COMPETENT PERSON'S REPORT FOR PORTLAND SANDSTONE DISCOVERY LOCATED IN PEDL 234 (ONSHORE UK)

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CPR for Portland Sandstone Discovery located in PEDL 234 (Onshore UK)
Release
20 February 2023

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Approval for issue

Jim Bradly		20 February 2023

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Our ref: ECV2493

Date: 20 February 2023

UK Oil & Gas PLC
8th Floor, Broadgate Tower
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Dear Stephen,

EVALUATION OF ASSET RESERVES

In response to a request by UK Oil & Gas PLC ("UKOG"), and the Letter of Engagement dated 04 November 2022 with UKOG (the "Agreement"), RPS Energy Limited ("RPS") has completed an independent evaluation of the Portland Sandstone Discovery located in PEDL 234 and PEDL 235, Onshore UK[1].

This report is issued by RPS under the appointment by UKOG and is produced as part of the Services detailed therein and subject to the terms and conditions of the Agreement.

We have estimated the Contingent Resources contained on-block as of 20 February 2023. All Reserves and Resources definitions and estimates shown in this report are based on the PRMS Guidelines (2018). The work was undertaken by a team of petroleum engineers, geoscientists and economists and is based on data supplied by UKOG. Our approach has been to review the work on in-place volumes presented at a kick-off meeting in UKOG's offices and then make any necessary adjustments to the reservoir property inputs to create an independent probabilistic range of potential gas-in-place volumetric assessments based on the findings of that review.

For production profile generation, UKOG presented some modelling using the Kappa software based on depletion drive. RPS ran additional modelling to account for potential aquifer encroachment in the Low case, while the Mid/High cases assume depletion drive only. Profiles were generated and input to an economic model which is based on UKOG's proposed 2-well development plan.

In estimating Resources, we have used standard geoscience and petroleum engineering techniques. We have estimated the degree of uncertainty inherent in the measurements and interpretation of the data and have calculated a range of recoverable volumes, based on predicted field performance and contracted gas sales.

We have taken the working interest that UKOG has in the Field as presented by UKOG. We have not investigated, nor do we make any warranty as to UKOG interest in the Assets.

A site visit was not conducted as there are currently no facilities to inspect.

UKOG provided LAS files containing raw and processed logs for 3 wells (GB-1, GB-2z & AI-1), core analysis reports, composite logs, mud logs, RFT data and the results of 3 DST tests in GB-1. UKOG presented a Kingdom project containing a regional 2D seismic dataset of which approximately 22 seismic lines intersect

[1] *The Portland Sandstone gas discovery was made by well GB-1, located in the neighbouring PEDL 235 (operated by IGas), but the mapped closure extends into PEDL 234, operated by UKOG.*

the discovered structure which straddles licenses PEDL 235 (IGas Energy) and PEDL 234 (UKOG). UKOG also provided the Kappa model on which they have based their production profiles and resulting estimates of recovery factor, and a report by Kappa examining Pressure Transient Analysis of the GB-1 Drill Stem Test #6 (DST6).

The initially-in-place (on block) gas volumes are presented in Table 1.1 of section 1.3. The gross and net entitlement Contingent Resources and the net-present-values of the 1C, 2C & 3C, as of 20 February 2023 are summarised in Tables 1.2 and 1.3 of sections 1.3 and 1.4, respectively.

QUALIFICATIONS

RPS is an independent consultancy specialising in petroleum reservoir evaluation and economic analysis. The provision of professional services has been solely on a fee basis. Andy Kirchin, MD – Technical, Training & Advisory, has supervised this evaluation. Andy Kirchin is a Chartered Geologist and Fellow of the British Geological Society with 35 years of experience in upstream oil and gas. Other RPS employees involved in this work hold at least a Master's degree in geology, geophysics, petroleum engineering or a related subject or have at least five years of relevant experience in the practice of geology, geophysics or petroleum engineering.

BASIS OF OPINION

The evaluation presented in this report reflects our informed judgment, based on accepted standards of professional investigation, but is subject to generally recognised uncertainties associated with the interpretation of geological, geophysical and engineering data. The evaluation has been conducted within our understanding of petroleum legislation, taxation and other regulations that currently apply to these interests. However, RPS is not in a position to attest to the property title, financial interest relationships or encumbrances related to the property. Our estimates of Resources are based on data provided by UKOG. We have accepted, without independent verification, the accuracy and completeness of this data.

The report represents RPS's best professional judgment and should not be considered a guarantee or prediction of results. It should be understood that any evaluation, particularly one involving future performance and development activities may be subject to significant variations over short periods of time as new information becomes available. This report relates specifically and solely to the subject assets and is conditional upon various assumptions that are described herein. This report must, therefore, be read in its entirety. This report was provided for the sole use of UKOG and their corporate advisors on a fee basis.

This report may be reproduced in its entirety. However, excerpts may only be reproduced or published (as required for regulated securities reporting purposes) with the express written permission of RPS.

Yours sincerely,
for RPS Energy Consultants Limited

Andy Kirchin C.Geol. FGS
Director, Subsurface Low-carbon Solutions

RPS Group
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15th December 2022

Letter of Representation

Dear Sirs,

Regarding the evaluation of UKOG's PEDL234 Loxley gas Reserves/Resources and independent appraisal of the economic value of these Reserves to December 16, 2022, we herein confirm to the best of our knowledge and belief as of the effective date of the reserves evaluation and as applicable, as of today, the following representations and information made available to RPS during the conduct of the evaluation:

We, UK Oil & Gas PLC ("UKOG"), have made available to you, RPS Group, Inc ("RPS"), certain records, information and data relating to the evaluated properties that we confirm is, with the exception of immaterial items, complete and accurate as of the effective date of the reserves evaluation, including the following:

- Accounting, financial, tax and contractual data
- Asset ownership and related encumbrance information
- Details concerning product marketing, transportation and processing arrangements
- All technical information including geological, engineering and processing arrangements
- Estimates of future abandonment and reclamation costs

We confirm that all financial and accounting information provided to RPS is, to the best of our knowledge, both on an individual entity basis and in total, entirely consistent with that reported by our company for public disclosure and audit purposes.

We confirm that our Company has satisfactory title to all of the assets, whether tangible, intangible or otherwise, for which accurate and current ownership information has been provided

With respect to all information provided to RPS regarding product marketing, transportation and processing arrangements, we confirm that we have disclosed to RPS all anticipated changes, terminations and additions to these arrangements that could reasonably be expected to have a material effect on the evaluation of our Company's reserves and future net revenues

With the possible exception of items of an immaterial nature, we confirm the following as of the effective date of the evaluation:

i. For all operated properties that RPS has evaluated, no changes have occurred or are reasonably expected to occur to the operating conditions or methods that have been used by our Company over the past 12 months except as disclosed to RPS. In the case of non-operated properties, we have advised RPS of any such changes of which we have been made aware.

ii. All regulatory approvals, permits and licences required to allow continuity of future operations and production from the evaluated properties are in place and, except as disclosed to RPS, there are no directives, orders, penalties or regulatory rulings in effect or expected to come into effect relating to the evaluated properties.

iii. Except as disclosed to RPS, we have no plans or intentions related to the ownership, development or operation of the evaluated properties that could reasonably be expected to materially affect the production levels or recovery of Reserves from the evaluated properties.

iv. If material changes of an adverse nature occur in the Company's operating performance subsequent to the effective date and prior to the report date, we will inform RPS of such changes prior to requesting approval for any public disclosure for any public disclosure of Reserves information.

Between the effective date of the report and the date of this letter, nothing has come to our attention that has materially affected or could materially affect our Reserves and the economic value of these Reserves that has not been disclosed to RPS.

Yours faithfully,

Stephen Sanderson
Chief Executive

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1 EXECUTIVE SUMMARY

1.1 Overview of PEDL 234 Portland Sandstone Discovery

In response to a request by UK Oil & Gas PLC ("UKOG"), and the Letter of Engagement dated November 4, 2022 with UKOG (the "Agreement"), RPS Energy Limited ("RPS") has completed an independent evaluation of the Portland Sandstone Discovery, located in PEDL 234 & the adjacent PEDL 235, onshore UK[2].

The field was discovered by Conoco in 1982 when they drilled the Godley Bridge-1 (GB-1) well. The field is located just north of the South Downs, WNW of the town of Horsham in Surrey, UK. It comprises a west-east elongate anticlinal structure which is mapped as a 4-way dip closure. The closure at the eastern end of the structure is poorly controlled by seismic meaning that exact trapping mechanism to the east is uncertain and could be structural or stratigraphic in nature.

The well encountered gas bearing Portland sandstone. In 1986 the GB-2 well was drilled and side-tracked to the GB-2z location; the Portland sandstone was found to be water wet. Also, in 1986 Conoco drilled the Alfold-1 well in PL203. The Alfold -1 well encountered Portland sandstone that was above an interpreted gas water contact but encountered tight sandstone and no gas was tested although it can be inferred to support the GWC by the resistivity curves. Subsequently the block has been split into two licences PEDL 235 which is licenced to IGas and PEDL234 that is licenced to UKOG.

UKOG were granted a two-year extension on their licence due to a prolonged planning consent process and the effects of the pandemic. Subsequently, UKOG has received approval from NSTA for a revised Loxley work programme, meaning that in order to satisfy the licence's Retention Area programme, the drilling of their next well (Loxley-1) must now commence before 30th June 2024[3].

UKOG are currently a 100% interest holder in the PEDL 234 licence.

The Loxley-1 well is intended to be the first of two development wells within the PEDL 234 licence. Although it will be designed and drilled as potential production well, it will still have an element of appraisal as it must first prove commercial flowrates are achievable which will depend on the height of the gas column and reservoir properties encountered. For this reason, the recoverable volumes predicted in this report are classified as Contingent Resources, Development Pending in accordance with the PRMS.

A site visit was not conducted as there are currently no facilities to inspect.

1.2 Surface Review

There are currently no surface facilities to report on, though planning permission to construct a drilling pad (with suitable access) for one well plus one side-track has been granted on appeal[4].

1.3 Subsurface and Resource Evaluation

Our approach has been to review the work on in-place volumes presented at a kick-off meeting in UKOG's offices and then make any necessary adjustments to the reservoir property inputs to create an independent probabilistic range of potential gas-in-place volumetric assessments based on the findings of that review.

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[2] *The Portland Sandstone gas discovery was made by well GB-1, located in the neighbouring PEDL 235 (operated by IGas) to the west of PEDL 234, but the mapped closure extends into PEDL 234, operated by UKOG.*

[3] https://irpages2.equitystory.com/websites/rns_news/English/1100/news-tool---rns---eqs-group.html?article=33273638&company=ukog

[4] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1080860/DL+IR_-_Land_South_of_Dunsfold_Road_and_East_of_High_Loxley_Road_Dunsfold_Surrey_-_3268579.pdf

For production profile generation, UKOG presented some modelling using the Kappa software based on depletion drive. RPS ran additional modelling to account for potential aquifer encroachment in the Low case, while the Mid/High cases assume depletion drive only. The resulting probabilistic distribution of in-place and recoverable Resources are set out in Table 1.1 and Table 1.2 below.

Profiles were generated and input to an economic model which is based on UKOG's proposed 2-well development plan. UKOG's Drillex, Capex, Opex and Abex were independently reviewed, and certain observations were presented back to UKOG. In general, RPS finds UKOG's development plan and costs to be reasonable at this stage of development but, based on conversation with UKOG and our own observations, some minor additional costs have been included on top of UKOG's estimates.

Gas from the wells will be dehydrated and acid gas removed before metering and export via a new 6.6 km export pipeline to the low-pressure Local Transmission System (LTS) at 38 barg. Initially the gas will free flow from the wells to the delivery point. However, capital expenditure allowances are included to retrofit gas compression to boost the facility export pressure as the reservoir pressure declines.

The economic evaluation has been made at a Gross (100% WI) basis and also an assumed unitisation case with net entitlement using an assumed Tract Participation ("TP") for UKOG of 77% based on the proportion of GIIP mapped on PEDL 234.

	GIIP (Bscf)		
	Low	Best	High
Whole Structure	35	57	86
PEDL 234	28	44	67

Table 1.1: Gross GIIP within PEDL 234

SUMMARY OF GAS CONTINGENT RESOURCES
As of 20 February 2023
BASE CASE PRICES AND COSTS

	Full Field Gross Resources[1] (Bscf)			UKOG Net Entitlement Resources[2] (Bscf) PEDL234		
	1C	2C	3C	1C	2C	3C
	21.0	40.2	68.7	16.2	31.0	52.9

Notes:

[1] *Gross Field Resources (100% basis) **after** economic limit test*

[2] *Companies net entitlement share of net field Resources **after** economic limit test*

Table 1.2: Gas Contingent Resources as of 20 February 2023

1.4 Economic Analysis

RPS prepared an economic model to determine the estimated economically recoverable Contingent Resources and to generate a cash flow forecast for each of the Contingent Resources case scenarios. Commerciality is assessed primarily on 2C resources as per PRMS guidelines.

A summary of the economic results is shown in Table 1.3. The economics are based on RPS' Q3 2022 gas forecast for the UK as presented in Table 5.13.

	ELT Date	Post-Tax Net Present Value (£MM, MOD)			
		0.0%	5.0%	10.0%	15.0%
1C	2034	75.6	55.0	41.1	30.4
2C	2036	166.1	118.2	86.5	64.0
3C	2037	345.5	228.4	156.2	109.3

Notes:

Table 1.3: PEDL 234 Post-Tax Valuation at RPS Base Case Price Scenario, 77% Net Entitlement

At the request of UKOG, a gas price sensitivity using a flat price of 186.05p/therm (£18.61/MMBtu) was also carried out. The gas price was based on the reported settlement price as of 31st December 2022. The NPV summary at 77% Net Entitlement is shown in Table 1.4

	ELT Date	Post-Tax Net Present Value (£ Million, MOD)			
		0.0%	5.0%	10.0%	15.0%
1C	2034	108.0	79.2	59.2	44.9
2C	2036	236.2	168.9	123.7	92.5
3C	2037	479.3	318.9	219.2	155.0

Notes:

Table 1.4: £18.61/MMBtu Economic Sensitivity Run for PEDL 234, 77% Net Entitlement

1.5 Risk and Opportunity Assessment

The Loxley-1 well is intended to be the first of two development wells within the PEDL 234 licence. Although it will be designed and drilled as potential production well, it will still have an element of appraisal as it must first prove commercial flowrates are achievable which will depend on the height of the gas column and reservoir properties encountered. For this reason, the recoverable volumes predicted in this report are classified as Contingent Resources, Development Pending in accordance with the PRMS.

2 INTRODUCTION

In response to a request by UK Oil & Gas PLC ("UKOG"), and the Letter of Engagement dated November 4, 2022 with UKOG (the "Agreement"), RPS Group, Inc ("RPS") has completed an independent evaluation of the Portland Sandstone Discovery, located in PEDL 234 & the adjacent PEDL 235, onshore UK[5].

This report is issued by RPS under the appointment by UKOG and is produced as part of the Services detailed therein and subject to the terms and conditions of the Agreement. The final deliverable from the work is to prepare a Competent Person's Report in support of the Company raising project or debt financing (the Purpose).

The field was discovered by Conoco in 1982 when they drilled the Godley Bridge-1 (GB-1) well. The well encountered gas bearing Portland sandstone. In 1986 the GB-2 well was drilled and side-tracked to the GB-2z location; the Portland sandstone was found to be water wet. Also, in 1986 Conoco drilled the Alfold-1 well on PL203. The Alfold -1 well encountered Portland sandstone that was above an interpreted gas water contact but encountered tight sandstone and no gas was tested although it can be inferred to support the GWC by the resistivity curves.

Subsequently the block has been split into two licences, PEDL 235, which is licenced to IGas, and PEDL234 which is licenced to UKOG. UKOG hold multiple licences within the Basin (Figure 2.1).

UKOG were granted a two-year extension on their licence due to a prolonged planning consent process and the effects of the pandemic. Subsequently, UKOG has received approval from NSTA for a revised Loxley work programme, meaning that in order to satisfy the licence's Retention Area programme, the drilling of their next well (Loxley-1) must now commence before 30th June 2024[6].

The effective date of the evaluation is 16th December 2022 and RPS is not aware of any material changes or events that would impact our assessment of the Resources reported in Table 1.2 and Section 5.2.

Asset	Country	Licence	Operator	Client Working Interest	Development Status	Licence Expiry Date	Partners
Loxley	U.K.	PEDL 234	UKOG	100%	Development Pending	30/6/2024	N/A

Table 2.1: Summary of UKOG Assets

[5] *The Portland Sandstone gas discovery was made by well GB-1, located in the neighbouring PEDL 235 (operated by IGas) to the west of PEDL 234, but the mapped closure extends into PEDL 234, operated by UKOG.*

[6] https://irpages2.equitystory.com/websites/rns_news/English/1100/news-tool---rns---eqs-group.html?article=33273638&company=ukog

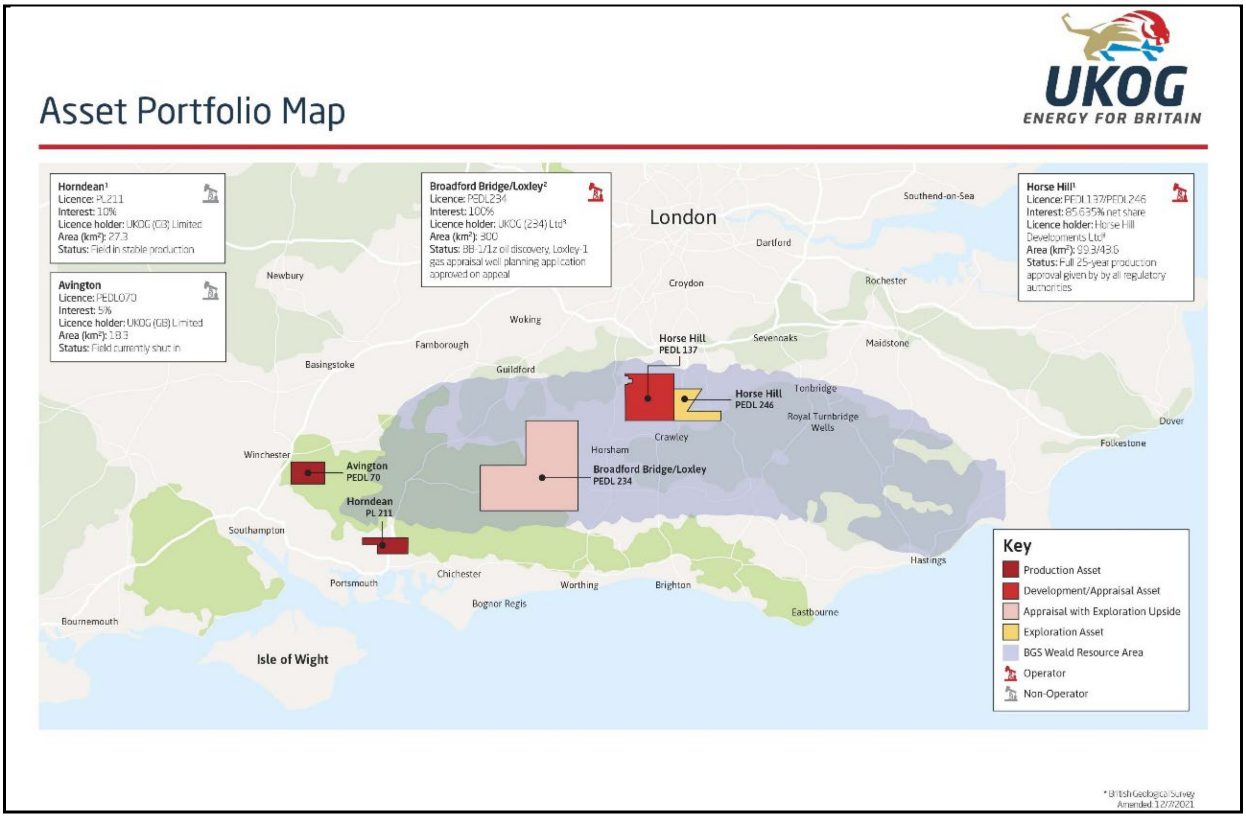

Figure 2.1: UKOG Onshore UK Assets including PEDL 234[7]

2.1 Database

2.1.1 Well Data

RPS were provided with LAS files containing the raw and processed log data for the three wells that were logged (GB-1,GB-2z, AI-1), Well tops from the 4 drilled wells (GB-1,GB-2, GB-2z, AI-1), along with original core analysis reports where available, composite logs, mud logs, repeat formation test data and the results of the 3 DST tests in the section in the GB-1 well.

2.1.2 Seismic Data

RPS examined the four well ties and seismic picks from twenty- two 2D seismic lines (approx. 360km, 180km on structure), this examination was carried out in the UKOG office on their database. No independent seismic interpretation has taken place although various checks and further seismic products to check the validity of the data were requested and received (**Figure 2.2**).

[7] *Source: UKOG*

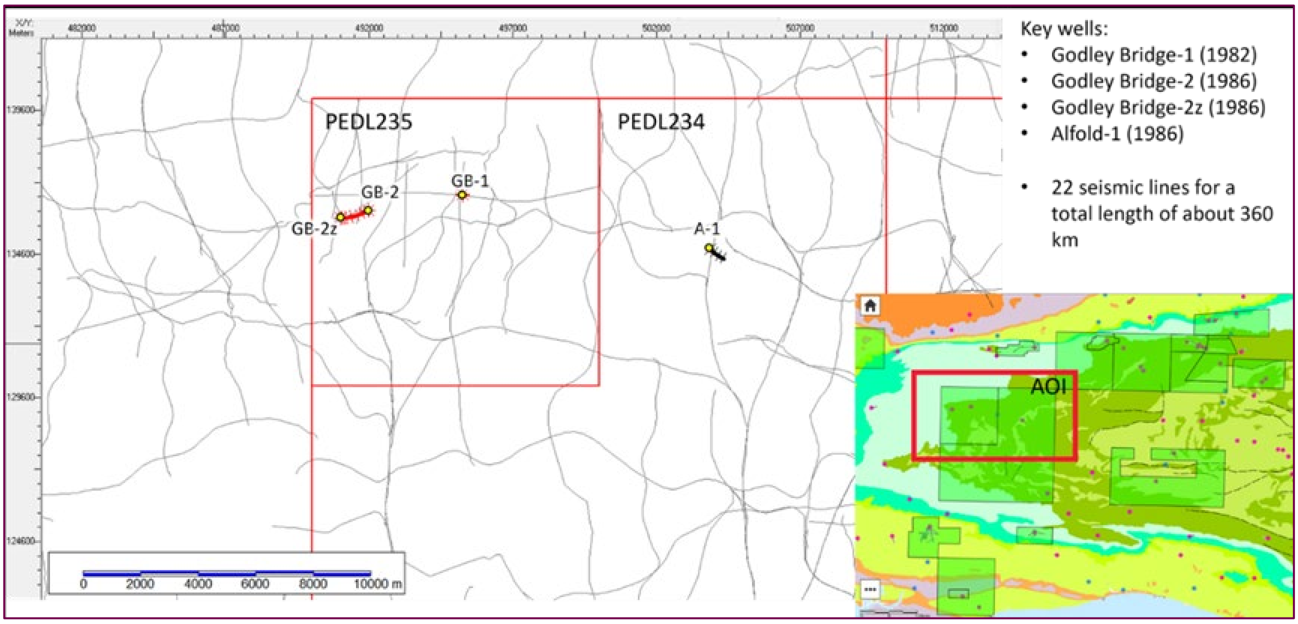

Figure 2.2: Map showing Well Locations and the Position of the Seismic Lines

3 BASIS OF OPINION

The evaluation presented in this report reflects our informed judgment, based on accepted standards of professional investigation, but is subject to generally recognised uncertainties associated with the interpretation of geological, geophysical and engineering data. The evaluation has been conducted within our understanding of petroleum legislation, taxation and other regulations that currently apply to these interests. However, RPS is not in a position to attest to the property title, financial interest relationships or encumbrances related to the property. Our estimates of Resources are based on data provided by UKOG. We have accepted, without independent verification, the accuracy and completeness of this data.

Our approach to the engagement has been to review the work presented by UKOG and make any necessary adjustments to the reservoir property and recovery mechanism inputs as we deemed fit to create an independent probabilistic range of potentially in-place and recoverable Contingent Resource volumetrics.

The report represents RPS's best professional judgment and should not be considered a guarantee or prediction of results. It should be understood that any evaluation, particularly one involving future performance and development activities may be subject to significant variations over short periods of time as new information becomes available. This report relates specifically and solely to the subject assets and is conditional upon various assumptions that are described herein. This report must, therefore, be read in its entirety. This report was provided for the sole use of UKOG and their corporate advisors on a fee basis.

The recoverable volumes predicted in this report are classified as Contingent Resources, Development Pending in accordance with the PRMS.

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4 SITE VISIT

A site visit was not conducted as there are currently no facilities to inspect.

5 LOXLEY DEVELOPMENT (PEDL 234)

The Loxley development is currently planned to be a two well development drilled from a single pad. The Loxley-1 well is intended to start drilling by year end 2023 and will be completed in Q1 2024 as the first of two development wells within the PEDL 234 licence. It will target one of two mapped highs within the PEDL 234 licence. Although it will be designed and drilled as potential production well, it will still have an element of appraisal as it must first prove commercial flowrates are achievable which will depend on the height of the gas column and reservoir properties encountered. For this reason, the recoverable volumes predicted in this report are classified as Contingent Resources, Development Pending in accordance with the PRMS.

If the Loxley-1 is successful, Loxley-2 will be drilled to maintain production on plateau (see Figure 5.7 in Section 5.1.1).

The field was discovered by Conoco in 1982 when they drilled the Godley Bridge-1 (GB-1) well. The well encountered gas bearing Portland sandstone. In 1986 the GB-2 well was drilled and side-tracked to the GB-2z location; the Portland Sandstone Formation was found to be water wet. Also, in 1986 Conoco drilled the Alfold-1 well that was at the time in the same licence. The Alfold-1 well encountered Portland sandstone that was above an interpreted gas water contact but encountered tight sandstone and no gas was tested, although it can be inferred to support the GWC by the resistivity curves.

	Well Name	Status	Notes
Exploration/Appraisal Wells	GB-1	P&A	Gas flow via DST tests
	GB-2	P&A	Mechanical problems
	GB-2z	P&A	Below GWC
	Al-1	P&A	Mostly below GWC

Table 5.1: Godley Bridge/Loxley Wells

5.1 Subsurface Evaluation

The Loxley development targets the eastern half of a west-east elongate anticlinal structure which is mapped as a 4-way dip closure of the Portland Sandstone. The Portland Sandstone is a producing interval in the nearby Horse Hill and Brockham oil fields, both of which are relatively mature fields, with oil and water production[8,9], suggesting the potential for water production from the Portland Sandstone.

The Loxley structure has tested gas from the GB-1 well through 3 DST's which produced dry gas and mud filtrate in the two higher ones and dry gas and formation water in the lowest. The development is therefore anticipated to be a dry gas with minimal condensate fluids. It was reported that gas samples, show some H_2S and CO_2 content (60 ppm and 2000 ppm respectively) which if confirmed will need to be processed out before gas can be put into the line.

5.1.1 Geophysical Assessment

5.1.1.1 Well Ties with Seismic

RPS examined the well ties constructed by UKOG through the use of synthetic seismograms and found that the ties to seismic were satisfactory. Noting that the markers that can be picked are not directly the top or

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[8] Horse Hill is operated by UKOG and has produced over 162 kbbl of oil from the Kimmeridge & Portland reservoirs, with reported water cuts of up to 70% observed on some wells (https://www.ukogplc.com/page.php?pID=135)

[9] Brockham is operated by Angus Energy, with production from the Portland reservoir, with produced water reinjected for pressure support (https://www.angusenergy.co.uk/what-we-do/brockham-oil-field/)

base of the reservoir section, but the overlying Anhydrite and Portland Limestone interface and a distinctive set of tops defining the Kimmeridge section below (Figure 5.1).

The position of the Top Portland sandstone can be inferred from the ties and can therefore be mapped on the 2D seismic database.

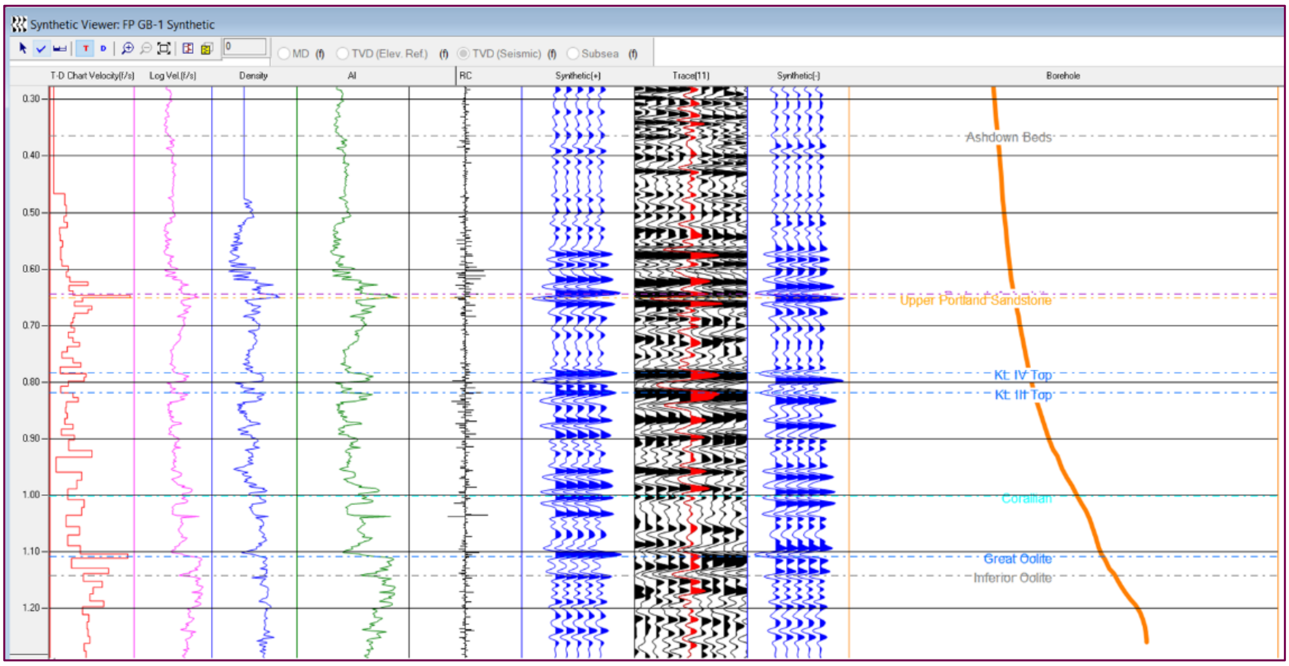

Figure 5.1: Godley Bridge-1 Synthetic well tie to line STA-10-04

Using the same definition for the picks each of the wells were subsequently tied to their nearest seismic lines (Figure 5.2, Figure 5.3 and Figure 5.4).

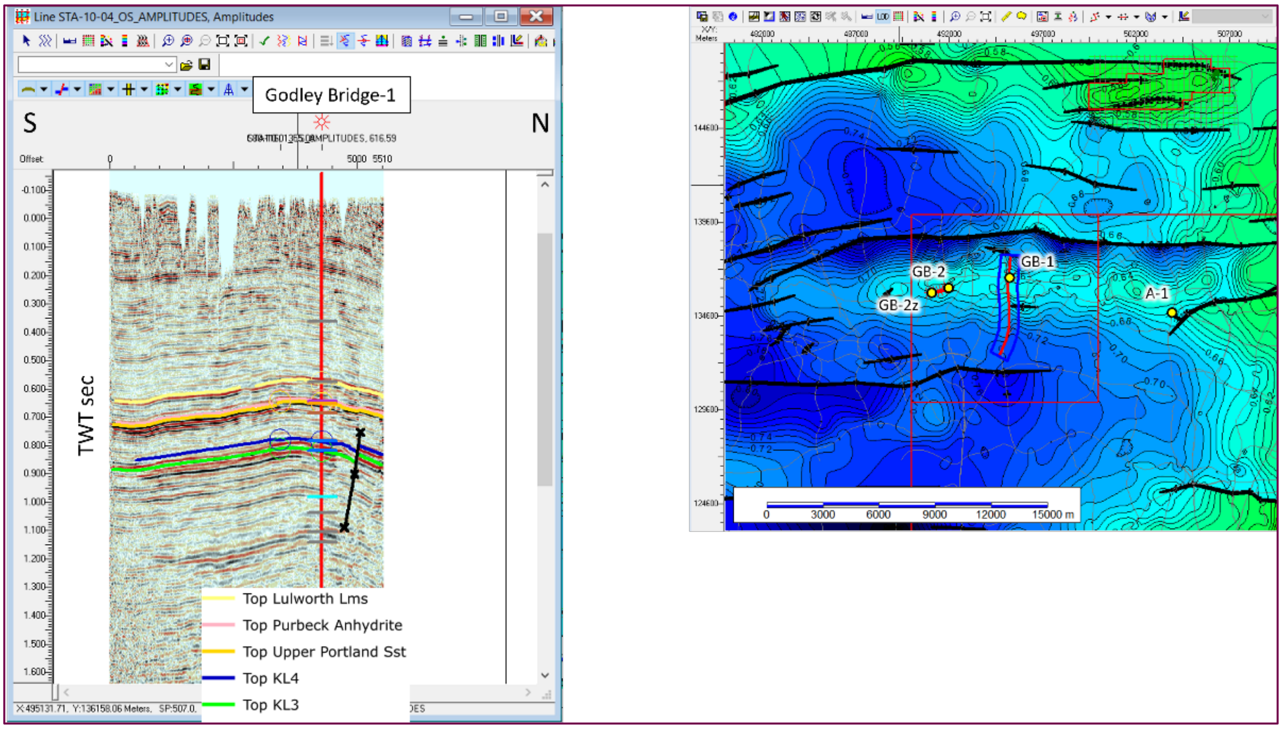

Figure 5.2: Godley Bridge-1 Seismic Tie

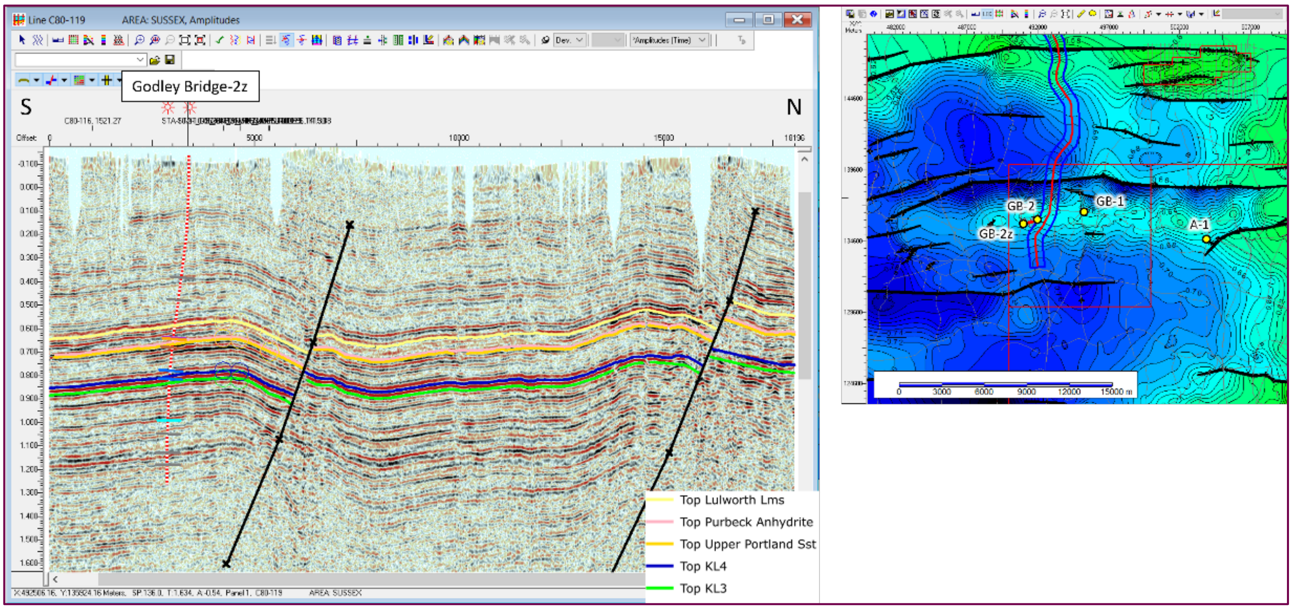

Figure 5.3: Godley Bridge-2z Seismic Tie

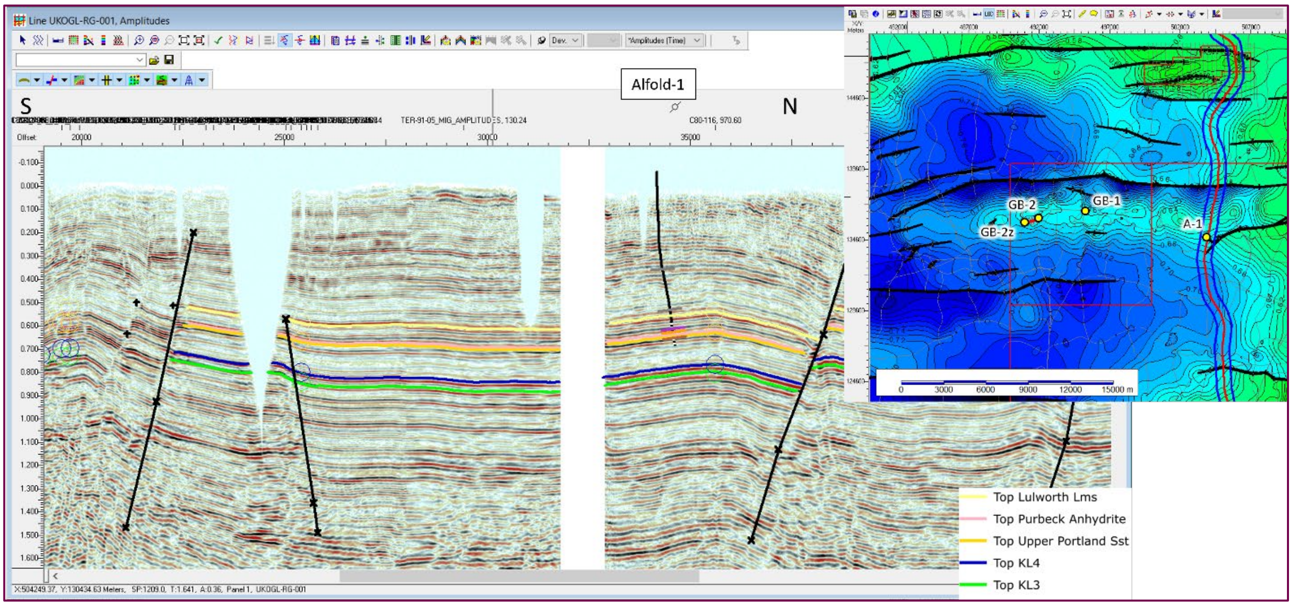

Figure 5.4: Alfold-1 Seismic Tie

5.1.1.2 Mapping

The Top Upper Portland Sandstone was subsequently mapped across the seismic database to produce a TWT map. RPS examined the picks on the seismic data and are satisfied that the mapping represents the structure displayed by the seismic data. The resultant map is shown in Figure 5.5.

5.1.1.3 Depth Conversion

UKOG defined a V_0K equation to depth convert the time data to depth, this equation was constructed using data from the Godley Bridge and Alfold wells, along with nearby wells from the Horse Hill field. A much larger regional data set from the lower cretaceous was also examined to ensure that the data fell within logical boundaries.

The V_0 map displayed in Figure 5.6 was applied to the time data and the depth map shown in Figure 5.7 was derived, RPS judged that the tie to the well depths is within acceptable limits.

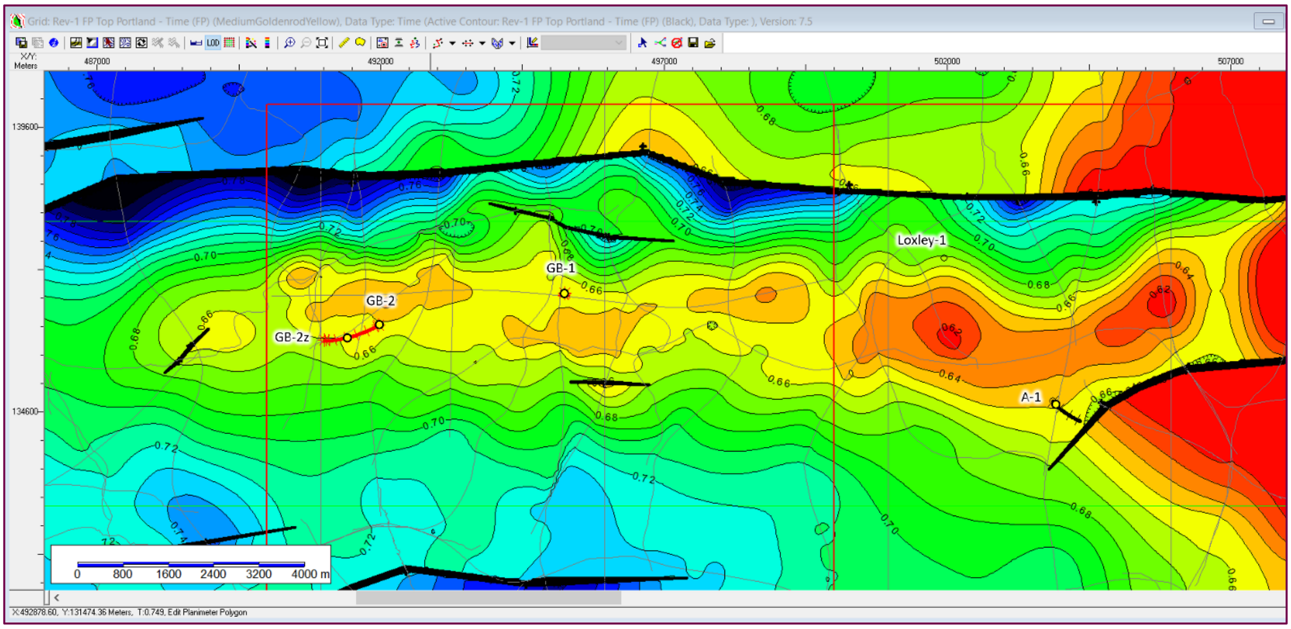

Figure 5.5: Top Upper Portland Sandstone (TWT) Seconds

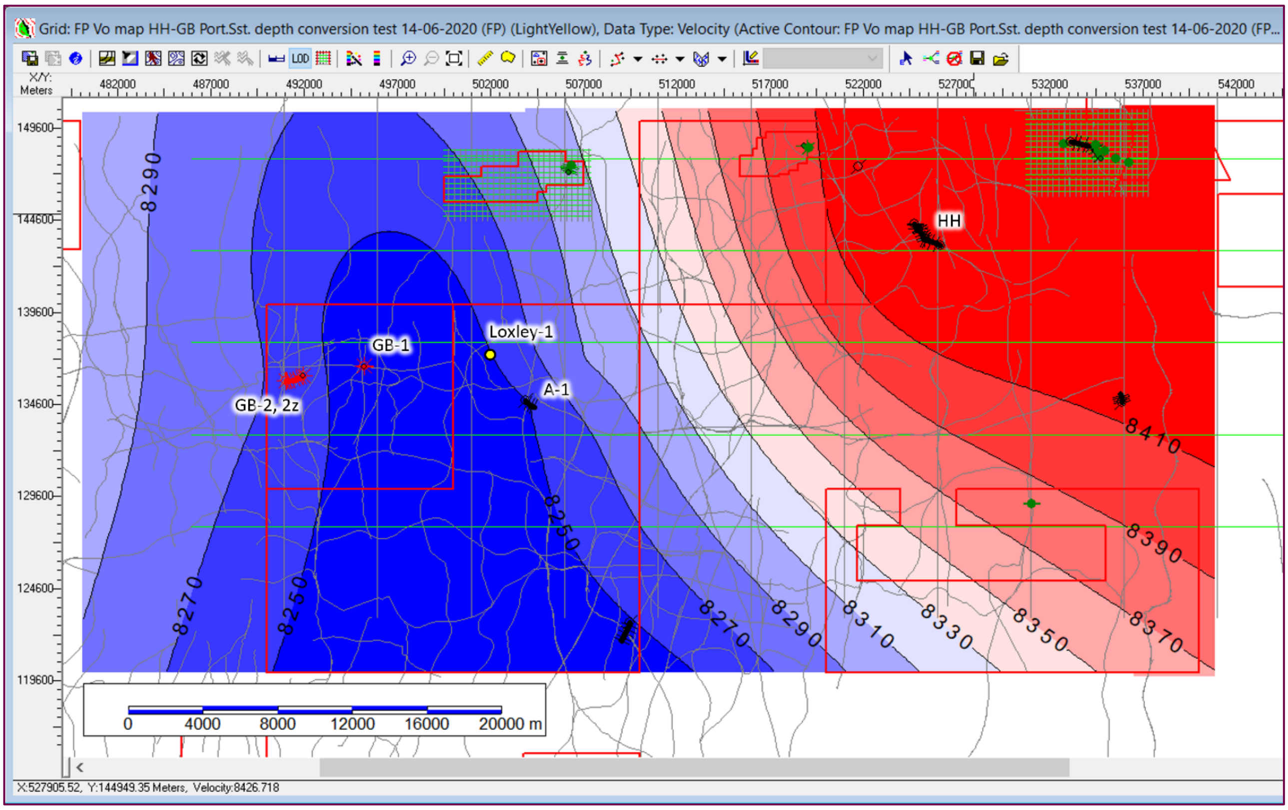

Figure 5.6: V0K Map used for Depth Conversion

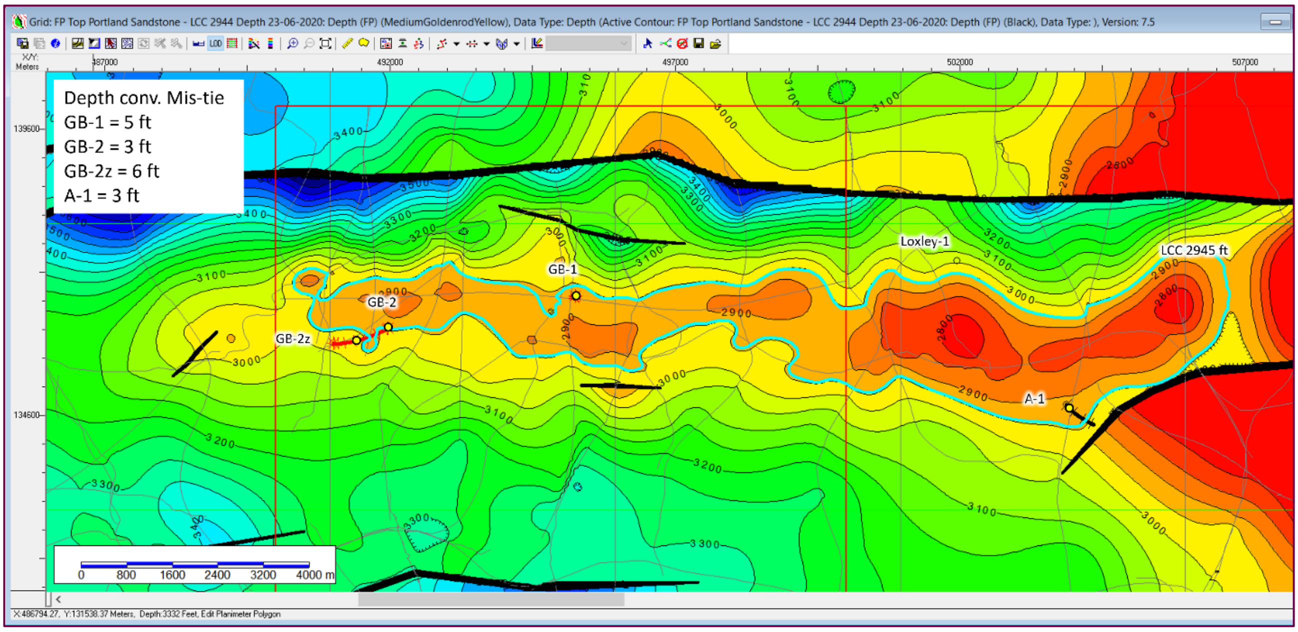

Figure 5.7: Top Upper Portland Sandstone Depth Structure Map[10] (ftTVDSS)

5.1.2 Geological Assessment

5.1.2.1 Depositional Environments

The Portland Sandstone Formation has been interpreted as a shallow marine sand (Figure 5.8).

[10] *Displays GWC defined in Petrophysics discussion (Section 5.1.3)*

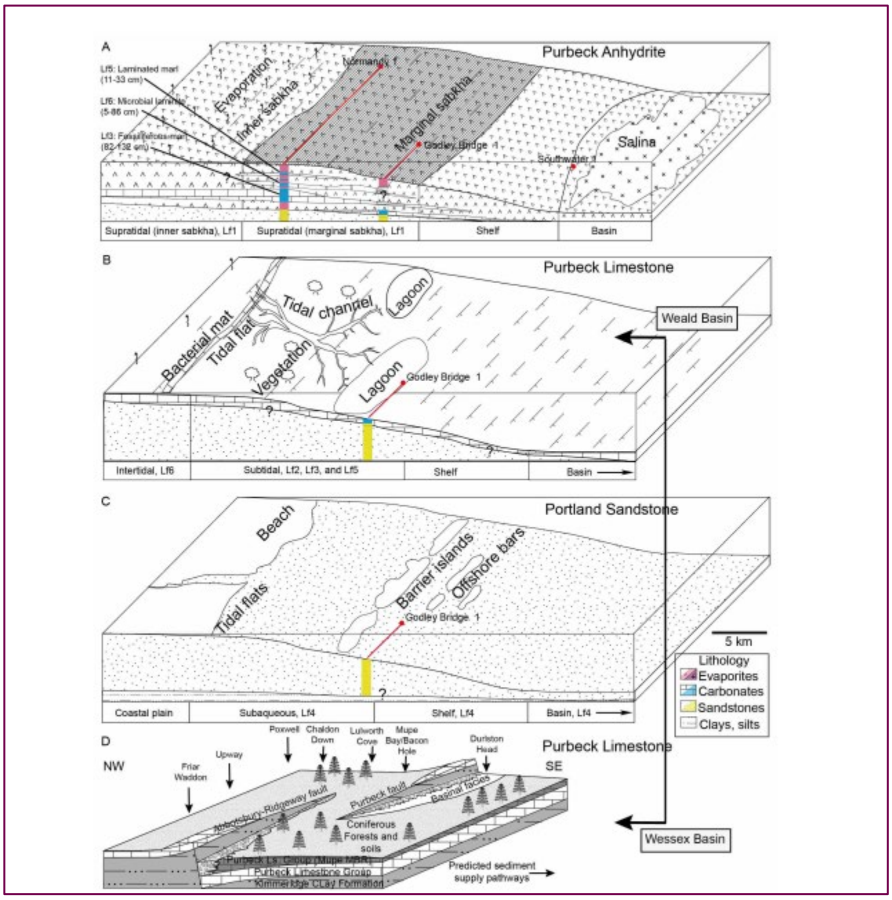

Figure 5.8: Diagram illustrating the Depositional Environments of the Portland Sandstone and the Overlying and Lateral Sedimentary Sequences[11]

The Portland sand overlies a marine mudstone (Kimmeridge) and in turn is overlain by limestones and evaporites laid down in restricted marine/brackish and hypersaline conditions. In the adjacent basin (Wessex) the lateral equivalent of the Portland sandstone is a shallow water carbonate platform.

5.1.2.2 Sedimentary Facies

The Upper Portland sandstone appears to vary in character between wells, particularly in the upper section (the gas bearing section in the field). The analysis of the core data revealed a difference in grain density between the top of the Portland section in the GB-1 well and the AI-1.

Abbott (2016) postulated that the area has potentially two sediment sources shown in Figure 5.9.

Considering the two sources of sediment supply and the dynamic nature of the depositional environment and the potential presence of offshore bars along with the shallow marine laid sediments in the Portland sandstone sequence, the facies changes noted are not a surprise.

Given the paucity of wells and the 2D seismic not having the resolution to accurately map facies changes at this scale RPS decided that the volumetric method for resource determination should reflect a probabilistic

[11] *Source: Depositional architecture and facies variability in anhydrite and polyhalite sequences: a multi-scale study of the Jurassic (Weald Basin, Brightling Mine) and Permian (Zechstein Basin, Boulby Mine) of the UK"; Imperial College - Sunshine Abbott: 2016*

distribution therefore considering the potential variability of the sediments and the properties of those sediments.

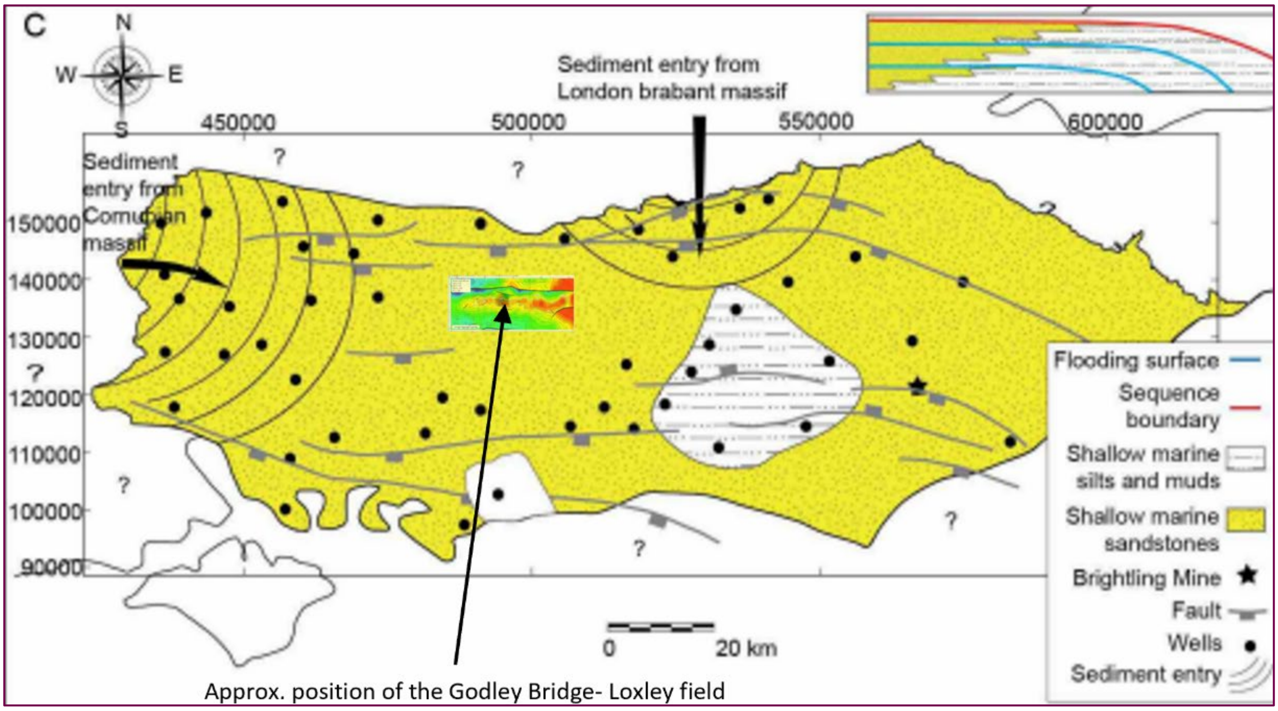

Figure 5.9: Regional Map showing Potential Sediment Input Sources to the Portland Sandstone[12]

5.1.2.3 Trap

The trap of the Godley Bridge structure is a broad east-west trending anticline of Tertiary age. The trap was formed as a result of the reactivation of a Lower Cretaceous-aged normal fault to the north (fault shown in Figure 5.7).

5.1.2.4 Seal

The seal to the reservoir is provided by the thin Portland Limestone and the overlying Purbeck Anhydrite.

The seal is proven by the presence of tested gas in the GB-1 well.

5.1.2.5 Source

The source of the gas is likely the underlying Kimmeridge Clay, it was noted that there was oil staining noted in the core analysis, but it is assumed to be a residual deposit and not indicative of an oil column in the sediments at this location**.**

5.1.3 Petrophysics

Three wells have been examined Godley Bridge-1 (GB-1), Godley Bridge-2Z (GB-2z) and Alfold-1 (Al-1).

The client provided LAS files containing the raw and processed log data, along with original core analysis reports where available, composite logs, mud logs, repeat formation test data and the results of the 3 DST tests in the section in the GB-1 well.

[12] *Source: Abbott, 2016*

5.1.3.1 Depth

Deviation surveys were made available to RPS, these were loaded for each well and the TVDSS depths calculated using a minimum curvature method and the elevation data derived from the original composite logs.

5.1.3.2 Volume of Clay

The Volume of clay curves presented by the client were felt to be supportable from examination of the data and were used in the calculations.

5.1.3.3 Porosity Calculation

The density log has been used to evaluate the porosity in the three logged wells. GB-1 and Al-1 contain core. GB-1 only over the upper sand interval but Alfold shows much more extensive core.

In GB-1 and GB-2z the core analysis indicates a grain density of 2.68 g/cc from the core analysis obtained for the GB-1 well for the Top Portland section gas bearing section, this gives a good match to the core porosity.

The upper sand in Alfold-1 3,691-3,745 ft MD (2,919 -2,969 ft TVDSS) appears to exhibit a different average grain density to the rest of the section from the core measurements of approx. 2.66 g/cc.

The sands below 3,749 ft MD appear to return to an average density of 2.68-2.69 g/cc

This would seem to indicate facies change between the GB-1 and Al-1 well at the top of the section.

5.1.3.4 Saturation

Water was recovered from the DST #7and the measured resistivity was assessed as 82,000 ppm.

Pickett plots (Figure 5.10) indicate an r_w of between 0.058 and 0.078 ohm.m in the Alfold and Godley Bridge wells this equates to approx. 81,000 ppm, therefore the sampled water of 82,000 ppm is thought to represent formation water.

5.1.3.5 Net to Gross

A permeability cut-off for net to gross of 1 mD has previously been used by the client on a calculated permeability log. RPS felt that a porosity cut-off reflecting a permeability of 1mD was more appropriate as the calculated permeability log does not match the core permeability very well whereas the calculated porosity log matches the core porosity.

A porosity cut-off of 10% was chosen as 10% represented approx.1 mD in the core data.

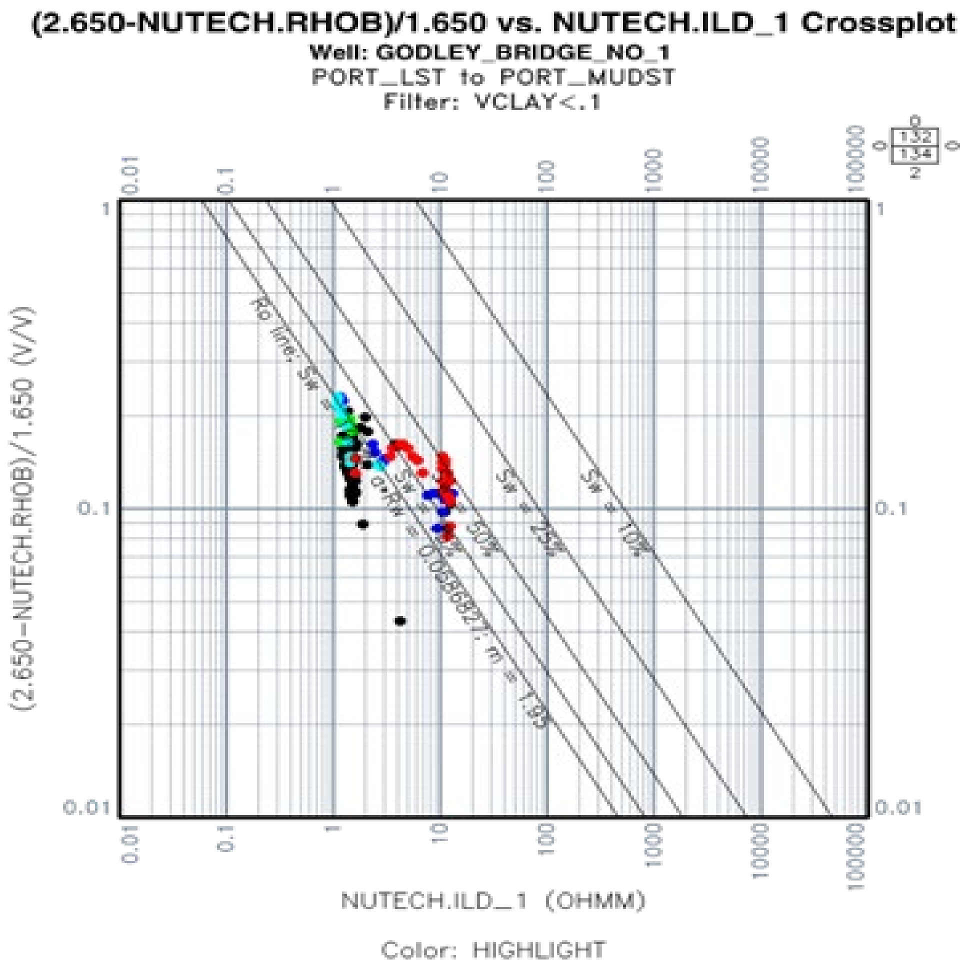

Figure 5.10: Pickett Plot of GB-1 Well

5.1.3.6 Gas Water Contact

The gas water contact (GWC) can be inferred from three data sources, the logs (specifically the deep reading resistivity), Repeat Formation Tester (RFT) data from the GB-1 well and the Drill Stem Tests (DST) from the GB-1 well.

The resistivity logs in both Alfold-1 and Godley Bridge-1 show a major drop in resistivity at a TVDSS depth of 2,945 ft (Figure 5.11 and Figure 5.12). The well Godley Bridge-2z well shows a water response in the resistivity log up to 2,972 ft TVDSS which is the top of the Portland sandstone in that location.

The RFT data available in Godley Bridge-1 shows two gradients a gas gradient (0.15psi/ft) and a water gradient (0.477 psi/ft) which when plotted against the data give an indication of a contact at 2,944 ft TVDSS, the lack of data points means that the accuracy is approx. +/- 1 foot. (See Figure 5.13).

The RFT data available in Alfold-1 plots a water gradient through the good test points indicating a water up to 2,951ft TVDSS.

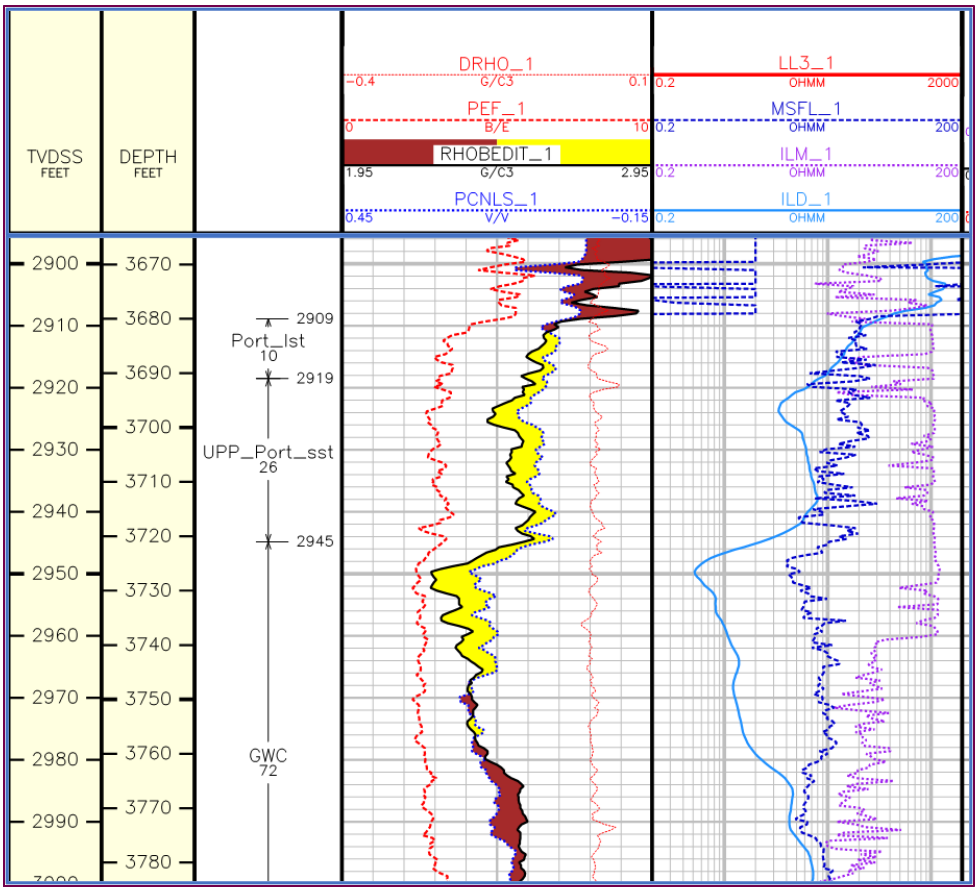

Figure 5.11: Log Panel showing the Density Log Response and the Deep Reading Resistivity Curve in AI-1

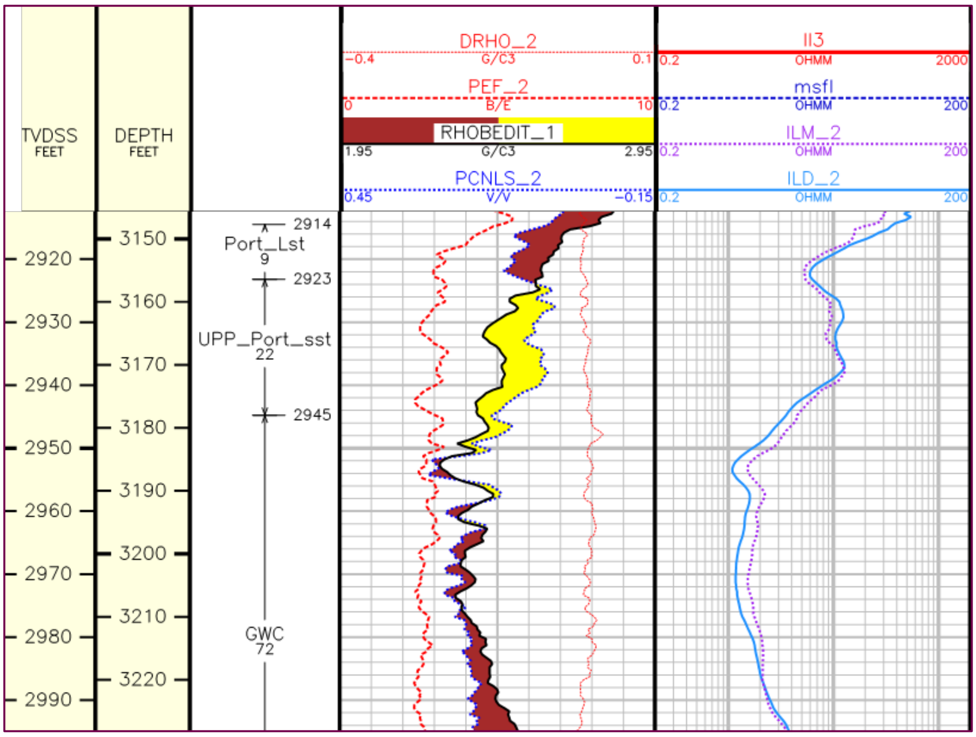

Figure 5.12: Log Panel showing the Density Log Response and Deep Reading Resistivity Curve in GB-1

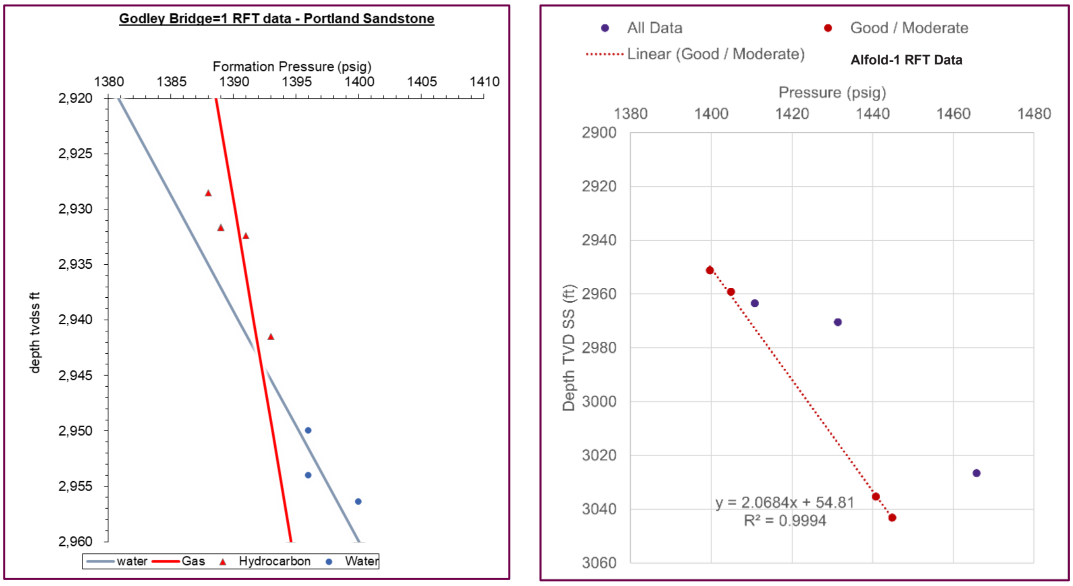

Figure 5.13: RFT Data from GB-1 and Al-1 Wells

The drill stem test data from Godley Bridge -1 indicates gas flow with filtrate from the first two tests and then gas with formation water from the third test (DST test numbers 5,6 and 7 respectively) (Table 5.2).

DST #	Interval (ft MDRKB)	Avg. Separator Gas Rate (Mscf/d)	Avg. WHP (psig)	Produced Fluid (stb)	Condensate Yield (stb/MMscf)	Additional
5	3160-3170	947	1002	2.4 (filtrate)	-	0.664 gas gravity, 6 ppm H_2S, 100ppm CO_2
6	3160-3180	1,342	949	9.3 (filtrate)	0.5	0.675 gas gravity, 2-20 ppm H_2S
7	3160-3190	1,045	883	21.7 (formation water)	0.7	0.665 gas gravity, 2-60 ppm H_2S, max. 2000ppm CO_2

Table 5.2: Results of DSTs in Godley Bridge-1

The final set of perforations to include the depth down to 3,190 ft MD (2,956 ft TVDSS) will have crossed over the speculated GWC and would have been expected to produce water. Given the evidence described above the Gas Water Contact was set at 2,945 ft TVDSS.

5.1.3.7 Permeability

The permeability is variable across the core data ranging from 0.02 mD up to 900 mD demonstrating the variable nature of the Portland sandstone.

There appears to be two distinct trends in the core data porosity permeability relationship, shown in Figure 5.14

This data could mean that permeability may be preferentially preserved by gas emplacement above the Gas Water Contact.

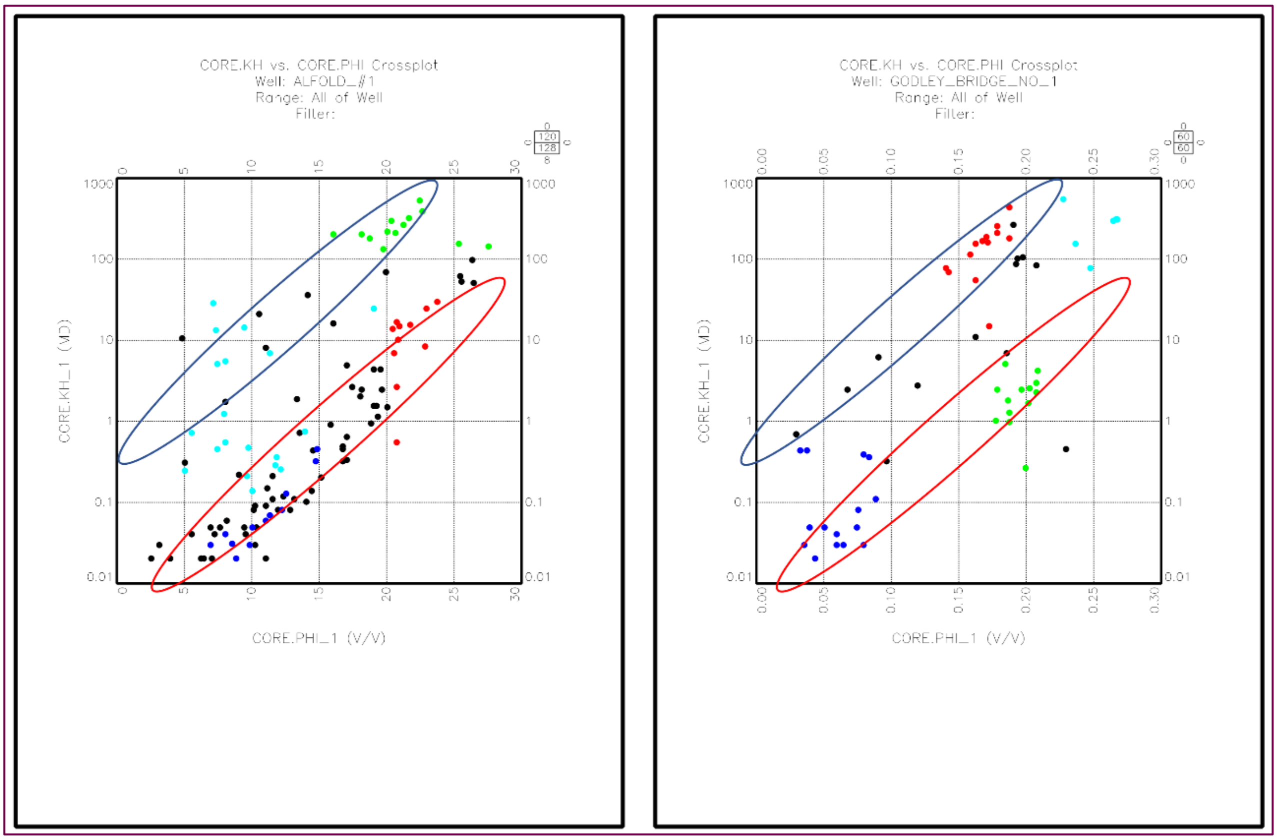

Figure 5.14: Two Permeability Trends in Core Data – blue ellipse above / red ellipse below GWC

5.1.3.8 Results

The results of the petrophysical analysis are shown in Figure 5.15, Figure 5.16 and Figure 5.17.

A diagram showing the wells in TVDSS is shown in Figure 5.18 and a further panel display showing the wells hung on the Top Portland sandstone is shown in Figure 5.19.

The average porosity values and an indicative saturation range were calculated from the data.

The porosity ranges from 6% through to 24% with an average of 15%.

The water saturation taken from the GB-1 well ranges from 38% to 63%, the average value was calculated to be approx. 54%, but for the purposes of the volumetric calculations this range has been flexed to allow for the fact that gas saturation in the up-dip sections would be expected to be higher.

The inputs into the probabilistic model are shown in Section5.1.4.

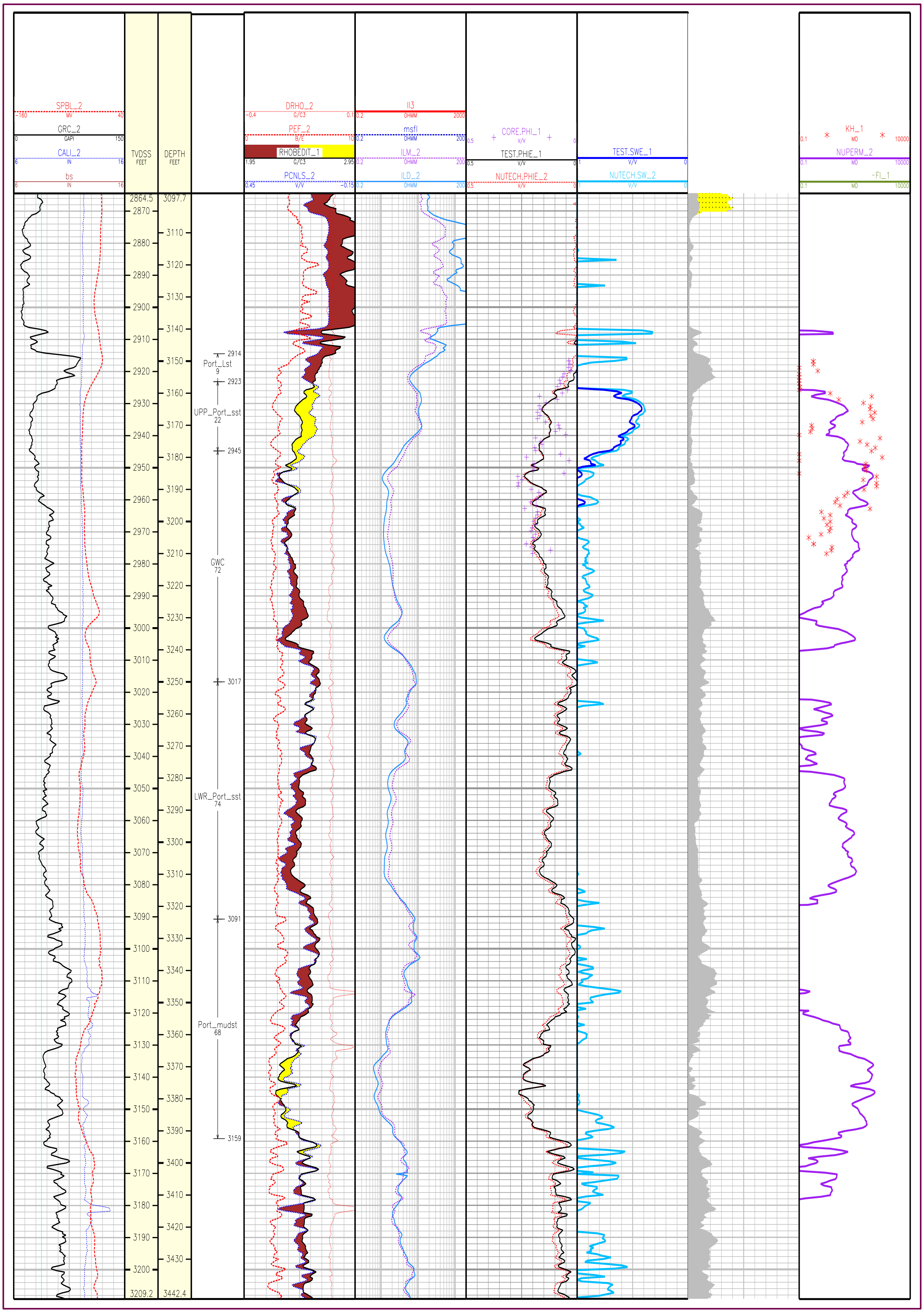

Figure 5.15: GB-1 Well (Referenced to TVDSS) Petrophysical Display

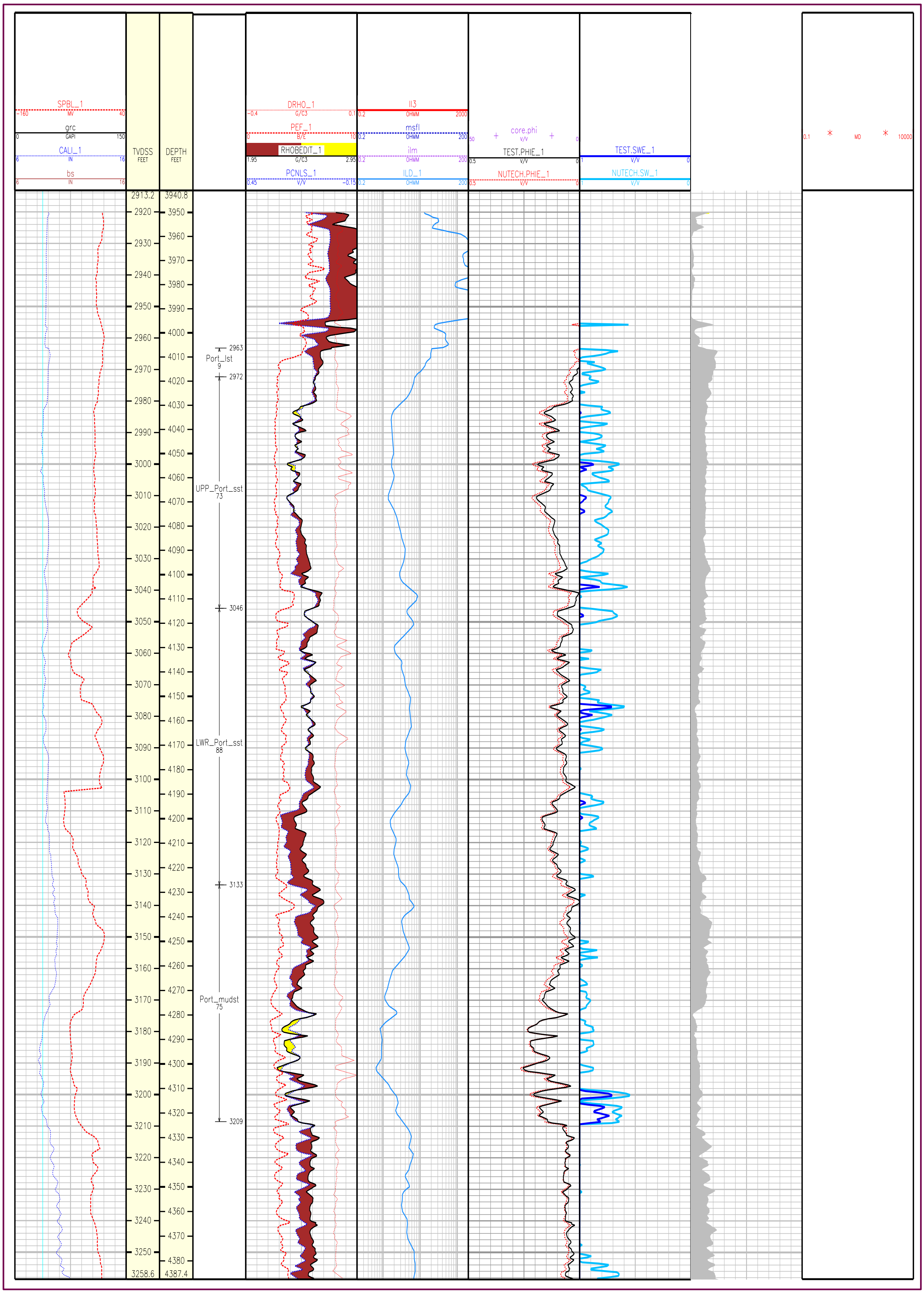

Figure 5.16: GB-2Z Well (Referenced to TVDSS) Petrophysical Display

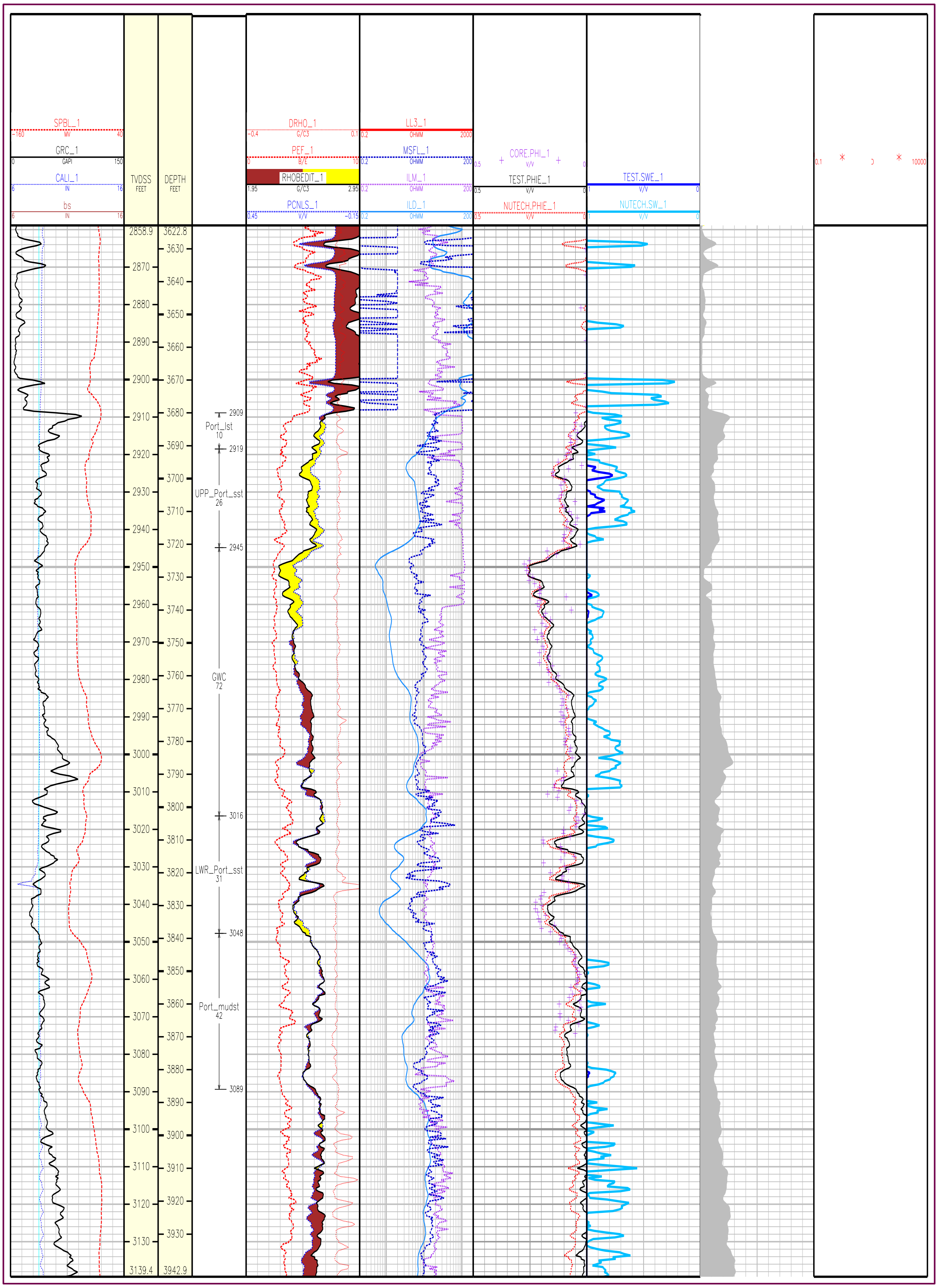

Figure 5.17: GB-2Z Well (Referenced to TVDSS) Petrophysical Display

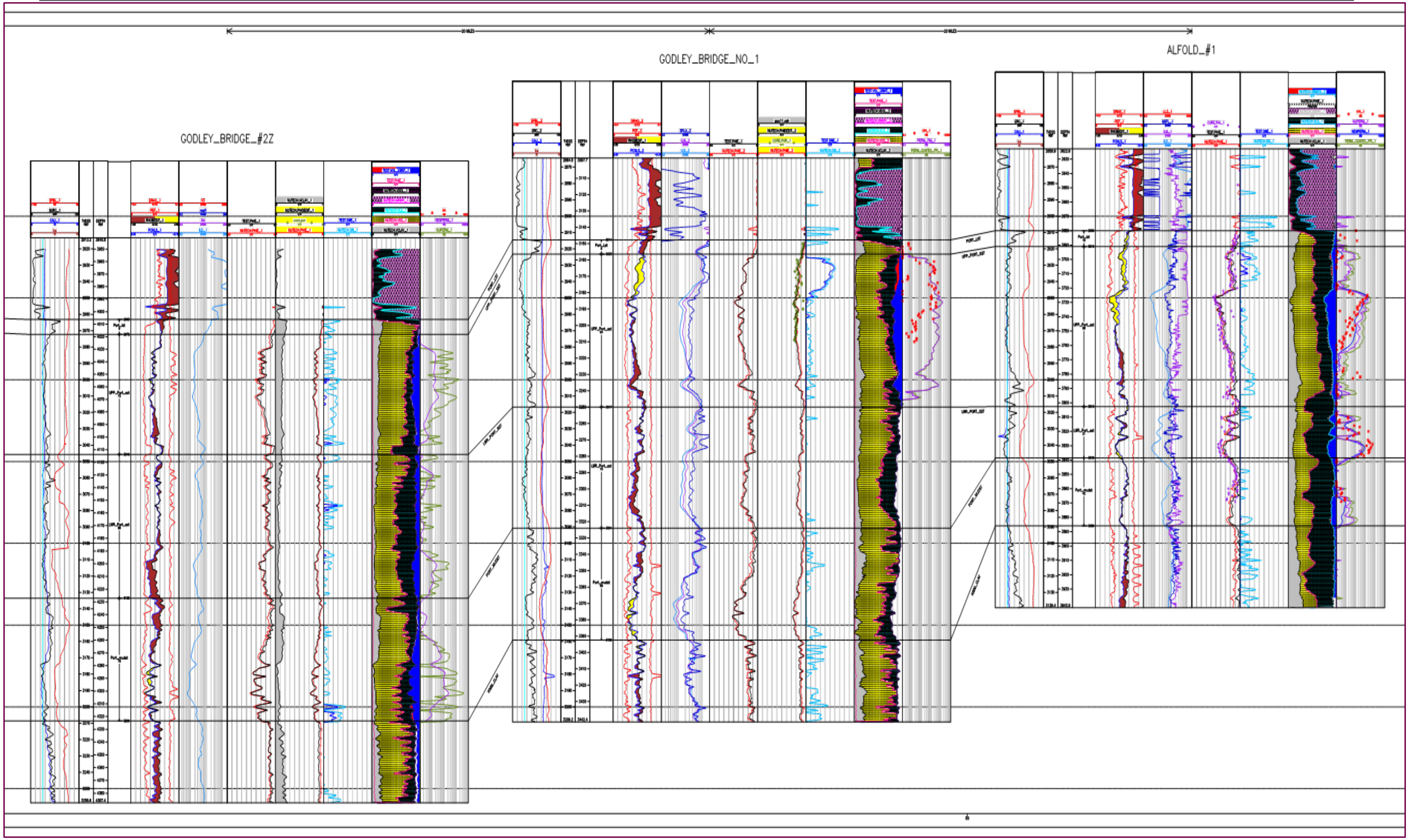

Figure 5.18: Well Section TVDSS (GB-1, GB-2Z, AL-1)

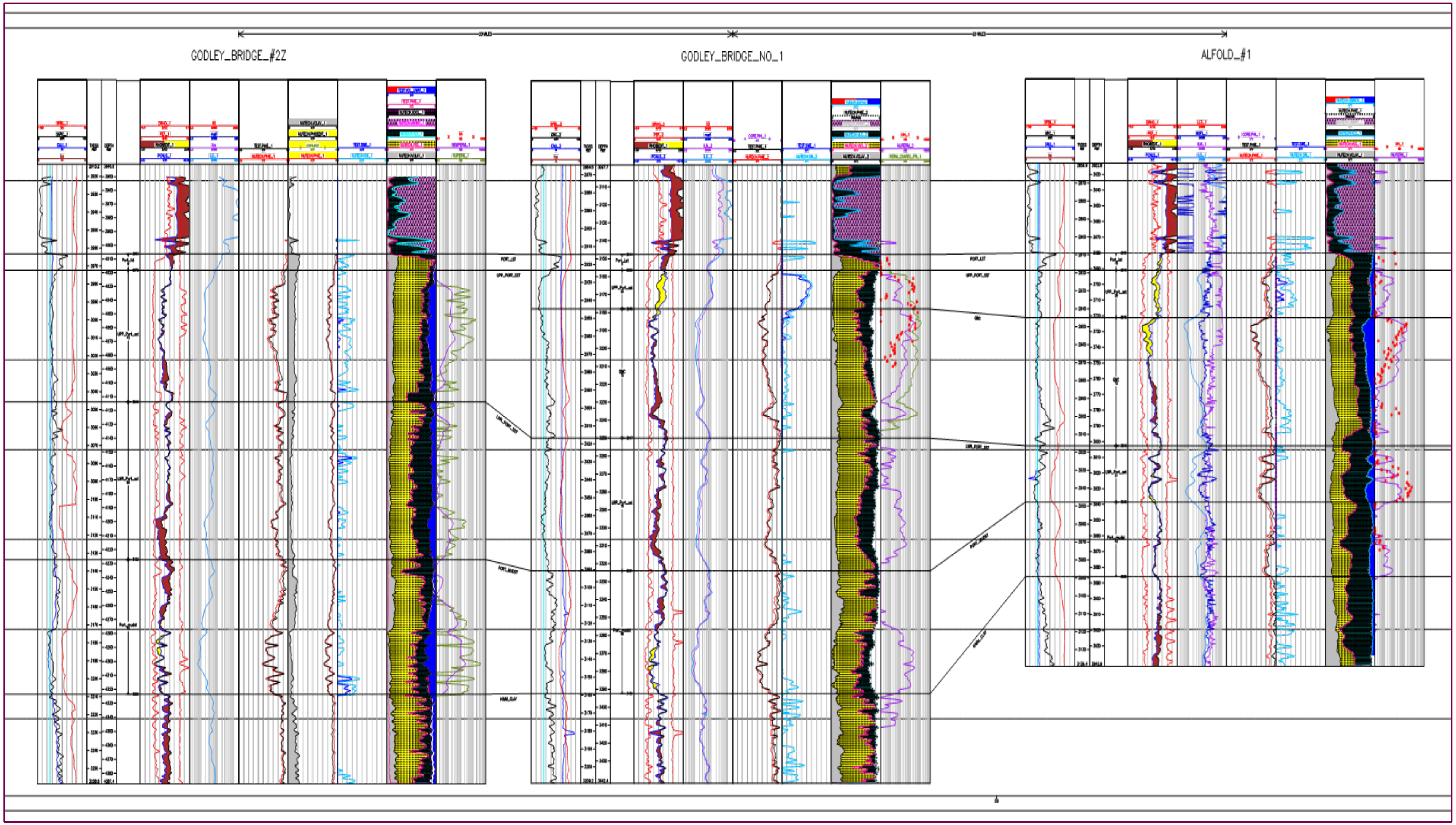

Figure 5.19: Well Section Hung on Top Portland Sandstone (GB-1, GB-2Z, AL-1)

5.1.4 Probabilistic Volumetrics

5.1.4.1 Methodology

RPS has used a probabilistic approach to calculate the initial volumes in place (GIIP)

A probabilistic model using normal distributions based on the inputs shown below was run iterating 20,000 times to give the range of results displayed in Section 5.1.4.3.

5.1.4.2 Input Data

The input data for the probabilistic runs are shown in Table 5.3:

Parameter	Unit	Distribution	Min	P90	P50	P10	Max
Thickness	ft	Normal	116	170	210	250	304
Area Uncertainty	%	Normal	41.5	75	100	125	159
GWC	ft TVDSS	Normal	2933	2940	2945	2950	2957
NTG	%	Normal	36.6	50	60	70	83.4
Porosity	%	Normal	5.6	11	15	19	24.4
Sw	%	Normal	38	43.3	49.4	55.9	63
FVF (1/Bg)	scf/cf	Normal	76.6	90	100	110	123
Gas Recovery	%	Single	100				

Table 5.3: Input Data for Probabilistic Volumetric Calculation

5.1.4.3 Probabilistic Volumetric Results

The calculated probabilistic volumes are shown in Table 5.4:

RPS GIIP (Bscf)	P90	P50	P10	Mean
Whole Structure	35	57	86	59
PEDL234	28	44	67	46
PEDL235	8	13	20	14

Table 5.4: GIIP across the Whole Structure and contained in the Structure that lies within PEDL234

5.1.5 Reservoir Engineering Assessment

Relatively little data is available for undertaking the Reservoir Engineering assessment.

RPS has been provided with a couple of PowerPoint presentations on work undertaken by Kappa Engineering to forecast production based on a two well development of the field. Kappa Engineering has also undertaken an interpretation of the DST#6 in GB-1 and a copy of the Kappa report was also provided[13].

Other than the DST's, there has been no production from the field. RPS has not been provided with any of the test reports, so is not able to comment on the cumulative volume of gas produced to date, but it is presumed to be negligible.

[13] *Independent Pressure Transient Analysis Review Report, Godley Bridge-1 DST#6, October 2022.*

No further engineering information has been made available. RPS is not aware of any special core analysis being available which would provide relative permeability data, nor any specific well design data. No other reports have been made available.

5.1.5.1 DST Interpretation

The Loxley structure has tested gas from the Godley Bridge-1 (GB-1) well through 3 DST's which produced dry gas and mud filtrate in the two higher ones and dry gas and formation water in the lowest, as shown in Table 5.5 below:

DST#	Interval (ft MDRKB)	Avg. Separator Gas Rate (Mscf/d)	Avg. WHP (psig)	Produced Fluid (stb)	Condensate Yield (stb/MMscf)	Additional
5	3160-3170	947	1002	2.4 (filtrate)	-	0.664 gas gravity, 6 ppm H_2S, 100ppm CO_2
6	3160-3180	1,342	949	9.3 (filtrate)	0.5	0.675 gas gravity, 2-20 ppm H_2S
7	3160-3190	1,045	883	21.7 (formation water)	0.7	0.665 gas gravity, 2-60 ppm H_2S, max. 2000ppm CO_2

Table 5.5: Summary of Drill Stem Tests on Portland Sandstone

All three tests undertaken were Cased hole, with the interval perforated with 4" 4spf guns. Reportedly no acid stimulation was performed post perforation and flow was induced using nitrogen.

Kappa Engineering has undertaken Pressure Transient Analysis of DST#6 from the Godley Bridge-1 well, performed in 1983.

The objectives of the Kappa study are reported to be:

To review the PTA model and confirm that DST#6 had a positive skin and that ideal productivity index would be higher without positive skin

To provide a short report stating input assumptions and resulted to be used for farmout material.

The report discusses the work undertaken. The available pressure data is very sparse due to low resolution/frequency, which leads to significant uncertainty in identifying radial flow stabilisation and hence the formation permeability. The Kappa work has estimated a range of permeabilities of 72-307mD based on various sensitivity cases and selects a value of 171mD as a base/reference case. These values are towards the upper end of reported core permeabilities but are within the data range (Figure 5.20).

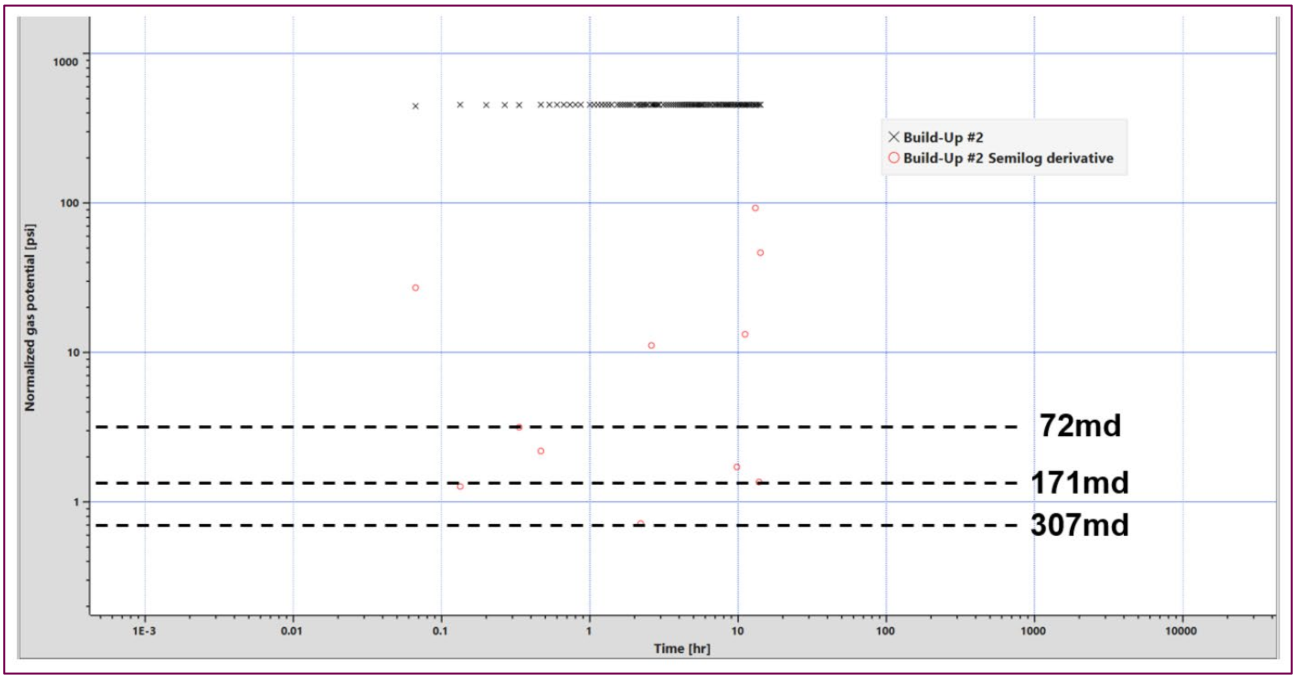

Figure 5.20: Kappa Engineering Selected Radial Flow Stabilisation

On the basis of the analyses discussed in the report, Kappa suggests that the test exhibited a mechanical skin value of 165, which is would substantially reduce well productivity. If this skin could be reduced to zero, the Kappa analysis suggests that a rate of 15-18 MMscf/d could be achieved for the same drawdown achieved by DST6.

RPS is inclined to suggest that the data is too sparse to make any definitive interpretation and therefore is of limited use in defining likely future well performance. Well productivity therefore remains one of the major contingencies.

5.1.5.2 Fluid Composition

Based on the results of the DSTs undertaken in the GB-1 well, produced fluids from future production is anticipated to be a dry gas with minimal (0.5-0.7 stb/MMscf) condensate volumes. Test and gas sample data is available from the three DST tests undertaken on the GB-1 well.

Fluid composition (gas and condensate) is reported in Table 5.6 and Table 5.7:

DST# Component	DST#5 mol%	DST#6 mol%	DST#7 mol%
N_2	4.27	4.52	4.02
H_2S	-	<0.01	-
CO_2	0.29	0.16	0.24
C1	85.61	85.47	85.98
C2	5.08	5.15	5.12
C3	2.78	2.78	2.71
iC4	0.41	0.41	0.39
nC4	0.83	0.84	0.82
iC5	0.23	0.21	0.22
nC5	0.21	0.19	0.2
C6	0.16	0.12	0.16
C7	0.09	0.12	0.1
C8	0.03	0.03	0.03
C9	0.01	-	0.01
Gas Gravity (air=1)	0.66	0.66	0.658

Table 5.6: Portland Sandstone Gas Composition

DST# Component	DST#5 wt%	DST#6 wt%	DST#7 wt%
C2	0.04	0.01	0.01
C3	0.79	0.95	0.62
iC4	0.98	1.37	0.97
nC4	3.52	5.12	3.8
iC5	4.66	6.6	5.16
nC5	6.5	8.86	7.01
C6	15.86	19.12	15.88
C7	22	23.71	22.86
C8	17.2	16.67	19.84
C9	6.46	5.36	7.59
C10+	21.99	12.23	16.26
Specific Gravity @ 60 deg F	0.7324	0.7065	0.7057
°API	61.7	68.78	69

Table 5.7: Portland Sandstone Condensate Composition

The gas composition shows relatively low CO_2 content, but N_2 content is 4.0-4.5%. All three DST summaries suggested some H_2S present, though this is not clearly represented in the gas compositions provided. This will need to be clarified by future appraisal wells.

RPS has confirmed that the Wobbe Index for all three gas samples is within the gas quality requirements for the National Transmission System (NTS)[14], ranging from 50.42 – 50.66 MJ/m^3. As a result, RPS has not included any sales gas shrinkage at this stage, though this will need to be confirmed during appraisal.

5.1.5.3 Production Forecasts

UKOG has estimated gas resources for Loxley based on a reservoir study performed by Kappa Engineering consultants.

The objectives of the Kappa study were to:

- Generate P90/P50/P10 forecasts
- Establish well timings required to maintain production plateau
- Provide THP/BHP forecasts for development planning
- Undertake sensitivities for aquifer size and contact depth

The workflow followed by Kappa is shown in Figure 5.21 below:

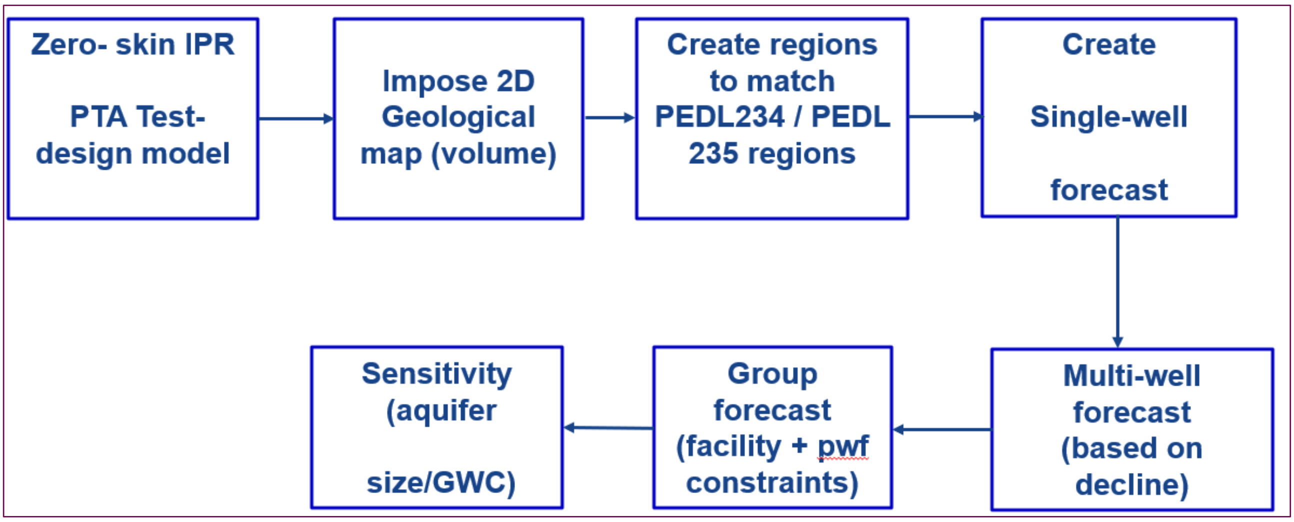

Figure 5.21: Kappa Engineering Workflow

The reservoir is relatively extensive in an east-west direction and is divided into two lobes with production proposed from the more prominent eastern lobe. The Kappa modelling studies investigated two cases; depletion drive and production with an active aquifer of 100 MMSTB volume, which is within reason based on regional understanding.

Kappa has assumed two wells in the P90/P50 case, with a third well included in the P10 case only. All wells assume a 4.5" OD (3.96" ID) completion with a 20 ft perforation section in a 30 ft net pay zone. Skin is assumed to be zero (0) in all cases.

The Kappa cases include a 30% trapped gas saturation where aquifer influx occurs, but 100% vertical and horizontal sweep efficiency. Minimum flowing BHP is assumed to be 300 psia but there are no other facilities constraints considered in generating the production forecasts.

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[14] https://www.nationalgrid.com/gas-transmission/data-and-operations/quality

The depletion cases show a typical recovery factor of 75-80%, while the aquifer cases (including trapped gas saturation of 30%) show the recovery factor reduces to approximately 60%.

No detailed special core analysis to determine gas recovery and microscopic core behaviour under water drive has been made, nor any reservoir simulation model scenarios under different aquifer strengths and realistic sweep patterns. However, RPS considers that a recovery factor range of 60-80% is reasonable at this stage of development planning, based on analogues (both local and international), accounting for variation in sweep efficiency and potential aquifer influx which may reduce recovery.

UKOG suggest that there is no evidence of aquifer influx from Pressure Transient Analysis (PTA) of available DST data. However, it is noted that the DST's were all of limited duration and hence RPS opines that aquifer influx cannot be ruled out. While there is limited regional production history from the Portland Sandstone, it has produced moderate amounts of water in the Horse Hill and Brockham fields. In addition, as the field is formed of two local highs there is potential for isolation or poor drainage of the PEDL 235 western high under the current development plan, siting the production wells in the PEDL 234 eastern more prominent highs.

There is a permeability contrast below the gas water contact and permeability is degraded relative to that in the gas bearing reservoir (Section 5.1.3.7) and as a result the energy of the aquifer in the base case is potentially limited.

Therefore, RPS has assumed an active aquifer in the P90 case with significant trapped gas saturation behind an advancing water drive, leading to a recovery factor of 60% of GIIP.

In the P50 and P10 cases, we have assumed there is no water influx and the field operates under depletion drive only.

RPS has reviewed a number of global analogue fields operating under depletion drive in similar sandstone reservoirs. The average recovery factor from these analogues is 70%, which sits in the middle of the range of recovery factors defined by the Kappa Engineering studies. On this basis, RPS has elected to use a deterministic P50 case recovery factor of 70% and has accepted the P10 case recovery factor determined by Kappa Engineering of 80%.

RPS has generated production forecasts based on the Kappa Engineering cases by scaling of the plateau length in the Kappa forecasts to align with the recovery factors noted above and the RPS volumetric estimates (Table 5.4).

The resulting RPS production forecasts are shown in Figure 5.22.

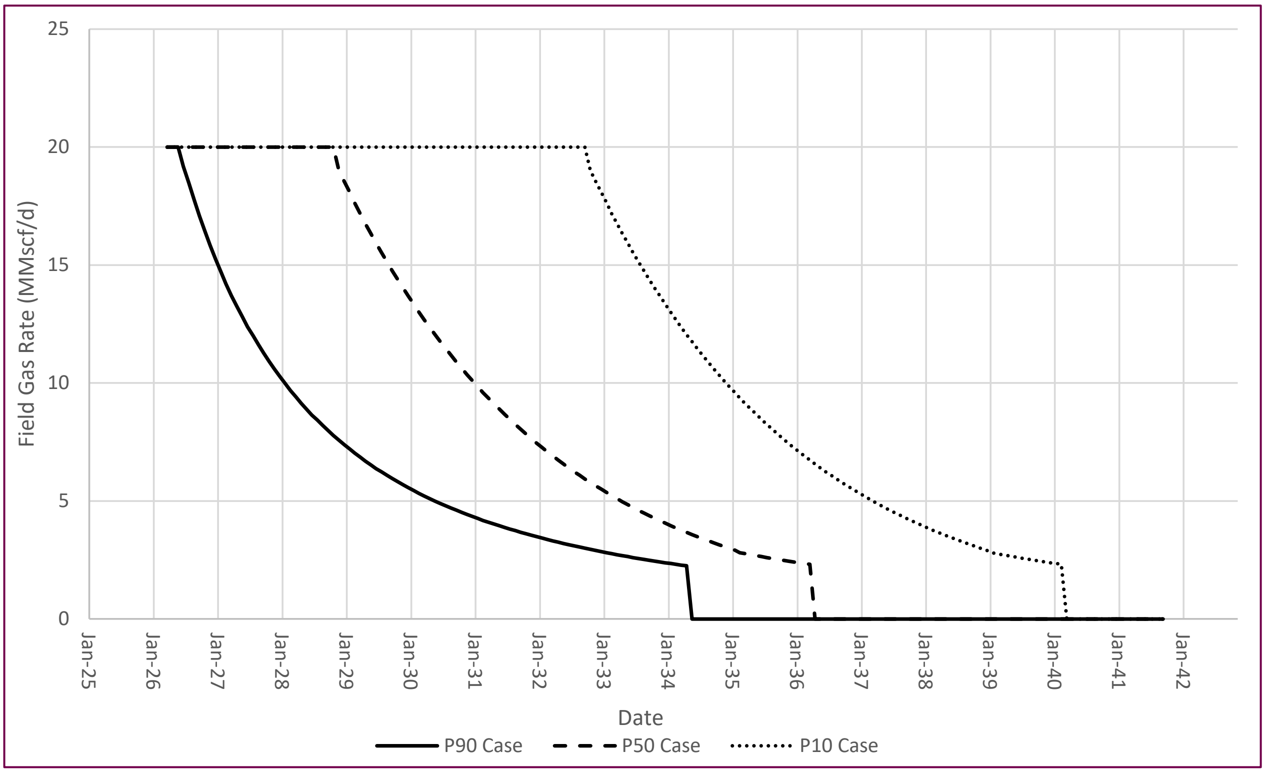

Figure 5.22: RPS Production Forecasts

Case	P90	P50	P10
GIIP (Bscf)	35	57	86
Recovery Factor (%)	60	70	80
EUR (Bscf)	21	40	69

Table 5.8: RPS Forecast Summary (Whole Structure, 100% WI)

Note, RPS has not included any fuel/flare/shrinkage currently. RPS assumes that any power requirements will be met by connection to existing power infrastructure (and therefore covered by Opex) and no routine flaring will be permitted.

RPS has also not assumed any downtime and that production efficiency is 100% at this stage. Given the relatively simple plant operation, RPS has also assumed no downtime during normal operation, though this will need to be considered in future reviews once the plant design has progressed.

The main engineering contingencies present are likely to be:

1) Confirmation that the forecast flow rates can be achieved from the planned production wells[15].

2) Confirmation of gas composition, H_2S content and condensate yield to allow for correct plant design.

[15] To date, DST rates were only approximately 1 MMscf/d. Kappa's interpretation of DST#6 suggests this may be due to a large mechanical skin during the test and that a zero skin well could produce at significantly higher rates (15-18 MMscf/d), though RPS believes the interpretation is uncertain due to the scarcity of the available pressure data. However, based on the reservoir properties from logs, there is no suggestion that these rates cannot be achieved from the planned wells if drilled successfully with minimum formation damage.

5.1.5.4 Surface (Wells and Facilities) Review

UKOG have provided an outline development concept for the Loxley development which RPS agrees is reasonable.

Gas from the wells will be dehydrated and acid gas removed before metering and export via a new 6.6 km export pipeline to the low-pressure Local Transmission System. Initially the gas will free flow from the wells to the delivery point. However, capital expenditure allowances are included to retrofit gas compression to boost the facility export pressure as the reservoir pressure declines.

UKOG have assumed a 6" export pipeline. Depending on the required delivery pressure the flowline pressure drop can be high at peak flows. UKOG are planning to deploy a composite pipeline system that is only available up to 6" diameter. During more detailed facility engineering studies, it may be necessary to revise this assumption for a larger diameter line or install a second pipeline in parallel. The costs carried forward into the evaluation assume a single pipeline will be sufficient.

The initial Loxley-1 well is an appraisal/keeper well. Final investment decision (FID) on the project will be subject to a satisfactory extended well test (EWT) from the Loxley-1 well. In the development case, production will initially be from the Loxley-1 well with a second well following, currently assumed to be drilled in Q1 2028. The current timeline from UKOG has the Loxley-1 well scheduled to spud at the end of year in 2023 and be drilled to completion in Q1 2024, this appears to allow reasonable time to plan the well and secure long lead items during 2023.

UKOG have targeted a first gas production date of Q2 2026. Again, in RPS's opinion this is reasonable. RPS has considered a 6-month window to complete an expected 30 day EWT program and further subsurface and reservoir studies, will be sufficient to allow UKOG to determine if the development is viable. FID during the second half of 2024 will allow 18 months to procure and install the processing facility. Compressors are usually one of the longest lead time items of equipment, but compression is deferred until 2028 so 18 months from FID to first production should be sufficient time.

In RPS's opinion, UKOG would need to undertake facility conceptual engineering design and FEED studies, Field Development Plan (FDP) and Environmental Impact Assessment (EIA) ahead of the Loxley-1 well to allow FID to be reached in 2024. The development schedule is shown in Figure 5.23 below.

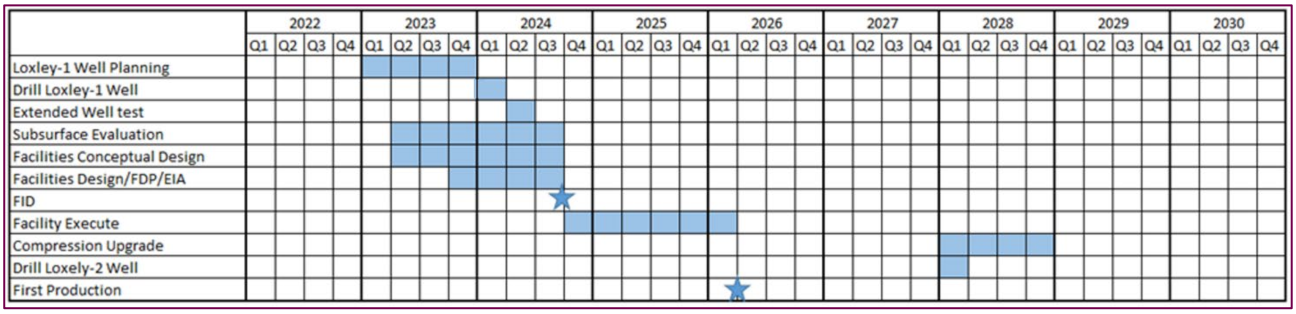

Figure 5.23: Development Schedule

5.1.5.5 Production and Cost Profiles

UKOG has provided a CAPEX estimate for the development which has been reviewed by RPS and in general RPS has determined it is reasonable and have largely accepted the UKOG cost estimate. UKOG have specified a contingency of 25% on the processing facility cost which, given the level of definition of the project, RPS agrees is reasonable. RPS have additionally applied this level of contingency allowance to the compression retrofit and pipeline costs. RPS have applied an additional 10% of facility costs for Owner's Costs, these are operator's costs associated by undertaking the development.

UKOG have provided an OPEX estimate of £1MM/year of which 66.7% is fixed and 33.3% is variable which RPS agrees as reasonable. However, RPS has included an additional element of fixed OPEX of £0.2m/year for the compression system when that is online.

UKOG have provided an estimate of the Abandonment costs. UKOG estimate £0.5m to P&A a well which RPS has accepted but the allowance of £1MM for the decommissioning of the facility, in RPS's opinion, is too low and this has been increased to £1.8MM resulting in a total ABEX allowance of £2.8MM, which conforms to the industry norm of facilities abandonment costs at 10% of the production facility CAPEX (Table 5.9).

Project CAPEX	Cost (£MM) - Real Terms
Facilities CAPEX	12.30
Compression CAPEX	2.95
Pipeline CAPEX	8.0
Facility/Compression/Pipeline Contingency (25%)	5.83
Owner's Costs (10%)	2.33
Loxley-1 Well	4.64
Loxley-2 Well	4.67
EWT Cost	0.5
Total Project CAPEX	**41.22**

Table 5.9: Development CAPEX

The costs and production profiles are provided in Table 5.10, Table 5.11 and Table 5.12 below. The Loxley-1 well and EWT has been classified as Exploration & Appraisal (E&A) cost. Abandonment costs have been assumed to be incurred in the two years following cessation of production (CoP). The profiles in Table 5.10, Table 5.11 and Table 5.12 below represent technical profiles and economic cut-off may occur earlier than shown.

	Gas Production	E&A Costs	Dev. Drilling	Facility Costs	Pipelines	Compressor Retrofit	Owner's Costs	Contingency	Total CAPEX	Fixed OPEX	Variable OPEX	Total OPEX	ABEX
	MMscfd	£MM	£MM	£MM	£MM	£MM	£MM	£MM	£MM	£MM	£MM	£MM	£MM
2022													
2023													
2024		5.1		3.1			0.3	0.8	9.3				
2025				9.2	8.0		1.7	4.3	23.2				
2026	13.7									0.5	0.2	0.7	
2027	12.7									0.7	0.2	0.9	
2028	8.8		4.7			3.0	0.3	0.7	8.7	0.7	0.1	0.8	
2029	6.5									0.9	0.1	1.0	
2030	5.0									0.9	0.1	0.9	
2031	3.9									0.9	0.1	0.9	
2032	3.2									0.9	0.1	0.9	
2033	2.6									0.9	0.0	0.9	
2034	1.0									0.9	0.0	0.9	
2035													1.4
2036													1.4
2037													
2038													
2039													
Total	21.0	5.1	4.7	12.3	8.0	3.0	2.3	5.8	41.2	7.0	1.0	8.0	2.8

Table 5.10: P90 Production & Costs Profile (Whole Structure, Gross 100% WI, 2022 Basis)

	Gas Production	E&A Costs	Dev. Drilling	Facility Costs	Pipelines	Compressor Retrofit	Owner's Costs	Contingency	Total CAPEX	Fixed OPEX	Variable OPEX	Total OPEX	ABEX
	MMscfd	£MM	£MM	£MM	£MM	£MM	£MM	£MM	£MM	£MM	£MM	£MM	£MM
2022													
2023													
2024		5.1		3.1			0.3	0.8	9.3				
2025				9.2	8.0		1.7	4.3	23.2				
2026	15.0									0.5	0.2	0.8	
2027	20.0									0.7	0.3	1.0	
2028	19.9		4.7			3.0	0.3	0.7	8.7	0.7	0.3	1.0	
2029	16.2									0.9	0.3	1.1	
2030	12.0									0.9	0.2	1.1	
2031	8.8									0.9	0.1	1.0	
2032	6.5									0.9	0.1	1.0	
2033	4.8									0.9	0.1	0.9	
2034	3.5									0.9	0.1	0.9	
2035	2.7									0.9	0.0	0.9	
2036	0.8									0.9	0.0	0.9	
2037													1.4
2038													1.4
2039													
Total	40.2	5.1	4.7	12.3	8.0	3.0	2.3	5.8	41.2	8.8	1.8	10.6	2.8

Table 5.11: P50 Production & Costs Profile (Whole Structure, Gross 100% WI, 2022 Basis)

	Gas Production	E&A Costs	Dev. Drilling	Facility Costs	Pipelines	Compressor Retrofit	Owner's Costs	Contingency	Total CAPEX	Fixed OPEX	Variable OPEX	Total OPEX	ABEX
	MMscfd	£MM	£MM	£MM	£MM	£MM	£MM	£MM	£MM	£MM	£MM	£MM	£MM
2022													
2023													
2024		5.1		3.1			0.3	0.8	9.3				
2025				9.2	8.0		1.7	4.3	23.2				
2026	15.0									0.5	0.2	0.8	
2027	20.0									0.7	0.3	1.0	
2028	20.0		4.7			3.0	0.3	0.7	8.7	0.7	0.3	1.0	
2029	20.0									0.9	0.3	1.2	
2030	20.0									0.9	0.3	1.2	
2031	20.0									0.9	0.3	1.2	
2032	20.0									0.9	0.3	1.2	
2033	18.9									0.9	0.3	1.2	
2034	14.3									0.9	0.2	1.1	
2035	10.5									0.9	0.2	1.0	
2036	7.8									0.9	0.1	1.0	
2037	1.6									0.9	0.1	1.0	
2038													1.4
2039													1.4
Total	68.7	5.1	4.7	12.3	8.0	3.0	2.3	5.8	41.2	9.6	3.2	12.9	2.8

Table 5.12: P10 Production & Costs Profile (Whole Structure, Gross 100% WI, 2022 Basis)

5.1.6 Economic Evaluation

RPS prepared an economic model to determine the estimated economically recoverable Contingent Resources and generate cash flow forecast for each of the Contingent Resources case scenarios. Commerciality is assessed primarily on 2C resources as per PRMS guidelines.

The economic evaluation has been made at a Gross (100% WI) basis and also an assumed unitisation case with net entitlement using an assumed Tract Participation ('TP') for UKOG of 77% based on the proportion of GIIP mapped on PEDL 234.

5.1.6.1 Fiscal Overview

PEDL 234 is subjected to ring-fence corporate income tax ('RFCT'), supplementary charge ('SC') and energy profit levy ('EPL').

The ring fence prevents taxable profits from oil and gas extraction in the UK and UK Continental Shelf being reduced by losses from other activities or by excessive interest payments.

Supplementary charge and energy profit levy are charged on the profits for RFCT, but without any deduction for finance costs.

For the purposes of calculating the supplementary charge and energy levy profit, adjusted ring fence profits can be reduced by an onshore allowance (70%) and by the New Investment Allowance (29%).

The energy profit levy is enforced for the period January 2023 to March 2028.

5.1.6.2 Gas Pricing Basis

PEDL 234 will sell its gas into the national grid at National Balance Point ('NBP') gas market prices. RPS provided a NBP gas price forecast, shown in Table 5.13

Year	Gas Price (£/MMBtu) real 2023	Gas Price (£/MMBtu) MOD
2023	35.1	35.1
2024	23.0	24.4
2025	16.6	17.9
2026	13.1	14.5
2027	12.9	14.6
2028	11.4	13.1
2029	10.4	12.2
2030	10.4	12.5
2031	10.4	12.7
2032+	11.2	13.9

Table 5.13: Gas Price Assumption for Loxley field

5.1.6.3 Cashflow Analysis

Cashflow Analysis for P90/P50/P10 cases at 100% Gross (WI) and 77% Net Entitlement is included in Appendix C (Tables C.1 to C.12).

The NPV summary at 100% Gross (WI) and 77% Net Entitlement are shown in Table 5.14 and Table 5.15 below:

	ELT Date	Post-Tax Net Present Value (£ Million, MOD)			
		0.0%	5.0%	10.0%	15.0%
1C	2034	98.4	71.9	53.4	40.1
2C	2036	215.9	153.9	112.4	83.7
3C	2037	448.9	297.0	202.9	142.6

Notes:

Table 5.14: Economic Assessment Summary for PEDL 234 - 100% Gross (WI)

	ELT Date	Post-Tax Net Present Value (£ Million, MOD)			
		0.0%	5.0%	10.0%	15.0%
1C	2034	75.6	55.0	41.1	30.4
2C	2036	166.1	118.2	86.5	64.0
3C	2037	345.5	228.4	156.2	109.3

Notes:

Table 5.15: Economic Assessment Summary for PEDL 234 - 77% Net Entitlement

5.1.6.4 Sensitivity Analysis

At the request of UKOG, a gas price sensitivity using a flat price of 186.05p/therm (£18.61/MMBtu) was carried out. The gas price was based on the reported settlement price as of 31st December 2022. The NPV summary at 100% Gross (WI) and 77% Net Entitlement are shown in Table 5.16 and Table 5.17 below.

	ELT Date	Post-Tax Net Present Value (£ Million, MOD)			
		0.0%	5.0%	10.0%	15.0%
1C	2034	140.3	102.8	76.8	58.3
2C	2036	306.8	219.4	160.7	120.2
3C	2037	622.5	414.2	284.7	201.3

Notes:

Table 5.16: Economic Sensitivity Run for PEDL 234 - 100% Gross (WI)

	ELT Date	Post-Tax Net Present Value (£ Million, MOD)			
		0.0%	5.0%	10.0%	15.0%
1C	2034	108.0	79.2	59.2	44.9
2C	2036	236.2	168.9	123.7	92.5
3C	2037	479.3	318.9	219.2	155.0

Notes:

Table 5.17: Economic Sensitivity Run for PEDL 234 - 77% Net Entitlement

5.2 Reserves and Resources

The Loxley-1 well is intended to be the first of two development wells within the PEDL 234 licence. Although it will be designed and drilled as potential production well, it will still have an element of appraisal as it must first prove commercial flowrates are achievable which will depend on the height of the gas column and reservoir properties encountered. For this reason, the economically recoverable volumes predicted in this report are classified as Contingent Resources, Development Pending in accordance with the PRMS.

The initially-in-place (on block) gas volumes are presented in Table 5.18 below and described in more detail in Section 5.1.4. The gross and net entitlement Contingent Resources, as of 20 February 2023 are summarised in Table 5.19.

	GIIP (Bscf)		
	P90	P50	P10
Whole Structure	**35**	**57**	**86**
PEDL 234	**28**	**44**	**67**

Table 5.18: Gross GIIP within PEDL 234

SUMMARY OF GAS CONTINGENT RESOURCES
As of 20 February 2023
BASE CASE PRICES AND COSTS

	Full Field Gross Resources[1] (Bscf)			UKOG Net Entitlement Resources[2] (Bscf) PEDL 234		
	1C	2C	3C	1C	2C	3C
	21.0	40.2	68.7	16.2	31.0	52.9

Notes:
*[1] Gross field Resources (100% basis) **after** economic limit test*
*[2] Companies working interest share of net field Resources **after** economic limit test*

Table 5.19: PEDL 234 Gas Contingent Resources as of 20 February 2023

5.3 Regional and HSE Risk Assessment

5.3.1 Regional Risks

- The UK government has licensed the area to UKOG to be explored and ultimately drilled.
- No other infrastructure is nearby to be used to treat the fluids and the facilities will be built on site with a 6.6 km pipeline to join this asset with the local low pressure gas pipeline system The pipeline route has not yet been permitted and remains a contingency to access the gas sales market.

5.3.2 Health, Safety and Environmental

- Health, Safety and Environmental ("HSE") risks associated with the business practices of UKOG are identified, assessed and mitigated through the effective implementation of their HSE Policy.
- All current wells are abandoned, and no facilities exist on the site.
- Given the current development status of the asset, RPS would anticipate all HSE issues to be addressed as part of field development planning process at a later date.

6 CONSULTANT'S INFORMATION

RPS is an experienced consultancy specialising in the provision of independent, third-party opinions on the technical and commercial aspects of subsurface operations, products and revenue streams. Neither RPS nor any of its personnel that worked on this evaluation has any commercial interest in any of the assets and opportunities evaluated in this Report.

The Report was provided on a fee-basis which is in no way contingent on the results and findings of the evaluation or any outcome of the use of the Report.

The RPS personnel that worked on the Report are professionally qualified with appropriate educational qualifications in geoscience, engineering and economics and levels of experience and expertise to perform the scope of work (Table 6.1).

Name	Role	Years of Experience	Qualifications	Professional Memberships
Andy Kirchin	Project Manager	35	BSc., C.Geol.	SPE, FGS
Phil Crookall	Principal Advisor	35	BSC, MSc	SPE
Jim Bradly	Peer Review	25	BEng, MSc, CEng	SPE, AIPN, MEI
Michael Clancy	Principal Engineer	35	BE, MSc, LLM, PhD	SPE
David Walker	Principal Costs Eng.	22	MEng	SPE
Esther Escobar-Burnham	Senior Economist	20	Econ., MBA, MSc	SPE, AMEI

Table 6.1: Summary of Consultant Personnel

7 DATA SOURCES

All data were supplied by UKOG.

The data consisted of a number of summary documents presented as Powerpoint slide-decks with access to certain well-log, seismic and engineering data as well as a detailed breakdown of anticipated cost data associated with the anticipated development requirements.

7.1.1 Well Data

RPS were provided with LAS files containing the raw and processed log data for the three wells that were logged (GB-1,GB-2z, Al-1), Well tops from the 4 drilled wells (GB-1,GB-2, GB-2z, Al-1), along with original core analysis reports where available, composite logs, mud logs Repeat formation test data and the results of the 3 DST tests in the section in the GB-1 well.

7.1.2 Seismic Data

RPS examined the four well ties and seismic picks from twenty- two 2D seismic lines (approx. 360km), this examination was carried out in the UKOG office on their database. No independent seismic interpretation has taken place although various checks and further seismic products to check the validity of the data were requested and received. The quality of the data is moderate to good.

7.1.3 Engineering Data

RPS has been provided with a couple of PowerPoint presentations on work undertaken by Kappa Engineering to forecast production based on a two well development of the field, limited information on the previous DST's undertaken on the GB-1 well and gas/condensate compositions from samples taken during the DST's.

Other than the DST's, there has been no production from the field. RPS has not been provided with any of the test reports, so is not able to comment on the cumulative volume of gas produced to date, but it is presumed to be negligible.

No further engineering information has been made available. RPS is not aware of any special core analysis being available which would provide relative permeability data, nor any specific well design data. No other reports have been made available.

7.1.4 Costs Data

RPS was provided with Capex, Opex and Abex estimates based on UKOG's current development assumptions. In general, RPS has determined the estimates to be reasonable and have largely accepted the UKOG cost estimates with some minor modification.

Appendix A
Glossary

1C	The low estimate of Contingent Resources. There is estimated to be a 90% probability that the quantities actually recovered could equal or exceed this estimate
2C	The best estimate of Contingent Resources. There is estimated to be a 50% probability that the quantities actually recovered could equal or exceed this estimate
3C	The high estimate of Contingent Resources. There is estimated to be a 10% probability that the quantities actually recovered could equal or exceed this estimate
1P	The low estimate of Reserves (proved). There is estimated to be a 90% probability that the quantities remaining to be recovered will equal or exceed this estimate
2P	The best estimate of Reserves (proved+probable). There is estimated to be a 50% probability that the quantities remaining to be recovered will equal or exceed this estimate
3P	The high estimate of Reserves (proved+probable+possible). There is estimated to be a 10% probability that the quantities remaining to be recovered will equal or exceed this estimate
1U	The unrisked low estimate of Prospective Resources
2U	The unrisked best estimate of Prospective Resources
3U	The unrisked high estimate of Prospective Resources
AVO	Amplitude versus Offset
B	Billion
bbl(s)	Barrels
bbls/d	Barrels per day
Bcm	Billion cubic metres
B_g	Gas formation volume factor
B_{gi}	Gas formation volume factor (initial)
B_o	Oil formation volume factor
B_{oi}	Oil formation volume factor (initial)
B_w	Water volume factor
boe	Barrels of oil equivalent
stb/d	Barrels of oil per day
BHP	Bottom hole pressure
Bscf	Billions of standard cubic feet
bwpd	Barrels of water per day
condensate	A mixture of hydrocarbons which exist in gaseous phase at reservoir conditions but are produced as a liquid at surface conditions
cP	Centipoise
Eclipse	A reservoir modelling software package
E_{gi}	Gas Expansion Factor
EMV	Expected Monetary Value
EUR	Estimated Ultimate Recovery
FBHP	Flowing bottom hole pressure
FTHP	Flowing tubing head pressure
ft	Feet
FWHP	Flowing well head pressure
FWL	Free Water Level

GDT	Gas Down To
GIIP	Gas Initially in Place
GOC	Gas oil Contact
GOR	Gas/oil ratio
GRV	Gross rock volume
GWC	Gas water contact
IPR	Inflow performance relationship
IRR	Internal rate of return
KB	Kelly Bushing
k_a	Absolute permeability
k_h	Horizontal permeability
km	Kilometres
LPG	Liquefied Petroleum Gases
m	Metres
m^3	Cubic metres
m^3/d	Cubic metres per day
ma	Million years
M	Thousand
M$	Thousand US dollars
MBAL	Material balance software
Mbbls	Thousand barrels
mD	Permeability in millidarcies
MD	Measured depth
MDT	Modular formation dynamics tester tool
MM	Million
MMbbls	Million barrels
MMscf/d	Millions of standard cubic feet per day
MMstb	Million stock tank barrels (at 14.7 psi and 60° F)
MMt	Millions of tonnes
MM$	Million US dollars
MPa	Mega pascals
m/s	Metres per second
msec	Milliseconds
Mt	Thousands of tonnes
mV	Millivolts
NTG or N:G	Net to gross ratio
NGL	Natural Gas Liquids
NPV	Net Present Value
OWC	Oil water contact
P90	There is estimated to be at least a 90% probability (P_{90}) that this quantity will equal or exceed this low estimate
P50	There is estimated to be at least a 50% probability (P_{50}) that this quantity will equal or exceed this best estimate
P10	There is estimated to be at least a 10% probability (P_{10}) that this quantity will equal or exceed this high estimate
PDR	Physical data room
Petrel	A geoscience and reservoir engineering software package

petroleum	Naturally occurring mixtures of hydrocarbons which are found beneath the Earth's surface in liquid, solid or gaseous form
phi	Porosity
p_i	Initial reservoir pressure
PI	Productivity index
ppm	Parts per million
psi	Pounds per square inch
psia	Pounds per square inch (absolute)
psig	Pounds per square inch (gauge)
p_{wf}	Flowing bottom hole pressure
PSDM	Pre-stack depth migrated seismic data
PSTM	Pre-stack time migrated seismic data
PVT	Pressure volume temperature
rb	Barrel(s) at reservoir conditions
rcf	Reservoir cubic feet
REP™	A Monte Carlo simulation software package
RF	Recovery factor
RFT	Repeat formation tester
RKB	Relative to kelly bushing
rm^3	Reservoir cubic metres
SCADA	Supervisory control and data acquisition
SCAL	Special Core Analysis
scf	Standard cubic feet measured at 14.7 pounds per square inch and 60° F
scf/d	Standard cubic feet per day
scf/stb	Standard cubic feet per stock tank barrel
SGS	Sequential Gaussion Simulation
SIBHP	Shut in bottom hole pressure
SIS	Sequential Indicator Simulation
sm^3	Standard cubic metres
S_o	Oil saturation
S_{oi}	Initial oil saturation
S_{or}	Residual oil saturation
S_{orw}	Residual oil saturation relative to water
sq. km	Square kilometers
stb	Stock tank barrels measured at 14.7 pounds per square inch and 60° F
stb/d	Stock tank barrels per day
STOIIP	Stock tank oil initially in place
S_w	Water saturation
S_{wc}	Vonnate water saturation
$	United States Dollars
t	Tonnes
THP	Tubing head pressure
Tscf	Trillion standard cubic feet
TVDSS	True vertical depth (sub-sea)
TVT	True vertical thickness
TWT	Two-way time
US$	United States Dollar

VDR	Virtual data room
VLP	Vertical lift performance
V_{sh}	Shale volume
VSP	Vertical Seismic Profile
W/m/K	Watts/metre/° K
WC	Water cut
WUT	Water Up To
Z	A measure of the "non-idealness" of gas
ϕ	Porosity
μ	Viscosity
μ_g	Viscosity of gas
μ_o	Viscosity of oil
μ_w	Viscosity of water

Appendix B
Summary of Reporting Guidelines

PRMS is a fully integrated system that provides the basis for classification and categorization of all petroleum reserves and resources.

B.1 Basic Principles and Definitions

A classification system of petroleum resources is a fundamental element that provides a common language for communicating both the confidence of a project's resources maturation status and the range of potential outcomes to the various entities. The PRMS provides transparency by requiring the assessment of various criteria that allow for the classification and categorization of a project's resources. The evaluation elements consider the risk of geologic discovery and the technical uncertainties together with a determination of the chance of achieving the commercial maturation status of a petroleum project.

The technical estimation of petroleum resources quantities involves the assessment of quantities and values that have an inherent degree of uncertainty. Quantities of petroleum and associated products can be reported in terms of volumes (e.g., barrels or cubic meters), mass (e.g., metric tonnes) or energy (e.g., Btu or Joule). These quantities are associated with exploration, appraisal, and development projects at various stages of design and implementation. The commercial aspects considered will relate the project's maturity status (e.g., technical, economical, regulatory, and legal) to the chance of project implementation.

The use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios. The application of PRMS must consider both technical and commercial factors that impact the project's feasibility, its productive life, and its related cash flows.

B.1.1 Petroleum Resources Classification Framework

Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid state. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide, and sulfur. In rare cases, non-hydrocarbon content can be greater than 50%.

The term resources as used herein is intended to encompass all quantities of petroleum naturally occurring within the Earth's crust, both discovered and undiscovered (whether recoverable or unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered as conventional or unconventional resources.

Figure A.1 graphically represents the PRMS resources classification system. The system classifies resources into discovered and undiscovered and defines the recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable Petroleum.

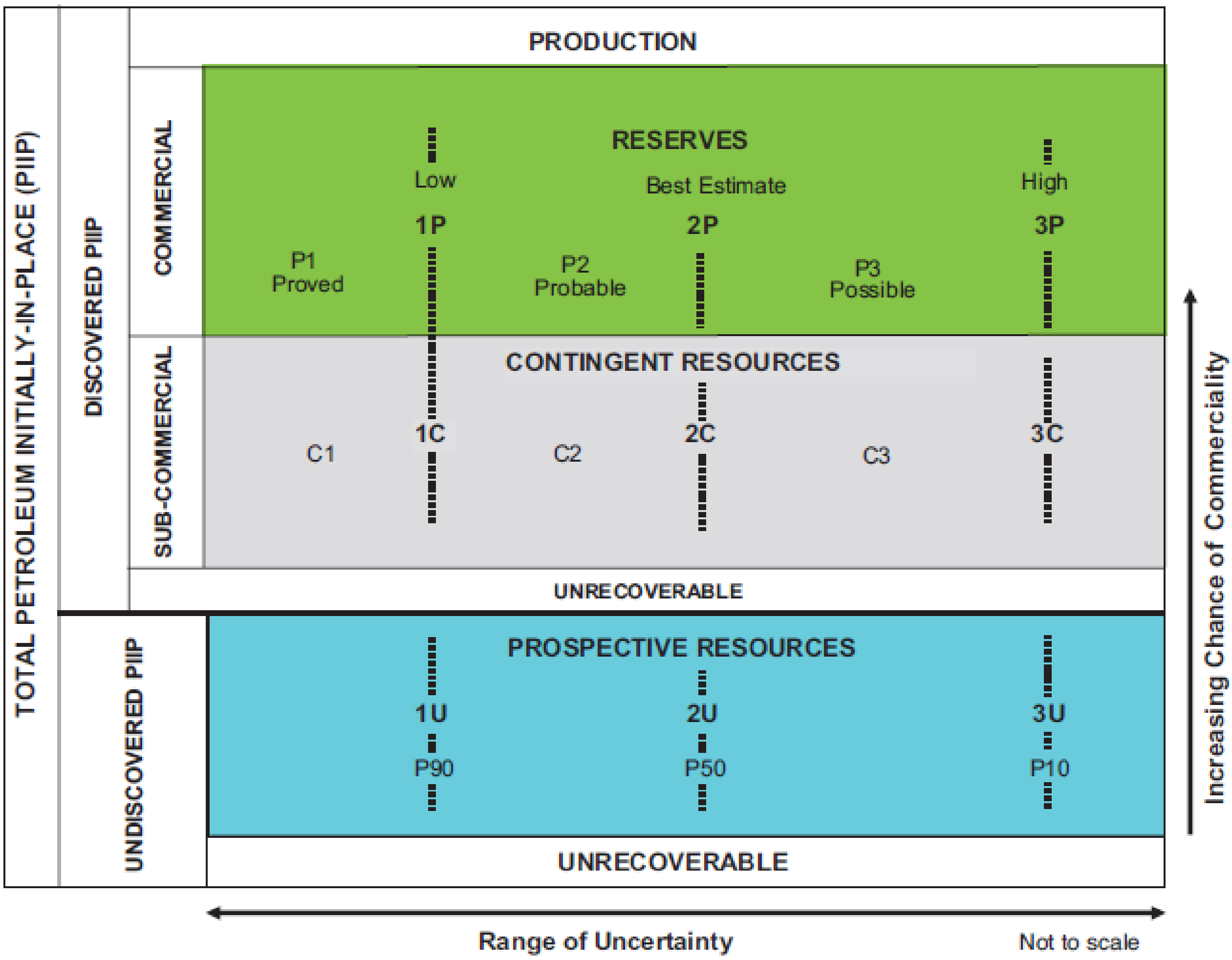

Figure A.1: Resources classification framework

The horizontal axis reflects the range of uncertainty of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the chance of commerciality, P_c, which is the chance that a project will be committed for development and reach commercial producing status.

The following definitions apply to the major subdivisions within the resources classification:

- **Total Petroleum Initially-In-Place (PIIP)** is all quantities of petroleum that are estimated to exist originally in naturally occurring accumulations, discovered and undiscovered, before production.

- **Discovered PIIP** is the quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production.

- **Production** is the cumulative quantities of petroleum that have been recovered at a given date. While all recoverable resources are estimated, and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage (see PRMS 2018 Section 3.2, Production Measurement).

Multiple development projects may be applied to each known or unknown accumulation, and each project will be forecast to recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into commercial, sub-commercial, and undiscovered, with the estimated recoverable quantities being classified as Reserves, Contingent Resources, or Prospective Resources respectively, as defined below.

- **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 satisfy four criteria: discovered, recoverable, commercial, and remaining (as of the evaluation's effective date) based on the development project(s) applied.

  Reserves are recommended as sales quantities as metered at the reference point. Where the entity also recognizes quantities consumed in operations (CiO) (see PRMS 2018 Section 3.2.2), as Reserves these quantities must be recorded separately. Non-hydrocarbon quantities are recognized as Reserves only when sold together with hydrocarbons or CiO associated with petroleum production. If the non-hydrocarbon is separated before sales, it is excluded from Reserves.

  Reserves are further categorized in accordance with the range of uncertainty and should be sub-classified based on project maturity and/or characterized by development and production status.

- **Contingent Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, by the application of development project(s) not currently considered to be commercial owing to one or more contingencies. Contingent Resources have an associated chance of development. 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 categorized in accordance with the range of uncertainty associated with the estimates and should be sub- classified based on project maturity and/or economic status.

- **Undiscovered PIIP** is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

- **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 geologic discovery and a chance of development. Prospective Resources are further categorized in accordance with the range of uncertainty associated with recoverable estimates, assuming discovery and development, and may be sub-classified based on project maturity.

- **Unrecoverable Resources** are that portion of either discovered or undiscovered PIIP evaluated, as of a given date, to be unrecoverable by the currently defined project(s). A portion of these quantities may become recoverable in the future as commercial circumstances change, technology is developed, or additional data are acquired. The remaining portion may never be recovered because of physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

The sum of Reserves, Contingent Resources, and Prospective Resources may be referred to as "remaining recoverable resources." Importantly, these quantities should not be aggregated without due consideration of the technical and commercial risk involved with their classification. When such terms are used, each classification component of the summation must be provided.

Other terms used in resource assessments include the following:

- **Estimated Ultimate Recovery (EUR)** is not a resources category or class, but a term that can be applied to an accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable plus those quantities already produced from the accumulation or group of accumulations. For clarity, EUR must reference the associated technical and commercial conditions for the resources; for example, proved EUR is Proved Reserves plus prior production.

- **Technically Recoverable Resources (TRR)** are those quantities of petroleum producible using currently available technology and industry practices, regardless of commercial considerations. TRR may be used for specific Projects or for groups of Projects, or, can be an undifferentiated estimate within an area (often basin-wide) of recovery potential.

Whenever these terms are used, the conditions associated with their usage must be clearly noted and documented.

B.1.2 Project Based Resource Evaluations

The resources evaluation process consists of identifying a recovery project or projects associated with one or more petroleum accumulations, estimating the quantities of PIIP, estimating that portion of those in-place quantities that can be recovered by each project, and classifying the project(s) based on maturity status or chance of commerciality.

The concept of a project-based classification system is further clarified by examining the elements contributing to an evaluation of net recoverable resources (see Figure A.2).

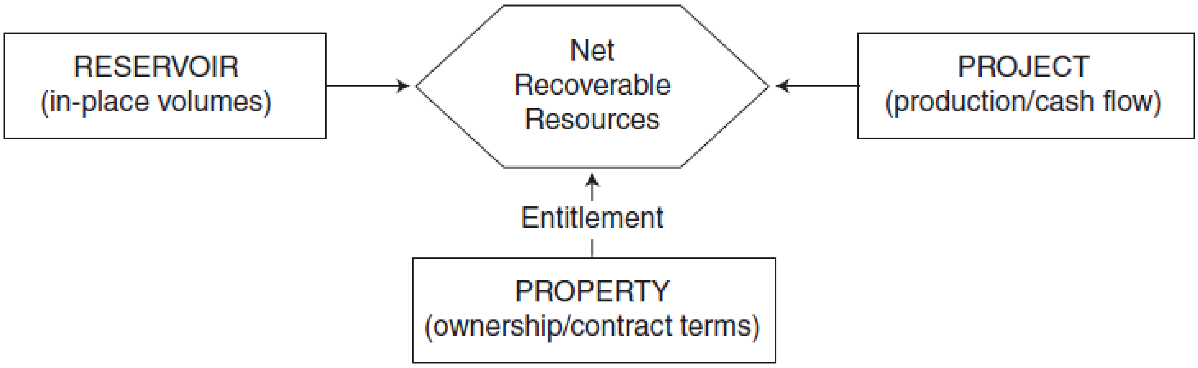

Figure A.2: Resources Evaluation

The reservoir (contains the petroleum accumulation): Key attributes include the types and quantities of PIIP and the fluid and rock properties that affect petroleum recovery.

The project: A project may constitute the development of a well, a single reservoir, or a small field; an incremental development in a producing field; or the integrated development of a field or several fields together with the associated processing facilities (e.g., compression). Within a project, a specific reservoir's development generates a unique production and cash-flow schedule at each level of certainty.

The integration of these schedules taken to the project's earliest truncation caused by technical, economic, or the contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to total PIIP quantities defines the project's recovery efficiency. Each project should have an associated recoverable resources range (low, best, and high estimate).

The property (lease or license area): Each property may have unique associated contractual rights and obligations, including the fiscal terms. This information allows definition of each participating entity's share of produced quantities (entitlement) and share of investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations that may be spatially unrelated to a potential single field designation.

An entity's net recoverable resources are the entitlement share of future production legally accruing under the terms of the development and production contract or license.

In the context of this relationship, the project is the primary element considered in the resources classification, and the net recoverable resources are the quantities derived from each project. A project represents a defined activity or set of activities to develop the petroleum accumulation(s) and the decisions taken to mature the resources to reserves. In general, it is recommended that an individual project has assigned to it a specific maturity level sub-class (See PRMS 2018 Section 2.1.3.5, Project Maturity Sub-

Classes) at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for the project (See PRMS 2018 Section 2.2.1, Range of Uncertainty). For completeness, a developed field is also considered to be a project.

An accumulation or potential accumulation of petroleum is often subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resources classes simultaneously. When multiple options for development exist early in project maturity, these options should be reflected as competing project alternatives to avoid double counting until decisions further refine the project scope and timing. Once the scope is described and the timing of decisions on future activities established, the decision steps will generally align with the project's classification. To assign recoverable resources of any class, a project's development plan, with detail that supports the resource commercial classification claimed, is needed.

The estimates of recoverable quantities must be stated in terms of the production derived from the potential development program even for Prospective Resources. Given the major uncertainties involved at this early stage, the development program will not be of the detail expected in later stages of maturity. In most cases, recovery efficiency may be based largely on analogous projects. In-place quantities for which a feasible project cannot be defined using current or reasonably forecast improvements in technology are classified as Unrecoverable.

Not all technically feasible development projects will be commercial. The commercial viability of a development project within a field's development plan is dependent on a forecast of the conditions that will exist during the time period encompassed by the project (see PRMS 2018 Section 3.1, Assessment of Commerciality).

Conditions include technical, economic (e.g., hurdle rates, commodity prices), operating and capital costs, marketing, sales route(s), and legal, environmental, social, and governmental factors forecast to exist and impact the project during the time period being evaluated. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions (e.g., inflation, market factors, and contingencies), exchange rates, transportation and processing infrastructure, fiscal terms, and taxes.

The resources being estimated are those quantities producible from a project as measured according to delivery specifications at the point of sale or custody transfer (see PRMS 2018 Section 3.2.1, Reference Point) and may permit forecasts of CiO quantities (see PRMS 2018 Section 3.2.2., Consumed in Operations). The cumulative production forecast from the effective date forward to cessation of production is the remaining recoverable resources quantity (see PRMS 2018 Section 3.1.1, Net Cash-Flow Evaluation).

The supporting data, analytical processes, and assumptions describing the technical and commercial basis used in an evaluation must be documented in sufficient detail to allow, as needed, a qualified reserves evaluator or qualified reserves auditor to clearly understand each project's basis for the estimation, categorization, and classification of recoverable resources quantities and, if appropriate, associated commercial assessment.

B.2 Classification and Categorization Guidelines

To consistently characterize petroleum projects, evaluations of all resources should be conducted in the context of the full classification system shown in Figure A.1. These guidelines reference this classification system and support an evaluation in which projects are "classified" based on their chance of commerciality, P_c (the vertical axis labeled Chance of Commerciality), and estimates of recoverable and marketable quantities associated with each project are "categorized" to reflect uncertainty (the horizontal axis). The actual workflow of classification versus categorization varies with individual projects and is often an iterative analysis leading to a final report. Report here refers to the presentation of evaluation results within the entity conducting the assessment and should not be construed as replacing requirements for public disclosures under guidelines established by regulatory and/or other government agencies.

B.2.1 Resources Classification

The PRMS classification establishes criteria for the classification of the total PIIP. A determination of a discovery differentiates between discovered and undiscovered PIIP. The application of a project further differentiates the recoverable from unrecoverable resources. The project is then evaluated to determine its maturity status to allow the classification distinction between commercial and sub-commercial projects. PRMS requires the project's recoverable resources quantities to be classified as either Reserves, Contingent Resources, or Prospective Resources.

B.2.1.1 Determination of Discovery Status

A discovered petroleum accumulation is determined to exist when one or more exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially recoverable hydrocarbons and thus have established a known accumulation. In the absence of a flow test or sampling, the discovery determination requires confidence in the presence of hydrocarbons and evidence of producibility, which may be supported by suitable producing analogs (see PRMS 2018 Section 4.1.1, Analogs). In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place quantity demonstrated by the well(s) and for evaluating the potential for commercial recovery.

Where a discovery has identified recoverable hydrocarbons, but is not considered viable to apply a project with established technology or with technology under development, such quantities may be classified as Discovered Unrecoverable with no Contingent Resources. In future evaluations, as appropriate for petroleum resources management purposes, a portion of these unrecoverable quantities may become recoverable resources as either commercial circumstances change or technological developments occur.

B.2.1.2 Determination of Commerciality

Discovered recoverable quantities (Contingent Resources) may be considered commercially mature, and thus attain Reserves classification, if the entity claiming commerciality has demonstrated a firm intention to proceed with development. This means the entity has satisfied the internal decision criteria (typically rate of return at or above the weighted average cost-of-capital or the hurdle rate). Commerciality is achieved with the entity's commitment to the project and all of the following criteria:

- Evidence of a technically mature, feasible development plan.
- Evidence of financial appropriations either being in place or having a high likelihood of being secured to implement the project.
- Evidence to support a reasonable time-frame for development.
- A reasonable assessment that the development projects will have positive economics and meet defined investment and operating criteria. This assessment is performed on the estimated entitlement forecast quantities and associated cash flow on which the investment decision is made (see PRMS 2018 Section 3.1.1, Net Cash-Flow Evaluation).
- A reasonable expectation that there will be a market for forecast sales quantities of the production required to justify development. There should also be similar confidence that all produced streams (e.g., oil, gas, water, CO_2) can be sold, stored, re-injected, or otherwise appropriately disposed.
- Evidence that the necessary production and transportation facilities are available or can be made available.
- Evidence that legal, contractual, environmental, regulatory, and government approvals are in place or will be forthcoming, together with resolving any social and economic concerns.

The commerciality test for Reserves determination is applied to the best estimate (P50) forecast quantities, which upon qualifying all commercial and technical maturity criteria and constraints become the *2P* Reserves. Stricter cases [e.g., low estimate (P90)] may be used for decision purposes or to investigate the range of commerciality (see PRMS 2018 Section 3.1.2, Economic Criteria). Typically, the low- and high-case project scenarios may be evaluated for sensitivities when considering project risk and upside opportunity.

To be included in the Reserves class, a project must be sufficiently defined to establish both its technical and commercial viability as noted in Section A.2.1.2. There must be a reasonable expectation that all required internal and external approvals will be forthcoming and evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where justifiable; for example, development of economic projects that take longer than five years to be developed or are deferred to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

While PRMS guidelines require financial appropriations evidence, they do not require that project financing be confirmed before classifying projects as Reserves. However, this may be another external reporting requirement. In many cases, financing is conditional upon the same criteria as above. In general, if there is not a reasonable expectation that financing or other forms of commitment (e.g., farm-outs) can be arranged so that the development will be initiated within a reasonable time-frame, then the project should be classified as Contingent Resources. If financing is reasonably expected to be in place at the time of the final investment decision (FID), the project's resources may be classified as Reserves.

B.2.1.3 Project Status and Chance of Commerciality

Evaluators have the option to establish a more detailed resources classification reporting system that can also provide the basis for portfolio management by subdividing the chance of commerciality axis according to project maturity. Such sub-classes may be characterized qualitatively by the project maturity level descriptions and associated quantitative chance of reaching commercial status and being placed on production.

As a project moves to a higher level of commercial maturity in the classification (see Figure A.1 vertical axis), there will be an increasing chance that the accumulation will be commercially developed and the project quantities move to Reserves. For Contingent and Prospective Resources, this is further expressed as a chance of commerciality, P_c, which incorporates the following underlying chance component(s):

- The chance that the potential accumulation will result in the discovery of a significant quantity of petroleum, which is called the "chance of geologic discovery," P_g.

- Once discovered, the chance that the known accumulation will be commercially developed is called the "chance of development," P_d.

There must be a high degree of certainty in the chance of commerciality, P_c, for Reserves to be assigned; for Contingent Resources, $P_c = P_d$; and for Prospective Resources, P_c is the product of P_g and P_d.

Contingent and Prospective Resources can have different project scopes (e.g., well count, development spacing, and facility size) as development uncertainties and project definition mature.

B.2.1.3.1 Project Maturity Sub-classes

As Figure A.3 illustrates, development projects and associated recoverable quantities may be sub- classified according to project maturity levels and the associated actions (i.e., business decisions) required to move a project toward commercial production.

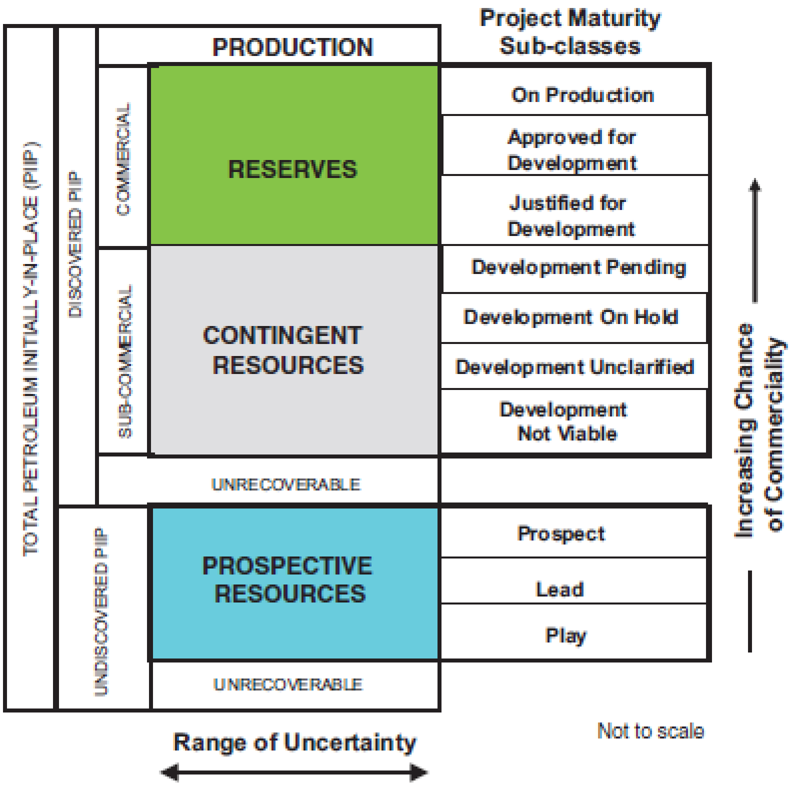

Figure A.3: Sub-classes based on project maturity

Maturity terminology and definitions for each project maturity class and sub-class are provided in PRMS 2018 Table I. This approach supports the management of portfolios of opportunities at various stages of exploration, appraisal, and development. Reserve sub-classes must achieve commerciality while Contingent and Prospective Resources sub-classes may be supplemented by associated quantitative estimates of chance of commerciality to mature.

Resources sub-class maturation is based on those actions that progress a project through final approvals to implementation and initiation of production and product sales. The boundaries between different levels of project maturity are frequently referred to as project "decision gates."

Projects that are classified as Reserves must meet the criteria as listed in Section A.2.1.2, Determination of Commerciality. Projects sub-classified as Justified for Development are agreed upon by the managing entity and partners as commercially viable and have support to advance the project, which includes a firm intent to proceed with development. All participating entities have agreed to the project and there are no known contingencies to the project from any official entity that will have to formally approve the project.

Justified for Development Reserves are reclassified to Approved for Development after a FID has been made. Projects should not remain in the Justified for Development sub-class for extended time periods without positive indications that all required approvals are expected to be obtained without undue delay. If there is no longer the reasonable expectation of project execution (i.e., historical track record of execution, project progress), the project shall be reclassified as Contingent Resources.

Projects classified as Contingent Resources have their sub-classes aligned with the entity's plan to manage its portfolio of projects. Thus, projects on known accumulations that are actively being studied, undergoing feasibility review, and have planned near-term operations (e.g., drilling) are placed in Contingent Resources Development Pending, while those that do not meet this test are placed into either Contingent Resources On Hold, Unclarified, or Not Viable.

Where commercial factors change and there is a significant risk that a project with Reserves will no longer proceed, the project shall be reclassified as Contingent Resources.

For Contingent Resources, evaluators should focus on gathering data and performing analyses to clarify and then mitigate those key conditions or contingencies that prevent commercial development. Note that the Contingent Resources sub-classes described above and shown in Figure A.3 are recommended; however, entities are at liberty to introduce additional sub-classes that align with project management goals.

For Prospective Resources, potential accumulations may mature from Play, to Lead and then to Prospect based on the ability to identify potentially commercially viable exploration projects. The Prospective Resources are evaluated according to chance of geologic discovery, P_g, and chance of development, P_d, which together determine the chance of commerciality, P_c. Commercially recoverable quantities under appropriate development projects are then estimated. The decision at each exploration phase is whether to undertake further data acquisition and/or studies designed to move the Play through to a drillable Prospect with a project description range commensurate with the Prospective Resources sub-class.

B.2.1.3.2 Reserves Status

Once projects satisfy commercial maturity (criteria given in PRMS 2018 Table 1), the associated quantities are classified as Reserves. These quantities may be allocated to the following subdivisions based on the funding and operational status of wells and associated facilities within the reservoir development plan (PRMS 2018 Table 2 provides detailed definitions and guidelines):

- **Developed Reserves** are quantities expected to be recovered from existing wells and facilities.
  - **Developed Producing Reserves** are expected to be recovered from completion intervals that are open and producing at the time of the estimate.
  - **Developed Non-Producing Reserves** include shut-in and behind-pipe reserves with minor costs to access.
- **Undeveloped Reserves** are quantities expected to be recovered through future significant investments.

The distinction between the "minor costs to access" Developed Non-Producing Reserves and the "significant investment" needed to develop Undeveloped Reserves requires the judgment of the evaluator taking into account the cost environment. A significant investment would be a relatively large expenditure when compared to the cost of drilling and completing a new well. A minor cost would be a lower expenditure when compared to the cost of drilling and completing a new well.

Once a project passes the commercial assessment and achieves Reserves status, it is then included with all other Reserves projects of the same category in the same field for estimating combined future production and applying the economic limit test (see PRMS 2018 Section 3.1, Assessment of Commerciality).

Where Reserves remain Undeveloped beyond a reasonable time-frame or have remained Undeveloped owing to postponements, evaluations should be critically reviewed to document reasons for the delay in initiating development and to justify retaining these quantities within the Reserves class. While there are specific circumstances where a longer delay (see Section A.2.1.2, Determination of Commerciality) is justified, a reasonable time-frame to commence the project is generally considered to be less than five years from the initial classification date.

Development and Production status are of significant importance for project portfolio management and financials. The Reserves status concept of Developed and Undeveloped status is based on the funding and operational status of wells and producing facilities within the development project. These status designations are applicable throughout the full range of Reserves uncertainty categories (1P, 2P, and 3P or Proved, Probable, and Possible). Even those projects that are Developed and On Production should have remaining uncertainty in recoverable quantities.

B.2.1.3.3 Economic Status

Projects may be further characterized by economic status. All projects classified as Reserves must be commercial under defined conditions (see PRMS 2018 Section 3.1, Assessment of Commerciality Assessment). Based on assumptions regarding future conditions and the impact on ultimate economic viability, projects currently classified as Contingent Resources may be broadly divided into two groups:

- **Economically Viable Contingent Resources** are those quantities associated with technically feasible projects where cash flows are positive under reasonably forecasted conditions but are not Reserves because it does not meet the commercial criteria defined in Section A.2.1.2.

- **Economically Not Viable Contingent Resources** are those quantities for which development projects are not expected to yield positive cash flows under reasonable forecast conditions.

The best estimate (or P50) production forecast is typically used for the economic evaluation for the commercial assessment of the project. The low case, when used as the primary case for a project decision, may be used to determine project economics. The economic evaluation of the project high case alone is not permitted to be used in the determination of the project's commerciality.

For Reserves, the best estimate production forecast reflects a specific development scenario recovery process, a certain number and type of wells, facilities, and infrastructure.

The project's low-case scenario is tested to ensure it is economic, which is required for Proved Reserves to exist (see Section A.2.2.2, Category Definitions and Guidelines). It is recommended to evaluate the low case and the high case (which will quantify the 3P Reserves) to convey the project downside risk and upside potential. The project development scenarios may vary in the number and type of wells, facilities, and infrastructure in Contingent Resources, but to recognize Reserves, there must exist the reasonable expectation to develop the project for the best estimate case.

The economic status may be identified independently of, or applied in combination with, project maturity sub-classification to more completely describe the project. Economic status is not the only qualifier that allows defining Contingent or Prospective Resources sub-classes. Within Contingent Resources, applying the project status to decision gates (and/or incorporating them in a plan to execute) more appropriately defines whether the project is placed into the sub-class of either Development Pending versus On Hold, Not Viable, or Unclarified.

Where evaluations are incomplete and it is premature to clearly define the associated cash flows, it is acceptable to note that the project economic status is "undetermined."

B.2.2 Resources Categorization

The horizontal axis in the resources classification in Figure A.1 defines the range of uncertainty in estimates of the quantities of recoverable, or potentially recoverable, petroleum associated with a project or group of projects. These estimates include the uncertainty components as follows:

- The total petroleum remaining within the accumulation (in-place resources).

- The technical uncertainty in the portion of the total petroleum that can be recovered by applying a defined development project or projects (i.e., the technology applied).

- Known variations in the commercial terms that may impact the quantities recovered and sold (e.g., market availability; contractual changes, such as production rate tiers or product quality specifications) are part of project's scope and are included in the horizontal axis, while the chance of satisfying the commercial terms is reflected in the classification (vertical axis).

The uncertainty in a project's recoverable quantities is reflected by the 1P, 2P, 3P, Proved (P1), Probable (P2), Possible (P3), 1C, 2C, 3C, C1, C2, and C3; or 1U, 2U, and 3U resources categories. The commercial chance of success is associated with resources classes or sub-classes and not with the resources categories reflecting the range of recoverable quantities.

There must be a single set of defined conditions applied for resource categorization. Use of different commercial assumptions for categorizing quantities is referred to as "split conditions" and are not allowed. Frequently, an entity will conduct project evaluation sensitivities to understand potential implications when making project selection decisions. Such sensitivities may be fully aligned to resource categories or may use single parameters, groups of parameters, or variances in the defined conditions.

Moreover, a single project is uniquely assigned to a sub-class along with its uncertainty range. For example, a project cannot have quantities classified in both Contingent Resources and Reserves, for instance as 1C, 2P, and 3P. This is referred to as "split classification."

B.2.2.1 Range of Uncertainty

Uncertainty is inherent in a project's resources estimation and is communicated in PRMS by reporting a range of category outcomes. The range of uncertainty of the recoverable and/or potentially recoverable quantities may be represented by either deterministic scenarios or by a probability distribution (see PRMS 2018 Section 4.2, Resources Assessment Methods).

When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

- There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
- There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
- There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

In some projects, the range of uncertainty may be limited, and the three scenarios may result in resources estimates that are not significantly different. In these situations, a single value estimate may be appropriate to describe the expected result.

When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental method, quantities for each confidence segment are estimated discretely (see Section A.2.2.2, Category Definitions and Guidelines).

Project resources are initially estimated using the above uncertainty range forecasts that incorporate the subsurface elements together with technical constraints related to wells and facilities. The technical forecasts then have additional commercial criteria applied (e.g., economics and license cutoffs are the most common) to estimate the entitlement quantities attributed and the resources classification status: Reserves, Contingent Resources, and Prospective Resources.

While there may be significant chance that sub-commercial and undiscovered accumulations will not achieve commercial production, it is useful to consider the range of potentially recoverable quantities independent of such likelihood when considering what resources class to assign the project quantities.

B.2.2.2 Category Definitions and Guidelines

Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental method, the deterministic scenario (cumulative) method, geostatistical methods, or probabilistic methods (see PRMS 2018 Section 4.2, Resources Assessment Methods). Also, combinations of these methods may be used.

Use of consistent terminology (Figure A.1 and Figure A.3) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high forecasts are used to estimate the resulting 1P/2P/3P quantities, respectively. The associated incremental quantities are termed Proved (P1), Probable (P2) and Possible (P3). Reserves are a subset of, and must be viewed within the context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, the criteria can be equally applied to Contingent and Prospective Resources. Upon satisfying the commercial maturity criteria for discovery and/or development, the project quantities will then move to the appropriate resources sub-class. PRMS 2018 Table 3 provides criteria for the Reserves categories determination.

For Contingent Resources, the general cumulative terms low/best/high estimates are used to estimate the resulting 1C/2C/3C quantities, respectively. The terms C1, C2, and C3 are defined for incremental quantities of Contingent Resources.

For Prospective Resources, the general cumulative terms low/best/high estimates also apply and are used to estimate the resulting 1U/2U/3U quantities. No specific terms are defined for incremental quantities within Prospective Resources.

Quantities in different classes and sub-classes cannot be aggregated without considering the varying degrees of technical uncertainty and commercial likelihood involved with the classification(s) and without considering the degree of dependency between them (see PRMS 2018 Section 4.2.1, Aggregating Resources Classes).

Without new technical information, there should be no change in the distribution of technically recoverable resources and the categorization boundaries when conditions are satisfied to reclassify a project from Contingent Resources to Reserves.

All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project (see PRMS 2018 Section 3.1, Assessment of Commerciality).

PRMS 2018 Tables 1, 2, and 3 present category definitions and provide guidelines designed to promote consistency in resources assessments. The following summarize the definitions for each Reserves category in terms of both the deterministic incremental method and the deterministic scenario method, and also provides the criteria if probabilistic methods are applied. For all methods (incremental, scenario, or probabilistic), low, best and high estimate technical forecasts are prepared at an effective date (unless justified otherwise), then tested to validate the commercial criteria, and truncated as applicable for determination of Reserves quantities.

- Proved Reserves are those quantities of Petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from known reservoirs and under defined technical and commercial conditions. If deterministic methods are used, the term "reasonable certainty" is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

- Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.

- Possible Reserves are those additional Reserves that analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P) Reserves, which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves that are located outside of the 2P area (not upside quantities to the 2P scenario) may exist only when the commercial and technical maturity criteria have been met (that incorporate the Possible development scope). Stand- alone Possible Reserves must reference a commercial 2P project (e.g., a lease adjacent to the commercial project that may be owned by a separate entity), otherwise stand-alone Possible is not permitted.

One, but not the sole, criterion for qualifying discovered resources and to categorize the project's range of its low/best/high or P90/P50/P10 estimates to either 1C/2C/3C or 1P/2P/3P is the distance away from known productive area(s) defined by the geoscience confidence in the subsurface.

A conservative (low-case) estimate may be required to support financing. However, for project justification, it is generally the best-estimate Reserves or Resources quantity that passes qualification because it is considered the most realistic assessment of a project's recoverable quantities. The best estimate is generally considered to represent the sum of Proved and Probable estimates (2P) for Reserves, or 2C when Contingent Resources are cited, when aggregating a field, multiple fields, or an entity's resources.

It should be noted that under the deterministic incremental method, discrete estimates are made for each category and should not be aggregated without due consideration of associated confidence. Results from the deterministic scenario, deterministic incremental, geostatistical and probabilistic methods applied to the same project should give comparable results (see PRMS 2018 Section 4.2, Resources Assessment Methods).

If material differences exist between the results of different methods, the evaluator should be prepared to explain these differences.

B.2.3 Incremental Projects

The initial resources assessment is based on application of a defined initial development project, even extending into Prospective Resources. Incremental projects are designed to either increase recovery efficiency, reduce costs, or accelerate production through either maintenance of or changes to wells, completions, or facilities or through infill drilling or by means of improved recovery. Such projects are classified according to the resources classification framework (Figure A.1), with preference for applying project maturity sub-classes (Figure A.3). Related incremental quantities are similarly categorized on the range of uncertainty of recovery. The projected recovery change can be included in Reserves if the degree of commitment is such that the project has achieved commercial maturity (See Section A.2.1.2, Determination of Commerciality). The quantity of such incremental recovery must be supported by technical evidence to justify the relative confidence in the resources category assigned.

An incremental project must have a defined development plan. A development plan may include projects targeting the entire field (or even multiple, linked fields), reservoirs, or single wells. Each incremental project will have its own planned timing for execution and resource quantities attributed to the project. Development plans may also include appraisal projects that will lead to subsequent project decisions based on appraisal outcomes.

Circumstances when development will be significantly delayed and where it is considered that Reserves are still justified should be clearly documented. If there is no longer the reasonable expectation of project execution (i.e., historical track record of execution, project progress), forecast project incremental recoveries are to be reclassified as Contingent Resources (see PRMS 2018 Section 2.1.2, Determination of Commerciality).

B.2.3.1 Workovers, Treatments and Changes of Equipment

Incremental recovery associated with a future workover, treatment (including hydraulic fracturing stimulation), re-treatment, changes to existing equipment, or other mechanical procedures where such projects have routinely been successful in analogous reservoirs may be classified as Developed Reserves, Undeveloped Reserves, or Contingent Resources, depending on the associated costs required (see Section A.2.1.3.2, Reserves Status) and the status of the project's commercial maturity elements.

Facilities that are either beyond their operational life, placed out of service, or removed from service cannot be associated with Reserves recognition. When required facilities become unavailable or out of service for longer than a year, it may be necessary to reclassify the Developed Reserves to either Undeveloped Reserves or Contingent Resources. A project that includes facility replacement or restoration of operational usefulness must be identified, commensurate with the resources classification.

B.2.3.2 Compression

Reduction in the backpressure through compression can increase the portion of in-place gas that can be commercially produced and thus included in resources estimates. If the eventual installation of compression meets commercial maturity requirements, the incremental recovery is included in either Undeveloped Reserves or Developed Reserves, depending on the investment on meeting the Developed or Undeveloped classification criteria. However, if the cost to implement compression is not significant, relative to the cost of one new well in the field, or there is reasonable expectation that compression will be implemented by a third party in a common sales line beyond the reference point, the incremental quantities may be classified as Developed Reserves. If compression facilities were not part of the original approved development plan and such costs are significant, it should be treated as a separate project subject to normal project maturity criteria.

B.2.3.3 Infill Drilling

Technical and commercial analyses may support drilling additional producing wells to reduce the wells spacing of the initial development plan, subject to government regulations. Infill drilling may have the combined effect of increasing recovery and acceleration production. Only the incremental recovery (i.e. recovery from infill wells less the recovery difference in earlier wells) can be considered as additional Reserves for the project; this incremental recovery may need to be reallocated.

B.2.3.4 Improved Recovery

Improved recovery is the additional petroleum obtained, beyond primary recovery, from naturally occurring reservoirs by supplementing the natural reservoir energy. It includes secondary recovery (e.g., waterflooding and pressure maintenance), tertiary recovery processes (thermal, miscible gas injection, chemical injection, and other types), and any other means of supplementing natural reservoir recovery processes.

Improved recovery projects must meet the same Reserves technical and commercial maturity criteria as primary recovery projects.

The judgment on commerciality is based on pilot project results within the subject reservoir or by comparison to a reservoir with analogous rock and fluid properties and where a similar established improved recovery project has been successfully applied.

Incremental recoveries through improved recovery methods that have yet to be established through routine, commercially successful applications are included as Reserves only after a favorable production response from the subject reservoir from either (a) a representative pilot or (b) an installed portion of the project, where the response provides support for the analysis on which the project is based. The improved recovery project's resources will remain classified as Contingent Resources Development Pending until the pilot has demonstrated both technical and commercial feasibility and the full project passes the Justified for Development "decision gate."

B.2.4 Unconventional Resources

The types of in-place petroleum resources defined as conventional and unconventional may require different evaluation approaches and/or extraction methods. However, the PRMS resources definitions, together with the classification system, apply to all types of petroleum accumulations regardless of the in- place characteristics, extraction method applied, or degree of processing required.

- Conventional resources exist in porous and permeable rock with pressure equilibrium. The PIIP is trapped in discrete accumulations related to a local geological structure feature and/or stratigraphic condition. Each conventional accumulation is typically bounded by a down dip contact with an aquifer, as its position is controlled by hydrodynamic interactions between buoyancy of petroleum in water versus capillary force. The petroleum is recovered through wellbores and typically requires minimal processing before sale.

- Unconventional resources exist in petroleum accumulations that are pervasive throughout a large area and are not significantly affected by hydrodynamic influences (also called "continuous-type deposit"). Usually there is not an obvious structural or stratigraphic trap. Examples include coalbed methane (CBM), basin-centered gas (low permeability), tight gas and tight oil (low permeability), gas hydrates, natural bitumen (very high viscosity oil), and oil shale (kerogen) deposits. Note that shale gas and shale oil are sub-types of tight gas and tight oil where the lithologies are predominantly shales or siltstones. These accumulations lack the porosity and permeability of conventional reservoirs required to flow without stimulation at economic rates. Typically, such accumulations require specialized extraction technology (e.g., dewatering of CBM, hydraulic fracturing stimulation for tight gas and tight oil, steam and/or solvents to mobilize natural bitumen for in-situ recovery, and in some cases, surface mining of oil sands). Moreover, the extracted petroleum may require significant processing before sale (e.g., bitumen upgraders).

For unconventional petroleum accumulations, reliance on continuous water contacts and pressure gradient analysis to interpret the extent of recoverable petroleum is not possible. Thus, there is typically a need for increased spatial sampling density to define uncertainty of in-place quantities, variations in reservoir and hydrocarbon quality, and to support design of specialized mining or in-situ extraction programs. In addition, unconventional resources typically require different evaluation techniques than conventional resources.

Extrapolation of reservoir presence or productivity beyond a control point within a resources accumulation must not be assumed unless there is technical evidence to support it. Therefore, extrapolation beyond the immediate vicinity of a control point should be limited unless there is clear engineering and/or geoscience evidence to show otherwise.

The extent of the discovery within a pervasive accumulation is based on the evaluator's reasonable confidence based on distances from existing experience, otherwise quantities remain as undiscovered. Where log and core data and nearby producing analogs provide evidence of potential economic viability, a successful well test may not be required to assign Contingent Resources. Pilot projects may be needed to define Reserves, which requires further evaluation of technical and commercial viability.

A fundamental characteristic of engagement in a repetitive task is that it may improve performance over time. Attempts to quantify this improvement gave rise to the concept of the manufacturing progress function commonly called the "learning curve." The learning curve is characterized by a decrease in time and/or costs, usually in the early stages of a project when processes are being optimized. At that time, each new improvement may be significant. As the project matures, further improvements in time or cost savings are typically less substantial. In oil and gas developments with high well counts and a continuous program of activity (multi-year), the use of a learning curve within a resources evaluation may be justified to predict improvements in either the time taken to carry out the activity, the cost to do so, or both. While each development project is unique, review of analogs can provide guidance on such predictions and the range of associated uncertainty in the resulting recoverable resources estimates (see also PRMS 2018 Section 3.1.2 Economic Criteria).

Source: Petroleum Resources Management System (revised June 2018), Version 1.01, Society of Petroleum Engineers

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Appendix C
Cashflow Forecasts

UKOG Loxley Production and Cashflow Forecasts (in nominal terms) - 1C

Year	WI Oil Prod. MMstb	WI Sales Gas Prod. Bscf	WI LPG Prod. MMstb	Revenue GBP mm	Capex GBP mm	Operating Costs GBP mm	Abex GBP mm	Total Costs GBP mm	Pre-tax Cash flow GBP mm	CT & SC & EPL GBP mm	Post-Tax Cash flow GBP mm	Disc. Factor @ 10%	Disc. Cashflow @ 10% GBP mm
2023	-	-	-	**-**	-	-	-	-	**-**	-	**-**	1.0	**-**
2024	-	-	-	**-**	9.5	-	-	9.5	**(9.5)**	-	**(9.5)**	0.9	**(8.2)**
2025	-	-	-	**-**	24.3	-	-	24.3	**(24.3)**	-	**(24.3)**	0.8	**(19.2)**
2026	-	5.0	-	**72.5**	-	0.8	-	0.8	**71.7**	15.0	**56.7**	0.7	**40.6**
2027	-	4.6	-	**67.7**	-	1.0	-	1.0	**66.8**	40.9	**25.9**	0.7	**16.9**
2028	-	3.2	-	**42.4**	9.5	0.9	-	10.4	**31.9**	31.5	**0.4**	0.6	**0.2**
2029	-	2.4	-	**28.9**	-	1.1	-	1.1	**27.8**	14.8	**13.0**	0.5	**7.0**
2030	-	1.8	-	**22.6**	-	1.1	-	1.1	**21.5**	9.5	**12.1**	0.5	**5.9**
2031	-	1.4	-	**18.2**	-	1.1	-	1.1	**17.1**	7.4	**9.7**	0.4	**4.3**
2032	-	1.2	-	**16.2**	-	1.1	-	1.1	**15.1**	6.3	**8.8**	0.4	**3.5**
2033	-	1.0	-	**13.6**	-	1.1	-	1.1	**12.5**	5.3	**7.1**	0.4	**2.6**
2034	-	0.4	-	**5.0**	-	1.1	-	1.1	**3.9**	2.7	**1.2**	0.3	**0.4**
2035	-	-	-	**-**	-	-	1.8	1.8	**(1.8)**	0.0	**(1.8)**	0.3	**(0.6)**
2036	-	-	-	**-**	-	-	1.8	1.8	**(1.8)**	(0.7)	**(1.1)**	0.3	**(0.3)**
2037	-	-	-	**-**	-	-	-	-	**-**	(0.2)	**0.2**	0.3	**0.1**
2038	-	-	-	**-**	-	-	-	-	**-**	-	**-**	0.2	**-**
2039	-	-	-	**-**	-	-	-	-	**-**	-	**-**	0.2	**-**
2040	-	-	-	**-**	-	-	-	-	**-**	-	**-**	0.2	**-**
Total	**-**	**21.0**	**-**	**287.2**	43.3	9.2	3.6	56.2	**231.0**	132.6	**98.4**		**53.4**

Table C.1: 100% Gross (WI) Production and Cashflow Forecast for Loxley asset – 1C

UKOG Loxley Production and Cashflow Forecasts (in nominal terms) - 2C

Year	WI Oil Prod. MMstb	WI Sales Gas Prod. Bscf	WI LPG Prod. MMstb	Revenue GBP mm	Capex GBP mm	Operating Costs GBP mm	Abex GBP mm	Total Costs GBP mm	Pre-tax Cash flow GBP mm	CT & SC & EPL GBP mm	Post-Tax Cash flow GBP mm	Disc. Factor @ 10%	Disc. Cashflow @ 10% GBP mm
2023	-	-	-	**-**	-	-	-	-	**-**	-	**-**	1.0	**-**
2024	-	-	-	**-**	9.5	-	-	9.5	**(9.5)**	-	**(9.5)**	0.9	**(8.2)**
2025	-	-	-	**-**	24.3	-	-	24.3	**(24.3)**	-	**(24.3)**	0.8	**(19.2)**
2026	-	5.5	-	**79.2**	-	0.8	-	0.8	**78.4**	18.3	**60.1**	0.7	**43.0**
2027	-	7.3	-	**106.4**	-	1.1	-	1.1	**105.3**	61.8	**43.5**	0.7	**28.3**
2028	-	7.3	-	**95.5**	9.5	1.1	-	10.6	**84.9**	67.7	**17.2**	0.6	**10.2**
2029	-	5.9	-	**72.2**	-	1.3	-	1.3	**71.0**	39.6	**31.4**	0.5	**16.9**
2030	-	4.4	-	**54.4**	-	1.2	-	1.2	**53.2**	23.6	**29.5**	0.5	**14.4**
2031	-	3.2	-	**41.0**	-	1.2	-	1.2	**39.8**	17.7	**22.1**	0.4	**9.8**
2032	-	2.4	-	**33.1**	-	1.2	-	1.2	**31.9**	13.8	**18.1**	0.4	**7.3**
2033	-	1.8	-	**24.8**	-	1.2	-	1.2	**23.6**	10.6	**13.1**	0.4	**4.8**
2034	-	1.3	-	**18.5**	-	1.2	-	1.2	**17.4**	7.8	**9.6**	0.3	**3.2**
2035	-	1.0	-	**14.2**	-	1.2	-	1.2	**13.1**	5.8	**7.3**	0.3	**2.2**
2036	-	0.3	-	**4.2**	-	1.1	-	1.1	**3.1**	2.6	**0.5**	0.3	**0.1**
2037	-	-	-	**-**	-	-	1.9	1.9	**(1.9)**	(0.1)	**(1.8)**	0.3	**(0.4)**
2038	-	-	-	**-**	-	-	1.9	1.9	**(1.9)**	(0.8)	**(1.1)**	0.2	**(0.3)**
2039	-	-	-	**-**	-	-	-	-	**-**	(0.3)	**0.3**	0.2	**0.1**
2040	-	-	-	**-**	-	-	-	-	**-**	-	**-**	0.2	**-**
Total	**-**	**40.2**	**-**	**543.6**	43.3	12.4	3.8	59.5	**484.1**	268.2	**215.9**		**112.4**

Table C.2: 100% Gross (WI) Production and Cashflow Forecast for Loxley asset – 2C

UKOG Loxley Production and Cashflow Forecasts (in nominal terms) - 3C

Year	WI Oil Prod. MMstb	WI Sales Gas Prod. Bscf	WI LPG Prod. MMstb	Revenue GBP mm	Capex GBP mm	Operating Costs GBP mm	Abex GBP mm	Total Costs GBP mm	Pre-tax Cash flow GBP mm	CT & SC & EPL GBP mm	Post-Tax Cash flow GBP mm	Disc. Factor @ 10%	Disc. Cashflow @ 10% GBP mm
2023	-	-	-	**-**	-	-	-	-	**-**	-	**-**	1.0	**-**
2024	-	-	-	**-**	9.5	-	-	9.5	**(9.5)**	-	**(9.5)**	0.9	**(8.2)**
2025	-	-	-	**-**	24.3	-	-	24.3	**(24.3)**	-	**(24.3)**	0.8	**(19.2)**
2026	-	5.5	-	**79.2**	-	0.8	-	0.8	**78.4**	18.3	**60.1**	0.7	**43.0**
2027	-	7.3	-	**106.4**	-	1.1	-	1.1	**105.3**	61.8	**43.5**	0.7	**28.3**
2028	-	7.3	-	**95.9**	9.5	1.1	-	10.6	**85.3**	67.9	**17.4**	0.6	**10.3**
2029	-	7.3	-	**89.2**	-	1.4	-	1.4	**87.9**	44.2	**43.7**	0.5	**23.5**
2030	-	7.3	-	**91.0**	-	1.4	-	1.4	**89.7**	35.6	**54.0**	0.5	**26.4**
2031	-	7.3	-	**92.9**	-	1.4	-	1.4	**91.5**	36.3	**55.1**	0.4	**24.5**
2032	-	7.3	-	**101.8**	-	1.4	-	1.4	**100.3**	39.0	**61.4**	0.4	**24.8**
2033	-	6.9	-	**97.7**	-	1.4	-	1.4	**96.2**	39.0	**57.2**	0.4	**21.0**
2034	-	5.2	-	**74.6**	-	1.4	-	1.4	**73.2**	32.4	**40.9**	0.3	**13.7**
2035	-	3.8	-	**55.8**	-	1.3	-	1.3	**54.5**	24.3	**30.2**	0.3	**9.2**
2036	-	2.8	-	**41.7**	-	1.3	-	1.3	**40.4**	18.1	**22.4**	0.3	**6.2**
2037	-	0.6	-	**8.8**	-	1.3	-	1.3	**7.5**	7.4	**0.1**	0.3	**0.0**
2038	-	-	-	**-**	-	-	1.9	1.9	**(1.9)**	0.5	**(2.4)**	0.2	**(0.5)**
2039	-	-	-	**-**	-	-	1.9	1.9	**(1.9)**	(0.8)	**(1.2)**	0.2	**(0.2)**
2040	-	-	-	**-**	-	-	-	-	**-**	(0.3)	**0.3**	0.2	**0.0**
Total	**-**	**68.7**	**-**	**935.1**	43.3	15.3	3.8	62.5	**872.6**	423.7	**448.9**		**202.9**

Table C.3: 100% Gross (WI) Production and Cashflow Forecast for Loxley asset – 3C

UKOG Loxley Production and Cashflow Forecasts (in nominal terms) - 1C

Year	WI Oil Prod. MMstb	WI Sales Gas Prod. Bscf	WI LPG Prod. MMstb	Revenue GBP mm	Capex GBP mm	Operating Costs GBP mm	Abex GBP mm	Total Costs GBP mm	Pre-tax Cash flow GBP mm	CT & SC & EPL GBP mm	Post-Tax Cash flow GBP mm	Disc. Factor @ 10%	Disc. Cashflow @ 10% GBP mm
2023	-	-	-	**-**	-	-	-	-	**-**	-	**-**	1.0	**-**
2024	-	-	-	**-**	7.3	-	-	7.3	**(7.3)**	-	**(7.3)**	0.9	**(6.3)**
2025	-	-	-	**-**	18.7	-	-	18.7	**(18.7)**	-	**(18.7)**	0.8	**(14.8)**
2026	-	3.9	-	**55.8**	-	0.6	-	0.6	**55.2**	11.5	**43.7**	0.7	**31.3**
2027	-	3.6	-	**52.1**	-	0.7	-	0.7	**51.4**	31.5	**19.9**	0.7	**13.0**
2028	-	2.5	-	**32.6**	7.3	0.7	-	8.0	**24.6**	24.3	**0.3**	0.6	**0.2**
2029	-	1.8	-	**22.3**	-	0.8	-	0.8	**21.4**	11.4	**10.0**	0.5	**5.4**
2030	-	1.4	-	**17.4**	-	0.8	-	0.8	**16.6**	7.3	**9.3**	0.5	**4.5**
2031	-	1.1	-	**14.0**	-	0.8	-	0.8	**13.2**	5.7	**7.5**	0.4	**3.3**
2032	-	0.9	-	**12.5**	-	0.8	-	0.8	**11.6**	4.9	**6.8**	0.4	**2.7**
2033	-	0.7	-	**10.4**	-	0.9	-	0.9	**9.6**	4.1	**5.5**	0.4	**2.0**
2034	-	0.3	-	**3.9**	-	0.8	-	0.8	**3.0**	2.1	**1.0**	0.3	**0.3**
2035	-	-	-	**-**	-	-	1.4	1.4	**(1.4)**	0.0	**(1.4)**	0.3	**(0.4)**
2036	-	-	-	**-**	-	-	1.4	1.4	**(1.4)**	(0.6)	**(0.8)**	0.3	**(0.2)**
2037	-	-	-	**-**	-	-	-	-	**-**	(0.2)	**0.2**	0.3	**0.0**
2038	-	-	-	**-**	-	-	-	-	**-**	-	**-**	0.2	**-**
2039	-	-	-	**-**	-	-	-	-	**-**	-	**-**	0.2	**-**
2040	-	-	-	**-**	-	-	-	-	**-**	-	**-**	0.2	**-**
Total	**-**	**16.2**	**-**	**221.1**	33.4	7.1	2.8	43.2	**177.9**	102.1	**75.8**		**41.1**

Table C.4: 77% Net Entitlement Production and Cashflow Forecast for Loxley asset – 1C

UKOG Loxley Production and Cashflow Forecasts (in nominal terms) - 2C

Year	WI Oil Prod. MMstb	WI Sales Gas Prod. Bscf	WI LPG Prod. MMstb	Revenue GBP mm	Capex GBP mm	Operating Costs GBP mm	Abex GBP mm	Total Costs GBP mm	Pre-tax Cash flow GBP mm	CT & SC & EPL GBP mm	Post-Tax Cash flow GBP mm	Disc. Factor @ 10%	Disc. Cashflow @ 10% GBP mm
2023	-	-	-	**-**	-	-	-	-	**-**	-	**-**	1.0	**-**
2024	-	-	-	**-**	7.3	-	-	7.3	**(7.3)**	-	**(7.3)**	0.9	**(6.3)**
2025	-	-	-	**-**	18.7	-	-	18.7	**(18.7)**	-	**(18.7)**	0.8	**(14.8)**
2026	-	4.2	-	**61.0**	-	0.6	-	0.6	**60.4**	14.1	**46.3**	0.7	**33.1**
2027	-	5.6	-	**81.9**	-	0.8	-	0.8	**81.1**	47.6	**33.5**	0.7	**21.8**
2028	-	5.6	-	**73.6**	7.3	0.8	-	8.2	**65.4**	52.1	**13.3**	0.6	**7.9**
2029	-	4.6	-	**55.6**	-	1.0	-	1.0	**54.6**	30.5	**24.2**	0.5	**13.0**
2030	-	3.4	-	**41.9**	-	0.9	-	0.9	**40.9**	18.2	**22.7**	0.5	**11.1**
2031	-	2.5	-	**31.5**	-	0.9	-	0.9	**30.6**	13.6	**17.0**	0.4	**7.6**
2032	-	1.8	-	**25.5**	-	0.9	-	0.9	**24.6**	10.6	**14.0**	0.4	**5.6**
2033	-	1.4	-	**19.1**	-	0.9	-	0.9	**18.2**	8.1	**10.1**	0.4	**3.7**
2034	-	1.0	-	**14.3**	-	0.9	-	0.9	**13.4**	6.0	**7.4**	0.3	**2.5**
2035	-	0.8	-	**11.0**	-	0.9	-	0.9	**10.1**	4.5	**5.6**	0.3	**1.7**
2036	-	0.2	-	**3.3**	-	0.9	-	0.9	**2.4**	2.0	**0.4**	0.3	**0.1**
2037	-	-	-	**-**	-	-	1.4	1.4	**(1.4)**	(0.1)	**(1.4)**	0.3	**(0.3)**
2038	-	-	-	**-**	-	-	1.5	1.5	**(1.5)**	(0.6)	**(0.9)**	0.2	**(0.2)**
2039	-	-	-	**-**	-	-	-	-	**-**	(0.2)	**0.2**	0.2	**0.0**
2040	-	-	-	**-**	-	-	-	-	**-**	-	**-**	0.2	**-**
Total	**-**	**31.0**	**-**	**418.6**	33.4	9.6	2.9	45.8	**372.7**	206.5	**166.2**		**86.5**

Table C.5: 77% Net Entitlement Production and Cashflow Forecast for Loxley asset – 2C

UKOG Loxley Production and Cashflow Forecasts (in nominal terms) - 3C

Year	WI Oil Prod. MMstb	WI Sales Gas Prod. Bscf	WI LPG Prod. MMstb	Revenue GBP mm	Capex GBP mm	Operating Costs GBP mm	Abex GBP mm	Total Costs GBP mm	Pre-tax Cash flow GBP mm	CT & SC & EPL GBP mm	Post-Tax Cash flow GBP mm	Disc. Factor @ 10%	Disc. Cashflow @ 10% GBP mm
2023	-	-	-	**-**	-	-	-	-	**-**	-	**-**	1.0	**-**
2024	-	-	-	**-**	7.3	-	-	7.3	**(7.3)**	-	**(7.3)**	0.9	**(6.3)**
2025	-	-	-	**-**	18.7	-	-	18.7	**(18.7)**	-	**(18.7)**	0.8	**(14.8)**
2026	-	4.2	-	**61.0**	-	0.6	-	0.6	**60.4**	14.1	**46.3**	0.7	**33.1**
2027	-	5.6	-	**81.9**	-	0.8	-	0.8	**81.1**	47.6	**33.5**	0.7	**21.8**
2028	-	5.6	-	**73.9**	7.3	0.9	-	8.2	**65.7**	52.2	**13.4**	0.6	**7.9**
2029	-	5.6	-	**68.7**	-	1.0	-	1.0	**67.7**	34.0	**33.6**	0.5	**18.1**
2030	-	5.6	-	**70.1**	-	1.1	-	1.1	**69.0**	27.4	**41.6**	0.5	**20.4**
2031	-	5.6	-	**71.5**	-	1.1	-	1.1	**70.4**	28.0	**42.5**	0.4	**18.9**
2032	-	5.6	-	**78.4**	-	1.1	-	1.1	**77.3**	30.0	**47.3**	0.4	**19.1**
2033	-	5.3	-	**75.2**	-	1.1	-	1.1	**74.1**	30.1	**44.0**	0.4	**16.2**
2034	-	4.0	-	**57.4**	-	1.1	-	1.1	**56.4**	24.9	**31.5**	0.3	**10.5**
2035	-	3.0	-	**43.0**	-	1.0	-	1.0	**42.0**	18.7	**23.3**	0.3	**7.1**
2036	-	2.2	-	**32.1**	-	1.0	-	1.0	**31.1**	13.9	**17.2**	0.3	**4.8**
2037	-	0.5	-	**6.8**	-	1.0	-	1.0	**5.7**	5.7	**0.1**	0.3	**0.0**
2038	-	-	-	**-**	-	-	1.5	1.5	**(1.5)**	0.4	**(1.8)**	0.2	**(0.4)**
2039	-	-	-	**-**	-	-	1.5	1.5	**(1.5)**	(0.6)	**(0.9)**	0.2	**(0.2)**
2040	-	-	-	**-**	-	-	-	-	**-**	(0.2)	**0.2**	0.2	**0.0**
Total	**-**	**52.9**	**-**	**720.0**	33.4	11.8	3.0	48.1	**671.9**	326.3	**345.6**		**156.2**

Table C.6: 77% Net Entitlement Production and Cashflow Forecast for Loxley asset – 3C

UKOG Loxley Production and Cashflow Forecasts (in nominal terms) - 1C

Year	WI Oil Prod. MMstb	WI Sales Gas Prod. Bscf	WI LPG Prod. MMstb	Revenue GBP mm	Capex GBP mm	Operating Costs GBP mm	Abex GBP mm	Total Costs GBP mm	Pre-tax Cash flow GBP mm	CT & SC & EPL GBP mm	Post-Tax Cash flow GBP mm	Disc. Factor @ 10%	Disc. Cashflow @ 10% GBP mm
2023	-	-	-	**-**	-	-	-	-	**-**	-	**-**	1.0	**-**
2024	-	-	-	**-**	9.5	-	-	9.5	**(9.5)**	-	**(9.5)**	0.9	**(8.2)**
2025	-	-	-	**-**	24.3	-	-	24.3	**(24.3)**	-	**(24.3)**	0.8	**(19.2)**
2026	-	5.0	-	**93.3**	-	0.8	-	0.8	**92.5**	25.4	**67.1**	0.7	**48.1**
2027	-	4.6	-	**86.5**	-	1.0	-	1.0	**85.5**	55.5	**30.1**	0.7	**19.6**
2028	-	3.2	-	**60.0**	9.5	0.9	-	10.4	**49.6**	45.0	**4.5**	0.6	**2.7**
2029	-	2.4	-	**44.1**	-	1.1	-	1.1	**43.0**	23.3	**19.7**	0.5	**10.6**
2030	-	1.8	-	**33.8**	-	1.1	-	1.1	**32.7**	14.4	**18.2**	0.5	**8.9**
2031	-	1.4	-	**26.7**	-	1.1	-	1.1	**25.6**	11.2	**14.4**	0.4	**6.4**
2032	-	1.2	-	**21.6**	-	1.1	-	1.1	**20.5**	8.9	**11.6**	0.4	**4.7**
2033	-	1.0	-	**17.9**	-	1.1	-	1.1	**16.8**	7.2	**9.6**	0.4	**3.5**
2034	-	0.4	-	**6.6**	-	1.1	-	1.1	**5.5**	3.7	**1.8**	0.3	**0.6**
2035	-	-	-	**-**	-	-	1.8	1.8	**(1.8)**	0.2	**(2.0)**	0.3	**(0.6)**
2036	-	-	-	**-**	-	-	1.8	1.8	**(1.8)**	(0.7)	**(1.1)**	0.3	**(0.3)**
2037	-	-	-	**-**	-	-	-	-	**-**	(0.2)	**0.2**	0.3	**0.1**
2038	-	-	-	**-**	-	-	-	-	**-**	-	**-**	0.2	**-**
2039	-	-	-	**-**	-	-	-	-	**-**	-	**-**	0.2	**-**
2040	-	-	-	**-**	-	-	-	-	**-**	-	**-**	0.2	**-**
Total	**-**	**21.0**	**-**	**390.3**	43.3	9.2	3.6	56.2	**334.2**	193.9	**140.3**		**76.8**

Table C.7: 186.05p/therm Gas price sensitivity. 100% Gross (WI) Production and Cashflow Forecast for Loxley asset – 1C

UKOG Loxley Production and Cashflow Forecasts (in nominal terms) - 2C

Year	WI Oil Prod. MMstb	WI Sales Gas Prod. Bscf	WI LPG Prod. MMstb	Revenue GBP mm	Capex GBP mm	Operating Costs GBP mm	Abex GBP mm	Total Costs GBP mm	Pre-tax Cash flow GBP mm	CT & SC & EPL GBP mm	Post-Tax Cash flow GBP mm	Disc. Factor @ 10%	Disc. Cashflow @ 10% GBP mm
2023	-	-	-	**-**	-	-	-	-	**-**	-	**-**	1.0	**-**
2024	-	-	-	**-**	9.5	-	-	9.5	**(9.5)**	-	**(9.5)**	0.9	**(8.2)**
2025	-	-	-	**-**	24.3	-	-	24.3	**(24.3)**	-	**(24.3)**	0.8	**(19.2)**
2026	-	5.5	-	**101.9**	-	0.8	-	0.8	**101.1**	29.7	**71.4**	0.7	**51.2**
2027	-	7.3	-	**135.9**	-	1.1	-	1.1	**134.8**	82.3	**52.6**	0.7	**34.2**
2028	-	7.3	-	**135.4**	9.5	1.1	-	10.6	**124.7**	94.9	**29.8**	0.6	**17.6**
2029	-	5.9	-	**110.0**	-	1.3	-	1.3	**108.7**	59.6	**49.1**	0.5	**26.4**
2030	-	4.4	-	**81.2**	-	1.2	-	1.2	**80.0**	35.8	**44.1**	0.5	**21.6**
2031	-	3.2	-	**59.9**	-	1.2	-	1.2	**58.7**	26.3	**32.4**	0.4	**14.4**
2032	-	2.4	-	**44.2**	-	1.2	-	1.2	**43.1**	19.3	**23.7**	0.4	**9.6**
2033	-	1.8	-	**32.6**	-	1.2	-	1.2	**31.5**	14.1	**17.3**	0.4	**6.4**
2034	-	1.3	-	**24.1**	-	1.2	-	1.2	**22.9**	10.3	**12.6**	0.3	**4.2**
2035	-	1.0	-	**18.2**	-	1.2	-	1.2	**17.1**	7.6	**9.5**	0.3	**2.9**
2036	-	0.3	-	**5.4**	-	1.1	-	1.1	**4.2**	3.4	**0.8**	0.3	**0.2**
2037	-	-	-	**-**	-	-	1.9	1.9	**(1.9)**	0.1	**(1.9)**	0.3	**(0.5)**
2038	-	-	-	**-**	-	-	1.9	1.9	**(1.9)**	(0.8)	**(1.1)**	0.2	**(0.3)**
2039	-	-	-	**-**	-	-	-	-	**-**	(0.3)	**0.3**	0.2	**0.1**
2040	-	-	-	**-**	-	-	-	-	**-**	-	**-**	0.2	**-**
Total	**-**	**40.2**	**-**	**748.8**	43.3	12.4	3.8	59.5	**689.3**	382.5	**306.8**		**160.7**

Table C.8: 186.05p/therm Gas price sensitivity. 100% Gross (WI) Production and Cashflow Forecast for Loxley asset – 2C

UKOG Loxley Production and Cashflow Forecasts (in nominal terms) - 3C

Year	WI Oil Prod. MMstb	WI Sales Gas Prod. Bscf	WI LPG Prod. MMstb	Revenue GBP mm	Capex GBP mm	Operating Costs GBP mm	Abex GBP mm	Total Costs GBP mm	Pre-tax Cash flow GBP mm	CT & SC & EPL GBP mm	Post-Tax Cash flow GBP mm	Disc. Factor @ 10%	Disc. Cashflow @ 10% GBP mm
2023	-	-	-	**-**	-	-	-	-	**-**	-	-	1.0	**-**
2024	-	-	-	**-**	9.5	-	-	9.5	**(9.5)**	-	(9.5)	0.9	**(8.2)**
2025	-	-	-	**-**	24.3	-	-	24.3	**(24.3)**	-	(24.3)	0.8	**(19.2)**
2026	-	5.5	-	**101.9**	-	0.8	-	0.8	**101.1**	29.7	71.4	0.7	**51.2**
2027	-	7.3	-	**135.9**	-	1.1	-	1.1	**134.8**	82.3	52.6	0.7	**34.2**
2028	-	7.3	-	**135.9**	9.5	1.1	-	10.6	**125.3**	95.2	30.0	0.6	**17.8**
2029	-	7.3	-	**135.9**	-	1.4	-	1.4	**134.6**	66.6	67.9	0.5	**36.6**
2030	-	7.3	-	**135.9**	-	1.4	-	1.4	**134.5**	53.8	80.7	0.5	**39.5**
2031	-	7.3	-	**135.9**	-	1.4	-	1.4	**134.5**	53.8	80.7	0.4	**35.9**
2032	-	7.3	-	**135.9**	-	1.4	-	1.4	**134.5**	53.8	80.7	0.4	**32.6**
2033	-	6.9	-	**128.6**	-	1.4	-	1.4	**127.2**	51.9	75.4	0.4	**27.7**
2034	-	5.2	-	**96.9**	-	1.4	-	1.4	**95.6**	42.4	53.1	0.3	**17.8**
2035	-	3.8	-	**71.5**	-	1.3	-	1.3	**70.2**	31.5	38.7	0.3	**11.8**
2036	-	2.8	-	**52.8**	-	1.3	-	1.3	**51.5**	23.1	28.4	0.3	**7.8**
2037	-	0.6	-	**10.9**	-	1.3	-	1.3	**9.6**	9.4	0.1	0.3	**0.0**
2038	-	-	-	**-**	-	-	1.9	1.9	**(1.9)**	0.8	(2.7)	0.2	**(0.6)**
2039	-	-	-	**-**	-	-	1.9	1.9	**(1.9)**	(0.8)	(1.2)	0.2	**(0.2)**
2040	-	-	-	**-**	-	-	-	-	**-**	(0.3)	0.3	0.2	**0.0**
Total	**-**	**68.7**	**-**	**1,278.2**	43.3	15.3	3.8	62.5	**1,215.7**	593.2	622.5		**284.7**

Table C.9: 186.05p/therm Gas price sensitivity. 100% Gross (WI) Production and Cashflow Forecast for Loxley asset – 3C

UKOG Loxley Production and Cashflow Forecasts (in nominal terms) - 1C

Year	WI Oil Prod. MMstb	WI Sales Gas Prod. Bscf	WI LPG Prod. MMstb	Revenue GBP mm	Capex GBP mm	Operating Costs GBP mm	Abex GBP mm	Total Costs GBP mm	Pre-tax Cash flow GBP mm	CT & SC & EPL GBP mm	Post-Tax Cash flow GBP mm	Disc. Factor @ 10%	Disc. Cashflow @ 10% GBP mm
2023	-	-	-	**-**	-	-	-	-	**-**	-	**-**	1.0	**-**
2024	-	-	-	**-**	7.3	-	-	7.3	**(7.3)**	-	**(7.3)**	0.9	**(6.3)**
2025	-	-	-	**-**	18.7	-	-	18.7	**(18.7)**	-	**(18.7)**	0.8	**(14.8)**
2026	-	3.9	-	**71.8**	-	0.6	-	0.6	**71.2**	19.5	**51.7**	0.7	**37.0**
2027	-	3.6	-	**66.6**	-	0.7	-	0.7	**65.8**	42.7	**23.1**	0.7	**15.1**
2028	-	2.5	-	**46.2**	7.3	0.7	-	8.0	**38.2**	34.7	**3.5**	0.6	**2.1**
2029	-	1.8	-	**33.9**	-	0.8	-	0.8	**33.1**	17.9	**15.2**	0.5	**8.2**
2030	-	1.4	-	**26.0**	-	0.8	-	0.8	**25.1**	11.1	**14.0**	0.5	**6.9**
2031	-	1.1	-	**20.5**	-	0.8	-	0.8	**19.7**	8.6	**11.1**	0.4	**4.9**
2032	-	0.9	-	**16.6**	-	0.8	-	0.8	**15.8**	6.8	**9.0**	0.4	**3.6**
2033	-	0.7	-	**13.8**	-	0.9	-	0.9	**12.9**	5.5	**7.4**	0.4	**2.7**
2034	-	0.3	-	**5.1**	-	0.8	-	0.8	**4.2**	2.8	**1.4**	0.3	**0.5**
2035	-	-	-	**-**	-	-	1.4	1.4	**(1.4)**	0.2	**(1.6)**	0.3	**(0.5)**
2036	-	-	-	**-**	-	-	1.4	1.4	**(1.4)**	(0.6)	**(0.8)**	0.3	**(0.2)**
2037	-	-	-	**-**	-	-	-	-	**-**	(0.2)	**0.2**	0.3	**0.0**
2038	-	-	-	**-**	-	-	-	-	**-**	-	**-**	0.2	**-**
2039	-	-	-	**-**	-	-	-	-	**-**	-	**-**	0.2	**-**
2040	-	-	-	**-**	-	-	-	-	**-**	-	**-**	0.2	**-**
Total	**-**	**16.2**	**-**	**300.6**	33.4	7.1	2.8	43.2	**257.3**	149.3	**108.0**		**59.2**

Table C.10: 186.05p/therm Gas price sensitivity. 77% Net Entitlement Production and Cashflow Forecast for Loxley asset – 1C

UKOG Loxley Production and Cashflow Forecasts (in nominal terms) - 2C

Year	WI Oil Prod.	WI Sales Gas Prod.	WI LPG Prod.	Revenue	Capex	Operating Costs	Abex	Total Costs	Pre-tax Cash flow	CT & SC & EPL	Post-Tax Cash flow	Disc. Factor	Disc. Cashflow @ 10%
	MMstb	Bscf	MMstb	GBP mm	GBP mm	GBP mm	GBP mm	GBP mm	GBP mm	GBP mm	GBP mm	@ 10%	GBP mm
2023	-	-	-	**-**	-	-	-	-	**-**	-	**-**	1.0	**-**
2024	-	-	-	**-**	7.3	-	-	7.3	**(7.3)**	-	**(7.3)**	0.9	**(6.3)**
2025	-	-	-	**-**	18.7	-	-	18.7	**(18.7)**	-	**(18.7)**	0.8	**(14.8)**
2026	-	4.2	-	**78.5**	-	0.6	-	0.6	**77.9**	22.9	**55.0**	0.7	**39.4**
2027	-	5.6	-	**104.7**	-	0.8	-	0.8	**103.8**	63.3	**40.5**	0.7	**26.4**
2028	-	5.6	-	**104.2**	7.3	0.8	-	8.2	**96.0**	73.1	**22.9**	0.6	**13.6**
2029	-	4.6	-	**84.7**	-	1.0	-	1.0	**83.7**	45.9	**37.8**	0.5	**20.4**
2030	-	3.4	-	**62.5**	-	0.9	-	0.9	**61.6**	27.6	**34.0**	0.5	**16.6**
2031	-	2.5	-	**46.1**	-	0.9	-	0.9	**45.2**	20.3	**25.0**	0.4	**11.1**
2032	-	1.8	-	**34.0**	-	0.9	-	0.9	**33.2**	14.9	**18.3**	0.4	**7.4**
2033	-	1.4	-	**25.1**	-	0.9	-	0.9	**24.2**	10.9	**13.4**	0.4	**4.9**
2034	-	1.0	-	**18.5**	-	0.9	-	0.9	**17.7**	7.9	**9.7**	0.3	**3.2**
2035	-	0.8	-	**14.0**	-	0.9	-	0.9	**13.1**	5.9	**7.3**	0.3	**2.2**
2036	-	0.2	-	**4.1**	-	0.9	-	0.9	**3.3**	2.6	**0.6**	0.3	**0.2**
2037	-	-	-	**-**	-	-	1.4	1.4	**(1.4)**	0.0	**(1.5)**	0.3	**(0.4)**
2038	-	-	-	**-**	-	-	1.5	1.5	**(1.5)**	(0.6)	**(0.9)**	0.2	**(0.2)**
2039	-	-	-	**-**	-	-	-	-	**-**	(0.2)	**0.2**	0.2	**0.0**
2040	-	-	-	**-**	-	-	-	-	**-**	-	**-**	0.2	**-**
Total	**-**	**31.0**	**-**	**576.6**	33.4	9.6	2.9	45.8	**530.8**	294.5	**236.2**		**123.7**

Table C.11: 186.05p/therm Gas price sensitivity. 77% Net Entitlement Production and Cashflow Forecast for Loxley asset – 2C

UKOG Loxley Production and Cashflow Forecasts (in nominal terms) - 3C

Year	WI Oil Prod. MMstb	WI Sales Gas Prod. Bscf	WI LPG Prod. MMstb	Revenue GBP mm	Capex GBP mm	Operating Costs GBP mm	Abex GBP mm	Total Costs GBP mm	Pre-tax Cash flow GBP mm	CT & SC & EPL GBP mm	Post-Tax Cash flow GBP mm	Disc. Factor @ 10%	Disc. Cashflow @ 10% GBP mm
2023	-	-	-	**-**	-	-	-	-	**-**	-	**-**	1.0	**-**
2024	-	-	-	**-**	7.3	-	-	7.3	**(7.3)**	-	**(7.3)**	0.9	**(6.3)**
2025	-	-	-	**-**	18.7	-	-	18.7	**(18.7)**	-	**(18.7)**	0.8	**(14.8)**
2026	-	4.2	-	**78.5**	-	0.6	-	0.6	**77.9**	22.9	**55.0**	0.7	**39.4**
2027	-	5.6	-	**104.7**	-	0.8	-	0.8	**103.8**	63.3	**40.5**	0.7	**26.4**
2028	-	5.6	-	**104.7**	7.3	0.9	-	8.2	**96.5**	73.3	**23.1**	0.6	**13.7**
2029	-	5.6	-	**104.7**	-	1.0	-	1.0	**103.6**	51.3	**52.3**	0.5	**28.1**
2030	-	5.6	-	**104.7**	-	1.1	-	1.1	**103.6**	41.4	**62.2**	0.5	**30.4**
2031	-	5.6	-	**104.7**	-	1.1	-	1.1	**103.6**	41.4	**62.1**	0.4	**27.6**
2032	-	5.6	-	**104.7**	-	1.1	-	1.1	**103.5**	41.4	**62.1**	0.4	**25.1**
2033	-	5.3	-	**99.1**	-	1.1	-	1.1	**97.9**	39.9	**58.0**	0.4	**21.3**
2034	-	4.0	-	**74.6**	-	1.1	-	1.1	**73.6**	32.7	**40.9**	0.3	**13.7**
2035	-	3.0	-	**55.1**	-	1.0	-	1.0	**54.1**	24.2	**29.8**	0.3	**9.1**
2036	-	2.2	-	**40.7**	-	1.0	-	1.0	**39.7**	17.8	**21.9**	0.3	**6.0**
2037	-	0.5	-	**8.4**	-	1.0	-	1.0	**7.4**	7.3	**0.1**	0.3	**0.0**
2038	-	-	-	**-**	-	-	1.5	1.5	**(1.5)**	0.6	**(2.1)**	0.2	**(0.5)**
2039	-	-	-	**-**	-	-	1.5	1.5	**(1.5)**	(0.6)	**(0.9)**	0.2	**(0.2)**
2040	-	-	-	**-**	-	-	-	-	**-**	(0.2)	**0.2**	0.2	**0.0**
Total	**-**	**52.9**	**-**	**984.2**	33.4	11.8	3.0	48.1	**936.1**	456.8	**479.3**		**219.2**

Table C.12: 186.05p/therm Gas price sensitivity. 77% Net Entitlement Production and Cashflow Forecast for Loxley asset – 3C

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