White Rose Extension Project

White Rose Development Plan Amendment

June 2014

EXECUTIVE SUMMARY

Husky Energy (Husky), as Operator, on behalf of its co-venturers Suncor Energy and Nalcor Energy - Oil and Gas, is submitting this White Rose Development Plan Amendment to outline and request approval for the White Rose Extension Project (WREP). The WREP consists of construction and operation of a wellhead platform (WHP) to access the West White Rose pool and other potential resources.

The WREP is the next step in further development of White Rose area resources. The West White Rose pool was identified for potential development in the original White Rose development plan and is the primary focus of the WREP. Development of WREP resources will provide oil production to assist in offsetting the natural decline in production from the main White Rose pool and the North Amethyst field.

The West White Rose pool is situated to the northwest of North Amethyst and to the west of the South Avalon pool. Structurally, it is the most deeply buried Ben Nevis-Avalon pool in the White Rose field. It is a structurally complex area, with a series of post-depositional northwest-southeast trending faults that segment the area into thin, rotated fault blocks. West White Rose has six delineation wells (J-49, E-28, O-28Y, O-28X, C-30 and C-30Z), one gas injection well (J-22 3), a pilot producer (E-18 10) and a pilot water injector (E-18 11). The pilot producer has been on production since 2011. Resources in the North Avalon pool, South Avalon pool, and Blocks 2 and 5 are considered to be part of the WREP region and are also discussed in detail in this amendment. The P50 recoverable resource estimate for the West White Rose pool (incremental), Blocks 2 and 5, North Avalon and South Avalon (incremental) is 18.3 10^6 m^3.

The West White Rose base depletion plan currently has 26 wells (13 producers and 13 water injectors). It is anticipated that the well count will vary, pending the actual reservoir geology and performance as development occurs. The final well count is subject to change and will ultimately be based upon the development viability in the area. The well schedule will be phased and new reservoir understanding will be incorporated in each subsequent phase. Base scenarios include the use of gas lift as primary artificial lift similar to the completions in South Avalon and North Amethyst. The use of electric submersible pumps as a secondary lift mechanism is being investigated, as well as the use of other well stimulation technologies.

The displacement strategy plans for the development pools include secondary recovery by water flood. A voidage replacement ratio between 1.0 and 1.2 will be targeted during the operational phase. The existing secondary recovery mechanism of water displacement will be maintained, but will be augmented with gas injection, water-alternating gas or partial pressure support where deemed viable.

Currently, all gas produced from the *SeaRose FPSO* is injected into the North Avalon and West White Rose pools. The existing gas storage capacity is approximately 2.9 billion Sm^3; the remaining capacity estimate is approximately 38 million Sm^3. The base case full-field gas utilization strategy consists of using the Northern Drill Centre gas storage capacity and injection for gas flood into South White Rose Extension (SWRX). Husky also plans to progress further gas utilization plans, including evaluation of other areas for gas injection at near-field locations and evaluation of further gas-enabled improved oil recovery applications.

The WHP will be comprised of a concrete gravity structure (CGS) with topsides consisting of drilling facilities, wellheads and support services such as accommodations for up to 144 persons, utilities, a flare boom and a helideck. The primary function of the WHP is drilling. There will be no oil storage in the CGS. All well fluids will be transferred via flexible risers and subsea flowlines to the *SeaRose* floating production, storage and offloading (*FPSO*) facility for processing, storage and offloading. The design of the WHP will account for the risks posed by icebergs, sea ice and the harsh environmental conditions found offshore Newfoundland and Labrador. The potential environmental effects of the operation of the *SeaRose FPSO* have not been assessed past 2020, the original projected life of the White Rose field. Husky Energy will complete environmental assessments as required to review potential effects and mitigation opportunities prior to the expiry of current approvals.

The WHP development will entail constructing the CGS in a purpose-built graving dock. A review of potential onshore CGS construction sites on the island of Newfoundland was undertaken and Argentia was identified as the most suitable location for construction of the CGS. The graving dock will be excavated and constructed within a 20 hectare plot that has been leased from the Argentia Management Authority at Argentia, NL. Potential support facilities for CGS construction include primary and secondary concrete batching plants, offices, mess hall, medical clinic, temporary sheds, lay down areas and storage areas. The construction site will be fully fenced with a security-controlled entrance. The graving dock will be fitted with concrete gates that will allow the facility to be re-used.

Following construction, the CGS will be towed out of the graving dock, towed offshore and situated in the western portion of the White Rose field. Once the CGS is on location and ballasted, the topsides will be installed by a specialized platform installation vessel (the *Pieter Schelte*) and the remaining hook-up and commissioning will be completed. The WHP will include a provision for cuttings re-injection as part of the base design for instances where synthetic-based mud is used. For portions of any well drilled using synthetic-based mud, associated cuttings will be injected into a dedicated injection well.

Production and water injection wells will incorporate, for each well, a total of three barriers against well flow. Of these, one will be a surface barrier (wellhead/Xmas tree) and two will be subsea barriers (i.e., TR-sub-surface safety valve(s) (SSSVs), packer, kill weight packer fluid). During drilling, primary well control will be in place at all times by maintaining a hydrostatic pressure gradient greater than the highest pore pressure gradient of any exposed productive formation in the wellbore. Secondary well control will be provided with a blowout preventer system designed in accordance with all applicable regulations and standards. In addition to the blowout preventer, a choke and kill manifold will be used to support the well control system. The manifold will allow for controlled flow to/from the wellbore as required for well control purposes, and will be sized appropriately for the application. A diverter system will be used to protect for shallow gas hazards.

The WHP will accommodate 20 well slots using conductor sharing wellhead technology in some or all wells, which allows two wells to be drilled in each conductor, for a total of up to 40 wells. The well count and designation of slots will be finalized once depletion planning is finalized.

The topsides facilities will have an operating weight of approximately 28,000 metric tonnes. The topsides facilities configuration will be designed to ensure maximum isolation of hazardous/process equipment and the well bay from the living quarters and helideck. The facilities will comprise:

- Drilling, completions and well intervention equipment
- Well bay and wellheads
- Oil production, test, water injection, gas injection and gas lift manifolds
- High-pressure water injection booster pumps
- Fuel gas heating and treatment
- Test separator and metering
- Safety and utility systems
- Integrated control and safety systems
- Telecommunications systems
- Power generation and distribution systems
- 144 person living quarters.

Gas lift, gas flood and fuel gas will be supplied from the *SeaRose FPSO* gas compression/injection system via a single high-pressure gas flowline, teed into the subsea flowline running between the Northern Drill Centre and the SWRX Drill Centre. There is no processing of produced fluids on the WHP and as such, produced water from WHP wells will be separated on the *SeaRose FPSO*. The *SeaRose FPSO* produced water handling systems will be used to treat the produced water from the WHP. Water injection will continue to be used as the primary means to support reservoir pressure in the White Rose field. The *SeaRose FPSO* will supply water injection to the WHP via the Central Drill Centre (CDC) water injection manifold.

The WHP will have an Integrated Control and Safety System for the protection of personnel, the environment and the facilities from accidental or abnormal operating conditions. The Integrated Control and Safety System will have an emergency shutdown system that will be interfaced with the *SeaRose FPSO* emergency shutdown system to shut down the import/export of hydrocarbons to both facilities during emergency situations.

The main power generation for the topsides will comprise dual-fuel (gas/diesel) turbine driven generators. A diesel-driven emergency generator and distribution system will supply all emergency electrical loads in accordance with the relevant regulations.

Active fire protection systems will meet the specific requirements of the *Newfoundland Offshore Petroleum Installations Regulations* (SOR/95-104) and referenced standards. In general, active fire protection will be designed to prevent fire from spreading to other areas, and to limit damage to structures and equipment.

The WHP will have two muster points. One muster point will be in the accommodations area temporary safe refuge, close to the lifeboat station. The other muster area will be located in the northeast corner of the WHP, near the second lifeboat station. Escape routes will be designed in accordance with the *Newfoundland Offshore Petroleum Installations Regulations*. Every work area will have at least two well-marked separate escape routes that are situated as far apart as is practicable. The WHP will be provided with a minimum 200 percent capacity of persons on board in lifeboats, 100 percent capacity in life rafts and 200 percent capacity in personnel environment survival suits.

Some provisions for future expansion will be included in the WHP design. Specifically, the WHP design includes risers for oil production, water injection and gas lift. In addition to development from the WHP, Husky may also develop up to two additional subsea drill centres in the White Rose region. The WHP will have the capability to tie-back one new drill centre. Tie-back of a second potential drill centre would be through an existing drill centre or directly to the *SeaRose FPSO*.

Subsea flowlines will interconnect the WHP with the *SeaRose FPSO* via valved mid-line tie-in structures in the existing production flowlines between the CDC and the *SeaRose FPS*O. A subsea water injection flowline will connect the WHP and the *SeaRose FPSO* via a flowline termination module that will be added to the end of the existing CDC water injection manifold. A gas supply flowline was connected between the WHP and a gas injection flowline between the Northern Drill Centre and the SWRX Drill Centre.

The WHP will be integrated into Husky's current operations organization. The WHP will be maintained and operated in accordance with the Husky Operational Integrity Management System. Husky intends to use its existing infrastructure and established service contracts to support operations on the WHP. The offshore installation manager on the *SeaRose FP*SO will have overall field responsibility for all installations, including the WHP. The WHP will have a dedicated offshore installation manager who will be responsible for overall operations on the WHP.

Husky has developed and implemented environmental monitoring procedures requiring compliance with Husky requirements and applicable legislation and regulations. These plans and procedures will be updated as required to include all infrastructure and activities associated with the WREP. An Environmental Protection and Compliance Monitoring Plan will be developed specifically for the WHP.

A WHP-specific ice management plan will be developed. The plan will have defined t-times specific to the facility and will also include an enhanced ice surveillance and management program.

A strong emergency response program supports the integrity of Husky operations. Husky's Incident Coordination Plan outlines the necessary resources, personnel, logistics and actions to implement a prompt, coordinated and rational response to any emergency. An installation-specific emergency response plan will be developed for the WHP. The WHP will have designated emergency response personnel.

Husky has instituted a spill prevention program with the goal of zero spills into the marine environment. Any unintentional discharge of a hydrocarbon will be considered to be an oil spill and may result in the activation of the East Coast Oil Spill Response Plan.

Total estimated WHP construction capital costs are $2.35 billion. Total estimated development drilling costs are $1.61 billion. The majority of WHP annual costs are included in the development drilling and completions capital cost estimate. Costs for the WHP associated with operations are expected to increase total field operating costs by 10 percent per year (or approximately $20 million per year increase over operating cost levels without the WHP).

Husky is committed to conducting all activities in a safe manner. A concept safety analysis was carried out during pre-front end engineering design and early front end engineering design to identify major hazards associated with the WHP, taking into account the basic design concepts, layout and intended operations, and assessing the risks to personnel and the environment resulting from these hazards. The concept safety analysis concluded that there were no areas for concern that would prevent demonstration that risks have been reduced to a level that is as low as reasonably practicable at the detailed design stage. The health, safety, environment and quality requirements for the WHP will be developed, implemented and managed in accordance with the principles and requirements of the Husky Operational Integrity Management System. Husky's Certifying Authority will be involved in all aspects of the WREP from design through operations. The WHP safety plan will outline the measures implemented for the safety and well-being of personnel, preservation of the environment and protection of the installation. The safety plan will provide a comprehensive summary of the components of the management system that will be applied to the WHP and how duties regarding safety, environmental protection and asset integrity will be fulfilled. The development of security-related processes specific for the WHP will be based on existing security systems and processes already in place for the *SeaRose FPSO* as appropriate. A facility-specific environmental protection and compliance monitoring plan will also be developed for the WHP. The potential environmental effects of the WHP were examined in the *White Rose Extension Project Environmental Assessment* (December 2012) and the *Response to Review Comments on the White Rose Extension Project Environmental Assessment* (April 2013).

As described in the *White Rose Extension Project Environmental Assessment* (December 2012), the WHP will be decommissioned and abandoned by first abandoning the wells in accordance with standard oil field practices, then decommissioning of the topsides, followed by decommissioning and abandonment of the CGS. The WHP will not be disposed of offshore, nor converted to another use on site.

Husky will continue to evaluate the opportunities to develop the White Rose gas resource. However, at the current stage of development in the White Rose region, the plan at this time is to use gas in support of oil recovery. Produced gas will continue to provide primary power to the *SeaRose FPSO* and will also be used for primary power on the WHP.

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ACRONYMS

Term	Description
API	American Petroleum Institute
bbl/d	barrels per day
BML	below mud line
BN	Ben Nevis
BNA	Ben Nevis-Avalon
BNEV_SLTST	Ben Nevis Siltstone
BOP	blowout preventer
°C	Celsius
CCE	constant composition expansion
CDC	Central Drill Centre
CGS	concrete gravity structure
C-NLOPB	Canada-Newfoundland and Labrador Offshore Petroleum Board
CRI	cuttings re-injection
CVD	constant volume depletion
d	day
DST	drill stem test
EEM	environmental effects monitoring
EPCMP	Environmental Protection and Compliance Monitoring Plan
ERD	extended reach drilling
ERT	Emergency Response Team
ESP	electric submersible pump
ESD	emergency shutdown system
FA	facies associations
FEED	front end engineering design
FGS	fire and gas system
FPSO	floating production, storage and offloading facility/vessel
FVF	formation volume factor
GIIP	gas initially in place
g	gram
GOR	gas-oil ratio
GR	gamma ray
HOIMS	Husky Operational Integrity Management System
HSEQ	Health, Safety, Environment and Quality
HVAC	heating, ventilation and air conditioning
ICOADS	International Comprehensive Ocean-Atmospheric Data Set
ICSS	integrated control and safety system
IMS IPM	information management system integrated production model
IOR	improved oil recovery

Term	Description
ISO	International Standards Organization
kg	kilograms
km	kilometre
km^2	square kilometres
kPa	kilopascals
l	litre
m	metres
m^3	cubic metres
m/s	metres per second
md	millidarcies
MD	measured depth
MDT	modular dynamic formation tester
mmscfd	million standard cubic feet per day
NDC	Northern Drill Centre
NFPA	National Fire Protection Association
OIM	offshore installation manager
OOIP	original oil in place
PC&T	Personnel Competency and Training
POB	persons on board
psi	pounds per square inch
PVT	pressure, volume, temperature
Rs	solution gas-oil ratio
RT	depth referenced to the rig floor rotary table
Rw	water resistivity
s	seconds
SBM	synthetic-based mud
SCAL	special core analysis
Sm^3/d	standard cubic metres per day
SSIV	subsea isolation valve
SSSV	sub-surface safety valve
Sw	water saturation
TVDss	true vertical depth subsea
VSP	vertical seismic profile
WAG	water-alternating gas
WHP	wellhead platform
WREP	White Rose Extension Project

1.0 OVERVIEW

Husky Energy (Husky), as Operator, on behalf of its co-venturers Suncor Energy and Nalcor Energy - Oil and Gas (Nalcor), is submitting this White Rose Development Plan Amendment to outline and request approval for the White Rose Extension Project (WREP). The WREP includes construction and operation of a wellhead platform (WHP) to access the West White Rose pool and other potential resources.

1.1 White Rose Extension Project Area

The WREP is contained within the White Rose region located on the Grand Banks, approximately 350 km east of the Island of Newfoundland on the eastern edge of the Jeanne d'Arc Basin (Figure 1-1).

Figure 1-1 White Rose Region

The White Rose region consists of both oil and gas resources, including the South Avalon pool (including Blocks 2 and 5), the North Avalon pool, the West White Rose pool, South White Rose Extension (SWRX) pool and the North Amethyst field. The location of the pools/fields in the White Rose region is illustrated in Figure 1-2. The main oil reservoir in the White Rose region is the Ben Nevis-Avalon Formation (BNA) sandstone. First oil from White Rose (South Avalon pool) was achieved in November 2005 and from the North Amethyst field in May 2010.

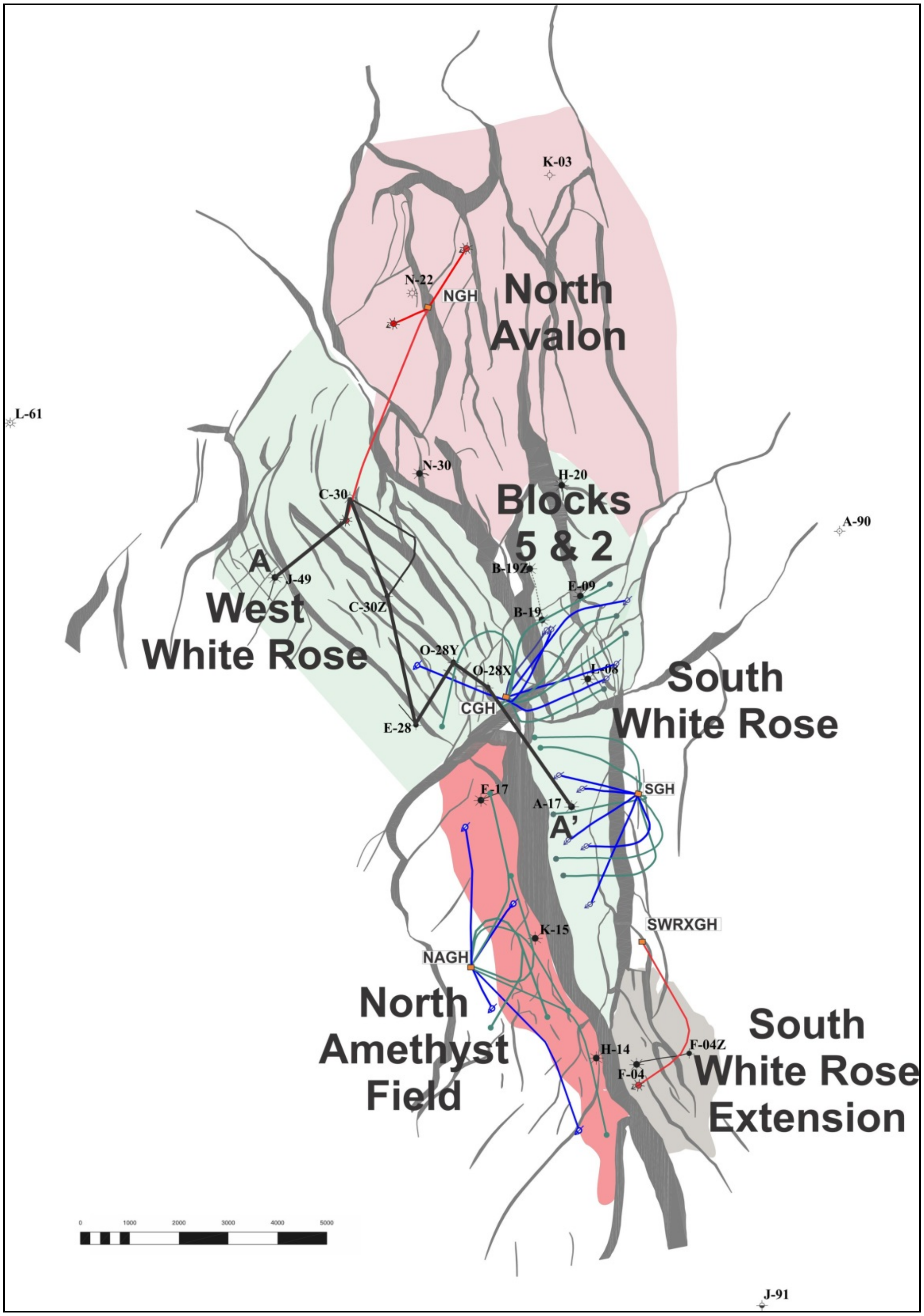


Figure 1-2 Location of Pools/Fields in the White Rose Region

The WHP will be primarily used to access the West White Rose pool. However, other resources are located within reach of the WHP and are considered as potential resources for development from the new facility. This amendment outlines the current basis for development of the West White Rose pool and also provides an overview of additional resources that could be developed from the WHP. The overviews will present the current basis under consideration for development of the South Avalon and North Avalon pools from the WHP. The basis of development for these pools will evolve with learning from further production history and field performance.

The North Amethyst field has a separate Development Plan from that of White Rose and it is currently not planned to use the WHP to access the North Amethyst resources. However, opportunities for improved oil recovery (IOR) from North Amethyst from the WHP may be feasible later in field life.

Husky continues to investigate additional potential opportunities within the White Rose region and further delineation has the potential to provide additional resources that may be accessed from the WHP.

1.2 Project Proponents

The interests of the co-venture parties in the South Avalon pool are:

- Husky Oil Operations Ltd: 72.5 percent
- Suncor Energy: 27.5 percent

The interests of the co-venture parties for all other WREP-associated pools are:

- Husky Oil Operations Ltd: 68.875 percent
- Suncor Energy: 26.125 percent
- Nalcor Energy - Oil and Gas: 5.00 percent.

1.3 Project Need and Justification

The WREP is the next step in further development of the White Rose region. The West White Rose pool was identified for potential development in the original White Rose development plan and is the primary focus of the WREP. Development of WREP resources will result in oil production to assist in offsetting the natural decline in production from the main South Avalon pool and the North Amethyst field. Oil production from the WREP will also result in additional royalties to the provincial government and a share of profits through Nalcor's equity interest in the WREP.

The evaluation of options for the WREP focused on concepts that used the *SeaRose* floating production, storage and offloading (*FPSO*) facility and existing subsea infrastructure. Two alternative development schemes, a subsea drill centre or a WHP, were considered for development of the West White Rose pool. Analysis of these alternatives indicated that the preferred means to recover the identified resources in the White Rose region was through the use of a WHP. The WHP offers lower drilling and completion costs as compared to a semi-submersible drilling rig and because the wellheads would be on the platform, rather than subsea, there are greater opportunities for well interventions and other practices to improve ultimate recovery of resources. The WHP will also be designed to allow for re-injection of synthetic-based mud (SBM) cuttings into a disposal well, rather than discharge of treated cuttings and the main power generation on the WHP will use natural gas rather than diesel fuel.

Throughout the development of the White Rose project, Husky has demonstrated a strong commitment to maximizing project benefits to Newfoundland and Labrador. Husky has policies and procedures in place to provide Newfoundland and Labrador and Canadian companies with full and fair opportunity and first consideration to supply goods and services in support of WREP development.

1.4 Scope of the Project

The WHP will consist of a concrete gravity structure (CGS) with topsides consisting of drilling facilities, wellheads and support services such as accommodations for up to 144 persons, utilities, a flare boom and a helideck. The primary function of the WHP is drilling. There will be no oil storage in the CGS. All well fluids will be transported via subsea flowlines to the *SeaRose FPSO* for processing, storage and offloading. The design of the WHP will account for the risks posed by icebergs, sea ice and the harsh environmental conditions found offshore Newfoundland and Labrador.

The original White Rose environmental assessment (White Rose Comprehensive Study, Husky Energy 2001) contemplated the construction of three or four subsea drill centres within the White Rose field. Three drill centres (Central, Southern and Northern) were constructed prior to a subsequent environmental assessment for five additional drill centres (Husky White Rose Development Project: New Drill Centre Construction and Operations Program Environmental Assessment - EA Addendum, LGL 2007). To date, only the North Amethyst and SWRX drill centres have been constructed of the five assessed for potential construction during the period from 2007 to 2015.

The WREP Environmental Assessment (Husky Energy 2012, 2013) re-assessed the effects of construction and operation of up to three drill centres during the life of the project. The productive life of the subsea infrastructure is estimated at 20 years and the productive life of the WHP is estimated at 25 years. The potential environmental effects of the operation of the *SeaRose FPSO* have not been assessed past 2020, the original projected life of the White Rose field. Husky Energy will complete environmental assessments as required to review potential effects and mitigation opportunities prior to the expiry of current approvals.

The WHP development will entail constructing the CGS in a purpose-built graving dock. A review of potential onshore CGS construction sites on the island of Newfoundland was undertaken and Argentia was identified as the most suitable location for the construction of the CGS. Following construction of the CGS, it will be towed and situated in the western portion of the White Rose region, where the topsides will be installed.

1.5 Project Schedule

The WREP schedule is depicted in Figure 1-3.

1.6 Environmental Assessment

The Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) is required to conduct an environmental assessment of proposed oil and gas projects, such as the WREP, before they may issue authorizations, licenses and permits for the purpose of enabling such projects to be developed. This type of project was listed on the *Inclusion List Regulations* under the *Canadian Environmental Assessment Act* (CEAA) and required a Screening level of assessment. The provincial environmental assessment process was also triggered by the requirement for construction of a graving dock at Argentia. The review by the C-NLOPB and provincial and federal agencies was a harmonized process coordinated by the C-NLOPB. The environmental assessment process for the WREP was completed in October 2013.

1.7 Documents Used in Preparation of the Development Plan Amendment

The following documents were used in preparation of the Development Plan Amendment:

- Wellhead Platform Basis of Design, WH-G-99W-G-SP-00002-001.
- Subsurface Basis of Design, WH-G-99W-G-SP-00003-001.
- Well Construction Basis of Design, WH-G-97W-D-SP-00001-001.
- Subsea Tie-back Basis of Design, WH-S-93W-U-RP-00001-001.
- White Rose Extension Environmental Assessment. December 2012. Husky Energy.
- Response to Review Comments on the White Rose Environmental Assessment. April 2013. Husky Energy.
- White Rose Extension Project CEAA Screening Report. September 2013. C-NLOPB.
- Preliminary Site Characterization of Proposed Wellhead Platform Location White Rose Extension Project. 2011. Fugro Geosurveys Inc.
- Summary of White Rose Physical Environmental Data for Production Systems. 2011. Oceans Ltd.

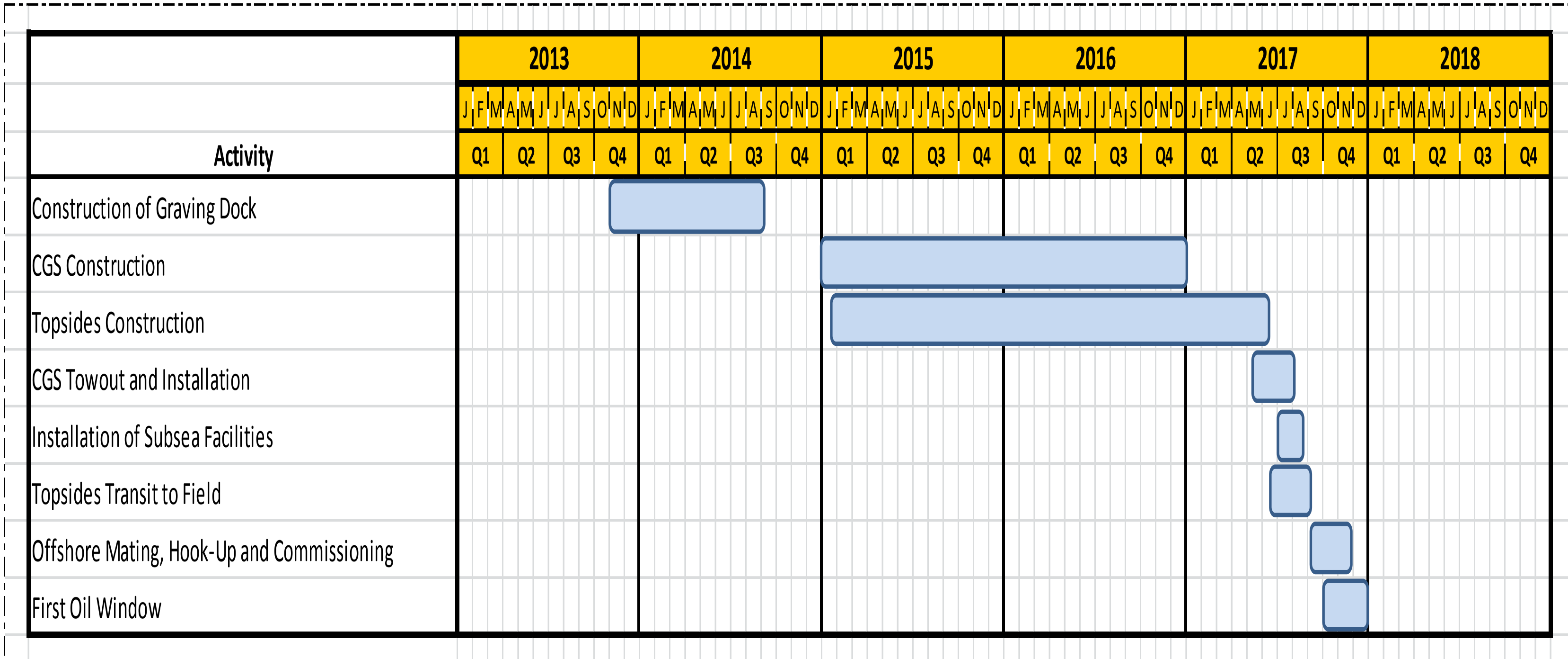


Figure 1-3 White Rose Extension Project Schedule

2.0 GEOLOGY, GEOPHYSICS AND PETROPHYSICS

2.1 Geology

2.1.1 White Rose Field General

The White Rose region is a highly faulted complex of rotated fault blocks, underlain by a basin-wide salt layer at depth. The White Rose region is bounded to the north and west by basinward-dipping flanks of a prominent high. The eastern margin of the structure abuts against the basin-bounding Trave Fault, while the southern boundary of the field encompasses the SWRX and North Amethyst pools.

A note of clarification is required regarding the nomenclature used in the 2001 White Rose Development Plan versus this current White Rose Development Plan Amendment. The reservoir section was termed the 'Avalon' in the 2001 Development Plan. As noted in the 2012 SWRX Development Plan Amendment, it is now believed that the reservoir section lies upon the mid-Aptian Unconformity, is middle Aptian to Albian in age, and is an overall fining-upward package within a transgressive systems tract. Consequently, the dominant reservoir interval is interpreted to be the Ben Nevis (BN) Formation, equivalent to the type section at BN I-45 designated by McAlpine (1990).

The BNA Formation is Aptian to Albian-aged, and consists of fine to very fine-grained quartzose sandstones deposited in shallow marine settings, dominantly shoreface. As of 2012, the White Rose region had been penetrated by 22 exploration and delineation wells. Three intersecting fault systems oriented northeast-southwest, north-northwest to south-southwest and north-south compartmentalize the area. As indicated by reservoir pressure data, a few major faults (for example, West Amethyst, Central and Twin), together with a low structural trend oriented north-northeast to south-southwest, segment the area into the following:

- South Avalon pool
- SWRX pool
- North Avalon pool
- North Amethyst field
- West White Rose pool.

The South Avalon pool, which is the focus of the White Rose development, is segregated into South Avalon, central Terrace and Blocks 2 and 5. The gross reservoir height in this area is approximately 350 m of stacked sandstones with an approximately 100 m thick oil column.

The SWRX pool is located to the south of the main South Avalon pool and has been delineated by the F-04 and the F-04Z wells. There has been no production from the SWRX pool to date. Development of the SWRX pool is covered under the White Rose Development Plan Amendment approved by the C-NLOPB in Decision 2013.04.

North Avalon is currently the region used to store produced gas from the White Rose region. It is also the location of the initial White Rose discovery well, N-22. The BNA reservoir at White Rose thins to the north, with approximately 50 m of net reservoir in the N-22 location.

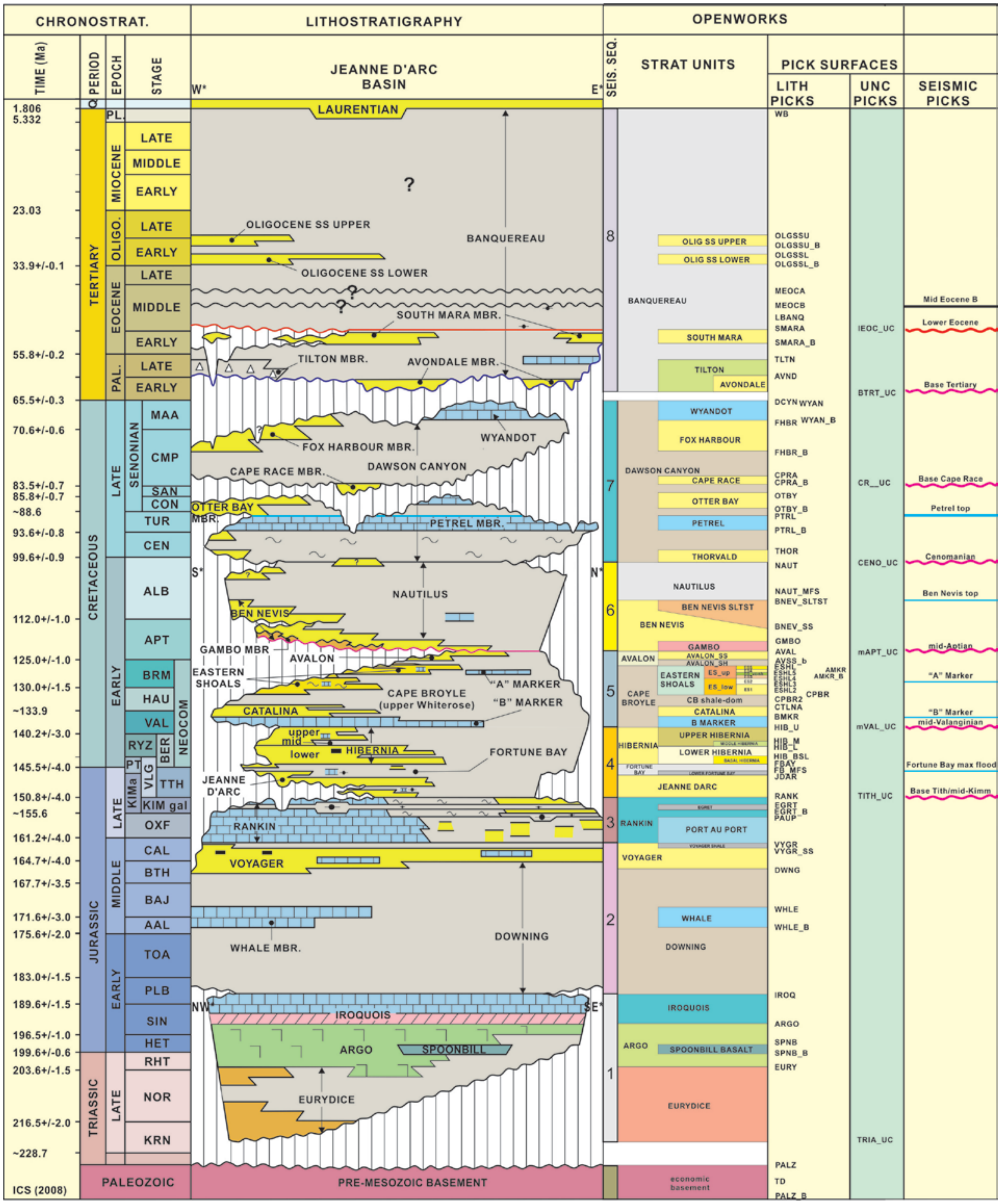
The North Amethyst BNA Formation was the first tie-back to the *SeaRose FPSO* to be developed in the White Rose region. It is buried approximately 600 m true vertical depth subsurface (TVDss) less than the South Avalon pool. The BN Formation within the North Amethyst field has approximately 210 m of stacked reservoir sandstones, with a 52 m oil column and an overlying gas cap.

The West White Rose pool is situated to the northwest of the North Amethyst field and to the west of the South Avalon pool. Structurally, it is the most deeply buried BNA pool in the White Rose field. It is a structurally complex area with a series of post-depositional northwest-southeast trending faults that segment the area into thin, rotated fault blocks. The southern region of the West White Rose pool has over 350 m of stacked BNA sandstones with an approximately 280 m oil column. The reservoir degrades to the north and west as the shallow marine shoreface transitions from proximal to more distal settings.

2.1.2 White Rose Regional Geology

2.1.2.1 White Rose Stratigraphy

The stratigraphic section penetrated by the wells drilled in the White Rose region generally comprises Tertiary to Lower Cretaceous strata, with rocks as old as Upper Jurassic locally encountered (Figure 2-1).



Note: Figure 2-1 was derived from Sinclair (1988, 1993) and incorporated McAlpine (1990) and Deptuck et al. (2003). General orientations of the stratigraphic section are noted at the top of each interval (i.e., W-E, S-N, NW-SE). The columns on the right show major tectono-stratigraphic subdivisions, directions of extension and styles of subsidence. Absolute ages are from Gradstein et al. (2005) and Ogg et al. (2008) as presented on the 2008 version of the International Stratigraphic Chart by the International Commission on Stratigraphy. Tectonic stages uses terminology of Nøttvedt et al. (1995) and Ravnås et al. (2000).

Figure 2-1 Lithostratigraphic Chart of the Jeanne d'Arc Basin

The Aptian/Albian-aged BNA Formation is the primary reservoir in the White Rose field. In general, the BNA is a marginal marine, shoreface succession throughout most of the field. The BNA is dominated by very fine- to fine-grained sandstones with siltstone and shale interbeds. The reservoir section ranges from 0 to 400 m in thickness. The main sandstone accumulations occur in the southeastern portion of the field, and were penetrated by the E-09, L-08 and A-17 wells (South Avalon pool) and O-28Y and E-28 (West White Rose), exhibiting thicknesses of up to 350 m of sandstone. The BNA Formation is absent in the area of the White Rose A-90 (porous, quartzose sandstone facies not present) and Trave E-87 (eroded or not deposited) wells.

The Nautilus Formation is primarily Albian in age and is present in all the wells in the White Rose region, although not to the north in the Trave E-87 well on the uplifted Central Ridge area. The Nautilus Formation conformably overlies the BNA Formation and is laterally equivalent where the BNA Formation shales out in distal settings. It represents a regional transgressive episode, depositing up to 470 m of compacted argillaceous beds in the West White Rose region. The Nautilus Formation is comprised of grey siltstones and shales with very minor sandstones. No reservoir quality rocks are present in the Nautilus Formation in the White Rose field. The Nautilus Formation forms the top seal for the BNA reservoir. Highly variable thicknesses of upper Aptian to middle Albian strata indicate that these beds were deposited during active extension.

Unconformably overlying the Nautilus Formation is the Cenomanian to Maastrictian aged Dawson Canyon Formation, consisting primarily of marls and calcareous shales. The Dawson Canyon Formation ranges in thickness from 100 to 500 m in the White Rose field. Few faults show evidence of continued growth during deposition of the Dawson Canyon Formation, indicating that active extension had ceased and regional thermal subsidence conditions prevailed during the Late Cretaceous. The Petrel Member limestones are present near the top of the Dawson Canyon Formation across much of the White Rose region, except where eroded in the vicinity of the A-17 well. It consists of a thin light grey to brown argillaceous limestone. The Wyandot Member chalky limestones were locally deposited in the North Avalon region as at White Rose N-22.

The Banquereau Formation in the White Rose field is composed of Tertiary clastics deposited during continued thermal subsidence. The Banquereau Formation is a thick shale succession (up to 2,500 m), with coarser clastics locally encountered at the base. The South Mara Member sandstone is occasionally present at the base of the Banquereau, closely overlying the Base Tertiary Unconformity. More often a sandy siltstone is present at the equivalent level. All the lowermost sandstones in the Tertiary were previously called “South Mara Member”, but Deptuck et al. (2003) split these into an upper “South Mara” and a lower “Avondale Member” sandstone. The gas-sandstones at White Rose L-61 have therefore been reclassified from South Mara to Avondale.

2.1.2.2 White Rose Structural Geology

Three episodes of rifting affected the White Rose region. During the first rifting phase, thick Argo salt beds were deposited. This salt was tectonically mobilized during the second and third rifting episodes, modifying and accentuating multiple rotated fault blocks. The Central Ridge was formed in the footwall of the Trave Fault Zone. Major north-south and northeast-southwest faults dissect the sediments deposited above the tectonically activated salt layer, including the source rocks. The third rifting stage had a pronounced influence on the area as it was divided into a major ridge (North Amethyst), the adjacent down-dropped terrace (South Avalon) and a northerly roughly circular dome with nearby associated synclines (northern White Rose Region). A fault fan, creating numerous rotated fault blocks, occupies the saddle-shaped low zone between the northern dome and the main producing area of the southern terrace. In the southeastern White Rose region, imbricates of the Trave Fault created graben blocks and flanking terraces where the BNA Formation was deposited, and high blocks that were subjected to continued erosion. The crestal areas of the White Rose dome became elevated and subjected to persistent erosion. The existence of BNA Formation in this area is difficult to prove by seismic correlation alone, given the presence of numerous faults of this tectonically-thinned section. Current geophysical interpretation indicates that little structural movement has occurred during the Late Cretaceous and Early Tertiary in the White Rose region.

A consistent seismic marker related to sediment deposited during the third extensional stage is recognizable over the entire White Rose region that could allow for consistent structural time mapping of the syn-rift BNA Formation. The Mid-Aptian Unconformity is the most widely recognizable surface in the seismic cube, but its character is variable, given the changing strata that subcrop the unconformity and the variable thickness and quality of sandstones that onlap the unconformity. Consequently, this complex surface at the base of the BNA Formation was interpreted for structural and tectonic characterization of the field.

The main structural elements of the White Rose region are displayed on Figure 2-2.

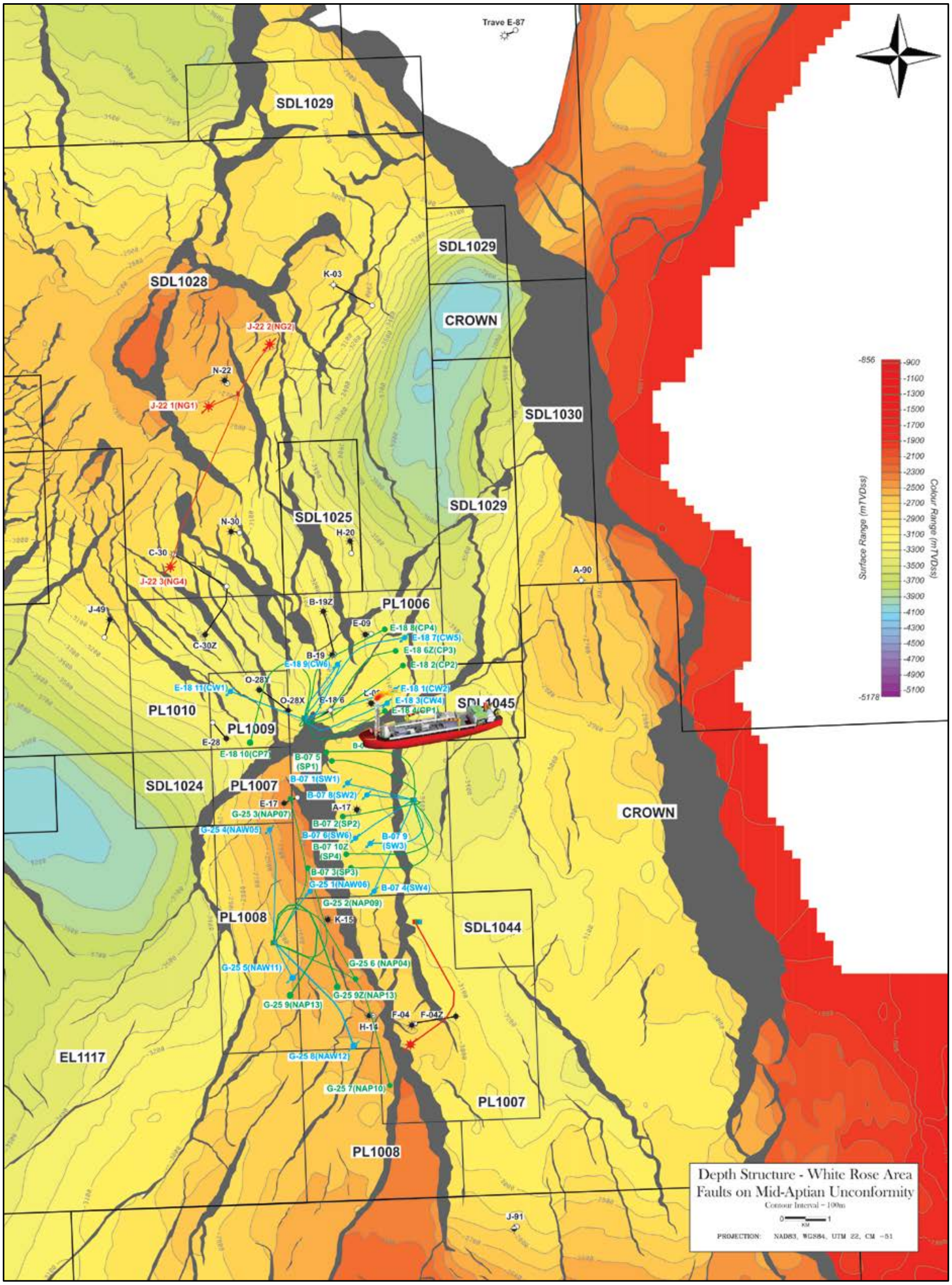


Figure 2-2 Geophysical Depth Structure Map of the Mid-Aptian Unconformity Surface over the White Rose Field

2.1.3 West White Rose Pool Geology

The current geologic interpretation used for geological modelling is an updated version of that presented in the 2001 White Rose Development Plan. At the time of the 2001 submission, there were seven delineation wells in the greater White Rose region that included the South, West and North White Rose sub-regions. The updated West White Rose model is confined to the West White Rose area and contains six delineation wells as well as the pilot oil producer/water injector pair from the Central Drill Centre (CDC), and a gas injector from the Northern Drill Centre (NDC) for a total of nine wells. Figure 2-3 depicts the general location of the West White Rose pool with respect to the existing development wells.

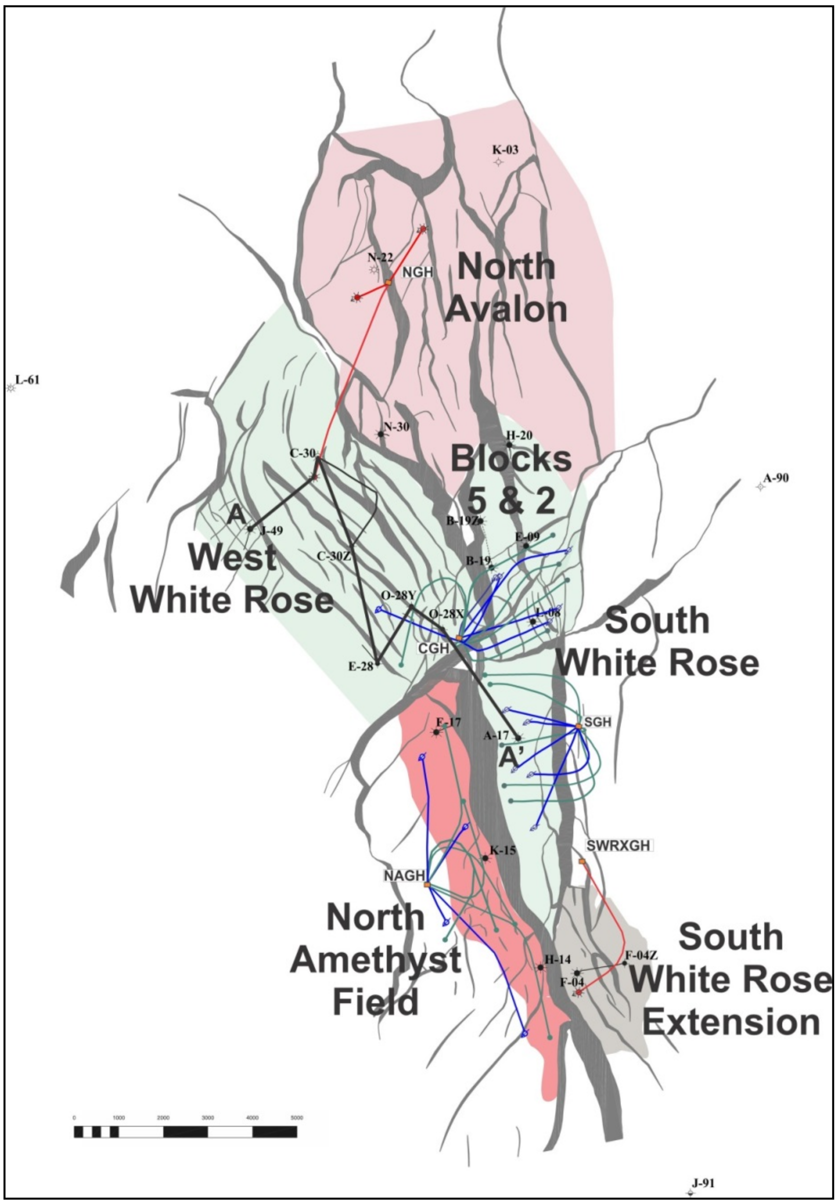
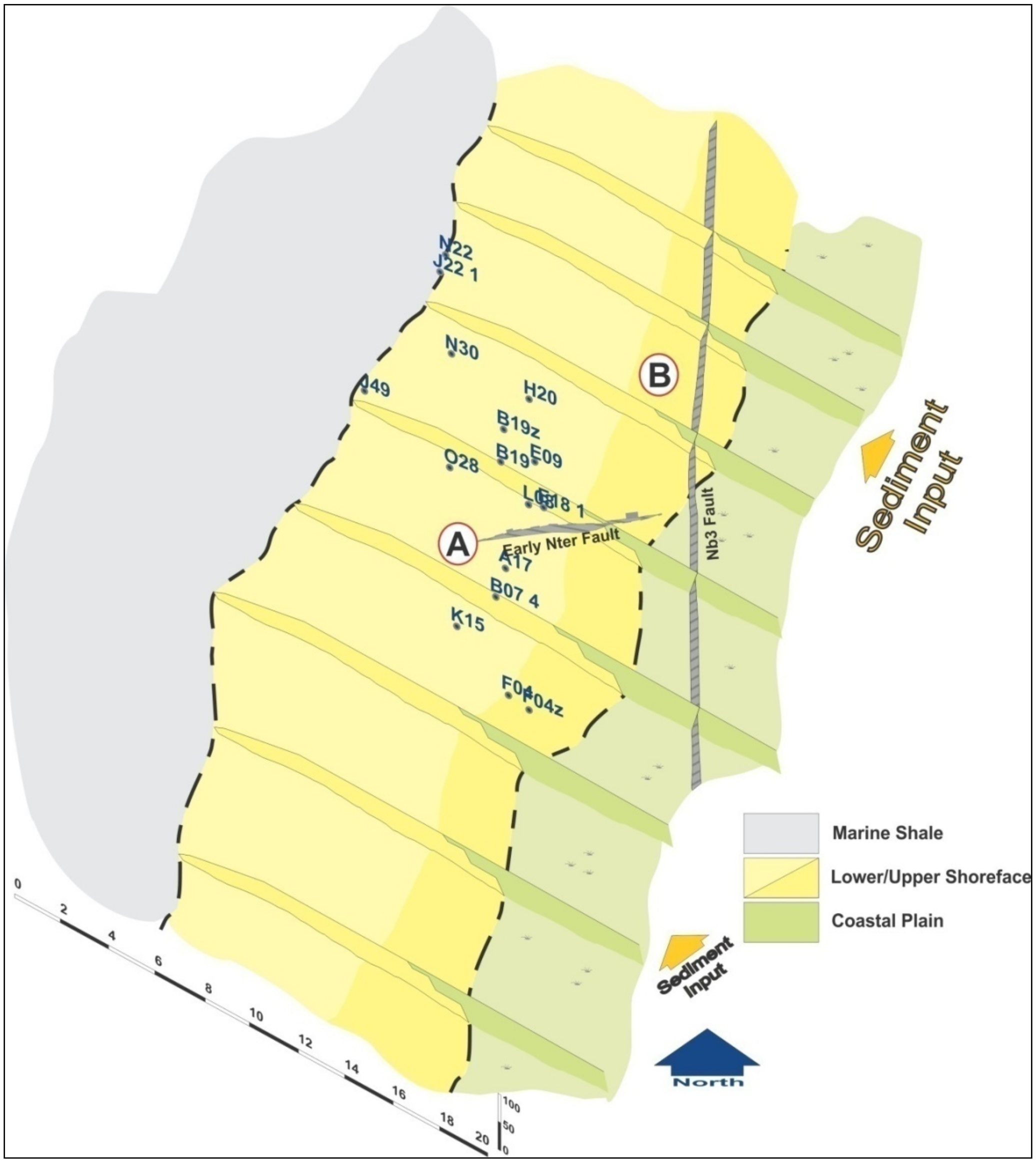


Figure 2-3 Location Map of the West White Rose Pool

The West White Rose pool contains some of the most distal expressions of the BNA reservoir in the White Rose field, and also captures the degradation from proximal to distal depositional environments. As a result, it is generally of lower reservoir quality than the South Avalon pool and is much more interbedded, containing more prominent parasequence boundaries (flooding surfaces). Points A and B on Figure 2-4 illustrate the depositional relationships to tectonic movement within the BNA Formation of the White Rose region.



Note: South Avalon development wells are not displayed

Figure 2-4 Schematic of Aerial Distribution of Shoreface Sandstone and Early Moving NTER/NB3 Faults Related to the Initial Phases of BNA Formation Deposition

A - Early NTer/NB3 (labelled in Figure 2-4) fault movement results in increased accommodation space and thicker BNA Formation relative to the southern field extents.

B - Most distal expression of the BNA Formation within the core White Rose region. Only the lower most parasequences contain reservoir quality sand.

2.1.4 West White Rose Regional Geology

Internal divisions of the BNA Formation in the West White Rose pool represent 11 parasequence sets; the BNA_Ramp, BNA_Shell_Cmt, BNA_150, BNA_100, BNA_200, BNA_325, BNA_350, BNA_300, BNA_450, BNA_400 and BNEV_SLTST from base to top, respectively (Figure 2-5). These units correspond with coarsening-upwards cycles that are evident in moderately distal wells (such as C-30Z), but lose resolution in both proximal and distal settings where the net to gross ratio is very high or very low. In the West White Rose pool, the internal divisions are interpretational, but correlated through the area nonetheless.

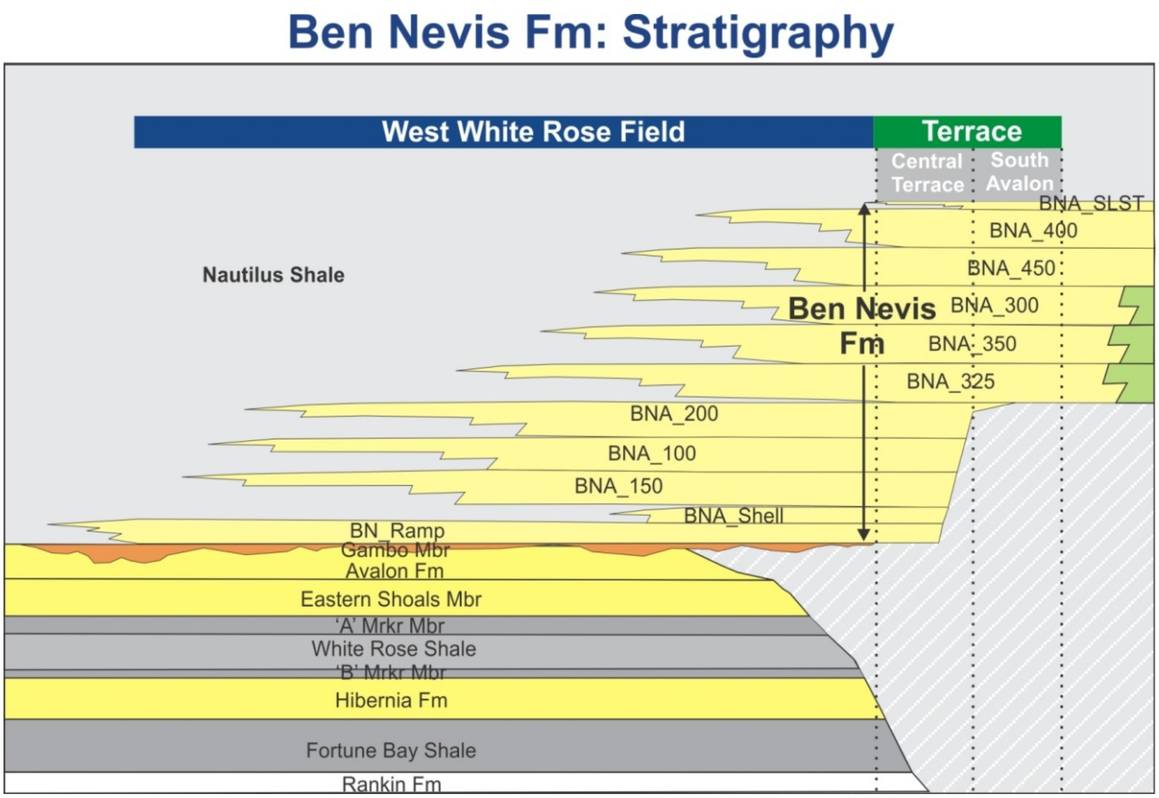


Figure 2-5 White Rose Field Stratigraphy Illustrating Internal Divisions of the BNA

The parasequence sets are fourth order cycles that are generally 6 to 250 m thick, 50 to 50,000 km^2 in aerial extent and have a depositional duration of 0.1 to 0.5 million years. Based on the assumption that these types of scales apply to the BNA at White Rose, the main correlation surfaces used throughout the field (in green on the cross sections in Figure 2-6) are marking fourth order flooding surfaces bounding the parasequence sets outlined in Figure 2-5. The number and nature of parasequences in the West White Rose pool create a more complex stratigraphic variation than in the South Avalon region.

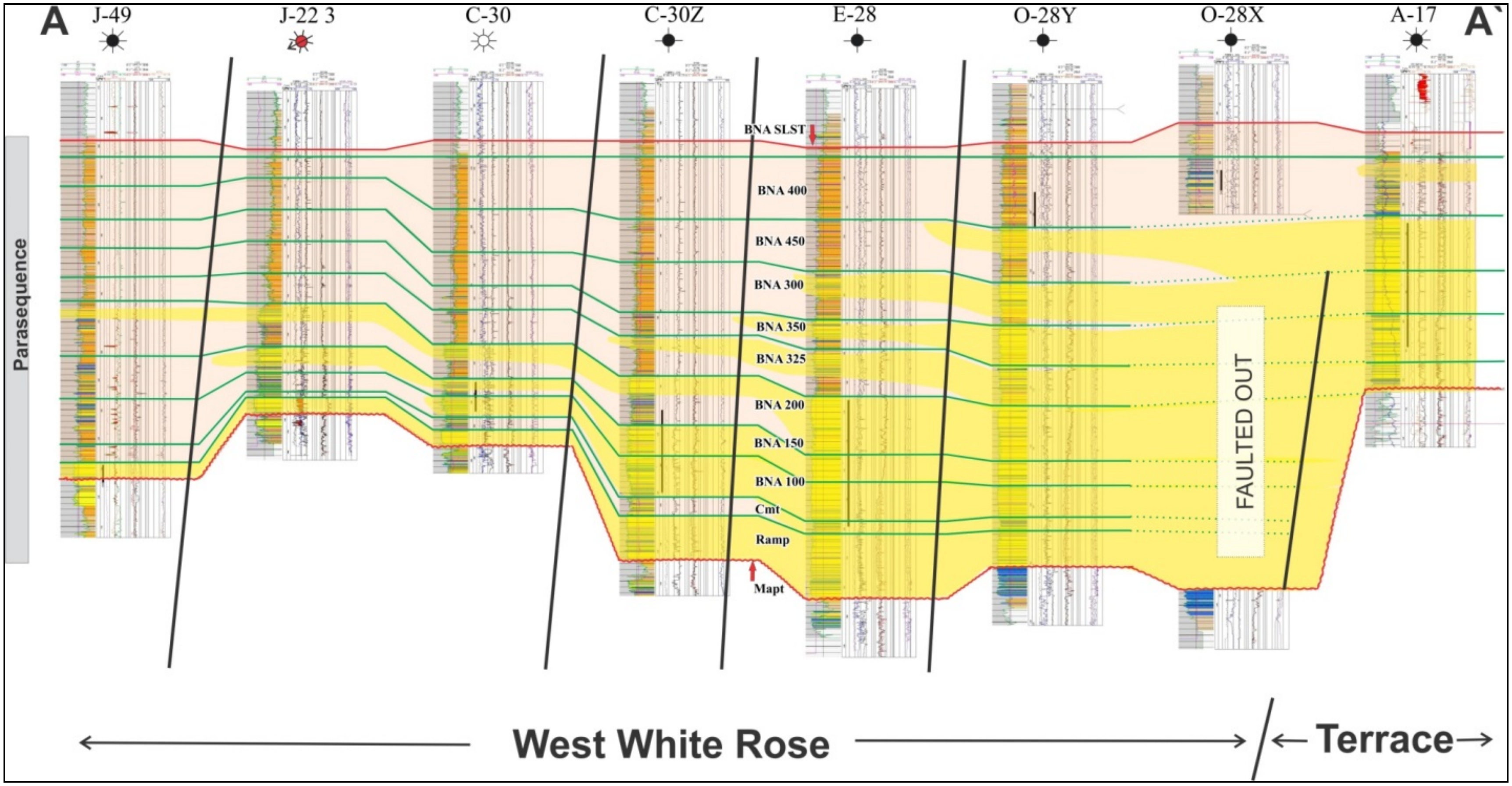
In comparison to the South Avalon pool, there is a higher proportion of fine-grained sediment within the BNA of West White Rose because it was deposited in a more distal shoreface environment. As well, the highly faulted nature of the pool adds structural complexity. These two factors place uncertainty on reservoir performance and could result in reservoir compartmentalization. Risk of reservoir compartmentalization is especially prevalent in the north and western extents of West White Rose, where reservoir quality rock is thinnest and requires less fault throw to become completely offset.

A single realization of the geological model has been created as a P50 representation of an in-place hydrocarbon estimate and has been used for development planning.

The West White Rose pool is segregated into several complex fault blocks by post-depositional normal faults, with throws ranging from less than 20 to 300 m. The full offset of the BNA across the NB3 fault (separates terrace from West White Rose pool) allows for different fluid contacts in the extension region relative to those encountered in the A-17 terrace region. In the distal region of the West White Rose pool, the fault throw does not allow for complete offset of the BNA Formation. Due to the decreasing net to gross ratio, there is full offset of the BNA reservoir section, which allows for different fluid contacts.

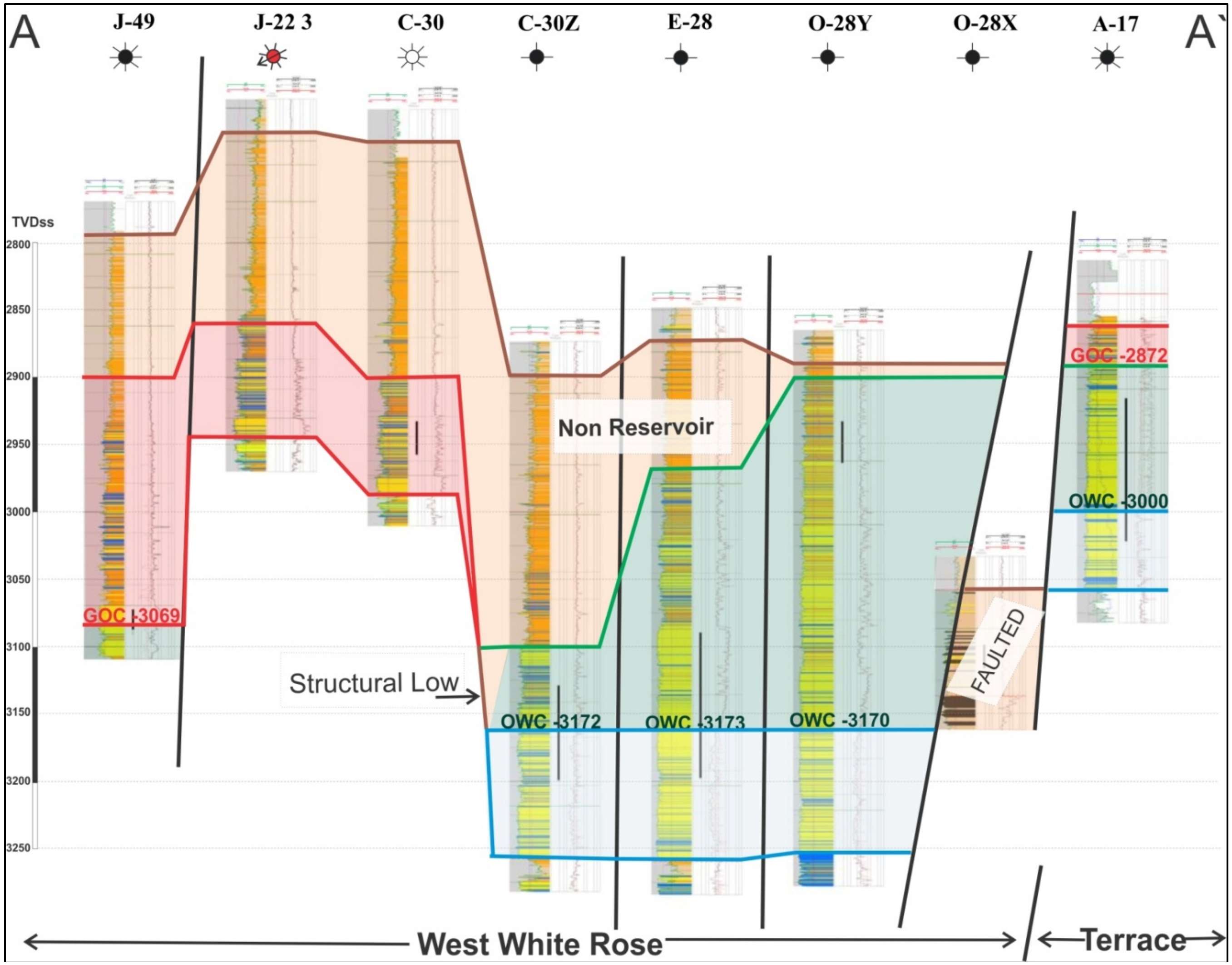
Faulting is not the sole method of isolating fluid contacts in the West White Rose pool area. The back-stepping parasequences, combined with a structural low running southwest-northeast through the middle of the pool, isolates the C-30 and J-22 3 gas from the structurally higher C-30Z and E-28 oil (Figure 2-7).

Figure 2-8 to Figure 2-13 represents depth output maps from the West White Rose area geological model.



Note: See Figure 2-3 for line label.

Figure 2-6 Stratigraphic Cross-section through West White Rose Region



Note: the fluid legs displayed by colour; red – gas, green – oil, blue – water. See Figure 2-3 for line label.

Figure 2-7 Structural Section Schematic of Terrace to West White Rose Region

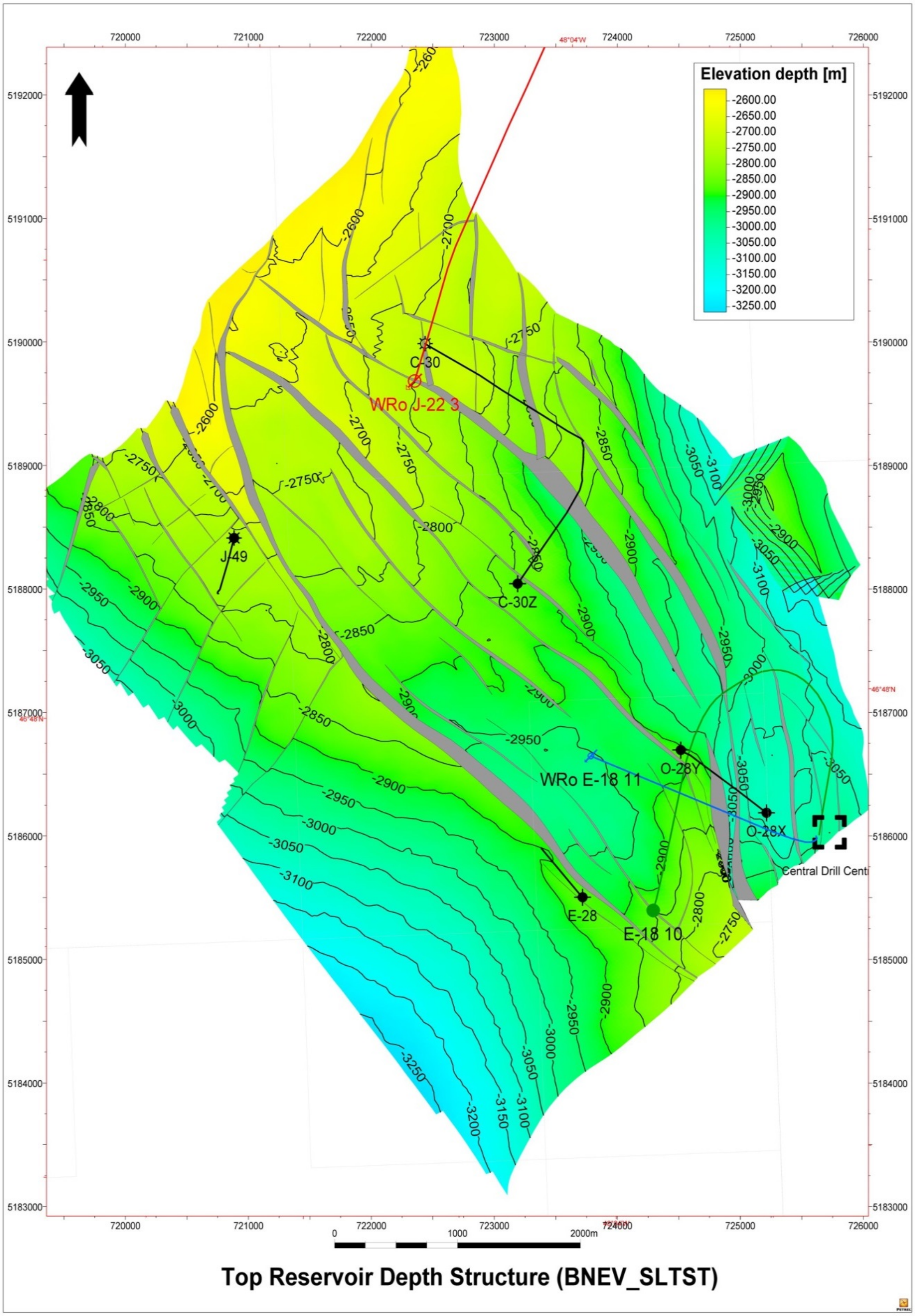


Figure 2-8 Top Reservoir Depth Structure Map (BNEV_SLTST)

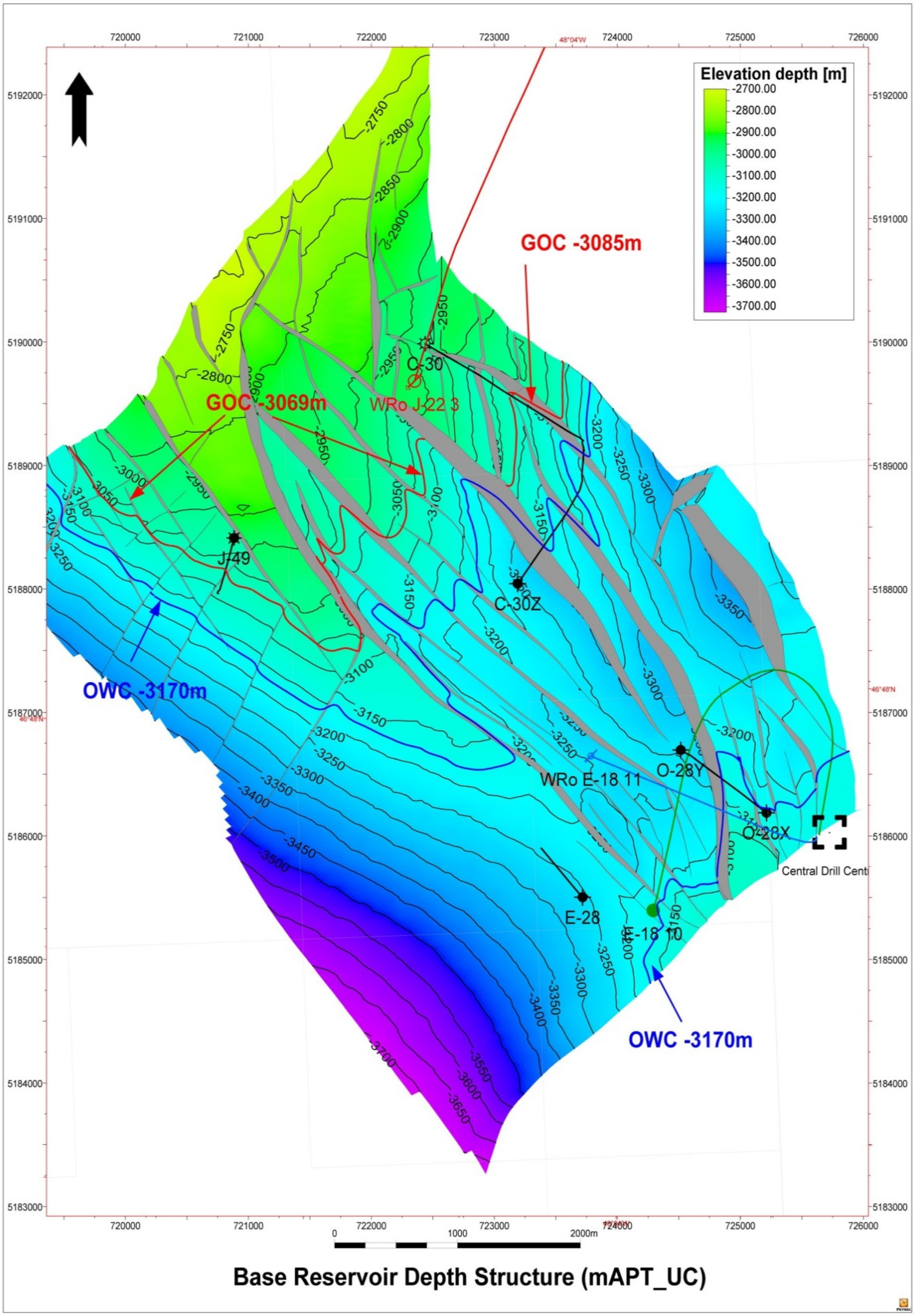


Figure 2-9 Base Reservoir Depth Structure Map (mAPT_UC)

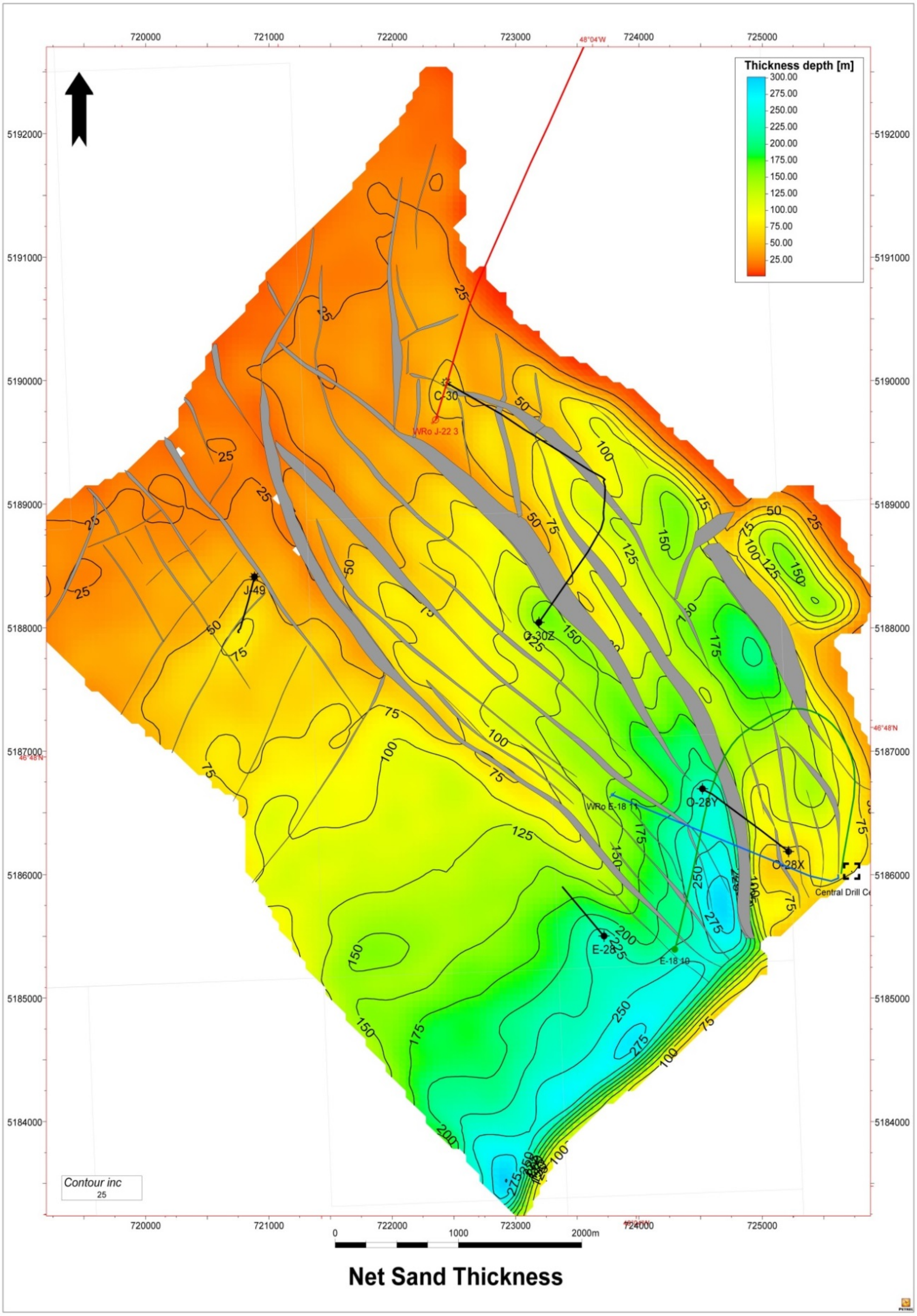


Figure 2-10 Net Sand Thickness Map for the West White Rose Pool

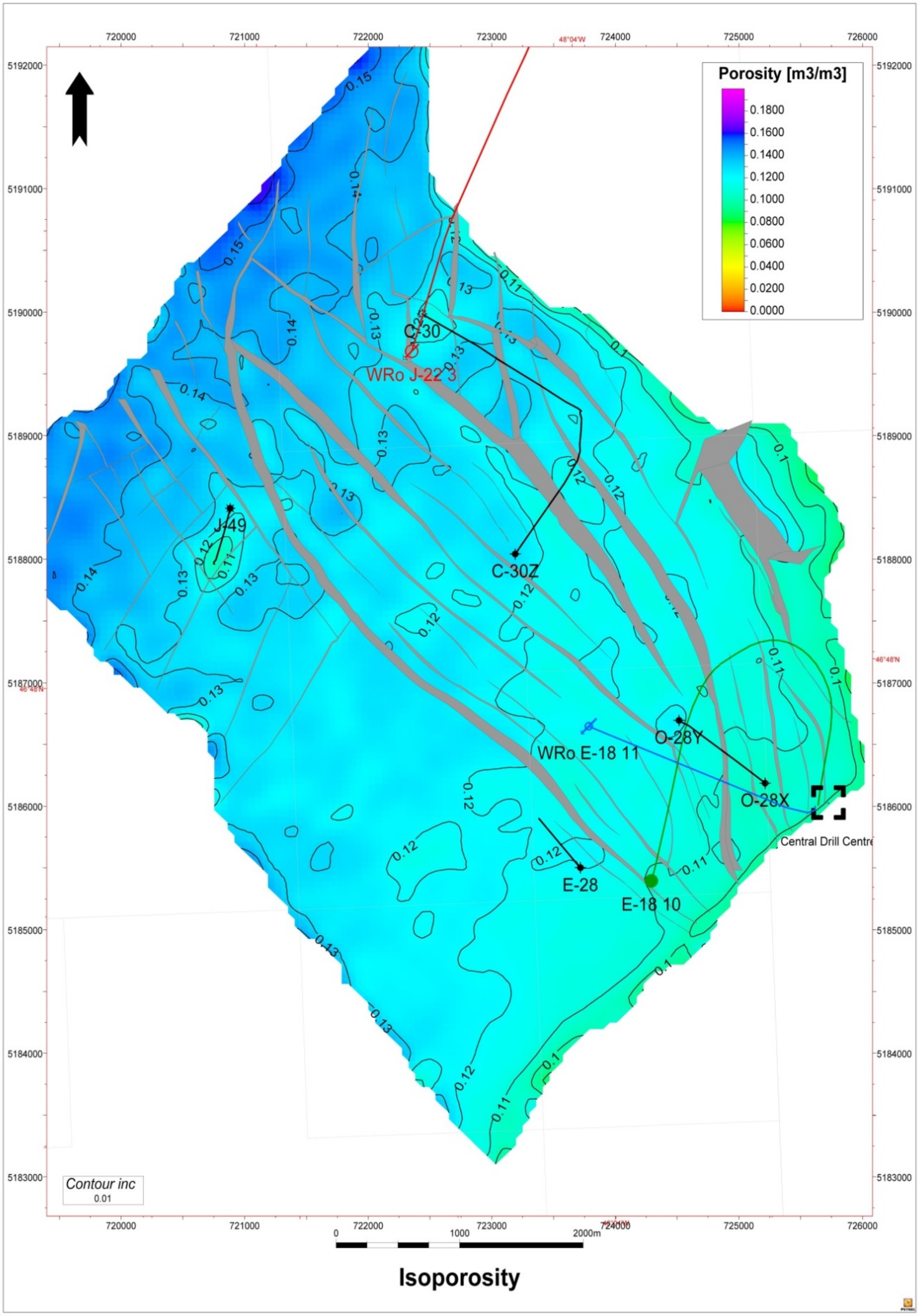


Figure 2-11 Isoporosity Map for the West White Rose Pool

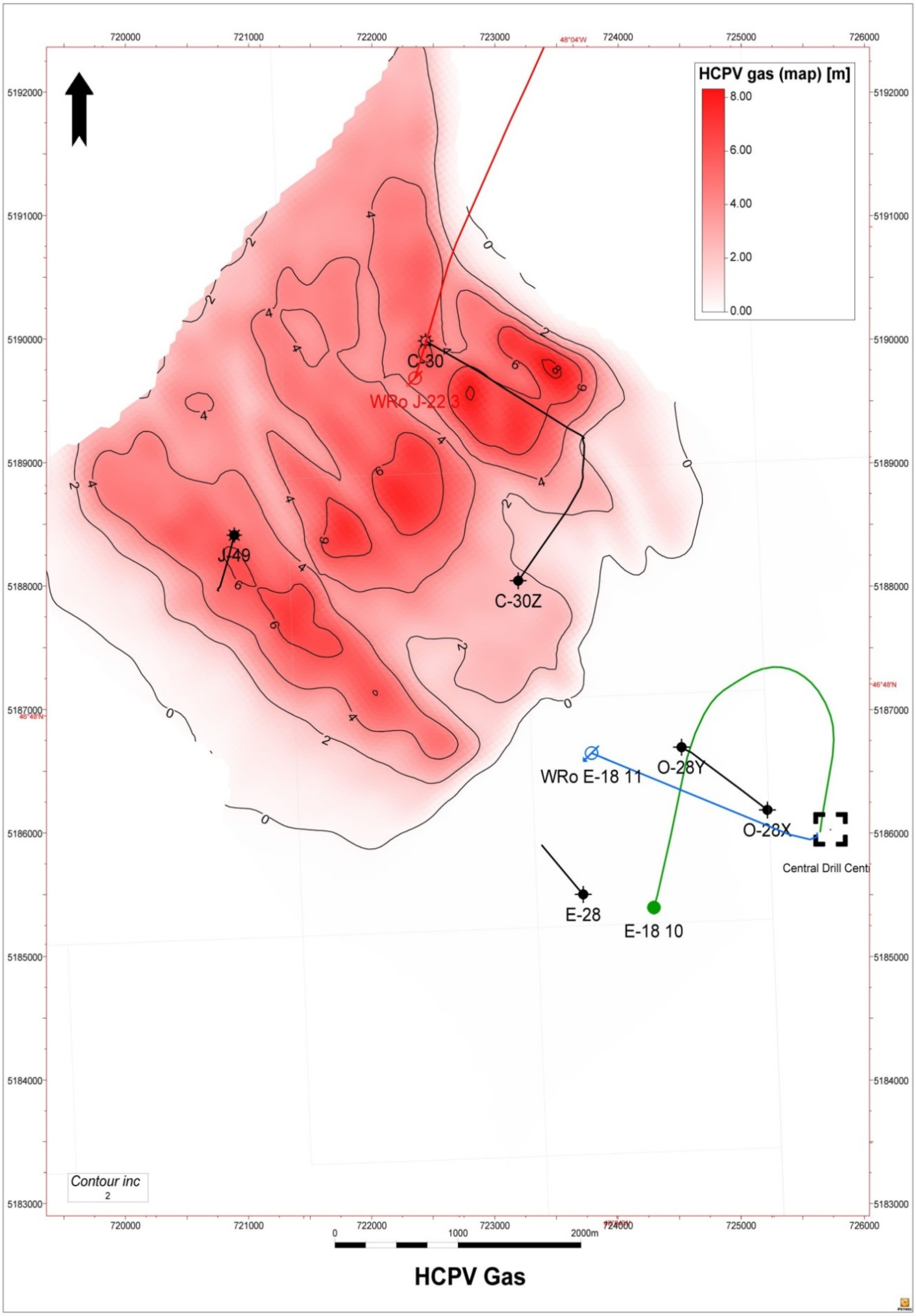


Figure 2-12 Hydrocarbon Pore Volume Gas Map for the West White Rose Pool

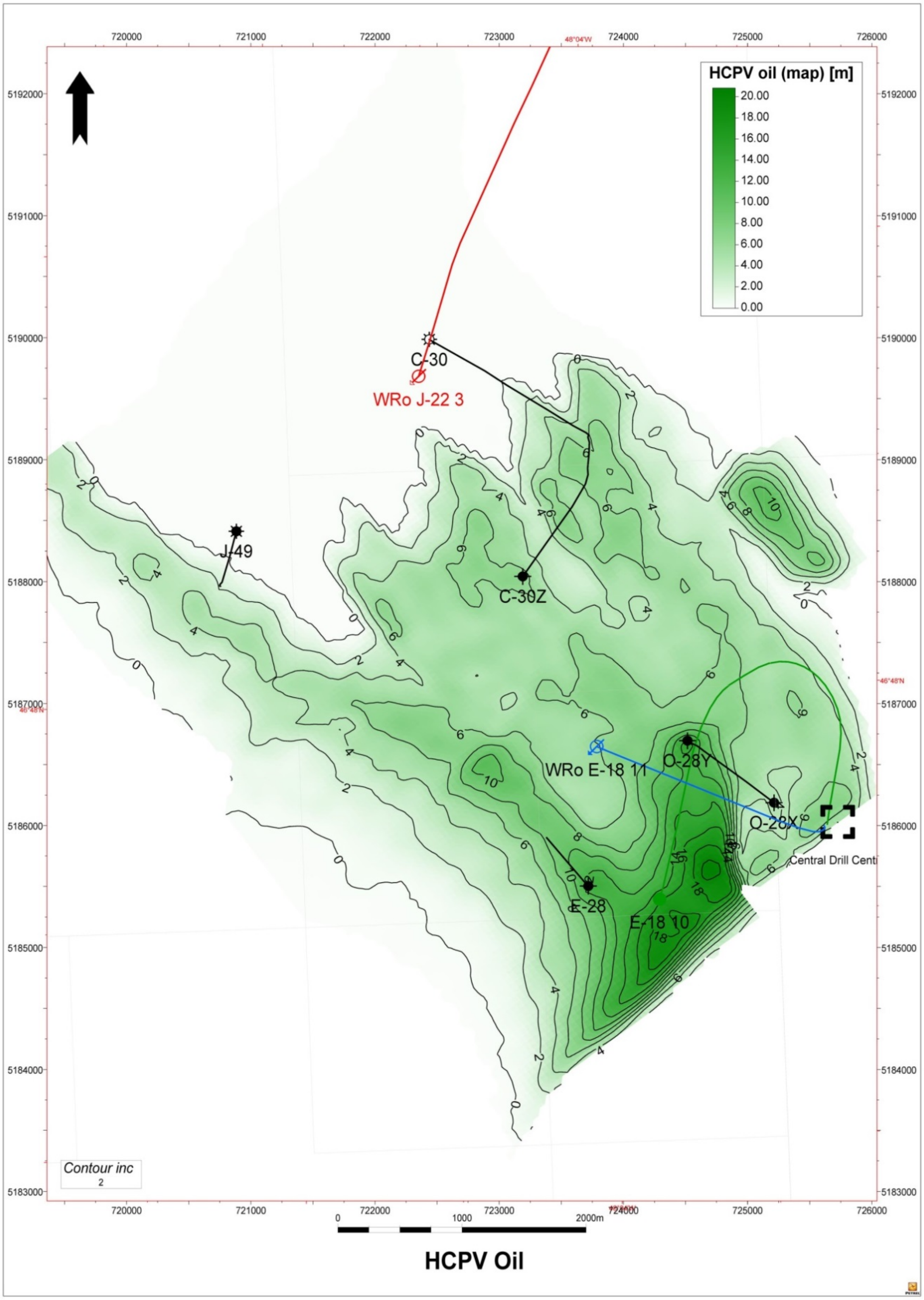


Figure 2-13 Hydrocarbon Pore Volume Oil Map for the West White Rose Pool

The 2001 White Rose Development Plan contained four main facies associations (FA). Recent analysis from log crossplot data as well as core analysis data supports an additional FA capturing a degraded sandstone facies. FA2 is added as a fifth FA and is described below along with the original four main facies.

1. FA1: Lower Shoreface Storm Deposits. Consisting of well-sorted, very fine-grained sandstone. This FA is the main reservoir rock type in the region. Facies encountered within this grouping are low-angle (hummocky to swaley), laminated sandstone, massive sandstone and parallel laminated sandstone. Varying amounts of shell bioclastic and sideritized shale ripup clasts are present as lags along basal scour contacts.
2. FA2: Bioturbated Lower Shoreface Storm Deposits. Consisting of well-sorted, very fine-grained sandstone with a bioturbated overprint from an overlying, nutrient-rich, finer-grained sediment deposition. Typically relic sedimentary structures are present, but usually indistinguishable in core. Can be heavily to lightly bioturbated and typically overly FA1 where preserved.
3. FA3: Lower Shoreface Fairweather Deposits. These intervals consist of heavily bioturbated siltstone to silty-sandstone. Primary sedimentary structures are rarely preserved.
4. FA4: Marine Deposits. Representing the distal component of White Rose region deposition. The facies types for this group are laminated and massive silty-shale to shale, with some minor bioturbated intervals.
5. Diagenetic Components. Although not representative of a primary depositional feature, due to the abundance of secondary components in the reservoir rock, these have been separated into three groups. Calcite cement is dominant within the BNA Formation and appears in various forms. Calcite nodules are defined by their round edges, as seen in both core and on image logs, and likely have poor lateral continuity. Calcitecan also be concentrated along shell lag intervals, appearing more lenticular and usually exhibiting convolute edges. Although more continuous than singular nodules, these occurrences are not likely to form intra-reservoir barriers. A third type, siderite nodules, are not significant in terms of reservoir proportion but are locally present, commonly within mud-lined trace fossils.

These FAs have been incorporated within the static reservoir model and the resultant dynamic model used in simulation.

2.1.5 South Avalon Geology and Geophysics Summary

The South Avalon pool is the original development within the White Rose region. Production and injection wells have been drilled from two subsea drill centres, the Central Drill Centre and the Southern Drill Centre. For the purpose of this amendment, the undeveloped Blocks 2 and 5 of the South Avalon pool will be discussed separately.

Geologically, the South Avalon pool is situated in a more proximal environment of deposition than the other BNA pools discussed in this document (Figure 2-14). It has a relatively high net reservoir, which deteriorates to the northwest. Reservoir parameters are such that there are few vertical baffles/barriers to flow within the reservoir. Structurally, the pool depth is approximately 2,850 to 2,900 m TVDss and contains approximately 130 to 140 m of oil column.

Figure 2-15 to Figure 2-20 represents depth output maps from the South Avalon geological model, including a structural section with facies distribution.

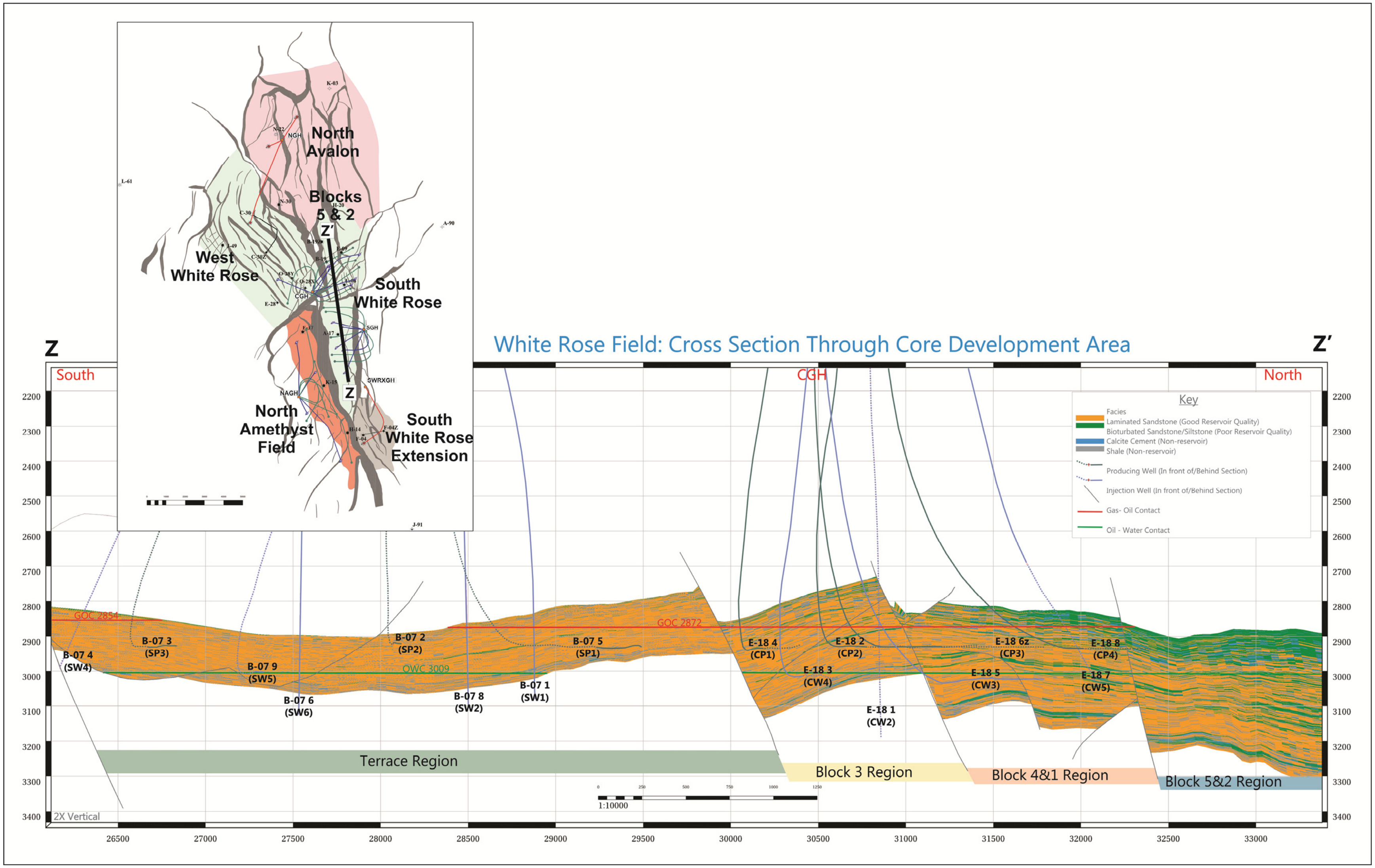


Figure 2-14 Structural Section with Facies Distribution taken from the RMS Geomodel of the South Avalon Pool

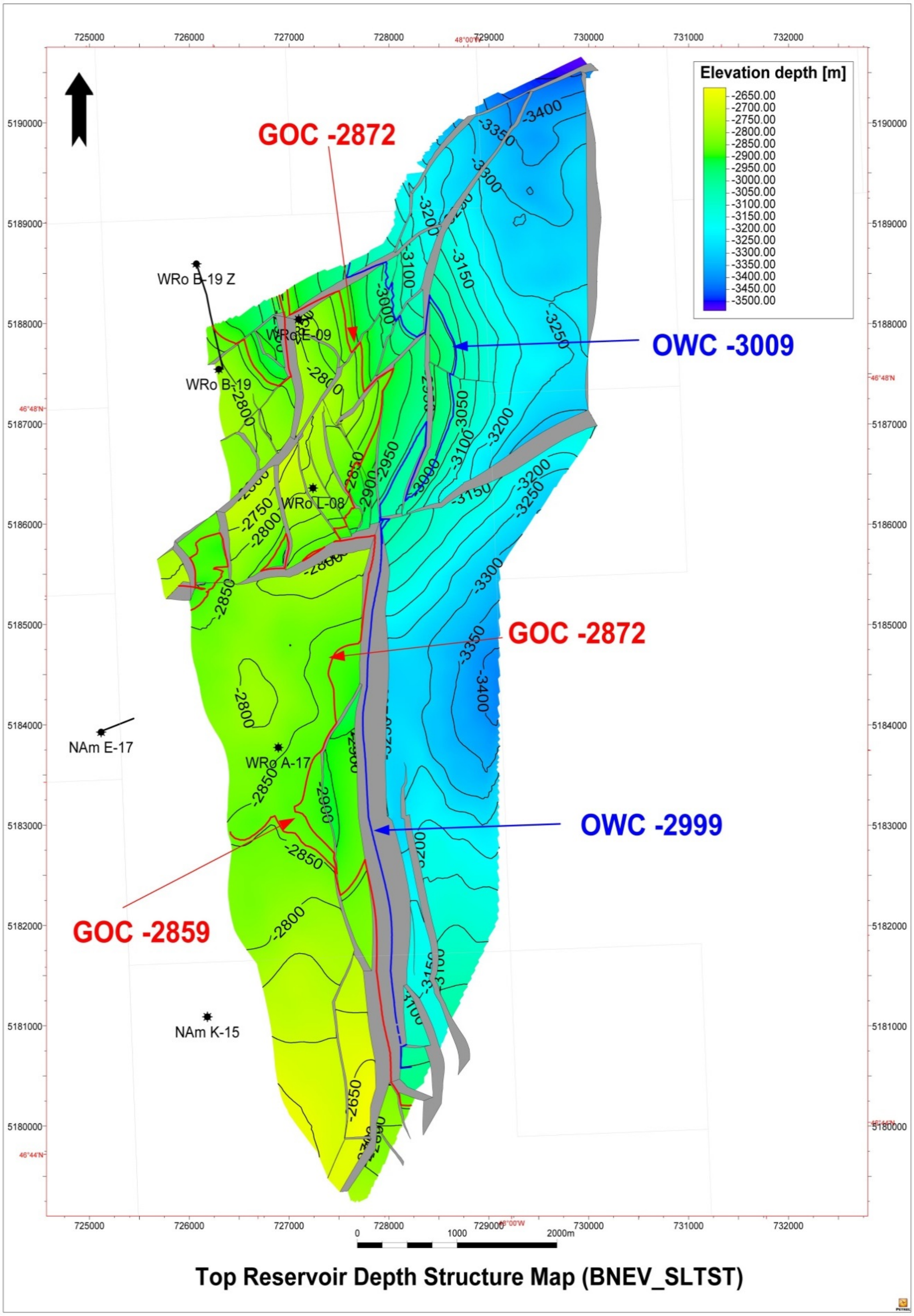


Figure 2-15 Top Reservoir Depth Structure Map (BNEV_SLTST) South Avalon Pool

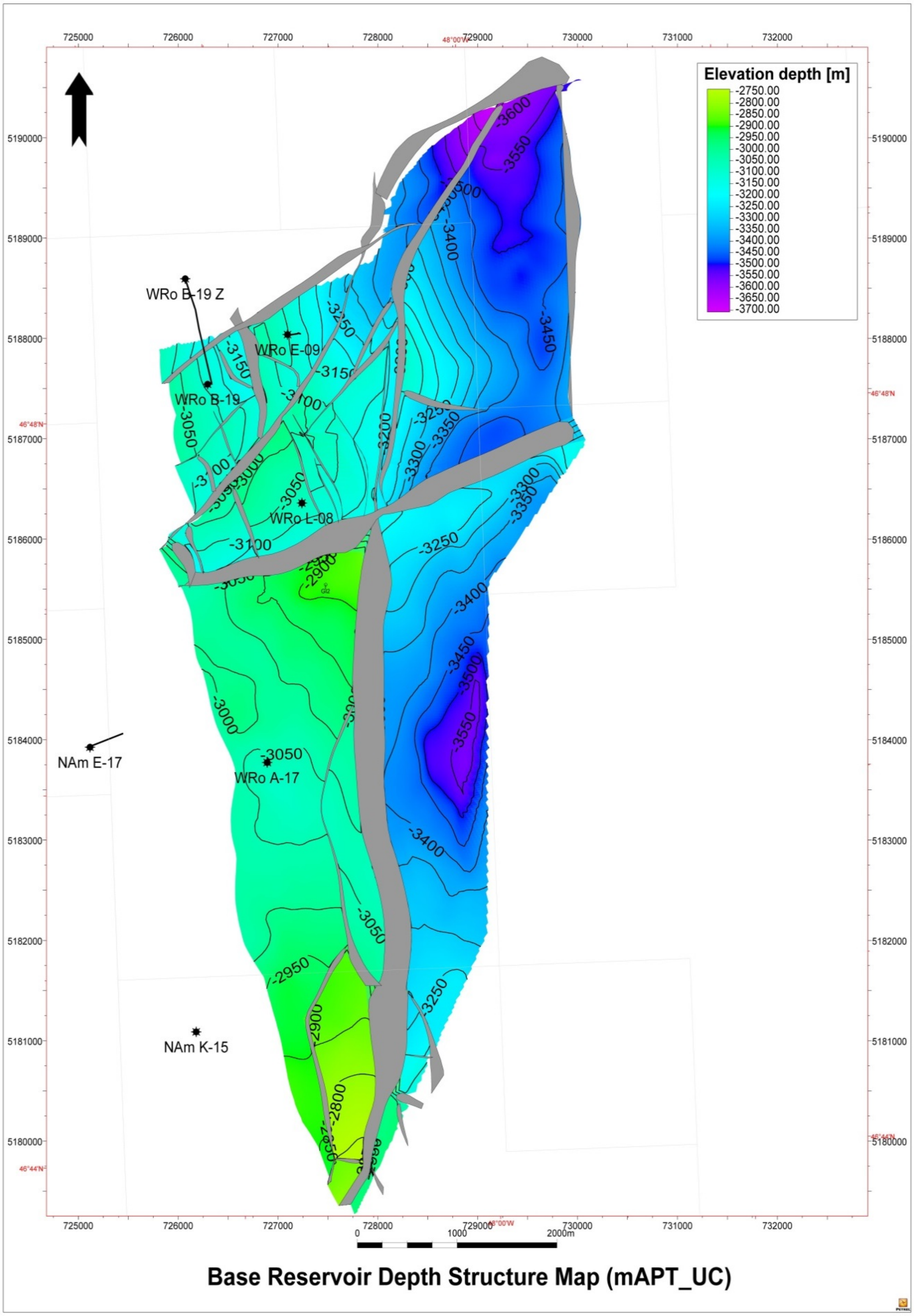


Figure 2-16 Base Reservoir Depth Structure Map (mAPT_UC) South Avalon Pool

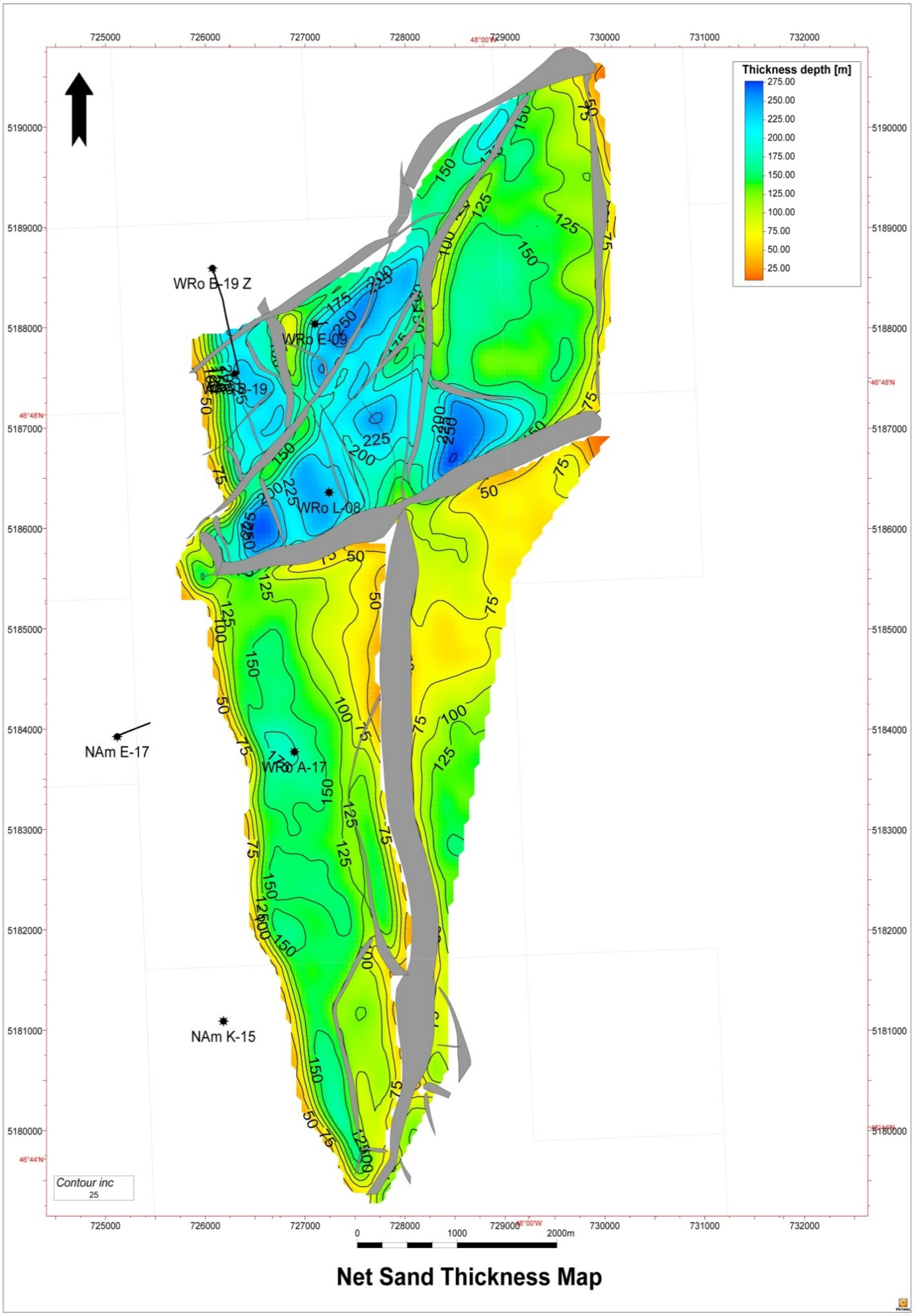


Figure 2-17 Net Sand Thickness Map for the South Avalon Pool

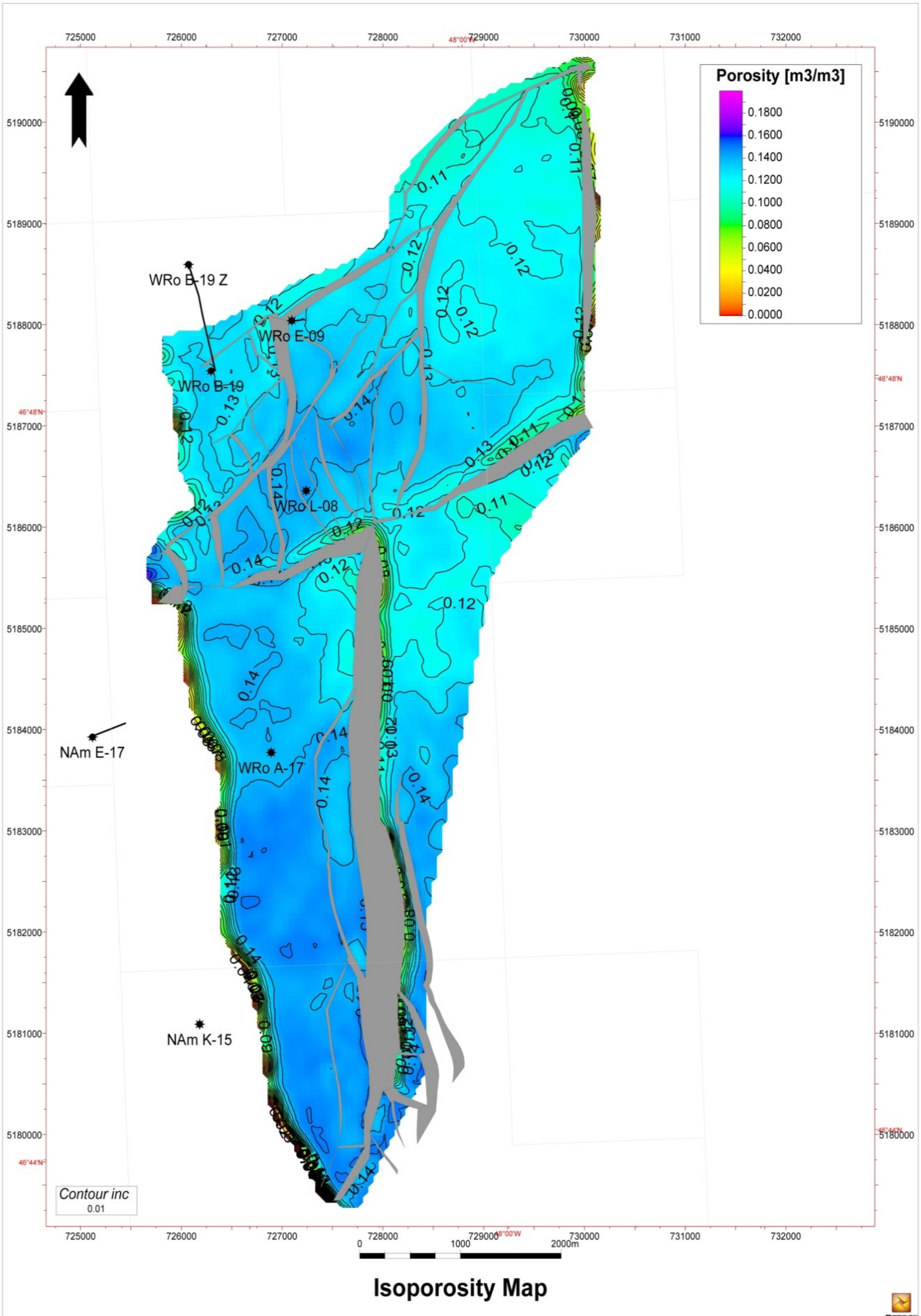


Figure 2-18 Isoporosity Map for the South Avalon Pool

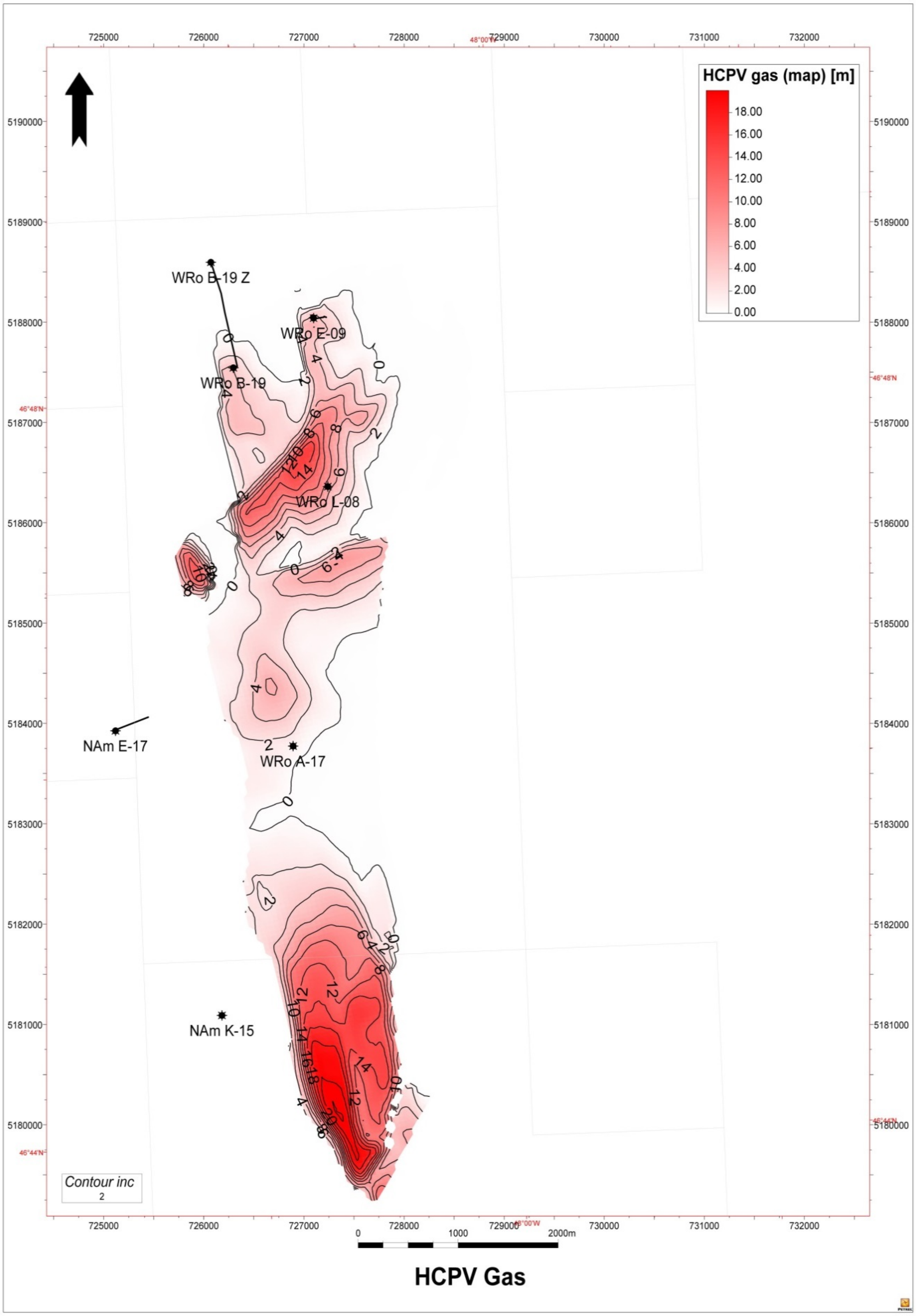


Figure 2-19 Hydrocarbon Pore Volume Gas Map for the South Avalon Pool

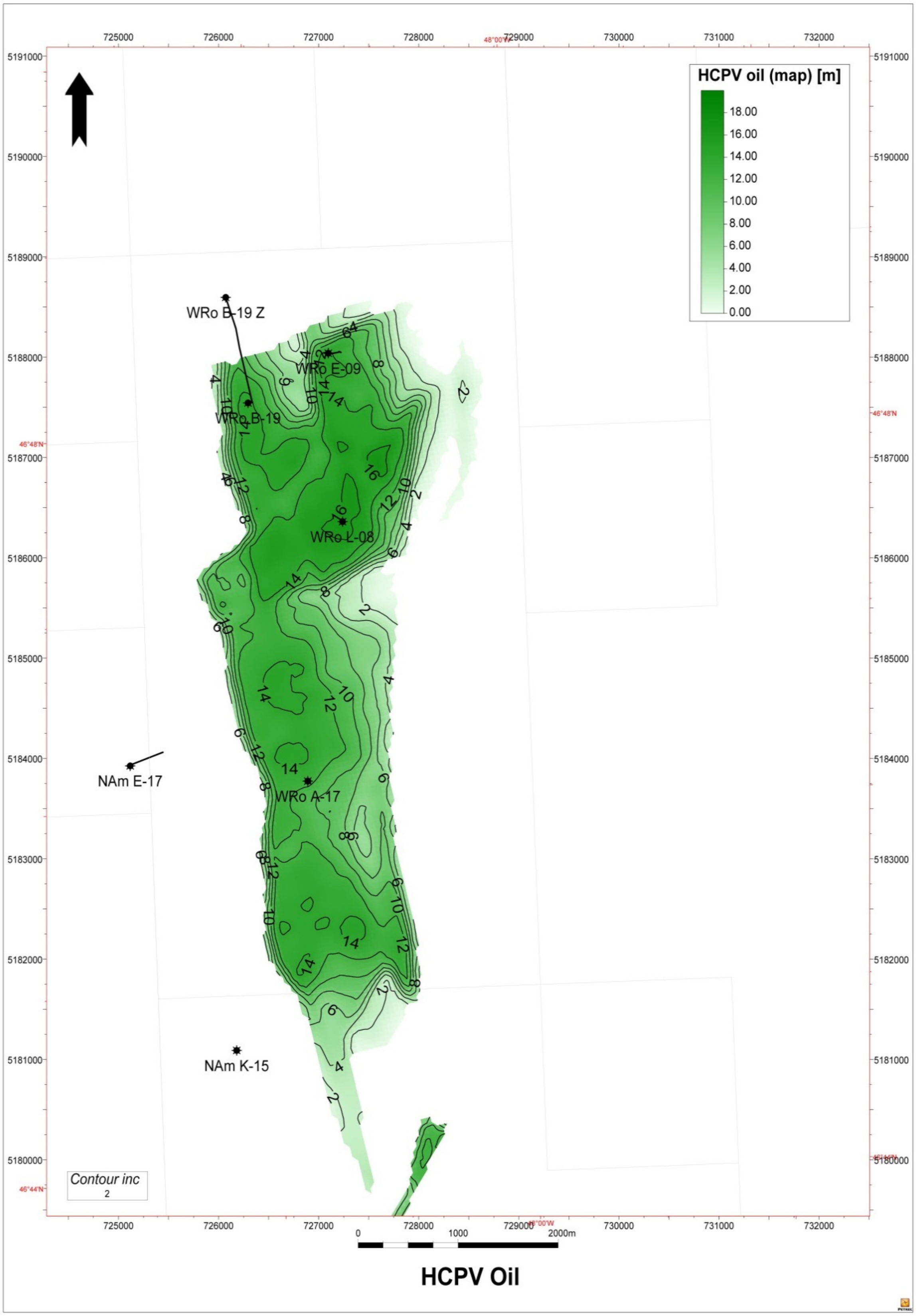


Figure 2-20 Hydrocarbon Pore Volume Oil Map for the South Avalon Pool

2.1.6 Blocks 2 and 5 Geology and Geophysics Summary

Two large fault blocks, Block 2 and Block 5, comprise the undeveloped northern extent of the South Avalon pool. South Avalon delineation well, H-20 (Block 2, the larger eastern block), which was drilled in 2000 and encountered 4.5 m of oil bearing sandstone and 146 m of reservoir-quality sandstone. The follow-up delineation well, B-19Z, tested the smaller up-dip block to the west (Block 5) in 2005. It discovered gas and oil over water. The majority of the reservoir-quality BNA sandstones of Blocks 2 and 5 are below the oil/water contact, which is consistent with the depositional model of the BNA in the White Rose region (Figure 2-21).

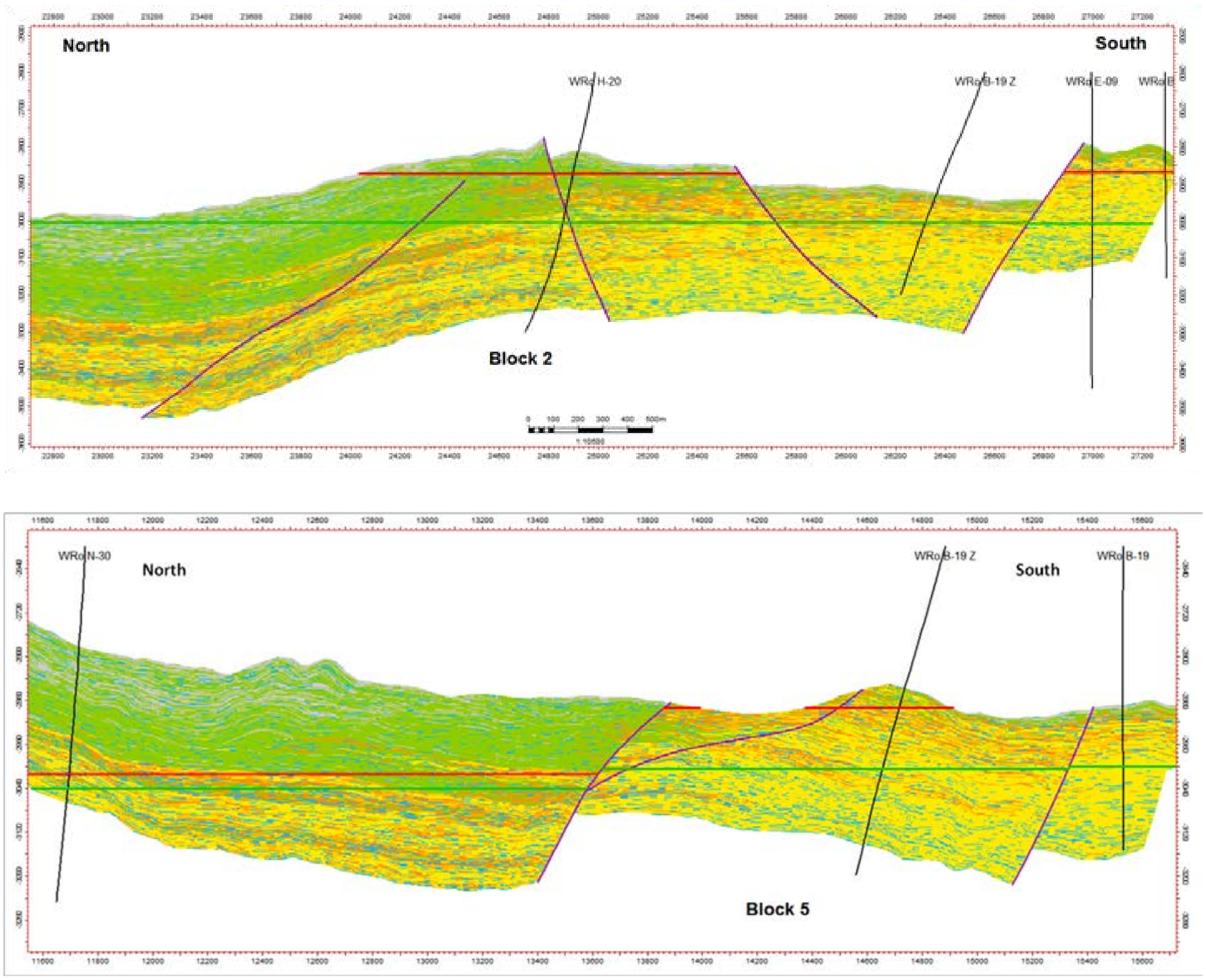


Figure 2-21 Structural Section with Facies Distribution of Blocks 2 and 5 Pools

Figure 2-22 to Figure 2-27 represents depth output maps from the preliminary Blocks 2 and 5 geological model, including a structural section with facies distribution. The reservoir model for Blocks 2 and 5 is currently under development.

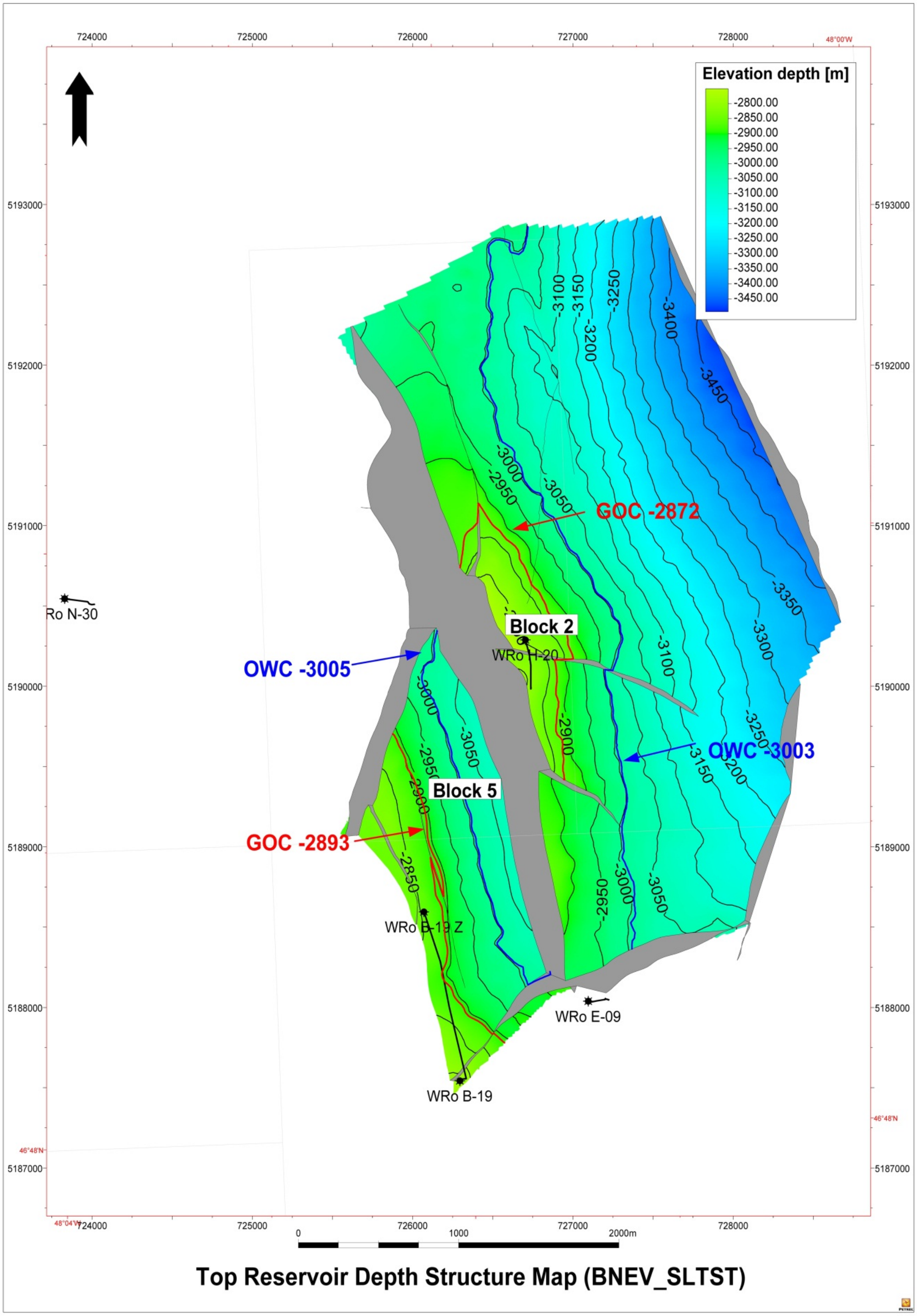


Figure 2-22 Top Reservoir Depth Structure Map (BNEV_SLTST) Blocks 2 and 5 Pool

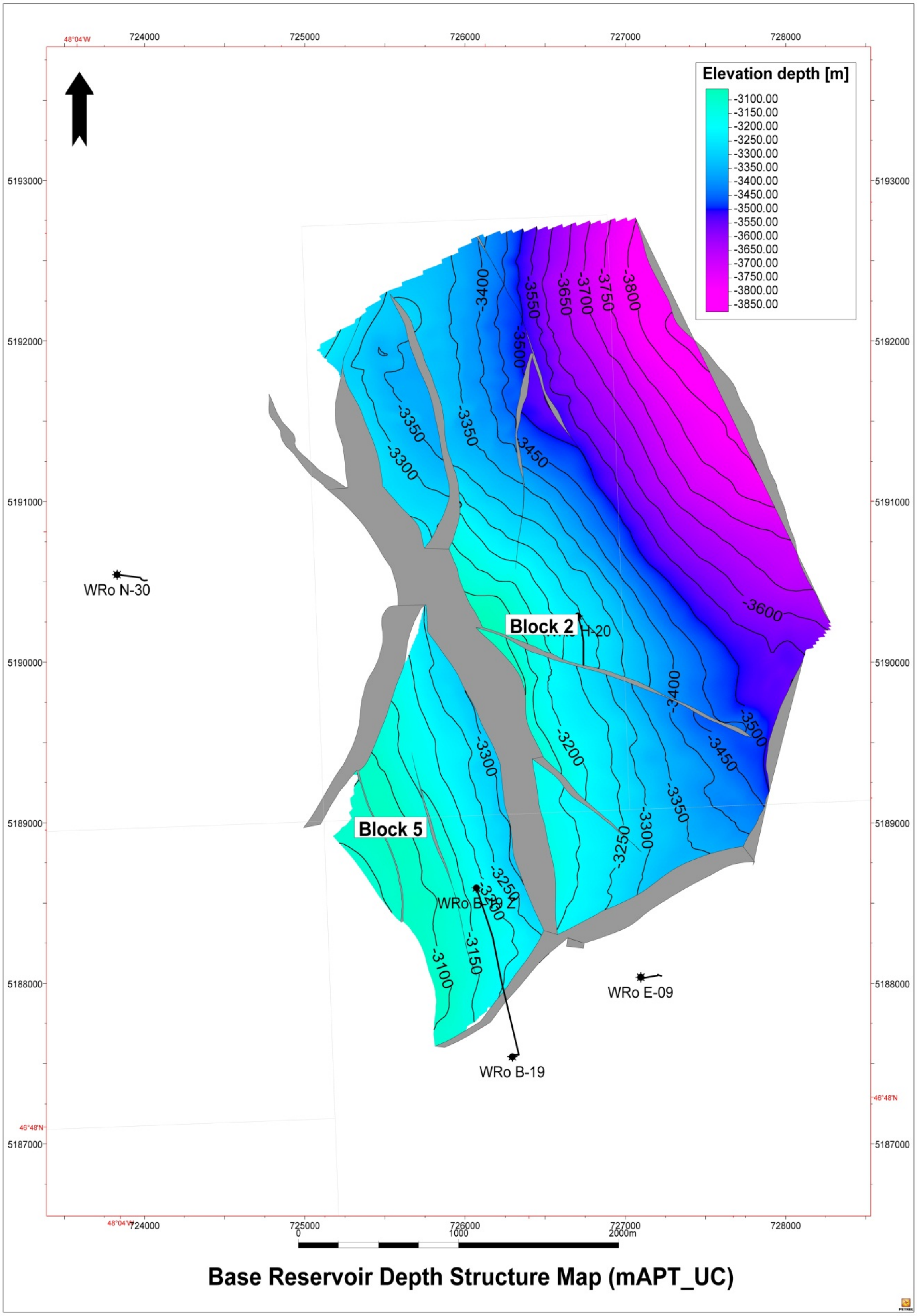


Figure 2-23 Base Reservoir Depth Structure Map (mAPT_UC) Blocks 2 and 5 Pool

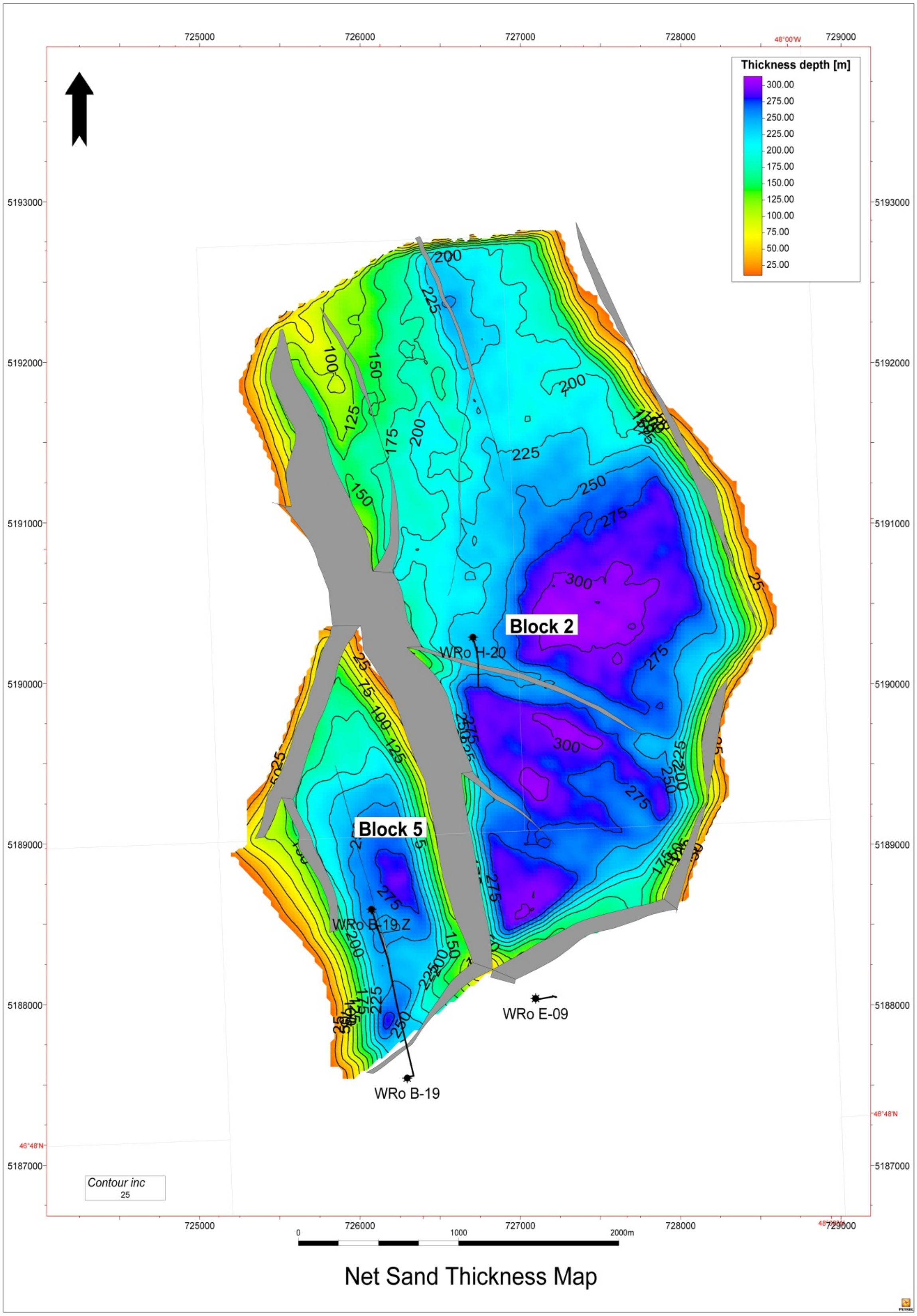


Figure 2-24 Net Sand Thickness Map for the Blocks 2 and 5 Pool

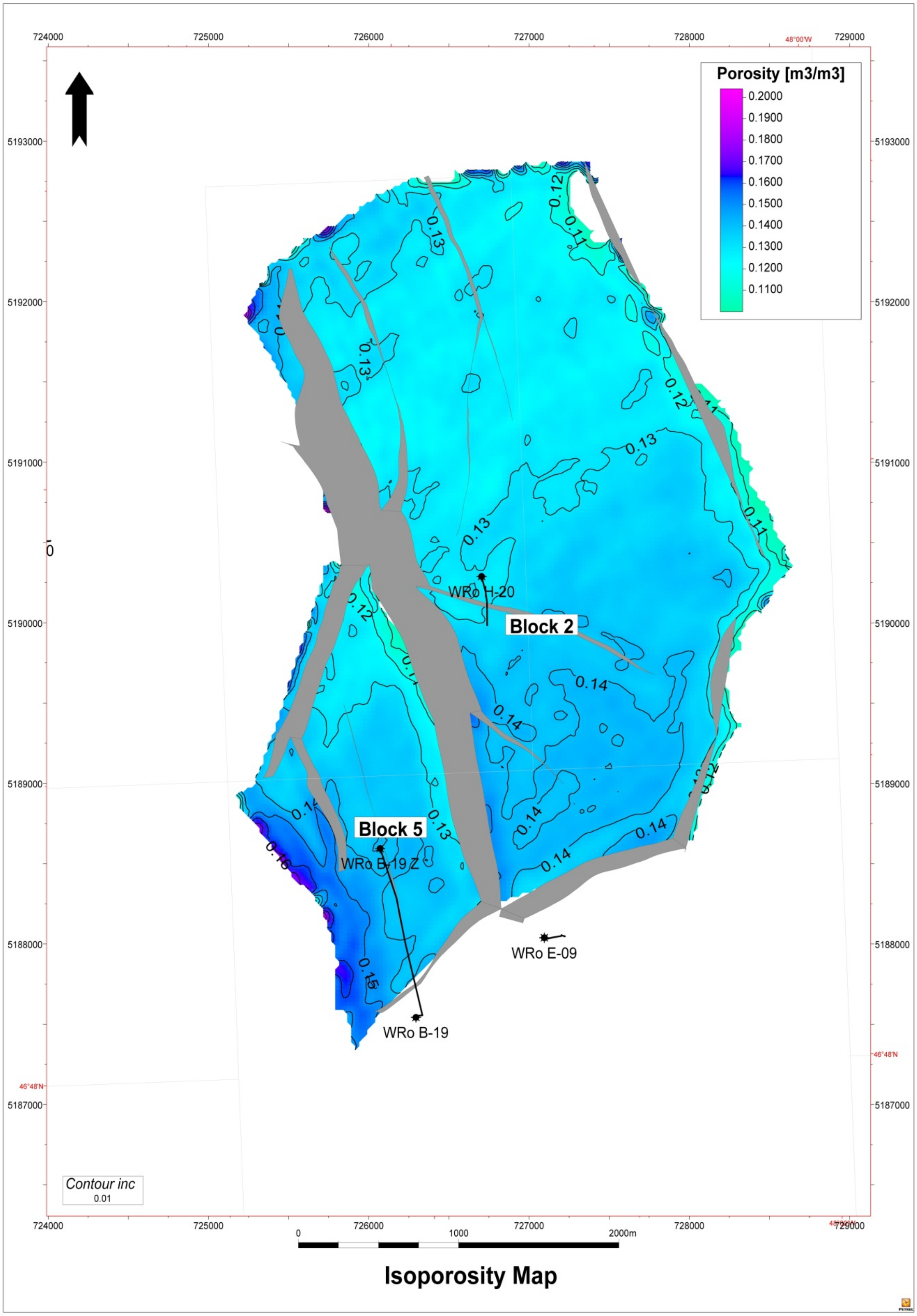


Figure 2-25 Isoporosity Map for the Blocks 2 and 5 Pool

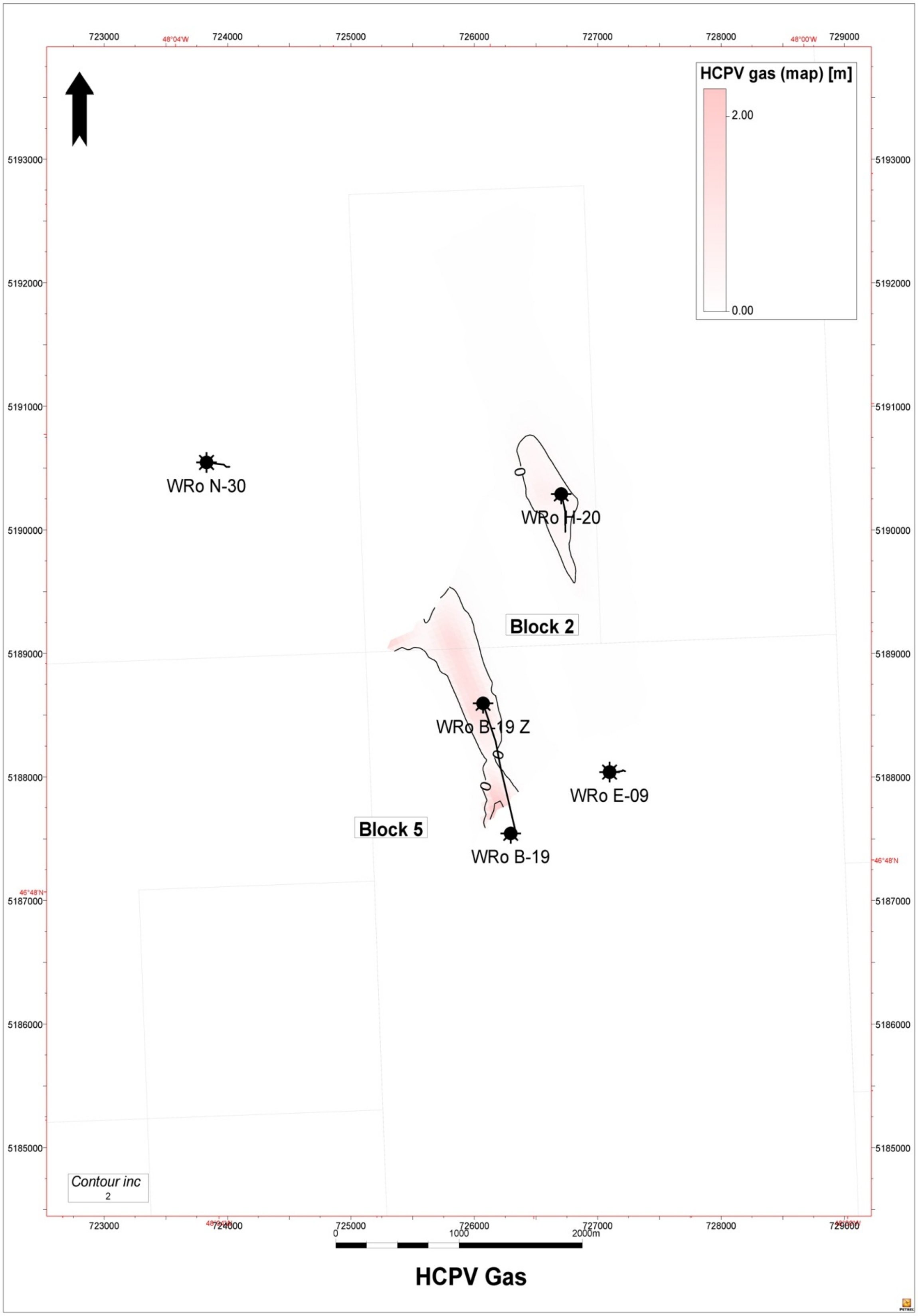


Figure 2-26 Hydrocarbon Pore Volume Gas Map for the Blocks 2 and 5 Pool

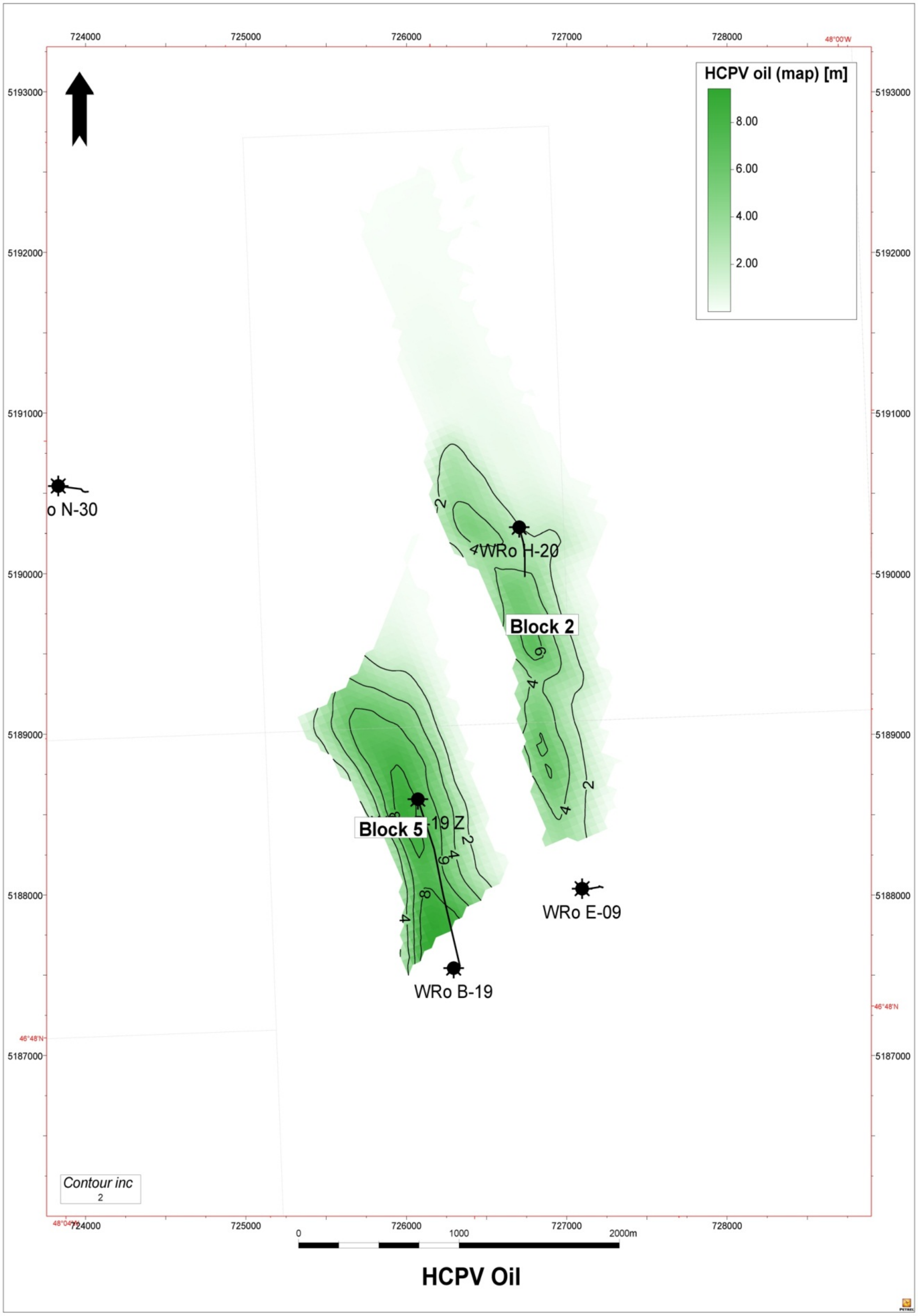


Figure 2-27 Hydrocarbon Pore Volume Oil Map for the Blocks 2 and 5 Pool

2.1.7 North Avalon Geology and Geophysics Summary

The North Avalon pool contains the White Rose discovery N-22 location, which encountered gas within the BNA. The NDC is located in the North Avalon area. NDC currently has three gas injection wells (J-22 1, J-22 2 and J-22 3), two of which are within the North Avalon pool (J-22 3 is drilled into the West White Rose pool). The N-30 delineation location was drilled in the southwest region of the North Avalon pool. Oil and gas were encountered at this location. The K-03 location was drilled to delineate the North Avalon reservoir and fluid contacts. It encountered very low reservoir quality and was wet upon penetration. North Avalon is the northernmost pool within the White Rose region and is the most distal representation of the distribution of the lower shoreface deposit that comprises the BNA Formation. Net reservoir is significantly lower than that of the South Avalon pool. There are two fault blocks accessed by the two North Avalon gas injectors. As in the West White Rose pool, compartmentalization is due to the thin reservoir being juxtaposed against non-reservoir across fault blocks (Figure 2-28).

Figure 2-29 to Figure 2-34 represents depth output maps from the North Avalon geological model, including a structural section with facies distribution.

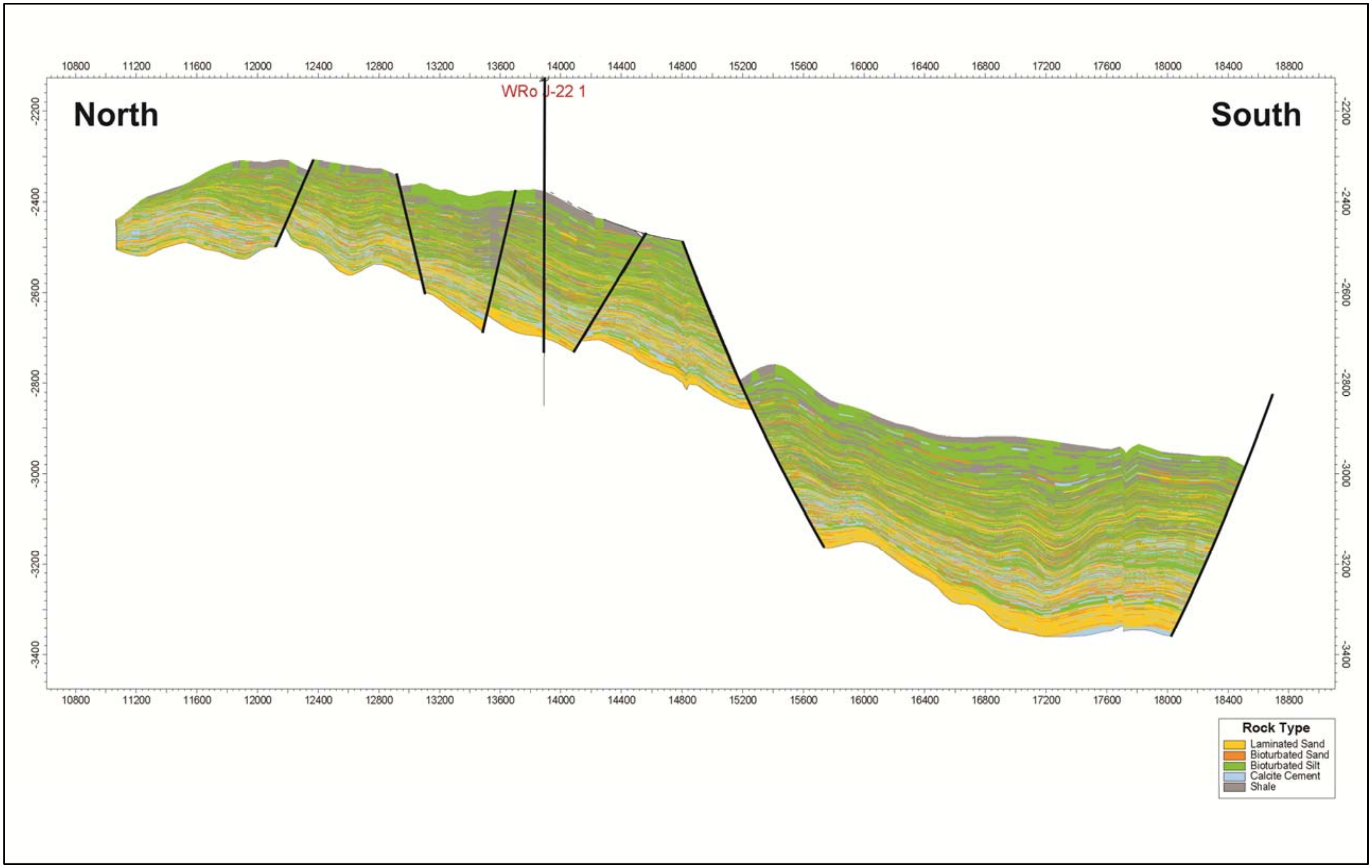


Figure 2-28 Structural Section with Facies Distribution of the North Avalon Pool

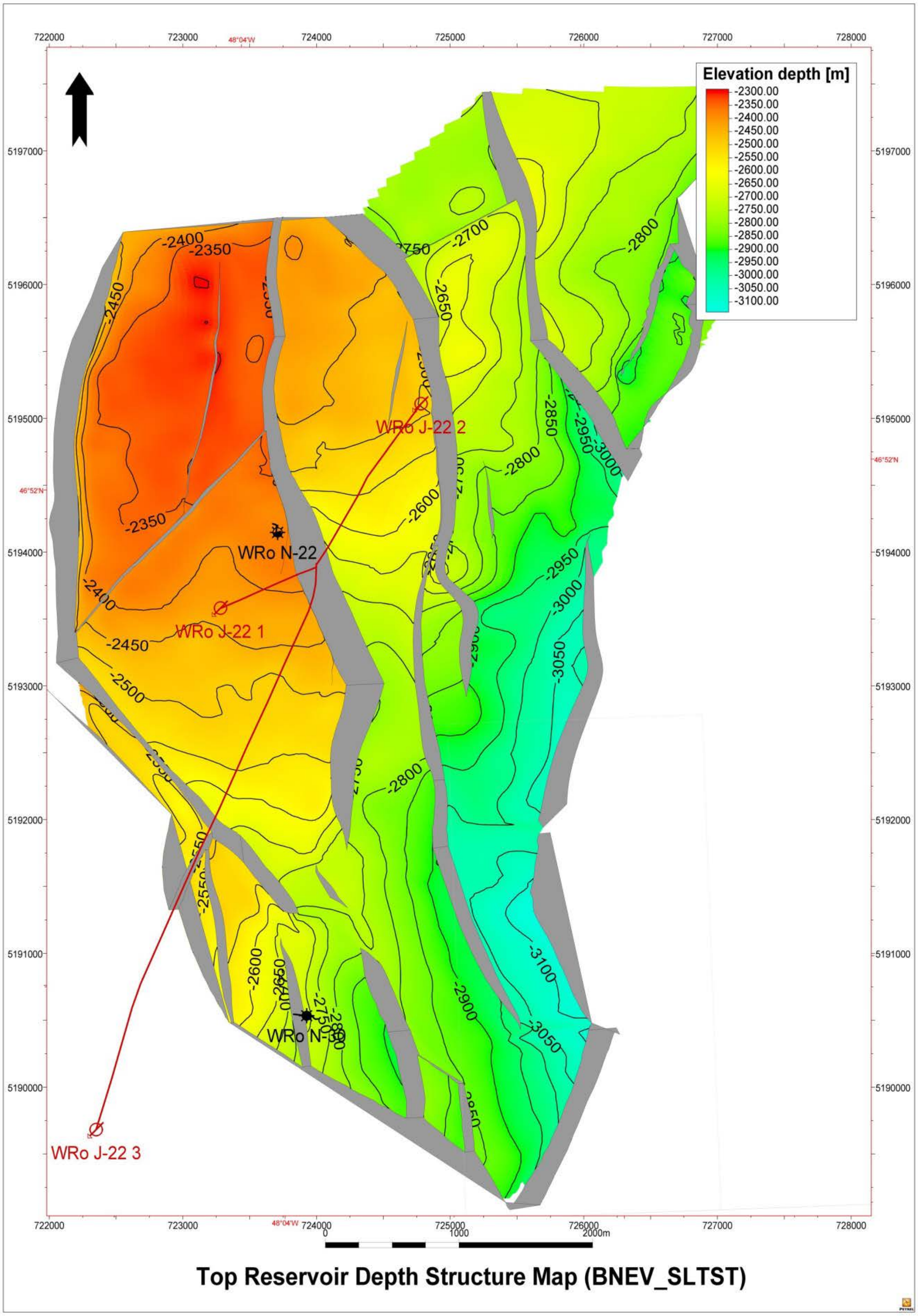


Figure 2-29 Top Reservoir Depth Structure Map (BNEV_SLTST) North Avalon Pool

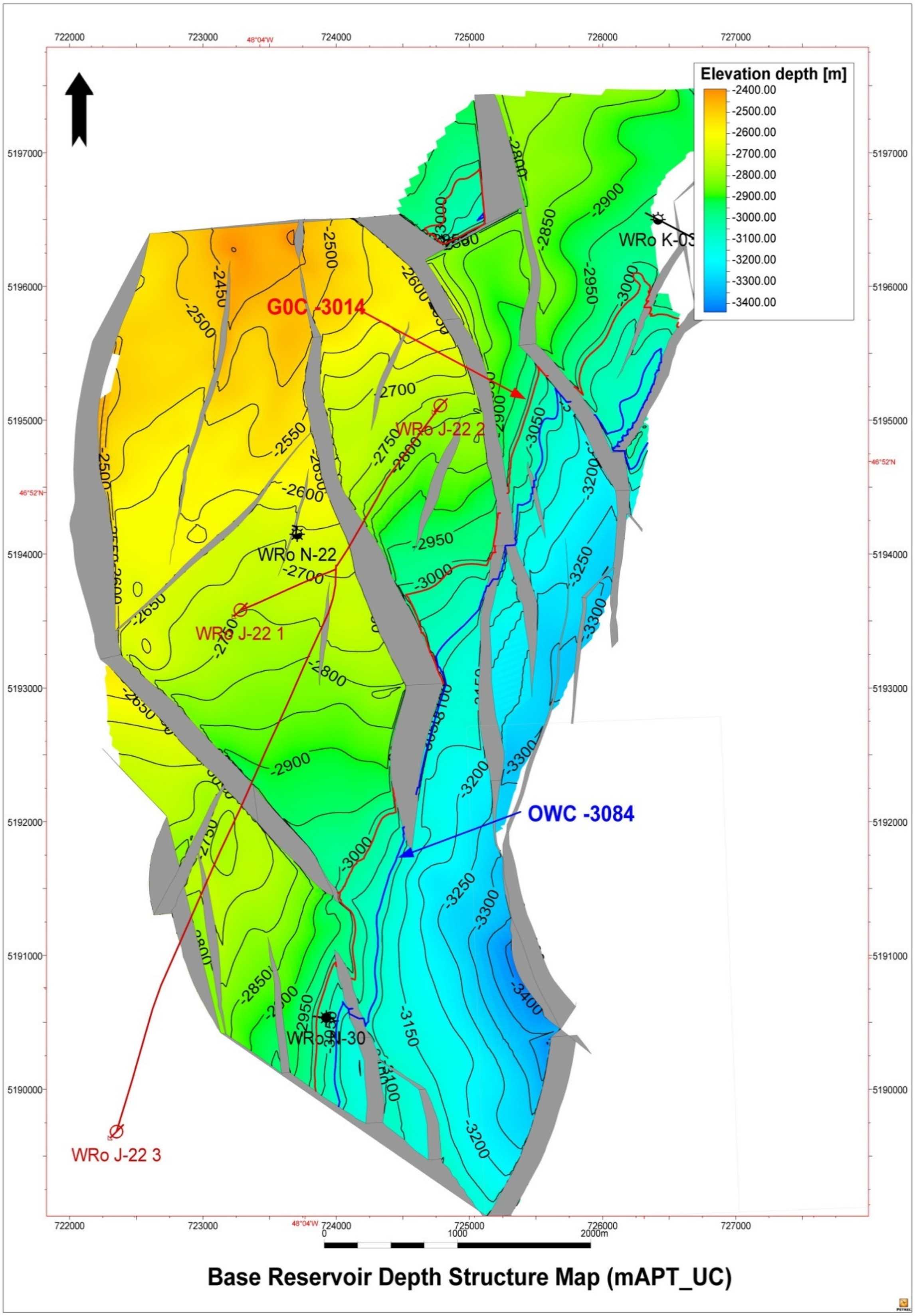


Figure 2-30 Base Reservoir Depth Structure Map (mAPT_UC) North Avalon Pool

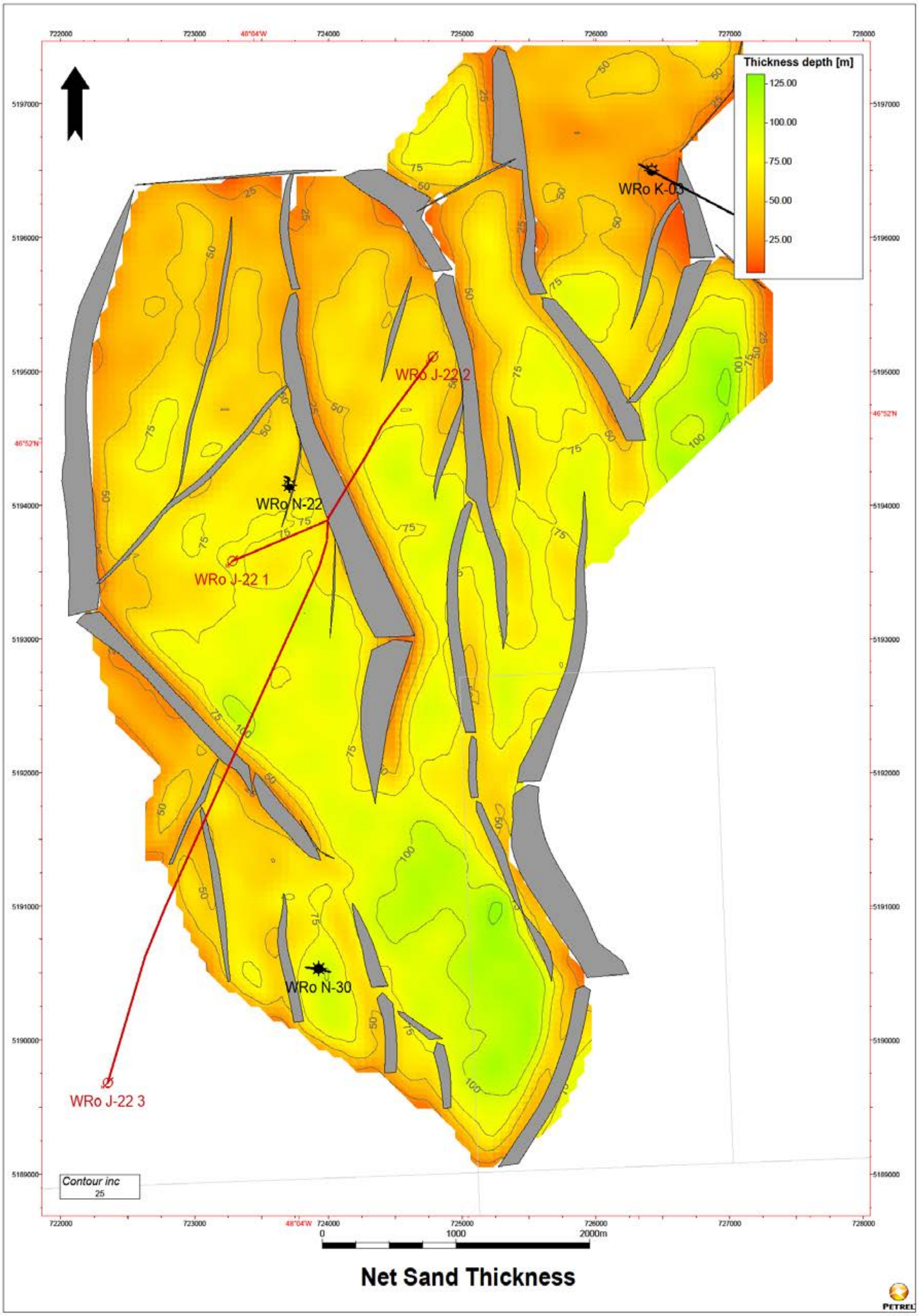


Figure 2-31 Net Sand Thickness Map for the North Avalon Pool

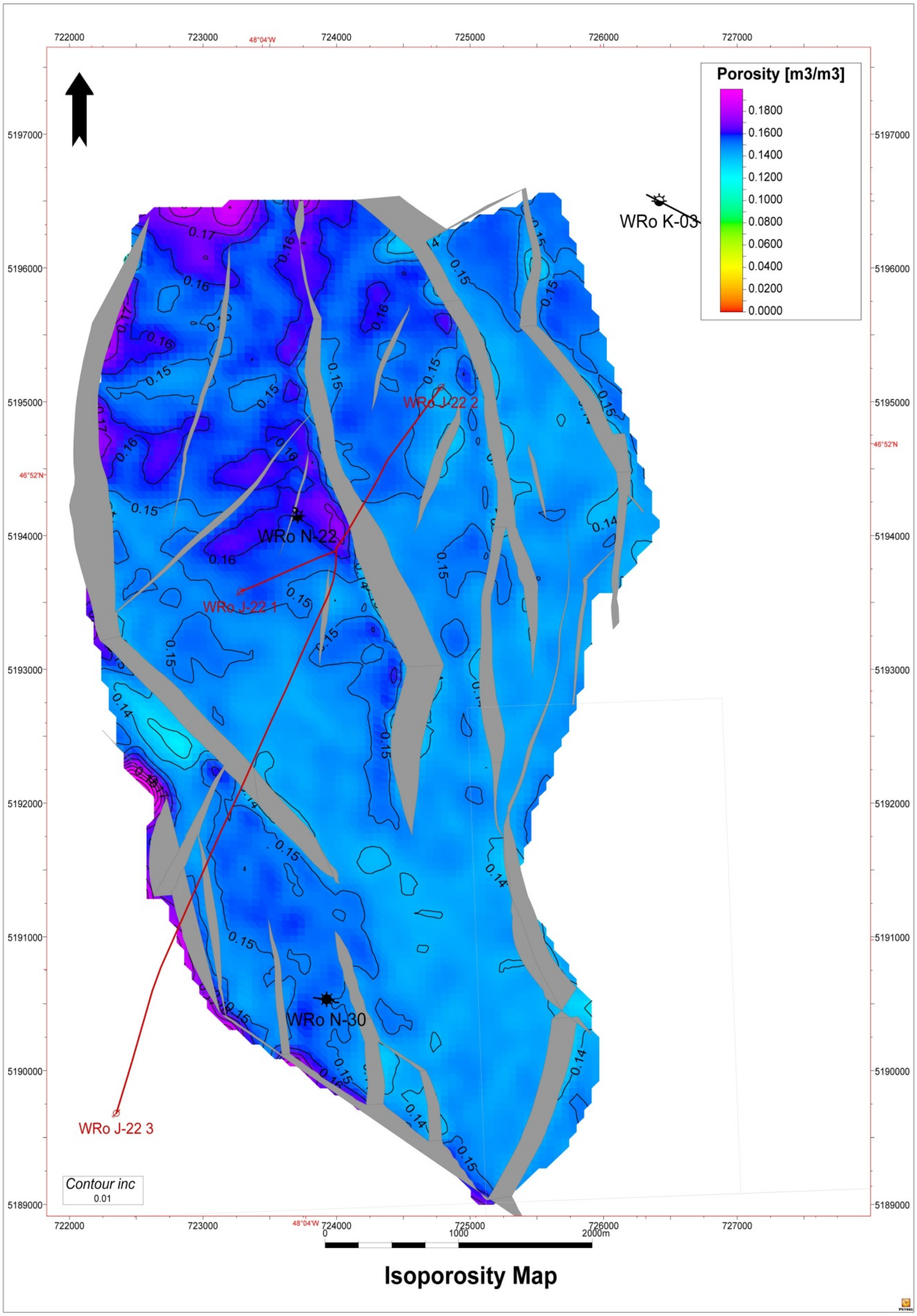


Figure 2-32 Isoporosity Map for the North Avalon Pool

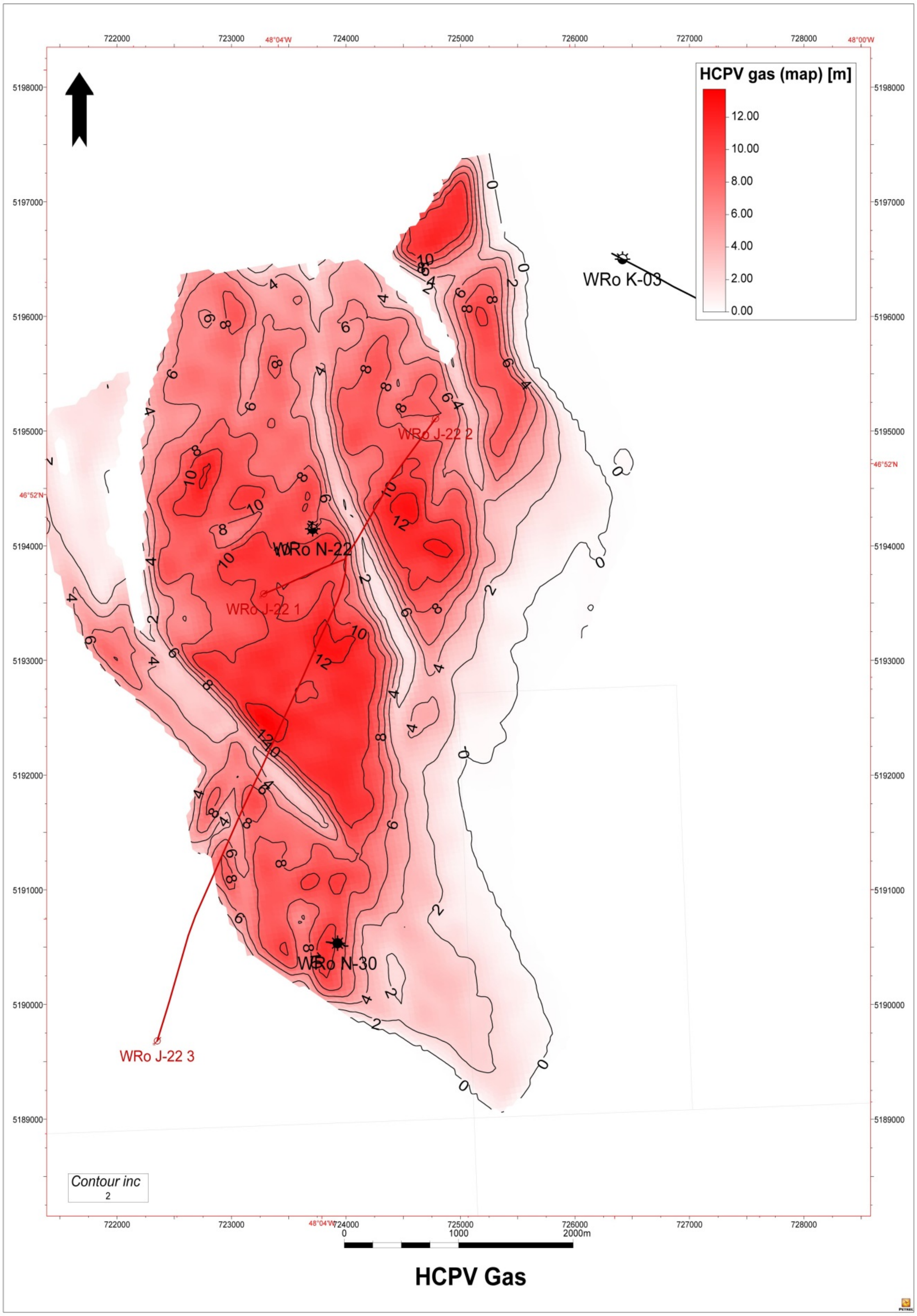


Figure 2-33 Hydrocarbon Pore Volume Gas Map for the North Avalon Pool

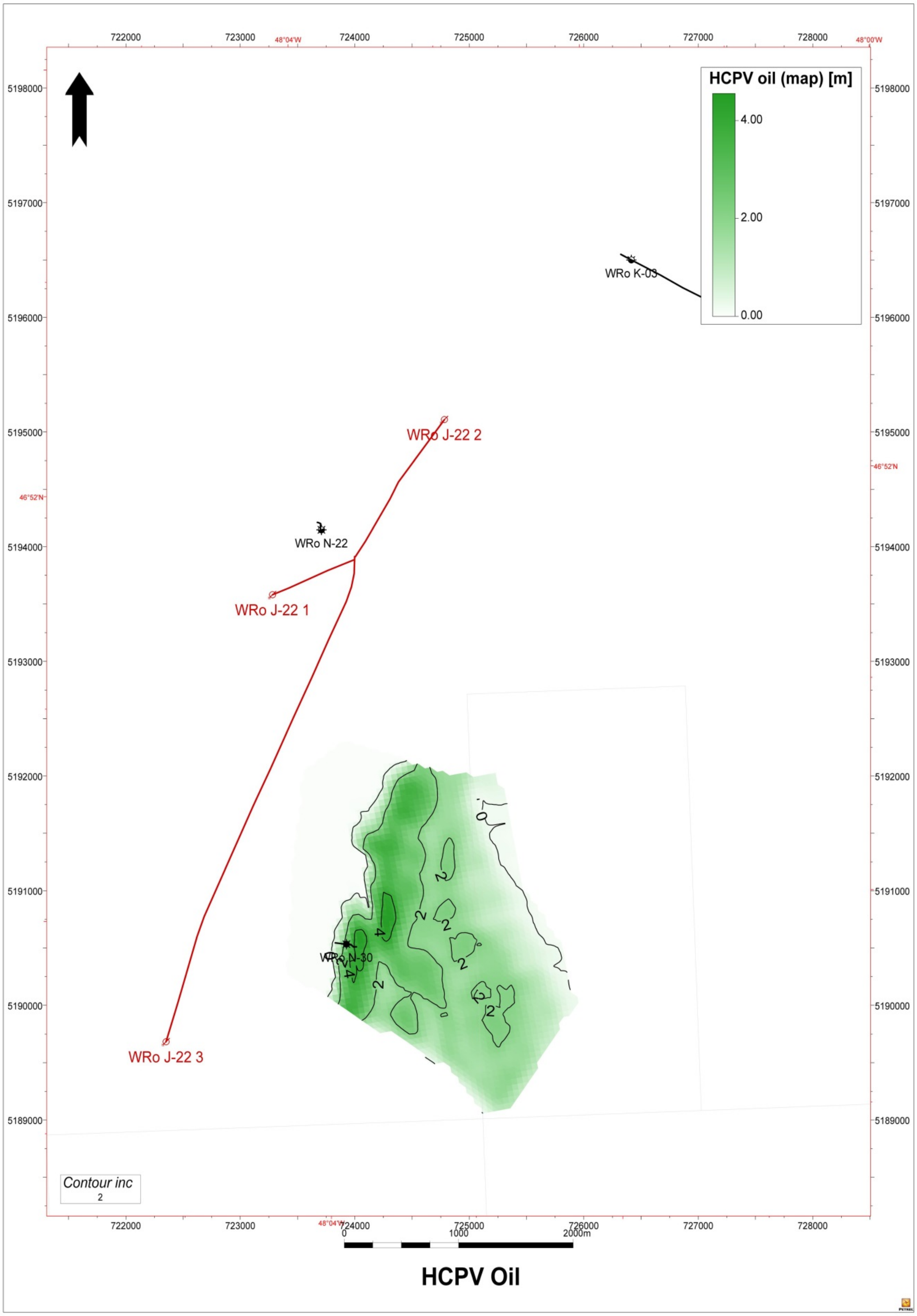


Figure 2-34 Hydrocarbon Pore Volume Oil Map for the North Avalon Pool

2.2 Geophysics

2.2.1 Seismic Surveys

The main seismic data for interpretation of the White Rose region was acquired in 2008. The survey coverage is shown in Figure 2-35. Approximately 1,485 km^2 of data were acquired over the region; however, there are still several gaps in the data. These gaps are the results of either obstacles (*SeaRose FPSO* in the field) or areas that could not be surveyed due to poor weather conditions. In these instances, older vintage data were used to fill the gaps pre-stack and were processed concurrently with the 2008 data.

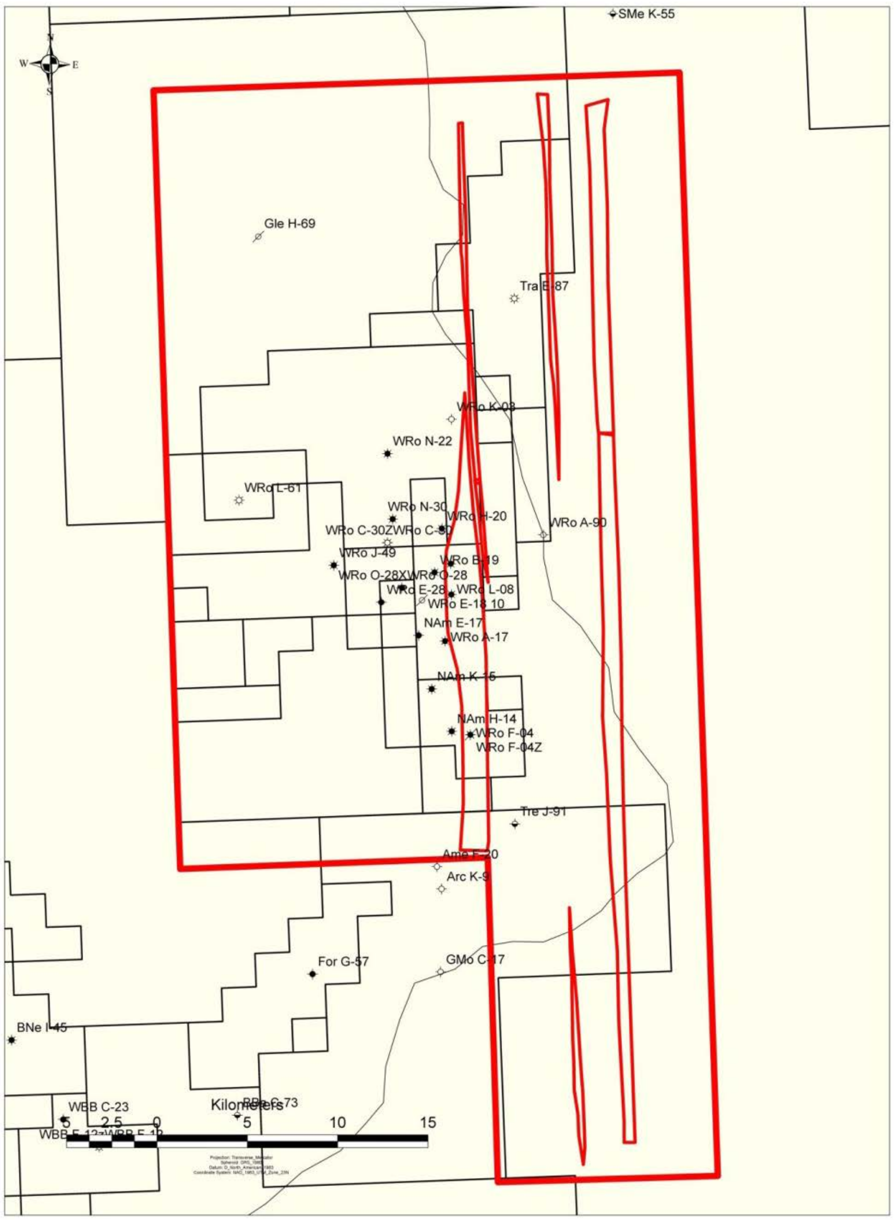


Figure 2-35 2008 White Rose Seismic Survey (red outline)

The objective of reacquiring seismic data over White Rose was to improve fault placement, mapping of internal BNA markers, improve de-multiple algorithms, and the imaging of deeper prospective intervals. Areas exist (such as South Avalon) within the data gap that suffer from degraded image quality. Therefore, South Avalon seismic interpretation is based on previous processing.

The 2008 data were acquired for Husky by CGG Veritas using the *Veritas Vantage*. A summary of main acquisition parameters from the 2008 survey is provided in Table 2-1.

Table 2-1 Seismic Acquisition Parameters

Recording Parameters	**WR2008**
Area	1,639 km^2
Line orientation	north-south
Water depths	80 to 120 m
Sampling rate	2 m/s
Nominal fold	80
Acquisition datum	WGS-84
Streamers	
Number of streamers	10
Streamer length	6,000 m
Streamer separation	75 m
Groups per streamer	480
Group length	12.5 m
Streamer depth	9 m
Seismic Source	
Source type	Bolt 15DDLL/1900LLXT
Shotpoint interval	18.75 m flip-flop
Centre-centre separation	37.5 m
Air pressure	2,000 psi
Volume	5,260 cubic inches
Source array depth	8 m

2.2.2 Processing and Interpretation of Seismic for WREP Region

The White Rose 2008 seismic data used for interpretation of the WREP region were an Anisotropic Pre-Stack Depth Migration volume. Seismic markers were synthetically tied to all relevant wells in the region. Most wells contained checkshot or vertical seismic profile (VSP)-corrected sonic logs, while some recent development wells contained sonic logs only. These were alternatively tied based on character. Three seismic horizons were interpreted over the WREP region: Mid-Aptian Unconformity (Figure 2-36); BNA_200 (Figure 2-37); and top BNEV_SLTST (Figure 2-38).

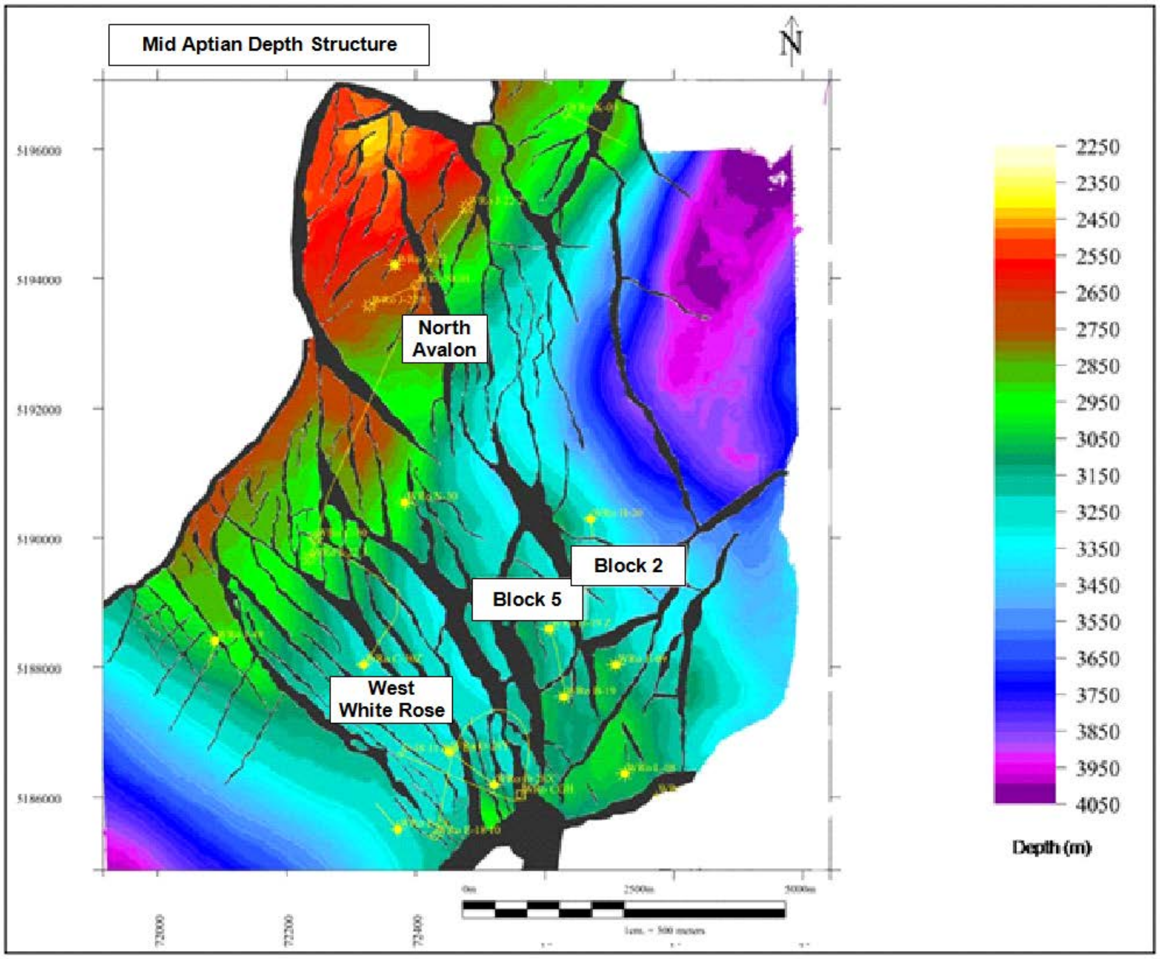


Figure 2-36 Mid-Aptian Depth Structure Map for WREP Region

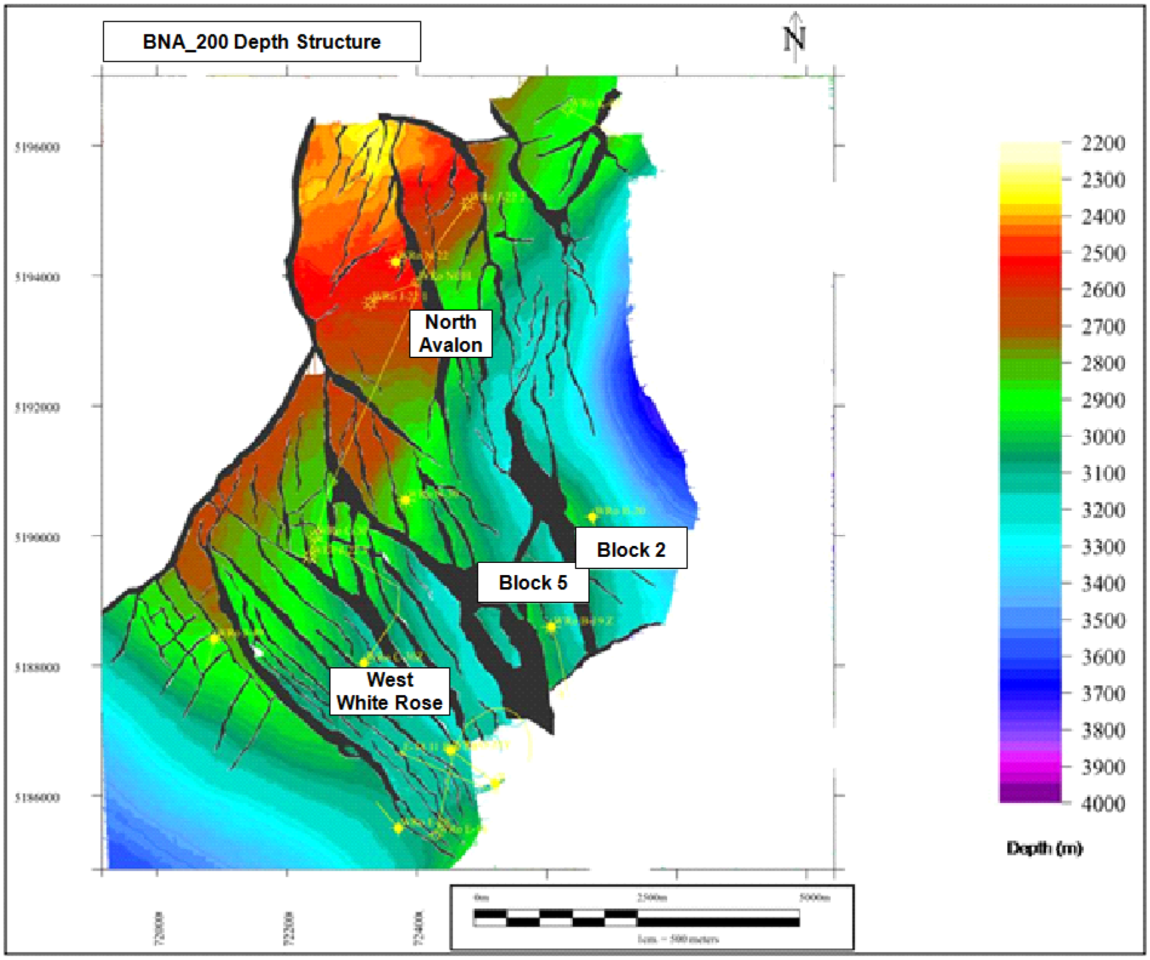


Figure 2-37 BNA_200 Depth Structure Map for WREP Region

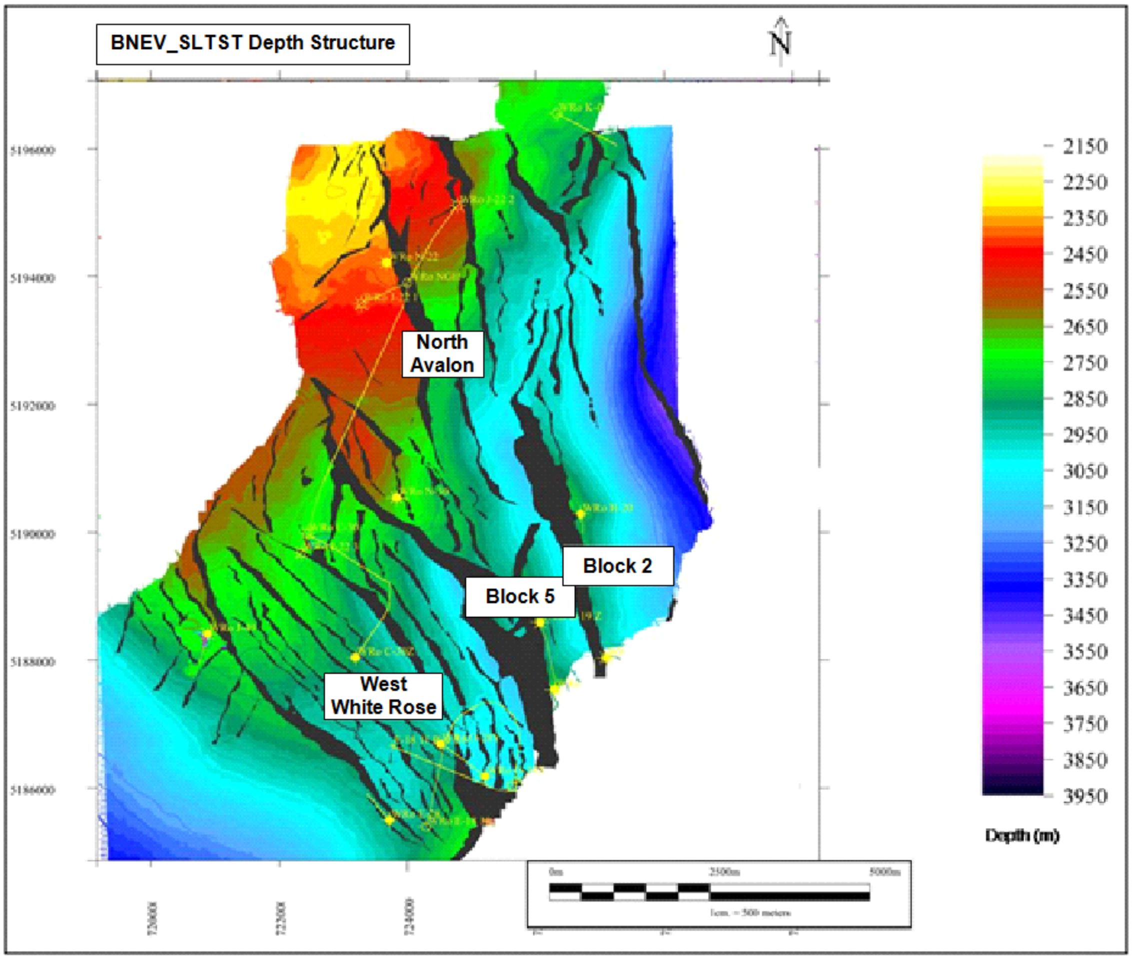


Figure 2-38 BNEV_SLTST Depth Structure Map for WREP Region

An important distinction must be made with the BNEV_SLTST seismic marker. In the WREP region, the progressively distal and fining-upward nature of the sandstone package causes a small impedance contrast that cannot distinguish a "top sandstone" marker. Hence, the top siltstone marker is interpreted over the WREP region, creating a situation where the siltstone cannot be reliably distinguished with the overlying Nautilus Formation shale.

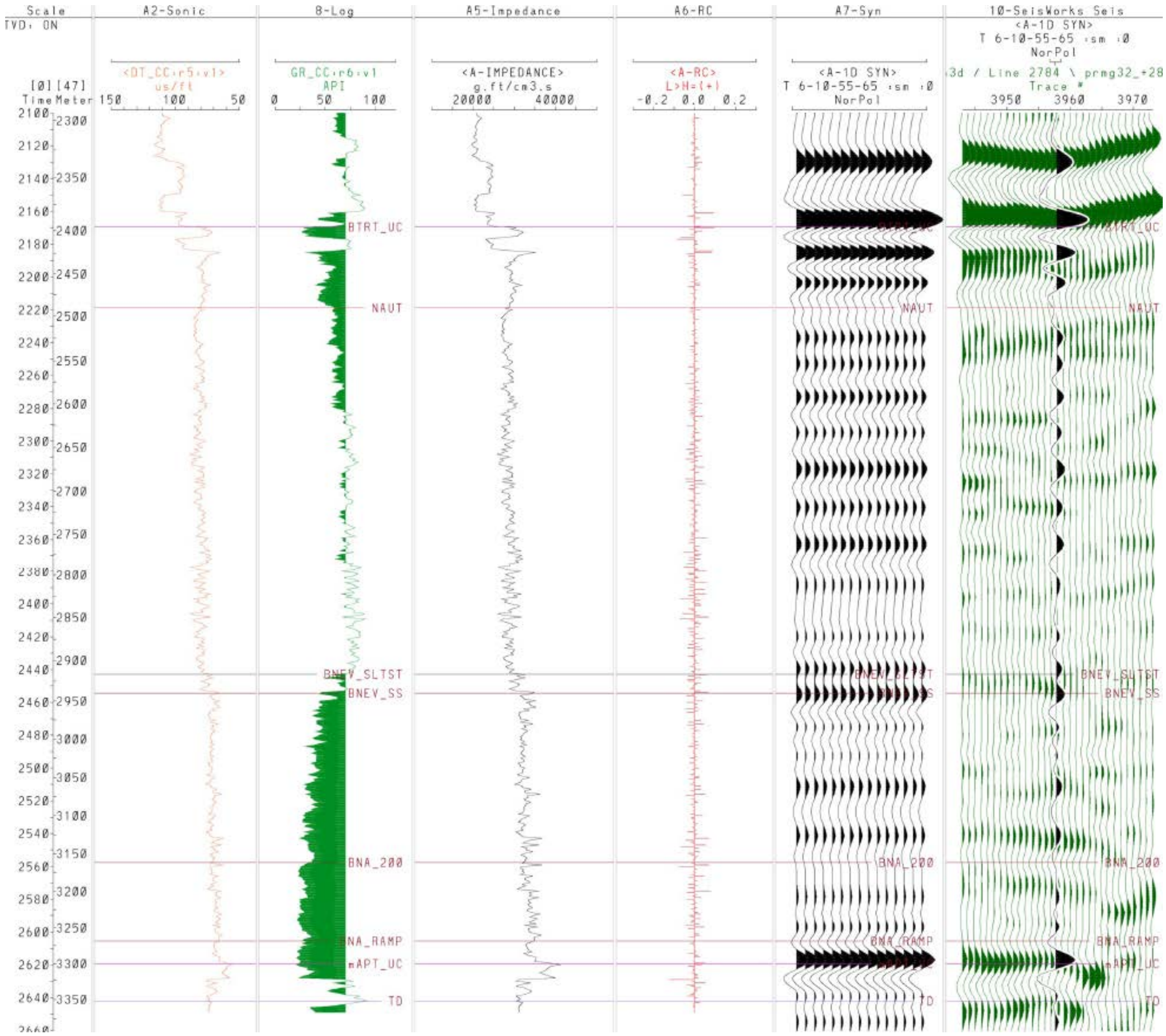
Overall, the quality of the 2008 seismic data (where acquired) is good. Interpretation was performed on a 12.5 m x 12.5 m data volume over the entire field. Some areas are more difficult to image depending on fault complexity, low impedance contrast with the overlying Nautilus Formation and/or seismic multiple interference, particularly for the top BNEV_SLTST marker. For example, multiple contaminations continue to occur in the northern regions of West White Rose and near the N-30 region of North Avalon. In these cases, the siltstone marker is guided by an isopached thickness from the BNA_200 to siltstone in the well data.

Another interpretation complexity arises in regions where the mid-Aptian Unconformity erodes the high impedance A-Marker limestone. This can create a tuning effect, particularly when the BNA_RAMP sand also thins below seismic resolution.

2.2.3 West White Rose Seismic Interpretation

Seismic data quality in the West White Rose region is fair to good. The high degree of faulting is resolvable within seismic resolution limits, and the base reservoir (mid-Aptian Unconformity) is a clear marker when not overlying the A-Marker within tuning limits. However, the top BNA Formation marker (BNA_SLTST) is more difficult to discern for two reasons. First, the upper BNA reservoir sandstones become more distal, resulting in less impedance contrast moving north. Secondly, a strong multiple window interferes with primary energy toward the northern extent of the pool. The actual top sandstone seismic marker deteriorates moving away from O-28Y, and becomes unresolvable from the C-30Z area northward. Internal seismic markers provide some assistance with mapping BNA sandstone parasequences, mainly within the lower BNA section.

The seismic-to-well tie was performed on all relevant west wells (including O-28Y, E-28, J-49, C-30/C-30Z and E-18 11). O-28Y is essentially the template well used to correlate seismic markers with the geological picks in West White Rose (Figure 2-39). Drilled in 2006, it has both reliable borehole evaluation tools and a good quality VSP that was acquired for depth and resolution control. The resultant tie is excellent, with both the top and base reservoir visible, plus internal BNA markers. The Mid Aptian Unconformity is a strong amplitude peak, whereas the top BNEV_SLTST is a weak to medium amplitude peak. In addition, the BNA_200 is now mapped consistently over West White Rose as a medium amplitude trough. The sonic log and subsequent synthetic seismogram also correlate well to the gamma ray log signature.



Note: Created from VSP-corrected sonic log and tied to 2005 processed surface seismic data. Top (BNEV_SLTST) and base reservoir (mAPT_UC) are discernible, plus internal BNA markers.

Figure 2-39 Synthetic Seismogram for O-28Y

Figure 2-40 to Figure 2-44 illustrate the complex structural faulting in the West White Rose pool compared to the South Avalon and North Avalon pools. The West White Rose pool differs from the other White Rose pools in that it contains narrow rotated fault blocks trending northwest-southeast.

The sandstone juxtaposition across the faults is further complicated by the distal nature of the reservoir in the upper BNA. This makes seismic attribute analysis less reliable in the West White Rose pool and is further complicated by the strong multiple windows toward the northern extent of the pool.

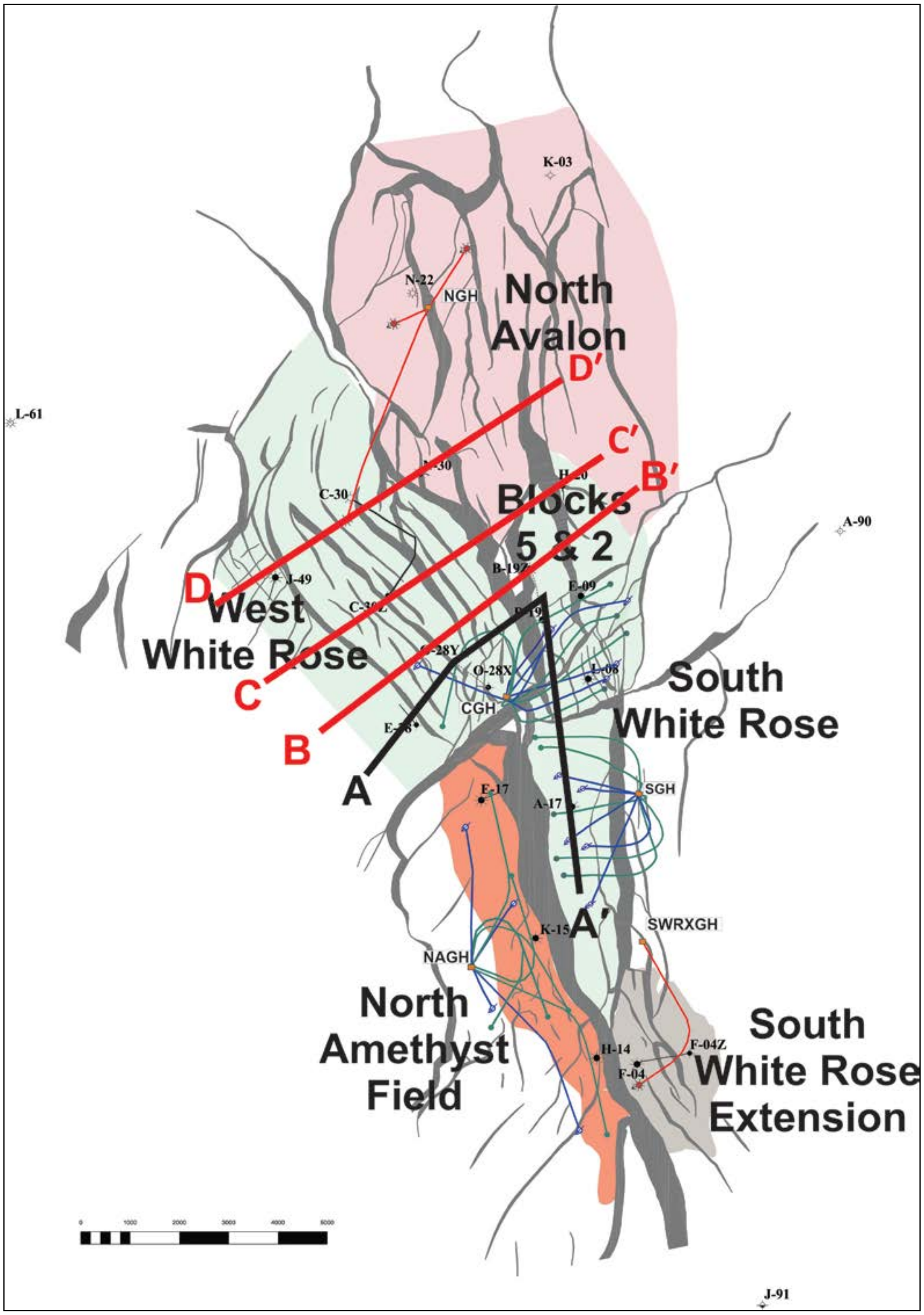
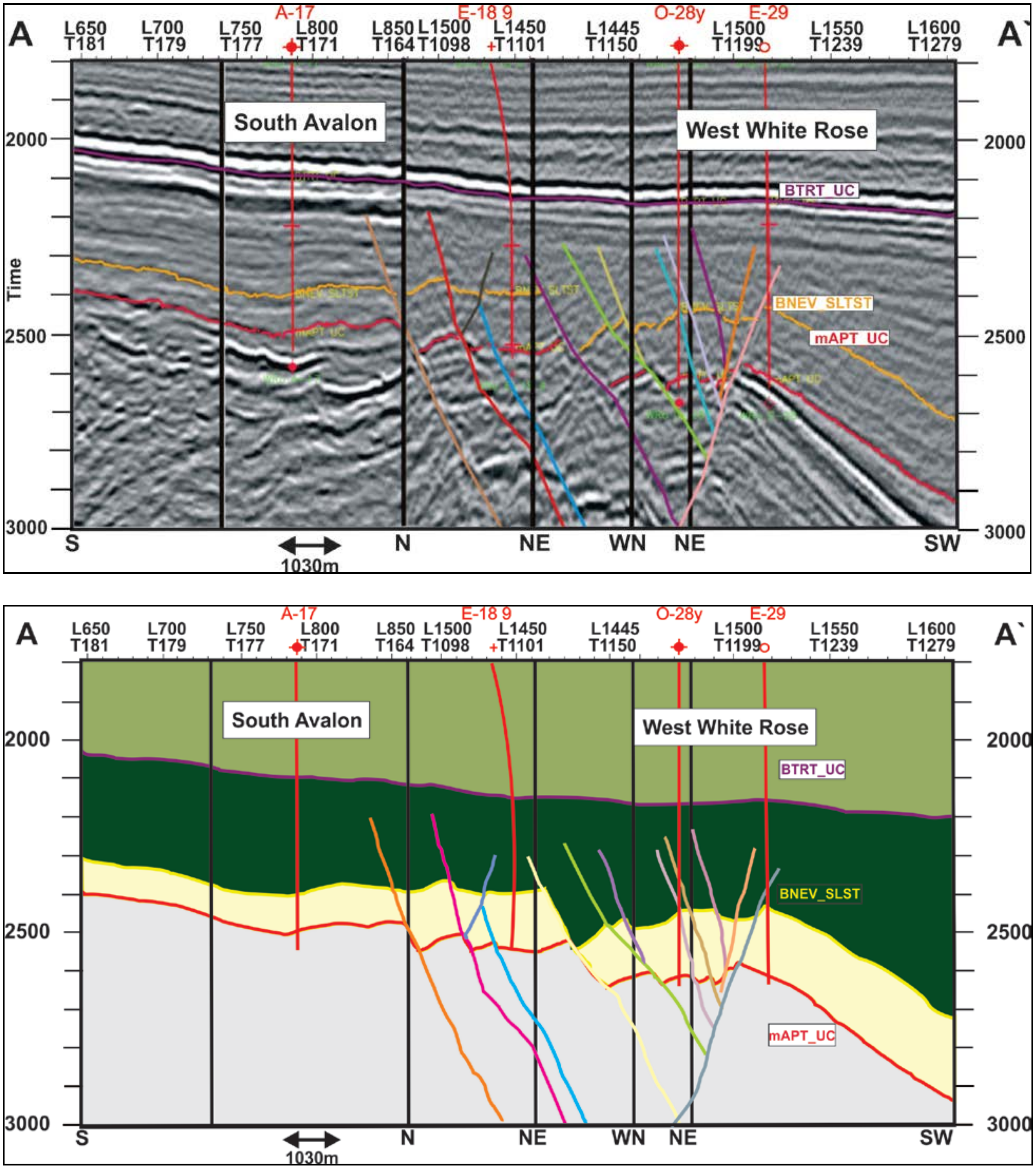
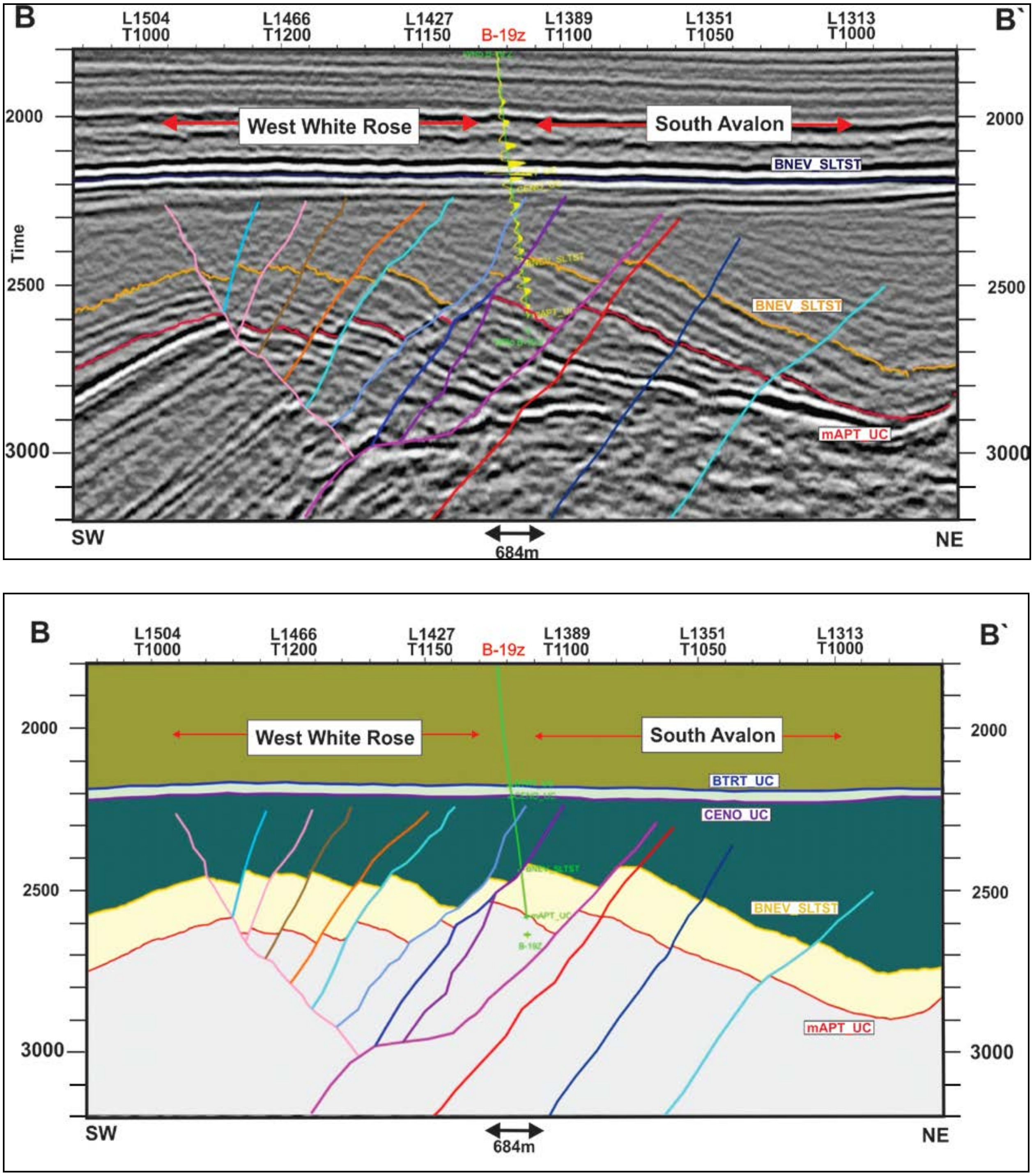


Figure 2-40 Location of Arbitrary Seismic Lines in Subsequent Figures



Note the change in structural character from the rest of the pool into the west.

Figure 2-41 Arbitrary Seismic line A-A' connecting the Terrace (A-17) to Blocks 3, 4, 1 (E-18 9) to West White Rose Region (O-28Y and E-28)



Note: Line runs southwest to northeast intersecting highly faulted West White Rose blocks and the lesser faulted South Avalon Blocks 2 and 5.

Figure 2-42 Arbitrary Seismic Line B -B' through the Central Extent of West White Rose Region

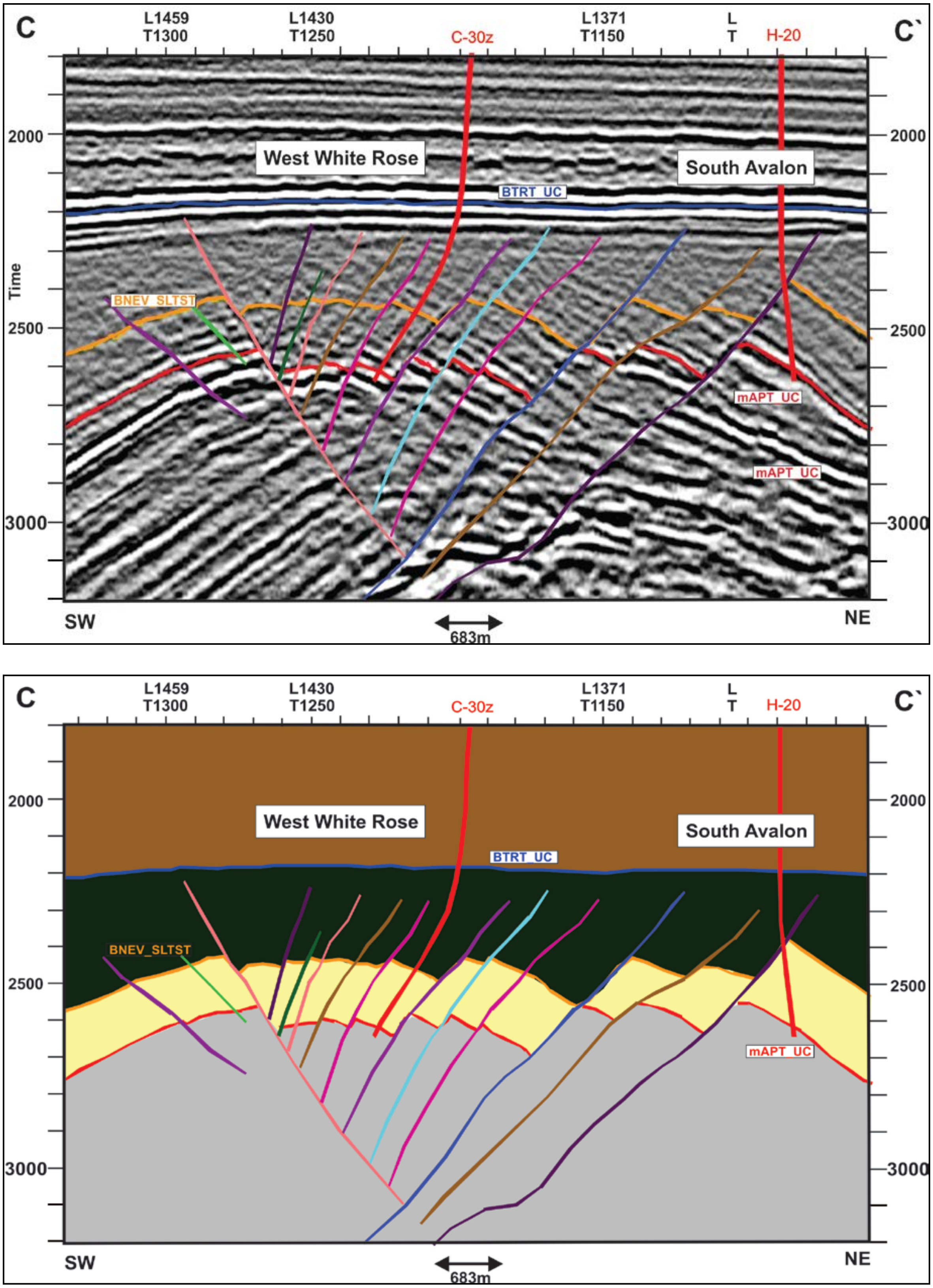
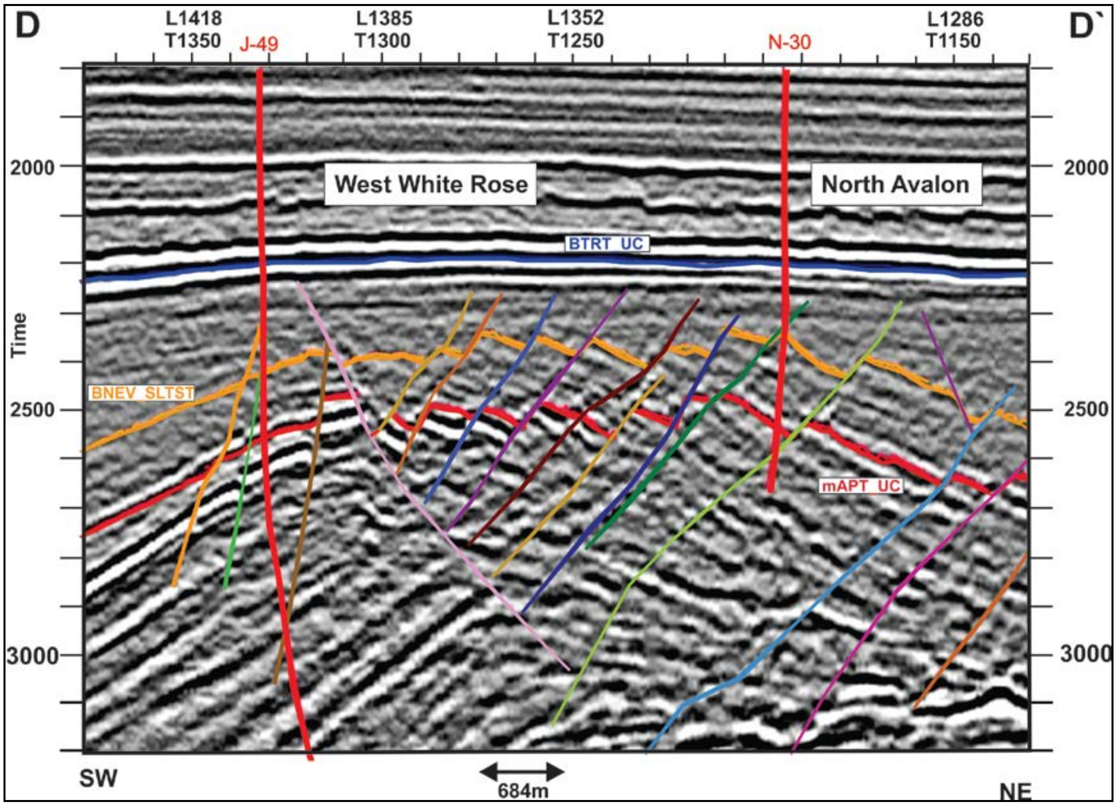


Figure 2-43 Arbitrary Seismic Line C-C' through the Central Extent of West White Rose Block 5



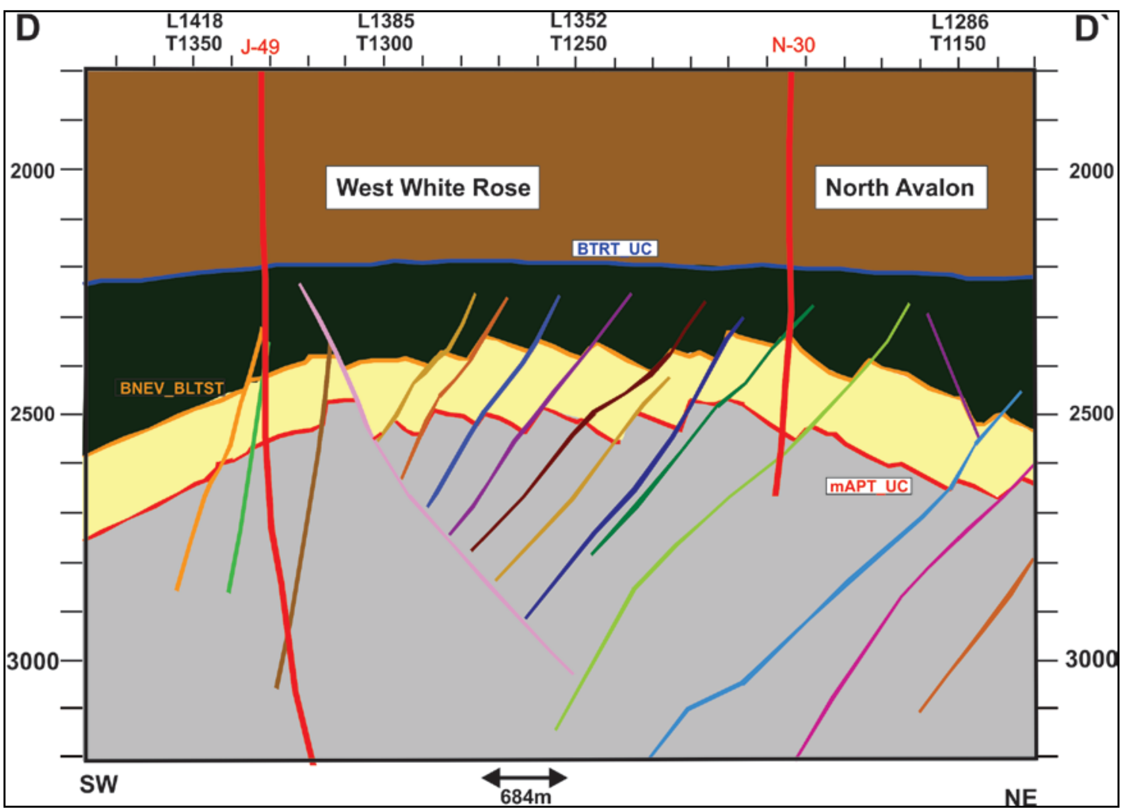


Figure 2-44 Arbitrary Seismic Line D-D' through the Northern Extent of West White Rose Region

2.2.4 Blocks 2 and 5 and North Avalon Seismic Interpretation

Blocks 2 and 5 and the North Avalon pool are equivalent to the West White Rose pool in terms of a progressively distal reservoir facies moving northward. However, the faulting is less prevalent. The key horizons interpreted were the Mid-Aptian Unconformity (i.e., base reservoir), BNA_200 and BNEV_SLTST (i.e., top formation). The "top sandstone" cannot be mapped in these regions because of low impedance contrast between sand and shale. However, interpretation of the intra-formational BNA_200 marker allows better constraint of the major back-stepping parasequences. This represents an important improvement over previous interpretation that inferred a continuous sandstone over the entire BNA Formation.

For the most northern regions (i.e., N-22, J-22-2, K-03), the BNA_RAMP constitutes the majority of remaining sandstone presence. However, there is uncertainty in mapping the presence and absolute thickness of BNA_RAMP in these areas because tuning of the seismic wavelet causes the RAMP to be irresolvable. Therefore, isopach "trends" in the BNA_RAMP, in conjunction with injection data in North Avalon, were used to constrain the presence of RAMP sandstone away from well control.

Figure 2-45 to Figure 2-49 illustrate the major interpretation features of Blocks 2 and 5 and North Avalon. The eastern extent of Figure 2-42 to Figure 2-44 also ties the major wells in these pools.

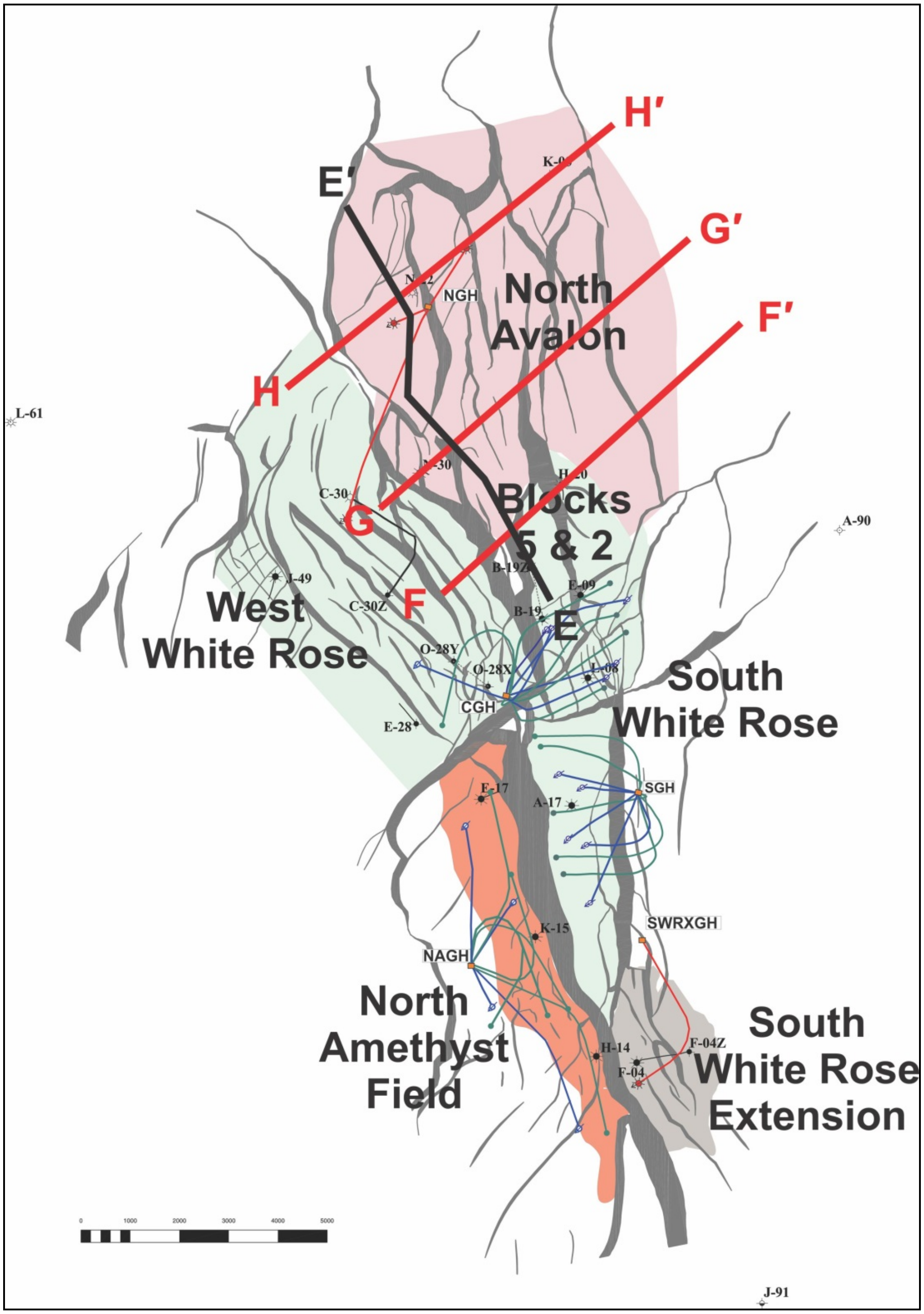
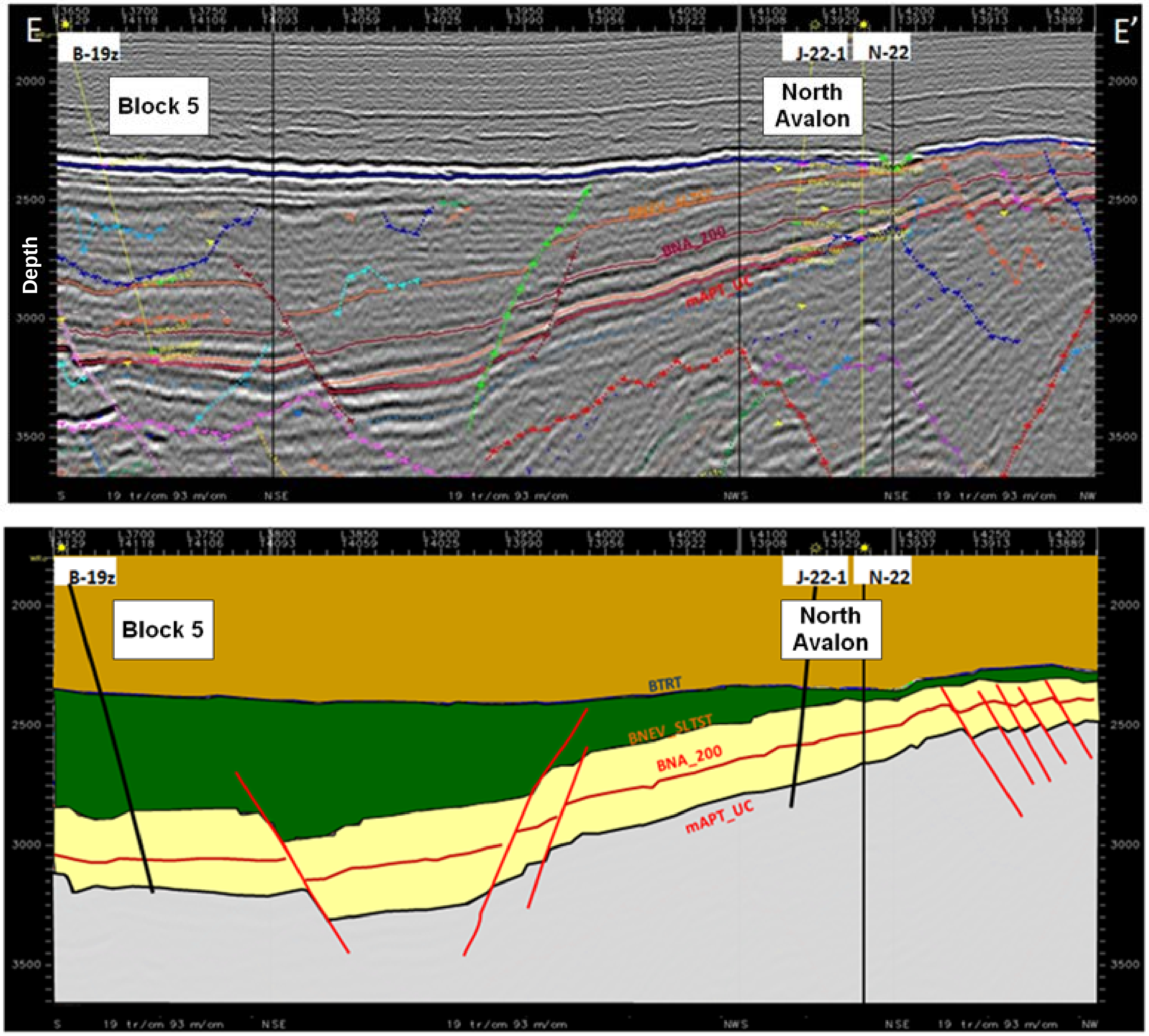


Figure 2-45 Arbitrary Seismic Lines through Blocks 2 and 5 and North Avalon Pool



The BNA shown in the subsequent schematics includes the entire BNA Formation and does not represent the presence or quality of sandstone, which cannot be reliably mapped seismically.

Figure 2-46 Arbitrary Seismic Line E-E' extending from Block 5 into North Avalon Gas Injection Region

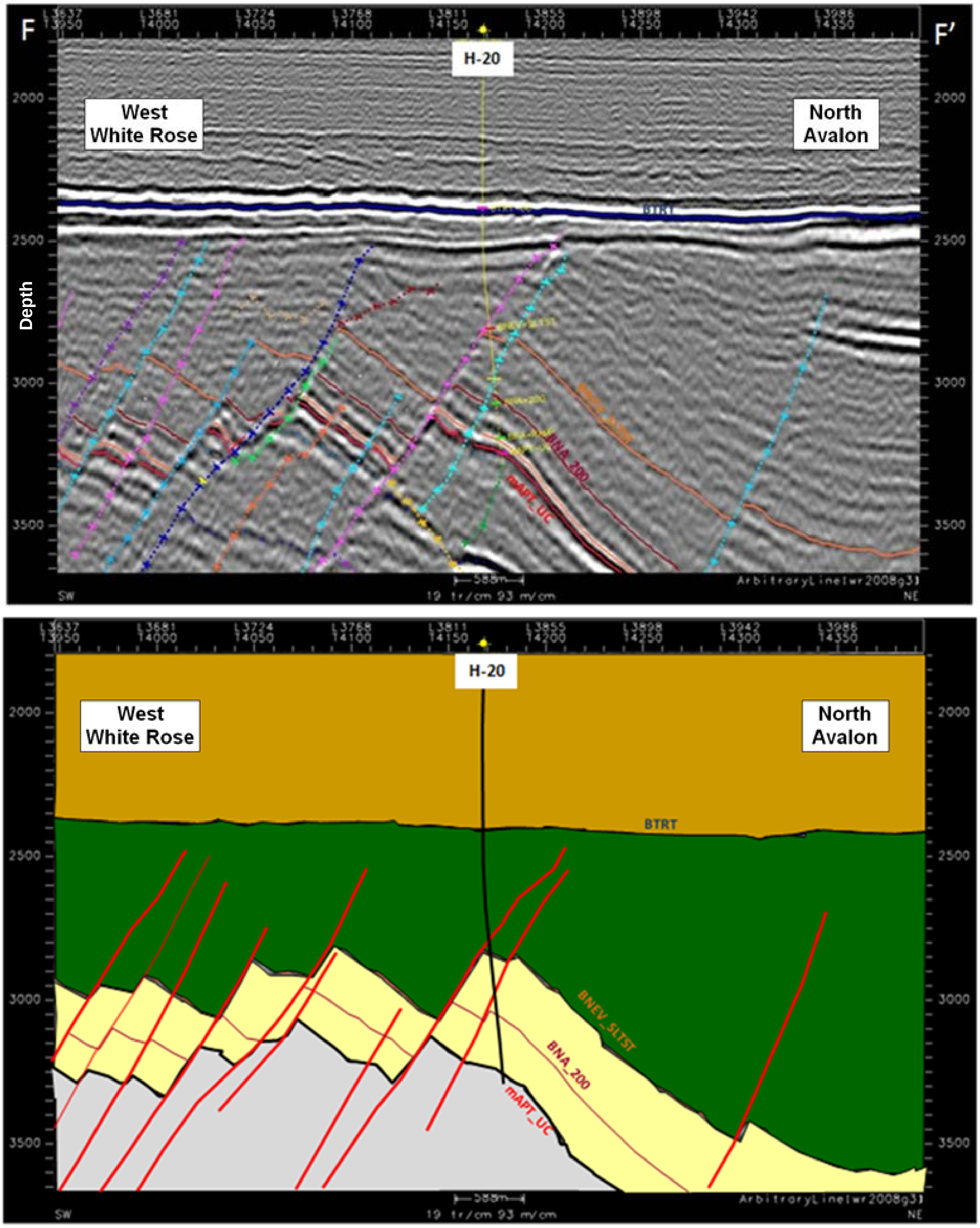


Figure 2-47 Arbitrary Seismic Line F-F' extending Through Block 2

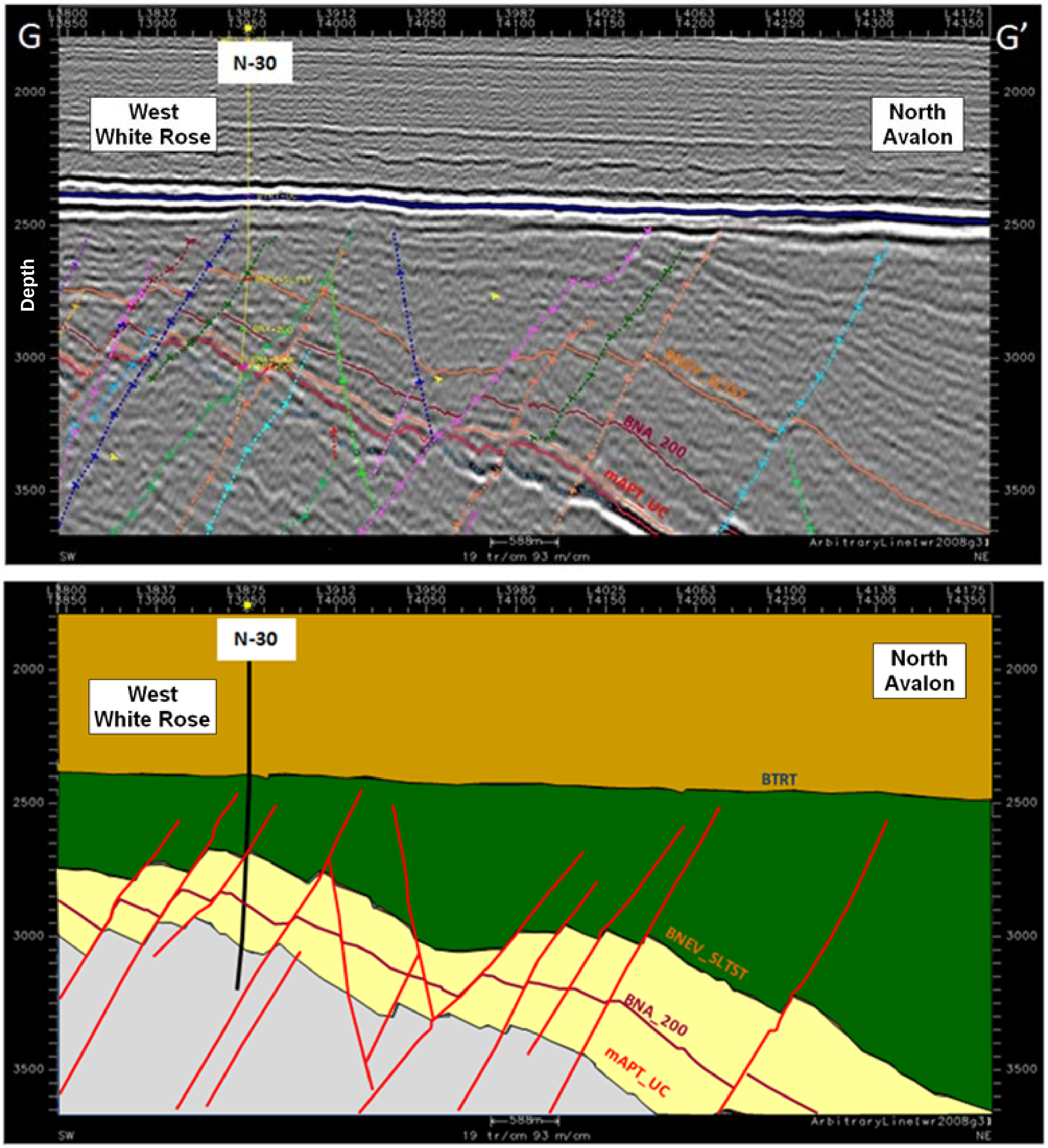


Figure 2-48 Arbitrary Seismic Line G-G' across White Rose N-30 Region

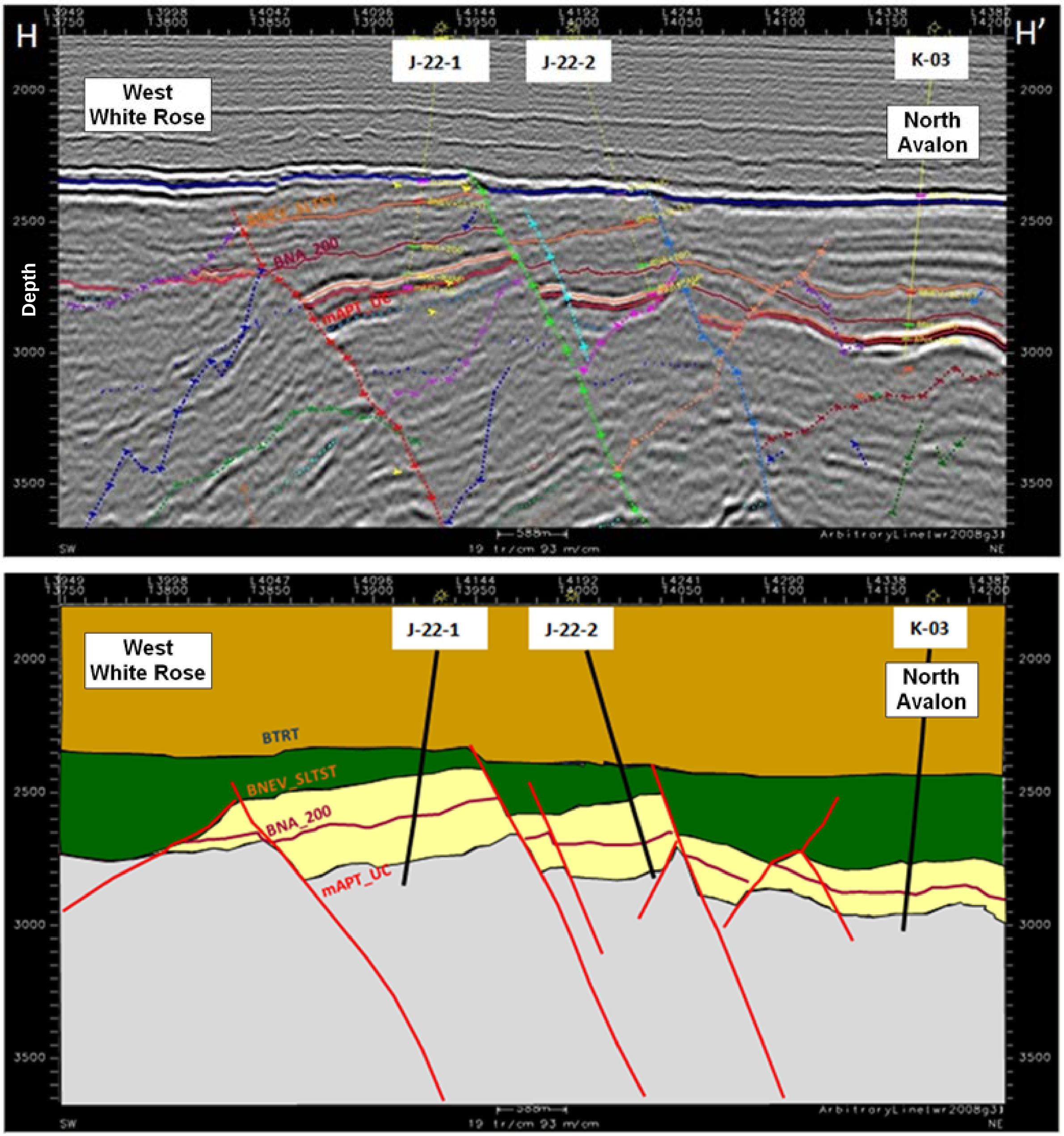


Figure 2-49 Arbitrary Seismic Line H-H' across the North Gas Injection Regions (J-22-1 and J-22-2) and the Wet K-03 Block

2.2.5 South Avalon Seismic Interpretation

As previously discussed, the South Avalon pool of White Rose was not covered during the 2008 seismic program because the presence of the *SeaRose FPSO* constituted an obstacle to surveying. It was also decided not to undershoot the region. As a result, previous acquisition vintages were used to "fill" in the gaps where available. However, the processed quality in these gaps appear far less superior to areas covered solely by the 2008 data. This is because the vintages (1990 and 1997) contain less offset range, lower fold and lower source strength. Therefore, processing parameters derived for optimal imaging of 2008 seismic data will be sub-optimal for the vintage infill data within the keyhole gap. This is especially problematic for fault imaging and ability to eliminate multiples in the keyhole. With the Central Terrace blocks being more compartmentalized than Southern Terrace (Figure 2-41), these faults are especially aliased on the 2008 keyhole processed data. Therefore, interpretation from previously processed seismic data are currently still being used. This seismic interpretation has not materially changed from pre-production and post-production updates that were subsequently input in to the existing geomodel. Figure 2-50 and Figure 2-51 are depth structure maps based on previous vintage seismic interpretation for the Mid Aptian Unconformity and Top Ben Nevis Formation.

No consistent seismic response can be correlated to anomalous fluid pressure within the White Rose field; as such, no anomalous pressures have been identified using seismic. The best estimates of reservoir pressure in the field are from the pressure data acquired during the drilling of wells within the White Rose field and through pressure buildup and fall off data acquired during annual pool pressure surveys.

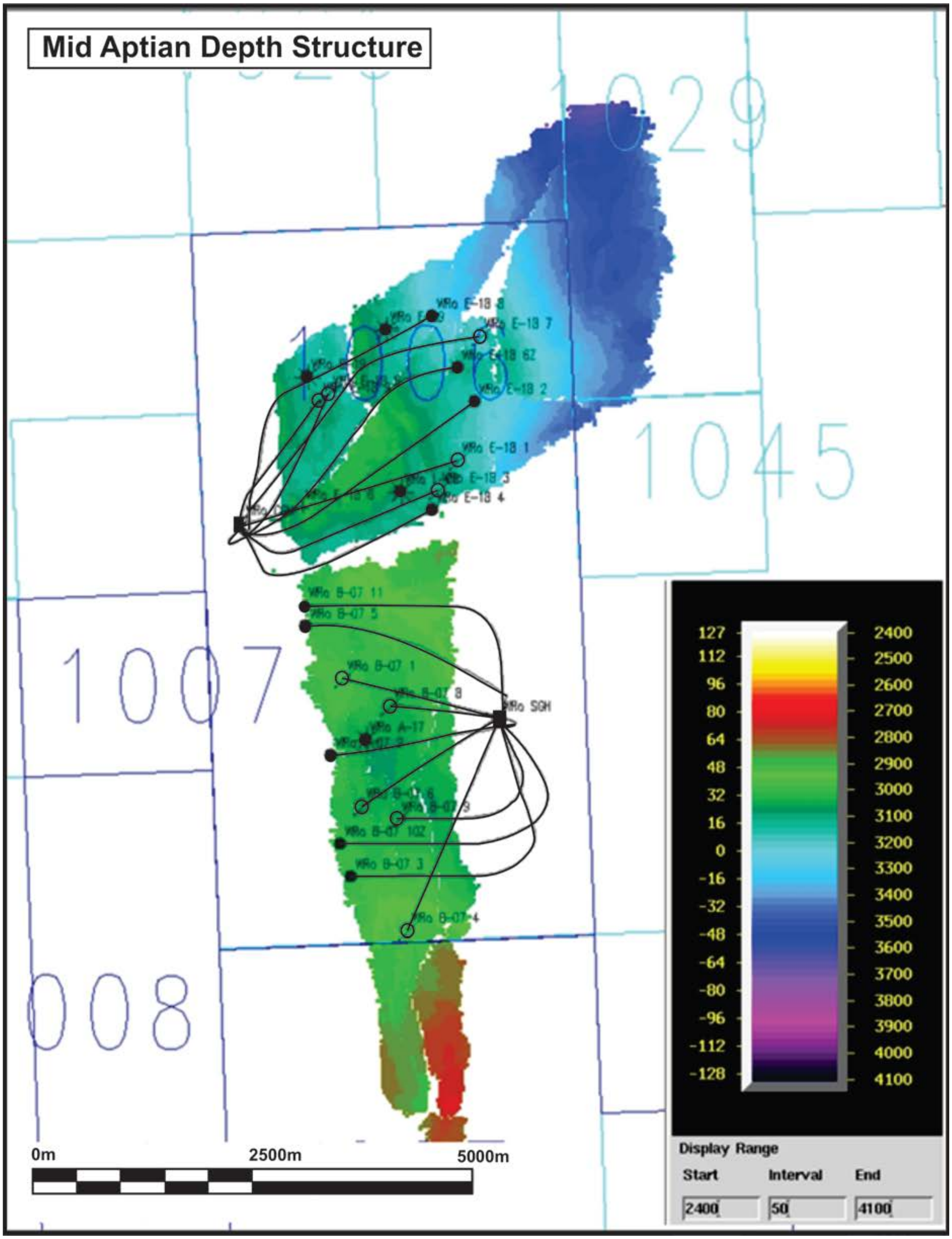


Figure 2-50 South Avalon Mid Aptian Depth Structure Map (pre-2008 data)

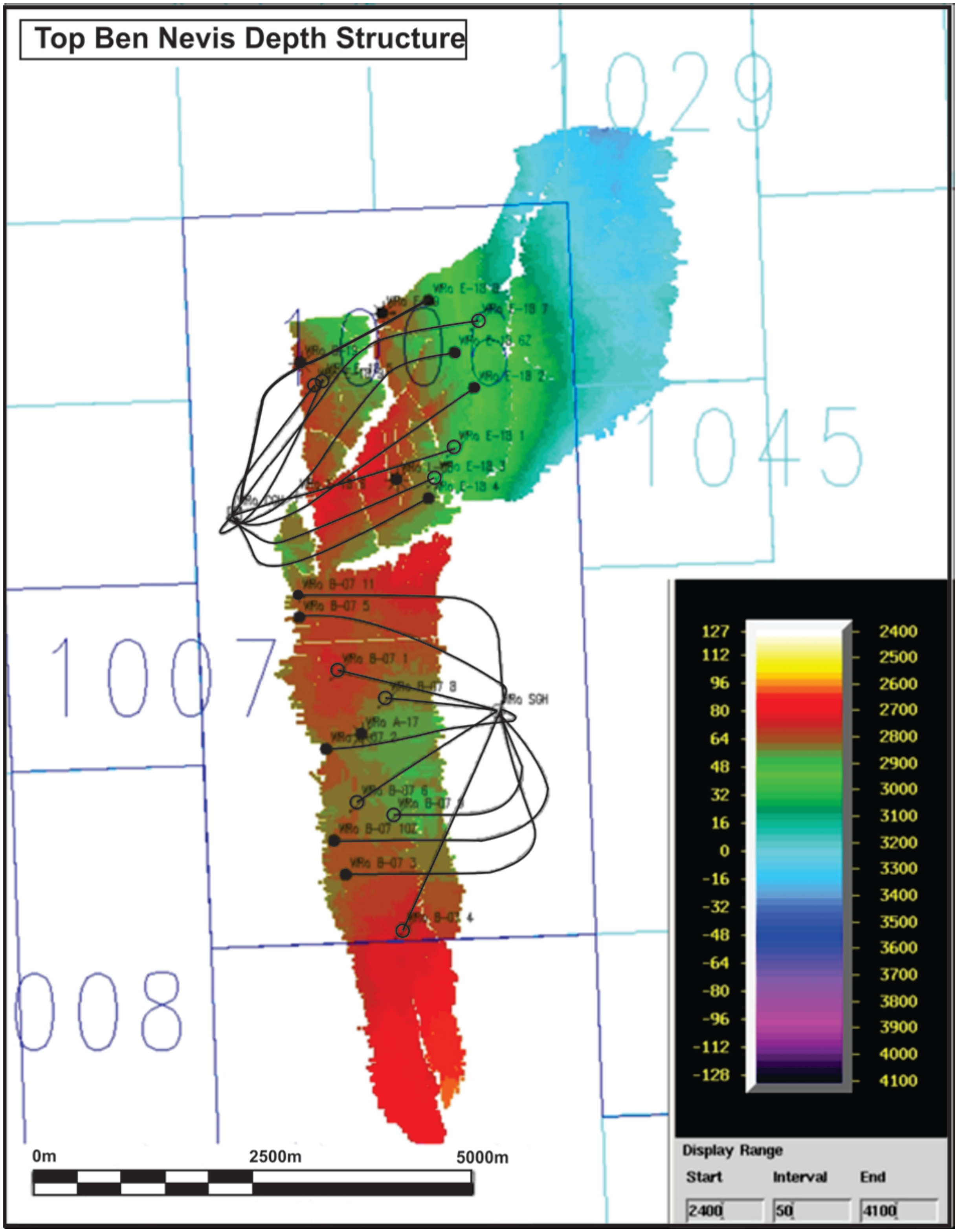


Figure 2-51 South Avalon Top Ben Nevis Formation Depth Structure Map (pre-2008 data)

2.3 Petrophysics

Petrophysical summaries for all the wells within the White Rose region, Blocks 2 and 5, the North Avalon pool and the West White Rose pool are provided in the following sections.

This amendment uses the extensive data (both well log and core) acquired in the J-49, O-28Y, O-28X, C-30, C-30Z, E-28, J-22 3, E-18 10, and E-18 11 wells for the analysis of the BNA Reservoir in the West White Rose pool.

All of the wells noted above encountered hydrocarbon-bearing sandstone, with reservoir properties similar to those in the development/delineation wells of White Rose. However, the amount of reservoir sandstone present diminishes towards the north and west. Given the increased argillaceous content and laminated nature of the reservoir sands, the general White Rose petrophysical model has been amended to more effectively deal with these localized variations in the BNA Reservoir in the West White Rose pool. Subsequently, the West White Rose petrophysics will be the primary focus of this section.

2.3.1 Petrophysical Data

The petrophysical analysis for the greater White Rose region is based on log data with calibration to core data.

2.3.1.1 Log Data

A comprehensive well log dataset has been acquired over the course of 29 years in the greater White Rose region.
Table 2-2 lists the wells that have been logged and the various means of conveyance in each well.

Table 2-2 Acquired White Rose Logs

Well	Date	Acquired Well Logs
L-08	May-99	HALS-LDT-CNL-GR-DSI-EMS, FMI-CMR-NGT, MDT,ZVSP
A-17	Jul-99	HALS-LDT-CNL-GR-DSI-EMS, FMI, AIT-CMR-NGT, MDT, USIT CBT, ZVSP
E-09	Oct-87	PI-SFL, CNL-LDT-GR, DDBHC, HDT, CVL, SAT-ZVSP, RFT
B-19	Sep-05	GR-AIT-PEX-DSI-EMS, GR-MDT
B-07 5	Jan-06	Ecoscope
B-07 2	Feb-02	GR-PEX-AIT-EMS-OBMI, USIT-DSI(VDL)-GPIT-AMS, GR-ARC-ADN
B-07 3	Jan-05	HNGS-AIT-PEX-OBMI, GR-ARC-ADN
E-18 4	Dec-05	EcoScope, GR-ARC-ADN
E-18 2	Apr-05	HNGS-AIT-LDT-PEX-OBMI, GR-ARC-ADN
E-18 6	Oct-06	Ecoscope-Lithotrak-Testrack

Well	Date	Acquired Well Logs
E-18 8	Apr-07	Ecoscope-Stethoscope
B-07 1	Dec-03	GR-AIT-PEX-DSI-EMS, GR-2OBMI, HNGS/MDT, GR-MSCT
B-07 8	Feb-06	GR-PEX through casing, GR-DSI through casing
B-07 9	Feb-05	GR-ARC-ADN
B-07 4	Jan-04	GR-AIT-PEX-DSI-EMS, GR-MDT, 2OBMI-HNGS, VSP
B-07 6	Mar-04	HNGS-AIT-PEX-EMS, GR-MDT
E-18 1	Nov-04	GR-PEX-2OBMI-MDT, HNGS-DSI through casing, VSP through casing
E-18 5	Aug-05	EcoScope, GR-ARC-ADN
E-18 3	Jun-05	GR-ARC-ADN
E-18 7	Jan-07	Ecoscope-Stethoscope
E-18 8	Apr-07	Ecoscope-Stethoscope
E-18 9	Mar 08	GR-AIT-PEX-DSI-EMS, GR-MDT, GR-2OBMI
B-07 10Z	Aug-08	Ecoscope-Stethoscope
B-07 11	Jul-12	GR-ARC-SADN-Stethoscope, Ecoscope-Stethoscope
H-20	Jun-00	HALS-LDT-CNL-GR-DSI-EMS, FMI-ECS-CMR, MDT, CSI-
B-19Z	Oct-05	GR-PEX-AIT-DSI-EMS, GR-MDT, 2OBMI-HNGS
N-22	Sep-84	DLL-MSFL, DI-SFL, CNL-LDT-GR, DDBHC, NGT, RFT, BGT, HDT, CHKST, CET
N-30	Sep-99	HALS-LDT-CNL-GR-DSI-EMS, FMI, AIT-CMR-NGT, MDT,MSCT, USIT-CBT, CSI-VSP
J-221	Apr-04	GR-AIT-PEX-GPIT, EMS, 2OBMI-DSI, GR-MDT
J-222	Aug-07	GR-AIT-PEX-DSI-EMS, GR-MDT, GR-2OBMI
K-03	Dec-07	GR-AIT-PEX-EMS, GR-MDT, VSP, GR-DSI, GR-2OBMI, GR-MSCT
F-04	Aug-03	GR-ARC, HALS-PEX-DSI-EMS, FMI-HNGS-CMRPlus, GR-MDT, GR-MSCT, GR-VSI
F-04Z	Sep-03	GR-ARC, HALS-PEX- EMS-GR-SP, FMI-HNGS-CNL, GR-DSI, GR-MDT
J-49	Sep-85	DLL-MSFL, CNL-LDT-GR, DDBHC, NGT, RFT, BGT, WST-DVSP,
O-28Y	May-06	GR-AIT-PEX-DSI-EMS, GR-MDT, CMR/2OBMI/HNGS, GR-MSCT
O-28X	Jun-06	GR-AIT-PEX-DSI-EMS-APS, GR-MDT, GR-MSCT, VSP
C-30	Jul-07	GR-AIT-PEX-APS-EMS, GR-MDT, GR-MRX
C-30Z	Oct-07	GR-CMRPlus, AIT-PEX-EMS, GR-MDT, GR-DSI-EMS-GPIT, GR-
E-28	Nov-08	GR-AIT-PEX-DSI-EMS, GR-MDT, VIT, PEX-OBMI-GPIT
J-22 3	Jan-09	GR-AIT-PEX, DSI,EMS-GPIT, GR-MDT, USIT
E-18 10	Sept-10	GR-ARC, Ecoscope-Stethoscope
E-18 11	Oct-11	GR-ARC-SADN-Stethescope, GPIT-EMSW-PPC-SS-PPC-GR, GR-

2.3.1.2 Core Data

Significant cores have been recovered from the BNA Formation in the greater White Rose region. Table 2-3 lists the amount of conventional core as well as sidewall cores taken in all wells in the greater White Rose region to date.

Table 2-3 Conventional and Sidewall Cores from the White Rose Region

White Rose Cores			All depths are measured (metres)			
Well	**Core Type**		**Start**	**Finish**	**Recovery**	**Formation**
A-17	Conventional	Core #1	2940.8	3047.0	106.3	Ben Nevis
L-08	Conventional	Core #1	2843.0	2866.5	23.1	Ben Nevis
L-08	Conventional	Core #2	2866.5	2883.5	15.5	Ben Nevis
L-08	Conventional	Core #3	2883.5	2936.6	53.1	Ben Nevis
L-08	Conventional	Core #4	2936.6	3043.6	107.0	Ben Nevis
L-08	Conventional	Core #5	3043.6	3061.9	18.3	Ben Nevis
E-09	Sidewall				31 partial recoveries	Ben Nevis
E-09	Sidewall				122 recovered	Various
H-20	Conventional	Core #1	2916.0	2966.0	50.0	Ben Nevis
H-20	Conventional	Core #2	2966.0	3022.0	54.0	Ben Nevis
H-20	Conventional	Core #3	3022.0	3038.0	12.5	Ben Nevis
N-30	Conventional	Core #1	2954.0	3064.0	110.6	Ben Nevis
N-30	Sidewall				10 recovered	Eastern Shoals
N-22	Sidewall				22 partial recoveries	Ben Nevis
N-22	Sidewall				180 recovered	Various
J-49	Conventional	Core #1	3096.5	3115.1	14.9	Ben Nevis
L-61	Conventional	Core #1	3006.3	3024.6	17.9	Ben Nevis/E. Shoals
L-61	Conventional	Core #2	3257.7	3271.8	13.4	Eastern Shoals
J-91	Sidewall				35 recovered	Nautilus/Ben Nevis
F-04	Conventional	Core #1	2764.0	2818.0	53.3	Ben Nevis
F-04	Conventional	Core #2	2818.0	2873.0	52.4	Ben Nevis
F-04	Sidewall				45 recovered	Various
B-07 1	Sidewall				32 recovered	Ben Nevis
B-07 4	Conventional	Core #1	3844.0	3914.0	67.6	Ben Nevis
B-07 4	Conventional	Core #2	3914.0	3935.7	22.0	Ben Nevis
B-07 4	Conventional	Core #3	3935.7	3982.9	47.2	Ben Nevis/Hibernia
J-22 1	Conventional	Core #1	2780.1	2883.5	103.2	Ben Nevis

White Rose Cores			All depths are measured (metres)			
Well	**Core Type**		**Start**	**Finish**	**Recovery**	**Formation**
E-18 1	Conventional	Core #1	4149.0	4203.0	52.9	Ben Nevis/E. Shoals
O-28Y	Conventional	Core #1	2981.0	3011.8	30.8	Ben Nevis
O-28Y	Sidewall		3373.5	3449.0	25 recovered	Ben Nevis/E. Shoals
O-28X	Conventional	Core #1	3406.4	3427.0	17.2	Ben Nevis
O-28X	Sidewall		3373.5	3447.0	25 recovered	Ben Nevis/E. Shoals
C-30	Conventional	Core#1	3480.0	3527.0	46.0	Ben Nevis
C-30Z	Conventional	Core#1	3530.0	3569.0	38.8	Ben Nevis
C-30Z	Conventional	Core#2	3569.0	3634.8	64.5	Ben Nevis
K-03	Sidewall				25 recovered	Various
E-18 9	Conventional	Core#1	3632.0	3647.0	14.9	Ben Nevis
E-18 9	Conventional	Core#2	3647.0	3738.0	88.3	Ben Nevis
E-28	Conventional	Core#1	3215.0	3123	108	Ben Nevis
E-18 11	Conventional	Core #1	3656.0	3719.3	63.3	Ben Nevis
E-18 11	Conventional	Core #2	3719.3	3727.9	8.6	Ben Nevis
K-15	Sidewall	25 recovered	2323.00	2528.00		Ben Nevis/E. Shoals
K-15	Conventional	Core #1	2335.30	2445.60	95.70	Ben Nevis
G-25 1	Conventional	Core#1	2833.00	2917.80	84.80	Ben Nevis

2.3.2 Calibration and Selection of Petrophysical Inputs

Core data have been used to adjust petrophysical analysis parameters for the effects of overburden compaction, and for the selection of electrical property parameters to be used in the calculation of water saturation. A representative formation water resistivity value has been selected from formation fluids recovered from the White Rose C-30Z in the West White Rose pool.

2.3.2.1 Overburden Compaction Factor

Standard core analysis may incorporate systematic errors because routine porosity and permeability values are measured at low pressures (e.g., 2,758 kPa) under laboratory conditions, which leads to an over-estimation of porosity and permeability under reservoir conditions. At surface conditions, pore volumes tend to expand with the decrease in confining pressure. To account for the impact of overburden pressure, special core analysis (SCAL) was undertaken using core plugs from White Rose A-17 and N-30 wells.

Porosity and permeability measurements were taken using a series of increasing pressures intended to reach up to, and span, reservoir pressures existing in the White Rose field. The resulting data have been trended to extract equations that link a decrease in reservoir porosity and permeability to an increase in overburden or reservoir-equivalent pressures, and to the original porosity and permeability of each sample. These equations provide the basis for adjusting all routine “as measured” lab porosities and permeabilities to those representing the same rock under reservoir conditions.

Figure 2-52 illustrates the relationship between core porosity at low pressure versus core porosity at simulated overburden pressure. Core porosity measurements, measured under laboratory conditions (when applying 400 psi or 2,758 kPa seating pressure), should be adjusted to reservoir equivalent values using the following equation:

$$\phi \ @ \ 30{,}000 \ kPa = 1.0191 \ (\phi \ @ \ 2{,}758 \ kPa) - \ 0.8695$$

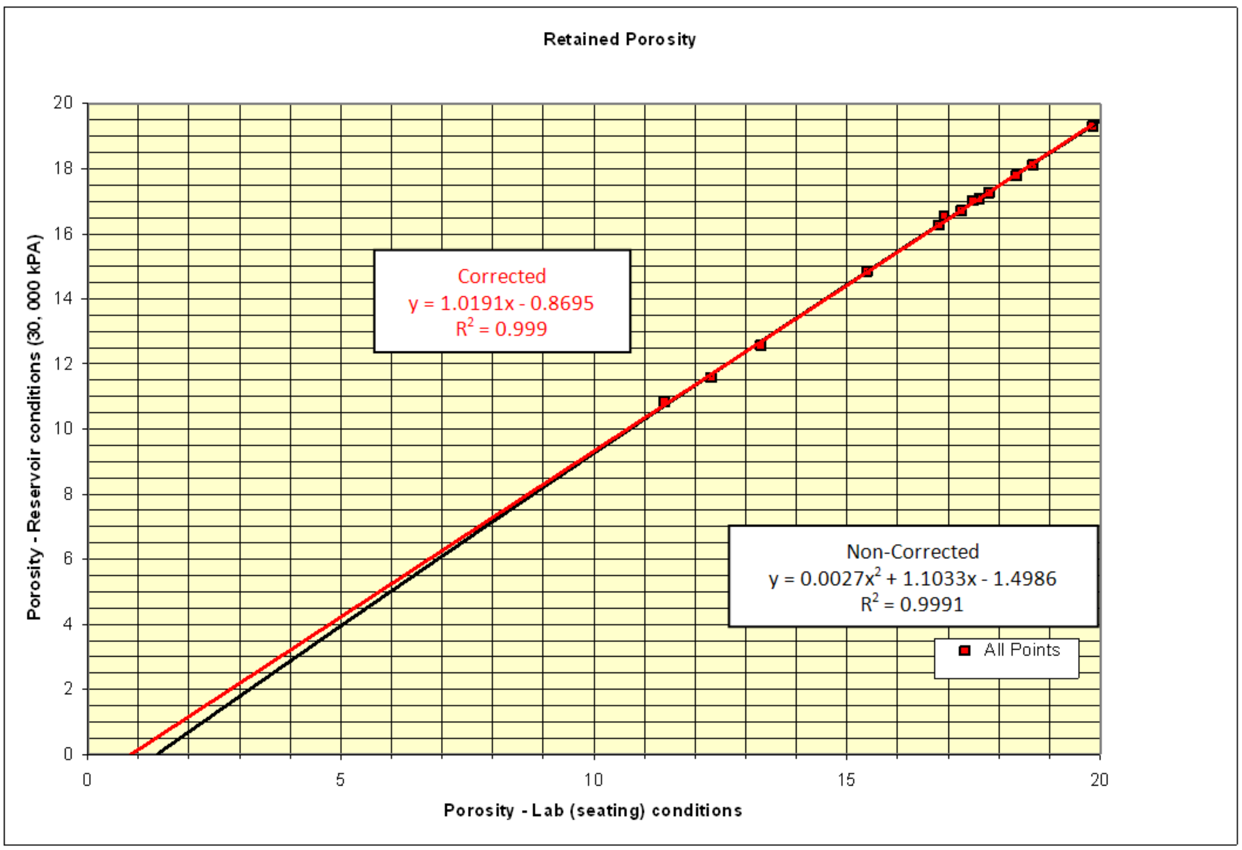


Figure 2-52 Core Porosity Reduction for Application of Simulated Reservoir Pressure

For the samples analyzed, the reservoir porosity averages 96.5 percent of laboratory values. Figure 2-53 illustrates the relationship between core permeability values measured at laboratory pressure and core permeability at simulated overburden pressure. Core permeability measurements, measured under laboratory conditions (when applying 400 psi or 2,758 kPa seating pressure), should be adjusted using the following equation:

$$K \ @ \ 30{,}000 \ kPa = 0.7088 \ (\ K \ @ \ 2{,}758 \ kPa \ )^{1.0442}$$

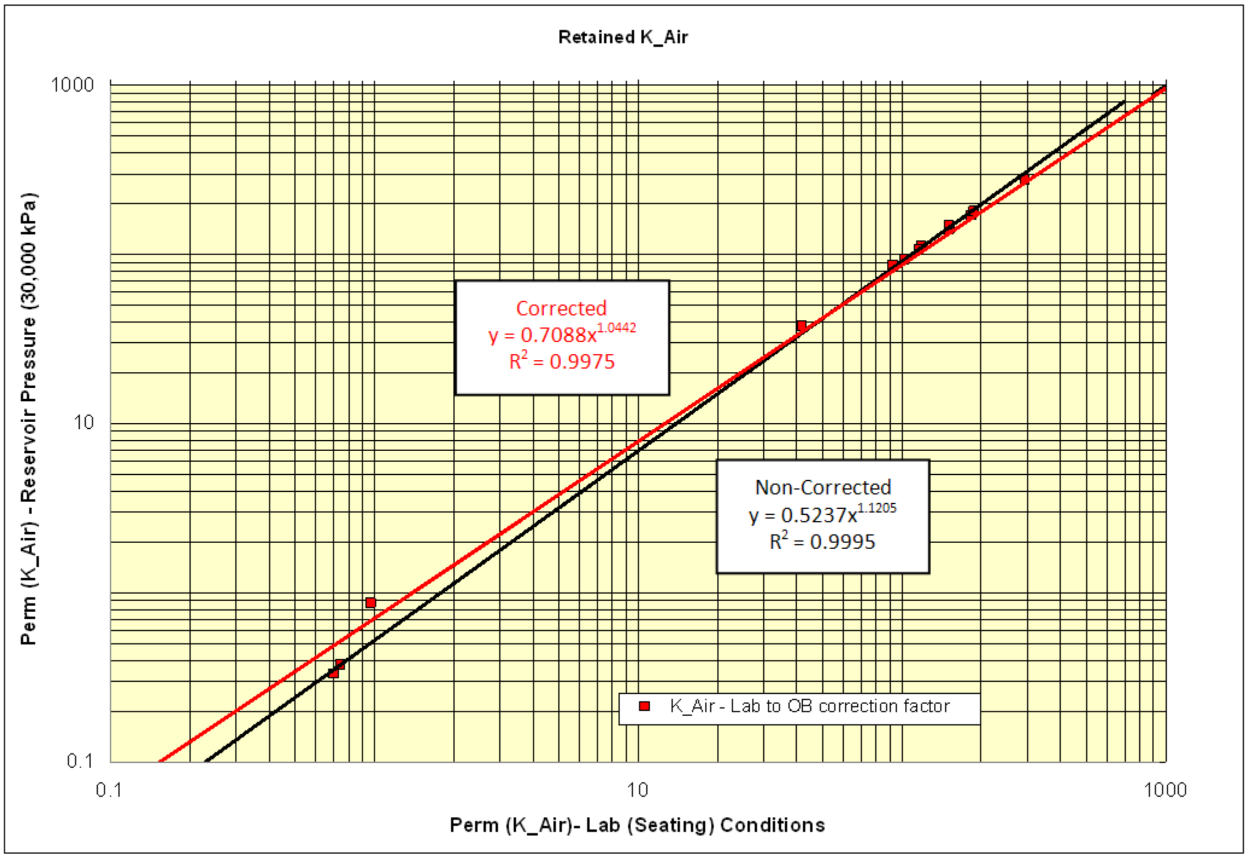


Figure 2-53 Core Permeability Reduction for Application of Simulated Reservoir Pressure

For the samples analyzed, the reservoir permeability averages 87.2 percent of laboratory values.

2.3.2.2 Formation Water Resistivity

The formation water resistivity (Rw) used in the West White Rose pool is Rw=0.14 @ 25°C. This value was determined from the analysis of water sample 1362, as can be seen in Figure 2-54.

HYCAL ENERGY RESEARCH LABORATORIES LTD.

Husky Energy Inc
White Rose Area, Ben Nevis - Avalon Formation
Reservoir Engineering Study
Hycal File #: Q178NE (2007)

APPENDIX A1
WATER COMPOSITIONAL ANALYSIS

Operator:	Husky Energy Inc		
Well Name:	C-30Z	File # :	Q178NE (2007)
Field:	White Rose	Formation:	Ben Nevis - Avalon
Sample Point:	Bottomhole	Date sampled:	Octobre 13, 2007
Container I.D.:	Sample 1362 (BT 6070)	Analysis Lab:	Maxxam

CATIONS			ANIONS		
Ion	mg/L	meq/L	Ion	mg/L	meq/L
Na^{+}	14400	626.37	Cl^{-}	23000	648.75
K^{+}	272	6.96	Br^{-}	0	0.00
Ca^{+2}	1100	54.89	I^{-}	0	0.00
Mg^{+2}	133	10.94	HCO_3^{-}	704	11.54
Ba^{+2}	2.23	0.03	SO_4^{-2}	241	5.02
Sr^{+2}	163	3.72	CO_3^{-2}	0.4	0.01
Fe^{+3}	2.36	0.13	OH^{-}	0.4	0.02
B^{+3}	0	0.00	H_2S	Absent	---
Mn^{+3}	0	0.00			

Total Dissolved Solid (mg/L)

41500	40018
At ignition	Calculated
Total suspended solids (mg/L)	Oil & Grease Content (mg/L)
1.029	1.337
Relative Density @ 25 °C	Refractive Index @ 25 °C
6.86	0.14
Observed pH	Resistivity ohm.m @25°C
3300	577
Total Hardness As $CaCO_3$ (mg/L)	Total Alkalinity As $CaCO_3$ (mg/L)

Logarithmic Patterm of Dissolved Ions, meq/L

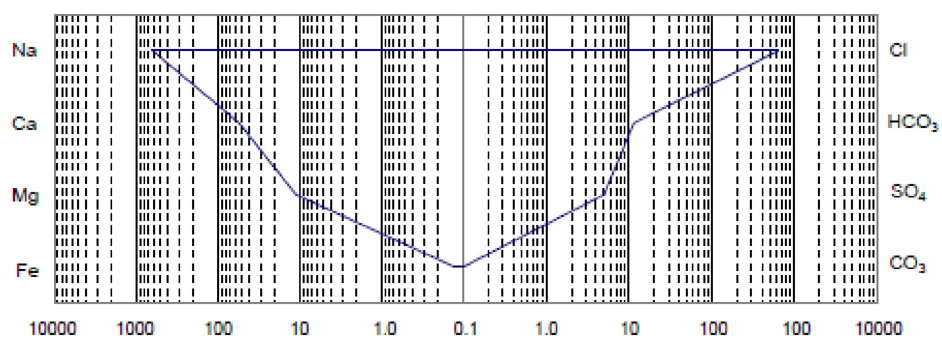


Figure 2-54 Water Analysis for the C-30Z Well

2.3.2.3 Electrical Properties M and N

SCAL was undertaken using the core acquired in the L-08 well in order to determine the correct cementation exponent, "M", and saturation exponent, "N". These exponents are used in determining water saturation values, using the log evaluation software.

The reported average values for M and N, when using an 'A'=1 are:

- Cementation exponent M=1.78
- Saturation exponent N=1.86.

By knowing the M and N values, it is possible to use the Pickett Plot in the known water leg to further validate the formation water resistivity obtained from the selected fluid sample.

2.3.3 Petrophysical Methodology

All wells within the West White Rose region have been evaluated using a deterministic petrophysical evaluation approach to allow for more accurate and consistent analyses.

The petrophysical analysis for the West White Rose pool was re-examined in light of the higher argillaceous content and laminated nature of the BNA Reservoir layers seen in log and core data.

One aspect implemented to fully resolve the portion of the BNA Reservoir seen in laminated sands was to use the high-resolution versions of the log curves available. For example, use of the standard resolution formation density porosity curve (depth step of 0.1524 m), which averages three consecutive density values and outputs the result at the mid-point, was not used in favor of using the high-resolution formation density porosity curve, which outputs a value every 0.0508 m (with no averaging of multiple values).

Overall, the update has provided more representative water saturation in the West White Rose pool. The facies re-determination resulted in a more representative calcite distribution and a better match with core descriptions. The permeability is calculated from the porosity value and the depositional facies identified for that depth (also determined from log data) and applied to the porosity-permeability developed for each of the facies. New summations were generated to identify the impact of the methodology update. The results, identified when reservoir and pay summations were re-run by well, were found to range from no change to moderate increases.

2.3.3.1 Volume of Shale

Quantifying the argillaceous nature of the reservoir in the West White Rose wells was amended to use the Larionov equation for older rocks. This is a two stage equation indicated by:

$$1.\, I\,GR = \frac{\left(GR_{log} - GR_{min}\right)}{GR_{max} - GR_{min}}$$

$$2. V_{sh} = 0.33 * (2^{2*I\,GR-1})$$

2.3.3.2 Effective Porosity

The effective porosity was calculated from the density porosity log corrected for shale volume, using the shale density of 2,620 kg/m^3 (from log results) and the matrix density of 2,650 kg/m^3 (confirmed in core data). Fluid density used in this workflow was that of the near wellbore fluid phase (drilling fluid filtrate), with a density of 820 kg/m^3. A correction for light hydrocarbon effect was made in reservoir intervals existing in the gas column. This criterion is captured in the effective porosity equation below:

$$\phi_e = \left(\frac{\rho_{matrix} - \rho}{\rho_{matrix} - \rho_{fluid}}\right) - V_{sh}\left(\frac{\rho_{shale} - \rho}{\rho_{matrix} - \rho_{fluid}}\right)$$

2.3.3.3 Water Saturation

Given the inter-bedded shaly sand nature of the BNA reservoir in the West White Rose pool, the Indonesia equation, seen below, was used for the water saturation calculation. The electrical properties used (A=1, M=1.78, N=1.86), as before, have come from the SCAL work completed on the L-08 well.

$$\frac{1}{R_t} = \left[\sqrt{\frac{\phi^m}{a * R_w}} + \frac{V_{sh}^{\frac{1-V_{sh}}{2}}}{\sqrt{R_{sh}}}\right] * S_w^{\frac{n}{2}}$$

2.3.3.4 Permeability

In addition to the refinement of effective porosity calculations, plugged full diameter and sidewall cores were used to create porosity-permeability equations by facies. The distribution of those cores throughout the BNA stratigraphic interval in the West White Rose pool is shown in Figure 2-55.

Figure 2-56 demonstrates the core porosity-permeability relationship by facies, based on both full diameter and sidewall cores.

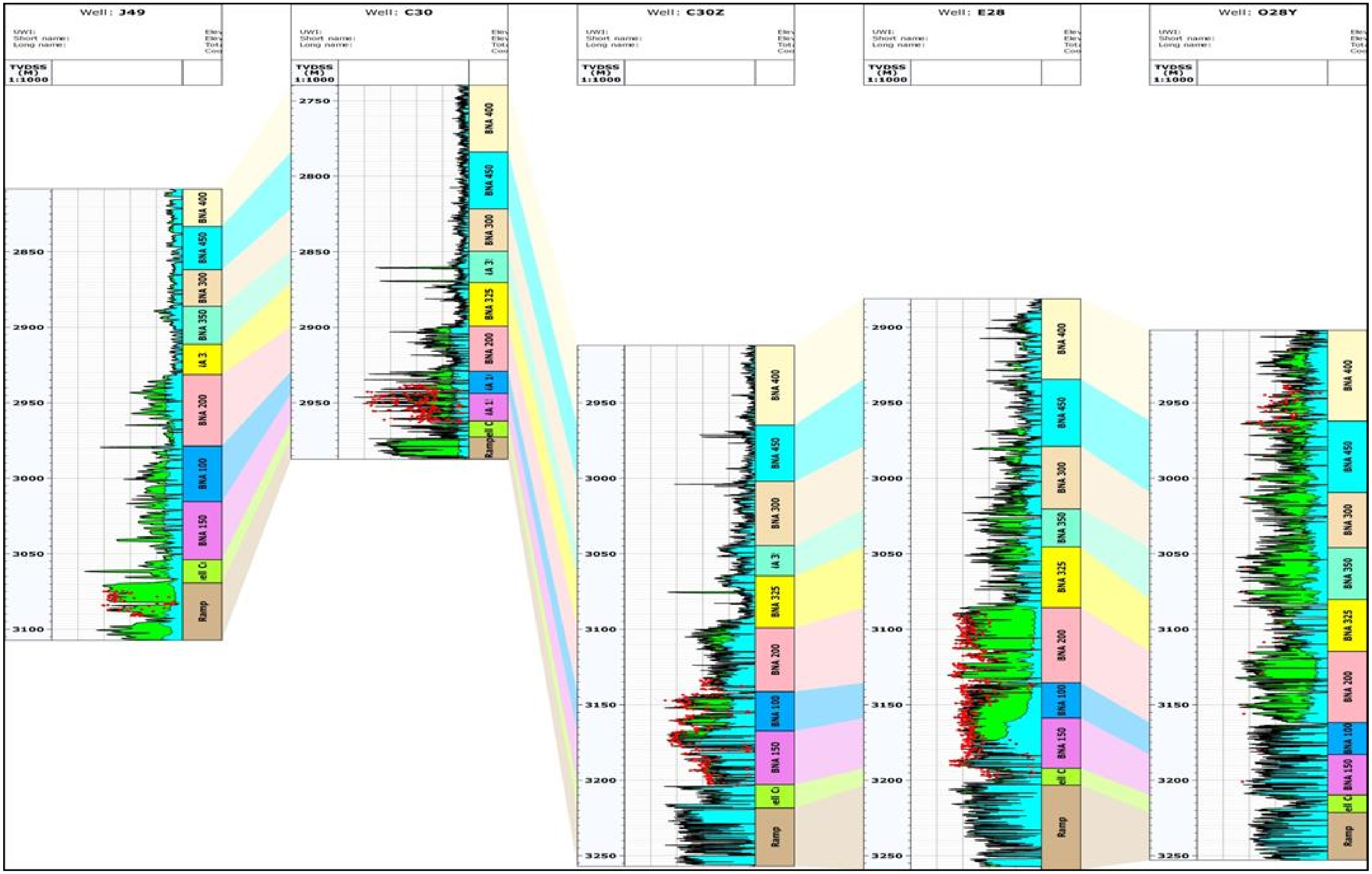


Figure 2-55 Sidewall and Full Diameter Core Distribution by Stratigraphic Level

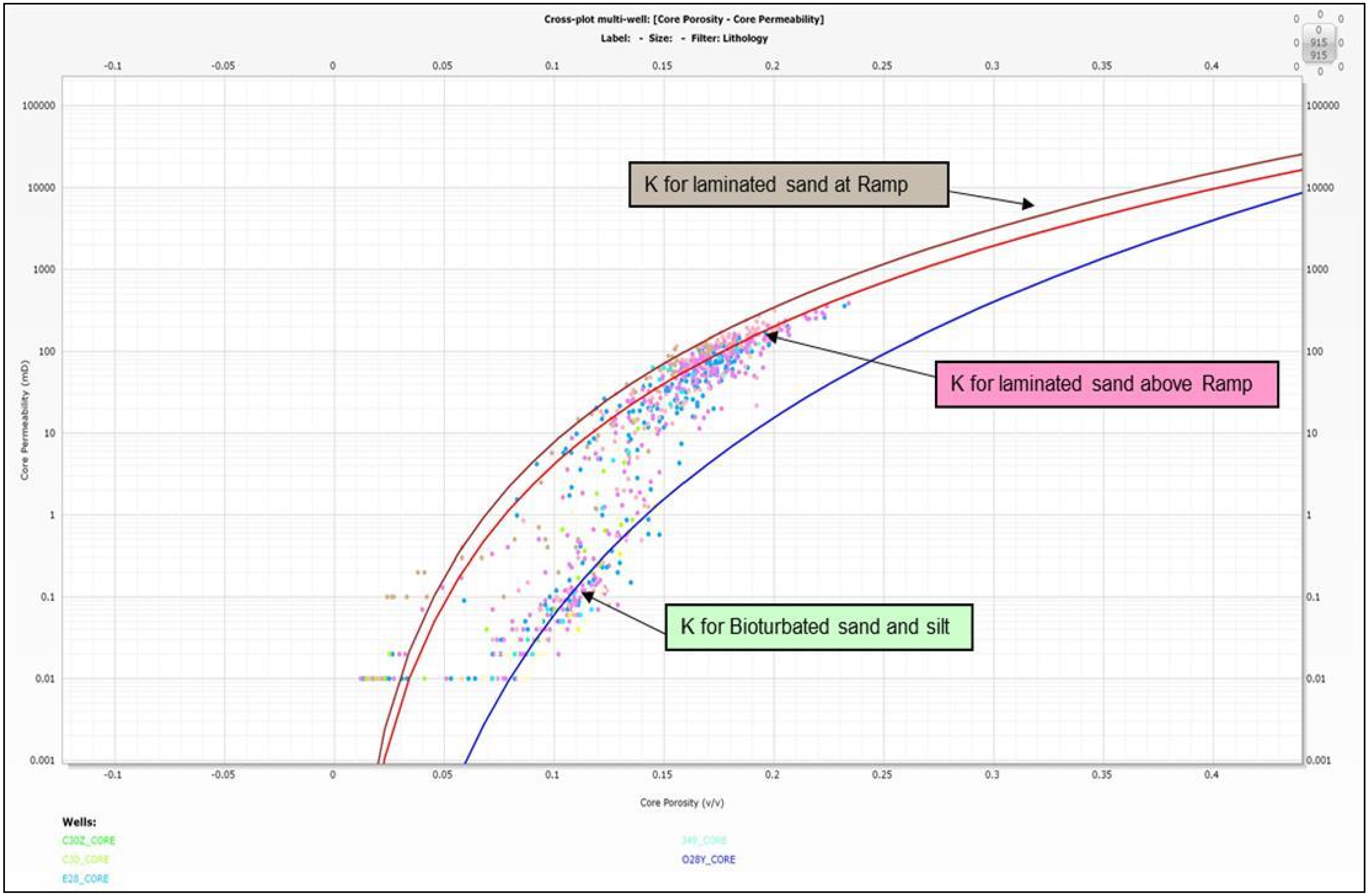


Figure 2-56 Core Data Phi/K Relationships by Depositional Facies

Ultimately, the permeability was calculated from the porosity and given facies assignment using the permeability regression equations shown in Figure 2-57 and displayed graphically in Figure 2-56.

Facies	Permeabilty Regression
Laminated Sand at Ramp	log10(CorePermeability) = + 5.466322 * log10(Core Porosity) + 6.357672
Laminated sand above Ramp	log10(Core Permeability) = + 5.591513 * log10(Core Porosity) + 6.211633
Bioturbated Sand and Silt	log10(Core Permeability) = + 4.875754 * log10(Core Porosity) + 4.40549

Figure 2-57 Core Data Phi/K Equations by Depositional Facies

2.3.3.5 Petrofacies Determination

The petrofacies definition for the West White Rose pool was determined using the porosity-volume of shale crossplot. The facies determination cutoffs are presented in Figure 2-58.

Rock Type	Lithology Code	Determination cutoff
Calcite Cement		VSH< 30 and PHIE< 5
Bioturbated sand		VSH< 30 and 5<PHIE< 10
Laminated Sand		VSH< 30 and PHIE>10
Bioturbated Silt		VSH> 30 and VSH< 70
Shale		VSH>70

Figure 2-58 Petrophysical Criteria - Depositional Facies

2.3.3.6 Reservoir and Net Pay Cutoffs

The reservoir and pay cutoffs for the West White Rose region have been updated to reflect the following:

Reservoir Cut-offs

Permeability	Cut-off 3 md	for oil and water reservoir
Permeability	Cut-off 0.5 md	for gas reservoir

Pay Cut-offs

Permeability	Cut-off 3 md	for oil and water reservoir
Permeability	Cut-off 0.5 md	for gas reservoir
Water saturation	Cut-off 50 percent	

2.3.4 Petrophysical Summaries

Analysis methodology has improved over time in the White Rose region. Subsequently, as reservoir understandings have evolved and additional learnings have been realized, petrophysical outputs and summations have also changed. Each phase of development has been based on the current petrophysical best practices at the time, which have been transferred to the latest and current version of summations for the White Rose region, as seen in Table 2-4 to Table 2-8.

Table 2-4 Petrophysical Summary for the Gas Leg Intervals

	Gas Leg						
	Well	Type	Top Depth (m TVDss)	Gross Thickness (m)	Net:Gross	Porosity (%)	Permeability (mD)
South Avalon	A-17	Delineation	2854.40	19.5	0.200	15.0	91.3
	B-07 1	Injector	2758.53	113.0	0.420	16.3	139.5
	B-07 2	Producer	NA	NA	NA	NA	NA
	B-07 3	Producer	NA	NA	NA	NA	NA
	B-07 4	Injector	2752.46	157.5	0.480	16.0	125.5
	B-07 5	Producer	NA	NA	NA	NA	NA
	B-07 6	Injector	2819.03	66.0	0.010	12.5	33.7
	B-07 8	Injector	2851.88	20.5	0.230	11.5	25.0
	B-07 9	Injector	NA	NA	NA	NA	NA
	B-07 10Z	Producer	NA	NA	NA	NA	NA
	B-07 11	Producer	NA	NA	NA	NA	NA
	B-19	Delineation	2779.50	94.0	0.270	14.0	68.2
	E-09	Delineation	2784.00	82.0	0.220	13.4	41.0
	E-18 1	Injector	NA	NA	NA	NA	NA
	E-18 2	Producer	NA	NA	NA	NA	NA
	E-18 3	Injector	NA	NA	NA	NA	NA
	E-18 4	Producer	NA	NA	NA	NA	NA
	E-18 5	Injector	NA	NA	NA	NA	NA
	E-18 6Z	Producer	NA	NA	NA	NA	NA
	E-18 7	Injector	NA	NA	NA	NA	NA
	E-18 8	Producer	NA	NA	NA	NA	NA
	E-18 9	Injector	2789.75	84.0	0.270	14.0	40.0
	L-08	Delineation	2771.20	102.0	0.460	15.6	92.6
Blocks 2 and 5	B-19Z	Delineation	2857.20	43.6	0.140	12.8	34.7
	H-20	Delineation	2807.10	0.2	0.002	13.0	13.9
North Avalon	J-22 1	Gas Injector	2589.70	159.7	0.280	18.0	189.1
	J-22 2	Gas Injector	2508.52	269.5	0.128	16.2	80.0
	N-22	Exploration	2414.19	245.3	0.192	15.1	13.0
	N-30	Delineation	2742.60	57.8	0.212	15.5	81.2
WWRX	C-30	Delineation	2740.92	246.1	0.128	15.1	104.7
	C-30Z	Delineation	NA	NA	NA	NA	NA
	E-28	Delineation	NA	NA	NA	NA	NA
	J-22 3	Gas Injector	2686.42	257.3	0.101	14.2	77.8
	J-49	Delineation	2808.48	260.3	0.041	13	40.1
	O-28X	Delineation	NA	NA	NA	NA	NA
	O-28Y	Delineation	NA	NA	NA	NA	NA
	E-18 10	Pilot Producer	NA	NA	NA	NA	NA
	E-18 11	Pilot Injector	NA	NA	NA	NA	NA

Table 2-5 Petrophysical Summary for the Oil Leg Intervals

	Oil Leg						
	Well	**Type**	**Top Depth (m TVDss)**	**Gross Thickness (m)**	**Net:Gross**	**Porosity (%)**	**Permeability (mD)**
South Avalon	A-17	Delineation	2874.40	125.3	0.740	16.4	99.0
	B-07 1	Injector	2871.53	113.8	0.800	16.5	140.5
	B-07 2	Producer	NA	1102.0	0.800	16.0	140.5
	B-07 3	Producer	NA	1075.0	0.910	17.0	170.0
	B-07 4	Injector	2858.94	131.5	0.760	17.0	156.0
	B-07 5	Producer	NA	1447.0	0.850	17.8	146.0
	B-07 6	Injector	2871.99	106.8	0.780	17.0	172.0
	B-07 8	Injector	2871.54	122.0	0.810	15.2	103.0
	B-07 9	Injector	NA	NA	NA	NA	NA
	B-07 10Z	Producer	NA	811.0	0.700	15.0	83.0
	B-07 11	Producer	NA	1130.0	0.829	16.7	119.9
	B-19	Delineation	2871.90	129.4	0.740	16.0	114.6
	E-09	Delineation	2869.40	138.2	0.730	16.0	72.6
	E-18 1	Injector	NA	110.5	0.760	16.0	94.9
	E-18 2	Producer	NA	2071.6	0.860	17.0	140.0
	E-18 3	Injector	NA	NA	NA	NA	NA
	E-18 4	Producer	NA	1247.0	0.880	17.0	140.0
	E-18 5	Injector	NA	NA	NA	NA	NA
	E-18 6Z	Producer	NA	1697.2	0.795	16.4	115.0
	E-18 7	Injector	NA	NA	NA	NA	NA
	E-18 8	Producer	NA	1044.5	0.644	14.7	72.5
	E-18 9	Injector	2873.80	130.0	0.740	16.0	78.0
	L-08	Delineation	2872.00	137.7	0.830	17.0	133.0
Blocks 2 and 5	B-19Z	Delineation	2893.60	128.0	0.390	15.4	86.9
	H-20	Delineation	2872.10	4.5	0.030	17.0	86.9
North Avalon	J-22 1	Gas Injector	NA	NA	NA	NA	NA
	J-22 2	Gas Injector	NA	NA	NA	NA	NA
	N-22	Exploration	NA	NA	NA	NA	NA
	N-30	Delineation	3014.00	10.2	0.693	16.0	91.9
WWRX	C-30	Delineation	NA	NA	NA	NA	NA
	C-30Z	Delineation	2872.47	300.3	0.051	15.2	53.3
	E-28	Delineation	2880.01	293.5	0.336	15.1	58.4
	J-22 3	Gas Injector	NA	NA	NA	NA	NA
	J-49	Delineation	3068.81	43.5	0.650	14.7	84.2
	O-28X	Delineation	3067.07	70.0	0.009	15.5	75.1
	O-28Y	Delineation	2890.60	276.5	0.426	14.7	53.2
	E-18 10	Pilot Producer	NA	1611.0	0.593	14.9	53.7
	E-18 11	Pilot Injector	2918.95	251.1	0.190	0.1	44.6

Table 2-6 Petrophysical Summary for the Water Leg Intervals

	Water Leg						
	Well	Type	Top Depth (m TVDss)	Gross Thickness (m)	Net:Gross	Porosity (%)	Permeability (mD)
South Avalon	A-17	Delineation	3000.00	58.0	0.710	16.0	85.0
	B-07 1	Injector	NA	NA	NA	NA	NA
	B-07 2	Producer	NA	NA	NA	NA	NA
	B-07 3	Producer	NA	NA	NA	NA	NA
	B-07 4	Injector	NA	NA	NA	NA	NA
	B-07 5	Producer	NA	NA	NA	NA	NA
	B-07 6	Injector	2998.45	66.5	0.650	16.7	157.0
	B-07 8	Injector	2992.62	42.3	0.700	14.7	87.0
	B-07 9	Injector	NA	454.9	0.750	16.5	144.8
	B-07 10Z	Producer	NA	NA	NA	NA	NA
	B-07 11	Producer	NA	NA	NA	NA	NA
	B-19	Delineation	2999.90	100.5	0.740	15.6	91.4
	E-09	Delineation	3008.30	111.5	0.750	15.0	69.0
	E-18 1	Injector	2840.42	242.0	0.780	16.0	91.6
	E-18 2	Producer	NA	NA	NA	NA	NA
	E-18 3	Injector	NA	1020.0	0.750	15.6	94.2
	E-18 4	Producer	NA	NA	NA	NA	NA
	E-18 5	Injector	NA	859.1	0.834	15.7	94.0
	E-18 6Z	Producer	NA	NA	NA	NA	NA
	E-18 7	Injector	NA	1028.5	0.850	15.5	92.0
	E-18 8	Producer	NA	NA	NA	NA	NA
	E-18 9	Injector	3003.72	99.0	0.750	14.5	47.0
	L-08	Delineation	3009.00	63.0	0.670	14.6	68.0
Blocks 2 and 5	B-19Z	Delineation	3004.81	191.6	0.770	16.0	110.7
	H-20	Delineation	3003.20	114.0	0.480	15.0	46.0
North Avalon	J-22 1	Gas Injector	NA	NA	NA	NA	NA
	J-22 2	Gas Injector	NA	NA	NA	NA	NA
	N-22	Exploration	NA	NA	NA	NA	NA
	N-30	Delineation	NA	NA	NA	NA	NA
WWRX	C-30	Delineation	NA	NA	NA	NA	NA
	C-30Z	Delineation	3172.77	83.0	0.631	14.6	69.2
	E-28	Delineation	3173.53	83.8	0.719	14.6	73.1
	J-22 3	Gas Injector	NA	NA	NA	NA	NA
	J-49	Delineation	NA	NA	NA	NA	NA
	O-28X	Delineation	NA	NA	NA	NA	NA
	O-28Y	Delineation	3167.09	111.5	0.551	14.3	51.7
	E-18 10	Pilot Producer	NA	NA	NA	NA	NA
	E-18 11	Pilot Injector	3170.05	93.7	0.744	14.1	42.4

Table 2-7 Petrophysical Summary for the Entire BNA Interval

	Total Ben Nevis Interval						
	Well	**Type**	**Top Depth (m TVDss)**	**Gross Thickness (m)**	**Net:Gross**	**Porosity (%)**	**Permeability (mD)**
South Avalon	A-17	Delineation	2854.50	203.1	0.700	16.1	92.4
South Avalon	B-07 1	Injector	2758.53	226.3	0.062	16.3	140.5
South Avalon	B-07 2	Producer	NA	1102.0	0.800	16.0	140.5
South Avalon	B-07 3	Producer	NA	1075.0	0.910	17.0	170.0
South Avalon	B-07 4	Injector	2752.46	285.5	0.062	16.5	145.5
South Avalon	B-07 5	Producer	NA	NA	NA	NA	NA
South Avalon	B-07 6	Injector	2819.03	234.7	0.560	16.9	162.0
South Avalon	B-07 8	Injector	2851.88	186.3	0.170	15.0	96.8
South Avalon	B-07 9	Injector	NA	454.9	0.750	16.5	144.8
South Avalon	B-07 10Z	Producer	NA	811.0	0.700	15.0	83.0
South Avalon	B-07 11	Producer	NA	1130.0	0.829	16.7	119.9
South Avalon	B-19	Delineation	2779.50	330.0	0.640	15.7	96.5
South Avalon	E-09	Delineation	2784.00	335.9	0.630	14.6	66.3
South Avalon	E-18 1	Injector	2840.42	242.0	0.780	16.0	91.6
South Avalon	E-18 2	Producer	NA	2071.6	0.860	17.0	140.0
South Avalon	E-18 3	Injector	NA	1020.0	0.750	15.6	94.2
South Avalon	E-18 4	Producer	NA	1247.0	0.880	17.0	140.0
South Avalon	E-18 5	Injector	NA	859.1	0.834	15.7	94.0
South Avalon	E-18 6Z	Producer	NA	1697.2	0.795	16.4	115.0
South Avalon	E-18 7	Injector	NA	1028.5	0.850	15.5	92.0
South Avalon	E-18 8	Producer	NA	1044.5	0.644	14.7	72.5
South Avalon	E-18 9	Injector	2789.75	313.0	0.650	15.0	47.6
South Avalon	L-08	Delineation	2771.20	300.9	0.710	16.3	109.8
Blocks 2 and 5	B-19Z	Delineation	2857.80	362.4	0.630	15.5	95.0
Blocks 2 and 5	H-20	Delineation	2807.10	433.0	0.340	15.1	47.9
North Avalon	J-22 1	Gas Injector	2589.70	159.7	0.280	18.0	189.1
North Avalon	J-22 2	Gas Injector	2508.52	269.5	0.128	16.2	80.0
North Avalon	N-22	Exploration	2414.19	245.3	0.192	15.1	13.0
North Avalon	N-30	Delineation	2742.60	286.1	0.238	15.6	82.8
WWRX	C-30	Delineation	2740.92	246.1	0.128	15.1	104.7
WWRX	C-30Z	Delineation	2872.47	383.3	0.238	14.4	58.1
WWRX	E-28	Delineation	2880.01	377.3	0.451	14.8	61.4
WWRX	J-22 3	Gas Injector	2686.42	257.3	0.101	14.2	77.8
WWRX	J-49	Delineation	2808.48	303.8	0.133	14.1	69.8
WWRX	O-28X	Delineation	3067.07	70.0	0.012	15.0	62.2
WWRX	O-28Y	Delineation	2890.60	390.0	0.540	14.1	46.5
WWRX	E-18 10	Pilot Producer	NA	1611.0	0.593	14.9	53.7
WWRX	E-18 11	Pilot Injector	2918.95	344.8	0.366	13.8	40.8

Table 2-8 Petrophysical Summary for H-70 and H-70Z

	Ben Nevis Ramp Interval						
H-70	**Well**	**Type**	**Top Depth (m TVDss)**	**Gross Thickness (m)**	**Net:Gross**	**Average Porosity (%)**	**Average Permeability (mD)**
	H-70	Delineation	3,088.97	25.800	0.524	0.150	79.146
	H-70Z	Delineation	3,383.93	509.280	0.666	0.132	22.419
*Please note that H-70 is not part of the development, nor is it reachable by the WHP.							

3.0 RESERVOIR ENGINEERING

The following section provides a reservoir engineering overview on a pool by pool basis. The West White Rose pool is the primary pool to be accessed by the WHP and will be addressed first. In addition, the South Avalon and North Avalon pools, which are located within reach of the WHP, are considered as potential WHP resources for development.

3.1 West White Rose

3.1.1 Reservoir Pressures

Reservoir pressures in the West White Rose pool are defined by hydrocarbon contacts and gradients encountered in a number of the exploration and delineation wells in the area.

Table 3-1 summarizes the fluid contacts encountered in each well within the West White Rose pool based upon log measurements. An oil-water contact of -3,170 m TVDss has been assumed for the West White Rose pool. A gas-oil contact of -3,069 m TVDss has been assumed within the J-49 region and a gas-oil contact of -3,085 m TVDss has been assumed within the C-30 region based upon acquired Modular Dynamic Tester (MDT) pressure data and known fluid gradients within the West White Rose pool.

Table 3-1 West White Rose Fluid Contacts (Log-based Measurements)

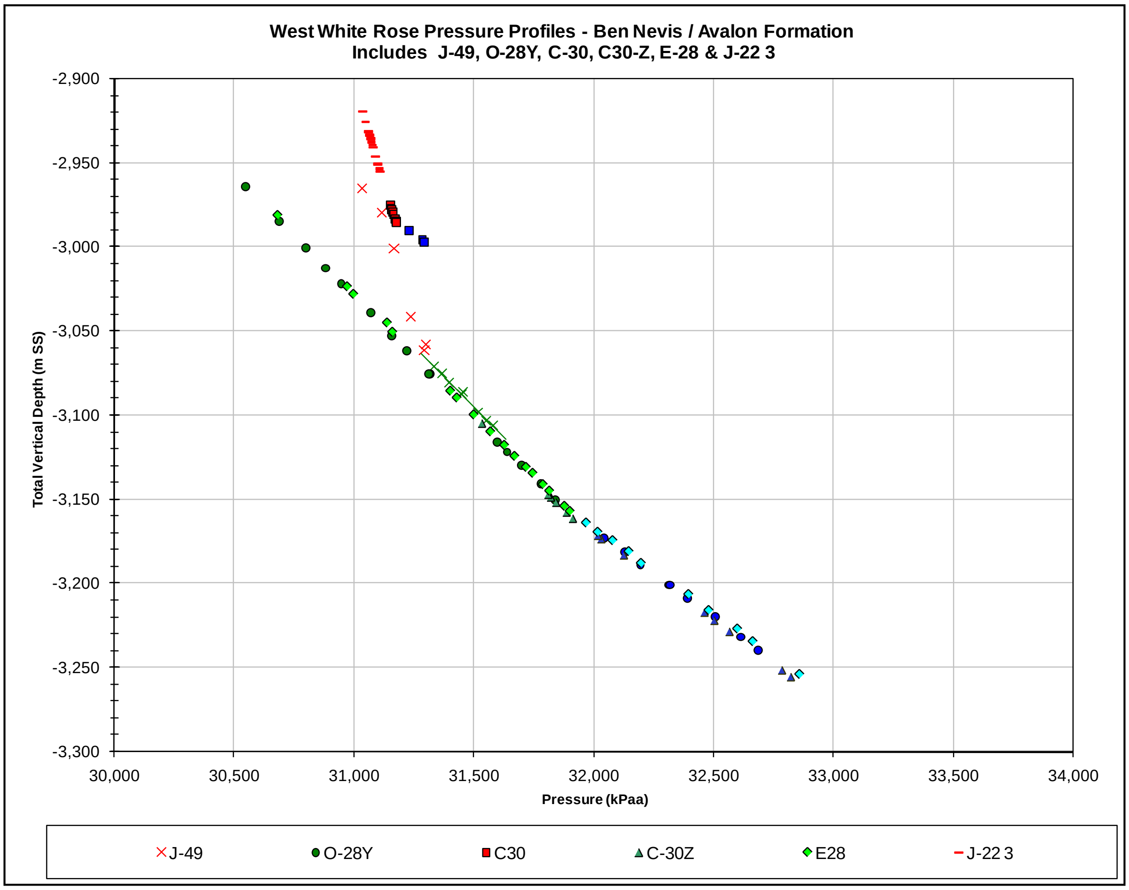
Well	Contact	Subsea Depth(m TVDss)
E-18 10	All oil, no fluid contact encountered	
E-18 11	Oil/water	3,170.1
E-28	Oil/water	3,173.5
O-28 Y	Oil/ water	3,167.1
C-30	All gas, no fluid contact encountered	
C-30Z	Oil/water	3,172.8
J-49	Gas/oil	3,068.8
J- 22 3	Gas injector, no fluid contact encountered	

Table 3-2 presents the West White Rose pool fluid gradients as determined through MDT data.

Table 3-2 West White Rose Fluid Gradients

Well	Reservoir Gas Gradient (kPa/m)	Reservoir Oil Gradient (kPa/m)	Reservoir Water Gradient (kPa/m)	PVT Live Oil Gradient (kPa/m)
E-18 10	N/A	6.83	N/A	N/A
E-18 11	N/A	N/A	N/A	N/A
E-28	N/A	7.24	9.82	7.20
O-28Y	N/A	6.90	9.70	7.19
C-30	2.50	N/A	N/A	N/A
C-30Z	N/A	6.74	9.66	7.48
J-49	1.78	6.85	N/A	N/A
J-22-3	2.11	N/A	N/A	N/A

The pressure elevation plot for the West White Rose pool is illustrated in Figure 3-1.



Note: Symbol shapes in the legend indicate the well from which the pressure data were acquired; symbol color indicates the fluid type (i.e., red – gas, green – oil, blue – water).

Figure 3-1 West White Rose Pressure Elevation Plot

3.1.2 Reservoir Temperatures

Early estimates of reservoir temperature in the West White Rose pool were made based on logging tools from delineation wells in the area. The wells considered were O-28X, O-28Y, C-30, C-30Z and E-28. The expected temperature range from these early estimates was from 110°C to 117°C.

The most accurate reservoir temperature data available at this time are from the start-up of the west pilot producer, E-18 10 and water injector, E-18 11. As shown in Figure 3-2, the downhole temperatures range from 108°C to 115°C, corresponding closely to the estimated temperatures from the delineation wells. Similarly, Figure 3-3 depicts the temperature gradient observed in the West White Rose Pool.

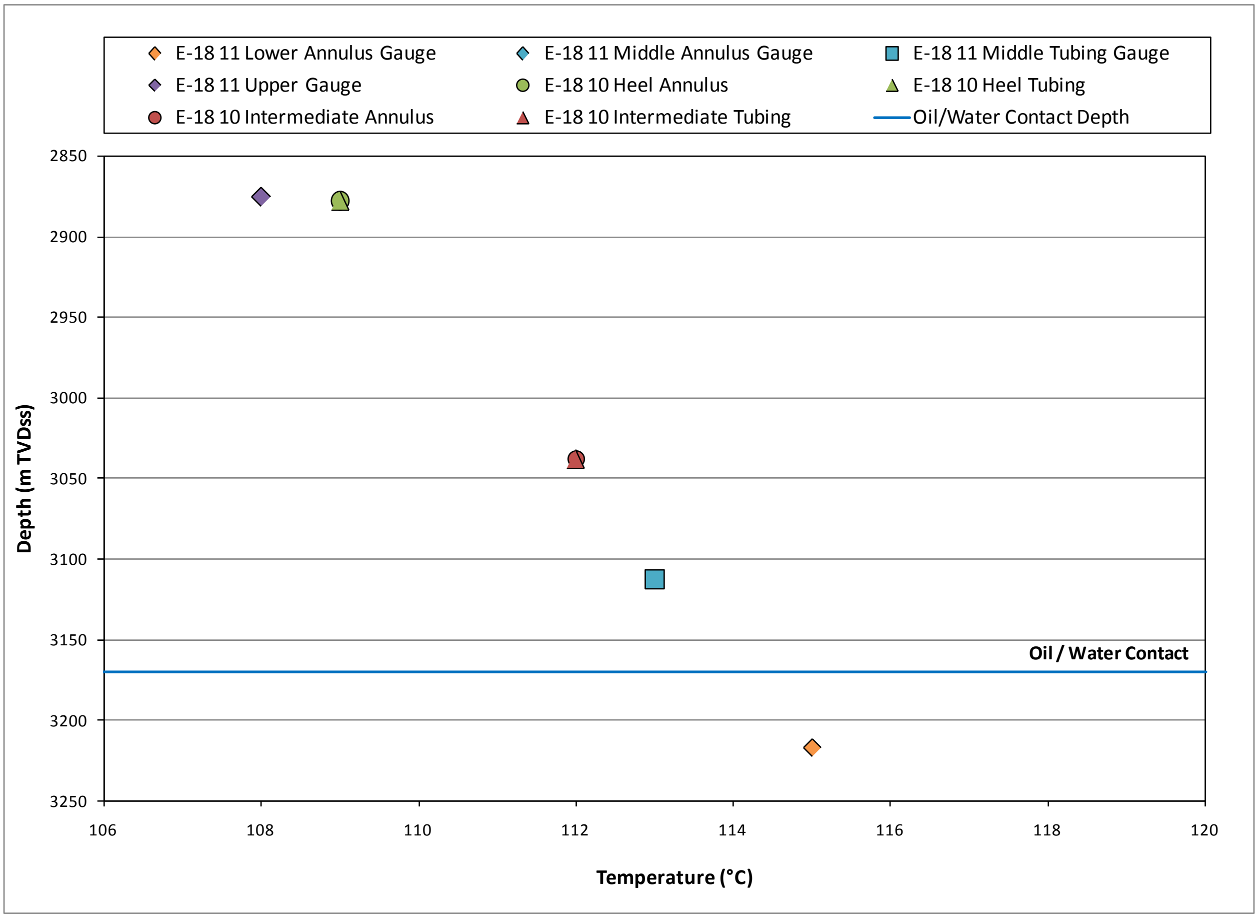


Figure 3-2 West White Rose Pilot Pair Gauge Temperature vs. Depth

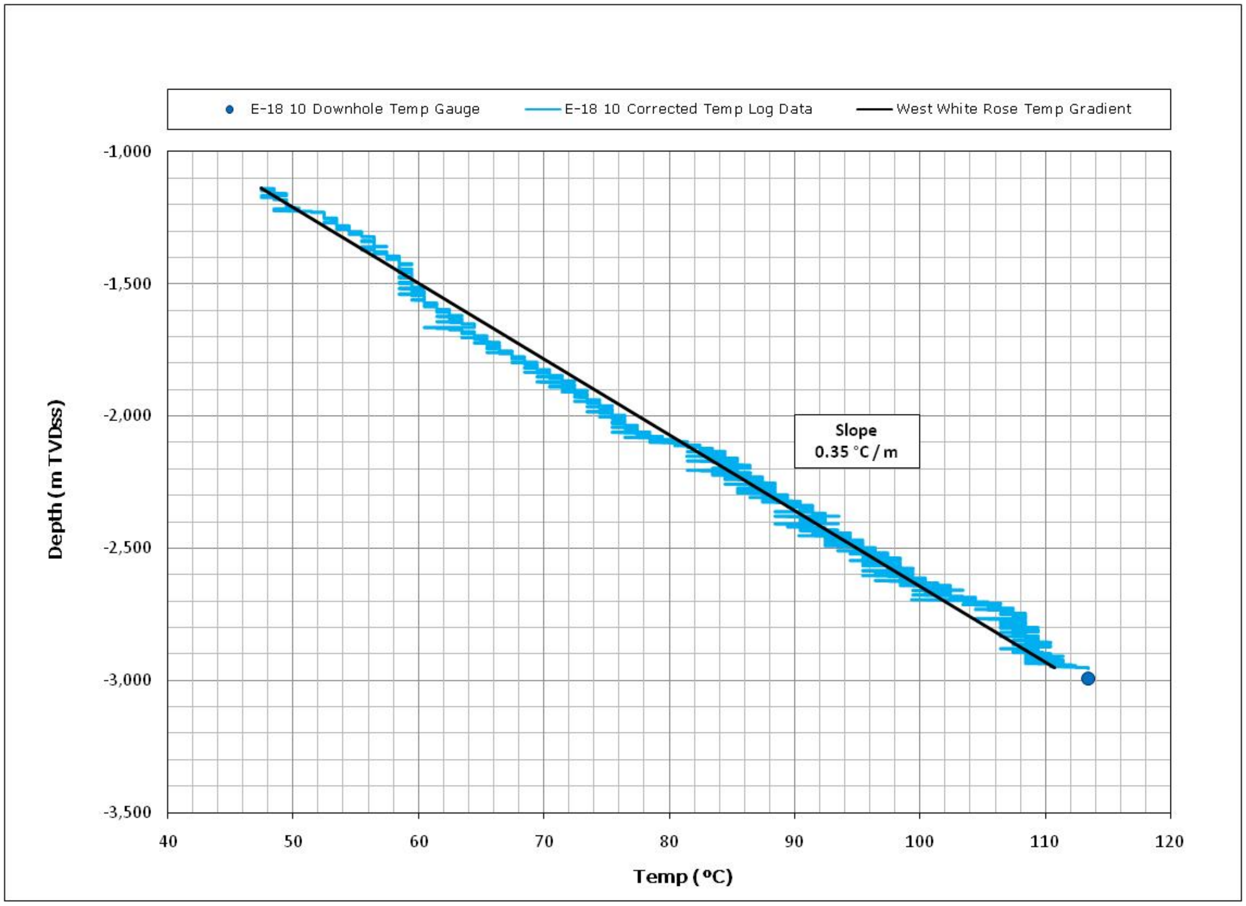


Figure 3-3 West White Rose Temperature Gradient

3.1.3 Fluid Characterization

Reservoir fluid samples were obtained in the O-28Y, C-30, C-30Z, E-28 and J-22 3 wells and detailed pressure, volume, temperature (PVT) analysis for the gas, oil and water samples were conducted. Table 3-3 provides a summary of the PVT analysis that has been conducted to date for wells in the West White Rose pool.

The PVT analysis conducted on the O-28Y oil sample 1365 was selected as the representative oil sample for the West White Rose simulation model. As measured in the laboratory, sample 1365 had a gas-oil ratio (GOR) of 127 m^3/m^3, a saturation pressure of 29,710 kPa and an initial formation volume factor (FVF) of 1.356 m^3/m^3. After correcting for separator flash conditions and mud contamination, the PVT properties adjusted for simulation are presented in Table 3-4.

Table 3-3 West White Rose Pool PVT Analysis

Well	Analysis	Sample No.
J-49	Differential Liberation	DST #6
C-30	Constant Volume Depletion	1360
C-30Z	Differential Liberation, CCE	1238
C-30Z	Multi-Stage Separator Analysis	1238
C-30Z	Water Analysis	1203 and 1362
E-28	Water Analysis	2863
E-28	Differential Liberation, CCE	1209, 1358
O-28Y	Differential Liberation, CCE	1365, 1206 and 1358
O-28Y	Multi-stage Separator Analysis	1365, 1206 and 1358

Table 3-4 West White Rose PVT for O-28Y (Sample 1365)

Pressure (bara)	Bo(A) (Rm^3/Sm^3)	Rs(B) (Sm^3/Sm^3)	Oil Viscosity (cp)		Pressure (bara)	Bg(C) (Rm^3/Sm^3)	Gas Viscosity (cp)
0.9	1.0440	0.0	2.23		1.0	1.34436	0.0133
11.2	1.0729	6.1	1.76		13.2	0.10110	0.0135
21.6	1.0867	10.6	1.55		25.5	0.05158	0.0137
56.1	1.1119	23.3	1.30		49.9	0.02539	0.0142
90.5	1.1380	35.9	1.10		86.6	0.01398	0.0154
125.0	1.1631	48.7	0.94		123.3	0.00952	0.0170
159.5	1.1902	62.5	0.82		159.9	0.00726	0.0189
193.9	1.2210	75.0	0.74		196.6	0.00596	0.0211
228.4	1.2529	90.8	0.68		233.3	0.00515	0.0234
262.9	1.2921	105.5	0.63		269.9	0.00460	0.0257
297.1	1.3420	118.1	0.59		297.1	0.00430	0.0274

(A) oil formation volume factor
(B) gas/oil ratio
(C) gas formation volume factor

A comparison of the results of the fluid analysis conducted on wells in the West White Rose pool to those of the South Avalon pool suggests that the fluids in the West White Rose pool are consistent.

PVT analysis was also conducted on gas samples from the C-30 and J-22 3 wells. The PVT properties of the gas interval at C-30 are very similar to other gas samples obtained in the White Rose field. The PVT fluid study results for gas in C-30 and J-22 3 are summarized in Table 3-5.

Table 3-5 West White Rose Gas PVT

	C-30	J-22 3
Sample Type	**Bottom Hole - MDT**	**Bottom Hole - MDT**
Sample ID	MPSR 1360	MPSR 3241
Sample Depth (m MD)	3,568	5,683
Mud System	SBM	SBM
Reservoir Pressure (kPa)	31,160	30,926
Reservoir Temp (°C)	110	110
Dew Point (kPa)	30,320	33,667
Z Factor*	0.9362	0.9790
Viscosity (cP)*	0.0265	
Density (g/cm^3)*	0.2263	0.2366
MW	22.25	21.3
CGR ($m^3/10^6\ m^3$)	218.42	199.79
CGR (stb/mmscf)	38.90	35.47
Mole Fraction:		
N_2	0.0053	0.0032
CO_2	0.0161	0.0161
H_2S	0.0000	0.0000
C1	0.8711	0.8818
C2	0.0377	0.0358
C3	0.0175	0.0164
i-C4	0.0031	0.0027
n-C4	0.0072	0.0061
i-C5	0.0035	0.0021
n-C5	0.0052	0.0029
C6	0.0047	0.0031
C7[1]	0.0026	0.0293
C8	0.0025	
C9	0.0024	
$C10^+$	0.0021	
$C6^+$ MW	128.22	133.00
$C6^+$ density (g/cm^3)	0.7811	0.7426

Water compositional analysis was also conducted on water samples taken from the C-30Z and E-28 wells. Table 3-6 summarizes the results of the C-30Z and E-28 water compositional analysis.

Table 3-6 West White Rose Water Compositional Analysis

	C-30Z	C-30Z	E-28
Sample Type	**Bottom Hole - MDT**	**Bottom Hole - MDT**	**Bottom Hole - MDT**
Sample ID	1362 MPSR	1203 MPSR	2863 MPSR
Sample Depth (m MD)	3,668	3,668	3,313
Total Dissolved Solids (mg/l)	40,018	39,856	51,742
pH	6.9	6.9	7.1
Cations/Anions:	mg/l	mg/l	mg/l
Na	14,400	14,100	16,860
K	272	279	292
Ca	1,100	1,140	1,280
Mg	133	137	136
Ba	2.2	2.1	2.8
Sr	163	163	263
Fe	2.36	1.94	39.00
Cl	23,000	23,000	29,581
HCO_3	704	733	775
SO_4	241	299	103
CO_3	<0.5	<0.5	<0.5
OH	<0.5	<0.5	<0.5

3.1.4 Special Core Analysis

SCAL studies have been completed on core acquired from the West White Rose pool. Relative permeability testing was conducted using stacked plug core samples obtained from West White Rose wells O-28Y, C-30Z and E-28. Water flood and gas flood unsteady state relative permeability tests were conducted on a total of ten stacks using both preserved and restored core.

Endpoints and resulting functions used in the West White Rose simulation model are listed in Table 3-7 and illustrated in Figure 3-4 and Figure 3-5.

Table 3-7 West White Rose SCAL Relative Permeability Endpoints

Endpoint	Facies				
	Laminated SS	Bioturbated SS	Bioturbated SltStn	Calcite	Shale
Swl	0.10	0.25	0.49	0.55	0.60
Swcr	0.10	0.25	0.49	0.55	0.60
Swu	1.00	1.00	1.00	1.00	1.00
Sowcr	0.28	0.33	0.38	0.40	0.35
Sogcr	0.28	0.32	0.35	0.36	0.35
Sgl	0.00	0.00	0.00	0.00	0.00
Sgcr	0.00	0.00	0.00	0.00	0.00
Sgu	0.90	0.75	0.49	0.45	0.40
Krw	1.00	1.00	1.00	1.00	1.00
Krwr	0.28	0.20	0.17	0.14	0.13
Krorw	0.80	0.72	0.67	0.63	0.60
Krg	1.00	1.00	1.00	1.00	1.00
Krgr	0.56	0.43	0.33	0.28	0.24
Krorg	0.80	0.72	0.67	0.63	0.60

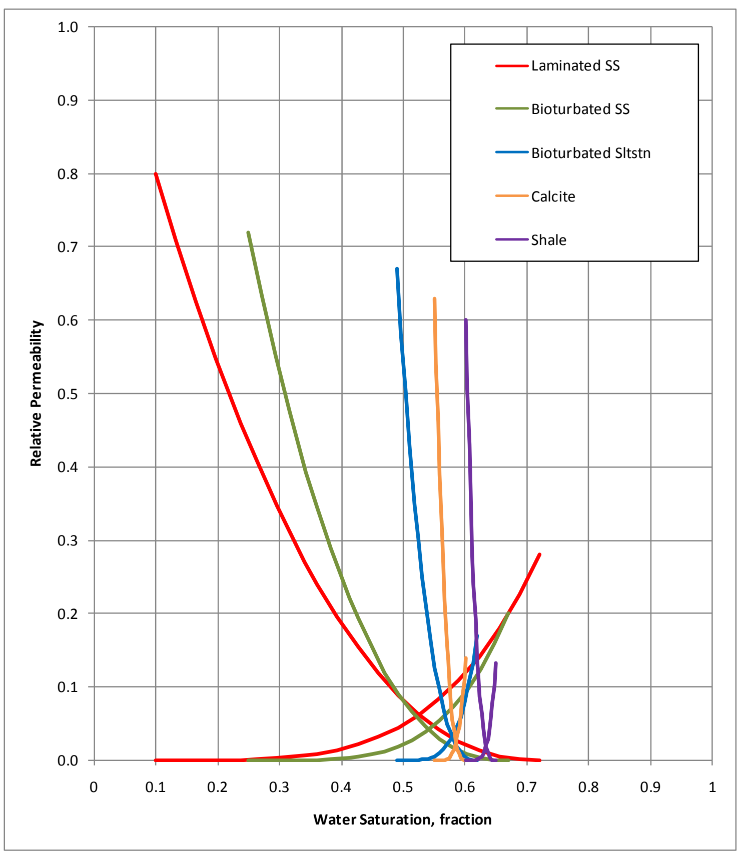


Figure 3-4 West White Rose Water-Oil Relative Permeability

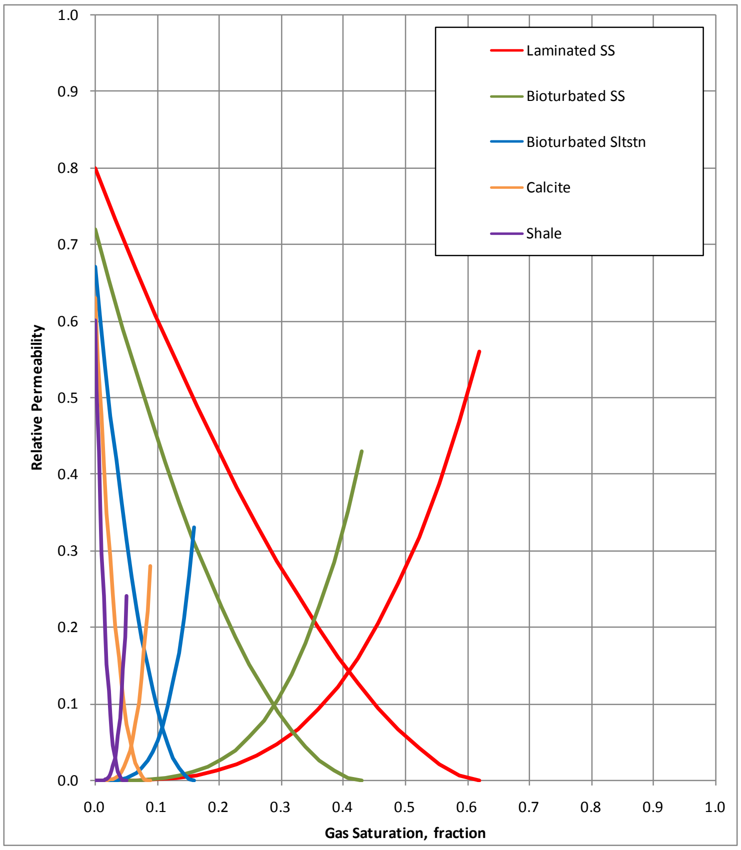


Figure 3-5 West White Rose Gas-Oil Relative Permeability

3.1.5 Vertical Interference Testing

3.1.5.1 O-28Y Vertical Interference Testing Results

In addition to MDT data, a vertical interference test was performed with the MDT tool in the O-28Y well. The vertical interference test was carried out with MDT dual probes set at 2.4 m apart. Table 3-8 shows the results of the vertical interference test.

Table 3-8 O-28Y Vertical Interference Testing Results

Test	Top(m KB)	Bottom (m KB)	Kv (mD)	Kh (mD)	Kv/Kh
VIT1	3169	3185	5	59.5	0.084

3.1.5.2 E-28 Vertical Interference Testing Results

Five vertical interference tests were performed on the E-28 delineation well in 2008 to assess the permeability of the reservoir. The results of the test are shown in Table 3-9.

Table 3-9 E-28 Vertical Interference Testing Results

Test	Fluid	Depth (m KB)	Kv (mD)	Kh (mD)	Kv/Kh
VIT1	Oil	3,173	5	59.5	0.084
VIT2	Water	3,303	7	72	0.097
VIT3	Oil	3,271	5	74	0.068
VIT4	Oil	3,271	4	74	0.054
VIT5	Oil	3,249	9.6	98	0.098

3.1.5.3 E-18 11 Vertical Interference Testing Results

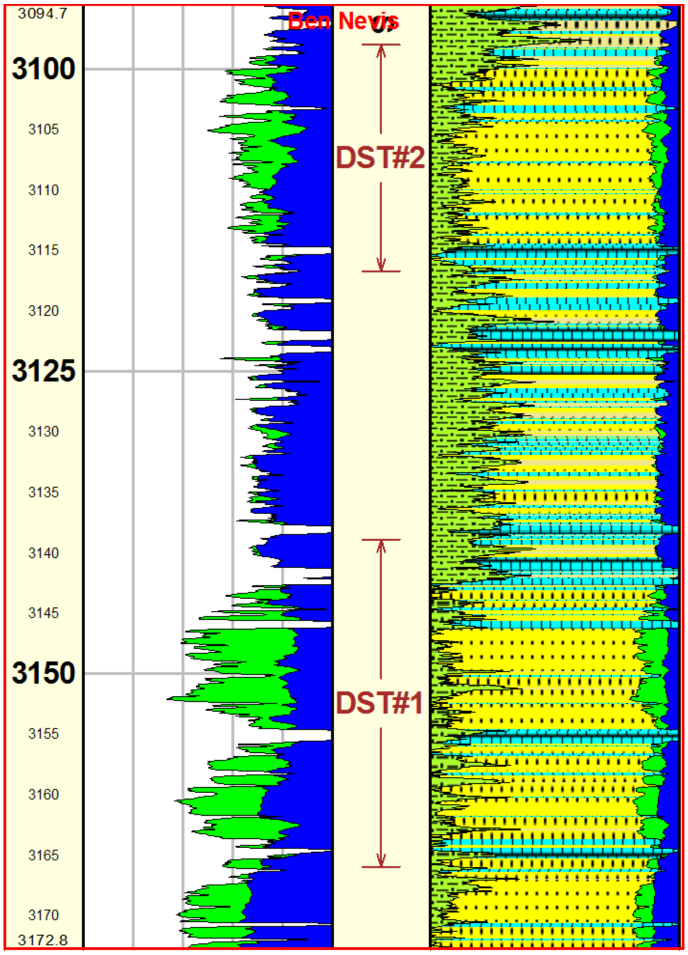
Vertical interference tests were performed on all three zones of the water injector, E-18 11. The purpose of the tests was to assess the vertical communication and permeability in the various parasequences of the formation. The tests were carried out with MDT dual probes. Table 3-10 shows the results of the vertical interference tests.

Table 3-10 E-18 11 Vertical Interference Testing Results

Test	Depth (m KB)	Kv (mD)	Kh (mD)	Kv/Kh
VIT 1 (Middle Zone)	3,151.42	7.9	75.4	0.105
VIT 2 (Upper Zone)	3,083.84	N/A	8.5	N/A
VIT 3 (Lower Zone)	3,268.32	0.003	3.8	0.001

3.1.6 C-30Z Drill Stem Test Results

Two separate drill stem tests (DSTs) were conducted over the lower and upper BNA intervals at the C-30 sidetrack well in 2007. The two DST intervals tested on the C-30Z well test are summarized in Figure 3-6.



Pay Cutoff:phi>10%, Sw<50%, k>3md

DST#2 : 3098 – 3117 TVDSS

Net Oil Pay	**3.5m**		
Gross	**19m**		
N/G	**19%**		
(Avg) Phi 12.2		**Sw 39**	
Vsh 17		**K 21 md**	

DST#1: 3139 - 3166 TVDSS

Net Oil Pay:	**11.5m**		
Gross	**27m**		
N/G	**42%**		
(Avg)Phi 15.2		**Sw 35**	
Vsh 10		**K 64 md**	

Figure 3-6 C-30Z DST Intervals

The lower BNA interval was successfully tested at rates of 190 Sm^3/d (1,200 bbl/d) during the main flow period and an extended shut-in period of 15 to 20 hours was also conducted during this DST. A second DST was attempted in the upper BNA interval, which did not flow to surface.

Figure 3-7 is a plot of the flow and build ups for the C-30Z DST #1.

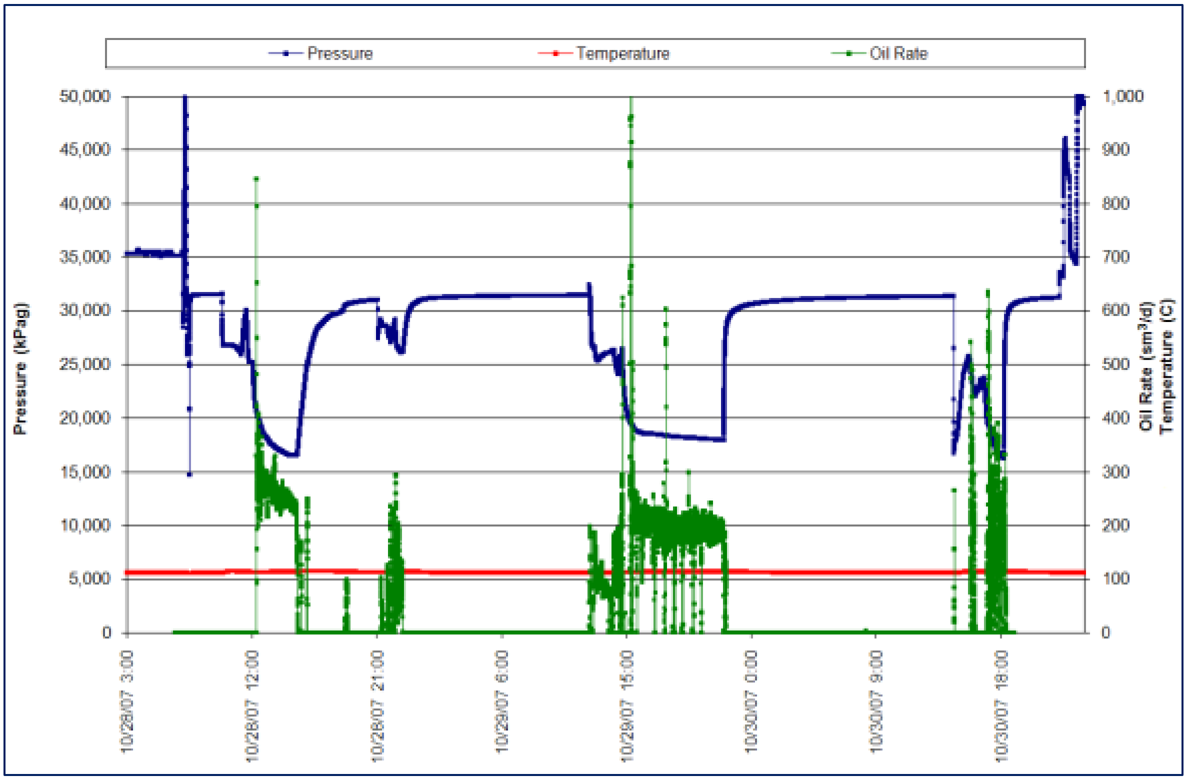


Figure 3-7 C-30Z DST Build-ups

Table 3-11 summarizes the results from the two DSTs performed on the C-30Z well, as well as the interpretations of the series of pressure build-ups.

C-30Z was drilled in the more distal area of the pool and provided an opportunity to test a variable and poorer sand quality section of the reservoir. The C-30Z well test objectives included assessing well productivity and obtaining representative reservoir fluid samples. Both objectives were met during DST operations. The DST inflow and pressure build-up data provides a benchmark for reservoir performance modeling, aiding in depletion planning.

Table 3-11 C-30Z DST Summary

White Rose C-30z Pressure Build -Up Results				
DST		Lower (#1)	Upper (#2)	
Elevation	(m KB)	23.0	23.0	
Top Perforations	(m MD KB)	3545.0	3484.0	
	(m TVD KB)	3161.9	3121.1	
Base Perforations	(m MD KB)	3585.0	3512.0	
	(m TVD KB)	3189.0	3139.7	
Primary Gauge Depth	(m MD KB)	3522.2	3450.2	
	(m TVD KB)	3146.5	3099.1	
	(m TVDss)	3123.5	3076.1	
MPP Depth	(m MD KB)	3565.0	3498.0	
	(m TVD KB)	3175.4	3130.3	
	(m TVDss)	3152.4	3107.3	
Build-up Period		Fourth	First (MIN)	Second (MAX)
Start Time		Oct-29-07 22:00	Nov-08-07 14:25	Nov-08-07 17:31
End Time		Oct-30-07 14:33	Nov-08-07 16:38	Nov-08-07 19:43
Shut-In Time	(hr)	16.6	2.2	2.2
Net Pay	(m)	11.5	3.4	
ϕ		0.152	0.122	
S_w		0.36	0.39	
Reservoir Temp	(°C)	113	112.3	
Measured FTHP	(kPa.g)	1,778	n/a	n/a
Final Oil Rate	(m3/d)	171.1	1.57	
Final Water Rate	(m3/d)	15.2	0	
Final Water Cut	(%)	8.2	0	
Final Producing GOR	(m3/m3)	80	n/a	n/a
p_{wf} @ Gauge Depth	(kPa.abs)	18,008	25,561	
Estimated Static Fluid Gradient	(kPa/m)	7.29	8.0	6.7
Estimated Flowing Gradient	(kPa/m MD)	5.0	6.7	6.7
Estimated p_{wf} @MPP	(kPa.abs)	18,222	25,881	
Approx Sandface Drawdown	(kPa.abs)	13,469	5,684	5,775
	(%)	42.5	18.0	18.2
Log Derived Horizontal Permeability	(mD)	77.4	23.7	
Permeability- Thickness (Vertical)	(md.m)	890	82	
Reservoir Model		Radial Composite CP Boundary	Radial Homogeneous Parallel Faults	
Test-Derived Horizontal Permeability	(mD)	23.5	0.2	1.02
Ratio of Test-Derived/Log Derived Horizontal Permeability		0.30	0.01	0.04
Permeability- Thickness, kh	(mD.m)	270	0.6	3.5
Assumed Drainage Area	(ha)	259	n/a	n/a
Estimated Time to Steady-State	(days)	28.6	n/a	n/a
Distance to CP Boundary. L	(m)	135	-	-
Distance to Nearer No-Flow Boundary. L_1	(m)	-	1.0	4.7
Distance to Farther No-flow Boundary. L_3	(m)	-	1.0	5.1
Estimated Radius of Investigation	(m)	83	5.7	13.3
Apparent Skin Factor		-1.32	2.0	3.5
Deviation Skin Factor (47.4° inclination: k_v/k_h = 0.1)		-0.25	-0.19	-0.19
Mechanical Skin Factor		-1.07	2.19	3.69
Pseudo-Skin Factor (for radial composite system)		6.0	n/a	n/a
Last Measured BU Pressure @ Gauge Depth	(kPa.abs)	31,213	32,787	
Ext'd Reservoir Pressure @ Gauge Depth	(kPa.abs)	31,480	31,316	31,447
Reservoir Pressure @ MPP Depth	(kPa.abs)	31,691	31,566	31,656
Pressure/Depth Gradient (from surface)	(kPa/m MD)	9.98	10.08	10.11
Observed Oil PI (no Vogel correction applied)	(m3/d/kPa)	0.013	n/a	n/a
Theoretical Oil PI (as tested)	(m3/d/kPa)	0.013	n/a	n/a

3.2 South Avalon (including Blocks 2 and 5)

3.2.1 Reservoir Pressures

Reservoir pressures in the South Avalon pool, including Blocks 2 and 5, are defined by hydrocarbon contacts and gradients encountered in several exploration, delineation and development wells. Table 3-12 shows the fluid contacts encountered in the South Avalon pool based upon log measurements.

Table 3-12 South Avalon Pool Fluid Contacts

Well	Contact	Subsea Depth (m TVDss)
A-17	Gas/ oil	2,874.4
L-08	Gas/ oil	2,872.0
E-09	Gas/ oil	2,869.4
H-20	Oil/water	3,003.2
B-07 1	Gas/oil	2,871.5
B-07 4	Gas/oil	2,858.9
B-07 6	Oil/water	2,998.5
B-07 11	Gas/oil	2,869.2
E-18 9	Gas/oil	2,873.8
	Oil/water	3,003.7
B-19Z	Gas/oil	2,893.6
	Oil/water	3,004.8

Within the Terrace region of the South Avalon pool, an oil-water contact of -2,999 m TVDss has been assumed. A gas-oil contact of -2,872 m TVDss has been assumed in the northern region of the Terrace and a gas-oil contact of -2,859 m TVDss has been assumed in the southern region of the Terrace. In the CDC region of the South Avalon pool, oil-water and gas-oil contacts of -3,009 m TVDss and -2,872 m TVDss, respectively, have been assumed. In Block 2, oil-water and gas-oil contacts of -3,005 m TVDss and -2,872 m TVDss, respectively, have been assumed. In Block 5, oil-water and gas-oil contacts of -3,003 m TVDss and -2,893 m TVDss, respectively, have been assumed.

Table 3-13 presents the South Avalon pool fluid gradients as determined from MDT data.

Table 3-13 South Avalon Fluid Gradients

Well	Reservoir Gas Gradient (kPa/m)	Reservoir Oil Gradient (kPa/m)	Reservoir Water Gradient (kPa/m)	PVT Live Oil Gradient (kPa/m)
A-17	1.71	6.96	9.71	7.07
L-08	2.11	6.98	9.69	7.06
E-09	2.28	7.09	9.81	6.85
H-20	N/A	6.15	9.67	N/A
B-07 1	2.13	6.84	N/A	N/A
B-07 4	2.06	6.92	N/A	N/A
B-07 6	N/A	7.18	10.22	N/A
B-19Z	1.11	7.06	9.74	N/A

The pressure elevation plot for the South Avalon pool is illustrated in Figure 3-8.

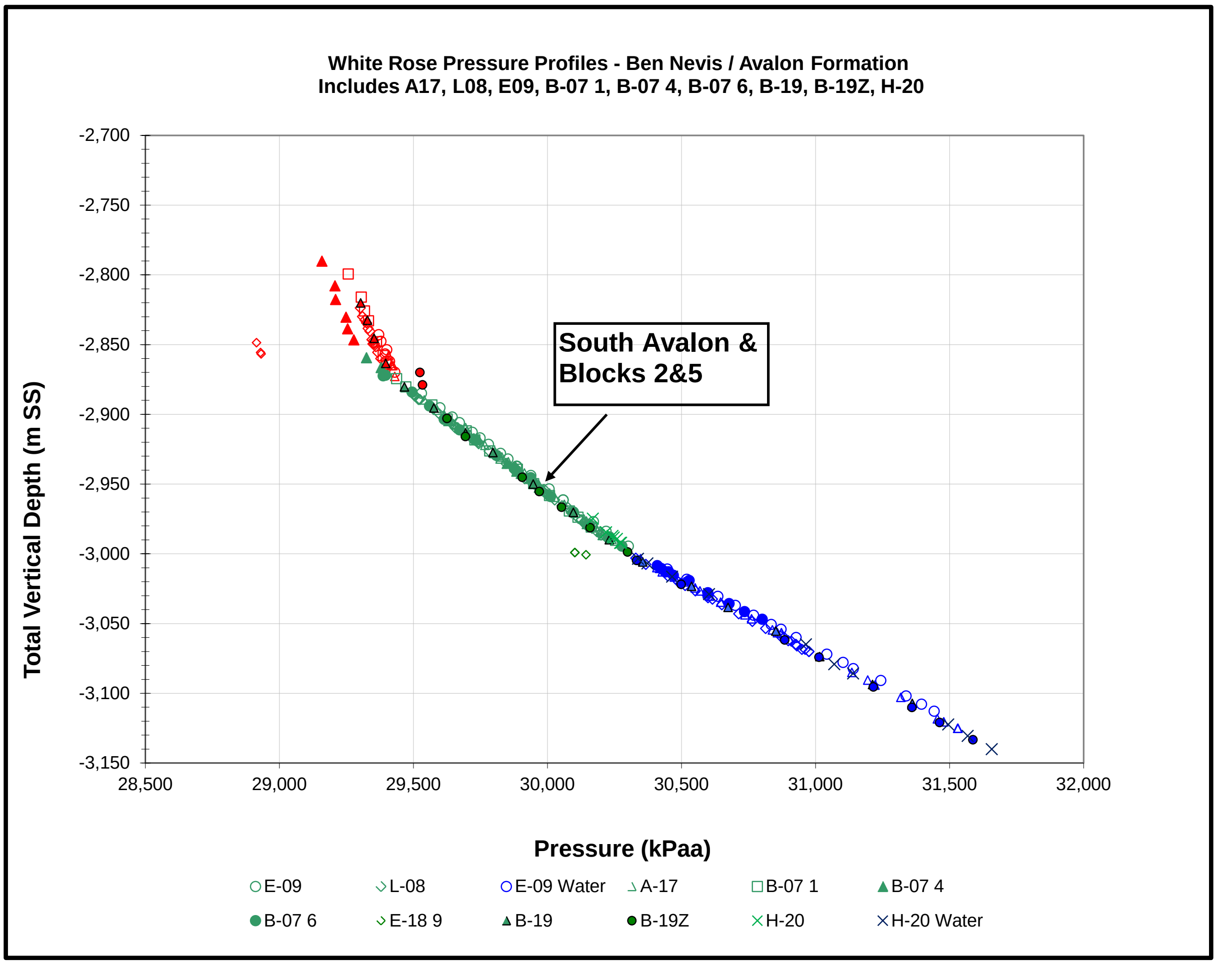


Figure 3-8 South Avalon Pool (including Blocks 2 and 5) Pressure Elevation Plot

3.2.2 Reservoir Temperature

The temperature gradient in South Avalon is well understood due to the number of South Avalon development wells that have been drilled. Static gauge temperatures prior to production/injection start-up for each well in the South Avalon pool are illustrated in Figure 3-9. A maximum initial temperature of 108°C was observed in the South Avalon pool, which was measured at the E-18 7 (CW5) water injection well. The maximum initial temperature observed within the Terrace region of the South Avalon pool was 105°C measured at the B-07 8 (SW2) water injection well. As a result, the estimated reservoir temperature for the South Avalon, including Blocks 2 and 5, is 106°C.

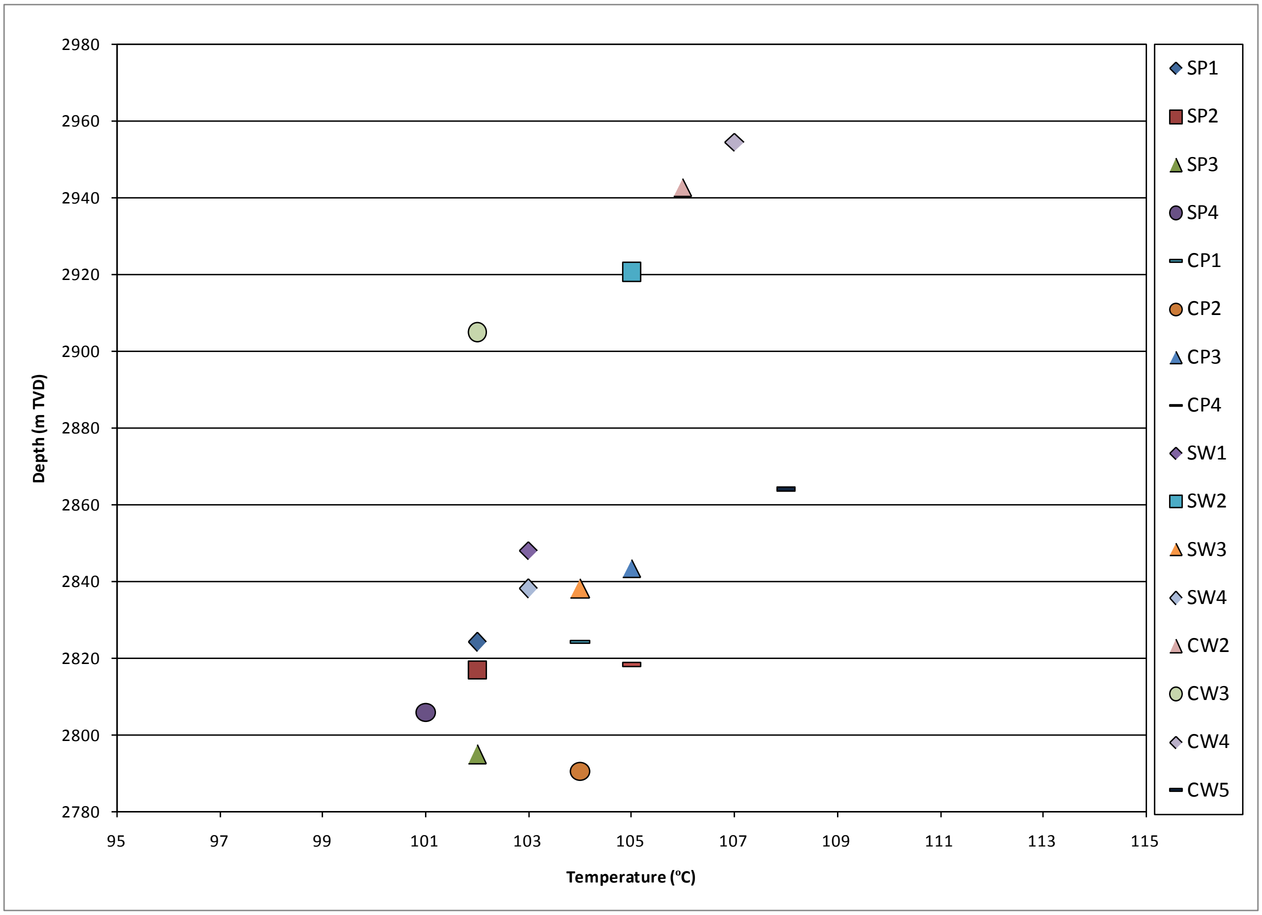


Figure 3-9 South Avalon Pool Production/Injection Well Initial Static Temperature @ Gauge

3.2.3 Fluid Characterization

Reservoir fluid samples were obtained in several wells in the South Avalon pool and detailed PVT analysis on the gas, oil and water samples were conducted. Table 3-14 provides a summary of the PVT analysis that has been conducted to date for wells in the South Avalon pool.

Table 3-14 South Avalon Pool PVT Analysis Well

Well	Analysis	Sample No.
A-17	GC, CCE, DLE, SEP	03-15 , 43-02
L-08	GC, CCE, DLE, SEP	283-06, 283-03
B-07 6	SEP	1360

The most representative PVT dataset for South Avalon, including Blocks 2 and 5, has a GOR of 128.5 m^3/m^3, a saturation pressure of 29,100 kPa and an initial FVF of 1.359 m^3/m^3. PVT properties are shown in Table 3-15. It should be noted that no gas cap samples have been obtained from the South Avalon pool to date.

Table 3-15 South Avalon PVT

Pressure (bara)	Bo (Rm^3/Sm^3)	Rs (Sm^3/Sm^3)	Oil viscosity (cp)
1	0.996	0.000	2.964
21	1.073	9.960	1.889
41	1.095	18.140	1.640
61	1.115	25.970	1.464
81	1.135	33.810	1.328
101	1.154	41.760	1.220
121	1.174	49.860	1.132
141	1.194	58.150	1.059
161	1.214	66.640	0.997
181	1.234	75.360	0.944
201	1.256	84.330	0.898
221	1.277	93.570	0.857
241	1.300	103.120	0.821
261	1.323	113.000	0.782
281	1.347	123.250	0.696
291	1.359	128.460	0.672

Pressure (bara)	Bg (m^3/Sm^3)	Gas viscosity (cp)
1	1.2992	0.0109
21	0.0608	0.0138
41	0.0306	0.0144
61	0.0203	0.0149
81	0.0151	0.0155
101	0.0120	0.0162
121	0.0100	0.0169
141	0.0086	0.0176
161	0.0075	0.0185
181	0.0067	0.0194
201	0.0061	0.0204
221	0.0056	0.0215
241	0.0052	0.0226
261	0.0048	0.0238
281	0.0046	0.0251
291	0.0044	0.0257

Three formation water samples have been taken from the South Avalon pool to date, which are summarized in Table 3-16.

Table 3-16 Summary of White Rose Formation Water Fluid Properties

Ion	Water Compositional Analysis Concentration (mg/l)		
	L-08	**A-17**	**B-07 6**
Sample	*	249-1	#1364
Na^{+}	15,000	8,505	8,500
K^{+}	700	2,310	160
Ca^{+2}	750	440	307
Mg^{+2}	100	85	29
Ba^{+2}	3.3	0.517	0.37
Sr^{+2}	120	22.3	30.9
Fe^{+2}	3.0	2.15	0.5
B^{+3}	58	37	63.9
Mn^{+3}	0.5	0.213	0.2
Cl^{-}	25,300	14,400	11,800
Br^{-}	50	43.8	55.4
I^{-}	50	<50.0	67.5
HCO_3^{-}	1,100	1,464	1,320
SO_4^{-2}	350	764	970
CO_3^{-}	Not Listed	Not Listed	6
OH^{-}	Not Listed	Not Listed	5
H_2S	Not Listed	Not Listed	Absent

Notes:
-L-08 analysis corrected for mud contamination. The data provided for L-08 is a synthetic formation water composition, derived from samples #208, #315, #233, #248, #311 and #199, that has been corrected for mud filtrate contamination. These data are the best estimated composition for formation water from L-08.
-A-17 analysis derived from corrections to a specific water sample analysis.
-B-07 6 analysis performed on a filtrate recovered from oil stained water containing sediment.

3.2.4 Special Core Analysis

There are five rock types defined in the South Avalon model: laminated sandstone; bioturbated sandstone; bioturbated siltstone; calcite; and shale. Table 3-17 lists the relative permeability end points for each rock type in the model.

Oil-water and gas-oil relative permeability curves for the South Avalon pool were derived from core flood tests from the White Rose L-08 well. The oil-water and gas-oil relative permeability curves for the South Avalon pool are illustrated in Figure 3-10 and Figure 3-11, respectively. The SCAL work conducted for the South Avalon pool is also considered representative of Blocks 2 and 5.

Table 3-17 South Avalon SCAL Relative Permeability Endpoints

Endpoint	Facies				
	Laminated SS	Bioturbated SS	Bioturbated SltStn	Calcite	Shale
Swl	0.10	0.15	0.20	0.25	0.30
Swcr	0.15	0.20	0.25	0.30	0.35
Swu	1.00	1.00	1.00	1.00	1.00
Sowcr	0.29	0.31	0.33	0.45	0.50
Sogcr	0.30	0.35	0.38	0.45	0.50
Sgl	0.00	0.00	0.00	0.00	0.00
Sgcr	0.05	0.08	0.10	0.10	0.10
Sgu	0.85	0.80	0.75	0.70	0.65
Krw	0.65	0.50	0.40	0.30	0.20
Krwr	0.20	0.15	0.10	0.05	0.05
Krow	0.85	0.75	0.65	0.50	0.40
Krorw	0.80	0.70	0.55	0.50	0.40
Krg	0.80	0.70	0.60	0.50	0.40
Krgr	0.35	0.20	0.15	0.10	0.05
Krog	0.85	0.75	0.65	0.50	0.40
Krorg	0.75	0.65	0.60	0.45	0.35

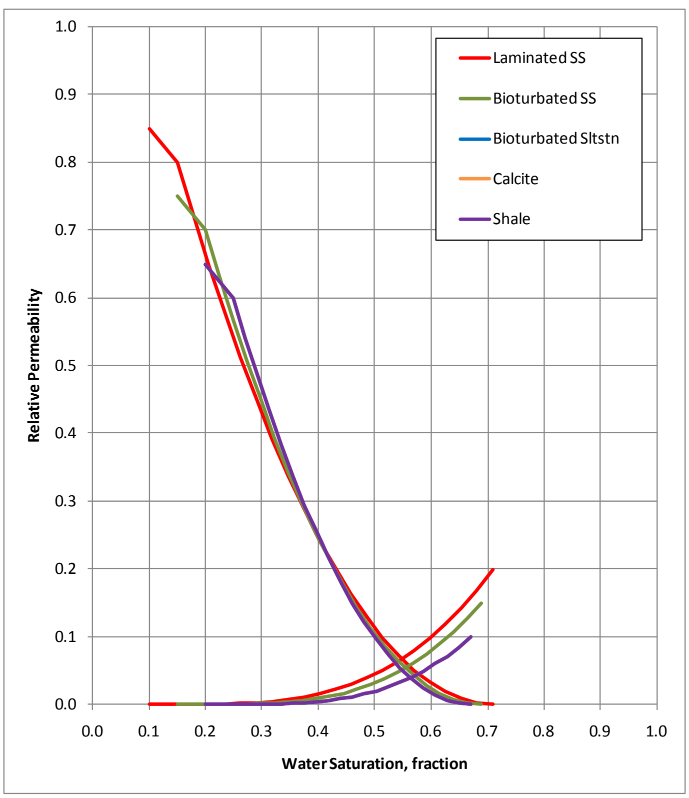


Figure 3-10 South Avalon Oil-Water Relative Permeability

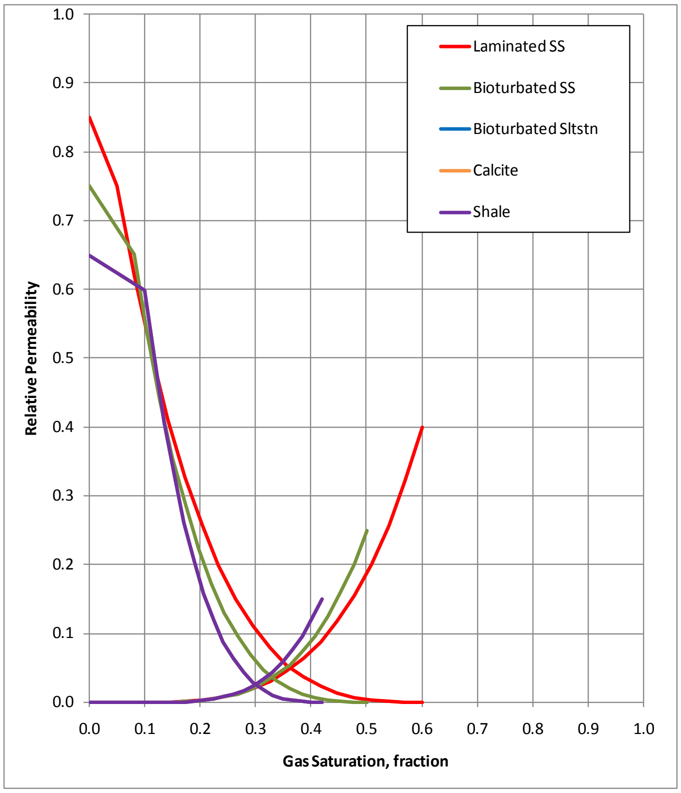


Figure 3-11 South Avalon Gas-Oil Relative Permeability

3.3 North Avalon

3.3.1 Reservoir Pressures

Reservoir pressures in North Avalon are defined by hydrocarbon contacts and gradients obtained in four wells within the region. Table 3-18 summarizes the fluid contacts encountered in each well of the North Avalon pool based upon log measurements.

Table 3-18 North Avalon Fluid Contacts

Well	Contact	Subsea Depth (m TVDss)
N-22	Gas, no fluid contact encountered	
N-30	Gas/oil	3,014
J-22 1	Gas injector, no fluid contact encountered	
J-22 2	Gas injector, no fluid contact encountered	
K-03	Water, no fluid contact encountered	

An oil-water contact of -3,084 m TVDss has been assumed for the North Avalon pool based upon MDT pressure data acquired during the drilling of N-30 and from regional fluid gradients within the White Rose field. Extrapolating the N-30 oil gradient derived from the MDT data with Ben Nevis regional water gradient provided an intersection at -3,084 m TVDss.

Table 3-19 shows the North Avalon pool fluid gradients as determined through MDT data.

Table 3-19 North Avalon Fluid Gradients

Well	Reservoir Gas Gradient (kPa/m)	Reservoir Oil Gradient (kPa/m)	Reservoir Water Gradient (kPa/m)	PVT Live Oil Gradient (kPa/m)
N-22	1.99	N/A	N/A	N/A
N-30	2.26	6.7	N/A	N/A
J-22 1	2.05	N/A	N/A	N/A
J-22 2	1.85	N/A	N/A	N/A

The pressure elevation plot for the North Avalon pool is illustrated in Figure 3-12.

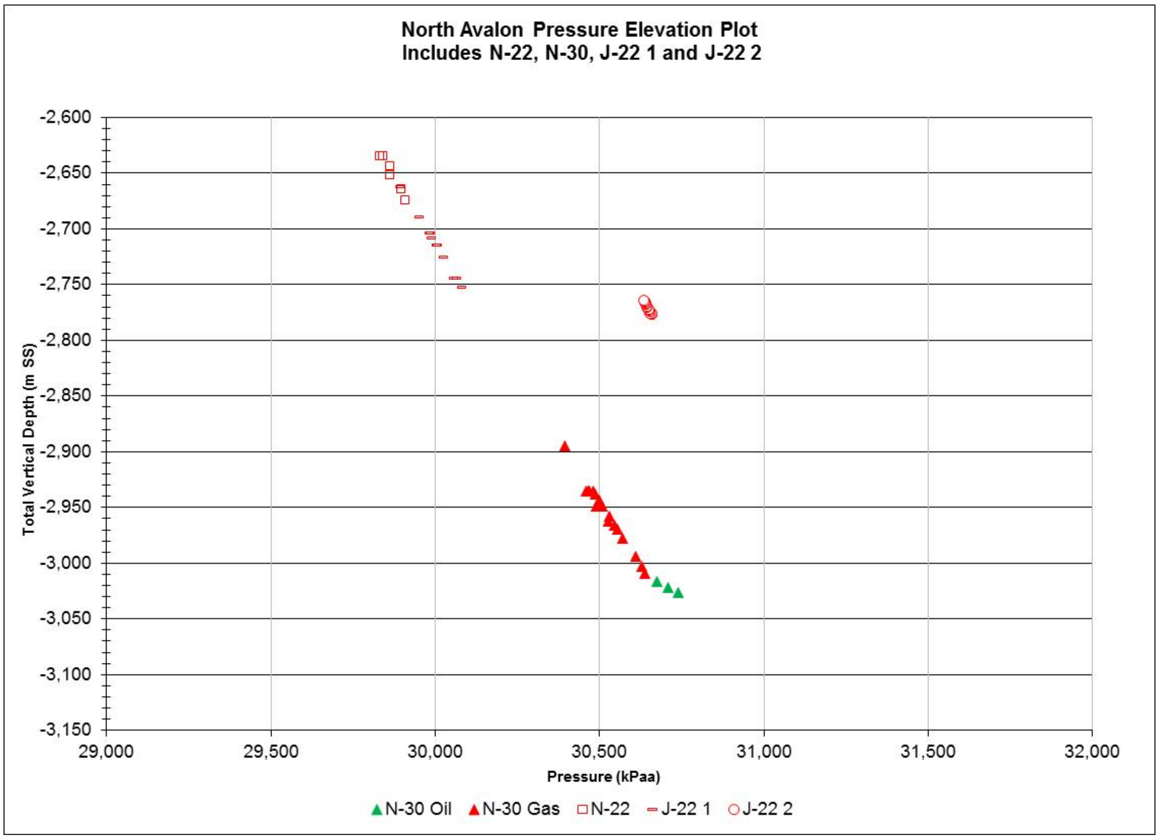


Figure 3-12 North Avalon Pressure Elevation Plot

3.3.2 Reservoir Temperatures

North Avalon reservoir temperature data has been estimated from two primary sources: downhole temperatures from current gas injectors J-22 1 and J-22 2; as well as West White Rose temperature data.

The anticipated temperature in the North Avalon pool ranges from 108°C to 115°C.

3.3.3 Fluid Characterization

Reservoir fluid properties were derived from the laboratory analysis of oil and gas samples obtained from North Avalon wells N-30, J-22 1 and J-22 2. Gas analysis, constant composition expansion (CCE) and constant volume depletion (CVD) experiments were performed on the various bottomhole samples obtained from J-22 1 and N-30 gas (condensate) samples, as well as surface samples obtained from the J-222 well. Table 3-20 summarizes the sample and tests conducted.

Table 3-20 North Avalon Pool PVT Analysis

Well	Analysis	Sample No.
N-30	CCE	248-02
N-30	CCE, CVD	248-06
N-30	Producing-GOR	42-05/248-06
N-30	Producing-GOR	42-13/248-06
N-30	Differential Liberation	Blended 42-13/248-06
J-22 1	CCE, CVD	MPSR 1359
J-22 1	CCE, CVD	Recombined: 14002-QA and 1206
J-22 2	CCE, CVD	Recombined TC1231 / MM75933

Based on the differential liberation experiment, the blended fluid sample has a saturation pressure of 30,751 kPa guage at 106°C, a solution gas-oil ratio (Rs) of 120.1 $m^3/m^3$and a FVF of 1.313 Rm^3/m^3.

Table 3-21 summarizes the representative PVT for the North Avalon pool. Table 3-22 summarizes the North Avalon gas PVT.

Table 3-21 North Avalon PVT

Pressure (bara)	Bo (Rm^3/Sm^3)	Rs (Sm^3/Sm^3)	Oil Viscosity (cp)
1.1	1.044	0.00	2.693
7.9	1.052	2.25	1.500
14.8	1.061	5.25	1.476
28.6	1.077	10.74	1.430
56.2	1.101	20.23	1.334
83.8	1.124	29.79	1.238
111.5	1.148	39.68	1.145
138.9	1.172	49.73	1.058
166.5	1.197	60.19	0.977
194.1	1.222	71.05	0.903
221.6	1.248	82.33	0.835
249.2	1.275	94.09	0.773
276.8	1.302	106.38	0.716
306.5	1.333	120.31	0.660

Pressure (bara)	Bg (Rm^3/Sm^3)	Gas Viscosity (cp)
1.1	1.197	0.011
7.9	0.165	0.013
14.8	0.087	0.013
28.6	0.045	0.013
56.2	0.022	0.014
83.8	0.015	0.015
101.0	0.012	0.016
142.9	0.008	0.017
160.3	0.007	0.017
181.3	0.006	0.018
223.2	0.005	0.020
240.6	0.005	0.021
282.5	0.004	0.023
306.5	0.004	0.024

Table 3-22 North Avalon Gas PVT

	N-30	J-22 1	J-22 2
Sample Type	**Bottom Hole - MDT**	**Bottom Hole - MDT**	**Surface - Recombined**
Sample ID	248-06	MPSR 1359	TC1231 / MM75933
Sample Depth (m MD)		2851.3	-
Mud System	WBM	SBM	SBM
Reservoir Pressure (kPa)	30,630	30,010	30,660
Reservoir Temp (°C)	106	106	106
Dew Point (kPa)	30,660	30,340	31,310
Z Factor*	0.9728	0.9131	0.96872
Viscosity (cP)*	0.0252	0.0240	0.0260
Density (g/cm^3)*	0.2141	0.2256	0.2213
MW	21.41	21.40	21.61
CGR ($m^3/10^6 m^3$)	182.75	183.52	181.66
CGR (stb/mmscf)	32.55	32.69	32.35
Mole Fraction:			
N_2	0.0013	0.0037	0.0044
CO_2	0.0153	0.0130	0.014
H_2S	0.0000	0.0000	0
C1	0.8924	0.8787	0.8731
C2	0.0389	0.0412	0.0414
C3	0.0185	0.0215	0.0215
i-C4	0.0032	0.0033	0.0033
n-C4	0.0074	0.0097	0.0094
i-C5	0.0015	0.0018	0.0023
n-C5	0.0024	0.0030	0.0032
C6	0.0017	0.0025	0.0032
C7[1]	0.0031	0.0013	0.0027
C8	0.0016	0.0038	0.0037
C9	0.0016	0.0024	0.0022
$C10^+$	0.0016	0.0019	
$C6^+$ MW	183.40	138.46	129.41
$C6^+$ density (g/cm^3)	0.8417	0.7920	0.7783
WBM = Water-based mud SBM = Synthetic-based mud			

3.3.4 Special Core Analysis

Special core analysis was conducted on core obtained from the N-30 well; however, the the relative permeabilities were deemed not representative. For this reason, relative permeability functions for the five facies types within the North Avalon pool were based upon the South Avalon model and were subsequently adjusted to accomodate the estimated irreducible water saturations. The resulting special core analysis end points are listed in Table 3-23 and illustrated in Figure 3-13 and Figure 3-14.

Table 3-23 North Avalon SCAL Relative Permeability Endpoints

Endpoint	Facies				
	Laminated SS	Bioturbated SS	Bioturbated SltStn	Calcite	Shale
Swl	0.10	0.15	0.20	0.30	0.35
Swcr	0.10	0.15	0.20	0.30	0.35
Swu	1.00	1.00	1.00	1.00	1.00
Sowcr	0.28	0.29	0.31	0.35	0.40
Sogcr	0.29	0.32	0.35	0.37	0.40
Sgl	0.00	0.00	0.00	0.00	0.00
Sgcr	0.05	0.08	0.10	0.10	0.10
Sgu	0.90	0.85	0.80	0.70	0.65
Krw	0.65	0.50	0.40	0.30	0.20
Krwr	0.20	0.15	0.10	0.05	0.05
Krorw	0.85	0.75	0.65	0.50	0.40
Krg	0.80	0.70	0.60	0.50	0.40
Krgr	0.35	0.20	0.15	0.10	0.05
Krorg	0.85	0.75	0.65	0.50	0.40

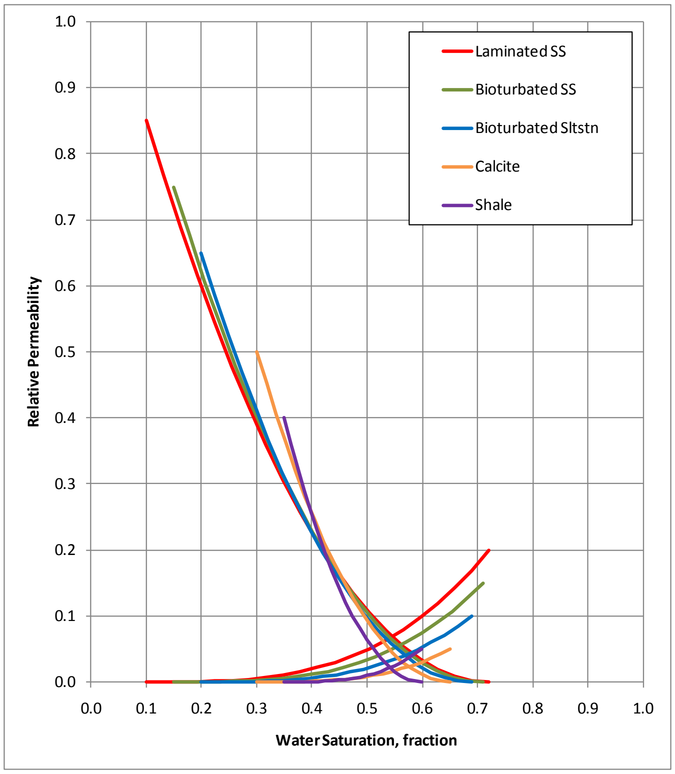


Figure 3-13 North Avalon Water-Oil Relative Permeability

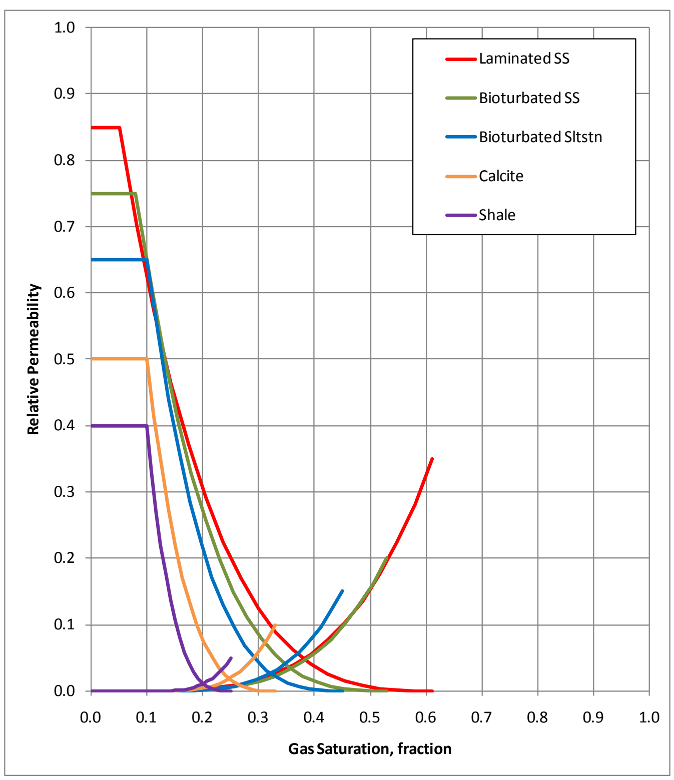


Figure 3-14 North Avalon Gas-Oil Relative Permeability

4.0 RESERVOIR EXPLOITATION

4.1 Reservoir Exploitation Overview

The WHP will be primarily used to access the West White Rose pool. However, other resources are located within reach of the WHP and are considered as potential resources for development from the new facility.

This section includes the current basis for the exploitation of the in-place resources in the West White Rose pool, as well as the additional resources that may be developed using the WHP. The additional potential resources are included to provide a full view of the resource that may be captured from the WHP.

This basis has leveraged learning from the White Rose and North Amethyst developments and considers the increased technical functionality provided by the WHP. The basis will evolve with learning through additional production history and field performance.

The development scenarios presented assume certain technological and operational efficiencies that will only be available through use of the WHP concept. This includes an estimate of the performance for the potential application of WHP-enabling technologies such as electrical submersible pumps (ESPs).

These scenarios are based on one realization of the potential development created from the current understanding of geological data and reservoir performance. As further data are acquired, the development philosophy will be adapted as required.

4.2 West White Rose Pool

4.2.1 Pilot Scheme Overview

The following sections describe the West White Rose Pilot Scheme results and its function as a basis for the West White Rose pool depletion strategy.

4.2.1.1 Pilot Scheme Objectives

The original objectives of the West White Rose Pilot Scheme were to acquire static and dynamic information with respect to the West White Rose pool. The objectives identified included:

- Obtain dynamic productivity and injectivity information, including:
    - Productivity index of a producer
    - Water injection fracture and propagation pressure

- Improved understanding of technical risks and appropriate mitigation, including:
  - Vertical barriers
  - Fault sealing
  - Compartmentalization
  - Reservoir connectivity
  - Lateral extent and quality of upper reservoir facies
- Improved evaluation of the pool for development
- Progression of an optimal depletion plan and completion design.

4.2.1.2 Pilot Scheme Design

E-18 10 is the West White Rose Pilot Scheme production well. It was designed as a two-zone intelligent completion, with a third zone having no downhole control. The completion is illustrated in Figure 4-1. The intelligent producer isolates three completion zones that cross the jB18a fault and BNA 325 parasequence boundary. The petrophysical analysis of E-18 10 is illustrated in Figure 4-2.

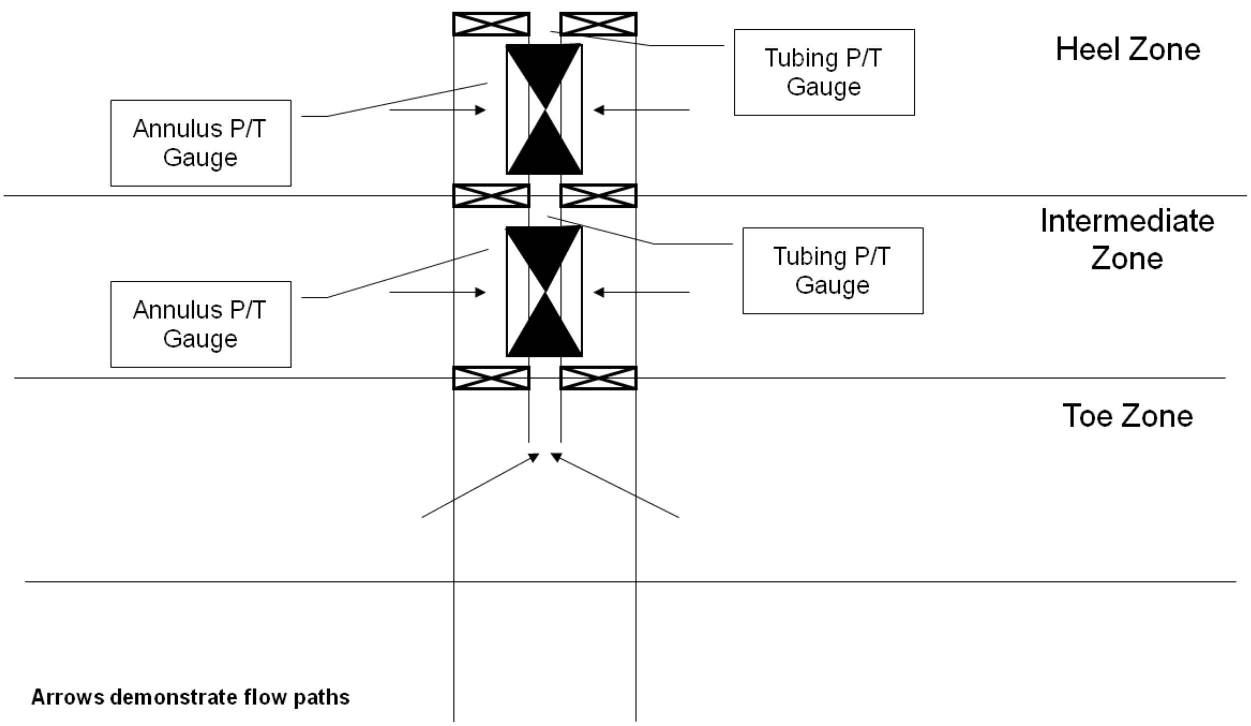


Figure 4-1 E-18 10 Pilot Producer Completion Schematic

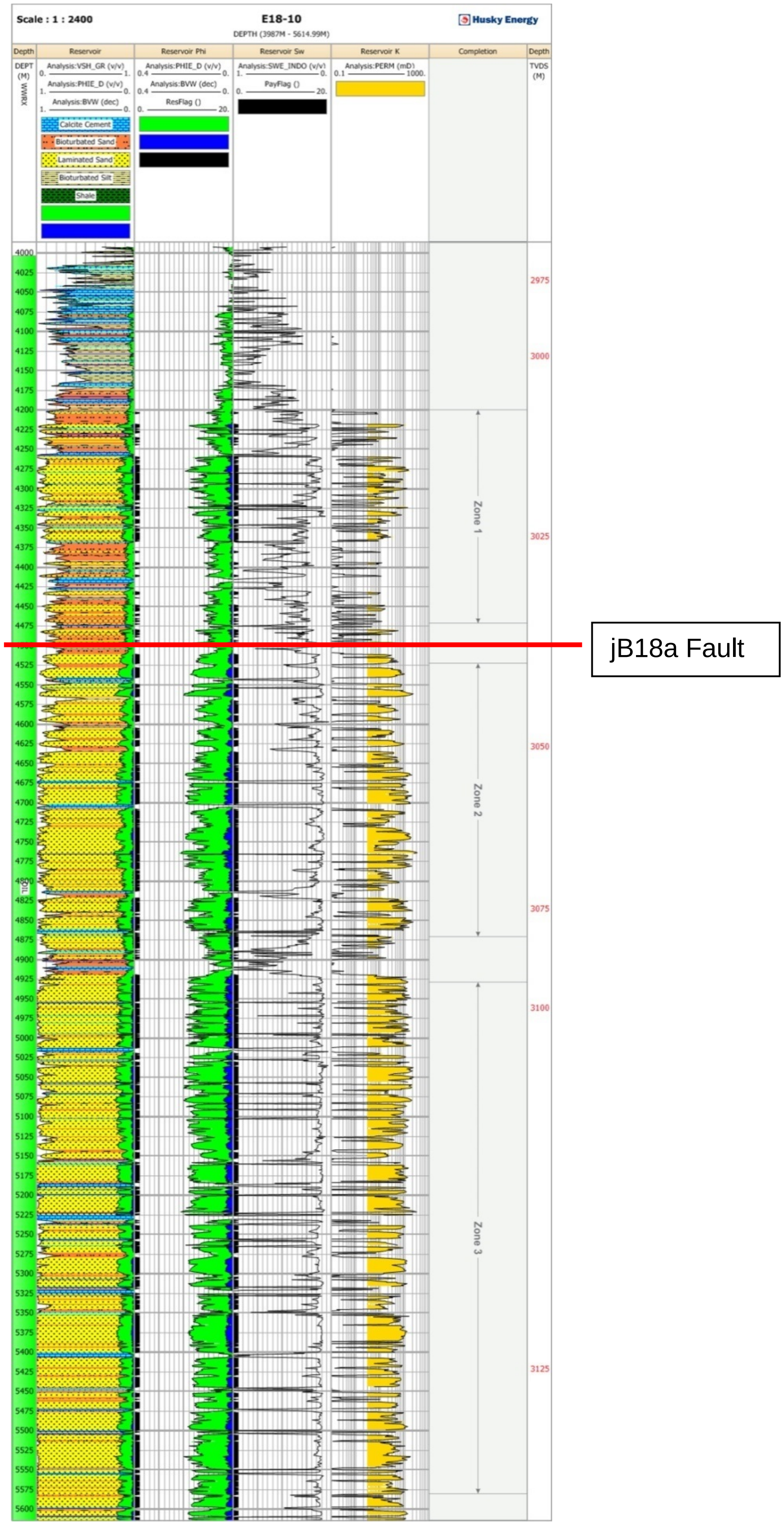


Figure 4-2 E-18 10 Pilot Producer Petrophysical Analysis

E-18 11 is the West White Rose Pilot Scheme water injection well. It was designed as a three-zone intelligent completion. The completion is illustrated in Figure 4-3. The intelligent water injector isolates three completion zones that cross the BNA 325 and BNA-Shell-Cement boundaries. The petrophysical analysis of E-18 11 is illustrated in Figure 4-4.

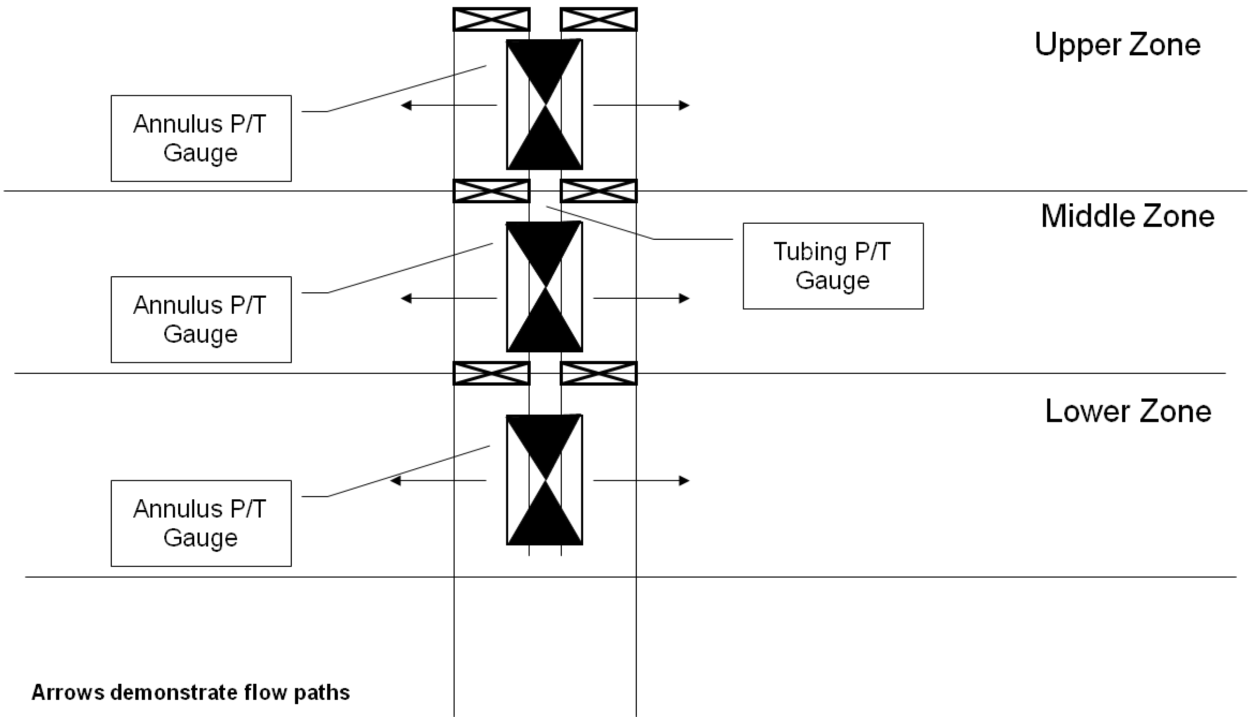


Figure 4-3 E-18 11 Pilot Injector Completion Schematic

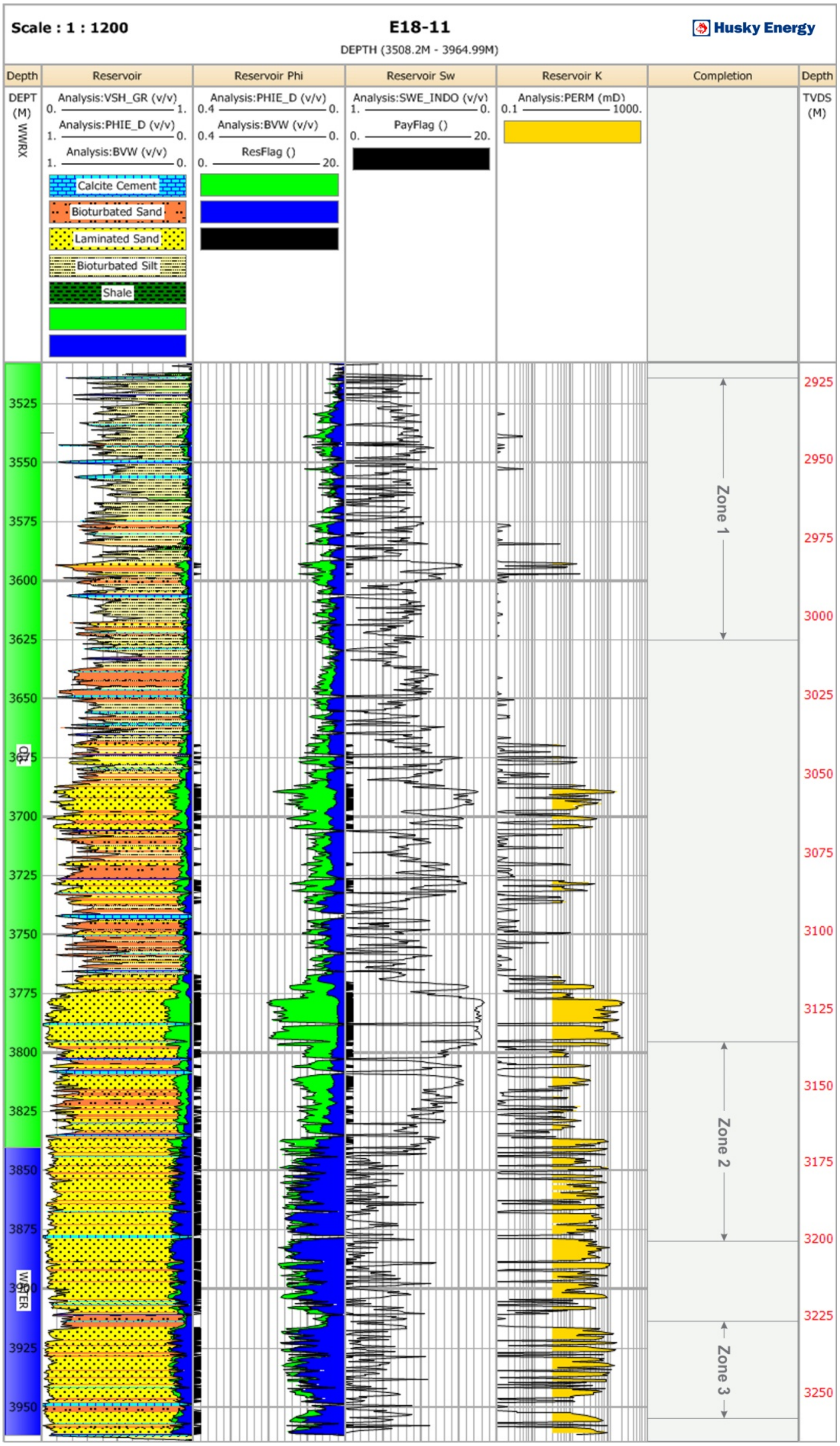


Figure 4-4 E-18 11 Pilot Injector Petrophysical Analysis

4.2.1.3 Pilot Scheme Results

The Pilot Scheme production well, E-18 10, was successfully completed in Q3 of 2011. First oil was established on September 5, 2011. The well underwent a clean-up program, followed by an extensive zonal/multi-rate performance program. The supporting Pilot Scheme water injection well, E-18 11, was successfully drilled in Q4 of 2011 and completed in Q2 of 2012. Figure 4-5 and Figure 4-6 illustrate the performance for E-18 10 and E-18 11, respectively, during 2011 and 2012. The base development forecast projects the total recoverable oil from the pilot pair to be 2.4 10^6 m^3.

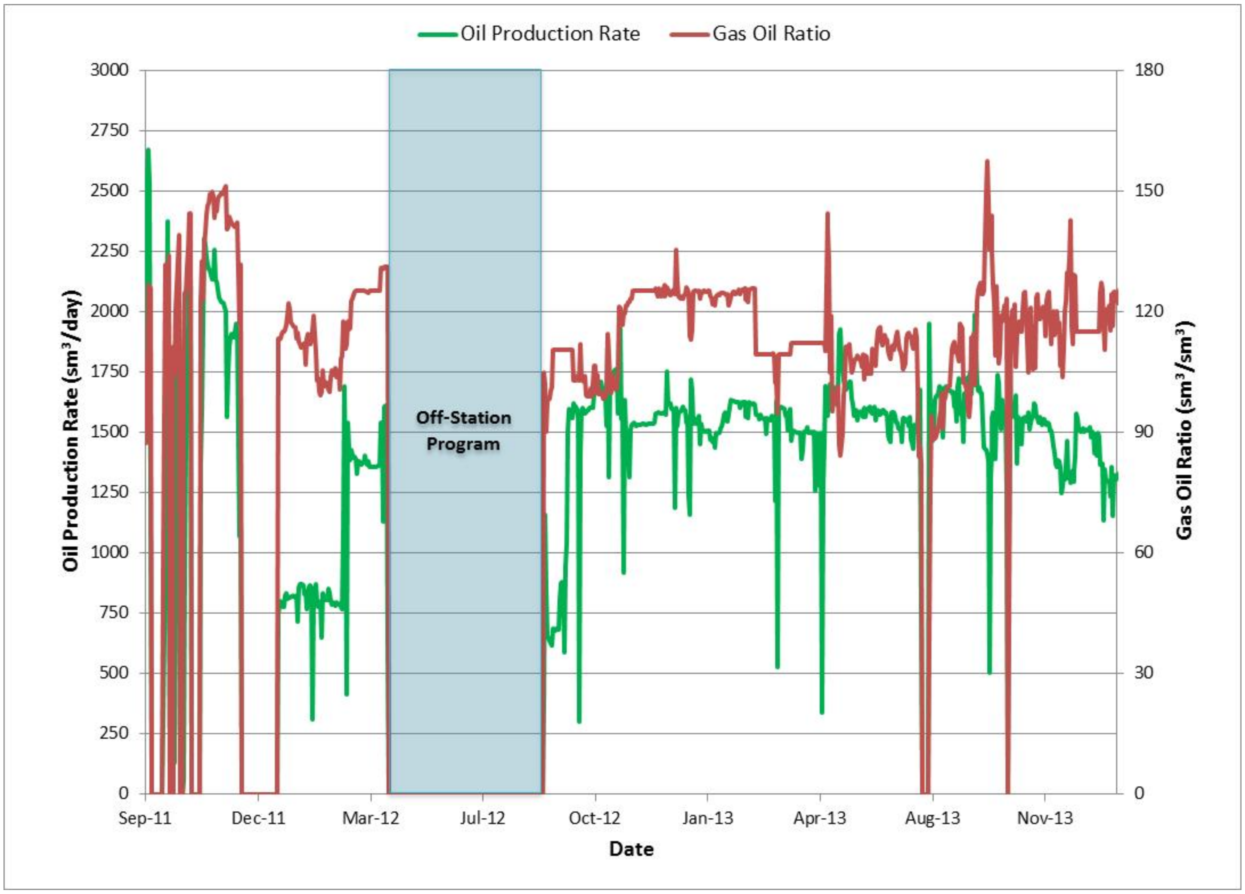


Figure 4-5 E-18 10 Production Rates

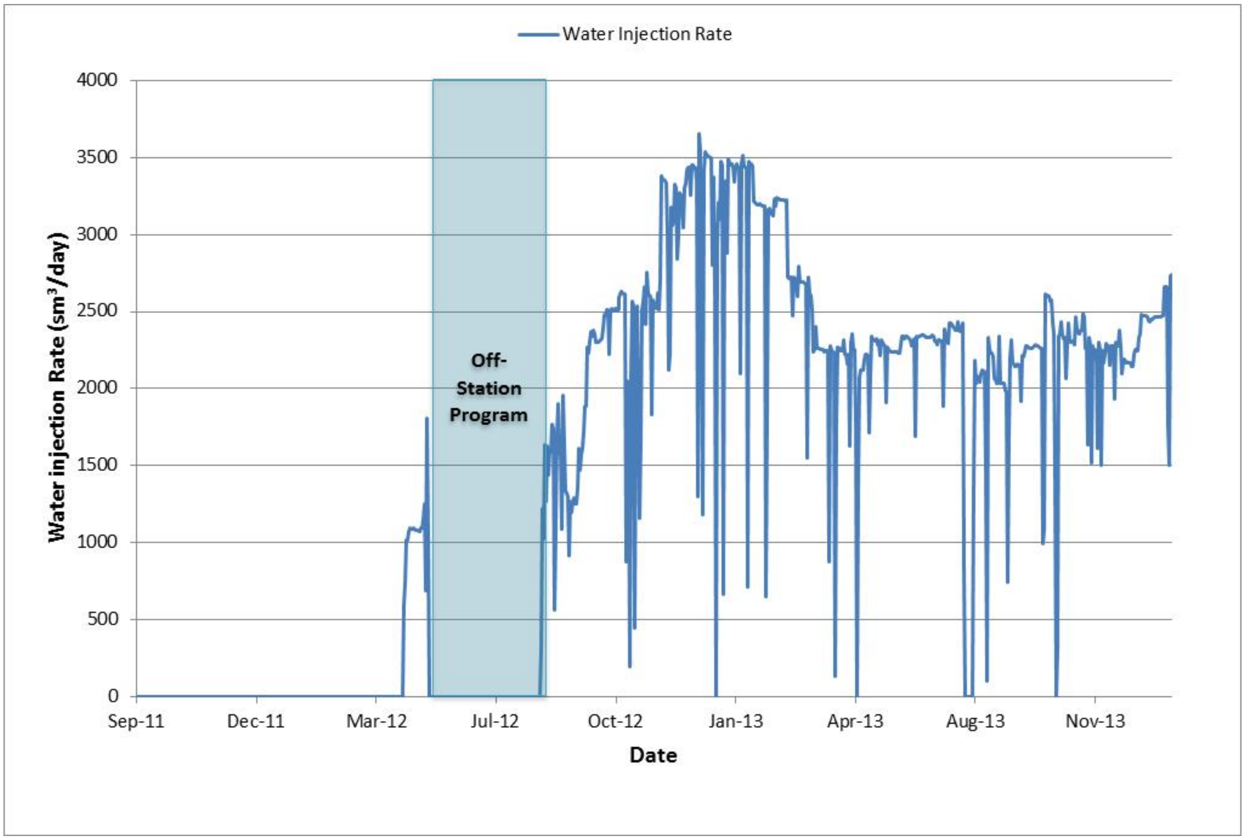


Figure 4-6 E-18 11 Injection Rates

Water injection began in April 2012 and interference and injection testing provided valuable insight into the characteristics of the West White Rose reservoir.

The learnings of the Pilot Scheme well pair are summarized as follows and will be used as a basis for the West White Rose depletion plan:

- Production rates from E-18 10 are towards the higher end of expectations. The estimates from the original development application production profile are shown in Figure 4-7. Actual performance approaches the profile of the high side simulation case

- E-18 10 has confirmed flow and provided quantitative estimates from the upper BNA, which is representative of the poorest quality reservoir (heel portion of the well)

- The fault jb18a (crossed by E-18 10) has demonstrated no communication, suggesting that it is highly baffled

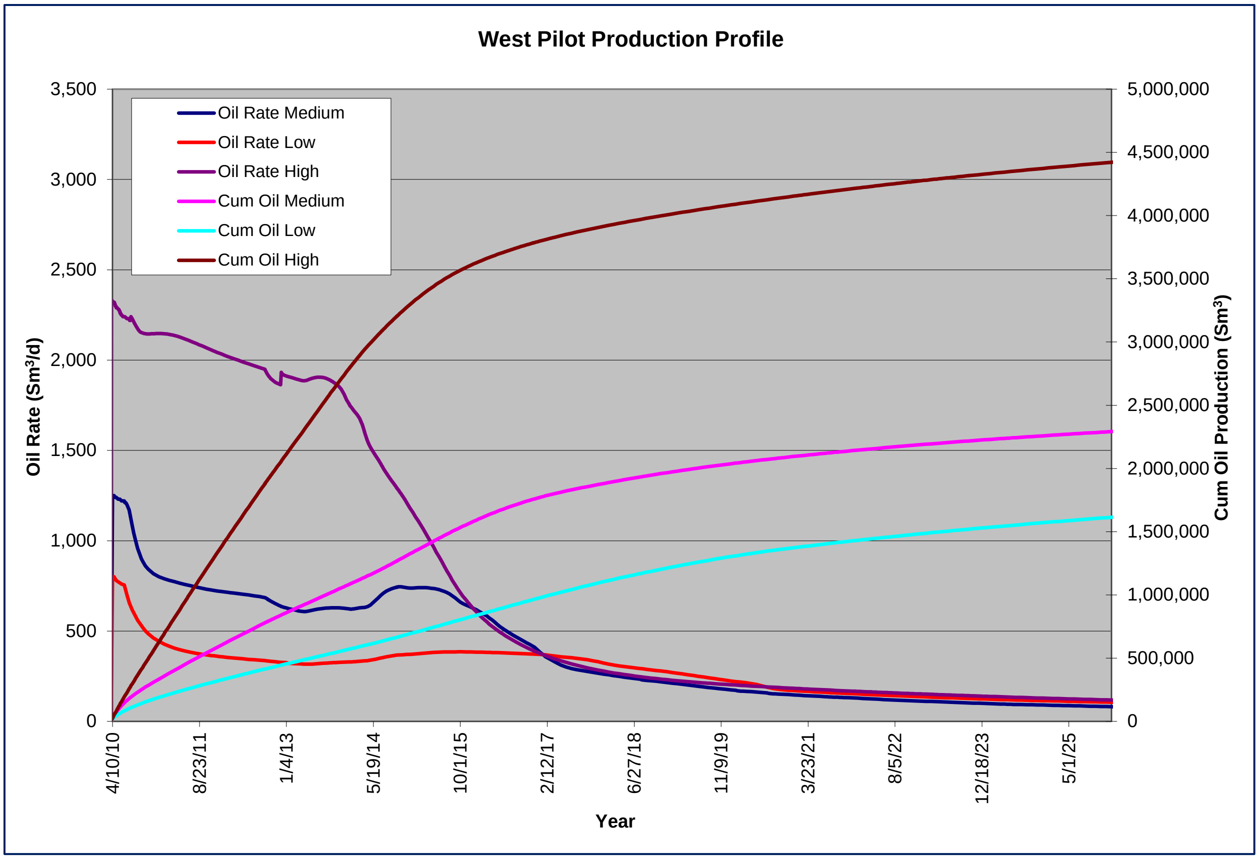


Figure 4-7 West Pilot Expected Production Profile

- Water injectivity has been achieved in all three completion zones (throughout BNA) of the water injection well, E-18 11. Thermal fracture is evident in the water injection well

- Interference testing between the producer and water injector has demonstrated pressure communication between the well pair:

  - Drawdown was observed in the MDT points of E-18 11 from the production of E-18 10

  - Pressure communication was observed at E-18 10 from water injection in the middle and upper zone of E-18 11

- Greater understanding of vertical barriers and parasequence boundaries was obtained:

  - BNA 325 baffling: E-18 11 vertical interference testing between the middle and upper zones confirmed no communication across the BNA_325, suggesting a highly baffled or sealing layer

- BNA-Shell-Cmt: E-18 11 vertical interference testing between the middle and lower zones confirmed no communication across the shell cement, suggesting a highly baffled or sealing layer

- E-18 11 lower completion zone injection testing: preliminary interference results have not demonstrated communication to E-18 10 producer to date

- Fracture injection and propagation pressures have been confirmed and will be used for development planning purposes.

4.2.2 Development Strategy

The West White Rose development plan is a single realization based upon a development concept philosophy and strategy. The Pilot Scheme learnings are an essential component of this philosophy and strategy. The Pilot Scheme has guided the development strategy with respect to:

- Well placement
- Well count
- Well orientation
- Artificial lift
- Well stimulation.

The development plan will be optimized as new learnings are acquired from further development drilling. Development drilling will lead to a greater understanding of the reservoir extent and facies distribution, resulting in potential changes to well count and spacing, as well as providing a greater understanding of the extent of the gas cap, which will influence well placement.

4.2.2.1 Development Area

The West White Rose development area is shown in Figure 4-8. The current base depletion scenario is overlaid, presenting the potential targets for water injectors and producers. The targets represent a proposed well layout; however, the actual number and location of the West White Rose wells will be optimized throughout the development of the region.

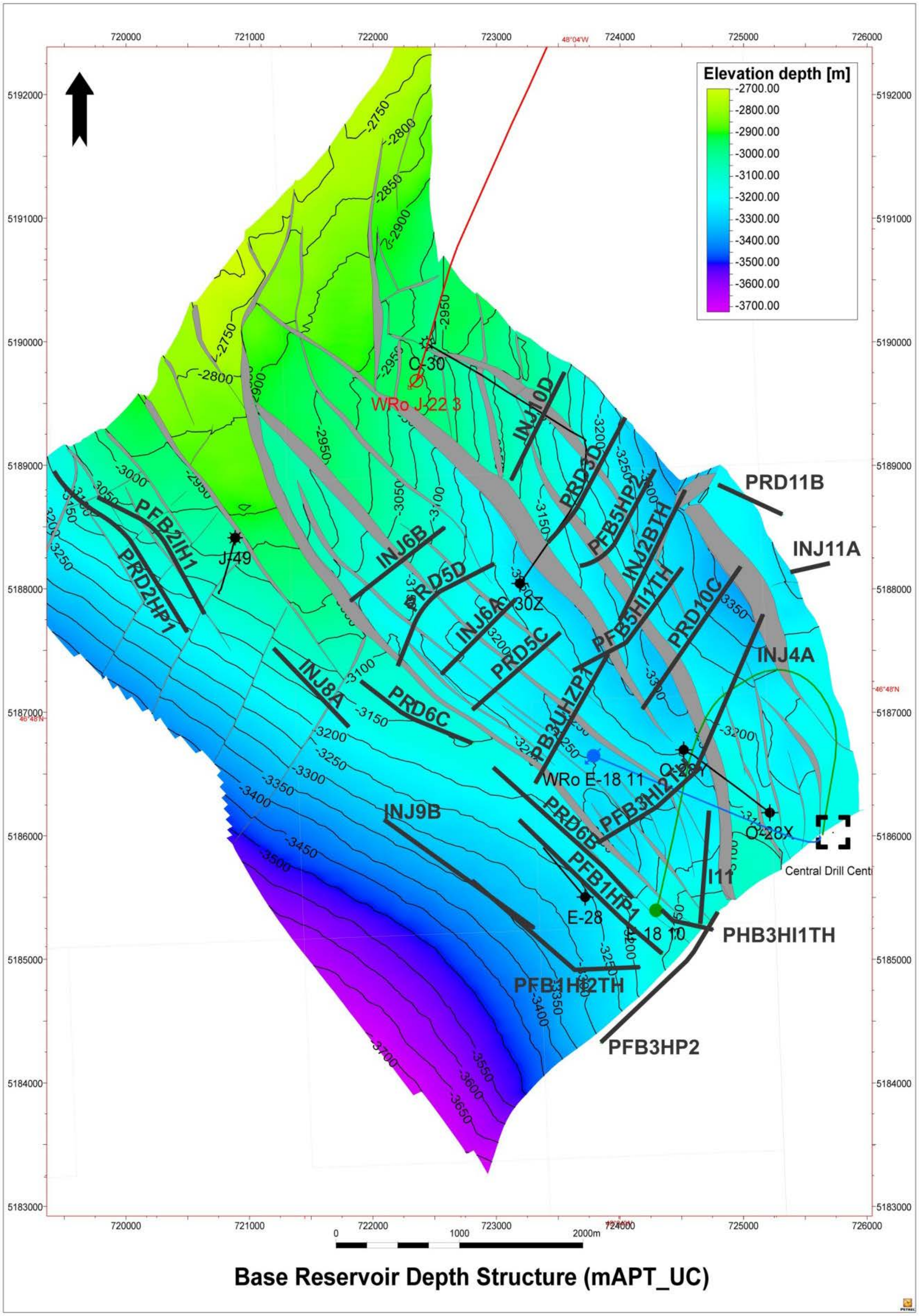


Figure 4-8 West White Rose Reservoir Depth Structure Map (mAPT_UC)

4.2.2.2 Well Placement

The Pilot Scheme results have provided a clearer picture on the overall vertical and horizontal interfaces within the reservoir. This knowledge has led to a well placement strategy.

Producers

Horizontal or highly deviated wells have been identified as the general well placement philosophy in the depletion plan. The selection of horizontal or highly deviated wells was driven by structure and low vertical permeability. More specifically, the ability to target multiple parasequences with horizontal or highly deviated wells facilitates higher sweep efficiencies.

Injectors

Water injectors were also identified to be highly deviated or horizontal under the current development philosophy. These well types allow intersection of horizontal and vertical barriers (faults, shell cement, BNA_325).

4.2.2.3 Well Count

The West White Rose base depletion plan currently has 26 wells (13 producers and 13 water injectors). This plan is based on the current deterministic geological interpretation of the reservoir and is the result of prediction simulation modelling found to best recover oil from the pool. The well count has leveraged learnings from the Pilot Scheme as well as existing developments.

The well spacing is modified throughout the reservoir. The change is driven mostly by the upper reservoir parasequences, where lower quality reservoir and relatively high original oil in place (OOIP) benefits from a tighter well spacing. The well spacing is such that pressure support can be maintained in the production wells for the anticipated production rates.

There will be further optimization of well design and, therefore, well counts and well planning may change as the region is developed. The number and location of the West White Rose wells will be optimized based upon the actual reservoir geology and performance as development occurs.

4.2.2.4 Well Orientation

Production and injection wells will be drilled in the northeast-southwest general direction as a general philosophy. The faults observed to date in the Pilot Scheme are highly baffling or sealing. Crossing faults in the northeast-southwest direction minimizes risk of sealed faults that could impact the ultimate recovery of resources.

Thermal fracturing in the water injector can affect the sweep efficiency of the water flood. The fracture orientation, based upon the maximum stress direction, is a key input into the depletion plan. Geo-mechanics work indicates the maximum stress direction is also in a northeast-southwest orientation. Thus, the wells will be generally aligned northeast-southwest in the direction of thermal fracture growth to avoid bypassing pay with water flood fractures.

Well orientation will be evaluated and adapted as stress directions and fault understanding grows on a well-by-well basis.

4.2.2.5 Artificial Lift

Production well productivity was established through the Pilot Scheme and Husky anticipates the use of gas lift as the primary artificial lift, similar to the completions in South Avalon and North Amethyst.

However, Husky is also considering the use of ESPs. In West White Rose, the wells were evaluated for ESPs as a secondary lift mechanism. ESPs are an industry-proven lift technology used around the world in both onshore and offshore environments. ESPs provide the ability to increase individual well drawdown, which can provide production acceleration and in some cases, an increase in overall recovery.

The review of the effectiveness of ESPs under various operating conditions is still ongoing. Not all wells may be ideal candidates for ESPs due to the potential risks of higher gas production from wells in close proximity to the associated gas cap.

Application of ESPs would be evaluated on a well-by-well basis as understanding of ESP performance and the reservoir-producing conditions increases.

4.2.2.6 Well Stimulation

The Pilot Scheme has aided in establishing the degree of vertical and horizontal connectivity of the West White Rose reservoir. Increasing reservoir contact is of particular importance in the lower permeability upper reservoir parasequences within West White Rose.

Potential solutions to improve overall connectivity of the interbedded parasequences and increase volumetric sweep are being evaluated and may include: hydraulic fracturing; near wellbore acidizing; short radius side tracks; and/or multilaterals. These options could improve productivity indices, provide increased initial production rates, provide production acceleration and may increase recovery.

The base development scenario identifies a number of production wells as stimulation candidates. Not all wells will be suitable for stimulation; therefore, an evaluation will be performed on a well-by-well basis. Some wells may not see benefits from stimulation due to the proximity to the associated gas cap or water leg.

As the performance of stimulated wells is assessed, the well placement and count may subsequently be changed to adapt to these learnings.

4.2.3 Reservoir Simulation

4.2.3.1 Simulation Model

The West White Rose ECLIPSE simulation model is based on a Petrel static model, which incorporated additional information obtained with the drilling of the Pilot Scheme wells.

The geological model was statistically populated and then upscaled. A uniform 2:1 upscaling ratio was applied in both horizontal directions. A variable upscaling ratio was applied in the vertical direction to represent the inherent heterogeneity. The geological model was up-scaled from 50 m X 50 m to approximately 100 m X 100 m. The simulation model has 60 x 79 x 350 cells (total 1.65 million cells).

The resulting West White Rose simulation model was assigned fluid, rock and equilibrium characteristics consistent with those described in preceding sections of this document.

The model was initialized with a water saturation distribution that was generated using saturation logs and a co-krigged geostatistical distribution. The resulting OOIP was 69.0 $e^6 m^3$ versus the P50 probabilistic OOIP of 72.9 $e^6 m^3$.

4.2.3.2 History Match

Well trajectories and completion details for E-18 10 and E-18 11 were input into the simulator, along with the daily production and injection rates and pressure information.

The simulation model was history matched to the observed production and pressure performance of the Pilot Scheme well pair.

4.2.4 Production Performance

The history matched simulation model was used to derive the West White Rose full-field development scenarios. The forecast from the base development simulation was input into the full-field Integrated Production Model (IPM). Figure 4-9 to Figure 4-11 illustrate the West White Rose oil, water and gas production profiles, as an output from IPM. Downtime from anticipated yearly turnaround programs have been incorporated in the forecast. These events are subject to change pending the future operational requirements of the *SeaRose FPSO*.

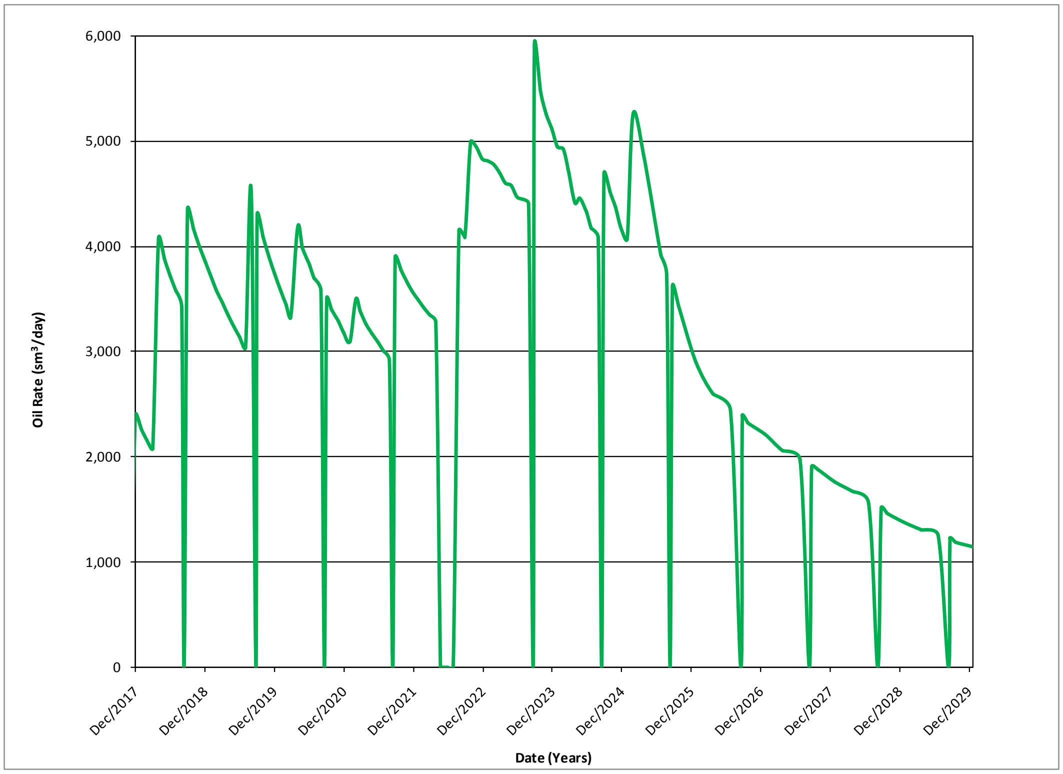


Figure 4-9 West White Rose Oil Production Profile

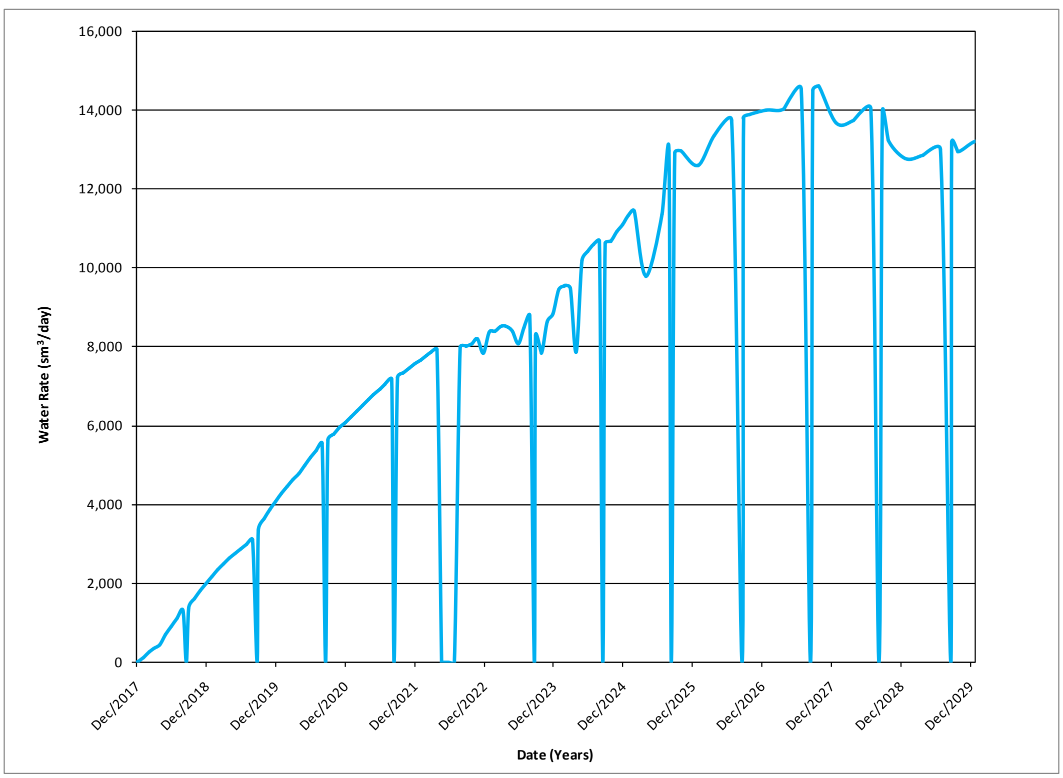


Figure 4-10 West White Rose Water Production Profile

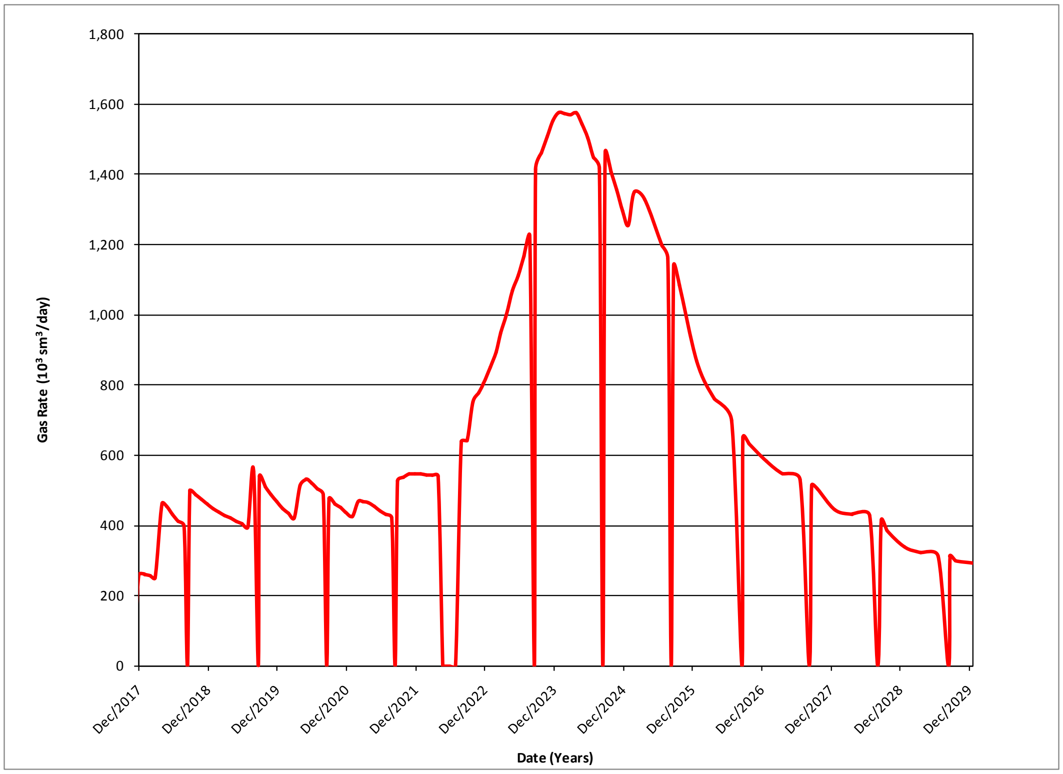


Figure 4-11 West White Rose Gas Production Profile

4.3 South Avalon

The South Avalon pool is considered a potential resource for development from the WHP in addition to the primary West White Rose pool.

4.3.1 Existing Pool Development Strategy

The South Avalon pool has been developed with mid-oil column horizontal production wells. Secondary pressure support and vertical water displacement is provided by underlying water injection wells located in the water leg where present. Reservoir pressure has been maintained at or above bubble point by maintaining a voidage replacement ratio of 1 to 1.2 since first oil in November 2005.

South Avalon was initially developed with eight horizontal production wells and ten water injection wells, four production wells in the Terrace block via the Southern Drill Centre and four in the Central block via the Central Drill Centre and five water injectors in the Terrace block and five in the Central block. Horizontal intelligent water injectors were used where pressure support was required to multiple fault blocks.

4.3.2 Incremental Pool Development Strategy

With maturing production in the South Avalon pool, IOR methods are being evaluated to improve oil recovery from the field. This work has resulted in the successful drilling of infill well B-07 11 (SP5) in 2012, which targeted attic oil accumulation in the northern most part of the Terrace block. Infill drilling results confirmed the presence of attic oil with virgin oil conditions.

A possible development approach would involve targeting the largest remaining attic oil accumulations with infill horizontal production wells. Further to infill drilling, water and gas injection into the gas cap could be used to displace the remaining attic oil to existing producers. Gas injection and/or water-alternating gas (WAG) injection into the gas cap could enable pressure support that is favorable to oil recovery via a sweep of attic oil to the existing mid-column producers. The reservoir management plan for the South Avalon pool would remain unchanged. Pressure would be maintained above bubble point and voidage replacement would be maintained in the 1.0 to 1.2 range. In a similar philosophy, a horizontal production infill well and the first South Avalon gas cap injector have been identified for the southern Terrace region and have been detailed in the *SWRX Development Plan Amendment* (approved by the C-NLOPB in Decision 2013.04).

4.3.2.1 Development Area

The South Avalon development area is shown in Figure 4-12. Potential infill and injection targets are indicated for illustrative purposes. Final well count and locations will be based on further IOR studies, field performance, optimization and feasibility.

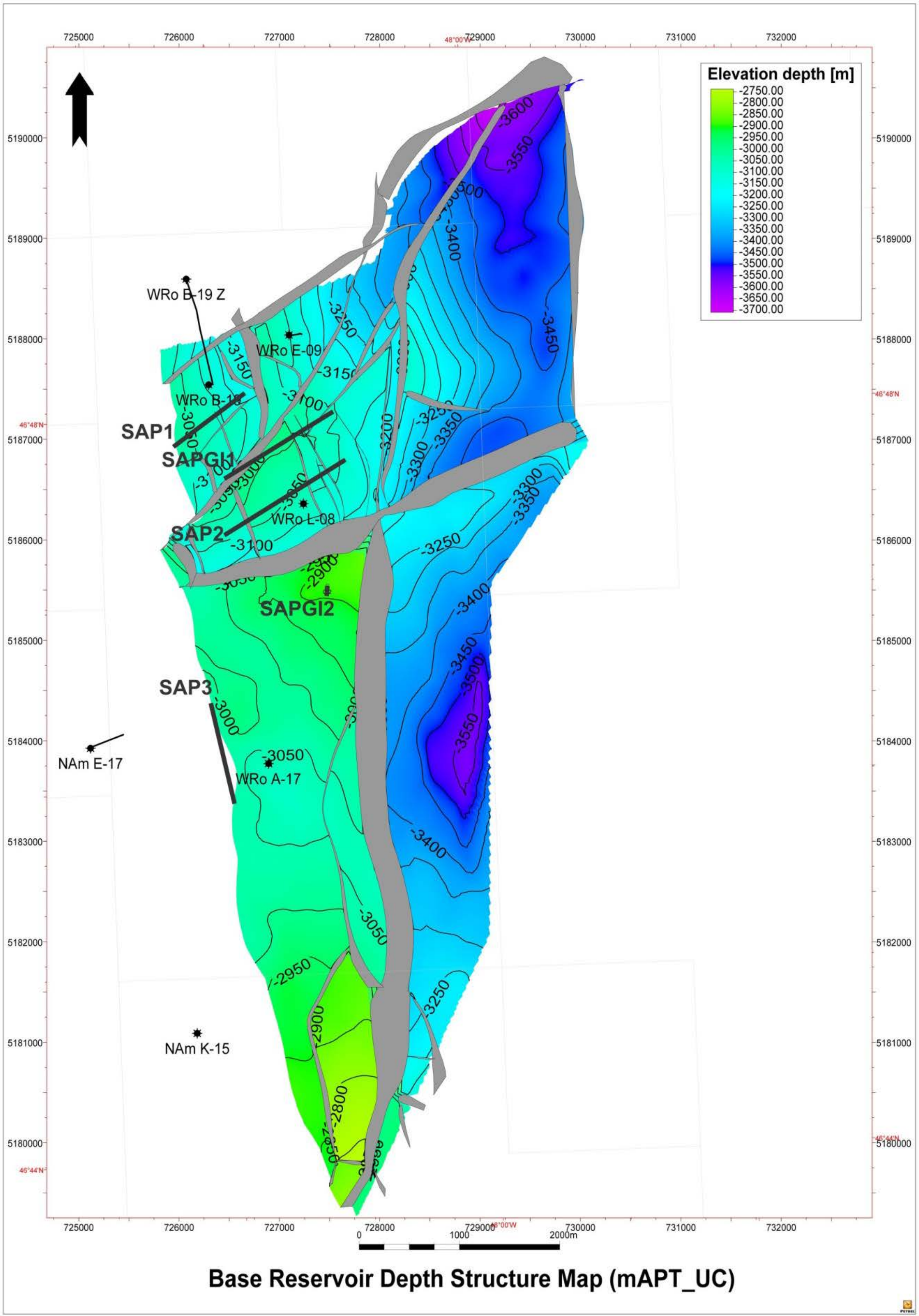


Figure 4-12 South Avalon Reservoir Depth Structure Map (mAPT_UC)

4.3.3 Well Count

The development scenario used to support the overview of South Avalon IOR potential was a five-well program (three infill producers and two gas injectors). This plan is based on a combination of simulation modelling and the probabilistic evaluation of potential remaining recoverable oil within the pool. Final well count and layout for South Avalon IOR may change upon further optimizations, and will ultimately be based upon the development viability in the area.

The basis for the well count has leveraged learnings from the existing developments and considers the increased technical functionality and improved drilling efficiency provided by the WHP. The basis will evolve with learning achieved through additional production history and field performance. Further optimization of well design will be conducted and, therefore, well counts and well planning may change.

4.3.4 Reservoir Simulation

The South Avalon simulation model was generated from the geological model after up-scaling of the cell dimensions and petrophysical characteristics. The geological model was up-scaled from 50 m X 50 m to approximately 100 m X 100 m. The simulation model has 26 x 83 x 240 cells (total 517,920 cells).

4.3.5 Production Performance

Oil, water and gas production profiles for the South Avalon IOR component of WREP are shown in Figure 4-13 to Figure 4-15, respectively. The production profiles are based on a single development scenario and represent the potential full-field incremental production supported by simulation or probabilistic analysis. The production forecast is based on a full-field integrated production model, which includes facility constraints and downtime for anticipated turnarounds programs. These events are subject to change, pending the future operational requirements of the *SeaRose FPSO*.

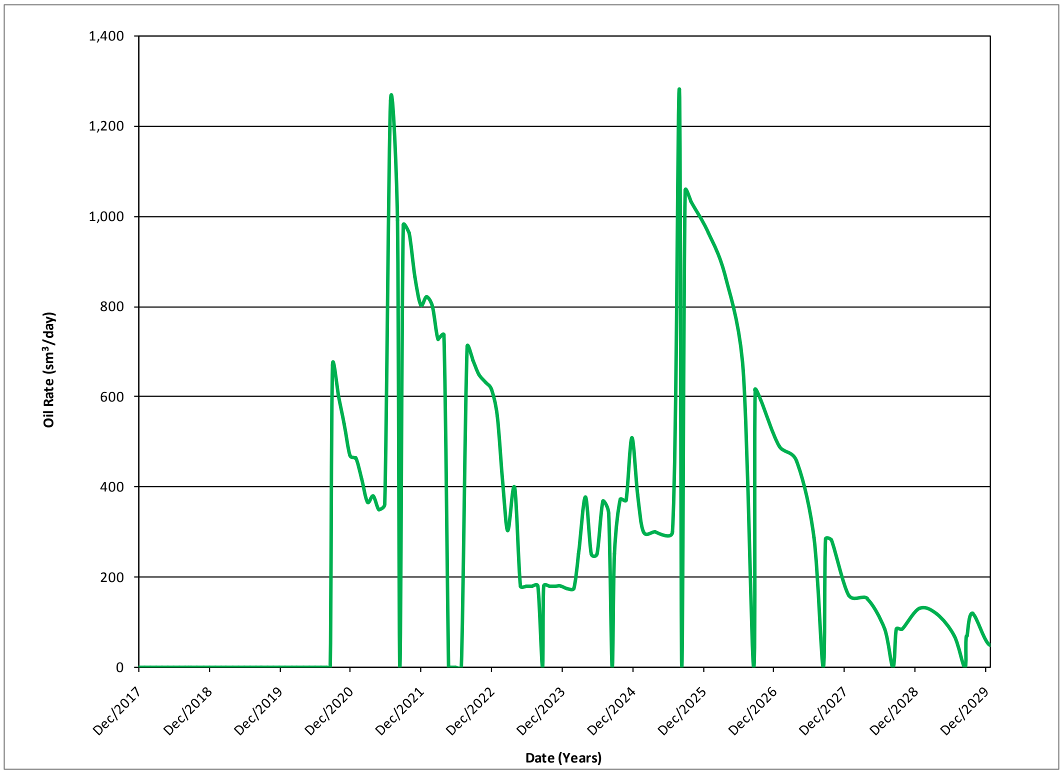


Figure 4-13 South Avalon Oil Production Profile

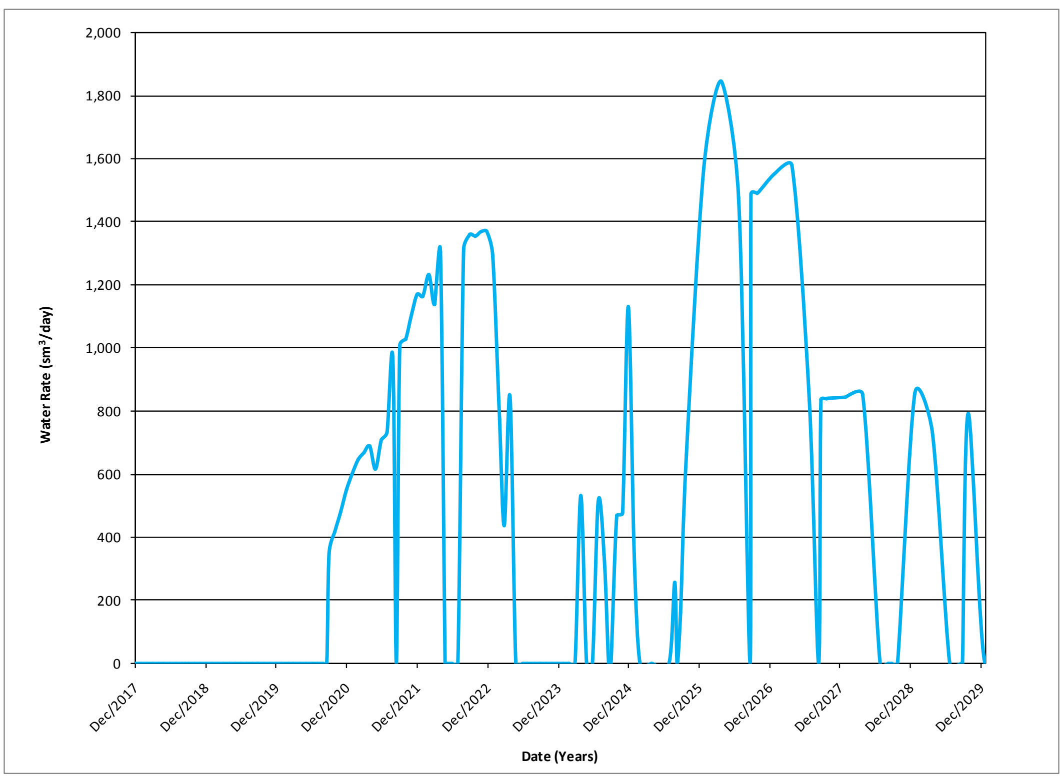


Figure 4-14 South Avalon Water Production Profile

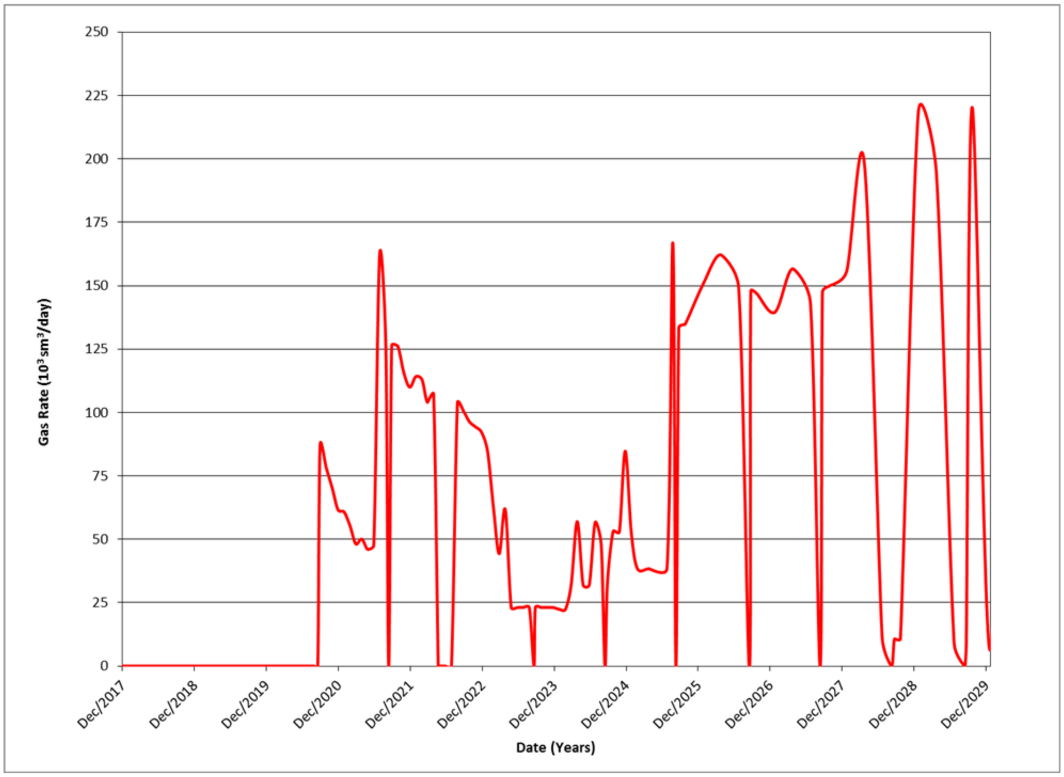


Figure 4-15 South Avalon Gas Production Profile

4.4 Blocks 2 and 5

Blocks 2 and 5 are considered a potential resource for development from the WHP in addition to the primary West White Rose pool.

4.4.1 Development Strategy

The current base development philosophy for Blocks 2 and 5 is similar to that of South Avalon, which includes horizontal producers in the oil column and horizontal underlying water injectors providing vertical pressure support from below. The current depletion plan consists of two horizontal producers (one in each of Blocks 2 and 5) and one intelligent horizontal water injector running through both Blocks 2 and 5. This proposed intelligent water injector solution leverages learnings from the existing South Avalon and North Amethyst fields, where intelligent water injectors are used for injection across multiple blocks.

Due to the relatively low gas breakthrough encountered in the South Avalon pool and small gas cap in place, the horizontal producers may be placed higher in the oil column to maximize recovery. The horizontal water injector would likely be drilled with an attempt to cross as many parasequences as possible to avoid potential baffling from any one individual parasequence boundary.

The reservoir management plan will be consistent with that of the South Avalon pool, which is to maintain a voidage replacement ratio between 1.0 and 1.2.This development scenario will be adapted as further geological and reservoir understanding is obtained based on observed production performance testing from Block 2 and 5.

4.4.1.1 Development Area

The Blocks 2 and 5 development area is shown in Figure 4-16. Potential production and injection targets are indicated for illustrative purposes. Final well count and locations will be based on further studies and optimization.

4.4.2 Well Count

The development scenario used to support the overview of Blocks 2 and 5 potential was a three-well program; two producers and one combined water injector. This plan is based on geological structure and contacts within the blocks and the current probabilistic evaluation of potential remaining recoverable within the pool. Final well count and layout for Blocks 2 and 5 may change upon further optimizations, and will ultimately be based upon the development viability in the area.

The basis for the well count has leveraged learnings from the existing developments and considers the increased technical functionality and improved drilling efficiency provided by the WHP. The basis will evolve with learning achieved through additional production history and field performance. Further optimization of well design will be conducted and, therefore, well counts and well planning may change.

4.4.3 Reservoir Simulation

The geological and simulation models for Blocks 2 and 5 are under development.

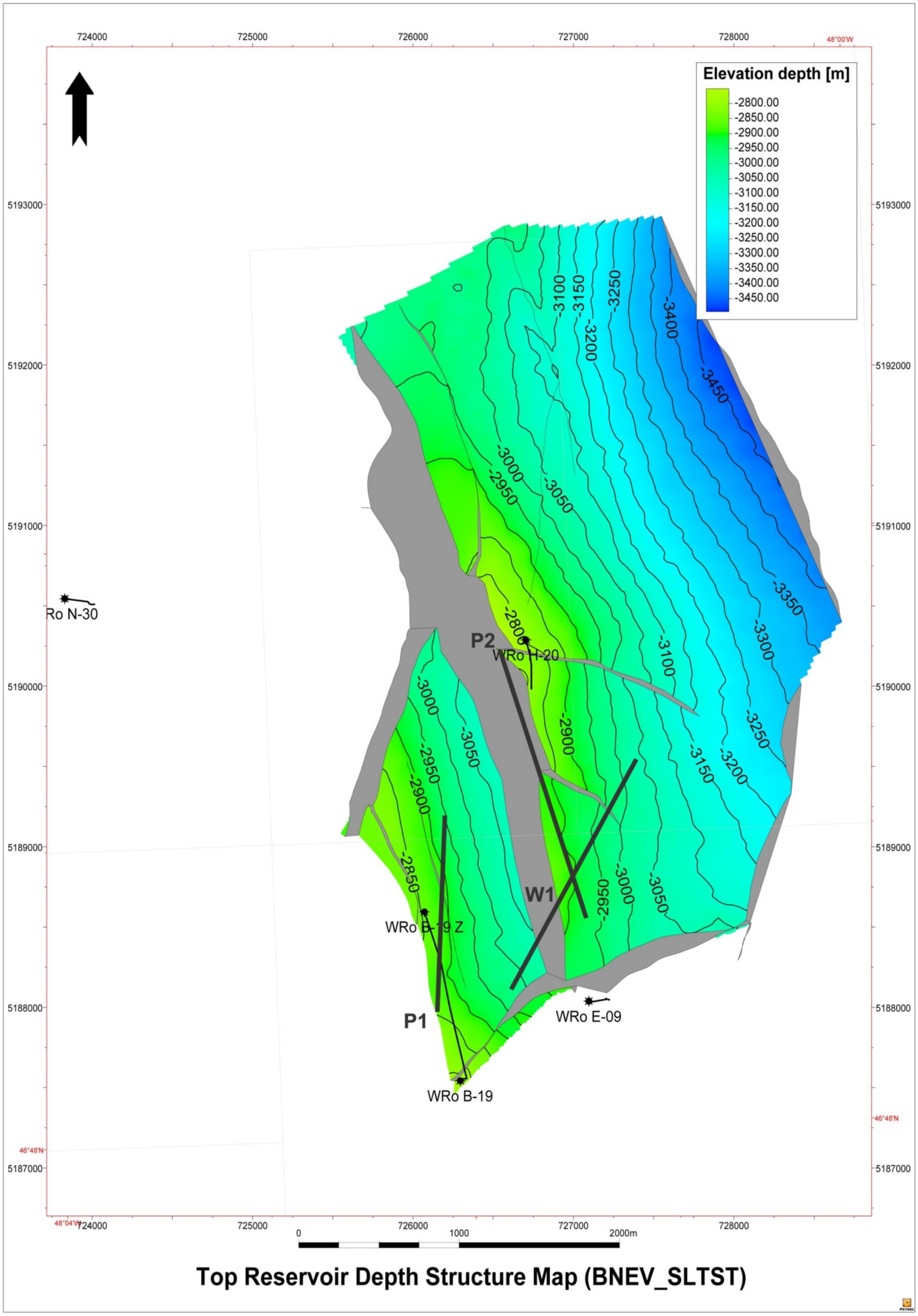


Figure 4-16 Blocks 2 and 5 Reservoir Depth Structure Map (mAPT_UC)

4.4.4 Production Performance

The Blocks 2 and 5 oil, water and gas production profiles are shown in Figure 4-17 to Figure 4-19, respectively. The recoverable production volumes presented in this Amendment had been based on probabilistic analysis. Production profiles have been generated based on analogous wells within the Central Region and Terrace sub-units of the South Avalon Pool. The production forecast is based on a full-field integrated production model, which includes facility constraints and downtime for anticipated turnaround programs. These events are subject to change pending the future operational requirements of the *SeaRose FPSO*. Actual production rates are subject to change following learning from additional modeling and optimization.

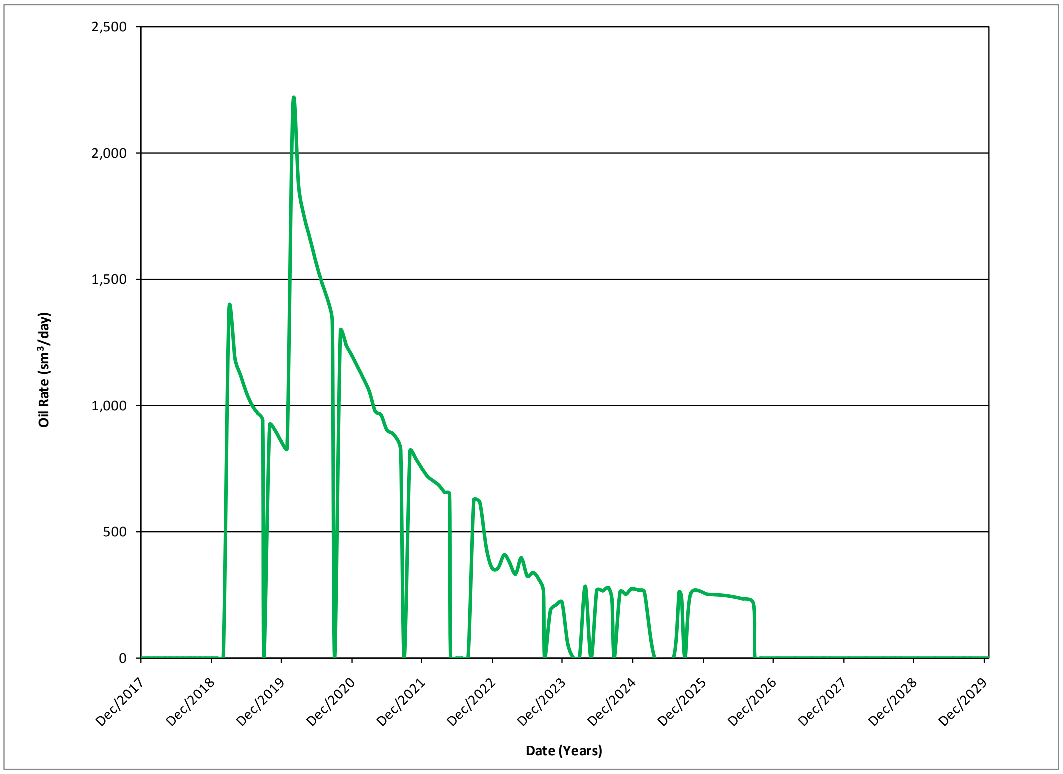


Figure 4-17 Blocks 2 and 5 Oil Production Profile

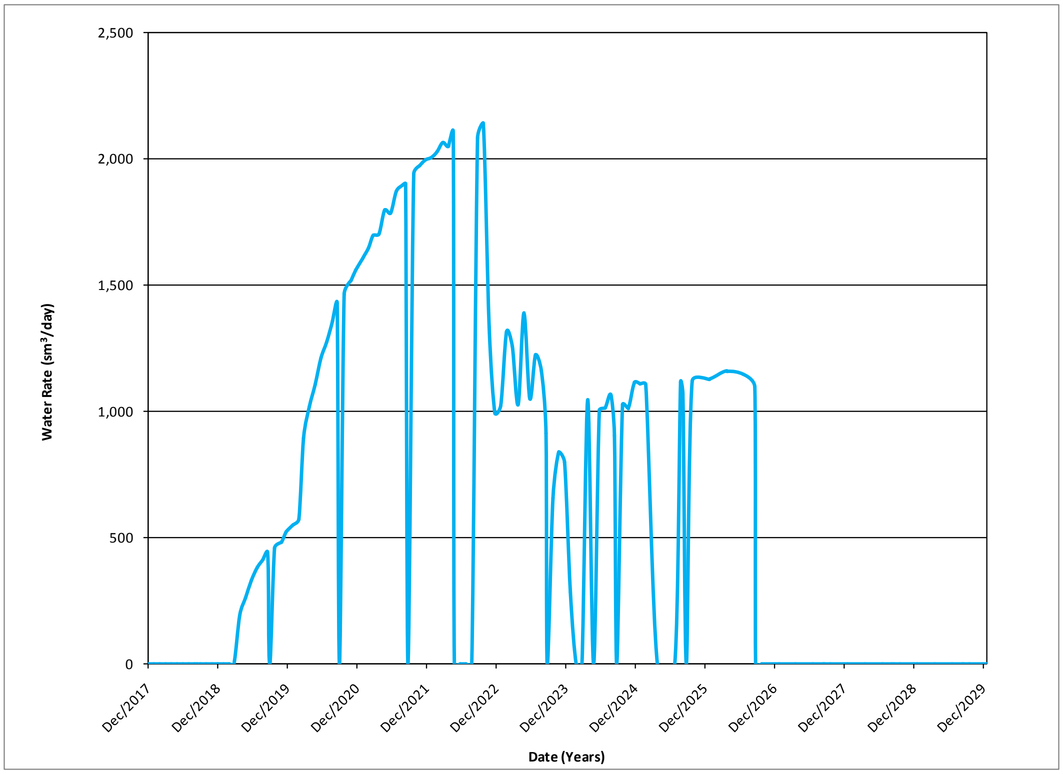


Figure 4-18 Blocks 2 and 5 Water Production Profile

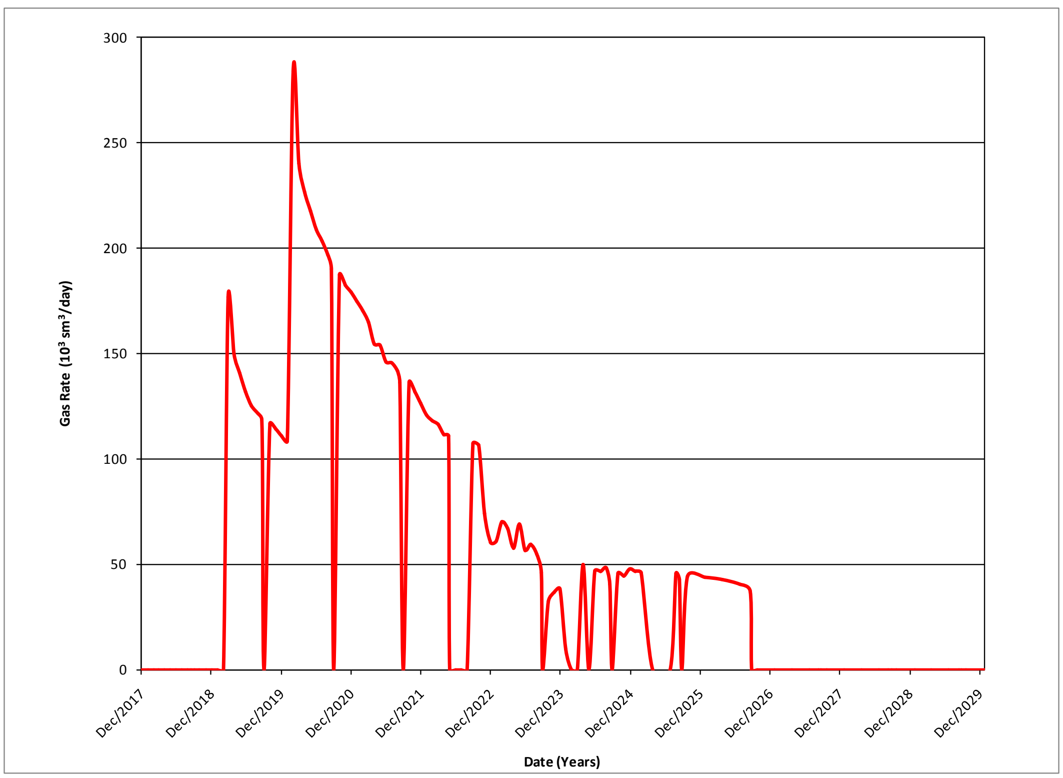


Figure 4-19 Blocks 2 and 5 Gas Production Profile

4.5 North Avalon

The North Avalon pool is considered a potential resource for development from the WHP in addition to the primary West White Rose pool.

4.5.1 Development Strategy

The current depletion scenario uses a single producer/injector well pair. The producer was placed at the south edge of the oil rim along a bounding fault in the centre of the oil column. Although near horizontal, the producer intersects several parasequences due to the dipping nature of the reservoir in this orientation. The supporting water injector was placed to the northeast of the producer in a near parallel orientation. The highly deviated injector also intersects several parasequences to maximize vertical sweep.

As reservoir and geological understanding is matured, the development plan will be adapted.

4.5.1.1 Development Area

The North Avalon development area is shown in Figure 4-20. The base development scenario is overlain on the reservoir area depicting one producer and injector pair.

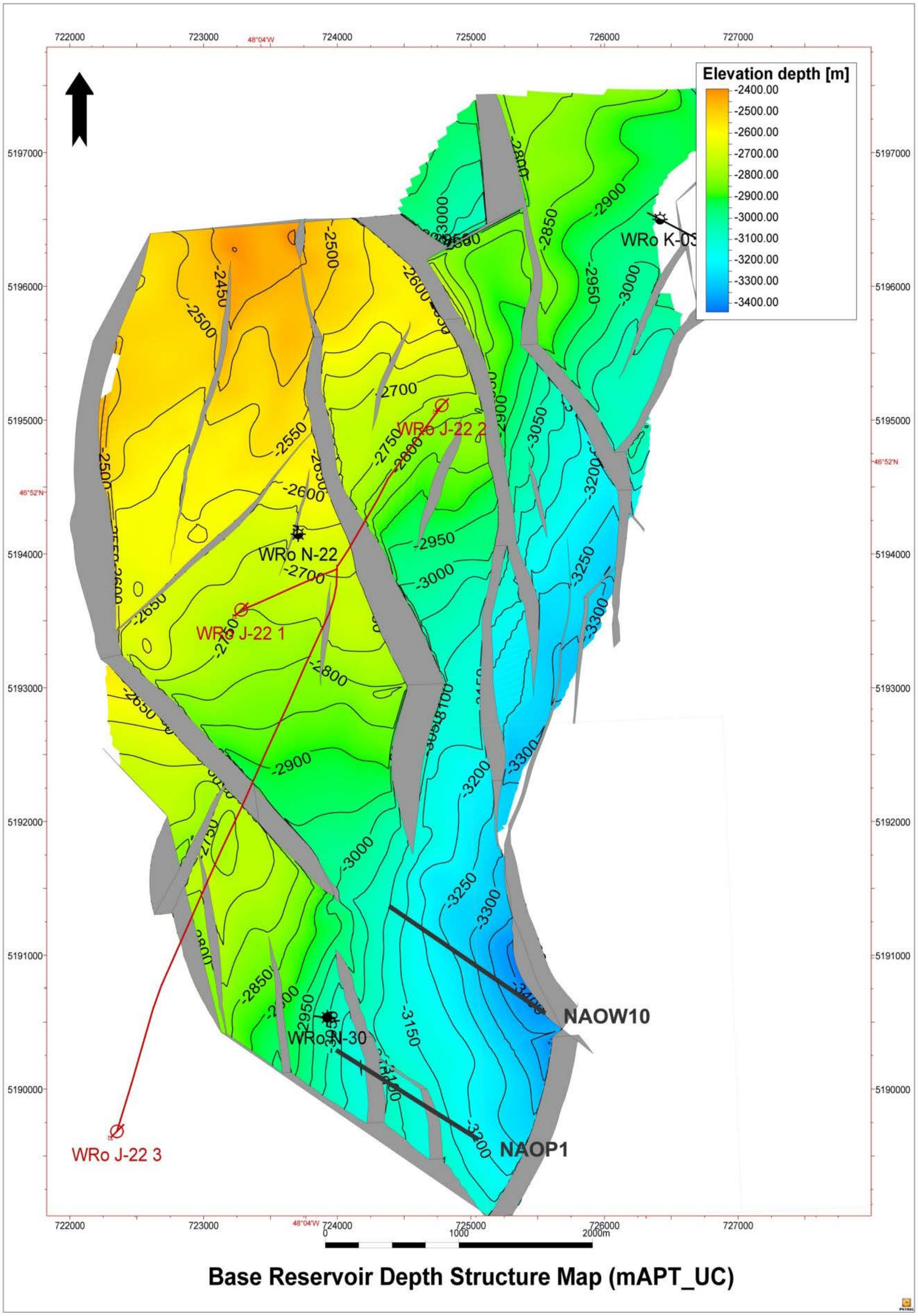


Figure 4-20 North Avalon Reservoir Depth Structure Map (mAPT_UC)

4.5.2 Well Count

The development scenario used to support the overview of North Avalon pool potential is a two-well program, one producer and one water injector. This plan is based on simulation modelling and the current probabilistic evaluation of potential remaining recoverable within the pool.

The basis for the well count has leveraged learnings from the existing developments and considers the increased technical functionality and improved drilling efficiency provided by the WHP. The basis will evolve with learning achieved through additional production history and field performance. Further optimization of well design will be conducted and, therefore, well counts and well planning may change.

4.5.3 Reservoir Simulation

The North Avalon ECLIPSE simulation model was based on a Petrel static model, which incorporates regional data from surrounding White Rose exploration and development wells in conjunction with North Avalon wells J-22 1, J-22 2 and N-30. The geological model was statistically populated and then upscaled to reduce the number of grid cells to a manageable number for dynamic simulation. A uniform 2:1 upscaling ratio was applied in both horizontal directions, resulting in a 50 m X 50 m dynamic grid. No vertical upscaling was applied to preserve the inherent heterogeneity. The resulting North Avalon simulation model was assigned fluid, rock and equilibrium characteristics consistent with those described in preceding sections of this amendment.

The model was initialized with a water saturation distribution that was generated using saturation logs and a co-krigged geostatistical distribution. The resulting deterministic OOIP is 6.394 e^6 m^3 versus the 6.2 e^6 m^3 P50 probabilistic value.

4.5.4 Production Performance

The North Avalon production profiles outlining oil, water, and gas production rates are shown in Figure 4-21 to Figure 4-23, respectively. These rates are derived from reservoir simulation and incorporated into the full-field integrated production model. The production forecast is based on a full-field integrated production model, which includes facility constraints and downtime for anticipated turnaround programs. These events are subject to change pending the future operational requirements of the *SeaRose FPSO.*

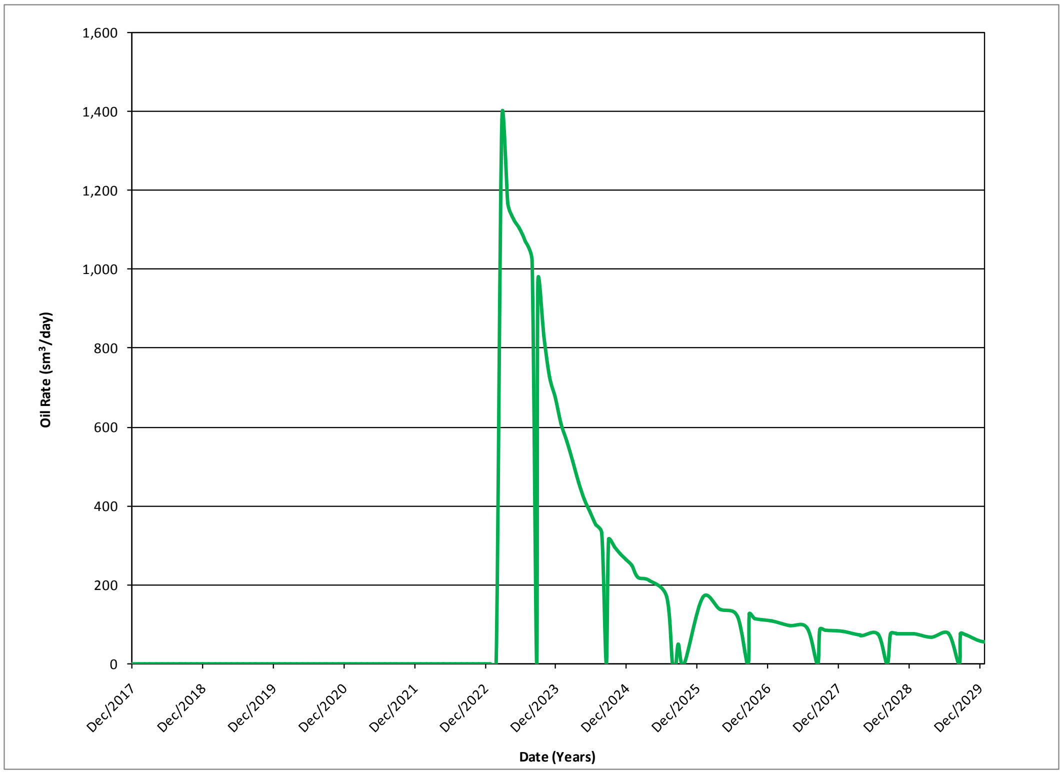


Figure 4-21 North Avalon Oil Production Profile

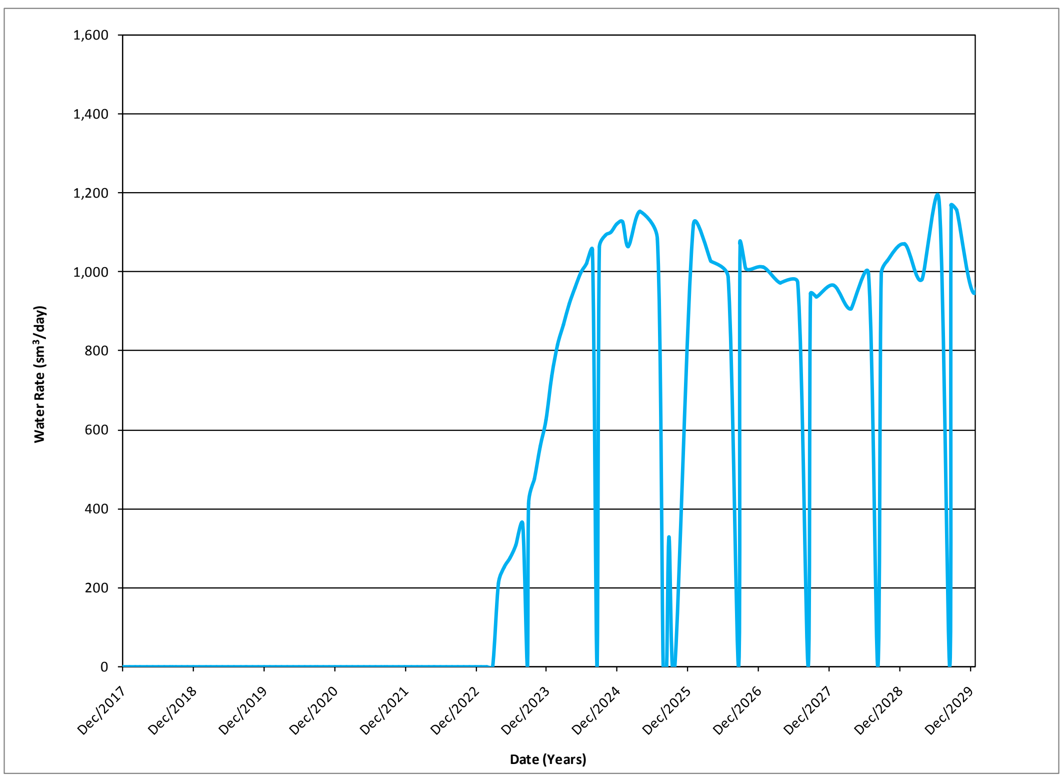


Figure 4-22 North Avalon Water Production Profile

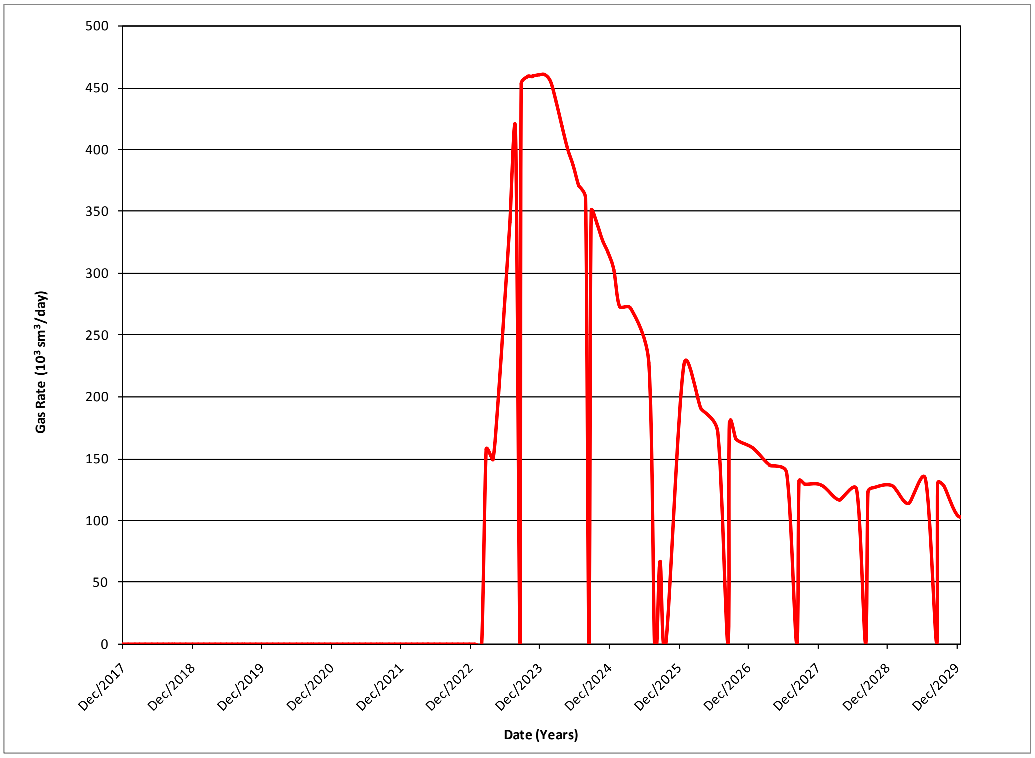


Figure 4-23 North Avalon Gas Production Profile

4.6 WREP Production Performance Well Scheduling Philosophy

A phased field development approach is planned through integrated development of the West White Rose pool in tandem with additional potential resources that may be developed using the WHP. The scheduling philosophy outlines the phases of the development of the West White Rose pool, with each phase providing information toward the success of the WREP. The order of fields developed is driven by the remaining recoverable resource and well count of each of the individual reservoirs. Therefore, the schedule is driven by West White Rose.

Within West White Rose the scheduling philosophy encompasses two key points:

- Wells deemed with the lowest geological risk are drilled near the beginning of the project. As these wells are developed, wells are drilled from south to north. This will provide learnings on geological trends. Characteristics such as facies distributions, productivity of varying sand qualities and lateral extent of gas cap are still elements of uncertainty as the field moves from proximal to distal.

- The well schedule incorporates periods of time to allow for learnings as new regions within the field are developed or new technologies are implemented. This time is required to assess learnings and adapt the development strategy for subsequent wells. During these windows of time, South Avalon, Blocks 2 and 5 and North Avalon will be developed.

4.7 WREP Development Well Schedule

A possible phased WREP development well schedule was assumed for the production profile, as presented in Table 4-1.

Table 4-1 Well Schedule

Count	Field/Pool	Well Name	Well Type	On-Line Date
1	West	PRD7B	Oil	Nov, 2016
2	Cuttings	Cuttings_1	Cuttings	Jan, 2017
3	West	PRD6B	Oil	Apr, 2017
4	West	INJ9B	Water Injector	Jun, 2017
5	West	PRD10C	Oil	Sep, 2017
6	West	INJ4A	Water Injector	Nov, 2017
7	BLK 2&5	2P1	Oil	Feb, 2018
8	BLK 2&5	5W1	Water Injector	May, 2018
9	West	PRD5C	Oil	Jul, 2018
10	West	INJ6A	Water Injector	Oct, 2018
11	BLK 2&5	5P1	Oil	Jan, 2019
12	West	PFB3HP2	Oil	Mar, 2019
13	West	PFB1HI2	Water Injector	Jun, 2019
14	South Avalon (SDC)	SAP3	Oil	Aug, 2019
15	South Avalon (SDC)	SAPGI2	Gas Injector	Nov, 2019
16	West	PFB1HP1	Oil	Jan, 2020
17	West	PFB3HI1	Water Injector	Apr, 2020
18	South Avalon (CDC)	SAP2	Oil	Jun, 2020
19	West	PRD6C	Oil	Sep, 2020
20	West	INJ8A	Water Injector	Nov, 2020
21	Cuttings 2	Cuttings_2	Cuttings	Jan, 2021
22	West	PRD5D	Oil	Apr, 2021
23	West	INJ6B	Water Injector	Jul, 2021
24	West	PRD3D	Oil	Sep, 2021
25	West	INJ10D	Water Injector	Dec, 2021
26	North Avalon	NAOP1	Oil	Mar, 2022
27	North Avalon	NAOW10	Water Injector	Jun, 2022
28	West	PFB5HP2	Oil	Aug, 2022
29	West	INJ2B	Water	Nov, 2022
30	West	B3UHZP1	Oil	Jan, 2023
31	West	PFB3HI2	Water Injector	Apr, 2023
32	South Avalon (CDC)	SAGI1	Gas Injector	Jun, 2023
33	West	PRD11B	Oil	Sep, 2023
34	West	INJ11A	Water Injector	Nov, 2023
35	West	PFB2HP1	Oil	Feb, 2024
36	West	PFB2HI1	Water Injector	May, 2024
37	South Avalon (CDC)	SAP1	Oil	Jul, 2024
38	West	PFB5HI1	Water Injector	Oct, 2024

4.8 WREP Production Profile

The schedule was implemented in IPM and incorporates all the individual field simulation results. Downtime was added for annual turnarounds and forecasted *SeaRose FPSO* off-station programs. The full-field WREP production profile is depicted in Figure 4-24, which includes:

- West White Rose
- Blocks 2 and 5
- North Avalon
- South Avalon IOR targeted through WHP.

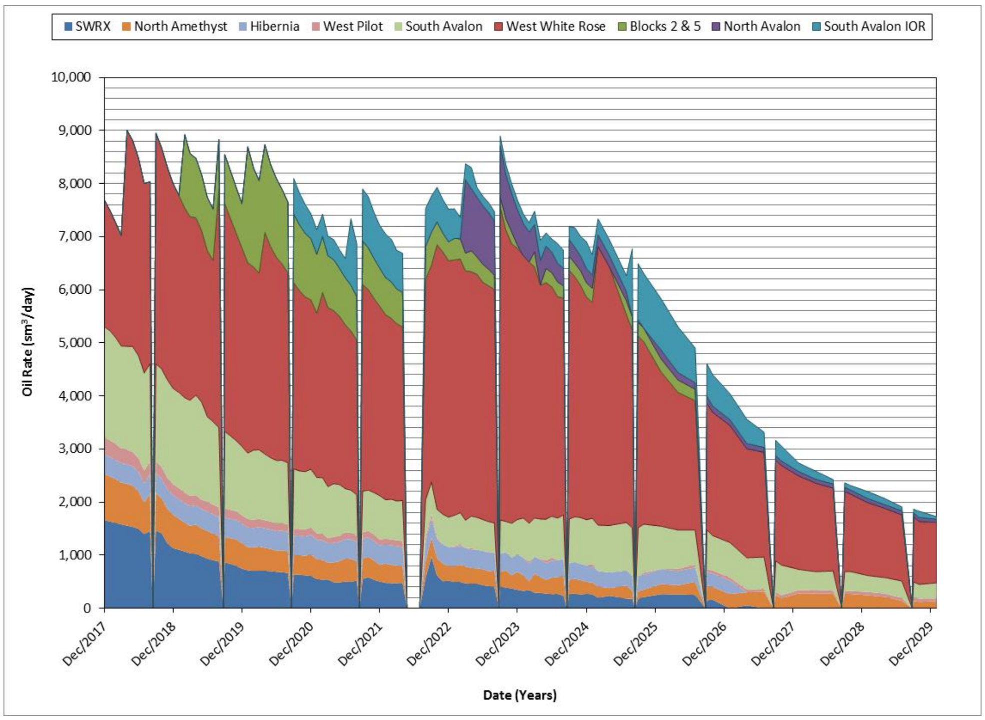


Figure 4-24 Full Field Oil Production Profile

As a reference case, the WREP development is depicted with the existing development production profile, which includes:

- Non-WREP-associated South Avalon production
- North Amethyst production
- West White Rose pilot production
- SWRX production
- North Amethyst Hibernia production.

Production data are also presented in tabular form in Appendices A and B.

Actual production rates will vary based on operational requirements for turnarounds. Changes in development philosophy due to new geological and reservoir interpretations will also vary estimations for production profiles.

The full-field WREP produced gas, total gas, gas lift, produced water, produced liquid, water injection and gas injection profiles are shown in Figure 4-25 through 4-31, respectively. The peak production and injection values identified on these plots are within the current topsides constraints of the *SeaRose FPSO*.

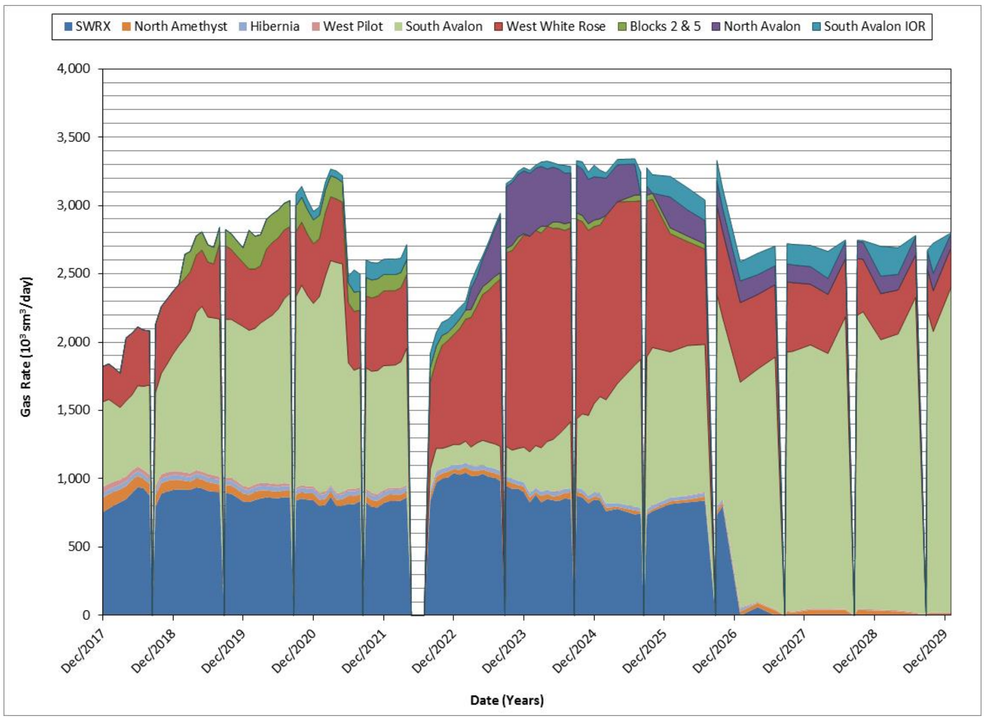


Figure 4-25 Full-Field Gas Production Profile

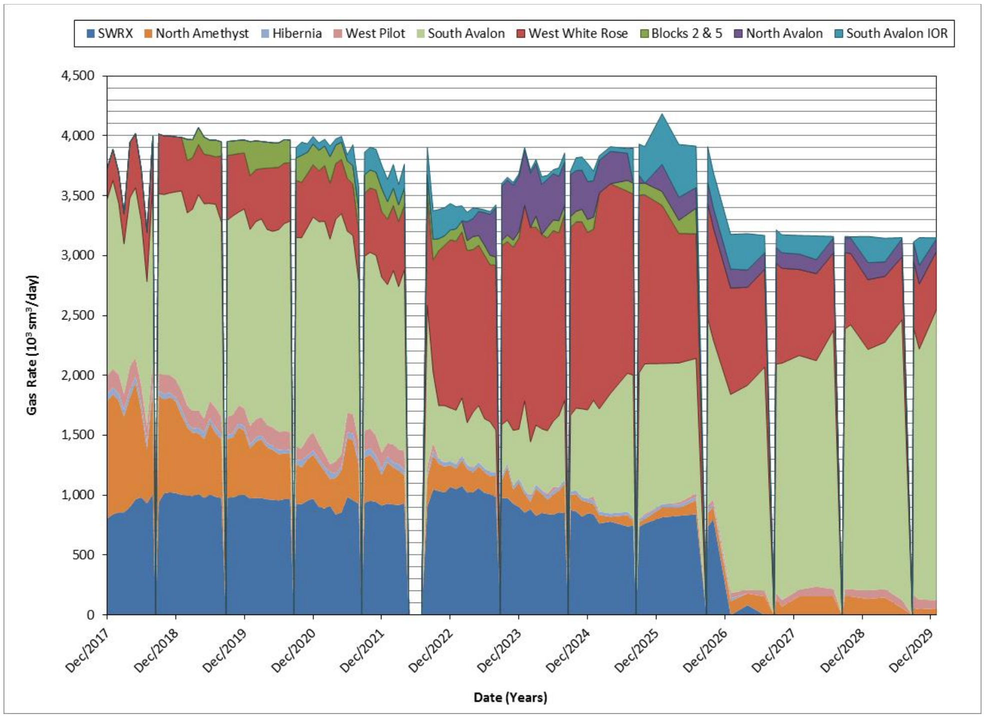


Figure 4-26 Full-Field Total Gas Profile

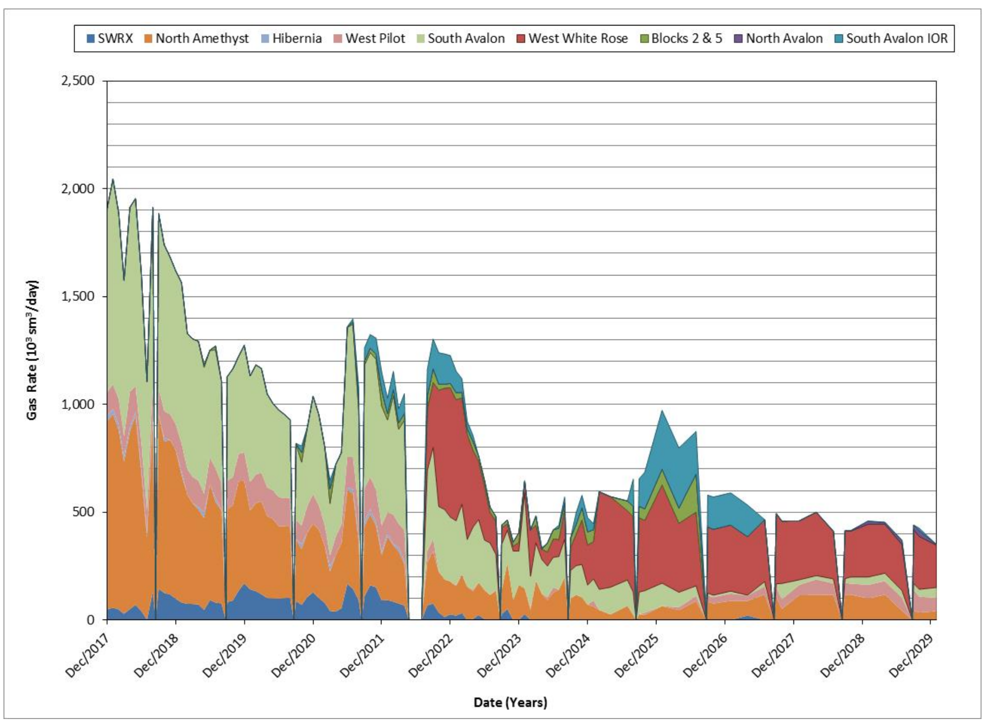


Figure 4-27 Full-Field Gas Lift Profile

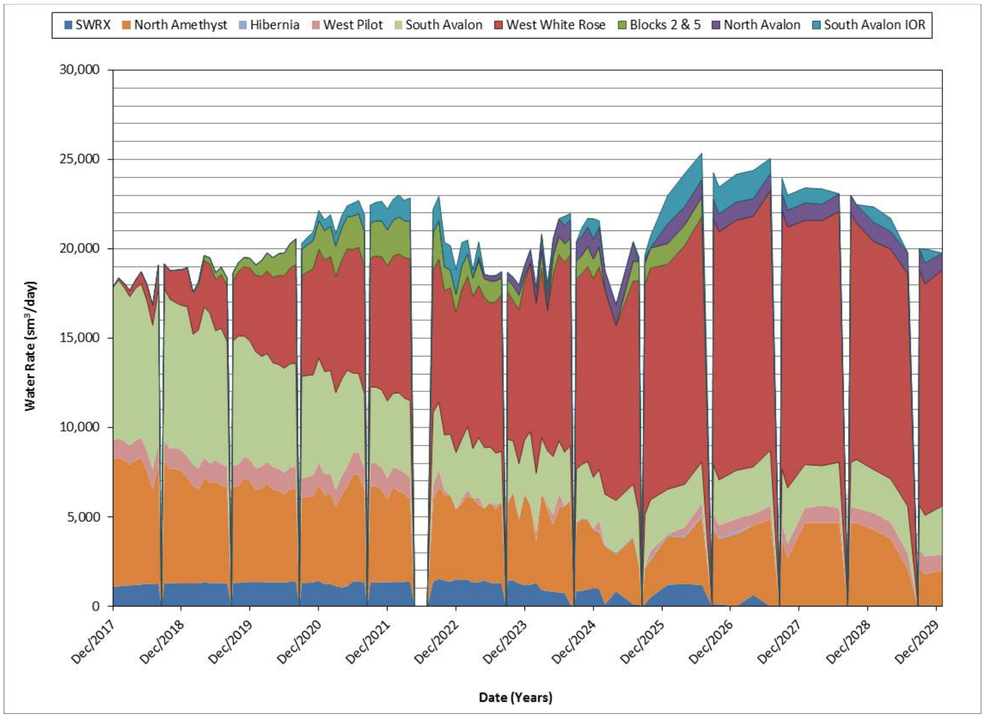


Figure 4-28 Full-Field Water Production Profile

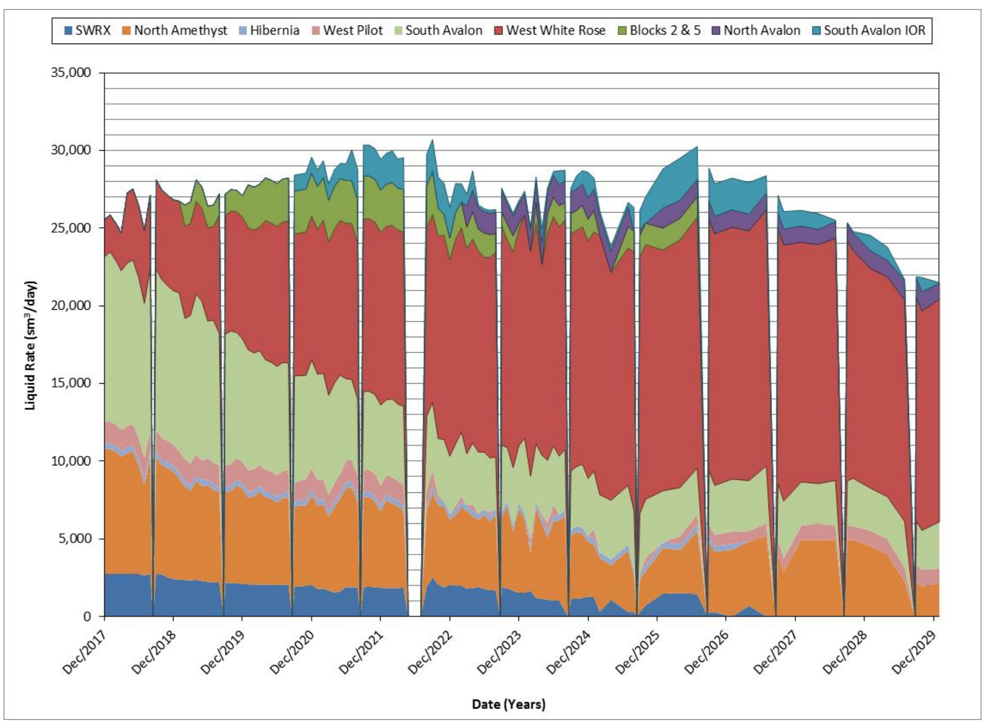


Figure 4-29 Full-Field Liquid Production Profile

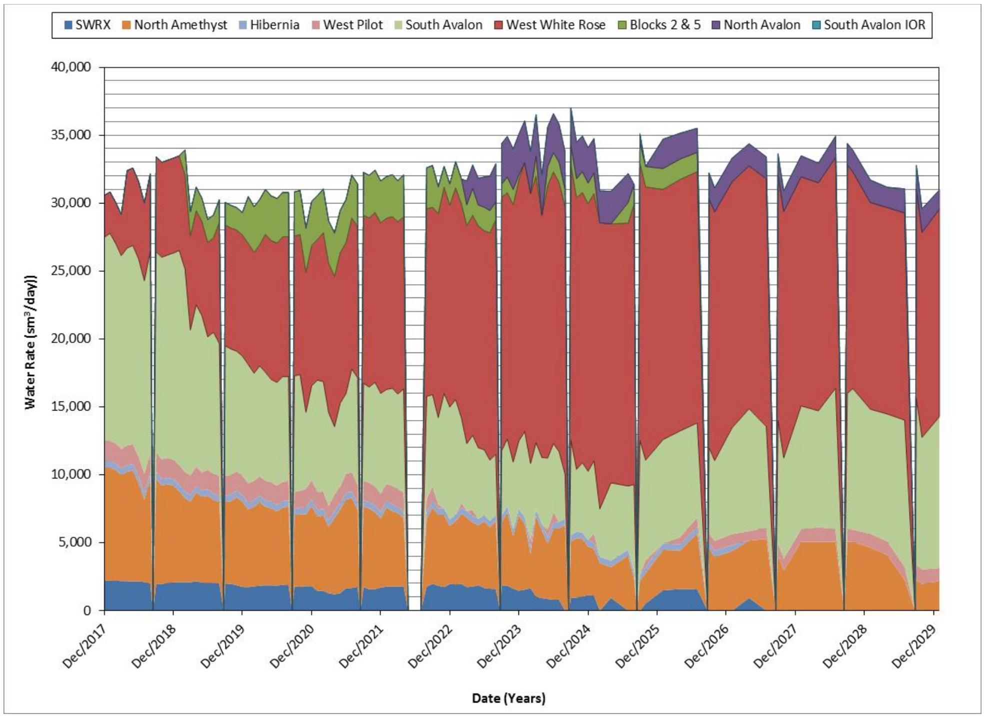


Figure 4-30 Full-Field Water Injection Profile

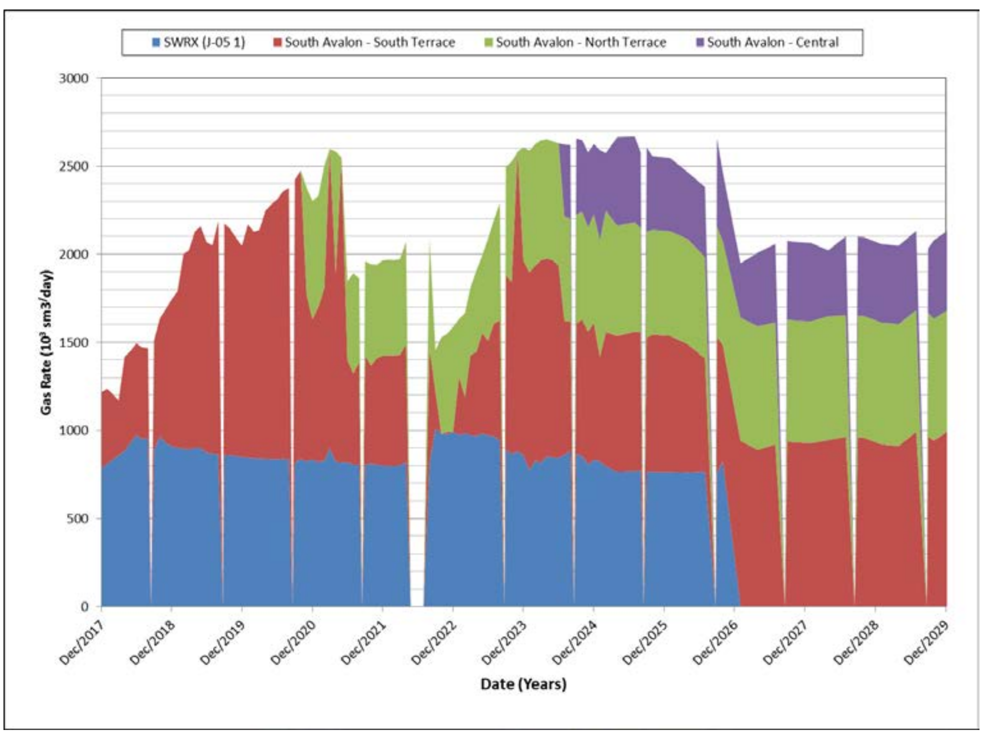


Figure 4-31 Full-Field Gas Injection Profile

4.9 WREP Reservoir Management Plan

4.9.1 Displacement Strategy

The displacement strategy plans for all development pools to include secondary recovery by water flood. A voidage replacement ratio between 1.0 and 1.2 will be targeted during the operational phase.

The existing secondary recovery mechanism of water displacement will be maintained, but may be augmented with gas injection, WAG, or partial pressure support if deemed viable.

The WHP will have the ability to change the flood mechanism to a gas flood or WAG. These displacement strategies will be evaluated and executed if required. The ongoing learnings from development of SWRX will provide key information about the potential benefits of gas flood in other areas.

4.9.2 Data Acquisition

Data acquisition will be conducted as per the *C-NLOPB Data Acquisition and Reporting Guidelines (September 2011).* Detailed data acquisition plans on an individual well basis will be submitted for approval as part of the Approval to Drill a Well application.

4.9.3 Reservoir Surveillance

New development wells will be equipped with equipment equivalent to the existing South Avalon and North Amethyst wells, which will provide pressure and temperature measurements downhole and at the wellhead.

4.9.4 Injection Fluids

4.9.4.1 Gas

Table 4-2 summarizes the composition of the gas that will be available for injection. The composition is based on the high-pressure compression suction scrubber gas analysis. Gas lift and gas injection will be supplied to the WHP from the dry gas produced on the *SeaRose FPSO*. The gas has a water content of 24 kg/million Sm^3 and a water dew point of approximately -18°C at 40 MPa.

Table 4-2 Injection Gas Composition

Gas Component	Mole Fraction		Specific Components	Mole Fraction
CO	0.0001			
H_2	Trace		neo-Hexane (C_6)	0.00000
He	0.0001		n-Hexane (C_6)	0.00084
O_2	0.0028		Methylcyclopentane (C_7)	0.00043
N_2	0.0135		Benzene (C_7)	0.00023
CO_2	0.0208		Cyclohexane (C_7)	0.00035
H_2S	0.0000		2,2,4-Trimethylpentane (C_8)	0.00000
C_1	0.8509		Methylcyclohexane (C_8)	0.00019
C_2	0.0554		Toluene (C_8)	0.00000
C_3	0.0318		Ethylbenzene (C_9)	Trace
iC_4	0.0045		m&p-Xylene (C_9)	0.00000
nC_4	0.0106		o-Xylene (C_9)	Trace
iC_5	0.0025		1,2,4-Trimethylbenzene (C_{10})	0.00000
nC_5	0.0031			
C_6	0.0021		**Plus Components**	
C_7	0.0011		C_7^+	0.00180
C_8	0.0007		C_{12}^+	0.00000
C_9	Trace		C_{15}^+	0.00000
C_{10}^+	0.0000			
TOTAL	**1.0000**			
Source: Maxxam report for Extended Gas Analysis of High Pressure Compressor Suction Scrubber, Lab No: B104883:Z50827, January 5, 2011				

4.9.4.2 Seawater

Currently, seawater is treated and injected from the *SeaRose FPSO*. Treatment includes de-aeration with continuous oxygen scavenger injection and weekly biocide dosing. Treated injection water from the *SeaRose FPSO* will be used by the WHP. Table 4-3 summarizes the injection water density and composition.

Table 4-3 Injected Seawater Analysis

Density	kg/m^3	1,024
Chemical Component		
Na	mg/l	9,772
K	mg/l	351
Ca	mg/l	438
Mg	mg/l	1,167
Cl	mg/l	17,498
HCO_3	mg/l	128
SO_4	mg/l	1,922
Reference: White Rose DA Volume 2 – 01/2001		

4.10 WREP Production Management Plan

4.10.1 Facility Constraints

Table 4-4 shows the *SeaRose FPSO* capacity constraints considered for the WHP concept evaluation.

Table 4-4 *SeaRose FPSO* Design Capacities

Component	m^3/d	bbl/d
Liquids	33,000	208,000
Oil	22,300	140,000
Produced Water	28,000	176,000
Water Injection	44,000	276,000
	MSm^3/d	**mmscfd**
Total Gas (associated with oil)	4.2	148

4.10.2 Well Testing

Given the addition of another test separator on the WHP, wells will have the ability to be routed to the test separator for routine well testing. As a secondary measure, third-party production allocation software will be installed to facilitate well estimation.

4.10.3 Artificial Lift

All production wells will include the use of gas lift as primary artificial lift, similar to the completions in South Avalon and North Amethyst. If feasible, some West White Rose wells will be considered for use of ESPs as a secondary lift mechanism.

Other potential WHP wells may also be targets for use of ESP technology. ESPs would be evaluated on a well- and field-specific basis during the final well design process.

4.10.4 Flow Assurance

There are no significant concerns with respect to scaling, hydrogen sulfide corrosion, or wax deposition for the fields developed by the WREP. Existing development well experience in the White Rose Development has reduced the uncertainty of these elements in the facility design.

Design of the facilities will ensure the crude oil remains above a temperature that will avoid problems associated with wax. The production systems exposed to produced fluids will be designed for sour service consistent with the present White Rose design and operating philosophies.

4.11 WREP Gas Management Plan

4.11.1 Gas Injection Overview

Produced gas from WREP will be re-injected through existing gas injection infrastructure within the White Rose region. Gas will be used primarily for further oil recovery through gas flood. The first gas flooded region will be SWRX. Additionally, a portion of the gas may be used for gas flood or WAG schemes to support oil production from various pools associated with the WREP. The White Rose gas utilization strategy includes a base gas injection plan and potential future gas injection opportunities.

4.11.2 Gas Volume Requirements

The anticipated production profile of the White Rose region, including current production of South Avalon and North Amethyst, future SWRX and North Amethyst Hibernia development and the WREP, indicates a gas volume requirement of 4.95 billion Sm^3 from January 1, 2014 to 2030, as per Table 4-5.

Table 4-5 Gas Volume Requirement

Component	Gas Volume Requirement (Billion Sm^3)
Base Development*	
North Amethyst	0.571
South Avalon Terrace	1.190
South Avalon Central Region	0.935
West White Rose Pilot	0.209
North Amethyst Hibernia	0.150
Total Base Development*	3.055
Total South White Rose*	1.050
WREP Incremental Development*	
Blocks 2 & 5	0.239
North Avalon	0.487
West White Rose	3.146
South Avalon	0.185
Total WREP Development*	4.057
White Rose Development Total*	**8.162**
Total Fuel Consumption	**3.212**
Net Gas Required	**4.95**
*Gas volumes reported are prior to fuel gas requirements being subtracted.	

The total gas produced over the life of the field is estimated at 13.1 billion Sm^3. This cumulative produced gas represents gas produced as a result of solution gas and gas cap gas, as well as the breakthrough of injection gas from gas injection wells for gas flood.

Accounting for fuel gas, the gas to be injected over the field life is estimated to be 10.1 billion Sm^3. A portion of this gas injected represents gas that is recycled through the reservoir and is therefore not considered net gas that will require handling. The portion of the gas injected volume to be handled is approximately 4.95 billion Sm^3 between the period of January 1, 2014 to 2030.

4.11.3 Gas Utilization Strategy

The White Rose gas utilization strategy includes a base injection plan (wells identified in Figure 4-32) as well as identification of potential future gas utilization opportunities.

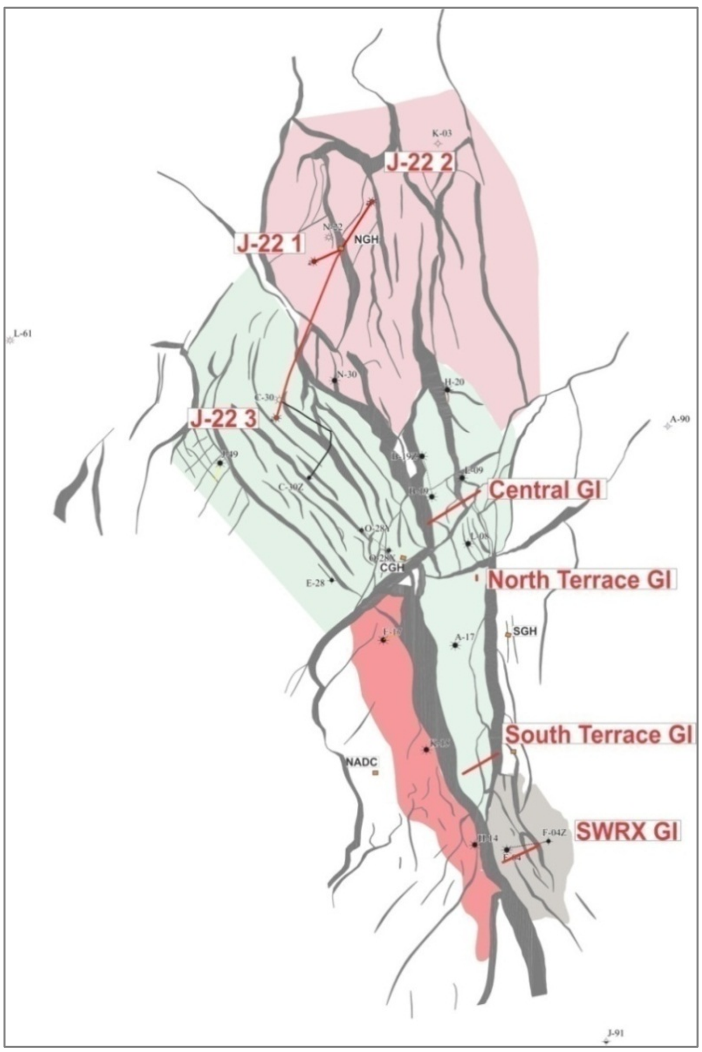


Figure 4-32 Gas Injection Locations

Base Plan: The following are expected to provide full-field gas injection utilization:

- Continued gas injection into North Avalon and West White Rose gas storage wells
- Gas flood into SWRX and South Avalon southern terrace region
- Gas flood into South Avalon northern terrace region and the central region.

Alternative Options Plan: The following are progress options in the event of additional developments and for contingency purposes:

- Gas injection into the North Avalon pool via a new NDC well J-22 4. Due to the drilling risk, well complexity and reservoir risk, J-22 4 is not a preferred gas storage option, but the option can be a contingent gas storage location.
- Evaluate the potential for delineation of gas injection opportunities at near-field locations. There is potential for gas storage from gas-bearing formations near the White Rose region. However, in all cases, further exploration and delineation drilling is required to determine the full extent of the storage capacity. These opportunities will continue to be progressed as part of the overall gas utilization strategy.
- Evaluate further gas-enabled (i.e., WAG, IOR) applications. The WAG process involves injecting gas, followed by injecting water into the same injection well. By alternating the injected fluid, mobility control can be improved and the gas can be used to capture upswept oil that would otherwise be bypassed by water flooding alone. Implementing a WAG scheme would provide a level of future gas use for voidage replacement.

4.11.3.1 Base Plan: North Avalon and West White Rose Pools

Currently, all gas produced from the *SeaRose FPSO* is injected into the North Avalon and West White Rose pools. The NDC is the gas injection drill centre for the overall White Rose region with three gas injection wells: J-22 1, J-22 2 and J-22 3. The remaining capacity estimate for these wells is approximately 38 million Sm^3 (Table 4-6). Periodic injection into North Avalon and West White Rose gas storage wells may occur as deemed necessary.

Table 4-6 Existing Storage Capacity

Location	Maximum Gas Storage Capacity (million Sm^3)	Injected Gas Jan 1 2014 (million Sm^3)	Remaining Capacity (million Sm^3)
North Avalon J-22 1	2,925	2,925	0
North Avalon J-22 2	258	243.6	14
West White Rose J-22 3	404	380.3	24
Total			38

4.11.3.2 Base Plan: Gas Injection into SWRX and South Avalon Southern Terrace

The SWRX drill centre will access both the SWRX pool and the southern portion of the South Avalon Terrace. The SWRX pool has a large gas cap into which gas can be used as voidage replacement for the development. The IOR plans for the South Avalon Terrace include gas injection in the southern gas cap. The western fault block of South Terrace will flood the gas cap and move oil down into the existing oil producers and a planned infill well. Gas flooding will require significant volumes in this region (Table 4-7). The eastern fault block of the South Terrace region is potentially isolated and may serve as a storage area if proven to be isolated from the producing portion of the Terrace.

Table 4-7 South White Rose and South Avalon Southern Terrace Gas Injection Volumes

Location	Voidage Replacement Volume (million Sm^3)
South White Rose	1,600
South Avalon South Terrace West	1,200
South Avalon South Terrace East	900
Total	**3,700**

4.11.3.3 Base Plan: Gas Injection into South Avalon Northern Terrace and Central Region

Gas cap gas injection was evaluated as part of the South Avalon IOR analysis and will continue to be matured. Gas injection into the gas caps of these regions may be used to displace the remaining attic oil to existing producers and will require a level of gas volume (Table 4-8).

Table 4-8 South Avalon Northern Terrace and Central Region Voidage Replacement Volumes

Location	Voidage Replacement Volume (million Sm^3)
South Avalon Terrace North	1,100
Central Region	500
Total	**1,600**

4.11.4 Summary

Gas injection into the NDC, SWRX and South Avalon, combined with contingency options, will use produced gas for WREP life-of-field.

The gas utilization strategy objective is to continually monitor and forecast gas injection volume requirements and to progress contingency options to ensure use of the produced gas for existing and future development of the White Rose region. The gas utilization strategy will continue to evolve as new information is collected.

5.0 HYDROCARBON RESOURCE ESTIMATES

5.1 Overview

The WHP will be primarily used to access the West White Rose pool. However, other resources are located within reach of the WHP and are considered as potential resources for development from the new facility.

This section presents the current basis for in place and recoverable volumes in the pools that are being considered for development from the WHP. This basis has leveraged learning from the White Rose and North Amethyst developments and considers the increased technical functionality provided by the WHP. The basis will evolve with learning achieved through additional production history and field performance.

5.2 Methodology

A probabilistic analysis of the in-place and recoverable oil resources has been performed. The analysis encompasses a full range of in-place resources and recoverable based on development strategy and geological uncertainty. The pools and sub-units that have been analyzed include West White Rose, North Avalon, South Avalon Terrace, South Avalon Central Region and South Avalon Blocks 2 and 5.

5.3 Original Hydrocarbon In-Place Estimates

The probabilistic OOIP and Gas Initially in Place (GIIP) for the West White Rose pool and other potential development areas have been summarized in Table 5-1.

The matured pools are supported by deterministic reservoir models that typically represent an approximate P50 basis. Since the simulation model for Blocks 2 and 5 is currently under development, the probabilistic range for Blocks 2 and 5 was based on estimated ranges of average reservoir properties.

The basis will evolve with learning through further technical evaluation and future drilling results.

Table 5-1 OOIP and GIIP Pool Summary

Pool	OOIP (10^6 m^3)		
	P90	**P50**	**P10**
West White Rose	50.5	72.9	94.0
North Avalon	4.8	6.2	8.0
Blocks 2 and 5			
Block 2	2.9	3.8	4.9
Block 5	1.5	1.9	2.6
South Avalon			
Terrace (Block 7)	40.3	47.6	56.1
Central (1 and 3)	29.2	34.6	40.6
Central (4)	3.7	4.3	5.1
	Solution GIIP (10^9 m^3)		
West White Rose	6.1	8.7	11.4
North Avalon	0.6	0.8	1.0
Blocks 2 and 5			
Block 2	0.4	0.5	0.6
Block 5	0.2	0.3	0.3
South Avalon			
Terrace (Block 7)	5.0	6.1	7.3
Central (1 and 3)	3.7	4.4	5.3
Central (4)	0.5	0.6	0.7
	Free GIIP (10^9 m^3)		
West White Rose	10.2	14.5	19.7
North Avalon	7.1	9.5	12.6
Blocks 2 and 5			
Block 2	0.3	0.4	0.6
Block 5	0.2	0.2	0.4
South Avalon			
Terrace (Block 7)	7.6	9.8	12.7
Central (1 and 3)	2.1	2.7	3.3
Central (4)	0.2	0.2	0.3

5.4 Recoverable Resource Estimates

The probabilistic recoverable resource range for the West White Rose pool and other potential development areas is provided in Table 5-2.

Table 5-2 Recoverable Resource Estimate Summary

Pool	Recoverable (10^6 m^3)		
	P90	**P50**	**P10**
West White Rose	10.1	17.1	21.3
West White Rose Incremental	7.8	14.8	18.9
Blocks 2 and 5	1.0	1.5	2.7
Blocks 2	0.6	1.0	1.8
Blocks 5	0.3	0.5	1.0
North Avalon	0.5	0.6	1.0
South Avalon Full Field	31.1	38.4	47.5
Terrace (Block 7)	16.7	21.3	27.1
Central (1 & 3)	12.2	15.2	18.8
Central (4)	1.5	1.9	2.3
Deterministic South Avalon Volumes			
	Low	**Mid**	**High**
South Avalon Existing Development	32.8	34.6	38.1
Terrace	17.8*	18.6*	20.8*
Central Region	15.0*	16.0*	17.3*
South Avalon WREP Incremental	0.8*	1.4*	2.4*
Terrace	0.4*	0.7*	1.2*
Central Region	0.4*	0.7*	1.2*
Notes: 1. *Indicates deterministic values ; 2. Probabilistic sum will not sum arithmetically			

The recoverable volumes are probabilistic ranges that use White Rose region historic well performance, pool-specific reservoir quality attributes and WHP-specific potential technology applications. The matured fields are supported by deterministic reservoir models that typically represent an approximate P50 basis.

The production profile basis, as presented within Section 4.0, assumes an end-of-field life of 2030.

In the case of West White Rose and South Avalon, where existing infrastructure will recover a portion of the oil-in-place, the recoverable volume represents the incremental portion associated with the WREP.

Consideration of the current West White Rose depletion plan recoverable basis and the additional potential resources that may be developed from the WHP yields a combined potential recoverable resource of 17.1 10^6 m^3.

The basis will evolve with learning through further technical evaluation, future drilling results, field performance history and maturing technology application.

The well counts or program of wells that were used in the development scenarios in Section 4.0 and that relate to the above P50 recovery basis are included in Table 5-3.

Table 5-3 Well Count per Development Scenario Summary

Pool	WREP Well Count
West White Rose	26
Blocks 2 and 5	3
North Avalon	2
South Avalon	5
Drill Cuttings Injection	2
Total	**38**

This basis will evolve with learning achieved through additional production history and field performance and the final well slot allocation will consider the feasibility of recovering the resource within the WHP capture area.

5.5 Secondary Reservoirs

Additional resources beyond the Ben Nevis have been discovered within the Hibernia, Eastern Shoals, South Mara and Jurassic Formations. These reservoirs have tested hydrocarbon within the capture area of the WHP but have continued uncertainty in the extent, quality, connectivity and feasibility of recovery. Their potential will continue to be evaluated as the region matures. A discussion of these secondary reservoirs is provided in the following sections.

5.5.1 Hibernia Formation

Hydrocarbons were encountered within the Hibernia Formation in the White Rose E-09 and N-22 wells, as well as the North Amethyst E-17 well. A Development Plan Amendment has been submitted to the C-NLOPB for development of the Hibernia Formation at the North Amethyst Field.

Additional potential exists within the Hibernia Formation in the White Rose area; however, uncertainty remains as to the extent, quality and productivity of the reservoir. The performance of the Hibernia Formation in the North Amethyst E-17 Block will be evaluated to determine the feasibility for potential development of the more compacted and faulted Hibernia Formation in the WREP development area.

5.5.2 Eastern Shoals Formation

Hydrocarbons have been tested from the Eastern Shoals Formation in the White Rose N-22, J-49 and N-30 wells. The N-22 well tested 40 x 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; however, no production tests were performed. The J-49 well tested gas and condensate with a 14 percent watercut. The Eastern Shoals reservoir that has been tested to date has been thin with variable presence and quality.

The Eastern Shoals is generally of a thickness less then what is seismically resolvable and therefore, the overall extent and reservoir quality of the Eastern Shoals Formation is unknown and considered limited due to the minimal thickness and penetrations to date. The thin reservoir sands of the Eastern Shoals Formation are not fully mapped and considering the uncertainty of presence and quality, there are no new resource estimates.

5.5.3 South Mara Member, Banquereau Formation

Only the White Rose L-61 well tested hydrocarbons within the South Mara Member. The L-61 well tested gas at a rate of 3.1 10^6 m^3/d of gas and 70 m^3/d of condensate from a thin sandstone within the South Mara Member. The area of potential resource 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 water saturation of 15 percent.

5.5.4 Jurassic Formation

A Jurassic sandstone was tested in the White Rose E-09 well at a rate of 10 x 10^3 m^3/d of gas. The ability to map this Jurassic sandstone is affected by limited well penetrations in the White Rose area, a high degree of faulting and decreasing seismic data quality at depth. There is a high degree of uncertainty related to reservoir potential and there are no established resource estimates to date. Should development of the Jurassic Formation below the existing development area be deemed feasible, this horizon could potentially be reached from the WHP.

6.0 DRILLING, COMPLETIONS AND INTERVENTIONS

6.1 Platform Development Drilling

Drilling, completions and intervention operations will be conducted from the WHP. The drilling rig will be designed for year-round operation. The drilling package will comprise a single derrick and associated drilling utilities. The rig design will allow for simultaneous drilling and wireline (electric and slick) and coiled tubing operations. Design of the drilling facilities will incorporate lessons learned from the design, construction and operation of White Rose, Terra Nova and Hibernia developments and other successful harsh environment projects around the world.

6.1.1 Preliminary Drilling and Completion Plans

The WHP will target the West White Rose reservoir and other potential prospects in the area. Wellbores will be extended reach with three-dimensional trajectories and horizontal or near-horizontal sections. Torque, drag and wellbore stability will be among the key well design considerations. Completions will be similar in range (with both open-hole and perforated designs) to those currently used on the subsea wells in the White Rose region. However, completions may vary in complexity due to the relative ease of subsequent access to the wellbore when compared to subsea completions. The ratio of producers to injectors, well targets and well trajectories will be refined as the WREP progresses.

6.1.2 Cuttings Re-Injection

The WHP will include a provision for cuttings re-injection (CRI) as part of the base design for instances where SBM is used. For portions of any well drilled using SBM, associated cuttings will be injected into a dedicated injection well. The base plan is to drill two CRI wells for cuttings disposal purposes. In addition, the WHP will have a secondary cuttings dryer system consistent with technology currently employed by mobile offshore drilling units operating in the area. This secondary dryer will be employed until the CRI system is functional. This secondary system will also be employed in the event of difficulties with the CRI system. Prior to having a CRI system in place, and in the event of CRI system failure, cuttings would be discharged overboard following processing with the secondary dryer.

A dedicated formation will be selected for the safe disposal of SBM cuttings and potentially other waste fluids associated with drilling, completions and intervention activities.

The CRI system will be designed to:

- Incorporate redundancy in order to minimize system upset while drilling with SBM
- Incorporate a reliable means to transport generated drill cuttings from each well slot to the CRI package.

Contingency options for operational upset in the event of a prolonged period of CRI system unavailability are currently under review.

The disposal formation will be confirmed and analyzed to determine optimum injectivity rates, containment boundaries and storage potential. The rheology and particle size of the injection slurry will be designed to optimize injection rates and the ultimate storage capacity of the disposal formation. The disposal formation will be accessed with a dedicated disposal well and/or via the open annuli of water injection wells.

6.1.3 Wellbore Hole and Casing Program

Table 6-1 indicates the preliminary range of hole diameters, casing sizes and casing setting depths. Wellbore hole diameters, casing sizes and setting depths will be finalized during detailed design.

Table 6-1 Preliminary Hole Size and Casing Program

Casing Size/Type	Hole Size (A)	Preliminary Material Specification (B)	Connection	Setting Depth (C,D)
914 mm Conductor	1,066 mm	X-52	To be determined	70 to 100 m TVDss
340 mm Surface	406 mm	L-80	Premium	800 to 1,500 m TVDss
298/273 x 244 mm Production	311 mm	L-80	Premium	2,850 m TVDss (±5,700 m RT)
178 mm Liner	216 mm	L-80 (Inj)/13 Cr L-80 (prod)	Premium	2,850 m TVDss (±7,700 m MD RT)
140 mm Screen	216 mm	L-80 (Inj)/13 Cr L-80 (Prod)	Premium	2,850 m TVD Seafloor (±7,700 m MD RT)
168 mm Screen	216 mm	L-80 (Inj)/13 Cr L-80 (Prod)	Premium	2,850 m TVD Seafloor (±7,700 m MD RT)
140 mm/178 mm Production Tubing	inside production casing	L-80 (Inj)/13 Cr L-80 (Prod)	Premium	2,850 m TVD Seafloor (±7,700 m MD RT)

Notes:
(A) Hole sizes may change as the well design is finalized.
(B) Further study is required to finalize material specification.
(C) Depths are approximate pending the final design and trajectory of each well.
(D) Depth Interpretation:
TVDss = true vertical depth subsea.
MD = measured depth.
RT = depth referenced to the rig floor rotary table.
Inj = injector
Prod = producer

6.1.3.1 Conductor/Surface Hole Sections

The conductor hole will be drilled below the WHP to the depth specified in Table 6-1. The base design is such that the interval will be drilled with water-based fluids, typically sea water and viscous sweeps. Cuttings, as well as fluid returns, from this hole section will be deposited in the WHP shaft. There is an ongoing evaluation of options that may permit all or a portion of cuttings, fluids returns and excess cement to be flushed from the CGS.

The conductor will be designed to support the weight of subsequent casing, liner and tubing strings. The conductor will be cemented in place. Care will be taken to confirm that the conductor will be set within vertical limits that prevent encroachment on adjacent wellbores. The conductor will seal off the unconsolidated formations near the seafloor and provide a flowpath for mud returns to the facility while drilling the next (surface) hole section.

The surface hole will be drilled below the conductor to the depth specified in Table 6-1. The base design is such that the interval will be drilled with water-based fluids, typically sea water and viscous sweeps. Drill cuttings, as well as fluid returns, from this section will be returned to the rig and routed overboard via a shale chute.

Surface casing will be set deep enough to isolate potential shallow gas zones and soft formations that could experience erosional issues. This casing will support the blowout preventer (BOP) stack and will be designed to allow the BOP to be closed on abnormal pressure events that may be encountered in the subsequent (production) hole section.

6.1.3.2 Production Casing

Production casing will notionally be a tapered string that will be set and cemented in or near the reservoir completion interval. This section of the well will be drilled with SBM. Cuttings will be routed to the CRI system for processing and injection into the designated disposal formation. The production casing will isolate the surface section from the production section and mechanically support the well.

The production casing will be designed and pressure-tested to allow for response to abnormal pressure events that may be encountered while drilling the reservoir. The production casing will also be designed and pressure-tested to handle the loads generated by a leak from the completion assembly during the production phase of the well.

Husky’s completion designs for production, water injection and gas injection wells will incorporate, for each well, a total of three barriers against well flow. Of these, one will be a surface barrier (wellhead/Xmas tree) and two will be subsea barriers (i.e., TR-SSSVs, packer, kill weight packer fluid).

6.1.3.3 Reservoir Section

The reservoir section will notionally be completed with a cemented liner or screens in open hole. Special SBM-based drill-in fluids may be used to drill the hole section. Drill-in fluids will be designed to minimize formation damage and are well- and application-specific. Cuttings from this wellbore section will be processed and injected into the designated disposal formation via the CRI system. Intelligent well technology may be used to produce from, or inject into, selected sections of a given well over its operating life. Graduated screen sizes may be used to allow for a more uniform production profile along the horizontal producers being planned.

6.1.3.4 Directional Drilling

Wells drilled from the WHP will involve detailed directional planning to intersect the reservoir target at specified coordinates, while maintaining acceptable limits of inclination, dogleg severity and separation factor. Directional drilling parameters will be based on experience obtained in the White Rose region and on industry standards to minimize casing wear and maximize drilling efficiency.

Rotary steerable systems and bent-housing motors will be used to directionally drill wells. Gyro surveys and measurement-while-drilling systems will monitor well trajectory while drilling. Near-real-time feedback will allow for trajectory corrections to be made when required to achieve optimum directional results with minimal effect on overall drilling performance.

6.1.4 Casing Cementation

In development wells, the planned top of cement for the production string will be situated below the shoe of the surface casing as mitigation against pressure build-up in the annulus. Table 6-2 shows the preliminary casing cementation parameters that will be used on the WHP.

Table 6-2 Preliminary WHP Casing Cementation

Casing	Cement Type	Planned Top	Slurry Density (kg/m^3)	Thickening Time (hr)	Excess	Mix Water
Conductor	Class “G”	Seafloor	1,900	>3	Gauge +150%	Sea water
Surface	Class “G”	Wellhead on WHP	1,545 lead 1,900 tail	>6 >5	Gauge +150%	Sea water
Production	Class “G”	Below previous shoe	1,620 lead 1,950 tail	>5 >4	Caliper +10%	Sea water
Liner	Class “G”	Liner top	1,950	>8	Caliper +10%	Drill water

6.1.5 Completions

Well completions will be designed to ensure operability over the expected range of production and injection conditions. It is anticipated that the wells will be completed with either 140 or 178 mm (5.5” or 7”) tubulars and will be equipped with the following:

- Surface barrier (wellhead/Xmas tree)
- Two subsea failsafe barriers (i.e., tubing retrievable – surface-controlled SSSVs, packer, kill weight packer fluid)
- Formation isolation valve to minimize fluid losses during completion and workovers to help mitigate formation damage
- Chemical injection mandrel directly above the production packer
- Gas lift mandrel
- Downhole pressure and temperature recorder placed as deep as practically possible from top of producing interval
- Flow control (polished bore nipple profiles with associated equipment locks, plugs)
- Production packers and associated equipment.

Gas flood and water injection wells will be of similar design, although they will not include gas lift mandrels or provision for downhole chemical injection.

Additional equipment that may be considered includes:

- Intelligent completion equipment with the ability to control individual production/ injection zones
- Fluid loss control device to allow for perforating of long horizontal sections (if required)
- Inflow control devices
- Multi-stage hydraulic fracturing equipment
- Fibre optics (distributed temperature measurement systems).

ESPs may also be considered. ESPs involve the use of a down hole pump to increase the pressure in the well to overcome the sum of flowing pressure losses. A submerged electrical motor is used to drive a multi-stage centrifugal pump with power to the motor supplied by an electric cable run from surface. Such units are ideally suited to produce high liquid volumes. The artificial lifting mechanism selected (gas lift and/or ESP) may be restricted by the actual well conditions such as well depth, production rates desired and fluid properties. For the WREP, gas lift has been selected as the primary lifting mechanism. ESPs will be evaluated on a per well basis based on their technical feasibility.

The deployment mechanisms being considered include conventional tubing-deployed ESP and coiled tubing-deployed ESP. Functionality for the deployment, operation and remediation of both deployment mechanisms has been incorporated into the design of the platform. If a well is selected as an ESP artificial lift candidate, gas lift will still be installed within the well to ensure continued production should the ESP program fail.

6.1.5.1 Multi-Function Wellbores

Multi-function wellbores are being considered for the WREP. Potential initiatives include:

- WAG injectors
- Converting gas injectors into producers
- Using the annuli of water injectors for CRI
- Converting a CRI well to a producer or injector.

The potential for these options will be further explored as well-specific design matures.

6.1.5.2 Completion Fluids

Completion fluids will vary depending on the formations and the type of completion employed. Fluids may be aqueous or non-aqueous and may differ at each stage of the operation. Completion fluids may be used for wellbore cleanup, perforating and as annulus or packer fluids

In addition to the chemical inhibition provided by the completion fluids left in the well, corrosion management will also rely on proper material selection, cathodic protection and pipe coating systems. The well design may allow the use of imaging tools to inspect the well over its operating life.

6.1.5.3 Wellbore Safety Systems

Safety systems will include the use of subsurface safety valves on all wells, operating in a failsafe manner in the event of a Xmas tree or wellhead failure. Production, water injection and gas injection wells will incorporate, for each well, a total of three barriers against well flow. Of these, one will be a surface barrier (wellhead/Xmas tree) and two will be subsea barriers (i.e., TR-SSSVs, packer, kill weight packer fluid). The Xmas tree and wellhead systems, which are key components of wellbore safety, are discussed further in Section 6.1.10.

6.1.6 Drilling Hazards

Typical potential issues that may be encountered during development drilling are outlined in the following sections. Details of potential drilling hazards for each well will be provided in individual Approval to Drill a Well applications that will be submitted to the C-NLOPB prior to the drilling of each well.

6.1.6.1 Shallow Gas Hazards

Husky has procedures in place for both shallow gas avoidance and shallow gas handling that have been successfully employed in the Grand Banks operating environment. These procedures will be reviewed and updated as required to reflect the WHP system.

6.1.6.2 Borehole Stability

While drilling at high inclination, some formations may potentially be unstable. Husky has practices in place to aid in the prediction and mitigation of potential wellbore instability. Drilling fluid properties and well trajectory limits will be designed to mitigate borehole instability using these current practices.

6.1.6.3 Formation Pressure

For the majority of White Rose wells drilled to date, no abnormal pressures or significant lost circulation have been identified. Wellbore hydraulics modelling and casing design will require that the extended reach wells being planned can be safely drilled while maintaining hole stability and avoiding lost circulation.

Should unexpected pressure be encountered, Husky procedures require that there is a reserve amount of weighting material available at all times. This requirement will extend to WHP operations.

6.1.6.4 Differential Sticking

Use of appropriate drilling fluid parameters, tripping practices and casing design will reduce the risk of differential sticking of drilling assemblies. Well-specific Approvals to Drill a Well will provide detailed measures that will be applied to minimize this issue.

6.1.7 Hydrogen Sulfide Potential

The production system, including flowlines exposed to produced fluids, will be designed for sour service according to National Association of Corrosion Engineers, MR-01-75, consistent with the present White Rose and North Amethyst design and operating philosophies.

6.1.8 Well Control System

During drilling, primary well control will be in place at all times by maintaining a hydrostatic pressure gradient greater than the highest pore pressure gradient of any exposed productive formation in the wellbore. Secondary well control will be provided with a BOP system designed in accordance with all applicable regulations and standards.

The BOP will include annular and ram type elements. Final well design, maximum formation pressure and WHP characteristics will determine the BOP configuration. The final BOP and support system design will be finalized during the detailed design process, but will be sized such that the wellbore can be sealed to prevent the flow of formation fluids.

In addition to the BOP, a choke and kill manifold will be used to support the well control system. The manifold will allow for controlled flow to/from the wellbore as required for well control purposes, and will be sized appropriately for the application.

A trip tank will be employed as a means of monitoring hole volumes in/out of the wellbore.

An atmospheric degasser will also be employed to provide for the separation of entrained gases from return flow from the wellbore.

6.1.9 Wellheads and Trees

The WHP will employ dual conductor technology as part of well construction activities. This technology allows for the placement of up to two wells in each well slot, and may be deployed on any of the WHP well slots. This allows for an increased well count without loss of base case well functionality.

Husky plans to make use of dual conductor technology as a means to increase well density possible from the WHP facility, thus allowing maximization of recoverable resources. As this technology forms part of the base case for the facility operations, risks associated with the use of the technology will be identified and managed as part of the base design.

The wellhead and tree design will meet all applicable regulations and standards. The tree will include provisions for two SSSVs, gas lift and chemical injection.

The wellhead and production trees will be rated to handle both temperature and pressure under static and flowing conditions. The trees will include remotely operated and manual master valves, a production wing valve and a swab valve for intervention access. Chokes downstream of the wing valve will control the well. The wellheads and trees will be instrumented to permit monitoring of pressures and temperature of the flow from both the WHP and the *SeaRose FPSO*.

The use of dual conductor technology may hamper potential future extended reach drilling (ERD) in that it introduces a limit to maximum diameter of the surface casing. During front end engineering design (FEED) and detailed design, further evaluation will be undertaken to confirm ERD potential from the WHP. It is anticipated that ERD wells requiring alternative casing architecture to that used in dual conductor technology can be accommodated through well slot allocation and by maintaining a number of single wellhead slots.

As part of the consideration related to maintaining single wellhead slots for ERD capability, alternative drilling techniques, such as multilateral well design, will be considered. The use of dual conductor technology is not anticipated to affect the ability to employ multilateral technology.

6.2 Interventions and Workovers

Interventions are expected to be a standard operating practice and the flexibility that they offer will be leveraged to assist with improved depletion strategies that will assist with maximizing field recovery factors. Potential interventions may include:

- Wellbore inspection and maintenance
- Well conversions
- Production logging
- Rigless wireline, coiled tubing and snubbing operations
- Recompletion or selective completion
- Well abandonment
- Sidetracking
- Hydraulic fracturing, stimulations and chemical treatments.

The ability to conduct intervention and/or workover activities concurrent with drilling and completion operations is a key attribute of the WHP.

6.3 Well Production Performance

Well performance modelling based on the reservoir properties of the pools under development from the WHP has been conducted for both flowing and artificial lift scenarios. The modelling suggests that initial oil rates of between 700 and 2,500 m^3/day are possible from the deviated/horizontal production wells completed with 140-mm tubing.

Water associated with oil production is expected to increase over the life of the development. The modelling 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. Gas lift side pocket mandrels will be included in the initial completion design for oil wells. In addition, other forms of artificial lift are under investigation, such as ESPs. The effect of gas lift on a well producing at 60 percent water cut is illustrated in Figure 6-1.

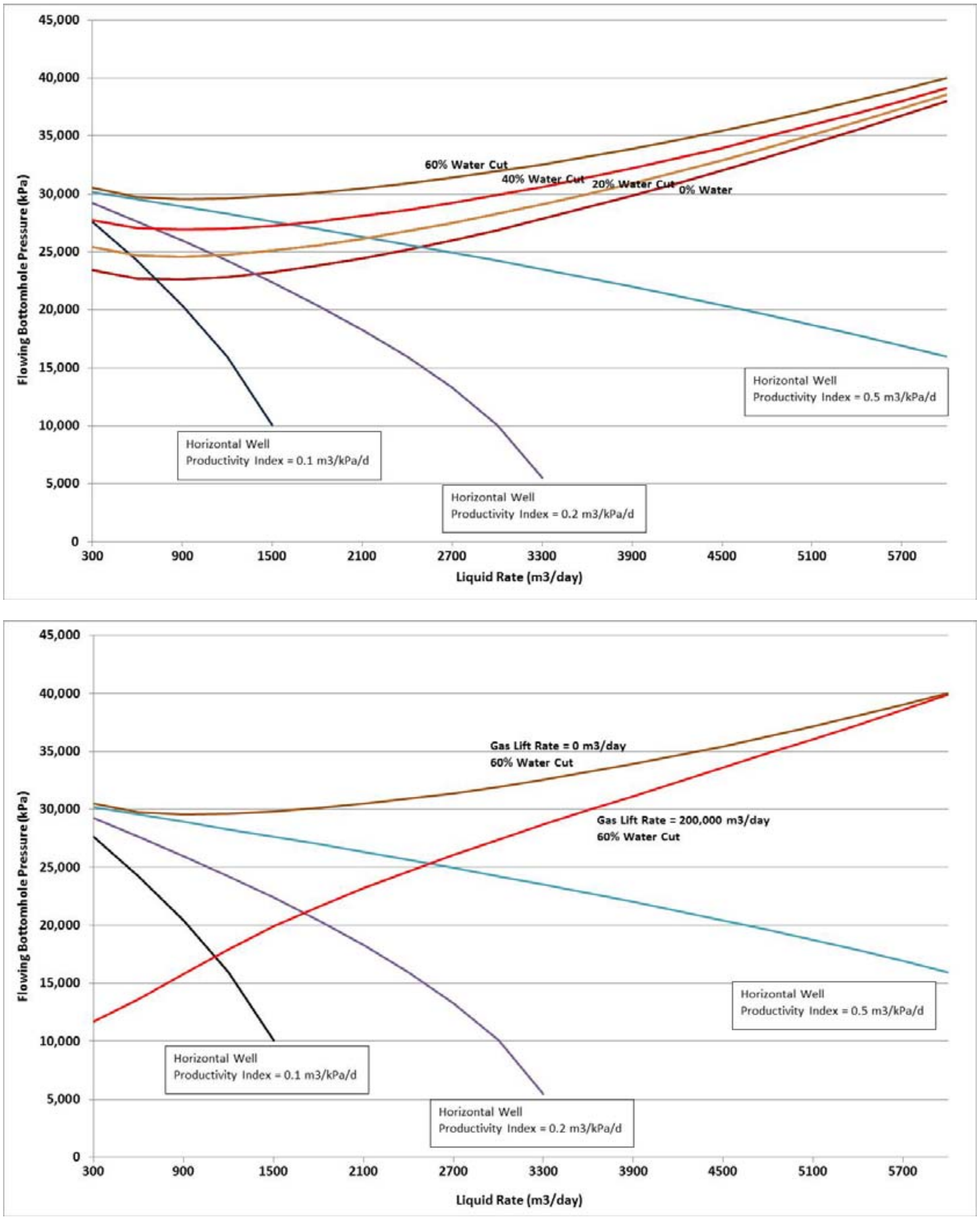


Figure 6-1 Well Performance Modelling Results

7.0 DESIGN CRITERIA

7.1 Physical Environmental Criteria

The Grand Banks region has a harsh environment due to the presence of intense mid-latitude low-pressure systems during fall and winter, tropical storms in late summer and fall, and sea ice and icebergs in spring. The intense winter storms occur frequently and generally have winds from the southwest, west, or northwest. The highest waves usually occur in January and February.

7.1.1 Wind

Monthly maximum wind speeds for the ICOADS and MSC50 Grid Point 11034 are presented in Table 7-1.

Table 7-1 Maximum Wind Speed (m/s) Statistics

Month	MSC50 Grid Point 11034	ICOADS	Ocean Ranger	*SeaRose FPSO*	Terra Nova FPSO	Glomar Grand Banks	GSF Grand Banks	Henry Goodrich	Hibernia
January	29.0	43.7	34.5	25.7	31.9	30.9	37.6	44.2	43.2
February	32.0	46.3	37.0	29.8	34.0	26.8	31.4	52.5	49.4
March	28.4	38.0	-	23.7	29.8	23.7	28.8	32.9	37.6
April	25.0	37.0	-	24.7	26.8	26.8	33.4	30.9	37.6
May	22.5	33.9	-	21.6	25.2	22.1	25.7	32.9	32.4
June	23.4	35.5	-	18.5	24.2	21.1	27.3	28.3	35.5
July	19.6	31.9	-	18.0	23.2	20.1	25.2	26.2	31.9
August	28.9	26.0	-	33.4	29.8	25.7	26.2	28.8	41.2
September	24.6	37.6	-	30.9	34.5	29.3	27.8	28.3	43.2
October	27.0	41.1	-	43.7	34.0	32.9	30.9	27.8	44.8
November	27.5	41.2	28.8	25.2	28.3	25.7	25.7	32.4	38.1
December	30.1	47.8	28.8	24.7	37.6	27.3	29.3	38.1	39.1

7.1.2 Air Temperature

Table 7-2 shows mean, minimum and maximum air temperatures in the Grand Banks area from the International Comprehensive Ocean-Atmospheric Data Set (ICOADS). These data span a 31-year period from January 01, 1980, to December 31, 2010.

Table 7-2 Air Temperatures

Month	Mean	Maximum	Minimum	Standard Deviation	Mean Daily Maximum	Mean Daily Minimum
January	0.1	12.0	-12.0	3.2	2.6	-2.2
February	-0.4	10.4	-12.1	3.1	1.9	-2.9
March	0.3	15.3	-17.3	2.8	2.5	-1.7
April	1.9	11.4	-7.3	2.4	4.1	0.1
May	4.1	13.0	-10.0	2.3	6.2	2.3
June	7.1	16.8	-1.2	2.4	9.3	5.3
July	11.9	25.3	-3.2	2.6	13.5	9.7
August	14.3	23.6	5.5	2.3	16.1	12.4
September	12.6	20.5	-4.0	2.5	14.7	10.7
October	8.8	18.4	-1.0	3.0	11.1	6.9
November	5.1	15.3	-4.6	3.0	7.5	3.2
December	2.1	12.8	-13.5	3.3	4.5	0.1
Source: ICOADS 1980-2010						

7.1.3 Waves

The maximum individual wave heights are presented in Table 7-3. Wave heights were calculated using the MSC50 hindcast data set. This data set was determined to be the most representative of the available data sets, as it provides a continuous 57-year period of 1 hourly data for the site.

Table 7-3 Extreme Maximum Wave Height Estimates for Return Periods of 1, 10, 25, 50 and 100 Years

Period	Maximum Wave Height (m)				
	1	10	25	50	100
January	16.7	22.0	23.6	24.9	26.1
February	15.7	22.4	24.5	26.1	27.7
March	13.1	18.9	20.7	22.0	23.4
April	10.3	15.9	17.6	18.9	20.2
May	8.4	14.3	16.2	17.6	19.0
June	7.2	11.5	12.9	13.9	14.9
July	6.3	9.9	11.0	11.8	12.7
August	6.9	12.4	14.2	15.5	16.8
September	9.6	16.7	19.0	20.7	22.3
October	11.5	18.4	20.5	22.2	23.8
November	13.5	19.3	21.2	22.5	23.9
December	16.2	21.7	23.4	24.7	26.0
Annual	19.9	23.7	25.2	26.3	27.4

7.1.4 Sea Temperature

Table 7-4 shows mean, minimum and maximum sea temperatures in the Grand Banks area from the International Comprehensive Ocean-Atmospheric Data Set.

Table 7-4 Sea Temperatures

Month	Mean	Maximum	Minimum	Standard Deviation	Mean Daily Maximum	Mean Daily Minimum
January	1.0	7.0	-2.0	1.5	2.3	0.2
February	0.3	6.0	-2.0	1.7	1.6	-0.4
March	0.3	6	-2.0	1.4	1.5	-0.4
April	1.0	7.5	-2.0	1.6	2.0	0.2
May	3.0	9.6	-2.0	1.8	4.2	1.8
June	5.9	14.0	-2.0	2.4	7.1	4.4
July	10.5	19.0	2.3	2.5	11.4	8.8
August	13.7	20.5	6.0	2.2	14.7	11.9
September	12.7	20.0	4.0	2.4	13.9	10.8
October	9.1	17.0	1.0	2.7	10.8	7.2
November	5.5	13	-1.9	2.6	7.25	3.9
December	2.7	10.2	-2.0	2.11	4.3	1.6
Source: ICOADS 1980-2010						

7.1.5 Current

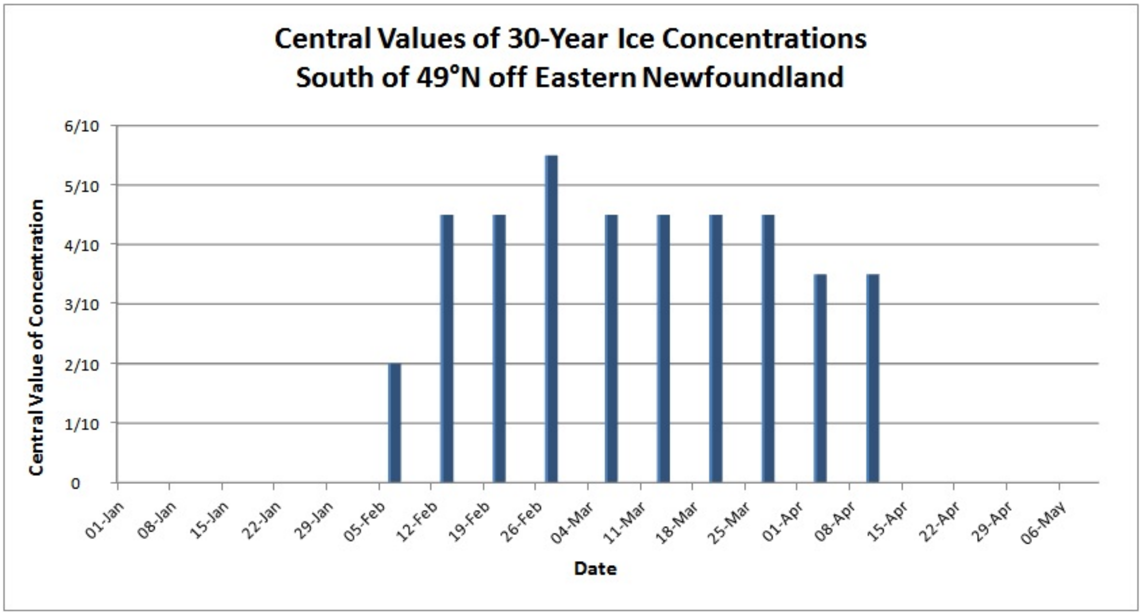
The following omni-directional current data were calculated using Gumbel Extreme Analysis. The values are those of the upper 95 percent confidence limits (Table 7-5).

Table 7-5 Design Maximum Current Speeds

Location	Return Period				
	1-Year	10-Year	25-Year	50-Year	100-Year
Near-surface (20 m) (m/s)	1.08	1.40	1.53	1.63	1.72
Mid-depth (~60 m)	0.60	0.66	0.69	0.71	0.73
Near-bottom (10 m above seabed) (m/s)	0.62	0.73	0.78	0.81	0.84
Source: Oceans Ltd. 2011; Current measurements at White Rose					

7.1.6 Sea Ice

The median sea ice concentrations for the Grand Banks south of 49°N are usually between 4/10 and 6/10 by early February and persist at this concentration through early April, after which they slowly decrease to 1/10th to 4/10ths coverage and recede to above 49°N, as illustrated in Figure 7-1 (the term "Central Value" was determined by averaging the minimum and maximum median concentrations of sea ice found below 49°N in each given week over the 30-year period between 1981 and 2010).



Source: CIS 2011

Figure 7-1 Central Values of 30-Year Median Ice Concentrations South of 49°N on the Grand Banks (1981 to 2010)

7.1.7 Icebergs

Icebergs originate from glaciers in Greenland and Ellesmere Island and drift south with the Labrador Current. Icebergs that have a draft greater than 120 m are unable to reach the White Rose field due to bathymetric restrictions. This will limit the size of icebergs interacting with structures in the White Rose field, with the exception of tabular icebergs, which tend to have a smaller draft. Table 7-6 presents the range of iceberg mass and drift speed for the White Rose region.

Table 7-6 Iceberg Mass and Drift Speed for White Rose Region from 1980 to 2010

Iceberg Sightings	Mean	Maximum
1 Degree Grid	60	215
Mass (t)	168,532	5,900,000
Speed (m/s)	0.26	1.8
Source: Oceans Ltd. 2011		

7.2 Design Loads Methodology

The effect of physical environmental loadings (wind, waves, current, ice, iceberg) on the WHP will be analyzed using established, recognized methods, and will be determined in accordance with the site's physical environmental criteria and governing design codes and standards. Model testing will be carried out to verify wave loads on the structure.

The WHP will be designed to meet International Standards Organization (ISO) 19906 L2 classification for ice loading on the structure. In all other aspects the WHP is designed for an L1 exposure level. The ISO 19906 L2 classification for ice loading on the WHP was selected based on the fact that the WHP is not an oil storage facility and is therefore deemed to have only a medium environment consequence should there be an impact to the facility from an ice event exceeding the design limits. The WHP will have minimal processing equipment on board and limited export line release potential due to the low volume of oil in the export line at any given time. Also, each well will have a total of three barriers against well flow (one surface barrier and two subsea barriers) and the production system, including flowlines, will be designed for sour service according to National Association of Corrosion Engineers, MR-01-75. As part of the requirements for design to the L2 classification, the WHP will require a plan to allow controlled evacuation of the facility as part of standard operations.

The effects of the environment on the WHP were examined in the *White Rose Extension Environmental Assessment* (December 2012) and the *Response to Review Comments on the White Rose Extension Project Environmental Assessment* (April 2013).

Engineering and design practices will be common across the existing White Rose field. Development and all designs will conform to the codes and standards referenced in the relevant regulations and associated guidelines. Generally accepted international standards, such as ANSI/ASME specifications, ISO standards and American Petroleum Institute (API) recommended practices, will be applied as appropriate and in cases where they are considered equal to or exceed the requirements of the Canadian equivalent. Alternative standards or codes not specified in the regulations and associated guidelines will only be used if accepted via the regulatory query process.

7.3 Functional Criteria

7.3.1 Design Life, Flow Rate and Capacities

The WHP facility will have a design life of 25 years and will be designed to accommodate the production conditions throughout the life of the facility. Table 7-7 summarizes these parameters, which will be refined during detailed design. Note that while the design life of the WHP will be 25 years, the current field life of the *SeaRose FPSO* is to 2025. Future studies will be conducted to assess the feasibility of extending the field life of the *SeaRose FPSO* beyond 2025. As well, other options to continue operation of the WHP beyond 2025 will be assessed in the future.

Table 7-7 WHP Production Profile Design Parameters

Fluid	Maximum Design Parameter
Daily Oil	7,800 m^3/d
Daily Water	17,000 m^3/d
Daily Liquid	22,000 m^3/d
Daily Total Gas (Produced+Lift)	2,500,000 Sm^3/d
Daily Gas Flood	1,650,000 Sm^3/d
Daily Gas Lift	1,450,000 Sm^3/d
Daily Water Injection	20,000 m^3/d

7.3.2 Drilling Facility Capacity

The WHP will have the capacity to drill, complete and intervene on all wells as required to develop the identified White Rose region resources. Well intervention activities will occur simultaneously with drilling and completion activities.

7.3.3 Operating Limits Imposed by the Environment

The effects of wind and waves on the WHP will be considered during the design of the facility and it is not expected that these environmental factors will result in any operating limits. Environmental limitations related to ice and icebergs will be addressed in a WHP-specific ice management plan that will be developed. The plan will define operational limits and outline the measures that will be required to ensure safety of personnel and protection of the environment.

7.4 Geotechnical Criteria

7.4.1 Seismic Hazard Potential

The WHP is located in a low seismic activity area and seismic loadcases are unlikely to be critical to WHP design. A desktop study was completed to assess the potential for seismic activity to be an important factor in WHP design. The study was conducted as per ISO 19901-2 and is considered to be conservative. A site-specific hazard assessment is being completed to refine the values used in the study.

7.4.2 Soil Characteristics

Site-specific geophysical and geotechnical data were acquired from WHP site investigation work, correlation of available nearby data and related published regional studies. The data were used to further characterize seabed bathymetry, interpret the stratigraphy, perform geotechnical analyses, define lateral variability and create a geological model of the WHP foundation zone.

Geotechnical soil parameters and strengths are based on the results of laboratory testing of samples acquired from site-specific boreholes to a depth of approximately 44 m below mud line (BML) and nearby boreholes to a depth of approximately 35 m BML.

The near-surface sediments are predominantly silica-based and categorized as fine sand with occasional fine to medium sub-rounded gravel. Shells and shell fragments were identified predominantly on the surface. The surficial sand thickness varies from near-zero to 2 to 3 m BML over short horizontal distances.

The underlying seabed sediment is an irregular ice-scoured glacial sediment surface with six distinct boundary units where the upper five units vary significantly in thickness. Unit boundaries were distinguished using site-specific samples in conjunction with changes in drilling conditions.

Site-specific boreholes were composed of six distinct units:

- Unit I - very dense gravelly sand
- Unit II - interbedded very dense silty sand with very stiff sandy silt/clay
- Unit III - very dense silty/clay-like gravelly sand
- Unit IV - very stiff silty clay with laminations and partings of silty fine sand
- Unit V - very dense silty/clay-like fine sand
- Unit VI - interbedded very stiff slightly sandy clay with very dense clay-like fine sand.

7.4.3 Iceberg Scour

Seafloor ice scour features (furrows and pits) of undetermined age are present within the investigation area for the WHP (Fugro Geosurveys 2011). The scours are evident in sonar imagery by their textural contrast with surrounding seabed sediments; the more defined scour features have visible relief in shaded multibeam bathymetry. Scour depths are typically less than 0.5 m. Pits are generally 1 m deep or less. A low-relief iceberg scour passes near the planned WHP installation site. The scour is less than 20 cm deep and less that 20 m wide. Present estimates of ice scour frequency are approximately 2×10^{-4} scours/km^2/year.

7.4.4 Shallow Gas Considerations

Geophysical surveys completed in 2005 and 2011 indicate a negligible risk of shallow gas under the WHP footprint. However, at noted in Section 6.1.7.1, Husky has procedures in place for both shallow gas avoidance and handling. These procedures will be reviewed and updated as required to reflect the WHP system.

8.0 WELLHEAD PLATFORM DESIGN

The WHP will consist of a CGS with topsides consisting of drilling facilities, wellheads and support services such as accommodations for up to 144 persons, utilities, flare boom and helideck.

The persons on board (POB) of 144 persons was determined through an analysis of the potential roles on the WHP, specifically:

- Roles that would be required on a full time basis (i.e., catering)
- Roles for specific drilling operations (i.e., interventions)
- Consideration of the simultaneous operations that are possible.

Based on this analysis, it was determined that 144 provided the POB necessary to safety operate the facility while executing the planned drilling program.

The following sections provide an overview of the WHP systems.

8.1 CGS Mechanical Outfitting Systems

8.1.1 Permanent Mechanical Outfittings

Main mechanical outfitting comprises risers, J-tubes, caissons, conductor guides and guide frames, deck connections, structural steelwork, access stairs and ladders, drill cuttings recovery system and temporary installation systems, as summarized below.

- J-Tubes will be provided for the following services:
  - Production risers
  - Water injection risers
  - Gas supply risers
  - Umbilicals
  - Future services
- Caissons - Caissons will consist of those required for firewater pumps, seawater life pumps, sewage discharge, treated deck drainage, seawater disposal and water-based mud drill cuttings. Seawater pump caissons and fire water pump caissons will be connected to sea water intakes. Water will be drawn from outside of the shaft.

- Miscellaneous Steelwork - The mechanical outfitting components of the CGS will include the following:
  - External and internal ladders
  - Access hatches
  - Pipeline and topsides installation aids
  - Handrails
  - Roof support steelwork
  - Embedment plates.
- Corrosion Protection System - Submerged carbon steel piping systems will be protected by a combination of anode cathodic protection and protective coatings for the intended design life. Corrosion resistant materials will be used where appropriate.
- Scour Protection – Crushed rock covering an area of approximately 12 m around the perimeter of the WHP will be placed as scour protection.

8.1.2 Ballasting Systems

The ballasting system will be designed to reliably control and monitor the floating draft of the CGS at float out, during the sea tow and during final installation. The components of the ballasting system will be specified to suit the environmental and operating conditions both at the construction site and during the installation phase offshore and will meet all requirements of the *Newfoundland Offshore Petroleum Installations Regulations*. The ballasting system will include redundancy to allow any procedure to be completed following failure of multiple components.

The CGS will be designed as a large number of structural cells. These cells will be interconnected to form a smaller number of pressure-competent ballasting compartments. The ballasting system will control the level of water in each of these compartments to control the draft and stability of the structure during all floating stages. Solid ballast may also be used as trim ballast and to control draft.

The ballasting system will be designed to support the re-floating of the WHP at the end of field life. This may necessitate the re-installation, replacement or maintenance of key components such as valves, pumps and the ballast control system.

8.1.3 Visual Inspection and Instrumentation for Monitoring

Requirements for visual inspection and instrumentation for monitoring the CGS will be determined during FEED in accordance with regulatory requirements.

8.1.4 Environmental Monitoring Systems

Systems will be in place to monitor metocean conditions as outlined in the C-NLOPB's *Offshore Physical Environmental Guidelines*. Parameters that will be measured include:

- Wave height
- Current
- Air and sea temperatures
- Waterline elevation
- Barometric pressure
- Wind speed/direction
- Visibility.

8.2 Topsides System Design

8.2.1 Overview

The main function of the proposed WHP is to provide a platform for 'dry tree' drilling and completions. Reservoir fluids produced to the WHP will be transported to the *SeaRose FPSO* for processing. The WHP will be equipped with minimal processing equipment.

The WHP topsides will be designed for operation in the environmental conditions found in the Grand Banks area. There will be no oil storage on the WHP. All crude oil produced through the WHP will be stored on the *SeaRose FPSO* for offloading to shuttle tankers. The oil handing capacity of *SeaRose FPSO* is 22,300 Sm^3/d (140,000 bbl/d). The oil handing capacity of the *SeaRose FPSO* is anticipated to accommodate the requirements of the WHP; therefore, no upgrades to the process systems will be required.

The fluids collected from WHP production wells will be routed to the production manifold. The production manifold arrangement will have production wells tied into a common but split production manifold leading into two main production lines. If a well requires testing, the well fluids will be directed to the test manifold and into the WHP test separator. Following testing, the oil, water and gas streams will be recombined and routed to one of the two main production lines.

The well fluids will then be transferred to the *SeaRose FPSO* via flexible risers and flowlines. The risers and flowlines will connect the WHP with the existing CDC flowlines via subsea tie-in structures. There is no oil storage on the WHP facility and all production fluids will be transferred to the *SeaRose FPSO* for processing, storage and offload, in the same manner as production from a subsea drill centre is currently managed.

Figure 8-1 shows the planned layout of the WHP topsides. Figure 8-2 provides a block flow schematic of WHP operations. Figure 8-3 depicts the layout of the White Rose field with the integration of the WHP into the existing infrastructure.

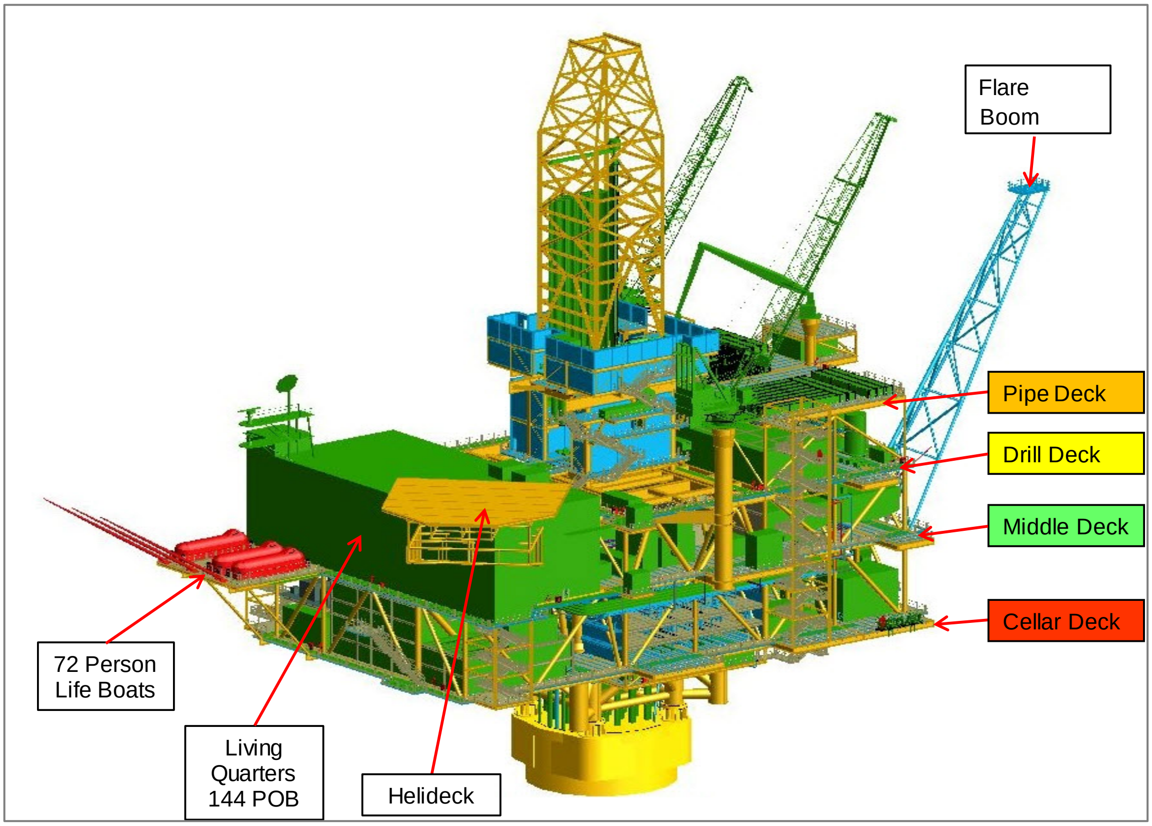


Figure 8-1 Layout of WHP Topsides

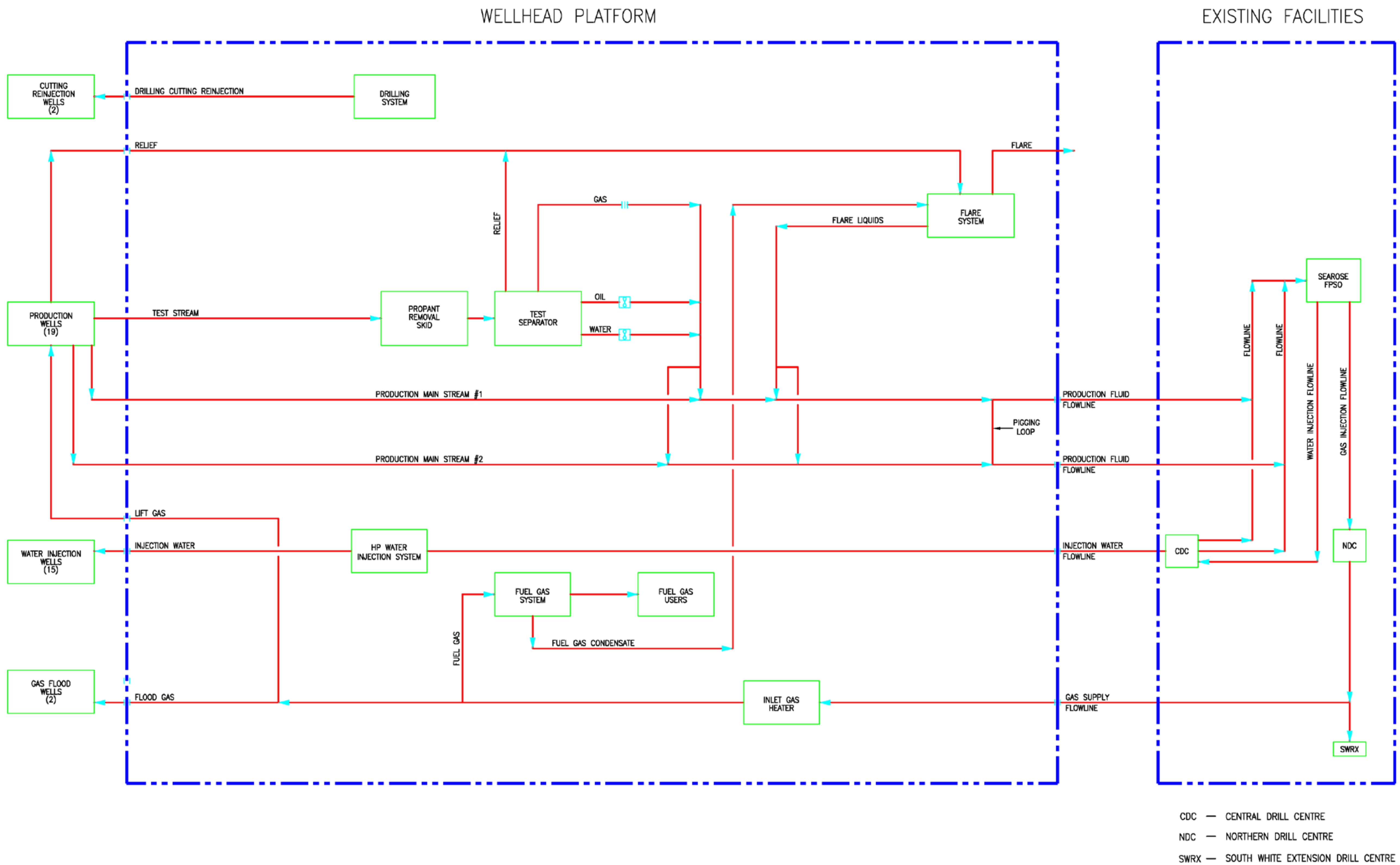


Figure 8-2 Block Flow Schematic of WHP Operations

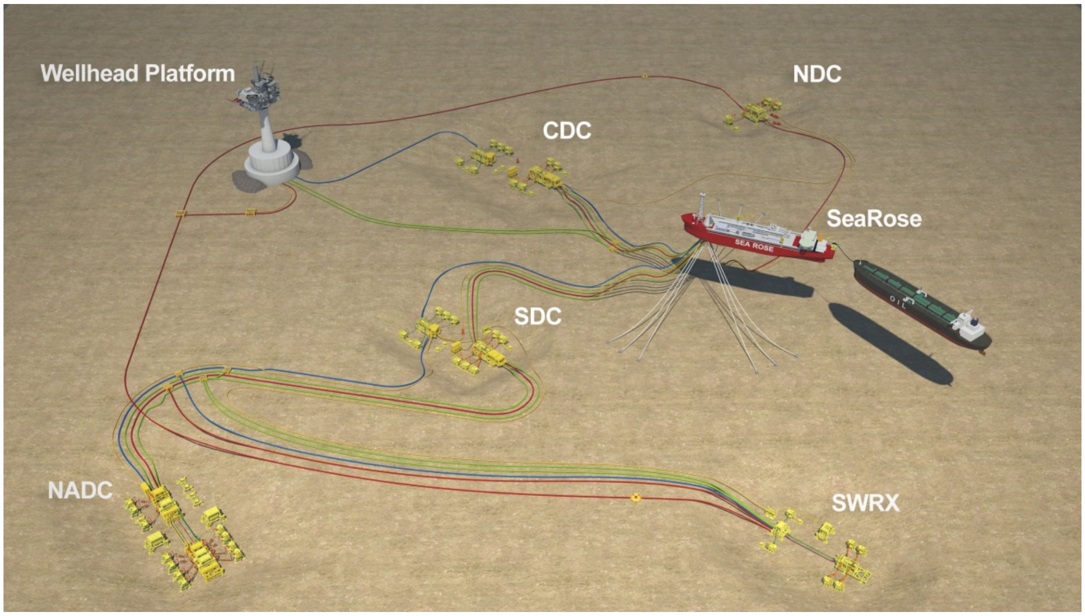


Figure 8-3 White Rose Field with WHP Integrated

The potential environmental effects of WHP operations have been examined in the *White Rose Extension Project Environmental Assessment* (December 2012) and *Response to Review Comments on the White Rose Extension Project Environmental Assessment* (April 2013).

The topsides facilities will have an operating weight of approximately 28,000 metric tonnes. The topsides facilities configuration will be designed for maximum isolation of hazardous/process equipment and well bay from the living quarters and helideck. The facilities will comprise:

- Drilling, completions and well intervention equipment
- Well bay and wellheads
- Oil production, test, water injection, gas injection, and gas lift manifolds
- High-pressure water injection booster pumps
- Fuel gas heating and treatment
- Test separator and metering
- Safety and utility systems
- Integrated Control and Safety System (ICSS)

- Telecommunications systems
- Power generation and distribution systems
- 144 person living quarters.

8.2.2 Production Systems

The WHP production system will consist of production manifolds to accommodate services for oil production, water injection, gas lift and gas flood.

The WHP will accommodate 20 well slots using conductor sharing wellhead technology in some or all wells, which allows two wells to be drilled in each conductor, for a total of up to 40 wells. It is anticipated that development of the West White Rose pool will require 26 wells. The final well counts are subject to change and will ultimately be based upon the development viability in the area. The remainder of the wells will be used to target additional potential resources that could be developed from the WHP.

The well count and slot designation will be finalized once depletion planning is finalized.

The production handling and testing system will consist of production manifolds and test manifolds. The production manifold arrangement will have approximately half of all 19 production wells leading to one side of a common but split production header and the remaining production wells leading to the other side of the header, with a crossover line joining the two. The common production header will be equipped with blind flanges to account for future well additions. The well fluids will be transferred via two flowlines to the *SeaRose FPSO* for processing.

If a well requires testing or initial clean-up, the well fluid will be directed to the test header. The test manifold and routing valves will be configured to allow any well to access the test separator.

8.2.2.1 Production Test Separator and Fluid Sampling

Production wells will be brought on-stream and tested via a three-phase test separator on the WHP. Testing frequency will be based upon regulatory requirements and production experience for effective reservoir management. Husky's Flow System Application will be updated as required to include the WHP.

A test heater may be required to accommodate well testing of future subsea tieback wells if the temperature of fluids arriving at the WHP is insufficient to obtain good phase separation. Space and weight requirements for the future installation of a test heater will be included in topsides design.

The tested fluids will be separated into oil, gas and water phases and measured through the associated phase flow meters. The tested oil stream, water stream and gas stream will be recombined and added to either of the main production lines without gas compression and liquid pumping, since the test separator will operate at a higher pressure than the export flowlines. In addition to the test separator on the WHP, the total produced oil, water and gas flows will be measured through multi-phase flow metres installed on the main production export lines.

The test separator will primarily be used for production well testing, but may also be used to effectively kick-off wells following a shut-down, as well as to clean-up wells following fracturing and completion activities.

Standard sampling points will be provided on gas and liquid lines to permit collection of fluid samples. The on-site laboratory facilities will be capable of routine production and drilling testing.

As part of the fracturing process, proppant is expected to be returned with the production fluids during initial production well start-up. To facilitate removal of proppant and other drilling debris left in the production wells after coil tubing cleanup, a permanent proppant clean-up skid will be installed upstream of the test separator. It is envisioned that the proppant clean-up skid will consist of a hydrocyclone, accumulator and proppant bin.

8.2.2.2 Gas Supply Systems

Gas lift, gas flood and fuel gas will be supplied from the *SeaRose FPSO* gas compression/injection system via a single high-pressure gas flowline teed into the subsea flowline. The *SeaRose FPSO* gas compression system comprises two parallel compressor trains with a total design capacity of 4.2 MSm^3/d. It is anticipated that WHP demand for gas for gas lift and platform fuel will be within the existing *SeaRose FPSO* gas compression capacities. Therefore, no compression upgrade to the *SeaRose FPSO* gas system will be required to accommodate WHP requirements.

The dehydrated and compressed gas supplied from the *SeaRose FPSO* will be used for gas flood, gas lift and fuel gas demand on the WHP. A gas supply flowline will be connected at a midline point between the NDC and SWRX drill centres and a gas supply riser will be connected at the WHP. A gas supply inlet heater is included in the WHP design for periods when it may be required to heat the full inlet gas stream above hydrate formation temperature.

Flood and lift gas will be distributed from the gas flood and gas lift manifolds and through the wellhead chokes to individual gas flood wells as well as production wells for gas lift. The gas flood wells will have methanol injection points for preventing hydrate formation.

WAG operation will be included in design of the gas flood manifold. The water injection manifold will be designed to provide access to all gas flood wells as well as water injection wells.

The fuel gas system will be designed to accommodate the required pressure and to meet the required specifications of the main power generation system. The fuel gas system will have sufficient volume to enable a smooth switch from fuel gas to diesel for the turbine generators.

Low pressure fuel gas will be used for purge of the flare header and to supply the flare pilots.

The gas flowrates to the various consumers will be metered in accordance with the C-NLOPB Measurement Guidelines.

8.2.2.3 Flare System

The flare system on the WHP will be an integrated part of the pressure relief and safety system of the facility. The design of flare and relief system of the WHP will be consistent with all applicable regulations and standards.

The flare system will include the manifolds, piping, flowlines, knock-out drum including pumps and heaters, the flare stack and the flare tip and will be sized to accommodate the requirements for all WHP flare operational scenarios.

The separated liquids in the flare knockout drum will be combined with WHP production fluids and transported to the *SeaRose FPSO* for further processing. The WHP flare system will be designed such that the depressurization of WHP topsides inventory can be managed by the WHP. Depressurization of the gas injection flowline connecting the WHP to the *SeaRose FPSO* will be managed by the *SeaRose FPSO* flare system. It is anticipated that the *SeaRose FPSO* flare system will be capable of handling any operational requirements as result of incorporation of the WHP into the system.

The process facilities and flare tip will be designed so that radiation levels for all flaring cases are below the limits specified by regulations for the flare tip height at all access ways and at all work locations. The location and elevation of the flare tip (length and angle flare stack) will be determined with consideration of the prevailing wind velocity and direction and the location of helideck and other equipment.

The flare system will be continuously purged with fuel gas. Flare ignition will be through a pilot burner with flame out detection and automatic re-ignition. The pilot fuel source will be fuel gas with a propane backup.

8.2.2.4 Produced Water System

There is no processing of produced fluids on the WHP and therefore, produced water from WHP wells will be separated, treated and disposed on the *SeaRose FPSO*. The *SeaRose FPSO* produced water handling systems will be used to treat the produced water from the WHP production system along with produced water from the existing production wells. The produced water design capacity on the *SeaRose FPSO* is 28,000 Sm^3/d. It is anticipated that the produced water handing capacity on *SeaRose FPSO* will be sufficient for the WHP production capacities. Therefore, no upgrades will be required on the *SeaRose FPSO* for produced water processing.

8.2.2.5 Water Injection System

Water injection will continue to be used as the primary means to support reservoir pressure in the White Rose field. The *SeaRose FPSO* will supply treated water injection to the WHP via the CDC water injection manifold. The current capacity of the *SeaRose FPSO* water injection system is 44,000 m^3/d at a maximum of 30 megaPascal gauge supply pressure. The capacity of the water injection system is anticipated to be sufficient to support WHP requirements. Therefore, no upgrades will be required to the water injection system on the *SeaRose FPSO*.

It is anticipated that water injection pressures up to 35 MPag at the WHP may be required to support the West White Rose reservoir. With the *SeaRose FPSO* turret limitation of 30 MPag and the piping pressure drops, high-pressure water injection pumps will be required on the WHP to meet the water injection pressure requirements. The injection water will be distributed to the water injection wells via water injection manifolds. Flow meters will measure the water volumes injected into each well.

8.2.2.6 Chemicals, Storage, Metering and Injection Systems

The WHP will have a stand-alone chemical injection, storage and metering system. A methanol injection system will be required on the WHP for hydrate prevention and equalization of surface-controlled SSSVs. Methanol injection will be required at cold start-up, as part of a planned shutdown, during upset conditions, or when bringing on new wells. The largest expected usage of methanol will occur before and after a planned shutdown, when wells and flowlines may require methanol treatment to prevent hydrate formation.

Scale inhibitor will also be required for injection at the WHP. Injection of scale inhibitor in production wells will be via a chemical injection mandrill in the well completion. The WHP will have a hypochlorite generation skid to treat seawater inlets.

The WHP will be designed to accommodate tie-in of future chemical injection equipment as required.

8.2.2.7 Control System

Control and measurement on the WHP will be achieved with the use of an ICSS. The WHP ICSS will be integrated with the *SeaRose FPSO* ICSS via a microwave communication system, allowing for bi-directional monitoring of all topsides and subsea systems. Primary Control of WHP utilities, manifolds, Xmas trees, water injection, metering and export systems related to oil production will be perform from the WHP Control Room and alternative will be performed from the *SeaRose* FPSO under restricted access. WHP drilling operations will not be controlled from the *SeaRose FPSO*.

The Central Control Room will be located in the WHP living quarters. An alternative control room for emergency situations will be located outside of the living quarters to permit incident response. Operational access to the alternative control stations will be managed by administrative controls and operating procedures. The control rooms will be ergonomically designed with consideration to lighting, body position and noise. An ergonomic review will be conducted during detailed design with consideration of lessons learned from the SeaRose FPSO's Central Control Room.

Interface equipment will be added to the ICSS on the *SeaRose FPSO* to permit communications between the WHP and the *SeaRose FPSO* ICSS. In the case of lost communications with the *SeaRose FPSO*, the WHP will be capable of functioning independently and of safely executing shutdown actions as required. As a minimum the WHP ICSS will be capable of the following:

- Continued monitoring and control of all WHP equipment and systems
- Safe shutdown/blowdown of all oil production related equipment
- Continued operation of all equipment and systems required for the safety of onboard personnel
- Continued drilling operations.

The WHP ICSS will be comprised of the following sub-systems:

- Process Control System for the control and monitoring of WHP systems including process/test separation, utilities, manifolds, Xmas trees, water injection and metering and export systems related to oil production
- Emergency Shutdown System (ESD) for the WHP process systems and for the facilities and drilling shutdown requirements. The ESD system will be SIL 2 rated
- Fire and Gas System (FGS) will be SIL 2 rated with logic segregated from the ESD system/logic

- Power Management System for the complete WHP facility to manage electrical generation and consumption requirements.

The WHP ICSS will also interface directly with the following sub-systems:

- Permanent, continuous surface read-out, downhole pressure and temperature gauges installed in all wells
- A Drilling Monitoring System, comprising of a Drilling Control and Data Acquisition system for the monitoring of drilling systems and equipment
- Unit Control Systems for packaged equipment such as power generators, fire water pumps, air compressors and hydraulic power units
- Condition Monitoring System (e.g., critical equipment such as turbine and driven equipment, high-pressure water injection pumps)
- Information Management System (IMS) for data collection, storage and reporting
- WHP structural monitoring system
- Environmental Monitoring System
- Subsea isolation valve (SSIV) on the gas supply flowline.

The *SeaRose FPSO* IMS will collect and store all data from WHP instrumentation and systems. The WHP IMS will also collect and store data from the WHP. Production and operation reports will be generated by the IMS.

The ICSS operator displays will follow the same graphics standards as the current *SeaRose FPSO* control systems to provide consistency of display between facilities.

8.2.2.8 Power Generation

Power generation and distribution facilities on the WHP will be a stand-alone isolated system. The main power generation for the topsides will comprise dual fuel (gas/diesel) turbine-driven generators that will employ best available technology for minimization of greenhouse gas emissions. Under normal operating conditions, the main power generators will supply all power requirements for the topsides equipment, including primary loads such as drilling, all other rotating equipment and utility systems. Fuel gas for the power generation system will be supplied from the *SeaRose FPSO*.

A diesel-driven emergency generator and distribution system will supply all emergency electrical loads in accordance with the relevant regulations.

8.2.2.9 Fluid Measurement, Sampling and Allocation

The WHP metering will comply with the *Drilling and Production Regulations Part VII – Measurements* and the C-NLOPB's Measurement Guidelines. Oil, water and gas will be metered on an individual well basis using the test separator and on a total platform basis using production export multi-phase flow metres. The flow meter data from the WHP ICSS will be sent to the *SeaRose FPSO* IMS for inclusion in consolidated production reports.

8.2.3 Utility Systems

8.2.3.1 Seawater Lift System

The seawater lift system will be designed for rates and pressures to support all WHP drilling and production operations seawater and cooling loads. Seawater inlets will draw water from below the thermocline to alleviate temperature issues related to warm surface currents. The seawater will be lifted by three caisson-mounted ESPs. The seawater with be filtered and distributed to the potable water maker, drillings utility water, utility water stations, proppant carrier fluid and hypochlorite generator. The seawater manifold pressure will be controlled by a back pressure valve. Surplus and returned seawater will be routed for overboard discharge via a sweater disposal caisson located in the CGS shaft below sea surface.

8.2.3.2 Potable/Fresh WaterSystem

A service water system will be included on the WHP to provide water for all required drilling, operations and potable water needs. Potable water generator, storage tanks and a bunkering system will be included. Two fresh water systems will be supplied for the platform systems, specifically utility water and potable water.

Fresh water for each system will be generated with a vacuum distillation package. The utility water system will contain a storage tank and a supply pump that provides utility water for wash down and chemical makeup. The potable water system will contain a storage tank that will supply water for the living quarters and the safety showers. The potable water for the living quarters will have redundant pumps, a bladder pressure tank and water sterilization and rehardening. The safety showers and eye wash stations will be heated water.

A connection to the drilling water tanks will be provided to supply drilling water when required. In normal operations drilling water will be provided by supply boat.

Facilities will be provided to enable all equipment and piping in the potable water system to be cleaned and sterilized by flushing.

8.2.3.3 Compressed Air Systems

The compressed air systems will provide air of a defined quality and pressure to various instruments, utility stations, the drilling bulk transfer system, drilling equipment and controls within the drilling equipment set and topsides, as well as to the nitrogen generator package. Compressed air will be divided into instrument, bulk and utility air uses, with priority given to instrument air requirements.

A dedicated compressed air system will provide oil-free dehydrated air to the facility. The compressors will be a 3 x 50 percent arrangement, with a 3 x 50 percent regenerative dryer system. Utility design criteria will be net air flow after dryers (outside of regeneration requirements). In the event of an upset, the air receiver capacity will supply critical air to users to allow safe shutdown of the facility.

8.2.3.4 Nitrogen Generation and Distribution Systems

The nitrogen system will be comprised of a nitrogen generation package and a nitrogen receiver and will be located in a naturally ventilated area on the WHP. Oxygen-rich gas will be ventilated to a location where personnel have no access and risk of fire/explosion is low.

The nitrogen gas system will provide continuous supply blanket gas to the closed drain header and methanol storage vessel. Nitrogen will also serve as back-up purge to the flare header. During start-up and maintenance, nitrogen will be used to purge the piping section and equipment to avoid mixing of air and hydrocarbon gas.

8.2.3.5 Heating, Ventilation and Air Conditioning Systems

Heating, ventilation and air conditioning (HVAC) systems will be included in the WHP design and will address all requirements for safety, accommodations, electrical rooms, equipment rooms, offices and drilling systems requirements. HVAC will be provided to all required areas in accordance with all applicable regulations.

The HVAC systems will be designed to maintain the comfort of the offshore personnel as well as performing a vital safety function. The HVAC systems in the living quarters will form part of the WHP's active safety system by pressurizing the living quarters space to prevent the ingress of smoke, fire, or gas as long as the air intake is not directly exposed to gas or smoke.

The HVAC system will also create and maintain internal pressure for the shale shaker room and over the mud pits (enclosed hazardous areas) to prevent gas migration into adjacent areas, as required.

For the warmest ambient temperature, the system will maintain a supply temperature of 18°C to 20°C to control rooms, including any additional air changes required to cool control equipment. For the coldest ambient temperature, the system will maintain a supply temperature of 25°C to accommodations. Each supply air handling unit will be equipped with heating and cooling coils sized for 100 percent of the duty. Relative humidity will be maintained from 30 to 60 percent.

The air intake arrangement will be a 2 x 100 percent design, with each air intake equipped with gas and smoke detection. Each intake will be positioned as far as practical apart so gas or smoke detection at one inlet does not impair the alternate intake.

The HVAC system will be designed for 2 x 100 percent duty. This includes the supply air (2 x 100 percent); return air (2 x 100 percent), dirty extract (2 x 100 percent) and galley extract (2 x 100 percent). All systems will have an automatic changeover function to switch to the spare fan should the primary unit fail.

8.2.3.6 Sewage Treatment System

The sewage treatment system will be sized to accommodate the maximum POB for the WHP. The system will be designed in accordance with all applicable regulations for treatment and disposal of sewage waste. The system will collect and dispose of all the waste from the living quarter wash basins, showers and galley waste disposal systems (grey water), as well as sanitary waste from the toilets (black water).

8.2.3.7 Closed Drain Systems

The closed drains system allows for collection and disposal of oil, gas and water from operational activities. The fluids from the closed drains system will be pumped to the flare knockout drums and then pumped to the production export lines via the flare knockout drum pumps. Fluids in the closed drains system will be managed in accordance with all applicable regulations.

8.2.3.8 Open Drain Systems

The open drains system will collect, treat and dispose of oil and water run-off from the WHP deck. The open drains systems will be designed in accordance with all applicable regulations.

There will be a non-hazardous open drain and hazardous open drain on the WHP. The non-hazardous open drain will collect drainage from accommodation and utility areas. The hazardous open drain is required to collect and remove washdown water, oily water from drip trays and skid pans, rain water and fire water from the drilling and process areas.

8.2.3.9 Diesel Fuel Systems

A system will be provided for the bunkering, storage and distribution of diesel fuel. The system will incorporate filter separators, transfer pumps recirculation pump and diesel loading stations.

8.2.3.10 Aviation Fuel

Aviation fuel storage and a dispensing skid will be designed in compliance with all applicable regulations.

8.2.4 Flowline Warming and Pigging

Prior to production start-ups, the warming of flowlines between the WHP and *SeaRose FPSO* will be carried out using the hot oil pumping capability currently available on the *SeaRose FPSO.* The WHP production export lines will have a pigable cross-over line to permit circulation of hot oil and round-trip pigging.

Pigging of the production flowlines will be carried out by launching pigs and receiving pigs in the *SeaRose FPSO* turret area using existing pigging equipment. It is anticipated the *SeaRose FPSO* hot oil recirculation system will be capable of handling any operational requirements as result of the incorporation of the WHP into the system.

8.2.5 Living Quarters

Living quarters will be designed to foster a sense of well-being and to promote interaction between occupants and provide facilities for sleeping, personal hygiene, catering and dining, laundry, recreation and medical services. All cabins will be designed for two persons, who will work on alternating shifts. The living quarters will be protected from hazardous areas by incorporation of fire-resistant and blast-rated external walls, roofs and undersides. The living quarters configuration and arrangement will ensure direct access to emergency evacuation routes, areas of temporary refuge and escape equipment.

8.2.6 Helideck

The WHP will be capable of accommodating Sikorsky S-92 (primary), EH101, Sikorsky S-61 and the Eurocopter AS332L Super Puma helicopters. The helideck will be designed to comply with applicable legislation. An aviation fuel storage and pumping system will be installed to provide refueling capability for the helicopters servicing the installation. A helicopter parking area will be provided as part of the helideck.

The helideck will be located on the southwest corner of the living quarters. The location will provide a clear flight corridor with unobstructed landing and take-off zones in accordance with CAP 437. The location of the helideck will also consider prevailing wind speed and direction and turbulence effects from wind across and around the installation, as well as artificial environmental effects such as heat plumes, flares and exhaust plumes.

The helideck will be equipped with primary and secondary access stairs, perimeter safety netting, perimeter lighting, general lighting, visual aids, recessed tie-downs, perimeter drainage, graphics and markings, active firefighting stations/equipment and rescue equipment.

8.2.7 Safety Systems

8.2.7.1 Well Control Systems

Refer to Section 6.1.9 for discussion on well control systems.

8.2.7.2 Alarm and Shutdown Systems

The WHP will have an ICSS comprised of the following main subsystems:

- ESD
- Process control system
- Drilling monitoring system
- FGS
- IMS.

A primary function of the ICSS is for the protection of personnel, the environment and the facilities from accidental or abnormal operating conditions.

The WHP ESD system will be interfaced with the *SeaRose FPSO* ESD system to shutdown the import/export of hydrocarbons to both facilities during emergency situations. The ESD will shut down, isolate and depressurize systems when hazards are detected. The ESD shutdown logic will be based on API 14C, as well as regulatory and equipment protection requirements.

The ICSS will provide alarms and indications from all the ICSS subsystems to the operators. The process control system will provide control and monitoring of process and utility systems, including alarms to indicate abnormal operating conditions.

The drilling monitoring system will provide remote control and monitoring of drilling systems and equipment, including alarms to indicate drilling system malfunctions.

8.2.7.3 Fire and Gas Detection System

The WHP fire and gas detection, control and alarm systems will provide early detection of fire and elevated levels of flammable or toxic gases, to alert personnel and initiate appropriate incident mitigation actions. The FGS will be an integrated part of the WHP ICSS. The ESD systems will be interfaced to the FGS to execute facilities shutdown levels, process isolation and electrical isolations when fire and/or gas hazards are detected.

8.2.7.4 Fire Suppression Systems

Active fire protection systems will meet the specific requirements of the *Newfoundland Offshore Petroleum Installations Regulations* (SOR/95-104) and referenced standards. In general, active fire protection will be designed to prevent fire from spreading to other areas, and to limit damage to structures and equipment.

The following fire extinguishing agents may be used in active fire protection systems; however, the final configuration of the systems will be determined following fire and explosion risk analysis:

- Water spray, or deluge systems in areas with the highest potential for gas release
- Combined water spray/foam systems in areas with the highest potential for release of flammable liquids. Combined water spray/foam systems will be designed to meet the requirements of National Fire Protection Agency (NFPA) 15 and NFPA 16
- Automatic sprinkler system in the accommodations area. The system will be designed in accordance with NFPA 13 requirements
- Gaseous or water mist systems, in enclosures that are not normally occupied
- Fire fighting for larger machinery spaces through a high expansion foam system designed to meet the requirements of NFPA 11
- A suitable active protection system for the galley in accordance with NFPA 17A
- Fire monitors to supplement areas protected by water spray and/or foam and/or provided as the primary means of active fire protection where such systems are not practical
- Water/foam monitors covering the helideck
- Telecommunications systems such as a general alarm public address, closed circuit television equipment and warning beacons will be provided to give personnel warning of potential hazards.

The WHP will also be protected with fire hydrants connected to the firewater distribution system. The number and position of the fire hydrants will be such that every part of the installation can be reached by two hydrants, in accordance with legislation. Fire hydrants will be capable of being connected to a foam source.

There will be at least two independent firewater sources, each capable of producing 100 percent of the maximum demand. The fire pumps will be located separately to prevent both pumps being rendered unserviceable by a single event. The firewater pumps will meet the NFPA 20 design and performance criteria.

8.2.7.5 Safety Stations

The WHP will have two muster points. One muster point will be in the accommodations area temporary safe refuge, close to the lifeboat station. The other muster area will be located in the northeast corner of the WHP near the second lifeboat station. The temporary safe refuge will have an emergency command centre with facilities to direct an emergency response and an orderly evacuation if required. The emergency command centre will include the following:

- Facilities to monitor WHP indicators and alarms
- Internal and external communications
- Means to manually activate fire suppression systems
- Means to manually initiate WHP shutdowns.

The temporary safe refuge will be suitability protected from fire and or explosions to allow time for emergency response and orderly evacuation.

8.2.7.6 Escape and Evacuation

Escape routes will be designed in accordance with the *Newfoundland Offshore Petroleum Installations Regulations*. Every work area will have at least two well-marked separate escape routes that are situated as far apart as is practicable. All escape routes and associated stairwells will be appropriately sheltered from the effects of fire and explosion.

The WHP will be provided with a minimum 200 percent capacity of POB in lifeboats and 100 percent capacity in life rafts and 200 percent capacity in personnel environment survival suits. The average weight of offshore personnel will be factored into evaluating the capacity of evacuation systems (as per C-NLOPB Safety Notice #2010.01, Reference 3). Husky will evaluate and incorporate the necessary technology to launch the lifeboats and life rafts.

Lifeboats and life rafts will be appropriately located close to the living quarters/temporary safe refuge. An additional set of lifeboat and life raft facilities will be located in another area based on the platform layout and in accordance with the requirements of the *Newfoundland Offshore Petroleum Installations Regulations*.

All POB will be equipped with marine abandonment suits to be kept in individual living quarters. The temporary safe refuge and secondary muster area will together contain additional marine abandonment suits, for a minimum of 200 percent of the POB in total and sufficient space for donning of the suits.

The WHP will be equipped with lifesaving equipment such as lifebuoys, radio beacons and lifeboat equipment. All safety equipment will meet international marine requirements and all applicable regulations.

8.2.8 System Reliability and Equipment Sparing

The WHP facilities and equipment will be designed with consideration of redundancy, reliability, availability and the intended life of the facilities, consistent with optimum maintenance intervention. Redundant equipment will be provided in accordance with regulatory requirements and to meet the facility target availability. Reliability, availability and maintainability analysis will be conducted during detailed design to determine the appropriate level of redundant equipment to achieve the target availability.

An operating and maintenance philosophy and plan will be developed. Equipment will be designed for high inherent reliability, good maintainability and operability. The design will include consideration for all components that require regular monitoring or maintenance to be easily accessible.

Setting of the WHP target availability takes into account the availability of the *SeaRose FPSO* production facilities and subsea equipment associated with the existing asset infrastructure.

8.2.9 Drilling Package

The drilling package will be a fit for adverse weather unit, with an integrated single drilling rig capable of drilling, completions, specialized well intervention and work-over operations. The drilling package will be comprised of a drilling equipment set and drill floor with derrick on the topsides. Other drilling equipment and support utilities will be incorporated within the topsides design. The drilling equipment set will be comprised of a drill floor supporting the derrick, associated equipment and the drilling control room, supported by a substructure housing the BOP and associated well control equipment.

8.2.9.1 Drilling Hoisting and Rotation

The derrick will be equipped with an electric driven drawworks. The drawworks will have an automatic drill feature, as well as a feature to enable the drawworks to operate with reduced power and speed. The drawworks/hoisting system will be equipped with an emergency stop device, which, in the event of main brake/hydraulic/electrical system failure, will have the capability to stop and lower the load safely.

The top drive system will be the primary method for drilling. The rotary table will be equipped with a hydraulic motor sized to assist in tool make-up/breakout and pipe manipulation.

8.2.9.2 Blow-out Preventer

The BOP will be capable of shutting in on or shearing all drilling tubular pipe sizes identified for use in development drilling on the WHP. For these shearing activities the rams will be able to shear and then hold pressure seal and will be comprised of a minimum of four remote hydraulic operated gate vales. The final ram configuration will be determined during detailed design and will meet all regulatory requirements.

8.2.9.3 Choke and Kill System

A drilling riser system, comprised of a high pressure riser and a low pressure riser, will connect the wellhead to the BOP and diverter. The low pressure riser will be used to connect the surface integrated wellhead to the diverter housing and the high pressure riser will be used to connect the wellhead to BOP. The BOP system will be connected to a choke and kill system. Manifold outlets will be configured such that well control fluids can be directed from the choke manifold to the mud gas separator, shakers, trip tank and overboard line.

8.2.9.4 Pipe Handling

To the extent possible, the pipe handling system will be designed for remotely controlled operation using proven systems and technology. The system will:

- Pick-up of pipe, casing, and riser (both high pressure and low pressure) from the pipe deck
- Transport pipe, casing, screens, and riser from the pipe deck to the drill floor
- Pick-up of pipe, casing, and riser within the drill floor/derrick area
- Make up of stands of drill pipe and running same through the rotary table
- Offline stand building of drill pipe.

The pipe rack will be sized to accommodate a 10 day re-supply period. This will include the longest casing, as well as backup drill pipe, auxiliary equipment, collars and drilling tools. The pipe rack will allow for the inspection and cleaning of tubulars. The pipe rack will be equipped with a knuckle boom crane and a dedicated catwalk machine.

8.2.9.5 Rig Controls and Monitoring

Rig control and monitoring systems for the WHP drilling, completion and intervention facilities will include:

- Drilling deck and drill floor machinery
- Derrick equipment
- Mud system
- Bulk system
- Drillers cabin controls
- Cement system
- Mud treatment and CRI systems
- Zone management and anti-collision system of all pipe handling and drill floor equipment
- Well control equipment
- Third party service equipment (interface).

Table 8-1 summarizes the equipment comprising the drilling package.

Table 8-1 Drilling Package Equipment

System	Equipment
Well Control System	BOP, BOP control unit, diverter system, choke and kill manifold, mud/gas separator, drilling risers, high-pressure choke and kill lines
Hoisting and Rotating System	Derrick, deadline anchor, drilling line, crown block, travelling block, top drive, drawworks, rotary table
Tubular Handling System	Pipedeck, fingerboard, knuckle boom crane, catwalk machine, iron roughneck, power slip, mousehole, pipe handling systems
Drilling Hydaulic Power Unit	Central hydraulic power unit
High-pressure Mud System	High-pressure mud pumps, high-pressure manifolds and piping system
Drilling Control and Data Acquisition System	Drilling control room, remote operation and monitoring of drilling equipment and systems
Mud Solids Control System	Mud returns, shale shakers, degasser and centrifuges
Mud Mixing and Storage System	Mud building and conditioning systems, low pressure transfer and storage
Bulk Barite, Bentonite and Calcium Carbonate	Storage vessels and transfer system

System	Equipment
High-pressure Cement System	High-pressure cement pump, high-pressure manifolds and piping system
Cement Mixing System	Mixing tub, liquid additive system, transfer pumps and piping system
Bulk Cement System	Storage vessels and transfer system
Rig Skidding System	Hydraulic jacks, grippers and clamping system
Cuttings Processing System	Fluidizing of cuttings and injection equipment and drying equipment
Drilling Drains System	Hazardous and non-hazardous open drains
Base Oil System	Storage vessels and transfer system, washdown unit
Brine System	Storage vessels, filtration and transfer systems
Drill Water System	Storage vessels and transfer system
Drilling General System	Pressurized washdown system, vacuum system, boat loading stations
Well Completions System	Fracturing and wellbore fluid handling systems
Well Interventions System	Wireline, logging, slickline and coiled tubing

8.2.10 Provisions for Future Expansion

The WHP is a fit-for-purpose platform and, as such, only services and equipment essential to safe, efficient drilling and production operations will be included on the platform. However, some provisions for future expansion will be included in the WHP design.

The WHP design will include provision for future tie-back of one subsea drill centre for oil development in the near-field. Specifically, the WHP design includes risers for production, water injection, gas lift and a J-tube for controls from a future subsea tie-back and provision for a heater on the test separator inlet. The WHP design will include provision of a gas export riser and a chemical riser for potential future gas production to a future gas processing facility.

No additional space or weight allowance for major future topsides equipment will be included in the WHP design. The production from a potential future oil or gas tie-back will be routed via the WHP to the *SeaRose FPSO* or a future gas gathering and export system.

The WHP design will also include provisional space for a modular well clean-up package. This equipment will be installed, as required, throughout the life of the WHP.

8.2.11 Future Subsea Developments

In addition to development from the WHP, Husky may also develop up to two additional subsea drill centres in the White Rose region. The WHP will have the capability to tie-back one new drill centre. Tie-back of a second potential drill centre would be through an existing drill centre or directly to the *SeaRose FPSO*. Any future development of drill centres would be the subject of separate Development Plans submitted to the C-NLOPB.

9.0 WHP CONSTRUCTION AND INSTALLATION

9.1 Approach to Project Management

Husky's philosophy for management of WHP engineering and subsequent construction and installation is to expand the current in-house organization as required. Husky has managed previous White Rose-related projects in the same manner using established and well-proven project management processes and procedures. Core WREP personnel will remain with the project and play an integral role as the project progresses through the execution stage, thus ensuring a progressive knowledge base during the engineering, procurement, construction and installation phases.

The potential environmental effects of WHP construction have been examined in the *White Rose Extension Project Environmental Assessment* (December 2012) and *Response to Review Comments on the White Rose Extension Project Environmental Assessment* (April 2013).

9.2 Topsides Facilities Construction

The topsides facilities will be constructed in an established fabrication yard. The contractor for topsides construction will be selected in 2014. A graphic depiction of the proposed topsides facility is a shown in Figure 9-1.

Figure 9-1 Proposed WHP Topsides Structure

9.3 CGS Construction

9.3.1 Graving Dock Construction

The graving dock will be constructed within a 20 hectare plot that has been leased from the Argentia Management Authority at Argentia, NL. Construction of the graving dock will take approximately nine months. The graving dock will be fitted with concrete gates that will allow the facility to be re-used. Figure 9-2 shows the location of the graving dock at the Argentia site. The excavation contractor will mobilize equipment primarily by road. Fuelling of equipment will be by tanker truck that will source fuel locally. Husky anticipates that equipment operators and associated support personnel will use their own vehicles to travel to and from the work site.

Figure 9-2 Graving Dock Location at Argentia, NL

9.3.2 Dock Gates Construction

The graving dock gates will be comprised of two gates, each 27.5 m high, 72 m long and 30 m wide. The gates will sit on a concrete sill and will connect to abutments that step up the side of the casting basin slope. When the graving dock is in the flooded condition, the gates will be drained of water until they become buoyant. Once buoyant, the gates are towed out of the graving dock, allowing open movement from the graving dock to the sea. To de-water the graving dock, the gates will be placed in position and filled with water, providing the necessary seal that allows the graving dock to be pumped dry.

Figure 9-3 shows the graving dock gates with the natural bund in place. The graving dock with bund removed and gates open and closed are shown in Figures 9-4 and 9-5, respectively.

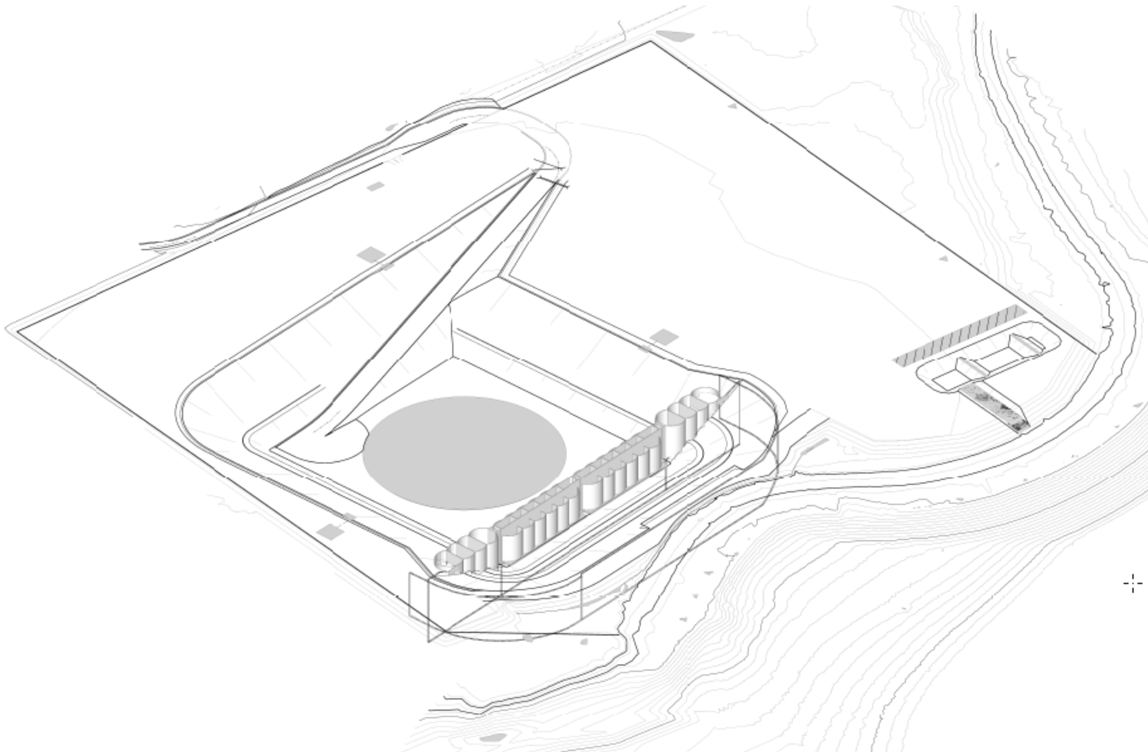


Figure 9-3 Graving Dock with Natural Bund and Dock Gates

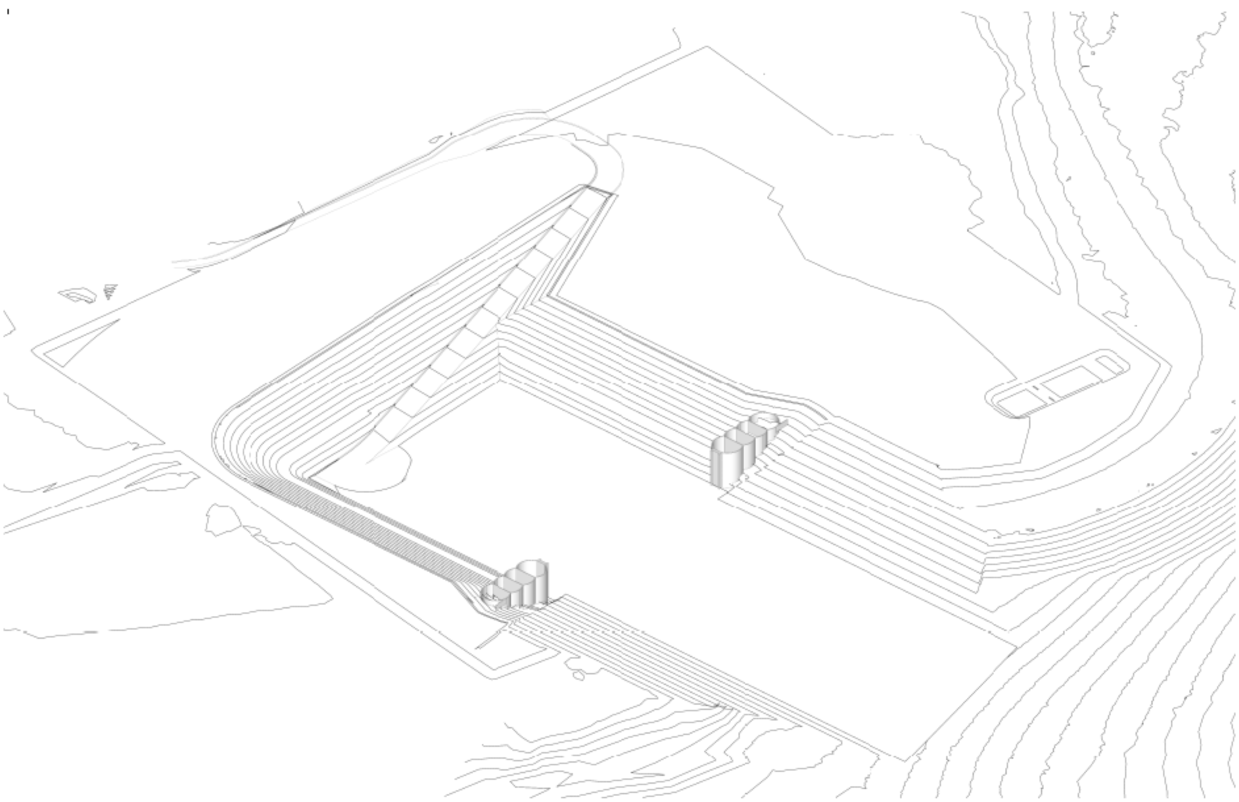


Figure 9-4 Graving Dock with Gates Open

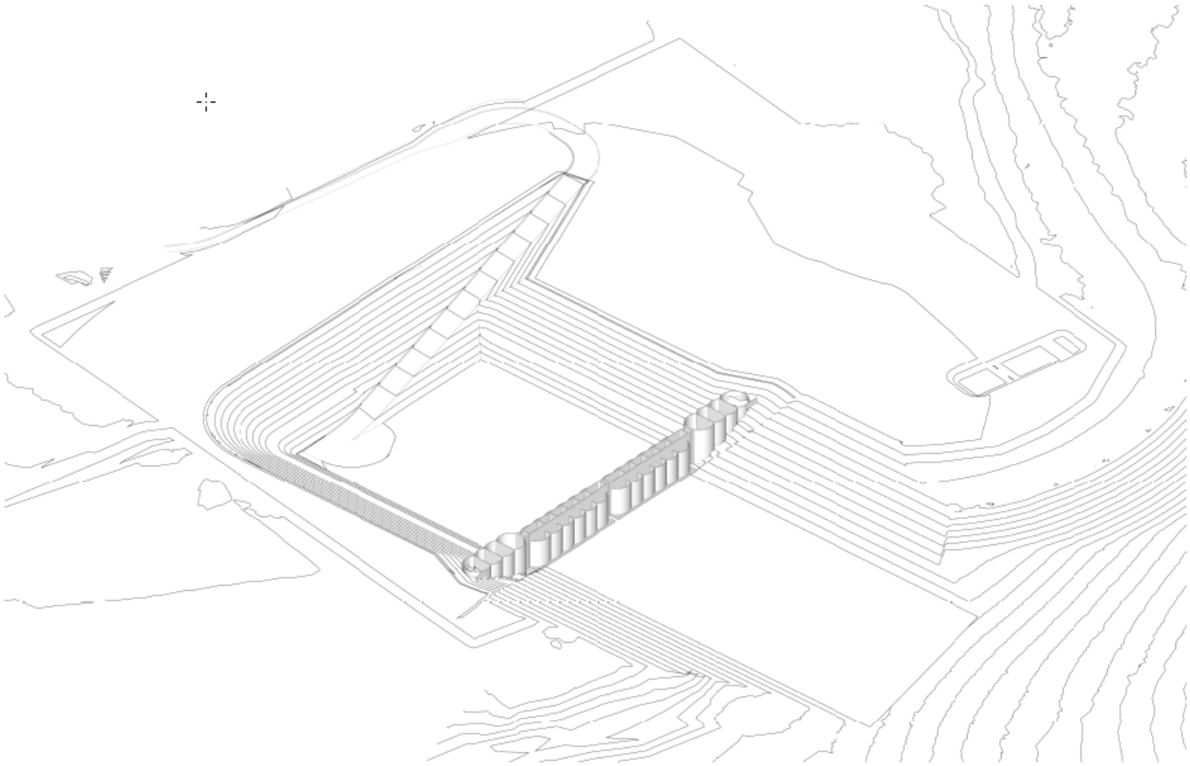


Figure 9-5 Graving Dock with Gates Closed

9.3.3 CGS Construction

The contractor responsible for the construction of the CGS will establish site infrastructure in accordance with an approved execution plan. Site facilities including temporary buildings will be established to support the construction program.

Potential support facilities include primary and secondary concrete batching plants, offices, mess hall, medical clinic, temporary sheds, lay down areas and storage areas. The construction site will be fully fenced with a security-controlled entrance. All buildings will be temporary and set on concrete sleepers or trailers above ground.

The primary materials that will be used in construction of the CGS are cement, sand, gravel and rebar for the concrete component, and structural steel and pipe within the CGS shaft. Approximately 72,000 m^3 of concrete will be poured over a 20-month period. Husky anticipates that the materials will be delivered by road to the site or by commercial sea freight to the Port of Argentia, where it will be offloaded and transported by road to the CGS construction site. Figure 9-6 shows the general phasing of CGS construction.

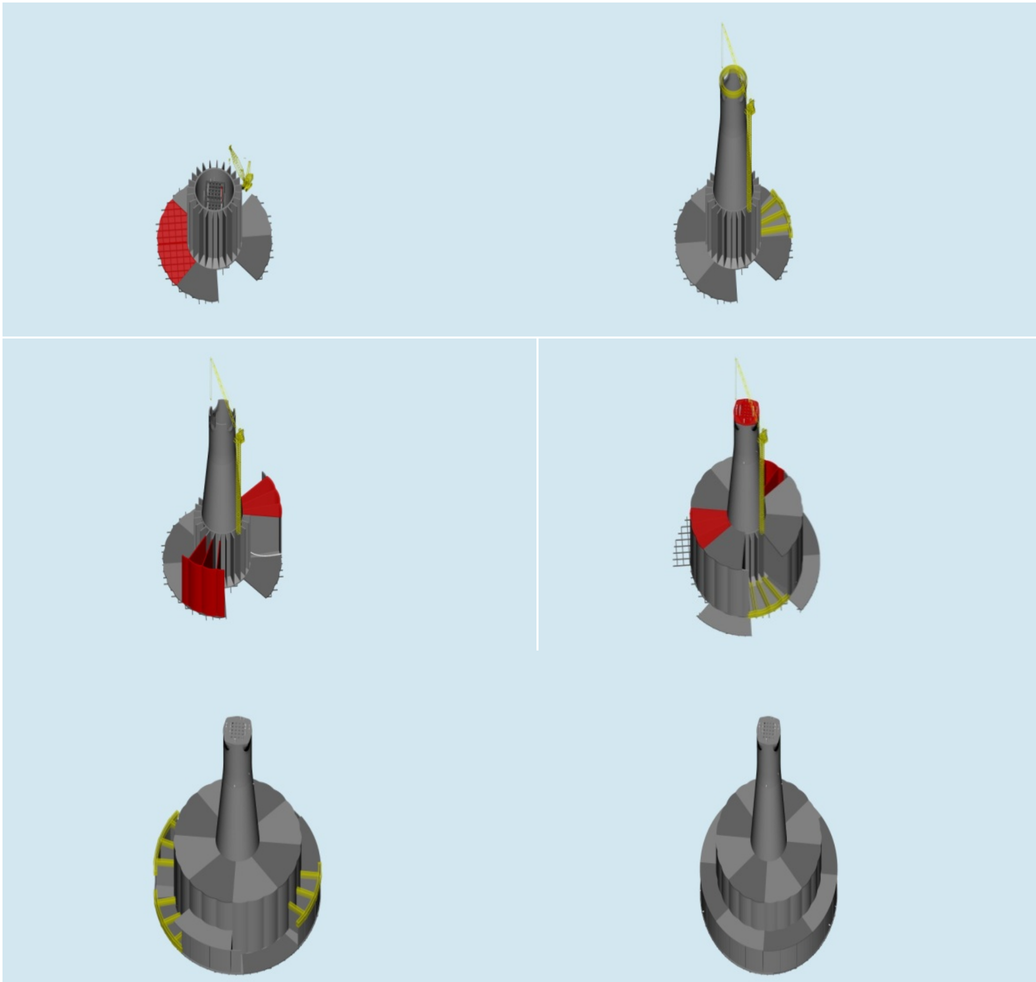


Figure 9-6 Phases of CGS Construction

9.3.4 Mechanical Outfitting

The single shaft of the CGS will contain all the mechanical components for WHP. The shaft will contain J-tubes to house flexible risers for the connection of the facilities to the *SeaRose FPSO*, drilling conductor guide frames, caissons for fire water pumps, sea water recovery, treated sewage water disposal, water-based drill cuttings discharge and access within the shaft.

During the mechanical fit-out work, the piping systems will be pressure tested. The shaft will ultimately be installed with a concrete slab and all penetrations through the shaft will be sealed and made water tight.

9.3.5 Float Out of CGS from Graving Dock

Once the CGS construction is completed, preparations will be made for the float out of the structure and tow to the White Rose field. The current schedule is for the CGS to be floated out in 2017 and installed at site. Supporting subsea hookups are also planned for 2017. Mating of the topsides will take place using a specialized installation vessel.

The graving dock will be flooded to equalize the hydrostatic pressure on either side of the bund. A combination of land excavation and dredging at the shoreline will be used to remove the bund. The dredger will also be used to dredge, as required, a channel from the graving dock to accommodate the draft of the CGS. The results of a seabed survey along the tow-out route indicate that the substrate is suitable for dredging and no blasting will be required. It is anticipated that excavation/dredging of the bund will take up to eight weeks to complete. Dredging of the tow-out channel is anticipated to take up to four months to complete and will be done prior to removal of the bund. During this period, the activities related to the dredging operation will be coordinated with the Port of Argentia.

Four tugs will be required to tow the CGS to the White Rose field. It is anticipated that the transit time will be approximately six days. The CGS will be ballasted into position at its permanent location in the White Rose field.

9.3.6 Placement of Ballast

It is currently planned that the CGS will be submerged to the appropriate depth for tow out to the White Rose field using solid ballast. Once the CGS is in position offshore, additional ballast will be added in order to set the CGS in place. A combination of solid and water ballast will be used.

9.4 Platform Integration

The original plan identified in the environmental assessment for this project envisioned topsides mating taking place at a deep water site in Placentia Bay. However, further investigation has indicated that mating of the topsides to the CGS at the permanent location in the White Rose field is a technically superior option. There are numerous benefits identified with mating of the topsides to the CGS at its offshore location in the White Rose field. These include greater stability during tow-out and a tow-out duration of approximately six days for the CGS versus 15 days for the WHP due to the greatly reduced draft (38 m vs. 115 m), which allows for a more direct tow route across the Grand Banks. As well, topsides mating offshore will mean there will be no interference with fishing and other marine activities in Placentia Bay. Figure 9-7 shows the potential tow-out route of the CGS from Placentia Bay to the White Rose field.

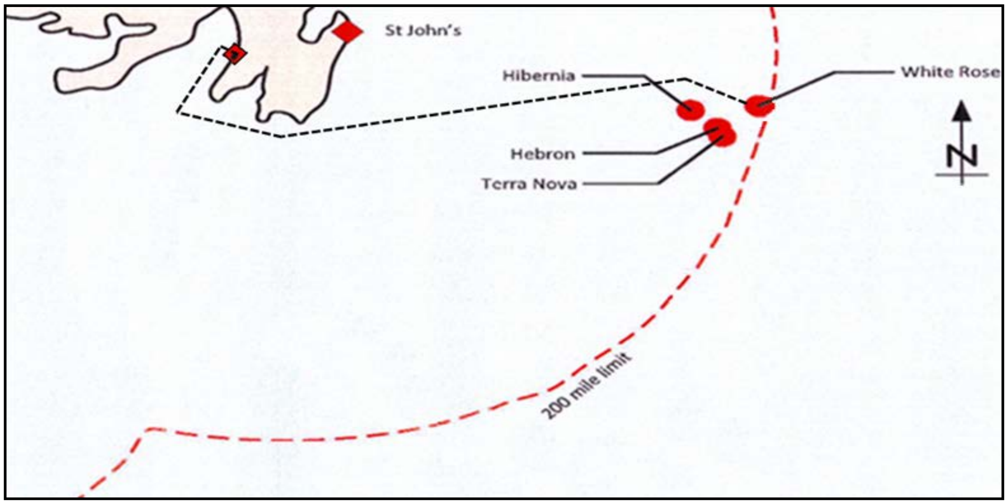


Figure 9-7 Potential Tow-out Route of CGS from Placentia Bay to the White Rose Field

The topsides structure will be fully integrated and commissioned to the extent possible at the fabrication yard, prior to being transported to the White Rose field. The topsides will be installed on the CGS by the *Pieter Schelte*. The *Pieter Schelte* is a dynamically positioned platform installation/decommissioning vessel with a topsides lift capacity of 48,000 tonnes (Figure 9-8). A detailed hook up and commissioning plan will be developed prior to mating of the topsides with the CGS. Use of a flotel and the availability on the *SeaRose FPSO* for housing personnel until the required safety systems are up and running on the WHP will be assessed as part of hook up and commissioning plan development.

Figure 9-8 *Pieter Schelte* Platform Installation Vessel

9.5 *SeaRose FPSO* Modifications

It is anticipated that there will be no modifications required to oil, water and gas handling and processing systems on the *SeaRose FPSO*. Modifications that are anticipated centre on integrating the WHP to function in a satellite platform mode and will be carried out by following the existing Management of Change procedures. The anticipated modifications include integration of controls systems and telecommunications between the *SeaRose FPSO* and the WHP.

Training related to integration of the WHP with *SeaRose FPSO* operations will be completed as required. The *SeaRose FPSO* operating and maintenance procedures, safety plan, environmental protection plan and emergency response plan will be reviewed and revised as required. An enhanced ice management plan will also be developed taking into consideration the WHP.

The design life of the WHP extends beyond the current design life of the *SeaRose FPSO*. Additional work will be completed to assess the impact and feasibility of extending the life of the *SeaRose FPSO*. Condition and operating regimes for the *SeaRose FPSO* and existing subsea equipment will continue to be monitored as part of Husky's integrity management program. The need for replacement will be evaluated as equipment approaches design life.

9.6 Subsea Infrastructure

9.6.1 Flowlines

Subsea flowlines will interconnect the WHP with the *SeaRose FPSO* via valved mid-line tie-in structures in the existing production flowlines between the CDC and the *SeaRose FPSO*. A subsea water injection flowline will connect the WHP and the *SeaRose FPSO* via a flowline termination module that will be added to the end of the existing CDC water injection manifold.

A gas supply flowline was connected between the WHP and a gas injection flowline between the NDC and the SWRX drill centre in 2013.

The flowlines will be installed by a specialized vessel. Tie-in to the WHP risers and to the existing manifolds and new tie-in structures will be done by divers deployed from a specialized diving support vessel.

The flowlines will be deployed directly onto the seafloor similar to the installation methods used for existing flowlines. Flowline weak links will be provided as necessary to protect the CDC wellheads and, potentially, the WHP risers from accidental loads transferred in the event of iceberg scour, dragging anchors, or fishing trawl-over. Dropped object protection may be provided in the vicinity of the WHP and flowlines entering or adjacent to the CDC.

Condition and operating regimes for the original CDC flowlines and risers will continue to be monitored as part of Husky's integrity management program. The need for replacement will be evaluated as equipment approaches design life and also at times that may be opportune for riser replacement, such as future *SeaRose FPSO* off station programs.

9.6.2 Umbilicals

An umbilical from the WHP to the SSIV will be required to control and monitor the SSIV. The SSIV umbilical will be installed directly on the seafloor from a vessel and it is expected that the umbilical will be pulled up through a J-tube at the WHP riser.

9.6.3 Modifications to Drill Centres

The existing manifolds in the CDC will be modified to incorporate tie-in flanges, isolation valves and flowline dewatering facilities. The modification to the manifolds will be made by divers.

9.6.4 Subsea Equipment Outside Drill Centres

Simple mid-line tie-in structures may be used to connect flowlines. The tie-in structures would consist of tie-in flanges and isolation valves and would allow pigging for production lines and a method of dewatering for the gas supply line.

There will be an SSIV on the gas supply flowline to the WHP. The SSIV structure will consist of a remotely activated isolation valve mounted in a support frame. The SSIV will be controlled via an electric/hydraulic umbilical from the WHP routed through a J-tube. The SSIV will be deployed by a construction vessel with tie-in by divers.

9.7 Field Hook-up, Commissioning and Start-up

Successful transition from the construction phase to the operational phase of the WREP is a key objective. An overall hook-up, commissioning and start-up philosophy will be developed early in the WREP and updated on a phase-by-phase basis as the WREP definition evolves.

Testing and commissioning plans will identify the testing requirements for each system. The testing and commissioning plans will include:

- Factory acceptance tests
- Factory integration tests
- System integration tests
- Mechanical completion

- Pre-commissioning
- At-shore commissioning
- Offshore hook-up
- Offshore commissioning and handover
- Start-up and operation.

The testing and commissioning plans will describe the type and scope of testing at each WREP location and phase to ensure that equipment is fully tested and functional prior to start-up.

Detailed hook-up, commissioning and start-up procedures will be prepared during detailed design. Commissioning requirements such as test connections will be incorporated into the equipment/system design.

Operation and maintenance manuals, commissioning dossiers, operating procedures and handover documentation will be prepared. The Certifying Authority will be involved with the testing/commissioning of platform safety systems, such as cause and effect testing of the ESD system and FGS and performance testing of emergency generators and firewater pumps. Operations personnel will be involved in the commissioning program as part of the training and preparations for start-up and subsequent operations.

9.8 Environmental Considerations of Construction and Installation

Environmental monitoring and reporting programs will be developed to ensure that environmental performance requirements are incorporated into all construction and installation activities.

WREP construction contractors will be required to develop Environmental Protection and Compliance Monitoring Plans (EPCMPs) specific to their work scope. The EPCMPs will be the basis for development of site-specific environmental management and reporting plans.

In addition to the Argentia graving dock site, it is anticipated that all other fabrication and construction activities for the WHP will take place in existing contractor-owned facilities. Each contractor will be responsible for obtaining and maintaining permits and licences as required for the jurisdiction in which the work takes place.

The WREP environmental assessment reports (*White Rose Extension Project Environmental Assessment* (December 2012) and *Response to Review Comments on the White Rose Extension Project Environmental Assessment* (April 2013) address the environmental effects of project activities in the marine environment, including dredging and excavation for tow-out at the Argentia site and offshore installation, commissioning and operation of the WHP. Mitigations identified in the environmental assessment will be implemented at Argentia and at the offshore WHP site.

10.0 WHITE ROSE EXTENSION PROJECT ASSET MANAGEMENT

10.1 Onshore Organization

The WHP will be integrated into Husky's current operations organization. The existing organization has all functions necessary for operations, including drilling and completions, subsurface, production operations, marine operations and logistics, health, safety, environment and quality (HSEQ), procurement, contracting, benefits monitoring and reporting and regulatory affairs. The integration of the WHP into Husky's onshore management organization may require hiring some additional personnel in various departments, including production operations, drilling and completions, HSEQ and logistics. The existing onshore Husky management systems that currently support operation of the *SeaRose FPSO* and for mobile offshore drilling units under contract to Husky will continue to apply.

Figure 10-1 depicts the reporting relationship between onshore and offshore and between the *SeaRose FPSO* and the WHP.

10.2 Offshore Organization

10.2.1 *SeaRose FPSO*

The current organization of the *SeaRose FPSO* will not be impacted by the addition of the WHP facility in the White Rose field. There will be no organizational changes required from an operations or production point of view. The offshore installation manager (OIM) will continue to be responsible for overall operations on the *SeaRose FPSO* and a marine supervisor will continue to be on board at all times. The management of operations and maintenance and services including HSEQ will be unchanged.

The OIM on the *SeaRose FPSO* will have overall field responsibility for all installations, including the WHP.

10.2.2 Wellhead Platform

The WHP will have a dedicated OIM who will be responsible for overall operations on the WHP. The OIM will be responsible to the production operations department. HSEQ and other support services on the WHP will be managed in the same manner as current operations on the *SeaRose FPSO*. Husky's drilling and completions department will oversee drilling and completions activities through a drilling contractor who will manage drilling and completions activities on the WHP. All personnel on the WHP will be responsible to the OIM during operations.

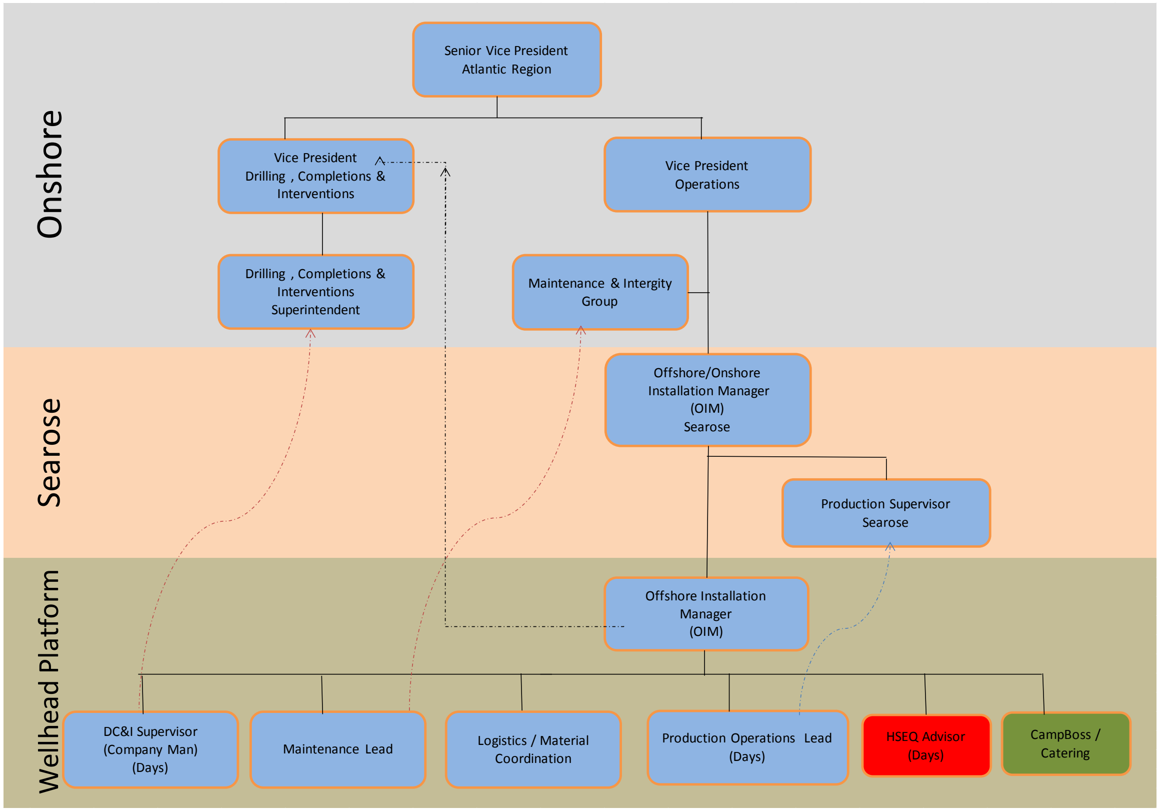


Figure 10-1 Reporting Relationship between Onshore and Offshore and between the *SeaRose FPSO* and the WHP

10.2.3 Operations and Maintenance

The WHP will be maintained and operated in accordance with Husky Operational Integrity Management System (HOIMS). Availability, operability, reliability, ease of maintenance and safety of personnel and equipment are of paramount importance. To this end, Husky's operating and maintenance philosophy will require that WHP equipment has a high inherent reliability, good maintainability and operability. The WHP will be designed so that all components that require regular monitoring or maintenance will be easily accessible.

10.2.4 Facility Availability

Availability of the WHP and associated infrastructure will be addressed in the design and will consider the remote location of the facilities and the potential impact on equipment repair times.

A target facility availability will be established for the WHP, based on a reliability and maintainability study of the topsides production equipment, drilling derrick and electrical equipment. The facility availability will be defined as the actual production volume expressed as a fraction of the target production volume.

The dependency upon the availability of the *SeaRose FPSO* facilities and associated subsea equipment will also be factored in the establishment of a target availability.

10.3 Sparing Philosophy

The sparing philosophy for WHP equipment will be developed to maximize availability of the facility for oil production and drilling operations.

10.4 Operating Philosophy

The WHP will be designed and constructed for continuous operation except for annual maintenance shutdowns. The design will allow for low operational cost and staffing and operation within the safety and environmental standards specified for the development. As Operator, Husky will be responsible for the efficient operation of the WHP and will recruit personnel with the appropriate skill sets and competency in managing and operating the facility.

10.5 Asset Integrity Management

Asset integrity will be considered throughout WHP system design and will maintain consistency with the existing asset integrity system on the *SeaRose FPSO*. As part of the life-of-field asset integrity management system, the following aspects will be considered:

- The Safety Critical Elements Management System defines how Husky manages the equipment integrity of its facilities by requiring that the facility's Safety Critical Elements continue to meet their respective performance standards. The WHP will be included in the overall Safety Critical Elements Management System.

- Environmental, structural and foundation integrity monitoring will be considered in the design of the WHP. Integrity monitoring systems will obtain real-time data to keep operators informed about the state of health of the WHP and the global environmental conditions.

10.6 Maintenance Strategy and Procedures

As with the existing *SeaRose FPSO*, a maintenance strategy will be developed and implemented for the WHP. Standardized equipment will be selected where appropriate and, where possible, aligned with the existing *SeaRose FPSO* facility. Equipment will be selected on the basis of reliability, criticality and life-cycle cost.

A computerized Maintenance Management System will be implemented for the WHP, similar to that in place for the *SeaRose FPSO*. The system database will collect all relevant maintenance data, including key technical lists, schedules, registers, inspection and test plans and supplier service life inspection and maintenance plans.

Maintenance procedures will be developed to ensure that all equipment is maintained in accordance with regulatory requirements and manufacture's recommendations. Condition-based monitoring programs will be developed to proactively identify and resolve maintenance issues. Inspection and testing programs will be developed in accordance with regulatory requirements and will be similar to the facilities integrity program currently implemented on the *SeaRose FPSO*.

10.7 Operating Procedures

The *SeaRose FPSO* has a suite of operating procedures in place. Similarly, a suite of operating procedures will be developed specifically for the WHP or, where appropriate, amended *SeaRose FPSO* procedures may be applied.

The following will be addressed in developing new and amended procedures:

- Drilling, completions and intervention operations
- Production operations and interface to *SeaRose FPSO* production systems
- Marine operations
- Overall emergency response
- Facility-specific emergency response
- Environmental protection and compliance monitoring
- Simultaneous operations.

10.8 Environmental Monitoring Procedures

To ensure consistent standards of operational integrity, Husky has developed the HOIMS. HOIMS provides a systematic approach toward achieving operational excellence and consists of 14 Elements - each with its own aim and set of expectations. As required by Element 8: Environmental Stewardship, Husky has developed and implemented environmental monitoring procedures requiring compliance with Husky requirements and applicable legislation and regulations.

Husky conducts an extensive environmental effects monitoring (EEM) program to evaluate the effects of drilling and oil production operations on the marine environment at the White Rose field. The EEM program, which commenced in 2004, monitors project effects on water quality, sediment quality and commercial fisheries. Monitoring is conducted bi-annually. The EEM program will be revised to include the WHP.

Additional environmental monitoring plans and procedures that have been developed and implemented by Husky for the White Rose and North Amethyst developments include:

- Chemical Management System and Chemical Screening Procedure
- Waste Management Plan
- Facility-specific EPCMPs that outline measures to manage waste streams from facilities, including bilge discharge, deck drainage, cooling water and produced water
- Air emissions monitoring (including greenhouse gas).

These plans and procedures will be updated as required to include all infrastructure and activities associated with the WREP. An EPCMP will be developed specifically for the WHP.

10.9 Ice Management Plan

The Well Head Platform (WHP) will be designed to meet ISO 19906 L2 exposure classification for ice loading on the structure. As per this code (refer to Table A.7), the exposure level is determined by the Life Safety Category (S2) and the Consequence Category (C2). The requirements for each category are as follows:

Life Safety Category (S2):

- Normally staffed facility
- Ability to reliably forecast a design environmental event and weather is not likely to inhibit down-staffing
- Planned down-staffing ahead of a design environmental event
- Sufficient time and resources to safely down-staff.

Consequence Category (C2):

- Production can be shut-in during a design event
- Wells that can flow have Subsurface Isolation Valves (SSIV's)
- Oil storage limited to process inventory and surge tanks for transfer
- Pipelines have limited hydrocarbon release potential.

The WHP will meet the design and operational requirements of ISO 19906 as described above for the S2 and C2 categories as follows:

WHP Life Safety Category (S2):

- The WHP will be a normally staffed facility.
- As described by ISO 19906, the design environmental event relating to ice is the ALIE (Abnormal Level Ice Event). Husky currently has comprehensive methods of early ice detection and will take a conservative approach to identify ALIE ice by considering iceberg water line length, mass, volume and speed.
- Husky has an Ice Management Plan that outlines the ice management policies and procedures developed to support offshore operations. This plan will be revised to meet the needs of the WHP, which is a permanent fixed structure. The Ice Management Plan will detail the down-staffing plan ahead of a design environmental event.
- The revised Ice Management Plan will include defined T-Times. The T-Time is the total time required to secure the facility and down-staff personnel. T-Time calculations will include the following inputs to ensure there is sufficient time for down-staffing:
    - The operational status of the facility will determine the time required to shutdown, secure wells, drain and purge the WHP facility.
    - Weather forecasting will ensure sufficient time for down-staffing after the operational phase is completed.
    - Historical weather statistics for a particular time of year will also be utilized to ensure sufficient time is allotted for down-staffing after the operational phase is completed.
    - Preferential mode of down-staffing will be via helicopter with transfer to a supply vessel as a contingency.

WHP Consequence Category (C2):

- The ability to shut-in production on the WHP facility is inherent in the design.
- WHP wells will be designed with SSIV's.
- The WHP will not have oil storage or processing. Oil will be transferred to the SeaRose FPSO for processing, storage and offloading. Therefore, oil storage on the WHP is limited.
- Pipelines as part of the WHP will have limited hydrocarbon release potential.

As shown, the Life Safety (S2) and Consequence Category (C2) requirements of ISO 19906 Code will be met through both engineering design and operational policies and procedures such as Husky's Ice Management Program. By meeting these requirements, the WHP structure will have an exposure class of L2 for ice loading.

10.10 Logistics

Husky intends to use its existing infrastructure and established service contracts to support operations on the WHP. Many long-term contracts have been established to support the *SeaRose FPSO,* as well as mobile offshore drilling units that have been under long-term contract with Husky.

10.10.1 Marine Base, Warehousing and Storage Yard

Husky uses an established shore base services contractor for all offshore loading requirements. This facility is equipped with cranes, forklifts and bulk loading/storage to support all vessel loading and offloading requirements. Multiple berths are available at this facility, allowing efficient servicing of multiple supply vessels.

Warehousing is available through Husky's current contractor, who has a facility with both indoor and outdoor storage space, which allows for the safe and coordinated storage of spares, long lead items and larger equipment.

10.10.2 Support Vessels

Husky currently has a fleet of four vessels servicing two offshore facilities. Fleet configuration depends on the size and capability of the vessels available, as well as the requirements of the offshore installations. The fleet is increased or decreased depending on demand and requirements. Vessels will be added to the fleet as required to support the WHP.

The main requirements of the fleet include:

- Providing standby and other support to offshore installations on a continuous basis, as per regulatory requirements
- Providing resupply to each offshore installation, ensuring that all materials, consumables and equipment are delivered in a timely manner
- Providing personnel transport to and from offshore facilities during times of reduced visibility that restricts helicopter transport, or because of other issues affecting availability of helicopter services
- While in the White Rose field, vessels provide a number of additional services in support of the offshore installations. These include:
  - Close standby duties for helicopter approach, overside work, remotely operated vehicle operations
  - Anchor handling when mobile offshore drilling units are present in field
  - Iceberg surveillance, towing and deflection

- EEM program
- Oil spill response
- Shuttle tanker mooring assistance
- Vessel heading control support
- Emergency response including person overboard assistance, on scene command, search and rescue, firefighting and emergency evacuation.

All supply vessel personnel are fully trained in emergency response and are knowledgeable with respect to Husky's policies, procedures and requirements. Various training exercises and safety drills are conducted on a regular basis. Such exercises include, but are not limited to, person overboard drills, search and rescue training with helicopters, fast rescue craft operation and oil spill response exercises.

10.10.3 Material Procurement and Movement

As with its existing offshore installations, Husky will plan to have an optimal level of spares inventory is available for emergency services and to support continued operation of the WHP. A spares philosophy will be developed to rank requirements based on criticality and to determine the most appropriate location for each item. Critical spares will be maintained on the WHP to ensure immediate availability.

Food and water will be supplied to the WHP on a regular basis via supply vessel. Such consumables will be procured and delivered via the same process that has been established for the other Husky installations operating at White Rose.

10.10.4 Personnel Movements

The primary mode of transport for personnel travelling offshore will be via helicopter. The WHP will have a POB limit of 144 and it is anticipated that Husky's existing helicopter services provider will be able to provide services, since capacity currently exists within the fleet. Personnel may also be transported via supply vessel during times of poor visibility or flying restrictions.

10.10.5 Subsea Support Requirements

Subsea support for the WHP will primarily be provided by a light intervention vessel. This vessel will be available for regular inspection and repair of subsea assets/tiebacks and is equipped with two remote operated vehicles and associated crew to conduct scopes as required.

If diving operations are required, Husky will contract a suitable dive support vessel to conduct the work. Similarly, if diver intervention is required, such services will be contracted separately and all associated risks and requirements will be evaluated. Husky has conducted several diving campaigns in the White Rose field using experienced personnel contracted to direct and control the operations under Husky supervision.

10.10.6 Communications

Equipment and systems will be installed onshore and offshore to provide industry-accepted high standards of communications on the WHP and between the WHP, the *SeaRose FPSO*, the Husky onshore operational centre offices, other offshore installations and shipping and aircraft in the vicinity.

The communications systems will include radio, telephone, telemetry, fibre optic, local area computer network and other related equipment necessary to provide the high standard of reliable communication that is required for safe and efficient operations. The systems will comply with all regulatory requirements. Redundancy and backup systems will be used to provide the maximum continuous uninterruptible communications capability available in all anticipated environmental conditions.

10.11 Emergency Response

10.11.1 Incident Coordination Plan

Within the HOIMS framework, Element 4 is dedicated to emergency preparedness. A strong emergency response program supports the integrity of Husky operations. In the Atlantic Region, this is accomplished by:

- A comprehensive response process
- Effective and accessible response documents
- Training
- Emergency Response Team (ERT) commitment.

Husky's *Incident Coordination* Plan outlines the necessary resources, personnel, logistics and actions to implement a prompt, coordinated and rational response to any emergency. It offers an efficient and balanced approach to dealing with the issues resulting directly from an emergency. The plan addresses those situations that result in:

- Concern for current or forecast conditions that cause an operational alert
- Public or regulatory concern for Husky operations
- Direct threats to human safety, or actual injury or death
- Threatened or actual damage to facilities or major equipment
- Terrorism, sabotage, or criminal acts
- Unintentional discharges to the natural environment.

The objective of the plan is to ensure that in the event of an offshore or onshore emergency, personnel are mobilized onshore as soon as possible to provide the necessary support required by an emergency site. The plan supplements the installation-specific emergency response plans that are currently in place for existing installations at White Rose. An installation-specific emergency response plan will be developed for the WHP.

10.11.2 Emergency Response Organization

The WHP will have designated emergency response personnel. In every case, the crew will be either in the command group, emergency action teams, or unassigned and expected to report to muster stations. The person in charge of the facility (OIM) will be in command of the response.

Husky's onshore ERT has two components: the Incident Coordination Centre, which can be mobilized quickly to provide direct support to the facility in distress; and the Regional Response Management Team, which may be mobilized immediately after the Incident Coordination Centre to manage the issues resulting from the emergency. Husky's Corporate Response Management Team is available to support the Atlantic Region Regional Response Management Team.

The WHP will have a designated area to be used as the emergency command centre during an emergency response.

10.11.3 Training and Exercises - Emergency Response

Drills are a vitally important and integral part of ensuring the emergency preparedness of the organization.

Drills and exercises are planned in such a manner so that all personnel assigned emergency roles, or who could be an alternate in an emergency role, receive experience during a drill.

10.11.3.1 Offshore

The WHP will develop a schedule of drills based on:

- Specific installation design and operations
- Regulatory requirements
- ERT training requirements
- *Canadian East Coast Offshore Petroleum Industry, Training and Qualification Guide*.

10.11.3.2 Onshore

The onshore ERT receives regular training and experience from planned exercises. The actual number of exercises completed annually varies depending on the level of offshore activity, with a minimum of four exercises completed in a calendar year. Exercise scenarios vary based on actual offshore activity and may be based on the following offshore emergencies:

- Security breach
- Fire and explosion
- Collision
- Oil release
- Hostage taking
- Well control.

10.11.4 Environmental Emergencies

Husky has instituted a spill prevention program with the goal of zero spills into the marine environment. Any unintentional discharge of a hydrocarbon will be considered to be an oil spill and may result in the activation of the *East Coast Oil Spill Response Plan*. This document details the response actions to be taken by Husky in the event of an oil spill while operating offshore Newfoundland and Labrador. These procedures are responsive to regulatory requirements for oil spill contingency planning.

The plan provides a comprehensive review of:

- Husky’s duties when it is the “responsible party” as defined by various acts and regulations
- Husky’s philosophy and policies concerning oil spill response
- The organization of Husky’s response efforts, and the evolution of those efforts with the increasing scale of the spill response
- Arrangements for assistance from contractors and other operators
- Environmental issues resulting from an offshore oil spill
- Husky’s policies concerning safety, oil spill waste management and training.

10.11.5 Training – Spill Response Operations

Key offshore personnel receive practical instruction in oil spill operations. Emphasis is on response to small spills as well as the initial response to a larger spill.

Husky has entered into a preparedness agreement with Eastern Canada Response Corporation, which includes the provision of the following services:

- Management and maintenance of Tier 1 equipment (sorbents, tracker buoys, single vessel sidesweep oil containment and recovery system)
- Management and maintenance of Tier 2 equipment
- Initial and recurrent training for vessel crews
- Oil spill contingency planning and exercises.

The WHP will be incorporated into the agreement with Eastern Canada Response Corporation.

10.11.5.1 Tier 1 Oil Spill Response Orientation

Under Husky's current training regime, all offshore personnel are given an overview of Tier 1 oil spill response operations. Topics covered include the nature of offshore oil spills, notification procedures, a review of available oil spill response resources and determining first response strategies. Similar training will be provided to all WHP personnel.

10.11.5.2 Oil Spill Response Techniques

As part of Husky's current training regime, all supply vessel crews, HSEQ advisors and weather observers are familiarized with on-water techniques applicable to their roles in a response.

Operational training includes sessions covering the following:

- Oil on water observations
- Use of the sorbent boom
- Oil sampling procedures
- Wildlife handling
- Basic seabird observation techniques.

On vessels that are assigned to standby duties in the White Rose field, crews are also trained in the use of the sorbent boom equipment and tracker buoy deployment. Designated vessels receive additional training on the deployment of the single vessel side sweep oil containment and recovery system.

Similar training will be provided to relevant WHP personnel and WHP support and standby vessel crews.

11.0 DECOMMISSIONING AND ABANDONMENT

11.1 Wellhead Platform

As described in the *White Rose Extension Project Environmental Assessment* (December 2012), the WHP will be decommissioned and abandoned by first abandoning the wells in accordance with standard oil field practices, then decommissioning of the topsides, followed by decommissioning and abandonment of the CGS. All infrastructure will be abandoned in accordance with the relevant regulations. The topsides will be removed from the CGS in a manner determined to be most effective at the time of decommissioning. The WHP will not be disposed of offshore, nor converted to another use on site.

11.2 Subsea Infrastructure

Subsea wells will be decommissioned and abandoned in accordance with standard oilfield practices. All equipment located in excavated drill centres will be removed and the drill centres will be left as they are. Xmas trees and manifolds will be purged, rendered safe and recovered.

All other subsea facilities on or above the seafloor, including riser base manifolds, loading riser manifolds and flowlines, will be purged and decommissioned in accordance with regulations prevailing at the time. Flowline sections that have been rock-dumped will not be recovered, and will be cut by divers at the locations where rock dumping ceases. Rock berms are approved by DFO as compensation for fish habitat loss and removal may constitute a harmful destruction of fish habitat and as such, could require a *Fisheries Act* Authorization.

All risers and umbilicals will be decommissioned, rendered safe and recovered.

12.0 DEVELOPMENT AND OPERATING COST DATA

12.1 Capital Cost Estimate

12.1.1 Development Drilling

Estimated drilling costs are provided in Table 12-1. Costs are based on 2012 price levels and include all applicable customs, duties and sales taxes.

Table 12-1 Development Drilling Capital Cost Estimate

Year	Drilling and Completions CAPEX ($MM)
2012	0.0
2013	0.0
2014	0.0
2015	0.0
2016	0.0
2017	69
2018	196
2019	196
2020	196
2021	196
2022	196
2023	196
2024	196
2025	167
2026	0.0
2027	0.0
2028	0.0
2029	0.0
TOTAL	**1,608**

The drilling capital cost estimate is based on the following assumptions:

- Drilling and completion operations will take place as described in this Development Plan Amendment
- Drilling costs are based on scoping level estimates for generic pool and well type
- Base rig rates and full rig spread rates are based on in-house data

- Supplier costs are based on current Atlantic Region cost environment
- 2012 price levels will continue throughout the period of drilling and completion operations.

12.1.2 WHP Construction

Estimated WHP capital costs are provided in Table 12-2. Costs are based on 2012 price levels and include all applicable customs, duties and sales taxes.

Table 12-2 Wellhead Platform Construction Capital Cost Estimate

Year	WHP Construction CAPEX ($MM)
2012	20
2013	170
2014	320
2015	630
2016	960
2017	250
TOTAL	**2,350**

The WHP capital cost estimate is based on the following assumptions:

- The development will take place as described in this Development Plan Amendment
- All facilities, goods and services will be acquired on a competitive basis in accordance with the approved Canada-Newfoundland and Labrador Benefits Plan Amendment.

The capital cost estimates include:

- Topsides:
  - Drilling rig equipment and derrick
  - Living quarters
  - Wellbay, test separator, water injection pumps
  - Flare boom
  - Helideck
  - Lifeboat stations
- CGS
- WREP management

- Contractor engineering and home office costs
- Quality assurance
- Infrastructure upgrades
- Site facility construction and operations
- Transportation and installation of WHP
- Completion and offshore hook-up
- Pre-start-up operations
- Subsea tie-ins to existing drill centre
- Supporting subsea structures, flowlines and umbilicals.

12.2 Operating Cost Estimate

The majority of WHP annual costs are included in the development drilling and completions capital cost estimate. Operating costs for the WHP associated with production operations are expected to increase total field production operating costs by 10 percent per year (or approximately $20 million per year increase over operating cost levels without the WHP).

The operating cost estimate is based on the following assumptions:

- The reservoir parameters will be as described in this Development Plan Amendment.
- Husky 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 Amendment.
- The economic conditions prevailing world-wide in 2012 will continue throughout the period of operation.

13.0 COMMITMENT TO SAFETY

13.1 Concept Safety Analysis and Target Levels of Safety

Pursuant to Section 43 of the *Newfoundland Offshore Petroleum Installations Regulations*, the operator is required to submit to the Chief Safety Officer a concept safety analysis of an installation that considers all components and activities associated with each phase in the life of the production installation. The concept safety analysis must include a determination of the frequency of occurrence and potential consequences of potential accidents identified, and details of safety measures designed to protect personnel and the environment from such accidents.

A concept safety analysis was carried out to identify major hazards associated with the WHP, taking into account the basic design concepts, layout and intended operations, and assessing the risks to personnel and the environment resulting from these hazards. Refer to Husky's Concept Safety Analysis for details related to the quantitative risk assessment completed for the L2 design classification for ice loading events. In all other aspects, the WHP is designed for an L1 exposure level. 'Target Levels of Safety' are addressed in the Concept Safety Analysis.

The risk assessment in the concept safety analysis is quantitative where it could be demonstrated that input data were available in the quantity and quality necessary to demonstrate confidence in results. Where quantitative assessment methods were inappropriate, given the nature or level of development of the subject matter, qualitative methods were employed.

The regulations require the selection of clear design goals aimed at protecting personnel and the environment, as this is fundamental to the design of offshore facilities. These design goals are known as Target Levels of Safety. Risks to personnel will be measured in terms of 'Individual Risk', which is a measure of the annual risk to an individual. Societal risk (also known as group risk) is a measure of the likelihood of multiple fatality accidents, and can be expressed as the frequency of accidents involving fatalities above a specified level.

The concept safety analysis concluded that there were no areas for concern that would prevent demonstration that risks have been reduced to a level that is as low as reasonably practicable at the detailed design stage. Further studies will be required at FEED and detailed design stages to confirm or refine the assumptions that have been made in the concept safety analysis.

The concept safety analysis is included as separate volume of this Development Application.

Target levels of safety with respect to environmental events have been described in the WREP Environmental Assessment (Husky Energy 2012, 2013), including the likelihood of environmental events of specified classes of magnitude (i.e., petroleum spill volume) and a discussion of the potential population-level effects of such events.

13.2 Risk Management

Effective risk management is an integral part of Husky's culture and is embedded into the company's operating philosophy, practices and business processes.

The Atlantic Region risk management process is a comprehensive process that requires that hazard identification studies and risk assessments be conducted at appropriate project and operation stages, and that the results of the assessments be incorporated into facility design and operation. The overall objective is the design, construction and operation of facilities that will permit incident-free performance for the life of their operation.

The process involves applying a logical and systematic method of identifying, analyzing, evaluating, treating, mitigating and communicating risks associated with any activity or process. In this respect, Husky follows *ISO 31000, Risk Management - Principles and Guidelines*. This standard is widely recognized as the international, authoritative standard for risk management and has been adopted by the Canadian Standards Association. Specific risk management steps that Husky undertakes as part of its project development and execution process include:

- Phase 1 (concept screening) - Identify facilities and activities to be assessed and perform very high-level risk screening in order to discover any insurmountable risk drivers.

- Phase 2 (concept selection) - Identify differences in risk levels among alternatives being considered; use results to develop the risk assessment plan and develop a preliminary risk register. Complete the concept safety analysis to support the regulatory application.

- Phase 3 (FEED) - Identify and address all important health, safety and environmental risks by performing process hazards analyses. Conduct technical safety studies and develop a quantitative risk assessment, if necessary, to ensure compliance with quantitative risk tolerance criteria; refine the risk register; prepare for safety integrity level/layer of protection analysis in next phase.

- Phase 4 (engineer, construct, install) - Revalidate and refine previous risk assessment work, complete final quantitative risk assessment and ensure risk tolerance criteria are met. Perform safety integrity level/layer of protection analysis based on the design. Verify closure of risk reduction recommendations.

- Phase 5 (operations, decommissioning) - Gather and assess lessons learned from the risk management process. Periodically revalidate risk profile over the life of the asset to ensure no new significant hazards or risks have been introduced.

13.3 Quality Assurance and Quality Control

Husky's Quality Management System is the internal mechanism by which strategies aimed at achieving specified quality goals and objectives are implemented. The system integrates the management of safety with other critically important aspects of the business, including health of personnel, impact of operations on the environment and the quality of work processes. It requires that these aspects are integral factors in project planning and decision-making. Husky recognizes the importance of the Quality Management System in achieving operational success.

The WHP will be operated in accordance with the requirements of CAN/CSA-ISO 9000-00. This approach to quality management is consistent with the C-NLOPB *Drilling and Production Guidelines*, which recommend management systems follow the principles set out in ISO 9000 series Quality Management Systems.

Monitoring the effectiveness of the management system and, in particular, the facility safety plan, is a key aspect of HOIMS. Audits and inspections will be conducted to review compliance with Husky, regulatory and industry standards and to identify opportunities for improvement. Audit results are formally reported and distributed to the personnel having accountability for the function being audited. Implementation and effectiveness of corrective actions are recorded and closure verified.

13.4 Certification Process

As required under the C-NLOPB *Certificate of Fitness Regulations*, the Certifying Authority is responsible for requiring that pertinent safety-related statutory requirements, industry codes and standards are complied with during the design, construction, installation and operation stages of the WHP. Husky's Certifying Authority will be involved in all aspects of the WREP, from design through operations.

13.5 Training Plan

Husky maintains a robust Personnel Competency and Training (PC&T) program that is administered to all onshore departments and offshore facilities within the Atlantic Region. For each department or facility, Husky maintains a Training and Competency Matrix that identifies requirements for individuals employed in each position. These matrices contain regulatory requirements as set forth in the Canadian Association of Petroleum Producers *Standard Practice for the Training and Qualifications of Personnel within the Atlantic Canada Offshore Petroleum Industry*, as well as Husky's own position-specific requirements and Transport Canada requirements deemed necessary for safe operations. A training and competency matrix will be developed for each position associated with the WHP.

HOIMS Element 6: PC&T Standard describes PC&T as a vital component of HOIMS in ensuring that Husky employees are trained and competent to safely perform the responsibilities of their positions. The Atlantic Region meets this standard through developing competency profiles, conducting competency assessments, taking remedial action (training) and evaluating the outcomes of the PC&T program. All four processes within the PC&T Standard are captured and reported through Husky's Learning Management System.

13.6 Safety and Environmental Management

13.6.1 Safety and Environmental Management System

Husky is committed to operational integrity. Operational integrity at Husky means operating all activities associated with the WHP safely and reliably so that personnel are protected, impact to the environment is minimized and physical assets (such as facilities and equipment) are protected from damage or loss.

The 14 elements of HOIMS and the associated aims and expectations provide a structured, comprehensive approach to meeting Husky's commitments to protect the safety and health of employees and protection of the environment. This commitment requires compliance with all applicable laws and regulations, facilities that are designed and operated to high standards and systematic identification and management of safety, health and environmental risk.

Fundamental to safe operations is ensuring that all levels of management demonstrate leadership and commitment to operational integrity. Achieving conformance to HOIMS expectations requires effective leadership and commitment at all levels of the organization.

The HSEQ requirements for the WHP will be developed, implemented and managed in accordance with the principles and requirements of HOIMS. Husky's policies and procedures related to the management of the WHP will be assimilated into the existing management system. This management system has been the foundation for the successful administration and safe operation of complex offshore facilities since commencement of White Rose production operations in 2005. In striving for continuous improvement, Husky's management system continues to be subject to rigorous audit and assessment internally, as well as by the C-NLOPB and other regulatory bodies.

13.6.2 Safety Plan

Pursuant to the requirements of the *Newfoundland Offshore Petroleum Drilling and Production Regulations*, the WHP safety plan will outline the measures implemented for the safety and well-being of personnel, preservation of the environment and protection of the installation. The safety plan will be comprised of the following sections:

I. Description of the Installation
II. Organization and Management
III. Basis of Safe Operations.

The safety plan will provide a comprehensive summary of the components of the management system that will be applied to the WHP and how duties regarding safety, environmental protection and asset integrity will be fulfilled. The overall scope of the safety plan will include a description of the safety- and emergency-related systems or processes applicable to the following major operational categories:

- Drilling and completion operations
- Well intervention and workover operations
- Subsea operations
- *SeaRose FPSO* interface
- Helicopter operations
- Standby and support vessel operations
- Simultaneous operations
- Other support services and operations.

The safety plan will place particular emphasis on describing specific design features, structures, or arrangements intended to eliminate or reduce risk, including emergency escape and evacuation arrangements. As appropriate, reference will be made in the safety plan to supporting documentation, including relevant codes and standards and applicable legislation.

As part of the requirements for design to the L2 classification, the WHP will also require a plan to allow controlled evacuation of the facility as part of standard operations should an ice event exceeding the design limits occur.

13.6.3 Environmental Protection and Compliance Monitoring Plan

Pursuant to the requirements of the *Newfoundland Offshore Petroleum Drilling and Production Regulations*, the WHP EPCMP will set out the procedures, practices, resources and monitoring to manage hazards and protect the environment. The main categories that will be covered by the EPCMP include:

- Responsibilities and Accountabilities
- Environmental Management
- Environmental Protection/Compliance Monitoring of Waste Streams
- Fuel and Chemical Handling
- Special Situations and Operations
- Bird Handling and Monitoring
- EEM
- Critical Environmental Protection Systems
- Accident and Incident Reporting and Investigation.

13.7 Security Plan

A WHP security plan will be developed outlining the measures that will be implemented for the security and integrity of personnel and the installation against the risk of injury, loss, or damage from criminal, hostile, or malicious acts.

The development of security-related processes specific for the WHP will be based on existing security systems and processes already in place for the *SeaRose FPSO* as appropriate. The WHP security plan will comply with the requirements of the C-NLOPB's *Requirements Respecting the Security of Offshore Facilities*.

14.0 WREP GAS RESOURCE

Husky continues to evaluate opportunities to develop the White Rose gas resource. However, with the existing identified gas resource and at the current stage of development in the White Rose region, available gas will be used in support of incremental oil recovery.

14.1 WREP Gas Resource

Table 14-1 summarizes the total remaining estimated gas resources for the WREP area as of January 1, 2014. The in-place volumes are based on the most recent deterministic geological models along with the volumes of produced gas that have been re-injected for storage and conservation.

Table 14-1 Estimated WREP Gas Resource

Area	Free Gas (10^9 Sm³)	Solution Gas (10^9 Sm³)	Injected Gas (10^9 Sm³)	Total Gas (10^9 Sm³)
South Avalon	12.5	8.5	-	21.0
Blocks 2 and 5	0.2	0.8	-	1.0
North Avalon	9.0	1.0	3.2	13.2
WWRX	11.6	8.0	0.4	20.0
SWRX	6.7	2.0	-	8.7
Total	40.0	20.3	3.6	63.9

14.2 WREP Gas Utilization

As described in Section 4.11, this Development Plan Amendment outlines the opportunity to use the gas as a secondary flood mechanism in a complementary fashion with water flood throughout the White Rose region. The development of SWRX will include recovery of the oil resource using a gas flood mechanism. SWRX has a large gas cap and gas will be injected and used as voidage replacement for development of the pool.

The base plan also includes gas flooding the southern portion of the South Avalon Terrace from the SWRX drill centre. The IOR plans for the South Avalon Terrace require gas injection in the southern area to gas flood the gas cap and move oil down into the existing oil producers and planned infill well. This will enable increased recovery of the "attic oil" in the South Avalon pool.

Execution of this plan will lead to further learning and potentially greater application of gas flood mechanisms for increased oil recovery throughout the White Rose region. Future development could include gas flood into the South Avalon northern terrace region and the central region (Blocks 1, 3 and 4). Figure 14-1 outlines a number of the potential gas flood locations across the White Rose region.

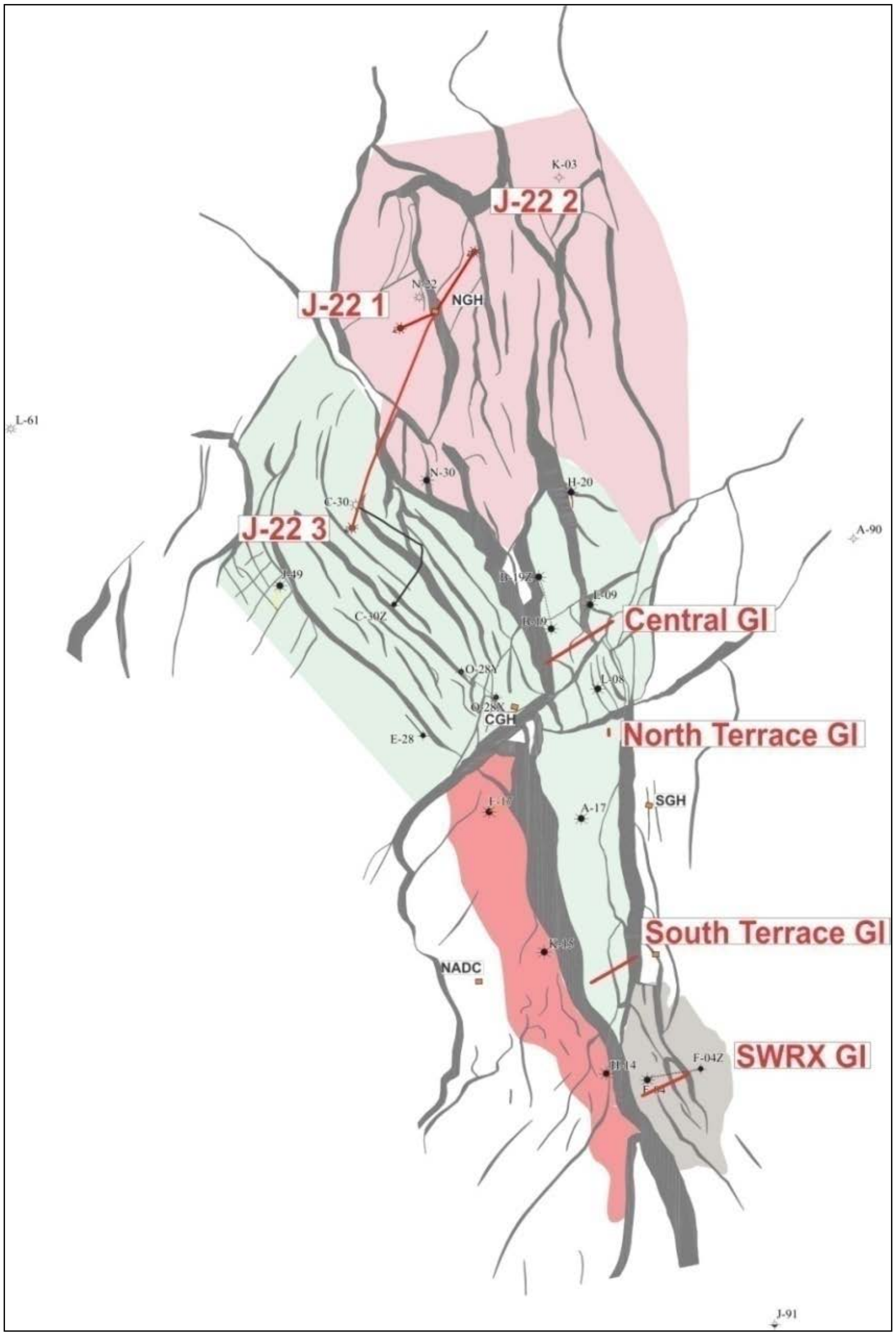


Figure 14-1 Potential Gas Injection Locations

Other gas-enabled applications such as WAG are also being reviewed for implementation and are consider to have high potential. By alternating the injected fluid with injected gas, mobility control can be improved and the gas can be used to capture upswept oil that would otherwise be bypassed by water flooding alone.

Produced gas will continue to provide primary power to the *SeaRose FPSO* and will also be used for primary power on the WHP.

Although current development schemes leverage gas to provide increased oil recovery, Husky continues to keep abreast of existing and evolving gas development technologies. Husky is aware of the limitations and advances of technologies such as compressed natural gas, floating liquefied natural gas, pipelines and associated onshore liquefied natural gas terminal options. As industry gains experience with these applications worldwide, Husky will continue to monitor these technologies with the goal of understanding the development potential for White Rose area gas resources at the maturation of the gas flood/WAG phase and/or in the event that the existing gas resource or discovery of additional resources provides a feasible development opportunity.

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Appendix A

Annualized Cumulative Production/Injection Profiles

Appendix A: Annualized Cumulative Production/Injection Profiles

Annual Oil Production (Mm3)											
	Existing Developments						WREP Developments				
Year	SWRX	Hibernia	West Pilot	North Amethyst	South Avalon	Total	West White Rose	Blocks 2 & 5	North Avalon	South Avalon	Total
2014	0.00	0.12	0.38	1.33	1.05	2.88	0.00	0.00	0.00	0.00	0.00
2015	0.40	0.12	0.30	0.69	1.18	2.69	0.00	0.00	0.00	0.00	0.00
2016	0.80	0.12	0.21	0.43	0.99	2.54	0.00	0.00	0.00	0.00	0.00
2017	0.61	0.12	0.13	0.29	0.75	1.89	0.07	0.00	0.00	0.00	0.07
2018	0.47	0.12	0.08	0.23	0.61	1.51	1.21	0.00	0.00	0.00	1.21
2019	0.31	0.12	0.06	0.17	0.53	1.19	1.31	0.33	0.00	0.00	1.64
2020	0.22	0.12	0.05	0.13	0.39	0.90	1.27	0.54	0.00	0.07	1.87
2021	0.17	0.12	0.04	0.12	0.28	0.73	1.18	0.31	0.00	0.23	1.72
2022	0.14	0.09	0.02	0.08	0.16	0.48	1.09	0.15	0.00	0.19	1.43
2023	0.14	0.11	0.00	0.10	0.19	0.55	1.75	0.10	0.30	0.09	2.25
2024	0.09	0.10	0.00	0.09	0.25	0.55	1.59	0.07	0.14	0.11	1.91
2025	0.06	0.07	0.00	0.05	0.23	0.41	1.48	0.05	0.05	0.21	1.79
2026	0.07	0.07	0.01	0.05	0.20	0.40	0.92	0.06	0.05	0.27	1.30
2027	0.00	0.00	0.01	0.07	0.16	0.25	0.71	0.00	0.03	0.13	0.88
2028	0.00	0.00	0.02	0.07	0.09	0.18	0.56	0.00	0.03	0.04	0.63
2029	0.00	0.00	0.02	0.05	0.08	0.15	0.46	0.00	0.03	0.04	0.52

Annual Gas Production (Mm3)											
	Existing Developments						WREP Developments				
Year	SWRX	Hibernia	West Pilot	North Amethyst	South Avalon	Total	West White Rose	Blocks 2 & 5	North Avalon	South Avalon	Total
2014	0	12	60	184	317	573	0	0	0	0	0
2015	78	12	43	100	280	513	0	0	0	0	0
2016	168	12	30	51	252	513	0	0	0	0	0
2017	235	12	19	37	223	526	16	0	0	0	16
2018	310	12	12	29	234	597	146	0	0	0	146
2019	305	12	9	21	387	734	155	49	0	0	204
2020	295	12	7	18	455	786	164	69	0	9	242
2021	286	12	5	17	403	724	170	49	0	32	251
2022	257	9	2	11	112	391	186	25	0	22	233
2023	332	10	0	13	68	423	421	15	106	11	553
2024	295	11	1	11	164	482	502	13	130	16	661
2025	270	10	1	7	354	642	396	11	67	32	506
2026	180	8	2	8	339	537	209	7	54	46	316
2027	6	0	3	11	578	597	160	0	43	48	250
2028	0	0	3	12	646	661	127	0	39	37	204
2029	0	0	3	6	687	696	95	0	37	26	157

Annual Total Gas (Lift + Produced) (Mm3)											
	Existing Developments						WREP Developments				
Year	SWRX	Hibernia	West Pilot	North Amethyst	South Avalon	Total	West White Rose	Blocks 2 & 5	North Avalon	South Avalon	Total
2014	0	22	73	375	672	1141	0	0	0	0	0
2015	92	22	59	404	600	1178	0	0	0	0	0
2016	195	23	55	315	595	1183	0	0	0	0	0
2017	268	22	53	303	544	1190	16	0	0	0	16
2018	360	19	59	308	552	1298	155	0	0	0	155
2019	386	15	58	206	651	1316	178	52	0	0	229
2020	368	14	55	151	660	1248	181	80	0	12	273
2021	349	18	50	134	625	1177	184	62	0	48	294
2022	293	12	20	74	275	674	286	38	0	63	387
2023	385	13	1	69	174	642	561	27	114	20	723
2024	327	12	3	56	241	639	609	28	146	25	808
2025	342	12	2	26	477	860	673	30	79	88	870
2026	291	11	12	43	592	949	470	32	82	159	743
2027	7	2	20	52	815	897	359	0	62	93	514
2028	0	0	29	66	898	993	288	0	56	54	398
2029	0	0	33	40	975	1048	242	0	60	60	363

Annual Water Production (Mm3)											
	Existing Developments						WREP Developments				
Year	SWRX	Hibernia	West Pilot	North Amethyst	South Avalon	Total	West White Rose	Blocks 2 & 5	North Avalon	South Avalon	Total
2014	0.00	0.00	0.07	2.50	2.28	4.85	0.00	0.00	0.00	0.00	0.00
2015	0.02	0.00	0.16	2.76	2.42	5.36	0.00	0.00	0.00	0.00	0.00
2016	0.12	0.00	0.26	2.52	2.77	5.67	0.00	0.00	0.00	0.00	0.00
2017	0.31	0.00	0.34	2.28	2.89	5.82	0.00	0.00	0.00	0.00	0.00
2018	0.43	0.00	0.39	2.30	2.94	6.06	0.35	0.00	0.00	0.00	0.35
2019	0.47	0.00	0.42	1.99	2.68	5.57	1.09	0.12	0.00	0.00	1.21
2020	0.48	0.00	0.43	1.81	2.09	4.80	1.85	0.44	0.00	0.05	2.34
2021	0.45	0.00	0.41	1.83	1.70	4.38	2.42	0.65	0.00	0.29	3.35
2022	0.38	0.00	0.20	1.28	1.02	2.87	2.12	0.47	0.00	0.34	2.93
2023	0.49	0.01	0.03	1.58	1.13	3.24	3.01	0.36	0.10	0.10	3.57
2024	0.32	0.02	0.06	1.49	1.11	2.99	3.58	0.27	0.35	0.10	4.30
2025	0.17	0.03	0.06	0.88	1.01	2.14	4.04	0.22	0.25	0.08	4.59
2026	0.30	0.04	0.16	1.16	0.89	2.54	4.79	0.27	0.37	0.57	6.01
2027	0.06	0.01	0.26	1.32	1.02	2.67	5.04	0.00	0.34	0.43	5.81
2028	0.00	0.00	0.31	1.63	0.87	2.81	4.77	0.00	0.34	0.15	5.27
2029	0.00	0.00	0.34	1.08	0.87	2.29	4.62	0.00	0.39	0.22	5.23

Annual Liquid Production (Mm3)											
	Existing Developments						WREP Developments				
Year	SWRX	Hibernia	West Pilot	North Amethyst	South Avalon	Total	West White Rose	Blocks 2 & 5	North Avalon	South Avalon	Total
2014	0.00	0.12	0.45	3.83	3.33	7.73	0.00	0.00	0.00	0.00	0.00
2015	0.42	0.12	0.46	3.45	3.60	8.04	0.00	0.00	0.00	0.00	0.00
2016	0.92	0.12	0.48	2.95	3.76	8.22	0.00	0.00	0.00	0.00	0.00
2017	0.92	0.12	0.47	2.57	3.64	7.71	0.07	0.00	0.00	0.00	0.07
2018	0.90	0.12	0.47	2.53	3.55	7.57	1.56	0.00	0.00	0.00	1.56
2019	0.78	0.12	0.48	2.16	3.21	6.76	2.39	0.45	0.00	0.00	2.84
2020	0.70	0.12	0.47	1.94	2.47	5.70	3.11	0.98	0.00	0.12	4.22
2021	0.61	0.12	0.45	1.95	1.98	5.11	3.60	0.96	0.00	0.52	5.07
2022	0.51	0.09	0.22	1.36	1.18	3.35	3.21	0.62	0.00	0.53	4.36
2023	0.63	0.12	0.04	1.68	1.32	3.79	4.76	0.46	0.41	0.19	5.82
2024	0.41	0.12	0.06	1.58	1.37	3.54	5.17	0.34	0.49	0.21	6.21
2025	0.23	0.10	0.06	0.92	1.24	2.55	5.53	0.27	0.29	0.29	6.38
2026	0.37	0.11	0.17	1.21	1.08	2.94	5.71	0.32	0.42	0.85	7.31
2027	0.06	0.01	0.28	1.39	1.18	2.92	5.76	0.00	0.38	0.56	6.69
2028	0.00	0.00	0.32	1.71	0.96	2.99	5.34	0.00	0.37	0.20	5.90
2029	0.00	0.00	0.36	1.13	0.95	2.44	5.08	0.00	0.42	0.26	5.75

Annual Water Injection (Mm3)											
	Existing Developments						WREP Developments				
Year	SWRX	Hibernia	West Pilot	North Amethyst	South Avalon	Total	West White Rose	Blocks 2 & 5	North Avalon	South Avalon	Total
2014	0.00	0.17	0.64	4.48	4.61	9.89	0.00	0.00	0.00	0.00	0.00
2015	0.33	0.17	0.58	3.80	4.59	9.47	0.00	0.00	0.00	0.00	0.00
2016	0.79	0.17	0.56	3.00	4.70	9.22	0.00	0.00	0.00	0.00	0.00
2017	0.80	0.17	0.52	2.71	4.27	8.47	0.10	0.00	0.00	0.00	0.10
2018	0.74	0.17	0.51	2.68	4.22	8.31	1.91	0.00	0.00	0.00	1.91
2019	0.73	0.17	0.51	2.27	3.55	7.23	2.78	0.55	0.00	0.00	3.33
2020	0.64	0.17	0.49	2.01	2.37	5.69	3.51	1.17	0.00	0.00	4.68
2021	0.53	0.17	0.46	2.04	1.92	5.13	4.01	1.10	0.00	0.00	5.11
2022	0.48	0.13	0.26	1.43	1.45	3.75	3.67	0.69	0.00	0.00	4.36
2023	0.64	0.17	0.02	1.69	1.43	3.96	6.12	0.51	0.74	0.00	7.37
2024	0.37	0.17	0.06	1.68	1.35	3.62	6.98	0.38	1.01	0.00	8.37
2025	0.16	0.13	0.02	0.86	1.14	2.31	6.96	0.30	0.52	0.00	7.78
2026	0.41	0.16	0.15	1.10	2.33	4.15	6.59	0.35	0.69	0.00	7.63
2027	0.09	0.08	0.27	1.53	2.61	4.58	6.38	0.00	0.57	0.00	6.95
2028	0.00	0.00	0.33	1.58	2.92	4.84	5.82	0.00	0.54	0.00	6.35
2029	0.00	0.00	0.35	1.45	3.47	5.27	5.44	0.00	0.59	0.00	6.04

Annual Gas Injection (Mm3)											
	Existing Developments						WREP Developments				
Year	SWRX	Hibernia	West Pilot	North Amethyst	South Avalon	Total	West White Rose	Blocks 2 & 5	North Avalon	South Avalon	Total
2014	422	0	0	0	0	422	0	0	0	0	0
2015	334	0	0	0	197	530	0	0	0	0	0
2016	360	0	0	0	163	523	0	0	0	0	0
2017	218	0	0	0	140	357	0	0	0	0	0
2018	291	0	0	0	177	468	0	0	0	0	0
2019	289	0	0	0	393	682	0	0	0	0	0
2020	272	0	0	0	440	712	0	0	0	36	36
2021	263	0	0	0	284	547	0	0	0	152	152
2022	219	0	0	0	91	310	0	0	0	130	130
2023	309	0	0	0	219	528	0	0	0	160	160
2024	273	0	0	0	307	581	0	0	0	276	276
2025	249	0	0	0	243	492	0	0	0	344	344
2026	256	0	0	0	234	491	0	0	0	328	328
2027	0	0	0	0	299	299	0	0	0	357	357
2028	0	0	0	0	306	306	0	0	0	361	361
2029	0	0	0	0	309	309	0	0	0	372	372

Appendix B

Cumulative Production/Injection Profiles

Appendix B: Cumulative Production/Injection Profiles

Cumulative Oil Production (Mm3)											
	Existing Developments						WREP Developments				
Year	SWRX	Hibernia	West Pilot	North Amethyst	South Avalon	Total	West White Rose	Blocks 2 & 5	North Avalon	South Avalon	Total
2014	0.00	0.12	0.38	1.33	1.05	2.88	0.00	0.00	0.00	0.00	0.00
2015	0.40	0.23	0.68	2.02	2.23	5.57	0.00	0.00	0.00	0.00	0.00
2016	1.20	0.35	0.90	2.45	3.21	8.11	0.00	0.00	0.00	0.00	0.00
2017	1.80	0.47	1.03	2.74	3.96	10.01	0.07	0.00	0.00	0.00	0.07
2018	2.28	0.59	1.11	2.97	4.57	11.52	1.28	0.00	0.00	0.00	1.28
2019	2.59	0.71	1.17	3.14	5.11	12.72	2.59	0.33	0.00	0.00	2.92
2020	2.81	0.83	1.22	3.27	5.49	13.62	3.86	0.87	0.00	0.07	4.80
2021	2.97	0.94	1.26	3.40	5.78	14.35	5.04	1.18	0.00	0.30	6.52
2022	3.11	1.03	1.27	3.48	5.94	14.82	6.13	1.33	0.00	0.49	7.95
2023	3.25	1.14	1.28	3.57	6.13	15.37	7.88	1.43	0.30	0.59	10.20
2024	3.34	1.25	1.28	3.67	6.38	15.92	9.47	1.50	0.44	0.69	12.11
2025	3.40	1.32	1.28	3.71	6.61	16.33	10.95	1.55	0.49	0.91	13.90
2026	3.47	1.39	1.29	3.77	6.81	16.73	11.87	1.61	0.54	1.18	15.20
2027	3.47	1.39	1.31	3.84	6.97	16.97	12.59	1.61	0.57	1.31	16.08
2028	3.47	1.39	1.32	3.91	7.06	17.15	13.15	1.61	0.60	1.36	16.71
2029	3.47	1.39	1.34	3.96	7.14	17.31	13.61	1.61	0.63	1.40	17.23

Cumulative Gas Production (Mm3)											
	Existing Developments						WREP Developments				
Year	SWRX	Hibernia	West Pilot	North Amethyst	South Avalon	Total	West White Rose	Blocks 2 & 5	North Avalon	South Avalon	Total
2014	0	12	60	184	317	573	0	0	0	0	0
2015	78	24	104	284	597	1087	0	0	0	0	0
2016	246	36	134	335	849	1599	0	0	0	0	0
2017	481	48	152	372	1072	2125	16	0	0	0	16
2018	791	60	164	401	1306	2723	162	0	0	0	162
2019	1096	72	173	422	1693	3456	316	49	0	0	365
2020	1391	84	180	440	2148	4243	480	118	0	9	607
2021	1677	96	185	457	2551	4967	650	167	0	42	858
2022	1934	105	188	468	2663	5358	836	192	0	64	1091
2023	2266	115	188	481	2731	5781	1257	207	106	75	1644
2024	2561	126	189	492	2895	6263	1759	220	235	91	2305
2025	2831	136	189	500	3249	6905	2155	231	302	123	2812
2026	3011	144	191	508	3588	7442	2364	238	356	170	3128
2027	3017	144	194	519	4166	8039	2523	238	399	218	3378
2028	3017	144	197	531	4812	8700	2651	238	438	254	3582
2029	3017	144	200	536	5499	9396	2746	238	475	280	3739

Cumulative Total Gas (Lift + Produced) (Mm3)											
	Existing Developments						WREP Developments				
Year	SWRX	Hibernia	West Pilot	North Amethyst	South Avalon	Total	West White Rose	Blocks 2 & 5	North Avalon	South Avalon	Total
2014	0	22	73	375	672	1141	0	0	0	0	0
2015	92	44	132	779	1272	2319	0	0	0	0	0
2016	287	67	187	1094	1867	3503	0	0	0	0	0
2017	555	89	241	1397	2410	4693	0	0	0	0	0
2018	915	108	299	1705	2962	5990	155	0	0	0	155
2019	1301	124	357	1911	3613	7307	333	52	0	0	384
2020	1669	138	412	2062	4274	8554	513	132	0	12	657
2021	2018	155	463	2196	4899	9731	698	194	0	60	952
2022	2311	167	482	2271	5174	10405	984	232	0	122	1338
2023	2697	180	483	2340	5348	11048	1545	259	114	143	2061
2024	3024	191	487	2395	5589	11686	2155	287	260	167	2869
2025	3366	203	489	2422	6066	12547	2827	316	340	255	3739
2026	3657	215	501	2465	6658	13496	3297	348	422	415	4482
2027	3664	217	521	2517	7473	14393	3656	348	484	508	4996
2028	3664	217	550	2584	8371	15386	3944	348	540	561	5394
2029	3664	217	584	2623	9346	16434	4186	348	601	622	5757

Cumulative Water Production (Mm3)											
	Existing Developments						WREP Developments				
Year	SWRX	Hibernia	West Pilot	North Amethyst	South Avalon	Total	West White Rose	Blocks 2 & 5	North Avalon	South Avalon	Total
2014	0.00	0.00	0.07	2.50	2.28	4.85	0.00	0.00	0.00	0.00	0.00
2015	0.02	0.00	0.22	5.25	4.70	10.20	0.00	0.00	0.00	0.00	0.00
2016	0.14	0.00	0.49	7.78	7.47	15.88	0.00	0.00	0.00	0.00	0.00
2017	0.45	0.00	0.82	10.05	10.36	21.70	0.07	0.00	0.00	0.00	0.07
2018	0.88	0.00	1.21	12.35	13.30	27.76	0.42	0.00	0.00	0.00	0.42
2019	1.35	0.00	1.64	14.35	15.98	33.32	1.51	0.12	0.00	0.00	1.63
2020	1.84	0.00	2.06	16.15	18.07	38.12	3.35	0.56	0.00	0.05	3.97
2021	2.28	0.00	2.47	17.98	19.77	42.50	5.77	1.21	0.00	0.34	7.32
2022	2.66	0.01	2.67	19.26	20.78	45.38	7.89	1.67	0.00	0.69	10.25
2023	3.15	0.01	2.70	20.85	21.91	48.62	10.90	2.03	0.10	0.79	13.82
2024	3.46	0.03	2.76	22.33	23.03	51.61	14.48	2.30	0.45	0.89	18.12
2025	3.64	0.06	2.82	23.21	24.03	53.75	18.52	2.53	0.70	0.97	22.71
2026	3.94	0.10	2.98	24.36	24.92	56.30	23.32	2.79	1.07	1.54	28.72
2027	4.00	0.11	3.24	25.68	25.94	58.97	28.36	2.79	1.41	1.97	34.53
2028	4.00	0.11	3.54	27.32	26.81	61.77	33.13	2.79	1.75	2.12	39.80
2029	4.00	0.11	3.88	28.39	27.68	64.06	37.75	2.79	2.14	2.34	45.03

Cumulative Liquid Production (Mm3)											
	Existing Developments						WREP Developments				
Year	SWRX	Hibernia	West Pilot	North Amethyst	South Avalon	Total	West White Rose	Blocks 2 & 5	North Avalon	South Avalon	Total
2014	0.00	0.12	0.45	3.83	3.33	7.73	0.00	0.00	0.00	0.00	0.00
2015	0.42	0.24	0.91	7.28	6.93	15.77	0.00	0.00	0.00	0.00	0.00
2016	1.34	0.36	1.39	10.22	10.69	23.99	0.00	0.00	0.00	0.00	0.00
2017	2.26	0.47	1.85	12.79	14.33	31.70	0.07	0.00	0.00	0.00	0.07
2018	3.16	0.59	2.32	15.33	17.87	39.28	1.63	0.00	0.00	0.00	1.63
2019	3.94	0.71	2.81	17.49	21.09	46.04	4.02	0.45	0.00	0.00	4.48
2020	4.64	0.83	3.28	19.43	23.56	51.74	7.14	1.43	0.00	0.12	8.69
2021	5.25	0.95	3.73	21.38	25.54	56.85	10.74	2.38	0.00	0.65	13.77
2022	5.77	1.04	3.94	22.74	26.72	60.20	13.94	3.00	0.00	1.18	18.12
2023	6.40	1.16	3.98	24.42	28.04	63.99	18.71	3.46	0.41	1.37	23.94
2024	6.81	1.28	4.04	26.00	29.41	67.53	23.88	3.80	0.89	1.58	30.16
2025	7.04	1.38	4.10	26.92	30.64	70.08	29.40	4.08	1.19	1.88	36.54
2026	7.40	1.49	4.27	28.13	31.73	73.02	35.11	4.40	1.61	2.72	43.84
2027	7.46	1.50	4.54	29.52	32.91	75.94	40.87	4.40	1.98	3.28	50.54
2028	7.46	1.50	4.87	31.23	33.87	78.93	46.21	4.40	2.35	3.48	56.44
2029	7.46	1.50	5.22	32.35	34.82	81.36	51.29	4.40	2.77	3.74	62.19

Cumulative Water Injection (Mm3)											
	Existing Developments						WREP Developments				
Year	SWRX	Hibernia	West Pilot	North Amethyst	South Avalon	Total	West White Rose	Blocks 2 & 5	North Avalon	South Avalon	Total
2014	0.00	0.17	0.64	4.48	4.61	9.89	0.00	0.00	0.00	0.00	0.00
2015	0.33	0.34	1.22	8.28	9.20	19.37	0.00	0.00	0.00	0.00	0.00
2016	1.13	0.51	1.78	11.28	13.90	28.59	0.00	0.00	0.00	0.00	0.00
2017	1.93	0.67	2.30	13.99	18.17	37.06	0.07	0.00	0.00	0.00	0.07
2018	2.67	0.84	2.81	16.66	22.39	45.37	1.98	0.00	0.00	0.00	1.98
2019	3.40	1.01	3.32	18.93	25.94	52.60	4.76	0.55	0.00	0.00	5.31
2020	4.04	1.18	3.81	20.95	28.31	58.29	8.27	1.72	0.00	0.00	9.99
2021	4.58	1.35	4.28	22.99	30.23	63.42	12.29	2.82	0.00	0.00	15.10
2022	5.06	1.48	4.54	24.41	31.68	67.17	15.95	3.51	0.00	0.00	19.46
2023	5.70	1.64	4.56	26.10	33.12	71.12	22.07	4.02	0.74	0.00	26.83
2024	6.06	1.81	4.62	27.78	34.47	74.75	29.05	4.40	1.75	0.00	35.20
2025	6.22	1.94	4.64	28.64	35.61	77.05	36.01	4.70	2.27	0.00	42.98
2026	6.64	2.11	4.79	29.74	37.94	81.21	42.60	5.05	2.96	0.00	50.61
2027	6.72	2.19	5.06	31.27	40.55	85.79	48.99	5.05	3.53	0.00	57.57
2028	6.72	2.19	5.40	32.85	43.47	90.62	54.80	5.05	4.07	0.00	63.92
2029	6.72	2.19	5.75	34.30	46.94	95.89	60.25	5.05	4.66	0.00	69.96

Cumulative Gas Injection (Mm3)											
	Existing Developments						WREP Developments				
Year	SWRX	Hibernia	West Pilot	North Amethyst	South Avalon	Total	West White Rose	Blocks 2 & 5	North Avalon	South Avalon	Total
2014	422	0	0	0	0	422	0	0	0	0	0
2015	755	0	0	0	197	952	0	0	0	0	0
2016	1115	0	0	0	360	1475	0	0	0	0	0
2017	1333	0	0	0	500	1833	0	0	0	0	0
2018	1624	0	0	0	677	2301	0	0	0	0	0
2019	1913	0	0	0	1070	2983	0	0	0	0	0
2020	2185	0	0	0	1510	3695	0	0	0	36	36
2021	2449	0	0	0	1793	4242	0	0	0	188	188
2022	2667	0	0	0	1885	4552	0	0	0	318	318
2023	2976	0	0	0	2103	5080	0	0	0	478	478
2024	3250	0	0	0	2411	5660	0	0	0	754	754
2025	3498	0	0	0	2654	6152	0	0	0	1098	1098
2026	3755	0	0	0	2889	6643	0	0	0	1426	1426
2027	3755	0	0	0	3188	6943	0	0	0	1784	1784
2028	3755	0	0	0	3494	7248	0	0	0	2145	2145
2029	3755	0	0	0	3803	7557	0	0	0	2517	2517

Appendix C

Tabulated Full-Field Production Profile

Appendix C: Tabulated Full-Field Production Profile

Full Field (WREP + Existing)							
Year	Annual Oil Production (Mm3)	Annual Gas Production (Mm3)	Annual Total Gas (Gas Lift + Produced) (Mm3)	Annual Water Production (Mm3)	Annual Liquid Production (Mm3)	Annual Water Injection (Mm3)	Annual Gas Injection (Mm3)
2014	2.88	573	1141	4.85	7.73	9.89	422
2015	2.69	513	1178	5.36	8.04	9.47	530
2016	2.54	513	1183	5.67	8.22	9.22	523
2017	1.97	542	1206	5.82	7.79	8.57	357
2018	2.73	743	1453	6.41	9.13	10.22	468
2019	2.83	937	1546	6.77	9.60	10.56	682
2020	2.78	1028	1520	7.14	9.92	10.37	748
2021	2.45	975	1471	7.73	10.18	10.24	699
2022	1.91	624	1061	5.80	7.71	8.11	440
2023	2.80	976	1365	6.82	9.61	11.33	688
2024	2.46	1143	1446	7.29	9.75	11.99	856
2025	2.20	1148	1730	6.73	8.93	10.09	836
2026	1.69	853	1693	8.55	10.25	11.78	819
2027	1.13	848	1411	8.48	9.61	11.53	657
2028	0.82	865	1391	8.08	8.89	11.19	667
2029	0.67	853	1410	7.52	8.19	11.31	682

Appendix D

Tabulated Full-Field Fuel Gas Profile

Appendix D: Tabulated Full-Field Fuel Gas Profile

Fuel Gas (Mm3)						
	Existing Developments (SeaRose)		WREP Developments (WHP)		Total	
Year	Annual	Cumulative	Annual	Cumulative	Annual	Cumulative
2014	146	146	0	0	146	146
2015	146	292	0	0	146	292
2016	146	438	0	0	146	438
2017	146	584	0	0	146	584
2018	146	730	73	73	219	803
2019	146	876	73	146	219	1022
2020	146	1022	73	219	219	1241
2021	146	1168	73	292	219	1460
2022	146	1314	73	365	219	1679
2023	146	1460	73	438	219	1898
2024	146	1606	73	511	219	2117
2025	146	1752	73	584	219	2336
2026	146	1898	73	657	219	2555
2027	146	2044	73	730	219	2774
2028	146	2190	73	803	219	2993
2029	146	2336	73	876	219	3212