TECHNICAL EVALUATION OF VIC/P57 FOR HIBISCUS PETROLEUM

Strictly Confidential

September 2012

DECISIONS WITH CONFIDENCE

DECLARATION

Hibiscus Petroleum Berhad (Hibiscus) has commissioned RISC Operations Pty Ltd (RISC) to provide an independent evaluation of the farmin opportunity to Block VIC/P57 (the Asset), being offered by 3D Oil Limited (3DO).

This evaluation is prepared and developed solely for the purposes of assisting Hibiscus in its evaluation of the Asset. It makes no recommendation or suggestion regarding the suitability of the Asset for any investment purpose.

RISC shall not be responsible for any or all claims, losses, damages, costs, charges, expenses, actions, demands, proceedings, liabilities or judgments which might be raised, made, or expressed to be made, suffered or incurred, directly or indirectly, in connection with investment decisions based on or motivated by this evaluation and the compilation of the information contained herein. All recipients of this evaluation are deemed to have accepted this disclaimer.

This evaluation is prepared from information made available to RISC by Hibiscus and certain publicly available information as RISC deemed relevant. RISC has not checked or independently verified the authenticity, thoroughness and/or accuracy of such information and has relied on such information. In arriving at the evaluation, RISC has also assumed that all the information provided is true, accurate, not misleading and complete in all respects and that all the 'information which is relevant to RISC's engagement has been provided and RISC has acted upon assurances from the management of Hibiscus that no relevant information has been omitted or remains undisclosed to RISC.

The Asset was not inspected on site, as this is not appropriate for a hydrocarbon resource located some 1.5 kms below the surface. The evaluation was based on data collected while drilling exploration and appraisal wells and from seismic data.

No part of this evaluation may be quoted, referred to or otherwise disclosed in any public document nor may any public reference to RISC be made, without RISC's prior written consent unless expressly required by laws, rules or regulations. In addition, no public announcement or communication concerning this evaluation may be made without RISC's prior written consent.

The evaluation of petroleum assets is subject to uncertainty because it involves judgments on many variables that cannot be precisely assessed, including reserves, future oil and gas production rates, the costs associated with producing these volumes, access to product markets, product prices and the potential impact of fiscal/regulatory changes.

The statements and opinions attributable to RISC are given in good faith and in the belief that such statements are neither false nor misleading.

RISC carried out this evaluation in their Head Office in Perth, Australia, and has oversight of all its offices, being located in Brisbane, Australia and London, UK.

Whilst every effort has been made to verify data and resolve apparent inconsistencies, neither RISC nor its servants accept any liability for its accuracy, nor do we warrant that our enquiries have revealed all of the matters, which an extensive examination may disclose. In particular, we have not independently verified property title, encumbrances, regulations that apply to these assets. RISC has also not audited the opening balances at the valuation date of past recovered and unrecovered development and exploration costs, undepreciated past development costs and tax losses.

We believe our review and conclusions are sound but no warranty of accuracy or reliability is given to our conclusions.

RISC confirms that there is no actual or potential conflict of interest in accepting this assignment and have maintained the strictest impartiality and objectivity in providing this independent advice. RISC has no pecuniary interest, other than to the extent of the professional fees receivable for the preparation of this report, or other interest in the assets evaluated, that could reasonably be regarded as affecting our ability to give an unbiased view of these assets.

Our review was carried out only for the purpose referred to above and may not have relevance in other contexts.

DOCUMENT CONTROL

Technical Evaluation of Block VIC/P57

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1. EXECUTIVE SUMMARY

The VIC/P57 Exploration License is located in the northwest of the Gippsland Basin with the northern boundary some 10 kms offshore of the south-east Victorian coast and infrastructure. The key assets within the permit are the West Seahorse Field, discovered in 1981, and two exploration prospects Sea Lion and Felix. 3DO are the sole equity holders and operators of the permit.

West Seahorse is a small offshore oil field of some 7.3 MMbbl EUR of light oil. It was discovered in 1981 and lies approximately 14 km from the coast and in 40m of water. While the majority of the field lies within VIC/P57, a small percentage lies in VIC/LI8, which is held by Esso Australia (50% and operator) and BHP (50%). The nearest oil processing facility is the Esso operated Longford Crude Stabilisation Plant which is approximately 38km away from the field. West Seahorse encountered hydrocarbons at three levels within the Eocene Upper Latrobe Group and at depths of some 1,500mss.

3DO plan to develop the West Seahorse Field either with a subsea completion and flowline tied back to shore or through a Mobile Offshore Production Unit ("MOPU") based development solution. A potential development solution, given an unitisation, could be to develop West Seahorse as a subsea tieback to the nearby Seahorse field (operated by Esso), thereby significantly reducing the development capex and improving the field's economics and discussions between 3DO and Esso are ongoing. While there is a risk that the development may suffer delays or other negative impacts due to potential negotiations between the two licenses, RISC has assumed no unitisation between the operators of Vic/P57 and VIC/L18, and therefore 100% recovery for the entire West Seahorse field to the VIC/P57 license . A summary of the MOPU development is given in Table 1-1.

Case - assuming MOPU development	Mid case scenario Production (mmbbls)	CAPEX $MM	Annual fixed OPEX $MM	Variable OPEX $MM	Technical recovery
2 wells – WSH + NE	6.4	118.3	33.9	$5/bbl	End 2034
2 wells – WSH Main + sidetrack	5.4	132.7	33.9	$5/bbl	End 2034

Table 1-1 Development Summary

Sea Lion is a robust exploration prospect on trend with similar reservoir and depths, close to West Seahorse and some 4 km from shore. If successful, it could be tied back to any West Seahorse development or directly to the shore.

Felix is a less robust exploration prospect. The reservoirs are deeper (at some 2500mss), the structure is not so well defined and some of it may lie in VIC/L18. The prospect is also located too far from West Seahorse to be considered for a tie back. It is close to producing fields held by Esso Australia and BHP, but tying back to these is not seen as a practical development option.

The hydrocarbon resources for VIC/P57 are given in Table 1-2. Where multiple reservoir levels are involved (West Seahorse Main, West Seahorse NE and Sea Lion),the numbers presented are based on a probabilistic calculation and addition to correctly account for the uncertainties in the various input parameters. This correctly assigns resource values to probabilities - the probability of achieving P90 outcomes at all reservoir levels is less than P90. The uncertainty range reflects the nature of the structure and recovery mechanisms.

Classification	Pool	Reservoir	OIP			Ultimate Recovery		
			P90	P50	P10	P90	P50	P10
Contingent	West Seahorse main	N1u, N1 and N2.6	6.5	8.15	10.5	4.1	5.5	7.1
Prospective	West Seahorse main	Gurnard	2.0	4.8	11.3	0.3	0.7	1.7
	West Seahorse NE	N1u, N1 and N2.6	1.1	1.6	2.1	0.7	1.0	1.4
		Gurnard	0.1	0.6	3.0	0	0.1	0.5
	Sea Lion	Gurnard, N1u, N1 and N2.6	14.3	19.5	26.0	7.8	11.0	15.3
	Felix	Sub-volcanics	2	12	37	1	6	19

Table 1-2 Unrisked Resource Estimates (MMstb, RISC)

West Seahorse-1 has demonstrated contingent resources in West Seahorse Main in the N1u, N1, and N2.6 reservoir. West Seahorse NE is a separate culmination, which has not been tested and while there is a high likelihood of hydrocarbons being present, this resource is classified as prospective. Hydrocarbons have been encountered in the Gurnard reservoir but this has not been tested and productivity is uncertain; so again, these resources are classified as prospective.

2. INTRODUCTION AND BASIS OF EVALUATION

2.1. SCOPE OF WORK AND AVAILABLE DATA

RISC made an independent evaluation of assets within VIC/P57 on the basis of data provided by Hibiscus and 3DO during May and July 2012. This includes an evaluation of the resource volumes, development options and costs.

We believe that we have been provided with all relevant documentation. In particular, 3DO retained Gaffney, Cline and Associates (GCA) in 2010 to conduct a technical review and prepare a statement of Reserves and Contingent Resources for the West Sea Horse Field, which provided useful reference material. Our approach has been to review and adjust the work provided; but we undertook our own volumetric evaluation to derive the resource ranges.

2.2. LICENCE STATUS

The Designated Authority for the offshore area of Victoria granted VIC/P57 to 3DO on 10 August 2011, for a 5 year period on the basis of an agreed minimum work requirement. During the first three years, 3DO must complete each component of the minimum work requirement (the primary work program). On commencement of the fourth year, the secondary work program becomes guaranteed on a year by year basis.

2.3. RESOURCE CLASSIFICATION

RISC uses the internationally recognised Petroleum Resources Management System (PRMS) of the Society of Petroleum Engineers (SPE) to define resource classification and volumes. The classification of resources is shown in Figure 2-1.

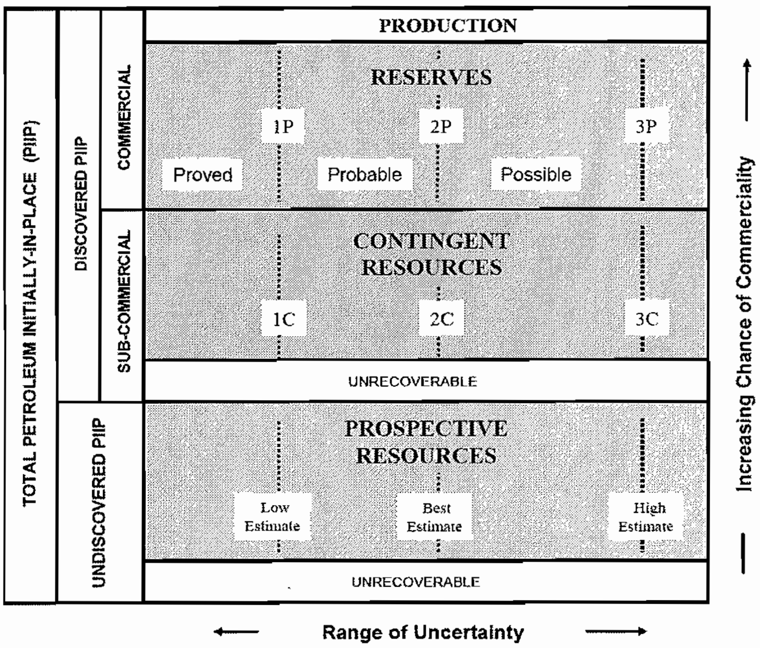

Figure 2-1 Resource Classification Framework

Under these guidelines, the range of uncertainty in potentially recoverable volumes may be represented by either deterministic scenarios or by a probability distribution derived from the probabilistic simulation of input variables. RISC has calculated resource volumes probabilistically.

3. GEOLOGICAL SETTING AND KEY ASSETS

The Gippsland Basin is a Cretaceous and Cenozoic depocentre which covers an area of 41,000 km^2 (Figure 3-1). It has been one of Australia's most prolific petroleum provinces with initial reserves for the developed fields estimated at more than 4 billion barrels of oil and condensate and 9.8 trillion cubic feet of sales gas. The basin is now in a mature stage, with oil production peaking in 1985 at about 500kbpd, which was 90% of the total Australian crude oil output that year.

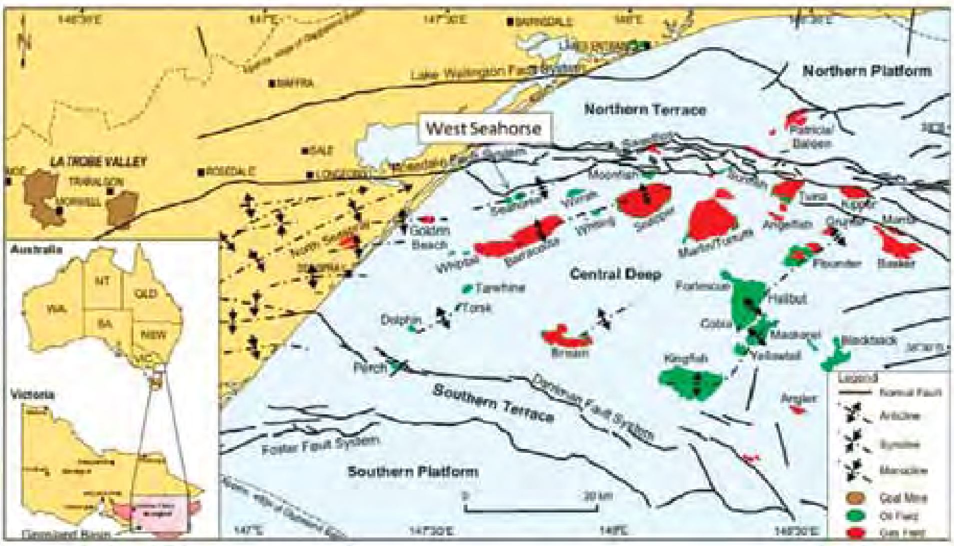

Figure 3-1 Gippsland Basin

The basin comprises a Central Deep basin, which opens out to the east, and flanking North and South Strzelecki Terraces. These are in turn bordered by North and South Platforms. Block VIC/P57 lies towards the northern boundary of the Central Deep. Initial rifting in the Early Cretaceous was accompanied by up to 3000m of volcanogenic and marine sediments of the Strzelecki Group as shown in Figure 3-2 (summary drawn from Geoscience Australia, 2012).

Renewed extension in the Turonian-Campanian established the Central Deep basin as the main depocentre, with coarse-grained alluvial and fluvio-lacustrine sediments of the lower Latrobe Group. The lowest units are the Emperor and Golden Beach Sub-groups. Minor marine incursions occurred from the Santonian, with significant diachronous formations as marine influence moved progressively onshore (Figure 3-2). Post-rift subsidence was reflected in general by alternating marine and non-marine fluvio-deltiac/alluvial deposition in the Late Cretaceous-Palaeogene of the Upper Latrobe Group. Lithologies include sands, shales and coals. The uppermost Latrobe Group sediments are the glauconitic Gurnard Formation, which reflects a more material marine setting. The Top Latrobe surface represents a major erosional period, which was followed by the Oligocene to Miocene Seaspray Group. The Lakes Entrance Formation, the lowest of the Seaspray units, provides regional seal to Latrobe Group hydrocarbon accumulations.

Subsequent events comprise canyon-cut and fill in the Eocene, and marine carbonate deposition commencing in the Early Oligocene; Middle Miocene compression formed a series of NE- to ENE-trending anticlines which host many of the basin's oil and gas accumulations.

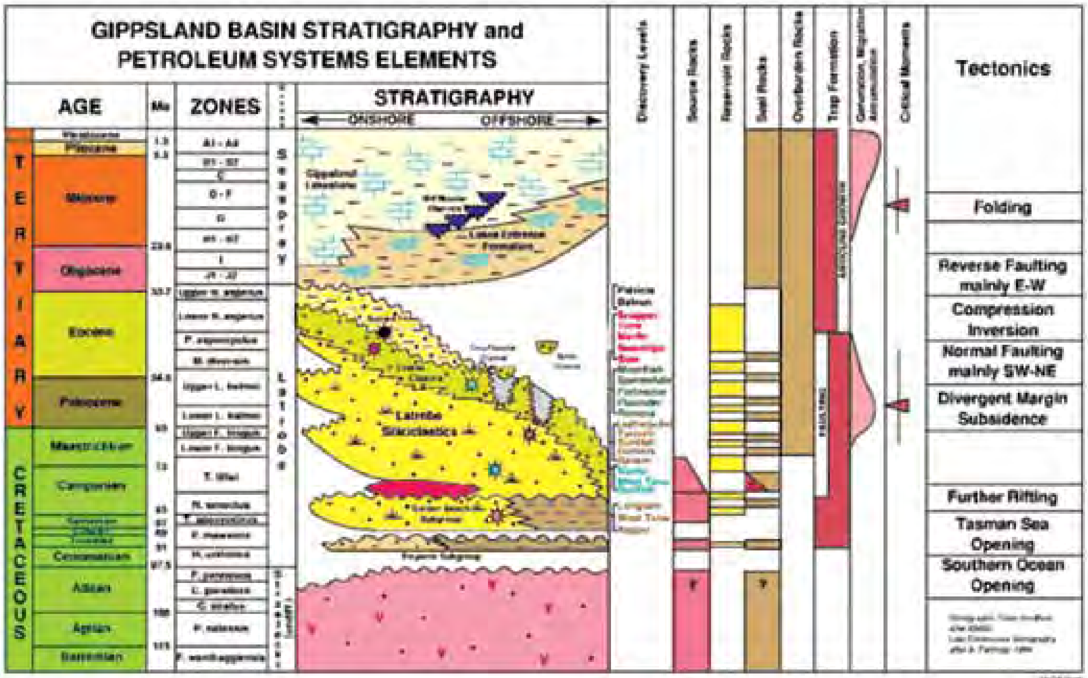

Figure 3-2 Gippsland Basin stratigraphy and petroleum system elements (Geoscience Australia, 2012)

The main reservoirs in the Gippsland Basin are a range of sand facies - the 'Coarse Clastics' - within the Upper Latrobe Group: braided and meandering fluvial, deltaic, nearshore and slope fan sandstones. While the Gurnard generally acts as a seal, it can also be of reservoir quality. Traps are structural and structural – stratigraphic, and occur notably at Top Latrobe and within intra-formational seals as Intra-Latrobe accumulations.

The hydrocarbons are largely sourced from non-marine facies of the upper Latrobe Group, but marine sources are also present. Crude oils are generally very light and paraffinic, ranging from 40 to 60 API (Dept Nat Resources & Environment 1998[1]). Some heavier oils discovered at shallow depths range from 14.6 to 25.6 degrees API and are thought to have been biologically degraded. The condensates range from 48 to 63 degrees API. The natural gases vary in condensate and carbon dioxide content.

Block VIC P/57 lies in the northwest of the Gippsland Basin, as shown in Figure 3-3. The key assets are the West Seahorse Field, discovered in 1981 and two exploration prospects Sea Lion and Felix, and these are the subject of this evaluation.

[1] *Dept of Natural Resources & Environment (Malek, R. & Mehin, K.) 1998 Oil and Gas Resources of Victoria*

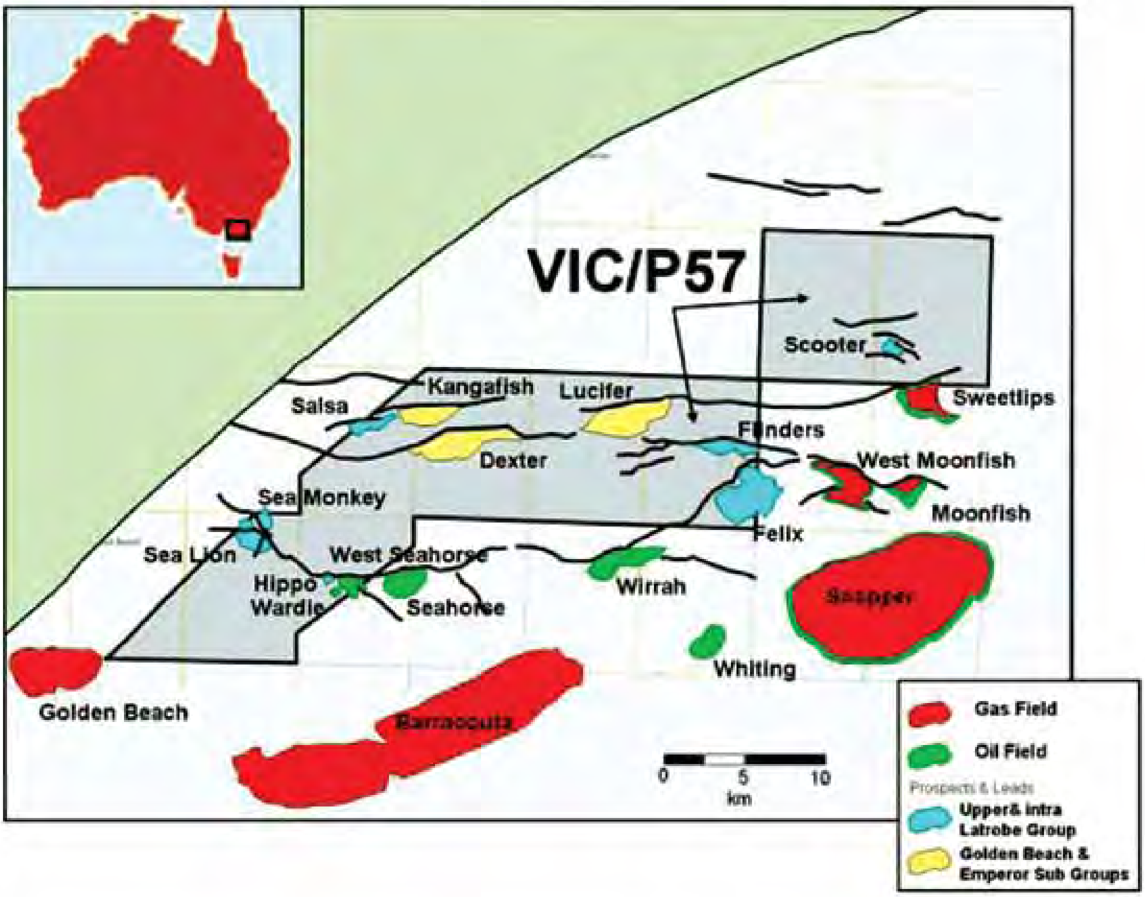

Figure 3-3 VIC/P57 Assets

4. WEST SEAHORSE: FIELD DESCRIPTION

4.1. INTRODUCTION

West Seahorse is a small and shallow relief structure which was discovered in 1981 by West Seahorse-1, and subsequently appraised by West Seahorse-2, West Seahorse-3 and Wardie-1 (Figure 4-1). The field is covered by the 3D seismic 'Northern Fields Survey', reprocessed as a Pre-Stack Depth Migration (PSDM) by Esso. The field is divided into main and NE pools, separated by a structural spill point at the tip-out of two faults. While the majority of the field lies within VIC/P57, a small percentage lies within VIC/LI8, which is held by Esso Australia (50% and operator) and BHP (50%).

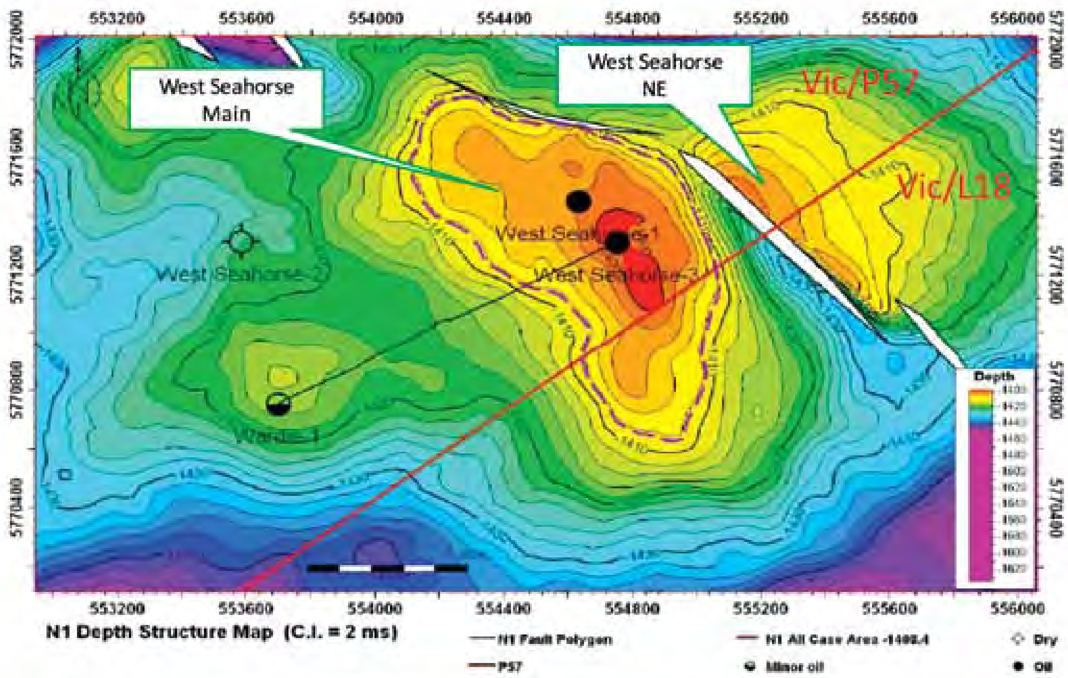

Figure 4-1 3DO West Seahorse depth map at top N1 reservoir

The main reservoirs in the West Seahorse field are Intra-Latrobe Group sands and a correlation of these is shown in Figure 4-2. Three units contain moveable oil: N1 Upper (N1u), N1 and N2.6. The N1u and N1 sands form a contiguous unit with a common hydrocarbon column. The deeper N2.6 sand lies some 50-60m below the base of the N1 sand. Oil is also present in the shallower Gurnard Formation, the uppermost unit of the Latrobe Group, but this unit was not tested.

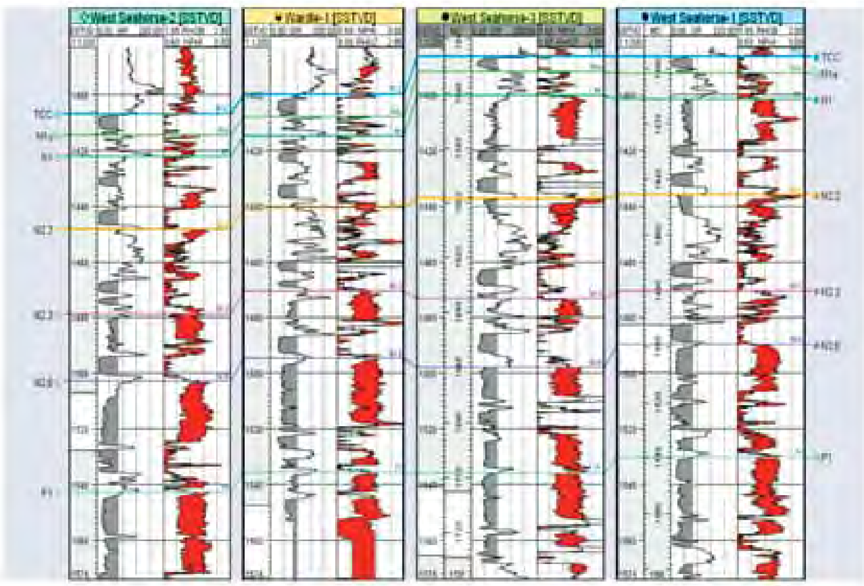

Figure 4-2 Well correlation in West Seahorse area (GCA)

4.2. SEISMIC INTERPRETATION

RISC has access to a Kingdom project, which contained the 3D seismic data, well logs and formation tops for all relevant wells and 3DO's interpretation.

3DO have interpreted three events at reservoir level - Top of Latrobe (TOL), N1 and N2.6 to map the top Gurnard, top N1 and top N2.6 respectively. The top N1 upper (N1u), was not mapped as it cannot be resolved on the seismic data. The seismic data is of high quality and the synthetic seismograms confirm the correlations made by 3DO as shown in Figure 4-3.

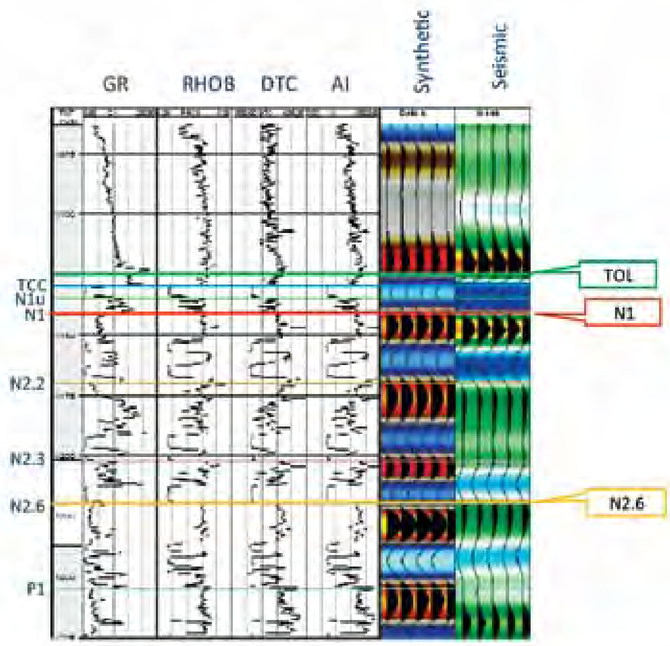

Figure 4-3 Synthetic Seismogram at West Seahorse-1 (after GCA)

A seismic line through West Seahorse-1 is shown in Figure 4-4. The interpreted events are from 3DO, and demonstrate the quality of the interpretation. However, RISC has re-interpreted the fault marking the NE limit of the field. The OWCs for the N1 and N2.6 reservoirs are also shown, which helps demonstrate the subtle nature of the structure.

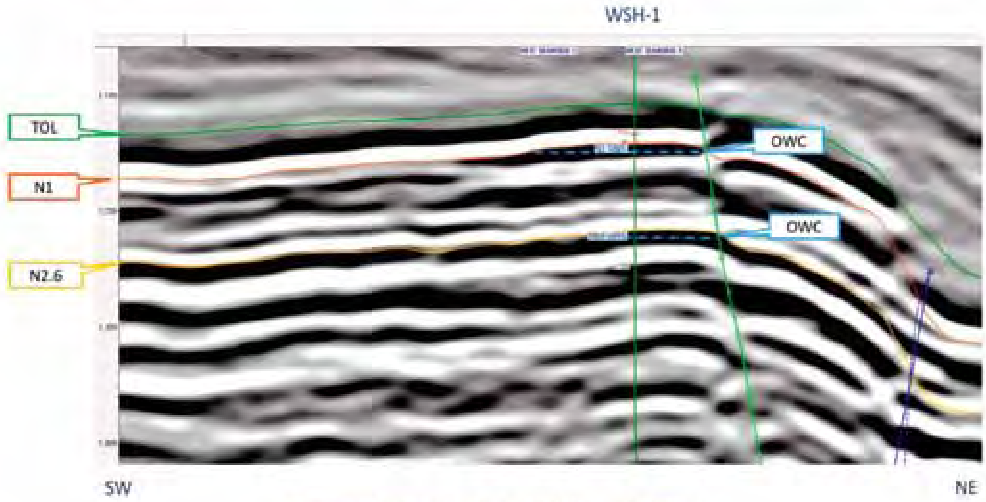

Figure 4-4 Seismic line 1522 through WSH-1

Both 3DO and GCA map a fault dependent structural saddle between West Seahorse Main and NE structures at TOL and N1 events as shown in Figure 4-5. RISC support this interpretation, and also note evidence of faulting at deeper levels - below the N2.6 event. RISC then also consider it possible that the N2.6 event is also faulted (giving a separation between the main and NE structures) as it would be more structurally reasonable, but just not resolved by the seismic data.

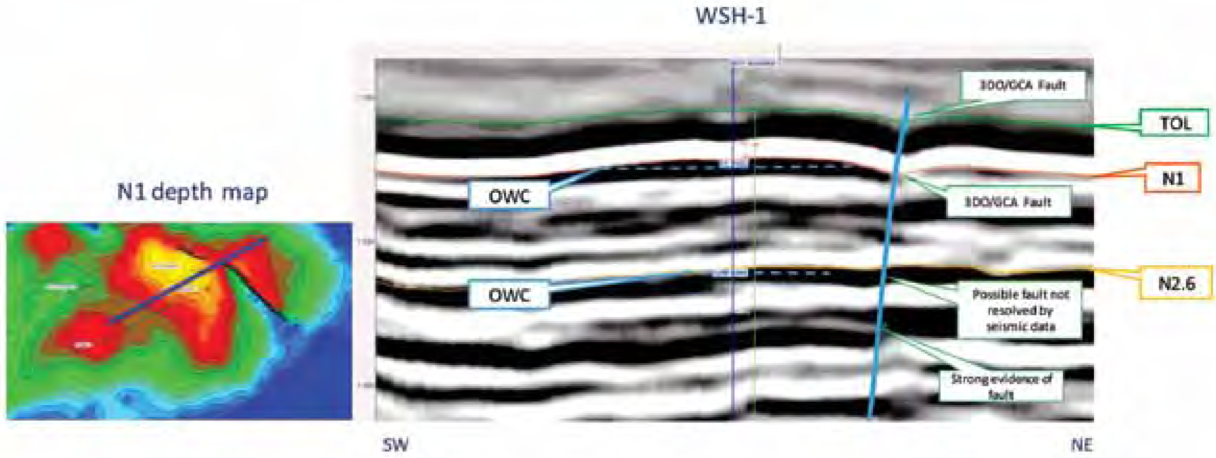

Figure 4-5 Arbitrary seismic line through West Seahorse saddle

Given the subtle nature of the structure, seismic pick and depth conversion uncertainty play an important role in determining the gross rock volume (GRV). 3DO used a simple regression based on well velocities for their depth conversion, which they have tied to wells. RISC supports this approach and has used the 3DO maps for the base case volumetrics. To understand the uncertainty in the depth maps, RISC have cross plotted the TWT pick with the pseudo average velocity derived from well formation tops (Figure 4-6). These plots show that there is a good relationship between the TWT pick and a pseudo average velocity that could be used for depth conversion. RISC has derived a simple V0, K equation as a best fit the well data and have used this to provide an independent depth conversion. From inspection of the plots, the uncertainty in the pseudo average velocity is in the order of +/- 50m/s or 2%. The exception is the N2.6 in West Seahorse-2, where there is a discrepancy of almost 100 m/s or 4%. Given the general consistency of the pseudo average velocities, RISC considers that a change in phase of the seismic wavelet is the likely cause; there is no apparent miss pick of the seismic horizon at this location. With this is mind, RISC considers a point uncertainty of +/- 4% which translates to +/- 6m.

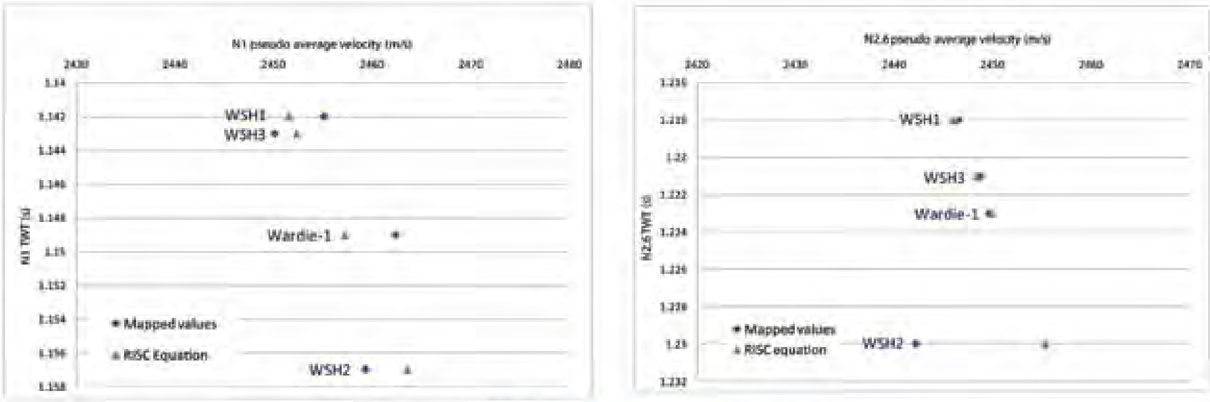

Figure 4-6 TWT picks vs pseudo average velocity

4.3. WELL RESULTS

The discovery well West Seahorse-1 was drilled in 1981 on an asymmetric anticline mapped on 2D seismic data, with closures interpreted at Top Latrobe, Intra Latrobe and Top Strzelecki levels. It reached TD within the Golden Beach Sub-Group, and encountered oil in the Eocene Latrobe Group. The N1 layer was tested (DST 1) and produced at a mean rate of 1,775 bopd of 48 degree API light crude on a half inch choke from the interval 1411-1416m MD. Oil was also sampled with RFT from the deeper N2.6 layer. Core data gave a maximum porosity of about 29%; DST results suggested formation permeability in the range 118 to 175mD. In the following year, West Seahorse-2 was drilled as an appraisal well; 1100m down flank to the east, but the key reservoirs were water-bearing and poorer quality.

West Seahorse-3 was drilled in 2008 by 3D Oil as a deviated well, 160m to the southeast of West Seahorse-1. The location was defined on 3D seismic data. Rotary sidewall cores were collected. The well terminated in the Upper Latrobe Group. Oil is present in the N1 layer, and sampled, but no drill stem tests were carried out. Analysis suggests a slight biodegradation. The deeper reservoirs were encountered low to prognosis, reportedly due to the intersection of a subtle fault, and were water-bearing. The well was suspended.

Wardie-1 was also drilled in 2008, from the same top hole location as West Seahorse-3, on a small separate culmination west of West Seahorse. Oil was not forecast to be present in the N1 sand; deeper levels were targets but were encountered low to prognosis and were water-bearing. Oil is present in the glauconitic Gurnard Formation, and in a sand above the main oil-bearing N1 sand in West Seahorse-1. With the structure being smaller than pre-drill estimates, the well was plugged and abandoned.

The Seahorse Field lies about 4 km to the east. This was discovered with Seahorse-1, drilled in 1978 on a fault-bounded anticline. Oil was encountered in five zones in the Latrobe Group, three being significant. Seahorse-1 is reported to have tested 2040 bopd of 53 degree API, with a gas-oil ratio of 200 scf/bbl (considered to be mildly biodegraded). Porosity in the discovery well averages 24%, and water saturation reported as 33%. Seahorse has been on production since 1990/1991.

4.4. PETROPHYSICS AND RESERVOIR PROPERTIES

RISC reviewed the petrophysical analysis conducted by GCA and undertook a quicklook independent interpretation of West Seahorse-1 and West Seahorse-3. The analysis aimed at the uppermost part of the reservoir i.e. reservoir expected within the structure. This was just down to the FWL in WSH-1, and taking an equivalent column to give a guide for WSH-3 (necessary as the FWL is at the top of the N2.6 reservoir in this well). Our results are given in Table 4-1.

Well	Reservoir	Net-to-gross %	Average porosity %	Average hydrocarbon Saturation %
West Seahorse-1	N1u	29	32	n/a
	N1	89	28	n/a
	N2.6	92	27	n/a
West Seahorse-3	N1u	12	31	86
	N1	75	25	87
	N2.6	97	27	in water

Table 4-1 West Seahorse-1 and -3 petrophysical properties (RISC)

RISC considers the hydrocarbon saturation estimates from West Seahorse-1 logs unreliable due to the poor quality of the data and has not used saturation data from West Seahorse-1 in our analysis.

4.4.1. Data

Data available were LAS files from West Seahorse-1 and West Seahorse-2, DLIS files from West Seahorse-3 and Wardie-1, plus core analysis data from conventional and rotary sidewall cores. RISC note that the LAS files were poorly prepared and the DLIS files represented only a subset of the original data. We consider that the data acquisition programs for the more recent wells failed to address the key uncertainties of reservoir thickness and quality, and hydrocarbon content. The preferable logging suite should have included NMR logs to investigate porosity (total and effective) as well as hydrocarbon content, plus borehole image logs to determine accurately sand thickness and thus net-to-gross.

4.4.2. Porosity, permeability and net-to-gross

A good relationship between porosity and permeability is shown by core data from the N1u, N1 and N2.6 sands and is discussed in Section 8.2. Given this, we consider that it may be appropriate to combine the N1u and N1 units as they also have a common free water level. However, we have treated them separately for the purposes of this evaluation to facilitate comparison with existing estimates.

We consider that GCA's porosity estimates are reasonable. However, net-to-gross estimation is difficult with the available low resolution log data. We consider that a greater uncertainty exists in net-to-gross than determined by GCA, and it is not clear that they have accounted for all the coal intervals. West Seahorse-2 shows that the coals in both N1u and N1 units reduce the potential net reservoir considerably.

The glauconitic sands of the Gurnard Formation have a high gamma ray response and are known to contain significant volumes of bound water. Total porosity is likely to be at least 25%, but the effective porosity may be half that value. In the total porosity domain, the net pay may be up to 95% of gross; but with high water saturation.

4.4.3. Water saturation

The existence of a fresh water wedge of formation water is a well known phenomenon in the northern Gippsland Basin. This relates to freshwater flushing of previously saline aquifers. Where hydrocarbon pools are present, the saline water leg is flushed, but the formation water within the hydrocarbon column remains unchanged. The difficulty then presented to petrophysical analysis is that conventional means to establish water resistivity from samples in water legs, and/or analysis of wireline responses within the water leg, are not meaningful. GCA have undertaken a complex manipulation of log data, including sonic, to determine a water saturation. However, from the information available, RISC has not been able to understand fully GCA's approach, nor therefore to confirm their analysis.

We consider that a significant transition zone is unlikely to be present, given the good reservoir quality, as shown by the steep tail-off of saturations in West Seahorse-3 in the clean sand of the N1 unit (Figure 4-7), which also shows clearly the coal intervals within this section. It is possible that a zone of mixed fresh and saline formation water is present towards the base of the hydrocarbon column, but there are no direct ways to quantify this. We have used a typical brine water salinity of 0.15 ohm-m at 68C°, or about 20,500 ppm NaCl equivalent. We consider that data quality and type are insufficient to determine water saturation in the West Seahorse-1 well.

No material hydrocarbons are present in West Seahorse-3 within the N2.6, and the well appears to be at the edge of the accumulation at this level. We note however from the digital data available, the SP log response at this level appears different to that illustrated by GCA, and seems to indicate different water salinities within the same sand, possibly indicating movement of water and hydrocarbon.

For the Gurnard, the water saturation may be 65% or higher (in the total porosity domain), although remains very uncertain. Total porosity includes clay bound water so the calculated porosity and water saturations are higher than usual and higher than the effective porosity and effective water saturations which exclude clay bound water. We calculate a hydrocarbon column to base reservoir, in West Seahorse-3, but note that no tests were undertaken.

West Seahorse-2 lies outside the field limits. No hydrocarbon saturations are determined. No hydrocarbons are determined for the P1 reservoir, which is therefore excluded from any resource.

The petrophysical summary plots of our evaluation are shown in Figure 4-7 to Figure 4-11.

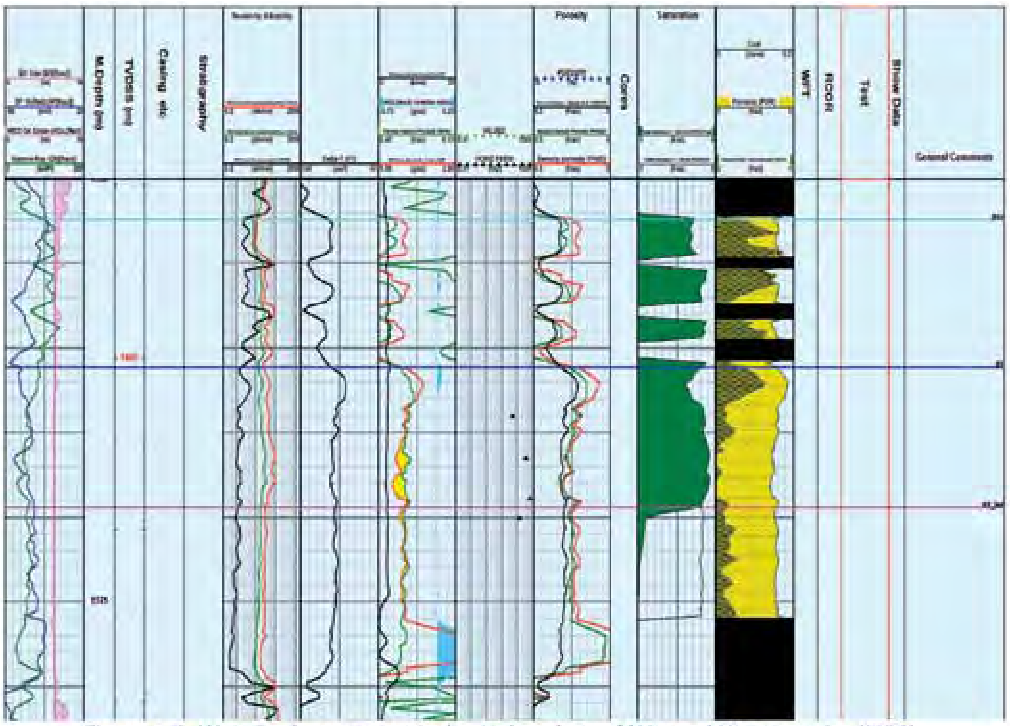

Figure 4-7 West Seahorse-3 petrophysical analysis of N1u and N1 reservoirs (RISC)

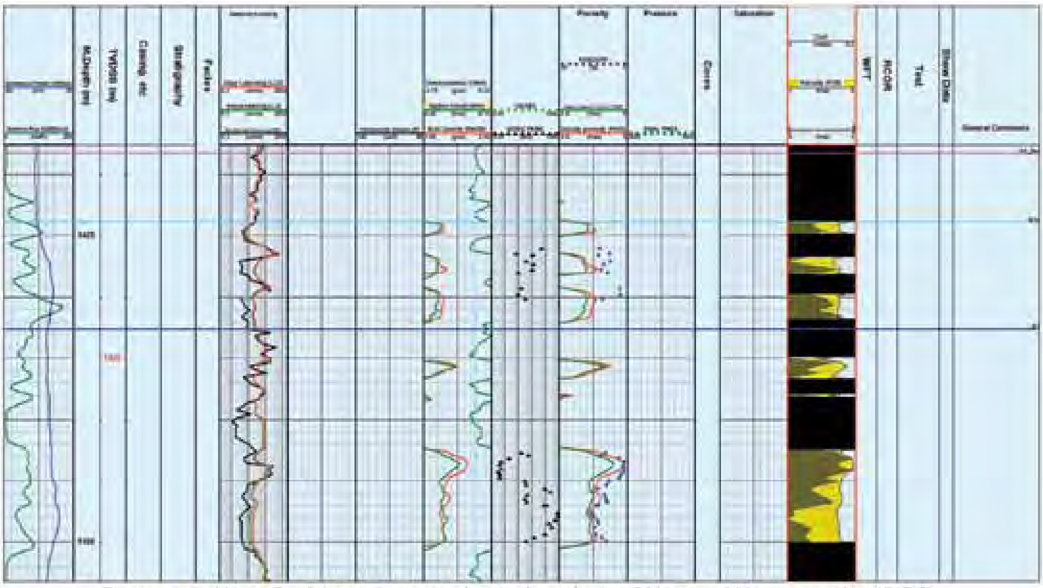

Figure 4-8 West Seahorse-2 petrophysical analysis of N1u and N1 reservoirs (RISC)

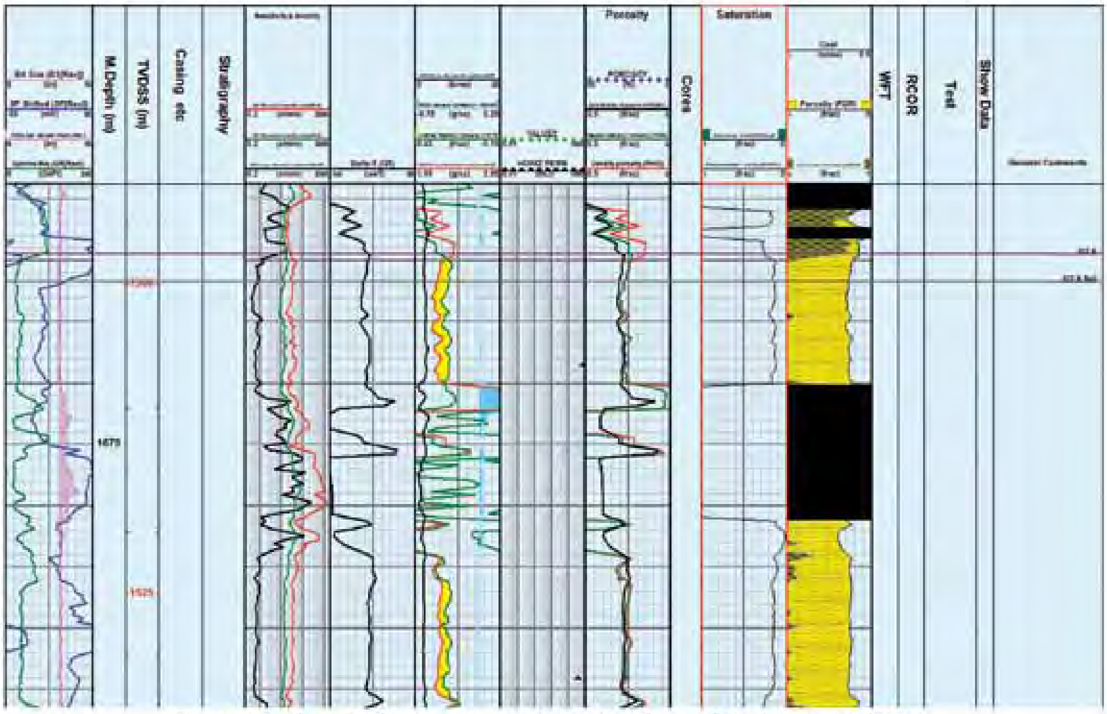

Figure 4-9 West Seahorse-3 petrophysical analysis of N2.6 reservoir (RISC)

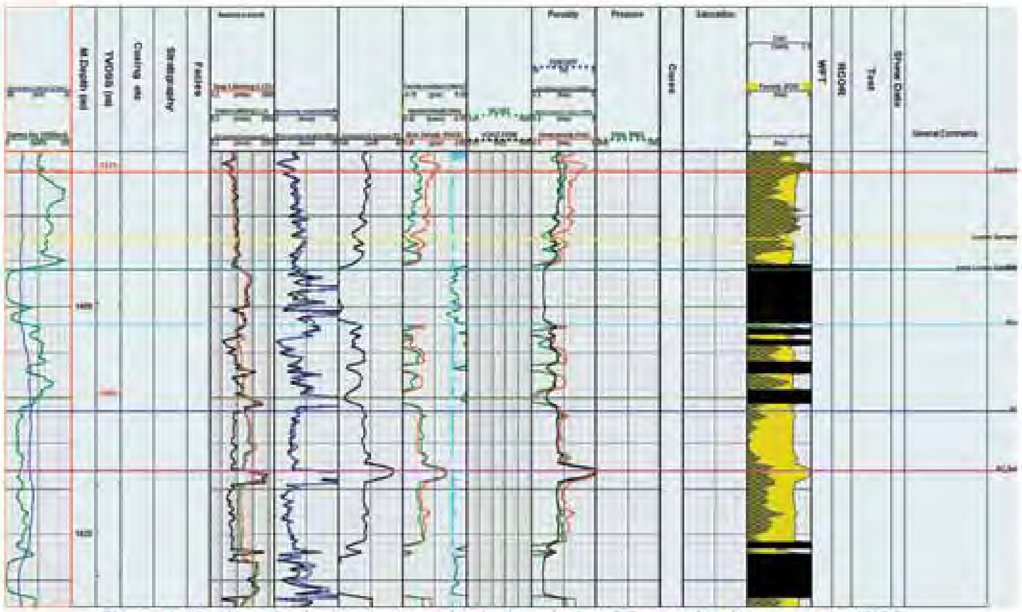

Figure 4-10 West Seahorse-1 petrophysical analysis of Gurnard to N1 reservoirs (RISC)

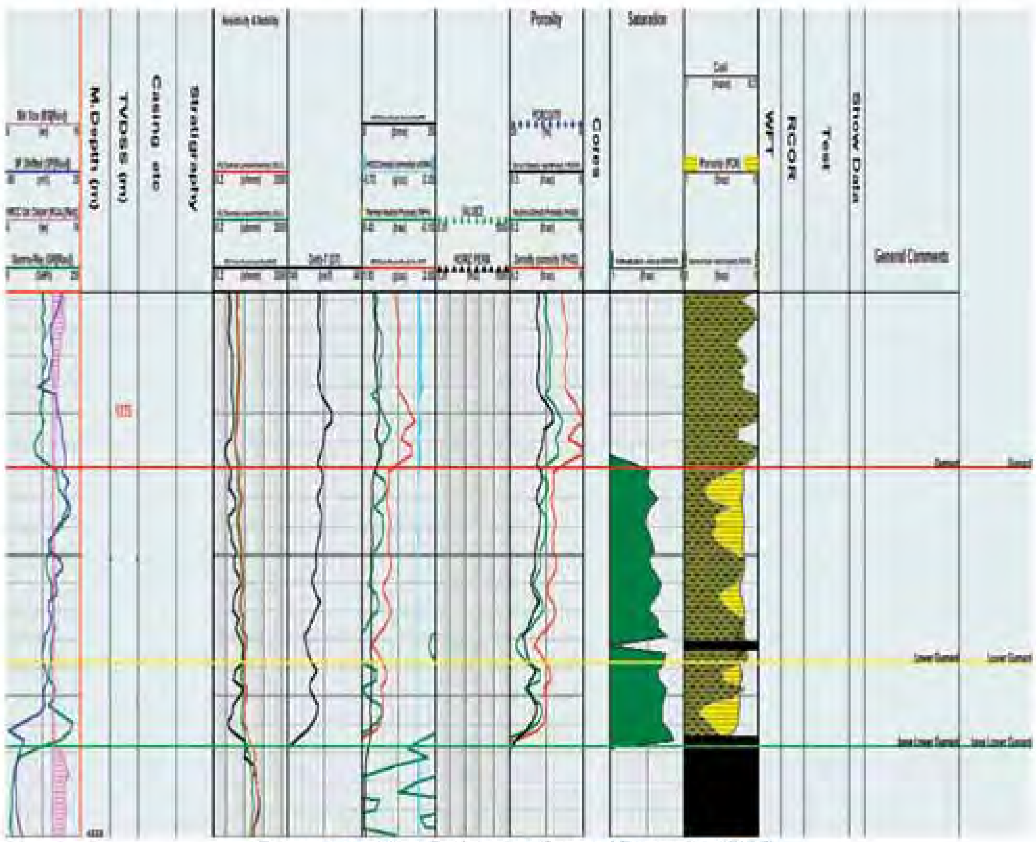

Figure 4-11 West Seahorse-3 Gurnard Formation (RISC)

4.5. FLUID CONTACTS

Fluid contacts in the West Seahorse (WSH) field are defined by logs and MDT measurements and are relatively well defined. RISC has utilised the contact ranges given in (Table 4-2) for estimating the OOIP for the main field and the N2.6 of the NE segment.

Reservoir	Shallow	Best	Deep
N1u	1407.4	1408.4	1409.5
N1	1407.4	1408.4	1409.5
N2.6	1497.5	1498.0	1498.5

Table 4-2 West Seahorse fluid contacts m TVDss

The best estimate for the N1 sand is from the apparent OWC drilled in WSH-3; and is shown on logs at 1408.4 metres TVDss (Figure 4-7). Figure 4-12 shows the available pressure data over the field. The oil gradient corresponds to a downhole oil density of 0.7 g/cc, which is as expected for oil with a stock tank API gravity of circa 48 degrees (or 0.78 g/cc). The water gradient corresponds to a density of 1.01 g/cc with the water gradient being consistent with an aquifer that is continuous from near sea level. This is in line with the local geographic conditions and noted aquifer behaviour elsewhere in the Gippsland Basin.

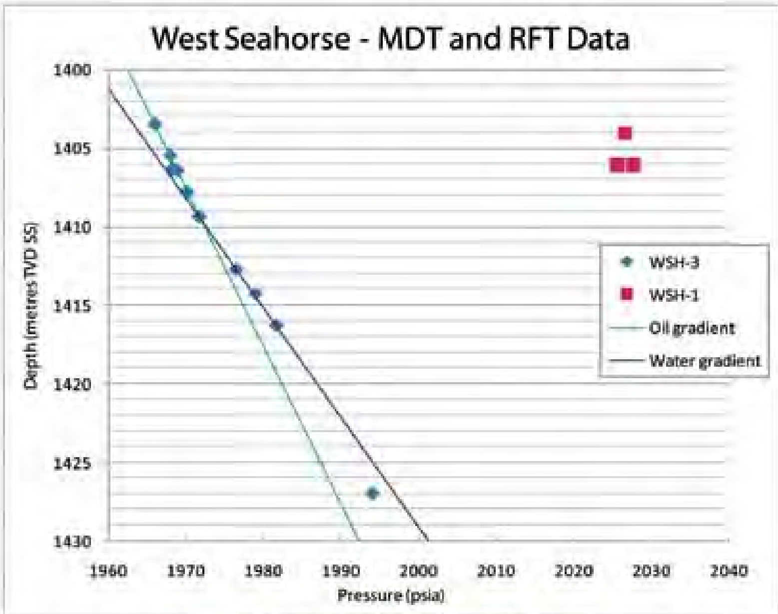

Figure 4-12 West Seahorse MDT and RFT data

The FWL for the N1 sand is interpreted at 1409.5 from MDT data in WSH-3 and RISC has taken this for the deep estimate for the OWC. The shallow estimate was derived from the depth of an RFT oil sample at 1407.4 m TVD SS in WSH-1.

Oil has not been sampled from the N1u sand and there is no MDT/RFT data at this interval either. However, the sands are in close vertical proximity to each other and RISC believes it is reasonable to assume the same contacts for the N1u as for the N1.

There is no evidence of an OWC in the N2.6 sand from the MDT in WSH-3. GCA has previously suggested a range of OWC for the N2.6 from logs run in WSH-1 as shown in Figure 4-13. RISC notes that these contacts are (effectively) at or below the top of the sand in WSH-3 (the top of the N2.6 in WSH-3 is at 1498 m TVD SS). RISC also notes that the water pressures in the N2.6 are consistent with the water pressures in the N1 sand, indicating a common aquifer system. Logs from WSH-3 indicate oil at low saturations in the N2.6

sand (Figure 4-13). The observed pressure depletion in the N1 sand and reported production from the N2.6 sand at Seahorse suggest that the N2.6 sand has been swept by the aquifer (in production time) and this would account for the low saturations and that the deeper contacts are now invalid due to aquifer movement since WSH-1 was drilled. Accordingly RISC is using a single OWC for the N2.6 sand at 1498.0 m TVD SS with a +/- 0.5 metre spread to allow for depth measurement errors.

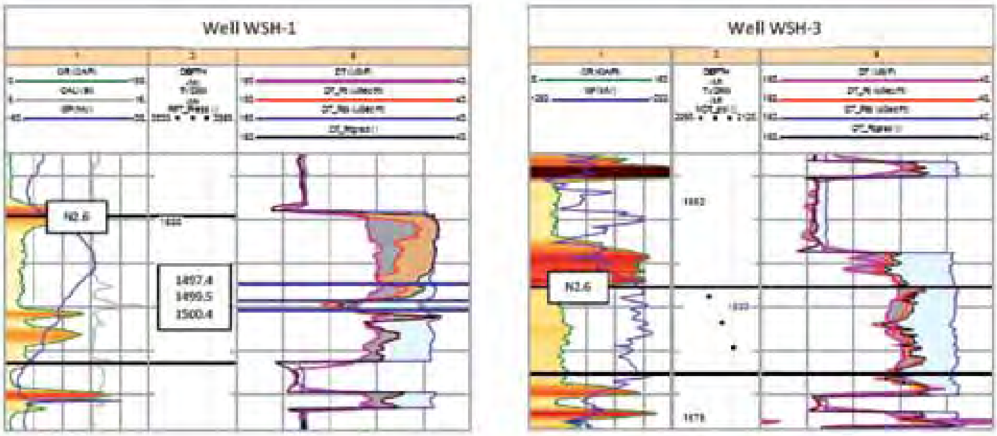

Figure 4-13 Log panel showing N2.6 OWC as interpreted by GCA (after figure 1.24 by GCA)

4.6. PVT

With similar pressure regimes and depths of the reservoirs RISC think it is reasonable to utilise a single set of PVT properties for the N1u, N1 and N2.6 sands (Table 4-3). Samples and analyses are mainly confined to the N1 sand.

West Seahorse Oil PVT Properties				
		Low	Best	High
Formation Volume Factor	rb/stb	1.18	1.16	1.14
Solution GOR	scf/stb	325	235	180

Table 4-3 West Seahorse Oil FVF and GOR

Formation volume factors were measured in lab analyses except for the FVF corresponding to a solution GOR of 180 scf/stb. This was estimated from a correlation which had been tuned to the other laboratory measured Bo values. The FVF has a relatively small range and corresponds to a variation in the OOIP of ~3.5%.

Oil in West Seahorse is a light crude with an API gravity of circa 48 degrees API. In situ oil viscosities are in the range of 0.5 – 0.6 cP. Gippsland Basin oils generally have only minor flow assurance issues and these are typically confined to waxing in the crude due to low seabed temperatures when wells or pipelines are shut in for extended periods. Pipelines are typically insulated and this overcomes most waxing issues.

The main PVT issues in West Seahorse are associated with the possible presence of H_2S and the GOR of the oil.

H_2S

H_2S was measured at 200 ppm during testing of the N1 sand at WSH-1 and at 300 ppm during testing of the same sand at Seahorse 1, but its presence remains unclear. H_2S was not measured in the laboratory on any samples from DSTs/MDTs or production samples from Seahorse 1 during some 20 years of production (advice from 3DO). The non-measurement in the laboratory could be put down to adsorption of the H_2S

onto the un-lined walls of the sample cylinders. There has been no issue with H_2S in the nearby producing Seahorse Field. RISC places more weight on this and accordingly believes there is no need to design for sour gas service at West Seahorse. RISC recommends sampling of the WSH fluids in lined cylinders when drilling WSH-3 ST as a prudent safety measure. Modifications for the presence of H_2S could still be made to the design at this stage if required (albeit at added expense).

GOR

The GOR of the oil at WSH has not been conclusively determined. It lies within the broad range shown in Table 4-3. The producing GOR during DST 1 at WSH-1 (N1 sand) was circa 135 scf/bbl of separator oil. Flashing the oil to stock tank conditions gave a total GOR of circa 180-200 scf/stb. Physical recombination of surface samples allowed measurement of the GOR as 233 scf/stb. Measurements on sub-surface samples (sample chambers run with DST string) showed GORs of circa 330 scf/stb. Bubble point pressures were 825 psig and 1285 psig respectively. Analysis of MDT samples from WSH-3 showed a GOR of 325 scf/stb and a bubble point pressure of 1227 psig.

RISC notes that an oil sample from West Seahorse 2 had a solution GOR of ~740 scf/stb and a bubble point pressure of 1368 psig. We have been unable to determine the reservoir from which this sample was taken and accordingly have not utilized the data in our analysis.

The main conclusions to be drawn from the GOR analysis are:

- The oil is under saturated;
- Bubble point pressure is significantly below initial reservoir pressure and is unlikely to be reached during production due to the strong aquifer drive;
- Producing GOR should remain essentially constant during production.

5. WEST SEAHORSE - EVALUATION OF IN-PLACE OIL

5.1. GROSS ROCK VOLUME

RISC has determined a range in gross rock volumes (GRV) that incorporates uncertainty in depth mapping and oil-water contact. The base case maps are taken from the 3DO grids, as RISC support these. For the main reservoirs (N1u, N1 and N2.6) we used area-depth pairs and an uncertainty on the area that covers the depth uncertainty; for the Gurnard we used a range in GRV.

N1u, N1 and N2.6 Reservoirs

The calculation of gross rock volume of the N1u is constrained between the depth surfaces of the Top N1u and Top N1, and is thus a constant parameter for each calculation. The column heights for both the N1u/N1 and N2.6 are small and the flatness of the structure is such that the fluid limit does not impinge on the base of either the N1 or the N2.6 reservoir. The volumetric calculation for these lower units thus uses the top surface only, limited by the OWC.

We have used the 3DO maps (as we support these) and contacts as defined in section 4.5, to determine the GRV for both West Seahorse Main and West Seahorse NE. Given the structural configuration, the contact in West Seahorse NE cannot be deeper than that of West Seahorse Main, although it can be shallower. As discussed in the Seismic Interpretation section, there is uncertainty associated with the depth maps. RISC estimates a point uncertainty of +/- 6m, and has translated this into an average uncertainty for the field to be in the order of +/- 3m. With comparison of the structural areas defined at the field limits, an uncertainty of 3m would be equivalent to about +/- 20% in area. For our volumetric calculations we have used area/depth pairs in conjunction with an area uncertainty of 20%. Our independently derived depth maps lie within these ranges. In addition, we have defined ranges of fluid limits for the main field and the exploration area as shown in Table 5-1 and Table 5-2 and discussed in section 4.5.

West Seahorse main field				
Reservoir	Distribution	P90, m TVDss	P50/ML, m TVDss	P10, m TVDss
N1u and N1	Beta	1407.4	1408.4	1409.5
N2.6	Beta	1497.5	1498.0	1498.5

Table 5-1 West Seahorse main reservoirs, Main field fluid limits

West Seahorse exploration: NE segment				
Reservoir	Distribution	P90, m TVDss	P50/ML, m TVDss	P10, m TVDss
N1u	Beta	Min 1400	ML 1405	Max 1410
N1	Beta	no volume	no volume	P10 1408.4
N2.6	Beta	1497.5	1498.0	1498.5

Table 5-2 West Seahorse main reservoirs, NE segment fluid limits

Details of gross rock volumes are given in Table 5-4. Note that the N1 has (minor) volumes in the NE segment only in an upside case, and can essentially be ignored. This is because the spill point is controlled by the shallower N1u, leaving only a small volume in the P10 case above this contact.

Resource areas as defined by RISC are shown in Figure 5-1 through to Figure 5-4.

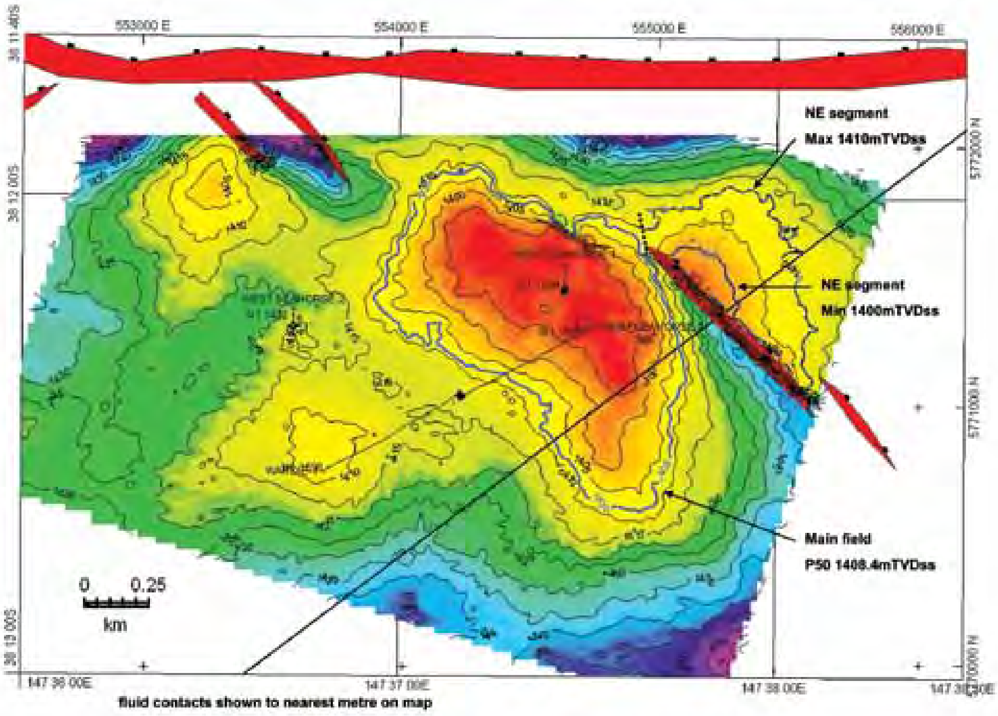

Figure 5-1 Top N1u Depth map with resource areas/field limits

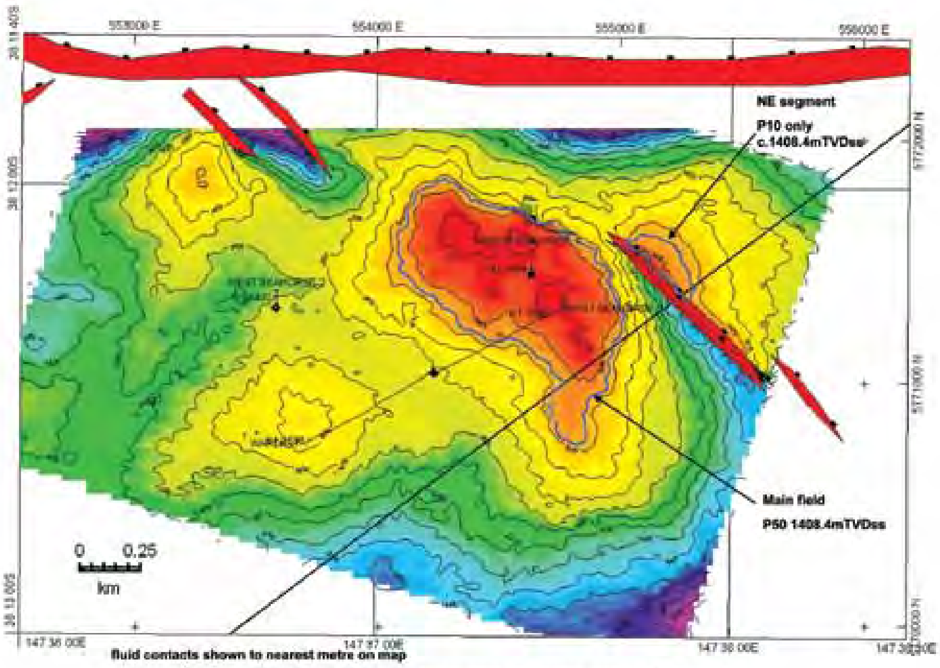

Figure 5-2 Top N1 depth map and resource areas/field limits

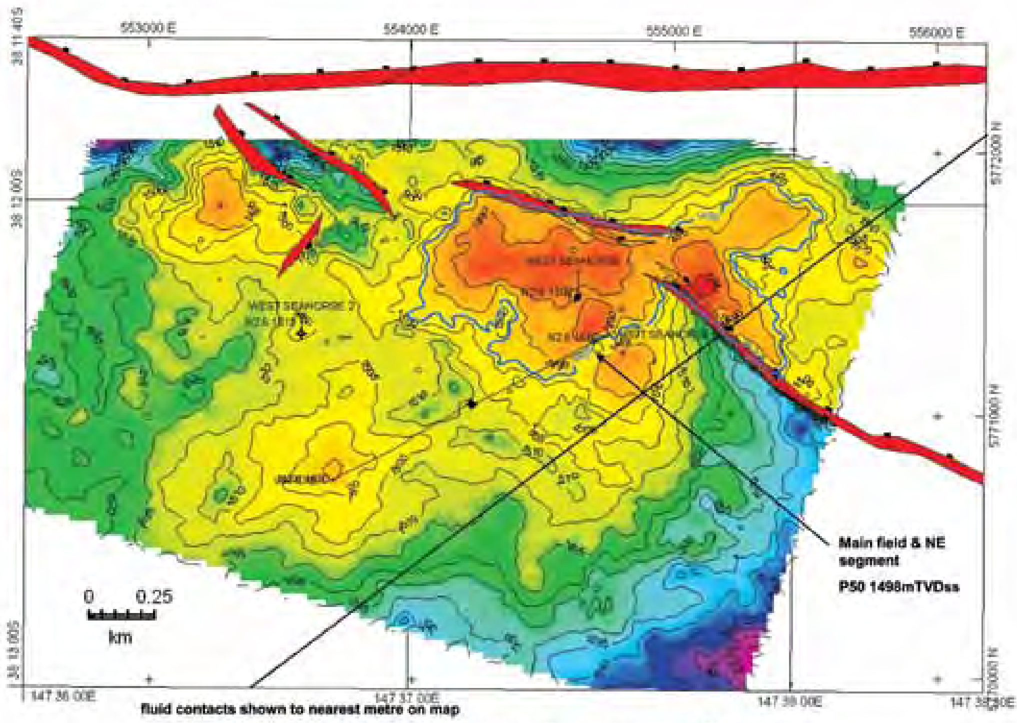

Figure 5-3 Top N2.6 Depth map and resource areas/field limits

Gurnard Formation

Hydrocarbons are present in the Gurnard Formation in West Seahorse-1, West Seahorse-3 and Wardie-1. However, oil is unproven in West Seahorse as no samples or tests have been performed. Oil was sampled but not tested in Wardie-1. In the main field, we have defined a P10 areal limit to the Gurnard at the base of the column in Wardie-1, at 1400m TVDss (Table 4-2, Figure 5-4). The West Seahorse-2 well lies within this area, although close to the margin. Possible hydrocarbons seen in this well are consistent with our approach. Our P90 limit for the main field is the base of the hydrocarbon column in West Seahorse-1 and -3, at 1386.2m TVDss.

The separate NE segment is treated as a prospective resource. Given that the P10 level defined for the main field fully encompasses the NE structure, this is used as the P10 limit for the NE structure. The P90 area is defined as a small crestal area at 1380m TVDss, given that degree of fill is not known.

Reservoir	Distribution	P90, m TVDss	P50/ML, m TVDss	P10, m TVDss
Gurnard, main field	log normal	1386.2	not specifically defined	1400
Gurnard, NE segment	log normal	1380	not specifically defined	1400

Table 5-3 West Seahorse Gurnard fluid contacts

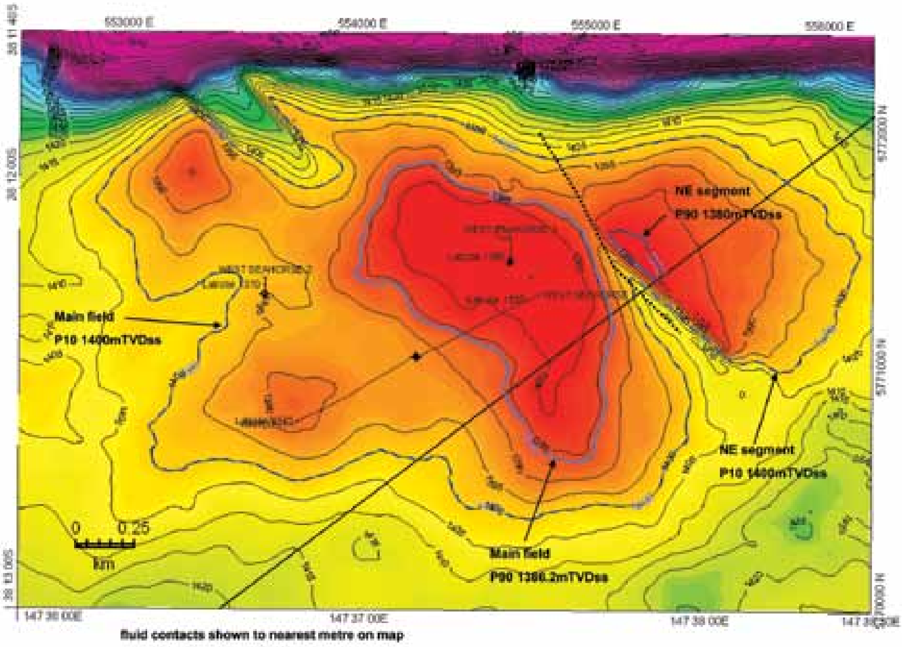

Figure 5-4 Top Gurnard Depth map with resource areas/field limits

Both the main West Seahorse field and the NE exploration segment are cut by the south eastern VIC/P57 permit boundary. We have calculated both total and on-block resource volumes; a summary of gross rock volumes is given in Table 5-4.

Reservoir	Case	Total		On-block	
		Main field, km^2-m	NE segment, km^2-m	Main field, km^2-m	NE segment, km^2-m
Gurnard	P90	4.57	0.31	3.95	0.02
	P50	10.1	1.35	8.42	0.255
	P10	22.8	6.24	17.9	3.25
N1u	P90	4.70	0.18	4.01	0.14
	P50	5.33	0.39	4.51	0.30
	P10	6.00	0.72	5.03	0.52
N1	P90	1.93	0.04	1.86	0.03
	P50	2.60	0.08	2.49	0.06
	P10	3.40	0.14	3.23	0.10
N2.6	P90	2.10	0.84	2.10	0.77
	P50	2.65	1.21	2.65	1.11
	P10	3.23	1.61	3.23	1.48

Table 5-4 West Seahorse gross rock volumes

5.2. RESERVOIR PROPERTIES

Based upon our review of the petrophysical properties of each well, we have defined ranges of input parameters for the various reservoirs in the following tables (Table 5-5, Table 5-6, Table 5-7).

Reservoir	Distribution	P90 %	P50 %	P10 %
Gurnard	log normal	60	75	95
N1u	log normal	21	40	75
N1	log normal	82	88	95
N2.6	log normal	92	94	97

Table 5-5 West Seahorse net-to-gross volumetric inputs

Reservoir	Distribution	P90 %	P50 %	P10 %
Gurnard	log normal	25	28	32
N1u	log normal	23	27	32
N1	log normal	23	26	29
N2.6	log normal	23	26	29

Table 5-6 West Seahorse average porosity volumetric inputs

Reservoir	Distribution	P90 %	Most Likely %	P10 %
Gurnard	beta	65	58	50
N1u	beta	25	19	10
N1	Beta	25	19	10
N2.6	beta	25	19	10

Table 5-7 West Seahorse average water saturation volumetric inputs

Formation volume factors were discussed in Section 4.6.

5.3. OIL IN-PLACE

On the basis of the evaluation and volumetric inputs provided above, RISC calculates the following in-place discovered and undiscovered volumes (Table 5-8, Table 5-9):

West Seahorse Main field - Oil Initially In-place								
	Total Field, 100% share, MMstb				On-block VIC/P57, 100% share, MMstb			
Reservoir	P90	P50	P10	Mean	P90	P50	P10	Mean
Gurnard	2.05	4.78	11.30	5.96	1.77	3.98	8.99	4.84
N1u	1.28	2.49	4.66	2.76	1.08	2.11	3.93	2.33
N1	1.88	2.62	3.60	2.40	1.81	2.51	3.42	2.58
N2.6	2.18	2.87	3.68	2.90	2.11	2.78	3.57	2.80
arithmetic addition: N reservoirs only	5.34	7.98	11.94	8.35	5.07	7.49	11.03	7.81

Table 5-8 West Seahorse Main field – Oil Initially in-place

West Seahorse NE Segment - Oil Initially In-place								
	Total Field, 100% share, MMstb				On-block VIC/P57, 100% share, MMstb			
Reservoir	P90	P50	P10	Mean	P90	P50	P10	Mean
Gurnard	0.14	0.65	3.04	1.29	0.01	0.12	1.57	0.75
N1u	0.07	0.18	0.43	0.22	0.05	0.14	0.31	0.16
N1	0.04	0.08	0.15	0.09	0.03	0.06	0.10	0.06
N2.6	0.88	1.31	1.81	1.33	0.80	1.19	1.64	1.21
arithmetic addition: N reservoirs only	0.99	1.57	2.39	1.64	0.88	1.39	2.05	1.43

Table 5-9 West Seahorse NE segment – Undiscovered Unrisked Oil Initially in-place

6. WEST SEAHORSE RESOURCE AREAS AND CLASSIFICATION

6.1. INTRODUCTION

RISC classifies the hydrocarbon volumes within the main area of the West Seahorse Field and the main reservoirs (N1u, N1 and N2.6) as contingent resources, while the Gurnard will remain a prospective resource until tested. The north-eastern segment of the West Seahorse structure is considered to be near field exploration and thus is also classified as a prospective resource (Figure 6-1). Additional prospective resources are present in the Sea Lion and Felix prospects. The contingent resources in West Seahorse can be booked as reserves once a development plan is approved by the permit owners and a production licence is granted by the government.

The West Seahorse structure is limited to the north by a WNW-ESE down-to-the-north fold and fault trend. The drilled structure is nevertheless essentially a four way dip closure. The closure to the northeast has a different nature, against a down-to-the south throw, in opposition to the fault to the west. Continuity of faulting is therefore not likely. However, the structural distinction of this 'NE segment' is such that we consider this undrilled area to be classified as near-field exploration. This position is strongly supported by the free water level for N1u/N1 at 1408.4 being essentially coincident with the spill into the NE area, rather than being full-to-spill. This suggests that the bounding fault to the NE segment may even be the reason for West Seahorse to be limited as it is; in other words that this fault is a breach point for the structure. This is not the case for the N2.6 sand, for which the free water level appears to be deeper than the spill point between the main field and the NE segment, but the structural differences remain (Section 4.2), and we have maintained the overall exploration status of this area. The Gurnard is less well understood, although the base of the apparent (unsampled) oil column in West Seahorse-1 and -3 is once again close to the spill point between the main and NE areas. The considerable uncertainties confirm that this NE area should be treated as exploration.

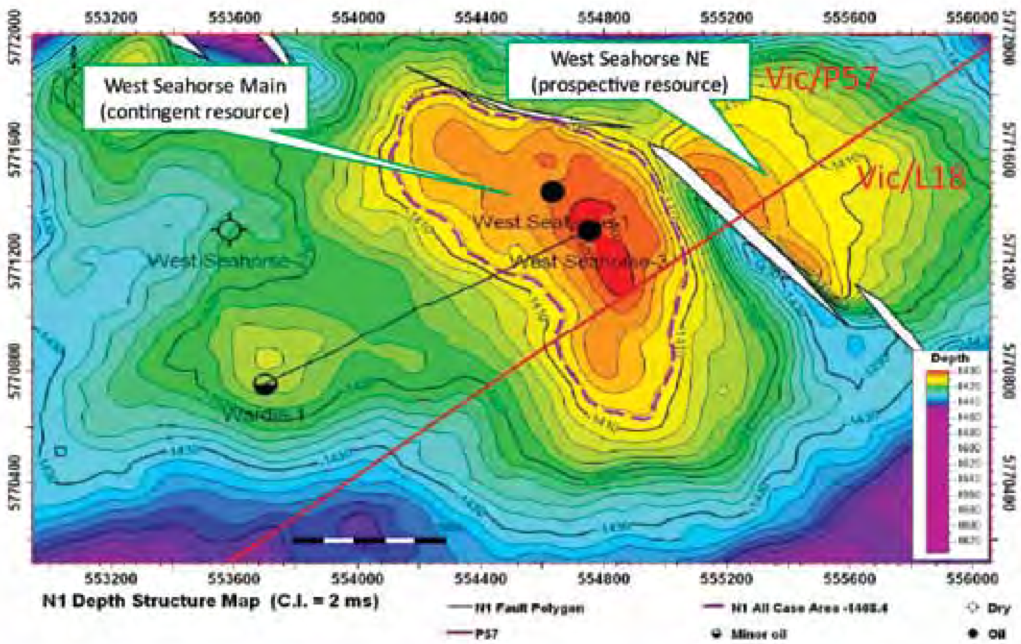

Figure 6-1 West Seahorse field structure showing contingent and prospective resource areas

This position is supported further from the omission in the current development plan of any well in this NE segment, and cannot be considered as reserves. Simulation by 3DO shows that drainage of this area is effectively non-existent for the N1 and N1u reservoirs, and very limited for the N2.6 reservoir. There are no plans to develop the Gurnard.

The Gurnard of the West Seahorse Main segment is a prospective resource due to uncertainties in reservoir deliverability, which RISC consider as very likely or 85% POS.

The NE segment is also classified by RISC as a prospective resource, albeit with a high chance of success. We note that GCA adopt a different position in that they include the NE area in their upside cases, as their depth map does not show the coincidence of the spillpoint referred to above. As prospective resources, the volumes estimated for the NE segment carry a chance of success. The trap is dependent on the SW fault and there is a small chance (10%) that this could leak, given the apparent limit of the N1u/N1 pool at northwestern termination of the fault bounding the NE segment. There is also small risk (10%) of flushing of the lower reservoirs, given that the N2.6 in the main structure does not appear to be full to spill. An additional reservoir deliverability risk is carried for the Gurnard.

Formation	Trap	Reservoir	Seal	Charge	Total
Gurnard	100	85	90	100	**75**
N1u/N1 and N2.6	100	100	90	90	**80**

Table 6-1 West Seahorse NE segment probability of success (%)

6.2. RESOURCE ESTIMATES

The resource estimates for VIC/P57 are given in Table 6-2. This is a probabilistic approach which combines uncertainties in reservoir parameters and recovery factors for the different pools. It is therefore different than the specific cases run to produce the production profiles given in sections 8.5 and 8.5.3.

Classification	Pool	Reservoir	OIP			Ultimate Recovery		
			P90	P50	P10	P90	P50	P10
Contingent	West Seahorse Main	N1u	1.3	2.5	4.7	0.8	1.6	3.0
		N1	1.9	2.6	3.6	1.2	1.7	2.3
		N2.6	2.2	2.9	3.7	1.4	1.9	2.4
		Probabilistic sum	6.5	8.15	10.5	4.1	5.5	7.1
Prospective	West Seahorse Main	Gurnard	2.0	4.8	11.3	0.3	0.7	1.7
	West Seahorse NE	N1u, N1 and N2.6	1.1	1.6	2.1	0.7	1.0	1.4
	West Seahorse NE	Gurnard	0.1	0.6	3.0	0	0.1	0.5

Table 6-2 Unrisked Full Field Resource Estimates (MMstb, RISC)

The recovery factors used for this analysis are given in Table 6-3 and are based on the creation of production type curves, as outlined in Section 8.3.

Levels	P90	Mode	P10
"N" reservoirs	58%	67%	71%
Gurnard	10%	15%	20%

Table 6-3 Input recovery factors (%) for probabilistic volumetric calculations

7. BASIS FOR EVALUATION

7.1. INTRODUCTION

The evaluation of the West Seahorse field involves considering a number of development options in addition to the geological uncertainties and outcomes described above. RISC have evaluated these using three development scenarios; phased 2 well development with a range of resource outcomes, phased 2 well development with different development concepts and a concurrent minimum 2 well development with a range of resource outcomes.

7.2. PHASED 2 WELL DEVELOPMENT WITH RANGE OF RESOURCE OUTCOMES

This approach assumes a well in West Seahorse Main by a re-entry of WSH-3, followed by a well in the West Seahorse NE a year later. It assumes development via wells with gas lift and subsea completions, with all fluids going back to shore to a new build processing plant. Single well production profiles for the West Seahorse Main were generated, based on the P90, P50 and P10 contingent OIP (the 'N' reservoirs).

7.3. PHASED 2 WELL DEVELOPMENT WITH DIFFERENT DEVELOPMENT CONCEPTS

This approach was used to identify the highest value development option. It assumes P50 OIP and the same timing of development as above. i.e. a well in West Seahorse Main, followed by a well in the West Seahorse NE a year later. The development options were designed to consider:

- Gas lift vs electric submersible pumps (ESPs);
- Subsea completion and pipeline to shore vs Mobile Offshore Production Unit (MOPU) and export to Floating Storage and Offtake (FSO) facility;
- New build plant vs tariff though third party facility.

7.4. CONCURRENT MINIMUM 2 WELL DEVELOPMENT

This approach was used to test the value of accelerating production by starting production from two wells concurrently and to test the sensitivity to having a minimum of two wells for security of supply. This case assumes one well in West Seahorse main and one well in West Seahorse NE, but the West Seahorse NE well is sidetracked onto the main reservoir in the event of West Seahorse NE failing. Thus the development has two producing wells in all cases. Production profiles were generated for P90, P50 and P10 OIP for the both structures. A MOPU vs subsea development was also evaluated.

8. WEST SEAHORSE - PRODUCTION FORECASTING

8.1. INITIAL RESERVOIR PRESSURE

RISC notes the GCA/3DO simulation assumes an initial pressure of ~ 1968 psia which allows for the observed depletion to date.

Pressure depletion is apparent in Figure 4-12 between the RFT data in WSH-1 and the MDT data in WSH-3. The RFT data is consistent with the extrapolated pressure from the DST run over the N1 sand in WSH-1. The pressure has declined from ~2030 psia to ~ 1970 psia.

WSH-1 was drilled in 1981 and WSH-3 in 2008. Pressure depletion has been observed in other non-producing fields in the Gippsland basin due to production from nearby fields. The pressure depletion suggests that the regional aquifer is not "infinite acting" although it does provide a strong water drive to the basin. The amount of pressure depletion observed is not sufficient to impact on development plans for the WSH field.

RISC recommends that pressure measurements are taken in any sidetrack of WSH-3 (and any other new wells) to confirm the rate of pressure depletion, so this can be incorporated into updates of the dynamic simulation models of the field.

8.2. INFLOW PERFORMANCE

RISC has reviewed the permeability and test data and believes that the permeabilities assigned by GCA to the N2.6 are too high. RISC estimated the net pay weighted permeability of N2.6 from core data to be 1330 mD and used this as the best estimate. Similarly we reduce GCA's low and high case permeabilities in N2.6 by 33%. The initial well production rates were reduced in line with the reduced KH. The permeability changes are summarised in Table 8-1.

	Permeability Estimates (mD)			
Source	**Level**	**Low**	**Best**	**High**
RISC	N1u	70	180	300
	N1	230	470	700
	N2.6	890	1330	2000
3DO	N1u	54	80	120
	N1	470	700	1050
	N2.6	1340	2000	3000
GCA	N1u	70	180	300
	N1	230	470	700
	N2.6	1340	2000	3000

Table 8-1 Permeability Estimates for West Seahorse Field

The permeability estimates for the N2.6 as used by GCA/3DO are 1340 – 2000 – 3000 mD for Low-Best-High estimates. RISC has been unable to find any convincing corroborating evidence for the high end of this range; a plot of core porosity vs core permeability shows only 2 points above 2000 mD and the majority below 500 mD (Figure 8-1).

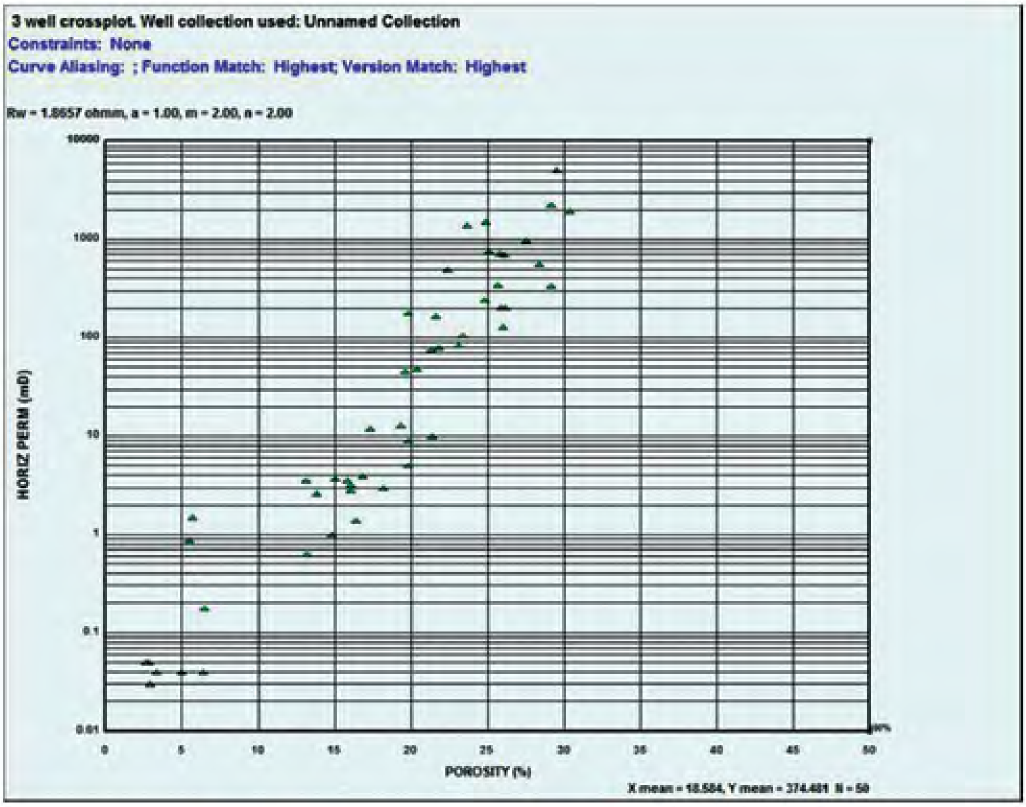

Figure 8-1 Ambient Permeability - Porosity Cross plot from core data

A review of N2.6 mobilities from MDT data in WSH-3 shows a single point with a mobility of 3834 mD/cP and two others around 2000 – 2200 mD/cP. A mobility of 3834 mD/cP corresponds to a permeability of 1900 – 2300 mD assuming mud filtrate viscosities of 0.5 – 0.6 cP.

RISC has been advised of simulated history matches to the Seahorse field carried out on behalf of another operator. 3DO state that this history match provides support for a high end permeability estimate in the N2.6 sand of 3000 mD. RISC does not agree with this view for the following reasons:

- There is no bottom hole pressure in the simulation match;
- No gas lift rates were available;
- The simulation match relies on flow correlations to estimate WHFP and BHP which are inherently uncertain without data correlation points;
- Maximum flow rate from the Seahorse field is circa 8000 bfpd.

Previous work by RISC reviewing flow correlations suggests that errors in the range of +/- 20% can be expected for a number of publically available correlations. (Beggs and Brill (1973), Payne et al (1979), Griffith et al (1973)). We note that the simulation work used a different correlation (Hagerdon and Brown) but we would expect a similar error range.

RISCs opinion is that while 3000 mD may have provided a history match to the Seahorse field the history match is (effectively) unconstrained and that using a permeability of 3000mD for the High (or P10) case is overly optimistic and does not agree with other data.

RISC acknowledges that simulation of West Seahorse shows an initial fluid (oil) rate of 20,000 bfpd is achievable from 2 wells with an N2.6 permeability of 2000 mD. This is higher than RISCs P10 initial rate of 15,000 bfpd. In RISCs opinion the 15,000 bfpd initial rate is appropriate for a valuation scenario given uncertainties in:

- Actual reservoir permeability at both new drill locations;
- Distribution of permeability throughout the reservoir;
- Well completion practices;
- Bottom hole flowing pressures;
- Actual flow rates from the Seahorse field.

RISC suggests that given all of these uncertainties an initial flow rate of 20,000 bfpd represents an outcome that is significantly less probable than appropriate for a P10 case.

In RISC's view, the data indicate that 2000 mD is a better value for the high estimate of (average) permeability in the N2.6 which is a reduction to 2/3 of the 3DO value. We have reduced the low and best estimates by the same ratio.

RISC also notes that GCA has suggested changes to the N1u and N1 permeability estimates used by 3DO and RISC concurs with these changes. It is important to note that the best estimate of permeability for the N1 sand is now in agreement with the recent re-interpretation of the DST over this sand in WSH-1.

The initial inflow of the proposed WSH-3 ST1 well has been simulated by 3DO/GCA. RISC has reduced these initial rates in line with the KH reduction estimated by RISC. The resulting initial rates are shown in Table 8-2.

Well Inflow Performance			
Initial Oil Rate (bopd)	Low	Best	High
GCA Report	8200	9600	10200
RISC Revision	6000	7100	7500
Note:	*Initial Oil rate = Initial Fluid rate*		

Table 8-2 Inflow Performance for proposed ST of WSH-3

8.3. PRODUCTION FORECAST METHODOLOGY

RISC has reviewed various production forecasts prepared by 3DO for internal purposes and from a previous review by GCA, which were derived from a simulation model of the West Seahorse field. RISC has not had access to this model but notes that the forecasts are characteristic of a thin column oil field being produced with a strong water drive; notably a rapid decline in oil rate with a corresponding increase in water rate and near constant total fluid rates. RISC has used these simulated forecasts to create type curves of oil production rate versus cumulative oil (as a fraction of OOIP) as shown in Figure 8-2.

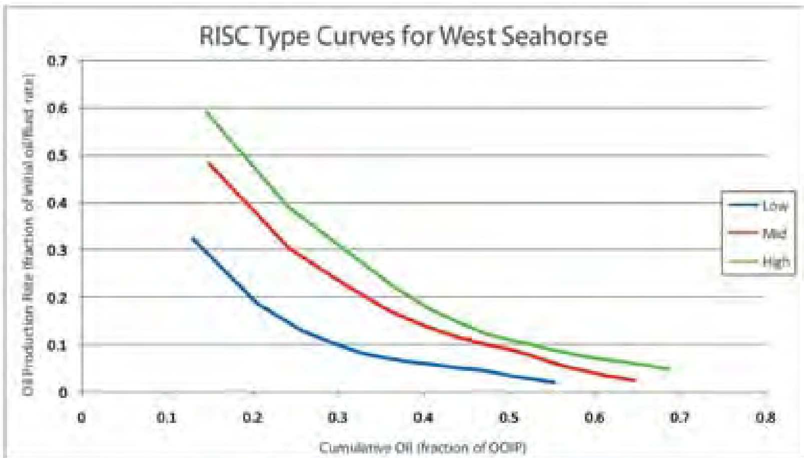

Figure 8-2 Production Forecast Type Curves

The simulated oil recovery factors (55% to 70%) are high by generally accepted world standards but are normal for the Gippsland Basin. The high recovery factors are due to the favourable light oil properties, good reservoir quality and effective aquifer sweep of the small structure, although significant water is produced and the late-life oil rates are correspondingly low.

The type curves can be compared to oil rate verses cumulative oil plots derived from GCA (Figure 8-3). The main difference is that RISC has a smaller separation of the mid and high type curves compared to the GCA 2C and 3C rate-cumulative oil curves. This difference occurs because RISC has used a lower OOIP to generate the high type curve than GCA used to generate their 3C curve. RISC reduced the OOIP by the volume of oil in the NE area of the N1u reservoir (circa 2.3 MMstb on GCA mapping) as we were advised by 3DO that this oil volume was not being drained. This fitted with our observation that if the OOIP nominated by GCA was used to generate the high type curve, it yielded:

- A lower percentage recovery than the mid type curve (over an equivalent time period);
- A similar recovery (71% vs 69%) to the mid type curve when run to abandonment.

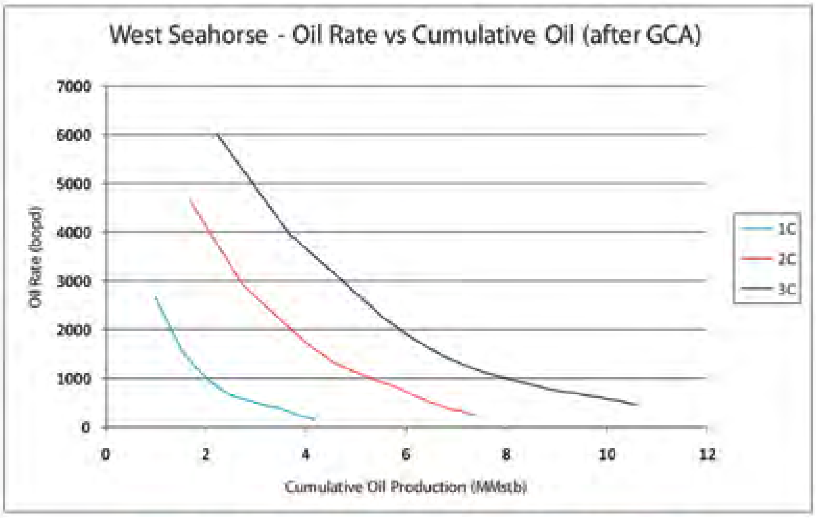

Figure 8-3 Oil Rate vs Cumulative Oil Plot as per GCA Forecast

8.4. DEVELOPMENT SCENARIOS

Once the type curves were generated they were used to generate production forecasts for West Seahorse Main, for the following development cases.

	West Seahorse Development Cases
Number	Description
1	Subsea well (s) with gas lift and flow of all fluids to shore to a new build processing plant
2a	Dry trees with gas lift on a MOPU with oil/water separation and oil/gas sent to shore to existing processing plant
2b	Dry trees with ESPs on a MOPU with oil /water separation and oil/gas sent to shore to existing processing plant
3a	Dry trees with gas lift on a MOPU with oil/water separation and an FSO with oil export by shuttle tanker; gas flared or used for fuel
3b	Dry trees with ESPs on a MOPU with oil/water separation and an FSO with oil export by shuttle tanker; gas flared or used for fuel
Note: Cases 2a - 3b assume water disposed of overboard after treatment	

Table 8-3 Development Cases for West Seahorse Main

The base case field development plan consists of a re-entry of WSH-3 and sidetracking it back to a location near WSH-1 where the N2.6 should be oil saturated. RISC is unaware of the detailed plan for the sidetrack of WSH-3; RISC suggests that the sidetracked well should aim to pass through each reservoir sand at a deviation close to 60° from vertical which will maximize contact with the reservoir. A detailed review of the well path geometry and required bottom hole location(s) should be undertaken to optimise delivery.

RISC expects that drainage of the NE field extension will be limited in a single well development due to water influx and this was confirmed by results from 3DO simulation models.

8.5. WEST SEAHORSE PRODUCTION AND RESOURCE FORECASTS

8.5.1. Single Well Cases for West Seahorse Main

The single well forecasts for West Seahorse Main were done for input evaluation of the 'phased two well development with range of resource outcomes' and 'phased two well development with different development concepts'. Production from a well in the NE pool is described in section 8.5.3. The forecast parameters and recoveries for the initial production licence period are shown in Table 8-4. An economic cut-off must be applied which may reduce the technical oil recovery shown. Similarly production may continue beyond the initial 20 years if economic and if a licence extension is granted. Production is assumed to commence in January 2015.

Case	Scenario	# wells	Initial Rate (bopd)	Downtime %	Technical Recovery to end 2034 (MMstb)	OOIP (MMstb)	RF %
1	Low	1	6000	10	3.5	6.5	54%
	Mid	1	7100	10	5.4	8.2	66%
	High	1	7500	10	7.4	10.5	70%
2a & 3a	Low	1	6000	5	3.6	6.5	55%
	Mid	1	7100	5	5.4	8.2	66%
	High	1	7500	5	7.4	10.5	70%
2b & 3b	Low	1	7000	15	3.6	6.5	55%
	Mid	1	8100	15	5.4	8.2	66%
	High	1	8500	15	7.4	10.5	71%

Note:OOIP is probabilistic sum of N1, N1U and N2.6 reservoirs for main pool only

Case 3a and 3b have identical forecasts to cases 2a and 2b respectively

Technical recovery is to end of 20 year initial production license; an economic cut-off must be applied

Table 8-4 Production Forecast parameters for Development cases - West Seahorse Main

The forecasts show a resource in the range of 3.5 – 7.4 MMstb dependent on the development scenario and the OOIP. The forecasts for the gas lifted subsea wells scenario; gas lifted well on a MOPU and ESP wells on a MOPU are shown in Figure 8-4, Figure 8-5 and Figure 8-6 respectively.

RISC notes that the flowing well head pressure (WHP) in the gas lifted MOPU scenario (cases 2a & 3a) should be lower than for the subsea cases (case 1) as not all of the well fluids are flown to shore. RISC's scope of work excluded detailed flow performance modelling of the wells and gathering systems but we have allowed for the additional initial rate that could be expected in the MOPU case by reducing the downtime. Initial rates and their impact on recovery are discussed in section 8.7.

RISC has applied a nominal 1000 bfpd (barrels of fluid per day) increase in initial oil rate for the ESP completed cases.

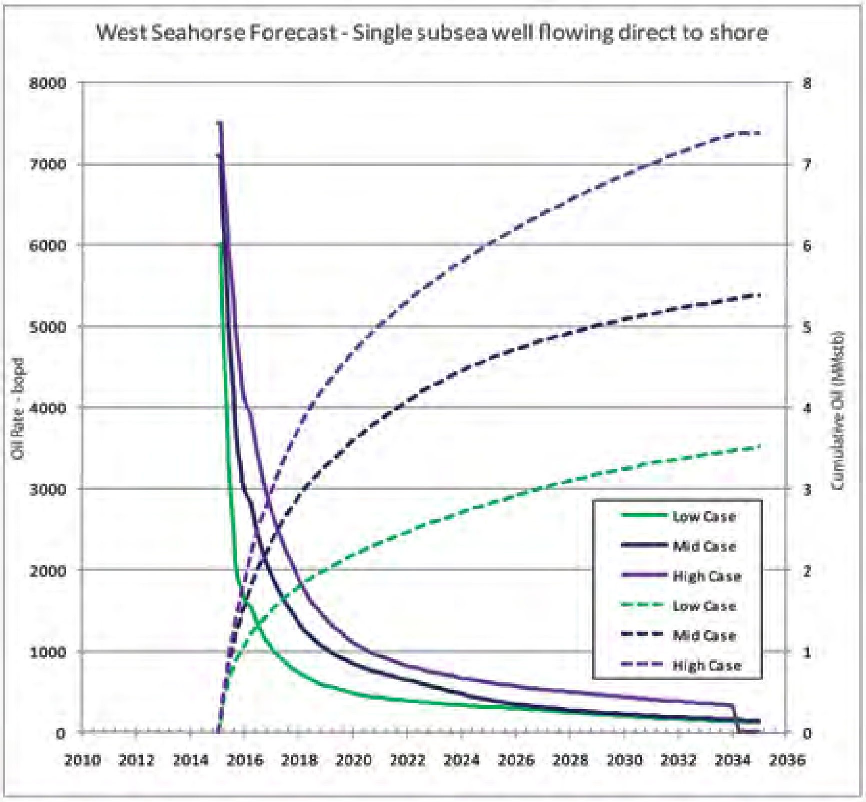

Figure 8-4 West Seahorse Main Production Forecast for single gas lifted well flowing to shore

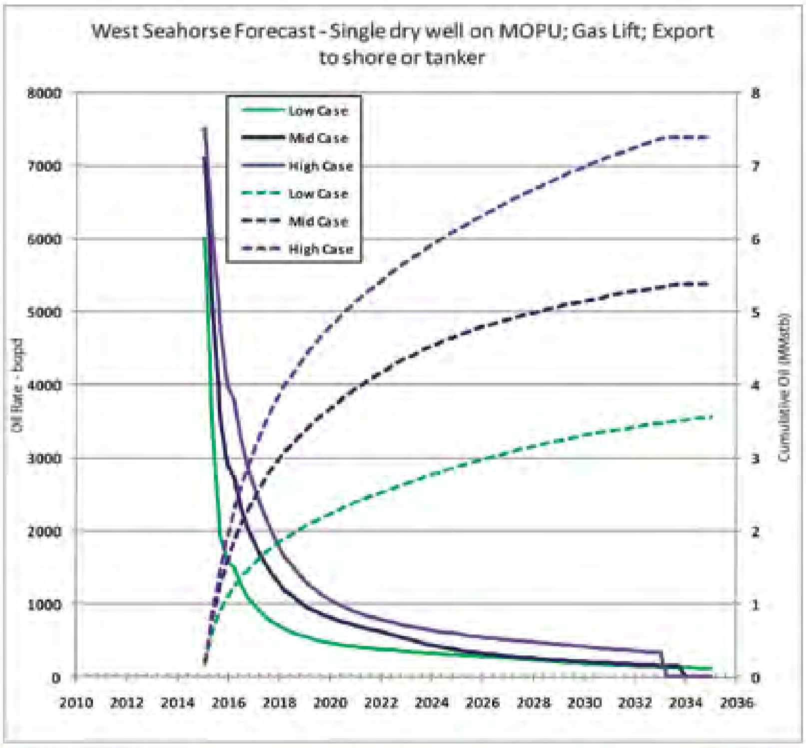

Figure 8-5 West Seahorse Main Production Forecast for single gas lifted well on a MOPU

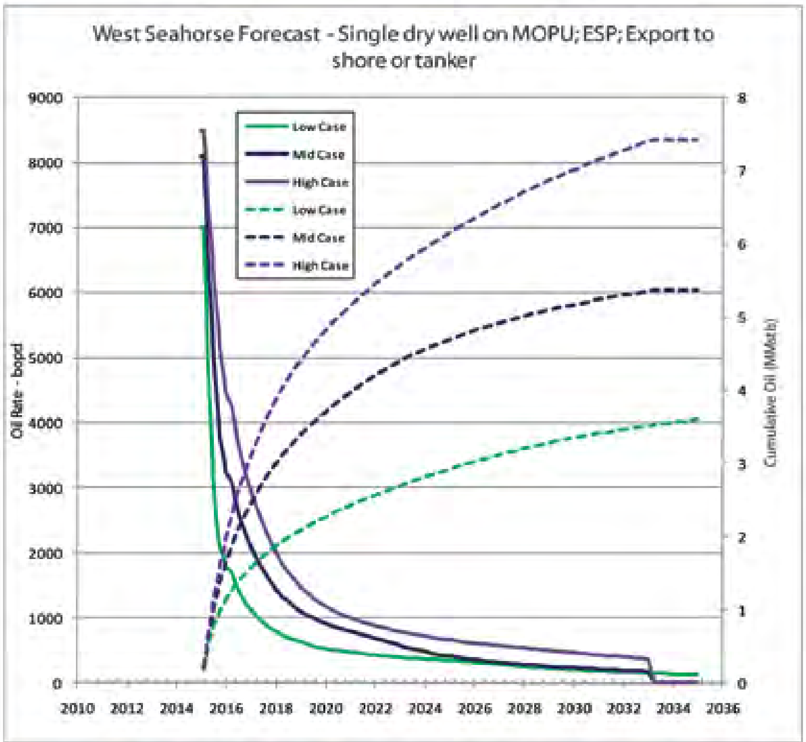

Figure 8-6 West Seahorse Main Production Forecast for single ESP well on a MOPU

8.5.2. Two well concurrent cases

RISC also prepared forecasts for two wells with both wells commencing in January 2015 for input to the 'Minimum concurrent 2 well development ' scenario and the results are tabulated in Table 8-5.

Cases 4 and 6 assumes a well in West Seahorse main and a successful well in West Seahorse NE. Cases 4 and 5 assumes production with subsea completion, while cases 6 and 7 assume production with a MOPU. Cases 5 and 7 assume a failure of West Seahorse NE, leading to a side track to have the second producing well also in West Seahorse Main. All cases assume gas lift.

The forecasting methodology remains as described in section 8.3. In cases 5 and 7 where two wells are completed in the main pool, the wells are assumed to have similar reservoir characteristics so that initial production rates are equal. Cases 4 and 6 have higher recoveries than case 5 and 7 as production from the NE pool is largely independent of the main pool (as evidenced by previous 3DO simulation work, section 8.3). It is notable that producing from two wells in the main pool does not yield incremental recovery compared to a single well; rather production is accelerated. This is a result of the homogeneous reservoir model used to derive the production forecasts. It is likely that the field is more heterogeneous than the model and that ultimate recovery from two wells will be slightly greater than from one well.

Production Forecast Parameters - Two well Cases							
Case	**Scenario**	**# wells**	**Initial Rate**	**Downtime**	**Recovery to end 2034**	**OOIP**	**RF**
			bopd	**%**	**MMstb**	**MMstb**	**%**
4	Low	1 Main, 1 NE	9000	10	4.1	7.6	54%
	Mid	1 Main, 1 NE	11100	10	6.4	9.8	66%
	High	1 Main, 1 NE	12500	10	8.9	12.6	70%
5	Low	2 Main, NE well P&A	12000	10	3.7	6.5	57%
	Mid	2 Main, NE well P&A	14200	10	5.4	8.2	67%
	High	2 Main, NE well P&A	15000	10	7.4	10.5	71%
6	Low	1 Main, 1 NE	9000	5	4.2	7.6	55%
	Mid	1 Main, 1 NE	11100	5	6.4	9.8	66%
	High	1 Main, 1 NE	12500	5	8.9	12.6	70%
7	Low	2 Main, NE well P&A	12000	5	3.5	6.5	54%
	Mid	2 Main, NE well P&A	14200	5	5.4	8.2	66%
	High	2 Main, NE well P&A	15000	5	7.4	10.5	71%

Note: *Cases 4 and 5 - gas lifted subsea wells flowing to shore*
Cases 6 and 7 - gas lifted wells flowing to MOPU and then to shore/FSO
Cases 5 and 7
Well in NE segment P&A, subsequently sidetracked to main field area
Both wells in main segment assumed to have the same initial rate
and brought on line at same time (1/1/2015).

Table 8-5 West Seahorse - Two well cases - Production Forecast Parameters and Recoveries

The production forecast for two wells in the main pool is shown in Figure 8-7 and for one well in each of the main pools and NE pool in Figure 8-8. These two figures show the gas lifted subsea cases. Forecasts for the gas lifted MOPU cases are similar except that downtime is lower at 5% pa for the MOPU case compared to 10% pa in the subsea cases.