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20th February 2009

Re: Resources Assessment of Oil & Gas Assets of Xcite Energy Resources Limited, Block 9/3b, Offshore UKCS

Xcite Energy Resources Limited ("XER") is a wholly owned subsidiary of Xcite Energy Limited ("Xcite" or the "Company"). At the request of Xcite, RPS Energy Limited ("RPS") has prepared an independent Resources Assessment on the Bentley field, located in Block 9/3b on the UKCS. We understand that this report may be used in connection with future fund raising activities by the Company, including discussions with potential farminees and business partners. We acknowledge that this report may be included in its entirety as per our consent below, or portions of this report summarised with RPS's express written permission, in documents prepared by the Company and its advisers in connection with these activities and that such documents, together with this report, may be filed with any stock exchange and other regulatory body and may be published electronically on websites accessible by the public, including a website of the Company.

This report has been compiled in accordance with Canadian Oil and Gas Evaluation Handbook ("COGEH").

In accordance with your instructions to us and the requirements of COGEH, we confirm that we:

1. are professionally qualified and a member in good standing of a self-regulatory organisation of engineers and/or geoscientists including SPEE, SPE, EI and AAPG;
2. have at least five years' relevant experience in the estimation, assessment and evaluation of oil and gas assets;
3. are independent of Xcite, its directors, senior management and advisers;
4. will be remunerated by way of a time-based fee and not by way of a fee that is linked to any successful funding or value of Xcite;
5. are not a sole practitioner;
6. have the relevant and appropriate qualifications, experience and technical knowledge to

appraise professionally and independently the assets, being all assets, licences, joint ventures or other arrangements owned by Xcite and its subsidiary undertakings or proposed to be exploited or utilised by it ("Assets") and liabilities, being all liabilities, royalty payments, contractual agreements and minimum funding requirements relating to the Xcite's work programme and Assets ("Liabilities"); and

7. consider that the scope of this Report is appropriate, given the maturity of the Company's Assets and Liabilities and includes and discloses all information required to be included therein and was prepared to a standard expected in accordance with COGEH.

Standard applied

In compiling this report we have used the definitions and guidelines set out in the 2007 SPE/WPC/AAPG/SPEE Petroleum Resource Management System ("PRMS" – see Appendix 2) as incorporated by COGEH (Society of Petroleum Evaluation Engineers & Canadian Institute of Mining, Metallurgy & Petroleum {CIM}).

Material change

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

Qualifications

RPS Energy is an independent consultancy specialising in petroleum reservoir evaluation and economic analysis. Except for the provision of professional services on a fee basis, RPS Energy does not have a commercial arrangement with any other person or company involved in the interests that are the subject of this report. Dr Graeme Simpson, a Director of RPS Energy, has supervised the evaluation.

Dr Simpson has thirty-four years of relevant experience. He is a Chartered Geologist, a Certified Petroleum Geologist, a Member of the Energy Institute, the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers. He has a PhD in Geology and is an Honorary Professor of Petroleum Geology at the University of Aberdeen. Other RPS Energy employees involved in this work hold at least a Masters 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.

The report represents our best professional judgement and should not be considered a guarantee or prediction of results. It should be understood that any evaluation of resource volumes may be subject to significant variations over short periods of time as new information become available and perceptions change.

Reliance on source data

The content of this report and our estimates of Contingent and Prospective Resources are based on seismic, exploration and test well data, and other geological data provided to us by Xcite. The Company provided us with all relevant and available data in its possession at the time of the drafting of this report. We have accepted, without independent verification, the accuracy and completeness of this data. The data is internally consistent with previous data supplied over the period that RPS Energy has been reviewing it.

As part of our work, we did not undertake a site visit to inspect any of the Company's exploration or development assets, as we did not consider that such an inspection would reveal information or data that would be material.

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

Consent

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

- the inclusion of this report, and a summary of portions of this report, in documents prepared by the Company and its advisers in connection with the Company's annual filing on the Toronto Stock Exchange;
- references to this report being made in such documents;
- the filing of this report with any stock exchange and other regulatory authority;
- the electronic publication of this report on websites accessible by the public, including a website of the Company; and
- the inclusion of our name in documents prepared in connection with the filing.

The report relates specifically and solely to the subject assets and is conditional upon various assumptions that are described herein. The report, of which this letter forms part, must therefore, be read in its entirety.

This report was provided for the sole use of Xcite on a fee basis. Except with permission from RPS Energy, this report may not be reproduced or redistributed, in whole or in part, to any other person or published, in whole or in part, for any other purpose without the express written consent of RPS Energy.

Summary of Resources

It is RPS Energy's opinion that the Bentley field should principally be classified as Contingent Resources. Block 9/3b was the subject of a Resources Assessment prepared at the request of Xcite by RPS Energy in September 2007 when four wells had been drilled on the block. Late in 2007, Xcite spudded the 9/3b-5 well and produced oil to surface on pump-assisted testing. On the basis of these test results a detailed field development plan was prepared by Xcite.

RPS Energy supports Xcite's conclusion that an 'early production system' (EPS) should be drilled and completed to conclusively demonstrate commercial flow-rates prior to (in the event of the EPS being a success) proceeding to a full field development.

RPS Energy has reviewed and audited the re-worked field development model assumptions presented by Xcite (as described in more detail in Section 2) and finds them to be plausible. The Company has developed a number of potential development scenarios which would deliver different volumes of produced oil. RPS Energy has selected 'low', 'base' and 'high' cases as representative of the likely range of Contingent Resources contained within the Bentley Field as shown in Table A below.

Field / Licence	Operator	Licence Interest	Low Case '1C'	Base Case '2C'	High Case '3C'	Risk Factor*
Bentley / UKCS Block 9/3b	Xcite Energy Resources Limited	100%	72.0MMbbls	122.5MMbbls	166.0MMbbls	70%

* Risk Factor is the Chance of Commerciality

Table A: Summary Table of Contingent Resources (Development Pending) currently targeted by development planning for the Bentley Field, UKCS Block 9/3b

In addition, there is a low risk prospect (Prospect A now referred to as Bentley East) and a lead that requires further structural delineation (Lead B) which are classified as Prospective Resources. These prospects are the subject of ongoing work, including analysis of the size and impact of the gas-cap inferred in Bentley East from the 3D seismic, and so have not been addressed in this report. Therefore their assessments as Prospective Resources remains unchanged from the previous Resource Assessment prepared by RPS in September 2007 and these are re-presented as Table B.

Oil (MMbbls)		Gross			Net Attributable			Risk Factor***	Operator
Block	Asset	Low Estimate (MMbbls)	Best Estimate (MMbbls)	High Estimate (MMbbls)	Low Estimate (MMbbls)	Best Estimate (MMbbls)	High Estimate (MMbbls)		
9/3b	Prospect A*	17.49	30.01	72.00	17.49	30.01	72.00	72%	Xcite
	Lead B**	5.71	10.86	28.40	5.71	10.86	28.40	25%	

*Best Estimate Area = 9.5km^2 with an Average Net Pay Thickness of 9.3 m
**Best Estimate Area = 4.6km^2 with an Average Net Pay Thickness of 6.9 m
***Risk Factor for Prospective Resources is the "Geological Chance of Success" or "Chance of Discovery"

Table B: Table from RPS Energy's September 2007 Report showing Block 9/3b Prospective Resources

The range of potentially recoverable oil volumes in each category has been calculated by RPS Energy, based on certain assumptions and modelling and these are tabulated above. There is no certainty that it will be economically or technically viable to produce any portion of the reported Contingent Resources.

Yours faithfully

On behalf of RPS Energy

Dr. Graeme S. Simpson,
Director

An INDEPENDENT EVALUATION REPORT

on the Bentley Field, UKCS Block 9/3b

on behalf of

Xcite Energy Limited

XCITE ENERGY

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 Xcite Energy Limited on a fee basis. Except with permission from RPS Energy, this report may not be reproduced or redistributed, in whole or in part, to any other person or published, in whole or in part, for any purpose without the express written consent of RPS Energy. Our estimates of potential reserves, resources, unrisked and risked values are based on data provided by the Company. We have accepted, without independent verification, the accuracy and completeness of these data.

All interpretations and conclusions presented herein are opinions based on inferences from geological, geophysical, engineering or other data. The report represents RPS Energy's best professional judgement and should not be considered a guarantee of results. Our liability is limited solely to the Company.

		An Independent Evaluation Report on the Bentley Field, UKCS Block 9/3b	
DATE	20th February 2009	PROJECT REFERENCE:	ECV1500
	AUTHORED:	**EDITED & CHECKED:**	**APPROVED:**
NAME	**Andy Kirchin**	**Graeme Simpson**	**Graeme Simpson**
SENT	EDITION	DESCRIPTION	COMMENT
	REV.6	Release Version	
FILE LOCATION:	Abchurch Lane:Sage:/Valuatn/Xcite_09/Report/CPR09_release.doc		

20th February 2009

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1 EXECUTIVE SUMMARY

1.1 Background and Introduction

This report relates to the Bentley field, located in the UKCS Block 9/3b (see Figure 1.1.1) in which Xcite Energy Limited ("Xcite" or the "Company") has a 100% working interest held through its subsidiary, Xcite Energy Resources Limited.

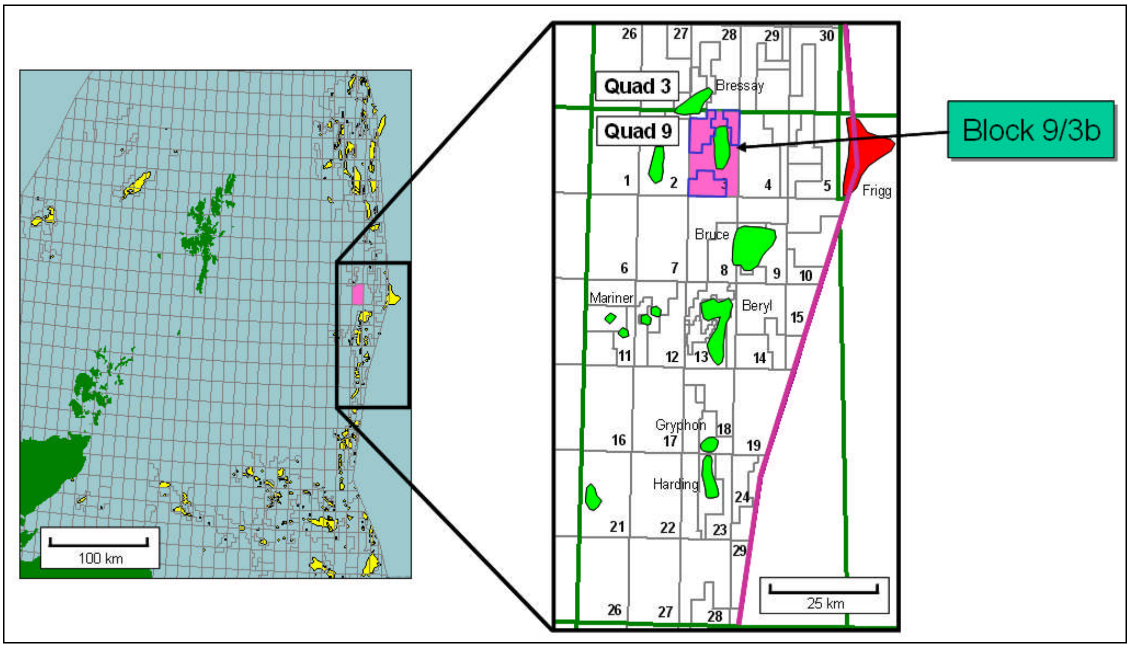


Figure 1.1.1: Basemap showing the location of the Bentley Field, UKCS Block 9/3b

Block 9/3b was the subject of a Resources Assessment prepared at the request of Xcite by RPS Energy in September 2007 when four wells had been drilled on the block. Late in 2007, Xcite spudded the 9/3b-5 well and produced oil to surface on pump-assisted testing. On the basis of these test results a detailed field development plan was prepared by Xcite.

During phase 1 of this evaluation, in the latter half of 2008, Xcite's initial field development plan was independently reviewed by RPS Energy. This review resulted in certain observations and recommendations to improve the robustness and deliverability of the development plan which Xcite have considered and incorporated into the development plan presented herein.

In RPS Energy's opinion, the Bentley field should be principally classified as Contingent Resources (Development Pending) as described in the 2007 SPE/WPC/AAPG/SPEE Petroleum Resource Management System ("PRMS" – see Appendix 2) as incorporated by COGEH (Society of Petroleum Evaluation Engineers & Canadian Institute of Mining, Metallurgy & Petroleum {CIM}). There are also some remaining, as yet, undrilled Prospective Resources but these have not been re-evaluated for the purposes of this report.

As a next step towards the development of the Bentley field, RPS Energy supports Xcite's conclusion that an 'early production system' (EPS) should be drilled and completed prior to (in the event of the EPS being a success) proceeding to a full field development. The aim of the EPS will be to prove Xcite's belief that commercial flow-rates of the Bentley 'heavy' oil are achievable and to establish a better quantification of the range of uncertainty such that the development plan can be appropriately scaled to optimise economic returns.

A minimum one well EPS programme with good definition and objectives will narrow the range of potential performance of the Bentley field and hence the range of recoverable reserves. If it is successful, it should enable Bentley to be designated as 1P and 2P Reserves within its core structure and will further enable detailed planning of a full field development. The principal objective of drilling additional wells during the EPS will be to increase 1P Reserves and designate further 2P Reserves. Additionally, it will provide information to further define the full field development plan.

1.2 Summary of Resources

Some key uncertainties remain over how the Bentley field will perform. The Company has undertaken extensive investigation and modelling to establish the significance of the 9/3b-5 well test and to predict the potential production characteristics and hence resource volumes.

During the initial phase of work, Xcite responded to observations and recommendations from RPS Energy, particularly with respect to the modelled flow-rate improvement predicted for the planned horizontal wells based on the results of the vertical 9/3b-5 well. Xcite has demonstrated that it has considered and modified, where necessary, its production profiles to accommodate these recommendations. It has also developed plausible and logical explanations for what at first sight might be viewed as non-standard or contradictory information when considering the future potential performance of the Bentley field and, in this context, the Company believes it has introduced a new level of understanding of the behaviour of this type of heavy oil in the North Sea. This understanding relies on certain reservoir and fluid parameters that are inter-dependent, where variation in one parameter can influence, or be compensated by, variation in another.

The combination of parameters currently modelled by Xcite is plausible in the context of the observed behaviour in the 9/3b-5 well and other wells on the adjacent Bressay field. It is possible, however, that there may be other combinations of these parameters that might also explain the observed data gathered thus far but result in a different prediction of future production. Consequently, the EPS is being designed to eliminate as much uncertainty as possible and to prove up the key assumptions used in the model, before committing to the full development of the Bentley field and, consequently, moving Bentley to a Reserves classification.

RPS Energy has reviewed and audited the re-worked field development model assumptions presented by Xcite (as described in more detail in Section 2) and finds them to be plausible. The Company has developed a number of potential development scenarios which would deliver different volumes of produced oil. RPS Energy has selected 'low', 'base' and 'high' cases as representative of the likely range of Contingent Resources contained within the Bentley Field as shown in Table 1.2.1 below.

It is noted that the volumes quoted below do not represent a probabilistic analysis of the potentially recoverable volumes from Block 9/3b (although the 'low', 'base' and 'high' cases are broadly equivalent to the P90, P50 and P10 from a probabilistic analysis). Rather, they are the result of simulated cases that relate to three currently modelled development scenarios, which account for a range of reservoir and performance parameters that need to be tested (by further appraisal – the EPS) and are described below.

Field / Licence	Operator	Licence Interest	Low Case '1C'	Base Case '2C'	High Case '3C'	Risk Factor*
Bentley / UKCS Block 9/3b	Xcite Energy Resources Limited	100%	72.0MMbbls	122.5MMbbls	166.0MMbbls	70%

* Risk Factor is the estimated probability that the Contingent Resources will become Reserves, based on current data and information

Table 1.2.1: Summary Table of Contingent Resources (Development Pending) currently targeted by development planning for the Bentley Field, UKCS Block 9/3b

Taking into account:

1. The results of the 9/3b-5 well on the Bentley field;
2. The study and analysis work and the full field development plan that have been undertaken by Xcite since the 9/3b-5 well;
3. The audit and review work that has been undertaken by RPS Energy;
4. The recommendations from RPS Energy that Xcite has incorporated into its modelling of the Bentley field; and
5. The recent (November 2008) publicly announced intention by StatoilHydro to move the adjacent and analogous Bressay field forward to development,

RPS Energy concludes that the Chance of Commerciality of the Bentley field at this is time is 70%.

To progress the above stated Contingent Resources to Reserves and to appropriately calibrate the scale of the full field development plan, Xcite intends to conduct a one to three well Early Production System (EPS) depending on a cost versus benefit analysis, in the latter half of 2010. RPS Energy has had sight of the current modelling and planning and concurs that this is the most effective way to proceed to reduce the current range of uncertainty and ensure that any future full field development plan is optimised for both maximum commercial chance of success and value.

Xcite commissioned KBC to conduct a market study for 'heavy' oil and to model the expected discount to 'Brent' in the future. Whilst such studies cannot be considered a guarantee, KBC's modelling suggests that the differential between standard crude such as Brent and heavy crudes such as Bentley will reduce as upgrading capacity increases. The discount of Bentley crude oil to dated Brent is therefore expected to decline as a percentage of the Brent price from around 16% currently to around 12% by 2020 and to slightly below 10% by 2030, assuming a relatively stable oil-price increase through time. For its economic model and project testing, Xcite has used a conservative flat discount rate of 15% to RPS Energy's forecast for Brent throughout the life of the field. RPS

Energy has reviewed Xcite's economic modelling and the main assumptions, input and resulting success case NPV10s are shown in Table 1.2.2 below:

Input assumption / Success Case Outcome	**Low-side Case** **1 Rig, 36 slots, 26 mother-bores, 38 side-tracks, 9 injectors**	**Base Case** **2 Rigs, 56 slots, 43 mother-bores, 33 side-tracks, 12 injectors**	**Up-side Case** **2 Rigs, 56 slots, 43 mother-bores, 33 side-tracks, 12 injectors**
Capex	$1,881 MM	$2,573 MM	$2,661 MM
Opex	$1,394 MM	$2,135 MM	$2,229 MM
Oil Price	$80 Brent (flat real) less 15% discount	$80 Brent (flat real) less 15% discount	$80 Brent (flat real) less 15% discount
Recoverable Resource	72.0 MMbbls	122.5 MMbbls	166.0 MMbbls
Field Life	13 years	15 years	15 years
Success Case NPV10	**$181 MM**	**$781 MM**	**$1,535 MM**
Success Case IRR	13.9%	23.6%	33.7%

Table 1.2.2: Summary table showing key economic input and Success Case NPV10

Taking the Base Case production profile from the currently modelled development plan (subject to calibration after the EPS), production start-up of Q2 2103, and the costs which appear to be reasonable (including 20% contingency on Capex and 10% contingency on Opex), the NPV10 (Net Present Value at 10% discount) is $781 MM representing an IRR of 23.6%. The details of the development scenarios are described in Section 2.3.3.

In addition to the main Bentley field, Xcite have identified additional prospectivity on Block 9/3b including the Bentley East Prospect - previously known as Prospect A - and Lead B. These prospects are the subject of ongoing work, including analysis of the size and impact of the gas-cap inferred in Bentley East from the 3D seismic, and so have not been addressed in this report. Therefore their assessments as Prospective Resources remains unchanged from the previous Resource Assessment prepared by RPS in September 2007 and these are re-presented as Table 1.2.3.

Oil (MMbbls)		**Gross**			**Net Attributable**			**Risk Factor*** **	**Operator**
Block	Asset	Low Estimate (MMbbls)	Best Estimate (MMbbls)	High Estimate (MMbbls)	Low Estimate (MMbbls)	Best Estimate (MMbbls)	High Estimate (MMbbls)		
9/3b	Prospect A*	17.49	30.01	72.00	17.49	30.01	72.00	72%	Xcite
	Lead B**	5.71	10.86	28.40	5.71	10.86	28.40	25%	

*Best Estimate Area = 9.5km^2 with an Average Net Pay Thickness of 9.3 m

**Best Estimate Area = 4.6km^2 with an Average Net Pay Thickness of 6.9 m

***Risk Factor for Prospective Resources is the "Geological Chance of Success" or "Chance of Discovery"

Table 1.2.3: Table from RPS Energy's September 2007 Report showing Block 9/3b Prospective Resources

2 DESCRIPTION OF THE BENTLEY FIELD

2.1 Introduction and History

The Bentley Field is a heavy oil accumulation that was discovered by Amoco (UK) Exploration Ltd ("Amoco") in 1977. It is located in UKCS Block 9/3b (see Figure 1.1.1), which originally covered an area of 200.9 sq km (pink shaded area on Figure 1.1.1) and an average water depth of 113m. This block, which lies 160 km east of the nearest landfall in the Shetland Isles, was awarded to Xcite within the UK 21st (Promote) Licence Round with effect from 1st October 2003. The licence comprises two 4 year periods followed by a third term of 18 years.

Having secured funding in 2007 to drill an appraisal well, a six month extension to the first period of the licence was granted up to 31st March 2008 when, according to the original terms, a 50% licence acreage relinquishment was required. The relinquishment was achieved such that the Bentley Field and all associated prospectivity remain wholly within Block 9/3b; the new licence boundary limits are shown on Figure 1.1.1 (blue polygons). As a result of the extension of the first licence period, the duration of the second 4 year period was correspondingly reduced and the next intervention (Xcite plans an EPS) is due by the end of September 2011. Assuming Xcite proceeds with the planned EPS (see below), the licence will be converted to a full production licence and will run to the end of September 2029.

2.1.1 Geological setting of the Bentley Field

In summary, the oil reservoir is found in the upper part of the Dornoch Fm, which was deposited as series of prograding shoreface sands during the Late Palaeocene and is overlain and top-sealed by the Eocene Balder Fm tuffs. The oil in Bentley was sourced from the Upper Jurassic Kimmeridge Clay Fm deeply buried in the Viking Graben to the east of Block 9/3b. Migration is believed to have occurred during the Eocene / Oligocene via the graben bounding fault system. Hydrocarbons are believed to have migrated into Bentley and then spilled northwards to charge the Bressay Field.

Three main seismic markers define the main reservoir units, namely the Top Balder, Top Dornoch and Base Dornoch. Figure 2.1.1 shows a representative seismic line across the structure. The seismic markers are described below, in order from oldest to youngest.

Base Dornoch (light blue): Defines the base of the sandy units of the Dornoch that overlie the shales of the Lista formation.

Top Dornoch (blue): Represents the top of the reservoir package and marks a change from the eroded sandy shelf/slope sediments into the overlying tuffaceous muds of the Balder sequence.

Top Balder (red): This is the top of the tuffaceous muds that cover and drape the eroded Dornoch units. This unit is the effective top seal for the 9/3b accumulations.

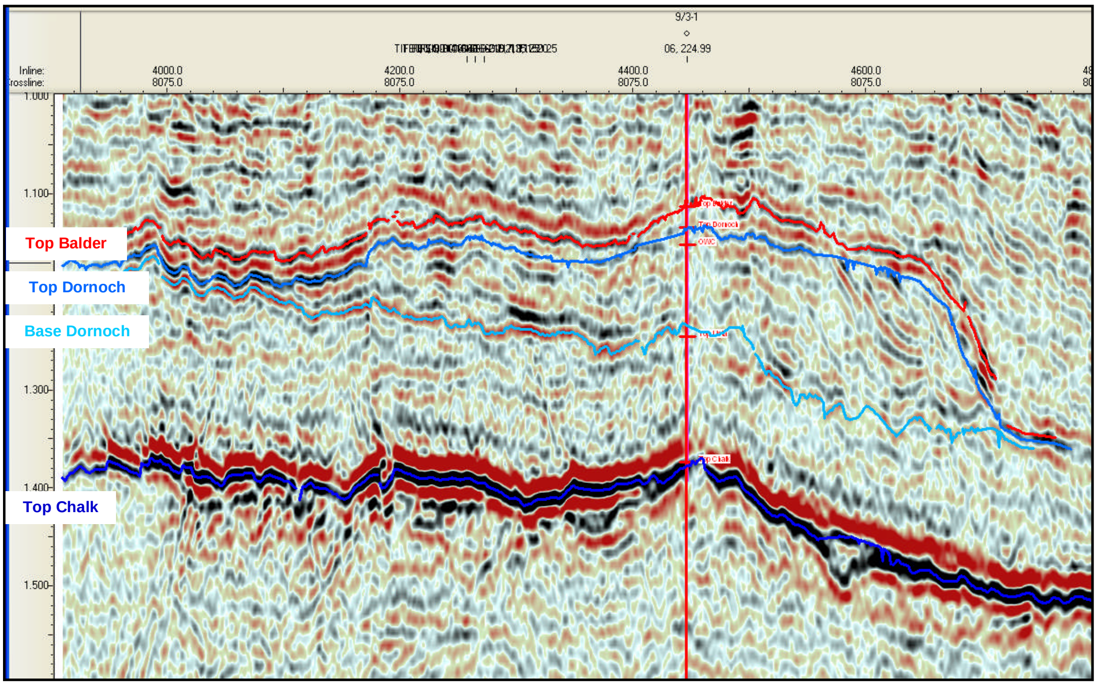


Figure 2.1.1: West-East Representative Seismic Line Across Bentley Structure

Figure 2.1.2 shows a west-east schematic cross-section.

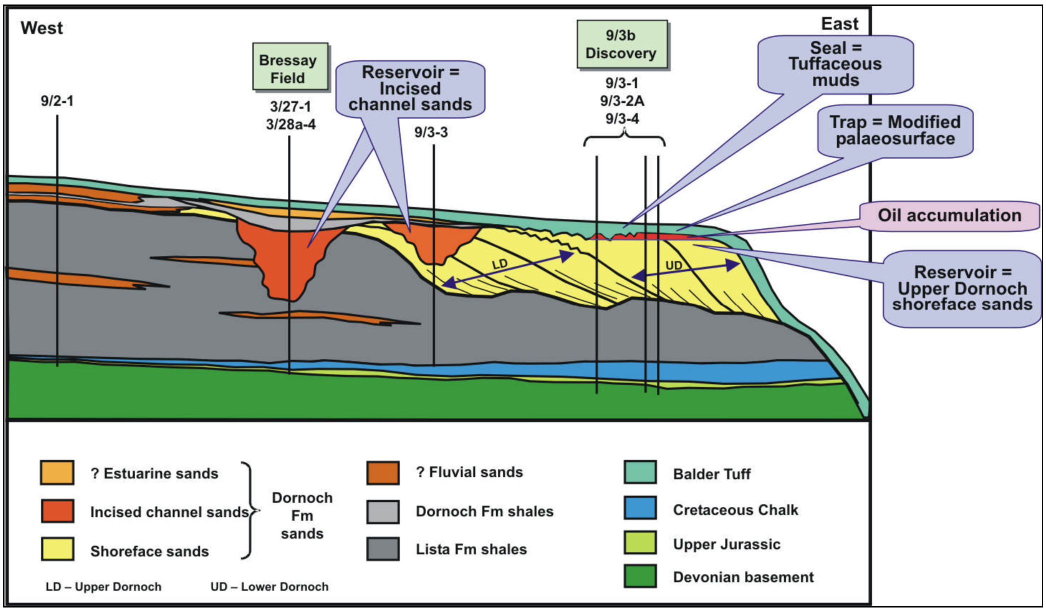


Figure 2.1.2: West-East Schematic Cross-Section through Block 9/3b

The basement in this region is composed predominantly of Devonian clastics. There is clear evidence of thickening of the Dornoch section within Block 9/3b, and this corresponds to prograding wedges of clastic material seen along the eastern edge of the license area. Within these wedges, internally eastward dipping clinoforms are common. The Top Dornoch surface has been incised and eroded in many places to produce a very rugose surface. There is some evidence of the Balder formation thickening in the incised valleys and lows (see Figure 2.1.3). This erosion in combination with subsequent differential compaction and regional tilting has created the present day four-way dip closure that hosts the 9/3 accumulation.

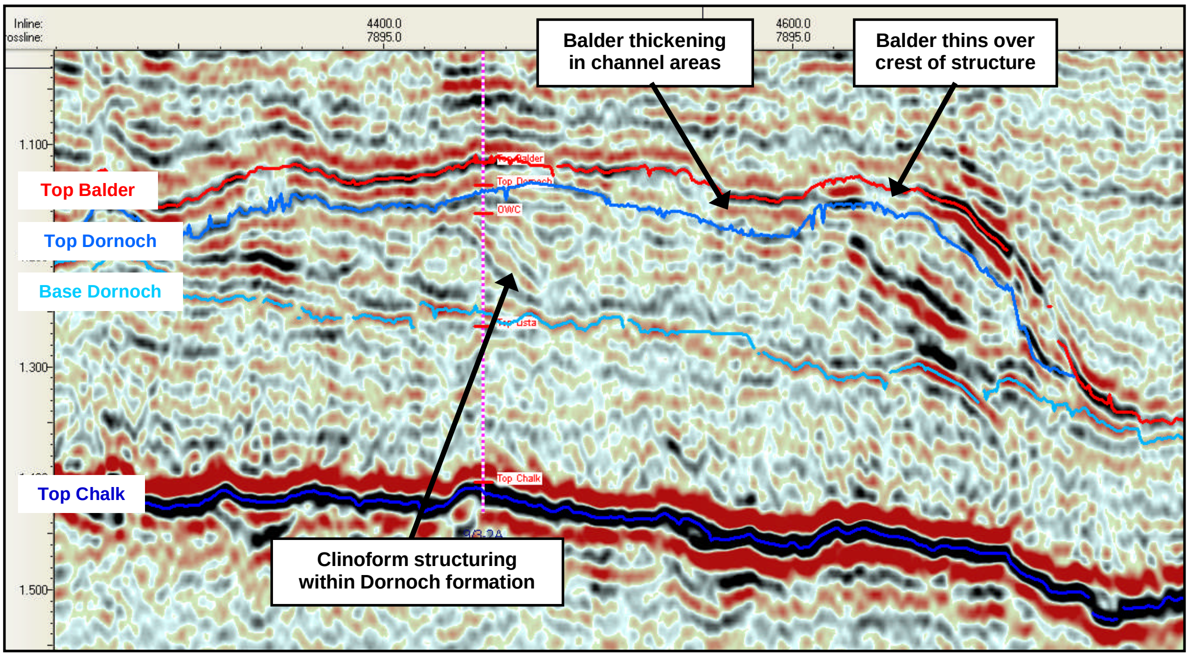


Figure 2.1.3: West-East Representative Seismic Line Showing Balder Thickening into Valleys and Lows

2.1.1.1 Direct Hydrocarbon Indicators (DHIs)

No direct hydrocarbon response is evident from the 9/3b oil column. This is to be expected, as the presence of heavy oil will have the same seismic response as that of water. However, where gas is present, high amplitudes and 'flatspots' can be observed. A gas cap is identifiable from seismic in the Bentley East area of the 9/3b accumulation. This is analogous to the known gas cap in the Bressay field to the north of Block 9/3b, where flat high amplitude reflectors are seen on the crest of the structure and gas has been confirmed by the wells (see Figure 2.1.4).

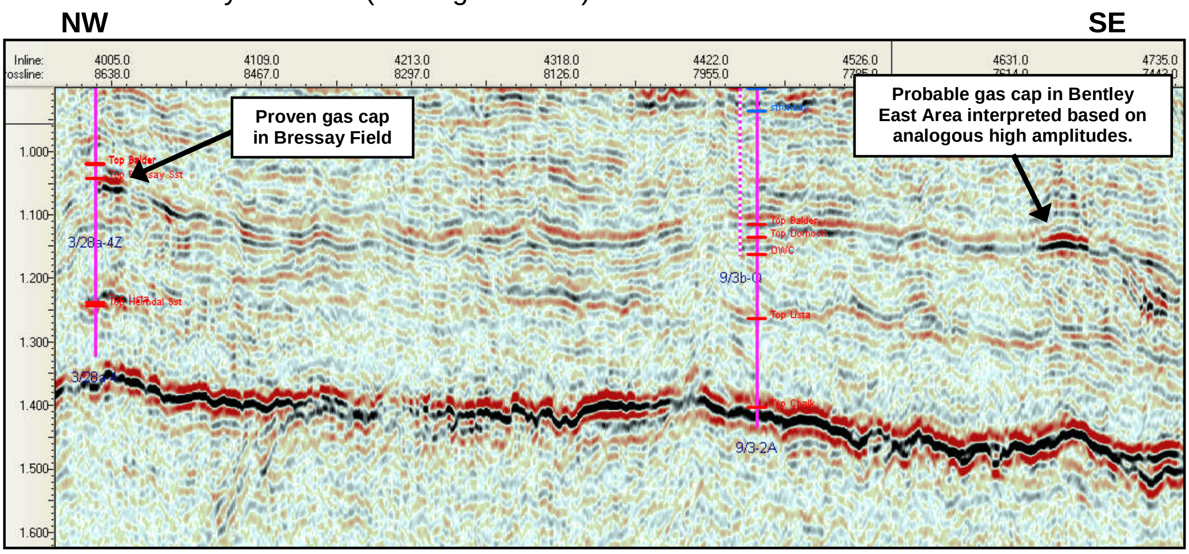


Figure 2.1.4: Gas Cap in Bressay and Probable Gas Cap in Bentley East Area

2.1.2 Bentley Drilling History

9/3-1. Drilled in 1977 by Amoco to a TD of 4845ft (3654ft tvdss) into Basement (Granite). P&A with oil shows in Palaeocene U. Dornoch Fm.

9/3-2A. Drilled in 1983 by Conoco to a TD of 4920ft (4837ft tvdss) into Palaeozoic (Devonian) conglomeratic breccias. P&A with oil shows in Palaeocene U. Dornoch Fm.

9/3-3. Drilled in 1986 by Conoco to a TD of 5003ft (4920ft tvdss) into Palaeozoic (Devonian) sandstones. P&A, no shows.

9/3-4. Drilled in 1986 by Conoco to a TD of 5000ft (4915ft tvdss) into Palaeozoic (Devonian) conglomeratic breccias. P&A with oil shows in Palaeocene U. Dornoch Fm.

9/3-5. Drilled in December 2007 by Xcite to a TD of 4105ft (4022ft tvdss) into the Palaeocene L. Dornoch Fm. Oil well, P&A in January 2008.

2.1.3 Seismic Reprocessing

During the latter half of 2008, Xcite undertook a re-processing of the 3D seismic data with CGGV. The early results of this re-processing are reported to be encouraging and the Company is currently conducting a re-interpretation and re-mapping exercise which is scheduled to be complete by end April 2009. The new data provides encouragement to an alternative model to that used for this evaluation, which could lead to an upside calculation of the STOIIP and a consequent upside in recoverable resources. This has not been incorporated in the work and calculations to date and represents a potential upside for the future.

2.1.4 Oil-in-place Estimates

RPS Energy's phase 1 review of STOIIP raised two issues not previously recognised. Firstly, a shaley sand towards the base of the 9/3-4 well which could impact the net to gross (N:G) in the southern part of the Bentley Field and secondly, a potentially shallower oil-water contact in the 9/3b-5 well tied in with what appears to be a 20 psia pressure drop when compared with the nearby 1983 9/3-2A well. For the purposes of this report, RPS Energy is not concerned with either of these potential reductions in STOIIP as they do not materially effect the development assumptions and consequent recoverable Resources that have been assigned thus far. Indeed, the introduction of a shaley sand towards the base of the oil bearing reservoir in the southern area may actually improve recovery characteristics, as it will impede water coning and thus maintain productivity for longer, for any given well in this area. This is thought likely to counter-act any reduction in STOIIP in the area potentially affected. However, whilst the possibility of a laterally extensive shaley zone in the southern area must be considered, the current depositional model (a pro-grading, shore front series of sands) would suggest that the shale deposition (possibly a drape) would be relatively restricted as it would probably be relatively steeply dipping. It is therefore unlikely that the shale is present over wide areas of the reservoir, though the possibility might be considered as a worst-case scenario.

The possibility of a shallower (approximately 11 feet) oil-water contact ("OWC") in the 9/3b-5 relative to the nearby 9/3-2A well is a source of potential STOIIP uncertainty. However, it is noted that there is 5 foot discrepancy between the original site-survey and the driller's seabed depth (the site survey measuring the seabed five feet deeper than that recorded during operations). This would place the currently interpreted OWC logged in the well within six feet of the OWC in 9/3-2A well if the site survey were correct.

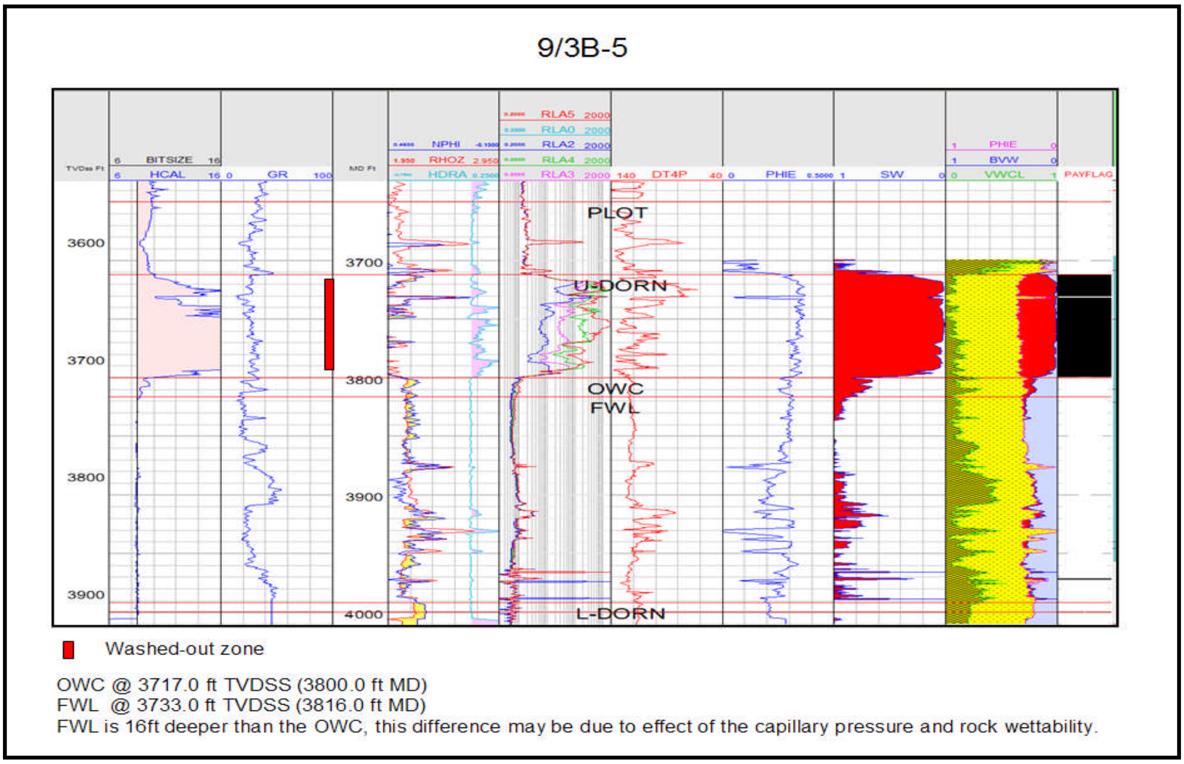


Figure 2.1.5: Well 9/3b-5 CPI

Examination of the 9/3b-5 CPI (see Figure 2.1.5) also reveals that the well seems not to exhibit a sharp oil saturation cut-off as would be expected (and is regionally observed in other wells) for a high permeability, high porosity reservoir such as is found in Bentley. The presence of an apparent ‘transition’ zone may be more of a local lithological effect which is impacting the predicted saturation, such that the first sharp reduction in oil saturation is reflecting more of an oil-down-to (“ODT”). As stated above, the uncertainty in STOIIP at this stage is not considered to be significant in the context of the Resources currently modelled and assigned.

In the event of a successful EPS, together with any re-interpretation and re-mapping that results from the 3D re-processing undertaken in 2008, the STOIIP will be completely re-evaluated (to include all relevant data collected during the EPS) and will become important in assessing the requirements of the full field development plan.

2.2 Impact of the 9/3b-5 well

2.2.1 Well test analysis

As described above, Xcite drilled the 9/3b-5 well in December 2007 and tested the accumulation using a Schlumberger crew in late January 2008. The test was principally designed to recover oil to the surface in order to prove the fluid characteristics which, at the time of drilling, were thought to be analogous to those of the Captain Field. The test was significantly foreshortened by bad weather and, perhaps more importantly, was conducted with the added pressure of an impending closure of the weather window. This impacted the analysis and decision-making given the need to gather information in the shortest possible time. As a result, the test was run according to pre-planned protocols rather than risking taking into account the somewhat heavier than expected crude that was actually recovered. This is described in more detail below.

The Drill Stem Test (DST) was performed from 23rd – 24th January 2008 (curtailed by weather). The DST string contained an ESP pump as the well was, as anticipated, not able to flow naturally due to the viscosity of the oil. However, the well did flow with the ESP pump and, after an intentionally slow (by normal standards) clean-up, the last 5-6 hours of the test (during which time basic sediment and water ("BS&W") were less than 2%) recovered oil to surface at an average rate of 109 stb/d. This flow-rate occurred with observations of 'slug-flow' and reduction in the average wellhead pressure and flow-rate for the last few hours of the test before it was shut-in for weather. As described in more detail below, the bottom-hole pressure ("BHP") never exhibited a stable period of equilibrium. However, the average flow-rate calculated by taking flow-rate from one hour either side of the point where the BHP reached its minimum is 127 stb/d. The highest instantaneous flow-rates after BS&W reduced to less than 2% were 250 stb/d and 200 stb/d as can be see in Figure 2.2.1 (the flow-rate is shown by the green line and green triangles which represent measurements from a positive displacement meter).

At first sight the flow-rate appears to be too low to be commercial in a relatively harsh offshore environment. However, well test analysis (as confirmed by Schlumberger) shows a high skin had developed with a most likely value of 29 (though some models indicate the skin could be as high as 69). In addition, as noted above, the well was in slug flow through the main flow test period and it was later observed that flow-rate appeared to decrease when the choke was opened and increase when the choke was reduced. This is somewhat counter-intuitive for a normal oil well and caused a careful analysis of the test data to be undertaken.

It was found that the fluid takes time to respond to the choke size but there was a good inverse relationship between choke size and fluid flow/pressure allowing for a delay of about 15-20 minutes. Further, it was observed that when the choke was opened up to its maximum of 28/64th, rather than the BHP reaching equilibrium and a steady maximum flow-rate, in fact the BHP began to rise and the flow rate reduced, exhibiting heavy slugging. Xcite and Schlumberger have expended considerable effort in analysing the test data and have produced a plausible explanation of the well's behaviour which will be tested by the forthcoming EPS. Indeed, based on the resulting assumptions, modelling indicates that the well's expected steady-state flow, even with the skin and oil properties encountered, could have been in excess of 200 bopd if a steady flow-rate at a lower choke size had been allowed to occur. The potential rates from an undamaged, zero skin, fully perforated section in well 9/3b-5 have been modelled by Schlumberger and are discussed in more detail in Section 2.2.3 and summarised in Table 2.2.2.

Figure 2.2.1 shows the test data recorded for the 9/3b-5 well.

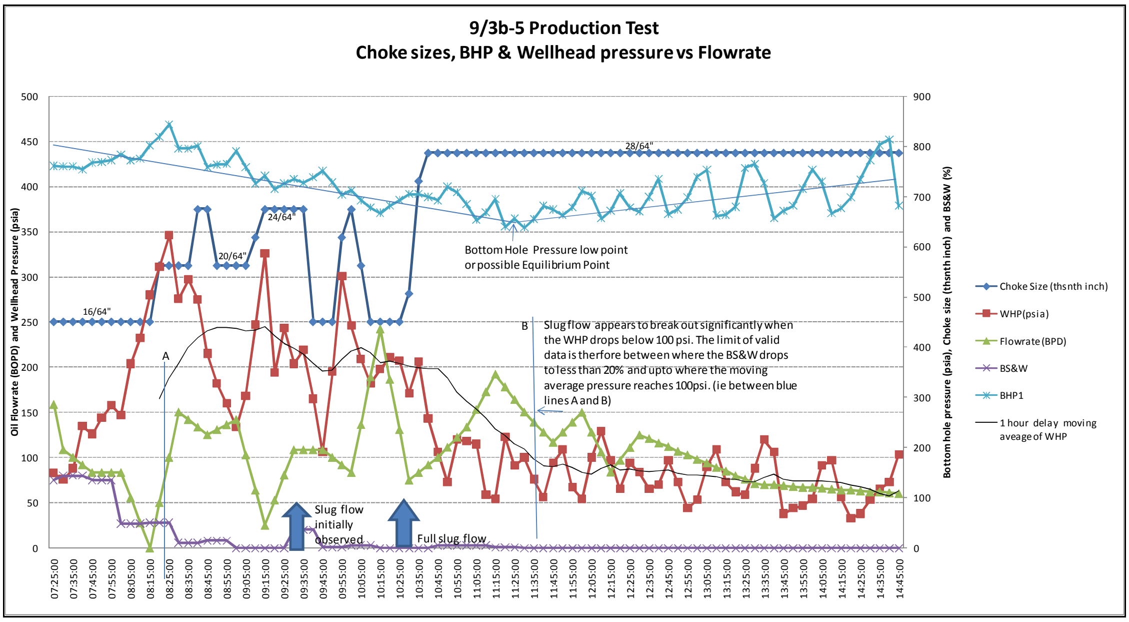


Figure 2.2.1: Test data including BHP data (right hand axis). (Source: Xcite)

The BHP shows two distinct trends. From 7.30am to around 11.25am the BHP was dropping (i.e. it had not reached equilibrium) and from 11.25am until 14.45pm the pressure was rising (i.e. beyond equilibrium). In the first period the flow entering the wellbore was the controlling influence on the overall system. Post 11.25am, the fluid could not be removed from the wellbore faster than it was entering and thus the pump, tubing, riser and choke ('post wellbore') were the controlling influence and, therefore, the BHP was rising. What is not observable is any reliable period where the bottom hole pressure was constant (i.e. at equilibrium) due to the fact that the well did not have a long enough period of test in a steady-state flow, i.e. at the restricted choke size, and where the post wellbore influencing factors were not over-riding the natural dynamics of the system. A longer period at the smaller choke size would, therefore, have allowed the flow to stabilise at its natural rate and potentially allowed the choke to be opened up a little more, post stabilisation and without allowing the wellhead pressure to drop below the significant gas breakout point, to achieve yet higher flow.

However, the metered flow-rates were rising before the influence of the final opening of the choke was felt by the system and reached in excess of 200 bopd prior to declining during the period beyond 'equilibrium' (which turned out be more or less a single point in time rather than a period). Nonetheless, the peak flow would be expected to occur just prior to the point where the BHP slope changed over, as the pressure signal would have changed from a feed-forward loop to a feed-back loop upon the wellhead pressure taking control. Therefore, it is not an unreasonable proposition that the pressure in the wellbore could have stabilised (probably somewhere between 550 and 650psi) and that a steady flow-rate in excess of 200 bopd could have been achieved if the wellbore pressure and consequential flow-rates had been allowed to reach equilibrium.

Xcite's hypothesis is that if the well had been allowed to reach equilibrium at a relatively small but constant choke size over a period of time (which was not possible even if it had been planned for because of the impending weather window closure), the positive feed-forward pressure loop could have been maintained by then gently opening up the choke to achieve a maximum flow-rate as supported by the pressure balance of the fluid inflow and pump capacity. The corollary to this is that a limited amount of de-gasification of the oil is desirable as this reduces the in-situ viscosity of the oil immediately adjacent to the wellbore making flow easier and resulting in higher rates.

As a test of this analysis, Xcite went on to see whether it could explain the nearby Bressay well-tests on the same basis. Whilst some of the tests are of such short duration that the evidence is somewhat equivocal, the 3/28a-2 well was on test for about 66 hours and produced at an average rate of 3200 bopd for the last 30 hours on a 2 inch choke. Critically, the well was allowed to achieve a pressure equilibrium for 24 hours on a choke of 24/64th inch before being gradually opened up over a period of several hours, whereupon the bottom hole pressure maintained feed-forward control and the flow-rate of oil to surface was built up to a maximum of 3800 bopd. The Bressay reservoir has considerably thicker net sand in places (incised channels) and Bentley is not expected to match the 3/28a-2 flow-rate in any vertical test. However, the reservoir properties and fluids are almost identical, which means that the Bressay 3/28a-2 well's behaviour lends considerable support to Xcite's analysis and expectations for future Bentley well tests.

Further support for the potential flow behaviour of the Bentley / Bressay oil when properly managed comes from the very recent 3/28a-6 DST run by StatoilHydro in early November 2008 and traded with Xcite's 9/3b-5. The choke size – flow-rate – pressure build-up relationship is consistent with the analysis carried out by Xcite such that pressure and flow-rate were both steadily increasing on a restricted choke of ½ inch before being shut in as the maximum off-take rate was reached. The pressure and flow-rates are consistent with Xcite's interpretation of the likely fluid behaviour in these reservoirs. Following the successful test in this well, StatoilHydro (Operator for Bressay) publically announced at an INTSOK meeting on 25th November 2008 that they are intending to proceed with the development of Bressay and will presumably be presenting a full field development plan to DECC in the near future.

It can be seen from the discussion above that, if the interpretations presented above are borne out by the EPS, pressure control and careful well management will be key to successfully achieving the required flow-rates to make the Bentley field a commercial oilfield. However, once the reservoir and fluid parameters are fully tested and understood it should be possible to calibrate the current modelling to enable optimum production for commercial exploitation.

2.2.2 Viscosity, Permeability and Mobilities

There is a complex interdependency between viscosity, GOR, permeability, mobility and pressure. Each parameter has an inherent range of uncertainty which can be critically influenced by every other parameter.

Direct measurements of viscosity were made at a variety of temperature and pressure conditions on both re-combined and dead oil. The most representative sample is thought to have been a reservoir pressured MDT sample, calculated by Oilphase, as giving a reservoir condition viscosity of 627 cP. A reconstituted dead oil sample taken from the stock tank fluid measured by Core Laboratories gave a viscosity of 1,111 cP (at 1,617 psig). The latter measurement was close to a similar sample collected from 9/3-2A well (also measured by Core Laboratories) which yielded a viscosity of 1,000 cP.

The Bentley Field reservoir is a very poorly consolidated sand(stone) which, by its very nature, makes recovering well preserved core samples from which to measure permeability challenging. Indeed, such core that is preserved is likely to be from the more cemented portions of the reservoir and thus potentially unrepresentative of the better permeabilities predicted from the geological model and observed mobilities etc. Nonetheless, two data points have been measured from core in wells 9/3-3 (Bentley) and 3/28a-4 (Bressay) which give average permeabilities of 1,175 mD and 750 mD respectively.

An indirect measurement of viscosity can come from matching well flow performance. Analysis of pressure response during well tests will give an indication of the mobility of the system. Skin effects can be estimated separately and taken into account to leave the fluid mobility as a factor of permeability and viscosity. With conventional oil reservoirs, it is normal to assume that direct viscosity measurements are correct and back calculate permeability from the mobility. However, where measured viscosity is in doubt, the reverse approach can be taken.

Given the range of mobilities derived from the Bentley and Bressay DST tests and using the average of the measured permeabilities, viscosity of the order of 100 cP is predicted, which is clearly too low. Conversely, using a viscosity of 1200 cP or more (as suggested by some of the dead oil measurements recorded) requires permeabilities in excess of 20 D to match the estimated mobilities, which seems unreasonably high. Using permeabilities in the range of 5 – 10 D and the most representative viscosity measurement taken to date (Oilphase MDT – 627 cP) gives predicted mobilities of between 8 to 16 mD/cP, which are consistent with the range of mobilities from available DST analyses. The Up-side low viscosity was selected to account for the higher mobilities that might be associated with ‘foamy’ oil behaviour, where gas partially comes out of solution but only in small bubbles which makes the oil/gas mixture more mobile. This requires careful pressure management since if the de-gasification is too rapid the gas coalesces and separates from the oil thereby leaving a non gassed-up and more viscous oil.

The modelling done by Schlumberger, Senergy and Xcite has resulted in a set of parameter ranges that appear to be internally consistent and supported by analogy. The input parameters to the model are as shown in Table 2.2.1 below.

Parameter	Low-side	Base case	Up-side
Viscosity	1,111 cP	627 cP	400 cP
Permeability	7.5 D	7.5 D	7.5 D
Mobility	6.8 mD/cP	12.0 mD/cP	18.8 mD/cP

Table 2.2.1: Viscosities, permeabilities and implied mobilities used in modelling

However, as can be seen above, there remains a large range of uncertainty in the in-situ oil viscosity and permeability which impacts many, if not all, of the remaining technical contingencies. The planned EPS is an essential step in resolving these technical contingencies.

2.2.3 Flow-rate prediction

One of the results of Schlumberger’s well test analysis and modelling in PIPESIM, was that the best match for a down-hole rate for the vertical 9/3b-5 well was found to be 110 bopd modelling flow into the pump only and 125 bopd modelling the whole system to the well-head including the BHP build-up. It is noted that a higher (than was measured from the MDT) gas:oil ratio (“GOR”) has to be used to explain the slug-flow. This is perhaps not unexpected since the MDT was a single flash and, as such, only captured the instantaneous GOR whereas ‘heavy’ oil is known to give up more gas with time and gradual pressure decrease. The average flow-rate measured at the surface for the last 6 hours of the test was 109 bopd (127 stb/d for the period of one hour either side of the BHP minimum) and, as described above, Xcite believe that a flow-rate in excess of 200 bopd would have been possible if the pressure build-up and choke size had been allowed to reach equilibrium. These rates therefore represent the low-side, base case and up-side test rates for the 52 ft completion (c.f. a maximum possible 87 ft pay section), with a skin of 29, consistent with an exploration well with drilling damage, limited entry perforations and thick cemented zone due to bore hole washout during drilling.

Assuming that the EPS proves up the viscosity, permeability, mobility, pressure build-up, GOR and predicted flow-rate in an initial vertical well, the next step is to model the expected increase in productivity that might be achieved by the introduction of horizontal wells.

As an initial guide to the potential improvement that might be expected from the use of horizontal completions, a modelling technique called Productivity Improvement Factor (“PIF”) was used. The methodology was created by Beliveau[1] and Levitan et al[2] using a large analogue database looking at typical improvements in initial rates when switching from vertical well producers to horizontal. The correct application of the methodology requires that the vertical well rate be for an “undamaged, fully penetrating” well. The 9/3b-5 was therefore corrected to the equivalent of being fully penetrating and undamaged (zero skin) using an industry standard technique (in this case by Schlumberger), giving a corrected rate of 569 bopd at 1000 psia BHP for the low-side case, 647 bopd for the base case and 1,034 bopd for the up-side case. For this calculation a skin of 29 was assumed. If a skin at the upper end of the range calculated from modelling (possibly as high as 69) had been assumed then the uplifted rates would have been higher.

According to the Levitan paper, the PIF methodology for predicting performance suggests using a normalisation of the productivity improvement factor to remove the impact of the variation in well length. When this was done the average of the normalised PIF distribution was 0.1896 and this average value is used to scale the ratio of the average length of the planned horizontal wells to the vertical height of the reservoir in the vertical well. The average length of the planned horizontal wells is 800 m and the full penetrated height used to calculate the ‘corrected’ flow-rate from the 9/3b-5 well is 87 ft (27 m). Therefore, the predicted improvement in achievable flow-rate is 5.7. In their analysis, Xcite have used 7 based on average reservoir height of 21 m but the difference for an empirical sense check such as this is not significant when compared to the fact that heavy oil reservoirs are probably under-sampled in the Levitan (BP) database. Indeed, both Beliveau and Levitan point out that heavy oil reservoirs would be expected

[1] Beliveau, D.: “Heterogeneity, Geostatistics, Horizontal Wells and Blackjack Poker”, SPE30745, SPE Annual Technical Conference and Exhibition, Dallas, 22-25 October 1995.
[2] Levitan, M., Clay, P. & Gilchrist, J.: “How Good Are Your Horizontal Wells?”, SPE68943, SPE European Formation Damage Conference, The Hague, 21-22 May 2001.

to have PIF ratios that are higher than average when compared to conventional reservoirs (which will form the majority of the sample database).

Consequently, RPS Energy believes that the expected improvement in flow-rate that might be achievable from horizontal wells will be as shown in Table 2.2.2 below.

Case	9/3b-5 Flow-rate from test (bopd)	9/3b-5 flow-rate corrected for skin=29 & 87 ft completion (bopd)	PIF = 5.7 for 800m undamaged well (bopd)
Low-side Case	110	569	3,255
Base Case	125	647	3,701
Up-side Case	>200	>1,034	>5,915

Table 2.2.2: PIF analysis of expected flow-rates for the Bentley Field

As noted above, the PIF analysis is an empirical sense-check on the likely rates that will be achieved based on the flow-rates achieved thus far from the vertical 9/3b-5 well. The rates could be argued to be pessimistic particularly when compared to the nearby Bressay 3/28a-2 well tested from a vertical section of some 140 ft of reservoir at a rate averaging 3200 bopd after an extended period of PBU and clean-up. The EPS will be designed to remove the current uncertainty and allow the full field development plan to be appropriately calibrated.

For the purposes of generating production profiles based on the three development scenarios outlined in Section 2.3, Xcite has built Eclipse Dynamic Models for a Low-side Case, a Base Case and an Up-side Case. In all cases, a skin of 5 has been assumed and that a proportion of every well would be non-effective due to production technology problems. In addition, a 5% downtime was introduced to scale the well productivity loss that might be caused by operational considerations such as pump replacement. Wellbore friction was also activated to replicate long wellbore pressure losses.

The non-effective wellbore distribution was distributed for each case as summarised in the Table 2.2.3.

Case	50% of drilled wells	Remaining 50% of drilled wells		
	Non-effective wellbore – randomly distributed	Non-effective wellbore – contiguous section at the 'heel' for $1/3^{rd}$ of wells	Non-effective wellbore – contiguous section at the 'mid-section' for $1/3^{rd}$ of wells	Non-effective wellbore – contiguous section at the 'toe' for $1/3^{rd}$ of wells
Low-side Case	25% (avg 200m)	25% (avg 200m)	25% (avg 200m)	25% (avg 200m)
Base Case	20% (avg 160m)	20% (avg 160m)	20% (avg 160m)	20% (avg 160m)
Up-side Case	10% (avg 80m)	10% (avg 80m)	10% (avg 80m)	10% (avg 80m)

Table 2.2.3: Distribution of non-effective wellbore in the simulation cases

The resulting initial rates (average) predicted by the simulator, assuming that none of the rates are capped are 2,161 bopd for the Low-side Case and 3,494 bopd for the Base Case. For all cases the off-take is restricted to 3,000 bopd and plateau production lasts between 8 and 12 months before declining rapidly with each well producing for about 3 years (on average). The average initial rates appear to be within the range of rates predicted by the PIF analysis described above. It is also noted that if the effective well-bore length is reduced to 600 m (as for the Low-side case), the resulting PIF value would be 4.2, resulting in predicted rate of 2,390 bopd matching the simulation prediction very well.

2.3 Development Strategy

2.3.1 Key Contingencies to be addressed

RPS Energy and Xcite have identified several key parameters (contingencies) in the existing modelling that need to be proved up in order for Bentley to go forward to full field development and be classified as Reserves. The following are deemed to be the most important in defining the ultimate recoverability and hence commercial outcome for the Bentley Field.

- Initial stabilised oil production rate achievable from a vertical or inclined well.
- Prove up production improvement from increased completion length possible through horizontal or high angle drilling.
- Test well production performance and pressure response over an extended period (10-30 days) to better model production prediction and calibrate development planning for well numbers and timing etc.
- Test rate of water movement through the oil during production.
- Determine the reservoir and aquifer pressure response to production.
- Determine relative permeabilities and Kv/Kh.
- Test upside formation depths from seismic re-mapping and modelling.
- Monitor sand production as a result of variation in flow-rate and pressure etc.

Xcite is currently in the process of planning an EPS in order to resolve as many of the contingencies described above as possible in as cost effective a manner as possible. A document detailing the planning and rationale of the EPS has been made available to RPS Energy ("Xcite Energy Resources Ltd; Bentley Field; Early Production System; Document Number EPS0101, revision 12"). This is a live document and will evolve as further analysis and modelling progresses. It is a document that is potentially commercially sensitive and RPS Energy does not consider it appropriate to re-present all the information held therein. However, we have satisfied ourselves that the Company is progressing its thoughts in a considered and structured way that is likely to maximise the information gathered to move the Bentley Contingent Resources to Reserves. The main objectives and rationale are described below.

2.3.2 Early Production System

The EPS is required as an essential step in achieving commercial development of the Bentley field for four principal and connected reasons:

- Firstly; to narrow the range of uncertainty in the potential performance of the Bentley field and hence the range of recoverable reserves, i.e. confirm the performance of the field during full field production operations.

- Secondly; to help optimise the facilities design and thus minimise costs.

- Thirdly; the EPS will assist in narrowing the range of possible economic returns and thus assist the financing process for the full field development.

- Fourthly; the EPS, by narrowing the performance range of uncertainty, will enable XER to maximise the value of the Bentley field and, therefore, maximise its ability to secure funding for the full field development.

Xcite has already determined that, assuming its modelling is proved to be correct (with reservoir and fluid behaviour at least as good as modelled in the Low-side Case), under all reasonable circumstances the Bentley field has commercially acceptable economics. On this basis, proceeding to the EPS is a logical next step.

The detailed scope of the EPS remains to be finalised, but as a minimum it will include a single well with a horizontal section (EPS-1) into the A area. Gathering more data in the B zone (EPS-2) would fine tune the performance of area B relative to area A, while EPS-3 would quantify the oil and gas reserves of Bentley East to establish if the gas volumes are adequate to replace the imported gas during full field operations, together with adding more recoverable reserves. EPS-2 and EPS-3 are considered as options to be included in the EPS work programme.

Xcite has noted, however, that as a certain amount of flexibility can be built into the full field development facilities at little extra cost, or indeed has to be put in place to cover outstanding uncertainties, some uncertainties are equally beneficially resolved during the operational phase of the full field development.

The wells under consideration into the three areas are shown in Figure 2.3.1.

Area A – EPS-1

The choice of only one well into Area A is persuasive and the key items for inclusion in that well test are:

- a coning test on the vertical well (benchmarking water movement);

- an initial rate test on the vertical well;

- horizontal sidetrack to demonstrate the ability to place a horizontal section at the desired depth in the reservoir section, that it can be successfully completed and produced at the predicted rates (to show headline rates); and

- a flow test, potentially multi-rate with build ups, of the horizontal section for a reasonable time (of between 10 and 30 days) to show relative permeability, Kv/Kh relationships, pressure support and oil mobility.

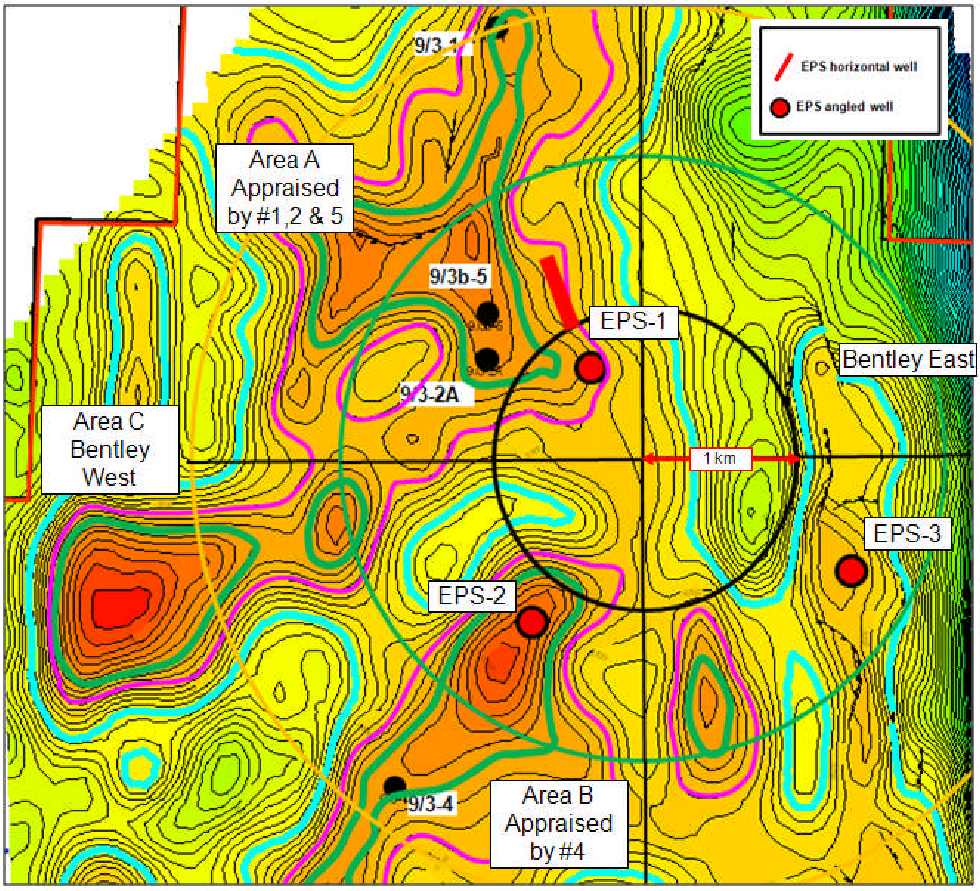


Figure 2.3.1: Schematic map showing current proposed potential EPS well sites

In addition, while drilling the vertical well into Area A, core tests in order to understand reservoir properties including grain size distribution, also appear to be useful at minimal additional cost. Information gleaned from core could avoid expensive capital expenditure options for the full field development.

Summary Recommendations

All options being considered for the EPS will be progressed to costing and estimating, so that robust cost-benefit analysis can be concluded for each material test. In addition, the details of the proposed tests will be considered e.g. optimum flow period, multi-rate tests, build-up periods etc.

The high level recommendations at this stage are:

1. The EPS programme should be designed to allow maximum flexibility with respect to number of wells drilled and duration of flow tests. The flexibility available will be determined principally by effective funds and commercial terms and conditions, with appropriate equipment availability also being relevant.

2. EPS-1 into Area A is the minimum EPS work programme, with all principal parameters for the Bentley field being confirmed during drilling and testing. The

precise flow period required for this well is still being reviewed within the 30 day envelope.

3. Area B and Bentley East wells should be properly assessed in the context of effective funds available and the cost-benefit of drilling and testing.

4. The overall EPS programme should also be considered in the context of the existing value of the Bentley field and the added value that the EPS delivers.

In conclusion, Xcite believes that a one well EPS programme with good definition and objectives will narrow the range of potential performance of the Bentley field and hence the range of uncertainty in the recoverable reserves. Assuming it is successful, it will enable Bentley to be designated as 1P and 2P Reserves within its core structure and will further enable detailed planning of a full field development.

The principal result of drilling additional wells during the EPS will be to increase 1P Reserves and designate further 2P Reserves. Additionally, it will provide information to further define the full field development plan.

2.3.3 Full Field Development

If the EPS is successful and provides positive resolution of the current contingencies, it is envisaged that Xcite will move to a full field development which will trigger the classification of Reserves.

This section describes Xcite's plan for the full field development. RPS Energy has reviewed this plan and concludes that it represents a logical and plausible way of developing the field and that it is consistent with the models and economics presented in this report.

As described above, the Bentley reservoir and its fluids are known to be challenging to produce compared to more conventional offshore North Sea oil developments. The reservoir has a relatively low energy and the crude is heavy and viscous, most notably at surface conditions after de-gassing. Since the reservoir is relatively shallow, has a limited pay thickness and is highly friable, well placement together with completion design and patterns are particularly important to enable efficient reservoir drainage and optimum economic recovery. The current planned well placement (wells running parallel to and within 200m of each other) and the relatively rapid angle build up and steering from the central platform will require a high degree of skill but is reminiscent of drilling in the Captain field amongst others. RPS Energy considers the drilling plan to be challenging but within the realms of today's technology.

Water mobility is likely to be significantly greater than oil mobility in this system resulting in the requirement to process significant volumes of formation water.

The basic top-side design will be a drilling and processing platform with floating storage unit ("FSU") tanker. For the Base case the platform is currently designed to have 56 slots with two drilling rigs which will drill 43 mother-bores, from which a further 33 side-tracks are anticipated, 12 water injectors and one water producer. The Low-side case anticipates a slightly smaller development targeting the 'A' and 'B' areas only, utilising 36 slots with one rig drilling 26 mother-bores and 38 sidetracks. The Low-side case has for 9 water injectors and one water producer.

The drilling and completion duration of a typical horizontal well has been studied by drilling and completion contractor, SPD, and their study concluded a 42 day duration for a producer well. These figures were used to calibrate a QUE$TOR model. In calculating the time to drill and complete the wells, a margin of 33% was added to the aggregate times calculated by the IHS QUE$TOR software, which were originally calculated based upon the average of the exploration and appraisal wells drilled into the 9/3b Block to date. There is good offset well data for the up-hole sections of the well.

The additional time added impacts the production profiles and allows time for re-drilling and additional side-tracking plus any unscheduled work-over requirements. This results in a total of 3360 drilling days, of which over 1000 are contingency days.

The development wells will include, on average, 800m horizontal sections (from a minimum of 200m to a maximum of 1350m). Further work is required to finalise the design, specifically drilling fluids and completion strategies, which have yet to be decided and could have an impact on the drilling facilities topsides design.

The current plan is for the production wells to be completed using slotted liners, the intention being to complete the initial oil wells with either a progressive cavity pump ("PCP") or hydraulic pump ("HP") during the oil only period until water breakthrough has occurred and the water content is over the critical water cut (around 55% water cut). Thereafter the intention is to replace the PCP with an electric submersible pump ("ESP") as the viscosity will have stabilised and dropped to close to that of water and the flow-rate will climb, exceeding the normal capacity of PCPs.

The principal rationale behind the initial use of PCPs is that they are much more suitable for service with heavy crude, which may contain sand and/or gas, and where there may be substantial variance in the viscosity of the well stream during minor upset periods. It is also desirable to minimise the pressure drop across the wellbore to ensure feed forward pressure control is maintained from the well bore to the wellhead. Severe sand control strategies can increase the pressure drop and, therefore, the use of the more sand tolerant PCP allows simpler sand control with slotted liners to thereby minimise pressure drop.

As a result of the friable nature of the reservoir, the facilities at surface must be able to cope with sand and fines. The exact volume of sand is still unknown at this stage and will not be known until after the EPS. It is felt that PCPs will be better able to cope with sand production in the early stages of production and at the time of early water breakthrough. Currently the treatment and disposal of sand is assumed to be covered by the available equipment and is included in the significant contingency for the well drilling and workover time and cost. Both drilling cuttings and sand would be disposed of using disposal wells, as yet to be defined.

RPS Energy believes that the pump strategy presented above is well thought through and will help maximise delivery from the reservoir.

Topsides Facilities

For the base case, the topside facilities are designed to cater for a bulk fluid flow-rate of 466,000 bpd (15% over the maximum planned fluid rate), of which the oil will peak at 64,000 bopd. The well fluid will flow to three large bulk water separators, sized to cater for 3 minutes hold up time at full flow, and will remove the free water, assumed to be 55% of the water in the well fluid. A series of laboratory tests demonstrate that 45% water-cut is the critical water-cut level when subject to high shear. When using PCPs and ESPs this critical water-cut may drop to 20% to 30%, but may be slightly higher if sand or fines are entrained in the well fluids.

Once the bulk water is separated, the remaining fluid is heated from 40°C to 90°C; first in a run down cross exchanger and then by a closed circuit heating medium system, prior to flowing into two parallel separators with 9 minutes residence time, where it is expected to de-water down to 10% water before passing to three parallel electrostatic coalescer vessels for reducing to 0.5% BS&W. A run down cooler cross exchanges with the incoming fluid before being transferred at 60°C to the dedicated Floating Storage Unit (FSU) tanker. The FSU will be a 150,000 dwt tanker converted for use as an FSU and will contain over 750,000 barrels of storage.

Adequate space on the FSU will be left to divert ‘off spec’ crude to dedicated tanks, which will be left to settle on its own over time and pumped into the sales cargo tanks when suitably dewatered.

Produced water is taken from all the dewatering separators and pumped through hydro-cyclones to remove any entrained oil, or any sand as a slurry. The oil is returned to the second stage separators and the sand slurry will be co-mingled with the drill cuttings and disposed of in disposal wells.

A test separator is included to test individual wells on a rotating basis. All fluids tested will be put back into the main production stream once measured.

Produced water, once treated, will be supplemented with water from a water source well that will be drilled at the beginning of the development programme. The combined make-up water and produced water will be injected through 12 water injection wells placed at the flanks of the producing area. The water injection system will be designed for 400,000 bwpd to be pumped to 725 psig prior to injection, using a single 4.91 MW gas turbine driven pump.

Utility systems will be provided for fuel gas, heating medium, open and closed drains and a flare and vent at 9 MMscfd. HVAC, fire fighting and mechanical handling systems are also included.

A gas import system (including 22km import line from Bruce or the Frigg gas line) is also included to provide make up fuel gas over and above associated gas anticipated (based on 100 GOR). The gas import is sized to import the complete fuel gas load, as no associated gas may be available at certain times.

The presence of a gas cap, if proved at Bentley East, would provide the potential to supply all required gas for the full field development. However, to err on the conservative side, the cost of purchasing all the required the gas at $5 / Mcf is included in the operating costs. This gas price is assumed to be to the futures gas price, less remaining transport to shore.

The drilling facilities contain two integrated drilling rigs with power and services provided by the mother platform. An accommodation unit with heli-deck is provided to service 91 onboard personnel.

22.1 MW of power generating facility is included using five Solar Taurus 60s or equivalent. Emergency power back up is also included.

While in many respects the platform proposed for Bentley is somewhat reminiscent of the late 70s early 80s platforms that were installed in the Northern North Sea, such as Thistle or Dunlin, the topsides will differ in some subtle but quite significant ways. The most significant factor is the absence of any requirement for sales gas handling, gas treatment and export systems. Thus Bentley will have a lower than average weight at 13,000 tonne dry, somewhat in line with the lower oil processing volume at 64,000 bopd despite the 50+ well count.

However, the greater water handling requirements add weight to the large bulk water separators and water injection facilities, but this volume of fluids mostly shows itself in the much more significant ‘wet’ topside weight of nearly 17,000 tonnes, for which the structure has to be designed.

This different configuration will also lower the ratio of both piping and support steel that would be normal for a typical North Sea platform, as the main weight contribution comes from the drilling unit (which has its own support steel, dealt with separately) and also in the significant weight of the separators (of which there are eight). In addition, most of the pipe-work needed will be of low pressure grades as the production is all artificially lifted, but for safety the design includes significant pipe work around the inlet manifolds and well bay area.

3 ECONOMICS

3.1 Summary of Commercial Assumptions

The main commercial terms and assumptions for the Bentley Field indicative success case valuation are summarised below:

3.1.1 Participation

Xcite are currently 100% licence owners of the Bentley Field.

3.1.2 Assumed Work Programme

Xcite plans to undertake a 1 to 3 well EPS programme costing an estimated $60MM to $100MM (subject to revision for future cost variations), to be conducted within the second licence period (by September 2011).

In the event that the EPS proves up the currently modelled mobilities and demonstrates that the planned completion techniques can deliver sustainable commercial flow rates (including the handling of sand production), Xcite will move toward a full field development program in the third and final licence period to 2029. The development program is described in more detail in Section 2.3.3 above. First oil is currently modelled as Q2, 2013.

3.1.3 Capital Costs

Xcite has used the IHS QUE$TOR software as the basis for calculating its CAPEX requirements. For drilling, Xcite has added 33% contingency of time (and hence costs) to the time calculated by QUE$TOR for drilling the wells. RPS Energy believes that the contingency allowed for is appropriate since the drilling program will be challenging and the physical number of wells will almost certainly result in drilling problems and unscheduled over-runs.

In addition to the drilling time contingency allowed, Xcite has allowed for 20% contingency on all capital items across the board.

As described in Section 2.3.3 above, it is anticipated that PCPs will be swapped out for the more expensive but greater volume handling ESPs after approximately 18 months for each well (when water cut reaches 60%). For conservative cost modelling purposes, Xcite have included the cost of ESPs at the outset (the cost of an ESP is nearly 10 times that of a PCP and considerably more than a HP), which also removes any pump swap-out timing assumption issues. In addition, the cost of replacing the ESPs is also included in the operating costs where, in Year 3 and beyond, Xcite provides for the cost of eight new ESPs each year.

The resultant CAPEX for each case is summarised in Table 3.1.1 below.

RPS Energy believes that the capital costs are a reasonable estimate based on the current maturity of design and lie within the industry normal for the utilized cost estimating approach of -25% to +25% range.

Capex Category	Low-side Case 1 Rig, 36 slots, 26 mother-bores, 38 side-tracks, 9 injectors	Base Case 2 Rigs, 56 slots, 43 mother-bores, 33 side-tracks, 12 injectors	Up-side Case 2 Rigs, 56 slots, 43 mother-bores, 33 side-tracks, 12 injectors
Intangible	$285.1 MM	$354.5 MM	$355.7 MM
Development wells	$298.8 MM	$440.3 MM	$442.8 MM
Platform & Design	$450.8 MM	$629.7 MM	$633.8 MM
Facilities	$591.2 MM	$826.3 MM	$895.5 MM
Pipelines	$74.3 MM	$76.8 MM	$77.7 MM
Total Development	**$1,700 MM**	**$2,328 MM**	**$2,406 MM**
Abandonment	$180.8 MM	$245.0 MM	$255.6 MM
Total Capex	**$1,881 MM**	**$2,573 MM**	**$2,661 MM**

Table 3.1.1: CAPEX for the Bentley development scenarios

3.1.4 Operating Costs

OPEX costs include Personnel, Maintenance and Inspection, together with Logistics, Consumables, Insurance, Administration and Transport Tariffs. The Consumables include fuel-gas for the platform. Xcite has allowed for a 10% contingency on top of all calculated OPEX. The resultant OPEX for each case is summarised in Table 3.1.2 below:

Opex Category	Low-side Case 1 Rig, 36 slots, 26 mother-bores, 38 side-tracks, 9 injectors	Base Case 2 Rigs, 56 slots, 43 mother-bores, 33 side-tracks, 12 injectors	Up-side Case 2 Rigs, 56 slots, 43 mother-bores, 33 side-tracks, 12 injectors
Fixed Opex	$1,217.7 MM	$1,838.4 MM	$1,829.0 MM
Variable Opex (plus Admin & Tariffs)	$176.5 MM	$296.4 MM	$440.4 MM
Total Opex	**$1,394 MM**	**$2,135 MM**	**$2,229 MM**

Table 3.1.2: OPEX for the Bentley development scenarios

The presence of a gas cap, if proved at Bentley East, would provide the potential to supply all required gas for the full field development. However, to err on the conservative side, the cost of purchasing all the required the gas at $5 / Mcf is included in the operating costs. This gas price is assumed to be to the futures gas price, less remaining transport to shore.

RPS Energy believes that the operating costs are a reasonable estimate based on the current maturity of design and, again, lie within the industry normal -25% to +25% range.

3.1.5 Oil Price

Xcite commissioned KBC to conduct a market study for 'heavy' oil and to model the expected discount to 'Brent' in the future. While such studies cannot be considered a guarantee, KBC's modelling suggests that the differential between standard crude such as Brent and heavy crudes such as Bentley will reduce as upgrading capacity increases. The discount of Bentley crude oil to dated Brent is therefore expected to decline as a percentage of the Brent price from around 16% currently to around 12% by 2020 and to slightly below 10% by 2030, assuming a relatively stable oil-price increase through time. For its economic model and project testing, Xcite has used a conservative flat discount rate of 15% to RPS Energy's forecast for Brent throughout the life of the field.

The forward curve is shown as Figure 3.1.1 below:

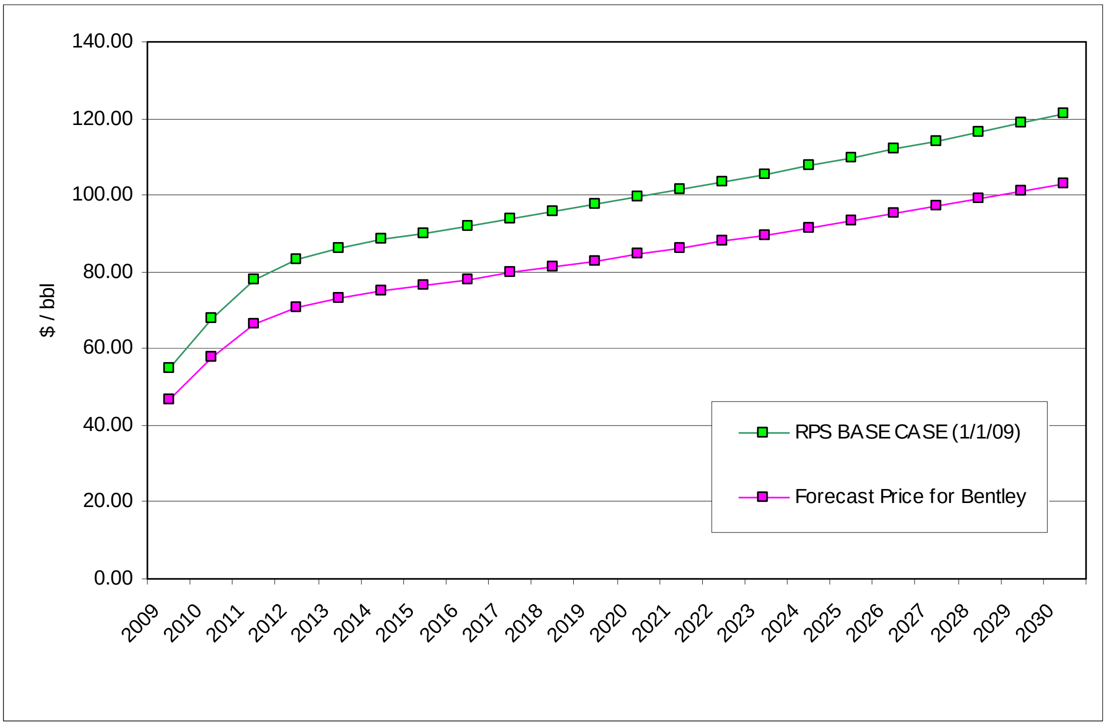


Figure 3.1.1: Forward oil-price curve for Brent and Bentley

3.2 Valuation Summary

RPS Energy has audited the input parameters to Xcite's valuation spreadsheets and considers them generally reasonable subject to confirmation of certain key reservoir parameters being proved up by the planned EPS.

However, assuming that the technical contingencies can be successfully mitigated, even towards the lower end of Xcite's expectations, it would appear that the project is capable of generating a positive success case NPV10 and a reasonable IRR. For the Base Case these success case numbers are $781 MM and 23.6% respectively using a constant 15% discount to RPS Energy's current Brent forecast oil price ($80 flat real). A summary table of the Economic assumptions and Success Case NPV10 for each case is shown as Table 3.2.1 below:

Input assumption / Success Case Outcome	**Low-side Case** 1 Rig, 36 slots, 26 mother-bores, 38 side-tracks, 9 injectors	**Base Case** 2 Rigs, 56 slots, 43 mother-bores, 33 side-tracks, 12 injectors	**Up-side Case** 2 Rigs, 56 slots, 43 mother-bores, 33 side-tracks, 12 injectors
Capex	$1,881 MM	$2,573 MM	$2,661 MM
Opex	$1,394 MM	$2,135 MM	$2,229 MM
Oil Price	$80 Brent (flat real) less 15% discount	$80 Brent (flat real) less 15% discount	$80 Brent (flat real) less 15% discount
Recoverable Resource	72.0 MMbbls	122.5 MMbbls	166.0 MMbbls
Field Life	13 years	15 years	15 years
Success Case NPV10	**$181 MM**	**$781 MM**	**$1,535 MM**
Success Case IRR	13.9%	23.6%	33.7%

Table 3.2.1: Summary table showing key economic input and Success Case NPV10

3.2.1 Conclusions

The Bentley Field is currently classified as Contingent Resources (Development Pending) but is soon to be subject to an EPS program designed to prove up certain key reservoir performance parameters before committing to a full field development plan. In the event that the EPS is successful, it is RPS's opinion that the current range of potential recoverable Resources is likely to increase following a complete review of the STOIIP model and the calibration of the full field development plan.

It is noted that the volumes quoted above do not represent a probabilistic analysis of the potentially recoverable volumes from Block 9/3b (although the 'low', 'base' and 'high' cases are broadly equivalent to the P90, P50 and P10 from a probabilistic analysis). Rather, they are the result of simulated cases that relate to three currently modelled development scenarios, which account for a range of reservoir and performance parameters that need to be tested as described above. Taking into account:

- The results of the 9/3b-5 well on the Bentley field;
- The study and analysis work and the full field development plan that have been undertaken by Xcite since the 9/3b-5 well;
- The audit and review work that has been undertaken by RPS Energy;
- The recommendations from RPS Energy that Xcite has incorporated into its modelling of the Bentley field; and
- The recent (November 2008) publicly announced intention by StatoilHydro to move the adjacent and analogous Bressay field forward to development,

RPS Energy concludes that the Chance of Commerciality of the Bentley field at this is time is 70%.

APPENDIX 1: GLOSSARY

Definitions used in this report are as follows.

$	U.S. dollars
/d	Per day
°API	American Petroleum Institute units of specific gravity of liquid petroleum
AVO	Amplitude versus offset
bbl(s)	Barrel(s)
BHP	Bottom hole pressure
boe	Barrel of Oil equivalent 6Bscf of gas = 1mmbbls oil
bopd	Barrels of oil per day
bpd	Barrels of fluids per day
Bscf	Billions of standard cubic feet
BS&W	Basic sediment and water
CGG	Compagnie Generale de Geophysique
cP	Centipoise – units of viscosity
CPI	Computed petrophysical interpretation
CPR	Competent person's report
DECC	Department of Energy and Climate Change
DHI	Direct hydrocarbon indicator
DST	Drill stem test
DTI	Department of Trade and Industry – briefly known as BERR and now as DECC
dwt	Dry weight tonnage
EPS	Early Production System
ESP	Electric submersible pump
EWT	Extended well test
FVF	Formation volume factor
FSU	Floating storage unit
GIIP	Standard volume of gas initially-in-place, i.e. prior to production
GOC	Gas-oil contact
GOR	Gas:oil ratio
GRV	Gross Rock Volume
HP	Hydraulic pump
HVAC	Heating, ventilation & air conditioning
IRR	Internal rate of return
Kv:Kh	The ratio of vertical versus horizontal permeability
Lead	An identified potential hydrocarbon trap which requires further work before becoming a drill-ready prospect
km, m, cm, mm	Kilometres, metres, centimetres and millimetres
M, MM, B, T	Thousands, millions, billions (thousand million), and Trillions (thousand billion) respectively
Mcf	Thousands of cubic feet
mD	Millidarcies – units of permeability
MDT	Modular (formation) Dynamic Test

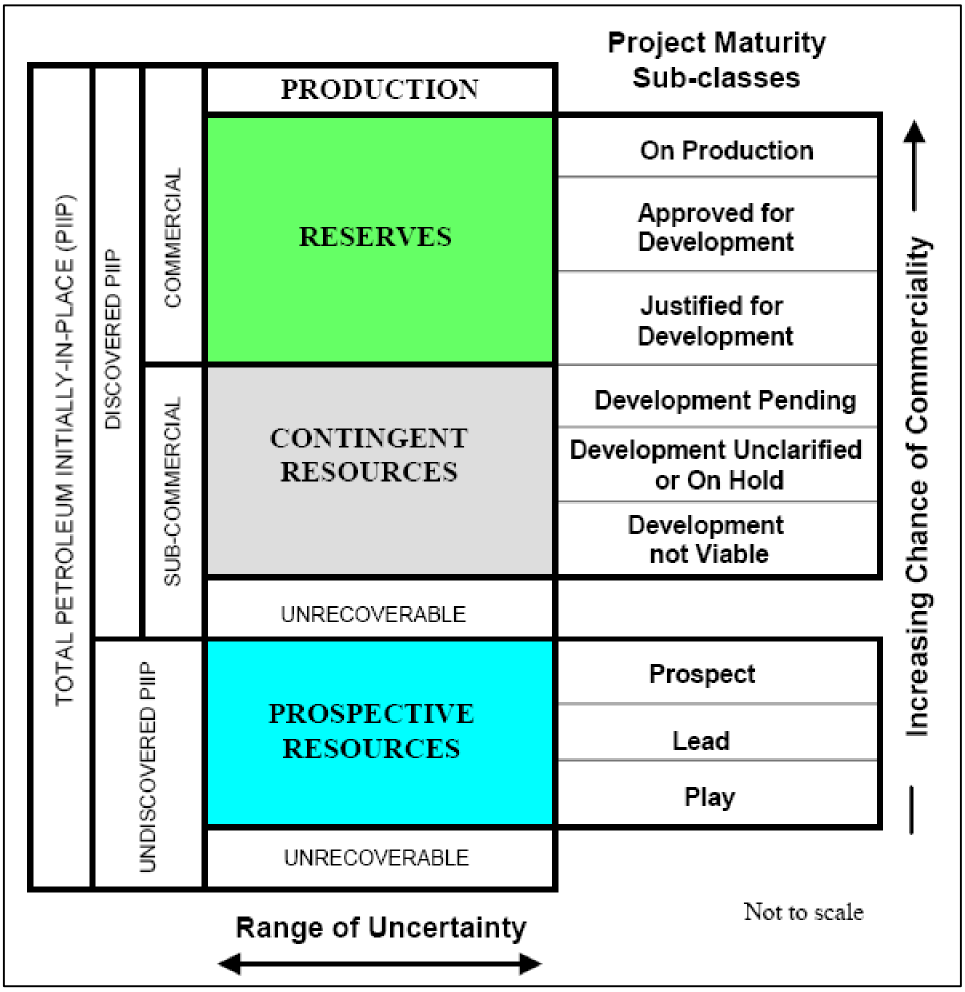
MW	Megawatts – units of power
NPV10	Net present value in money of the day using a 10% forward discount rate
NTG or N:G	Net to Gross
ODT	Oil Down To
OWC	Oil-water contact
P10	10% probability that value will be equal to or greater than stated value
P50	50% probability that value will be equal to or greater than stated value
P90	90% probability that value will be equal to or greater than stated value
PBU	Pressure Build-up
PCP	Progressive cavity pump
Petroleum	Oil and/or gas
PIF	Productivity Improvement Factor
Prospect	An identified potential hydrocarbon trap which is sufficiently well defined and de-risked to merit the drilling of an exploration well
psia	Pounds per square inch measured in atmospheric conditions as opposed to in a vacuum
RF	Recovery Factor
RFT	Repeat Formation Test
RMS	Root Mean Squared
scf	Standard cubic feet measured at 14.7 psia and 60° Fahrenheit
SPD	A firm now owned by Baker specialising in drilling and production tools and equipment
stb	Stock tank barrel(s) measured at 14.7 psia and 60° Fahrenheit
STOIIP	Stock tank volume of oil initially-in-place, i.e. prior to production
Sw	Water Saturation
TD	Total Depth
TVDSS or tvdss	True vertical depth sub-sea
UKCS	United Kingdom continental shelf

APPENDIX 2: RESERVES & RESOURCES DEFINITIONS

The second edition of COGEH (September 1st 2007) notes due consideration of the SPE-PRMS has been given and that this resulted in notable in notable changes to resource definitions but only minor editorial changes to the previous reserves definition and guidance.

COGEH defines Contingent Resources as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political, and regulatory matters, or a lack of markets. There is no certainty that it will be commercially viable to produce any portion of the resources

The diagram below illustrates the different reserve and resource categories as defined by the PRMS and used in this report.



Given below are brief definitions of the main resource categories, which are also referred to in Section 5.3.4 b of Volume 1 of COGEH 2nd edition. Fuller definitions can be found in the documents "Petroleum Resources Management System"[3] and the associated "Estimating and Auditing Standards for Reserves"[4] on the Society of Petroleum Engineers (SPE) website (www.spe.org)

Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.	Contingent Resources 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 level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g. drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time frame. Note that disappointing appraisal/evaluation results could lead to a re-classification of the project to "On Hold" or "Not Viable" status. The project "decision gate" is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.

Prospective Resources

The potential volume of hydrocarbon that could be commercially produced from an, as yet, undiscovered field.

[3] www.spe.org/spe-app/spe/industry/reserves/prms.html
[4] www.spe.org/spe-app/spe/industry/reserves/audit.html

APPENDIX 3: INDEPENDENT PETROLEUM CONSULTANT'S CONSENT AND WAIVER OF LIABILITY

The undersigned firm of Independent Petroleum Consultants knows that it is named as having prepared an independent report of the oil resources of the Bentley field UKCS Block 9/3b operated by Xcite Energy Limited, through its wholly-owned subsidiary, Xcite Energy Resources Limited, and it hereby gives consent to the use of its name and to the said reports. The effective date of the original report is 31st December, 2008.

In the course of the evaluation, Xcite Energy Limited provided RPS Energy Limited personnel with basic information which included petroleum and licensing agreements, geologic and test information, contractual terms, studies made by other parties, economic evaluation spreadsheets and discussions of future plans. Any other engineering or geological data required to conduct the evaluation upon which the report is based, was obtained from public literature, and from RPS Energy non-confidential files and previous technical resource evaluation reports on the subject property. The extent and character of ownership and accuracy of all factual data supplied for this evaluation, from all sources, has been accepted as represented. RPS Energy reserves the right to review all calculations referred to or included in the said reports and, if considered necessary, to revise the estimates in light of erroneous data supplied or information existing but not made available at the effective date, which becomes known subsequent to the effective date of the reports.

There is considerable uncertainty in attempting to interpret and extrapolate field and well data and no guarantee can be given, or is implied, that the projections made in this report will be achieved. The report and resource potential estimates represent the consultant's best efforts to assess the assets within the scope, time frame and budget agreed with the client. Moreover, the material presented is based on data provided by Xcite Energy Limited. RPS Energy cannot be held responsible for decisions that are made based on this data or report. The use of this material and report is, therefore, at the user's own discretion and risk. The report is presented in its entirety and may not be made available or used without the complete content of the reports, except by Xcite Energy Limited in connection with the proposed filing, which we have approved. RPS Energy liability shall be limited to the correction of any computational errors contained herein.

Dr. Graeme S. Simpson, Chartered Geologist, a Certified Petroleum Geologist, a Member of the Energy Institute, the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers.
Director, RPS Energy

APPENDIX 4: CERTIFICATE OF QUALIFICATION

I, Graeme S. Simpson, of 20, Abchurch Lane, London, EC4N 7BB, U.K., a Certified Petroleum Geologist (AAPG) at RPS Energy Limited and supervisor of a property evaluation (the "Evaluation"), dated February 2009 prepared for Xcite Energy Limited for the purposes of its intended filing, do hereby certify that:

- I am a Certified Petroleum Geologist (AAPG) employed by RPS Energy Limited which did prepare a detailed evaluation of various interests owned by Xcite Energy Resources Limited, a wholly owned subsidiary of Xcite Energy Limited, as at 31st December 2008.

- I attended the University of Sheffield in England and that I graduated with a Ph.D. in Geology in 1975, that I am a Certified Petroleum Geologist (AAPG), a Member of the Energy Institute and the Society of Petroleum Evaluation Engineers; that I have in excess of 34 years experience in Petroleum Geoscience and Evaluation relating to international oil and gas properties.

- I have not, directly or indirectly, received an interest, and I do not expect to receive an interest, direct or indirect, in Xcite Energy Limited, or any associate or affiliate of the company.

- The evaluation was prepared based upon information supplied by Xcite Energy Limited, as well as other public data sources. A field inspection of the Bentley field was not conducted in as part of this review; however such an inspection was not considered necessary.

Dr. Graeme S. Simpson, Chartered Geologist, a Certified Petroleum Geologist, a Member of the Energy Institute, the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers.
Director, RPS Energy