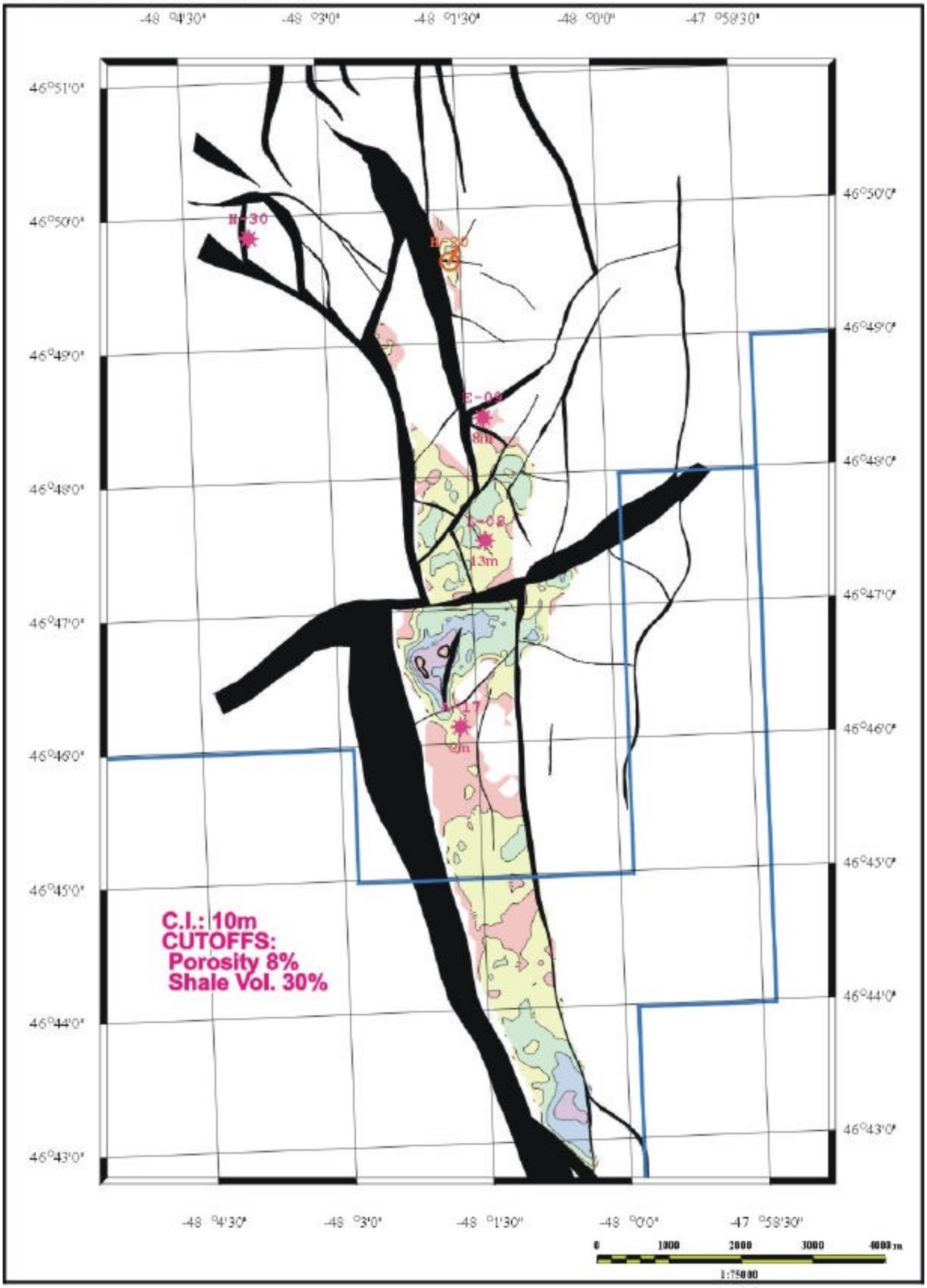

Figure 2.3-43

South Avalon Pool
AVALON ISOPOROSITY

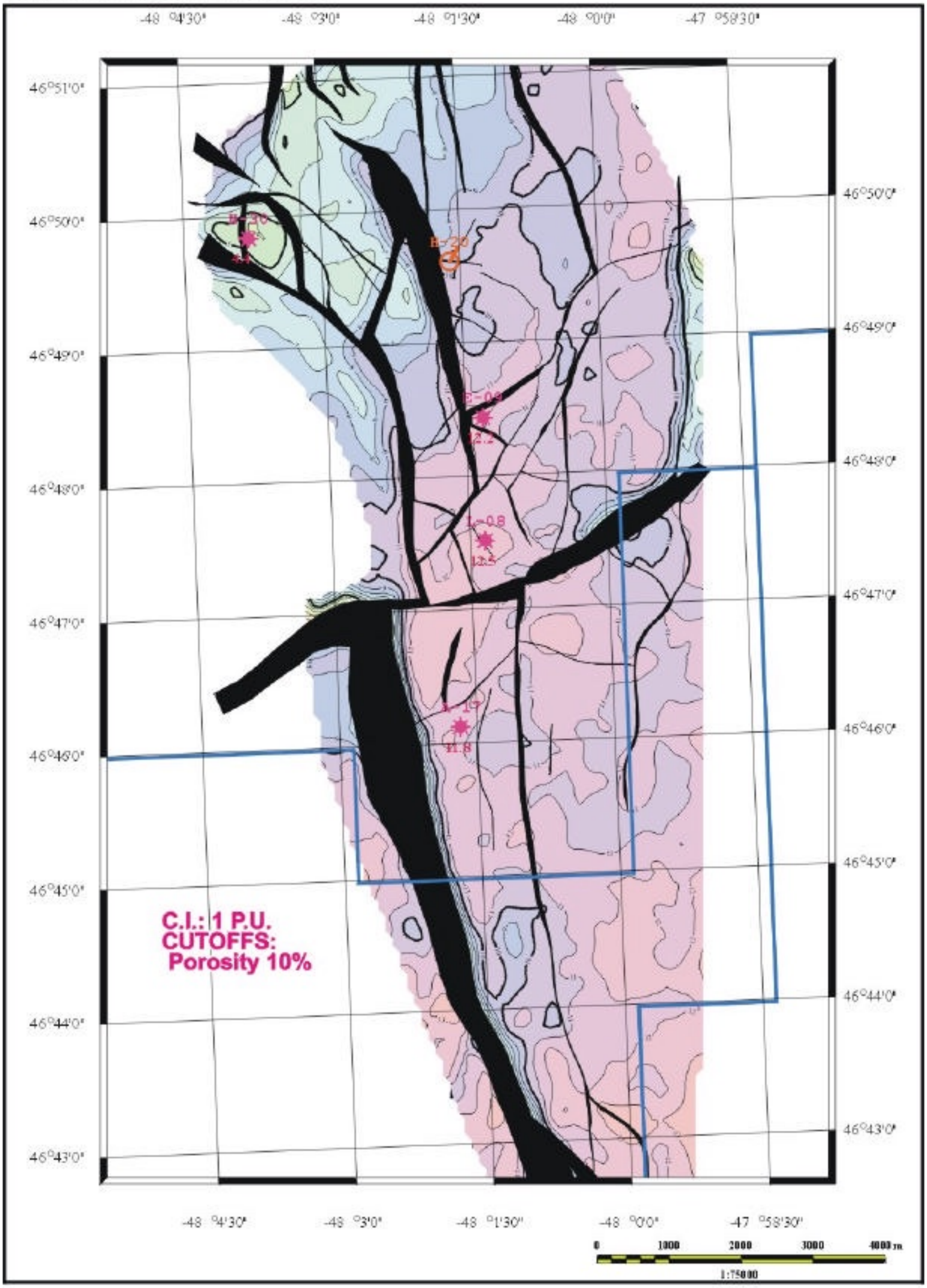

Figure 2.3-44

South Avalon Pool
LAYER 1 ISOPOROSITY

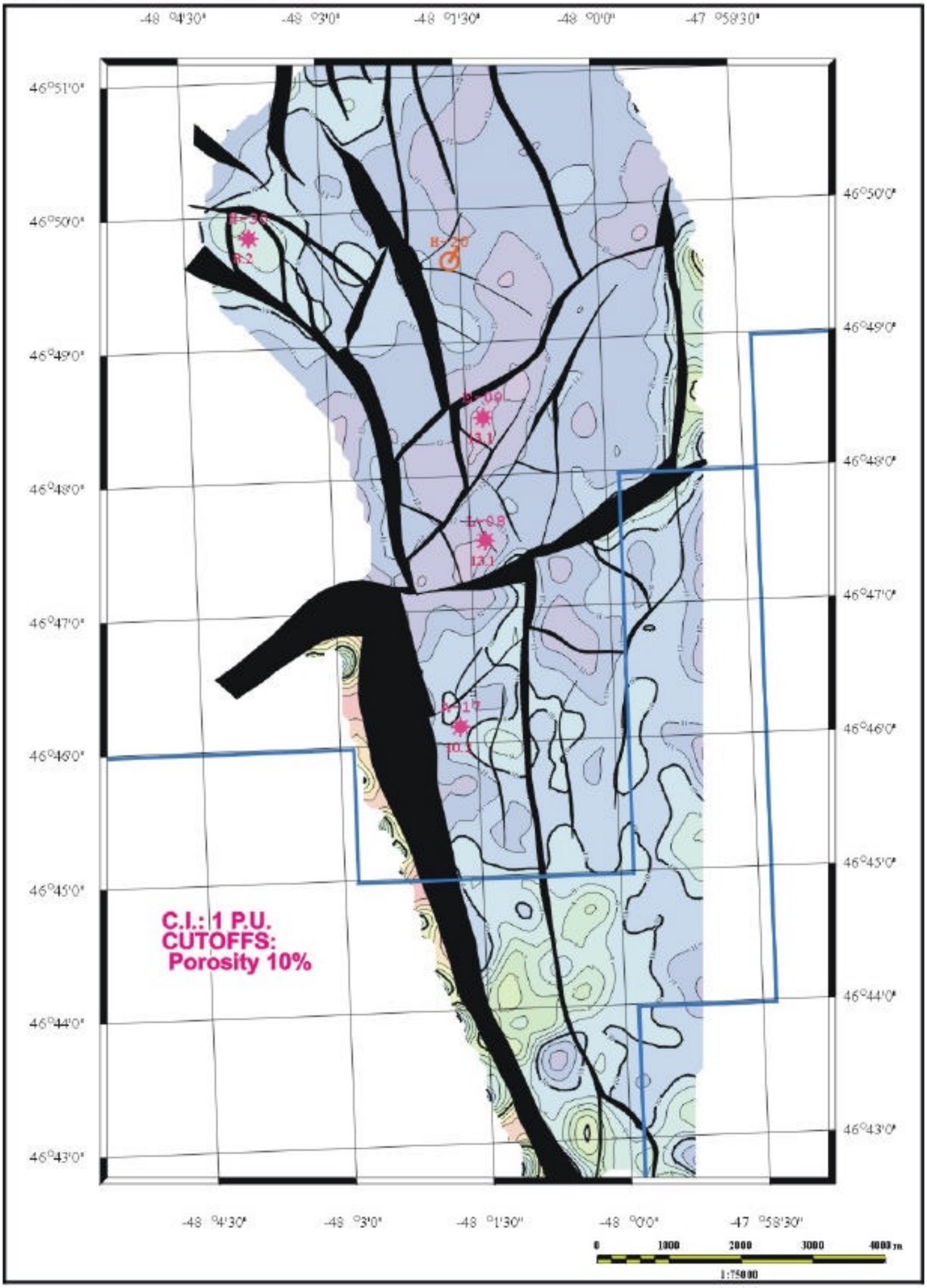

Figure 2.3-45

South Avalon Pool
LAYER 2 ISOPOROSITY

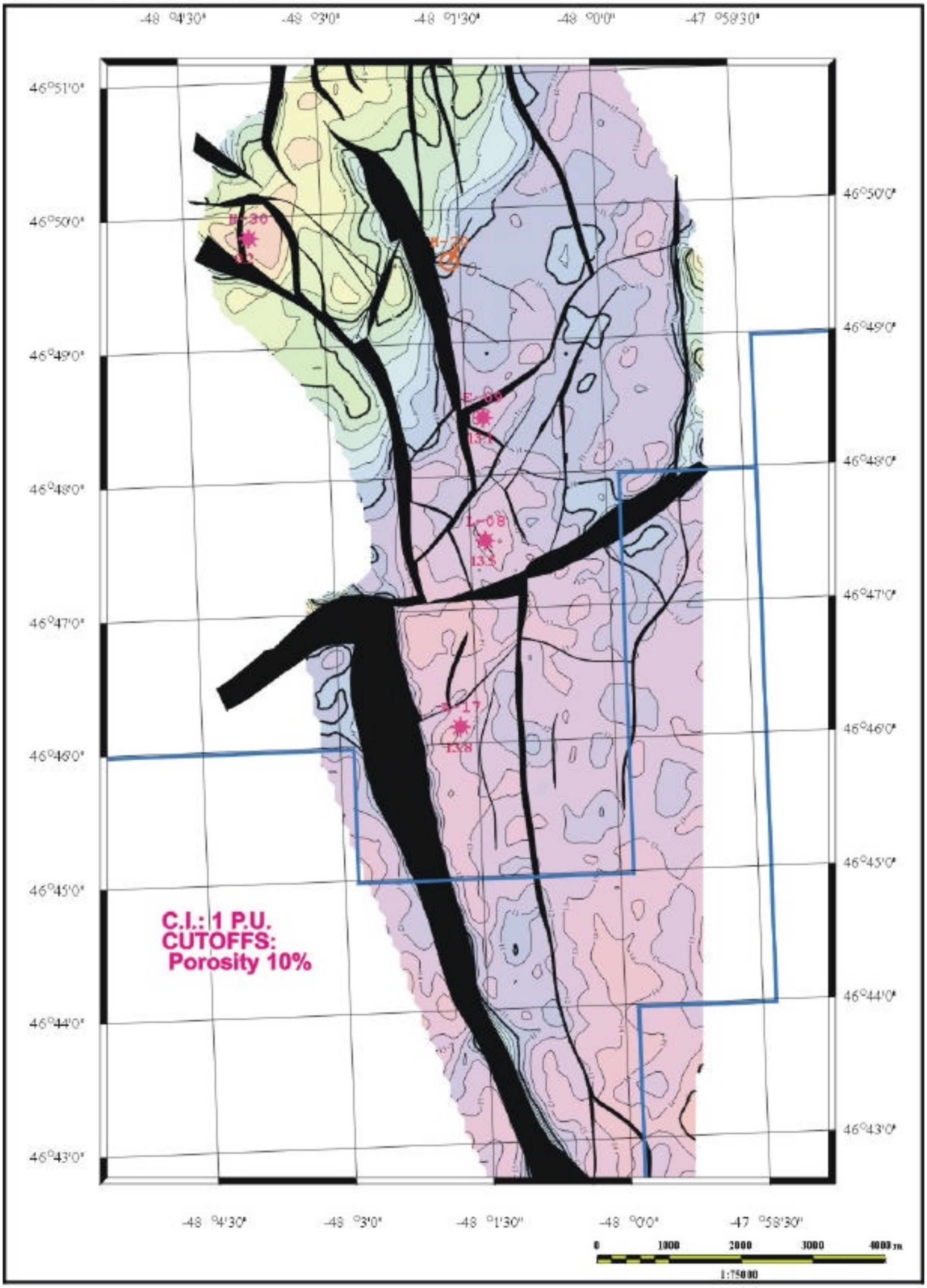

Figure 2.3-46

South Avalon Pool
LAYER 3 ISOPOROSITY

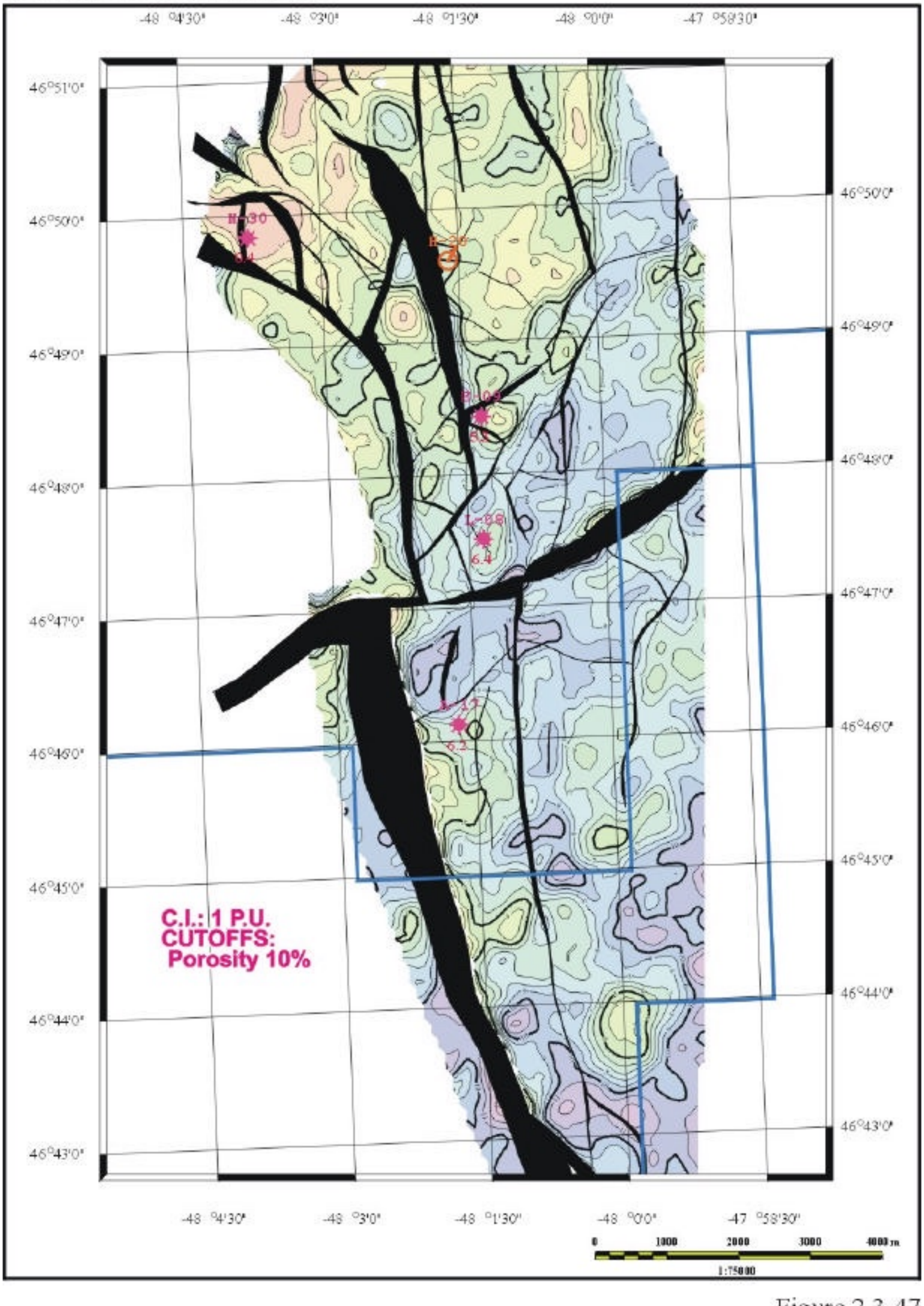

Figure 2.3-47

South Avalon Pool
AVALON OIL HCPV

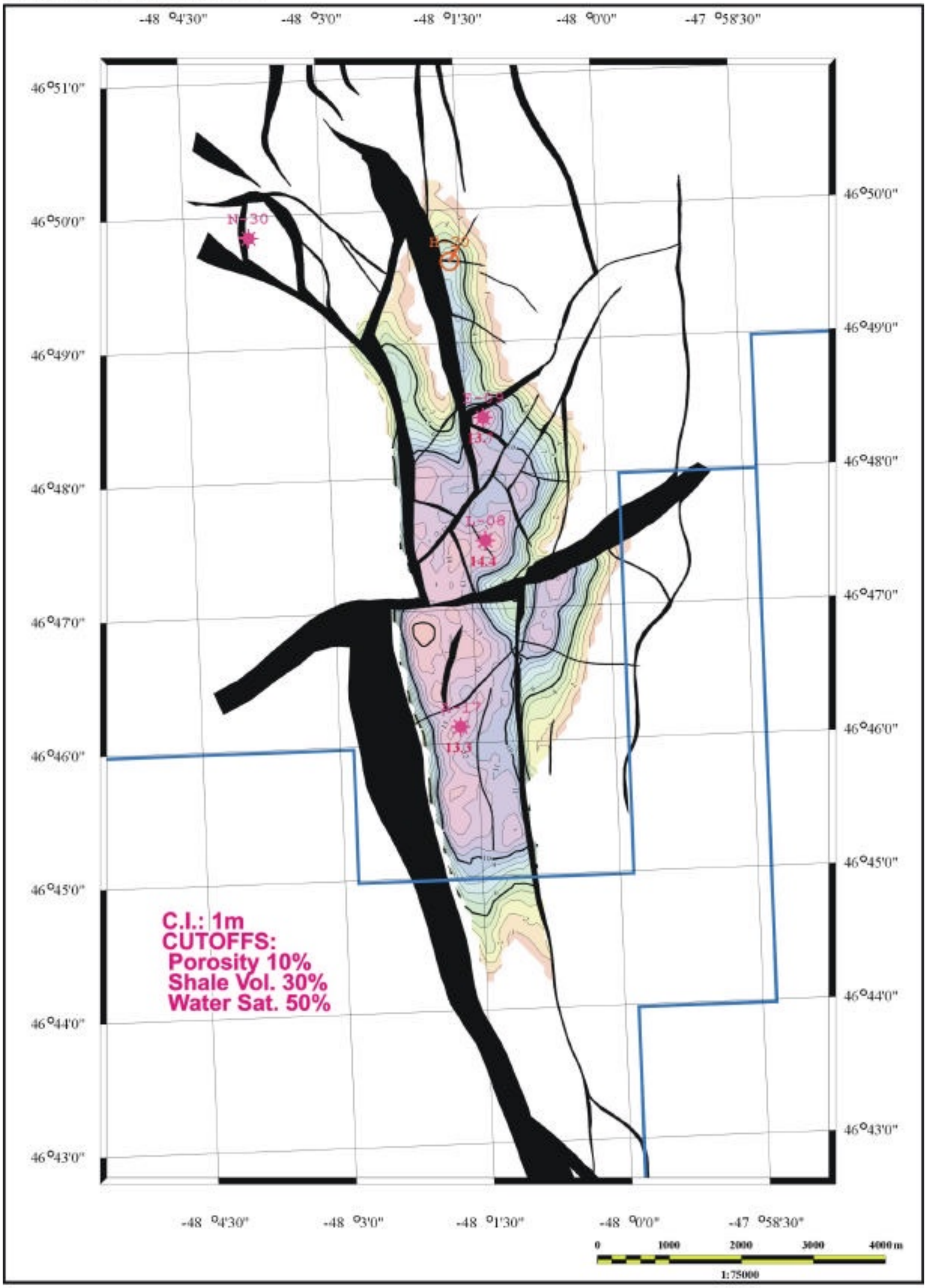

Figure 2.3-48

South Avalon Pool
LAYER 1 OIL HCPV

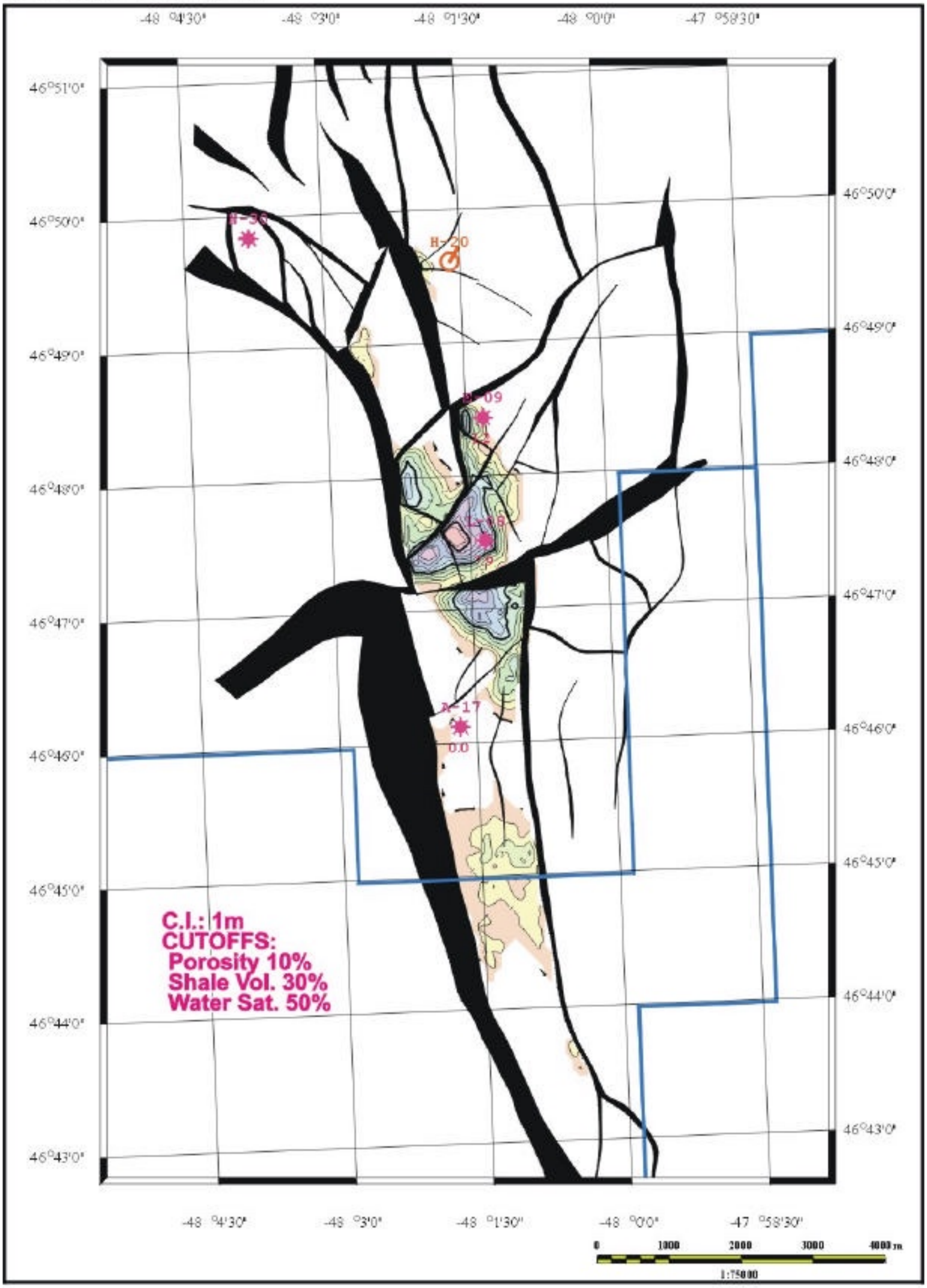

Figure 2.3-49

South Avalon Pool
LAYER 2 OIL HCPV

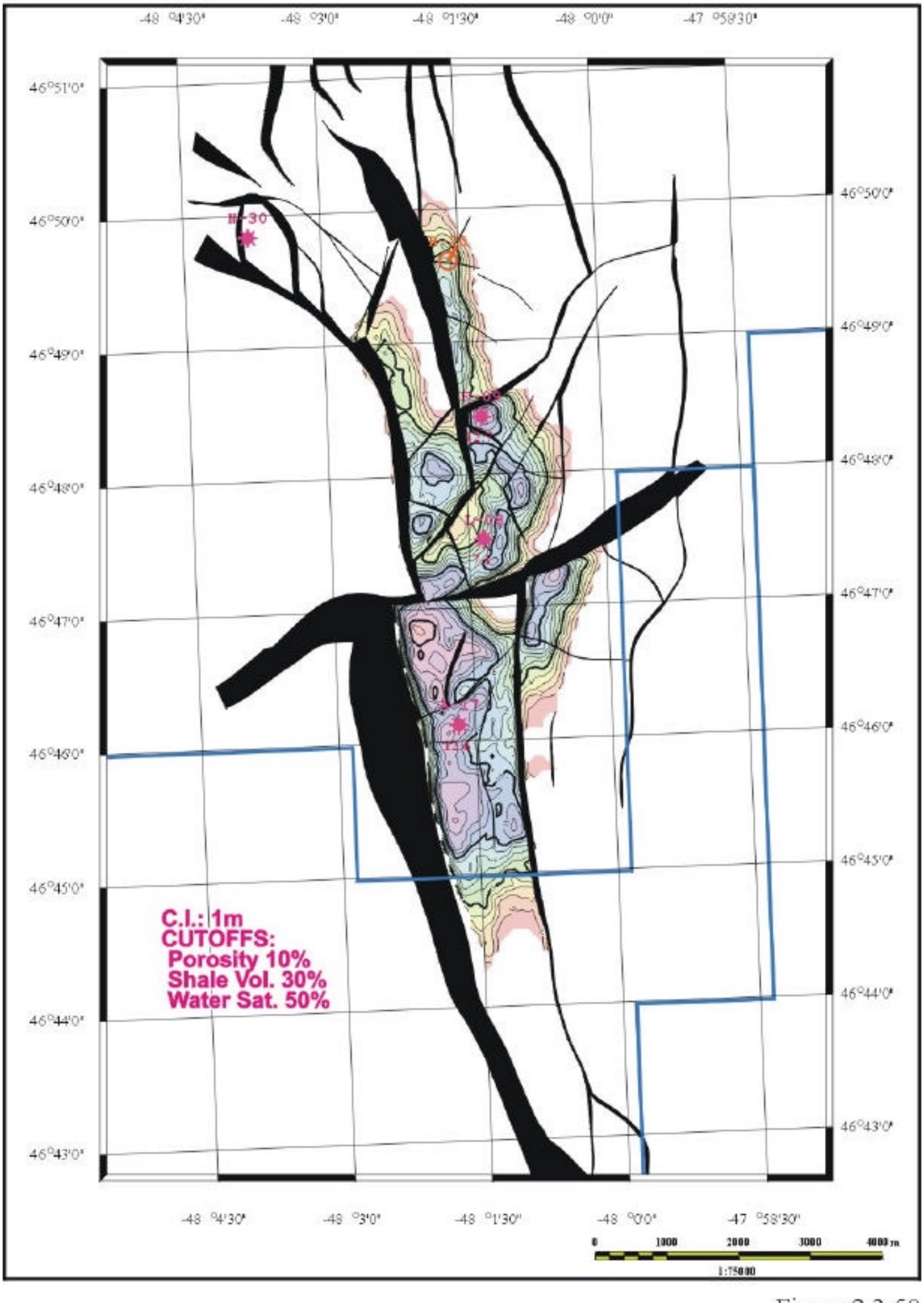

Figure 2.3-50

South Avalon Pool
LAYER 3 OIL HCPV

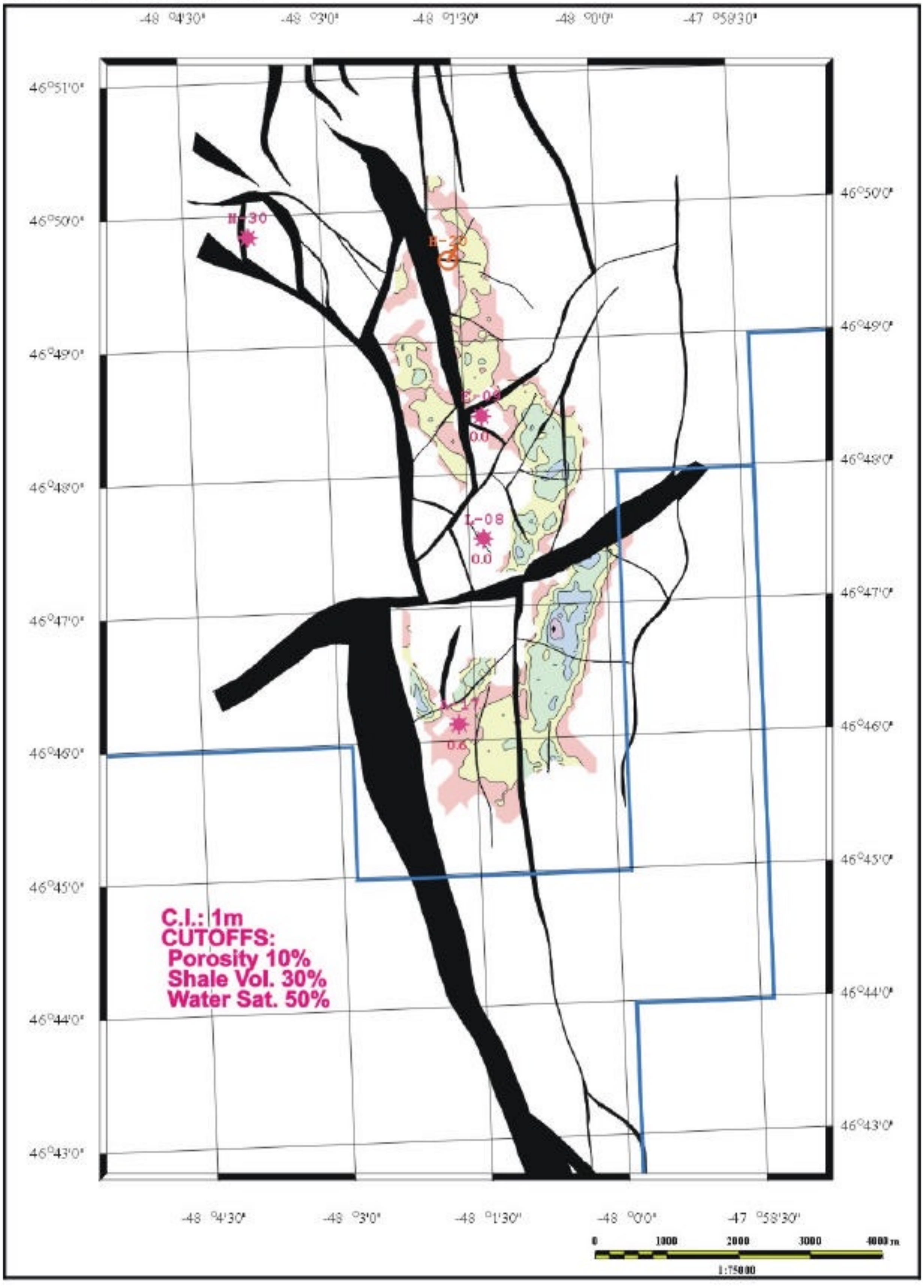

Figure 2.3-51

South Avalon Pool
AVALON GAS HCPV

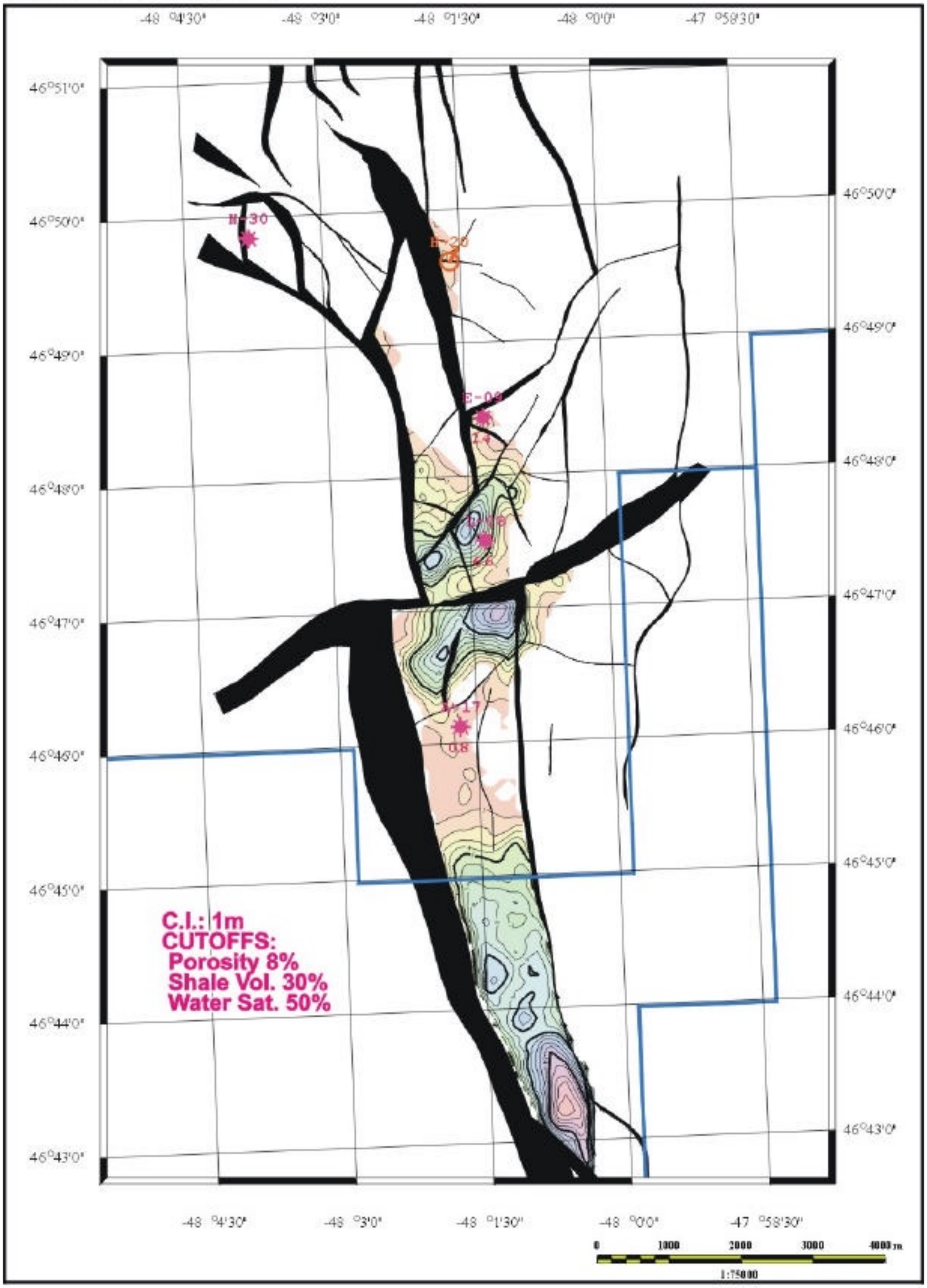

Figure 2.3-52

South Avalon Pool
LAYER 2 GAS HCPV

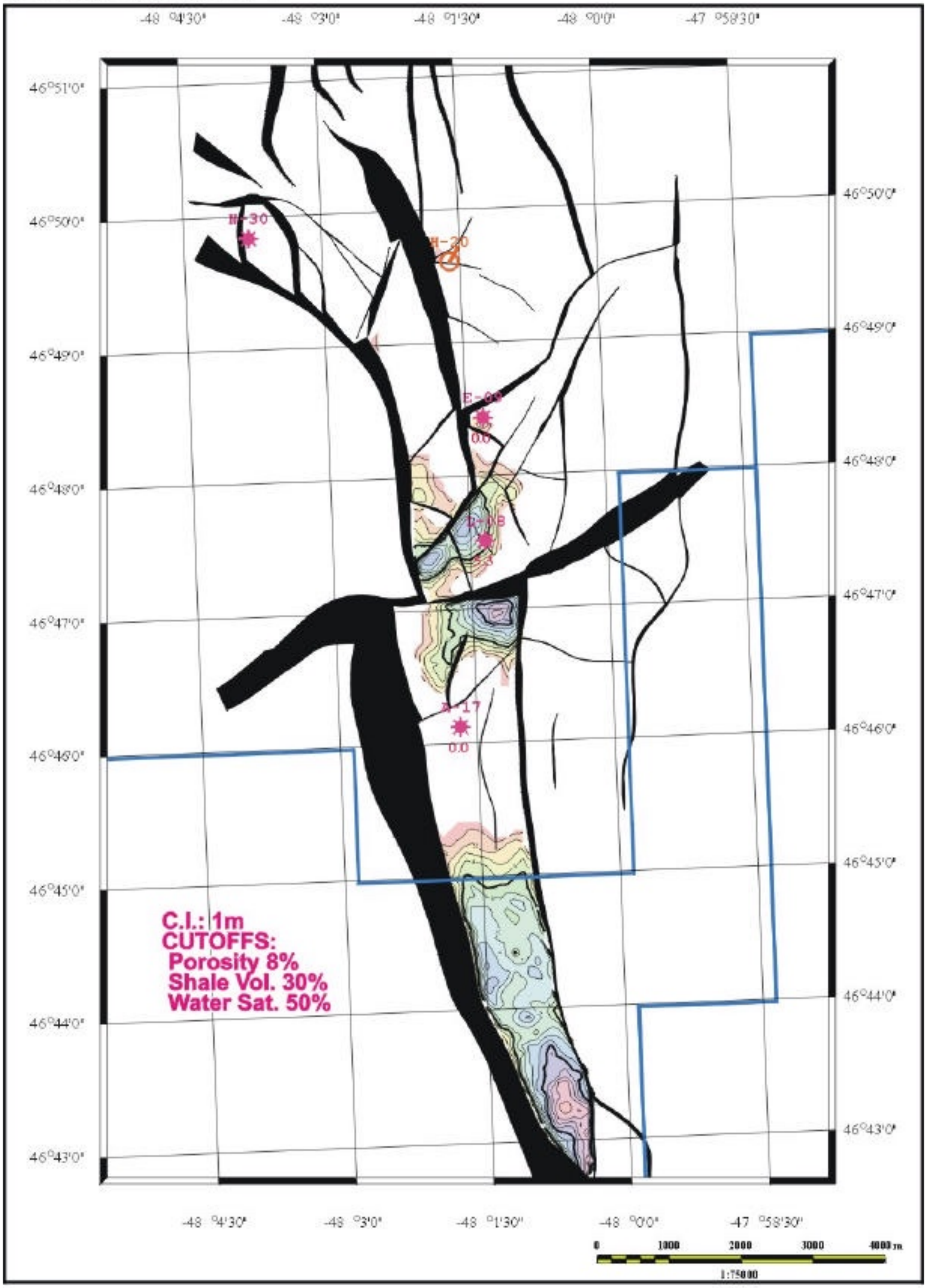

Figure 2.3-53

South Avalon Pool
LAYER 3 GAS HCPV

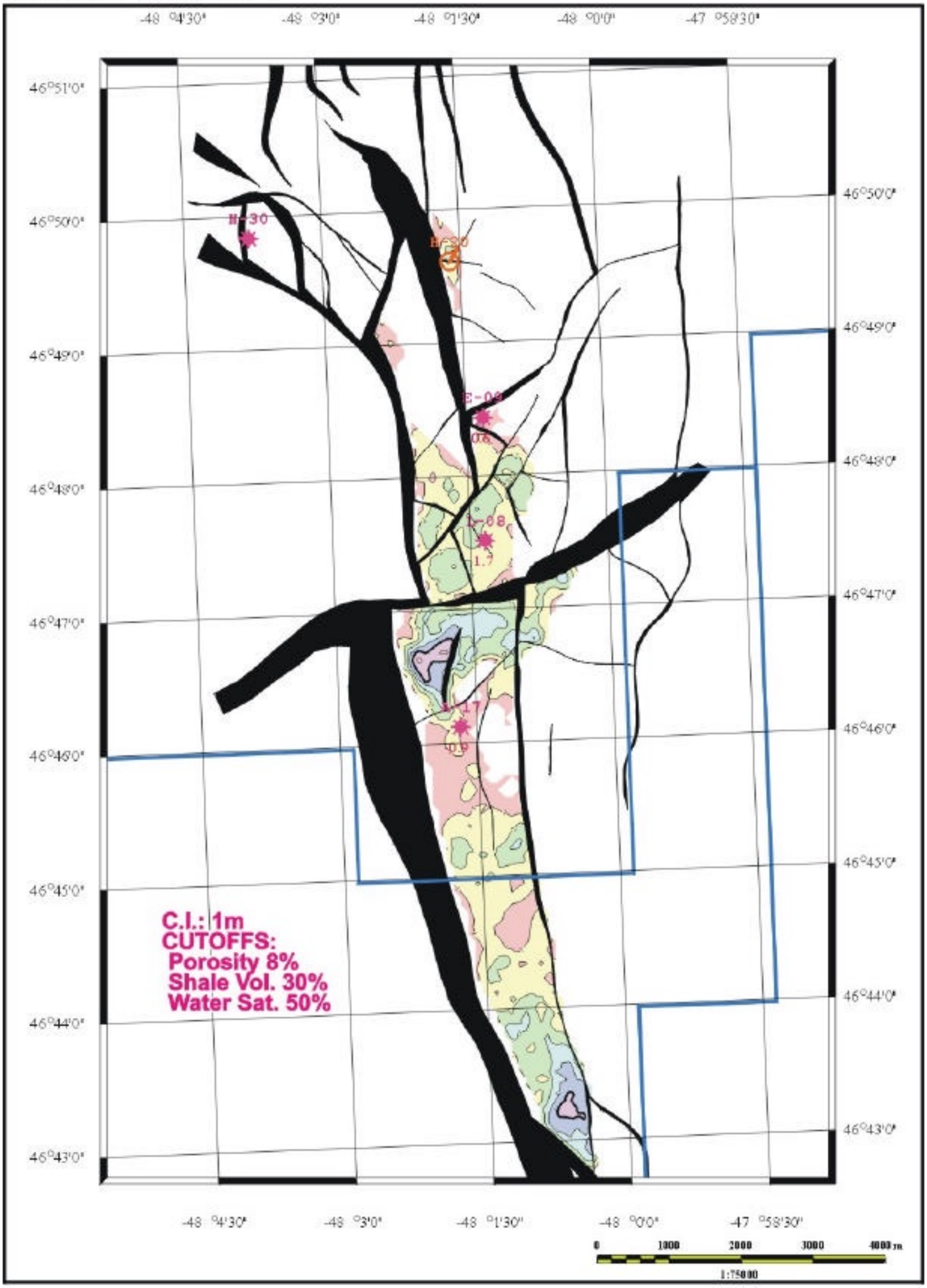

Figure 2.3-54

APPENDIX 8.A

Relevant Codes and Standards

Table 8.A-1 Codes and Standards for the Floating Production Facility

Agency	Title	Reference
American Petroleum Institute	Classification of Locations for Electrical Installations at Petroleum Facilities	API RP 500
	Recommended Practice for Design and Installation of Electrical Systems for Offshore Production Platforms	API RP 14F
	Specification for Offshore Cranes	API Spec 2C
	Recommended Practice for Operation and Maintenance of Offshore Cranes	API RP 2D
	Recommended Practice for the Design and Installation of Pressure-Relieving Systems in Refineries	API RP 520
	Guide for Pressure-Relieving and Depressuring Systems	API RP 521
	Flanged Steel Safety-Relief Valves	API STD 526
	Flexible Pipe	API 17B
	Subsea Wellhead and Christmas Tree Equipment	API 17D
	Seat Tightness of Pressure-Relief Valves	API STD 527
	Venting Atmospheric and Low-Pressure Storage Tanks	API STD 2000
	Recommended Practice for Analysis, Design, Installation and Testing of Basic Surface Safety Systems for Offshore Production Platforms	API RP 14C
	Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems	API RP 14E
	Specification for Oil and Gas Separators	API Spec 12J
	Centrifugal Compressors for General Refinery Service	API STD 617
	Reciprocating Compressors for General Refinery Service	API STD 618
	Recommended Practice for In-Service Inspection of Mooring Hardware for Floating Drilling Units	API RP 21
American Society of Mechanical Engineers	Boiler and Pressure Vessel Code	Sections I, II, V, VII, VIII, IX
Canadian Standards Association	Canadian Electrical Code Part I	C22.1
	Test Methods and Electrical Wires and Cables	C22.2
	General Requirements, Design Criteria, the Environment, and Loads	CAN/CSA* S471
	Quality Management and Systems	CAN/CSA 9000 series
	Steel Structures, Offshore Structures	CAN/CSA S473
	Concrete Structures	CAN/CSA S474
	Boiler, Pressure Vessel and Pressure Piping Code	CSA B-51
	Foundations, Offshore Structures	CAN/CSA S472

Agency	Title	Reference
International Electrotechnical Commission	Electrical Installation in Ships, Part 3: Cables	Publication 92-3
	Tests on Electrical Cables Under Fire Conditions, Part 3	IEC 332-3
International Maritime Organization	International Conference on Safety of Life at Sea	
	International Safety Management Code	ISM Code
	Code for the Construction and Equipment of Mobile Offshore Drilling Units	
	International Convention on Load Lines	
National Association of Corrosion Engineers	Sulfide Stress Cracking Resistant Metallic Materials for Oil Field Equipment	MR-01-75
National Fire Protection Association	Standard for Water Spray Fixed Systems for Fire Protection	NFPA 15
	Recommended Practice for the Inspection, Testing and Maintenance of Sprinkler Systems	NFPA 13A
	Standard on Basic Classification of Flammable and Combustible Liquids	NFPA 321
	Standard on Carbon Dioxide Extinguishing Systems	NFPA 12
	Standard for the Installation of Centrifugal Fire Pumps	NFPA 20
	Standard on Deluge Foam-Water Sprinkler and Foam-Water Spray Systems	NFPA 16
	Standard on Automatic Fire Detectors	NFPA 72E
	Standard for the Installation, Maintenance and Use of Protective Signaling Systems	NFPA 72
Transport Canada	Guidelines Respecting Helicopter Facilities on Ships	TP4414
	MODU Code	
CSA = Canadian Standards Association		

Table 8.A-2 Codes and Standards for Subsea Facilities

Agency	Title	Reference
American Petroleum Institute	Recommended Practice for Design and Operation of Subsea Production Systems	API RP 17A
	Specifications for Subsurface Safety Valve Equipment	API Spec 14A
	Recommended Practice for Design, Installation, Repair and Operation of Subsurface Safety Valve Systems	API RP 14B
	Specification for Wellhead and Christmas Tree Equipment Systems	API Spec 6A
	Specification for Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service	API Spec 14D
	Recommended Practice for Installation, Maintenance, and Repair of Surface Safety Valves and Underwater Safety Valves Offshore	API RP 14H
Canadian Standards Association	Oil and Gas Pipeline Systems	CAN/CSA Z662
Det norske Veritas	Safety and Reliability of Subsea Production Systems	Guideline No. 1-85
	Flexible Pipes and Hoses for Submarine Pipeline Systems	TNA 503
CSA = Canadian Standards Association		

Table 8.A-3 Codes and Standards for Shuttle Tankers

Agency	Title	Reference
American Bureau of Shipping	Steel Vessel Rules	
Transport Canada	*Canadian Shipping Act*	
Institution of Electrical and Electronic Engineers	Recommended Practices for Electrical Installations on Shipboard	S45
International Maritime Organization	International Load Line Convention International Conference on Safety of Life at Sea *International Telecommunications Radio Regulations* *International Regulations for Prevention of Collisions at Sea* International Convention on Tonnage Measurement of Ships	