Competent Person's Report

PEDL126, Markwells Wood

UK Oil & Gas Investments PLC

Assignment Number: L400157-S00
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Disclaimer

Xodus has made every effort to ensure that the interpretations, conclusions and recommendations presented herein are accurate and reliable in accordance with good industry practice and its own quality management procedures. Xodus does not, however, guarantee the correctness of any such interpretations and shall not be liable or responsible for any loss, costs, damages or expenses incurred or sustained by anyone resulting from any interpretation or recommendation made by any of its officers, agents or employees.

R06	14/09/2015	Final Report	CdG	CdG	CdG	
R05	11/09/2015	Final Draft Report Including Comments from NOMAD	CdG	CdG	CdG	
R04	09/09/2015	Final Draft Report Including Additional Client Comments	CdG	CdG	CdG	
R03	04/09/2015	Final Draft Report Including Additional Client Comments	AOC	CdG	CdG	
R02	28/08/2015	Issued for review following client comments	AOC	CdG	CdG	
R01	10/08/2015	Issued for Review	AOC	CdG	CdG	-
Rev	**Date**	**Description**	**Issued By**	**Checked By**	**Approved By**	**Client Approval**

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The Directors

UK Oil and Gas Investments PLC

Suite 3B, Princes House,

38 Jermyn Street, London, SW1Y 6DN

14 September 2015

Dear Sirs,

Reference: Competent Person's Report

Markwells Wood, PEDL126 Weald Basin, Southern England

In accordance with your instructions, Xodus Group Ltd. (Xodus) has reviewed the Markwells Wood discovery in PEDL126. Only the Middle Jurassic Great Oolite Limestones have been reviewed. These are considered to be developed through conventional petroleum industry methods.

We were requested to provide an independent evaluation of the In Place Hydrocarbons and recoverable volumes expected in accordance with the 2007 Petroleum Resources Management System prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG) and the Society of Petroleum Evaluation Engineers (SPEE)[1]. The results of this work have been presented in accordance with the requirements of the AIM Market of the London Stock Exchange, in particular as described in the "Note for Mining and Oil and Gas Companies - June 2009"[2].

Volumes are expressed as gross Stock Tank Oil Initially In Place volumes (STOIIP) and the recoverable volumes are expressed as gross and net Contingent Resources.

In conducting this review we have utilised information and interpretations supplied by UK Oil & Gas Investments PLC (UKOG), comprising operator information, geological, geophysical, petrophysical, well logs and other data along with various technical reports. We have reviewed the information provided and modified assumptions where we considered this to be appropriate. Site visits were not considered necessary for the purposes of this report.

Standard geological and engineering techniques accepted by the petroleum industry were used in estimating the STOIIP. These techniques rely on geo-scientific interpretation and judgement; hence the resources included in this evaluation are estimates only and should not be construed to be exact quantities. It should be recognised that such estimates of recoverable volumes may increase or decrease in future if more data becomes available and/or there are changes to the technical interpretation.

We acknowledge that this report may be included in its entirety, or portions of this report summarised, in documents prepared by UKOG and its advisers in connection with commercial or financial activities and that such documents, together with this report, may be filed with any stock exchange and other regulatory body and may be published electronically on websites accessible by the public, including UKOG's website.

[1] See references 1 to 4 in Section 6

[2] See reference 5 in Section 6

1 EXECUTIVE SUMMARY

This report has been prepared for UKOG solely on the PEDL126 licence. UKOG also have interests in the following licences: Horse Hill, PEDL137 (UKOG's Economic Interest: 20.358%); Horse Hill, PEDL246 (20.358%); Offshore Isle of Wight, P1916 (77.5%), Horndean PL211 (10%); Avington, PEDL070 (5%); Baxters Copse, PEDL233 (50%); Lidsey, PL241 (4.2%); Brockham, PL235 (3.6%); Holmwood Prospect, PEDL143 (20%).

UK Oil & Gas Investments PLC (UKOG) has a 100% interest in Licence PEDL126. There is no UKOG Director interest in the asset other than indirectly through the Director's shares ownership in UKOG.

The Markwells Wood discovery on the licence was made by the Markwells Wood-1 well (MW-1) which was drilled by Northern Petroleum (now UKOG) in 2010. The MW-1 discovery lies in an approximately 308 foot thick section of the Middle Jurassic Great Oolite Limestone reservoir within a tilted fault block of Later Cimmerian age. The structure is defined by 2D seismic data.

UKOG has carried out an interpretation of the seismic on the licence, incorporating all local well information together with a revised petrophysical evaluation of MW-1 and evaluation of the previous petrophysical work, particularly on determination of fluid contacts and water saturation (Sw). UKOG has used the latest interpretations to assess the Stock Tank Oil Initially In Place (STOIIP) volumes. In addition UKOG has reviewed the interpretation of well test data from MW-1 and used well data from the analogous Horndean field, which lies close by to the west, to estimate future well productivity from a planned horizontal well and to develop a notional field development scenario on which an estimate of recoverable resource volumes has been based.

After further analysis, it is UKOG's intention to initially drill a long horizontal side track off MW-1 and to start production operations. Depending on the results from this side-track, UKOG will then plan additional wells to optimise the overall field economic recovery.

Xodus has independently reviewed the STOIIP and recoverable volume estimates. As such Xodus has reviewed UKOG's seismic interpretation and the underlying Kingdom project, the well data, and related petrophysics reports, dynamic data and analogue field data. Xodus independently derived the STOIIP volume estimates through use of a stochastic simulation software tool, REP, similar to the approach used by UKOG, resulting in a Best Case STOIIP estimate of 45.6 MMbbl. Xodus derived its own recoverable volume estimates by developing a simple dynamic model, built in Petrel and Eclipse software. This model was history matched against the MW-1 Extended Well Test (EWT) production and subsequently used to estimate the productivity of a new horizontal well and to estimate recoverable volumes under Xodus' notional 1C, 2C and 3C field development scenarios.

The simulation results for a horizontal sidetrack well MW-1ST show that well performance is similar to the performance of nearby Horndean wells and the Best Case has a recoverable volume of approximately 400,000 barrels of oil after 20 years and 600,000 barrels after 40 years.

The gross PEDL126 Great Oolite recoverable volume ranges estimated by Xodus are as per the table below. Xodus has classified the volumes as Contingent Resources, being contingent on UKOG achieving both internal and external approvals for a Field Development Plan (FDP) and upon the development been shown to be commercial. The 1C volume estimate is based on a field development of 2 new horizontal wells, whereas the 2C and 3C volume estimates are based on 5 new horizontal wells on the field[3].

[3] Please note that whereas the Xodus simulation model (and resulting production predictions) describes a possible reflection of the actual reservoir performance, that this model is an oversimplification of reality and that many other scenarios are possible. Moreover, Xodus notional field development does not optimise overall recovery, nor does it take into account the commerciality of production from incremental wells. As such, the 1C, 2C and 3C volumes could be higher than those stated in this CPR (e.g. through incremental recovery from infill wells), but the commerciality of the volumes – at the point of upgrading to Reserves status – would be questionable. Xodus believes that its estimates provide a balanced view of Markwells Wood potential at this stage. It is recommended that further reservoir model refinement is done prior to the Field Development Plan submission.

Comparing the Recovery Factor (RF[4]) of these estimated volumes with the RF observed in nearby analogue fields (e.g. Horndean and Singleton which have a RF of up to 7%), indicates that there may be further upside possible beyond the Xodus 3C estimate. Once UKOG has acquired pressure data from the initial horizontal wells, there may be scope for additional infill wells above the 5 wells currently modelled.

Oil Contingent Resources[5]	**Gross Volumes**			**Net to UKOG**			**Risk Factor**	**Operator**
(MMbbl)	**1C[6]**	**2C**	**3C**	**1C**	**2C**	**3C**		
Markwells Wood	0.63	1.25	2.71	0.63	1.25	2.71	75%	UKOG GB Ltd

The Risk Factor[7] was determined to be 75% for these Contingent Resources, to reflect the remaining subsurface, operational, commercial and socio-economical risks related to the development and implementation of the full field, which will likely be significantly influenced by the results from the first horizontal production well.

Conclusions

Xodus has reviewed the available information on the Markwells Wood discovery and concludes that the approach followed by UKOG to estimate the STOIIP is sound and is based on an adequate interpretation of the available data. Xodus considers that the approach followed by UKOG in estimating future well performance, using type curves based on the Horndean analogue wells, to be justifiable. In a different approach Xodus used a simulation model and arrived at results that are in good conformance with UKOG's analogous Horndean well performance. Although no economic analysis was conducted, the expected well performance gives confidence that production from a new well is likely to be commercial.

Xodus derived a 1C, 2C and 3C range of Contingent Resource volume estimates, which it believes provides a reasonable reflection of the potential on the discovery, given the current status of knowledge.

The next UKOG activities will likely focus on further analysis of the reservoir and on developing a detailed Field Development Plan. This would likely include analysis of advanced drilling and completions technologies to further improve the well performance and overall field recovery.

Professional Qualifications

Xodus is an independent, international energy consultancy. Established in 2005, the company has 500+ subsurface and surface focused personnel spread across thirteen offices in Aberdeen, Anglesey, Dubai, Edinburgh, Glasgow, The Hague, Houston, Lagos, London, Orkney, Oslo, Perth and Southampton.

The wells and subsurface division specialise in petroleum reservoir engineering, geology and geophysics and petroleum economics. All of these services are supplied under an accredited ISO9001 quality assurance system.

Except for the provision of professional services on a fee basis, Xodus has no commercial arrangement with any person or company involved in the interest that is the subject of this report.

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4 Recovery Factor is defined as the ratio of the cumulative recoverable oil to STOIIP.

5 Contingent Resources as defined by the PRMS 2007 are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingent Resources are a class of discovered recoverable resources

6 1C, 2C and 3C recoverable resources are as defined in the 2007 Petroleum Resources Management System prepared by the Oil and Gas reserves Committee of the Society of Petroleum Engineers, denoting the Low, Best and High estimate scenario respectively of Contingent Resources

7 Risk Factor for Contingent Resources is defined by AIM guidance notes as the estimated chance, or probability, that the volumes will be commercially extracted.

Chris de Goey is Head of Xodus Advisory in London and was responsible for supervising this evaluation. Chris has a broad commercial background in the energy industry. Starting his career in Shell he then joined Accenture where he worked on market entry, organisational, marketing, performance management and operational solutions for IOCs and European utilities. He subsequently took on management roles in venture capital and corporate finance focusing on oil and gas and renewables. For 3 years prior to joining Xodus Chris led an oil and gas evaluation group, assisting banks, private equity and operators with financing due diligence, delivering competent person reports and feasibility studies. Chris has an MSc in Applied Physics from Delft University. He is a member of the Petroleum Exploration Society of Great Britain and the Society of Petroleum Engineers.

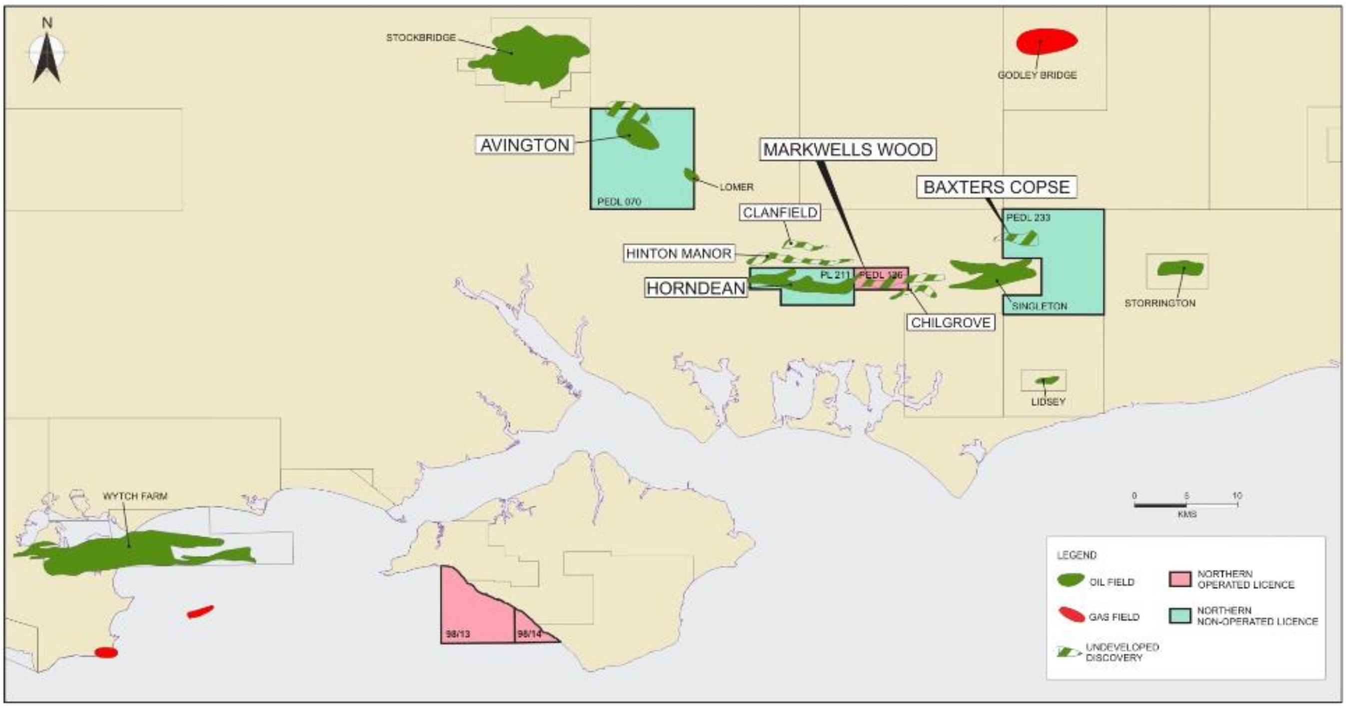
Yours faithfully,

Chris de Goey

Director Advisory, London, Xodus Group Ltd
For and on behalf of Xodus Group Ltd.

2 INTRODUCTION

This report was prepared by Xodus Group Ltd in August 2015 at the request of the Directors of UK Oil & Gas Investments PLC (UKOG, or the Company). It consists of an evaluation of one discovery, Markwells Wood, in PEDL126 in the Weald Basin, in which UKOG holds a 100% interest (Figure 2.1).



Source: NOP, July 2014

Figure 2.1 Location map of UKOG licences including PEDL126

2.1 Licence Details

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Asset, Country	Operator	UKOG Interest	Status	Licence Expiry	Licence Area (km^2)
PEDL126, UK	UKOG	100%	Exploration	30/06/2016	11.2

Table 2.1 Petroleum licence interests

2.2 Sources of Information

The content of this report and our estimates of resources are based on data provided to us by UKOG. We have accepted, without independent verification, the accuracy and completeness of this data.

The data available for review varied depending on the asset and is noted in the body of the report for each asset.

2.3 Requirements

In accordance with your instructions to us we confirm that:

- we are professionally qualified and a member in good standing of a self-regulatory organisation of engineers and/or geoscientists;

- Chris de Goey is a Director of Xodus Advisory, London and was responsible for supervising this evaluation;

- we have at least five years relevant experience in the estimation, assessment and evaluation of oil and gas assets;

- we are independent of the Company, its directors, senior management and advisers;

- we will be remunerated by way of a time-based fee and not by way of a fee that is linked to the value of the Company;

- we are not a sole practitioner;

- we have the relevant and appropriate qualifications, experience and technical knowledge to appraise professionally and independently the assets, being all assets, licences, joint ventures or other arrangements owned by the Company or proposed to be exploited or utilised by it (Assets) and liabilities, being all liabilities, royalty payments, contractual agreements and minimum funding requirements relating to the Company's work programme and Assets (Liabilities).

2.4 Standards Applied

In compiling this report we have used the definitions and guidelines set out in the 2007 Petroleum Resources Management System prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG) and the Society of Petroleum Evaluation Engineers (SPEE).

2.5 No Material Change

We confirm that to our knowledge there has been no material change of circumstances or available information since the effective date of this report and we are not aware of any significant matters, arising from our evaluation, that are not covered within this report which might be of a material nature with respect to the Company valuation.

2.6 Liability

All interpretations and conclusions presented herein are opinions based on inferences from geological, geophysical, or other data. The report represents Xodus' best professional judgment and should not be considered a guarantee of results. Our liability is limited solely to UKOG for the correction of erroneous statements or calculations. The use of this material and report is at the user's own discretion and risk.

2.7 Consent

We hereby consent, and have not revoked such consent, to:

- the inclusion of this report, and a summary of portions of this report, in documents prepared by the Company and its advisers;

- the filing of this report with any stock exchange and other regulatory authority;

- the electronic publication of this report on websites accessible by the public, including a website of the Company; and

- the inclusion of our name in documents prepared in connection to commercial or financial activities.

The report relates specifically and solely to the subject assets and is conditional upon various assumptions that are described herein. The report must therefore, be read in its entirety. This report was provided for the sole use of UKOG on a fee basis. This report may not be reproduced or redistributed, in whole or in part, to any other person or published, in whole or in part, for any other purpose without the express written consent of Xodus.

3 REGIONAL GEOLOGY

The Markwells Wood discovery is situated in the Weald Basin in South Eastern England. The Weald Basin is situated south of London and extends from Southampton and Winchester in the west to Maidstone and Hastings in the east across the counties of East and West Sussex, Kent and Hampshire.

3.1 Background

The Weald Basin is one of three sedimentary basins within a system of post-Variscan depocentres and intra-basinal highs that developed across central southern England and adjacent offshore areas between the Triassic and Tertiary periods.

Adjacent to the Weald Basin is the Wessex-Channel Basin and to the south east lies the Paris Basin (Figure 3.1). The Weald Basin is bounded to the north by the London-Brabant Massif and is separated from the Wessex-Channel and Paris Basins by a regional arch called the Hampshire-Dieppe High.

Figure 3.1 Geologic map of south east England and the English Channel region

3.2 Structure & Stratigraphy

The structural history of the Weald Basin can be divided into three main phases:

1. A pre-Mesozoic period resulting in a platform of Palaeozoic rocks;
2. A Mesozoic period of subsidence and sedimentation;
3. A period of Tertiary uplift and Alpine related basin inversion.

The Weald Basin itself was formed in phase two by rapid subsidence associated with thermal relaxation following early Mesozoic extensional block faulting.

The basin appears initially to have taken the form of an easterly extension of the Wessex Basin but became the major depocentre during the Upper Jurassic and Lower Cretaceous, with associated active faulting.

These movements appear to have ceased prior to Albian times and a full Upper Cretaceous cover is believed to have been deposited in a gentle downwarp, which extended far beyond the confines of the Weald and Wessex Basins.

Major inversion of the Weald Basin took place in the Tertiary, with both gentle regional uplift, which in the eastern part of the basin is estimated to have exceeded 5,000 feet (1525 metres), and intense local uplift along pre-existing zones of weakness, which led to the formation of compressional features such as tight folds and reverse faults. Zones of Tertiary deformation appear to have been strongly influenced by underlying, particularly Hercynian, structural trends.

3.3 Petroleum Systems

The Weald Basin is a proven petroleum system (see Figure 3.2) with several commercial producing fields and discoveries, mostly on the flanks of the basin. Since the early 1980s, oil field production has been from Goodworth, Horndean, Humbly Grove, Palmers Wood, Singleton, Stockbridge and Storrington, and gas production from the Albury field.

Lower Jurassic source rocks reached maturity in the early Cretaceous and initial migration occurred at this time, often over long distances, into traps closed by pre-Aptian faults. Tertiary tilting and uplift led to the breaching of many of these pre-existing traps and the formation of large folded closures. A second phase of hydrocarbon migration, particularly of gas, took place at this time, with significant vertical migration along fault zones.

Major reservoirs located to date occur in Middle Jurassic carbonates and Upper Jurassic sandstones, but deep burial in the basin has caused considerable destruction of primary reservoir characteristics; changes in the temperature and pressure regimes and the mobilization of fluids within the basin resulting from the Tertiary uplift caused further diagenetic changes, particularly in the carbonate reservoirs.

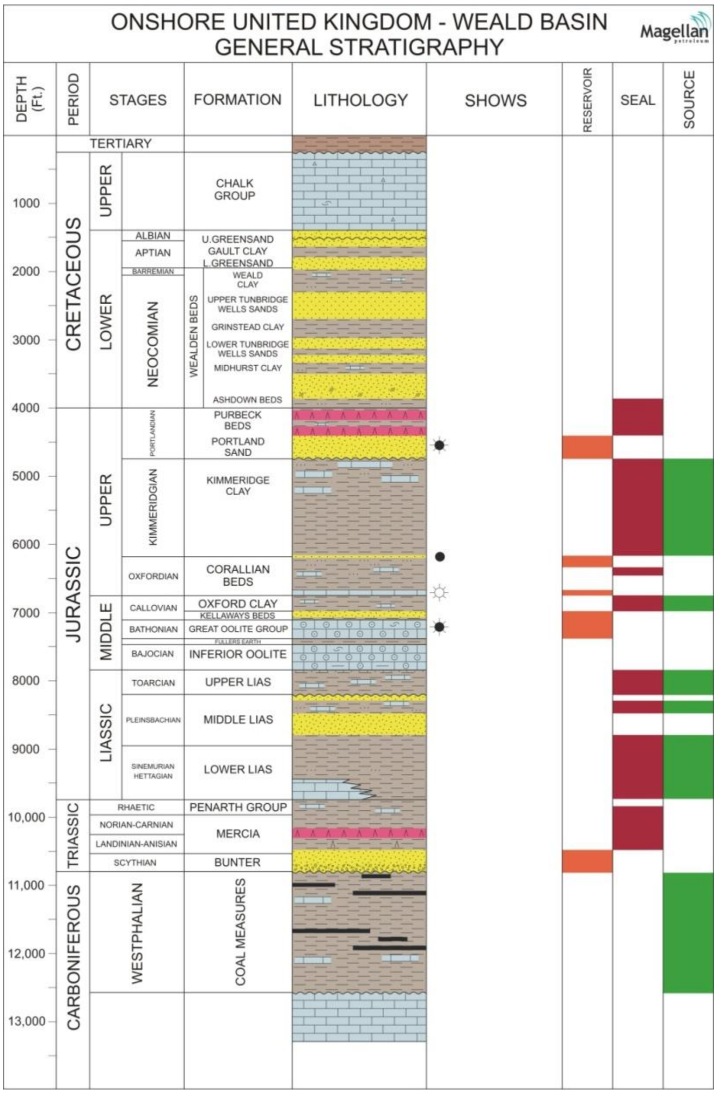


Figure 3.2 Primary Weald proven oil play details

4 MARKWELLS WOOD DISCOVERY

The Markwells Wood discovery was made in 2010 by the Markwells Wood-1 well (MW-1), drilled by Northern Petroleum (now UKOG), which remains the only well on the discovery. Oil was encountered in the Middle Jurassic Great Oolite Limestones.

4.1 Structure

4.1.1 Seismic

The Markwells Wood area is covered by a grid of 2D seismic lines of varying vintages, mainly from the early 1980s (Figure 4.1). The seismic database reviewed was provided as a Kingdom SMT project by UKOG. North to south trending dip lines are spaced between 600m-1200m, with strike lines at a similar spacing.

466 line km of the base seismic dataset were reprocessed in 2010-2011 by GES and have provided a great improvement on the original dataset, allowing improved confidence in both the horizon and fault interpretation over the structure. Data quality in general is deemed to be acceptable for structural mapping. However, some small misties between the seismic still exist in the database. This has been accounted for in mapping, and any small jumps between lines are deemed to be inconsequential to the structural mapping.

Eight main lines cover the field area; with the nearest line to the MW-1 well shown in Figure 4.2, with the line through the highest structural closure shown in Figure 4.3. Picking across the structure is of high quality, while fault mapping appears reasonable, intersecting the main structural breaks. Correlation between lines is good with no obvious jumps in the interpretation.

A single well has been drilled on the field, MW-1. The surface location of the well lies approximately 75m away from the nearest seismic control (line CV85-369). As the well deviates to the south, the well track and seismic line navigation cross, with the effect that at reservoir level they are just 5m apart. As such, it is possible to get a high quality well-seismic tie adding confidence to the accuracy of event picking on the seismic. The well-seismic tie is shown in Figure 4.4. A good fit is achieved using a SEG-Y Positive (Acoustic Impedance Increase = Peak) synthetic Ormsby wavelet, allowing for some small shifts to tie events

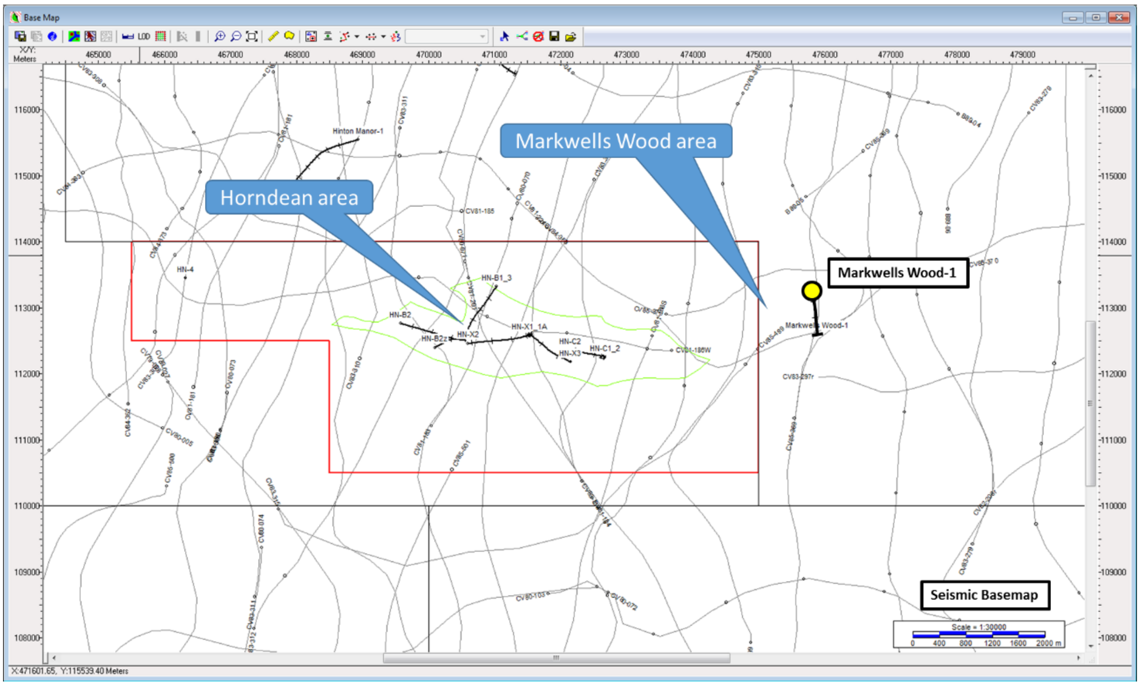


Figure 4.1 Markwells Wood licence area seismic coverage

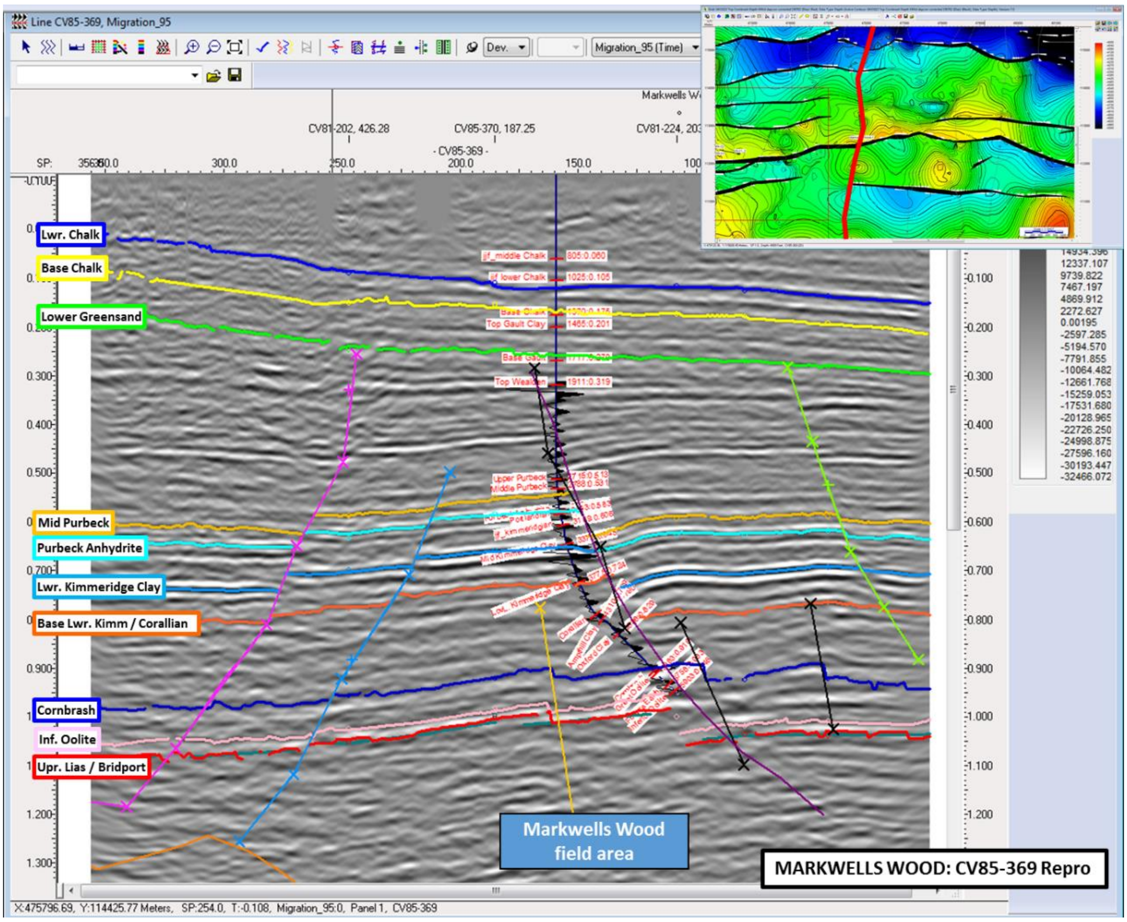


Figure 4.2 Line CV85-369 (reprocessed)

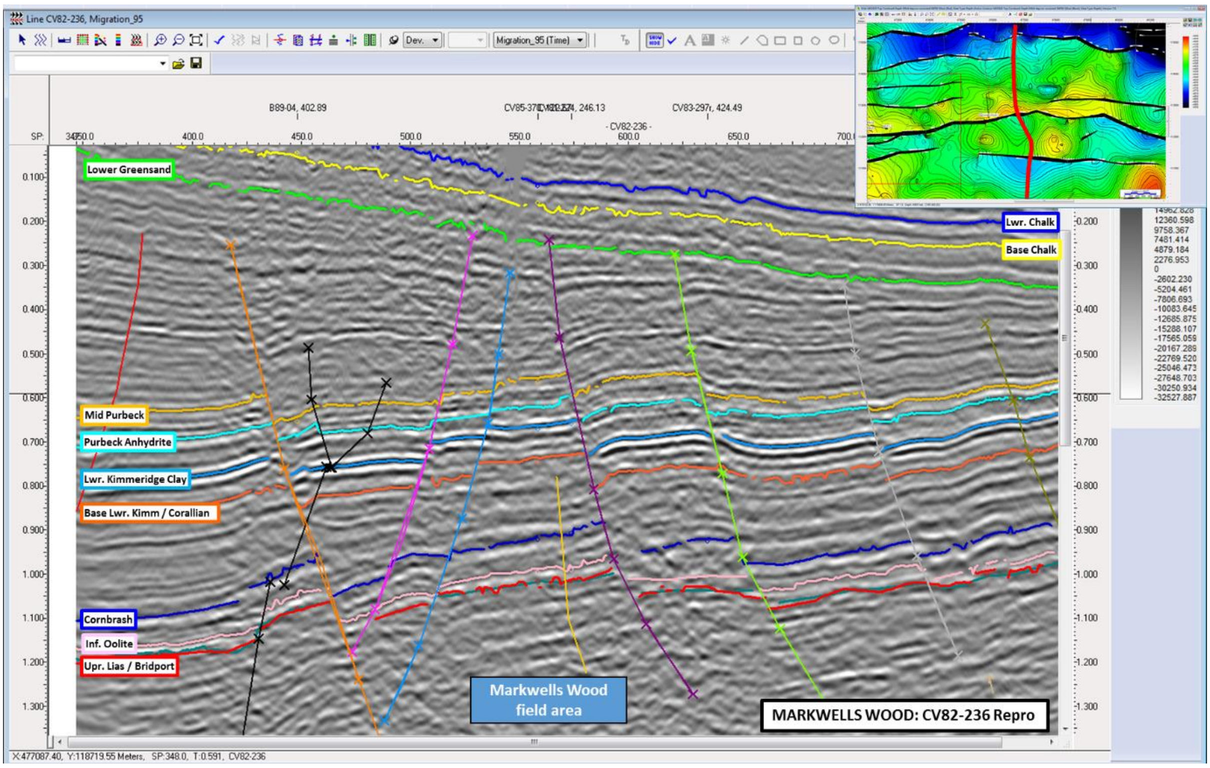


Figure 4.3 Line CV82-236 (reprocessed)

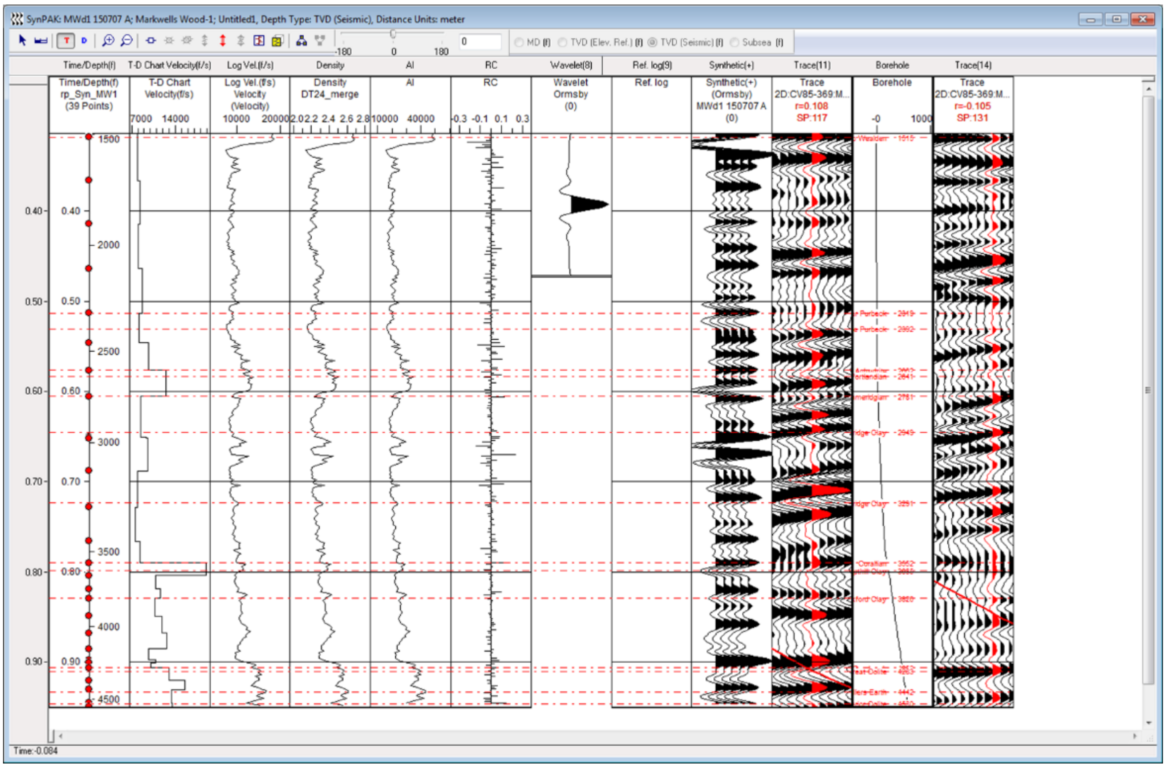


Figure 4.4 MW-1 well-to-seismic tie

4.1.2 Interpretation and Mapping

Xodus have not carried out any independent seismic interpretation or depth conversion. A thorough review has been undertaken and some simple depth conversion sensitivities have been examined. Based upon this review, Xodus believe that the operator's time mapping is considered to be mainly reliable and of a high standard, and that any small amendments considered would be of minor materiality to the structure. Regional TWT interpretation was provided for 11 horizons over the area. Time picks have been gridded at a single level, Top Cornbrash using a grid cell size of 50m x 50m. This cell size is deemed sufficiently fine to avoid over-simplifying and smoothing the structure by using too wide a spacing. The Top Cornbrash TWT grid was subsequently used for input to the depth conversion. Figure 4.5 below shows the Top Cornbrash gridded TWT map.

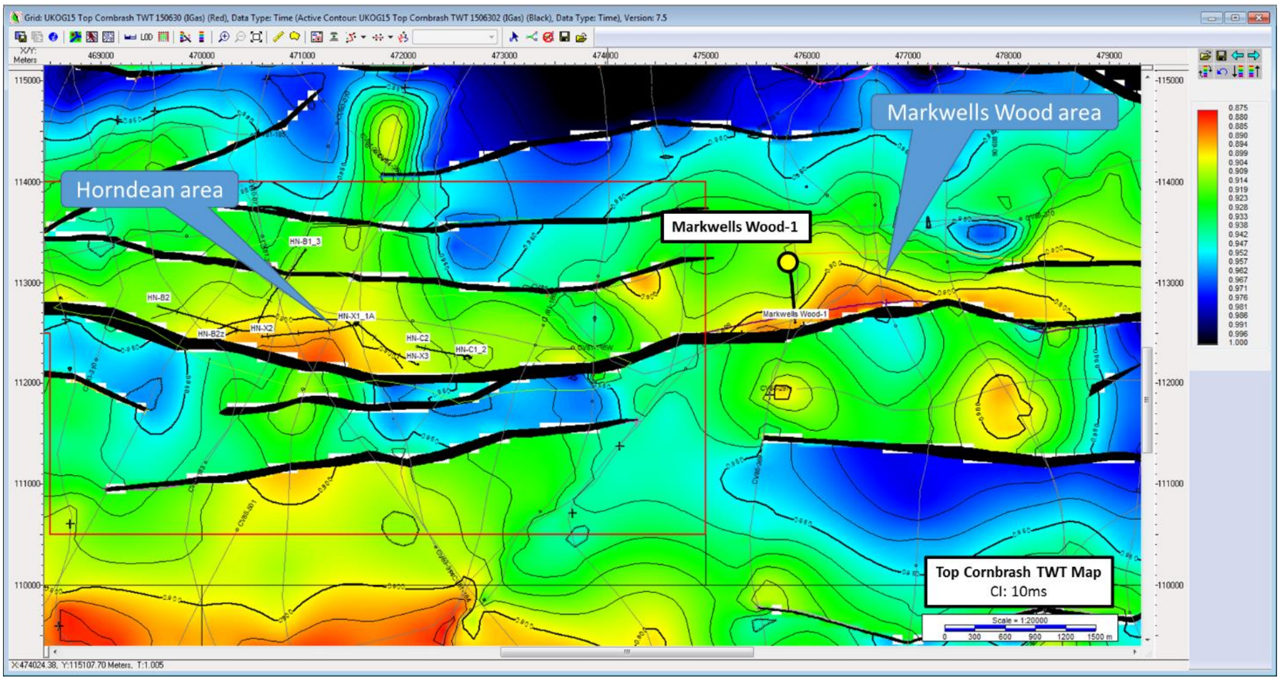


Figure 4.5 Top Cornbrash TWT structure grid (w/faults)

4.1.3 Depth Conversion

The discovery is deemed to be well-defined from seismic time mapping at all horizons over the area. The quality and density of the fault interpretation is deemed sufficient, with the fault polygons providing a good representation of fault heave in the Markwells Wood area.

UKOG have analysed the velocity functions of all nearby wells and found a generally consistent trend in the upper section of all wells to Top Cornbrash. Beneath the Cornbrash, velocity notably increases such that any deeper surfaces would require a different function. Additionally, the nearby (~3,500m to the west) Horndean-C2 well yields a clearly anomalous velocity trend and has been discounted (Figure 4.6).

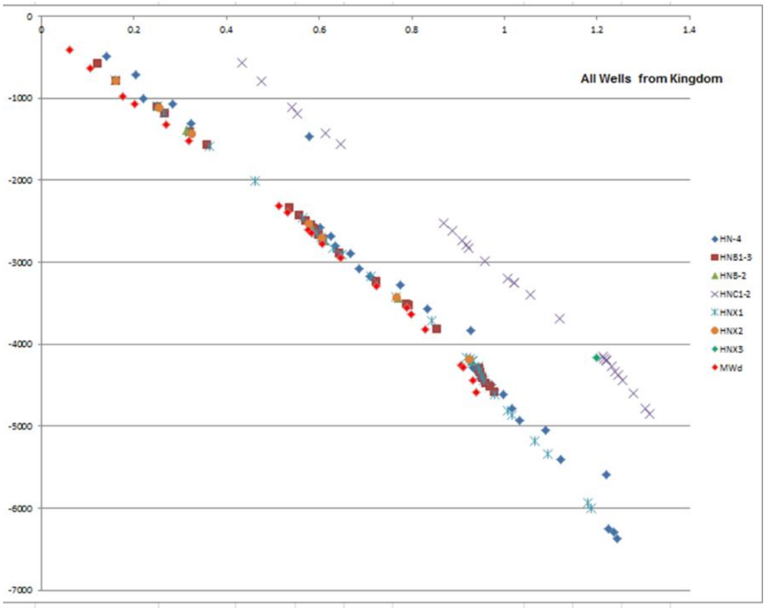


Figure 4.6 **Velocity functions from nearby Horndean wells & MW-1 (red diamonds)**[8]

Based upon consistent velocity function observed (removing the anomalous Horndean-C2 well), a depth conversion of the Top Cornbrash marker has been carried out, with residuals to the wells subsequently handled via a correction grid. Residuals from the initial depth conversion were all noted to be consistently deeper than actual depths, and all were noted to be greater than 100ft.

During the depth conversion the following function was applied:

$$Z = -1198.48*TWT^2 – 3337.46*TWT – 295.84$$

The top reservoir depth map is shown in Figure 4.7.

[8] Note HNC1-2 lying anomalously off-trend to the other wells

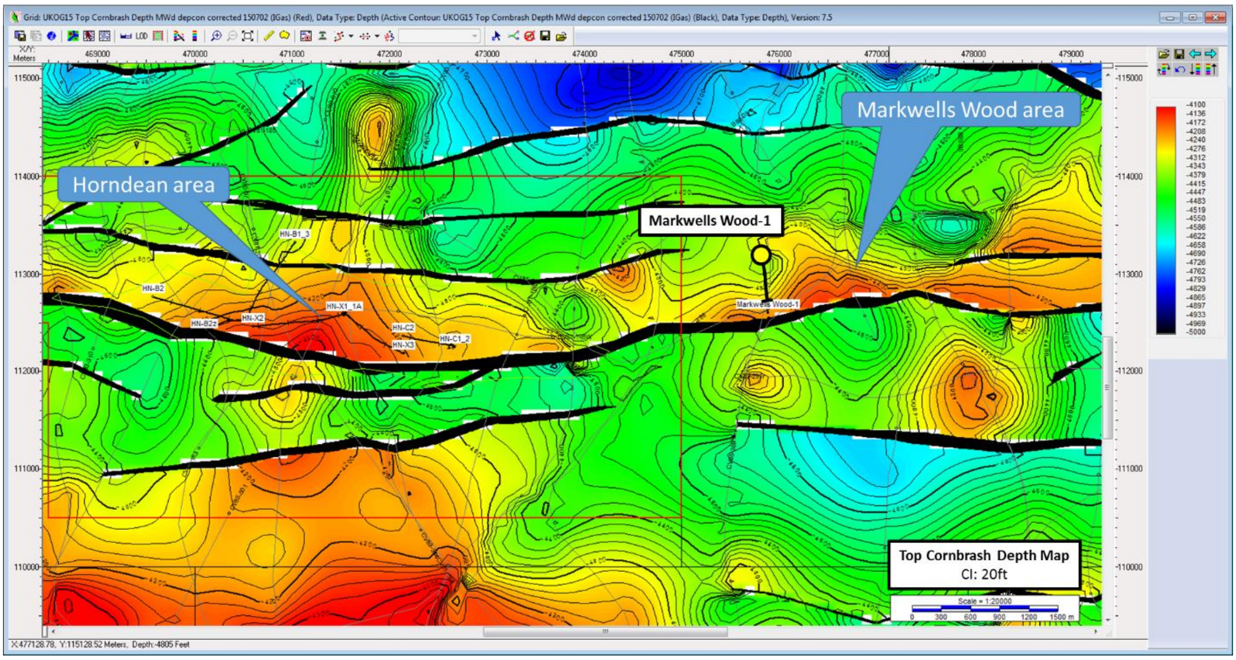


Figure 4.7 Top Cornbrash depth grid

The discovery is deemed to be well-defined from seismic time mapping at all horizons over the area. Both horizon and fault mapping appear robust and are good technical representations of the subsurface structure. However, it is recognised that some uncertainty will naturally exist in the mapping due to data availability.

Depth conversion, while simplistic in the area, is wholly compatible with the field area and control available, without over-complicating the process (deemed unnecessary due to the consistent velocity profile observed in the wells).

4.2 Reservoir

The reservoir of the Markwells Wood discovery is the Great Oolite Limestone formation, which is a common reservoir unit in the Weald Basin. The Markwells Wood well encountered 308 ft of the Great Oolite reservoirs from the top of the Cornbrash to the base of the Lower Massive Oolite / top of the Fullers Earth which was logged and cored.

The Great Oolite is a stacked sequence of oolite shoals, which was deposited in the Middle Jurassic on an open marine, carbonate ramp similar to that seen in the Bahamas Bank in the present day. The reservoir rock is generally a clean oolitic limestone with minor argillaceous horizons, the main reservoir facies are oolitic peloidal grainstones and packstones but the best reservoir units are cross-stratified oolitic grainstones. Finer grained intervals composed of less well-sorted wackestones and mudstone are generally non-reservoir. The reservoir has also been subject to complex diagenesis, which has created both additional moldic porosity and calcite cements resulting in poorly connected pore spaces and low permeability. The average porosity of the reservoir is about 15%, but permeability is commonly less than 1mD. The low permeability leads to high capillary entry pressures and a transition zone above the free water level that extends over approximately 500 ft.

The reservoir is split into 5 zones.

- The Cornbrash – comprises shales and argillaceous limestones which have low porosity and permeability; there is some localised porosity development related to dolomitisation
- Interbedded Oolite – has variable thickness and facies with moderate porosity, which is mostly intra particle and poorly connected. Sediments were deposited in small scale oolite bars and washover deposits

- Upper Massive Oolite – this is the best reservoir interval and was deposited as tide dominated oolitic shoals which have formed metre scale bedding; they also have mainly intra-particle porosity but it is enhanced by moldic porosity which improves permeability
- Oncolites – composed of burrowed mudstones the oncolites have low porosity and permeability
- Lower Massive Oolite – good reservoir of well-sorted packstones and grainstones deposited on oolitic shoals; intra-particle porosity is developed with some enhancement resulting from dissolution but reduced by cementation. In Markwells Wood this zone is close to the FWL and therefore water saturation is extremely high.

A geological summary of the Great Oolite was available and demonstrates the lateral continuity and thickness variations in the different zones along strike in the analogue fields of Horndean to the west and Chilgrove to the east. An isopach map generated from well data shows Markwells Wood to be on the edge of a thick oolite shoal. Reservoir quality is observed to decrease to the east, off the shoal, but is locally variable. Reservoir properties are comparable across the analogue wells.

A detailed petrophysical study was available for the Markwells Wood well and the nearby wells from analogue fields Horndean and Chilgrove. Xodus has not carried out a detailed audit of the petrophysical interpretation, but has found the methodology applied to be in good practice and the results consistent with the values expected from similar reservoir units in the Weald basin. Figure 4.8 shows the MW-1 CPI.

All formations are seen to be petrophysically similar across the three fields / discoveries; porosities vary from 6-18% and permeability is less than 5mD, Markwells Wood fits into the middle of this range. A thick transition zone of over 500ft is assumed because of the high entry pressure and different oil water contacts are expected depending on the reservoir properties. An Oil Down To (ODT) is recorded in MW-1 at 4,400 ft TVDSS. A number of different methods has been used to calculate water saturation and determine the Free Water Level (FWL). Using a Sw height method, a FWL of 4,590 ft TVDSS has been calculated and this has been used as the basis for assigning Oil Water Contact (OWC) depths for volumetrics. The results of the petrophysical study have been used in the determination of STOIIP.

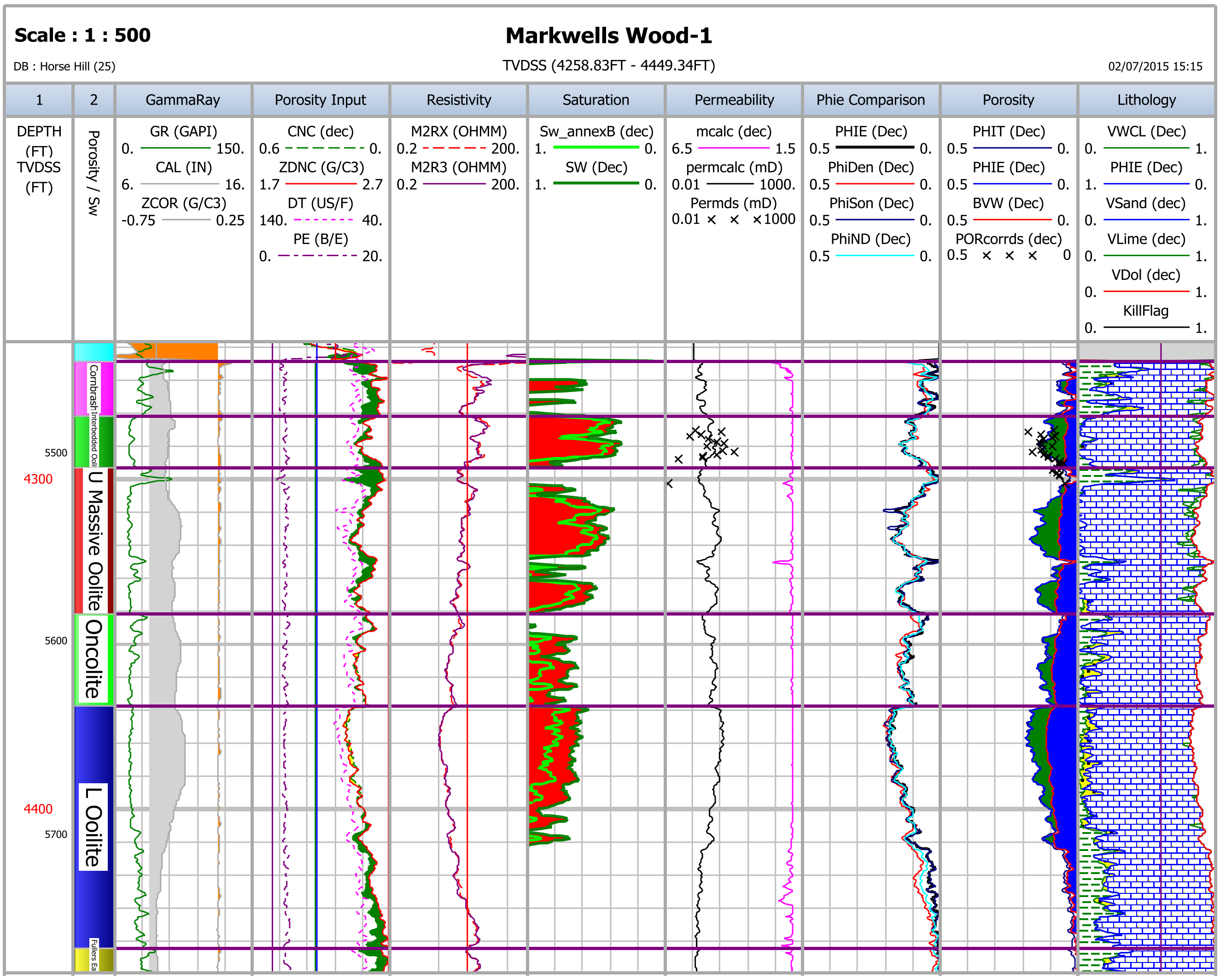


Figure 4.8 MW-1 CPI across the Great Oolite formation

4.3 Hydrocarbon In Place Estimates

4.3.1 Approach

Xodus' STOIIP values were calculated stochastically using REP5 software from Logicom E&P. Xodus has followed the approach applied by UKOG in calculating volumes for each reservoir zone and has found the values and ranges used by UKOG to generally be fair, although some adjustments have been made where deemed appropriate.

For the purposes of Gross Rock Volume (GRV) and STOIIP calculations, the top reservoir map was loaded into Petrel. Figure 4.9 shows the top reservoir map with the polygons used in Petrel for determining GRVs.

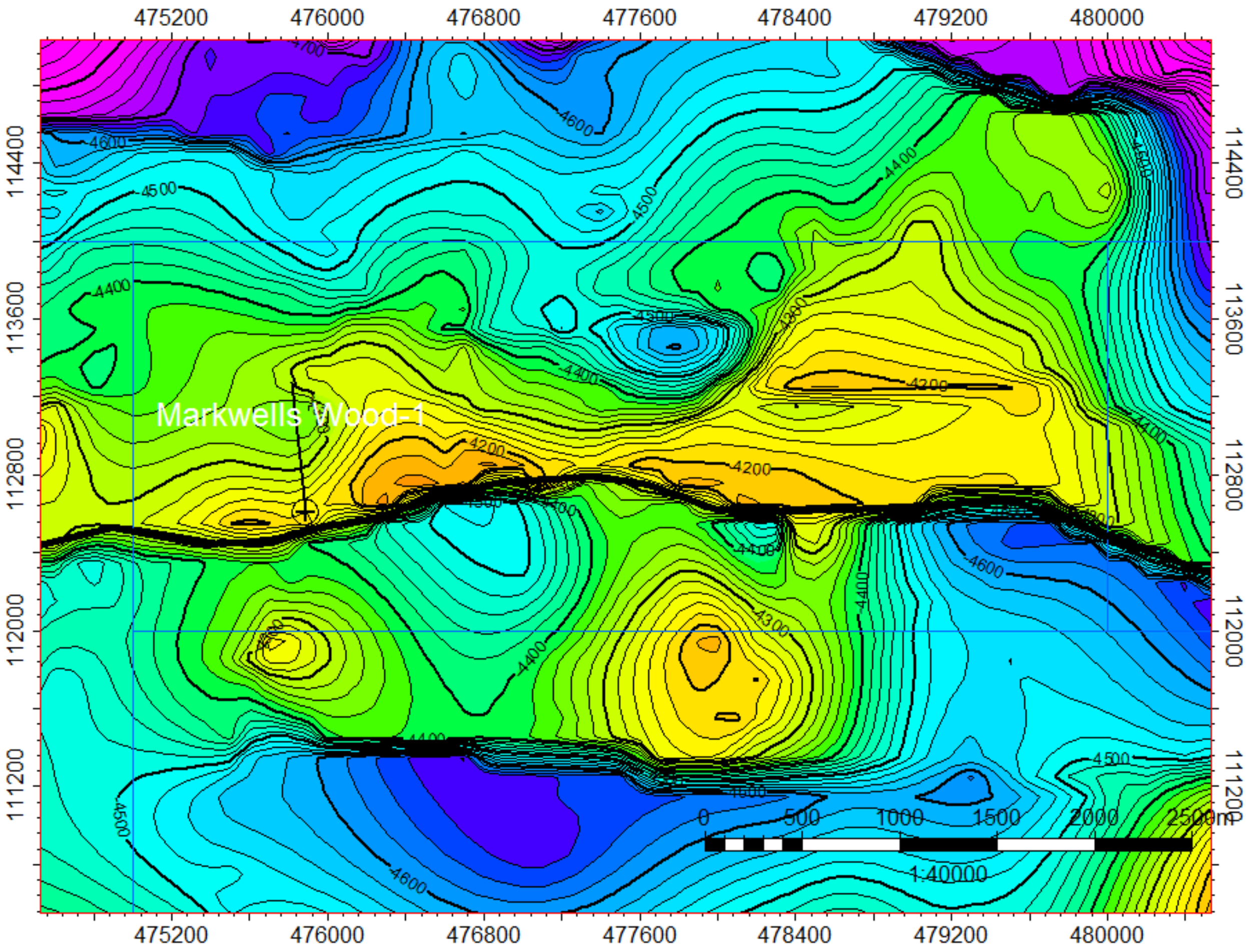


Figure 4.9 Map showing top Cornbrash

Area depth data was calculated using Petrel software for the Cornbrash map within the structural boundaries; polygons were used to define the fault block. For the other reservoir zones, a shift was applied to the top input data to account for the thickness of the overlying units to generate top structure maps for each zone. Zones cannot be mapped individually from seismic data. The REP files from UKOG contained a depth shift for each reservoir zone to isopach down from the top reservoir map to the top of each zone. These were not changed by Xodus, but rather than a single depth shift, a range has been applied with a beta distribution. The minimum shift is generally the thickness from the MW-1 well and in the mid and high case by the thicknesses from the Chilgrove-1 well and Horndean-2 well, which are the closest wells to Markwells Wood.

The OWC has been taken from the petrophysical interpretation work. The FWL was calculated as 4,590 ft TVDSS and the OWC is thought to be 160ft shallower than this. A deeper contact has been assumed in the higher quality Upper Massive Oolite and shallower contact in the Cornbrash and Oncolite.

Reservoir thicknesses were taken from the gross thicknesses observed in the wells. A normal distribution was generated using the MW-1 well thickness and either the Chilgrove-1 well or the Horndean-2 well, depending on which was the most appropriate in relation to the overall well correlation and observed regional thickness changes.

Net to gross, porosity and water saturation have been taken from the results of the petrophysical interpretation of the same three wells. Ranges and distributions for these parameters were generated using a similar method to reservoir thickness, as described above.

Formation Volume Factor (FVF) and Gas Oil Ratios (GOR) have been accepted by Xodus and are unchanged from the UKOG inputs.

Cornbrash	Unit	Shape	Min	P90	P50	P10	Max	Mode	Mean
Thickness	ft	Normal	4.3	11	16	21	27.7	16	16
Area uncertainty	%	Normal	41.5	75	100	125	159	100	100
OWC	ft	Normal	4283	4350	4400	4450	4517	4400	4400
Net-to-gross	%	Beta	1.5	2.42	5.25	10	20	3.3	5.78
Porosity	%	Normal	7.19	8.4	9.3	10.2	11.4	9.3	9.3
Sw	%	Normal	25.6	42.2	54.6	67	83.6	54.6	54.6
FVF (Bo)	rb/stb	Normal	0.976	1.04	1.09	1.14	1.2	1.09	1.09
GOR	scf/bbl	Lognor	12	25	43.3	75	157	36	47.5

Interbedded Oolite	Unit	Shape	Min	P90	P50	P10	Max	Mode	Mean
Thickness	ft	Normal	0	15.5	27.8	40	56.4	27.8	27.8
Shift Top Reservoir	ft	Beta	7.28	11.2	18	27	40.5	16	18.6
Area uncertainty	%	Normal	41.5	75	100	125	159	100	100
OWC	ft	Normal	4360	4400	4430	4460	4500	4430	4430
Net-to-gross	%	Normal	51.4	64.9	74.9	85	98.5	74.9	74.9
Porosity	%	Normal	7.25	9.4	11	12.6	14.7	11	11
Sw	%	Normal	28.6	39.7	48	56.2	67.3	48	48
FVF (Bo)	rb/stb	Normal	0.976	1.04	1.09	1.14	1.2	1.09	1.09
GOR	scf/bbl	Lognor	12	25	43.3	75	157	36	47.5

U Massive Oolite	Unit	Shape	Min	P90	P50	P10	Max	Mode	Mean
Thickness	ft	Normal	29.6	44.6	55.8	67	82	55.8	55.8
Shift Top Reservoir	ft	Beta	22	31.5	47.1	67	95.9	43	48.3
Area uncertainty	%	Normal	41.5	75	100	125	159	100	100
OWC	ft	Normal	4360	4400	4430	4460	4500	4430	4430
Net-to-gross	%	Normal	57.6	69	77.5	86	97.4	77.5	77.5
Porosity	%	Normal	9.59	11.5	12.9	14.3	16.2	12.9	12.9
Sw	%	Normal	35.9	45.6	52.8	60	69.7	52.8	52.8
FVF (Bo)	rb/stb	Normal	0.976	1.04	1.09	1.14	1.2	1.09	1.09
GOR	scf/bbl	Lognor	12	25	43.3	75	157	36	47.5

Oncolite	Unit	Shape	Min	P90	P50	P10	Max	Mode	Mean
Thickness	ft	Beta	14	20.7	28.5	36.9	46	28	28.7
Shift Top Reservoir	ft	Beta	65.8	76	95	121	162	88.5	97
Area uncertainty	%	Normal	41.5	75	100	125	159	100	100
OWC	ft	Normal	4372	4383	4391	4399	4410	4391	4391
Net-to-gross	%	Beta	1	30.4	50.7	67	77	55	49.7
Porosity	%	Normal	5.12	7.8	9.8	11.8	14.5	9.8	9.8
Sw	%	Normal	60.7	72.9	82	91.1	103	82	82
FVF (Bo)	rb/stb	Normal	0.976	1.04	1.09	1.14	1.2	1.09	1.09
GOR	scf/bbl	Lognor	12	25	43.3	75	157	36	47.5

L Massive Oolite	Unit	Shape	Min	P90	P50	P10	Max	Mode	Mean
Thickness	ft	Lognor	40.6	57	73.4	94.5	133	70.6	74.8
Shift Top Reservoir	ft	Beta	93.9	103	123	153	206	114	126
Area uncertainty	%	Normal	41.5	75	100	125	159	100	100
OWC	ft	Beta	4360	4400	4430	4460	4500	4430	4430
Net-to-gross	%	Beta	43	47.9	57.6	71	93	54	58.7
Porosity	%	Normal	5.1	10.2	14	17.8	22.9	14	14
Sw	%	Normal	56	64	70	76	84	70	70
FVF (Bo)	rb/stb	Normal	0.976	1.04	1.09	1.14	1.2	1.09	1.09
GOR	scf/bbl	Lognor	12	25	43.3	75	157	36	47.5

Table 4.1 Parameters used in the estimation of STOIIP

4.3.2 In Place Volumes

Having loaded the above surfaces and parameters in REP, the model was then run for 10,000 iterations. Table 4.2 shows Xodus' Gross STOIIP estimates for the Markwells Wood discovery for the whole structure. Because of the stochastic nature of the calculations and because the volumes were separately derived for each zone, the totals are stochastic sums and do not sum together arithmetically.

STOIIP (MMbbl)	Low	Best	High	Mean
Cornbrash	0.15	0.37	0.89	0.46
Interbedded Oolite	6.74	13.4	22.9	14.3

Upper Massive Oolite	13.8	22.4	35.0	23.6
Oncolite	0.36	0.98	2.09	1.13
Lower Massive Oolite	2.66	6.3	12.4	7.07
Markwells Wood Total	**32.7**	**45.6**	**61.8**	**46.6**

Table 4.2 Xodus' Markwells Wood gross STOIIP estimate

Xodus' calculated STOIIP for Markwells Wood is very close to that determined by UKOG as shown in Table 4.3.

STOIIP (MMbbl)	Low	Best	High	Mean
Markwells Wood (Gross 100%)	33.7	46.5	63.0	47.6

Table 4.3 UKOG's Markwells Wood gross STOIIP estimate

4.4 Production History and Review of Reservoir Dynamic Behaviour

MW-1 produced during an Extended Well Test (EWT) and the well was then shut in by the previous operator of the licence. The nearby Horndean field has seen some success with horizontal wells and UKOG believes that this success can be reproduced on Markwells Wood. As such, UKOG has modelled well performance for a future horizontal producer (a horizontal well drilled as an up-dip sidetrack of MW-1) on the worst performing horizontal Horndean well (Horndean-X3). Xodus agrees with UKOG that this is a prudent approach, also when taking into account the option to drill longer well trajectories and to apply modern well completion and reservoir stimulation technologies which may further enhance well productivity.

Nevertheless, Xodus took a different approach to determine reservoir productivity and well performance, taking the MW-1 EWT data into account.

A numerical reservoir model has been developed using Eclipse reservoir simulation software. A simple reservoir model was built in Petrel using the latest top reservoir grids and thicknesses of reservoir zones from MW-1. The model was populated with porosity and net to gross based on the petrophysical interpretations provided by UKOG. All reservoir parameters were kept constant within each layer in the model.

The dynamic data provided was reviewed and used for defining other parameters. Where data was not available values from the nearby Horndean field were taken as a good analogue.

4.4.1 MW-1 Extended Well Test (Production History)

MW-1 was tested from December 2011 to May 2012 and produced 3,931 bbl in total during that period. Figure 4.10 shows the results of the test. The EWT has previously been studied by OPC[9] who concluded that a dual porosity model should be used to match the test results.

[9] A Review of the Performance of Markwells Wood 1, Onshore UK, Oilfield Production Consultants (OPC) Ltd, 31 October 2012

It should be noted that there was evidence of wax production during the EWT, which may have restricted production rates. This is evidenced by the recovery in production immediately following the hot oil de-waxing treatments.

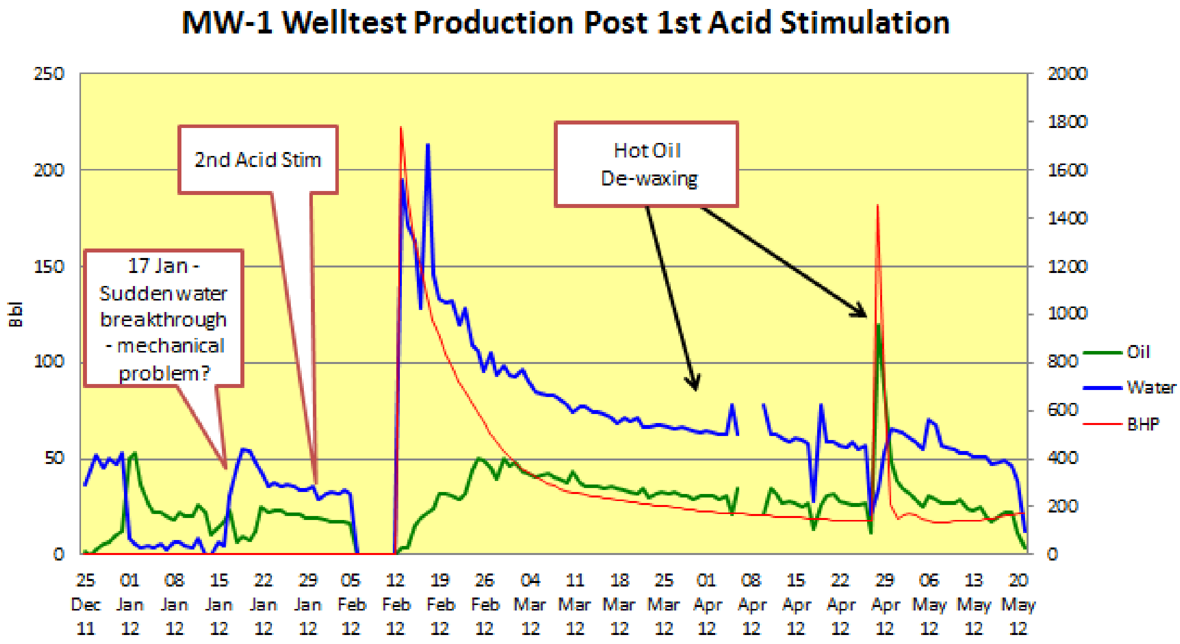
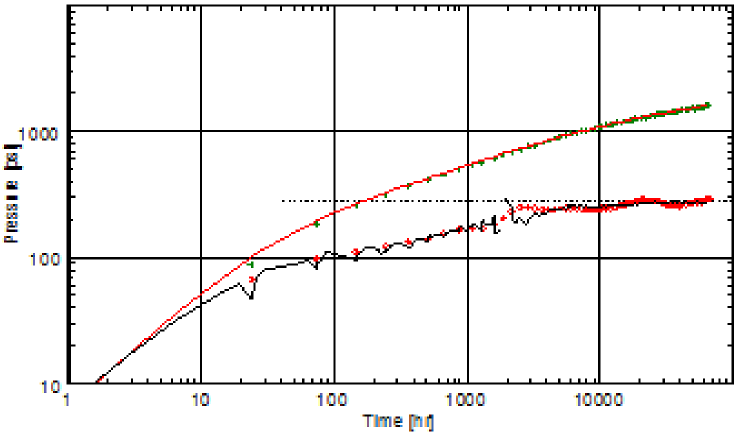


Figure 4.10 MW-1 extended well test

As part of Xodus' review, the OPC interpretation has been revisited to check whether an alternative model can be proposed.

Due to the short durations of the build-ups (BU) in the MW-1 EWT it is not possible to identify any characteristic reservoir flow regimes. Analysis of the drawdown data shows greater uncertainties as it is very much dependent on the accuracy of the rate measurement.

As gauge data were not available, the Bottom Hole Pressure (BHP) was digitised from the OPC report to allow analysis. Rate curves and pressure curves were smoothed for the analysis, see Figure 4.11.



Log-Log plot: (p-p@dt=0).Q/[qn-qn-1] and derivative [psi] vs dt [hr]

Figure 4.11 Log-log plot of MW-1 drawdown

The derivative of the slope shows the influence of the fracture followed by a period of stabilisation, supporting the OPC interpretation. Xodus' interpretation of the part of the EWT between 12th February 2012 and 28th April 2012 is that the well intersects a fracture of 138 ft half-length and reservoir permeability of 37mD ft. After taking into account the relative permeabilities of the oil and water (the well produced 69% water) a single-phase permeability of 95 mD ft is calculated from the MW-1 well test. Assuming flow from the Upper Massive Oolite only, as this is the highest quality reservoir zone with a thickness of 40 ft, an average permeability of 2.4mD is determined, applying a lognormal distribution gives a distribution which can be used in modelling as shown in the following table.

Permeability	P90	P50	P10
k, mD	1.6	2.4	3.4

Table 4.4 Permeability assumptions used in Xodus modelling

Porosity and Permeability

Air permeability measured on cores varies from 0.1 mD to 10 mD with no reliable correlation between permeability and porosity, even when considering different facies. The porosity-permeability transform from the OPC report was used to generate permeability in the model from the modelled porosity; a permeability multiplier was applied where it is thought the Upper Massive Oolite has the best permeability.

The horizontal permeability is assumed to be isotropic and a ratio of vertical to horizontal permeability (kv/kh) was used as an input for the vertical permeability. This ratio has no impact on the MW-1 history match, but is however important in forecasting the performance of a horizontal well.

PVT

No PVT data is available for Markwells Wood. PVT assumptions are as reported in the Horndean oil field, Field Development Plan, June 1988[10]. The parameters are summarised in the table below.

[10] The Horndean oilfield, Field Development and Production Programme, Annex B, submission to the Department of Energy, Carless Exploration Ltd, June 1988

Reservoir Parameters	
Reservoir Datum	4,374 ft TVDSS
Pressure at Datum	2,026 psia
Temperature at Datum	142 °F
Saturation Pressure (Bubble point pressure	363 psia
Viscosity at initial conditions	1.65 cP
Fluid density at initial conditions	0.783 g/cc
FVF at initial conditions	1.135 res bbl/st bbl
Solution Gas Oil Ratio (Rs)	168 scf/stb
Compressibility above Pbpt:	8.22 x 10^{-6} vol/vol/psi^{-1}
Gravity of residual oil:	35.4 °API
Wax content of residual oil	10.6% w/w
Water Properties	
Total solids	99650 mg/l
Based upon Correlations	
Compressibility cw	2.5 10^{-6} psi^{-1}
Volume factor: Bw	1.015
Viscosity at datum conditions	0.6 cp

Table 4.5 Summary of PVT parameters from Horndean field

Water Saturation

Initial water saturation and relative permeability curves were taken from the Horndean-2 well as no capillary curves have been measured on MW-1. An irreducible water saturation of 30% and a residual oil saturation of 30% were used. These parameters were not changed for the history match. An OWC at 4400 ft TVDSS was used, with FWL assumed to be 160 ft deeper. Figure 4.12 shows the water saturation in the model.

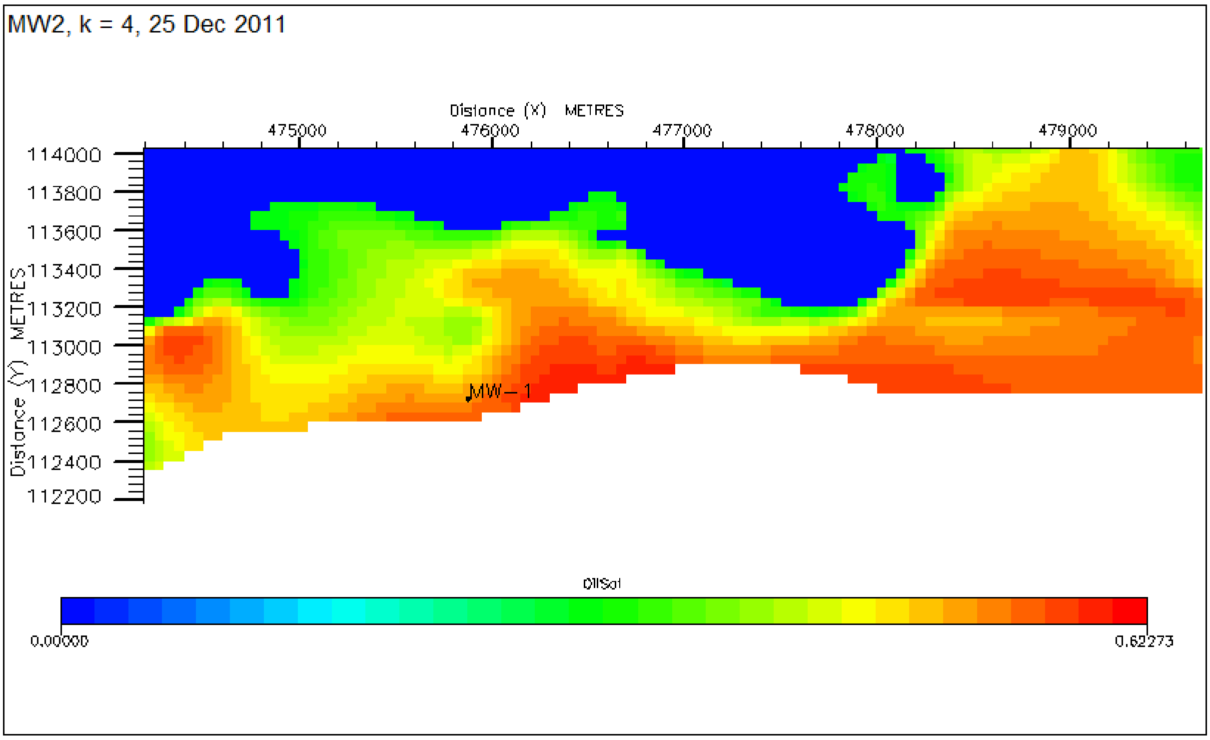


Figure 4.12 Oil saturation in the Markwells Wood model

4.4.2 History Match

The porosity-permeability relationship derived by OPC was used to generate permeability in the model with a permeability multiplier applied to all layers in order to match the well test. The fracture, observed on well test, is not modelled specifically as there are too many uncertainties on the fracture dimensions. A skin was applied to represent the fracture. The history match for MW-1 is shown in Figure 4.13.

During the history match, no attempt was made to match the bottom hole pressure of MW-1. The permeability multiplier was adjusted, within a reasonable range, to match the produced fluids

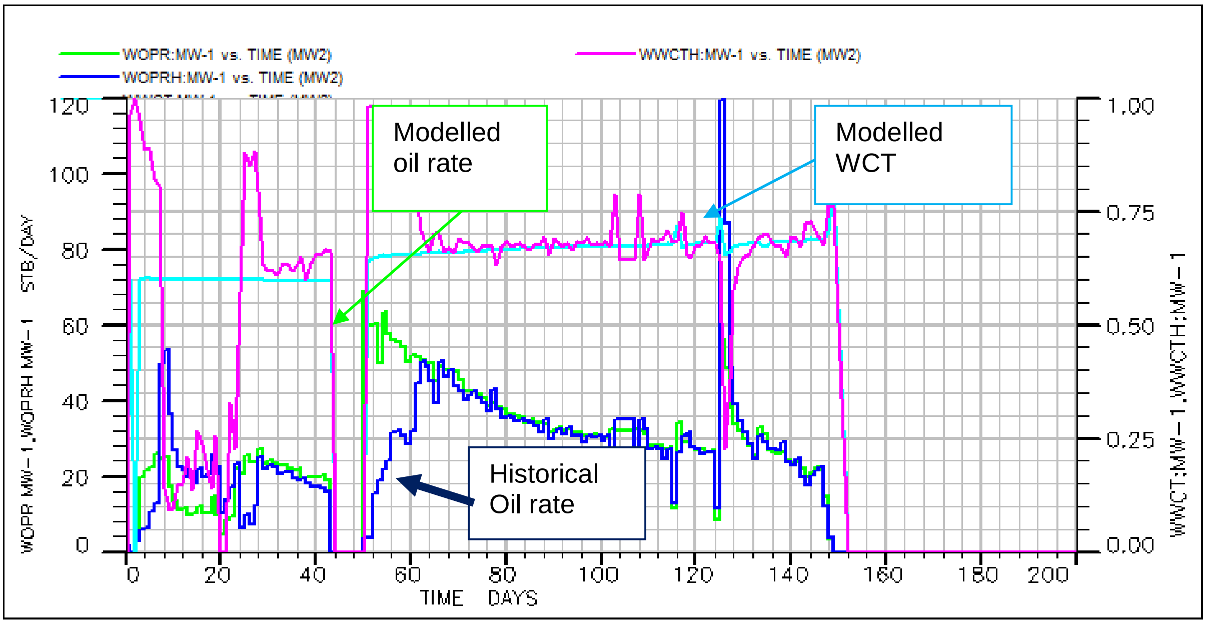


Figure 4.13 History match of MW-1 EWT

4.4.3 Estimated Well Performance

As per UKOG's plan for a horizontal well in the crest of the structure, a production forecast has been generated for a side track to MW-1 with a 1,200 m length horizontal well with an east-west azimuth (denoted MW-1ST in Figure 4.14). The well is positioned high in the structure and targets the layers with the highest permeability in the Upper Massive Oolite zone (Figure 4.15). Further optimisation of well positioning is possible but not undertaken for this report.

UKOG have predicted well performance of the horizontal well based on a conservative analogy to the Horndean-X3 well, which is the poorest performing horizontal well on the Horndean field. A type curve for the well was derived from the Horndean-X3 well to allow modelling of cumulative oil rates at Markwells Wood. The modelling does not account for the well position in the oil column, reservoir quality or lateral length among other factors. Nevertheless, given the direct analogy of Horndean to Markwells Wood and the short distance between the fields, Xodus considers the approach taken by UKOG to be reasonable.

Xodus has predicted future well performance of MW-1ST using the Eclipse model, which has been calibrated to the MW-1 well test results. The simulated oil production rates for the horizontal well MW-1ST are in line with the oil rate production of some horizontal wells in Horndean, a field that produces from the same structure and reservoir less than a kilometre away (see Figure 4.7).

Low, Best and High case production forecasts for the proposed well have been generated using the Best case as a basis for adjustments. A description of the assumptions for each case and the production figures are shown below.

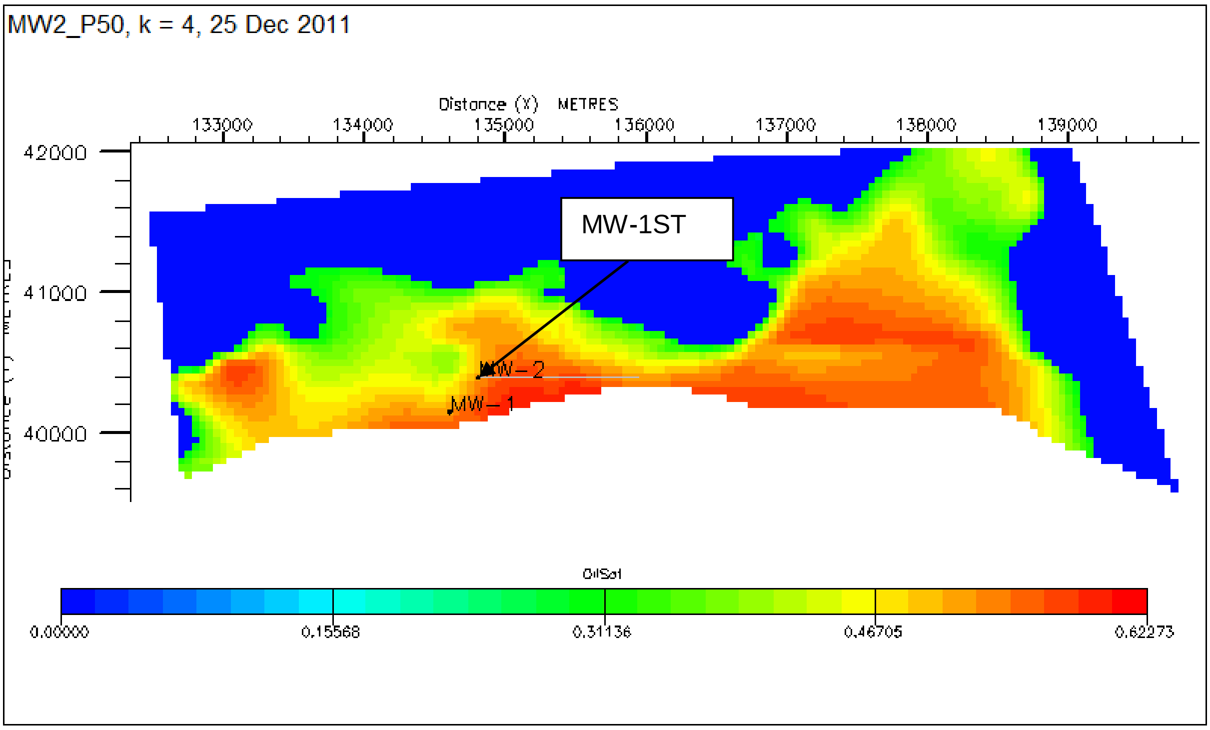


Figure 4.14 Initial oil saturation in the model showing the location of the MW-1ST well

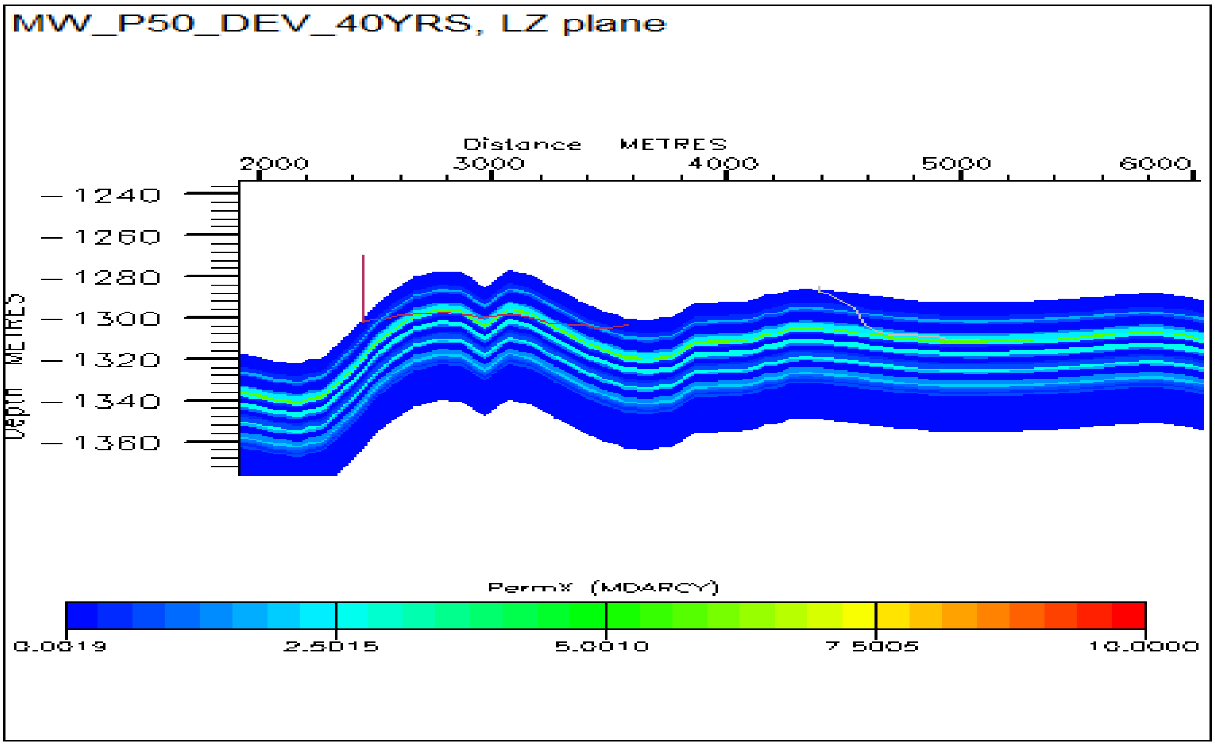


Figure 4.15 MW-1 ST cross section permeability

Best Case

The Best case keeps the history-matched parameters from MW-1. The ratio of vertical permeability to horizontal permeability (kv/kh) was set to 0.05. Table 4.6 gives the annual production figures for the Best case.

Best Case MW-1ST horizontal									
Year	**Oil Rate stbpd**	**Cum Oil stb**	**Daily Water bwpd**	**Cum Water stb**	**Year**	**Oil Rate stbpd**	**Cum Oil stb**	**Daily Water bwpd**	**Cum Water stb**
1	124	45,442	37	13,538	**21**	33	412,867	51	347,243
2	85	76,645	32	25,251	**22**	32	424,609	51	365,915
3	75	104,073	35	37,974	**23**	31	435,998	51	384,594
4	69	129,261	37	51,634	**24**	30	447,052	51	403,269
5	64	152,848	40	66,139	**25**	29	457,815	51	421,980
6	61	175,007	42	81,289	**26**	29	468,246	51	440,615
7	58	195,996	43	97,027	**27**	28	478,386	51	459,215
8	55	215,950	44	113,267	**28**	27	488,250	51	477,772
9	52	235,025	46	129,982	**29**	26	497,874	51	496,332
10	50	253,206	47	147,015	**30**	26	507,219	51	514,784
11	48	270,617	48	164,361	**31**	25	516,321	50	533,176
12	46	287,318	48	181,973	**32**	24	525,191	50	551,501
13	44	303,407	49	199,859	**33**	24	533,861	50	569,803
14	42	318,843	49	217,885	**34**	23	542,293	50	587,978
15	41	333,710	50	236,068	**35**	23	550,518	50	606,071
16	39	348,047	50	254,382	**36**	22	558,546	49	624,078
17	38	361,920	50	272,852	**37**	21	566,404	49	642,046
18	37	375,287	51	291,355	**38**	21	574,058	49	659,873
19	35	388,212	51	309,924	**39**	20	581,534	49	677,605
20	34	400,720	51	328,541	**40**	20	588,839	48	695,241

Table 4.6 Best case production forecast for MW-1ST

Low Case

The Low case has been built from the Best case, reducing the permeability multiplier and reducing the KvKh to 0.01. Other parameters and all the other inputs remained unchanged.

Low Case MW-1ST horizontal									
Year	**Oil Rate stbpd**	**Cum Oil stb**	**Daily Water bwpd**	**Cum Water stb**	**Year**	**Oil Rate stbpd**	**Cum Oil stb**	**Daily Water bwpd**	**Cum Water stb**
1	63	22,915	26	9,591	**21**	22	237,735	29	194,532
2	43	38,653	19	16,529	**22**	22	245,757	30	205,312
3	39	52,979	20	23,695	**23**	22	253,619	30	216,158
4	37	66,417	21	31,219	**24**	21	261,327	30	227,062
5	35	79,228	22	39,110	**25**	21	268,909	30	238,050
6	34	91,469	22	47,298	**26**	20	276,328	30	249,053
7	32	103,257	23	55,780	**27**	20	283,610	30	260,098
8	31	114,646	24	64,529	**28**	20	290,761	30	271,180
9	30	125,705	25	73,547	**29**	19	297,804	30	282,323
10	29	136,406	25	82,763	**30**	19	304,704	31	293,462
11	28	146,805	26	92,185	**31**	19	311,486	31	304,625
12	28	156,921	26	101,796	**32**	18	318,153	31	315,807
13	27	166,800	27	111,605	**33**	18	324,726	31	327,036
14	26	176,403	27	121,544	**34**	18	331,174	31	338,247
15	26	185,772	28	131,626	**35**	17	337,517	31	349,467
16	25	194,920	28	141,837	**36**	17	343,760	31	360,693
17	24	203,880	28	152,195	**37**	17	349,922	31	371,954
18	24	212,616	29	162,633	**38**	17	355,971	31	383,185
19	23	221,161	29	173,169	**39**	16	361,928	31	394,414
20	23	229,524	29	183,795	**40**	16	367,795	31	405,640

Table 4.7 Low case production forecast for MW-1ST

High Case

For the high case the permeability multiplier was increased by a factor 2 and vertical / horizontal permeability ratio (kv/kh) to 0.1. Table 4.8 gives the annual production figures for the high case.

High Case MW-1ST horizontal									
Year	**Oil Rate stbpd**	**Cum Oil stb**	**Daily Water bwpd**	**Cum Water stb**	**Year**	**Oil Rate stbpd**	**Cum Oil stb**	**Daily Water bwpd**	**Cum Water stb**
1	258	94,498	76	27,951	**21**	37	642,196	84	648,671
2	167	155,325	71	53,727	**22**	35	654,909	83	678,933
3	140	206,537	75	80,939	**23**	33	667,027	82	708,848
4	123	251,443	78	109,566	**24**	32	678,588	81	738,408
5	110	291,640	82	139,463	**25**	30	689,659	80	767,683
6	99	327,846	84	170,192	**26**	29	700,212	79	796,508
7	90	360,812	86	201,596	**27**	28	710,309	78	824,958
8	83	391,037	87	233,492	**28**	26	719,977	77	853,031
9	76	418,978	88	265,807	**29**	25	729,267	76	880,799
10	71	444,781	89	298,236	**30**	24	738,150	75	908,109
11	66	468,773	89	330,760	**31**	23	746,673	74	935,036
12	61	491,161	89	363,298	**32**	22	754,858	73	961,579
13	57	512,175	89	395,872	**33**	22	762,742	72	987,810
14	54	531,846	89	428,245	**34**	21	770,300	71	1,013,585
15	51	550,356	88	460,457	**35**	20	777,569	70	1,038,979
16	48	567,813	88	492,468	**36**	19	784,563	69	1,063,993
17	45	584,351	87	524,330	**37**	18	791,314	67	1,088,695
18	43	599,960	86	555,842	**38**	18	797,798	66	1,112,954
19	41	614,757	86	587,069	**39**	17	804,044	65	1,136,839
20	38	628,804	85	617,990	**40**	16	810,065	64	1,160,354

Table 4.8 High case production forecast for MW-1ST

The plots below show comparisons of the production forecasts for each case (Figure 4.16) and of the oil rate and cumulative production for the first 10,000 days (~28 years) of production, compared to the Horndean wells (Figure 4.17 and Figure 4.18). It can be seen from these plots that the modelled well profiles are in reasonable agreement with the Horndean wells and that the simulated Best Case has slightly better performance than the Horndean-X3 well.

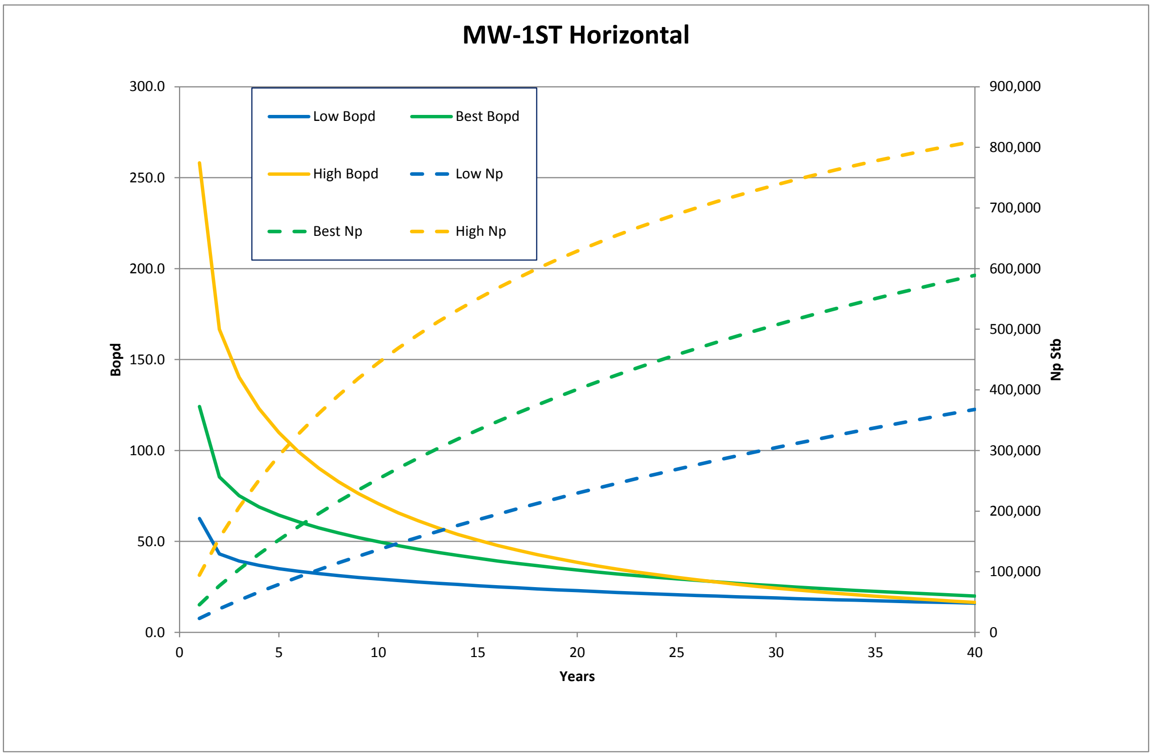


Figure 4.16 Production Forecasts MW-1ST cases

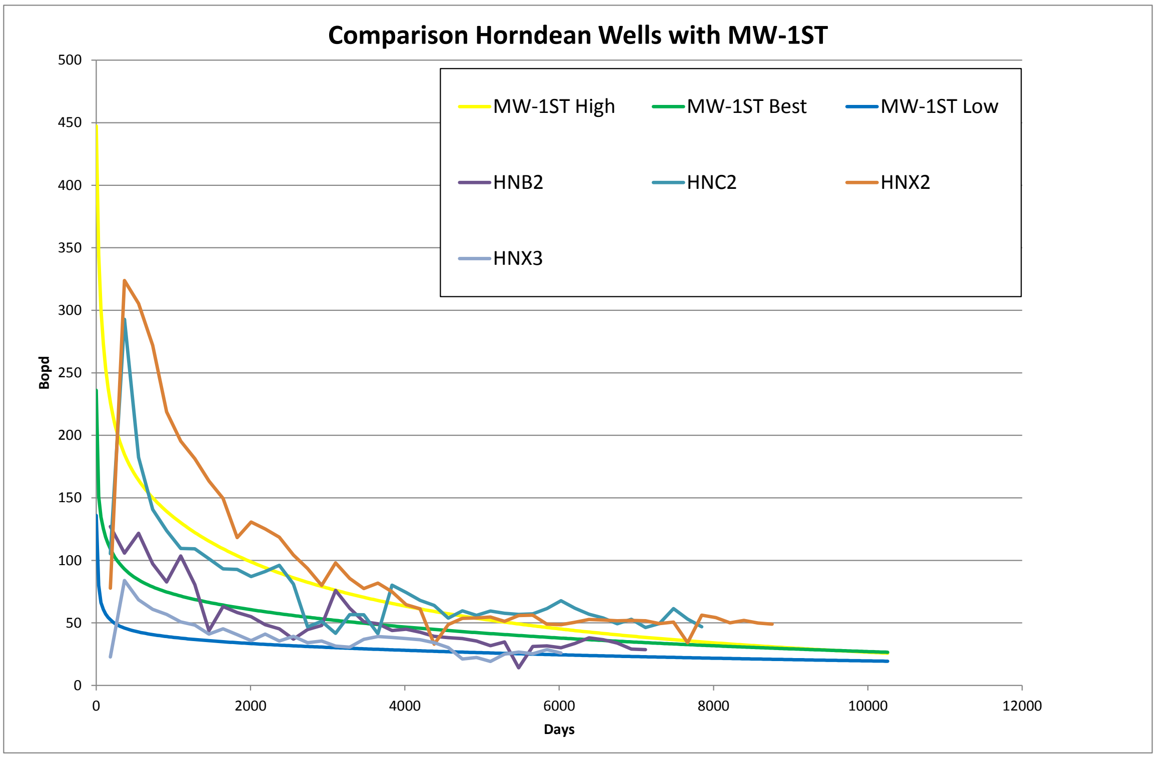


Figure 4.17 Comparison of oil rate for the MW-1ST cases with the Horndean wells

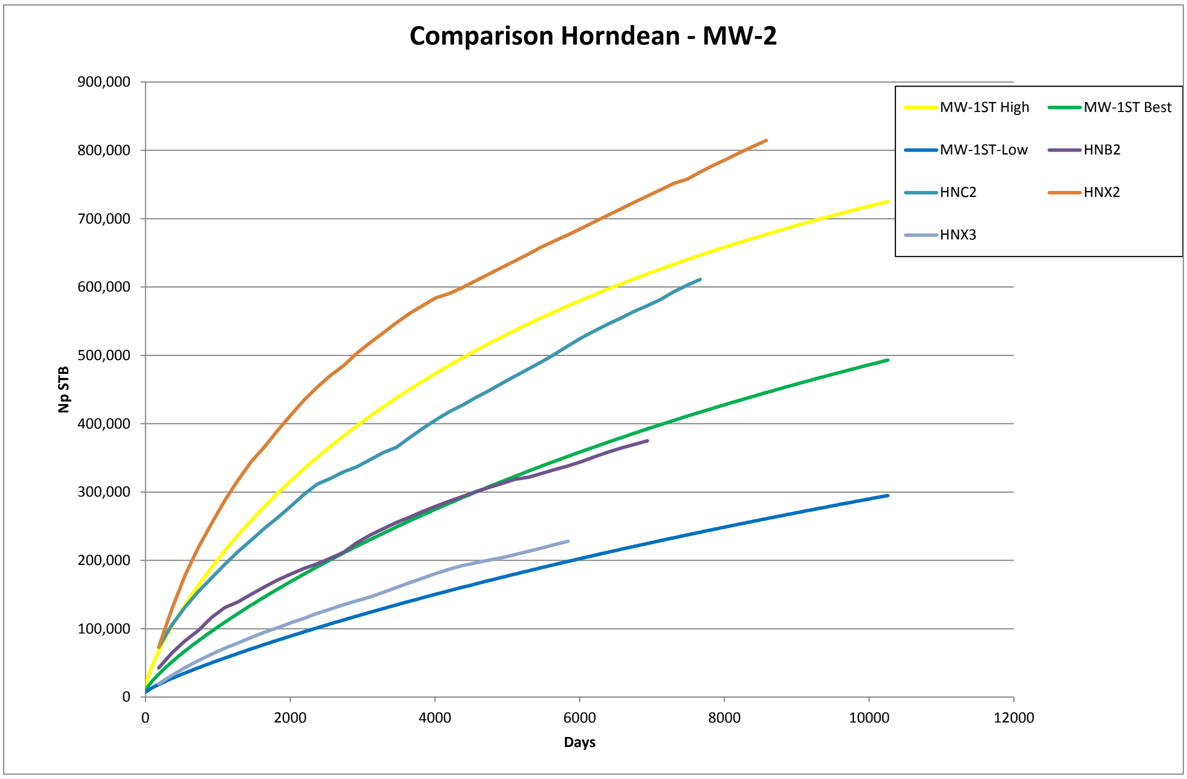


Figure 4.18 Comparison of cumulative production for the MW-1ST cases with the Horndean wells

4.5 Field Development Scenarios

To date no Markwells Wood Field Development Plan has been prepared. UKOG has proposed a notional development, which places a number of long horizontal wells in as much vertical relief from the transition zone as possible. UKOG is also investigating novel conventional drilling and completion techniques that may assist optimising the recovery from the wells and from the field overall. A field development with up to four phases is mooted with two horizontal wells in the first phase, four in each of the second and third phases and five in the fourth phase, as shown in the schematic provided by UKOG in Figure 4.19.

UKOG scenarios for estimating contingent resource are based on increasing well count with the phases as described.

> 1C: 2 lateral wells, east and west of MW-1 – phase 1

> 2C: 4 additional lateral wells (6 in total) – phase 2

> 3C: 9 further lateral wells (15 in total) – phases 3 and 4

Although UKOG have prioritised the wells in terms of possible length, position above FWL, reservoir quality and structural control, at present all wells are predicted to have the same performance in all cases as defined by the Horndean-X3 type curve derived by UKOG and are estimated to produce approximately 342,000 barrels each over a 35-year period. UKOG realises that such a development scenario provides an initial estimate only, that further analysis is required to prepare for an initial horizontal well and that new information gained from that well will determine further field development.

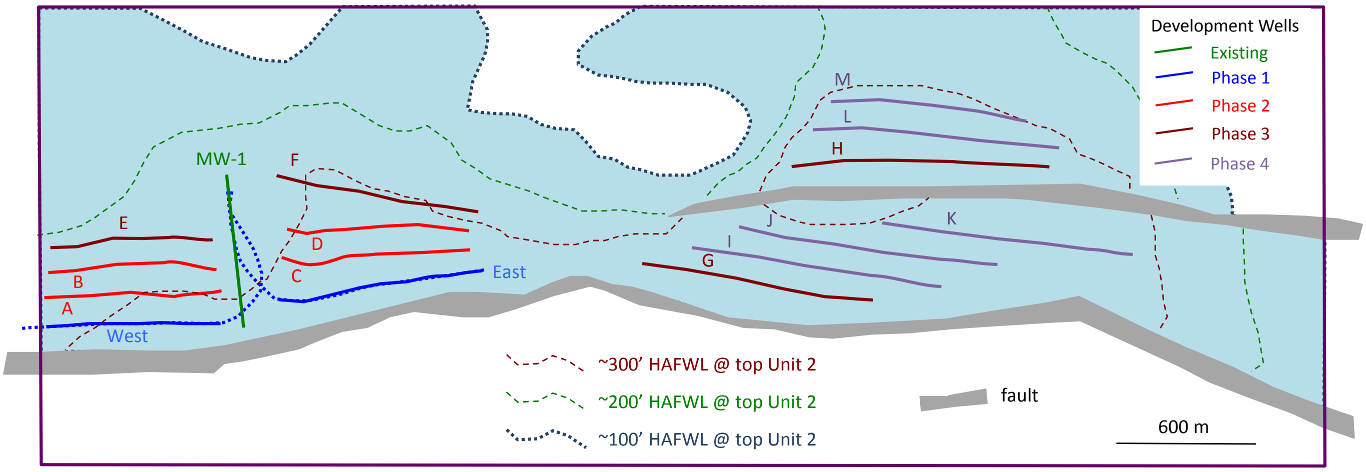


Figure 4.19 Notional phased FDP proposed by UKOG

To determine the Contingent Resource recoverable volumes Xodus assumed the following notional development scenarios (see also Figure 4.20):

- 1C: 2 horizontal production wells (MW-1ST and MW6) – assuming reservoir quality as per MW-1ST Low Case model
- 2C: 5 horizontal production wells (MW-1ST, MW3, MW4, MW5 and MW6) – assuming reservoir quality as per MW-1ST Best Case model
- 3C: 5 horizontal production wells (MW-1ST, MW3, MW4, MW5 and MW6) – assuming reservoir quality as per MW-1ST High Case model and assuming no interference between wells

Well performance for each of the 1C, 2C and 3C scenarios is simulated in the Eclipse model. The 2C scenario is derived from a model where the parameters such as reservoir permeability and kv/kh (vertical to horizontal permeability ratio) were used to obtain the history match the MW-1 well test. In the 1C scenario the reservoir permeability multiplier and kv/kh were reduced. In the 3C scenario the reservoir permeability multiplier and kv/kh were increased beyond the values used to match the EWT.

Wells have the same or a slightly shorter horizontal section than MW-1ST, depending on locally available space and they are positioned in the Upper Massive Oolite zone with its better permeability. The locations of the wells are different to those placed by UKOG and are shown in Figure 4.20. Wells come onstream in a phased fashion with the last well producing first oil 6 months after the first well.

In Xodus' simulation results the production wells in the development scenarios have poorer performance per well than the simulated MW-1ST, because performance is dependent on the length of penetration of best layers and distance to OWC, which dictates the water cut and because of pressure interference between wells and overall depletion. Xodus recognises that its Eclipse simulation is only a crude model of the Markwells Wood reservoir and that further refinements are needed to better reflect reality[11]. Additionally, well placement can be improved to increase well productivity and contribution from further production wells would increase total field oil recovery. Overall, Xodus believes that its 1C, 2C and 3C ranges provide a balanced, if conservative, reflection of the current state of knowledge of the field and its development.

[11] For instance, no interference between wells is reported in nearby fields, including Horndean, although no proof (e.g. pressure measurements) of this is available. The Eclipse model could be adjusted to reduce inter-well connectivity, which UKOG believes to be a more accurate reflection of the actual field.

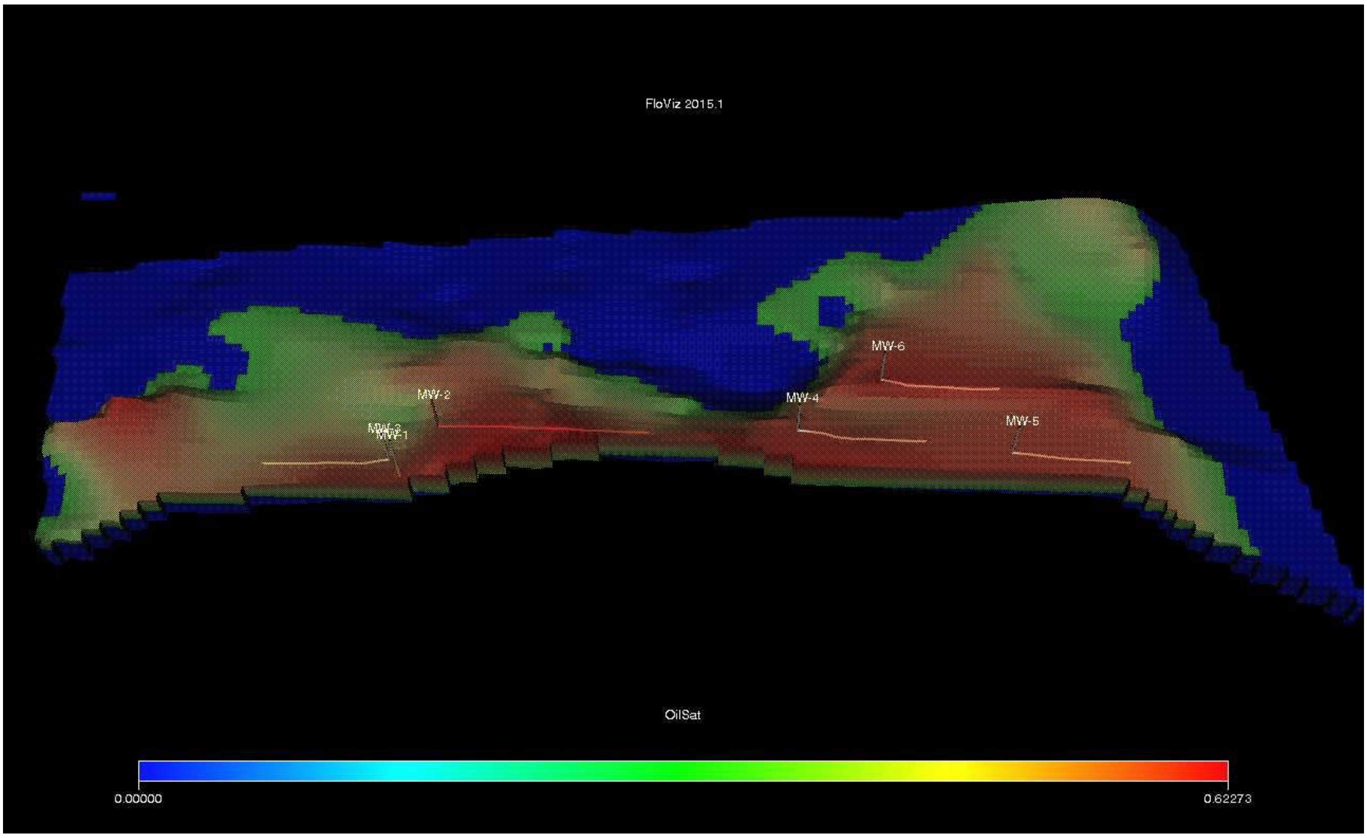


Figure 4.20 Location of Xodus notional development wells

4.6 Full Field Production Profiles

Running the Eclipse models on the three suggested full field development scenarios, Xodus arrived at the following production profiles.

Total Markwells Wood Field – 1C

Year	Oil Rate stbpd	Cum Oil stb	Daily Water bwpd	Cum Water stb	Year	Oil Rate stbpd	Cum Oil stb	Daily Water bwpd	Cum Water stb
1	79	28,884	28	5,135	**21**	39	400,578	39	271,845
2	75	56,196	31	16,613	**22**	39	414,499	38	286,434
3	68	80,991	30	27,603	**23**	38	428,149	37	300,986
4	64	104,253	31	38,993	**24**	37	441,537	37	315,534
5	61	126,425	32	50,830	**25**	36	454,708	36	330,069
6	58	147,601	34	63,111	**26**	36	467,599	35	344,624
7	56	167,979	35	75,721	**27**	35	480,255	35	359,114
8	54	187,657	35	88,650	**28**	34	492,684	34	373,572
9	52	206,760	36	101,855	**29**	34	504,926	33	387,993
10	51	225,241	37	115,335	**30**	33	516,922	33	402,411
11	49	243,199	37	128,984	**31**	33	528,711	32	416,744
12	48	260,674	38	142,812	**32**	32	540,299	32	431,025
13	47	277,744	38	156,791	**33**	31	551,723	31	445,253
14	45	294,345	39	170,938	**34**	31	562,927	31	459,461
15	44	310,549	39	185,155	**35**	30	573,946	30	473,569
16	43	326,378	39	199,460	**36**	30	584,787	30	487,612
17	42	341,892	39	213,838	**37**	29	595,482	29	501,588
18	41	357,024	40	228,314	**38**	29	605,977	29	515,533
19	41	371,833	40	242,795	**39**	29	616,307	28	529,368
20	40	386,334	40	257,308	**40**	28	626,476	28	543,128

Table 4.9 Annual production for 1C case

Total Markwells Wood Field – 2C									
Year	**Oil Rate stbpd**	**Cum Oil stb**	**Daily Water bwpd**	**Cum Water stb**	**Year**	**Oil Rate stbpd**	**Cum Oil stb**	**Daily Water bwpd**	**Cum Water stb**
1	262	95,966	56	20,384	**21**	63	975,837	99	977,049
2	250	187,373	163	80,059	**22**	59	997,533	96	1,012,185
3	211	264,223	147	133,742	**23**	56	1,018,133	93	1,046,276
4	186	332,193	217	212,789	**24**	54	1,037,700	91	1,079,346
5	169	393,903	144	265,383	**25**	51	1,056,344	88	1,111,500
6	155	450,387	142	317,329	**26**	48	1,074,017	85	1,142,586
7	143	502,678	140	368,588	**27**	46	1,090,823	83	1,172,715
8	133	551,359	138	419,020	**28**	44	1,106,809	80	1,201,908
9	125	596,978	136	468,648	**29**	42	1,122,060	77	1,230,265
10	117	639,620	133	517,126	**30**	40	1,136,535	75	1,257,655
11	110	679,680	130	564,538	**31**	38	1,150,316	73	1,284,178
12	103	717,383	127	610,847	**32**	36	1,163,439	70	1,309,855
13	97	753,013	124	656,155	**33**	34	1,175,971	68	1,334,778
14	92	786,540	121	700,200	**34**	33	1,187,877	66	1,358,832
15	87	818,210	118	743,102	**35**	31	1,199,222	64	1,382,108
16	82	848,154	114	784,861	**36**	30	1,210,035	62	1,404,628
17	78	876,564	111	825,595	**37**	28	1,220,370	60	1,426,471
18	73	903,391	108	865,088	**38**	27	1,230,196	58	1,447,541
19	70	928,812	105	903,469	**39**	26	1,239,566	56	1,467,917
20	66	952,913	102	940,751	**40**	24	1,248,503	54	1,487,621

Table 4.10 Annual production for 2C case

Total Markwells Wood Field – 3C									
Year	**Oil Rate stbpd**	**Cum Oil stb**	**Daily Water bwpd**	**Cum Water stb**	**Year**	**Oil Rate stbpd**	**Cum Oil stb**	**Daily Water bwpd**	**Cum Water stb**
1	429	157,110	250	45,975	**21**	157	1,826,657	95	1,558,742
2	402	303,751	389	188,232	**22**	153	1,882,684	88	1,591,065
3	343	429,023	342	313,192	**23**	150	1,937,379	82	1,620,905
4	311	542,424	317	429,043	**24**	146	1,990,808	76	1,648,522
5	288	647,738	297	537,464	**25**	143	2,043,173	70	1,674,074
6	270	746,244	279	639,456	**26**	140	2,094,245	65	1,697,772
7	255	839,378	261	734,847	**27**	137	2,144,219	60	1,719,626
8	243	927,944	245	824,210	**28**	134	2,193,143	55	1,739,832
9	232	1,012,765	229	907,821	**29**	131	2,241,188	51	1,758,509
10	222	1,093,837	214	986,156	**30**	129	2,288,132	47	1,775,816
11	213	1,171,759	200	1,059,052	**31**	126	2,334,144	44	1,791,763
12	206	1,246,834	186	1,127,017	**32**	124	2,379,260	40	1,806,497
13	199	1,319,508	173	1,190,293	**33**	121	2,423,631	37	1,820,106
14	192	1,389,599	161	1,249,310	**34**	119	2,467,045	34	1,832,709
15	186	1,457,493	150	1,304,004	**35**	117	2,509,651	32	1,844,313
16	180	1,523,347	139	1,354,804	**36**	115	2,551,477	29	1,855,028
17	175	1,587,472	129	1,401,953	**37**	113	2,592,659	27	1,864,920
18	170	1,649,642	120	1,445,807	**38**	111	2,632,996	25	1,874,075
19	166	1,710,140	111	1,486,354	**39**	109	2,672,625	23	1,882,500
20	161	1,769,065	103	1,523,930	**40**	107	2,711,566	21	1,890,275

Table 4.11 Annual production for 3C case

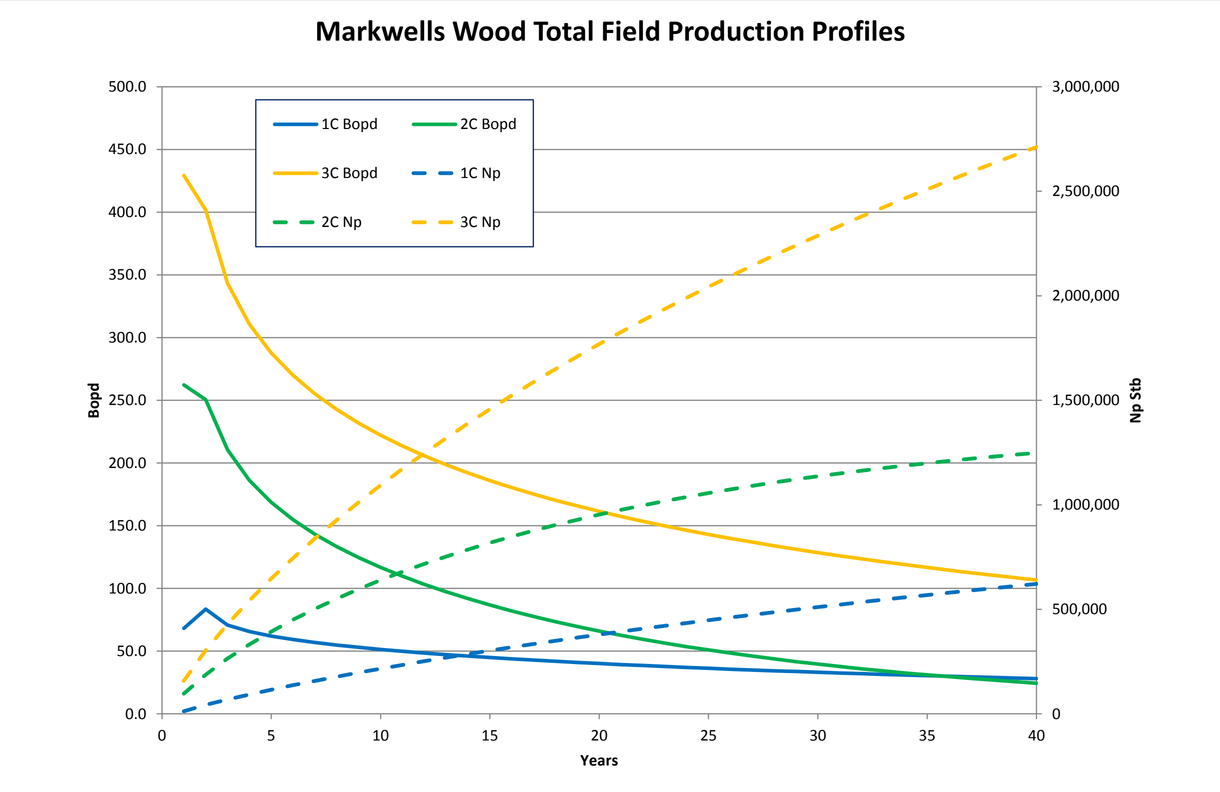


Figure 4.21 Xodus' total field production forecast - rates and cumulative production

4.7 Recoverable Resources

Total recoverable resources are based on the simulated production from the proposed horizontal wells. The base case simulation with 5 horizontal wells was chosen as the 2C, the 1C case has 2 horizontal wells and poorer reservoir permeability, the high case has 5 horizontal production wells and assumes a better reservoir permeability than that used in the 2C scenario. The high case also assumes no interference between wells. The resulting Gross and Net Contingent Resources volumes are provided in Table 4.12.

Oil Contingent Resources	**Gross Volumes**			**Net to UKOG**		
(MMbbl)	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
Markwells Wood	0.63	1.25	2.71	0.63	1.25	2.71

Table 4.12 Xodus estimation of Markwells Wood Contingent Resources

The recoverable volumes are contingent upon UKOG achieving internal and external authorisation for its Field Development Plan and on the development being commercial and able to secure adequate financing. No economic analysis was undertaken to assess the commerciality of the field.

Analogous producing fields nearby, including Singleton and Horndean, appear to have Recovery Factors that are in the range of 4.5% - 7% and even higher RF values have been mentioned in other reports[12]. Xodus does not have the data to verify these third party benchmarks. Moreover, these benchmarks are not readily transferable to Markwells Wood as they do not take into account the specific local reservoir properties.

Applying a 5% RF to the Best STOIIP values (but excluding the water saturated Lower Massive Oolite STOIIP) gives a recoverable resource volume of approximately 2 MMbbl. Applying a 7% RF to the High STOIIP values (again excluding the Lower Massive Oolite), gives a recoverable resource volume of approximately 3.5 MMbbl.

Therefore the RF benchmarks indicate that additional recovery above the Xodus 3C estimate is possible. At the time that pressure data from the future Markwells Wood wells will become available, a more accurate reservoir dynamic model can be developed, which may indicate scope for further infill wells above the Xodus 3C scenario.

[12] See for instance page 17 of “Competent Person’s Report Conducted for IGas Energy Plc, Senergy, January 2014.

5 CONCLUSIONS

Xodus has carried out an independent review of the work undertaken by UKOG in the determination of Contingent Resources for the Markwells Wood discovery.

Xodus has found the work carried out by UKOG to be technically justifiable. The STOIIP calculated by Xodus was very similar to that calculated by UKOG. Although Xodus based its reservoir productivity estimates on a reservoir simulation rather than UKOG's approach of using analogue wells, the resulting single well performance was found to be in reasonable agreement. An initial estimate of total field recoverable resources was based on three deterministic development scenarios.

The next UKOG activities on the discovery are expected to include further analysis of the reservoir, forecasted well performance and production rates and the development of a detailed Field Development Plan. This is likely to include analysis of advanced drilling and completions technologies to further improve the well performance and overall recovery.

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7 NOMENCLATURE

Term	Meaning	Units of measurement
2D	Two dimensional seismic data covering length and depth of a given geological surface	
3D	Three dimensional seismic data covering length, breadth and depth of a given geological surface	
AAPG	American Association of Petroleum Geologists	
AI	Acoustic impedance – a type of seismic attribute	
AIM	Alternative Investment Market of the London Stock Exchange	
API	American Petroleum Institute	API
AVO	Amplitude versus offset or amplitude variation with offset is often used as a direct hydrocarbon indicator	
Best Estimate	An estimate representing the best technical assessment of projected volumes. Often associated with a central, P_{50} or mean value	
bbl	barrel	
BHP	Bottom hole pressure	psi
BU	Build up	
Contingent Resources	Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterised by their economic status	
CPI	Computer-processed interpretation	
D	Day	

EWT	Extended Well Test	
ft	Foot/feet	ft
º F / º C	Degrees Fahrenheit / Centigrade	
FDP	Field Development Plan	
FVF	Formation Volume Factor	
FWL	Free water level	
GDT	Gas Down To	ft or m
GIIP	Gas Initially In Place	
GR	Gamma ray	
GOR	Gas Oil Ratio	
GRV	Gross Rock Volume	
GWC	Gas-water contact	
H	Thickness	ft or m
High Estimate	An estimate representing the high technical assessment of projected volumes. Often associated with a high or P_{10} value	
HCIIP	Hydrocarbons Initially In Place	
k	Permeability	mD
k_a	Air permeability	mD
K_h	Permeability-thickness	mDft
km	Kilometres	km
k_w	Water permeability	mD
Low Estimate	An estimate representing the low technical assessment of projected volumes. Often associated with a low or P_{90} value	High Estimate
m	Metres	
MD	Measured depth	ft or m
mD	Millidarcies	
MDRKB	Measured Depth Rotary Kelly Bushing	ft or m
MDBRT	Measured Depth Below Rotary Table	ft or m
Mean	The arithmetic average of a set of values	
msec	Millisecond	
MM	Million	
MMbbl	Millions of barrels of oil	
MMboe	Millions of barrels of oil equivalent	

MMstb	Millions of barrels of stock tank oil	
MW-1	Markwells Wood-1 well	
N/G	Net to gross	
NPV	Net Present Value	
OBM	Oil based mud	
ODT	Oil down to	
OWC	Oil water contact	
P_{10}	The probability of that a stated volume will be equalled or exceeded. In this example a 10% chance that the actual volume will be greater than or equal to that stated	
P_{50}	The probability of that a stated volume will be equalled or exceeded. In this example a 50% chance that the actual volume will be greater than or equal to that stated	
P_{90}	The probability of that a stated volume will be equalled or exceeded. In this example a 90% chance that the actual volume will be greater than or equal to that stated	
P_{99}	The probability of that a stated volume will be equalled or exceeded. In this example a 99% chance that the actual volume will be greater than or equal to that stated	
P_{res}	Reservoir pressure	psi
PEDL	Petroleum Exploration and Development Licence	
Ppg	Pounds per gallon	
PRMS	Petroleum Resources Management System	
Producing	Related to development projects (e.g. wells and platforms): Active facilities, currently involved in the extraction (production) of hydrocarbons from discovered reservoirs	

Prospective Resources	Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity
PVT	Pressure Volume Temperature: measurement of the variation in petroleum properties as the stated parameters are varied
REP	Reserves Evaluation Programme - REP5 software from Logicom E&P
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterised by development and production status
Rw	Water resistivity
Seismic	Use of sound waves generated by controlled explosions to ascertain the nature of the subsurface geological structures. 2D records a cross section through the subsurface while 3D provides a three dimensional image of the subsurface
So	Oil saturation
SPE	Society of Petroleum Engineers
SPEE	Society of Petroleum Evaluation Engineers
STOIIP	Stock Tank Oil Initially In Place
Sw	Water saturation

ratio

TD	Total depth	ft or m
TVDBRT	True vertical depth below rotary table	ft or m
TVDSS	True vertical depth sub sea	ft or m
TWT	Two Way Time	ms or s
UKOG	UK Oil & Gas Investments PLC	
VoK	Average velocity function for depth conversion of time based seismic data, where Vo is the initial velocity and k provides information on the increase or decrease in velocity with depth. V0+k therefore provides a method of depth conversion using a linear velocity field, increasing or decreasing with depth for each geological zone	
VSP	Vertical Seismic Profile	
WGR	Water gas ratio	
WHP	Wellhead pressure	psi
WPC	World Petroleum Council	
WUT	Water up to	
z	Depth, commonly a negative number if below sea level, equivalent to TVDSS	m or ft

XODUS & AUTHOR CREDENTIALS

Xodus is an independent, international energy consultancy. Established in 2005, the company has 500+ subsurface and surface focused personnel spread across thirteen offices in Aberdeen, Anglesey, Dubai, Edinburgh, Glasgow, The Hague, Houston, Lagos, London, Orkney, Oslo, Perth and Southampton.
The wells and subsurface division specialise in petroleum reservoir engineering, geology and geophysics and petroleum economics. All of these services are supplied under an accredited ISO9001 quality assurance system.
Except for the provision of professional services on a fee basis, Xodus has no commercial arrangement with any person or company involved in the interest that is the subject of this report.

Chris de Goey
Chris de Goey is Head of Xodus Advisory in London and was responsible for supervising this evaluation.
Chris has a broad commercial background in the energy industry. Starting his career in Shell he then joined Accenture where he worked on market entry, organisational, marketing, performance management and operational solutions for IOCs and European utilities. He subsequently took on management roles in venture capital and corporate finance focusing on oil and gas and renewables. For 3 years prior to joining Xodus Chris led an oil and gas evaluation group, assisting banks, private equity and operators with financing due diligence, delivering competent person reports and feasibility studies. Chris has an MSc in Applied Physics from Delft University. He is a member of the Petroleum Exploration Society of Great Britain and the Society of Petroleum Engineers.

David McGurk
David McGurk is a Principal Geophysicist with almost 14 years' experience in structural and quantitative interpretation, reservoir characterisation and prospect generation. He has a broad, varied skill-set with a regional focus on West Africa, in particular the transform margin from Gambia to Cote d'Ivoire.

David has a background in consultancy and operating companies; recently working with Tullow Oil's research group supporting West African and South American assets and New Ventures. He previously worked for Senergy working as a consultant geophysicist on a wide range of projects including being a member of the commercial team working on asset evaluations and reserves audits. He is highly computer literate with experience in using all major packages for interpretation and geophysical analysis. David has a BSc in Geology from Queens University Belfast and an MSc in Tectonics from Royal Holloway.

Andrew O'Connell
Andrew O'Connell is a Senior Geologist with a broad and deep international E&P experience. He is certified Petrel Specialist in Geology and Modelling.

He began his career as a mudlogger and data engineer in the Danish sector of the North Sea, Georgia and Equatorial Guinea before completing his MSc. He subsequently worked on exploration and new ventures projects for Regal Petroleum and Gulf Keystone. In 2008 Andrew joined Senergy and worked as a consultant geologist on projects covering many aspects of E&P but primarily in field development, reservoir modelling and asset evaluation projects. Andrew has a BSc in Applied and Environmental Geology from the University of Birmingham and an MSc in Petroleum Geoscience from Imperial College, London.

Fabrice Toussaint

Fabrice is a versatile executive manager and leader with Petroleum Engineering as his core competency. With over 18 years of international and domestic experience in oil and gas operations in on and off-shore, assets evaluation and management Fabrice has gained invaluable experience in the commercialisation of marginal projects. He has worked as a consultant petroleum engineer for six years following senior roles in both small and large oil companies and major service providers.