Horizon Oil Limited ABN 51 009 799 455
Level 7, 134 William Street, Woolloomooloo NSW Australia 2011
Tel +61 2 9332 5000, Fax +61 2 9332 5050 www.horizonoil.com.au

18 June 2014

The Manager, Company Announcements
Australian Securities Exchange Limited
Exchange Centre
20 Bridge Street
Sydney NSW 2000

**Independent Technical Specialist's Report**

As announced on 29 April 2014, Horizon Oil Limited (Horizon Oil) and Roc Oil Company Limited (Roc) propose to merge the two companies by way of a scheme of arrangement.

As part of that process, Horizon Oil Limited has engaged Deloitte Corporate Finance Pty Ltd (Deloitte) to prepare an independent expert's report to consider whether the merger is in the best interests of Horizon Oil's shareholders. As part of its work, Deloitte engaged RISC Operations Pty Ltd (RISC) to provide an independent technical specialist's report on Horizon Oil and Roc's assets.

Horizon Oil's scheme booklet and the Deloitte independent expert's report, together with the RISC technical specialist's report are subject to review by the Australian Securities Investment Commission (ASIC) and Court approval.

On 16 June 2014, as a consequence of its statutory continuous disclosure obligations, Roc Oil released its expert's report in respect of the proposed merger. Roc's expert also engaged RISC and, accordingly, RISC's report was included in Roc's independent expert's report.

In view of the release of the RISC report by Roc, Deloitte has consented to Horizon Oil releasing the RISC report prepared for Deloitte. A copy of that report is attached.

Yours faithfully

**Michael Sheridan**
Chief Financial Officer and Company Secretary

For further information please contact: Michael Sheridan
Telephone: (+612) 9332 5000
Facsimile: (+612) 9332 5050
Email: exploration@horizonoil.com.au
Or visit www.horizonoil.com.au

Media:
**Ian Pemberton**
P&L corporate communications
+61 402 256 576

# INDEPENDENT TECHNICAL SPECIALIST REPORT ON THE PETROLEUM PROPERTIES OF ROC OIL COMPANY LIMITED AND HORIZON OIL LIMITED FOR DELOITTE CORPORATE FINANCE PTY LIMITED

Strictly Confidential

June 2014

DECISIONS WITH CONFIDENCE

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# 1. SUMMARY

## 1.1. OVERVIEW

The document comprises the Independent Technical Specialists Report by RISC Operations Pty Ltd (RISC) to assist the Independent Expert Deloitte Corporate Finance Pty Limited (Deloitte) in the preparation of an Independent Expert's Report to the Directors of Horizon Oil Limited (Horizon) on the proposed merger of Horizon and Roc Oil Company Limited (Roc). The location of the petroleum properties and interests of both companies are shown in Figure 1-1 and Figure 1-2.

The report documents our review of the petroleum reserves, resources and associated development schedules, production and cost forecasts (projects) provided by Horizon and Roc to the Independent Expert which have been used to value the oil and gas properties. We have also addressed the risks associated with the projects. We have audited the estimates provided by both companies and made such adjustments that in our judgment were necessary to provide a reasonable assessment and reflect current information.

This report also provides an opinion on the fair market value of the exploration properties of both companies.

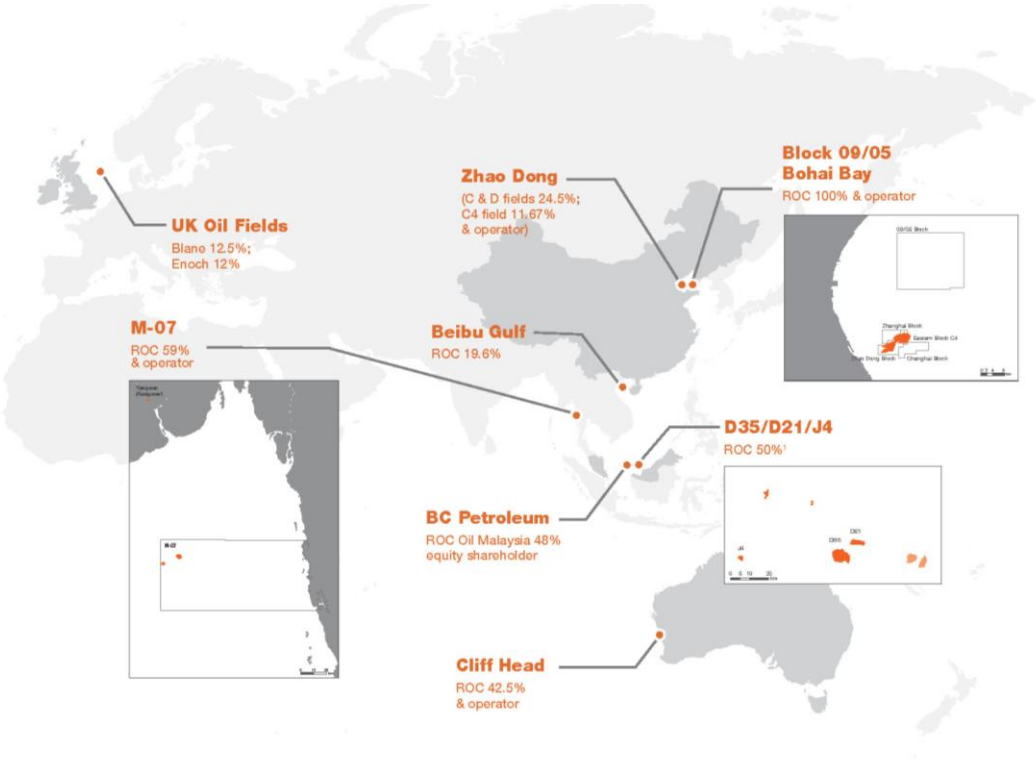


**Figure 1-1 Location Map Roc Oil and Gas Properties**

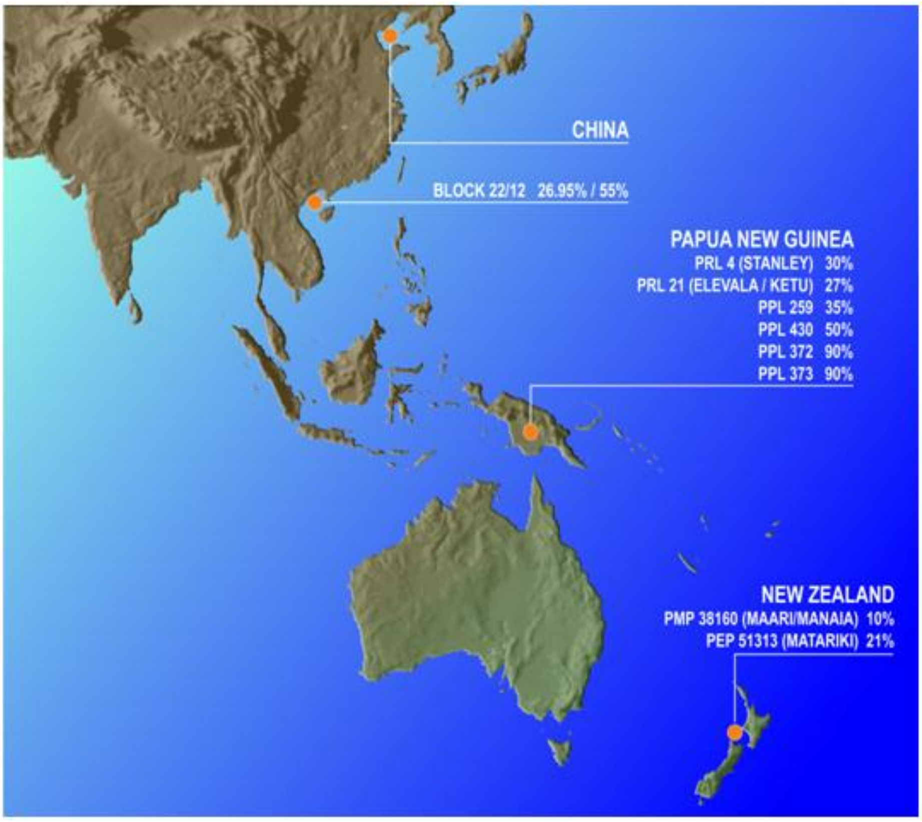


**Figure 1-2 Location Map Horizon Oil and Gas Properties**

The reserves and contingent resources of both companies assessed in this report are shown in Table 1-1, Table 1-2, Table 1-3, Table 1-4.

Details of the costs and production profiles associated with the development and production of these resources are included in our report.

| Area | Gross 2P Reserves | | Working Interest | Net WI 2P Reserves | |
|---|---|---|---|---|---|
| | Oil MMstb | Gas Bcf | % | Oil MMstb | Gas Bcf |
| Australia | 5.1 | 0.0 | 42.5% | 2.2 | 0 |
| United Kingdom | 12.0 | 0.7 | 12.5% | 1.5 | 0.1 |
| Bohai Bay[1] | 17.5 | 4.8 | 11.7-25.4% | 4.1 | 1.1 |
| Beibu Gulf[1] | 24.4 | 0.0 | 19.6% | 4.8 | 0 |
| D35/J4/D21[1] | 27.6 | 42.9 | 30%[2] | 8.3 | 12.9 |
| **Total** | **86.6** | **48.4** | | **20.9** | **14.1** |
| 1. Reserve and resource entitlement is determined by the net economic interest which is a function of the PSC terms, costs and prices prevailing during the PSC term. Depending on these factors, there may be a material difference between the working interest and the net economic interest. | | | | | |
| 2. Subject to Petronas approval | | | | | |

**Table 1-1 Roc Gross and Working Interest 2P Reserves at 1/1/2014**

| Area | Gross 2C Resources | | Working Interest | Net WI 2C Resources | |
|---|---|---|---|---|---|
| | Oil MMstb | Gas Bcf | % | Oil MMstb | Gas Bcf |
| Australia | 5.3 | 0.0 | 42.5% | 2.3 | 0 |
| United Kingdom | 7.3 | 50.0 | 12.5% | 0.9 | 6.3 |
| Bohai Bay[1] | 21.6 | 4.9 | 11.7-25.4% | 5.1 | 1.1 |
| Beibu Gulf[1] | 11.5 | 0.0 | 40.0%[2] | 4.6 | 0.1 |
| D35/J4/D21[1] | 96.0 | 71.9 | 30.0%[3] | 28.8 | 21.6 |
| **Total** | **141.7** | **126.8** | | **41.7** | **29.1** |

1. Reserve and resource entitlement is determined by the net economic interest which is a function of the PSC terms, costs and prices prevailing during the PSC term. Depending on these factors, there may be a material difference between the working interest and the net economic interest.

2. CNOOC has the right to back in for 51% reducing the 40% interest to 19.6%

3. Subject to Petronas approval

**Table 1-2 Roc Gross and Working Interest 2C Contingent Resources at 1/1/2014**

| Area | Gross 2P Reserves | | Working Interest | Net WI 2P Reserves | |
|---|---|---|---|---|---|
| | Oil MMstb | Gas Bcf | % | Oil MMstb | Gas Bcf |
| New Zealand | 59.5 | 0 | 10.0% | 6.0 | 0 |
| Beibu Gulf[1] | 24.4 | 0 | 26.95% | 6.6 | 0 |
| PNG | 11.4 | 0 | 30.0%[2] | 3.4 | 0 |
| **Total** | **95.3** | **0** | | **16.0** | **0** |

1. Reserve and resource entitlement is determined by the net economic interest which is a function of the PSC terms, costs and prices prevailing during the PSC term. Depending on these factors, there may be a material difference between the working interest and the net economic interest.

2. PNG Govt has the right to back in for up to 22.5%, reducing the 30% interest to 23.25%

**Table 1-3 Horizon Gross and Working Interest 2P Reserves at 1/1/2014**

| Area | Gross 2C Resources | | Working Interest | Net WI 2C Resources | |
|---|---|---|---|---|---|
| | Oil MMstb | Gas Bcf | % | Oil MMstb | Gas Bcf |
| New Zealand | 0.9 | 0 | 10.0% | 0.1 | 0.0 |
| Beibu Gulf[1] | 11.5 | 0 | 55.0%[2] | 6.3 | 0.0 |
| PNG | 50.9 | 1378 | 27.0-30.0%[3] | 13.8 | 384.0 |
| **Total** | **63.3** | **1378.0** | | **20.2** | **384.0** |

1. Reserve and resource entitlement is determined by the net economic interest which is a function of the PSC terms, costs and prices prevailing during the PSC term. Depending on these factors, there may be a material difference between the working interest and the net economic interest.

2. CNOOC has the right to back in for 51% reducing the 55% interest to 26.95%

3. PNG Govt has the right to back in for up to 22.5%, reducing the 30% interest to 23.25% and the 27% interest to 20.9%

**Table 1-4 Horizon Gross and Working Interest 2C Contingent Resources at 1/1/2014**

## 1.2. EXPLORATION VALUATION

RISC has assessed the fair market value of Roc's and Horizon's exploration interests using a combination of methods including value of the work program, farmin promotes from comparable transactions and expected monetary value (EMV), the basis of which is included in our report. Our estimates are summarised in Table 1-5 and Table 1-6.

| Asset | Fair Market Value US$ million Horizon net working interest | | |
|---|---|---|---|
| | Low | Mid | High |
| New Zealand | 7.6 | 7.6 | 15.2 |
| China | 0.0 | 4.4 | 8.8 |
| PNG | 16.1 | 20.1 | 66.3 |
| Total | **23.7** | **32.1** | **90.3** |

**Table 1-5 Exploration Valuation - Horizon Net Working Interest**

| Asset | Fair Market Value US$ million Roc net working interest | | |
|---|---|---|---|
| | Low | Mid | High |
| Australia | 0.0 | 0.0 | 8.5 |
| China | 15.7 | 18.9 | 33.0 |
| Malaysia | 0.0 | 10.5 | 18.5 |
| Myanmar | 0.0 | 1.7 | 1.7 |
| **Total** | **15.7** | **31.1** | **61.7** |

**Table 1-6 Exploration Valuation - Roc Net Working Interest**

# 2. TERMS OF REFERENCE

Deloitte has requested RISC to provide the following services (the Services) to assist Deloitte to prepare the Independent Expert's Report (IER):

- input and advice on the appropriateness of the assumptions adopted in the financial models for Horizon and Roc (the Models), namely:
  - the level of reserves and resources
  - production profiles (including production profiles or potential expansion cases)
  - operating expenditure, including rehabilitation and abandonment costs
  - capital expenditure
  - any other assumptions you consider relevant.

  If you consider an assumption included in the Models to be unreasonable, you need to advise us and provide advice to enable us to make the appropriate changes to the Models to reflect a reasonable projection.
- provide a brief technical overview of the development and exploration assets in which Horizon and Roc have an interest
- assist with our assessment of the reasonableness of the assumptions for additional development scenarios, in the event that more than one development scenario is considered by us
- provide an opinion as to the fair market value of the exploration assets of Horizon and Roc
- assist with the estimation of tariffs for utilising gas export infrastructure for a gas price netback calculation
- prepare a short-form report (Report) summarising your findings, including your opinion as to the fair market value of the exploration assets of Horizon and Roc, and your findings relating to the underlying assumptions for each financial model. Your report will form part of the IER prepared by Deloitte Corporate Finance and may be provided (in part or full) to Horizon and its shareholders. We will discuss the form and content of your Report with you at the outset of this project

The Services exclude any work in relation to:

- marketing, commodity price and exchange rate assumptions adopted in the Models
- financial and / or corporate taxation analysis
- discount rate determination
- an assessment of the merits of the Proposed Scheme.

# 3. BASIS OF ASSESSMENT

The data and information used in the preparation of this report were provided by Roc and Horizon supplemented by public domain information. RISC has relied upon the information provided and has undertaken the evaluation on the basis of a review and audit of existing interpretations and assessments as supplied making adjustments that in our judgment were necessary.

RISC has reviewed the reserves/resources in accordance with the Society of Petroleum Engineers internationally recognised Petroleum Resources Management System (SPE-PRMS)[1].

RISC has also been requested to provide an opinion on the fair market value of the exploration properties of both companies. We have carried out our valuation in accordance with the VALMIN code[2].

Unless otherwise stated, all resources are presented as gross quantities and costs are in US$ real terms with a reference date of 1 January 2014 (RT2014).

**Exploration Valuation**

The valuation is based on the concept of 'fair market value' (Value) as defined by the VALMIN Code. The VALMIN Code defines Value as the amount of money (or the cash equivalent of some other consideration) determined by the Expert in accordance with the provisions of the VALMIN Code for which the Mineral or Petroleum Asset or Security should change hands on the Valuation Date in an open and unrestricted market between a willing buyer and a willing seller in an "arm's length" transaction, with each party acting knowledgeably, prudently and without compulsion.

A range of oil and gas industry accepted practices in relation to exploration properties has been considered to determine value, which are described below.

**Comparable Transactions**

The Value of exploration properties can be estimated using recent comparable transactions. Such transactions may provide relevant metrics such as Value per unit of reserves, contingent or Prospective Resources, price paid per unit area of the permit or % interest. The VALMIN Code advises Value must also take into account risk and premium or discount relating to market, strategic or other considerations.

**Farmin**

An estimate of Value can be based on an estimation of the share of future costs likely to be borne by a reasonable farminee under prevailing market conditions. A premium or promotion factor may be paid by the farminee. The promotion factor is defined as the ratio of the proportion of the activity being paid for and the amount of equity being earned.

The nominal permit value is defined as the amount spent by the farminee divided by the interest earned. The premium value for the permit is the difference between the nominal value and the cost of the activity.

The premium or promotion factor will be dependent upon the perceived prospectivity of the property, competition and general market conditions. The premium value is equivalent to the

[1] SPE/WPC/AAPG/SPEE 2007 Petroleum Resources Management System

[2] Code for the Technical Assessment and Valuation of Mineral and Petroleum Assets and Securities for Independent Expert Reports 2005 Edition

faminee paying the farmor a cash amount in return for the acquisition of the interest in the permit and is the fair market value.

Farmin transactions may have several stages. For example, a farminee may acquire an initial interest by committing to a future cost in the first stage of the transaction, but has an option to acquire an additional interest or interests in return to committing to funding a further work programme or programmes.

Farmin agreements can also include re-imbursement of past costs and bonus payments once certain milestones are achieved; for example declaration of commerciality, or achieving threshold reserves volumes. Depending on their conditionality, such future payments may contribute to Value. However, they may need to be adjusted for the time value of money and risk of occurring.

**Work Program**

The costs of a future work program may also be used to estimate Value. The work program valuation relies on the assumption that unless there is evidence to the contrary the permit is worth what a company will spend on it. This method is relevant for permits in the early stages of exploration and for expenditure which is firmly committed as part of a venture budget or as agreed with the government as a condition of holding the permit. There may need to be an adjustment for risk and the time value of money.

**Expected Monetary Value (EMV)**

EMV is the risked net present value (NPV) of a prospect. EMV is calculated as the success case NPV times the probability of success less the NPV of failure multiplied by the probability of failure. The EMV method provides a more representative estimate of Value in areas with a statistically significant number of mature prospects within proven commercial hydrocarbon provinces where the chance of success and volumes can be assessed with a reasonable degree of predictability.

The EMV valuation can also be used as a relative measure for ranking exploration prospects within a portfolio to make drilling decisions, assessing commercial potential and to demonstrate the commercial attractiveness of a permit, which may influence a buyer or seller.

# 4. AUSTRALIA

## 4.1. CLIFF HEAD

### 4.1.1. Field Description

The Cliff Head field is located in licence area WA-31-L in the Perth Basin, 10km offshore Western Australia in 15-20m of water. Roc holds a 42.5% working interest and is the Operator.


**Figure 4-1 Location Map - Cliff Head**

The field started production in May 2006 and in March 2014 gross oil production was 2.1 Mstb/d at 93% water cut and a GOR of 22 scf/stb. Cumulative production to 31 December 2013 was 13.6 MMstb.

Oil is trapped in Permian Dongara, Irwin River Coal Measures (IRCM) and underlying High Cliff Sandstone (HCS) reservoirs. The field comprises a main NW-SE trending horst, with a continuous large fault to the north, and a combination of overall dip closure and several fault segments to the south.

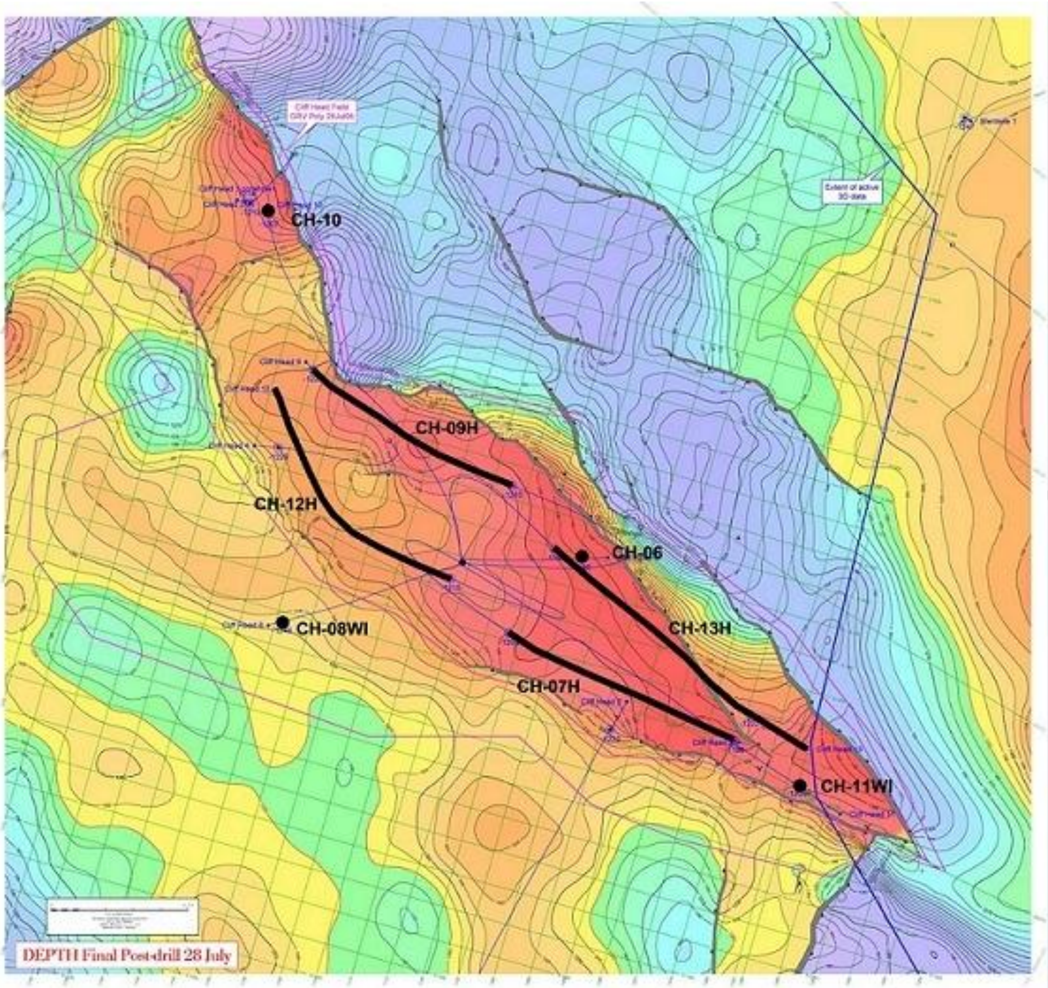


Figure 4-2 Top Reservoir Map - Cliff Head

The discovery well, Cliff Head-1 was drilled in December 2001. Five further appraisal wells, six production wells and two water injection wells have now been drilled, providing good structural control. A single oil water contact at 1,260 m TVDSS has been estimated from pressure gradient data.

The average net-to-gross ratio of the reservoir is about 87%, with average porosity about 18%. Permeabilities vary widely, from 1mD to over 1000 mD. Open fractures are reported from cored lower units of the Irwin River Coal Measures.

Offshore development consists of a minimum facility platform that is not normally manned. Electric Submersible Pumps (ESP) are installed in each producer to aid production and to allow increasing water cut. Routine ESP replacement upon failure will continue with an estimated 30 day turn around. Larger pumps have successfully been installed in CH-10 and CH-12 and are available for CH-07 and CH-13H when the current pumps fail. This will accelerate and provide incremental production before the economic cut-off.  The reservoir has strong aquifer drive and sweep is supplement by produced water re-injection in wells CH-08 and more recently watered out producer  CH-09H.

Oil processing is carried out onshore at the purpose built Arrowsmith processing plant from which the oil is transported by road tanker to the BP refinery at Kwinana. The export, production, road tanker and flow assurance facilities have been demonstrated to work with this waxy crude.

No further development is planned. However, an additional development well in the West High area has been under consideration for several years and the joint venture is looking at surfactant injection to reduce the fraction of residual oil and hence enhance the oil recovery.

### 4.1.2. Production and Cost forecast

Roc's 2P production and cost forecasts have been reviewed and are considered reasonable and consistent with RISC's 1 January 2014 reserves estimate. The ESP in CH-13 failed on 25-March-2014 and is planned to be replaced with a larger pump in May 2014. The forecast uptime is 92% including downtime caused by ESP failure and replacement.

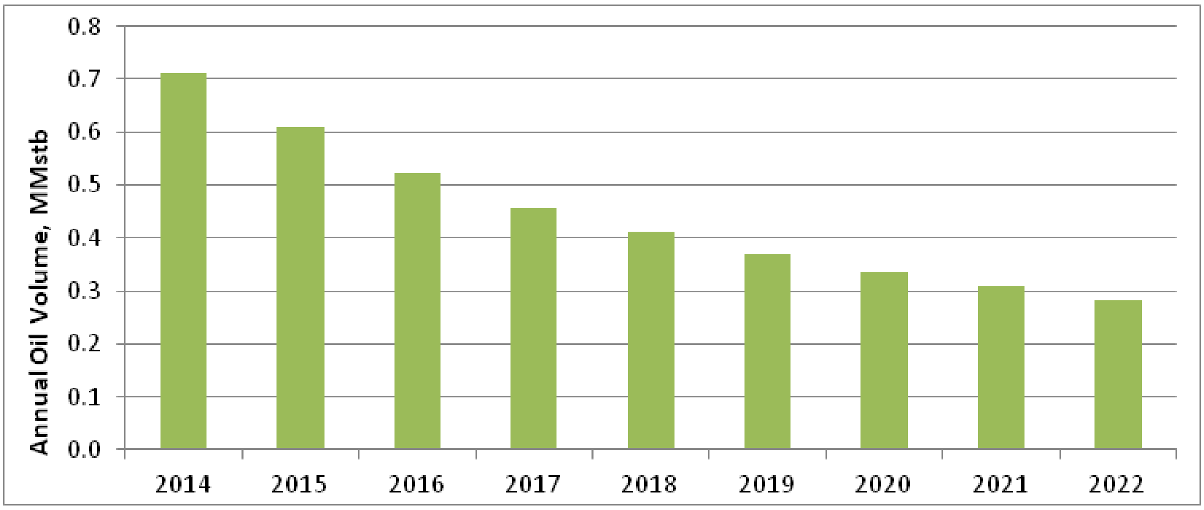


**Figure 4-3 Gross 2P Production Forecast - Cliff Head**

Figure 4-4 shows Roc's estimate for Cliff Head annual operating costs.

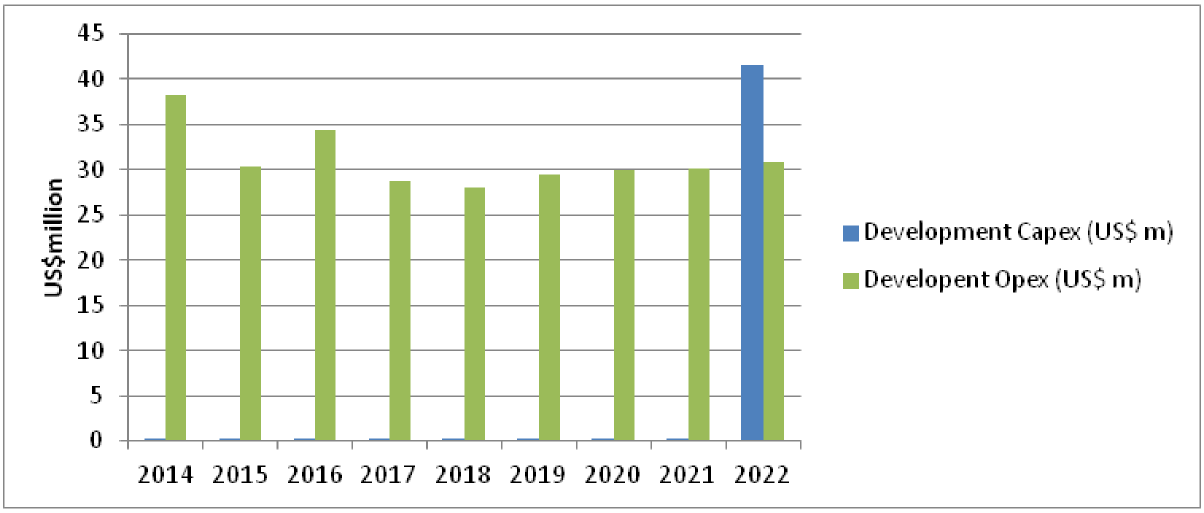


**Figure 4-4 Gross Operating Cost Forecast - Cliff Head**

Operating costs in 2014 are based on the work program and budget submitted to JV partners and included a contingent budget of A$15.8 million for; water injection pipeline repairs at A$1.5 million (though pipeline repairs are also included in the firm budget), enhanced oil recovery (EOR) implementation at A$6.0 million, two well interventions at A$3.2 million, engineering studies at A$1.7 million. RISC estimate that later in the field life there will be modest savings associated with reducing and ultimately eliminating non routine costs. To convert to US$ we have used an exchange rate of 0.9.

No further development capital expenditure is anticipated but Roc has included US$0.3 million p.a. for minor capital expenditure associated with upkeep of the facilities.

RISC has estimated the abandonment costs for the field to be US$34 million in 2014 real terms. This includes P&A expenditure for 9 wells and removal of the offshore platform and onshore production facilities. It is assumed that the pipelines will be cut and abandoned in-situ below the mud line.

Table 4-1 contains the reserves estimated by RISC.

| | 1P | 2P | 3P |
|---|---|---|---|
| Oil MMstb | 3.4 | 5.1 | 6.7 |

Table 4-1 Gross Reserve Estimate at 1 January 2014 - Cliff Head

From the period 1 January 2014 to 31 March 2014 there has been a further depletion of 200,000 bbl gross due to production. There are no gas reserves in Cliff Head.

Contingent oil resources estimated by RISC for a West High well and EOR (surfactant injection) are shown in Table 4-2.

| Gross Contingent Resources Oil (MMstb) | 2C |
|---|---|
| West High well | 1.3 |
| EOR | 4.0 |

Table 4-2 Gross 2C Contingent Resource Estimate at 1 January 2014 - Cliff Head

Roc is currently reviewing its portfolio of opportunities in and near Cliff Head with a view to identifying if commercially feasible projects exist.

## 4.2. EXPLORATION

Exploration prospectivity exists in the Mentelle prospect, which lies to the north east of the Cliff Head field and updip of well Mentelle-1 (Figure 4-5). The prospect is a rotated fault block with a gently westward dipping flank and fault bounded to the east. Mentelle-1 was drilled in 2003 and while it was dry, analysis of the well results suggests an 8m paleo-oil column below the regional seal. Roc believe that the prospect tilted post migration of oil and therefore the volume updip of the Mentelle well can be varied to give upside in the resources.

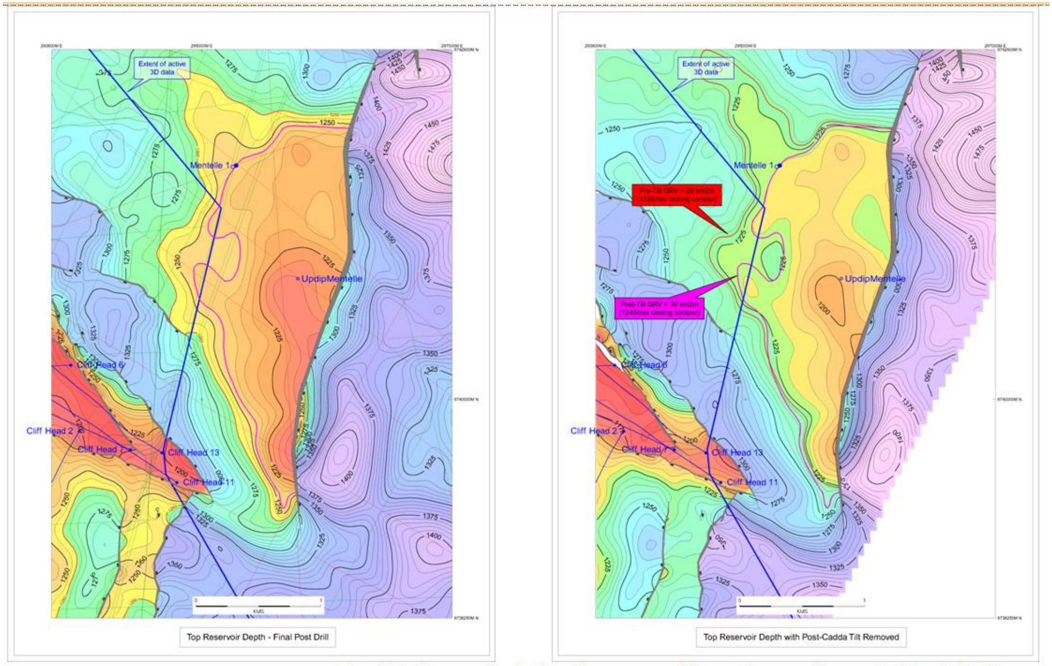


**Figure 4-5 Mentelle depth maps post and pre-tilt**

RISC considers Updip Mentelle as a valid exploration prospect and supports the prospective resources provided by Roc (Table 4-3).

RISC supports the prospect probability of success (POS) as assessed by Roc at 24%.

| | Best Estimate MMstb |
|---|---|
| Mentelle Prospect | 3.3 |

**Table 4-3 Gross Best Estimate Prospective Resources as at 1 January 2014 - Mentelle Prospect**

Whilst these resources are unlikely to interest a farminee at present volumes, costs and prices, there could be some value in the prospect in the future. In the low and mid cases, we have not assigned any value. In the high case, we have based the value on a 2:1 farmin promote of a well which gives a value net to Roc of $8.5 million

# 5. UNITED KINGDOM

## 5.1. BLANE AND ENOCH FIELD DESCRIPTION

Roc has a 12.50% unitised interest in Block 30/3A which contains the Blane field and a 12.501% unitised interest in Blocks 16/13a and 16/13E. Enoch is located in Block 16/13a.

Blane is a low relief anticlinal structure straddling the UK-Norway median line in the southern part of the North Sea Central Graben in 73m water depth.

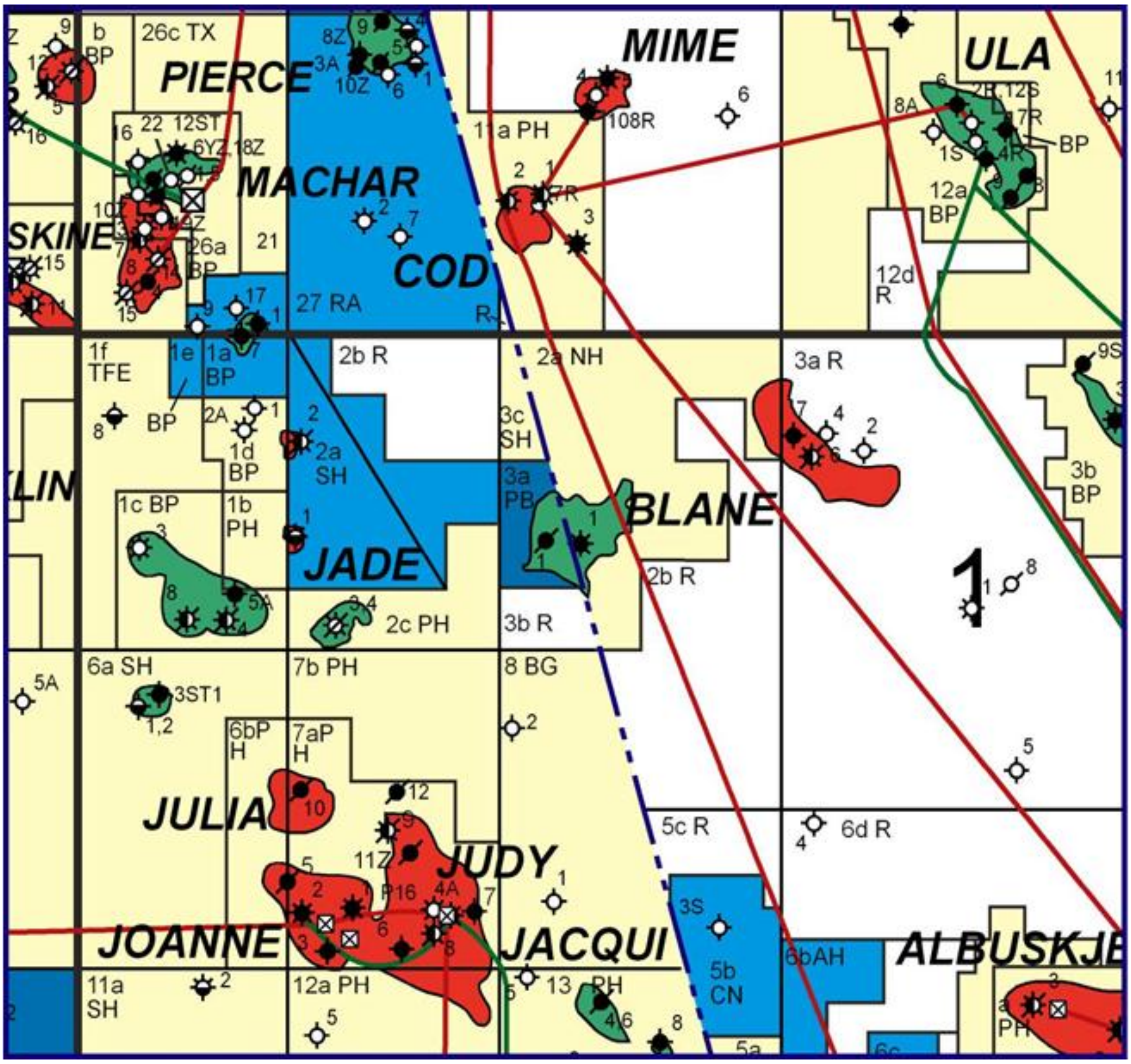


Figure 5-1 Location Map - Blane

The discovery well, N1/2-1 in the Norwegian sector and well 30/3a-1 in the UK sector were both drilled in 1989 and both tested light oil at rates in excess of 5,000 stb/d from the Palaeocene Forties Formation at depths just below 3000m.

The reservoir contains 42° API oil with a GOR of 428 scf/stb, 0.33 cp viscosity, a bubble point pressure of 1,930 psia compared to the initial reservoir pressure of 5,634 psia at 3,139 m TVDSS.

The field has been unitised and started production in September 2007 from two horizontal subsea producers. A water injector was added in March/April 2008. The wells are tied back to the Ula platform (Operator BP) located 34 km away in the Norwegian sector of the North Sea.

Water production started in April 2011 and has increased to 47% water cut.

Production uptime averaged 71% on but improved to 97% in April 2014. There have been reliability issues identified with the type of subsea tree that is installed on the Blane wells and the operator is currently investigating what remediation actions may be required.

In April 2014 the field produced an average of 6,676 bpd oil+NGL and 0.4 MMscf/d gas sales. Cumulative gross sales at 31 January 2014 were 22.1 MMstb oil+NGL and 4.2 Bscf of gas.

Enoch is a low relief anticlinal structure straddling the UK-Norway median line in the southern part of the South Viking Graben. Water depth is approximately 120 m.

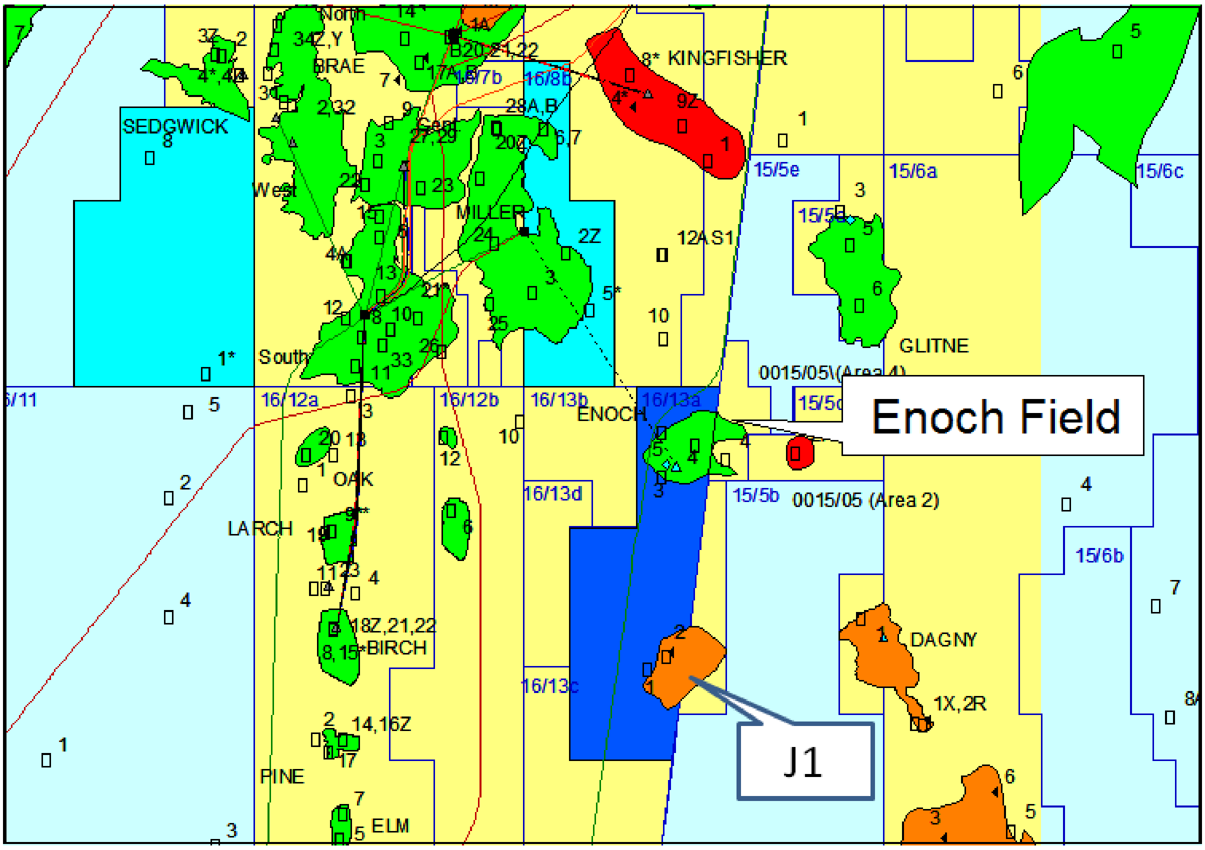


Figure 5-2 Location Map - Enoch Field and J1 discovery

The field was discovered by UKCS well 16/13a-3, drilled by Britoil in 1985, which encountered oil in the Flugga Sandstone Member of the Paleocene/Eocene Sele Formation. Approximately 100 ft of highly porous net sands were logged with a top at 6,887 ft TVDSS. A DST across the interval 6973-7,014 ft MD (6,891-6,996 ft TVDSS) produced 5.9 Mstb/d of 38o API oil but a DST in a lower zone at 7,040-7,050 ft mD (6,958-6,968 ft TVDSS) produced only water. The field extent is defined by five wells: 16/13a–3, 16/13a–4 and 16/13a–5 on the UK side and 15/5–2 and 15/5 –4 on the Norwegian side.

The field was unitised with a UK/Norwegian equity split of 80%/20% which is now fixed. It is operated by Talisman UK Ltd. There are no plans for further development of the field.

Enoch started production to the Brae-A platform from the single horizontal development well, 16/13a-7 on 31 May 2007. The early oil production rate was around 10 Mstb/d and at end-2011 had declined to around 2.2 Mstb/d. Gas lift was initiated in January 2008.

Enoch Field has been shut-in since January 2012 due to the failure of the subsea tree. The field is a single well subsea tied back to the Brae-A platform Operated by Marathon. The subsea tree was removed in 2013 but replacement has been delayed by weather and the estimated production start-up is June 2014.

The integrity of the 15km, 8" carbon steel pipeline to Brae is also a concern. The Operator has concluded that operations can resume with effective corrosion inhibition for a limited period, after which an internal inspection is required.

## 5.2. BLANE AND ENOCH PRODUCTION AND COST FORECAST

RISC has reviewed Roc's 2P production and cost forecasts and considers them to be reasonable and consistent with RISC's 1 January 2014 reserves estimate. An infill well is under consideration for drilling Q3 2015 and classified as a Contingent Resource.

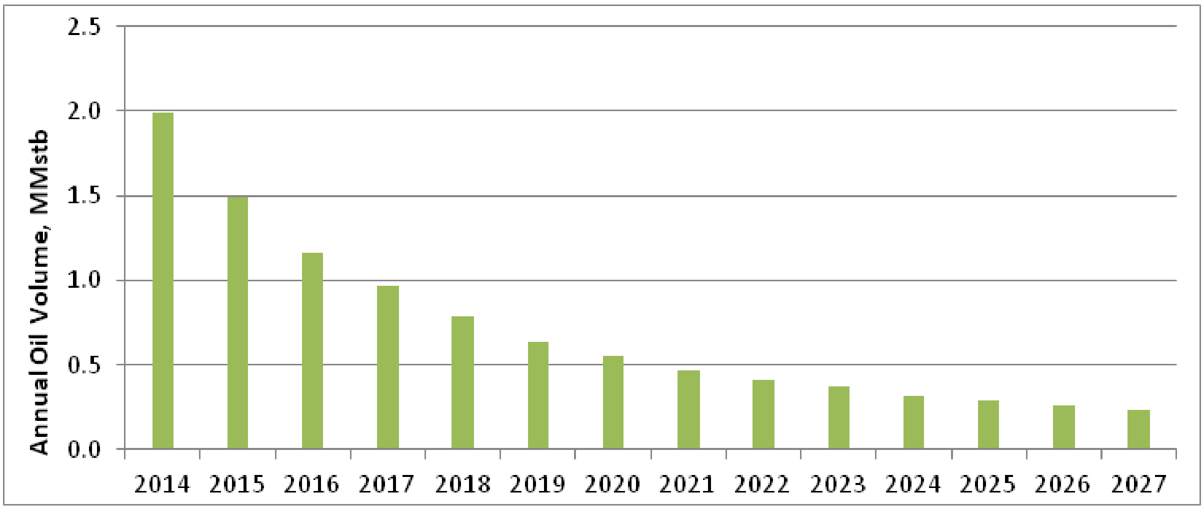


**Figure 5-3 Gross 2P Oil Production Forecast - Blane**

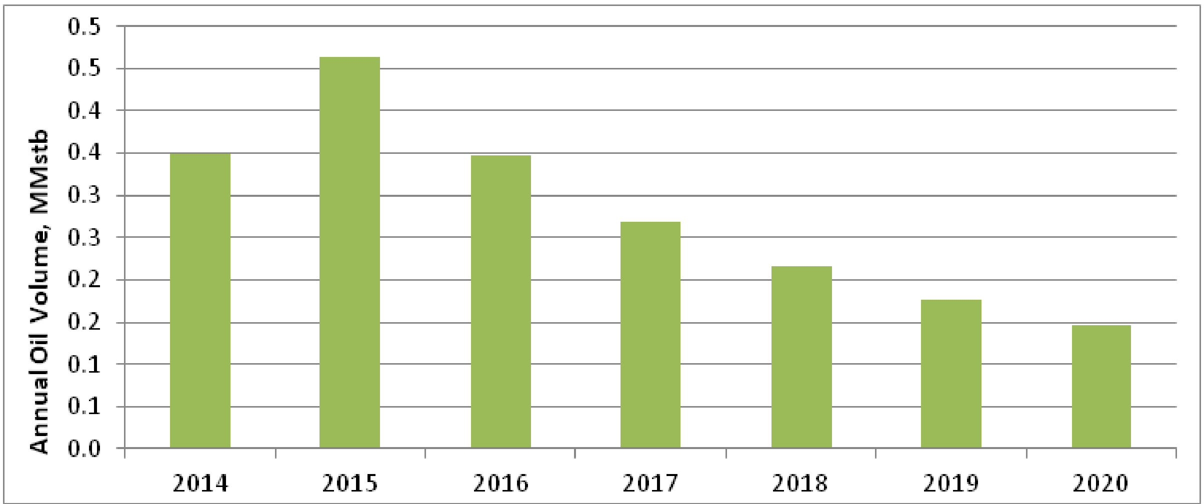


**Figure 5-4 Gross 2P Production Forecast - Enoch**

The Blane production forecasts assume no further development activities, therefore capital expenditure beyond 2013 is small. No capital costs are included in the 2014 budget, although previous years have had US$3-4 million for specific minor projects. We think it is prudent to allow US$0.8 million per annum until 2023 for minor Blane projects and associated project management.

Fixed base operating costs in 2014 are estimated to be US$9.1 million. However, there is also provision for scale squeezes and subsea tree maintenance in 2014 and every fourth year costing an additional US$6.4 million due to the ongoing issues experienced in these areas.

A significant proportion of operating costs are variable related to tariffs for use of the Ula platform (including processing, gas lift and water injection), transportation through the Ekofisk and Norpipe pipelines and processing and storage at the Teeside terminal. Figure 5-5 shows Roc's total gross 2P operating cost estimate for Blane.

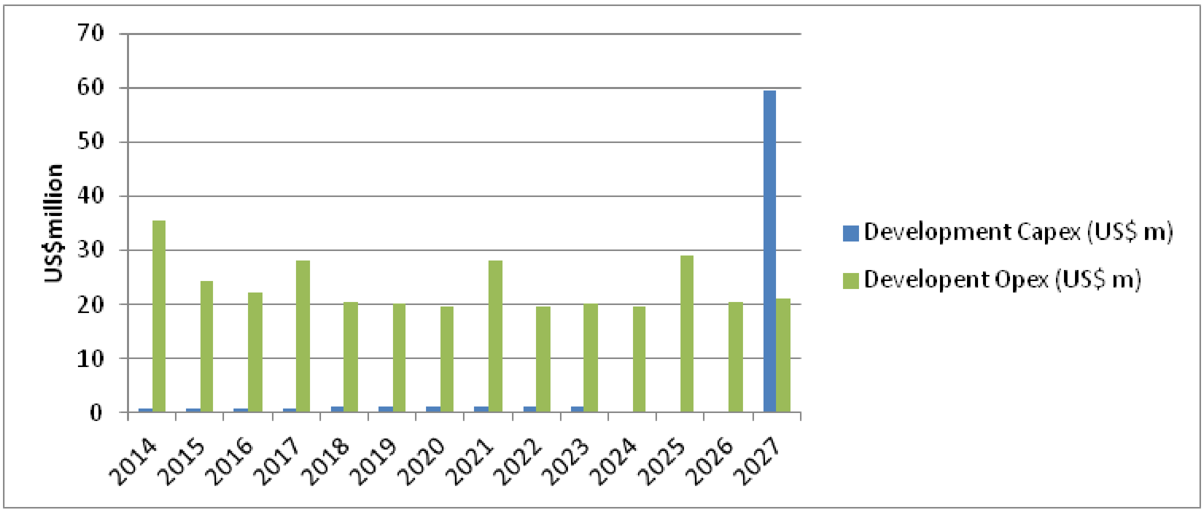


**Figure 5-5 Gross Operating Cost Forecast - Blane**

US$41 million (RT2014) has been allowed for abandonment of the Blane infrastructure in 2027/2028.

For Enoch, delays to the subsea tree replacement is estimated to have increase the AFE cost of £33.7 to £48.6 million, with £43.6 million spent as of March 2014. Following the subsea tree repair we anticipate minimal capital costs of less than US$0.8 million p.a. going forward associated with minor projects.

RISC estimates direct operating costs (excluding tariffs) of £1.3 million p.a. beyond 2014 with progressive reductions towards the end of field life. The majority of operating costs are related to costs associated with the host and export infrastructure - the Brae pipeline, platform (including gas and liquids processing, gas flare and gas lift) and Forties Production System pipeline tariff. The previous agreement regarding these tariff's has lapsed and a new agreement is currently being negotiated. The operator of the Brae field's (Marathon) has proposed new tariff's that range from unchanged for gas handling costs and pipeline costs up to 10 times increase for water handling costs. Currently the Enoch JV are in negotiations regarding this issue. We have assumed an increase tariff in adopting a mid point range from the previous tariff to the current proposal.

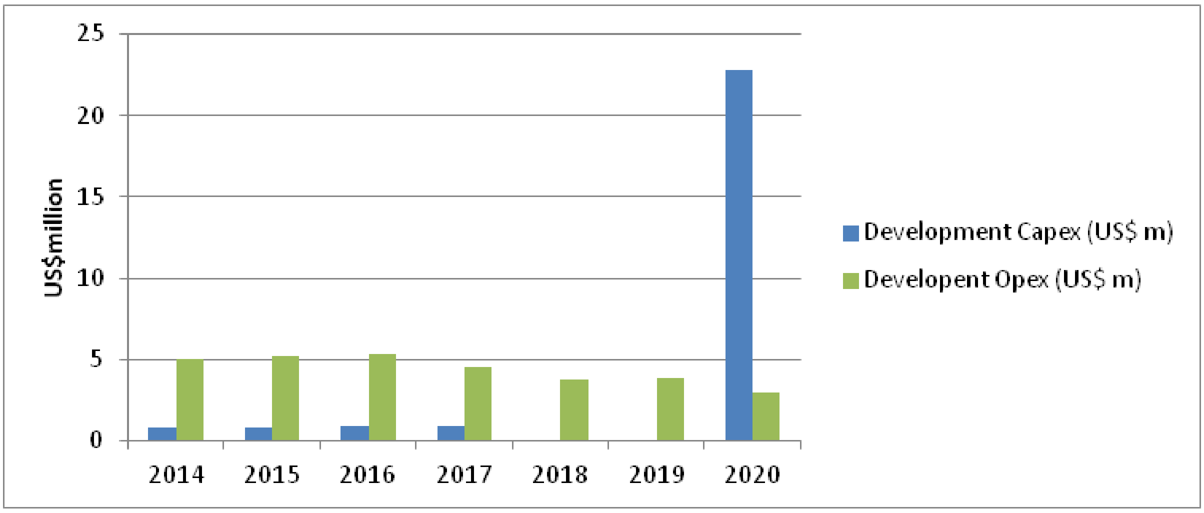


Figure 5-6 Gross Operating Cost Forecast - Enoch

US$19.5 million (RT2014) has been allowed for abandonment of the Enoch infrastructure in 2021.

## 5.3. RESERVES AND CONTINGENT RESOURCES

The Blane and Enoch reserves estimates are shown in Table 5-1.

| | 1P | 2P | 3P |
|---|---|---|---|
| Blane Gas Reserves Bcf | 0.4 | 0.7 | 1.2 |
| Blane Oil + NGL Reserves MMstb | 5.8 | 10.0 | 17.1 |
| Enoch Oil Reserves MMstb | 1.3 | 2.0 | 2.6 |

Table 5-1 Gross Reserves as at 1 January 2014 - Blane and Enoch

For Blane, from the period 1 January 2014 to 31 March 2014 there has been a further depletion of 426,038 bbl and 14.6 MMscf gross due to production. Cumulative production for Enoch to 31 December 2013 is 8.3 MMstb gross.

In addition, contingent resources have been identified (Table 5-2). The Blane infill well will target the crest of the structure and the current 'reference concept' is a sidetrack which could occur in 2015 with first production starting November 2015. Wells costs are estimated at about £60 million (100%). The project is currently in the operator's 'Select Phase' pending an investment decision later this year. With respect to life extension, there are no firm plans for these activities and we consider the value to be small.

| | 2C MMstb |
|---|---|
| Blane Field Life Extension | 0.9 |
| Infill Well | 4.9 |
| **Total Blane** | **5.8** |
| Enoch extended field life | 0.5 |
| **Total** | **6.3** |

Table 5-2 Gross 2C Contingent Resources at 1 January 2014 - Blane and Enoch

## 5.4. J1 DISCOVERY - BLOCK 16/13E (15% ROC)

The J1 gas condensate accumulation in Block 16/13e was discovered in 1984 by well 16/13a-2z (Figure 5-7). Resources are classified as contingent as there are no firm plans for development.

The well encountered gas bearing sands in the Hugin formation. The field is dip-closed to the west, north and south, but fault bounded to the east. It is mapped to straddle the UK/Norway border with an estimated GIIP split of 75% UK and 25% Norway. RISC has not had access to the seismic data and cannot independently verify the field mapping or this split, but it appears plausible based on an inspection of the Enterprise(Oil, 2002) report.

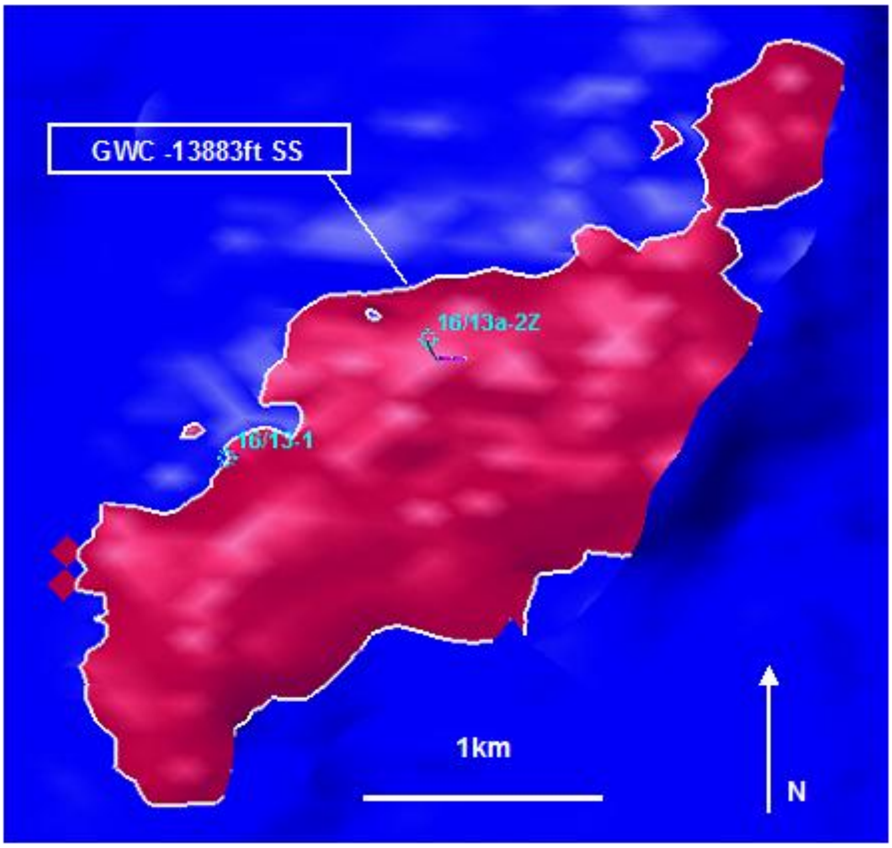


Figure 5-7 Field Outline - J1

Reservoir quality is good, with 98 ft net pay from a gross section of 127 ft. The well intersected a gas water contact at –13,883ft SS. Two DST's were performed and flowed 31 MMscf/d gas with 2,337 stb/d condensate and at 22 MMscf/d with 1,707 stb/d condensate. The well 16/13-1 encountered an oil-charged 5ft thick sand of Ryazanian age, which was tested and flowed a low gravity oil of 22-26 degrees API at a rate of 0.22 Mstb/d. RISC has reviewed the well test data, field evaluation and independently estimated the contingent resources shown in Table 5-3.

| | 2C |
|---|---|
| Gas (bcf) | 50 |
| Condensate (MMstb) | 1.0 |

**Table 5-3 2C Gross Contingent Resources Estimate at 1 January 2014 - 16/13e J1**

J1 development via a tie back to the Miller platform was initially suggested. However, the Miller field ceased production in 2007 and is in the process of being decommissioned. The Brae platform is an alternative host but has limited remaining life.

RISC estimate a low probability of development given the limited resource, lack of opportunity and activity to progress a development. Therefore, RISC assigns no value to this small 1984 discovery.

## 5.5. EXPLORATION

No further exploration potential has been identified

# 6. NEW ZEALAND

## 6.1. MAARI/MANAIA/MANGEHEWA

### 6.1.1. Field Description

The Maari and Manaia fields are located in PMP 38160 offshore New Zealand (shown in Figure 6-1), in which Horizon Oil holds a 10% interest. The fields are operated by OMV New Zealand Limited (OMV).

Production commenced in February 2009 and averaged 9000 stb/d in March 2014 from 6 production wells.


Figure 6-1 Maari and Manaia Field Location

Oil is produced via a well head platform to the FPSO Raroa in a water depth of approximately 100m. Following a refurbishment of the FPSO mooring and turret system in 2013, a major new project called the Maari Growth Project is underway. This project comprises:

- drilling of 2 new producers and 1 new injector in the Maari Moki reservoir and the conversion of 1 producer to a water injector
- drilling of 1 new producer in the Maari Mangahewa reservoir
- drilling of 1 new extended reach producer in the Manaia Mangahewa reservoir

The Maari Growth project anticipates increasing production to 20,000 stb/d gross by end 2014. It also aims to remedy problems with the water injection scheme, which has not generated the expected benefits and resulted in a reserves downgrade in 2013.

A structural section showing the location of significant reservoirs is shown in Figure 6-2.

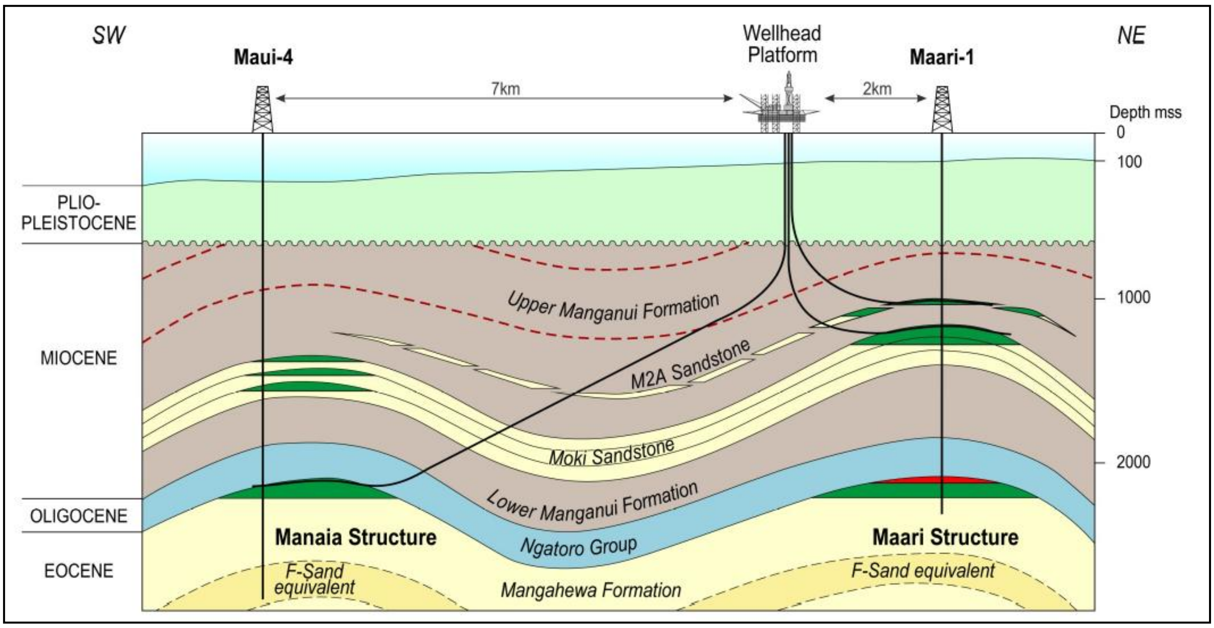


**Figure 6-2 Maari Manaia Structural Section (from Horizon)**

The Maari Field currently produces from the Moki and M2A sands, both of which were deposited as turbidites in the Miocene downwarping of the Taranaki Basin. Further oil is reservoired in the deeper Mangahewa Formation of the Kapuni Group, which was deposited in the post-rift thermal sag phase in the Eocene, which has been producing from the Manaia field.

A deviated well from the Maari platform has been drilled to the Mangahewa Formation of the Manaia field and is currently producing. There is further potential for oil in the Manaia Moki Formation; oil shows were observed during the drilling of the Maui-4 discovery well and further significant shows were intersected in the recent Manaia-2 appraisal well. The evaluation of these results is not yet complete and no resource has been assigned to this reservoir.

The Maari Field is covered by 3D seismic data acquired by Shell Todd in 1999. The data has been reprocessed several times, most recently in 2009 and is of fair quality, but has an area of poor data and a push-down underneath a gas cloud over the central part of the field, shown in Figure 2.3 below. The Operator (OMV) has acquired a new seismic survey over the field which is presently being reprocessed. It is expected that this will improve definition and aid in delineation well and development well locations and also lower the range on resource and reserve estimates.

The Moki reservoir provides the bulk of the production. The Operator's structure map at the Top Moki reservoir (Figure 6-3) is considered well-defined due mainly to the amount of well penetrations. The wells drilled to date have not encountered large depth issues. Faulting in this reservoir is minor.

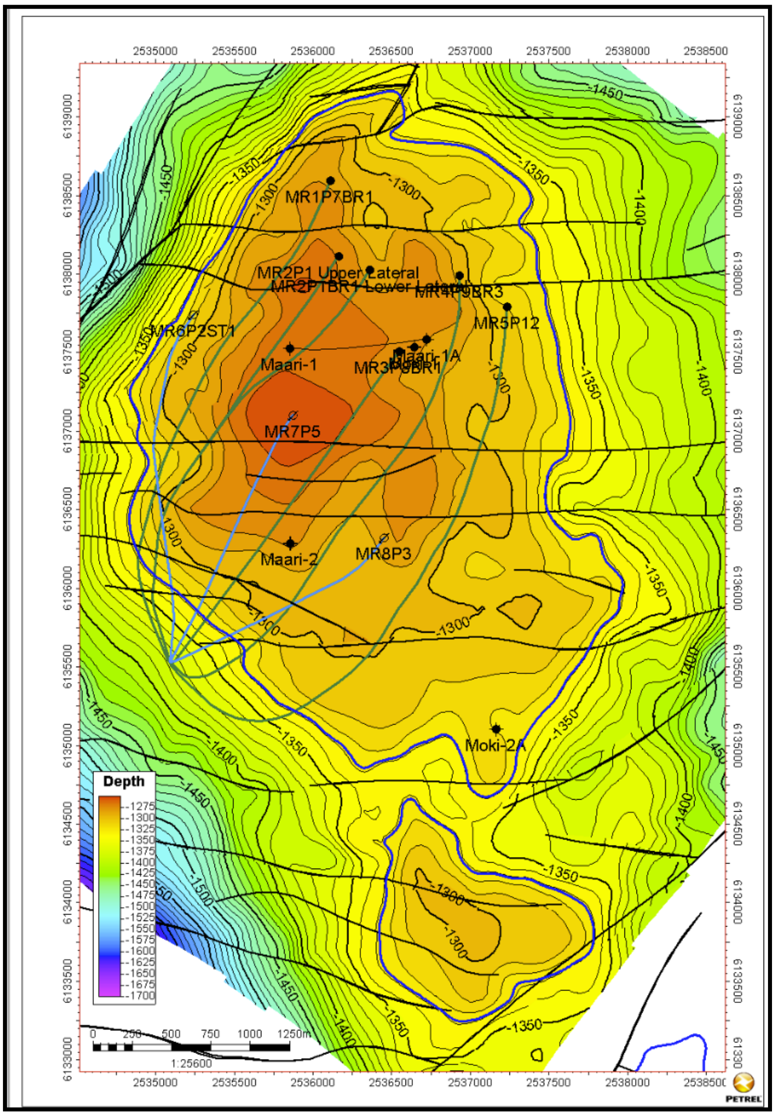


**Figure 6-3 Maari Moki Depth Map**

The Moki and M2A sands are deepwater turbidites deposited during the Miocene downwarping of the Taranaki Basin. The Moki contains seven fining-upwards depositional cycles of which the lower cycles are easily correlatable. However, the upper cycles display more lateral variation in deposition, possibly due to channel migration over subtle sea floor depth variations. The Maari Moki oil column is contained within the upper two cycles (separated by a thin shale).

The M2A sands appear to be a distal basin floor fan and are thinner and possibly less areally continuous than the Moki sands.

The deeper Mangahewa sands of the Kapuni Group were deposited in the post-rift thermal sag phase in the Eocene. The Mangahewa sands are fluvial in origin, leading to significant areal variations in reservoir quality.

RISC has estimated STOIIP ranges for the Maari and Manaia accumulations reservoir shown in Table 6-1.

| Reservoir | Low | Best | High |
|---|---|---|---|
| Maari Moki STOIIP (MMbbl) | 115 | 163 | 223 |
| Maari M2a | 21 | 27 | 34 |
| Maari Mangehewa | 9 | 14 | 20 |
| Manaia Mangehewa | 22 | 32 | 47 |

**Table 6-1 Maari and Manaia Field STOIIP Estimates**

Reserves are shown in Table 6-2. These are based on RISC's estimates as at 30 June 2013 updated for production.

| Field | Reserves (MMstb) | | |
|---|---|---|---|
| | 1P | 2P | 3P |
| Maari | 30.3 | 55.2 | 93.3 |
| Manaia | 2.4 | 4.3 | 7.2 |
| Total | 32.7 | 59.5 | 100.5 |

**Table 6-2 Gross Reserves as at 1 January 2014 - Maari and Manaia Fields**

Cumulative production to 31 December 2013 is 22.69 MMstb gross. From the period 1 January 2014 to 31 March 2014 there has been a further depletion of 883,000 bbl gross due to production.

RISC has also estimated a further 0.9 MMstb of contingent resources attributable for water injection on the Maari M2A reservoir (Table 6-3). We are not aware of any plans to progress this project.

| Reservoir | 2C (MMstb) |
|---|---|
| Maari M2A Water Injection | 0.9 |

**Table 6-3 Gross 2C Contingent Resources as at 1 January, 2014 - Maari M2A**

### 6.1.2. Production and Cost Forecast

RISC has reviewed and accepts the profile used by Horizon for the 2P production forecast for the Maari and Manaia fields which is consistent with our reserves estimates. OMV provided a short-term production forecast to account for planned downtime for maintenance and operations which has been incorporated. From 2015 onward, Horizon's 2P forecast reverts to the RISC Year-End 2013 2P forecast (Figure 6-4). Production is truncated in 2030, however there is still significant tail production beyond this period. There are no gas sales/reserves.

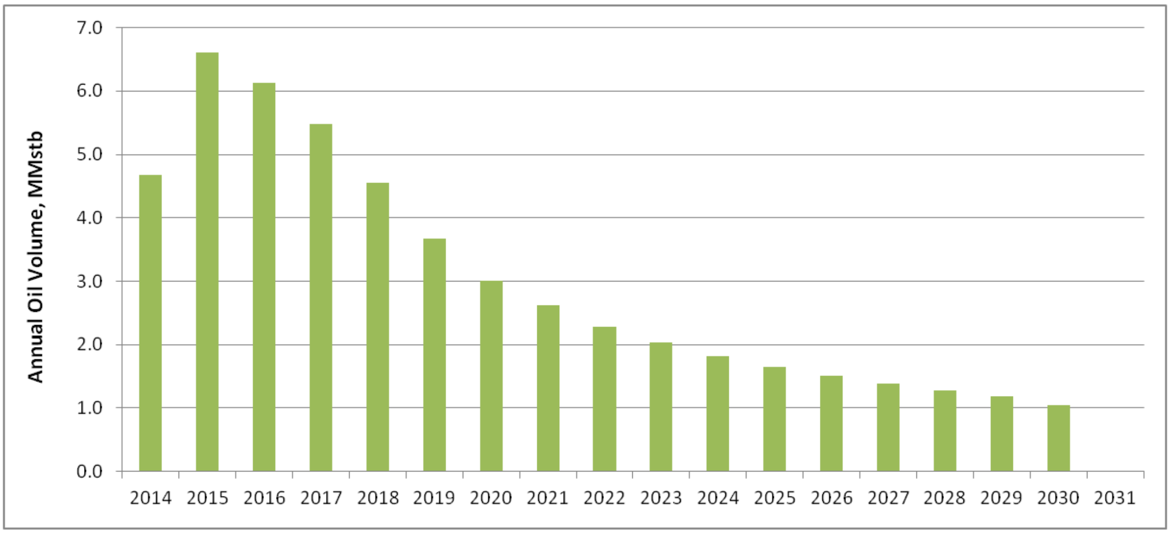


**Figure 6-4 Gross 2P Oil Production Forecast - Maari and Manaia**

Also considered is a 2P case with no benefit from the water injection at the Maari Moki field. This is a downside case where the water injection fails to boost oil production. Other than the Maari Moki upper reservoir, the rest of the production forecast is the same as the 2P case above. The net impact is 6.9 MMbbl over the forecast period.

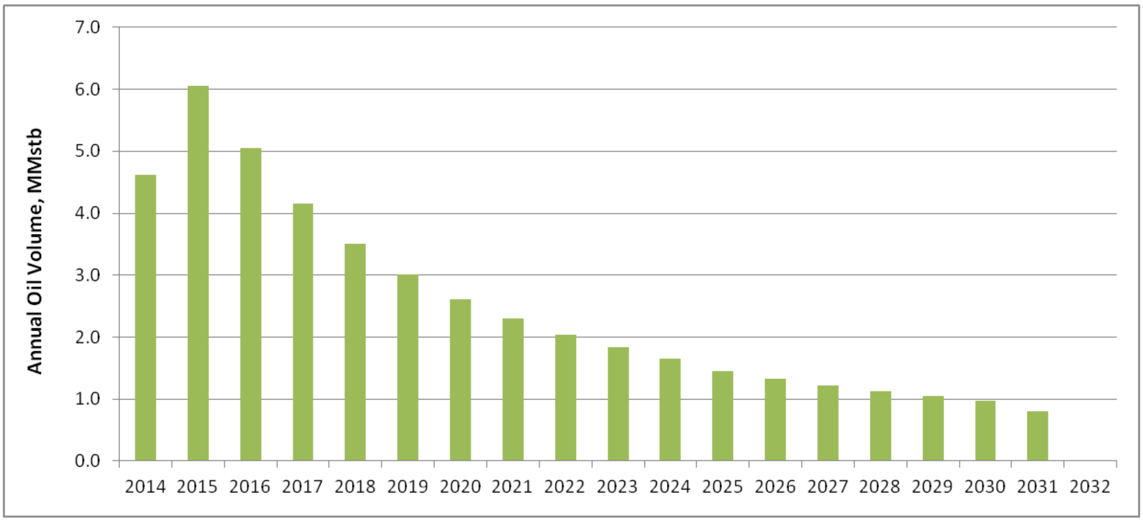


**Table 6-4 Gross Oil Production Forecast - No Benefit from Water Injection at Maari Moki Upper**

RISC has reviewed and accepted the cost profiles provided by Horizon in their economic model.

The Maari-Manaia development involves a not-normally manned wellhead platform housing the wellheads of the five production and three water injection wells, linked via subsea flowlines to the floating production, storage and offloading vessel ('FPSO') Raroa, anchored 1.5 km away. The production wells are lifted with downhole Electrical Submersible Pumps (ESPs). Because the ESPs need regular replacement, a workover rig is kept on the platform. Water is injected to maintain reservoir pressure.

Total gross capital costs consistent with the production forecast are anticipated to be NZ$341m (million) over the period 2014-16 (US$27m net to Horizon). RISC has categorised capital costs into development wells, major repairs/upgrade and appraisal.

Appraisal costs of NZ$42m were budgeted in 2014 for a Manaia appraisal well that was recently completed.

Development well costs of approximately NZ$280m are budgeted for 2 infill producers (Maari Deep, Maari Full field), 2 sidetracks (Moki Cycle 1 & Cycle 2) and 1 new well + recompletion for water injection.

The remaining capital costs are NZ$18m for the remaining capitalised FPSO lease, recompletions and 'Running the Business' costs.

Capital cost forecast 2014-16 is shown in Figure 6-5 below. Note these costs exclude any exploration activities. Abandonment costs are estimated at $70 million.

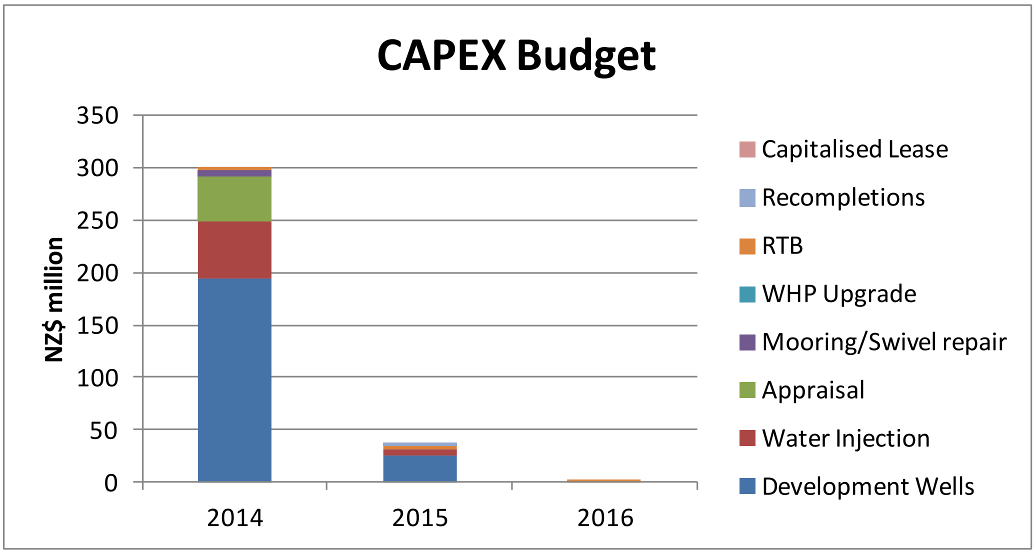


**Figure 6-5 Gross Capital Budget - Maari and Manaia Fields**

After 2014 the Operator forecasts operating costs (opex) to increase slightly before falling as production declines.

The major component of opex is the Operating fee, which is approximately NZ$42m in 2014. This is a largely contracted amount and therefore carries relatively little uncertainty.

The element of operating costs with the highest uncertainty is workover costs for ESP changeouts. The budget forecasts ESP workover costs of NZ$11-14m pa, reflecting an assumption of 3 workovers per year.

The operating cost budget to 2023, extrapolated to 2031 is shown in Figure 6-6 below. The exchange rate used was 0.8.

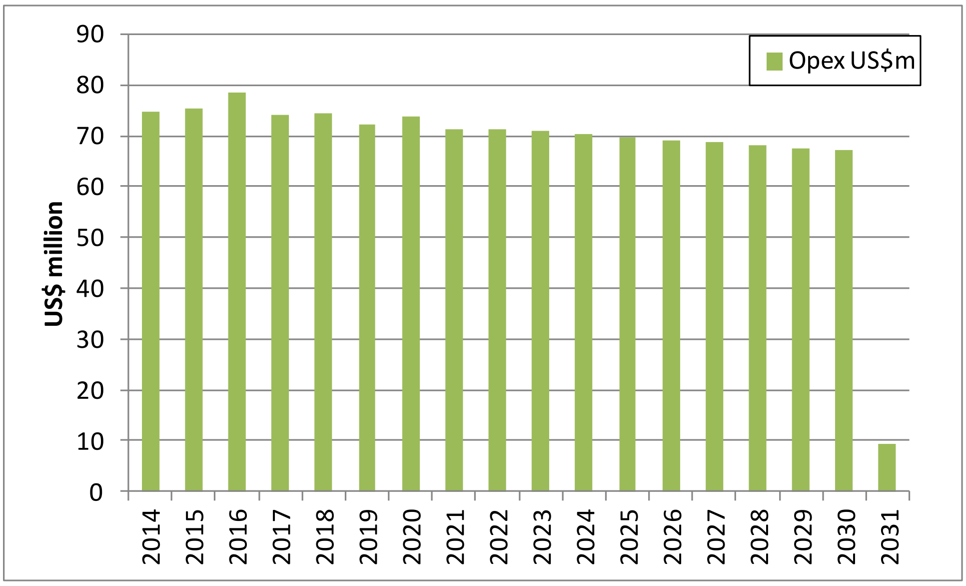


Figure 6-6 Gross Operating Cost Budget - Maari and Manaia Fields

## 6.2. EXPLORATION

Exploration potential exists in the Whio Prospect. This is a separate structure at both Moki and M2A reservoir level with further potential in the Mangahewa and deeper Farewell, Kaimiro and North Cape reservoirs.

OMV will be drilling this well as a farm-in, reducing Horizons interest from 21% to 10% to match the Maari and Manaia Fields in the event of a commercial discovery. Drilling is scheduled to commence in June 2014 at a budget cost of approximately $40 million gross.

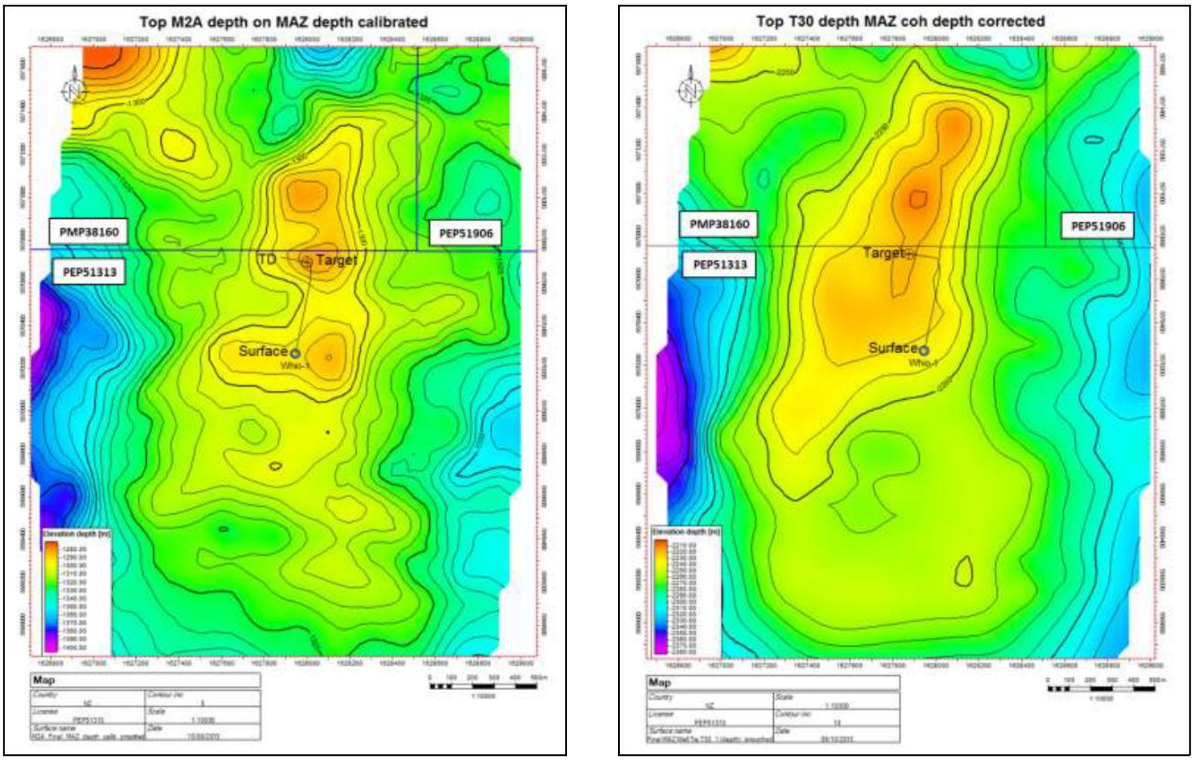


Figure 6-7 Whio Prospect M2A and Moki Depth Maps

The operator OMV calculates best estimate prospective resources of 15 MMbbl in the M2A, Moki and Mangahewa reservoirs.

These resource ranges have been checked by RISC and are considered reasonable.

If successful, Whio could be developed using a satellite well head platform, linked back to the Maari FPSO.

Gas volumes are significant, and we have assumed the gas is used for fuel or flared.

In the success case, Whio can be developed using 4 deviated wells, tied back to Maari field.

An initial rate of 15,000 bopd was based on initial rates from the analogue wells in the existing development. Gas volumes of 20 Bcf are assumed used for fuel, or flared.

The Mid Case production forecast for Maari 2P reserves plus Whio is shown below.

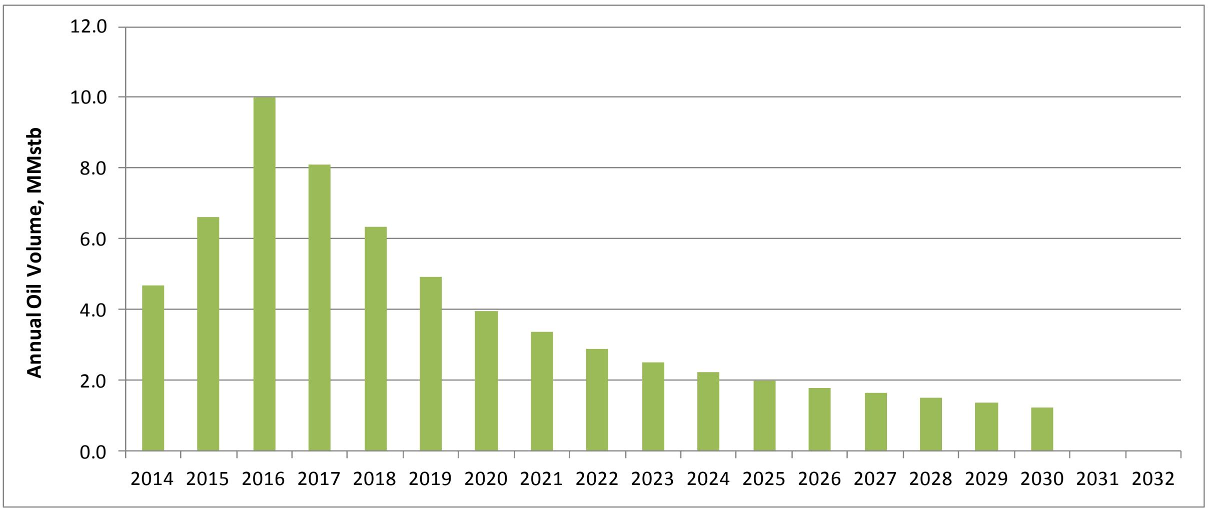


**Figure 6-8 Maari 2P + Best Estimate Gross Production Forecast - Whio Prospect**

The development is assumed to begin in mid 2014 with the drilling of an exploration well at a cost of US$40 million (fully carried). It is assumed that if the exploration well is successful the development could be approved in 2016. The construction, installation and tieback (via subsea pipeline to Maari WHP) of a new well head platform will occur in 2017 and 2018 and is forecast to cost US$100 million. The drilling of 4 horizontal development wells in 2018 is estimated to cost US$200 million ($50 million per well).

Fixed operating costs of US$14 million p.a. have been estimated based on support for an unmanned WHP and workovers every three years for the producing wells. Variable operating costs of $1/bbl are included. Abandonment is estimated to cost US$50 million for the development.

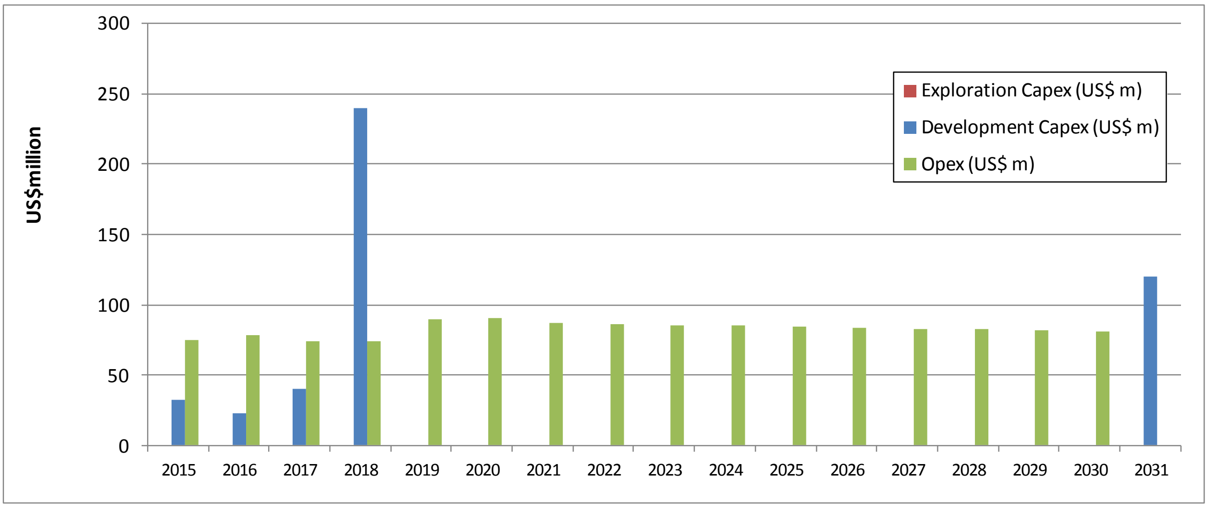


**Figure 6-9 Gross Capex and Opex - Whio Prospect**

In the low and mid cases, the permit value is based on the farmout terms with OMV in which OMV pays Horizon's 21% share ($8.4 million) to earn an 11% interest. This represents a promote of 1.9 valuing Horizon's interest at $7.6 million.

In the case of an unsuccessful well, the transfer of interest does not occur, we have assumed that for the high case the farmout could be duplicated valuing the interest at $15.2 million.

The EMV calculations indicate a value of $13.0 million for Horizon's 10% share which is comparable to the high case valuation.

# 7. CHINA PROPERTIES

## 7.1. BEIBU GULF

Roc’s and Horizon's interests are contained in the Beibu Gulf Area A and B. Roc holds a 19.60% interest and Horizon a 26.95% interest in the development and production assets. Interests in the exploration and appraisal phase are Roc 40% and Horizon 55%. The producing fields are WZ6-12 North, WZ6-12 South, WZ12-8 West and the non-producing fields WZ12-8 East and WZ 12-3 (Figure 7-1). The development and production assets are operated by CNOOC (51%). Upon declaration of commerciality of a development project, CNOOC has the right to back in for 51% and assume operatorship which has been exercised in the development and production assets to date.

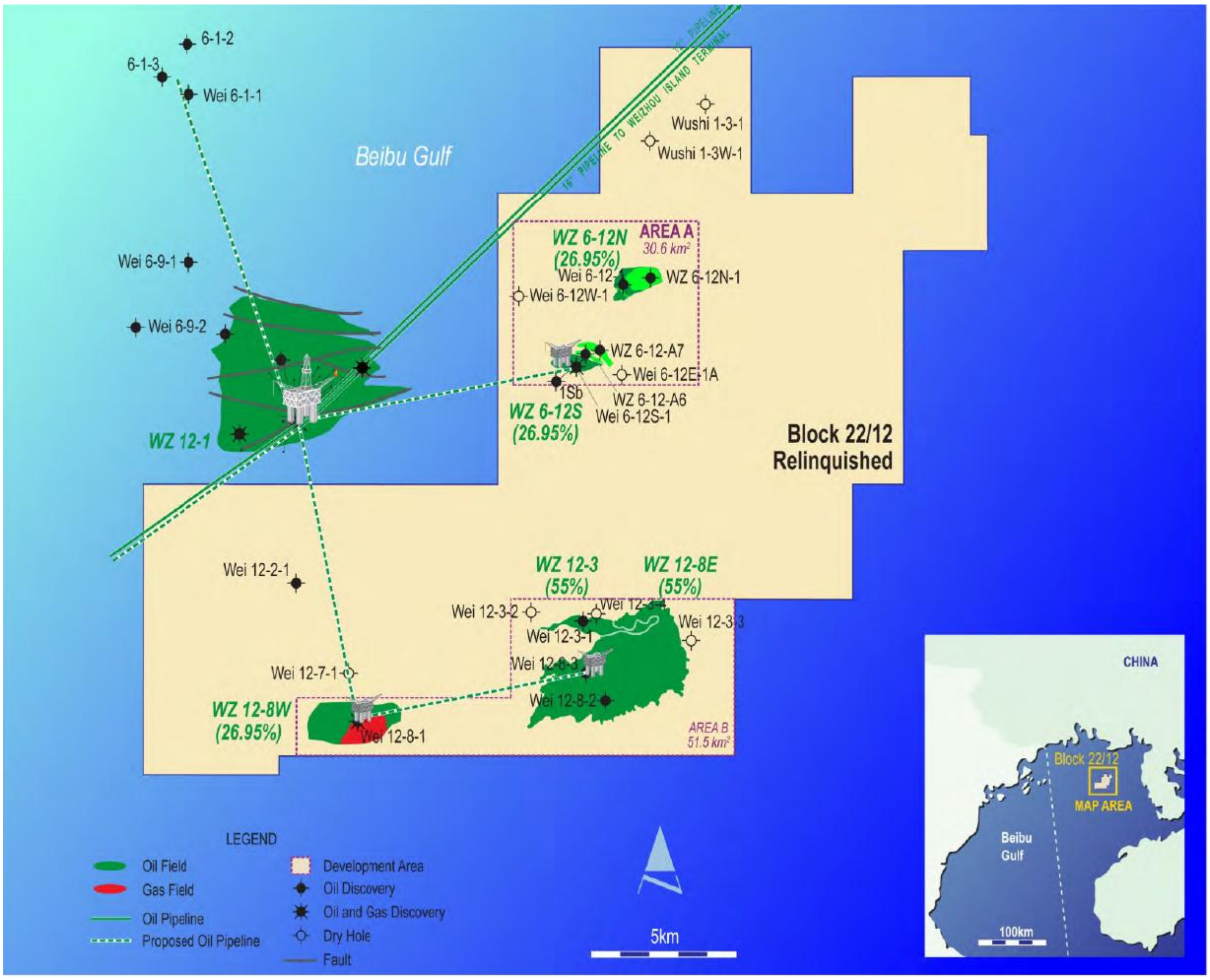


**Figure 7-1 Location Map – Beibu Block 22-12**

The Wei 6-12 oil field was discovered in 2002. An appraisal well on the Wei 12-8 East oil field drilled in 2004 confirmed the presence of oil but indicated that the oil was viscous so commercial development would not be straightforward. In 2006, the drilling of the Wei 6-12S-1 exploration well made a significant oil discovery which was appraised by four wells.

Following the formal end to the exploration period for Block 22/12 on 30 September 2008, the WZ6-12, WZ6-12 South and WZ12-8 West oil fields were declared development areas.

In 2010 CNOOC elected to participate for its full 51% share in the development, reducing Roc's and Horizon's share to 19.60% an 26.95% respectively. The Overall Development Plan (ODP) was completed in 2010 and following final CNOOC approval in January 2011 the joint venture proceeded to its Final Investment Decision in February 2011. CNOOC assumed operatorship of the project in 2Q11 and a CNOOC operating subsidiary company (Weizhou Operating Company) was established.

The Beibu Gulf development project was completed in 2013. Beibu first oil commenced in March 2013 with production reaching forecast rates. The development incorporates two remote wellhead platforms and one joint processing platform, which are connected by bridge to the CNOOC WZ 12-1A platform complex and utilise existing water injection and gas processing facilities.

The initial development phase targeting the WZ 6-12 North and South & Sliver Fields and the WZ 12-8 West Field is complete with 15 wells on production. Ten development wells were drilled from the WZ 6-12 platform and five development wells from the WZ 12-8 platform.

The two undeveloped oil accumulations in the retained development areas are WZ 12-8 East and WZ 12-3. Development feasibility studies are in progress.

### 7.1.1. Field Description

Oil contained in the fields is reservoired in Eocene-aged fluvial-lacustrine sandstones of the Luishagang Formation, Miocene-aged Jiaowei shallow marine sandstones and the Oligocene-aged Weizhou sandstones. Oil quality varies from light to heavy quality, low to high viscosity, with some waxy crude.

RISC has reviewed the reservoir mapping, geological modelling and volumetrics carried out by Roc and considers them to be reasonable. Roc's estimate of STOIIP, reserves and contingent resources are shown in Table 7-1 and Table 7-2. RISC has estimated the 12-8E contingent resources (Table 7-3).

| Field | STOIIP (MMstb) | | |
|---|---|---|---|
| | Low | Best | High |
| WZ 6-12 North | 25.8 | 30.5 | 36.2 |
| WZ 6-12 South and Sliver Block | 23.2 | 28.0 | 30.3 |
| WZ 12-8 West | 19.5 | 26.2 | 27.7 |
| W 12-8 East (incl. 12-3) | 68.5 | 84.7 | 94.2 |
| Total | 137.0 | 169.4 | 188.4 |

**Table 7-1 Discovered STOIIP as at 1 January 2014 - Beibu Gulf**

| Field | Reserves (MMstb) | |
|---|---|---|
| | 1P | 2P |
| WZ 6-12 South and Sliver Block | 7.1 | 8.9 |
| WZ 6-12 North | 8.7 | 10.1 |
| WZ 12-8 West | 4.1 | 5.4 |
| Total | 19.9 | 24.4 |

Table 7-2 Gross Reserves as at 1 January 2014 - Beibu Gulf

| Contingent Resources | 2C (MMstb) |
|---|---|
| WZ 12-8 East (incl. 12-3) | 11.5 |

Table 7-3 Gross 2C Contingent Resources as at 1 January 2014 - WZ12-8E RISC Estimate

Cumulative production to 31 December 2014 was 3.0 MMstb. From the period 1 January 2014 to 31 March 2014 there has been a further depletion of 1.2 MMbbl gross due to production.

**WZ12-6-12 North Field**

The field consists of stacked pay in the T30, T31 and T32 units. WZ 6-12-1 discovered the WZ 6-12 North Field in March 2002. The trap is a fault sealed structure with dip closure to the west, Figure 7-2. The well intersected 13.5 m of excellent quality net oil pay in the Weizhou T31C sand but was not tested. The follow up WZ 6-12N-1 vertical exploration well in October 2012 intersected 9.5 m of gross oil pay in the T31C and 33.7 m of gross oil pay in the T32L. Also 13.5 m of gross oil pay was intersected in the shallower T30D sand.

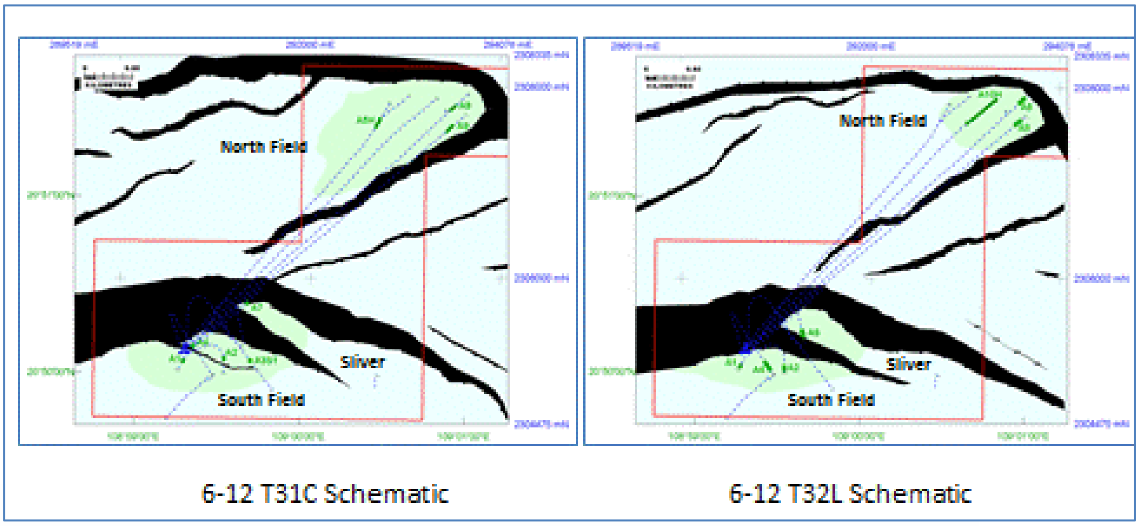


Figure 7-2 Well locations and schematic North, South and "Sliver" Block Field Areas

**WZ12-6-12 South Field and "Sliver "Block**

The WZ 6-12S discovery was made in May 2006, approximately 3 km southwest of well WZ 6-12-1. The WZ 6-12S-1 well, discovered over 70 m of net pay, mainly oil, in multiple sands of the Weizhou Formation. Gas was found in two thin sands. The trap is a hanging wall rollover structure, approximately 2 km long and 1 km wide, against an arcuate east-west trending fault, Figure 7-2. Faulting has created two structural provinces within the field that have been named "South Block" and "Sliver" Block".

Adjacent to but not part of the interpreted WZ 6-12 South Field lies a separate interpreted fault related high which is designated the "Sliver" Block This prospect was matured by the Foreign JV for exploration drilling via a well drilled from the WZ 6-12 Wellhead Platform (WZ 6-12-A7).

Well WZ 6-12A-6 intersected oil pay in the T30D and T31U in the South area and in the T 32L in the "Sliver" area. The hydrocarbon type within the T30 A is uncertain and the T30B is gas bearing. The T31C is thin and is interpreted to be fault affected.

Well WZ 6-12-A7 intersected oil pay in the T31C and T32U sands in the northern part of the "Sliver" Block. The upper sands (T30 to T31U) were faulted out at this location, as were the T32 L sands. The T31C sand with 6 m of gross oil-bearing sand is interpreted to be in reservoir continuity with the thin T31C sand intersected in well WZ 6-12E-1A. Brightening of T31C seismic amplitudes downdip of the A-7 well suggests the presence of thicker reservoir development. WZ 6-12-A7 intersected 26.5m of gross sand and 2.3 m of net oil pay in the T32U sand. A limited MDT run (restricted by hole condition) was conducted in A7 with sampling of one zone.

Figure 7-3 is a well cross section showing the correlation and continuity of reservoir units within the South Field and Figure 7-3 is a schematic cross section showing the structural relationship between the South Field, "Sliver Block" and North Field.

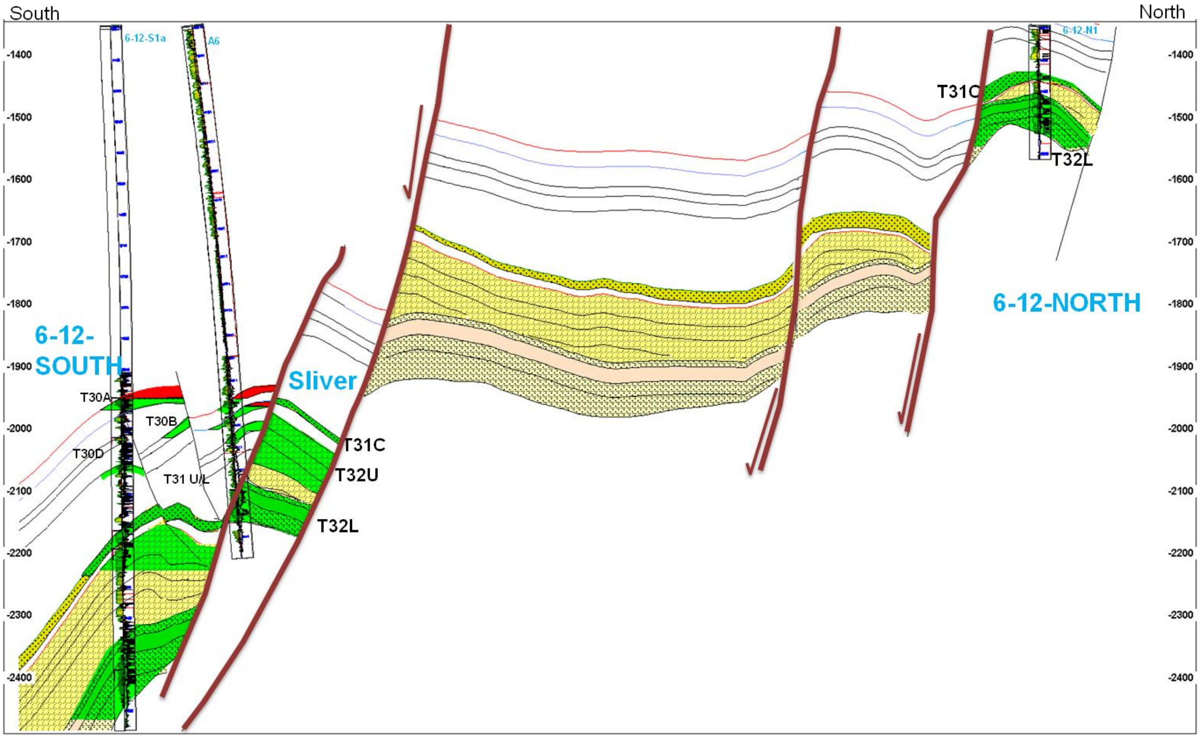


**Figure 7-3 Structural relationship of WZ 6-12 South, "Sliver" and North Fields**

Roc has estimated initial OOIP using the Petrosys mapping software (at 1P, 2P and 3P levels of confidence) and Petrel 3D geological modelling software (2P only). RISC has reviewed Roc's Petrel

RE model which is based on a single geological realization using a stochastic distribution of properties and is satisfied that the model represents a reasonable “most likely” realization of the subsurface geology.

**WZ12-8 West**

The WZ 12-8 West field was discovered by the WZ 12-8-1 well drilled in 1993. The well encountered a 12 m net oil column and a 2 m overlaying gas column within the Jiaowei Formation. Four DSTs were run and a series of RFT sampling and measurements were conducted. The well free flowed 1300 barrels per day of 21 degree API oil with 2.1 MMscf/d of gas on test.

Development drilling was undertaken during 2013. This programme included an initial pilot hole, WZ 12-8-A1P, which penetrated the entire reservoir sequence and acquired conventional core over the lower portion of the J2 reservoir. Subsequently five horizontal reservoir sections were drilled in an east to west direction.

Confidence in the latest mapping is provided by the seismic amplitude anomaly shown as yellow to red colour fill in Figure 7-4 which generally conforms closely to the structural limits of the oil pool (the green polygon marks the depth of the OWC at -953 mTVDss and the red polygon marks the GOC at -943.5 mTVDss). These amplitudes continue to the east and are interpreted by Roc to identify a continuing migration route from west to east. RISC notes that anomalous amplitudes can be caused by lithology variation and tuning effects (reservoir thinning) in addition to hydrocarbon saturation.

The only fault of any significance for the J2 reservoir is the southern boundary fault. No internal faults of any significance are mapped and production compartmentalisation caused by faulting is not anticipated.

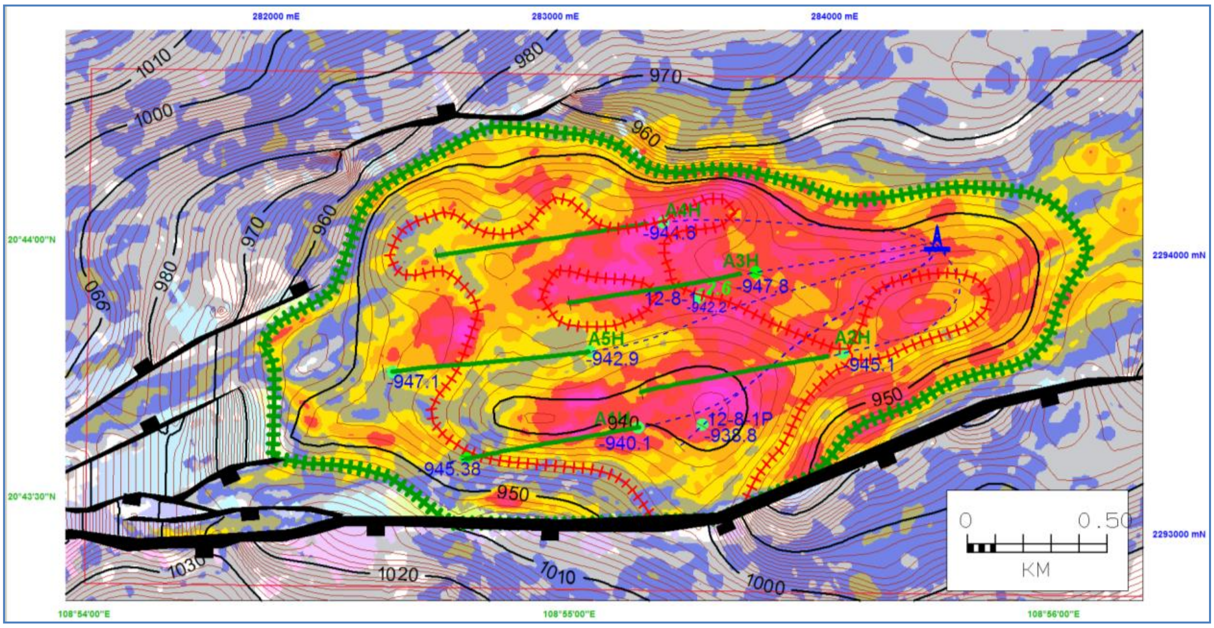


**Figure 7-4 Final well tied top J2 reservoir depth structure map (post development drilling)**

### WZ12-8 East (incl 12-3)

The WZ12-8 East Weizhou oil accumulation was discovered in 1982 by Wei 12-3-1. The well was a combined structural test of the Middle Miocence Jiaowei Formation and stratigraphic test of an interpreted lower Weizhou Formation pinchout upon Basement. A single 11.5 m oil bearing Weizhou sand was encountered (net oil pay 9.8 m). The Jiaowei sands were encountered water bearing and outside of structural closure.

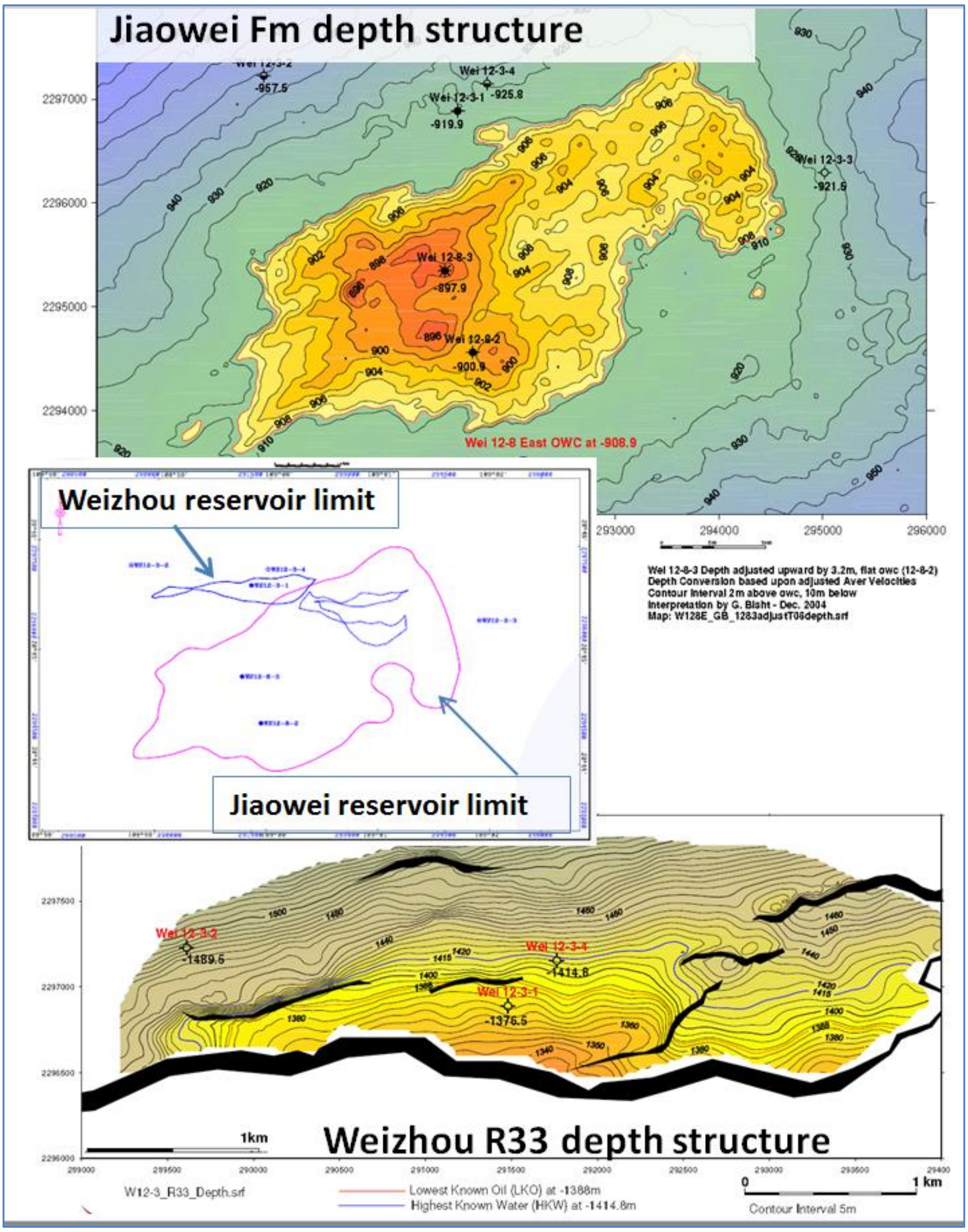


**Figure 7-5 WZ12-8 East reservoir depth structure maps and field limits**

A drill stem test of this sand flowed oil at a maximum rate of 1380 bopd on a 48/64" choke. The oil contained only minor solution gas at 56 scf/stb. The oil has a gravity range of 32.7 to 33.9 degrees API and a wax content of 18.9 to 22.3%. The pour point is 30 to 32 degrees Celsius. The Wei 12-3-1 crude is very similar in nature and quality to the Weizhou oil under production in the Wei 12-1 oilfield and is characteristic of Eocene Liushagang generated oil. The Weizhou oil is volumetrically small, with a best estimate STOIIP of 3.4 MMstb.

The vast majority of the oil is contained in the Jiaowei reservoir which was discovered in 1994 when the WZ 12-8-2 well intersected an 8 m oil column at a depth of 930.5 m within highly porous and permeable, shallow-water marine sands. The well tested 2295 bopd of 21 degree API oil from the interval 931 – 935 m with artificial lift provided by ESP. Unlike the deeper Weizhou accumulation, the Jaiowei trap is relatively simple and is defined by 3D seismic as a simple, unfaulted four way dip closure, as shown in Figure 7-5 (upper map).

### 7.1.2. Production and Cost Forecasts

Roc has based the 2P production forecast on the RISC Year End 2013 2P reserves forecast. We have reviewed this and agree with the forecast. 2P oil production and related cost for Beibu WZ6-12 North, South and 12-8 West are shown below.

As WZ 6-12 and 12-8W fields are already developed, capital costs from 1 Jan 2014 will be minor. There are US$3m each for 6-12 and 12-8W in 2016 for minor upgrade works.

The Operator forecasts operating costs to plateau are approximately US$50m p.a. in the early years of production. Initially approximately 50% of operating costs are tariffs for processing and transportation through CNOOC owned facilities, though this declines as production declines. Fixed costs are approximately US$20m pa and up to US$10m pa is allowed for workovers to change out the ESPs. We are in agreement with the operating costs in Roc's economic model.

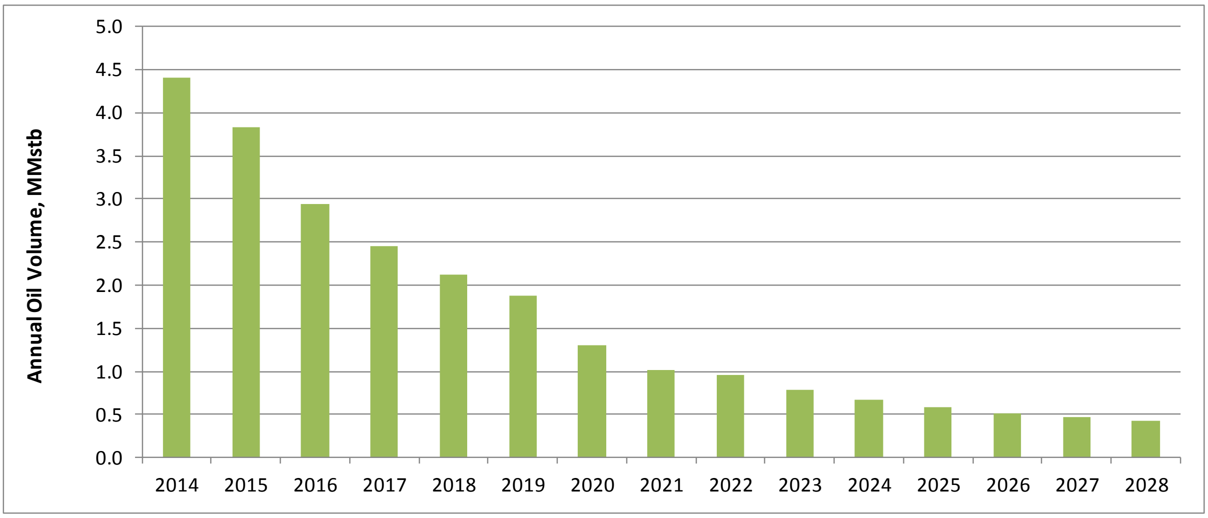


**Figure 7-6 Gross 2P Oil Production Forecast - Beibu WZ6-12 N, 6-12 S and 12-8 W**

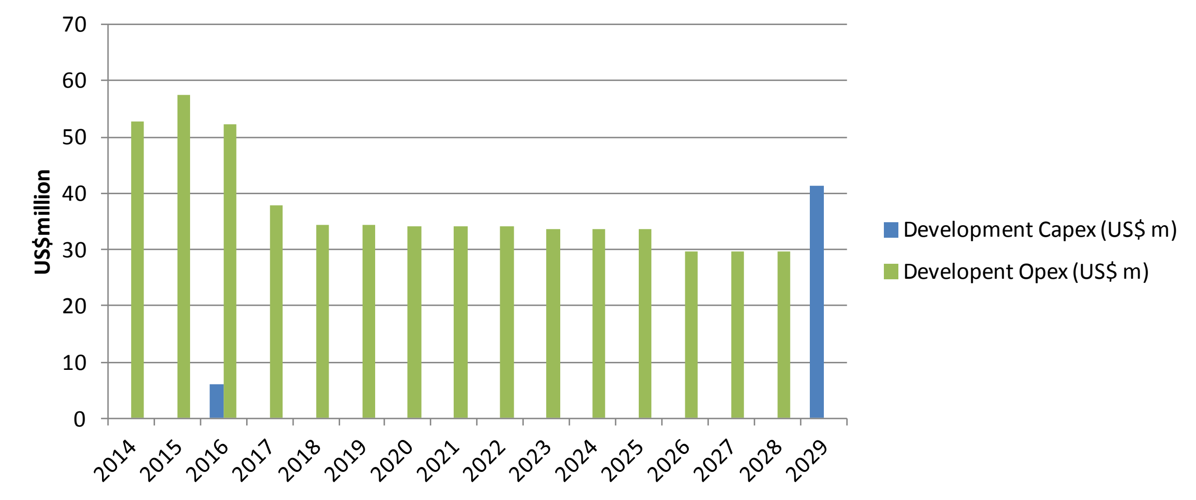


Table 7-4 Gross 2P Cost Forecast - Beibu WZ6-12, 6-12 S and 12-8 W

### 7.1.3. 12-8 East Proposed Development

The development plan is under study by CNOOC. RISC has reviewed the results of CNOOC's reservoir simulation studies and considers them to be reasonable and in line with analogue fields. The current JV concept is a phased development of 4 initial wells that include elements of appraisal followed by 3 wells based on results. The concept targets 5.4 MMstb of Contingent Resources. We have adjusted development plan and forecasts to be in line with Roc's STOIIP estimates which is a potentially larger development. We have prepared a development concept based on this larger scheme.

RISC has assumed the Weizhou reservoir to be developed by 1 horizontal well with 13 horizontal wells in the Jiaowei reservoir.

The WZ12-8E development is currently categorised as Contingent Resources. RISC estimates the total oil production over the 20 year forecast period is 11.5 MMstb. Figure 7-7presents the forecast of the combined 2P+2C oil production.

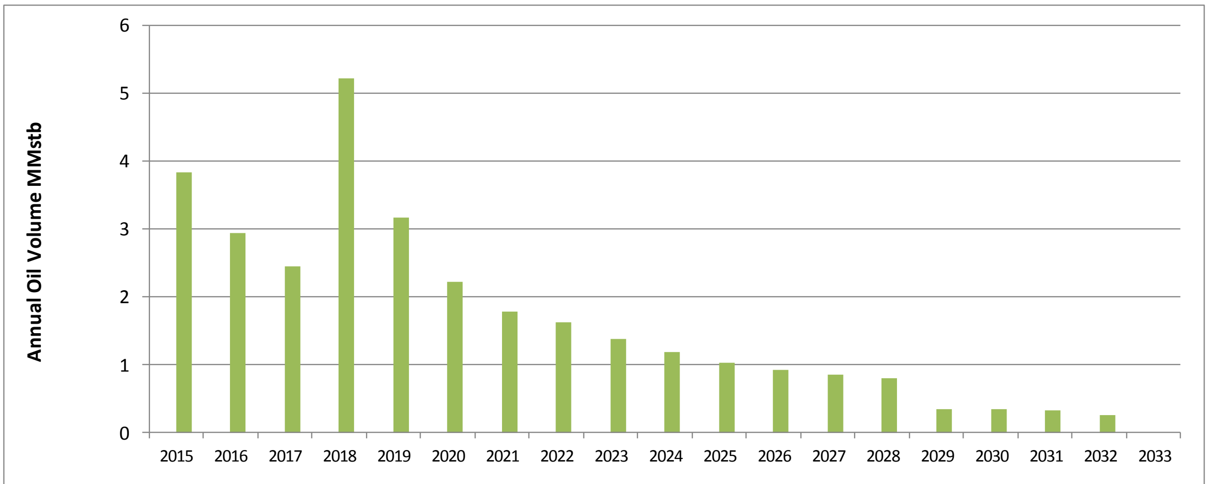


Figure 7-7 Gross 2P+2C Gross Production Forecast – 2P Plus WZ12-8E

It is assumed the development could be approved in 2016. The construction, installation and tieback (via subsea pipeline to WZ-128W WHP) of a new well head platform will occur in 2016 and 2017 and is forecast to cost US$45 million. The drilling of 14 horizontal development wells in 2017 is estimated to cost US$168 million ($12 million per well).

Fixed operating costs of US$24 million p.a. have been estimated based on support for an unmanned WHP and workovers every three years for the producing wells. Variable operating costs according to the Beibu production agreement tariff's are included.

Abandonment is estimated to cost US$38 million for the development. Figure 7-8 presents the cost forecast.

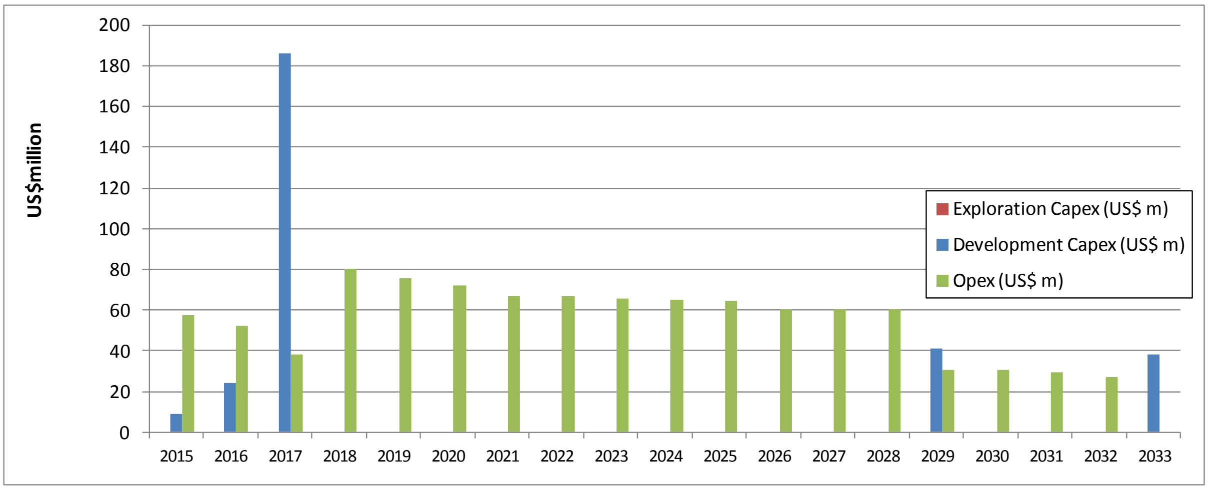


**Figure 7-8 2P+2C Cost Forecast – 2P Plus WZ12-8E**

### 7.1.4. Exploration

The joint venture is evaluating the drilling of 2 prospects (Figure 7-9). A well needs to be drilled to retain the exploration interests in the block.

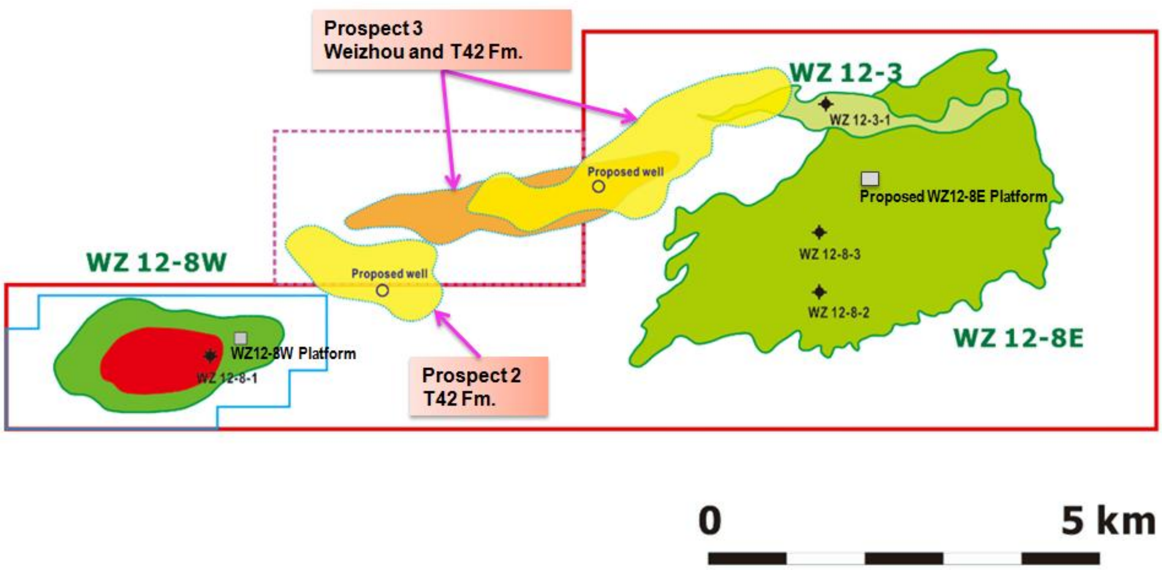


**Figure 7-9 Beibu Gulf Exploration Prospects (subject to approval of license boundary extension shown in dotted red line)**

Prospect 3 is targeting Weizhou and T42 level sands with an aggregate oil in place estimate of 24 MMstb gross. The main Weizhou has a POS of 32% estimated by Roc. Prospect 2 has mapped potential in-place resources of 6 MMstb at the T42 level and has a POS of 9% estimated by Roc.
RISC has not reviewed the volumetrics and mapping. We have prepared a conceptual development of Prospect 3 for evaluation of potential value. We have estimated prospective resources of 5 MMstb gross for this prospect subject to a license boundary extension.

**Prospect-3 Proposed Development**

The development of Prospect-3 is assumed to begin in 2015 with the drilling of an exploration well at a cost of US$8 million. This will be followed up with an appraisal well in 2016 if successful at a cost of US$10 million.

It is assumed the development could be approved in 2017. The construction, installation and tieback (via subsea pipeline to WZ-128W WHP) of a new well head platform will occur in 2018 and 2019 and is forecast to cost US$45 million. The drilling of 5 horizontal development wells in 2019 is estimated to cost US$60 million ($12 million per well).

The production forecast for  Block 22-12 2P + 2C + Prospect-3 is given below.

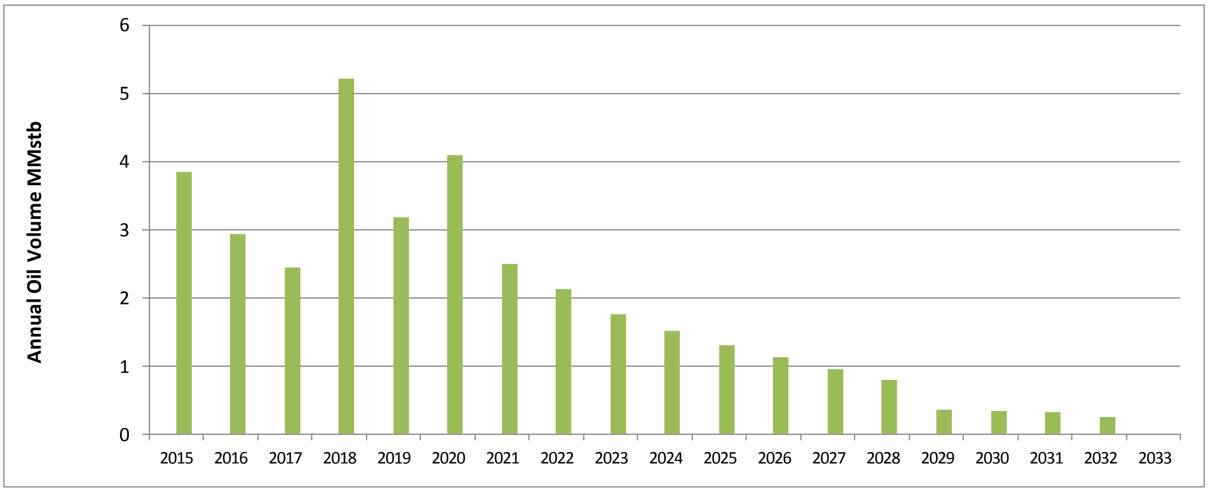


Figure 7-10 Gross Production Forecast: 2P Plus 2C Plus Prospect-3

Fixed operating costs of US$24 million p.a. have been estimated based on support for an unmanned WHP and workovers every three years for the producing wells. Variable operating costs according to the Beibu production agreement tariff's are included.

Abandonment is estimated to cost US$20 million for the development.

Figure 7-11 presents the cost forecast.

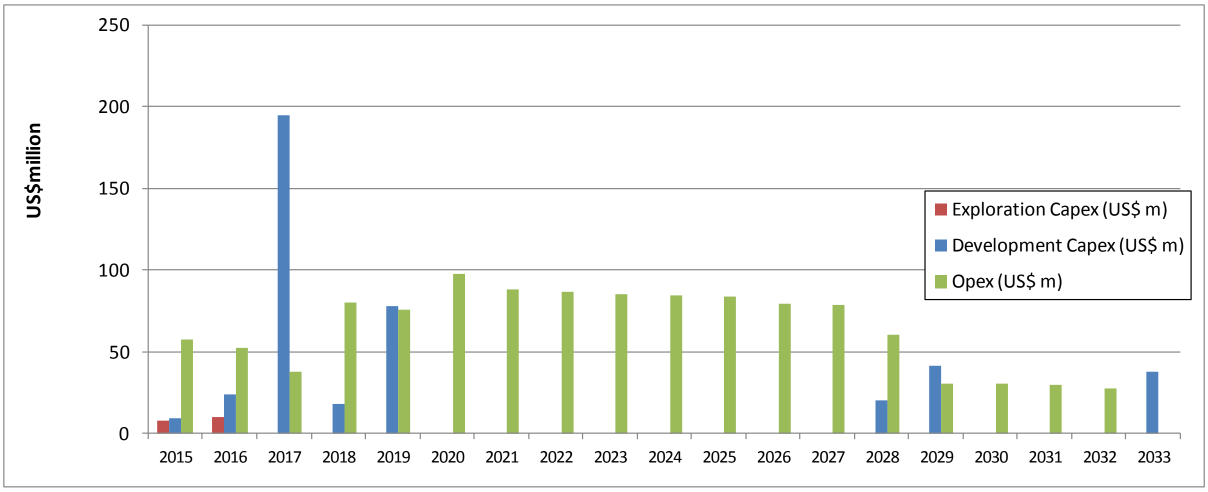


**Figure 7-11 Cost Forecast 2P + 2C + Prospect-3**

For the mid case valuation, we have assumed that an $8 million exploration well ($4.4 million and $3.2 million net working to interest to Horizon and Roc respectively) could be farmed out on a 2:1 promote. In the high case, we have assumed a 2 well option including Prospect-2. In the low case, we have assumed no farmout premium. The values for each company are summarised in Table 7-5.

| Company | Low<br>US$ million | Mid<br>US$ million | High<br>US$ million |
|---|---|---|---|
| Horizon (55%) | 0.0 | 4.4 | 8.8 |
| Roc (40%) | 0.0 | 3.2 | 6.4 |

**Table 7-5 Beibu Gulf Exploration Fair Market Value - Net Horizon and Roc Working Interest**

## 7.2. BOHAI BAY

Roc's interests in the Bohai Bay are in the Zhao Dong Block, Zhanghai and Chenghai Blocks and the exploration block 09/05, Figure 7-12. Roc's interest are as follows:

**Zhao Dong Block**

- Development interest of 24.5% in the Zhao Dong field development incl. C &D fields
- Unitised interest of 11.667% in C4 field development
- 50% exploration interest

**Zhanghai & Chenghai Blocks**

- 39.2% interest

**Bohai Block 09/05**

- 100% interest

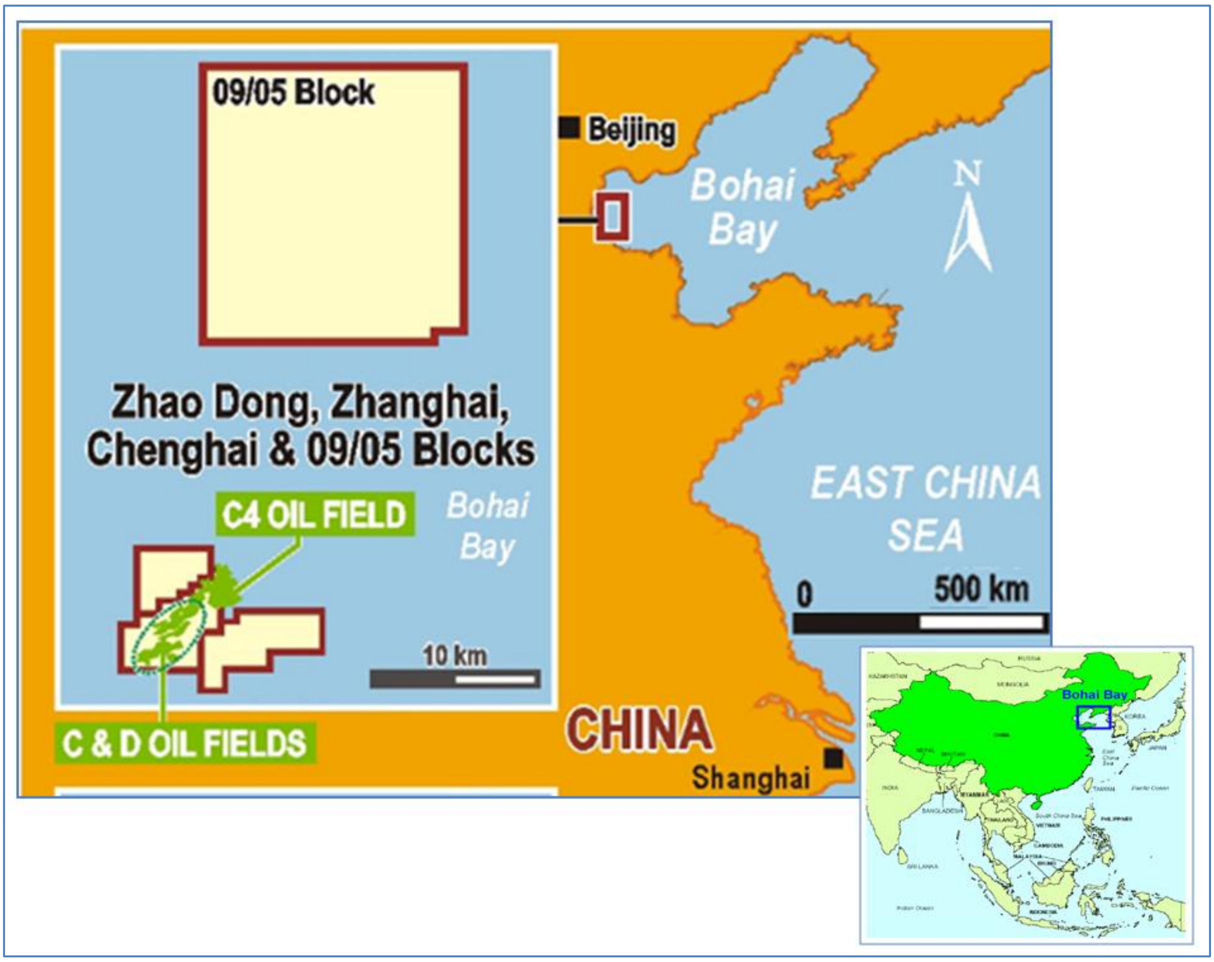


**Figure 7-12 Location Map – Bohai Bay**

Roc acquired a 24.5% operated interest in the ZD Block in mid-2006 via the acquisition of 100% of the shares of Apache China Corporation LDC. The ZD Block contains the C&D fields which commenced production in 2003 and part of the C4 field. At the time Roc acquired the asset, approximately 20 MMstb of oil had been produced from the C&D fields.

The fields are currently producing and undergoing simultaneous continuous development. Since acquiring the asset, the Roc-led joint venture has drilled over 120 development wells in the block, installed two platforms adjacent to the existing Zhao Dong platforms and installed new facilities at C4. The gross production in March 2014 averaged 16,200 bbl/d of oil and 8.6 MMscf/d of gas (3.2 MMscf/d sales).

In March 2011, the existing Petroleum Contract covering the Zhao Dong Block was modified to include the adjacent Zhanghai and Chenghai Blocks with the aim of commercialising previous near field discoveries in the area and encouraging further exploration activity. Any potential commercial development in the blocks would utilise the existing Zhao Dong facilities. The term of the Zhao Dong Contract and Production Period will be extended when and as necessary to accommodate any new production from the additional blocks.

On 11 May 2012, Roc was awarded a 100% operated interest in the new exploration block 09/05 offshore Bohai, located approximately 15km north of Roc's Zhao Dong block. The minimum work commitment for the first phase of the exploration period includes 3D seismic acquisition and the drilling of exploration wells.

In October 2013, Roc successfully completed the 162km$^2$ 3D ocean bottom cable (OBC) seismic campaign in the 09/05 exploration licence. Seismic processing has commenced and will assist in high grading the prospect inventory, in preparation for commencement of early exploration drilling.

Roc has signed a farmout option agreement with Horizon Oil (Beibu) Limited (HZN). Under the terms of the agreement Horizon will pay 40% of all petroleum exploration costs incurred until the exercise or lapse of the option, which entitles Horizon the right to farm into a 40% working interest in Block 09/05. In advance of spudding the first exploration well Horizon can exercise the option to acquire the 40% interest by paying a 2 for 1 promote on two exploration wells. In light of the proposed merger with Roc, Horizon has elected not to exercise the option.

### 7.2.1. Field Description

The Bohai Bay is a prolific oil producing province with stacked reservoirs system, ranging in age from Palaeozoic to Tertiary. Reservoir quality is good to excellent. The source rock is rich and generative. The Zhao Dong Block is extremely oil prone and oil is generally found wherever a suitable trap exists. Within the block, 27 different stratigraphic levels are known to contain oil; 16 of these are currently productive. Oil is waxy with a low pour point and a low acid content.

The Zhao Dong C/D Fields and the C-4 Field, (Figure 7-13) comprise a large number - some 150 - separate oil pools, with over 20 different productive reservoir horizons and sands having been shown to contain mobile oil and gas. In many cases, individual pools are segmented by internal faults. As well as drilled fault blocks, there are many undrilled compartments, largely contiguous with the existing drilled areas.

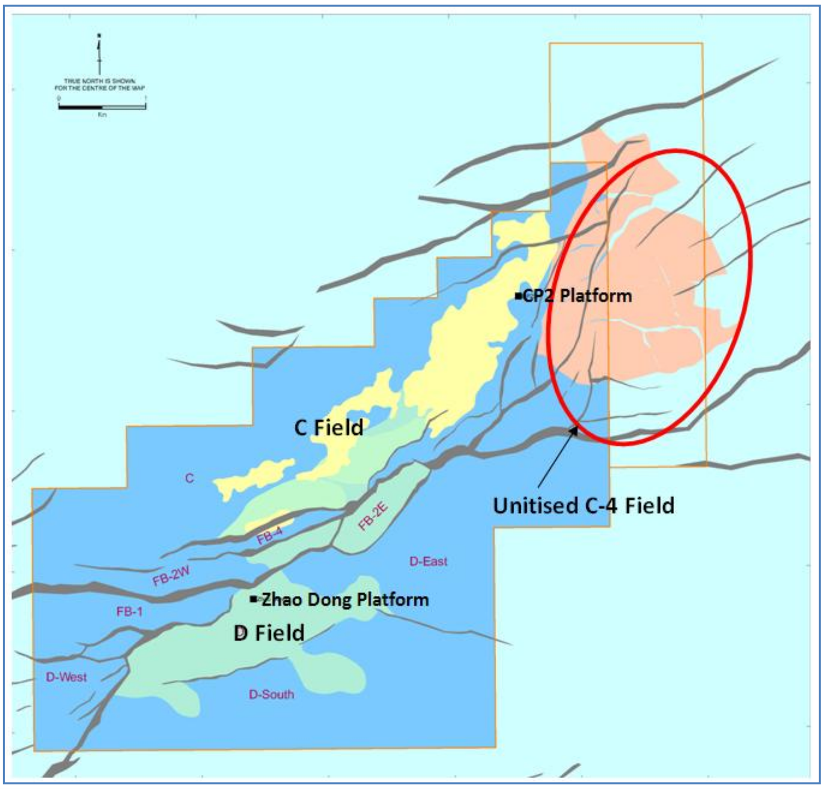


Figure 7-13 Zhao Dong and C4 oil accumulation map

A comprehensive 3D seismic data set covers the whole Zhao Dong Block and this, together with the large number of existing well penetrations in the developed C/D Fields, provides confidence in the mapping of the different horizons, and the in-place oil volumes and reserves which have been estimated for the fields. Several vintages of seismic data have been used historically; until 2008 the primary interpretation volume was a 3D dataset acquired by Apache in 1997-1998. This had been reprocessed at least once, including relatively unsuccessful post-stack inversion. In 2008 a new reprocessing project using available Petrochina data was undertaken with the aim of producing a better structural image through pre-stack depth migration. However, Roc stated that the data quality is poor over the Lower Tertiary & Pre-Tertiary section.

The pools relying on Eocene and older reservoirs are structurally defined. In the Upper Tertiary, amplitudes have been used by Roc to guide reservoir trend mapping, although these do not necessarily indicate the presence of oil.

The oldest principal reservoirs are the fluvial and lacustrine Jurassic Mz1-2/3 and Mz1-4/5 units, which contain sections of coarse conglomerate. The marginal lacustrine / deltaic Shahejie Formation provides reservoir sands in the Eocene Es2 unit. There are numerous productive intervals within the Upper Tertiary Guantao Ng (continental braided and meandering fluvial) and Lower Minghauzhen Nm (marginal lacustrine and meandering fluvial) formations. A schematic cross section showing the types of play is given as Figure 7-14.

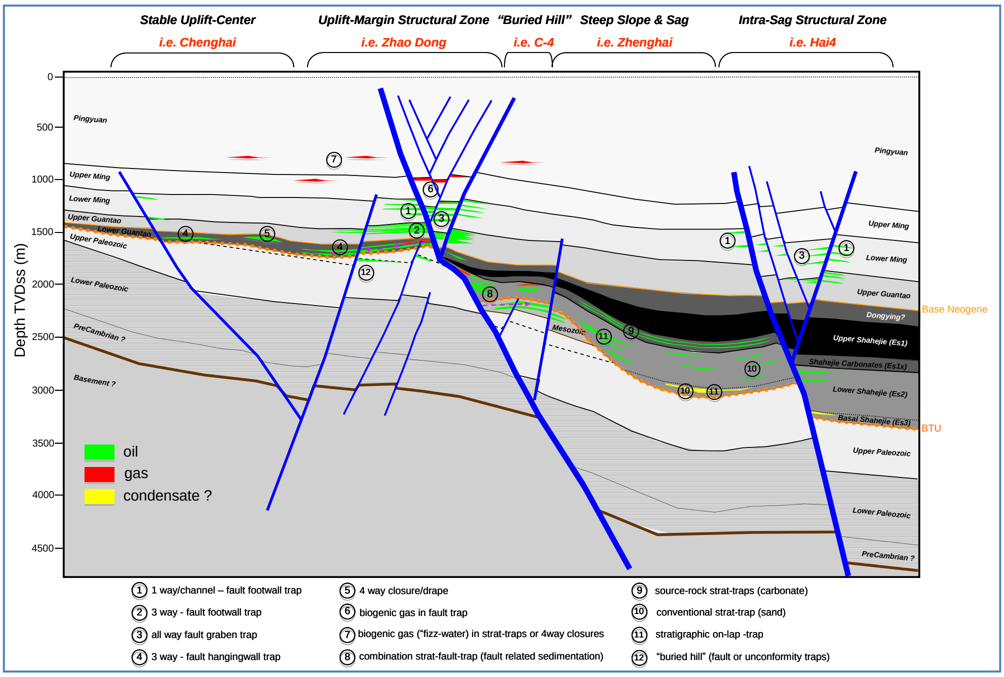


**Figure 7-14 Schematic cross-section showing typical plays**

RISC has reviewed and audited the methodology and input data that has been used by Roc to estimate STOIIP. Roc's volumetric probabilistic methodology is supported. We made our own assessment of the NRV and were able to support overall the Roc NRV inputs.

We have made a series of deterministic checks as a check against Roc's STOIIP range. Pool areas have been calculated from Roc depth maps by digitising of areas based on Roc's lowest known oil (LKO) (generally low case) and OWC (high case or ML as appropriate).

RISC has accepted the net pay and porosity determinations from petrophysics and used them in our volumetric calculations. In general RISC has used average net pay and average porosity values which associated with the range in areas to deterministically calculate STOIIP. This gives an acceptably wide range in STOIIP.

RISC STOIIP estimates were compared against the Roc STOIIP. Where differences were small and/or explainable, the Roc STOIIP was accepted. The largest differences were at the P90 level, although differences were always within 10%. Where differences were material RISC discussed these with Roc, who accepted RISC's proposed values. We therefore support Roc's estimate of STOIIP which range from for the Zhao Dong Field. A summary of the discovered STOIIP and reserves is included in Table 7-6 and Table 7-7. These oil volumes exclude about 30 MMstb undiscovered STOIIP.

| Field | Low | Best | High |
|---|---|---|---|
| | Oil MMstb | Oil MMstb | Oil MMstb |
| Zhao Dong C/D | 302.0 | 357.5 | 422.0 |
| Zhao Dong C-4 | 27.0 | 40.5 | 60.4 |
| **Total** | **329.0** | **398.0** | **482.4** |

Table 7-6 STOIIP as at 1 January 2014 - Bohai Bay

| Field | 1P | | 2P | | 3P | |
|---|---|---|---|---|---|---|
| | Oil MMstb | Gas bcf | Oil MMstb | Gas bcf | Oil MMstb | Gas bcf |
| Zhao Dong C/D | 12.7 | 3.0 | 16.0 | 4.3 | 20.8 | 6.1 |
| Zhao Dong C-4 | 1.0 | 0.3 | 1.5 | 0.5 | 2.0 | 0.7 |
| **Total** | **13.7** | **3.3** | **17.5** | **4.8** | **22.8** | **6.8** |

Table 7-7 Gross Reserves as at 1 January 2014 - Bohai Bay

| Field | 2C MMstb | 2C Bcf |
|---|---|---|
| C&D | 20.2 | 4.5 |
| C-4 | 1.4 | 0.4 |
| **Total** | **21.6** | **4.9** |

Table 7-8 Gross 2C Contingent Resources as at 1 January 2014 - Bohai Bay

Cumulative production to 31 December 2013 was 70.0 MMstb of oil and 35.6 bcf of gas for C and D fields and 4.6 MMstb of oil and 3.9 bcf of gas from C-4. Total cumulative gas sales were 7.3 bcf. From the period 1 January 2014 to 31 March 2014 there has been a further depletion of 1.3 MMstb from C/D fields and 0.17 MMstb from C-4 gross due to production. Gas sales were approximately 0.4 bcf over the same period.

### 7.2.2. Production and Cost forecast

The Zhao Dong offshore facilities comprise four bridge-linked platforms; two for drilling and accommodation and two for production and processing.

The C4 Field Unit facilities comprise a wellhead platform and pipelines to the C&D field platform. Production is delivered to onshore processing plant by pipelines.

Oil and gas production from Zhao Dong Block fields C&D and C4 are being augmented with an ongoing development drilling program.

Roc has used the RISC Year End 2013 reserves report as the basis for the production profiles. RISC has reviewed these and accepts their use in the evaluation. The following plots show the annual oil and gas volumes for C&D Fields and C-4.

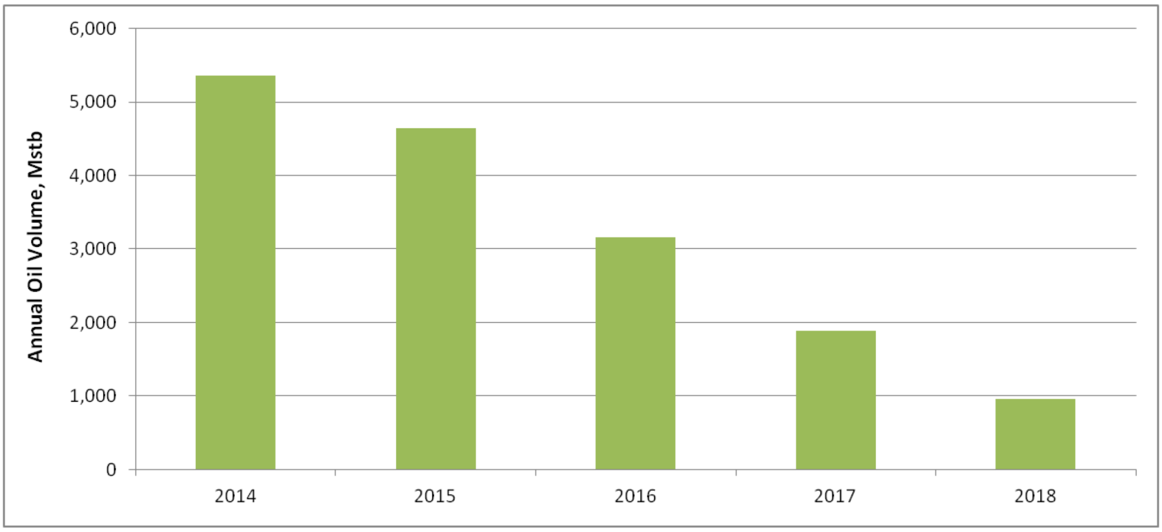


Figure 7-15 2P Gross Oil Production Forecast - C&D Fields

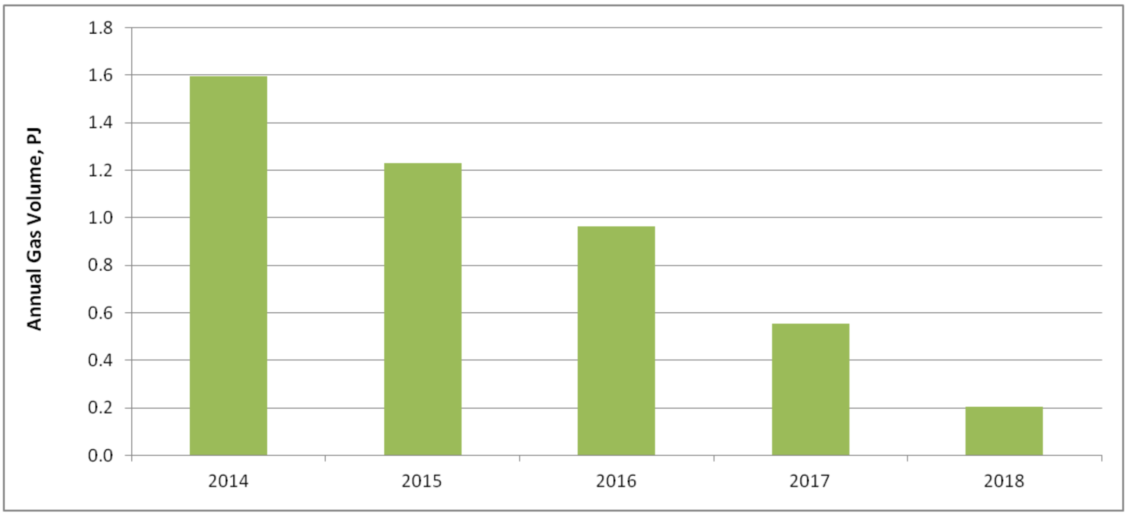


Table 7-9 2P Gross Sales Gas Production Forecast - C&D Fields

Note that in Roc's financial model, the C and D Fields were each allocated 50% of the total identified by RISC for the full C&D Field forecast. As the equity in these fields is the same, this is not a concern.

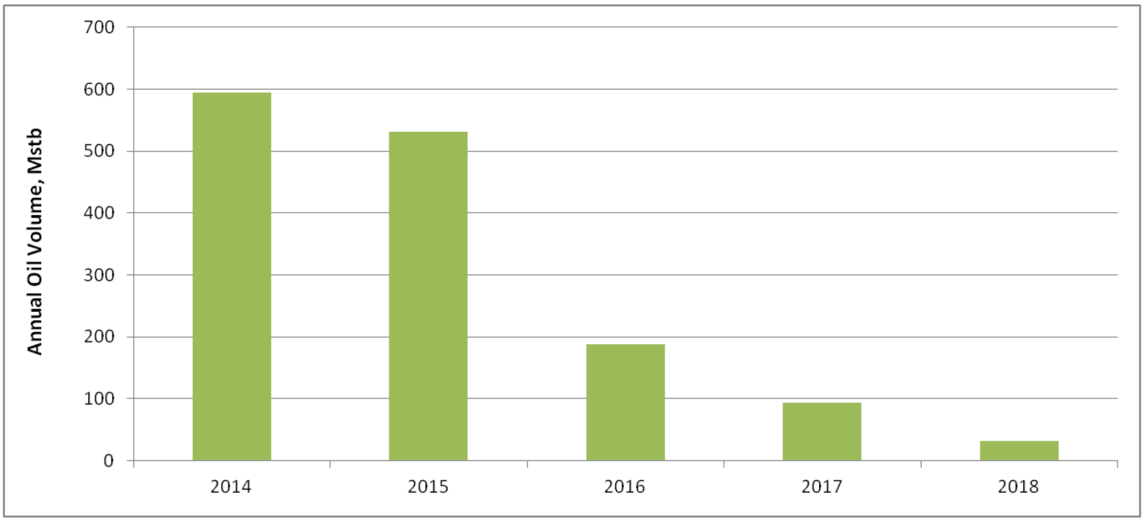


Figure 7-16 2P Gross Oil Production Forecast - C-4 Field

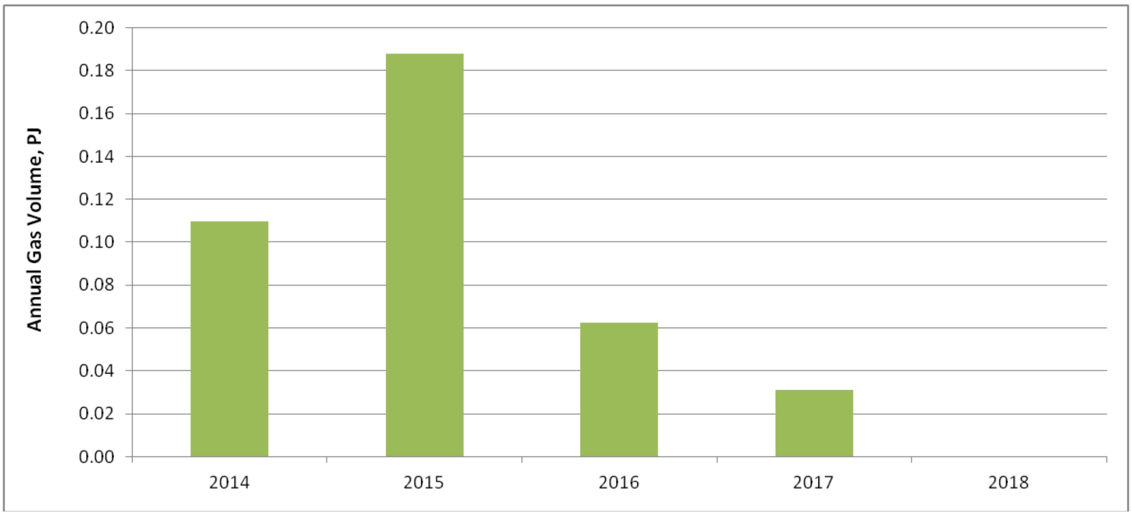


Table 7-10 2P Gross Gas Production Forecast - C-4 Field

No further production is expected from the New Block I, which ceased production in 2013.

**Contingent Resource Scenario**

A scenario which produces a proportion of the 2C contingent resources has been assessed.

The contingent resources were split by Roc into four categories:

- Developed, Licence Extension
- Undeveloped, Licence Extension
- Development Unclarified
- Development Not Viable

Of a total 21.6 MMstb identified within these categories, 7.7 MMstb require a licence extension and 9.3 MMstb of development projects were not viable (too small, or too difficult).

If the PSC was extended beyond the current PSC end date of September 2018, a portion of these resources may be migrated to reserves categories.

In the scenario with an approved extension of PSC period to 2023, incremental development activities could become economically attractive and could be considered new reserves. Additionally, the tail-end of the current development would be migrated to reserves.

Roc modelled this scenario with new development activities and created new cost and production profiles. The extended plan, with oil sales to 2023, has an increment of 14.4 MMstb over the RISC 2P for period 2014-2023. This plan reflects a case of 2P+2C resources with truncation at 2023. RISC has made a distinction between the volume produced in a 5-year extension, and the YE2013 2C volume. The volume beyond 2023 is not included in this scenario.

The figures below show the oil and gas production profiles for the 2P+2C case with a 5 year extension. These include C&D Fields and C-4.

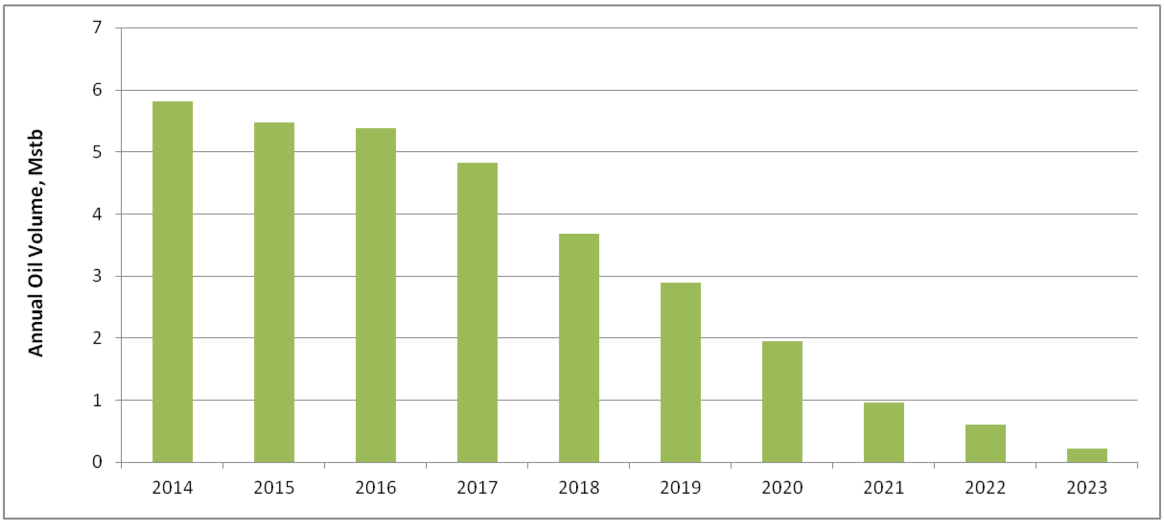


**Figure 7-17 2P+2C Gross Oil Production Forecast - All Fields**

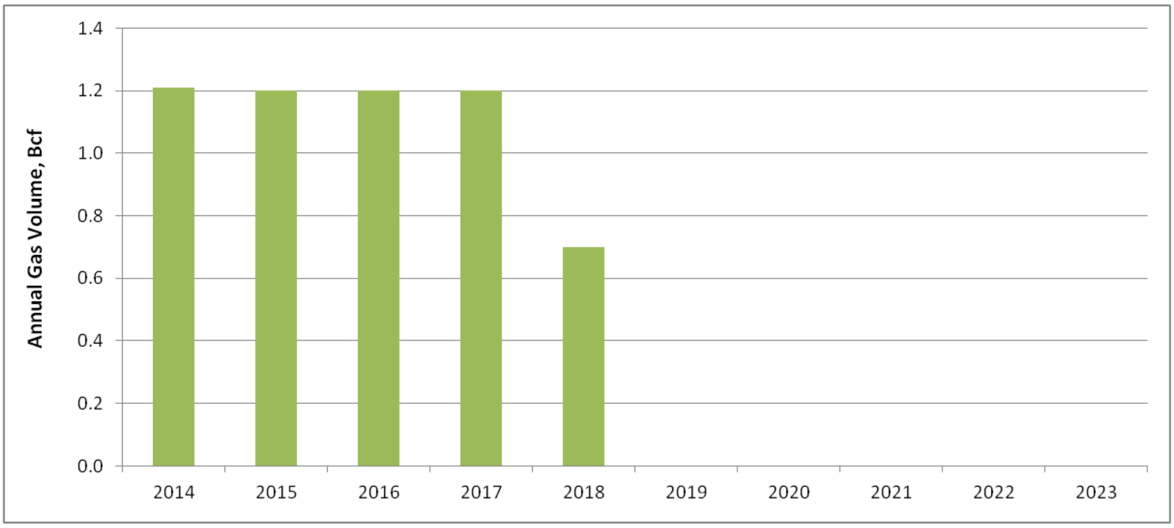


**Figure 7-18 2P+2C Gross Gas Sales Forecast - All Fields**

Note that sales gas volumes do not extend beyond 2018, although oil production continues to 2023 in the 2P+2C case. This due to an increasing proportion of produced gas being used for fuel.

### Capital Costs

Capital costs totaling $280m are forecast for the 2P case. Most of this cost relates to drilling 42 development wells, the balance is for facilities costs including increasing water handling capacity and well hookups.

In the 2P+2C (truncated to 2023) case the estimated capital cost expenditure is $811m. The bulk of this cost relates to the drilling of an additional 77 wells and a new well head platform.

### Operating Costs

Operating costs are forecast to be $499.6m (with $65.7 of abex contained in this) to end of PSC decreasing from $130m in 2014 to approx $40m in 2018 in the 2P case. In the 2P+2C case the total opex is forecast to be $720.8m (with $101.3 of abandonment costs contained in this) with a similar profile from 2014-2018 and tail costs continuing until 2023.

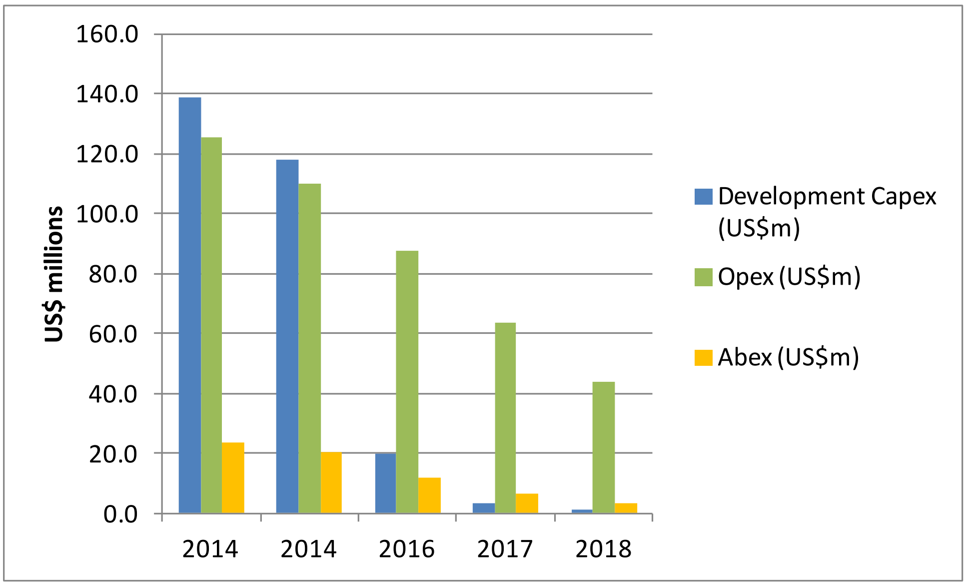


Figure 7-19 Gross 2P Costs - Bohai Bay

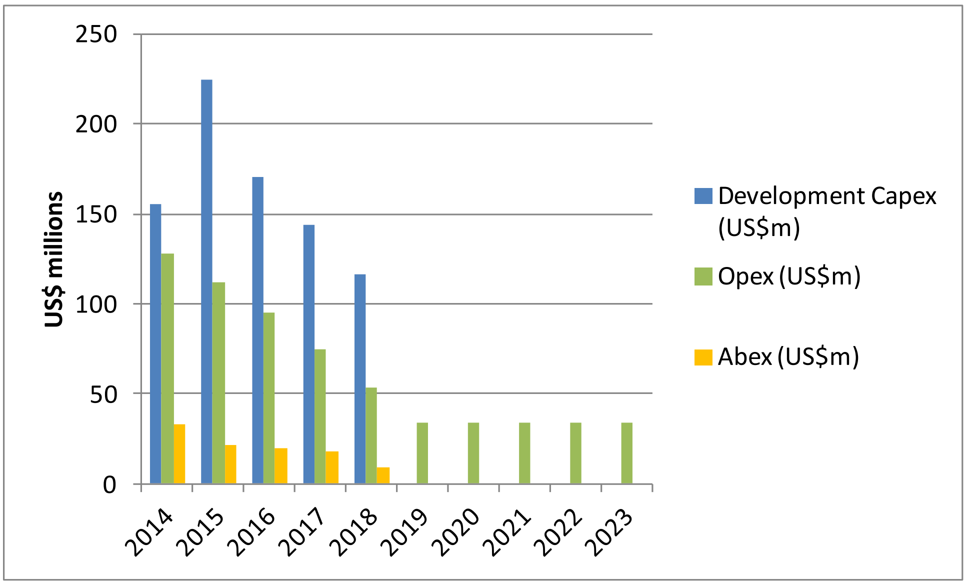

Figure 7-20 Gross 2P+2C Costs - Bohai Bay

### 7.2.3. Exploration

Exploration and appraisal potential exists in the 09/05, Zhanghai and Chenghai Blocks.

In March 2011, the Zhao Dong Joint Venture was awarded two additional offshore areas, adjoining the Zhao Dong PSC, as an extension to the existing acreage (Figure 7-21). Historical exploration campaigns resulted in discovery of oil in both blocks. There is potential to access portions of these new blocks from the Zhao Dong platforms, particularly areas within the Northern block. To date only one well (ZH-01P) has been put on production through the CP2 platform. Production from August 2011 to May 2013 was only 0.14 MMstb (gross) and no further reserves or contingent resources are assigned.

Roc has a 39.2% working interest in these new areas. The pool from which well ZH-01P produced straddled the block boundary and was unitised with Roc holding a net 33.5% interest.

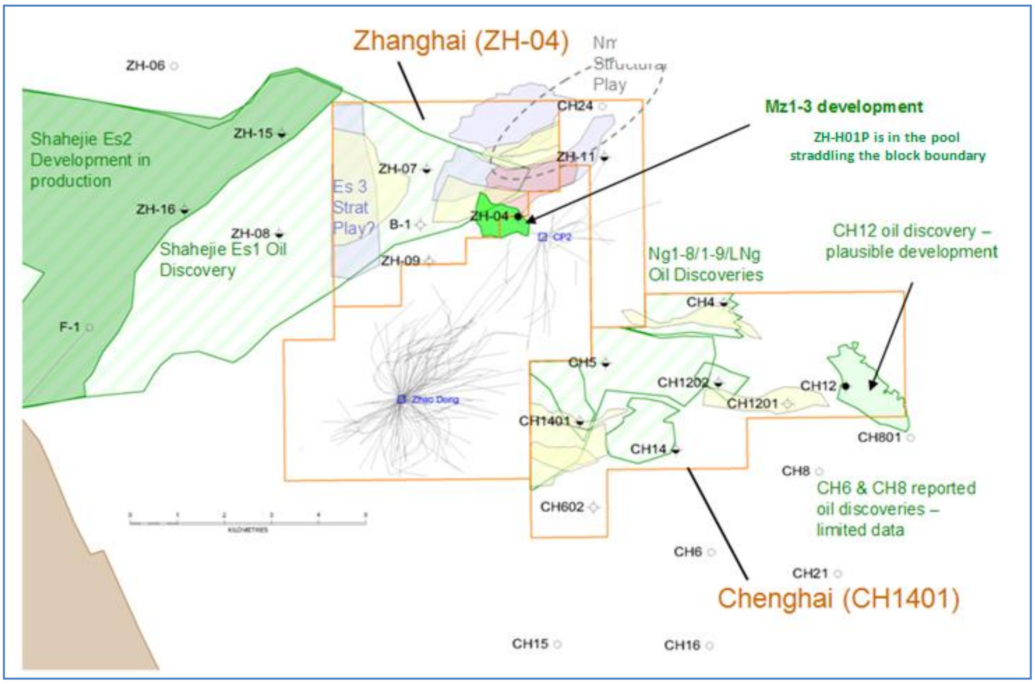


Figure 7-21 Map showing Zhaghai and Chenghai Blocks, Zhao Dong wells and Discoveries

### 7.2.4. Chenghai Block Development

RISC understands that the Chenghai Block contains a number of viscous oil discoveries. We have not had access to basic data on this block nor seen any mapping, log interpretation, fluid analysis or any assessment of volumetrics. RISC understands that Roc has estimated 60-80MMstb STOIIP. We have briefly reviewed some reservoir engineering work conducted by Roc that considered potential recovery methods for the viscous oils encountered in wells drilled to date.

The reported fluid properties indicate reservoir oil viscosity generally in the range from 600 to 1700 cP - although the measured viscosity on fluid samples at well CH5 is reported at 20 cP and CH1401 120-150 cP.

Roc's review of available technologies considered:

- conventional production (depletion /water drive)
- miscible solvents
- steam injection
- polymer flooding
- combustion floods

Roc concluded that the technology for developing the higher viscosity crudes at reservoir depths of 1450 mss in an offshore cost environment is not reliably available, although there could be scope to apply onshore technologies, however in the absence of valid analogues this would be a frontier application.

No contingent or prospective resources have been assessed to date.

RISC has assigned no further value to the exploration in the Zhanghai and Chenghai blocks,

Horizon had an option to farm into Block 09/05 for a 40% interest by paying 40% of the ongoing costs to earn the option and the right to farm into a 40% interest by drilling two exploration well at a 2:1 promote. The option has since expired and Roc now holds 100%.

Block 09/05 2014 budget has an amount of $21.1 million including $1 million for G&G studies and $14.7 million. There is a further contingent budget of $1.7 million for seismic and $9.2 million for drilling.

Assuming that Roc can attract the same terms as Horizon offered and assuming a 2 well cost plus studies and seismic of $26.6 million, this values the block at $26.6 million. However there is no certainty that similar terms could be obtained. In the low and mid cases, we have assumed a 2:1 farmin on the firm G&G studies and a well for a total cost of $15.7 million, which would value the permit at $15.7 million. The high case value is $26.6 million.

# 8. PAPUA NEW GUINEA

## 8.1. PRL 4

### 8.1.1. Stanley Field Description

The Stanley Field is located in permit PRL4 (Figure 8-1). Horizon has a 30% interest in the permit, which will reduce to 23.25% in the event that the PNG Government exercises its back-in rights of up to 22.5%. The permit is operated by Talisman Nuigini Pty Ltd.

In April 2014, the Stanley Project was approved by the PNG Government and the development licence (PDL 10) was awarded on 30 May 2014. The Stanley project entails the production of 140 million cubic feet (MMscf/d) of gas per day from two wells, extraction of initially over 4,000 barrels of condensate per day with re-injection of the dry gas until a gas market develops. First production is scheduled for mid 2016.

Options to monetise the gas include supply to the Ok Tedi and Frieda River mines or local users for power generation and/or gas export via a 1-2 Mtpa LNG project under consideration. The potential to sell gas into third party LNG projects also exists.

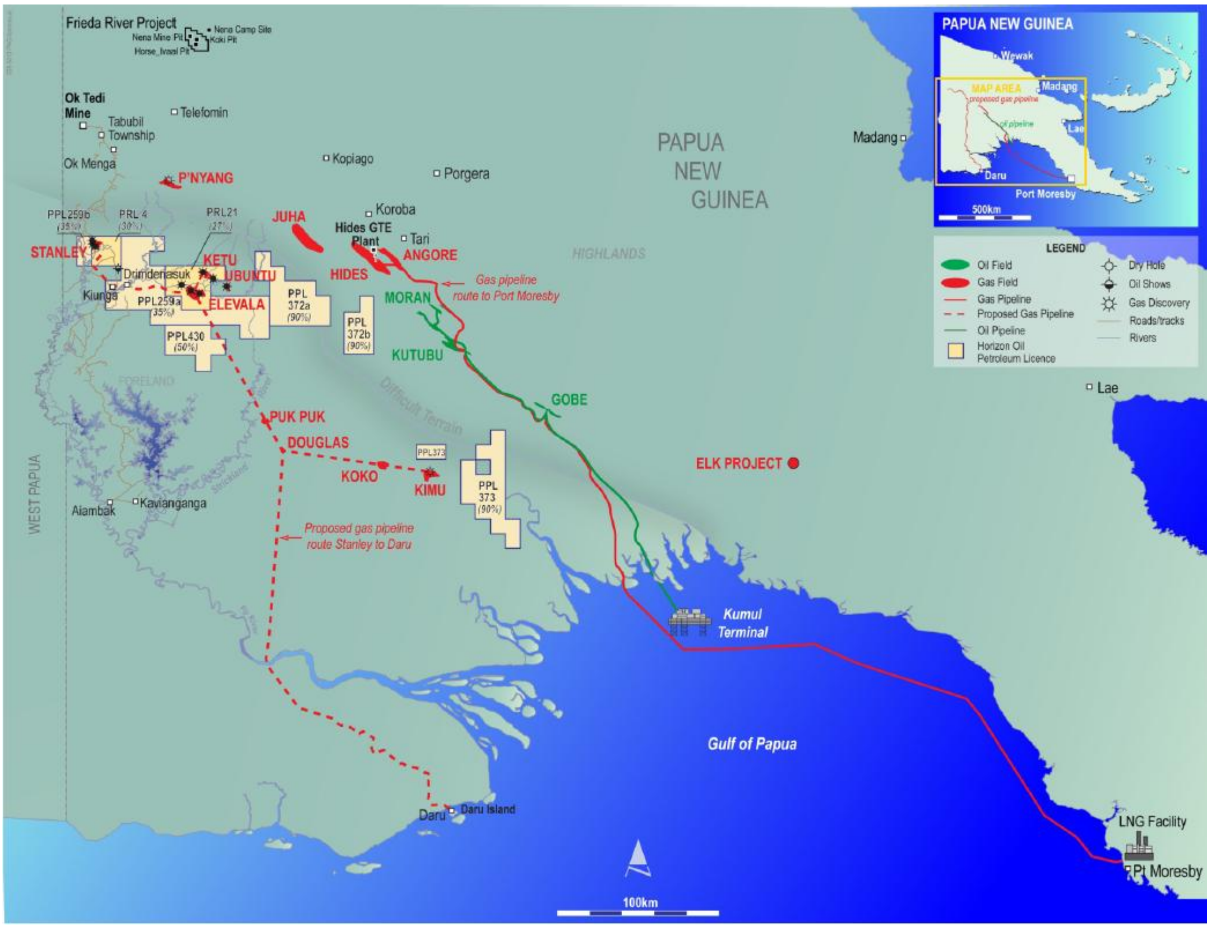


Figure 8-1 Horizon PNG Interest Location Map

Three wells and one sidetrack have been drilled to date on the Stanley structure. Stanley-1 was drilled in 1999 and discovered gas in the Toro Sandstone, which was later tested by Horizon in 2008 at a rate of 9 MMscf/d gas. The well subsequently flowed gas on open flow at 30 MMscf/d.

In 2011, Stanley-2 was drilled as a near vertical well targeting the Toro reservoir on the crest of the structure, with the additional objective of testing for deeper reservoirs. The well proved the Toro Sandstone to be gas bearing on the central portion of the field with 22.1m of net gas sand, and also encountered a deeper gas bearing reservoir, named the Kimu Sandstone, with 41.2m of net gas sand. Both reservoirs encountered gas to the base of reservoir and demonstrated a common gas gradient consistent with the gas column at Stanley-1.

In order to obtain a full suite of core across the gas bearing reservoirs, the well was sidetracked as Stanley-2ST1 adjacent to the original wellbore. Stanley-2ST1 encountered a similar net gas sand thicknesses to Stanley-2 in the Toro and Kimu reservoirs as expected. The sands then completed and tested gas separately at up to 30 MMscf/d and up to 40 MMscf/d respectively.

The field extends into the adjacent PPL259 permit and is the subject of a unitisation determination. However since Horizon has 30% interest in PRL4 and a 35% interest in PPL259 (prior to PNG Government back-in) it is largely hedged against the unitisation outcome and will have minor impact on Horizon's interests. As this is commercially sensitive, we have not included a structure map.

Probabilistic gas and condensate in place have been calculated for both the Toro reservoir and the Kimu reservoir. Static modeling has been undertaken to provide input into the dynamic modeling. RISC considers the static model reasonable and adequate for this purpose. RISC has audited the reserves and resources as at 30 June 2012 (Table 8-1). We are satisfied that that there is no new information available since that date which would have a material bearing on our conclusions.

| | P90 | P50 | P10 |
|---|---|---|---|
| GIIP bcf | 474 | 591 | 728 |
| CONDENSATE IN PLACE MMbbl | 14.2 | 17.7 | 21.8 |
| **Reserves** | **1P** | **2P** | **3P** |
| Condensate (MMbbl) | 8.3 | 11.4 | 14.4 |
| **Contingent Resources** | **2C** | | |
| Gross Gas (bcf)(1) | 399 | | |
| Condensate (MMbbl)(2) | 1.3 | | |

Notes:
(1) Includes potential LPG resources with a yield of 1.97 tonne/MMscf
(2) Approximately 10% of condensate recovery is attributed to the gas sales phase and is a contingent resource pending gas commercialisation

**Table 8-1 Stanley Field Gross Reserves and Resources as at 30 June 2012**

### 8.1.2. Production and Cost forecast

#### *8.1.2.1. Project Overview*

The Stanley development will consist of two production and two dry gas injection wells. Two of these wells Stanley-2ST1 and Stanley-4 were drilled in 2011. Stanley-2 will be used as a producer from the Toro and Kimu sands. Stanley-4 will be used as a gas injector for the Kimu. Two additional wells Stanley-3 and 5 will be drilled.

The gas plant will be located near the existing wells, where site clearance is largely completed. The facilities scope includes 2 x 50% processing trains capable of processing a total of 140 MMscfd nameplate capacity gas (133 MMscf/d annual average). Initial condensate rate is expected to be just over 4000 bbl/d annual average. Main components of the gas plant are as follows:

- 2 x 50% 70 MMscf/d Inlet Separator Modules;
- 2 x 50% 70 MMscf/d Refrigeration Modules;
- 4 x 25% 35 MMscf/d Gas Driven Injection Compressors;
- 1 x 100% Condensate Stabilization Module;
- 1 x 100% Re-cycle Compressor;
- 2 x 100% Condensate Transfer Pumps;
- 1 x 40,000 Bbl condensate tank;
- 2 x 50% 70 MMscf/d Mercury treatment beds;
- 2 x 50% 2,000 bpd Mercury treatment beds;
- 1 x 60,000 Bbl condensate storage tank at Kiunga lay down area;
- 2 x 100% Condensate Transfer Pumps at Kiunga Condensate Transfer Station;
- 3 x 50% GENSETS at Stanley Gas Plant;
- 2 x 100% GENSETS at Kiunga Condensate Transfer Station.

Processed gas from the Stanley Gas Plant will be used for the following:

- fuel gas for power, compression and process;
- remaining gas will be re-injected into the reservoir;
- As and when gas markets become available (e.g. power generation at mine sites) gas will be exported to various customers.

Stabilised condensate produced by the Stanley Gas Plant will be shipped via a 40 km 6" pipeline to a new loading terminal located on the Fly River at Kiunga. Kiunga is a major river port with infrastructure that allows significant quantities of copper to be shipped from the OK Tedi copper mine. The proposed condensate shipping facility will be located near the Kiunga airport at the site of an existing staging area used to support drilling operations. A short 1 ½ km condensate transfer pipeline will move the product from the shipping facility to a riverside wharf on the Fly River, approximately 1 km downstream of the OK Tedi wharf at Kiunga.

#### *8.1.2.2. Cost and schedule estimates*

RISC has reviewed the Horizon cost and schedule basis for the Stanley field development and in the main finds them to be reasonable. RISC has made adjustments to the project budget to include the effect of project delays and added contingency on some items where necessary. The Stanley capital cost estimate is shown in Table 8-2.

There has also been a change of operatorship, with Talisman assuming the role of operator, and this has the potential to further delay the project. Nevertheless, RISC believes that a two year project execution schedule is achievable and considers that a start-up date of 1 July 2016 is achievable provided that the production licence is awarded as planned.

| Cost Item | US$ Million |
|---|---|
| Project Management and Supervision | 15 |
| Stanley Gas Plant | 221 |
| Pipeline | 40 |
| Kiunga Storage and Load out facilities | 27 |
| Wells (including Stack costs) | 78 |
| **Total Capital Cost** | **381** |
| **Abandonment** | **38** |
| **Operating Cost/year** | **26** |

**Table 8-2 Stanley Gross Capital and Operating Costs as at 1.1.2014 - RISC estimate**

Operating costs for the Stanley development, as indicated in the Horizon corporate model, are approximately $26 million per year including condensate transport costs. RISC has reviewed the operating costs and considers these costs reasonable.

The above capital and operating costs are also appropriate for both a stand-alone liquids stripping scheme and a scheme which includes future gas sales on the basis that all the necessary equipment is already in place and on the assumption that the gas is sold on an ex-field basis (Figure 8-2). In the case of gas export, opex extends until 2041.

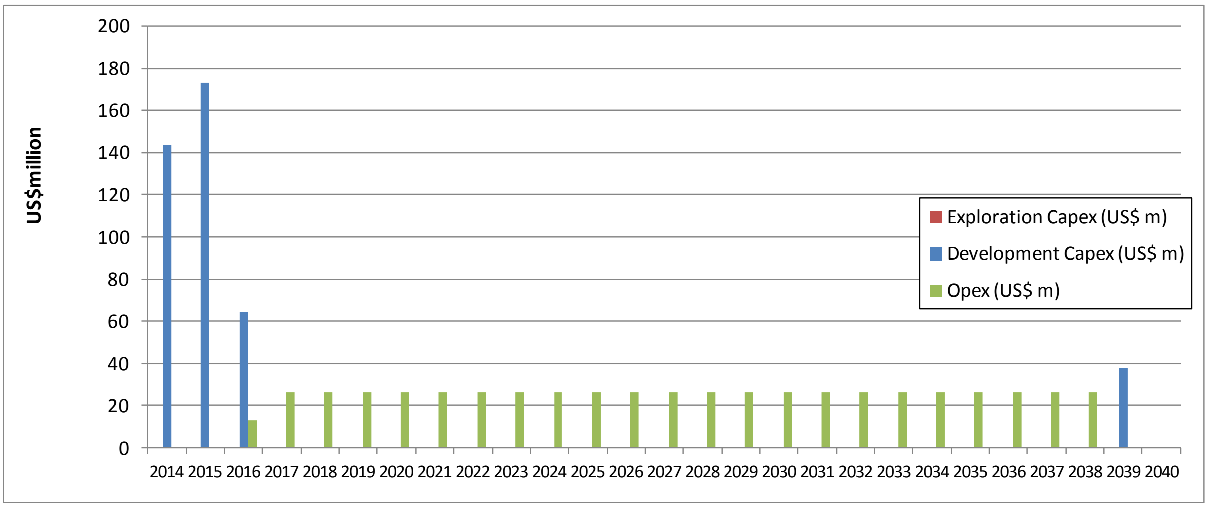


**Figure 8-2 Stanley 2P Liquids Stripping Gross Cost Forecast - RISC Estimate**

### *8.1.2.3. Production forecast*

RISC has considered two production scenarios:

**2P Reserves Case**
A stand-alone liquids stripping scheme which produces the 11.4 MMbbl of condensate reserves.

Horizon have generated a dynamic simulation model of the Stanley field to evaluate a range of development and production concepts. RISC has reviewed the model inputs and made changes where necessary. Production forecasts at the 2P level have been generated by RISC for condensate stripping (with lean gas reinjected back into the reservoir). Condensate stripping is assumed to commence in July 2016. The field is assumed to produce raw gas at a capacity of 140 MMSCFD before an allowed downtime of 5% which yields an average raw gas rate of 133 MMSCFD, and lean gas is reinjected at an average rate of 124 MMSCFD after condensate is removed and a small amount of gas is used for fuel and flare. The production and cost forecasts are shown in Figure 8-3 and Figure 8-2.

The condensate-gas ratio (CGR) for Stanley gas has been derived from PVT analysis of eighteen downhole and surface gas and condensate samples from the Toro and Kimu reservoirs. The expected produced initial CGR is approximately 30 bbls per MMSCF taking into account process yields and will be able to remove condensate from the gas down to a level of 3 bbls per MMSCF. The produced CGR will decline as lean gas breaks through in produces and the reservoir pressure decreases.

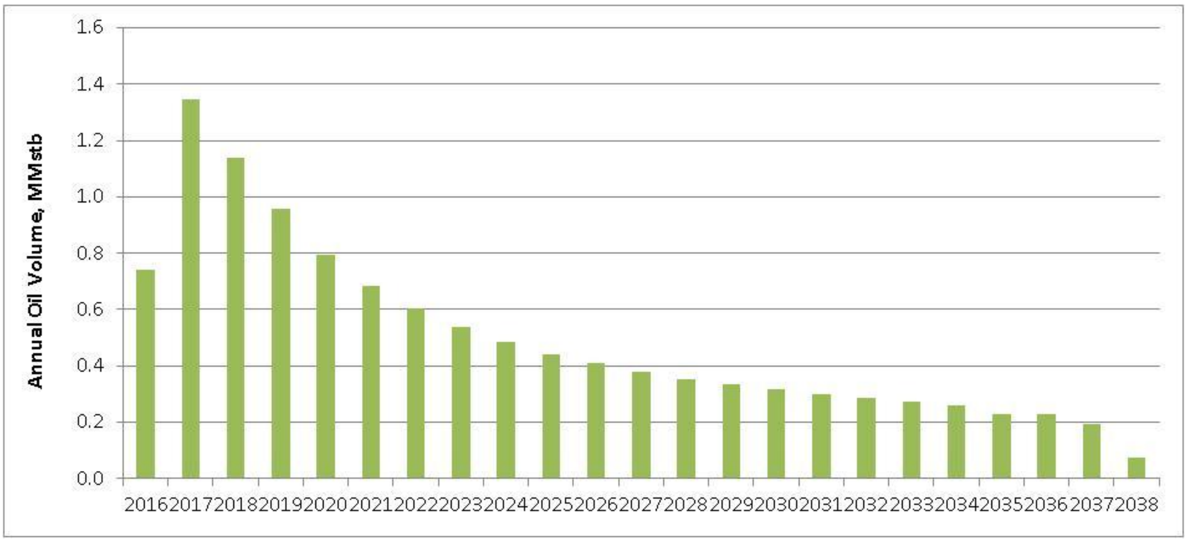


**Figure 8-3 Stanley 2P Gross Production Forecast – Condensate stripping only**

**2P+2C Resources Case**
In this scenario, liquids stripping for 3 years is followed by gas export. This develops the 2C gas resources and an additional 1.3 MMstb of condensate from the field blowdown. Lean is reinjected back into the reservoir for three years and condensate removed and sold, after which time a gas sales opportunity has been captured and the lean gas is instead exported. In the RISC forecasts, produced gas is assumed to be sold to Ok Tedi mine (power generation) at a rate of 2.4-3 PJ/a ,with the remainder to 18 PJ/a available for sales to the potential Frieda River mine and other potential buyers of gas in the region.

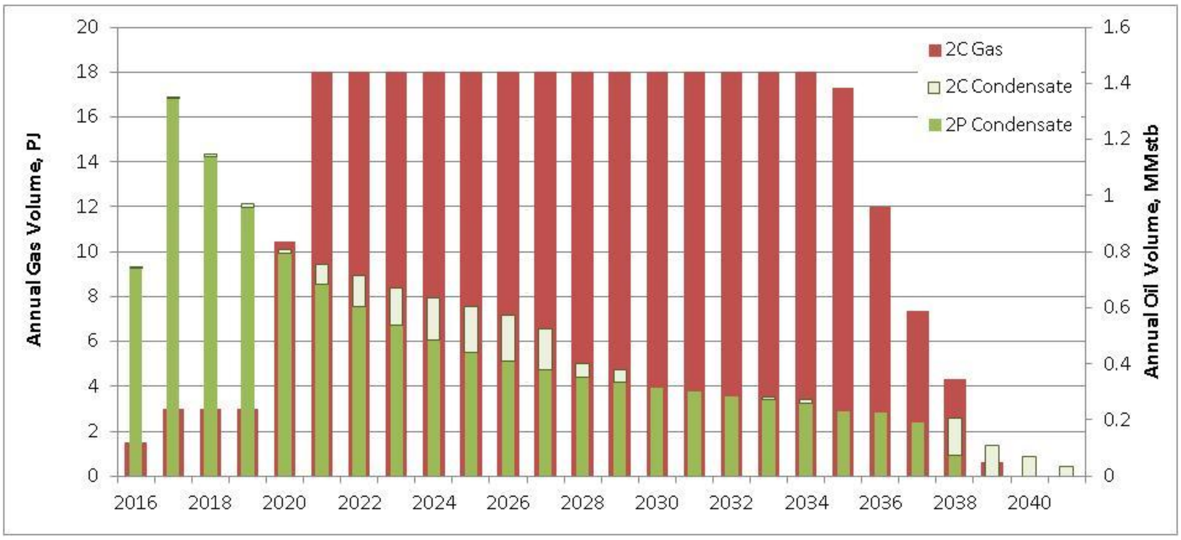


**Figure 8-4 2P+2C Gross Production Forecast – Condensate stripping and gas export**

The liquids stripping project is already approved and risks associated with the gas sales are primarily commercial in nature. We consider the technical risks associated with this scenario to be low and have not made any adjustment for risk.

### 8.1.3. PRL 4 Exploration

There is potential for additional closures located to the northeast of the Stanley field to be drilled and tied back to the Stanley development. It is expected that prospective incremental structures will be firmed up when further drilling on the Stanley Field has been completed and uncertainty in the depth conversion calibrated further. Exploration drilling, if justified, would not be undertaken until after 2016 when the drilling results from Stanley and possibly further seismic acquired.

Note that PDL 10 (Stanley field) will only be awarded over graticular blocks 1622 (contained in PPL 259) and 1623 (one of a total of 4 graticular blocks in PRL 4). Following award of PDL, the remaining 3 blocks are released back to the State to be subject to a public tender. Horizon, Talisman and Osaka Gas have submitted an application to the State to extend the life of the remaining blocks contained in PRL 4.

We have not assigned any exploration value to this permit.

## 8.2. PRL 21

### 8.2.1. Elevala and Ketu Field Description

Horizon has a 27% interest in PRL 21 which will reduce to 20.925% assuming the PNG Government excercises its back-in rights. PRL 21 is located to the east of PRL 4 (Stanley field) and contains the Elevala and Ketu gas condensate fields (Figure 8-1). The operator is Horizon.

Horizon has prepared a preliminary field development plan and submitted a development licence application for the Elevala and Ketu fields. The development concept is analogous to the Stanley Project but on a larger scale. The concept involves producing an annual average rate of 210 MMscf/d (140 MMscf/d from Elevala and 70 MMscf/d from Ketu) and reinjecting lean gas back into the reservoir. Options to monetise the gas include gas export via a 1-2 Mtpa LNG project under consideration or sale into third party LNG projects.

The Elevala Field was discovered by the Elevala-1 well drilled by BP in 1990. The well encountered gas throughout the Elevala Sandstone reservoir and gas shows in the deeper Toro reservoir. The Elevala reservoir was tested, flowing gas at a rate of 11.9 MMscf/d. An attempt was made to test the Toro reservoir which was unsuccessful, leaving the test string in the hole and precluding a further test attempt. Potential for gas in the Toro reservoir below the Elevala and Tingu structure exists and has been noted as prospective resources.

The Ketu Field is located 14 km northeast of Elevala. The Ketu-1ST well was drilled in 1991 by BP and encountered similar gas condensate in the Elevala Sandstone with no evidence of a GWC (the original hole was abandoned due to hole conditions and a sidetrack drilled).

The Elevala-2 appraisal well was drilled in late 2011, encountering approximately 19m net gas bearing reservoir in the Elevala Sandstone. The well was sidetracked downdip into Elevala-2ST1 in order to establish the GWC, and encountered approximately 17m of water wet Elevala Sandstone. Pressure data acquired in both wellbores enabled a determination of the gas water contact at -3,045 mTVDss across a shale between two sands. The western lobe of the structure was drilled in August 2013 by the Tingu-1 well which confirmed the extension of the Elevala field into the eastern lobe and now incorporates the Tingu accumulation. The Tingu-1 well was tested at up to 46 MMscf/d and encountered the GWC at -3,044 mTVDss. The Toro sandstone was encountered water bearing at the Tingu-1 location, however updip gas potential remains.

The structure of the fields are defined by grid of 2D seismic data, with a line spacing of 1.5 to 2.5km between dip lines and 4km between strike lines,  of different vintages and variable quality. The time and depth mapping has been reviewed by RISC and is supported.

Elevala is shown to be an areally large, low relief structure, closing against faults to the south and possibly bisected by a northeast-southwest fault (Figure 8-5).

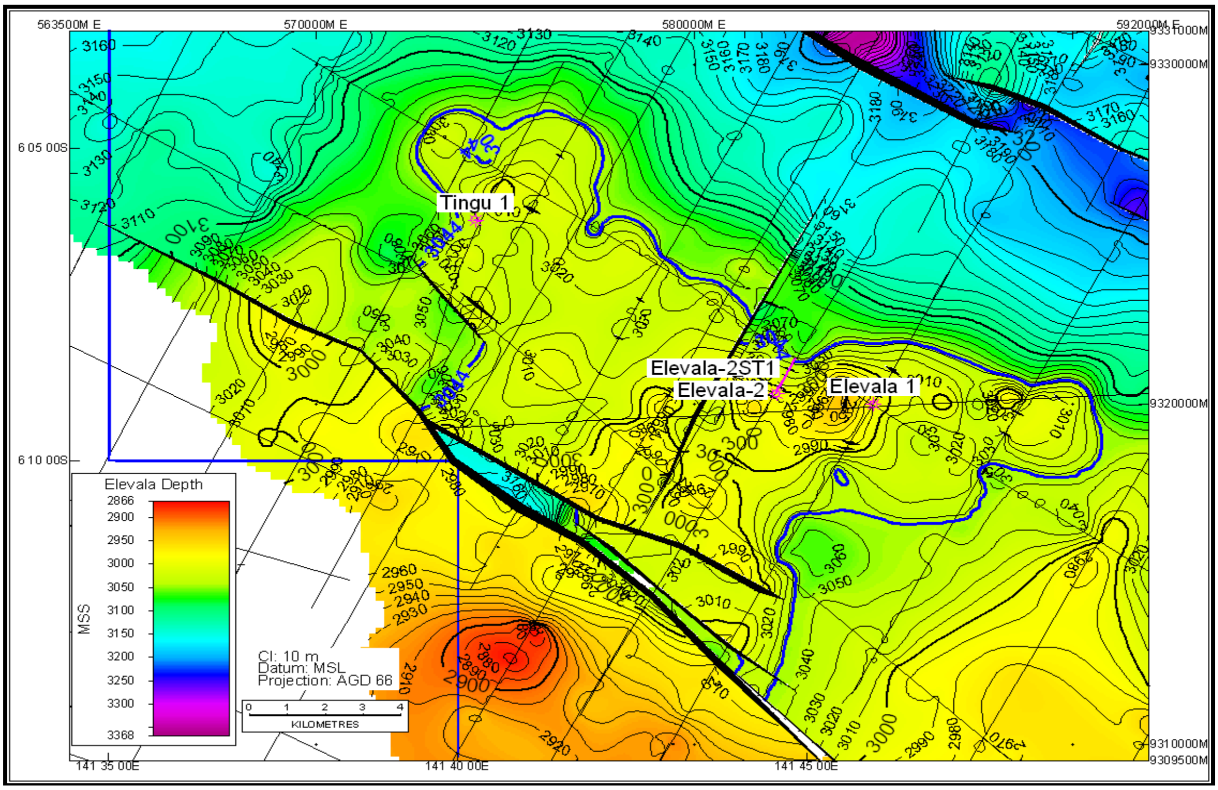


Figure 8-5  Elevala Field Elevala Reservoir Depth Structure Map

The Ketu Field has a range of potential gas water contacts of 3,220 to 3,235 mTVDss, determined pressure gradients. The Ketu Elevala reservoir depth structure map is shown in Figure 8-6.

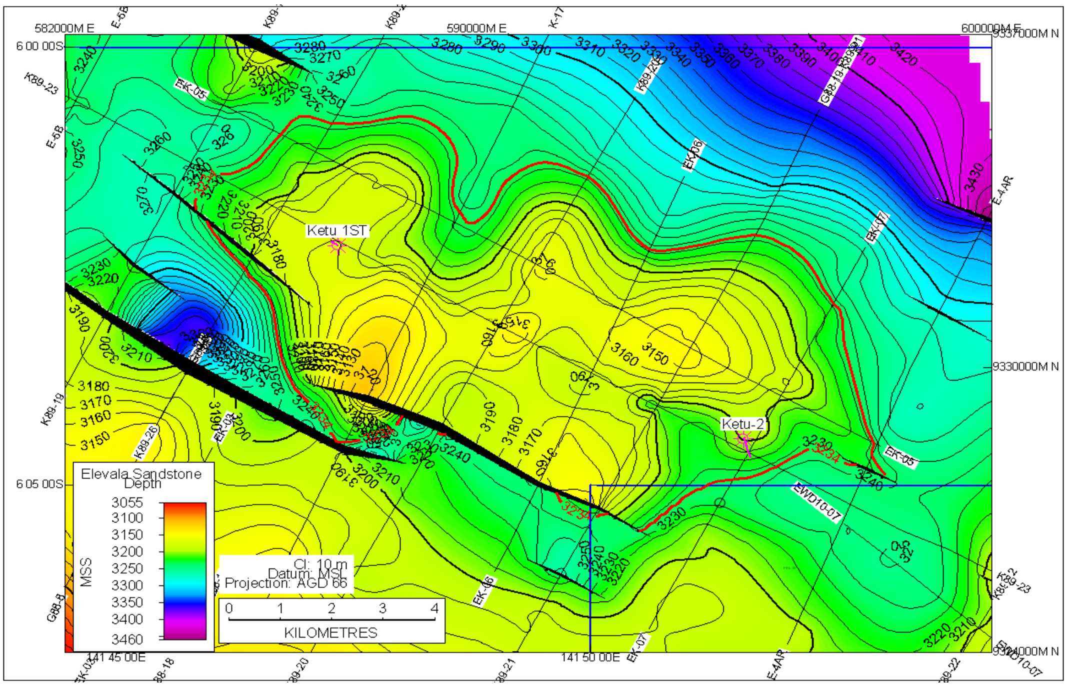


Figure 8-6 Ketu Field Elevala Reservoir Depth Structure Map

Static and dynamic modeling has been undertaken. RISC considers the reference case model reasonable. The reference case static models was used as the input for the dynamic modeling.

RISC has reviewed the reference case static and dynamic models and considers them fit for purpose given the project maturity level. Horizon intends to undertake further uncertainty modeling prior to the project FID decision in late 2014. RISC independently calculated a similar range of resources and therefore supports the resource ranges derived by Horizon shown in Table 8-3 .

| | **2C Gross Contingent Resource** | | |
|---|---|---|---|
| | Elevala | Ketu | Total |
| GIIP (Bcf) | 1258 | 522 | 1780 |
| Condensate in Place (MMstb) | 65.8 | 31.3 | 97.1 |
| Gross Gas EUR (Bcf) | 688 | 291 | 979 |
| Gross Condensate EUR (MMstb)[1] | 35.4 | 14.2 | 49.6 |
| 1. Volumes are for gas export scenario. Liquids stripping stand alone recovers 51 MMstb. | | | |

Table 8-3 Elevala and Ketu Gross 2C Contingent Resource Estimates as at 1 January 2014

### 8.2.2. Production and Cost forecast

RISC has evaluated two development cases:

**Liquids Stripping**
This concept is based on the following development:

- 5 wells, 2 producers and 2 injectors in Elevala and 1 producer in Ketu
- A gas plant similar in design to the Stanley gas plant, but with 3 production trains and a total production and injection capacity of 240mmscf/d (resulting in an annualized capacity of 210mmscf/d when downtime is taken into account).
- Condensate will be exported via a 60km pipeline to a new storage and ship loading facility located at Drimdemasuk on the Fly River (North of Kiunga).
- Total gross condensate production over the 20 year project life is 51 MMstb

**Liquids Stripping plus gas Export**
The facilities installed are identical to the liquids stripping project, however gas injection ceases after 3 years when 210 MMscf/d nameplate capacity gas sales to a 1.5 Mtpa nameplate capacity (1.3 Mtpa annual average) LNG project begins. It is assumed that the gas is sold on an ex-field basis, so no new facilities are required.

Total gross gas produced is 1,024 PJ with 49.6 MMstb of condensate.

#### *8.2.2.1. Cost and schedule estimates*

RISC has reviewed the Horizon cost and schedule basis for the Elevala and Ketu field development. We conclude that the project cost estimates are reasonable, but we consider the project schedule to achieve a start-up date of 1/1/2018 as proposed by Horizon may be optimistic.

Whilst we believe a 36 month project timeframe to be reasonable for the duration of the execution phase, We consider that, given the current position of the project, the requirement for JV and government and regulatory approvals will put pressure on the schedule. The specific cause and impact of delay is difficult to predict at this point, and we therefore have evaluated a sensitivity of a 12 month delay to start-up to the beginning of 2019. This also has some impact on project costs, and we have therefore revised the project costs in line with our expectations.

We note that Horizon have included a 20% contingency on the facility costs, and support this level of contingency at this point. We have compared estimated well costs with the currently proposed Stanley wells, and support the well costs on the basis of a standard US$35 million per well at this point.

RISC's Elevala-Ketu capital cost estimates are shown in Table 8-4.

|  | 1/1/2018 start up US$ Million | 1/1/2019 start up US$ Million |
|---|---|---|
| Development Planning (Pre FID) | 33 | 60 |
| Gas Plant | 388 | 390 |
| Pipeline | 210 | 210 |
| Terminal, Storage and Load out facilities | 40 | 40 |
| Roads | 55 | 55 |
| HSE, Regulatory, PM & Owners Costs | 52 | 55 |
| Contingency (20%) | 143 | 149 |
| Wells (5) | 175 | 175 |
| **Total Cost** | **1095** | **1135** |
| **Operating Cost/year** | **50** | **50** |

Table 8-4 Elevala-Ketu Gross Capital and Operating Costs - RISC estimate

Operating costs for the Elevala-Ketu development are approximately US$50 million per year including condensate transport costs. RISC has reviewed the operating costs and considers these costs reasonable. The capital and operating profiles for the 2018 and 2019 start up cases are shown in Figure 8-7and Figure 8-8.

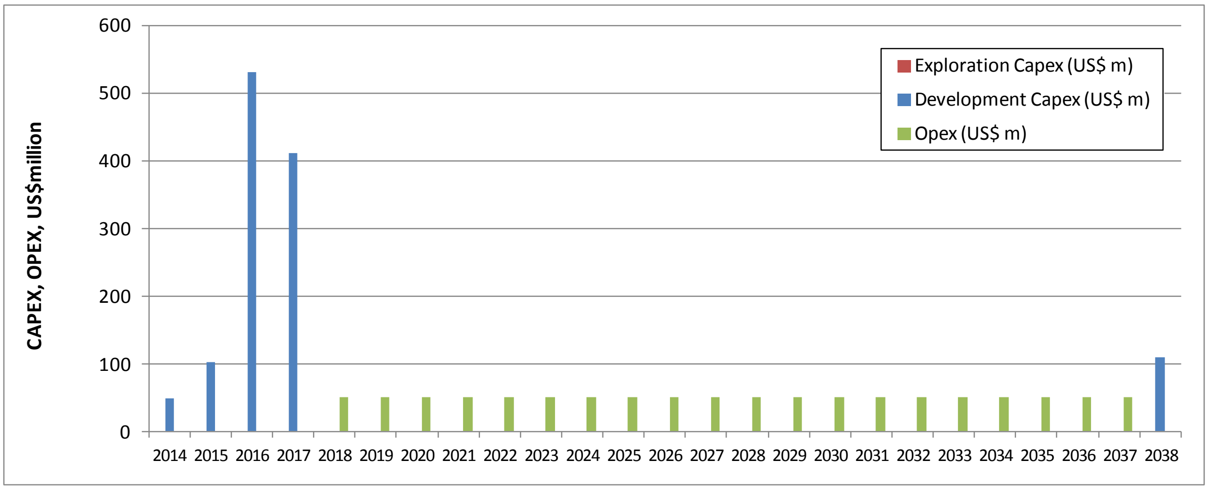


Figure 8-7 Elevela-Ketu Gross Cost Forecast - Liquids Stripping Only 1/1/2018 Start Up

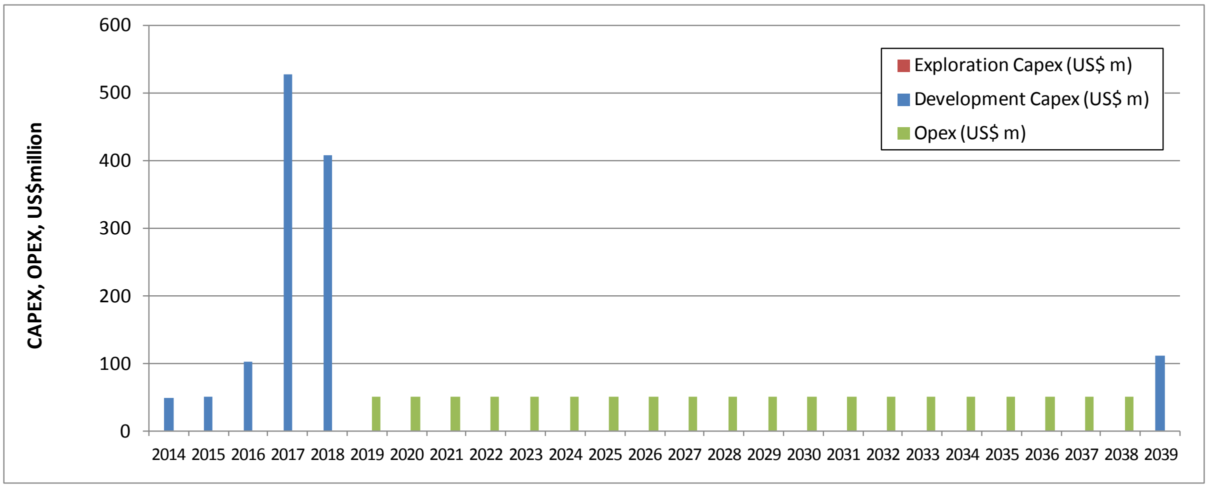


**Figure 8-8 Elevela-Ketu Gross Cost Forecast - Liquids Stripping Only 1/1/2019 Start Up**

#### *8.2.2.2. Production forecasts*

The condensate-gas ratio (CGR) for Elevala and Ketu gas has been derived from a number of downhole and surface samples of gas and condensate. After accounting for process yields, the expected produced initial CGR for Elevala gas is 52 bbls per MMSCF which will decline as lean gas breaks through in produces and the reservoir pressure decreases. Ketu gas, after similar process modeling, is expected to have an initial CGR of 57 bbls per MMSCF.

Horizon has generated dynamic simulation models of the Elevala and Ketu fields to evaluate a range of development and production concepts. RISC has reviewed the model inputs and made changes where necessary. Production forecasts have been generated by RISC for condensate stripping (with lean gas reinjected back into each field). Condensate stripping is assumed to commence in January 2018.The Elevala field is assumed to produce raw gas at a capacity of 140 MMSCFD, while the Ketu field is produced at 70 MMSCFD before condensate is stripped. Downtime of 13% has been assumed.

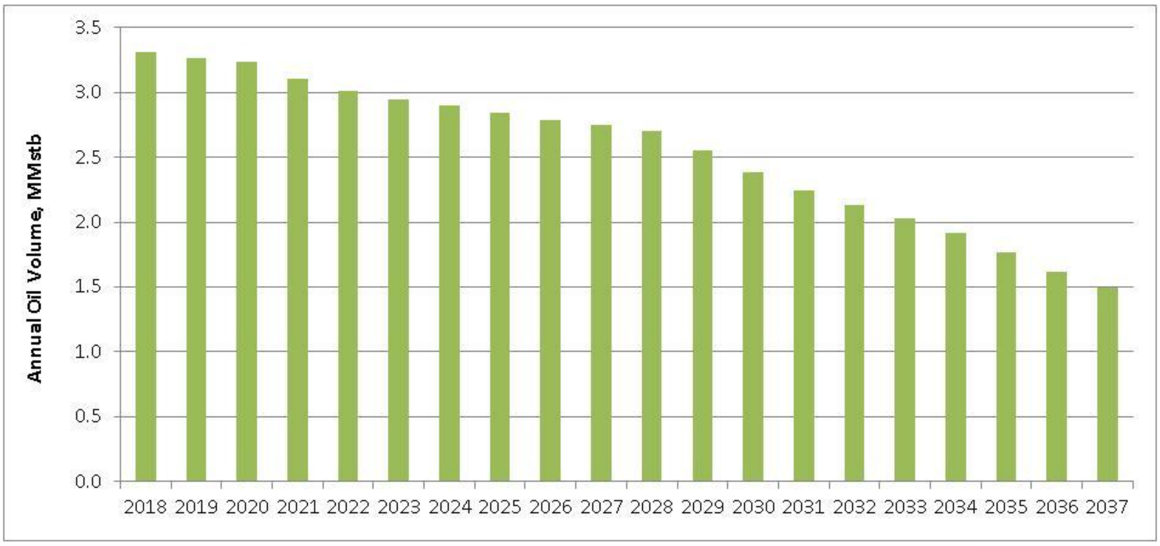


**Figure 8-9 Elevala-Ketu 2C Gross Production Forecast – Condensate stripping only**

RISC has also generated forecasts for a gas export development, whereby lean is reinjected back into the Elevala and Ketu fields  after condensate stripping for three years, by which time the lean gas is instead exported to an 1.5 MTPA LNG facility at an equivalent raw gas rate of 210 MMSCFD.

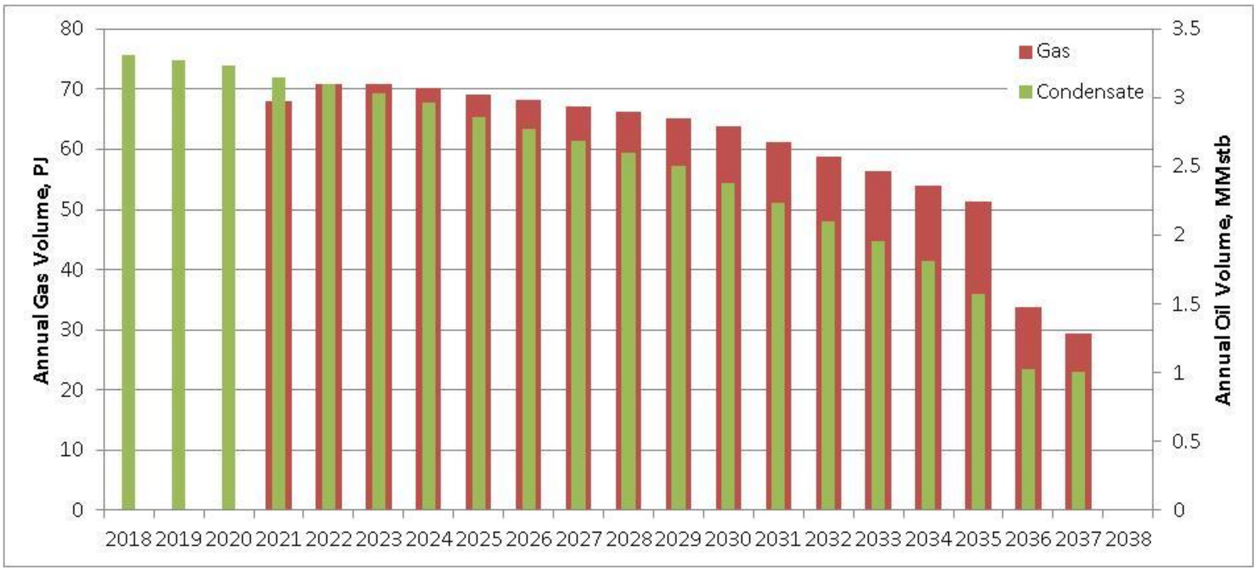


**Figure 8-10  Elevala-Ketu 2C Gross Production Forecast – Condensate stripping and gas export**

### 8.2.3. Gas Export (via Mid-scale LNG)

RISC has reviewed the estimated capital and operating costs provided by Horizon for their indicative netback pricing calculations.

The base scenario put forward by Horizon includes an export gas (and condensate) pipeline to Mugumugu, where a barge mounted LNG facility will be located. From here river shuttle tankers will export the LNG to Daru where they will load larger export sized tankers for the international LNG market. Horizon has allowed for 3 river carriers and 2 export carriers.

RISC considers the overall estimated CAPEX to be reasonable, however we have some concerns about the LNG transfer and export arrangements, and consider that an alternative scenario with an LNG export facility located at Daru provides a more robust scenario.

We consider that the proposed scheme will require an additional export carrier, and possibly an additional river carrier, to ensure LNG transfer operations do not significantly reduce system availability and performance. The export carriers will be to the cost of the gas offtaker, however they will incur significant demurrage costs due to the river export scheme which will affect the value of the product. To account for this, we have included the demurrage costs in the opex. In addition development planning costs (pre-FID) have been included (Table 8-5).

| | CAPEX US$ Million | OPEX US$ Million/year |
|---|---|---|
| Development Planning (Pre FID) | 50 | |
| Pipeline (Elevala-Mugumugu) | 580 | |
| LNG Plant (Barge) | 920 | 40 |
| Other CAPEX | 480 | 5 |
| LNG River Carriers | | 48 |
| Demurrage on LNG Export Carriers | | 37 |
| **TOTAL Cost** | **2030** | **130** |

**Table 8-5 Gas Export Infrastructure Gross Costs - RISC Estimate**

## 8.3. EXPLORATION

Horizon holds interests in  a number of permits in PNG with exploration potential (Figure 8-11).

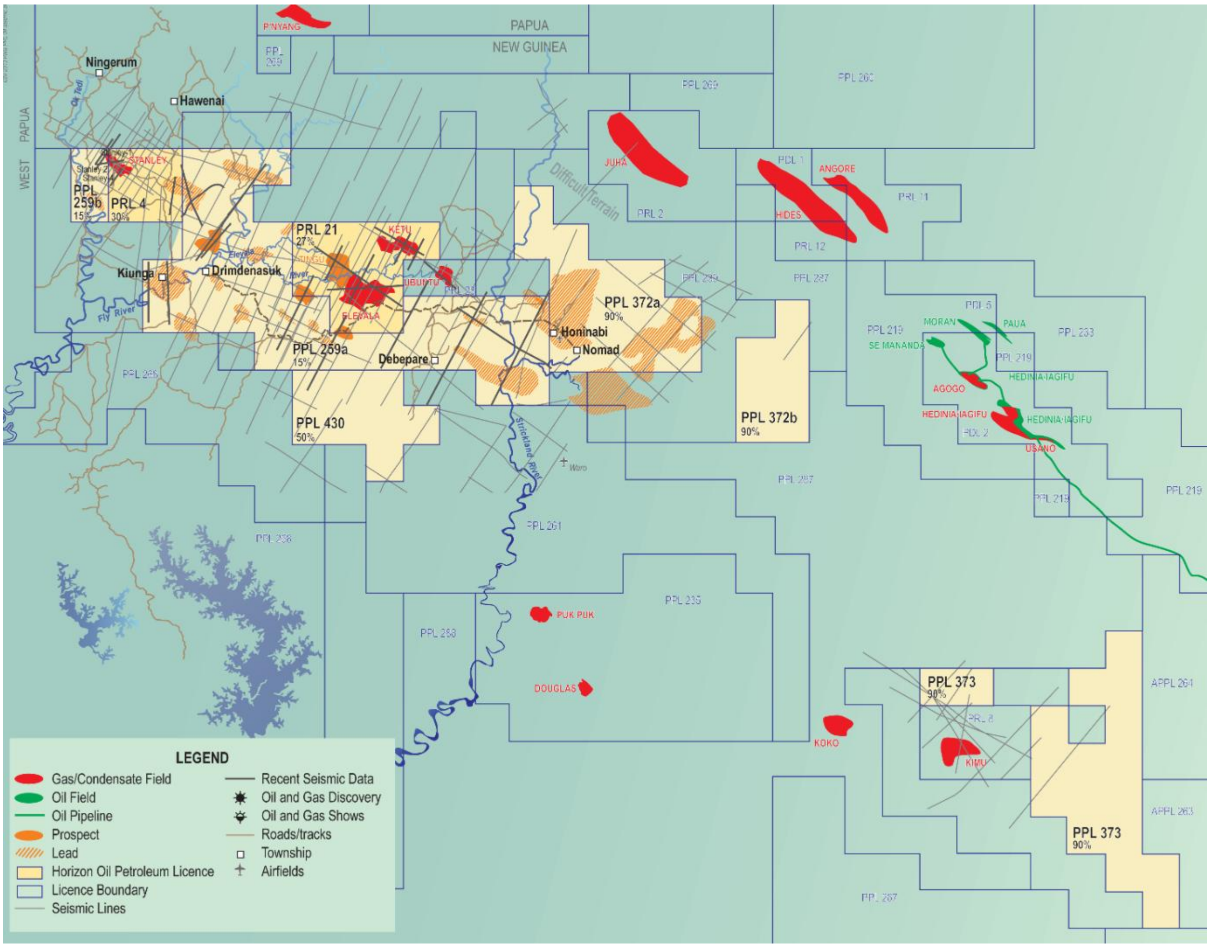


Figure 8-11 Horizon PNG Exploration Acreage

### 8.3.1. PRL 21

Potential exists in the Toro reservoir below the eastern and western crests of the Elevala Field, termed the Elevala Toro and the Tingu Toro prospects.

The Toro reservoir underlies the Elevala sandstone in the Elevala Field and is likely to underlie the Elevala reservoir in the Tingu Toro Prospect. The Elevala-1 well petrophysical analysis indicates gas saturations in the Toro reservoir, and the pressure readings taken across the reservoir indicate that this section could contain gas, which if the Ketu Field Toro reservoir aquifer pressures were taken into the Elevala Field might have a potential contact at 3,100 mTVDss.

The Toro reservoir has not been tested in either of the Elevala wells, however it was about to be tested in the Elevala-1 well, but the test encountered problems and the test tool was left in the well.

In order to calculate prospective resources for the Toro reservoir, areas were derived from the Toro depth map, supplied by Horizon. The Tingu area was measured with a high case immediately updip from the Tingu-1 well penetration, resulting in a P50 area of 12km$^2$. The Elevala Toro had 6.5km$^2$ updip from the wells, which was used as the P90 input and the area of closure to a possible gas-down-to of -3100m (58km$^2$) was used as the P10 input.

The reservoir parameters were derived from petrophysical analysis. The prospective resource ranges are tabulated below.

| Elevala Toro Reservoir Case | Elevala Toro Best Estimate | Tingu Toro Best Estimate | **Total Best Estimate** |
|---|---|---|---|
| GIIP (Bcf) | 71 | 43 | **114.0** |
| Condensate initially in-place (MMbbl) | 3.7 | 2.2 | **5.9** |
| Recoverable Gas (Bcf) | 39 | 23 | **62.0** |
| Recoverable Condensate (MMbbl) | 2 | 1.2 | **3.2** |

**Table 8-6 Tingu Toro Gross Best Estimate Prospective Resources as at 1 January 2014**

RISC considers that the Toro reservoir prospects underlying the two culminations in the Elevala Field have a POS of 50%.

**Exploration Valuation**

There are no further commitments on PRL 21.

The 2014 work program and budget mainly comprises development planning, plus technical costs, and direct costs and community affairs, leading to a budget of $38.4 million.

The low case value assumes the cost of deepening two development wells assuming no farmin promote, so the net value is zero.

The mid case value has been based on a risk adjusted value of the liquids in the 2 prospects of $4 million net to Horizon's 27% interest. The upside case assumes value for both liquids and gas of $20 million.

### 8.3.2. PPL259

Horizon holds a 35% interest in PPL 259 operated by Eaglewood Energy. PPL 259 lies between the Stanley and Elevala Fields and extends to the southeast of Elevala as shown in Figure 8-12.

The most mature exploration acreage is west PPL 259, where the Nama prospect, shown in Figure 8-12, located on the border between PPL 259 and PRL 4, will be drilled in Q3 2014.

Three further prospects: Herea, Bese and Aongena have been identified as further potential drilling candidates with a total of 180 Bcf (gross) P50 recoverable unrisked gas prospective resources and 6 MMbbl (gross) of condensate.

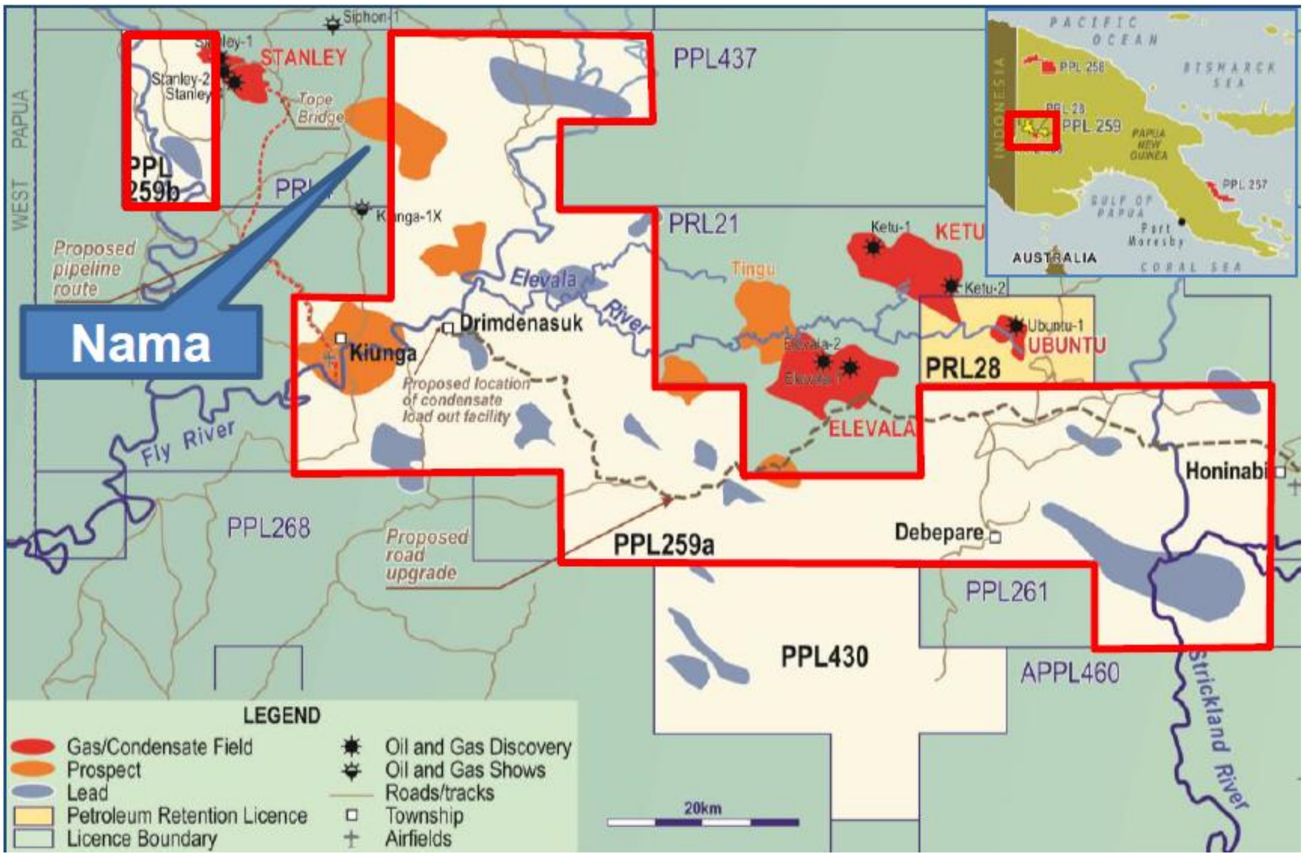


**Figure 8-12 PPL 259 Block Location and Prospects**

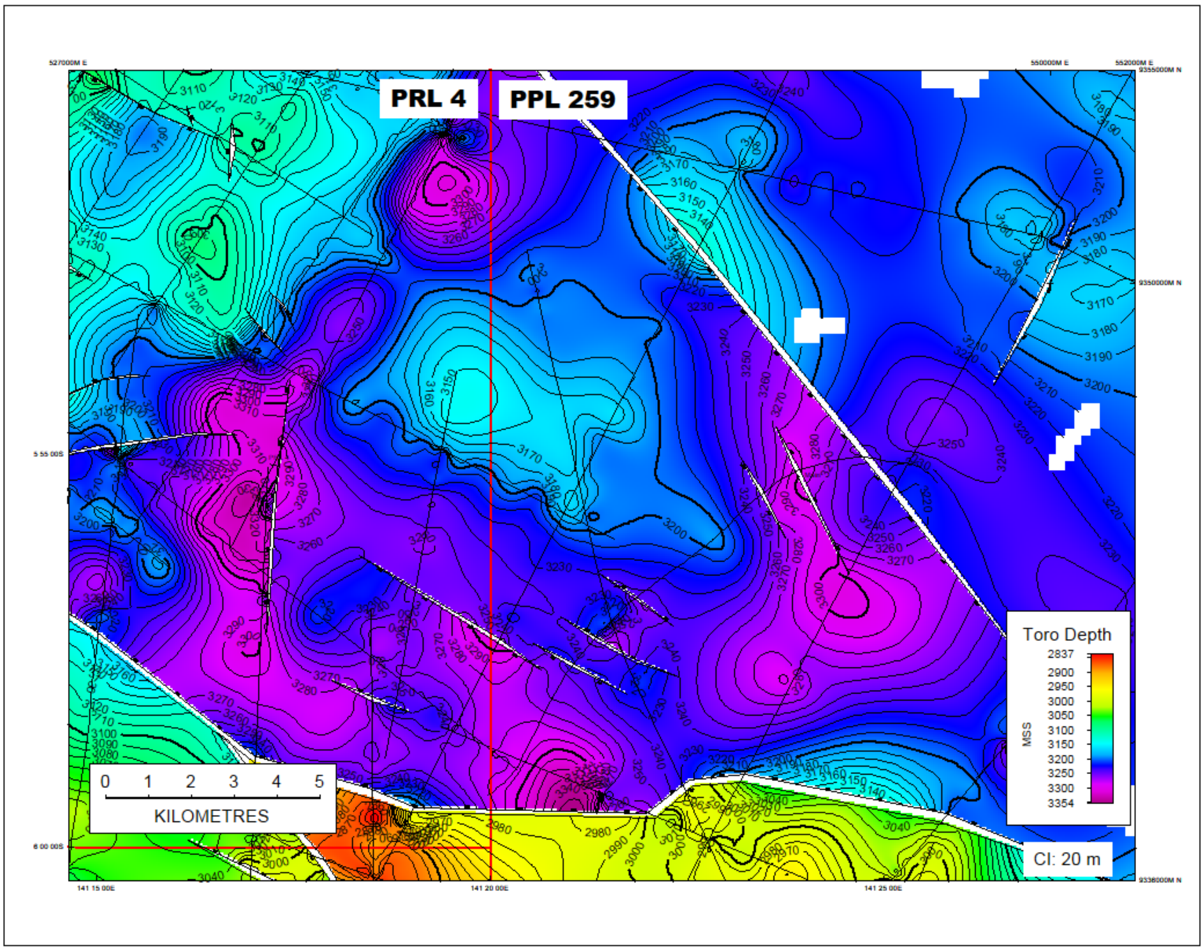


**Figure 8-13 PPL 259 Nama Prospect Toro Depth Structure Map**

The Nama prospect is defined on four seismic lines of varying vintage and is noted to be a fairly robust structure for which prospective resources have been calculated at the Toro reservoir level, however there is upside potential if either the Elevala or Kimu reservoirs. Eaglewood hold the following prospective resources for the Nama Prospect:

| Nama Prospect Case | Best Estimate |
|---|---|
| GIIP (Bcf) | 255 |
| Condensate in Place (MMbbl) | 5.4 |
| Recoverable Gas (Bcf) | 149 |
| Recoverable Condensate (MMbbl) | 2.9 |

**Table 8-7 Nama Prospect Gross Best Estimate Prospective Resources as at 1 January 2014**

RISC has independently calculated resource estimates for the Nama prospect and accept the Eaglewood prospective resource estimates above. The prospect is calculated to have a POS of 35%.

A portion of the prospect as mapped potentially lies in PRL4. For the purposes of this evaluation, RISC has not assumed a split as Horizon has comparable interests in PPL 259 and PRL 4 and is therefore the impact on the valuation is not material.

**Exploration Valuation**

PPL 259 has a seismic and a well commitment for 2014 with a further well to be drilled by 2016.

The technical part of the 2014 budget comprises firm expenditure of $45.4 million.

It is expected that the expenditure for 2015 and 2016 will be in the order of $50 million if a further exploration well is drilled.

Horizon is increasing its interest in PPL 259 by 20% from Eaglewood Energy Inc. by paying a contribution to back costs of $3.75 million and contribution of $5 million to Eaglewood for the next well, a total of $8.75 million for 20%. This values their 35% interest upon completion of the transaction at $15.3 million, which we have adopted as the low and mid fair market value.

The high case valuation has also been calculated on a $/boe basis, resulting in an upside value of another prospect success of $30 million after adjustment for risk, which is incremental to the farmin premium.

### 8.3.3. PPL 372 and PPL 373

Horizon also holds a 90% interest in PPL 372 and PPL 373, located to the southeast of PPL 259 (Figure 8-11). These permits are in an early stage of exploration.

In respect of PPL 372, the previous operator, Oil Search, identified two large leads in the permit, Honinabi and Mogulu North, on sparse, very poor quality seismic, and gravity and magnetic data.

The 2014 budget for PPL 372 and PPL373 each carry $0.5 million gross for studies and a contingent budget of $4.1 million for 2D seismic.

Horizon carries a fair value of $0.8 million for this transaction which we have adopted as the fair market value.

### 8.3.4. PPL 430

Horizon holds a 50% interest in PPL 430, located to the south of PPL 259. This permit is in an early stage of exploration, and as yet contains leads only.

License PPL 430 was awarded to Horizon (as Ketu Petroleum Ltd) and Eaglewood Energy each partner holding 50% on 25 July 2013.The firm commitment over the first two years of the licence is as follows:

- Data Collection and Analysis
- Sources and Migration Studies
- Geological Studies
- Seismic Reprocessing
- Seismic Acquisition (approximately 20km) and interpretation.

These are to be completed at a cost of no less than US$1.0 million

The 2014 firm work program comprises technical costs and community relations with a budget of $550,000 with a contingent work program of 50 km of 2D seismic acquisition at a total budget of $4.6 million.

The gross expenditure on PPL 430 will range from the commitment of US$1 million to the firm plus contingent exploration program of US$4.9 million.

We have assigned a value of $0.5 million for Horizon's interest in the high case in this permit based on the value of the permit commitment.

### 8.3.5. PNG Exploration Value Summary

A summary of the PNG exploration fair market value is shown in Table 8-8.

| Permit | Low<br>US$ million | Mid<br>US$ million | High<br>US$ million |
|---|---|---|---|
| PRL 21 | 0.0 | 4.0 | 20.0 |
| PPL 259 | 15.3 | 15.3 | 45.0 |
| PPL 372 and 373 | 0.8 | 0.8 | 0.8 |
| PPL 430 | 0.0 | 0.0 | 0.5 |
| **Total** | **16.1** | **20.1** | **66.3** |

Table 8-8 PNG Exploration Fair Market Value - Net Horizon Working Interest

# 9. MALAYSIA

## 9.1. D35/ J4/ D21

### 9.1.1. Field description

In April 2014, Roc announced a farm-in for a 50% participating interest in the D35/D21/J4 fields. Roc has subsequently reported the intention to farm-out a 20% participating interest, subject to PETRONAS approval.

The farm-in agreement includes amendments to the existing PSC effective from 1 January 2014 until December 2034. The PSC terms are designed for field redevelopment and enhanced oil recovery (EOR) to commercially encourage progressive incremental oil development over the full life of the PSC.

Geologically, the fields lie within the western Balingian province of the Sarawak Basin. The fields are located on the continental shelf offshore Eastern Malaysia within a licence area of 150 km2, in water depths of approximately 50 m. D35 is the largest of the three fields with the longest production history and represents a significant brownfield redevelopment project.  Within the D35 field boundary, there is evidence of significant appraisal and near-field exploration potential. J4 and D21 are satellite producing assets with similar potential and together they comprise the D35, D21 and J4 PSC.

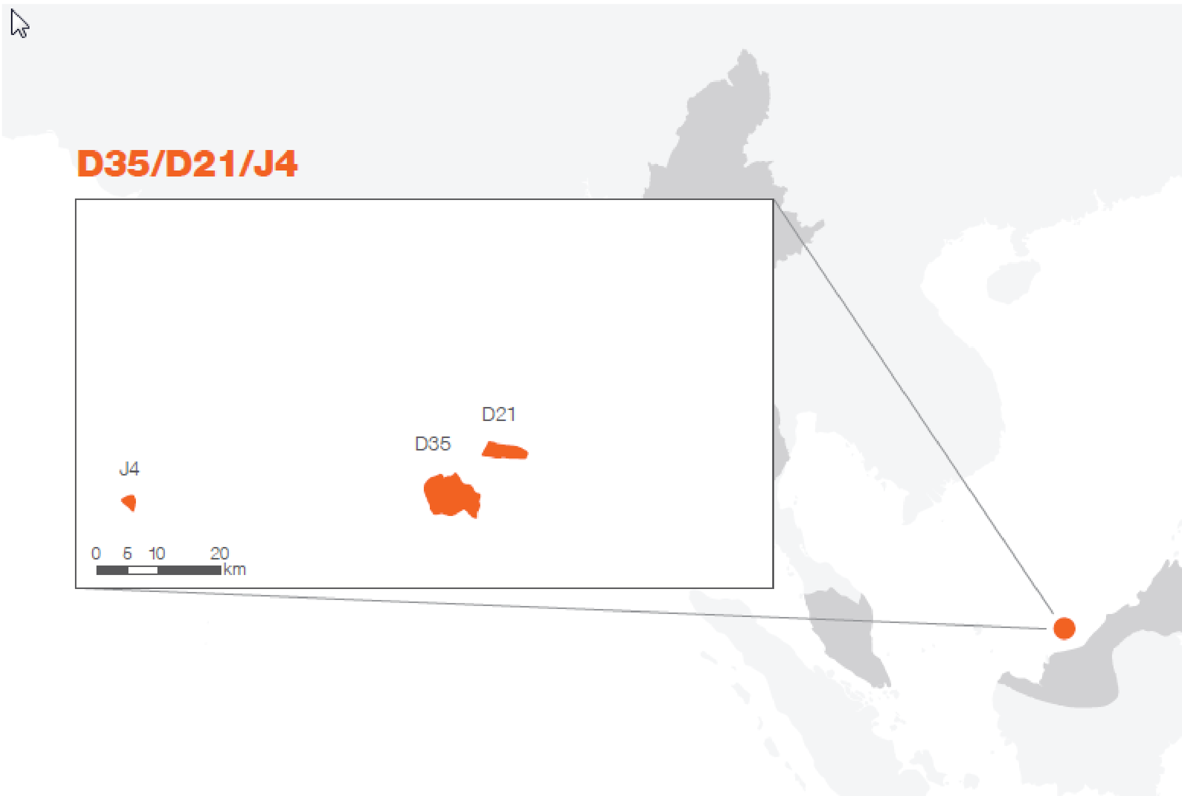


**Figure 9-1 Location Map – Malaysian Fields, offshore Sarawak**

In March 2014, the fields are currently producing 9,914 stb/d of oil (3,979 bbl/d from D35, 3,815 from J4 and 2,120 from D21). Roc has estimated that D35 contains a STOIIP in the range of 400-736 MMstb in the major and minor reservoirs plus further gas resources that are under review. Cumulative production to end 2013 is estimated at 86.6 MMstb of oil and 260 bcf of gas. RISC has not included structure maps in the report as they are deemed commercially sensitive.

In J4, Roc estimates a STOIIP of 41-117 MMstb with 67-183 bcf associated and solution gas. Cumulative production to end 2013 is estimated at approximately 12.2 MMstb of oil and 11.3 bcf of gas.

In D21, Roc estimates a STOIIP of 34-80 MMstb with 102-151 bcf of associated, non-associated and solution GIIP in the Cycle II reservoirs. Cumulative production to end 2013 is estimated at approximately 0.6 MMstb of oil and 0.6 bcf of gas.

The estimates presented herein should not be construed as being estimates supported by PETRONAS.

### 9.1.2. Production forecast

D35 and J4 are mature fields with established production history whereas D21 came onstream in 2013. D35 came onstream in 1994 and is located in 47m of water.

#### *9.1.2.1. Development description*

Roc's plans to redevelop the fields entail a number of progressive stages:

| SPE PRMS Category | Activity Description |
|---|---|
| **Reserves** | Arrest the decline of existing well stock and undertake a number of production enhancement activities including new wells |
| **Contingent Resources** | Additional wells and sidetracks contributing incremental oil production and water flood in the major reservoirs |
| | Introduction of EOR techniques |
| | Water flood in the minor reservoirs |

**Table 9-1 D35/J4/D21 further development stages**

Roc's forecast oil production for the successive stages is illustrated in Figure 9-2.

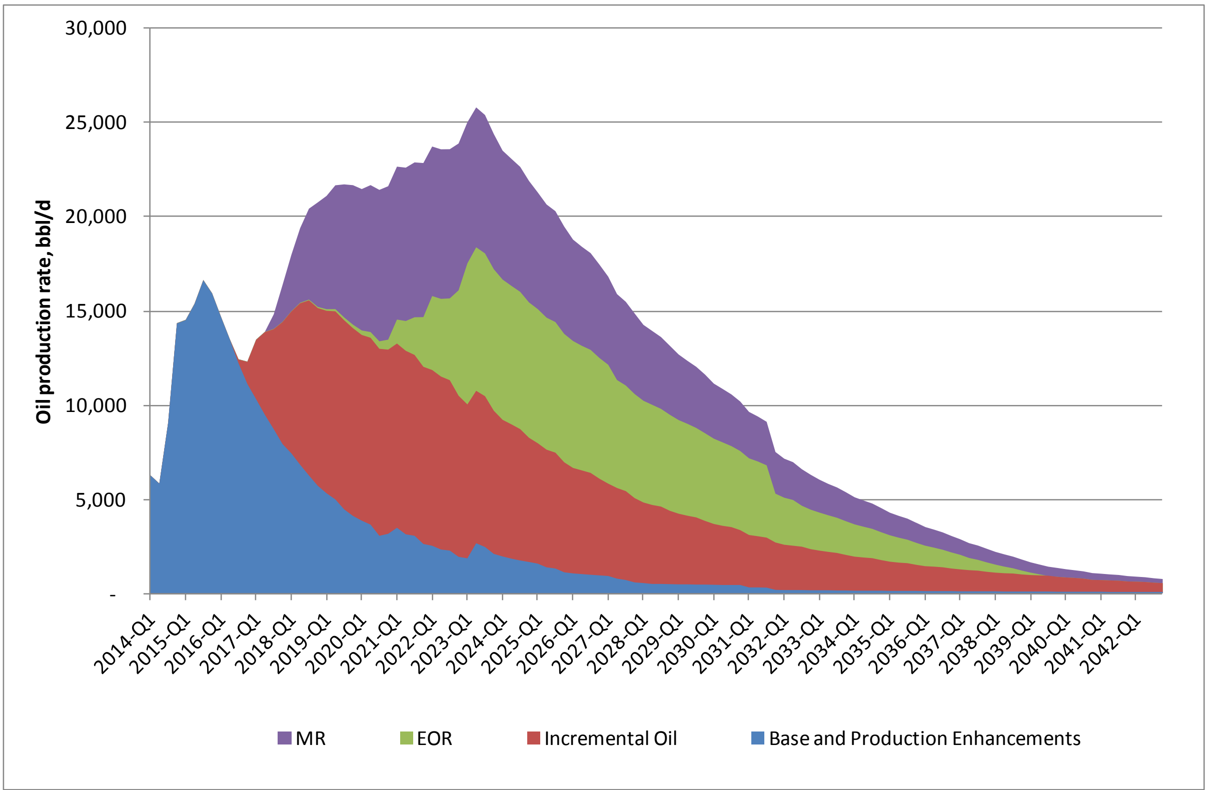


**Figure 9-2 Gross oil production forecast, D35/J4/D21- Roc estimates**

D35 is a 'hub' field with the largest infrastructure consisting of a central processing platform, 3 wellhead platforms, an accommodation and a riser platform. Oil export and gas export pipelines, connect the hub to shore.

Roc proposes a significant redevelopment of the field. Initially this will consist of wireline interventions, workovers and sidetracks from existing wells as well as drilling. The minimum work commitment is in 2 parts. Part 1 consists of the drilling of wells, 1 workover and preparation and submission of a redevelopment FDP. Part 2, subject to FID, consists of drilling more wells and the implementation of water injection, application of EOR and, upon success, extension of water injection to the minor reservoirs.

J4 consists of a wellhead platform with well test facilities tied back to D35 via a multiphase pipeline. Short term remedial activities consist of wireline work (mainly reperforations) and facilities rejuvenation. The Contingent Resources consist of a sidetrack and further work is anticipated.

D21 consists of wellhead platform with well test facilities tied back to D35 via a multiphase pipeline. The Contingent Resources of D21 consist of a development well, a recompletion, sidetrack and reperforations. An exploration well is also part of the proposed activity.

### Roc's reserve and resource estimates

Roc's reserves and resource estimates are shown in Table 9-2 allocated according to the recovery expected from future development activities. RISC has evaluated the reserves and resources at field and reservoir level but for reasons of commercial sensitivity has been requested to report aggregate PSC level quantities.

RISC has reviewed and supports the 2P Reserve and the incremental oil estimates subject to a further risk adjustment for the waterflood portion of the incremental oil. The EOR and minor reservoir incremental estimates have little definition at present and will be subject to the successful implementation of the incremental oil portion of the Contingent Resources. The EOR and minor reservoir estimates have not been risk adjusted.

| Product | Production 31/12/2013 | 2P Reserve | | | 2C Contingent Resource | | | |
|---|---|---|---|---|---|---|---|---|
| | | Total | Base | Production Enhancement | Total | Incremental Oil | EOR | Minor Reservoirs |
| Oil MMstb | 99.4 | 27.6 | 11.6 | 16.0 | 96.0 | 40.0 | 24.5 | 31.5 |
| Gas Bcf prod/sales | 272.1/222.1 | 42.9 | 41.7 | 1.2 | 71.9 | 71.9 | 0.0 | 0.0 |
| Note: Roc's working interest is 30% subject to finalisation of PETRONAS approval. Under PRMS guidelines, Roc's reserve and resource entitlement is determined by their net economic interest which is a function of the PSC terms, costs and prices prevailing during the PSC term. Depending on these factors, there may be a material difference between the working interest and Roc's net economic interest. | | | | | | | | |

Table 9-2 D35/J4/D21 Gross Reserves and Resources - Roc estimates as at 1 January 2014

Based on recent production performance, RISC has projected that there has been a further depletion of approximately 1 MMstb and 4 bcf gross from the period 1 January 2014 to 31 March 2014. The actual production during this period has yet to be confirmed.

### Base and production enhancement activities

Roc is forecasting oil recovery of 27.6 MMbbl gross from the existing field decline (11.6 MMbbl) and production enhancements (16 MMbbl). RISC considers that this is a reasonable total overall.

The three fields are currently producing approximately 10,000 bbl/d of oil, the production enhancement activities target an increase to approximately 17,000 bbl/d. Based on the production decline, RISC considers that the existing producers will recover the 11.6 MMbbl, which is a conservative estimate.

#### i. Incremental recovery from existing wells

RISC has undertaken a comprehensive review of logs for all gas and oil 'behind-pipe' opportunities in D35 for recompletion in the existing wells. In aggregate, RISC believes the Roc assessment is reasonable.

#### ii. Acceleration projects

There are a number of opportunities to accelerate production from sands in D35 that have already produced in the existing wells from activities such as reperforation and acidizing. Whilst the acceleration activities do not contribute substantially to the recovered volumes. RISC estimates rate improvements in excess of 2,000 bbl/d.

#### iii. Drilling activities

RISC has reviewed Roc's proposed infill drilling locations for D35 and has also independently generated infill drilling locations and recovery.

We note that there are risks to these infill well volumes and incremental projects, e.g. the sands have been pressure-depleted due to production from adjacent wells (which will reduce recovery factor and initial productivity), and that the GOC in each sand has expanded to below the depth of intersection due to pressure depletion (causing gas to be intersected rather than oil, reducing ultimate recovery). The production enhancement activities have accounted for the perceived technical risks.

RISC has not reviewed the production enhancement activities identified by Roc for J4, however, activities of a similar nature to those in D35 are expected. Overall a slightly conservative production forecast from the existing D35/J4/D21 wells negates the need to risk the J4 activities.

**Incremental oil production activities**

**i. Water injection**

These planned activities require a major investment in re-development through water flood designed to re-pressurize and sweep remaining oil accumulations and possible EOR applications that may further increase recovered volumes.

RISC has reviewed of the potential recovery following water injection into the D35 field and supports Roc’s estimate as an unrisked estimate of additional recovery from the application of water injection in the major reservoirs.

However, RISC notes that there are a number of characteristics of the D35 field that are potentially detrimental to efficient water flood:

- reservoir compartmentalisation - the field has a significant compartmentalisation, probably more than recognised by current mapping. Compartmentalisation is important in determining the location of water injection wells and the flow path of injected water; and
- some target reservoirs show a degree of vertical stratification.

Whilst neither of these factors precludes water injection they will result is some loss of efficiency which could lead to reduced recovery or additional costs.

RISC has estimated the incremental oil production rate from successful water injection estimated is 6,500 bbl/d in the mid case (unrisked). Roc will carry out studies and injection pilots before proceeding to full scale water injection. At this stage, there is uncertainty in the scope and conformance of the waterflood and we recommend risking the water injection project by 50%.

**ii. Further infill drilling**

RISC has reviewed the possible locations for additional drainage points targeting the minor reservoirs and considers additional recovery is achievable. RISC has not evaluated the economics of these wells.

Compartmentalisation of the minor reservoirs, both structural and stratigraphic, heightens the development risk in these reservoirs.

If the minor reservoirs are developed, the additional penetrations through the major sands will increase the chance of success of the water flood.

In aggregate, we recommend applying a technical risk factor of 70% to the Incremental Oil Contingent Resource.

**EOR**

Roc has considered the possible application of enhanced oil recovery (EOR) techniques to further the production from the field. EOR is a complex area of study and has not been addressed in detail other than to relate a possible EOR benefit to the produced water profile of the incremental oil. Roc has noted that typically, successful EOR projects can increase recovery by 10% in the swept areas of the reservoir. Roc estimates that the application of EOR techniques to suitable reservoirs could increase recovery by 10% and ascribes an additional 24.5 MMbbl recoverable. RISC has not quantified an EOR estimate but notes that the estimate appears high.

At this stage of development the EOR project is conceptual and dependent on results in the major reservoir waterflood project, which has yet to be demonstrated and we recommend applying a technical risk factor of not greater than 25%.

**Minor reservoirs (MR)**

Further primary development of the minor reservoirs has been considered in detail by RISC and is included in incremental oil activities. Roc has, in addition, indicated the possible introduction of water injection to these (minor) reservoirs for an additional 31.5 MMbbl recovery. Targeting these reservoirs will benefit from additional knowledge gained from earlier infill and water injection wells drilled to the main reservoirs.

At this stage of development the minor reservoir project is conceptual and dependent on results in the major reservoir waterflood project, which has yet to be demonstrated. There is also increased risk of lateral discontinuities in the minor reservoirs and we recommend applying a technical risk factor of not greater than 25%.

### 9.1.3. Capital and operating cost forecast

Roc estimate base case costs of $75 million for the D35/D21/J4 fields, this is mostly for D35 ($61 million) with small components for the other fields.

**Capital Costs**

Roc estimate base and production enhancement capital costs totaling $206m for the initial redevelopment of the 3 fields. This total includes $35 million for two exploration wells in the D35 field and $10.5 million for re-perforations in the J4. The remainder of the costs are for remedial well work, new wells and a new platform in the D35 field.

Costs for incremental oil activities will depend on the results of the FEED study and pilot water injection pilot but are estimated to be $837 million. This is mostly for additional facilities that will be required for water injection and water handling as well as new platforms and over 30 new wells. See Table 9-3 below for Capex breakdown.

It should be noted that the costs (and resources) for the incremental oil, EOR and minor reservoir projects are based on the assumption of a conceptual full field implementation. As discussed above the scope and benefit of these projects has yet to be finalised. It is not expected that the full capital would need to be deployed under the risked scenario.

| US$ million<br>RT 2014 | Base | Base and Production Enhancement | Incremental Oil | EOR | MR |
|---|---|---|---|---|---|
| D35 | 61 | 195 | 760 | 20 | 296 |
| D21 | 2 | | 55 | | |
| J4 | 12 | 11 | 21 | | |
| Total | 75 | 206 | 836 | 20 | 296 |

Table 9-3 D35/D21/J4 Gross Capex Summary – Roc estimates

All costs include 17% contingency.

### Abandonment Costs

The abandonment costs for the fields have been provided by Roc and are summarised below. RISC believes that these costs are reasonable.

| Project | Abandonment Costs (US$ million RT 2014) |
|---|---|
| Base + Production Enhancement | 50 |
| Incremental Oil | 80 |
| EOR | 0 |
| MR | 9.1 |

Table 9-4 Gross Abandonment Cost Summary – Roc estimates

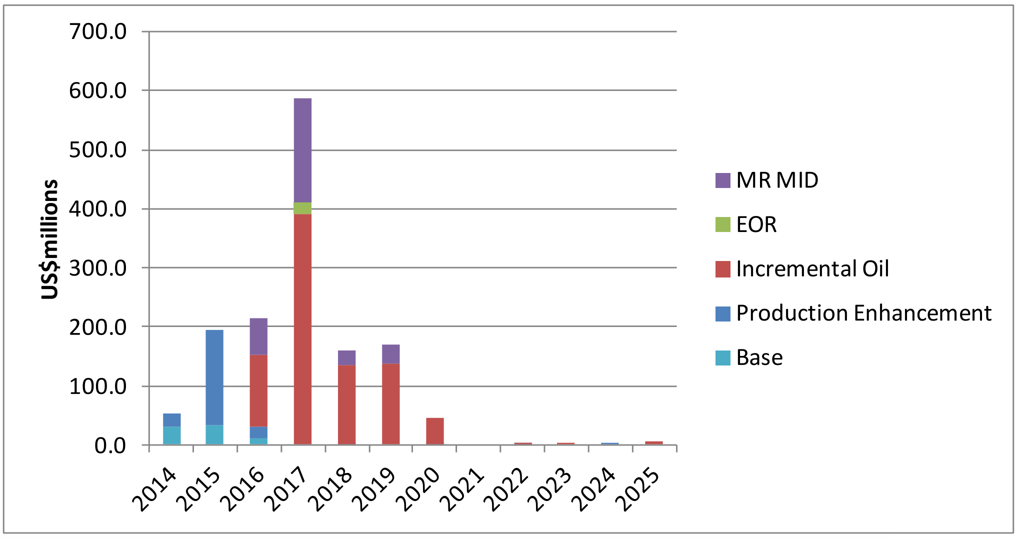


Figure 9-3 D35/D21/J4 Gross Capex Phasing – Roc estimates

#### Operating Costs

Due to limitations on the availability of cost data, Roc have estimated operating costs based on their experience rather than actual historical data.

The costs for the base case +production enhancement vary from $100 million to $75 million p.a. gross and then are steady in real terms after 2018. The increase related to incremental oil is from $12-18 million p.a. gross, the EOR increment is $5-6 million p.a. and the MR increment is $10 million p.a gross. These costs appear reasonable to RISC. See chart below for a summary of the costs.

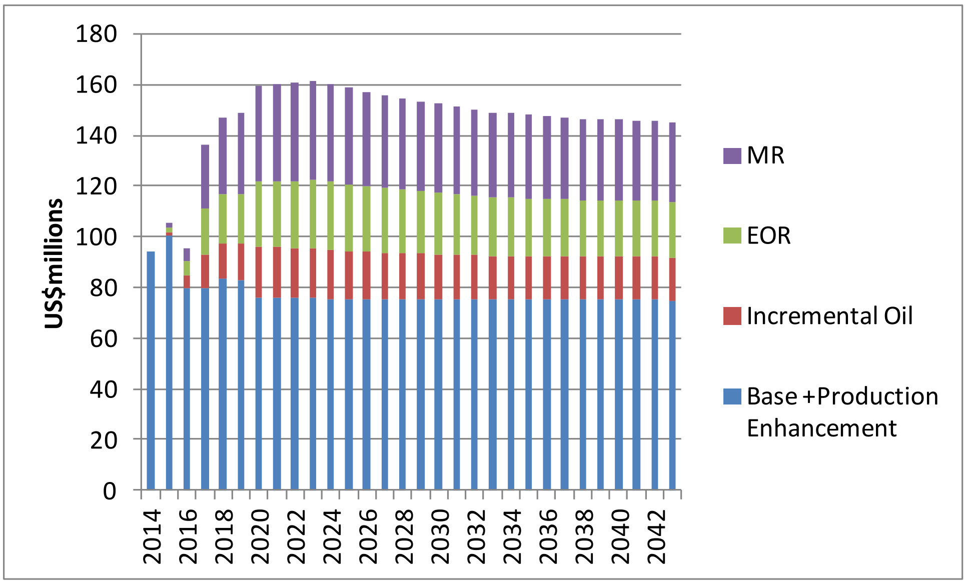


Figure 9-4 D35/D21/J4 Gross Opex Phasing – Roc estimates

## 9.2. BALAI CLUSTER

RISC did not carry out a technical review of the Balai Cluster Risked Service Contract. The Capex recovery profile has been assessed by the Independent Expert.

## 9.3. EXPLORATION

Roc has reviewed leads and prospects that had been identified in the vicinity of the D35 Field. We note the work of developing leads is at an early stage and further work on prospect risking and ranking will be undertaken.

RISC has not conducted its own independent review of the inventory and therefore we are not in a position to comment on the robustness of the technical interpretation. We note that about half of the leads are small and would not be justified for drilling on present volumetrics and risking. We have estimated the value of the exploration portfolio based on the information provided by Roc and made an adjustment for a notional drillable portfolio that could potentially materialise. We believe that 3-5 MMbbl (risked, Roc 30% working interest) of exploration potential could mature in a reasonable time frame.

Although dependent upon further review of the 3D seismic, Roc is sufficiently encouraged to suggest an exploration program to mature these prospects and leads. The notional program includes:

• One (1) Firm Exploration well

• One (1) Contingent Exploration well OR seismic work program

The net cost of the work program for Roc's 30% working interest is estimated to be $10.5 million.

In the low and mid cases, we have valued the exploration potential based on the work program and a notional farmin promote. In the low case, we have assumed that there is no promote. In the mid case, we have assumed a farmin partner could be attracted on the basis of a 2:1 promote. In the high case, we have recognised the potentially attractive nature of the near-field exploration and have assigned value based on prospective resources of 4 MMbbl Roc net working interest which after risk adjustment provides an expected monetary value (EMV) of $8 million incremental to the mid case farmin promote. RISC's estimates of fair market value is shown in Table 9-5.

| Low<br>US$ million | Mid<br>US$ million | High<br>US$ million |
|---|---|---|
| 0 | 10.5 | 18.5 |

**Table 9-5 Malaysia D35 Exploration Fair Market Value - Net Roc Working Interest**

# 10. MYANMAR

In March Roc was notified by the Myanmar Ministry of Energy (MOE) of the successful award of a PSC for a shallow water Block, M7, in the Moattama basin, offshore Myanmar (Figure 10-1).

The PSC award is subject to finalisation of terms with the MOE and Roc Board approval. Roc will hold a 59.375% interest and operate the licence. The other partners are Tap Oil 35.625% and Smart E&P International Ltd 5% carried interest.

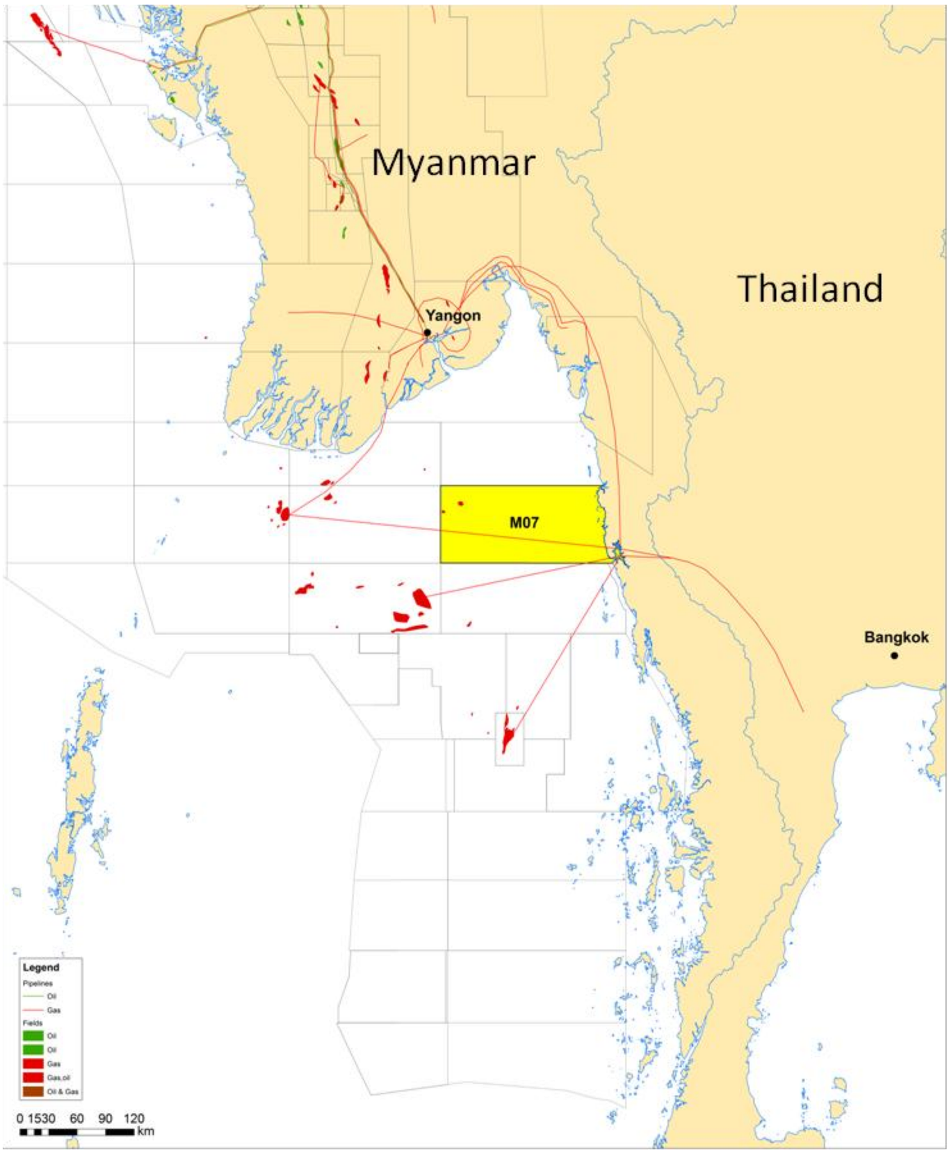


**Figure 10-1 Myanmar Block M7 Location Map**

The block award includes a provision for the JV to undertake an 18 month study of the existing seismic and well data which Roc are hoping to get from the MOE and an Environmental Impact Assessment. After this period the JV has the option to pay the signature bonus and enter into a three year exploration work program. Roc will pay 62.5% which includes a 3.125% share of the carry of Smart E&P International, its local partner.

RISC has reviewed the work program and considers it to be reasonable. The details of the bid programme is commercially confidential and is not disclosed in this report.

Block M7 covers approximately 13,000km2 and is 160 km east of the 6.7 Tcf GIIP Yadana gas field and 110km north east of the Zawtika biogenic gas field where reserves range from 435 Bcf to 2Tcf in multiple fault bounded Mio Pliocene delta front sandstones. The latter is consistent with the type of play in M7 however to date only two small uneconomic discoveries have been made in M7 in wells M-07-2 and Janaka-1. There are two other dry holes in the block and a reasonable grid of legacy 2D data.

Prospectivity in the block may be limited to the western side of the Sagaing Fault Zone (M7 West zone Figure 10-2) where the two small gas discoveries have been made. The area is highly faulted creating multiple small structures.

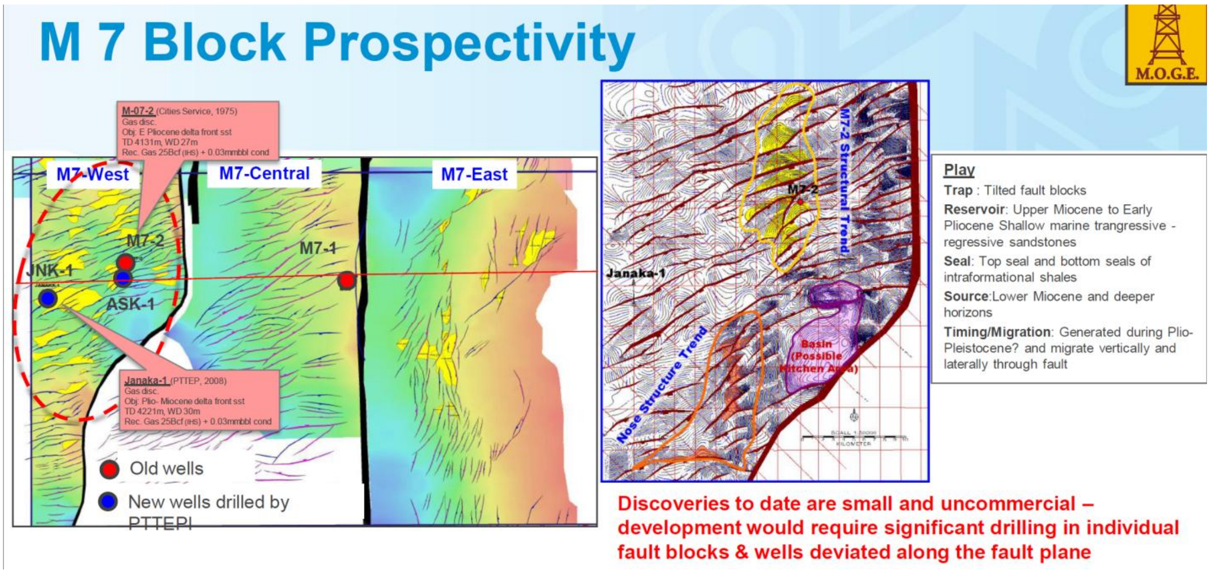


**Figure 10-2 M7 Block Prospectivity**

Due to the early stage of exploration in the block, we have valued the permit based on the value of the work program, which is estimated to be $2.75 million for the initial 18 months ($ 1.72 million net to Roc).

In the low case, we have not assigned a premium value so the net fair market value of the block is zero.

In the mid and high cases, value for this block might be crystallised by Roc farming down their interest for a carry on their initial period costs of $1.7 million on a 2:1 promote, therefore valuing their interest at $0 to $1.7 million (Table 10-1).

| Low<br>US$ million | Mid<br>US$ million | High<br>US$ million |
|---|---|---|
| 0 | 1.7 | 1.7 |

**Table 10-1 Myanmar M7 Block Exploration Fair Market Value - Net Roc Working Interest**

# 11. DECLARATIONS

## 11.1. QUALIFICATIONS

RISC is an independent oil and gas advisory firm. All of the RISC staff engaged in this assignment are professionally qualified engineers, geoscientists or analysts, each with many years of relevant experience and most have in excess of 20 years.

The preparation of this report has been supervised by Mr. Geoffrey Barker, RISC Partner. He has over thirty years of global experience in the upstream hydrocarbon industry, with extensive expertise in the areas of asset valuation, business strategies, evaluation of conventional and non-conventional petroleum (coal seam gas and tight gas), due diligence assessment for mergers, acquisitions and project finance requirements and reserves assessment/certification and preparation of Independent Technical Specialist reports. Mr. Barker is a Past Chairman of the SPE WA Section, a past member of the SPE International's Oil and Gas Reserves Committee 2007-2009, and is a co-author of the Guidelines for Application of the Petroleum Resources Management System published by the SPE in November 2011 (Chapter 8.5 Coal Bed Methane). Mr Barker is a Member of the Society of Petroleum Engineers (SPE),  and holds a BSc (Chemistry), Melbourne University, 1980 and a M.Eng.Sc (Pet Eng), Sydney University, 1989 and is a qualified petroleum reserves and resources evaluator (QPPRE) as defined by ASX listing rules.

RISC was founded in 1994 to provide independent advice to companies associated with the oil and gas industry. Today the company has approximately 40 highly experienced professional staff at offices in Perth and Brisbane, Australia and London, UK. We have completed over 1500 assignments in 68 countries for nearly 500 clients. Our services cover the entire range of the oil and gas business lifecycle and include:

- Oil and gas asset valuations, expert advice to banks for debt or equity finance;
- Exploration / portfolio management;
- Field development studies and operations planning;
- Reserves assessment and certification, peer reviews;
- Gas market advice;
- Independent Expert / Expert Witness;
- Strategy and corporate planning.

## 11.2. RELIANCE

This Report is to be relied upon by Deloitte Corporate Finance Pty Limited (Deloitte) acting as the Independent Expert. RISC Operations Pty Ltd (RISC) acknowledges that the Deloitte and the Directors of Horizon Oil Limited (Horizon) will use and place reliance on this Report in evaluating the proposed merger with Roc Oil Company Limited (Roc).

## 11.3. VALMIN CODE

This Report has been prepared in accordance with the Code for the Technical Assessment and Valuation of Mineral and Petroleum Assets and Securities for Independent Expert Reports 2005 Edition ("The VALMIN Code").

## 11.4. PETROLEUM RESOURCES MANAGEMENT SYSTEM

In the preparation of this Report, RISC has complied with the guidelines and definitions of the Petroleum Resources Management System approved by the Board of the Society of Petroleum Engineers in 2007 (PRMS).

## 11.5. REPORT TO BE PRESENTED IN ITS ENTIRETY

RISC has been advised by Horizon that this report will be presented in its entirety without summarisation.

## 11.6. INDEPENDENCE

This report does not give and must not be interpreted as giving, an opinion, recommendation or advice on a financial product within the meaning of section 766B of the Corporations Act 2001 or section 12BAB of the Australian Securities and Investments Commission Act 2001.

RISC is not operating under an Australian financial services licence in providing this report.

In accordance with regulation 7.6.01(1)(u) of the Corporations Regulation 2001. RISC makes the following disclosures:

- RISC is independent with respect to Horizon and Deloitte and confirms that there is no conflict of interest with any party involved in the assignment;
- Under the terms of engagement between RISC and Deloitte for the provision of this report RISC will receive a fee, based on time expended and our current standard terms and conditions, payable by Deloitte. The payment of this fee is not contingent on the outcome of any transaction between Deloitte, Horizon, Roc and other party;
- The Directors and staff of RISC involved in the preparation of this report hold no interest in Deloitte, Horizon or Roc.

## 11.7. LIMITATIONS

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

The statements and opinions attributable to RISC are given in good faith and in the belief that such statements are neither false nor misleading. In carrying out its tasks, RISC has considered and relied upon information obtained from Deloitte, Roc and Horizon as well as information in the public domain.

The information provided to RISC has included both hard copy and electronic information supplemented with discussions between RISC and key Horizon and Roc staff.

Whilst every effort has been made to verify data and resolve apparent inconsistencies, we believe our review and conclusions are sound, but neither RISC nor its servants accept any liability, except any liability which cannot be excluded by law, for its accuracy, nor do we warrant that our enquiries have revealed all of the matters, which an extensive examination may disclose. In particular, we have not independently verified property title, encumbrances or regulations that apply to this asset(s). RISC has also not audited the opening balances at the economic evaluation date of past recovered and unrecovered development and exploration costs, undepreciated past development costs and tax losses.

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

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

## 11.8. CONSENT

RISC has consented to this report, in the form and context in which it appears, being included in the Scheme of Arrangement for Horizon Oil Limited. Neither the whole nor any part of this report nor any reference to it may be included in or attached to any other document, circular, resolution, letter or statement without the prior consent of RISC.

This Report is authorised for release by Mr. Geoffrey Barker, RISC Partner dated 13 June 2014.

Geoffrey J Barker
Partner

# 12. LIST OF TERMS

The following lists, along with a brief definition, abbreviated terms that are commonly used in the oil and gas industry and which may be used in this report.

| Abbreviation | Definition |
|---|---|
| 1P | Equivalent to Proved reserves or Proved in-place quantities, depending on the context. |
| 1Q | 1st Quarter |
| 2P | The sum of Proved and Probable reserves or in-place quantities, depending on the context. |
| 2Q | 2nd Quarter |
| 2D | Two Dimensional |
| 3D | Three Dimensional |
| 4D | Four Dimensional – time lapsed 3D in relation to seismic |
| 3P | The sum of Proved, Probable and Possible Reserves or in-place quantities, depending on the context. |
| 3Q | 3rd Quarter |
| 4Q | 4th Quarter |
| AFE | Authority for Expenditure |
| Bbl | US Barrel |
| BBL/D | US Barrels per day |
| BCF | Billion (109) cubic feet |
| BCM | Billion (109) cubic meters |
| BFPD | Barrels of fluid per day |
| BOPD | Barrels of oil per day |
| BTU | British Thermal Units |
| BOE | barrels of oil equivalent<br>(equivalent to 1 bbl oil, 1 bbl condensate, 1 bbl NGL, 6,000 scf gas) |
| BOEPD | US barrels of oil equivalent per day |
| BWPD | Barrels of water per day |
| °C | Degrees Celsius |

| Abbreviation | Definition |
|---|---|
| Capex | Capital expenditure |
| CAPM | Capital asset pricing model |
| CGR | Condensate Gas Ratio – usually expressed as bbl/MMscf |
| 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 are a class of discovered recoverable resources as defined in the SPE-PRMS. |
| CO2 | Carbon dioxide |
| CP | Centipoise (measure of viscosity) |
| CPI | Consumer Price Index |
| DEG | Degrees |
| DHI | Direct hydrocarbon indicator |
| Discount Rate | The interest rate used to discount future cash flows into a dollars of a reference date |
| DST | Drill stem test |
| E&P | Exploration and Production |
| EG | Gas expansion factor. Gas volume at standard (surface) conditions / gas volume at reservoir conditions (pressure & temperature) |
| EIA | US Energy Information Administration |
| EMV | Expected Monetary Value |
| EOR | Enhanced Oil Recovery |
| ESP | Electric submersible pump |
| EUR | Economic ultimate recovery |
| Expectation | The mean of a probability distribution |
| F | Degrees Fahrenheit |
| FDP | Field Development Plan |
| FEED | Front End Engineering and design |
| FID | Final investment decision |

| Abbreviation | Definition |
|---|---|
| FM | Formation |
| FPSO | Floating Production Storage and offtake unit |
| FWL | Free Water Level |
| FVF | Formation volume factor |
| GIIP | Gas Initially In Place |
| GJ | Giga (109) joules |
| GOC | Gas-oil contact |
| GOR | Gas oil ratio |
| GRV | Gross rock volume |
| GSA | Gas sales agreement |
| GTL | Gas To Liquid(s) |
| GWC | Gas water contact |
| H2S | Hydrogen sulphide |
| HHV | Higher heating value |
| ID | Internal diameter |
| IRR | Internal Rate of Return is the discount rate that results in the NPV being equal to zero. |
| JV(P) | Joint Venture (Partners) |
| Kh | Horizontal permeability |
| km2 | Square kilometres |
| Krw | Relative permeability to water |
| Kv | Vertical permeability |
| kPa | Kilo (thousand) Pascals (measurement of pressure) |
| Mstb/d | Thousand Stock tank barrels per day |
| LIBOR | London inter-bank offered rate |
| LNG | Liquefied Natural Gas |
| LTBR | Long-Term Bond Rate |

| Abbreviation | Definition |
|---|---|
| m | Metres |
| Marathon | Marathon Oil Corporation |
| MDT | Modular dynamic (formation) tester |
| mD | Millidarcies (permeability) |
| MJ | Mega (106) Joules |
| MMbbl | Million US barrels |
| MMscf(d) | Million standard cubic feet (per day) |
| MMstb | Million US stock tank barrels |
| MOD | Money of the Day (nominal dollars) as opposed to money in real terms |
| MOU | Memorandum of Understanding |
| Mscf | Thousand standard cubic feet |
| Mstb | Thousand US stock tank barrels |
| Mtpa | Millions of tons per annum |
| MPa | Mega (106) pascal (measurement of pressure) |
| mss | Metres subsea |
| MSV | Mean Success Volume |
| mTVDss | Metres true vertical depth subsea |
| MW | Megawatt |
| NPV | Net Present Value (of a series of cash flows) |
| NTG | Net to Gross (ratio) |
| ODT | Oil down to |
| GIIP | Original Gas In Place |
| STOIIP | Original Oil in Place |
| Opex | Operating expenditure |
| OWC | Oil-water contact |
| P90, P50, P10 | 90%, 50% & 10% probabilities respectively that the stated quantities will be equalled or exceeded. The P90, P50 and P10 quantities correspond to the Proved |

| Abbreviation | Definition |
|---|---|
| | (1P), Proved + Probable (2P) and Proved + Probable + Possible (3P) confidence levels respectively. |
| PBU | Pressure build-up |
| PJ | Peta (1015) Joules |
| POS | Probability of Success |
| Possible Reserves | As defined in the SPE-PRMS, an incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Possible Reserves are those additional reserves which 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) 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. |
| Probable Reserves | As defined in the SPE-PRMS, an incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Probable Reserves are those additional Reserves that 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. |
| Prospective Resources | Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations as defined in the SPE-PRMS. |
| Proved Reserves | As defined in the SPE-PRMS, an incremental category of estimated recoverable volumes associated with a defined degree of uncertainty Proved Reserves are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. 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. Often referred to as 1P, also as "Proven". |
| PSC | Production Sharing Contract |
| PSDM | Pre-stack depth migration |
| PSTM | Pre-stack time migration |
| psia | Pounds per square inch pressure absolute |

| Abbreviation | Definition |
| --- | --- |
| p.u. | Porosity unit e.g. porosity of 20% +/- 2 p.u. equals a porosity range of 18% to 22% |
| PVT | Pressure, volume & temperature |
| QA/QC | Quality Assurance/ Control |
| rb/stb | Reservoir barrels per stock tank barrel under standard conditions |
| RFT | Repeat Formation Test |
| Real Terms (RT) | Real Terms (in the reference date dollars) as opposed to Nominal Terms of Money of the Day |
| Reserves | RESERVES are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status. |
| RT | Measured from Rotary Table or Real Terms, depending on context |
| SC | Service Contract |
| scf | Standard cubic feet (measured at 60 degrees F and 14.7 psia) |
| Sg | Gas saturation |
| Sgr | Residual gas saturation |
| SRD | Seismic reference datum lake level |
| SPE | Society of Petroleum Engineers |
| SPE-PRMS | Petroleum Resources Management System, approved by the Board of the SPE March 2007 and endorsed by the Boards of Society of Petroleum Engineers, American Association of Petroleum Geologists, World Petroleum Council and Society of Petroleum Evaluation Engineers. |
| s.u. | Fluid saturation unit. e.g. saturation of 80% +/- 10 s.u. equals a saturation range of 70% to 90% |
| stb | Stock tank barrels |
| STOIIP | Stock Tank Oil Initially In Place |
| Sw | Water saturation |
| TCM | Technical committee meeting |

| Abbreviation | Definition |
|---|---|
| Tcf | Trillion (1012) cubic feet |
| TJ | Tera (1012) Joules |
| TLP | Tension Leg Platform |
| TRSSV | Tubing retrievable subsurface safety valve |
| TVD | True vertical depth |
| US$ | United States dollar |
| US$ million | Million United States dollars |
| WACC | Weighted average cost of capital |
| WHFP | Well Head Flowing Pressure |
| Working interest | A company's equity interest in a project before reduction for royalties or production share owed to others under the applicable fiscal terms. |
| WPC | World Petroleum Council |
| WTI | West Texas Intermediate Crude Oil |

Level 2
1138 Hay Street
WEST PERTH WA 6005
P. +61 8 9420 6660
F. +61 8 9420 6690
E. admin@riscadvisory.com

Level 2
147 Coronation Drive
MILTON QLD 4064
P. +61 7 3025 3369
F. +61 7 3025 3300
E. admin@riscadvisory.com

53 Chandos Place
Covent Garden
LONDON WC2N 4HS
P. +44 20 7484 8740
F. +44 20 7812 6677
E. riscuk@riscpl.com

DIFC, The Gate Building
Level 15, Office 63
Sheikh Zayed Road
DUBAI UAE
P. +971 4 401 9875
F. +61 8 9420 6690
E. admin@riscadvisory.com

www.riscadvisory.com

*DECISIONS WITH CONFIDENCE*